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## ABSTRACT

A comprehensive inventory has been taken of oxides of nitrogen (NOx) emissions from stationary sources within the South Coast Air Basin for the period of July 1972 through June 1973. Included are the emissions from over 1500 point sources assessed from detailed device and fuel use information provided by operators, and emissions from area distributed domestic, commercial, and industrial sources, essentially accounting for all fuel burned by stationary sources in the Basin. Although there was no directly comparable inventory with which to compare, it is believed that the inventoried emissions were some 15-20% higher than had previously been estimated. Power plant emissions were found to still be dominant, followed by those from refineries, and then by a number of lesser source categories.

Seasonal variations of emissions were assessed, as was the geographical distribution on a 10 km grid square basis. Forecasts were made of emissions in the several source categories for 1975 and 1980.

The stationary source NOx emissions were added to predicted mobile source emissions and the total was compared with an EPA air quality prediction for the Basin in order to estimate the reduction required to meet Federal air quality standards. The amount of stationary source emissions that could be reduced on a cost effective basis equal to or greater than that of current mobile source controls was examined on a device class basis. A substantial portion of the needed reduction was determined as potentially achievable on a cost effective basis using known combustion modification techniques. Under the worst case situation still further reduction would be required however. Securing a substantial increase in available natural gas supply for the Basin was shown to be a very effective means of achieving the additional reduction if somehow it could be accomplished.

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APPENDICES

# 1.0 INTRODUCTION

One of the prime weapons in the fight for improved air quality has been the regulations passed which limit the pollutant emission levels for various categories of emission sources. In order to create successful overall regulation strategies and specific effective regulations the responsible political bodies have found the need for expert technical inputs on the control limits practically achievable within existing or foreseeable technology, the cost of implementing such control technology, and the aggregate reduction in air basin emissions thereby anticipated. In California the responsibility for providing these technical inputs and for recommending regulations for consideration by the Legislature is that of the Air Resources Board.

While primary concentration on emissions control regulations at the state level has been focused on mobile sources thus far, as it should be from the present balance of emissions, the time is projected when as a result of these regulations the mobile source emissions will be reduced to equality with the growing stationary source emissions. The date of this crossover has been projected[1,2] as occurring before 1980, however it may well occur before that. Looking ahead, it is clearly evident that public and legislative attention will shift toward consideration of the need and feasibility of additional regulations for stationary sources as stationary and mobile sources approach emissions parity.

Anticipating this shift of attention, the Air Resources Board has initiated a program to provide needed technical inputs with respect to possible further control of one major pollutant component, the oxides of nitrogen, in the State's most congested air basin, the South Coast Air Basin. The objectives of the program are to improve the existing inventory of stationary source nitrogen oxides emissions, to assess the potential and cost for reducing existing emissions levels, and to forecast future emissions trends as a function of fuels availability, control expenditures, and time.

This report presents the results of that program which was comprised of two phases. During the first phase the objectives were to establish a preliminary assessment of the most significant sources in the Basin based on existing data and to identify the potentially most significant uncertainties in that existing data. During the second phase an objective was to reduce these uncertainties by collecting additional use information on known devices, by reducing the number of unaccounted-for devices, and by performing a series of stack emissions measurements on selected devices. Concurrently with the measurements assessments were made of the applicability of existing NOx reduction technology to the most significant device types, although resources available did not permit actual demonstration of the assessed reduction methods. The improved data obtained during the second phase were utilized to update the Basin emission inventory, and to make projections of future emissions trends.

The approach taken in the first phase was to make maximum use of emission inventory data available within the files of county (APCD), state (ARB) and federal (EPA) regulatory agencies, supplemented by data which were found to be "fairly readily" available from gas and electric utility companies, and major industrial facilities, principally refineries. Since there was no Basin-wide air pollution control agency at the initiation of this program no formal Basin-wide inventory was found to exist. The existing county APCD inventories were found to have been conducted with a variety of approaches and degrees of thoroughness, and to include area and point sources lying outside of the South Coast Air Basin (see Figure 1-1). For the most part APCD inventories[1,3,4,5,6,7] were found to be based on devices on permit and hence did not include significant emissions for devices not on permit except for rough estimates in some cases. Variations in computation methods ranged from estimates based on assumed full load operation full time, to proper accounting for actual part load operation during actual operating hours only. Some emissions were calculated from broad based emissions factors of uncertain applicability, while others were computed from test measurements on the individual device.

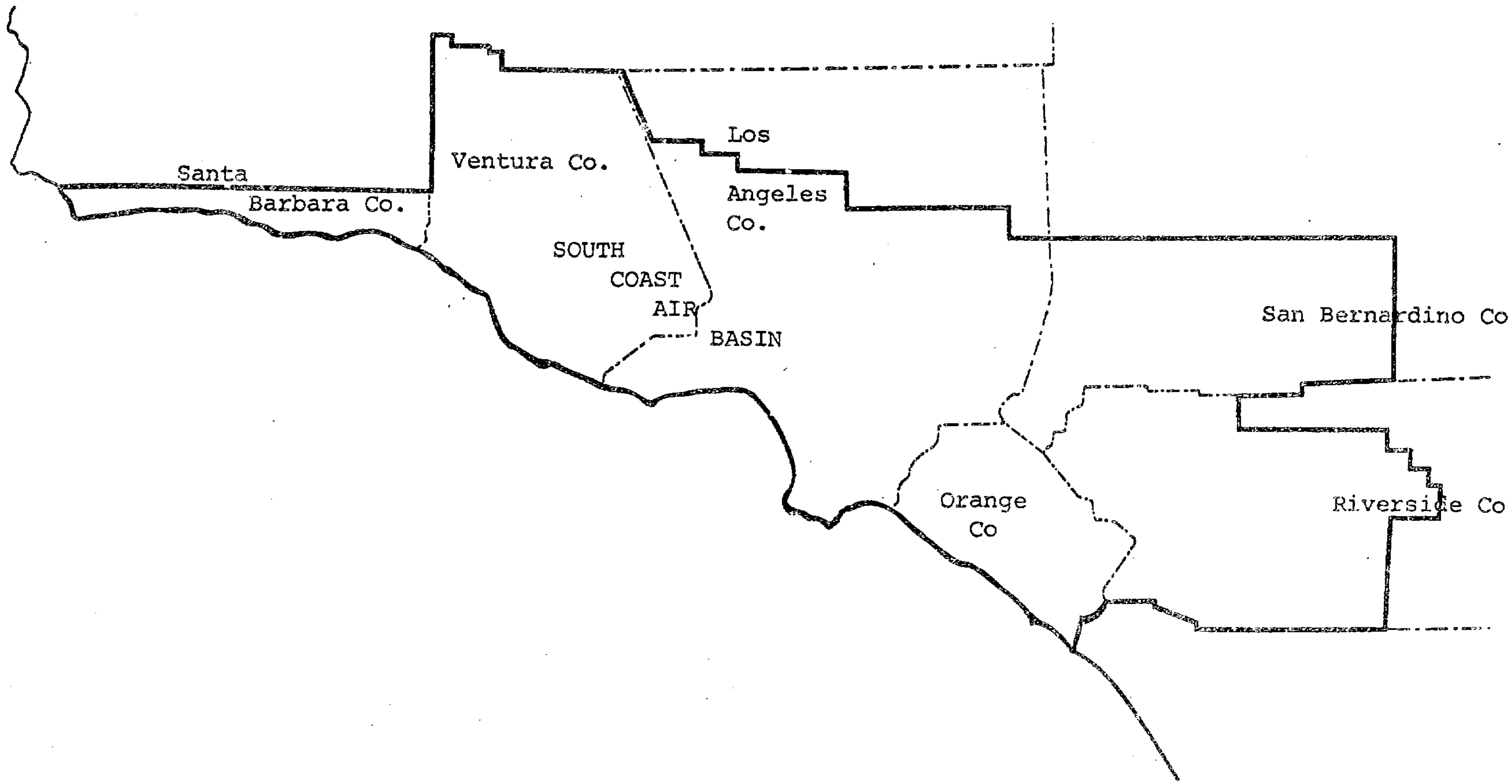


Figure 1-1. Boundaries Of The South Coast Air Basin



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During the past year the EPA initiated a series of air basin emission inventories, including one for the South Coast Air Basin presently being completed.[8,9] The basis for that inventory is the inclusion of only those plant sites or devices emitting in excess of 100 tons/year of any pollutant.[10] That cut off for NOx would correspond in firing rate to something between 125 million Btu/hr (MMB/H) and 250 MMB/H depending on fuel and hours of operation per year. The preliminary results for the LA County portion of the inventory were made available[11] and were found to include NOx data on 166 devices in 70 plants emitting an annual total of 66,440 tons NOx which corresponds to 71% of the LAC APCD estimate for stationary sources, exclusive of area sources. Emissions were computed based primarily on EPA published emission factors.[12] The only emission figure presented for each source was the annual total.

Within the spirit of the previously stated Phase I objectives of this program the preliminary inventory conducted sought to make the following improvements over the existing inventories:

1. Use of uniform methods of computation for all devices inventoried in all counties of the Basin.
2. Inclusion of more point sources by extending down to smaller devices and including devices not on APCD permit system where possible.
3. Determination of daily summer and winter rates in addition to annual total emission.
4. Attempt to properly account for varying emissions with device operation of varying fractions of full rated load where fuel use data is available.
5. Determination and geographical distribution of residential, commercial, and minor industrial area source emissions, and geographical distribution of point source emissions.
6. Assembly of the data in an inexpensive electronic data processing system to facilitate desired sorts, summation and updates.

-- all within the limitation of using data available from EPA, ARB, APCD, utility and industry files.

During the second phase of the program major reductions in the existing uncertainties in the data were achieved by receipt of fuel-use questionnaires from over 500 companies in the Basin, and by conducting a 22 week field test program during which approximately 150 source tests for NOx emissions were performed. The results of these two sources of new information, plus new information obtained from the electric utilities and the natural gas utility company, have been utilized to provide the basis for an inventory of stationary source NOx emissions in the Basin for the period July 1972 through June 1973 and for projections to 1975 and 1980. As an element of the field test program estimates were made of the applicability, costs, and cost effectiveness of emissions reductions for sources tested and like sources in the Basin.

In the second section of this report is a background information discussion of NOx formation processes, of variables and uncertainties in these processes, of NOx control principles, and of NOx reactions in the atmosphere.

In the third section of this report definitions and rationale for emissions rates determined are presented. A discussion of sources of data and their limitations is presented in the fourth section. In the fifth section the emissions calculations methods used are discussed. The data format and EDP processing is discussed in the sixth section. A summary of the results of the preliminary inventory is presented and briefly discussed in the seventh section as a basis for the priorities of the test program. The objectives, sources tested, test equipment and procedures of the field test program are described in the eighth section. Overall results of the test program, and the revised inventory are presented on a source category basis in the ninth section. Discussion of the inventory and forecasts, and discussion of the reduction potential and cost effectiveness assessments are presented in the tenth and eleventh sections respectively. A summary and conclusion are presented in the twelfth section.

The reader who is primarily interested in the program results is encouraged to read the background section on NOx formation, control, and disposition and then to skip to the presentation and discussion of the results beginning in Section 9.

## 2.0 BACKGROUND INFORMATION

### 2.1 NOx Formation Processes

Combustion generated oxides of nitrogen are presently recognized as major pollutants which react in the atmosphere to form photochemical smog. The predominant oxides of nitrogen are $NO_2$, and NO which can later be oxidized to $NO_2$ in the atmosphere. The NO forms at high temperature in an excess of air. The usually stable oxygen molecule dissociates to oxygen atoms which are very reactive and which attack the otherwide stable $N_2$ molecule. However, even at high temperature the nitrogen cannot compete effectively with the fuel for the scarce oxygen. Thus this thermally generated NO is formed in limited amounts. In other words, nitrogen is not a good "fuel" and requires a specific set of circumstances for it to be oxidized. Still another reaction occurs between $O_2$ and N radicals present in certain fuels, also forming NO. The NO formed by this route is referred to as "fuel NO" or alternatively "organic NO." While the thermal NO formation mechanism has been treated extensively in the literature, e.g.[13,14] fuel NO kinetic mechanism studies have appeared only recently.[15,16,17] From one of the fuel nitrogen kinetic mechanisms suggested,[17] it would appear that the complex real mechanism can be adequately represented by the instantaneous release of N atoms on the time scale of the initial combustion reaction breakdown of the fuel to hydrogen and CO. The N atoms thus released are oxidized by $O_2$ to NO. Thus both the thermal and fuel NO can be described by the Zeldovich mechanism[18]

$$N_2 + O \rightarrow NO + N \qquad \text{(reaction 1)}$$

$$O_2 + N \rightarrow NO + O \qquad \text{(reaction 2)}$$

For thermal NO, reaction (1) indicates that molecular nitrogen reacts with atomic oxygen to produce NO. This reaction is much slower than reaction (2) and, hence, it controls the rate of formation of NO. However, the formation of an NO molecule from reaction (1) is accompanied by the release of an N atom, which rapidly forms another NO molecule from reaction (2). Reactions (1) and (2) are, respectively, the chain-making and chain-breaking mechanisms; and the O atom is the chain carrier. Liquid (oil) and solid (coal) fuels contain up to about 1 to 2% nitrogen. The end products of N in fuel is mainly NO. The fuel N reacts with $O_2$ to form NO through reaction (2), and it also reacts with NO to form $N_2$ in the backward direction of reaction (1). Since NO in reactions (1) and (2) comes from both thermal and fuel sources, calculations for both NO must be performed simultaneously. For natural gas, however, which does not contain significant nitrogen radicals, only thermal NO is formed.

Through the use of thermochemical equilibrium and chemical kinetic analyses it has been possible to approximately model the controlling influences of combustion stoichiometry, temperature, and residence time of NO formation in utility boilers and gas turbunes assuming one dimensional, homogeneous air/fuel flow.

Formation of NO is known to be extremely sensitive to temperature. Under one particular environment, the amount of thermal NO produced from reactions (1) and (2) may be taken as[19]

$$[NO] = 5.2x10^{13} e^{-72,300/T} [N_2] [O_2]^{1/2} t$$

where the bracket indicates mole fraction, T is temperature in °K, and t is residence time in seconds. This equation shows that NO concentration is a strong exponential function of temperature, is directly proportional to the concentration of $N_2$ and to the residence time, and varies with $O_2$ to the one-half power. Control of NO is thus achieved through an optimization of these parameters.

Because of the strong temperature dependency, NO is primarily produced in hot combustion zones even though there exist only small amounts of $O_2$. In typical hydrocarbon-air flames, $[N_2]$ is of the order of 0.7 and is relatively difficult and fruitless to modify. The $[O_2]$ is of the order of 0.01 and can be reduced by reducing the burner excess air. Although the relation between $[O_2]$ in flame zones and excess air depends on complex processes of turbulent mixing and has not been theoretically predicted with success, it has been found in practice that NO increases with excess air up to perhaps 30-50% excess air. Temperature may be reduced by employing off-stoichiometric combustion, reduced air-preheat, flue gas recirculation, etc., as discussed in Section 2.3. For example, a reduction of flame temperature of 300°F accompanied by a reduction of $O_2$ by a factor of 2 (corresponding roughly to a reduction of 700°F in air temperature or to 15% flue gas recirculation) reduces NO by a factor of about 10. Finally, the residence time in high temperature regions may be reduced by various methods of controlling air-fuel mixing, such as by employing staged combustion as also discussed in Section 2.3.

Most combustors operate with turbulent mixing combustion flames at the burner nozzle. Turbulent eddies of air and fuel mix and are then ignited by the diffusion of excited atoms to form a primary combustion zone. The ignition process for hydrocarbons is almost instantaneous in comparison to the eddy life time during which the NO is formed.

Boilers are inherently nonadiabatic in overall operation, thus their design is controlled by heat transfer rather than by combustion kinetics. This characteristic can be exploited by forcing the combustion process to occur at lower temperatures. The chemical kinetics for the minimization of NO dictates that hydrocarbon combustion should proceed to completion only after substantial heat loss from the reacting fuel and combustion air has occurred. Various combustion modification techniques have been successfully developed to reduce the flame temperature, and thus reduce the NO formation in boilers by 50 to 85%. These are discussed in Section 2.3.

## 2.2 Process Variables, Uncertainties In NO Production From Stationary Sources

The publication of a particular value for the emission rate of nitrogen oxides (e.g., lb NOx/da) from a particular source carries with it the integration of a high degree of variability and uncertainty. These variabilities and uncertainties must be understood by anyone who is to make effective use of the published emission value.

For a source which in fact is a cumulation of a large number of individual sources within a given source category, the emission rate must of necessity be an average per source times the number of sources; or alternatively an average emission factor (e.g., lb NOx/$10^6$ Btu fuel consumed, or lb NOx/lb product produced) times the cumulative fuel consumption or production rate. Obviously there is some uncertainty in the census of the category of emitting device and in the fuel consumption or production rate, but these can be refined to whatever degree resources permit. Those devices outside of any regulatory permit structure (air pollution, fire, safety, etc.) are obviously more difficult and hence costly to inventory accurately than those within a permit structure. Often it is necessary to infer a census figure from other data such as population.

Over and above the census and fuel or production rate uncertainties there are major variables and uncertainties in the emission factor from device to device. These are preferably established by individual measurement of the emissions of each device within the category (if the number is small). When large numbers of sources are involved, averaged emission factors are determined from averaging some number of tests (usually small with respect to the number of sources) or from educated estimates. An early effort to establish such factors[20] was based solely upon fuel type (oil or gas) and fuel burning rate (Btu/hr). Examples of such a correlation of emissions data from a variety of gas-fired and oil-fired combustion devices are presented in Figure 2-1 and 2-2. The correlations were found to fit the limited data with most of the data falling within a spread of about +100%, -50%.

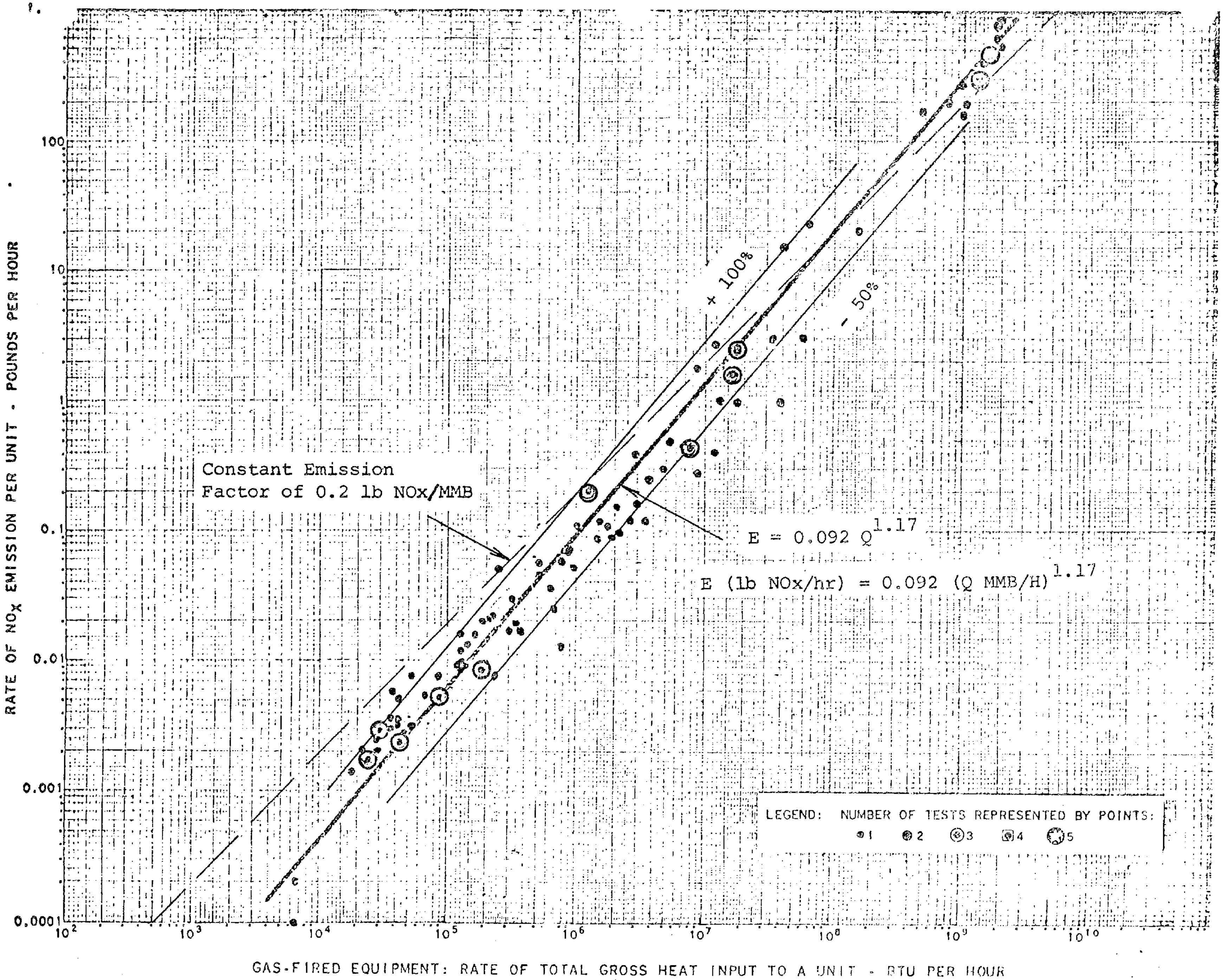


Figure 2-1. Results Of Tests Of Gas-Fired Combustion Equipment From Refrigerators To Power-Plant Boilers[20]

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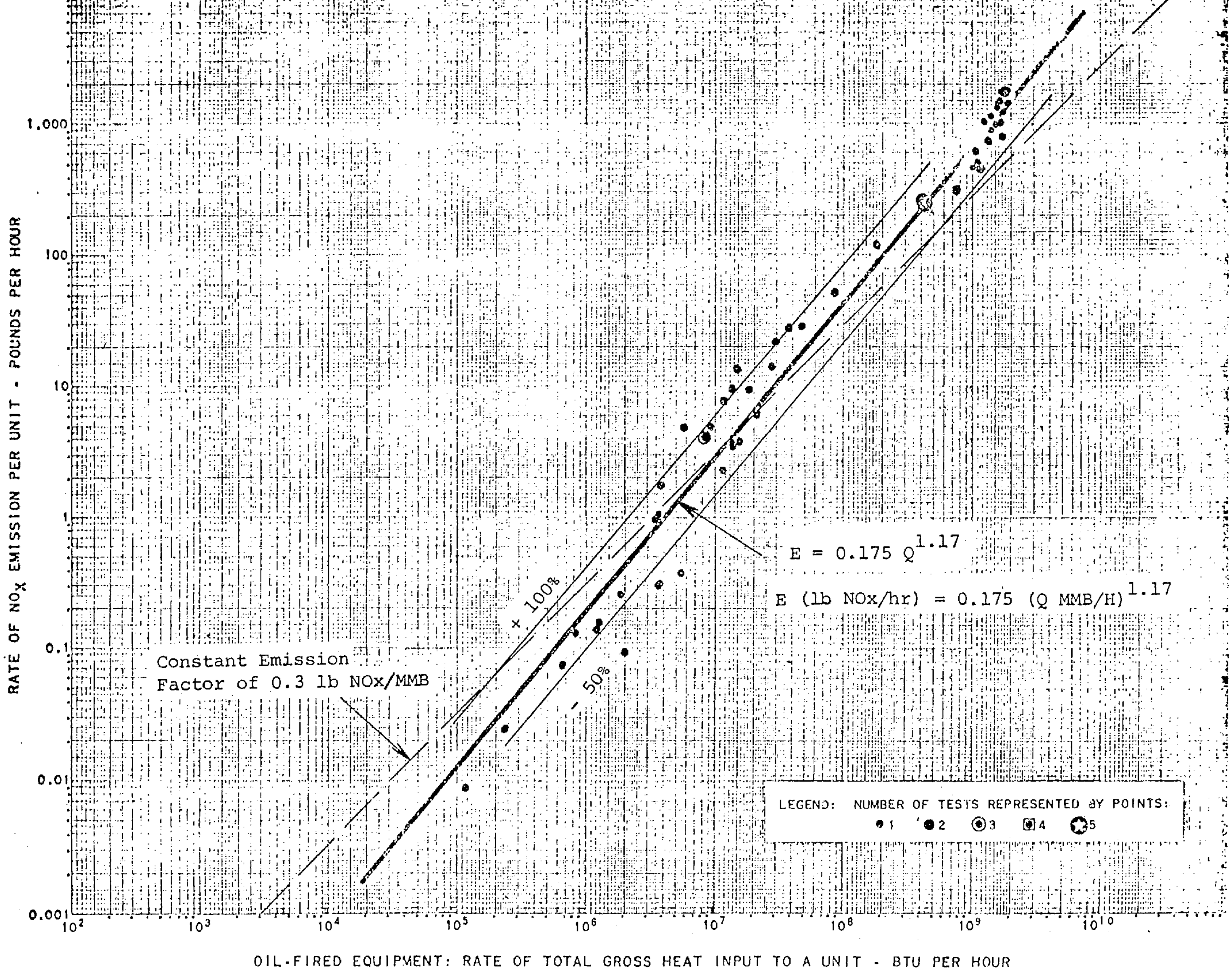


Figure 2-2. Results Of Tests Of Oil-Fired Combustion Equipment From Small Kilns To Power-Plant Boilers[20]

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The correlation curves showed a steadily rising emission factor (lbs NOx/$10^6$ Btu) with increasing device burning rate Btu/hr, about 50% increase in emission factor for each factor of ten increase in burning rate. The degree of data spread about an average emission factor increasing with burning rate, as exhibited by this data, continues to be typical of current emissions test programs (see appendix C and H) in which a modest data sample (50-200 tests) is utilized. The cause for such data spread is of course the uncorrelated design and operational parameters which are in general too numerous to correlate with such a limited data base. The most significant of the device design parameters are basic device design type, the adiabaticity of the combustion zone, the specific combustion volume, the surface temperature of the walls, the extent of internal recirculation, the extent of air preheat, the type of liquid fuel atomization, the type of forced mixing of fuel and air, the number of burners or size of flame, the extent of application of NOx control principles, etc. Of nearly equal significance are the operational factors such as level of excess air, wall surface cleanliness, fraction of rated load, maintenance, uniformity of burner and register adjustment, implementation of NOx control principles like off-stoichiometric combustion or flue gas recirculation, organic nitrogen content of oil fuel, etc. The difference between low fuel nitrogen i.e. <0.1% and high fuel nitrogen >0.5% may account for approximately 200 ppm, or about 0.2 lb NOx/MMB. Of the order of 20% variation can occur for the same boiler between clean conditions (after extended gas firing) and dirty conditions (after extended oil firing). The level of excess oxygen with which the device is being operated can have an effect as high as 40 ppm per percent excess oxygen, limited on the low side by smoke emission or carbon monoxide emission. Air preheat level can have an effect approaching 100 ppm per 100°F air preheat temperature change. Perhaps most important of all for some devices is the effect of load, where highest emission factors are often encountered at full load and reduced factors are encountered at reduced loads. Combustion modifications, implemented to reduce emissions, can have effects ranging up to about 85% reduction as discussed in the following section.

All of these factors must be understood and accounted for in assessing the significance of any single measurement, and determining a representative average emission rate over a number of devices, or over a day, or a year.

Fortunately, for large sources, where the largest variation in these design and operational variables may occur and have the largest effect, the number of units is usually low enough that individual measurements of emissions for the unit of interest are often available or can be obtained. For smaller sources with larger numbers of units these design and operational variables are usually unspecified and thus may cause a significant spread (i.e., approx. +100%) about average emission factors. While these variations may be satisfactorily averaged out over large numbers, the reduction to lower numbers on a local geographic basis may lead to substantial error. Subsequent to the effort of compiling averaged emissions factors in Ref. 12, based on existing data, the EPA has contracted for testing programs leading to improved emissions factors for utility boilers,[21] domestic and commercial heaters,[22] stationary gas turbines, stationary IC engines,[23] and industrial-package boilers.[24] Although improved emission factors should come out of these programs, such factors cannot take the place of individual unit emission measurements when the numbers of units make it practical.

## 2.3 NOx Reduction Methods

As discussed in Section 2.1 the formation of NOx in a flame according to chemical kinetic prediction is proportional to the square root of the concentration of oxygen atoms, a high power exponential of temperature, and the residence time at formation conditions. It naturally follows then that reduction of emissions of NOx can be affected by modifying the combustion by reducing residence time at temperatures above about 3600°R, the temperature below which the exponential temperature factor becomes negligible, and by reducing the concentration of oxygen in the combustion zone.

The excess oxygen is an operationally controllable parameter in most boilers, gas turbines, and IC engines. As the excess oxygen is reduced below a certain level the combustion process produces excess CO when burning gas or smoke when burning oil. In the interest of operating at low NOx levels it is important to be able to control the excess oxygen at the level just above that of the onset of this excess CO or smoke. Typically the NOx penalty for operation above this minimum excess oxygen is some 20 to 40 ppm per percent excess oxygen.

The most important combustion modification parameter is the flame temperature itself since it has the most dramatic impact on the NOx formation rate. The flame temperature can be reduced by: shifting the air-fuel ratio off of the stoichiometric value in the primary flame zone; by diluting the incoming air with recirculated flue gas reducing the temperature rise per unit quantity of fuel burned; by reducing the temperature of the incoming air; by injecting a coolant such as water or steam; and by increasing the rate of removal of heat from the flame zone. Each of these modifications has been tried, found to reduce NOx, and found to be applicable in some particular set of circumstances.

The shifting of flame zone temperature off of maximum temperature stoichiometric conditions can be accomplished without major penalty in fuel economy by burning in two stages. The initial stage can be operated fuel-rich, and additional air can be added downstream to keep the overall process at the desired near stoichiometric ratio (i.e., with a few percent excess oxygen). One of the most economic ways of doing this with existing utility boilers having multiple burners is called off-stoichiometric (O/S) firing.[25] It involves shutting off the fuel supply to 10 to 30% of the burners (stratigically located by testing), adding that extra fuel through the remaining burners, continuing the normal air flow through the remaining burners, and continuing the air flow through the registers of the burners taken out of service. In this way the fueled burners are operated at excess fuel conditions (equivalence ratios from about 1.1 to 1.3), producing a lower temperature flame zone. Overall furnace equivalence ratio is maintained in the desired range (0.9 to 0.95) by the addition of the remaining air through the registers of the burners taken out of service. Essential to the success of this technique is the removal of heat from the initial combustion products prior to the completion of the combustion with the second stage air addition. As a consequence those zones where oxygen concentration is stoichiometric or higher are at a temperature several hundred degrees lower than adiabatic flame temperature. This method has been found to be effective on both thermal and fuel NO, reducing NOx by 40-80% depending upon the fuel, boiler design, and the normal range of boiler operation conditions. An alternative to taking burners out of service is the use of so-called NOx ports built into some utility boilers. However, these ports are often restricted to air flow rates that preclude taking the primary zone as far off-stoichiometric conditions as one might wish to go.

By recirculating up to 20 or 30% of the flue gas into the primary zone, thereby increasing the primary zone gas flow rate per unit of fuel burned, the temperature rise and hence maximum temperature is reduced. Approximately 40 to 70% reduction in NOx can be achieved for gas fuel combustion, less for oil, depending on boiler design and operating conditions, with the first 25 to 30% flue gas recirculation.[25] Beyond this the benefits from recirculation diminish rapidly. Further increase in recirculation is often precluded by burner stability problems. While up to 10 or 15% recirculation capability sometimes has been built into existing boilers as a means of controlling steam temperature, alterning the recirculation capability to reduce NO, or adding it is expensive and often precluded by space limitations.

Flame temperature can also be reduced by reducing the temperature of the incoming air. When this is an option, by having some degree of bypass of the air preheater, this can be an effective NOx reduction technique. The amount of the reduction achievable is approximately 30 to 40% per 100°F down from normal air preheat temperature of about 650°F. Unfortunately this reduction method is not utilized very often due to absence of air preheater bypass and/or an unacceptable performance penalty.

As discussed in Ref. 25, the techniques of off-stoichiometric combustion, gas recirculation, and reduced air preheat can be effectively utilized in combination. The reductions obtainable are complementary since the respective methods reduce NO by different mechanisms. Off-stoichiometric combustion reduces the oxygen concentration at peak temperatures while gas recirculation and reduced air preheat simply reduce the level of peak temperature.

Finally, primary zone flame temperature can be reduced by adding water, either directly as a spray, or by utilizing steam to enhance vaporization of fuel oil. The former is practical for use in reducing NOx in gas turbines where the addition of water to the extent of about 1 lb. water per lb. of fuel can reduce the NOx by about 40-50%.[26] Some experience with water injection in oil and gas fired utility boilers has also been obtained. Steam atomization of oil in utility boilers has been found to reduce NO significantly in some circumstances, partly because better atomization allow operation at lower excess oxygen without smoking, and partly due to reduction of flame temperature by the steam.

The reduction of residence time at NO formation temperatures is for the most part tied up with combustion system design and is not readily available as an NO reduction control variable. Understanding the principles involved, however, helps one to understand the differences in NO that are inherent in a particular design and are encountered from unit to unit. For example, the residence time at formation conditions in boilers can be changed by flame length and intensity variations affected by the degree of swirl applied to the incoming air. The residence time at formation temperatures can also be affected by the rate at which heat is removed from the primary zone, which can be affected by the boiler cleanliness, by use of either water tubes or refractory in the furnace floor, and by the extent of flame zone recirculation.

The volume of the combustion zone in gas turbine combustors that contains combustion products at NO formation conditions, and hence residence time, can be changed by changing the air addition schedule by burner can design. Gas turbine combustors normally operate in an essentially adiabatic mode with initial near-stoichiometric combustion followed by substantial air addition. The subsequent air addition acts to quench the NO formation reactions and by dilution produces mean gas temperatures low enough to be compatible with the turbine, i.e., less than about 2000°F. Power producing gas turbines are generally operated at constant air flow rate with fuel flow rate throttled with load, providing a varying air/fuel ratio. The trick is to control combustion at fuel-rich conditions and then to program the air addition in such a manner that the NO formation zone is minimized by quenching (i.e., reduce residence time at temperatures above about 3600°R). The air must not be added so suddenly, however, that flame stability (blowout) problems are encountered at low load (low fuel flow rate). Alternatively NO can be reduced by suppressing the maximum flame temperature by adding water. Both techniques are in successful field use at this time.[26,27]

## 2.4 NOx Reactions In The Atmosphere To Produce Photochemical Smog

Once released to the atmosphere nitric oxide NO proceeds gradually to $NO_2$ through the reaction

$$2NO + O_2 \rightarrow 2NO_2 \quad \text{(reaction 3)}$$

This reaction is favored by lowered temperatures.[28] Thus as the hot exhaust gases cool to ambient temperatures in the atmosphere in the presence of abundant $O_2$, nearly all of the NO eventually converts to $NO_2$. About half of the NO is converted to $NO_2$ in roughly 30 minutes under these conditions.

A substantial fraction of the $NO_2$ exposed to sunlight in the atmosphere undergoes photolysis to form ozone $O_3$, the primary constituent of the atmospheric pollutant category called "oxidant." The reactions involved are

$$NO_2 + h\nu \rightarrow NO + O \quad \text{(reaction 4)}$$

$$O + O_2 + M \rightarrow O_3 + M \quad \text{(reaction 5)}$$

$$O_3 + NO \rightarrow NO_2 + O_2 \quad \text{(reaction 6)}$$

where $h\nu$ denotes photon energy, and M denotes an inert third body. The initial reaction is the absorption of the ultraviolet energy by the $NO_2$ molecule, decomposing it into NO and highly reactive oxygen atoms. These react vary rapidly with $O_2$ to form ozone. In the presence of NO some of the $O_3$ reacts to again form $NO_2$. Were there not other reactions taking place with the $O_3$, reactions (4), (5) and (6) would yield no net products since by this reaction chain $NO_2$ is regenerated. Some of the highly reactive O, $O_2$ and NO react with hydrocarbons in the atmosphere to yield products such as aldehydes (e.g., formaldegyde and acrolin), peroxides, hydroperoxides, alkyl nitrates, carbon monoxide, peroxyacetylnitrate (PAN), peroxybenzoyl nitrate (PBzN), etc.

The photochemical processes occurring in the atmosphere depends on light intensity, its spectral distribution, hydrocarbon reactivity, composition of reactants, wind movement, etc. In the atmosphere, as NO is being converted to $NO_2$, reactive hydrocarbons begin to disappear while aldehydes, PAN, and other organic products begin to form. When NO is completely oxidized and $NO_2$ reaches a peak, $O_3$ begins to form and increase in concentration. The kinetics of this process are such that the peak source emissions between 7 a.m. and 8 a.m. (from the morning traffic) results in a peak oxidant concentration about noon, after which it gradually decays.[29]

## 3.0 EMISSIONS RATES AND FACTORS

Traditionally emissions inventories conducted have quantified the emissions of a source in terms of tons of NOx counted as $NO_2$ (i.e., a molecular weight of 46) per year, or alternatively tons per average day. The tons per year basis is significant in that it is supposedly an integrated rate which properly reflects the number of days the source burns oil and the number it burns gas, and properly accounts for the usually significant difference in pollutant concentrations between the two fuels. To be quantitatively correct the annual rate must also properly reflect the number of hours per day the device typically operates and the average fraction of rated load. The annual rate has been adopted as the standard for emissions inventorying by the EPA.[10] Hence, for comparative purposes, this is one of the several rates computed and summed in the present NOx inventory. Unfortunately the annual integrated figures do not have much to do with an air quality violation event which is typically more related to the emissions of a given few days during which a basin experiences a stable inversion.

Thus a measure of daily emissions is more relevant, but not just 1/365 of the annual figure since this represents some unattained average day. Of much more significance is a peak or worst case day, since several of these could occur back to back during a stable inversion. Since the emissions levels are related to the quantity of fuel burned, days of maximum emissions tend to be highest fuel consumption days. Industrial fuel use tends to be fairly constant, whereas utility fuel use normally has two pronounced peaks; one during hot summer days of peak air conditioning electric load and the other during cold, dark, mid-winter days (particularly near Christmas when there is considerable retail commercial activity). Domestic fuel use has a single peak occurring during the coldest period of the year, typically December or January. Thus summer daily emissions (determined for mid-August) and winter daily emissions (determined for late December) were determined to be of direct interest for this inventory. However, since fuel consumption information from most sources is broken down only on a monthly basis, it was only possible to inventory emissions on an average daily basis for the two months selected, August and December, rather than the "peak" day basis that would have been preferred. Perhaps there is a higher probability of more lasting stable inversions at other periods of the year when the fuel consumption and hence, emissions are lower. However, the possibility of such inversions at the periods selected cannot be discounted and hence these serve as "average potentially worst case" days.

Two other individual source emissions rates which are computed but never summed in the present inventory, are the hourly maxima rates at full rated load on oil and on gas. These rates represent maximum emissions potential and are useful as intermediate values in computing peak daily and annual integrated emissions. Each of the computational procedures used are described in Section 5 of this report.

Ideally in compiling an emissions inventory one would like to have a direct measurement of pollutant concentration in the flue gas stack of each device under each operating condition. Clearly this is not possible because of the effort required. Hence, some basis of generalization is required. The most useful generalization has been to relate the emissions to the rate of energy consumption for like types of devices burning like types of fuels. Generally such emissions factors are expressed in terms of pounds of NOx (as $NO_2$) per million Btu of input energy to the combustion device and are found to slowly increase in magnitude with increasing device size or rated full load as discussed in Section 2.2. Such factors as these, compiled by the EPA,[12] by the LAC APCD[20] and by others, have been used in this inventory where specific test data on individual device emission concentration has not been available or when the sample of data taken during the program was inadequate to justify modification of the published factors. The hazard that must be avoided is the over generalization of emission factors and their application to conditions to which they do not apply. Furthermore, it must be recognized that the emissions of individual units may differ from the average values represented by the emission factor by as much as plus 100% or minus 50% (or even larger for a few exceptional devices) for reasons discussed in Section 2.2. However, when used for a large sample of similar devices, properly selected emissions factors should give a representative total emission value for the sample.

## 4.0 DATA SOURCES

As a basic approach to conducting this program maximum use was made of data avialable as published information or contained in the files of public agencies and utilities, and of data obtained from industry.

By virtue of its broad and active area of responsibility and the advanced state of organization of its emissions inventory data, the Los Angeles County APCD was the prime source of data for the preliminary inventory. The LAC APCD has approximarely 35,000 issued active permits and at the start of this program had processed information for about half of these permit units into an electronic data processing (EDP) system. LAC APCD priority was given to processing the most significant source classes such as utilities and refineries, and the most significant device classes such as boilers, turbines, etc. However no assurance could be given by the LAC APCD that the EDP processed half of the permits contained information on all devices in a priority source class. The EDP data file was obtained from the LAC APCD in tape form and was computer processed. The tape file was found to contain the following data on each device.

- Operating company name, plant address, location on a 1 mile grid.
- Device category classification.
- Operating hours each day of the week.
- Pollutant emission rates (in lbs/hr), including NOx.

The initial sort revealed that of the approximately 16,000 permit units recorded on the tape approximately 2,700 were recorded as being NOx emitters. In an attempt to keep the number of units inventoried as individual devices to a more manageable number, and yet account for at least 90% of the emissions, a cut off of 2 lb NOx/hr was explored. The sum of the emissions from the 700 LAC APCD devices emitting in excess of 2 lb NOx/hr was found to exceed 95% of all of the NOx emissions (on an hourly basis) of the LAC APCD EDP emission inventory, and hence was adopted as a pragmatic cutoff for this inventory. This maximum hourly rate of 2 lb/hr was judged to correspond to full load emissions from gas burning external combustion devices of approximately 20 million Btu/hr (MMB/H), and oil burning devices of approximately 10 MMB/H. Hence these were adopted as equivalent bases for cutoff of the inventory although under certain limited circumstances, discussed later, some devices were retained down to 14 MMB/H gas fired and 8 MMB/H oil fired. It should be noted that the 2 lb/hr cutoff on a year around operating device would correspond to about 9 tons NOx/year, or about a factor of 10 below the EPA inventory cutoff.[10] In the final inventory a uniform cutoff of 10 MMB/H was adopted for all devices except large gas burning internal combustion engines (having roughly ten times higher emissions factors) for which the cutoff was extended down to 1 MMB/H which corresponds to about 140 BHP.

Other valuable data obtained from the LAC APCD was daily fuel use (natural gas, refinery gas, and oil) by plant location for 10 electric utility stations,[30] 7 major refineries, and 4 minor refineries[31] for the period August 1972 through June 1973. In addition monthly fuel use was obtained from LAC APCD files for about 120 industrial, commercial and institutional plant sites. Although many of these sites were large fuel users, this list can not be construed as a complete list of fuel used by the 120 largest fuel using plant sites.

Similar identification and device characteristics information was also obtained for several hundred devices (larger than the cutoff) from the APCD's of Orange, Riverside, San Bernardino, Santa Barbara, and Ventura Counties. In addition a limited quantity of fuel use data was obtained, primarily for utilities and a few singularly large industrial sites. As in Los Angeles information was obtained only for devices on permit (and not necessarily all of these). Other devices of interest, not being on permit, could not be identified from APCD files. Devices which do not operate on a standby fuel (oil) are not required to have a permit unless they are very large. While economics tend to force most operators of larger boilers to an interruptable gas supply and a standby liquid fuel supply, there are a significant number of smaller boilers 10-30 MMB/H, on continuous gas and hence are not on permit. In an attempt to get information on these boilers, the State Industrial Safety files were checked. Approximately 150 boilers, not previously identified from APCD permit files were located and described. There are undoubtedly more than this in operation but could not be traced down in the time available. The other major category of non-permit devices, responsible for a considerably larger total emission, is the gas fired reciprocating engines that drive compressors for the utilities and refineries. Identification and use patterns of some portion of these engines was obtained from a refinery hydrocarbon inventory conducted by the ARB in 1973,[32] and from the Southern California Gas Company.[33] Southern California Gas Company also made some of their gas driven engines available for emissions testing as part of this program, and also provided data on gas distribution within the Basin, monthly variations,[33] and projections of gas availability out through 1980.[34]

A considerable amount of device design and operational data essential to conducting this inventory on a specific unit by unit basis was obtained from the managers of the several major refineries in the Basin.[35-41] This information some of which was considered confidential, included specific unit identification with respect to the LAC APCD permit system, design heat input rating, type and function of device, typical operating load fraction, typical fuel compositions and heating values, type of draft, extent of air preheat, number of burners, CO consumed as fuel in the CO boilers, and projections of fuel use. The program could not have been carried out to the level of detail and accuracy without the considerable effort to which the refinery staffs went in supplying the requested data on nearly 500 combustion devices. The refinery staffs also contributed extensively through their cooperation with the test phase of the program discussed in Appendix C.

With regard to the electric utility class of sources a considerable amount of data for each individual electric generation combustion unit was provided by the Los Angeles Department of Water and Power,[42] Southern California Edison Co.,[43] Public Service Departments of Glendale[44] and Burbank,[45] and the Pasadena Department of Water and Power.[46] The data provided include unit design type, operational modes and limitations, monthly capacity factors , diurnal load patterns, fuel use distribution, fuel type, NOx controls implemented or tested, projections of generating load and unit use, and most importantly specific NOx emissions test results as a function of load for each of the large units that come under regulation and like data for some of the smaller unregulated units. In addition, NOx control modes and projection of NOx emissions for the future were provided. The assembly, review and communication of this mass of data required considerable effort on the part of the staffs of each of these companies, and was essential to our being able to treat each unit at the level of detail and accuracy of this inventory.

NOx emissions compilations for individual units based on earlier data with unspecified operational modes were obtained from both LAC APCD[47] and ARB[48] files and used for comparison in certain situations where current data were unavailable or the current data provided appeared to be anomalous.

Other sources of emissions data tapped during the program were the test data files of the Los Angeles, San Bernardino, and Orange County APCD's. Because of the broad extent of the LAC APCD source test data file, about 360 NOx tests since 1951, and because each record had to be screened by an APCD officer for trade secret data prior to making it available, only a limited sampling of test data was requested for this program. The 90 test reports requested for review were restricted to the latest test results from six categories of sources which were: 1966-67 internal combustion engine tests, 1968-69 bake oven tests, 1969-73 glass furnace tests, 1968-73 fluidized bed catalytic cracking unit tests, 1968-73 asphalt drier tests, and 1971 metal furnace tests. Data from these tests were either applied to applicable specific units in some cases, or were used to supplement and compare with data obtained during this program used to establish emission factors. Data obtained from San Bernardino were primarily from the Kaiser Steel plant in Fontana, while Orange County provided data on the Huntington Beach electric generating station.

Finally, with respect to the determination of area distributed NOx sources, extensive use was made of demographic data obtained during the 1970 census. Emissions factors used for small commercial and industrial furnaces, and heaters were those published by the EPA.[12]

During the preliminary inventory it became apparent that the single most significant contribution to the estimate of emissions from the miscellaneous combustion devices from commercial and institutional sites and from industrial plants other than refineries and electric generating stations was the uncertainty in the fuel use patterns for these devices. Needed was data on hours per day, days per week these units were operated and the normal fraction of rated load. In order to obtain this data a two page questionnaire was sent out to approximately 500 plants in the Basin. Samples of the questionnaire are shown in Figures B-1 and B-2 in Appendix B. Information was requested on each device within each plant rated in excess of 10 MMB/H heat input, or 140 BHP for internal combustion engines. Where possible APCD Permit #, Device Type and Rate Energy Input were filled in prior to mailing the forms. This was done in order to provide the most complete possible identification of the device in question. Information was also requested on any additional devices, in the appropriate size ranges, that were not identified on the questionnaire. In addition to device identification and rating information, requested was operational hours, operational load fraction, and fuel use for August and December 1972 and 1973 as well as total fuel use for those two years. The response to these questionnaires was exceptional, in that over 95% were returned with the information requested, providing a very detailed picture of fuel use previously unavailable.

# 5.0 COMPUTATION METHODS

## 5.1 Point Sources

The emissiors from a given source can be characterized by the product of a firing rate times an emission factor times a unit of time. When each of these is possibly a variable the emission rate is the integral of the product over the time interval of interest;

$$E_j = \int q\ f\ d\left(\frac{t}{T_j}\right) \tag{5-1}$$

where $E_j$ is the emission rate in mass units of NOx per time interval (lbs. per hr) $T_j$, q is the time dependent firing rate of the device in thermal units per unit of time (million Btu/hr), f is the load dependent emission factor in mass units of NOx per thermal unit (lb NOx/million Btu) and t is the time variable. For convenience the time variable t is normalized to vary between 0 and unity by introducing T, the number of operating hours per time interval $T_j$. The ratio of the instantaneous firing rate q to the name-plate firing rate Q is assumed to be a function of time, and the ratio of the load dependent emission factor f to the full load emission factor F is assumed to be a function of load fraction.

$$E_j = QF\left(\frac{T}{T_j}\right) \int_0^1 \frac{q}{Q}\left(\frac{t}{T}\right) \frac{f}{F}\left(\frac{q}{Q}\right) d\left(\frac{t}{T}\right) \tag{5-2}$$

A power law emission factor - load factor relationship (discussed later) is assumed

$$\frac{f}{F} = \left(\frac{q}{Q}\right)^{\alpha} \tag{5-3}$$

which yields

$$E_j = QF\left(\frac{T}{T_j}\right) \int_0^1 \frac{q}{Q}\left(\frac{t}{T}\right)^{1+\alpha} d\left(\frac{t}{T}\right) \tag{5-4}$$

where j indicates H for hour, D for day, M for month, A for annual. A consistent set of units is $T/T_j$ operating hours per period j, Q in millions Btu/hr, and F in lb NOx/million Btu.

For further convenience a capacity factor is defined as the time averaged fraction of full load over the operational period T

$$C_F = \left(\frac{\bar{q}}{Q}\right) = \int_0^1 \frac{q}{Q}\left(\frac{t}{T}\right) d\left(\frac{t}{T}\right) \tag{5-5}$$

which is related to the fuel use $W_j$ for the period $T_j$ by

$$\dot{W}_j = \frac{W_j}{T_j} = \frac{Q\,(T/T_j)\,C_{Fj}}{H} \tag{5-6}$$

where H is the higher heating value of the fuel per unit mass. Substituting (5-5) and (5-6) into equation (5-4) yields

$$E_j \cong QFC_F{}^{1+\alpha}\left(\frac{T}{T_j}\right) \tag{5-7}$$

which is exact only for $\alpha = 0$, but introduces no more than about 10% error up to $\alpha = 3$ for the typical diurnal utility load variation which is essentially symetric about the average load and has a peak no more than about 50% above the average. Using equation (5-6)

$$E_j \cong Q^{-\alpha} F \,(H\,\dot{W}_j)^{1+\alpha} \left(\frac{T}{T_j}\right)^{-\alpha} \tag{5-8}$$

The full load emission factor is generally found to be dependent on size as related to name-plate firing rate by

$$F = CQ^{\beta} \tag{5-9}$$

Where C is a function of the fuel, the device type, and operating mode. Substituting (5-9) into equations (5-7) and (5-8) yields the final general form:

$$E_j \cong CQ^{1+\beta}\, C_F{}^{1+\alpha} \left(\frac{T}{T_j}\right) \tag{5-10}$$

or

$$E_j \cong CQ^{\beta-\alpha}\,(H\,\dot{W}_j)^{1+\alpha} \left(\frac{T}{T_j}\right)^{-\alpha} \tag{5-11}$$

For large combustion devices, such as utility boilers, there is generally not enough data of similar type devices operating on similar fuels and similar operational modes to establish a good statistical value of $\beta$. In most cases the unit itself will have been tested and an emission concentration P in units of ppm of NOx corrected to a standard dilution (usually 3% oxygen) will be known, allowing F to be computed from

$$F = \frac{MN}{H} P \qquad (5\text{-}12)$$

where M is 46 the molecular weight of $NO_2$, and N is the moles of dry flue gas per pound of fuel. The variation of f with load is usually measured as well as the full load value F. Because of unit to unit peculiarities, particular having to do with the operating oxygen level necessary to avoid smoke or excessive CO, the variation of f with q cannot be reliably generalized. In the absence of test data, however, a rough generalization can be made that $\alpha$ (Equation 5-3) is near zero for oil fuel and near unity for gaseous fuel over the normal load fraction range, i.e., about 0.5 to 1.0.

For small units such as industrial and commercial package boilers, heaters, etc., data on large numbers of units operating both at full load and partial load have been correlated with firing rate by LA APCD.[20] No separate presentation of individual unit emission factor variation with load fraction was given. Because of unit to unit variations (discussed in Section 2.2) a rather large spread of the data (+100%, −50%) about a curve depicted by Equation 5-9 resulted, as shown in Figures 2-1 and 2-2. Nevertheless in the absence of data for specific devices such a correlation applied to a large inventory of devices will probably give a representative total emission. The LAC APCD correlation for both oil and natural gas resulted in a value of $\beta$ of 0.17 with the value of C for oil about twice that for natural gas. It is likely that this correlation included a substantial quantity of data obtained at less than full load. In the absence of specific part-load variation of emission factor ($\alpha$) it is reasonable to assume a value of ($\alpha$) equal to the full load variation of emission factor with device thermal rating ($\beta$). This puts a near upper emission value bound on partial load variation of (f) and probably introduces small error since most industrial devices tend to operate at a near constant fraction (near unity) of their rated load.

From Equation (5-10) (assuming $\alpha \simeq \beta$) the computation equations for the summer daily, winter daily, and average annual NOx emissions respectively are derived for a source for which an estimate of capacity factor only is available:

$$E_{Ds} = 0.012\ C_g\ (Q\ C_F)_s^{1+\beta}\ (T/T_D)_s \tag{5-13}$$

$$E_{Dw} = 0.012\ C_o\ (Q\ C_F)_w^{1+\beta}\ (T/T_D)_w \tag{5-14}$$

$$E_A = 0.012\ Q^{1+\beta}\left[C_g C_{Fg}^{\ 1+\beta}\ (T/T_D)_g D_g + C_o C_{Fo}^{\ 1+\beta}\ (T/T_D)_o D_o\right] \tag{5-15}$$

where subscript s refers to summer (chosen as average for the month of August), w refers to winter (chosen as average for the month of December), where 0.012 is the conversion from pounds NOx per hour to tons NOx per day, where D is the number of days of operation, where subscript g refers to natural gas and subscript o refers to oil, and where $(T/T_D)_g$ and $(T/T_D)_o$ represent average fraction of day in operation when burning gas and oil respectively.

For a source with known annual fuel use $W_A$ (for the assumption of $\alpha \simeq \beta$). The respective rates from equation 5-11 are given by

$$E_{Ds} = 0.012\ C_g\ (\bar{H} \cdot \dot{W}_A)^{1+\beta}\ (T/T_D)^{-\beta} \tag{5-16}$$

$$E_{Dw} = 0.012\ C_o\ (\bar{H} \cdot \dot{W}_A)^{1+\beta}\ (T/T_D)^{-\beta} \tag{5-17}$$

$$E_A = 0.012\ (\bar{H} \cdot \dot{W}_A)^{1+\beta}\ [C_g D_g + C_o D_o]\ (T/T_D)^{-\beta} \tag{5-18}$$

based on the implication of a constant averaged capacity factor given by

$$\bar{C}_{FA} = \bar{H}\ \dot{W}_A / Q\ (T/T_A) \tag{5-19}$$

where $\bar{H}$ is fuel use weighted between $H_o$ and $H_g$, and where it is presumed that August operation is on gas while December operation is on oil.

For groups of devices of varying name-plate ratings $Q_i$ operating at a given plant, when only a plant fuel use is known, it is assumed that all devices operate at the same capacity factor given by

$$C_{Fs} = H_g \dot{W}_{AUG} \Big/ (T/T_D)_{AUG} \sum_i Q_i \tag{5-20}$$

$$\overline{C}_{FA} = \overline{H} \dot{W}_A \Big/ (T/T_A) \sum_i Q_i \tag{5-21}$$

$$E_{Ds_i} = 0.012\ C_g \left[ (H_g \dot{W}_{AUG})^{1+\beta} \Big/ (T/T_D)^{\beta}_{AUG} \right] Q_i^{1+\beta} \Big/ (\sum_i Q_i)^{1+\beta} \tag{5-22}$$

and

$$E_{A_i} = 0.012 \left[ C_g H_g^{1+\beta} D_g \Big/ (T/T_D)^{\beta}_g + C_o H_o^{1+\beta} D_o \Big/ (T/T_D)^{\beta}_o \right] Q_i^{1+\beta} \Big/ (\sum_i Q_i)^{1+\beta} \tag{5-23}$$

Finally for units with both specific test data on emissions as a function of load and plant-wide monthly fuel report, such as at the electrical generation stations

$$E_{Ds} = 0.012\ Q_{ug}\ (MN_g P_g / H_g)\ (T/T_D)_{u,AUG}\ (\dot{W}_{p,AUG} H_g \Big/ \sum_u Q_u)^{1+\alpha} \tag{5-24}$$

where subscript u denotes unit, and subscript p denotes plant. When individual unit fuel report data is available a unit capacity factor can be derived and the emissions computed directly from equations (5-7) and (5-12).

## 5.2 Area Sources

General -- Large numbers of small combustion devices, i.e., smaller than the major device cutoff in each of the three categories, domestic, commercial/institutional, and industrial are distributed over the Basin. The emissions from these devices must be estimated from average emissions factors applied to distributed fuel use. For all practical purposes fuels other than natural gas can be neglected because they represent such a small fraction of the energy used in distributed sources in the Basin. The rationale for the distribution of fuel use for domestic sources is clearly related to population distribution. Unfortunately there is no readily available equivalent commercial and industrial activity census on which to base the distribution in these categories. Hence a rather arbitrary distribution basis was used.

Domestic -- For the domestic category the emissions are given by

$$E_{j,Dn} = (H\,\overline{F})_g \cdot \dot{W}_{j,Dn} \qquad (5\text{-}25)$$

where E is the emission rate in mass units of NOx per time interval j for domestic devices in grid square n, where $H_g$ and $\overline{F}_g$ are the heat value per unit fuel mass and average emissions factor respectively for gas, where $W_j$ is the fuel use in mass units over the interval j, and where n is the designation of the particular grid square within the Basin. For this inventory, the grid square adopted was 10Km (6.2 mi) square, as defined by the NEDS UTM coordinate system[10] used for point sources and located on the map of Figure 5-1. Grid squares are designated by a seven digit figure, the first three of which (in units of 1,000 meters) represents the UTM coordinate of the western boundary of the grid square, and the remaining four digits represent the southern boundary of the grid square in similar units. Because several of the grid squares contained area of more than one county, the area of the squares were properly allocated among the counties. Similarly area lying outside of the Basin or in the ocean was also properly accounted for in characterizing the grid square area on which to base the distributed emissions.

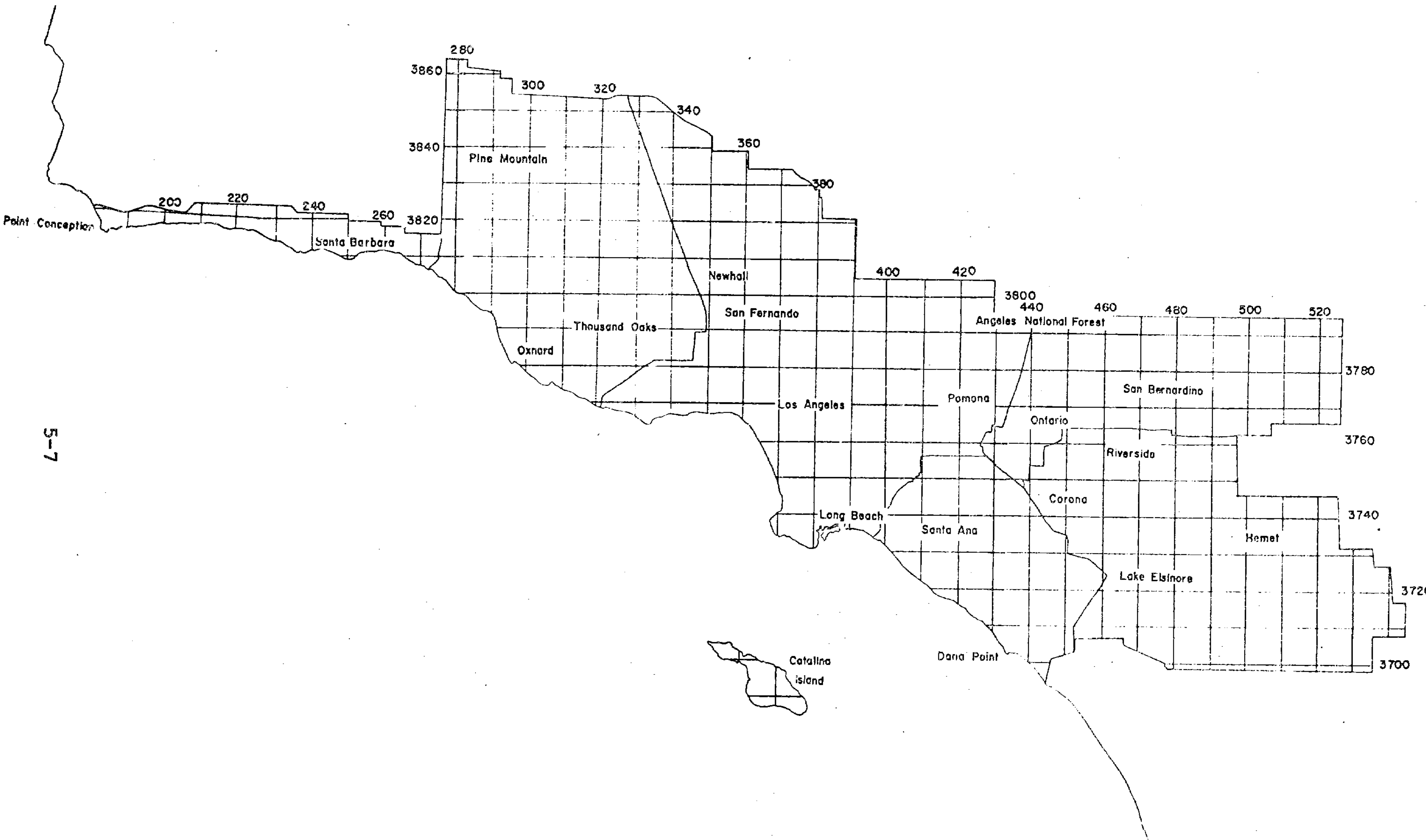


Figure 5-1. 10 km UTM Grid Square Locations in South Coast Air Basin.



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Since no distribution of the natural gas burned by distributed domestic sources, homes, apartments, etc. was available on a more local basis than the county a rationale for distribution was developed. It was concluded that the fundamental basis for the distribution should be population but that the fuel use should be modulated by some measure of standard of living since this relates to the size of the residence per person and hence to the fuel used for heating. The population of each grid square was determined from the 1970 census data as distributed and mapped by census tract by Western Economic Research Co.[49] and by the U.S. Census Bureau. Population of each 10 Km grid square in the Basin was determined to the nearest 1,000. Zero population was assigned to those grid squares with population less than 1,000. Data on average family unit income by census tract was obtained from the same sources as the population data, and from this an average family income for each grid square was determined. The income adjustment on fuel use was taken to be linear with family income up to $20,000 year. The actual modulation factor used was the median family income of the grid square divided by the mean median family income for the six counties of the Basin which is about $11,000 per year. Multiplying the income adjustment factor by the population generated a gas use proportionality factor $G_n$ for each grid square n. Dividing $G_n$ by the sum of $G_n$ in each county gave a determination of the fraction of that county's distributed domestic gas use that could be attributed to a particular grid square, thus

$$\dot{W}_{jn} = \left[ G_n \Big/ \sum_{\substack{n=1,\\ \text{county}}}^{N} G_n \right] \left( \dot{W}_{j\ \substack{\text{domestic,}\\ \text{county}}} \right) \tag{5-26}$$

The Basin portion of the county wide domestic gas use for July '72 - June '73 was obtained for each of the six counties from the Southern California Gas Company[33] which distributes gas to all of the Basin with the exception of Long Beach which has its own distribution system. A portion of the Long Beach gas is purchased from Southern California Gas Company and a portion is generated from city owned wells. Data on the Long Beach gas use was obtained from the Long Beach Gas Company and was appropriately factored into the total distribution within Los Angeles County.

The heating value $H_g$ for the Basin natural gas was taken as that adopted by LAC APCD as the Basin average 1,050 Btu/scf. The emission factor was taken from the results of source testing on this program, and recent EPA tests (both discussed in Appendix H) to be 0.10 lbs NOx per million Btu.

Minor Industrial -- In order to complete the stationary source inventory it was also necessary to account for the emissions due to industrially operated combustion devices in the size range below that adopted for the point source inventory, i.e., about 10 million Btu/hr. In order to distribute gas use by this category of devices -- areas of high industrial activity were identified using data from the Los Angeles Chamber of Commerce. Unfortunately no satisfactory means was devised to quantitatively differentiate the level of industrial activity from one "industrially active" grid square to another so all such grid squares were considered to be equal in terms of their minor industrial gas use for the inventory. The "industrially active" grid squares are identified on the map on Figure 5-2. An active area proportionality was applied to grid squares not wholely within a county, within the Basin, or on land.

The total county wide industrial gas use was obtained from SCGC.[33] From that the total, gas fuel use calculated for or reported for inventoried point sources was subtracted in order to determine the remainder, that burned by the distributed minor industrial devices.

The emission factor applied was that from the EPA compilation,[12] 150 lbs NOx per million cu. ft. of gas or 0.142 lb NOx/MMB. An equation similar to equation 5-25 was used to compute $\dot{E}_{j,In}$ the distributed minor industrial emission rate for the period j for grid square n.

Minor Commercial/Institutional -- As in the case of industrial devices of a size below the point source inventory cutoff, so must the minor commercial/institutional sources be accounted for through their fuel use. In this category is included office buildings, retail sales outlets,

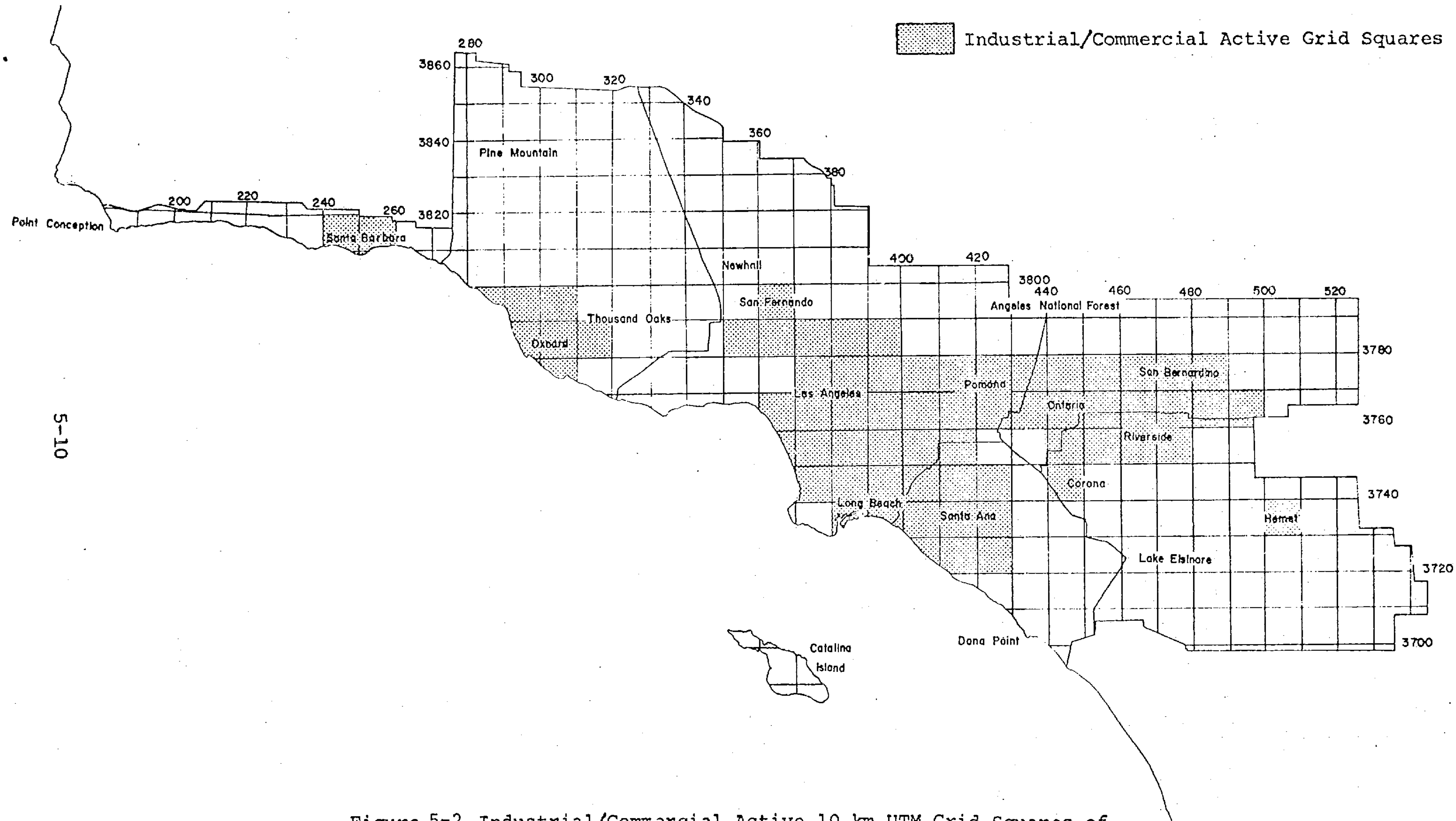


Figure 5-2. Industrial/Commercial Active 10 km UTM Grid Squares of South Coast Air Basin

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cleaners, laundries, hotels, schools, motels, etc. Again no satisfactory method for quantitatively distributing minor commercial/institutional activity could be found. Hence the approach taken was to identify those grid squares which could be characterized as containing substantial commercial/institutional activity and to these grid squares equally distribute 95% of the commercial/institutional gas use not attributed to individual sources, after accounting for the fraction of the area of the grid square not in the Basin or not on land. The remaining 5% of the gas in this category was distributed to the remaining grid squares.

The total county-wide commercial/institutional fuel use was obtained from the SCGC.[33] From that total in each county was subtracted that computed or reported for inventoried point sources. The remainder was distributed according to the active commercial/institutional area basis described above.

The emission factor applied was from the EPA compilation[12], 100 lbs NOx per million cu. ft. or 0.095 lbs NOx/MMB. An equation similar to equation 5-24 was used to compute $E_{j,Cn}$, the distributed commercial/institutional emissions for the grid square n for the period j.

## 6.0 DATA FORMAT, PROCESSING

At the request of the ARB staff the data record format selected for the point source inventory is that of the Environmental Protection Agency's National Environmental Data Systems (NEDS). This data system is defined in Reference 10, EPA "Guide for Compiling a Comprehensive Emission Inventory." The data is formated onto five cards of 80 columns each plus an additional 80 column card for each fuel burned or product produced by the inventoried device. A reproduction of the EPA NEDS form is presented in Figure 6-1. Identity and location information is contained on the first card, coordinate location and stack data on the second card, design capacity and control equipment data on the third card, use data and emissions data on the fourth card, and compliance information on the fifth card. Because of the limited scope of the present inventory, i.e., NOx only, certain of the NEDS data blocks have not been utilized as indicated by the shaded blocks in the version of the form used for this program, Figure 6-2. Additional identification information such as APCD permit number and state industrial safety permit number have been added in blank columns as indicated.

Because of a need to record more detail on device use and other emissions rates than the annual average, use has been made of the NEDS Variable Data Input Form.[10] Using this format for identification, the additional data has been formatted onto four additional cards as shown in Figure 6-3. The first two of these relate to present emissions, the third with possible future emissions with operational changes and the fourth with possible future emissions with hardware changes. Thus the complete record for each device in the present inventory is comprised of 9 cards plus one additional card for each fuel burned and each product produced. Not all data is presently available on each source in the inventory hence some blanks remain in the records for some of the sources.

While hard copies of the initial version of each record are on file, the records have been coded onto tape cassettes using USASCII

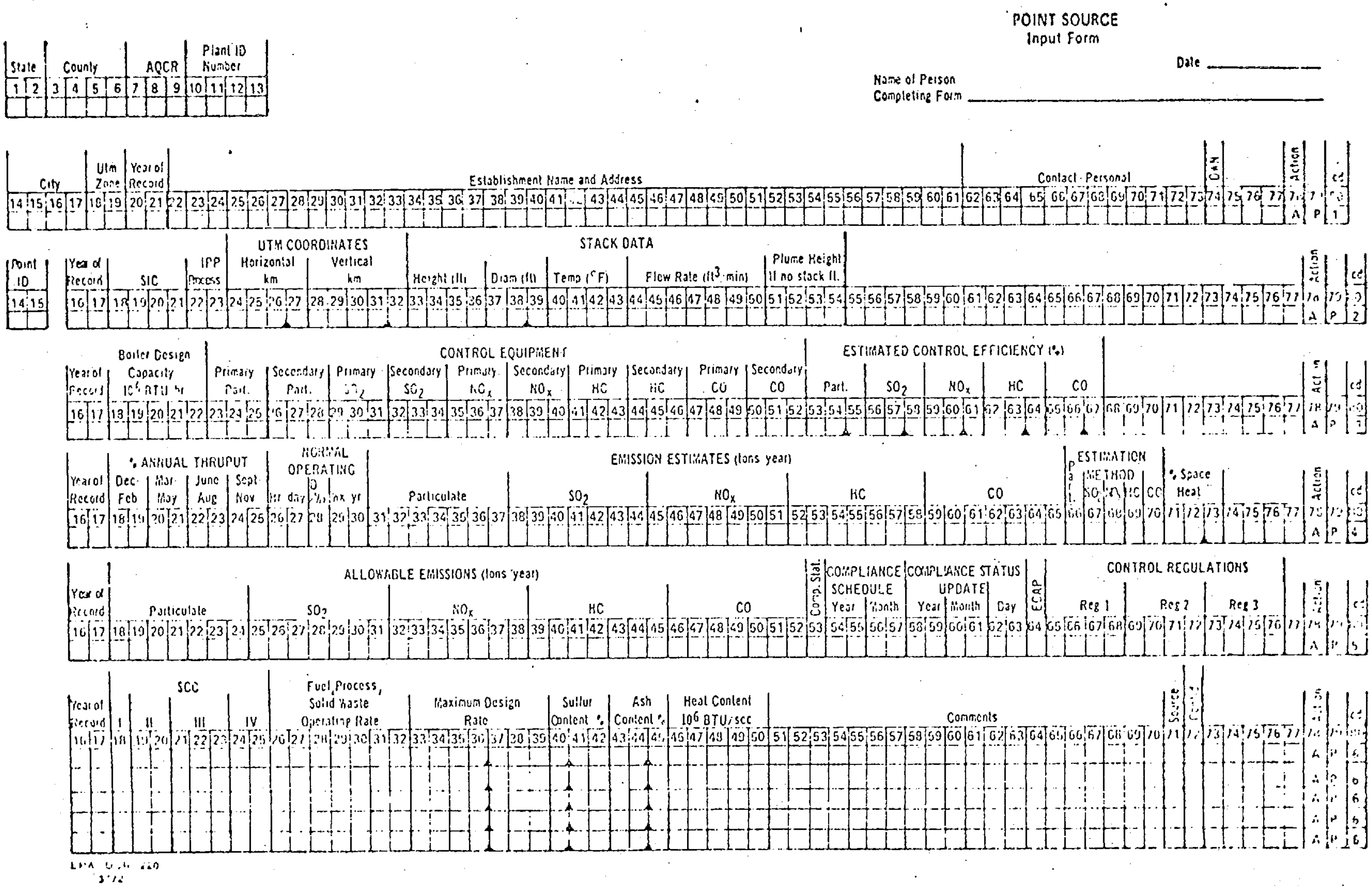


Figure 6-1. EPA NEDS Point Source Coding Form

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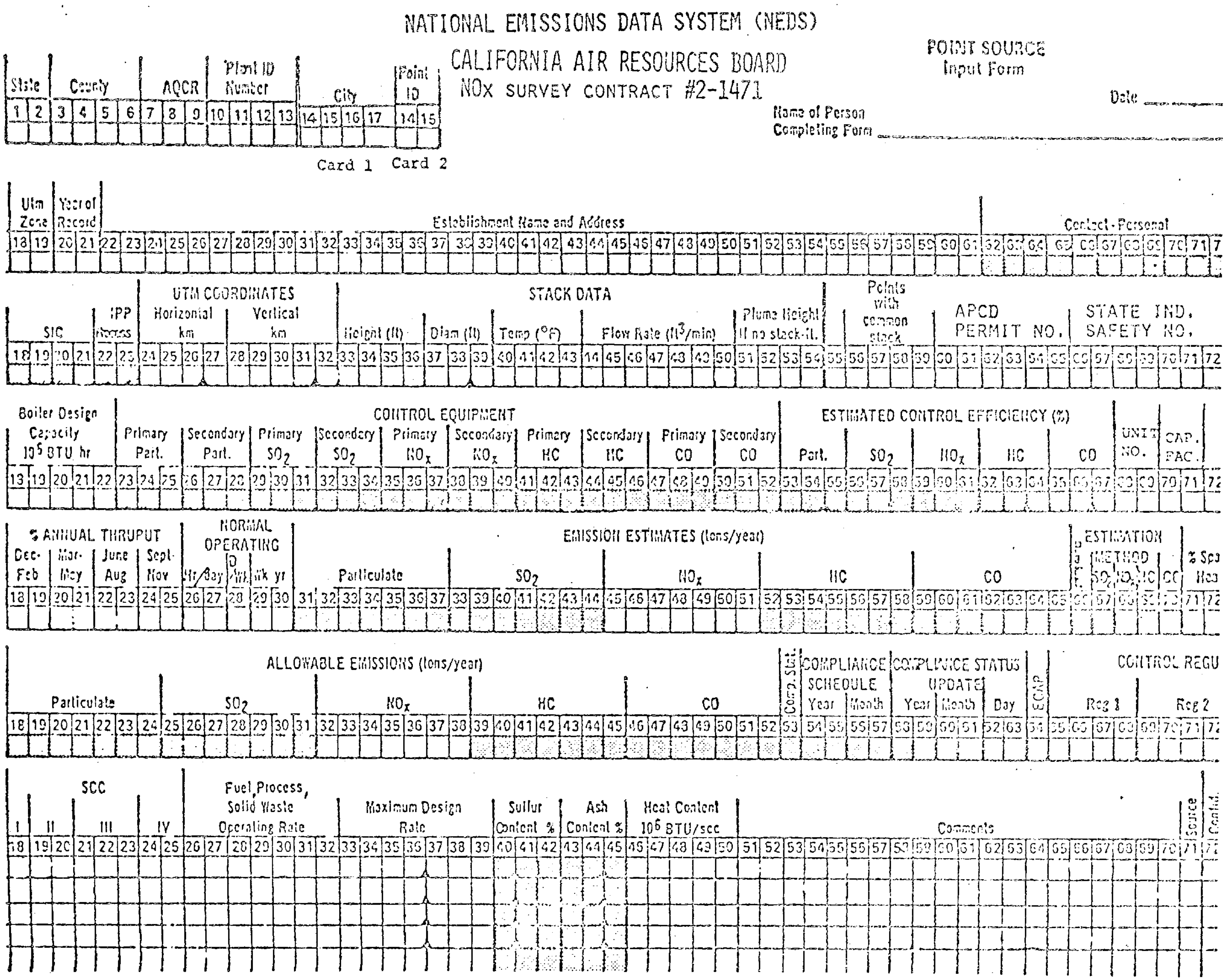
NATIONAL EMISSIONS DATA SYSTEM (NEDS)

CALIFORNIA AIR RESOURCES BOARD

NOx SURVEY CONTRACT #2-1471

POINT SOURCE
Input Form

Date

Name of Person Completing Form

State | County | AQCR | Plant ID Number | City | Point ID

Card 1 Card 2

Utm Zone | Year of Record | Establishment Name and Address | Contact - Personal

SIC | IPP | UTM COORDINATES: Horizontal km, Vertical km | STACK DATA: Height (ft), Diam (ft), Temp (°F), Flow Rate ($ft^3$/min), Plume Height if no stack-ft. | Points with common stack | APCD PERMIT NO. | STATE IND. SAFETY NO.

Boiler Design Capacity $10^5$ BTU hr | CONTROL EQUIPMENT: Primary Part., Secondary Part., Primary $SO_2$, Secondary $SO_2$, Primary $NO_x$, Secondary $NO_x$, Primary HC, Secondary HC, Primary CO, Secondary CO | ESTIMATED CONTROL EFFICIENCY (%): Part., $SO_2$, $NO_x$, HC, CO | UNIT NO. | CAP. FAC.

% ANNUAL THRUPUT: Dec-Feb, Mar-May, June-Aug, Sept-Nov | NORMAL OPERATING: Hr/Day, D/Wk, Wk/yr | EMISSION ESTIMATES (tons/year): Particulate, $SO_2$, $NO_x$, HC, CO | ESTIMATION METHOD: $SO_2$, $NO_x$, HC, CO | % Spa Hea

ALLOWABLE EMISSIONS (tons/year): Particulate, $SO_2$, $NO_x$, HC, CO | Comp. Stat. | COMPLIANCE SCHEDULE: Year, Month | COMPLIANCE STATUS UPDATE: Year, Month, Day | ECAP | CONTROL REGU: Reg 1, Reg 2

SCC: I, II, III, IV | Fuel, Process, Solid Waste Operating Rate | Maximum Design Rate | Sulfur Content % | Ash Content % | Heat Content $10^6$ BTU/sec | Comments | Source | Confid.

Figure 6-2. Modified NEDS Form for ARB NOx Inventory

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**VARIABLE DATA INPUT FORM**

NATIONAL EMISSIONS DATA SYSTEM (NEDS)
CALIFORNIA AIR RESOURCES BOARD
NOx SURVEY CONTRACT #2-1471

DATE________________
NAME OF PERSON
COMPLETING FORM________________

| STATE | COUNTY | AQCR | PLANT ID NUMBER | POINT ID | YEAR OF RECORD |
|---|---|---|---|---|---|
| 1 2 | 3 4 5 6 | 7 8 9 | 10 11 12 13 | 14 15 | 16 17 |

PRESENT

| $E_H$ | $P_G$ | $P_O$ | $\alpha_G$ | $\alpha_O$ | $F_G$ | $F_O$ | |
|---|---|---|---|---|---|---|---|
| 18 19 20 21 | 22 23 24 25 | 26 27 28 29 | 30 31 32 | 33 34 35 | 36 37 38 39 | 40 41 42 43 | 44 45 46 47 48 49 50 51 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 |

PRESENT

| $E_{DS}$ | $E_{DW}$ | $E_A$ | $C_{FS}$ | $C_{FW}$ | $C_{FG}$ | $C_{FO}$ | $T_S$ | $T_W$ | $D_G$ | $D_O$ | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 19 20 21 22 | 23 24 25 26 27 | 28 29 30 31 | 32 33 | 34 35 | 36 37 | 38 39 | 40 41 | 42 43 | 44 45 46 | 47 48 49 | 50 51 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 |

WITH OPERATIONAL MODIFICATIONS

| $E_H$ | $E_{DS}$ | $E_{DW}$ | $E_A$ | $F_G$ | $F_O$ | CAP. COST | OP. COST | |
|---|---|---|---|---|---|---|---|---|
| 18 19 20 21 | 22 23 24 25 26 | 27 28 29 30 31 | 32 33 34 35 | 36 37 38 39 | 40 41 42 43 | 44 45 46 47 | 48 49 50 51 | 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 |

WITH HARDWARE MODIFICATIONS

| $E_H$ | $E_{DS}$ | $E_{DW}$ | $E_A$ | $F_G$ | $F_O$ | CAP. COST | OP. COST | |
|---|---|---|---|---|---|---|---|---|
| 18 19 20 21 | 22 23 24 25 26 | 27 28 29 30 31 | 32 33 34 35 | 36 37 38 39 | 40 41 42 43 | 44 45 46 47 | 48 49 50 51 | 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 |

Figure 6-3. Modified Variable Data Input Form
For ARB NOx Inventory

5800-179

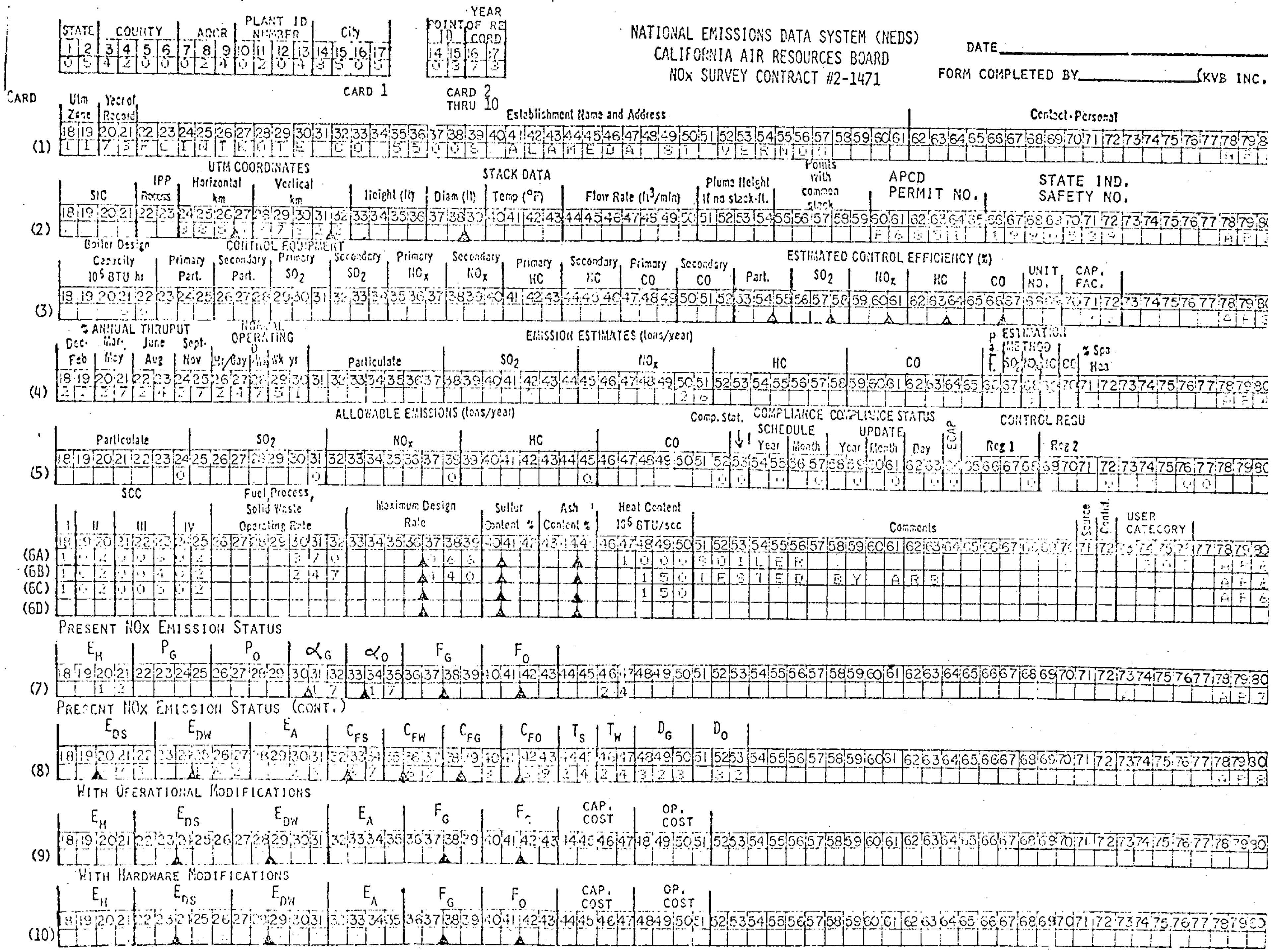
convention and transferred to a magnetic random access disc of a digital computer. All subsequent modifications to the original records were made directly on the disc. Hence copies of the ammended records can be provided as a printout from the disc on request. An example is shown at Figure 6-4.

## 6.1 Physical Description

The ARB data base as it currently exists is made up of approximately 1500 data records in NEDS format. Each record describes a specific device located within the South Coast Air Basin. An exception was made for certain sources which were made up of a number of identical devices (such as turbines or IC engines) which are normally operated together and sometimes which share a common stack. The number of such devices comprising the source is noted in the record. The records are each organized into fifteen 80-column card images. At present, over 150 specific data items have been defined to describe each record. Space has been left within each record to accomodate the definition of additional data items as the need arises.

Access to the ARB NOx data base for the duration of the present program was through the DATAPOINT 2200 DOS. The data base itself, resi-led on two discs. The primary disc was the working disc from which reports were written. The sole purpose of the secondary disc was to provide a back up capability in the event of a computer malfunction.

Data was stored on the discs in an indexed sequential manner. That is, each card image was identified by a fifteen character key where all keys within a given record are the same. To insure uniqueness of the keys, each was made up from the following five data items: state, county, AQCR, (Air Quality Control Region, 24 for the South Coast Air Basin), plant ID, and point ID. A directory was generated and written on the first file on the disc. The directory was indexed by record keys and then corresponding location on the disc. The original data base and all subsequent bench-marked versions were sorted (sequenced) in ascending order of the data block keys.



NATIONAL EMISSIONS DATA SYSTEM (NEDS)
CALIFORNIA AIR RESOURCES BOARD
NOx SURVEY CONTRACT #2-1471

DATE ____________

FORM COMPLETED BY ____________ (KVB INC.

| STATE | | COUNTY | | | | AQCR | | | PLANT ID NUMBER | | | | City | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 |
| 0 | 5 | 4 | 2 | 0 | 0 | 0 | 2 | 4 | 0 | 2 | 0 | 4 | 3 | 5 | 0 | 5 |

CARD 1

| POINT ID | | YEAR OF RECORD | |
|---|---|---|---|
| 14 | 15 | 16 | 17 |
| 0 | 3 | 7 | 3 |

CARD 2 THRU 10

CARD

(1) Utm Zone; Year of Record; Establishment Name and Address; Contact-Personal
1 1 7 3 F C I N T K O T E C O 5 5 0 0 S A L A M E D A S T V E R N O N

(2) SIC; IPP Process; UTM COORDINATES: Horizontal km, Vertical km; STACK DATA: Height (ft), Diam (ft), Temp (°F), Flow Rate (ft³/min), Plume Height if no stack-ft., Points with common stack; APCD PERMIT NO.; STATE IND. SAFETY NO.

(3) Boiler Design Capacity $10^6$ BTU hr; CONTROL EQUIPMENT: Primary Part., Secondary Part., Primary $SO_2$, Secondary $SO_2$, Primary $NO_x$, Secondary $NO_x$, Primary HC, Secondary HC, Primary CO, Secondary CO; ESTIMATED CONTROL EFFICIENCY (%): Part., $SO_2$, $NO_x$, HC, CO; UNIT NO.; CAP. FAC.

(4) % ANNUAL THRUPUT: Dec-Feb, Mar-May, June-Aug, Sept-Nov; NORMAL OPERATING: Hr/Day, Day/Wk, Wk/Yr; EMISSION ESTIMATES (tons/year): Particulate, $SO_2$, $NO_x$, HC, CO; ESTIMATION METHOD: Part., $SO_2$, $NO_x$, HC, CO; % Spa Hea

(5) ALLOWABLE EMISSIONS (tons/year): Particulate, $SO_2$, $NO_x$, HC, CO; Comp. Stat.; COMPLIANCE SCHEDULE: Year, Month; COMPLIANCE STATUS UPDATE: Year, Month, Day; ECAP; CONTROL REGU: Reg 1, Reg 2

(6A)–(6D) SCC: I, II, III, IV; Fuel, Process, Solid Waste Operating Rate; Maximum Design Rate; Sulfur Content %; Ash Content %; Heat Content $10^6$ BTU/scc; Comments; Source; Confid.; USER CATEGORY

(6A) 1 0 2 0 0 5 0 4 — 3 7 0 — 0 6 5 — 1 0 0 0 — B O I L E R
(6B) 1 0 2 0 0 4 0 2 — 2 4 7 — 1 4 0 — 1 5 0 — T E S T E D B Y A R B
(6C) 1 0 2 0 0 5 0 2 — 1 5 0
(6D)

PRESENT NOx EMISSION STATUS

(7) $E_H$; $P_G$; $P_O$; $\alpha_G$; $\alpha_O$; $F_G$; $F_O$

PRESENT NOx EMISSION STATUS (CONT.)

(8) $E_{DS}$; $E_{DW}$; $E_A$; $C_{FS}$; $C_{FW}$; $C_{FG}$; $C_{FO}$; $T_S$; $T_W$; $D_G$; $D_O$

WITH OPERATIONAL MODIFICATIONS

(9) $E_H$; $E_{DS}$; $E_{DW}$; $E_A$; $F_G$; $F_O$; CAP. COST; OP. COST

WITH HARDWARE MODIFICATIONS

(10) $E_H$; $E_{DS}$; $E_{DW}$; $E_A$; $F_G$; $F_O$; CAP. COST; OP. COST

Figure 6-4. Sample NEDS Record Print Out

## 6.2 Operational Procedure

Two modes of operation were used in connection with the data base. The most important function was that of providing information from which reports were written. To do this, data must be extracted from the total data base and processed (sorted, summed, etc.) to produce the desired reports. The actual report writing was accomplished through the use of a higher level programming language available on the DATAPOINT 2200 computer.

The second mode of operation was that of maintenance and included additions, deletions, and modifications to the entire data base. This was carried on in support to both the field testing program and acquiring data from other sources. New data was assimilated into the data base as it was acquired, thus providing the most up-to-date data from which to write reports.

Another facet of maintenance was that of "benchmarking" the data base. This was accomplished through a three step procedure. First, the data base was sequenced and a new directory written on both the primary and secondary discs. Second, a dated benchmark listing of the entire data base was written. Finally, the complete final version of the ARB NOx data base was written to an industry compatible magnetic tape. As defined by the requestor either an ASCII or EBCDIC 7-track or 9-track 800 bpi standard tape can be provided. This last step will provide two benefits. First, an addition back-up capability is available. Second and more important, it insures both compatability and availability to other types of computing equipment.

## 6.3 Data Base Management

One of the more important functions of this part of the total project was to preserve the integrity of the data base. Great care went into insuring that the data base as it currently exists and during its maintenance would not be destroyed. The back-up procedures described above permit its reconstruction with minimal time and effort.

Similarly, procedures were developed to preserve the validity of the current and future version of the data base. These procedures were implemented to guarantee that data may not be added, deleted, and/or modified unless duly authorized and recorded.

In summarizing the data for the inventory summations were made on three bases, type of device, category of application, and geographical location. The device type sort was made on the NEDS source classification code (SCC code, NEDS card 6, columns 18 through 25). A summary of the more significant device categories and their respective SCC codes is presented in Table 6-I. While the SCC code also contains information on device application it was found that this code was not satisfactory for many common heat transfer devices such as boilers and heaters since the application category is not specifically defined for these devices. Hence to make it possible to sort in terms of applications categories similar to those used by the APCD's, an application category classification was devised and was recorded in column 18-21 of card B. A summary of the more significant application categories is presented in Table 6-II. The geographical sort was made on the basis of the 10 Km grid system adopted which is defined by the even 10,000 meter lines of the UTM coordinate system. Devices originally located by the LAC APCD data file were located on a 1 mile grid system and were subsequently transferred to the UTM grid system to an accuracy of $\pm$ 1/2 mile.

SOURCE CLASSIFICATION CODE (SCC)

APPLICABLE TO ARB SCAB NOx INVENTORY

**TABLE 6-I**

| | I | II | III | IV |
|---|---|---|---|---|
| BOILERS | 1 | | | |
| Electric | | 0 1 | | |
| Industrial | | 0 2 | | |
| Commercial/Institutional | | 0 3 | | |
| Nat. Gas | | | 0 0 6 | |
| Ref. Gas | | | 0 0 7 | |
| Dist. Oil | | | 0 0 5 | |
| Resid. Oil | | | 0 0 4 | |
| Nat. Gas & Resid. * | | | 0 6 4 | |
| Nat. Gas & Ref. Gas * | | | 0 6 7 | |
| Nat. Gas & Dist. Oil * | | | 0 6 5 | |
| Ref. Gas & Resid Oil * | | | 0 7 4 | |
| Other | | x x | x x x | |
| IC ENGINES | 2 | | | |
| Electric Turbine | | 0 1 | | 0 1 |
| Dist. Oil | | | 0 0 1 | |
| Nat. Gas | | | 0 0 2 | |
| Dist. Oil & Nat. Gas | | | 0 1 2 | |
| Industrial Turbine | | 0 2 | | 0 1 |
| Dist. Oil | | | 0 0 1 | |
| Nat. Gas | | | 0 0 2 | |
| Dist. Oil & Nat Gas * | | | 0 1 2 | |
| Reciprocating-Electric | | 0 1 | 0 0 3 | 0 1 |
| Reciprocating-Industrial | | 0 2 | x x x | 0 2 |
| Reciprocating-Commercial/Institutional | | 0 3 | x x x | 0 1 |
| Industrial Jet Engine | | 0 4 | 0 0 1 | 0 1 |
| Other | | x x | x x x | x x |
| HEATERS | | | | |
| Petroleum Industry | 3 | 0 6 | 0 0 1 | |
| Oil | | | | 0 1 |
| Oil | | | | 0 3 |
| Gas | | | | 0 2 |
| Gas | | | | 0 4 |
| FURNACE METAL | | | | |
| Primary | 3 | 0 3 | x x x | x x |
| Secondary | 3 | 0 4 | x x x | x x |
| Metal Melting in-process Fuel | 3 | 9 0 | x x x | 0 5 |
| Industrial Chemical Process | 3 | 0 1 | x x x | x x |
| Industrial Food/AG Process | 3 | 0 2 | x x x | x x |
| Industrial Mineral Process | 3 | 0 5 | x x x | x x |
| Asphaltic concrete | 3 | 0 5 | 0 0 2 | x x |
| " | 3 | 9 0 | x x x | 0 1 |
| Cement | 3 | 0 5 | 0 0 6 | x x |
| Cement | 3 | 9 0 | x x x | 0 2 |
| Ceramic/clay | 3 | 0 5 | 0 0 8 | x x |
| Brick Kiln | 3 | 9 0 | x x x | 0 6 |
| Frit | 3 | 0 5 | 0 1 3 | x x |
| Glass | 3 | 0 5 | 0 1 4 | x x |
| Gypsum | 3 | 0 5 | 0 1 5 | x x |
| Mineral Wool | 3 | 0 5 | 0 1 7 | x x |
| Industrial Process - Petroleum | 3 | 0 6 | x x x | x x |
| Industrial Process - Metal Fab. | 3 | 0 9 | x x x | x x |
| Industrial Process - Textile | 3 | 3 0 | x x x | x x |



*Combined Fuel firing designation derived by combining individual fuel designations - not part of SCC system.

TABLE 6-II

APPLICATION CATEGORY CLASSIFICATION

01 - UTILITY

01 - Gas turbine - electric generation
02 - Steam boiler " "
03 - Other IC device " "
04 - IC devices - natural gas transmission
05 - Standby electric generation - telephone

02 - INDUSTRIAL - CHEMICAL & RELATED INDUSTRIES

01 - Agricultural chemicals and fertilizers
02 - Intermediates, plastics, resins, rubber, adhesives
03 - Paints, coatings, etc.
04 - Pharmaceuticals and cosmetics
05 - Unclassified

03 - INDUSTRIAL - MANUFACTURING, MAINTENANCE, AND ASSEMBLY

01 - Heavy (metal fabrication, forging, etc.)
02 - Medium (auto and aircraft assembly, maintenance)
03 - Light (toy, electronics, textiles)
04 - Unclassified

04 - INDUSTRIAL - METALLURGICAL

01 - Iron and steel production
02 - Aluminum production
03 - Other metal production, melting

05 - INDUSTRIAL - MINERAL INDUSTRIES

01 - Asphalt paving
02 - Cement and concrete
03 - Glass
04 - Mineral wool, rock wool, insulation
05 - Tile, pipe, ceramics
05 - Unclassified

06 - INDUSTRIAL - PETROLEUM & GAS INDUSTRIES

01 - Oil-gas field operations
02 - Oil-gas transportation and storage
03 - Refineries
04 - Unclassified

07 - INDUSTRIAL - AGRICULTURE & FOOD PROCESSING

01 - Canning and food drying
02 - Citrus
03 - Seafood
04 - Sugar
05 - Unclassified

08 - INDUSTRIAL - UNCLASSIFIED

01 - Other food industries (bakeries, meat packing, etc.)
02 - Lumber industries (milling, etc.)
03 - Miscellaneous

10 - COMMERCIAL

01 - Commercial office buildings
02 - Process plants (cleaners, laundry, paint shops)
03 - Retail outlets (department stores, food stores, etc.)
04 - Unclassified

11 - INSTITUTIONAL

01 - Governmental operations
02 - Hospitals
03 - Penal institutions
04 - Educational institutions
05 - Unclassified

## 7.0 SUMMARY OF PRELIMINARY INVENTORY

The function of the preliminary NOx emission inventory of this program,[50] was to provide a quick-look result based on available information, and to estimate the uncertainties in the major category emissions figures, in order to provide a basis for setting priorities as to which data should be improved by either additional data gathering or by field testing of particular device types. Some of the preliminary inventory results are repeated in this section to provide the background on which the field testing and further data gathering were based. The period inventoried was from July, 1972 through June, 1973. This period was selected because it was the latest period for which electric utility plant, refinery plant, and some industrial plant fuel use data were available from LAC APCD records. For clarity of presentation, only winter (Dec. 1972) daily emissions are presented.

The summary of the preliminary inventory arranged by device type is presented in Table 7-I. It can be seen that boilers clearly dominate the emissions, being responsible for just over half of the total of about 500 tons/day for the stationary sources in the Basin in December 1972. Of the boiler emissions most is seen to be from the 70 utility boilers in the Basin. The largest emissions of device categories beneath the utility boilers is seen to be the industrial boilers (including some in the refineries) and petroleum process heaters, at about 60 tons/day each. The next largest emitting device categories are domestic space heaters and appliances, primary metal furnaces, and stationary reciprocating internal combustion engines, each at about half of that or 30 tons/day. The remaining categories including commercial space heaters, secondary metal furnaces, gas turbines, and miscellaneous mineral production kilns each emit substantially less. The data sources and computation methods utilized for the preliminary inventory were described in Sections 4.0 and 5.0 respectively. Perhaps worth mentioning again was the use of refinery process heater and boiler emissions data for operation with refinery

TABLE 7-I

DEVICE TYPE SUMMARY

Winter Daily NOx Emission, Tons NOx/Day

| | | | | |
|---|---|---|---|---|
| I | BOILERS | | 275 | 55% |
| | A. 70* Utility | 208.5 | | |
| | B. 373 Industrial | 55.5 | | |
| | C. 245 Commercial/Institutional | 11.2 | | |
| II | PROCESS HEATERS | | 69 | 14% |
| | A. 337 Petroleum | 69.3 | | |
| III | SMALL SPACE HEATERS, APPLIANCES | | 61 | 12% |
| | A. Domestic | 30.8 | | |
| | B. Commercial | 15.8 | | |
| | C. Industrial | 13.9 | | |
| IV | METAL FURNACES | | 34 | 6.8% |
| | A. 32 Primary Metals | 25.5 | | |
| | B. 81 Secondary Metals | 8.1 | | |
| V | INTERNAL COMBUSTION ENGINES | | 33 | 6.6% |
| | A. 321 Reciprocating | 31.3 | | |
| | B. 32 Gas Turbines | 1.6 | | |
| VI | KILNS, DRYERS | | 21 | 4.2% |
| | A. 10 Cement | 6.3 | | |
| | B. 22 Glass | 6.3 | | |
| | C. 13 Food Products | 3.5 | | |
| | D. 23 Miscellaneous Mineral | 2.5 | | |
| | E. 34 Asphalt | 1.4 | | |
| | F. 32 Ceramics/Clay | 0.8 | | |
| VII | MISCELLANEOUS | | 6 | 1.2% |
| | Total | | 499 | |

*Number of devices in device subcategory make gas obtained from the Bay Area APCD.[51] This data, which was found to yield an emissions factor nearly twice as high as the factor used by LAC APCD in their inventories, is compared in Appendix C with data obtained during the test phase of this program.

The summary of the inventory arranged by application categories as defined in Table 6-II is presented in Table 7-II. Electricity generation is clearly the most significant application category, accounting for about 40% of the emissions. Refineries are the next largest emitting application category responsible for a bit over 20% of the emissions, followed by metallugical industry emissions at and domestic emissions each at about 7%. Most of the remaining categories are seen to fall in the 2-4% range.

Summaries in terms of geographical distributions and seasonal variations are not repeated from the preliminary inventory but will be presented and discussed only for the final inventory in Section 9.0.

In Table 7-III is listed the emission estimate from the preliminary inventory for the eight leading categories of devices. For the purposes of this section of the report, the utility boilers under APCD emission regulations are separated into a different category from those not under APCD regulation. In the final column of Table 7-III is an estimate of the uncertainty in each of these emissions summations. The uncertainty in the emission estimate for the large regulated utility boilers, most of which have been repeatedly tested, is estimated to be only about $\pm$ 10%, this due to operational variations, degradations and uncertainty in the test measurements as discussed in Section 2.2. The large uncertainty of the estimate of the emissions of the refinery heaters and boilers is due to the inventory having been based on very uncertain device heat rate data, on uncertainty of fuel type in use, and on emission factor data resulting from the BA APCD refinery gas burning tests[51] discussed in more detail in Appendix C. The EPA[12] emission factor for natural gas and the LAC APCD emission factor for refineries both are only about 50% of the factor derived from the BA APCD data, thus contributing to the estimated $\pm$ 25% overall uncertainty. Approximately 60% of the smaller utility boilers,

TABLE 7-II

APPLICATION CATEGORY SUMMARY

Winter Daily NOx Emission, Tons NOx/Day

| | | | |
|---|---|---|---|
| I UTILITY | | 213 | 43% |
| A. 70* Steam Boilers | 208.5 | | |
| B. 68 IC Engines, Gas Trans. | 4.3 | | |
| C. 23 Standby Gas Turbines | 0.6 | | |
| II INDUSTRIAL-PETROLEUM & GAS | | 127 | 25% |
| A. 456 Refineries | 112.5 | | |
| B. 42 Field Operations | 9.9 | | |
| C. 16 Transport & Storage | 1.8 | | |
| D. 3 Unclassified | 2.9 | | |
| III INDUSTRIAL-METALLURGICAL | | 35 | 7.0% |
| A. 52 Iron & Steel Prod. | 32.2 | | |
| B. 52 Aluminum Production | 2.5 | | |
| C. 8 Other | 0.3 | | |
| IV INDUSTRIAL - MINERAL | | 19 | 3.8% |
| A. 11 Cement | 6.4 | | |
| B. 21 Glass | 6.1 | | |
| C. 39 Asphalt | 2.3 | | |
| D. 17 Insulation | 1.3 | | |
| E. 43 Tile, Pipe, Ceramic | 1.0 | | |
| F. 10 Unclassified | 1.6 | | |
| V INDUSTRIAL-AGRICULTURE, FOOD | | 10.1 | 2.0% |
| VI INDUSTRIAL-CHEMICAL RELATED | | 9.9 | 2.0% |
| A. 65 Plastics & Resins | 4.7 | | |
| B. 11 Agricultureal-Chem. | 0.9 | | |
| C. 24 Unclassified | 4.3 | | |
| VII INDUSTRIAL-MANUFACTURING, ASSEMBLY 130 | | 9.4 | 1.9% |
| VIII INSTITUTIONAL 145 | | 8.6 | 1.7% |
| IX INDUSTRIAL-UNCLASSIFIED 42 | | 2.9 | 0.6% |
| X COMMERCIAL 53 | | 2.4 | 0.5% |
| Total Point Sources | | 437.4 | |
| Total Area Sources | | 61 | 12% |
| | | 498.4 | |

*Number of devices in device subcategory

TABLE 7-III

MAJOR SOURCE ORDER

| | | Winter Daily Emission Level Tons/NOx Day | | Estimated Uncertainty |
|---|---|---|---|---|
| (1) | 22 Utility Boilers, regulated | 112 | | ± 10% |
| | $Q > 2000$ MMB/H | | | |
| (2) | 413 Refinery Heaters and Boilers | 104 | | + 25% |
| | $10 < Q < 770$ MMB/H | | | − 50% |
| (3) | 48 Utility Boilers, unregulated | 96 | | |
| | $250 < Q < 2150$ MMB/H | | | |
| | 30 with emissions data | | 71 | ± 10% |
| | 18 without emissions data | | 25 | + 40% |
| (4) | Many small space heaters and appliances | | | |
| | $0.02 < Q < 10$ MMB/H | 61 | | ± 25% |
| (5) | 52 Iron and Steel Furnaces | 32 | | ± 40% |
| | $10 < Q < 470$ MMB/H | | | |
| (6) | 321 Reciprocating Engines | 31 | | ± 25% |
| | $1 < Q < 15$ MMB/H | | | |
| (7) | 307 Industrial Boilers† | 21 | | ± 50% |
| | $10 < Q < 690$ MMB/H | | | |
| (8) | 10 Cement Kilns | 6 | | + 300% |
| | $16 < Q < 350$ MMB/H | | | |
| | Total | 463 | | ± 25% |

†Exclusive of refinery boilers

below the APCD regulation limits, have been tested. It is estimated that the uncertainty of the emission summation on the untested 40% may be about + 40%, i.e., the emission estimate for these boilers may be up to 40% too low. Emissions estimated from nationwide established emissions factors by the EPA[12] for small domestic appliances are estimated to be accurate to within about 25%, the uncertainty being primarily due to poor inventory distribution of gas use between devices of varying size below the 10 MMB/H cutoff. The rather large uncertainty estimated for the iron and steel production furnace estimate is the consequence of varying fuels and possibly inaccurately determined time-averaged test results for the batch processes involved. The emissions factors for the reciprocating engines having been established in a fairly broad test program for EPA[23] are judged to yield a ± 25% uncertainty in the emission summation when combined with uncertainties in engine tuning, operational duty of inventoried devices and the potential incompleteness of the census of devices in this category. The uncertainty in the industrial boiler estimate is the consequence of using an emission factor correlation from LAC APCD[20] having about a +100%, -50% variation of unit-to-unit emissions, and due to uncertainties in estimates of operational hours on which to base the emission estimate. Finally the extremely large estimated error (on the low side) for the cement kilns is the result of having used an EPA[12] emission factor which when checked against a SBC APCD test result yielded values as much as a factor of three too low. Strong temporal variations of the actual emission rate with system operating conditions are known to occur as a consequence of the delicate balance of conditions that set the maximum temperature in the process. The problem is to obtain a representative time averaged value with swings in emission rate over the range from 25% to 100% of peak values.

In Table 7-IV the inventory estimate of emissions from each of the 9 major device categories has been multiplied by its respective percent uncertainty to yield the magnitude of the uncertainty in each category in tons/day. It can be seen that the uncertainty in the refinery heater and boiler emissions is significantly higher than the others. The next three

TABLE 7-IV

MAJOR EMISSION UNCERTAINTY ORDER

| | | | Uncertainty |
|---|---|---|---|
| (1) | 413 | Refinery heaters and boilers | + 26 t/d<br>- 52 t/d |
| (2) | 10 | Cement Kilns | + 18 t/d |
| (3) | | Many small space heaters and appliances | ± 15 t/d |
| (4) | 52 | Iron and Steel furnaces | ± 13 t/d |
| (5) | 22 | Large Utility Boilers, regulated | ± 11 t/d |
| (6) | 307 | Industrial boilers* | ± 11 t/d |
| (7) | 18 | Small Utility boilers, unregulated, without emissions data | ± 10 t/d |
| (8) | 321 | Reciprocating Engines | ± 8 t/d |
| (9) | 30 | Small Utility boilers, unregulated, with emissions data | ± 7 t/d |
| | | Total | + 119 t/d<br>- 117 t/d |

*Exclusive of refinery boilers

device categories are seen to be about equally uncertain, followed by another group of three device categories about equally uncertain with somewhat lower magnitude of uncertainty in the reciprocating engine and tested-unregulated utility boiler categories. The comparative magnitudes of uncertainty indicated in Table 7-IV served as the basis for establishing test priorities in the field test portion of this program.

## 8.0 TEST PROGRAM

### 8.1 Objectives

The test program formulated during the initial phase of this program had three main objectives:

1. Quantify the NOx emissions from major individual combustion devices in the South Coast Air Basin which have not been measured or at least not recently measured.

2. Characterize the emission levels from different classes of combustion devices to provide an applicable base for emission factor data which can be applied to untested devices.

3. Obtain sufficient design and operational characteristics for devices for which the NOx emissions are measured to enable an assessment to be made of the potential for reduction of emissions by combustion or hardware modifications.

The first objective was the dominant influence on selection of the specific devices tested. The majority of the units tested consume large amounts of fuel and thus are large sources of NOx. In many cases the uncertainties in emission levels were great enough to cause a significant uncertainty in estimates of the total NOx emitted by stationary sources in the South Coast Air Basin. For example, estimates of refinery emissions vary from 45-50 tons of NOx per day in 1973[52] using LAC APCD emission factors to over 100 tons per day using the results of Bay Area APCD measurements,[51] Fig. C-1. Thus an uncertainty of 12% of the Basin average total of about 425 tons per day exists from this source alone.

Other significant sources for which sufficiently accurate data are not currently available are summarized in Table 7-IV. The most important devices are discussed in the order of their significance and uncertainty in Section 7.0 of this report. The largest single class of NOx emitters, large utility boilers, has been extensively tested. It was judged that further tests of those boilers would not materially reduce the uncertainty in their current emission inventory, since it is primarily due to operational variables, cleanliness, fuel and load scheduling, ect. as discussed in Section 2.2.

In order to meet the second objective, some types of units for which test data were currently available were also investigated during this program. Examples are smaller utility boilers, industrial boilers, stationary internal combustion engines, glass furnaces, and cement kilns. The use of consistent test methods, calibration procedures and fuel analyses were necessary to adequately characterize these classes of devices. For example, in the case of the refinery data, no refinery fuel gas analyses were reported by either the LAC APCD or BA APCD. Yet wide variations are known to occur in refinery gas composition which can significantly effect NOx emissions. (See further discussion in Appendix H.) Another source of uncertainty is the use of different test methods. Many of the available data were obtained by grab sample techniques using the PDS method while the more recent data have been obtained from continuous reading chemiluminescence instruments of the type used during this program.

Achievement of the third objective is essential to achieving the overall program objective of assessing the applicability and impact of NOx control options. The possible application of off-stoichiometric combustion, flue gas recirculation, low excess air operation, or other methods for reducing NOx is dependent upon a knowledge of parameters such as process temperature, combustion residence time, fuel nitrogen content, burner geometry, and others. For example, for devices where oil of high nitrogen content is burned, flue gas recirculation is much less effective than is off-stoichiometric combustion in reduction of NOx emissions. However, devices with few burners or more isothermal combustion regions would respond more favorably to the former method. See further discussion in Section 2.3.

## 8.2 Test Matrix

A test matrix, selected to satisfy the test objectives discussed in Section 8.1 is given in Table 8-I. The large number of refinery devices including boilers, heaters, catalytic crackers, CO boilers, and gas driven compressors was selected because of the present large uncertainty in these devices. Carbon monoxide boilers, for example, are generally rated at quite high firing rates and were believed to have comparatively high NOx emissions although some conflicting data suggested the concentrations may be quite low. Thus about 1/3 of the test time of this program was devoted to refinery devices.

Because of the small number of devices and the extremely high uncertainty in the presently available NOx emissions from the 4 large cement kilns in the Basin, it was intended that all 4 be tested in the program. Because one was out of service at the time of the tests only 3 were actually tested.

About 31 tests of residential, and small commercial building forced air furnaces, wall furnaces, and hot water heaters were conducted during the program. While this can in no way be considered as a statistical sample of the millions of such devices in the Basin, the tests gave some indication of the spread of emissions values that might be expected about averaged emissions factors for such devices resulting from design and maintenance variables.

Nearly one fourth of the furnaces used both in primary and secondary steel production at the three steel production/fabrication facilities in the Basin were tested in the program. Included were open hearth furnaces, coking ovens, and sintering mills. Of particular interest was accurate time-wise integration of the variable emissions rates over the durations of these batch processes.

As indicated in Section 8.1 no further testing was conducted of emissions regulated and unregulated utility boilers for which recent emissions

TABLE 8-I

TEST MATRIX

Number of Devices Tested in Each Category

| Application Categories ↓ / Devices → | Boilers <100 MMB/H | Boilers 100-250 MMB/H | Boilers >250 MMB/H | Turbines | Internal Combustion Engines | Furnaces | Kilns | Heaters | CO Boilers | |
|---|---|---|---|---|---|---|---|---|---|---|
| Electric Utility | | | 6 | | | | | | | 6 |
| Refinery | 6 | 5 | 4 | | 6 | | | 27 | 4 | 52 |
| Glass | | | | | | 1 | | | | 1 |
| Steel | | 1 | 1 | | | 12 | | | | 14 |
| Miscellaneous Industrial | 28 | | | | 4 | | 6 | | | 38 |
| Commercial | 6 | | | | | | | 7 | | 13 |
| Institutional | | | | | | | | | | |
| Domestic | | | | | | | | 31 | | 31 |
| | 40 | 6 | 11 | | 10 | 13 | 6 | 65 | 4 | 155 |

data were available from utility or APCD sources. Tests were confined to the category of unregulated small utility boilers for which no recent test data were available. Of particular interest were emissions data as a function of load and excess air for oil fuel.

Because of the large number of devices and wide diversity in design and operational characteristics of the industrial and commercial boiler categories about 1/5 of the source testing effort was devoted to these categories. Unfortunately in a short test program as this it was not possible to obtain data during operation on both oil and gas fuels. The fuel being used almost exclusively during the test program was found to be natural gas. Current data on oil burning boilers in this category was obtained from another program,[24] and was utilized in the inventory as discussed in Appendix G.

Natural gas fired reciprocating internal combustion engines were tested in limited numbers at gas distribution installations of the Southern California Gas Company and in one of the gas production fields in the Basin. Additional tests in this category were intended but could not be conducted due to the units being out of service at the time of the scheduled tests.

Finally, a few non priority devices were tested such as glass furnaces and pottery kilns in order to spot check some of the emission factor data suggested[12] for such devices.

For the most part the types and sizes of devices that were intended for test, in accord with the priorities established in the preliminary inventory (see Section 7.0), were actually made available for test during this program. However it was not always possible to obtain data with the fuel desired or the operational conditions preferred, since the tests were conducted on the basis of voluntary consent of the operators.

It must be pointed out that in a limited test program such as this that it was not possible to get statistically significant quantities of data. But even from limited data such as this can be derived an estimate of the true value of the trends and the deviations from test to test by applying limited test statistical techniques to the data.

The data from all of the tests are tabulated in Appendix A, and are correlated and discussed with respect to this inventory and with respect to other available data in Appendices C - J arranged by device category.

## 8.3 Test Measurements and Equipment

In order to characterize the emissions of nitrogen oxides from combustion devices several simultaneous measurements were made and the geometric and operational variables of the device were recorded. The variables measured and the equipment used are summarized in Table 8-II. The measurement of flue gas oxygen was required to establish the basis for correcting actual nitrogen oxide concentrations to the standard reference (3% oxygen) concentration level and to establish the total flue gas flow rate. In addition, knowledge of the oxygen (or excess air) level is important to correlation of the test results since higher oxygen levels usually result in increased NOx production in the flame zone.

Carbon monoxide measurements are not used directly in the data reduction. However, the CO concentration in the flue gas is a very sensitive indicator of combustion efficiency. High CO levels, if the excess air is adequate, usually indicate malfunctioning burners or poor air register adjustment. (Lower nitrogen oxide levels usually result from combustion conditions leading to incipient high CO concentrations.)

The stack flow rate for all boilers was calculated from fuel flow or steam flow information coupled with exhaust gas analyses. It was preferred to determine the stack flow rate this way because it was usually not possible to do an acceptably accurate velocity traverse due to (1) inadequate number of sample ports, (2) restricted access to many of the existing sample ports, and (3) stack configurations having severe flow disturbances such as bends, dampers, braces, etc.

In plants where the fuel flow to the test device could be measured, it was possible, using the excess oxygen concentration value and the hydrogen/carbon ratio of the fuel, to calculate the stack flow rate very

TABLE 8-II

MEASURED VARIABLES AND INSTRUMENTS

| Variable | Instrument or Method | Comments |
|---|---|---|
| 1. Carbon Monoxide | Non-dispersive infrared analyzer - Beckman model 865 | |
| 2. Oxygen | Teledyne model 326A | |
| 3. Nitric Oxide (NO) | Chemiluminescence analyzer TECO model 10 | |
| 4. Total Oxides of Nitrogen (NOx) | Chemiluminescence analyzer TECO model 10, $NO_2$ Converter | Heated sample line |
| 5. Exhaust gas flow rate | Combination of (2) and fuel rate (or) pitot probe and thermocouple probe | Preferred method |
| 6. Flue Gas Temperature | Operator Data (or) thermocouple probe | Preferred method |

accurately. In cases where only the steam flow rate could be determined an 85% boiler efficiency was assumed and the fuel flow rate was estimated. The only data available for a few boilers was the feedwater flow rate. In these cases it was assumed that all of the feedwater was converted to steam (no leaks) and then the same assumptions were used to estimate the fuel flow rate. Once the fuel rate was established, the stack flow rate was calculated as described. The relations to calculate total nitrogen oxide emitted (as $NO_2$) are summarized in Table C-IV of Appendix C for the general case of a fuel gas or oil of variable content (including CO and inerts).

Operator data, geometric, and flow variables recorded for each device where applicable are summarized in Tables 8-III and 8-IV which are reproductions of the data forms used during the program.

The test instruments were installed in a delivery van which could be readily moved from plant to plant and which was self contained except for the need for 110V power for extended operation. The schematic flow diagram for the instruments is given in Figure 8-1. The instrument package and van resulted in an efficient method for making measurements. The time to obtain test data was primarily paced by instrument warm up time and time for the test device to achieve desired steady state conditioning.

The probes used for extracting the gaseous samples were stainless steel tubing of 1/4" to 3/8" o.d. Length was varied to accomodate different duct sizes. For cases where the duct was traversed by inserting or withdrawing the probe, the exposed portion was wrapped with asbestos cloth tape to avoid condensation. The portion of the flue gas sample tested for NO was routed directly through a heated teflon line and heated capillary section to the chemiluminescence instrument. NOx was determined by passing the sample first through a $NO_2$ to NO converter (a stainless coil heated to 750°C) and then to the NO instrument. The NO reading was subtracted from the NOx reading to obtain the $NO_2$ as a difference. However, during the course of the program difficulty was encountered with the $NO_2$-NO converter under certain conditions. During tests of an internal combustion engine

## TABLE 8-III

COMBUSTION DEVICE DATA SHEET

Date__________

User Category__________

Device Type__________

By__________

**1.0 LOCATION-OWNERSHIP**

1. Owner/User__________
2. Plant Contact/Title__________
3. Plant Address__________
4. UTM Coordinates: Horizontal__________km; Vertical__________km
5. Company Contact/Title__________
6. Company Address__________

**2.0 IDENTIFICATION**

1. Type of Device__________
2. Type of Process; use__________
3. Manufacturer & Model: Serial numbers__________
4. Burner Manufacturer & Model Serial Number__________
5. APCD Permit Number__________
6. APCD Permit Restrictions__________
7. State Boiler Number__________
8. Federal Registry Number__________
9. Date of Manufacturer/installation__________

**3.0 DESCRIPTION**

1. Maximum design heat input__________
2. Operating maximum heat input__________
3. Number of Burners__________
4. Type of Burners__________
5. Heat transfer description__________
6. Draft type__________
7. Efficiency__________%
8. Heated surface area__________sq. ft.
9. Air injection description__________
10. Recirculation capability__________
11. Maximum percent recirculation__________
12. Superheat, reheat capabilities__________
13. Stack arrangement__________
14. Electrostatic precipitator__________
15. Scrubber__________
16. Stack height__________ft.
17. Stack diameter__________ft.
18. General condition (heat transfer surface, other)__________
19. Other information__________
20. Device diagram:



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TABLE 8-IV

TEST DATA SHEET

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 1. Date | | | | | | | | |
| 2. Test Number | | | | | | | | |
| 3. Max. Operating Load, % | | | | | | | | |
| 4. Max. Design Load, % | | | | | | | | |
| 5. Fuel Type | | | | | | | | |
| 6. Fuel Flow | | | | | | | | |
| 7. Fuel Pressure | | | | | | | | |
| 8. Atomization | | | | | | | | |
| | | | | | | | | |
| 9. Air Flow | | | | | | | | |
| 10. Air Injection Pressure | | | | | | | | |
| 11. Recirculation, % | | | | | | | | |
| 12. Furnace Pressure | | | | | | | | |
| 13. Air Distribution (NOx Ports, etc.) | | | | | | | | |
| | | | | | | | | |
| 14. Air Temperature | | | | | | | | |
| 15. Recirculation, % | | | | | | | | |
| 16. Medium Temperature IN | | | | | | | | |
| 17. Medium Temperature OUT | | | | | | | | |
| 18. Medium Pressure | | | | | | | | |
| 19. Medium Flow Rate | | | | | | | | |
| 20. NO, ppm | | | | | | | | |
| 21. $NO_2$, ppm | | | | | | | | |
| 22. CO, ppm | | | | | | | | |
| 23. $O_2$, % | | | | | | | | |
| 24. Flue Gas Temperature (before preheater) | | | | | | | | |
| 25. Flue Gas Temperature (After preheater) | | | | | | | | |
| 26. Furnace Temperature | | | | | | | | |

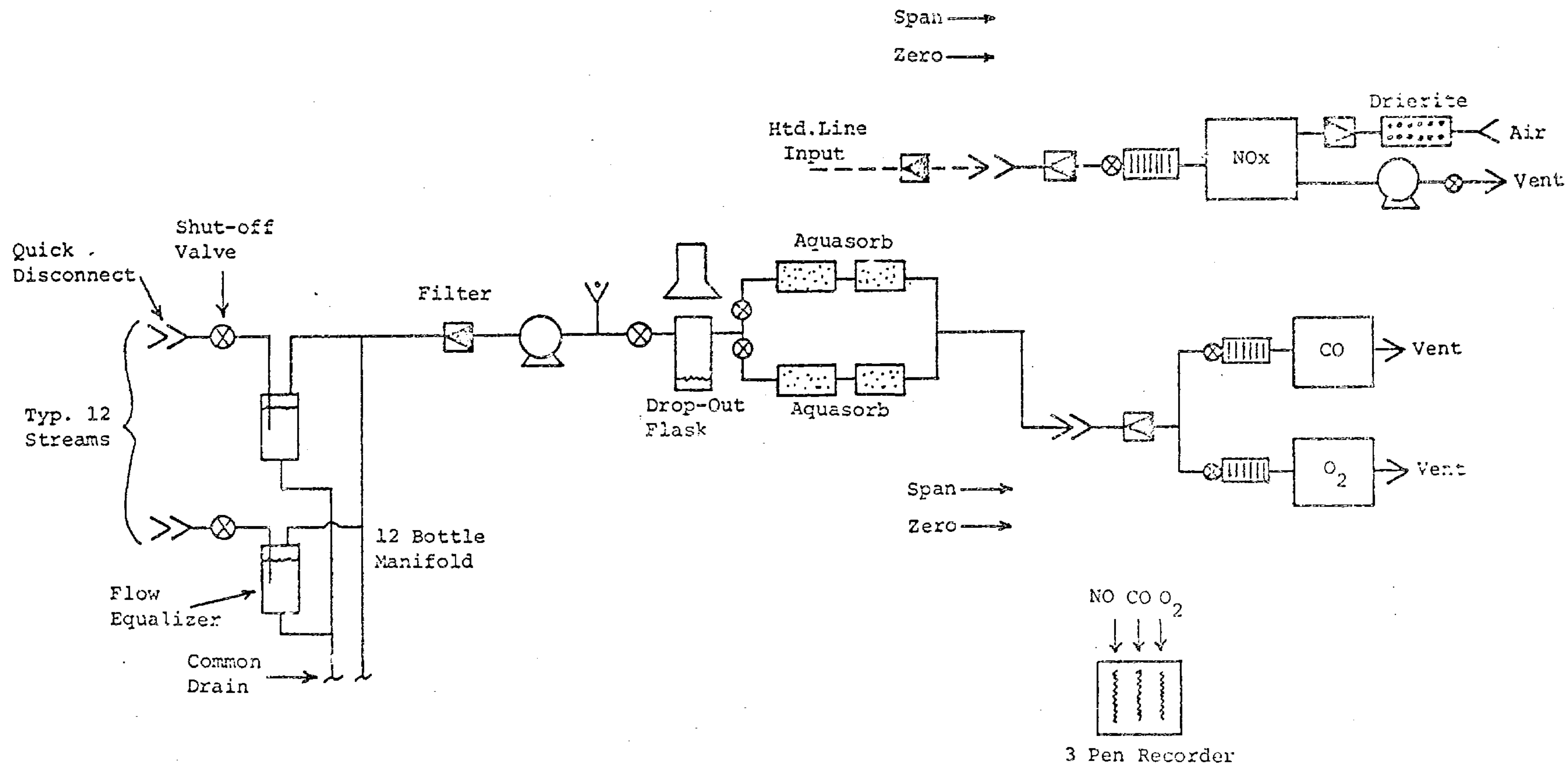


Figure 8-1. KVB Mobile Van Flue Gas Monitoring System Flow Schematic

with a high CO level in the exhaust, the NOx reading, initially above the NO reading, decayed to zero over a period of about 10 minutes. The phenomena of CO interference with the converter has been noted in the literature.[22] Since some 18% of refinery units, and several other devices tested had high CO concentrations in the flue gas, and since the interference apparently persists after the initial exposure[22] the NOx readings were not regularly accepted as reliable (although they were recorded in some cases). As an alternative the primary measurement was that of nitrogen oxide. In final emissions estimates the nitrogen oxide emissions were increased by 5% to reflect normal $NO_2$ percentages for external combustion devices. The uncertainty in the NOx determination thus introduced was probably no more than about 2%. Data obtained with the $NO_2$-NO converter during this program ranged from negative values (during CO interference) to as high as 20%.

The portion of the sample analyzed for oxygen and carbon monoxide was passed through bubblers and driers to eliminate any moisture. It was subsequently routed to the analytical instruments.

"Dry" measurement of NO was accomplished in the same manner. However, some difficulties were encountered due to moisture absorption above the capacity of driers with subsequent excessive heating. In some cases as a result only "wet" readings were obtained for NO.

8.4 Test Procedure

The basic instrument measurement procedure used for the field test program is summarized below:

1. Turn on instruments, heated capillary module, heated line.

2. Wait until instruments are stable ($\lesssim$ 1 ppm/3 min. drift). This typically requires 3 hours from cold situation, about 1/2 hour if the unit has been in standby condition.

3. Establish the instrument zero by using a standard $N_2$ gas of zero concentration of NO, CO and $O_2$.

4. Standardize the instrument calibration using standard gases of known concentrations of NO, CO and $O_2$.

5. Re-check the zero.

6. Take measurements of CO, $O_2$ and dry NO from the exhaust ducting.

7. Repeat for a new probe position if traverse is used.

8. Re-check instrument calibrations every 15 minutes to 30 minutes, depending on initial stability. If significant drift is encountered, record the new value and re-standardize.

9. If a velocity traverse was used it was carried out with pitot probe and thermocouple after completion of the NO measurements.

10. When testing is complete, purge the instruments and shutdown or place in standby condition.

The operating mode and accessibility of the combustion device were paramount in determining the test plan for each unit. Probes were inserted through existing sampling ports usually located upstream of the air preheater if there is one. The preferred test plan was to make measurements at several probe locations in the exhaust gas ducting at a constant set of operating parameters; then, repeat for a variation of the important parameters (such as heat input, excess air, air register setting, etc.) in a controlled manner.

However, in testing of refinery and most industrial devices it was found that the steady state conditions necessary to arrive at an accurate difference reading for $NO_2$ or at separate spatial and temporal effects were usually not available. Test data were recorded continuously, but are only read off for data reduction purposes during periods of steady operation of the order of 5 to 10 minutes. When fuel changes or load changes result in major shifts additional data were taken at the new quasi steady state point. In addition, in some cases existing, unheated, instrument lines had to be used for the sample, eliminating the possibility of a wet NO or NOx measurement. Moreover, because of the interdependence of various devices in refineries practically no controlled variation of combustion parameters there was found possible.

During the refinery tests, and during other tests with oil fuel, samples of the fuel gas and fuel oil were taken during the period when measurements were made so that chemical composition and heating value information could be obtained. Examples of these gas analyses are furnished in Table C-V of Appendix C.

## 8.5 Measurement Uncertainty

All instruments were calibrated before and after each test point with standard reference gas samples. Using this procedure the estimated accuracy of the measurement are NO, $O_2$, and CO each 3.0% and NOx 3.2% for the inherent linearity and hysterisis characteristics of the instruments used.

The test data were converted from nitrogen oxide concentration in parts per million by volume to pounds per hour and pounds per million BTU by using the relations summarized in Table C-IV of Appendix C. For natural gas and oil combustion these relations have been simplified to curves such as those of Figure 8-2. In either case, the fuel flow or heat input must be known or estimated as discussed previously to convert to emissions rates in mass per unit of time. However, one of the major limitations in existing instrumentation of the units tested was fuel flow rate. In many cases no instrumentation existed. In others antiquated or uncalibrated instruments and readout devices were found for which the fuel reading was inconsistent with the process heat balance or manufacturers information. Probably the most pessimistic estimate of fuel flow or process flow measurement accuracy would be $\pm$ 10%.

Where fuel flow was not measured, an added uncertainty resulted from the unit efficiency assumptions. The assumed 85% is probably the maximum efficiency to be expected. Estimated by one refinery were as low as 70%. Thus the maximum error on those tests where efficiency is assumed to calculated fuel flow would be + 20%, - 0%.

Fuel analysis heating value is required for stack flow in refineries. For three comparable samples the difference between the KVB reading and the refinery reading for heating values were 5.0%, 6.9% and 6.6% for an average of 6.2%. The maximum estimated error range for the measured and derived quantities is summarized in Table 8-V.

All test data is summarized in Appendix A together with an indication of whether the fuel flow was measured or derived.

TABLE 8-V

MAXIMUM ESTIMATED ERROR IN MEASURED CONCENTRATIONS AND CALCULATED NOx EMISSIONS

| | Concentration | Emission Factor | Total Emissions |
|---|---|---|---|
| 1. Fuel Flow Measured Natural Gas or Oil | ± 3% | ± 3% | ± 13% |
| 2. Fuel Flow Measured Refinery Gas | ± 3% | ± 9% | ± 19% |
| 3. Process Flow Measured Natural Gas or Oil | ± 3% | ± 3% | + 23%<br>- 3% |
| 4. Process Flow Measured Refinery Gas | ± 3% | ± 9% | + 29%<br>- 9% |

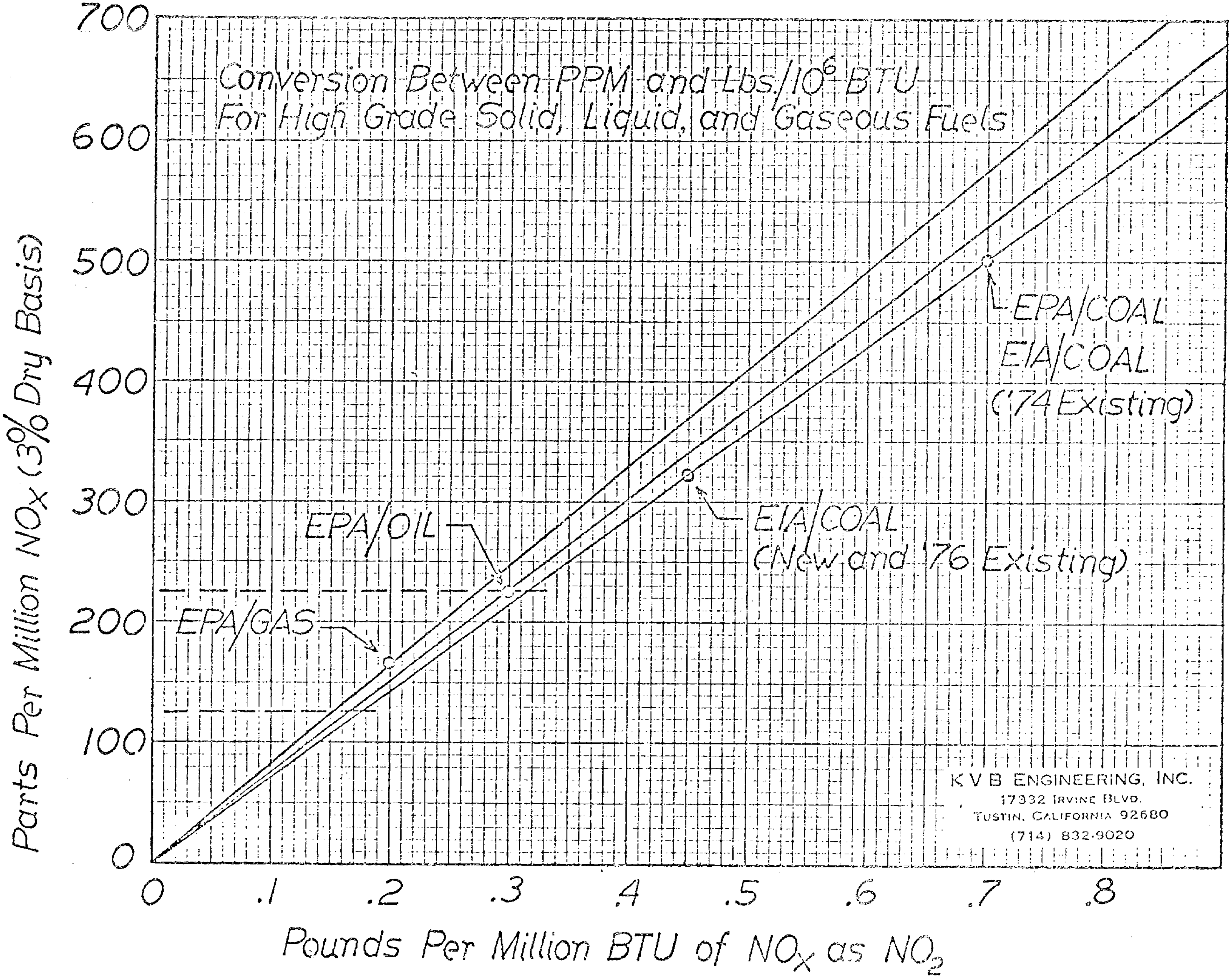


Figure 8-2. Conversion Between Volumetric And Mass Concentrations of NOx Emissions

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## 9.0 INVENTORY OF NOx EMISSIONS IN SOUTH COAST AIR BASIN FOR THE PERIOD JULY 1972 - JUNE 1973

The results of the Basin NOx inventory, the summaries of emissions from the stationary and area sources for the period July 1972 - June 1973 are presented in this section. The 1972-73 inventory is summarized on three bases: (1) by device type, (2) by application and (3) by geographic location. The classification based on device type makes use of the NEDS source classification code SCC described in Section 6. While primarily a device-type oriented classification system, with subcategories for kinds of devices within a category and type of fuel burned, the system also relates to the type of application to which some devices are devoted. Unfortunately this latter aspect is not uniformly treated for all device categories, and does not match up well with the application classifications commonly in use by the APCD's in their inventories. Hence a separate application classification better matched to the APCD's classifications was devised (Table 6-II). Apparent minor contradictions in the emissions levels between the two classification systems are the result of the respective class definitions. For example the device summary shows about 1.3 tons/day for ceramics and clay kilns, compared with about 1.6 tons/day for ceramics and clay production in the application category; the difference being the consequence of other devices than kilns being used in connection with ceramics and clay related operations. Some small differences also have resulted in the rounding off process.

The inventory is based on the specific period from Junly 1972 through June 1973. As such the inventory reflects specific situations during that time period such as outages of certain large devices, particular operational modes utilized, strikes, gas availability, hydro power availability, etc.

As indicated in Section 3.0, emissions have been inventoried on the basis of a summer (August) daily value, a winter (December) daily value, and an annual total. The comparison of these values, as they relate to the several device and application categories will be discussed in Section 10.

For clarity, the discussions of comparative emissions between the various device, application and geographic categories in this Section will be primarily based on the winter daily emission rates in tons/day, i.e., average daily emissions during December 1972 for those days during which most interruptible gas was assumed to have been curtailed and oil substituted.

## 9.1 Inventory By Device Category

The summary of the device type inventory is presented in Table 9-I. Boilers clearly dominate, emitting 50% of the NOx, followed by process heaters at 16%, small space heaters and appliances also at 16%, stationary internal combustion engines at about 8%, kilns and dryers at about 5%, and metal furnaces at about 4%.

Boilers - Utility -- Large utility boilers are seen to dominate the emissions in the boiler category due to their size and to their comparatively high duty factor (i.e. load fraction, and hours of operation). Winter daily emissions (burning oil) were found to be about twice summer daily emissions and about 28% above annual average daily emissions. In the utility boiler category the inventory shows that 68% (141 tons/day) of the winter daily emissions came from the 24 boilers whose rating exceeds 1775 million Btu/hour (MMB/H) the present LA APCD control limit. During the December 1972 three of the major units were out of service and hence did not contribute to the emission total. Had they been in service at comparable duty factors and emissions levels to their respective sister units the total daily emissions could have been 27 tons/day higher. During the 1972-73 inventory period, boilers in Los Angeles County larger than 1775 MMB/H were required to meet an exhaust concentration limit of NOx on gas of 225 ppm and on oil 325 ppm corrected to a standard oxygen concentration of 3%. See Table D-I for variations in the control limits for other counties in the Basin. In January 1975, the regulations will change to 125 ppm on gas and 225 ppm on oil. Assuming 1972-73 duty factors, the resulting reduction has been projected in Appendix D at about 8% or 14 tons/day for the annual average, based on projected availability of gas to supply only about 6% of energy requirements.

TABLE 9-I

DEVICE TYPE INVENTORY SUMMARY

Daily NOx Emissions, tons/day

| | Number | Dec. 1972 | | Aug. 1972 | | July '72 - June '73 | |
|---|---|---|---|---|---|---|---|
| I. BOILERS | 684 | | 274.1 | | 160.5 | | 207.9 |
| A. Utility | 70 | 213.8 | | 113.5 | | 167.7 | |
| B. Industrial - Refinery | 83 | 31.7 | | 30.6 | | 25.7 | |
| C. Industrial - Other | 287 | 19.3 | | 11.5 | | 10.4 | |
| D. Commercial/ Institutional | 244 | 9.4 | | 4.9 | | 4.2 | |
| II. PROCESS HEATERS | | | | | | | |
| A. Petroleum | 344 | | 88.3 | | 54.6 | | 50.2 |
| III. SMALL HEATERS, BOILERS | | | 86.7 | | 31.8 | | 57.1 |
| A. Domestic | -- | 61.5 | | 18.2 | | 39.1 | |
| B. Commercial | -- | 13.3 | | 5.9 | | 9.6 | |
| C. Industrial | -- | 11.9 | | 7.7 | | 8.4 | |
| IV. INTERNAL COMBUSTION ENGINES | | | 45.1 | | 51.5 | | 42.4 |
| A. Reciprocating | 468 | 42.9 | | 48.5 | | 40.0 | |
| B. Gas Turbine Units | 44 | 2.2 | | 3.0 | | 2.4 | |
| V. KILNS, DRYERS | 103 | | 26.4 | | 52.7 | | 46.3 |
| A. Cement Kilns | 10 | 13.0 | | 37.4 | | 32.5 | |
| B. Glass Furnaces | 22 | 10.8 | | 12.7 | | 12.1 | |
| C. Ceramics/Clay Kilns | 37 | 1.5 | | 2.0 | | 1.3 | |
| D. Asphalt Dryers | 34 | 1.1 | | 0.6 | | 0.4 | |
| VI. METAL PRODUCTION FURNACES | | | 19.3 | | 19.6 | | 17.8 |
| A. Secondary Metals | 64 | 12.6 | | 13.3 | | 12.2 | |
| B. Primary Metals | 61 | 6.7 | | 6.3 | | 5.6 | |
| VII. MISCELLANEOUS | 129 | | 3.8 | | 4.7 | | 3.6 |
| TOTAL | | | 543.7 | 375.4 | | | 425.3 |

During the inventory period most of the boilers operated on natural gas during the summer, low sulfur residual oil during the winter, with approximately a 43-57 balance (gas-oil) for the year. The consequence to Basin emissions of the projected near elimination of gas fuel for utility boilers can be seen by comparing the summer (gas burning) to the winter (oil burning) emissions in Table 9-I.

In conducting the utility boiler inventory there was ample data on full load and part load NOx emissions concentration of most of the large units available from the operators. Only in the medium boiler class (1775-1000 MMB/H) and small boiler class (<1000 MMB/H) was there incomplete data. Thus the limited source testing of this program devoted to utility boilers was concentrated on these two size classes (see Appendix D). The improvement to existing utility boiler emissions inventories resulted from detailed month by month calculations for each unit using specific test data and individual unit capacity factor data obtained for the inventory period. These detailed results and the input data utilized are presented in tables in Appendix D.

Boilers - Industrial -- This category of boilers included 370 units in the inventory ranging from 582 MMB/H down to the cut off of 10 MMB/H. Only 13 boilers exceeded 240 MMB/H but they accounted for 20 tons/day or about 40% of the total 51 tons/day emitted by industrial boilers. Units in the range from 240 to 100 MMB/H numbered about 28 and accounted for another 13 tons/day or about 25% of the total emitted by industrial boilers larger than 10 MMB/H. Only 61 industrial boilers in the inventory were found to burn only natural gas and these were responsible for only 7% of the industrial boiler emissions. Other boilers probably exist in the Basin which burn only natural gas fuels but since they do not require APCD permits they were difficult to locate. In any event their emissions are believed to be quite low in the aggregate.

The industrial boilers operating in refineries, although only 83 in number, mostly burn refinery gas and distillate oil and were found to be responsible for 62% of the industrial boiler emissions during the winter month inventoried, and 70% average for the year. This assessment of emissions from refinery boilers (and oil process heaters discussed below) burning refinery gas is considerably higher than that of previous LAC APCD inventories. The basis for this assessment is the combined result of data obtained on 49 refinery gas fired heaters and boilers tested during this program (as discussed in Appendix C), and tests by the Bay Area APCD on 63 refinery heaters and boilers also burning refinery gas.[51] While good agreement was found between these data and the LAC APCD correlation[20] of gas fired combustion equipment (see Figure 2-1) at low heat rates (boiler size 10-40 MMB/H), at higher heat rates the BA APCD and the new data diverged sharply (see Figure C-1). Because of this divergence, the fuel-use weighted emission factor for these devices was found to be about 50% higher on an annual average basis than the factor that had previously been used for assessing Basin refinery emissions. The basic reason for the substantially higher emissions is believed to be the higher energy content of the refinery gas, compared with natural gas, leading to higher combustion temperatures, thus promoting higher NOx emissions. Rather than using an average overall emission factor in this inventory, separate size dependent correlations were developed for three classes of refinery combustion devices (see Figure C-2) and then were applied to each of the several hundred refinery devices individually. Burner arrangement, number of burners, type of draft, and preheat were each found to be important parameters.

<u>Boilers - Commercial/Institutional</u> -- The 244 units in the inventory that comprise this category were responsible for only 9.4 tons/day or only 3% of the boiler emissions. They ranged up to 147 MMB/H but only 3 exceeded 100 MMB/H. Over 80% of this category of emissions was produced from units in the inventory burning both natural gas and distillate oil. Additional units larger than 10 MMB/H probably exist in the Basin which burn only natural gas but since they require no permit were difficult to identify. The error resulting from this deficiency in the inventory is probably quite small however. In both this and the industrial boiler category the needed information on load fraction and operational hours was obtained by fuel-use questionnaires received from about 500 plants in the Basin (see Section 4).

Emissions for the inventory for this source class, and for industrial boilers other than refinery, were computed from the size dependent emissions correlations developed by the LAC APCD[20] separately for gas fuel (see Figure 2-1) and for distillate oil fuel (see Figure 2-2). These correlations were reinforced by the results of tests during this program of 33 natural gas fired industrial and commercial boilers fired at rates between about 6 and 100 MMB/H. In addition the results of tests of 23 natural gas fired boilers from a concurrent EPA program[24] were also used and were found to support the same correlations (see Appendix G). Only one oil fired device was tested during this program (because little oil was being burned during the test period) but additional tests results on oil fired boilers were obtained from the same EPA program and were found to agree with the correlation of oil fired devices by the LAC APCD (Figure 2-2). Undoubtedly the NOx emissions of those industrial and commercial boilers is dependent on more parameters than just firing rate. Were the data correlated on the basis of more of these, such as burner size, preheat, etc., the data spread would be reduced, but it is doubtful that the inventory would be appreciably improved.

Process Heaters --- The second most significant device category in total daily NOx emissions during December 1972 was that of process heaters which were found to be responsible for about 16% of the total emissions, or about 88 tons/day. The range of heat input ratings of inventoried units in this source category is from 450 MMB/H down to 10 MMB/H with 12 units over 250 MMB/H and 62 over 100 MMB/H. Almost all of the 344 units in this category were used in refineries to heat oil or other petroleum products, hence most operated on a combination of natural gas, refinery gas, and residual oil. Some operate with a mixture of all three. It is the very frequent and significant change in fuel composition with resulting changes in fuel heat content, that make these emissions extremely variable and hence hard to characterize as discussed in Appendix C. The basis for assessing the source emissions during firing with refinery gas was the same as used for refinery boilers (discussed above). For the reasons mentioned, the emissions from this source category are also nearly 50% higher on an annual average basis than previous inventories. As with the refinery boilers, emission factors were determined for each separate device type from the correlation derived from this program (Figure C-2) and applied to each unit individually to arrive at the total inventory of emissions for this source category.

<u>Small Space Heaters, Boilers</u> -- The third most significant device category in terms of total emissions is that of the small domestic, commercial and industrial space heaters and appliances. These units, all rated well below the 10 MMB/H cut-off comprised an inventory of about 8 million, based on census data on gas burning residences. The emissions for these devices, estimated from gas fuel usage and new emissions factors was inventoried at about 87 tons/day in the winter amounting to about 16% of the total South Coast Air Basin stationary source NOx emissions. Domestic device emissions were found to constitute about 70% of these area distributed source emissions and commercial and industrial each about 15%. Care was taken to subtract off all of the gas use by individual inventoried industrial and commercial devices from total gaseous fuel distributed in the Basin by Southern California Gas Company and the City of Long Beach. Any error in this procedure, would tend to lead to a somewhat low estimate of emissions since gas not assigned to individual devices of over 10 MMB/H rating was presumed to be burned by small devices with appropriately low emissions factors. The emission factor recommended by the EPA [12] for domestic gas fired appliances was 0.05 lb NOx as $NO_2$/MMB. However the data from the LAC APCD[20] presented in Figure 2-1, over the range from 20,000 to 300,000 Btu/hr was found to have an average factor of 0.09 lb NOx as $NO_2$/MMB, whereas results from 30 tests in this program (see Appendix H) and results from a recent EPA program [53] both averaged 0.10 lb NOx as $NO_2$/MMB. Hence the latter figure was thus selected for this inventory for domestic appliances. The EPA recommended factors for somewhat larger commercial and small industrial natural gas fired appliances and boilers was used for these segments of the area source inventory, 0.10 and 0.15 lb NOx as $NO_2$/MMB respectively.

Internal Combustion Engines -- The fourth most significant device category is that of stationary internal combustion engines which as an inventoried group emitted about 45 tons/day or about 8% of the South Coast Air Basin total for NOx from stationary sources. Of this subtotal most of the emissions (43 tons/day) are produced from gas burning reciprocating engines driving gas trasmission compressors in the refineries and the gas company transmission lines. Because of the high combustion pressures involved, and the resulting high combustion temperatures the emissions from gas fueled reciprocating engines[23] tend to be nearly a factor of 10 higher per Btu of energy supplied than are the external combustion devices such as boilers and heaters. Hence for this category the inventory cut off was extended downward to about 1 MMB/H, which for average specific fuel consumption of 0.4 lb/BHP/hr and heating value of about 18,000 Btu/lb corresponds to about 140 BHP. Units in the inventory were found to range up to 2000 BHP. Since IC engines are not within the APCD permit system the 468 unit inventory of this device category is likely to be incomplete.

The average emission factor of gas burning reciprocating internal combustion engines tested as part of this program was found to be 1.64 lb NOx as $NO_2$/NNB. This only about half of the figure established during an EPA program by Shell,[23] 3.7 lb NOx/MMB. Since only a limited sample was tested during this program the higher Shell factor was adopted. A very wide range of emissions were encountered during the testing of these engines on this program due probably to engine loading, maintenance, and operational adjustments.

The remainder of emissions in the IC engine category came from 32 gas turbines. Their aggregate emissions during the winter (December), amount to only about 2.4 tons/day and a bit more during the summer (August). Since these are primarily used as peaking units or for emergency purposes, the total annual hours of operation remains quite low, accounting for the low contribution from gas turbines.

Kilns and Dryers -- This category of devices includes kilns and dryers used in the production of cement, glass, asphalt, and ceramic/clay products. Together, the 103 devices inventories were estimated to have emitted about 26 tons NOx/day in December 1972, 52 tons/NOx/day in August 1972, and 46 tons/day for the annual average. The very large seasonal change which went opposite in direction to the seasonal change in other source categories was primarily the result of the largest subcategory the cement kilns. In this subcategory over 90% of the emissions were attributed to 4 large kilns, 2 each rated at 350 and 220 MMB/H respectively. Three of the four kilns were tested in this program (see Appendix F), the fourth being out of service during the test period. The emissions during gas firing were found to be higher than the level at which they had been previously inventoried[3] by about a factor of 3 to 4. As a result both of the cement plants when operating on gas were found to be emitting at rates in excess of a medium sized electric utility generation station (1000 Mw). It was also found, however, that when operating on oil fuel, the emissions levels were lower by over a factor of two, contrary to the comparison of oil to gas burning in boilers and heaters. An explanation is given in Appendix F. Thus there is a large change in emissions from summer gas burning to winter oil burning operating at present. Future shortages of natural gas may automatically reduce the emissions from these kilns, while increasing the emissions from most other devices (see Section 11).

Glass furnaces were found to be the second most significant contribution to this source category, emitting in excess of 10 tons NOx/day. The inventory of these devices numbered 22. The test phase of this program included but one glass furnace (see Appendix I). Emissions for the others were obtained from LAC APCD test reports of the specific furnaces. Again, rather large differences in emissions from furnace to furnace were evident suggesting potential for improvement in emissions by closer control of certain operational parameters.

Together the 37 ceramics kilns and 34 asphalt dryers, in the Basin, using EPA factors,[12] were estimated to be emitting only about 2.6 tons/day maximum and 1.7 tons/day on the average over the year. Only a limited amount of testing on some small ceramics kilns was conducted as part of this program (see Appendix A).

Metal Furnaces, Pots -- The sixth most significant device category is that of primary metal production furnaces, and melting pots and fabrication ovens for secondary metal production. This category emits about 20 tons/day, most of which is emitted by 32 ferrous metal production furnaces and coking ovens. Most of those are located at Kaiser Steel, Fontana. The largest of these are blast furnaces rated near 400 MMB/H, but because of operation far over to the fuel rich side of stoichiometric fuel-air ratio, the emissions are quite low from these units. The large emitters are the 8 open hearth furnaces, each of which burn oil and emit about 1 ton/day while in operation even though rated at only 72 MMB/H. Tests on two of these furnaces, on coke ovens, sinter machines, and boilers were conducted at the Kaiser plant as part of this program (see Appendix E). The results of these tests when applied to the Kaiser plant inventory were found to agree closely with previously available results.[54]

A total of 54 units are involved with the production of aluminum and other nonferrous metals. These devices, rated up to about 50 MMB/H, however, are reported to be quite low emitters according to APCD files, emitting a total of less than 1 ton/day. About 95 furnaces and ovens in the inventory are used in metal fabrication and together account for about 2 tons/day emissions. Emissions estimates from metal furnaces are believed to be quite uncertain due to strong unit-to-unit variations which depend on maximum temperatures reached and on residence times of combustion gases which are subject to considerable variation from furnace-to-furnace.

## 9.2 Inventory by Application Category

The purpose of this cut of the inventory is to summarize emissions by application category in order to indicate what types of activities are responsible for what fractions of the total stationary source emissions. This breakdown is summarized in Table 9-II on an annual average daily emission basis, summarized by county portion of the Basin.

Utilities -- The combined electric and gas utilities contribute the dominant fraction of the total stationary source emissions of NOx at this time about 42% or about 177 tons/day. Of this total, the boilers dominate, emitting 168 tons/day, followed by gas transmission 8.2 tons/day, and standby gas turbines about 0.6 tons/day. Special situations occurring during the inventory period are mentioned in the previous section. Each of the counties except Riverside and Santa Barbara have major power generation stations located within their portion of the Basin.

Industrial - Petroleum & Gas -- The second most significant contributor is clearly the petroleum industry which emits about 106 tons/day or 25% of the total. The dominant component of this aggregate comes from the 7 major and 7 minor refineries, i.e., 93 tons/day. This is the sum of emissions from heaters, compressors, boilers, fluidized bed catalytic crackers, and other miscellaneous refinery devices. Field operations and transport constitute the remaining portion.

Industrial - Mineral -- Mineral processing industries comprise the third most significant application category, emitting about 48 tons/day or 11% of the total stationary source emissions. The two principal components of this total are cement production concentrated in Riverside and San Bernardino Counties and glass production, followed by ceramics and clay production, and by asphalt production.

Industrial - Metallurgical -- The sum of all metal processing, fabrication, remelting and reclamation represents the fourth most significant application category. The furnaces and ovens emit a total of about 20 tons/day or about 5% of the South Coast Air Basin stationary source NOx emissions.

TABLE 9-II

APPLICATION CATEGORY INVENTORY SUMMARY

Average Daily Emission of NOx Tons/Day

July 1972 - June 1973

| Application Category | L.A. | Orange | River. | San.Ber | St.Bar | Ven. | SCAB |
|---|---|---|---|---|---|---|---|
| **I. UTILITY** | | | | | | | |
| A. Electric Power Generation - Boilers | 117.5 | 16.1 | | 15.3 | | 18.8 | 167.7 |
| B. Natural Gas Transmission | 7.1 | 0.1 | | | 0.6 | 0.4 | 8.2 |
| C. Elect. Power Generation - Gas Turbines | 0.4 | 0.2 | | 0.1 | | 0.1 | 0.8 |
| **II. INDUSTRIAL - PETROLEUM & GAS** | | | | | | | |
| A. Refining | 90.0 | | | | | 3.2 | 93.2 |
| B. Field Operations | 7.8 | 1.2 | | | | -- | 9.0 |
| C. Transport & Storage | 1.1 | 0.1 | | | | | 1.2 |
| D. Unclassified | 2.6 | | | | | | 2.6 |
| **III. INDUSTRIAL - MINERAL** | | | | | | | |
| A. Cement Production | | | 20.0 | 12.4 | | | 32.4 |
| B. Glass Manufacturing | 11.7 | 0.6 | -- | | | | 12.3 |
| C. Ceramic/Clay Production | 0.9 | | 0.6 | 0.1 | | | 1.6 |
| D. Asphalt Production | 0.2 | | -- | 0.1 | 0.1 | 0.1 | 0.5 |
| E. Unclassified | 0.5 | | | 0.1 | | 0.3 | 0.9 |
| **IV. INDUSTRIAL - METALLURGICAL** | | | | | | | |
| A. Iron & Steel Production | 4.9 | | | 14.5 | | | 19.4 |
| B. Aluminum Production | 0.2 | | 0.1 | | | -- | 0.3 |
| C. Other | 0.3 | | | | | | 0.3 |
| **V. INDUSTRIAL - CHEMICAL** | | | | | | | |
| A. Plastics & Resins | 2.5 | 0.1 | | | | | 2.6 |
| B. Agriculture - Chem. | 0.1 | 1.7 | | | | | 1.8 |
| C. Unclassified | 1.3 | -- | -- | | | | 1.3 |
| **VI. COMMERCIAL** | 2.6 | 0.8 | | | | | 3.4 |
| **VII. INSTITUTIONAL** | 2.1 | 0.2 | 0.1 | 0.3 | | 0.1 | 2.8 |
| **VIII. INDUSTRIAL - UNCLASSIFIED** | 1.9 | 0.1 | -- | 0.1 | | -- | 2.1 |
| **IX. INDUSTRIAL - AGRICULTURE, FOOD** | 1.2 | 0.4 | 0.1 | 0.2 | | -- | 1.9 |
| **X. INDUSTRIAL - MFG. ASSEMBLY** | 1.1 | 0.4 | -- | 0.2 | | -- | 1.7 |
| | 258 | 22 | 21 | 43 | .7 | 23 | 368 |

-- less than 0.05 tons/day

blank - no sources this category

The major component of this total is that of the Kaiser Steel Plant in San Bernardino County, the only producer of ferrous metals from raw materials in the Basin.

The remaining application categories amount to 17.6 tons of NOx per day or 4% of annual average emissions. Listed in the order of their importance these application categories are Chemical, Commercial, Institutional, Unclassified Industrial, Agriculture/Food, and Manufacturing/Assembly.

## 9.3 Inventory by Geographical Location

The emissions from both point sources rated over about 10 MMB/H as well as from area distributed sources such as domestic space heaters and small appliances, and small commercial and industrial heaters and furnaces, have been summed on a 10 Km grid square basis as described in Section 5.2 of this report. Each grid square is identified by the name of a major city located within the grid square. The geographic distribution of the Basin winter, summer, and annual average daily emissions, is presented in Figures 9-1, 9-2 and 9-3 respectively. Table 9-III presents a summary of the geographic distribution results, the emissions estimated from the inventory for the 27 grid squares (out of 290) in which the winter daily rate was in excess of 3 tons/day. Listed also are the summer daily, and annual NOx emissions from the same grid squares. The sum of the emissions from these 27 grid squares accounts for about 83% of the total estimated stationary source NOx emissions in the Basin. Table 9-III also shows the plant or plants making the major contribution to each grid square's total emissions. It can be seen that most grid squares are dominated by an electric utility plant or plants, by a refinery or refineries, or by a major industrial plant such as steel or cement. In only a few of these grid squares is the population-related area sources a major factor. This is designated by "area" in the major plant column. It is significant to note that 44% of the stationary source emissions come from just five grid squared located contiguously in the South West corner of the Basin, upwind of most of the

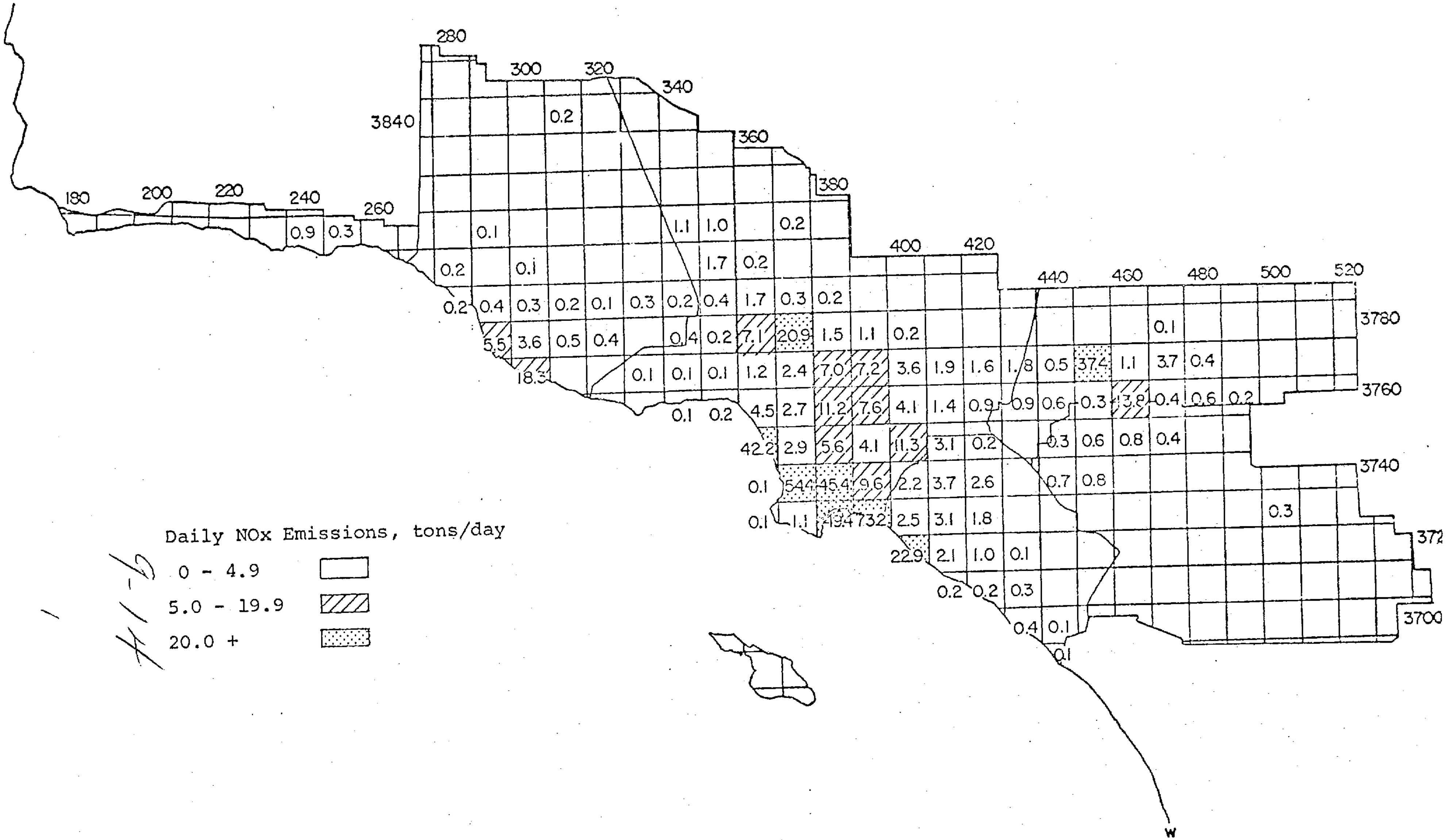


Figure 9-1. Distribution of Winter Average Daily NOx Emissions in the South Coast Air Basin

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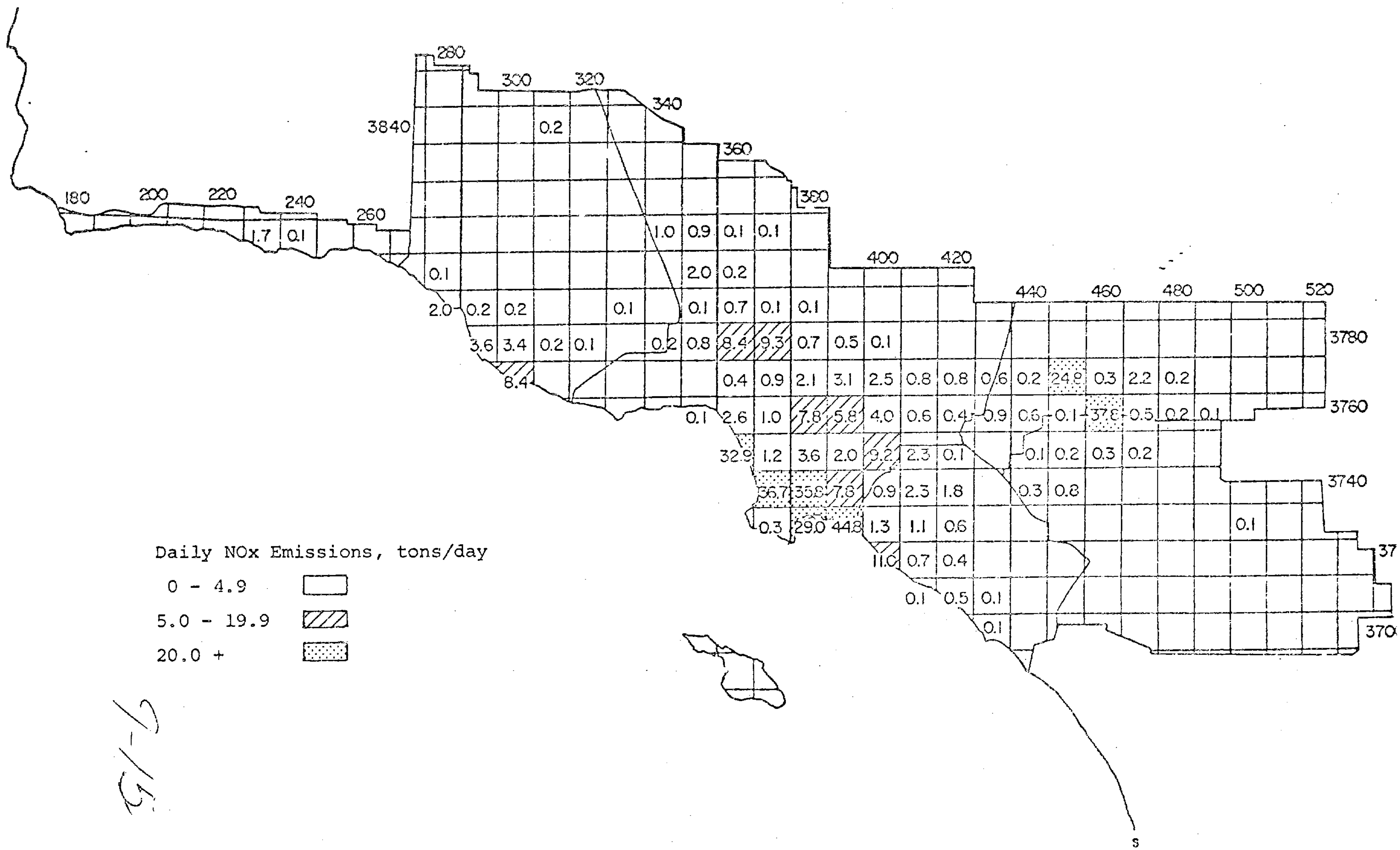


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Figure 9-2. Distribution of Summer Average Daily NOx Emissions in the South Coast Air Basin

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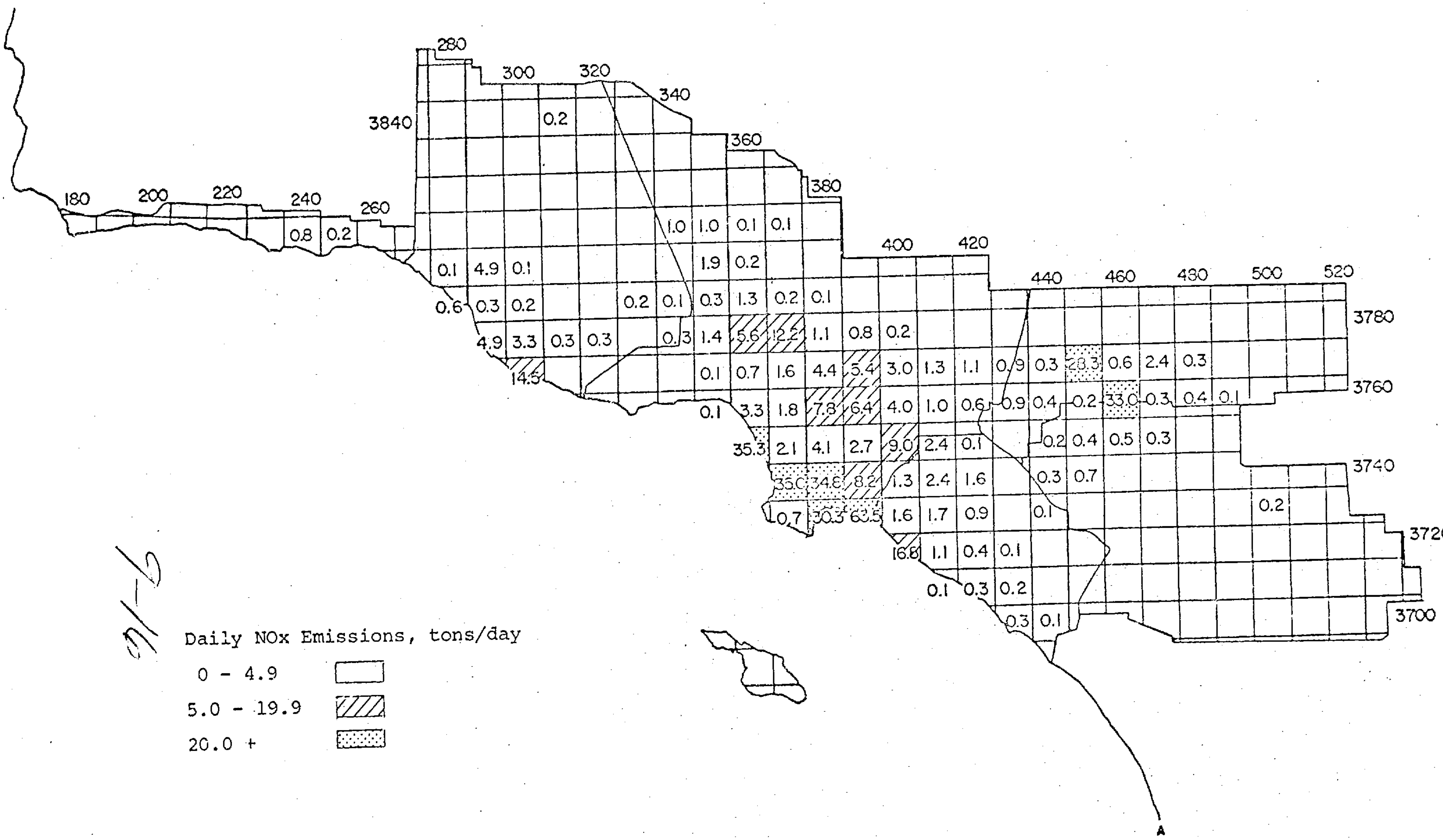


Figure 9-3. Distribution of Annual Average Daily NOx Emissions in the South Coast Air Basin

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TAB. 9-III

GEOGRAPHIC DISTRIBUTION

| Grid Location S | Grid Location W | Major City | Grid Daily NOx Emissions in Tons/Day Dec.'72 | Aug.'72 | Average July'72-June'73 | Major Plants |
|---|---|---|---|---|---|---|
| 39 | 373 | Long Beach | 73.2 | 44.8 | 63.4 | Edison, Alamitos; LA DWP Haynes Sta. |
| 37 | 374 | Torrance | 54.4 | 36.7 | 35.0 | Edison, Redondo Sta.; Mobil Refinery |
| 38 | 373 | LA Harbor | 51.9 | 29.1 | 30.4 | LA DWP Harbor Sta.; Texaco; Union |
| 38 | 374 | Paramount | 45.4 | 35.8 | 34.8 | ARCO Refinery; Shell Refinery |
| 36 | 375 | LA International | 42.2 | 32.9 | 35.4 | Edison, El Segundo; DWP Scattergood; Standard Refinery |
| 45 | 377 | Fontana | 37.4 | 24.8 | 28.3 | Edison, Etiwanda Sta.; Kaiser Steel |
| 40 | 372 | Huntington Beach | 22.9 | 11.0 | 16.8 | Edison, Huntington Beach Station |
| 37 | 378 | Burbank | 20.9 | 9.3 | 12.2 | LA DWP Valley Sta.; Burbank Public Serv. |
| 30 | 377 | Point Mugu | 18.3 | 8.4 | 14.5 | Edison, Ormond Beach Station |
| 46 | 376 | Rubidoux | 13.8 | 37.8 | 32.9 | American Cement; Cal Portland Cement |
| 40 | 375 | Whittier | 11.3 | 9.2 | 9.0 | Gulf Refinery; Powerine Ref.; Area |
| 38 | 376 | Downtown LA | 11.2 | 7.8 | 7.8 | Bethlehem Steel; Container Corp.; Area; Glass Container |
| 39 | 374 | Lakewood | 9.6 | 7.8 | 8.1 | Standard Oil Gas Pumping Station |
| 39 | 376 | East LA | 7.6 | 5.8 | 6.4 | Area; Anchor Hocking Glass |
| 39 | 377 | Pasadena | 7.2 | 3.1 | 5.4 | Pasadena DWP; Area |
| 36 | 378 | Sepulveda | 7.1 | 8.4 | 5.6 | So. Cal. Gas Pumping Station |
| 38 | 377 | Glendale | 7.0 | 2.1 | 4.4 | Glendale Public Service; Area |
| 38 | 375 | Watts | 5.6 | 3.6 | 4.1 | Latchford Glass; Union Oil Pumping |
| 29 | 378 | Oxnard | 5.5 | 3.6 | 4.9 | Edison, Mandalay Station |
| 36 | 376 | Santa Monica | 4.5 | 2.6 | 3.3 | Area; UCLA; Century Park |
| 39 | 375 | Downey | 4.1 | 2.0 | 2.7 | Douglas Refinery; Area |
| 40 | 376 | El Monte | 4.1 | 4.0 | 4.0 | So. Cal. Gas Pumping Station |
| 47 | 377 | San Bernardino | 3.7 | 2.2 | 2.4 | Edison, San Bernardino Station |
| 41 | 374 | Anaheim | 3.7 | 2.3 | 2.4 | Area |
| 30 | 378 | Oxnard AF Base | 3.6 | 3.4 | 3.3 | Continental Oil |
| 40 | 377 | Arcadia | 3.6 | 2.5 | 3.0 | Ball Glass; Area |
| 41 | 373 | Santa Ana | 3.1 | 1.1 | 1.7 | Area (Res.) |
| | | | 482.9 | 342.1 | 382.2 | |

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center of population.

In addition to this concentration there are only four other areas with grids having emissions in excess of about 10 tons/day. They are the large power plants up near Ventura, the power plants in the north central portion of the San Fernando Valley, the Downtown LA-Vernon area, and the steel and cement plants in the Western portion of San Bernardino county.

## 9.4 Seasonal Variation

The data discussed in the previous parts of this section were presented in terms of the winter (December 1972), summer (August 1972) and annual average (July 1972 - June 1973) daily values of NOx emissions in tons/day. The monthly variation of daily NOx emissions for the Basin is of interest. In addition to the winter daily value of 548 tons/day, the inventory built up by summing induvidual device emissions and area source emissions gave a summer daily value of 375 tons/day (August, 1972), and an annual average of 425 tons/day. Since emissions were not specifically inventoried for other than August and December, the best way to establish the seasonal variation is to examine the monthly variation of fuel use by each major emission category. APCD fuel use records, gas company data for both firm and interruptible gas use in the Basin portion of the six counties, and data obtained from fuel-use questionnaires gave a fairly accurate account of most fuel used in the Basin each month during the inventory period. From the combination of this data a fuel use by month chart was devised for the Basin for the inventory period, Figure 9-4. From this monthly fuel use chart, combined with appropriate NOx weighting factors and using specific monthly emissions computed for the electric utility power plants, a monthly profile of NOx was devised, Figure 9-5. As can be seen, the highest emission month was January, which was slightly above December. The August daily value was found to be about equal to July, the lowest month of the year. It is evident that the increased use of fuel oil as a substitute for natural gas in the months of November through March is a major factor in the sharp winter peak, out weighing the weather factor.

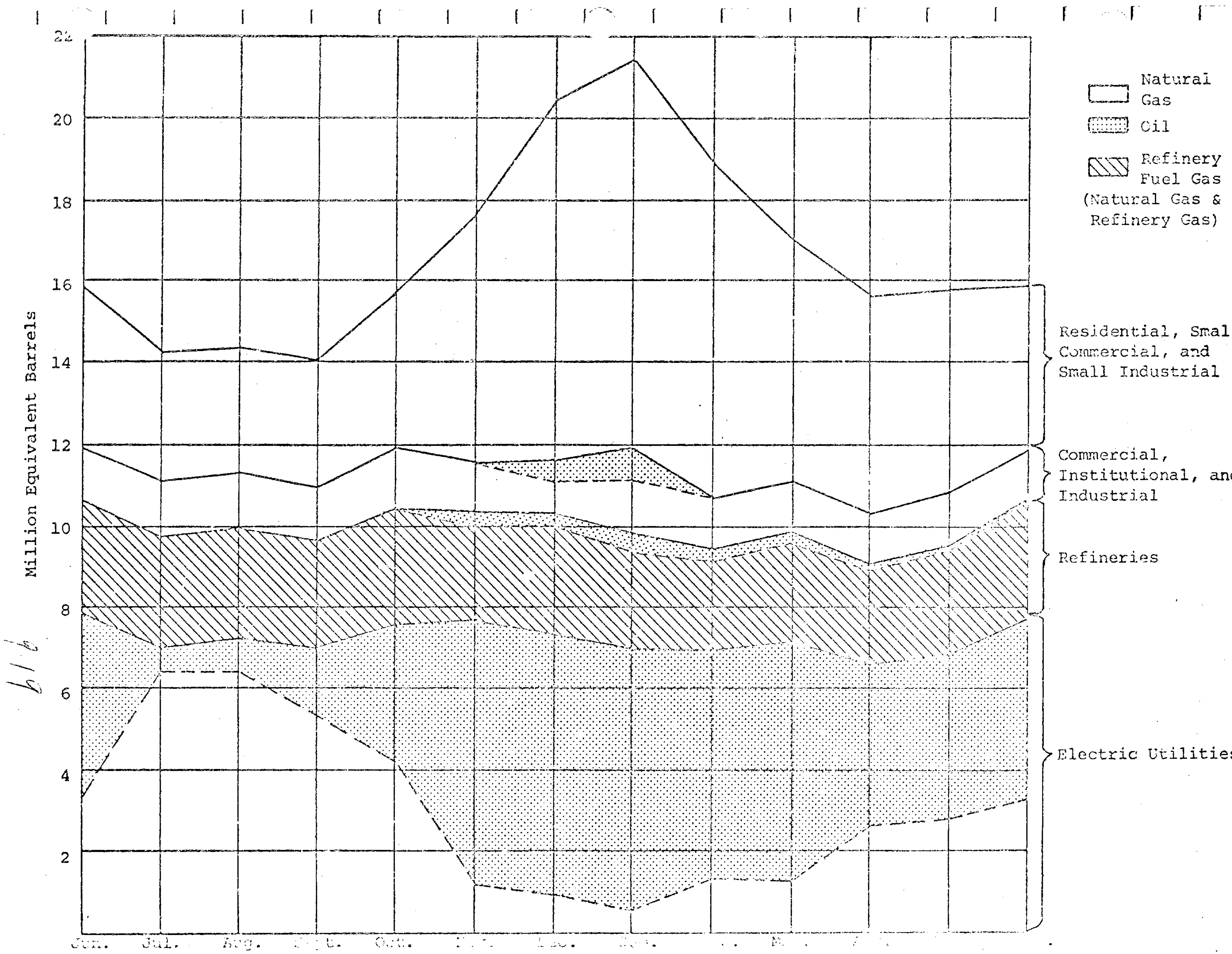


Figure 9-4. Monthly Variation of Fuel Use For the Period July 1972 - June 1973 For the South Coast Air Basin

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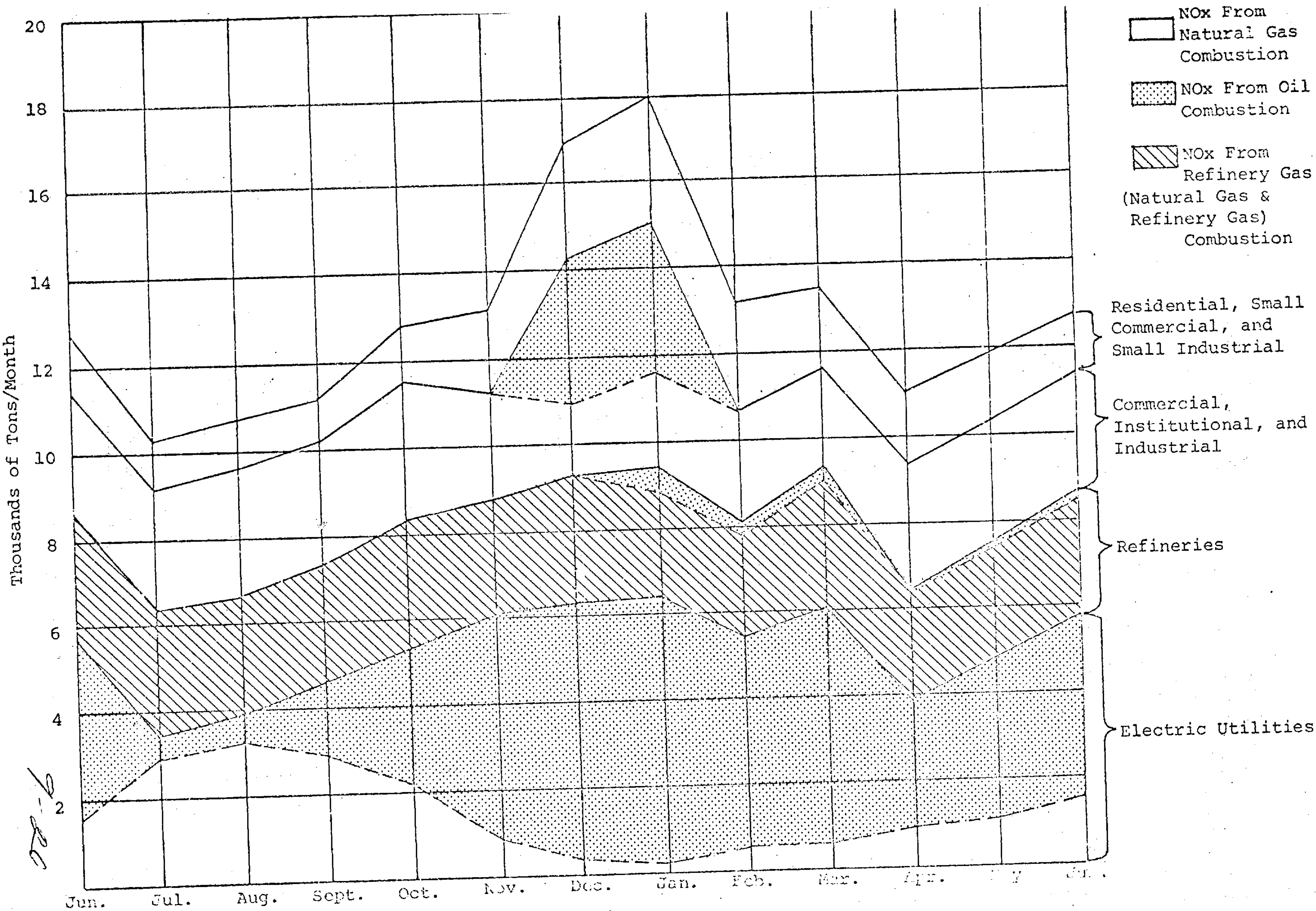


Figure 9-5. Monthly Variation of NOx Emissions For the Period July 1972 - June 1973 For the South Coast Air Basin

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## 10.0 INVENTORY FORECAST AND AIR QUALITY IMPLICATIONS

With the results derived from the inventory of stationary sources emissions of NOx in the Basin it is of interest to approximately relate the geographic distirbution of emissions to local variations in ambient $NO_2$ concentrations under worst condition days. Beyond that it is of interest to forecast future trends in total Basin-wide stationary source emissions and to relate these to projected future Basin automotive emissions in order to determine the approximate level of stationary source emissions reductions needed to meet Federal Air Quality Standards in the Basin.

### 10.1 Approximate Relation Between Emissions And Air Quality

The relationship between localized emissions and either local or overall Basin air quality (atmospheric concentrations of pollutants) is a complex subject involving both atmospheric photochemistry and meteorology. It has not been the purpose of this investigation to delve into air quality models but rather to provide the inputs for such models for at least one contaminant, NOx. Nevertheless it is of interest to relate local emissions to local air quality in an approximate way simply to put the inventoried emissions levels into perspective as to their potential significance. For this purpose a simple control box convection model has been considered where the "box" is defined as 10 km by 10 km (the grid system adopted) by H km the inversion height. A unidirectional, steady, uniform velocity, convective air flow is assumed in a direction normal to one of the sides of the "box." Molecular diffusion is considered to be negligible with respect to the convective air flow. The local emissions from sources in the grid square are assumed to be distributed uniformly over the area of the grid square. Within the box NO is assumed to have reacted to $NO_2$ but atmospheric reactions to change $NO_2$ to oxidant are ignored and the concentration of $NO_2$ assumed to be uniform, i.e., well stirred. (By considering the eventual concentration of oxidant to be linearly proportional to the $NO_2$ concentration, the model could alternatively be considered an oxidant concentration model.) With these gross simplifications the local $NO_2$

concentration is related to total grid emissions by

$$C_n = C_{no} + \frac{C_{n-1}\, v\, L\, H\, t + E_n\, t}{L^2 H + v\, L\, H\, t} \qquad (10\text{-}1)$$

where $C_n$ is $NO_2$ concentration in grid n at time t, $C_{no}$ is initial $NO_2$ concentration in grid n at time zero when the uniform steady ventilating wind velocity drops to velocity v, $C_{n-1}$ is $NO_2$ concentration in the grid n-1 immediately upwind of grid n, L is 10 km the grid width and length, H is the inversion height, t is time counted from time zero, and where $E_n$ is the total emissions rate from point line and area sources within grid n.

Two limiting cases are considered. The first is when there is complete stagnation, i.e., no convective wind velocity, then

$$C_n = C_{no} + \frac{E_n\, t}{L^2\, H} \qquad (10\text{-}2)$$

indicating that the concentration will build up linearly with both time and emissions rate and inversely with inversion height. As an example, the value of $E_n$ that will result in $C_n$ equal to first stage alert concentration of 0.25 ppm $NO_2$ in 24 hours of stagnation, starting with $C_{no}$ of zero, turns out to be 52 tons/day for a 1 km inversion height. For half of that inversion height, the value of E would reduce to 26 tons/day to produce first stage alert concentration in 24 hours. This emissions rate is exceeded by stationary source emissions alone in several grid squares in the Basin. By ignoring molecular diffusion the actual value of $E_n$ would probably be slightly higher. By assuming uniformity of concentration within the grid for the model it is neglected that certain points within the grid would actually reach first stage alert concentration sooner than 24 hours and others later.

Of perhaps greater interest is the case where there is a steady low ventilating air flow of velocity v. The grid $NO_2$ concentration varies with time for a while but rather quickly reaches an asymptotic steady state level given by

$$C_n = C_{n-1} + \frac{E_n}{v\ L\ H} \tag{10-3}$$

where this asymptotic value is approached very closely in a time equal to several times L/v. For an ocean boardering grid square for which $C_{n-1}$ is zero, the emissions $E_n$ which would generate grid concentration equal to first stage alert (or any other selected concentration) is linearly related to the ventilating velocity v. Thus for a 1 km inversion, and for a near stagnation velocity of 1 mi/hr average, the grid-wide emissions rate that would generate first stage alert concentrations of $NO_2$ would be about 202 tons/day. Thus it can be ssen that even a small ventilating velocity has a large effect. Average wind velocities are of course higher than the 1 MPH assumed, but air quality events occur due to exceptional days. It must be noted however that the concentration in each successive downwind grid builds directly upon concentrations being delivered from its upwind grid. For example the build up was computed for a southerly wind of 1 MPH blowing up the South-North corridor from LA Harbor to Tujunga (UTM grid marking westerly boundary 380, Figure 5-1). Considering only the inventoried winter daily emissions from stationary sources in this corridor the steady state $NO_2$ concentration built up from .05 ppm in the LA Harbor grid to 0.125 ppm in the Tujunga grid assuming a constant inversion height of 1 km. (If the inversion height increased along the corridor this of course will reduce the build up.) Thus under certain conditions, on the basis assumed, it can be seen that in the corridor considered stationary source emissions alone are capable of contributing up to 50% of the emissions that would lead to exceeding the first stage alert level. Similar rates of build can be computed for the several West-East corridors that begin at the Santa Monica Bay.

## 10.2 1975, 1980 NOx EMISSIONS FORECAST

The 1972-73 inventory of NOx emissions from stationary sources in the South Coast Air Basin has been used as the baseline from which to forecast the emissions levels in 1975 and in 1980. The forecast is tabulated in Table 10-I.

The increasing NOx emissions from utility boilers in 1975 as compared with 1972-73 is expected to occur even though January 1975 is the compliance date for the reduction of gas fuel combustion NOx concentration limit from 225 ppm to 125 ppm, and oil fuel combustion from 325 ppm to 225 ppm over the whole Basin. This paradoxical increase in the total emissions in the face of substantial reductions in the NOx concentrations allowable in the exhaust gases is the result of (1) several of the units in 1972-73 already being below existing NOx limits, some approaching the 1975 limits (2) a modest increase of 1.5% in projected power generation and (3) a drop from about 43% to 7% in the fraction of total energy requirements supplied by natural gas fuel. Since emissions from oil fuel combustion on a given unit are typically about twice as high as emissions from natural gas fuel combustion the later factor, of course, is the dominant reason for the increase. Increasing load or annual capacity factor on a given unit tends to increase emissions more than the load increase due to the fact that the concentration of NO usually increases with load, as does the total exhaust gas flow itself. This factor is largely responsible for the projected increase in emissions from 1975 to 1980 during which period a 13% increase in Basin power generation is predicted by the utilities. (This is going to be achieved by installation of combined cycle unit in Long Beach, bringing a large existing unit on line, and increasing the annual average capacity factor on other units.) In addition it is projected that the gas availability will drop from 7% to about 1% in 1980. It should be noted that the conservative (by former standards) estimate of the rate of increase of Basin power generation is not the same as a projection of increase in load as the ratio of power imported into the Basin to total power can of course shift. In particular an unpredictable

TABLE 10-I

FORECAST OF NOx EMISSIONS FROM STATIONARY SOURCES
IN THE SOUTH COAST AIR BASIN

| | | 1972-73 | 1975 | 1980 |
|---|---|---|---|---|
| I | Boilers | | | |
| | A. Utility | 168 | 192 | 240 |
| | B. Refinery | 26 | 27 | 29 |
| | C. Other | 15 | 22 | 27 |
| II | Process Heaters | 50 | 50 | 55 |
| III | Small Heaters, Boilers | 57 | 58 | 68 |
| IV | Internal Combustion Engines | 42 | 42 | 46 |
| V | Kilns, Dryers | 46 | 32 | 32 |
| VI | Metal Production Furnaces | 18 | 18 | 18 |
| VII | Miscellaneous | 3 | 3 | 3 |
| | | 425 | 444 | 518 |

very wet season in the Pacific Northwest can markedly reduce the total power generated in the Basin in a given year. Further discussion of individual utility company forecasts of power generation and gas availability is presented in Appendix D. Clearly the utility boiler contribution to the Basin emissions remains the largest of all of the source categories out through 1980 and in fact increases more rapidly than do emissions from other sources. Unfortunately these devices have already been regulated to such an extent that further reduction in emissions with oil the prime fuel is very unlikely on a basis that is competitively cost effective with other options (see discussion in Appendix D-4). The only attractive option for reducing this component of the Basin emissions substantially is for a shift in national allocation priorities to divert enough gas back into the Basin to fuel its power plants. The rationale for California seeking such a shift is discussed in Section 11.9.

Only a very modest 10% increase in emissions from refinery boilers, process heaters, and reciprocating engines is forecast for 1980 as compared with 1975. This is based on the best information on fuel burning forecast by the refineries. Only two additions to the Basin refinery capacity are expected to be on line by 1980, the low sulfur oil processing plants of Standard and ARCO. Very little capacity, below that necessary for maintenance, went unused in 1972-73 hence little additional increase in fuel burning is anticipated from higher capacity use of existing refinery facilities.

The rather sharp increase in the emissions projected for 1975 for other boilers (commercial, institutional, and industrial other than refinery) is the combination of a projected 15% increase in energy requirements coupled with a reduction in gas availability from 95% to 67%, both projected by the Southern California Gas Company in its report to the PUC.[34] The increase from 1975 to 1980 is based almost entirely on a SCGC projected increase in "industrial interruptible" energy requirements of 25%.[34]

Small heaters, boilers and other devices on firm natural gas supply are projected to remain about constant from 1972-73 to 1975 and then increase by 14% in 1980. This projection is also based on the SCGC energy requirements projections.[34]

Since fuel use by gas fueled reciprocating internal combustion engines is dominated by the refinery use of such devices, the emissions growth in this category is directly linked to that of the refinery projections discussed above.

The projected sharp change in the emissions from the kilns and dryers category is based on the assumption that increasing gas curtailment will force the conversion of the 4 major cement kilns from natural gas to oil or possibly coal as early as 1975. As discussed in Appendix F, these kilns which are the principal emitters of NOx from this category, appear to have substantially reduced emissions when burning oil contrary to the trend for boilers and process heaters.

There was no basis available with which to project changes in the metal production furnace or miscellaneous categories.

Thus it is projected that without further stationary source emissions controls in the Basin that emissions from these sources will increase by about 4% in 1975 and an additional 16% by 1980, with power plant emissions the principle component of the increase.

## 10.3 Relation of Emissions to Average Basin Ambient Air Quality

In order to relate the average annual Basin emission of NOx to the Basin ambient air quality it is necessary to add the stationary source component to the mobile source component. This is particularly difficult to do with any reliability at this time because the forecasts of the mobile source component are in a state of flux as various modified strategies and controls are considered and as delays in projected impelementation dates occur. One projection, obtained from the California Air Resources Board staff[55] is plotted in Figure 10-1 for total motor vehicle NOx emissions in the Basin for the years 1970 through 1981. Also plotted on the figure is the stationary source inventory average figure for 1972-73,425 tons/day and the forecasts for 1975 and 1980, as well as the sum of these emissions. For the year July 1972-June 1973 it is seen that stationary sources represent about 28% of total Basin emissions. Note that by mid 1979, however, when mobile source controls will have taken nearly maximum effect the stationary source component will have reached 50%.

In EPA modeling of ambient air quality in the various Air Quality Regions a proportional relationship has been assumed between annual NOx emissions and annual average $NO_2$ concentrations.[56] The annual $NO_2$ concentration standard has been set at 100 $\mu g/m^3$ which corresponds to a concentration of about 0.05 ppm. The air quality in Air Quality Region 24, the South Coast Air Basin, has been predicted by the EPA[56] for the years of 1977, 1980 and 1985 at 116, 108, and 110 $\mu g/m^3$ assuming the 1977 automotive NOx control set at 0.4 gm/mi. This is believed to be the same basis as the ARB forecast of automotive emissions in the Basin. Following the assumption that air quality levels ($\mu g/m^3$) are proportional to emissions it is seen that the Basin emissions would have to be reduced by 16% or 183 tons/day average in 1977, and by 8% or 80 tons/day average in 1980, in order to meet the Federal annual $NO_2$ standard of 100 $\mu g/m^3$. If it is presumed that the reduction in emissions represented by the 0.4 gm/mi control limit is as far as such controls can cost effectively go, then the only alternatives left are combinations of reduced vehicle miles traveled in the Basin and further

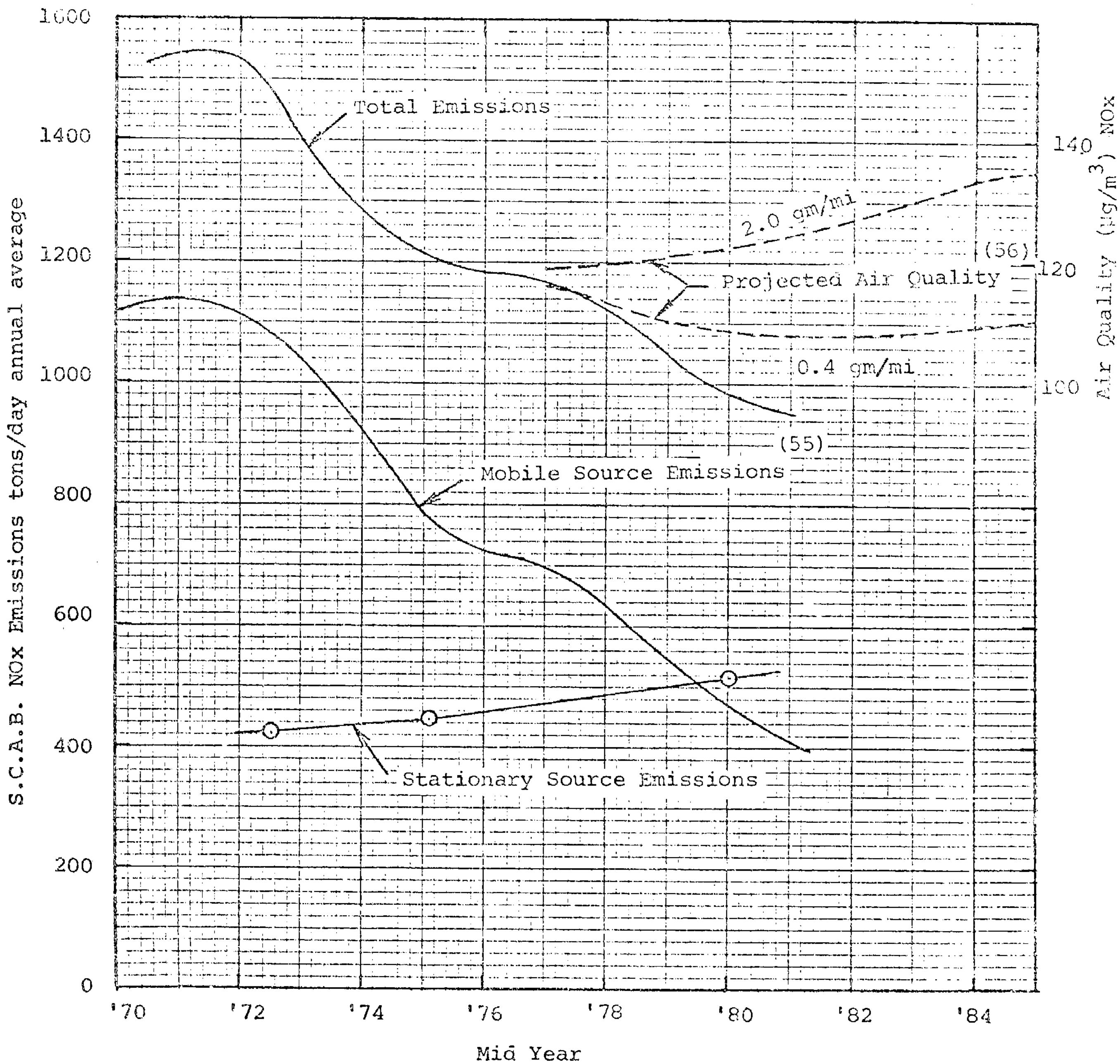


Figure 10-1. Mobile And Stationary Source Emissions of NOx For South Coast Air Basin Compared With EPA Predicted Air Quality

reduction in emissions from stationary sources. With all of the public reaction to proposed forced reductions in vehicle miles it is clearly of interest to see how much of the needed reduction is achievable from increased control of stationary sources.

The EPA model of Basin air quality levels mentioned above, it should be mentioned, is based on the assumption of industrial combustion devices being under some level of control that requires low excess air firing (see Sections 2.2 and 11.3). Further it should be noted that EPA model projections of Basin air quality levels for the less stringent automotive control limit of 2 gm/mi, now under consideration, would yield 119, and 122 $\mu g/m^3$ in 1977, and 1980 respectively. These levels would require reductions of about 220 tons/day in both years even if the projected automotive total emissions component didn't rise as surely it would.

## 11.0 DISCUSSION OF POTENTIAL AND COSTS OF REDUCING EMISSIONS

### 11.1 Cost, Cost Effectiveness Approach

Separate discussions have been made of the potential for reduction of NOx emissions in each of the eight source categories considered in this program,

- oil refineries
- electric utility power plants
- steel production furnaces
- cement production kilns
- industrial boilers
- domestic appliances
- glass production furnaces
- internal combustion engines

(appendices C through J). Each of these categories has been considered as to the applicability of the established emissions reduction techniques such as low excess air, staged combustion, flue gas recirculation, reduced air preheat, water injection (the principles of which are discussed in Section 2.3), and other special situation reduction techniques such as fuel allocation, stack gas cleanup etc. The quantitative potential NOx reduction for each source category has been assessed, as well as the aggregate costs involved, and the resultant potential cost effectiveness. The results are brought together and discussed later in this section.

In order to make meaningful comparisons of the various emissions reduction options it was necessary to put them on a common basis, one that could be compared with other options for reducing Basin emissions. Chosen was a cost effectiveness ratio defined as pounds of NOx (counted as fully converted to $NO_2$, molecular weight of 46) prevented or reduced per dollar of annual cost. Since there was generally some uncertainty in the estimate of the amount of NOx that could be prevented the value selected was consistantly estimated conservatively low. Likewise since there was even more uncertainty in establishing generalized costs for the reductions, these were generally estimated conservatively high. Thus it is believed that the amount of the reductions, and the cost effectiveness ratios established are both conservatively low. In a number of cases the combustion modification reduction techniques considered, while firmly established for other devices such as large boilers, have not in fact been demonstrated as being feasible for some of the specific devices considered in this study. Hence the basic feasibility of some of the techniques for some of the devices requires demonstration before their projected reductions can be counted on.

With regard to the estimation of costs, in each instance where applicable the costs were composed of an annualized fraction of the capital cost, an annual fuel cost to cover the consequence of any resultant fuel penalty due to loss of efficiency, and an annual maintenance cost. The capital cost was the sum of hardware and construction costs, and engineering costs for implementation of the modification. For most cost effectiveness calculations the capital cost was annualized at the rate of 20% per year as they have been for cost effectiveness studies by EPA and others. In some cases a lower annualization percentage could logically have been selected and would have resulted in somewhat improved cost effectiveness ratios. Fuel costs were dealt with by assuming the cost of natural gas constant at $0.50/MMB, low sulfur oil at $1/MMB in 1972-73, and at $2/MMB in 1974 and beyond. Because of limited natural gas availability in the future, cost penalties resulting from lost efficiency was set at $2/MMB on the assumption that oil would have to be used to make up the needed additional fuel. Maintenance was taken as a fixed 5% of the capital investment, however in certain situations, as noted, the projected fuel saving derived from improved efficiency due to lower excess air was traded even for the maintenance costs. More on the specifics of the cost elements of particular emissions reduction techniques is presented later in this section.

While cost effectiveness of reductions has been assessed for whole source categories, it is of interest to examine cost effectiveness of individual units, and have the basis for generalizing the sizes, reductions, etc. that will result in attractive cost effectiveness ratios. For this reason a general relationship was developed

$$CE_M = \frac{q \cdot F_S \cdot R_M \cdot T_A}{A + Bq + CqT_A} \qquad (11\text{-}1)$$

where CE is cost effectiveness ratio in lbs NOx as $NO_2$ reduced per dollar annualized cost, q is annual average firing rate in MMB/H, $F_S$ is source or source category emission factor in lbs NOx/MMB, $R_M$ is reduction fraction resulting from modification M, $T_A$ is annual hours of operation, A is that part of annualized capital cost in dollars that is independent of the size of the device, Bq is the size dependent portion of the annualized capital cost, and $CqT_A$ is the fuel cost portion of the annualized cost of implementing the emission reduction modification, relating in particular to any loss of efficiency due to the reduction method. For small devices as the fixed cost term in the denominator dominates, the cost effectiveness becomes directly proportional to the device size,

$$CE_M \cong \frac{q\ F_S\ R_M\ T_A}{A} \qquad \text{for } A >> q(B + C\ T_A) \qquad (11\text{-}2)$$

By specifying a minimum CE of interest for a given device category with particular $(F)(R_M)T_A$ and A, equation 11-2 can be used to show the smallest size device (q) for which the specified CE can be achieved. At the other extreme, for large devices for certain of the emissions reductions techniques, the fixed cost term in the denominator becomes negligible giving

$$CE_M = \frac{F_S\ R_M\ T_A}{B + C\ T_A} \qquad \text{for } q(B + C) >> A \qquad (11\text{-}3)$$

in which $CE_M$ is essentially a unique value for a given reduction technique for a given type of emission source operating $T_A$ hours per year.

## 11.2 Cost Effectiveness Of State And Federal Vehicle Emissions Controls

Before proceeding with discussion of each of the established emission reduction techniques in terms of these relationships it is of value to put the absolute CE ratios into some type of perspective. For this purpose the CE ratio for two automotive emissions reduction programs are computed and discussed.

For the California NOx automotive retrofit program the estimated 5 year average South Coast Air Basin reduction of NOx emissions is 50 tons/day, and the maximum reduction estimate is 75 tons/day in 1975.[55] Based on a vehicle population of $1.95 \times 10^6$ 1965-70 vehicles in the Basin the average reduction is 19 lbs/year/vehicle, or 28 lb/year/vehicle maximum. The capital cost is limited by law to $35, which annualized at 20%/year is $7/yr annual capital cost. The fuel penalty is estimated at 5%, which at an assumed 6,000 average miles/year per vehicle and 50¢/gallon amounts to an annual fuel cost of $11.25. The total annual cost is $18.25 and the cost effectiveness works out to be 1.05 lb NOx as $NO_2$ prevented per dollar annual cost for the 5 year average, and 1.5 lb/dollar maximum in 1975.

The other mobile source emission control example is based on the EPA suggested proportional exhaust gas recirculation.[56] The estimated reduction is 2 gm/mi which is equivalent to 50 lb NOx as $NO_2$ per year per vehicle based on 11,400 miles per year. The annual maintenance cost is estimated at $4/year, the annual capital cost is estimated at 20% of $32, and the fuel penalty is estimated at $25/year based on a 6% fuel penalty and 50¢/gallon fuel cost, 13.5 average mi/gallon for a total annual cost of $36.[56] The cost effectiveness thus is 1.4 lb of NOx as $NO_2$/dollar annual cost, which is quite similar to the CE ratio for the California retrofit program. This is also the same cost effectiveness ratio derived by comparing overall 1980 and 1985 costs and emissions reductions for the EPA 2 gm/mi vehicle control strategy versus their 0.4 gm/mi strategy.[56]

## 11.3 Cost Effectiveness Of Low Excess Air Combustion

Low excess air operation is one of the several demonstrated techniques for reducing NOx emissions. The principle involved is discussed in Section 2.3. In small boilers it has been found [24] that on the average emissions from units firing #2 oil are reduced about 10 ppm for each one percent reduction in excess oxygen (about 5% in excess air); that emissions from units firing #6 oil are reduced about 20 ppm for each percent reduction in $O_2$; that emissions from gas fired units without air preheat are not sensitive to excess oxygen; and that gas fired units with air preheat are reduced about 20 ppm for each percent reduction in oxygen. Although very high temperature devices (furnaces, kilns) have been found in this study to be much more sensitive to oxygen level than these results, an average of 15 ppm per percent oxygen might be a representative average sensitivity for most of the point source devices in the inventory other than the high temperature devices and the utility boilers which for the most part are already operating very close to their minimum oxygen level. For the sample of 50 industrail boilers tested in the EPA industrial boiler program[24] the average level of excess air was found to be about 30%, which corresponds to about 5% oxygen. Most devices are capable of operating at excess air levels down to about 15%, representing a reduction of about 2% in oxygen and thus 30 ppm reduction in NO on the average.

Excess air can usually be reduced in commercial, institutional and most industrial combustion devices, and with the reduction an improvement in fuel efficiency can be gained by reducing stack gas losses. With that incentive well known it must be assumed that all operators operate within the limits of the information they are receiving on the combustion process, within the limitations of the condition of the device, and within the available automatic controls or time alloted to manual control. Therefore in order to implement low excess air operation new equipment must be supplied. The equipment will usually be improved oxygen sampling and measuring systems and improved controls. It is expected that the cost of such equipment is essentially independent of device size except that one can afford more expensive, more automatic equipment for larger more expensive devices. There will however probably be a lower limit of cost which we here estimate as about $8,500 per unit, covering the cost of oxygen instrumentation, its installation and check out. Annualizing this cost at 20% per year, and an assumption of an average reduction of 2% in oxygen, which corresponds to 30 ppm (about 0.04 lb/MMB), equation 11-2 can be used to examine the lower limit of device size times annual operating hours for which a given CE ratio can be realized. Arbitrarily selecting the minimum CE at 1 lb/$ and assuming 6000 hours/year

$$q_{minimum} = \frac{(1 \text{ lb/\$})(\$8,500)(0.2/\text{yr})}{(0.04 \text{ lb/MMB})(6000 \text{ hr/yr})} = 7 \text{ MMB/H}$$

which is below the lower cut off of devices counted in this inventory. For all larger devices, operating comparable numbers of hours per year the CE ratio will be approximately in proportion to the device size.

If the fuel saving is considered in the above example, using equation 11-1, assuming about 1/2% fuel efficiency gain for 2% reduction in excess oxygen the minimum q for a CE of 1 lb/$ reduces to about 5.7 MMB/H. For these assumed conditions the value of q at which the fuel savings just balances off the annualized capital cost is about 28 MMB/H.

If all of the devices in the inventory, except the utility boilers which are presumed to be operating at near minimum excess oxygen, were operated with 2% lower oxygen than at present the total reduction in gas and oil fuel combustion NOx emissions would be about 2400 tons/year lower, based on Basin fuel use by devices in the inventory other than utility boilers.

## 11.4 Cost Effectiveness Of Two Stage Combustion

Two stage combustion can reduce the nitric oxide formed both from the thermal process and from the organic nitrogen in the fuel as discussed in Section 2. Implementation is often carried out by removing 15-30% of the burners from service, allowing air to continue to enter through the idle burners and increasing the fuel flow through the active burners to maintain the same total fuel flow. In order to maintain this fuel flow it is often necessary to obtain new oil gun tips or modify the existing ones. Finding the pattern of burners to take out of service, the proper air register settings, the level of excess $O_2$, etc. which gives the lowest nitric oxide emission along with satisfactory combustion conditions, (i.e., low carbon monoxide, no smoke, low combustibles, minimal loss of efficiency) is usually a trial and error process.

Two stage combustion can also be implemented by use of overfire air ports (NOx ports). These are openings into the boiler from the air supply, usually the wind box, in addition to the burner openings. The ports can be put into the units at the time they are built or later as a retrofit. The correct placement of the ports so as to avoid an increase in required air, excess carbon monoxide or smoke, is frequently a difficult engineering problem.

Staged combustion has been used to reduce nitric oxide emissions from all sizes of boilers and laboratory test devices burning gas, liquid and solid fuels. Although the experience to date is limited primarily to boilers and test devices there is no particular reason why the technique could not be applied to a wider range of devices of interest.

The cost elements in utilizing staged combustion are almost entirely related to the engineering necessary to set up this mode of operation. For smaller devices the fixed setup cost far out weighs the size dependent hardware cost or any fuel penalty cost, hence equation 11-2 can be used to examine the limiting CE ratio for small units. The estimated minimum capital cost for setup on small units is here estimated at $10,000, which is assumed annualized at 20% per year. Assuming a 35% reduction from an initial emission rate of 0.3 lb NOx/MMB, the minimum q for a CE ratio of 1 lb/$ is

$$q_{minimum} = \frac{(0.2/yr)(\$10,000)(1\ lb/\$)}{(.105\ lb/MMB)(6000\ hrs)} = 3.2\ MMB/HR$$

For a 3000 hr/yr device the minimum q at which a CE of 1 lb/$ could be achieved would of course be 6.4 MMB/HR, both of which are below the inventory cut off limit. Another way of looking at the lower device size limit of cost effective reduction is that present level of emissions $q\ F_S\ T_A$ for which a given percent reduction and annualized cost would yield the desired CE ratio. For CE of 1 lb/$ and at 35% reduction, $q\ F\ T_A$ is equal to about 6000 lbs NOx/yr or 3 tons/year.

For a 50 MMB/HR boiler, operating 6000 hrs/year the setup cost might be $30,000, a fuel penalty might be about 1/4%, and the reduction might be about 0.1 lb/MMB. For this example the CE ratio is

$$CE = \frac{(50\ MMB/H)(0.1\ lb/MMB)(6000\ Hr)}{(.2)(30,000)\$/yr + (6000\ hr/yr)(.0025)(\$2/MMB)(50\ MMB/Hr)} = 4\ lb/\$$$

Refineries emit 34,000 tons per year of NOx as $NO_2$. By using two stage combustion in these devices which for the most part burn gas fuel it is estimated these emissions could be reduced by 35%. Almost all refinery devices emit more than 3 tons per year. Therefore it is estimated that the emissions from refineries could be reduced by 12,000 tons per year.

Considering the commercial, institutional, and industrial boilers other than in the refineries, about 5400 tons of NOx is emitted per year. It is estimated that the emissions from these boilers could be reduced by about 35% for a total reduction from this source category of about 1900 tons/year.

## 11.5 Cost Effectiveness Of Flue Gas Recirculation

Flue gas recirculation is a technique for reduction of nitric oxide formation that has been utilized on a few large utility boilers thus far. As discussed in Section 2.3 it reduces the formation of nitric oxide by reducing the flame temperature. The technique more effectively reduces the emissions from gas fuel flames then it does from oil fuel flames.

This technique is implemented by taking part of the flue gas and adding it to the combustion air. Reductions of 50% and greater can be expected with gas fuel while reductions which are not so large can be expected with oil fuel. The technique involves taking part of the flue gas, usually at about 700°F and mixing it with the combustion air. The recirculation of flue gas may create a number of problems which will require correction or limit the units on which the procedure can be applied. The increased volumetric gas flow rate may increase pressure drops through registers, burner throats, convective passes ducts or other parts of the device. This increased pressure drop may require increased forced draft fan capacity (load) or even modification of the unit. The reduced temperature and increased gas flow rate will alter the heat transfer pattern. The decreased temperature will reduce the radiative heat transfer while the increased gas flow rate will increase the convective heat transfer. Devices which don't have wind boxes such as natural draft units and some induced draft units are difficult to retrofit with flue gas recirculation. A wind box with flue gas introduction would have to be constructed for such devices before flue gas recirculation could be used. Control equipment is required for all size units and although less expensive controls may be required for smaller units the decrease in control cost is not linear with size. The minimum cost for installing a flue gas recirculation system on a small boiler is estimated to be $30,000, which cost will clearly dominate the fuel penalty cost which is estimated at about 1% in efficiency for normal recirculation percentage flow. Thus if the average emission reduction realizable from the recirculation is established at 40%, and capital cost is annualized at 20% per year. The minimum size boiler for which a CE ratio of 1 lb/$ is achievable is, from equation 11-2, assuming a 6000 hr/year operation,

$$q = \frac{(0.2/\text{yr})(\$30{,}000)(1\ \text{lb}/\$)}{(0.4 \times 0.3\ \text{lb/MMB})(6000\ \text{hr/yr})} = 8.3\ \text{MMB/HR}$$

or alternatively, devices whose emissions are in excess of 15,000 pounds of NOx per year (7.5 tons/year) could be controlled on a CE ratio in excess of 1 lb/$ using flue gas recirculation if the minimum cost is $30,000 annualized at 20%/year.

On a larger boiler, say about 100 MMB/H, the cost of the flue gas recirculation would be of the order of $1,000/MMB. Assuming the fuel penalty at 1% due to the recirculation, and other factors as in the above example the CE ratio turns out to be

$$CE = \frac{(100\ \text{MMB/H})(0.3\ \text{lb/MMB})(.4)(6000\ \text{hr/yr})}{(0.2/\text{yr})(\$100{,}000) + (6000\ \text{hr/yr})(0.1)(\$2/\text{MMB})(100\ \text{MMB/H})} = 2.3$$

Considering refineries there are about 75 devices with forced draft and emissions in excess of 7.5 tons/year. Natural draft and induced draft units are not expected to be easily retrofitted with flue gas recirculation. The 75 devices emit about 15,000 tons of NOx as $NO_2$ per year. At 40% reduction, the Basin reduction from this category would be about 6000 tons per year at a cost effectiveness ratio in excess of 1 lb/$.

In addition to the refinery devices there are a number of commercial, institutional, and industrial devices which emit NOx in excess of 7.5 tons/year. Together they emit a total of about 4,000 tons/year and thus a 40% reduction would yield a Basin reduction of about 1600 tons per year.

## 11.6 Cost Effectiveness Of Reduced Air Preheat

Reducing the preheat of the incoming air can reduce the flame temperature and the production of nitric oxide as discussed in Section 2.3. Implementation is carried out by allowing part of the incoming air to by-pass the air preheater. Frequently air preheaters have by-passes on them. In cases where the air preheaters are built without by-passes the equipment can usually be modified with little expense.

The technique has the obvious limit that devices which do not have air preheaters can not have their combustion air temperature reduced. The second limitation is that processes which require that the product reach very high temperatures, such as, open hearth furnaces, glass melters, cement kilns, etc., need air preheat not only for efficiency but simply to operate satisfactorily. Therefore reduction in air preheat is not practical for such devices. The final limitation is that reduction in air preheat, while an effective method of reducing thermal fixation of nitrogen, is not a very effective method of reducing emissions produced from fuel bound nitrogen. Thus the technique is not always effective on oil fires.

Since there are only negligible hardware and engineering costs involved with implementing reduced air preheat operation, the costs for this control technique are dominated by fuel costs as a result of lost efficiency. As noted in Section 2.3 a 100°F reduction in air preheat can result in a 30 to 40% reduction in NOx emissions with a resultant loss of about 3% in fuel efficiency. For this control method, equation 11-1 reduces to

$$CE = \frac{F_S \quad R_M}{(\Delta \text{ efficiency})(\text{fuel cost \$/MMB})}$$

where it is evident that fuel cost per heating value unit is a key factor. While natural gas presently costs about \$.50/MMB to large users, it must be realized that in a situation of limited gas supply each Btu of energy lost through efficiency loss will have to be ultimately made up by a Btu of oil fuel energy, thus the appropriate unit fuel change made to reducing air preheat should be that of oil. The figure assumed for oil costs in this analysis is \$2/MMB. Thus it can be shown that a CE ratio in excess of 1 lb/\$ can be achieved with any air preheated device having an uncontrolled emission factor in excess of 0.2 lb NOx/MMB.

$$F_S = \frac{(CE)(\Delta\ \text{efficiency})(\text{fuel cost})}{(R_M)}$$

$$= \frac{(1\ \text{lb/\$})(.03)(\$2/\text{MMB})}{(0.30)}$$

$$= 0.2\ \text{lb NOx/MMB}$$

Most of the larger devices that would have air preheaters operate at an emission level in excess of this figure. It is estimated that only about half of the boilers (other than in refineries) larger than 100 MMB/H have air preheaters, only about 1/10 of those between 100 and 50 MMB/H, and few if any below 50 MMB/H. A 30% reduction in the emissions from these devices would represent only about 200 tons/year.

Emissions from refineries which are primarily gas burners, and will continue to be so since they produce their own gas, could be reduced by lowering the air preheat. Taking 0.2 lb NOx/MMB initial emission rate as the cut off, the emission from refineries could be reduced by about 6500 tons per year at cost effectiveness ratios of greater than 1 pound per dollar by reduced air preheat. This reduction would be about 20% of the refinery emissions.

## 11.7 Cost Effectiveness Of Water Injection

Injecting water into the combustion air before the air enters the burner(s) is another method of reducing NOx emissions discussed in Section 2.3. The use of one pound of water per pound of fuel will reduce emissions by 40-50% as discussed in Section 2.3.

The technique is not successful unless the water is evaporated before it enters the burner. If it enters the burner as a water drop it will not evaporate rapidly enough to alter the peak flame temperature. Therefore, the usefulness of this procedure is for the most part restricted to devices with air preheaters. Water injection like reduced air preheat would not be useful in processes that require that the product reach very high temperatures such as open hearth furnaces, glass melters, cement kilns, etc., since the use of this technique would render the process inoperable. The procedure is only partially effective when oil fuel is being used so its consideration here will be limited to gas fuel.

The cost elements in reducing emission by water injection are almost entirely dominated by fuel costs. This is due to the fact that water injection at the rate of 1 lb of water per lb of fuel results in approximately a 6% efficiency penalty most of which is due to the necessity of supplying the water latent heat of vaporization and heating up the water vapor to air preheat temperature. The cost of the water is negligible with respect to the fuel costs. The emission reduction that can be realized from such water injection is about 40%. Again assuming a fuel cost of \$2/MMB for the same reasons explained in the subsection on reduced air preheat, it can be shown that a CE ratio in excess of 1 lb/\$ can be achieved with any air preheated boiler having an uncontrolled emission factor in excess of

$$F_S = \frac{(\text{CE})(\Delta\ \text{efficiency})(\text{fuel cost})}{(R_M)}$$

$$= \frac{(1\ \text{lb/\$})(0.06)(\$2/\text{MMB})}{(0.40)}$$

$$= 0.3\ \text{lb NOx/MMB}$$

with CE independent of unit size or hours of operation.

As with air preheat the potential for reduction of NOx by water injection in gas burning industrial and commercial boilers is estimated to be quite small. Emissions from refineries boilers and heaters, which are primarily gas burners and will continue to be so, could be reduced significantly by use of water injection. Taking 0.3 lb NOx/MMB as the lower limit cutoff, the emissions from refineries could be reduced by about 3650 tons/year which is about 10% of the refinery emissions.

## 11.8 Summary Of Basin Emission Reduction Potential From Combustion Modifications

Potential opportunities for reducing the NOx emissions for each of the several categories of stationary emissions sources in the Basin have been assessed, and discussed in the respective appendices C-J or in this section in discussing cost effectiveness of reductions by various techniques. These potential reductions are summarized in Table 11-I. In compiling these reductions, control options were considered with cost effectiveness ratios down to about 1 lb of NOx as $NO_2$ reduced per dollar annualized cost. Since in each source category there were not control options that spanned the whole range of cost effectiveness down to 1 lb/dollar, the reductions are not based on a uniform extension down to that level in each category. It is believed that the reductions have been estimated conservatively low and the costs conservatively high for the most part.

Because of the comparatively small numbers of devices and level of detail known on these devices, the reductions in several source categories were based on considerations of individual units. These categories included small unregulated utility boilers, open hearth furnaces in steel mills, glass production furnaces, and cement kilns. With the large number of devices in the oil refinery boiler and heater categories, stationary internal combustion engines, and industrial/commercial/ institutional boiler categories it was necessary to estimate costs and

TABLE 11-1

SUMMARY OF POTENTIAL NOx EMISSIONS REDUCTIONS - STATIONARY SOURCES SOUTH COAST AIR BASIN

| Source Category | # Units Reduced | Present Annual Emissions tons/day | Primary Reduction Method | Projected Reduction tons/day | Estimated Average CE Ratio lb/$ | Primary Cost Element |
|---|---|---|---|---|---|---|
| Oil Refinery Heaters & Boilers | 430 | 76.6 | LEA, TSC | 25.7 | 10 | set up, instrumentation |
| IC Engines | 468 | 39.6 | Manifold Temp. Speed | 20.0 | 100 | fuel |
| Cement Kilns | 4 | 32.5 | Convert to oil | 14.8 | 1.4 | fuel |
| Utility Boilers 1775>Q>1500 MMB/H | 14 | 168 | TSC, FGR | 9.0 | 2.7 | FGR hardware TSC set up |
| Industrial, Commercial Boilers | 531 | 14.6 | LEA, TSC | 5.5 | 2.5 | set up, instrumentation |
| Glass Furnaces | 8 | 12.1 | LEA, Electric boost | 4.8 | 3 | maintenance, electrical energy |
| Open Hearth Furnaces | 12 | 11.6 | LEA | 4.1 | 9 | instruments, controls |
| | | | TOTAL | 84 tons/day | 28 | |

LEA = low excess air

TSC = two stage combustion

FGR = flue gas recirculation

reductions on an average, overall basis rather than unit by unit. Specific unit examples were computed for those refinery boilers and heaters tested in this program (see Table C-IX).

It can be seen in Table 11-I that the aggregate potential reduction in the Basin was found to be about 84 tons/day at an average cost effectiveness of about 28 lb NOx prevented per dollar annualized cost. This cost effectiveness ratio is very attractive compared with automotive control options (see discussion Section 11.2), but is to a large extent a result of the very high ratio and reduction for the stationary internal combustion engines. This particular assessed reduction in based more on the broader range of data cited in Reference 23 than on the limited sample of reciprocating internal combustion engine emission data obtained during this program (Appendix J). Hence there is some uncertainty in the applicability to the specific engine population in the Basin. Thus perhaps a Basin-wide reduction in stationary source emissions of 70-100 tons/day may in fact be achievable through the modifications suggested and other control options for specific situations not considered. The Basin average cost effectiveness ratio would come down sharply if the internal combustion engine reduction could not be achieved as estimated.

One major potential component to possible Basin emission reductions not shown is that related to domestic appliances. If a one third or so reduction in this category could be realized another 15 tons/day would result. The only potential avenue to thie reduction known is that through low emission burners which are under development. But it is not clear at this time how effective they will be and whether the price can be set low enough, with installation, to make this a cost effective reduction (see Appendix H). Because of the number of devices this reduction would necessarily stretch out over a length of time to achieve the change of burners.

Finally, it must be noted that the very low percentage reduction in the largest component of current emissions, the utility power plants, is the consequence of this source category having already achieved major reductions through fuel regulations in the '60's and through combustion modifications in the early '70's (see discussion in Appendix D). The next increment of potential reduction in emissions beyond that indicated in Table 11-1 would come at a cost effectiveness ratio markedly reduced below these considered in this study. The major change in utility boiler emissions toward higher levels that started last year and will continue for another year is the direct consequence of rapidly falling availability of natural gas as a power plant fuel. A reversal in this trend, back toward the gas availability levels of the early '70's could have as much impact on Basin emissions as the sum total of all of the combustion modifications discussed in the preceding portions of this section.

## 11.9 Fuel Type Selection As An Emissions Control Option

In the previous section the extent of Basin-wide NOx emissions considered to be potentially reducible on a cost effective basis, comparable with that for mobil source emission controls, was found to be about 20% of Basin stationary source emissions or 84 ±15 tons/day. Still another option for further reduction should be considered, that being the resubstitution of natural gas fuel for oil fuel for power plant consumption in the Basin. In discussing the 1973 inventory and the forecasts to 1975 and 1980 in Section 10 the dominant change resulting in sharply increasing NOx emissions is the decline of natural gas availability to the electric utilities. From over 80% of electric utility energy requirements being supplied by natural gas fuel in 1970, subsequent projected curtailment has reduced the natural gas availability to only 5% of utility requirements in 1975 and less beyond. This of course necessitates the shift to oil fuel.

The utility boiler NOx regulation for 1975 and beyond for gas fuel (see Table D-1) is 125 ppm or about 0.15 lb NOx as $NO_2$/MMB, and for oil 225 ppm or about 0.3 lb/MMB, for a gas to oil difference of about 0.15 lb/MMB. Both of these levels are considered to be attainable with regulated large boilers. Even for unregulated smaller boilers, although probably higher than these absolute numbers, the difference between gas and oil operation is typically 100 ppm or .15 lb/MMB. At 1972-73 generation rates in the Basin the total energy output from the utilities was 55 million Mw-hr which corresponds to about 535 million million Btu energy requirement. Thus the emissions penalty being imposed on the Basin for burning all oil versus all gas is approximately 76.5 million pounds of NOx as $NO_2$ per year or 105 tons/day which is about 25% of stationary source emissions. At current prices the average oil cost to the electric utilities is about $2 per million Btu vs about $.50 per million Btu for gas. Thus in effect the Basin electric utilities are paying a premium of $1.50 per million Btu for oil compared with gas if it were available. For the $1.50 per million Btu premium the Basin is getting in return a net increase in NOx production of 0.15 lb NOx as $NO_2$ per million Btu, which means residents of the Basin are buying

NOx at a cost of $10 per pound. The amount of NOx to be bought by Basin residents in 1975 is approximately 7.6 lbs per capita at a cost of about $76 per capita.

This curious situation has apparently resulted from Federal Power Commission rulings on priority use of natural gas. Their first priority is apparently domestic and other firm gas use. From an environmental and energy conservation standpoint this is understandable since to get 1 Btu of energy (heat) into the home it is necessary to provide about 1.25 Btu worth of gas to the home versus about 2.5 Btu worth of gas to the electric utility to provide the same heat to the home by way of electricity. The next priorities are various industrial interruptible gas customers in designated blocks A-D. In apparently last priority are the electric utilities. The Southern California Gas Company advises that deliveries to them through the interstate pipeline are curtailed in accord with how they distribute their gas between the several priority blocks. The more they supply steam-electric needs the more they are curtailed. Their gas supply for the years 1974 and 1975 has been scheduled by their suppliers (El Paso and Transwestern) through FPC priorities to provide sufficient gas to serve all firm gas needs, 80 and then 67% of other interruptible gas needs, and 19 and then 7% of steam-electric gas needs.[34] For 1976 and beyond two sets of service percentage figures are offered, one assuming no new gas supplies, and the other assuming new sources such as coal gasification plants. On the basis of no new sources, firm requirements are expected to be only 82% met by 1980, other interruptible gas service completely curtailed by 1980, and steam-electric needs are only 3% met by 1980. Under the assumption of planned new sources, firm requirements are expected to be 100% met through 1980, other interruptible requirements are 69% met, and steam-electric only 8% met.[55]

It is interesting to note from the FPC published fuel distribution and cost statistics[57] that in the period from May 1973 through April 1974 while the Pacific region (California, Oregon, Washington) was receiving 43% of its steam-electric gas requirements as interruptible gas (and Southern California about 30%), the West South Central (WSC) region (Arkansas, Louisiana, Oklahoma, Texas) was receiving 90% of its gas requirements as firm gas supplies, at a 30% lower unit price than paid in the Pacific region. During that period the WSC region consumed 2000 million million Btu of gas to 421 million million Btu of gas by the Pacific region. If this favored supply priority for the WSC Region persists beyond 1974 as the electric utilities in the Pacific region (particularly in Southern California) are curtailed down to the projected 2-8% of their gas needs, an interesting alternative suggest itself. It is suggested that in principal Southern California could trade 535 million million Btu's worth of oil (costing about $1.07 billion) for 535 million million Btu's worth of WSC natural gas (about 25% of its use, costing about $0.2 billion) and come out even financially and way ahead environmentally. In the process Southern California would make it possible for electric utilities to burn natural gas exclusively, reducing the Basin emissions by about 100 tons/day or 25% of the Basin stationary source emissions. Why would the WSC Region agree to such an exchange? Because paradoxically WSC could also reduce its emissions by the exchange. This is because WSC utility boilers for the most part are not regulated with regard to NOx emissions. It has been often found that large unregulated gas fired boilers emit more NOx than large unregulated oil fired boilers, even though by combustion modifications the gas fired boilers can be reduced to lower levels of emissions than can the oil fired boilers. Thus by properly selecting the 25% of WSC boiler capacity to be converted, the exchange of gas for oil could reduce WSC emissions. Obviously certain additional costs would accrue from the exchange, the transportation of the oil to WSC and the cost of converting WSC boilers from gas to oil. Relative to the fuel costs involved these costs might be absorbed as a cost of emissions reductions and still result in a very attractive cost effectiveness ratio.

Obviously such a voluntary exchange as suggested is improbable but it was used to illustrate the point that in principal the FPC gas allocation priorities could be modified to achieve the same result, a major environmental gain. From a national air quality standpoint it would still be sensible to shift gas presently being used in WSC power plants to Southern California even if the possibility of reducing WSC emissions by burning oil was not realized. This is due to the fact that no air quality problem related to NOx emissions exists in the WSC region as it does in Southern California.

Still another alternative that must be considered is a substantial increase in the well head price of natural gas by modifying or deregulating those prices. Presumably there is some price at which the economics are sufficiently attractive that new sources will be produced with sufficient capacity to supply all of our Southern California gas needs. These potential new sources could include new oil-gas fields, coal gasification plants, and shipments of liquified natural gas from overseas. It is interesting to note that if \$1.21 per million Btu was high enough to stimulate development of a sufficient supply, it would cost the consumer absolutely no more than he is paying today when natural gas is supplied to large utility customers at about \$.50 per million Btu and oil fuel costs about \$2 per million Btu. Energy consumption in Southern California is distributed roughly 40% to retail, 20% to industry and 40% to electric utilities. At 30% industrial gas curtailment, and approaching 100% electric utility gas curtailment beyond 1975 the real end cost to the consumer of a million Btu's distributed 40% retail, 20% industrial and 40% utility is (0.4 MMB x \$.50 + .14 MMB x \$.50 + .07 MMB x \$2.00 + .40 MMB x \$2.00 = \$1.21/MMB). Interestingly enough this is approximately the cost range of new coal gasification sources of substitute natural gas being requested for approval by Southern California Gas Company. At \$1.21 per million Btu there would thus be a "no cost" reduction of 100 tons of NOx per day. If a 1 lb NOx reduction per dollar cost effectiveness were acceptable then the gas cost could be raised another 15 cents per million Btu to \$1.36.

## 12.0 SUMMARY - CONCLUSIONS

A comprehensive inventory has been taken of nitric oxides emissions from point and area distributed stationary sources in the South Coast Air Basin for the period from July 1972 through June 1973. The inventory is based on detailed device design and fuel use information on over 1500 sources provided by over 500 companies, institutions and government agencies. The emissions were determined from the combined use of established fuel use related emissions factors, of specific test data available from the operators or APCD, and of the results of 155 device emissions tests conducted during this program.

Although no previous Basin-wide inventory for the same period based on uniform methodology is available for direct comparison, the total inventoried annual average emissions are believed to be about 15-20% higher than previously estimated by the several APCD's in the Basin. The most significant differences were concentrated in the refinery and cement production source categories.

It is clearly evident from the inventory that the electric utility power plants are still the dominant emission source category in the Basin (40%), followed by the petroleum industry (25%), area distributed sources (13%), the mineral processing industry (11%), and the metallurgical industry (5%). Following at some distance are the chemical industry, large commercial buildings and institutions, and agriculture and food processing.

It was found that maximum daily emissions, which typically occur in December and January during most severe curtailment of natural gas, are about 30% higher than annual average emissions rates.

The emissions, distributed on a 10 km (6.2 mi) grid square system, were found to be highly concentrated in the south-west corner of the Basin where 47% of the total was found to be emanating from just 5 grid squares in which a high concentration of refineries and power plants are located. Unfortunately from an air pollution standpoint these grid squares are strategically located upwind of a substantial portion of the Basin.

The localized stationary source emissions in December-January in several of these grid squares were found to be sufficient to generate first stage alert $NO_2$ concentrations, under completely stagnant conditions and typical inversion heights, in less than one day even if all mobile source emissions in these grids were eliminated. With low ventilating velocities and typical inversion heights, it was estimated that stationary source emissions alone could generate $NO_2$ concentration buildups in the wind direction along certain high emissions corridors which were a high percentage of first stage alert concentrations.

A forecast made of the total stationary source emissions in the Basin predicts a 4% growth between the inventory period July 1972-June 1973 and 1975, and a 16% increase from 1975 to 1980. A major changing component of the emissions is that of the electric utility power plants which are increasing even as more stringent regulations are implemented due to the combined effect of modestly increasing load and sharply decreasing natural gas availability. This is due to the fact that boiler emissions from oil combustion are nearly twice those of combustion controlled boiler emissions from natural gas combustion.

Combining the inventoried and forecast stationary source emissions with those of mobile sources in the Basin (as estimated by the California Air Resources Board), the stationary source component was found to be 28% of the Basin total emissions in the 1972-73 inventory period. By 1979 it was forecast that stationary source emissions would reach 50% of the total as mobile sources declined due to an increasing population of controlled vehicles. Relating the total emissions to the Basin air quality model estimated by the EPA, it was found that reductions in total emissions of between 80 and 200 tons/day average must be effected in order to meet Federal Air Quality Standards beyond 1977. The reduction required varies with year and is critically dependent on how stringent are the mobile source controls to be implemented.

An examination of each of the emission source categories in the inventory as to the potential reductions that could be effected more cost effectively than present automotive controls showed that reductions of approximately 70-100 tons/day were potentially attainable using known combustion modification techniques. However before that potential can be assured it will be necessary to successfully demonstrate some of the techniques on some of the devices to which they have not previously been applied. As either an alternative or a supplementary means of reducing Basin emissions, it was shown that resubstitution of natural gas for oil fuel in the utility power plants and in industry would be especially effective, yielding up to about a 100 ton/day reduction in NOx. Thus a strenuous effort to influence a change in Federal Power Commission allocation of natural gas on Basin environmental grounds would be justified.

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# APPENDIX A

## TEST DATA SUMMARY

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Wall Heater | .033* | 31.4 scfh | 0 | -- | | 20 | 5 | 17.0 | 23 | | 90 | 1.15 | 0.0042 | 0.126 | |
| 2 | Wall Heater | .030* | 28.2 " | 0 | -- | | 23 | 5 | 15.5 | 26 | | 75 | 1.13 | 0.0031 | 0.103 | |
| 3 | Wall Heater | .028* | 26.8 " | 0 | -- | | 20 | 5 | 16.0 | 24 | | 72 | 1.20 | 0.0029 | 0.104 | |
| 4 | Water Heater | .039* | 37.0 " | 0 | -- | | 30 | 5 | 15.0 | 34 | | 90 | 1.13 | 0.0048 | 0.124 | |
| 5 | Water Heater | .042* | 40.4 " | 0 | -- | | 26 | 5 | 16.0 | 30 | | 94 | 1.15 | 0.0056 | 0.131 | |
| 6 | Forced Air Heater | .071* | 67.3 " | 0 | -- | | 24 | 1 | 13.0 | 26 | | 54 | 1.08 | 0.0052 | 0.072 | |
| 7 | Water Heater | .049* | 46.1 " | 0 | -- | | 41 | 0 | 12.5 | 43 | | 87 | 1.05 | 0.0053 | 0.110 | |
| 8 | Forced Air Heater | .110* | 104.3 " | 0 | -- | | 24 | 5 | 14.5 | 27 | | 66 | 1.13 | 0.0098 | 0.090 | |
| 9 | Water Heater | .038* | 36.0 " | 0 | -- | | 20 | 1 | 15.5 | 22 | | 65 | 1.10 | 0.0033 | 0.087 | |
| 10 | Forced Air Heater | .125* | 120.0 " | 0 | -- | | 25 | 5 | 14.5 | 28 | | 69 | 1.12 | 0.0118 | 0.093 | |
| 11 | Water Heater | .056* | 52.9 " | 0 | -- | | 22 | 0 | 15.5 | 24 | | 72 | 1.09 | 0.0053 | 0.096 | |
| 12A | Refinery Boiler | 397* | 43 eq. Bbl/h | 20 Bbl/h | 305,000 lb/h | | 280 | 7 | 4.5 | -- | | 305 | -- | 152.5 | 0.384 | [Babcock & Wilcox PF1 6 burners, forced draft with preheat. Steam atomization. None combusted oil droplets impinging on far wall.] |
| 12B | " | " | 43 " | 20 " | " | | 260 | 5 | 4.7 | -- | | 287 | -- | 143.4 | 0.361 | |
| 12C | " | " | 43 " | 20 " | " | | 250 | 5 | 4.7 | -- | | 276 | -- | 137.9 | 0.347 | |
| 12D | " | " | 53 " | 10 " | " | | 280 | 5 | 4.8 | -- | | 311 | -- | 154.6 | 0.389 | |
| 12E | " | " | 33 " | 30 " | " | | 250 | 5 | 4.6 | -- | | 274 | -- | 137.5 | 0.346 | |
| 12F | " | " | 23 " | 40 " | " | | 260 | 5 | 4.4 | -- | | 282 | -- | 142.1 | 0.358 | |
| 12G | " | " | 18 " | 45 " | " | | 270 | 5 | 4.4 | -- | | 293 | -- | -- | -- | |
| 13A | CO Waste Heat Boiler | 506+ | 133,500 scfh + CO fuel | 0 | 320,000 lb/h | | 168 | 0 | 1.4 | 173 | | 154 | 1.03 | 241.6 | 0.646 | [Babcock and Wilcox H-330. FCCU Regenerator Exhaust. 9 CO burners, 15 fuel gas. Forced draft with economizer.] |
| 13B | " | " | " | " | " | | 151 | 0 | 1.4 | 156 | | 138 | 1.03 | 216.5 | 0.579 | |
| 13C | " | " | " | " | " | | 155 | 0 | 1.4 | 160 | | 142 | 1.03 | 222.8 | 0.596 | |
| 13D | " | " | " | " | " | | 155 | 0 | 1.3 | 160 | | 142 | 1.03 | 222.8 | 0.596 | |
| 13E | " | " | " | " | " | | 160 | 0 | 1.4 | 165 | | 147 | 1.03 | 230.6 | 0.617 | |
| 13F | " | " | " | " | " | | 140 | 0 | 1.2 | 145 | | 127 | 1.04 | 199.2 | 0.533 | |
| 13G | " | " | " | " | " | | 140 | 0 | 1.3 | 145 | | 128 | 1.04 | 200.8 | 0.537 | |
| 13H | " | " | " | " | " | | 155 | 0 | 1.3 | 160 | | 142 | 1.03 | 222.8 | 0.596 | |
| 13I | " | " | " | " | " | | 135 | 0 | 1.3 | 140 | | 123 | 1.04 | 193.0 | 0.516 | |
| 14 | " | 521+ | " | " | 330,000 lb/h | | 140 | 0 | 1.0 | 145 | | 126 | 1.04 | 196.7 | 0.528 | |
| 15 | Process Boiler | 342+ | 0 | 54.2 Bbl/h | 225,000 lb/h | | 260 | 3 | 4.4 | 270 | | 282 | 1.04 | 123.8 | 0.362 | [Combustion Engineering, 2 Drum Water Tube, 6 Burners. Balanced draft with preheater. Unburned oil droplets impinging on far wall.] |
| 16 | " | 320+ | 103,000 scfh | 23.6 Bbl/h | 210,000 lb/h | | 260 | 3 | 5.4 | 270 | | 300 | 1.04 | -- | -- | |

*from fuel flow    +from process heat balance

(1) Many test measurements were made to characterize the complete cycle on these devices. Emission factor and other information are summarized in the test of the report.

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 16A | Process Boiler | 320+ | 103,000 scfh | 23.6 Bbl/h | 210,000 lb/h | | 260 | 3 | 5.4 | 270 | | 300 | 1.04 | 120.1 | 0.383 | |
| 16B | " | " | " | " | " | | 260 | 4 | 5.5 | 270 | | 302 | 1.04 | 120.9 | 0.385 | |
| 16C | " | " | " | " | " | | 255 | 4 | 5.4 | 265 | | 294 | 1.04 | 117.7 | 0.375 | |
| 16D | " | " | " | " | " | | 250 | 4 | 5.5 | 260 | | 290 | 1.04 | 116.1 | 0.370 | |
| 17A | " | 369+ | 140,000 scfh | 21.6 Bbl/h | 242,000 lb/h | | 280 | 5 | 5.2 | 290 | | 319 | 1.04 | 146.7 | 0.407 | |
| 17B | " | " | " | " | " | | 275 | 5 | 4.0 | 285 | | 291 | 1.04 | 134.2 | 0.372 | |
| 17C | " | " | " | " | " | | 260 | 5 | 4.6 | 270 | | 285 | 1.04 | 131.2 | 0.364 | |
| 17D | " | " | " | " | " | | 250 | 5 | 4.8 | 260 | | 278 | 1.05 | 128.0 | 0.355 | |
| 17E | " | " | " | " | " | | 240 | 5 | 5.2 | 250 | | 273 | 1.04 | 125.6 | 0.348 | |
| 17F | " | " | " | " | " | | 240 | 5 | 6.2 | 250 | | 292 | 1.04 | 134.0 | 0.372 | |
| 17G | " | " | " | " | " | | 340 | 5 | 3.6 | 250 | | 281 | 1.04 | 129.1 | 0.353 | |
| 18 | " | 301+ | 140,000 scfh | 10.8 Bbl/h | 197,000 lb/h | | 250 | 32 | 2.6 | 260 | | 245 | 1.05 | 72.4 | 0.313 | |
| 19 | 600 HP I.C.E. 250 RPM | -- | -- | -- | -- | | 270 | >2000 | 0.2 | 290 | | 234 | 1.07 | -- | 0.285 | [Ingersoll Rand KVG 6DL253] |
| 20 | Process Heater | 105* | 100,000 scfh | 0 | -- | | 78 | 30 | 6.8 | 81 | | 99 | 1.04 | 8.3 | 0.111 | [Benzene-Toluene-Xylene, Catalytic Reactor Heater.] |
| 20A | " | " | " | " | -- | | 50 | 310 | 3.4 | -- | | 51 | -- | 4.3 | 0.057 | [Born, 50 burners, horizontal. Natural draft, no preheater.] |
| 20B | " | " | " | " | -- | | 70 | 5 | 5.0 | 71 | | 79 | 1.01 | 6.7 | 0.089 | |
| 20C | " | " | " | " | -- | | 82 | 5 | 3.6 | -- | | 85 | -- | 7.2 | 0.095 | |
| 20D | " | " | " | " | -- | | 73 | 5 | 3.5 | -- | | 75 | -- | 6.3 | 0.084 | |
| 20E | " | " | " | " | -- | | 80 | 5 | 3.9 | -- | | 84 | -- | 7.1 | 0.094 | |
| 20F | " | " | " | " | -- | | 82 | 5 | 3.8 | -- | | 86 | -- | 7.3 | 0.096 | |
| 20G | " | " | " | " | -- | | 84 | 4 | 3.9 | -- | | 88 | -- | 7.4 | 0.099 | |
| 20H | " | " | " | " | -- | | 52 | 4 | 3.3 | -- | | 53 | -- | 4.5 | 0.059 | |
| 21A | " | 102* | 96,960 scfh | 0 | -- | | 77 | 0 | 4.6 | -- | | 85 | -- | 6.9 | 0.095 | |
| 21B | " | " | " | " | -- | | 79 | " | 4.1 | -- | | 84 | -- | 6.9 | 0.094 | |
| 21C | " | " | " | " | -- | | 77 | " | 4.0 | -- | | 82 | -- | 6.7 | 0.092 | |
| 21D | " | " | " | " | -- | | 86 | " | 4.4 | -- | | 93 | -- | 7.6 | 0.104 | |
| 21E | " | " | " | " | -- | | 84 | " | 4.3 | -- | | 91 | -- | 7.4 | 0.102 | |
| 22A | " | 103* | 98,100 scfh | " | -- | | 90 | " | 3.4 | -- | | 92 | -- | 7.6 | 0.103 | |
| 22B | " | " | " | " | -- | | 94 | " | 3.8 | -- | | 98 | -- | 8.1 | 0.110 | |
| 22C | " | " | " | " | -- | | 95 | " | 4.1 | -- | | 101 | -- | 8.4 | 0.113 | |
| 22D | " | " | " | " | -- | | 94 | " | 4.4 | -- | | 102 | -- | 8.4 | 0.114 | |
| 22E | " | " | " | " | -- | | 88 | " | 4.8 | -- | | 98 | -- | 8.1 | 0.110 | |
| 22F | " | " | " | " | -- | | 73 | " | 5.6 | 76 | | 85 | 1.04 | 7.0 | 0.095 | [Born 7068. 12 burners vertically upward. Natural draft, no preheater.] |
| 23A | Crude Heater | 60+ | 0 | 9.5 Bbl/h | 696 Bbl/h | | 135 | 4 | 5.0 | -- | | 152 | -- | 11.7 | 0.195 | |
| 23B | " | " | " | " | " | | 135 | 4 | 5.0 | -- | | 152 | -- | 11.7 | 0.195 | |
| 23C | " | " | " | " | " | | 125 | 5 | 4.4 | -- | | 136 | -- | 10.5 | 0.175 | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 23D | Crude Heater | 60+ | 0 | 9.5 Bbl/h | 696 Bbl/h | | 117 | 4 | 4.7 | -- | | 129 | -- | 9.9 | 0.165 | |
| 23E | " | " | " | " | " | | 125 | 5 | 4.1 | -- | | 133 | -- | 10.3 | 0.171 | |
| 23F | " | " | " | " | " | | 118 | 5 | 3.9 | -- | | 124 | -- | 9.6 | 0.159 | |
| 24 | Process Heater | 62.4* | 36,500 scfh | 0 | 918 Bbl/h | | 270 | 5 | 7.5 | 290 | | 360 | 1.07 | 27.0 | 0.432 | [Braun Sinclair type 810, 12 burners |
| 24A | " | " | " | " | " | | 250 | 4 | 7.4 | -- | | 331 | -- | -- | -- | firing vertically downward. Induced |
| 24B | " | " | " | " | " | | 300 | 4 | 7.4 | -- | | 400 | -- | 30.0 | 0.480 | draft, preheater.] |
| 24C | " | " | " | " | " | | 260 | 4 | 6.2 | -- | | 316 | -- | 23.7 | 0.380 | [Very hot refractory crown. Air |
| 24D | " | " | " | " | " | | 230 | 5 | 5.8 | 240 | | 272 | 1.04 | 20.5 | 0.328 | leak around crown.] |
| 24E | " | " | " | " | " | | 245 | 5 | 6.2 | -- | | 298 | -- | 22.4 | 0.359 | |
| 24F | " | " | " | " | " | | 280 | 5 | 7.1 | 285 | | 363 | 1.02 | 27.2 | 0.436 | |
| 24G | " | " | " | " | " | | (240) | 4 | (11.0) | -- | | (432) | -- | -- | -- | |
| 24H | " | " | " | " | " | | 270 | 4 | 7.0 | -- | | 347 | -- | 26.0 | 0.417 | |
| 25 | " | " | " | " | " | | 250 | 20 | 6.4 | -- | | 308 | -- | 23.1 | 0.371 | |
| 26 | Process Heater | 39.4* | 35,700 | 0 | 1017 Bbl/h | | 795 | 0 | 5.4 | -- | | 917 | -- | 45.9 | 1.160 | [Braun Sinclair "De Florey". |
| 26A | " | " | " | " | " | | 910 | 0 | 4.8 | 980 | | 1011 | 1.08 | 50.6 | 1.280 | heater. 12 burners |
| 26B | " | " | " | " | " | | 550 | 0 | 5.9 | -- | | 656 | -- | 32.8 | 0.831 | firing vertically |
| 26C | " | " | " | " | " | | 490 | 0 | 6.2 | -- | | 596 | -- | 29.8 | 0.755 | downward with |
| 27A | " | " | " | " | " | | 615 | 0 | 5.4 | -- | | 710 | -- | 35.5 | 0.899 | preheater.] |
| 27B | " | " | " | " | " | | 750 | 0 | 4.8 | -- | | 833 | -- | 41.7 | 1.055 | |
| 27C | " | " | " | " | " | | 820 | 0 | 5.0 | -- | | 923 | -- | 46.2 | 1.169 | |
| 27D | " | " | " | " | " | | 695 | 0 | 5.5 | -- | | 807 | -- | 40.4 | 1.022 | |
| 27E | " | " | " | " | " | | 730 | 0 | 5.2 | -- | | 832 | -- | 41.6 | 1.053 | |
| 27F | " | " | " | " | " | | 690 | 0 | 5.6 | -- | | 800 | -- | 40.3 | 1.020 | |
| 27G | " | " | " | " | " | | 680 | 0 | 5.4 | 690 | | 785 | 1.01 | 39.3 | 0.994 | |
| 27 | " | " | " | " | " | | 610 | 0 | 5.0 | -- | | 686 | -- | 34.3 | 0.869 | |
| 28 | 550 HP I.C.E. | -- | 2600 scfh | 0 | -- | | 3000 | 350 | 1.1 | -- | | 2710 | -- | 8.90 | 3.29 | [Ingersoll Rand, Ser. No. |
| 28A | " | -- | " | " | -- | | 1000 | >2000 | .05 | -- | | 859 | -- | 2.84 | 1.04 | 8AJ 334, 8 cyl.] |
| 29 | " | -- | " | " | -- | | 2600 | 2600 | 1.6 | -- | | 2412 | -- | 8.0 | 2.93 | |
| 29A | " | -- | " | " | -- | | 900 | >2000 | .05 | -- | | 773 | -- | 2.56 | 0.939 | |
| 29B | " | -- | " | " | -- | | 2400 | 350 | .09 | -- | | 2066 | -- | 6.85 | 2.51 | |
| 29C | " | -- | " | " | -- | | 1000 | >2000 | .05 | -- | | 859 | -- | 2.85 | 1.043 | |
| 30 | Forced Air Heater | .146+ | 120 | 0 | -- | | 46 | 5 | 10.8 | 51 | | 81 | [illegible] | 0.0138 | 0.109 | [Commercial Bldg.] |
| 30A | " | .063+ | 60 | " | -- | | 58 | 0 | 1.0 | -- | | 52 | -- | 0.0040 | 0.063 | [Commercial Bldg.] |
| 30B | " | .146+ | 120 | " | -- | | 42 | 15 | 10.8 | 48 | | 74 | 1.14 | 0.0130 | 0.103 | [Commercial Bldg.] |

A-3

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates | | | NO (ppm) | | CO (ppm) | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) | | NOx/ NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Fuel Gas | Fuel Oil | Process | Dry | Wet | Dry | | | Dry | Wet | | | | |
| 30C | Forced Air Heater | .146$^{+}$ | 120 | 0 | -- | | 37 | 15 | 11.5 | 42 | | 70 | 1.14 | 0.0121 | 0.096 | [Commercial Bldg.] |
| 30D | " | .101$^{+}$ | 96 | " | -- | | 60 | 5 | 8.7 | 65 | | 88 | 1.08 | 0.0116 | 0.115 | [Commercial Bldg.] |
| 30E | " | -- | -- | " | -- | | 42 | 30 | 12.5 | -- | | 89 | -- | -- | 0.108 | [Commercial Bldg.] |
| 30F | " | .101$^{+}$ | 96 | " | -- | | 49 | 5 | 9.5 | 52 | | 77 | 1.06 | 0.0117 | 0.117 | [Commercial Bldg.] |
| 30G | " | .113$^{+}$ | 108 | " | -- | | 28 | 5 | 14.0 | 34 | | 72 | 1.21 | 0.0120 | 0.106 | [Commercial Bldg.] |
| 31 | Process Heater | 53.5* | 37,500 | 0 | 950 Bbl/h | | 480 | 4 | 5.8 | -- | | 568 | -- | 41.0 | 0.806 | [Same unit as test 24 with air leak repaired.] |
| 31A | " | " | " | " | " | | 280 | 5 | 5.6 | -- | | 327 | -- | 23.6 | 0.464 | |
| 31B | " | " | " | " | " | | 280 | 4 | 5.5 | 340 | | 327 | 1.21 | 23.6 | 0.464 | |
| 32 | " | " | " | " | " | | 270 | 4 | 5.6 | -- | | 316 | -- | 22.8 | 0.449 | |
| 32A | " | " | " | " | " | | 260 | 3 | 5.5 | -- | | 302 | -- | 21.8 | 0.429 | |
| 32B | " | " | " | " | " | | 240 | 999 | 4.2 | -- | | 257 | -- | 18.6 | 0.366 | |
| 32C | " | " | " | " | " | | 320 | 2 | 5.6 | -- | | 374 | -- | 27.0 | 0.531 | |
| 32D | " | " | " | " | " | | 290 | 4 | 5.2 | -- | | 330 | -- | 23.8 | 0.469 | |
| 32E | " | " | " | " | " | | 290 | 3 | 5.2 | -- | | 330 | -- | 23.8 | 0.469 | |
| 33 | " | 55.9* | 38,500 scfh | -- | " | | 270 | 3 | 5.7 | -- | | 318 | -- | 23.6 | 0.451 | |
| 33A | " | " | " | -- | " | | 250 | 10 | 5.1 | -- | | 283 | -- | 21.0 | 0.402 | |
| 33B | " | " | " | -- | " | | 220 | >2000 | 3.8 | -- | | 230 | -- | 17.1 | 0.328 | |
| 33C | " | " | " | -- | " | | 260 | 15 | 4.7 | -- | | 287 | -- | 21.3 | 0.408 | |
| 34 | " | " | " | -- | " | | 300 | 1475 | 4.1 | -- | | 320 | -- | 23.8 | 0.456 | |
| 34A | " | " | " | -- | " | | 300 | 1500 | 4.1 | -- | | 320 | -- | 23.8 | 0.456 | |
| 35 | Process Boiler | 52.9$^{+}$ | 26,000 scfh | (2.5 Bbl/h) | 45,000 lb/h | | 72 | 15 | 7.8 | -- | | 98 | -- | 6.3 | 0.121 | |
| 35A | " | " | " | " | " | | 79 | 10 | 7.2 | 82 | | 103 | 1.04 | 6.6 | 0.127 | |
| 35B | " | " | " | " | " | | 80 | 10 | 7.0 | 83 | | 103 | 1.04 | 6.6 | 0.127 | [Riley Stoker, 3 drum water tube, 1 oil and 1 gas burner, forced draft, no preheater.] |
| 35C | " | " | " | " | " | | 80 | 10 | 7.4 | 83 | | 106 | 1.04 | 6.8 | 0.130 | |
| 35D | " | " | " | " | " | | 82 | 6 | 7.2 | 82 | | 107 | 1.00 | 6.9 | 0.132 | |
| 35E | " | " | " | " | " | | 80 | 5 | 7.2 | 83 | | 104 | 1.04 | 6.7 | 0.128 | |
| 36 | Process Boiler | 64.1$^{+}$ | 33,000 scfh | (2.7 Bbl/h) | 54,500 lb/h | | 97 | 5 | 3.9 | 99 | | 102 | 1.02 | 8.0 | 0.126 | |
| 36A | " | " | " | " | " | | 97 | 4 | 3.8 | 99 | | 102 | 1.02 | 8.0 | 0.126 | |
| 36B | " | " | " | " | " | | 98 | 4 | 4.2 | -- | | 105 | -- | 8.2 | 0.130 | |
| 36C | " | " | " | " | " | | 98 | 3 | 4.1 | -- | | 104 | -- | 8.1 | 0.128 | |
| 36D | " | " | " | " | " | | 97 | 3 | 4.2 | -- | | 104 | -- | 8.1 | 0.128 | [Union Iron Works, 1 oil, 1 gas burner, forced draft, no preheater] |
| 36E | " | " | " | " | " | | 97 | 3 | 3.9 | 98 | | 102 | 1.01 | 8.0 | 0.126 | |

A-5

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 37 | CO Waste Heat Boiler | 61.2+ | -- | -- | 52,000 lb/h | | 165 | 10 | 4.5 | -- | | 180 | -- | 49.9 | 0.815 | |
| 37A | " | " | -- | -- | " | | 153 | 10 | 3.9 | 157 | | 161 | 1.03 | 43.1 | 0.704 | |
| 37B | " | " | -- | -- | " | | 155 | 10 | 3.6 | 160 | | 160 | 1.03 | 42.2 | 0.690 | |
| 37C | " | " | -- | -- | " | | 158 | 10 | 3.3 | 160 | | 161 | 1.01 | 41.8 | 0.683 | [Alcorn, 817-1236, 4 horizontal burners, forced draft, no preheat.] |
| 37D | " | " | -- | -- | " | | 150 | 10 | 3.5 | 153 | | 154 | 1.02 | 40.4 | 0.660 | |
| 37E | " | " | -- | -- | " | | 140 | 10 | 3.7 | 145 | | 146 | 1.04 | 38.7 | 0.632 | |
| 38 | Crude Heater | 82.0+ | 32,130 scfh | (6.3 Bbl/h) | 45,000 Bbl/d | | 127 | 0 | 5.2 | -- | | 145 | -- | 15.1 | 0.182 | |
| 38A | " | " | " | " | " | | 127 | " | 5.4 | -- | | 147 | -- | 15.3 | 0.185 | [Crude heater, 8 oil and 2 gas burners firing vertically upward, induced draft with preheater.] |
| 38B | " | " | " | " | " | | 123 | " | 5.6 | -- | | 144 | -- | 15.0 | 0.181 | |
| 38C | " | " | " | " | " | | 110 | " | 5.4 | -- | | (127) | -- | 13.2 | 0.160 | |
| 38D | " | " | " | " | " | | 108 | " | 5.4 | -- | | (125) | -- | 13.0 | 0.157 | |
| 38E | " | " | " | " | " | | 100 | " | 5.3 | -- | | (115) | -- | 12.0 | 0.145 | |
| 38F | " | " | " | " | " | | 125 | " | 5.4 | -- | | 144 | -- | 15.0 | 0.181 | |
| 38G | " | " | " | " | " | | 130 | " | 5.4 | -- | | 150 | -- | 15.6 | 0.189 | |
| 39 | Heat Medium Heater | 96.5* | 37,600 scfh | 10.5 Bbl/h | 50,000 Bbl/d | 183 | 163 | 0 | 6.4 | -- | 226 | 201 | -- | 10.1 | 0.275 | [Braun Custom, 24 gas and 24 oil burners, horizontal natural draft] |
| 39A | " | " | " | " | " | 210 | 193 | 0 | 5.8 | -- | 249 | 229 | -- | 11.2 | 0.304 | |
| 39B | " | " | " | " | " | 235 | 198 | 0 | 6.7 | -- | 296 | 249 | -- | 13.2 | 0.360 | |
| 39C | " | " | " | " | " | 228 | 193 | 0 | 5.6 | -- | 266 | 226 | -- | 11.9 | 0.324 | |
| 39D | " | " | " | " | " | 170 | 160 | 0 | 5.1 | -- | 192 | 181 | -- | 8.6 | 0.234 | |
| 39E | " | " | " | " | " | 240 | 207 | 0 | 5.2 | -- | 273 | 236 | -- | 12.2 | 0.333 | |
| 40 | Process Boiler | 98.5* | 0 | 15.6 Bbl/h | 97,500 lb/h | 220 | 205 | 0 | 7.1 | -- | 285 | 265 | -- | 36.5 | 0.380 | [B&W Water Tube 4 gas and 4 oil burners, horizontal forced draft, no preheater.] |
| 40A | " | " | " | " | " | 245 | 230 | 0 | 6.4 | -- | 302 | 284 | -- | 38.7 | 0.400 | |
| 40B | " | " | " | " | " | 248 | 230 | 0 | 6.2 | -- | 302 | 280 | -- | 38.7 | 0.410 | |
| 40C | " | " | " | " | " | 248 | 230 | 0 | 6.6 | -- | 310 | 288 | -- | 39.7 | 0.421 | |
| 40D | " | " | " | " | " | 230 | 220 | 0 | 7.1 | -- | 298 | 285 | -- | 38.1 | 0.404 | |
| 40E | " | " | " | " | " | 228 | 192 | 0 | 6.2 | -- | 277 | 234 | -- | 35.5 | 0.376 | |
| 41 | Process Boiler | * | --- | 0 | 23,500 lb/h | 135 | 115 | 0 | 10.5 | -- | 231 | 197 | -- | 12.5 | 0.273 | [B&W Water Tube, 4 gas and 4 oil burners horizontal forced draft, no preheater, Tests 41, 42, 43 identical units.] |
| 41A | " | | | 0 | " | | 75 | 448 | 8.5 | -- | | 108 | -- | 4.5 | 0.128 | |
| 42 | Process Boiler | * | | 0 | 27,500 lb/h | | 190 | 0 | 8.2 | -- | | 267 | -- | 12.2 | 0.323 | |
| 42A | " | | | 0 | " | 157 | 155 | 0 | 7.6 | -- | 211 | 202 | -- | 9.6 | 0.254 | |
| 43 | Process Boiler | * | | 0 | 25,000 lb/h | 95 | 90 | 0 | 12.0 | -- | 190 | 180 | -- | 7.9 | 0.230 | |
| 43A | " | | | 0 | " | 85 | 85 | 0 | 12.0 | -- | 170 | 170 | -- | 7.1 | 0.206 | |
| 44 | Coker Heater | 57.8* | 55,700 scfh | 0 | 16,900 Bbl/d | 105 | 75 | 0 | 5.0 | -- | 118 | 84 | -- | 9.8 | 0.139 | [Lummus, 32 burners, vertically upward, natural draft.] |
| 44A | " | " | " | " | " | 115 | 100 | 0 | 6.5 | -- | 143 | 124 | -- | 11.9 | 0.168 | |
| 44B | " | " | " | " | " | 100 | 100 | 0 | 5.5 | -- | 116 | 116 | -- | 9.7 | 0.137 | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 45 | Flasher Heater | 109* | 58,500 scfh | 6.3 Bbl/h | 28,500 Bbl/d | 218 | 192 | 0 | 3.2 | -- | 220 | 194 | -- | 29.8 | 0.278 | Lummus, 32 burners, vertically upward, natural draft. |
| 45A | " | " | " | " | " | | 177 | 0 | 2.5 | -- | | 172 | -- | 23.4 | 0.218 | |
| 45B | " | " | " | " | " | 220 | 208 | 0 | 2.8 | -- | 218 | 206 | -- | 29.6 | 0.276 | |
| 45C | " | " | " | " | " | 218 | 190 | 0 | 2.8 | -- | 216 | 188 | -- | 29.3 | 0.273 | |
| 45D | " | " | " | " | " | 222 | 185 | 0 | 2.7 | -- | 218 | 182 | -- | 29.6 | 0.276 | |
| 45E | " | " | " | " | " | 210 | 170 | 0 | 3.4 | -- | 215 | 174 | -- | 29.2 | 0.272 | |
| 45F | " | " | " | " | " | 198 | 154 | 0 | 2.7 | -- | 195 | 151 | -- | 26.5 | 0.247 | |
| 45G | " | " | " | " | " | 176 | 120 | 0 | 2.9 | -- | 175 | 119 | -- | 23.8 | 0.221 | |
| 45H | " | " | " | " | " | 198 | 165 | 0 | 2.8 | -- | 196 | 163 | -- | 26.6 | 0.248 | |
| 46 | Flasher Heater | 109* | 58,500 scfh | 6.3 Bbl/h | 28,500 Bbl/h | 145 | 130 | 800 | 2.9 | -- | 144 | 129 | -- | -- | -- | Identical to unit of Test 45. |
| 46A | " | " | " | " | " | 185 | 155 | 450 | 3.2 | -- | 187 | 157 | -- | 25.4 | 0.237 | |
| 47 | Crude Heater | 236* | 154,600 scfh | 0 | 49,400 Bbl/d | 44 | | 200 — 800 | 6.1 | -- | | 53 | -- | 15.3 | 0.065 | Alcorn 71154-1594, 48 burners, horizontal natural draft, identical units Tests 47 and 48 |
| 47A | " | 228* | 160,400 scfh | 0 | " | 221 | | 820 | 5.7 | -- | | 26 | -- | 7.1 | 0.031 | |
| 48 | Crude Heater | 180* | 131,300 scfh | 0 | 47,800 Bbl/d | 109 | | 0 | 4.6 | -- | | 120 | -- | 26.0 | 0.144 | |
| 49 | Crude Heater | 104.5* | 88,500 scfh | 0 | 54,000 Bbl/d | 48 | | 170 | 2.6 | -- | 47 | | -- | 6.0 | 0.058 | Foster Wheeler atmospheric furnace down draft #0-956, 14 horizontal burners forced draft, with preheat. |
| 49A | " | " | " | " | " | 33 | 30 | 400 | 2.2 | 34 | 32 | 31 | 1.13 | 4.1 | 0.039 | |
| 49B | " | " | " | " | " | 32 | | 280 | 1.5 | -- | 30 | | -- | 3.8 | 0.037 | |
| 49C | " | " | " | " | " | 32 | | 600 | 1.4 | -- | 29 | | -- | 3.7 | 0.036 | |
| 49D | " | " | " | " | " | 28 | | 200 | 2.0 | -- | 27 | | -- | 3.5 | 0.033 | |
| 49E | " | " | " | " | " | 28 | | 340 | 2.2 | -- | 27 | | -- | 3.5 | 0.033 | |
| 49F | " | " | " | " | " | 36 | | 310 | 1.8 | -- | 34 | | -- | 4.4 | 0.042 | |
| 50 | Process Boiler | 191.5* | 111,800 scfh | 0 | 170,000 lb/h | 340 | | 0 | 3.0 | -- | 340 | | -- | 80.0 | 0.418 | B&W 2 Drum Water Tube, 4 gas/oil burners, horizontal, balanced draft with preheater |
| 50A | " | 195.8* | 114,300 scfh | " | 168,000 lb/h | 480 | | 0 | 3.0 | -- | 480 | | -- | 115.5 | 0.590 | |
| 50B | " | 124.9* | 72,900 scfh | " | 115,000 lb/h | 300 | | 0 | 3.3 | -- | 305 | | -- | 46.8 | 0.375 | |
| 50C | " | 149.9* | 87,500 scfh | " | 140,000 lb/h | 405 | 380 | 0 | 2.9 | 405 | 403 | 378 | 1.07 | 74.3 | 0.495 | |
| 50D | " | 158.3* | 92,400 scfh | " | 140,000 lb/h | 420 | | 0 | 3.0 | -- | 420 | | -- | 81.7 | 0.516 | |
| 50E | " | 208.3* | 121,600 scfh | " | 177,000 lb/h | 535 | | 0 | 2.8 | -- | 529 | | -- | 135.5 | 0.651 | |
| 51 | " | 187.0* | 117,700 scfh | " | 180,000 lb/h | 400 | 390 | 0 | 3.0 | 400 | 400 | 390 | 1.03 | 91.4 | 0.489 | |
| 51A | " | 187.0* | 117,700 scfh | " | 175,000 lb/h | 465 | | 0 | 4.0 | -- | 492 | | -- | 112.2 | 0.600 | |
| 51B | " | 173.8* | 100,400 scfh | " | 162,000 lb/h | 390 | | 0 | 5.7 | -- | 459 | | -- | 97.0 | 0.558 | |
| 51C | " | 187.0* | 117,700 scfh | " | 176,000 lb/h | 400 | | 0 | 5.4 | -- | 462 | | -- | 105.1 | 0.562 | |
| 51D | " | 187.0* | 117,700 scfh | " | 176,000 lb/h | 440 | | 0 | 5.4 | -- | 508 | | -- | 115.5 | 0.618 | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 52 | Process Boiler | 198.7* | 112,800 scfh | tr. | 167,000 lb/h | 320 | 300 | 0 | 4.8 | -- | 356 | 333 | -- | 81.8 | 0.449 | [Riley Stoker, 7 gas and 7 oil burners, HOR, FD with preheat.] |
| 53 | Process Boiler | 211.7* | 112,800 scfh | tr. | 168,000 lb/h | 660 | 620 | 0 | 4.6 | 645 | 724 | 680 | 1.04 | 160.9 | 0.899 | |
| 54 | Process Heater | 167.4* | 160,000 scfh | 0 | -- | 50 | 75 | 0 | 2.3 | -- | 48 | 72 | -- | 14.7 | 0.088 | [Topping column, reboiler Htr, Alcorn 1624, 32 horizontal burners, nat. draft, no preheat.] |
| 54A | " | " | " | " | -- | 78 | 80 | 0 | 2.9 | -- | 73 | 80 | -- | 16.3 | 0.097 | |
| 55 | " | " | " | " | -- | 75 | | 0 | 3.0 | -- | 75 | | -- | 15.2 | 0.091 | |
| 55A | " | " | " | " | -- | 72 | | 0 | 2.9 | -- | 72 | | -- | 14.6 | 0.087 | |
| 55B | " | " | " | " | -- | 82 | | 0 | 3.4 | -- | 84 | | -- | 17.1 | 0.102 | |
| 56 | Crude Heater | 65.5* | 53,300 scfh | 0 | -- | 64 | | 0 | 4.2/ 9.0* | -- | 96 | | -- | 7.4 | 0.114 | [4 Hor. fan mix burners, nat. draft, no preheat.] |
| 57 | Reformer Htr. | 256* | 172,700 scfh | " | 27,000 Mcfd | 95 | 83 | 0 | 4.4 | 84 | 103 | 90 | 1.01 | 35.2 | 0.137 | |
| 57A | " | " | " | " | " | 92 | 95 | 0 | 4.4 | 98 | 100 | 103 | 1.03 | 35.2 | 0.137 | [Hydrogen reformer heater, Selas, 608 horizontal burners, nat. draft, no preheater.] |
| 57B | " | " | " | " | " | 101 | 95 | 0 | 3.8 | 98 | 106 | 99 | 1.03 | 36.3 | 0.141 | |
| 57C | " | " | " | " | " | 88 | 84 | 0 | 3.9 | -- | 93 | 88 | -- | 31.8 | 0.124 | |
| 57D | " | " | " | " | " | 95 | 84 | 0 | 4.0 | 85 | 101 | 89 | 1.01 | 34.6 | 0.134 | |
| 57E | " | " | " | " | " | 98 | 78 | 0 | 4.3 | 84 | 106 | 84 | 1.08 | 36.2 | 0.141 | |
| 58 | Process Heater | 113* | 79,600 scfh | 0 | 37,400 Bbl/d | 218 | 210 | 0 | 6.4 | -- | 269 | 259 | -- | 40.3 | 0.354 | [Reboiler Htr., Foster Wheeler, 14 burners vertically up, BD, preheat.] |
| 59 | " | " | " | " | " | 212 | 210 | 0 | 6.2 | -- | 258 | 255 | -- | 38.7 | 0.340 | |
| 60 | Process Boiler | 149.6* | 95,000 scfh | -- | 100,000 lb/h | 320 | 260 | 0 | 1.2 | -- | 291 | 236 | -- | 57.9 | 0.383 | |
| 60A | " | " | " | -- | " | 270 | 310 | 0 | 1.2 | -- | 246 | 282 | -- | 49.0 | 0.324 | [B&W integral furnace boiler, 3 burners, hor. balance draft, preheat.] |
| 60B | " | " | " | -- | " | 320 | 300 | 0 | 1.1 | -- | 289 | 271 | -- | 57.5 | 0.381 | |
| 60C | " | " | " | -- | " | | 290 | 0 | 1.1 | -- | | 262 | -- | 52.1 | 0.345 | |
| 61 | Process Boiler | 119* | 55,000 scfh | 3.6 gpm | 90,000 lb/h | | 105 | 0 | 6.4 | -- | 130 | | -- | 20.2 | 0.170 | [B&W integral furnace boiler, 3 hor. burners, balanced draft with preheater.] |
| 61A | " | " | " | " | " | 152 | 148 | 0 | 6.3 | 153 | 186 | 181 | 1.03 | 20.9 | 0.244 | |
| 61B | " | " | " | " | " | 152 | 148 | 0 | 6.4 | 150 | 187 | 183 | 1.01 | 29.1 | 0.246 | |
| 61C | " | " | " | " | " | 100 | 115 | 0 | 10.5 | 113 | 185 | 197 | -- | 30.4 | 0.256 | |
| 61D | " | " | " | " | " | 135 | 143 | 0 | 6.6 | 149 | 169 | 179 | -- | 27.8 | 0.234 | |
| 61E | " | " | " | " | " | 135 | 140 | 0 | 8.5 | 145 | 194 | 202 | -- | 31.2 | 0.263 | |
| 61F | " | " | " | " | " | 100 | 104 | 0 | 10.5 | 105 | 171 | 178 | 1.01 | 27.5 | 0.232 | |
| 62 | Process Boiler | (250)* | 54,000 scfh | (19 gpm) | 55,000 lb/h | 112 | 105 | 0 | 6.6 | 111 | 140 | 131 | 1.06 | (46.8) | 0.187 | [B&W integral furnace boiler, 3 hor. burners balanced draft with preheater.] |
| 62A | " | " | " | " | " | 112 | 106 | 0 | 6.8 | 109 | 142 | 134 | 1.03 | (47.4) | 0.190 | |
| 62B | " | " | " | " | " | 106 | | 0 | 6.9 | -- | 135 | | -- | (45.2) | 0.181 | |
| 62C | " | " | " | " | " | 100 | | 0 | 7.8 | -- | 136 | | -- | (45.5) | 0.182 | |
| 62D | " | " | " | " | " | 120 | 114 | 0 | 6.8 | -- | 152 | 145 | -- | (50.83) | 0.203 | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 63 | Crude Heater | 62* | 38,900 scfh | 0 | 23,200 Bbl/d | 46 | | 0 | 13.0 | -- | 104 | | -- | 8.2 | 0.133 | Petrochem 304A, 6 burners nat. draft. |
| 64 | Reformer Heater | 312* | 196,000 scfh | " | 16,000 Bbl/d 94,000 Mscfd | 105 | 95 | 0 | 6.2 | 100 | 128 | 116 | 1.05 | 51.9 | 0.166 | C.F. Braun, 98 hor. burners, center refractory wall, nat. draft. |
| 64A | " | " | " | " | " | 107 | 100 | 0 | 5.4 | 103 | 124 | 115 | 1.03 | 50.3 | 0.161 | |
| 64B | " | " | " | " | " | 109 | 96 | 0 | 5.2 | -- | 124 | 109 | -- | 50.6 | 0.162 | |
| 64C | " | " | " | " | " | 101 | 95 | 0 | 5.3 | 100 | 116 | 109 | 1.05 | 47.1 | 0.151 | |
| 64D | " | " | " | " | " | 100 | 93 | 0 | 5.3 | 95 | 115 | 107 | 1.02 | 46.7 | 0.150 | |
| 64E | " | " | " | " | " | 108 | 105 | 0 | 5.6 | -- | 126 | 123 | -- | 51.4 | 0.165 | |
| 65 | **Crude Heater** | 74* | **54,200 scfh** | 0 | 32,500 Bbl/d | 61 | 53 | 0 | 14.0 | -- | 157 | 136 | -- | 13.7 | 0.186 | Kellogg, forced draft, no preheater, recirc. of flue gas, 4 burners horz. |
| 65A | " | " | " | " | " | 63 | 55 | 0 | 14.0 | 61 | 162 | 141 | 1.11 | 14.1 | 0.192 | |
| 65B | " | " | " | " | " | 63 | 58 | 0 | 14.0 | 60 | 162 | 141 | 1.03 | 14.1 | 0.192 | |
| 65C | " | " | " | " | " | 56 | 54 | 0 | 14.0 | 55 | 144 | 139 | 1.02 | 12.6 | 0.171 | |
| 65D | " | " | " | " | " | 56 | 55 | 0 | 14.0 | 56 | 144 | 141 | 1.02 | 12.6 | 0.171 | |
| 66 | Coking Heater | 130* | 273,000 scfh (2 units) | 0 | 40,300 Bbl/d | 195 | 190 | 0 | 5.4 | -- | 225 | 219 | -- | 26.8 | 0.271 | Lummus B134BA, Box type, 80 vertical burners, FD with preheater, 3-4 burners plugged. |
| 66A | " | " | " | " | " | | 190 | 0 | 5.6 | -- | 222 | | -- | 26.4 | 0.267 | |
| 67 | " | " | " | " | " | 240 | 220 | 0 | 5.0 | 235 | 270 | 248 | 1.07 | 48.1 | 0.384 | |
| 67A | " | " | " | " | " | 240 | 220 | 0 | 5.0 | 230 | 270 | 248 | 1.05 | 48.1 | 0.384 | |
| 67B | " | " | " | " | " | 230 | 215 | 0 | 5.2 | 220 | 262 | 245 | 1.02 | 46.7 | 0.373 | |
| 67C | " | " | " | " | " | 215 | 200 | 0 | 5.0 | 205 | 242 | 225 | 1.03 | 43.1 | 0.344 | |
| 67D | " | " | " | " | " | 220 | 200 | 0 | 5.3 | 210 | 252 | 229 | 1.05 | 44.9 | 0.359 | |
| 68 | Charge Heater | 241* | " | 0 | 56,900 Bbl/d | 71 | | 0 | 10.5 | -- | 122 | | -- | 34.4 | 0.145 | Born upflow, ser. 1473, 36 vert. upward burners, nat. draft, no swirl, 'cold' refractory. |
| 68A | " | " | " | " | " | 88 | | 0 | 9.0 | -- | 132 | | -- | 37.4 | 0.157 | |
| 68B | " | " | " | " | " | 66 | | 0 | 10.5 | -- | 113 | | -- | 32.0 | 0.134 | |
| 69 | Reboiler Heater | 16* | 61,000 scfh (3 units) | 380 | 19,800 Bbl/d | 30 | 27 | 0 | 15.5 | 30 | 98 | 88 | 1.11 | 1.9 | 0.118 | |
| 69A | " | " | " | 290 | " | 31 | 29 | 0 | 15.0 | 34 | 93 | 87 | 1.17 | 1.8 | 0.112 | 8 vertically up burners, nat. draft. |
| 69B | " | " | " | 300 | " | 33 | 30 | 0 | 14.5 | 39 | 91 | 83 | 1.30 | 1.8 | 0.110 | |
| 69C | " | " | " | 320 | " | 32 | 28 | 0 | 15.0 | 36 | 96 | 84 | 1.29 | 1.8 | 0.116 | |
| 70 | Reboiler Heater | 24* | 61,000 scfh | 0 | 41,500 Bbl/d | 83 | 76 | 0 | 10.5 | 78 | 142 | 130 | 1.03 | 4.1 | 0.171 | Born, 4 burners vert. upward, N.D. |
| 71 | Debutanizer Heater | 18* | (3 units) | 0 | 41,600 Bbl/d | 109 | 96 | 0 | 5.0 | 100 | 172 | 108 | 1.04 | 2.7 | 0.149 | Born, 5 burners vert. upward N.D. |
| 72 | CO Waste Heat Boiler | 291* | 163,900+CO | 0 | 208,000 lb/h | 137 | | 60 | 3.4 | -- | 140 | | -- | 101.1 | 0.347 | B&W, 2 Drum Wt. FD, No preheat prec. up str. of boiler. |
| 73 | Forced Air Heater | .126* | 120 scfh | 0 | -- | 28 | 26 | 0 | 13.5 | 28 | 67 | 62 | 1.08 | 0.011 | 0.087 | |
| 74 | Water Heater | .042‡ | 40 scfh | 0 | -- | 74 | 73 | 0 | 6.6 | 76 | 93 | 91 | 1.04 | 0.005 | 0.118 | |
| 75 | Gas Dryer | .008* | 7.5 scfh | 0 | -- | 4 | | 0 | 19,0 | -- | | 36 | -- | -- | 0.044 | |
| 76 | Forced Air Heater | .122* | 116 scfh | 0 | -- | 35 | 33 | 0 | 14.5 | 36 | 97 | 91 | 1.09 | 0.0155 | 0.127 | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 77 | Water Heater | .042* | 40 scfh | 0 | -- | 18 | 18 | 0 | 16.5 | -- | 72 | | -- | 0.0037 | 0.087 | |
| 78 | Gas Dryer | .030* | 29 scfh | 0 | -- | 5 | | 0 | 19.5 | -- | 58 | | -- | 0.0021 | 0.070 | |
| 79 | Water Heater | .046* | 44 scfh | 0 | -- | 42 | 39 | 0 | 6.8 | 41 | 53 | 49 | 1.05 | 0.0031 | 0.068 | |
| 80 | Forced Air Heater | .128* | 122 scfh | 0 | -- | 41 | 39 | 0 | 11.8 | 41 | 80 | 76 | 1.05 | 0.0131 | 0.102 | |
| 81 | Forced Air Heater | .108* | 103 scfh | 0 | -- | 31 | 29 | 0 | 13.5 | 32 | 74 | 70 | 1.10 | 0.0106 | 0.098 | |
| 82 | Forced Air Heater | .084* | 80 scfh | 0 | -- | 44 | 40 | 0 | 12.5 | 48 | 93 | 85 | 1.20 | 0.0112 | 0.133 | |
| 83 | Water Heater | .042* | 40 scfh | 0 | -- | 63 | 60 | 0 | 7.6 | 62 | 85 | 81 | 1.03 | 0.0045 | 0.107 | |
| 84 | Package Boiler #3 | 58.8* | 56,000 scfh | | 59,000 lb/h | 185 | 155 | 100 | 2.3 | 163 | 178 | 149 | 1.05 | 13.3 | 0.226 | [Union, 3 Drum, Wt, 4 burners, BD, no preheat.] |
| 84A | " | " | " | | " | 183 | 158 | 60 | 2.5 | 166 | 178 | 154 | 1.05 | 13.3 | 0.226 | |
| 85 | Package Boiler #4 | 57.8* | 55,000 scfh | | 62,500 lb/h | 190 | 160 | 40 | 2.8 | 170 | 188 | 158 | 1.06 | 13.9 | 0.240 | [Union, 3 Drum, Wt, 4 burners, BD, No preheat.] |
| 85A | " | " | " | | " | 185 | 157 | 10 | 3.0 | 162 | 185 | 157 | 1.03 | 13.3 | 0.231 | |
| 85B | " | " | " | | " | 185 | 164 | 10 | 3.0 | 160 | 185 | 164 | .98 | 13.0 | 0.224 | |
| 85C | " | " | " | | " | 177 | 159 | 5 | 3.0 | 160 | 177 | 159 | 1.01 | 12.5 | 0.216 | |
| 85D | " | " | " | | " | 170 | 155 | 30 | 2.8 | 157 | 168 | 153 | 1.01 | 11.9 | 0.206 | |
| 85E | " | " | " | | " | 175 | 152 | 10 | 2.9 | 155 | 174 | 151 | 1.02 | 12.4 | 0.215 | |
| 86 | Package Boiler #1 | 68.3* | 65,000 scfh | | 75,000 lb/h | 195 | 175 | 10 | 2.9 | 182 | 194 | 174 | 1.04 | 16.6 | 0.244 | [Union, Type H, 3 Drum, Wt, 4 burners, BD, no preheat.] |
| 86A | " | " | " | | " | 190 | 170 | 10 | 2.9 | -- | 189 | 169 | -- | 15.7 | 0.229 | |
| 86B | " | " | " | | " | 185 | 168 | 0 | 2.9 | 170 | 184 | 167 | 1.01 | 15.4 | 0.226 | |
| 86C | " | " | " | | " | 178 | 168 | 0 | 3.0 | 173 | 178 | 168 | 1.03 | 15.2 | 0.222 | |
| 86D | " | " | " | | " | 180 | 165 | 0 | 3.2 | 170 | 182 | 167 | 1.03 | 15.5 | 0.227 | |
| 86E | " | " | " | | " | 175 | 168 | 0 | 3.2 | -- | 177 | 170 | -- | 14.7 | 0.215 | |
| 87 | Package Boiler #2 | 65.1* | 62,000 scfh | | 57,000 lb/h | 163 | 145 | 0 | 4.6 | 147 | 179 | 159 | 1.01 | 14.3 | 0.220 | [Union Type H, 3 Drum, Wt, 4 burners BD, no preheat.] |
| 88 | " | 80.9* | 77,000 scfh | | 71,000 lb/h | 185 | 170 | 0 | 3.8 | 175 | 194 | 178 | 1.03 | 19.0 | 0.235 | |
| 89 | " | 57.8* | 55,000 scfh | | 51,000 lb/h | 160 | 145 | 0 | 4.9 | 148 | 179 | 162 | 1.02 | 12.8 | 0.221 | |
| 90 | Forced Air Heater | .151* | 144 scfh | | -- | 34 | 32 | 225 | 10.5 | 35 | 58 | 55 | 1.09 | 0.0116 | 0.076 | |
| 91 | Water Heater | .036* | 34 scfh | | -- | 83 | 81 | 0 | 8.2 | 83 | 117 | 114 | 1.02 | 0.0052 | 0.146 | |
| 92 | Water Heater | .036* | 34 scfh | | -- | 61 | 58 | 0 | 6.4 | 61 | 75 | 72 | 1.05 | 0.0034 | 0.096 | |
| 93 | Forced Air Heater | .138* | 131 scfh | | -- | 22 | 20 | 0 | 14.5 | 22 | 61 | 55 | 1.10 | 0.0112 | 0.081 | |
| 94 | Forced Air Heater | .112* | 107 scfh | | -- | 33 | 32 | 0 | 12.0 | 35 | 66 | 64 | 1.09 | 0.0098 | 0.087 | |
| 95 | Water Heater | .043* | 41 scfh | | -- | 69 | 60 | 0 | 6.4 | 64 | 85 | 74 | 1.07 | 0.0047 | 0.109 | |
| 96 | Atmospheric Crude Heater | 394* | 358,000 scfh (353,000 scfh) | | 121,000 Bbl/d | 128 | 115 | 0 | 3.1 | 120 | 129 | 116 | 1.04 | 62.4 | 0.158 | [Alcorn S/N HC50942 1358 40 vert. burners.] |
| 96A | " | " | | | " | 114 | 103 | 0 | 3.7 | 107 | 119 | 107 | 1.04 | 57.4 | 0.146 | |
| 96B | " | " | " | | " | 120 | 110 | 0 | 4.0 | -- | 127 | 116 | -- | 61.5 | 0.156 | |
| 96C | " | " | " | | " | 133 | 115 | 0 | 3.7 | -- | 138 | 120 | -- | 67.0 | 0.170 | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 97 | Vac. Crude Heater | 141* | 122,900 scfh (95,750 scfh) | | 87,000 Bbl/d | 115 | 110 | 0 | 2.8 | 113 | 114 | 109 | 1.03 | 21.0 | 0.149 | [40 vertical burners, nat. draft] |
| 97A | " | " | " | | " | 130 | 120 | 0 | 2.8 | 123 | 128 | 118 | 1.03 | 23.5 | 0.167 | |
| 97B | " | " | " | | " | 125 | 115 | 0 | 3.0 | 120 | 125 | 115 | 1.04 | 23.0 | 0.163 | |
| 97C | " | " | " | | " | 130 | 125 | 0 | 3.8 | 128 | 136 | 131 | 1.02 | 25.0 | 0.177 | |
| 97D | " | " | " | | " | 135 | 130 | 0 | 3.6 | -- | 140 | 134 | -- | 25.7 | 0.183 | |
| 97E | " | " | " | | " | 130 | | 0 | -- | -- | | | -- | -- | -- | |
| 98 | " | 114* | (8380 scfh) | 434 Bbl/d | 87,000 Bbl/d | 70 | 59 | 20 | 7.8 | 62 | 95 | 80 | 1.05 | 13.2 | 0.127 | [Petrochem, 45 burners, nat. draft, small preheat.] |
| 98A | " | " | " | " | " | 65 | 59 | 10 | 6.2 | 60 | 79 | 72 | 1.02 | 11.0 | 0.105 | |
| 99 | Reformer Heater | 153* | 132,500 scfh | 0 | 17,000 Bbl/d | 66 | 60 | 0 | 3.2 | -- | 67 | 61 | -- | 13.5 | 0.088 | |
| 100 | Reformer Heater | 365* | 217,000 scfh (321,900 scfh) | 0 | 33,400 Mscfd | 115 | 110 | 0 | 5.1 | 112 | 130 | 125 | 1.02 | 62.4 | 0.171 | [Foster-Wheeler, 5016-444, 136 burners, nat. draft, horz.] |
| 100A | " | " | " | " | " | 125 | 114 | 0 | 4.9 | 116 | 140 | 127 | 1.02 | 67.3 | 0.184 | |
| 100B | " | " | " | " | " | 118 | 110 | 0 | 5.2 | 115 | 134 | 125 | 1.05 | 64.3 | 0.176 | |
| 100C | " | " | " | " | " | 110 | 105 | 0 | 5.8 | 110 | 130 | 124 | 1.05 | 62.4 | 0.171 | |
| 100D | " | " | " | " | " | 115 | | 0 | 5.0 | 0 | | 129 | -- | 62.0 | 0.170 | |
| 100E | " | " | " | " | " | 138 | 125 | 0 | 5.0 | 130 | 155 | 141 | 1.04 | 74.4 | 0.204 | |
| 101 | Process Boiler | 293* | 118,500 scfh (131,400 scfh) | 238 Bbl/d (255 Bbl/d) | 153,000 lb/h | 185 | 155 | 0 | 4.4 | 160 | 200 | 168 | 1.03 | 16.4 | 0.268 | [Erie City Iron Works, 4 burners, FD, preheat.] |
| 102 | CO Waste Heat Boiler | 438 * | (321,900 scfh) | 0 | 270,000 lb/h | 163 | 150 | 40 | 3.7 | 155 | 170 | 156 | 1.03 | 240.4 | 0.787 | [Foster Wheeler 36-4211, FD] |
| 102A | " | " | " | " | " | 170 | 165 | 90 | 4.0 | -- | 180 | 175 | -- | 251.4 | 0.823 | |
| 102B | " | " | " | " | " | 172 | 175 | 90 | 3.9 | -- | 181 | 184 | -- | 255.5 | 0.836 | |
| 102C | " | " | " | " | " | 158 | 150 | 90 | 3.8 | -- | 165 | 157 | -- | 227.9 | 0.747 | |
| 102D | " | " | " | " | " | 180 | 162 | 90 | 3.8 | -- | 188 | 170 | -- | 259.5 | 0.850 | |
| 102E | " | " | " | " | " | 170 | | 90 | 3.8 | -- | | 178 | -- | 245.8 | 0.804 | |
| 103 | Coker Heater | * | 53,300 scfh | 0 | 11,250 Bbl/d | 74 | | 0 | 5.2 | -- | 84 | | -- | 7.5 | 0.110 | [Foster-Wheeler 5-16-583, 32 burners, vert. N.D.] |
| 104 | Reheat Furnace 12" | 128 MBtu/hr | -- | 0 | -- | 59 | 59 | 0 | 10.2 | 63 | 98 | 97 | 1.07 | 16.3 | 0.127 | |
| 105 | " | " | -- | 0 | -- | 61 | 58 | 0 | 10.0 | 59 | 100 | 95 | 1.02 | 14.9 | 0.117 | |
| 105A | " | " | -- | 0 | -- | 53 | 60 | 0 | 10.2 | 66 | 88 | 100 | 1.10 | 17.1 | 0.133 | |
| 105B (2) | " | " | -- | 0 | -- | | | | | | | | | | | |
| 106 (2) | Reheat Furnace 10" | 21 MBtu/hr | 20,000 scfh | 0 | 0 | | | | | | | | | | | |
| 106A (2) | " | | | | | | | | | | | | | | | |
| 106B (2) | " | | | | | | | | | | | | | | | |
| 106C (2) | " | | | | | | | | | | | | | | | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 107 | Steel Soak Pit #9 | 18.9 MBtu/hr | 18,000 scfh | -- | -- | 79 | 74 | 10 | 4.6 | 75 | 87 | 79 | 1.01 | 1.89 | 0.099 | |
| 107A | " | " | " | -- | -- | 70 | 66 | 0 | 7.4 | 78 | 86 | 87 | 1.11 | 2.36 | 0.125 | |
| 107B | " | " | " | -- | -- | 58 | 55 | 0 | 11.0 | 58 | 105 | 104 | 1.05 | 2.39 | | |
| 108 | Steel Soak Pit #10 | 6.3* | 6,000 scfh | -- | -- | 46 | 45 | 0 | 8.4 | 45 | 66 | 64 | 1.00 | 0.491 | 0.078 | |
| 108A | " | 5.67* | 5,400 scfh | -- | -- | 54 | 51 | 0 | 7.4 | 52 | 66 | 68 | 1.02 | 0.473 | 0.083 | |
| 108B | " | 6.3* | 6,000 scfh | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | |
| 108C | " | 18.7* | 17,800 scfh | -- | -- | 77 | | 10 | 5.0 | -- | 87 | | -- | 1.96 | 0.105 | |
| 109 | Reheat Furnace 10" | 14.7* | 14,000 scfh | -- | -- | 11.5 | 10.5 | 0 | 17.0 | 12.5 | 50 | 57 | 1.19 | 1.00 | 0.068 | |
| 109A | " | 73.5* | 70,000 scfh | -- | -- | 28 | 30 | 90 | 11.0 | 28 | 50 | 60 | .93 | 4.49 | 0.061 | |
| 109B | " | 8.4* | 8,000 scfh | -- | -- | 14 | 13 | 0 | 19.0 | 9 | 94 | 93 | .69 | 0.824 | 0.098 | |
| 109C | " | 7.35* | 7,000 scfh | -- | -- | 6.5 | 4 | 0 | 18.5 | 5 | 77 | 94 | 1.25 | 0.320 | 0.043 | |
| 110 | Open Hearth Furnace (1) | 50.25 | 35,000 scfh | 1.5 gpm | -- | 820 | | 0 | 3.8 | | | | | | | |
| 110A | " | " | " | " | -- | 800 | | 900 | 3.6 | | | | | | | |
| 110B | " | " | " | " | -- | 1125 | | 560 | 3.8 | | | | | | | |
| 110C | " | " | " | " | -- | 1350 | | 60 | 5.7 | | | | | | | |
| 110D | " | " | " | " | -- | 1300 | | 100 | 4.4 | | | | | | | |
| 110E | " | " | " | " | -- | 1250 | | 200 | 4.0 | | | | | | | |
| 110F | " | " | " | " | -- | 1400 | | 110 | 4.5 | | | | | | | |
| 111 | " | 50.25* | 35,000 scfh | 1.5 sac/ min | -- | 1600 | 2000 | 110 | 4.0 | 2125 | 1690 | 2320 | 1.06 | 124.9 | 2.48 | |
| 112 | " | 50.25* | 35,000 scfh | " | -- | 1475 | | 980 | 3.0 | | 1475 | | | 91.9 | 1.83 | |
| 112A | " | " | " | " | -- | 1200 | | 780 | 3.5 | | 1235 | | | 76.9 | 1.53 | |
| 112B | " | " | " | " | -- | 1050 | | 10 | 3.5 | | 1030 | | | 67.3 | 1.34 | |
| 112C | " | " | " | " | -- | 890 | | 860 | 2.3 | | 870 | | | 54.2 | 1.07 | |
| 112D | " | " | " | " | -- | 975 | | 1040 | 2.5 | | 950 | | | 59.2 | 1.18 | |
| 112E | " | " | " | " | -- | 1200 | | 20 – 1160 | 3.0 | | 1200 | | | 74.7 | 1.49 | |
| 112F | " | 50.25* | 35,000 scfh | 1.5 sac/ min | -- | 1250 | | 10 – 560 | 3.5 | | 1285 | | | 80.0 | 1.59 | |
| 113 | " | " | " | " | -- | 1490 | | 10 – 240 | 4.5 | | 1625 | | | 101.2 | 2.01 | |
| 114 | " | " | " | " | -- | 1475 | 3000 | 10 – 0 | 5.0 | 3000 | 1660 | 3380 | 1.00 | 157.0 | 3.12 | |
| 114A | " | " | " | " | -- | 1700 | 2800 | 10 – 80 | 4.5 | 3000 | | | 1.07 | | | |
| 114B | " | " | " | " | -- | | 3100 | 10 | 5.0 | 3200 | | | 1.03 | | | |
| 114C | " | " | " | " | -- | | 3200 | 5 – 20 | 5.0 | | | 3600 | | 224.2 | 4.46 | |
| 114D | " | " | " | " | -- | | 3250 | 10 – 100 | 4.5 | | | 3640 | | 226.7 | 4.51 | |
| 114E | " | " | " | " | -- | | 3800 | 5 – 28 | 5.0 | | | 4275 | | 266.3 | 5.30 | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 115 | Open Hearth Furnace(1) | 53.4* | 38,000 scfh | 1.5 sac/min | -- | | 2900 | 220 | 4.0 | -- | | 3075 | -- | 203.5 | 3.81 | |
| 116 | " | " | " | " | -- | | 190 | >2000 | 1.5 | | | 175 | | 11.6 | 0.22 | |
| 116A | " | " | " | " | -- | | 80-2225 | >2000 | 1.0 | | | 72-2010 | | 66.2 | 1.24 | |
| 116B | " | " | " | " | -- | | 3600 | 10 - 840 | | | | 3640 | | 240.9 | 4.51 | |
| 117 | " | 58.1* | 42,500 scfh | " | -- | | 2125 | 0 | 4.5 | | | 2320 | | 167.1 | 2.88 | ⌈Post Cycle⌋ |
| 118 | " | 56.6* | 41,000 scfh | " | -- | | 1425 | 0 | 10.5 | | | 2330 | | 163.5 | 2.89 | ⌈First fire on cycle⌋ |
| 118A | " | " | " | " | -- | | 1450 | 0 | 10.6 | 1450 | | 2510 | 1.00 | 176.1 | 3.11 | |
| 118B | " | " | " | " | -- | | 1750 | 0 | 13.0 | | | 3940 | | 276.4 | 4.88 | |
| 118C | " | " | " | " | -- | | 1325 | 0 | 11.7 | | | 2560 | | 179.6 | 3.17 | |
| 118D | " | 43.6* | 41,500 scfh | 0 | -- | | 1350 | 0 | 12.0 | | | 2700 | | 145.7 | 3.35 | |
| 119 | " | 52.1* | 41,000 scfh | 1.0 gpm | -- | | 600 | 10 – 60 | 10.0 | | | 1080 | | 69.7 | 1.34 | |
| 119A | " | " | " | " | -- | | 800 | 10 – 90 | 10.0 | | | 1320 | | 85.2 | 1.64 | |
| 119B | " | " | " | " | -- | | 950 | 10 – 20 | 10.5 | | | 1630 | | 105.3 | 2.02 | |
| 119C | " | " | " | " | -- | | 800 | 10 – 90 | 10.0 | | | 1320 | | 85.2 | 1.64 | |
| 119D | " | " | " | " | -- | | 825 | 10 – 45 | 10.5 | | | 1405 | | 91.4 | 1.75 | |
| 119E | " | " | " | " | -- | | 900 | 10 – 60 | 10.0 | | | 1470 | | 94.9 | 1.82 | |
| 119F | " | " | " | " | -- | | 1600 | 10 – 20 | 10.5 | | | 2720 | | 175.7 | 3.37 | |
| 119G | " | " | " | " | -- | | 900 | 10 – 15 | 10.5 | | | 1540 | | 99.5 | 1.91 | |
| 119H | " | " | " | " | -- | | 1500 | 10 – 20 | 10.0 | | | 2460 | | 158.9 | 3.85 | |
| 119I | " | " | " | " | -- | | 825 | 10 – 40 | 10.0 | | | 1350 | | 87.2 | 1.67 | |
| 119J | " | " | " | " | -- | | 700 | 10 – 15 | 9.7 | | | 1115 | | 72.0 | 1.38 | |
| 119K | " | " | " | " | -- | | 700 | 10 – 25 | 9.5 | | | 1095 | | 70.7 | 1.36 | |
| 120 | " | 52.2* | 41,000 scfh | 1.02 | -- | | 710 | 10 – 15 | 9.7 | | | 1130 | | 73.1 | 1.40 | |
| 120A | " | " | " | " | -- | | 880 | 10 – 15 | 10.0 | | | 1440 | | 93.2 | 1.79 | |
| 120B | " | 51.8* | 40,000 scfh | 1.085 | -- | | 880 | 10 – 15 | 9.5 | | | 1380 | | 88.6 | 1.71 | |
| 120C | " | " | " | " | -- | | 1250 | 10 – 25 | 9.7 | | | 1990 | | 127.8 | 2.47 | |
| 120D | " | " | " | " | -- | | 650 | 0 – 15 | 9.8 | | | 1045 | | 67.1 | 1.30 | |
| 120E | " | " | " | " | -- | | 1225 | 5 – 40 | 9.6 | | | 1935 | | 124.2 | 2.40 | |
| 120F | " | " | " | " | -- | | 625 | 5 – 45 | 10.0 | | | 1021 | | 65.5 | 1.27 | |
| 120G | " | " | " | " | -- | | 1050 | 5 – 45 | 9.4 | | | 1630 | | 104.7 | 2.02 | |
| 121 | " | 51.8* | 40,000 scfh | 1.085 | -- | | 400 | 60 – 160 | 9.1 | | | 605 | | 38.8 | 0.75 | |
| 121A | " | " | " | " | -- | | 750 | 40 – 580 | 8.5 | | | 1080 | | 69.3 | 1.34 | |
| 121B | " | " | " | " | -- | | 1300 | 10 – 120 | 9.3 | | | 2000 | | 128.4 | 2.48 | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 121C | Open Hearth Furnace (1) | 51.8* | 40,000 scfh | 1.085 | -- | | 1000 | 5 – 15 | 9.3 | 980 | | 1540 | 0.98 | 99.9 | 1.91 | |
| 121D | " | " | " | " | -- | | 480 | 40 – 200 | 10.5 | | | 820 | | 52.6 | 1.02 | |
| 121E | " | " | " | " | -- | | 60-700 | 1300 | 9.6 | | | 95-1105 | | 38.5 | 0.74 | |
| 121F | " | " | " | " | -- | | 770 | 10 – 580 | 10.5 | | | 1320 | | 84.8 | 1.63 | |
| 121G | " | " | " | " | -- | | 1050 | 10 – 260 | 11.1 | 1050 | | 1910 | 1.00 | 122.6 | 2.37 | |
| 122 | " | 52.4* | 41,000 scfh | 1.035 | -- | | 1200 | 10 – 40 | 9.5 | | | 1880 | | 122.1 | 2.33 | |
| 122A | " | " | " | " | -- | | 1200 | 5 – 40 | 9.1 | | | 1815 | | 117.9 | 2.25 | |
| 122B | " | " | " | " | -- | | 1225 | 5 – 40 | 9.4 | | | 1900 | | 123.4 | 2.36 | |
| 122C | " | " | " | " | -- | | 1700 | 5 – 40 | 10.2 | | | 2820 | | 183.2 | 3.50 | |
| 122D | " | " | " | " | -- | | 1500 | 5 – 35 | 10.1 | | | 2480 | | 161.1 | 3.07 | |
| 122E | " | " | " | " | -- | | 1200 | 5 – 20 | 9.3 | | | 1850 | | 120.2 | 2.29 | |
| 122F | " | " | " | " | -- | | 1200 | 5 – 35 | 9.5 | | | 1800 | | 116.9 | 2.23 | |
| 122G | " | " | " | " | -- | | 1350 | 4 – 20 | 9.6 | | | 2115 | | 137.4 | 2.62 | |
| 122H | " | " | " | " | -- | | 1575 | 4 – 20 | 9.9 | | | 2525 | | 164.0 | 3.13 | |
| 122I | " | " | " | " | -- | | 1450 | 3 – 15 | 9.6 | | | 2290 | | 148.7 | 2.84 | |
| 122J | " | " | " | " | -- | | 1500 | 3 – 15 | 9.2 | | | 2290 | | 148.7 | 2.84 | |
| 123 | " | 51.2* | 40,000 scfh | 1.025 gpm | -- | | 2050 | 2 – 35 | 8.7 | | | 3000 | | 190.4 | 3.72 | |
| 123A | " | " | " | " | -- | | 2250 | 0 | 10.5 | | | 3870 | | 245.6 | 4.80 | |
| 123B | " | " | " | " | -- | | 2000 | 0 | 10.4 | | | 2125 | | 134.9 | 2.63 | |
| 123C | " | " | " | " | -- | | 1900 | 0 | 10.2 | (11.2) | | 3170 | | 201.2 | 3.93 | |
| 123D | " | " | " | " | -- | | 2000 | 0 | 10.3 | 3000 | | 3365 | | 213.6 | 4.17 | |
| 123E | " | " | " | " | -- | | 1875 | 0 – 5 | 10.1 | | | 3100 | | 196.7 | 3.84 | |
| 123F | " | " | " | " | -- | | 1625 | 0 | 10.0 | | | 2630 | | 166.9 | 3.26 | |
| 124 | " | 54.97* | 39,500 scfh | 1.5 gpm | -- | | 2300 | 0 | 10.1 | | | 3800 | | 258.9 | 4.71 | [3845 NO peak @ 3% $O_2$] |
| 124A | " | 57.3* | 40,000 scfh | 1.7 gpm | -- | | 1975 | 0 | 10.1 | | | 3260 | | 231.6 | 4.04 | |
| 124B | " | " | " | " | -- | | 1700 | 0 | 10.2 | | | 2840 | | 201.7 | 3.52 | |
| 124C | " | " | " | " | -- | | 1875 | 0 | 10.5 | | | 3220 | | 228.7 | 3.99 | |
| 124D | " | 55.0* | " | " | -- | | 1875 | 0 | 11.2 | 2025 | | 3440 | 1.08 | 234.5 | 4.26 | |
| 124E | " | " | " | " | -- | | 1910 | 0 | 11.2 | 1975 | | 3500 | 1.03 | 238.6 | 4.34 | |
| 124F | " | " | " | " | -- | | 1775 | 0 | 10.8 | | | 3140 | | 214.1 | 3.89 | |
| 124G | " | " | " | " | -- | | 1875 | 0 | 10.4 | | | 3180 | | 216.8 | 3.94 | |
| 124H | " | " | " | " | -- | | 2400 | 0 | 12.5 | | | 5100 | | 347.7 | 6.32 | |
| 124I | " | " | " | " | -- | | 2100 | 0 | 12.5 | | | 4450 | | 303.4 | 5.52 | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/ NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 125 | Coke Oven (1) | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | |
| 125A | " | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | |
| 126 | " | 147* | 37500/1400000 scfh COG/BFG | 0 | -- | | 115 | >2000 | 5.7 | | | 135 | | | | |
| 126A | " | " | " | " | -- | | 90 | " | 6.0 | | | 108 | | | | |
| 126B | " | " | " | " | -- | | 125 | " | 5.5 | | | 146 | | | | |
| 126C | " | " | " | " | -- | | 133 | " | 5.7 | | | 157 | | | | |
| 126D | " | " | " | " | -- | | 150 | " | 5.5 | | | 174 | | | | |
| 127 | " | 144 | 37500/1377000 scfh COG/BFG | " | -- | | 85 | " | 5.4 | | | 98 | | | | |
| 127A | " | " | " | " | -- | | 60 | " | 5.5 | | | 70 | | | | |
| 127B | " | " | " | " | -- | | 75 | " | 5.5 | | | 87 | | | | |
| 127C | " | " | " | " | -- | | 65 | " | 10.5 | | | 112 | | | | |
| 128 | Coke Oven (1) | 102 | 185,000 scfh COG | 0 | -- | | 100 | 440 | 10.0 | | | 164 | | | | |
| 128A | " | " | " | " | -- | | 110 | 460 | 10.2 | 115 | | 183 | 1.05 | | | |
| 128B | " | " | " | " | -- | | 110 | 460 | 10.0 | | | 180 | | | | |
| 129 | Open Hearth Furnace (1) | 7.6 | -- | 50 gph | -- | | 460 | 30 - 395 | 13.5 | | | 1105 | | 11.2 | 1.47 | |
| 129A | " | 60.4* | -- | 400 gph | -- | | 460 | 15 - 260 | 13.2 | | | 1075 | | 86.6 | 1.43 | |
| 129B | " | " | -- | " | -- | | 580 | 15 - 280 | 13.0 | | | 1305 | | 105.1 | 1.74 | |
| 129C | " | " | -- | " | -- | | 560 | 25 - 270 | 12.8 | | | 1230 | | 99.1 | 1.64 | |
| 129D | " | " | -- | " | -- | | 700 | 20 - 240 | 12.5 | | | 1430 | | 119.2 | 1.97 | |
| 129E | " | " | -- | " | -- | | 700 | 20 - 80 | 12.5 | | | 1480 | | 119.2 | 1.97 | |
| 129F | " | " | -- | " | -- | | 950 | 25 - 200 | 12.5 | | | 2005 | | 161.5 | 2.67 | |
| 129G | " | " | -- | " | -- | | 160 | 20 - 60 | 12.3 | | | 1570 | | 126.4 | 2.09 | |
| 130 | " | 60.4* | -- | 400 gph | -- | | 1100 | 25 - 140 | 12.0 | | | 2200 | | 177.2 | 2.96 | |
| 130A | " | " | -- | " | -- | | 900 | 20 - 60 | 12.0 | | | 1800 | | 145.0 | 2.40 | |
| 130B | " | " | -- | " | -- | | 1100 | 25 - 260 | 11.9 | | | 2185 | | 176.0 | 2.91 | |
| 130C | " | " | -- | " | -- | | 1000 | 20 - 60 | 11.9 | | | 1970 | | 158.7 | 2.63 | |
| 130D | " | " | -- | " | -- | | 1000 | 20 - 60 | 11.6 | | | 1915 | | 154.2 | 2.55 | |
| 130E | " | " | -- | " | -- | | 1200 | 20 - 60 | 11.5 | | | 2285 | | 184.0 | 3.05 | |
| 130F | " | " | -- | " | -- | | 950 | 20 - 100 | 15.0 | | | 2850 | | 229.5 | 3.30 | |
| 130G | " | " | -- | " | -- | | 900 | 20 - 30 | 13.2 | | | 2080 | | 167.5 | 2.77 | Added Melten Metal |
| 130H | " | " | -- | " | -- | | 1000 | 10 - 20 | 17.0 | | | 4500 | | 362.4 | 6.00 | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 131 | Open Hearth Furnace(1) | 60.4* | -- | 400 gph | -- | | 90 | 10 | 14.0 | | | 232 | | 18.7 | 0.31 | |
| 131A | " | " | -- | " | -- | | 100 | 10 | 14.0 | | | 257 | | 20.7 | 0.34 | |
| 131B | " | " | -- | " | -- | | 90 | 10 | 14.0 | | | 232 | | 18.7 | 0.31 | |
| 131C | " | " | -- | " | -- | | 100 | 10 | 14.0 | | | 257 | | 18.7 | 0.34 | |
| 131D | " | " | -- | " | -- | | 90 | 10 | 14.1 | | | 235 | | 18.9 | 0.31 | |
| 131E | " | " | -- | " | -- | | 100 | 10 | 14.1 | | | 261 | | 21.0 | 0.35 | |
| 131F | " | " | -- | " | -- | | 90 | 10 | 14.0 | | | 232 | | 18.7 | 0.31 | |
| 131G | " | " | -- | " | -- | | 100 | 10 | 14.0 | | | 257 | | 18.7 | 0.34 | |
| 131H | " | " | -- | " | -- | | 90 | 10 | 13.9 | | | 228 | | 18.4 | 0.31 | |
| 131I | " | " | -- | " | -- | | 100 | 10 | 13.9 | | | 254 | | 20.5 | 0.34 | |
| 132 | " | " | -- | " | -- | | 125 | 10 | 14.0 | | | 322 | | 25.9 | 0.43 | |
| 132A | " | " | -- | " | -- | | 190 | 10 - 60 | 13.5 | | | 455 | | 36.6 | 0.61 | |
| 132B | " | " | -- | " | -- | | 215 | 20 - 580 | 12.5 | | | 455 | | 36.6 | 0.61 | |
| 132C | " | " | -- | " | -- | | 280 | 40 - 260 | 12.5 | | | 592 | | 47.7 | 0.79 | |
| 132D | " | " | -- | " | -- | | 370 | 5 - 200 | 12.3 | | | 765 | | 61.6 | 1.02 | |
| 132E | " | " | -- | " | -- | | 390 | 15 - 200 | 11.6 | | | 746 | | 60.1 | 0.99 | |
| 132F | " | " | -- | " | -- | | 520 | 60 - 260 | 12.5 | | | 1100 | | 88.6 | 1.47 | |
| 133 | " | 57.4* | -- | 380 gph | -- | | 400 | 10 - 280 | 11.5 | | | 760 | | 58.2 | 1.01 | |
| 133A | " | " | -- | " | -- | | 520 | 10 - 250 | 11.3 | | | 1075 | | 87.3 | 1.43 | |
| 133B | " | " | -- | " | -- | | 870 | 10 - 480 | 10.5 | | | 1490 | | 114.0 | 1.99 | |
| 133C | " | " | -- | " | -- | | 1100 | 10 - 120 | 11.5 | | | 2095 | | 160.3 | 2.97 | |
| 133D | " | " | -- | " | -- | | 925 | 10 - 50 | 11.5 | | | 1750 | | 133.9 | 2.33 | |
| 133E | " | " | -- | " | -- | | 1060 | 5 - 50 | 12.8 | | | 2320 | | 177.6 | 3.09 | |
| 133F | " | " | -- | " | -- | | 940 | 0 | 15.0 | | | 2820 | | 215.8 | 3.76 | |
| 134 | " | 71.0* | -- | 470 gph | -- | | 900 | 0 - 40 | 12.0 | | | 1800 | | 170.4 | 2.40 | |
| 134A | " | " | -- | " | -- | | 700 | 0 - 40 | 10.5 | | | 1200 | | 113.6 | 1.60 | |
| 134B | " | " | -- | " | -- | | -- | -- | -- | | | -- | | -- | -- | |
| 134C | " | " | -- | " | -- | | -- | -- | -- | | | -- | | -- | -- | |
| 134D | " | " | -- | " | -- | | -- | -- | -- | | | -- | | -- | -- | |
| 135 | " | 72.5* | -- | 480 gph | -- | | 750 | 60 - 220 | 11.0 | | | 1440 | | 139.2 | 1.92 | |
| 135A | " | " | -- | " | -- | | 36 | >2000 | 6.0 | | | 43 | | 4.2 | 0.06 | Add ore |
| 135B | " | " | -- | " | -- | | 150 | >2000 | 9.0 | | | 225 | | 21.7 | 0.30 | |
| 135C | " | " | -- | " | -- | | 530 | 300 ->2000 | 9.0 | | | 795 | | 76.8 | 1.06 | |
| 135D | " | " | -- | " | -- | | 240 | 80 - 496 | 9.2 | | | 354 | | 34.2 | 0.47 | |
| 135E | " | " | -- | " | -- | | 1025 | 80 - 380 | 10.0 | | | 1675 | | 161.9 | 2.23 | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 136 | Open Hearth Furnace(1) | 73.2* | -- | 485 gph | -- | | 1100 | 40 – 200 | 11.0 | | | 1980 | | 193.2 | 2.64 | |
| 136A | " | " | -- | " | -- | | 1125 | 0 – 40 | 10.8 | | | 1985 | | 193.7 | 2.65 | |
| 136B | " | " | -- | " | -- | | 1125 | 10 – 240 | 10.5 | | | 1925 | | 187.9 | 2.57 | |
| 136C | " | " | -- | " | -- | | 590 | 5 – 80 | 10.5 | | | 1010 | | 98.6 | 1.35 | |
| 136D | " | " | -- | " | -- | | 200 | 15 – 200 | 9.3 | | | 308 | | 30.1 | 0.41 | |
| 136E | " | " | -- | " | -- | | 740 | 5 – 90 | 9.5 | | | 1160 | | 113.2 | 1.55 | |
| 137 | " | 85.1* | -- | 570 gph | -- | | 1200 | 0 – 40 | 11.0 | | | 2160 | | 245.1 | 2.88 | |
| 137A | " | " | -- | " | -- | | 1300 | 0 – 40 | 12.0 | 1300 | | 2600 | 1.00 | 295.0 | 3.47 | |
| 137B | " | " | -- | " | -- | | 1300 | 0 – 40 | 12.6 | | | 2790 | | 316.6 | 3.72 | |
| 137C | " | " | -- | " | -- | | 1350 | 0 | 12.5 | | | 2880 | | 326.8 | 3.84 | |
| 137D | " | " | -- | " | -- | | 1975 | 0 | 12.0 | | | 3980 | | 451.6 | 5.31 | |
| 138 | " | 98.1* | -- | 650 gph | -- | | 2125 | 0 | 12.0 | | | 4260 | | 557.2 | 5.68 | |
| 138A | " | " | -- | " | -- | | 1600 | 0 | 13.8 | | | | | | | Capillary Plugged, False Readings |
| 138B-138Q | " | " | -- | " | -- | -- | -- | -- -- | -- | -- | -- | -- | -- | -- | -- | |
| 139 | Open Hearth Furnace(1) | 92.9* | -- | 615 gph | -- | | 2050 | 35 – 85 | 10.0 | | | 4100 | | 507.8 | 5.47 | 2975°F |
| 139A | " | " | -- | " | -- | | 1950 | 20 – 35 | 12.0 | | | 3900 | | 483.1 | 5.20 | |
| 139B | " | " | -- | " | -- | | 1650 | 15 – 25 | 12.0 | | | 3300 | | 408.8 | 4.40 | |
| 139C | " | " | -- | " | -- | | 2425 | 0 – 15 | 12.5 | | | 5150 | | 637.9 | 6.87 | Post Tap Fire |
| 139D | " | " | -- | " | -- | | 2800 | 15 | 12.1 | | | 5675 | | 702.9 | 7.57 | |
| 140 | " | 92.9* | -- | 615 gph | -- | | 0 | 0 | 19.1 | | | | | | | Blow Out Oven |
| 140A | " | " | -- | " | -- | | 5 | 0 | 19.9 | | | 65 | | 8.05 | 0.087 | Making Bottom |
| 140B | " | " | -- | " | -- | | 1225 | 0 | 16.5 | | | 4900 | | 606.9 | 6.63 | First Fire |
| 140C | " | " | -- | " | -- | | 0 | 0 | 19.5 | | | | | | | Bottom Check |
| 140D | " | " | -- | " | -- | | 1600 | 0 | 14.5 | | | 4425 | | 548.1 | 5.90 | Second Fire |
| 140E | " | " | -- | " | -- | | 0 | 0 | 20.0 | | | | | | | First Charge |
| 141 | " | 60.4* | -- | 400 gph | -- | | 1025 | 0 | 17.5 | | | 5290 | | 426.0 | 7.05 | Charge Fire |
| 141A | " | " | -- | " | -- | | 775 | 0 | 15.0 | | | 2325 | | 187.2 | 3.10 | Charge Fire |
| 141B | " | " | -- | " | -- | | 810 | 0 | 13.0 | | | 1825 | | 147.0 | 2.43 | Undercover fire |
| 141C | " | " | -- | " | -- | | 580 | 0 | 14.0 | | | 1490 | | 120.0 | 1.99 | Cover fire |
| 141D | " | " | -- | " | -- | | 880 | 0 | 12.3 | | | 1820 | | 146.6 | 2.43 | Cover fire |
| 141E | " | " | -- | " | -- | | 720 | 5 – 60 | 12.0 | | | 1440 | | 116.0 | 1.92 | Charge fire |
| 141F | " | " | -- | " | -- | | 140 | 0 | 12.3 | | | 1560 | | 125.6 | 2.08 | Charge fire |
| 141G | " | " | -- | " | -- | | 705 | 0 | 12.5 | 745 | | 1490 | 1.06 | 120.0 | 1.99 | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 142 | Open Hearth Furnace(1) | 60.4* | -- | 400 gph | -- | | 650 | 30 – 50 | 11.5 | | | 1230 | | 99.1 | 1.64 | |
| 142A | " | " | -- | " | -- | | 460 | 10 – 55 | 11.5 | | | 870 | | 70.1 | 1.16 | |
| 142B | " | " | -- | " | -- | | 320 | 0 | 12.0 | | | 640 | | 51.5 | 0.85 | ⌈Bank Doors⌋ |
| 142C | " | " | -- | " | -- | | 470 | 20 – 75 | 11.2 | | | 875 | | 70.5 | 1.17 | |
| 142D | " | " | -- | " | -- | | 580 | 0 | 12.5 | | | 1100 | | 88.6 | 1.47 | |
| 142E | " | " | -- | " | -- | | 650 | 50 – 250 | 11.5 | | | 1230 | | 99.1 | 1.64 | |
| 142F | " | " | -- | " | -- | | 880 | 35 – 400 | 11.2 | | | 1620 | | 130.5 | 2.16 | |
| 142G | " | " | -- | " | -- | | 980 | 30 – 175 | 11.0 | | | 1760 | | 141.7 | 2.35 | |
| 143 | " | 81.5* | -- | 540 gph | -- | | 1050 | 50 – 400 | 11.0 | | | 1890 | | 205.4 | 2.52 | |
| 143A | " | " | -- | " | -- | | 1150 | 25 – 200 | 11.0 | | | 2070 | | 224.9 | 2.76 | |
| 143B | " | " | -- | " | -- | | 1300 | 50 – 400 | 11.0 | | | 2340 | | 254.3 | 3.12 | |
| 143C | " | " | -- | " | -- | | 1350 | 25 – 150 | 11.0 | | | 2430 | | 264.1 | 3.24 | ⌈Add 165 tons metal⌋ |
| 144 | " | 60.4* | -- | 400 gph | -- | | 560 | 5 – 200 | 12.6 | | | 1200 | | 96.6 | 1.60 | ⌈1st load cover fire⌋ |
| 144A | " | " | -- | " | -- | | 700 | 0 | 12.8 | | | 1535 | | 123.6 | 2.05 | ⌈Slag⌋ |
| 144B | " | " | -- | " | -- | | 175 | 1900 – >2000 | 9.6 | | | 274 | | 22.1 | 0.37 | ⌈Add 165 tons metal⌋ |
| 144C | " | " | -- | " | -- | | 815 | 60 – 2000+ | 11.1 | | | 1480 | | 119.2 | 1.97 | ⌈2nd load cover fire⌋ |
| 144D | " | " | -- | " | -- | | 70-999 | 10 – 80 | 14.5 | | | 32-2760 | | 112.4 | 1.86 | ⌈Slag, 2nd charge fire⌋ |
| 144E | " | " | -- | " | -- | | 410 | 10 | 11.1 | | | 746 | | 60.1 | 0.99 | ⌈2nd charge fire⌋ |
| 145 | " | 63.4* | -- | 420 gph | -- | | 590 | 40 – 180 | 10.8 | | | 1040 | | 87.9 | 1.39 | ⌈Slag fire⌋ |
| 145A | " | " | -- | " | -- | | 560 | 20 – 120 | 10.6 | | | 970 | | 82.0 | 1.29 | ⌈2nd charge fire⌋ |
| 145B | " | " | -- | " | -- | | 650 | 40 – 400 | 10.0 | | | 1065 | | 40.0 | 1.42 | ⌈Flow rate Increase, $O_2$ inject inc.⌋ |
| 146 | " | 73.2* | -- | 485 gph | -- | | 10 | 380 – 460 | 7.5 | | | 33 | | 3.22 | 0.04 | " |
| 146A | " | " | -- | " | -- | | 20 | 780 – 2000 | 7.0 | | | 36 | | 2.54 | 0.03 | " |
| 146B | " | " | -- | " | -- | | 20 | 220 – 780 | 6.4 | | | 25 | | 2.44 | 0.03 | " |
| 146C | " | " | -- | " | -- | | 17 | 300 – 640 | 6.1 | | | 23 | | 2.24 | 0.03 | " |
| 146D | " | " | -- | " | -- | | 18 | 80 – 380 | 6.0 | | | 10 | | 1.76 | 0.02 | ⌈Fuel rich⌋ |
| 146E | " | " | -- | " | -- | | 16 | 110 – 140 | 5.0 | | | 18 | | 1.76 | 0.02 | ⌈No spiles as dampers⌋ |
| 147 | " | 77.0* | -- | 510 gph | -- | | 0 | 110 – 210 | 4.5 | | | 0 | | 0 | 0 | ⌈Change from side to side⌋ |
| 147A | " | " | -- | " | -- | | 0 | 80 – 115 | 4.6 | | | 0 | | 0 | 0 | |
| 147B | " | " | -- | " | -- | | 0 | 40 – 80 | 5.5 | | | 0 | | 0 | 0 | |
| 147C | " | " | -- | " | -- | | 0 | 80 | 5.8 | | | 0 | | 0 | 0 | |
| 147D | " | " | -- | " | -- | | 0 | 40 – 200 | 6.5 | | | 0 | | 0 | 0 | ⌈2620°F⌋ |
| 147E | " | " | -- | " | -- | | 8 | 220 – 910 | 7.5 | | | 25 | | 0.83 | 0.03 | ⌈Add 1 lime (burnt)⌋ |
| 147F | " | " | -- | " | -- | | 0 | 60 – 220 | 7.5 | | | 0 | | 0 | 0 | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 148 | Open Hearth Furnace(1) | 71.0* | -- | 470 gph | -- | | 26 | >2000 | 3.2 | | | 26 | | 2.46 | 0.03 | [30% smoke, add 2 ore] |
| 148A | " | " | -- | " | -- | | 0 | 160 | 5.9 | | | | | | 0 | [O] |
| 148B | " | " | -- | " | -- | | 910 | 40 – 200 | 8.0 | | | 1260 | | 119.3 | 1.68 | |
| 148C | " | " | -- | " | -- | | 440 | 10 – 40 | 8.6 | | | 640 | | 60.6 | 0.85 | |
| 148D | " | " | -- | " | -- | | 1075 | 10 – 100 | 9.0 | | | 1620 | | 153.4 | 2.16 | |
| 148E | " | " | -- | " | -- | | 800 | 10 | 9.3 | | | 1230 | | 116.4 | 1.64 | |
| 149 | " | 71.0* | -- | 410 gph | -- | | 1025 | 10 – 40 | 9.1 | | | 1550 | | 146.7 | 2.07 | |
| 149A | " | " | -- | " | -- | | 490 | 10 | 9.4 | | | 760 | | 71.9 | 1.01 | |
| 149B | " | " | -- | " | -- | | 315 | 10 | 8.6 | | | 465 | | 44.0 | 0.62 | |
| 149C | " | " | -- | " | -- | | 290 | 10 | 8.0 | | | 401 | | 38.0 | 0.53 | |
| 149D | " | " | -- | " | -- | | 190 | 10 | 9.1 | | | 289 | | 27.4 | 0.39 | |
| 149E | " | " | -- | " | -- | | 1200 | 10 – 15 | 9.4 | | | 1860 | | 176.0 | 2.48 | |
| 150 | " | 67.2* | -- | 445 gph | -- | | 860 | 10 | 9.2 | | | 1310 | | 117.4 | 1.75 | |
| 150A | " | " | -- | " | -- | | 1025 | 10 | 9.2 | | | 1870 | | 167.6 | 2.49 | |
| 150B | " | " | -- | " | -- | | 975 | 10 | 10.1 | | | 1610 | | 144.3 | 2.14 | |
| 150C | " | " | -- | " | -- | | 500 | 10 | 9.6 | | | 790 | | 70.- | 1.05 | |
| 150D | " | " | -- | " | -- | | 475 | 10 | 8.6 | | | 690 | | 61.8 | 0.92 | |
| 150E | " | " | -- | " | -- | | 1225 | 10 | 8.6 | | | 1780 | | 159.5 | 2.37 | |
| 150F | " | " | -- | " | -- | | 1200 | 10 | 9.9 | | | 1950 | | 174.7 | 2.60 | |
| 151 | " | 71.0* | -- | 470 gph | -- | | 850 | 10 | 9.6 | | | 1340 | | 126.9 | 1.79 | |
| 151A | " | " | -- | " | -- | | 625 | 40 – 1260 | 8.1 | | | 872 | | 82.5 | 1.16 | |
| 151B | " | " | -- | " | -- | | 450 | 40 | 7.6 | | | 605 | | 57.3 | 0.807 | |
| 151C | " | " | -- | " | -- | | 24 | 15 | 6.4 | | | 30 | | 2.84 | 0.04 | [Fuel change, full oil] |
| 151D | " | " | -- | " | -- | | 29 | 140 | 6.1 | | | 35 | | 3.31 | 0.05 | [Fuel rich] |
| 151E | " | " | -- | " | -- | | 370 | 15 | 7.5 | | | 493 | | 46.7 | 0.66 | |
| 152 | " | 117.8* | -- | 780 gph | -- | | 78 | 15 | 7.9 | | | 107 | | 16.8 | 0.14 | |
| 152A | " | " | -- | " | -- | | 730 | 10 | 8.0 | | | 1010 | | 158.6 | 1.35 | |
| 152B | " | " | -- | " | -- | | 260 | 10 | 8.5 | | | 374 | | 58.7 | 0.50 | [Start tap] |
| 152C | " | " | -- | " | -- | | 1300 | 10 | 11.5 | | | 2460 | | 386.4 | 3.28 | |
| 153 | " | 60.4* | -- | 400 gph | -- | | 1300 | 10 | 12.0 | | | 2600 | | 209.4 | 3.47 | |
| 153A | " | " | -- | " | -- | | 2600 | 10 | 12.3 | | | 5390 | | 434.1 | 7.18 | |
| 153B | " | " | -- | " | -- | | 2100 | 10 | 13.0 | | | 4740 | | 381.7 | 6.32 | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 154 | Open Hearth Furnace(1) | 135+ | 50,000 lb/hr | -- | 100,000 lb/hr steam | | 59 | 190 – 680 | 4.3 | | | 54 | | | | |
| 154A | " | " | " | -- | " | | 49 | 50 – 200 | 4.8 | | | 54 | | | | |
| 154B | " | " | " | -- | " | | 41 | 10 – 100 | 5.2 | | | 47 | | | | |
| 154C | " | " | " | -- | " | | 43 | 10 | 5.4 | | | 50 | | | | |
| 154D | " | " | " | -- | " | | 52 | 0 | 7.0 | 65 | | 67 | 1.25 | | | |
| 154E | " | " | " | -- | " | | 43 | 0 | 5.8 | 45 | | 51 | 1.05 | | | |
| 154F | " | " | " | -- | " | | 47 | 0 | 5.3 | 53 | | 54 | 1.13 | | | |
| 154G | " | " | " | -- | " | | 41 | 10 | 5.2 | 45 | | 47 | 1.10 | | | |
| 154H | " | " | " | -- | " | | 44 | 10 | 5.5 | 46 | | 51 | 1.05 | | | |
| 155 | Boiler(1) | 346* | $1.4 \times 10^6$ CFH BFG<br>400,000 CFH COG | -- | 250,000 lb/hr steam | | 43 | 240 | 6.1 | | | 52 | | | | |
| 155A | " | " | " | -- | " | | 43 | 140 | 6.2 | | | 52 | | | | |
| 155B | " | " | " | -- | " | | 48 | 360 | 5.4 | 52 | | 55 | 1.08 | | | |
| 156 | Sinter Furnace(1) | 72.0* | 13,000 CFH COG<br>5902 lb/hr coke | -- | 50 T/hr | | 38 | >2000 | 17.5 | 43 | | 195 | 1.13 | | | |
| 156A | " | " | " | -- | " | | 52 | >2000 | 18.0 | | | 311 | | | | |
| 156B | " | " | " | -- | " | | 54 | >2000 | 18.0 | | | 324 | | | | |
| 156C | " | " | " | -- | " | | 63 | 1990 | 12.3 | | | 307 | | | | |
| 156D | " | " | " | -- | " | | 45 | 1440 | 18.5 | 49 | | 324 | 1.09 | | | |
| 157 | Sinter Furnace(1) | 62.9* | 24,500 CFH COG<br>4426 lb/hr coke | -- | 43 T/hr | | 57 | >2000 | 17.3 | 61 | | 278 | 1.07 | | | |
| 157A | " | " | " | -- | " | | 57 | >2000 | 17.3 | 62 | | 278 | 1.09 | | | |
| 158 | Kiln No. 2(1) | 233* | 222,000 scfh | -- | 50 T/hr prod | | 700 | 10 | 15.0 | | | 2100 | 1.03 | 540.1 | 2.54 | |
| 158A | " | " | " | -- | " | | 640 | 0 | 15.0 | 660 | | 1920 | 1.03 | 540.1 | 2.32 | |
| 158B | " | " | " | -- | " | | 650 | 0 | 14.9 | 665 | | 1920 | 1.02 | 540 | 2.32 | |
| 158C | " | " | " | -- | " | | 650 | 0 | 14.8 | 670 | | 1890 | 1.03 | 532 | 2.28 | |
| 158D | " | " | " | -- | " | | 640 | 0 | 14.8 | 620 | | 1860 | .97 | 524 | 2.25 | |
| 158E | " | " | " | -- | " | | 620 | 0 | 14.8 | 640 | | 1800 | 1.03 | 507 | 2.17 | |
| 158F | " | " | " | -- | " | | 640 | 0 | 14.8 | 680 | | 1860 | 1.06 | 524 | 2.25 | |
| 158G | " | " | " | -- | " | | 660 | 0 | 14.8 | 665 | | 1915 | 1.01 | 539 | 2.31 | |
| 158H | " | " | " | -- | " | | 680 | 0 | 14.8 | 695 | | 1975 | 1.02 | 556 | 2.39 | |
| 159 | " | " | " | -- | " | | 750 | 5 | 14.5 | 0 | | 2080 | -- | 585 | 2.51 | |
| 159A | " | " | " | -- | " | | 790 | 9 | 14.3 | | | 2110 | -- | 594 | 2.55 | |
| 159B | " | " | " | -- | " | | 830 | 10 | 14.2 | | | 2200 | -- | 619 | 2.66 | |
| 159C | " | " | " | -- | " | | 860 | 10 | 14.2 | | | 2280 | -- | 642 | 2.75 | |
| 159D | " | " | " | -- | " | | 900 | 10 | 14.2 | | | 2380 | -- | 670 | 2.88 | |

H 20

A 21

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/ NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 160 | Kiln No. 2(1) | 233* | 220,000 scfh | -- | 50 T/hr prod | | 620 | 0 | 15.2 | 625 | | 1920 | 1.01 | 541 | 2.32 | |
| 161 | " | " | " | -- | " | | 700 | 0 | 15.5 | 715 | | 2285 | 1.02 | 643 | 2.76 | |
| 162 | Kiln No. 1(1) | 212* | -- | 23.25 gpm | 50 T/hr prod | | 130 | 0 | 15.0 | 148 | | 390 | 1.14 | 110 | 0.52 | |
| 163 | " | 223* | -- | 24.5 gpm | " | | 250 | 10 | 14.2 | 262 | | 661 | 1.05 | 197 | 0.88 | |
| 163A | " | " | -- | " | " | | 260 | 5 | 14.2 | 280 | | 689 | 1.08 | 205 | 0.92 | |
| 163B | " | " | -- | " | " | | 265 | 5 | 14.2 | | | 703 | | 209 | 0.94 | |
| 163C | " | " | -- | " | " | | 240 | 5 | 14.2 | 265 | | 635 | 1.10 | 188 | 0.85 | |
| 163D | " | " | -- | " | " | | 205 | 5 | 14.2 | 200 | | 543 | .98 | 161 | 0.72 | |
| 163E | " | " | -- | " | " | | 200 | 5 | 14.2 | 205 | | 530 | 1.03 | 158 | 0.71 | |
| 163F | " | 225* | -- | 24.7 gpm | " | | 220 | 5 | 14.1 | 229 | | 575 | 1.04 | 172 | 0.77 | |
| 163G | " | " | -- | " | " | | 215 | 5 | 14.0 | 215 | | 553 | 1.00 | 166 | 0.74 | |
| 163H | " | " | -- | " | " | | 240 | 5 | 14.1 | | | 628 | -- | 188 | 0.84 | |
| 163I | " | " | -- | " | " | | 220 | 5 | 14.1 | 235 | | 575 | 1.07 | 172 | 0.77 | |
| 164 | " | 241.5* | 230,000 scfh | -- | 50 T/hr prod | | 690 | 0 | 14.5 | | | 1910 | -- | 557 | 2.30 | |
| 164A | " | " | " | -- | " | | 430 | 0 | 14.0 | 445 | | 1105 | 1.03 | 322 | 1.33 | |
| 165 | " | 241.5* | 230,000 scfh | -- | " | | 500 | 0 | 14.0 | 490 | | 1285 | .98 | 375 | 1.55 | |
| 165A | " | " | " | -- | " | | 490 | 0 | 14.0 | 505 | | 1260 | 1.03 | 368 | 1.52 | |
| 165B | " | " | " | -- | " | | 500 | 0 | 14.0 | 520 | | 1285 | 1.04 | 375 | 1.55 | |
| 165C | " | 241.5" | 2300,000 scfh | -- | 50 T/hr prod | | 475 | 0 | 14.0 | 495 | | 1220 | 1.04 | 356 | 1.47 | |
| 165D | " | " | " | -- | " | | 440 | 0 | 14.0 | 445 | | 1120 | 1.01 | 326 | 1.35 | |
| 165E | " | " | " | -- | " | | 450 | 0 | 14.0 | 480 | | 1150 | 1.07 | 336 | 1.39 | |
| 165F | " | " | " | -- | " | | 450 | 0 | 14.0 | 470 | | 1150 | 1.04 | 336 | 1.39 | |
| 166 | Kiln No. 2(1) | 105.2* | 100,000 scfh | -- | 56 T/hr feed | | 230 | 70 | 10.0 | | | | | | | |
| 166A | " | " | " | -- | " | | 295 | 80 | 9.0 | | | | | | | |
| 166B | " | " | " | -- | " | | 925 | 100 | 1.8 | | | | | | | |
| 166C | " | " | " | -- | " | | 900 | 80 | 2.0 | | | | | | | |
| 166D | " | " | " | -- | " | | 1040 | 75 | 2.1 | | | | | | | |
| 166E | " | " | " | -- | " | | 1110 | 75 | 2.2 | | | | | | | |
| 166F | " | " | " | -- | " | | 860 | 75 | 2.8 | | | | | | | |
| 166G | " | " | " | -- | " | | 1160 | 75 | 2.3 | | | | | | | |
| 167 | " | 199.9* | 190,000 scfh | -- | 56 T/hr feed | | 1710 | 100 | 1.8 | | | | | | | |
| 167A | " | " | " | -- | " | | 2000 | 80 | 3.0 | | | | | | | |
| 167B | " | " | " | -- | " | | 2500 | 90 | 3.5 | | | | | | | |
| 167C | " | " | " | -- | " | | 2775 | 100 | 3.3 | | | | | | | |
| 167D | " | " | " | -- | " | | 2800 | 90 | 2.8 | | | | | | | |
| `67E | " | " | " | -- | " | | 2100 | 500 | 1.0 | | | | | | | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 168 | Kiln No. 2 (1) | 236.7* | 225,000 scfh | -- | 53 T/hr feed | | 1560 | 880 | 0.03 | | | | | | | |
| 168A | " | " | " | -- | " | | 2200 | 520 | 0.05 | | | | | | | |
| 168B | " | " | " | -- | " | | 2325 | 100 | 0.06 | | | | | | | |
| 168C | " | " | " | -- | " | | 2275 | 100 | 0.075 | | | | | | | |
| 168D | " | 236.7* | 235,000 scfh | -- | 60 | | 1800 | 100 | 1.0 | | | | | | | |
| 168E | " | " | " | -- | " | | 2000 | 340 | 0.04 | | | | | | | |
| 168F | " | " | " | -- | " | | 2200 | 315 | 0.05 | | | | | | | |
| 168G | " | " | " | -- | " | | 2625 | 100 | 1.1 | | | | | | | |
| 169 | " | 226.2* | 215,000 scfh | -- | 68.7 T/hr feed | | 2850 | 80 | 1.5 | | | | | | | |
| 169A | " | " | " | -- | " | | 3100 | 80 | 2.1 | | | | | | | |
| 169B | " | " | " | -- | " | | 2900 | 75 | 2.3 | | | | | | | |
| 169C | " | " | " | -- | " | | 3100 | 70 | 2.1 | | | | | | | |
| 169D | " | " | " | -- | " | | 3200 | 60 | 2.4 | | | | | | | |
| 169E | " | " | " | -- | " | | 2950 | 60 | 2.8 | | | | | | | |
| 169F | " | " | " | -- | " | | 2900 | 60 | 2.7 | | | | | | | |
| 170 | " | 233.5* | 222,000 scfh | -- | 75 T/hr feed | | 2100 | 60 | 2.8 | | | | | | | |
| 170A | " | " | " | -- | " | | 3050 | 65 | 2.3 | | | | | | | |
| 170B | " | " | " | -- | " | | 3800 | 65 | 3.0 | | | | | | | |
| 170C | " | " | " | -- | " | | 3800 | 60 | 3.3 | | | | | | | |
| 170D | " | " | " | -- | " | | 3800 | 60 | 3.6 | | | | | | | |
| 170E | " | " | " | -- | " | | 3600 | 60 | 3.3 | | | | | | | |
| 170F | " | " | " | -- | " | | 3800 | 60 | 3.5 | | | | | | | |
| 170G | " | " | " | -- | " | | 3200 | 60 | 2.8 | | | | | | | |
| 170H | " | " | " | -- | " | | 3100 | 60 | 2.8 | | | | | | | |
| 171 | " | 247.7* | 235,000 scfh | -- | 84 T/hr feed | | 2400 | 60 | 3.3 | | | | | | | |
| 171A | " | " | " | -- | " | | 2200 | 60 | 3.1 | | | | | | | |
| 171B | " | " | " | -- | " | | 2400 | 60 | 3.0 | | | | | | | |
| 171C | " | " | " | -- | " | | 2800 | 60 | 3.1 | | | | | | | |
| 171D | " | " | " | -- | " | | 2600 | 60 | 3.0 | | | | | | | |
| 171E | " | " | " | -- | " | | 2600 | 60 | 3.0 | | | | | | | |
| 171F | " | " | " | -- | " | | 2600 | 60 | 2.6 | | | | | | | |
| 171G | " | " | " | -- | " | | 2600 | 60 | 2.5 | | | | | | | |
| 172 | " | 257.7* | 245,000 scfh | -- | 86 T/hr feed | | 2500 | 60 | 2.3 | | | | | | | |
| 172A | " | " | " | -- | " | | 2600 | 60 | 2.1 | | | | | | | |
| 172B | " | " | " | -- | " | | 2300 | 60 | 1.6 | | | | | | | |

A 22

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates Fuel Gas | Fuel Oil | Process | NO (ppm) Dry | Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | Wet | NOx/ NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 173 | Kiln No. 2(1) | 273.5* | 260,000 scfh | -- | 100 T/hr feed | | 2100 | 0 | 1.25 | | | | | | | |
| 173A | " | " | " | -- | " | | 1025 | 0 | 1.3 | | | | | | | |
| 173B | " | " | " | -- | " | | 1900 | 0 | 1.1 | | | | | | | |
| 173C | " | " | " | -- | " | | 2075 | 0 | 1.2 | | | | | | | |
| 173D | " | " | " | -- | " | | 2400 | 0 | 1.3 | | | | | | | |
| 173E | " | " | " | -- | " | | 2200 | 0 | 1.1 | | | | | | | |
| 173F | " | " | " | -- | " | | 2300 | 0 | 1.2 | | | | | | | |
| 174 | " | 271.4* | 258,000 scfh | -- | 100 T/hr feed | | 2500 | 0 | 1.4 | | | | | | | |
| 174A | " | " | " | -- | " | | 2250 | 0 | 1.3 | | | | | | | |
| 174B | " | " | " | -- | " | | 2250 | 0 | 1.6 | | | | | | | |
| 174C | " | " | " | -- | " | | 2600 | 0 | 1.4 | | | | | | | |
| 174D | " | " | " | -- | " | | 2000 | 0 | 1.1 | | | | | | | |
| 174E | " | " | " | -- | " | | 2500 | 0 | 1.3 | | | | | | | |
| 174F | " | " | " | -- | " | | 2600 | 0 | 1.4 | | | | | | | |
| 174G | " | " | " | -- | " | | 2500 | 0 | 1.6 | | | | | | | |
| 175 | " | 239.9* | 228,000 scfh | -- | 100 T/hr feed | | 2500 | 0 | 1.4 | | | | | | | |
| 175A | " | " | " | -- | " | | 2500 | 0 | 1.4 | | | | | | | |
| 175B | " | " | " | -- | " | | 2500 | 0 | 1.4 | | | | | | | |
| 176 | " | 239.9* | 228,000 scfh | -- | 102 T/hr feed | | 3600 | 0 | 1.4 | | | | | | | |
| 176A | " | " | " | -- | " | | 3700 | 0 | 4.5 | | | | | | | |
| 176B | " | " | " | -- | " | | 3500 | 0 | 4.0 | | | | | | | |
| 176C | " | " | " | -- | " | | 3800 | 0 | 3.5 | | | | | | | |
| 176D | " | " | " | -- | " | | 3500 | 0 | 3.0 | | | | | | | |
| 176E | " | " | " | -- | " | | 3000 | 0 | 2.5 | | | | | | | |
| 176F | " | " | " | -- | " | | 2700 | 0 | 2.0 | | | | | | | |
| 176G | " | " | " | -- | " | | 2800 | 0 | 1.5 | | | | | | | |
| 176H | " | " | " | -- | " | | 3000 | 0 | 1.1 | | | | | | | |
| 176I | " | " | " | -- | " | | 2400 | 0 | 1.0 | | | | | | | |
| 177 | " | 270.4* | 257,000 scfh | -- | 94.5 T/hr feed | | 2200 | 0 | 2.0 | | | | | | | |
| 177A | " | " | " | -- | " | | 2400 | 0 | 1.9 | | | | | | | |
| 177B | " | " | " | -- | " | | 2600 | 0 | 2.0 | | | | | | | |
| 177C | " | " | " | -- | " | | 2800 | 0 | 2.0 | | | | | | | |
| 178 | Water Heater | .037* | 35.0 | -- | -- | 51 | 47 | 5 | 6.5 | 49 | 63 | 58 | 1.04 | -- | 0.074 | |
| 179 | Forced Air Heater | .084* | 88.2 | -- | -- | 27 | 25 | 5 | 13.2 | 26 | 62 | 58 | 1.04 | -- | 0.073 | |
| 180 | Swin Pool Heater | .216* | 205.7 | -- | -- | 106 | 99 | 10 | 8.5 | 105 | 153 | 143 | 1.06 | -- | 0.187 | |

A-23

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 181 | Glass Furnace, North(1) | 52.6* | 50,000 scfh | -- | -- | | 206 | 0 | 13.0 | 210 | | | 1.02 | | | |
| 181A | " | " | " | -- | -- | | 194 | 0 | 13.0 | | | | | | | |
| 182 | " | 52.6* | 50,000 scfh | -- | -- | | 204 | 0 | 12.8 | | | | | | | |
| 182A | " | 52.6* | 50,000 scfh | -- | -- | | 200 | 0 | 12.8 | 205 | | | 1.03 | | | |
| 183 | " | 52.6* | 50,000 scfh | -- | -- | | 200 | 0 | 12.6 | 205 | | | 1.03 | | | |
| 183A | " | " | " | -- | -- | | 193 | 0 | 12.6 | 199 | | | 1.03 | | | |
| 184 | " | 56.6* | 50,000 scfh | -- | -- | | 196 | 0 | 12.6 | 203 | | | 1.04 | | | |
| 184A | " | 52.6* | 50,000 scfh | -- | -- | | 185 | 0 | 12.5 | 192 | | | 1.04 | | | |
| 185 | South Glass Furnace(1) | 52.6* | 50,000 scfh | -- | -- | | 213 | 0 | 12.5 | 227 | | | 1.07 | | | |
| 185A | " | " | " | -- | -- | | 197 | 5 | 12.3 | 204 | | | 1.04 | | | |
| 186 | " | 52.6* | 50,000 scfh | -- | -- | | 212 | 0 | 12.5 | 219 | | | 1.03 | | | |
| 186A | " | " | " | -- | -- | | 206 | 0 | 12.3 | 212 | | | 1.03 | | | |
| 187 | " | 53.7* | 51,000 scfh | -- | -- | | 220 | 5 | 12.5 | | | | | | | |
| 187A | " | " | " | -- | -- | | 212 | 5 | 12.5 | | | | | | | |
| 187B | " | " | " | -- | -- | | 190 | 5 | 12.4 | | | | | | | |
| 187C | " | " | " | -- | -- | | 203 | 5 | 12.4 | | | | | | | |
| 187D | " | " | " | -- | -- | | 215 | 5 | 12.3 | | | | | | | |
| 187E | " | " | " | -- | -- | | 203 | 5 | 12.3 | | | | | | | |
| 188 | " | " | " | -- | -- | | 83 | 10 | 2.1 | | | | | | | |
| 188A | Boiler | 36.8 | 35,000 scfh | -- | 34,000 lb/h | 88 | 79 | 10 | 2.0 | 82 | 83 | 75 | 1.04 | 3.7 | 0.100 | [B&W FMD-1351, 1 burner water wall, forced draft, no preheater.] |
| 188B | " | " | " | -- | " | 76 | 73 | 10 | 2.2 | 75 | 73 | 70 | 1.03 | 3.2 | 0.0876 | |
| 189 | " | 26.3 | 25,000 scfh | -- | 22,000 lb/h | 77 | 33 | 10 | 2.5 | 76 | 75 | 71 | 1.04 | 2.4 | 0.0900 | |
| 190 | " | 31.5 | 30,000 scfh | -- | 26,000 lb/h | 71 | 64 | 10 | 2.3 | 72 | 68 | 62 | 1.13 | 2.6 | 0.0816 | |
| 191 | " | 52.5 | 50,000 scfh | -- | 44,000 lb/h | | 82 | 15 | 2.0 | 84 | (93) | 77 | 1.02 | 5.9 | 0.112 | |
| 191A | " | " | " | -- | " | | 75 | 0 | 2.0 | | (85) | 71 | | 5.4 | 0.102 | |
| 191B | " | " | " | -- | " | | 79 | 0 | 2.0 | | (90) | 75 | | 5.7 | 0.108 | |
| 191C | " | " | " | -- | " | | 67 | 0 | 2.3 | | (77) | 64 | | 4.8 | 0.092 | |
| 191D | " | " | " | -- | " | | 68 | 0 | 2.3 | | (78) | 65 | | 4.9 | 0.094 | |
| 192 | " | 37.8 | 36,000 scfh | -- | 33,000 lb/h | 85 | 67 | 0 | 2.1 | 67 | 81 | 64 | 1.00 | 3.7 | 0.097 | |
| 193 | " | 31.5 | 30,000 scfh | -- | 27,000 lb/h | | 57 | 0 | 2.8 | | (67) | 56 | | 2.5 | 0.080 | |
| 193A | " | " | " | -- | " | | 75 | 10 | 1.9 | 80 | (85) | 71 | 1.07 | 3.2 | 0.102 | |
| 194 | Boiler | 5.3 | 5,000 | -- | not known | 14 | 11 | 440 | 15.5 | 16 | 46 | 36 | 1.45 | .29 | 0.055 | [Combustion Engineering, 1 burner, ring with center oil gun, forced draft, no preheat.] |
| 195 | " | 5.3 | 5,000 | -- | " | 23 | 19 | 380 | 12.5 | 26 | 49 | 40 | 1.37 | .31 | 0.059 | |

| Test No. | Combustion Device | Heat Input MMBtu/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMBtu) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 196 | Boiler | 21.0 | 20,000 | -- | not known | 78 | 75 | 10 | 4.5 | 77 | 85 | 82 | 1.03 | 2.14 | 0.102 | |
| 197 | " | -- | not known | -- | " | 17 | 14 | 440 | 15.5 | 16 | 56 | 46 | 1.14 | -- | 0.067 | |
| 198 | " | 29.4 | 28,000 | -- | " | | 84 | 90 | 6.8 | 87 | (122) | 106 | 1.04 | 4.29 | 0.146 | |
| 199 | " | 32.6 | 31,000 | -- | " | | 100 | 70 | 6.1 | 105 | (140) | 121 | 1.05 | 5.48 | 0.168 | |
| 200 | " | 7.35* | not known | -- | 6250 lb/h | | 21 | 170 | 12.6 | | (49) | 45 | | .43 | 0.059 | [B&W Integral Furnace, Type FM, 1 burner, ring with oil gun, forced draft, no preheater.] |
| 200A | " | " | " | -- | " | | 14 | 460 | 13.3 | | (36) | 33 | | .32 | 0.043 | |
| 201 | " | " | " | -- | " | | 21 | 175 | 12.7 | | (50) | 46 | | .44 | 0.060 | |
| 201A | " | " | " | -- | " | | 15 | 380 | 13.2 | | (38) | 35 | | .34 | 0.046 | |
| 202 | " | " | " | -- | " | | 35 | 10 | 11.2 | | (71) | 64 | | .63 | 0.085 | |
| 203 | " | " | " | -- | " | | 47 | 10 | 9.5 | | (80) | 74 | | .73 | 0.100 | |
| 203A | " | " | " | -- | " | | 15 | 10 | 12.0 | 17 | (37) | 30 | 1.13 | .33 | 0.044 | |
| 204 | Boiler No. 5 | 32.1* | 30,600 | -- | 25,500 lb/h | 84 | 79 | 0 | 7.6 | 82 | 113 | 106 | 1.04 | 4.40 | 0.137 | [B&W Stirling, 4 drum water tube, 5 burners, natural draft, no preheater.] |
| 204A | " | 32.1* | 30,600 | -- | 25,500 lb/h | 90 | 82 | 0 | 6.6 | 84 | 113 | 103 | 1.02 | 4.40 | 0.137 | |
| 205 | " | 47.3* | 45,000 | -- | 31,000/ 36,000 lb/h | | 76 | 50-380 | 4.6 | 84 | (98) | 83 | 1.11 | --- | --- | |
| 205A | " | " | " | -- | " | 93 | 81 | 110 | 5.1 | 84 | 105 | 92 | 1.14 | 6.01 | 0.127 | |
| 205B | " | 42.0* | 40,000 | -- | 30,000/ 37,000 lb/h | 77 | 63 | 2000+ | 3.6 | 67 | 80 | 65 | 1.03 | 4.07 | 0.097 | |
| 205C | " | 49.1* | 46,800 | -- | 35,000 lb/h | 84 | 81 | 0 | 8.4 | 83 | 120 | 116 | 1.02 | 7.12 | 0.145 | |
| 206 | " | 12.1* | 11,500 | -- | 13,000/ 14,000 lb/h | 33 | 29 | 0 | 12.8 | 30 | 72 | 64 | 1.03 | 1.05 | 0.087 | |
| 207 | Boiler No. 4 | 23.4* | 22,300 | -- | 17,200 lb/h | 66 | 63 | | 8.5 | 65 | 95 | 91 | 1.03 | 2.69 | 0.115 | [B&W Stirling, 4 Drum WT, 2 burners, forced draft, no preheater.] |
| 207A | " | " | " | -- | " | 74 | 67 | | 8.4 | 71 | 106 | 96 | 1.06 | 3.00 | 0.128 | |
| 208 | " | 39.4* | 37,500 | -- | 22,000 lb/h | 84 | 71 | | 5.5 | 73 | 98 | 82 | 1.03 | 4.69 | 0.119 | |
| 208A | " | 39.2* | 37,300 | -- | 19,000/ 26,000 lb/h | 95 | 77 | | 4.0 | 82 | 101 | 87 | 1.06 | 4.78 | 0.122 | |
| 208B | " | 39.1* | 37,200 | -- | 23,400 lb/h | 98 | 85 | | 3.7 | 87 | 102 | 88 | 1.02 | 4.81 | 0.123 | |
| 209 | " | 9.24* | 8,800 | -- | 3000/6500 lb/h | 13 | 10 | 20-345 | 15.2 | 17 | 40 | 31 | 1.70 | .44 | 0.048 | |
| 210 | Boiler No. 2 | 21.3+ | na | -- | 18,100 lb/h | 55 | 52 | 0 | 6.2 | -- | 67 | 63 | | 1.73 | 0.081 | [B&W Integral Furnace FM, 1 ring burner with oil gun, forced draft, no preheater.] |
| 210A | " | 19.1+ | " | -- | 16,200 lb/h | 53 | 48 | 0 | 6.7 | 52 | 67 | 60 | 1.08 | 1.55 | 0.081 | |
| 210B | " | 22.7+ | " | -- | 19,300 lb/h | 68 | 59 | 0 | 5.2 | | 77 | 67 | | 2.11 | 0.093 | |
| 211 | Boiler No. 1 | 14.6+ | " | -- | 12,400 lb/h | 46 | 47 | 260-386 | 4.4 | 48 | 50 | 51 | 1.02 | .89 | 0.061 | [Superior Combustion Industries Inc., DS 4.5-21, 1 ring burner w. oil gun, FD, no preheater.] |
| 212 | " | " | " | -- | " | 48 | 44 | 500-590 | 3.2 | 48 | 49 | 44 | 1.09 | .86 | 0.059 | |
| 213 | " | " | " | -- | " | 44 | 41 | 500-590 | 4.2 | 45 | 47 | 44 | 1.10 | .83 | 0.057 | |
| 214 | Boiler No. 1 | 10.2+ | " | -- | 495 gpm | 55 | 51 | 0 | 9.8 | 54 | 88 | 82 | 1.06 | 1.1 | 0.107 | [International LaMont, Mod. #TJW-C-3000-5, Used for water heating one burner.] |
| 215 | " | 7.3+ | " | -- | 495 gpm | 56 | 50 | 0 | 8.9 | 53 | 83 | 74 | 1.06 | .73 | 0.100 | |

A-26

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Fuel Oil | Process | NO (ppm): Dry | NO (ppm): Wet | CO (ppm): Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$): Dry | NO(3% $O_2$): Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 216 | Boiler No. 1 | 9.3+ | na | -- | 495 gpm | | 80 | 10 | 4.5 | 82 | (102) | 87 | 1.05 | 1.1 | 0.122 | |
| 216A | " | " | " | -- | 498 gpm | | 70 | 0 | 5.5 | -- | (94) | 81 | -- | 1.1 | 0.113 | |
| 216B | " | " | " | -- | " | | 80 | 0 | 5.0 | -- | (105) | 90 | -- | 1.2 | 0.126 | |
| 216C | " | " | " | -- | " | | 6 | 10 | 13.0 | -- | (15) | 14 | -- | 0.17 | 0.018 | |
| 216D | " | " | " | -- | " | | 72 | 100 | 8.5 | -- | (118) | 104 | -- | 1.32 | 0.142 | |
| 216E | " | " | " | -- | " | 72 | 66 | 10 | 7.5 | 68 | 96 | 88 | 1.03 | 1.1 | 0.116 | |
| 217 | " | " | " | -- | 500 gpm | 28 | 22 | 490 | 15.5 | 27 | 92 | 72 | 1.23 | 1.0 | 0.111 | |
| 218 | Boiler No. 2 | -- | -- | -- | 495 gpm | | 8 | 0 | 20.5 | -- | -- | -- | -- | -- | -- | |
| 218' | " | -- | -- | -- | " | | 33 | 440 | 12.5 | -- | (77) | 70 | -- | -- | 0.092 | Same as boiler of tests 214-217 |
| 218A | " | -- | -- | -- | " | | 20 | 430 | 12.0 | 23 | (44) | 40 | 1.15 | -- | 0.053 | |
| 219 | " | 4.4+ | -- | -- | " | 70 | 62 | 0 | 6.0 | 70 | 84 | 74 | 1.13 | .45 | 0.102 | |
| 220 | " | 2.0+ | -- | -- | " | 34 | 25 | 20 | 10.7 | 32 | 59 | 44 | 1.28 | .14 | 0.071 | |
| 221 | Kiln, Intermittent # 32 | 6.04* | 5750 | -- | -- | 130 | 108 | 0 | 2.4 | 115 | 126 | 105 | 1.06 | .92 | 0.153 | Beehive kiln at full firing rate and temp. |
| 222 | " | " | " | -- | -- | 123 | 110 | 0 | 2.2 | 115 | 118 | 105 | 1.05 | .86 | 0.143 | |
| 223 | " | " | " | -- | -- | 128 | 115 | 0 | 5.0 | 132 | 144 | 129 | 1.15 | 1.1 | 0.174 | |
| 224 | " | " | " | -- | -- | | 120 | 0 | 5.0 | 125 | (158) | 135 | 1.04 | 1.1 | 0.190 | |
| 225 | Kiln, Intermittent #42 | -- | -- | -- | -- | | 0 | 0 | 19.5 | -- | | 0 | -- | -- | 0 | Beehive kiln during water drying. |
| 226 | Tunnel Kiln #2 | 17.4* | 16,600 | -- | -- | | 10 | 10 | 18.5 | -- | (76) | 72 | -- | 1.59 | 0.091 | Data during different stages of loading and discharge. |
| 226A | " | " | " | -- | -- | | 12 | 10 | 18.5 | -- | (91) | 86 | -- | 1.90 | 0.109 | |
| 226B | " | " | " | -- | -- | | 5.5 | 0 | 19.5 | -- | (70) | 66 | -- | 1.46 | 0.084 | |
| 226C | " | " | " | -- | -- | 15 | 12 | 10 | 19.0 | 15 | 135 | 108 | 1.25 | 2.86 | 0.164 | |
| 226D | " | " | " | -- | -- | [illegible] | 5.9 | [illegible] | [illegible] | | [illegible] | [illegible] | [illegible] | [illegible] | 0.120 | |
| 226E | " | " | " | -- | -- | 8.5 | 8.3 | 25 | 19.5 | 10 | 102 | 100 | 1.20 | 2.16 | 0.124 | |
| 226F | " | " | " | -- | -- | 10 | 9.5 | 6 | 18.6 | 10 | 75 | 71 | 1.05 | 1.59 | 0.091 | |
| 226G | " | " | " | -- | -- | 11.5 | 11.8 | 15 | 18.0 | 12.5 | 69 | 71 | 1.06 | 1.46 | 0.084 | |
| 227 | Boiler No. 1 | 48.0+ | not known | -- | 40,800 lb/h | 130 | 120 | 0 | 5.6* | 122 | 152 | 140 | 1.02 | 8.9 | 0.185 | B&W Integral Furnace, 3 burner balanced draft, air preheat, heat exchanger. |
| 227A' | " | " | " | -- | " | | 135 | 55 | 3.1 | -- | (162) | 136 | -- | 9.3 | 0.194 | |
| 227A | " | " | " | -- | " | 163 | | 10 | 4.0 | -- | 173 | | -- | 10.1 | 0.210 | |
| 227B | " | " | " | -- | " | 163 | | 10 | 4.2 | -- | 175 | | -- | 10.2 | 0.213 | |
| 228 | Boiler No. 2 | 25.9+ | " | -- | 22,000 lb/h | 100 | | 650 | 2.4 | -- | 97 | | -- | 3.1 | 0.118 | Riley Badenhausen, S/N 1309, 2 burners, forced draft, no preheat. |
| 228A | " | " | " | -- | " | 120 | | 0 | 3.9* | -- | 126 | | -- | 4.0 | 0.153 | |
| 229 | " | 25.3+ | " | -- | 21,500 lb/h | 118 | | 0 | 3.9 | -- | 124 | | -- | 3.8 | 0.151 | |
| 230 | Boiler No. 3 | 49.4+ | " | -- | 42,000 lb/h | 118 | 112 | 0 | 6.7* | 115 | 149 | 141 | 1.03 | 8.9 | 0.181 | E&W Integral Tube Furnace, Size F-16-AE, 3 burners, FD, preheat. |
| 230A | " | " | " | -- | " | 165 | | 0 | 3.0 | | 165 | | -- | 9.9 | 0.200 | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates | | | NO (ppm) | | CO (ppm) | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) | | NOx/ NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Fuel Gas | Fuel Oil | Process | Dry | Wet | Dry | | | Dry | Wet | | | | |
| 231 | Boiler No. 4 | $48.2^{+}$ | not known | -- | 41,000 lb/h | 208 | | 10 | 2.8 | -- | 206 | | -- | 12.1 | 0.250 | [B&W F-743, 3 burners FD, preheat.] |
| 232 | " | " | " | -- | " | 165 | 158 | 0 | 6.0* | 161 | 198 | 190 | 1.02 | 11.6 | 0.240 | |
| 233 | Boiler No. 5 | $30.0^{+}$ | " | -- | 25,500 lb/h | 90 | 90 | 290 | 2.6 | -- | 88 | 88 | -- | 3.2 | 0.107 | [Coen, 1 burner, ND, no preheat.] |
| 234 | Boiler No. 4 | $45.3^{+}$ | " | -- | 38,500 lb/h | 72 | 65 | 0 | 8.1 | 66 | 101 | 91 | 1.02 | 3.7 | 0.123 | |
| 235 | " | $72.9^{+}$ | " | -- | 62,000 lb/h | 75 | 72 | 0 | 6.5 | 74 | 93 | 89 | 1.03 | 8.2 | 0.113 | [B&W Integral Furnace Boiler, 1 burner, FD.] |
| 236 | Boiler No. 3 | $29.4^{+}$ | " | -- | 25,000 lb/h | 93 | | 5 | 3.6 | -- | 96 | | -- | 3.4 | 0.117 | [Same as unit of tests 234-235.] |
| 237 | " | " | " | -- | " | 92 | | 10 | 3.0 | -- | 92 | | -- | 3.3 | 0.112 | |
| 237A | " | $55.9^{+}$ | " | -- | 47,500 lb/h | 94 | | 550 | 1.0 | -- | 87 | | -- | 5.9 | 0.106 | |
| 238 | Boiler 2 | $32.9^{+}$ | " | -- | 28,000 lb/h | 69 | 66 | 0 | 5.0 | 68 | 78 | 74 | 1.03 | 3.1 | 0.095 | [Same as units of tests 234-235.] |
| 238A | " | " | " | -- | " | 74 | 67 | 0 | 5.8 | 70 | 88 | 79 | 1.04 | 3.5 | 0.107 | |
| 239 | " | $67.1^{+}$ | " | -- | 57,000 lb/h | 90 | 85 | 15 | 3.0 | 87 | 90 | 85 | 1.02 | 7.3 | 0.109 | |
| 239A | " | $52.9^{+}$ | " | -- | 45,000 lb/h | 90 | | 15 | 3.0 | -- | 90 | | -- | 5.8 | 0.109 | |
| 240 | " | $32.9^{+}$ | " | -- | 28,000 lb/h | 45 | 85 | 15 | 3.0 | 86 | 95 | 85 | 1.01 | 3.8 | 0.115 | |
| 241 | Boiler 1 | $31.8^{+}$ | " | -- | 27,000 lb/h | 93 | | 5 | 3.6 | -- | 96 | | -- | 3.7 | 0.117 | [Same as units of tests 234-235.] |
| 242 | " | $40.0^{+}$ | " | -- | 34,000 lb/h | 92 | | 10 | 3.0 | -- | 92 | | -- | 4.5 | 0.112 | |
| 243 | " | $50.0^{+}$ | " | -- | 42,500 lb/h | 94 | | 550 | 1.6 | -- | 87 | | -- | 5.3 | 0.106 | |
| 244 | Boiler 8 | $16.9^{+}$ | " | -- | 14,400 lb/h | 135 | 135 | 50 | 7.5 | 140 | 162 | 160 | 1.04 | 3.3 | 0.197 | [3 burners each subdivided into 91 smaller burners, firing through refractory sleeve.] |
| 245 | " | $23.8^{+}$ | " | -- | 20,250 lb/h | 165 | 150 | 2000+ | 6.2 | 150 | 200 | 182 | 1.00 | 5.8 | 0.243 | |
| 246 | " | $21.2^{+}$ | " | -- | 18,000 lb/h | 173 | 153 | 1200 | 6.4 | 159 | 213 | 189 | 1.04 | 5.5 | 0.259 | |
| 247 | " | $23.8^{+}$ | " | -- | 20,250 lb/h | 170 | 140 | 2000+ | 5.4 | 155 | 213 | 162 | 1.11 | 6.2 | 0.259 | |
| 248 | " | $25.4^{+}$ | " | -- | 21,600 lb/h | 246 | 228 | 120 | 6.2 | 235 | 299 | 277 | 1.03 | 9.2 | 0.363 | |
| 249 | " | $22.2^{+}$ | " | -- | 18,900 lb/h | 180 | 165 | 0 | 7.2 | 170 | 235 | 215 | 1.03 | 6.3 | 0.285 | |
| 250 | " | " | " | -- | " | 170 | 156 | 2000 | 7.0 | 166 | 204 | 201 | 1.06 | 6.3 | 0.248 | |
| 251 | Boiler 7 | $12.2^{+}$ | " | -- | 9000-11,700 lb/h | 115 | 110 | 2000 | 5.6 | 110 | 159 | 129 | 1.00 | 2.4 | 0.193 | [3 burners, each subdivided into 91 smaller burners, firing through refractory sleeve.] |
| 252 | " | $23.8^{+}$ | " | -- | 19,800 - 20,700 lb/h | | 95 | >2000 | 4.6 | -- | (122) | 104 | -- | 3.5 | 0.146 | |
| 253 | " | $26.5^{+}$ | " | -- | 21,600 - 23,400 lb/h | 115 | | >2000 | 8.0 | -- | 159 | | -- | 5.1 | 0.193 | |
| 254 | " | " | " | -- | " | 105 | | >2000 | 2.8 | -- | 104 | | -- | 3.3 | 0.126 | |
| 255 | Boiler 1 | $47.1^{+}$ | " | -- | 40,000 lb/h | 133 | 120 | 0 | 5.2 | 125 | 152 | 137 | 1.04 | 8.7 | 0.185 | [B&W Integral Furnace, 6101-1, 3 burners, FD with air preheat, heat exchanger, methane + $H_2$] |
| 255A | " | " | " | -- | " | 131 | | 0 | 4.9 | -- | 147 | | -- | 8.4 | 0.179 | |
| 255B | " | " | " | -- | " | 132 | | 0 | 5.0 | -- | 149 | | -- | 8.5 | 0.181 | |
| 256 | Boiler 2 | " | " | -- | " | 92 | 79 | 10 | 2.2 | 80 | 88 | 76 | 1.01 | 5.0 | 0.107 | [Same as units of tests 255-255B] |
| 257 | " | " | " | -- | " | | 95 | 10 | 2.2 | -- | (109) | 91 | -- | 6.2 | 0.131 | |
| 258 | Dowtherm Heater | 3.0* | 2835 scfh | -- | " | 45 | 44 | 30 | 8.2 | 67 | 63 | 62 | 1.52 | .23 | 0.076 | [Union P170280, 1 burner hor. FD.] |

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| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 259 | Dowtherm Heater | 1.7* | 1636 scfh | -- | 40,000 lb/h | 24 | 23 | 20 | 8.0 | 24 | 33 | 32 | 1.04 | .07 | 0.040 | [Union P170540, 1 burner hor, FD] |
| 260 | Boiler 1 | 45.9+ | not known | -- | 39,000 lb/h | 51 | 50 | 0 | 7.2 | 52 | 67 | 65 | 1.04 | 3.7 | 0.080 | [Union, Contract 90047, ID, no preheat] |
| 261 | " | 48.2+ | " | -- | 41,000 lb/h | 58 | 55 | 0 | 6.6 | 56 | 73 | 69 | 1.02 | 4.2 | 0.088 | |
| 262 | Boiler 2 | 4.7+ | " | -- | 4,000 lb/h | | 95 | 0 | 10.0 | 97 | (173) | 155 | 1.02 | .98 | 0.208 | [B&W, contract FM-2306, 1 burner, FD, no preheat, firing into hot refractory] |
| 263 | " | 12.9+ | " | -- | 11,000 lb/h | 152 | 148 | 0 | 3.6 | 152 | 157 | 153 | 1.03 | 2.4 | 0.186 | |
| 264 | " | 21.4+ | " | -- | 18,200 lb/h | | 170 | 20 | 4.2 | 173 | (215) | 182 | 1.02 | 5.5 | 0.258 | |
| 265 | Power Plant | 491.1* | -- | 26,000 lb/h | 375,000 lb/h | 240 | 220 | 10 | 4.4 | 225 | 260 | 239 | 1.02 | 168.4 | 0.343 | [Riley Stoker Turbo-fire boiler, serial no. 3454, 6 burners WT, SH, RH, economizer, "Apollo fuel oil additive] |
| 266 | " | 472.2* | -- | 25,000 lb/h | 373,000 lb/h | 195 | 178 | 10 | 2.6 | 182 | 191 | 174 | 1.02 | 119.0 | 0.252 | |
| 267 | " | 387.2* | -- | 20,500 lb/h | 315,000 lb/h | 198 | 178 | 10 | 2.4 | 182 | 191 | 172 | 1.02 | 97.6 | 0.252 | |
| 268 | " | 396.7* | -- | 21,000 lb/h | 308,000 lb/h | 205 | 188 | 10 | 3.9 | 192 | 216 | 198 | 1.02 | 113.1 | 0.285 | |
| 269 | " | " | -- | " | 310,000 lb/h | 178 | 160 | 10 | 3.9 | 163 | 188 | 168 | 1.02 | 98.4 | 0.248 | |
| 270 | " | " | -- | " | " | 168 | 152 | 20 | 3.6 | 155 | 174 | 157 | 1.02 | 91.2 | 0.230 | |
| 271 | " | 388.3* | 190,800 scfh | 10,000 lb/h | 305,000 lb/h | 232 | 212 | 10 | 2.2 | 216 | 222 | | 1.02 | 109.5 | 0.282 | |
| 272 | " | 407.3* | " | 11,000 lb/h | 307,000 lb/h | 260 | 234 | 10 | 3.9 | 238 | 273 | | 1.02 | 140.9 | 0.346 | |
| 273 | " | 420.0* | 400,000 scfh | 0 | 320,000 lb/h | 140 | 138 | 10 | 2.8 | 138 | 138 | | 1.00 | 70.6 | 0.168 | |
| 274 | " | 436.6* | 83,000 scfh | 18,500 lb/h | 320,000 lb/h | 225 | 212 | 10 | 4.0 | 215 | 238 | | 1.01 | 131.9 | 0.302 | |
| 275 | " | " | " | " | 321,000 lb/h | 188 | 180 | 10 | 3.0 | 184 | 188 | 180 | 1.02 | 103.9 | 0.238 | |
| 276 | " | 514.3* | 85,000 scfh | 22,500 lb/h | 380,000 lb/h | 199 | 182 | 10 | 2.8 | 188 | 199 | | 1.03 | 138.6 | 0.250 | |
| 277 | " | 179.4* | 0 | 9,500 lb/h | 120,000 lb/h | | 130 | 10 | 7.2 | 135 | 195 | 170 | 1.04 | 46.1 | 0.257 | |
| 278 | " | 174.7* | 0 | 9,250 lb/h | " | 125 | 115 | 15 | 5.2 | 120 | 142 | | 1.04 | 32.7 | 0.187 | |
| 279 | " | 252.0* | 240,000 | 0 | 165,000 lb/h | 147 | 142 | 5 | 5.6 | 150 | 170 | | 1.06 | 52.2 | 0.207 | |
| 280 | " | 241.5* | 230,000 | 0 | 160,000 lb/h | 115 | 105 | 10 | 2.5 | 110 | 112 | | 1.05 | 32.8 | 0.136 | [B&W type FMD-10, Mod., No. 78B, 1 |
| 281 | Process Boiler | 30.6* | not known | -- | 26,000 lb/h | | 95 | 2000+ | .2 | 98 | (102) | 83 | 1.03 | 3.7 | 0.122 | burner, FD] |
| 282 | Power Plant Boiler | 113.4* | 108,000 scfh | -- | 107,000 lb/h | 103 | 79 | 40 | 12.0 | 82 | 185 | 156 | 1.04 | 25.2 | 0.222 | [B&W Rad. 26-3 1/2] |
| 283 | " | 239.4* | 228,000 scfh | -- | 209,000 lb/h | 145 | 130 | 10 | 6.6 | 135 | 181 | 162 | 1.04 | 52.0 | 0.217 | |
| 284 | " | 393.8* | 375,000 scfh | -- | 312,000 lb/h | 193 | 180 | 5 | 5.8 | 185 | 228 | 213 | 1.03 | 107.7 | 0.274 | |
| 285 | " | 507.2* | 483,000 scfh | -- | 400,000 lb/h | 280 | 260 | >5 | 4.2 | 265 | 300 | 278 | 1.02 | 182.6 | 0.360 | |
| 286 | Power Plant Boiler | 113.4* | 108,000 scfh | -- | 110,000 lb/h | 92 | 84 | 0 | 10.5 | 88 | 158 | 144 | 1.05 | 21.5 | 0.190 | |
| 287 | " | 231.0* | 220,000 scfh | -- | 218,000 lb/h | 195 | 165 | 0 | 5.4 | 172 | 225 | 190 | 1.04 | 62.4 | 0.270 | |
| 288 | " | 329.7* | 314,000 scfh | -- | 310,000 lb/h | 215 | 200 | >5 | 5.0 | 205 | 242 | 225 | 1.03 | 95.7 | 0.290 | |
| 289 | " | 412.7* | 393,000 scfh | -- | 400,000 lb/h | 310 | 300 | >5 | 4.0 | 305 | 328 | 318 | 1.02 | 162.4 | 0.394 | |
| 290 | " | 162.8* | -- | 8,800 lb/h | 118,000 lb/h | 130 | 103 | >5 | 12.0 | 119 | 234 | 206 | 1.16 | 50.3 | 0.309 | |
| 291 | " | 310.8* | -- | 16,800 " | 212,000 lb/h | 193 | 182 | 10 | 8.7 | 185 | 282 | 266 | 1.02 | 115.6 | 0.372 | |
| 292 | " | 432.9* | -- | 23,400 " | 309,000 lb/h | 210 | 193 | 10 | 7.0 | 199 | 271 | 249 | 1.03 | 154.9 | 0.358 | |
| 293 | " | 503.2* | -- | 27,200 " | 360,000 lb/h | 235 | 225 | 10 | 6.6 | 232 | 294 | 281 | 1.03 | 195.3 | 0.388 | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 294 | Power Plant Boiler | 162.8* | -- | 8,800 lb/h | 115,000 lb/h | 142 | 130 | >5 | 10.0 | 135 | 232 | 212 | 1.04 | 49.9 | 0.306 | |
| 295 | (same as tests 281-285) | 281.2* | -- | 15,200 " | 200,000 lb/h | 210 | 194 | >5 | 8.0 | 200 | 290 | 268 | 1.03 | 107.6 | 0.383 | |
| 296 | " | 436.6* | -- | 23,600 " | 300,000 lb/h | 225 | 210 | 10 | 6.8 | 215 | 285 | 266 | 1.02 | 164.2 | 0.376 | |
| 297 | " | 540.2* | -- | 29,200 " | 370,000 lb/h | 240 | 228 | 10 | 6.0 | 228 | 288 | 271 | 1.00 | 205.4 | 0.380 | |
| 298 | Power Plant Boiler | 451.5* | 430,000 scfh | -- | 305,000 lb/h | 185 | 167 | 0 | 9.2 | 173 | 282 | 255 | 1.04 | 152.6 | 0.338 | |
| 298A | " | " | " | -- | " | 193 | 182 | 0 | 9.8 | -- | 310 | 292 | -- | 167.8 | 0.372 | |
| 298B | " | " | " | -- | " | 232 | 220 | 0 | 7.5 | -- | 310 | 294 | -- | 167.8 | 0.372 | |
| 298C | " | " | " | -- | " | 240 | 225 | 0 | 7.3 | -- | 316 | 296 | -- | 171.1 | 0.379 | |
| 298D | " | " | " | -- | " | 223 | 210 | 0 | 8.5 | - | 321 | 302 | -- | 173.8 | 0.385 | |
| 298E | " | " | " | -- | " | 215 | 200 | 0 | 9.5 | -- | 337 | 313 | -- | 182.6 | 0.404 | |
| 299 | " | 1332* | 720,000 scfh | -- | 540,000 lb/h | 143 | 120 | 5 | 2.7 | -- | 141 | 118 | -- | 225.4 | 0.169 | |
| 299A | " | " | " | -- | " | 175 | 150 | 10 | 3.2 | -- | 177 | 152 | -- | 282.9 | 0.212 | |
| 300 | " | 2054* | 1,110,000 scfh | -- | 800,000 lb/h | 212 | 190 | 10 | 2.4 | -- | 205 | 184 | -- | 505.3 | 0.246 | |
| 300A | " | " | " | -- | " | 175 | 155 | 50 | 2.0 | -- | 166 | 147 | -- | 409.2 | 0.199 | |
| 301 | " | 1481* | 1,410,000 scfh | -- | 1,120,000 lb/h | 295 | 280 | 40 | 1.5 | -- | 272 | 258 | -- | 483.4 | 0.326 | |
| 301A | " | " | " | -- | " | 215 | 195 | 80 | 4.2 | -- | 238 | 209 | -- | 408.8 | 0.276 | |
| 301B | " | " | " | -- | " | 260 | 223 | 5 | 3.0 | -- | 260 | 223 | -- | 462.1 | 0.312 | |
| 301C | " | " | " | -- | " | 260 | 250 | 20 | 2.8 | -- | 257 | 247 | -- | 456.7 | 0.373 | |
| 301D | " | " | " | -- | " | 320 | 290 | 5 | 2.5 | -- | 311 | 282 | -- | 552.7 | 0.329 | |
| 301E | " | " | " | -- | " | 250 | 230 | 20 | 4.6 | -- | 274 | 252 | -- | 487.0 | 0.329 | |
| 302 | " | 573.5* | -- | 31,000 lb/h | 425,000 lb/h | 225 | 210 | 0 | 7.2 | -- | 279 | 260 | -- | 211.2 | 0.368 | |
| 302A | " | " | -- | " | " | 232 | 220 | 0 | 5.0 | -- | 262 | 249 | -- | 198.3 | 0.346 | |
| 302B | " | " | -- | " | " | 235 | 230 | 0 | 5.6 | -- | 275 | 269 | -- | 208.2 | 0.363 | |
| 302C | " | " | -- | " | " | 250 | 250 | 0 | 5.6 | -- | 293 | 293 | -- | 221.8 | 0.387 | |
| 302D | " | " | -- | " | " | 210 | 205 | 0 | 7.4 | -- | 279 | 273 | -- | 211.2 | 0.368 | |
| 302E | " | " | -- | " | " | | 205 | 0 | 8.4 | -- | | 293 | -- | 221.8 | 0.387 | |
| 303 | " | 962.0* | -- | 52,000 lb/h | 625,000 lb/h | 178 | 173 | 0 | 4.4 | -- | 194 | 189 | -- | 246.3 | 0.256 | |
| 303A | " | " | -- | " | " | 195 | 180 | 0 | 3.2 | -- | 197 | 182 | -- | 250.2 | 0.260 | |
| 304 | " | 1332* | -- | 72,000 lb/h | 845,000 lb/h | 209 | 190 | 10 | 2.6 | -- | 204 | 186 | -- | 358.7 | 0.269 | |
| 304A | " | " | -- | " | " | 193 | 180 | 10 | 3.0 | -- | 193 | 180 | -- | 339.3 | 0.255 | |

| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/ NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 305 | Power Plant Boiler | 1684-1813* | -- | 91,000-98,000 lb/h | 1,110,000 lb/h | 320 | 300 | 10 | 3.6 | -- | 331 | 310 | -- | 764.1 | 0.437 | |
| 305A | " | " | -- | " | " | 260 | 240 | 10 | 6.4 | -- | 320 | 296 | -- | 738.6 | 0.422 | |
| 305B | " | " | -- | " | " | 325 | 305 | 10 | 2.8 | -- | 320 | 301 | -- | 738.6 | 0.422 | |
| 305C | " | " | -- | " | " | 340 | 320 | 40 | 2.4 | -- | 329 | 301 | -- | 759.3 | 0.434 | |
| 305D | " | " | -- | " | " | 320 | 295 | 250 | 2.0 | -- | 304 | 280 | -- | 701.6 | 0.401 | |
| 305E | " | " | -- | " | " | 275 | 260 | 100 | 4.2 | -- | 295 | 279 | -- | 680.9 | 0.389 | |
| 306 | Industrial Boiler | 105.9+ | -- | -- | 90,000 lb/h | 85 | 76 | 2000+ | 4.1 | 80 | 98 | 89 | 1.05 | 12.5 | 0.118 | |
| 307 | Industrial Boiler | 32.4+ | -- | -- | 27,500 lb/h | 48 | 28 | 0 | 7.5 | -- | 64 | 37 | -- | 2.5 | 0.077 | |
| 308 | Industrial Boiler | 16.5+ | -- | -- | 14,000 lb/h | 85 | 66 | 0 | 8.0 | -- | 118 | 91 | -- | 2.3 | 0.142 | |
| 309 | " | 33.5+ | -- | -- | 28,500 lb/h | 120 | 120 | 0 | 5.0 | -- | 135 | 135 | -- | 5.4 | 0.162 | |
| 310 | Industrial Boiler | 37.8* | 3600 | -- | not known | | 44 | 45 | 13.5 | 58 | (101) | 93 | 1.09 | 4.6 | 0.121 | |
| 311 | " | " | " | -- | " | 50 | 45 | 45 | 12.5 | 48 | 95 | 85 | 1.07 | 4.3 | 0.114 | |
| 312 | " | 49.1* | 4680 | -- | " | 71 | 52 | 60 | 9.5 | 66 | 111 | 81 | 1.27 | 6.5 | 0.133 | |
| 313 | Compressor I.C.E. | 4.79+ | not known | -- | -- | | 520 | 50 | 13.5 | 540 | (1362) | 1250 | 1.04 | 7.8 | 1.634 | |
| 314 | " | 4.72+ | " | -- | -- | (540) | 700 | 90 | 13.5 | (650) | (1830) | 1680 | .93 | 10.4 | 2.20 | |
| 315 | " | 9.65+ | " | -- | -- | 270 | 240 | 90 | 15.0 | 260 | 810 | 720 | 1.08 | 9.4 | 0.972 | |
| 316 | " | 7.15+ | " | -- | -- | 54 | 40 | 90 | 16.0 | 50 | 195 | 144 | 1.25 | 1.7 | 0.234 | |
| 317 | " | 14.30+ | " | -- | -- | (370) | 450 | 115 | 15.5 | 460 | (1590) | 1460 | 1.02 | 27.3 | 1.908 | |
| 317A | " | " | " | -- | -- | 425 | 410 | 100 | 15.0 | 425 | 1275 | 1230 | 1.04 | 21.9 | 1.530 | [No data taken] |
| 318 | " | 7.87+ | " | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | |
| 319 | " | " | " | -- | -- | | 1050 | 100 | 13.8 | 1125 | (2853) | 2625 | 1.07 | 26.9 | 3.424 | |
| 319A | " | " | " | -- | -- | 580 | 550 | 100 | 13.5 | 560 | 1415 | 1340 | 1.02 | 13.4 | 1.698 | |
| 320 | Industrial Boiler | -- | " | -- | 0 | 13.5 | 6.8 | 50 | 19.0 | 7.4 | 122 | 61 | 1.09 | -- | 0.15 | |
| 321 | " | 28.8+ | " | -- | 24,500 lb/h | 80 | 64 | 10 | 5.0 | 67 | 90 | 72 | 1.05 | 3.1 | 0.11 | |
| 322 | " | 27.4+ | " | -- | 23,300 lb/h | 66 | 52 | 10 | 6.2 | 54 | 80 | 63 | 1.04 | 2.6 | 0.10 | |
| 323 | " | 27.1+ | " | -- | 23,000 lb/h | 70 | 63 | 10 | 4.2 | 65 | 75 | 67 | 1.03 | 2.4 | 0.09 | |
| 324 | " | 14.7+ | " | -- | 12,500 lb/h | 36 | 30 | 0 | 9.9 | 32 | 58 | 48 | 1.07 | 1.0 | 0.070 | |
| 325 | " | -- | " | -- | 0 | 27 | 17 | 350 | 15.0 | 17 | 81 | 51 | 1.00 | -- | 0.097 | |
| 226 | " | 16.9+ | " | -- | 14,400 lb/h | 43 | 34 | 110 | 5.2 | 34 | 49 | 39 | 1.00 | .99 | 0.060 | |
| 327 | " | 25.3+ | " | -- | 21,500 lb/h | 48 | 38 | 50 | 8.0 | 38 | 66 | 53 | 1.00 | 2.0 | 0.079 | |
| 328 | Compressor I.C.E. | 1.28+ | " | -- | -- | | 500 | 260 | 14.0 | 600 | (1397) | 1285 | 1.20 | 2.2 | 1.676 | |
| 329 | " | " | " | -- | -- | | 550 | 350 | 14.3 | 625 | (1609) | 1480 | 1.14 | 2.5 | 1.931 | |
| 330 | " | " | " | -- | -- | 425 | 350 | 300 | 14.5 | 450 | 1200 | 990 | 1.29 | 1.8 | 1.44 | |

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| Test No. | Combustion Device | Heat Input MMB/h | Flow Rates: Fuel Gas | Flow Rates: Fuel Oil | Flow Rates: Process | NO (ppm) Dry | NO (ppm) Wet | CO (ppm) Dry | $O_2$,% Dry | NOx (ppm) | NO(3% $O_2$) Dry | NO(3% $O_2$) Wet | NOx/NO | NO(lb/h) | Emission Factor (lb/MMB) (NO as $NO_2$) | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 331 | Compressor I.C.E. | 1.03+ | not known | -- | -- | 110 | 80 | 200 | 15.0 | 100 | 330 | 240 | 1.25 | .41 | 0.40 | |
| 332 | " | 5.01+ | " | -- | -- | 1250 | 1225 | 200 | 13.0 | 1250 | 2812 | 2756 | 1.02 | 16.9 | 3.37 | |
| 333 | " | 3.79+ | " | -- | -- | 1525 | 1425 | 340 | 12.5 | 1475 | 3229 | 3018 | 1.04 | 14.7 | 3.88 | [4295 peak NO @ 3% $O_2$] |
| 334 | Open Hearth Furnace(1) | -- | -- | -- | -- | | 3225 | 600 | 4.0 | | | 3420 | | | | |
| 335 | " | -- | 40.5x10$^3$ scfh | 1 gpm | -- | 2400 | 3625 | 400 | 4.6 | | 2635 | 3985 | | | | |
| 336 | " | -- | -- | -- | -- | | 3600 | 0 | 10.0 | 3750 | | 5390 | 1.04 | | | [6710 peak NO @ 3% $O_2$] |
| 337 | " | -- | -- | -- | -- | 1400 | 2025 | 340 | 12.0 | 3000 | 2800 | 5850 | 1.03 | | | [8100 peak NO @ 3% $O_2$] |
| 338 | " | -- | -- | -- | -- | | 3400 | 0 | 10.0 | | | 5560 | | | | |
| 339 | Water Cooled Probe | -- | -- | -- | -- | | 3400 | 20 | 10.0 | | | 5560 | | | | |
| 340 | " | -- | -- | -- | -- | 2400 | 4000 | 300 | 4.0 | | 2520 | 4240 | | | | |
| 341 | " | -- | -- | -- | -- | | 3800 | 300 | 3.5 | | | 3910 | | | | |
| 342 | " | -- | -- | -- | -- | 2200 | 3700 | 540 | 3.5 | 3800 | 2265 | 3810 | 1.03 | | | |
| 343 | " | -- | -- | -- | -- | | 3150 | 1640 | 3.5 | 3400 | | 3400 | 1.08 | | | |
| 344 | " | -- | -- | -- | -- | | 3000 | 700 | 3.5 | | | 4115 | | | | |
| 345 | " | -- | -- | -- | -- | | 5100 | 2000 | 3.5 | | | 5250 | | | | |
| 346 | " | -- | -- | -- | -- | | 6000 | 2000 | 3.5 | | | 6175 | | | | |

APPENDIX B - QUESTIONNAIRE

1. <u>DEVICE RATING, OPERATIONAL DATA</u>

OWNER/OPERATOR ______________________________________________

PLANT ADDRESS ______________________________________________

PLANT CONTACT ______________________________ PHONE ______________

PLANT PRINCIPAL PRODUCT ______________________________________

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| A. | Device Number | | | | | | | | Misc Small Devices |
| B. | Plant Unit Number | | | | | | | | |
| C. | APCD Permit # | | | | | | | | |
| D. | Device Type | | | | | | | | |
| E. | Rated Energy Input | | Millions Btu/hr | | | | | | <10 |
| F. | | | Gallons Oil/hr | | | | | | |
| G. | Rated Energy Output | | 1000 lb Steam/hr | | | | | | |
| H. | | | BHP | | | | | | |
| I. | Typical Operational hr/day | | Aug.-Hrs. | | | | | | |
| J. | | | Dec.-Hrs. | | | | | | |
| K. | Typical Operational Days/Week | | Aug.-Days | | | | | | |
| L. | | | Dec.-Days | | | | | | |
| M. | Typical Operational Duty Cycle | | Continuous | | | | | | |
| N. | | | On-Min. | | | | | | |
| O. | | | Off-Min. | | | | | | |
| P. | Total Operational Hours | 1972 | Gas-Hrs. | | | | | | |
| Q. | | | Oil-Hrs. | | | | | | |
| R. | | 1973 | Gas-Hrs. | | | | | | |
| S. | | | Oil-Hrs. | | | | | | |
| T. | Typical Operational Load Fraction | | Aug. % | | | | | | |
| U. | | | Dec. % | | | | | | |
| V. | | | Year % | | | | | | |

Figure B-1. Fuel Use Questionnaire For ARB NOx Inventory Part I - Device Rating, Operational Data

## II. FUEL USE

| | | PLANT TOTAL | DEVICE | | | | MISC SMALL DEVICES |
|---|---|---|---|---|---|---|---|
| GAS | Calendar 1972 | | | | | | |
| Type________ | August 1972 | | | | | | |
| Units________ | December 1972 | | | | | | |
| Heating Value______ Btu/cu.ft. | Calendar 1973 | | | | | | |
| | August 1973 | | | | | | |
| | December 1973 | | | | | | |
| OIL | Calendar 1972 | | | | | | |
| Type______ #___ | August 1972 | | | | | | |
| Units________ | December 1972 | | | | | | |
| Heating Value______ Btu/lb | Calendar 1973 | | | | | | |
| | August 1973 | | | | | | |
| | December 1973 | | | | | | |
| OIL | Calendar 1972 | | | | | | |
| Type______ #___ | August 1972 | | | | | | |
| Units________ | December 1972 | | | | | | |
| Heating Value______ Btu/lb | Calendar 1973 | | | | | | |
| | August 1973 | | | | | | |
| | December 1973 | | | | | | |

Figure B-2 Fuel Use Questionnaire For ARB NOx Inventory Part II - Fuel Use

| BIBLIOGRAPHIC DATA SHEET | 1. Report No. ARB-R-2-1471-74-31 | 2. | PB 237 688 |
|---|---|---|---|

| | |
|---|---|
| 4. Title and Subtitle<br>CONTROL OF OXIDES OF NITROGEN FROM STATIONARY SOURCES IN THE SOUTH COAST AIR BASIN (OF CALIFORNIA). | 5. Report Date<br>Sept. 1974<br>6. |
| 7. Author(s)<br>D. R. Bartz, K.W. Arledge, J.E.Gabrielson, L.G.Hays, S.C.Hunter | 8. Performing Organization Rept. No. KVB-5 800-179 |
| 9. Performing Organization Name and Address<br>KVB Engineering, Inc.<br>17332 Irvine Blvd.<br>Tustin, CA. 92680 | 10. Project/Task/Work Unit No.<br>~~ARB-2-387-19~~<br>11. Contract/Grant No.<br>~~ARB 2-1471~~ |
| 12. Sponsoring Organization Name and Address<br>Air Resources Board<br>Resources Agency<br>1709-11th Street<br>Sacramento, CA. 95814 | 13. Type of Report & Period Covered<br>Final 9/73-10/74<br>14. |

15. Supplementary Notes

16. Abstracts

A comprehensive inventory has been taken of oxides of nitrogen ($NO_x$) emissions from stationary sources within the South Coast Air Basin in California for the period of July 1972 through June 1973. Included are the emissions from over 1500 point sources assessed from detailed device and fuel use information provided by operators, and emissions from area distributed domestic, commercial, and industrial sources, essentially accounting for all fuel burned by stationary sources in the Basin.

Seasonal variations of emissions were assessed, as was the geographical distribution on a 10 km grid square basis. Forecasts were made of emissions in the several source categories for 1975 and 1980.

The amount of stationary source emissions that could be reduced on a cost effective basis equal to or greater than that of current mobile source controls was examined.

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

Air Pollution
Air Pollution Control Equipment
Power
Electric Power Plants
Refining
Smog
Contaminants
Oxides
Emission Exhaust Gases
Combustion Products
Combustion Efficiency
Boilers
Fuel Oil
Gas Fuel

**PRICES SUBJECT TO CHANGE**

17b. Identifiers/Open-Ended Terms

Oxides of nitrogen ($NO_x$) emissions
Stationary source emissions
Cost-effective emission reductions
Power plant emissions
Refinery emissions
Control of oxides of nitrogen
South Coast Air Basin



17c. COSATI Field/Group 0402 1002 1301 1308 2102 0702 1108 1302 1407 2104

| | | |
|---|---|---|
| 18. Availability Statement Release unlimited. Available from National Technical Information Services, 5285 Port Royal Road, Springfield, VA. 22151 | 19. Security Class (This Report) UNCLASSIFIED<br>20. Security Class (This Page) UNCLASSIFIED | 21. No. of Pages |

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