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Emission Characterization of Stationary NO_x Sources: Volume I. Results

Interagency Energy/Environment R&D Program Report

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Emission Characterization of Stationary NO_X Sources: Volume I. Results

by

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PREFACE

This is the third in a series of 10 special reports to be documented in the "Environmental Assessment of Stationary Source NO_x Combustion Modification Technologies" (NO_x E/A). The NO_x E/A is a 36-month program which began in July 1976. The program has two main objectives: (1) to identify the multimedia environmental impact of stationary combustion sources and NO_x combustion modification controls, and (2) to identify the most cost-effective, environmentally sound NO_x combustion modification controls for attaining and maintaining current and projected NO_2 air quality standards to the year 2000. The reports resulting from this effort will document the economic, environmental and operational impact of reducing NO_x to a given level on specific combustion sources with current and emerging control technology. This information is intended for use by:

- Equipment manufacturers and users concerned with selecting the most appropriate control techniques to meet regulatory standards
- Control R&D groups concerned with providing a sufficient breadth of environmentally sound control techniques to meet the diverse control implementation needs in NO_2 critical Air Quality Control Regions
- Environmental planners involved in formulating abatement strategies to meet current or projected air quality standards

The program structure incorporating the above objectives is shown in Figure P-1. The rectangular symbols denote specific subtasks while the oval symbols show program output. The arrows show the sequence of subtasks and the major interactions among tasks. The top half of the figure shows the initial effort to set preliminary source/control priorities. These efforts are documented in the "Preliminary Environmental Assessment of Combustion Modification Techniques," October 1977, EPA report 600/7-77-119a. The bottom half of the figure shows the major program efforts which are currently underway.

The two major tasks in the NO_x E/A are: (1) Process Engineering and Environmental Assessment, and (2) Systems Analysis. In the first task, the environmental, economic, and operational impacts of specific source/control combinations will be assessed. On the basis of this assessment, the incremental multimedia impacts from the use of combustion modification NO_x controls will be identified and ranked. The systems analysis task will in turn use these results to identify and rank the most effective source/control combinations to comply, on a local basis, with the current NO_2 air quality standards and projected NO_2 related standards. As shown in Figure P-1, the supporting tasks for these efforts are the Baseline Emissions Characterization, Evaluation of Emission Impacts and Standards, and Experimental Testing.

The emissions characterization documented in this report supports both the environmental assessment task and the systems analysis. The major objective is to assess the multimedia pollution potential of effluent streams from uncontrolled stationary fuel combustion sources. This will be accomplished by: (1) updating and refining emission estimates from earlier emissions inventories, and (2) approximating

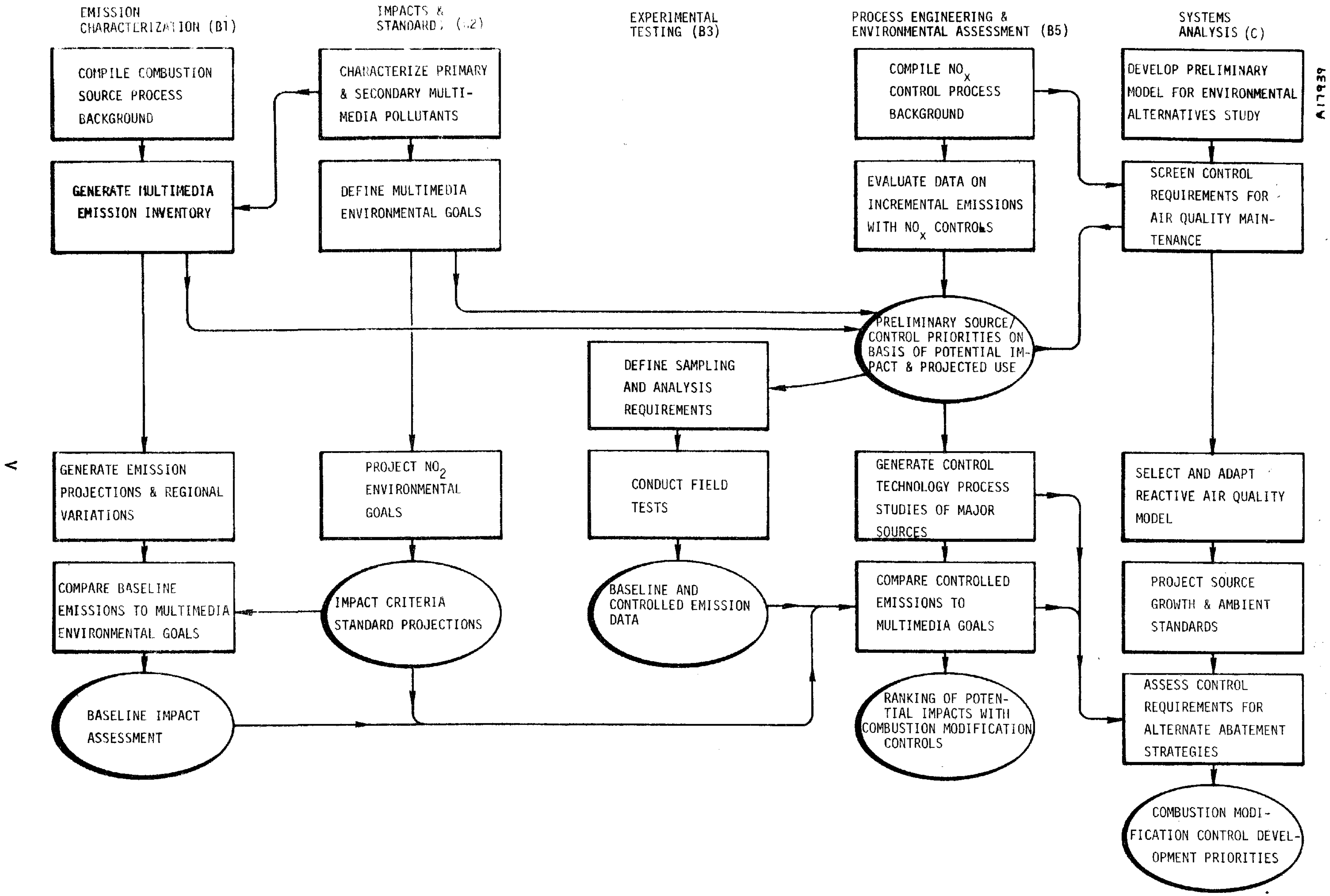

Figure P-1. NO_x E/A approach.

emissions transport and transformation to obtain estimates of ambient pollutant concentrations. The resultant concentrations are then compared to multimedia impact criteria to flag sources, effluent streams, and pollutants with potential for adverse environmental effects. This comparison results in an incremental multimedia impact ranking of stationary sources and provides the baseline reference for the subsequent assessment of the environmental, economic, and operational impacts of specific source/control combinations. Other objectives of the emission characterization are to: (1) evaluate regional emission patterns due to source, fuel, and emission control distribution, and (2) project equipment population, fuel usage, and emissions to the year 2000. These efforts support the systems analysis of alternate NO_x controls, since regional inventories and source projections to the year 2000 are required in the air quality modeling to determine NO_x control needs for meeting and maintaining ambient air quality standards.

This report is comprised of two volumes. Volume I contains the documentation for generating present and future emissions inventories and assessing the pollution impact potential of emissions from specific equipment/fuel combinations. Volume II presents the supporting appendices for these tasks.

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SECTION 1

INTRODUCTION

Since the Clean Air Act of 1970, a moderate level of NO_x control has been developed and implemented for many stationary combustion NO_x sources. However, recent EPA studies show that stationary source controls must be increased to maintain NO_2 ambient air quality. The need for additional stationary NO_x controls results from easing of mobile source emission standards, increasing stationary source NO_x emissions, and the prospect of a short-term NO_2 air quality standard.

Since NO_x controls now are being implemented and additional controls will be developed in the future, there is a pressing need to affirm that these controls are environmentally sound and ensure that the timing and implementation of emerging controls will allow stationary NO_x sources to meet future air quality standards. The NO_x E/A program addresses these needs by: (1) identifying the multimedia environmental impact of stationary combustion NO_x sources, (2) identifying the incremental multimedia environmental impact of combustion modification NO_x controls, and (3) identifying the most cost-effective source/control combinations to maintain alternate ambient NO_2 standards through the year 2000 in NO_2 critical areas.

1.1 OBJECTIVES OF THIS REPORT

The emissions characterization effort supports the NO_x E/A objectives by compiling and evaluating data on current and projected stationary source fuel consumption and multimedia emissions. These results are used in the NO_x E/A to set priorities on stationary source equipment types according to national or regional emissions. Additionally, the emission estimates generated in this task are used together with estimates of pollutant impact criteria to define the impact potential of specific source/fuel combinations during baseline, uncontrolled operation. The resulting estimate of impact potential is used as a reference for the subsequent assessment of the impact potential of NO_x combustion modification controls. The results also are used to highlight areas where additional R&D is required to quantify baseline impacts or control requirements.

The major steps in the emissions characterization task are as follows:

- Categorize stationary NO_x source equipment/fuel combinations according to pollutant formation potential
- Quantify current stationary source fuel consumption, by equipment type, on a regional and national basis
- Compile multimedia effluent emission factors for the combinations of equipment/fuel/effluent streams identified as significant
- Develop a national and regional multimedia emissions inventory for stationary combustion sources for 1974
- Estimate the extent of NO_x controls on a national basis; generate a controlled national NO_x emissions inventory

- Formulate energy, equipment, and control scenarios representative of projected national trends; project national emissions to the year 2000
- Develop a source analysis modeling methodology to rank various source/fuel combinations according to pollution potential
- Provide problem definition and priorities for future research and controls development

1.2 ORGANIZATION AND STRUCTURE OF REPORT

Figure 1-1 shows the approach of the emissions characterization task and the organization of this report. The preliminary characterization of NO_x equipment sources, compilation of emission factors, and determination of fuel consumption which resulted in the 1974 controlled national emissions inventory are documented in the "Preliminary Environmental Assessment of Combustion Modification Techniques" (Reference 1-1). Section 2 of this report describes the characterization and classification of NO_x sources. This classification was carried through the environmental rankings and will be used for process engineering efforts and systems analyses in future tasks. Section 2 includes a summary of sources and effluent streams that are of potential concern as NO_x sources.

Section 3 summarizes data on fuels composition and usage. Both regional and national fuel usage are needed to generate comprehensive national and regional emissions inventories for 1974. National fuel consumption was projected through the year 2000, considering several possible conditions such as conservation, use of nuclear power and coal conversion. These scenarios are required to generate the future

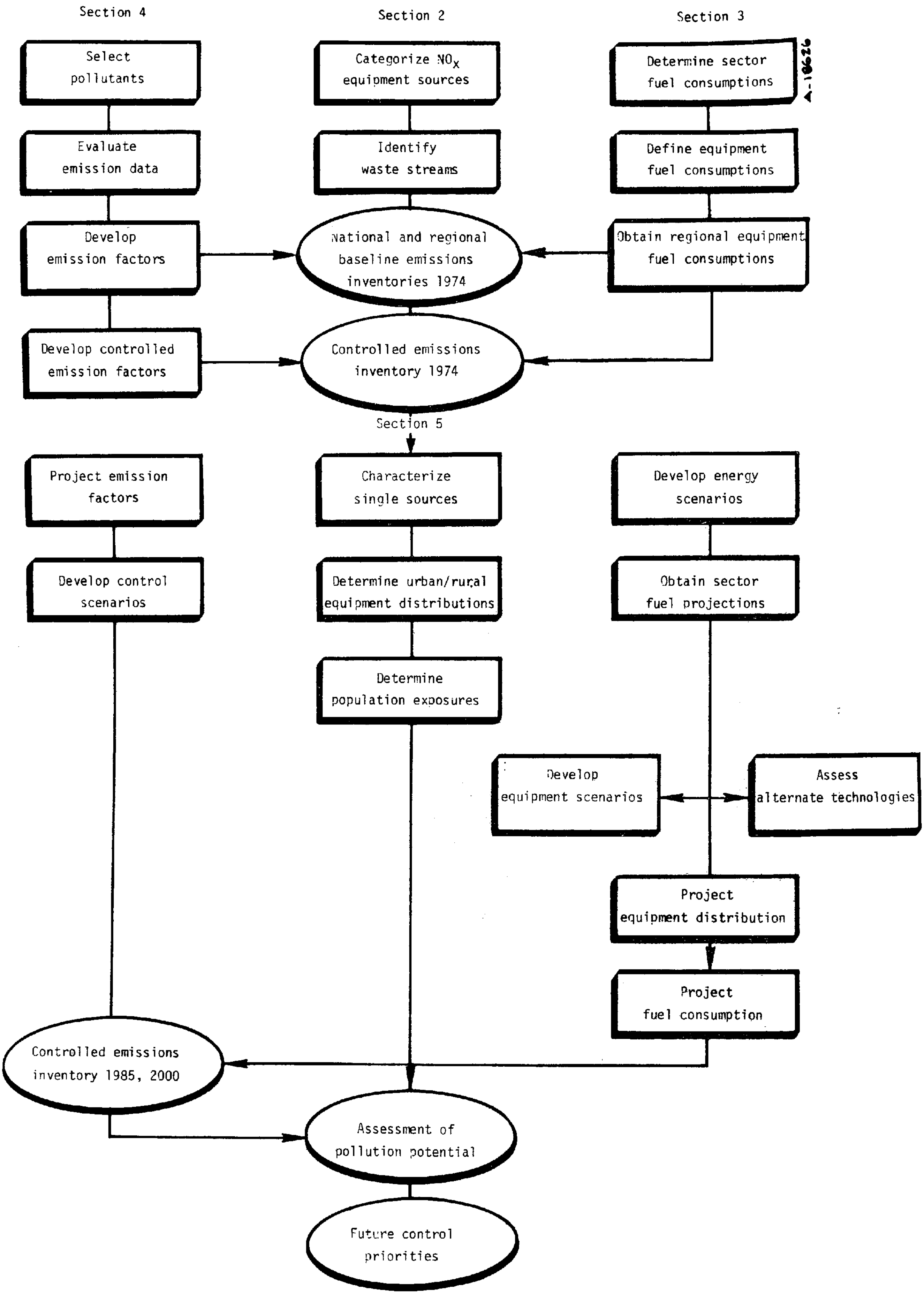

Figure 1-1. Emissions characterization approach.

emissions inventories in Section 4 and to conduct the source analysis modeling in Section 5.

In Section 4, multimedia effluents are quantified for the combinations of equipment types, fuels, and effluent streams identified in Sections 2 and 3. Both a national emissions inventory and regional inventories are presented for 1974. Additionally, the current and projected implementation of NO_x controls is estimated to yield controlled NO_x inventories for 1974, 1985, and 2000.

The energy projections, equipment distribution trends, and future environmental regulations from Section 4 are integrated in Section 5 with urban/rural equipment distributions and source population proximities to provide inputs to the Source Analysis Model (SAM). The SAM approximates pollutant transport to estimate ground level pollutant concentration profiles. These concentrations are compared to pollutant impact criteria to estimate the population potentially exposed to adverse levels of pollutant concentrations. These results are used to rank sources according to their multimedia environmental impact. The results highlight where R&D is needed to further quantify impact potential or to control adverse emission levels for specific source/pollutant combinations. It should be noted here that the results of this study are meant as qualitative indicators of potential problems rather than rigid priorities.

1.3 TECHNICAL SUMMARY

In this report, gaseous, liquid, and solid effluents from stationary sources are assessed . National and regional emissions inventories are developed for the year 1974. Then, emissions are projected to the years 1985 and 2000 for five energy scenarios which represent alternate energy futures. Rankings of stationary sources are presented for national emissions in years 1974, 1985, and 2000. Using these data as inputs, a source analysis model was developed to evaluate the total pollution potential of stationary combustion sources. Rankings of pollution potential are provided for 1974 and for the years 1985 and 2000 based on the reference high nuclear energy scenario with stringent New Source Performance Standard (NSPS) controls.

Major results of this report are as follows:

- Utility boilers generate about 50 percent of stationary source NO_x emissions, packaged boilers about 20 percent, and all other anthropogenic sources the remaining 30 percent. Although there are over 70 equipment/fuel combinations, the 30 most significant sources account for about 90 percent of all combustion related NO_x emissions. Tangential coal-fired utility boilers have the highest total nationwide NO_x emission loading, while reciprocating IC engines firing natural gas are the second highest.
- NO_x reductions from implementing controls were negligible in 1974. Based on a survey of boilers in areas with NO_x emission regulations, it is estimated that applying NO_x controls resulted in a 3.0 percent reduction in nationwide utility boiler emissions. This corresponds to a 1.6 percent reduction in total stationary fuel combustion emissions.
- Under the low nuclear growth scenario, total NO_x emissions are projected to increase by about 30 percent by the year 2000, even under stringent NSPS control. Utility boiler emissions are projected to increase by about 80 percent over 1974 levels, even with NSPS implementation. However, if nuclear energy is

used to provide a larger share of national electrical needs, these projected NO_x increases will be significantly lower.

- Regional emissions inventories developed for 1974 show significant regional variations in NO_x by equipment/fuel type. These variations result from both the regional fuel mix and from the distribution of stationary source equipment.
- The 1974 source assessment ranking indicates that coal-fired utility and stoker-fired boilers have the largest pollution impact potential of all stationary sources. Beryllium has the largest potential impact of all pollutant species. Moreover, of all fossil fuels, coal firing generates the largest emissions of beryllium. Since use of coal is projected to increase significantly from 1974 to the year 2000, the pollution potential of coal-fired stationary sources should increase proportionally during this period.

REFERENCES FOR SECTION 1

1-1. Mason, H. B., et. al., "Preliminary Environmental Assessment of Combustion Modification Techniques: Volume II, Technical Results," EPA-600/7-77-119b, NTIS-PB 276 681/AS, Acurex Corp., October 1977.

SECTION 2

NO_x SOURCE CHARACTERIZATION

This section presents a preliminary characterization of NO_x sources that will be used to structure the environmental assessment and process engineering efforts in the NO_x E/A program. The main objective is to categorize equipment design according to characteristics which affect the formation and/or control potential of multimedia pollutants. Emphasis is on stationary combustion sources of NO_x. However, other sources of NO_x also are of interest in this program, since the extent to which NO_x controls are needed for stationary combustion sources depends on how well these other sources can be controlled.

To characterize NO_x sources, the following steps were performed:

- Identify significant sources of NO_x; group sources according to formative mechanism and nature of release into the environment
- Categorize stationary combustion sources according to equipment and/or fuel characteristics affecting the generation and/or control of combustion generated pollution
- Qualify equipment fuel categories on the basis of current and projected use and design trends; develop a provisional list of equipment/fuel combinations to be carried through subsequent

emissions inventories, process studies, and environmental assessments

- Identify effluent streams from stationary combustion source equipment/fuel categories which may be perturbed when NO_x combustion modification controls are used
- Identify operating modes (transients, upsets, maintenance) which perturb emissions when using NO_x combustion modification controls

Significant sources of NO_x are grouped in Figure 2-1 according to the way NO_x is released into the atmosphere and the mechanisms leading to its formation. On a global basis, natural emissions caused by biological decay and lightning account for about 90 percent of total NO_x emissions. However, in urban areas up to 90 percent of ambient NO_x is produced by manmade sources -- primarily in combustion effluent streams. The seven major categories of stationary sources bracketed under "fuel combustion" in the figure are emphasized throughout the NO_x E/A.

Stationary combustion sources that may have a significant impact on NO_x emissions are categorized in Section 2.1. Transient and nonstandard conditions are discussed in Section 2.2. Section 2.3 describes major trends in equipment types; the equipment categories and trends described in this section are the basis for the inventories in Section 4 and the source analysis modeling in Section 5. Mobile emissions are described briefly in Section 2.4, noncombustion sources are discussed in Section 2.5, and fugitive emissions are described in Section 2.6. A general assessment of data is given in Section 2.7.

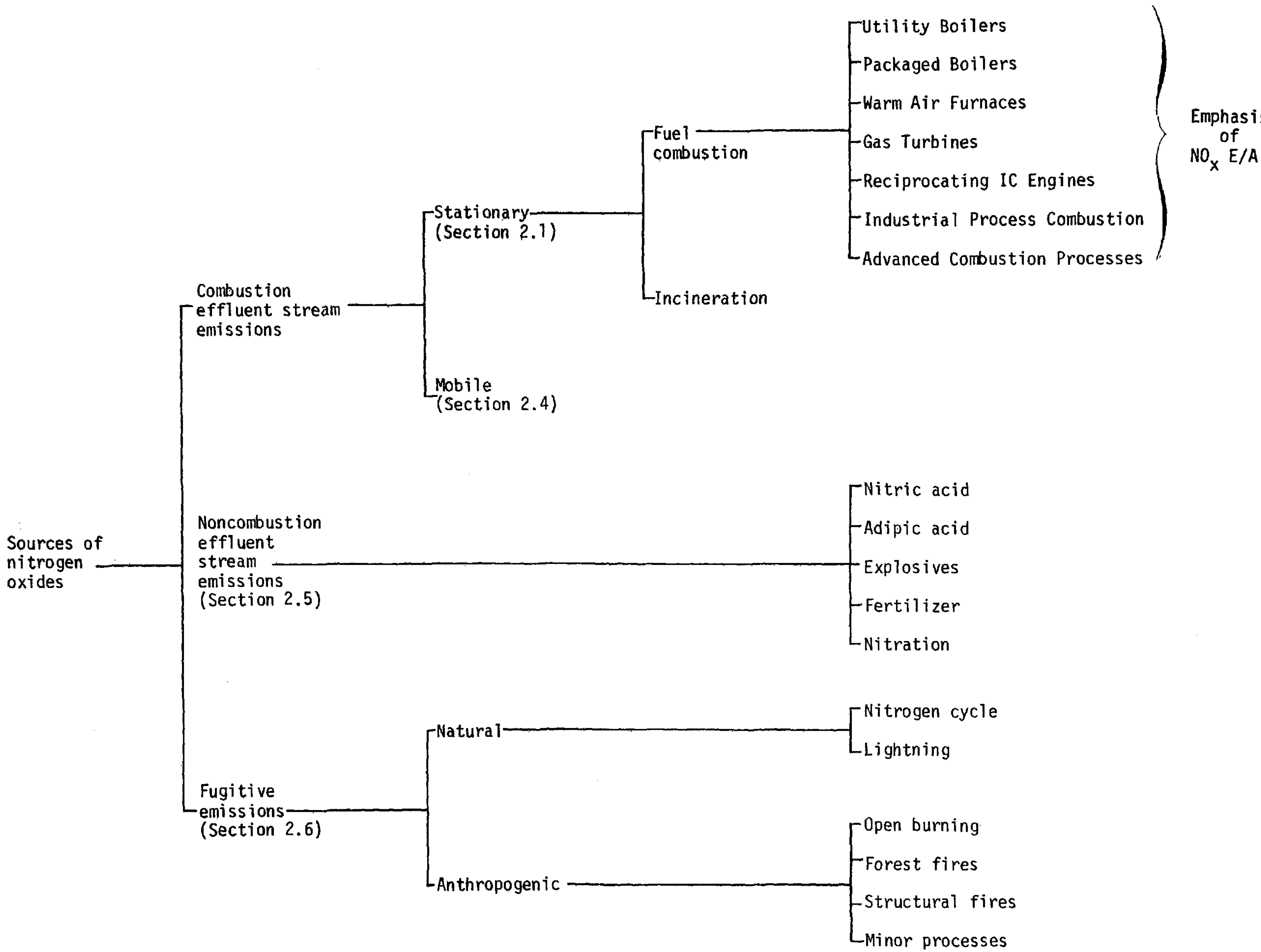

Figure 2-1. Sources of nitrogen oxide emissions.

2.1 STATIONARY FUEL COMBUSTION SOURCES

The major categories of stationary fuel combustion sources are summarized in Tables 2-1 through 2-6. These tables list the major designs in each sector, and the variations in design and fuels which are known to affect emissions. The primary design types are those projected for widespread use in the 1980's and thus, are candidates for application of NO_x controls. Secondary design types are those that are either diminishing in use or are unlikely candidates for widespread use of NO_x controls in the near future. Secondary design types will be considered in this report, but not in subsequent NO_x E/A studies. Major design characteristics of each firing type are given in these tables to provide general descriptions of combustion sources. The effluent streams and operating modes presented in these tables represent general operating conditions and may vary for different combustion units. The effluent streams identified are inputs for the emissions inventory in Section 4 and the pollution potential ranking in Section 5. Because quantitative data on the effects of transient and nonstandard operating conditions were sparse, these data were not considered further in the emissions inventory.

Table 2-7 describes several alternate or advanced energy systems that are in developmental stages. A number of these systems are expected to be used commercially in the 1980's and 1990's.

The final categorization of stationary combustion sources is presented in Table 2-8. This table shows the equipment/fuel categories that merit separate consideration in the emissions inventory in Section 4 and the ranking of pollution potential in Section 5.

TABLE 2-1. SUMMARY OF UTILITY AND LARGE INDUSTRIAL BOILER CHARACTERIZATION (Reference 2-2)

Design Type	Design Characteristics	Process Ranges	Fuel Consumption (%)	Effluent Streams	Operating Modes	Effects of Transient, Nonstandard Operation	Trends	Future Importance
Tangential	Fuel and air nozzles in each corner of the combustion chamber are directed tangentially to a small firing circle in the chamber. Resulting spin of the flames mixes the fuel and air in the combustion zone.	<u>Input Capacity</u>: 73 MW to 3800 MW <u>Steam Pressure</u>: 18.6 MPa (subcritical) 26.2 MPa (supercritical) <u>Steam Temperature</u>: 755K to 840K <u>Furnace Volume</u>: Up to 38,000 m^3 <u>Furnace Pressure</u> 50 Pa to 1000 Pa <u>Furnace Heat Release</u>: Coal - 104 to 250 kW/m^3 Oil, gas - 208 to 518 kW/m^3 <u>Excess Air</u> 25% coal 10% oil 8% gas	67% coal fired 18% oil fired 15% gas fired	<u>Gaseous</u> Flue gas containing flyash, volatilized trace elements, SO_2 NO, other pollutants. <u>Liquid</u> Scrubber streams, ash sluicing streams, wet bottom slag streams. <u>Solid</u> Solid ash removal Flyash removal	Soot blowing, on-off transients, load transients, upsets, fuel additives, rapping, vibrating.	During startup, NO_x emissions are low since flame temperatures not developed. During load reductions, emissions of NO_x decrease because of lower flame temperatures. NO_x should decrease following soot blow due to improved heat transfer.	Trend toward coal firing in new units; conversion to oil and coal in existing units. 19.4% of current installed units.	Primary
Single Wall	Burners mounted to single furnace wall -- up to 36 on single wall.	Units typically limited in capacity to about 400 MW (electric) because of furnace area.	43% coal 22% oil fired 35% gas fired	<u>Gaseous</u> Flue gas containing flyash, volatilized trace elements, SO_2, NO, other pollutants. <u>Liquid</u> Scrubber streams, ash sluicing streams, wet bottom slag streams. <u>Solid</u> Solid ash removal Flyash removal	Soot blowing, on-off transients load transients, upsets, fuel additives, rapping, vibrating.	During startup, NO_x emissions are low since flame temperatures not developed. During load reductions, emissions of NO_x decrease because of lower flame temperatures. NO_x should decrease following soot blow due to improved heat transfer.	Trend toward coal firing in new units; wet bottom units no longer manufactured due to operational problems with low sulfur coals and high combustion temperatures promoting NO_x. 59% of current installed units.	Primary

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TABLE 2-1. Continued

Design Type	Design Characteristics	Process Ranges	Fuel Consumption (%)	Effluent Streams	Operating Modes	Effects of Transient, Nonstandard Operation	Trends	Future Importance
Horizontally Opposed Wall	Burners are mounted on opposite furnace walls -- up to 36 burners per wall.	Units typically designed in sizes greater than 400 MW (electric).	32% coal 21% oil 47% gas (includes turbo furnace)	Gaseous Flue gas containing flyash, volatilized trace elements, SO_2, NO, other pollutants. Liquid Scrubber streams, ash sluicing streams, wet bottom slag streams. Solid Solid ash removal Flyash removal	Soot blowing, on-off transients, load transients, upsets, fuel additives, rapping, vibrating.	During startup, NO_x emissions are low since flame temperatures not developed. During load reductions, emissions of NO_x decrease because of lower flame temperatures. NO_x should decrease following soot blow due to improved heat transfer.	Trend toward coal firing and conversions to oil and coal firing; again, wet bottoms being phased out. 8.2% of current installed units. units.	Primary
Turbo Furnace	Air and fuel fired down toward furnace bottom using burners spaced across opposed furnace walls. Flame propogates slowly passing vertically to the upper furnace. NO is usually low due to long combustion time and relatively low flame temperature.	Units typically designed in sizes greater than 400 MW (electric)	32% coal 21% oil 47% gas (includes horizontally opposed wall)	Gaseous Flue gas containing flyash, volatilized trace elements, SO_2, NO, other pollutants. Liquid Scrubber streams, ash sluicing streams, wet bottom slag streams.	Soot blowing, on-off transients, load transients, upsets, fuel additives, rapping, vibrating.	During startup, NO_x emissions are low since flame temperatures not developed. During load reductions, emissions of NO_x decrease because of lower flame temperatures. NO_x should decrease following soot blow due to improved heat transfer.	Trend toward coal firing -- (capacity included with opposed wall).	Primary

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TABLE 2-1. Concluded

Design Type	Design Characteristics	Process Ranges	Fuel Consumption (%)	Effluent Streams	Operating Modes	Effects of Transient Nonstandard Operation	Trends	Future Importance
Cyclone	Fuel and air introduced circumferentially into cooled furnace to produce swirling, high temperature flame; cyclone chamber separate from main furnace; cyclone furnace must operate at high temperatures since it is a slagging furnace.	Furnace Heat Release: 4.67 to 8.28 MW/m^3	92% coal 4% oil 4% gas	Gaseous Flue gas containing flyash, volatilized trace elements, SO_2, NO, and other pollutants. Liquid Scrubber streams Solid Solid ash removal Flyash removal	Soot blowing, on-off transients, load transients, upsets, fuel additives, rapping, vibrating.	During startup, NO_x emissions are low since flame temperatures not developed. During load reductions, emissions of NO_x decrease because of lower flame temperatures. NO_x should decrease following soot blow due to improved heat transfer.	Two cyclone boilers sold since 1974 have not proven adaptable to emissions regulations. Must operate at high temperatures resulting in high thermal NO_x fixation; also operational problems with low sulfur coal. 3.3% of installed units.	Secondary
Vertical and Stoker	Vertical firing results from downward firing pattern. Used to a limited degree to fire anthracite coal. Stoker projects fuel into the furnace over the fire permitting suspension burning of fine fuel particles. Spreader stokers are the primary design type.	Surface Heat Release: 1.1 to 1.9 MW/m^2	100% coal	Gaseous Flue gas containing flyash, volatilized trace elements, SO_2, NO, and other pollutants. Liquid Scrubber streams Solid Solid ash removal Flyash removal	Soot blowing, on-off transients load transients, upsets, fuel additives, rapping, vibrating.	During startup, NO_x emissions are low since flame temperatures not developed. During load reductions, emissions of NO_x decrease because of lower flame temperatures. NO_x should decrease following soot blow due to improved heat transfer.	Since anthracite usage has declined, vertical fired boilers are no longer sold. Design capacity limitations and high cost have caused stokers usage to diminish. 9.9% of current installed units.	Secondary

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TABLE 2-2. SUMMARY OF PACKAGED BOILER CHARACTERIZATION

Design Type	Design Characteristics	Typical Operational Values	Fuel Consumption (%)	Effluent Streams	Operating Modes	Effects of Transient, Nonstandard Operation	Trends	Future Importance
Watertube	Combustion gases circulate around boiler tubes that have water passing through them. Essentially the only type of boiler available above 29 MW (heat input).	Oil-Fired Watertube: Capacity: 38 MW Furnace volume: 123 m^3 Heat release: 310 kW/m^3 Burner type: steam atomization Fuel preheat: 392K Stack temperature: 422K Excess oxygen: 5%	41% coal 21% oil 38% gas	Gaseous Flue gas Particulate catch Hopper ash Liquid Ash sluicing water Scrubber streams Solids Solid ash removal	Soot blowing, on-off transients, upsets, fuel additives.	During startup, low NO_x emissions. During load reductions NO_x lowered. Soot blowing should cause lower gas temperature due to improved heat transfer, thus lowering NO_x.	Pulverized coal and stokers for large watertubes.	Primary
Scotch Firetube	Cylindrical shell with one or more furnaces in the lower portion. Combustion takes place in front section. Combustion products flow back to rear combustion chamber, flow through tubes to smoke box, then discharge.	Scotch Firetube-Oil: Capacity: 2.9 MW Furnace volume: 2.5 m^3 Heat release: 1190 kW/m^3 Operating pressure 1030 kPa Burners: Air atomizing (2) Fuel preheat: 371K Excess oxygen: 4.9%	59% oil 41% gas	Flue gas Bottom ash	On-off transients, load transients, upsets, fuel additives.	Changes in firing rate have little effect on NO_x emissions from firetubes. Fuel oil temperature increases tend to decrease NO_x emissions.	Scotch firetubes currently show growth over other firetube designs.	Primary
HRT Firetube	Hot gases pass to back of unit, enter horizontal tubes, returning to front of the boiler then exit through smoke box.		55% oil 35% gas	Flue gas Bottom ash	On-off transients, load transients, upsets, fuel additives.	Changes in firing rate have little effect on NO_x emissions from firetubes. Fuel oil temperature increases tend to decrease NO_x emissions.	Trend toward decreasing use of HRT.	Secondary

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TABLE 2-2. Concluded

Design Type	Design Characteristics	Typical Operational Values	Fuel Consumption (%)	Effluent Streams	Operating Modes	Effects of Transient, Nonstandard Operation	Trends	Future Importance
Firebox Firetube	Combustion gases enter front of first tube pass, travel to rear smoke box, return through second pass to gas outlet at the boiler front.		53% oil 57% gas	Flue gas Bottom ash	On-off transients, load transients, upsets, fuel additives.	Changes in firing rate have little effect on NOx emissions from firetubes. Fuel oil temperature increase.tend to decrease NOx emissions.	Decreasing use of firebox firetubes	Secondary
Cast Iron Boilers	Gases rise through vertical section, and discharge through the exhaust duct. Water is heated as it passes upwards through the watertubes.	Cast Iron: Distillate oil Capacity: 0.38 MW Furnace volume: 0.57 m³ Heat release: 673 kW/m³ Operating pressure: 103 kPa Burner type: Pressure atomizing (1) Fuel preheat: None Excess oxygen: 4.4%	59% oil 41% gas	Flue gas Bottom ash	On-off cycling, transients			Secondary
Steam and Hot Water Units	Besides small residential units, shell boilers, compact, locomotive, short firebox, vertical firetube, straight tube, and coal research designs are grouped here.		1.5% coal 56% oil 42.5% gas	Flue gas	On-off cycling, transients			Secondary

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TABLE 2-3. SUMMARY OF WARM AIR FURNACES CHARACTERIZATION

Design Type	Design Characteristics	Design Ranges	Fuel Consumption (%)	Effluent Streams	Operating Modes	Effects of Transient, Nonstandard Operation	Trends	Future Importance
Commercial and Residential Central Warm Air Furnaces	Furnaces in central heaters enclosed in steel casing; fuel burned in combustion space of heat exchangers. Heat exchangers have a single combustion chamber, either cylindrical or divided into individual sections; combustion gases pass through secondary gas passages of the heat exchanger and exit through flue.	Typical Gas-Fired Forced Air Furnace Heat exchanger area: 2.8 to 3.3 m^2 Draft system: Natural Excess combustion air: 20% to 50% Overall heat transfer coefficient: 11.3 to 17 W/m^2K Combustion chamber pressure: $\pm$ 49.8 Pa Exit flue gas temperature: 506 to 617K Overall efficiency: 75% to 80% On-off operation	31% distillate oil 69% gas (Miscellaneous combustion fuels such as wood, LPG, etc. combined with natural gas.)	Flue gas	On-off cycling, transients	NO_x emissions levels rise at a steady rate after initial jump due to ignition, drop off quickly after the burner is turned off. NO_x emissions increase with on time of burner. Improper burner adjustment, damaged components, increase NO_x by as much as 50%.	Oil firing in new units, trend to high efficiency in new units. General decline in natural gas usage; increase in electric heat, trend toward using low NO_x burners; increased use of high efficiency burners.	Primary
Space Heaters	Room heaters self-contained; equipped with a flue if oil fired. Heat by radiation, or natural or forced air circulation.		23% distillate oil 73% gas (Miscellaneous combustion fuels such as wood, LPG, etc., combined with natural gas.) (Includes other residential combustion.)	Flue gas	On-off cycling, transients	NO_x emissions levels rise at a steady rate after initial jump due to ignition, drop off quickly after the burner is turned off. NO_x emissions increase with on time of burner. Improper burner adjustment, damaged components, increase NO_x by as much as 50%.	Oil firing in new units, trend to high efficiency in new units. General decline in natural gas usage; increase in electric heat, trend toward using low NO_x burners; increased use of high efficiency burners.	Secondary

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TABLE 2-3. Concluded

Design Type	Design Characteristics	Design Ranges	Fuel Consumption (%)	Effluent Streams	Operating Modes	Effects of Transient, Nonstandard Operation	Trends	Future Importance
Other Residential Combustion	Miscellaneous equipment includes ranges and ovens, clothes dryers, fireplaces, swimming pool heaters, refrigerating and air-conditioning equipment.			Flue gas	On-off cycling, transients	NO_x emissions levels rise at a steady rate after initial jump due to ignition, drop off quickly after the burner is turned off. NO_x emissions increase with on time of burner. Improper burner adjustment, damaged components, increase NO_x by as much as 50%.	Increased use of electric heat; high efficiency in new units.	Secondary

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TABLE 2-4. SUMMARY OF GAS TURBINE CHARACTERIZATION

Design Type	Design Characteristics	Typical Operational Values	Fuel Consumption (%)	Effluent Streams	Operating Modes	Effects of Transient, Nonstandard Operation	Trends	Future Importance
Utility and Industrial Simple and Regenerative Cycles	Rotary internal combustion engines. Simple gas turbine consists of compressor, combustion chamber, and turbine. Fuel is burned before quenching. Hot gases quenched by secondary combustion air, expanded through a turbine providing shaft horsepower. Regenerative cycles use hot gases to preheat inlet air.	<u>Utility Gas Turbine Simple Cycle</u> Capacity: 92.3 MW Specific fuel consumption: 11.67 MJ/kWh Compression ratio: 10:1 Exhaust flow: 345 kg/s Exhaust temp: 822K	45% gas 55% oil	Flue gas	On-off transient, load following, idling at spinning reserve.	NO_x emissions generally increase with increasing power. Increased turbine compressor inlet temperatures cause NO_x to increase. Behavior of NO_x is directly related to rpm when corrected to a constant percent O_2.	Trend to higher turbine inlet temperatures, larger capacity and oil firing in new units; rapid growth projected.	Primary
Combined Cycles, Repowering	Combined cycle is a basic simple cycle unit exhausting to a waste heat boiler to recover thermal energy. Repowering adds a combustion turbine to an existing steam plant, involving the mechanical or thermal integration of the combustion or steam cycles.	<u>Utility Gas Turbine Combined Cycle</u> Capacity: 364.5 MW (4 turbines) Specific fuel consumption: 8.56 MJ/kWh Compression ratio: 10:1 Exhaust flow: 256 kg/s (1 turbine) Exhaust temperature: 811K	negligible	Flue gas	On-off transient, load following, idling at spinning reserve.	NO_x emissions generally increase with increasing power. Increased turbine compressor inlet temperatures cause NO_x to increase. Behavior of NO_x is directly related to rpm when corrected to a constant percent O_2.	Use of combined cycles should increase because of improved heat rate and fuel flexibility of unit.	Secondary

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TABLE 2-5. SUMMARY OF RECIPROCATING IC ENGINE CHARACTERIZATION

Design Type	Design Characteristics	Process Ranges	Fuel Consumption (%)	Effluent Streams	Operating Modes	Effects of Transient, Nonstandard Operation	Trends	Future Importance
Compression Ignition, Turbo-Charged, Naturally Aspirated	Air or an air-and-gas mixture is compression heated in cylinders. Diesel fuel is then injected into the hot gas, causing spontaneous ignition.		67% gas 15% diesel 11% gasoline 7% dual (oil and gas) (all IC engines)	Exhaust gas	On-off transients, idling, upsets	NO_x emissions peak near stoichiometric air-to-fuel ratio. NO_x emissions diminish with decreasing load, greater speed and timing retard.	IC engines finding use for compressor applications on pipelines; low growth rate of diesel units; IC engines increasingly being replaced by gas turbines for standby applications in buildings, hospitals, etc., because of space, weight, noise, vibration.	Primary
Spark Ignition, Turbo-Charged, Aspirated	Combustion is spark initiated. Natural gas or gasoline is either injected or premixed with the combustion air in a carbureted system.		67% gas 15% diesel 11% gasoline 7% dual (oil and gas) (all IC engines)	Exhaust gas	On-off transients, idling, upsets	NO_x emissions peak near stoichiometric air-to-fuel ratio. NO_x emissions diminish with decreasing load, greater speed and timing retard.	IC engines finding use for compressor applications on pipelines; low growth rate of diesel units; IC engines increasingly being replaced by gas turbines for standby applications in buildings, hospitals, etc., because of space, weight, noise, vibration.	Primary
Blower Scavenged	Air charging by means of a low pressure blower, which also helps purge exhaust gases.		67% gas 15% diesel 11% gasoline 7% dual (oil and gas) (all IC engines)	Exhaust gas	On-off transients, idling, upsets	NO_x emissions peak near stoichiometric air-to-fuel ratio. NO_x emissions diminish with decreasing load, greater speed and timing retard.	New large units tending toward turbocharging	Secondary

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TABLE 2-6. SUMMARY OF INDUSTRIAL PROCESS HEATING CHARACTERIZATION

Process Type	Design Characteristics	Process Ranges	Fuel Consumption (%)	Effluent Streams	Operating Modes	Trends	Future Importance
Cement Kilns	Kilns are rotary cylindrical devices up to 230m in length. Feedstock moves through kiln in opposite direction from products of combustion	Kiln product temperature: 1,756K	45% gas 40% coal 15% oil	Combustion products and entrained substances from feedstock	Charging operations, upsets, starting transients	Coal firing in new units; energy improvements due to grate preheaters and shorter, less energy intensive kilns.	Primary
Glass Melting Furnaces	Continuous reverberatory furnaces; end port or side port. Flame burns over glass surface; combustion gas exits through opposite end exhaust stack after heating the combustion air.	Furnace temperatures: 1528 to 1583K	Natural gas- and oil-fired; coal is unsuitable due to impurties.	Combustion products and entrained substances from feedstock	Charging operations, upsets, starting transients	Trend toward use of electric melters, or electrically assisted conventional melters; use of oil instead of gas in fossil fuel units.	Primary
Annealing Lehrs	Used to control the cooling of gas to prevent stains. Lehrs fired by atmospheric, premix, or excess air burners.		Natural gas- and oil-fired; coal unsuitable	Combustion products	Upsets, transients		Primary
Coke Oven Underfire	Produce metallurgical coke from coal from the distillation of volatile matter producing coke oven gas; done in long rows of slot type ovens; fuel gas supplies required heat. Spent combustion gas heats inlet air.	Flue temperature: 1500K	Blast furnace gas and coke oven gas are primary fuels	Combustion products	Charging operations, upsets, starting transients	Projected fuel consumption about 5% annual	Primary

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TABLE 2-6. Continued

Process Type	Design Characteristics	Process Ranges	Fuel Consumption (%)	Effluent Streams	Operating Modes	Trends	Future Importance
Steel Sintering Machines	Used to agglomerate ore fines, flue dust, and coke breeze for charging of a blast furnace. These products travel on a traveling grate sintering machine; after ignition, is forced up through the mixture causing fusion and agglomeration.		Low Btu gas	Combustion products and entrained substances from feedstock	Upsets, starting transients	Operation declining because of system incompatability; pelletizing replacing sintering lines	Primary
Open Hearth Furnaces	The charge is melted in a shallow hearth by heat from a flame passing over the charge and radiation from the heated dome. Spent combustion gases preheat the inlet combustion gases.		Low Btu gas such as blast furnace gas	Combustion products and entrained substances from feedstock	Charging, upseting, starting transients.	Basic oxygen furnace in new units; fuel consumption decreasing by 8% per year	Primary
Brick and Ceramic Kilns	Tunnel or periodic kiln used most often. Periodic: hot gases drawn over bricks, down through them by underground flues, and out of the oven to the chimney. Tunnel: cars carrying bricks travel by rail through kiln at about one car per hour.	Kiln product temperatures: 1367K	Oil, gas, or coal (coal use less common)	Combustion products and entrained substances from driers and feedstocks.	Upsets, starting transients, charging	Tunnel kilns in new units; continuous production with heat recovery	Primary

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TABLE 2-6. Concluded

Process Type	Design Characteristics	Process Ranges	Fuel Consumption (%)	Effluent Streams	Operating Modes	Trends	Future Importance
Catalytic Cracking	Preheated gas and oil is charged to a moving stream of hot regenerated catalyst. The gas and oil is cracked in the reactor; products pass through cylone for separation and are then cut into products in fractionator.	Process temperature: 840 to 922K Fuel consumption: 829 kJ/ℓ feedstock.	Oil, gas, or electricity	Combustion products and volatilized products or catalysts	Starting transients, charging	Growth about 2% annually	Primary
Process Heaters	Two basic types -- mechanical draft and forced draft. Constructed as either horizontal box or vertical cylindrical.		70% process gas	Combustion products	Upsets, starting transients	New units are mechanical draft with combustion air preheater	Primary
Refinery and Iron and Steel Flares	Used for the control of gaseous combustible emissions from stationary sources		Waste gas	Combustion products	Upsets, transients		Primary

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TABLE 2-7. SUMMARY OF ADVANCED COMBUSTION SYSTEMS

Advanced Combustion System	Process Description	Advantages	State of Development
Repowering	Addition of a combustion turbine to an existing steam plant, involving the mechanical or thermal integration of the combustion and the steam cycle.	Improved efficiency	Currently available
Pressurized Boilers	Pressurized boilers operate at furnace pressures up to about 1 million pascals, or about 10 atmospheres. Suited to gas and oil or other fuels which can be introduced into the combustion furnace under pressure. Major application will probably involve fluidized bed combustion.	Increased heat transfer; higher volumetric heat release; reduced boiler size	Currently available
Low Btu Coal Gasification	Gas produced from coal by fixed bed, entrained bed, fluidized bed gasification or with oil. Gas produced by these processes can be converted into pipeline quality gas by water gas shift and methanation.	Produce fuels suitable for conventional steam plants and combined cycle turbine-steam plants Economical advantages in using onsite production of low Btu gas for combined cycle gas turbines	Pilot plants -- (1983-1985) 20 x 10^6 m^3 capacity unit -- 1983
Fluidized Bed Combustion	Air is blown through granular bed of noncombustible materials, (coal ash or lime) causing granulated bed particles to become suspended. Fuel, normally crushed coal, pneumatically injected near the bottom of bed and combusted at temperatures between 1033K and 1367K. Operating pressures range from atmospheric to 25 atmospheres. High-pressure units are designed to be used in combined gas turbine/steam cycles in which the fluidized bed unit acts as external combustor for the gas turbine and a steam generator for steam turbine.	• High heat transfer ratio and volumetric heat releases • Reduction of ash fouling and high temperature corrosion resulting from low combustion temperature • Burn low grade fuels more readily than conventional boilers	30 MW atmospheric -- being demonstrated
Advanced HT Gas Turbine Steam Cycles	Present combined cycle units are economically feasible only for intermediate range plants, but increasing inlet temperatures to 1972K would improve unit efficiency to about 50 percent. Coupling this new design to a nearby low Btu gasification unit would give a total efficiency of about 38 percent, which compares favorably to present day coal-fired steam plants.	Increase efficiency	Commercially available mid-1980's

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TABLE 2-7. Concluded

Advanced Combustion System	Process Description	Advantages	State of Development
Binary Cycle Topping and Bottoming	There are two types of binary cycles: the topping cycle, which uses a high temperature cycle to "top" a low temperature cycle and the bottoming cycle which uses ammonia or other suitable fluids and the exhaust heat of a steam cycle.	Increase conventional steam plant efficiencies to 50 or 60 percent	Demonstration plants early 1980's
MHD Open Cycle	Magnetohydrodynamic (MHD) generators convert mechanical energy to electrical energy by interaction of moving conducting fluid and a stationary magnetic field. Open cycle processes may use fossil fuel combustion products as a conducting fluid simply by seeding with an ionized salt of potassium or cesium. A waste-heat boiler is used in conjunction with MHD unit to recover thermal energy from the exhaust gases.	Projected cycle efficiencies are 50 percent with potential for as high as 60 percent in the long term	50 MW demonstration plant late 1980's
Catalytic Combustion	Catalytic combustion is being applied for gas turbine combustors and area sources. By premixing fuel and air, temperatures in adiabatic catalytic combustion section can be lowered to approximately the turbine inlet temperature. System relies on catalyst to rapidly combust lean mixtures that result from the total premixing. Excellent catalyst performance at temperatures up to 1756K (2700F) has been demonstrated for short periods of time (75 hours) in feasibility studies.	Greatly reduce thermal NO_x; improve unit efficiency	Gas turbine demonstration 1980

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TABLE 2-8. SIGNIFICANT STATIONARY FUEL COMBUSTION EQUIPMENT TYPES/MAJOR FUELS

Utility Sector (Field Erected Watertubes)	Fuel
Tangential	PC, O, G
Wall Fired	PC, O, G
Horizontally Opposed and Turbo Furnace	PC, O, G
Cyclone	PC, O
Vertical and Stoker	C
Packaged Boiler Sector	
Watertube 29 to 73 MW[a] (100 to 250 MBtu/hr)	PC, O, G, PG
Watertube <29 MW[a] (<100 MBtu/hr)	C, O, G, PG
Firetube Scotch	O, G, PG
Firetube HRT	C, O, G, PG
Firetube Firebox	C, O, G, PG
Cast Iron	O, G
Residential	C, O, G
Warm Air Furnace Sector	
Central Heaters	O, G
Space Heaters	O, G
Other Residential Combustion	O, G

PC -- Pulverized coal
C -- Stoker coal or other coal
O -- Oil
G -- Gas
PG -- Process gas

[a]Heat input
[b]Heat output

TABLE 2-8. Continued

Gas Turbines	
Large >15 MW[b] (>20,000 hp)	O, G
Medium 4 to 15 MW[b] (5,000 to 20,000 hp)	O, G
Small <4 MW[b] (<5,000 hp)	O, G
Reciprocating IC Engines	
Large Bore >75 kW/cyl[b] (>100 hp/cyl)	O, G
Medium 75 kW to 75 kW/cyl[b] (100 hp to 100 hp/cyl)	O, G
Small <75 kW[b] (<100 hp)	O, G
Industrial Process Heating	
Glass Melters	
Glass Annealing Kilns	
Cement Kilns	
Petroleum Refinery	
Process Heaters	
Catalytic Crackers	

PC -- Pulverized coal
C -- Stoker coal or other coal
O -- Oil
G -- Gas
PG -- Process gas

[a]Heat input
[b]Heat output

TABLE 2-8. Concluded

Brick and Ceramic Kilns

Iron and Steel

Coke Oven Underfire

Sintering Machines

Soaking Pits and Reheat Ovens

PC -- Pulverized coal
C -- Stoker coal or other coal
O -- Oil
G -- Gas
PG -- Process gas

2.2 PERIODIC OR NONSTANDARD OPERATIONS

2.2.1 Utility and Large Industrial Boilers

Emissions during nonstandard operation have not been extensively quantified. Table 2-9 summarizes the qualitative effects of nonstandard operating procedures on effluent streams for a dry bottom, coal-fired boiler (Reference 2-1).

During startup, when flame temperatures have not developed, NO_x emissions generally are low. However, particulate emissions may be high since precipitators are generally not energized during startup. In addition, unburned carbon may be emitted due to poor mixing in the combustion region.

NO_x emissions should decrease as furnace temperatures are lowered during load reductions. However, if excess air levels are increased to maintain steam temperatures, NO_x emissions actually may increase. A recent study shows that particulate emissions per unit of heat input decrease with load reduction (Reference 2-2).

Particulate emissions increase during soot blowing as the tube surfaces are cleaned. NO_x emissions should decrease after soot blowing because of the lower gas temperatures caused by increased heat transfer through the tube walls. Failures of equipment such as air preheaters may also reduce NO_x emissions by causing lower flame zone temperatures. If additives are used to control SO_2 emissions, both bottom ash and particulate emissions may increase by over 50 percent of the normal emission levels (References 2-3, 2-4).

2.2.2 Packaged Boilers

Since large packaged boilers >29 MW heat input (>100 MBtu/hr) operate much like utility boilers, the effects of transients and nonstandard

TABLE 2-9. EFFECT OF NONSTANDARD OPERATING PROCEDURES ON THE EFFLUENT STREAMS FROM A DRY BOTTOM PULVERIZED COAL-FIRED BOILER (Reference 2-1)[a]

Procedure	Frequency	Gaseous	Liquid	Solid
Soot blowing	3 to 4/day	●[a]	●	●
Startup, shutdown	12 to 50/yr	●	●	
Load change	1/day	●	●	
Fuel additives	Continuous if used	●	●	●
Rapping, vibrating	3 to 4/day	●	●	●
Flameout	<1/yr	●		●
Upset	<1/yr	●		
Equipment failure	Several/yr	●	●	●

[a]Indicates possible effect on stream composition.

operations should be similar to those discussed in Section 2.2.1. For smaller packaged boilers, combustion characteristics are significantly different. Although quantitative data for nonstandard operating conditions are sparse, load changes are known to have a relatively small effect on NO_x emissions (Reference 2-5). However, increasing the fuel preheat temperature of oil-fired boilers may increase NO_x emissions. At low preheat temperatures, the atomizing pressure is not sufficient to properly atomize the colder, more viscous oil; this results in lower atomization efficiency.

2.2.3 Warm Air Furnaces

The transient and nonstandard operations of warm air furnaces include on-off cycling and out-of-tune or worn burner operation (Reference 2-6).

During ignition and shutdown transients, some pollutants reach peak levels. In some cases, these peaks account for most of the pollutants emitted. Figure 2-2 (Reference 2-7) shows emission levels from oil burners for one complete cycle. Most of the CO and HC emissions are produced during ignition and after the burner has been shut off. Particulates peak during ignition, but taper off steadily until the burner is shut off.

The initial peak at ignition is caused by the inability of the cold refractory to support complete combustion. This incomplete combustion produces peaks in the HC, CO, and particulate emissions. As the refractory warms up, more complete combustion occurs, thus decreasing combustible emissions. After shutdown, some fuel leaks from the nozzle, which produces another peak in both the CO and HC emissions (Reference 2-7). This can be controlled to some degree by using a solenoid.

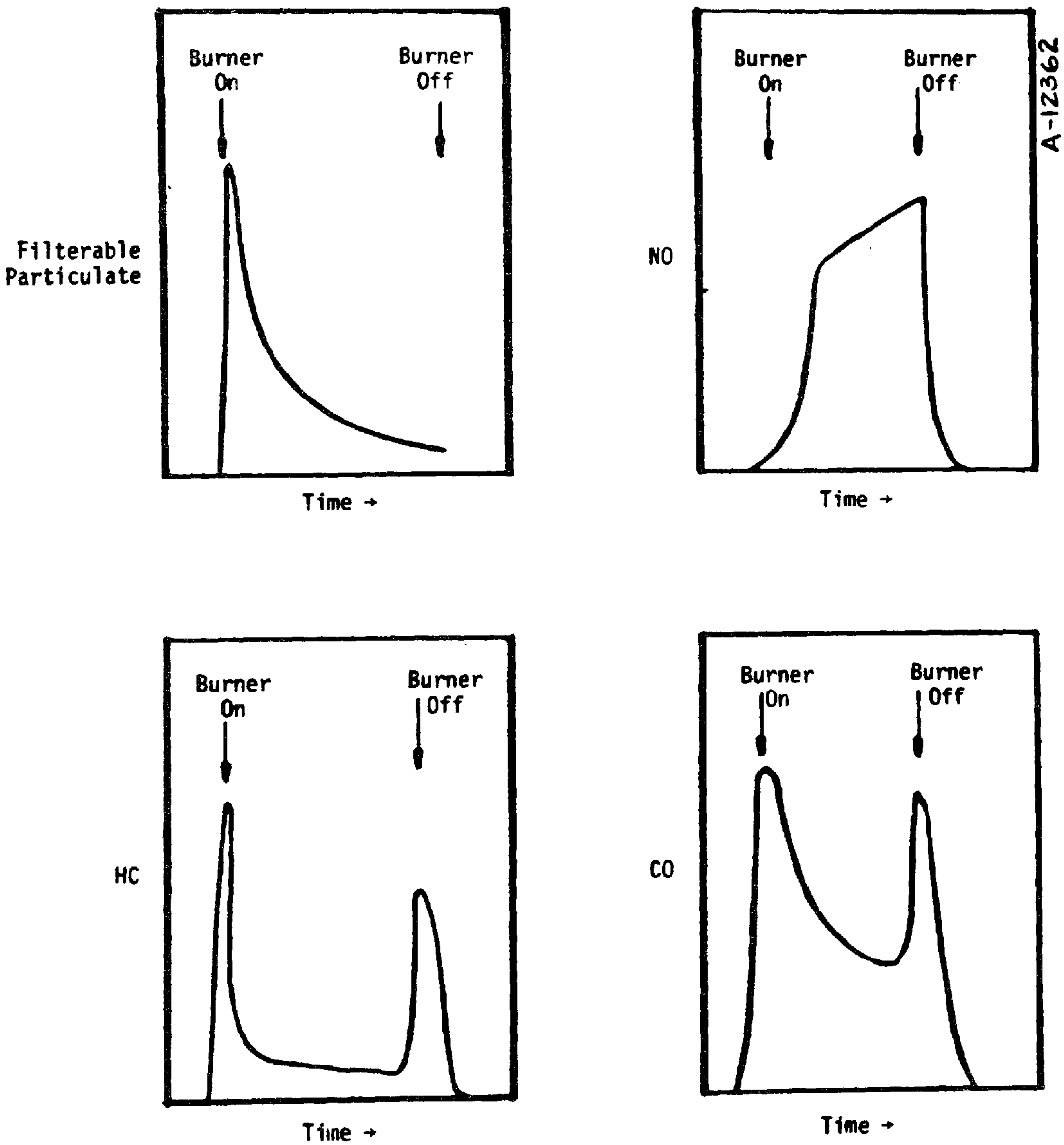


Figure 2-2. Characteristic emissions of oil burners during one complete cycle (Reference 2-7).

The transient emissions of NO_x generally correspond to the thermal history of the firebox. At startup, the emissions increase rapidly as the temperature rises above the thermal NO_x threshold. During the cycle, the emissions continue to increase at a gradual rate as the refractory firebox is heated causing a corresponding increase in the temperature of the combustion gases. At shutdown, NO_x emissions decrease rapidly as the gas temperature is quenched by incoming air.

Transient emissions characteristics of gas burners should be very similar to those of oil burners. However, the HC and CO emissions that occur after shutoff in gas burners are probably not as high as those from oil burners, since gas leaks are minimal after burner shutoff.

The duration of the "on" period within a cycle of a coal-fired warm air furnace does not significantly affect polycyclic organic matter (POM) and particulate emissions (Reference 2-8). However, particulate and POM loadings generated during the "off" transient are higher than those produced during the "on" transient for coals with volatile matter contents greater than 20 percent. This phenomenon is caused by incomplete combustion of tars emitted from the volatile coal. Data trends from two samples show that NO_x emissions increase as the "on" time of a cycle is increased.

Improper burner adjustment, dirty burner cups or nozzles, or damaged components can significantly increase pollutant emissions. Extensive field testing of oil burners is reported in References 2-9 and 2-10. This testing shows that with proper maintenance, smoke, CO, HC, and NO_x emissions are reduced by over 50 percent, while filterable particulate is reduced by almost 25 percent.

For gas burners, tuning, cleaning, and replacement of worn burner components should not have as drastic an effect. Gas burners provide much cleaner combustion, and can be expected to stay tuned for extended periods with no maintenance problems.

2.2.4 Gas Turbines

The transient and nonstandard operations of gas turbines can be separated into three groups: operational variations, startup/shutdown, and equipment failures. Operational variations include changes in load, speed, power, ambient conditions, and variations in fuel quality.

Generally, gas turbines are designed to operate most efficiently at their rated capacity. However, deviations from these rated conditions are often necessary, which can cause the gas turbines to lose efficiency as well as change emissions characteristics.

The most frequently changed operational variables are load and/or speed. Two studies (References 2-11 and 2-12) have indicated that generally, CO, NO_x and HC emissions vary with change in power or load as shown in Figure 2-3.

The profile of NO_x emissions resulting from changes in turbine speed is shown in Figure 2-4 (Reference 2-13). These data show that the behavior of NO_x emissions with changes in rpm is inherently related to the air-to-fuel ratio when corrected to a constant percent oxygen. Gas turbine ambient operating conditions also affect pollutant emissions (Reference 2-12). NO_x emissions increase with increased compressor inlet temperature, whereas CO and HC decrease.

Few data presently are available on emission characteristics during startup/shutdown or equipment failures. However, CO, HC, smoke and particulate emissions should increase during these periods because of

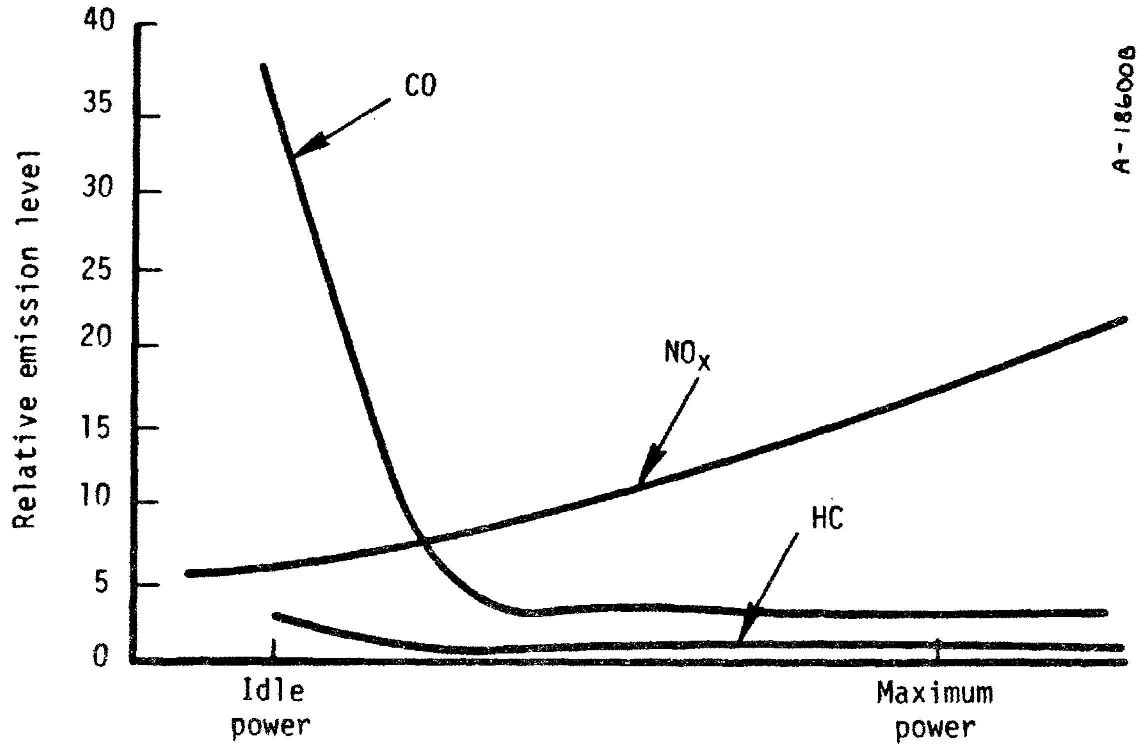
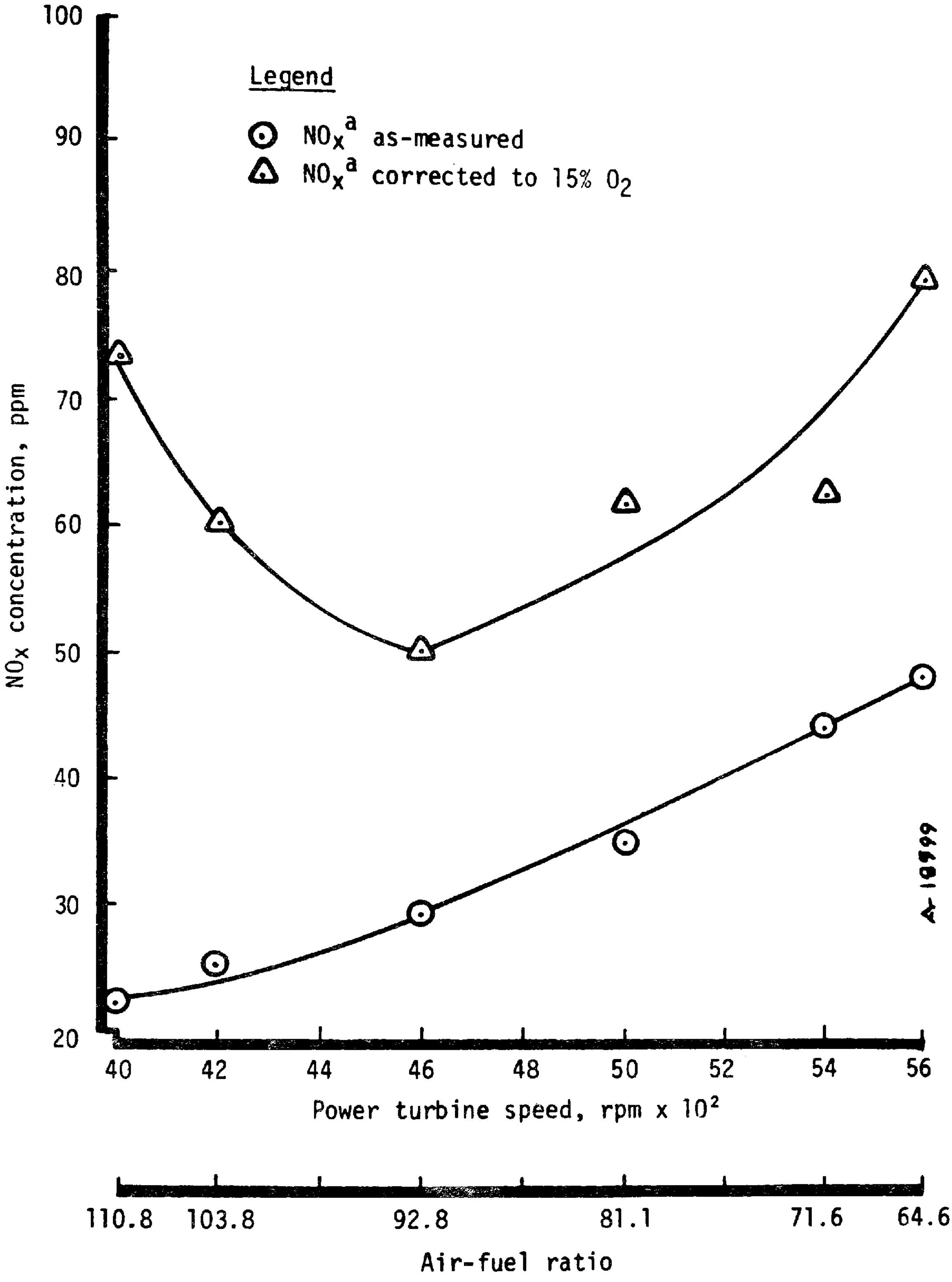


Figure 2-3. Gas turbine generator emissions due to power variations (Reference 2-11 and 2-12).



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[a] NO_2 basis

Figure 2-4. The effect of turbine speed and air-fuel ratio on NO_x concentrations (Reference 2-13).

incomplete combustion. Under these conditions, air-to-fuel ratios are not stable and combustion temeratures are low. NO_x emissions diminish therefore, because of the lower combustor temperatures.

2.2.5 Reciprocating IC Engines

Nonstandard operating conditions include load change, startup and shutdown transients, and upsets such as fuel or electrical system failure. Large IC engines used for power generation or pipeline compression applications are generally well maintained for economy. Moreover, they are run steadily for many hours at their most efficient operating condition. However, smaller engines are not maintained as well, and frequently are operated in transient modes. Transients affect emissions largely through their influence on air-to-fuel ratios. Figure 2-5 (Reference 2-14) presents emission trends caused by these variations for a typical gasoline engine. This figure shows that NO_x emissions peak near the air-to-fuel stoichiometric ratio.

Other operational variations such as load, engine speed, and spark timing also affect pollutant emissions. In general, NO_x emissions diminish with decreasing load, greater speed, and retarded timing. Variations in ambient temperature also affect emissions of pollutants. Recent experiments on automotive gasoline engines indicate that ambient temperature reductions increase HC and CO. However, NO_x levels are not greatly affected by changes in ambient temperature (References 2-15 through 2-18).

Most stationary engines burn No. 2 diesel fuel or natural gas. The properties of pipeline quality natural gas are essentially constant, but field gas can vary in composition and sulfur content. These variations affect the emissions of all gaseous pollutants as well as the engine

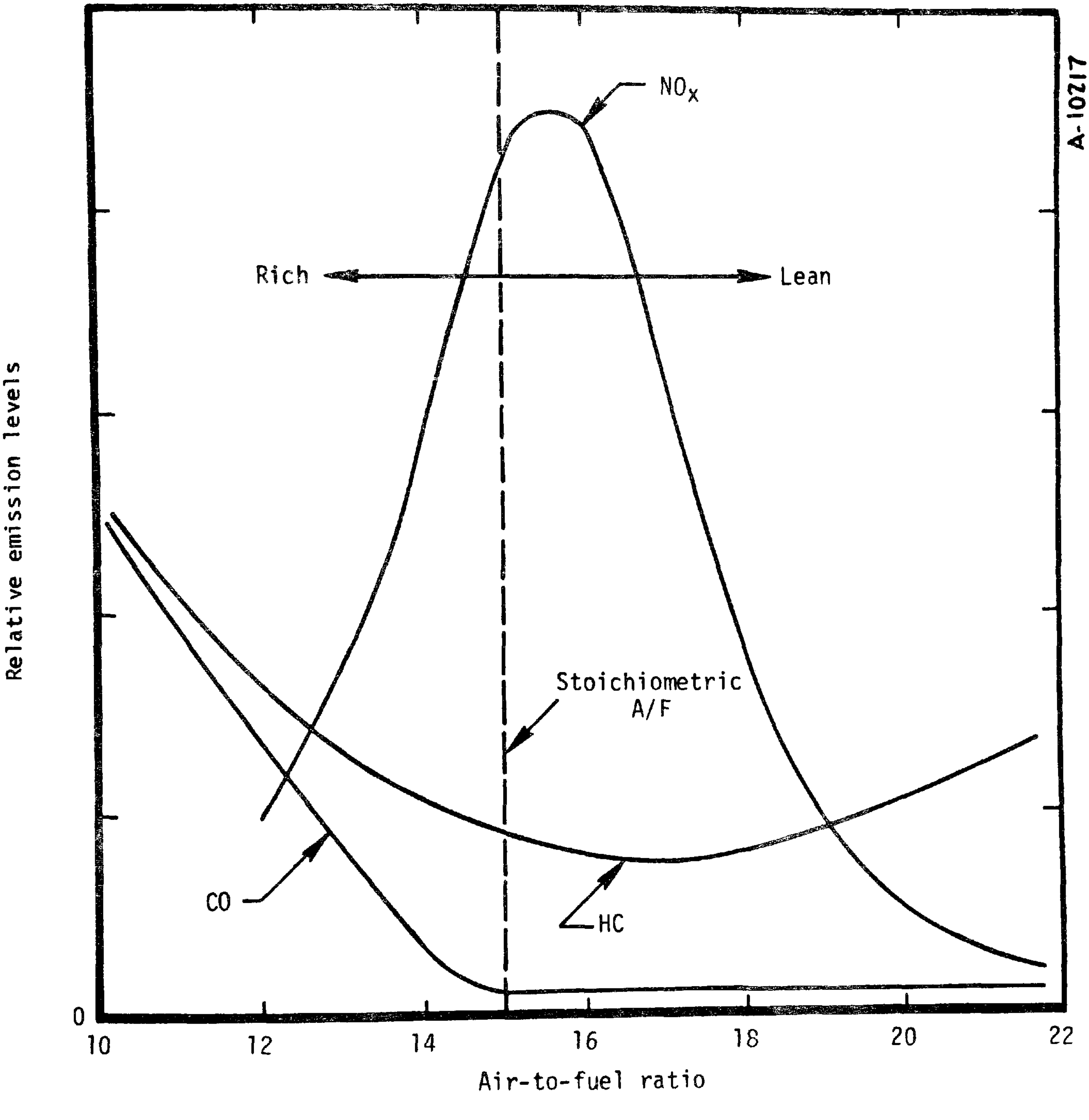

Figure 2-5. Effect of A/F ratio on emissions in a gasoline engine (Reference 2-14).

performance. For diesel oils, the most important properties are viscosity, cetane number, distillation point, and sulfur and ash content. In general, only the sulfur content varies significantly in commercial grade fuels, and hence only SO_2 emissions are affected noticeably by normal fuel variations.

2.3 EQUIPMENT TRENDS

The trends in equipment use are a major consideration in categorizing important NO_x sources and assessing their future pollution potential. This section discusses these trends for the stationary NO_x sources given in Section 2.1.

2.3.1 Utility and Large Industrial Boilers

The trend in utility boiler design is towards coal firing. According to manufacturers (References 2-19 through 2-23), no oil- or gas-fired units have been sold for the past 2 years and many previously ordered oil units have been converted to coal firing during the design phase (Reference 2-19). In addition, government agencies are applying pressure on utilities and industries to switch to coal as their primary fuel. For example, the Department of Energy (DOE) is prohibiting the use of either natural gas or oil by selected major industrial users of fuel. In addition, DOE is preparing to serve "construction orders," requiring that major fuel burning installations (MFBIs) design alternatives to oil or gas firing. MFBIs are defined as units firing 29 MW (heat input) of fuel in a single combustion unit. For new construction however, MFBIs may be as small as 15 MW (heat input), if combined with one or more other combustors (Reference 2-24).

Tangential, single wall, and opposed wall firing (including turbo firing) are the most common utility designs. Tangential boilers have a wide capacity range, while single wall firing is typically limited in capacity to 400 MW (electric), and opposed wall firing is generally used for larger sizes (>400 MW electric). Tangential units currently represent about 43 percent of new sales.

The trend of the last 10 years to larger capacities appears to have slowed. In fact, many utilities have chosen to install two small boiler units rather than a single larger unit. When larger boiler capacities were used, division walls in the combustion chamber were employed -- particularly for oil and gas firing. This increased the available heat transfer surface and produced two smaller combustion chambers with aerodynamic and combustion characteristics similar to smaller units. Large coal-fired furnaces, however, generally do not use division walls because they cannot be cleaned easily by soot blowing (Reference 2-19). Since coal will be used more extensively for utility boilers, using divided combustion chambers is not expected to be a significant trend in the future.

Stokers, cyclones, and vertical firing are now seldom used for new utility boilers. Cyclone furnaces were being sold as late as 1974, but because the units have not proven adaptable to emissions regulations, sales have halted. Cyclone furnaces were originally developed by Babcock & Wilcox to burn Illinois coal, which has a low ash fusion temperature. Recently they have been used to burn lignite. Because the cyclone furnace is designed to operate as a slagging furnace, it must operate at high combustion temperatures (Reference 2-25). Since high temperatures result in high thermal NO_x formation, cyclone furnaces have become unpopular. However, cyclones may be used in the future to fire some lignites. Vertical fired furnaces fire anthracite coal, which is difficult to burn in conventional boilers because of its low volatile content. Since anthracite use as a utility boiler fuel is decreasing, vertical furnaces are no longer sold and few are found in the field.

Wet bottom furnaces are also no longer manufactured. This design has operational problems with low sulfur coal and a high combustion temperature which promotes NO_x formation.

2.3.2 Packaged Boilers

Trends toward coal burning packaged boilers are less certain. In the past, pulverized coal has seldom been used in packaged watertube boilers because of the capital costs involved with coal pulverization and handling equipment. However, the availability and competitive cost of coal compared to oil will probably lead to increasing use of pulverized coal in larger packaged watertube units. Coal-fired units as small as 20 MW (heat input) are now being marketed (Reference 2-26). However, the growth in pulverized coal-fired packaged boilers is only speculative at this point, since no manufacturer has yet received any purchase order for this type of boiler (Reference 2-30). Stoker-fired packaged boiler use (<29 MW heat input) is expected to increase. In addition, new oil-fired boilers are presently being designed with the capability of adapting to a stoker-fired coal system (References 2-27, 2-28, and 2-29).

Sales data show that firebox units have diminished in popularity during the past 5 years (Reference 2-31). Scotch firetubes are currently the most popular type of oil-fired boiler. Although no units are being sold strictly for gas firing, dual fuel (oil- and gas-firing) units are being designed for areas where coal is not available.

Cast iron boilers are being installed in increasingly smaller sizes for hot water heating applications instead of for steam applications. The average capacity of cast iron boilers may reach as low as 15 kW (heat input) in the next few years. However, no major equipment design changes are expected for these units (Reference 2-32).

2.3.3 Warm Air Furnaces

According to U.S. Census statistics for 1970, over 55 percent of the nation's heating units were warm air furnaces. About 67 percent of these units burned natural gas, while distillate fuel oil was fired in 23 percent of the units. Coal, wood, and various bottled, tank, or LP gas accounted for the remaining 10 percent of the fuel used. There has been a continuing trend in the recent past toward commercial and residential warm air furnaces which use natural gas. However, the percentage of equipment in the entire residential and commercial sector fueled by natural gas is expected to drop from 37 percent in 1974 to 35 percent by 1985, and to 32 percent by 2000 (Reference 2-33). Moreover, the use of fossil fuels of all types in this sector is expected to drop from 79 percent in 1974 to 57 percent in 2000. Nationwide, the most important fuels for warm air furnaces will still be natural gas and distillate oils.

Current research efforts mainly emphasize the design of low emission burners and the improvement of furnace efficiency.

2.3.4 Gas Turbines

The growth of gas turbines has been extremely rapid since the mid-1960's because of their low initial costs, ease of maintenance, high power-to-weight ratio, reliability, and short delivery time.

Large gas turbines recently have shown a trend toward higher capacities and improved heat rates. A recent survey of users (Reference 2-34) indicates that combined cycle turbines are the preferred future design for intermediate or baseload applications because of their improved heat rate and fuel flexibility. In contrast, simple cycle turbines are preferred for peaking. In the same survey, users predicted that gas turbines will continue to supply about 10 percent of the total electrical generating capacity through at least 1985. Because of this significant growth, large gas turbines will be a major equipment type in the future and thus will be dealt with separately here.

The trend of using gas turbines for baseload electricity generation was interrupted during the OPEC oil embargo. Because of the uncertain petroleum situation, the orders for combined cycle gas turbine generators dropped sharply. According to a current survey, the demand for combined cycle gas turbine generators is still low. However, sales may rise rapidly if construction of nuclear and fossil fuel power plants continues to be delayed (References 2-35 and 2-36).

The growth of combined cycle gas turbine generators depends on their potential for burning coal derived fuels. Currently, DOE and EPRI are pursuing research programs in gas turbine development. The first of these programs is investigating the development of high temperature gas turbines burning coal derived fuels; the second is considering pressurized, fluidized beds that will burn coal to replace the oil combustor cans in the gas turbines. There is a good possibility that these advanced systems will be commercialized before 2000, perhaps as early as the late 1980's (Reference 2-37).

2.3.5 Reciprocating IC Engines

Large-Power Engines

Most of the large engines used for electric power generation are owned by municipal power companies and are used for baseload generation in areas where construction of large steam generating plants is not justified. Power companies either purchase electricity from nearby large utilities -- if electricity is available and cost-effective -- or purchase large reciprocating IC engines for onsite power generation.

Emergency standby power for nuclear reactors was recently considered to be the most rapidly growing application for high-power diesel engines. Because these engines satisfy a quick startup requirement that gas turbines do not, industry representatives indicate that the high-power diesel engines have virtually no competition for this market (Reference 2-14). However, future trends in this market area are unpredictable because nuclear power generation in the near future is uncertain.

High-power engines are used in municipal sewage treatment plants to generate electricity and pump water from digester gas. Reciprocating IC engines are being used increasingly in areas where the digester gas can be burned to supplement other more expensive fuels (Reference 2-14).

Medium-Power Engines

Many users currently are purchasing diesel rather than gasoline engines, particularly for high load and usage applications. Diesels are being used for agricultural applications because they give good fuel economy and can meet the expanding irrigation and shaft power markets. Although natural gas fueled engines had wide application for agricultural irrigation in the past, many major engine manufacturers plan to discontinue this product line by 1980, primarily because of uncertainty in the availability of natural gas (Reference 2-14).

Medium-power reciprocating engines face competition from substitute power sources in nearly all applications. Direct purchase of electricity and the use of electric motors result in lower maintenance, and lower initial and operating costs for small general industrial and agricultural applications. Thus, markets for medium-power reciprocating engines are declining except where electricity is inaccessible or impractical (Reference 2-14).

Gas turbines are also competing strongly with reciprocating engines, although initial costs of most small gas turbines (300 to 1500 hp) exceed those of similar size reciprocating engines. Gas turbines are better suited for most standby applications in hospitals and commercial buildings where space, weight, noise, and vibration are constraints (Reference 2-14).

Low-Power Engines

In this sector, low-power engines are being replaced by electric motors. However, use of small engines (<15 hp) for homes, lawns and gardens, and off-road vehicles has grown substantially in the last few years (Reference 2-14). Since most of these uses are for nonessential services, continued growth depends heavily on future economic and fuels stability.

2.3.6 Industrial Process Trends

Iron and Steel Industry

Use of sintering lines is declining at the rate of about 3.4 percent annually because they cannot accommodate rolling mill scale contaminated with rolling oil. Pelletizing, the preferred process, will eventually replace sinter lines because it can handle rolling mill scale and has reduced energy requirements and emissions. Although pelletizing uses primarily gasoline and diesel fuels, the Bureau of Mines has found no major problems with firing pulverized coal in this process. Currently, pellet systems with provisions for coal firing are under consideration (Reference 2-38).

Open hearth furnaces are now being replaced in the steel industry by the basic oxygen furnace. In fact, fuel consumption in open hearth furnaces is decreasing at about 8 percent per year (Reference 2-39). However, open hearth furnaces are still an important source of NO_x emissions because of existing furnaces, which have very high combustion air preheat temperatures, high operating temperatures, and practice oxygen lancing.

Because continuous casting of molten metal is becoming the preferred method for iron and steel making, the need for soaking pits and reheat furnaces is diminishing. However, the growth in the overall iron and steel industry is strong enough to still support a 2.8 percent annual increase in process fuel consumption (Reference 2-39). In addition, present projections show a 5.7 percent annual increase in fuel consumption for coke ovens (Reference 2-39).

Glass Industry

The current trend in the glass industry is towards electric melters, or at least electrically assisted conventional melters. In addition, fuel oil is increasingly being used in place of natural gas because of natural gas shortages and price increases. Coal, for the most part, is an unacceptable fuel for the glass industry because of its impurities. However, coal gasification may become a useful and economically viable fuel source for the glass industry.

Cement Industry

It is expected that many cement industries will convert to coal firing in the near future as a result of DOE directives (Reference 2-24).

According to current DOE statistics, 90 percent of all cement plants should be able to use coal by 1980, compared to 66 percent in 1976 and 76 percent today (Reference 2-24). The cement industry has reduced energy consumption by using grate preheaters and quicker, less energy intensive kilns. One further improvement may be to replace traditional rotary kilns with fluidized bed kilns. Volatiles and ash are sent to the flue via an indirect heat exchanger in the fluidized bed kiln, making it unnecessary to plug in the conventional kiln preheaters.

Cement industry figures show that the industry has grown at an average rate of about 1.9 percent annually over the past 20 years. Industry projections, however, predict a greater growth in the next few years of between 2.6 to 4.1 percent per year (Reference 2-40).

Petroleum Refining

Current trends are toward mechanical draft process heaters with a combustion air preheater, primarily because they conserve more energy than natural draft heaters.

Process heaters are fueled primarily (60 to 80 percent) by process gas, a byproduct of the refinery process. The auxiliary fuel is generally oil. However, oil consumption will probably decline as more process gas with a lower sulfur content is used. Recently promulgated regulations limit atmospheric sulfuric oxide emissions from process heaters, requiring use of low sulfur process gas. It has been estimated that these regulations will reduce current oil consumption by as much as 28 percent (Reference 2-41). A 2.7 percent annual increase in process heating is projected for 1980, and a 2.9 percent annual increase for 1985 (Reference 2-40).

Catalytic cracking capacity increased by about 1.7 percent per year between 1960 and 1973. Future growth will depend on energy and environmental policy, and on the demand for low sulfur fuel oil. Present estimates of future growth are from 1 to 3 percent per year (Reference 2-40).

Brick and Ceramics

The brick and ceramics industries are lowering manufacturing costs through high-volume continuous production with heat recovery where feasible. Tunnel kilns increasingly are being used. In the future, these kilns will be the principal type within these industries.

Both pulverized coal and coal gas firing are being used more frequently in the brick and ceramics industries. Since sulfur can affect the quality of the brick by changing its color, glazing, etc., low sulfur coal is required. Thus, long-term predictions of coal use in these industries are uncertain, since they depend on the availability of low sulfur coal (Reference 2-39).

2.4 MOBILE COMBUSTION SOURCES

Mobile combustion sources are the second major cause of atmospheric NO_x emissions. Although a detailed assessment of mobile sources is not within the scope of this program, these sources still must be defined to understand the total impact of NO_x emissions. NO_x emissions estimates from mobile sources will be included in Section 4 so that stationary and mobile sources can be compared.

Mobile sources include both highway and nonhighway vehicles. Highway vehicles can be divided into the following categories:

- Passenger cars and light-duty trucks powered by gaseous (LPG, CNG, LNG), diesel, or gasoline fuels

- Heavy-duty trucks powered by gaseous (LPG, CNG, LNG), diesel, or gasoline fuels
- Motorcycles powered by gasoline

Nonhighway vehicles can be divided into the following categories:

- Aircraft
- Locomotives
- Vessels -- further divided into inboard and outboard
- Small general utility engines -- snowmobiles, minibikes, dune buggies, small electric generators, etc.

2.5 NONCOMBUSTION SOURCES

Noncombustion NO_x emissions are produced by several primary chemical manufacturing processes. Although none of these processes have significant emissions on a national scale, they are often serious sources of pollution locally. The most important of these processes are:

- Nitric acid manufacture
- Adipic acid manufacture
- Explosives manufacture

Emissions from these sources are discussed below.

Nitric Acid Manufacture

Nitric acid, HNO_3, is usually manufactured by ammonia oxidation. This acid is used primarily for nitrate fertilizers (~15 percent), and for organic chemical manufacture, steel pickling, and military munitions (25 percent). Emissions from nitric acid plants are not significant on a national scale, but are frequently of great concern locally. Catalytic burners, typically used to control NO_x, reduce the NO_2 concentration of the tail gas and produce a colorless stream consisting mostly of N_2, O_2, and CO_2.

The projected growth rate for the industry is 7.2 percent annually (Reference 2-40).

Adipic Acid Manufacture

Adipic acid, $(CH_2)_4$ $(COOH)_2$, is manufactured by catalytic oxidation of cyclohexane, with cyclohexanone and cyclohexanol as intermediates. Although emissions from adipic acid plants may not be significant on a national scale, they can be very serious on a localized basis -- only five plants produce nearly 1.5 billion tons annually (Reference 2-42). The industry as a whole has recently slowed its historically rapid growth. In fact, growth is expected to decrease from approximately 7 percent annually to about 4 percent annually over the next 3 years (Reference 2-42).

Explosives Manufacture

Explosives can be divided into four major classifications: bulk explosives, propellants, initiating agents, and specialty explosives. The bulk explosives and propellants are manufactured by reacting concentrated acids with an organic material in a nitration step. Acid fumes from the nitration step are a serious pollutant emission if they are not recovered and recycled. Growth in the explosives industry is highly dependent on a number of fluctuating factors and therefore cannot be accurately projected.

2.6 FUGITIVE EMISSIONS

The final sources of atmospheric NO_x emissions are man-made and natural fugitive emissions. These sources generally are not controlled, except to eliminate the source in extreme cases, and their evaluation is not within the scope of the present assessment. However, estimates of NO_x emissions from these sources will be made in Section 4 for comparison with other NO_x sources.

Manmade sources of fugitive NO_x emissions include:

- Open burning of municipal waste, landscape refuse, agricultural field refuse, wood refuse, and bulky industrial refuse
- Grain elevators
- Forest fires -- both accidental and controlled burning
- Structural fires -- both accidental and planned
- Minor processes -- such as welding and acid pickling

2.7 CONCLUSIONS

The most important source of NO_x emissions is the utility boiler category. This sector is generally well documented, especially for information concerning fuel consumption and composition, the amount of electrical power generated, and installed capacity. Because this sector is strictly regulated, boiler parameters are also well documented. However, data are lacking on furnace design characteristics for older equipment. Although general information is available, specific data on furnace populations and distribution, unit load factors, use of mixed fuel firing, and furnace design trends are difficult to obtain. In this report, missing data were supplied, in part, by industry contacts, but more complete information is needed. There is also little information available on fuel use practices -- particularly statistics on fuel origin, blending, switching, and backup. Potentially valuable information on how new equipment is put on line and older equipment retired is also generally unavailable.

Because of the wide range of packaged boiler types and their lack of strict regulation, data on packaged boilers is not as complete as data for other sectors. In addition, the equipment categorizations defined in this report are not entirely consistent with previous emissions inventories and industry surveys. Although data for sales of new packaged boilers are comprehensive, little information is available on boiler fuel switching, retirement practices, operational maintenance, and burner distribution. As a result, the final categorization of equipment types is based strongly on recent sales.

Warm air furnace equipment distributions are based mainly on recent U.S. Census estimates which are considered reliable. Data for other residential and commercial combustion equipment types included in this sector also came from the U.S. Census Bureau. However, these data are not as useful because specific details are lacking -- particularly the fuel consumed by various equipment types.

Data for the gas turbine sector are fairly accurate because they are based on recent installed capacity estimates. These estimates came from the Turbine Standard Support and Environmental Impact Statement prepared to support a NSPS for gas turbines. One obvious data gap, however, is the absence of information on smaller capacity units. Because of uncertainty in the availability of clean fuels, the growth of the gas turbine industry is difficult to predict.

Data for the reciprocating IC engine sector came mainly from the recent standard support document and are considered to be of relatively high quality. Applications, installed capacities, load factors, and fuels are well documented. Very small gasoline engines, like those used on lawnmowers, chainsaws, etc., have been excluded because statistics on their distribution and use are very difficult to obtain.

Process heating sector data are of good quality for the processes included in this report. A number of minor processes were excluded from this sector because of their relatively minor applications. The major processes, and those which may be subject to combustion control in the future, are included in this sector. Although not all noncombustion processes are discussed in this report, the major noncombustion processes are considered. Of greatest concern in this sector are those processes, like nitric acid plants, which may cause serious local pollution problems.

Other equipment or process sources of NO_x mentioned here are not covered extensively in this report, but are included only to make the data complete. In most cases, existing data on many of these less important sources are limited.

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SECTION 3

FUELS CHARACTERIZATION AND CONSUMPTION

This section characterizes fuel composition and consumption for equipment and fuel combinations described in Section 2. These data are important input for the Section 4 emissions inventory and the Source Analysis Model in Section 5. Since fossil fuels account for almost all of the energy consumed by stationary combustion sources nationally, the survey includes only these fuels. Section 3.1 describes the characteristics of the three major fossil fuels and their derivatives. Section 3.2 summarizes the annual fuel consumption by the major stationary source equipment sectors and by individual equipment types within each sector. Regional fuel consumptions for stationary source sectors and for individual equipment types are presented in Section 3.3. Projections of fuel consumption for 1985 and 2000 are given in Section 3.4.

3.1 FUEL CHARACTERISTICS

Fuel characteristics are required in the present study to specify emission factors for combustion-generated pollutants (NO_x, SO_2, trace metallics, organics). Fossil fuels show large variations in chemical and physical properties due to variations in origin and processing. To estimate multimedia effluents produced by combustion sources, representative fuel properties were determined for a range of fuels from different geographic regions. This approach was taken because data were insufficient to treat each fuel type separately. Data were insufficient in the following areas:

- Comprehensive data which relate fuel consumption to fuel origin and its properties are lacking
- Emission factors are not available for all types of fuel and are often given in terms of average fuel properties
- There are no comprehensive data which quantify the effects of various fuel cleaning practices such as blending, washing, desulfurization, and demetallization by fuel suppliers
- Fuel consumption for a given fuel source or region is highly variable, making precise characterization impossible (Reference 3-1)

The approach for compiling fuel composition was based on the requirements for the emission factor specification discussed in Section 4. For emissions of SO_2, particulate, and trace metals, the stack concentration of pollutants is highly dependent on fuel composition and less dependent on combustion conditions or specific equipment type. Thus, for these pollutants, it is necessary to directly relate emission factors to fuel concentration. For NO_x, CO, HC and organics, emissions are kinetically controlled and depend both on combustion conditions and fuel content. For these pollutants, variations in emission factors due to differences in fuel content are treated by specifying representative emission factors for each equipment/fuel combination, e.g., tangential utility boilers firing bituminous coal and watertube packaged boilers firing residual oil, rather than directly relating emissions to fuel content.

Trace elements invariably contaminate liquid and solid fuels. This is an especially important factor to consider in the combustion of residual fuel oil and coal, since these fuels have high concentrations of trace elements and are burned in large quantities each year. In this study, the trace metal emission loading from the combustion of natural gas and distillate oil is assumed negligible compared to residual oil and coal combustion. This assumption will have essentially no impact on estimated total trace element emissions from stationary sources.

Trace element concentrations typically vary within a single coal-producing region, and even within a single seam (Reference 3-2). Since the trace element content of individual coal samples is highly variable, representative concentration levels for coal were determined. More detailed evaluation of the trace element content of various coals is unjustified because: (1) the availabile data on trace element emission factors are generally of poor quality, and (2) establishing representative values using highly varying data is inaccurate. One study, in fact, suggests that trace element emissions from fossil fuels are so variable that they must be determined on a plant-to-plant basis for a rigorous analysis (Reference 3-3).

Characterization of trace elements in residual fuel oils is even more difficult than for coal because: (1) trace elements in residual fuel oils vary even more than those in coal, and (2) specific data on the origin, refinery practices and blending techniques of the residual oil used at the burner are lacking. Demetallization, desulfurization, blending of various grades of oil that varies from refinery to refinery, and supply and demand strongly influence the transportation and final destination of petroleum products. Because the petroleum market is always changing, rigid assumptions about refinery origins cannot be made. As a result, only one average set of trace element concentrations is given for residual fuel oil. Table 3-1 displays the trace element concentrations and summarizes other important properties of each of the major fossil fuel types (References 3-4, 3-5, and 3-6). These properties will be used throughout the remainder of this section.

The characterization of the sulfur content of coal and heavy oil, and the ash content of coal was made for three fuel classes. This was because the variation of these properties is so large that a single representative class would be unrealistic. Sulfur (S) and ash (A) contents of the following fuels are considered representative of the fossil fuels consumed by stationary sources:

- Petroleum fuels
  - Residual fuel oil
    - Interior province (high sulfur) -- 2.0 percent S
    - Eastern province (medium sulfur) -- 1.0 percent S
    - Western province (low sulfur) -- 0.5 percent S
  - Distillate fuel oil, 0.25 percent S
  - Gasoline, <0.05 percent S
- Coal
  - Bituminous and sub-bituminous
    - Interior province (high sulfur) -- 2.8 percent S, 9 percent A
    - Eastern province (medium sulfur) -- 2.2 percent S, 9.2 percent A
    - Western province (low sulfur) -- 1.6 percent S, 8.7 percent A

TABLE 3-1. PROPERTIES AND TRACE ELEMENTS OF REPRESENTATIVE FOSSIL FUELS (References 3-4, 3-5, and 3-6)

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	Anthracite Coal	Sub-bituminous and Bituminous			Lignite Coal	Residual Fuel Oil			Distillate Oil	Gasoline	Natural Gas
		High S	Medium S	Low S		High S	Medium S	Low S			
Ash %	11.9	9.	9.2	8.7	12.8	Trace	Trace	Trace	0	0	0
Sulfur %	0.6	2.8	2.2	1.6	0.4	2.0	1.0	0.5	0.25	<0.05	<0.1
Heating Value[a]	30,238	27,912	27,912	23,260	18,608	39,021			39,021	34,840	37,259
Al (ppm)	--	12,240		10,200	8,160	753			Trace	Trace	Trace
Sb	0.1	1.3		1.1	0.9	0.2					
As	9.3	15		13	10	0.2					
Ba	54	36		30	24	39					
Be	2.8	1.7		1.5	1.2	--					
Bi	0.1	1.		0.8	0.7	--					
B	1.0	114		95	76	3.0					
Cd	0.1	2.9		2.4	2.0	2.0					
Co	84	9.1		7.6	6.1	30.					
Cr	112	14.		12.	10.	30,					
Cu	70	40.		33	26	25.					
Pb	8.3	14		12	9.2	19					
Mn	169	53		45	36	25					
Hg	0.3	0.2		0.2	0.1	0.1					
Mo	9.3	8.0		6.7	5.3	2.5					
Ni	47	22		19	15	1,208					
P	--	63		53	42	--					
Se	0.2	2.0		1.7	1.3	10					
V	12	33		28	22	1,803					
Zn	31	312		260	208	40					
Zr	45	72		60	48	19					

[a]H.V. in kJ/kg -- coal
kJ/ℓ -- oil
kJ/m^3 -- gas

-- North Dakota lignite, 0.4 percent S, 12.8 percent A

-- Pennsylvania anthracite, 0.6 percent S, 11.9 percent A

- Natural gas, <0.1 percent S

The medium sulfur levels of coal and residual oil correspond to the average sulfur concentration of fuels used in U.S. utilities in 1974 (Reference 3-7). Although data on fuel sulfur composition are available for the utility boiler sector, there are relatively few data available for other sectors. When consumption data for fuels were not available by specific sulfur content, medium sulfur concentrations are used where applicable.

3.2 FUEL CONSUMPTION

Estimates of fuel consumption for stationary sources (or annual product output for process heating sources) are presented in this subsection. Fuel consumption was compiled for the year 1974, since this was the most recent year for which comprehensive and complete regional data were available. For comparative purposes it was important that both the national and regional fuel consumption data represented the same year. Table 3-2 summarizes total annual consumption for coal, petroleum, and gas. These totals do not reflect total energy consumed by stationary sources, because some of the process industries and nonfossil fuel use have not been included.

Total U.S. energy use in 1974 totaled about 77 EJ (72×10^{15} Btu) (Reference 3-8), of which 94 percent was supplied by the fossil fuels -- coal, petroleum, and natural gas. Approximately 57 percent of the total energy was used by stationary sources. Fossil fuels furnished 92 percent of the energy for these stationary sources; the remainder was supplied by nuclear, hydroelectric, and other miscellaneous sources such as waste

TABLE 3-2. 1974 STATIONARY SOURCE FUEL CONSUMPTION (EJ)[a]

Equipment Sector	Coal	Oil	Gas	Total Fuel
Utility Boilers	10.833	3.483	4.906	19.222
Packaged Boilers[c]	3.470	5.780	6.323[b]	15.573
Warm Air Furnaces and Miscellaneous Combustion	--	2.132	5.542	7.674
Gas Turbines	--	0.844	0.681	1.525
Reciprocating IC Engines	--	0.328[d]	0.914[e]	1.242
Total	14.303	12.567	18.366	45.236

[a]EJ/yr = 10^{18} J/yr

[b]Includes process gas

[c]This sector includes steam and hot water units

[d]Includes gasoline and oil portion of dual fuel

[e]Includes natural gas portion of dual fuel

fuels, wood, and geothermal . Of the total amount of fossil fuels burned in stationary sources, coal contributed 26 percent, natural gas 44 percent, and petroleum 30 percent. Unlike petroleum, which is also a major source of energy for transportation, coal and natural gas are used primarily in stationary applications.

The following discussion presents estimates of fuel consumption and reviews information sources for the major equipment sectors identified in Section 2.

3.2.1 Utility and Large Industrial Boilers

Fuel consumption estimates for utility boilers are reasonably comprehensive due to the regulation of the industry. Table 3-3 gives a detailed summary of the fuel consumed by significant utility boiler equipment types. This summary was derived from the following sources:

- Federal Power Commission (FPC) -- fuel consumption by type of fuel and sulfur content (References 3-7 and 3-9)
- GCA -- analysis of FPC-67 tapes to provide data on the total number of boilers and the fuel breakdowns (Reference 3-10)
- Monsanto -- analysis of the cyclone boiler population and fuel consumptions (Reference 3-11)
- Office of Air Quality and Planning Standards (OAQPS) -- analysis of lignite fired steam generators (Reference 3-12)
- A. D. Little -- analysis of the electric utilities and equipment manufacturers (Reference 3-13)
- Battelle -- analysis of the boiler population and fuels for nonutility application (Reference 3-14)
- Bureau of Mines -- data on domestic coal production and end use by state; data on petroleum products (Reference 3-15)

TABLE 3-3. 1974 UTILITY BOILER FUEL CONSUMPTION (EJ)

Utility Boilers	Medium Sulfur Bituminous and Sub-bituminous	High Sulfur Bituminous and Sub-bituminous	Low Sulfur Bituminous and Sub-bituminous	Lignite	Anthracite	Total Coal	High Sulfur Residual and Crude	Medium Sulfur Residual and Crude	Low Sulfur Residual and Crude	Total Residual and Crude	Distillate	Total Oil	Natural Gas	Total All Fuels
Tangential	2.624	1.584	0.869	0.053	—	5.130	0.196	0.492	0.636	1.324	0.036	1.360	1.134	7.624
Single Wall Fired	1.513	0.914	0.501	0.011	—	2.939	0.196	0.493	0.637	1.326	0.169	1.495	2.453	6.887
Horizontally Opposed Wall and Turbo Furnace	0.423	0.255	0.140	0.021	—	0.839	0.079	0.199	0.258	0.536	0.015	0.551	1.258	2.648
Cyclone	0.158	1.292	—	0.137	—	1.587	0.012	0.028	0.037	0.077	—	0.077	0.061	1.725
Vertical and Stoker	0.110	0.110	—	0.009	0.109	0.338	—	—	—	—	—	—	—	0.338

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- *Power* Magazine -- miscellaneous information on various equipment and fuel trends (Reference 3-16)

Two simplifications were used in arriving at these estimates:

- Distillate oil and kerosene are combined with the residual fuel oil category, since distillate oil accounted for only about 5 percent of utility steam plant total oil consumption (References 3-14 and 3-17)
- Coke, coke breeze, refuse, process gas, wood, bagasse, black liquor, sewage sludge, etc., are negligible for utility boiler application

It was found that coal accounted for 56 percent of the fuel consumed by utility boilers, natural gas 26 percent, and oil 18 percent. Coal-fired utility boilers used about 76 percent of the total energy supplied by coal to all stationary sources. Utility boilers burned only 28 percent of both oil and gas fuels consumed by stationary sources.

3.2.2 Packaged Boilers

Fuel consumption data for packaged boilers are not as reliable as data for utility boilers, due to the diversity of packaged boiler designs, the wide variety of applications, the lack of regulation and documented data, the large number of installed units and their characteristic wide fuel flexibilities. Table 3-4 lists fuel consumption estimates for packaged boiler designs that consume significant amounts of fuel. These estimates were derived from a number of sources:

- Battelle -- analysis of the national boiler population by capacity and fuel (Reference 3-14)
- Battelle -- analysis of the equipment design distribution (Reference 3-18)

TABLE 3-4. 1974 PACKAGED BOILER FUEL CONSUMPTION (EJ)

T-147a

Packaged Boilers	Anthracite	Bituminous or Lignite	Total Coal	Residual Oil	Distillate Oil	Total Oil	Natural Gas	Process Gas	Total Fuel
Wall Firing Watertube >29 MW[a]	—	0.510	0.510	0.637	0.085	0.722	0.928	0.130	2.290
Stoker Watertube >29 MW[a]	—	0.466	0.466	—	—	—	—	—	0.466
Single Burner Watertube <29 MW[a]	—	0.317	0.317	0.595	0.103	0.698	1.690	0.130	2.835
Single Burner Scotch Firetube <29 MW[a]	—	—	—	0.945	0.446	1.391	0.972	0.019	2.382
Single Burner HRT Firetube <29 MW[a]	—	—	—	0.370	0.263	0.633	0.535	—	1.168
Single Burner Firebox Firetube	—	—	—	0.609	0.403	1.012	0.899	0.019	1.930
Single Burner Cast Iron Boiler	—	—	—	0.195	0.181	0.376	0.264	—	0.640
Stoker Watertube <29 MW[a]	0.021	1.533	1.554	—	—	—	—	—	1.554
Stoker Firetube <29 MW[a]	0.042	0.556	0.598	—	—	—	—	—	0.598
Steam or Hot Water Units (Residential Only)	0.014	0.011	0.025	0.069	0.880	0.949	0.737	—	1.711

[a]Heat input

- U.S. Department of Commerce -- data on boiler sales for 1968 to 1974 (Reference 3-19)
- The Research Corporation of New England (TRC) -- historical trends in packaged boiler fuels (Reference 3-20)

The assumptions used to estimate fuel consumption for packaged boilers included the following:

- All boilers greater than 29 MW (100 MBtu/hr) input capacity are watertube designs and are single wall fired
- Pulverized coal is not fired in units with input capacity less than 29 MW
- All coal for residential and commercial heating is burned in steam and hot water units

In 1974, energy supplied to packaged boilers was 34 percent of the total fossil fuel consumed by stationary sources for energy conversion. Of this total consumption, 24 percent of total coal, 46 percent of total oil, and 34 percent of total gas used by stationary sources was consumed by packaged boilers. Coal, the most widely used fuel in utility boilers, is also used widely in industrial boilers for the larger watertube pulverized and stoker units. At present, coal is less seldom used in the new firetube or the smaller watertube boilers because the ease of transportation and distribution of oil and gas fuels is important to users of packaged boilers.

3.2.3 Warm Air Furnaces and Other Commercial and Residential Combustion

In this sector, the range of equipment designs and large number of units cause uncertainties in the fuel consumption estimates. Estimated fuel consumption for commercial and residential combustion as well as for various cooking appliances, clothes dryers, refrigeration units, etc., listed as "other" is presented in Table 3-5. The major source for these estimates was the 1970 U.S. Census (Reference 3-21).

The basic assumptions used in making these estimates were:

- The amount of wood, refuse, and other nonfossil fuels burned in warm air furnaces is minimal
- Units fueled by tank, bottled or liquefied petroleum gas are not a large portion of the total. Since these units are generally located in rural areas and cause no localized impacts, they were combined with natural gas-fired units.
- Coal firing in warm air furnaces is insignificant

Total warm air furnace fuel consumption in 1974 represented about 17 percent of the total used in stationary sources for energy conversion. The natural gas consumption in this sector is in the same range as that for utility and packaged boilers, whereas the amount of oil is less.

3.2.4 Gas Turbines

Because there are relatively few types of major applications and manufacturers of gas turbines and the utility applications are regulated, the 1974 estimates of fuel consumption for gas turbines are of high quality. Table 3-6 gives the fuel consumption estimates for the three gas turbine capacity ranges. These estimates are derived from a number of sources:

- Gas Turbine (GT)-Standards Support Document -- installation and generation for all applications and capacity ranges except utilities (Reference 3-22)
- FPC -- installation, generation, and fuel consumption for all utility and pipeline applications (References 3-9 and 3-23)

TABLE 3-5. 1974 WARM AIR FURNACE AND OTHER COMMERCIAL AND RESIDENTIAL COMBUSTION FUEL CONSUMPTION (EJ)

Warm Air Furnaces	Distillate Oil	Natural Gas[a]	Total Fuel
Warm Air Central Furnaces	1.405	3.091	4.496
Warm Air Room Heaters	0.727	1.451	2.178
Miscellaneous Commercial/Residential Combustion	—	1.0	1.0

[a]Includes bottled, tank or LPG

TABLE 3-6. 1974 GAS TURBINE FUEL CONSUMPTION (EJ)

Gas Turbines	Natural Gas	Oil[a]	Total
Gas Turbines >15 MW[b]	0.212	0.264	0.476
Gas Turbines 4 MW to 15 MW[b]	0.468	0.579	1.047
Gas Turbines <4 MW[b]	0.001	0.001	0.002

[a]Includes distillate, diesel, residual oils

[b]Power output

- Sawyer's GT Catalog -- miscellaneous information on utility and pipeline applications (Reference 3-24)
- GT International -- data on gas turbine electric utility installations (Reference 3-25)

These estimates were made on the basis of the following assumptions:

- Typical specific heat rates for the three capacity ranges were 10.9 MJ/kWh (10,300 Btu/kW-hr), 13.9 MJ/kWh (13,200 Btu/kW-hr) and 16.4 MJ/kWh (15,500 Btu/kW-hr) for large, medium, and small capacity turbines, respectively
- Specific fuel consumption does not vary significantly with load, which means total fuel consumption can be determined directly from specific fuel consumption and generation totals
- The amount of alternate fuels, such as gasified or liquefied coals, shale oil, process gas, pulverized coal, or refuse, burned in turbines is negligible

The total energy consumed by gas turbines was about 3.4 percent of the total stationary source fuel consumption in 1974. As Table 3-6 shows, medium-capacity units consumed more fuel than the large units. The bulk of the fuel consumption of these medium-capacity turbines was either in the oil and gas industry, where equipment operates almost constantly, or in private sector electricity generation, where equipment operates about three-quarters of the time.

3.2.5 Reciprocating IC Engines

This sector represents an extremely wide range of designs, applications and manufacturers. A recent study (Reference 3-26), however, has characterized reciprocating IC engines by installed capacity and annual generation by fuel, and data from this study have been used extensively for this sector. For consistency with other sections of this report, data from Reference 3-9 have been used for installed capacity, annual generation, and fuel consumption of IC engines used by electrical utilities. Table 3-7 gives fuel consumption figures for significant equipment types determined in Section 2.

The following assumptions were used in arriving at these estimates:

- Specific fuel consumption averaged 9.9 MJ/kWh (7000 Btu/hp-hr), 11.3 MJ/kWh (8000 Btu/hp-hr), and 11.3 MJ/kWh for large-, medium-, and small-capacity ranges, respectively
- Specific fuel consumption does not vary significantly with load, so that overall fuel consumption can be determined from specific fuel consumption and generation totals
- No gasoline is burned in large- or medium-capacity equipment
- No natural gas is burned in small-capacity equipment

The total energy consumed by this sector is about 3 percent of the total consumption of fuel used for energy conversion in stationary sources. Natural gas is the major fuel, particularly in the large-bore units. The major user of natural gas-fired, large-bore engines is the oil and gas industry, where units usually operate over 8000 hours a year.

3.2.6 Industrial Process Heating

Production totals for various processes within this sector are used instead of fuel consumption totals. This was done because emission factors for industrial process heating are usually presented in terms of production totals. Moreover, production figures are more reliable than energy consumption statistics for heating operations in most industries.

Table 3-8 gives production data for the major process heating industries, and Table 3-9 gives fuel consumption data for refinery process

TABLE 3-7. 1974 RECIPROCATING IC ENGINE FUEL CONSUMPTION (EJ)

Reciprocating IC Engines	Natural Gas	Distillate Oil (Diesel)	Gasoline	Dual (Oil + Gas)	Total Fuel
Compression Ignition >75 kW/cyl[a]	—	0.054	—	0.058 Gas 0.012 Oil	0.124
Spark Ignition >75 kW/cyl[a]	0.813	—	—	—	0.813
Compression Ignition 75 kW to 75 kW/cyl[a] >1000 rpm	—	0.129	—	—	0.129
Spark Ignition 75 kW to 75 kW/cyl[a] >1000 rpm	0.043	—	0.084	—	0.127
Compression Ignition <75 kW[a]	—	—	—	—	—
Spark Ignition <75 kW[a]	—	—	0.049	—	0.049

[a]Power output

TABLE 3-8. 1974 INDUSTRIAL PROCESS HEATING PRODUCTION

Industrial Process Heating	Annual Production
Cement Kilns	7.696×10^7 Mg
Glass Melting Furnaces	1.542×10^7 Mg
Glass Annealing Lehrs	1.542×10^7 Mg
Coke Oven Underfire	5.701×10^7 Mg
Steel Sintering Machines	4.851×10^7 Mg
Open Hearth Furnaces	3.227×10^7 Mg
Brick and Ceramic Kilns	3.158×10^7 Mg
Catalytic Cracking	2.294×10^{11} ℓ feed
Refinery Flares	7773 Mg NO_x/yr[a]
Iron and Steel Flares	318 Mg NO_x/yr[a]

[a] NO_x estimates

TABLE 3-9. 1974 REFINERY PROCESS HEATING FUEL CONSUMPTION (EJ)

Heater Type	Gas	Oil	Total Fuel
Natural draft	1.119	0.256	1.375
Forced draft	0.128	0.081	0.209
Total	1.247	0.337	1.584

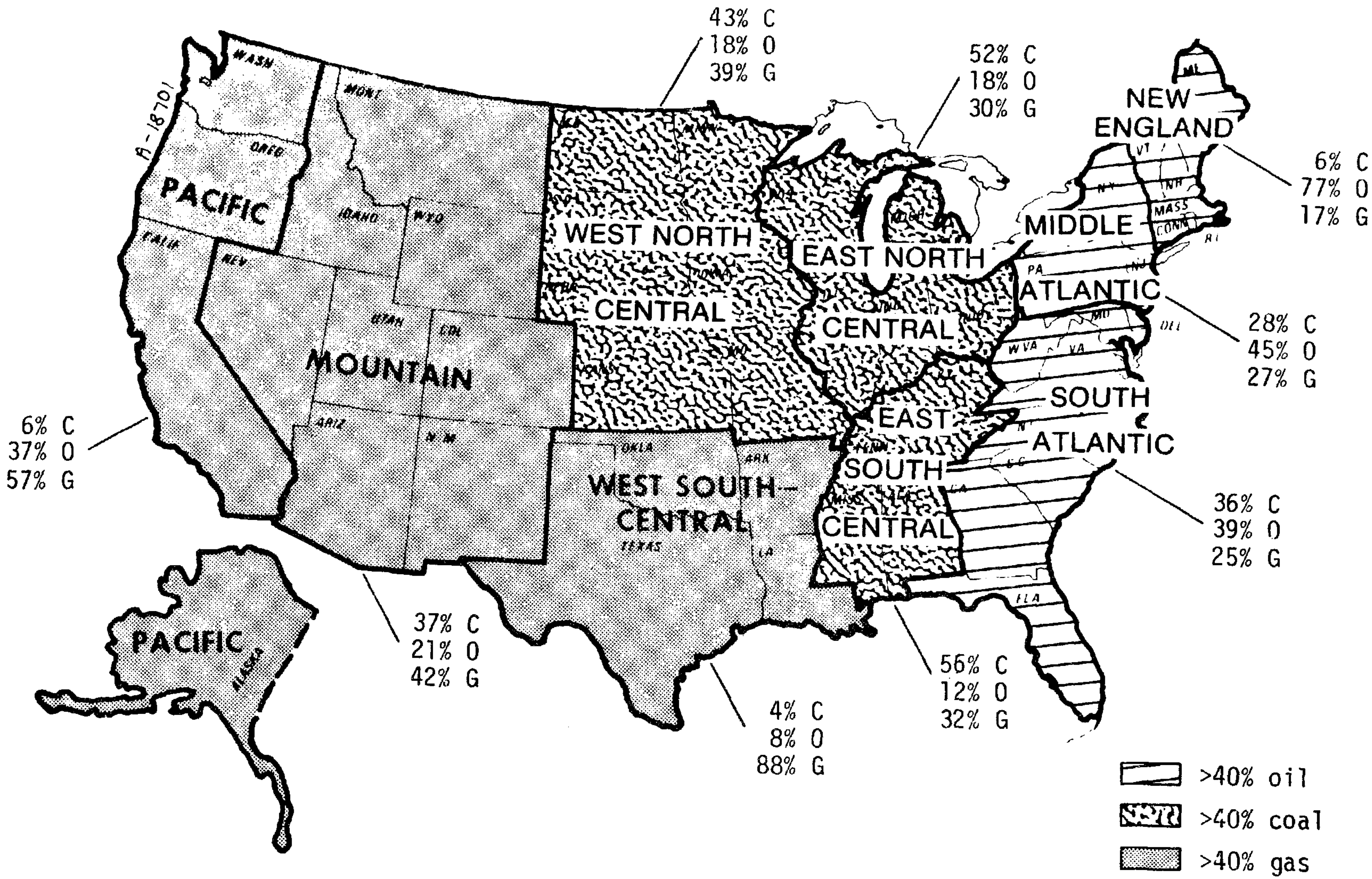
heaters. Complete statistics are kept by industry associations, so there are many reliable sources for these data. The primary sources for these statistics were:

- Walden -- data on the iron and steel industry (Reference 3-27)
- Bureau of Mines -- data on the iron and steel industry, cement industry, brick and ceramic industry (Reference 3-15)
- Institute of Gas Technology (IGT) -- data on cement kilns, glass manufacturers, petroleum refineries, cement industry (Reference 3-28)
- TRC -- data on brick and ceramic kilns (Reference 3-20)
- Lockheed -- data on refinery flares (Reference 3-29)
- KVB -- data on refinery process heaters (Reference 3-30)

3.3 REGIONAL FUEL CONSUMPTION

Regional fuel consumptions were compiled by equipment design type. In this way, regional differences in both fuel consumption and equipment type could be evaluated.

Census Bureau regions were used to partition national fuel consumption geographically. These regions are also used in data compiled by FPC and the Bureau of Mines. Since the majority of our data come from these sources, using the same regional divisions causes minimal data adjustment. Figure 3-1 displays these regional divisions. The codings on this map represent areas having their energy consumption met by over 40 percent of either oil, coal, or natural gas. This figure shows that oil is the major fuel used in the East Coast. The West Coast and Southwest are supplied largely by natural gas, and the Midwest relies primarily on coal for its fossil fuel requirements.



(Except South Atlantic, where oil represents 39% total fuel consumption.)

Figure 3-1. Regional fuel distributions.

In the following discussion, the sources and reliability of the fuel consumption estimates are given. Tabular summaries of regional fuel consumption are presented in Appendix A of Volume II (Tables A-1 to A-44). These totals do not reflect total energy consumed by stationary sources because electrical inputs from nonfossil fuel sources are excluded. The same basic assumptions that were used to simplify the estimates of national fuel consumption by sector are also used here for regional consumption.

3.3.1 Utility and Large Industrial Boilers

Regional fuel consumption estimates for utility boilers are considered very accurate because of the excellent correlation between independent data sources. The following sources were used:

- FPC -- fuel consumption by type of fuel and sulfur content (Reference 3-31)
- Bureau of Mines -- data on domestic fossil fuel production and end use by state (Reference 3-32)
- National Emissions Data System (NEDS) -- fuel consumption by region and end use (Reference 3-33)
- Battelle -- analysis of boiler populations and fuels (Reference 3-14)

The FPC data was used to determine the regional distribution of coal, oil, and gas because they were the best documented. These data were supplemented by data on large industrial boilers from Battelle.

Figure 3-2 shows the regional distribution of fuel use for utility and large industrial boilers. The coding designations indicate areas where a single fuel represents more than 50 percent of the total fuel consumption. As shown, coal is the most common fuel in the Midwest, while

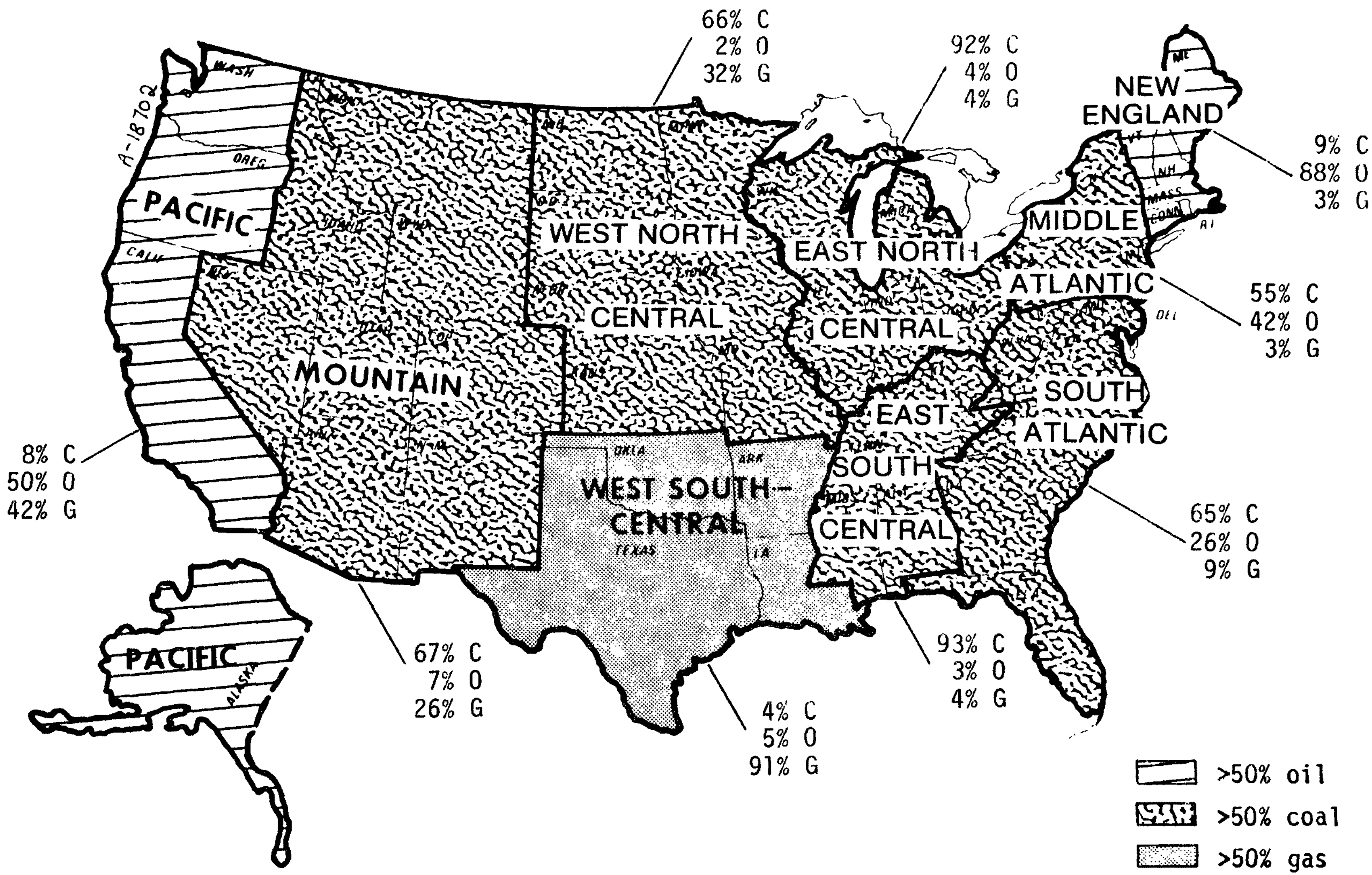


Figure 3-2. Regional fuel distributions for utility and large industrial boilers.

in the far West and New England, oil is the most widely used fuel. The West-South-Central region is heavily dominated by natural gas use. Tables A-1 to A-9 in Appendix A of Volume II present regional summaries of utility boiler fuel consumption.

3.3.2 Packaged Boilers

Regional fuel consumption estimates for packaged boilers were determined from the following sources:

- Battelle -- analysis of equipment design distribution (Reference 3-18)
- Battelle -- analysis of national boiler population by capacity and fuel (Reference 3-14)
- NEDS -- fuel consumption by region and end use (Reference 3-33)
- Catalytic -- regional sales data from the Hydronics Institute (Reference 3-34)
- Bureau of Mines -- data on domestic fuel production and end use by state (Reference 3-32)
- U.S. Department of Commerce -- data on boiler sales, 1968 to 1974 (References 3-19)

Fuel consumption data for the packaged boiler sector are not as accurate as for utility boilers. Tables A-10 to A-18 in Volume II give these regional fuel consumption data. Nonetheless, there was good correlation between all data sources except the Bureau of Mines petroleum data, because they include space heating uses. The same fuel distributions as in the utility and large industrial boiler sector are prevalent in the packaged boiler sector. Oil is a major fuel in New England. Both natural gas and oil are used on the West Coast, with natural gas receiving slightly higher usage.

3.3.3 Warm Air Furnaces and Other Commercial and Residential Combustion

NEDS data (Reference 3-33) were used to develop the residential fuel consumption inventory. These data correlate with the Bureau of Mines household energy consumption values (Reference 3-32). Tables A-19 to A-22 present regional fuel consumption values. Natural gas and oil are the major fuels used in warm air furnaces. Coal use in this sector represents about 1.5 percent of total coal usage and less than 0.1 percent of this sector's total energy consumption, according to Bureau of Mines fuel consumption data. Hence, coal use is not considered in this sector. Natural gas is the preferred fuel, strongly dominating the Middle Atlantic, East-North-Central, East-South-Central, West-South-Central, and Pacific regions.

3.3.4 Gas Turbines

Since major gas turbine applications for utilities are closely regulated, estimates of fuel consumption for gas turbines are accurate. Other gas turbine applications can be traced by manufacturer.

The following sources were used for our estimates:

- Electric World -- Annual statistical report (Reference 3-35) for regional distribution of gas turbines by installed capacity
- NEDS -- fuel consumption by region and use (Reference 3-33)
- Bureau of Mines -- data on domestic fossil fuel production and end use (Reference 3-36)
- Sawyer's GT Catalog -- miscellaneous information on utility and pipeline applications (Reference 3-24)
- GT International -- data on gas turbine utility installations (Reference 3-25)

- Bureau of Mines -- data on gas turbine utility installations by state (Reference 3-32)

Electric World is an excellent source of data, since it separates reciprocating IC engines from gas turbines. The other data sources do not make this distinction. In this sector, distillate oil and natural gas are used primarily. Distillate oil is the primary fuel in the New England and Middle Atlantic regions. The West-North-Central, East-North-Central, Mountain and Pacific regions are primarily supplied by natural gas. Tables A-23 to A-26 present these fuel consumption data.

3.3.5 Reciprocating IC Engines

The recent standard support document (Reference 3-37) was used to categorize the wide range of designs, applications, and manufacturers of reciprocating IC engines. These classifications were partitioned into regions using the following sources:

- Standard support document for Reciprocating IC Engines -- characterization of reciprocating IC engines by capacity, and annual generation by fuel (Reference 3-37)
- NEDS -- fuel consumption by region and end use (Reference 3-33)
- American Gas Association -- regional installed horsepower for gas transport (Reference 3-38)
- Senate Committees - National Energy Transportation -- data on pipeline usage for oil transport (Reference 3-39)
- American Gas Association -- 1974 data on gas production (Reference 3-40)
- FPC -- data on electric energy production by industry (Reference 3-41)

Where comparison was possible, there was good correlation between data sources. Tables A-27 to A-35 give summaries of fuel consumption data. Distillate oil, natural gas, and dual fuels (oil and gas) are the major fuel categories in this sector. Again, New England is dominated by oil usage, while natural gas is the major fuel in the Southwest. The Pacific region uses both oil and natural gas and the Midwest is dominated by dual fuel usage.

3.3.6 Industrial Processes

Regional production totals instead of fuel consumption were used to estimate emissions for industrial processes because emission factors are usually given in terms of production totals for industrial processes. There are a number of reliable sources that provide accurate information. These sources have compiled data mainly from industry statistics.

The following sources were used:

- Monsanto -- data on glass melting (Reference 3-42)
- Walden -- data on iron and steel (Reference 3-27)
- Radian -- data on iron and steel (Reference 3-43)
- Bureau of Mines -- commodity data summarized (Reference 3-15)
- IGT -- data on cement kilns, glass manufacturers, petroleum refineries, and the cement industry (Reference 3-28)
- EPA Development Document -- data on petroleum refineries (Reference 3-44)
- Gordian Associates -- data on petroleum refining, cement, steel, and glass (Reference 3-45)
- Lockheed -- data on refinery flares (Reference 3-29)

Tables A-36 to A-44 provide summaries of regional process heating data.

3.4 ENERGY SCENARIO DEVELOPMENT

Energy projections are needed in this study to estimate the trends and order-of-magnitude potential environmental problems from stationary source combustion. Since energy supply and allocation can vary greatly, several projections for energy growth and equipment/fuel use were selected and carried through the evaluation of potential environmental problems. The scenarios were selected to cover the range of probable developments in energy supply and consumption. Factors considered in selecting the scenarios were:

- Energy Conditions
  - Fuel availability and cost
  - Federal regulations
- Equipment Conditions
  - Evolving design trends
  - Environmental constraints on equipment design (i.e., wet bottom boilers promoting thermal NO_x)
- Environmental Conditions
  - Federal regulations
  - Control technology advances

Section 3.4.1 discusses how alternative energy scenarios were selected and developed from the available literature. Section 3.4.2 describes the sources used for determining future equipment use trends. The environmental control scenario is discussed in Section 4.3. These future patterns are then used to develop emission inventories for years 1985 and 2000 in Section 4, and to rank the pollution potential of sources in Section 5.

3.4.1 Energy Alternatives

Five different energy scenarios were examined. The main factors considered in each alternative were: (1) the effect of government regulations and policies on the rate of growth in demand for energy resources, (2) the equipment additions, by fuel type, required to meet demand and source attrition, and (3) the effect of oil-to-coal, gas-to-coal, and gas-to-oil conversions on fuel consumption. The five energy alternatives are:

- Reference -- low nuclear
- Reference -- high nuclear
- Conservation
- Electrification
- Synthetics

Figure 3-3 shows the mix of fuels and equipment types for each scenario. These alternatives encompass a variety of contingencies in both total energy demand and demand for specific fuels which lead to important differences in the type and quantity of pollutants released.

Development of Energy Scenarios

In selecting energy alternatives, background information was obtained from DOE (References 3-49, 3-50), and to a lesser extent from References 3-34 through 3-65. The DOE projections were used to take advantage of the technical expertise and the wide circulation of their results. Also, as shown in Table 3-10, scenarios developed by other groups do not vary significantly from projections by DOE. Indeed, several of these projections are based heavily on DOE results. A number of earlier fuel supply/demand studies have become largely obsolete due to the OPEC oil embargo in the fall of 1973.

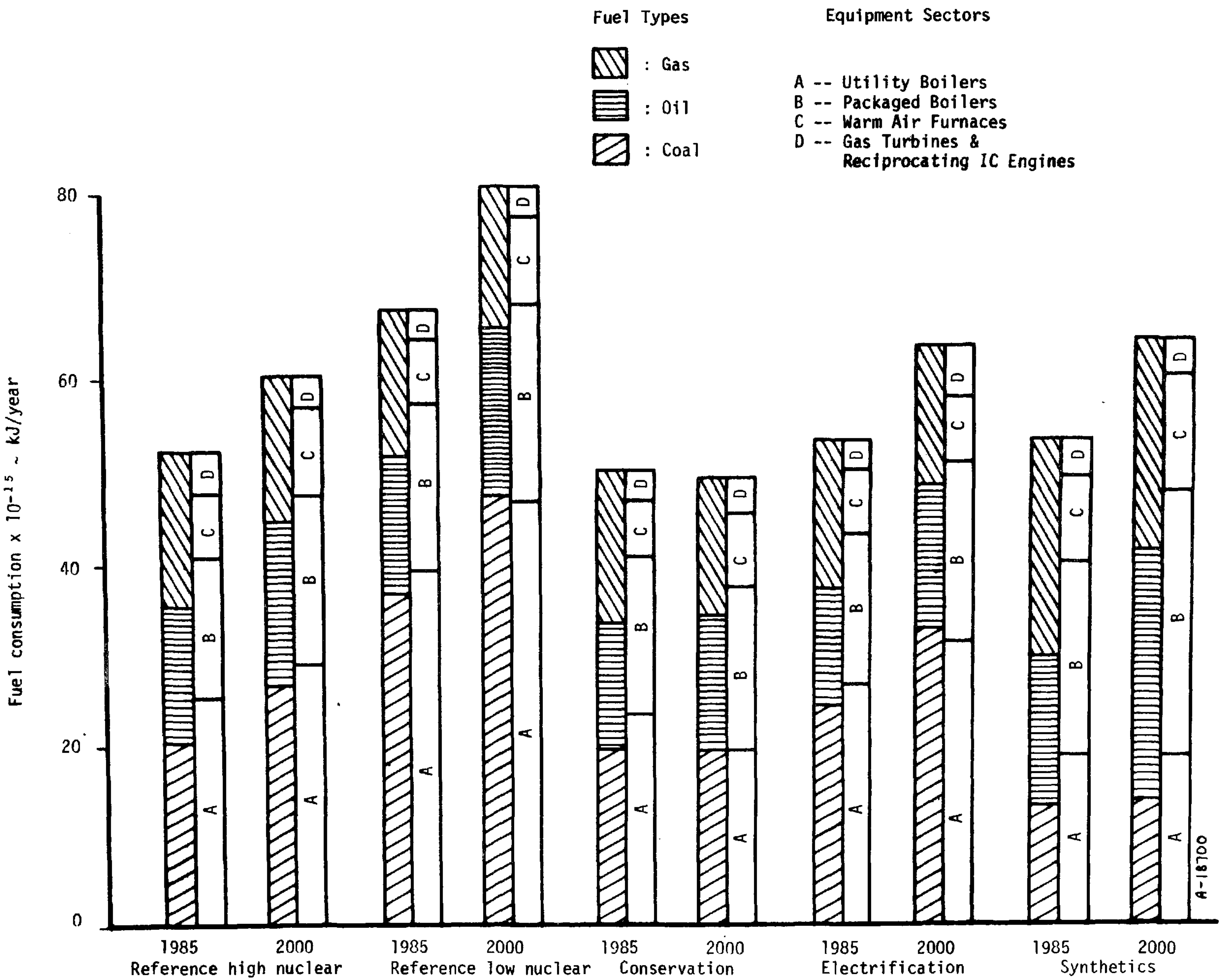


Figure 3-3. Energy scenarios.

TABLE 3-10. FORECASTS OF TOTAL U.S. ENERGY CONSUMPTION IN 1985 AND 2000 (EJ)

Energy Projections	1985	2000
Dupree and West	122.93	202.26
National Petroleum Council	118.58	N/A
Project Independence -- Business as Usual	114.95	N/A
Energy Policy Project -- Historical	122.26	197.10
Organization for Economic Cooperation and Development -- Base	120.49	N/A
DOE -- No New Initiatives[a]	113.09	174.41
EEI -- Medium Growth	109.93	N/A
Mobil Oil	105.72	N/A
Dupree and Corsentino	109.13	172.26
DOE -- 1976 Reference[a]	108.87	N/A

[a]Major references used

Descriptions of Scenarios

Reference Case -- High Nuclear

This case assumes that current consumption patterns continue with no major design or efficiency improvements in the residential, commercial or industrial sectors. This scenario does not assume passage of any energy conservation actions which are currently under consideration by Federal and State legislatures. However, the dependence of energy demand on energy cost is considered.

On the supply side, oil and gas production draws on the remaining recoverable domestic resources, without the benefits of tertiary or any other new recovery methods. Coal and nuclear powerplants continue to expand to meet electricity demand, limited only by the ability to construct or convert plants. Nuclear powerplants are projected to meet 65 percent of the demand for new power generation by the year 2000. Other energy sources such as geothermal, hydroelectric, and urban waste are projected to grow as required to meet energy demand, without pushing the technical development of the technology. In addition, it is assumed that there are no unforeseen energy developments which would make their use a high national priority.

Reference Case -- Low Nuclear

The low nuclear case again assumes that current consumption patterns continue with no specific improvements in the residential, commercial, and industrial sectors. Coal and nuclear powerplants continue to meet new electricity capacity demand. However, this scenario assumes a lower use of nuclear power and a higher use of coal. Nuclear power accounts for 35 percent of new generating capacity through the year 2000, whereas coal accounts for 65 percent. This scenario would occur if there was increased pressure to use our coal resources to meet future energy demand, and if the use of nuclear powerplants continues to be low because of concerns about safety, waste disposal, safeguard costs, or uranium costs.

Conservation

The conservation scenario was developed to examine energy conservation efforts such as improving energy conversion efficiency and increasing the use of energy resources presently available. This means increasing the recovery of gas and oil (secondary, tertiary recovery) and using waste materials from recycling and energy conversion. Thus, energy demand is effectively reduced, but the major sources of energy remain essentially the same. Additionally, it is assumed that new secondary sources requiring some end user initiative will be implemented (municipal refuse, agricultural wastes etc.). The key assumptions are:

- Domestic oil and gas production are increased by implementing new recovery technologies
- Waste materials are used as fuels
- Solar heating and cooling, and geothermal heat are implemented to reduce the need for fossil fuels in process heating and residential or commercial space heating
- Thermal efficiency standards are set for residential and commercial buildings
- Efficiency guidelines are implemented for industrial and commercial applications

Electrification

This scenario maximizes potential end uses of electricity and uses as much electric generating capacity as possible. In addition, existing oil- and gas-fired equipment is converted to coal where possible. Key assumptions considered in this scenario include:

- Coal firing is used in new boilers greater than 29 MW (heat input)
- Nuclear power is maximized in new utility generating capacity
- Oil and gas firing in space heating equipment in new buildings is restricted
- Natural gas firing in new packaged boilers is replaced by coal and, to a lesser extent, by oil
- Half of the natural gas units in the process heating sector are replaced by electricity
- Existing oil- and gas-fired packaged boilers are converted to coal firing where practical

Synthetics

This scenario considers the effects of increased supply of synthetic liquids and gaseous fuels. It evaluates the impact of drawing on vast resources of coal and oil shale to produce liquid and gaseous fuels as direct substitutes for petroleum fuels. Of the five scenarios, this scenario results in the smallest disruption in end use equipment types. The total energy projected is quite close to the reference scenario, although much less oil and natural gas are consumed. This scenario also assumes that growth in electric generating capacity is largely met by light water reactors, so that new coal production can be used for synthetics. Key assumptions considered are:

- Enhanced recovery of oil and gas (using new recovery technologies, i.e., tertiary, secondary recovery)

- New fuels produced from
  - -- Coal
  - -- Oil shale
  - -- Biomass

The primary impacts here are in the packaged boiler and small combustion equipment sectors. This sector depends largely on synthetic gases and liquids derived from coal, because oil- and gas-fired boilers in this size range generally cannot be converted to burn coal economically and efficiently with present technology.

3.4.2 Key Uncertainties in Scenario Development

The scenarios developed in this section are based on highly speculative future conditions. Thus, these scenarios only serve to bracket possible future energy conditions, so that potential environmental impacts associated with these energy conditions can be assessed.

Coal

Although these are potential environmental problems when recovering and using large quantities of coal, the trend toward increased coal use is expected to continue. This trend is being accelerated by Federal legislation such as the Energy Supply and Environmental Coordination Act (ESECA) which was passed in 1974 following the OPEC oil embargo. This legislation was designed to reduce our dependence on foreign oil through expanded use of abundant coal reserves. ESECA was amended in 1975 by the Energy Policy and Conservation Act (EPCA) which gave DOE authority to order utilities and other major fuel burning installations (MFBIs) to include a capability for coal firing in new plants. MFBIs, defined as sources with at least 29 MW heat input from a single combustion unit, essentially are forced to burn coal unless this action poses a "significant risk" to public health or significantly impairs the reliability of service.

The growth in coal consumption, however, is predicated on numerous contingencies in fuel supply and energy/environmental technology. One example is the projected cost and reliability of flue gas desulfurization (FGD) systems. Current SO_x regulations have severely limited the use of most Eastern coal -- about 35 percent of our coal resources. Thus, if FGD systems are successful, it will mean less use of low sulfur Western coals by Eastern utilities.

However, if FDG systems prove unfavorable for any number of reasons, existing rail and barge systems may not be able to handle the large increase in low sulfur Western coal that must be transported to Eastern users. In addition, the technical and economic feasibility of coal conversion is still uncertain. Although a number of coal conversion techniques are nearing the demonstration stage, the potential reduction in conversion efficiency and associated increases in electricity costs are major concerns.

Oil

Changes in import prices and supply are major areas of uncertainty in projecting oil consumption. In addition, the development of Outer Continental Shelf oil and Alaska oil will have regional effects on supply. Also, since domestic supplies of petroleum are limited, means are being sought to reduce consumption of liquid fuels while increasing their synthesis from other sources. However, the technical and economic feasibility of several of these processes has not been demonstrated.

Natural Gas

Domestic production of natural gas is declining rapidly. A proposed pipeline to deliver gas from Alaska in the mid-eighties will increase production temporarily. However, production will probably decline rapidly after this source is exhausted unless recovery and extensive offshore development is pursued. Unfortunately, these developments are not considered to be economical by the industry at today's regulated prices. However, if price controls on interstate natural gas are eliminated, there may be incentive for further development and gas production. In addition to the uncertainty concerning deregulation, technology for development of alternative synthetic gas is questionable. This will affect the supply of gas, since the shortfall in gas supplies in the 1980's will have to be made up by synthetic gas, primarily from coal.

Alternate Energy Sources

There are large uncertainties in the development of alternate energy sources. Oil shale presents major developmental, environmental and financial problems. Production of oil from oil shale is minimal and problems such as restoring land scarred by mining, disposing of enormous amounts of oil shale refuse, and providing for large amounts of water required for refineries are serious developmental problems. Hydroelectric sources generate some of the cheapest electricity in the United States -- however, hydroelectric applications are severely limited by geography. Geothermal sources are also geographically limited and face uncertain technical development. Both thermal and photoelectric solar conversion are not economical at present for central power generation. Their use is highly dependent on the future cost and availability of alternate fuels.

3.5 EQUIPMENT SCENARIOS

This subsection describes the methods used to divide total projected energy use into application sectors and into individual equipment types within each sector. This discussion is followed by summary tables of energy consumption by sector for the reference scenarios in 1985 and 2000.

3.5.1 Stationary Source Type

Projected increases in energy consumption for specific equipment types were obtained primarily from projections by trade organizations and government agencies. When these projections were not available, historical energy consumption or projected new plant capacities were extrapolated to the year 1985 or 2000. Clearly, the projected increases in energy consumption are uncertain -- sudden changes in demand or consumption patterns, or economic factors such as price controls and availability of raw materials, could alter them. However, every attempt was made to cross check the various projections to develop results as accurately as possible. In addition, by looking at several scenarios the most likely changes in energy growth are considered and the range of equipment projection uncertainties are bracketed.

3.5.2 Equipment Attrition Rates

Estimates of equipment attrition are used to determine the rate at which 1974 energy consumption is replaced by new equipment, since new equipment must comply with new source performance controls. Two approaches were used here. The first approach was to relate the number of projected plant closings to 1974 plant capacity levels. When sufficient data were not available to generate these estimates, a second method, based on known equipment lifetimes, was used. With this method, equipment lifetimes were directly converted to attrition rates. For example, if a utility boiler has an estimated 50 year economic life, the attrition rate was assumed to be 2 percent per year. For the most part, attrition rates for each sector were based on limited historical data, so engineering judgement was required to apportion the attrition rates among specific equipment types.

3.5.3 Summary

Energy projections by specific equipment/fuel types were generated for 1985 and 2000 for five energy scenarios. The resulting projections are carried through the emission projections, discussed in Section 4, and the Section 5 evaluation of pollution potential. Summaries of energy consumption in the reference scenarios are given in Tables 3-11 through 3-14. Appendix B of Volume II gives detailed energy usage by specific equipment type for these scenarios.

TABLE 3-11. 1985 STATIONARY SOURCE FUEL CONSUMPTION: REFERENCE CASE -- HIGH NUCLEAR (EJ)

Equipment Sector	Coal	Oil	Gas	Total Fuel
Utility Boilers	19.278	2.775	3.265	25.318
Packaged Boilers[b]	1.967	7.937	6.653[a]	16.557
Warm Air Furnaces and Miscellaneous Combustion	--	2.898	4.748	7.646
Gas Turbines	--	0.968	1.194	2.162
Reciprocating IC Engines	--	0.436[c]	0.457[d]	0.893
Total	21.245	15.014	16.317	52.576

[a]Includes process gas

[b]This sector includes steam and hot water units

[c]Includes gasoline and oil portion of dual fuel

[d]Includes natural gas portion of dual fuel

TABLE 3-12. 2000 STATIONARY SOURCE FUEL CONSUMPTION: REFERENCE CASE -- HIGH NUCLEAR (EJ)

Equipment Sector	Coal	Oil	Gas	Total Fuel
Utility Boilers	24.398	4.339	--	28.737
Packaged Boilers[b]	2.763	8.802	6.949[a]	18.514
Warm Air Furnaces and Miscellaneous Combustion	--	2.800	6.634	9.434
Gas Turbines	--	1.752	1.390	3.142
Reciprocating IC Engines	--	0.472[c]	0.240[d]	0.712
Total	27.161	18.165	15.213	60.539

[a]Includes process gas

[b]This sector includes steam and hot water units

[c]Includes gasoline and oil portion of dual fuel

[d]Includes natural gas portion of dual fuel

TABLE 3-13. 1985 STATIONARY SOURCE FUEL CONSUMPTION: REFERENCE CASE -- LOW NUCLEAR (EJ)

Equipment Sector	Coal	Oil	Gas	Total Fuel
Utility Boilers	33.737	2.775	3.265	39.777
Packaged Boilers[b]	3.442	7.937	6.653[a]	18.032
Warm Air Furnaces and Miscellaneous Combustion	--	2.898	4.748	7.646
Gas Turbines	--	0.968	1.194	2.162
Reciprocating IC Engines	--	0.436[c]	0.457[d]	0.893
Total	37.179	15.014	16.317	68.510

[a]Includes process gas

[b]This sector includes steam and hot water units

[c]Includes gasoline and oil portion of dual fuel

[d]Includes natural gas portion of dual fuel

TABLE 3-14. 2000 STATIONARY SOURCE FUEL CONSUMPTION: REFERENCE CASE -- LOW NUCLEAR (EJ)

Equipment Sector	Coal	Oil	Gas	Total Fuel
Utility Boilers	42.697	4.339	--	47.036
Packaged Boilers[b]	4.835	8.802	6.949[a]	20.586
Warm Air Furnaces and Miscellaneous Combustion	--	2.800	6.634	9.434
Gas Turbines	--	1.752	1.390	3.142
Reciprocating IC Engines	--	0.472[c]	0.240[d]	0.712
Total	47.532	18.165	15.213	80.910

[a]Includes process gas

[b]This sector includes steam and hot water units

[c]Includes gasoline and oil portion of dual fuel

[d]Includes natural gas portion of dual fuel

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SECTION 4

MULTIMEDIA EMISSIONS INVENTORIES

This section presents national and regional multimedia emissions inventories for the stationary NO_x sources and fuels identified in Section 2. The national inventory considers NO_x, SO_x and particulate controls applied to new and existing utility boilers. Projected national inventories (1985 and 2000) have been included and reflect the emissions reductions due to anticipated NSPS regulations for select stationary sources and the reference energy scenarios given in Section 3.4.1. Regional NO_x emissions inventories are presented for 1974 for uncontrolled stationary sources.

Multimedia pollutants inventoried include the primary criteria pollutants (NO_x, SO_x, CO, HC, and particulates), sulfates, POMs, trace metals, and liquid and solid effluent streams. Insufficient data exist to quantify emissions for other stationary source pollutants. The 1974 national emissions inventory for NO_x was extended to include sources of NO_x other than stationary combustion sources (mobile, noncombustion, fugitive) in order to compare the relative contributions of all NO_x sources.

Results presented here are only for criteria pollutants; results for sulfates, POMs, trace metals, and liquid and solid effluent streams are given in Appendix D of Volume II.

The inventories in this section form a basis for assessing stationary source pollution potential in the Section 5 source analysis modeling. Data gaps identified here highlight areas where further testing is needed.

The emissions inventories were generated through the following sequence:

- Compile multimedia emission factor data (Section 4.1)
  - -- Base fuel derived pollutant emission factors on trace composition of fuels
  - -- Base combustion derived pollutant emission factors on unit fuel consumption for specific equipment designs
- Inventory degree of implementation of NO_x, SO_x, and particulate controls (Section 4.2)
- Develop future environmental scenarios (Section 4.3)
- Generate national emissions inventories for 1974 (Section 4.4)
- Project national emissions inventories for 1985, 2000 (Section 4.5)
- Generate regional inventories (Section 4.6)

4.1 EMISSION FACTORS

This section presents uncontrolled emission factors for significant stationary sources of NO_x. Emission factors were compiled for the following fuels: lignite, bituminous, and anthracite coal; distillate and residual oil, and natural gas. Since emissions data from process gas utilization are lacking, emission factors for natural gas were used for this fuel. Whenever possible, emission factors are expressed in terms of fuel inputs, i.e., nanograms NO_2 per Joule heat input. For the industrial process heating sector, emission factors are expressed as a function of product output.

Emissions of criteria pollutants, NO_x, SO_x, HC, CO, and total particulate have been extensively tested. The quality of the emission factors for these pollutants is generally high. Unfortunately, the quality of the measurements for other species -- POMs, sulfates, and trace elements -- varies widely. Tables of emission factors for criteria pollutants have been included in this section, while those for POMs, sulfates and trace metals are given in Appendix D of Volume II.

The emission factors were obtained from AP-42 (Reference 4-1) and its supplements, from a survey of existing literature, and from preliminary results of ongoing test programs. Whenever possible, AP-42 and its supplements have been used as sources, since they usually reflect the most recent test results. Where emission factors are not available for specific design types, emission factors have been estimated from test results on similar equipment. Where a range of emission factors is available, an average value has been assigned. Each of the following subsections includes a discussion of the data sources for the emission factors, along with the rationale for their selection and their relation to AP-42 emission factors.

All emission factors represent uncontrolled operating conditions (without pollution control devices) for the major equipment types outlined in Section 2, except where noted.

4.1.1 Utility and Large Industrial Boilers

Table 4-1 gives uncontrolled emission factors for the criteria pollutants from utility boilers. NO_x emission factors for these boilers were largely obtained from AP-42 supplements (References 4-2, 4-3). These

TABLE 4-1. UTILITY BOILER CRITERIA POLLUTANT EMISSION FACTORS (ng/J)

T-157a

Equipment Type	NO_x	SO_x[a]	Particulates[a,b]	CO	HC
Utility Boilers					
Tangential					
Anthracite	275	585S	261A	15.5	0.43
Bituminous and Sub-bituminous	275	602S	195A	11.2	0.86
Lignite	245	808S	175A	27.1	8.2
Residual Oil	153	482S	30.5S + 8.6 (30.5)	8.6	0.86
Distillate Oil	153	434S	6.0	15.5	6.0
Natural Gas	129	0.3	2.2 - 6.5 (4.3)	7.3	0.86
Single Wall Fired					
Anthracite	322	585S	261A	15.5	0.43
Bituminous and Sub-bituminous	322	602S	186A	21.9	0.86
Lignite	353	808S	175A	27.1	8.2
Residual Oil	322	482S	30.5S + 8.6 (30.5)	13.3	0.86
Distillate Oil	322	434S	6.0	15.5	6.0
Natural Gas	301	0.3	2.2 - 6.5 (4.3)	11.6	0.86
Opposed Wall and Turbo Furnace					
Anthracite	322	585S	261A	15.5	0.43
Bituminous and Sub-bituminous	322	602S	186A	8.6	0.86
Lignite	353	808S	175A	27.1	8.2
Residual Oil	322	482S	30.5S + 8.6 (30.5)	12.5	0.86
Distillate Oil	322	434S	6.0	15.5	6.0
Natural Gas	301	0.3	2.2 - 6.5 (4.3)	10.7	0.86
Cyclone					
Anthracite	559	585S	35.7A	15.5	6.45
Bituminous and Sub-bituminous	559	679S	35.7A	18.1	6.45
Lignite	374	808S	174.5A	27.1	8.17
Residual Oil	219	492S	30.5S + 8.6 (30.5)	15.5	6.02
Distillate Oil	219	6.0	6.0	15.5	6.02
Natural Gas	241	0.3	2.25 - 6.4 (4.3)	7.3	6.02
Vertical and Stoker					
Anthracite	269	585S	30.5A	92.0	3.01
Bituminous and Sub-bituminous	269	679S	233A	35.7	5.59
Lignite	269	808S	188A	53.7	8.17

[a]S represents the percent sulfur in the fuel, A represents the percent ash in the fuel.

[b]Numbers in parentheses are average values.

values agree with measurements from utility boiler field testing (References 4-4 through 4-11). However, values for cyclone furnaces and lignite-fired boilers were obtained from more recent studies (References 4-12, 4-13).

Emission factors for SO_x, particulate, HC, and CO were gathered from the available literature for tangential, single wall, and opposed wall bituminous coal-fired furnaces (References 4-4 through 4-11). Since there are very few available data for vertical fired boilers, AP-42 emission factors (Reference 4-1) were used. Emission factors for HC and CO from tangential, single wall, and opposed wall residual oil-fired boilers were obtained from References 4-4 through 4-11. These numbers are considerably lower than AP-42 values. Particulate and SO_x emission factors from AP-42 used here are in excellent agreement with recent field test results (References 4-2, 4-3). AP-42 and its supplements were also used as a source of emission factors for distillate oil.

POM values for utility boilers were obtained from References 4-11 and 4-14. Additional data were sought both in the literature and by contacting principal EPA investigators (References 4-15 through 4-19). No additional POM data from stationary combustion sources considered in this report have been published. However, a number of field test programs are underway or have recently been concluded. These programs include measurements of POM emissions from coal- and oil-fired steam generators, but the data have not yet been released pending sample analysis and review by EPA project officers. Since values from available data for coal-fired powerplants vary by two or three orders of magnitude -- depending upon the equipment type -- the highest value was conservatively suggested for use in the inventories.

Sulfate emission factors for coal-fired utility boilers were determined from field testing (Reference 4-20).

Emission factors for trace metals for this sector come from References 4-21 through 4-28. There is fair agreement on the partitioning and enrichment properties of specific trace elements presented in these studies; however, the agreement is not sufficient to warrant the use of any more than average trace metal concentrations in the fuel. Thus, these emission factors are estimates rather than exact values, and must be applied carefully.

Solid and liquid emission values for utility boilers come from References 4-22, 4-29, and 4-30. These values are only of fair quality since control applications and efficiencies vary widely for different utility boilers.

4.1.2 Packaged Boilers

Packaged boilers have been grouped into two categories according to capacity: boilers with thermal input capacities between 29 MW and 73 MW (100 to 250 MBtu/hr), and those with less than 29 MW thermal input capacity. Table 4-2 presents uncontrolled emission factors for the criteria pollutants for these two classes of boilers. The emission factors come from field testing of industrial boilers (References 4-31 and 4-32) as well as AP-42 and its supplements (References 4-1 through 4-3).

The firing and emission characteristics of the large industrial boilers (>73 MW heat input) are similar to those of utility boilers. CO and HC emission factors used here for bituminous coal, oil, and gas were obtained from field tests (References 4-31 and 4-33) and are considerably lower than those supplied by AP-42. Emission factors for NO_x, particulates, and SO_x for large packaged boilers came from both field

TABLE 4-2. PACKAGED BOILER CRITERIA POLLUTANT EMISSION FACTORS (ng/J)

T-150a

Equipment Type	NO_x	SO_x[a]	Particulates[a]	CO	HC
Wall Fired Watertubes					
29 MW to 73 MW (input)					
Anthracite	322	585S	261A	0.6	0.43
Bituminous and Lignite	322	559S	186A	0.04	2.2
Residual Oil	322	408S	30.5S + 8.6	3.9	3.0
Distillate Oil	322	434S	7.74	—	3.0
Natural Gas	301	0.3	1.72	9.0	3.9
Process Gas	301	—	—	—	—
Stoker Watertubes					
29 MW to 73 MW (input)					
Anthracite	269	584.7S	30.5A	92	3.0
Bituminous and Lignite	269	756.6S	233A	25	4.3
Single Burner Watertubes					
<29 MW (input)					
Residual Oil	184	482S	30.5S + 8.6	3.4	0.86
Distillate Oil	67.5	434S	8.2	1.6	0.43
Natural Gas	98.9	3.4	3.4	8.6	1.7
Process Gas	98.9	—	—	—	—
Scotch Firetubes					
Residual Oil	184	482S	30.5S + 8.6	3.4	0.86
Distillate Oil	67.5	434S	7.3	1.6	0.43
Natural Gas	98.9	0.3	2.6	8.6	1.7
Process Gas	98.9	—	—	—	—
Firebox Firetubes					
Residual Oil	184	482S	30.5S + 8.6	3.4	0.86
Distillate Oil	67.5	434S	7.3	1.6	0.43
Natural Gas	98.9	0.3	2.6	8.6	1.7
Process Gas	98.9	—	—	—	—
HRT Firetubes					
Residual Oil	184	482S	83	3.4	0.9
Distillate Oil	67.5	436S	3.9	1.7	0.4
Natural Gas	98.9	0.3	2.6	8.6	1.7
Cast Iron Boilers					
Residual Oil	184	482S	30.5S + 8.6	3.4	0.86
Distillate Oil	67.5	434S	3.7	1.6	0.43
Natural Gas	51.6	0.3	2.6	8.6	1.7
Stoker Watertubes					
<29 MW (input)					
Anthracite	179	585S	31A	92	3.0
Bituminous and Lignite	179	672S	232A	21	18

[a]S represents sulfur of fuel, A represents percent ash of the fuel.

TABLE 4-2. Concluded

T-150a

Equipment Type	NO_x	SO_x [a]	Particulates[a]	CO	HC
Stoker Firetubes					
Anthracite	179	585S	31A	92	3.0
Bituminous and Lignite	179	672S	232A	21	18
Residential Steam Units					
Anthracite	179.3	585S	307	138	307
Bituminous and Lignite	179.3	679S	358.2	1612.5	358.2
Residual Oil	162	481.5	83	15.48	3.01
Distillate Oil	55	434S	7.7	30.5	4.73
Natural Gas	34.4	0.26	4.3	8.6	3.4

[a] S represents sulfur of fuel, A represents percent ash of the fuel.

testing (References 4-31 and 4-33) and AP-42 and its supplements (References 4-1 through 4-3). There is excellent correspondence between these two data sources. Since there has been very little field testing of boilers firing anthracite coal, AP-42 emission factors for this fuel could not be cross-checked with other sources.

Emission factors for packaged boilers with less than 29 MW heat input capacity came largely from field testing of industrial and commercial boilers, and space heating units at baseline operating conditions (References 4-31 through 4-34). The data were averaged where baseline data were available for more than one unit of a specific design type. When test data were not available for a specific equipment/fuel combination, AP-42 values or test data from similar equipment were used.

In general, these is excellent correspondence between AP-42 supplements (References 4-2, 4-3) and field testing (References 4-31 through 4-34) for NO_x, SO_x, and particulate emissions from packaged boilers. The only area of significant disagreement is the emission factors for small packaged oil-fired boilers, where values from field testing (References 4-31 through 4-34) are considerably lower than values from the AP-42 supplement (Reference 4-3). In general, small watertube, scotch firetube, firebox firetube, HRT firetube, and cast iron boilers fired by single burners have similar combustion characteristics and thus, similar emission factors.

POM emission factors for packaged boilers came from recent field testing (References 4-35 through 4-37) and AP-33 (Reference 4-14). Again, there are differences of several orders of magnitude between AP-33 values and the results of recent field tests. Because the data available are sparse and vary widely, the highest values have been given. In addition, it was assumed that scotch firetubes, HRT firetubes and firebox firetubes have the same POM emission characteristics, and that shell boilers and cast iron boilers also have similar POM emission characteristics. The data show a trend toward larger POM emissions from smaller units. This is reasonable since smaller boilers usually are less carefully regulated than large ones, and have less efficient firing and operation.

Field testing data for sulfate emissions and trace elements from packaged boilers also are sparse. Some field tests have been performed (Reference 4-32), but few data are quantified. It has been assumed that trace element emission factors are similar for large packaged and utility boilers since they usually have similar operating characteristics. However, this assumption does not hold for small packaged boilers. In addition, care must be exercised in using trace element factors, since they may vary by two or more orders of magnitude depending on the fuel.

Liquid and solid emission factors were obtained from References 4-22 and 4-38. Almost all of the solid and liquid effluents are generated by coal-burning boilers. Since the implementation and efficiency of control varies widely within this sector, these emission factors are only of fair quality.

4.1.3 Warm Air Furnaces

Table 4-3 displays uncontrolled emission factors for the criteria pollutants from warm air furnaces. NO_x emission factors come from field tests (Reference 4-34) and from an AP-42 supplement (Reference 4-3). Emission factors for the remaining criteria pollutants come from field testing (References 4-34, 4-39 and 4-40), studies (References 4-41, and 4-42), and AP-42 supplements (References 4-2, and 4-3). In general, the agreement between these sources of data is excellent. Since values from AP-42 supplements accurately represent the emission characteristics of warm air furnaces, most of the emission factors for warm air furnaces come from these supplements.

Little testing has been done on POMs emitted from warm air furnaces, particularly during the on-off cycle transient which is expected to promote POM formation. The little data available are mainly from AP-33 (Reference 4-14). Because supporting data are lacking and most POM tests have been inconsistent, the values in Appendix D are only an order-of-magnitude estimate of POM emissions.

Sulfate emission factors from warm air furnaces are not yet available.

Trace element emission factors for warm air furnaces cannot be determined from the existing data. The only significant source should be the small number of coal-fired units that are insignificant on a national scale, but could present localized pollution problems.

The only solid or liquid effluent generated by this equipment sector is the bottom ash from coal combustion. An emission factor was obtained from Reference 4-22. Again, this effluent stream is insignificant nationally, but could cause some regional problems.

4.1.4 Gas Turbines

Emission factors for gas turbines come from field studies (References 4-43, 4-44, and 4-45) and an AP-42 supplement (Reference 4-46).

TABLE 4-3. WARM AIR FURNACE AND MISCELLANEOUS COMMERCIAL AND RESIDENTIAL COMBUSTION CRITERIA POLLUTANT EMISSION FACTORS (ng/J)

Equipment Type	NO_x	SO_x [a]	Particulates [c]	CO	HC
Warm Air Central Furnace					
Oil	61.0	434S	7.7	31	4.7
Natural Gas	34.4	0.358	2.2 - 6.5 (4.3)	12	3.4
Warm Air Room Heaters					
Oil	61.0	434S	7.7	31	4.7
Natural Gas	34.4	0.258	2.2 - 6.5 (4.3)	12	3.4
Miscellaneous Combustion [b]					
Natural Gas	34.4	0.258	2.2 - 6.5 (4.3)	12	3.4

[a] S represents percent sulfur in the fuel.

[b] All miscellaneous combustion fuels (wood, LPG, etc.) combined with natural gas.

[c] Numbers in parentheses denote average values.

TABLE 4-4. GAS TURBINE CRITERIA POLLUTANT EMISSION FACTORS (ng/J)

Equipment Types	NO_x	SO_x	Part.	CO	HC
Gas Turbines >15 MW (output)					
Natural Gas	195	2.2	6.0	49.0	8.6
Diesel oil	365	10.7	16.0	47.0	8.6
Gas Turbines 4 MW to 15 MW (output)					
Natural Gas	194	2.2	6.0	49.4	8.2
Diesel oil	365	10.7	15.5	47.3	9.9
Gas Turbines <4 MW (output)					
Natural Gas	194	2.2	6.0	49.4	8.2
Diesel oil	365	10.7	15.5	47.3	9.9

Table 4-4 gives uncontrolled emission factors for the criteria pollutants, taken primarily from the recent Gas Turbine Standard Support Document (Reference 4-43). Values from the AP-42 supplement for non-NO_x criteria pollutants are in excellent agreement with values from field studies (References 4-44 and 4-45).

Emission factors for POMs and sulfates from gas turbines cannot be determined at present since extensive field testing has not been conducted. There are no liquid or solid effluents resulting from combustion related gas turbine operation.

4.1.5 Reciprocating IC Engines

The range of equipment design combinations for reciprocating IC engines is so varied that it is impractical to identify emission factors for each equipment/fuel combination. Consequently, reciprocating IC engines have been categorized as either spark ignition or compression ignition engines in three capacity ranges. Table 4-5 presents uncontrolled emission factors for the criteria pollutants for these equipment types.

NO_x emission factors have been derived from values presented in a current IC engine study (Reference 4-47). Non-NO_x criteria pollutant emission factors come from recent AP-42 supplements (References 4-2 and 4-46) and correspond closely with the results of field tests (Reference 4-48).

Data are insufficient to quantify emission factors for POMs, sulfates, and trace elements from reciprocating IC engines. Trace element concentrations will vary by orders of magnitude -- depending on the fuel and the operating characteristics of the reciprocating engine measured. Because of these variations, it is impossible to determine specific emission factors to span this range of operating conditions. There are no

TABLE 4-5. RECIPROCATING IC ENGINES CRITERIA POLLUTANT EMISSION FACTORS (ng/J)

Equipment Types	NO_x	SO_x	Part.	CO	HC
Compression Ignition >75 kW/cyl (output)					
Distillate Oil	1,741	95.9	103	313	115
Dual Fuel[a]	1,023	---	---	---	---
Spark Ignition >75 kW/cyl (output					
Natural Gas	1,552	0.22	---	177	555
CI 75 kW to 75 kW/cyl (output) >1,000 rpm					
Distillate Oil	1,741	95.9	103	313	115
SI 75 kW to 75 kW/cyl (output) >1,000 rpm					
Natural Gas	1,552	0.22	---	177	555
Gasoline	1,195	16.3	19.8	12,081	405
CI <75 kW (output) 2-4 cyl					
Distillate Oil	1,677	95.9	95.9	313	115
SI <75 kW (output) 2-4 cyl					
Gasoline	774	16.8	19.8	12,081	405

[a]oil and gas

liquid or solid effluents resulting from combustion related IC engine operation.

4.1.6 Industrial Process Combustion

Direct process heat from fuel combustion has a wide range of industrial applications and is produced by many different types of equipment. In addition, process heat is generated in many industries by a large number of small-scale processes which as a whole may have significant impact but are hard to quantify individually. Nevertheless, there are several major industrial pollution sources, and these industries are discussed here. Uncontrolled emission factors for the criteria pollutants, based on product output, are presented in Table 4-6. Refinery process heating emission factors are presented in Table 4-7.

Cement and glass industries which use kilns, furnaces, and ovens to heat raw materials, are significant sources of NO_x. Emission factors for NO_x from these processes primarily come from a recent study of these industries (Reference 4-49). Non-NO_x criteria pollutant emission factors have been determined partially from AP-42 values (Reference 4-1). Very few data are presently available for sulfate, POM, and trace element emissions from cement kilns. Sulfate emission factors come from Reference 4-50, although the values presented are questionable. Solid emission factors for the cement industry come from Reference 4-51. These values also are questionable since total particulate loadings from the particulate control device may include emissions from grinding, dryers and other processes, as well as particulates from combustion. Solid and liquid effluents from the glass industry are insignificant, since natural

TABLE 4-6. INDUSTRIAL PROCESS COMBUSTION CRITERIA POLLUTANT EMISSION FACTORS (g/kg PRODUCT)

Process Types	NO_x	SO_x	Part.	CO	HC
Cement Kilns	1.30	5.09	122	NA	NA
Glass Melting Furnaces	3.68	2.12	1.0	NA	NA
Glass Annealing Lehrs	0.69	NA	NA	NA	NA
Coke Oven Underfire	0.07	2.84	37.7	NA	NA
Steel Sintering Lines	0.52	0.71	10.0	22.0	NA
Open Hearth Furnaces	0.62 oil 0.37 gas	0.70	6.0	NA	NA
Brick & Cement Kilns	0.25	0.54	65.0	0.1	0.04
Catalytic Cracking	0.20[a]	1.41[a]	0.69[a]	39.1[a]	0.63
Refinery Flares Iron & Steel Flares	b	NIL	NIL	NIL	0.43[c]

[a] g/ℓ Feed

[b] Production is not quantifiable. Estimate of NO_x is made in Section 3.2.6.

[c] g HC/ℓ requiring capacity

TABLE 4-7. REFINERY PROCESS HEATING CRITERIA POLLUTANT EMISSION FACTORS (ng/J)

Heater Type	Fuel	NO_x	SO_x	Part.	CO	HC
Natural Draft	Gas	70.1	860S[c]	8.6	NIL[a]	12.9
	Oil[a]	154.8	627S[b]	78.4	NIL	13.1
Forced Draft	Gas	110.5	860S[c]	8.6	NIL	12.9
	Oil[d]	184.5	627S[b]	78.4	NIL	13.1

[a]Assumed fuel oil nitrogen content of 0.2 percent and a fuel nitrogen conversion to NO of 50 percent

[b]Fuel oil sulfur content (weight percent)

[c]Refinery gas sulfur content

[d]Negligible emissions

gas and low sulfur oil are the major fuels. Coal is not used because it has a high level of impurities.

The iron and steel industry produces large quantities of NO_x emissions from its ovens and furnaces. Most of the emissions come from coke oven underfiring, steel sintering machines, and open hearth furnaces. Emission factors for NO_x for the iron and steel industry have been determined from Reference 4-52. Other criteria pollutant factors come from References 4-52 and 4-53. Solid effluents are negligible from coke ovens, since coke ovens are predominantly gas fired and particulate collectors are seldom installed. An emission factor for liquid effluents comes from a screening document for the iron and steel industry (Reference 4-54). A solids emission factor for steel sintering was obtained from Reference 4-52. The emission factors for open hearth furnaces were obtained from Reference 4-54.

The petroleum industry also produces NO_x emissions from refinery flares, fluid catalytic crackers and process heaters. NO_x emission factors for refinery flares and catalytic crackers were obtained from a recent study of process heating (Reference 4-49). NO_x emission factors for refinery process heaters were obtained from a recent study of combustion technology for controlling NO_x from petroleum process heaters (Reference 4-55). The values reported here are for both natural draft and forced draft refinery heaters firing gas and oil. Emission factors for non-NO_x criteria pollutants come from AP-42 (Reference 4-1) and from emission studies (References 4-53 and 4-56). Noncriteria emission factors are not available. Liquid and solid effluents are insignificant.

4.2 INVENTORY OF CONTROL IMPLEMENTATION

Emissions from stationary combustion sources are highly dependent on the fuel type and the control equipment used. Emissions of particulates from large point sources are extensively controlled. Since NO_x emissions are less extensively regulated, however, there are few NO_x controls applied to existing equipment. The effects of SO_x controls on total emissions are also insignificant. This subsection describes the degree of control which now exists for particulates, SO_x and NO_x. The section 3 estimates of stationary source fuel consumption are coupled with the emission factors presented in Section 4.1 and the control factors developed here to determine total emission loadings. These emissions inventories are presented in Section 4.4 for controlled particulate and SO_x emissions and uncontrolled and controlled NO_x emissions for 1974.

The incentive for control development is caused by two separate regulatory mechanisms, the Federal Standards of Performance for New Stationary Sources (NSPS) and State Implementation Plans (SIPs). These regulations are intended to assist in air quality maintenance and attainment of future air quality goals.

The Clean Air Act of 1970 requires that EPA establish standards of performance for all major new stationary sources. These standards must set levels of control that reflect the degree of emission reduction for stationary sources that can be achieved using Best Available Control Technology (BACT) -- taking cost into consideration.

The major objectives of New Source Performance Standards are to mitigate air pollution problems systematically and cost-effectively by concentrating on new rather than existing sources. The basis for this approach is to maximize the opportunities for economic growth within the constraints of environmental goals by requiring new sources to operate as cleanly as possible. It also recognizes that retrofit controls are more costly than incorporating controls during the design phase. Moreover, in some cases, retrofit controls cannot reflect the best technology because of incompatibilities with existing structures and operational requirements.

The other regulations are State Implementation Plans (SIPs). The primary responsibility for implementing SIPs lies with the states. If NSPS are not sufficient to attain or to maintain National Ambient Air Quality Standards (NAAQS) in control regions, then additional emission standards are set by the states through SIPs.

The control factors developed here reflect the use of these mechanisms. Although at present the impact of NSPS on nationwide emission loadings is small, in future years NSPS regulations should significantly reduce total levels of mass emissions.

4.2.1 Particulate Control

Centrifugal collectors and electrostatic precipitators are the most widely used particulate controls for stationary combustion sources. Since coal- and oil-fired boilers contribute approximately 98 percent of utility boiler particulate emissions, the controls on these boilers are of paramount importance. Gas-fired boiler particulate emissions are negligible by comparison and will not be considered further in this section. Representative values for the percent of particulate controls in the utility and industrial sector and the impacts of these controls on total particulate emissions are presented below.

4.2.1.1 Utility and Large Industrial Boilers

Several recent particulate studies (References 4-22, and 4-42) have provided information on the particulate controls installed on utility boilers. Table 4-8 shows the percent of particulates collected from utility boilers. Twelve percent of pulverized coal-fired boilers have no collection devices, and approximately 35 percent of oil-fired boilers are not controlled.

Assuming representative efficiencies for control equipment types, it has been estimated that 75 percent of the particulates generated in residual oil-fired boilers are not collected. More importantly, 35 percent of the flyash formed in pulverized coal-fired boilers, 25 percent of the flyash in cyclone boilers and 50 percent of the flyash in stokers are also not collected.

4.2.1.2 Industrial Boilers

A recent source assessment document for industrial boilers (Reference 4-56) was used to determine the distribution of controls for pulverized coal-fired boilers, stokers, and residual and distillate oil-fired boilers. Approximately 75 percent of small industrial stokers (<29 MW input, 100 MBtu/hr) and 30 percent of the larger boilers are not controlled. It is assumed that controls for small pulverized coal industrial boilers (<29 MW input) are not significant. As shown in Table 4-8, about 50 percent of particulate emissions from large coal-fired industrial boilers are collected. However, for smaller units, 95 percent of the particulates from residual oil-fired boilers and 85 percent of the particulates from small coal stokers are released to the atmosphere.

4.2.1.3 Industrial Processes

In the industrial sector, the cement industry uses cyclones and electrostatic precipitators as particulate controls. Table 4-8 shows that approximately 82 percent of particulate emissions are removed from the effluent stream by control devices (Reference 4-57).

4.2.2 SO_x Control

Flue gas desulfurization and low sulfur fuels were examined for their applicability and effectiveness as NO_x controls. Coal cleaning currently has insignificant use nationwide. Two recent surveys of flue gas desulfurization (References 4-58 and 4-59) indicated that the total installed capacity of FGD equipment on utility sized boilers is about 5000 MWe. Compared to the total installed electricity capacity of about 350,000 MWe (Reference 4-60), the effect of FDG is very small.

The primary means of meeting local SO_x control regulations is by using low sulfur fuel either by itself or in blends with high sulfur fuel. Since the sulfur concentration in these fuels is strictly monitored at the utility level, the use of utility fuel consumption and sulfur concentration data will result in a controlled inventory. Since the utility sector uses most of the sulfur containing coal and oil and is the most heavily regulated, the controlled utility inventory combined with uncontrolled emissions in the remaining sectors serves as the 1974 controlled SO_x inventory. In the future however, the Clean Air Act Amendments of 1977, which require SO_x emissions to be reduced as a function of sulfur in the fuel rather than as total emission loadings, will eliminate the use of low sulfur coals as a control method.

4.2.3 NO_x Control

NO_x controls were obtained by applying state and local NO_x regulations (Appendix E) to combustion equipment within each region. For the reference year 1974, the 1971 NSPS regulations had no effect on emissions due to the 3 to 5 year time lag between equipment orders and startup. As Table E-1 in Volume II shows, utility boilers are the most extensively regulated sector, whereas gas turbines and large packaged boilers are regulated only in certain regions. However, examination of data shows that only utility boilers are controlled with greater than 1 percent effect on nationwide emission loading. Thus, only utility boilers are discussed in this section.

In calculating the effect of NO_x controls for utility boilers, the uncontrolled emissions of a specific boiler were reduced by the ratio of the controlled to the uncontrolled emission factor. For example, if the emission limitation for oil fueled boilers is 129 ng/J and the uncontrolled emission factor is 153 ng/J, then the reduction of NO_x emissions (assuming 100 percent compliance) is 16 percent. A more detailed explanation of the methodology is given in Appendix D of Volume II.

The degree of current control for coal-fired utility boilers is small. However, this control is increasing as retrofit controls are used and new units designed to meet the NSPS are installed. Comparisons of the controlled and uncontrolled NO_x emission rates are presented in Section 4.4.

4.2.4 Regional Controls

State and local standards for new and existing sources are given in Appendix E. In certain areas, standards for new sources are the same as the Federal NSPS, and were omitted. In areas such as Los Angeles, regional controls may be much more stringent than NSPS regulations, in order to reduce localized pollution problems or to comply with SIPs.

The regional emissions regulations survey can be somewhat misleading. In some areas, units may not be in compliance with emission standards because of local variances or lack of enforcement. In addition, some units may actually be controlled to levels below the current regulation or have added controls for energy conservation or community relations. For these reasons, obtaining an accurate estimate of regional controls is extremely difficult and of questionable accuracy.

Section 4.4 shows that the decrease in national emissions due to NO_x controls is approximately 1.6 percent. Because of this minor effect and the uncertainty in estimating regional controls, further assessment of regional controls is unwarranted.

4.3 PROJECTED EMISSIONS REGULATIONS

This subsection describes the methodology for projecting emissions into the future, and includes consideration of projected New Source Performance Standards. These emissions projections are used in Section 4.5 to project national emissions inventories and in Section 5 to assess the potential environmental impacts of stationary combustion sources.

By law, NSPS are reviewed and revised for additional stringency as advanced control technology is developed and demonstrated. Candidate NSPS technologies include not only stack controls, but also process changes and the impacts of variations in fuels, combustion methods, and raw materials. Thus, the projected promulgation of NSPS must reflect a gradual process that provides for the lead times needed to develop control methods, test procedures, and technical enforcement capabilities.

Table 4-9 displays the most stringent NO_x controls that probably can be achieved if NO_x control development efforts are expanded and accelerated (References 4-53 and 4-61 through 4-72). In some cases, the control technology has already been demonstrated.

The NSPS projections were combined with the following factors to arrive at emissions projections:

- (Growth or decline) in energy consumption
- Replacement of obsolete sources
- Fuel switching

The NSPS projections were imposed on all capacity additions within a sector, including new source growth, units replacing obsolete sources, and fuel switching to coal. Each of these influences on emissions projections are incorporated in the emission projection equation developed here.

TABLE 4-9. ESTIMATED FUTURE NSPS CONTROLS

Equipment Types	Fuel	Date Implemented	Standard (ng/J)
Utility and Large Industrial Boilers (>73 MW)[a]	Coal	1971 1978 1981 1985 1988	300 258 215 172 129
	Oil	1971	129
	Gas	1971	86
Large Packaged Boilers (>7.3) MW)[a]	Coal	1979 1985 1990	258 215 172
	Oil	1979	129
	Gas	1979	86
Small Packaged Boilers (< 7.3 MW)[a]	Coal	1981	50% reduction
	Oil	1979	129
	Gas	1979	86
Small Commercial and Residential Units	Oil	1983	30
	Gas	1983	17
Gas Turbines		1978 1983	129 86

[a]Thermal input

TABLE 4-9. Concluded

Equipment Types	Fuel	Date Implemented	Standard (ng/J)
IC Engines	Dist. Oil	1979 1985	1390 1040
	Natural Gas	1979 1985	1240 930
	Gasoline	1979 1985	950 710
Process Combustion		1981 1990	20% reduction 40% reduction

[a]Thermal input

Figure 4-1 shows the effects of these parameters on total energy consumption for coal-fired utility boilers in one of the reference scenarios. As shown in this figure, the energy consumed by sources that have switched to coal firing helps offset some of the lost capacity due to due to source obsolescence and reduce requirements for additional energy growth within a sector.

This methodology does not specifically consider the growth of nuclear sources since nuclear growth has already been separated from stationary fossil fuel consumption projections in Section 3. However, it is implicitly considered in that it greatly influences the level of fossil fuel combustion needed to meet national energy demands.

To estimate the total emissions resulting from the gradual implementation of NSPS NO_x controls on new sources (Table 4-9) and continued operation of old sources that are not required to comply with NSPS, the following equation was used:

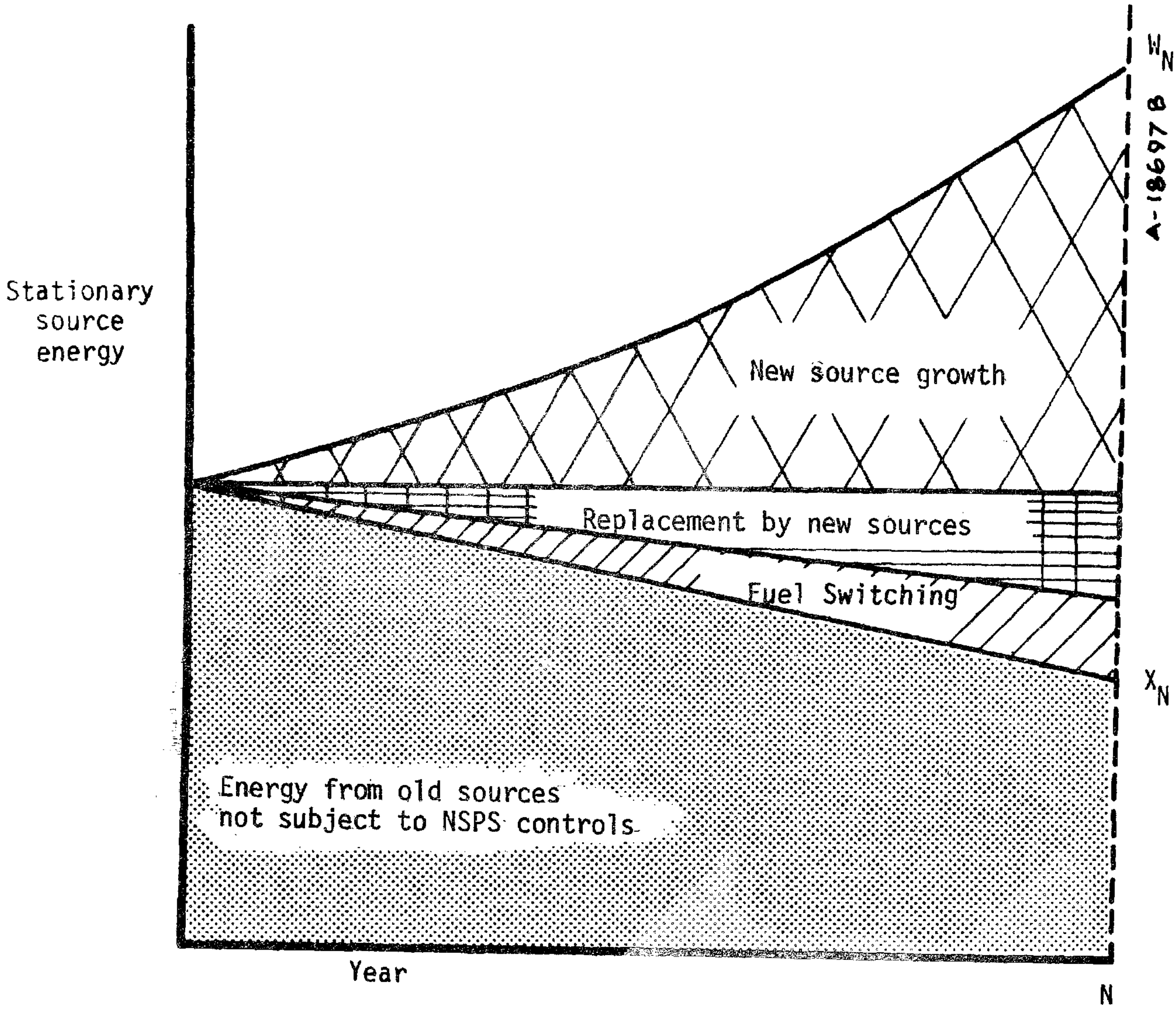


Figure 4-1. Energy representation in the environmental scenario. (Assuming only one NSPS, constant between time limits).

$$EM_N = \sum_{i=1}^{a} \left[\left[(W_{i+1} - W_i) - (X_{i+1} - X_i) \right] NSPS_i + \left[(X_N)(EF)(CF_N) \right] \right]$$

$$+ \left[(W_N - W_{a-1}) - (X_N - X_{a-1}) \right] NSPS_a \qquad (4\text{-}1)$$

where EM_N = total emissions in year N reflecting NSPS control of appropriate sources

a = denotes last NSPS increment for summation to year N

N = end year of summation

i = denotes number of NSPS control level changes for source type

W = total energy consumption

X = total energy consumption due to old sources

NSPS = allowable emission factor under new source performance standard

EF = uncontrolled emission factor

CF_N = control factor reflecting current stationary source controls (the methodology for deriving this is given in Appendix D)

The summation equation indicates the potential for NO_x emission reduction through implementation of stringent NO_x controls. It accounts for increasingly stringent NSPS controls by summing the individual influences of each control between the specified time limits. Thus, if a source type has three increasingly stringent NSPS to the year 2000, then this summation equation will be comprised of three separate sets of terms, representing the individual NSPS that are summed to yield total emissions to 2000.

Equation 4-1 has two major components. The first component of this equation accounts for energy consumption by new sources which must comply with NSPS controls. Within this first major component, the two terms represent energy sources that must comply with NSPS controls. First, growth in energy consumption is met by new sources (W_{i+1} - W_i) which must comply with NSPS controls. Second, obsolete sources replaced by new units, and sources which switch fuels (X_i - X_{i+1}) must also meet NSPS controls. Of course, since additional energy is added here by fuel switching, energy is subtracted from the original fuel consumption sector.

The second major component of this equation represents energy consumption from old sources that are not required to meet NSPS constraints. These sources may be controlled at the present time or may be required to retrofit NO_x controls at some future time. Such control is accounted for by the factor CF.

Energy consumption was assumed to follow a compound growth rate,

$$W_N = W_O (1 + B)^Y \tag{4-2}$$

where B = compound energy use growth rate for each specific equipment type under consideration

Y = number of elapsed years

Source obsolescence is accounted for by a simple decline rate,

$$X_N = W_o \times Y \times A \tag{4-3}$$

where A = specific source obsolescence rate, and X_N is in the energy from old sources.

A 50-year life was assumed for utilities and large combustion equipment (i.e., A = .02); correspondingly shorter lives were assumed for other equipment types. For simplicity, the capacity lost due to source obsolescence for oil and gas sources was assumed to be replaced by coal burning equipment, whenever possible.

4.4 NATIONAL EMISSIONS INVENTORY -- 1974

This section presents an inventory of major combustion related pollutants originating from stationary fuel burning sources of NO_x. The inventory includes the criteria pollutants NO_x, SO_x, CO, HC, and particulates emitted from gaseous effluent streams. A more complete emissions inventory is given in Appendix D in Volume II by equipment type for 17 fuel categories and the following pollutants: criteria pollutants, sulfates, trace metalics, POMs and trace elements in hopper ash and flyash.

4.4.1 Stationary Source Sector Emissions

Tables C-1 through C-6 in Appendix C, provide 1974 criteria pollutant emissions and totals for the following sectors:

- Utililty Boilers -- Table C-1
- Packaged Boilers -- Table C-2
- Warm Air Furnaces -- Table C-3
- Gas Turbines -- Table C-4
- Reciprocating IC Engines -- Table C-5
- Industrial Process Heating -- C-6

The emission estimates are for 1974, because this is the most recent year for which comprehensive fuel consumption data are available for both the nation and individual regions. All units are in Gg per year. These tables give uncontrolled emission figures for NO_x and controlled emission figures for SO_x and particulates.

Table 4-10 summarizes the total emissions from the sectors listed above.

4.4.2 Summary of Air Pollutant Emissions

The distribution of anthropogenic NO_x emissions nationwide is shown in Figure 4-2 for 1974. Stationary source emissions are subdivided by sector and fuel type in Table 4-11. The estimates of utility boiler emissions account for the reduction from using of NO_x controls as discussed in Section 4.2. Based on a survey of boilers in areas with NO_x emissions regulations, it is estimated that application of NO_x controls in 1974 resulted in a 3.0 percent reduction in nationwide utility boiler emissions as shown in Table 4-12. This corresponds to a 1.6 percent reduction in stationary fuel combustion emissions. Reductions resulting from controls on other sources was negligible in 1974.

In general, the stationary source NO_x emissions totals and the distribution of NO_x emissions among equipment types for 1974 show little change from 1972 inventories. Also, the current inventory shows generally good agreement with recent inventories from EPA's Office of Air Quality Planning and Standards and other groups. One difference in the inventory is for industrial packaged boilers. Here, recent estimates by various groups differ by as much as a factor of 2 -- primarily due to uncertainty in total fuel consumption for this sector.

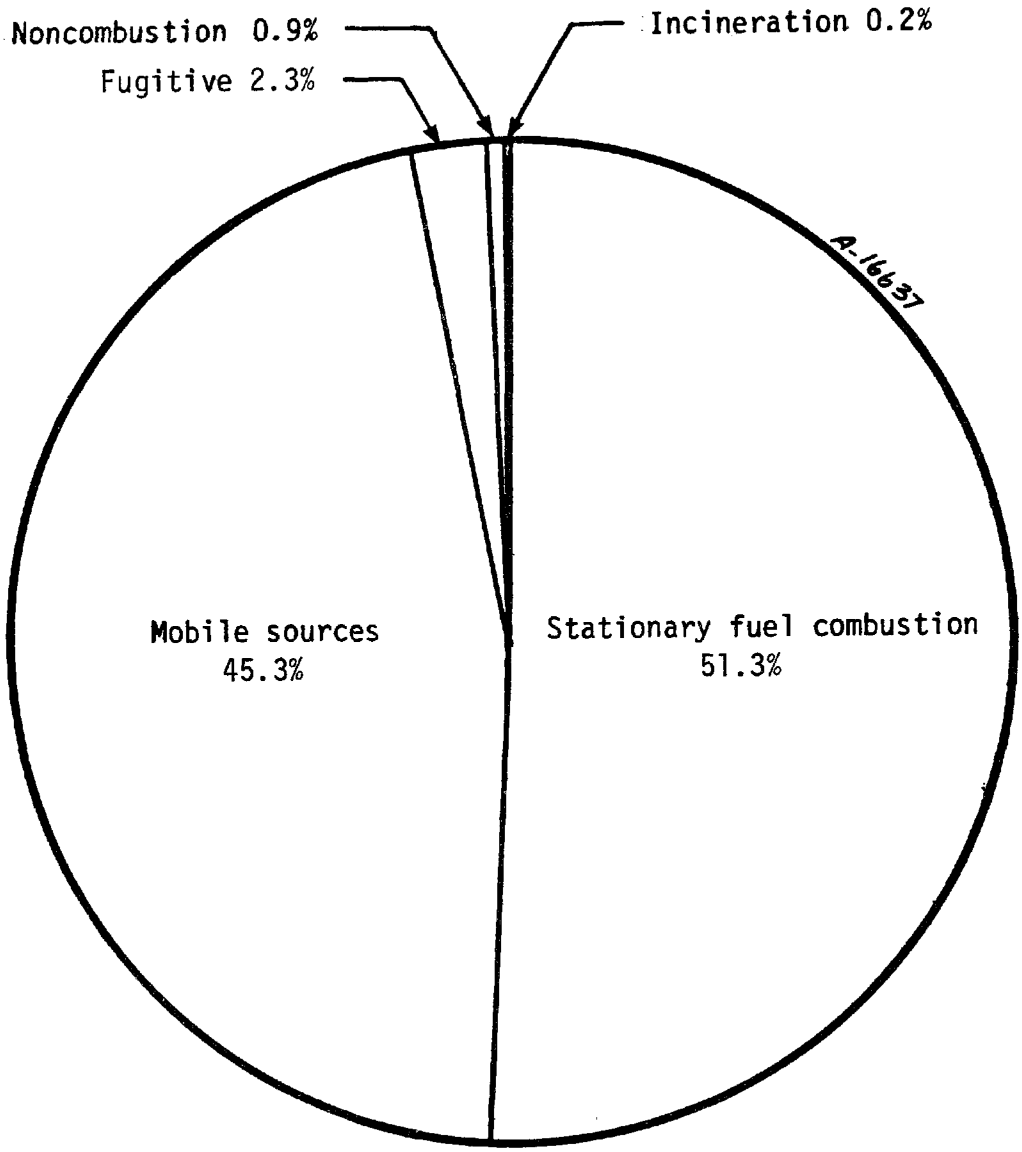
The emissions inventory summaries for other pollutants are shown on Table 4-13. The data for the criteria pollutants are regarded as good and the results of the current inventories are in reasonable agreement with other recent inventories. The data for the noncriteria pollutants and liquid or solid effluent streams, however, were sparse and exhibited large scatter. The emission factors for POMs, for example, varied by as much as

TABLE 4-10. ANNUAL CRITERIA POLLUTANT EMISSIONS BY SECTOR (UNCONTROLLED NO_x) (Gg)

Equipment Sector	NO_x [a]	SO_x [b]	HC	CO	Part.
Utility Boilers	5,741	16,768	29.5	269.6	5,965
Packaged Boilers	2,345	6,405	72.1	175.4	4,930.3
Warm Air Furnaces and Miscellaneous Combustion	321	232	29.7	133	39.3
Gas Turbines	440	10.5	13.7	73.4	17.3
Reciprocating IC Engines	1,857	19.6	578	1,824	21.5
Industrial Process Heating	426	622	166	9,079	4,766
Total	11,130	24,057	889	11,554	15,739

[a] NO_2 basis

[b] SO_2 basis



	Gg	1,000 tons	Percent Total
Stationary Fuel Combustion	10,957	12,078	(51.3)
Fugitive Emissions	498	548	(2.3)
Noncombustion	193	212	(0.9)
Incineration	40	44	(0.2)
Mobile Sources	9,630	10,600	(45.3)
TOTAL	21,318	23,482	100

Figure 4-2. Distribution of anthropogenic NO_x emissions for the year 1974.

TABLE 4-11. SUMMARY OF 1974 STATIONARY SOURCE NO_x[a] EMISSIONS BY FUEL -- Gg (Percent of Total)

Sector	Coal	Oil	Gas	Total
Utility Boilers	3,564 (30.5)	848 (7.3)	1156 (9.9)	5568 (47.6)
Packaged Boilers[b]	679.7 (5.8)	886 (7.6)	779 (6.7)	2344.7 (20.1)
Warm Air Furnaces		131 (1.1)	190 (1.6)	321 (2.8)
Gas Turbines		308 (2.6)	132 (1.1)	440 (3.7)
Reciprocating IC Engines	—	456[c] (3.9)	1400 (12.0)	1856 (15.9)
Industrial Process Heating	—	—	—	426 (3.6)
Noncombustion	—	—	—	193 (1.7)
Incineration	—	—	—	40 (0.4)
Fugitive	—	—	—	498 (4.3)
Total	4,243.7 (36.3)	2,629 (22.5)	3,657 (31.3)	11,687

[a] NO_2 basis

[b] Includes steam and hot water commercial and residential heating units

[c] Includes gasoline

TABLE 4-12. COMPARISON OF CONTROLLED AND UNCONTROLLED ANNUAL STATIONARY SOURCE NO_x[a] EMISSIONS

T-195a

Sector and Equipment Type	Fuel	1974 Controlled NO_x^b (Gg)	1974 Uncontrolled NO_x^b (Gg)	Percent Reduction (%)
Utility Boilers				
Tangential	Coal	1,408	1,409	0.1
	Oil	205	208	1.4
	Gas	138	146	5.5
Wall Firing	Coal	945	946	0.1
	Oil	458	481	4.8
	Gas	649	738	12.3
Horizontally Opposed	Coal	271	271	0
	Oil	169	175	5.1
	Gas	352	379	6.7
Cyclone	Coal	849	863	1.6
	Oil	16	17	6.0
	Gas	15	15	0
Vertical and Stoker	Coal	93	93	0
TOTAL UTILITY	All	5,568	5,741	3.0
Package Boilers	All	2,345	2,345	–
Commercial and Residential Furnaces	All	321	321	–
Gas Turbines	All	440	440	–
Reciprocating IC Engines	All	1,857	1,857	–
Industrial Process Heating	All	426	426	–
TOTAL	All	10,957	11,130	1.6

[a] NO_2 basis

[b] Controlled by regulations existing December 1976

TABLE 4-13. SUMMARY OF AIR AND SOLID POLLUTANT EMISSIONS FROM STATIONARY FUEL BURNING EQUIPMENT (Gg)

T-176c

Sector	NO_x[b]	SO_x	HC	CO	Part.	Sulfates	POM	Dry[c] Ash Removal	Sluiced[c] Ash Removal
Utility Boilers	5,568	16,768	29.5	270	5,965	231	0.01 – 1.2	6.2	24.8
Packaged Boilers	2,345	6,405	72.1	175	4,930	146	0.2 – 67.8	1.1	4.4
Warm Air Furnaces & Misc. Comb.	321	232	29.7	132.6	39.3	6.4	0.06	--	--
Gas Turbines	440	10.5	13.7	73.4	17.3	a	a	--	--
Recip. IC Engines	1,857	19.6	578	1,824	21.5	a	a	--	--
Process Heating	426	622	166	9,079	4,766	a	a	--	--
TOTAL	10,957	24,057	889	11,554	15,739	383	69	7.3	29.2

[a]No emission factor available

[b]Controlled NO_x, NO_2 basis

[c]Based on 80 percent hopper and flyash removal by sluicing methods; 20 percent dry solid removal

two orders of magnitude. Table 4-13 shows estimates of total POM emissions. There are several ongoing field test programs which are sampling noncriteria pollutants. The current inventory will be updated with these results as they become available. Table 4-14 ranks equipment/fuel combinations by annual nationwide NO_x emissions and lists the corresponding ranking based on fuel consumption and emissions of criteria pollutants. Although there were over 70 equipment/fuel combinations inventoried, the 30 most significant combinations account for about 90 percent of NO_x emissions. However, the ranking of specific equipment/fuel types depends both on total installed capacity and emission factors. A high ranking, therefore, does not necessarily imply that a given source is a high emitter. In general, coal-fired sources rank high in SO_x and particulate emissions, while IC engines dominate CO and hydrocarbon emissions.

These pollutant emission values are used in the Section 5 source analysis modeling to provide a pollution potential ranking of stationary combustion sources.

4.5 NATIONAL EMISSIONS INVENTORIES -- 1985, 2000

This section presents emissions inventories for 1985 and 2000 for combustion related pollutants resulting from stationary fuel burning NO_x sources for the reference scenarios. (The reference scenarios are discussed in Section 3.4). These emissions inventories are a culmination of the projected 1985 and 2000 fuel consumption data presented in Section 3.5.3 and the control projections developed in Section 4.3. These inventories include the criteria pollutants NO_x, SO_x, CO, HC, and particulates emitted from gaseous effluent streams. Secondary emphasis

TABLE 4-14. NO_x[a] MASS EMISSION RANKING OF STATIONARY COMBUSTION EQUIPMENT AND CRITERIA POLLUTANT AND FUEL USE CROSS RANKING

T-182b

Rank	Sector	Equipment Type	Fuel	Annual NO_x Emissions (Mg)	Cumulative (Mg)	Cumulative (Percent)	Fuel Rank	SO_x Rank	CO Rank	HC Rank	Part. Rank
1	Utility Boilers	Tangential	Coal	1,410,000	1,410,000	12.7	1	1	7	16	2
2	Reciprocating IC Engines	>75 kW/cyl[c]	Gas	1,262,000	2,672,000	24.0	21	>30	4	1	>30
3	Utility Boilers	Wall Firing	Coal	946,000	3,618,000	32.5	3	2	6	23	5
4	Utility Boilers	Cyclone	Coal	863,500	4,481,500	40.3	6	3	12	9	13
5	Utility Boilers	Wall Firing	Gas	738,300	5,219,800	46.9	4	>30	13	28	>30
6	Utility Boilers	Wall Firing	Oil	481,000	5,700,800	51.2	8	9	17	27	18
7	Utility Boilers	Horizontally Opposed	Gas	378,700	6,079,500	54.6	14	>30	24	>30	>30
8	Reciprocating IC Engines	75 kW to 75 kW/cyl[c]	Oil	325,000	6,404,500	57.5	>30	>30	3	3	26
9	Packaged Boilers	Wall Firing WT[d] >29 MW[b]	Gas	318,500	6,723,000	60.4	16	>30	29	19	>30
10	Packaged Boilers	Stoker Firing WT[d] <29 MW[b]	Coal	278,170	7,001,170	62.9	7	4	11	4	1
11	Utility Boilers	Horizontally Opposed	Coal	270,800	7,271,970	65.3	23	5	>30	>30	7
12	Packaged Boilers	Wall Firing WT[d] >29 MW[b]	Oil	232,480	7,504,450	67.4	26	16	>30	26	22
13	Utility Boilers	Tangential	Oil	208,000	7,712,450	69.3	12	10	27	>30	19
14	Packaged Boilers	Scotch FT[e]	Oil	203,990	7,916,440	71.1	11	11	>30	>30	16
15	Packaged Boilers	Single Burner WT[d] <29 MW[b]	Gas	180,000	8,096,440	72.7	5	>30	>30	22	>30
16	Utility Boilers	Horizontally Opposed	Oil	177,900	8,274,340	74.3	>30	17	>30	>30	27
17	Packaged Boilers	Single Burner WT[d] <29 MW[b]	Coal	164,220	8,438,560	75.8	>30	8	>30	>30	9
18	Industrial Process Comb.	Refinery Heaters Forced & Natural Draft	Oil	147,350	8,585,910	77.1	>30	29	>30	18	21
19	Utility Boilers	Tangential	Gas	146,000	8,731,910	78.5	13	>30	>30	>30	>30
20	Packaged Boilers	Firebox FT[e]	Oil	139,260	8,871,170	79.7	17	13	>30	>30	20

[a] NO_2 basis
[b] Heat input
[c] Heat output
[d] Watertube
[e] Firetube

TABLE 4-14. Concluded

T-182b

Rank	Sector	Equipment Type	Fuel	Annual NO_x Emissions (Mg)	Cumulative (Mg)	Cumulative (Percent)	Fuel Rank	SO_x Rank	CO Rank	HC Rank	Part. Rank
21	Packaged Boilers	Stoker Firing WT[d]	Coal	125,300	8,996,520	80.8	>30	7	28	29	8
22	Gas Turbines	4 to 15 MW[c]	Oil	118,500	9,115,020	81.9	30	>30	15	14	>30
23	Packaged Boilers	Single Burner WT[d] <29 MW[b]	Oil	116,430	9,231,450	82.9	27	15	>30	>30	23
24	Warm Air Furnaces	Central	Gas	106,300	9,337,750	83.9	2	>30	10	8	25
25	Packaged Boilers	Stoker Firing FT[e] <29 MW[b]	Coal	102,040	9,439,790	84.8	29	6	>30	10	6
26	Packaged Boilers	Scotch FT[e]	Gas	98,010	9,537,800	85.7	19	>30	>30	>30	>30
27	Gas Turbines	>15 MW[c]	Oil	97,400	9,635,200	86.6	>30	>30	>30	30	>30
28	Reciprocating IC Engines	>75 kW/cyl[c]	Oil	94,000	9,729,200	87.4	>30	>30	22	13	>30
29	Industrial Process Comb.	Refinery Heaters Forced & Natural Draft	Gas	92,608	9,821,808	88.2	15	>30	>30	7	30
30	Utility Boilers	Vertical and Stoker	Coal	90,900	9,912,708	89.1	>30	12	>20	>30	10

[a] NO_x Ranks
[b] Heat input
[c] Heat output
[d] Watertube
[e] Firetube

was given to sulfates, trace metallics, POMs and trace elements in hopper ash and flyash.

4.5.1 Summary of Air Pollutant Emissions

Tables 4-15 through 4-18 summarize total NO_x emissions from fuel user sources for 1985 and 2000 respectively, for the reference scenarios. NO_x emissions show little change between 1985 and 2000 for the high nuclear scenario, even through fuel consumption rises by 41 percent. This is a result of progressively stringent NO_x controls enforced through the use of NSPS. The low nuclear scenario shows an increase in NO_x emissions even with the implementation of NSPS. This is a result of the large increase in fossil fuel combustion within this scenario particularly for coal firing.

NO_x mass emissions rankings of stationary combustion equipment are presented in Tables 4-19 and 4-20 for 1985 and 2000 respectively, for the reference high nuclear scenario. The 30 most significant sources account for over 90 percent of total NO_x emissions. Tangential boilers appear to be the most significant NO_x source through the year 2000 if projected trends continue. Coal-fired stationary sources generally should increase their share of NO_x emissions and dominate the highest rankings. Coal-fired sources also rank high in SO_x and particulate emissions. Natural gas-fired combustion sources show lower NO_x emissions rankings on this list due to decreases in fuel consumption and implementation of NSPS controls. In 2000, the highest natural gas source is tenth on the ranking, compared to second in 1974. Oil-fired sources also show a gradual decrease in NO_x emissions due to their attrition and replacement with coal-fired sources. These rankings, however, are based on projected equipment fuel consumption and growth rates, and

TABLE 4-15. SUMMARY OF ANNUAL NO_x[a] EMISSIONS FROM FUEL USER SOURCES (1985): : :
REFERENCE SCENARIO -- LOW NUCLEAR

Sector	NO_x Production -- Gg (% of Total)			Total By Sector -- Gg (% of Total)	Cummulative (%)
	Gas	Coal	Oil		
Utility Boilers	711.0 (5.84)	6053.6 (49.68)	646.0 (5.30)	7,410.0 (60.82)	60.82
Packaged Boilers	743.0 (6.10)	674.0 (5.53)	915.0 (7.51)	2332.2 (19.14)	79.96
Warm Air Furnaces	136.0 (1.12)	--	125.0 (1.03)	261.0 (2.14)	82.10
Gas Turbines	171.0 (1.40)	--	375.0 (3.08)	546.0 (4.48)	86.58
Reciprocating IC Engines	627.0 (5.15)	--	456.0 (3.74)	1,083.0 (8.89)	95.47
Process Heating	--	--	--	260.0 (2.13)	97.60
Noncombustion	--	--	--	239.0 (1.96)	99.57
Incineration	--	--	--	53.0 (0.44)	100.0
Total by Fuels	2,338.0 (19.19)	6,727.0 (55.21)	2,517.0 (20.66)	12,184.0	

T-871

[a]NO_2 basis

TABLE 4-16. SUMMARY OF ANNUAL NO_x[a] EMISSIONS FROM FUEL USER SOURCES (2000): REFERENCE SCENARIO -- LOW NUCLEAR

Sector	NO_x Production -- Gg (% of Total)			Total By Sector -- Gg (% of Total)	Cummulative (%)
	Gas	Coal	Oil		
Utility Boilers	--	9,337.0 (64.10)	767.0 (5.27)	10,104.0 (69.36)	72.07
Packaged Boilers	548.0 (3.76)	785.0 (5.39)	861.0 (5.91)	2,194.0 (15.06)	83.32
Warm Air Furnaces	139.0 (0.95)	--	103.0 (0.70)	242.0 (1.67)	85.54
Gas Turbines	192.0 (1.32)	--	379.0 (2.60)	571.0 (3.92)	89.61
Reciprocating IC Engines	288.0 (1.98)	--	470.0 (3.23)	758.0 (5.20)	95.02
Process Heating	--	--	--	300.0 (2.07)	97.16
Noncombustion	--	--	--	322.0 (2.21)	99.46
Incineration	--	--	--	76.0 (0.52)	100.0
Total By Fuels	1,167.0 (8.01)	10,122.0 (69.49)	2,580.0 (17.71)	14,567.0	

T-872

[a]NO_2 basis

TABLE 4-17. SUMMARY OF ANNUAL NO_x[a] EMISSIONS FROM FUEL USER SOURCES (1985): REFERENCE SCENARIO -- HIGH NUCLEAR

Sector	NO_x Production -- Gg (% of Total)			Total By Sector -- Gg (% of Total)	Cummulative (%)
	Gas	Coal	Oil		
Utility Boilers	712.0 (6.53)	5,062.0 (46.42)	646.0 (5.92)	6,420.0 (58.87)	58.87
Packaged Boilers	743.0 (6.81)	385.0 (3.53)	915.0 (8.39)	2,043.0 (18.73)	77.61
Warm Air Furnaces	136.0 (1.25)	--	125.0 (1.15)	261.0 (2.39)	80.00
Gas Turbines	171.0 (1.57)	--	375.0 (3.44)	546.0 (5.00)	85.01
Reciprocating IC Engines	627.0 (5.75)	--	456.0 (4.18)	1,083.0 (9.93)	94.94
Process Heating	--	--	--	260.0 (2.38)	97.32
Noncombustion	--	--	--	239.0 (2.19)	99.51
Incineration	--	--	--	53.0 (0.50)	100.0
Total by Fuels	2,389.0 (21.91)	5,447.0 (49.95)	2,517.0 (23.08)	10,905.0	

T-873

[a] NO_2 basis

TABLE 4-18. SUMMARY OF ANNUAL NO_x[a] EMISSIONS FROM FUEL USER SOURCES (2000): REFERENCE SCENARIO -- HIGH NUCLEAR

Sector	NO_x Production -- Gg (% of Total)			Total By Sector -- Gg (% of Total)	Cummulative (%)
	Gas	Coal	Oil		
Utility Boilers	--	5,259.0 (51.80)	767.0 (7.56)	6,026.0 (59.36)	59.36
Packaged Boilers	548.0 (5.40)	448.0 (4.41)	861.0 (8.48)	1,857.0 (18.29)	77.65
Warm Air Furnaces	139.0 (1.37)	--	103.0 (1.01)	242.0 (2.38)	80.03
Gas Turbines	192.0 (1.89)	--	379.0 (3.73)	571.0 (5.62)	85.56
Reciprocating IC Engines	288.0 (2.84)	--	470.0 (4.63)	758.0 (7.47)	93.13
Process Heating	--	--	--	300.0 (2.96)	96.08
Noncombustion	--	--	--	322.0 (3.17)	99.25
Incineration	--	--	--	76.0 (0.75)	100.0
Total By Fuels	1,167.0 (11.50)	5,707.0 (56.22)	2,580.0 (25.41)	10,152.0	

T-874

[a]NO_2 basis

TABLE 4-19. YEAR 1985 -- NO_x MASS EMISSIONS RANKING FOR STATIONARY COMBUSTION EQUIPMENT AND CRITERIA POLLUTANT CROSS RANKING

Rank	Sector	Equipment Type	Fuel	Annual NO_x Emissions (Mg)	SO_x Rank	CO Rank	HC Rank	Part Rank
1	Utility Boilers	Tangential	Coal	2,413,820	1	5	9	1
2	Utility Boilers	Wall Firing	Coal	1,530,400	2	4	17	4
3	Utility Boilers	Cyclone	Coal	678,820	3	16	13	12
4	Utility Boilers	Wall Firing	Gas	564,900	>30	14	>30	30
5	Reciprocating IC Engines	SI[e]>75 kW/cyl[b]	Gas	537,000	>30	3	1	>30
6	Utility Boilers	Horizontally Opposed	Coal	437,450	4	22	>30	7
7	Utility Boilers	Wall Firing	Oil	396,990	7	20	>30	19
8	Utility Boilers	Horizontally Opposed	Gas	306,840	>30	26	>30	>30
9	Reciprocating IC Engines	CI[f] 75 kW to 75 kW/cyl[b]	Oil	289,010	29	8	6	23
10	Gas Turbines	Simple Cycle 4 MW to 15 MW[b]	Oil	274,480	>30	10	14	26
11	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Gas	268,340	>30	27	18	>30
12	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Oil	223,890	13	>30	28	17
13	Packaged Boilers	Scotch FT[d] <29 MW	Oil	210,190	6	>30	>30	13
14	Packaged Boilers	Single Burner WT[c] <29 MW[a]	Gas	207,310	>30	19	24	>30
15	Utility Boilers	Tangential	Oil	185,290	8	28	>30	20
16	Reciprocating IC Engines	SI[e]>75 kW to 75 kW/cyl[b]	Gas	178,720	>30	1	3	>30
17	Packaged Boilers	Stoker Firing WT[c] <29 MW[a]	Coal	158,220	5	18	7	5
18	Utility Boilers	Horizontally Opposed	Oil	146,310	17	>30	>30	29
19	Packaged Boilers	Firebox FT[d] <29 MW[a]	Oil	143,500	10	>30	>30	16
20	Packaged Boilers	Single Burner WT[c] <29 MW[a]	Oil	137,260	12	>30	>30	18
21	Reciprocating IC Engines	CI[f]>75 kW/cyl	Oil	127,060	>30	15	10	>30

[a]Heat input
[b]Heat output
[c]Watertube
[d]Firetube
[e]Spark Ignition
[f]Compression Ignition

TABLE 4-19. Concluded

Rank	Sector	Equipment Type	Fuel	Annual NO_x Emissions (Mg)	SO_x Rank	CO Rank	HC Rank	Part. Rank
22	Utility Boilers	Tangential	Gas	126,170	>30	>30	>30	>30
23	Gas Turbines	Simple Cycle 4 MW to 15 MW[b]	Gas	118,150	>30	13	19	>30
24	Gas Turbines	Simple Cycle >15 MW[b]	Oil	99,251	>30	17	23	>30
25	Packaged Boilers	Scotch FT[d] <29 MW[a]	Gas	93,700	>30	29	30	>30
26	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Coal	93,410	14	>30	>30	9
27	Packaged Boilers	HRT Boiler	Oil	88,630	16	>30	>30	15
28	Reciprocating IC Engines	CI[f]>75 kW/cyl[b]	Dual	88,390	>30	25	4	>30
29	Packaged Boilers	Firebox FT[d] <29 MW[a]	Gas	86,800	>30	>30	>30	>30
30	Warm Air Furnaces	Warm Air Central Furnace	Gas	82,520	>30	11	11	27

T-859

[a]Heat input
[b]Heat output
[c]Watertube
[d]Firetube
[e]Spark Ignition
[f]Compression Ignition

TABLE 4-20. YEAR 2000 -- NO_x MASS EMISSIONS RANKING FOR STATIONARY COMBUSTION EQUIPMENT AND CRITERIA POLLUTANT CROSS RANKING

Rank	Sector	Equipment Type	Fuel	Annual NO_x Emissions (Mg)	SO Rank	CO Rank	HC Rank	Part. Rank
1	Utility Boilers	Tangential	Coal	2,704,100	1	6	10	4
2	Utility Boilers	Wall Firing	Coal	1,838,820	2	4	16	5
3	Utility Boilers	Horizontally Opposed	Coal	582,530	4	20	>30	7
4	Utility Boilers	Cyclone	Coal	450,280	5	25	21	14
5	Utility Boilers	Wall Firing	Oil	450,130	9	17	29	18
6	Utility Boilers	Tangential	Oil	279,610	10	22	>30	19
7	Reciprocating IC Engines	CI[f] 75 kW to 75 kW/cyl[b]	Oil	269,810	>30	10	7	28
8	Gas Turbines	Simple Cylce 4 MW to 15 MW[b]	Oil	256,590	>30	15	18	>30
9	Packaged Boilers	Stoker Firing WT[c] <29 MW[a]	Coal	244,070	3	16	5	2
10	Reciprocating IC Engines	SI[e] >75 kW/cyl[b]	Gas	201,700	>30	5	1	>30
11	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Oil	199,860	23	>30	28	21
12	Packaged Boilers	Scotch FT[d] <29 MW[a]	Oil	197,720	6	>30	>30	15
13	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Gas	195,030	>30	>30	23	>30
14	Packaged Boilers	Single Burner WT <29 MW[a]	Gas	181,780	>30	24	27	>30
15	Reciprocating IC Engines	SI[e] 75 kW to 75 kW/cyl[b]	Gas	167,250	>30	2	3	>30
16	Utility Boilers	Horizontally Opposed	Oil	165,900	16	>30	>30	26
17	Reciprocating IC Engines	CI[f] >75 kW/cyl[b]	Oil	159,460	>30	13	9	>30
18	Packaged Boilers	Single Burner WT[c] <29 MW[a]	Oil	140,960	14	>30	>30	22
19	Packaged Boilers	Firebox FT[d] <29 MW[a]	Oil	134,980	12	>30	>30	20
20	Gas Turbines	Simple Cycle >15 MW[b]	Oil	122,020	>30	9	13	27
21	Gas Turbines	Simple Cycle 4 MW to 15 MW[b]	Gas	110,390	>30	19	22	>30

T-860

[a] Heat input

[b] Heat output

[c] Watertube

[d] Firetube

[e] Spark Ignition

[f] Compression Ignition

TABLE 4-20. Concluded

Rank	Sector	Equipment Type	Fuel	Annual NO_x Emissions (Mg)	SO Rank	CO Rank	HC Rank	Part. Rank
22	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Coal	105,180	11	>30	>30	9
23	Packaged Boilers	Stoker WT[c] >29 MW[a]	Coal	87,612	8	30	>30	8
24	Reciprocating IC Engines	CI[f] >75 kW/cyl[b]	Dual (Oil and Gas)	84,080	>30	26	14	>30
25	Packaged Boilers	HRT Boiler	Oil	83,370	15	>30	>30	17
26	Gas Turbines	Simple Cycle >15 MW[b]	Gas	81,550	>30	14	17	>30
27	Warm Air Furnaces	Warm Air Central Furnace	Gas	77,640	>30	11	11	29
28	Packaged Boilers	Scotch FT[d] <29 MW[a]	Gas	74,320	>30	>30	>30	>30
29	Ind. Process Comb.	Refinery Htr. Nat. Draft	Dual (Oil and Gas)	73,260	>30	>30	8	>30
30	Packaged Boilers	Firebox FT[b] <29 MW[a]	Gas	68,850	>30	>30	>30	>30

T-860

[a]Heat input

[b]Heat output

[c]Watertube

[d]Firetube

[e]Spark Ignition

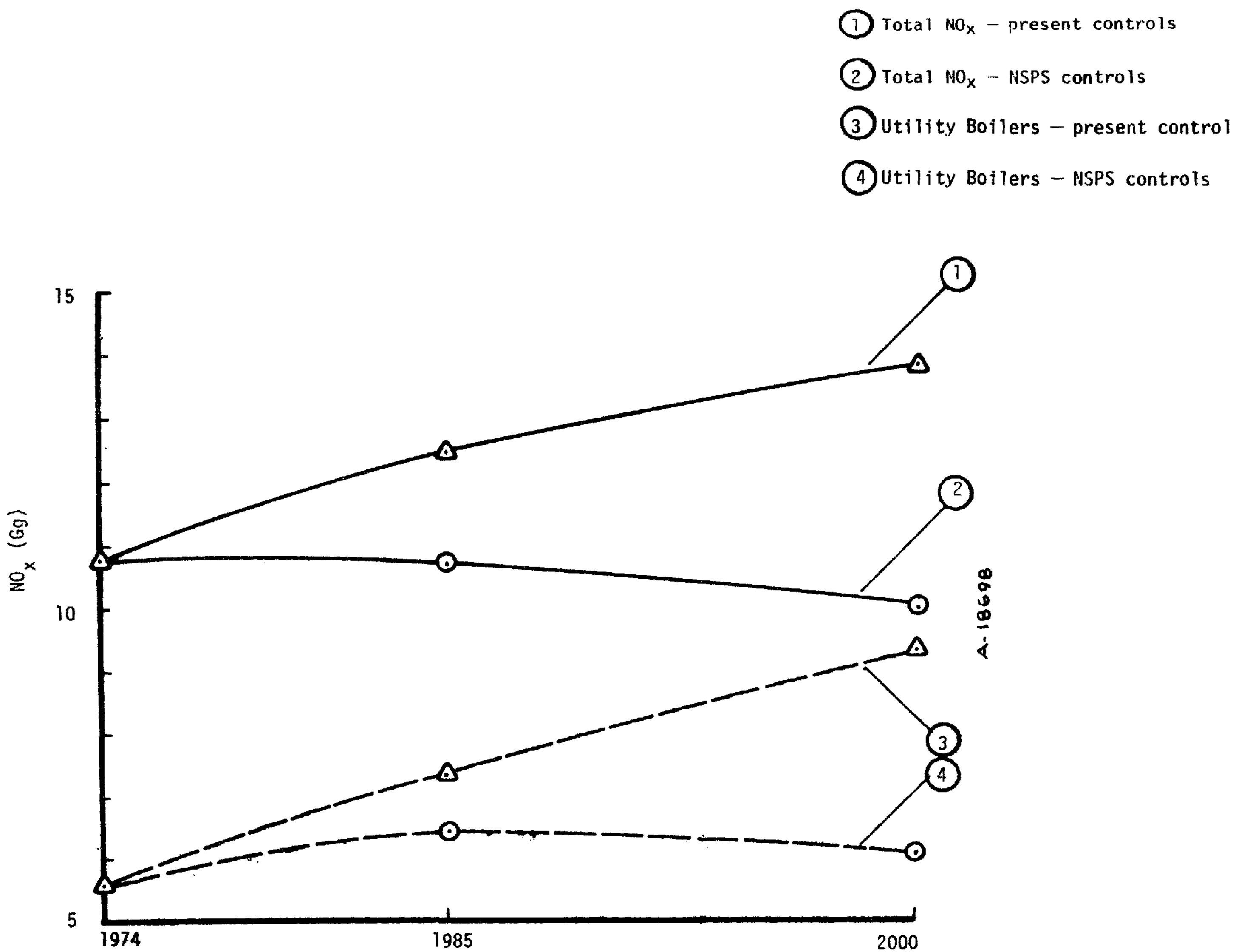
[f]Compression Ignition

implementation of tentative NSPS controls. Thus, because of the uncertainty of these projections, these rankings again should be considered only as qualitative indications of future trends, not as quantitative conclusions.

4.5.2 Summary and Conclusions

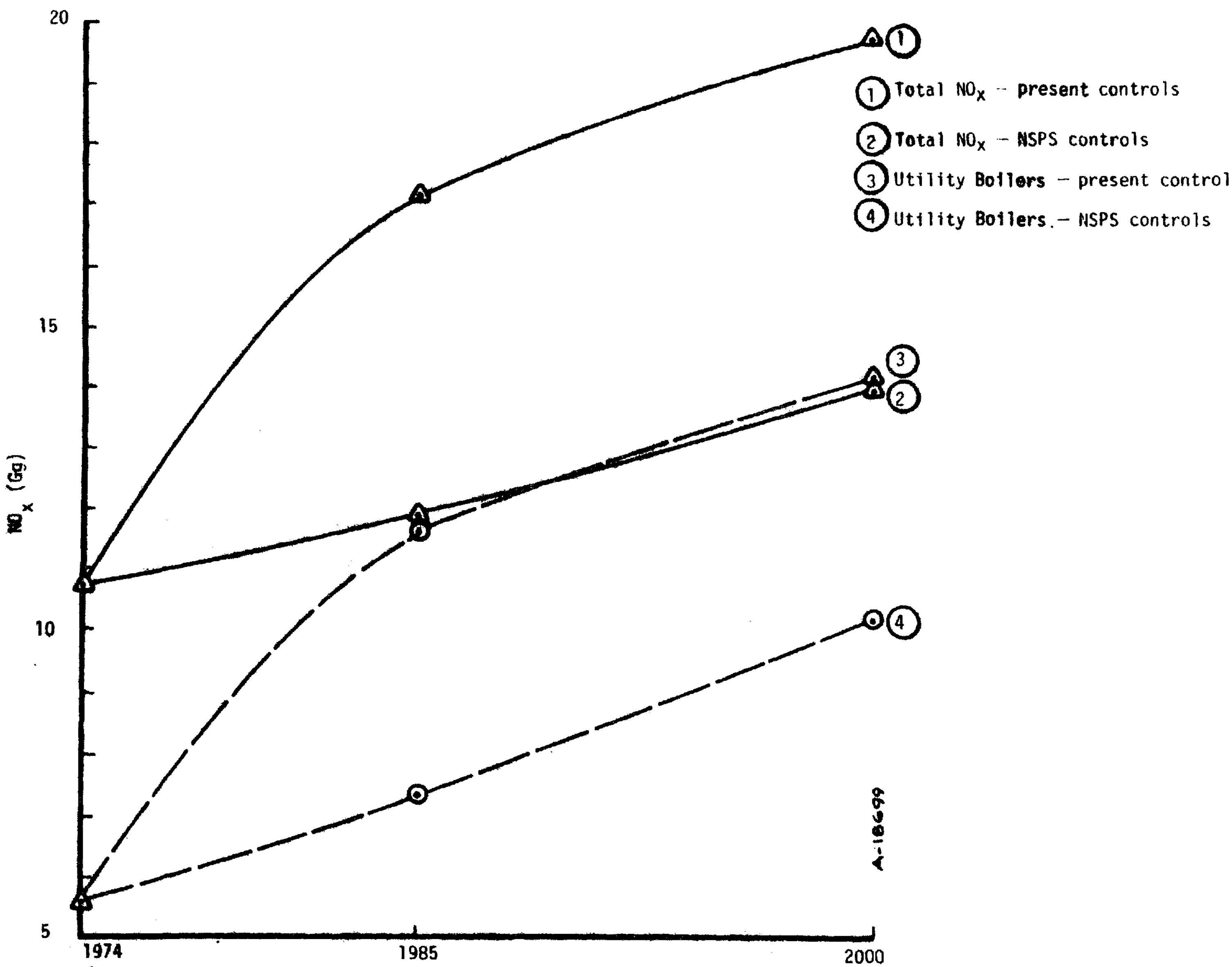
The present level of NO_x controls will not significantly reduce NO_x emissions in the year 2000 period. Curve 1 of Figures 4-3 and 4-4 shows that under current controls, NO_x should increase by 30 percent by the year 2000 with the high nuclear scenario and by about 80 percent with the low nuclear scenario. Utility boiler NO_x emissions should represent most of that increase because of the high demand for electricity through the year 2000.

At present, NSPS have only been set for large boilers -- 73 MW heat input (250 MBtu/hr) and nitric acid plants. These standards represent only a small portion of the NSPS control potential. Obviously, more stringent controls are required to contain NO_x emissions in the 1990's. Curve 2 of Figure 4-3 shows the result of applying increasingly stringent controls to stationary sources for the high nuclear case. In 1985, total NO_x emissions with NSPS control show no significant change from 1974. However, as the controls schedule becomes increasingly more stringent, total NO_x emissions drop slightly from the 1974 value -- a reduction of 7 percent. NO_x emissions from utility boilers without NSPS control increase by about 27 percent in 1985 as shown in Curve 3. However, with increasingly stringent NSPS controls, these emissions are reduced to 8 percent over the 1974 level by the year 2000 as shown in Curve 4.



[a] NO_2 basis

Figure 4-3. NO_x[a] emissions projections -- stationary sources (reference scenario -- high nuclear).



[a] NO_2 basis

Figure 4-4. NO_x[a] emissions projections -- stationary sources (reference scenario -- low nuclear).

However, if nuclear power growth remains low due to concerns about safety, cost, leadtime, and waste disposal, fossil fuel combustion sources will have to meet most of the increasing energy demand. Curve 2 of Figure 4-4 shows that total NO_x emissions increase by about 30 percent, even with strict NSPS controls under the reference low nuclear scenario. Utility boiler NO_x emissions increase by about 80 percent over 1974 emission levels even with NSPS control, as shown by Curve 4. Thus, it is clear that even stringent NSPS controls are not sufficient to reduce NO_x levels for large increases in fossil fuel consumption in this scenario.

Argonne (Reference 4-64) also has shown that even with aggressive setting of NSPS, under a low nuclear growth scenario, NO_x emissions still increase substantially over the 1975 to 1990 period. In fact, 1990 emissions are projected to be about 44 percent higher than 1975 levels. The Argonne projections are somewhat higher than the results in this section, since they used higher energy growth rates for most sectors.

Thus, current controls are probably not sufficient to suppress NO_x emissions growth in the future. Moreover, even implementing a strict set of NSPS controls may not be sufficient to maintain current NO_x levels if coal usage increases due to continued low nuclear energy growth. Thus, to maximize the effectiveness of the NO_x control strategy, high priority should be given to sources that are experiencing rapid growth and generate high NO_x.

4.6 REGIONAL EMISSIONS INVENTORY

This section presents regional emissions inventories for combustion related pollutants resulting from stationary combustion sources of NO_x. Table 4-21 summarizes NO_x emissions for the nine reqions discussed in Section 3.3. These inventories result from the regional fuel consumption

TABLE 4-21. DISTRIBUTION OF REGIONAL UNCONTROLLED NO_x[a] EMISSIONS (Gg) -- 1974

Sector and Equipment Type	Fuel	New England	Middle Atlantic	E-N-Central	W-N-Central	South Atlantic	E-S-Central	W-S-Central	Mountain	Pacific	Total
Utility Boilers											
Tangential	Coal	7.5	161.8	477.8	132.9	281.6	220.4	18.6	97.8	11.4	1409.8
	Oil	30.6	55.7	10.4	1.4	61.2	3.8	9.0	4.5	31.8	208.4
	Gas	0.4	1.9	5.1	15.0	9.4	2.2	90.5	8.7	13.1	146.3
Wall Fired	Coal	5.0	108.3	321.0	89.3	189.2	148.1	12.5	65.7	7.7	946.8
	Oil	70.9	128.8	24.0	3.1	141.5	8.7	20.8	10.3	73.4	481.5
	Gas	2.1	9.6	26.0	75.8	47.3	10.9	456.6	43.9	66.3	738.5
Horizontally Opposed	Coal	1.4	31.0	91.8	25.5	54.1	42.4	3.6	18.8	2.2	270.8
	Oil	61.8	37.4	8.8	1.2	37.1	3.2	7.7	3.8	17.0	178.0
	Gas	2.2	4.9	13.3	38.9	24.3	5.6	234.1	22.5	34.0	379.8
Cyclone	Coal	1.5	98.6	292.3	81.2	172.2	134.8	11.4	59.8	7.0	858.8
	Oil	2.5	4.5	0.8	0.1	5.0	0.3	0.7	0.4	2.6	16.9
	Gas	0.1	0.2	0.5	1.4	0.9	0.2	9.1	0.9	1.3	14.6
Vertical and Stoker	Coal	0.5	10.4	30.8	8.6	18.1	14.2	1.2	6.3	0.8	90.9
Subtotal	All	186.5	653.1	1302.6	474.4	1041.9	594.8	875.8	343.4	268.6	5741.1
Packaged Boilers	All	142.0	361.3	603.0	175.1	400.5	166.5	243.3	93.3	189.9	2374.9
Commercial and Residential Furnaces	All	9.5	31.2	65.5	22.7	56.5	22.9	42.6	25.4	44.4	320.7
Gas Turbines	All	131.0	66.8	19.3	36.7	33.8	9.4	83.9	52.3	7.3	440.5
IC Engines	All	11.7	60.5	247.7	359.4	79.4	129.6	681.8	206.2	74.4	1850.7
Process Heating	All	0.5	61.4	84.4	24.5	17.5	26.3	144.3	2.8	48.2	410.0
Subtotal		294.7	81.2	1019.9	618.4	587.7	354.7	1195.9	380.0	364.2	5396.8
Total	All	481.7	1234.3	2322.5	1092.8	1629.6	949.5	2071.7	723.4	632.8	11137.0

[a] NO_2 basis

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data for 1974 presented in Section 3 and emission factors given in Section 4. These emission estimates are for uncontrolled NO_x only, since as discussed in Section 4.2.4, the impact of NO_x control implementation on a regional basis is small in 1974.

Over 40 percent of all NO_x emissions from utility boilers are from the East-North-Central and the South Atlantic regions. The New England region produces less than 5 percent of utility boiler NO_x emissions. In addition, areas such as New England and the Far West may be most strongly affected by fuel switching to coal since they are heavily dominated by oil and gas firing. The East-North-Central and South Atlantic regions generate over 40 percent of the NO_x emissions, from packaged boilers. Considering all stationary sources, the East-North-Central and West-South-Central regions of the nation generate the highest levels of NO_x, representing about 40 percent of the total emissions.

The regional inventories developed here show significant localized variations of NO_x emissions by fuel/equipment type. These variations result from both the regional fuel mix variations and the distribution of stationary source types. Thus, a national policy of NO_x control must be broad enough to encompass these regional variations in developing strategies for future NO_x emissions reductions.

4.6.1 Conclusion

In general, the emission totals generated in the criteria pollutant inventory are considered to be of relatively high quality. However, the emissions inventory projections are based on tenuous assumptions about future conditions. Because of the inherent uncertainties in these projections, they should be considered only as qualitative indicators of energy and environmental contingencies. The regional emissions inventories are felt to be of good quality, except for the packaged boiler sector, where the data for oil-fired units show some discrepancy. The quality of sector emissions ranges from good for utility boilers; to fair to good for the warm air furnace, gas turbine, and reciprocating IC engine sectors; to fair for the packaged boiler and industrial process heating sectors.

Preliminary estimates of sulfates, POMs, and trace element emissions are of poor quality because data are very sparse and inconsistent. Liquid and solid pollutants (trace elements) from stationary source combustion are also of very poor quality, which is due, in part, to a lack of exact monitoring of fuel composition. Several comments can be made about the quality of the pollutant data in the inventory:

- In the packaged boiler sector, fuel consumption, equipment emission factors and emissions are difficult to quantify. This is due to the large capacity range of the equipment sector, the lack of regulation, the diversity of equipment design, and the extremely large population of this sector.
- The industrial process combustion sector is also extremely difficult to quantify. The difficulty arises from the lack of data on specific fuel properties and poor fuel consumption data. Further complexities are the large number of process heating applications, and the variations in equipment design and combustion practices from industry to industry.

- POM emissions were treated as a single pollutant because few data were available for specific POM compounds. Even the available POM data exhibited large scatter which warranted reporting upper and lower extremes for the emission factors and emission rates. Extensive testing is needed in all sectors.
- Transient or nonconventional operations and their effect on multimedia emission rates were treated only superficially. Test data were generally unavailable except in space heating applications where some transient data were available. Test data are needed before these effects can be quantified.

Subsequent efforts to update the inventory will improve the estimates of noncriteria pollutants and liquid and solid effluents, pending new test results. Through the remainder of the NO_x E/A program, related research programs and testing will be monitored to continually update the emissions inventories developed in this section. This will ensure that these inventories are current and reflect the most accurate data available.

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SECTION 5

SOURCE ANALYSIS MODEL

The growth projections and emissions data of Sections 3 and 4, used to generate emissions inventories, help to indicate the pollution potential of sources or groups of sources. However, in those sections, source rankings based on total pollutant emission loading neglected important factors such as the total number of people exposed and the ambient level to which they were exposed. Therefore, these and other factors were incorporated into a Source Analysis Model (SAM). This model was used to more accurately estimate the pollution potential of a source and to compare it to other sources.

5.1 SOURCE ANALYSIS MODEL

This model is based on the hypothesis that the impact of a particular type of source (e.g., tangential coal-fired boilers) is directly proportional to: (1) the ground-level concentration of pollutant species due to a single source compared to an impact threshold limit, (2) the number of people exposed to that concentration from a single source, and (3) the total number of sources of that type nationwide. It is similar to other models -- in particular, a model developed by Monsanto (Reference 5-1). The primary difference between the SAM and the Monsanto model is the way each treats population exposure and background ambient pollutant concentration. The SAM makes more direct use of available data than other models -- particularly for flue gas effluents. With this model, simple dispersion calculations for gaseous streams can easily be done. Liquid and solid effluent streams must be handled more approximately due to the complicated pathway from source to receptor.

Section 5.1.1 describes how the model is applied to gaseous effluent streams and Section 5.1.2 describes how it treats liquid and solid streams. Section 5.2 discusses the data which is used for the analyses made in this report. The results of the analyses are discussed in Section 5.3, and the implications of the results are discussed in Section 5.4.

5.1.1 Gaseous Effluent Streams

Using the source impact hypothesis described above, the impact of the gaseous effluent streams from all sources of type i can be defined as

$$I_i = \sum_j P_j \sum_k \int \chi_{jk}/\chi_k A \, dA \qquad (5\text{-}1)$$

where I_i = impact due to all sources of type i (e.g., bituminous coal-fired tangential boilers)

j = an index identifying each of the individual sources

P_j = population density near source j

k = index identifying each pollutant species (e.g., NO_2)

χ_{jk} = ground level concentration of species k due to source j

$\chi_k A$ = permissible ground level concentration of species k (i.e., concentration below which adverse health effects are negligible)

dA = an element of area near the source

This definition, then, ascribes a high impact factor to sources that expose many people to high pollutant concentrations. Because detailed input data are required, a direct calculation of this factor for all combustion sources is not warranted for present purposes. However, the problem can be made manageable by approximations. These approximations are described as the equation is discussed, term by term, in the rest of this section. Point sources are discussed in Section 5.1.1.1 and distributed sources (e.g., residential heaters) are discussed in 5.1.1.2. A flow chart illustrating the major elements of both calculations is shown later in Figure 5-5. The reader may find it useful to refer to this while reading the following sections.

5.1.1.1 Point Source Calculations

Allowable Concentrations

The allowable ground level concentrations ($\chi_k A$) can be defined in several ways. If the calculated impacts are to be used for comparing sources to one another, the concentrations must represent a consistent set of values indicating the relative toxicity of each pollutant. Because one of the most current and complete lists of these values is found in the Multimedia Environmental Goals, or MEGs (Reference 5-2), the values found there, specified as χ_k^{MEG}, will be used throughout this report. These values represent the assumed maximum permissible concentration of a chemical species that causes no adverse health effects in humans.

The impact factor is defined here as proportional to the ratio χ_k/χ_k^{MEG} -- that is, a linear dose-response curve is assumed. Although there is evidence that the curve may be highly nonlinear in some cases, the lack of data in this area and the increased complication of including such details in the assessment justify defining the impact factor as above.

Calculation of Ground Level Concentration

If reactions between pollutant species are neglected, and uniform topology is assumed, the ground level concentration of a pollutant issuing from a point source of gaseous emissions (χ_{jk}) can be calculated from a Gaussian plume dispersion formula. The pollutant emission rate, the stack height, and meteorological information are the only required inputs. (See, for example, Reference 5-3). For the analyses in this report, the wind speed (4 m/s) and atmospheric stability class (D) were assumed constant for all sources and locations. These values represent averages across the nation and throughout the year.

Given the meteorological data above and an assumed mixing height of 1500 m, the ground level concentration along the plume centerline, χ_{jk}, normalized with the source emission rate for species k, Q_{jk}, can be plotted as a function of distance from the source as shown in Figure 5-1. Each curve represents one value of the stack height, H. These curves can be generated easily on a computer and, given the assumptions above, require only stack height as an input parameter. Actual stack height is used and the buoyancy effects which cause a slightly higher effective emission height are ignored. Once the ratio χ_{jk}/Q_{jk} is determined, the ground-level concentration is found by multiplying the ratio by the pollutant emission rate, Q_{jk}.

Calculation of the Integral: Limits of Integration

To determine the impact factor, the integral

$$\int \chi_{jk}/\chi_k^{MEG}\, dA \qquad (5\text{-}2)$$

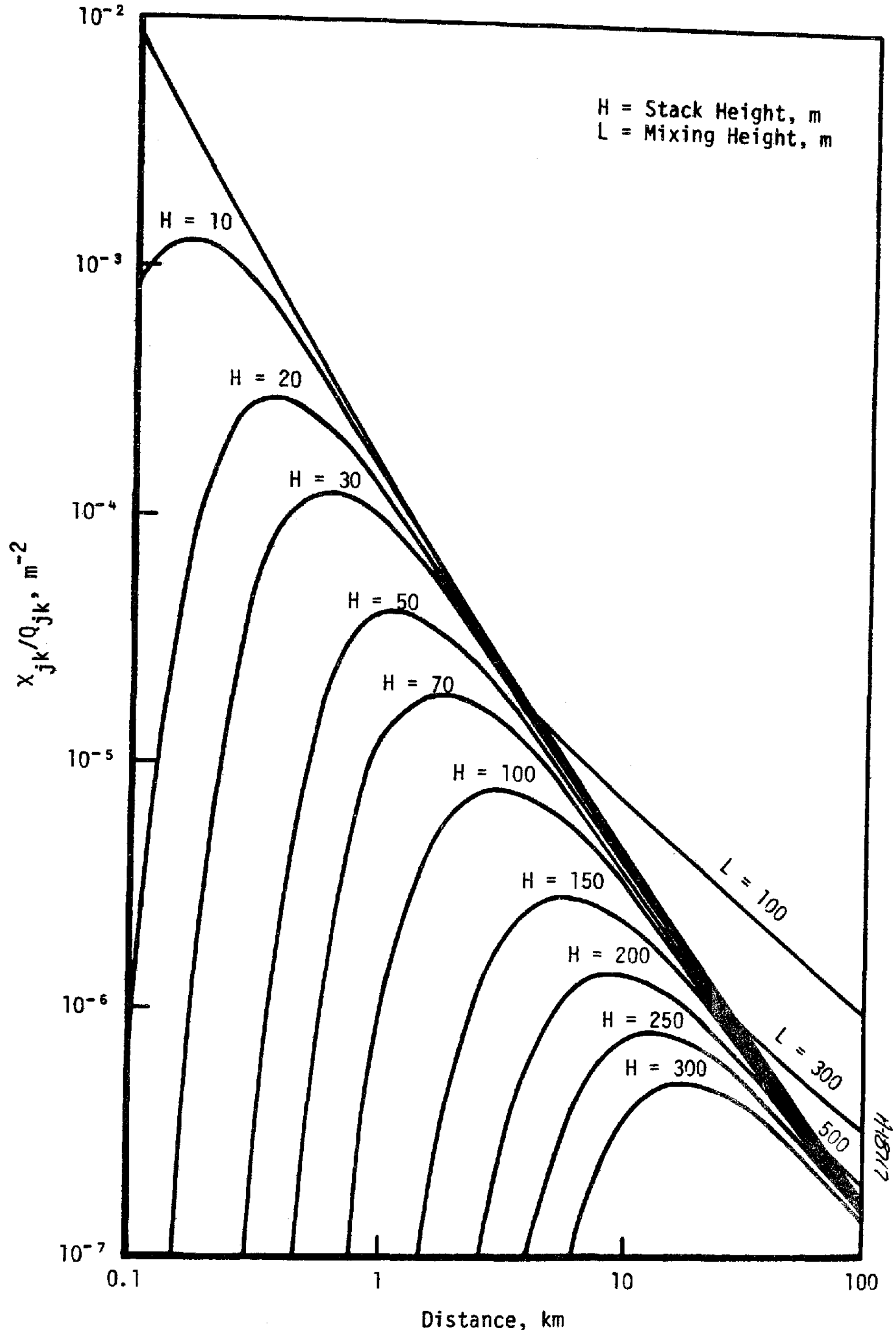

Figure 5-1. Ground level concentration -- Gaussian plume.

must be evaluated. However, this poses two problems. The first problem is that in the discussion above, a method for calculating the plume centerline concentration is given but results are not given for off-centerline concentrations. The second problem is defining the limits of the integration.

The problem of off-centerline concentrations is solved by assuming that the ground-level concentration is a function only of the distance from the source, r, and is given by the centerline value in Figure 5-2. This assumption is much the same as the assumption that the wind direction is random over time. Using this assumption, the integral can be given in the form

$$2\pi/\chi_k^{MEG} \int_a^b r \, \chi_{jk} (r) \, dr \tag{5-3}$$

where the limits of integration, r = a,b are still undefined. This form of the integral was used in the analyses. It can be quickly evaluated on a computer.

The limits of integration in Equation 5-3 might be defined practically by integrating over all areas in which the ground level concentration exceeds the maximum allowable concentration. This approach assumes that concentrations less than the maximum allowable concentration, χ_k^{MEG}, are not harmful and should not contribute to the integral. However, this approach places a large dependence on the accuracy of the MEG. To account for possible inconsistencies in the MEGs, a safety factor of 10 was used. Hence, the integral was evaluated over those regions where $\chi_{jk} \geq 0.1 \, \chi_k^{MEG}$.

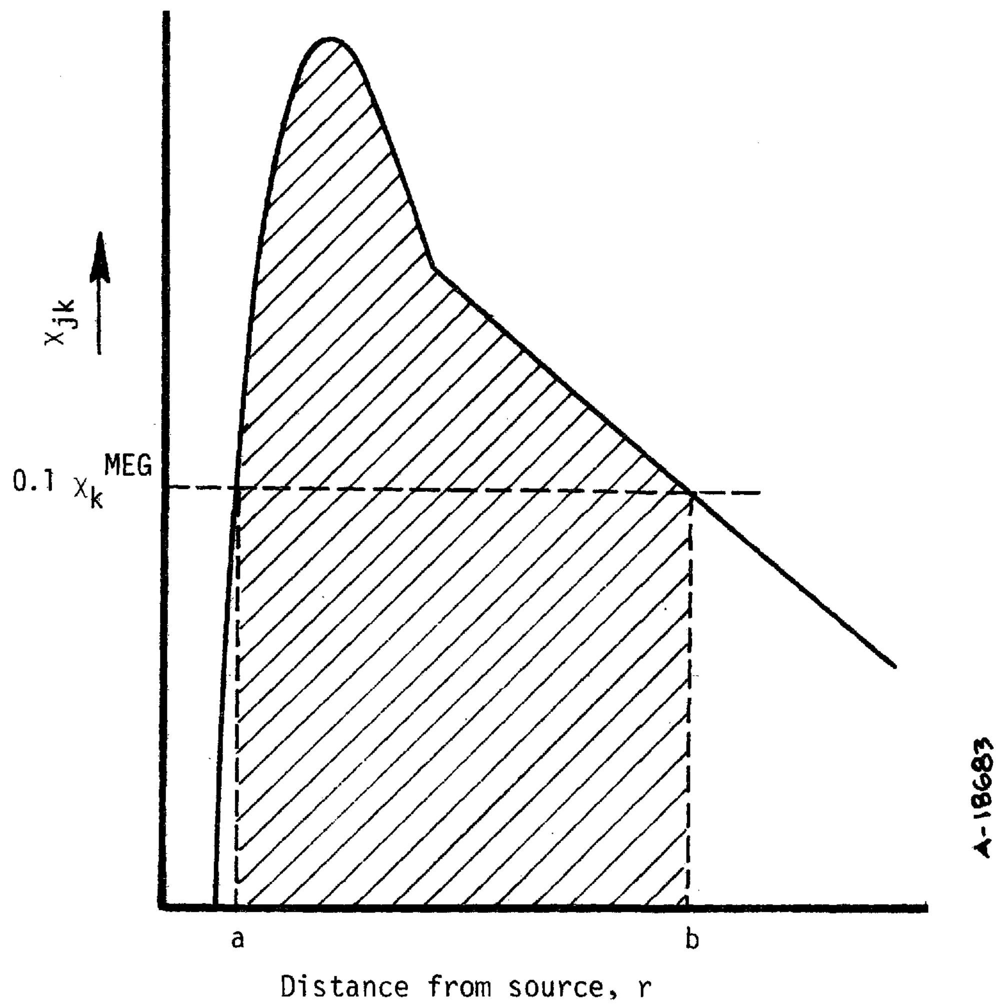

Figure 5-2. Limits of integration for point sources.

These limits are shown graphically in Figure 5-2. The ground-level concentration of a particular species, k, is plotted as a function of distance from the source. The limits of integration, a and b, are shown as the two points at which the ground level concentration due to the source just equals 0.1 χ_k^{MEG}. The integration is performed over the shaded area.

Inclusion of Natural Background

In many areas, the background concentration of a particular pollutant may approach or exceed the concentration (χ_{jk}) due to a single source.

Since adding sources in regions with high existing background levels may cause ambient pollutant concentrations which are harmful, the background, χ_k^B, should be included in the definition of the impact factor. The background is included here by replacing the integrand χ_{jk}/χ_k^{MEG} with $(\chi_{jk} + \chi_k^B)/\chi_k^{MEG}$. This approach, although somewhat conservative, was selected because the plume centerline dispersion calculation was made assuming zero background concentration. Use of χ_k^B in the numerator thus compensates for the simplified dispersion calculation. The modified integrand requires that the limits of integration be modified to allow integration over regions where χ_{jk} is less than 0.1 χ_k^{MEG} criteria, but $(\chi_{jk} + \chi_k^B)$ is not. Accordingly, the lower limit of integration (a) is defined as the lesser of the distances at which either: (1) χ_{jk} = 0.1 χ_k^{MEG}, or (2) $(\chi_{jk} + \chi_k^B)$ = 0.1 χ_k^{MEG} and $\chi_{jk} \geq 0.1\ \chi_k^B$.

Similarly, the upper limit (b) is the larger of the distances that satisfy the above conditions. This definition ensures that the integration is performed over regions where either:

1. The ground level concentration due to the source (χ_{jk}) exceeds the impact criteria
2. The resulting ground level concentration (which is the sum of χ_{jk} and the background due to other sources ($\chi_{jk} + \chi_k^B$) exceeds the criteria and χ_{jk} constitutes a significant portion (10 percent) of that concentration

These criteria are used in the analysis to define the exposed impact area. The value of the integral

$$2\pi/\chi_k^{MEG} \int_a^b (\chi_{jk} + \chi_k^B)\ r\ dr \tag{5-4}$$

between these two limits gives an indication of the impact of pollutant k from source j.

Impact Parameter

Just as the integral above indicates the impact of a single pollutant from a particular source, a sum over pollutant species indicates the impact (excluding population density effects) due to all pollutants. Hence, three impact parameters are defined:

$$IP_j^N = \sum_k 2\pi/\chi_k^{MEG} \int_a^b (\chi_{jk})\ r\ dr \tag{5-5}$$

$$IP_j^R = \sum_k 2\pi/\chi_k^{MEG} \int_a^b (\chi_{jk} + \chi_k^{BR})\ r\ dr \tag{5-6}$$

$$IP_j^U = \sum_k 2\pi/\chi_k^{MEG} \int_a^b (\chi_{jk} + \chi_k^{BU})\ r\ dr \tag{5-7}$$

where χ_k^{BR} is the average rural background concentration of species k, and χ_k^{BU} is the average urban background. Since each single source realistically cannot be considered separately and assigned an individual local background concentration and local population density, only two cases are considered: those in a rural setting and those in an urban setting. All sources are included in one of these categories.

The first impact parameter, IP_j^N, represents the impact of source j in an area in which there is no natural background, i.e., a pristine environment. The second and third parameters, IP_j^R and IP_j^U, represent the impact of the source in a noticeably impacted rural and an urban setting, respectively.

Population Density

At this point, the impact parameters represent sums over area integrals of pollutant concentrations. The population in the high concentration area has not been considered. Because it is impractical to multiply the impact parameter for each source by the local population density, only two different values of the density are used: a rural value, P_R, and an urban value, P_U. Classifying each source as either rural or urban, the single source impact factors (for source j) are defined as

$$IF_j^R = (P_R) \times (IP_j^R) \tag{5-8}$$

and

$$IF_j^U = (P_U) \times (IP_j^U) \tag{5-9}$$

These factors, then, represent a measure of the environmental impact (more specifically, human health impact) of a single source such as one boiler located in either a rural or an urban area.

<u>Total Impact</u>

The impact of all sources of the same type -- some urban and some rural -- can be calculated by

$$IF_j^T = (N_R)\ (IF_j^R) + (N_U)\ (IF_j^U) \qquad (5\text{-}10)$$

where N_R and N_U are the number of rural and urban sources, respectively. The average impact of a single source then becomes

$$IF_j^{avg} + IF_j^T/(N_R + N_U) \qquad (5\text{-}11)$$

These two numbers (the total impact factor and the average source impact factor) represent numbers by which the impacts of sources of different types can be compared.

5.1.1.2 Distributed Sources

The model described above can also be applied to distributed sources -- sources such as home furnaces whose emission rates are constant over a large area. The basic change in the model is in the dispersion calculation.

For distributed sources, a model from Holzworth (Reference 5-4) is used which predicts a ground level concentration along the wind direction as

$$\chi_{jk}/Q_{jk} = 3.405\ x^{0.115} \qquad x \leq 7312 \qquad (5\text{-}12)$$

$$\chi_{jk}/Q_{jk} = 9.35 + (8.33 \times 10^{-5})\ x - 3535/x \qquad x > 7312 \text{ meters} \qquad (5\text{-}13)$$

where x = distance from source edge along wind (m)

χ_{jk} = ambient concentration of species k (g/m^3), due to source type j

Q_{jk} = source emission rate of species k ($g/m^2 \cdot s$), due to source type j

Here the mixing height and wind speed are the same as in the Gaussian model. This predicted concentration profile is shown in Figure 5-3. For this case, the area integral of concentration can be put into the form

$$S_{max}/\chi_k^{MEG} \int_a^b \chi_{jk}(x)\, dx \qquad (5\text{-}14)$$

where S_{max} is the maximum length of the source along the wind direction and the source area is assumed to be square. The lower limit of integration is defined in the same way as for the point sources; the upper limit (b) is equal to S_{max}. These limits are shown graphically in Figure 5-4 where the area for the integration is shown cross-hatched.

Again, as with point sources, three impact parameters are defined

$$IP_j^N = \sum_k S_{max}/\chi_k^{MEG} \int_a^b \chi_{jk} dx \qquad (5\text{-}15)$$

$$IP_j^R = \sum_k S_{max}/\chi_k^{MEG} \int_a^b (\chi_{jk} + \chi_k^{BR})\, dx \qquad (5\text{-}16)$$

$$IP_j^U = \sum_k S_{max}/\chi_k^{MEG} \int_a^b (\chi_{jk} + \chi_k^{BU})\, dx \qquad (5\text{-}17)$$

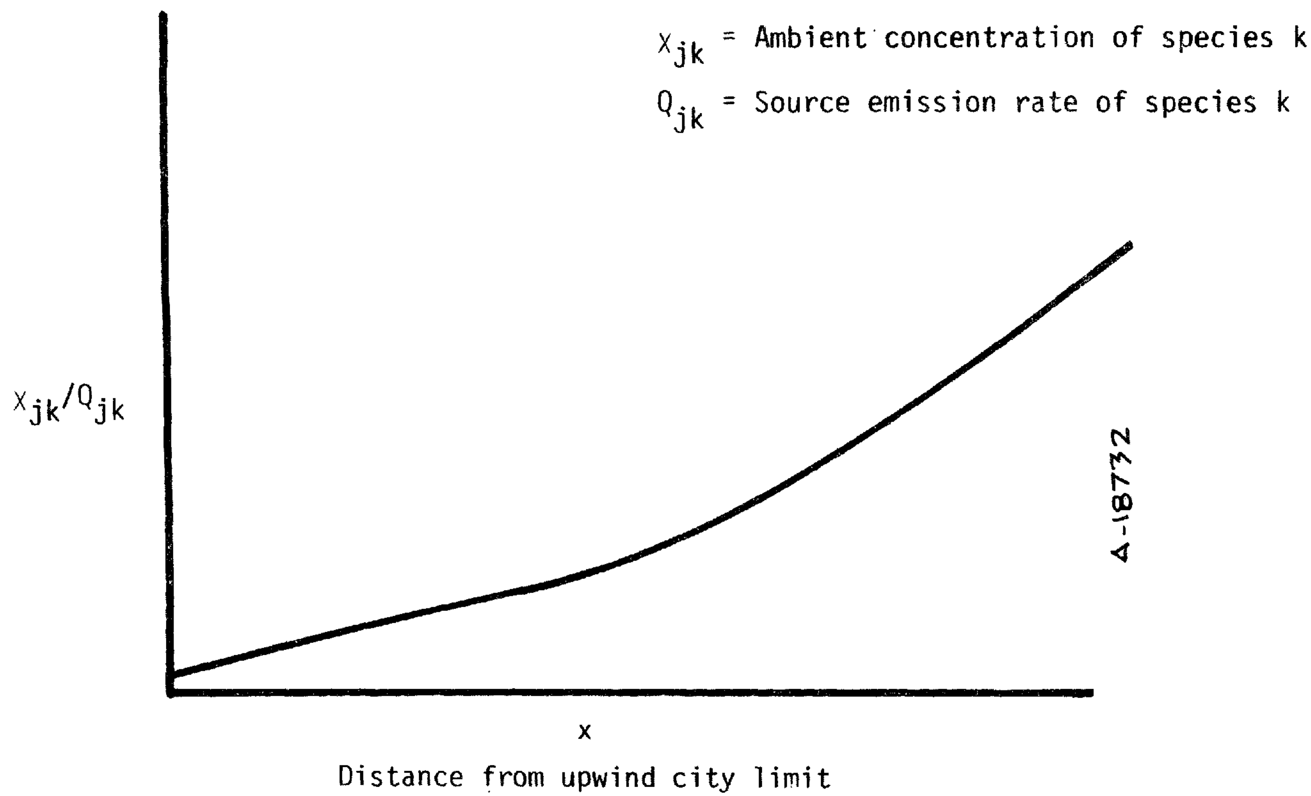

Figure 5-3. Ground-level concentration -- distributed sources.

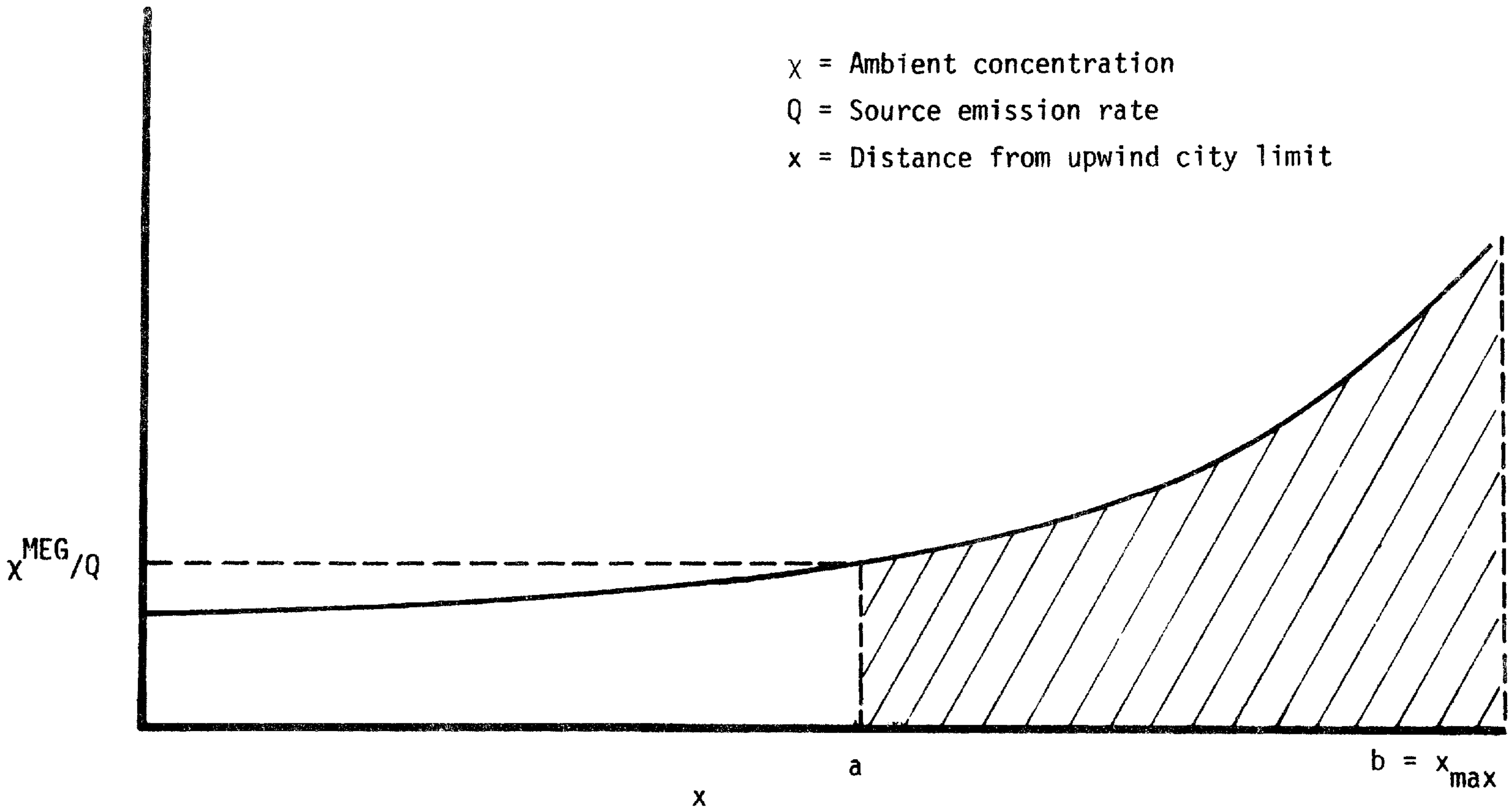

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Figure 5-4. Limits of integration for distributed sources.

These parameters are sums over the integrals of each species with corrections for local background. They are used to generate total and average impact factors in the same way as were the point source impact parameters.

5.1.1.3 Summary of Air Impact Assessment Methodology

The methodology described above is summarized in the flow chart of Figure 5-5. First, integrals for the ground level concentration due to a source are calculated over the area in which the concentration due to that source is appreciable, accounting for background concentrations from natural and all other anthropogenic sources. These integrals are not impact factors but indicate the contribution of each species to the total impact factor. Next, these single species integrals are summed over all emitted species to obtain impact parameters. The impact parameters for urban and rural sources are then multiplied by urban and rural population densities, respectively, to produce single-source impact factors. The resulting numbers indicate the impact of a single source in a rural or urban location. Multiplying these single source factors by the respective numbers of urban and rural sources gives the total air impact factor for sources of the type considered. Dividing this factor by the total number of sources gives the average impact factor for the sources. The total and average impact factors are the primary indicators of interest in the source analysis.

5.1.2 Liquid and Solid Effluent Streams

It is difficult to evaluate the impact of solid and liquid effluent streams in as much detail as gaseous streams. This is primarily because a large number of variables are involved in dispersion of liquid and solid

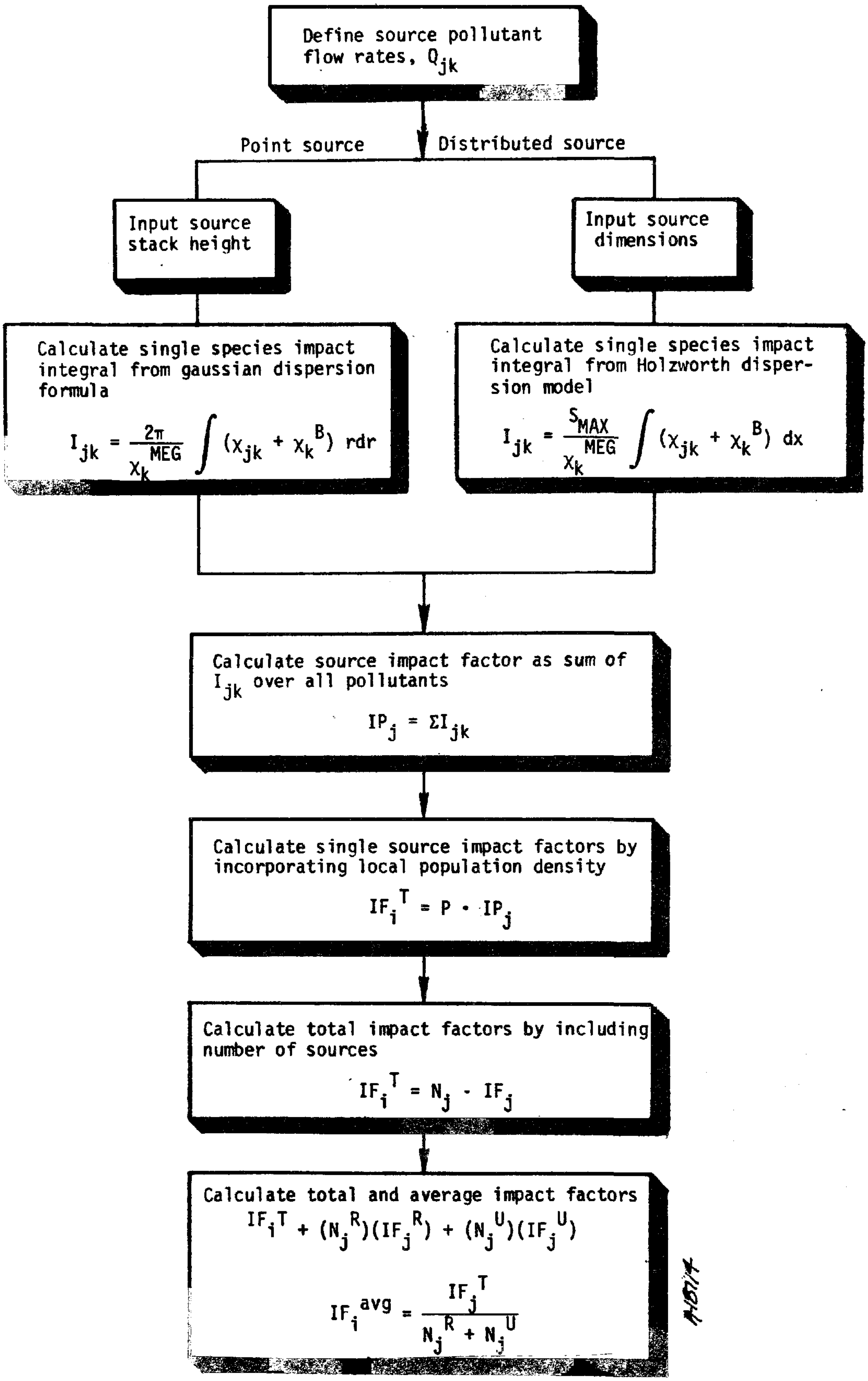

Figure 5-5. Air impact analysis calculation sequence.

NOMENCLATURE

Q_{jk}	Emission rate of species k from source j
χ_{jk}	Ground level concentration of species k due to source j
r	Distance from point source along wind direction
x	Distance along wind direction for distributed source
S_{max}	Total length of distributed source
H	Point source stack height
L	Mixing height
χ_k^{MEG}	Multimedia Environmental Goal (MEG) for species k (represents maximum permissible concentration)
χ_k^{BU}	Average urban background concentration of species k
χ_k^{BR}	Average rural background concentration of species k
I_{jk}^{N}	Natural single species impact integral
I_{jk}^{R}	Rural single species impact integral
I_{jk}^{U}	Urban single species impact integral
IP_j^{N}	Natural source impact parameter
IP_j^{R}	Rural source impact parameter
IP_j^{U}	Urban source impact paramenter

Figure 5-5. Continued

NOMENCLATURE	
IF_j^R	Rural single source impact factor
IF_j^U	Urban single source impact factor
P_R	Average rural population density
P_U	Average urban population density
IF_j^T	Total source impact factor
IF_j^{avg}	Average source impact factor
N_j^R	Number of sources of type j in rural location
N_j^U	Number of sources of type j in urban location

Figure 5-5. Concluded

effluents and certain required input data are scarce. Consequently, a more approximate method was used.

The approach chosen is very similar to the SAM/IA procedure (Reference 5-5) which uses a rapid screening procedure for assessing the impact of liquid and solid effluent streams. The procedure, shown schematically in Figure 5-6, compares the concentration of each species in the effluent stream to MATE (Minimum Acute Toxicity Effluent) concentrations. The MATE concentrations are one type of Multimedia Environmental Goal (MEG) derived by Research Triangle Institute (Reference 5-6). They describe approximate threshold concentrations which may cause harmful responses in humans under acute exposure.

The assessment procedure compares the concentration of each species in the effluent stream to the MATE. The resulting ratio is termed the single species hazard factor. The degree of hazard for each effluent stream is defined as the sum of these quantities over all pollutant species, and the impact factor for the effluent stream is defined as the product of the hazard factor and the effluent stream flowrate. (If a source has more than one effluent stream, the source impact factor is defined as the sum of the impact factors for each liquid or solid effluent stream.)

Finally, the total impact factor for the source type is defined as the product of the single source impact factor and the number of sources. This total impact factor is used for source-to-source comparisons.

5.2 DATA REQUIREMENTS

The effectiveness of the source analysis model in highlighting potential environmental problems and in ranking sources depends totally on the accuracy of the input data. Data required for the model include the

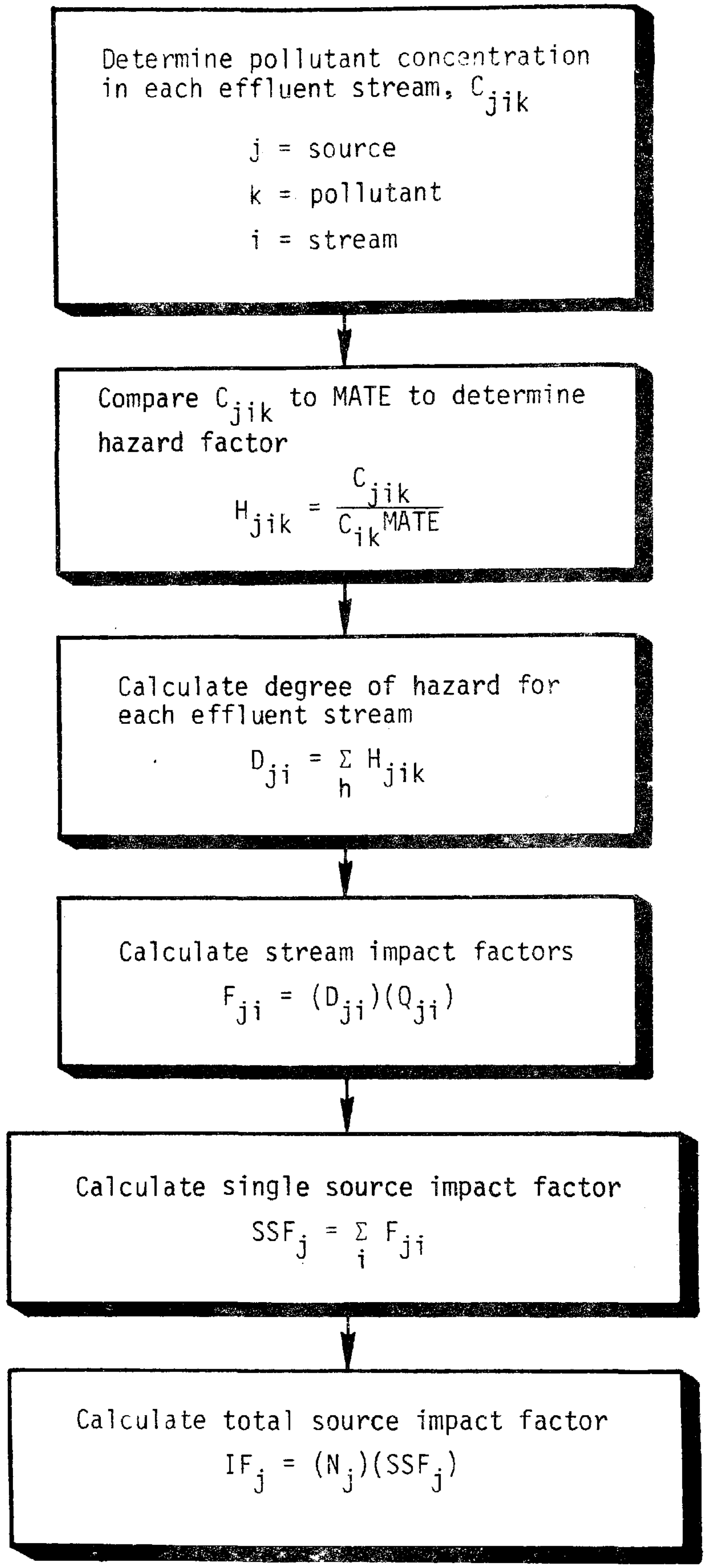

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Figure 5-6. Liquid and solid impact analysis calculation sequence.

NOMENCLATURE	
C_{jik}	Concentration of pollutant species k in effluent stream i of source j
H_{jik}	Hazard factor
D_{ji}	Degree of hazard for effluent stream i of source j
Q_{ji}	Flow rate of effluent stream i of source j (g/s)
F_{ji}	Stream impact factor
SSF_j	Single source impact factor
IF_j	Total source impact factor

Figure 5-6. Concluded

effluent stream flow rate for each pollutant, source characteristics such as discharge rate and stack height, population exposure to specific source types in urban and rural areas and ambient background pollutant concentrations. This section discusses the sources used for obtaining input data.

5.2.1 Emission Rates

Emission factors were compiled in Section 4.1 for specific equipment/fuel types. The effluent stream pollutant concentrations required for the Source Analysis Model were based directly on these data. Tabular summaries of the emission factors are given in Section 4.1.

5.2.2 Point Source Stack Heights

Stack heights of stationary sources were obtained by three methods. First, stack heights of utility boilers were obtained from statistics of the power industry (Reference 5-7). Stack heights for oil-, gas-, and coal-fired boilers were obtained statistically from a large set of data and are felt to be of highest quality. Next, stack heights for packaged boilers were obtained from related survey documents (References 5-8, and 5-9). The accuracy of this data is only fair, since the packaged boiler sector is made up of widely varying equipment types and applications, therefore stack heights vary. Stack heights for the remaining sectors came from both trade and industry associations as well as government agencies (References 5-10 through 5-16).

5.2.3 Urban/Rural Air Quality Control Regions (AQCRs)

The population densities in the source vicinity needed for the impact factor calculation (Equation 5-8, 5-9) were estimated by classifying each Air Quality Control Region (AQCR) into one of the following three categories:

- Urban AQCRs -- AQCRs containing a Standard Metropolitan Statistical Area (SMSA) with population greater than 700,000 and population density greater than 50 people/$(km)^2$
- Rural AQCRs -- AQCRs having a population density less than 50 people/$(km)^2$, containing no SMSAs with a population of more than 700,000
- Mixed AQCRs -- AQCRs having large urban and rural sections. For example, AQCR 217 (San Antonio) has a population density of 15 people/$(km)^2$, with an SMSA population of greater than 700,000. In such an AQCR, the SMSA is considered urban and the rest of the area is considered rural.

Information sources used for this categorization include:

- EPA -- Air Quality and Emission Trends Annual Report -- population and land areas of AQCRs (Reference 5-17)
- Bureau of Census -- land area of SMSAs (Reference 5-18)

- Bureau of Census -- Statistical Abstract -- populations of cities and SMSAs and future population projections (Reference 5-19)

Figure 5-7 displays the AQCR categorization. Although only 20 percent of the AQCRs are urban, these represent 50 percent of the national population.

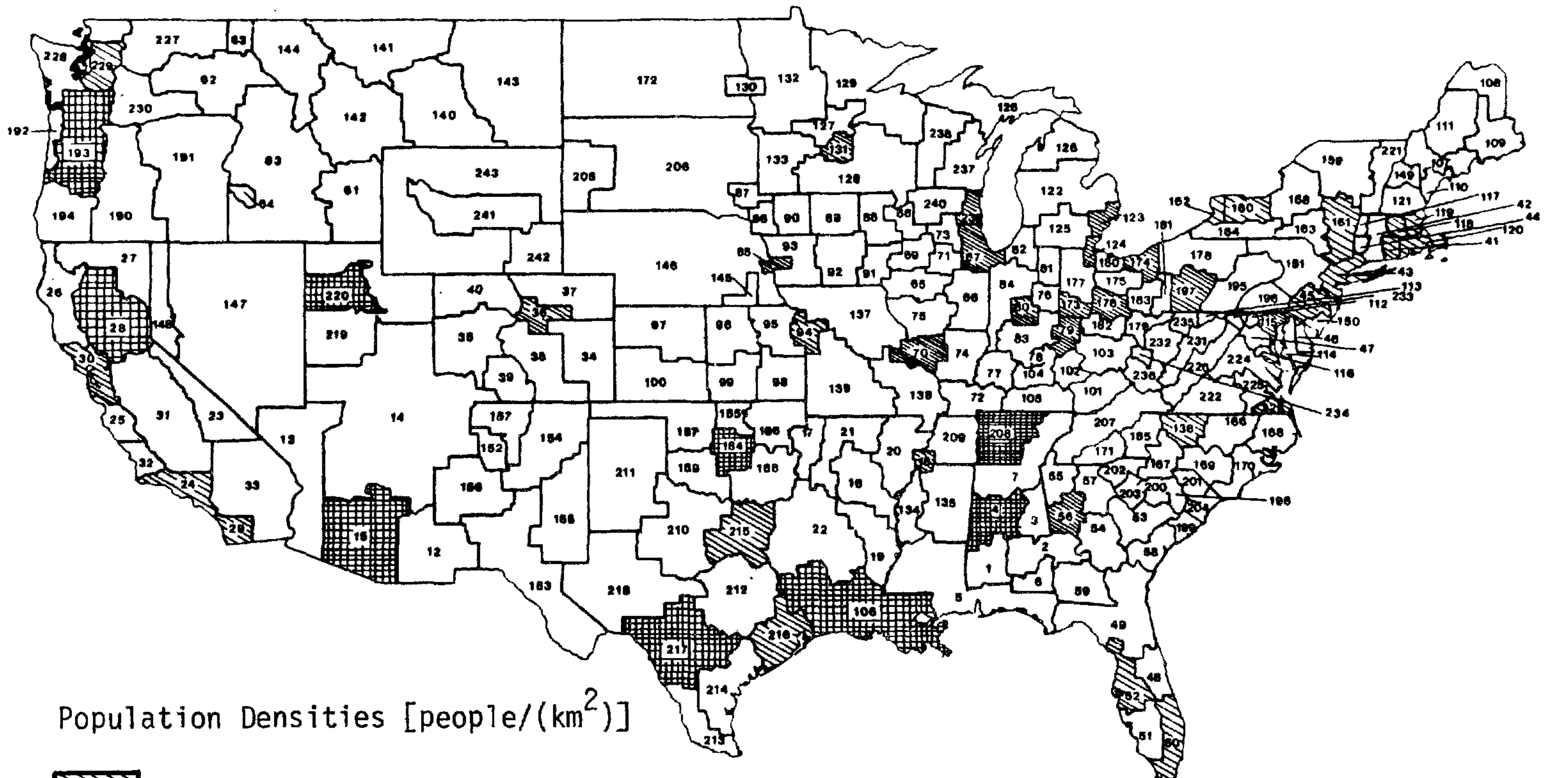
5.2.4 Urban/Rural Equipment Splits

Stationary combustion sources were grouped according to urban and rural locations using National Emissions Data System (NEDS) (Reference 5-20) fuel consumption data. The amount of fuel consumed in each AQCR was determined for each equipment type. Then, these AQCR fuel consumptions were grouped into categories representing urban and rural areas (AQCRs). The urban/rural equipment split was assumed equal to the urban/rural fuel split. For mixed urban/rural AQCRs, the equipment population was prorated by the proportion of the population in the urban area (SMSA) and the rural area of the AQCR.

5.2.5 Urban and Rural Ambient Pollutant Concentrations

In accordance with the Clean Air Act, ambient air quality data resulting from air monitoring operations of state, local, and federal networks must be reported each calendar quarter to the Environmental Protection Agency. The EPA Storage and Retrieval of Aerometric Data (SAROAD) system is the repository for these data. EPA periodically publishes summaries of all data submitted and these summaries are available to the public upon request. The summaries were used in the Source Analysis Model for background concentrations of criteria pollutants, and most noncriteria pollutants (Reference 5-21 through 5-27).

Trace element values not reported from SAROAD were obtained from current published reports (Reference 5-28 through 5-33). Since these data



Population Densities [people/(km^2)]

>50 -- urban AQCR.

<50 with large urban area -- mixed AQCR.

<50 without large urban area -- rural AQCR.

are generally for isolated geographical areas, the overall data quality on a national basis is poor.

5.2.6 Average Source Fuel Consumption

Average fuel consumptions for utility boilers were obtained for each firing type and fuel from analysis of FPC-67 tapes. These values were used to determine the total number of sources in each equipment sector (References 5-34 and 5-35). Average fuel consumptions for packaged boiler equipment types came from recent EPA documents (References 5-36 and 5-37). The packaged boiler data are not as accurate as the utility data, since this sector is large and varied. Consumption data for the remaining combustion sources were obtained from both published data, trade, and industrial associations and government agencies (References 5-38 through 5-44). These values are of fair quality. The size ranges of most of these equipment types are large, and thus it is difficult to define an average value.

5.3 SOURCE ANALYSIS MODELING RESULTS

Relative rankings of the pollution impact potential of stationary combustion sources are given in this subsection for gaseous, and liquid and solid effluents. Pollution impact potentials were evaluated for the criteria pollutants -- NO_x, SO_x, CO, HC, and particulates -- as well as sulfates, trace metallics, POMs and trace elements. Separate rankings are given for gaseous pollutants and for liquid and solid pollutants. Pollution impact potential is also projected to 1985 and 2000. The rankings in this section are based on the low nuclear reference energy projection scenario described in Section 3.4.1.

5.3.1 Gaseous Pollution Potential Rankings

A ranking of gaseous pollution potential for the 30 most significant sources in 1974 is given in Table 5-1. The "total impact factor" shown in the final column of the table is the composite impact factor (defined in Section 5.1.1) for all gaseous species included in the emissions inventory. Thus, to rank a specific equipment type, the following were considered: (1) emission rates and effluent toxicity, (2) total number of sources installed nationwide, (3) ambient background near each source, and (4) the population exposed to each effluent from that equipment type in urban and rural areas.

Table 5-2 ranks sources on the basis of the "average source impact factor," defined in Section 5.1.1 as the total impact factor divided by the total number of sources (both urban and rural). This impact factor includes the same four considerations described for the total pollution potential factor of Table 5-1. Comparing Table 5-2 to Table 5-1 shows whether a high impact factor is the result of many "moderately dirty" sources or only a few "very dirty" sources.

Table 5-3 lists the 30 sources with the highest NO_x pollution potential. The impact factors on this table are the single pollutant impact factor for NO_x described in Section 5.1.1. They exclude background concentrations, population densities and total number of sources. A high ranking indicates a large area (urban or rural) exposed to high NO_x levels from a single source.

Because the future growth of each source type is a major consideration in developing effective control priorities, the total pollution potential rankings of stationary sources for 1985 and 2000 are given in Tables 5-4 and 5-5, respectively. The cross rankings in 1985 and

TABLE 5-1. TOTAL POLLUTION POTENTIAL RANKING (GASEOUS) STATIONARY SOURCES IN YEAR 1974

Rank	Sector	Equipment Type	Fuel	Total Impact Factor
1	Packaged Boilers	Stoker Firing WT[c] <29 MW[a]	Coal	6.73×10^{11}
2	Packaged Boilers	Stoker Firing FT[d] <29 MW[a]	Coal	5.59×10^{11}
3	Utility Boilers	Tangential	Coal	1.42×10^{11}
4	Utility Boilers	Wall Firing	Coal	1.09×10^{11}
5	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Coal	7.78×10^{10}
6	Packaged Boilers	Stoker Firing WT[c] <29 MW[a]	Coal	7.64×10^{10}
7	Utility Boilers	Vertical & Stoker	Coal	5.69×10^{10}
8	Utility Boilers	Cyclone	Coal	4.12×10^{10}
9	Utility Boilers	Horizontally Opposed	Coal	2.10×10^{10}
10	Utility Boilers	Tangential	Oil	2.65×10^{9}
11	Utility Boilers	Wall Firing	Oil	2.22×10^{9}
12	Utility Boilers	Horizontally Opposed	Oil	1.13×10^{9}
13	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Oil	7.02×10^{8}
14	Packaged Boilers	Scotch FT[d] <29 MW[a]	Oil	5.50×10^{8}
15	Packaged Boilers	Firebox FT[d] <29 MW[a]	Oil	3.64×10^{8}
16	Utility Boilers	Tangential	Gas	3.20×10^{8}
17	Packaged Boilers	Scotch FT[d]	Gas	2.88×10^{8}

T-622

[a]Heat input

[b]Heat output

[c]Watertube

[d]Firetube

TABLE 5-1. Concluded

Rank	Sector	Equipment Type	Fuel	Total Impact Factor
18	Ind. Process Comb.	Coke Oven Underfire	Processed Material	2.84×10^8
19	Reciprocating IC Engines	SI[e] >75 kW/cyl[b]	Gas	2.3×10^8
20	Packaged Boilers	Single Burner WT[c] <29 MW[a]	Oil	2.28×10^8
21	Packaged Boilers	HTR Boiler <29 MW[a]	Oil	2.25×10^8
22	Packaged Boilers	Brick & Ceramic Kilns	Processed Material	2.01×10^8
23	Utility Boilers	Horizontally Opposed	Gas	1.61×10^8
24	Utility Boilers	Wall Firing	Gas	1.28×10^8
25	Utility Boilers	Cyclone	Oil	1.27×10^8
26	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Gas	2.72×10^7
27	Ind. Process Comb.	Cement Kilns	Processed Material	2.71×10^7
28	Packaged Boilers	Cast Iron	Oil	2.47×10^7
29	Gas Turbines	Simple Cycle >15 MW[b]	Oil	2.39×10^7
30	Ind. Process Comb.	Refinery Htr. Nat. Draft	Gas	2.22×10^7

T-622

[a]Heat input

[b]Heat output

[c]Watertube

[d]Firetube

[e]Spark ignition

TABLE 5-2. AVERAGE SOURCE POLLUTION POTENTIAL RANKING (GASEOUS) STATIONARY SOURCES IN YEAR 1974

Rank	Sector	Equipment Type	Fuel	Average Impact Factor
1	Utility Boilers	Horizontally Opposed	Coal	4.26×10^8
2	Utility Boilers	Cyclone	Coal	3.52×10^8
3	Utility Boilers	Tangential	Coal	3.11×10^8
4	Utility Boilers	Wall Firing	Coal	1.76×10^8
5	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Coal	1.21×10^8
6	Packaged Boilers	Stoker Firing WT[c] <29 MW[a]	Coal	8.45×10^7
7	Packaged Boilers	Stoker Firing WT[c] <29 MW[a]	Coal	8.35×10^7
8	Utility Boilers	Vertical and Stoker	Coal	7.34×10^7
9	Packaged Boilers	Stoker Firing FT[d] <29 MW[a]	Coal	2.29×10^7
10	Utility Boilers	Horizontially Opposed	Oil	1.52×10^7
11	Utility Boilers	Tangential	Oil	1.39×10^7
12	Utility Boilers	Cyclone	Oil	3.27×10^6
13	Utility Boilers	Wall Firing	Oil	2.21×10^6
14	Utility Boilers	Horizontally Opposed	Oil	1.76×10^6
15	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Oil	7.71×10^5
16	Utility Boilers	Wall Firing	Gas	2.49×10^5
17	Utility Boilers	Tangential	Gas	1.54×10^5
18	Utility Boilers	Cyclone	Gas	9.55×10^4

T-621

[a]Heat input

[b]Heat output

[c]Watertube

[d]Firetube

TABLE 5-2. Concluded

Rank	Sector	Equipment Type	Fuel	Total Impact Factor
19	Gas Turbines	Simple Cycle >15 MW[b]	Oil	8.70×10^4
20	Ind. Process Comb.	Refinery Htr. Nat. Draft	Oil	6.60×10^4
21	Ind. Process Comb.	Refinery Htr. Forced Draft	Oil	5.81×10^4
22	Gas Turbines	Simple Cycle >15 MW[b]	Gas	5.80×10^4
23	Packaged Boiler	Wall Firing WT[c] >29 MW[a]	Gas	5.26×10^4
24	Packaged Boiler	Single Burner WT[c] <29 MW[a]	Oil	3.21×10^4
25	Ind. Process Comb.	Refinery Htr. Forced Draft	Gas	2.73×10^4
26	Ind. Process Comb.	Refinery Htr. Nat. Draft	Gas	2.09×10^4
27	Ind. Process Comb.	Coke Oven Underfire	Processed Material	1.92×10^4
28	Packaged Boilers	Scotch FT[d] <29 MW[a]	Gas	1.26×10^4
29	Ind. Process Comb.	Cement Kilns	Processed Material	1.24×10^4
30	Packaged Boilers	Scotch FT[d] <29 MW[a]	Oil	1.20×10^4

T-621

[a]Heat input

[b]Heat output

[c]Watertube

[d]Firetube

TABLE 5-3. NO_x[e] POLLUTION POTENTIAL RANKING STATIONARY SOURCES IN 1974

Rank	Sector	Equipment Type	Fuel	NO_x Impact Factor
1	Utility Boilers	Cyclone	Bituminous	4.97×10^9
2	Utility Boilers	Horizontally Opposed	Lignite	3.40×10^9
3	Utility Boilers	Horizontally Opposed	Gas	2.80×10^9
4	Utility Boilers	Horizontally Opposed	Bituminous	2.78×10^9
5	Utility Boilers	Cyclone	Lignite	2.44×10^9
6	Utility Boilers	Tangential	Bituminous	9.82×10^8
7	Utility Boilers	Horizontally Opposed	Oil	9.21×10^8
8	Utility Boilers	Tangential	Lignite	8.22×10^8
9	Utility Boilers	Tangential	Gas	3.79×10^8
10	Utility Boilers	Wall Firing	Lignite	2.88×10^8
11	Utility Boilers	Tangential	Oil	2.55×10^8
12	Utility Boilers	Wall Firing	Bituminous	2.43×10^8
13	Utility Boilers	Wall Firing	Gas	2.30×10^8
14	Utility Boilers	Cyclone	Gas	1.37×10^8
15	Gas Turbines	Simple Cycle >15 MW[b]	Oil	1.24×10^8
16	Gas Turbines	Simple Cycle >15 MW[b]	Oil	1.24×10^7
17	Ind. Process Comb.	Refinery Htr. Forced Draft	Oil	5.14×10^7

T-613

[a]Heat input

[b]Heat output

[c]Watertube

[d]Firetube

[e]NO_2 basis

TABLE 5-3. Concluded

Rank	Sector	Equipment Type	Fuel	NO_x Impact Factor
18	Utility Boilers	Wall Firing	Oil	4.81×10^7
19	Utility Boilers	Cyclone	Oil	4.07×10^7
20	Ind. Process Comb.	Refinery Htr. Nat. Draft	Oil	3.89×10^7
21	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Oil	2.59×10^7
22	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Bit./Lig. Coal	2.59×10^7
23	Ind. Process Comb.	Refinery Htr. Forced Draft	Gas	2.45×10^7
24	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Gas	2.25×10^7
25	Ind. Process Comb.	Refinery Htr. Nat. Draft	Gas	1.26×10^7
26	Packaged Boilers	Stoker Firing WT[c] >29 MW[a]	Bit./Lig. Coal	6.00×10^6
27	Reciprocating IC Engines	CI[e] >75 kW/cyl[b]	Oil	4.09×10^6
28	Reciprocating IC Engines	SI[f] >75 kW/cyl[b]	Gas	3.51×10^6
29	Packaged Boilers	Stoker Firing WT[c] <29 MW[a]	Bit./Lig. Coal	2.47×10^6
30	Reciprocating IC Engines	CI[e] >75 kW/cyl[b]	Dual (Oil + Gas)	1.97×10^4

T-613

[a]Heat input

[b]Heat output

[c]Watertube

[d]Firetube

[e]Compression ignition

[f]Spark ignition

TABLE 5-4. TOTAL POLLUTION POTENTIAL RANKING (GASEOUS) STATIONARY SOURCES IN YEAR 1985

Rank	Sector	Equipment Type	Fuel	Total Impact Factor
1	Packaged Boilers	Stoker Firing WT[c] <29 MW[a]	Coal	4.19×10^{11}
2	Packaged Boilers	Stoker Firing FT[d] <29 MW[a]	Coal	3.48×10^{11}
3	Utility Boilers	Tangential	Coal	3.04×10^{11}
4	Utility Boilers	Wall Firing	Coal	2.34×10^{11}
5	Utility Boilers	Vertical and Stoker	Coal	5.00×10^{10}
6	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Coal	4.84×10^{10}
7	Packaged Boilers	Stoker Firing WT[c] >29 MW[a]	Coal	4.76×10^{10}
8	Utility Boilers	Horizontally Opposed	Coal	4.55×10^{10}
9	Utility Boilers	Cyclone	Coal	3.69×10^{10}
10	Utility Boilers	Tangential	Oil	2.31×10^{9}
11	Utility Boilers	Wall Firing	Oil	1.05×10^{9}
12	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Oil	1.04×10^{9}
13	Utility Boilers	Horizontally Opposed	Oil	9.83×10^{8}
14	Packaged Boilers	Scotch FT[d] <29 MW[a]	Oil	8.24×10^{8}
15	Packaged Boilers	Firebox FT[d] <29 MW[a]	Oil	5.46×10^{8}
16	Packaged Boilers	Scotch FT[d] <29 MW[a]	Gas	3.87×10^{8}
17	Packaged Boilers	Single Burner WT[c] <29 MW[a]	Oil	3.43×10^{8}

T-614

[a]Heat input

[b]Heat output

[c]Watertube

[d]Firetube

TABLE 5-4. Concluded

Rank	Sector	Equipment Type	Fuel	Total Impact Factor
18	Packaged Boilers	HRT Boilers <29 MW[a]	Oil	3.38×10^8
19	Ind. Process Comb.	Coke Oven Underfire	Processed Mat'l	3.15×10^8
20	Ind. Process Comb.	Brick and Ceramic Kilns	Processed Mat'l	2.23×10^8
21	Utility Boilers	Cyclone	Oil	1.13×10^8
22	Reciprocating IC Engines	SI[e] >75 kW/cyl[b]	Gas	1.08×10^8
23	Utility Boilers	Horizontally Opposed	Gas	9.48×10^7
24	Utility Boilers	Wall Firing	Gas	8.30×10^7
25	Packaged Boilers	Cast Iron Boilers	Oil	3.73×10^7
26	Ind. Process Comb.	Cement Kilns	Processed Mat'l	3.00×10^7
27	Gas Turbines	Simple Cycle >15 MW[b]	Oil	2.67×10^7
28	Ind. Process Comb.	Refinery Htr. Nat. Draft	Gas	2.45×10^7
29	Reciprocating IC Engines	CI[f] >75 kW/cyl[b]	Oil	2.26×10^7
30	Gas Turbines	Simple Cycle >15 MW[b]	Gas	1.81×10^7

T-614

[a] Heat input

[b] Heat output

[c] Watertube

[d] Firetube

[e] Spark ignition

[f] Compression ignition

TABLE 5-5. TOTAL POLLUTION POTENTIAL RANKING (GASEOUS)
STATIONARY SOURCES IN YEAR 2000

Rank	Sector	Equipment Type	Fuel	Total Impact Factor
1	Packaged Boiler	Stoker Firing WT[c] <29 MW[a]	Coal	6.59×10^{11}
2	Packaged Boiler	Stoker Firing FT[d] <29 MW[a]	Coal	5.47×10^{11}
3	Utility Boilers	Tangential	Coal	4.46×10^{11}
4	Utility Boilers	Wall Firing	Coal	3.43×10^{11}
5	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Coal	7.62×10^{10}
6	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Coal	7.48×10^{10}
7	Utility Boilers	Horizontally Opposed	Coal	6.66×10^{10}
8	Utility Boilers	Vertical and Stoker	Coal	4.13×10^{10}
9	Utility Boilers	Cyclone	Coal	2.70×10^{10}
10	Utility Boilers	Tangential	Oil	3.85×10^{9}
11	Utility Boilers	Wall Firing	Oil	3.32×10^{9}
12	Utility Boilers	Horizontally Opposed	Oil	1.62×10^{9}
13	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Oil	1.28×10^{9}
14	Packaged Boilers	Scotch FT[d] <29 MW[a]	Oil	1.02×10^{9}
15	Packaged Boilers	Firebox FT[d] <29 MW[a]	Oil	6.78×10^{8}
16	Ind. Process Comb.	Coke Oven Underfire	Processed Mat'l	4.25×10^{8}
17	Packaged Boilers	HRT Boilers <29 MW[a]	Oil	4.19×10^{8}

T-615

[a]Heat input

[b]Heat output

[c]Watertube

[d]Firetube

TABLE 5-5. Concluded

Rank	Sector	Equipment Type	Fuel	Total Impact Factor
18	Packaged Boilers	Single Burner WT[c] <29 MW[a]	Oil	4.15×10^8
19	Packaged Boilers	Scotch FT[d] <29 MW[a]	Gas	3.90×10^8
20	Ind. Process Comb.	Brick and Ceramic Kilns	Processed Mat'l	3.00×10^8
21	Utility Boilers	Cyclone	Oil	9.34×10^7
22	Packaged Boilers	Cast Iron Boilers	Oil	4.63×10^7
23	Reciprocating IC Engines	SI[e] >75 kW/cyl[b]	Gas	4.55×10^7
24	Ind. Process Comb.	Cement Kilns	Processed Mat'l	4.04×10^7
25	Gas Turbines	Simple Cycle >15 MW[b]	Oil	3.82×10^7
26	Gas Turbines	Simple Cycle >15 MW[b]	Gas	3.41×10^7
27	Reciprocating IC Engines	CI[f] >75 kW/cyl[b]	Oil	3.03×10^7
28	Ind. Process Comb.	Refinery Htr. Nat. Draft	Gas	2.98×10^7
29	Ind. Process Comb.	Open Hearth Furnaces	Processed Mat'l	2.41×10^7
30	Ind. Process Comb.	Refinery Htr. Nat. Draft	Oil	1.89×10^7

T-615

[a]Heat input

[b]Heat output

[c]Watertube

[d]Firetube

[e]Spark ignition

[f]Compression ignition

2000 of the 30 highest stationary sources in 1974 are summarized in Table 5-6, showing changes in ranking for these years.

Trends in pollution potential through the year 2000 are presented for the three major fuels for the reference, conservation, electrification, and synthetics scenarios in Appendix H of Volume II. The tables for each scenario are given as follows:

- Reference high nuclear: Figures H-1 to H-5
- Reference low nuclear: Figures H-6 to H-10
- Conservation: Figures H-11 to H-15
- Electrification: Figures H-16 to H-20
- Synthetics: Figures H-21 to H-25

These trends are based on the total impact factor (Equation 5-10) which considers all sources nationwide, ambient pollutant backgrounds, and the exposed population.

Finally, Tables 5-7 through 5-9 summarize single source pollution potentials for each pollutant, equipment, fuel combination considered in this assessment. These potentials are based on single pollutant impact factors that consider ambient pollutant backgrounds but exclude exposed population densities and total equipment population. In these tables, pollutants are denoted by XXX if they have a high pollution potential or single species impact factor in a region with no natural background. Pollutants which have high concentrations only when emitted into regions already containing typical rural or urban background levels are denoted by XX and X, respectively.

5.3.2 Liquid and Solids Pollution Potential Ranking

Few data are available to assess the pollution potential of solid and liquid effluent streams. In fact, the only liquid and solid emission

TABLE 5-6. TOTAL POLLUTION POTENTIAL CROSS RANKING (GASEOUS) STATIONARY SOURCES IN YEAR 1974

1974 Ranking	Sector	Equipment Type	Fuel	1985 Ranking	2000 Ranking
1	Packaged Boilers	Stoker Firing WT[c] <29 MW[a]	Coal	1	1
2	Packaged Boilers	Stoker Firing FT[d] <29 MW[a]	Coal	2	2
3	Utility Boilers	Tangential	Coal	3	3
4	Utility Boilers	Wall Firing	Coal	4	4
5	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Coal	6	5
6	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Coal	7	6
7	Utility Boilers	Vertical and Stoker	Coal	5	8
8	Utility Boilers	Cyclone	Coal	9	9
9	Utility Boilers	Horizontally Opposed	Coal	8	7
10	Utility Boilers	Tangential	Oil	10	10
11	Utility Boilers	Wall Firing	Oil	11	11
12	Utility Boilers	Horizontally Opposed	Oil	13	12
13	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Oil	12	13
14	Packaged Boilers	Scotch FT[d] <29 MW[a]	Oil	14	14
15	Packaged boilers	Firebox FT[d] <29 MW[a]	Oil	15	15
16	Utility Boilers	Tangential	Gas	>30	>30
17	Packaged Boilers	Scotch FT[d] <29 MW[a]	Gas	16	19

T-616

[a] Heat input

[b] Heat output

[c] Watertube

[d] Firetube

TABLE 5-6. Concluded

1974 Ranking	Sector	Equipment Type	Fuel	1985 Ranking	2000 Ranking
18	Ind. Process comb.	Coke Oven Underfire	Processed Mat'l	19	16
19	Reciprocating IC Engines	SI[e] >75 kW/cyl[b]	Gas	22	23
20	Packaged Boilers	Single Burner WT[c] < 29 MW[a]	Oil	17	18
21	Packaged Boilers	HRT Boilers	Oil	18	17
22	Ind. Process Comb.	Brick and Ceramic Kilns	Processed Mat'l	20	20
23	Utility Boilers	Horizontally Opposed	Gas	23	>30
24	Utility Boilers	Wall Firing	Gas	24	>30
25	Utility Boilers	Cyclones	Oil	21	21
26	Packaged Boilers	Wall Firing WT[c] >29 MW[a]	Gas	>30	>30
27	Ind. Process Comb.	Cement Kilns	Processed Mat'l	26	24
28	Packaged Boilers	Cast Iron Boilers	Oil	25	22
29	Gas Turbines	Simple Cycle >15 MW[b]	Oil	27	25
30	Ind. Process Comb.	Refinery Htr. Nat. Draft	Gas	28	28

T-616

[a]Heat input

[b]Heat output

[c]Watertube

[d]Firetube

[e]Spark ignition

[f]Compression ignition

TABLE 5-7. UTILITY BOILERS -- POLLUTION POTENTIAL OF SINGLE POLLUTANTS

Equipment	Fuel	NO_x	SO_x	HC	CO	Part.	SO_3	POM	Ba	Be	B	Cr	Co	Cu	Pb	Mn	Hg	Mo	Ni	V	Zn	Zr	As	Bi	Al	Sb	Cd	Se	P	Sr
Tangential	Bituminous	X	XXX			XXX				XXX		XX													XXX					
	Lignite		XX			XXX				XXX		X													XXX					
	Residual Oil	XX	XXX									XXX							XXX	XXX										
	Distillate Oil	XX	X																											
	Natural Gas	XXX																												
Wall Firing	Bituminous	X	XXX							XXX																				
	Lignite	X								XXX																				
	Residual Oil	X	X									X							XXX											
	Distillate Oil	X																												
	Natural Gas	XXX																												
Cyclone	Bituminous	XXX	XXX							XXX		XXX													XXX					
	Lignite	XX	XX			XXX				XXX		XX													XXX					
	Residual Oil	X	X									X							XXX	XXX										
	Distillate Oil																													
	Natural Gas	XXX																												
Vertical & Stoker	Anthracite									XXX																				
	Bituminous									XXX																				
	Lignite									XXX																				

T-263

XXX -- Pristine environment
XX -- Rural environment
X -- Urban environment

TABLE 5-8. PACKAGED BOILERS -- POLLUTION POTENTIAL OF SINGLE POLLUTANTS

T-264

Equipment	Fuel	NO_x	SO_x	HC	CO	Part.	SO_3	POM	Ba	Be	B	Cr	Co	Cu	Pb	Mn	Hg	Mo	Ni	V	Zn	Zr	As	Bi	Al	Sb	Cd	Se	P	Sr
Wall Firing WT[a]	Bituminous/ Lignite	X	XXX							XXX																				
	Residual Oil	X	X										X						XXX											
Stoker Firing WT[a] >29 MW[c]	Bituminous/ Lignite		XXX							XXX																				
Single Burner WT[a] <29 MW[c]	Residual Oil	X	X									X							XXX	XXX										
Scotch FT[b]	Distillate Oil							XXX																						
	Natural Gas							XXX																						
	Process Gas	X						XXX																						
	Residual Oil		X					XXX				X							XXX											
Firebox FT[b]	Distillate Oil							XXX																						
	Residual Oil		X					XXX											XXX											
Stoker Firing WT[a] <29 MW[c]	Anthracite									XXX		XXX																		
	Bituminous/ Lignite	X	XXX			XXX				XXX		XXX													XXX					
Stoker Firing FT[b]	Anthracite							X		XXX		XXX																		
	Bituminuous/ Lignite		XXX			XXX		X		XXX																				
HRT Boiler	Distillate Oil							XXX																						
	Residual Oil		X					XXX											XXX											

XXX -- Pristine environment
XX -- Rural environment
X -- Urban environment

[a]Watertube

[b]Firetube

[c]Heat input

TABLE 5-9. GAS TURBINES, RECIPROCATING IC ENGINES, AND INDUSTRIAL PROCESS HEATING -- POLLUTION POTENTIAL OF SINGLE POLLUTANTS

T-265

Equipment	Fuel	NO_x	SO_x	HC	CO	Part.	SO_3	POM	Ba	Be	B	Cr	Co	Cu	Pb	Mn	Hg	Mo	Ni	V	Zn	Zr	As	Bi	Al	Sb	Cd	Se	P	Sr
Simple Cycle >15 MW[a]	Distillate Oil	XXX	XXX			XXX																								
	Natural Gas	XXX																												
Compression Ignition >75 kW/cyl[a]	Distillate Oil	XXX																												
	Dual (Oiland Gas)	XXX																												
Spark Ignition >75 kW/cyl[a]	Natural Gas	XXX																												
Coke Oven Underfire	Processed Material					XXX																								
Brick & Ceramic Kilns	Processed Material					XXX																								
Refinery Heaters -- Natural Draft	Gas	XXX																												
Refinery Heaters -- Natural Draft	Oil	XXX	XXX			XXX																								
Refinery Heaters -- Forced Draft	Gas	XXX																												
Refinery Heaters -- Forced Draft	Oil	XXX	XXX			XXX																								

XXX -- Pristine environment

XX -- Rural environment

X -- Urban environment

[a]Heat output

streams which have been characterized to any extent are the ash discharge streams of utility and large industrial boilers. Although these sources are the only ones considered in this assessment, they account for well over 90 percent of all combustion-generated solid and liquid wastes.

Table 5-10 lists solid and liquid impact parameters (as described in Section 5.1.2). These impact parameters indicate the degree of hazard within each effluent stream. They are obtained by comparing the concentration of each species in the effluent stream to a specific MATE. The sum of the ratios for all pollutants in the effluent stream is then an indication of the unit pollution potential of each effluent stream.

The ranking of pollution potential from liquid and solid effluent streams is given in Table 5-11. This ranking is based on total impact fators that reflect the toxicity of the effluent for a particular boiler type, and the total quantity of emissions (as defined in Section 5.1.2).

TABLE 5-10. POLLUTION PARAMETERS (LIQUID AND SOLID) STATIONARY SOURCES IN YEAR 1974

	Bottom Ash (solid)	Bottom Ash (slurry)	Flyash (solid)
Anthracite coal	0.045	0.000024	0.051
Bituminous coal	0.139	0.000015	0.112
Lignite coal	0.119	0.000014	0.082
Residual oil	0.496	0.000012	0.723
Distillate oil	0	0	0
Natural gas	0	0	0

TABLE 5-11. TOTAL POLLUTION POTENTIAL RANKING (LIQUID AND SOLID) STATIONARY SOURCES IN YEAR 1974

Rank	Sector	Equipment Type	Fuel	Total Impact Factor
1	Utility Boilers	Tangential	Coal	621×10^{12}
2	Utility Boilers	Wall Firing	Oil	472×10^{12}
3	Utility Boilers	Tangential	Oil	468×10^{12}
4	Utility Boilers	Wall Firing	Coal	357×10^{12}
5	Utility Boilers	Cyclone	Coal	349×10^{12}
6	Packaged Boilers	Stoker Firing WT[b] >29 MW[a]	Coal	191×10^{12}
7	Utility Boilers	Horizontally Opposed	Oil	189×10^{12}
8	Packaged Boilers	Wall Firing WT[b] >29 MW[a]	Oil	114×10^{12}
9	Utility Boilers	Horizontally Opposed	Coal	101×10^{12}
10	Packaged Boilers	Wall Firing WT[b] >29 MW[a]	Coal	53×10^{12}
11	Utility Boilers	Cyclone	Oil	52×10^{12}
12	Utility Boilers	Vertical and Stoker	Coal	29×10^{12}

T-865

[a]Heat input

[b]Watertube

These factors are obtained by multiplying the impact parameters for specific effluent streams by the respective single source effluent stream flow rate and the total number of sources nationwide.

5.4 CONCLUSIONS

In this study, a Source Analysis Model was developed to identify and rank potential environmental problems due either to specific pollutants from a single effluent stream or from the entire source. The model can indicate impact potential either for a single source or the nationwide aggregate of sources considering population proximity to the source. This model will be used during the NO_x Control Environmental Assessment Program to screen potential problems and evaluate control options as detailed multimedia emissions data become available from the field test programs of the EPA and other agencies. For the present study, available data for use in the model were compiled for source emissions, human health impact threshold criteria, population densities near the sources, and emission growth rates. Although these data are not as complete as desired, they were used with the SAM model to obtain a tentative indication of potential problem areas. The following list summarizes capabilities of the SAM model and notes specific cases which were run in this study:

Source Analysis Model Capabilities	Test Cases
• Total nationwide impact factors for specific source types, considering population exposure and all pollutants inventoried for gaseous effluent streams	-- Total gaseous effluent stream pollution potential ranking for 1974 (Table 5-1) -- Average gaseous effluent stream pollution potential ranking for 1974 (Table 5-2)

Source Analysis Model Capabilities	Test Cases
• Total nationwide impact factors for all pollutants inventoried for liquid and solid effluent streams	-- Total liquid and solid effluent stream pollution potential ranking for 1974 (Table 5-11)
• Projections of total nationwide impact factors	-- Total gaseous effluent stream pollution potential ranking for 1985 and 2000 (Tables 5-4, 5-5)
	-- Total gaseous effluent stream pollution potential cross ranking for 1974, 1985 and 2000 (Table 5-6)
• Single source, single pollutant impact not considering population exposure	-- NO_x single source pollution potential ranking for stationary sources (Table 5-3)
	-- Pollution potential of single pollutants from utility boilers, packaged boilers, gas turbines, IC engines and industrial process heating (Tables 5-7 to 5-9)

Additional impact factor results are tabulated in Appendices F, G, and H of Volume II.

Although the impact factor results generated in this study are useful for detecting gross qualitative trends, firm quantitative conclusions are precluded by inadequacies in the data and the uncertainties in projected energy usage. Key data needs are as follows:

- Multimedia source emissions data
  - -- Most of the noncriteria pollutant emissions data are for compound classes or sample fractions; species concentrations are needed for compound classes showing pollution potential

-- POM and trace element data are sparse and exhibit large scatter from different samplings. Emissions of these pollutants are highly dependent on the origin of the fuel and the specific stationary source and effluent stream from which the data were obtained.

-- Data on emissions during transient or nonstandard operation are virtually nonexistent. New tests are needed if these effects are to be considered.

-- Liquid and solid emissions data are only quantified for the utility and large industrial boiler equipment sector. Although this sector represents the major portion of liquid and solid pollution potential, further study of packaged boilers and industrial process heating effluent streams should be pursued. In addition, the fractions of total ash which are emitted as bottom ash and flyash vary from boiler type to boiler type. However, sufficient data were not available to estimate this effect.

- Health impact threshold criteria

  -- The Multimedia Environmental Goals (MEGs) are preliminary, and for screening purposes only. They are not ambient standards, but rather indications of ambient concentrations at which health effects from continuous exposure should be investigated. In addition, compounds were not speciated. Since one health effects value was used to represent the entire pollutant class, various highly toxic species were not considered.

- Population exposure to source emissions
  - -- Specific values for average source size and urban/rural splits were in many cases based on poor quality data. For utility and large industrial boilers, and most packaged units, the data were adequate. However, for internal combustion engines and industrial process heating, data exhibited a wide range of values making specification difficult.

Most of these data needs are being addressed in ongoing assessments by the EPA. As the data become available, they are being added to the Source Analysis Model data base to augment and update the present results. The conclusions from the results using the current data base are summarized below.

The 1974 total pollution potential rankings, Table 5-1, indicate that watertube and firetube stokers of less than 29 MW input capacity have the largest total impact factors of all stationary sources. However, tangential and wall fired boilers have the next highest rankings and similar pollution impact factors. The difference in impact factors for the three sources is within the uncertainty of the data.

Stoker fired boilers have the highest total pollution potential ranking -- primarily because of the influence of beryllium. This trace metal has a threshold limit value two orders of magnitude lower than any other pollutant considered here. Because of this, sources with the highest levels of beryllium emissions will dominate the pollution potential ranking irregardless of the impact potential from other pollutants.

Of all fossil fuels, coal firing generates the highest emissions of beryllium. Although utility and large industrial boilers are the largest stationary source coal users, they generally have lower beryllium emissions than stoker fired boilers. For example, a recent trace metal study (Reference 5-45) has shown that a coal-fired boiler with an electrostatic precipitator can collect about 81 percent of total beryllium in coal. With future extensive use of particulate control devices on utility and large industrial boilers, reductions in beryllium should continue to be significant. However, small stokers -- the second largest stationary source coal users -- have negligible particulate controls (<15 percent) causing high beryllium levels in the flue gas. This, coupled with the fact that industrial boilers generally have low stacks, contributes to the high pollution potential ranking of stokers.

To illustrate this hypothesis, the Source Analysis Model was run without beryllium for 1974, 1985, and 2000. These rankings given in Tables 5-12 to 5-14, show that without beryllium, tangential and wall fired utility boilers using coal have the highest pollution potential. In addition, oil fired units are significant contributors to total pollution potential when the dominant effect of high beryllium levels in coal is excluded. These results illustrate that pollution potential rankings are highly dependent on the accuracy of both emissions data and impact data. If the health impact threshold of beryllium were raised, the ranking of combustion sources would change significantly.

As shown in Table 5-2, opposed wall fired boilers have the highest average source pollution potential. This impact value was obtained by dividing the total impact factor by the total number of sources of a specific equipment type. Opposed wall fired units are used for the larger

TABLE 5-12. TOTAL POLLUTUTION POTENTIAL RANKING[c] (GASEOUS) STATIONARY SOURCES IN YEAR 1974

Rank	Sector	Equipment Type	Fuel	Total Impact Factor
1	Utility Boilers	Tangential	Coal	7.85×10^9
2	Utility Boilers	Wall Firing	Coal	3.85×10^9
3	Utility Boilers	Tangential	Oil	2.65×10^9
4	Utility Boilers	Wall Firing	Oil	2.24×10^9
5	Utility Boilers	Cyclone	Coal	1.84×10^9
6	Packaged Boilers	Stoker Firing WT[d] <29 MW[a]	Coal	1.46×10^9
7	Utility Boilers	Horizontally Opposed	Coal	1.15×10^9
8	Utility Boilers	Horizontally Opposed	Coal	1.15×10^9
9	Packaged Boilers	Wall Firing WT[d] >29 MW[a]	Oil	7.02×10^8
10	Packaged Boilers	Scotch FT[e] <29 MW[a]	Oil	5.49×10^8
11	Packaged Boilers	Wall Firing WT[d] >29 MW[a]	Coal	4.53×10^8
12	Packaged Boilers	Firebox FT[e] <29 MW[a]	Oil	3.64×10^8
13	Packaged Boilers	Stoker Firing WT[d] >29 MW[a]	Coal	2.51×10^8
14	Packaged Boilers	Scotch FT[e] <29 MW[a]	Gas	2.88×10^8
15	Packaged Boilers	Stoker Firing FT[e] <29 MW[a]	Coal	2.85×10^8
16	Ind. Process Comb.	Coke Oven Underfire	Processed Mat'l	2.84×10^8

T-862

[a]Heat input

[b]Heat output

[c]Without beryllium

[d]Watertube

[e]Firetube

TABLE 5-12. Concluded

Rank	Sector	Equipment Type	Fuel	Total Impact Factor
17	Reciprocating IC Engines	SI >75 kW/cyl[b]	Gas	2.31×10^{8}
18	Packaged Boilers	Single Burner WT[d] <29 MW[a]	Oil	2.28×10^{8}
19	Packaged Boilers	HRT Boilers <29 MW[a]	Oil	2.25×10^{8}
20	Ind. Process Comb.	Brick & Ceramic Kilns	Processed Mat'l	2.00×10^{8}
21	Utility Boilers	Horizontally Opposed	Gas	1.61×10^{8}
22	Utility Boilers	Wall Firing	Gas	1.28×10^{8}
23	Utility Boilers	Cyclone	Oil	1.27×10^{8}
24	Utility Boilers	Vertical & Stoker	Coal	5.78×10^{7}
25	Utility Boilers	Tangential	Gas	3.22×10^{7}
26	Packaged Boilers	Wall Firing WT[d] >29 MW[a]	Gas	2.79×10^{7}
27	Ind. Process Comb.	Cement Kilns	Processed Mat'l	2.71×10^{7}
28	Packaged Boilers	Cast Iron Boilers	Oil	2.47×10^{7}
29	Gas Turbines	Simple Cycle >15 MW[b]	Oil	2.38×10^{7}
30	Ind. Process Comb.	Refinery Htr. Nat. Draft	Gas	2.22×10^{7}

T-862

[a] Heat input

[b] Heat output

[c] Without beryllium

[d] Watertube

[e] Firetube

TABLE 5-13. TOTAL POLLUTION POTENTIAL RANKING[c] (GASEOUS) STATIONARY SOURCES IN YEAR 1985

Rank	Sector	Equipment Type	Fuel	Total Impact Factor
1	Utility Boilers	Tangential	Coal	1.13×10^{10}
2	Utility Boilers	Wall Firing	Coal	4.46×10^{9}
3	Utility Boilers	Tangential	Oil	2.31×10^{9}
4	Utility Boilers	Wall Firing	Oil	1.95×10^{9}
5	Utility Boilers	Horizontally Opposed	Coal	1.92×10^{9}
6	Utility Boilers	Cyclone	Coal	1.62×10^{9}
7	Packaged Boilers	Wall Firing WT[d] >29 MW[a]	Oil	1.04×10^{9}
8	Utility Boilers	Horizontally Opposed	Oil	9.83×10^{8}
9	Packaged Boilers	Stoker Firing WT[d] >29 MW[a]	Coal	9.10×10^{8}
10	Packaged Boilers	Scotch FT[e] <29 MW[a]	Oil	8.24×10^{8}
11	Packaged Boilers	Firebox FT[e] <29 MW[a]	Oil	5.46×10^{8}
12	Packaged Boilers	Scotch FT[e] <29 MW[a]	Gas	3.87×10^{8}
13	Packaged Boilers	Single Burner WT[d] <29 MW[a]	Oil	3.43×10^{8}
14	Packaged Boilers	HRT boilers <29 MW[a]	Oil	3.38×10^{8}
15	Ind. Process Comb.	Coke Oven Underfire	Processed Mat'l	3.15×10^{8}
16	Packaged Boilers	Wall Firing WT[d] >29 MW[a]	Coal	2.82×10^{8}
17	Ind. Process Comb.	Brick & Ceramic Kilns	Processed Mat'l	2.23×10^{8}

T-863

[a]Heat input

[b]Heat output

[c]Without beryllium

[d]Watertube

[e]Firetube

TABLE 5-13. Concluded

Rank Factor	Sector	Equipment Type	Fuel	Total Impact
18	Packaged Boilers	Stoker Firing WT[d] >29 MW[a]	Coal	2.18×10^8
19	Packaged Boilers	Stoker Firing FT[e] <29 MW[a]	Coal	1.78×10^8
20	Utility Boilers	Cyclone	Oil	1.13×10^8
21	Reciprocating IC Engines	SI> 75 kW/cyl[b]	Gas	1.08×10^8
22	Utility Boilers	Horizontally Opposed	Gas	9.48×10^7
23	Utility Boilers	Wall Firing	Gas	8.30×10^7
24	Utility Boilers	Vertical & Stoker	Coal	5.07×10^7
25	Packaged Boilers	Cast Iron Boilers	Oil	3.73×10^7
26	Ind. Process Comb.	Cement Kilns	Processed Mat'l	3.00×10^7
27	Gas Turbines	Simple Cycle >15 MW[b]	Oil	2.67×10^7
28	Reciprocating IC Engines	CI> 75 kW/cyl[b]	Dual (oil + gas)	2.63×10^7
29	Ind. Process Comb.	Refinery Htr. Nat. Draft	Gas	2.45×10^7
30	Utility Boilers	Tangential	Gas	2.33×10^7

T-863

[a] Heat input

[b] Heat output

[c] Without beryllium

[d] Watertube

[e] Firetube

TABLE 5-14. TOTAL POLLUTION POTENTIAL RANKING[c] (GASEOUS) STATIONARY SOURCES IN YEAR 2000

Rank Factor	Sector	Equipment Type	Fuel	Total Impact
1	Utility Boilers	Tangential	Coal	1.37×10^{10}
2	Utility Boilers	Wall Firing	Coal	4.51×10^{9}
3	Utility Boilers	Wall Firing	Oil	3.28×10^{9}
4	Utility Boilers	Horizontally Opposed	Coal	2.46×10^{9}
5	Packaged Boilers	Wall Firing WT[d] >29 MW[a]	Oil	1.66×10^{9}
6	Utility Boilers	Horizontallly Opposed	Oil	1.61×10^{9}
7	Packaged Boilers	Stoker Firing WT[d] <29 MW[a]	Coal	1.43×10^{9}
8	Utility Boilers	Cyclone	Coal	1.21×10^{9}
9	Packaged Boilers	Scotch FT[e] <29 MW[a]	Oil	1.02×10^{9}
10	Packaged Boilers	Firebox FT[e] <29 MW[a]	Oil	6.78×10^{8}
11	Packaged Boilers	Wall Firing WT[d] >29 MW[a]	Coal	4.35×10^{8}
12	Ind. Process Comb.	Coke Oven Underfire	Processed Mat'l	4.25×10^{8}
13	Packaged Boilers	HRT Boilers <29 MW[a]	Oil	4.19×10^{8}
14	Packaged Boilers	Single Burner WT[d] <29 MW[a]	Oil	4.15×10^{8}
15	Packaged Boilers	Scotch FT[e] <29 MW[a]	Gas	3.90×10^{8}
16	Packaged Boilers	Stoker Fired WT[d] >29 MW[a]	Coal	3.40×10^{8}
17	Ind. Process Comb.	Brick & Ceramic Kilns	Processed Mat'l	3.00×10^{8}

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[a]Heat input

[b]Heat output

[c]Without beryllium

[d]Watertube

[e]Firetube

TABLE 5-14. Concluded

Rank Factor	Sector	Equipment Type	Fuel	Total Impact
18	Packaged Boilers	Stoker Fired FT[e] <29 MW[a]	Coal	2.79×10^{8}
19	Utility Boilers	Cyclone	Oil	9.34×10^{7}
20	Packaged Boilers	Cast Iron Boilers	Oil	4.63×10^{7}
21	Reciprocating IC Engines	SI >75 kW/cyl[b]	Gas	4.55×10^{7}
22	Utility Boilers	Vertical & Stoker	Coal	4.19×10^{7}
23	Utility Boilers	Tangential	Oil	3.85×10^{7}
24	Gas Turbines	Simple Cycle >15 MW[b]	Oil	3.82×10^{7}
25	Gas Turbines	Simple Cycle >15 MW[b]	Gas	3.41×10^{7}
26	Reciprocating IC Engines	CI >75 kW/cyl[b]	Dual (oil + gas)	3.20×10^{7}
27	Ind. Process Comb.	Refinery Htr. Nat. Draft	Gas	2.98×10^{7}
28	Ind. Process Comb.	Open Hearth Furnaces	Processed Mat'l	2.41×10^{7}
29	Ind. Process Comb.	Refinery Htr. Nat. Draft	Oil	1.89×10^{7}
30	Reciprocating IC Engines	CI >75 kW/cyl[b]	Oil	1.43×10^{7}

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[a]Heat input

[b]Heat output

[c]Without beryllium

[d]Watertube

[e]Firetube

capacity ranges (>400 MW electric). Because of their large size and resulting high fuel consumption, opposed wall boilers have a high average source pollution potential. However, this result must be used with care since the ranking is not normalized for energy consumption. For example, a 600 MW (electrical output) opposed wall fired boiler may have less pollution potential than three 200 MW (electric output) single wall fired boilers required to supply the same power. This ranking is primarily intended to assess characteristic average source impacts. Stokers are lower in the ranking because their impact is a result of many smaller sources rather than a fewer large single sources.

Table 5-3 shows that cyclone boilers have the highest single source NO_x impact. This is primarily because uncontrolled NO_x emissions from cyclone (coal-fired) boilers are more than double the emissions from tangential units and about 75 percent higher than wall fired units. However, the total nationwide pollution potential of cyclones should decline in the future since the use of cyclones will decrease due to their high levels of emissions.

Since use of coal is projected to greatly increase, the predominance of coal-fired units in the 1974 source rankings is reinforced for 1985 and 2000. Stoker fired units are projected to remain the source type with highest pollution potential in the 1980's and 1990's because of the dominant effect of beryllium emissions. If beryllium is not considered in the modeling, or if stringent controls are projected for stoker particulate emissions, tangential coal fired-boilers again become the major source of pollution potential through the year 2000. In general, oil-fired units are the second most significant group, with natural gas-fired units having the least pollution potential because of projected decreases in natural gas consumption.

The reference low nuclear scenario shows the largest pollution potentials through the year 2000. As mentioned earlier, this scenario postulates that coal-fired units will meet most of the increased demand for power generation, and nuclear power will only play a secondary role. As coal use increases under this scenario, the pollution potential impacts from fossil fuels will increase proportionally. This, of course, does not consider the environmental effects of nuclear powerplants. A careful assessment of the potentials for environmental degradation from nuclear powerplants could result in these plants having higher impacts than coal fired units. Under this condition, the reference high nuclear case may have the highest overall pollution potential impact.

The synthetics scenario yields the lowest total pollution potential. This low pollution potential results primarily from using synthetic liquids and gases instead of coal for stationary combustion. In addition, nuclear power is largely relied upon for power generation, so that coal is saved for use as a feedstock for gasification and liquefaction processes. One possibly significant factor not considered here is the pollution potential of intermediate fuel conversion processes. Since the intent of the scenario development was only to examine trends in pollution potential from end-use stationary combustion equipment, these intermediate sources were not considered. However, a more rigorous analysis of total emission loadings for each scenario may show these intermediate conversion steps to be highly significant.

The major trace elements with significant pollution potential are beryllium, chromium, nickel, vanadium, and aluminum. Trace element pollution appears to be significant for utility and packaged boilers firing coal or heavy oil. Beryllium, as already noted has high pollution potential because of its toxicity. Nickel also is a toxic effluent from both oil- and coal-firing. Vanadium and chromium appear to be significant in residual oil-firing because of their high toxicity. In contrast, aluminum is significant in both coal- and oil-firing because of the magnitude of emissions rather than the toxicity. For example, aluminum emissions (ppm) are 30 to 40 times higher for bituminous coal than for other trace elements considered in this assessment. In fact, aluminum is, in general, the most abundant trace element in coal -- representing in some cases up to 2 percent of total coal (Reference 5-45).

Tangential coal-fired boilers have the highest liquid and solid effluent stream pollution potential, as a result of high installed capacity and selective partitioning of toxic trace elements within the flyash and bottom ash streams. Stoker fired boilers do not have a high ranking. Since the use of particulate controls is low for smaller units, toxic elements like beryllium go out the stack rather than being collected in the flyash hopper as a solid effluent. Oil-fired combustion sources are second and third on the ranking because of high concentrations of vanadium and nickel in the ash from residual oil-firing. In addition to their toxicity, vanadium and nickel are usually highly concentrated in the bottom ash and flyash streams of combustion units. Thus, the pollution potential of liquids and solids from stationary source combustion is highly dependent not only on the overall fuel consumption of the equipment type, but also on the selective partitioning of toxic trace elements within the liquid and solid effluent streams and the degree of pollutant controls.

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16. ABSTRACT The report gives results of an inventory of gaseous, liquid, and solid effluents from stationary NOx sources, projected to the year 2000, and ranks them according to their potential for environmental hazard. It classifies sources according to their pollution formation characteristics, and gives results of a compilation of emission factors and regional and national fuel consumption data for specific equipment/fuel types. It gives results of an emission inventory for NOx, SOx, CO, HC, particulates, sulfates, POM, and liquid or solid effluents. It projecus emissions to 1985 and to 2000 for five energy scenarios, depicting alternative uses of coal, nuclear power, and synthetic fuels. It ranks sources by nationwide emissions loading for 1974, 1985, and 2000. It describes a source analysis model used to estimate pollution hazard, considering ambient dispersion, population exposure, background concentrations, and health-based impact threshold limits. It applies the model the model to the emission inventory to produce source rankings based on both single-pollutant and total-multimedia impact factors.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Air Pollution	Boilers	Air Pollution Control	13B	13A
Nitrogen Oxides	Gas Turbines	Stationary Sources	07B	13G
Organic Compounds	Internal Combustion	Environmental Assess-	07C	
Inorganic Compounds	Engines	ment		21G
Fossil Fuels	Ranking	Particulates	21D	12B
Dust	Inventories	Emission Factors	11G	15E

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