Economic Impact Analysis of the Final Stationary Combustion Turbines NESHAP: Final Report

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Economic Impact Analysis of the Final Stationary Combustion Turbines NESHAP

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SELECT LIST OF ACRONYMS AND ABBREVIATIONS

CAA: Clean Air Act
CO: Carbon Monoxide
COPD: Chronic Obstructive Pulmonary Disease
CCCT: Combined-Cycle Combustion Turbine
C/S: Cost to Sales Ratio
DOE: Department of Energy
EO: Executive Order\
EPA: Environmental Protection Agency
EWG: Exempt Wholesale Generators
GW: Gigawatt
HAP: Hazardous Air Pollutant
ICCR: Industrial Combustion Coordinated Rulemaking
IPP: Independent Power Producer
kWh: Kilowatt Hour
lb: Pound
mills/kWh: Mills per Kilowatt Hour
mmBTU: Millions of British Thermal Units
MACT: Maximum Achievable Control Technology
MW: Megawatts
Mwh: Megawatt Hours
NAAQS: National Ambient Air Quality Standards
NAICS: North American Industrial Classification System
NESHAP: National Emission Standards for Hazardous Air Pollutants
NPR: Notice of Proposed Rulemaking
NSPS: New Source Performance Standards
NSR: New Source Review
OMB: Office of Management and Budget
O&M: Operation and Maintenance
P/E: Partial Equilibrium
PM: Particulate Matter
ppbdv: Parts Per Billion, dry volume
ppm: Parts Per Million
PRA: Paperwork Reduction Act of 1995
RFA: Regulatory Flexibility Act
SAB: Science Advisory Board
SBA: Small Business Administration

SBREFA:	Small Business Regulatory Enforcement Fairness Act of 1996
SCCT:	Simple-Cycle Combustion Turbine
SIC:	Standard Industrial Classification
SOA:	Secondary Organic Aerosols
TAC:	Total Annual Cost
tpd:	Tons Per Day
tpy:	Tons Per Year
UMRA:	Unfunded Mandates Reform Act
VOCs:	Volatile Organic Compounds

SECTION 1

INTRODUCTION

The U.S. Environmental Protection Agency (referred to as EPA or the Agency) is developing regulations under Section 112 of the Clean Air Act (CAA) for new stationary combustion turbines. The majority of stationary combustion turbines burn natural gas and are used in the electric power and natural gas industries. The regulations are designed to reduce emissions of hazardous air pollutants (HAPs) generated by the combustion of fossil fuels in combustion turbines. The primary HAPs emitted by turbines include formaldehyde, acetaldehyde, toluene, and benzene. To inform this rulemaking, the Innovative Strategies and Economics Group (ISEG) of EPA's Office of Air Quality Planning and Standards (OAQPS) has developed an economic impact analysis (EIA) to estimate the potential social costs of the regulation. This report presents the results of this analysis in which a market model was used to analyze the impacts of the air pollution rule on society.

1.1 Agency Requirements for an EIA

Congress and the Executive Office have imposed statutory and administrative requirements for conducting economic analyses to accompany regulatory actions. Section 317 of the CAA specifically requires estimation of the cost and economic impacts for specific regulations and standards proposed under the authority of the Act. In addition, Executive Order (EO) 12866 requires a more comprehensive analysis of benefits and costs for *significant* regulatory actions.[1] Other statutory and administrative requirements include examination of the composition and distribution of benefits and costs. For example, the Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement and Fairness Act of 1996 (SBREFA), requires EPA to consider the economic impacts of regulatory actions on small entities. Also, Executive Order 13211 requires EPA to consider for particular rules the impacts on energy markets.

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[1]Office of Management and Budget (OMB) guidance under EO 12866 stipulates that a full benefit-cost analysis is required only when the regulatory action has an annual effect on the economy of $100 million or more.

1.2 Scope and Purpose

The CAA's purpose is to protect and enhance the quality of the nation's air resources (Section 101(b)). Section 112 of the CAA Amendments of 1990 establishes the authority to set national emissions standards for HAPs. This report evaluates the economic impacts of pollution control requirements placed on stationary combustion turbines under these amendments. These control requirements are designed to reduce releases of HAPs into the atmosphere.

To reduce emissions of HAPs, the Agency establishes maximum achievable control technology (MACT) standards. The term "MACT floor" refers to the minimum control technology on which MACT standards can be based. For existing major sources, the MACT floor is the average emissions limitation achieved by the best performing 12 percent of sources (if there are 30 or more sources in the category or subcategory). For new sources, the MACT floor must be no less stringent than the emissions control achieved in practice by the best controlled similar source. The MACT can also be chosen to be more stringent than the floor, considering the costs and the health and environmental impacts. Emissions reductions and the costs associated with the regulation are based primarily on the installation of an oxidation catalyst emission control device, such as a carbon monoxide (CO) oxidation catalyst. These control devices are used to reduce CO emissions and are currently installed on several stationary combustion turbines. In addition, performance testing is required of all affected stationary combustion turbines.

The regulation affects new stationary combustion turbines over 1 megawatt (MW). This analysis uses data from EPA's Inventory Database V.4—Turbines (referred to as the Inventory Database). To estimate the economic impacts associated with the regulation, new stationary combustion turbines are projected through the year 2005.

1.3 Organization of the Report

The remainder of this report is divided into six sections that describe the methodology and present results of this analysis:

- Section 2 provides background information on combustion turbine technologies and compares the equipment, installation, and operating costs of simple-cycle combustion turbines (SCCTs) and combined-cycle combustion turbines (CCCTs).
- Section 3 provides background information on the regulatory alternatives examined, information on the emission reductions associated with the rule, and health effects from exposure to the HAPs emitted by combustion turbines.

- Section 4 provides projections of new stationary combustion turbines through the year 2005. This section also profiles the population of existing turbines.
- Section 5 profiles the electric service industry (NAICS 221), oil and gas extraction industry (NAICS 211), and the natural gas pipeline industry (NAICS 486).
- Section 6 presents the methodology for assessing the economic impacts of the NESHAP and describes the computerized market model used to estimate the social cost impacts and to dissagregate impacts into changes in producer and consumer surplus.
- Section 7 presents the economic impact estimates for the NESHAP and describes the control alternatives used to estimate the impacts. This section also discusses the regulation's impact on energy supply, distribution, and use.
- Section 8 provides the Agency's analysis of the regulation's impact on small entities.

In addition to these sections, Appendix A details the market model approach used to predict the economic impacts of the NESHAP. Appendix B describes the limitations of the data and market model and presents sensitivity analyses associated with key assumptions.

SECTION 2

COMBUSTION TURBINE TECHNOLOGIES AND COSTS

This section provides background information on combustion turbine technologies. Included is a discussion of simple-cycle combustion turbines (SCCTs) and combined-cycle combustion turbines (CCCTs), along with a comparison of fuel efficiency and capital costs between the two classes of turbines.

2.1 Simple-Cycle Combustion Turbine Technologies

Most stationary combustion turbines use natural gas to generate shaft power that is converted into electricity.[1] Combustion turbines have four basic components, as shown in Figure 2-1.

1. The compressor raises the air pressure up to thirty times atmospheric.

2. A fuel compressor is used to pressurize the fuel.

3. The compressed air is heated in the combustion chamber at which point fuel is added and ignited.

4. The hot, high pressure gases are then expanded through a power turbine, producing shaft power, which is used to drive the air and fluid compressors and a generator or other mechanical drive device. Approximately one-third of the power developed by the power turbine can be required by the compressors.

Electric utilities primarily use simple-cycle combustion turbines as peaking or backup units. Their relatively low capital costs and quick start-up capabilities make them ideal for partial operation to generate power at periods of high demand or to provide ancillary services, such

[1]Combustion turbine technology used for aircraft engines is virtually the same except the energy is used to generate thrust.

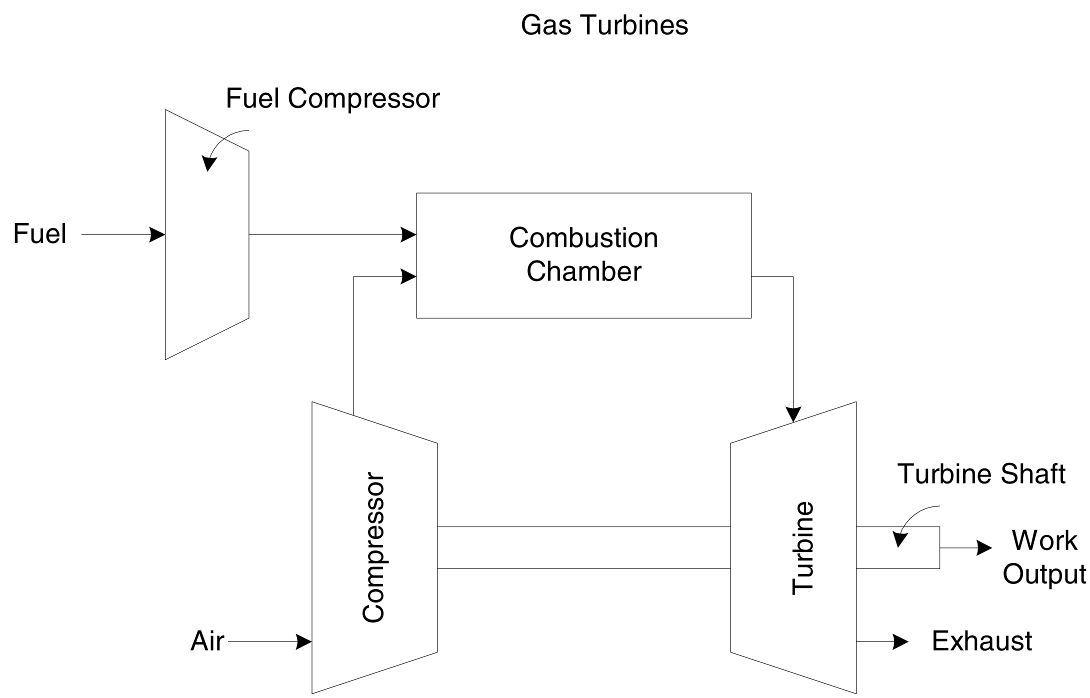

Figure 2-1. Simple-Cycle Gas Turbine

Source: Hay, Nelson E., ed. 1988. *Guide to Natural Gas Cogeneration*. Lilburn, GA: The Fairmont Press, Inc.

as spinning reserves or black-start back-up capacity.[2] The disadvantage of simple-cycle systems is that they are relatively inefficient, thus making them less attractive as base load generating units.

2.2 Combined-Cycle Combustion Turbines Technologies

The combined-cycle system incorporates two simple-cycle systems into one generation unit to maximize energy efficiency. Energy is produced in the first cycle using a

[2]Spinning reserves are unloaded generating capacity that is synchronized to the grid that can begin to respond immediately to correct for generation/load imbalances caused by generation and transmission outages and that is fully available within 10 minutes. Black-start capacity refers to generating capacity that can be made fully available within 30 to 60 minutes to back up operating reserves and for commercial purposes.

gas turbine; then the heat that remains is used to create steam, which is run through a steam turbine. Thus, two single units, gas and steam, are put together to minimize lost potential energy.

The second cycle is a steam turbine. In a CCCT, the waste heat remaining from the gas turbine cycle is used in a boiler to produce steam. The steam is then put through a steam turbine, producing power. The remaining steam is recondensed and either returned to the boiler where it is sent through the process again or sold to a nearby industrial site to be used in a production process. Figure 2-2 shows a gas-fired CCCT.

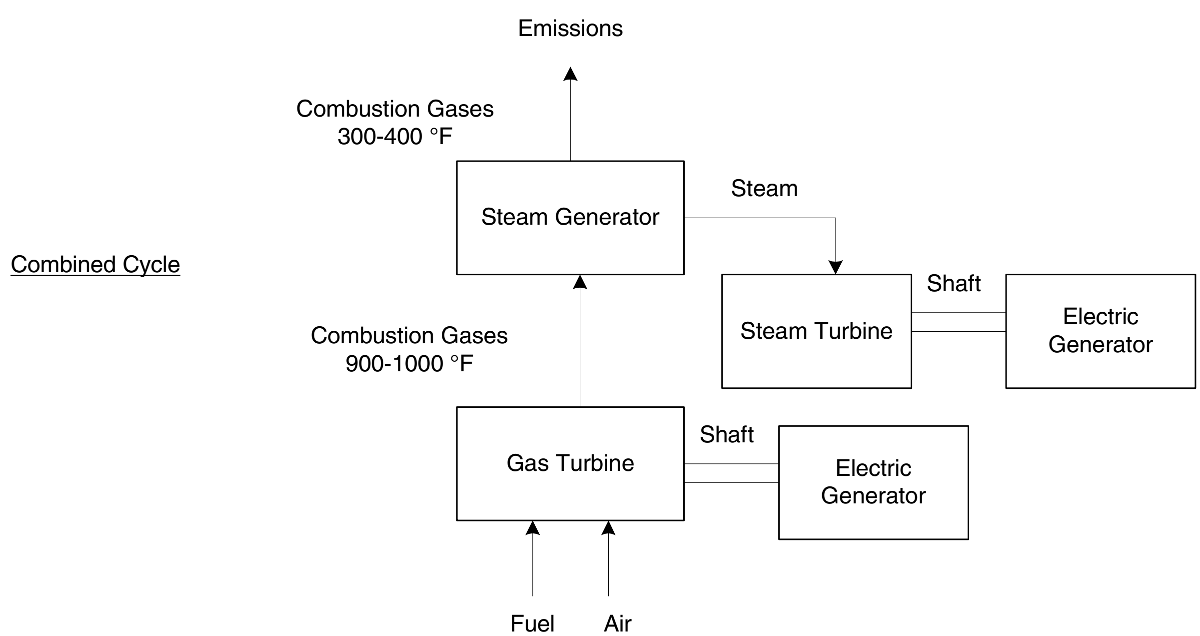

Figure 2-2. Combined-Cycle Gas Turbine

Source: Siemens Westinghouse. August 31, 1999. Presentation.

There are significant efficiency gains in using a combined-cycle turbine compared to simple-cycle systems. With SCCTs, adding a second stage allows for heat that otherwise would have been emitted and completely wasted to be used to create additional power or steam for industrial purposes. For example, a SCCT with an efficiency of 38.5 percent, adding a second stage increases the efficiency to 58 percent, a 20 percent increase in efficiency (Siemens, 1999). General Electric (1999) has recently developed a 480 MW system that will operate at 60 percent net combined-cycle efficiency.

In addition to energy efficiency gains, CCCTs also offer environmental efficiency gains compared to existing coal plants. In addition, efficiency gains associated with the CCCT lead to lower emissions compared to SCCTs. As Table 2-1 shows, the 58 percent efficiency turbine decreases NO_x emissions by 14 percent over simple-cycle combustion turbines and 89 percent over existing coal electricity generation plants. In addition, CO_2 emissions will be 5 percent lower than emissions from SCCTs and 64 percent lower than existing coal plants.

Table 2-1. Comparison of Emissions from Coal-Fired and Simple-Cycle Turbines and Combined-Cycle Turbines

	NO_x (lb/MW-hr)	CO_2 (lb/MW-hr)
Coal electricity generation	5.7	2,190
Simple-cycle turbines	0.7	825
Combined-cycle turbines	0.6	780

Source: Siemens Westinghouse. August 31, 1999. Presentation.

2.3 Capital and Installation Costs

CCCT capital and installation costs are approximately 30 percent less ($/MW) than a conventional coal or oil steam power plant's capital and installation costs, and CCCT costs are likely to decrease over the next 10 years. Gas turbine combined-cycle plants range from approximately $300 per kW installed for very large utility-scale plants to $1,000 per kW ($1998) for small industrial cogeneration installation (*GTW Handbook*, 1999). However, the prices of construction can vary as a result of local labor market conditions and the geographic conditions of the site (*GTW Handbook*, 1999). SCCTs are approximately half the cost of CCCT units.

Table 2-2 breaks down the budgeted construction costs of a gas-fired 107 MW combined-cycle cogenerating station at John F. Kennedy International Airport that was

Table 2-2. Overall Installation Costs

Construction costs can vary dramatically. This table shows the budgeted cost for a gas-fired 107 MW combined-cycle cogenerating station at John F. Kennedy International Airport in Brooklyn, New York. The power plant uses two 40 MW Stewart & Stevenson LM6000 gas turbine generators each exhausting into a triple pressure heat recovery steam generator raising steam for processes and to power a nominal 27 MW steam turbine generator. Budgeted prices are in 1995–1996 U.S. dollars.

Budget Equipment Pricing	**$ Amount**
Gas turbine generators	$24,000,000
Heat recovery steam generators	10,000,000
Steam turbine generator set	4,000,000
Condenser	300,000
Cooling towers	800,000
Transformer and switchgear	8,000,000
Balance of plant equipment	7,500,000
Subtotal, equipment	$54,600,000
Budget Services and Labor	
Mechanical and electrical construction	$20-75,000,000
Engineering	4,000,000
Subtotal, services	$24-79,000,000
Total Capital Cost	**$78,600,000-133,600,000**

Source: *1998–99 GTW Handbook*. "Turnkey Combined Cycle Plant Budget Price Levels." Fairfield, CT: Pequot Pub. Pgs. 16–26.

installed several years ago. As shown in Table 2-2, the construction price can range dramatically. This job finished near the top of the budget, close to $133,600,000. According to *Gas Turbine World*, the typical budget price for a 168 MW plant is $80,600,000, ($480/kW) for a plant with net efficiency of 50.9 percent (*GTW Handbook*, 1999).

2.4 O&M Costs Including Fuel

Fuel accounts for one-half to two-thirds of total production costs (annualized capital, operation and maintenance, fuel costs) associated with generating power using combustion turbines. Table 2-3 compares the percentage of costs spent on annualized capital, operation and maintenance, and fuel for both simple turbines and CCCTs.

Table 2-3. Comparison of Percentage of Costs[a]

	Simple Cycle	Combined Cycle
% Capital costs	50	25
% Operation and maintenance	10	10
% Fuel	40	65

[a] Based on a review of marketing information from turbine manufacturers and the *GTW Handbook*.

The fuel costs may vary depending on the plant's location. In areas where gas costs are high, for a base-load CCCT power plant, fuel costs can account for up to 70 percent of total plant costs—including acquisition, owning and operating costs, and debt service (*GTW Handbook*, 1999). General Electric's "H" design goals for future CCCT systems are to reduce power plant operating costs by at least 10 percent compared to today's technology as a direct result of using less fuel. The higher efficiency allows more power to be generated with the same amount of fuel, resulting in a substantial fuel cost savings for the plant owner (General Electric, 1999).

SECTION 3

BACKGROUND ON HEALTH AFFECTS AND REGULATORY ALTERNATIVES

3.1 Background

Section 112 of the CAA requires EPA to list categories and subcategories of major sources and area sources of HAP and to establish NESHAPs for the listed source categories and subcategories. The stationary turbine source category was listed on July 16, 1992 (57 FR 31576). Major sources of HAPs are those that have the potential to emit greater than 10 ton/yr of any one HAP or 25 ton/yr of any combination of HAPs.

3.1.1 Criteria Used in NESHAP Development

Section 112 of the CAA requires that we establish NESHAPs for controlling HAPs from both new and existing major sources. The CAA requires the NESHAP to reflect the maximum degree of reduction in emissions of HAPs that is achievable. This level of control is commonly referred to as the MACT.

The MACT floor is the minimum control level allowed for a NESHAP and is defined under Section 112(d)(3) of the CAA. In essence, the MACT floor ensures that the standard is set at a level that assures that all major sources achieve the level of control at least as stringent as that already achieved by the better controlled and lower emitting sources in each source category or subcategory. For new sources, the MACT standards cannot be less stringent than the emission control that is achieved in practice by the best controlled similar source. The MACT standards for existing sources can be less stringent than standards for new sources, but they cannot be less stringent than the average emission limitation achieved by the best performing 12 percent of existing sources in the category or subcategory (or the best performing five sources for categories or subcategories with fewer than 30 sources).

In developing MACT, we also consider control options that are more stringent than the floor. We may establish standards more stringent than the floor based on the consideration of cost of achieving the emissions reductions, any nonair quality health and environmental impacts, and energy requirements.

Discussion of the costs and other impacts associated with the MACT floor and other alternatives can be found in Section 4.

3.2 Health Effects Associated with HAPs from Stationary Combustion Turbines

Several HAPs are emitted from stationary combustion turbines. These HAP emissions are formed during combustion or result from HAP compounds contained in the fuel burned.

Among the HAPs that have been measured in emission tests that were conducted at natural gas-fired and distillate oil-fired combustion turbines are 1,3 butadiene, acetaldehyde, acrolein, benzene, ethylbenzene, formaldehyde, naphthalene, poly aromatic hydrocarbons (PAH), propylene oxide, toluene, and xylenes. Metallic HAPs from distillate oil-fired stationary combustion turbines that have been measured are arsenic, beryllium, cadmium, chromium, lead, manganese, mercury, nickel, and selenium. Natural gas-fired stationary combustion turbines do not emit metallic HAP.

Although numerous HAPs may be emitted from combustion turbines, only a few account for essentially all the mass (about 97 percent) of HAP emissions from natural gas-fired stationary combustion turbines. These HAP are formaldehyde, toluene, benzene, and acetaldehyde.

The HAPs emitted in the largest quantity is formaldehyde. Formaldehyde is a probable human carcinogen and can cause irritation of the eyes and respiratory tract, coughing, dry throat, tightening of the chest, headache, and heart palpitations. Acute inhalation has caused bronchitis, pulmonary edema, pneumonitis, pneumonia, and death due to respiratory failure. Long-term exposure can cause dermatitis and sensitization of the skin and respiratory tract.

Other HAPs emitted in significant quantities from stationary combustion turbines include toluene, benzene, and acetaldehyde. The health effect of primary concern for toluene is dysfunction of the central nervous system (CNS). Toluene vapor also causes narcosis. Controlled exposure of human subjects produced mild fatigue, weakness, confusion, lacrimation, and paresthesia; at higher exposure levels there were also euphoria, headache, dizziness, dilated pupils, and nausea. After effects included nervousness, muscular fatigue, and insomnia persisting for several days. Acute exposure may cause irritation of the eyes, respiratory tract, and skin. It may also cause fatigue, weakness, confusion, headache, and drowsiness. Very high concentrations may cause unconsciousness and death.

Benzene is a known human carcinogen. The health effects of benzene include nerve inflammation, CNS depression, and cardiac sensitization. Chronic exposure to benzene can cause fatigue, nervousness, irritability, blurred vision, and labored breathing and has produced anorexia and irreversible injury to the blood-forming organs; effects include aplastic anemia and leukemia. Acute exposure can cause dizziness, euphoria, giddiness, headache, nausea, staggering gait, weakness, drowsiness, respiratory irritation, pulmonary edema, pneumonia, gastrointestinal irritation, convulsions, and paralysis. Benzene can also cause irritation to the skin, eyes, and mucous membranes.

Acetaldehyde is a probable human carcinogen. The health effects for acetaldehyde are irritation of the eyes, mucous membranes, skin, and upper respiratory tract, and it is a CNS depressant in humans. Chronic exposure can cause conjunctivitis, coughing, difficult breathing, and dermatitis. Chronic exposure may cause heart and kidney damage, embryotoxicity, and teratogenic effects.

3.3 Summary of the Rule

The rule applies to you if you own or operate a stationary combustion turbine that is located at a major source of HAP emissions, the definition of which is mentioned above.

It should be noted that the rule does not apply to stationary combustion turbines located at an area source of HAP emissions. An area source of HAP emissions is a plant site that does not emit any single HAP at a rate of 10 tons (9.07 megagrams) or greater per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or greater per year. To determine whether a facility is a major source, EPA will accept HAP emissions estimated using a HAP emission factor of 0.000202 pounds per million British thermal units (Btu) factors listed in Table 3-1. If the turbine mainly operates at high load, the emission factor for greater than 80 percent load should be used. If the turbine operates on varying loads, the emission factor for all loads should be used. Emission factors were developed based on data from the combustion turbines emissions database. A copy of the emissions database may be downloaded off the Internet at http://www.epa.gov/ttn/atw/combust/turbine/turbpg.html.

The rule does not cover duct burners. They are part of the waste heat recovery unit in a combined cycle system. Waste heat recovery units, whether part of a cogeneration system or a combined cycle system, are steam-generating units and are not covered by the rule.

Finally, the rule does not apply to stationary combustion engine test cells/stands because these facilities will be covered by another NESHAP, 40 CFR part 63, subpart PPPPP.

For those sources that are covered, eight subcategories have been defined within the stationary combustion turbine source category. Although all stationary combustion turbines are subject to the rule, each subcategory has distinct requirements. For example, existing diffusion flame combustion turbines and stationary combustion turbines with a rated peak

Table 3-1. Summary of HAP Emission Factors

Turbine	Load	Fuel	HAP Emission Factor (lb/MMBtu)
Diffusion Flame	All loads	Natural Gas	0.0188
Diffusion Flame	>80%	Natural Gas	0.00479
Diffusion Flame	All loads	Diesel	0.00241
Diffusion Flame	>80%	Diesel	0.00233
Lean Premix	All loads	Natural Gas	0.000644
Lean Premix	>80%	Natural Gas	0.000212

power output of less than 1.0 megawatt (MW) (at International Organization for Standardization (ISO) standard day conditions) are not required to comply with emission limitations, record-keeping, or reporting requirements in the rule. New or reconstructed stationary combustion turbines and existing lean premix stationary combustion turbines with a rated peak power output of 1.0 MW or more that either operate exclusively as an emergency stationary combustion turbine, as a limited use stationary combustion turbine, or as a stationary combustion turbine that burns landfill gas or digester gas as its primary fuel must only comply with the initial notification requirements. New or reconstructed diffusion flame or lean premix combustion turbines must comply with emission limitations, record-keeping, and reporting requirements in the rule. You must determine your source's subcategory to determine which requirements apply to your source.

3.3.1 Source Categories and Subcategories Affected by the Rule

A stationary combustion turbine includes:

- all equipment, including, but not limited to, the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment);
- any ancillary components and subcomponents comprising any simple cycle stationary combustion turbine; and
- any regenerative/recuperative cycle stationary combustion turbine, or the combustion turbine portion of any stationary combined cycle steam/electric generating system.

Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. A stationary combustion turbine may, however, be mounted on a vehicle for portability or transportability.

Stationary combustion turbines have been divided into the following eight subcategories:

1. emergency stationary combustion turbines,
2. stationary combustion turbines that burn landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis or where gasified MSW is used to generate 10 percent or more of the gross heat input to the stationary combustion turbine on an annual basis,
3. stationary combustion turbines of less than 1 MW rated peak power output,
4. stationary lean premix combustion turbines when firing natural gas and up to 50 hours of distillate oil on an annual basis,
5. stationary lean premix combustion turbines when firing distillate oil,
6. stationary diffusion flame combustion turbines when firing natural gas and up to 50 hours of distillate oil on an annual basis,
7. stationary diffusion flame combustion turbines when firing distillate oil, and
8. stationary combustion turbines operated on the North Slope of Alaska (defined as the area north of the Arctic Circle [latitude 66.5E North]).

An emergency stationary combustion turbine means any stationary combustion turbine that operates as a mechanical or electrical power source when the primary power source for a facility has been rendered inoperable by an emergency situation. One example is emergency power for critical networks or equipment when electric power from the normal source of power is interrupted. Peaking units at electric utilities and other types of stationary combustion turbines that typically operate at low capacity factors, but are not confined to operation in an emergency, are not emergency stationary combustion turbines. There is no time limit on the use of emergency stationary sources.

Stationary combustion turbines that burn landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis or stationary combustion turbines where gasified MSW is used to generate 10 percent or more of the gross heat input to the stationary combustion turbine on an annual basis qualify as a separate subcategory because the types of control available for these turbines are limited.

Stationary combustion turbines of less than 1 MW rated peak power output were also identified as a subcategory. These small stationary combustion turbines are few in number, and, to our knowledge, none use emission control technology to reduce HAPs. Therefore, it would be inappropriate to require HAP emission controls to be applied to them without further information on control technology performance.

Two subcategories of stationary lean premix combustion turbines were established: stationary lean premix combustion turbines when firing natural gas and up to 50 hours of distillate oil on an annual basis, and stationary lean premix combustion turbines when firing distillate oil. Lean premix technology, introduced in the 1990s, was developed to reduce nitrogen oxide (NO_x) emissions without the use of add-on controls. In a lean premix combustor, the air and fuel are thoroughly mixed to form a lean mixture for combustion. Mixing may occur before or in the combustion chamber. Lean premix combustors emit lower levels of NO_x, carbon monoxide (CO), formaldehyde, and other HAPs than diffusion flame combustion turbines.

Two subcategories of stationary diffusion flame combustion turbines were established: stationary diffusion flame combustion turbines when firing natural gas and up to 50 hours of distillate oil on an annual basis, and stationary diffusion flame combustion turbines when firing distillate oil. In a diffusion flame combustor, the fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. Hazardous air pollutants emissions from these turbines can be significantly decreased with the addition of air pollution control equipment.

Stationary combustion turbines located on the North Slope of Alaska have been identified as a subcategory because of operating limitations and uncertainties regarding the application of controls to these units. There are very few of these units, and none have installed emission controls for reducing HAPs.

3.3.2 Emission Limitations and Operating Limitations

As the owner or operator of a new or reconstructed stationary lean premix combustion turbine when firing natural gas and up to 50 hours of distillate oil on an annual basis, a new or reconstructed stationary lean premix combustion turbine when firing distillate oil, a new or reconstructed stationary diffusion flame combustion turbine when firing natural gas and up to 50 hours of distillate oil on an annual basis, or a new or reconstructed stationary diffusion flame combustion turbine when firing distillate oil located at major sources of HAP emissions, you must comply with the emission limitation to reduce the concentration of formaldehyde in the exhaust from the new or reconstructed stationary combustion turbine to 91 parts per billion by volume (ppbv) or less, dry basis (ppbvd), at 15 percent oxygen by the effective date of the standards (or upon startup if you start up your stationary combustion turbine after the effective date of the standards).

If you comply with the emission limitation for formaldehyde emissions and you use an oxidation catalyst emission control device, you must continuously monitor the oxidation catalyst inlet temperature and maintain the inlet temperature to the oxidation catalyst within the range recommended by the catalyst manufacturer.

If you comply with the emission limitation for formaldehyde emissions and you do not use an oxidation catalyst emission control device, you must petition the Administrator for approval of operating limitations or approval of no operating limitations.

3.3.3 Initial Compliance Requirements

If you operate a new or reconstructed stationary lean premix combustion turbine when firing natural gas and up to 50 hours of distillate oil on an annual basis, a new or reconstructed stationary lean premix combustion turbine when firing distillate oil, a new or reconstructed stationary diffusion flame combustion turbine when firing natural gas and up to 50 hours of distillate oil on an annual basis, or a new or reconstructed stationary diffusion flame combustion turbine when firing distillate oil, you must conduct an initial performance test using Test Method 320 of 40 CFR part 63, appendix A, to demonstrate that the outlet concentration of formaldehyde is 91 ppbvd or less (corrected to 15 percent oxygen). To correct to 15 percent oxygen, dry basis, you must measure oxygen using Method 3A or 3B of 40 CFR part 60, appendix A, and moisture using either Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A. The initial performance test must be conducted at high load conditions, defined as 100 percent ±10 percent.

If you operate a new or reconstructed stationary combustion turbine and use an oxidation catalyst emission control device, you must also install a continuous parameter monitoring system (CPMS) to continuously monitor the oxidation catalyst inlet temperature.

If you operate a new or reconstructed stationary combustion turbine and you do not use an oxidation catalyst emission control device, you must petition the Administrator for approval of operating limitations or approval of no operating limitations.

If you petition the Administrator for approval of operating limitations, your petition must include the following: (1) identification of the specific parameters you propose to use as operating limitations; (2) a discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions; (3) a discussion of how you will establish the upper and/or lower values for these parameters that will establish the limits on these parameters in the operating limitations; (4) a discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and (5) a discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

If you petition the Administrator for approval of no operating limitations, your petition must include the following: (1) identification of the parameters associated with operation of the stationary combustion turbine and any emission control device that could change intentionally (e.g., operator adjustment, automatic controller adjustment) or unintentionally (e.g., wear and tear, error) on a routine basis or over time; (2) a discussion of the relationship, if any, between changes in these parameters and changes in HAP emissions; (3) for those parameters with a relationship to HAP emissions, a discussion of whether establishing limitations on these parameters would serve to limit HAP emissions; (4) for those parameters with a relationship to HAP emissions, a discussion of how you could establish upper and/or lower values for these parameters which would establish limits on these parameters in operating limitations; (5) for those parameters with a relationship to HAP emissions, a discussion identifying the methods you could use to measure these parameters and the instruments you could use to monitor them, as well as the relative accuracy and precision of these methods and instruments; (6) for these parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and (7) a discussion of why, from your point of view, it is infeasible, unreasonable, or unnecessary to adopt these parameters as operating limitations.

3.3.4 Continuous Compliance Provisions

Several general continuous compliance requirements apply to stationary combustion turbines required to comply with the emission limitations. You are required to comply with the emission limitations and the operating limitations (if applicable) at all times, except during startup, shutdown, and malfunction of your stationary combustion turbine. You must also operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment according to good air pollution control practices at all times, including startup, shutdown, and malfunction. You must conduct monitoring at all times that the stationary combustion turbine is operating, except during periods of malfunction of the monitoring equipment or necessary repairs and quality assurance or control activities, such as calibration checks.

To demonstrate continuous compliance with the emission limitations, you must conduct annual performance tests for formaldehyde. You must conduct the annual performance tests using Test Method 320 of 40 CFR part 63, appendix A, to demonstrate that the outlet concentration of formaldehyde is at or below 91 ppbvd of formaldehyde (correct to 15 percent oxygen). The annual performance test must be conducted at high load conditions, defined as 100 percent ±10 percent.

If you operate a new or reconstructed stationary combustion turbine and you use an oxidation catalyst emission control device, you must demonstrate continuous compliance with the operating limitations by continuously monitoring the oxidation catalyst inlet temperature. The 4-hour rolling average of the valid data must be within the range recommended by the catalyst manufacturer.

If you operate a new or reconstructed stationary combustion turbine and you do not use an oxidation catalyst emission control device, you must demonstrate continuous compliance with the operating limitations by continuously monitoring parameters which have been approved by the Administrator (if any).

3.3.5 Notification, Record-keeping, and Reporting Requirements

You must submit all of the applicable notifications as listed in the NESHAP General Provisions (40 CFR part 63, subpart A), including an initial notification, notification of performance test or evaluation, and a notification of compliance, for each stationary combustion turbine that must comply with the emission limitations. If your new or reconstructed source is located at a major source, has greater than 1 MW rated peak power output, and is an emergency stationary combustion turbine, limited use stationary combustion turbine or a combustion turbine that fires landfill or digester gas as its primary fuel, you must submit only an initial notification.

For each combustion turbine subject to the emission limitations, you must record all of the data necessary to determine if you are in compliance with the emission limitations. Your records must be in a form suitable and readily available for review. You must also keep each record for 5 years following the date of each occurrence, measurement, maintenance, report, or record. Records must remain on site for at least 2 years and then can be maintained off site for the remaining 3 years.

3.4 Rationale for Selecting Standards

3.4.1 Selection of Source Categories and Subcategories

Stationary combustion turbines can be major sources of HAP emissions, and, as a result, we listed them as a major source category for regulatory development under section 112 of the CAA, which allows us to establish subcategories within a source category for the purpose of regulation. Consequently, we evaluated several criteria associated with stationary combustion turbines that might serve as potential subcategories.

We identified emergency stationary combustion turbines as a subcategory. Emergency stationary combustion turbines operate only in emergencies, such as a loss of power provided by another source. These types of stationary combustion turbines operate infrequently and, when called on to operate, must respond without failure and without lengthy periods of startup. These conditions limit the applicability of HAP emission control technology to emergency stationary combustion turbines.

Similarly, stationary combustion turbines that burn landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis or where gasified MSW is used to generate 10 percent or more of the gross heat input to the stationary combustion turbine on an annual basis were identified as a subcategory. Landfill gas, digester gas, and gasified MSW contain a family of chemicals referred to as siloxanes, which limit the application of HAP emission control technology.

Stationary combustion turbines of less than 1 MW rated peak power output were also identified as a subcategory. We believe these small stationary combustion turbines are few in number and, to our knowledge, none use emission control technology to reduce HAP. Therefore, we believe it would be inappropriate to require HAP emission controls to be applied to them without further information on control technology performance.

Stationary combustion turbines can be classified as either diffusion flame or lean premix. We examined formaldehyde test data for both diffusion flame and lean premix stationary combustion turbines and observed that uncontrolled formaldehyde emissions for stationary lean premix combustion turbines are significantly lower than those of stationary diffusion flame combustion turbines. Because of the difference in the two technologies, we decided to establish subcategories for diffusion flame and lean premix stationary combustion turbines.

We further investigated subcategorizing lean premix turbines based on fuel. At the time of proposal, EPA was not aware of the availability of distillate oil-fired stationary combustion turbines that operated in the lean premix mode. We received comments indicating otherwise during the public comment period from combustion turbine manufacturers. We believe there is a difference in uncontrolled HAP emissions between natural gas and distillate oil for stationary lean premix combustion turbines. This is based on test data for stationary diffusion flame combustion turbines that clearly show there is a difference in uncontrolled HAP emissions between natural gas and distillate oil. We believe this also would apply to stationary lean premix combustion turbines. For stationary lean premix combustion turbines, NO_x emissions also vary depending on which fuel is burned in the combustion process. Information from combustion turbine vendors indicate that NO_x emission guarantees for distillate oil can be up to five times higher than the NO_x emission guarantees for natural gas for stationary lean premix combustion turbines. Finally, the mass of total emissions may be similar for natural gas and distillate oil, but some pollutants such as formaldehyde are lower for distillate oil, and other pollutants such as PAH and metals are higher for oil. For all practical purposes, uncontrolled natural gas metal emissions are nonexistent, while they are emitted in small quantities when burning distillate oil. Based on these reasons, EPA felt that it was appropriate to further subcategorize lean premix combustion turbines based on fuel. Hence, we established a subcategory of stationary lean premix combustion turbines when firing natural gas and up to 50 hours of distillate oil on an annual basis and a subcategory of stationary lean premix combustion turbines when firing distillate oil. We are permitting lean premix combustion turbines when firing natural gas to use up to 50 hours of distillate oil on an annual basis because we want to minimize switching between fuel subcategories and limit potential confusion caused when stationary combustion turbines switch subcategories based on fuel. Allowing 50 hours of distillate oil use on an annual basis is sufficient to minimize switching between subcategories and limit confusion. We expect that the majority of distillate oil burned in stationary combustion turbines will be fuel oil number 2. We recognize that stationary combustion turbine owners and operators may burn different varieties of distillate oil; however, we believe that any other distillate oil combusted will be of similar quality and composition to fuel oil number 2. We do not anticipate that owners and operators will burn any other liquid-based fuel that is more contaminated with metals than fuel oil number 2 and expect that most available liquid fuels that may be used in stationary combustion turbines will be similar and fairly consistent.

We further investigated subcategorizing diffusion flame turbines based on fuel. For diffusion flame turbines, test data show that HAP emissions vary depending on which fuel is burned. Formaldehyde emissions are in general lower for diffusion flame units firing distillate oil versus diffusion flame units firing natural gas. Emissions data also show that NO_x levels are higher for diffusion flame units firing distillate oil than diffusion flame units firing natural gas. Finally, other fuel differences between natural gas and distillate oil include higher levels of pollutants such as PAH and metals in the emissions of stationary diffusion flame combustion turbines burning distillate oil. Quantities of these pollutants are small for distillate oil; metal emissions from natural gas are at nondetectable levels. Therefore, we felt that it was appropriate to further subcategorize diffusion flame combustion turbines based on fuel. Hence, we established a subcategory of stationary diffusion flame combustion turbines when firing natural gas and up to 50 hours of distillate oil on an annual basis and a subcategory of stationary diffusion flame combustion turbines when firing distillate oil. We are permitting stationary diffusion flame combustion turbines when firing natural gas to use 50 hours of distillate oil on an annual basis because we wish to minimize switching between fuel subcategories and limit potential confusion caused when stationary combustion turbines switch subcategories based on fuel. As previously indicated, we expect that most owners and operators of stationary combustion turbines will burn distillate oil of the form fuel oil number 2. However, we recognize that other liquid-based fuels may be also be fired, but these fuels will be similar to fuel oil number 2, and we do not expect owners and operators to burn any other fuel that is more contaminated with metals.

Stationary combustion turbines located on the North Slope of Alaska have been identified as a subcategory because of operation limitations and uncertainties regarding the application of controls to these units. There are very few of these units, and none have installed emission controls for reducing HAPs.

3.4.2 Determination of Basis and Level of Emission Limitations for Existing Sources

As established in Section 112 of the CAA, the MACT standards must be no less stringent than the MACT floor. The MACT floor for existing sources is the average emission limitation achieved by the best performing 12 percent of existing sources.

3.4.2.1 MACT Floor for Existing Diffusion Flame Combustion Turbines

EPA has established two subcategories of stationary diffusion flame combustion turbines: stationary diffusion flame combustion turbines when firing natural gas and up to 50 hours of distillate oil on an annual basis and stationary diffusion flame combustion turbines when firing distillate oil. We believe emissions of each HAP are relatively homogeneous within each of these two subcategories and any variation in HAP emissions cannot be readily controlled except by add-on control. To determine the MACT floor for both subcategories of existing stationary diffusion flame combustion turbines, we consulted the inventory database previously discussed in this preamble. At least 80 percent of those turbines are assumed to be diffusion flame combustion turbines, based on conversations with turbine manufacturers.

We investigated the use of good operating practices for stationary diffusion flame combustion turbines to determine if using such practices might identify a MACT floor. There are no references in the inventory database to good operating practices for any stationary combustion turbines.

Most stationary diffusion flame combustion turbines will not operate unless preset conditions established by the manufacturer are met. Stationary diffusion flame combustion turbines, by manufacturer design, permit little operator involvement and there are no operating parameters, such as air/fuel ratio, for the operator to adjust. We concluded, therefore, that there are no specific good operating practices that could reduce HAP emissions or that could serve to identify a MACT floor.

Another approach we investigated to identify a MACT floor was to review the requirements in existing state regulations and permits. No state regulations exist for HAP emission limits for stationary combustion turbines. Only one state permit limitation for a single HAP (benzene) was identified. Therefore, we were unable to use state regulations or permits to identify a MACT floor.

We examined the inventory database for information on HAP emission control technology. There were no turbines controlled with oxidation catalyst systems in the inventory database, so we used information supplied by catalyst vendors. There are about 200 oxidation catalyst systems installed in the United States. The only control technology currently proven to reduce HAP emissions from stationary diffusion flame combustion turbines is an oxidation catalyst emission control device, such as a CO oxidation catalyst. These control devices are used to reduce CO emissions and are currently installed on several stationary combustion turbines.

Less than 3 percent of existing stationary diffusion flame combustion turbines firing natural gas in the United States, based on information in our inventory database and information from catalyst vendors, are equipped with oxidation catalyst emission control devices. Therefore, the average of the best performing 12 percent of existing diffusion flame combustion turbines when firing natural gas and up to 50 hours of distillate oil on an annual basis is no HAP emission reduction.

We estimate that less than 1 percent of existing stationary diffusion flame combustion turbines firing distillate oil have oxidation catalyst systems installed. Thus, the average of the best performing 12 percent of existing diffusion flame combustion turbines when firing distillate oil is no HAP emission reduction.

In the rule, we requested sources to submit any HAP emissions test data available from stationary combustion turbines. After the proposal, we also contacted several state agencies to request emissions test data from diffusion flame combustion turbines. Because of the CARB advisory issued on April 28, 2000, which stated that formaldehyde emissions data where the NO_x levels were greater than 50 ppmvd were suspect and should be flagged as nonquantitative, we conducted an analysis of existing diffusion flame emissions test data. Tests where the NO_x emissions were greater than 50 ppm or tests where the NO_x levels were unknown were excluded from our analysis. Most of the diffusion flame tests in the emissions database were unable to pass the screening. Therefore, we specifically requested states to provide test reports for diffusion flame combustion turbines where Method 320 was used, or CARB 430 was used and the NO_x emissions were below 50 ppmvd. During the comment period we received three additional test reports for testing conducted on a total of five stationary diffusion flame combustion turbines.

As a result, we concluded the MACT floor for both subcategories of existing stationary diffusion flame combustion turbines is no emission reduction.

3.4.2.2 MACT for Existing Diffusion Flame Combustion Turbines

To determine MACT for both subcategories of existing diffusion flame combustion turbines, regulatory alternatives more stringent than the MACT floor were evaluated. One beyond-the-floor regulatory option is requiring a control device that incorporates oxidation. However, cost-per-ton estimates of oxidation catalyst emission control devices for controlling total HAPs from stationary diffusion flame combustion turbines were deemed excessive. In addition, we attempted to identify good operation practices that could reduce HAP emissions. We were unable to identify any good operation practices that could achieve this goal. For these reasons, MACT for both subcategories of existing stationary diffusion flame combustion turbines is equal to the MACT floor (i.e., no emission reduction).

3.4.2.3 MACT Floor for Existing Lean Premix Combustion Turbines

EPA has established two subcategories of stationary lean premix combustion turbines: stationary lean premix combustion turbines when firing natural gas and up to 50 hours of distillate oil on an annual basis and stationary lean premix combustion turbines when firing distillate oil. Emissions of each HAP are relatively homogeneous within each of these two subcategories, and any variation in HAP emissions cannot be readily controlled except by add-on control. To determine the MACT floor for both subcategories of existing stationary lean premix combustion turbines, EPA's combustion turbine inventory database was consulted.

The inventory database provides population information on stationary combustion turbines in the United States and was constructed to support the development of the rule. Data in the inventory database are based on information from available databases, such as the Aerometric Information Retrieval System (AIRS), the Ozone Transport and Assessment Group (OTAG), and state and local agencies' databases. The first version of the database was released in 1997. Subsequent versions have been released reflecting additional or updated data. The most recent release of the database is Version 4, released in November 1998.

The inventory database contains information on approximately 4,800 stationary combustion turbines. The current stationary combustion turbine population is estimated to be about 8,000 turbines. Therefore, the inventory database represents about 60 percent of the stationary combustion turbines in the United States. At least 20 percent of those turbines are estimated to be lean premix combustion turbines, based on conversations with turbine manufacturers.

The information contained in the inventory database is believed to be representative of stationary combustion turbines primarily because of its comprehensiveness. The database includes both small and large stationary combustion turbines in different user segments. Forty-eight percent are "industrial," 39 percent are "utility," and 13 percent are "pipeline." Note that independent power producers (IPP) are included in the utility and industrial segments.

We examined the inventory database to identify any good operation practices that could lead to the removal of HAP. We were unsuccessful in identifying any such practices. Therefore, we were unable to use operation practices to identify a MACT floor.

Another approach we investigated to identify a MACT floor was to review the requirements in existing state regulations and permits. No state regulations exist for HAP emission limits for stationary combustion turbines. Only one state permit limitation for a single HAP (benzene) was identified. Therefore, we were unable to use state regulations or permits to identify a MACT floor.

The only add-on control technology currently proven to reduce HAP emissions from stationary lean premix combustion turbines is an oxidation catalyst emission control device. At proposal, the inventory database indicated that no existing stationary lean premix combustion turbines were controlled with oxidation catalyst systems. During the public comment period, we received a test report where a lean premix combustion turbine burning natural gas was tested twice about 2 years apart with an oxidation catalyst in operation.

We estimate that about 1 percent of existing lean premix combustion turbines burning natural gas may have oxidation catalyst systems installed. Accordingly, the average of the best performing 12 percent is no emission reduction. Therefore, the MACT floor for existing stationary lean premix combustion turbines when firing natural gas and up to 50 hours of distillate oil on an annual basis is no emission reduction.

For lean premix combustion turbines burning distillate oil, we do not have data indicating that oxidation catalysts have been installed; therefore, we expect that less than 1 percent have oxidation catalysts installed. Accordingly, the average of the best performing 12 percent is still no emission reduction. Therefore, we concluded that the MACT floor for existing stationary lean premix combustion turbines when firing distillate oil is no emission reduction.

3.4.2.4 MACT for Existing Lean Premix Combustion Turbines

To determine MACT for both subcategories of existing stationary lean premix combustion turbines, we evaluated regulatory alternatives more stringent than the MACT floor. We considered requiring the use of an oxidation catalyst emission control device. According to catalyst vendors, oxidation catalysts are currently being used on some existing lean premix stationary combustion turbines. In addition, we recently received a test report where testing was conducted on a lean premix unit with an oxidation catalyst. However, an analysis of the application of oxidation catalyst control to existing lean premix stationary combustion turbines showed that the incremental cost per ton of HAP removed was excessive. For these reasons, we concluded that MACT for both subcategories of existing stationary lean premix combustion turbines is the same as the MACT floor (i.e., no emission reduction).

3.4.3 New Sources

For new sources, the MACT floor is defined as the emission control that is achieved in practice by the best controlled similar source. When deriving the MACT floor for a particular category or subcategory, we must consider all measures that could result in reducing HAP emissions. These measures will include potential installation of add-on control technology, but other operational modifications such as adjustment of equipment, revision of work practices, and material substitution should also be considered. Where emissions are relatively homogeneous across the sources in a category or subcategory, and any variation in HAP emissions that does occur cannot be readily attributed to differences in any factor that is susceptible to control by the owner or operator, the MACT floor for a particular hazardous air pollutant or group of HAPs may be expressed in terms of reductions achieved by using potential add-on controls.

3.4.3.1 New Diffusion Flame Combustion Turbines when Firing Natural Gas and up to 50 Hours of Distillate Oil

To identify the MACT floor for new stationary diffusion flame combustion turbines when firing natural gas and up to 50 hours of distillate oil on an annual basis located at major sources, we based our analysis on the performance of the best turbine. Individual HAP emissions are relatively homogeneous within the subcategory of stationary diffusion flame combustion turbines when firing natural gas and any variation in HAP emissions cannot be readily controlled except by add-on control. The best performing turbine in this subcategory is equipped with an oxidation catalyst.

As previously indicated, formaldehyde is the HAP emitted in the highest concentrations from stationary combustion turbines, and data show that HAP emission levels and formaldehyde emission levels are related. We have, therefore, concluded that formaldehyde is an appropriate surrogate for all organic HAP emissions.

Formaldehyde was measured by CARB 430 at the outlet of the oxidation catalyst. We applied a bias factor of 1.7 to the formaldehyde concentration obtained by CARB 430 for the best performing turbine. The corrected outlet concentration of formaldehyde from the best performing turbine was 15 ppbvd. We only have one controlled test for this turbine, but we expect that similar variability would be associated with this turbine as was associated with the best performing lean premix turbine. Therefore, applying a factor of 5 to the formaldehyde concentration measured at the outlet of the best performing diffusion flame turbine is appropriate to account for variability. Therefore, we would establish a formaldehyde emission limitation of 75 ppbvd based on the outlet of the control device. However, with a similar control system, we would expect that the emission limit should be no lower than the emission limit for lean premix turbines because diffusion flame turbines on average emit more HAP. The MACT floor for new stationary diffusion flame combustion turbines when firing natural gas and up to 50 hours of distillate oil on an annual basis is, therefore, an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen.

We were unable to identify any beyond-the-floor regulatory alternatives for new stationary diffusion flame combustion turbines when firing natural gas and up to 50 hours of distillate oil on an annual basis. We know of no emission control technology currently available that can reduce HAP emissions to levels lower than that achieved by using oxidation catalyst emission control devices. We concluded, therefore, that MACT for new diffusion flame stationary combustion turbines when firing natural gas and up to 50 hours of distillate oil on an annual basis is equivalent to the MACT floor (i.e., an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen).

3.4.3.2 New Diffusion Flame Combustion Turbines when Firing Distillate Oil

To determine the MACT floor for new diffusion flame combustion turbines when firing distillate oil, we again based our analysis on the best performing turbine. Emissions of each individual HAP are relatively homogeneous within stationary diffusion flame combustion turbines when firing distillate oil, and any variation in HAP emissions cannot be readily controlled except by add-on control. The best performing turbine in this subcategory is equipped with an oxidation catalyst.

As previously described in more detail, we are using formaldehyde as a surrogate for all organic HAP emissions. The formaldehyde was measured with EPA Method 0011 at the outlet of the control device. EPA Method 0011 is similar to CARB 430, and the problems associated with CARB 430 are expected to be associated with EPA Method 0011. So again we applied a bias factor of 1.7 to the formaldehyde outlet concentration of the best performing diffusion flame turbine firing distillate oil. The corrected formaldehyde concentration from this turbine is 44 ppbvd. We only had one controlled test for this turbine but would expect some variability as has been shown with other turbines. However, because formaldehyde emissions from distillate oil fired turbines are lower on average by a factor of 1.4, we do not believe that the MACT emission limit should be set higher than the emission limit for new stationary diffusion flame combustion turbines when firing natural gas and up to 50 hours of distillate oil on an annual basis. Therefore, the MACT floor for new stationary diffusion flame combustion turbines when firing distillate oil is an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen.

We examined the inventory database to identify any operating practices that could affect metal emissions. We were unable to identify any such practices. We also determined that no existing diffusion flame stationary combustion turbines firing distillate oil are equipped with emission control devices for reducing PM, which could also reduce metal emissions. Therefore, the MACT floor for new diffusion flame combustion turbines when firing distillate oil is an emission limit of 91 ppbvd of formaldehyde at 15 percent oxygen.

To determine MACT for new stationary diffusion flame combustion turbines when firing distillate oil, we tried to identify beyond-the-floor options. There are currently no beyond-the-floor regulatory alternatives for this subcategory as we know of no emission control technology current available that can reduce HAP emissions to levels lower than that obtained with using an oxidation catalyst. We, therefore, determined that MACT for new diffusion flame combustion turbines when firing distillate oil is equivalent to the MACT floor of 91 ppbvd formaldehyde at 15 percent oxygen.

3.4.3.3 New Lean Premix Combustion Turbines when Firing Natural Gas and up to 50 Hours of Distillate Oil

To determine the MACT floor for new stationary lean premix combustion turbines when firing natural gas and up to 50 hours of distillate oil on annual basis, we reviewed the emissions data we had available at proposal and additional test reports received during the comment period. To set the MACT floor for new sources in this subcategory, we chose the best performing turbine. Emissions of each HAP are relatively homogeneous within the subcategory of stationary lean premix combustion turbines when firing natural gas and any variation in HAP emissions cannot be readily controlled except by add-on control. The best performing turbine is equipped with an oxidation catalyst.

We considered using a surrogate to reduce the costs associated with monitoring, while at the same time being relatively sure that the pollutants the surrogate is supposed to represent are also controlled. We investigated the use of formaldehyde concentration as a surrogate for all organic HAP emissions. Formaldehyde is the HAP emitted in the highest concentrations from stationary combustion turbines. Formaldehyde, toluene, benzene, and acetaldehyde account for essentially all the mass of HAP emissions from the stationary combustion turbine exhaust, and emissions data show that these pollutants are equally controlled by an oxidation catalyst.

Information from testing conducted on a diffusion flame combustion turbine equipped with an oxidation catalyst control system indicated that the formaldehyde and acetaldehyde emission reduction efficiency achieved was 97 and 94 percent, respectively. Later, an expert task group reached the conclusion that both formaldehyde and acetaldehyde were controlled at least 90 percent. In addition, emissions tests conducted on reciprocating internal combustion engines (RICE) at Colorado State University (CSU) in 1998 showed that the benzene emission reduction efficiency across an oxidation catalyst averaged 73 percent, and the toluene emission reduction averaged 77 percent for 16 runs at various engine conditions on a two-stroke lean burn engine. The toluene emission reduction efficiency across the oxidation catalyst averaged 85 percent for ten runs at various engine conditions on a compression ignition RICE. We would expect the emissions reductions efficiencies for benzene and toluene from combustion turbines to be as high or higher than those reported for the CSU RICE tests because combustion turbines catalyst temperatures are generally higher.

Finally, catalyst performance information obtained from a catalyst vendor indicated that the percent conversion for an oxidation catalyst system installed on combustion turbines did not vary significantly between formaldehyde, benzene, and toluene. The percent conversion was measured at 77, 72, and 71 for formaldehyde, benzene, and toluene, respectively. Although emissions reductions for large molecules may in theory be less than for formaldehyde, the above information shows that formaldehyde is a good surrogate for the most significant HAP pollutants emitted from combustion turbines as demonstrated by evaluating the reduction efficiency of larger, heavier molecules, hence taking differences in molecular density into account. In addition, emission data show that HAP emission levels and formaldehyde emission levels are related, in the sense that when emissions of one are low, emissions of the other are low and vice versa. This leads us to conclude that emission control technologies that lead to reductions in formaldehyde emissions will lead to reductions in organic HAP emissions. For the reasons provided above, it is appropriate to use formaldehyde as a surrogate for all organic HAP emissions.

The formaldehyde concentration from the best performing turbine was measured at the outlet of the control device using CARB 430. Concerns were raised during the public comment period that CARB 430 formaldehyde results can be biased low as compared to formaldehyde results obtained by FTIR. For a comprehensive discussion of test methods and the development of the correlation between CARB 430 and FTIR formaldehyde levels, please refer to the memorandum entitled “Review of Test Methods and Data used to Quantify Formaldehyde Concentrations from Combustion Turbines” (Docket ID Number OAR-2002-0060). A bias factor of 1.7 was, therefore, applied to the formaldehyde concentration of the best performing turbine. The best performing turbine was tested twice under the same conditions about 2 years apart where one test measured 19 ppbvd and the other test measured 91 ppbvd formaldehyde (numbers have been bias corrected). We took the position that because both of these tests were performed under similar conditions but at different times, this represented the variability of the best performing unit and used the higher value as the MACT floor. The MACT floor for new stationary lean premix combustion turbines when firing natural gas and up to 50 hours of distillate oil on an annual basis is, therefore, an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen.

No beyond-the-floor regulatory alternatives were identified for new lean premix turbines when firing natural gas and up to 50 hours of distillate oil on an annual basis. The MACT floor for this subcategory is based on the performance of a lean premix turbine equipped with an oxidation catalyst. We are not aware of any add-on control devices that can reduce HAP emissions to levels lower than those resulting from the application of oxidation catalyst systems. We, therefore, determined that MACT for new stationary lean premix combustion turbines when firing natural gas and up to 50 hours of distillate oil on an annual basis is the same as the MACT floor (i.e., an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen).

3.4.3.4 New Lean Premix Combustion Turbines when Firing Distillate Oil

We do not have any tests for lean premix combustion turbines firing any other fuels besides natural gas. However, emissions of each HAP are relatively homogeneous within lean premix combustion turbines when firing distillate oil and any variation in HAP emissions cannot be readily controlled except by add-on control. We expect that the level of control achieved by the application of oxidation catalyst control to lean premix units when firing natural gas and up to 50 hours of distillate oil on an annual basis would be equivalent to the level of control achieved by applying an oxidation catalyst to a lean premix unit when firing distillate oil. We also expect that the HAP emissions from lean premix units when firing distillate oil would be equal to or less than the HAP emissions from lean premix units when firing natural gas and up to 50 hours of distillate oil on an annual basis. We have these expectations based on the fact that dual-fuel units using oxidation catalyst systems operate on distillate oil and the fact that catalyst vendors indicate that oxidation catalyst systems operate equally well on either fuel. Therefore, we used the best performing turbine from the lean premix when firing natural gas and up to 50 hours of distillate oil on an annual basis subcategory to set the MACT floor for lean premix units when firing distillate oil. As a result, the MACT floor for new stationary lean premix combustion turbines when firing distillate oil is an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen. We examined the inventory database to identify any operating practices that could affect metal emissions. We were unable to identify any such practices. We also determined that no existing diffusion flame stationary combustion turbines firing distillate oil are equipped with emission control devices for the reduction of PM, which could also reduce metal emissions.

We examined the inventory database in an attempt to identify any operating practices that could affect metal emissions; however, we were unable to identify any such practices. We also referred to the inventory database to determine if any existing lean premix stationary combustion turbines firing distillate oil were equipped with emission controls for the reduction of PM, which would also reduce metal emissions. No such units were found in the inventory database, and none were identified by commenters during the public comment period. For this reason, the MACT floor for new stationary lean premix combustion turbines when firing distillate oil is an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen.

We were unable to identify any beyond-the-floor regulatory alternatives for new stationary diffusion flame combustion turbines when firing distillate oil. We know of no emission control technology currently available that can reduce HAP emissions to levels lower than that achieved through the use of oxidation catalyst emission control devices. We concluded, therefore, that MACT for new lean premix combustion turbines when firing distillate oil is equivalent to the MACT floor (i.e., an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen).

3.4.4 MACT for Other Subcategories

Although the final rule will apply to all stationary combustion turbines located at major sources of HAP emissions, emergency stationary combustion turbines, stationary combustion turbines that burn landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis or where gasified MSW is used to generate 10 percent or more of the gross heat input to the stationary combustion turbine on an annual basis, stationary combustion turbines of less than 1 MW rated peak power output, and stationary combustion turbines located on the North Slope of Alaska are not required to meet the emission limitations or operating limitations.

For each of the other subcategories of stationary combustion turbines, we have concerns about the applicability of emission control technology. For example, emergency stationary combustion turbines operate infrequently. In addition, when called on to operate they must respond immediately without failure and without lengthy startup periods. This infrequent operation limits the applicability of HAP emission control technology.

Landfill and digester gases contain a family of silicon-based gases called siloxanes. Siloxanes are also a component of municipal waste. Combustion of siloxanes forms compounds that can foul post-combustion catalysts, rendering catalysts inoperable within a very short period of time. It is our judgment based on public comments that firing even 10 percent landfill or digester gas will cause fouling that will render the oxidation catalyst inoperable within a short period of time. Pretreatment of exhaust gases to remove siloxanes was investigated. However, no pretreatment systems are in use and their long-term effectiveness is unknown. We also considered fuel switching for this subcategory of turbines. Switching to a different fuel such as natural gas or diesel would potentially allow the turbine to apply an oxidation catalyst emission control device. However, fuel switching would defeat the purpose of using this type of fuel, which would then either be allowed to escape uncontrolled or would be burned in a flare with no energy recovery. We believe that switching landfill or digester gas or gasified MSW to another fuel is inappropriate and is an environmentally inferior option.

For stationary combustion turbines of less than 1 MW rated peak power output, we have concerns about the effectiveness of scaling down the oxidation catalyst emission control technology. Just as there are often unforeseen problems associated with scaling up a technology, there can be problems associated with scaling down a technology.

Stationary combustion turbines located on the North Slope of Alaska have been identified as a subcategory because of operation limitations and uncertainties regarding the application of controls to these units. There are very few of these units, and none have installed emission controls for reducing HAP.

As a result, we identified subcategories for each of these types of stationary combustion turbines and investigated MACT floors and MACT for each subcategory. As expected, because we identified these types of stationary combustion turbines as separate subcategories based on concerns about the applicability of emission control technology, we found no stationary combustion turbines in these subcategories using any emission control technology to reduce HAP emissions. As discussed above, we are not aware of any work practices that might constitute a MACT floor, nor did we find that using a particular fuel results in HAP emissions reductions. The MACT floor, therefore, for each of these subcategories is no emission reduction.

Despite our concerns with the applicability of emission control technology, we examined the cost per ton of HAP removed for these subcategories. Whether our concerns are warranted or not, we consider the incremental cost per ton of HAP removed excessive—primarily because of the very small reduction in HAP emissions that would result.

We also considered the nonair health, environmental, and energy impacts of an oxidation catalyst system, and concluded that there would be only a small energy impact and no nonair health or environmental impacts. However, as stated above, we did not adopt this regulatory option because of cost considerations and concerns about the applicability of this technology to these subcategories. We were not able to identify any other means of achieving HAP emission reduction for these subcategories.

As a result, for all of these reasons, we conclude that MACT for these subcategories is the MACT floor (i.e., no emission reduction).

3.4.5 Selection of Initial Compliance Requirements

New and reconstructed sources complying with the emission limitation for formaldehyde emissions are required to conduct an initial performance test. The purpose of the initial test is to demonstrate initial compliance with the formaldehyde emission limitation.

3.4.5.1 How Did We Select the Continuous Compliance Requirements?

If you must comply with the emission limitations, continuous compliance with these requirements is required at all times except during startup, shutdown, and malfunction of your stationary combustion turbine. You are required to develop a startup, shutdown, and malfunction plan.

We considered requiring a CEMS; however, we concluded that the costs of a formaldehyde CEMS were excessive and were not yet demonstrated at the low formaldehyde levels of the standards. We considered requiring those sources to continuously monitor operating load to demonstrate continuous compliance because the data establishing the formaldehyde outlet concentration level are based on tests that were done at high loads. However, we believe that the performance of a stationary combustion turbine at high load is also indicative of its operation at lower loads. In fact, the operator can make no parameter adjustments that would lead to lower emissions.

For these reasons, EPA determined that it would be appropriate to require sources that comply with the emission limitation for formaldehyde emissions and that use an oxidation catalyst emission control device to continuously monitor the oxidation catalyst inlet temperature. Continuously monitoring the oxidation catalyst inlet temperature and maintaining this temperature within the range recommended by the catalyst manufacturer will ensure proper operation of the oxidation catalyst emission control device and continuous compliance with the emission limitation for formaldehyde.

Sources that do not use an oxidation catalyst emission control device are required to petition the Administrator for approval of operating limitations or approval of no operating limitations.

3.4.5.2 How Did We Select the Testing Methods to Measure these Low Concentrations of Formaldehyde?

The final rule requires the use of Method 320 to determine compliance with the emission limitation for formaldehyde. With regard to formaldehyde, we believe systems meeting the requirements of Method 320, a self-validating FTIR method, can be used to attain detection limits for formaldehyde concentrations well below the current emission limitations with a path length of 10 meters or less. Some of the older technology may require 100 or even 200 meter path lengths. We expect state-of-the-art digital signal processing (to reduce signal to noise ratio) would be needed. Method 320 also includes formaldehyde spike recovery criteria, which require spike recoveries of 70 to 130 percent.

Although we believe FTIR systems can meet the requirements of Method 320 and measure formaldehyde concentrations at these low levels, we have limited experience with their use. As a result, we solicited comments on the ability and use of FTIR systems to meet the validation and quality assurance requirements of Method 320 for the purpose of determining compliance with the emission limitation for formaldehyde. Commenters were generally in agreement that Method 320 is the most accurate and reliable test method currently available to test for formaldehyde emissions from the stationary combustion turbine exhaust.

As an alternative to Method 320, we proposed Method 323 for natural gas-fired sources. Method 323 uses the acetyl acetone colorimetric method to measure formaldehyde emissions in the exhaust of natural gas-fired, stationary combustion sources. Commenters did not support Method 323 and were concerned whether this method could provide reliable results. In addition, Method 323 has not been validated or demonstrated for use on stationary combustion turbines emitting low formaldehyde emissions. Therefore, Method 323 has not been included as a compliance method for formaldehyde in the final rule.

At proposal we believed CARB Method 430 and EPA SW-846 Method 0011 were capable of measuring formaldehyde concentrations at these low levels. Commenters were not supportive of these methods. In addition, CARB 430 is susceptible to interferences and sample loss contribute to large measurement variability. Method 0011 uses a similar analytical approach to CARB 430 and has many shortcomings and limited application opportunities. Accordingly, we are not including CARB 430 and Method 0011 in the final rule.

For these reasons, EPA has specified that Method 320 should be used to determine compliance with the formaldehyde emission limitation in the final rule.

SECTION 4

PROJECTION OF UNITS AND FACILITIES IN AFFECTED SECTORS

The regulation will affect turbine units with capacity over 1 MW. As a result, the economic impact estimates presented in Section 6 and the small business screening analysis presented in Section 7 are based on the population of existing units and the projection of new combustion turbine units through the year 2007. This section begins with a review of the technical characteristics and industry distribution of existing combustion turbines contained in the Agency's Inventory Database. It presents projected growth estimates for combustion turbines greater than 1 MW and describes trends in the electric utility industry. It also presents (in Section 4.3) the estimated number of existing and new combustion turbines that will be affected by this rule.

4.1 Profile of Existing Combustion Turbine Units

This section profiles existing combustion turbine units (greater than 1 MW) with respect to business applications, industry of parent company, and fuel use. For nonutility combustion turbines, the population of existing sources will be used to provide the characteristics of new combustion turbines constructed through the year 2007.

The population of existing combustion turbine units used in the analysis was developed from the EPA Inventory Database V.4— Turbines (referred to as the Inventory Database). The combustion turbines contained in the Inventory Database are based on information from the Aerometric Information Retrieval System (AIRS) and Ozone Transport Assessment Group (OTAG) databases, state and local permit records, and the combustion source Information Collection Request (ICR) conducted by the Agency in 1997. The list of combustion turbine units contained in the Inventory Database was reviewed and updated by industry and environmental stakeholders as part of the Industrial Combustion Coordinated Rulemaking (ICCR), chartered under the Federal Advisory Committee Act (FACA).

From the Inventory Database, EPA identified 2,072 combustion turbines with greater than 1 MW capacity. More than 2,800 additional turbines were listed in the database, but their records lacked capacity information and/or industry information, so these units are excluded from this analysis. The total estimated population of existing combustion turbines is about 8,000, so the coverage in the Inventory Database of the estimated existing combustion turbine population is approximately 60 percent. The profiles presented below are based in the 2,072 combustion turbines in the Inventory Database above 1 MW of capacity with valid information for inclusion in the analyses conducted for this rule.

4.1.1 Distribution of Units and Facilities by Industry

Table 4-1 presents the number of combustion turbines and facilities owning turbines by NAICS code. Forty-seven percent of existing combustion turbines are in Utilities (NAICS 221), 22 percent are in Pipeline Transportation, and 18 percent are in Oil and Gas Extraction (NAICS 211). Section 4 presents industry profiles for the electric power, natural gas pipelines, and oil and gas industries. The remaining units are primarily distributed across the manufacturing sector and are concentrated in the chemical and petroleum industries.

4.1.2 Technical Characteristics

This section characterizes the population of 2,072 units by MW capacity, fuel type, hours of operation, annual MWh produced (or equivalent), and simple or combined cycle.

- MW Capacity: Unit capacities in the population range between 1 and 368 MW. Although some units have large capacities in excess of 100 MW, about half (1,000 units) have capacities between 1 and 10 MW (see Figure 4-1). Only approximately 13 percent (278 units) have capacities greater than 100 MW. The total estimated capacity of all the units in the population is 79,909 MW.

- Fuel type: Natural gas is the most common fuel consumed by units in the population. About 28 percent (579 units) use distillate oil, which is more commonly known as diesel fuel. A relatively small number (53 units) consume other fuels, such as landfill gas, crude oil, and residual fuel oil.

  Although only 28 percent of units use distillate oil, in terms of the total MW capacity of the population, distillate oil fuels a disproportionate percentage, nearly 43 percent. This implies either that many of the mid- to large-sized turbines are fueled by distillate oil, that natural gas is more common in smaller units, or that a combination of the two explains this fact.

- Hours of Operation: Nearly half of all turbines (925 units) operate more than 7,500 hours per year (see Table 4-2). A year consists of approximately 8,760 hours. Although 488 units operate less than 500 hours per year, only 414 units operate between 500 and 7,500 hours per year. Information on annual hours of operation was unavailable for 245 (or 12 percent) of the 2,072 units. Because the

Table 4-1. Facilities With Units Having Capacities Above 1 MW by Industry Grouping and Government Sector

NAICS	Description	# Units	# Facilities
112	Animal Production	1	1
211	Oil and Gas Extraction	365	105
212	Mining (Except Oil and Gas)	3	3
221	Utilities	983	393
233	Building, Developing, and General Contracting	1	1
235	Special Trade Contractors	2	1
311	Food Manufacturing	18	11
321	Wood Products Manufacturing	3	2
322	Paper Manufacturing	17	11
324	Petroleum and Coal Products Manufacturing	34	11
325	Chemical Manufacturing	63	39
326	Plastics and Rubber Products Manufacturing	4	3
327	Nonmetallic Mineral Product Manufacturing	1	1
331	Primary Metal Manufacturing	13	4
332	Fabricated Metal Product Manufacturing	2	2
333	Machinery Manufacturing	2	2
334	Computer and Electronic Product Manufacturing	6	5
335	Electrical Equipment, Appliance, and Component Manufacturing	1	1
336	Transportation Equipment Manufacturing	3	3
337	Furniture and Related Product Manufacturing	1	1
339	Miscellaneous Manufacturing	3	3
422	Wholesale Trade, Nondurable Goods	6	4
486	Pipeline Transportation	448	244
488	Support Activities for Transportation	1	1
513	Broadcasting and Telecommunications	1	1
522	Credit Intermediation and Related Activities	3	1
541	Professional, Scientific, and Technical Services	2	2
561	Administrative and Support Services	1	1
611	Educational Services	10	8
622	Hospitals	23	14
721	Accommodation	1	1
923	Administration of Human Resource Programs	1	1
926	Administration of Economic Programs	1	1
928	National Security and International Affairs	42	12
Unknown	Industry Classification Unknown	6	5
Total		2,072	899

Source: Industrial Combustion Coordinated Rulemaking (ICCR). 1998. Data/Information Submitted to the Coordinating Committee at the Final Meeting of the Industrial Combustion Coordinated Rulemaking Federal Advisory Committee. EPA Docket Numbers A-94-63, II-K-4b2 through -4b5. Research Triangle Park, North Carolina. September 16-17.

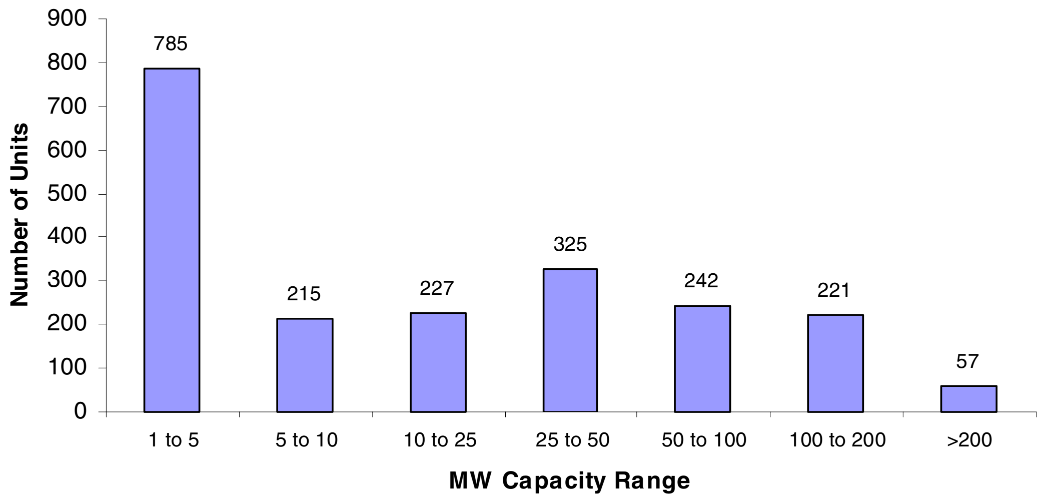

Figure 4-1. Number of Units by MW Capacity

Table 4-2. Stationary Combustion Turbine Projections

	Total Number of New Units
Utility Turbines	
Base load energy (combined cycle)	136
Peak power (simple cycle)	66
Total utility turbines	202
Nonutility Turbines	
Small	3
Medium	9
Large	4
Total nonutility turbines	16
Total in 5th year	218
Average per year	44

vast majority of those units were located on pipelines, which operate 24 hours a day, or at electric utility plants, many of the 245 units probably operate more than 7,500 hours a year.

- Annual MWh Equivalent: Figure 4-2 presents the distribution of units by the estimated annual MWh equivalent produced by each unit. For units that are used for compression or other functions, their likely MWh output was estimated using their MW capacity and annual hours of operation. Annual MWh for 245 units lacking annual hours of operation information was not calculated. Figure 4-3 includes data for the other 1,827 units, more than one-third of which have output of between 10,000 and 50,000 MWh a year. 360 units have output of less than 5,000 MWh, and 217 units have output greater than 500,000 MWh.

- Simple vs. combined cycle: Information was not available from the Inventory Database on the type of turbine. However, based on industry sales data, a breakdown of 1998 industry orders shows that 32 percent of the orders were for peak SCCTs and the remaining 68 percent were for CCCTs. Sixty percent of the buyers were merchant plants, 10 percent were independent power producers (IPPs), and the remaining 30 percent were rate-base utility generators (Siemens Westinghouse, 1999).

4.2 Projected Growth of Combustion Turbines

The Agency estimates there will be a total of 218 new stationary combustion turbines over the next 5 years (see Table 4-2). This projection is based on information supplied from the turbine manufacturing industry, state permit data compiled by EPA, and Gas Turbine World's *1999-2000 Handbook on Gas Turbine Orders and Installations*.

4.2.1 Comparison of Alternative Growth Estimates

Specific growth projections for combustion turbines vary with respect to the timing of the construction of new units. Table 4-3 shows that according to 1998 projections made by the Department of Energy (DOE), U.S. electric utilities were planning to install 316 new units between 1998 and 2007. The units are expected to average 165 MW. The majority of these units are projected to be CCCTs (DOE, 1999d). According to a second study, the Department of Energy projects 300 GW of new generation capacity will be needed by the year 2020 (Reuters News Service, 1999).

Because the electric utility industry accounts for over 90 percent of the projected new units and 97 percent of the projected new capacity in MW and nearly half of the existing units and 72 percent of the existing capacity in MW, the remainder of this section focuses on the trends in the electric utility industry.

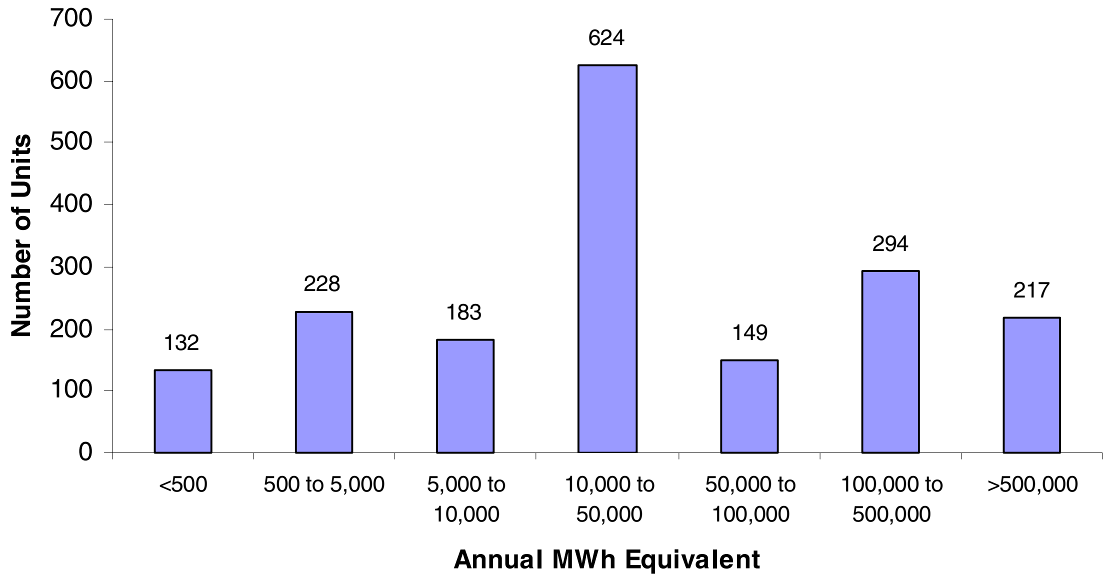

Figure 4-2. Number of Units by Annual MWh Output Equivalent

Note: Excludes 245 units for which information on annual hours of operation was unavailable.

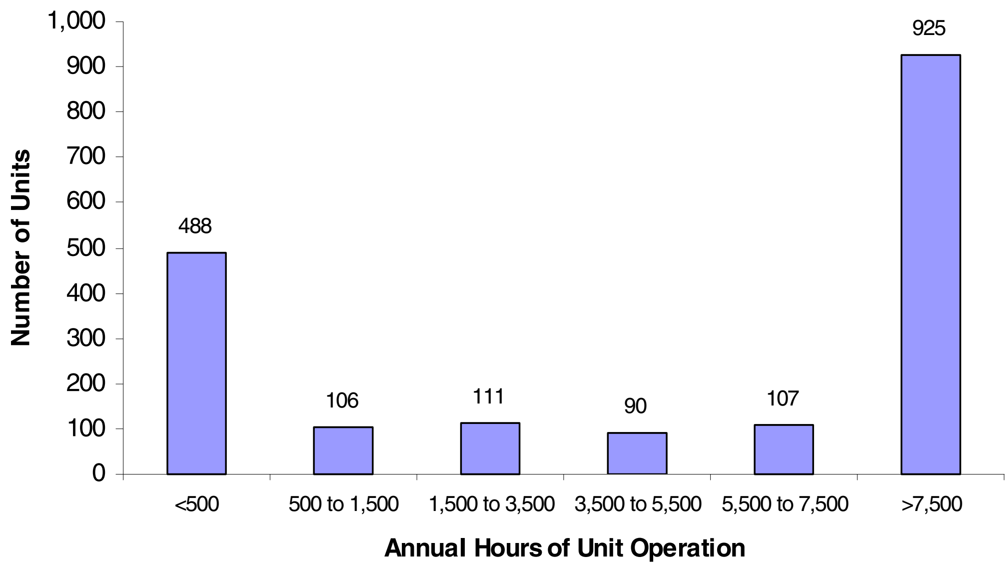

Figure 4-3. Number of Units by Annual Hours of Operation

Note: Excludes 245 units for which information on annual hours of operation was unavailable.

Table 4-3. Planned Capacity Additions at U.S. Public Utilities, 1998 through 2007, as of January 1, 1998

Year	Number of Units	Generator Nameplate Capacity (MW)
U.S. Total	316	52,044
1998	60	2,020
1999	25	2,298
2000	31	3,875
2001	31	5,843
2002	35	5,978
2003	34	8,201
2004	26	5,707
2005	31	7,576
2006	22	5,879
2007	21	4,667

Notes: Total may not equal the sum of components because of independent rounding.

Source: U.S. Department of Energy, Energy Information Administration. 1999c. *Electric Power Annual 1998*. Volumes I and II. Washington, DC: U.S. Department of Energy.

4.3 Number of Affected Stationary Combustion Turbines

We estimate that 20 percent of the stationary combustion turbines affected by this rule will be located at major sources. This estimate is based on an examination by EPA of permit data, which indicated that utility turbines will primarily be installed at greenfield power plants where no other sources of HAP emissions will be present. Greenfield power plants that had a total capacity of more than the calculated MW were assumed to be major sources, while those that were less were assumed to be area sources. Industrial turbines were all assumed to go into brownfield sites that were already major HAP sites. Based on this analysis of permit data, it is expected that twenty percent of new turbines will be major sources. EPA also assumed that this percentage applied to existing sources. Because only existing LPC turbines have a MACT requirement, the EPA estimated the number of existing LPC turbines to be about ten percent of the total number of turbines (8,000). This amounts to 800 existing LPC turbines, of which twenty percent are major or an estimated 160 LPC turbines that are major. Because these 160 turbines are located at major sources, these turbines can be defined as potentially subject to a MACT standard (since all other sources would not be subject to a MACT such as this one). Of these 160 turbines, 10 or about 6 percent are expected to install an oxidation catalyst system to comply with the emission limitations. This estimate is for the fifth year after promulgation. The calculation that is used to derive this estimate is in the "Cost Impacts Associated with Stationary Combustion Turbine MACT," a memo that is in the public docket. As a result, the environmental and energy impacts presented here reflect these estimates.

For new stationary combustion turbines, 771 new turbines are projected to come online by the fifth year after promulgation as shown in Table 4-2; 20 percent or 154 are expected to be at major sources. Ten of these 154 turbines are expected to require installation of an oxidation catalyst to meet the emission limitations in the rule for new sources. Thus, the percentage of new stationary combustion turbines affected is about 6.5 percent. A breakdown of these 154 turbines shows that 75 new base load energy turbines and 24 peak power turbines will be affected in the next 5 years. For new nonutility turbines, 56 new units will be affected in the next 5 years.

Based on the description in the previous two paragraphs, 20 stationary combustion turbines will have to apply an oxidation catalyst to meet the emission limitations associated with this rule.

Finally, in the fifth year after promulgation, 59 turbines are expected to require performance testing. This total includes the 31 new turbines (which is 20 percent of 154) that come online that year and are required to conduct an initial performance test to demonstrate compliance. EPA also estimates that an additional 10 percent of combustion turbines installed prior to the fifth year may be required to conduct performance testing to demonstrate compliance if the enforcing agency has reason to believe the turbine is not performing correctly. Therefore, 10 percent of the 123 affected turbines projected to be installed in the first four years after promulgation, 10 percent of the 160 affected turbines that existed before promulgation, and 31 new turbines will conduct performance testing in the fifth year, which equals 59 (12 + 16 + 31) turbines total. The calculations of these estimates are in "Cost Impacts Associated with Stationary Combustion MACT," a memo that is in the public docket

4.4 HAP and Other Emission Reductions

The rule will reduce total national HAP emissions by an estimated 81 tons/year in the fifth year after the standards are promulgated. The emissions reductions achieved by the rule would be come from the sources that install an oxidation catalyst control system. We estimate that about 10 existing lean premix combustion turbines will install oxidation catalyst control to comply with the standard. In addition, we estimate that about 5 percent of new stationary combustion turbines will install oxidation catalyst control to comply with the standards. The other 95 percent of new stationary combustion turbines will be lean premix, a pollution prevention technology which in most cases does not require the use of oxidation catalyst control. The lean premix turbines are currently being installed to meet NO_x emission standards. The reduction of HAP emissions for these stationary combustion turbines is difficult to assess because it is a pollution prevention technology and is being installed to meet NO_x limits, not as a result of MACT for stationary combustion turbines. Therefore, as stated previously, the HAP emissions reductions obtained by the rule result only from the sources that install an oxidation catalyst control system.

To estimate the baseline HAP emissions and reductions associated with this rule, national HAP emissions in the absence of the rule were calculated using an emission factor from the emissions database. We assumed new stationary combustion turbines are operated 8,760 hours annually. We then assumed a HAP reduction of 95 percent, achieved by using oxidation catalyst emission control devices to comply with the emission limitation to reduce CO emissions, and applied this reduction to the baseline HAP emissions to estimate total national HAP emission reduction. The total national HAP emission reduction of 81 tons per year in the fifth year following promulgation is the sum of formaldehyde, acetaldehyde, benzene, and toluene emission reductions.

In addition to HAP emission reductions, the rule will reduce criteria air pollutant emissions, primarily CO emissions, though there will be a very small amount of PM and VOC emission reductions as well. There are estimated to be 3,800 tons of CO emission reductions associated with this rule. PM emissions are very low from stationary combustion turbines since virtually all of the affected turbines burn natural gas or similar gaseous fuels. Very few existing turbines burn oils, and we do not believe any new affected turbines in the next five years will exclusively use an oil fuel. Any turbines that are built to use oils are likely to be dual fuel-fired, which means they can operate off of two different types of fuel that are likely to be natural gas and diesel oil. In any event, oxidation catalyst control systems will reduce PM emissions by 25 to 50 percent. Oxidation catalyst control systems will reduce VOC emissions as well. The control efficiency depends on the specific compounds. However, we believe that VOC (and hydrocarbon [HC]) emissions from combustion turbines that are not HAP are very low and we have been unable to quantify emission reductions for these pollutants.

4.5 Energy and Other Impacts from Direct Application of Control Measures

The only energy impact from the direct application of oxidation catalyst control systems is the pressure drop across the oxidation catalyst bed of typically 1 to 1-1/2 inches of water pressure drop. According to information contained in the Gas Turbine World 1999-2000 Handbook (GTWH), a rough rule of thumb for heavy frame turbines, which are the types of turbines which we believe will mostly be installed in the next five years, is that every four inches of water pressure outlet loss is equivalent to a 0.6 percent heat rate loss resulting in a 0.6 percent power output loss. (Heat rate is a measure of the amount of inlet heat input to a turbine required to produce a certain amount of power. When the turbine heat rate increases, more inlet heat is required to produce the same amount of power resulting in a decrease in the thermal efficiency.)

Vendors state that an oxidation catalyst system can be designed so that the maximum pressure drop across the control device does not exceed 1.5 inches of water pressure drop including the catalyst system and housing. Therefore, the heat rate increase is expected to be about 0.15 percent (1/4 x 0.6 percent) increase per inch of water pressure drop increase in the turbine outlet. (Other studies by Gas Technology Institute have indicated that this value is 0.105 percent per inch of turbine outlet pressure drop. However we chose to use the GTWH value for this calculation.) Therefore for a 1.5 inch pressure drop across an oxidation catalyst system, the power output loss is estimated to be 0.225 percent (1.5 x 0.15). This represents the energy impact which is very low.

4.5.1 Water Impacts

Oxidation catalyst systems do not use water or produce water so the water impacts are expected to be very low.

4.5.2 Solid Waste Impacts

Oxidation catalyst are made with precious metals. When the catalyst charge is replaced (about every six years), the old catalyst is usually sent to a catalyst metal processor who reclaims the precious metals and the owner/operator gets a reimbursement from the processor. Therefore, because the spent catalyst is recycled, the solid waste impact is very small.

4.6 Trends in the Electric Utility Industry

Most industry and government forecasts project sizable growth of new electric power generation capacity in the near future to meet the increase in consumer demand for electricity and the retirement of aging coal and nuclear units. Experts agree that this new capacity will mainly come from SCCTs and CCCT units fueled by natural gas. Two factors have contributed to recent and projected dominance of gas combustion turbines to meet the demand for new generation capacity:

- Technology advances in combustion turbines have increased efficiency.
- Deregulation of the electric utility industry has opened the market to smaller independent operators with applications ideally suited for combustion turbines.

Over the next 5 years deregulation of the electric power industry will be the main factor influencing the growth of combustion turbines to generate electric power. Deregulation is influencing the demand for utility combustion turbines in the following ways:

1. Competitive markets for wholesale power are leading to the replacement of less-efficient coal and nuclear power plants. Because of advances in gas turbine technology, new SCCTs and CCCTs are more economical compared to new oil and coal power plants and less-efficient existing plants.
2. Competitive markets for wholesale power have led to an increased demand for bulk transmission resources. However, economic and political factors continue to limit the growth in new transmission corridors. Combustion turbine units that are smaller in size and more environmentally friendly (compared to coal or nuclear power plants) can be placed throughout the grid (referred to as distributed generation) to alleviate transmission constraints.

3. Deregulation has opened the market to merchant power producers and IPPs. The smaller-scale combustion turbine power plants are ideal for these market players who generally serve niche markets where there are capacity shortages or where industrial steam loads are high.[1]

[1]Most industry experts agree that (at least in the short run) deregulation will lead to four major regional power markets in the U.S. Bulk transmission interfaces between these four regional markets will continue to be capacity strained, implying that electricity prices may continue to vary from region to region. In addition, there will be local metropolitan areas or geographically isolated areas, such as San Francisco, where transmission constraints will restrict "perfect" competition. In these areas, small-scale distributed generation, such as CCCTs, will be able to command price premiums for electric power.

SECTION 5

PROFILES OF AFFECTED INDUSTRIES

This section contains profiles of the major industries affected by the regulation of stationary combustion turbines. The Agency anticipates that most of the direct costs of the regulation will be borne by the electric services (NAICS 22111) sector. However, the crude oil and natural gas extraction (NAICS 211) and natural gas pipelines (NAICS 486) sectors will be indirectly affected through changes in industry production and fuel switching. Together, these energy sectors account for about 90 percent of the existing combustion turbines (greater than 1 MW) identified by the Agency in the Inventory Database. The remaining combustion turbines are spread across a wide variety of industries, most notably chemicals and allied products, petroleum products, health services, and national security agencies, and are primarily used for self-generated electricity or co-generated electricity and process steam. Direct costs on these industries are expected to be minimal.

The Agency projects that growth in new combustion turbines that will be affected by the regulation will also be concentrated in the electric services, crude oil and natural gas extraction, and natural gas industries. This section contains background information on these three industries to help inform the regulatory process.

5.1 Electric Utility Industry (NAICS 22111)

This profile of the U.S. electric power industry provides background information on the evolution of the electricity industry, the composition of a traditional regulated electric utility, the current market structure of the electric industry, and deregulation trends and the potential future market structure of the electricity market. This profile also discusses current industry characteristics and trends that will influence the future generation and consumption of electricity.

5.1.1 Market Structure of the Electric Power Industry

The ongoing process of deregulation of wholesale and retail electric markets is changing the structure of the electric power industry. Deregulation is leading to the functional unbundling of generation, transmission, and distribution and to competition in the generation segment of the industry. This section provides background on the current structure of the industry and future deregulation trends. It begins with a brief overview of the evolution of the electric power industry because the future market structure will, in large part, be determined by the existing infrastructure and capital assets that have evolved over the past decades.

5.1.1.1 The Evolution of the Electric Power Industry

The electric utility industry began as isolated local service systems with the first electric companies evolving in densely populated metropolitan areas like New York and Chicago. Prior to World War I, rural electrification was a piecemeal process. Only small, isolated systems existed, typically serving a single town. The first high-voltage transmission network was built in the Chicago area in 1911 (the Lake County experiment). This new network connected the smaller systems surrounding Chicago and resulted in substantial production economies, lower customer prices, and increased company profits.

In light of the success of the Lake County experiment, the 1910s and 1920s saw increased consolidation and rapid growth in electricity usage. During this period, efficiency gains and demand growth provided the financing for system expansions. Even though the capacity costs (fixed costs per peak kW demanded) were typically twice as large with the consolidated/interconnected supply systems, the fixed costs per unit of energy production (kWh) were comparable to those of the old single-city system. This was the case because of load factor improvements, which resulted from aggregating customer demand.

Whereas the average fixed cost per customer was relatively unchanged as a result of the move from single-city to consolidated supply systems, large savings were realized from decreases in operating costs. In particular, fuel costs per kWh decreased 70 percent because of the improved combustion efficiency of larger plants and lower fuel prices for purchases of large quantities. In addition, operation and maintenance costs decreased 85 percent, primarily as a result of decreased labor intensity.

During the 1920s, only a small part of the efficiency gains were passed on to customers in the form of lower prices. Producers retained the bulk of the productivity increases as profits. These profits provided the internal capital to finance system expansions and to buy out smaller suppliers. Industry expansion and consolidation led to the development of large utility holding companies whose assets were shares of common stock in many different operating utilities.

The speculative fever of the 1920s led to holding companies purchasing one another, creating financial pyramids based on inflated estimates of company assets. With the stock market crash in 1929, shareholders who had realized both real economic profits and speculative gains lost large amounts of money. The financial collapse of the utility holding companies led to new levels of utility regulation.

From the 1930s through the 1960s, the regulated mandate of electric utilities was basically unchanged: to provide safe, adequate, and reliable service to all electricity users. The majority of the state and federal laws regulating utilities in place during this era had been written shortly after the Depression. The laws were primarily designed to prevent "ruinous competition" through costly duplication of utility functions and to protect customers against exploitation from a monopoly supplier.

During this period, most utilities were vertically integrated, controlling everything from generation to distribution. Economies of scale in generation and the inefficiency of duplicating transmission and distribution systems made the electric utility industry a textbook example of a natural monopoly. Electricity was viewed as a homogeneous good from which there were no product unbundling opportunities or unique product offerings on which competition could get a foothold. In addition, the industry was extremely capital-intensive, providing a sizable barrier to entry even if the monopoly status of the utilities had not been protected.

From the 1930s to the 1960s, the electric industry experienced almost continuous growth in demand. In addition, there was a steady stream of technological innovations in generation, transmission, and distribution operations. The increased economies of scale, technological advances, and fast demand growth led to steadily declining unit costs. However, in an environment of decreasing unit costs, there were few rate cases and almost no pressure from customers to change the system. This period is often referred to as the golden era for the electric utility industry.

5.1.1.2 Structure of the Traditional Regulated Utility

The utilities vary substantially in size, type, and function. Figure 5-1 illustrates the typical structure of the electric utility market. Even with the technological and regulatory changes in the 1970s and 1980s, at the beginning of the 1990s the structure of the electric utility industry could still be characterized in terms of generation, transmission, and distribution. Commercial and retail customers were in essence "captive," and rates and service quality were primarily determined by public utility commissions.

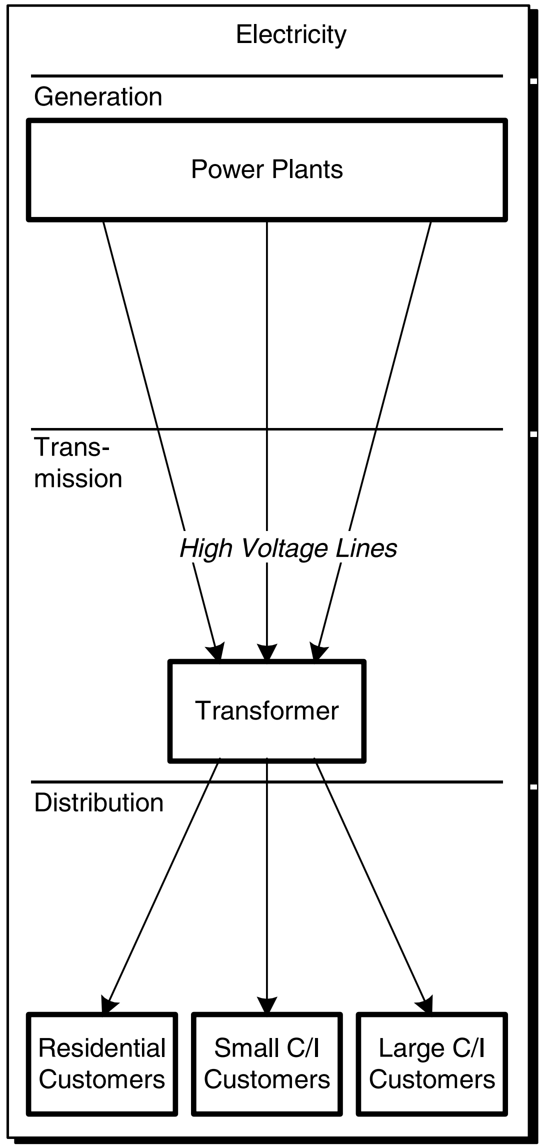

Figure 5-1. Traditional Electric Power Industry Structure

The majority of utilities are interconnected and belong to a regional power pool. Pooling arrangements enable facilities to coordinate the economic dispatch of generation facilities and manage transmission congestion. In addition, pooling diverse loads can increase load factors and decrease costs by sharing reserve capacity.

Generation. Coal-fired plants have historically accounted for the bulk of electricity generation in the United States. With abundant national coal reserves and advances in pollution abatement technology, such as advanced scrubbers for pulverized coal and flue gas-desulfurization systems, coal will likely remain the fuel of choice for most existing generating facilities over the near term.

Natural gas accounts for approximately 10 percent of current generation capacity but is expected to grow; advances in natural gas exploration and extraction technologies and new coal gasification have contributed to the use of natural gas for power generation.

Nuclear plants and renewable energy sources (e.g., hydroelectric, solar, wind) provide approximately 20 percent and 10 percent of current generating capacity, respectively. However, there are no plans for new nuclear facilities to be constructed, and there is little additional growth forecasted in renewable energy.

Transmission. Transmission refers to high voltage lines used to link generators to substations where power is stepped down for local distribution. Transmission systems have been traditionally characterized as a collection of independently operated networks or grids interconnected by bulk transmission interfaces.

Within a well-defined service territory, the regulated utility has historically had responsibility for all aspects of developing, maintaining, and operating transmissions. These responsibilities included

- system planning and expanding,
- maintaining power quality and stability, and
- responding to failures.

Isolated systems were connected primarily to increase (and lower the cost of) power reliability. Most utilities maintained sufficient generating capacity to meet customer needs, and bulk transactions were initially used only to support extreme demands or equipment outages.

Distribution. Low-voltage distribution systems that deliver electricity to customers comprise integrated networks of smaller wires and substations that take the higher voltage and step it down to lower levels to match customers' needs.

The distribution system is the classic example of a natural monopoly because it is not practical to have more than one set of lines running through neighborhoods or from the curb to the house.

5.1.1.3 Current Electric Power Supply Chain

This section provides background on existing activities and emerging participants in the electric power supply chain.[1] Because the restructuring plans and time tables are made at the state level, the issues of asset ownership and control throughout the current supply chain in the electric power industry vary from state to state. However, the activities conducted throughout the supply chain are generally the same.

Table 5-1 shows costs by utility ownership and by segment of the supply chain. Generation accounts for approximately 75 percent of the cost of delivered electric power.

Figure 5-2 provides an overview of the electric power supply chain, highlighting a combination of activities and service providers. The activities/members of the electric power supply chain are typically grouped into generation, transmission, and distribution. These three segments are described in the following sections.

Generation. As part of deregulation, the transmission and distribution of electricity are being separated from the business of generating electricity, and a new competitive market in electricity generation is evolving. As power generators prepare for the competitive market, the share of electricity generation attributed to nonutilities and utilities is shifting.

More than 7,000 electricity suppliers currently operate in the U.S. market. As shown in Table 5-2, approximately 42 percent of suppliers are utilities and 58 percent are nonutilities. Utilities include investor-owned, cooperatives, and municipal systems. Of the approximately 3,100 utilities operating in the United States, only about 700 generate electric power. The majority of utilities distribute electricity that they have purchased from power generators via their own distribution systems.

Utility and nonutility generators produced a total of 3,369 billion kWh in 1995. Although utilities generate the vast majority of electricity produced in the United States, nonutility generators are quickly eroding utilities' shares of the market. Nonutility generators include private entities that generate power for their own use or to sell to utilities or other end users. Between 1985 and 1995, nonutility generation increased from 98 billion kWh (3.8 percent of total generation) to 374 billion kWh (11.1 percent). Figure 5-3 illustrates this shift in the share of utility and nonutility generation.

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[1]The electric power supply chain includes all generation, transmission, distribution, administrative, and market activities needed to deliver electric power to consumers.

Table 5-1. Total Expenditures in 1996 ($$10^3$)

Utility Ownership	Generation	Transmission	Distribution	Customer Accounts and Sales	Administration and General Expenses
Investor-owned	80,891,644	2,216,113	6,124,443	6,204,229	13,820,059
Publicly owned	12,495,324	840,931	1,017,646	486,195	1,360,111
Federal	3,685,719	327,443	1,435	55,536	443,809
Cooperatives	15,105,404	338,625	1,133,984	564,887	1,257,015
	112,178,091	3,723,112	8,277,508	7,310,847	16,880,994
	75.6%	2.5%	5.6%	4.9%	11.4%
	148,370,552				

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 1998a. *Financial Statistics of Major Publicly Owned Electric Utilities, 1997*. Washington, DC: U.S. Department of Energy.

U.S. Department of Energy, Energy Information Administration (EIA). 1997. *Financial Statistics of Major U.S. Investor-Owned Electric Utilities, 1996*. Washington, DC: U.S. Department of Energy.

Utilities. There are four categories of utilities: investor-owned utilities (IOUs), publicly owned utilities, cooperative utilities, and federal utilities. Of the four, only IOUs always generate electricity.

IOUs are increasingly selling off generation assets to nonutilities or converting those assets into nonutilities (Haltmaier, 1998). To prepare for the competitive market, IOUs have been lowering their operating costs, merging, and diversifying into nonutility businesses.

In 1995, utilities generated 89 percent of electricity, a decrease from 96 percent in 1985. IOUs generate the majority of the electricity produced in the United States. IOUs are either individual corporations or a holding company, in which a parent company operates one or more utilities integrated with one another. IOUs account for approximately three-quarters of utility generation, a percentage that held constant between 1985 and 1995.

Utilities owned by the federal government accounted for about one-tenth of generation in both 1985 and 1995. The federal government operated a small number of large utilities in 1995 that supplied power to large industrial consumers or federal installations. The Tennessee Valley Authority is an example of a federal utility.

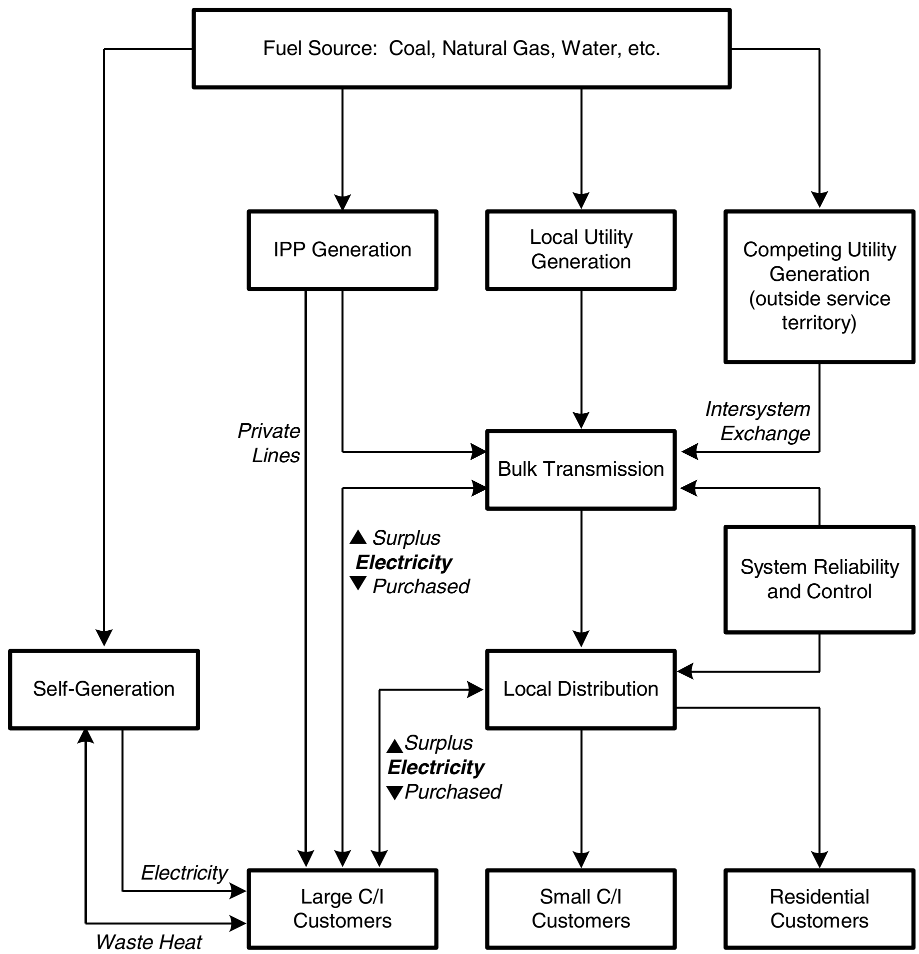


Figure 5-2. Electric Utility Industry

Many states, municipalities, and other government organizations also own and operate utilities, although the majority do not generate electricity. Those that do generate electricity operate capacity to supply some or all of their customers' needs. They tend to be small, localized outfits and can be found in 47 states. These publicly owned utilities accounted for about one-tenth of utility generation in 1985 and 1995. In a deregulated market, these generators may be in direct competition with other utilities to service their market.

Table 5-2. Number of Electricity Suppliers in 1999

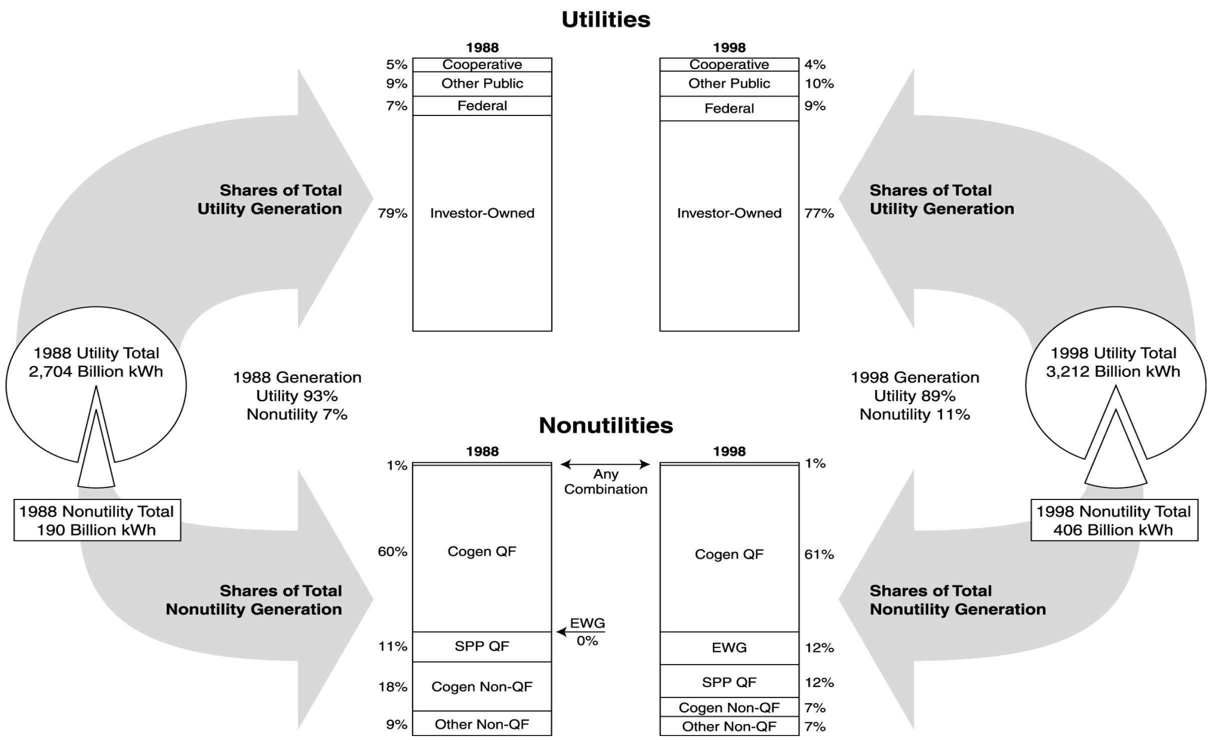
Electricity Suppliers	Number	Percent
Utilities	3,124	42%
Investor-owned utilities	222	
Cooperatives	875	
Municipal systems	1,885	
Public power districts	73	
State projects	55	
Federal agencies	14	
Nonutilities	4,247	58%
Nonutilities (excluding EWGs)	4,103	
Exempt wholesale generators	144	
Total	7,371	100%

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999g. *The Changing Structure of the Electric Power Industry 1999: Mergers and Other Corporate Combinations*. Washington, DC: U.S. Department of Energy.

Rural electric cooperatives are the fourth category of utilities. They are formed and owned by groups of residents in rural areas to supply power to those areas. Cooperatives generally purchase from other utilities the energy that they sell to customers, but some generate their own power. Cooperatives only produced 5 percent of utility generation in 1985 and only 6 percent in 1995.

Nonutilities. Nonutilities are private entities that generate power for their own use or to sell to utilities or other establishments. Nonutilities are usually operated at mines and manufacturing facilities, such as chemical plants and paper mills, or are operated by electric and gas service companies (DOE, EIA, 1998b). More than 4,200 nonutilities operate in the United States.

Between 1985 and 1995, nonutility generators increased their share of electricity generation from 4 percent to 11 percent (see Figure 5-3). In 1978, the Public Utilities Regulatory Policies Act (PURPA) stipulated that electric utilities must interconnect with and purchase capacity and energy offered by any qualifying nonutility. In 1996, FERC issued Orders 888 and 889 that opened transmission access to nonutilities and required utilities to



[a] Includes facilities classified in more than one of the following FERC designated categories: cogenerator QF, small power producer QF, or exempt wholesale generator.
Cogen = Cogenerator.
EWG = Exempt wholesale generator.
Other Non-QF = Nocogenerator Non-QF.
QF = Qualifying facility.
SPP = Small power producer.
Note: Sum of components may not equal total due to independent rounding. Classes for nonutility generation are determined by the class of each generating unit.
Sources: **Utility data:** U.S. Department of Energy, Energy Information Administration (EIA). 1996b. *Electric Power Annual 1995*. Volumes I and II. DOE/EIA-0348(95)/1. Washington, DC: U.S. Department of Energy; Table 8 (and previous issues); **1985 nonutility data:** Shares of generation estimated by EIA; total generation from Edison Electric Institute (EEI). 1998. *Statistical Yearbook of the Electric Utility Industry 1998*. November. Washington, DC; **1995 nonutility data:** U.S. Department of Energy, Energy Information Administration (EIA). 1996b. *Electric Power Annual 1995*. Volumes I and II. DOE/EIA-0348(95)/1. Washington, DC: U.S. Department of Energy.

Figure 5-3. Utility and Nonutility Generation and Shares by Class, 1988 and 1998

share information about available transmission capacity. These moves established wholesale competition, spurring nonutilities to increase generation and firms to invest in nonutility generation.

Nonutilities are frequently categorized by their FERC classification and the type of technology they employ. There are three categories of nonutilities: cogenerators, small power producers (SPPs), and exempt wholesale generators (EWGs).

Cogenerators are nonutilities that sequentially or simultaneously produce electricity and another form of energy (such as heat or steam) using the same fuel source. At cogeneration facilities, steam is used to drive a turbine to generate electricity. The waste heat and steam from driving the turbine is then used as an input in an industrial or commercial process. For a cogenerator to qualify or interconnect with utilities, it must meet certain ownership, operating, and efficiency criteria specified by FERC. In 1985, about 55 percent of nonutility generation was produced by cogenerators that qualified or met FERC's specifications and sold power to utilities. By 1995 the percentage increased to 67 percent as the push for deregulation gathered momentum. At the same time, the percentage that was produced by nonqualifying cogenerators decreased from 25 percent to 9 percent.

SPPs typically generate power using renewable resources, such as biomass, solar energy, wind, or water. However, increasingly SPPs include companies that self-generate power using combustion turbines and sell excess power back to the grid. As with cogenerators, SPPs must fulfill a series of FERC requirements to interconnect with utilities. PURPA revisions enabled nonutility renewable electricity to grow significantly, and SPPs have responded by improving technologies, decreasing costs, and increasing efficiency and reliability (DOE, EIA, 1998b). Between 1985 and 1995, the percentage of SPP nonutility generation nearly doubled to 13 percent.

EWGs produce electricity for the wholesale market. Also known as IPPs, EWGs typically contract directly with large bulk customers, such as large industrial and commercial facilities and utilities. They do not operate any transmission or distribution facilities but pay tariffs to use facilities owned and operated by utilities. Unlike with qualifying cogenerators and SPPs, utilities are not required to purchase energy produced by EWGs, but they may do so at market-based prices. EWGs did not exist until the Energy Policy Act created them in 1992, and by 1995 they generated about 2 percent of nonutility electricity.

In 1995, about 4 percent of nonutility generation was produced by facilities that were classified as any combination of cogenerator, SPP, and EWG. An additional 6 percent was produced by facilities that generate electricity for their own consumption.

Transmission. Whereas the market for electricity generation is moving toward a competitive structure, the transmission of electricity is currently (and will likely remain) a regulated, monopoly operation. In areas where power markets are developing, generators pay tariffs to distribute their electricity over established lines owned and maintained by independent organizations. Independent service operators (ISOs) will most likely coordinate transmission operations and generation dispatch over the bulk power system.

The bulk power transmission system consists of three large regional networks, which also encompass smaller groups. The three networks are geographically defined: the Eastern Interconnect in the eastern two-thirds of the nation; the Western Interconnect in the western portion; and the Texas Interconnect, which encompasses the majority of Texas. The western and eastern networks are each fully integrated with Canada. The western is also integrated with Mexico. Within each network, the electricity producers are connected by extra high-voltage connections that allow them to transfer electrical energy from one part of the network to the other.

The bulk power system makes it possible for electric power producers to engage in wholesale trade. In 1995, utilities sold 1,283 billion kWh to other utilities. The amount of energy sold by nonutilities has increased dramatically from 40 billion kWh in 1986 to 222 billion kWh in 1995, an average annual increase of 21 percent (DOE, EIA, 1996a). Distribution utilities and large industrial and commercial customers also have the option of purchasing electricity in bulk at market prices from their local utility, a nonutility, or another utility. The process of transmitting electricity between suppliers via a third party is known as wholesale wheeling.

The wholesale trade for electricity is increasingly handled by power marketers (brokers). Power marketers act as independent middlemen that buy and sell wholesale electricity at market prices (EEI, 1999). Customers include large commercial and industrial facilities in addition to utilities. Power marketers emerged in response to increased competition. Brokers do not own generation facilities, transmissions systems, or distribution assets, but they may be affiliated with a holding company that operates generation facilities. Currently, 570 power marketers operate in the United States. The amount of power sold by marketers increased from 3 million MWh to 2.3 billion MWh between 1995 and 1998. This is the equivalent of going from powering 1 million homes to powering 240 million homes

(EEI, 1999). Table 5-3 lists the top ten power marketers by sales for the first quarter of 1999.

Table 5-3. Top Power Marketing Companies, First Quarter 1999

Company	Total MWh Sold
Enron Power Marketing, Inc.	78,002,931
Southern Company Energy Marketing, L.P.	38,367,107
Aquila Power Corp.	29,083,612
PG&E Energy Trading-Power, L.P.	28,463,487
Duke Energy Trading & Marketing, L.L.C.	22,276,608
LG&E Energy Marketing, Inc.	15,468,749
Entergy Power Marketing Corp.	12,670,520
PacifiCorp Power Marketing, Inc.	11,800,263
Tractebel Energy Marketing, Inc.	10,041,039
NorAm Energy Services, Inc.	9,817,306

Source: Resource Data International. 1999. "PMA Online Top 25 Power Marketer Rankings." *Power Marketers Online Magazine*. <http://www.powermarketers.com/top25a.htm.> As obtained on August 11, 1999.

Distribution. The local distribution system for electricity is expected to remain a regulated monopoly operation. But power producers will soon be able to compete for retail customers by paying tariffs to entities that distribute the power. Utilities may designate an ISO to operate the distribution system or continue to operate it themselves. If the utility operates its own system, it is required by law to charge the same tariff to other power producers that it charges producers within its own corporate umbrella. The sale of electricity by a utility or other supplier to a customer in another utility's retail service territory is known as retail wheeling.

Supporters of retail wheeling claim that it will help lower the average price paid for electricity. The states with the highest average prices for electricity are expected to be the first to permit retail wheeling; wholesale wheeling is already permitted nationwide. In 1996, California, New England, and the Mid-Atlantic States had the highest average prices for electricity, paying 3 cents or more per kilowatt-hour than the national average of 6.9 cents (DOE, EIA, 1998b). Open access to the electricity supply, coupled with a proliferation of electricity suppliers, should combine to create falling electricity prices and increasing usage.

By 2002, the nationwide average price for electricity is projected to be 11 percent lower than in 1995, an average annual decline of roughly 2 percent (Haltmaier, 1998).

The explosion in computer and other information technology usage in the commercial sector is expected to offset energy efficiency gains in the residential and industrial sectors and lead to a net increase in the demand for electricity. Retail wheeling has the potential to allow customers to lower their costs per kilowatt-hour by purchasing electricity from suppliers that best fit their usage profiles. Large commercial and industrial customers engaged in self-generation or cogeneration will also be able to sell surplus electricity in the wholesale market.

5.1.1.4 Overview of Deregulation and the Potential Future Structure of the Electricity Market

Beginning in the latter part of the 19th century and continuing for about 100 years, the prevailing view of policymakers and the public was that the government should use its power to require or prescribe the economic behavior of "natural monopolies" such as electric utilities. The traditional argument is that it does not make economic sense for there to be more than one supplier—running two sets of wires from generating facilities to end users is more costly than one set. However, since monopoly supply is not generally regarded as likely to provide a socially optimal allocation of resources, regulation of rates and other economic variables was seen as a necessary feature of the system.

Beginning in the 1970s, the public policy view shifted against traditional regulatory approaches and in favor of deregulation for many important industries including transportation, communications, finance, and energy. The major drivers for deregulation of electric power included the following:

- existence of rate differentials across regions offering the promise of benefits from more efficient use of existing generation resources if the power can be transmitted across larger geographic areas than was typical in the era of industry regulation;
- the erosion of economies of scale in generation with advances in combustion turbine technology;
- complexity of providing a regulated industry with the incentives to make socially efficient investment choices;
- difficulty of providing a responsive regulatory process that can quickly adjust rates and conditions of service in response to changing technological and market conditions; and

- complexity of monitoring utilities' cost of service and establishing cost-based rates for various customer classes that promote economic efficiency while at the same time addressing equity concerns of regulatory commissions.

Viewed from one perspective, not much changes in the electric industry with restructuring. The same functions are being performed, essentially the same resources are being used, and in a broad sense the same reliability criteria are being met. In other ways, the very nature of restructuring, the harnessing of competitive forces to perform a previously regulated function, changes almost everything. Each provider and each function become separate competitive entities that must be judged on their own.

This move to market-based provision of generation services is not matched on the transmission and distribution side. Network interactions on AC transmission systems have made it impossible to have separate transmission paths compete. Hence, transmission and distribution remain regulated. Transmission and generation heavily interact, however, and transmission congestion can prevent specific generation from getting to market. Transmission expansion planning becomes an open process with many interested parties. This open process, coupled with frequent public opposition to transmission expansion, slows transmission enhancement. The net result is greatly increased pressure on the transmission system.

Restructuring of the electric power industry could result in any one of several possible market structures. In fact, different parts of the country will probably use different structures, as the current trend indicates. The eventual structure may be dominated by a power exchange, bilateral contracts, or a combination. A strong Regional Transmission Organization (RTO) may operate in the area, or a vertically integrated utility may continue to operate a control area. In any case, several important characteristics will change:

- Commercial provision of generation-based services (e.g., energy, regulation, load following, voltage control, contingency reserves, backup supply) will replace regulated service provision. This drastically changes how the service provider is assessed.
- Individual transactions will replace aggregated supply meeting aggregated demand. It will be necessary to continuously assess each individual's performance.
- Transaction sizes will shrink. Instead of dealing only in hundreds and thousands of MW, it will be necessary to accommodate transactions of a few MW and less.

- Supply flexibility will greatly increase. Instead of services coming from a fixed fleet of generators, service provision will change dynamically among many potential suppliers as market conditions change.

5.1.2 Electricity Generation

Because of the uncertainties associated with the future course of deregulation, forecasting deregulation's impact on generation trends, and hence growth in combustion turbines, is difficult. However, most industry experts believe that deregulation will lead to increased competition in the wholesale (and eventually retail) power markets, driving out high cost producers of electricity, and that there will be an increased reliance on distributed generation to compensate for growing demands on the transmission system.

In 2000, the United States relied on fossil fuels to produce almost 74 percent of its electricity. Table 5-4 shows a breakdown of generation by energy source.[2] Whereas natural gas seems to play a relatively minor role among utility producers, it represents 30 percent of capacity among nonutility producers. This is because nonutilities use coal and petroleum to the same extent as the larger, traditionally regulated utility power producers.

Among nonutility producers, manufacturing facilities contain the largest electricity-generating capacity. Table 5-5 illustrates that, from 1995 through 1999, manufacturing facilities consistently had the capacity to produce over two-thirds of nonutility electricity generation.

In 1997 cogenerators produced energy totaling 146 billion kWh for their own use. Cogenerators are expected to continue to increase their generation capabilities at a slightly slower rate than utilities.

Table 5-6 further disaggregates capacity by prime mover and energy source at electric utilities. As the table shows, hydroelectric and steam are the two prime movers with the most units, while steam and nuclear generators have the greatest total capacity. Combustion turbines' (including the second stage of CCCTs) generation represents approximately 10 percent of total U.S. capacity.

Figure 5-4 shows the annual electricity sales by sector from 1970 with projections through 2020.

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[2]Nonutility power producers have approximately 10 percent of the capacity of utility power producers.

Table 5-4. Industry Capability by Energy Source, 2000

Energy Source	Utility Generators (MW)	Nonutility Generators (MW)	Total (MW)
Fossil fuels	424,218	173,320	597,538
Coal	259,059	56,190	315,249
Natural gas	38,964	58,668	97,632
Petroleum	26,250	13,003	39,253
Duel-fired	99,945	45,549	145,494
Nuclear	85,519	12,038	97,557
Hydroelectric	91,590	7,478	99,068
Renewable/other	1,050	16,322	17,372
Total	602,377	209,248	811,625

Sources: U.S. Department of Energy, Energy Information Administration. 2000. *Electric Power Annual, 1999*, Vol. 2. DOE/EIA-0348(99)/2. Washington, DC: U.S. Department of Energy.

Table 5-5. Installed Capacity at U.S. Nonutility Attributed to Major Industry Groups and Census Division, 1995 through 1999 (MW)

Year	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
1995	47,606	15,124[a]	2,165	3,428	544	1,388[a]	70,254
1996	49,529	16,050	2,181	3,313	542	1,575	73,189
1997	49,791	16,559	2,223	3,306	616	1,510	74,004
1998	51,255	24,527	2,506	3,275	534	15,989	98,085
1999	52,430	78,419	2,342	5,123	536	28,506	167,357

[a] Revised data.

Notes: All data are for 1 MW and greater. Data for 1997 are preliminary; data for prior years are final. Totals may not equal sum of components because of independent rounding.

Source: U.S. Department of Energy, Energy Information Administration (EIA). 2000. *Electric Power Annual 1999,* Volume II. Washington, DC: U.S. Department of Energy.

Table 5-6. Existing Capacity at U.S. Electric Utilities by Prime Mover and Energy Source, as of January 1, 1998

Prime Mover Energy Source	Number of Units	Generator Nameplate Capacity (MW)
U.S. Total	10,421	754,925
Steam	2,117	469,210
Coal only	911	276,895
Other solids[a]	15	334
Petroleum only	137	22,476
Gas only	117	10,840
Other solids/coal[a]	1	2
Solids/petroleum[b]	72	10,796
Solids/gas[b]	232	36,763
Solids/petroleum/gas[b]	1	558
Petroleum/gas	624	110,324
Internal Combustion	2,892	5,075
Petroleum only	1,799	2,671
Gas only	48	66
Petroleum/gas	1,044	2,335
Other solids only[a]	1	3
Combustion Turbine	1,549	63,131
Petroleum only	625	22,802
Gas only	179	5,776
Petroleum/gas	745	34,554
Second Stage of CCCTs	202	16,224
Petroleum only	11	470
Gas only	29	2,331
Coal/petroleum	1	326
Coal/gas	1	113
Petroleum/gas	100	8,852
Waste heat	60	4,130
Nuclear	107	107,632
Hydroelectric (conventional)	3,352	73,202
Hydroelectric (pumped storage)	141	18,669
Geothermal	27	1,746
Solar	11	5
Wind	19	14

[a] Includes wood, wood waste, and nonwood waste.
[b] Includes coal, wood, wood waste, and nonwood waste.

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999c. *Electric Power Annual 1998*. Volumes I and II. Washington, DC: U.S. Department of Energy.

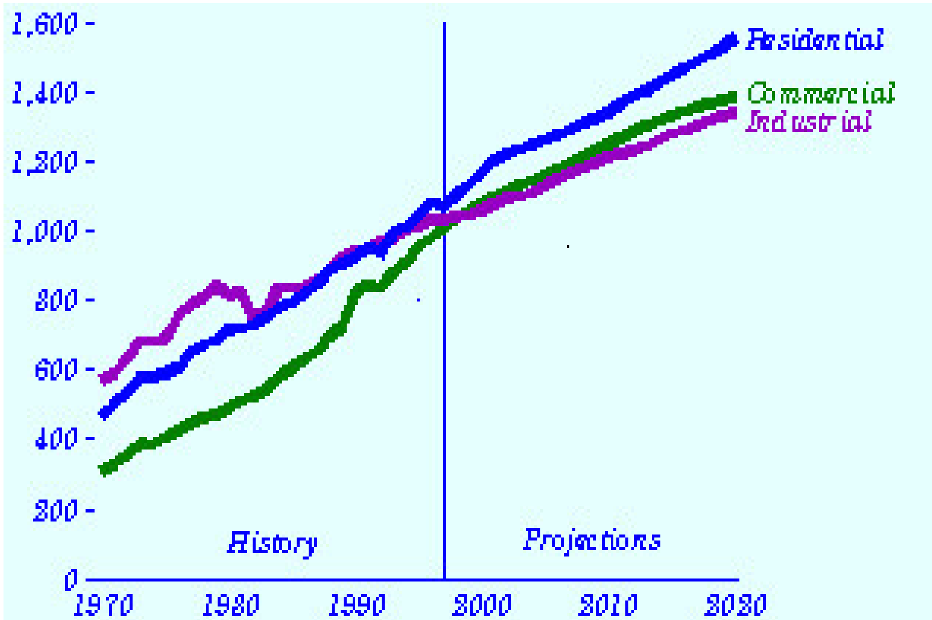

Figure 5-4. Annual Electricity Sales by Sector

The literature suggests that electricity consumption is relatively price inelastic. Consumers are generally unable or unwilling to forego a large amount of consumption as the price increases. Numerous studies have investigated the short-run elasticity of demand for electricity. Overall, the studies suggest that, for a 1 percent increase in the price of electricity, demand will decrease by 0.15 percent. However, as Table 5-7 shows, elasticities vary greatly, depending on the demand characteristics of end users and the price structure. Demand elasticities are estimated to range from a –0.05 percent elasticity of demand for a "flat rates" case (i.e., no time-of-use assumption) up to a –0.50 percent demand elasticity for a "high consumer response" case (DOE, EIA, 1999b).

5.1.2.1 Growth in Generation Capacity

The electric industry is continuing to grow and change. Throughout the country, electric utility capacity additions are slightly outpacing capacity retirements. The trend goes beyond an increasing capacity but also shows that coal units are slowly being replaced by newer, more efficient methods of producing energy. In 1997, 71 electric utility units were closed, decreasing capacity by 2,127 MW. Of those, six were coal facilities and 43 were

Table 5-7. Key Parameters in the Cases

	Key Assumptions			
Case Name	**Cost Reduction and Efficiency Improvements**	**Short-Run Elasticity of Demand (Percent)**	**Natural Gas Prices**	**Capacity Additions**
AEO97 Reference Case	AEO97 Reference Case	—	AEO97 Reference Case	As needed to meet demand
No Competition	No change from 1995	—	AEO97 Reference Case	As needed to meet demand
Flat Rates (no time-of-use rates)	AEO97 Reference Case	-0.05	AEO97 Reference Case	As needed to meet demand
Moderate Consumer Response	AEO97 Reference Case	-0.15	AEO97 Reference Case	As needed to meet demand
High Consumer Response	AEO97 Reference Case	-0.50	AEO97 Reference Case	As needed to meet demand
High Efficiency	Increased cost savings and efficiencies	-0.15	AEO97 Reference Case	As needed to meet demand
No Capacity Additions	AEO97 Reference Case	-0.15	AEO97 Low Oil and Gas Supply Technology Case	Not allowed
High Gas Price	AEO97 Reference Case	-0.15	AEO97 High Oil and Gas Supply Technology Case	As needed to meet demand
Low Gas Price	AEO97 Reference Case	-0.15	AEO97 Reference Case	As needed to meet demand
High Value of Reliability	AEO97 Reference Case	-0.15	AEO97 Reference Case	As needed to meet demand
Half O&M	AEO97 Reference Case	-0.15	AEO97 Reference Case	As needed to meet demand
Intense Competition	AEO97 Reference Case	-0.15	AEO97 Reference Case	As needed to meet demand

— = not applicable.

Source: U.S. Department of Energy, Energy Information Administration, Office of Integrated Analysis and Forecasting. "Competitive Electricity Price Projections." <http://www.eia.doe.gov/oiaf/elepri97/chap3.html>. As obtained on November 15, 1999b.

petroleum facilities. However, of the 62 facility additions (2,918 MW), none were coal powered, while 24 use petroleum. Gas installations slightly outpaced petroleum ones, totaling 25 new units at electric utilities in 1997. Table 5-8 outlines capacity additions and retirements at U.S. electric utilities by energy source.

Table 5-8. Capacity Additions and Retirements at U.S. Electric Utilities by Energy Source, 1997

Primary Energy Source	Additions		Retirements	
	Number of Units	Generator Nameplate Capacity (MW)	Number of Units	Generator Nameplate Capacity (MW)
U.S. total	62	2,918	71	2127
Coal	—	—	6	281
Petroleum	24	199	43	445
Gas	25	2,475	18	405
Water (pumped storage hydroelectric)	—	—	—	—
Nuclear	—	—	2	995
Waste heat	3	171	—	—
Renewable[a]	10	73	2	1

[a] Includes conventional hydroelectric; geothermal; biomass (wood, wood waste, nonwood waste); solar; and wind.

Note: Total may not equal the sum of components because of independent rounding.

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999c. *Electric Power Annual 1998*. Volumes I and II. Washington, DC: U.S. Department of Energy.

Planned additions indicate a strong trend towards gas-powered turbine/stationary combustion units. Three-quarters of the gas turbine/stationary combustion units are expected to be gas-powered with the remaining quarter petroleum-powered. Based on 1998 planned additions, it is likely that all additional petroleum-fueled units in the near future will be gas turbine/stationary combustion units, not steam. Table 5-9 shows planned capacity additions by prime mover and energy source.

Table 5-9. Fossil-Fueled Existing Capacity and Planned Capacity Additions at U.S. Electric Utilities by Prime Mover and Primary Energy Source, as of January 1, 1998

	Planned Additions[a]	
Prime Mover Energy Source	**Number of Units**	**Generator Nameplate Capacity (MW)**
U.S. Total	272	50,184
Steam	45	18,518
Coal	8	2,559
Petroleum	—	—
Gas	37	15,959
Gas Turbine/Internal Combustion	226	31,663
Petroleum	52	1,444
Gas	174	30,219

[a] Planned additions are for 1998 through 2007. Totals include one 2.9 MW fuel cell unit.

Notes: Total may not equal the sum of components because of independent rounding. The Form EIA-860 was revised during 1995 to collect data as of January 1 of the reporting year, where "reporting year" is the calendar year in which the report is required to be filed with the Energy Information Administration. These data reflect the status of electric plants/generators as of January 1; however, dynamic data are based on occurrences in the previous calendar year (e.g., capabilities and energy sources based on test and consumption in the previous year).

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999c. *Electric Power Annual 1998*. Volumes I and II. Washington, DC: U.S. Department of Energy.

5.1.3 Electricity Consumption

This section analyzes the growth projections for electricity consumption as well as the price elasticity of demand for electricity. Growth in electricity consumption has traditionally paralleled GDP growth. However, improved energy efficiency of electrical equipment, such as high-efficiency motors, has slowed demand growth over the past few decades. The magnitude of the relationship has been decreasing over time, from growth of 7 percent per year in the 1960s down to 1 percent in the 1980s. As a result, determining what the future growth will be is difficult, although it is expected to be positive (DOE, EIA, 1999a). Table 5-10 shows consumption by sector of the economy over the past 10 years. The table shows that since 1989 electricity sales have increased at least 10 percent in all four

Table 5-10. U.S. Electric Utility Retail Sales of Electricity by Sector, 1989 Through July 1999 (Million kWh)

Period	Residential	Commercial	Industrial	Other[a]	All Sectors
1989	905,525	725,861	925,659	89,765	2,646,809
1990	924,019	751,027	945,522	91,988	2,712,555
1991	955,417	765,664	946,583	94,339	2,762,003
1992	935,939	761,271	972,714	93,442	2,763,365
1993	994,781	794,573	977,164	94,944	2,861,462
1994	1,008,482	820,269	1,007,981	97,830	2,934,563
1995	1,042,501	862,685	1,012,693	95,407	3,013,287
1996	1,082,491	887,425	1,030,356	97,539	3,097,810
1997	1,075,767	928,440	1,032,653	102,901	3,139,761
1998	1,124,004	948,904	1,047,346	99,868	3,220,121
Percentage change 1989-1998	19%	24%	12%	10%	18%

[a] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 1999c. *Electric Power Annual 1998*. Volumes I and II. Washington, DC: U.S. Department of Energy.

U.S. Department of Energy, Energy Information Administration (EIA). 1996b. *Electric Power Annual 1995*. Volumes I and II. Washington, DC: U.S. Department of Energy.

sectors. The commercial sector has experienced the largest increase, followed by residential consumption.

In the future, residential demand is expected to be at the forefront of increased electricity consumption. Between 1997 and 2020, residential demand is expected to increase at 1.6 percent annually. Commercial growth in demand is expected to be approximately 1.4 percent, while industry is expected to increase demand by 1.1 percent (DOE, EIA, 1999a).

5.2 Oil and Gas Extraction (NAICS 211)

The crude petroleum and natural gas industry encompasses the oil and gas extraction process from the exploration for oil and natural gas deposits through the transportation of the product from the production site. The primary products of this industry are natural gas, natural gas liquids, and crude petroleum.

5.2.1 Introduction

The United States is home to half of the major oil and gas companies operating around the globe. Although small firms account for nearly 45 percent of U.S. crude oil and natural gas output, the domestic oil and gas industry is dominated by 20 integrated petroleum and natural gas refiners and producers, such as Exxon Mobil, BP Amoco, and Chevron (Lillis, 1998). Despite the presence of many large global players, the industry experiences a more turbulent business cycle than most other major U.S. industries. Because the industry imports 60 percent of the crude oil used as an input into refineries, it is susceptible to fluctuations in crude oil output and prices, which are strongly influenced by the Organization of Petroleum Exporting Countries (OPEC). OPEC is a cartel consisting of most of the world's largest petroleum-producing countries that acts to increase the profits of member countries. In contrast, natural gas markets in the United States are competitive and relatively stable. Most natural gas used in the United States comes from domestic and Canadian sources.

NAICS 211 includes five major industry groups (see Table 5-11):

- NAICS 211111 (SIC 1311): Crude petroleum and natural gas. Firms in this industry are primarily involved in operating oil and gas fields. These firms may also explore for crude oil and natural gas, drill and complete wells, and separate crude oil and natural gas components from natural gas liquids and produced fluids.
- NAICS 211112 (SIC 1321): Natural gas liquids (NGL). NGL firms separate NGLs from crude oil and natural gas at the site of production. Propane and butane are NGLs.
- NAICS 213111 (SIC 1381): Drilling oil and gas wells. Firms in this industry drill oil and natural gas wells on a contract or fee basis.
- NAICS 213112/54136 (SIC 1382): Oil and gas field exploration services. Firms in this industry perform geological, geophysical, and other exploration services.
- NAICS 213112 (SIC 1389): Oil and gas field services, not elsewhere classified. Companies in this industry perform services on a contract or fee basis that are not classified in the above industries. Services include drill-site preparations, such as building foundations and excavating pits, and maintenance.

Table 5-11. Crude Petroleum and Natural Gas Industries Likely to Be Affected by the Regulation

SIC	NAICS	Description
1311	211111	Crude Petroleum and Natural Gas
1321	211112	Natural Gas Liquids
1381	213111	Drilling Oil and Gas Wells
1382	213112	Oil and Gas Exploration Services
	54136	Geophysical Surveying and Mapping Services
1389	213112	Oil and Gas Field Services, N.E.C.

In 1997, more than 6,800 crude oil and natural gas extraction companies (NAICS 211111) generated $75 billion in revenues. Revenues for 1997 were approximately 5 percent higher than revenues in 1992, although the number of companies and employees declined 11.5 and 42.5 percent, respectively.

Table 5-12 shows the NGL extraction industry (NAICS 211112) experienced a decline in the number of companies, establishments, and employees. The industry's revenues declined nearly 8.0 percent between 1992 and 1997, from $27 billion per year to $24.8 billion per year.

Revenues for NAICS 213111, drilling oil and gas wells, more than doubled between 1992 and 1997. In 1992, the industry employed 47,700 employees at 1,698 companies and generated $3.6 billion in annual revenues. By the end of 1997, the industry's annual revenues were $7.3 billion, a 106 percent improvement. Although the total number of companies and establishments decreased from 1992 levels, industry employment increased 13 percent to 53,865.

The recent transition from the SIC system to the North American Industrial Classification System (NAICS) changed how some industries are organized for information collection purposes and thus how certain economic census data are aggregated. Some SIC codes were combined, others were separated, and some activities were classified under one NAICS code and the remaining activities classified under another. The oil and gas field services industry is an example of an industry code that was reclassified. Under NAICS, SIC 1382, Oil and Gas Exploration Services, and SIC 1389, Oil and Gas Services Not Elsewhere Classified, were combined. The geophysical surveying and mapping services portion of SIC

Table 5-12. Summary Statistics, Crude Oil and Natural Gas Extraction and Related Industries

NAICS	Industry	Number of Companies	Number of Establishments	Revenues ($1997 10^3)	Employees
211111	Crude Oil and Natural Gas Extraction				
	1992	7,688	9,391	71,622,600	174,300
	1997	6,802	7,781	75,162,580	100,308
211112	Natural Gas Liquid Extraction				
	1992	108	591	26,979,200	12,000
	1997	89	529	24,828,503	10,549
213111	Drilling Oil and Gas Wells				
	1992	1,698	2,125	3,552,707	47,700
	1997	1,371	1,638	7,317,963	53,865
213112	Oil and Gas Field Services				
	1997	6,385	7,068	11,547,563	106,339

Sources: U.S. Department of Commerce, Bureau of the Census. 1999a. *1997 Economic Census, Mining Industry Series: Crude Petroleum and Natural Gas Extraction*. EC97N-2111A. Washington, DC: U.S. Department of Commerce.

U.S. Department of Commerce, Bureau of the Census. 1995a. *1992 Census of Mineral Industries, Industry Series: Crude Petroleum and Natural Gas*. MIC92-I-13A. Washington, DC: U.S. Department of Commerce.

1382 was reclassified and grouped into NAICS 54136. The adjustments to SIC 1382/89 have made comparison between the 1992 and 1997 economic censes difficult at this time. The U.S. Census Bureau has yet to publish a comparison report. Thus, for this industry only 1997 census data are presented. For that year, nearly 6,400 companies operated under SIC 1382/89 (NAICS 213112), employing more than 100,000 people and generating $11.5 billion in revenues.

5.2.2 Supply Side

Characterizing the supply side of the industry involves describing the production processes, the types of output, major by-products, costs of production, and capacity utilization.

5.2.2.1 Production Processes

There are four major processes in the oil and gas extraction industry: exploration, well development, production, and site abandonment (EPA, 1999b). Exploration is the search for rock formations associated with oil and/or natural gas deposits. Nearly all oil and natural gas deposits are located in sedimentary rock. Certain geological clues, such as porous rock with an overlying layer of low-permeability rock, help guide exploration companies to a possible source of hydrocarbons. While exploring a potential site, the firm conducts geophysical prospecting and exploratory drilling.

After an economically viable field is located, the well development process begins. Well holes, or well bores, are drilled to a depth of between 1,000 and 30,000 feet, with an average depth of about 5,500 feet (EPA, 1999b). The drilling procedure is the same for both onshore and offshore sites. A steel or diamond drill bit, which may be anywhere between 4 inches and 3 feet in diameter, is used to chip off rock to increase the depth of the hole. The drill bit is connected to the rock by several pieces of hardened pipe known collectively as the drill string. As the hole is drilled, casing is placed in the well to stabilize the hole and prevent caving. Drilling fluid is pumped down through the center of the drill string to lubricate the equipment. The fluid returns to the surface through the space between the drill string and the rock formation or casing. Once the well has been drilled, rigging, derricks, and other production equipment are installed. Onshore fields are equipped with a pad and roads; ships, floating structures, or a fixed platform are procured for offshore fields.

Production is the process of extracting hydrocarbons through the well and separating saleable components from water and silt. Oil and natural gas are naturally occurring co-products, and most production sites handle crude oil and gas from more than one well. Once the hydrocarbons are brought to the surface, they are separated into a spectrum of substances, including liquid hydrocarbons, gas, and water and other nonsaleable constituents. After being extracted, crude oil is always delivered to a refinery for processing; natural gas may be processed at the field or at a natural gas processing plant to remove impurities. Natural gas is separated from crude oil by passing the hydrocarbons through one or two decreasing pressure chambers. Excess water is removed from the crude oil, at which point the oil is about 98 percent pure, a purity sufficient for storage or transport to a refinery (EPA, 1999b). Excess water is returned to the well to facilitate the production process, but silt is discarded. If enough natural pressure does not exist in the reservoir to force the hydrocarbons through the well, then the reservoir is pressurized using pumps or excess water to lift the hydrocarbons.

Natural gas is conditioned using a dehydration and a sweetening process, which removes hydrogen sulfide and carbon dioxide, so that it is of high enough quality to pass through transmission systems. The gas may be conditioned at the field or at one of the 623 operating gas-processing facilities located in gas-producing states, such as Texas, Louisiana, Oklahoma, and Wyoming. These plants also produce the nation's NGLs, propane and butane (NGSA et al., 2000c).

Site abandonment occurs when a site lacks the potential to produce economic quantities of natural gas or when a production well is no longer economically viable. The well(s) are plugged using long cement plugs and steel plated caps, and supporting production equipment is disassembled and moved offsite.

5.2.2.2 Types of Output

The oil and gas industry's principal products are crude oil, natural gas, and NGLs (see Tables 5-13 and 5-14). Refineries process crude oil into several petroleum products. These products include motor gasoline (40 percent of crude oil); diesel and home heating oil (20 percent); jet fuels (10 percent); waxes, asphalts, and other nonfuel products (5 percent); feedstocks for the petrochemical industry (3 percent); and other lesser products (DOE, EIA, 1999d).

Natural gas is produced from either oil wells (known as "associated gas") or wells that are drilled for the primary purpose of obtaining natural gas (known as "nonassociated gas") (see Table 5-14). Methane is the predominant component of natural gas (about 85 percent), but ethane (about 10 percent), propane, and butane are also significant components (see Table 5-13). Propane and butane, the heavier components of natural gas, exist as liquids when cooled and compressed. These latter two components are usually separated and processed as NGLs (EPA, 1999b).

Table 5-13. U.S. Supply of Crude Oil and Petroleum Products (10^3 barrels), 1998

Commodity	Field Production	Refinery Production	Imports
Crude Oil	2,281,919		3,177,584
Natural Gas Liquids	642,202	245,918	82,081
Ethane/ethylene	221,675	11,444	6,230
Propane/propylene	187,369	200,815	50,146
Normal butane/butylene	54,093	29,333	8,612
Isobutane/isobutylene	66,179	4,326	5,675
Other	112,886		11,418
Other Liquids	69,477		211,266
Finished Petroleum Products	69,427	5,970,090	437,515
Finished motor gasoline	69,427	2,880,521	113,606
Finished aviation gasoline		7,118	43
Jet fuel		556,834	45,143
Kerosene		27,848	466
Distillate fuel oil		1,249,881	76,618
Residual fuel oil		277,957	100,537
Naptha		89,176	22,388
Other oils		78,858	61,554
Special napthas		24,263	2,671
Lubricants		67,263	3,327
Waxes		8,355	613
Petroleum coke		260,061	263
Asphalt and road oil		181,910	10,183
Still gas		239,539	
Miscellaneous products		20,506	103
Total	3,063,025	6,216,008	3,908,446

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999f. *Petroleum Supply Annual 1998, Volume I.* Washington, DC: U.S. Department of Energy.

Table 5-14. U.S. Natural Gas Production, 1998

Gross Withdrawls	Production (10^6 cubic feet)
From gas wells	17,558,621
From oil wells	6,365,612
Less losses and repressuring	5,216,477
Total	18,707,756

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999e. *Natural Gas Annual 1998*. Washington, DC: U.S. Department of Energy.

5.2.2.3 Major By-products

The engines that provide pumping action at wells and push crude oil and natural gas through pipes to processing plants, refineries, and storage locations produce HAPs. HAPs produced in engines include formaldehyde, acetaldehyde, acrolein, and methanol.

5.2.2.4 Costs of Production

The 42 percent decrease in the number of people employed by the crude oil and natural gas extraction industry between 1992 and 1997 was matched by a corresponding 40 percent decrease in the industry's annual payroll (see Table 5-15). During the same period, industry outlays for supplies, such as equipment and other supplies, increased over 32 percent, and capital expenditures nearly doubled. Automation, mergers, and corporate downsizing have made this industry less labor-intensive (Lillis, 1998).

Unlike the crude oil and gas extraction industry, the NGL extraction industry's payroll increased over 6 percent even though total industry employment declined 12 percent. The industry's expenditures on capital projects, such as investments in fields, production facilities, and other investments, increased 11.4 percent between 1992 and 1997. The cost of supplies did, however, decrease 13 percent from $23.3 billion in 1992 to $20.3 billion in 1997.

Employment increased in Drilling Oil and Gas Wells. In 1992, the industry employed 47,700 people, increasing 13 percent to 53,865 in 1997. During a period where industry revenues increased over 100 percent, the industry's payroll increased 41 percent and the cost of supplies increased 182 percent.

Table 5-15. Costs of Production, Crude Oil and Natural Gas Extraction and Related Industries

NAICS	Industry	Employees	Payroll ($1997 10^3)	Cost of Supplies Used, Purchased Machinery Installed, Etc. ($1997 10^3)	Capital Expenditures ($1997 10^3)
211111	Crude Oil and Natural Gas Extraction				
	1992	174,300	$8,331,849	$16,547,510	$10,860,260
	1997	100,308	$4,968,722	$21,908,191	$21,117,850
211112	Natural Gas Liquid Extraction				
	1992	12,000	$509,272	$23,382,770	$609,302
	1997	10,549	$541,593	$20,359,528	$678,479
213111	Drilling Oil and Gas Wells				
	1992	47,700	$1,358,784	$1,344,509	$286,509
	1997	53,865	$1,918,086	$7,317,963	$2,209,300
213112	Oil and Gas Field Services				
	1997	106,339	$3,628,416	$3,076,039	$1,165,018

Sources: U.S. Department of Commerce, Bureau of the Census. 1999a. *1997 Economic Census, Mining, Industry Series: Crude Petroleum and Natural Gas Extraction*. EC97N-2111A. Washington, DC: U.S. Department of Commerce.

U.S. Department of Commerce, Bureau of the Census. 1995a. *1992 Census of Mineral Industries, Industry Series: Crude Petroleum and Natural Gas*. MIC92-I-13A. Washington, DC: U.S. Department of Commerce.

5.2.2.5 Capacity Utilization

U.S. annual oil and gas production is a small percentage of total U.S. reserves. In 1998, oil producers extracted approximately 1.5 percent of the nation's proven crude oil reserves (see Table 5-16). A slightly lesser percentage of natural gas was extracted (1.4 percent), and an even smaller percentage of NGLs was extracted (0.9 percent). The

Table 5-16. Estimated U.S. Oil and Gas Reserves, Annual Production, and Imports, 1998

Category	Reserves	Annual Production	Imports
Crude oil (10^6 barrels)	152,453	2,281	3,178
Natural gas (10^9 cubic feet)	1,330,930	18,708	3,152
Natural gas liquids (10^6 barrels)	26,792	246	NA

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 1999h. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1998 Annual Report*. Washington, DC: U.S. Department of Energy.

U.S. Department of Energy, Energy Information Administration (EIA). 1999f. *Petroleum Supply Annual 1998, Volume I*. Washington DC: U.S. Department of Energy.

United States produces approximately 40 percent (2,281 million barrels) of its annual crude oil consumption, importing the remainder of its crude oil from Canada, Latin America, Africa, and the Middle East (3,178 million barrels). Approximately 17 percent (3,152 billion cubic feet) of U.S. natural gas supply is imported. Most imported natural gas originates in Canadian fields in the Rocky Mountains and off the Coast of Nova Scotia and New Brunswick.

5.2.3 Demand Side

Characterizing the demand side of the industry involves describing product characteristics. Crude oil, or unrefined petroleum, is a complex mixture of hydrocarbons that is the most important of the primary fossil fuels. Refined petroleum products are used for petrochemicals, lubrication, heating, and fuel. Petrochemicals derived from crude oil are the source of chemical products such as solvents, paints, plastics, synthetic rubber and fibers, soaps and cleansing agents, waxes, jellies, and fertilizers. Petroleum products also fuel the engines of automobiles, airplanes, ships, tractors, trucks, and rockets. Other applications include fuel for electric power generation, lubricants for machines, heating, and asphalt (Berger and Anderson, 1978). Because the market for crude oil is global and its price set by OPEC, slight increases in the cost of producing crude oil in the United States will have little effect on the price of products that use crude oil as an intermediate good. Production cost increases will be absorbed by the producer, not passed along to consumers.

Natural gas is a colorless, flammable gaseous hydrocarbon consisting for the most part of methane and ethane. The largest single application for natural gas is as a domestic or industrial fuel. However, other specialized applications have emerged over the years, such as a nonpolluting fuel for buses and other motor vehicles. Carbon black, a pigment made by burning natural gas with little air and collecting the resulting soot, is an important ingredient in dyes, inks, and rubber compounding operations. Also, much of the world's ammonia is manufactured from natural gas; ammonia is used either directly or indirectly in urea, hydrogen cyanide, nitric acid, and fertilizers (Tussing and Tippee, 1995).

5.2.4 Organization of the Industry

Many oil and gas firms are merging to remain competitive in both the global and domestic marketplaces. By merging with their peers, these companies may reduce operating expenses and reap greater economies of scale than they would otherwise. Recent mergers, such as BP Amoco and Exxon Mobil, have reduced the number of companies and facilities operating in the United States. Currently, there are 20 domestic major oil and gas companies, and only 40 major global companies in the world (Conces, 2000). Most U.S. oil and gas firms are concentrated in states with significant oil and gas reserves, such as Texas, Louisiana, California, Oklahoma, and Alaska.

Tables 5-17 through 5-20 present the number of facilities and value of shipments by facility employee count for each of the four NIACS 211 industries. In 1997, 6,802 oil and gas extraction companies operated 7,781 facilities, an average of 1.14 facilities per company (see Table 5-17). Facilities with more than 100 employees produced more than 55 percent of the industry's value of shipments. Although the number of companies and the number of facilities operating in 1992 were both greater then than in 1997, the distribution of shipment values by employee size was similar to that of 1992.

Facilities employing fewer than 50 people in the NGLs extraction industry accounted for 64 percent, or $15.8 billion, of the industry's total value of shipments in 1997 (see Table 5-18). Four hundred eighty-seven of the industry's 529 facilities are in that employment category. This also means that a relatively small number of larger facilities produced 36 percent of the industry's annual output, in terms of dollar value. The number of facilities with zero to four employees and the number with 50 or more employees decreased during the 5-year period, accounting for most of the 10.5 percent decline in the number of facilities from 1992 to 1997. The average number of facilities per company was 5.5 and 5.9 in 1992 and 1997, respectively.

Table 5-17. Size of Establishments and Value of Shipments, Crude Oil and Natural Gas Extraction Industry (NAICS 211111), 1997 and 1992

	1997		1992	
Average Number of Employees in Facility	**Number of Facilities**	**Value of Shipments ($1997 10^3)**	**Number of Facilities**	**Value of Shipments ($1997 10^3)**
0 to 4 employees	5,249	$5,810,925	6,184	$5,378,330
5 to 9 employees	1,161	$3,924,929	1,402	$3,592,560
10 to 19 employees	661	$4,843,634	790	$4,504,830
20 to 49 employees	412	$10,538,529	523	$8,820,100
50 to 99 employees	132	$8,646,336	203	$5,942,130
100 to 249 employees	105		154	$11,289,730
250 to 499 employees	40		68	$8,135,850
500 to 999 employees	14	$41,318,227	46	$14,693,630
1,000 to 2,499 employees	5		18	$9,265,530
2,500 or more employees	2		3	D
Total	7,781	$75,162,580	9,391	$71,622,600

D = undisclosed
Sums do not add to totals due to independent rounding.

Sources: U.S. Department of Commerce, Bureau of the Census. 1999a. *1997 Economic Census, Mining, Industry Series: Crude Petroleum and Natural Gas Extraction.* EC97N-2111A. Washington, DC: U.S. Department of Commerce.

U.S. Department of Commerce, Bureau of the Census. 1995a. *1992 Census of Mineral Industries, Industry Series: Crude Petroleum and Natural Gas*. MIC92-I-13A. Washington, DC: U.S. Department of Commerce.

As mentioned earlier, the oil and gas well drilling industry's 1997 value of shipments were 106 percent larger than 1992's value of shipments (see Table 5-19). However, the number of companies primarily involved in this industry declined by 327 over 5 years, and 487 facilities closed during the same period. The distribution of the number of facilities by employment size shifted towards those that employed 20 or more people. In 1997, those facilities earned two-thirds of the industry's revenues.

Table 5-18. Size of Establishments and Value of Shipments, Natural Gas Liquids Industry (NAICS 211112), 1997 and 1992

Average Number of Employees in Facility	1997		1992	
	Number of Facilities	Value of Shipments ($1997 10^3)	Number of Facilities	Value of Shipments ($1997 10^3)
0 to 4 employees	143	$1,407,192	190	$2,668,000
5 to 9 employees	101	$1,611,156	92	$1,786,862
10 to 19 employees	122	$4,982,941	112	$5,240,927
20 to 49 employees	121	$7,828,439	145	$10,287,200
50 to 99 employees	35	$5,430,448	36	$4,789,849
100 to 249 employees	3	D	14	$2,205,819
250 to 499 employees	3	D	2	D
500 to 999 employees	1	D	0	—
1,000 to 2,499 employees	0	—	0	—
2,500 or more employees	0	—	0	—
Total	529	$24,828,503	591	$26,979,200

D = undisclosed
Sums do not add to totals due to independent rounding.

Sources: U.S. Department of Commerce, Bureau of the Census. 1999b. *1997 Economic Census, Mining, Industry Series: Natural Gas Liquid Extraction*. EC97N-2111b. Washington, DC: U.S. Department of Commerce.

U.S. Department of Commerce, Bureau of the Census. 1995b. *1992 Census of Mineral Industries, Industry Series: Natural Gas Liquids*. MIC92-I-13B. Washington, DC: U.S. Department of Commerce.

In 1997, 6,385 companies operated 7,068 oil and gas field services facilities, an average of 1.1 facilities per company. Most facilities employed four or fewer employees; however, those facilities with 20 or more employees accounted for the majority of the industry's revenues (see Table 5-20).

Table 5-19. Size of Establishments and Value of Shipments, Drilling Oil and Gas Wells Industry (NAICS 213111), 1997 and 1992

Average Number of Employees in Facility	1997 Number of Facilities	1997 Value of Shipments ($1997 10^3)	1992 Number of Facilities	1992 Value of Shipments ($1997 10^3)
0 to 4 employees	825	$107,828	1,110	$254,586
5 to 9 employees	215	$231,522	321	$182,711
10 to 19 employees	197	$254,782	244	$256,767
20 to 49 employees	200	$1,008,375	233	$572,819
50 to 99 employees	95	$785,804	120	$605,931
100 to 249 employees	75	$1,069,895	70	$816,004
250 to 499 employees	10	$435,178	19	$528,108
500 to 999 employees	14	$1,574,139	5	$97,254
1,000 to 2,499 employees	6	D	3	$238,427
2,500 or more employees	1	D	—	—
Total	1,638	$7,317,963	2,125	$3,552,707

D = undisclosed
Sums do not add to totals due to independent rounding.

Sources: U.S. Department of Commerce, Bureau of the Census. 1999c. *1997 Economic Census, Mining, Industry Series: Drilling Oil and Gas Wells*. EC97N-2131A. Washington, DC: U.S. Department of Commerce.

U.S. Department of Commerce, Bureau of the Census. 1995c. *1992 Census of Mineral Industries, Industry Series: Oil and Gas Field Services.* MIC92-I-13C. Washington, DC: U.S. Department of Commerce.

5.2.5 Markets and Trends

Between 1990 and 1998, crude oil consumption increased 1.4 percent per year, and natural gas consumption increased 2.0 percent per year. The increase in natural gas consumption came mostly at the expense of coal consumption (EPA, 1999b). The Energy Information Administration (EIA), a unit of the Department of Energy, anticipates that natural gas consumption will continue to grow at a similar rate through the year 2020 to 32 trillion cubic feet/year (DOE, EIA, 1999d). They also expect crude oil consumption to grow at an annual rate of less than 1 percent over the same period.

Table 5-20. Size of Establishments and Value of Shipments, Oil and Gas Field Services (NAICS 213112), 1997 and 1992

Average Number of Employees at Facility	1997	
	Number of Facilities	Value of Shipments ($\$1997\ 10^3$)
0 to 4 employees	4,122	$706,396
5 to 9 employees	1,143	$571,745
10 to 19 employees	835	$904,356
20 to 49 employees	629	$1,460,920
50 to 99 employees	211	$1,480,904
100 to 249 employees	84	$1,175,766
250 to 499 employees	21	$754,377
500 to 999 employees	13	$1,755,689
1,000 to 2,499 employees	9	D
2,500 or more employees	1	D
Total	7,068	$11,547,563

D = undisclosed
Sums do not add to totals due to independent rounding.

Source: U.S. Department of Commerce, Bureau of the Census. 1999d. *1997 Economic Census, Mining, Industry Series: Support Activities for Oil and Gas Operations*. EC97N-2131B. Washington, DC: U.S. Department of Commerce.

5.3 Natural Gas Pipelines

The natural gas pipeline industry (NAICS 4862) comprises establishments primarily engaged in the pipeline transportation of natural gas from processing plants to local distribution systems. Also included in this industry are natural gas storage facilities, such as depleted gas fields and aquifers.

5.3.1 Introduction

The natural gas industry can be divided into three segments, or links: production, transmission, and distribution. Natural gas pipeline companies are the second link, performing the vital function of linking gas producers with the local distribution companies and their customers. Pipelines transmit natural gas from gas fields or processing plants through high compression steel pipe to their customers. By the end of 1998, there were more than 300,000 miles of transmission lines (OPS, 2000).

The interstate pipeline companies that linked the producing and consuming markets functioned mainly as resellers or merchants of gas until about the 1980s. Rather than acting as common carriers (i.e., providers only of transportation), pipelines typically bought and resold the gas to a distribution company or to some other downstream pipelines that would later resell the gas to distributers. Today, virtually all pipelines are common carriers, transporting gas owned by other firms instead of wholesaling or reselling natural gas (Tussing and Tippee, 1995).

According to the U.S. Bureau of the Census, the natural gas pipeline industry's revenues totaled $19.6 billion in 1997. Pipeline companies operated 1,450 facilities and employed 35,789 people (see Table 5-21). The industry's annual payroll is nearly $1.9 billion.

Table 5-21. Summary Statistics for the Natural Gas Pipeline Industry (NAICS 4862), 1997

Establishments	1,450
Revenue ($$10^3$)	$19,626,833
Annual payroll ($$10^3$)	$1,870,950
Paid employees	35,789

Source: U.S. Department of Commerce, Bureau of the Census. 2000. *1997 Economic Census, Transportation and Warehousing: Geographic Area Series*. EC97T48A-US. Washington, DC: Government Printing Office.

As noted previously, the recent transition from the SIC system to the NAICS changed how some industries are organized for information collection purposes and thus how certain economic census data are aggregated. Some SIC codes were combined, others were separated, and some activities were classified under one NAICS code and the remaining activities classified under another. The natural gas transmission (pipelines) industry is an example of an industry code that was reclassified. Under NAICS, SIC 4922, natural gas transmission (pipelines), and a portion of SIC 4923, natural gas distribution, were combined. The adjustments have made comparison between the 1992 and 1997 economic censes difficult at this time. The U.S. Census Bureau has yet to publish a comparison report. Thus, for this industry only 1997 census data are presented.

5.3.2 Supply Side

Characterizing the supply side involves describing services provided by the industry, by-products, the costs of production, and capacity utilization.

5.3.2.1 Service Description

Natural gas is delivered from gas processing plants and fields to distributers via a nationwide network of over 300,000 miles of transmission pipelines (NGSA et al., 2000a). The majority of pipelines are composed of steel pipes that measure from 20 to 42 inches in diameter and operate 24 hours a day. Natural gas enters pipelines at gas fields, storage facilities, or gas processing plants and is "pushed" through the pipe to the city gate or interconnections, the point at which distribution companies receive the gas. Pipeline operators use sophisticated computer and mechanical equipment to monitor the safety and efficiency of the network.

Reciprocating stationary combustion engines compress and provide the pushing force needed to maintain the flow of gas through the pipeline. When natural gas is transmitted, it is compressed to reduce the volume of gas and to maintain pushing pressure. The gas pressure in pipelines is usually between 300 and 1,300 psi, but lesser and higher pressures may be used. To maintain compression and keep the gas moving, compressor stations are located every 50 to 100 miles along the pipeline. Most compressors are large reciprocating engines powered by a small portion of the natural gas being transmitted through the pipeline.

There are over 8,000 gas compressing stations along U.S. gas pipelines, each equipped with one or more engines. The combined output capability of U.S. compressor engines is over 20 million hp (NGSA et al., 2000a). Nearly 5,000 engines have individual output capabilities from 500 to over 8,000 hp. The replacement cost of this subset of larger engines is estimated by the Gas Research Institute to be $18 billion (Whelan, 1998).

Before or after natural gas is delivered to a distribution company, it may be stored in an underground facility. Underground storage facilities are most often depleted oil and/or gas fields, aquifers, or salt caverns. Natural gas storage allows distribution and pipeline companies to serve their customers more reliably by withdrawing more gas from storage during peak-use periods and reduces the time needed to respond to increased gas demand

(NGSA et al., 2000b). In this way, storage guarantees continuous service, even when production or pipeline transportation services are interrupted.

5.3.2.2 By-products

According to the Natural Gas Supply Association (NGSA), about 3 percent of the natural gas moved through pipelines escapes. The engines that provide pumping action at plants and push crude oil and natural gas through pipelines to customers and storage facilities produce HAPs. As noted previously, HAPs produced in engines include formaldehyde, acetaldehyde, acrolein, and methanol.

5.3.2.3 Costs of Production

Between 1996 and 2000, pipeline firms committed over $14 billion to 177 expansion and new construction projects. These projects added over 15,000 miles and 36,178 million cubic feet per day (MMcf/d) capacity to the transmission pipeline system. Table 5-22 summarizes the investments made in pipeline projects during the past 5 years. Building new pipelines is more expensive than expanding existing pipelines. For the period covered in the table, the average cost per project mile was $862,000. However, the costs for pipeline expansions averaged $542,000, or 29 cents per cubic foot of capacity added. New pipelines averaged $1,157,000 per mile at 48 cents per cubic foot of capacity.

Pipelines must pay for the natural gas that is consumed to power the compressor engines. The amount consumed and the price paid have fluctuated in recent years. In 1998, pipelines consumed 635,477 MMcf of gas, paying, on average, $2.01 per 1,000 cubic feet. Pipelines used less natural gas in 1998 than in previous years; the price paid for that gas fluctuated between $1.49 and $2.29 between 1994 and 1997 (see Table 5-23). For companies that transmit natural gas through their own pipelines the cost of the natural gas consumed is considered a business expense.

5.3.2.4 Capacity Utilization

During the past 15 years, interstate pipeline capacity has increased significantly. In 1990, the transmission pipeline system's capacity was 74,158 MMcf/day (see Table 5-24). By the end of 1997, capacity reached 85,847 MMcf/day, an increase of approximately 16 percent. The system's usage has increased at a faster rate than capacity. The average daily flow was 60,286 MMcf/day in 1997, a 22 percent increase over 1990's rates. Currently, the system operates at approximately 72 percent of capacity.

Table 5-22. Summary Profile of Completed and Proposed Natural Gas Pipeline Projects, 1996 to 2000

	All Type Projects						New Pipelines		Expansions	
Year	**Number of Projects**	**System Mileage**	**New Capacity (MMcf/d)**	**Project Costs ($$10^6$)**	**Average Cost per Mile ($$10^3$)**	**Costs per Cubic Foot Capacity (cents)**	**Average Cost per Mile ($$10^3$)**	**Costs per Cubic Foot Capacity (cents)**	**Average Cost per Mile ($$10^3$)**	**Costs per Cubic Foot Capacity (cents)**
1996	26	1,029	2,574	$552	$448	21	$983	17	$288	27
1997	42	3,124	6,542	$1,397	$415	21	$554	22	$360	21
1998	54	3,388	11,060	$2,861	$1,257	30	$1,301	31	$622	22
1999	36	3,753	8,205	$3,135	$727	37	$805	46	$527	31
2000	19	4,364	7,795	$6,339	$1,450	81	$1,455	91	$940	57
Total	177	15,660	36,178	$14,285	$862	39	$1,157	48	$542	29

Note: Sums may not add to totals because of independent rounding.

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999d. *Natural Gas 1998: Issues and Trends*. Washington, DC: U.S. Department of Energy.

Table 5-23. Energy Usage and Cost of Fuel, 1994-1998

Year	Pipeline Fuel (MMcf)	Average Price ($ per 1,000 cubic feet)
1994	685,362	1.70
1995	700,335	1.49
1996	711,446	2.27
1997	751,470	2.29
1998	635,477	2.01

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999e. *Natural Gas Annual 1998*. Washington, DC: US Department of Energy.

Table 5-24. Transmission Pipeline Capacity, Average Daily Flows, and Usage Rates, 1990 and 1997

	1990	1997	Percent Change
Capacity (MMcf per day)	74,158	85,847	16
Average Flow (MMcf per day)	49,584	60,286	22
Usage Rate (percent)	68	72	4

Source: U.S. Department of Energy, Energy Information Administration. 1999d. *Natural Gas 1998: Issues and Trends*. Washington, DC: US Department of Energy.

5.3.3 Demand Side

Most pipeline customers are local distribution companies that deliver natural gas from pipelines to local customers. Many large gas users will buy from marketers and enter into special delivery contracts with pipelines. However, local distribution companies (LDCs) serve most residential, commercial, and light industrial customers. LDCs also use compressor engines to pump natural gas to and from storage facilities and through the gas lines in their service area.

While economic considerations strongly favor pipeline transportation of natural gas, liquified natural gas (LNG) emerged during the 1970s as a transportation option for markets inaccessible to pipelines or where pipelines are not economically feasible. Thus, LNG is a substitute for natural gas transmission via pipelines. LNG is natural gas that has been liquified by lowering its temperature. LNG takes up about 1/600 of the space gaseous natural gas takes up, making transportation by ship possible. However, virtually all of the natural gas consumed in the United States reaches its consumer market via pipelines because of the relatively high expense of transporting LNG and its volatility. Most markets that receive LNG are located far from pipelines or production facilities, such as Japan—the world's largest LNG importer, Spain, France, and Korea (Tussing and Tippee, 1995).

5.3.4 Organization of the Industry

Much like other energy-related industries, the natural gas pipeline industry is dominated by large investor-owned corporations. Smaller companies are few because of the real estate, capital, and operating costs associated with constructing and maintaining pipelines (Tussing and Tippee, 1995). Many of the large corporations are merging to remain competitive as the industry adjusts to restructuring and increased levels of competition. Increasingly, new pipelines are built by partnerships: groups of energy-related companies share capital costs through joint ventures and strategic alliances (DOE, EIA, 1999d). Ranked by system mileage, the largest pipeline companies in the United States are El Paso Energy (which recently merged with Southern Natural Gas Co.), Enron, Williams Cos., Coastal Corp., and Duke Energy (see Table 5-25). El Paso Energy and Coastal intend to merge in mid-2000.

5.3.5 Markets and Trends

During the past decade, interstate pipeline capacity has increased 16 percent. Many existing pipelines underwent expansion projects, and 15 new interstate pipelines were constructed. In 1999 and 2000, proposals for pipeline expansions and additions called for a $9.5 billion investment, an increase of 16.0 billion cubic feet per day of capacity (DOE, EIA, 1999d).

The EIA (1999d) expects natural gas consumption to grow steadily, with demand forecasted to reach 32 trillion cubic feet by 2020. The expected increase in natural gas demand has significant implications for the natural gas pipeline system.

Table 5-25. Five Largest Natural Gas Pipeline Companies by System Mileage, 2000

Company	Headquarters	Sales ($1999 10^6)	Employment (1999)	Miles of Pipeline
El Paso Energy Corporation Incl. El Paso Natural Gas Co. Southern Natural Gas Co. Tennessee Gas Pipe Line Co.	Houston, TX	$5,782	4,700	40,200
Enron Corporation Incl. Northern Border Pipe Line Co. Northern Natural Gas Co. Transwestern Pipeline Co.	Houston, TX	$40,112	17,800	32,000
Williams Companies, Inc. Incl. Transcontinental Gas Pipe Line Northwest Pipe Line Co. Texas Gas Pipe Line Co.	Tulsa, OK	$8,593	21,011	27,000
The Coastal Corporation Incl. ANR Pipeline Co. Colorado Interstate Gas Co.	Houston, TX	$8,197	13,000	18,000
Duke Energy Corporation Incl. Panhandle Eastern Pipeline Co. Algonquin Gas Transmission Co. Texas Eastern Transmission Co.	Charlotte, NC	$21,742	21,000	11,500

Sources: Heil, Scott F., Ed. *Ward's Business Directory of U.S. Private and Public Companies 1998, Volume 5*. Detroit, MI: Gale Research Inc.

Sales, employment, and system mileage: Hoover's Incorporated. 1998. Hoover's Company Profiles. Austin, TX: Hoover's Incorporated. <http://www.hoovers.com/>.

The EIA (1999d) expects the interregional pipeline system, a network that connects the lower 48 states and the Canadian provinces, to grow at an annual rate of 0.7 percent between 2001 and 2020. However, natural gas consumption is expected to grow at more than twice that annual rate, 1.8 percent, over that same period. The majority of the growth in consumption is expected to be fueled by the electric generation sector. According to the EIA, a key issue is what kinds of infrastructure changes will be required to meet this demand and what the financial and environmental costs will be of expanding the pipeline network.

The EIA addresses the discrepancy between annual consumption growth and interregional pipeline capacity growth with the following explanation: "Overall, interregional pipeline capacity (including imports) is projected to grow at an annual rate of only about 0.7 percent between 2001 and 2020 (compared with 3.7 percent between 1997 and 2000 and 3.8 percent between 1990 and 2000). However, EIA also forecasts that consumption will grow at a rate of 27 Bcf per day (1.8 percent annually) during the same period. The difference between these two growth estimates is predicted upon the assumption that capacity additions to support increased demand will be local expansions of facilities within regions (through added compression and pipeline looping) rather than through new long-haul (interregional) systems or large-scale expansions" (1999d, p. 125).

SECTION 6

ECONOMIC ANALYSIS METHODS

This section presents the methodology for analyzing the economic impacts of the NESHAP. Implementation of this methodology will provide the economic data and supporting information needed by EPA to support its regulatory determination. This analysis is based on microeconomic theory and the methods developed for earlier EPA studies to operationalize this theory. These methods are tailored to and extended for this analysis, as appropriate, to meet EPA's requirements for an economic impact analysis (EIA) of controls placed on stationary combustion turbines.

This methodology section includes a description of the Agency requirements for conducting an EIA, background information on typical economic modeling approaches, the conceptual approach selected for this EIA, and an overview of the computerized market model used in the analysis. The focus of this section is on the approach for modeling the electricity market and its interactions with other energy markets and final product markets. Appendix A contains additional detail on estimating changes is producer and consumer surplus in the nonelectric utility markets included in the economic model.

6.1 Agency Requirements for Conducting an EIA

The CAA provides the statutory authority under which all air quality regulations and standards are implemented by OAQPS. The 1990 CAA Amendments require that EPA establish emission standards for sources releasing any of the listed HAPs.

Congress and the Executive Office have imposed requirements for conducting economic analyses to accompany regulatory actions. The Agency has published its guidelines for developing an EIA (EPA, 1999a). Section 312 of the CAA specifically requires a comprehensive analysis that considers benefits, costs, and other effects associated with compliance. On the benefits side, it requires consideration of all the economic, public health, and environmental benefits of compliance. On the cost side, it requires consideration of the effects on employment, productivity, cost of living, economic growth, and the overall economy. These effects are evaluated by measures of facility- and company-level production impacts and societal-level producer and consumer welfare impacts. The RFA and SBREFA require regulatory agencies to consider the economic impacts of regulatory actions on small entities. Executive Order 12866 requires regulatory agencies to conduct an analysis of the economic benefits and costs of all proposed regulatory actions with projected costs greater than $100 million. Also, Executive Order 13211 requires EPA to consider for particular rules the impacts on energy markets. The Agency's draft Economic Analysis Guidelines provide detailed instructions and expectations for economic analyses that support rulemaking (EPA, 1999a). The EIA provides the data and information needed to comply with the federal regulation, the executive order, and the guidance manual.

6.2 Overview of Economic Modeling Approaches

In general, the EIA methodology needs to allow EPA to consider the effect of the different regulatory alternatives. Several types of economic impact modeling approaches have been developed to support regulatory development. These approaches can be viewed as varying along two modeling dimensions:

- the scope of economic decisionmaking accounted for in the model and
- the scope of interaction between different segments of the economy.

Each of these dimensions was considered in recommending our approach. The advantages and disadvantages of each are discussed below.

6.2.1 Modeling Dimension 1: Scope of Economic Decisionmaking

Models incorporating different levels of economic decisionmaking can generally be categorized as *with* behavior responses and *without* behavior responses (accounting approach). Table 6-1 provides a brief comparison of the two approaches. The behavioral approach is grounded in economic theory related to producer and consumer behavior in response to changes in market conditions. In essence, this approach models the expected reallocation of society's resources in response to a regulation. The behavioral approach explicitly models the changes in market prices and production. Resulting changes in price and quantity are key inputs into the determination of a number of important phenomena in an EIA, such as changes in producer surplus, changes in consumer surplus, and net social welfare effects. For example, a large price increase may imply that consumers bear a large share of the regulatory burden, thereby mitigating the impact on producers' profits and plant closures.

In contrast, the nonbehavioral/accounting approach essentially holds fixed all interaction between facility production and market forces. In this approach, a simplifying assumption is made that the firm absorbs all control costs, and discounted cash flow analysis is used to evaluate the burden of the control costs. Typically, engineering control costs are weighted by the number of affected units to develop "engineering" estimates of the total annualized costs. These costs are then compared to company or industry sales to evaluate the regulation's impact.

Table 6-1. Comparison of Modeling Approaches

EIA With Behavioral Responses

Incorporates control costs into production function

Includes change in quantity produced

Includes change in market price

Estimates impacts for

- affected producers
- unaffected producers
- consumers
- foreign trade

EIA Without Behavioral Responses

- Assumes firm absorbs all control costs
- Typically uses discounted cash flow analysis to evaluate burden of control costs
- Includes depreciation schedules and corporate tax implications
- Does *not* adjust for changes in market price
- Does *not* adjust for changes in plant production

6.2.2 Modeling Dimension 2: Interaction Between Economic Sectors

Because of the large number of markets potentially affected by the combustion turbines regulation, an issue arises concerning the level of sectoral interaction to model. In the broadest sense, all markets are directly or indirectly linked in the economy; thus, all commodities and markets are to some extent affected by the regulation. For example, the control costs on turbines may directly affect the market for aluminum if aluminum plants are operating turbines for self-generation of electricity or generation of process steam. However, control costs will also indirectly affect the market for aluminum because the cost of electricity will increase. As a result, the increased price of aluminum production (due to direct and indirect costs on the aluminum industry) may be passed onto consumers of aluminum products.

The appropriate level of market interactions to be included in the EIA is determined by the scope of the regulation across industries and the ability of affected firms to pass along the regulatory costs in the form of higher prices. Alternative approaches for modeling interactions between economic sectors can generally be divided in three groups:

- Partial equilibrium model: Individual markets are modeled in isolation. The only factor affecting the market is the cost of the regulation on facilities in the industry being modeled.

- General equilibrium model: All sectors of the economy are modeled together. General equilibrium models operationalize neoclassical microeconomic theory by modeling not only the direct effects of control costs, but also potential input substitution effects, changes in production levels associated with changes in market prices across all sectors, and the associated changes in welfare economywide. A disadvantage of general equilibrium modeling is that substantial time and resources are required to develop a new model or tailor an existing model for analyzing regulatory alternatives.

- Multiple-market partial equilibrium model: A subset of related markets are modeled together, with intersectoral linkages explicitly specified. To account for the relationships and links between different markets without employing a full general equilibrium model, analysts can use an integrated partial equilibrium model. In instances where separate markets are closely related and there are strong interconnections, there are significant advantages to estimating market adjustments in different markets simultaneously using an integrated market modeling approach.

6.3 Selected Modeling Approach Used for Combustion Turbine Analysis

To conduct the analysis for the combustion turbine MACT, the Agency used a market modeling approach that incorporates behavioral responses in a multiple-market partial equilibrium model as described above. The majority of the regulation's control costs are projected to be associated with combustion turbines in the electricity market. These control costs will increase the price of energy, affecting almost all sectors of the economy. Because the elasticity of demand for energy varies across fuel types, it is important to use a market modeling approach to estimate the share of the burden borne by producers and consumers.

Multiple-market partial equilibrium analysis provides a manageable approach to incorporate interactions between energy markets and final product markets into the EIA to accurately estimate the impact of the regulation. The multiple-market partial equilibrium approach represents an intermediate step between a simple, single-market partial equilibrium approach and a full general equilibrium approach. This approach involves identifying and modeling the most significant subset of market interactions using an integrated partial equilibrium framework. In effect, the modeling technique is to link a series of standard partial equilibrium models by specifying the interactions between supply functions and then solving for all prices and quantities across all markets simultaneously.

Figure 6-1 presents an overview of the key market linkages included in the economic impact modeling approach used to analyze the combustion turbines MACT. The focus of the analysis is on the energy supply chain, including the extraction and distribution of natural gas and oil, the generation of electricity, and the consumption of energy by producers of final products and services. As shown in Figure 6-1, wholesale electricity generators consume natural gas and petroleum products to generate electricity that is then used in the production of final products and services. In addition, the final product and service markets also use natural gas and petroleum products as an input into their production process. This analysis explicitly models the linkages between these market segments.

The control costs associated with the regulation will directly affect the cost of the generation of wholesale electricity using combustion turbines. In addition to the direct impact of control costs on entities installing new combustion turbines, indirect impacts are passed along the energy supply chain through changes in prices. For example, the price of natural gas will increase because of two effects: the higher price of electricity used in the natural gas industry and increased demand for natural gas generated by fuel switching from electricity to natural gas. Similarly, production costs for manufacturers of final products will change as a result of price of electricity and natural gas.

Also included in the impact model is feedback on changes in outputs in final product markets to the demand for Btus in the fuel markets. The change in facility output is determined by the size of the Btu cost increase (typically variable cost per output), the facility's production function (slope of facility-level supply curve), and the characteristics of the facility's downstream market (other market suppliers and market demanders). For example, if consumers' demand for a product is not sensitive to price, then producers can pass the cost of the regulation through to consumers and the facility output will not change. However, if only a small number of facilities in a market are affected, then competition will prevent a facility from raising its prices.

One possible feedback pathway *not* explicitly modeled is technical changes in manufacturing processes. For example, if the cost of Btus increases, a facility may use measures to increase manufacturing efficiency or capture waste heat. These facility-level responses are a form of pollution prevention. However, directly incorporating these responses into the model is beyond the scope of our analysis.[1]

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[1]Technical changes are indirectly captured through the own-price and cross-price elasticities of demand used to model fuel switching. These are discussed in Section 6.4.1.

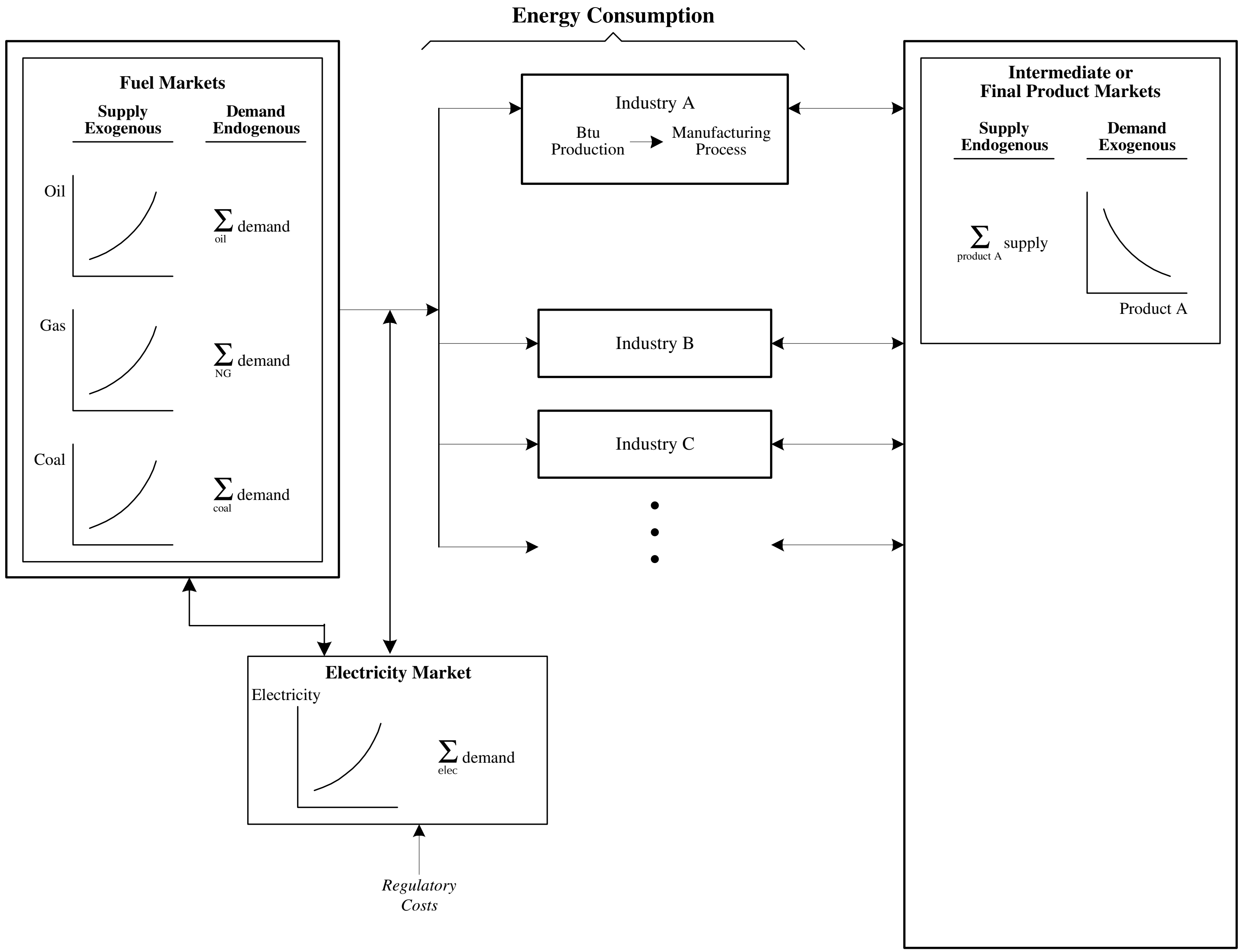

Figure 6-1. Links Between Energy and Final Product Markets

The major market segments included in the model and the intermarket linkages connecting the fuel markets and final product and service markets are described below. Because, as mentioned in Section 3, the overwhelming majority of combustion turbine units are used to generate wholesale electric power, the discussion focuses on the electricity market.

6.3.1 Electricity Markets

In this analysis, the market for base load energy and peak power are modeled separately. As the industry deregulates, it is becoming increasingly common for separate market prices to be determined for these two commodity attributes of electricity. In addition, the growth of CCCTs is being driven primarily by growth in base load energy demand, and the growth in SCCTs will be driven primarily by growth in peak demand. And because the relative impact on the control costs is greater for SCCTs compared to CCCTs, economic impacts will be different for base load energy and peak power.[2]

The base load energy and peak power market analyses compare the baseline equilibrium (without the regulation) to the regulated market equilibrium. Figure 6-2a presents a generalized market for the base load electricity that includes the installation of new turbines to meet demand growth for base load power.[3] Existing source supply is characterized by an upward-sloping marginal cost (supply) curve. The supply of new base load generation capacity is characterized by constant marginal costs and is modeled as a horizontal supply curve through the current market price. Figure 6-2b shows that the control costs associated with the rule will affect both existing and new sources of supply, shifting the market supply curve and leading to an increase in price and decrease in quantity of base load power consumed.

6.3.2 Other Energy Markets

The petroleum, natural gas, and coal markets are also included in the market model. Because the overwhelming majority of the affected combustion turbines is projected to be used in the electricity market, the other energy markets are assumed not to be directly affected by the rule. However, these markets will be indirectly affected through changes in input fuel prices (i.e., a supply shift) and changes in demand from final product and service

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[2]The same controls are required for SCCTs and for CCCTs. But the relative costs are higher for SCCTs because their equipment and installation costs are approximately 40 percent less compared to CCCTs. Control costs are discussed in Section 6.1.

[3]A similar figure and analysis apply for peak load power with the exception that peak load supply is generally less responsive to price changes at the margin (i.e., base load elasticity of supply > peak load elasticity of supply).

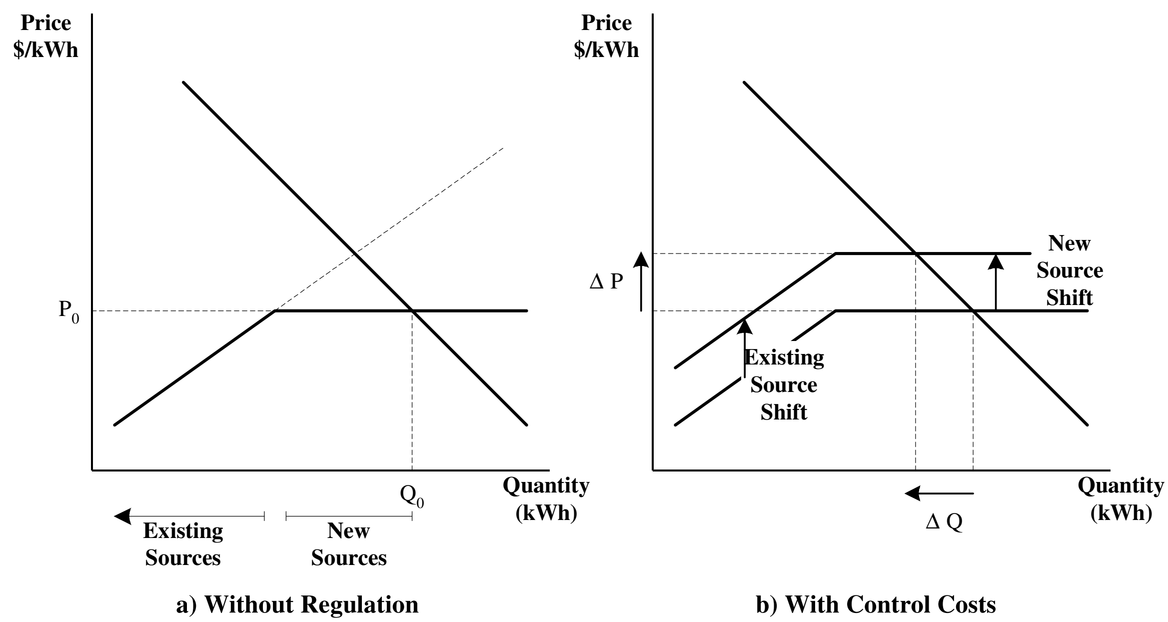


Figure 6-2. Electricity Market

markets using these energy sources (i.e., a demand shift). The ultimate impact on market price and quantities depends on the relative magnitudes of these shifts. Note the demand for other fuels may increase (Figure 6-3a) as firms switch away from electricity to petroleum, natural gas, or coal, or demand may decrease (Figure 6-3b) as the higher price for electricity suppresses economic activity decreasing demand for all fuels.

6.3.3 Supply and Demand Elasticities for Energy Markets

The market model incorporates behavioral changes based on the price elasticities of supply and demand. The price elasticities used to estimate the economic impacts presented in Section 6.3 are given in Table 6-2. Appendix B contains the sensitivity analysis for the key supply and demand elasticity assumptions.

Because most of the direct cost impacts fall on the combustion turbines in electricity markets, the price elasticities of supply in the electricity markets are important factors influencing the size and distribution of the economic impacts associated with the combustion turbine regulation. The elasticities of supply are intended to represent the behavioral

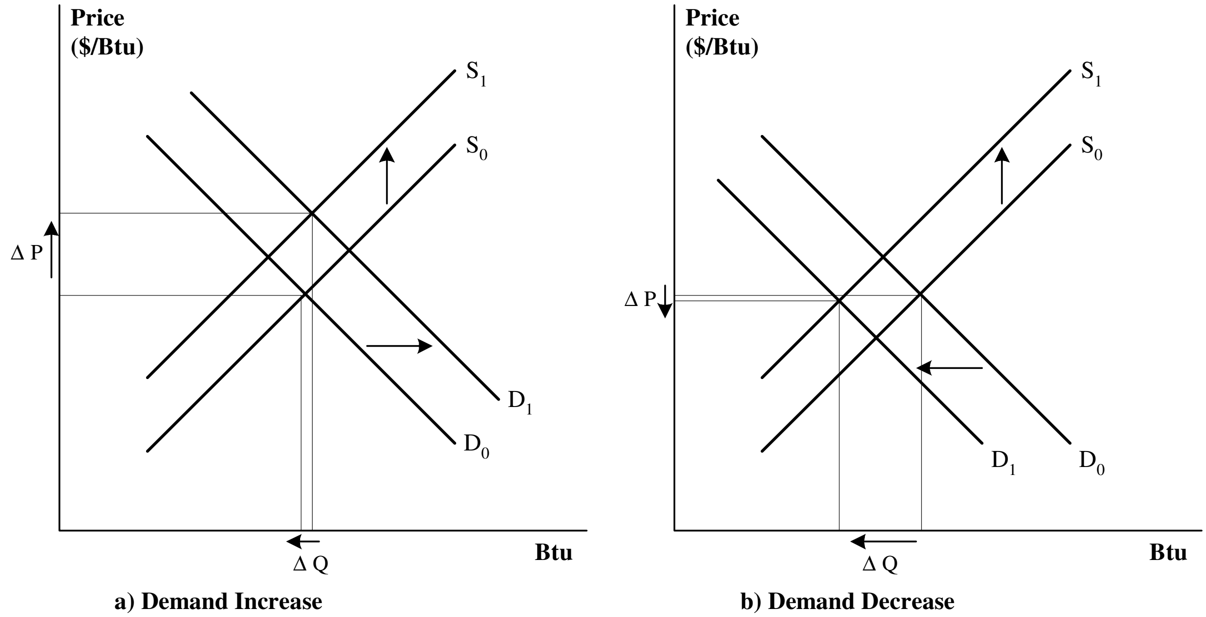


Figure 6-3. Potential Market Effects of the MACT on Petroleum, Natural Gas, or Coal

responses from existing sources.[4] However, in general, there is no consensus on estimates of the price elasticity of supply for electricity. Estimates of the elasticity of supply for electric power were unavailable. This is in part because, under traditional regulation, the electric utility industry had a mandate to serve all its customers. In addition, utilities werecompensated on a rate-based rate of return. As a result, the market concept of supply elasticity was not the driving force in utilities' capital investment decisions. To operationalize the model, a supply elasticity of 0.75 was assumed for the base load energy market. We assumed that the peak power market was one-half of base load energy elasticity. Given the uncertainty surrounding these parameters, the Agency conducted a sensitivity analysis for this value. The results of this sensitivity analysis are reported in Appendix B.

In contrast, many studies have been conducted on the elasticity of demand for electricity, and it is generally agreed that, in the short run, the demand for electricity is relatively inelastic. Most residential, commercial, and industrial electricity consumers do not significantly adjust short-run behavior in response to changes in the price of electricity. The elasticity of demand for electricity is primarily driven by long-run decisions regarding

[4]The supply curve for new sources is assumed to be horizontal, reflecting a constant marginal cost of production for new sources.

Table 6-2. Supply and Demand Elasticities

Energy Sectors	Elasticity of Supply	Elasticity of Demand			
		Manufacturing	Commercial[a]	Transportation[a]	Residential[a]
Electricity: baseload energy	0.75	Derived demand	Derived demand	–0.24	–0.23
Electricity: peak power	0.375[b]	Derived demand	Derived demand	–0.24	–0.23
Natural gas	0.41[c]	Derived demand	Derived demand	–0.47	–0.26
Petroleum	0.58[d]	Derived demand	Derived demand	–0.28	–0.28
Coal	1.0[e]	Derived demand	Derived demand	–0.28	–0.28

[a] Energy Information Administration. 2000. "Issues in Midterm Analysis and Forecasting 1999—Table 1." <http://www.eia.doe.gov/oaif/issues/pricetbl1.html>. As obtained on May 8, 2000.
[b] Assumed to be one-half of baseload energy elasticity.
[c] Dahl, Carol A., and Thomas E. Duggan. 1996. "U.S. Energy Product Supply Elasticities: A Survey and Application to the U.S. Oil Market." *Resource and Energy Economics*18:243-263.
[d] Hogman, William W. 1989. "World Oil Price Projections: A Sensitivity Analysis." Prepared pursuant to the Harvard-Japan World Oil Market Study. Cambridge, MA: Energy Environmental Policy Center, John F. Kennedy School of Government, Harvard University.
[e] Zimmerman, M.B. 1977. "Modeling Depletion in the Mineral Industry: The Case of Coal." *The Bell Journal of Economics* 8(2):41-65.

equipment efficiency and fuel substitution. Table 6-6 shows the elasticities of demand used for the commercial, residential, and transportation sectors.

Additional elasticity of demand parameters for the commercial, residential, and transportation sectors, by fuel type (natural gas, petroleum and coal), were obtained from the Energy Information Administration. The elasticity of demand in the energy market for the manufacturing sector is not specified because the model calculates the derived demand for each of the five energy markets modeled. In effect, adjustments in the final product markets due to changes in production levels and fuel switching are used to estimate changes in demand, eliminating the need for demand elasticity parameters in the energy markets.

6.3.4 Final Product and Service Markets

Producers of final products and services are segmented into industrial, commercial, transportation, and residential sectors. The industrial sector is further partitioned into the 23 manufacturing, agricultural, and mining sectors. A partial equilibrium analysis was conducted for each of these model the supply and demand of final products. Changes in production levels and fuel switching due to the regulation's impact on the price of electricity are then linked back into the energy markets.

6.3.4.1 Modeling the Impact on the Industrial and Commercial Sectors

The impact of the regulation on these sectors was modeled using changes in the cost of Btus used in production processes. In this context, Btus refer to the generic energy requirements that are used to generate process heat, process steam, or shaft power. As shown in Figure 6-4, the regulation will increase the cost of Btu production indirectly through increases in the price of Btus due to control costs on wholesale electricity generators. The effect is similar to placing a tax on certain types of energy sources (i.e., on Btus generated by combustion turbines). The firms' reactions to the change in the cost of Btu production feeds back into the energy markets in two ways (see Figure 6-4). The first feedback pathway is through changing the fuel used in the production process. This can include fuel switching, such as switching from gas turbines to power processes to diesel engines, and/or process changes that increase energy efficiency and reduce the amount of Btus required per unit of output. Fuel switching impacts are modeled using cross-price elasticities of demand between energy sources and own-price elasticities.

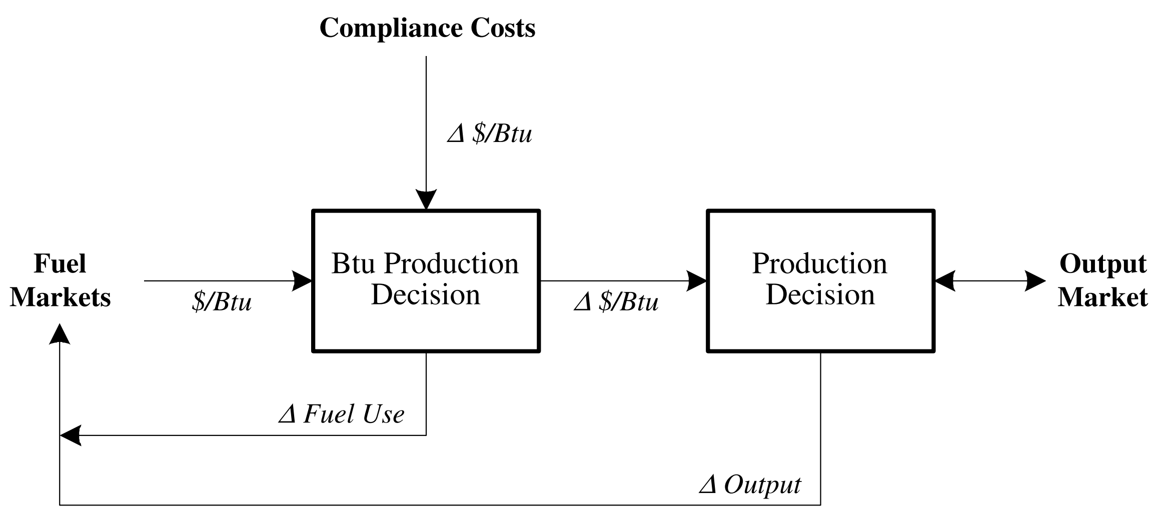


Figure 6-4. Fuel Market Interactions with Facility-Level Production Decisions

EPA modeled fuel switching using secondary data developed by the U.S. Department of Energy for the National Energy Modeling System (NEMS). Table 6-3 contains fuel price elasticities of demand for electricity, natural gas, petroleum products, and coal. The diagonal elements in the table represent own-price elasticities. For example, the table indicates that for steam coal, a 1 percent change in the price of coal will lead to a 0.499 percent decrease in the use of coal. The off diagonal elements are cross-price elasticities and indicate fuel switching propensities. For example, for steam coal, the second column indicates that a 1 percent increase in the price of coal will lead to a 0.061 percent increase in the use of natural gas.

Table 6-3. Fuel Price Elasticities

	Own and Cross Elasticities in 2015				
Inputs	**Electricity**	**Natural Gas**	**Coal**	**Residual**	**Distillate**
Electricity	–0.074	0.092	0.605	0.080	0.017
Natural Gas	0.496	–0.229	1.087	0.346	0.014
Steam Coal	0.021	0.061	–0.499	0.151	0.023
Residual	0.236	0.036	0.650	–0.587	0.012
Distillate	0.247	0.002	0.578	0.044	–0.055

Source: U.S. Department of Energy, Energy Information Administration (EIA). January 1998c. *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*. DOE/EIA-M064(98). Washington, DC: U.S. Department of Energy.

The second feedback pathway to the energy markets is through the facility's change in output. Because Btus are an input into the production process, price increases (↑$/Btu) lead to an upward shift in the industry supply curve. In a perfectly competitive market, the point where supply equals demand determines the market price and quantity. A shift in the industry supply curve leads to a change in the equilibrium market price and quantity. EPA assumed constant returns to scale in production so that the percentage change in the equilibrium market quantity in each final product and service market equals the percentage change in Btus consumed by industries.

The change in equilibrium supply and demand in each final industrial and commercial sector was modeled using a partial equilibrium approach. The size of the regulation-induced shifts in the final product supply curves is a function of the indirect fuel costs (determined by the change in fuel prices and the fuel intensity) relative to variable production costs in each manufacturing industry.

It was assumed that the demand for final industrial and commercial products and services is unchanged by the regulation. However, because the demand function quantifies the change in quantity demanded in response to a change in price, the baseline demand conditions are important in determining the regulation's impact. Because prices changes are anticipated to be small, the key demand parameters are the elasticity of demand with respect to changes in the price of final products. Demand elasticities for each of the sectors included in the analysis are reported in Table 6-4.

6.3.4.2 Impact on the Residential Sector and Transportation Sectors

The residential and transportation sector does not bear any direct costs associated with the regulation because they do not own combustion turbines. However, they bear indirect costs due to price increases. These sectors' change in energy demand in response to changes in energy prices is modeled as a series of demand curves parameterized by elasticity of demand parameters (see Table 6-2).

6.3.4.3 Impact on the Government Sector

All combustion turbines projected to be installed by government entities will be for local generation of electricity. These municipal generators are grouped into the electricity energy market; thus the government sector is not explicitly included in the model.

6.4 Summary of the Economic Impact Model

We summarize the linkages used to operationalize the estimation of economic impacts associated with the compliance costs in Figure 6-5.

Control costs on new turbines used for generators will shift the supply curve for wholesale electricity. The new equilibrium price and quantity in the electricity market will determine the distribution of impacts between producers (electricity generators) and consumers. Changes in wholesale electricity generators' demand for input fuels (due to changes in the market quantity of electricity) feed back into the natural gas, coal, and petroleum markets.

Finally, manufacturers experience supply curve shifts due to changes in prices for natural gas, petroleum, electricity, and coal. The share of these costs borne by producers (manufactures) and consumers is determined by the new equilibrium price and quantity in the final product and service markets. Changes in manufacturers' Btu demands due to fuel switching and changes in production levels feed back into the energy markets.

Table 6-4. Supply and Demand Elasticities for Industrial and Commercial Sectors

NAICS	Description	Supply	Demand
Industrial Sectors			
311	Food	0.75	–1.00
312	Beverage and Tobacco Products	0.75	–1.30
313	Textile Mills	0.75	–1.50
314	Textile Product Mills	0.75	–1.50
315	Apparel	0.75	–1.10
316	Leather and Allied Products	0.75	–1.20
321	Wood Products	0.75	–1.00
322	Paper	0.75	–1.50
323	Printing and Related Support	0.75	–1.80
325	Chemicals	0.75	–1.80
326	Plastics and Rubber Products	0.75	–1.80
327	Nonmetallic Mineral Products	0.75	–1.00
331	Primary Metals	0.75	–1.00
332	Fabricated Metal Products	0.75	–0.20
333	Machinery	0.75	–0.50
334	Computer and Electronic Products	0.75	–0.30
335	Electrical Equip., Appliances, and Components	0.75	–0.50
336	Transportation Equipment	0.75	–0.50
337	Furniture and Related Products	0.75	–1.80
339	Miscellaneous	0.75	–0.60
11	Agricultural Sector	0.75	–1.80
23	Construction Sector	0.75	–1.00
21	Other Mining Sector	0.75	–0.30
Commercial Sector (NAICS 42-45;51-56;61-72)		0.75	–1.00

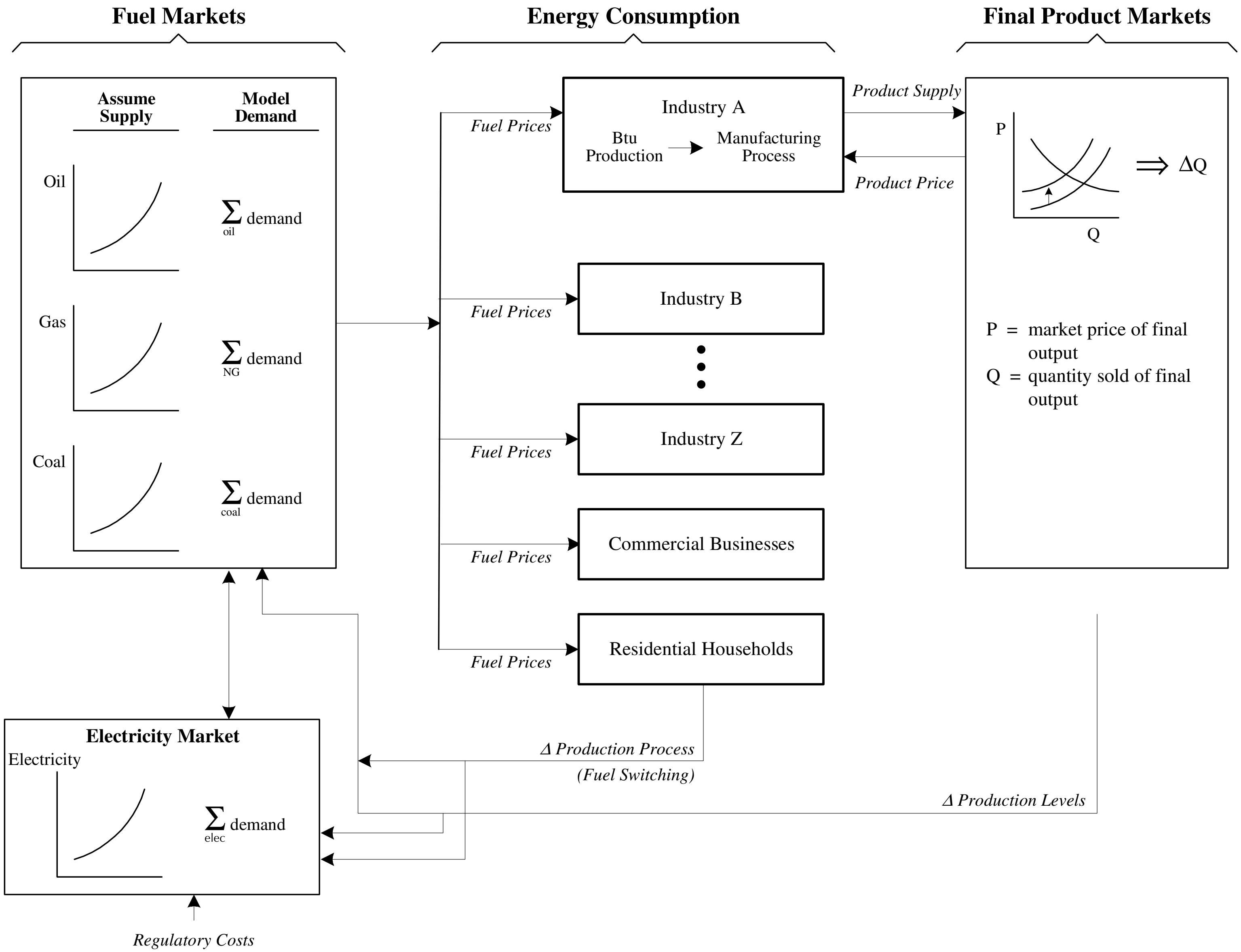


Figure 6-5. Operationalizing the Estimation of Economic Impact

Adjustments in price and quantity in all energy and final product markets occur simultaneously. A computer model was used to numerically simulate market adjustments by iterating over commodity prices until equilibrium is reached (i.e., until supply equals demand in all markets being modeled) and to estimate the economic impact of the regulation (change in producer and consumer surplus) in the sectors of the economy being modeled.

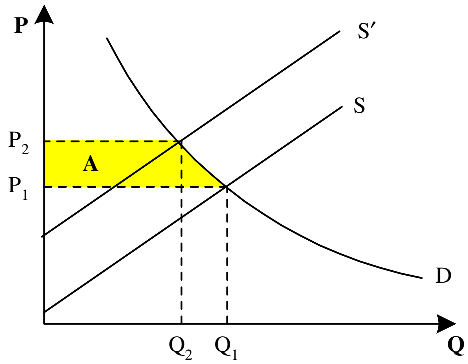
This model comprises a series of computer spreadsheet modules. The modules integrate the engineering inputs and the market-level adjustment parameters to estimate the regulation's impact on the price and quantity in each market being analyzed. At the heart of the model is a market-clearing algorithm that compares the total quantity supplied to the total quantity demanded for each market commodity. Appendix A describes the computer model in more detail.

6.4.1 Estimating Changes in Social Welfare

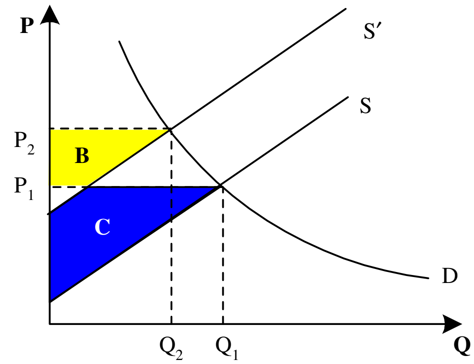
The combustion turbine regulation will impact almost every sector of the economy either directly through control costs or indirectly through changes in the price of energy and final products. For example, a share of control costs that originate in the energy markets are passed through the final product markets and are borne by both the producers and consumers of final products. To estimate the total change in social welfare without double-counting impacts across the linked partial equilibrium markets being modeled, EPA quantified social welfare changes for the following categories:

- change in producer surplus in the energy markets,
- change in producer surplus in the final product and service markets,
- change in consumer surplus in the final product and service markets, residential and transportation energy markets.

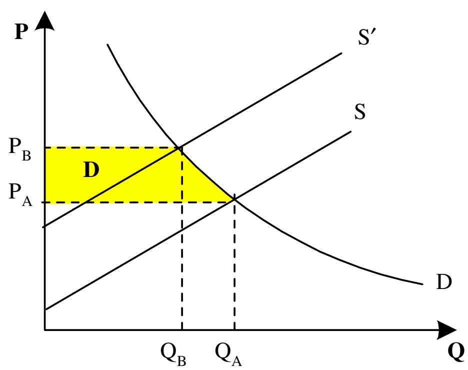
Figure 6-6 illustrates the change in producer and consumer surplus in the intermediate energy market and the final product markets. For example, assume a simple world with only one energy market, wholesale electricity, and one final product market, pulp and paper. If the regulation increased the cost of generating wholesale electricity, then part of the cost of the regulation will be borne by the electricity producers as decreased producer surplus and part of the costs will be passed on to the pulp and paper manufacturers. In Figure 6-6a, the pulp and paper manufacturers are the consumers of electricity, so the change in consumer surplus is displayed. This change in consumer surplus in the energy market is captured by the final product market (because the consumer is the pulp and paper industry in this case), where it is split between consumer surplus and producer surplus in those markets. Figure 6-6b shows the change in producer surplus in the energy market.



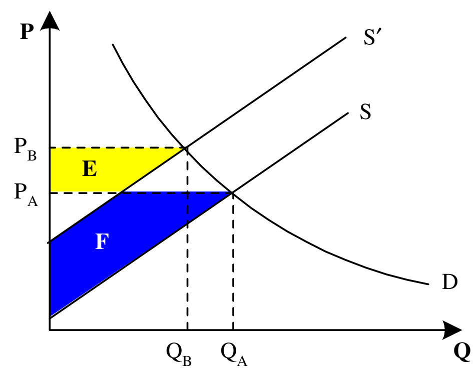
(a) Change in Consumer Surplus in the Energy Market



(b) Change in Producer Surplus in the Energy Market



(c) Change in Consumer Surplus in Final Product Markets



(d) Change in Producer Surplus in Final Product Markets

Figure 6-6. Changes in Economic Welfare with Regulation

As shown in Figures 6-6c and 6-6d, the cost affects the pulp and paper industry by shifting up the supply curve in the pulp and paper market. These higher electricity prices therefore lead to costs in the pulp and paper industry that are distributed between producers and consumers of paper products in the form of lower producer surplus and lower consumer surplus. Note that the change in consumer surplus in the intermediate energy market must equal the total change in consumer and producer surplus in the final product market. Thus, to avoid double-counting, the change in consumer surplus in the intermediate energy market was not quantified; instead the total change in social welfare was calculated as

$$\text{Change in Social Welfare} = \sum \Delta PSE + \sum \Delta PSF + \sum \Delta CSF + \sum \Delta CSRT \qquad (6.1)$$

where

ΔPSE = change in producer surplus in the energy markets,

ΔPSF = change in producer surplus in the final product markets,

ΔCSF = change in consumer surplus in the final product markets, and

$\Delta CSRT$ = change in consumer surplus residential and transportation energy markets.

Appendix A contains the detailed equations used to calculate the change in producer and consumer surplus in the appropriate intermediate and final product markets.

SECTION 7

ECONOMIC IMPACT ANALYSIS

Control measures implemented to comply with the regulation will impose regulatory costs on affected facilities in the energy, manufacturing, commercial, and government sectors. These costs will be distributed between producers and consumers through changes in energy prices and changes in prices of final products and services. This section describes the engineering control costs of the regulatory alternatives and presents the economic impact estimates, including energy impacts, of the regulation.

7.1 Engineering Control Cost Inputs

The cost impacts associated with the regulation in the fifth year after promulgation comprise capital and annual operating, performance testing, monitoring, recordkeeping, and reporting costs. The Department of Energy (DOE) projects the 218 new combustion turbines will begin operation during the 5-year period between 2002 and 2007. Of these new turbines, it is estimated that approximately 44 units (20 percent) will be located at major HAP sources and be required to comply with the combustion turbine NESHAP.

EPA estimates the annualized capital costs of these add-on controls for 44 new stationary combustion turbines (170 MW) are $42.6 million (see Table 7-1).[1] Additional annual costs include performance testing, monitoring, recordkeeping, reporting, and the annual costs of the oxidation catalyst control system and CEMS yielding a total annual cost of $43.3 million for affected units. All new sources will be required to conduct an initial performance test to demonstrate compliance. In addition, EPA estimates that every year most of the "nonaffected" new sources (70 percent) may have to perform an initial notification to comply with the regulation. The total cost for initial notification for 123 new turbines is estimated to be approximately $12,000. For more details on the derivation of these costs, refer to the "Cost Analysis for Impacts Associated with Stationary Combustion Turbine MACT," a memo that is in the public docket.

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[1]All costs are reported in 1998 dollars.

Table 7-1. Engineering Cost Analysis for the Stationary Combustion Turbine MACT Standard ($1998)

	Combine per Turbine	Number of Affected Turbines	Total Cost
Capital Costs			
CEMS	$3,000	44	$132,000
Oxidation catalyst	$3,255,377	44	$143,236,588
Total Capital Cost			$143,368,588
Annual Costs			
CEMS	$427	44	$18,788
Oxidation catalyst	$969,499	44	$42,657,956
Performance tests	$12,350	44	$543,400
Monitoring, recordkeeping, reporting	$2,709	44	$119,201
Initial notification only	98	123	$11,993
Total Annual Cost (1998$)			$43,351,338

[a]Revenues and costs are in 1998$.

7.1.1 Computing Supply Shifts in the Electricity Market

For the purpose of the market model, the electric services industry is broken into two market sectors: base load energy and peak power. As shown in Section 4 (Table 4-3), EPA estimates approximately two-thirds of new combustion turbine units are projected to contribute to the base load energy market, and the remaining one-third are projected to contribute to the peak power market. As a result, the control costs for the electricity are distributed 67 percent to the electric base load energy market and 33 percent to the peak power market. The relative shift in the supply curve for each segment is presented as the percentage shift in the price of the marginal unit produced. The percentage shift is calculated as the ratio of control costs to the revenue of the affected portion of the industry[2] (see Table 7-2). As shown, new affected sources with add-on controls and testing requirements have the largest supply shift (1.8 percent for base load energy and 3.5 percent for peak power). The supply shifters for the remaining segments are all less than 0.1 percent.

[2]Revenue in the electric utility industry was segmented into the base load and peak power markets assuming an 80/20 split, respectively. This ratio was estimated based on discussions with industry experts.

Table 7-2. Summary of Turbine Cost Information and Supply Shifts

	Share Units of Market (%)	Revenue[a] ($$10^9$)	Control Costs[a] ($$10^6$)	Supply Shift (%)
Base Load Energy				
Existing—unaffected	95.08	169.0	0.00	0.00
New unaffected	1.07	1.9	0.00	0.00
New affected—notification only	2.59	4.6	0.01	0.00
New affected—notification and capital	0.92	1.6	29.04	1.77
Total	100.00	177.6	29.05	0.02
Peak Power				
Existing—unaffected	95.08	42.2	0.00	0.00
New unaffected	1.07	0.5	0.00	0.00
New affected—notification only	2.59	1.1	0.00	0.00
New affected—notification and capital	0.92	0.4	14.30	3.48
Total	100.00	44.4	14.31	0.03
Total		222.1	43.35	

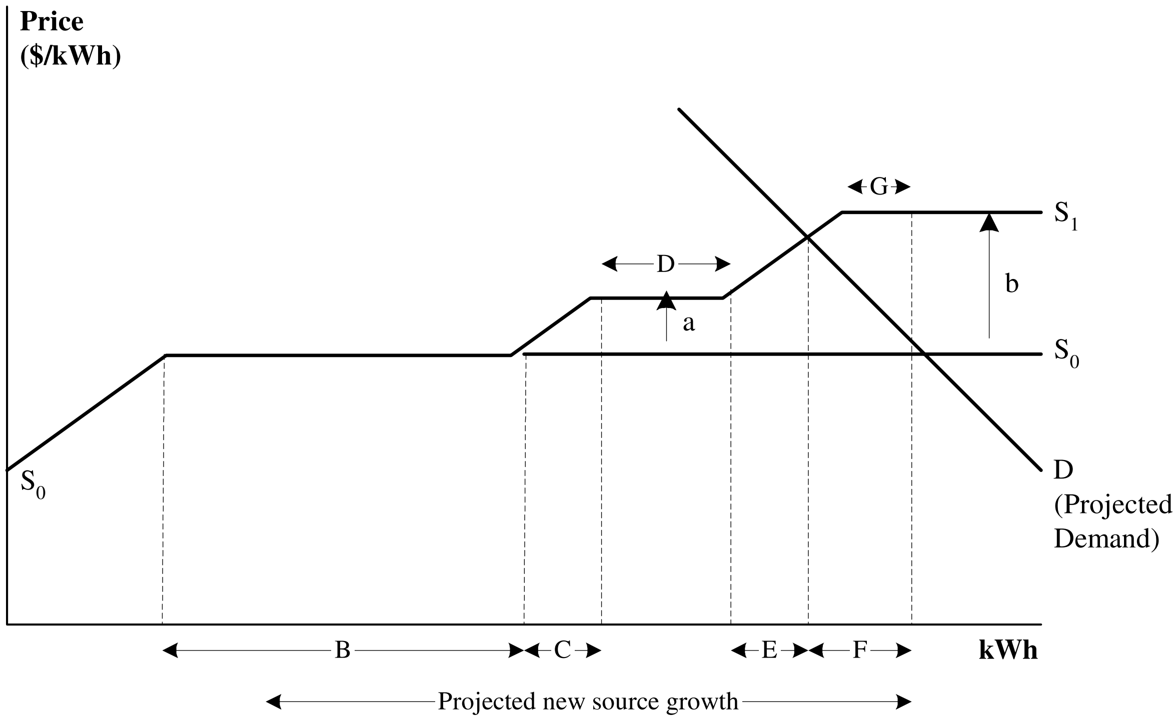
[a]Revenues and costs are in 1998$.

Figure 7-1 illustrates the supply shifts and shows the with-regulation supply curve S_1. In this example, the regulation leads to an increased supply by unaffected existing units, crowding out the new units with add-on capital costs.

7.2 Market-Level Results

The model projects the MACT standard will increase base load electricity price by 0.529 percent and peak power prices by 0.717 percent (see Table 7-3). Domestic production declines by 0.534 and 0.665 percent, respectively.

The analysis also shows the impact on distribution of electricity supply (see Table 7-4). First, it delays entry of affected new units with add-on controls and testing requirements because price does not sufficiently increase to cover the costs of production for these units. Second, the increase in the price of electricity will make it profitable for existing unaffected sources to increase supply, displacing approximately 0.92 percent of affected new supply. This increase in supply implies that fewer older units may be retired as a result of the regulation. The remaining change in quantity results from decreased consumer demand as the prices of base load energy and peak power increase.



B = New unaffected unit supply
B+C = Increase in supply from existing units
D = New notification only
F = Decreased quantity demanded due to price increase
G = Affected supply that delays entry into the market until demand sufficiently grows
a = Supply shift for new monitoring only units
b = Supply shift for new testing and capital equipment units

Figure 7-1. Market for Baseload Electricity

Table 7-3. Market-Level Impacts of Stationary Combustion Turbines MACT Standard: 2005

Energy Markets		Percent Change: Price	Percent Change: Quantity[a]
Petroleum		0.019	0.010
Natural Gas		0.052	0.018
Base Electricity		0.529	–0.534
Peak Electricity		0.717	–0.665
Coal		–0.244	–0.244
Industrial Sectors NAICS Description	**Description**	**Percent Change: Price**	**Percent Change: Quantity**
311	Food	0.001	–0.001
312	Beverage and Tobacco Products	0.000	–0.001
313	Textile Mills	0.002	–0.003
314	Textile Product Mills	0.001	–0.001
315	Apparel	0.000	0.000
316	Leather and Allied Products	0.001	–0.001
321	Wood Products	0.002	–0.002
322	Paper	0.002	–0.003
323	Printing and Related Support	0.001	–0.001
325	Chemicals	0.002	–0.004
326	Plastics and Rubber Products	0.002	–0.003
327	Nonmetallic Mineral Products	0.004	–0.004
331	Primary Metals	0.005	–0.005
332	Fabricated Metal Products	0.003	–0.001
333	Machinery	0.001	–0.001
334	Computer and Electronic Products	0.001	0.000
335	Electrical Equipment, Appliances, and Components	0.001	–0.001
336	Transportation Equipment	0.001	–0.001
337	Furniture and Related Products	0.001	–0.001
339	Miscellaneous	0.001	–0.001
11	Agricultural Sector	0.003	–0.005
23	Construction Sector	0.012	–0.012
21	Other Mining Sector	0.002	–0.001
Commercial Sector		0.002	–0.002

[a]Actual value for all 0.000 entries for the various sectors is > –0.001 and < 0.

Table 7-4. Changes in Market Shares for Electricity Suppliers

	Baseline Shares (%)	With Regulation Shares (%)
Existing—unaffected	95.42	96.32
New unaffected	1.07	1.07
New affected—testing only	2.59	2.60
New affected—testing and capital	0.92	0.00

In the natural gas and petroleum markets, both the price and quantity increase, indicating that an increase in demand for the fuel (due to fuel switching) dominates the upward shift in the supply curve (increased electricity costs as a fuel input). Price increases in these markets are below 0.1 percent. Price and quantity decrease in the coal market, reflecting the decreased demand for coal as electric utilities reduce output. Market-level impacts on downstream product and service markets are less than 0.3 percent.

7.3 Social Cost Estimates

The social impact of a regulatory action is traditionally measured by the change in economic welfare that it generates. The social costs of the rule will be distributed across producers of energy and their customers. Producers experience welfare impacts resulting from changes in profits corresponding with the changes in production levels and market prices. Consumers experience welfare impacts due to changes in market prices and consumption levels. However, it is important to emphasize that this measure does not include benefits that occur outside the market, that is, the value of reduced levels of air pollution with the regulation.

The national compliance cost estimates are often used to approximate the social cost of the rule. The engineering analysis estimated annual costs of $43.4 million. In cases where the engineering costs of compliance are used to estimate social cost, the burden of the regulation is measured as falling solely on the affected producers, who experience a profit loss exactly equal to these cost estimates. Thus, the entire loss is a change in producer surplus with no change (by assumption) in consumer surplus, because no change in market price is estimated. This is typically referred to as a "full-cost absorption" scenario in which all factors of production are assumed to all factors of production are assumed to be fixed and firms are unable to adjust their output levels when faced with additional costs.

In contrast, the economic analysis conducted by the Agency accounts for behavioral responses by producers and consumers to the regulation, as affected producers shift costs to other economic agents. This approach results in a social cost estimate that may differ from the engineering compliance cost estimate and also provides insights on how the regulatory burden is distributed across stakeholders. As shown in Table 7-5, the economic model estimates the total social cost of the rule to be $7.8 million. The social cost estimate is 18 percent of the estimated engineering costs as a result of behavioral changes of producers and consumers. The major behavioral change is that units with testing and add-on capital controls are crowded out of the new source market; hence these costs are not incurred by society. Therefore the social costs primarily reflect higher costs by existing units to increase supply, and the deadweight loss to consumers as price increases and quantity decreases.

The analysis also shows important distributional impacts across stakeholders. For example, the model projects consumers will bear a burden of $860 million, as a result of higher energy prices. In contrast, producer surplus increases by $853 million as energy producers, particularly the electricity industry, become more profitable with higher prices.

7.4 Executive Order 13211 (Energy Effects)

Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 Fed. Reg. 28355 [May 22, 2001]), requires EPA to prepare and submit a Statement of Energy Effects to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, for certain actions identified as "significant energy actions." Section 4(b) of Executive Order 13211 defines "significant energy actions" as "any action by an agency (normally published in the *Federal Register*) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking:

- that is a significant regulatory action under Executive Order 12866 or any successor order, and is likely to have a significant adverse effect on the supply, distribution, or use of energy; or
- that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action."

Table 7-5. Distribution of Social Costs of Stationary Combustion Turbines MACT Standard: 2005 ($1998 10^6)

Sectors/Markets		Change in: Producer Surplus	Change in: Consumer Surplus	Change in: Social Welfare
Energy Sector				
Petroleum (NAICS 32411, 4861)		$55.56	NA	NA
Natural Gas (NAICS 21111, 4862, 2212)		$45.41	NA	NA
Electricity (NAICS 22111, 221122, 221121)		$1,297.01	NA	NA
Coal (NAICS 2121)		–$76.94	NA	NA
Subtotal:		$1,321.05	NA	NA
Industrial Sector NAICS	**Description**	**Producer Surplus**	**Consumer Surplus**	**Social Welfare**
311	Food	–$6.5	–$4.9	–$11.4
312	Beverage and Tobacco Products	–$0.8	–$0.4	–$1.2
313	Textiles Mills	–$3.3	–$1.7	–$5.0
314	Textile Product Mills	–$0.6	–$0.3	–$0.9
315	Apparel	–$0.5	–$0.4	–$0.9
316	Leather and Allied Products	–$0.1	–$0.1	–$0.1
321	Wood Products	–$2.0	–$1.5	–$3.5
322	Paper	–$8.5	–$4.3	–$12.8
323	Printing and Related Support	–$1.7	–$0.7	–$2.5
325	Chemicals	–$22.9	–$9.5	–$32.5
326	Plastics and Rubber Products	–$6.2	–$2.6	–$8.7
327	Nonmetallic Mineral Products	–$4.1	–$3.1	–$7.1
331	Primary Metals	–$15.2	–$11.4	–$26.7
332	Fabricated Metal Products	–$1.9	–$6.9	–$8.8
333	Machinery	–$1.9	–$2.8	–$4.7
334	Computer and Electronic Products	–$1.8	–$4.6	–$6.4
335	Electrical Equipment, Appliances, and Components	–$1.1	–$1.6	–$2.7
336	Transportation Equipment	–$3.8	–$5.7	–$9.6
337	Furniture and Related Products	–$1.0	–$0.4	–$1.5
339	Miscellaneous	–$0.9	–$1.1	–$2.0
11	Agricultural Sector	–$12.7	–$5.3	–$18.0
23	Construction Sector	–$131.7	–$98.7	–$230.4
21	Other Mining Sector	–$0.7	–$1.6	–$2.3
Industrial Sector Subtotal:		–$229.9	–$169.7	–$399.6
Commercial Sector		–$238.7	–$179.0	–$417.7
Residential Sector		NA	–$454.9	–$454.9
Transportation Sector		NA	–$56.7	–$56.7
Subtotal		–$468.6	–$860.3	–$1,328.9
Grand Total		$852.5	–$860.3	–7.8

Given the magnitude of the annual costs, no Statement of Energy Effects will be completed. However, to provide some information on the impacts of the rule on affected energy markets, the following estimates have been prepared *Energy Price Effects.* As described in the market-level results section, electricity prices are projected to increase by less than 1 percent. Petroleum and natural gas prices are all projected to increase by less than 0.1 percent. The price of coal is projected to decrease slightly.

Impacts on Electricity Supply, Distribution, and Use. We project the increased compliance costs for the electricity market will result in an annual production decline of approximately 20.4 billion kWh and a delay of new installed capacity of 7,480 MW. Note these effects have been mitigated to some degree in two ways:

- The delay in installed capacity is offset by increased supply from existing unaffected sources, implying that fewer older units may be retired as a result of the regulation.
- Sectors previously using electricity in the baseline will switch to other energy sources (see below).

Impacts on Petroleum, Natural Gas, and Coal Supply, Distribution, and Use. The rule will lead to higher electricity prices relative to other fuel types, resulting in fuel switching. The model projects increases in petroleum production/consumption of approximately 2,000 barrels per day. Similarly, natural gas production/consumption is projected to increase by 11.7 million cubic feet per day. The model also projects decreases in coal production/consumption of approximately 8,000 short tons per year.

SECTION 8

SMALL ENTITY IMPACTS

The regulatory costs imposed on domestic producers and government entities to reduce air emissions from combustion turbines will have a direct impact on owners of the affected facilities. Firms or individuals that own the facilities with combustion turbines are legal business entities that have the capacity to conduct business transactions and make business decisions that affect the facility. The legal and financial responsibility for compliance with a regulatory action ultimately rests with these owners, who must bear the financial consequences of their decisions. Environmental regulations potentially affect all sizes of businesses, but small businesses may have special problems relative to large businesses in complying with such regulations.

The RFA of 1980 requires that special consideration be given to small entities affected by federal regulations. The RFA was amended in 1996 by SBREFA to strengthen the RFA's analytical and procedural requirements. Prior to enactment of SBREFA, EPA exceeded the requirements of the RFA by requiring the preparation of a regulatory flexibility analysis for every rule that would have any impact, no matter how minor, on any number, no matter how small, of small entities. Under SBREFA, however, the Agency decided to implement the RFA as written and to require a regulatory flexibility analysis only for rules that will have a significant impact on a substantial number of small entities. In practical terms, the amount of analysis of impacts to small entities has not changed, for SBREFA required EPA to increase involvement of small entities in the rulemaking process.

This section investigates characteristics of businesses and government entities that are likely to install new combustion turbines affected by this rule and provides a preliminary screening-level analysis to assist in determining whether this rule is likely to impose a significant impact on a substantial number of the small businesses within this industry.

The screening-level analysis employed here is a "sales test," which computes the annualized compliance costs as a share of sales/revenue for existing companies/government entities. Existing companies/government entities with combustion turbines are used to provide insights into future companies/government entities that are likely to install new turbines that are affected by the regulation.

8.1 Identifying Small Businesses

As described in Section 3 of this report, the Agency has projected that approximately 218 new combustion turbines will begin operation during the 5-year period between 2002 and 2007. Of this population approximately 20 percent of the new turbines are projected to be located at major sources. Thus approximately 44 sources would be required to comply with the combustion turbines NESHAP. No existing combustion turbines will be effected by the regulation. However, because it is not possible to project specific companies or government organizations that will purchase combustion turbines in the future, the small business screening analysis for the combustion turbine rule is based on the evaluation of existing owners of combustion turbines. It is assumed that the existing size and ownership distribution of combustion turbines contained in the Inventory Database is representative of the future growth in new combustion turbines. The remainder of this section presents cost and sales information on small companies and government organizations that own existing combustion turbines of 1 MW or greater.

8.2 Screening-Level Analysis

Based on the Inventory Database and Small Business Administration (SBA) definitions, 29 small entities own 51 units, which are located at 35 facilities.[1] The 51 units owned by small entities represent approximately 2.5 percent of the 2,072 units in the Inventory Database with valid capacity information. As with the total population, not all units owned by small entities will incur costs as a result of the regulation. However, because we do not have the information to determine which units will be affected, we have included all potentially affected small entities in the screening analysis, recognizing that this yields an overestimate of the impacts on small entities.

[1]Public and private electric service providers are defined as small if their annual generation is less than 4 million kWh. Local government entities that own combustion turbines are defined as small if the city population is fewer than 50,000. In the manufacturing sector, companies are defined as small if the total employment of the parent company is fewer than 500.

Table 8-1 presents the distribution of small entities by business type.[2] As is the case with the majority of turbine operators, ownership of turbines in the Inventory Database by small companies is concentrated in the electric services industry. In fact, 22 of small entities are municipalities that own and operate local utility systems. The remaining entities are either small energy (e.g., oil and gas) firms or small manufacturing companies.

To assess the potential impact of this rule on the 29 small companies and government entities that own combustion turbines, the Agency considered the regulatory control costs presented in Section 7. For this screening-level analysis, annual compliance costs were defined as the annualized costs of performance tests, monitoring, recordkeeping, and reporting imposed on each company or government entity assuming that it owned or were to install one turbine. The total annualized cost associated with these activities is $25,119 (1998 dollars). Control costs of oxidation catalysts and CEMs were not included in the screening analysis because the Agency estimates that only a small number units per year will require these add-on capital costs. It is highly unlikely that small entities will be installing 170 MW turbines and would be required to install this equipment.

The results of this initial screening analysis are shown in Table 8-2. If each entity owned or were to install one turbine, the annual compliance costs, as a percentage of annual revenues, for small companies and government organizations would range from 0.01 to 0.46 percent. The average (median) compliance cost-to-sales ratio (CSR) is 0.11 percent. As shown, none of the small entities are affected above the 1 percent level.

8.3 Assessment

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

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[2]The Inventory Database also contains small turbines that are not included in Table 8-1. These units, frequently referred to as “micro turbines,” did not meet the 1 MW size requirements and are excluded from this rule. Six hundred thirty-five units at 204 facilities in the Inventory Database had unit capacities under 1 MW. As a result, a large number of small entities potentially purchasing combustion turbines in the future will not be affected by the regulation due to the rule’s size cutoff.

Table 8-1. Number of Units Greater than 1 MW at Small Parents by Industry

NAICS	Description	Number of Units	Number of Units Greater than 1 MW Owned by Small Parents	Number of Small Parents
112	Animal Production	1		
211	Oil and Gas Extraction	365	5	2
212	Mining (Except Oil and Gas)	3		
221	Utilities	983	35	22
233	Building, Developing, and General Contracting	1		
235	Special Trade Contractors	2		
311	Food Manufacturing	18		
321	Wood Products Manufacturing	3	2	1
322	Paper Manufacturing	17		
324	Petroleum and Coal Products Manufacturing	34		
325	Chemical Manufacturing	63	1	1
326	Plastics and Rubber Products Manufacturing	4		
327	Nonmetallic Mineral Product Manufacturing	1		
331	Primary Metal Manufacturing	13		
332	Fabricated metal Product Manufacturing	2		
333	Machinery Manufacturing	2		
334	Computer and Electronic Product Manufacturing	6		
335	Electrical Equipment, Appliance, and Component Manufacturing	1		
336	Transportation Equipment Manufacturing	3	1	1
337	Furniture and Related Product Manufacturing	1		
339	Miscellaneous Manufacturing	3		
422	Wholesale Trade, Nondurable Goods	6		
486	Pipeline Transportation	448	7	2
488	Support Activities for Transportation	1		
513	Broadcasting and Telecommunications	1		
522	Credit Intermediation and Related Activities	3		
541	Professional, Scientific, and Technical Services	2		
561	Administrative and Support Services	1		
611	Educational Services	10		
622	Hospitals	23		
721	Accommodation	1		
923	Administration of Human Resource Programs	1		
926	Administration of Economic Programs	1		
928	National Security and International Affairs	42		
Unknown	Industry Classification Unknown	6		
	TOTAL	2,072	51	29

Table 8-2. Summary Statistics for SBREFA Screening Analysis: Recommended Alternative

Total Number of Small Entities	29	
Average Annual Compliance Cost per Small Entity[a]	$15,059	
	Number	Share (%)
Entities with Sales/Revenue Data	29	100
Compliance costs are <1% of sales	0	0
Compliance costs are ≥1 to 3% of sales	0	0
Compliance costs are ≥3% of sales	0	0
Compliance Cost-to-Sales/Revenue Ratios		
Average	0.07	
Median	0.04	
Maximum	0.28	
Minimum	0.01	

[a]Assumes no market responses (i.e., price and output adjustments) by regulated entities.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as:

- a small business whose parent company has fewer than 100 or 1,000 employees, depending on size definition for the affected NAICS code, or fewer than 4 billion kW-hr per year of electricity usage;
- a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of fewer than 50,000; and
- a small organization that is any not-for-profit enterprise, which is independently owned and operated and is not dominant in its field.

It should be noted that small entities in six three-digit NAICS codes are affected by this rule, and the small business definition applied to each industry by NAICS code is that listed in the SBA size standards (13 CFR 121).

After considering the economic impacts of today's rule on small entities, this analysis determines this action will not have a significant economic impact on a substantial number of small entities. This certification is based on two analytical approaches:

- examining the hypothetical impacts on small entities based on the existing combustion turbines inventory, and presuming that the existing mix of combustion turbines among industries is a good approximation of the mix of new turbines that will be installed over the next 5 years, and
- considering influences on the decision by small entities to install new turbines.

First, based on the existing combustion turbines inventory, this analysis determines that only 29 small entities out of 300 small entities would have been impacted by this rule if it had affected existing sources. These 29 small entities own 51 affected turbines in the existing combustion turbines inventory, which represents only 2.5 percent of the existing turbines overall. Of these entities, 22 of these entities are small communities and seven are small firms. None of the 29 affected small entities are estimated to have compliance costs that exceed 1 percent of their revenues. Based on industry profit margin (i.e., profits per sales) data for the electric services industry (92 percent of all affected turbines) shown in the industry profile, the average return on sales for the industries is 4.6 percent. It should be noted that a comparison of profits with costs for small communities in this analysis is valid, for the small communities manage the electric services they own in a similar fashion to the small firms affected by this rule. No small entity is estimated to have compliance cost to sales of greater than the average return on sales. In addition, the rule is likely to also increase profits at the many small firms and increase revenues for the many small communities using turbines that are not affected by the rule as a result of the very slight increase in market prices.

Second, another approach to examining small entity impacts is to look at the influences on purchases of new turbines by small entities in the next 5 years. It is very likely that the ongoing deregulation of the electric power industry across the nation will minimize the rule's impacts on small entities. Increased competition in the electric power industry is forecasted to decrease the market price for wholesale electric power. Open access to the grid and lower market prices for electricity will make it less attractive for local communities to purchase and operate new combustion turbines.[3] Regardless of either analytical approach,

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[3]The increasing trend is for local governments to engage in municipal aggregation and purchase long- and short-term power contracts through the emerging wholesale markets (see Cliburn, 2001).

the Agency concludes that this rule will not have a significant impact on a substantial number of small entities.

Although this rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities. In this rule, the Agency is applying the minimum level of control and the minimum level of monitoring, recordkeeping, and reporting to affected sources allowed by the CAA. In addition, as mentioned earlier in the preamble, turbines with capacities under 1.0 MW are not covered by this rule. This provision should reduce the level of small entity impacts. EPA continues to be interested in the potential impacts of the rule on small entities and welcomes comments on issues related to such impacts.

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APPENDIX A

OVERVIEW OF THE MARKET MODEL

To develop estimates of the economic impacts on society resulting from the regulation, the Agency developed a computational model using a framework that is consistent with economic analyses performed for other rules. This approach employs standard microeconomic concepts to model behavioral responses expected to occur with the regulation. This appendix describes the spreadsheet model in detail and discusses how the Agency

- characterized the supply and demand in the energy markets,
- characterized supply and demand responses in industrial and commercial markets,
- introduced a policy "shock" into the electricity market by using control cost-induced shifts in the supply functions of affected supply segments (new and existing sources),
- introduced indirect shifts in market supply functions resulting from changes in energy prices
- used a solution algorithm to determine a new with-regulation equilibrium in each market.

A.1 Energy Markets

The operational model includes five energy markets: coal, electricity (base load energy), electricity (peak power), natural gas, and petroleum. The following sections describe supply and demand equations the Agency developed to characterize these markets. The data source for the price and quantity data used to calibrate the model is the Department of Energy's Supplemental Tables to the Annual Energy Outlook 2000 (DOE, EIA, 2001).

A.1.1 Supply Side Modeling

The Agency modeled the existing market supply of energy markets (Q_{Si}) using a single representative supplier with an upward-sloping supply curve. The Cobb-Douglas (CD) function specification is

$$Q_{S_i} = A_i \bullet (p_i - c_i - \sum_{i=1}^{n} \alpha_i \Delta p_i)^{\varepsilon^{s_i}} \qquad \text{(A.1)}$$

where

Q_{S_i}	=	the supply of energy product i,
A_i	=	a parameter that calibrates the supply equation to replicate the estimated 2005 level of production (Btu),
p_i	=	the 2005 ($/Btu) market price for product i, and
c_i	=	direct compliance costs (electricity markets only). Supply shifts were computed and reported in Section 6, Table 6-2.
$\sum_{i=1}^{n} \alpha_i \Delta p_i$	=	indirect effects of changes in input prices, where α is the fuel share, i indexes the energy market. The fuel share is allowed to vary using a fuel switching rule using cross-price elasticities of demand between energy sources, as described in Section 5 of the report.
ε^{S_i}	=	the domestic supply elasticity for product i.

For the electricity markets, new supply sources are characterized with a constant marginal cost (supply) curve. In baseline, these units are willing to supply their generation capacity at the baseline market price (P_{0i}). With regulation, affected sources are willing to supply their generation capacity if the new price (P_{1i}) exceeds costs (baseline + direct + indirect) :

$$P_{1i} \geq [P_{0i} + c_i + \sum_{i=1}^{n} \alpha_i \Delta p_i] \qquad \text{(A.2)}$$

A.1.2 Demand Side Modeling

Market demand in the energy markets (Q_{Di}) is expressed as the sum of the energy, residential, transportation, industrial, and commercial sectors:

$$Q_{Di} = \sum_{j=1}^{n} q_{Dij} \ , \qquad \text{(A.3)}$$

where i indexes the energy market and j indexes the consuming sector. The Agency modeled the residential, and transportation sectors as single representative demanders using a simple Cobb Douglas specification:

$$q_{Dij} = A_{ij} p_i^{\eta_{ij}} , \tag{A.4}$$

where p is the market price, η is an assumed demand elasticity (actual values are presented in Section 5, Table 5-2), and A is a demand parameter. In contrast, the energy, industrial and commercial sectors demand is modeled as a derived demand resulting from the production/consumption choices in agricultural, energy, mining, manufacturing, and service industries. Changes in energy demand for these industries respond to changes in output and fuel switching that occurs in response to changes in relative energy prices projected in the energy markets. For each sector, energy demand is expressed as follows:

$$q_{Dij1} = (1 + \%\Delta Q_{Dj}) \cdot (q_{Dij0}) \cdot FSW \tag{A.5}$$

where q_D is demand for energy, Q_D is output in the final product or service market, FSW is a factor generated by the fuel switching algorithm, i indexes the energy market, j indexes the market. The subscripts 0 and 1 represent baseline and with regulation conditions, respectively.

A.2 Industrial and Commercial Markets

Given data limitations associated with the scope of potentially affected industrial and commercial markets, EPA used an alternative approach to estimate the relative changes in price and quantities. These measures are used to compute change in economic welfare as described in Section A.4.

A.2.1 Compute Percentage Change in Market Price

First, we computed the change in production costs resulting from changes in the market price of fuels (determined in the energy markets):

$$\%\Delta c_j = \sum_{i=1}^{n} \alpha_i \Delta p_i , \tag{A.6}$$

where α is the fuel share[1], i indexes the energy market, and j indexes the industrial or commercial market. We use the results from equation A.6 and the market supply and demand elasticities to compute the change in market price[2]:

$$\%\Delta p_j = \%\Delta c_j \cdot \left[\frac{\varepsilon^{s_i}}{\varepsilon^{s_i} - \eta_i}\right] \tag{A.7}$$

A.2.2 Compute Percentage Change in Market Quantity

Using the percentage change in the price calculated in Equation A.7 and assumptions regarding the market demand elasticity, the relative change in quantity was computed. For example, in a market where the demand elasticity is assumed to be -1 (i.e., unitary), a 1 percent increase in price results in a 1 percent decrease in quantity. This change was then input into equation A.5 to determine energy demand.

A.3 With-Regulation Market Equilibrium Determination

Market adjustments can be conceptualized as an interactive feedback process. Supply segments face increased production costs as a result of the rule and are willing to supply smaller quantities at the baseline price. This reduction in market supply leads to an increase in the market price that all producers and consumers face, which leads to further responses by producers and consumers and thus new market prices, and so on. The new with-regulation equilibrium is the result of a series of iterations in which price is adjusted and producers and consumers respond, until a set of stable market prices arises where total market supply equals market demand (i.e., $Qs = Q_D$) in each market. Market price adjustment takes place based on a price revision rule that adjusts price upward (downward) by a given percentage in response to excess demand (excess supply).

The algorithm for determining with-regulation equilibria can be summarized by seven recursive steps:

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[1]The fuel share is allowed to vary using a fuel switching rule using cross-price elasticities of demand between energy sources, as described in Section 5.

[2]The approach is based on a mathematical model of tax incidence analysis decribed in Nicholson (1998) pages 444-445.

1. Impose the control costs on electricity supply segments, thereby affecting their supply decisions.

2. Recalculate the market supply in the energy markets. Excess demand exists.

3. Determine the new energy prices via a price revision rule.

4. Recalculate energy market supply.

5. Account for fuel switching given new energy prices. Solve for new equilibrium in final product and service market.

6. Compute energy demand.

7. Compare supply and demand in energy markets. If equilibrium conditions are not satisfied, go to Step 3, resulting in a new set of energy prices. Repeat until equilibrium conditions are satisfied (i.e., the ratio of supply to demand is arbitrarily close to one).

A.4 Computing Social Costs

In the energy markets, consumers(residential and transportation) and producer surplus were calculated using standard methods based on the price and quantity before and after regulation. In the industrial and commercial markets, however, there is no easily defined price or quantity due to the wide variety of products that fall under each sector (i.e. NAICs code). Therefore, methods of calculating consumer and producer surplus are defined based on relative changes in price and quantity and total industry sales rather than on the price and quantity directly. The following sections describe how we derive welfare estimates for these markets.

A.4.1 Change in Consumer Surplus

If price and quantities were available, a linear approximation of the change in consumer surplus can be calculated using the following formula:

$$\Delta CS = -[(\Delta P)\, Q_0 - 0.5(\Delta Q)\, (\Delta P)], \tag{A.8}$$

where Q_0 denotes the baseline quantity. Given the model only estimates relative changes in price and quantity for each industrial/commercial market, changes in consumer surplus were calculated using these data and total revenue by NAICS code as shown below:

$$\Delta CS = -[(\Delta P)\, Q_1 - 0.5\, (\Delta Q)\, (\Delta P)]\, (P_1\, Q_1)/(P_1\, Q_1)$$

$$\Delta CS = -[\%\Delta P - 0.5\, (\%\Delta P)\, (\%\Delta Q)]\, (P_1\, Q_1). \qquad \text{(A.9)}$$

A.4.2 Change in Producer Surplus

If price and quantities were available, a linear approximation could also be used to compute the change in producer surplus:

$$\Delta PS = -[((CC/Q_1) - \Delta P)(Q_1 - \Delta Q)] + 0.5\, [(CC/Q_1 - \Delta P)\, (\Delta Q)], \qquad \text{(A.10)}$$

where CC/Q_1 equals the per-unit "cost-shifter" of the regulation. Again, we transform this equation into one that relies only on percentage changes in price and quantity, total revenue,[3] and compliance costs:

$$\Delta PS = -\, [((CC/Q_1) - \Delta P)(Q_1 - \Delta Q)] + 0.5\, [((CC/Q_1) - \Delta P)(\Delta Q)](P_1\, Q_1)/(P_1\, Q_1)$$

$$\Delta PS = -\, [(\%\text{ cost shift} - \%\Delta P)(1 - \%\Delta Q) + 0.5\, (\%\text{ cost shift} - \%\Delta P\,)(\%\Delta Q)][P_1\, Q_1]$$

$$\Delta PS = -\, [\%\text{ cost shift} - \%\Delta P\,][1 - 0.5(\%\Delta Q)][TR], \qquad \text{(A.11)}$$

[3]Multiplying price and quantity in an industry yields total industry revenue. The U.S. Census Bureau provides shipment data for the NAICs codes included in the economic model.

APPENDIX B

ASSUMPTIONS AND SENSITIVITY ANALYSIS

In developing the economic model to estimate the impacts of the stationary combustion turbine NESHAP, several assumptions were necessary to make the model operational. This appendix lists and explains the major model assumptions and describes their potential impact on the analysis results. Sensitivity analyses are presented for numeric assumptions.

Assumption: The domestic markets for energy are perfectly competitive.

Explanation: Assuming that the markets for energy are perfectly competitive implies that individual producers are not capable of unilaterally affecting the prices they receive for their products. Under perfect competition, firms that raise their price above the competitive price are unable to sell at that higher price because they are a small share of the market and consumers can easily buy from one of a multitude of other firms that are selling at the competitive price level. Given the relatively homogeneous nature of individual energy products (petroleum, coal, natural gas, electricity), the assumption of perfect competition at the national level seems to be appropriate.

Possible Impact: If energy markets were in fact imperfectly competitive, implying that individual producers can exercise market power and thus affect the prices they receive for their products, then the economic model would understate possible increases in the price of energy due to the regulation as well as the social costs of the regulation. Under imperfect competition, energy producers would be able to pass along more of the costs of the regulation to consumers; thus, consumer surplus losses would be greater, and producer surplus losses would be smaller in the energy markets.

Assumption: Base load energy and peak power represent 80 percent and 20 percent, respectively, of the total cost of electricity production.

Explanation: With deregulation, it is increasingly common for base load energy and peak power to be traded as different commodities. This economic model segments the electricity market into these separate markets. However, no production cost or sales data are currently available to partition the electricity market into base load and peak power markets. The 80/20 percent was obtained from discussions with industry experts.

Sensitivity Analysis: Table B-1 shows how estimated economic impacts change as the share of base load versus peak power costs varies.

Table B-1. Sensitivity Analysis: Base Load and Peak Power Markets' Share of Electricity Production Costs ($\$10^6$)

	Base Load = 70% Peak = 30%	Base Load = 80% Peak = 20%	Base Load = 90% Peak = 10%
Change in producer surplus	870.4	852.5	835.2
Change in consumer surplus	–878.6	–860.3	–842.7
Change in social welfare	–8.1	–7.8	–7.5

Assumption: The elasticity of supply in the base load and peak power electricity markets for existing sources is approximately 0.75 and 0.38, respectively.

Explanation: The price elasticity of supply in the electricity markets represents the behavioral responses from existing sources to changes in the price of electricity. However, there is no consensus on estimates of the price elasticity of supply for electricity. This is in part because, under traditional regulation, the electric utility industry had a mandate to serve all its customers and utilities were compensated on a rate-based rate of return. As a result, the market concept of supply elasticity was not the driving force in utilities' capital investment decisions. This has changed under deregulation. The market price for electricity has become the determining factor in decisions to retire older units or to make higher cost units available to the market.

Sensitivity Analysis: Table B-2 shows how the economic impact estimates vary as the elasticity of supply in the electricity markets varies.

Table B-2. Sensitivity Analysis: Elasticity of Supply in the Electricity Markets

	ES = –25%	Base Case	ES = + 25%
Change in producer surplus	942.4	852.5	778.8
Change in consumer surplus	–951.2	–860.3	–785.8
Change in social welfare	–8.8	–7.8	–7.0

Assumption: The domestic markets for final products and services are all perfectly competitive.

***Explanation**:* Assuming that these markets are perfectly competitive implies that the producers of these products are unable to unilaterally affect the prices they receive for their products. Because the industries used in this analysis are aggregated across a large number of individual producers, it is a reasonable assumption that the individual producers have a very small share of industry sales and cannot individually influence the price of output from that industry.

Possible Impact: If these product markets were in fact imperfectly competitive, implying that individual producers can exercise market power and thus affect the prices they receive for their products, then the economic model would understate possible increases in the price of final products due to the regulation as well as the social costs of the regulation. Under imperfect competition, producers would be able to pass along more of the costs of the regulation to consumers; thus, consumer surplus losses would be greater, and producer surplus losses would be smaller in the final product markets.

Assumption: The elasticity of supply in final product markets.

Explanation: The final product markets are modeled at the two-, and three-digit NAICS codes level to operationalize the economic model. Because of the high level of aggregation, elasticities of supply and demand estimates are not often available in the literature. The elasticities of supply and demand in the final product markets primarily determine the distribution of economic impacts between producers and consumers.

Sensitivity Analysis: Table B-3 shows how the economic impact estimates vary as the supply and demand elasticities in the final product markets vary.

Table B-3. Sensitivity Analysis: Supply and Demand Elasticities in the Final Product Markets

	ES = –25% ED = –25%	ES = Base Case ED = Base Case	ES = +25% ED = +25%
Change in producer surplus	853.0	852.5	851.9
Change in consumer surplus	–860.9	–860.3	–859.8
Change in social welfare	–7.8	–7.8	–7.8

Assumption: The amount of energy (in terms of Btus) required to produce a unit of output in the final product markets remains constant as output changes and prices.

Explanation: The importance of this assumption is that when output in the final product markets changes as a result of a change in energy prices, it is assumed that the amount of fuel used changes in the same proportion as output, although the distribution of fuel usage among fuel types may change due to fuel switching. This change in the demand for fuels feeds into the energy markets and affects the equilibrium price and quantity in the energy markets.

Possible Impact: For example, fuel usage per unit output may change if the price of energy increases because of increased energy efficiency. National energy-efficiency trends are included in the model through projected Btu consumption (i.e., Btu consumption is projected to grow more slowly than output). However, if the regulation leads to increased energy efficiency because of higher fuel prices, this will result in a smaller economic impact than the model results presented in Section 6 indicate.

Assumption: Sensitivity to Fuel Switching.

Sensitivity Analysis: Table B-4 shows how the economic impact estimates vary as fuel-switching is turned on or off in the model.

Table B-4. Sensitivity Analysis: Own- and Cross-Price Elasticities Used to Model Fuel Switching

	Base Case	Without Fuel Switching
Change in producer surplus	852.5	194.2
Change in consumer surplus	–860.3	–208.6
Change in social welfare	–7.8	–14.3

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16. ABSTRACT

This report evaluates the economic impacts of the Final Stationary Combustion Turbines NESHAP. The social costs of the rule are estimated by incorporating the expected costs of compliance in a partial equilibrium model and projecting the market impacts. The report also provides the screening analysis for small business impacts.

17. KEY WORDS AND DOCUMENT ANALYSIS

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