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METHODS FOR ESTIMATING METHANE AND NITROUS OXIDE EMISSIONS FROM STATIONARY COMBUSTION

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INTRODUCTION

The EIIP guidelines are designed to describe emission estimation techniques for greenhouse gas sources in a clear and unambiguous manner and to facilitate preparation of inventories at the state level. This chapter presents the methodology for estimating methane and nitrous oxide emissions from stationary combustion. The methodology presented in this chapter has been revised to reflect new activity data, emission factors, and methods pertaining to this source category. Where possible, the methodology has been updated to be consistent with the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2002*.

Section 2 of this chapter contains a general description of this source category. Section 3 provides a listing of the steps involved in estimating methane and nitrous oxide emissions from stationary combustion. Section 4 presents the preferred estimation method. Section 5 presents the IPCC Tier 2 estimation method as an alternative and more in-depth approach for estimating emissions. A summary of uncertainty for this source category is provided in Section 6. References used in developing this chapter are identified in Section 7.

In addition to these guidelines, there are a series of user friendly spreadsheet tools available to assist in the development of emission inventories at the state level. Please consult the Stationary Combustion Module of the State Inventory Tool[1] to calculate emissions from this source category using the preferred emission estimation method.

[1] Note: The spreadsheet tool may have a different order of calculations, and may not show all calculations to the user.

2

SOURCE CATEGORY DESCRIPTION

2.1 EMISSION SOURCES

In addition to carbon dioxide, combustion of fuels at stationary sources results in emissions of five greenhouse gases: methane (CH_4), nitrous oxide (N_2O), carbon monoxide, nitrogen oxides, and non-methane volatile organic compounds.[2] For the first two of these greenhouse gases (CH_4 and N_2O), global warming potential values have been developed, which allow for normalization of all emissions to a common unit of metric tons of carbon equivalent. No Global Warming Potential values have yet been developed for the other three types of gases (carbon monoxide, nitrogen oxides, and non-methane volatile organic compounds); thus, they cannot be included in a greenhouse gas inventory. Consequently, this chapter only describes how to estimate emissions of CH_4 and N_2O from fuel combustion at stationary sources.

Other than CH_4 and N_2O, gases emitted from these activities are not considered major contributors to climate change. Data on gases such as carbon monoxide, nitrogen oxides, and non-methane volatile organic compounds are already collected by state environmental or air quality agencies to determine state compliance with Clean Air Act regulations.

2.2 FACTORS INFLUENCING EMISSIONS

In general, emissions of CH_4 and N_2O will vary with the type of fuel combusted, the size and vintage of the combustion technology, the maintenance and operation of this technology, and the type of pollution control technology used.

N_2O is produced from the combustion of fuels, and the mechanisms of its formation are fairly well understood. The level of N_2O emissions depends on the combustion temperature, with the highest N_2O emissions at a temperature of 1,000 degrees Kelvin. For combustion temperatures below 800 or above 1200 degrees Kelvin (980 to 1700 degrees Fahrenheit), the N_2O emissions are negligible (IPCC/UNEP/OECD/IEA 1997).

CH_4, carbon monoxide, and non-methane volatile organic compounds are unburned gaseous combustibles that are emitted in small quantities due to incomplete combustion; more of these gases are released when combustion temperatures are relatively low. Emissions of these gases are also influenced by technology type, size, vintage, maintenance, operation, and emission controls. Larger, higher efficiency combustion facilities tend to have higher temperatures and thus lower emission factors for these gases. Emissions may range several orders of magnitude above the average for facilities that are improperly maintained or poorly operated, such as may

[2] Carbon dioxide emissions from fossil fuel combustion are covered in Chapter 1 of this volume.

be the case for many older units. Similarly, during start-up periods, combustion efficiency is lowest, and emissions of carbon monoxide and non-methane volatile organic compounds are higher than during periods of full operation.

3

OVERVIEW OF AVAILABLE METHODS

The recommended method to estimate methane and nitrous oxide emissions from fuel combustion in stationary sources is the Tier 1 approach developed by the Intergovernmental Panel on Climate Change (IPCC/UNEP/OECD/IEA 1997). This approach, presented in Section 4, is consistent with the approach used in the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1900-2002* (U.S. EPA 2004).

The methodology involves the following steps: (1) obtain the required data on fuel consumption in each sector; (2) make data adjustments; (3) estimate emissions using the IPCC Tier 1 approach; (4) sum across all fuel types and sectors to derive total emissions; and (5) convert units to metric tons of carbon equivalent. The Stationary Combustion Module of the State Inventory Tool can be used in conjunction with the methods described in Section 4.

An alternative approach, presented in Section 5, is recommended if more detailed data are available. This approach, which will allow for a more accurate estimate of emissions, requires information on the proportions of each fuel combusted using various combustion technologies for each industry sector.

4

PREFERRED METHOD FOR ESTIMATING EMISSIONS

Estimation of emissions from stationary sources using the Intergovernmental Panel on Climate Change (IPCC) Tier 1 approach can be described using the following basic formula, which indicates that total emissions for a particular state equal the sum of emissions for both methane (CH_4) and nitrous oxide (N_2O) across sectors and fuel types.

$$Emissions = \Sigma (Activity_{ab} \times EF_{ab})$$

where:	Activity	=	Energy input (BBtu);
	EF	=	Emission factor (mt/BBtu);
	a	=	Primary fuel type; and
	b	=	Sector.

As seen in this equation, emission estimation is based on two sets of data, each of which vary by primary fuel type (coal, oil, or gas), and sector: (1) energy activities and (2) emission factors.

The methodologies for estimating emissions of these two gases are identical; therefore the general methodology is provided below and followed by an example for N_2O. The methodology consists of five steps: (1) obtain required data; (2) make data adjustments; (3) estimate emissions using the IPCC Tier 1 approach; (4) sum across all fuel types and sectors to derive total emissions; and (5) convert units to metric tons of carbon equivalent (MTCE).

Step (1): Obtain Required Data

- *Required Data*: The required data are the amount of coal, petroleum, natural gas, and wood combusted in the residential, commercial, industrial, and electric utility sectors.

- *Data Sources*: In-state agencies should be consulted first. However, if it is difficult to obtain data from these sources, state-level data derived from EIA's *State Energy Data* (*SED*) *2000* (EIA 2003b) can be used, which is provided in the Stationary Combustion Module of the State Inventory Tool (hereafter referred to as the State Inventory Tool). Stationary sources are often categorized into four sectors: residential, commercial, industrial, and electric utilities.[3] As the emission factors provided in this chapter require activity levels reported in

[3] Transportation is another sector frequently encountered in energy consumption statistics, but is not a stationary source. Transportation sector emissions are addressed in Chapter 1 (CO_2) and Chapter 3 (CH_4 and N_2O).

billion British thermal units (BBtu), refer to Box 1 in Chapter 1 to convert from other magnitudes of Btu (e.g., Btu, MMBtu). If data are presented in units of barrels, tons, or billion cubic feet, convert to Btu using the heat contents in Table 2.4-1 and Table 2.4-2.

Step (2): Make Data Adjustments

- *Adjust for non-energy uses of fuels.* Many fossil fuels are used for non-energy purposes to some degree. For example, LPG is used for production of solvents and synthetic rubber; oil is used to produce asphalt, naphthas, and lubricants; and coal is used to produce coke, yielding crude light oil and crude tar as by-products, which are used in the chemical industry. Since these fuels are not combusted when used for purposes such as these, their consumption should be subtracted from statistics that include total fuel use.

  For each fuel type that has non-energy uses (as listed in Table 1.4-6 in Chapter 1), subtract the quantity of fuel consumed in non-energy uses, based on (1) the total amount consumed and (2) the fraction consumed for non-energy uses. See Chapter 1 for an example on how to carry out this adjustment calculation. For data on the fraction of each fuel type consumed for non-energy uses, in-state sources, such as state energy commissions or public utility commissions, should be consulted first. In the absence of state-specific data, estimates of the national-level fraction of each fuel type used for non-energy uses can be determined using the Annual Energy Review 2002 (EIA 2003a) and SED 2000 (EIA 2003d), and the national fractions may be used as a proxy for the state fractions although this method will be less accurate. In the absence of state-specific data, estimates of the national-level fraction of each fuel type used for non-energy uses can be determined using the Annual Energy Review 2002 (EIA 2003a) and SED 2000 (EIA 2003d), and the national fractions may be used as a proxy for the state fractions although this method will be less accurate.

- *Synthetic natural gas production*: EIA's coal data also include industrial coal used to make synthetic natural gas, which is also accounted for under natural gas consumption data. Therefore, the energy content of synthetic natural gas should be subtracted from the energy content of industrial coal to prevent double counting of emissions. State-specific natural gas data can be obtained from EIA's *Natural Gas Annual* (EIA 2004) and is also provided in the State Inventory Tool.

Step (3): Estimate Emissions Using the IPCC Tier 1 Approach

- To estimate emissions using this approach, multiply fuel use in BBtu by the appropriate emission factor in Table 2.4-3. The State Inventory Tool follows this approach and provides default fuel consumption data from the *SED 2000*.[4]

Step (4): Sum Across All Fuel Types and Sectors to Derive Total Emissions

[4] If your state has data on the amount of coal, oil, natural gas, and wood combusted by technology type, you may follow the more complex Tier 2 approach described in Section 5.

- Sum the estimates of CH_4 and N_2O emission across all fuels and sectors to derive total emissions (in metric tons) of each gas.

Step (5): Convert Units to Metric Tons of Carbon Equivalent

- To obtain emissions in metric tons of CO_2 equivalent ($MTCO_2E$), multiply the emissions in metric tons for each of the gases by the Global Warming Potential (GWP) for each gas. The GWPs of CH_4 and N_2O are 21 and 310, respectively.

- Convert the data from $MTCO_2E$ of gas to MTCE by multiplying by 12/44, which is the ratio of the atomic weight of C to the molecular weight of CO_2.

Example: In Colorado, fuels used for combustion in the residential sector in 2000 were 191 BBtu of coal, 10,798 BBtu of oil, 117,139 BBtu of natural gas, and 8,476 BBtu of wood. N_2O emissions can be estimated using the Tier 1 method as follows:

Coal

191 BBtu x 0.00140 metric tons N_2O/BBtu = 0.2674 metric tons N_2O
0.2674 metric tons N_2O x 310 (GWP for N_2O) = 83 $MTCO_2E$
83 $MTCO_2E$ x 12 C/44 CO_2 = **23 MTCE**

Oil

10,798 BBtu x 0.00060 metric tons N_2O/BBtu = 6.4788 metric tons N_2O
6.4788 metric tons N_2O x 310 (GWP for N_2O) = 2,008 $MTCO_2E$
2,008 $MTCO_2E$ x 12 C/44 CO_2 = **548 MTCE**

Natural Gas

117,139 BBtu x 0.00009 metric tons N_2O/BBtu = 10.5425 metric tons N_2O
10.5425 metric tons N_2O x 310 (GWP for N_2O) = 3,268 $MTCO_2E$
3,268 $MTCO_2E$ x 12 C/44 CO_2 = **891 MTCE**

Wood

8,476 BBtu x 0.00380 metric tons N_2O/BBtu = 32.2088 metric tons N_2O
32.2088 metric tons N_2O x 310 (GWP for N_2O) = 9,985 $MTCO_2E$
9,985 $MTCO_2E$ x 12 C/44 CO_2 = **2,723 MTCE**

Table 2.4-1: Heat Contents

Fuel Type	Heat Equivalents
Coal (MMBtu/short ton)	
Residential Coal	[a]
Commercial Coal	[a]
Industrial Coking Coal	[a]
Industrial Other Coal	[a]
Utility Coal	[a]
Natural Gas (Btu/cubic foot)	[b]
Petroleum (MMBtu/barrel)	
Asphalt and Road Oil	6.636
Aviation Gasoline	5.048
Distillate Fuel Oil	5.825
Jet Fuel: Kerosene Type	5.670
Jet Fuel: Naphtha Type	5.355
Kerosene	5.670
Liquefied Petroleum Gases (LPG)	[a]
Lubricants	6.065
Miscellaneous Petroleum Products	5.796
Crude Oil	5.800
Naphtha (<401 deg. F)	5.248
Special Naphthas	5.248
Other Oil (>401 deg. F)	5.825
Unfinished Oils	5.825
Pentanes Plus	4.620
Petroleum Coke	6.024
Residual Fuel Oil	6.287
Still Gas	6.000
Waxes	5.537

a. Annually variable heat contents. Values presented in Table 2.4-2.

b. Varies annually by state. National averages provided in Table 2.4-2.

Source: EIA 2003a.

Table 2.4-2: Annually Variable Heat Contents

Fuel	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Coal (MMBtu/ton)													
Residential Coal	23.137	23.114	23.105	22.994	23.112	23.118	23.011	22.494	21.620	23.880	25.020	24.905	24.836
Commercial Coal	23.137	23.114	23.105	22.994	23.112	23.118	23.011	22.494	21.620	23.880	25.020	24.905	24.836
Industrial Coking Coal	26.799	26.799	26.799	26.800	26.800	26.800	26.800	26.800	27.426	27.426	27.426	27.426	27.426
Industrial Other Coal	22.457	22.460	22.250	22.123	22.068	21.950	22.105	22.172	23.164	22.489	22.433	23.209	23.361
Utility Coal [a]	20.779	20.730	20.709	20.677	20.589	20.543	20.547	20.518	20.516	20.490	20.511	20.279	20.479
Petroleum (MMBtu/barrel)													
Motor Gasoline	5.253	5.253	5.253	5.253	5.230	5.215	5.216	5.213	5.212	5.211	5.210	5.210	5.208
LPG	3.625	3.614	3.624	3.606	3.635	3.623	3.613	3.616	3.614	3.616	3.607	3.614	3.612
Natural Gas [b] (Btu/cubic foot)	1,029	1,030	1,030	1,027	1,028	1,026	1,026	1,026	1,031	1,027	1,025	1,028	1,027

[a] Heat content for utility coal represents the average heat content for coal used for electric utilities and independent power producers based on the new EIA classification of electric power data.
[b] Heat contents varying by state are presented in the State Inventory Tool. Note this is dry natural gas.
Source: EIA 2003a.

Table 2.4-3: CH_4 and N_2O Emission Factors by Fuel Type and Sector (metric tons/BBtu)

Fuel/End-Use Sector	N_2O	CH_4
Coal		
Residential	0.00140	0.30069
Commercial	0.00140	0.01002
Industrial	0.00140	0.01002
Electric Utilities	0.00140	0.00100
Petroleum		
Residential	0.00060	0.01002
Commercial	0.00060	0.01002
Industrial	0.00060	0.00200
Electric Utilities	0.00060	0.00301
Natural Gas		
Residential	0.00009	0.00475
Commercial	0.00009	0.00475
Industrial	0.00009	0.00475
Electric Utilities	0.00009	0.00095
Wood		
Residential	0.00380	0.28487
Commercial	0.00380	0.28487
Industrial	0.00380	0.02849
Electric Utilities	0.00380	0.02849

Source: Derived from IPCC/UNEP/OECD/IEA 1997.

5

ALTERNATIVE METHODS FOR ESTIMATING EMISSIONS

Estimation of methane (CH_4) and nitrous oxide (N_2O) emissions from stationary sources using the more detailed IPCC Tier 2 approach can be described using the following basic formula, which indicates that total emissions for a particular state equal the sum of emissions across activities, technologies, and fuel types:

$$Emissions = \Sigma(EF_{abc} \times Activity_{abc} \times (100\text{-}R_{abc})/100)$$

Where:	EF	=	Emission factor (kg/terajoule[5]);
	Activity	=	Energy input (terajoules);
	R_{abc}	=	Percentage reduction in emissions due to controls;
	a	=	Fuel type;
	b	=	Sector activity; and
	c	=	Technology type.

As seen in this equation, emission estimation is based on three sets of data, each of which vary by fuel type, sector, and technology: (1) energy activities, (2) emission factors, and (3) control technologies.

This section presents the steps involved in using this methodology.

- Apportion the state's energy consumption by stationary sources into the sector categories and technology subcategories shown in Tables 2.5-1 through 2.5-5, and further apportion these values by the types of pollution control used, as shown in Tables 2.5-6 through 2.5-9. Note that the latter apportionment may require making assumptions about the distribution of pollution control technologies for each combustion technology. In making the latter apportionment, a simplified approach involves grouping together all pollution control technologies for which data on CH_4 and N_2O reductions are not provided in Tables 2.5-6 through 2.5-9.[6]

- If using an alternative data source for emission factors, apportion energy consumption into the categories specified in the alternative data source.

[5] A terajoule (TJ) equals 10^{12} joules (J).

[6] Note that the emission control performance is negligible for most technologies for both N_2O and CH_4.

- If the data are reported in higher heating values (as are data reported by the EIA), convert the values from higher heating values (gross calorific values, GCV) to lower heating values (net calorific values, NCV). The difference between the higher and lower heating value of a fuel is the heat of condensation of moisture in the fuel during combustion. The lower heating value excludes this. Since most of the world uses net calorific values, the IPCC emission factors, used later in this chapter, are based on net calorific values. For petroleum products and coal, the net calorific values are about five percent lower than gross calorific values. Thus, for petroleum products and coal, multiply the higher heating values (gross calorific values) by 0.95 to obtain lower heating values (net calorific values). For natural gas and wood (or other biomass), which contain more moisture, multiply the higher heating values (gross calorific values) by 0.90 to obtain lower heating values (net calorific values).

- Convert the fuel consumption values to TJ, using 947.8 MMBtu/TJ or 1,055.055 J/Btu.

Example:	A hypothetical state's electric utility sector used 10 trillion Btu of coal (lower heating value) in dry bottom, wall-fired boilers, with half of that used in boilers using low NO_x burners for emission controls. To convert the units to TJ, perform the following calculations: 10 TBtu x (10^{12} Btu/1 TBtu) x (1 MMBtu/10^6 Btu) = 10 x 10^6 MMBtu 10 x 10^6 MMBtu x (1 TJ/947.8 MMBtu) =10,551 TJ ½ of 10,551 TJ = **5,276 TJ** used in each type of boiler (with and without low NO_x burners)

- To estimate N_2O and CH_4 emissions, multiply the energy consumption by each subcategory of stationary sources (in TJ) by (1) the respective emission factors for N_2O and CH_4 in kg/TJ), and (2) a value of ((100 - the emissions control performance for each gas)/100). Emission factors are provided in 2.5-1 through 2.5-5 and emission control performance values are provided in Tables 2.5-6 through 2.5-9.

- Sum the emissions of N_2O and CH_4, separately, across all subcategories to obtain total N_2O and CH_4 emissions (in kg).

Example:	A hypothetical state uses 5,276 TJ of coal in dry bottom, wall-fired utility boilers without emission controls, and the same amount in the same type of boilers with low NO_x burners. To estimate CH_4 emissions from utility coal combustion, perform the following calculations: *For boilers without emission control, simply multiply energy consumption by the emission factor for CH_4* (use the factor for dry bottom, wall-fired boilers): (5,276 TJ) x (0.7 kg CH_4/TJ) = 3,693 kg CH_4 *For boilers with emissions control, adjust for emissions control performance* (note that in Table 2.5-8, all CH_4 emissions reductions associated with performance controls are negligible): (5,276 TJ) x (0.7 kg CH_4/TJ) x ((100 - 0)/100) = 3,693 kg CH_4 *Total* (3,693 + 3,693) kg CH_4 = **7,386 kg CH_4**

- Convert the data from kg of gas to metric tons of gas by dividing the number of kg of gas by 1,000.

- To obtain emissions in metric tons of CO_2 equivalent ($MTCO_2E$), multiply the emissions in metric tons for each of the gases by the GWP for each gas. The GWPs of CH_4 and N_2O are 21 and 310, respectively.

- Convert the data from $MTCO_2E$ of gas to metric tons of carbon equivalent (MTCE) by multiplying by 12/44, which is the ratio of the atomic weight of C to the molecular weight of CO_2.

Example:	To convert emissions data from kg of CH_4 to MTCE, perform the following calculations:
	7,386 kg CH_4 x (1 metric ton/1,000 kg) = 7.386 metric tons CH_4
	7.386 metric tons CH_4 x 21 (GWP for CH_4) = 155.1 $MTCO_2E$
	155.1 $MTCO_2E$ x 12 C/44 CO_2 = **42.3 MTCE**

Table 2.5-1: Utility Boiler Source Performance

		Emission Factors (kg/TJ energy input)				
Basic Technology	**Configuration**	**CO**	**CH_4**	**NO_x**	**N_2O**	**NMVOCs**
Coal						
Pulverised Bituminous Combustion	Dry Bottom, wall fired	9	0.7	380	1.6	NAV
	Dry Bottom, tangentially fired	9	0.7	250	0.5	NAV
	Wet Bottom	9	0.9	590	1.6	NAV
Bituminous Spreader Stokers	With and without re-injection	87	1.0	240	1.6	NAV
Bituminous Fluidised Bed Combustor	Circulating Bed	310	1.0	68	96	NAV
	Bubbling Bed	310	1.0	270	96	NAV
Bituminous Cyclone Furnace		9	0.2	590	1.6	NAV
Anthracite Stokers		10	NAV	160	NAV	NAV
Anthracite Fluidised Bed Combustors		5.2	NAV	31	NAV	NAV
Anthracite Pulverised Coal Boilers		310	NAV	NAV	NAV	NAV
Pulverised Lignite Combustion	Dry Bottom, tangentially fired	NAV	NAV	130	NAV	NAV
	Dry Bottom, wall fired	45	NAV	200	NAV	NAV
Lignite Cyclone Furnace		NAV	NAV	220	NAV	NAV
Lignite Spreader Stokers		NAV	NAV	100	NAV	NAV
Lignite Atmospheric Fluidised Bed		2.8	NAV	63	42	NAV
Oil						
Residual Fuel Oil/Shale Oil	Normal Firing	15	0.9	200	0.3	NAV
	Tangential Firing	15	0.9	130	0.3	NAV
Distillate Fuel Oil	Normal Firing	16	0.9	220	0.4	NAV
	Tangential Firing	16	0.9	140	0.4	NAV
Distillate Fuel Gaseous Turbines		21	NAV	300	NAV	NAV
Large Diesel Fuel Engines >600hp (447kW)		350	4.0	1300	NAV	NAV
Natural Gas						
Boilers		18	0.1[a]	250	NAV	NAV
Large Gas-Fired Gas Turbines >3MW		46	6*	190	NAV	NAV
Large Dual-Fuel Engines		340	240	1300	NAV	NAV
Municipal Solid Waste (MSW)						
Mass Burn Waterwall Combustors		22	NAV	170	NAV	NAV
MSW - Mass Feed[a]		98	NAV	140	NAV	NAV

Source: US EPA (1995).
(a) Adapted from Radian, 1990.

Note: large dual-fuel engines are large engines that can run on either natural gas or oil. "Large" is typically defined for regulatory purposes as having a capacity to combust more than 250 MMBtu/hr of fuel; an alternative, equivalent definition is having a capacity to generate about 25 megawatts of power.
NAV = Not available.

Table 2.5-2: Industrial Boiler Performance

		Emission Factors (kg/TJ energy input)				
Basic Technology	Configuration	CO	CH_4	NO_x	N_2O	NMVOCs
Coal						
Bit./Sub-bit. Overfeed Stoker Boilers		110	1.0	130	1.6	NAV
Bit./Sub-bit. Underfeed Stoker Boilers		190	14	170	1.6	NAV
Bit./Sub-bit. Hand-fed Units		4800	87	160	1.6	NAV
Bituminous/Sub-bituminous Pulverised	Dry Bottom, wall fired	9	0.7	380	1.6	NAV
	Dry Bottom, tangentially fired	9	0.7	250	0.5	NAV
	Wet Bottom	9	0.9	590	1.6	NAV
Bituminous Spreader Stokers		87	1.0	240	1.6	NAV
Bit./Sub-bit. Fluidised Bed Combustor	Circulating Bed	310	1.0	68	96	NAV
	Bubbling Bed	310	1.0	270	96	NAV
Anthracite Stokers		10	NAV	160	NAV	NAV
Anthr. Fluidised Bed Combustor Boilers		5.2	NAV	31	NAV	NAV
Anthracite Pulverised Coal Boilers		NAV	NAV	310	NAV	NAV
Oil						
Residual Fuel Oil Boilers		15	3.0	170	0.3	NAV
Distillate Fuel Oil Boilers		16	0.2	65	0.4	NAV
Small Waste Oil Boilers <0.1MW		15	NAV	58	NAV	NAV
LPG Boilers	Propane	17	NAV	96	NAV	NAV
	Butane	16	NAV	97	NAV	NAV
Small Stationary Internal Comb. Engines	Gasoline <250hp (186 kW)	27	NAV	0.7	NAV	NAV
	Diesel <600hp (447 kW)	0.4	NAV	1.9	NAV	NAV
Large Stationary Diesel Engines >600hp (447 kW)		0.3	0.0	1.3	NAV	NAV
Natural Gas						
Large Boilers >100 MBtu/h (293 MW)		18	1.4	250	NAV	NAV
Small Boilers 10-100 MBtu/h (29.3-293 MW)		16	1.4	64	NAV	NAV
Heavy Duty Nat. Gas Compressor Eng.	Turbines	2.0	0.6	4.1	NAV	NAV
	2-Cycle Lean Burn	4.7	17	33	NAV	NAV
	4-Cycle Lean Burn	5.1	13	39	NAV	NAV
	4-Cycle Rich Burn	20	2.9	28	NAV	NAV
Wood						
Fuel Cell/Dutch Oven Boilers		290	NAV	17	NAV	NAV
Stoker Boilers		590	15	65	NAV	NAV
FBC Boilers		61	NAV	87	NAV	NAV
Bagasse/Ag. Waste Boilers		NAV	NAV	68	NAV	NAV
MSW						
MSW Boilers	Mass Burn Waterwall	22	NAV	170	NAV	NAV
	Mass Burn Rotary Waterwall	36	NAV	110	NAV	NAV
	Mass Burn Rotary Refrac. Wall	64	NAV	120	NAV	NAV
	Modular, Excess Air	NAV	NAV	120	NAV	NAV
	Modular, Starved Air	14	NAV	150	NAV	NAV
Refuse Derived Combustors		90	NAV	240	NAV	NAV
Source: US EPA (1995).						

Note: NAV = Not available.

Table 2.5-3: Kilns, Ovens, and Dryers Source Performance

		Emission Factors (kg/TJ energy input)[a]				
Industry	**Source**	**CO**	**CH_4**	**NO_x**	**N_2O**	**NMVOCs**
Cement, Lime	Kilns - Natural Gas	83	1.1	1,111	NAV	NAV
Cement, Lime	Kilns - Oil	79	1.0	527	NAV	NAV
Cement, Lime	Kilns - Coal	79	1.0	527	NAV	NAV
Coking, Steel	Coke Oven	211	1	35[b]	NAV	16[b]
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer - Natural Gas	11	1.1	64	NAV	NAV
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer - Oil	16	1.0	168	NAV	NAV
Chemical Processes, Wood, Asphalt, Copper, Phosphate	Dryer - Coal	179	1.0	226	NAV	NAV

Source: Radian, 1990.

(a) Values were originally based on gross calorific value; they were converted to net calorific value by assuming that net calorific values were 5 per cent lower than gross calorific values for coal and oil, and 10 per cent lower for natural gas. These percentage adjustments are the OECD/IEA assumption on how to convert from gross to net calorific values.

(b) Joint EMEP/CORINAIR (1996).

Note: NAV = Not available.

Table 2.5-4: Residential Source Performance

		Emission Factors (kg/TJ energy input)				
Basic Technology	**Configuration**	**CO**	**CH_4**	**NO_x**	**N_2O**	**NMVOCs**
Coal						
Anthracite Space Heaters		NAV	150	55	NAV	NAV
Coal Hot Water Heaters[(a)]		18	NAV	160	NAV	NAV
Coal Furnaces[(a)]		480	NAV	230	NAV	NAV
Coal Stoves[(a)]		3600	NAV	180	NAV	NAV
Oil						
Residual Fuel Oil		15	1.4	170	NAV	NAV
Distillate Fuel Oil		16	0.7	65	NAV	NAV
Furnaces		16	5.8	59	0.2	NAV
Propane/Butane Furnaces[(a)]		10	1.1	47	NAV	NAV
Natural Gas						
Furnaces		18	NAV	43	NAV	NAV
Gas Heaters[(a)]		10	1	47	NAV	NAV
Wood						
Wood Pits[(a)]		4900	200	150	NAV	NAV
Fireplaces		11000	NAV	110	NAV	NAV
Stoves	Conventional	10000	210	120	NAV	NAV
	Non-catalytic	6100	NAV	NAV	NAV	NAV
	Catalytic	4500	380	87	NAV	NAV
	Pellet, Certified	1700	NAV	600	NAV	NAV
	Pellet, Exempt	2300	NAV	NAV	NAV	NAV
Masonry Heater	Exempt	6500	NAV	NAV	NAV	NAV

Source: US EPA (1995).
(a) Adapted from Radian, 1990.

Note: NAV = Not available.

Table 2.5-5: Commercial Source Performance

		Emission Factors (kg/TJ energy input)				
Basic Technology	**Configuration**	**CO**	**CH_4**	**NO_x**	**N_2O**	**NMVOCs**
Coal						
Coal Boilers[(a)]		200	10	240	NAV	NAV
Oil						
Residual Fuel Oil/Shale Oil		15	1.4	170	0.3	NAV
Distillate Fuel Oil		16	0.7	65	0.4	NAV
Waste Oil Space Heaters	Vaporising Burner	5.0	NAV	33	NAV	NAV
	Atomising Burner	6.3	NAV	48	NAV	NAV
LPG Boilers	Propane	8.4	NAV	71	NAV	NAV
	Butane	12	NAV	70	NAV	NAV
Natural Gas						
Boilers		9.4	1.2	45	2.3	NAV
Wood						
Incineration - high efficiency[(a)]		440	NAV	130	NAV	NAV
Waste						
Mass Burn Waterwall		22	NAV	170	NAV	NAV
Combustors		NAV	NAV	NAV	NAV	NAV
MSW Boilers[(a)]		19	NAV	460	NAV	NAV

Source: US EPA (1995).
(a) Adapted from Radian, 1990.

Note: NAV = Not available.

Table 2.5-6: Utility Emission Controls Performance

Technology	Efficiency Loss[a] (%)	CO Reduction (%)	CH_4 Reduction (%)	NO_x Reduction (%)	N_2O Reduction (%)	NMVOCs Reduction (%)	Date Available[b]
Low Excess Air (LEA)	-0.5	+	+	15	NAV	NAV	1970
Overfire Air (OFA) - Coal	0.5	+	+	25	NAV	NAV	1970
OFA - Gas	1.25	+	+	40	NAV	NAV	1970
OFA - Oil	0.5	+	+	30	NAV	NAV	1970
Low NO_x Burner (LNB) - Coal	0.25	+	+	35	NAV	NAV	1980
LNB - Tangentially Fired	0.25	+	+	35	NAV	NAV	1980
LNB - Oil	0.25	+	+	35	NAV	NAV	1980
LNB - Gas	0.25	+	+	50	NAV	NAV	1980
Cyclone Combustion Modification	0.5	NAV	NAV	40	NAV	NAV	1990
Ammonia Injection	0.5	+	+	60	NAV	NAV	1985
Selective Catalytic Reduction (SCR) - Coal	1	8	+	80	NAV	NAV	1985
SCR - Oil, AFBC	1	8	+	80	NAV	NAV	1985
SCR - Gas	1	8	+	80	60	NAV	1985
Water Injection - Gas Turbine Simple Cycle	1	+	+	70	NAV	NAV	1975
SCR - Gas Turbine	1	8	+	80	60	NAV	1985
Retrofit LEA	-0.5	+	+	15	NAV	NAV	1970
Retrofit OFA - Coal	0.5	+	+	25	NAV	NAV	1970
Retrofit OFA - Gas	1.25	+	+	40	NAV	NAV	1970
Retrofit OFA - Oil	0.5	+	+	30	NAV	NAV	1970
Retrofit LNB - Coal	0.25	+	+	35	NAV	NAV	1980
Retrofit LNB - Oil	0.25	+	+	35	NAV	NAV	1980
Retrofit LNB - Gas	0.25	+	+	50	NAV	NAV	1980
Burners Out of Service	0.5	+	+	30	NAV	NAV	1975

(a) Efficiency loss as a percentage of end-user energy conversion efficiency (ratio of energy output to energy input for each technology) due to the addition of an emission control technology. Negative loss indicates an efficiency improvement.

(b) Date technology is assumed to be commercially available.

Note: A "+" indicates negligible reduction.

Source: Radian, 1990.

Note: NAV = Not available.

Table 2.5-7: Industrial Boiler Emission Controls Performance

Technology	Efficiency Loss[a] (%)	CO Reduction (%)	CH_4 Reduction (%)	NO_x Reduction (%)	N_2O Reduction (%)	NMVOCs Reduction (%)	Date Available[b]
Low Excess Air (LEA)	-0.5	+	+	15	NAV	NAV	1970
Overfire Air (OFA) - Coal	0.5	+	+	25	NAV	NAV	1970
OFA - Gas	1.25	+	+	40	NAV	NAV	1970
OFA - Oil	0.5	+	+	30	NAV	NAV	1970
Low NO_x Burner (LNB) - Coal	0.25	+	+	35	NAV	NAV	1980
LNB - Oil	0.25	+	+	35	NAV	NAV	1980
LNB - Gas	0.25	+	+	50	NAV	NAV	1980
Flue Gas Recirculation	0.5	+	+	40	NAV	NAV	1975
Ammonia Injection	0.5	+	+	60	NAV	NAV	1985
Selective Catalytic Reduction (SCR) - Coal	1	8	+	80	NAV	NAV	1985
SCR - Oil, AFBC	1	8	+	80	NAV	NAV	1985
SCR - Gas	1	8	+	80	60	NAV	1985
Retrofit LEA	-0.5	+	+	15	NAV	NAV	1970
Retrofit OFA - Coal	0.5	+	+	25	NAV	NAV	1970
Retrofit OFA - Gas	1.25	+	+	40	NAV	NAV	1970
Retrofit OFA - Oil	0.5	+	+	30	NAV	NAV	1970
Retrofit LNB - Coal	0.25	+	+	35	NAV	NAV	1980
Retrofit LNB - Oil	0.25	+	+	35	NAV	NAV	1980
Retrofit LNB - Gas	0.25	+	+	50	NAV	NAV	1980

(a) Efficiency loss as a percentage of end-user energy conversion efficiency (ratio of energy output to energy input for each technology) due to the addition of an emission control technology. Negative loss indicates an efficiency improvement.

(b) Date technology is assumed to be commercially available.

Note: A "+" indicates negligible reduction.

Source: Radian, 1990.

Note: NAV = Not available.

Table 2.5-8: Kiln, Ovens, and Dryers Emission Controls Performance

Technology	Efficiency Loss[a] (%)	CO Reduction (%)	CH_4 Reduction (%)	NO_x Reduction (%)	N_2O Reduction (%)	NMVOCs Reduction (%)	Date Available[b]
LEA - Kilns, Dryers	-6.4	+	+	14	NAV	NAV	1980
LNB - Kilns, Dryers	0	+	+	35	NAV	NAV	1985
SCR - Coke Oven	1.0	8	+	80	60	NAV	1979
Nitrogen Injection	NAV	NAV	NAV	30	NAV	NAV	1990
Fuel Staging	NAV	NAV	NAV	50	NAV	NAV	1995

(a) Efficiency loss as a percentage of end-user energy conversion efficiency (ratio of energy output to energy input for each technology) due to the addition of an emission control technology. Negative loss indicates an efficiency improvement.

(b) Date technology is assumed to be commercially available.

Note: A "+" indicates negligible reduction.

Source: Radian, 1990.

Note: NAV = Not available.

Table 2.5-9: Residential and Commercial Emission Controls Performance

Technology	Efficiency Loss[(a)] (%)	CO Reduction (%)	CH_4 Reduction (%)	NO_x Reduction (%)	N_2O Reduction (%)	NMVOCs Reduction (%)	Date Available[(b)]
Catalytic Woodstove	-44	90	90	-27	NAV	NAV	1985
Non-Catalytic Modified Combustion Stove	-30	15	50	-5	NAV	NAV	1985
Flame Retention Burner Head	-9	28	NAV	NAV	NAV	NAV	
Controlled Mixed Burner Head	-7	43	NAV	44	NAV	NAV	
Integrated Furnace System	-12	13	NAV	69	NAV	NAV	
Blueray Burner/Furnace	-12	74	NAV	84	NAV	NAV	
M.A.N. Burner	-13	NAV	NAV	71	NAV	NAV	1980
Radiant Screens	-7	62	NAV	55	NAV	NAV	
Secondary Air Baffle	NAV	16	NAV	40	NAV	NAV	
Surface Comb. Burner	NAV	55	NAV	79	NAV	NAV	
Amana HTM	-21	-55	NAV	79	NAV	NAV	
Modulating Furnace	-7	NAV	NAV	32	NAV	NAV	
Pulse Combuster	-36	NAV	NAV	47	NAV	NAV	
Catalytic Combuster	-29	NAV	NAV	86	NAV	NAV	
Replace Worn Units	NAV	65	NAV	NAV	NAV	NAV	
Tuning, Seasonal Maintenance	-2	16	NAV	NAV	NAV	NAV	
Reduced Excessive Firing	-19	14	NAV	NAV	NAV	NAV	
Reduced Excessive Firing with New Retention Burner	-40	14	NAV	NAV	NAV	NAV	
Positive Chimney Dampers	-8	11	NAV	NAV	NAV	NAV	
Increased Thermostat Anticipator	-1	43	NAV	NAV	NAV	NAV	
Night Thermostat Cutback	-15	17	NAV	NAV	NAV	NAV	
Low Excess Air	-0.8	NAV	NAV	15	NAV	NAV	1970
Flue Gas Recirculation	0.6	NAV	NAV	50	NAV	NAV	1975
Over-fire Air	1	NAV	NAV	20-30	NAV	NAV	1970
Low NO_x Burners	0.6	NAV	NAV	40-50	NAV	NAV	1980

(a) Efficiency loss as a percentage of end-user energy conversion efficiency (ratio of energy output to energy input for each technology) due to the addition of an emission control technology. Negative loss indicates an efficiency improvement.

(b) Date technology is assumed to be commercially available.

Source: Radian, 1990.

Note: NAV = Not available.

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UNCERTAINTY SUMMARY

The amount of methane (CH_4) and nitrous oxide (N_2O) emitted from stationary combustion depends on the amount and type of fuel (coal, petroleum, natural gas, and wood) used, the type of technology in which it is combusted (e.g., boilers, water heaters, furnaces), and the type of emission control. In general, the more detailed information available on the combustion activity, the lower the uncertainty. However, as noted in the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997), the contribution of CH_4 and N_2O to overall emissions is small and the estimates are highly uncertain. Uncertainties exist in both the emission factors and activity data used to derive emission estimates.

As noted in Section 2.2, the combustion temperature at which the technology operates impacts the level of CH_4 and N_2O emissions. For instance, N_2O emissions are negligible when temperatures reach below 800 or above 1200 degrees Kelvin, while CH_4 emissions are highest when combustion temperatures are low, usually in smaller combustion sources (IPCC/UNEP/OECD/IEA 1997). Because of the combined difficulty in obtaining specific combustion technology information and the relatively low contribution of this source to a state's total emissions, IPCC states that the Tier 1 approach (the methodology presented in this chapter) is sufficient. However, the emission factors used are aggregated by sector, representing only a limited subset of combustion conditions. Therefore, the results of the IPCC Tier 1 approach are far more uncertain than those estimated using the more detailed IPCC Tier 2 approach. The Tier 2 emission factors account for specific pollution control technologies used with each combustion technology, but still have uncertainty because these factors represent the average performance of technologies.

Uncertainties may also exist in the activity data used to derive emission estimates. For example, in the EIA SEDR data sets wood used in fireplaces, wood stoves, and campfires is not fully captured. Uncertainties are also associated with the allocation of fuel consumption data to individual end-use sectors and estimation of the fraction of fuels used for non-energy.

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