United States Environmental Protection Agency	Office Of Air Quality Planning And Standards Research Triangle Park, NC 27711	November 2002 FINAL REPORT

Air

Economic Impact Analysis of the Proposed Stationary Combustion Turbines NESHAP

Final Report

Economic Analysis of the Stationary Combustion Turbines MACT Standard

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Prepared for

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EPA Contract Number 68-D-99-024
RTI Project Number 7647.004.385

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

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 proposed 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 proposed 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 proposed *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 existing and new stationary combustion turbines.

The proposed regulation affects existing and 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 provide background information on the regulatory alternatives examined, information on the emission reductions associated with the proposed rule, and health effects from exposure to the HAP emitted by combustion turbines.

- Section 4 provides projections of new stationary combustion turbines through the year 2005. This section profiles the population of existing turbines as well.
- Section 6 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 proposed 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 proposed 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.

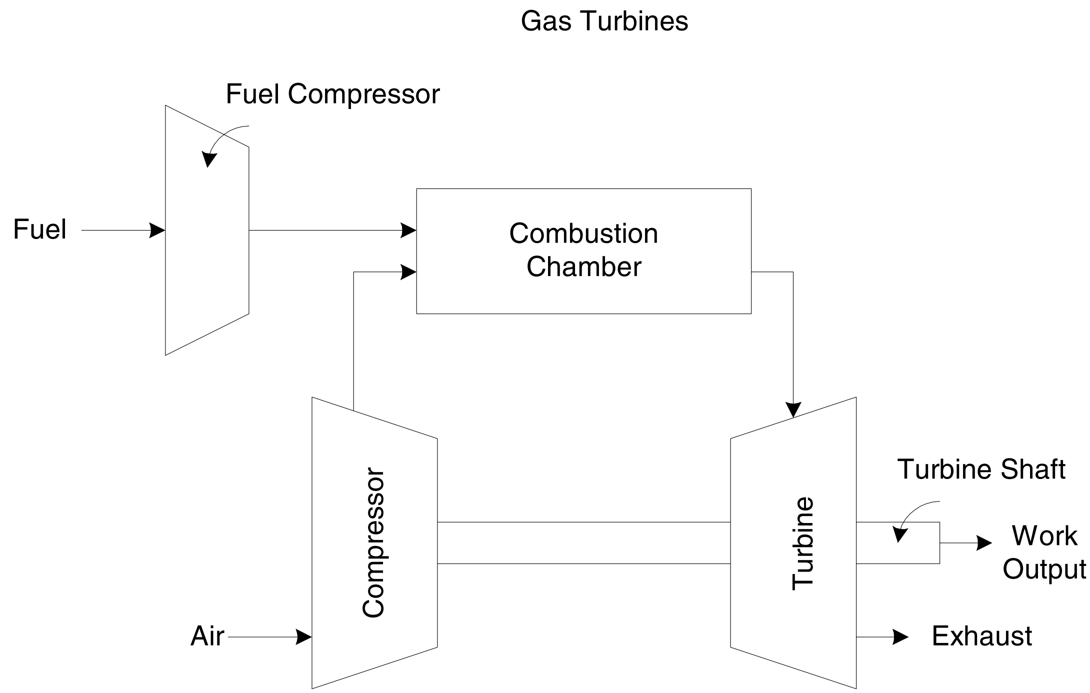

Figure 2-1. Simple-Cycle Gas Turbine

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 gas turbine; then the heat that remains is used to create steam, which is run through a steam

[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.

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.

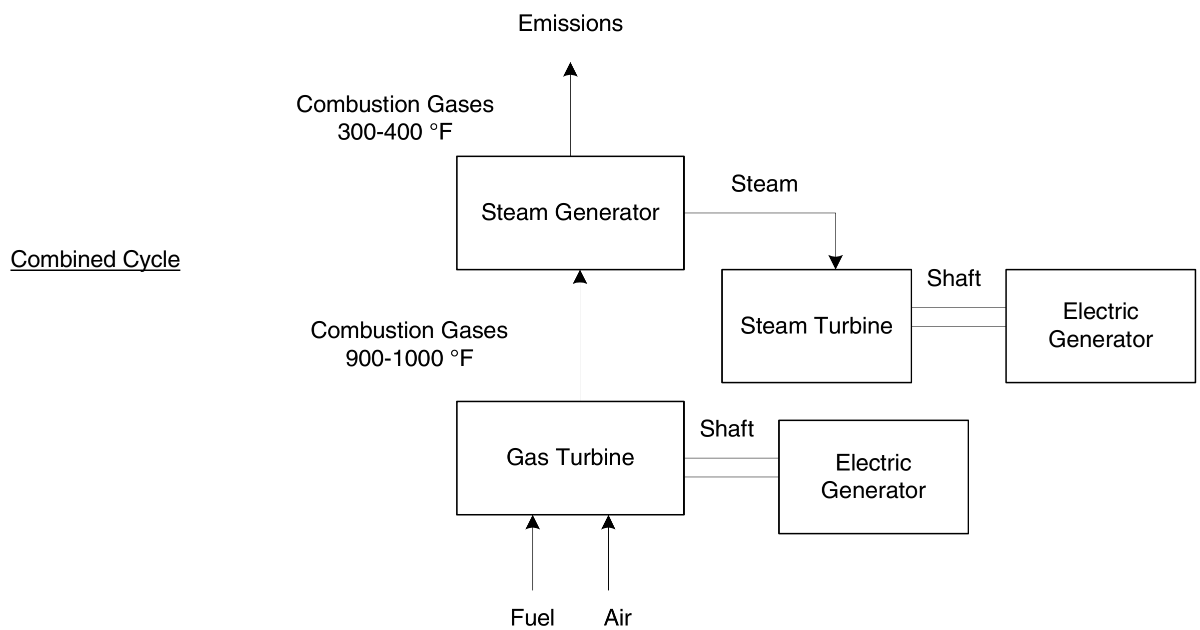

Figure 2-2. Combined-Cycle Gas Turbine

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 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).

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.

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.

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*

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*.

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 us to list categories and subcategories of major sources and area sources of HAP and to establish NESHAP for the listed source categories and subcategories. The stationary turbine source category was listed on July 16, 1992 (57 FR 31576). Major sources of HAP 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 HAP.

3.1.1 Criteria Used in NESHAP Development

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

The MACT floor is the minimum control level allowed for 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 5 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 HAP from Stationary Combustion Turbines

Several HAP 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 HAP which 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 HAP from distillate oil fired stationary combustion turbines that have been measured are: arsenic, beryllium, cadmium, chromium, lead, manganese, mercury, nickel, and selenium.

Although numerous HAP 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 HAP 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 HAP 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. Acetaldehyde is a potential carcinogen in humans.

3.3 Summary of the Proposed Rule

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

It should be noted that the proposed 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 proposed 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 proposed rule.

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

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

For those sources that are covered, six subcategories have been defined within the stationary combustion turbine source category. While all stationary combustion turbines are subject to the proposed rule, each subcategory has distinct requirements. For example, existing diffusion flame combustion turbines and stationary combustion turbines with a rated peak 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, recordkeeping or reporting requirements in the proposed 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 which 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, recordkeeping and reporting requirements in the proposed 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 Proposed Rule

The proposed rule covers any stationary combustion turbine, a type of emission source defined as:

- any simple cycle stationary combustion turbine,
- any regenerative/ recuperative cycle stationary combustion turbine,
- the combustion turbine portion of any stationary cogeneration cycle combustion system, 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. The combustion turbine may, however, be mounted on a vehicle for portability or transportability.

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

1. emergency stationary combustion turbines,
2. limited use stationary combustion turbines,
3. stationary combustion turbines which fire landfill gas or digester gas as their primary fuel,
4. stationary combustion turbines of less than 1 MW rated peak power output,
5. stationary diffusion flame combustion turbines, and
6. stationary lean premix combustion turbines.

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.

A limited use stationary combustion turbine means any stationary combustion turbine that operates 50 hours or less per calendar year. One example is a stationary combustion turbine used to stabilize electrical power voltage and protect sensitive electronic equipment during periods of "brown outs."

Stationary combustion turbines which fire landfill gas or digester gas as their primary fuel 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 HAP. Given the very small size of these stationary combustion turbines and the lack of application of HAP emission control technologies, we have concerns about the applicability of HAP emission control technology to them.

The stationary diffusion flame combustion turbines subcategory includes only diffusion flame combustion turbines that are greater than 1 MW rated peak power output and are not emergency stationary combustion turbines, limited use stationary combustion turbines, or stationary combustion turbines which fire landfill gas or digester gas as their primary fuel.

The stationary lean premix combustion turbines subcategory includes only lean premix combustion turbines that are greater than 1 MW rated peak power output and are not emergency stationary combustion turbines, limited use stationary combustion turbines, or stationary combustion turbines which fire landfill gas or digester gas as their primary fuel. Lean premix technology, introduced in the 1990's, was developed to reduce NO_x emissions without the use of add on controls. In a staged lean premix combustor, the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. The staged entry limits the flame temperature and the residence time at the peak flame temperature. Lean premix combustors emit lower levels of NO_x, carbon monoxide (CO), formaldehyde and other HAP than diffusion flame combustion turbines.

The sources of HAP emissions from stationary combustion turbines are the exhaust gases from combustion of gaseous and liquid fuels.

3.3.2 Emission Limitations and Operating Limitations

As the owner or operator of an existing lean premix stationary combustion turbine or a new or reconstructed stationary combustion turbine located at a major source of HAP emissions, you must comply with one of the following two emission limitations by the effective date of the standard (or upon startup if you start up your stationary combustion turbine after the effective date of the standard):

(1) reduce CO emissions in the exhaust from the new or reconstructed stationary combustion turbine by 95 percent or more, if you use an oxidation catalyst emission control device; or

(2) reduce the concentration of formaldehyde in the exhaust from the new or reconstructed stationary combustion turbine to 43 parts per billion by volume or less, dry basis (ppbvd), at 15 percent oxygen, if you use means other than an oxidation catalyst emission control device.

There are no operating limitations if you choose to comply with the emission limitation for CO emission reduction. If you comply with the emission limitation for formaldehyde emissions and your stationary combustion turbine is not lean premix or diffusion flame, you must comply with any additional operating limitations approved by the Administrator, as discussed later.

As mentioned earlier, stationary combustion turbines with a rated peak power output of less than 1.0 MW, emergency stationary combustion turbines, limited use stationary combustion turbines, and stationary combustion turbines which burn landfill gas or digester gas as their primary fuel, are not required to comply with these emission limitations. In addition, existing diffusion flame stationary combustion turbines, are not required to comply with these emission limitations. Table 3-2 summarizes the HAP emission limitation requirements in this proposed rule for each subcategory of affected sources.

3.3.3 Initial Compliance Requirements

The initial compliance requirements for a stationary combustion turbine vary depending on the subcategory of your combustion turbine and your control strategy.

If you operate a new or reconstructed stationary combustion turbine and comply with the emission limitation for CO emission reduction, you must install a continuous emission monitoring system (CEMS) to measure CO and either carbon dioxide or oxygen simultaneously at the inlet and outlet of the oxidation catalyst emission control device. To demonstrate initial compliance, you must conduct an initial performance evaluation using Performance Specifications 3 and 4A of 40 CFR part 60, Appendix B. You must demonstrate that the reduction of CO emissions is at least 95 percent using the first 4-hour average after a successful performance evaluation. Your inlet and outlet measurements must be on a dry basis and corrected to 15 percent oxygen or equivalent carbon dioxide content.

Table 3-2. Emission Limitations for Each Affected Subcategory of Sources

Subcategory	Emission Limitation	Comment
Existing Diffusion Flame Stationary Combustion Turbine $\geq$ 1.0 MW	None.	No requirements.
Existing Lean Premix Stationary Combustion Turbine $\geq$ 1.0 MW or New/Reconstructed Stationary Combustion Turbine $\geq$ 1.0 MW	1) Reduce CO emissions by 95% or more, if you use an oxidation catalyst emission control device or 2) Reduce the concentration of formaldehyde to 43 ppbvd @ 15% O_2, if you use means other than an oxidation catalyst emission control device.	
Emergency Stationary Combustion Turbine or Limited Use Stationary Combustion Turbine or Landfill/Digester Gas Stationary Combustion Turbine	No emission limitations.	Initial notification requirements only.
< 1 MW Stationary Combustion Turbine	None.	No requirements.

You must also conduct an annual relative accuracy test audit (RATA) of the CEMS using Performance Specifications 3 and 4A of 40 CFR part 60, B.

If you operate a new or reconstructed combustion turbine or an existing lean premix combustion turbine and comply with the emission limitation for formaldehyde emissions, you must conduct an initial performance test using Test Method 320 of 40 CFR part 63, A;

ARB Method 430 of California Environmental Protection Agency, Air Resources Board, 2020 L Street, Sacramento, CA 95812; or EPA Solid Waste (SW)-846 Method 0011 to demonstrate that the outlet concentration of formaldehyde is 43 ppbvd or less (corrected to 15 percent oxygen). Natural gas-fired sources may also use the proposed Test Method 323 of 40 CFR part 63, A, to measure formaldehyde. To correct to 15 percent oxygen, dry basis, you must measure oxygen using Method 3A or 3B of 40 CFR part 60, A, and moisture using Method 4 of 40 CFR part 60, Appendix A.

As stated previously, if you choose to comply with the emission limitation for formaldehyde emissions and your stationary combustion turbine is not lean premix or diffusion flame, you must also 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 which 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 which could change intentionally (e.g., operator adjustment, automatic controller adjustment, etc.) or unintentionally (e.g., wear and tear, error, etc.) 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 or unreasonable 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 all 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 CO emission reduction limitation, you must calibrate and operate your CEMS according to the requirements in 40 CFR 63.8. You must continuously monitor and record the CO concentration before and after the oxidation catalyst emission control device and calculate the percent reduction of CO emissions hourly. The reduction in CO emissions must be 95 percent or more, based on a rolling 4-hour average, averaged every hour.

To demonstrate continuous compliance with the operating limitations (if applicable), you must continuously monitor the values of any parameters which have been approved by the Administrator as operating limitations.

The proposed rule does not require your lean premix combustion turbine to demonstrate continuous compliance. It is assumed that if you meet the low NO_x emission levels required by your federally enforceable permit (or guaranteed by the turbine manufacturer if there is no permit level), your turbine is in compliance with the 43 ppbvd formaldehyde emission limit.

CEMS are available which can accurately measure CO emission reduction at the low concentrations found in the combustion turbine exhaust following an oxidation catalyst emission control device. For more information on these type of CEMS, please refer to the rule preamble.

3.3.5 Notification, Recordkeeping 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 which 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 which 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.

You must submit a compliance report semiannually for each new or reconstructed stationary combustion turbine that must comply with the CO emission reduction limitation. This report must contain the company name and address, a statement by a responsible official that the report is accurate, a statement of compliance, or documentation of any deviation from the requirements of the proposed rule during the reporting period.

3.4 Rationale for Selecting Proposed Standards

3.4.1 Selection of Source Categories and Subcategories

As mentioned above, 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. Section 112 of the CAA allows us to establish subcategories within a source category for the purpose of regulation.

As mentioned above, we identified six subcategories of stationary combustion turbines located at major sources: (1) emergency stationary combustion turbines, (2) limited use stationary combustion turbines, (3) stationary combustion turbines which fire landfill gas or digester gas as their primary fuel, (4) stationary combustion turbines of less than 1 MW rated peak power output, (5) stationary diffusion flame combustion turbines, and (6) stationary lean premix combustion turbines.

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. An analysis of the formaldehyde emissions data shows that uncontrolled formaldehyde emissions from stationary lean premix combustion turbines are comparable to controlled formaldehyde emissions from stationary diffusion flame combustion turbines controlled with oxidation catalyst systems. Due to the difference in the two technologies, we decided to establish subcategories for diffusion flame and lean premix stationary combustion turbines.

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 upon 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.

Limited use stationary combustion turbines were also identified as a subcategory. These types of stationary combustion turbines are operated 50 hours per calendar year or less. They are used primarily to stabilize electrical power voltage levels during periods of “brown outs” to prevent damage to sensitive electronic equipment. As with emergency stationary combustion turbines, they are operated infrequently and, when called upon to operate, must respond without failure and without lengthy periods of startup. These conditions limit the applicability of HAP emission control technology.

Similarly, stationary combustion turbines which fire landfill gas or digester gas as their primary fuel were identified as a subcategory. Landfill and digester gases 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. Given the very small size of these stationary combustion turbines and the lack of application of HAP emission control technologies, we have concerns about the applicability of HAP emission control technology to them.

3.4.2 Determination of Basis and Level of Proposed 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

To determine the MACT floor for existing stationary diffusion flame combustion turbines, we primarily consulted two databases: an inventory database and an emissions database. The MACT floors and MACT for stationary diffusion flame combustion turbines located at major sources were developed through the analyses of these databases.

The inventory database provides population information on stationary combustion turbines in the United States (U.S.) and was constructed in order to support the proposed rulemaking. 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. This database is available on the Internet at <http://www.epa.gov/ttn/atw/combust/iccrarch/ct.html>.

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 U.S. At least 90 percent of those turbines are assumed to be diffusion flame 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 for information on HAP emission control technology for these sources. 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 currently installed in the U.S. 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. However, less than 3 percent of existing stationary diffusion flame combustion turbines in the U.S., based on information in our inventory database and information from catalyst vendors, are equipped with oxidation catalyst emission control devices; thus, the average of the best performing 12 percent of existing diffusion flame combustion turbines is no HAP emissions reductions.

We also investigated the use of good operating practices for stationary diffusion flame combustion turbines to determine if the use of 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 which could reduce HAP emissions or which could serve to identify a MACT floor.

We also investigated switching fuels in existing diffusion flame combustion turbines using fuels which result in higher HAP emissions with fuels that result in lower HAP emissions. The summation of emission factors for various HAP when using natural gas (usually considered the cleanest fuel), diesel fuel, landfill, or digester gas were comparable based on the emission factor information that is available. Therefore, we could not identify a MACT floor based on use of a particular fuel.

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.

As a result, we concluded the MACT floor for existing stationary diffusion flame combustion turbines is no emissions reductions.

3.4.2.2 MACT for Existing Diffusion Flame Combustion Turbines

To determine MACT for existing stationary diffusion flame combustion turbines, we evaluated regulatory alternatives more stringent than the MACT floor. For existing diffusion flame sources, in terms of an emission control technology which could serve as the basis for MACT, we considered two above-the-floor options. The first option considered was the use of an oxidation catalyst emission control device. However, we concluded that the incremental annual cost per ton of HAP removed for this option is excessive. The cost per ton of oxidation catalyst emission control devices for control of total HAPs from diffusion flame stationary combustion turbines ranges from $23,000 per metric ton for a 170 MW unit to $303,000 per metric ton for a 1.13 MW unit, assuming emission rates based on the highest reported emission factors for all HAPs. The cost per ton values range from $189,000 for a 170 MW unit to $2,500,000 for a 1.13 MW unit when the average emission factor is used. Based on these estimates, the incremental cost per ton for the above-the-floor option for existing diffusion flame stationary combustion turbines was determined to be excessive.

It should be noted that the incremental cost per ton is the difference in annual costs between this regulatory option and the MACT floor divided by the difference in annual emissions. It is often used as a measure of the economic feasibility of applying emission control technology to a source.

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 due to incremental cost considerations.

The second option considered was to switch fuels in existing turbines using fuels which result in higher HAP emissions with fuels that result in lower HAP emissions. As stated above, we could not find a fuel that was clearly less HAP emitting. Therefore, we could find no basis to further consider fuel switching as an above-the-floor HAP emissions reductions option. We were unable to identify any other above-the-floor regulatory option to consider. As discussed above, we are not aware of any specific good operating practices for diffusion flame turbines that could reduce HAP emissions. As a result, we concluded that

MACT for existing diffusion flame combustion turbines is the MACT floor (i.e., no emissions reductions).

3.4.2.3 MACT Floor for Existing Lean Premix Combustion Turbines

There are an estimated 800 lean premix combustion turbines in the U.S., of which 160 are estimated to be major sources. For existing lean premix combustion turbines, we must establish a MACT floor which represents the average emission limitation achieved by the best performing 12 percent of the existing sources for which we have emissions information. We have emissions information on five existing lean premix combustion turbines. Therefore, we plan to establish the MACT floor based on the performance of the best performing lean premix combustion turbine. (This best performing turbine represents the top 20 percent of the existing turbines for which we have emissions information and will also be used to establish the MACT floor for new lean premix combustion turbines.) The best performing existing lean premix combustion turbine achieved a level of formaldehyde concentration emission which averaged 6.1 parts per billion (ppb) formaldehyde at 15 percent oxygen (O_2). This is the best performer out of five lean premix combustion turbine tests for which we have data.

The test method that was used to measure the emissions from the best performing turbine was California Air Resources Board (CARB) Method 430. We do not believe that the MACT emission limit should be set lower than the limit of detection of the method. If it were, we could not determine whether a source with test results at the limit of detection was actually in compliance with the MACT emission limit. For the test runs on the best performing turbine, we determined that the method had a minimum detection level (MDL) of between 2 and 3 ppb formaldehyde. We want to ensure that the MACT floor reflects the variability in the limit of detection determined by different, competent testers throughout the U.S. using the same method, i.e., CARB Method 430. We only have one test, the test conducted on the best performing turbine, to try to determine a limit of detection for this method, and this is not enough information to determine the variability in the limit of detection among different testers. If we had sufficient information on the limit of detection determined by different competent testers using Method 430, under similar conditions, we would analyze the results to determine the average limit of detection and its standard deviation. To establish a limit of detection that would be achievable by approximately 99 percent of all the testers, we would add three times the standard deviation to the average limit of detection. Since we do not have this information, we can attempt to estimate it. We believe that it is reasonable to assume that the standard deviation of the limit of detection is no greater than the single estimate of the limit that we have. If we multiply the single value of the limit of detection by three and add it to itself, the result is an estimate of the upper bound for the limit of detection that is four times the single measured value that we have. Based on the considerations above, the lowest MACT floor that we believe would take into account the variability in the MDL is 12 ppb. This level provides a safety factor of four to account for uncertainty in whether testers could routinely achieve a limit of detection of 2 to 3 ppb formaldehyde.

Variations in the performance in the best performing turbine could occur if that turbine were located in different areas of the U.S., or if tests were run at different times of the year. Another potential source of variability is the variability associated with procedures for sampling and analyzing the emissions samples. As seen by the performance of the best performing turbine, variations occur within a matter of hours under the same environmental, operational, and test method conditions. For the three test runs, the formaldehyde concentration varied between 5.1 and 7.7 ppb formaldehyde, a factor of 1.5 during only a 3 hour period. Furthermore, for all five lean premix combustion turbines tested, the average formaldehyde concentration varied between 6.1 and 41 ppb, a factor of seven. A review of the emission test reports showed no specific reasons to account for the variability; the tests were properly conducted, and the lean premix combustion turbines were operating properly. Thus, at least some portion of the variability, and possibly all, is due to factors other than turbine performance. The five tests were conducted at three locations in the Western U.S. at significantly different altitudes, and were conducted at different times of the year (April through December). Ambient formaldehyde levels could also have been a factor.

Based on this variability, it is possible that the best performing turbine could vary by a factor of seven or more. It is believed that 43 ppbvd formaldehyde is a reasonable approximation of the performance of the best performing turbine, taking into account all of the types of variability discussed previously. Therefore, the MACT floor for existing lean premix turbines is 43 ppbvd formaldehyde at 15 percent oxygen.

The lean premix combustor turbine technology varies to some extent regarding its uncontrolled emissions of NO_x and CO and possibly HAP. The data that we have obtained for the five source tests were based primarily on lean premix combustor turbines that can achieve lower than 15 ppm NO_x and less than 5 ppm CO (at full load) at 15 percent O_2 without add-on controls. Lean premix combustor turbines which have these characteristics are the types of lean premix combustor turbines that we believe will most likely achieve the 43 ppb formaldehyde emission limit. Other types of lean premix combustor turbines which achieve 45 ppm NO_x and as high as 200 ppm CO at 15 percent O2 may not achieve the 43 ppb formaldehyde emission limit. Typically, the lean premix combustor turbines in the latter category are smaller aeroderivative turbines.

Therefore, we realize that not all lean premix combustor turbines will be able to achieve the 43 ppb formaldehyde emission limitation and some will have to install add-on controls. Most new turbines projected to be installed at power plants are expected to be able to achieve the 43 ppb emission limitation.

3.4.2.4 MACT for Existing Lean Premix Combustion Turbines

To determine MACT for existing stationary lean premix combustion turbines, we evaluated regulatory alternatives more stringent than the MACT floor. For existing lean premix turbines, in terms of an emission control technology which could serve as the basis for MACT, we considered the use of an oxidation catalyst emission control device. According to catalyst vendors, oxidation catalyst emission control is being used on some existing lean premix combustion turbines, however, we lack specific data regarding the performance of turbines with such controls. The concentration of formaldehyde in the exhaust stream from lean premix combustion turbines is already significantly lower than the concentration of formaldehyde in the exhaust stream from diffusion flame combustion turbines, and any reduction achieved by oxidation catalyst control would be difficult to measure. In addition, the annual cost per ton of oxidation catalyst emission control devices for control of total HAPs from lean premix stationary combustion turbines ranges from $364,000 per metric ton for a 170 MW unit to $4,900,000 per metric ton for a 1.13 MW unit, assuming emission rates based on the highest reported emission factors for all HAPs. The cost per ton values range from $1,200,000 for a 170 MW unit to $16,000,000 for a 1.13 MW unit when the average emission factor is used. Based on these estimates, the incremental cost per ton for the above-the-floor option for existing diffusion flame stationary combustion turbines was determined to be excessive. Thus, the excessive cost per ton estimate combined with the lack of measurable reduction of formaldehyde by oxidation catalyst control leads us to not choose this option for proposal. We also considered the use of good operating practices to reduce HAP emissions, but determined that we could not identify specific good operating practices that would reduce HAP emissions. Similarly, we also considered requiring the use of a particular fuel to reduce HAP emissions but concluded that fuel switching would not result in further HAP emissions reductions. As a result, we are proposing to set MACT for existing lean premix combustion turbines at the MACT floor (i.e., 43 ppbvd formaldehyde).

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.

3.4.3.1 MACT Floor for New Diffusion Flame Combustion Turbines

To identify the MACT floor for new stationary combustion turbines located at major sources, we consulted the inventory database and oxidation catalyst vendor information. As mentioned earlier, oxidation catalyst emission control devices are currently installed on about 3 percent of stationary diffusion flame combustion turbines. This 3 percent represents about 200 stationary combustion turbines. We also considered whether the best controlled diffusion flame combustion turbine might be using good operating practices or a particular fuel that would reduce HAP emissions further and concluded that we could not identify specific good operating practices that would reduce HAP emissions, and that fuel switching would not result in further HAP emissions reductions. We concluded, therefore, that the level of HAP emission control achieved by the use of oxidation catalyst emission control devices is the MACT floor for new stationary combustion turbines.

After establishing this basis for the MACT floor, we determined the level of performance based on the data available in the emissions database.

We then examined the emission control efficiency achieved by an oxidation catalyst emission control device on a stationary combustion turbine. We concluded that CO emission reductions are a good surrogate for HAP emissions reductions for oxidation catalyst emission control devices.

This conclusion that CO emission reductions are a good surrogate for HAP emissions reductions achieved through the use of oxidation catalyst emission control devices is also supported by data we have collected from the use of oxidation catalyst emission control devices on stationary reciprocating internal combustion engines (RICE). These data from stationary RICE also show a direct relationship between CO emission reductions and HAP emissions reductions. When oxidation catalyst emission control devices are used to reduce CO emissions, they will reduce HAP emissions.

The emissions database contains several emission test reports that measured HAP and CO emissions from stationary combustion turbines, but no emission test reports that measure the emission reduction efficiency of an oxidation catalyst emission control device (measuring CO and HAP emissions both before and after the control device). However, we obtained information from a catalyst vendor for two tests for one turbine. The results of those tests show that a CO reduction of 95 to 98 percent was achieved using an oxidation catalyst control system. We reviewed the test report for the data to assure that the turbine was operated correctly and that there was no turbine or control device malfunction; we found no discrepancy. In addition to emissions testing data, we reviewed design data from oxidation catalyst vendors for the systems installed in the U.S. The typical emission reduction for turbines that have been installed is 90 percent CO emission reduction, with a few systems that are designed to be 95 percent or greater.

We reviewed other factors such as operator training in addition to the control technology itself that could potentially result in better emission reduction, but we found no effect of those factors on the control efficiency. Based on the conclusions and data, we believe that 95 percent represents the level of control that can be achieved by the best controlled similar source. As a result, we concluded that the level of performance associated with the MACT floor (i.e., use of an oxidation catalyst emission control device) is an emission reduction efficiency of 95 percent or more for CO. The MACT floor for new stationary diffusion flame combustion turbines is, therefore, a CO emission reduction efficiency of 95 percent or more, using an oxidation catalyst control system.

3.4.3.2 MACT for New Diffusion Flame Combustion Turbines

We were unable to identify any above-the-floor regulatory alternatives for new stationary combustion turbines. We know of no emission control technology currently available which can reduce HAP emissions to levels lower than that achieved through the use of oxidation catalyst emission control devices. Similarly, we know of no work practice that could further reduce HAP emissions. In addition, fuel switching will not result in further reductions of HAP emissions. We concluded, therefore, that MACT for new diffusion flame stationary combustion turbines is equivalent to the MACT floor. It should be noted that the majority of new combustion turbines are expected to be lean premix combustion turbines based on the significantly reduced emissions of NO_x, CO, and formaldehyde. We estimate that less than 5 percent of new combustion turbines will be diffusion flame. Diesel-fired combustion turbines cannot be operated in the lean premix mode, and these turbines would have to install an oxidation catalyst system.

3.4.3.3 MACT Floor for New Lean Premix Combustion Turbines

To determine the MACT floor for new stationary lean premix combustion turbines, we based our analysis on the same emissions data for formaldehyde that we used for the existing MACT floor. The MACT floor for existing lean premix combustion turbines is based on the performance of the best performing lean premix combustion turbine; this same level of performance can, therefore, be used to determine the MACT floor for new lean premix combustion turbines. As discussed previously in the existing source MACT discussion, we believe that 43 ppbvd formaldehyde represents the best performing turbine. The MACT floor for new lean premix combustion turbines is, therefore, an emission limit of 43 ppbvd formaldehyde.

3.4.3.4 MACT for New Lean Premix Combustion Turbines

To determine MACT for new stationary lean premix combustion turbines, we evaluated regulatory alternatives more stringent than the MACT floor. As with existing lean premix combustion turbines, we considered the use of an oxidation catalyst control system. However, although catalyst vendors have indicated that some existing lean premix combustion turbines are using oxidation catalyst emission control, we lack specific data regarding the performance of turbines with such controls. The HAP concentration in the lean premix combustion turbine exhaust is very low and, therefore, would be difficult to measure if it were further reduced through the installation of an oxidation catalyst. Due to the low HAP levels, the cost per ton of HAP removed would be very high. We concluded, therefore, that MACT for new stationary lean premix combustion turbines is equivalent to the MACT floor.

3.4.4 MACT for Other Subcategories

Although the proposed rule would apply to all stationary combustion turbines located at major sources of HAP emissions, emergency stationary combustion turbines, limited use stationary combustion turbines, stationary combustion turbines which fire landfill gas or digester gas as their primary fuel, and stationary combustion turbines of less than 1 MW rated peak power output are not required to meet the emission limitations or operating limitations.

Landfill and digester gases contain a family of silicon based gases called siloxanes. Combustion of siloxanes forms compounds that can foul post-combustion catalysts, rendering catalysts inoperable within a very short time period. 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 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.

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, since 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 the use of a particular fuel results in HAP emissions reductions. The MACT floor, therefore, for each of these subcategories is no emissions 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 annual cost per ton of HAP removed excessive - primarily because of the very small reduction in HAP emissions that would result. For example, based on the average HAP emissions factor, the cost per ton of HAP removed for a small combustion turbine (defined in the cost analysis as a model turbine with a capacity of 1.13 MW) is $2.5 million (1999 dollars). It has been shown that as the stationary combustion turbine size decreases, the cost per ton of HAP reduced increases; therefore the cost per ton of a turbine smaller than 1.13 MW would be even greater than $2.5 million. The excessive cost per ton for the application of oxidation catalyst emission control is primarily due to the limited amount of HAP reduction that would result from the use of such control. In addition, it is unknown whether these types of controls are even applicable for small stationary combustion turbines. We are unaware of any applications of this type of control for small stationary combustion turbines. Hence, we conclude that MACT for small stationary combustion turbines (i.e., combustion turbines < 1.0 MW in capacity) is the MACT floor (no emission reductions).

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 due to 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 emissions reductions 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 emissions reductions).

3.4.5 Format of Standard for New Diffusion Flame Combustion Turbines

We are proposing two options for complying with the standard for new diffusion flame combustion turbines. You may reduce CO by 95 percent if you use an oxidation catalyst emission control device, or reduce the concentration of formaldehyde in the exhaust from the turbine to 43 ppb by volume or less, dry basis, at 15 percent oxygen.

We considered proposing an emission limitation for HAP, but are proposing a CO emission reduction limitation as a surrogate for a HAP emission limitation. We have decided to propose the use of the CO emission reduction limitation as a surrogate for the HAP emission limitation, because CO monitoring is currently being used by combustion turbine owners and operators, it is significantly easier and less expensive to measure and monitor CO than to measure and monitor each HAP, and because we believe that CO reduction is a good measure of performance of the oxidation catalyst emission control device. Monitoring equipment for CO is readily available, which is not the case for HAP monitoring equipment.

We are also proposing a percent reduction in CO emissions as the emission limitation, rather than a single value for CO emissions. The data upon which MACT are based show that while the level of CO emissions entering an oxidation catalyst emission control device may vary, the oxidation catalyst emission control device is able to maintain a CO emission reduction efficiency of 95 percent or more.

We are also proposing an alternative emission limitation for formaldehyde emissions. You may choose to comply with the emission limitation for CO emission reduction (if you use an oxidation catalyst emission control device) or you may choose to comply with the emission limitation for formaldehyde emission concentration (if you use some means other than an oxidation catalyst control device to reduce HAP emissions). We would like to promote the development and eventual use of alternative emission control technologies (including pollution prevention technologies) to reduce HAP emissions, and we believe an alternative emission limitation written in terms of formaldehyde emissions will serve to do so. We are soliciting information on HAP and CO emissions data from alternative emission control technologies during the comment period. We are particularly interested in obtaining test reports where HAP and CO emissions reductions were measured with methods that we are recommending to be used to measure HAP in the proposed rule.

For the emission limitation, we propose to use formaldehyde as a surrogate for all HAP. Formaldehyde is the HAP emitted in the highest concentrations from stationary combustion turbines. In addition, the 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 which lead to reductions in formaldehyde emissions will lead to reductions in HAP emissions.

The emission limitation for formaldehyde is in units of parts per billion, and all measurements must be corrected to 15 percent oxygen, dry basis, to provide a common basis. A volume concentration was chosen for the emission limitation because it can be measured directly.

We based the alternative emission limitation on the ability of lean premix technology to reduce emissions to 43 ppbvd (at 15 percent oxygen). The reduction in formaldehyde emissions is approximately equivalent to that achieved when CO emissions are reduced by 95 percent through the use of an oxidation catalyst emission control device.

As discussed later, we consider the cost of formaldehyde CEMS excessive for the purpose of ensuring continuous compliance with this emission limitation for formaldehyde emissions. As a result, we selected stack emission testing to demonstrate compliance with the emission limitation.

3.4.5.1 Initial Compliance Requirements

The emissions tests which form the basis of the proposed rule were conducted using EPA or CARB test methods. The proposed rule requires the use of these EPA or CARB test methods to determine compliance. This ensures that the same procedures that were used to obtain the emission data upon which the emission limitations are based are used for compliance testing. By using the same test methods, we eliminate the possibility of measurement bias and interference influencing determinations of compliance.

For sources complying with the emission limitation to reduce CO emissions, an initial performance evaluation is required. The performance evaluation will validate performance of the CEMS. The proposed rule also requires an annual relative accuracy test audit (RATA) to ensure that performance of the CEMS does not deteriorate over time. The first 4-hour period following this performance evaluation of the CO CEMS will be used to determine initial compliance with the CO emission reduction limitation.

New and reconstructed sources and existing lean premix combustor turbines complying with the emission limitation to reduce 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.

3.4.5.2 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 not required to develop a startup, shutdown or malfunction plan since we do not believe meaningful procedures could be developed.

We consider the use of CEMS the best means of ensuring continuous compliance with emission limitations, and alternatives to CEMS are considered only if we consider the use of a CEMS technically or economically infeasible. For sources complying with the emission limitation for CO emission reduction, we believe it is feasible to require a CEMS because the costs for a CO CEMS are reasonable. Thus, the proposed rule requires the use of a CO CEMS to continuously monitor the reduction in CO emissions.

For sources complying with the emission limitation for formaldehyde emissions, we also considered requiring a CEMS; however, we concluded that the costs of a formaldehyde CEMS were excessive. 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 lean premix 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.

3.4.5.3 Selection of Monitoring and Testing Methods to Measure Low Concentrations of CO and Formaldehyde

We believe CEMS are available which can measure CO emissions at the low concentrations found in the exhaust from a stationary combustion turbine following an oxidation catalyst emission control device. Our performance specifications for CO CEMS, however, have not been updated recently and do not reflect the performance capabilities of such systems at these low CO concentration levels.

Today's proposal specifies the use of Method 10 as the reference method to certify the performance of the CO CEMS. We also believe Method 10 is capable of measuring CO concentrations as low as those experienced in the exhaust of a stationary combustion turbine following an oxidation catalyst emission control device. However, the performance criteria in Addenda A of Method 10 have not been revised recently and are not suitable for certifying the performance of a CO CEMS at these low CO concentrations. Specifically, we believe the range and minimum detectable sensitivity should be changed to reflect target concentrations as low as 0.1 parts per million (ppm) CO in some cases. We also expect that dual range instruments will be necessary to measure CO concentrations at the inlet and at the outlet of an oxidation catalyst emission control device.

Based on comments we receive on CO CEMS, we anticipate revising Method 10 and our performance specifications (PS4 and PS4A) for CO CEMS to ensure the installation and use of CEMS suitable for determining compliance with the emission limitation for CO emission reduction. If we should promulgate today's proposed rule for stationary combustion turbines before completing these revisions, however, we may require all new and reconstructed stationary combustion turbines subject to the final rule to demonstrate compliance with the formaldehyde emission limitation, or a formaldehyde percent reduction limitation similar to the CO percent reduction emission limitation, until we have adopted final revisions to Method 10 and our performance specifications for CO CEMS.

On the other hand, if the comments we receive lead us to conclude that CO CEMS are not capable of being used to determine compliance with the emission limitation for CO emission reduction, there are several alternatives we may consider. One alternative would be to delete the proposed percent reduction emission limitation for CO and require compliance with a comparable formaldehyde percent reduction limitation. This alternative would require periodic stack emission testing before and after the control device and would also require owners and operators to petition the Administrator for additional operating limitations, as proposed today for those choosing to comply with the emission limitation for formaldehyde.

Another alternative would be to delete the proposed emission limitation for CO emission reduction and require compliance with the proposed emission limitation for formaldehyde. This alternative could require more frequent emission testing and could also require owners and operators to petition the Administrator for additional operating limitations.

Another alternative would be to require the use of Method 320 (i.e., FTIR systems) to determine compliance with the emission limitation for CO emission reduction. This alternative could also require more frequent emission testing and require owners and operators to petition the Administrator for additional operating limitations, as proposed today for those choosing to comply with the emission limitation for formaldehyde.

Based on the comments we receive on FTIR systems and Method 320, we may develop additional or revised criteria for the use of FTIR systems and/or Method 320 to determine compliance with the emission limitation for formaldehyde.

If we should conclude that neither CO CEMS or FTIR systems are capable of being used to determine compliance with the emission limitations for CO or formaldehyde emissions, then we may delete the emission limitations for CO and formaldehyde emissions and adopt an emission limitation consisting of an equipment and work practice requirement. This alternative would require the use of oxidation catalyst emission control devices which meet specific and narrow design and operating criteria.

We believe the emission limitations we are proposing for CO emission reduction and formaldehyde emission concentration are superior to these alternatives for a number of reasons that are elaborated upon in the rule preamble. However, we solicit comments on these alternatives, should we conclude that the proposed emission limitations for CO emission reduction and formaldehyde emission concentration are inappropriate because of difficulties in monitoring or measuring CO emission reduction or formaldehyde emission concentration to determine compliance. We also solicit suggestions and recommendations for other alternatives, should we conclude the proposed emission limitations are inappropriate because of monitoring or measurement difficulties.

It should be noted that the proposed notification, recordkeeping, and reporting requirements are based on the NESHAP General Provisions of 40 CFR part 63.

3.5 Consideration of Options for Low-Risk Sources

We have made every effort in developing the proposal to minimize the cost to the regulated community and allow maximum flexibility in compliance options consistent with our statutory obligations. We recognize, however, that the proposal may still require some facilities to take costly steps to further control emissions even though those emissions may not result in exposures which could pose an excess individual lifetime cancer risk greater than one in 1 million or exceed thresholds determined to provide an ample margin of safety for protecting public health and the environment from the effects of HAP. We are, therefore, specifically soliciting comment on whether there are further ways to structure the proposed rule to focus on the facilities which pose significant risks and avoid the imposition of high costs on facilities that pose little risk to public health and the environment.

Representatives of the plywood and composite wood products industry provided EPA with descriptions of three mechanisms that they believed could be used to implement more cost-effective reductions in risk. The docket for today's proposed rule contains "white papers" prepared by the plywood and composite wood products industry that outline their proposed approaches (see docket number A-98-44, Item#II-D-525). These approaches could be effective in focusing regulatory controls on facilities that pose significant risks and avoiding the imposition of high costs on facilities that pose little risk to public health or the environment, and we are seeking public comment on the utility of each of these approaches with respect to this rule.

One of the approaches, an applicability cutoff for threshold pollutants, would be implemented under the authority of CAA Section 112(d)(4); the second approach, subcategorization and delisting, would be implemented under the authority of CAA Sections 112(c)(5) and 112(c)(9); and the third approach would involve the use of a concentration-based applicability threshold. We are seeking comment on whether these approaches are legally justified and, if so, we ask for information that could be used to support such approaches.

In addition, on August 21, 2002, the Agency received a petition from the Gas Turbine Association (GTA) requesting that natural gas fueled combustion turbines be delisted and a study that they believed would justify delisting. Section 112(c)(9) of the CAA provides EPA with the authority to delist categories or subcategories either in response to the petition of any person or upon the Administrator's own motion. The GTA that the study supports a determination that HAP emissions from gas turbines would not result in a lifetime cancer risk greater than one in a million to the individual in the population most exposed to the emissions or non-carcinogenic health risk exceeding a level which is adequate to protect public health with an ample margin of safety. We have reviewed the GTA study and responded to the GTA on October 11, 2002 with questions and areas that we believe need further analysis.   The EPA's request for further information and all information provided by the petitioner to date is located in the docket for today's proposed rule.

The MACT program outlined in CAA Section 112(d) is intended to reduce emissions of HAP through the application of MACT to major sources of toxic air pollutants. Section 112(c)(9) is intended to allow EPA to avoid setting MACT standards for sources or subcategories of sources that pose less than a specified level of risk to public health and the environment. The EPA requests comment on whether the proposals described here appropriately coordinate these provisions of CAA Section 112. The two health-based approaches focus on assessing inhalation exposures or accounting for adverse environmental impacts. EPA specifically requests comment on the appropriateness and necessity of extending these approaches to account for noninhalation exposures of certain HAP which may deposit from the atmosphere after being emitted into the air or to account for adverse environmental impacts. In addition to the specific requests for comment noted in this section, we are also interested in any information or comment concerning technical limitations, environmental and cost impacts, compliance assurance, legal rationale, and implementation relevant to the identified approaches. We also request comment on appropriate practicable and verifiable methods to ensure that sources' emissions remain below levels that protect public health and the environment. We will evaluate all comments before determining whether to include an approach in the final rule.

3.5.1 Industry HAP Emissions and Potential Health Effects

For the stationary combustion turbines source category, four HAP account for essentially all of the mass of HAP emissions. Those four HAP are formaldehyde, toluene, benzene, and acetaldehyde. Additional HAP which have been measured in emission tests that were conducted at natural gas fired and distillate oil fired combustion turbines are: 1,3 butadiene, acrolein, ethylbenzene, naphthalene, polycyclic aromatic hydrocarbons (PAHs), propylene oxide, and xylenes. The following metallic HAP emissions have been measured from distillate oil fired stationary combustion turbines: arsenic, beryllium, cadmium, chromium, lead, manganese, mercury, nickel, and selenium.

Of the four HAP emitted in the largest quantities by this source category, all can cause toxic effects following sufficient exposure. The potential toxic effects of these four HAP are discussed earlier in Section 3.2 and in Section D of the rule preamble.

In accordance with Section 112(k), EPA developed a list of 33 HAP which present the greatest threat to public health in the largest number of urban areas. Of the four predominant HAP, three (acetaldehyde, benzene, and formaldehyde) are included on this list for the EPA's Urban Air Toxics Program. Eleven of the other emitted HAP (acrolein, arsenic compounds, beryllium compounds, 1,3-butadiene, cadmium compounds, chromium compounds, lead compounds, manganese compounds, mercury compounds, nickel compounds, and PAHs (as POM)) also appear on the list. In November 1998, EPA published "A Multimedia Strategy for Priority Persistent, Bioaccumulative, and Toxic (PBT) Pollutants." None of the predominant four HAP emitted by stationary combustion turbine operations appears on the published list of compounds referred to in the EPA's PBT strategy. Three of the other HAP (mercury compounds, cadmium compounds, and PAHs) appear on the list.

Of the HAP emitted by stationary combustion turbine operations, fifteen (acetaldehyde, acrolein, arsenic compounds, benzene, beryllium compounds, 1,3-butadiene, cadmium compounds, chromium compounds, formaldehyde, lead compounds, mercury compounds, naphthalene, nickel compounds, PAHs, and propylene oxide) are carcinogens that, at present, are not considered to have thresholds for cancer effects. Formaldehyde, however, is a potential threshold carcinogen, and EPA is currently revising the dose-response assessment for formaldehyde.

3.5.2 Applicability Cutoffs for Threshold Pollutants Under Section 112(d)(4) of the CAA

The first approach is an "applicability cutoff" for threshold pollutants that is based on EPA's authority under CAA Section 112(d)(4) to establish standards for HAP which are "threshold pollutants." A "threshold pollutant" is one for which there is a concentration or dose below which adverse effects are not expected to occur over a lifetime of exposure. For such pollutants, Section 112(d)(4) allows EPA to consider the threshold level, with an ample margin of safety, when establishing emissions standards. Specifically, Section 112(d)(4) allows EPA to establish emission standards that are not based upon the MACT specified under Section 112(d)(2) for pollutants for which a health threshold has been established. Such standards may be less stringent than MACT. Historically, EPA has interpreted 112(d)(4) to allow categories of sources that emit only threshold pollutants to avoid further regulation if those emissions result in ambient levels that do not exceed the threshold, with an ample margin of safety.[1]

A different interpretation would allow us to exempt individual facilities within a source category that meet the §112(d)(4) requirements. There are three potential scenarios

[1] See 63 FR 18754, 18765-66 (April 15, 1998) (Pulp and Paper Sources Proposed NESHAP)

under this interpretation of the §112(d)(4) provision. One scenario would allow an exemption for individual facilities that emit only threshold pollutants and can demonstrate that their emissions of threshold pollutants would not result in air concentrations above the threshold levels, with an ample margin of safety, even if the category is otherwise subject to MACT. A second scenario would allow the §112(d)(4) provision to be applied to both threshold and nonthreshold pollutants, using the 1 in a million cancer risk level for decisionmaking for nonthreshold pollutants.

A third scenario would allow a §112(d)(4) exemption at a facility that emits both threshold and nonthreshold pollutants. For those emission points where only threshold pollutants are emitted and where emissions of the threshold pollutants would not result in air concentrations above the threshold levels, with an ample margin of safety, those emission points could be exempt from the MACT standards. The MACT standards would still apply to nonthreshold emissions from other emission points at the source. For this third scenario, emission points that emit a combination of threshold and nonthreshold pollutants that are co-controlled by MACT would still be subject to the MACT level of control. However, any threshold HAP eligible for exemption under §112(d)(4) that are controlled by control devices different from those controlling nonthreshold HAP would be able to use the exemption, and the facility would still be subject to the parts of the standards that control nonthreshold pollutants or that control both threshold and nonthreshold pollutants.

Estimation of hazard quotients and hazard indices. Under the §112(d)(4) approach, EPA would have to determine that emissions of each of the threshold pollutants emitted by automobile and light-duty truck surface coating operations at the facility do not exceed the threshold levels, with an ample margin of safety.

The common approach for evaluating the potential hazard of a threshold air pollutant is to calculate a "hazard quotient" by dividing the pollutant's inhalation exposure concentration (often assumed to be equivalent to its estimated concentration in air at a location where people could be exposed) by the pollutant's inhalation Reference Concentration (RfC). An RfC is an estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure that, over a lifetime, likely would not result in the occurrence of adverse health effects in humans, including sensitive individuals.

The EPA typically establishes an RfC by applying uncertainty factors to the critical toxic effect derived from the lowest- or no-observed-adverse-effect level of a pollutant.[2] A hazard quotient less than one means that the exposure concentration of the pollutant is less than the RfC, and, therefore, presumed to be without appreciable risk of adverse health effects. A hazard quotient greater than one means that the exposure concentration of the pollutant is greater than the RfC. Further, EPA guidance for assessing exposures to mixtures of threshold pollutants recommends calculating a hazard index (HI) by summing the individual hazard quotients for those pollutants in the mixture that affect the same target organ or system by the same mechanism[3]. The HI values would be interpreted similarly to hazard quotients; values below one would generally be considered to be without appreciable risk of adverse health effects, and values above one would generally be cause for concern.

For the determinations discussed herein, EPA would generally plan to use RfC values contained in EPA's toxicology database, the Integrated Risk Information System (IRIS). When a pollutant does not have an approved RfC in IRIS, or when a pollutant is a carcinogen, EPA would have to determine whether a threshold exists based upon the availability of specific data on the pollutant's mode or mechanism of action, potentially using a health threshold value from an alternative source such as the Agency for Toxic Substances and Disease Registry (ATSDR) or the California Environmental Protection Agency (CalEPA). Table 3-3 provides, RfCs, as well as unit risk estimates, for the HAP emitted by combustion turbine operations. A unit risk estimate is defined as the upper-bound excess lifetime cancer risk estimated to result from continuous exposure to an agent at a concentration of 1 ug/m^3 in the air.

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[2] "Methods for Derivation of Inhalation Reference Concentrations and Applications of Inhalation Dosimetry." EPA-600/8-90-066F, Office of Research and Development, USEPA, October 1994.

[3] "Supplementary Guidance for Conducting Health Risk Assessment of Chemical Mixtures. Risk Assessment Forum Technical Panel," EPA/630/R-00/002. USEPA, August 2000. http://www.epa.gov/nceawww1/pdfs/chem mix/chem mix 08 2001.pdf.

Table 3-3. Dose-Response Assessment Values for HAP Reported Emitted by the Combustion Turbine Source Category

Chemical Name	CAS No.	Reference Concentration[a] (mg/m^3)	Unit Risk Estimate[b] (1/(ug/m^3))
Acetaldehyde	75-07-0	9.0E-03 IRIS	2.2E-06 IRIS
Acrolein	107-02-8	2.0E-05 IRIS	
Arsenic compounds	7440-38-2	3.0E-05 CAL	4.3E-03 IRIS
Benzene	71-43-2	6.0E-02 CAL	7.8E-06 IRIS
Beryllium compounds	7440-41-7	2.0E-05 IRIS	2.4E-03 IRIS
1,3-Butadiene	106-99-0	2.0E-03 IRIS	3.0E-05 EPA ORD
Cadmium compounds	7440-43-9	2.0E-05 IRIS	1.8E-03 IRIS
Chromium (VI) compounds	18540-29-9	1.0E-04 IRIS	1.2E-02 IRIS
Ethyl benzene	100-41-4	1.0E+00 IRIS	
Formaldehyde	50-00-0	9.8E-03 ATSDR	1.3E-05 IRIS
Lead compounds	7439-92-1		1.2E-05 CAL
Manganese compounds	7439-96-5	5.0E-05 IRIS	
Mercury compounds	HG_CMPDS	9.0E-05 CAL	
Naphthalene	91-20-3	3.0E-03 IRIS	
Nickel compounds	7440-02-0	2.0E-04 ATSDR	9.1E-01 CAL
PAHs (shown below as 7-PAH)			
Benzo(a)anthracene	56-55-3		1.1E-04 CAL
Benzo(b)fluoranthene	205-99-2		1.1E-04 CAL
Benzo(k)fluoranthene	207-08-9		1.1E-04 CAL
Benzo(a)pyrene	50-32-8		1.1E-03 CAL
Chrysene	218-01-9		1.1E-05 CAL
Dibenz(a,h)anthracene	53-70-3		1.2E-03 CAL
Indeno(1,2,3-cd)pyrene	193-39-5		1.4E-04 CAL

(continued)

Table 3-3. Dose-Response Assessment Values for HAP Reported Emitted by the Combustion Turbine Source Category (continued)

Chemical Name	CAS No.	Reference Concentration[a] (mg/m^3)	Unit Risk Estimate[b] ($1/(ug/m^3)$)
Propylene oxide	75-56-9	3.0E-02 IRIS	3.7E-06 IRIS
Selenium compounds	7782-49-2	2.0E-02 CAL	
Toluene	108-88-3	4.0E-01 IRIS	
Xylenes (mixed)	1330-20-7	4.3E-01 ATSDR	

[a] Reference Concentration: An estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups which include children, asthmatics, and the elderly) that is likely to be without an appreciable risk of deleterious effects during a lifetime. It can be derived from various types of human or animal data, with uncertainty factors generally applied to reflect limitations of the data used.

[b] Unit Risk Estimate: The upper-bound excess lifetime cancer risk estimated to result from continuous exposure to an agent at a concentration of 1 ug/m^3 in air. The interpretation of the Unit Risk Estimate would be as follows: if the Unit Risk Estimate = 1.5 x 10-6 per ug/m^3, 1.5 excess tumors are expected to develop per 1,000,000 people if exposed daily for a lifetime to 1 ug of the chemical in 1 cubic meter of air. Unit Risk Estimates are considered upper bound estimates, meaning they represent a plausible upper limit to the true value. (Note that this is usually not a true statistical confidence limit.) The true risk is likely to be less, but could be greater.

Sources: IRIS = EPA Integrated Risk Information System (http://www.epa.gov/iris/subst/index.html)
ATSDR = U.S. Agency for Toxic Substances and Disease Registry (http://www.atsdr.cdc.gov/mrls.html)
CAL = California Office of Environmental Health Hazard Assessment (http://www.oehha.ca.gov/air/hot_spots/index.html)
HEAST = EPA Health Effects Assessment Summary Tables (#PB(=97-921199, July 1997)

To establish an applicability cutoff under Section 112(d)(4), EPA would need to define ambient air exposure concentration limits for any threshold pollutants involved. There are several factors to consider when establishing such concentrations. First, we would need to ensure that the concentrations that would be established would protect public health with an ample margin of safety. As discussed above, the approach EPA commonly uses when evaluating the potential hazard of a threshold air pollutant is to calculate the pollutant's hazard quotient, which is the exposure concentration divided by the RfC.

The EPA's "Supplementary Guidance for Conducting Health Risk Assessment of Chemical Mixtures" suggests that the noncancer health effects associated with a mixture of pollutants ideally are assessed by considering the pollutants' common mechanisms of toxicity.[4] The guidance also suggests that when exposures to mixtures of pollutants are being evaluated, the risk assessor may calculate a HI. The recommended method is to calculate multiple hazard indices for each exposure route of interest, and for a single specific toxic effect or toxicity to a single target organ. The default approach recommended by the guidance is to sum the hazard quotients for those pollutants that induce the same toxic effect or affect the same target organ. A mixture is then assessed by several HIs, each representing one toxic effect or target organ. The guidance notes that the pollutants included in the HI calculation are any pollutants that show the effect being assessed, regardless of the critical effect upon which the RfC is based. The guidance cautions that if the target organ or toxic effect for which the HI is calculated is different from the RfC's critical effect, then the RfC for that chemical will be an overestimate, that is, the resultant HI potentially may be overprotective. Conversely, since the calculation of a HI does not account for the fact that the potency of a mixture of HAP can be more potent than the sum of the individual HAP potencies, a HI may potentially be underprotective in some situations.

Options for establishing a HI limit. One consideration in establishing a HI limit is whether the analysis considers the total ambient air concentrations of all the emitted HAP to which the public is exposed[5]. There are several options for establishing a HI limit for the §112(d)(4) analysis that reflect, to varying degrees, public exposure.

One option is to allow the hazard index posed by all threshold HAP emitted by combustion turbines at the facility to be no greater than one. This approach is protective if no additional threshold HAP exposures would be anticipated from other sources at, or in the vicinity of, the facility or through other routes of exposure (i.e., through ingestion).

A second option is to adopt a "default percentage" approach, whereby the HI limit of the HAP emitted by the facility is set at some percentage or fraction of one (e.g., 20 percent or 0.2). This approach recognizes the fact that the facility in question is only one of many sources of threshold HAP to which people are typically exposed every day. Because noncancer risk assessment is predicated on total exposure or dose, and because risk assessments focus only on an individual source, establishing a HI limit of 0.2 would account for an assumption that 20 percent of an individual's total exposure is from that individual source. For the purposes of this discussion, we will call all sources of HAP, other than

[4] ibid.

[5] Senate Debate on Conference Report (October 27, 1990), reprinted in "A Legislative History of the Clean Air Act Amendments of 1990," Comm. Print S. Prt. 103-38 (1993) ("Legis. Hist.") at 868.

operations within the source category at the facility in question, “background” sources. If the affected source is allowed to emit HAP such that its own impacts could result in HI values of one, total exposures to threshold HAP in the vicinity of the facility could be substantially greater than one due to background sources, and this would not be protective of public health, since only HI values below one are considered to be without appreciable risk of adverse health effects. Thus, setting the HI limit for the facility at some default percentage of one will provide a buffer which would help to ensure that total exposures to threshold HAP near the facility (i.e., in combination with exposures due to background sources) will generally not exceed one, and can generally be considered to be without appreciable risk of adverse health effects.

The EPA requests comment on using the “default percentage” approach and on setting the default HI limit at 0.2. The EPA is also requesting comment on whether an alternative HI limit, in some multiple of 1, would be a more appropriate applicability cutoff.

A third option is to use available data (from scientific literature or EPA studies, for example) to determine background concentrations of HAP, possibly on a national or regional basis. These data would be used to estimate the exposures to HAP from noncombustion turbine sources in the vicinity of an individual facility. For example, EPA’s National-Scale Air Toxics Assessment (NATA)[6] and ATSDR’s Toxicological Profiles[7] contain information about background concentrations of some HAP in the atmosphere and other media. The combined exposures from an affected source and from background emissions (as determined from the literature or studies) would then not be allowed to exceed a HI limit of 1. The EPA requests comment on the appropriateness of setting the hazard index limit at one for such an analysis.

A fourth option is to allow facilities to estimate or measure their own facility-specific background HAP concentrations for use in their analysis. With regard to the third and fourth options, EPA requests comment on how these analyses could be structured. Specifically, EPA requests comment on how the analyses should take into account background exposure levels from air, water, food and soil encountered by the individuals exposed to emissions from this source category. In addition, we request comment on how such analyses should account for potential increases in exposures due to the use of a new HAP or the increased use of a previously emitted HAP, or the effect of other nearby sources that release HAP.

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[6]See <http://www.epa.gov/ttn/atw/nata>

[7]See <http://www.atsdr.cdc.gov/toxpro2.html>.

The EPA requests comment on the feasibility and scientific validity of each of these or other options. Finally, EPA requests comment on how we should implement the Section 112(d)(4) applicability cutoffs, including appropriate mechanisms for applying cutoffs to individual facilities. For example, would the Title V permit process provide an appropriate mechanism?

Tiered analytical approach for predicting exposure. Establishing that a facility meets the cutoffs established under Section 112(d)(4) will necessarily involve combining estimates of pollutant emissions with air dispersion modeling to predict exposures. The EPA envisions that we would promote a tiered analytical approach for these determinations. A tiered analysis involves making successive refinements in modeling methodologies and input data to derive successively less conservative, more realistic estimates of pollutant concentrations in air and estimates of risk.

As a first tier of analysis, EPA could develop a series of simple look-up tables based on the results of air dispersion modeling conducted using conservative input assumptions. By specifying a limited number of input parameters, such as stack height, distance to property line, and emission rate, a facility could use these look-up tables to determine easily whether the emissions from their sources might cause a hazard index limit to be exceeded.

A facility that does not pass this initial conservative screening analysis could implement increasingly more site-specific but more resource-intensive tiers of analysis using EPA-approved modeling procedures, in an attempt to demonstrate that their facility does not exceed the HI limit. Existing EPA guidance could provide the basis for conducting such a tiered analysis.[8]

The EPA requests comment on methods for constructing and implementing a tiered analysis for determining applicability of the Section 112(d)(4) criterion to specific combustion turbine sources. Ambient monitoring data could possibly be used to supplement or supplant the tiered modeling analysis described above. We envision that the appropriate monitoring to support such a determination could be extensive. The EPA requests comment on the appropriate use of monitoring in the determinations described above.

Accounting for dose-response relationships. In the past, EPA routinely treated carcinogens as nonthreshold pollutants. The EPA recognizes that advances in risk

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[8]"A Tiered Modeling Approach for Assessing the Risks due to Sources of Hazardous Air Pollutants." EPA-450/4-92-001. David E. Guinnup, Office of Air Quality Planning and Standards, USEPA, March 1992.

assessment science and policyHAP. The EPA's draft Guidelines for Carcinogen Risk Assessment[9] suggest that carcinogens be assigned nonlinear dose-response relationships where data warrant. Moreover, it is possible that dose-response curves for some pollutants may reach zero risk at a dose greater than zero, creating a threshold for carcinogenic effects. It is possible that future evaluations of the carcinogens emitted by this source category would determine that one or more of the carcinogens in the category is a threshold carcinogen or is a carcinogen that exhibits a nonlinear dose-response relationship but does not have a threshold.

The dose-response assessment for formaldehyde is currently undergoing revision by EPA. As part of this revision effort, EPA is evaluating formaldehyde as a potential nonlinear carcinogen. The revised dose-response assessment will be subject to review by the EPA Science Advisory Board, followed by full consensus review, before adoption into the EPA IRIS. At this time, EPA estimates that the consensus review will be completed by the end of 2003. The revision of the dose-response assessment could affect the potency factor of formaldehyde, as well as its status as a threshold or nonthreshold pollutant. At this time, the outcome is not known. In addition to the current reassessment by EPA, there have been several reassessments of the toxicity and carcinogenicity of formaldehyde in recent years, including work by the World Health Organization and the Canadian Ministry of Health.

The EPA requests comment on how we should consider the state of the science as it relates to the treatment of threshold pollutants when making determinations under §112(d)(4). In addition, EPA requests comment on whether there is a level of emissions of a nonthreshold carcinogenic HAP at which it would be appropriate to allow a facility to use the scenarios discussed under the allow us to create subcategories of stationary combustion turbines. Those subcategories could be delisted if it were demonstrated that they met the requirements of CAA Section 112(c)(9). The GTA letter includes information on the risks created by emissions from lean-premix turbines. We are already proposing a subcategory for lean-premix turbines and in that discussion describe how these turbines are clearly technologically different from other types of stationary combustion turbines. While the GTA letter did not provide sufficient information for us to delist lean-premix turbines at this time, lean-premix turbines are a subcategory that could be delisted if GTA or other commenters provide sufficient information for us to determine that this subcategory satisfies the requirements of CAA Section 112(c)(9).

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[9] "Draft Revised Guidelines for Carcinogen Risk Assessment." NCEA-F-0644. USEPA, Risk Assessment Forum, July 1999. pp 3-9ff. http://www.epa.gov/ncea/raf/pdfs/cancer_gls.pdf.

Natural gas fired turbines are another example of a subcategory that might be delisted under this approach. We have created subcategories based on fuel type in other MACT rules and believe that fuel type could be an appropriate way of subcategorizing stationary combustion turbines or of creating further subdivisions within the subcategories contained in the proposed rule. We are not proposing a subcategory for natural gas fired turbines at this time, although we could create such a subcategory . While the information presented in GTA's letter is not sufficient for us to make this determination at this time, additional information on the emissions and risks from natural gas fired turbines could lead us to delist natural gas fired turbines under this approach.

The EPA requests comment on the concept of identifying technologically-based subcategories that may include only low-risk facilities within the combustion turbine source category and on the specific examples presented above.

Another approach to using the authority granted in CAA Section 112(c)(9) is presented in the white paper prepared by representatives of the plywood and composite wood products industry (see docket OAR 2002-0060). The EPA is considering whether it would be possible to establish a subcategory of facilities within the larger source category that would meet the risk-based criteria for delisting. Such criteria would likely include the same requirements as described previously for the second scenario under the CAA Section 112(d)(4) approach, whereby a facility would be in the low-risk subcategory if its emissions of threshold pollutants do not result in exposures which exceed the HI limits and if its emissions of nonthreshold pollutants do not exceed a cancer risk level of 10^{-6}. The EPA requests comment on what an appropriate HI limit would be for a determination that a facility be included in the low-risk subcategory.

Since each facility in such a subcategory would be a low-risk facility (i.e., if each met these criteria), the subcategory could be delisted in accordance with Section 112(c)(9), thereby limiting the costs and impacts of the proposed MACT rule to only those facilities that do not qualify for subcategorization and delisting.

Facilities seeking to be included in the delisted subcategory would be responsible for providing all data required to determine whether they are eligible for inclusion. Facilities that could not demonstrate that they are eligible to be included in the low-risk subcategory would be subject to MACT and possible future residual risk standards. The EPA solicits comment on implementing a risk-based approach for establishing subcategories of stationary combustion turbines.

Establishing that a facility qualifies for the low-risk subcategory under §112(c)(9) will necessarily involve combining estimates of pollutant emissions with air dispersion modeling to predict exposures. The EPA envisions that we would employ the same tiered analysis described earlier in the §112 (d)(4) discussion for these determinations.

One concern that EPA has with respect to this §112(c)(9) approach is the effect that it could have on the MACT floors. If many of the facilities in the low-risk subcategory are well-controlled, that could make the MACT floor less stringent for the remaining facilities. One approach that has been suggested to mitigate this effect would be to establish the MACT floor now based on controls in place for the entire category and to allow facilities to become part of the low-risk subcategory in the future, after the MACT standards are established. This would allow low-risk facilities to use the §112(c)(9) exemption without affecting the MACT floor calculation. The EPA requests comment on this suggested approach.

If a §112(c)(9) approach were adopted, the requirements of the rule would not apply to any source that demonstrates that it belongs in a subcategory which has been delisted under §112(c)(9).

SECTION 4

PROJECTION OF UNITS AND FACILITIES IN AFFECTED SECTORS

The proposed regulation will affect existing and new combustion 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 2005. 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 proposed 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 2005.

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 proposed 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.

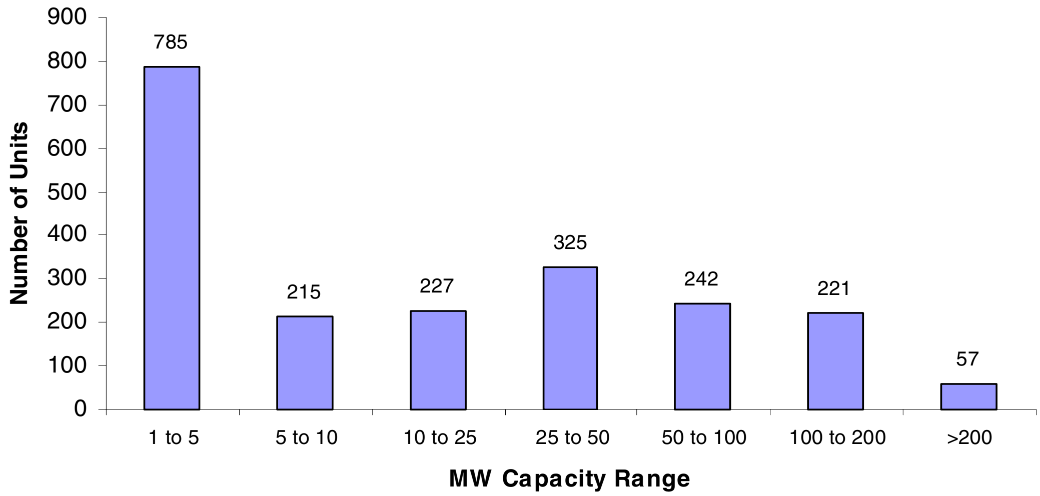

Figure 4-1. Number of Units by MW Capacity

Table 4-2. Stationary Combustion Turbine Projections

	Total Number of New Units
Utility Turbines	
Base load energy (combined cycle)	480
Peak power (simple cycle)	235
Nonutility Turbines	
Small	10
Medium	31
Large	15
Total in 5th year	771
Average per year	154

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 771 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, 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 70 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.

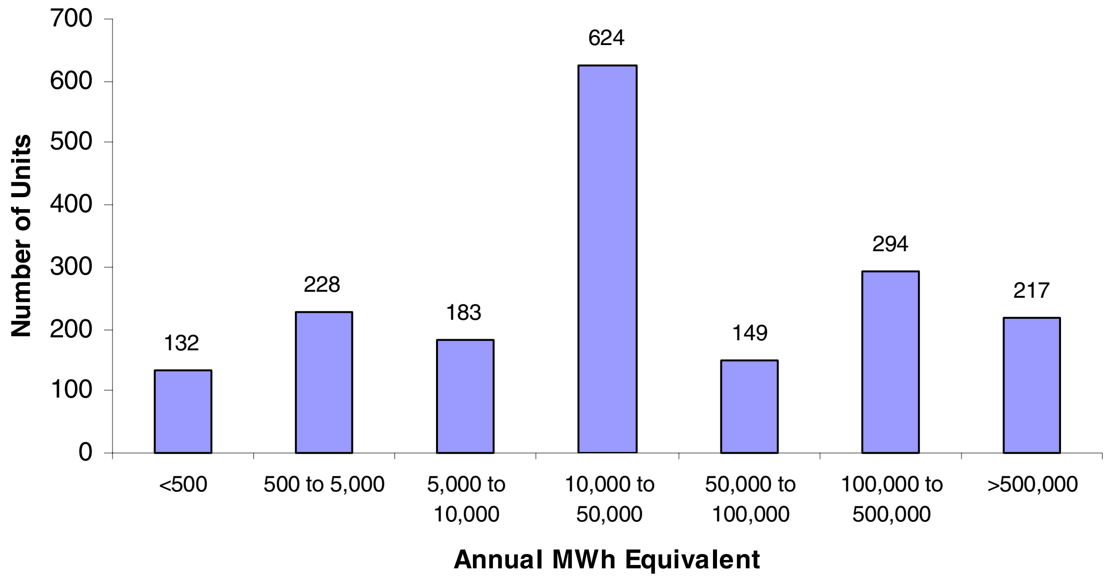

Figure 4-2. Number of Units by Annual MWh Output Equivalent

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

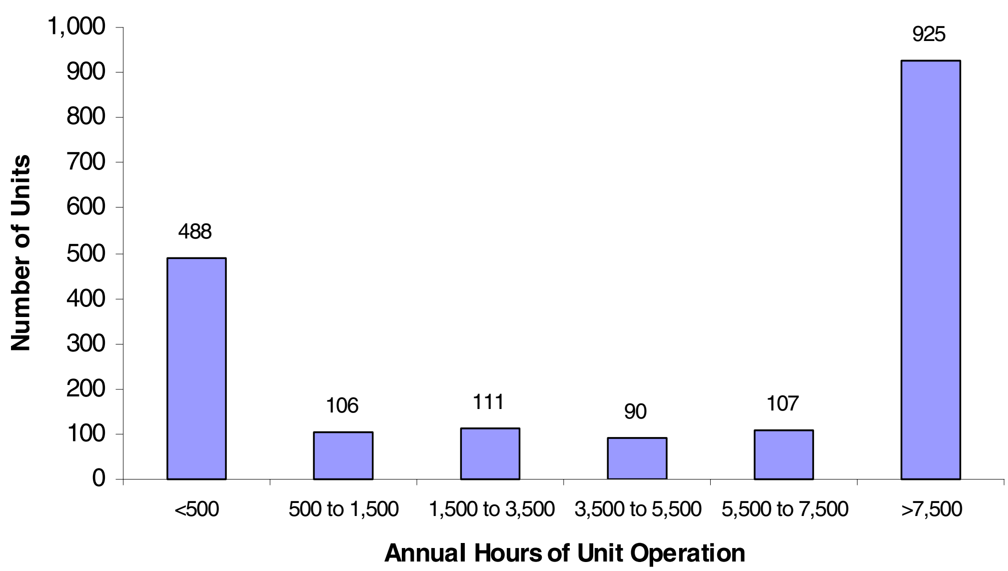

Figure 4-3. Number of Units by Annual Hours of Operation

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 proposed 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. The EPA also assumed that this percentage applied to existing sources. Since 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. This amounts to 800 existing LPC turbines, of which twenty percent are major or an estimated 160 LPC turbines that are major. Since 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 six 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 derives 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 five years. For new nonutility turbines, 56 new units will be affected in the next five years.

Based on the description in the previous two paragraphs, twenty stationary combustion turbines will have to apply an oxidation catalyst to meet the emission limitations associated with this proposed 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. The 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 proposed rule will reduce total national HAP emissions by an estimated 81 tons/year in the 5th year after the standards are promulgated. The emissions reductions achieved by the proposed 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 proposed rule result only from the sources that install an oxidation catalyst control system.

To estimate the baseline HAP emissions and reductions associated with this proposed rule, national HAP emissions in the absence of the proposed 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 proposed 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 proposed 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. Three 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.
- Lower and less-volatile natural gas prices have increased cost-effectiveness and lowered risk.
- 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 proposed 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 proposed 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.

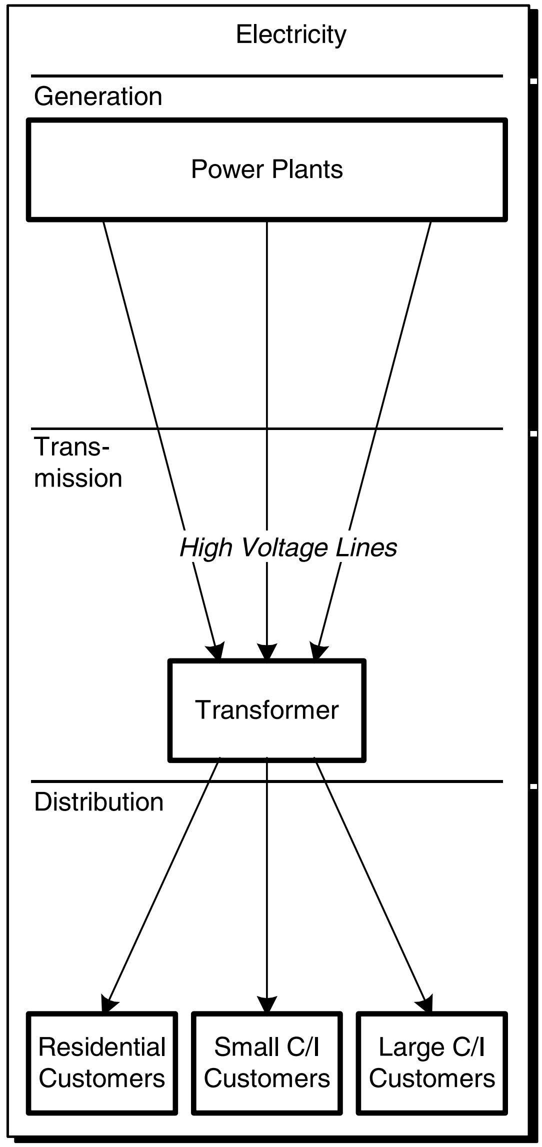

Figure 5-1. Traditional Electric Power Industry Structure

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.

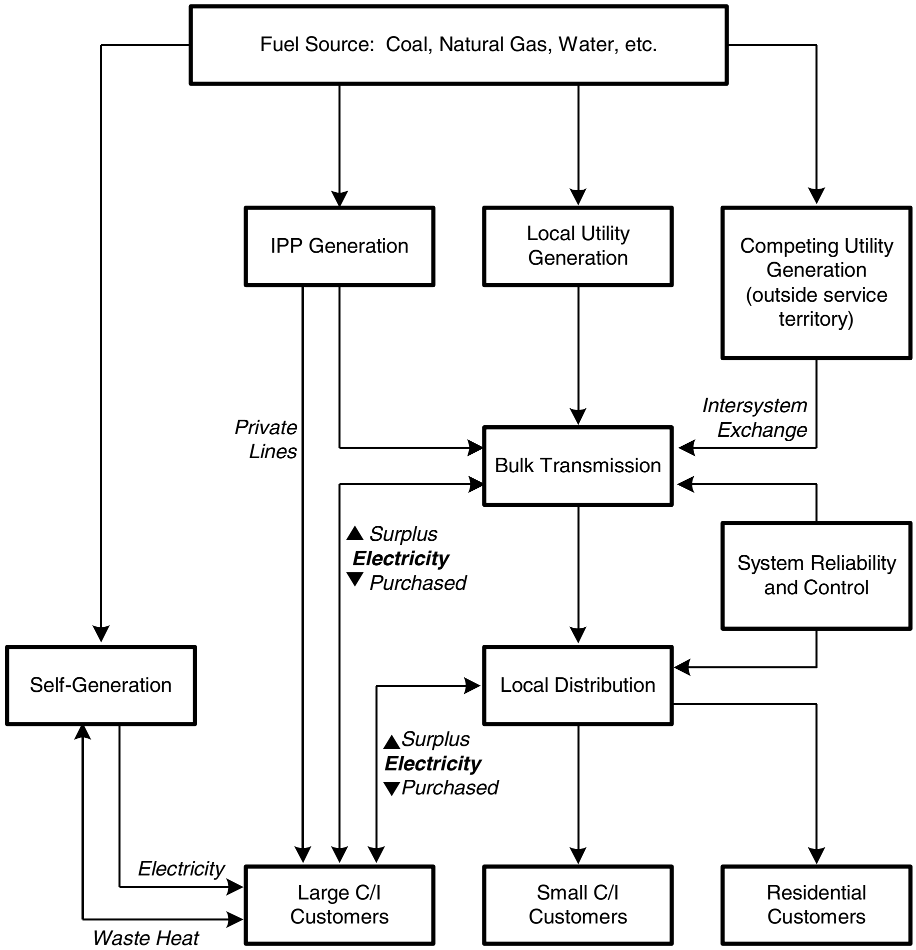


Figure 5-2. Electric Utility Industry

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

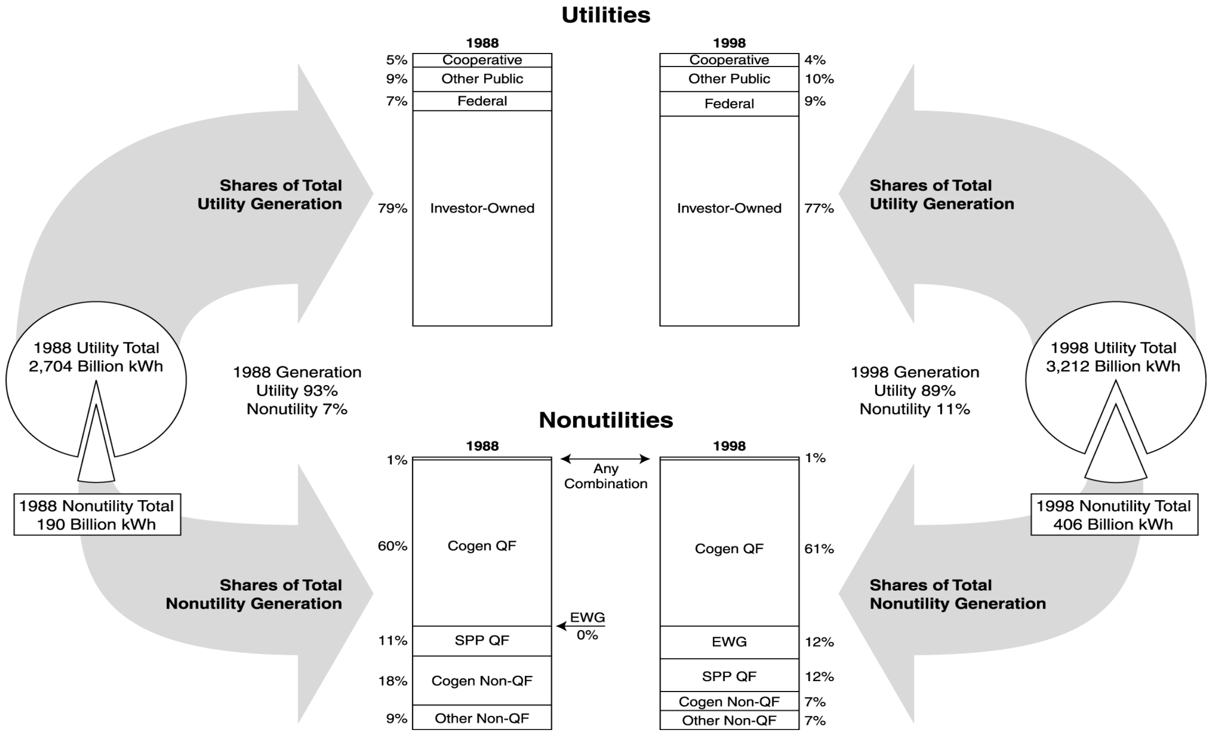
Electricity Suppliers	Number	Percent
Utilities	3,124	42%
Investor-owned utilities	222	
Cooperatives	875	
Municipal systems	1,885	
Public power districts	73	
State projects	55	
Federal agencies	14	
Nonutilities	4,247	58%
Nonutilities (excluding EWGs)	4,103	
Exempt wholesale generators	144	
Total	7,371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



[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

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.

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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.

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 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 5-7 outlines capacity additions and retirements at U.S. electric utilities by energy source.

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 5-8 shows planned capacity additions by prime mover and energy source.

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 5-9 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 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).

Table 5-7. Capacity Additions and Retirements at U.S. Electric Utilities by Energy Source, 1997

	Additions		Retirements	
Primary Energy Source	**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.

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

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 5-10 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).

Table 5-8. 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.

5.2 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

Table 5-9. 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.

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):

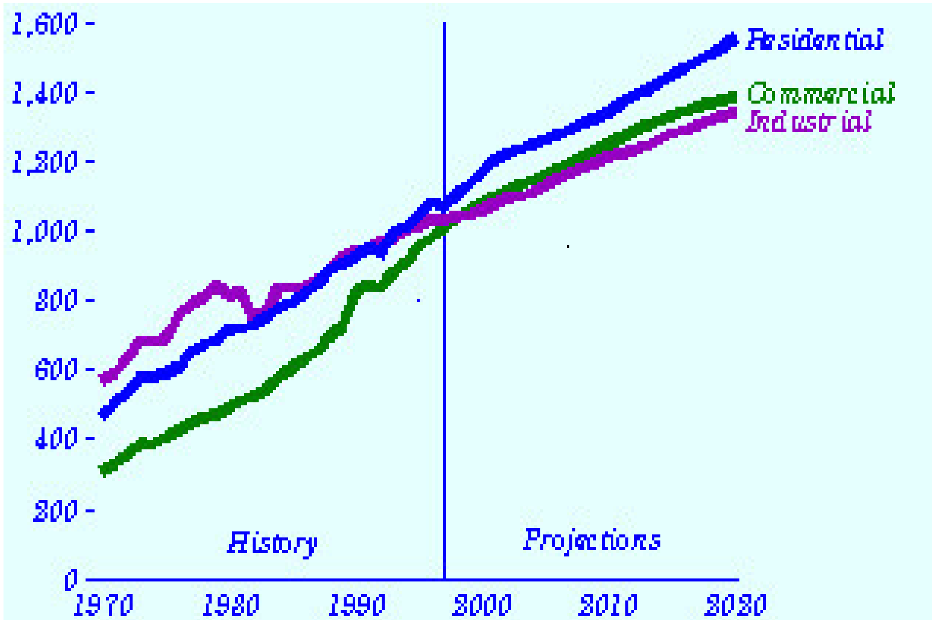

Figure 5-4. Annual Electricity Sales by Sector

- 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 5-10. 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.

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

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	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

	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	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		1992	
	Number of Facilities	Value of Shipments ($1997 10^3)	Number of Facilities	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

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	1997 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.

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.

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.

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.

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 5-24. 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

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/>.

$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.

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 proposed 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

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

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.

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 proposed 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 proposed 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.

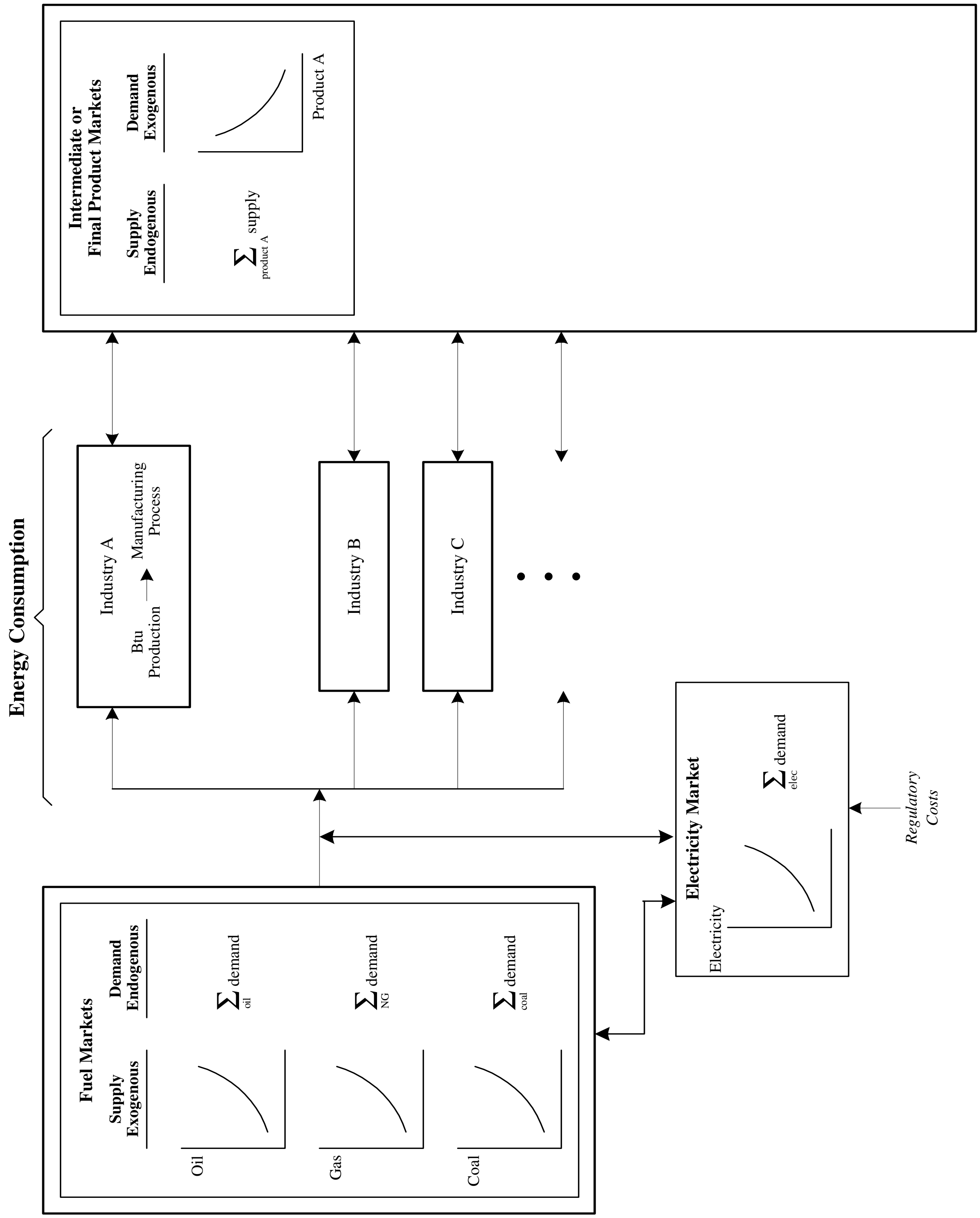

Figure 6-1. Links Between Energy and Final Product Markets

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]

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 the overwhelming majority 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.

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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.

[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).

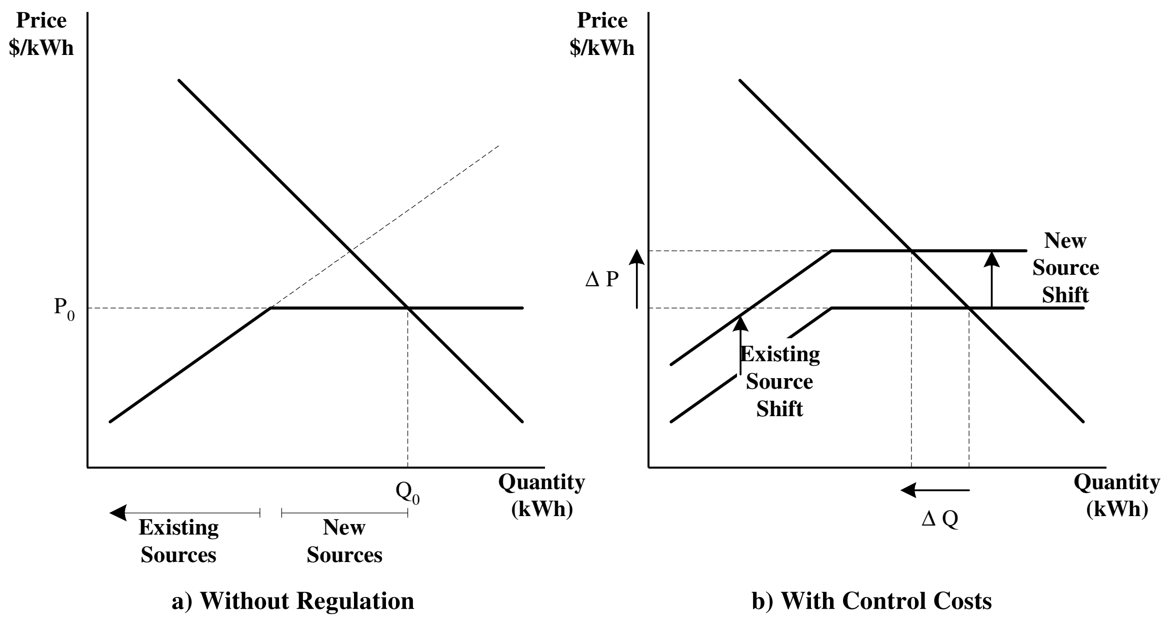


Figure 6-2. Electricity Market

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 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.

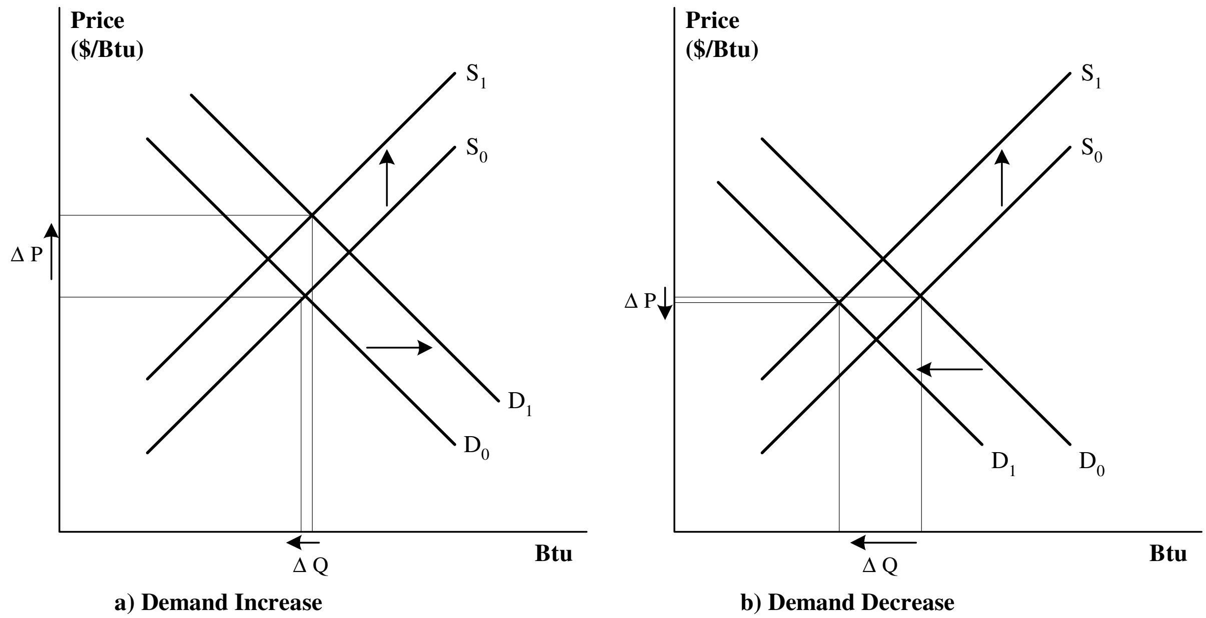


Figure 6-3. Potential Market Effects of the Proposed MACT on Petroleum, Natural Gas, or Coal

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

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.

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 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. 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.

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

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 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,

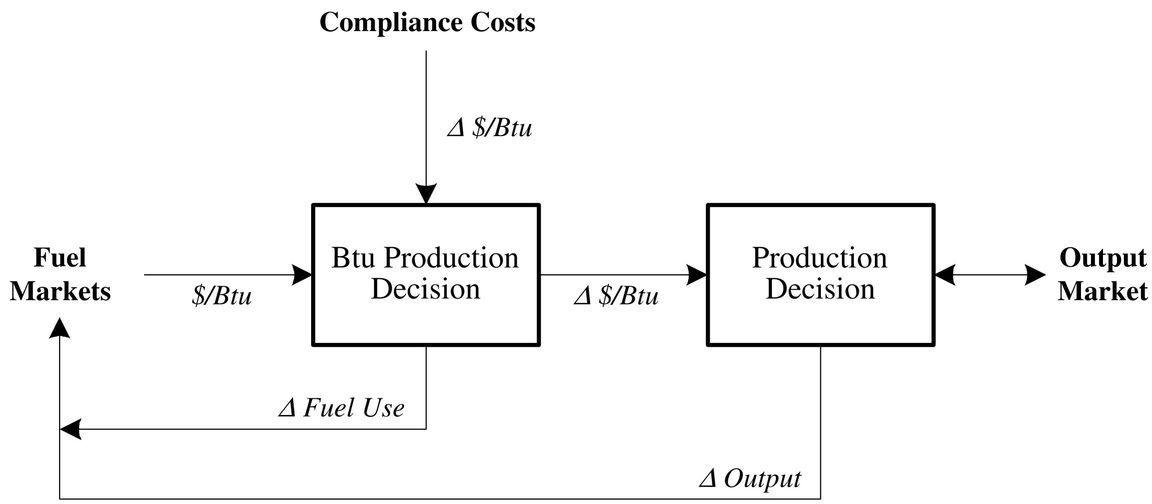


Figure 6-4. Fuel Market Interactions with Facility-Level Production Decisions

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.

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.

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

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.

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.

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

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.

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.

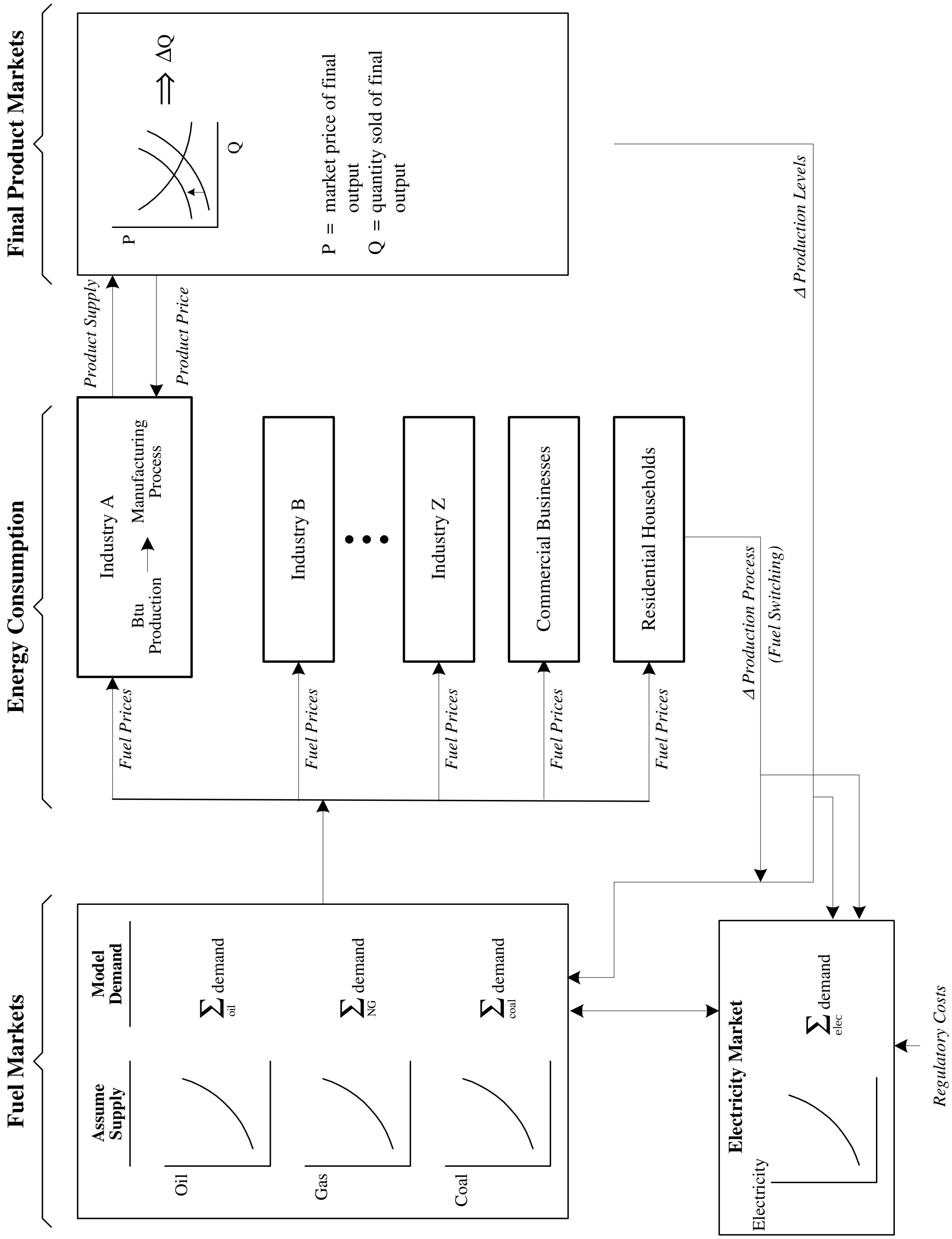


Figure 6-5. Operationalizing the Estimation of Economic Impact

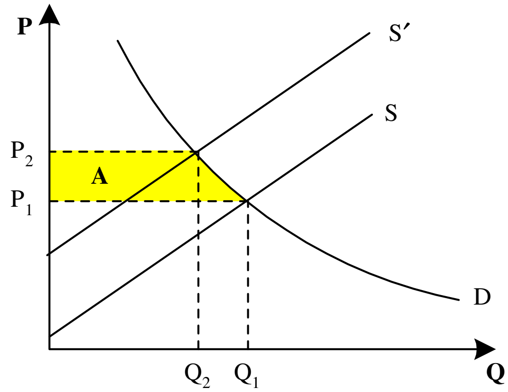
This model comprises a series of computer spreadsheet modules. The modules integrate the engineering inputs and the market-level adjustment parameters to estimate the regulation's impact on the price and quantity in each market being analyzed. At the heart of the model is a market-clearing algorithm 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

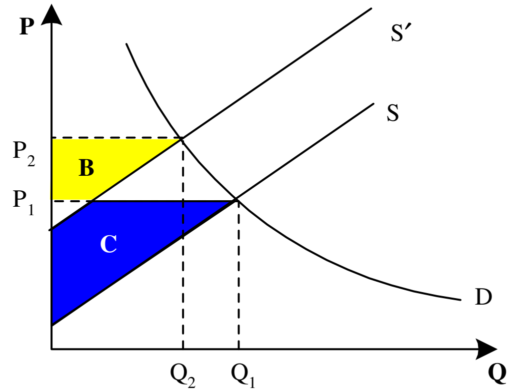
The combustion turbine regulation will impact almost every sector of the economy either directly through control costs or indirectly through changes in the price of energy and final products. For example, a share of control costs that originate in the energy markets are passed through the final product 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.

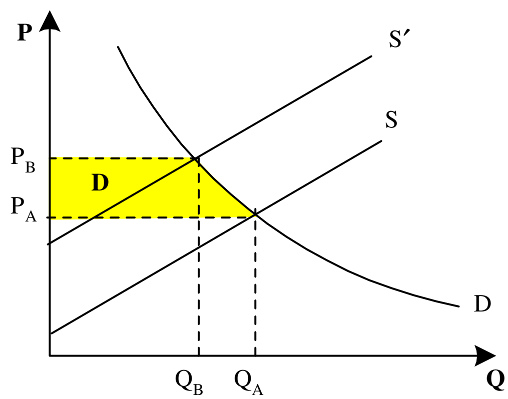
Figure 6-6 illustrates the change in producer and consumer surplus in the intermediate energy market and the final product markets. For example, assume a simple world with only one energy market, wholesale electricity, and one final product market, pulp and paper. If the regulation increased the cost 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.



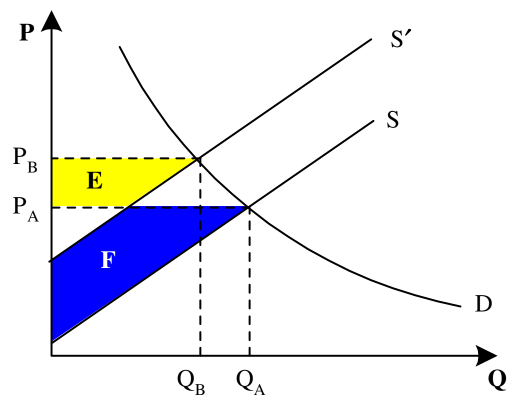
(a) Change in Consumer Surplus in the Energy Market



(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 proposed 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 proposed 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. Sources meeting the formaldehyde emission limit of 43 parts per billion (ppb) will have no capital costs. As described in Section 4, EPA estimates that only a percentage of new sources (6.5 percent) and 6 percent of existing sources will not be able to meet the formaldehyde limit without an add-on control device and will therefore install oxidation catalyst control. For new sources, this is equivalent to two stationary combustion turbines per year or ten stationary combustion turbines in the fifth year. For existing sources, this represents an additional ten stationary combustion turbines. These sources will also be required to use a CO continuous emission monitoring system (CEMS) to monitor the catalyst reduction efficiency.

EPA estimates the annualized capital costs of these add-on controls for ten stationary combustion turbines (170 MW) are $19.4 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. All new sources will be required to conduct an initial performance test to demonstrate compliance. In addition, EPA estimates that every year an additional small percentage of existing major lean pre-mix (LPC) turbines and new sources may

[1] All costs are reported in 1998 dollars.

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

	Cost per Turbine	Number of Affected Turbines	Total Cost
Capital Costs			
CEMS	$164,500	20	$3,290,000
Oxidation catalyst	$3,255,377	20	$65,107,540
Total Capital Cost			**$68,397,540**
Annual Costs			
CEMS	$32,896	20	$657,920
Oxidation catalyst	$969,499	20	$19,389,980
Performance tests	$20,585	59	$1,214,515
Monitoring, recordkeeping, reporting			$267,543
Total Annual Cost (1998$)			**$21,529,958**

have to conduct a performance test to demonstrate compliance to the appropriate enforcement agency. The cost for performance testing for 59 turbines is estimated to be $1.2 million. The annual costs due to the monitoring, recordkeeping, and reporting requirements of the regulation are estimated to be $267,500. Therefore, the total annual cost in the fifth year is estimated to be $21.5 million (1998$). 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.

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 3.6 percent for peak power). The supply shifters for the remaining segments are all less than 0.2 percent.

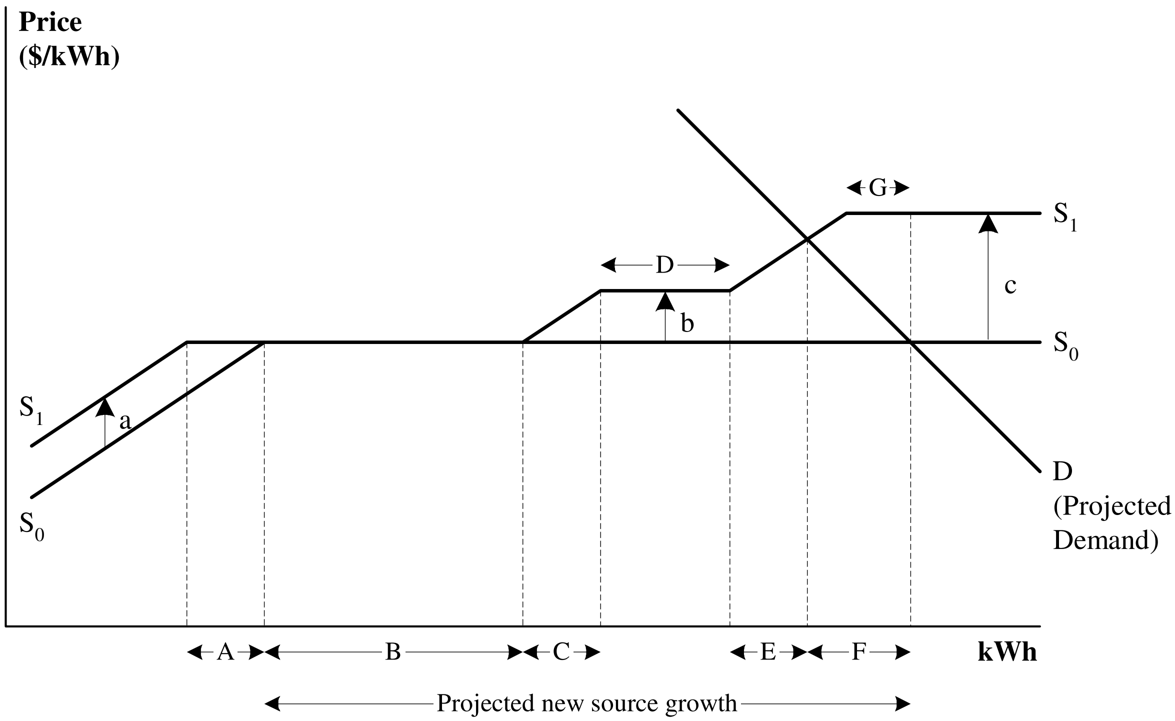
Table 7-2. Summary of Turbine Cost Information and Supply Shifts

	Share Units of Market (%)	Revenue[a] ($$10^9$)	Control Costs[a] ($$10^6$)	Supply Shift (%)
Base Load Energy				
Existing—unaffected	83.46	148.6	0.00	0.00
Existing—testing only	0.13	0.2	0.10	0.05
Existing—testing and capital	0.21	0.4	6.88	1.84
New unaffected	15.30	27.2	0.00	0.00
New affected—testing only	0.69	1.2	0.56	0.05
New affected—testing and capital	0.21	0.4	6.88	1.84
Total	100.00	177.6	14.43	0.01
Peak Power				
Existing—unaffected	83.46	37.1	0.00	0.00
Existing—testing only	0.13	0.1	0.05	0.09
Existing—testing and capital	0.21	0.1	3.39	3.63
New unaffected	15.30	6.8	0.00	0.00
New affected—testing only	0.69	0.3	0.27	0.09
New affected—testing and capital	0.21	0.1	3.39	3.63
Total	100.00	44.4	7.10	0.02
Total		222.1	21.53	

[a]Revenues and costs are in 1998$.

[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.

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.



A = Decrease in supply from affected existing units
A + B = New unaffected unit supply
C + E = Increase in supply from unaffected existing units
D = New testing 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 affected existing units
b = Supply shift for new testing only units
c = Supply shift for new testing and capital equipment units

Figure 7-1. Market for Base Load Electricity

The model projects the MACT standard will increase base load electricity price by 0.128 percent and peak power prices by 0.170 percent (see Table 7-3). Domestic production declines by 0.129 and 0.158 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 0.2 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.

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 all small (i.e., less than 0.01 percent).

7.2 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 $21.5 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

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

		Percent Change	
Energy Markets		**Price**	**Quantity***
Petroleum		0.005	0.002
Natural Gas		0.012	0.004
Base Electricity		0.128	–0.129
Peak Electricity		0.170	–0.158
Coal		–0.059	–0.059
Industrial Sectors		**Percent Change**	
NAICS Description	**Description**	**Price**	**Quantity**
311	Food	0.000	0.000
312	Beverage and Tobacco Products	0.000	0.000
313	Textile Mills	0.000	–0.001
314	Textile Product Mills	0.000	0.000
315	Apparel	0.000	0.000
316	Leather and Allied Products	0.000	0.000
321	Wood Products	0.000	0.000
322	Paper	0.000	–0.001
323	Printing and Related Support	0.000	0.000
325	Chemicals	0.001	–0.001
326	Plastics and Rubber Products	0.000	–0.001
327	Nonmetallic Mineral Products	0.001	–0.001
331	Primary Metals	0.001	–0.001
332	Fabricated Metal Products	0.001	0.000
333	Machinery	0.000	0.000
334	Computer and Electronic Products	0.000	0.000
335	Electrical Equipment, Appliances, and Components	0.000	0.000
336	Transportation Equipment	0.000	0.000
337	Furniture and Related Products	0.000	0.000
339	Miscellaneous	0.000	0.000
11	Agricultural Sector	0.001	–0.001
23	Construction Sector	0.003	–0.003
21	Other Mining Sector	0.001	0.000
Commercial Sector		0.000	0.000

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

	Baseline Shares (%)	With Regulation Shares (%)
Existing—unaffected	83.46	83.65
Existing—testing only	0.13	0.13
Existing—testing and capital	0.21	0.21
New unaffected	15.30	15.32
New affected—testing only	0.69	0.69
New affected—testing and capital	0.21	0.00

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 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 $13.3 million. The economic impact estimate is 62 percent of the estimated engineering costs as a result of behavioral changes of producers and consumers. The major behavioral change is that units with add-on capital controls are crowded out of the new source market; hence these costs are not incurred by society. The $13.3 million in 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 $208 million, as a result of higher energy prices. In contrast, producer surplus increases by $194 million as energy producers, particularly the electricity industry, become more profitable with higher prices.

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)		$13.18	NA	NA
Natural Gas (NAICS 21111, 4862, 2212)		$10.62	NA	NA
Electricity (NAICS 22111, 221122, 221121)		$302.26	NA	NA
Coal (NAICS 2121)		–$18.59	NA	NA
Subtotal:		$307.46	NA	NA
Industrial Sector		**Change in:**		
NAICS	**Description**	**Producer Surplus**	**Consumer Surplus**	**Social Welfare**
311	Food	–$1.6	–$1.2	–$2.7
312	Beverage and Tobacco Products	–$0.2	–$0.1	–$0.3
313	Textiles Mills	–$0.8	–$0.4	–$1.2
314	Textile Product Mills	–$0.1	–$0.1	–$0.2
315	Apparel	–$0.1	–$0.1	–$0.2
316	Leather and Allied Products	–$0.0	$0.0	–$0.0
321	Wood Products	–$0.5	–$0.4	–$0.9
322	Paper	–$2.1	–$1.0	–$3.1
323	Printing and Related Support	–$0.4	–$0.2	–$0.6
325	Chemicals	–$5.5	–$2.3	–$7.8
326	Plastics and Rubber Products	–$1.5	–$0.6	–$2.1
327	Nonmetallic Mineral Products	–$1.0	–$0.7	–$1.7
331	Primary Metals	–$3.7	–$2.8	–$6.4
332	Fabricated Metal Products	–$0.4	–$1.7	–$2.1
333	Machinery	–$0.5	–$0.7	–$1.1
334	Computer and Electronic Products	–$0.4	–$1.1	–$1.6
335	Electrical Equipment, Appliances, and Components	–$0.3	–$0.4	–$0.6
336	Transportation Equipment	–$0.9	–$1.4	–$2.3
337	Furniture and Related Products	–$0.2	–$0.1	–$0.4
339	Miscellaneous	–$0.2	–$0.3	–$0.5
11	Agricultural Sector	–$3.1	–$1.3	–$4.3
23	Construction Sector	–$31.8	–$23.9	–$55.7
21	Other Mining Sector	–$0.2	–$0.4	–$0.6
Industrial Sector Subtotal:		–$55.5	–$41.0	–$96.5
Commercial Sector		–$57.7	–$43.3	–$101.0
Residential Sector		NA	–$109.8	–$109.8
Transportation Sector		NA	–$13.5	–$13.5
Subtotal		–$113.2	–$207.6	–$320.8
Grand Total		$194.3	–$207.6	–$13.3

7.3 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."

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 proposed 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 4.9 billion kWh and a delay of new installed capacity of 1,700 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 proposed 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 475 barrels per day. Similarly, natural gas production/consumption is projected to increase by 3.0 million cubic feet per day. The model also projects decreases in coal production/consumption of approximately 700,000 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 proposed 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 715 new combustion turbines in the electric services industry and 43 new combustion turbines in all remaining sectors of the economy will be affected by the regulation. In addition, approximately 8,000 existing combustion turbines in the electric services industry and 16 existing combustion turbines in all remaining sectors of the economy will be affected by the regulation. 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 10 existing and two 170 MW 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.

[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]	$25,119	
	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	0.11	
Median	0.07	
Maximum	0.46	
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 proposed 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 proposed 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 proposed 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 proposed 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

[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).

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

Although this proposed 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 proposed rule. This provision should reduce the level of small entity impacts. EPA continues to be interested in the potential impacts of the proposed 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 proposed 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

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

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) :

$$P_{1i} \geq \left[P_{0i} + c_i + \sum_{i=1}^{n} \alpha_i \Delta p_i\right] \tag{A.2}$$

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:

$$Q_{Di} = \sum_{j=1}^{n} q_{Dij} , \tag{A.3}$$

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

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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.

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:

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:

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

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

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:

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

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:

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

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

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

[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	198.1	194.3	191.0
Change in consumer surplus	–211.5	–207.6	–204.1
Change in social welfare	–13.4	–13.3	–13.1

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	–213.2	194.3	178.5
Change in consumer surplus	–226.8	–207.6	–191.6
Change in social welfare	–13.6	–13.3	–13.1

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	194.4	194.3	194.1
Change in consumer surplus	207.7	–207.6	–207.4
Change in social welfare	–13.3	–13.3	–13.3

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	194.3	194.2
Change in consumer surplus	–207.6	–208.6
Change in social welfare	–13.3	–14.3