Economic Analysis of the Internal Combustion Engines MACT Standard

Final Report

Prepared for

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Office of Air Quality Planning and Standards
Innovative Strategies and Economics Group (ISEG)
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EPA Contract Number 68-D-99-024
RTI Project Number 7647-001-013

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This report contains portions of the economic impact analysis report that are related to the industry profile.

SECTION 2

RICE TECHNOLOGIES AND UNIT PROFILE

EPA identified 2,645 existing engines at 834 facilities (potentially affected by this rule), mostly in either the oil and gas extraction industry or the natural gas transmission industry. This includes all of the identified engines in the database greater than 500 hp. The data for these units, which were used to generate the effects of the proposed regulation on the affected RICE population, were developed from the EPA Inventory Database V.4—Internal Combustion (IC) Engines (referred to as the Inventory Database). The list of engines in this database was itself developed from information in the Aerometric Information Retrieval System (AIRS) and Ozone Transport Assessment Group (OTAG) databases and state and local permit records. As part of the Industrial Combustion Coordinated Rulemaking (ICCR) Federal Advisory Committee Act (FACA) process, industry and environmental stakeholders reviewed the engines units in the EPA Inventory Database. Because the only existing RICE affected by the rules are 4SRB, most of the engines in the database would not have any control costs. Only 889 of the engines in the database are expected to incur any control costs. In addition, stakeholders contributed to the Inventory Database by identifying and including omitted units. This section provides background information on RICE technologies, the units and facilities in the Inventory Database, and engines population estimates. Included is a discussion of pollutants associated with these units and the cost of installing control technologies.

2.1 Engines Technologies

The IC engines affected by the regulation are of three design categories as discussed in Section 1: 2SLB, 4SLB, and 4SRB. In an IC engine, a mixture of air and fuel is burned in engine cylinders. A series of pistons and a crankshaft convert the energy of the expanding gases into mechanical work. Apart from the number of strokes, two or four, engines are differentiated by their air-to-fuel (A/F) ratio. As defined by the Gas Research Institute (2000), the relative proportions of air and fuel are expressed as the mass of air to that of fuel and is called the A/F ratio. The A/F ratio is called “stoichiometric” if the mixture contains the minimum amount of air that supplies sufficient oxygen to complete combustion of the fuel.

Rich burn engines operate near the fuel-air stoichiometric limit with excess oxygen levels less than 4 percent. Lean burn engines operate with significantly higher excess oxygen levels (GRI, 2000). The majority of the information contained in this section is from the Gas Research Institute's publication, "Engine Design, Operation, and Control in the Natural Gas Industry" (2000).

2.1.1 Two-Stroke Engines

A two-stroke engine completes the power cycle in one revolution of the crankshaft. The crankshaft in an IC engine is attached to the pistons. When the pistons move up and down, the crankshaft turns and converts the reciprocating motion of the pistons into rotary motion. The first stroke begins with the piston at the top of the cylinder. At this time, the engine's combustion chamber contains a compressed mixture of fuel and air. The mixture is ignited by a spark that causes a sudden increase in temperature and pressure that forces the piston downward, transferring power to the crankshaft. As the piston travels downward, air and exhaust ports are uncovered, allowing combustion gases to exit and fresh air to enter. During the second stroke, the air and exhaust ports close and fuel is injected into the cylinder. As the piston returns to its starting position, the upward motion compresses the fuel and air mixture. When the piston reaches the top of the cylinder, the compressed fuel and air mixture is ignited again and the cycle begins again.

Because fresh air is used to clear combustion gases from the cylinder, two-stroke engines operate with an A/F ratio greater than stoichiometric and are, therefore, all of the "lean-burn" design type. A/F ratios for 2SLB engines range between 20:1 and 60:1. Their exhaust temperatures are normally between 550 and 800°F. All 2SLB engines are direct-injected (i.e., fuel is injected directly into the cylinder) (GRI, 2000).

2.1.2 Four-Stroke Engines

A four-stroke engine completes the power cycle in two revolutions of the crankshaft. The first stroke is the intake stroke during which the intake valve opens and the exhaust valve closes. The downward motion of the piston draws air (direct injected) or a mixture of air and fuel (premixed) into the cylinder. During the second stroke, the intake valve closes, and the fuel is injected (direct injected) into the cylinder as the piston moves upward to compress the air and fuel mixture. As the piston finishes its upward stroke, a spark ignites the mixture, causing a sudden increase in temperature and pressure. The increased pressure drives the piston downward (i.e., the third stroke), delivering power to the crankshaft. During the fourth stroke, the exhaust valve opens and the piston moves upwards to force the exhaust gases out of the cylinder. The regulation will affect two types of spark ignition, four-stroke engines: 4SLB and 4SRB.

Four-Stroke Lean Burn. Compared to the 2SLB engine, the 4SLB engine reduces the presence of high fuel concentration and temperature gradients in the cylinder by mixing the air and fuel during the second stroke. Compared to a 4SRB engine, the increased A/F ratio in 4SLB engines reduces combustion and exhaust temperatures. A/F ratios for this engine configuration are similar to those of 2SLB engines.

Four-Stroke Rich Burn. 4SRB engines have A/F ratios near stoichiometric, meaning that in these engines the proportion of fuel relative to air is greater than in lean-burn engines. All turbo-charged engines that do not introduce fresh air to sweep combustion gases out of the cylinder after ignition are 4SRB engines (GRI, 2000). A/F ratios for these engines typically range between 16:1 and 20:1. Exhaust temperature is higher in rich-burn engines than in lean-burn engines.

2.1.3 Compression Ignition Units

CI units almost always operate as lean burn engines. They can be configured as either 2SLB or 4SLB; the distinction is that CI engines are fueled by distillate fuel oil (diesel oil), not by natural gas. Fuel consumption is an important determinant in the type of emissions from these units; combustion of natural gas and combustion of diesel oil may each have separate types and proportions of emissions. Because of this difference in fuel consumption, the type of control equipment, and thus cost, varies from natural gas-fueled units, even if those using diesel are of the same engine configuration and horsepower (hp).

2.2 Emissions

The proposed regulation aims to reduce HAP emissions. HAPs of concern include formaldehyde, acetaldehyde, acrolein, and methanol. Without the regulation, annual HAP emissions are estimated to be 49,967 tons each year by 2005. The proposed regulation will decrease emissions to 36,185 tons, for a total reduction of 13,782 tons (Ali, 2000). Table 2-1 contains the HAP emissions factors for each engine configuration in pounds per hour. Emissions are greatest for 2SLB engines, which, on average, emit 1.08 lbs. per hour of HAPs, and least for CI engines, which emit 0.03 lbs. per hour.

Table 2-1. HAP Emissions Factors by Engine Configuration (lbs/hour)[a]

Engine Configuration	Emissions Factor (lbs/hour)
2SLB	1.0791
4SLB	1.0108
4SRB	0.0707
CI	0.0344

[a] The HAP emissions factors presented are the sum of the factors for formaldehyde, acetaldehyde, acrolein, and methanol.

2.3 Control Costs

The primary method identified by EPA for controlling emissions from 2SLB, 4SLB, and CI engines is the use of oxidation catalyst systems. However, few existing 2SLB, 4SLB, and CI engines currently use these systems to control their emissions. Less than 1 percent of 2SLB and CI engines are controlled, and only about 3 percent of 4SLB engines are controlled. All of these numbers are well below the 12 percent criteria for a MACT floor in each subcategory, so the MACT floor in these categories was considered to be no control. An above-the-floor MACT option of requiring oxidation catalyst systems was considered for these subcategories of engines, but it was determined that the incremental cost of this alternative would be excessive (EPA, 2000).

Unlike the situation for the other engine configurations, more than 12 percent of existing 4SRB stationary RICE control emissions. The method used to control emissions from 4SRB engines is known as nonselective catalytic reduction (NSCR). Because more than 12 percent of existing engines in this category are controlled, the MACT floor for existing 4SRB engines is considered to be the level of HAP emissions reduction achieved by using NSCR systems. Although less than 12 percent of existing 2SLB, 4SLB, and CI engines are controlled with oxidation catalyst systems, there are a few stationary RICE operating with these systems in each of these subcategories. Therefore, the MACT floor for new sources in these subcategories is defined as the level of HAP emissions control achieved using oxidation catalyst systems. For new 4SRB engines, the MACT floor is the same as for existing engines.

The required control for new 4SRB engines is the level of HAP emissions reduction achieved using NSCR systems (EPA, 2000).

Each unit in the Inventory Database was grouped into one of 12 categories, or model types, based on its engine configuration, horsepower, and fuel type. For each of those model types, the annualized cost of installing pollution control equipment to achieve the floor level of control and the associated administrative, operating, monitoring, and maintenance costs for that equipment were estimated. This allowed annual cost estimates to be available for each unit in the Inventory Database. Once the unit-level cost elements were available, they were summed using ownership information to determine costs at the facility- and parent firm-levels.

The annual cost of control and monitoring for these units ranges between $20,000 and $254,000. Table 2-2 lists the model types, characteristics, and costs[1] for the 12 unit categories as well as the number of units from the Inventory Database that fall into those categories.[2] Affected engines that have capacities between 500 and 1,000 hp generally have costs less than $30,000 per year. Affected engines that have capacities between 1,000 and 5,000 hp have control and monitoring costs between $65,000 and $90,000 per year. Affected engines with capacities greater than 5,000 hp have annual control and monitoring costs greater than $200,000 per year. Based on the proportion of each model number included in the Inventory Database, the mean cost expected per affected new engine is $57,288 and the median is $65,959.[3]

2.4 Profile of RICE Units and Facilities in Inventory Database

2.4.1 Unit Characterization

Engines in the Inventory Database range in capacity from 500 to 8,000 hp. Despite the presence of units with horsepower capacity of 5,000 or more, the vast majority of units are less than 1,500 hp (see Figure 2-1). About 80 percent of the Inventory units, 2,088

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[1]Costs are calculated based on values in Ali (2000).

[2]Not all existing engines listed will incur these costs. The only existing engines in the database subject to controls are 4SRB engines (models 7, 8, and 9).

[3]However, the Agency expects a different growth pattern than one proportional to the Inventory Database. Expected growth is outlined and cost per engine based on that projection is provided in Section 2.5.

Table 2-2. Total Annual Control Cost, Number of Units, and Unit Characteristics of Engines in the Inventory Database by Model Number

Model Number	Number[a] of Units	Engine Configuration	Fuel Type	Hp Range	Annual Control Cost	Annual Monitoring Cost	Average Total Annual Cost
1	259	2SLB	Natural gas	500 to 1,000	$16,500	$5,959	$22,459
2	500	2SLB	Natural gas	1,000 to 5,000	$66,000	$5,959	$71,959
3	57	2SLB	Natural gas	5,000 to 10,000	$165,000	$58,800	$223,800
4	170	4SLB	Natural gas	500 to 1,000	$15,000	$5,959	$20,959
5	608	4SLB	Natural gas	1,000 to 5,000	$60,000	$5,959	$65,959
6	37	4SLB	Natural gas	5,000 to 10,000	$150,000	$58,800	$208,800
7	650	4SRB	Natural gas	500 to 1,000	$20,250	$6,496	$26,746
8	238	4SRB	Natural gas	1,000 to 5,000	$81,000	$6,496	$87,496
9	1	4SRB	Natural gas	5,000 to 10,000	$202,500	$21,618	$224,118
10	63	CI	Diesel	500 to 1,000	$19,500	$5,959	$25,459
11	60	CI	Diesel	1,000 to 5,000	$78,000	$5,959	$83,959
12	2	CI	Diesel	5,000 to 10,000	$195,000	$58,800	$253,800

[a] These are the number of units of each model type included in the Inventory Database. However, only the 4SRB engines (models 7, 8, and 9) in the database are subject to controls because the MACT floor for existing 2SLB, 4SLB, and CI engines is no control.

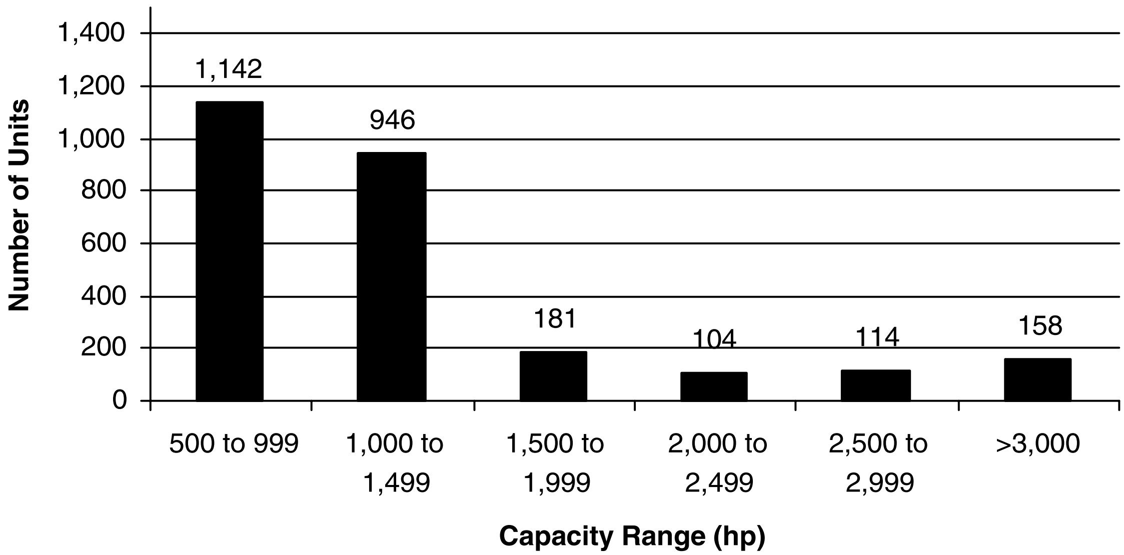

Figure 2-1. Capacity Ranges for Engines in the Inventory Database

engines, have capacities less than 1,500 hp. More than half of those engines have less than 1,000 hp. Only 557 units are greater than 1,500 hp.

About two-thirds of the units in the Inventory Database are described as lean-burn units (see Figure 2-2). All of the rich-burn units are four-stroke; the lean-burn units are split fairly evenly between two-stroke and four-stroke configurations. Also, 95 percent of the units use natural gas for fuel (only about 5 percent are CI units).

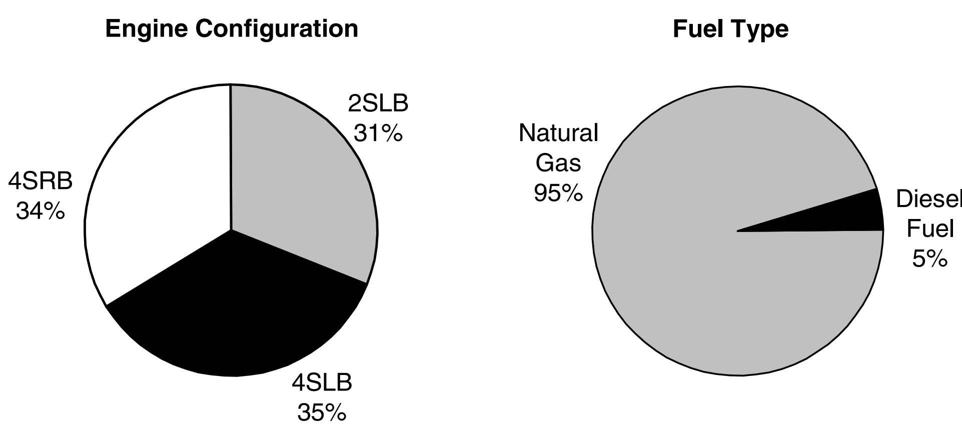

Figure 2-2. Characteristics of Engines in the Inventory Database

2.4.2 Facility Characterization

The 2,645 units identified in the Inventory Database are located at 834 facilities. Table 2-3 presents the distribution of units and facilities by industry grouping. Most of the Inventory Database units are concentrated in two industries: oil and gas extraction and electric and gas services. Table 2-4 provides unit and facility counts by four-digit SIC code for these two industries. According to their four-digit SIC codes, most of the units are located at compression stations on natural gas pipelines or at oil and gas fields and plants. The only other industries with relatively sizable numbers of units at the two-digit SIC code level are the mining and quarrying industry and health services, such as clinics and hospitals.

2.5 Projected Growth of RICE

The Agency estimates that, without the rule, by the end of 2005 the U.S. will have 20,306 new IC engines with horsepower greater than 500. These estimates are based on the expected growth in the number of engines in each of the 12 model categories listed in Table 2-5. Table 2-5 lists several unit counts: units in the Inventory Database, existing affected units, and projected unit growth over 5 years. The latter two categories are also broken out by the total number of units and the number of units that would have been controlled regardless of the rule.

Existing 2SLB engines (model numbers 1, 2, and 3) are not affected by the rule. As new 2SLB units come online, however, they will be required to install the requisite control equipment and operators will have to adhere to monitoring requirements. It is estimated that 500 new 2SLB engines of greater than 500 hp will have come into operation by the end of 2005, none of which are expected to be greater than 1,000 hp.

Existing 4SLB engines (model numbers 4, 5, and 6) are also not affected by this rule. In the absence of this rule, it is expected that 3 percent of new units would come online controlled in the future based on the percentage of units currently controlled (Ali, 2000). Therefore, only the remaining 97 percent (2,060 of 2,124 units) will have control costs associated with the rule. The cost of controlling the additional remaining 3 percent was not included in the rule’s cost because it would have been borne by industry regardless of the rule; the rule will not affect those business decisions. However, all 2,124 new 4SLB engines will incur monitoring costs. It is expected that very few of these units will be greater than 5,000 hp.

Table 2-3. Number of Units and Facilities and Average Number of Units per Facility by Industry in the Inventory Database

SIC	Industry Description	Number of Units	Number of Facilities	Average Number of Units Per Facility
02	Agricultural Services	1	1	1.0
10	Metal Mining	1	1	1.0
13	Oil & Gas Extraction	1,146	311	3.7
14	Mining & Quarrying of Nonmetallic Minerals, Except Fuels	32	27	1.2
16	Heavy Construction	1	1	1.0
20	Food & Kindred Products	15	4	3.8
21	Textile Mill Products	9	1	9.0
26	Pulp & Paper	1	1	1.0
28	Chemicals & Allied Products	16	4	4.0
29	Petroleum Refining & Related Industries	11	7	1.6
30	Rubber & Misc. Plastics	3	2	1.5
32	Stone, Clay, Glass, & Concrete Products	1	1	1.0
33	Primary Metals Industries	3	1	3.0
45	Transportation by Air	1	1	1.0
46	Pipelines, Except Natural Gas	8	4	2.0
49	Electric, Gas, & Sanitary Services	1,311	436	3.0
50	Durable Goods Wholesale Trade	1	1	1.0
55	Automotive Dealers & Gas Stations	4	1	4.0
63	Insurance Carriers	5	3	1.7
65	Real Estate	1	1	1.0
73	Business Services	13	1	13.0
80	Health Services	36	20	1.8
82	Educational Services	1	1	1.0
92	Justice, Public Order, & Safety	4	1	4.0
Unknown		20	2	10.0
Total		2,645	834	3.2

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.

Table 2-4. Units and Facilities in the Oil and Gas Extraction (SIC 13) and Electric, Gas, and Sanitary Services (SIC 49) Industries in the Inventory Database

SIC	Description	Number of Units	Number of Facilities
1311	Crude Petroleum & Natural Gas	543	193
1321	Natural Gas Liquids	601	117
1382	Oil & Gas Field Exploration Services	3	1
1389	Oil & Gas Field Services, N.E.C.	1	1
Subtotal		1,148	312
4911	Electric Services	31	12
4922	Natural Gas Transmission	1,268	416
4924	Natural Gas Distribution	1	1
4941	Water Supply	1	1
4952	Sewerage Systems	2	1
4953	Refuse Systems	2	1
Subtotal		1,305	432
Total		2,453	744

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.

The only existing engines that are affected by the rule are 4SRB engines (model numbers 7, 8, and 9). Those engines that are not already controlled, 3,339 units, will have to install control equipment. All existing 4SRB engines (4,573 units) must comply with the monitoring component of the rule. For new sources, the Agency estimates that 27 percent (1,157 units) would come online controlled without the rule based on the current population of 4SRB engines (Ali, 2000). Thus, control costs for these units are not included in the total cost of the rule. However, all 4,283 units projected to enter into operation by the end of 2005 will incur monitoring costs. Most existing units are less than 1,000 hp, but the majority of new units are expected to be between 1,000 and 5,000 hp.

Table 2-5. Weights and 2005 Total Population Estimates

Model Number	Engine Configuration	Units in Inventory Database	Total Existing Affected Units[a]	Existing Affected Uncontrolled Units	Total 5-year Growth in Affected Units	5-year Growth in Affected Uncontrolled Units[b]	Total Affected Units (2005)	Unit Weights (Total Affected Units/Inventory Database [2005])
1	2SLB	259	0	0	500	500	500	1.931
2	2SLB	500	0	0	0	0	0	—
3	2SLB	57	0	0	0	0	0	—
4	4SLB	170	0	0	2,124	2,060	2,124	12.494
5	4SLB	608	0	0	3,412	3,308	3,412	5.612
6	4SLB	37	0	0	12	10	12	0.324
7	4SRB	650	3,353	2,448	1,858	1,356	5,211	8.017
8	4SRB	238	1,215	887	2,417	1,764	3,632	15.261
9	4SRB	1	5	4	8	6	13	13.000
10	CI	63	0	0	5,985	5,985	5,985	95.000
11	CI	60	0	0	3,990	3,990	3,990	66.500
12	CI	2	0	0	0	0	0	—
Total		2,645	4,573	3,339	20,306	18,979	24,879	

[a] The only existing engines affected by this rule are 4SRB engines, some of which are already controlled in the absence of this rule. Monitoring costs due to the rule apply to all of the 4SRB engines, even those already controlled.

[b] It is assumed that 27 percent of new 4SRB and 3 percent of new 4SLB engines would be controlled in the absence of this regulation. Therefore, the costs of controls for these engines are not included in the total cost of the regulation. However, the monitoring costs incurred by all of these engines due to the rule are included in calculating the total cost.

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.

Similar to 2SLB and 4SLB engines, only new CI engines (model numbers 10, 11, and 12) will be affected by this rule. Existing CI engines do not have to add any controls. None of these engines are projected to be controlled in the absence of regulation. Therefore, all 9,975 units estimated to enter into operation by the end of 2005 will be subject to both control and monitoring costs under the regulation. About 60 percent of these units are expected to be under 1,000 hp; no units are expected to be greater than 5,000 hp.

Although growth estimates by engine configuration and horsepower are available, estimates of the growth in the number of units by industry are not. To assess the distribution of the engines estimated to be operating in 2005 across industries, unit-level weights were attached by model number to each engine in the Inventory Database. These weights, which are listed in Table 2-5, allow each unit in the Inventory Database to represent a number (or fraction) of units that are predicted to be in use by the end of 2005. The weights were then summed by two-digit SIC code to estimate the distribution of 24,879 units by industry.

A principal effect of using this weighting process is that the dominance of the oil and gas extraction and electric and gas services industries was diminished because other industries had units with configurations associated with greater growth projections, and thus weights, which increased their estimated number of future units. The total number of affected units in 2005 by industry is presented in Table 2-6. The third column lists the number of units in the Inventory Database. The fourth column presents the estimated population based on the unit configuration weights. Whereas the units used in either oil and gas extraction (SIC 13) or electric and gas services (SIC 49) account for 93 percent of the units in the Inventory Database, they only account for 68 percent of the estimated population in 2005 using the weights in Table 2-5. The weighting system gave added prominence to industries such as mining and quarrying, real estate, and health services that use mainly CI engines because CI engines are underrepresented in the database relative to the estimated population of these engines.

Based on the unit projections in Table 2-6, the engineering control costs of this regulation would be $1,114.7 million in 2005. These costs are inputs into the market model used in Section 4 to estimate the changes in price and quantity taking place in each affected market as a result of the regulation as well as the social costs of the rule. The magnitude and distribution of the regulatory costs' impact on the economy depend on the relative size of the

Table 2-6. Engineering Costs by SIC Code

SIC	Industry Description	Number of Units in Inventory Database	Estimated 2005 Affected Population	Engineering Costs (1998$)
02	Agricultural Services	1	8	170,587
10	Metal Mining	1	95	2,418,605
13	Oil & Gas Extraction	1,146	7,162	295,406,008
14	Mining & Quarrying of Nonmetallic Minerals, Except Fuels	32	2,483	96,402,266
16	Heavy Construction	1	0	0
20	Food & Kindred Products	15	156	9,402,703
21	Textile Mill Products	9	77	2,555,362
26	Pulp & Paper	1	67	5,583,274
28	Chemicals & Allied Products	16	431	21,692,922
29	Petroleum Refining & Related Industries	11	370	13,455,194
30	Rubber & Misc. Plastics	3	91	6,095,706
32	Stone, Clay, Glass, & Concrete Products	1	95	2,418,605
33	Primary Metals Industries	3	17	1,079,665
45	Transportation by Air	1	8	170,587
46	Pipelines, Except Natural Gas	8	306	8,422,194
49	Electric, Gas, & Sanitary Services	1,311	9,750	471,576,378
50	Durable Goods Wholesale Trade	1	95	2,418,605
55	Automotive Dealers & Gas Stations	4	32	682,349
63	Insurance Carriers	5	216	17,090,995
65	Real Estate	1	95	2,418,605
73	Business Services	13	23	1,174,792
80	Health Services	36	2,906	132,291,790
82	Educational Services	1	67	5,503,274
92	Justice, Public Order, & Safety	4	323	16,003,757
Unknown		20	8	170,587
Total		2,645	24,879	1,114,684,811

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.

impact on individual markets (relative shift of the market supply curves) and the behavioral responses of producers and consumers in each market (as measured by the elasticity of supply and the elasticity of demand).

SECTION 3

PROFILES OF AFFECTED INDUSTRIES

This section contains profiles of the industries most directly affected by the proposed regulation of RICE. Most existing engines that would be subject to the regulation are concentrated in two industries, petroleum and natural gas extraction (SIC 13) and natural gas transmission (SIC 4922). Together, they account for over 90 percent of the engines identified by EPA in the Inventory Database that would fall under this rule. (The remaining units are spread across various industries, most notably mining and quarrying of nonmetallic minerals, health services, and various manufacturing industries, such as food and kindred products and chemicals and allied products.) Most new engines that would be affected by this regulation are also projected to be in these industries.

The oil and natural gas industry is divided into five distinct sectors: (1) exploration, (2) production, (3) transportation, (4) refining, and (5) marketing. The NESHAP considers controls on the use of RICE, which are used in this industry primarily to power compressors used for crude oil and natural gas extraction and natural gas pipeline transportation. Therefore, this section contains background information on the petroleum and natural gas extraction industry and the natural gas transmission industry to help inform the regulatory process.

3.1 Crude Petroleum and Natural Gas (SIC 13)

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.

3.1.1 Introduction

The U.S. is home to half of the major oil and gas companies operating around the globe. Although small firms account for nearly 45 percent of U.S. crude oil and natural gas output, the domestic oil and gas industry is dominated by 20 integrated petroleum and natural gas refiners and producers, such as Exxon Mobil, BP Amoco, and Chevron (Lillis, 1998). Despite the presence of many large global players, the industry experiences a more turbulent business cycle than most other major U.S. industries. Because oil is an international commodity, the U.S. production of crude oil is affected by the world crude oil price, the price of alternative fuels, and existing regulations. Domestic oil production has been falling in recent years. Total U.S. crude oil production is expected to fall to 5.78 million barrels per day in 2000, the lowest annual U.S. crude oil output since 1950 (DOE, EIA, 2000). 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 may be influenced by the Organization of Petroleum Exporting Countries (OPEC).[4]

In contrast, natural gas markets in the U.S. are competitive and relatively stable. Domestic natural gas production has been on an upward trend since the mid-1980s. Almost all natural gas used in the U.S. comes from domestic and Canadian sources.

Within SIC 13, there are five major industry groups (see Table 3-1):

- SIC 1311 (NAICS 211111): Crude petroleum and natural gas. Firms in this industry are primarily involved in the operation of 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.
- SIC 1321 (NAICS 211112): Natural gas liquids (NGL). NGL firms separate NGLs from crude oil and natural gas at the site of production. Propane and butane are examples of NGLs.
- SIC 1381 (NAICS 213111): Drilling oil and gas wells. Firms in this industry drill oil and natural gas wells on a contract or fee basis.
- SIC 1382 (NAICS 213112/54136): Oil and gas field exploration services. Firms in this industry perform geological, geophysical, and other exploration services.
- SIC 1389 (NAICS 213112): 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

[4]OPEC is a cartel consisting of most of the world's largest petroleum-producing countries that attempts to increase the profits of member countries.

Table 3-1. 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.

building foundations and excavating pits, and maintenance.

In 1997, more than 6,800 crude oil and natural gas extraction companies (SIC 1311) generated $75 billion in revenues (see Table 3-2). 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 3-2 shows the NGL extraction industry (SIC 1321) 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 SIC 1381, 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 53,685.

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

Table 3-2. Summary Statistics, Crude Oil and Natural Gas Extraction and Related Industries

SIC	Industry	Number of Companies	Number of Establishments	Revenues ($1997 10^3)	Employees
1311	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
1321	Natural Gas Liquid Extraction				
	1992	108	591	26,979,200	12,000
	1997	89	529	24,828,503	10,549
1381	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
1382/89	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*. Washington, DC: U.S. Department of Commerce.

U.S. Department of Commerce, Bureau of the Census. 1995a. *1992 Census of Mineral Industries, Industry Series*. Washington, DC: U.S. Department of Commerce.

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 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.

3.1.2 Supply Side Characteristics

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.

3.1.2.1 Production Processes

Domestic production occurs within the contiguous 48 U.S., Alaska, and at offshore facilities. There are four major stages in oil and gas extraction: 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 produce a combination of oil and gas; however, some wells produce little natural gas, while others may produce only natural gas. Once the hydrocarbons are brought to the surface, they are separated into a spectrum of products. Natural gas is separated from crude oil by passing the hydrocarbons through one or two decreasing pressure chambers. Crude oil is always delivered to a refinery for processing and excess water is removed, at which point the oil is about 98 percent pure, a purity sufficient for storage or transport to a refinery (EPA, 1999b). Natural gas may be processed at the field or at a natural gas processing plant to remove impurities. The primary extracted streams and recovered products associated with the oil and natural gas industry include crude oil, natural gas, condensate, and produced water. The products are briefly described below.

Crude oil can be classified as paraffinic, naphthenic, or intermediate. Paraffinic (or heavy) crude is used as an input to the manufacture of lube oils and kerosene. Naphthenic (or light) crude is used as an input to the manufacture of gasoline and asphalt. Intermediate crudes are those that do not fit into either category. The classification of crude oil is determined by a gravity measure developed by the American Petroleum Institute (API). API gravity is a weight per unit volume measure of a hydrocarbon liquid. A heavy crude is one with an API gravity of 20° or less, and a light crude, which flows freely at atmospheric temperature, usually has an API gravity in the range of the high 30s to the low 40s (EPA, 1999a).

Natural gas is a mixture of hydrocarbons and varying quantities of nonhydrocarbons that exist either in gaseous phase or in solution with crude oil from underground reservoirs. Natural gas may be classified as either wet or dry gas. Wet gas is unprocessed or partially processed natural gas produced from a reservoir that contains condensable hydrocarbons. Dry gas is natural gas whose water content has been reduced through dehydration, or natural gas that contains little or no commercially recoverable liquid hydrocarbons.

Condensates are hydrocarbons that are in a gaseous state under reservoir conditions (prior to production), but which become liquid during the production process. Condensates have an API gravity in the 50° to 120° range (EPA, 1999a). According to historical data, condensates account for about 4.5 to 5 percent of total crude oil production.

Produced water is recovered from a production well or is separated from the extracted hydrocarbon streams. More than 90 percent of produced water is reinjected into the well for disposal and to enhance production by providing increased pressure during extraction. The remainder is released into surface water or disposed of as waste.

In addition to the products discussed above, other various hydrocarbons may be recovered through the processing of the extracted streams. These hydrocarbons include mixed natural gas liquids, natural gasoline, propane, butane, and liquefied petroleum gas.

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.

3.1.2.2 Types of Output

The oil and gas industry's principal products are crude oil, natural gas, and NGLs (see Tables 3-3 and 3-4). 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, 1999a).

Natural gas is produced from either oil wells (known as "associated gas") or wells that are drilled for the primary objective of obtaining natural gas (known as "nonassociated gas") (see Table 3-4). 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 3-3). 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 natural gas liquids (EPA, 1999b). A small amount of the natural gas produced is consumed as fuel by the engines used in extracting and transporting the gas, and the remainder is transported through pipelines for use by residential, commercial, industrial, and electric utility users.

3.1.2.3 Major By-products

In addition to the various products of the oil and natural gas extraction process described above, there are some additional by-products generated during the extraction process. Oil and natural gas are composed of widely varying constituents and proportions depending on the site of extraction. The removal and separation of individual hydrocarbons

Table 3-3. 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. 1999c. *Petroleum Supply Annual 1998, Volume I.* Washington, DC: U.S. Department of Energy.

Table 3-4. U.S. Natural Gas Production, 1998

Gross Withdrawals	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. 1999b. *Natural Gas Annual 1998*. Washington, DC: U.S. Department of Energy.

during processing is possible because of the differing physical properties of the various components. Each component has a distinctive weight, boiling point, vapor pressure, and other characteristics, making separation relatively simple. Most natural gas is processed to separate hydrocarbon liquids that are more valuable as separate products, such as ethane, propane, butane, isobutane, and natural gasoline. Natural gas may also include water, hydrogen sulfide, carbon dioxide, nitrogen, helium, or other diluents/contaminants. The water present is either recovered from the well or separated from the hydrocarbon streams being extracted. More than 90 percent of the produced water is reinjected into the well to increase pressure during extraction. If hydrogen sulfide, which is poisonous and corrosive, is present, it is removed and further processed to recover elemental sulfur for commercial sale. In addition, processing facilities may remove carbon dioxide to prevent corrosion and to use for injection into the well to increase pressure and enhance oil recovery, recover helium for commercial sale, and may remove nitrogen to increase the heating value of the gas (NGSA et al., 2000c). Finally, 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.

3.1.2.4 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 3-5). During the same period, industry outlays for supplies, such as equipment and other supplies, increased over 32 percent,

Table 3-5. Costs of Production, Crude Oil and Natural Gas Extraction and Related Industries

SIC	Industry	Employees	Payroll ($1997 10^3)	Cost of Supplies Used, Purchased Machinery Installed, Etc. ($1997 10^3)	Capital Expenditures ($1997 10^3)
1311	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
1321	Natural Gas Liquid Extraction				
	1992	12,000	$509,272	$23,382,770	$609,302
	1997	10,549	$541,593	$20,359,528	$678,479
1381	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
1382/89	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*. Washington, DC: U.S. Department of Commerce.

U.S. Department of Commerce, Bureau of the Census. 1995a. *1992 Census of Mineral Industries, Industry Series*. Washington, DC: U.S. Department of Commerce.

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 SIC 1381, Drilling Oil and Gas Wells. In 1992, the industry employed 47,700 people, increasing 13 percent to 53,685 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.

3.1.2.5 Imports and Domestic 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 3-6). 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 U.S. 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.

Table 3-6. 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. 1999d. *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. 1999c. *Petroleum Supply Annual 1998, Volume I.* Washington DC: U.S. Department of Energy.

3.1.3 Demand Side Characteristics

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 influenced by OPEC, slight increases in the cost of producing crude oil in the U.S. will have little effect on the prices of products that use crude oil as an intermediate good. Production cost increases are likely to be absorbed mainly by the producer, with little of the increased cost passed along to consumers.

Natural gas is a colorless, flammable gaseous hydrocarbon consisting for the most part of methane and ethane. Natural gas is used by residential, commercial, industrial, and electric utility users. Total consumption of natural gas in the U.S. was 21,262 billion cubic feet in 1998. Industrial consumers accounted for the largest share of this total, consuming 8,686 billion cubic feet, while residential, commercial, and electric utility consumption was 4,520 billion cubic feet, 3,005 billion cubic feet, and 3,258 billion cubic feet, respectively. The remainder of U.S. consumption was by natural gas producers in their plants and on their gas pipelines. The largest single application for natural gas is as a domestic or industrial fuel. Natural gas is also becoming increasingly important for generating electricity. Although these are the primary uses, 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).

The primary substitutes for oil and natural gas are coal, electricity, and each other. Consumers of these energy products are expected to respond to changes in the relative prices between these four energy markets by changing the proportions of these fuels they consume. For example, if the price of natural gas were to increase relative to other fuels, then it is likely that consumers would substitute oil, coal, and electricity for natural gas. This effect of changing prices is commonly referred to as fuel-switching. The extent to which consumers change their fuel usage depends on such factors as the availability of alternative fuels and the capital requirements involved. If they own equipment that can run on multiple fuels, then it may be relatively easy to switch fuel usage as prices change. However, if existing capital cannot easily be modified to run on an alternative fuel, then it is less likely for a consumer to change fuels in the short run. If the relative price of the fuel currently in use remains elevated in the long run, some additional consumers will switch fuels as they replace existing capital with new capital capable of using relatively cheaper fuels. For example, if the price of natural gas were to increase greatly relative to the price of electricity for residential consumers, most consumers are unlikely to replace their natural gas furnaces immediately due to the high cost of doing so. However, new construction would be less likely to include natural gas furnaces, and if the price of natural gas were to remain relatively high compared with electricity in the long run, residential consumers would be more likely to replace their natural gas furnaces with electric heat pumps as their existing furnaces wear out.

3.1.4 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 U.S. 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 3-7 through 3-10 present the number of facilities and value of shipments by facility employee count for each of the four SIC 13 industries. In 1997, 6,802 oil and gas extraction companies operated 7,781 facilities, an average of 1.14 facilities per company (see Table 3-7). 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 3-8). 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 produce

Table 3-7. Size of Establishments and Value of Shipments, Crude Oil and Natural Gas Extraction Industry (SIC 1311), 1997 and 1992

	1997		1992	
Average Number of Employees in Facility	Number of Facilities	Value of Shipments (\$1997 10^3)	Number of Facilities	Value of Shipments (\$1997 10^3)
0 to 4 employees	5,249	$5,810,925	6184	$5,378,330
5 to 9 employees	1,161	$3,924,929	1402	$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.

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.

As mentioned earlier, the oil and gas well drilling industry's 1997 value of shipments

Table 3-8. Size of Establishments and Value of Shipments, Natural Gas Liquids Industry (SIC 1321), 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.

were 106 percent larger than 1992's value of shipments. However, the number of companies primarily involved in this industry declined by 327 over 5 years, and 487 facilities closed during the same period (see Table 3-9). 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.

In 1997, 6,385 companies operated 7,068 oil and gas field services facilities, an

Table 3-9. Size of Establishments and Value of Shipments, Drilling Oil and Gas Wells Industry, 1997 and 1992

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

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

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

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

average of 1.1 facilities per company. The Inventory Database includes 1,599 facilities in SIC 13. 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 3-10).

3.1.5 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

Table 3-10. Size of Establishments and Value of Shipments, Oil and Gas Field Services (SIC 1382/89), 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.

consumption came mostly at the expense of coal consumption (EPA, 1999b). The Energy Information Administration (EIA) anticipates that natural gas consumption will continue to grow at a similar rate through the year 2020 to 32 trillion cubic feet/year. Prices are expected to grow steadily, increasing overall by about 0.6 percent annually (DOE, EIA, 1999a). They also expect crude oil consumption to grow at an annual rate of less than 1 percent over the same period (DOE, EIA, 1999a). For ease of comparison, the quantities used for all energy markets modeled for this EIA are defined in terms of quadrillions of Btus and prices are defined as dollars per million Btus. In 2005, the year used for this analysis, the EIA (2000a) projects 24.57 quadrillion Btus of natural gas will be consumed at an average price of $4.23/million Btus, and 41.21 quadrillion Btus of petroleum products will be consumed at an average price of $8.22/million Btus.

3.2 Natural Gas Pipeline Industry

The natural gas pipeline industry (SIC 4922/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.

3.2.1 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 (U.S. Department of Transportation, 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 3-11). The Inventory Database contains 1,401 facilities in SIC 4922, so the majority of pipeline companies are included. The industry's annual payroll is nearly $1.9 billion.

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

Table 3-11. 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.

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.

3.2.2 Supply Side Characteristics

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

3.2.2.1 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 internal 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 horsepower (NGSA et al., 2000a). Nearly 5,000 engines have individual output capabilities from 500 to over 8,000 horsepower. 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.

3.2.2.2 Major By-products

There are no major by-products of the natural gas pipeline industry itself. However, 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.

3.2.2.3 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. Because there are compression stations about every 50 to 100 miles along gas pipelines, the addition of 15,000 miles of pipeline implies that 150 to 300 compression stations were added. There are varying numbers of engines at different stations, but the average is three engines per compression station in the Inventory Database. Thus, approximately 450 to 900 new engines were added along pipelines over the period 1996 through 2000. Table 3-12 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.

Table 3-12. 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. 1999a. *Natural Gas 1998: Issues and Trends*. Washington, DC: U.S. Department of Energy.

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. Thus, firms spent approximately $1.28 billion in 1998 for the fueling of RICE used on pipelines. 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 3-13). For companies that transmit natural gas through their own pipelines the cost of the natural gas consumed is considered a business expense.

Table 3-13. 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. 1999b. *Natural Gas Annual 1998*. Washington, DC: US Department of Energy.

3.2.2.4 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 3-14). By the end of 1997, capacity reached 85,847 Mmcf/day, an increase of approximately 16 percent. The system's usage, however, 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.

3.2.2.5 Imports

Approximately 17 percent of the U.S. natural gas supply is imported, primarily from Canadian fields. In many economic analyses, the imported supply is treated separately from the domestic supply because of the difference in the impact of domestic regulation. However,

Table 3-14. 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. 1999a. *Natural Gas 1998: Issues and Trends*. Washington, DC: US Department of Energy.

it is assumed that the imported gas will still be subject to control costs when it is transported through pipelines in the U.S. Thus, the imported supply is not differentiated because the regulation will affect it in a similar manner to domestically supplied gas since they use the same distribution method.

3.2.3 Demand Side Characteristics

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 U.S. 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).

3.2.4 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, 1999a). Ranked by system mileage, the largest pipeline companies in the U.S. are El Paso Energy (which recently merged with Southern Natural Gas Co.), Enron, Williams Cos., Coastal Corp., and Duke Energy (see Table 3-15). El Paso Energy and Coastal intend to merge in mid-2000.

3.2.5 Markets and Trends

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

The EIA (1999a), a unit of the Department of Energy, 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 (1999a) 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.

Table 3-15. 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	$10,581	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. 1998. *Ward's Business Directory of U.S. Private and Public Companies 1998, Volume 5*. Detroit, MI: Gale Research Inc.

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