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EMISSIONS AND COST ESTIMATES FOR GLOBALLY SIGNIFICANT ANTHROPOGENIC COMBUSTION SOURCES OF NO_x, N_2O, CH_4, CO, and CO_2

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SECTION 3

UTILITY SOURCES AND CONTROLS

As part of the utility category, performance and costs estimates were developed for 15 utility plant technologies and for 9 emission control technologies. The source and control technologies primarily include conventional, commercially available technologies. The first part of this section discusses the development of efficiency, emission factor, and cost estimates for utility sources. A discussion of efficiency penalty, emission reduction efficiency, and costs for utility emission control technologies follows. A glossary of all abbreviated terms appearing in the tables of this section appears at the end of this report.

DATA FOR EMISSION SOURCES

Table 8 summarizes the efficiency, emission factor, and cost estimates developed for 15 utility plant technologies. These include natural gas, distillate oil, residual oil, shale oil, coal, wood, and municipal solid waste (MSW) combustion technologies. The efficiency for each technology is based on the conversion of fuel energy to electricity delivered to the user. Costs are 1985 annualized costs based on the total electricity delivered to the user over a period of 1 year. Uncontrolled emission factor estimates are reported on the basis of grams of pollutant emitted per gigajoule of electricity delivered to the user. To the right of each emission factor is the emission factor quality rating. For each utility technology, appropriate control technologies are identified by codes. The codes within parenthesis are retrofit options.

Efficiency and Transmission Loss

The utility plant efficiency estimates reported in Table 8 represent the conversion of fuel energy to electricity delivered to end-users through a transmission and distribution system. Typically, power plant electrical generation is measured at the busbar, which approximately represents the boundary between the power plant and the electrical distribution system. Additional losses in transformers, transmission wires, and other equipment are

TABLE 8. UTILITY BOILER SOURCE PERFORMANCE AND COSTS

Source	Efficiency (%)	Cost[a] ($/J end-use)	Emissions Factors (g/GJ delivered electricity) and Data Quality Ratings (A - E): CO_2	CO	CH_4	N_2O	NO_x	Controls[b]
Natural Gas - Boilers	32.4	6.4E-09	150,000 A	53 A	0.4 C	N/A	740 A	U1, U3, U8, U10, U13, U18, (U19, U21, U25, U26, U27)
Gas Turbine Combined Cycle	42.0	4.3E-09	120,300 A	70 A	13 C	N/A	400 A	U14, U15
Gas Turbine Simple Cycle	26.4	1.0E-09	191,400 A	110 A	20 C	N/A	640 A	U14, U15
Residual Oil Boilers	32.4	6.7E-09	230,000 A	43 A	2.2 A	N/A	590 A	U1, U4, U7, U10, U12, U17, (U19, U22, U24, U26, U27)
Distillate Oil Boilers	32.4	6.7E-09	220,000 A	43 D	0.1 D	N/A	200 D	U1, U4, U7, U10, U12, U17, (U19, U22, U24, U26, U27)
Shale Oil Boilers	32.4	6.7E-09	230,000 E	43 E	2.2 E	N/A	590 E	U1, U4, U7, U10, U12, U17, (U19, U22, U24, U26, U27)
MSW - Mass Feed	18.7	3.8E-08	460,000 D	500 B	N/A	N/A	710 B	U1
MSW - Refuse Derived Fuel	18.7	3.8E-08	450,000 D	N/A	N/A	N/A	N/A	U1

TABLE 8. (Continued)

Source	Efficiency (%)	Cost[a] ($/J end-use)	Emissions Factors (g/GJ delivered electricity) and Data Quality Ratings (A - E): CO_2	CO	CH_4	N_2O	NO_x	Controls[b]
Coal-Spreader Stoker	31.0	N/A	340,000 C	370 B	2.1 B	2.5 E	1,000 B	U1, U2, U10, U11, U16, (U19, U20, U27)
Coal-Fluidized Bed Combined Cycle	35.0	1.2E-08	290,000 C	N/A	1.8 C	N/A	N/A	U10, U12, U16, (U27)
Coal-Fluidized Bed	31.4	9.5E-09	330,000 C	N/A	2.0 C	N/A	770 C	U10, U12, U16, (U27)
Coal - Pulverized Coal	31.3	9.5E-09	330,000 C	42 B	2.0 B	2.5 E	2,600 C	U9, U10, U11, U16, (U27)
Coal-Tangentially Fired	31.3	9.5E-09	330,000 C	42 B	2.0 B	2.5 E	1,000 B	U1, U2, U6, U10, U11, U16, (U19, U20, U23, U26, U27)
Coal - Pulverized Coal Wall-Fired	31.3	9.5E-09	330,000 C	42 B	2.0 B	2.5 E	1,400 B	U1, U2, U5, U10, U11, U16, (U19, U20, U23, U26, U27)
Wood-Fired Boilers	15.9	1.3E-08	590,000 C	8,800 D	88 E	N/A	670 C	U1, U10, U11, (U19, U27)

[a]All costs in 1985 dollars.

[b]Control codes in parenthesis indicate the retrofit emission control options. The controls are defined ibn Table 11.

incurred in the distribution of electricity from the power plant to the end-users.

To estimate the end-user energy conversion efficiency, first the busbar efficiency was estimated; the busbar efficiency for each source was then reduced to account for typical transmission losses using a global average transmission loss. The development of busbar efficiency estimates will be discussed separately for each emission source. The development of the transmission loss estimate, which was applied to all utility sources, will be discussed first.

The global average transmission loss as a percent of busbar generation was determined by ranking the largest electricity generating nations and their transmission losses. From this information, a generation-weighted transmission loss was derived. Table 9 presents the top 11 electricity generating countries, which represent nearly 75 percent of the world's total generation. The rankings in Table 9 are based on U.N. data. The weighted average loss is 8 percent. Therefore, a transmission efficiency of 92 percent was applied to all busbar efficiencies to determine the net efficiency of electricity production and distribution.

The efficiency estimates for natural gas-, distillate oil-, residual oil-, and shale oil-fired boilers are all 32.4 percent conversion of fuel energy to end-user electricity. The efficiency for these four fuels is estimated to be the same because typically natural gas-fired and oil-fired boilers have the same thermal efficiency. Boiler efficiency is estimated to be 88 percent, based on 85 percent efficiency for a boiler without air preheat and an additional 3 percentage points due to air preheat (U.S. EPA, 1982a; Babcock and Wilcox, 1978). The boiler efficiency is limited by the combustion efficiency, heat transfer losses within the boiler, and losses due to energy exhausted in flue gas. The overall power plant efficiency is limited by the boiler efficiency and by other factors. These factors include cycle losses and auxiliary equipment. The cycle efficiency is limited by the maximum theoretical efficiency for any heat engine. Additional losses in an actual power plant cycle are introduced by inefficiencies in the turbine. Energy is required to operate power plant auxiliary machinery such as fans and pumps, which reduce the energy available for transmission. The busbar efficiency for these four sources, after accounting for boiler efficiency, cycle efficiency, and auxiliary power requirements, is 35.2 percent.

TABLE 9. GLOBAL AVERAGE TRANSMISSION LOSS

Country	Percent of World Total Generation[a]	Percent Weight	Percent Loss[b]
United States of America	26.7	36	7.0
Union of Soviet Socialtist Republic	16.1	22	8.3
Japan	7.0	9	6.1
Canada	4.7	6	8.5
People's Republic of China	4.1	6	14.6
Federal Republic of Germany	4.1	6	4.3
France	3.3	4	7.5
United Kingdom	3.0	4	8.1
Italy	1.9	3	8.8
Brazil	1.9	3	8.3
India	1.8	2	18.0
TOTAL	74.6	100	AVE = 8.0[c]

[a]Includes fossil fuel, hydroelectric, and nuclear generation.

[b]Percent of busbar generation lost in transmission and distribution.

[c]Weighted average based on electrical generation.

Source: United Nations, 1986.

A globally representative simple cycle gas turbine efficiency was estimated based on projected international sales data for several gas turbine models and a sales-weighted average of their respective efficiencies. Gas turbine models with the highest projected sales included most General Electric models, the Westinghouse 251 and 501, and models from Brown Boveri, Rolls Royce, Avco, and Solar. The average efficiency for a simple cycle gas turbine, including a transmission loss of 8 percent, is 26.4 percent. As a check, this efficiency was compared to the 1985 U.S. national efficiency, adjusted for transmission loss, of 26.2 percent, indicating that the estimate derived from a global sales-weighted average is reasonable.

Busbar efficiencies for combined cycle gas turbines range from roughly 43 percent to 50 percent (Cohen et al., 1987). Assuming a representative efficiency approximately in the middle of this range, an end-user energy conversion efficiency of 42 percent was derived.

The efficiencies for coal boilers were estimated in a manner similar to those for oil and gas boilers. For spreader stoker coal boilers, a boiler efficiency of 81 percent was adjusted to 84 percent to account for air preheat (Babcock and Wilcox, 1978). The utility boiler efficiency for pulverized coal (PC) boilers, including cyclone, tangentially fired (TF), and wall-fired (WF) units, is approximately 85 percent, including air preheat (Holstein, 1981). From these boiler efficiencies, and from cycle losses and the typical energy requirements for power plant auxiliaries as previously discussed, the busbar efficiency was estimated to be 33.7 percent for spreader stoker units and 34.0 percent for the pulverized coal units. These values are equivalent to an end-user energy conversion efficiencies of 31.0 percent and 31.3 percent, respectively.

The busbar efficiency of coal-fired fluidized bed (FB) and fluidized bed combined cycle (FBCC) plants are 34.1 percent and 38.0 percent, respectively. The corresponding end-user energy conversion efficiencies, including transmission loss, are 31.4 percent and 35.0 percent, respectively. The busbar efficiency of municipal solid waste (MSW) mass feed-fired utility plants is approximately 20.3 percent (EPRI, 1986). This efficiency, adjusted for transmission loss, is 18.7 percent. No data were readily available for MSW refuse derived fuel (RDF)-fired utility plants; the efficiency of the mass feed unit was assumed to be representative of the efficiency of a RDF unit. A typical efficiency for wood-fired utility plants is 17.3 percent at the busbar, adjusted to 15.9 percent at the end-user (EPRI, 1986).

Emission Factors

For many emission sources, the emission factors for NO_x, CO, and CH_4 are based on AP-42 emission factors converted to an energy output basis using the appropriate fuel property data from Table 5 and the end-use energy conversion efficiency from Table 8. The emissions sources for which AP-42 factors were available for NO_x, CO, and CH_4 include natural gas, residual oil, distillate oil, coal spreader stoker, pulverized coal cyclone, pulverized coal tangential fired, and pulverized coal wall-fired boilers. The NO_x, CO, and CH_4 emission factors for other sources will be discussed in more detail. Because emissions of CO and CH_4 for utility sources are generally negligible on a mass basis compared to CO_2, the CO_2 emission factor was calculated only from the fuel properties. The exception to this includes wood-fired boilers, for which CO emissions were included in the carbon balance, and gas turbines, for which both CO and CH_4 were included.

The emission factors for N_2O are estimated based on limited test data for sources or fuels for which test data were available. Recent measurements have shown that most of the existing N_2O data were collected with procedures that allow formation of N_2O in sample containers awaiting analysis. Only those measurements made with new procedures can be considered reliable at this time. Consequently, the N_2O data base is very small, consisting of measurements at less than a dozen coal-fired power plants (Montgomery et al., 1989).

The emission factors for NO_x and CO for natural gas-fired utility gas turbines were available on an energy input basis (Shih et al., 1979). Although the emission characteristics of simple cycle and combined cycle gas turbines are the same on an energy input basis, they differ on an energy output basis because of differences in efficiency. The emission factors for NO_x and CO were converted to an energy output basis using the gas turbine efficiencies in Table 8. An emission factor for CH_4 was available and was converted from a mass to an energy basis using the heating value of natural gas from Table 5 and the end-use efficiencies for gas turbines (Touchton et al., 1982). The CO_2 emission factors for gas turbines were calculated including both CO and CH_4 in the carbon balance. N_2O emissions were estimated as approximately 5 percent of NO_x emissions, based on tests for natural gas-fired sources.

Although no emission factors for utility distillate oil-fired sources were available in AP-42, distillate oil utility emissions were estimated based on the ratio of distillate oil industrial boiler emissions to residual oil industrial boiler emissions multiplied by the residual oil utility boiler emissions for NO_x and CH_4. For CO, the emission factor was assumed to be the same as for residual oil utility boilers since the AP-42 CO emission factors for industrial and commercial residual and distillate oil boilers are all the same. No emission factors were readily available for shale oil-fired boilers. The emissions of shale oil boilers were assumed to be the same as those for residual oil-fired boilers because of similarities in the fuel properties of both oil types.

For MSW mass burn boilers, the CO emission factor is based on 11 test measurements from sources in the United States, Japan, Germany, Sweden, and Canada (Young et al., 1979). The NO_x emission factor is based on data for industrial mass burn facilities. No data were readily available for CH_4 or N_2O emissions for MSW boilers. No emissions data was available for MSW RDF-fired boilers.

For fluidized bed boiler utility plants, the NO_x emission factor is based on test data (U.S. EPA, 1982b). CH_4 emissions are assumed to be the same as for other types of coal-fired boilers because AP-42 CH_4 emission factors for all types of coal-fired utility boilers except underfeed stokers are the same. No data were readily available for CO emissions from fluidized bed boilers. The emission rate of N_2O is assumed to be roughly 25 percent of that for NO_x, although it is likely that, because fluidized bed boilers typically operate at lower temperatures than other boiler types, N_2O emission could differ substantially from this estimate. For fluidized bed combined cycle utility plants, no emission factors were readily available. However, the CH_4 emission factor was calculated by assuming that the emissions on a mass bass are the same as for other coal boilers, and the CO_2 emission factor was calculated by carbon mass balance.

For wood-fired boilers, emission factors for industrial boilers from AP-42 were used to calculate the end-use energy-based emission factors for NO_x, CO, and CH_4.

Cost

The basis for the costs in Table 8 is summarized in Table 10. These costs are only approximately representative of global average costs, and, as noted in Section 2, great care should be exercised in qualifying any conclusions reached using these estimates. Table 10 presents the capacity, total capital cost, annual costs, and economic life assumed in calculating the levelized annual cost. For all utility sources, a capacity factor of 0.45 was used, based on the average global utilization of installed electricity generating capacity from U.N. statistics (United Nations, 1986). Representative average source capacities were selected as the basis for the cost estimates. However, in cases where costs were not available for an average size plant, the cost estimates are based on a plant capacity for which costs were readily available. The costs were converted to an end-user energy basis using transmission efficiency for those costs that were available on a busbar basis. All costs are in 1985 dollars and were annualized in constant dollars in Table 8 using a discount rate of 5 percent and the economic life indicated in the table.

UTILITY SOURCE EMISSION CONTROL TECHNOLOGIES

Emission control technologies for utility plants and their performance and cost parameter estimates are summarized in Table 11. Table 11 includes the control technology codes corresponding to Table 8. Table 11 also includes the efficiency penalty due to each control technology, the levelized cost in constant dollars on an end-use energy basis, the emission reduction for each pollutant, and the estimated availability date.

Nine distinct control technologies are included in Table 11. One of the technologies is an advanced technology for removing CO_2 from the utility plant flue gas using an adsorption/regeneration technique and disposal of the CO_2 by injection into evacuated salt mines or into the ocean. Although this technology is not commercially proven, it is included to provide an option for CO_2 control. Of course, another option for reducing CO_2 emission on an energy output basis is improvement of the energy conversion efficiency associated with the emission source. Although only nine technologies were evaluated for utility emission controls, in many cases the performance or cost of these

TABLE 10. UTILITY PLANT COSTS[a]

Source	Capacity (MW)	Capital Cost ($ 10^6)	Annual Cost ($ 10^6)	Reference	Life (years)
Natural Gas Boiler	300	320	4.4	17	30
Gas Turbine Combined Cycle	220	150	2.9	8	30
Gas Turbine Simple Cycle	75	30	0.3	8	30
Residual Oil Boiler	300	340	4.4	17	30
Distillate Oil Boiler[b]	300	340	4.4	--	30
Shale Oil Boiler[b]	300	340	4.4	--	30
MSW - Mass Feed	45	200	6.2	8	20
MSW - RDF	45	200	6.2	8	20
Coal - FBCC	500	780	34	8	40
Coal - FB	500	660	23	8	40
Coal - Cyclone[c]	300	410	9.2	17	30
Coal - TF[c]	300	410	9.2	--	30
Coal - WF[c]	300	410	9.2	--	30
Wood	24	49	1.0	8	30

[a] All costs in 1985 dollars.
[b] Assumed same costs as for residual oil-fired boilers.
[c] The costs for all PC boilers are assumed to be the same.

Source: Holstein, 1981.

TABLE 11. UTILITY EMISSION CONTROLS PERFORMANCE AND COSTS

Technology	Code	Efficiency Loss[a] (%)	Cost[b] ($/J End-Use)	CO_2 Reduction (%)	CO Reduction (%)	CH_4 Reduction (%)	N_2O Reduction (%)	NO_x Reduction (%)	Date Available
Low Excess Air	U1	-0.5	2.4E-12	Negligible	Negligible	Negligible	N/A	15	1970
Overfire Air - Coal	U2	0.5	7.5E-12	Negligible	Negligible	Negligible	N/A	25	1970
Overfire Air - Gas	U3	1.25	7.5E-12	Negligible	Negligible	Negligible	N/A	40	1970
Overfire Air - Oil	U4	0.5	7.5E-12	Negligible	Negligible	Negligible	N/A	30	1970
Low NO_x Burner - Coal	U5	0.25	2.2E-11	Negligible	Negligible	Negligible	N/A	35	1980
Low NO_x Burner - TF	U6	0.25	6.7E-11	Negligible	Negligible	Negligible	N/A	35	1980
Low NO_x Burner - Oil	U7	0.25	2.1E-11	Negligible	Negligible	Negligible	N/A	35	1980
Low NO_x Burner - Gas	U8	0.25	2.1E-11	Negligible	Negligible	Negligible	N/A	50	1980
Cyclone Combustion Modification	U9	0.5	1.6E-10	N/A	N/A	N/A	N/A	40	1990
Ammonia Injection	U10	0.5	5.5E-10	Negligible	Negligible	Negligible	N/A	60	1985
SCR[c] - Coal	U11	1	1.5E-09	Negligible	8	Negligible	N/A	80	1985
SCR - Oil, AFBC	U12	1	1.1E-09	Negligible	8	Negligible	N/A	80	1985
SCR - Gas	U13	1	7.1E-10	Negligible	8	Negligible	60	80	1985
Water Injection - Gas Turbine Simple Cycle	U14	1	1.4E-10	Negligible	Negligible	Negligible	N/A	70	1975

TABLE 11. (Continued)

Technology	Code	Efficiency Loss (%)[a]	Cost[b] ($/J End-Use)	CO_2 Reduction (%)	CO Reduction (%)	CH_4 Reduction (%)	N_2O Reduction (%)	NO_x Reduction (%)	Date Available
SCR - Gas Turbine	U15	1	2.0E-09	Negligible	8	Negligible	60	80	1985
CO_2 Scrubbing - Coal	U16	22.5	5.0E-09	90	N/A	N/A	N/A	N/A	2000
CO_2 Scrubbing - Oil	U17	16.0	5.0E-09	90	N/A	N/A	N/A	N/A	2000
CO_2 Scrubbing - Gas	U18	11.3	5.0E-09	90	N/A	N/A	N/A	N/A	2000
Retrofit LEA	U19	-0.5	3.2E-12	Negligible	Negligible	Negligible	N/A	15	1970
Retrofit OFA - Coal	U20	0.5	7.2E-12	Negligible	Negligible	Negligible	N/A	25	1970
Retrofit OFA - Gas	U21	1.25	7.2E-12	Negligible	Negligible	Negligible	N/A	40	1970
Retrofit OFA - Oil	U22	0.5	7.2E-12	Negligible	Negligible	Negligible	N/A	30	1970
Retrofit LNB - Coal	U23	0.25	2.4E-11	Negligible	Negligible	Negligible	N/A	35	1980
Retrofit LNB - Oil	U24	0.25	5.4E-11	Negligible	Negligible	Negligible	N/A	35	1980
Retrofit LNB - Gas	U25	0.25	5.4E-11	Negligible	Negligible	Negligible	N/A	50	1980
Burners Out of Service (BOOS)	U26	0.5	0	Negligible	Negligible	Negligible	N/A	30	1975
Retrofit SCR[c]	U27								

[a] Efficiency loss as a percent of end-user energy conversion efficiency. Negative loss indicates an efficiency improvement.
[b] All costs in 1985 dollars.
[c] SCR = Selective catalytic reduction.
[d] Retrofit SCR performance may be assumed to be the same as for a new SCR systems, but cost is a factor of 1.5 greater.
N/A = not available.

technologies varies depending on the source to which they are applied. Costs for several of the technologies were also evaluated on a retrofit basis.

Efficiency penalties, emission reduction efficiencies, and costs are discussed below.

Efficiency Penalties

The efficiency penalties for most technologies were taken directly from the literature. It should be emphasized that the efficiency penalties are nominal values and are likely to vary from one application to another. The penalties for low excess air, overfire air, low NO_x burners, and ammonia injection are based on the efficiency penalty to an industrial boiler since utility data were not readily available (Kim et al., 1979).

Little detail was available for cyclone staged combustion modifications (Thompson et al., 1987). An efficiency penalty of 0.5 percent was assumed as a rough estimate.

The efficiency penalty for selective catalytic reduction (SCR) is based on an estimated increase in utility plant heat rate of roughly 0.8 percent (Bauer and Spendle, 1984). A nominal value of 1 percent penalty is assumed.

The efficiency penalty for gas turbine water injection is a function of the water injection rate. For the control level considered, a 1 percent efficiency penalty was selected as representative based on the required water injection rate (U.S. EPA, 1987).

The efficiency penalties for the CO_2 scrubber are substantial and vary depending on the fuel burned. The CO_2 scrubbing system results in a significant penalty on the thermal cycle of the power plant because steam is required for CO_2 regeneration; thermal energy is needed to remove CO_2 from the solvent on which it is absorbed from the flue gas. In addition, electricity is required to liquefy the CO_2 and to transport it via pipeline to its ultimate disposal site. The electricity requirement for the liquefaction and disposal depends only on the quantity of CO_2 requiring disposal. The quantity is higher for coal on an energy basis because coal has a higher ratio of carbon per unit heating value than does oil, and both oil and coal have a higher ratio of carbon to unit heating value than does natural gas. Therefore, the energy penalty for CO_2 removal at a coal-fired power plant is higher than that for a natural gas-fired plant due to the different properties of the two fuels (Steinberg et al., 1984).

Removal Efficiencies

The removal efficiencies for low excess air, overfire air, and low NO_x burners are based on a review of several references. These technologies generally impact only NO_x emissions. Average maximum removal efficiencies were selected; the efficiencies vary for overfire air and low NO_x burners as a function of the fuel fired. If operated properly, these technologies generally do not significantly impact the emissions of CO, CH_4, and CO_2. No data were readily available for N_2O.

Little information was readily available on the NO_x removal efficiency of cyclone furnace combustion modifications since it is a relatively new technology, and no data were readily available on the impact of cyclone combustion modifications on other species. However, a nominal value of 40 percent NO_x reduction is reported (Thompson et al., 1987).

On the average, ammonia injection is capable of 60 percent NO_x removal. No significant impact on the emissions of the other compounds is reported (Kim et al., 1979).

SCR can reduce emissions of N_2O, based on a test of a natural gas-fired internal combustion engine. No data were available regarding the effect of SCR on N_2O in the flue gas of coal- or oil-fired sources. SCR also reduces CO by a small percentage,but is primarily most effective in reducing NO_x by about 80 percent (Castaldini and Waterland, 1986).

Gas turbine water injection is capable of over 70 percent NO_x reduction. Although water injection can impact the emissions of CO and CH_4 to some extent in specific applications, on the average, the impact is negligible. The impact on CO_2 emissions is likely to be negligible in any case (U.S. EPA, 1977a).

No data is available on the impact of the advanced concept CO_2 scrubbing system on pollutants other than CO_2, for which the design removal efficiency is 90 percent (Steinberg et al., 1984).

Burners out of service (BOOS) is a retrofit control option which can be applied to wall-fired or tangentially fired boilers and is capable of about 30 percent NO_x removal for coal, oil, or natural gas (Kim et al., 1979).

Cost

The basis for the annualized control technology costs in Table 11 is presented in Table 12. Table 12 lists the emission source capacity, and the control technology capital cost and nonfuel annual costs. All costs are in 1985 dollars, and the costs in Table 11 were levelized based on a capacity factor of 0.45, an economic life of 30 years, and an interest rate of 5 percent. The factors used to calculate retrofit costs based on the costs for new controls are included in the table.

Because in some cases costs were available only for a control technology applied to sources of arbitrary capacities, it was not always possible to develop control costs using the same source capacity as for the source costs. Although the capacities of some sources and controls used for costing do not match, developing costs on a consistent capacity basis would have required effort beyond the scope of this project, and would have required additional assumptions in many cases.

TABLE 12. UTILITY EMISSION CONTROL COSTS[a]

Technology	Source Category	Capital Cost ($1,000)	Annual Cost ($1,000)
Low Excess Air (LEA)	2500×10^6 Btu/hr input	67	3
Overfire Air (OFA)	500 MW output	460	23
Low NO_x Burner (LNB)	500 MW output	1,400	69
LNB - Tangential Firing[b]	500 MW output	4,100	210
Cyclone Combustion Modification	-	$20/KW	$1/KW/yr
Ammonia Injection	200×10^6 Btu/hr input	350	120
SCR - Coal[c]	300 MW output	26,000	4,500
SCR - Oil, FBC[c]	300 MW output	22,000	3,400
SCR - Gas[c]	300 MW output	18,000	1,900
Water Injection - Gas Turbine (Simple Cycle)	400×10^6 Btu/hr input	710	14
SCR - Gas Turbine	400×10^6 Btu/hr input	3,300	680
CO_2 Scrubber	-	$673/KW	$45/KW/yr
Retrofit LEA	Ratio of retrofit to new cost is 1.32		
Retrofit OFA	Ratio of retrofit to new cost is 1.64		
Retrofit LNB	Ratio of retrofit to new cost is 1.54		
Retrofit SCR	Ratio of retrofit to new cost is 1.5		

[a]All costs in 1985 dollars.

[b]Assumed cost for low NO_x burners applied to tangentially fired furnaces to be three times the cost for other low NO_x burners as an order-of-magnitude estimate.

[c]SCR costs calculated from an algorithm based on Bauer and Spendle, 1984.

Sources: Steinberg et al., 1984; U.S. EPA, 1977a.

SECTION 4
INDUSTRIAL BOILER SOURCES AND CONTROLS

Performance and cost estimates were developed for seven industrial boiler types and six industrial boiler emission control technologies. All of the boilers and controls represent currently available technologies. This section discusses source performance and cost estimates, as well as emission control performance and cost estimates.

SOURCES

Table 13 summarizes the efficiency, cost, and emission factor estimates developed for industrial boilers. Estimates were developed for sources burning coal, residual oil, distillate oil, natural gas, wood, bagasse and agricultural waste, and MSW. The efficiency is based on the conversion of fuel energy to thermal energy for water to steam generation. The costs are based on the annual energy delivered in generating steam. The emission factors are reported on the basis of grams of pollutant emitted per gigajoule of energy delivered to a steam user. The energy delivered to a steam user is the difference between the thermal energy contained in the steam leaving the industrial boiler and the thermal energy in the condensate water returning from the user back to the boiler. To the right of each emission factor is the corresponding quality rating. For each industrial boiler technology, the appropriate control technologies are identified by codes.

Efficiency

The efficiency estimates in Table 13 represent the conversion of fuel energy to the energy delivered to a steam user. The estimates are based on information from NSPS background information documents for industrial boilers (U.S. EPA, 1982a,b).

Most coal-fired industrial boilers in the United States are watertube boilers. These may be pulverized coal or stoker designs. The efficiency of coal-fired industrial boilers ranges from about 78 percent for underfeed stokers to about 82 percent for pulverized coal-fired boilers. A value of 80 percent was selected as representative of coal-fired industrial boilers. Oil

TABLE 13. INDUSTRIAL BOILER SOURCE PERFORMANCE AND COST

Source	Efficiency (%)	Cost[a] ($/J end-use)	Emissions Factors (g/GJ delivered steam) and Data Quality Ratings (A - E)					Controls[b]
			CO_2	CO	CH_4	N_2O	NO_x	
Coal-Fired Boilers[d]	80	3.6E-09	130,000 C	110 B	2.9 B	N/A E	390 B	11, 12, 15, 19, 110, (113, 116, 117, 120)
Residual Oil-Fired Boiler	85	1.4E-09	88,000 A	17 A	3.3 A	N/A E	180 A	11, 14, 16, 18, 19, 111, (113, 116, 118, 120)
Natural Gas-Fired	85	1.4E-09	57,000 A	18 A	1.5 C	N/A E	71 A	11, 13, 17, 18, 19, 112, (113, 115, 119, 120)
Wood-Fired Boilers	68	6.3E-09	140,000 C	2,100 D	21 E	N/A E	160 C	11, 19, 110, (114)
Bagasse/Agricultural Waste-Fired Boilers	60	N/A	150,000 A	2,700 E	N/A	N/A	140 C	11
MSW - Mass burn	70	N/A	120,000 D	130 B	N/A	N/A	190 C	11
MSW - Small modular	55	N/A	160,000 D	32 B	N/A	N/A	240 C	11

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[a]All costs in 1985 dollars.

[b]Control codes in parenthesis indicate retrofit emission control options. The controls are defined in Table 15.

fired and natural gas-fired watertube boilers generally have similar efficiencies of roughly 85 percent (U.S. EPA, 1982a).

Spreader stoker designs are the most common for boilers firing wood waste and typically have efficiencies of 65 to 70 percent. A value of 68 percent was selected as representative. Spreader stoker boilers firing bagasse are roughly 60 percent efficient. MSW mass feed boilers have an efficiency of 70 percent, whereas MSW small modular boilers have an efficiency of 55 percent (U.S. EPA, 1982b).

Emission Factors

No N_2O emission factors for industrial boilers have been provided since all existing test data have recently been shown to be inaccurate.

For coal-fired industrial boilers, emission factors for NO_x, CO, and CH_4 were estimated from AP-42 emission factors for pulverized coal, spreader stoker, overfeed stoker, and underfeed stoker industrial boilers. The emission factors for these four boiler types were averaged for each of the three pollutants based on the percent of the total U.S. coal-fired boiler capacity represented by each source. Using a boiler population weighted average approach, it is possible to represent the emissions of different coal-fired boiler types with a single set of emission factors. Pulverized coal boilers comprised roughly 37 percent of the total based on capacity, whereas spreader stoker, underfeed stoker, and overfeed stoker comprised 26 percent, 27 percent, and 10 percent of the total, respectively (U.S. EPA, 1982a). The weighted average emission factors were converted from a mass to an input energy basis using the coal heating value from Table 5 and then to an output energy basis using the boiler efficiency from Table 13.

The NO_x, CO, and CH_4 emission factors for residual oil-, natural gas-, and wood-fired boilers were taken from AP-42 and converted to an output energy basis using the appropriate fuel heating values and boiler efficiencies.

For bagasse-fired boilers, no data were readily available from which to develop a CH_4 emission factor. The emission factor for CO on a mass basis was assumed to be the same as for wood-fired industrial boilers. A NO_x emission factor based on energy input was available.

For MSW-fired units, the NO_x emission factor is the same on an energy input basis for small modular and mass-burn boilers (U.S. EPA, 1982b). However, on an energy output basis the factors differ because the efficiency of mass burn units is estimated to be higher than that of small modular units. The CO emission factors for both mass-burn and small modular MSW facilities are based on test data (Shindler, 1987). No data were readily available for CH_4 emissions from MSW industrial boilers.

Cost

The basis for the cost estimates in Table 13 are summarized in Table 14. Table 14 includes the boiler size in terms of inlet fuel energy, the capital cost, and the non-fuel annual costs. These costs were levelized using an economic life of 30 years, an interest rate of 5 percent, and a capacity factor of 0.55. The costs are in 1985 dollars, and exclude fuel cost. As was the case for utility sources, representative capacities were selected as the basis for cost estimates unless limited availability of cost data required the use of arbitrary capacities. Although the selection of capacity impacts the energy-based cost due to economies of scale, the costs developed for this project, as noted in Section 2, are intended to be approximately representative. A more detailed cost analysis is beyond the scope of this project.

EMISSION CONTROL TECHNOLOGIES

Emission control technologies for industrial boilers and their performance and cost parameter estimates are summarized in Table 15. Table 15 includes the control technology code, efficiency penalty, cost, emission reduction efficiency, and availability date.

Six different control technologies were evaluated. For many of these, the cost, efficiency penalty, and emission reduction efficiency vary significantly for different boilers. The efficiency penalty and emission reduction efficiencies for low excess air, overfire air, low NO_x burners, ammonia injection, and selective catalytic reduction are discussed in Section 3. The costs for these technologies applied to industrial boilers differ, however, from costs for applications to utility boilers, primarily due to economies of scale.

TABLE 14. INDUSTRIAL BOILER SOURCE COSTS[a]

Fuel	Capacity (10^6 Btu/hr input)	Capital Cost ($1,000)	Annual Cost[b] ($1,000)
Natural Gas	100	2,400	455
Distillate Oil	100	2,440	455
Residual Oil	100	2,420	455
Coal	100	9,000	865
Wood	30	2,950	460

[a]Costs in 1985 dollars.

[b]Excludes fuel costs.

Source: U.S. EPA, 1982a.

TABLE 15. INDUSTRIAL BOILER EMISSION CONTROLS PERFORMANCE AND COSTS

Technology	Code	Efficiency Loss (%)	Cost[a] ($/J End-Use)	CO_2 Reduction (%)	CO Reduction (%)	CH_4 Reduction (%)	N_2O Reduction (%)	NO_x Reduction (%)	Date Available
Low Excess Air	11	-0.5	6.8E-12	Negligible	Negligible	Negligible	N/A	15	1970
Overfire Air - Coal	12	0.5	4.4E-12	Negligible	Negligible	Negligible	N/A	25	1970
Overfire Air - Gas	13	1.25	4.4E-12	Negligible	Negligible	Negligible	N/A	40	1970
Overfire Air - Oil	14	0.5	4.4E-12	Negligible	Negligible	Negligible	N/A	30	1970
Low NO_x Burner - Coal	15	0.25	1.5E-11	Negligible	Negligible	Negligible	N/A	35	1980
Low NO_x Burner - Oil	16	0.25	3.5E-11	Negligible	Negligible	Negligible	N/A	35	1980
Low NO_x Burner - Gas	17	0.25	3.5E-11	Negligible	Negligible	Negligible	N/A	50	1980
Flue Gas Recirculation	18	0.5	1.1E-10	Negligible	Negligible	Negligible	N/A	40	1975
Ammonia Injection	19	0.5	1.8E-10	Negligible	Negligible	Negligible	N/A	60	1985
SCR - Coal	110	1	1.1E-09	Negligible	8	Negligible	N/A	60	1985
SCR - Oil, AFBC	111	1	5.8E-10	Negligible	8	Negligible	N/A	80	1985
SCR - Gas	112	1	2.0E-10	Negligible	8	Negligible	60	80	1985
Retrofit LEA	113	-0.5	9.[illegible]E-12	Negligible	Negligible	Negligible	N/A	15	1970
Retrofit OFA - Coal	114	0.5	7.2E-12	Negligible	Negligible	Negligible	N/A	25	1970
Retrofit OFA - Gas	115	1.25	7.2E-12	Negligible	Negligible	Negligible	N/A	40	1970
Retrofit OFA - Oil	116	0.5	[illegible].2E-12	Negligible	Negligible	Negligible	N/A	30	1970

TABLE 15. (Continued)

Technology	Code	Efficiency Loss[a] (%)	Cost[b] ($/J End-Use)	CO_2 Reduction (%)	CO Reduction (%)	CH_4 Reduction (%)	N_2O Reduction (%)	NO_x Reduction (%)	Date Available
Retrofit LNB - Coal	117	0.25	2.4E-11	Negligible	Negligible	Negligible	N/A	35	1980
Retrofit LNB - Oil	118	0.25	5.4E-11	Negligible	Negligible	Negligible	N/A	35	1980
Retrofit LNB - Gas	119	0.25	5.4E-11	Negligible	Negligible	Negligible	N/A	50	1980

[a]All costs in 1985 dollars.

N/A = not available.

Efficiency Penalty

For a more complete discussion of efficiency penalties, which are assumed the same as for utility boilers, see Section 3. The efficiency penalties for the industrial boiler emission control technologies were taken directly from the literature for low excess air, overfire air, low NO_x burners, and ammonia injection as discussed for utility sources. The efficiency penalty for SCR was estimated in the same manner as for utility sources.

Flue gas recirculation has roughly a 0.5 percent impact on industrial boiler efficiency (Kim et al., 1979).

Removal Efficiencies

The removal efficiencies for low excess air, overfire air, low NO_x burners, ammonia injection, and SCR are estimated to be the same for industrial boilers as for utility boilers, as discussed in Section 3. Flue gas recirculation is capable of about 40 percent reduction of NO_x for oil- and gas-fired boilers. No impact was reported for CO or hydrocarbons (Kim et al., 1979).

Costs

The boiler size, capital cost, and nonfuel annual costs assumed to calculate each of the control technology costs are summarized in Table 16. These costs are in 1985 dollars and were levelized using an economic life of 30 years, an interest rate of 5 percent, and a capacity factor of 0.55. In all cases, the same capacity factor was used for industrial boiler emission source and controls. It was not possible in all cases to use the same source category in the cost estimates for a particular source and the corresponding control, due to limited availability of data.

TABLE 16. INDUSTRIAL BOILER EMISSION CONTROL COSTS[a]

Technology	Source Category (10^6 Btu/hr input)	Capital Cost ($1,000)	Annual Cost ($1,000)
Low Excess Air	100	67	1.2
Overfire Air	1,090	168	8.4
Low NO_x Burner	100	124	6.2
LNB - Coal	1,530	1,270	64
Flue Gas Recirculation	100	39	40
Ammonia Injection	200	350	120
SCR - Coal[b]	100	2,600	121
SCR - Oil[b]	750	8,900	3,700
SCR - Gas	100	445	58
Retrofit LEA	Ratio of retrofit to new cost is 1.32		
Retrofit OFA	Ratio of retrofit to new cost is 1.64		
Retrofit LNB	Ratio of retrofit to new cost is 1.54		

[a]All costs in 1985 dollars.

[b]SCR costs calculated from an algorithm based on Bauer and Spendle, 1984; other data from Kim et al., 1979.

SECTION 5
KILNS, OVENS, AND DRYERS

Performance estimates were developed for seven sources and five controls as part of the kilns, ovens, and dryers category. The sources include lime/cement kilns, coke ovens, and dryers. Control technologies were identified for these sources. This section discusses the development of efficiency and emission factor estimates for kilns, ovens, and dryers. The dryers discussed in this section exclude coal dryers, which are discussed with other fuel production emission sources in Section 6. Performance and cost parameters for emission control technologies for these sources are also discussed in this section.

SOURCES

The performance parameters for each of the sources included in this category are summarized in Table 17. Indicated in the table are some of the industries in which these emission sources are commonly found. A range of values for the thermal efficiency of kilns and dryers is given. The emission factors are given in grams of pollutant emitted per gigajoule (g/GJ) of input fuel energy for these emission sources. The emission factor quality rating is given to the right of each emission factor. The appropriate control technologies for each source are noted by control code in the last column of the table.

Efficiency

The thermal efficiency of a kiln or dryer is the percent of the input fuel energy that is used to heat the material charge within the kiln. Kiln efficiencies range from about 45 percent to 80 percent, but typically are within 65 percent to 75 percent. Dryer efficiencies range from about 30 percent to 65 percent depending on the temperature at which drying occurs. The overall efficiency of an industrial facility containing a kiln or dryer can be improved by recovering the waste heat from the kiln or dryer for use in other equipment (Perry and Chilton, 1973).

SECTION 6
FUEL PRODUCTION

This section includes most major sources of greenhouse gases that are emitted in the production of coal, oil, gas, and wood fuels. In general, the key sources included here are: coal mining and processing operations, oil and gas drilling and transport operations, oil refining, oil shale and coal liquefication production operations, and charcoal production. Since oil refining operations include a large and diverse number of individual sources, a composite emission factor was developed based on a "model refinery" configuration. Use of this single factor can simplify the emissions estimating procedure in global models.

SOURCE DESCRIPTIONS, EMISSION FACTORS AND EFFICIENCY DATA

Table 19 summarizes the emission factors and efficiency data for key fuel production sources. As the table shows, several significant sources of greenhouse gases exist in the fuel production industry. These sources are organized in the table and in the remainder of this section by fuel type as listed below:

- Oil Production Sources
  - petroleum refining
  - oil shale retorting
  - wellhead venting
- Gas Production Sources
  - gas transmission systems
- Coal Production Sources
  - active mines
  - coal drying
  - coal gasification
  - coal liquefication
- Wood-Related Sources
  - charcoal production

Brief process descriptions and a discussion of emission factor development procedures used for each category are discussed in the next four

TABLE 19. FUEL PRODUCTION SOURCE PERFORMANCE

Source	Efficiency (%)	Emissions Factors and Data Quality Ratings (A - E)[a] CO_2	CO	CH_4	N_2O	NO_x	Controls[b]
Gas Refining	N/A	N/A	Negligible D	Negligible D	N/A	Negligible D	
Petroleum Refining	N/A	23,400 D g/bbl crude	1730 D g/bbl crude	0.948 D g/bbl crude	N/A	49 D g/bbl crude	See Table 21
Coal Cleaning	N/A	4,719 B g/ton coal mined	N/A	N/A	N/A	37 C g/ton coal mined	
Oil Shale-Surface	78	15,000 C g/GJ out	17 C g/GJ out	23 C g/GJ out	N/A	61 C g/GJ out	F1
Oil Shale - In-situ	60	1,500 C g/GJ out	0.6 C g/GJ out	8.6 C g/GJ out	N/A	20 C g/GJ out	F1,F2,F3,F5,F6
Lurgi Gasification	65	56,000 D g/GJ out	64 C g/GJ out	N/A	N/A	150 C g/GJ out	F8
Liquefaction Acid Gas	66	23,000 C g/GJ out	2.5 C g/GJ out	N/A	N/A	trace C	

TABLE 19. (Continued)

Source	Efficiency (%)	Emissions Factors and Data Quality Ratings (A - E)[a]: CO_2	CO	CH_4	N_2O	NO_x	Controls[b]
Charcoal Production	N/A	68,000 E g/GJ out	5,800 D g/GJ out	1,700 D g/GJ out	N/A	410 D g/GJ out	F9
Natural Gas Transmission	N/A	486 D g/GJ out	2.4 D g/GJ out	2.5 D g/GJ out	N/A	10.6 D g/GJ out	F22,F23,F24
Active Coal Mines	N/A	N/A	N/A	4,920 D g/ton coal mined	N/A	N/A	
Natural Gas Leaks	N/A	N/A	N/A	5.72 E g/m^3 gas marketed	N/A	N/A	
Natural Gas Vented	N/A	N/A	N/A	0.57 E g/m^3 gas marketed	N/A	N/A	

[a]For a discussion of the emission factor data quality ratings, see Section 2.

[b]Control codes are defined in Table 20.

N/A = Not available.

Process Areas with Heaters	Fraction of Refinery Flow to Heaters (bbl feed/bbl crude)
Atmospheric distillation	1.0
Vacuum distillation	.420
Delayed choking	.170
Visbreaking	.170 (assumed value)
FCC	.284
Hydrocracking	.057
Gas/Oil hydrodesulfurization	.035
Hydrotreating	.057 (assumed value)
Catalytic reforming	.201
Alkylation	.066
Isomerization	.008
Hydrodesulfurization	.066 (assumed value)

Process heater emission factors for oil- and gas-fired heaters were available on a pounds of pollutant per barrel of process heater feed basis (U.S. EPA, 1980). They were then assigned weights according to their natural gas-residual oil fraction of occurrence: refineries generally use natural gas to fuel 90 percent of their heaters and residual oil to fire the remaining 10 percent. These factors were next normalized to a per barrel of crude feed into the refinery using the factors listed above. The CO_2 emission factors for the fired heaters are based only on the fuel properties of natural gas and residual oil; i.e., CO and CH_4 are neglected in the carbon balance. CO_2 calculated for these two fuels was assigned weights using the 90 to 10 percent split described above.

Finally, the weighted process heater factors for the process areas listed above were summed to yield total process heater emissions for a typical refinery.

Oil Shale Retorting--

Emissions factors are reported for surface and *in situ* oil shale retorting, which is the removal of shale oil from its shale matrix by heating with combustion, either above or below ground, respectively (UNEP, 1985). Some of the released shale oil is used for the combustion in this process, and the combustion gases are vented.

The emission factors in Table 19 for CO_2, CO, CH_4, and NO_x for surface and *in situ* shale retorting are based on the total estimated emissions from a 50,000 bbl/day plant, converted to an energy basis using the heating value of crude shale oil from Section 2 (Table 5). The CH_4 emission factor for both sources was assumed to be the same as the total hydrocarbon emission factor because CH_4 comprises most of the hydrocarbon emissions from retorting (UNEP, 1985).

Wellhead Venting--

With rising gas prices, the volume of vented gas in the United States has fallen steadily since 1960. However, some venting of gas at the wellhead continues in the United States, usually involving gas brought up with associated oil which is not economically recoverable. Maintenance and unscheduled downtime also result in the need to vent or flare gas.

Methane emissions from vented natural gas pose a similar problem to that of natural gas leaks in that data on the breakdown between natural gas vented and natural gas flared at the wellhead are not readily available. In the United States, 0.4 percent of the total gas production in 1985 was flared or vented (AGA, 1986). Most States that have a gas production industry require that gas be flared rather than vented; thus, the American Gas Association estimates that at least about 0.1 percent of the total gas produced in the United States is vented (AGA, 1986). Assuming 88.3 volume percent CH_4 in natural gas, this corresponds to 0.572 grams of methane vented per cubic meter of marketed natural gas. Again, the U.S. percentage of natural gas vented at the wellhead may not reflect the global situation. One source indicates that "the lack of markets and infrastructure for using natural gas as a fuel leads to massive flaring at oil fields in some remote locations" (Marland and Rotty, 1984).

Gas Production Sources

Compared to oil related sources, there are relatively few sources of emissions in gas production. However, the few sources that do exist are not insignificant with regard to their total emissions. Gas transmission system leaks, and pipeline compression/transport engine emissions are the major sources. Acid gas flares at gas refining facilities are a potentially significant source of CO_2 but few data were available with which to calculate CO_2 emissions. Emissions of other gases from gas refining are negligible, according to AP-42.

Pipeline Leaks--

In gas transmission pipeline systems, greenhouse gas emissions occur from two main sources:

- pipeline system leaks, and
- transport/compression engines.

Gas pipeline systems leak methane emissions to the atmosphere, primarily from valves, flanges, and corroded transmission lines. No firm data can be found on the amount of natural gas leaked or lost. Lost and unaccounted for gas is about 2 percent of marketed gas production in the United States each year, but this includes gas unallocated due to meter inaccuracies, theft, and temperature and/or pressure differences. It is estimated that unallocated gas accounts for 50 percent or more of the unaccounted for gas in the United States. Thus a conservative estimate of gas leaked would be 1 percent of marketed gas production. Assuming that 88.3 percent (by volume) of this natural gas is methane, the amount of CH_4 leaked into the atmosphere would be 0.883 percent of the marketed gas production. This corresponds to 5.72 grams of methane leaked per cubic meter of marketed natural gas, using the assumed density of 647.7 grams/m^3.

Because data are not readily available for global methane leaks, it is not known whether methane loss for the United States is a valid gauge for world methane loss.

Transport/Compression Engine Emissions--

Emissions from internal combustion engines and gas turbines in the pipeline/transport system occur as a result of burning fossil fuels and the emission specie is primarily CO_2. The NO_x, CO, and hydrocarbon emission factors for natural gas internal combustion engines and gas turbines and diesel internal combustion engines used in pipelines are available on an energy input basis (Shih et al., 1979). A CH_4 emission factor for internal combustion engines was determined by assuming that 10 percent of total hydrocarbon emissions from diesel-fueled engines is methane and 80 percent of total hydrocarbon emissions from natural gas fueled engines is methane (U.S. EPA, 1977b). The emission factor for CH_4 from a natural gas-fired gas turbine is taken directly from test data. The CO_2 emission factors for internal combustion engines and gas turbines are based on carbon balances including CO and CH_4 using appropriate fuel properties from Section 2 (Table 5).

The emissions for the natural gas, internal combustion engines and gas turbines and diesel internal combustion engines were then aggregated according to their use (Shih et al., 1979). Natural gas pipelines use approximately 3 percent of the gas transmitted to run the compressor engines (Shih et al., 1979; Marland and Rotty, 1984).

Coal Production Sources

Active Coal Mines--

Methane present within coal seams may be liberated when the seams are penetrated to mine the coal. Methane is vented in a fairly pure form from active coal mines. Current literature outlines various ways to estimate the amount vented based on an emission factor of cubic meters of methane per ton of coal mined. Some authors give one general emission factor, whereas others present different factors for the different grades of coal mined: anthracite, bituminous, subbituminous, and lignite. Some vented methane is used onsite in coal-drying, for example, and it is not clear whether the various literature estimates include this methane or not. It was assumed here that the emission factors reported in the literature estimate only what is vented to the atmosphere. If this is incorrect, factors presented in this report may be slightly overestimated.

Emission factors for methane from active coal mines from several current references are summarized here:

CH_4 Emission Factor	Reference
6.25 m^3/ton bituminous and anthracite coal mined 2.5 m^3/ton subbituminous coal mined 1.25 m^3/ton lignite	Marland and Rotty, 1984 ——
6.2-15.6 m^3/ton bituminous and anthracite coal mined	Byrer et al., 1987; Boykins et al., 1981
<6.2 m^3/ton subbituminous and lignite coal mined	——
18-19 m^3/ton coal mined	Crutzen, 1987; U.S. DOE, 1987

Based on engineering judgment, a reasonable "middle-of-the-road" value appears to be 7.6 m^3/ton coal mined. With an assumed density of 647.7 grams/cubic meter, the emission factor on a mass basis is 4,922 grams CH_4 per ton of coal mined.

Coal Drying--

The drying of coal can be accomplished with a fluidized bed dryer, in which coal is suspended and dried above a perforated plate by rising hot coat combustion gases. Data were not available for flash and multilouvered dryers.

Uncontrolled dryer exhaust emissions were taken from AP-42 on the basis of a ton of coal dried. The CO_2 emission factor was calculated from ten data points for the CO_2 concentration in the exhaust gas from coal dryers and the corresponding flue gas flowrates. Dryer exhaust gases are the only source of greenhouse gases in a coal drying process. Since not all coal mined requires drying, these emissions were weighted by the ratio of tons of coal dried per ton of coal mined. To calculate this factor, 1975 U.S. coal cleaning market data were used. Of the coal mined, 49.3 percent underwent a cleaning operation (U.S. DOE, 1987).

Coal Gasification--

Gasification, in simple terms, is the combination of coal and steam to form CO, H_2, and CH_4. The heat to drive the gasification process is maintained by coal combustion. A Lurgi gasifier, which contains a counter-current moving bed of coal and steam, is used as the basis for the emission factors presented in Table 19. Reported emission factors are for an entire Lurgi plant.

The emission factors for Lurgi gasification were calculated from data on estimated annual emissions from a 250 x 10^9 Btu/day Lurgi plant (U.S. EPA, 1978). The CO_2 emission factor was calculated with a carbon balance by balancing the input coal carbon with the output synthesis gas carbon (which was reported as roughly 65 percent of the synthesis gas) and the output carbon contained in the CO emissions. The input coal was calculated based on a daily output of 250 x 10^9 Btu, the process efficiency reported in Table 19, and the coal heating value presented in Section 2 (Table 5).

Coal Liquefaction--

Liquefaction processes produce usable liquid products from coal. A major source of emissions from liquefaction processes is the acid gas flare that burns a vent stream of reaction by-products.

The CO_2, CO, and NO_x emission factors for coal liquefaction are based on emissions data for the Synthoil®, H-Coal®, and Exxon Donor Solvent® Processes (Parker and Dykstra, 1978). The Synthoil® process has four product streams (product oil, light fuel oil, liquid by-products, and by-products gas) and the H-Coal® and Exxon Donor Solvent® each had three product streams (naphthas, fuel gas, and heavy oils). Product flow rates and heating values of these products were given for each of the three processes. These were used to convert the emissions from a mass to an energy output basis.

Wood-Related Sources

The production of charcoal is performed by a controlled combustion of wood in a kiln or continuous furnace. Emissions result from the wood combustion flue gases. The emission factors for CO, CH_4, and NO_x from charcoal production were readily available, and were converted to an energy basis using the estimated heating value of charcoal from Section 2 (Table 5) (Moscowitz, 1978). The CO_2 was calculated by a carbon balance using the following: carbon in wood (reported as roughly 50 percent), carbon out in CO and CH_4, and carbon out in produced charcoal (roughly 87 percent). It was assumed the remaining carbon is available for CO_2 formation.

Efficiency Data

The efficiencies for surface and *in situ* oil shale retorting are estimates of the percent of shale oil recovered from shale during the retorting process. The estimate for the surface retort conversion efficiency, 78 percent, is based on an average of the Paraho Direct, Paraho Indirect, and TOSCO II retort conversion efficiencies. The estimate for the in-situ retorting conversion efficiency, 60 percent, is based on a single *in situ* retorting conversion efficiency value (U.S. EPA, 1980).

The efficiency for coal liquefaction is an average of the overall thermal efficiencies for three liquefaction processes; Synthoil®, H-Coal®, and Exxon Donor Solvent® Processes. The overall thermal efficiency is defined in this content as the ratio of the heating value of all products and by- products to the heating value of all input feed materials (Parker and Dykstra, 1978). This average is 66 percent.

The efficiency for Lurgi gasification is the coal-to-product gas thermal efficiency, which is defined as the ratio of the heat content of coal to the heat content in the product gas. This value is 65 percent (U.S. EPA, 1978).

The efficiency for pipeline gas turbine is based on conversion of fuel energy to shaft horsepower. The efficiency of 34 percent for internal combustion engines is based on a typical heat rate of 7500 Btu/hp-hr, which is a commonly assumed heat rate from AP-42.

EMISSION CONTROL TECHNOLOGIES

Emission control technology performance and cost estimates are presented in Table 20. For each of the control technologies, Table 20 includes a control technology code, efficiency penalty, levelized cost on an energy or production basis, emission reduction efficiency, and availability date. The following sections describe each of the categories of data separately. For the model oil refinery discussed previously, a combination of these technologies is applied.

Emission Reduction Efficiency

For several of the fuel production emission sources, limited information was available from which to identify the applicability of control technologies and, in many instances, data were not available from which to estimate the emission reduction efficiencies for various control technologies. Therefore, the removal efficiencies for some controls were assumed to be the same for fuel production sources as for similar sources to which they are applied. This technology transfer was assumed for CO boilers, afterburners, FGR retrofits, SCR retrofits, Nonselective catalytic reduction (NSCR) retrofits, SCA, LEA, and SCA used in conjunction with LEA.

Recall that a single emission factor is used to represent a "model refinery" and that factor includes the emissions associated with many different sources within the refinery. In order to quantify the impact of

TABLE 20. FUEL PRODUCTION EMISSION CONTROLS PERFORMANCE AND COST

Technology	Code	Efficiency Loss[a] (%)	Cost (1985 $)	CO_2 Reduction (%)	CO Reduction (%)	CH_4 Reduction (%)	N_2O Reduction (%)	NO_x Reduction (%)	Date Available
Selective Catalytic Reduction (SCR)	F1	N/A	N/A	Negligible	Negligible	Negligible	N/A	80	1999
LEA	F2	N/A	N/A	Negligible	Negligible	Negligible	N/A	15	1985
Two Stage Combustion	F3	N/A	N/A	Negligible	Negligible	Negligible	N/A	30	1985
Water Injection	F4	1	6.4E-11 $/J input	Negligible	Negligible	Negligible	N/A	70	1965
Fast Heat Release	F5	N/A	N/A	Negligible	Negligible	Negligible	N/A	10	1985
NH_3 Injection	F6	N/A	1.6E-13 $/J output	Negligible	Negligible	Negligible	N/A	60	1985
High Temperature Regeneration	F7	N/A	N/A	N/A	99	N/A	N/A	N/A	1985
CO Boiler	F8	N/A	N/A	N/A	99	100	N/A	-125	1985
Afterburner	F9	N/A	$1.87/ton dry wood	-1	90	N/A	N/A	N/A	1985
FGR Retrofit - O.O.	F10	0.5	0.036 $/ bbl crude	N/A	N/A	N/A	N/A	38	1985
FGR Retrofit - Gas	F11	0.5	0.036 $/ bbl crude	N/A	N/A	N/A	N/A	57	1983

TABLE 20. (Continued)

Technology	Code	Efficiency Loss[a] (%)	Cost (1985 $)	CO_2 Reduction (%)	CO Reduction (%)	CH_4 Reduction (%)	N_2O Reduction (%)	NO_x Reduction (%)	Date Available
SCR Retrofit - Gas	F12	1	0.424 $/ bbl crude	N/A	N/A	N/A	N/A	69	1983
SCR Retrofit - D.O.	F13	1	0.424 $/ bbl crude	N/A	N/A	N/A	N/A	78	
SCR Retrofit - R.O.	F14	1	0.424 $/ bbl crude	N/A	N/A	N/A	N/A	90	
SNCR-NH_3 Retrofit	F15	0.5	0.069 $/ bbl crude	N/A	N/A	N/A	N/A	53	
SCA - Gas	F16	-0.3	0.006 $/ bbl crude	N/A	N/A	N/A	N/A	60	1979
SCA - R.O.	F17	-0.8	0.056 $/ bbl crude	N/A	N/A	N/A	N/A	34	1979
LEA - Gas	F18	-3.9	0.019 $/ bbl crude	N/A	N/A	N/A	N/A	15	
LEA - R.O.	F19	-4.2	0.019 $/ bbl crude	N/A	N/A	N/A	N/A	28	
LEA & SCA - Gas	F20	-6.7	0.078 $/ bbl crude	N/A	N/A	N/A	N/A	71	1979

TABLE 20. (Continued)

Technology	Code	Efficiency Loss[a] (%)	Cost (1985 $)	CO_2 Reduction (%)	CO Reduction (%)	CH_4 Reduction (%)	N_2O Reduction (%)	NO_x Reduction (%)	Date Available
SCR Retrofit - Gas	F12	1	0.424 $/ bbl crude	N/A	N/A	N/A	N/A	69	1983
SCR Retrofit - D.O.	F13	1	0.424 $/ bbl crude	N/A	N/A	N/A	N/A	78	
SCR Retrofit - R.O.	F14	1	0.424 $/ bbl crude	N/A	N/A	N/A	N/A	90	
SNCR-NH_3 Retrofit	F15	0.5	0.069 $/ bbl crude	N/A	N/A	N/A	N/A	53	
SCA - Gas	F16	-0.3	0.006 $/ bbl crude	N/A	N/A	N/A	N/A	60	1979
SCA - R.O.	F17	-0.8	0.056 $/ bbl crude	N/A	N/A	N/A	N/A	34	1979
LEA - Gas	F18	-3.9	0.019 $/ bbl crude	N/A	N/A	N/A	N/A	15	
LEA - R.O.	F19	-4.2	0.019 $/ bbl crude	N/A	N/A	N/A	N/A	28	
LEA & SCA - Gas	F20	-6.7	0.078 $/ bbl crude	N/A	N/A	N/A	N/A	71	1979

TABLE 20. (Continued)

Technology	Code	Efficiency Loss[a] (%)	Cost (1985 $)	CO_2 Reduction (%)	CO Reduction (%)	CH_4 Reduction (%)	N_2O Reduction (%)	NO_x Reduction (%)	Date Available
LEA & SCA - R.O.	F21	-6.7	0.078 $/ bbl crude	N/A	N/A	N/A	N/A	53	1979
Pre-Stratified Charge	F22	-3	3.9E-11 $/J input	Negligible	-20	-50	N/A	80	1987
Non-Selective Cat. Red	F23	7	2.8E-10 $/J input	Negligible	15	40	70	90	1984
Selective Catalytic Red.	F24	1	9.5E-10 $/J input	Negligible	8	Negligible	60	80	1985

[a] A negative efficiency loss indicates an improvement in efficiency.

N/A = not available.

adding controls to these many different sources, a composite emission reduction efficiency factor was developed. The reduction efficiencies for NO_x, CO_2, CO, and CH_4 for the "model refinery" were calculated by applying a wide range of control technologies to the individual emission sources. These sources, which were described previously, are shown with a listing of all potentially applicable control technologies in Table 21. The emissions from individual sources after control were summed and compared to the sum of all uncontrolled sources to calculate a refinery-wide reduction efficiency.

Two control scenarios for the model petroleum refinery were investigated. Level 1 represents a well-controlled refinery, and Level 2 represents a baseline-controlled refinery. The controls chosen for these two levels are shown in Table 22. For Level 1, refinery-wide CO_2, CO, CH_4, and NO_x reduction efficiencies are -111.5, 99.0, 100, and 53 percent, respectively. For Level 2, refinery-wide CO_2, CO, CH_4, and NO_x reduction efficiencies are -111.5, 98.8, 43.2, and 12.2 percent, respectively. The CO_2 reduction efficiency increases by 11 percent for both levels because CO and CH_4 destroyed creates additional CO_2.

Several technologies are potentially applicable to oil shale retorting for NO_x control, but are not commercially proven with this source (Ando, 1973; U.S. EPA, 1983). Caution should be exercised when conceptually applying these technologies to retorting. They included: SCR, LEA, two-stage combustion, and lowering the combustion temperature with a fast heat release. Estimated NO_x removal efficiencies are reported in Table 20.

A CO boiler can be applied downstream of several fuel production emission sources such as Lurgi gasification for heat recovery. Although CO boilers result in roughly 100 percent CO emission reduction, they are a source of NO_x and CO_2. For control of CO emissions from charcoal production, an afterburner can be used. The roughly 90 percent decreased in CO using an afterburner is accompanied by a slight increase in CO_2 emissions (Waterland et al., 1982; Kim et al., 1979).

The emission reduction for Prestratified Charge (PSC) and NSCR applied to turbines or internal combustion (IC) engines in pipeline systems is based on limited test data. PSC is capable of about 80 percent NO_x reduction on average, but may result in increases in emissions of CO and CH_4 (Benson and Hunter, 1986). NSCR is capable of 90 percent NO_x reduction on average, and also reduces CO, CH_4, and N_2O, according to limited test data. Although CO

TABLE 21. REFINERY SOURCES AND CONTROLS

Sources	Applicable Control Technologies by Technology Code[a]			
	CO_2	CO	CH_4	NO_x
Vacuum Distillation	--	F8	F8	
Catalytic Cracking	--	F7, F8	F8	
Process Heaters				
Oil	--	F8	--	F14, F15, F17, F19, F21
Natural Gas	--	F8	--	F11, F12, F16, F20

[a]See Table 20 for code descriptions.

TABLE 22. REFINERY CONTROL LEVELS[a]

Sources	Level 1 Well Controlled	Level 2 Baseline
Vacuum Distillation NO_x	None	None
Vacuum Distillation CO	F8	F8
Catalytic Cracking NO_x	None	F8
Catalytic Cracking CO	F8	F8
Process Heaters Natural Gas NO_x	F12	F18
Process Heaters Natural Gas CO	F8	None
Process Heaters Residual Oil NO_x	F14	F19
Process Heaters Residual Oil CO	F8	None

[a]See Table 20 for code descriptions.

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