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Stationary Internal Combustion Engines in the United States

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Abstract

A survey of stationary reciprocating engines in the U.S. was conducted to compile the following information: (1) types and applications of engines, (2) typical pollutant emissions factors for diesel, dual fuel, and natural gas engines, (3) differences between engines that cause emissions to vary, (4) total horsepower and emissions from engines, (5) pollution potential of stationary engines in densely populated regions, and (6) potential emissions control techniques. Where appropriate, gas turbines were included in the survey.

In 1971, an estimated 34.8 million horsepower of reciprocating engines and 35.5 million horsepower of gas turbines were operating in the U.S. The principal functions of engines are oil and gas pipelines (35%), agriculture (22%), and electric power generation (16%). Total NOx emissions from engines are 2.2 million tons annually, of which 42 percent are generated by pipeline engines. Carbon monoxide and hydrocarbon emissions are an order of magnitude lower. Emissions control techniques having potential as short to intermediate term solutions include precombustion chambers for diesel engines and water injection and valve timing modifications for gas and diesel engines. Over the longer term, catalytic reduction of NOx appears to have the greatest potential.

Table of Contents

Page

Stationary Internal Combustion Engines in the United States

I. Introduction

Stationary internal combustion engines are used by virtually every segment of U.S. industry. Gas turbines and reciprocating engines drive electric power generators, pipeline compressors and pumps, municipal water and sewage pumps, and various types of industrial equipment.

At the present time, emission regulations do not exist for stationary engines either at the state or federal level. The logical first step in the development of rational and effective regulations is to investigate the contribution of stationary engines to atmospheric pollution. This report describes the results of a brief survey of stationary engines in the U.S. with the purpose of providing some of this needed information.

1. Objectives and Scope

The general objective of the survey was to estimate the contribution of stationary reciprocating engines to atmospheric pollution in the U.S. More specifically, the following information has been sought:

a. Types and applications of engines.

b. Typical mass emissions factors for diesel, dual fuel, and gas engines.

c. Importance of other pollutants besides nitrogen oxides.

d. Differences between engines that cause emissions to differ.

e. Installed horsepower, power generation, fuel consumption, and emissions from stationary engines and gas turbines.

f. Pollution potential of large installations of engines in densely populated regions, e.g., gas pipeline compressor stations.

g. Potential emissions control techniques.

h. Independent check of previous estimate of NOx emissions from engines by ESSO Research and Engineering Company.

Although the survey was oriented towards reciprocating engines, data for other power sources, particularly gas turbines, are included in the discussion wherever appropriate.

2. Survey of Stationary Engine Manufacturers

The figures and data discussed in this report are based on both published documents and a survey of engine manufacturers conducted by questionnaire. Sample copies of the survey questionnaire and accompanying letter are contained in the Appendix to this report. The questionnaire asks for engine population and emissions data for each manufacturer's line of stationary engines. The intention was to use these data to generate detailed information on the total installed horsepower in the U.S., and the distribution of horsepower by type, size, and geographical location. Unfortunately, only a few of the questionnaires that were returned contained the data needed to perform this kind of analysis. Consequently it was necessary to rely on other data sources. However, much of the data used to derive emissions factors in this report were taken directly from the questionnaire responses. In addition, engine design data for early engine models no longer in production were provided by some manufacturers. The completed survey questionnaires are contained in the confidential supplement to this report.

Supplemental data sources included statistical publications of the Federal Power Commission, American Gas Association, and American Petroleum Institute and various trade journals including Power, World Oil, and The Oil and Gas Journal.

3. Organization of the Survey Report

Following the Introduction and Summary and Conclusions sections, there is a brief description of the types of engines in use and their applications in Section Three. The fourth section describes current trends in the use of stationary engines and gas turbines. Section Five presents the emissions factors used to estimate annual emissions and discusses reasons for differences in emissions factors. Section Six contains estimates of annual power generation, fuel consumption, and emissions from stationary engines in the U.S. The seventh section discusses the potential of stationary engines as local pollution menaces in populated areas. The final and eighth section discusses the methods available for reducing pollutant emissions. The Appendix contains a sample of the survey questionnaire sent to the U.S. engine manufacturers, the emissions data used to derive emissions factors presented in Section Five, and supplemental data on installed horsepower at gas pipeline compressor stations and electric power generating facilities.

II. Summary and Conclusions

1. Installed Horsepower and Emissions

The major results of the stationary engine survey are shown in Table 1 and Figure 1. In 1971, the estimated total horsepower of reciprocating engines was 34.7 million Bhp. The total for gas turbines was 35.5 million Bhp. The major applications of reciprocating engine horsepower are oil and gas pipeline pumps and compressors (35.1%), agriculture (21.6%), electric power generation (15.5%), and natural gas production (9.3%). About 54 percent of the reciprocating engine horsepower is natural gas engine, and 34.2 percent and 11.8 percent are diesel and dual fuel engine, respectively. About 76 percent of the fuel Btu's consumed by reciprocating engines are provided by natural gas and the remainder by distillate fuel oil.

Estimated power generation figures indicate that reciprocating engines are running at about 58 percent capacity while gas turbines are running at about 22 percent capacity. Capacity factors are low in electric power generation ($\sim$ 12 percent) due to the use of engines and turbines in peak shaving service. In contrast, capacity factors are relatively high on gas pipelines (90 percent), where gas engine and turbine compressors are run almost continuously at full load.

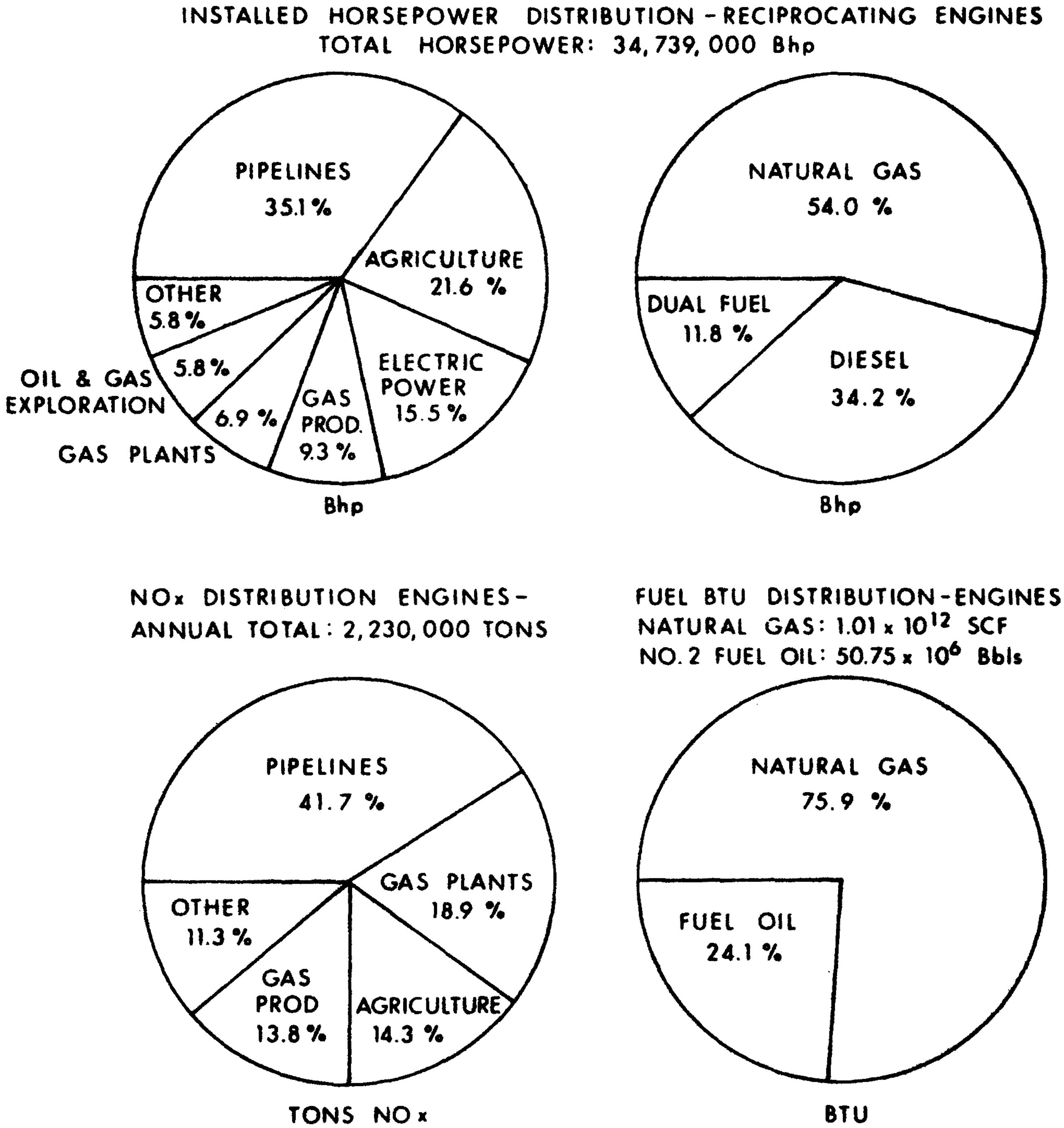
TABLE 1

Estimated Installed Horsepower, Fuel Consumption

Power Generation, and Emissions in 1971

	Reciprocating I.C. Engine	Gas Turbine
Installed Horsepower (Bhp)	34,739,000	35,490,000
Fuel Consumption:		
Natural Gas (10^6 SCF)	1,010,105	1,518,540
Fuel Oil (1000 Bbls)	50,750	45,400
Power Generation (10^6 Bhp-hr)	176,870	69,510
Capacity Factor	58.1%	22.4%
Emissions (Tons)		
NOx	2,230,000	130,200
CO	651,600	-
HC_t	282,100	-
NOx Emissions as a Percentage of Total NOx Emissions in 1968:[a)]		
All Sources	10.8%	0.6%
Stationary Sources Only	17.6%	1.0%

[a)] All Sources: 20,600,000 tons; Stationary Sources Only: 12,700,000 tons (Reference 40).



72/396/8

Figure 1. Population Characteristics of Stationary Engines in the U.S.

Total NOx emissions from stationary reciprocating engines were an estimated 2.2 million tons in 1971. This figure is almost identical to the previous estimate published by ESSO Research and Engineering in 1969[7] (2.3 million tons). The ESSO estimate did not include emissions from sources outside of the oil and gas industry. In addition, NOx estimates emissions for the individual sectors are higher than those presented in this report. Figure 1 shows that about 80 percent of the present estimate of total NOx emissions from stationary engines is generated by oil and gas related applications. Consequently, the present estimated NOx emissions are lower than but still the same order of magnitude as the ESSO estimates.

Hydrocarbon and CO emissions are estimated to be 282 and 652 thousand tons, respectively, and are not felt to cause significant problems. Hydrocarbon and CO emissions are generally low for diesel engines, however smoke and particulate emissions are sometimes troublesome. Two cycle gas engines have somewhat higher hydrocarbon emissions than other engines.

2. Stationary Engines as a Local Pollution Source

In some applications such as natural gas pipelines, it is not uncommon to have 20 to 60 thousand horsepower of reciprocating engine capacity at a single location. In order to determine whether these large engine colonies adversely affect the air environment in densely populated areas, "house count" data provided by a large gas pipeline company were analyzed to determine the population density in the immediate vicinity of the compressor stations. The analysis indicated that human exposure to the engine emissions is minimal in terms of the number of people affected. Most of the stations are remote - 37 percent have no houses or people within an eighth of a mile. It is still significant, however, that there is some human exposure at the majority of the compressor stations.

3. Trends in Engine Applications

In recent years, the major users of stationary engines and gas turbines - large electric utilities and natural gas pipelines - have been favoring large gas turbines in new installations. The primary reason is the relative ease and cost of installation. Small rural electrical utilities and total energy installations in hospitals, schools, and commercial establishments are still favoring diesel-electric sets. Reciprocating gas engines are being replaced in process applications in refineries and chemical plants by electric and steam turbine drive units, for reasons of greater reliability and less down time. Crude oil and products pipelines use some diesel and dual fuel engines to drive pumps, however, the major power source is the electric motor.

Crude oil production uses engines to drive only about four percent of the estimated 400,000 beam-pumped wells in existence, the remainder being driven by electric motors. Most of the 53,000 oil wells on gas lift are supplied high pressure gas from gas engine-compressors.

Large electric utilities are favoring so-called combined cycle gas turbine units in new installations. A waste heat boiler recovers heat from the turbine exhaust and generates steam for process use or to drive a steam turbine. The industry is now looking towards the gas turbine for continuous power generation in addition to peak power generation. This is due to the delays in nuclear plant construction while environmental questions are being answered.

The use of reciprocating engines in stationary applications is growing moderately in some areas, e.g., rural electric power, declining in others, e.g., process compression, and staying relatively constant in others.

4. Potential for Emissions Control

Two types of emission controls are available for reducing NOx emissions from stationary engines - engine modification and exhaust treatment. Engine modification controls can be further broken down into changes in operating conditions and hardware modifications.

Simple changes in operating conditions that reduce emissions include retarding the ignition timing, increasing air/fuel ratio, reducing torque, increasing speed, decreasing air manifold temperature, and increasing exhaust back pressure. More drastic changes that require hardware modifications include exhaust recirculation, water injection, increased valve overlap, and use of a precombustion chamber or stratified charge combustion. Most of these changes cause fuel consumption to increase so that the exhaust treatment methods may be more attractive long term solutions. They include exhaust thermal reactors, catalytic oxidation of CO and hydrocarbon, catalytic reduction of NOx by CO, H_2, natural gas, or ammonia, stack gas scrubbing, and solid sorbents. The catalytic converter appears to be the only practical exhaust treatment method for stationary engines.

The control methods having the greatest potential over the short and intermediate term appear to be valve timing adjustment and water injection for gas engines and precombustion chambers and water injection for diesels. Over the long term, catalytic reduction of NOx by ammonia or natural gas appears to have the greatest potential. In the case of reduction by ammonia, the method will work in the presence of high oxygen concentrations, and oxidation of CO and unburned hydrocarbons proceeds simultaneously. Catalytic reduction has the additional advantage that it is not necessary to change engine operating conditions away from the optimum conditions for maximum performance or fuel economy.

It must be emphasized, however, that a significant level of development work must be carried out before effective emissions control of stationary engines will be possible. The development effort should focus on maximizing fuel economy, performance, and engine life while minimizing pollutant emissions.

5. Conclusions

a. Total NOx emissions from reciprocating engines and gas turbines were 2.2 million and 110 thousand tons, respectively, in 1971.

b. These figures are of the same order of magnitude as estimates published by ESSO in 1969, although contributions from the various applications differ.

c. Hydrocarbon and carbon monoxide emissions from stationary engines are of minor importance relative to nitrogen oxides. Sulfur dioxide emissions are a problem only where fuel sulfur content is significant.

d. The present trend in gas pipelines, large electric utility, oil refinery, and chemical plant applications is towards gas turbine, steam turbine and electric drives and away from reciprocating engines. However, rural electric utilities and other small applications in remote locations are continuing to rely on diesel engines.

e. Large installations of reciprocating engines on gas pipelines and at electric power plants do not pose a significant pollution threat to densely populated areas. However, it is still significant that small numbers of people are exposed to high NOx emissions in some cases.

f. Short term NOx control methods with the highest potentials are precombustion chambers for diesels, increased valve overlap for four-cycle naturally aspirated engines, and water injection for all types of engines.

g. Over the longer term, catalytic exhaust treatment methods have the highest potential.

h. Emissions regulations for stationary engines must allow adequate time for the development of effective and economical emissions control technology. It will be necessary to demonstrate that the emissions control system does not adversely affect engine life, reliability, or fuel consumption.

III. Types and Applications of Engines in the U.S.

1. Types of Engines

Stationary reciprocating engines can be classified into several categories depending upon the method of ignition of the fuel-air mixture, number of strokes per cycle, methods of air and fuel charging, and application. Table 2 summarizes the various alternatives.

The air/fuel mixture is ignited either by an electrical spark discharge (spark ignition engines) or by compression heating (diesel engines). Either two or four strokes per cycle are used. Air is introduced by natural aspiration, air blower, supercharging, or turbocharging. Fuel is introduced by carburetion or direct injection into the cylinder. Fuels include natural gas, distillate fuel oil, residual fuel oil, and even crude oil in a few cases. Most stationary engines operate at medium and high speeds (>1000 rpm) and are connected externally to other equipment, such as electric power generators, pumps, and high speed compressors. Other engines are built to run at low speeds and drive reciprocating compressor cylinders built integrally into the engine block. These integral compressors are used mainly in oil and gas production and on natural gas pipelines.

a. Natural Gas Engines

Natural gas engines are almost always spark ignited, since it is difficult to run a high compression ratio diesel engine on gas fuel without detonation and uneven burning. Ignition timing is usually advanced to up to

20 degrees before top dead center. In four cycle gas engines, the gas fuel is either mixed with air in a carburetor and passed into the cylinder through an intake valve or is injected directly into the cylinder. Four-cycle gas engines can be naturally aspirated, i.e., the air/fuel mixture is drawn into the engine by the natural pumping action of the cylinders. Supercharging and turbocharging are used to supply air to the engine above atmospheric pressure and increase the power output of a given engine. The turbocharger is powered by an exhaust-driven turbine, while the supercharger is driven off the engine crankshaft.

In two-cycle gas engines the fuel is injected directly into the cylinder, and combustion and scavenging air enter through ports in the cylinder wall which are uncovered as the piston nears the bottom of its stroke. Two-cycle engines can be either "uniflow" or "loop" scavenged. In the former case, incoming air dilutes the exhaust gases and the mixture exits through an open exhaust valve in the cylinder head. In loop-scavenged engines, the scavenging air-exhaust mixture leaves through exhaust ports in the cylinder wall. A ridge on top of the piston causes air to loop through the cylinder and sweep out the exhaust gases. As a result of exhaust scavenging, exhaust pollutants are diluted to about 1/2 to 2/3 of their original concentrations. Thus, in the case of two cycle engines, air/fuel ratio cannot be estimated directly from exhaust composition.

TABLE 2

Types of Stationary Internal Combustion Engines

Ignition Type	Spark Ignition	Diesel	Dual Fuel
Fuel	Natural Gas	No. 2 Oil	Natural Gas 95%
Strokes/Cycle	<------------------------ 2 or 4 ------------------------>		
Air Charging:			
2-cycle	<-Atmospheric Blower, Supercharged, or Turbocharged--------->		
4-cycle	<-Naturally Aspirated, Supercharged, or Turbocharged-------->		
Fuel Charging	Direct Injection or Carbureted	Direct Injection or Precombustion Chamber	Direct Injection
Engine Speed	High Speed or Low Speed Integral Compressor-Engine	High Speed	High Speed or Low Speed Integral Compressor

b. Diesel Engines

The general features and forms of diesel engines are similar to those of spark ignition gas engines with a few exceptions. The fuel is generally a light distillate oil such as No. 2 oil. Combustion is controlled by injecting fuel into the cylinder through a spray nozzle at the proper time during the compression stroke, usually a few degrees before top dead center. Diesel engines have higher compression ratios than spark-gas engines, typically

13:1 vs 8:1. This allows compression heating of air trapped in the cylinder to a high enough temperature to ignite the fuel droplets as they are injected into the cylinder.

Caterpillar Tractor and several other diesel manufacturers use a precombustion chamber to initiate combustion.[9,29] The fuel is injected into a small chamber appended to the main cylinder chamber, where it ignites in the presence of less than the stoichiometric requirement of air. The mixture is then forced out into the main chamber where the air/fuel mixture is very lean, typically 20:1. This system is analogous to the stratified charge combustion system being considered for automotive NOx control. Indeed, one advantage of the precombustion chamber system over the conventional system is that smoke, NOx, and exhaust odor have been found to be lower.[9]

c. Dual Fuel Engines

Dual fuel engines can operate either on 100 percent fuel oil or a mixture of natural gas and fuel oil, usually up to 95 percent natural gas on the basis of heating value. The fuel oil serves as a pilot for ignition of the gas fuel, which is difficult to ignite by compression heating alone.

Dual fuel engines have at least two advantages over spark ignition gas engines and full diesel engines - greater fuel flexibility and better fuel economy. The higher compression ratio results in higher thermal efficiency than occurs in the spark gas engine.

A variation of the dual-fuel engine, the tri-fuel engine allows operation in the spark ignition gas mode as well as the full diesel and dual fuel modes.

2. Applications

The major applications of stationary engines and gas turbines in the industrial, commercial, and public sectors are listed in Table 3. The most prevalent uses are as power sources for electric power generators and gas pipeline compressors.

a. Oil and Gas Industry

The oil and gas industry is probably the single largest user in terms of installed horsepower and power generation. In oil and gas exploration, engines are used to drive drilling equipment, mud pumps, and electric power generators. Some oil well beam pumps are driven directly by small engines, while other wells are pumped by "gas lift", with gas supplied by an engine-driven compressor. Natural gas processing plants use engines to drive both refrigeration and process compressors. Natural gas pipelines are major users of large integral gas engine-compressors. Oil refineries and chemical plants use engines to a limited extent to drive process compressors and stand-by electric power generators. The most frequent applications are catalytic cracking and reforming units. There seems to be a trend in refineries and chemical plants, however, to replace engines by electric motors and steam turbine drives.

TABLE 3

Applications of Stationary Internal Combustion Engines

Industry	Principle Engine Types	Application
Electric Utility	Diesel Dual Fuel Gas Turbine	1. Continuous power generation 2. Peaking power 3. Standby power 4. Total energy
Natural Gas Utility	Spark Ignition-Gas Gas Turbine	1. Compressor drives - transmission, distribution, storage, field and gathering.
Petroleum	Spark Ignition-Gas Diesel Gas Turbine	1. Oil and gas well drilling operations. 2. Oil well pumping 3. Gas well recompression 4. Gas plant compressors 5. Refinery process compressors 6. Plant cooling water pumps 7. Electric power generation
Chemical	Spark Ignition-Gas Diesel Gas Turbine	1. Process compressors 2. Cooling water pumps 3. Electric power generation
General Industrial	Spark Ignition-Gas Diesel Dual Fuel Gas Turbine	1. Electric power generation 2. Mechanical drive
Commercial and Municipal	Spark Ignition-Gas Diesel Gas Turbine	1. Electric power generation 2. Total energy 3. Water pumping 4. Sewage pumping

b. Electric Utility Industry

The electric utility industry uses engines and gas turbines for both continuous and peaking power service. The emphasis is on peaking power in large utility companies and on continuous power in smaller municipal utilities. Total energy systems have been on the rise in recent years in schools, hospitals, and shopping centers.[11] These systems generate all required electric power and use the waste heat to generate steam and provide other utilities.

Municipalities and commercial concerns use engines principally to generate either continuous or standby electric power and to drive water and sewage pumps.

IV. Trends in the Use of Stationary Engines and Gas Turbines

The current trends in new engine orders reflect the pressures coming from environmental, cost, and fuel shortage considerations. Gas turbines are known to provide more reliable service at lower installed cost per horsepower than diesel and gas engines. As described later, NOx emissions are about an order of magnitude lower and CO and hydrocarbon emissions are not a problem in the case of gas turbines. Consequently, the shipments of new gas turbine equipment have risen steeply in the last five years, while reciprocating engine shipments have decreased some.

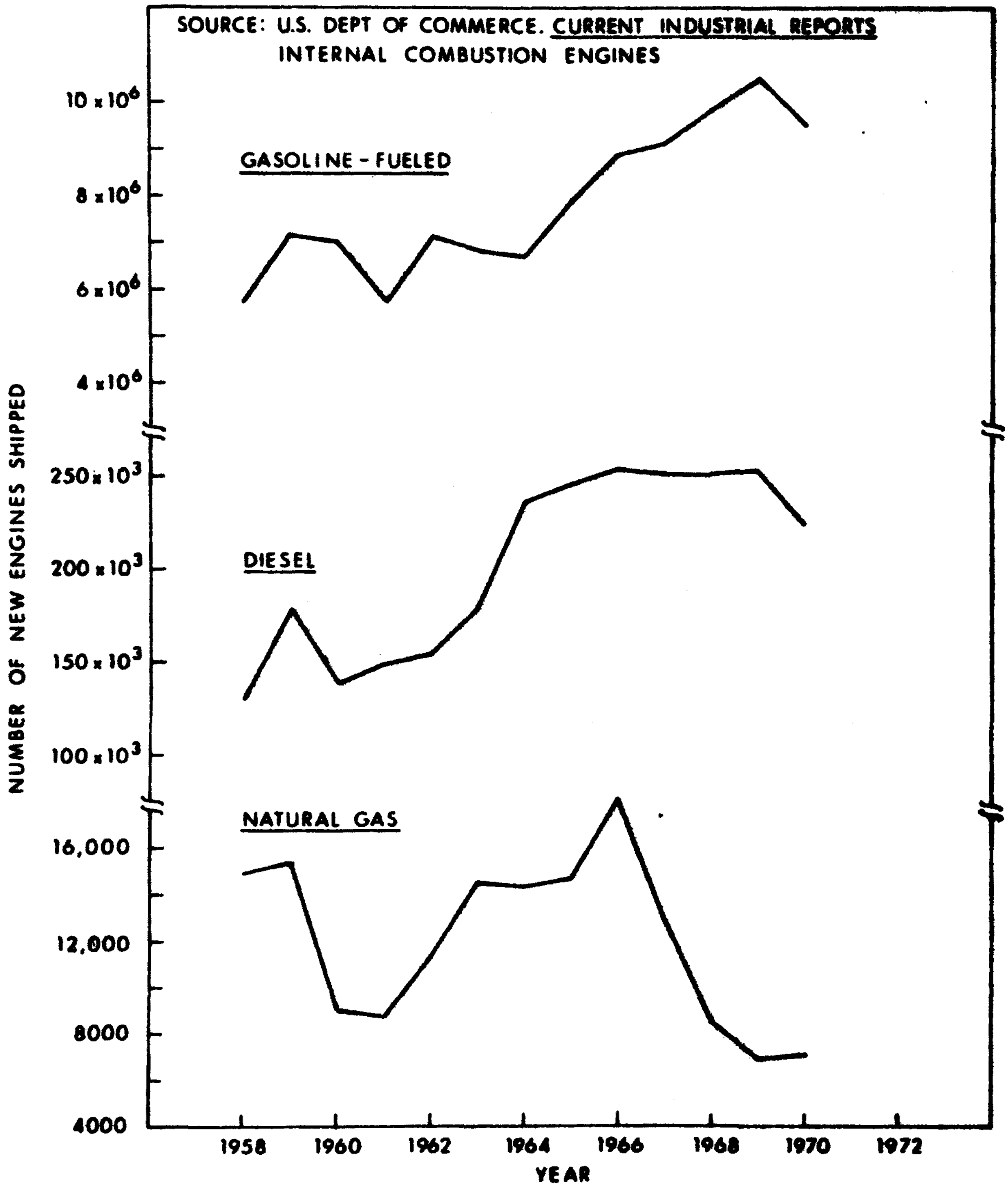
Figure 2 shows annual shipments of new nonautomotive gasoline, diesel, and natural gas reciprocating engines in the U.S. for the years 1958 through 1970.[37,38] Table 4 shows the ultimate applications of the three types of engines. The totals include engines exported from the United States, the number exported being less than 5 percent in most cases.

1. Natural Gas Pipelines

Gas engine shipments have dropped significantly from a peak of 18,000 in 1966 to about 7,000 in 1970. This is viewed to be the result of both the economic recession and the inroads made by the gas turbine in new compressor horsepower on natural gas pipelines. Figure 3 shows new and added compressor horsepower installed on U.S. transmission pipelines for the years 1960 through 1971.[32] Before 1968, the reciprocating gas engine held a decided edge; however, the gas turbine has been in the lead since. In 1971, almost twice as much gas turbine horsepower as reciprocating horsepower was installed by the industry. In new installations, the trend is towards using a single large gas turbine, typically 10 to 20,000 hp, to drive a centrifugal compressor. The reasons are dependability, ease of operation, and installed cost. The gas turbine costs about half as much as the gas engine-compressor to install ($271/hp vs $426/hp in 1971).[21,32] Additions to existing compressor stations often use equipment that is similar to what is already present, i.e., gas engine or turbine. It should be noted, however, that very little expansion is presently in progress, as the gas supply is not presently increasing and the industry is struggling to supply gas to existing customers.

2. Electric Power Generation

The electric utility industry is also making increasing use of the gas turbine-generator set in new installations. Annual installations are expected to hover around 6,000 MW capacity over the next three years.[34] For the past five years or so, the large investor-owned electric utilities have



72/396/1

Figure 2. Annual Shipments of Non-Automotive Reciprocating Engines in U.S. 1958 to 1970

TABLE 4

Internal Combustion Engines: Number vs End Use[37,38]

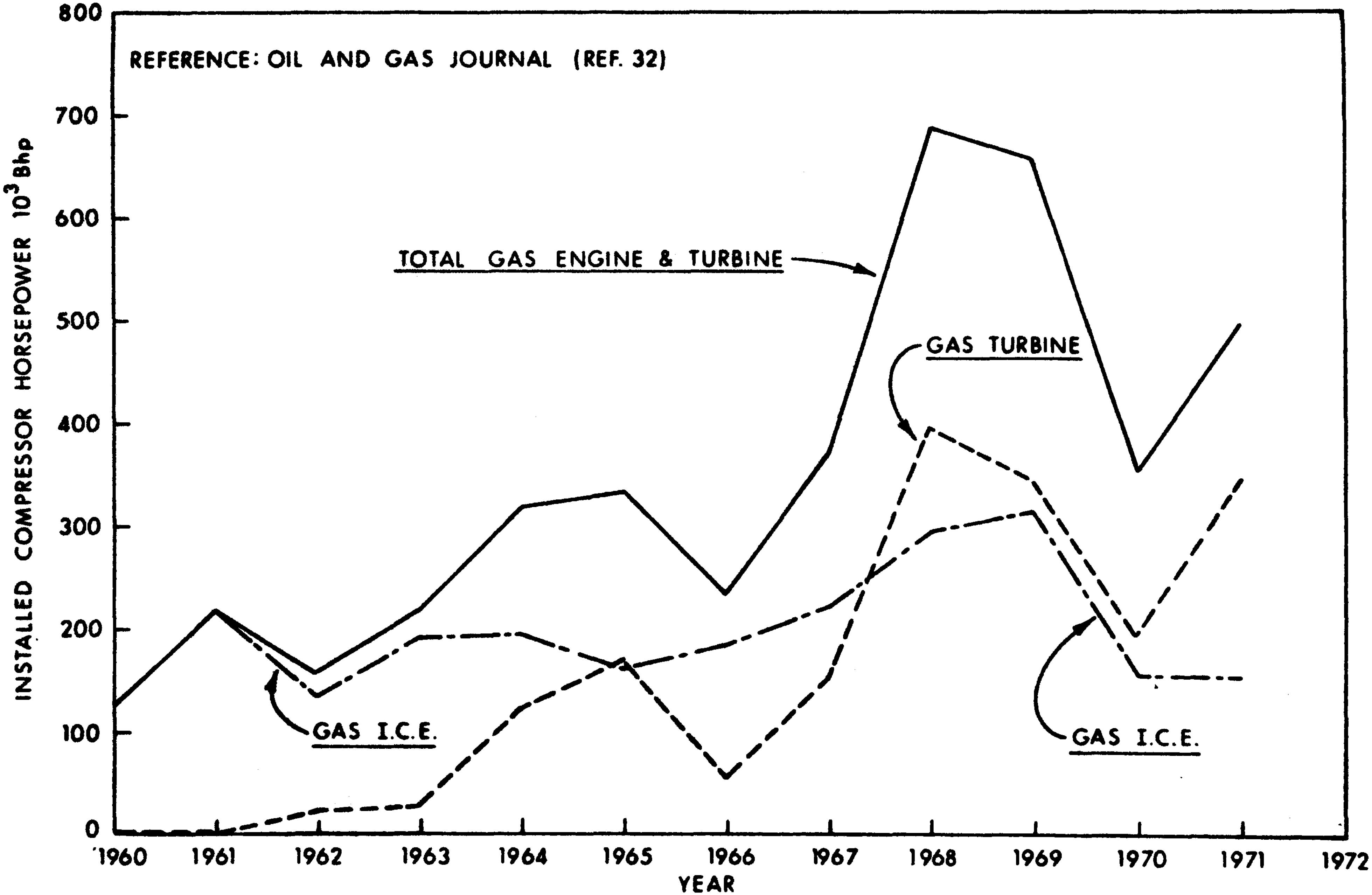
Year:	1970	1969	1968	1967	1966	1965	1964	1963	1963-70 Cumulative Total	% of Total
Gasoline:										
Marine	61,663	106,693	84,624	103,478	103,899	39,937	29,463	28,005	557,762	0.80%
Lawn & Garden	8,013,961	8,717,864	8,236,693	7,555,701	6,422,221	5,766,819	4,760,683	5,084,262	56,291,668	81.08
Chain Saws					482,194	442,855	435,152	373,263		
Agriculture	169,977	187,437	193,380	202,167	509,543	417,507	434,175	430,362	2,544,548	3.66
Subtotal	8,245,601	9,011,994	8,514,697	7,861,346	7,517,857	6,667,118	5,659,473	5,915,892	59,393,978	85.54%
Construction	152,178	175,605	104,638	121,225	132,214	85,076	66,052	51,136	888,124	1.28
Generator Sets	86,264	90,760	67,798	67,930	76,678	67,769	59,190	43,542	559,931	0.81
General Industrial	1,073,564	1,249,185	1,134,638	1,070,887	1,173,939	1,087,760	949,007	851,068	8,590,048	12.37
Subtotal	1,312,006	1,515,550	1,307,074	1,260,042	1,382,831	1,240,605	1,074,249	945,746	10,038,103	14.46%
Overall Total	9,557,607	10,527,544	9,821,771	9,121,388	8,900,488	7,907,723	6,733,722	6,825,638	69,432,081	100.00%
Diesel:										
Marine	6,745	8,604	9,762	9,764	7,213					
Agriculture	65,641	80,264	96,460	102,459	94,509	103,325	118,064	82,028	742,750	39.06%
Subtotal	72,386	88,868	106,222	112,223	101,722	103,325	118,064	82,028		
Construction	91,048	104,284	92,932	90,338	98,865	56,305[a]	47,111[a]	36,861[a]		
Generator Sets	10,201	8,535	6,070	5,564	12,746	13,209	9,548	8,519	74,392	3.91%
Locomotive	52,218	52,045	46,645	44,327	41,156			1,419		
General Industrial						73,880	63,320	50,517		
Subtotal	153,647	164,864	145,647	140,229	152,767	143,394	119,979	97,316		
Overall Total	225,853	253,732	251,869	252,452	254,489	246,719	237,043	179,344	1,901,501	100.00%

TABLE 4 (continued)

Year	1970	1969	1968	1967	1966	1965	1964	1963	1963-70 Cumulative Total	% of Total
Gas:										
Agriculture	2,987[b)]	3,257	3,947	6,873	11,460	5,654	5,780	8,788	48,746	50.08%
Construction / Generator Sets	2,342[b)]	2,694	3,547	4,799	5,539	8,266	7,700	5,142	40,029	41.13
General Industrial	1,821	1,002	1,028	1,260	1,135	839	911	562	8,558	8.79
Subtotal	4,163	3,696	4,575	6,059	6,674	9,105	8,611	5,704	48,587	49.92
Overall Total	7,150	6,953	8,522	12,932	18,134	14,759	14,391	14,492	97,333	100.00%

a) Includes Marine engines.

b) Estimates based on distribution of gas engines in Agriculture and Construction/Generator Sets for previous three years.



72/396/2

Figure 3. New and Added Compressor Capacity on Gas Transmission Pipelines - 1960 to 1971

favored gas turbines over reciprocating engines in new peak shaving units. As a result of delays in the construction of new nuclear generating capacity, due to environmental questions, the industry is looking at the gas turbine to generate continuous power in addition to peaking power.

Forecasts of fuel shortages and rising fuel oil prices have brought renewed interest from the industry in combined-cycle gas turbines.[34)] A waste heat boiler recovers energy from the hot exhaust from the gas turbine and generates steam to drive an auxiliary steam turbine. As much as a 40 percent increase in power capacity is achieved by using the combined cycle as opposed to the "open" cycle with no heat recovery. This at least partially eliminates one of the prime objections to the gas turbine - its low cycle efficiency, typically 23 percent in the open cycle configuration.

Reciprocating engines, principally diesel and dual fuel engines, will find continuing demand as power sources for electric generators in small municipalities, hospitals, schools, and shopping centers which are too small to use a large gas turbine unit. Table 5 summarizes data from the trade journal Power,[34)] collected in an annual survey of engines ordered from U.S. engine manufacturers. The samples are heavily weighted towards electric power generation, and do not fairly represent engines ordered by other segments of industry, particularly the petroleum industry. Consequently, the table shows only the percentages for the principle applications, types, and fuels for engines ordered in the U.S. and Canada. Recently there has been a marked increase in applications in continuous electric power generation. Most of the engines are full diesel, and the principle fuels are No. 2 fuel oil in the case of diesel engines and No. 2 fuel oil and natural gas in the case of dual fuel engines.

V. Emissions Factors for Gas Turbines and Diesel, Dual Fuel, and Gas Engines

The emissions factors used to estimate total NOx, CO, and hydrocarbon emissions from stationary engines are described in this section. Before presenting the data, it is appropriate to discuss several important points which greatly affect the magnitude of pollutant emissions from engines. These include both the engine operating conditions at the time of the emissions tests, and the emissions test methods.

1. Effect of Engine Operating Conditions

Exhaust emissions can vary over a considerable range depending upon the condition of the engine, operating conditions, and various design factors. The most important operating conditions are the air/fuel ratio of the trapped charge mixture, and the load or torque on the engine. Other factors of lesser importance include the ignition timing (reciprocating engines), and the air temperature and humidity.

a. Air/Fuel Ratio

The air/fuel ratio can be expressed as either a weight or volume ratio (gas fuels). It expresses the relative fractions of air and fuel present in the mixture burned in the cylinders of reciprocating engines and in the combustors of gas turbines. Perhaps a more meaningful parameter is the equivalence ratio ϕ, which is the ratio of the stoichiometric and actual air/fuel ratios:

$$\phi = \frac{(A/F)_{Stoich}}{(A/F)_{Actual}} \quad .$$

For ϕ less than unity, the air/fuel mixture is lean.

TABLE 5

Statistical Survey of Stationary Engines Purchased in U.S. and Canada by Year

Reference: Power "Plant Design Report," 1963 through 1972

Principle Use	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972
					Year of Survey					
Electric Power Generation										
Continuous Power	29.0%	34.0%	26.2%	-	26.5%	27.3%	30.0%	20.0%	34.9%	51.0%
Peaking Power	1.0	3.0	13.1	-	2.4	0.0	8.0	19.0	12.6	9.0
Standby Power	26.0	26.0	9.8	-	8.4	1.6	11.0	21.0	21.3	31.0
Total Energy	0.0	0.0	11.5	-	6.0	17.9	21.0	34.0	25.7	0.3
Subtotal (Electric Gen.)	56.0%	63.0%	60.6%	-	43.3%	46.8%	60.0%	94.0%	94.5%	91.3%
Pump Drive	17.0	18.0	0.0	-	7.2	13.3	6.5	0	3.0	2.0
Compressor Drive	27.0	19.0	6.5	-	49.5	30.2	18.5	2.0	2.5	0.0
Mechanical Drive			32.7	-	0.0	9.7	5.0	4.0	0.0	0.0
Other			0.2	-	0.0	0.0	0.0	0.0	0.0	6.7
Total	100.0%	100.0%	100.0%	-	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Engine Type										
Natural Gas	30.4%	38.0%	53.8%	52.3%	67.2%	66.1%	43.4%	21.2%	22.2%	-
Full Diesel	49.0	49.0	26.1	12.4	18.4	13.6	32.4	46.5	45.5	58.0%
Dual Fuel	19.6	12.0	20.1	35.3	14.4	19.3	24.2	32.3	32.3	42.0
Tri-Fuel	1.0	1.0	0.0	0.0		1.0				
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

TABLE 5 (continued)

Principal Use	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972
Fuel Type										
No. 2 Oil			35.0%	37.9%	21.9%	8.9%	24.2%	43.0%	40.3%	41.2%
No. 2 Oil and Gas						14.4	24.2	21.2	14.9	40.2
No. 5 Oil						1.1				1.0
No. 6 Oil						.2		.5	2.0	
Navy Oil						.2				
Diesel Oil			15.0	1.8	4.9	3.3	6.1	3.0	3.0	16.6
Crude Oil						.9				
Natural Gas			50.0	53.5	73.2	69.2	45.5	32.3	39.8	
Other				6.8		1.8				1.0
Total			100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Literature data in Figure 4 demonstrate how the air/fuel ratio affects exhaust concentrations of NOx, CO, and hydrocarbon for a 4-cycle gasoline - fueled laboratory engine.[1] The NOx concentration reaches a maximum for an air/fuel ratio slightly on the lean side of stoichiometric. Richer mixtures result in lower available oxygen concentrations, while leaner mixtures result in lower flame temperatures. Both factors result in less favorable conditions for the formation of nitrogen oxides. Carbon monoxide emissions are essentially functions of oxygen availability and thus are significant only for rich mixtures. Hydrocarbon emissions result principally from quenching of the combustion reaction at the cylinder wall and tend to be higher for both rich and very lean mixtures. The former effect results from the lack of available oxygen for combustion and the latter from lean misfires under oxygen rich conditions.

b. Engine Torque

Varying load is the predominant factor which causes emissions from engines and gas turbines to vary with time. Laboratory studies suggest, however, that the effect is primarily one of simultaneous changes in the air/fuel ratio.[25] Nevertheless, load or torque has a primary effect on emissions via its effect on combustion pressure which in turn affects the rates of formation of nitrogen oxides and combustion of CO and hydrocarbons.

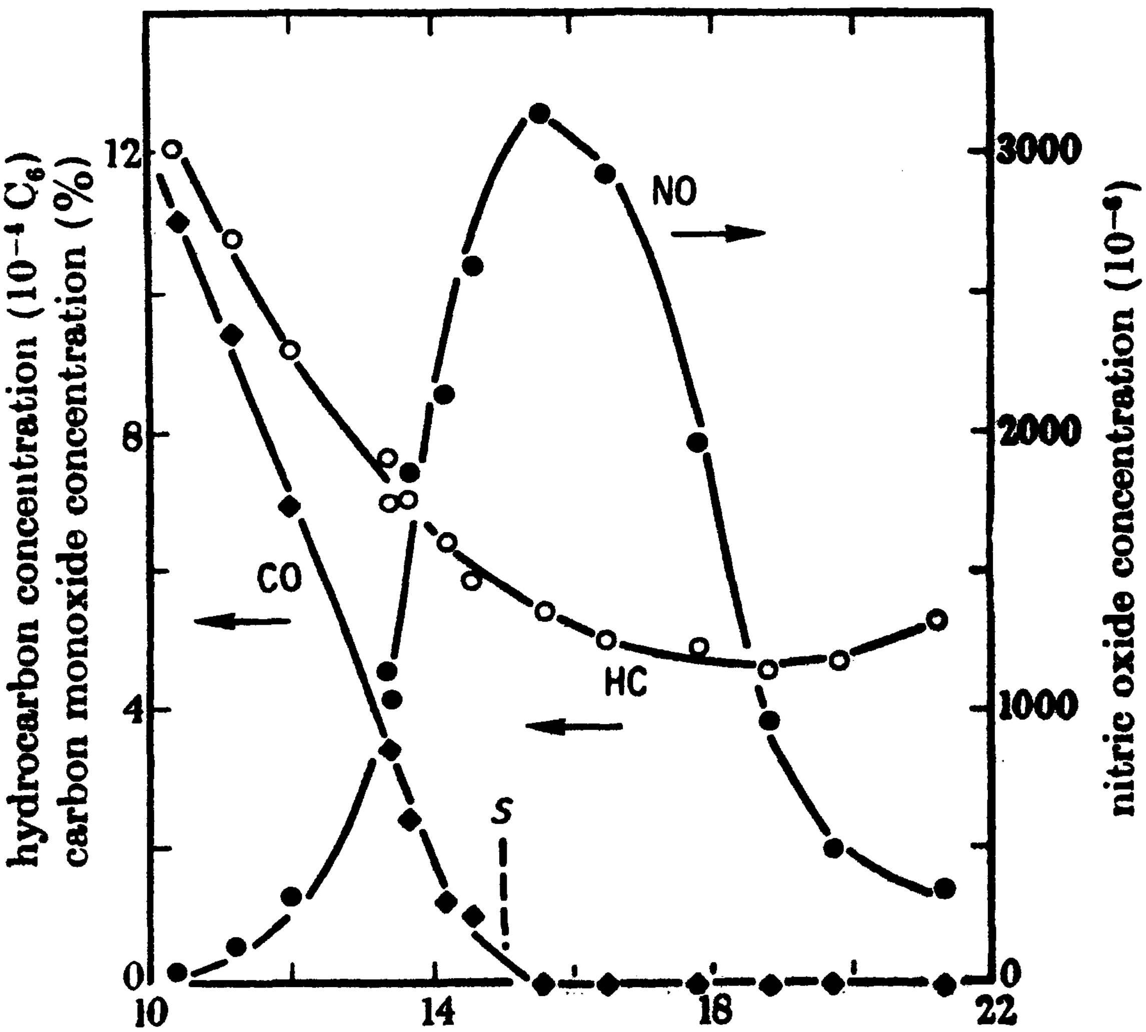
Figure 5 shows the effect of torque on the brake specific mass emissions of nitrogen oxides for three Cooper Bessemer engines.[25,35] The two spark-ignition gas engines (GMVA-8 and GMVH-8) show great sensitivity of specific NOx emissions to torque, while the diesel engine (KSV-12) is less sensitive to torque in both the full diesel and dual fuel modes. Data from other sources show the same relative effects for gas and diesel engines.[9] As torque increases, the air/fuel ratios decrease and combustion temperatures increase in both gas and diesel engines. In the case of natural gas combustion, both effects tend to increase NOx emissions. However, the two effects tend to cancel in liquid fuel combustion in diesel engines. The air/fuel ratio is already on the rich side of the peak NOx setting, and further enrichment leads to lower NOx formation. Thus, the gas engine exhibits greater NOx sensitivity to torque than the diesel engine.

Gas turbines are also known to exhibit NOx sensitivity to load.[46] Combustion intensity and temperature increase with load, leading to higher NOx concentrations in the exhaust. However, exhaust flow does not increase in proportion to load. Thus, specific mass emissions of NOx are less sensitive to load than in the case of gas engines.

At a given speed, power output is proportional to torque. Hence, derating an engine, i.e., operating below rated load, would be expected to be an effective NOx control method only in the case of gas engines. As load is reduced, the magnitude of diesel and dual fuel NOx emissions per unit power output does not change significantly. It is also significant that as load is reduced, specific fuel consumption and HC and CO emissions both increase in gas and dual fuel engines. This is illustrated in Figure 6 for a Cooper-Bessemer GMVA-8 gas engine.[25]

2. Test Procedures

Considerable variations in exhaust emissions can result from seemingly minor differences in test procedures. In addition to the exhaust concentrations of pollutants, it is necessary to determine engine power output and exhaust flow rate in order to calculate specific mass emission rates (grams/brake/horsepower-hour). The latter requires accurate measurement of fuel flow rate



The effects of air–fuel ratio on hydrocarbon, carbon monoxide, and nitric oxide exhaust emissions.

Figure 4 (Reference 1).

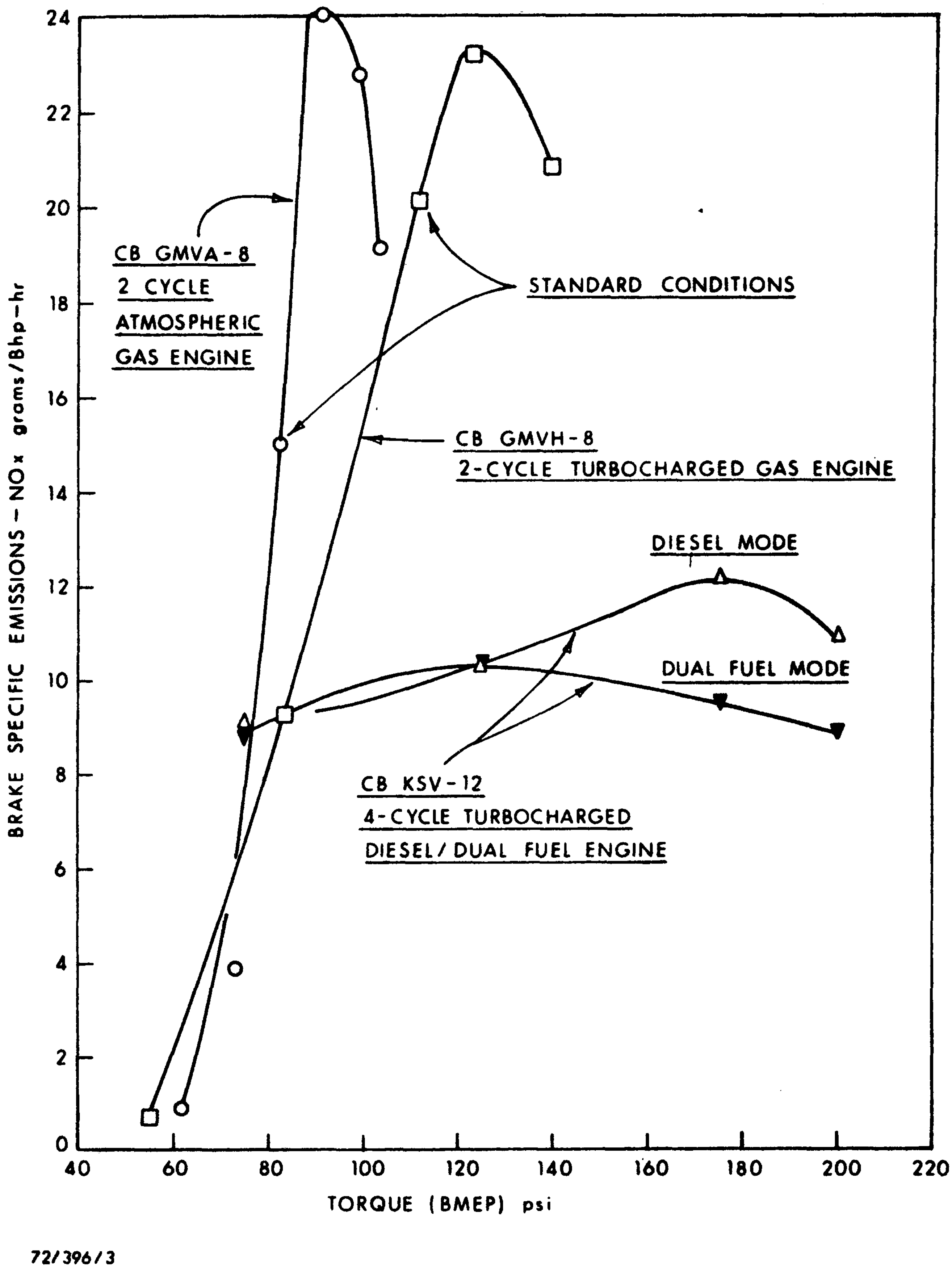


Figure 5. Effect of Load on Specific NOx Emissions - Cooper Bessemer Gas and Diesel Engines

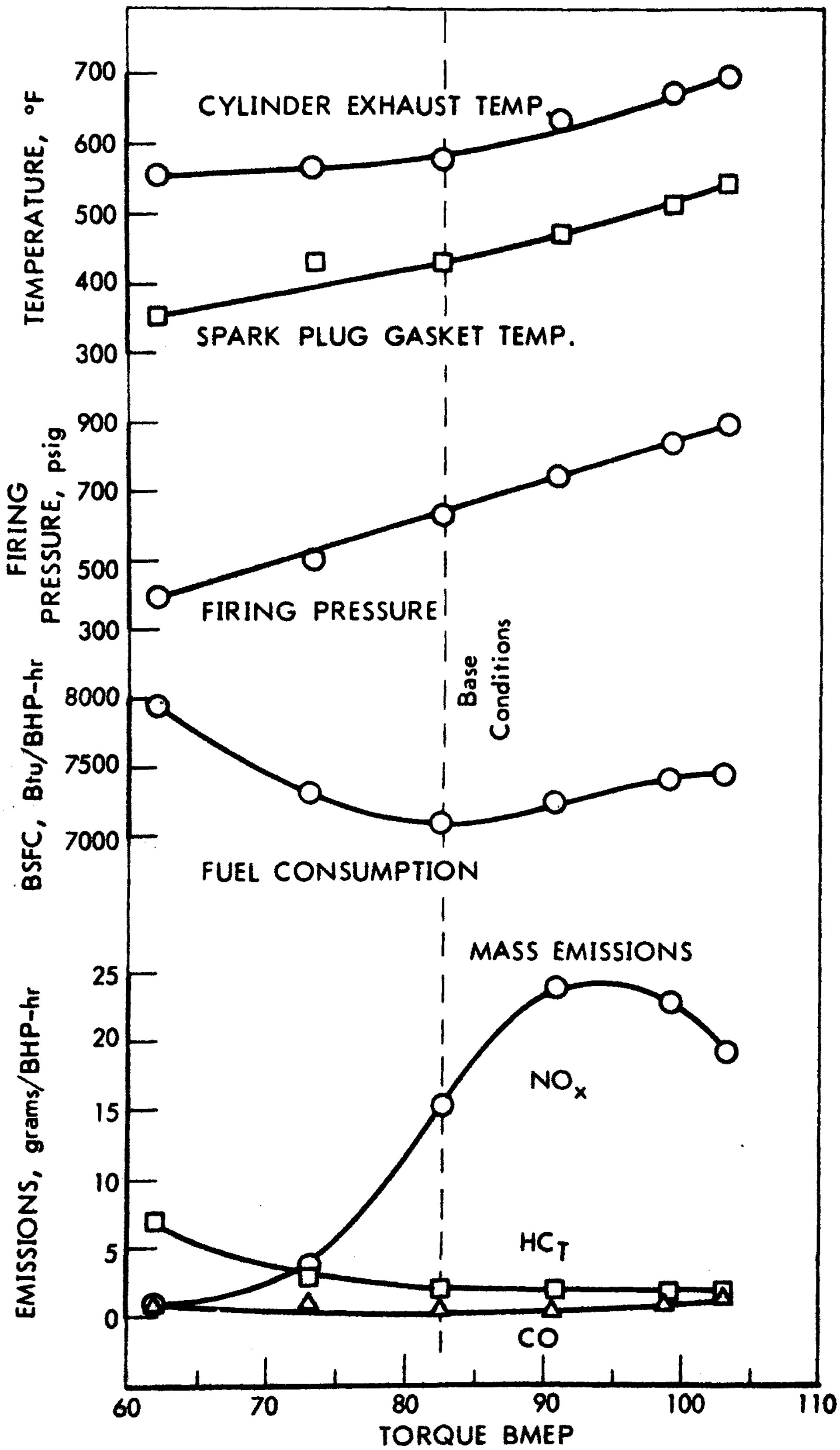


Figure 6. Effect of Torque at Constant Speed

Cooper Bessemer GMVA-8 2-Stroke Atmospheric Spark-Gas Engine
Base Conditions, Speed = 300 RPM

and composition and air flow rate or exhaust CO_2 and O_2 concentration. Different analytical instruments may yield differing values for CO_2 or O_2 concentrations which would lead to different exhaust flows and specific mass emissions values. In those cases in which the engine is driving a pump or compressor, it might be difficult to determine power output, which would introduce some uncertainty into the results. Likewise, different exhaust sample treatment and analytical techniques will cause differences. Consequently, there is a great deal of uncertainty in the emissions factors presented in the next section, and they can only be considered to be order of magnitude estimates.

There has been some effort within the U.S. engine manufacturing industry to standardize emissions testing procedures for stationary engines. The Diesel Engine Manufacturers Association has developed an emissions test code in cooperation with the University of Michigan. The test code has been reviewed by the U.S. Environmental Protection Agency, and is being revised before being published. It is hoped that the DEMA Emissions Test Code will eliminate much of the variation found in emissions test data.

3. Emissions Factors

Table 6 summarizes the emissions factors used to estimate exhaust emissions from gas, diesel, and dual fuel engines and gas turbines in the U.S. Emissions factors are reported for nitrogen oxides (as NO_2), carbon monoxide (CO), and total hydrocarbons (HC_t as methane) in units of (grams/brake horsepower hour), (lb/million Btu fuel burned) and ppm concentration at stoichiometric conditions. The sources of data and method of derivation are described below.

An important point to note is that diesel engine emissions are usually but not always, measured over the California 13 mode test cycle, which is summarized in the Appendix. Consequently, diesel emissions factors are given in two groups - the first group is based on emissions data collected over the 13 mode cycle, while the second is based on emissions tests run at constant speed and load. The latter factors should be used in those cases where the engines are run for long periods of time at constant speed, e.g., electric power generation.

4. Differences in Emissions Factors

Except for gas turbines, dual fuel, and precombustion chamber diesel engines, NOx factors exhibit only minor differences among the different engine types, and NOx factors are in the range 10 to 14 grams/Bhp-hr. Gas turbines are an order of magnitude lower, primarily as a result of the lower peak temperatures in the combustion chamber. Gas turbine emissions of NOx are higher by about a factor of two in the oil fired mode than in the gas fired mode.[46] Precombustion chamber type diesels emit about half as much NOx as direct injection diesels. This is probably due to a stratified charge combustion effect in which combustion is initiated in a fuel-rich environment. The dual-fuel engine has a significantly lower specific fuel consumption than the gas engine, which is probably the reason NOx emissions are also lower. The dual-fuel engine burns gas predominantly. Ignition occurs by compression heating and liquid fuel ignition, leading to higher thermal efficiencies and lower BSFC.

Hydrocarbon and CO emissions data show more variability between engines and emissions tests. However, four-cycle engines show generally

TABLE 6

Stationary Engine and Gas Turbine Emission Factors

RECIPROCATING ENGINES

Engine Type	# Cycles	Charging[a)] Air	Charging[a)] Fuel	BSFC	g/Bhp-hr NOx	g/Bhp-hr CO	g/Bhp-hr HC_t	lb/10^6 Btu[b)] NOx	lb/10^6 Btu[b)] CO	lb/10^6 Btu[b)] HC_t	ppm @ Stoichiometric[c)] NOx	ppm @ Stoichiometric[c)] CO	ppm @ Stoichiometric[c)] HC_t	Remarks
				16/Bhp-hr										
Diesel	4	TC	DI	0.37	13.8	3.8	1.4	4.2	1.2	0.43	3220	1460	940	13 Mode Test
		NA	DI	0.43	11.2	5.3	5.6	2.9	1.4	1.4	2250	1750	3220	13 Mode Test
		TC	PC	0.37	5.3	1.6	0.34	1.6	0.49	0.10	1240	610	230	13 Mode Test
		NA	PC	0.43	5.9	2.5	0.3	1.5	0.65	0.078	1180	820	170	13 Mode Test
	2	SC	DI	0.40	14.7	6.1	0.8	4.1	1.7	0.22	3170	2160	500	13 Mode Test
	4	TC	DI	0.37	11.0	3.9	0.13	3.3	1.2	.040	2570	1490	90	Constant Conditions
		TC	PC	0.37	7.5	0.92	0.10	2.3	0.28	.030	1750	350	70	Constant Conditions
		NA	PC	0.43	6.0	0.96	0.18	1.6	0.25	.047	1200	320	100	Constant Conditions
				Btu/Bhp-hr										
Dual Fuel	4	TC	DI	5970	8.2	2.0	3.1	3.0	0.74	1.1	2050	410	1430	
Natural Gas	4	TC	DI	6830	12.2	1.0	2.0	3.9	0.32	0.65	2660	360	1250	
		NA	C	7150	11.8	1.4	2.0	3.6	0.43	0.62	2460	480	1200	
	4	TC	High Speed	7000	12.8	5.7	2.1	4.0	1.8	0.66	2730	1990	1280	
	2	TC	DI	6635	10.5	2.7	4.4	3.5	0.90	1.5	2360	1000	2830	
		Atmos.	DI	7100	12.0	0.3	4.0	3.3	0.093	3.3	2520	100	2410	
Gas Turbine				11,185	1.7	-	-	0.34	-	-	225	-	-	

a) "TC" = Turbocharged, "SC" = Supercharged, NA = Naturally-Aspirated, "DI" = Direct Injection, "PC" = Precombustion Chamber.

b) Assumes: Gas LHV = 950 $\frac{Btu}{SCF}$; Oil HHV = 19,600 Btu/lb; Dual fuel engines burn 21% oil, 79% gas.

c) Assumes: MW oil = 180, n_c = 12.7, n_H = 27.4; for gas n_c = 1.1, n_H = 4.4.

higher CO emissions and lower hydrocarbon emissions than 2-cycle engines. Many 4-cycle engines are operated at or near stoichiometric conditions which increases CO emissions. Conversely, 2-cycle engines operate with large excess air quantities trapped in the cylinder during combustion. However, unburned fuel can more easily escape from two-cycle engines, particularly loop-scavenged engines in which the exhaust escapes through ports in the cylinder walls.

Hydrocarbon and CO emissions are not generally a problem for gas turbines. Secondary air dilutes the exhaust to approximately 400% excess air at high temperature which effectively oxidizes any unburned hydrocarbon and CO.

5. Sources of Data

The emissions factors are composites of data collected from 1) literature sources, 2) survey questionnaire responses from engine manufacturers, and 3) industrial sources of field data.

Diesel engine factors are based on the questionnaire responses of Allis Chalmers, Caterpillar Tractor, and Cooper Bessemer and data published by Cooper Bessemer[35]) and the U.S. Bureau of Mines.[23,24]) Dual fuel engine factors are based on data supplied by DeLaval Turbine and data published and supplied by Cooper Bessemer.[35]) Gas engine and gas turbine factors were derived from data supplied by Cooper Bessemer,[25,35]) Ingersoll Rand, Caterpillar Tractor, and Southern California Gas Company.

6. Method of Derivation

The emissions factors for each type of engine are averages of full load specific mass emissions (grams/Bhp-hr) weighted by the brake horsepower of each engine included in the sample. Specific fuel consumption factors (Btu/Bhp-hr) are derived in the same way. Emissions factors related to heat duty (lb/10^6 Btu) are derived by dividing the mass emissions factor by the fuel consumption factor and converting grams to pounds. Exhaust concentrations of pollutants are derived by calculating the exhaust volume (wet) that would result at stoichiometric conditions per unit power generation (Bhp-hr). Gas fuel is assumed to have a heating value of 950 Btu/lb and carbon and hydrogen numbers of 1.1 and 4.4 moles/mole fuel, respectively. The corresponding quantities for liquid fuel are 19,600 Btu/lb, 12.7 and 27.4 moles/mole, and the molecular weight is 180.

VI. Installed Horsepower, Fuel Consumption, and Emissions of Stationary Engines and Gas Turbines in the U S.

This section presents estimates of the total installed horsepower, annual fuel consumption, and pollutant emissions for stationary engines and gas turbines in the U.S. The major engine users included in the tabulation are electric power generation, oil and gas pipelines, natural gas processing plants, oil and gas exploration, crude oil production, and natural gas production. Other miscellaneous applications include water and sewage pumping and industrial drives.

1. Overall Statistics

Table 7 is a tabulation of estimated installed horsepower, fuel consumption, and annual emissions for stationary reciprocating engines and gas turbines in the U.S.

In 1971, the total installed horsepower was 34.7 million horsepower for reciprocating engines and 35.5 million horsepower for gas turbines. The breakdown of reciprocating engine horsepower by type is 34.2 percent diesel, 11.8 percent dual fuel, and 54 percent gas engine. For reciprocating engines 15.5 percent of the horsepower is used in electric power generation, 35.2 percent on oil and gas pipelines, 21.6 percent in agricultural irrigation pumping, 9.3 percent in natural gas production, and smaller fractions in oil and gas exploration, and crude oil production. The gas turbine statistics have been adjusted to reflect an estimated 7.5 million kilowatts additional generating capacity brought into operation during 1971 by the electric utilities.[45)] This was done to bring the electric utility data for 1970, presented in the next section, up to 1971 levels.

Total fuel consumption by engines and gas turbines is estimated to be 1.5×10^{12} SCF natural gas and 96 million barrels distillate fuel oil. About 66 percent of the gas and 53 percent of the oil are burned in stationary engines.

Total NOx, CO, and hydrocarbon emissions from reciprocating engines are estimated to be 2.3 million, 6.52 thousand, and 282 thousand tons, respectively. Estimated NOx emissions from gas turbines are 130 thousand tons. Of the total NOx emissions from reciprocating engines, it is estimated that 41.7 percent is from oil and gas pipelines, 18.9 percent is from natural gas processing plants, 14.3 percent is from agricultural sources, and 13.8 percent is from natural gas production.

2. Electric Power Generation

On the basis of total installed horsepower of reciprocating engines and gas turbines (19.2×10^6 kw or 25.8×10^6 Bhp in 1970), electric power generation is the major user of internal combustion power.[11)] Since capacity factors are about 12 percent, however, electric power generation is overshadowed by oil and gas pipelines in power generation and pollutant emissions.

a. Power Generation and Capacity

Table 8 summarizes Federal Power Commission estimates of U.S. electric power capacity and generation from all sources for 1970, 1980, and 1990.[11)] In 1970, the total power generating capacity was 340×10^6 kw and power generation was 1541×10^9 kw-hr. Stationary engines and gas turbines provided 5.6 percent of the generating capacity and 1.4 percent of the power generation. By 1990, it is predicted that total capacity and generation will increase 271 and 284 percent, respectively. At the same time, the contribution of engines and gas turbines to total generating capacity will increase slightly to 6.0 percent, while the contribution to power generation will decrease to 0.8 percent.

About 20 percent of the I.C. engine and gas turbine capacity was provided by engines in 1970.[11)] This fraction will decrease to 16 percent by 1980. FPC statistics show that the proportion was 16 percent engines in large investor-owned utility companies in 1970. This fraction will decrease further as large combined-cycle gas turbines are installed instead of diesel-electric sets.

TABLE 7

Stationary Engines and Gas Turbines - Estimated Installed Horsepower, Fuel Consumption and Emissions - 1971

Application	Installed Horsepower 10^3 Bhp: Diesel	Dual Fuel	Gas Engine	Gas Turbine	Total	Fuel Consumption: Natural Gas 10^6 SCF	No. 2 Oil 1000 Bbls	Annual Emissions, Tons: Reciprocating Engines NOx	CO	HC_t	Gas Turbines NOx	Total NOx	Power Generation 10^6 Bhp-hr: Recip.	Gas Turbine
Electric Power Generation	1,570[a]	3,710[a]	90[a]	30,440[b]	35,810[b]	118,920	48,100	62,440	18,200	16,260	62,920	124,730	5,900	33,240
Oil and Gas Pipelines	830	390	10,990	3,520	15,730	749,590	7,030	930,200	297,800	279,200	39,800	970,000	73,700	21,260
Natural Gas Processing Plants	0	0	2,410	1,530	3,940	404,300	-	429,690	55,170	117,240	26,130	448,820	31,280	15,010
Oil and Gas Exploration	1,500	0	500	0	2,000	4,755	2,530	31,720	11,170	2,840	-	31,720	2,580	-
Crude Oil Production	0	0	852	0	0	39,870	-	62,370	22,030	25,930	-	62,370	5,410	-
Natural Gas Production	0	0	3,237	0	0	177,610	-	308,200	98,300	98,300	-	308,200	24,100	-
Agricultural	7,500	0	0	0	7,500	-	34,300	318,700	116,900	2,900	-	318,700	26,280	-
Industrial Process	0	0	230	0	230	11,100	-	19,300	6,160	6,160	-	19,300	1,510	-
Municipal Water and Sewage	465	0	465	0	930	22,500	3,990	76,100	25,900	12,500	-	76,100	6,110	-
Total	11,865	4,100	18,774	35,490	70,229	1,528,645	96,150	2,229,720	651,630	282,130	130,220	2,359,940	176,870	69,510
		34,739												
% of Total													Capacity Factors	
Reciprocating Only	34.16%	11.80%	54.04%		100.0%	66.07%	52.78%						58.1%	22.4%
Including Gas Turbine	16.90	5.84	26.73	50.53	100.0			94.48%	100.0%	100.0%	5.52%			

a) Estimated 1970 data.

b) Adjusted from estimated gas turbine data for 1970.

TABLE 8

U. S. Electric Power Generation by Type of Capacity, 1970, 1980, and 1990[a)]

Power Source	Capacity 10^6 kw	Capacity %	Generation 10^9 kw-hr	Generation %	Capacity Factor %
			1970 - Actual		
Conventional hydro	51.6	15.2%	253	16.4%	56%
Pumped-storage hydro	3.6	1.1	4	0.3	13
Fossil steam	259.1	76.2	1,241	80.5	55
Nuclear	6.5	1.9	22	1.4	39
IC engine	4.0	1.2	4.4	0.3	12
Gas turbine	15.2	4.4	16.6	1.1	12
U. S. Total	340	100.0%	1,541	100.0%	52%
			1980 - Estimated		
Conventional hydro	68	10.2%	292	9.3%	49%
Pumped-storage hydro	27	4.1	25	0.8	10
Fossil steam	390	58.6	1,895	60.9	55
Nuclear	140	21.1	874	28.1	71
IC engine	8	1.2	5.4	0.2	8
Gas turbine	32	4.8	21.6	0.7	8
U. S. Total	665	100.0%	3,113	100.0%	53%
			1990 - Estimated		
Conventional hydro	82	6.5%	319	5.4%	44%
Pumped-storage hydro	70	5.5	62	1.1	10
Fossil steam	558	44.3	2,579	43.5	53
Nuclear	475	37.7	2,913	49.2	70
IC engine	12	1.0	7.8	0.1	7
Gas turbine	63	5.0	41.2	0.7	7
U. S. Total	1,260	100.0%	5,922	100.0%	54%

[a)] Annual Power Survey, 1970, Federal Power Commission, Washington, D.C. (1971)

b. Population Characteristics of Reciprocating Engines

ASME data on the cost of diesel and gas engine power[6] have been analyzed to determine the population characteristics of I.C. engines used by the electric utility industry. The results are summarized in Table 9. The ASME engine sample represents about 20 percent of the reciprocating engine horsepower used in electric power generation.

About 36 percent of the engines and 30 percent of the kilowatt capacity are supplied by oil-fueled diesels and most of the remainders by dual-fuel diesels. Less than two percent is supplied by natural gas engines. Overall, 55 percent of the engines are two-cycle and 45 percent are four-cycle. The average power capacity is 1793 kw and the average fuel consumption is 11,300 Btu/kw-hr (8425 Btu/Bhp-hr). For No. 2 oil, this corresponds to 0.5816/kw-hr (0.44 lb/Bhp-hr).

c. Fuel Consumption and Emissions

Table 10 summaries estimates of annual power generation, fuel consumption and pollutant emissions from stationary engines and gas turbines in power generation for the years 1970, 1980, and 1990. Power generation was estimated by assuming that engines and gas turbines generate power in the same ratio as their installed capacities. Fuel consumption and NOx, CO, and hydrocarbon emissions estimates were calculated from power generation using weighted average factors based on the population distribution in Table 9.

Total NOx emissions were 104 thousand tons in 1970 of which 60 percent was generated by engines. The fractional contribution from engines will decrease to 52 percent in 1990, as gas turbines are installed in favor of reciprocating engines. The absolute magnitude of NOx emissions from engines and turbines in electric power generation is still small in comparison to emissions from the oil and gas industry.

3. Crude Oil, Product, and Natural Gas Pipelines

In 1971, the total natural gas, crude oil, and products pipeline mileage in the U.S. was over 1,100,000 miles, long enough to circle the earth's equator more than 40 times. Of this total, about half is small diameter pipe used in gas distribution to users, about a quarter is used in field gathering and long distance transmission of natural gas, and a quarter is used in gathering and transmission of crude oil and petroleum products.

a. Installed Horsepower

Tables 11 and 12 summarize current estimates of total installed horsepower by absolute magnitudes and percentages, respectively, for crude oil and products pipelines and natural gas transmission, distribution, and field/gathering pipelines. These estimates are based on data published by the American Gas Association,[3,4] the American Petroleum Institute,[5] Pipeline News,[33] and the Oil and Gas Journal.[13] Data from the last reference are reproduced in the Appendix.

The total installed horsepower on all pipelines is estimated to be 22,125,000 Bhp. Overall, reciprocating gas engines and electric drives make up

TABLE 9

Reciprocating Engine Population Characteristics in Electric Power Generation [a)]

Number of Engines in Sample: 454

Total Power Capacity: 806,120 kw

Total Power Generation: 1944.37 x 10^6 kw-hr

Engine Type		Percent of Total Number	Percent of Total Kw Capacity	Percent of Total Kw-hr Generation	Average Power Capacity per Unit Kw	Average Power Capacity per Unit BHP	Average Capacity Factor	Percent Installed Before 1945	Percent Installed 1945-55	Percent Installed 1955-65	Percent Installed After 1965
Oil-Fuel Diesel	2-Cycle	25.1%	21.7%	19.9%	1548	2075	25.1%	47.1	36.8	12.3	3.8
	4-Cycle	10.8	7.5	6.1	1251	1678	22.0	33.3	37.8	22.2	6.9
	Total	35.9	29.2	26.0	1458	1956	24.3	43.1	37.1	15.2	4.6
Dual-Fuel	2-Cycle	30.0	34.6	40.0	2070	2775	31.5	1.5	40.7	37.8	20.0
	4-Cycle	32.1	34.6	32.2	1928	2585	26.2	2.8	30.8	37.0	29.4
	Total	62.1	69.2	72.2	1996	2677	28.9	2.2	35.6	37.4	24.8
Natural Gas Spark	2-Cycle	0.2	0.2	0.06	1690	2266	7.4	0	100.0	0	0
	4-Cycle	1.8	1.4	1.7	1476	1979	32.0	25.0	75.0	0	0
	Total	2.0	1.6	1.8	1499	2011	28.9	22.2	77.8	0	0
All Engines	2-Cycle	55.3	56.5	60.0	1831	2456	30.0	21.5	39.3	26.4	12.8
	4-Cycle	44.7	43.5	40.0	1764	2366	25.6	10.7	34.2	32.1	23.0
	Total	100.0	100.0	100.0	1793	2405	27.5	16.7	37.0	29.0	17.3

a) Data source "1972 Report on Diesel and Gas Engines Power Costs", American Society Mechanical Engineers, New York (1972).

b) Dual-fuel engine data include 2 tri-fuel 4-cycle engines rated at 8110 kw; average fuel mix 79% natural gas, 21% No. 2 fuel oil.

TABLE 10

Electric Power Generation, Fuel Consumption, and Emissions - 1970, 1980, and 1990

Year	Type	Power Generation 10^9 kw-hr	Fuel Consumption[b)] 10^6SCF	No. 2 Oil 10^3 bbls	Annual Emissions Tons[c)] NOx	CO	HC_t	% of NOx
1970	Recip. Engine[a)]	4.4	22,750	2,900	62,440	18,200	16,260	60.0
	Gas Turbine	16.6	64,400	30,400	41,710	-	-	40.0
	Total	21.0	87,150	33,300	104,150	18,200	16,260	100.0
1980	Recip. Engine	5.4	27,900	3,590	76,630	22,350	19,960	58.5
	Gas Turbine	21.6	83,850	53,000	54,280	-	-	41.5
	Total	27.0	111,750	56,590	130,910	22,350	19,960	100.0
1990	Recip. Engine	7.8	40,320	5,180	110,700	32,280	28,825	51.7
	Gas Turbine	41.2	159,900	75,850	103,500	-	-	48.3
	Total	49.0	200,220	81,030	204,200	32,280	28,825	100.0

a) The following distribution of power generation (kw-hr) is assumed for reciprocating engines: 19.9% 2-cycle diesel, 6.1% 4-cycle diesel, 40.0% 4-cycle dual fuel, 32.2% 2-cycle dual fuel, 0.06% 2-cycle natural gas, and 1.7% 4-cycle natural gas.

b) Fuel properties assumed: gas LHV = 950 Btu/SCF, oil HHV = 19,600 Btu/lb; dual fuel engines burn 79% gas, 21% oil based on Btu's. Fuel consumption: diesels 0.4 lb/Bhp-hr, dual fuel 6200 Btu/Bhp-hr, gas engine 7000 Btu/Bhp-hr, gas turbines 11,000 Btu/Bhp-hr.

c) Emissions factors:

	Grams/Bhp-hr NOx	CO	HC_t
Reciprocating Engines	9.6	2.8	2.5
Gas Turbines	1.7	0	0

TABLE 11

Oil and Gas Pipelines - Installed Horsepower and Pipeline Mileage

Compressor Drive	Installed Compressor and Pump Horsepower (BHP): Natural Gas Utilities Only: Transmission	Distribution	Storage	Field + Gathering	Crude Oil	Products	Total	% of Total
Recip. Gas Engine	7,573,030	680,760	1,042,390	1,540,225	147,280	6,120	10,989,805	49.67%
Diesel	-	16,740	-		783,590	28,890	829,220	3.75
Dual Fuel	-	-	-		211,230	178,430	389,660	1.76
Total Recip.	7,573,030	697,500	1,042,390	1,540,225	1,142,100	213,440	12,208,685	55.18%
Gas Turbine	3,090,940	-	-	264,160	65,520	100,940	3,521,560	15.92
Steam Turbine	129,540	42,180	-	-	1,050	-	172,770	0.78
Electric	470,850	333,570	-	-	4,032,700	1,384,920	6,222,040	28.12
Total Horsepower	11,264,360[a)]	1,073,250	1,042,390[c)]	1,804,385[a)]	5,241,370[d)]	1,699,300	22,125,055	100.00%
Pipeline Miles	252,621[c)]	595,653[c)]	3,704[a)]	66,556[c)]	149,051[b)]	73,570[b)]	1,141,155	-

a) Source: Oil and Gas Journal, 127-139, June 12, 1972.

b) Source: Petroleum Facts and Figures, 1971 Edition, American Petroleum Institute, New York (1971).

c) Source: Gas Facts, A Statistical Record of the Gas Utility Industry in 1970, American Gas Association, Arlington, Virginia (1971).

d) Horsepower factors and power source distributions derived from data in the Pipe Line News "Annual Directory of Pipelines" 1971-72 Issue.

TABLE 12

Oil and Gas Pipelines - Percentage Breakdown of Installed Horsepower by Power Source and Application

Percent of Total Within Application

	Natural Gas						
Power Source	Trans-mission	Distri-bution	Storage	Field + Gathering	Crude Oil	Products	% of Total
Recip. Gas Engine	67.23%	63.43%	100.0%	85.36%	2.81%	0.36%	49.67%
Diesel	-	1.56	-	-	14.95	1.70	3.75
Dual Fuel	-	-	-	-	4.03	10.50	1.76
Total Recip.	67.23%	64.99%	100.0%	85.36%	21.79%	12.56%	55.18%
Gas Turbine	27.4	-	-	14.64	1.25	5.94	15.92
Steam Turbine	1.15	3.93	-	-	0.02	-	0.78
Electric	4.18	31.08	-	-	76.94	81.50	28.12
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Total Horsepower	11,264,360	1,073,250	1,042,390	1,804,385	5,241,370	1,699,300	22,125,055

the largest fractions of the total (49.7% and 28.1%, respectively). Other power sources include diesel engines (3.8%), dual fuel engines (1.8%), gas turbines (15.9%), and steam turbines (0.8%). Thus, reciprocating engines provide 55.2 percent and gas turbines 15.9 percent of the installed horsepower on pipelines.

About 50 percent of the horsepower is located on natural gas transmission pipelines, 5 percent each on gas distribution lines and at storage fields, 10 percent in the field, 25 percent on crude oil pipelines, and 5 percent on products pipelines.

Most of the horsepower in natural gas pipeline applications is provided by gas engines and turbines. On transmission pipelines, 67.2 percent of the horsepower is gas engine, 27.4 percent is gas turbine and only 5.4 percent is steam turbine and electric drive. In contrast, 76.9 percent and 81.5 percent of the horsepower on crude oil and products pipelines, respectively, are provided by electric drives, and only 23.0 percent and 18.5 percent comes from engines and turbines.

Table 13 summarizes population data for reciprocating gas engines on natural gas transmission pipelines. The data are derived from data published in an AGA directory of reciprocating engines.[4] A total of 3257 engines and 6,926,289 horsepower are listed in the directory. There are no naturally aspirated 4-cycle gas engines listed. About 62.1 percent of the engines and 47.0 percent of the horsepower are 2-cycle atmospheric gas engines. Turbocharged 2-cycle and 4-cycle engines contribute 30.6 and 22.4 percent of the horsepower. Overall, the average horsepower is 2127 Bhp.

b. Fuel Consumption and Emissions

Estimates of the current annual fuel consumption and pollutant emissions of NOx, CO, and hydrocarbons by pipeline engines and gas turbines are given in Table 14. Power generation was estimated using pipeline fuel consumption data published by the U.S. Bureau of Mines.[39] The relative power generation by gas engines and turbines was assumed to be in proportion to their power generating capacity. Diesel and dual fuel engine power generation were prorated from the gas engine and turbine power generation. Emissions factors for gas engines are composites based on the population characteristics in Table 13.

Total NOx emissions from pipeline engines and gas turbines are estimated to be 970,118 tons of which 87.5 percent comes from gas engines, and 4.1 percent comes from gas turbines. Total CO and hydrocarbon emissions are each about one third the magnitude of NOx emissions.

4. Natural Gas Processing Plants

Natural gas processing plants are used to recover liquid petroleum products and remove hydrogen sulfide from produced natural gas. Bureau of Mines data show that during 1971, more than 19×10^{12} standard cubic feet of natural gas were processed and 600 million gallons of liquid products were recovered by gas plants in the U.S.[39]

TABLE 13

Population Characteristics of Reciprocating Gas Engine Compressors on Natural Gas Pipelines[a)]

Engine Type	Number of Units	% of Total No.	Installed Horsepower[b)]	% of Total BHP	Average Horsepower
4-Cycle Spark-Gas					
Naturally-Aspirated	0	0%	0	0%	-
Turbocharged	808	24.8	1,550,909	22.4	1919
2-Cycle Spark-Gas					
Atmospheric	2021	62.1	3,258,410	47.0	1612
Turbocharged	428	13.1	2,116,970	30.6	4946
Totals	3257	100.0	6,926,289	100.0	2127

a) Data Source: "Directory of Reciprocating Gas Engines in Use by Various Gas Pipeline Companies," American Gas Association, Arlington, Va. (Sept. 1971).

b) Excludes unclassified horsepower.

TABLE 14

Oil and Gas Pipelines - Engine and Gas Turbine Fuel Consumption, Power Generation, and Emissions (1971)

Engine Type	Fuel Consumption[a)] Gas 10^6 SCF	Fuel Consumption[a)] No. 2 Oil 10^3 Bbls	Power Generation[a)] 10^6 Bhp-hr	1971 Emissions (Tons)[a)] NOx	1971 Emissions (Tons)[a)] CO	1971 Emissions (Tons)[a)] HC_t	1971 Emissions (Tons)[a)] % of NOx
Recip. Gas Engine	488,900	-	66,350	848,400	270,600	270,600	87.5%
Diesel	-	6520	5,000	60,600	22,000	550	6.2
Dual Fuel	12,120	510	2,350	21,200	5,200	8,030	2.2
Total Recip.	501,020	7030	73,700	930,200	297,800	279,200	95.9%
Gas Turbine	248,570	-	21,260	39,800	-	-	4.1
Total	749,590[b)]	7030	94,960	970,000	297,800	279,200	100.0%

a) Assumed values for brake specific fuel consumption (BSFC), and specific emissions (BSE):

	BSFC	BSE (grams/Bhp-hr) NOx	BSE (grams/Bhp-hr) CO	BSE (grams/Bhp-hr) HC_t
Reciprocating Gas Engines	7,000 Btu/Bhp-hr	11.6	3.7	3.7
Diesel Engines	0.4 lb/Bhp-hr	11	4	0.1
Dual Fuel Engines	6,200 Btu/Bhp-hr	8.2	2.0	3.1
Gas Turbines	11,000 Btu/Bhp-hr	1.7	-	-

Dual Fuel engines average 79% gas and 21% No. 2 oil based on Btu content.

b) U.S. Bureau of Mines, Mineral Industry Surveys, "Natural Gas Production and Consumption 1971" (1972).

a. Applications of Engines

The principle application of engines in gas plants is to drive gas compressors. Other power sources include gas turbines, steam turbines, and electric drives. Gas turbines with heat recovery are being favored in new plants producing more than 200,000 gal/day liquids. High speed 4-cycle gas engines are favored in smaller plants.

In high pressure gas plants, e.g., those that receive gas at high pressure, liquid products are often recovered cryogenically and engines and gas turbines drive refrigeration compressors and compress flashed gases. In low pressure plants the compressors raise the gases to sales pressure (500 to 1000 psig).

b. Estimated Horsepower, Fuel Consumption, and Emissions

Table 15 summarizes estimates of current installed horsepower, fuel consumption, power generation, and pollutant emissions from engines and gas turbines in gas plants. The estimates are based on a survey of a large number of gas plants in the U.S. The survey showed that about 100 hp of compressor capacity is installed per 10^6 SCF per day throughput and that about 46 percent of the installed horsepower is reciprocating gas engine, 29 percent is gas turbine, 23 percent is steam turbine, and 2 percent is electric drive. The survey also showed that about 2.1 percent of the gas throughput is burned in boilers, heaters, and other non-engine uses.

Extrapolation of these data to the 1971 gas throughput (19,253 x 10^9 SCF) yields a total installed horsepower of 5,275,000 and an annual fuel consumption of 230,500 x 10^6 SCF in engines and of 173,800 x 10^6 SCF in gas turbines. Annual power generation and emissions were estimated from fuel consumption. Annual NOx emissions for reciprocating engines were estimated at 420,690 tons and those for gas turbines, 28,130 tons. The emissions factors for reciprocating gas engines are weighted averages and assume that the engine population consists of 69.0 percent 2-cycle atmospheric, 7.6 percent 4-cycle naturally aspirated, and 23.4 percent high speed 4-cycle turbocharged gas engines. These proportions were also derived from industry survey data.

5. Oil and Gas Exploration and Production

Stationary engines are used to drive a variety of equipment in both oil and gas exploration and production. In exploration, gas and diesel engines drive electric generators, drawworks, drilling mud pumps, and rotary drilling rigs. Crude oil production uses engines to drive beam pumps, gas lift compressors and hydraulic pump power pumps. Repressuring compressors are driven by engines in gas production.

a. Exploration

Figure 7 shows the trends in the number of wells drilled and total well footage in U.S. oil and gas exploration for 1962 through 1971.[5,42] During this period, there has been a general downtrend in the number of wells drilled (-45%) and an uptrend in the average well depth (+15%). In 1971, 26,077 wells were drilled, of which 44.1 percent were oil producers, 13.0 percent were gas producers, 40.0 percent were dry holes, and 2.8 percent were service wells.

TABLE 15

Natural Gas Processing Plants - Compressor Horsepower, Power Generation, and Emissions - 1971

	% of Total	1971
Natural Gas Processed[a)] - 10^6 SCF	-	19,252,807
Liquids Recovered[a)] - 1000 Bbls.	-	617,915
Compressor Horsepower - Bhp		
Reciprocating Gas Engines[b)]	45.7%	2,410,600
Gas Turbines	29.0	1,529,800
Steam Turbines	23.1	1,218,500
Electric Drives	2.2	116,100
Total	100.0%	5,275,000
Fuel Consumption - 10^6 SCF		
Reciprocating Gas Engines	1.2%	230,500
Gas Turbines	0.9	173,800
Boilers, Heaters, and Misc.	1.1	211,790
Total (3.2% of throughput)	3.2%	616,090

Power Generation and Emissions:[c)]

	Power Generation 10^6 Bhp-hr	Emissions Tons NOx	CO	HC_t
Reciprocating Gas Engines	31,280	420,690	55,170	117,240
Gas Turbines	15,010	28,130	0	0
Total	46,290	448,820	55,170	117,240

a) U.S. Bureau of Mines, Mineral Industry Surveys, "Natural Gas Production and Consumption - 1971" (1972).

b) Assume 69.0% 2-cycle atmospheric, 7.6% 4-cycle naturally aspirated, and 23.4% 4-cycle high-speed turbocharged gas engines.

c) Fuel Consumption and Emissions Factors:

	BSFC Btu/Bhp-hr	Grams/Bhp-hr NOx	CO	HC_t
Reciprocating Gas Engines	7,000	12.2	1.6	3.4
Gas Turbines	11,000	1.7	0	0

Natural Gas LHV: 950 Btu/SCF

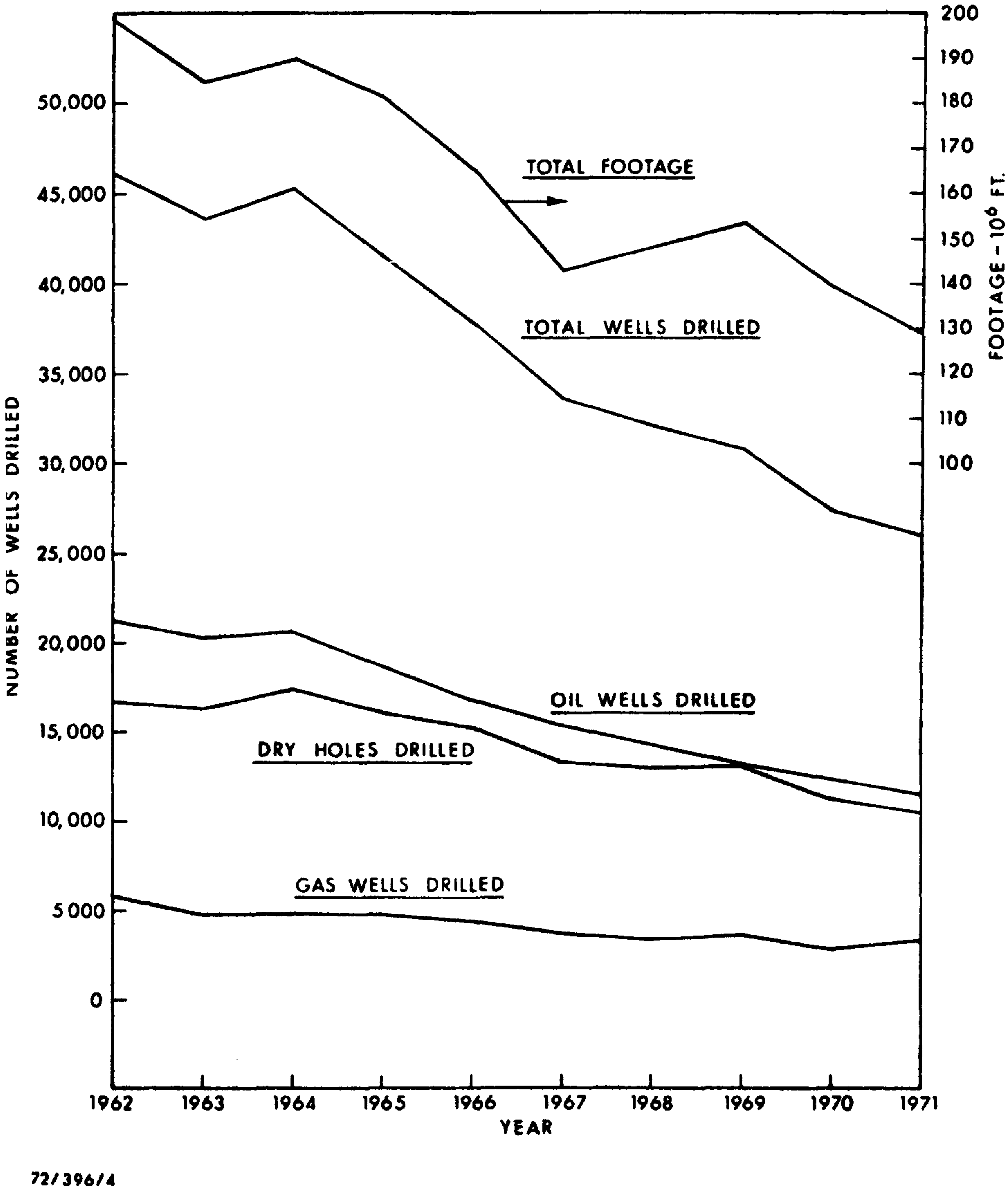


Figure 7. U.S. Oil and Gas Exploration 1962 - 1971

Source : World Oil, Forecast-Review Issues (1961-72)

The total footage drilled was 129 million feet, and the overall average well depth was 4950 feet.

Both diesel and gas engines are used on drilling rigs. An industry survey indicated that, on the average, each drilling rig uses about 1000 engine horsepower of which 75 percent is diesel engine. Typically, this includes two 75 kw AC power generators corresponding to a total of about 200 horsepower. During 1971, an average of 1235 drilling rigs were in use in the U.S., a decrease from 1506 in 1970 and 2074 in 1969. Assuming there are about 2000 drilling rigs in existence, but not necessarily operating at the same time, the total installed engine horsepower on drilling rigs is about 2 million Bhp. Power generation by engines is in the area of 2000 Bhp-hr per 100 ft of well depth drilled.

Table 16 summarizes estimated statistics for drilling rigs in oil and gas exploration during 1971. Power generation is estimated at 2.5×10^9 Bhp-hr, corresponding to a capacity factor of about 14 percent. Assuming 25 percent of the power was generated by gas engines and the remainder by diesels, fuel consumption is estimated at 2.5 million barrels of No. 2 fuel oil and 4800 million SCF of natural gas. Total NOx emissions are 31,700 tons of which 74 percent is produced by diesels.

b. Production

As shown in Figure 8, U.S. crude oil and natural gas production increased steadily between 1962 and 1970 but since then have shown signs of leveling off or decreasing.[3,5,42] In 1971, crude oil production averaged more than 9.5 million barrels per day and gross natural gas production was more than 24×10^{12} SCF. Approximately 78 percent of this gas production was from gas wells and the remainder from oil wells. Net marketed gas production, left over after repressuring, vented, and flared gas are deducted, was more than 22×10^{12} SCF.[39]

Tables 17 and 18 summarize estimated statistics for stationary engines in crude oil and natural gas production, respectively.

(1) Oil Production

In 1971, there were 512,471 producing oil wells in the U.S. Approximately 92 percent of these were on artificial lift, and the remainder were naturally flowing without the aid of mechanical pumps. An industry survey indicated that 78 percent of the wells are beam pumped, 10 percent are on gas lift, and 3.5 percent are on hydraulic lift. The pumping method depends on well depth. Beam pumps are favored for relatively shallow wells (<9000 feet) and gas and hydraulic lifts for deeper wells.

Beam pumps are usually driven by electric motors - only about 4 percent are driven by gas engines. Beam pump engines are specified to run at about 65 percent of rated load, so that NOx emissions are likely to be less than half the full load value or about 5 grams/Bhp-hr.

In contrast, compressors used in gas-lift pumping are almost always driven by gas engines (95%). Two-stage reciprocating compressors are most common, and are built either integrally with the engine or as separate units.

TABLE 16

Oil and Gas Exploration - Power Generation, Fuel Consumption and Emissions - 1971

			1971
Total Number of Wells Drilled in U.S.[a]			26,077
Total Footage[a] -		ft	129,060,434
Average Footage[a] -		ft	4,949
Installed Engine Horsepower			2,000,000
Power Generation[b]	10^6 Bhp-hr		2,581
Fuel Consumption:[c]	No. 2 Oil @ 75%	(1000 Bbls)	2,526
	Natural Gas @ 25%	(10^6 SCF)	4,755

Emissions:[d]

	Tons		
	NOx	CO	HC_t
Diesel Engines	23,470	8,540	213
Gas Engines	8,250	2,630	2,630
Total	31,720	11,170	2,840

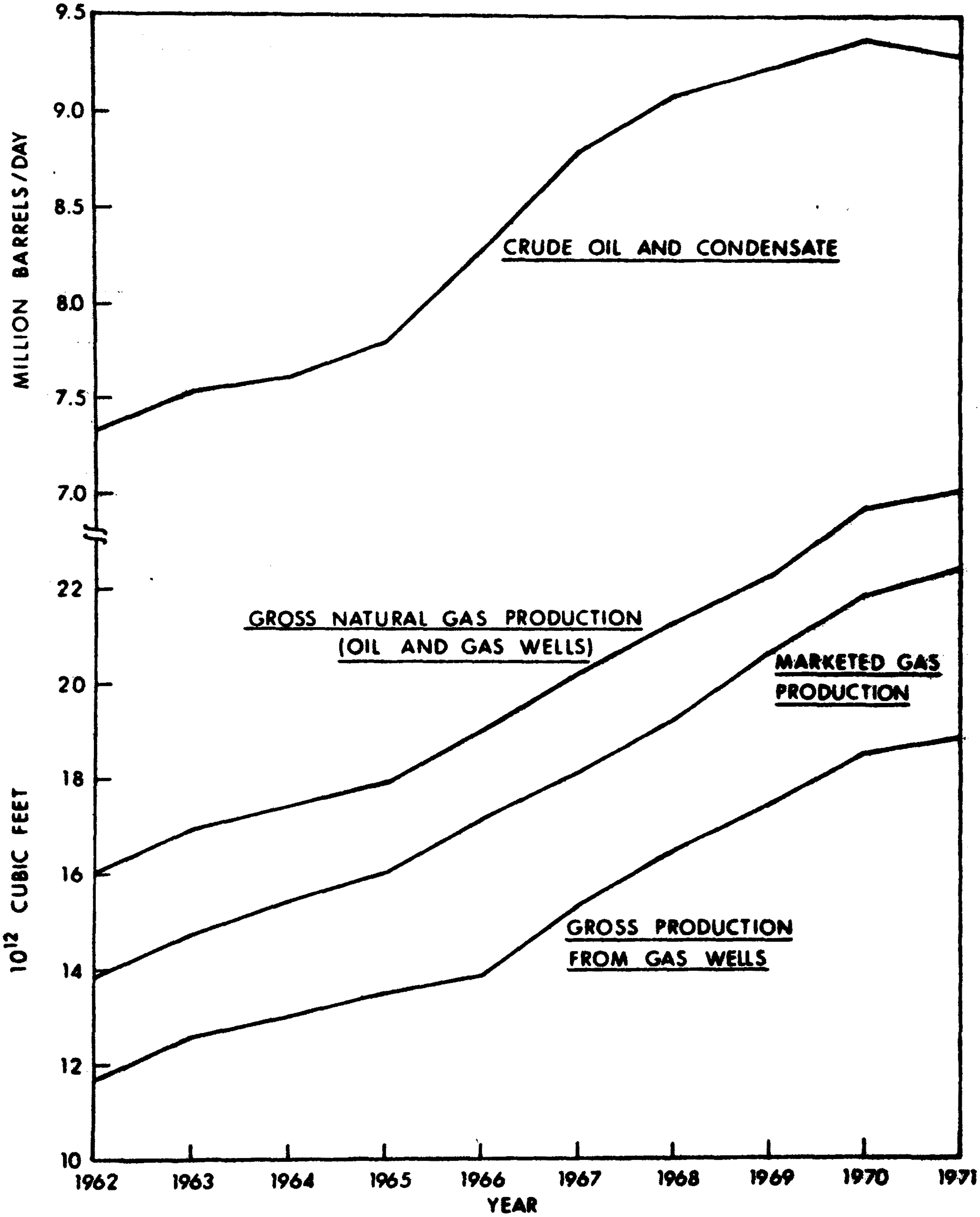
a) Source: World Oil, February 15, 1972.

b) Assumes 2000 Bhp-hr/100 ft drilled.

c) Assumes 75% of power generated by diesels at 0.4 lb/Bhp-hr, 7.3 lb/gal and 25% by gas engines at 7000 Btu/Bhp-hr, 950 Btu/SCF.

d) Emissions Factors:

	Grams/Bhp-hr		
	NOx	CO	HC_t
Diesel Engines	11	4	0.1
Gas Engines	11.6	3.7	3.7



72/396/5

Figure 8. U.S. Oil and Gas Production 1962 - 1971

TABLE 17

Crude Oil Production - Power Generation, Fuel Consumption, and Emissions - 1971

	% of Total		1971
Number of Producing Oil Wells[a)]	-		512,471
Number on Artificial Lift[a)]	91.7%		469,809
Estimated Number[b)]			
Beam Pumped	77.9		399,277
Gas Lift	10.3		52,562
Hydraulic Lift	3.5		18,270
Estimated Number Driven by Engines[b)]			
Beam Pumps	3.1		15,971
Gas Lift Compressors	9.7		49,934
Power Capacity and Generation	Bhp		10^6 Bhp-hr
Beam Pump Gas Engines	214,000		938.0
Gas Lift Gas Engines	638,000		4473.0
Fuel Consumption:[e)] 10^6 SCF gas			
Beam Pump Engines			6,910
Gas Lift Engines			32,960
Total			39,870
Emissions[f)]	Annual Tons		
	NOx	CO	HC_t
Beam Pump Engines	5,170	3,830	3,830
Gas Lift Engines	57,200	18,200	22,100
Total	62,370	22,030	25,930

a) Source: World Oil, February 15, 1972.

b) Based on industry survey of distribution of pumping units.

c) Beam pump engine power generation

$$= \frac{2.5\ (\text{Average Well Depth})(\text{Avg Daily Production})\ \rho\text{oil + water}}{136{,}800 \times (\text{Avg fraction water})\ \rho\text{oil}} \times 8760$$

Average daily production by engine driven beam pumps = 229,441 bbls, 78.6% from 4500 ft wells (75% water) and 21.4% from 8500 ft wells (70% water).

d) Gas lift engine power generation =

$$\left\{23n\left[\left(\frac{Pd}{Ps}\right)^{1/n} \times 1.05\right] \text{Bhp}/10^6\ \text{SCF}\right\}\left(G\ \frac{\text{SCF gas}}{\text{Bbl oil produced}}\right)$$

Assumes compressor has n = 2 stages, pressure ratio is Pd/P_s = 14, and G = 10,000 SCF of gas is injected in well per barrel of produced liquids (oil and water). Annual production by engine driven gas lift is 724,148,000 bbls.

e) Assumes 7000 Btu/Bhp-hr at 950 Btu/SCF.

TABLE 17 (Continued)

f) Emissions factors

	Grams/Bhp-hr		
	NOx	CO	HC_t
Beam pump engines	5.0	3.7	3.7
Gas lift engines	11.6	3.7	3.7

TABLE 18

Natural Gas Production - Power Generation, Fuel Consumption, and Emissions

			1971
Gross Production[a)]:	Gas Wells (10^6 SCF)		18,925,136
	Oil Wells (10^6 SCF)		5,187,837
	Total (10^6 SCF)		24,103,973
Number of Producing Gas Wells[b)]			117,300
Power Capacity - Gas Engines[c)] (Bhp)			3,237,000
Power Generation - Gas Engines (10^6/Bhp-hr)			24,104
Fuel Consumption by Gas Engines[d)] (10^6/SCF)			177,608
Emissions:		Emission Factor grams/Bhp-hr	Annual Tons
	NOx	11.6	308,200
	CO	3.7	98,300
	HC_T	3.7	98,300

a) U.S. Bureau of Mines, Mineral Industry Surveys, "Natural Gas Production and Consumption - 1971" (1972).

b) World Oil, February 15, 1972.

c) Assumes 1,000 Bhp-hr/10^6 SCF produced gas.

d) Assumes 7,000 Btu/Bhp-hr at 950 Btu/SCF.

Compressor pressure ratios are typically 12 to 16.[16] Gas lift is the most prevalent artificial lift method found on offshore platforms.

Hydraulic lift utilizes a submerged piston pump driven by a piston engine running on high pressure hydraulic fluid supplied from the surface. It is assumed that the hydraulic pressure pumps are driven by electric drives.

The estimated engine power generation for beam pump engines in 1971 was 938 x 10^6 Bhp-hr and 4473 x 10^6 Bhp-hr for gas lift engines. Fuel consumption was 6900 x 10^6 SCF and 32,960 x 10^6 SCF, respectively. Beam pump and gas lift engines emitted 5170 and 57,200 tons of nitrogen oxides, respectively.

These estimates were derived using representative well data for the Gulf Coast area and the remainder of the U.S.[5] For the Gulf Coast area it was assumed that the average well depth is 8500 ft, the produced liquids contain 70 percent water, 1971 production was 1,519 million barrels from 76,800 wells, and 70 percent of the wells are on artificial lift. For the remainder of the U.S., the average well depth is assumed to be 4500 feet, water content is 75 percent, 1,967 million barrels were produced in 1971 from 435,600 wells, and 95 percent of the wells are on artificial lift. Per barrel of fluids produced by gas lift, it was assumed that 10,000 SCF of gas is compressed.

(2) Natural Gas Production

In 1971, the number of producing gas wells in the U.S. was 117,300 and the gross natural gas production from gas wells was 18.9 x 10^{12} SCF, and from oil wells 5.2 x 10^{12} SCF.[39] In gas production, engines are used to drive compressors that repressure gas for reinjection into the producing formation. An industry survey indicated that gas engines generate about 1000 Bhp-hr per million standard cubic feet of gross production, not including power generation in gas-lift pumping of oil wells. Power generation and fuel consumption are estimated to be 24.1 x 10^9 Bhp-hr and 177.6 x 10^9 SCF, respectively. Annual NOx emissions are 308,200 tons.

6. Miscellaneous Applications

Stationary engines are also used to drive agricultural water pumps, industrial process equipment and plant air compressors, and municipal water and sewage pumps. Table 19 gives estimates of installed horsepower, power generation, fuel consumption, and emissions for each of these applications. Estimated power capacities are taken from an AGA report.[19] For agricultural, industrial, and municipal engines, respectively, it was assumed that capacity factors are 40, 75, and 75 percent, and engine types are diesel, gas engine, and 50 percent diesel/50 percent gas engine.

VII. Significance of Stationary Engines as a Local Pollution Source

In the previous section, it was estimated that NOx emissions from stationary reciprocating engines total 2.2 million tons annually. Almost half of this is generated by engines on oil and gas pipelines alone. Since large concentrations of horsepower, e.g., 10,000 to 60,000 Bhp, are often located in one place, it is important to determine the potential of stationary engines as pollution hazards in populated areas.

TABLE 19

Miscellaneous Applications - Installed Horsepower, Power Generation and Emissions[a)]

	Agricultural Wells	Industrial Process and Plant Air	Municipal Water and Sewage Pumping
Installed Horsepower	7,500,000	230,000	930,000
Estimated Capacity Factor	40%	75%	75%
Power Generation 10^6 Bhp-hr	26,280	1,510	6,110
Engine Type:			
Diesel	100%	0%	50%
Natural Gas	0%	100%	50%
Fuel Consumption:[b)]			
1,000 Bbls Oil	34,300	0	3,990
10^6 SCF Gas	0	11,100	22,500
Emissions Tons:			
NOx	318,700	19,300	76,100
CO	116,900	6,160	25,900
HC_T	2,900	6,160	12,500

a) Source: American Gas Association, Gas Engine Market Study, Report by William E. Hill and Co. (1968).

b) Assumes 0.4 lb/Bhp-hr, 7.3 lb/gal for diesels, 7,000 Btu/Bhp-hr, 950 Btu/SCF for gas engines.

c) Emission Factors: grams/Bhp-hr

	NOx	CO	HC_T
Diesels	11	4	0.1
Gas Engines	11.6	3.7	3.7

1. Natural Gas Transmission Compressor Stations - An Example

The prime user of large concentrations of reciprocating gas engine power is the natural gas transmission pipeline. For one large U.S. gas transmission company, installed horsepower at mainline compressor stations ranges between about 15,000 and 40,000 Bhp. The corresponding full-load NOx emission rate ranges between 330 and 880 lb/hr.[a] Using standard dispersion formulas, the maximum ground level NOx concentrations are predicted to range between 3900 and 10,500 micrograms/cubic meter, approximately one eighth mile downwind (adjusted to one-hour sampling time).[b] These predictions are very likely conservative (high). They are significantly higher than the California standard for nitrogen dioxide - 470 μg/cu meter one hour maximum (0.25 ppm). Most of the NOx is emitted as nitric oxide (NO), although it is converted rapidly to nitrogen dioxide by photochemical reactions between NO, O_2, hydrocarbons, and OH free radicals. Nevertheless, it is clear that gas pipeline engines are potential problems in densely populated areas.

The question is then, how dense is the population in the immediate area surrounding the compressor stations?

Figure 9 summarizes population data derived from the pipeline "house count" compiled by a major gas transmission company. The number of houses located in a 1/4 x 1/4 mile square surrounding each compressor station was determined. Census data were used to estimate the number of people occupying the houses. The results of the analysis are reported in Figure 9 as the percentage of compressor stations having X people living within 1/8 mile and the percentage having Y people within 1/8 mile per 1000 Bhp installed compressor horsepower.

More than 37 percent of the compressor stations have no houses or people living within any of the 1/4 x 1/4 mile square areas. An additional 34.2 percent of the stations have fewer than 10 people within the immediate area. Analysis of the data shows that fewer than six people live near most of these stations. Less than one person per 1000 Bhp installed horsepower is in the immediate area at 79.8 percent of the stations.

2. Conclusion

These statistics indicate that human exposure to pipeline engine emissions is minimal. It is still significant, however, that a small number of people and station operators may be exposed to ambient NOx concentrations in excess of air quality standards.

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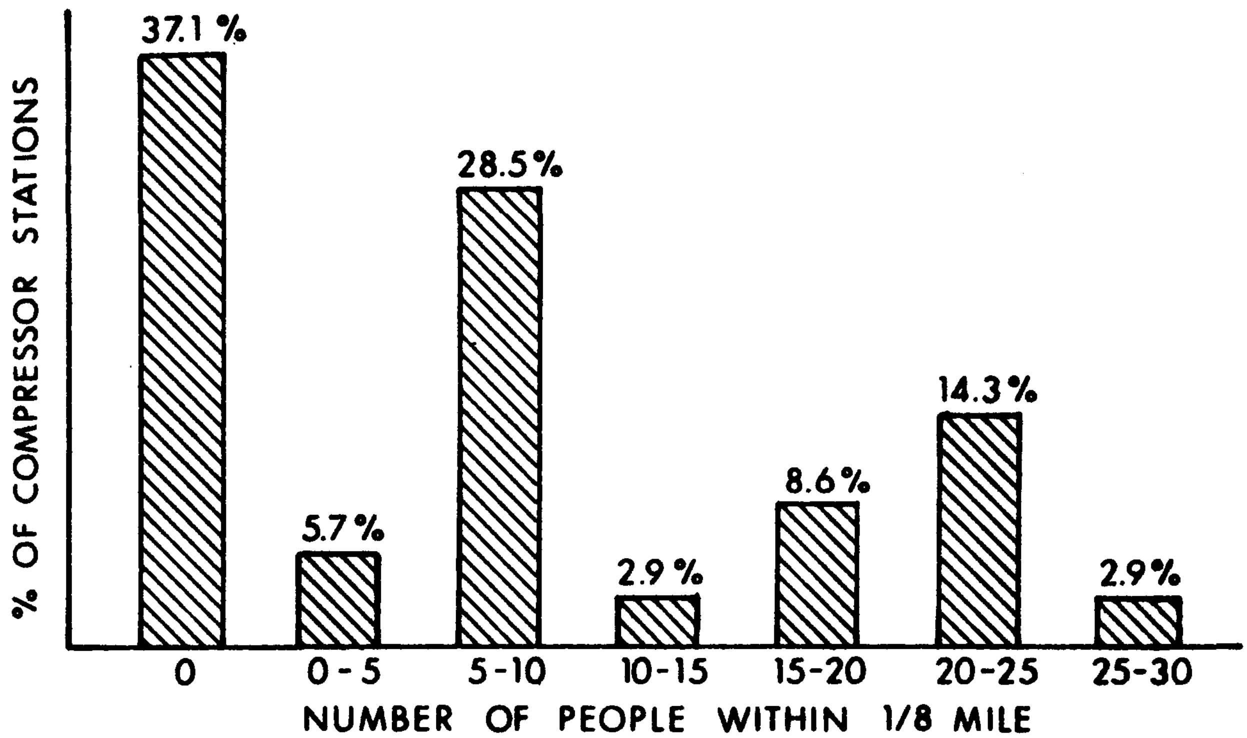
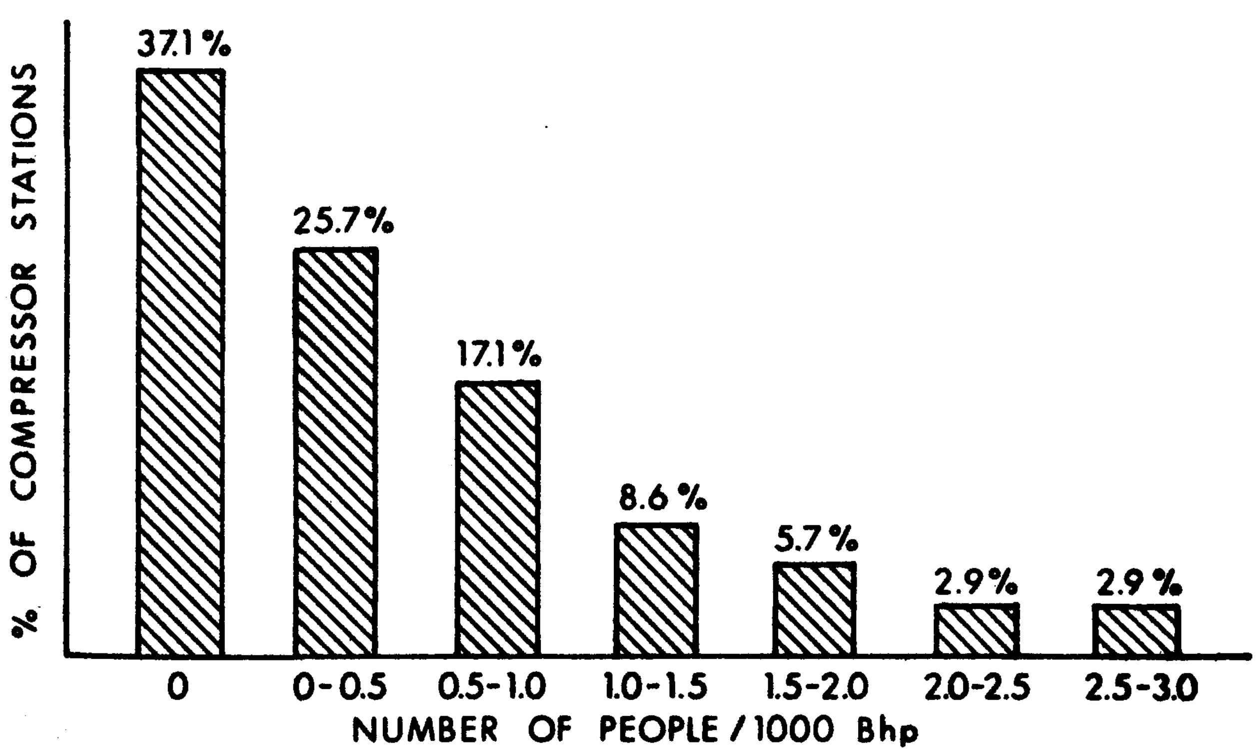
a) Assumes NOx emitted at 10 grams/Bhp-hr as NO_2.

b) D. B. Turner, Workbook of Atmospheric Disperson Estimates (Ref 44); assumed stability Class C, wind velocity = 2 meter/sec, stack height = 20 meters,

$$\frac{C(1\ \text{hour sample})}{C(3\ \text{min sample})} = 0.545$$





72/396/7

Figure 9. Number of People Within 1/8 Mile of Compressor Stations

VIII. Potential Emissions Control Methods for Stationary Reciprocating Engines

During the past decade, the automotive industry has been actively studying emissions control systems for the internal combustion engine in order to meet increasingly restrictive regulations. Consequently, the available emissions control techniques are already well defined for the reciprocating engine. This section summarizes the available control methods and makes some general observations on those methods that appear to have the greatest potential for stationary engine applications.

1. Promising Emissions Control Techniques

The exhaust pollutants of concern are nitrogen oxides, carbon monoxide, hydrocarbons, and to a lesser extent, particulates and sulfur dioxide. Two types of control techniques are available - engine modification and exhaust treatment methods (Table 20).

Engine modifications can be further classified into hardware changes and simple changes in operating conditions. Examples of the latter include speed, torque, air/fuel ratio, ignition and fuel injection timing, air temperature and pressure, and exhaust back pressure. Modifications that require hardware changes include exhaust recirculation, water injection, modified valve timing, compression ratio, and addition of precombustion chambers and other combustion chamber modifications. Most engine modifications cannot be used to control NOx and CO/HC emissions simultaneously. Changes that reduce NOx emissions generally have the reverse effect on CO, and hydrocarbon emissions and fuel consumption. This behavior results from the fact that the conditions that favor NOx formation-high temperatures and readily available oxygen - also favor combustion of CO and hydrocarbons.

Exhaust treatment controls include exhaust thermal reactors, catalytic oxidation of CO and hydrocarbons, and catalytic reduction of NOx. They can be added to new or existing engines with little or no effect on engine performance and fuel consumption.

Which techniques would be the most effective emission control methods for stationary engines? The answer will require a close examination of the effects of the various controls on fuel consumption, reliability, durability and engine life, in addition to emissions control effectiveness. The forecasted increases in fuel prices, particularly natural gas, will place a premium on maximizing fuel economy. The high first cost of reciprocating engines will eliminate any emissions control method that adversely affects engine life or realiability. It is clear that the answer cannot be quickly determined without additional study. However, on the basis of available information, which is summarized in the next sections, the following emission control methods appear to have the greatest potential as short term, intermediate term and long term solutions:

TABLE 20

Emission Control Methods for Reciprocating Engines

I. Engine Modifications		
A. Operating Conditions:	1.	Speed
	2.	Torque/Load
	3.	Air/Fuel Ratio
	4.	Ignition Timing
	5.	Fuel Injection Timing
	6.	Air Temperature
	7.	Air Pressure
	8.	Exhaust Back Pressure
B. Engine Hardware:	1.	Exhaust Recirculation
	2.	Water Injection
	3.	Valve Timing
	4.	Combustion Chamber - Stratified Charge
	5.	Compression Ratio
II. Exhaust Treatment		
A. Exhaust Thermal Reactor (CO/HC)		
B. Catalytic Converter:	1.	Oxidation (CO/HC)
	2.	Reduction of NOx by CO, H_2, NH_3, or natural gas

Engine	Short and Intermediate Terms		Long-Term
Diesel	Water Injection	Precombustion Chamber	Catalytic NOx Reduction
Natural Gas	Water Injection	Increased Valve Overlap for 4-Cycle N.A. Engines	Catalytic NOx Reduction

2. Engine Modification Methods

a. Operating Conditions

Over the years, a large number of papers have been published by the auto industry and the engine manufacturers on the effect of operating conditions on emissions. Figure 10 contains representative data published by Nebel and Jackson of General Motors,[26] showing the effects of air/fuel ratio, ignition timing, manifold pressure, speed, and compression ratio on exhaust NOx concentration for a single-cylinder spark ignition gasoline engine. Nitrogen oxides concentration increases with spark advance, manifold pressure, compression ratio, and increasing speed under rich conditions and decreasing speed under lean conditions.

For stationary engines, however, it is more meaningful to investigate the effect of operating conditions on mass emissions and fuel consumption at constant power. The Cooper Bessemer Company and Caterpillar Tractor Company have published such data for gas engines and diesel engines, respectively. Some of the Cooper Bessemer data were reproduced in a previous section of this report (Figures 5 and 6).

Figures 11 through 16 show the effect of ignition timing, air flow rate, air manifold temperature, speed, torque, and exhaust back pressure on emissions and fuel consumption for a Cooper Bessemer GMVA-8 two cycle atmospheric gas engine. The data were generated in a joint test program conducted by Cooper Bessemer and Shell Development Company.[25] Fuel consumption and NOx emissions show the greatest sensitivities to conditions, while CO and hydrocarbon emissions are relatively insensitive. The most dramatic effects are those of torque at constant speed and speed at constant power (torque decreasing as speed increases).

Table 21 summarizes the effects of various changes away from standard operating conditions for the GMVA-8. Retarding the ignition from 10° to 4° btdc reduces NOx emissions 16 percent but increases fuel consumption by 6 percent. A reduction of the air manifold temperature from 130 to 80°F reduced NOx emissions by 47 percent and increased fuel consumption by one percent. The most impressive NOx emissions reduction occurred by increasing speed from 300 to 330 rpm. NOx emissions were reduced by 58 percent to 6.4 grams/Bhp-hr and fuel consumption increased only 1.6 percent.

Simultaneous determination of the air/fuel ratio of the mixture trapped in the cylinder showed that many of the effects are attributable in part to a simultaneous change in the air/fuel ratio. Reducing the air/manifold temperature and increasing the exhaust back pressure each increased the air density in the air manifold, resulting in a leaner air/fuel mixture and lower NOx emissions. Hence the effect of a given parameter depends greatly on the

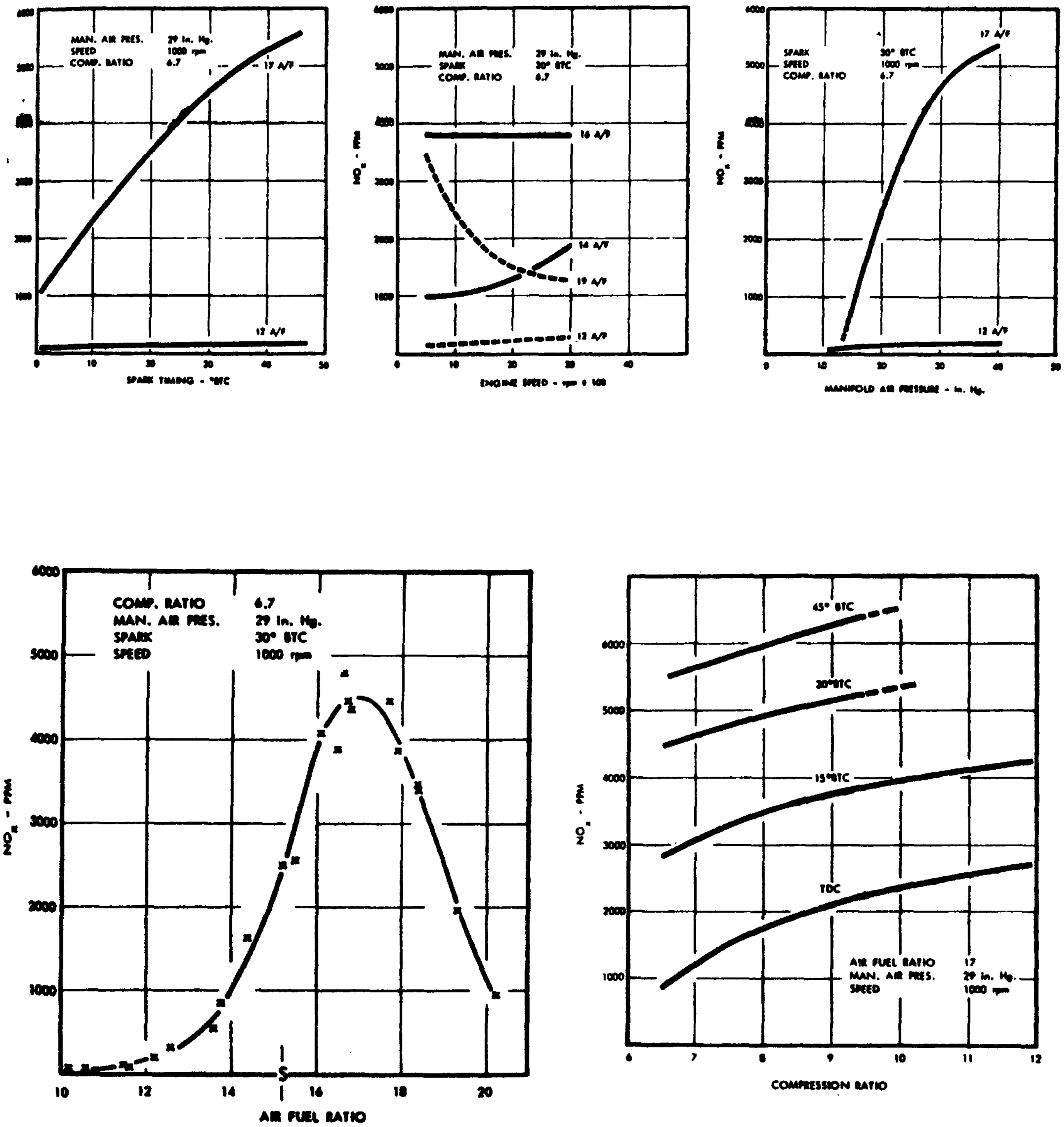


Figure 10. Effect of Air/Fuel Ratio, Spark Timing, Manifold Pressure, Speed, and Compression Ratio on Exhaust NOx Concentration - 4-Cycle Gasoline Engine (Reference 26).

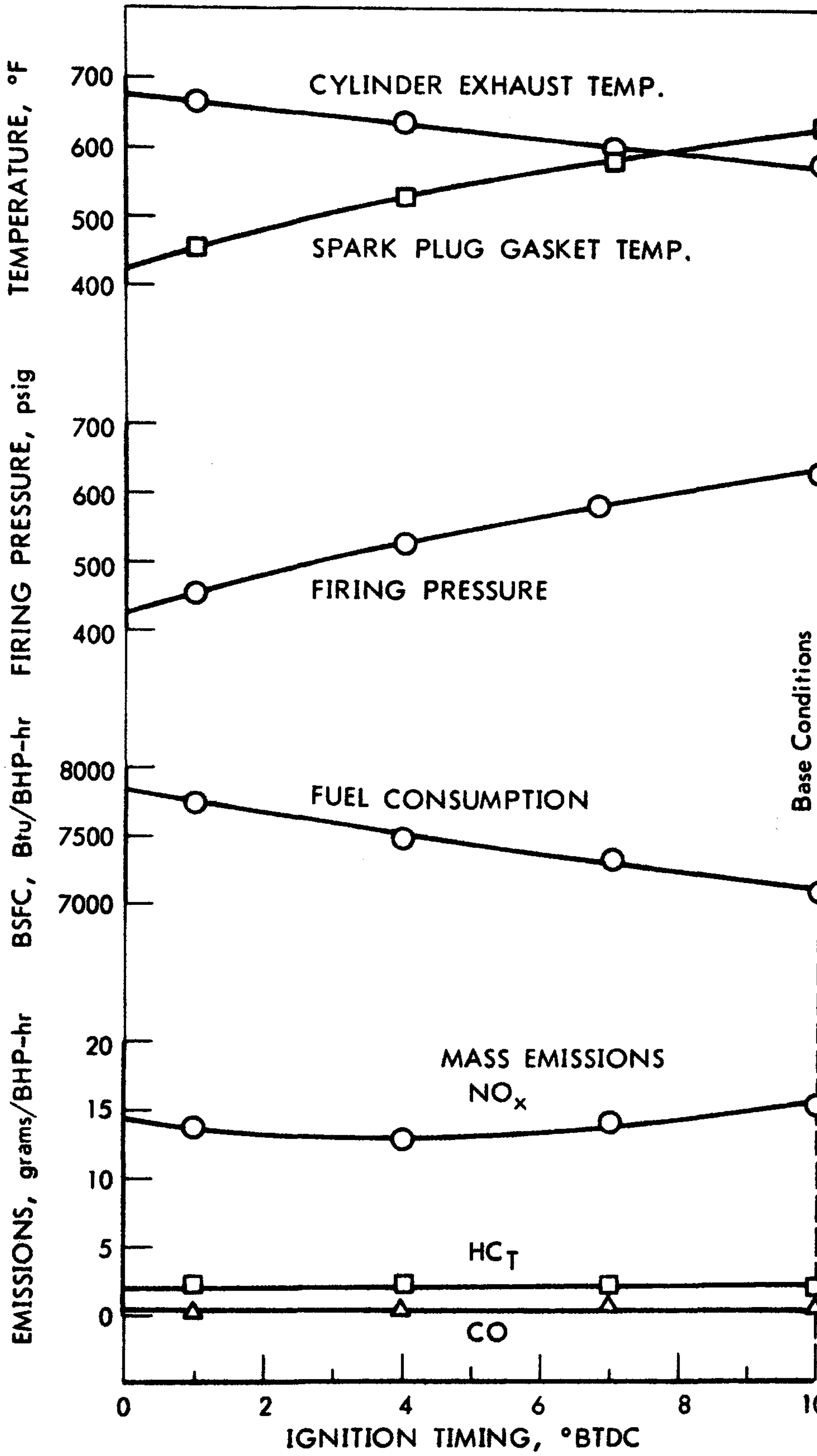


Figure 11. Effect of Ignition Timing

Cooper Bessemer GMVA-8 2-Stroke Atmospheric Spark-Gas Engine
1080 BHP at 300 RPM, 82.5 BMEP, Base Conditions

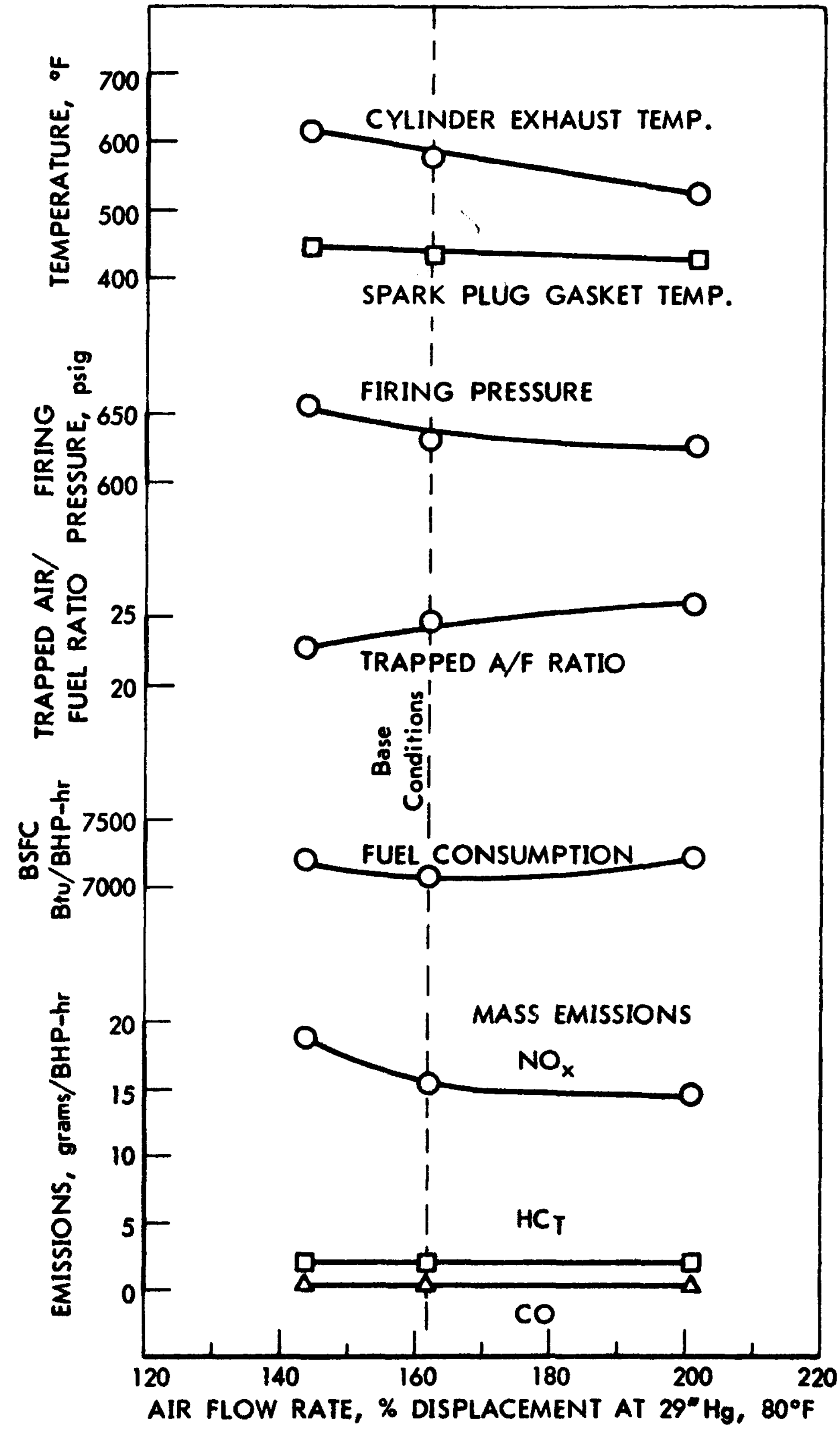


Figure 12. Effect of Air Flow Rate

Cooper Bessemer GMVA-8 2-Stroke Atmospheric Spark-Gas Engine
1080 BHP at 300 RPM, 82.5 BMEP, Base Conditions

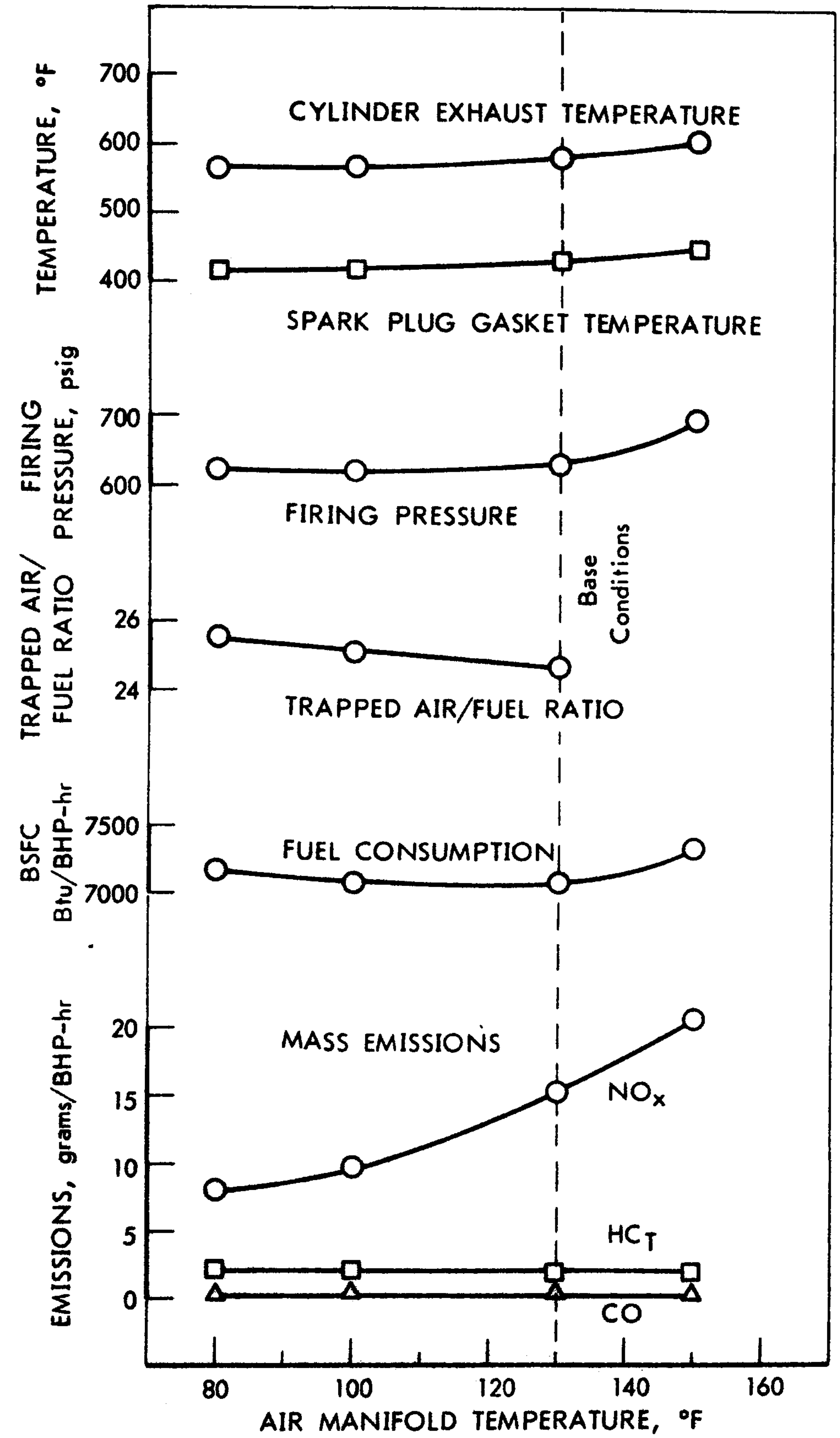


Figure 13. Effect of Air Manifold Temperature

Cooper Bessemer GMVA-8 2-Stroke Atmospheric Spark-Gas Engine
1080 BHP at 330 RPM, 82.5 BMEP, Base Conditions

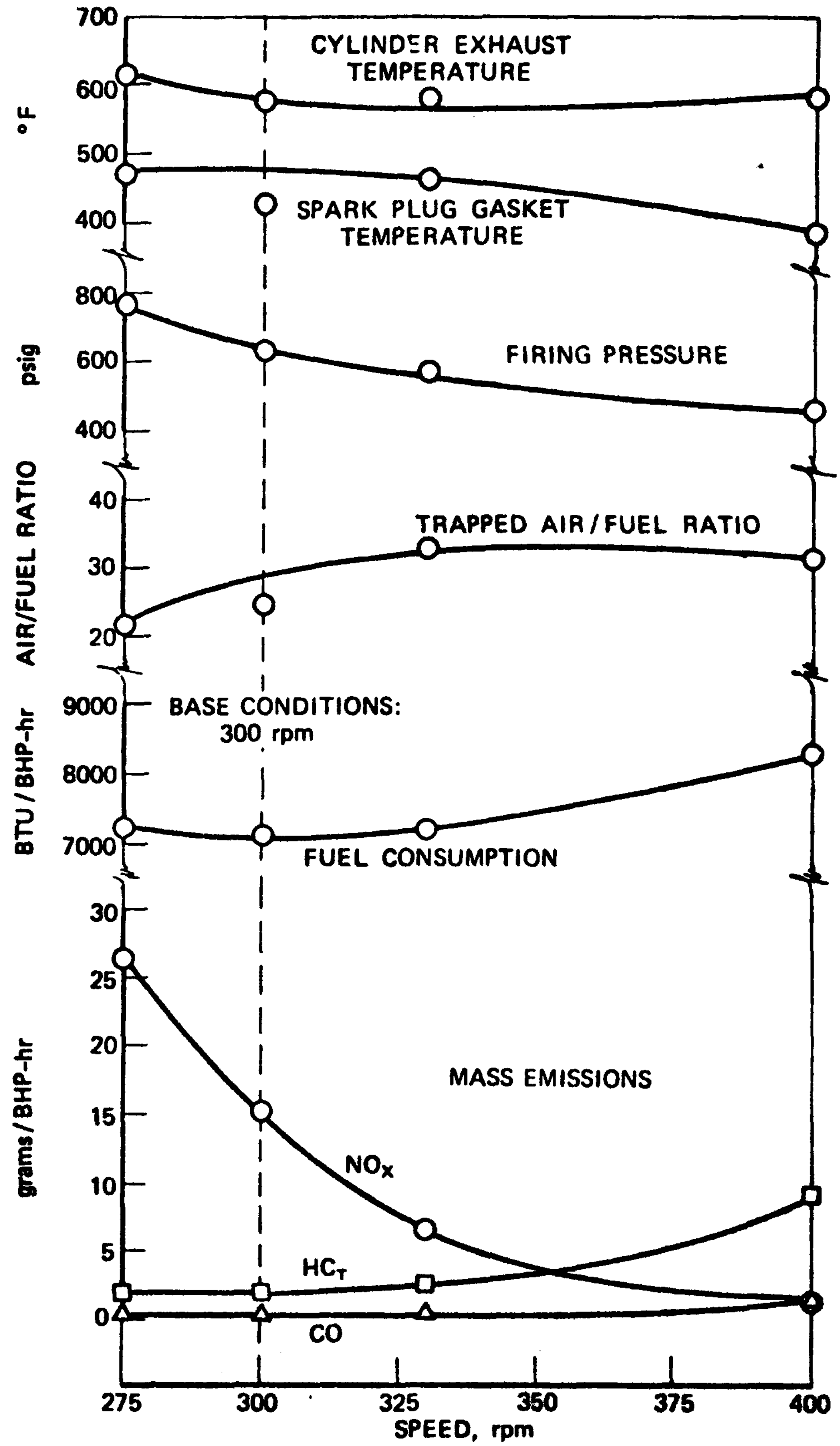


Figure 14. Effect of Speed at Constant Power

Cooper Bessemer GMVA-8 2-Stroke Atmospheric Spark-Gas Engine
Power Output 1080 BHP, Base Conditions

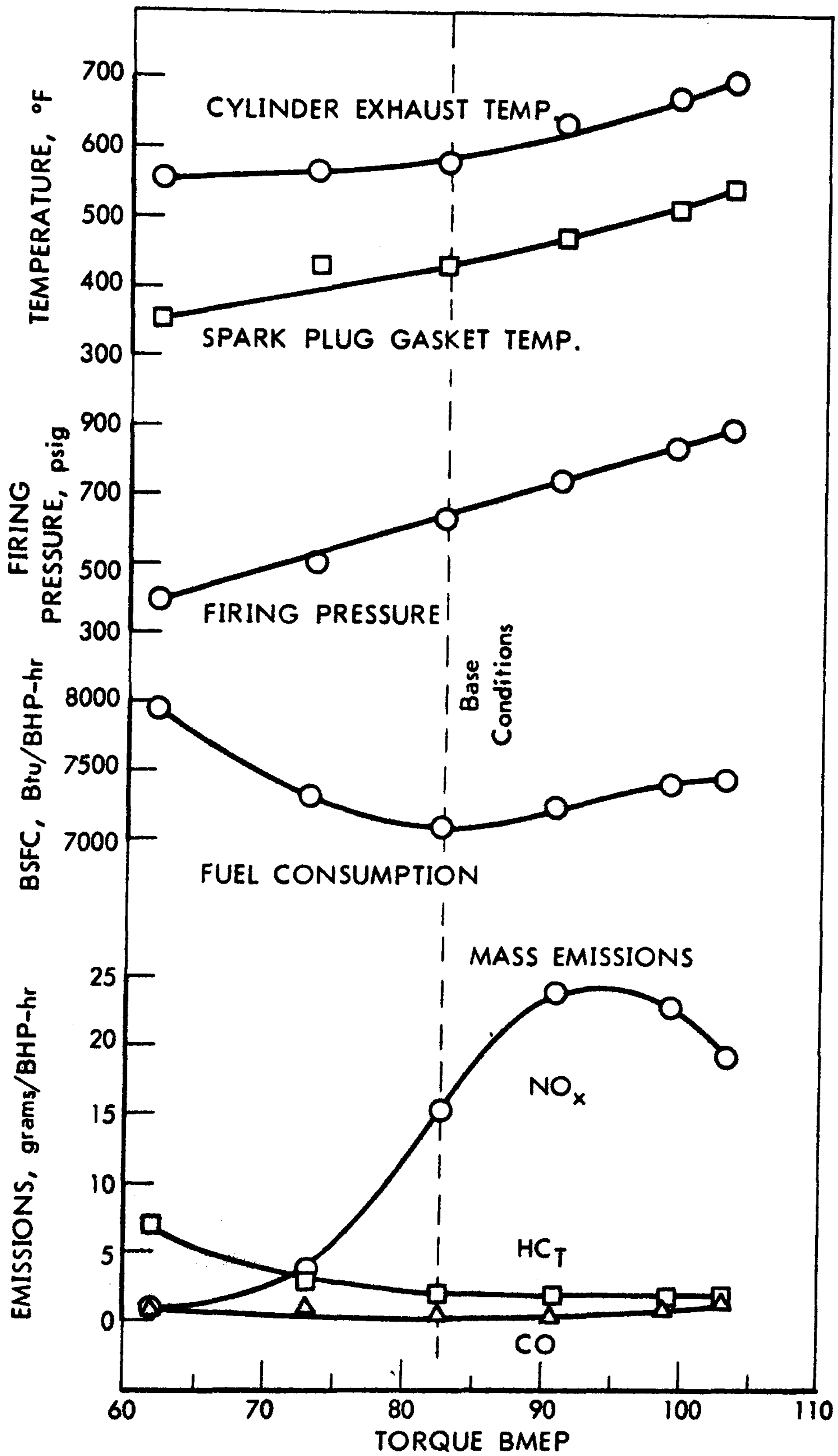


Figure 15. Effect of Torque at Constant Speed

Cooper Bessemer GMVA-8 2-Stroke Atmospheric Spark-Gas Engine
Base Conditions, Speed = 300 RPM

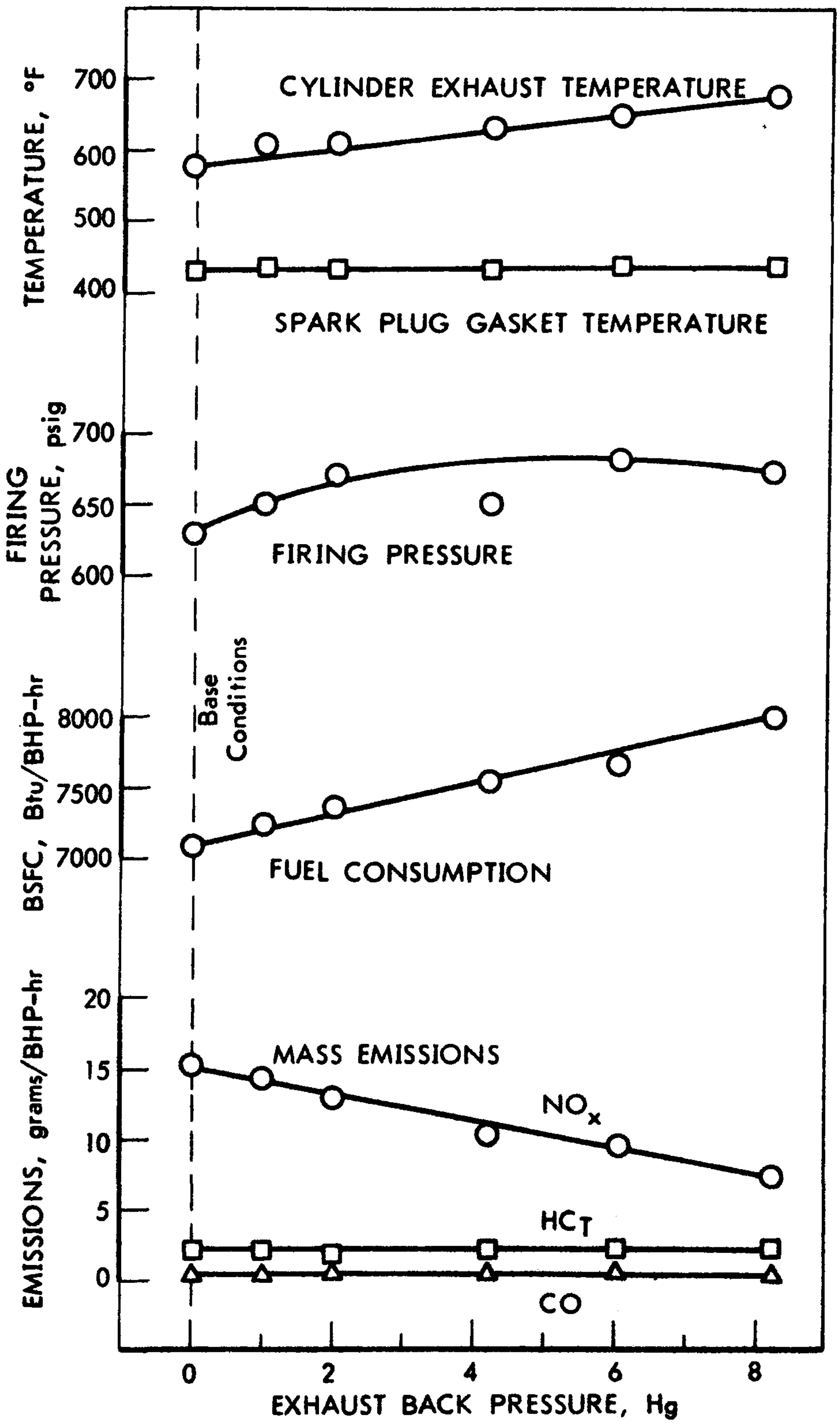


Figure 16. Effect of Exhaust Back Pressure

Cooper Bessemer GMVA-8 2-Stroke Atmospheric Spark-Gas Engine
1080 BHP at 300 RPM, 82.5 BMEP, Base Conditions

Table 21. EMISSION CONTROL BY MODIFICATION OF OPERATING CONDITIONS

Cooper Bessemer GMVA-8 Two-Stroke Atmospheric Spark-Gas Engine

Operating Conditions	Mass Emissions (Grams/BHP-Hr)			Exhaust Conc (ppm_v)			Fuel Consumption (Btu/BHP-Hr)	Change From Base Values	
	NO_x	HC_T	CO	NO_x	HC_T	CO		NO_x Emissions	Fuel Consumption
Base Conditions[a)]	15.23	1.94	.29	1079	395	34	7079	-	-
Retard Ignition 10° to 4° BTDC	12.75	2.26	.35	918	466	42	7496	-16.2%	+5.8%
Increase Air Flow 161 to 201% Displacement	14.66	2.14	.22	842	352	21	7223	-3.7%	+2.0%
Decrease Air Manifold Temp 130 to 80°F	8.09	2.19	.34	574	446	40	7169	-46.9%	+1.2%
Increase Exhaust Back Pressure 0 to 6" Hg	9.53	2.16	.30	686	447	36	7673	-37.4%	+8.4%
Increase Speed at Constant BHP 300 to 330 RPM	6.41	2.24	.41	418	420	44	7192	-57.9%	+1.6%
Combination of: 4° BTDC Ignition 100°F Air Manifold Temp	10.63	2.08	.32	760	426	38	7572	-30.2%	+7.0%
4° BTDC Ignition 100°F Air Manifold Temp 182.1% Displacement Air	8.73	2.19	.31	549	395	32	7654	-42.7%	+8.1%
4° BTDC Ignition 100°F Air Manifold Temp 182.1% Displacement Air 8.2" Hg Exhaust Back Pressure	5.26	2.28	.40	332	412	41	8702	-65.5%	+22.9%

a) Base Conditions: Speed - 300 RPM; Power - 1080 BHP; Torque - 82.5 BMEP; Ignition - 10° BTDC; Air Flow Rate - 160% Displacement; Air Manifold Temp - 130°F; Exhaust Back Pressure - 0" Hg type of engine. The same thing can be said for applicability of a given NOx control technique. For example, increasing the exhaust back pressure cannot be applied to turbo-charged engines, and speed cannot be increased easily on integral compressor engines due to torsional vibration criticals at some non-design speeds.

Figure 17 contains hydrocarbon, CO, and NO emission maps from California 13 mode cycle tests of a typical Caterpillar precombustion chamber diesel engine.[9] The maps show how mass emissions vary as functions of engine power output and speed. At a given speed, NO emissions are essentially proportional to power output, and at constant power NO emissions tend to increase with speed. As pointed out previously, this behavior is fundamentally different from that of gas engines. Hydrocarbon and CO emissions exhibit much more variability with speed, however.

b. Hardware Modifications

The second phase in the application of emission controls is hardware modifications. The candidates include exhaust recirculation, water injection, valve timing changes, combustion chamber redesign, and modifying the compression ratio. Mass emissions are somewhat proportional to fuel consumption so that changes that improve fuel economy may reduce emissions.

(1) Exhaust Recirculation (EGR)

Exhaust recirculation (EGR) is now being used by the U.S. auto industry in some new cars to reduce NOx emissions. The fundamental effect is that of charge dilution, i.e., oxygen concentration is lower and the heat capacity of the charge is higher, leading to lower temperatures and lower NOx emissions. Figure 18 shows the effect of EGR on NOx concentration as a function of air/fuel ratio and fraction EGR for a spark ignition gasoline engine.[22] At 15 percent EGR, the peak NOx concentration is reduced by 85 percent.

Caterpillar Tractor have published EGR data for a precombustion chamber diesel engine[9] (Figure 19). At 15 percent EGR and 100 percent rated torque, NOx emissions decrease from 830 to 220 grams/hour, a reduction of about 73 percent. At higher speeds or lower torque, the effectiveness is diminished.

Exhaust recirculation has a great number of technical problems that must be overcome before application to stationary engines. A system is needed to accurately meter the amount of exhaust recirculated. An efficient heat exchanger must be developed to cool the exhaust without condensing the water vapor contained in the exhaust. This is particularly true for four-cycle gas engines for which exhaust temperatures are in the range 1100 to 1200°F. Particularly for diesel engines, problems with fouling of intake manifolds, after coolers, and other equipment by particulates must be overcome. Finally, the long term effects on lubricating oil and engine life must be assessed.

In view of these problems, it would appear that other control methods have greater potential than EGR for effectively controlling emissions with fewer problems.

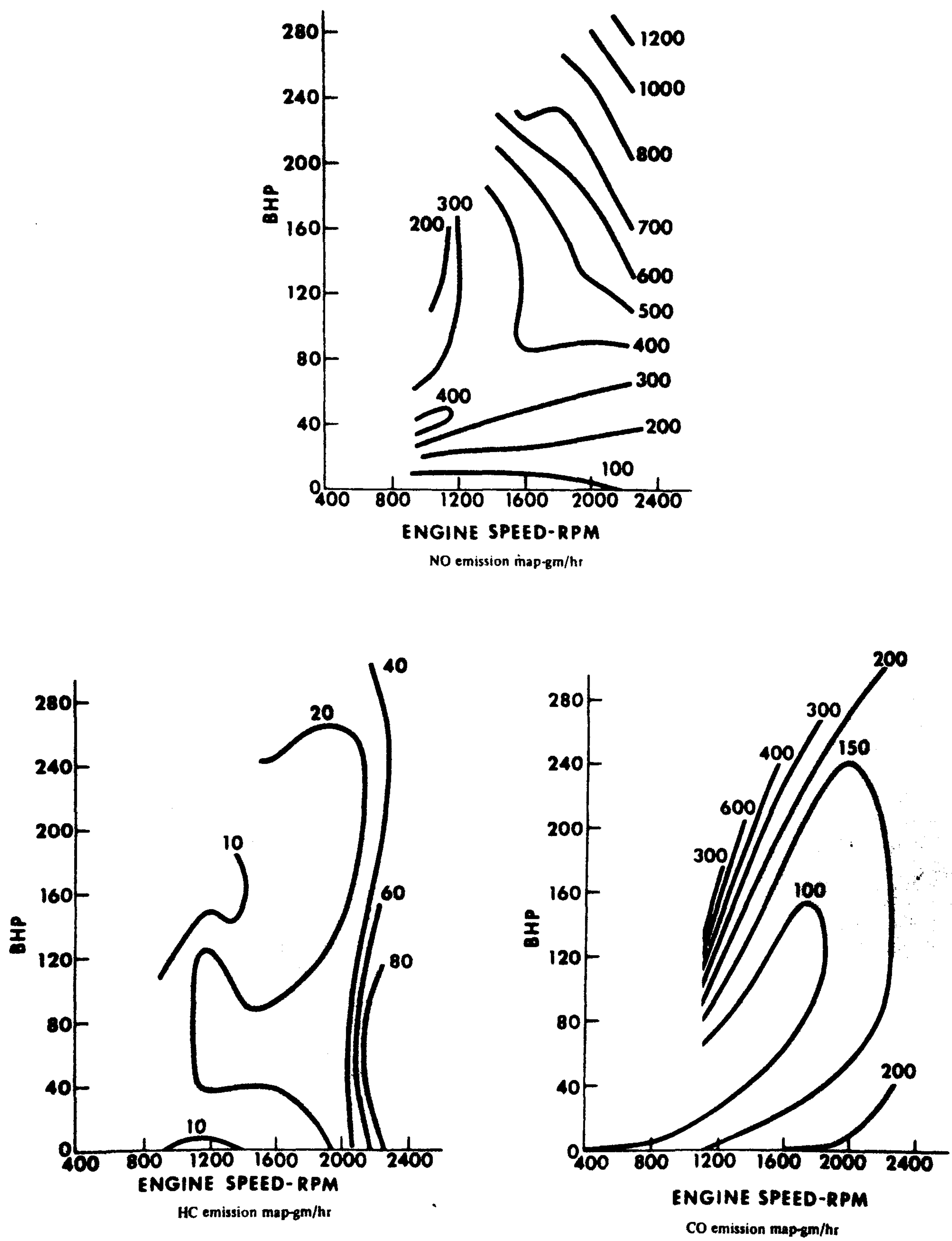


Figure 17. Effect of Speed and Power Output on Emissions - Caterpillar 4-Cycle Precombustion Chamber Diesel (Reference 9).

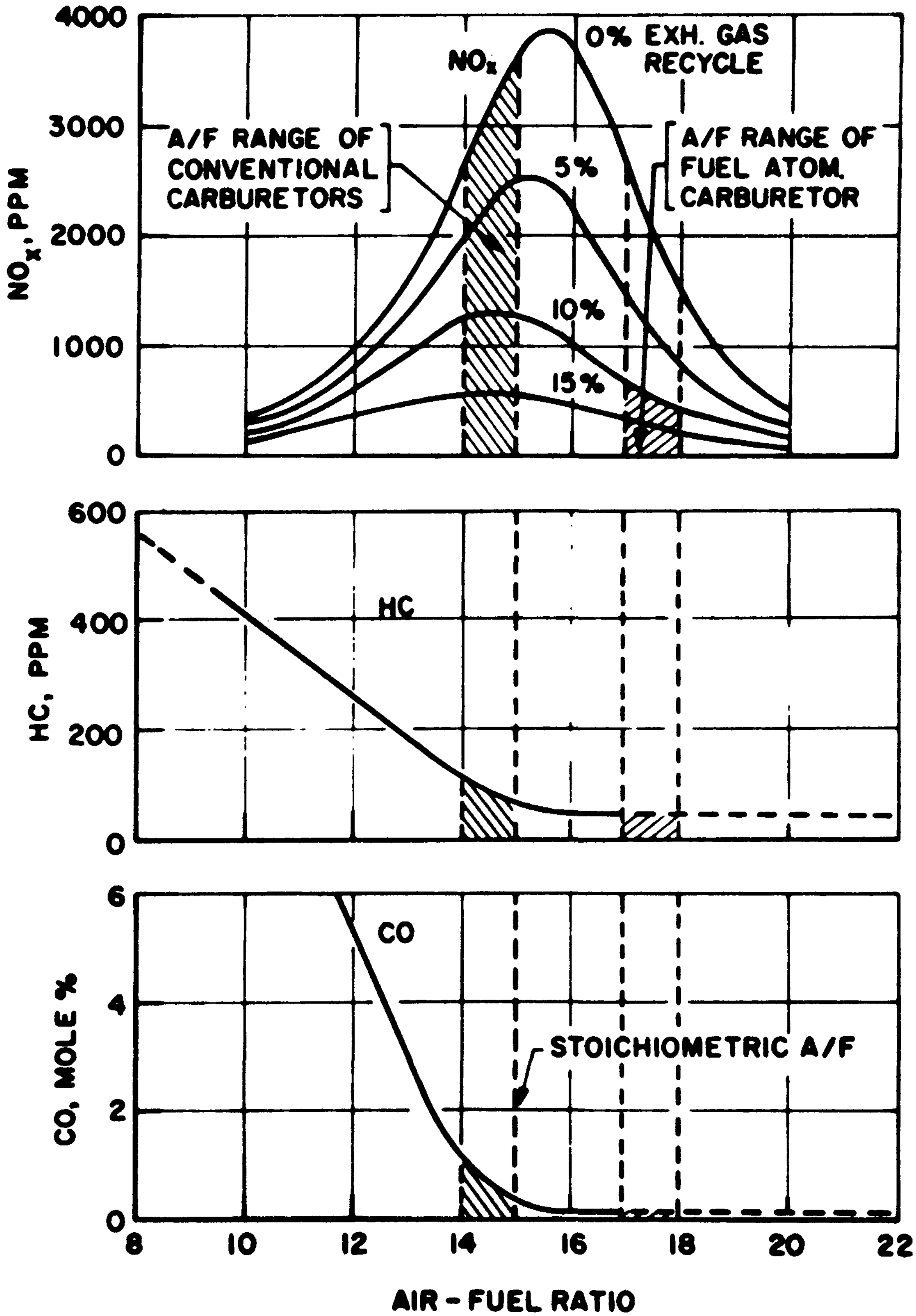
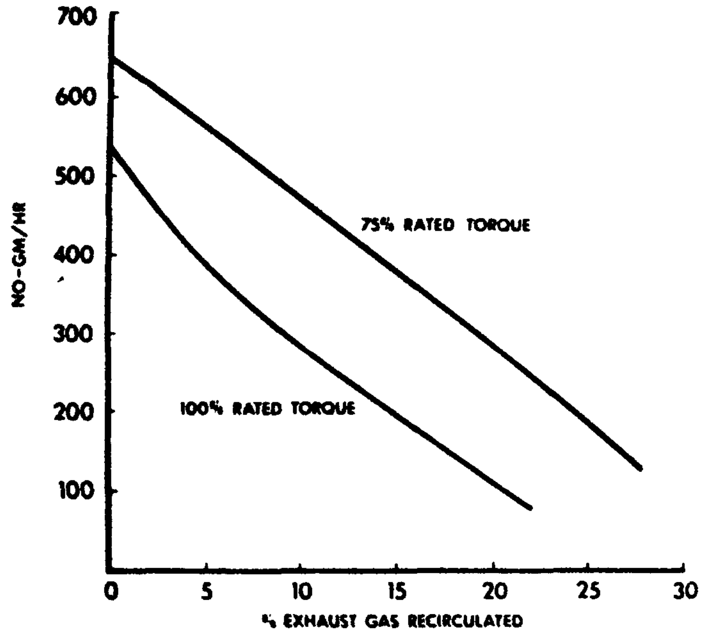
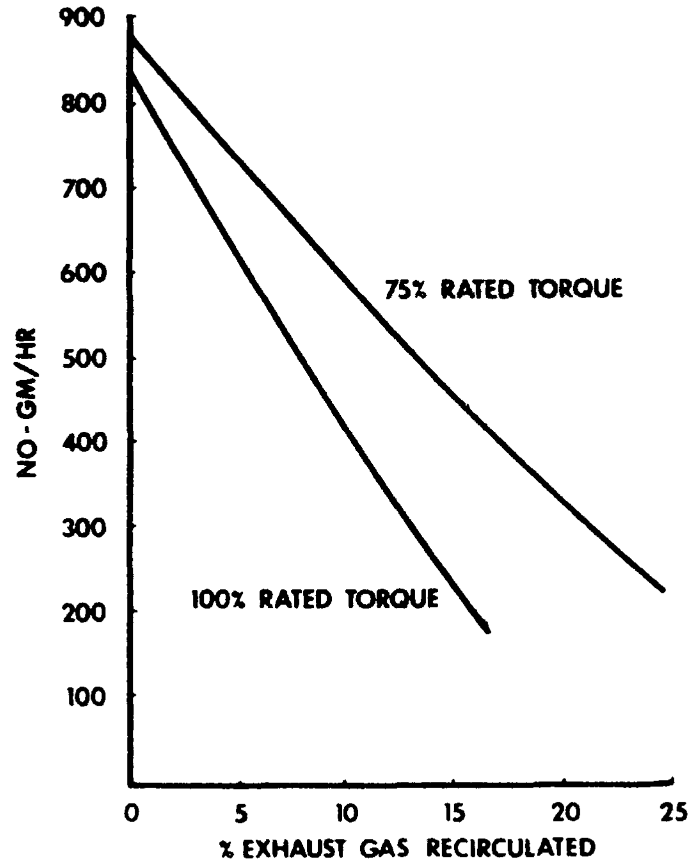


Figure 18. Nitric Oxide Concentration in the Exhaust Gas of a Car as a Function of Air-Fuel Ratios with Recycling Rate as Parameter (Reference 22).



Exhaust recirculation versus NO emission - engine type D at 1600 rpm



Exhaust recirculation versus NO emission -engine type D at 2200 rpm

Figure 19. Effect of Exhaust Recirculation on NOx Emissions - Caterpillar 4-Cycle Precombustion Chamber Diesel (Reference 9).

(2) Water Injection

Water injection serves the same function as exhaust recirculation in reducing of NOx emissions - intake charge dilution. It is accomplished by injecting distilled or deionized water either directly into each cylinder or at the intake valve of each cylinder. Injection of at least one pound of water for each pound of fuel burned will reduce NOx emissions by 70 percent or more. At the same time, fuel consumption is increased considerably.

Figure 20 demonstrates the effect of water injection on exhaust NOx emissions for a laboratory spark ignition gasoline engine.[28] Under lean conditions (ϕ = 0.93), injection of 1.25 lb water/lb fuel reduces NOx concentration from about 1000 to 100 ppm. Similar data are given in Figure 21 for a Caterpillar precombustion chamber diesel.[9] At 1.5 lb water/lb fuel and 100% of rated torque, NOx mass emissions are reduced from 600 to 200 grams/hr, a reduction of 67 percent. The results of water injection tests on an Ingersoll-Rand PKVGR-12 four-cycle naturally aspirated gas engine are shown in Figure 22.[43] Water injection at 2 gpm (1.62 lb H_2O/lb fuel) reduced NOx emissions by 82.4 percent but increased fuel consumption by 9.8 percent.

Before water injection can be widely applied in the field, the long term effects on lubricating oil and engine life will have to be investigated. Economical sources of deionized water in remote locations are needed. At 1.0 lb water/lb fuel, a plant using 10,000 Bhp total horsepower will require about 400 gallons per hour of distilled water at full load.

(3) Valve Timing

Valve timing is also known to affect emissions. In the case of four-cycle naturally-aspirated engines, increasing the valve overlap will produce the same effect as exhaust recirculation. At the end of the exhaust stroke the intake and exhaust valves are open simultaneously (overlap). Exhaust gas can pass back into the cylinder due to the pressure difference between the intake and exhaust manifolds. As valve overlap is increased, the fraction of exhaust present in the fresh charge increases, resulting in an EGR effect.

In a recent paper, Freeman and Nicholson of General Motors[15] present data on the effect of valve timing on exhaust emissions from a 350 CID automobile engine (Figure 23). An increase in valve overlap from .38 deg-in to 2.74 deg-in reduced NOx emissions by about 60 percent. Hydrocarbon emissions are also reduced slightly, while CO emissions are not affected. The authors do not provide any fuel consumption data, however, it is probable that fuel economy does suffer as valve overlap increases.

For stationary engine applications, valve timing modification has some potential for emissions control. It is a far simpler alternative than exhaust recirculation and could probably be applied to existing engines as well as new engines. Increased valve overlap, however, can be applied only to four-cycle naturally-aspirated engines.

(4) Stratified Charge Combustion

Stratified charge combustion requires modification of the combustion chamber and fuel injection system such that ignition of the air/fuel mixture

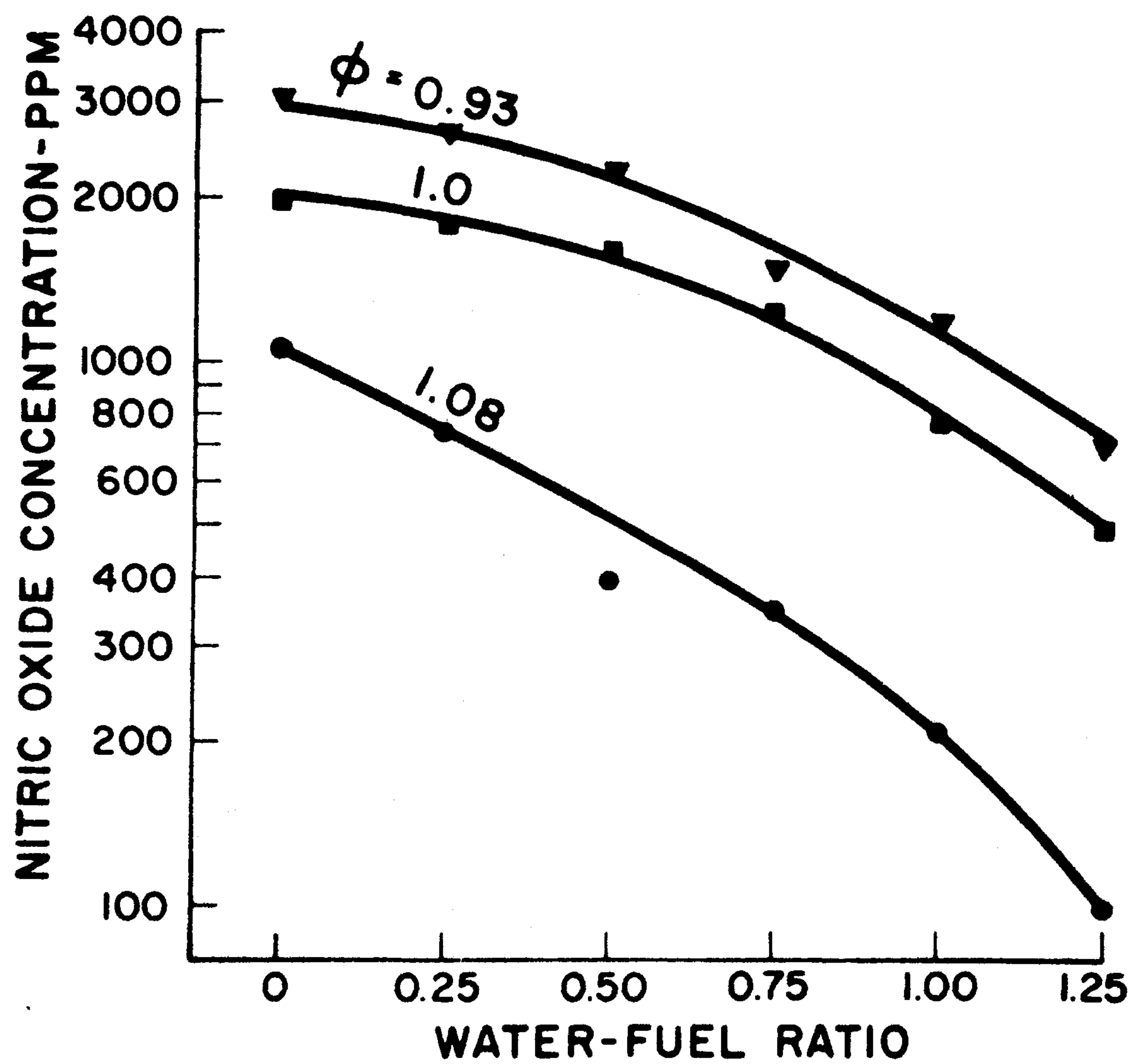
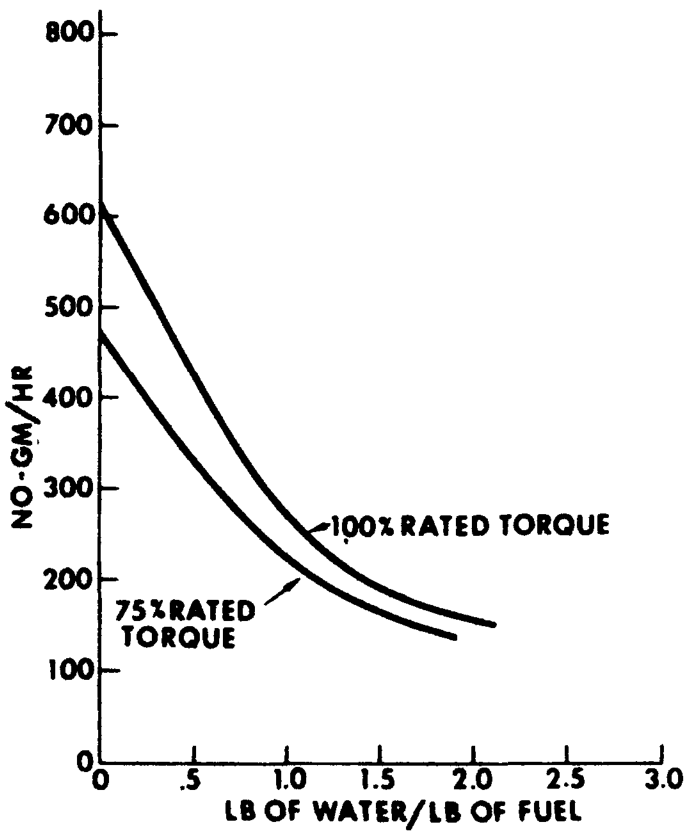
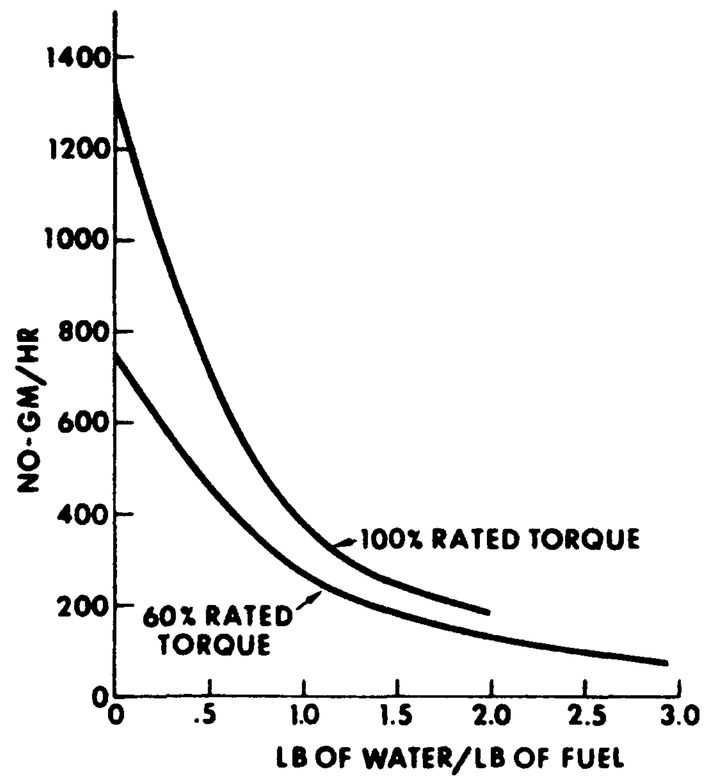


Figure 20. Effect of Water Injection on NOx Emissions - 4-Cycle CFR Gasoline Engine (Reference 28).



Water induction versus NO emission - engine type A at 1600 rpm



Water induction versus NO emission - engine type A at 2200 rpm

Figure 21. Effect of Water Injection on NOx Emissions - Caterpillar 4-Cycle Precombustion Chamber Diesel Engine (Reference 9).

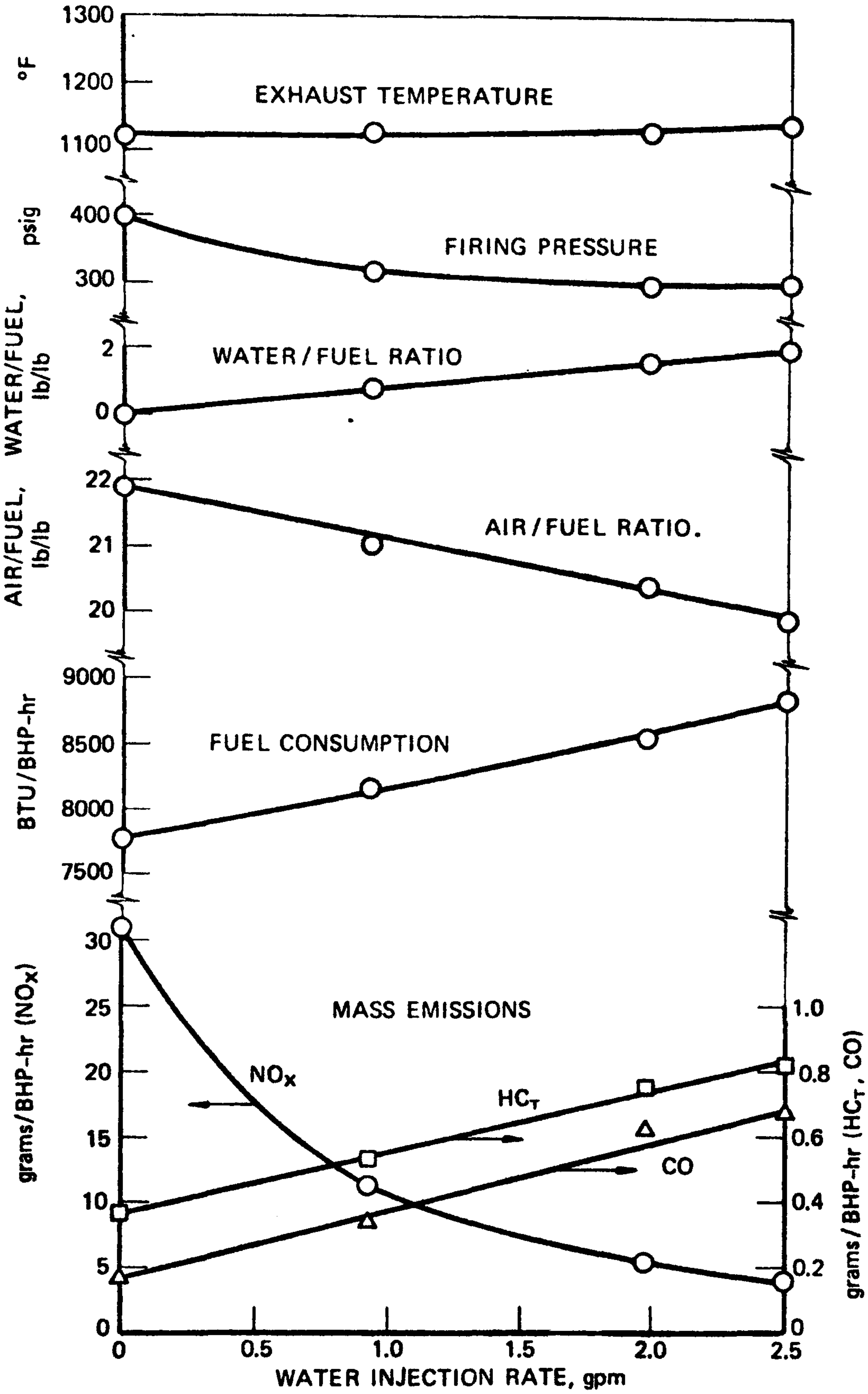


Figure 22. Effect of Water Injection

Ingersoll-Rand PKVGR-12 4-Cycle N.A. Spark-Gas Engine

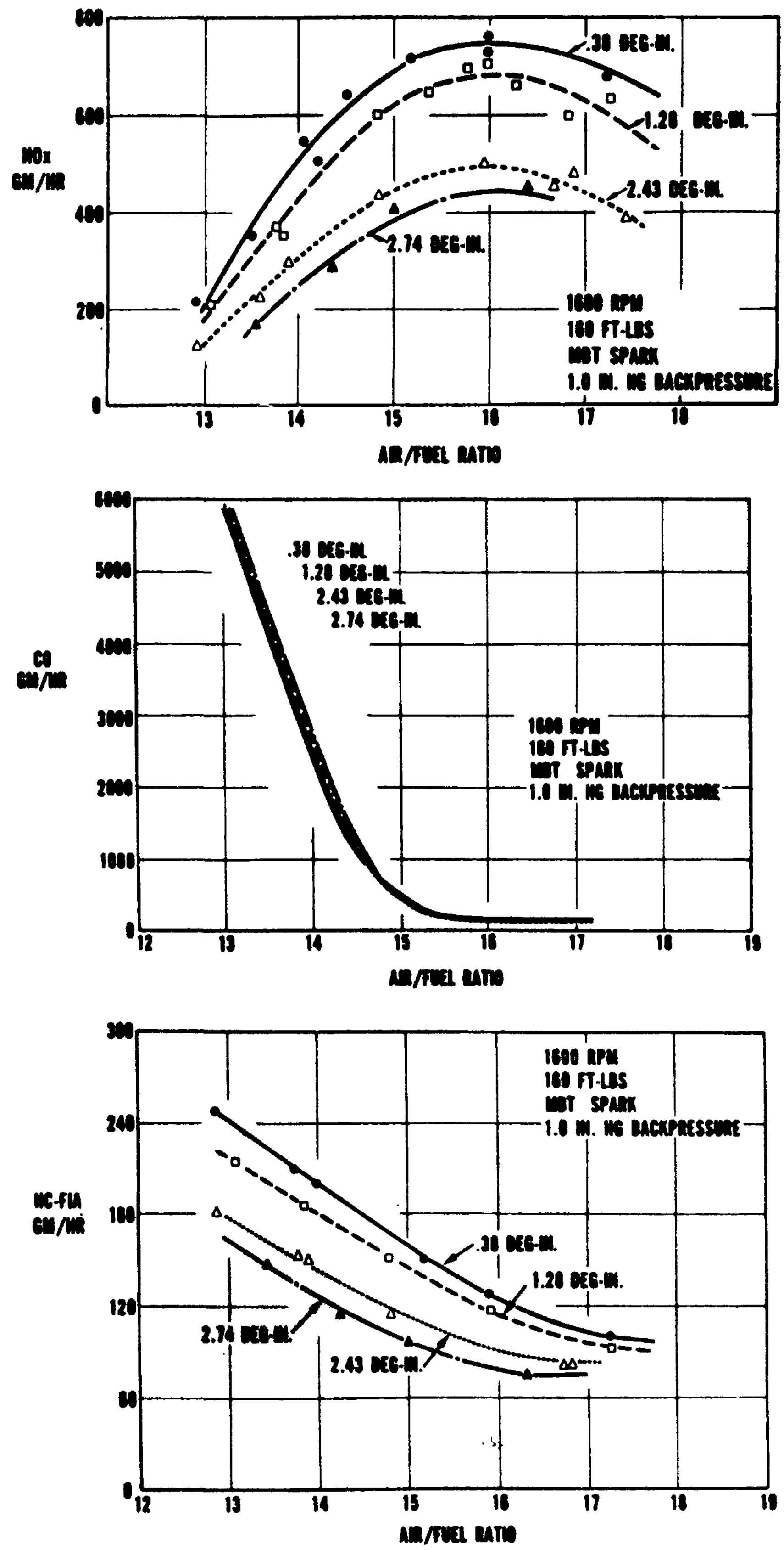


Figure 23. Effect of Valve Overlap on Emissions - 4-Cycle Gasoline Engine (Reference 15).

occurs under fuel rich conditions even though the air/fuel ratio of the overall mixture is lean. The system is analogous to two-stage air addition in boilers and results in reduced NOx emission levels, due to the rich mixture present in the combustion zone. Hydrocarbon and CO emissions are generally low also due to the overall lean air/fuel ratio. Precombustion chambers have been in use since before air pollution became a public concern. The principal advantages were smoother operation and easier starting.

Caterpillar Tractor designs their line of diesel engines around the precombustion chamber concept.[9] Figure 24 is a schematic of the precombustion chamber built into the cylinder head. Air enters through the intake valve and finds its way into the precombustion chamber. Near the end of the combustion stroke, fuel oil is injected into the precombustion chamber and ignites upon contact with air heated by compression. The small volume of the precombustion chamber ensures that less than the stoichiometric amount of air is present and NOx formation is minimized. Expansion of the hot gases carries them into the main combustion chamber where more air is present to complete the combustion of fuel and CO. To illustrate the effectiveness of stratified charge combustion, NOx emissions for one Caterpillar diesel with precombustion chamber were measured at 5.5 grams/Bhp-hr compared to 11 or 12 grams/Bhp-hr for a conventional direct-injection diesel.

Stratified charge combustion could also be applied to spark ignition engines. Newhall and El-Messiri report data from tests of a precombustion chamber system on a modified single cylinder CFR engine. The fuel injector and spark plug were mounted in the precombustion chamber and the fuel was iso-octane. Figure 25 illustrates the effect of ignition timing and fuel-air equivalence ratio, on the exhaust concentration and mass emissions of NOx. The overall air/fuel mixture was lean in each case, and NO concentrations were less than 400 ppm for ignition advances up to 15° btdc. In comparison, the peak NOx concentration for conventional carbureted gasoline engine is about 3000 ppm at 15° btdc (Figure 10). Thus stratified charge combustion results in almost an order of magnitude reduction in NOx emissions.

The effectiveness of stratified charge combusion for spark ignition gasoline engines and oil fire diesel engines has been demonstrated. Injection of liquid fuel into the precombustion chamber facilitates stratification of fuel-lean and fuel-rich regions in the combustion chamber. According to one gas engine manufacturer, stratified charge combustion is also possible for gas engines. However, it is much more difficult to control and is more sensitive to operating conditions. Thus, stratified charge combustion may not be practical in the case of gas engines.

Additional development work will be necessary before additional diesel engine manufacturers will be able to include precombustion chamber technology in their engine designs. The use of precombustion chambers has the potential of reducing diesel emissions of NOx by at least a factor of two.

(3) Exhaust Treatment Controls

Nitrogen oxides and unburned CO and hydrocarbons can be either removed or converted to nitrogen, carbon dioxide, and water by devices located at the engine exhaust. These devices include exhaust manifold thermal reactors, catalytic converters, stack gas scrubbers, and solid sorbents. For reasons outlined in the following sections, including effectiveness, ease of installation, and no adverse effect on fuel economy, we have concluded that the catalytic converter is the most practical exhaust treatment system for stationary engines.

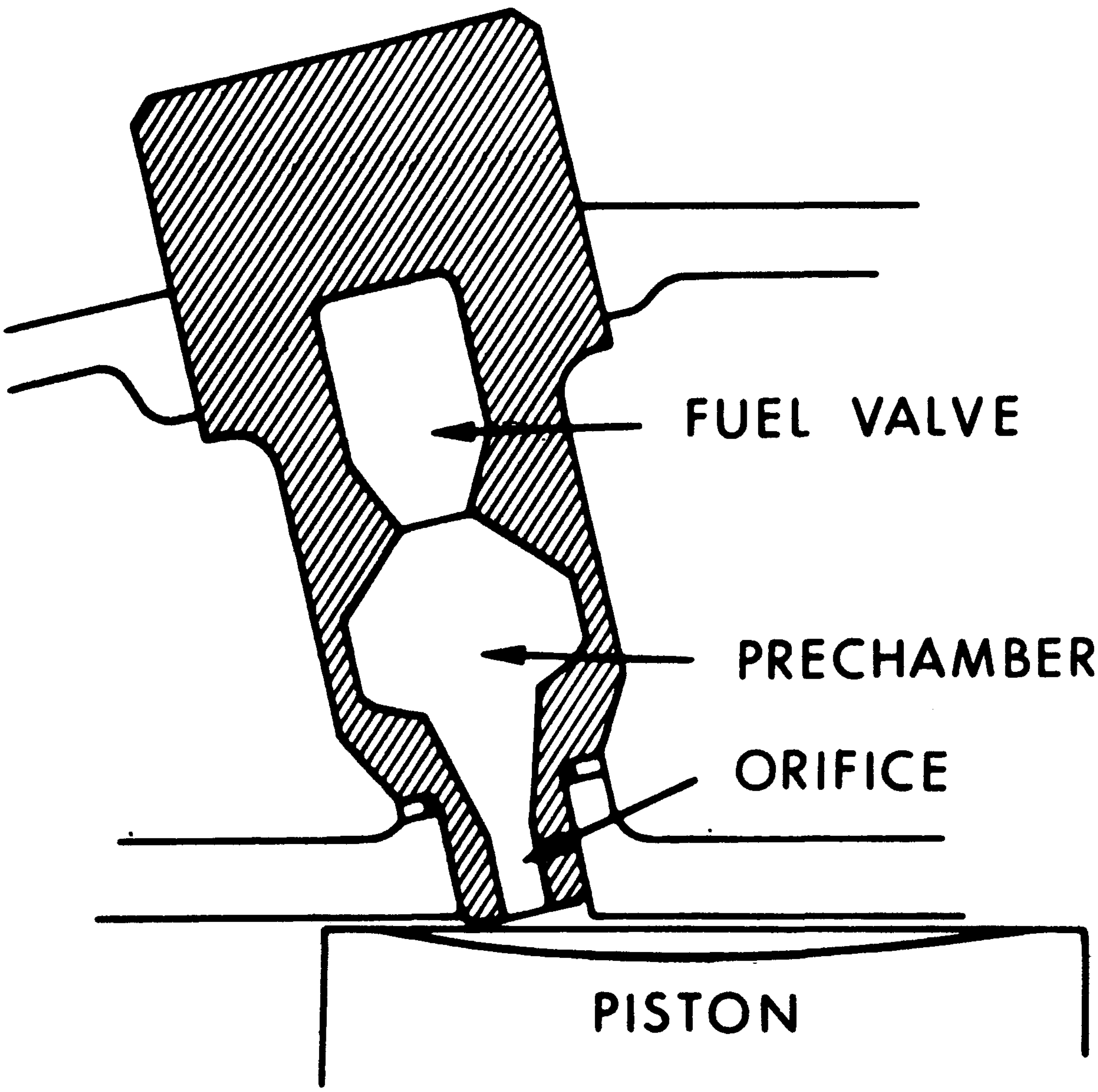


Figure 24. Precombustion Chamber System (Reference 9).

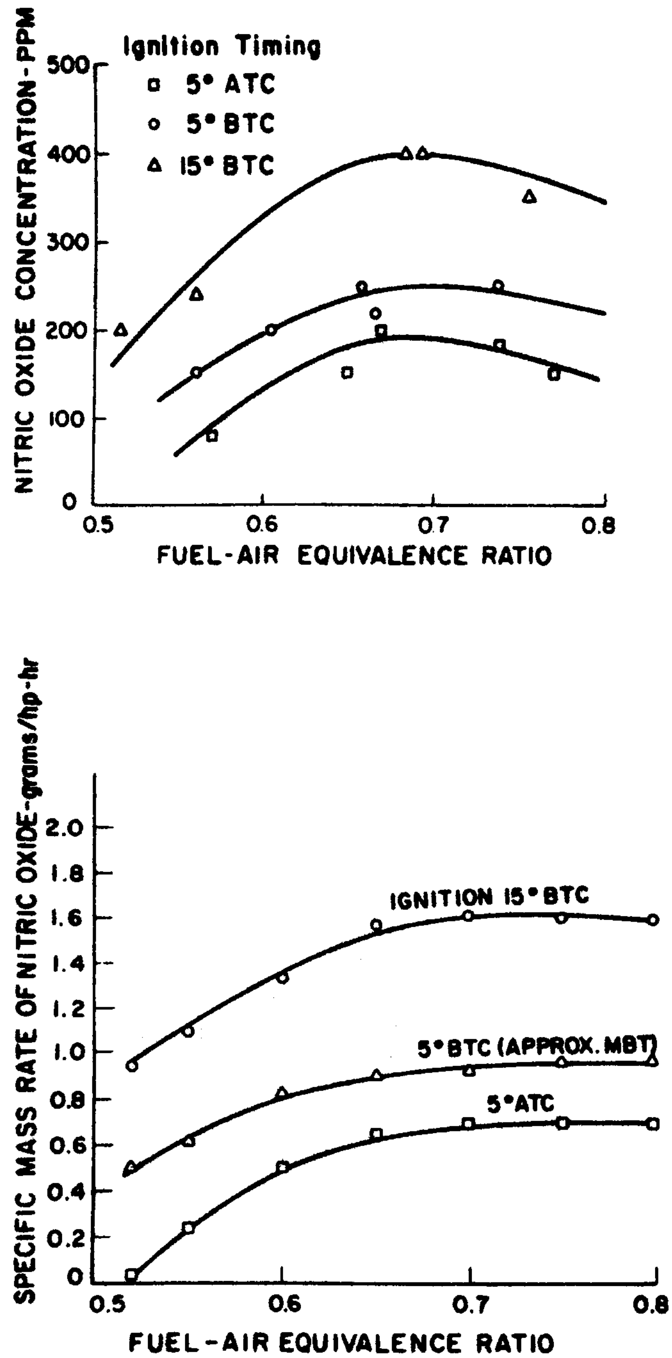


Figure 25. Effect of Ignition Timing and Fuel/Air Equivalence Ratio - 4-Cycle Precombustion Chamber Gasoline Engine. (Reference 27).

a. Exhaust Thermal Reactors

The exhaust thermal reactor is a modified exhaust manifold designed to maintain high enough temperatures to burn up unburned CO and hydrocarbons in the exhaust - about 1300 to 1400°F. The auto industry has found it necessary to operate the engine on a rich mixture in order to provide enough CO and hydrocarbon to maintain these temperatures. Rich mixture operation is not felt to be practical for stationary diesel and gas engines due to the resulting poor fuel economy and smoke emissions. Lean mixtures can also be used with thermal reactors, however higher exhaust temperatures are required.

b. Stack Gas Scrubbing and Solid Sorption

Stack gas scrubbing and solid sorption each create secondary pollution problems that must be solved, the former a liquid waste problem, the latter a solid waste problem. Although these controls could be applied in the form of a single unit that treats all exhaust from engines, boilers, and other combustion equipment, they do not seem to have much potential for emissions control of engines alone.

c. Catalytic Converters

Both nitrogen oxides and unburned CO and hydrocarbons can be converted to harmless species in catalytic converters. The design of a catalytic unit for a stationary engine would be much simpler than for an automotive engine, because it would not be necessary to meet the automotive requirements of minimum warmup time and operation over widely varying flow rates and temperatures.

(1) Oxidation of CO and Hydrocarbons

In the converter, CO and unburned hydrocarbons are removed by catalytic oxidation to CO_2 and water:

$$CO + 1/2\ O_2 \text{ -------> } CO_2$$

$$HC + O_2 \text{ -------> } CO_2 + H_2O$$

The catalyst allows the reactions to occur at lower temperatures than are required in a noncatalytic thermal reactor. Most four-cycle engines operate with lean air/fuel ratios, and have sufficient oxygen present in the exhaust for the oxidation reactions (4-5%). Two-cycle engines always have a large excess of oxygen in the exhaust as a result of dilution by scavenging air (15% O_2). However, four-cycle engines operating on a rich or stoichiometric mixture will require mixing additional air with the exhaust.

(2) Reduction of NOx by CO, H_2, NH_3, or Natural Gas

NOx can be removed by catalytic reduction by CO and hydrogen present in the exhaust or by an added reducing agent such as natural gas or ammonia:

$$NO + CO \text{ -------> } CO_2 + 1/2\ N_2$$

$$NO + H_2 \text{ -------> } H_2O + 1/2\ N_2$$

$$4NO + CH_4 \text{ -------> } CO_2 + 2H_2O + 2N_2$$

$$3NO + 2NH_3 \text{ -------> } 3H_2O + 5/2\ N_2$$

Hydrogen and CO will be present in sufficient amounts for NOx reduction only in the case of four-cycle engines operating on rich mixtures. Hydrogen is produced via the watergas shift reaction under rich conditions:

$$CO + H_2O \text{ -------> } H_2 + CO_2$$

and is probably the primary reducing agent. The automotive industry has found that under certain conditions, mainly low oxygen concentrations and low temperatures, the hydrogen can also reduce nitric oxide to ammonia:[36)]

$$5/2\ H_2 + NO \text{ -------> } NH_3 + H_2O$$

leading to an unwanted by-product.

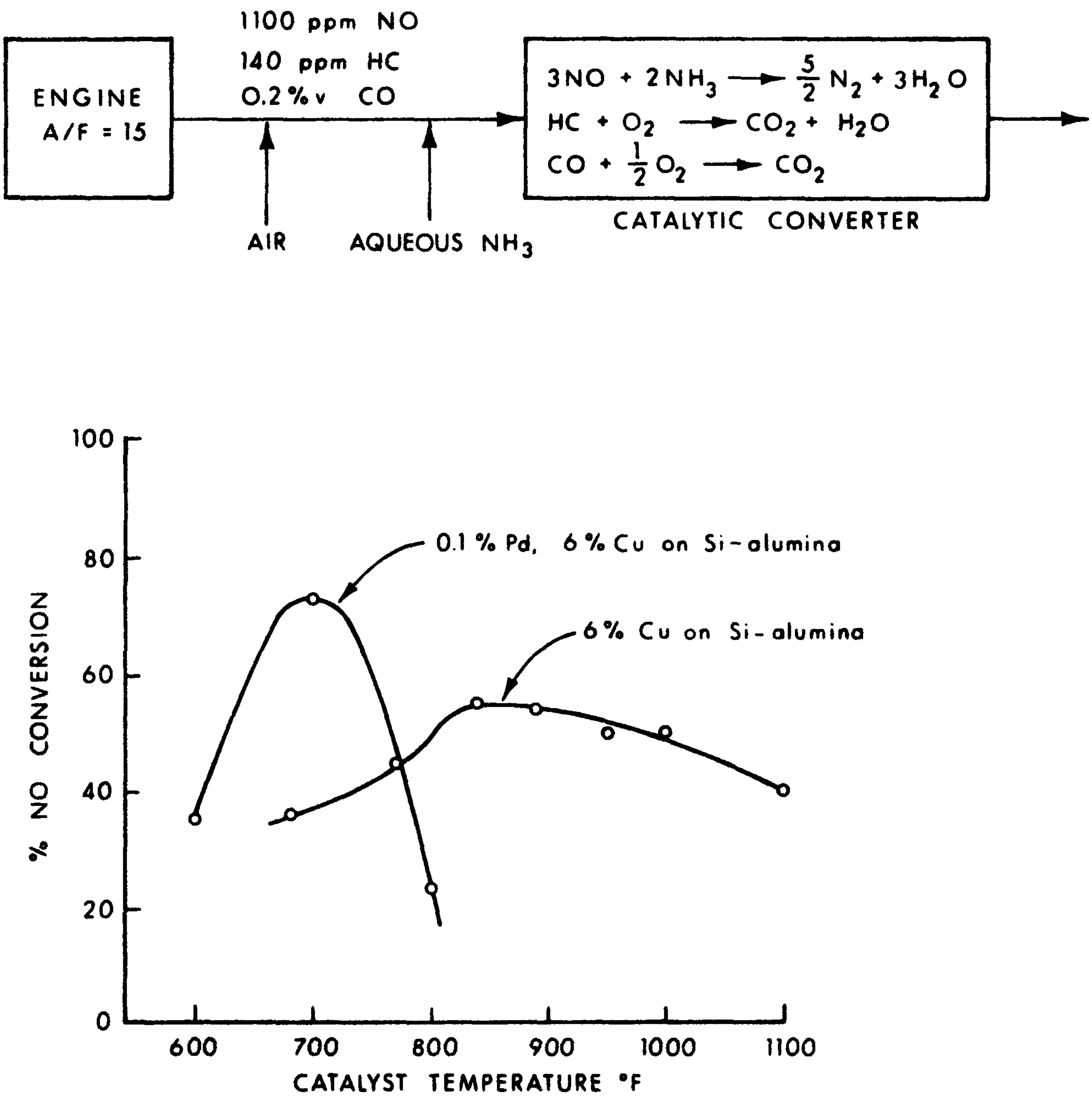
Most stationary engines are operated at lean air/fuel settings for reasons of better fuel economy. Enough oxygen is present in the exhaust to make it necessary to add a reducing agent such as hydrogen, natural gas, or ammonia to the exhaust before catalytic reduction. At high O_2 concentrations, it is known that hydrogen and natural gas will react preferentially with the oxygen. In the case of natural gas, it is necessary to add enough gas to completely react with the oxygen before NOx can be reduced. If the oxygen concentration is high, as in the case of two-cycle engines, it is necessary to use multiple catalytic stages with interstage addition of natural gas in order to avoid burning up the catalyst.

Ammonia, however, will reduce NOx even in the presence of oxygen. Figure 26 reproduces data reported in an Ethyl Corporation patent.[17)] Exhaust from an internal combustion engine was passed over a palladium/copper oxide catalyst and the conversion of NOx was monitored as a function of temperature. An optimum temperature was found near 700°F at which overall NOx conversion reached a maximum near 75 percent. Above this optimum temperature, the ammonia reducing agent begins to oxidize to nitric oxide and water:

$$2NH_3 + 5/2\ O_2 \text{ -------> } 2\ NO + 3\ H_2O$$

Similar data are shown in Figure 27 for a platinum catalyst unit operating at space velocities between 10,000 and 90,000 hr^{-1}.[2)] The optimum temperature occurs near 220°C (428°F). Optimum removal of NOx is above 90 percent, and is relatively insensitive to space velocities. These results were obtained using a synthetic mixture containing 3000 ppm NO, $3\%_v$ O_2, $0.8\%_v$ H_2O, and 3000 ppm NH_3. The water vapor content of engine exhaust is closer to 15 percent for four-cycle engines. Consequently, the anticipated conversion would very likely be lower, since water vapor competes for catalytic sites.

A second advantage of the ammonia reduction system, is that catalytic oxidation of CO and hydrocarbon will occur simultaneously over the same catalyst. For the copper oxide catalyst identified in Figure 26, 46 percent



72/396/6 (REFERENCE; U. S. PATENT 3,449,063)

Figure 26. Catalytic Reduction of NOx By Ammonia

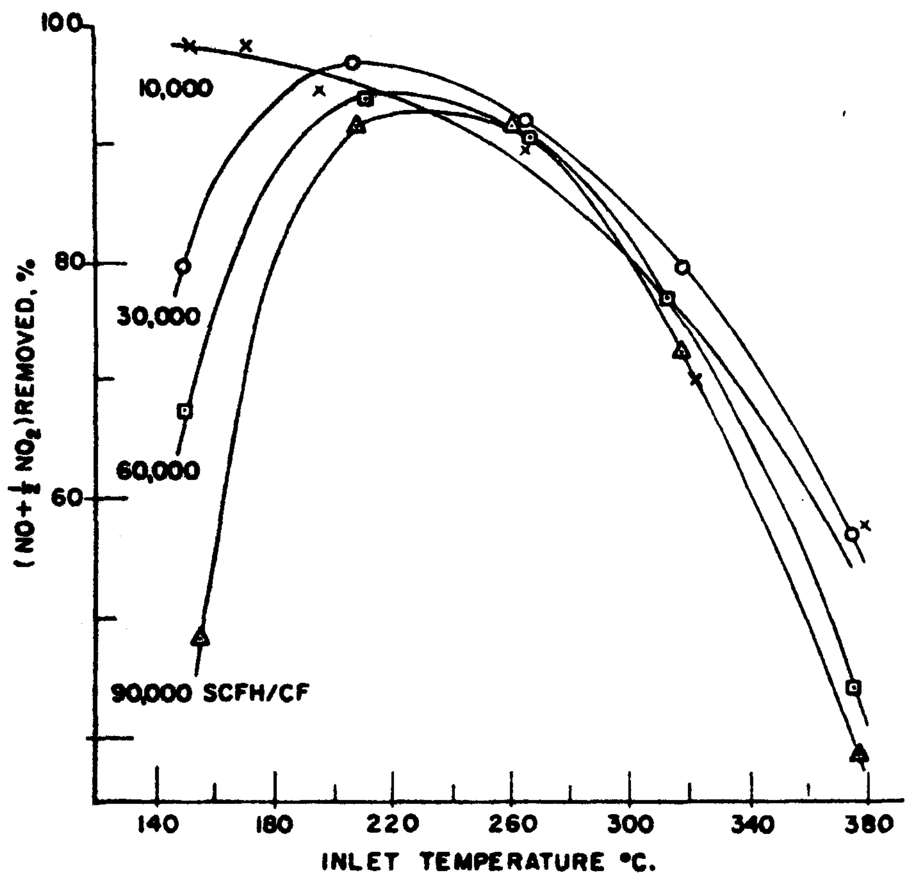


Figure 27. Catalytic Reduction of NO by Ammonia over Platinum Catalyst (Reference 2).

of the carbon monoxide and 38 percent of the hydrocarbons had been removed at the optimum temperature for NOx reduction (840°F).

To maintain a space velocity in the range 30,000 to 50,000 hr^{-1}, a 1000 Bhp engine would require about two cubic feet of catalyst. The most attractive catalyst configuration is the ceramic honeycomb supported catalyst being favored by Ford Motor Company. The system provides both longer life and lower pressure drop than catalysts supported on ceramic pellets. Presently, a platinum honeycomb catalyst would cost about $1500/cu ft. However, this price will very likely drop in the future. In any case, the cost of a catalytic unit will probably be small relative to the cost of the engine itself ($200 to $350/Bhp).

Of all the possible emission control methods, catalytic reduction by ammonia, natural gas or CO would seem to be the best long term NOx control method for stationary engines. The method allows operation of the engine at conditions corresponding to maximum fuel economy or power, and is known to be effective for controlling all three pollutants.

Significant development work will be required, however, before wide scale application will be practical. Information on the optimum catalyst formulation and composition, catalyst durability, and resistance to catalyst poisons in the fuel must be sought to develop a practical catalytic converter for stationary engines. With regard to the ammonia NOx reduction system, it must be determined whether the system will work at the oxygen concentrations present in two-cycle engine exhaust. The effects of catalyst poisons present in gas and oil fuel on catalyst life must be determined. These include sulfur and metal impurities.

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Appendix

SHELL DEVELOPMENT COMPANY
A DIVISION OF SHELL OIL COMPANY
3737 BELLAIRE BOULEVARD
HOUSTON, TEXAS 77025

MAILING ADDRESS
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HOUSTON, TEXAS 77001

BELLAIRE
RESEARCH CENTER

August 10, 1972

Mr. E. L. Case
Vice President Marketing
Worthington - CEI, Inc.
1252 Elm Street
West Springfield, Massachusetts 01089

Dear Mr. Case:

STATIONARY ENGINE SURVEY - EPA SERVICES
CONTRACT EHSD-71-45, TASK 24

We are conducting a survey of stationary reciprocating I.C. engines in the territorial U.S. for the Combustion Research Section of the Environmental Protection Agency's Office of Research and Monitoring. The objectives of the survey are: first to estimate the present and future importance of stationary engines as sources of the major air pollutants and in particular nitrogen oxides, and second to compile existing data on emission levels of stationary engines and the costs of emissions control by various methods. The survey will cover all types of reciprocating engines including diesel, spark ignition, naturally-aspirated, and super- and turbocharged engines.

The specific information being sought includes:

1. Engine design features in past, present, and future units.

2. Major engine manufacturers and associations representing the manufacturers and users.

3. General trends in engine types, ages, sizes, and applications.

4. Distribution of existing engines by type, size, application, industry, and geographical location.

5. Fuel types and their physical and chemical properties.

6. Fuel consumption classified by type and geographical location.

7. Achievable pollutant emission levels and the cost of emissions control.

We believe that this information can be most efficiently obtained from the engine manufacturers directly rather than from the engine users.

Hence, we have mailed the enclosed questionnaire to several engine manufacturers similar to your company. The success of the survey depends on a quantitative response by the industry. Consequently, we urge you to participate in the survey and to answer the questions as completely as possible.

The questionnaire consists of seven sections, including (1) company identification, (2) company products, (3) engines in use, (4) participation in manufacturers associations, (5) design practices, (6) engine data, and (7) emissions data.

Section 6 should be completed for each engine model now in use. In those cases in which the requested data are proprietary, please give as much information as possible. It would also be desirable if you could release to us your experience or use list for each engine model. The data contained in these lists will be used to compile a detailed census and a pollutant emissions inventory for stationary engines, broken down by type, size, application, and geographical area. If you desire, we will keep your experience lists in strictest confidence, and they will be returned to you without being photocopied. The engine census will be reported in a format that does not identify either the engine manufacturers or specific locations. Thus, there is little risk of releasing confidential business data to the public.

We are aware of several existing compilations of stationary engines in use by specific industries, such as the privately owned electric utility and natural gas pipeline and utility companies. We do not feel, however, that the survey will be sufficiently thorough without this direct survey of the engine manufacturers.

We would appreciate receiving the completed questionnaire by September 15, 1972. A self-addressed, postage-paid envelope is enclosed for this purpose. If you have any questions or desire additional copies of all or part of the questionnaire, please call us collect at: 713-667-5661 and ask for C. R. McGowin.

Your cooperation in participating in this survey will be greatly appreciated.

Very truly yours,

ORIGINAL SIGNED BY

S. A. Shain
Project Manager

CM:pjh

Enclosures

bc with enclosures: E. E. Berkau, Combustion Research Section
Environmental Protection Agency

bc without enclosures: J. R. Street
F. A. Cleland
M. E. Doyle
C. R. McGowin

RECIPIENTS OF QUESTIONAIRE - - - - - - - - - - - EPA STATIONARY ENGINE SURVEY

Mr. E. L. Case
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1252 Elm Street
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Mr. Richard Waldo
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White Motor Corporation
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Mr. T. J. Bullock
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Manager of Sales and Services
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Mr. H. D. Clark
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Mr. R. E. Acker
Manager of Market Planning and Research
Detroit Diesel Allison
Division of General Motors
13400 West Outer Drive
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EPA SERVICES CONTRACT EHSD-71-45 - TASK 24

Survey of Stationary Engine Manufacturers

Date ______________

1. Company Identification

A. Name and location of company:

Name: ______________________________

Address: ______________________________

City: ______________ State: ______________ Zip Code: ______

B. Person to contact regarding this report:

Name: ______________________________

Title: ______________________________

Address: ______________________________

City: ______________ State: ______________ Zip Code: ______

Telephone (Area Code): ______________________________

C. Person completing questionaire (if different from above):

Name: ______________________________

Title: ______________________________

Address: ______________________________

City: ______________ State: ______________ Zip Code: ______

Telephone (Area Code): ______________________________

2. Company Products

List your company's major product lines in addition to engines.

3. <u>Engines in Use</u>

List below engine models manufactured by your company and now in use in the U.S. For each engine, give a brief description, the number and average age of those still in operation, and, if not proprietary, the number sold over the last five years.

Engine Model	Brief Description	Engines Still Operating		Number Sold Since 1967	Still on Market?
		Number	Average Age		

4. Participation in Manufacturers' Associations

Describe below your company's participation in associations and industry groups associated with the manufacture and use of internal combustion engines. Mention company representation on executive committees and other leadership positions.

5. Design Practice

Describe briefly the present practices and criteria used in designing engines manufactured by your company. Include discussion of your assessment of current trends in design, size, and application of engines.

6. Engine Data

Manufacturer:____________________

Complete for each stationary engine model now in use. If some or all of the data are already in table form,it will be sufficient to attach these tables and fill in the remaining data below. If possible, attach experience or use list for each model.

Engine Model:					
No. Cylinders Available:					
Type of Service:					
Average Age of Engines:					
Average Age Weighted by Power Output:					
Now being Marketed?:					
Engine Type:					
Strokes/Cycle					
Ignition Type[a]					
Fuels[b]					
Air Charging[c]					
Fuel Charging[d]					
Exhaust Scavenging[e]					
Design Data:					
Speed (rpm)					
Torque-BMEP (psia)					
Power-BHP/Cylinder					
Bore × Stroke (in.)					
Compression Ratio					
Ignition Timing at Rated Speed, Load					
Air/Fuel Equivalence Ratio Range					
Guaranteed BSFC:					
Other Design Features:					

[a] rk or compression ignition.

[b] Natural gas, diesel, dual, gasoline, or other fuel.

[c] Naturally-aspirated, atmospheric, supercharged, turbocharged (pulse or constant pressure), or other

[d] Direct injection (single or divided chamber), carbureted, or other.

[e] Loop or uniflow.

Emissions Data

A. Have you conducted emissions tests on stationary engines manufactured by your company? Yes _______ No _______.

If answer is No, skip to question I.

B. Which exhaust pollutants were monitored? Hydrocarbons __________

Carbon Monoxide _______

Nitrogen Oxides _______

Other _________________

Were analyses performed for individual hydrocarbon components? Yes ________

No _________

Nitrogen oxide components? Yes ________

No _________

C. Which engine models were tested? List below and indicate whether engine was tested on a test bench or at a field location.

Engine Tested	Location

D. Which engine operating parameters were monitored during these tests?

Air/Fuel Ratio ________________ Ignition Timing ________________

Speed ________________ Air Temperature ________________

Power Output ________________ Other (Describe Below) ____________

Fuel Consumption ________________

E. If available, list ranges of exhaust pollutant concentrations measured in the exhaust and indicate whether engine was run at rated speed and load. In addition, give a brief description of test procedure, analytical instrumentation used, etc.

Engine Tested	Pollutant	Concentration Range	Rated Conditions?

F. Indicate below those emissions control methods you have tested on stationary engines.

Air/Fuel Mixture Adjustment ______________

Ignition Timing ________________________

Fuel Injection Timing ___________________

Speed Adjustment _______________________

Exhaust Recycle ________________________

Water Injection ________________________

Stratified Charge Combustion ____________

Catalytic Treatment _____________________

Other __________________________________

G. Please comment on the effect of these emission controls on engine performance, fuel consumption, and other variables. Give estimated cost of application for both new and existing engines.

H. List below the percentage reduction in emissions obtained by application of emission controls to stationary engines.

Engine Tested	Emission Control Used	% Change Mass Emissions			% Change Fuel Consumption
		NO_x	HC_T	CO	

I. Are you aware of any emissions tests conducted by outside organizations on your stationary engines? Yes ____ No ____. If yes, what organization?

If possible, describe results of the emissions tests below or attach report.

California 13 Mode Cycle for Diesel Truck Engines

Rated Speed % Load ± 2%	Intermediate Speed % Load ± 2%	Low Idle Speed % Load ± 2%
100	100	0
75	75	0
50	50	0
25	25	
2	2	

Intermediate speed is peak torque speed or 60% of rated speed, whichever is higher.

Weighting factor is 0.20 for average low idle mode and 0.08 for all other modes.

EMISSIONS DATA

4-Cycle Diesels - Precombustion Chamber

Engine	BHP (Full Load)	BSFC (lb/Bhp-hr)	Specific Emissions (g/Bhp-hr) NOx	CO	HC_t	Reference[a)]
Turbocharged (13 Mode Test)						
A	250		5.5	1.0	0.2	QI
B	850		5.5	1.3	0.2	QI
C	970		4.0	1.6	0.3	QI
D	750		6.4	1.9	0.6	QI
I	88.6		6.1	2.3	0.34	23
Turbocharged (Continuous Test)						
E	750		7.8	0.8	0.05	QI
I	100		5.6	1.6	0.4	23
Naturally-Aspirated (13 Mode Test)						
F	125		5.9	2.5	0.3	QI
Naturally-Aspirated (Continuous Test)						
G	125		6.0	0.96	0.18	QI

a) QI = Questionnaire Response or User Survey

EMISSIONS DATA

2-Cycle Diesels - Direct Injection

Engine	BHP (Full Load)	BSFC (lb/Bhp-hr)	Specific Emissions (g/Bhp-hr) NOx	CO	HC_t	Reference[a)]
(13 Mode Test)						
J	46.7		14.7	6.1	0.8	23
(Continuous Test)						
J	50		14.6	2.5	1.2	23

a) QI = Questionnaire Response or User Survey

EMISSIONS DATA

4-Cycle Dual-Fuel Engines

Engine	BHP (Full Load)	BSFC (lb/Bhp-hr)	Specific Emissions (g/Bhp-hr) NOx	CO	HC_t	Reference[a)]
(Turbocharged)						
A	7707	5760	7.7	0.61	1.9	QI
B	4296	6340	8.96	4.50	5.16	35

a) QI = Questionnaire Response or User Survey

EMISSIONS DATA

2-Cycle Turbocharged Gas Engines

Engine	BHP	BSFC (Btu/Bhp-hr)	Specific Emissions (g/Bhp-hr) NOx	CO	HC_t	Reference[a)]
A	1600	6632	20.13	0.17	1.58	35
B	2140	7000	7.4			QI
C	1940	7200	8.9			QI
D	5233	6110	11.8	2.0	1.1	QI
E	400	7177	7.6		10.1	QI
F	800	7071	14.2	1.7	4.4	QI
G	800	7071	9.4	6.0	30.6	QI
H	1000	7067	16.8	7.4		QI
I	2260	7500	9.6			QI
J	1950	7500	12.1			QI
K	1613	6099	9.7	3.8	4.5	QI
L	1535	6409	10.9	3.0	3.2	QI
M	3600	6123	9.1	1.8	4.1	QI
N	3655	6108	7.4	2.5	4.4	QI
O	2000	7067	8.5	4.6	5.4	QI

a) QI = Questionnaire Response or User Survey

EMISSIONS DATA

2-Cycle Atmospheric Gas Engines

Engine	BHP (Full Load)	BSFC (Btu/Bhp-hr)	Specific Emissions (g/Bhp-hr) NOx	CO	HC_t	Reference[a)]
A	1080	7079	15.23	0.29	1.94	25
B	1350	7700	10.0			QI
C	1600	7177	4.6		5.0	QI
D	400	7177	7.6		10.1	QI
E	2200	7774	17.9		17.0	QI

a) QI = Questionnaire Response or User Survey

EMISSIONS DATA

4-Cycle Turbocharged Gas Engines

Engine	BHP (Full Load)	BSFC (Btu/Bhp-hr)	Specific Emissions (g/Bhp-hr) NOx	CO	HC_t	Reference[a)]
A	1950	7300	14.1			QI
B	4000	6500	10.4			QI
C	925	7067	15.7	0.9	6.5	QI
D	750	7063	12.5	1.1		QI

a) QI = Questionnaire Response or User Survey

EMISSIONS DATA

4-Cycle Naturally-Aspirated Gas Engines

Engine	BHP (Full Load)	BSFC (Btu/Bhp-hr)	Specific Emissions (g/Bhp-hr) NOx	CO	HC_t	Reference[a)]
A	225		12.6	1.6	3.1	QI
B	800	8432	9.1	0.5	16.8	QI
C	1170	6509	14.4	1.3	2.5	QI
D	496	6599	10.2	3.2	0.8	QI
E	190	5975	12.8	2.4	9.3	QI
F	800		10.9		2.0	QI

a) QI = Questionnaire Response or User Survey

EMISSIONS DATA

4-Cycle High-Speed Gas Engines

Engine	BHP (Full Load)	BSFC Btu/Bhp-hr)	Specific Emissions (g/Bhp-hr) NOx	CO	HC_t	Reference[a)]
A	310		12.1	6.3	3.5	QI
B	1323		13.0	5.6	1.8	QI

a) QI = Questionnaire Response or User Survey

EMISSIONS DATA

Gas Turbines

Engine	BHP (Full Load)	BSFC Btu/Bhp-hr)	Specific Emissions (g/Bhp-hr) NOx	CO	HC_t	Reference[a)]
Natural Gas Fuel						
A	6200	12,377	3.2			QI
B	6900	12,104	2.8			QI
C	1100	11,000	0.84			QI
D	1100	11,000	1.0			QI
E	13,950	11,000	1.7			QI
F	13,950	11,000	1.5			QI
G	14,700	11,000	0.92			QI
H	14,700	11,000	1.6			QI
I	14,700	11,000	1.5			QI

a) QI = Questionnaire Response or User Survey

GAS PIPELINES

Company	Miles of pipeline: Trans.	Miles of pipeline: Field	Miles of pipeline: Storage	Miles of pipeline: Total	Compressor stations: Transmission No.	Compressor stations: Transmission Hp	Compressor stations: Other No.	Compressor stations: Other Hp	Compressor stations: Total hp	Total sales (MMcf)	Gas plant ($1,000)	Additions ($1,000)	Operating revenue ($1,000)	Net income ($1,000)
Alabama-Tennessee Natural Gas Co.	296	.....	....	296	2	2,450	..		2,450	33,513	12,803	404	15,354	1,138
Algonquin Gas Transmission Co.	927	.....	...	927	3	30,900	.		30,900	137,111	167,719	3,550	98,061	5,795
Arkansas Louisiana Gas Co.	5,820	1,876	8	7,704	19	68,310	44	40,370	108,680	409,452	457,105	24,298	162,841	24,494
Arkansas-Missouri Power Co.	227	....	..	227	....	.....	..	..	....	7,370	10,689	672	32,640	1,704
Arkansas Oklahoma Gas Corp.	409	204	4	617	1	370	6	590	960	14,841	17,471	893	7,602	614
Baca Gas Gathering System, Inc.	....	58	....	58	....	..	2	610	610	2,770	946	1	510	5
Black Marlin Pipeline Co.	54	.....	..	54	....	.....	...	......	......	*50,651	6,749	......	1,090	188
Blue Dolphin Pipe Line Co.	49	....	....	49	....	.....	...	......	......	*64,750	......	......	1,042	552
Bluebonnet Gas Corp.	......	.....	....	......	....	......	...	......	......	1,609	104	2	265	4
Bluefield Gas Co.	31	.....	..	31	....	.....	...	.....	......	1,228	1,710	206	1,044	50
Caprock Pipeline Co.	30	2	..	32	....	.....	1	340	340	2,728	868	.....	670	10
Carnegie Natural Gas Co.	229	894	.	1,123	6	4,092	6	500	4,592	27,548	41,843	438	16,878	......
Cascade Natural Gas Corp.	121	48	.	169	1	1,320	3	5,182	6,502	64,912	......	......	38,650	2,432
Chandeleur Pipe Line Co.	160	...	...	160	....	......	..	.....	......	*37,820	16,400	504	1,078	(873)
Cimarron Transmission Co.	......	39	.	39	....	......	..	......	...	13,679	1,180	......	2,867	38
Cities Service Gas Co.	5,345	2,602	174	8,121	36	221,110	32	70,480	291,590	530,464	332,522	27,411	158,289	17,907
Colorado Interstate Gas Co.	2,051	2,003	130	4,184	13	99,030	36	68,247	167,277	399,527	258,916	18,695	104,409	10,003
Columbia Gas Transmission Corp.	10,754	6,569	1,136	18,459	84	344,721	30	107,095	451,816	1,354,146	1,087,711	62,636	732,667	52,303
Columbia Gulf Transmission Co.	3,382	.....	..	3,382	12	472,820			472,820	*616,565	616,714	45,990	99,628	25,386
Commercial Pipeline Co., Inc.	......	.....	....	......	....	.....	.	......	......	369	570	141	247	(18)
Consolidated Gas Supply Corp.	3,569	3,886	519	7,974	17	79,440	54	205,370	284,810	704,930	637,650	30,194	399,743	20,142
Delta Gas, Inc.	......	.....	....	......	..	.....	..	....	......	......	1,830	85	615	1
East Tennessee Natural Gas Co.	1,012	.....	....	1,012	9	18,320	..	...	18,320	90,114	51,207	2,421	40,125	2,581
Eastern Shore Natural Gas Co.	238	...	.	238	....	...	..	...	......	7,980	6,946	459	4,945	456
El Paso Natural Gas Co.	12,611	10,102	22	22,735	80	946,372	65	573,545	1,519,917	1,797,920	2,089,636	148,478	722,631	73,868

GAS PIPELINES

Company	Miles of pipeline: Trans.	Field	Storage	Total	Compressor stations: Transmission No.	Hp	Other No.	Hp	Total hp	Total sales (MMcf)	Gas plant ($1,000)	Additions	Operating revenue	Net income
Emmitsburg Gas Co.	13	...	...	13	...	...	...	...	...	448	487	2	271	(18)
Equitable Gas Co.	796	1,174	129	2,099	7	28,150	16	11,965	40,115	89,463	200,802	12,715	83,888	8,025
Farmland Industries, Inc.	...	52	...	52	...	...	...	...	...	*5,889	600	5	88	2
Florida Gas Transmission Co.	4,212	...	...	4,212	20	144,500	12	2,775	147,275	135,182	367,720	4,356	95,393	14,518
Gardner Pipeline, Inc.	8	...	...	8	...	...	...	...	...	*217	244	...	29	...
Gas Transport, Inc.	91	...	...	91	...	...	...	...	...	3,849	1,247	7	1,676	77
Grand Valley Transmission Co.	...	...	...	...	...	...	...	...	...	3,222	1,096	11	585	19
Granite State Gas Transmission, Inc.	65	...	...	65	1	375	...		375	4,083	2,814	133	3,090	55
Great Lakes Gas Transmission Co.	1,022	...	...	1,022	12	298,500			298,500	84,729	302,610	28,115	70,594	1,254
Great Plains Natural Gas Co.	65	...	...	65	...	...			...	3,997	7,118	514	3,268	278
Hampshire Gas Co.	...	...	18	18	...	...	1	1,640	1,640	...	5,791	5,791	71	(72)
Indiana Utilities Corp.	21	...	...	21	...	...				270	715	41	325	26
Inland Gas Co.	139	348	...	487	...	...	5	1,135	1,135	18,033	11,211	1,126	8,755	722
Inter-City Minnesota Pipelines Ltd.	...	...	...	...	...	...	...		...	7,113	2,532	419	3,775	81
Interstate Power Co.	...	...	...	...	...	...	...		...	25,040	16,643	937	66,859	7,524
Iowa-Illinois Gas & Electric Co.	...	...	...	...			...	...	...	86,552	96,283	5,805	104,004	9,112
Iowa Public Service Co.	...	...	...	...			...	...	...	54,889	38,246	2,228	77,860	10,082
Iroquois Gas Corp.	1,144	234	187	1,565	5	9,400	5	3,820	13,280	138,377	215,321	12,767	135,133	5,780
Kansas-Nebraska Natural Gas Co.	8,904	1,548	12	10,464	18	81,760	20	15,965	97,725	119,205	185,473	18,212	58,792	7,651
Kentucky-West Virginia Gas Co,	27	1,779	...	1,806	2	4,485	6	10,400	14,885	24,413	89,085	4,226	11,569	3,410
Lawrenceburg Gas Transmission Corp.	6	...	...	6	...	...	...		...	5,305	201	...	2,058	17
Lake Shore Pipe Line Co.	37	...		37	...	...				14,945	1,934	...	7,373	36
Lone Star Gas Co.	8,089	1,954	72	10,115	25	33,450	18	24,170	57,620	434,180	528,425	21,284	202,841	25,809
Louisiana-Nevada Transit Co.	33	...	...	33	...	...			...	4,552	1,579	69	1,168	(137)
Marengo Corp.	38	...	...	38	...				...	561	150	7	344	16
McCulloch Interstate Gas Co.	170			170	2	5,500			5,500	22,472	8,647	1,015	4,549	(22)
Michigan Gas Storage Co.	568	151		719	1	15,700	1	37,300	53,000	88,328	51,282	152	40,773	1,906
Michigan Wisconsin Pipe Line Co.	7,033	1,627	24	8,684	35	637,810	8	72,925	710,735	763,229	939,040	82,578	353,634	26,635
Mid Louisiana Gas Co.	386	333		719	2	20,100	1	2,200	22,300	31,836	35,315	4,139	7,764	1,418
Midwestern Gas Transmission Co.	903		12	915	14	86,010	2	1,593	87,603	209,506	133,249	4,510	130,837	5,818
Mississippi River Transmission Corp.	1,748	266	41	2,055	21	119,325	4	21,085	140,410	244,464	174,353	5,964	109,815	6,991
Montana-Dakota Utilities Co.	2,733	508	2	3,243	13	39,905	2	1,210	41,115	48,879	119,746	5,829	58,160	7,792
Mountain Fuel Supply Co.	708	670	6	1,384	3	14,720	40	12,803	27,523	125,647	224,961	15,471	61,464	8,351
Mountain Gas Co.	64	...	...	64	...					2,635	...	...	758	
Natural Gas Pipeline Co. of America	9,405	1,186	197	10,788	49	911,700	36	88,655	1,000,355	1,062,582	1,285,461	57,705	432,845	41,559
North Penn Gas Co.	619	511	17	1,147	6	625	4	5,165	5,790	28,434	21,887	1,511	18,861	947
Northern Natural Gas Co.	17,535	4,437	97	22,069	59	869,260	73	66,368	935,628	877,774	1,198,692	40,897	393,428	76,267
Northern Utilities, Inc.	614	40	...	654	2	820	1	865	1,685	22,157	15,627	1,071	7,892	604
Ohio River Pipeline Corp.	23	...	...	23	...	...	...	...	...	10,285	1,053	131	4,651	19
Oklahoma Natural Gas Gathering Corp.	26	172	...	198	...	...	1	12,500	12,500	18,899	6,311	171	3,764	179
O'Fallon Gas Service, Inc.	...	...	...	...	...	...	...		...	562	1,535	212	683	45
Orange & Rockland Utilities, Inc.	...	...	...	...	...	...	...	...	...	23,316	44,962	4,782	74,271	7,474
Pacific Gas Transmission Co.	639	...		639	12	233,970			233,970	339,565	177,104	7,884	111,673	4,705
Panhandle Eastern Pipe Line Co.	6,666	2,563	93	9,322	41	586,354	16	73,977	660,331	770,800	705,013	40,219	295,577	36,056
Penn-Jersey Pipe Line Co.	5	...	...	5	...	...	...	...	...	*1,149	236		23	5
Pennsylvania & Southern Gas Co.	49	...		49	...		...			5,915	9,442	755	5,000	369
Pennsylvania Gas Co.	418	239	115	772	2	9,500	3	2,300	11,890	73,515	56,820	2,628	33,212	2,638
Raton Natural Gas Co.	21	...	...	21	...	...	...	...	...	877	1,095	14	587	30
Sabine Pipe Line Co.	174	...	...	174	...	...	...	...	...	*60,846	19,104	10	1,935	383
Sea Robin Pipeline Co.	195	27	...	222	...	...	...	...	...	80,016	83,416	4,363	29,552	3,402

GAS PIPELINES

Company	Miles of pipeline: Trans.	Miles of pipeline: Field	Miles of pipeline: Storage	Miles of pipeline: Total	Compressor stations: Transmission No.	Transmission Hp	Other No.	Other Hp	Total hp	Total sales (MMcf)	Gas plant ($1,000)	Additions ($1,000)	Operating revenue ($1,000)	Net income ($1,000)
Shenandoah Gas Co.	68	.....	....	68	....	......	...	......	......	4,537	5,961	262	3,264	(3)
South County Gas Co.	......	.....	....	....	....	......	...	......	......	367	942	29	727	(12)
South Georgia Natural Gas Co.	773	..		773	2	3,500	..		3,500	26,911	16,557	199	12,881	1,046
South Texas Natural Gas Gathering Co.	302	290	.	592	3	9,000	7	2,590	11,590	67,955	23,242	308	14,021	(285)
Southern Natural Gas Co.	6,681	148		6,829	36	351,160	80	11,864	363,024	689,148	638,199	24,701	272,332	27,518
Southwest Gas Corp.	1,447	....	.	1,447	3	5,200			5,200	77,028	101,094	6,583	49,413	3,564
Standard Pacific Gas Lines Inc.	224	...	.	224	...	..	..	..	.....	*110,001	15,737	1,426	745	(61)
Sylvania Corp.	......	48	43	91			1	825	825	1,757	9,382	2,842	884	7
Tenneco Gas Pipeline Co.	12,740	55	2	12,797	58	1,188,325	1	16,200	1,204,525	1,291,367	1,918,281	60,148	563,315	142,681
Tennessee Gas Pipe Line Co.	17	....	....	17	....	......	...	....	......	80	430	....	79	14
Tennessee Natural Gas Lines, Inc.	56	.		56	...	.	..		.	32,879	2,393	11	14,615	1,217
Texas Eastern Transmission Corp.	8,738	48	183	8,969	75	1,176,110	29	84,998	1,261,108	983,161	1,505,031	59,288	461,344	67,602
Texas Gas Pipe Line Corp.	57			57	1	2,000			2,000	8,050	2,518	3	1,472	25
Texas Gas Transmission Corp.	5,535	41	183	5,759	19	459,010	10	14,097	473,107	738,538	579,777	18,653	271,918	21,171
Tidal Transmission Co.	85		..	85	....	...				24,246	8,804	4	1,445	152
Transcontinental Gas Pipe Line Corp.	8,638	86	92	8,816	36	933,385	12	42,919	976,304	981,309	1,592,790	50,206	438,209	52,203
Transwestern Pipeline Co.	3,123	.		3,123	85	187,828			187,828	325,213	356,830	16,081	125,877	14,460
Trunkline Gas Co.	3,138	842	.	3,980	16	308,450	2	23,550	332,000	537,361	578,574	12,830	202,424	13,656
Union Light, Heat & Power Co.	....	1	29	30	.		..		...	17,006	32,842	2,982	37,892	2,282
United Gas Pipe Line Co.	7,391	1,627	21	9,039	32	189,305	7	38,250	227,555	1,388,973	594,037	7,662	386,851	7,670
United Natural Gas Co.	1,451	1,522	136	3,109	12	8,913	7	8,098	17,011	98,155	97,866	4,187	67,427	5,854
Valley Gas Transmission, Inc.	269	...		269	...	.	1	550	550	32,821	4,522	115	6,233	61
Washington Gas Light Co.	368			368	....	.....	2	15,920	15,920	106,140	380,529	28,827	141,317	9,102
West Texas Gathering Co.	59	66	...	125	....	.....	3	1,079	1,079	93,631	4,226	15	17,567	93
Western Gas Interstate Co.	186	...	....	186	....	.....	...	...	......	4,056	1,607	357	1,023	52
Western Transmission Corp.	......	35	..	35	....	.	...	..	......	940	1,415	......	197	(37)
Wheeler Gas Co.	......	....	....	......	....	...	...	...	..	103	......	.....	85	(20)
Zenith Natural Gas Co.	27	18	..	45	....		1	300	300	1,136	454	3	222	3
1971 Totals	184,099	52,929	3,704	240,732	1,013	11,264,360	717	1,804,385	13,068,745	19,245,181	21,686,034	1,065,981	8,859,187	936,982
1970 Totals	183,671	51,996	3,582	239,249	1,021	10,626,326	713	1,625,470	12,251,796	18,820,200	20,729,147	2,201,640	8,201,669	815,680
Differences	428	933	122	1,483	(8)	638.034	4	178,915	816,949	424,981	956,887	1,135,659	657,518	121,302

*Transported for others and not included in total sales
Data collected by Robert W. Gary, consultant

OIL PIPELINES

Company	Miles of pipeline: Crude Gathering	Crude Trunk	Products	Total	Deliveries (1,000 bbl): Crude	Products	Total	Total trunkline traffic (Million bbl-miles): Crude	Products	Total	Carrier property ($1,000)	Change ($1,000)	Operating revenue ($1,000)	Net income ($1,000)
Acorn Pipe Line Co.	.....	.....	...	......	11,230	...	11,230	5,215	.	5,215	3,256	5	1,297	418
Airforce Pipeline, Inc.	.....	.....	5	5	......	166	166	....	8,705	8,705	296		95	28
Allegheny Pipeline Co.	.....	....	541	541	......	8,685	8,685	....	2,956	2,956	11,988	1,574	2,069	707
American Petrofina Co.	.....	....	46	46	......	987	987	.....	48	48	1,044	.....	144	96
Amoco Pipeline Co.	2,465	8,621	88	11,174	387,427	64,847	452,274	173,758	2,205	175,963	280,729	2,904	68,692	13,819

OIL PIPELINES

Company	Miles of pipeline: Crude: Gathering	Crude: Trunk	Products	Total	Deliveries (1,000 bbl): Crude	Products	Total	Total trunkline traffic (Million bbl-miles): Crude	Products	Total	Carrier property ($1,000)	Change ($1,000)	Operating revenue ($1,000)	Net income ($1,000)
Arapahoe Pipe Line Co.	705	796		1,501	25,637		25,637	9,545		9,545	35,976	353	4,290	(18)
ARCO Pipe Line Co.	2,590	3,964	3,823	10,377	279,079	140,939	420,018	74,210	20,480	94,693	340,375	35,950	46,193	10,640
Ashland Pipe Line Co.	519	820	225	1,564	66,920	6,300	73,220	42,423	1,707	44,130	60,139	4,125	17,928	4,083
Badger Pipe Line Co.			331	331		44,470	44,470		3,159	3,159	16,822	343	4,593	1,028
Bell Creek Pipe Line Co.	70			70	3,985		3,985				1,922		472	90
Belle Fourche Pipeline Co.		943		943	34,450		34,450	18		18	18,125	664	6,890	1,117
Bigheart Transport, Inc.					7,320		7,320				1,190	12	674	143
Black Lake Pipe Line Co.		255		255	10,827		10,827	1,863		1,863	9,824	2	1,575	544
Black Mesa Pipeline, Inc.			*273	*273		*1,093	*1,093		*298	*298	37,940		4,758	(421)
Buckeye Pipe Line Co.	1,818	1,028	3,020	5,866	153,590	192,131	345,721	15,300	26,699	41,999	207,211	879	39,741	10,471
Butte Pipe Line Co.		511		511	26,079		26,079	6,816		6,816	20,371	22	4,128	759
Calnev Pipe Line Co.			260	260		13,566	13,566		2,620	2,620	14,607	522	4,951	1,988
Cherokee Pipe Line Co.	351	511	1,515	2,377	25,592	44,369	69,961	2,266	10,139	12,405	40,735	(247)	7,264	709
Chevron Pipe Line Co.	257	1,432	1,494	3,183	166,042	28,236	194,278	23,738	8,800	32,538	111,604	2,695	25,030	7,483
Cheyenne Pipeline Co.	5	34	220	259	703	4,810	5,513	24	1,058	1,082	4,503		1,009	487
Chicap Pipe Line Co.		234		234	51,951		51,951	10,876		10,876	25,798	129	2,516	(200)
Cities Service Pipe Line Co.	676	630	106	1,412	83,543	4,143	87,686	11,892	392	12,284	29,187	1,158	8,335	2,104
Collins Pipeline Co.			124	124		602	602		2,679	2,679	12,762	564	2,819	1,126
Colonial Pipeline Co.			3,690	3,690		424,240	424,240		483,211	483,211	514,800	102,978	108,820	26,691
Continental Pipe Line Co.	3,705	1,081	564	5,350	115,889	13,127	129,016	14,256	2,779	17,035	82,023	1,963	23,996	8,090
Cook Inlet Pipe Line Co.		55		55	52,200		52,200	1,497		1,497	41,867	543	11,808	5,394
CRA, Inc.	666	207		873	18,892		18,892	609		609	7,144	26	1,319	
Crown-Rancho Pipe Line Corp.					‡7,128		‡7,128	‡2,677		‡2,677	‡2,013		‡898	‡625
Diamond Shamrock Oil & Gas Co.			622	622		8,378	8,378		2,845	2,845	17,757	914	2,378	102
Dixie Pipeline Co.			1,298	1,298		19,141	19,141		12,171	12,171	56,950	2,618	12,354	3,864
Emerald Pipe Line Corp.			113	113		1,460	1,460		129	129	1,337		234	57
Eureka Pipe Line Co.	3,143	431		3,574	4,913		4,913	99		99	8,171	27	2,532	135
Fairview Pipe Line Co.	52			52	866		866				747	14	130	18
Four Corners Pipe Line Co.	187	722		909	13,172		13,172	7,691		7,691	47,765	(45)	5,549	118
Getty Pipe Co.			575	575		2,119	2,119		112	112	3,135		554	
Gulf Central Pipeline Co.			1,880	1,880		4,742	†4,742		3,131	†3,131	106,078	3,001	3,041	(9,390)
Gulf Refining Co.	2,115	3,696	1,858	7,669	309,129	132,216	441,345	13,030	25,077	38,107	197,314	20,365	32,997	5,638
Hess Pipeline Co.	52	422		474	22,451		22,451	19		19	20,013	3,694	3,446	682
Humble Pipe Line Co.	3,453	6,635	2,350	12,438	496,666	127,056	623,722	67,497	10,117	77,614	400,288	48,177	71,370	25,605
Hydrocarbon Transportation, Inc.			1,232	1,232		18,675	18,675		7,516	7,516	79,552	20,439	8,054	1,567
Jayhawk Pipeline Corp.	235	460		695	30,079		30,079	4,061		4,061	17,377	428	3,351	588
Jet Line, Inc.			90	90		9,197	9,197		560	560	5,445	128	1,278	130
Kaneb Pipe Line Co.			1,261	1,261		34,458	34,458		7,257	7,257	37,081	1,509	10,327	2,409
Kaw Pipe Line Co.	1,433			1,433	21,812		21,812				11,539	(30)	2,191	248
Kenai Pipe Line Co.		24		24	26,159		26,159	288		288	12,213	11	2,125	462
Kerr-McGee Pipeline Corp.	8	33		41	1,107		1,107	37		37	855		277	78
Lake Charles Pipe Line Co.		12		12	68,834		68,834	209		209	4,466	66	989	212
Lakehead Pipe Line Co., Inc.		2,391		2,391	313,329		313,329	255,040		255,040	329,941	16,193	64,709	18,009
Laurel Pipe Line Co.			451	451		41,843	41,843		7,431	7,431	54,138	600	7,010	1,192
MAPCO, Inc.			4,274	4,274		70,237	70,237		28,536	28,536	126,726	2,801	28,308	10,650
Marathon Pipe Line Co.	1,327	1,235	715	3,277	211,881	27,195	239,076	40,339	4,380	44,719	116,914	6,742	22,748	5,017
Michigan-Ohio Pipeline Corp.		389		389	11,524		11,524	1,031		1,031	6,315	159	1,363	58
Mid-Valley Pipeline Co.		1,004		1,004	117,212		117,212	87,391		87,391	80,274	(741)	15,909	3,863
Minnesota Pipe Line Co.		260		260	46,091		46,091				18,193	1,093	8,092	2,373
Mobil Pipe Line Co.	4,628	5,080	2,426	12,134	242,526	95,705	338,231	88,351	20,317	108,668	258,820	26,126	56,182	16,615

OIL PIPELINES

Company	Miles of pipeline: Crude: Gathering	Crude: Trunk	Products	Total	Deliveries (1,000 bbD): Crude	Products	Total	Total trunkline traffic (Million bbl-miles): Crude	Products	Total	Carrier property ($1,000)	Change ($1,000)	Operating revenue ($1,000)	Net income ($1,000)
National Transit Co.	2,826	840	6	3,672	8,167	247	8,414	660	1	661	11,630	410	8,167	(129)
Ohio River Pipe Line Co.	.....	2	111	113	2,970	3,765	6,735	6	250	256	1,651	354	301	(66)
Okan Pipeline Co.	.....	.....	438	438	.....	4,719	4,719	.....	780	780	6,775	8	1,113	207
Olympic Pipe Line Co.	.....	.....	314	314	.....	48,403	48,403	.....	8,153	8,153	33,990	3,206	7,219	2,565
OMR Pipe Line Co.	.....	.....	604	604	.....	24,164	24,164	.....	8,559	8,559	23,662	630	6,336	1,650
Paloma Pipe Line Co.	.....	.....	.....	.....	15,985	.....	15,985	1,774	.....	1,774	6,151	1,241	2,757	1,232
Panotex Pipe Line Co.	238	97	.....	335	4,141	.....	4,141	.....	.....	.....	4,650	60	885	.....
Phillips Petroleum Co.	.....	.....	362	362	.....	11,642	11,642	.....	3,112	3,112	10,568	(928)	3,532	869
Phillips Pipe Line Co.	1,190	1,996	2,695	5,881	99,055	128,431	227,486	22,653	41,943	64,596	135,657	(1,840)	36,231	5,541
Pioneer Pipe Line Co.	.....	.....	303	303	.....	6,476	6,476	.....	1,719	1,719	8,821	10	1,923	593
Plantation Pipe Line Co.	.....	.....	3,948	3,948	.....	169,452	169,452	.....	98,111	98,111	234,741	42,105	46,585	15,552
Platte Pipe Line Co.	.....	1,257	.....	1,257	55,937	.....	55,937	37,735	...	37,735	69,747	(142)	11,728	3,135
Portal Pipe Line Co.	210	550	....	760	7,363	.....	7,363	2,647	...	2,647	19,473	(19)	3,128	882
Portland Pipe Line Corp.	.....	514	....	514	160,493	.....	160,493	26,692		26,692	51,854	958	12,094	2,403
Pure Transportation Co.	654	533	80	1,267	103,035	15,483	118,518	23,508	180	23,688	53,662	1,855	13,587	4,511
Santa Fe Pipeline Co.	.....	.....	821	821	.....	7,832	7,832	.....	6,430	6,430	2,943	10	3,169	(1,751)
Shamrock Pipe Line Corp.	589	233	181	1,003	13,969	7,722	21,691	764	601	1,365	12,550	(108)	2,554	656
Shell Pipe Line Corp.	2,148	4,955	306	7,409	353,646	77,112	430,758	118,776	3,618	122,394	203,979	1,577	52,800	12,767
Skelly Pipeline Co.	.....	133	143	276	4,910	10,161	15,071	654	1,445	2,099	7,105	212	1,519	722
Sohio Pipe Line Co.	1,377	1,344	3	2,724	78,175	1,177	79,352	17,335	4	17,339	132,790	31,300	10,254	2,267
Southcap Pipe Line Co.	.....	.....	.....	.....	35,753		35,753	22,604	..	22,604	28,692	(314)	5,675	2,260
Southern Pacific Pipe Lines, Inc.	.....	.....	2,461	2,461	.....	171,156	171,156	.....	20,581	20,581	121,600	5,506	33,620	10,523
Sun Oil Co. of Michigan	.....	.....	9	9	.....	6,792	6,792	.....	61	61	649	649	80	14
Sun Pipe Line Co.	1,315	1,197	1,320	3,832	100,877	65,448	166,325	6,251	7,927	14,178	75,522	1,182	21,186	4,829
Tecumseh Pipe Line Co.	.....	206	..	206	29,688	.....	29,688	3,467	...	3,467	14,750	8	1,557	273

OIL PIPELINES

Company	Miles of pipeline: Crude Gathering	Miles of pipeline: Crude Trunk	Miles of pipeline: Products	Miles of pipeline: Total	Deliveries (1,000 bbl): Crude	Deliveries (1,000 bbl): Products	Deliveries (1,000 bbl): Total	Total trunkline traffic (Million bbl-miles): Crude	Total trunkline traffic (Million bbl-miles): Products	Total trunkline traffic (Million bbl-miles): Total	Carrier property ($1,000)	Change ($1,000)	Operating revenue ($1,000)	Net income ($1,000)
Texaco-Cities Service Pipe Line Co.	....	1,878	277	2,155	98,480	4,484	102,964	22,559	429	22,988	50,906	38	6,923	1,368
Texas Eastern Transmission Corp.	...		2,600	2,600	....	99,531	99,531		49,834	49,834	162,424	7,713	33,019	11,399
Texas-New Mexico Pipe Line Co.	2,069	2,214		4,283	162,453	...	162,453	19,949	.....	19,949	78,796	510	13,707	3,421
Texas Pipe Line Co.	1,659	2,105	552	4,316	334,424	167,418	501,842	88,736	9,098	97,834	206,375	6,048	45,627	12,580
Trans Mountain Oil Pipe Line Corp.	....	64		64	79,279	...	79,279	3,608		3,608	5,600	....	1,797	702
Trans-Ohio Pipeline Co.	....	...	34	34	.....	506	506	...	17	17	1,435	306	106	38
UCAR Pipeline, Inc.	....	...	58	58	......	844	844		26	26	4,527	32	73	(391)
Wabash Pipe Line Co.	....	....	372	372	....	32,816	32,816		5,357	5,357	22,021	35	3,600	569
West Emerald Pipe Line Corp.	....		296	296	......	2,709	2,709		661	661	1,678	....	493	70
West Shore Pipe Line Co.	....		296	296	....	54,041	54,041		6,624	6,624	22,546	656	6,287	1,357
West Texas Gulf Pipe Line Co,		581		581	132,526		132,526	54,044		54,044	43,569	15	8,423	2,114
Western Oil Transportation Co., Inc.	918			918	16,702		16,702		....	......	11,550	(63)	2,908	1,427
White Shoal Pipeline Corp.	3			3	9,285		9,285	330		330	2,522	1,125	815	364
Williams Brothers Pipe Line Co.	....		7,503	7,503	13,093	140,858	153,951	173	57,883	58,056	350,341	10,099	56,953	14,594
Wolverine Pipe Line Co.	....		455	455		40,717	40,717		8,791	8,791	32,313	1,113	4,962	951
Wyco Pipe Line Co.			731	731		739	739		4,522	4,522	20,566	420	5,072	1,333
Yellowstone Pipe Line Co.			751	751		18,259	18,259		8,460	8,460	26,499	144	6,480	1,741
1971 totals	45,656	64,615	63,500	173,771	5,379,513	2,908,237	8,287,750	1,434,314	1,062,691	2,497,005	6,255,295	427,574	1,254,109	312,818
1970 totals	45,479	65,949	60,354	171,782	5,280,999	2,849,470	8,130,469	1,414,987	1,019,714	2,434,201	5,778,271	375,395	1,186,701	298,327
Differences	177	(1,334)	3,146	1,989	98,514	58,767	157,281	19,327	42,977	62,804	477,024	52,179	67,408	14,491

*Coal slurry †Anhydrous ammonia ‡1970 data

Data collected by William B. Edwards, transportation consultant

ESTIMATED ELECTRIC POWER GENERATION BY REGIONS AND TYPE OF CAPACITY, 1970, 1980, and 1990 (Ref. 11)

	1970—Actual			1980—Estimated			1990—Estimated		
	Capacity MW	Generation		Capacity MW	Generation		Capacity MW	Generation	
		10^6 MWh	% of Total		10^6 MWh	% of Total		10^6 MWh	% of Total
				Northeast					
Conv. hydro	5,800	35	11.9	7,000	34	6.5	7,000	35	3.7
P.S. hydro	1,800	3	1.0	9,000	8	1.5	19,000	17	1.8
I.C. and G.T.	6,300	6	2.0	9,000	6	1.2	13.000	9	1.0
Fossil steam	47,500	238	80.7	47,000	228	43.2	47,000	190	20.2
Nuclear	3,500	13	4.4	41,000	251	47.6	115,000	691	73.3
Total	64,900	295	100.0	113,000	527	100.0	201,000	942	100.0
				East Central					
Conv. hydro	1,000	4	1.5	2,000	4	0.8	3,000	6	0.7
P.S. hydro	100			4,000	4	0.8	14,000	12	1.3
I.C. and G.T.	2,400	2	0.8	7,000	5	1.0	12,000	8	0.9
Fossil steam	51,200	254	97.7	77,000	398	80.8	115,000	604	67.5
Nuclear	300			13,000	82	16.6	42,000	265	29.6
Total	55,000	260	100.0	103,000	493	100.0	186,000	895	100.0
				Southeast					
Conv. hydro	9,300	30	9.8	11,000	37	5.8	13,000	38	3.1
P.S. hydro	100	1	0.3	4,000	4	0.6	13,000	11	0.9
I.C. and G.T.	2,700	4	1.3	6,000	4	0.6	14,000	9	0.7
Fossil steam	51,600	270	88.6	77,000	383	59.7	121,000	573	47.0
Nuclear	0	0	0.0	34,000	214	33.3	94,000	590	48.3
Total	63,700	305	100.0	132,000	642	100.0	255,000	1,221	100.0
				West Central					
Conv. hydro	3,500	15	8.3	3,000	14	3.8	3,000	14	2.0
P.S. hydro	400		0.0	2,000	2	0.5	4,000	4	0.6
I.C. and G.T.	4,200	5	2.8	8,000	5	1.3	14,000	9	1.3
Fossil steam	33,000	158	87.3	50,000	235	63.0	54,000	220	31.2
Nuclear	1,500	3	1.6	19,000	117	31.4	77,000	457	64.9
Total	42,600	181	100.0	82,000	373	100.0	152,000	704	100.0

—Continued

	1970—Actual			1980—Estimated			1990—Estimated		
	Capacity MW	Generation		Capacity MW	Generation		Capacity MW	Generation	
		10^6 MWh	% of Total		10^6 MWh	% of Total		10^6 MWh	% of Total
South Central									
Conv. hydro	2,300	5	2.6	3,000	8	1.8	4,000	9	1.0
P.S. hydro	100	...	...	3,000	3	0.7	8,000	7	0.8
I.C. and G.T.	2,100	3	1.5	7,000	5	1.1	14,000	9	1.5
Fossil steam	44,400	188	95.9	85,000	382	85.2	139,000	596	65.7
Nuclear	0	0	0.0	8,000	50	11.2	46,000	290	31.8
Total	48,900	196	100.0	106,000	448	100.0	211,000	911	100.0
West									
Conv. hydro	29,700	164	54.0	42,000	195	31.0	52,000	217	17.4
P.S. hydro	1,100	...	0.0	5,000	4	0.6	12,000	11	0.9
I.C. and G.T.	1,500	1	0.3	3,000	2	0.3	8,000	5	0.4
Fossil steam	31,400	133	43.7	54,000	269	42.7	82,000	396	31.7
Nuclear	1,200	6	2.0	25,000	160	25.4	101,000	620	49.6
Total	64,900	304	100.0	129,000	630	100.0	255,000	1,249	100.0
Contiguous United States									
Conv. hydro	51,600	253	16.4	68,000	292	9.4	82,000	319	5.4
P.S. hydro	3,600	4	0.3	27,000	25	0.8	70,000	62	1.0
I.C. and G.T.	19,200	21	1.4	40,000	27	0.9	75,000	49	0.8
Fossil steam	259,100	1,241	80.5	390,000	1,895	60.9	558,000	2,579	43.5
Nuclear	6,500	22	1.4	140,000	874	28.0	475,000	2,913	49.3
Total	340,000	1,541	100.0	665,000	3,113	100.0	1,260,000	5,922	100.0

[1] Excludes in-plant uses but includes pumping energy for pumped storage projects.

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15. Supplementary Notes

16. Abstracts

The report gives the results of a survey of stationary reciprocating engines in the United States, conducted to compile the following information: (1) types and applications of engines; (2) typical pollutant emissions factors for diesel, dual fuel, and natural gas engines; (3) differences between engines that cause emissions to vary; (4) total horsepower and emissions from engines; (5) pollution potential of stationary engines in densely populated regions; and (6) potential emissions control techniques. Where appropriate, the survey includes gas turbines.

17. Key Words and Document Analysis. 17a. Descriptors

Air Pollution
*Internal Combustion Engines
Stationary Engines
Nitrogen Oxides
Gas Engines
Diesel Engines
Gas Turbine Engines

17b. Identifiers/Open-Ended Terms

*Air Pollution Control
Stationary Sources
Dual Fuel Engines
Natural Gas Engines

17c. COSATI Field/Group 13B, 21A, 21B, 21D, 21E, 21G

18. Availability Statement	19. Security Class (This Report)	21. No. of Pages
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