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METHODOLOGIES FOR QUANTIFYING POLLUTION PREVENTION BENEFITS FROM LANDFILL GAS CONTROL AND UTILIZATION

by

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16. ABSTRACT The report describes developing emission factors for controlled primary pollutants (e.g., nonmethane organic compounds) and secondary air pollutants (e.g., carbon monoxide). The report addresses the following criteria air pollutants and greenhouse gases: carbon dioxide, carbon monoxide, methane, nitrogen oxides, nonmethane organic compounds, and sulfur dioxide. For this report, primary pollutants are those contained in landfill gas (LFG), and secondary pollutants are those resulting from the combustion of LFG by control or utilization equipment. Data are included that allow an analyst to convert emission factors to units that allow for direct comparison with energy alternatives (e.g., pounds of a pollutant released per kilowatt-hour of electricity produced). (NOTE: A combination of mass balance methods and emission factors based on source data can be used to compare air pollution potential between different LFG control or utilization options. These methods and emission factors can also be used to compare between LFG utilization projects and the more established energy alternatives (e.g., coal, natural gas). Uncontrolled and controlled LFG emission inventories can also be prepared to assess the benefits of LFG control or utilization. LFG flaring is the only control option addressed in this report, but three utilization options are included.)

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
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Earth Fills	Stationary Sources	13C
Gases	Landfill Gas	07D
Emission		14G
Estimating		
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ABSTRACT

A combination of mass balance methods and emission factors based on source data can be used to make comparisons in air pollution potential between different landfill gas (LFG) control or utilization options. These methods and emission factors can also be used to make comparisons between LFG utilization projects and the more established energy alternatives (e.g., coal, natural gas). Uncontrolled and controlled LFG emission inventories can also be prepared to assess the benefits of LFG control or utilization. LFG flaring is the only control option addressed in this report, while the utilization options include reciprocating internal combustion (RIC) engines, steam and gas turbines, and boilers.

This report describes the development of emission factors for controlled primary pollutants (e.g., nonmethane organic compounds) and secondary air pollutants (e.g., carbon monoxide). The following criteria air pollutants and greenhouse gases are addressed in this document: nonmethane organic compounds, carbon monoxide, sulfur dioxide, nitrogen oxides, carbon dioxide, and methane. For this report, primary pollutants are those contained in LFG and secondary pollutants are those resulting from the combustion of LFG by control or utilization equipment. Data are included that allow an analyst to convert emission factors to units that allow for direct comparison with the energy alternatives mentioned above (e.g., pounds of a pollutant released per kilowatt-hour of electricity produced).

Methods to prepare uncontrolled and controlled LFG emission inventories are also included. The methods describe the mass balance techniques needed to estimate emissions of the primary and some secondary LFG pollutants and the use of secondary pollutant emission factors for those species that can not be estimated by mass balance.

An example is included that demonstrates the methods and use of the data presented in the report. The example shows how emission factors are developed for LFG flare control and an LFG utilization with an RIC engine, a gas turbine, and a boiler. Comparison emission factors are developed for a coal-fired steam power plant, a natural gas turbine power plant, and an industrial boiler. An emission inventory of an uncontrolled landfill is also developed and compared to emission inventories projected for the landfill following installation of an LFG flare, RIC engine plant, gas turbine plant, or boiler.

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ABBREVIATIONS

AEERL	Air and Energy Engineering Research Laboratory
Btu	British thermal unit
CAA	Clean Air Act
CFC	Chlorofluorocarbon(s)
DOE	U.S. Department of Energy
EF	Emission factor
EPA	U.S. Environmental Protection Agency
eq.	Equation
ESP	Electrostatic precipitator
ft	Foot or feet
GHG	Greenhouse gas
HHV	Higher heating value
HOP	Hours of operation
HR	Heat rate
hr	Hour
kJ	Kilojoule
kWh	Kilowatt-hour
lb/MMBtu	Pounds of a pollutant per million British thermal units
LFG	Landfill gas
Mg	Megagram or metric ton
min	Minute
MW	Molecular weight
NMOC	Nonmethane organic compounds
NSPS	New Source Performance Standard
PM-10	Particulate matter less than 10 micrometers in diameter
ppmv	Parts per million by volume
RIC	Reciprocating internal combustion
RS^{-}	Reduced sulfur
SCR	Selective Catalytic Reduction
SD	System down-time
yr	Year

SYMBOLS

CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
η_{col}	Collection efficiency of the LFG collection system (% collected/100%)
η_{cmb}	Combustion efficiency of the LFG control/utilization device [(inlet - outlet)/inlet]
C_{CO2}	Concentration of CO_2 (ppmv)
Hc_m	Heat content of methane
H_2S	Hydrogen sulfide
k	LFG generation constant (yr^{-1})
LF_{fr}	Fraction of the landfill area to be controlled (% controlled/100%)
L_0	CH_4 generation capacity of a landfill (ft^3/Mg)
N_2	Nitrogen
NO_x	Nitrogen oxides
Q_i	Heat input (MMBtu/hr)
q_f	LFG fuel flow rate (ft^3/min)
SO_2	Sulfur dioxide
V_{LFG}	Generation rate of LFG (ft^3/unit time)
FR_{CH4}	CH_4 content of LFG ($ft^3 CH_4/ft^3$ LFG)

CONVERSIONS

Multiply	*By*	*To Obtain*
LENGTH		
Feet	0.3048	Meters
Inches	0.0254	Meters
Meters	39.37	Inches
Meters	3.281	Feet
Meters	10^6	Microns
AREA		
Acres	4.4050	Square meters
Hectares	2.471	Acres
Square meters	10.764	Square feet
Square feet	0.0929	Square meters
VOLUME		
Acre feet	123.35	Cubic meters
Barrels	0.159	Cubic meters
Cubic feet	0.0283	Cubic meters
Cubic meters	1,000	Liters
Gallons	3.785	Liters
MASS		
Kilograms	2.2046	Pounds
Pounds	0.4536	Kilograms
Tons (english)	0.907	Tonnes (metric)
Tonnes (metric)	1.1023	Tons (english)
Tonnes (metric)	1,000	Kilograms
DENSITY		
Kilograms per cubic meter	0.0624	Pounds per cubic foot
Pounds per cubic foot	16.01	Kilograms per cubic meter
Grams per liter	0.0624	Pounds per cubic foot
PRESSURE		
Pascal	1	Newton/m^2 (1 Newton is the force required to accelerate 1 kg at 1 m/second^2.)
Atmospheres	101,325	Pascals
Pounds per square inch	6,894	Pascals
Pascals	1.45×10^{-4}	Pounds per square inch
Bar	10^5	Pascal
Inches of water	249	Pascal

(Continued)

CONVERSIONS (Continued)

Multiply	*By*	*To Obtain*
POWER		
Watts	1	Newtonmeter/sec. or Joule/sec.
Watts	0.05692	Btu/minute
Watts	1.341×10^{-3}	Horsepower
ENERGY		
Joules	1	Wattsecond or Newtonmeter
Kilowatt-hours	3,415	Btus
Kilowatt-hours	1.341	Horsepower-hours
Kilowatt-hours	3.60×10^{6}	Btu
Btus	1,054	Joules
MISCELLANEOUS		
Cubic meters per hectare	14.291	Cubic feet per acre
Cubic meters per hour	0.5886	Cubic feet per minute
Cubic feet per minute	0.02831	Cubic meters per minute
Cubic feet per lb per year	61	Cubic meters per tonne per year
Btu/scf	37,243	Joule/cubic meter

1. INTRODUCTION

1.1 Background

The United States Environmental Protection Agency (EPA) proposed emission guidelines for existing municipal solid waste landfills (hereafter referred to as municipal landfills) and New Source Performance Standards (NSPS) for new municipal landfills in May of 1991. The guidelines and NSPS are expected to require from 500 and 700 landfills to install and maintain landfill gas (LFG) collection and control systems.[1] The LFG collection and control systems are required to reduce LFG emissions that include nonmethane organic compounds (NMOC). Control or utilization of LFG emissions is also desirable to reduce emissions of greenhouse gases (GHGs), such as methane.

In this document, LFG control systems refer to flares, where there is no recovery of the associated energy. In contrast, LFG utilization refers to the recovery of LFG energy either as primary heat (e.g., industrial boiler or space heater) or as a fuel source to drive electricity generating equipment. Currently, these are the most common utilization options. Additional LFG utilization projects include the upgrading of LFG for use as pipeline quality gas or vehicle fuel. Potential future uses of LFG include its use in fuel cells or as a feedstock in chemical manufacturing processes. The Air and Energy Engineering Research Laboratory (AEERL) of EPA is conducting ongoing research to provide information on energy conversion and other utilization options for LFG as a means of assisting landfill owners/operators that may be affected by the new municipal landfill emission requirements.

The combustion of LFG in flares, reciprocating internal combustion (RIC) engines, gas turbines, and boilers produces emissions of nitrogen oxides (NO_x) and carbon monoxide (CO), often referred to as secondary emissions. Since some of these secondary emissions are of concern in ozone, CO (and in some cases particulate matter less than 10 microns [PM-10]) nonattainment areas, methods to comparatively assess emissions resulting from LFG control/utilization with other forms of energy production are needed. Also, GHGs are of global concern and, therefore, a comparison of the net benefits or drawbacks associated with LFG control/utilization and other forms of energy production is often of interest.

Until recently, comparative information on the relative types and amounts of primary emissions resulting from uncontrolled municipal landfills and secondary emissions produced by the systems used to control/utilize LFG were lacking. During EPA's development of the NSPS for municipal landfills and work on developing AP-42 emission factors for municipal landfills, emission test data were obtained that can be used to assess both uncontrolled LFG emissions and emissions associated with various LFG control/utilization projects.[2,3] EPA AEERL continues to gather information on the emissions from LFG utilization/control and this information will be used to make future refinements to the data bases used to quantify and compare air pollutant emissions associated with these projects.

1.2 Purpose

The primary purpose of this document is to provide a methodology to prepare emission factors for criteria air pollutants and GHGs resulting from LFG control/utilization projects. This information may be useful to State/Regional officials, owners and operators of landfills, and LFG developers during evaluations of available landfill gas control/utilization technologies. The emissions estimation methodology is based on the principles of mass balance and also relies on assumptions of primary pollutant (e.g., NMOC) control efficiencies and secondary pollutant production rates as measured during source tests conducted over approximately the last 10 years. Examples using case studies are provided to illustrate the steps in the methodology. In these cases, sources of information on default concentrations for LFG constituents and secondary pollutant emission rates are given, but the reader is cautioned that site-specific information should be used if available.

In addition, it is the purpose of this document to acquaint the reader with sources of information and methods to quantify and compare emissions from alternative energy sources and compare them to emissions from LFG utilization technologies. Emissions are quantified in units that allow for direct comparisons between LFG utilization options (e.g., LFG RIC engine versus LFG turbine) and alternative energy sources (e.g., LFG utilization option versus coal-fired boiler power plant).

The secondary purpose of the document is to provide additional data and methods to prepare both uncontrolled and controlled LFG emission inventories. Using these methods, an analyst can prepare an air pollution balance sheet of uncontrolled landfill versus controlled landfill emissions.

A methodology for the preparation of a complete balance sheet of all air pollutant emissions associated with the procurement, refinement, transport, storage, and use of LFG and comparison fuels (e.g., coal) is beyond the scope of this document. However, in comparing emissions on large spatial scales (e.g., national, global), emissions resulting from each stage of the fuel cycle may be significant. The reader is, therefore, cautioned that the methodology and guidance presented here does not account for all emissions in the fuel cycle.

The use of the methodology presented in this document is expected to vary depending on the location of the landfill being evaluated. Examples of where the methodology may be useful include:

- analyzing ozone precursor emission increases and decreases (e.g., NMOC, NO_x) in nonattainment areas;
- assessing impacts of potential emission increases and decreases of GHGs;
- accounting for the energy benefits of utilizing LFG as compared to LFG control (i.e., flaring); and/or
- comparing emissions from controlled and uncontrolled landfills.

2. ASSESSING UNCONTROLLED LFG EMISSIONS

This chapter presents a methodology for estimating uncontrolled NMOC and GHG emissions from landfills. The best estimates for uncontrolled emissions will be made with the use of site-specific data such as LFG generation rate; collection efficiency; and methane (CH_4), carbon dioxide (CO_2), and NMOC content. Alternatively, the LFG generation rate and emissions of uncontrolled substances can be modeled with EPA's Landfill Air Emissions Estimation Model (EPA's model).[4] A new version of EPA's model is expected to be released by December 1994. For instances where site-specific data are not available, default values are provided in the model.

For uncontrolled landfills, NMOC is of concern due to its role as an ozone precursor. Previous efforts by EPA to estimate the NMOC content of LFG provide a range of values from a few hundred parts per million by volume (ppmv) as hexane to over 10,000 ppmv as hexane.[3] A mean value of 1,170 ppmv as hexane was reported in the AP-42 background document and a recommended value of 4,400 ppmv was given for landfills known to have a co-disposal history (i.e., landfills that received both municipal and commercial/industrial organic wastes). The AP-42 section on landfill emissions may be revised within the next 1 to 2 years to incorporate new emission test data results. With the incorporation of new source test data, the default values for LFG constituents are expected to change. The background given here is provided to further stress the importance of the use of site-specific data.

EPA's model can be used to estimate seasonal or annual uncontrolled landfill emissions. However, if site specific data are available for the LFG generation rate and characterization (i.e., concentrations of CH_4, CO_2, and NMOC), better estimations of seasonal or annual emissions can be made with the following equation:

$$ER_{ucl} = [C_C]\ [MW/(385.1 \times 10^6)]\ [V_{LFG}]\ [1/2{,}000] \qquad \text{(eq. 1)}$$

Where:	ER_{ucl}	=	uncontrolled emission rate (ton/yr)
	C_C	=	concentration of the compound of interest (ppmv)
	MW	=	molecular weight of C (lb/lb-mole)
	385.1×10^6	=	conversion factor, ppmv to lb/ft^3
	V_{LFG}	=	generation rate of LFG (ft^3/yr)
	1/2,000	=	conversion factor, lb to ton

An example use of equation 1 to develop an uncontrolled emission inventory is provided Section 4.1.

3. DETERMINING CONTROLLED LFG EMISSION FACTORS AND EMISSION RATES

This chapter presents the methodology and supporting data needed to estimate emissions from LFG control and utilization equipment. Sections 3.1 through 3.3 cover emissions of criteria pollutants or ozone precursors, including CO, NO_x, NMOC, and sulfur dioxide (SO_2). Sections 3.4 and 3.5 provide a discussion on the estimation of GHG emissions (i.e., CH_4 and CO_2).

To allow for comparison of LFG emission factors (EFs) to other energy sources (e.g., coal, distillate oil, natural gas) and to make comparisons between the various utilization options at a given landfill, controlled EFs are expressed as follows:

- *Flares and Boilers* — EFs are expressed as a function of the heat input to the system (i.e., heat content of the LFG). An example would be pounds of a pollutant per million British thermal units (lb/MMBtu). Comparisons can be made to other utilization options or energy sources using this EF and those from other published sources (e.g., AP-42).

- *RIC Engines and Turbines* — EFs are also derived in terms of heat input. However, since the work performed by these utilization options has primarily been in the form of electricity generation, EFs are then converted to terms of energy production [e.g. pounds per kilowatt-hour (lb/kWh)]. These EFs are derived from the mass per heat input EFs with the use of a plant heat rate (HR). The value of HR (Btu/kWh) accounts for the thermal efficiency of the combustion unit, the efficiency of the generator, and parasitic energy losses of the system (power used to run auxiliary equipment).

A comparison can be made to uncontrolled emissions (determined in Section 2) by calculating seasonal or annual emission totals from the EFs determined for control/utilization equipment. For these comparisons, the efficiency of the LFG collection system (η_{col}) needs to be established. Although collection efficiencies have been reported to range from 60 to 85 percent, a default of 75 percent is often used when site-specific data are not available.[3] As with all of the data presented in this document, site-specific data should be used whenever possible to ensure the accuracy of emission estimates. Values of η_{col} used in the methodology presented in this document are corrected to account for the fraction of the landfill to be controlled (LF_{fr}). For instance, if 90 percent of a landfill is to be served by a collection system, a 75 percent system efficiency, η_{col} is estimated as 67.5 percent [i.e., (0.75 x 0.90) x 100].

To determine the EFs described above, the heat input (Q_i) to the control/utilization device must first be estimated. The LFG flow rate (q_f) can be estimated by multiplying the LFG generation rate by the collection efficiency. It is assumed that ambient air infiltration is kept to a minimum (< 5 percent) and that this will have a negligible impact on the LFG composition (e.g., CH_4 and CO_2 content). Ambient air infiltration refers to ambient air (i.e., occurring above the landfill) being drawn into the landfill and hence present in the LFG due to overdrawing of the collection system. Table 1 lists the default values for determining controlled emission rates, if site-specific data are not available. Q_i can then be calculated as follows:

$$Q_i = [q_f]\,[FR_{CH4}]\,[Hc_m]\,[1/10^6]\,[60] \qquad \text{(eq. 2)}$$

Where: Q_i	=	heat input (MMBtu/hr)
q_f	=	LFG fuel flow rate (ft^3/min) = [LFG generation rate] [η_{col}]
η_{col}	=	LFG collection efficiency of the system [% collected/100%] [LF_{fr}]
LF_{fr}	=	fraction of the landfill to be controlled (% controlled/100%)
FR_{CH4}	=	LFG CH_4 content (ft^3 CH_4/ft^3 LFG)
Hc_m	=	heat content of methane (1,012 Btu/ft^3)

$1/10^6$	=	conversion factor, Btu to MMBtu
60	=	conversion factor, min to hr

TABLE 1. DEFAULT LANDFILL PARAMETERS

Parameter	Value (percent)
CH_4 content of LFG*	50
CO_2 content of LFG*	50
LFG collection efficiency (η_{col})*	75
System down-time (SD)[a]	
- flare control	3
- LFG utilization (engine, boiler, or turbine)	7

* Reference 3.

The LFG generation rate needed for equation 2 can be determined by running EPA's model and summing the generation rates for CH_4 and CO_2. System down-time (SD) refers to the amount of time on an annual basis that the control/utilization system is not operated due to maintenance or break-downs. Estimates of SD should be obtained from equipment vendor guarantees. The values for SD in table 1 were obtained from an industry contact and represent values that may be quoted by an equipment vendor.[a] The following Sections describe the methodology for developing EFs and seasonal or annual emission estimates.

3.1 Carbon Monoxide and Nitrogen Oxides

Emission factors for the secondary compounds, CO and NO_x, are presented in table 2. Except for RIC engines, these EFs were developed from a statistical analysis of recent source test data.[5-16] The CO and NO_x EFs for RIC engines were developed from data published in EPA's NSPS Background Document.[2]

All EFs are presented in table 2 in terms of the heat input to the control or utilization device. For electricity generating utilization equipment, the method for converting EFs to units of mass of CO or NO_x emitted per unit of energy output is presented in the RIC subsection below.

Flares. The EFs for flares have the highest data quality ratings in table 2, due to the relatively large number of high quality source tests available for use in their development. The "B" rating does not necessarily mean that the EFs are of the highest possible quality, since quality ratings are assigned from A (highest) through E (lowest). In general, "A" rated EFs are developed from the best source test data available and there is a minimal amount of variability in the data that represents a randomly selected sample of the source population. At the other end of the scale, an "E" rated EF may be developed from lower quality test data and/or there may be evidence of variability within the source population. Also, the "E" rated EF may not have been derived from a large randomly-selected sample of the source population.[17]

[a] Personal communication, C. Anderson, Rust Environment and Infrastructure, Naperville, IL, August 8, 1994.

TABLE 2. DEFAULT LFG EMISSION FACTORS FOR CO AND NO_x

Control or Utilization Device	Emission Factor						
	CO			NO_x*			Ref.
	kg/kJ	lb/MMBtu	Data Quality**	kg/kJ	lb/MMBtu	Data Quality**	
Enclosed Flares†	7.22×10^{-8}	0.168	B	3.92×10^{-8}	9.12×10^{-2}	C	5-11
RIC Engines (lean burn)	1.99×10^{-7}	0.462	D	1.03×10^{-7}	0.239	D	2
RIC Engines (rich burn)	3.37×10^{-7}	0.783	N/A	3.80×10^{-7}	0.883	N/A	2
Gas Turbines	4.10×10^{-8}	9.54×10^{-2}	E	4.07×10^{-8}	9.49×10^{-2}	E	12-15
Boilers/ Steam Turbines††	2.37×10^{-9}	5.52×10^{-3}	D	1.23×10^{-8}	2.85×10^{-2}	E	5,16

* NO_x is expressed as NO_2.
** Data quality ratings are from A (highest) to E (lowest).
† Data are for enclosed flares. No data on open flares were available.
†† EFs may require adjustment upward by up to 12 percent to account for equipment heat loss with the use of LFG versus comparison fuels.

To calculate seasonal or annual emissions using the EFs in table 2, the heat input rate to the control/utilization device (from equation 2) is used along with an estimate of the system down-time as follows (adjustments may be needed when evaluating emissions for boilers or steam turbines, see below):

$$\text{Annual emissions (ton/yr)} = [EF]\,[Q_i]\,[HOP]\,[1/2{,}000] \qquad \text{(eq. 3)}$$

Where: EF = emission factor (lb/MMBtu)

Q_i = heat input (MMBtu/hr, from eq. 2)

HOP = hours of operation (hr/yr) = 8,760 [1 - (SD/100 %)]

SD = system down-time (%)

1/2,000 = conversion factor, lb to ton

Boilers and Steam Turbines. Emission factors for boilers and steam turbines using LFG are also presented in table 2. An EF based on two source tests for boilers is also listed for steam turbines due to the similarity of these two sources and the lack of any quality source test data for steam turbines. Annual emissions can be calculated using the EFs above and equation 3.

To obtain an EF or an emissions estimate for use in comparison to other energy options (e.g., natural gas-fired industrial boiler), the EF or the emissions estimate should be adjusted upward by 12 percent. This adjustment is needed to account for the approximate 12 percent loss in heat output associated with the use of LFG versus a conventional fuel (e.g., natural gas).[18] Therefore, the EF in table 2 or the result from equation 3 should be adjusted by dividing by 0.88 (1 - 0.12). An example scenario is given in Section 4.4

that shows adjusted boiler EFs and emission rates.

If a flare back-up control is to be used during system down-time (i.e., for utilization options), equation 3 should be applied again using the number of hours that the flare will be operated [e.g., HOP = (8760) x (SD/100 percent)] and the appropriate EF for a flare. The emissions from the flare are then added to the emissions for the utilization option to obtain an annual total. Examples of the estimation methodologies are included in Chapter 4.

For steam turbines, methods for converting the EF to terms of energy output are given in the next subsection.

RIC Engines and Gas Turbines. Table 2 also provides EFs for CO and NO_x from RIC engines and gas turbines using LFG. Emission factors obtained from table 2 above do not account for emission reductions associated with the use of control equipment such as CO catalysts in RIC engines. One test report for RIC engines indicated that a CO conversion efficiency of approximately 74 percent (range of 58-88 percent) is achievable with the use of a CO catalyst. Caution should be used in assigning control efficiencies for any catalyst, since poisoning of the catalyst (e.g., with silicon-based compounds) may be a problem.[19] If a catalyst is present, the controlled emission factor can be calculated as follows:

$$\text{Controlled EF} = [\text{EF}]\,[1 - \eta_{cat}] \qquad \text{(eq. 4)}$$

Where: η_{cat} = control efficiency of the catalyst (% conversion/100%)

Currently, controls for CO and NO_x on LFG utilization equipment are not widely used and sufficient data are not currently available to determine default values for the use of such controls. Therefore, equation 5 is provided for specific instances, such as when a guaranteed conversion efficiency is obtained from an equipment vendor.

As with flares and boilers, seasonal or annual emission totals can be calculated with the EFs presented above, the heat input to the system, and equation 3. As discussed above for boilers and steam turbines, emissions from a backup flare should also be considered in annual or seasonal totals.

Since the utilization equipment in table 2 are primarily used to generate electricity, it is desirable to express EFs in terms of mass per unit of energy output. This conversion allows for comparisons of potential emissions to be made to other types of energy utilization (e.g., coal or natural gas combustion). To obtain these factors, the EFs in table 2 are multiplied by HR, a value that represents the overall facility operating efficiency:

$$\text{EF (lb/kWh)} = [\text{EF (lb/MMBtu)}]\,[\text{HR}]\,[1/10^6] \qquad \text{(eq. 5)}$$

Where: HR = facility heat rate (Btu/kWh)

The facility heat rate accounts for the efficiency of the combustion unit and generator and any parasitic energy losses (i.e., from running auxiliary equipment). Table 3 provides a list of HR default values for RIC engines and gas and steam turbines. These values are averages that were obtained from source test reports and equipment vendors with the exception of steam turbines. Steam turbines are assumed to have an overall plant efficiency of 30 percent.[20] This equates to a facility heat rate of 11,373 Btu/kWh. As mentioned earlier, site-specific data are preferable to the use of default values presented in this document. Values of HR, for example, may vary considerably for a given technology depending on the size of the unit.

TABLE 3. DEFAULT FACILITY HEAT RATES FOR LFG UTILIZATION

Utilization Device	Heat Rate		Reference Number
	kJ/kWh	Btu/kWh	
RIC engine	10,458	9,906	21[b,c]
Gas turbine	15,042	14,247	18, 22[d]
Steam turbine	12,009	11,373	20

3.2 Nonmethane Organic Compounds

Controlled NMOC EFs can be derived by using equation 6 below. The calculation requires values for the NMOC and CH_4 concentrations in LFG and the combustion efficiency (η_{cmb}) of the particular control/utilization device. The best estimates of η_{cmb} will be equipment vendor guarantees. In order to make approximate estimates of NMOC emissions, a default value of 98 percent can be assumed for η_{cmb} for all control/utilization options. Well maintained and operated equipment should achieve in excess of 98 percent combustion. However, data reviewed from source tests of different control/utilization options indicate that these levels are not always achieved in practice. Sufficient data is not currently available to develop a default value of η_{cmb} for each control/utilization option. Therefore, the importance of using vendor-guaranteed efficiencies cannot be over emphasized.

An NMOC EF for collected LFG (NMOC EF_{col}) can be derived as follows:

$$EF_{col}\ (\text{lb/MMBtu}) = [C_{NMOC}]\ [MW/(385.1 \times 10^6)]\ [FR_{CH4}]^{-1}\ [Hc_m]^{-1}\ [10^6]\ [1 - \eta_{cmb}] \qquad \text{(eq. 6)}$$

Where: C_{NMOC} = NMOC concentration of LFG (ppmv as hexane)

MW	=	molecular weight of NMOC as hexane (86 lb/lb-mole)
385.1×10^6	=	conversion factor, ppmv to lb/ft^3
FR_{CH4}	=	LFG methane content (ft^3 CH_4/ft^3 LFG)
Hc_m	=	heat content of methane (1,012 Btu/ft^3)
10^6	=	conversion factor, Btu to MMBtu
η_{cmb}	=	combustion efficiency of the equipment (% combusted/100%)

The EF from equation 6 can be converted from a heat input to a power output basis with equation 5 and the appropriate value of HR from table 3.

The method used to estimate seasonal or annual NMOC emissions needs to account for the following sources of emissions: (1) emissions that occur while LFG is being collected, but not combusted due to the inefficiency of the combustion device; (2) emissions occurring during system operation due to inefficiencies of the collection system (i.e., NMOC as part of uncollected LFG); and (3) emissions occurring during system

[b] Personal communication, Eldon Rumba, Waukesha Pearce, Houston, TX, July 7, 1994.

[c] Personal communication, Dean Manning, Cooper Energy Services, Garden Grove, CA, July 7, 1994.

[d] Personal communication, Ron Swift, Solar Turbines, San Diego, CA, July 7, 1994.

down-time (SD). Equation 7 below accounts for all of these sources to estimate controlled NMOC emissions (the final term, η_{cmb}, refers to the combustion efficiency of any backup control, such as a flare):

$$\text{Annual emissions (ton/yr)} = \{[\text{NMOC } EF_{col}]\ [Q_i]\ [HOP]\ [1/2{,}000]\} + \{[\text{NMOC } ER_{ucl}]\ [1 - \eta_{col}]\} + \{[\text{NMOC } ER_{ucl}]\ [\eta_{col}]\ [SD]\ [1 - \eta_{cmb}]\} \quad \text{(eq. 7)}$$

Where: NMOC EF_{col}	=	controlled EF for collected LFG, see eq. 7 (lb/MMBtu)
Q_i	=	heat input to the system, see eq. 3 (MMBtu/hr)
NMOC ER_{ucl}	=	uncontrolled NMOC emission rate, see Section 2 (ton/yr)
η_{col}	=	efficiency of LFG collection system (% collected/100%)
HOP	=	hours of operation (hr/yr) = 8760 [1 - (SD/100%)]
SD	=	fraction of time the system is down (% down)
η_{cmb}	=	combustion efficiency of the flare backup, if applicable (% combusted/100%)
1/2,000	=	conversion factor, lb to ton

3.3 Sulfur Dioxide

Emissions of SO_2 are determined using mass balance techniques. The primary assumption used to estimate emissions is that 100 percent of the reduced sulfur (RS^-) compounds in the LFG are oxidized to SO_2 for any control or utilization device evaluated.

Ideally, the results of an analysis of the LFG for total sulfur (expressed as ppmv S) should be used to determine an EF and to estimate seasonal or annual emissions. The first step is to determine the amount of SO_2 produced from the combustion of all sulfur-containing compounds. This is performed using two substeps. The first of these is to convert the concentration of S in ppmv to a mass/volume relationship:

$$\text{mass/volume (lb/ft}^3) = [C_S]\ [MW_S/385.1 \times 10^6] \quad \text{(eq. 8)}$$

Where: C_S	=	LFG concentration of S (ppmv)
MW_S	=	molecular weight of S (32 lb/lb-mole)
385.1×10^6	=	conversion factor, ppmv to lb/ft^3

The second substep is to convert the mass of S per unit volume of LFG to an EF in terms of mass of SO_2 produced per unit of heat input:

$$EFSO_2 = [\text{lb S/ft}^3\ \text{LFG}]\ [FR_{CH4}]^{-1}\ [Hc_m]^{-1}\ [MW_{SO2}/MW_S]\ [\text{mole } SO_2/\text{mole S}]\ [10^6] \quad \text{(eq. 9)}$$

Where: $EFSO_2$	=	lb SO_2/MMBtu
FR_{CH4}	=	LFG CH_4 content (ft^3 CH_4/ft^3 LFG)
Hc_m	=	heat content of methane (1,012 Btu/ft^3)
MW_{SO2}	=	molecular weight of SO_2 (64 lb/lb-mole)
MW_S	=	molecular weight of the S (32 lb/lb-mole)
mole SO_2/mole S	=	mole SO_2 produced per mole S consumed (lb-mole/lb-mole)

Commonly, LFG analyses are available for individual RS^- compounds and not total S. Therefore, SO_2 production is determined in a similar fashion using equations 8 and 9 for each RS^- compound. The appropriate values for concentration and MW for each species will be needed to determine species-specific SO_2 production potentials. After determining SO_2 production for each RS^- compound, these values are summed to provide a total SO_2 EF:

$$\text{Total } SO_2 \text{ EF (lb/MMBtu)} = \Sigma\ EFSO_{2\ (1\text{-}i)} \qquad \text{(eq. 10)}$$

Where: $EFSO_{2\ (1)}$ = first $EFSO_2$ determined (lb/MMBtu)

$EFSO_{2\ (i)}$ = last $EFSO_2$ determined (lb/MMBtu)

Seasonal or annual emissions can be determined using equation 3. Emission factors can be converted to terms of mass per unit of energy output with equation 5.

3.4 Methane

Emissions of CH_4 are estimated using the same methods established for NMOC (see Section 3.2). As with NMOC, sufficient data are not currently available to develop a methane control efficiency for each control/utilization option. However, well operated and maintained equipment should achieve in excess of 99.9 percent control (i.e., $\eta_{cmb} > 0.999$). This value can be used as a default when vendor-guaranteed combustion efficiencies are not available. Additional variables needed to use equations 6 and 7 include LFG CH_4 concentration and the molecular weight of CH_4 (MW = 16). As with NMOC, an EF in terms of power output can be derived using equation 5 and the appropriate plant heat rate given in table 3.

3.5 Carbon Dioxide

Emissions of CO_2 are also determined by mass balance. Carbon dioxide emissions are the result of CO_2 being a significant component of LFG as well as being formed during the combustion of CH_4 and NMOC. The first step is to express the amount of LFG CO_2 (i.e., the CO_2 fraction of the collected LFG) flowing through the control device in terms of mass per heat input. Using equation 6:

Step 1:

$$CO_2\ EF_1\ \text{(lb/MMBtu)} = [C_{CO2}]\ [MW/385.1 \times 10^6]\ [FR_{CH4}]^{-1}\ [Hc_m]^{-1}\ [10^6]\ [1 - \eta_{cmb}]$$

Where: C_{CO2} = CO_2 concentration of LFG (ppmv)

MW = molecular weight of CO_2 (44 lb/lb-mole)

385.1×10^6 = conversion factor, ppmv to lb/ft^3

FR_{CH4} = LFG CH_4 content (ft^3 CH_4/ft^3 LFG)

Hc_m = heat content of methane (1,012 Btu/ft^3)

10^6 = conversion factor, Btu to MMBtu

η_{cmb} = combustion efficiency of the device ($\eta_{cmb} = 0$ for CO_2)

The next step is to determine the amount of CO_2 formed from the combustion of CH_4 and to express it in terms of heat input. First, the LFG CH_4 concentration is converted to a mass per heat input relationship through modification of equation 7 by substituting the following variables for methane: C_{CH4}, MW = 16, and the control efficiency (default $\eta_{cmb} = 0.999$).

Step 2.1:

$$\text{lb } CH_4\text{/MMBtu} = [C_{CH4}]\ [MW/(385.1 \times 10^6)]\ [FR_{CH4}]^{-1}\ [Hc_m]^{-1}\ [10^6]\ [\eta_{cmb}] \qquad \text{(eq. 11)}$$

Next, the methane input to the system is converted to CO_2 output:

Step 2.2:
CO_2 EF_2 (lb/MMBtu) = [lb CH_4/MMBtu] [MW_{CO2}/MW_{CH4}] [mole CH_4/mole CO_2] (eq. 12)

The third step is to determine CO_2 formation from the combustion of NMOC. Equations 11 and 12 can be used by substituting the NMOC concentration, molecular weight, and combustion efficiency (NOTE: 6 moles of CO_2 are formed for each mole of NMOC as hexane combusted):

Step 3.1:
lb NMOC/MMBtu = [C_{NMOC}] [MW/(385.1 x 10^6)] [FR_{CH4}]$^{-1}$ [Hc_m]$^{-1}$ [10^6] [η_{cmb}]

Step 3.2:
CO_2 EF_3 (lb/MMBtu) = [lb NMOC/MMBtu] [η_{cmb}] [MW_{CO2}/MW_{NMOC}] [6 mole CO_2/mole NMOC]

Finally, the amount of CO formed during the combustion of organics in steps 2 and 3 above needs to be subtracted out. For this step, the vendor-supplied CO emission factor (or the default CO EF) from table 2, if necessary) is used and converted to the CO_2 equivalent:

Step 4:
CO_2 EF_4 (lb/MMBtu) = [EF_{CO}] [MW_{CO2}/MW_{CO}] (eq. 13)

The final step is to combine the results of the four previous steps to obtain an overall EF for collected LFG (CO_2 EF_{col}):

Step 5:
CO_2 EF_{col} (lb/MMBtu) = $EF_1 + EF_2 + EF_3 - EF_4$ (eq. 14)

The EF determined by equation 14 can be used to make comparisons to other power generation processes by converting it to lb/kWh (using equation 5). This EF does not account for CO_2 emissions that are not captured by the LFG collection system. However, as discussed in Section 1, the intent of this document is to provide both methods to derive EFs for alternative energy comparisons and methods to prepare uncontrolled and controlled emission estimates. Comparison EFs (e.g., lb/MMBtu or lb/kWh) do not include emissions of uncollected LFG constituents. Hence, when preparing controlled emission inventories equation 7 should be used to estimate CO_2 emissions, including uncollected CO_2, as follows:

$$\text{Annual emissions (ton/yr)} = \{[CO_2\ EF_{col}]\ [Q_i]\ [HOP]\ [1/2{,}000]\} + \{[CO_2\ ER_{ucl}]\ [1 - \eta_{col}]\} + \{[CO_2\ ER_{ucl}]\ [\eta_{col}]\ [SD]\ [1 - \eta_{cmb}]\}$$

Where: CO_2 EF_{col}	=	controlled EF for collected LFG, see eq. 15 (lb/MMBtu)
Q_i	=	heat input to the system, see eq. 3 (MMBtu/hr)
CO_2 ER_{ucl}	=	uncontrolled CO_2 emission rate (ton/yr)
η_{col}	=	efficiency of LFG collection system (% collected/100%)
HOP	=	hours of operation (hr/yr) = 8760 [1 - (SD/100%)]
SD	=	system down-time (% down)
η_{cmb}	=	combustion efficiency of flare backup, if applicable, (η_{cmb} = 0 for CO_2)

4. EXAMPLE ASSESSMENT OF LFG CONTROL AND UTILIZATION

An example assessment is presented in this chapter to illustrate the methods presented in Chapters 2 and 3. The example includes the development of an uncontrolled landfill emissions inventory and the development of EFs and controlled emission estimates following LFG control/utilization with the following technologies: a flare, an RIC engine, a gas turbine, and a boiler. Comparisons are made for the two electricity-generating utilization options to electricity production at a coal-fired steam power plant and a natural gas turbine power plant. Emissions from the LFG boiler are compared against an industrial boiler of similar size fired on natural gas or distillate oil.

4.1 Uncontrolled Landfill Emissions

Table 4 provides operating parameters for the example landfill. These landfill values were taken from a case study for a landfill operating near the coast of California. The LFG collection efficiency for this system guaranteed by the vendor is 75 percent, however only 90 percent of the landfill will be served by the collection system. Therefore, η_{col} will be 0.75 x 0.90 = 0.675. The modeled LFG generation rate is 1,160 ft^3/min. Therefore, the estimated collection rate of LFG is 67.5 percent of 1,160 ft^3/min or 783 ft^3/min. A hypothetical sampling program conducted on the LFG established the LFG constituent concentrations given in table 5.

TABLE 4. EXAMPLE LANDFILL OPERATING PARAMETERS

Date Opened: 1966
Waste in Place: 4 million tons
Waste Fill Rate: 850 tons/day
Total Fill Area: 490 acres
Area Filled (early 1991): 90 acres
Climate: Mediterranean
Annual Rainfall: 11 inches
Fraction of the Landfill to be Controlled = 0.90
LFG Collection System Efficiency = 75%
LFG Collection Rate: 783 ft^3/min
LFG Generation Rate: 1,160 ft^3/min

Uncontrolled emissions are estimated with the representative values from table 5 and equation 1.

For example, annual uncontrolled NMOC emissions are calculated as follows:

$$\text{NMOC } ER_{ucl} \text{ (ton/yr)} = [C_c]\,[MW/(385.1 \times 10^6)]\,[V_{LFG}]\,[1/2{,}000]$$

$$= [1{,}170 \text{ ppmv}]\,[86/(385.1 \times 10^6)]\,[6.10 \times 10^8 \text{ ft}^3\text{/yr}]\,[1/2{,}000]$$

$$= 79.7 \text{ tons/yr}$$

Annual uncontrolled emissions for NMOC, CO_2, and CH_4 are summarized below in table 6.

TABLE 5. LFG CONSTITUENT CONCENTRATIONS

Compound	Molecular Weight	Concentration: (ppmv)
Ozone Precursors*		
NMOC as hexane	86	1170
Reduced Sulfur Compounds		
t-Butyl mercaptan	90	0.14
Dimethyl disulfide	92	0.14
Carbon disulfide	76	0.11
Carbonyl sulfide	60	0.095
Dimethyl disulfide	92	0.14
Dimethyl sulfide	62	6.50
Ethyl mercaptan (ethanethiol)	62	0.42
Hydrogen sulfide	34	43.6
Isopropyl mercaptan	76	1.00
Methyl ethyl sulfide	76	0.29
Methyl mercaptan (methanethiol)	48	2.20
Greenhouse Gases†		
Carbon dioxide	44	450,000
Methane	16	550,000

* This is equivalent to the default concentration given in AP-42.[3]
† NMOC is also a member of this group.

TABLE 6. EXAMPLE ASSESSMENT: ANNUAL UNCONTROLLED EMISSIONS

Compound	Annual Emissions, ER_{ucl}	
	(Mg/yr)	(ton/yr)
Ozone Precursors		
NMOC as hexane	72.3	79.7
Greenhouse Gases		
Carbon Dioxide	14,223	15,682
Methane	6,321	6,970

4.2 Controlled Landfill Gas Emissions

As discussed in Section 3, the first step to deriving EFs and seasonal or annual emissions for each LFG control or utilization device is to estimate the heat input (Q_i) to the control or utilization system. Using equation 2:

$$Q_i = [q_f]\,[FR_{CH4}]\,[Hc_m]\,[1/10^6]\,[60]$$
$$= [783\ ft^3 LFG/min]\,[0.55\ ft^3\ CH_4/ft^3\ LFG]\,[1{,}012\ Btu/ft^3\ CH_4]\,[1/10^6]\,[60]$$
$$= 26.15\ MMBtu/hr$$

The derivation of EFs and emission estimates following flare control or LFG utilization using a RIC engine, gas turbine, or boiler is presented in the following Sections.

4.2.1 Emissions Resulting from LFG Control Using a Flare

Secondary Compounds. Emissions of secondary compounds, such as NO_x and CO, are calculated using the EFs presented in table 2 and equation 3. For example, CO emissions from the flare would be:

Annual emissions (ton/yr)

$$= [EF]\,[Q_i]\,[HOP]\,[1/2{,}000]$$
$$= [0.168\ lb/MMBtu]\,[26.15\ MMBtu/hr]\,[8{,}760\ \{1 - (3/100)\}\ hr/yr]\,[1/2{,}000]$$
$$= 18.7\ ton/yr$$

The annual hours of operation (HOP) are estimated with the default system down-time for flares of three percent from table 1. A summary of EFs and annual emission estimates for secondary compounds is given in table 7.

Controlled Primary Emissions (NMOC and CH_4). NMOC emissions are determined by first deriving an EF in terms of heat input to the flare. Using the NMOC concentration from table 5, an assumed combustion efficiency of 98 percent, and equation 6:

NMOC EF_{col} (lb/MMBtu)

$$= [C_{NMOC}]\,[MW/(385.1 \times 10^6)]\,[FR_{CH4}]^{-1}\,[Hc_m]^{-1}\,[10^6]\,[1 - \eta_{cmb}]$$
$$= [1{,}170\ ppmv]\,[86/385.1 \times 10^6]\,[ft^3\ LFG/0.55\ ft^3\ CH_4]\,[ft^3\ CH_4/1{,}012\ Btu]\,[10^6]\,[1 - (98/100)]$$
$$= 9.39 \times 10^{-3}\ lb/MMBtu$$

Annual emissions are then calculated with equation 7 and a collection efficiency of 67.5 percent. It is assumed that there is no backup control device for the flare during system down-time ($\eta_{cmb} = 0$), also HOP was determined assuming SD = 3 percent:

Annual emissions (ton/yr)

$$= \{[NMOC\ EF_{col}]\,[Q_i][HOP]\,[1/2{,}000]\} + \{[NMOC\ ER_{ucl}][1 - \eta_{col}]\} + \{NMOC\ ER_{ucl}\,[\eta_{col}]\,[SD]\,[1 - \eta_{cmb}]\}$$
$$= \{[9.39 \times 10^{-3}\ lb/MMBtu]\,[26.15\ MMBtu/hr]\,[8{,}497\ hr/yr]\,[1\ ton/2{,}000\ lb]\} + \{[79.7\ ton/yr]\ [1 - 0.675]\} + \{[79.7\ ton/yr]\,[0.675]\,[0.03]\,[1 - 0]\}$$
$$= 1.04\ ton/yr + 25.9\ ton/yr + 1.60\ ton/yr$$
$$= 28.5\ ton/yr$$

TABLE 7. FLARE EXAMPLE: SUMMARY OF CONTROLLED AIR POLLUTANT EMISSION FACTORS AND EMISSION RATES

Compound	Emission Factor, EF_{col}		Emission Rate	
	kg/kJ	lb/MMBtu	Mg/yr	ton/yr
Criteria Pollutants/Ozone Precursors				
Carbon Monoxide	7.22×10^{-8}	0.168	16.9	18.7
Nitrogen Oxides (as NO_2)	3.92×10^{-8}	9.12×10^{-2}	9.2	10.1
NMOC (as hexane), total			25.9	28.5
from LFG combustion	4.04×10^{-9}	9.39×10^{-3}	0.94	1.04
during System Downtime			1.46	1.60
from uncollected LFG			23.5	25.9
Sulfur Dioxide	7.01×10^{-9}	1.63×10^{-2}	1.64	1.81
Greenhouse Gases				
Carbon dioxide, total			25,792	28,412
from LFG combustion	8.87×10^{-5}	207	20,863	22,997
during System Downtime			289	318
from uncollected LFG			4,627	5,097
Methane, total			2,188	2,411
from LFG combustion	1.77×10^{-8}	4.11×10^{-2}	4.15	4.57
during System Downtime			128	141
from uncollected LFG			2,056	2,265

The CH_4 EF and emissions are determined using the same methods used to calculate the NMOC EF and emissions with the exception of an assumed combustion efficiency of 99.9 percent. Using the CH_4 concentration from table 5, the CH_4 combustion efficiency, and equation 6:

CH_4 EF_{col} (lb/MMBtu)

$$= [C_{CH4}]\,[MW/(385.1 \times 10^6)]\,[FR_{CH4}]^{-1}\,[Hc_m]^{-1}\,[10^6]\,[1 - \eta_{cmb}]$$

$$= [550{,}000 \text{ ppmv}]\,[16/385.1 \times 10^6]\,[\text{ft}^3 \text{ LFG}/0.55 \text{ ft}^3 \text{ CH}_4]\,[\text{ft}^3 \text{ CH}_4/1{,}012 \text{ Btu}]\,[10^6]\,[1 - 0.999]$$

$$= 4.11 \times 10^{-2} \text{ lb/MMBtu}$$

Annual emissions are estimated with equation 7:

Annual emissions (ton/yr)

$$= \{[CH_4\ EF_{col}][Q_i][HOP][1/2{,}000]\} + \{[CH_4\ ER_{ucl}][1 - \eta_{col}]\} + \{[CH_4\ ER_{ucl}]\,[\eta_{col}]]\,[SD]\,[1 - \eta_{cmb}]\}$$

$$= \{[4.11 \times 10^{-2} \text{ lb/MMBtu}]\,[26.15 \text{ MMBtu/hr}]\,[8{,}497 \text{ hr/yr}]\,[1 \text{ ton}/2{,}000 \text{ lb}]\} +$$

$$\{[6{,}970 \text{ ton/yr}]\,[1 - 0.675]\} + \{[6{,}970 \text{ ton/yr}]\,[0.03]\,[0.675]\,[1 - 0]\}$$

$$= 4.57 + 2{,}265 + 141$$

$$= 2{,}411 \text{ ton/yr}$$

Controlled EFs and annual emission estimates for NMOC and CH_4 are presented in table 7.

Sulfur Dioxide. Emissions of SO_2 are determined by a mass balance of the amount of sulfur entering the control system, in the form of RS^- compounds, and the amount exiting the system. It is assumed that 100 percent of the RS^- is oxidized and that all is emitted in the form of SO_2. Using the constituent concentrations from table 5 and equations 8 through 10:

From table 5, RS^- compounds, MW, and representative concentrations:

carbon disulfide, 76, 0.11	carbonyl sulfide, 60, 0.095
hydrogen sulfide, 34, 43.6	dimethyl sulfide, 62, 6.5
methyl mercaptan, 48, 2.2	isopropyl mercaptan, 76, 1.0
t-butyl mercaptan, 90, 0.14	ethyl mercaptan, 62, 0.42
dimethyl disulfide, 92, 0.14	methyl ethyl sulfide, 76, 0.29

The first step is to convert the volume to volume concentrations (ppmv) to a mass per unit volume basis (lb/ft^3). Using equation 8, the mass per unit volume of carbon disulfide is calculated below:

mass/volume (lb/ft^3)

$$= (C_C)\ (MW/385.1 \times 10^6)$$

$$= (0.11\ ppmv)\ (76/385.1 \times 10^6) = 2.17 \times 10^{-8}\ lb/ft^3$$

Second, the mass per unit volume input is converted to a mass per unit of heat input using equation 9:

EF

$$= (lb\ RS^-/ft^3\ LFG)\ (FR_{CH4})^{-1}\ (Hc_m)^{-1}\ [(MW_{SO2})/MW_{RS-})]\ (mole\ SO_2/mole\ RS^-)\ (10^6)$$

$$= (2.17 \times 10^{-8}\ lb/ft^3 LFG)\ (ft^3\ LFG/0.55\ ft^3\ CH_4)\ (ft^3\ CH_4/1{,}012\ Btu)\ (64/76)\ (2/1)\ (10^6)$$

$$= 6.57 \times 10^{-5}\ lb\ SO_2/MMBtu$$

The two steps above are repeated for each RS^- species. The results are then used in equation 10 to determine the overall SO_2 EF:

Total SO_2 EF

$$= \Sigma\ EFSO_{2\ (1\text{-}i)}$$

$$= 6.57 \times 10^{-5} + 1.30 \times 10^{-2} + 6.57 \times 10^{-4} + 4.18 \times 10^{-5} + 8.36 \times 10^{-5} + 2.84 \times 10^{-5} + 1.94 \times 10^{-3} + 2.99 \times 10^{-4} + 1.25 \times 10^{-4} + 8.66 \times 10^{-5}$$

$$= 1.63 \times 10^{-2}\ lb\ SO_2/MMBtu$$

Annual emissions can now be determined with equation 3:

Annual SO_2 emissions

$$= [EF]\ [Q_i]\ [HOP]\ [1/2{,}000]$$

$$= (1.63 \times 10^{-2}\ lb/MMBtu)\ (26.15\ MMBtu/hr)\ [8{,}760\ (1 - 3/100)\ hr/yr]\ (ton/2{,}000\ lb)$$

$$= 1.81\ ton/yr$$

Carbon Dioxide. CO_2 emissions are also determined by mass balance with equations 6, 11 through 14, and equation 8. The amount of CO_2 contained in the collected LFG is combined with CO_2 formed during the combustion of CH_4 and NMOC. The carbon (in CH_4 and NMOC), which is oxidized only to CO, is then subtracted. The first step is to express the amount of LFG CO_2 collected (and hence emitted) by the control system in terms of mass per unit of heat input (e.g., lb/MMBtu). Using the CO_2 concentration from table 5 and equation 6 ($\eta_{cmb} = 0$ for CO_2):

CO_2 EF_1 (lb/MMBtu)

$$= [C_{CO2}]\ [MW/385.1 \times 10^6]\ [FR_{CH4}]^{-1}\ [Hc_m]^{-1}\ [10^6]\ [1 - \eta_{cmb}]$$

$$= (450{,}000\ ppmv)\ (44/385.1 \times 10^6)\ (ft^3\ LFG/0.55\ ft^3\ CH_4)\ (ft^3\ CH_4/1{,}012\ Btu)\ (10^6)\ (1 - 0)$$

$$= 92.4\ lb\ CO_2/MMBtu$$

The second and third steps are used to estimate the amount of CO_2 formed during the combustion of CH_4 and NMOC. The methane input to the system is estimated using the methane concentration from table 5, equation 11, and η_{cmb} for CH_4 (99.9 percent):

lb CH_4/MMBtu

$$= [C_{CH4}]\ [MW/(385.1 \times 10^6)]\ [FR_{CH4}]^{-1}\ [Hc_m]^{-1}\ [10^6]\ [\eta_{cmb}]$$

$$= (550{,}000\ ppmv)\ (16/385.1 \times 10^6)\ (ft^3\ LFG/0.55\ ft^3\ CH_4)\ (ft^3\ CH_4/1{,}012\ Btu)\ (10^6)\ (0.999)$$

$$= 41.0\ lb\ CH_4/MMBtu$$

Next, the methane input to the system is converted to CO_2 output using equation 12:

CO_2 EF_2 (lb/MMBtu)

$$= [lb\ CH_4/MMBtu]\ [MW_{CO2}/MW_{CH4}]\ [mole\ CO_2/mole\ CH_4]$$

$$= (41.0\ lb\ CH_4/MMBtu)\ (44/16)\ (1/1)$$

$$= 113\ lb\ CO_2/MMBtu$$

The same process is used to determine the amount of CO_2 formed from the combustion of NMOC using the NMOC concentration from table 5, the average combustion control efficiency, and equations 11 and 12:

lb NMOC/MMBtu

$$= [C_{NMOC}]\ [MW/(385.1 \times 10^6)]\ [FR_{CH4}]^{-1}\ [Hc_m]^{-1}\ [10^6]\ [\eta_{cmb}]$$

$$= (1{,}170\ ppmv)\ (86/385.1 \times 10^6)\ (ft^3\ LFG/0.55\ ft^3\ CH_4)\ (ft^3\ CH_4/1{,}012\ Btu)\ (10^6)\ (0.98)$$

$$= 0.46\ lb\ NMOC/MMBtu$$

CO_2 EF_3 (lb/MMBtu)

$$= [lb\ NMOC/MMBtu]\ [MW_{CO2}/MW_{NMOC}]\ [6\ mole\ CO_2/mole\ NMOC]$$

$$= (0.46\ lb\ NMOC/MMBtu)\ (44/86)\ (6/1)$$

$$= 1.41\ lb\ CO_2/MMBtu$$

The fourth step is to determine the amount of CO_2 that needs to be subtracted out due to incomplete combustion of the organics to CO. The CO EF for flares from table 2 is used in this step, along with equation 13 to convert CO to the CO_2 equivalent:

CO_2 EF_4

$= [EF_{CO}] [MW_{CO2}/MW_{CO}]$

$= (0.168 \text{ lb CO/MMBtu}) (44/28)$

$= 0.264 \text{ lb } CO_2/\text{MMBtu}$

Finally, equation 14 is used to determine the CO_2 EF for collected LFG:

CO_2 EF_{col}

$= EF_1 + EF_2 + EF_3 - EF_4$

$= 92.4 \text{ lb/MMBtu} + 113 \text{ lb/MMBtu} + 1.41 \text{ lb/MMBtu} - 0.264 \text{ lb/MMBtu}$

$= 207 \text{ lb/MMBtu}$

Annual controlled emissions of CO_2 can now be estimated with equation 7:

CO_2 emissions (ton/yr)

$= \{[CO_2 EF_{col}] [Q_i] [HOP] [1/2{,}000]\} + \{[CO_2 ER_{ucl}] [1 - \eta_{col}]\} + \{[CO_2 ER_{ucl}] [\eta_{col}] [SD] [1 - \eta_{cmb}]\}$

$= \{(207 \text{ lb/MMBtu}) (26.15 \text{ MMBtu/hr}) (8497 \text{ hr/yr}) (\text{ton}/2{,}000 \text{ lb})\} + \{(15{,}682 \text{ ton/yr}) (1 - 0.675)\} + \{(15{,}682 \text{ ton/yr}) (0.675) (0.03) (1 - 0)$

$= 22{,}997 + 5{,}097 + 318$

$= 28{,}412 \text{ ton/yr}$

Table 7 provides a summary of the EFs and controlled emission rates for the flare example.

4.2.2 Emissions Resulting from LFG Utilization Using a RIC Engine

Emissions for the example landfill following installation of a LFG collection system and a RIC engine utilization system are presented in this section. The RIC engine is assumed to be capable of consuming the 26.15 MMBtu/hr heat input determined in Section 4.2.1 for the 783 ft^3/min of LFG collected. The utilization system is assumed to have a 93 percent availability or 7 percent SD. When the system is down, the collected LFG is sent to an on-site flare. A summary of controlled emissions for the RIC engine example is presented in table 8.

Secondary Compounds. Annual emissions of secondary compounds, such as NO_x and CO are calculated in similar fashion to those estimated for a flare (see Section 4.2.1). As for flares, annual emissions are calculated using the EFs presented in table 2 and equation 3. For example, CO emissions from a RIC engine would be determined as follows:

Annual emissions from the utilization system

$= [EF] [Q_i] [HOP] [1/2{,}000]$

$= [0.462 \text{ lb/MMBtu}] [26.15 \text{ MMBtu/hr}] \{8{,}760 \text{ hr/yr} [1 - (7/100)]\} [1/2{,}000]$

$= 49.2 \text{ ton/yr}$

During the RIC engine downtime, the back-up flare is operating and producing carbon monoxide. To calculate emissions created during downtime, the CO flare emission factor from table 2 is used.

TABLE 8. RIC ENGINE EXAMPLE: SUMMARY OF CONTROLLED AIR POLLUTANT EMISSION FACTORS AND EMISSION RATES

Compound	Emission Factor, EF_{col}		Emission Rate	
	kg/kWh	lb/kWh	Mg/yr	ton/yr
Criteria Pollutants/Ozone Precursors				
Carbon Monoxide	2.08×10^{-3}	4.58 x 10	45.9	50.6
Nitrogen Oxides	1.07×10^{-3}	2.37 x 10	23.8	26.2
NMOC (as hexane), total	4.22×10^{-5}	9.30 x 10	24.5	27.0
from LFG combustion			0.91	1.00
during System Downtime			0.07	0.08
from uncollected LFG			23.5	25.9
Sulfur Dioxide	7.35×10^{-5}	1.62 x 10	1.70	1.87
Greenhouse Gases				
Carbon Dioxide, total			25,203	27,781
from LFG combustion	0.926	2.04	19,907	21,943
during System Downtime			672	741
from uncollected LFG			4,624	5,097
Methane, total			2,059	2,270
from LFG combustion	1.85×10^{-4}	4.07 x 10	3.97	4.38
during System Downtime			0.30	0.33
from uncollected LFG			2,055	2,265

Annual emissions from the backup flare

= [EF] [Q_i] [HOP] [1/2,000]

= [0.168 lb/MMBtu] [26.15 MMBtu/hr] [8,760 hr/yr (0.07)] [1/2,000]

= 1.35 ton/yr

Total annual emissions are the sum for the utilization device and the flare:

= 49.2 + 1.35

= 50.6 ton/yr

An EF for alternative energy comparison purposes (lb/kWh), can be derived from the EF for the utilization device above, equation 5, and the default heat rate for RIC engines from table 3. For CO:

EF (lb/kWh)

= [EF (lb/MMBtu)] [HR] [$1/10^6$]

= [0.462 lb/MMBtu] [9,906 Btu/kWh] [$1/10^6$]

= 4.58×10^{-3} lb/kWh

Emissions and EFs for CO and NO_x are presented in table 8.

Controlled Primary Emissions (NMOC and CH_4). NMOC emissions are determined as above for flares. Since the combustion efficiency for the RIC engine is assumed to be the same as for the flare (i.e., 98 percent), the EF in terms of heat input to the system will be the same. If a different combustion efficiency had been guaranteed by the equipment vendor, then equation 6 would be used to derive an EF.

The EF, in mass per unit heat input, is then converted to mass per energy output with the plant heat rate, HR, for RIC engines:

EF (lb/kWh)

$$= [EF\ (lb/MMBtu)]\ [HR]\ [1/10^6]$$

$$= [9.39 \times 10^{-3}\ lb/MMBtu]\ [9{,}906\ Btu/kWh]\ [1/10^6]$$

$$= 9.30 \times 10^{-5}\ lb/kWh$$

Annual emissions are calculated with equation 7 and a collection efficiency of 67.5 percent:

Annual emissions

$$= \{[EF_{col}]\ [Q_i]\ [HOP]\ [1/2{,}000]\} + \{[NMOC\ ER_{ucl}]\ [1 - \eta_{col}]\} + \{[NMOC\ ER_{ucl}]\ [SD]\ [\eta_{col}]\ [1 - \eta_{cmb}]\}$$

$$= \{[9.39 \times 10^{-3}\ lb/MMBtu]\ [26.15\ MMBtu/hr]\ [8147\ hr/yr]\ [1\ ton/2{,}000\ lb]\} + \{[79.7\ ton/yr]\ [1 - 0.675]\} + \{[79.7\ ton/yr]\ [0.07]\ [0.675]\ [1 - 0.98]\}$$

$$= 1.00\ ton/yr + 25.9\ ton/yr + 0.08\ ton/yr$$

$$= 27.0\ ton/yr$$

The CH_4 EF and emissions are determined using the same methods used to calculate the flare CH_4 EF and emissions. The EF in mass per unit heat input is converted to mass per energy output with the plant heat rate, HR, for RIC engines:

EF (lb/kWh)

$$= [EF\ (lb/MMBtu)]\ [HR]\ [1/10^6]$$

$$= [4.11 \times 10^{-2}\ lb/MMBtu]\ [9{,}906\ Btu/kWh]\ [1/10^6]$$

$$= 4.07 \times 10^{-4}\ lb/kWh$$

Annual emissions are estimated with equation 7:

Annual emissions (ton/yr)

$$= \{[CH_4\ EF_{col}][Q_i][HOP][1/2{,}000]\} + \{[CH_4\ ER_{ucl}][1 - \eta_{col}]\} + \{[CH_4\ ER_{ucl}]\ [\eta_{col}]]\ [SD]\ [1 - \eta_{cmb}]\}$$

$$= \{[4.11 \times 10^{-2}\ lb/MMBtu]\ [26.15\ MMBtu/hr]\ [8{,}147\ hr/yr]\ [1\ ton/2{,}000\ lb]\} + \{[6{,}970\ ton/yr]\ [1 - 0.675]\} + \{[6{,}970\ ton/yr]\ [0.07]\ [0.675]\ [1 - 0.999]\}$$

$$= 4.38 + 2{,}265 + 0.33$$

$$= 2{,}270\ ton/yr$$

Controlled EFs and annual emission estimates of NMOC and CH_4 are presented in table 8.

Sulfur Dioxide. Emissions of SO_2 are determined by mass balance with the assumption that all control/utilization technologies will convert 100 percent of the RS^- in the LFG to SO_2. Therefore the EF results obtained above for a flare will be the same for an RIC engine (see Section 4.2.1). Annual emissions are calculated for the RIC engine and the back-up flare. Since a flare is used during SD, HOP for the RIC/flare combination is 8,760 hours per year.

Annual SO_2 emissions

$$= [EF]\ [Q_i]\ [HOP]\ [1/2{,}000]$$
$$= (1.63 \times 10^{-2}\ lb/MMBtu)\ (26.15\ MMBtu/hr)\ [8{,}760\ hr/yr]\ (ton/2{,}000\ lb)$$
$$= 1.87\ ton/yr$$

The only calculation required is to convert the EF to a mass per energy output basis. Using equation 5 and the EF determined above for flares:

EF (lb/kWh)

$$= [EF\ (lb/MMBtu)]\ [HR]\ [1/10^6]$$
$$= [1.63 \times 10^{-2}\ lb/MMBtu]\ [9{,}906\ Btu/kWh]\ [1/10^6]$$
$$= 1.62 \times 10^{-4}\ lb/kWh$$

Carbon Dioxide. The determination of emission factors and emission rates is the same as that done for flares in Section 4.2.1 with three exceptions; the system downtime used to calculate the HOP used to calculate annual emissions for RIC engines (7 percent), the CO emission factor, and the flare back-up. First, the only value that will change in deriving an emission factor is the CO EF for RIC engines from table 2. The CO_2 equivalent EF (CO_2EF_4) is derived with equation 13:

$CO_2\ EF_4$

$$= [EF_{CO}]\ [MW_{CO2}/MW_{CO}]$$
$$= (0.462\ lb\ CO/MMBtu)\ (44/28)$$
$$= 0.726\ lb\ CO_2/MMBtu$$

Using equation 14 to determine the overall CO_2 EF:

$CO_2\ EF_{col}$

$$= EF_1 + EF_2 + EF_3 - EF_4$$
$$= 92.4\ lb/MMBtu + 113\ lb/MMBtu + 1.41\ lb/MMBtu - 0.726\ lb/MMBtu$$
$$= 206\ lb/MMBtu$$

CO_2 emissions (ton/yr)

$$= \{[CO_2\ EF_{col}]\ [Q_i]\ [HOP]\ [1/2{,}000]\} + \{[CO_2\ ER_{ucl}]\ [1 - \eta_{col}]\} + \{[CO_2\ ER_{ucl}]\ [\eta_{col}]\ [SD]\ [1 - \eta_{cmb}]\}$$
$$= \{(206\ lb/MMBtu)\ (26.15\ MMBtu/hr)\ (8{,}147\ hr/yr)\ (ton/2{,}000\ lb)\} + \{(15{,}682\ ton/yr)\ (1 - 0.675)\} + \{(15{,}682\ ton/yr)\ (0.675)\ (0.07)\ (1 - 0)\}$$
$$= 21{,}943 + 5{,}097 + 741$$
$$= 27{,}781\ ton/yr$$

The emission factor above can be expressed in terms of energy output with equation 5:

EF (lb/kWh)

$$= [EF\ (lb/MMBtu)]\ [HR]\ [1/10^6]$$
$$= [206\ lb/MMBtu]\ [9906\ Btu/kWh]\ [1/10^6]$$
$$= 2.04\ lb/kWh$$

4.2.3 Emissions Resulting from LFG Utilization Using a Gas Turbine

Emissions for the example landfill following installation of a LFG collection and gas turbine utilization system are presented in this Section. As with the RIC engine example, the turbine is assumed to be capable of

consuming the 26.15 MMBtu/hr heat input determined in Section 4.2.1. Also, for this example system downtime and combustion efficiencies are assumed to be the same as for RIC engines. EFs and emission rates are calculated in similar fashion to the flare and RIC engine examples given in Section 4.2.1 and 4.2.2, respectively. A summary of controlled emissions for the gas turbine utilization option is presented in table 9.

Secondary Compounds. As with RIC engines, annual emissions are calculated using the EFs presented in table 2 and equation 3. For example, CO emissions from the gas turbine would be:

Annual emissions for the gas turbine plant

= [EF] [Q_i] [HOP] [1/2,000]

= [9.54×10^{-2} lb/MMBtu] [26.15 MMBtu/hr] [8,760 {1 - (7/100)} hr/yr] [1/2,000]

= 10.2 ton/yr

During the gas turbine downtime, the back-up flare is operating and producing carbon monoxide. To calculate emissions created during the downtime, we use the CO flare emission factor:

Annual emissions for the flare

= [EF] [Q_i] [HOP] [1/2,000]

= [0.168 lb/MMBtu] [26.15 MMBtu/hr] [(8,760 hr/yr) (0.07)] [1/2,000]

= 1.35 ton/yr

Total annual CO emissions

= 10.2 + 1.35

= 11.6 ton/yr

An EF for alternative energy comparison purposes (lb/kWh), can be derived from equation 5 and the default heat rate for gas turbines in table 3. For CO:

EF (lb/kWh)

= [EF (lb/MMBtu)] [HR] [$1/10^6$]

= [9.54×10^{-2} lb/MMBtu] [14,247 Btu/kWh] [$1/10^6$]

= 1.36×10^{-3} lb/kWh

Emissions and EFs for the secondary compounds are presented in table 9.

Controlled Primary Emissions (NMOC and CH_4). Since the combustion efficiency for gas turbines is assumed to be the same as for RIC engines (i.e., 99.9 percent for CH_4 and 98 percent for NMOC), the NMOC and CH_4 EF and annual emissions are determined as above for RIC engines (see Section 4.2.2).

For energy comparisons, the EF in mass per unit heat input is converted to mass per energy output with the plant heat rate, HR, for gas turbines:

NMOC EF (lb/kWh)

= [EF (lb/MMBtu)] [HR] [$1/10^6$]

= [9.39×10^{-3} lb/MMBtu] [14,247 Btu/kWh] [$1/10^6$]

= 1.34×10^{-4} lb/kWh

TABLE 9. GAS TURBINE EXAMPLE: SUMMARY OF CONTROLLED AIR POLLUTANT EMISSION FACTORS AND EMISSION RATES

Compound	Emission Factor, EF_{col}		Emission Rate	
	kg/kWh	lb/kWh	Mg/yr	ton/yr
Criteria Pollutants/Ozone Precursors				
Carbon Monoxide	6.17×10^{-4}	1.36×10^{-3}	10.5	11.6
Nitrogen Oxides (as NO_2)	6.14×10^{-3}	1.35×10^{-3}	9.8	10.8
NMOC (as hexane), total			24.5	27.0
from LFG combustion	6.07×10^{-5}	1.34×10^{-4}	0.91	1.00
during System Downtime			0.07	0.08
from uncollected LFG			23.5	25.9
Sulfur Dioxide	1.05×10^{-5}	2.32×10^{-4}	1.70	1.87
Greenhouse Gases				
Carbon Dioxide, total			25,300	27,888
from LFG combustion	1.34	2.95	20,004	22,050
during System Downtime			672	741
from uncollected LFG			4,624	5,097
Methane, total			2,059	2,270
from LFG combustion	2.66×10^{-4}	5.86×10^{-4}	3.97	4.38
during System Downtime			0.30	0.33
from uncollected LFG			2,055	2,265

CH_4 EF (lb/kWh)

$$= [EF\ (lb/MMBtu)]\ [HR]\ [1/10^6]$$

$$= [4.11 \times 10^{-2}\ lb/MMBtu]\ [14{,}247\ Btu/kWh]\ [1/10^6]$$

$$= 5.86 \times 10^{-4}\ lb/kWh$$

Controlled gas turbine EFs and annual emission estimates of NMOC and CH_4 are presented in table 9.

Sulfur Dioxide. Emissions of SO_2 are determined by mass balance with the assumption that all control/utilization technologies will convert 100 percent of the RS^- in the LFG to SO_2. Therefore, the results obtained above for a RIC engine will be the same for a gas turbine (see Section 4.2.2). The only additional calculation required is to convert the EF to a mass per energy output basis. Using equation 5 and the EF determined above for flares:

EF (lb/kWh)

$$= [EF\ (lb/MMBtu)]\ [HR]\ [1/10^6]$$

$$= [1.63 \times 10^{-2}\ lb/MMBtu]\ [14{,}247\ Btu/kWh]\ [1/10^6]$$

$$= 2.32 \times 10^{-4}\ lb/kWh$$

Carbon Dioxide. The determination of a controlled emission factor and emission rate is the same as that

done for RIC Engines in Section 4.2.2, since the assumptions for combustion efficiency and system downtime are the same. The only difference that needs to be accounted for is the difference in CO emission factors for equation 13:

CO_2 EF_4

$= [EF_{CO}] [MW_{CO2}/MW_{CO}]$

$= (9.54 \times 10^{-2}$ lb CO/MMBtu) (44/28)

$= 0.150$ lb CO_2/MMBtu

Using equation 14 to determine the overall CO_2 EF:

CO_2 EF_{col}

$= EF_1 + EF_2 + EF_3 - EF_4$

= 92.4 lb/MMBtu + 113 lb/MMBtu + 1.41 lb/MMBtu - 0.150 lb/MMBtu

= 207 lb/MMBtu

CO_2 emissions (ton/yr)

$= \{[CO_2\ EF_{col}] [Q_i] [HOP] [1/2{,}000]\} + \{[CO_2\ ER_{ucl}] [1 - \eta_{col}]\} + \{[CO_2\ ER_{ucl}] [\eta_{col}] [SD] [1 - \eta_{cmb}]\}$

= {(207 lb/MMBtu) (26.15 MMBtu/hr) (8,147 hr/yr) (ton/2,000 lb)} + {(15,682 ton/yr) (1 - 0.675)} + {(15,682 ton/yr) (0.675) (0.07) (1-0)

= 22,050 + 5,097 + 741

= 27,888 ton/yr

The gas turbine emission factor can be expressed in terms of energy output with equation 5 and the plant heat rate for gas turbines:

EF (lb/kWh)

= [EF (lb/MMBtu)] [HR] $[1/10^6]$

= [207 lb/MMBtu] [14,247 Btu/kWh] $[10^6]$

= 2.95 lb/kWh

4.2.4 Emissions Resulting from LFG Control Using a Boiler

Emissions for the example landfill following installation of a LFG collection system and boiler are presented in this section. The boiler is assumed to be capable of consuming the 26.15 MMBtu/hr heat input determined in Section 4.2.1 for the 783 ft^3/min of LFG collected. Also, the combustion efficiencies and system downtime assumptions used in the previous two sections are used here. A summary of controlled emissions for the boiler example is presented in table 10.

Secondary Compounds. Annual emissions of secondary compounds, such as NO_x and CO are calculated in similar fashion to those estimated for a flare (see Section 4.2.1). As for flares, annual emissions are calculated using the EFs presented in table 2 and equation 3. For example, CO emissions from a boiler would be (assuming 7 percent system down-time):

Annual emissions for the boiler

$= [EF] [Q_i] [HOP] [1/2{,}000]$

$= [5.52 \times 10^{-3}$ lb/MMBtu] [26.15 MMBtu/hr] [8,760 hr/yr {1 - (7/100)}] [1/2,000]

= 0.588 ton/yr

TABLE 10. BOILER EXAMPLE: SUMMARY OF CONTROLLED AIR POLLUTANT EMISSION FACTORS AND EMISSION RATES

Compound	Emission Factor, EF_{col}		Emission Rate	
	kg/kJ	lb/MMBtu	Mg/yr	ton/yr
Criteria Pollutants/Ozone Precursors				
Carbon Monoxide	2.37×10^{-9}	5.52×10^{-3}	1.79	1.94
Nitrogen Oxides	1.23×10^{-8}	2.85×10^{-2}	3.42	3.77
NMOC (as hexane), total			24.5	27.0
from LFG combustion	4.04×10^{-9}	9.39×10^{-3}	0.91	1.00
during System D			0.07	0.08
from uncollected LFG			23.5	25.9
Sulfur Dioxide	7.01×10^{-9}	1.63×10^{-2}	1.70	1.87
Greenhouse Gases				
Carbon Dioxide, total			25,300	27,888
from LFG combustion	8.87×10^{-5}	206	20,004	22,050
during System Downtime			672	741
from uncollected LFG			4,624	5,097
Methane, total			2,059	2,270
from LFG combustion	1.77×10^{-8}	4.11×10^{-2}	3.97	4.38
during System Downtime			0.30	0.33
from uncollected LFG			2,055	2,265

During the boiler downtime, the back-up flare is operating and producing carbon monoxide. To calculate emissions created during the downtime, we use the CO flare emission factor from table 2.

Annual emissions from the flare back-up

= [EF] [Q_i] [HOP] [1/2,000]

= [0.168 lb/MMBtu] [26.15 MMBtu/hr] [8,760 hr/yr 0.07] [1/2,000]

= 1.35 ton/yr

Total annual CO emissions

= 0.588 + 1.35

= 1.94 ton/yr

Emissions and EFs for the other secondary compounds are presented in table 10.

Controlled Primary Emissions (NMOC and CH_4). The NMOC and CH_4 EF and annual emissions are determined as above for RIC engines (see Section 4.2.2). Controlled LFG boiler EFs and annual emission estimates for NMOC and CH_4 are presented in table 10.

Sulfur Dioxide. Emissions of SO_2 are determined by mass balance with the assumption that all control/utilization technologies will convert 100 percent of the RS^- in the LFG to SO_2. Therefore the results

obtained above (Section 4.2.2) for a RIC engine will be the same for a boiler.

Carbon Dioxide. The determination of emission factors and emission rates is the same as that done for RIC engines in Section 4.2.2. The only difference is that the CO emission factor for boilers needs to be used in equation 13:

$$CO_2\ EF_4 = [EF_{CO}]\ [MW_{CO2}/MW_{CO}] = (5.52 \times 10^{-3}\ \text{lb CO/MMBtu})\ (44/28) = 8.67 \times 10^{-3}\ \text{lb } CO_2\text{/MMBtu}$$

Using equation 14 to determine the overall CO_2 EF:

$$CO_2\ EF_{col} = EF_1 + EF_2 + EF_3 - EF_4 = 92.4\ \text{lb/MMBtu} + 113\ \text{lb/MMBtu} + 1.41\ \text{lb/MMBtu} - 0.0087\ \text{lb/MMBtu} = 207\ \text{lb/MMBtu}$$

Annual CO_2 emissions are calculated as for the previous two utilization options:

$$= \{[CO_2\ EF_{col}]\ [Q_i]\ [HOP]\ [1/2{,}000]\} + \{[CO_2\ ER_{ucl}]\ [1 - \eta_{col}]\} + \{[CO_2\ ER_{ucl}]\ [\eta_{col}]\ [SD]\ [1 - \eta_{cmb}]\}$$

$$= \{(207\ \text{lb/MMBtu})\ (26.15\ \text{MMBtu/hr})\ (8{,}147\ \text{hr/yr})\ (\text{ton}/2{,}000\ \text{lb})\} + \{(15{,}682\ \text{ton/yr})\ (1 - 0.675)\} + \{(15{,}682\ \text{ton/yr})\ (0.675)\ (0.07)\ (1 - 0)\}$$

$$= 22{,}050 + 5{,}097 + 741 = 27{,}888\ \text{ton/yr}$$

4.3 Deriving Emissions for Alternative Energy Sources

Emission factors for alternative energy sources, presented in terms of either heat input or energy output consistent with those developed in Section 4.2, are needed to make comparisons associated with the use of LFG utilization equipment and other sources of energy. This section discusses sources of data needed to develop comparison EFs and emission estimates. This discussion pertains to fossil fuels including coal, residual and distillate oils, and natural gas.

As with determining EFs and emission estimates for LFG utilization and control, site-specific data will provide the most accurate comparisons. A State or local air agency should be able to provide EFs for local electricity generation sources, such as natural gas or coal-fired power plants. If these EFs are not presented in the same terms as those described in Section 3, they can be converted with the data and conversion factors presented below.

In the absence of site-specific emissions data from local utilities, EFs presented in EPA's AP-42,[23] or obtained from local air pollution control agencies can be used. AP-42 provides comprehensive emissions data on criteria pollutants and their precursors and some data on GHGs. For the assessment of alternative energy sources presented below, AP-42 is used as the primary source of emissions data.

Table 11 lists emission factor conversion data for the EFs presented in AP-42 along with fuel sulfur and carbon content. EFs for coal combustion sources are typically given in lb/ton or the metric units of kg/Mg of coal consumed. To convert this EF to units of heat input, equation 15 can be used. Fuel densities are included in table 11 for instances where the EF must be converted from units of mass emissions per mass of liquid or gaseous fuel (e.g., lb CO_2/lb residual oil).

TABLE 11. EMISSION FACTOR CONVERSION DATA AND FUEL PARAMETERS*

Fuel Type	HHV* kJ (MMBtu)	Density* kg (lb)	Sulfur* % weight	Carbon** % weight
Bituminous/ Subbituminous coal	3.02×10^7/Mg (26/ton)	1 kg/kg (1/lb)	0.6 - 5.4	66.6
Anthracite coal	2.85×10^7/Mg (24.6/ton)	1 kg/kg (1/lb)	0.5 - 1.0	79.7
Residual oil	4.18×10^4/l (0.15/gal)	0.944/l (7.88/gal)	0.5 - 4.0	N/A
Distillate oil	3.90×10^4/l (0.14/gal)	0.845/l (7.05/gal)	0.2 - 1.0	85.6
Natural gas	$3.91 \times 10^{13}/m^3$ ($1.05 \times 10^{-3}/ft^3$)	$0.673/m^3$ ($1/23.8\ ft^3$)	8.15×10^{-4}†	N/A

* Reference 23.
** Reference 24.
† Reference 25.
l = liters; gal = gallons; m = meters.
N/A = Not available or applicable.

$$EF\ (lb/MMBtu) = [EF_u]\ [HHV]^{-1}\ [10^6] \qquad \text{(eq. 15)}$$

Where: EF_u = emission factor based on units of fuel consumed (lb/unit)
HHV = higher heating value of the fuel (Btu/unit)
10^6 = conversion factor, Btu to MMBtu

After any necessary conversions have been made to the EFs for the comparison energy projects, direct comparisons can be made to those calculated for LFG control using a flare or LFG utilization with a boiler or process heater. To develop useful comparisons for LFG utilization projects that produce electricity, equation 5 should be used along with an appropriate HR value to convert the EFs based on heat input to EFs based on power output. Values of HR for the comparison technologies assessed in this document are presented in table 12. These values were obtained from the U.S. Department of Energy [(DOE)].[26] DOE publishes data on the annual average nationwide plant HR for fossil fuel-fired steam electric plants. For the most recent year, 1993, the average HR was 10,352 Btu/kWh. DOE also publishes data on other electricity generation technologies. An average plant heat was also developed for natural gas-fired turbines using the DOE data (see table 12). As with all of the data presented in this document, site-specific data on the plant HRs of local utilities should be selected for use over the default values in table 12, whenever available.

The following three Sections, 4.3.1 through 4.3.3, present EFs and emission estimates for four typical alternative energy utilization technologies: a coal-fired steam power plant, a natural gas-fired turbine power plant, and an industrial boiler fired on either natural gas or distillate oil.

TABLE 12. DEFAULT PLANT HEAT RATES FOR COMPARISON TECHNOLOGIES*

Utilization Technology	Heat Rate	
	kJ/kWh	Btu/kWh
Fossil fuel-fired steam electric plants	10,932	10,352
Natural gas-fired turbines	15,323	14,510

* Reference 26.

4.3.1 Coal-Fired Steam Power Plant

Emission factors and emission rates for a pulverized coal (bituminous/subbituminous), dry bottom, wall-fired boiler were determined based on emission rates contained in Section 1.1 of AP-42, and fuel parameters presented in table 11 of this document. Certain assumptions were made to convert units of EFs into units directly comparable to the EFs developed for LFG utilization technologies, and to estimate emissions from the EFs. These assumptions are as follows:

- Heat input to plant = 26.15 MMBtu/hr (equivalent to the example assessment prepared for the LFG utilization technologies, see Section 4.2)
- Higher heating value of bituminous/subbituminous coal = 26 MMBtu/ton [23]
- Hours of operation = 8,147 hr/yr (based on 24 hr/day, 365 day/yr, 7 percent down-time)
- Sulfur content = 3 percent by weight (mid-point of sulfur content reported in AP-42, and shown in Table 11)
- Carbon content = 66.6 percent by weight [24]
- Plant HR = 1.035×10^{-2} MMBtu/kWh [26]
- Control efficiencies = 80 percent control of SO_2 for a wet scrubber, and 25 percent control of NO_x for staged combustion.[23]

The results of the conversions of AP-42 EFs for a coal-fired boiler into units of kg/kJ, lb/MMBtu, kg/kWh, and lb/kWh, and calculation of emission rates (Mg/yr, ton/yr) are shown in table 13. Calculation of SO_2 emissions is dependent on the sulfur content of the fuel. The method used to calculate SO_2 emissions from coal combustion is shown below.

Uncontrolled AP-42 emission factor = $38\,(S)(1 - \eta)$ lb SO_2/ton fuel combusted

Where: S = weight percent sulfur content as fired
η = control efficiency
percent sulfur for bituminous coal = 3 percent
percent control due to wet scrubber = 80 percent

Controlled SO_2 emissions = $38(3)(1 - 0.80) = 22.80$ lb SO_2 /ton coal combusted

TABLE 13. COAL-FIRED STEAM POWER PLANT: SUMMARY OF EMISSION FACTORS AND EMISSION RATES

Compound	Emission Factor				Emission Rate	
	kg/kJ	lb/MMBtu	kg/kWh	lb/kWh	Mg/yr	Ton/yr
Criteria Pollutants/Ozone Precursors						
Carbon	8.26×10^{-9}	1.92×10^{-2}	9.04×10^{-5}	1.99×10^{-4}	1.86	2.05
Nitrogen	2.70×10^{-7}	0.63	2.94×10^{-3}	6.48×10^{-3}	60.6	66.7
NMOC	9.93×10^{-10}	2.31×10^{-3}	1.45×10^{-5}	2.39×10^{-5}	0.22	0.25
Sulfur	3.77×10^{-7}	0.88	4.12×10^{-3}	9.08×10^{-3}	84.8	93.4
Greenhouse Gases						
Carbon	8.09×10^{-5}	188	0.88	1.94	18,180	20,026
Methane	6.61×10^{-10}	1.54×10^{-3}	7.23×10^{-6}	1.59×10^{-5}	0.15	0.16

4.3.2 Natural Gas-Fired Turbine

Emission factors and emission rates for a gas-fired turbine controlled with selective catalytic reduction (SCR) with water injection were determined based on emission rates contained in Section 3.1 of AP-42, and fuel parameters presented in table 11 of this document. Certain assumptions were made to convert units of EFs into units directly comparable to the EFs developed for LFG utilization technologies, and to estimate emissions from the EFs. These assumptions are as follows:

- Heat input to plant = 26.15 MMBtu/hr (equivalent to the example assessment prepared for the LFG utilization technologies, see Section 4.2)
- Higher heating value of natural gas = 1,050 MMBtu/MMcf [23]
- Hours of operation = 8,147 hr/yr (based on 24 hr/day, 365 day/yr, 7 percent down-time)
- Sulfur content = 8.150×10^{-4} percent by weight.[25] Emission factor for SO_2 = 259(S)
- Plant HR = 14,510 Btu/kWh (table 12)
- Control efficiencies = AP-42 emission factors represent controlled emissions (SCR control efficiencies for NO_x typically range from 70-90 percent).[27]

The results of the conversions of AP-42 EFs for a gas-fired turbine into units of kg/kJ, lb/MMBtu, kg/kWh, and lb/kWh, and calculation of emission rates (Mg/yr, ton/yr) are shown in table 14.

TABLE 14. NATURAL GAS TURBINE POWER PLANT: SUMMARY OF EMISSION FACTORS AND EMISSION RATES

Compound	Emission Factor				Emission Rate	
	kg/kJ	lb/MMBtu	kg/kWh	lb/kWh	Mg/yr	Ton/yr
Criteria Pollutants/Ozone Precursors						
Carbon Monoxide	3.60×10^{-9}	8.40×10^{-3}	5.53×10^{-5}	1.22×10^{-4}	0.81	0.89
Nitrogen Oxides	1.29×10^{-8}	3.00×10^{-2}	1.97×10^{-4}	4.35×10^{-4}	2.90	3.20
NMOC	1.38×10^{-9}	3.20×10^{-3}	2.11×10^{-5}	4.64×10^{-5}	0.31	0.34
Sulfur Dioxide	3.29×10^{-10}	7.66×10^{-4}	5.04×10^{-6}	1.11×10^{-5}	7.40×10^{-2}	8.16×10^{-2}
Greenhouse Gases						
Methane	6.02×10^{-9}	1.40×10^{-2}	9.22×10^{-5}	2.03×10^{-4}	1.35	1.49
Carbon Dioxide	4.82×10^{-5}	112	0.74	1.63	10,823	11,929

4.3.3 Industrial Boiler

Emission factors and emission estimates are derived in this section for an industrial boiler fired on either natural gas or distillate oil. As with the energy alternatives above, the industrial boiler is assumed to consume the same amount of energy as the LFG control/utilization options discussed in Section 4.2.

Natural Gas-Fired Boiler — Emission factors and emission rates for a industrial gas-fired external combustion boiler were determined based on emission rates contained in Section 1.4 of AP-42 and fuel parameters presented in table 11 of this document. Certain assumptions were made to convert units of emission factors into units directly comparable to the emission factors developed for LFG utilization technologies, and to estimate emissions from the EFs. These assumptions are as follows:

- Heat input to plant = 26.15 MMBtu/hr (per the analysis done on sample LFG utilization technologies, see Section 4.2)
- Higher heating value of natural gas = 1,050 MMBtu/MMft^3 (table 11)
- Hours of operation = 8,147 hr/yr (based on 24 hr/day, 365 day/yr, 7 percent down-time)
- Sulfur content = 8.150×10^{-4} percent by weight[25]
- Control efficiencies = Not applicable, boiler is uncontrolled. AP-42 emission factors represent uncontrolled emissions.

The results of the conversions of AP-42 EFs for a natural gas-fired external combustion boiler into units of kg/kJ and lb/MMBtu, and calculation of emission rates (Mg/yr, ton/yr) are shown in table 15. It is important to note that all of the emissions estimated for this example represent uncontrolled emissions. In certain areas (i.e., ozone nonattainment areas), control efficiencies for specific pollutants should be used

TABLE 15. NATURAL GAS-FIRED BOILER: SUMMARY OF EMISSION FACTORS AND EMISSION RATES

Compound	Emission Factor		Emission Rate	
	kg/kJ	lb/MMBtu	Mg/yr	Ton/yr
Criteria Pollutants/Ozone Precursors				
Carbon Monoxide	1.43×10^{-8}	3.33×10^{-2}	3.22	3.55
Nitrogen Oxides	5.74×10^{-8}	0.133	12.9	14.2
NMOC	1.14×10^{-9}	2.65×10^{-3}	0.256	0.282
Sulfur Dioxide	2.46×10^{-10}	5.71×10^{-4}	5.52×10^{-2}	6.09×10^{-2}
Greenhouse Gases				
Carbon Dioxide	4.92×10^{-5}	114	11,023	12,143
Methane	1.24×10^{-9}	2.87×10^{-3}	0.278	0.306

to adjust the uncontrolled EF to a controlled EF (see equation 4). As an example for natural gas combustion, NO_x controls, such as low-NO_x burners or selective catalytic reduction, may be required on industrial boilers in ozone nonattainment areas. AP-42 contains information on pollution control efficiencies for common control technologies.[23]

Distillate Oil-Fired Boiler — Emission factors and emission rates for a distillate oil-fired boiler were determined based on emission rates contained in Section 1.3 of AP-42, and fuel parameters presented in table 11 of this document. Certain assumptions were made to convert units of EFs into units directly comparable to the EFs developed for LFG utilization technologies, and to estimate emission rates from the EFs. These assumptions are as follows:

- Heat input to plant = 26.15 MMBtu/hr (per analysis done on sample LFG utilization technologies, see Section 4.2)
- Higher heating value of distillate oil = 140 MMBtu/1000 gal [23]
- Hours of operation = 8,146 hr/yr (based on 24 hr/day, 365 day/yr, 7 percent down-time).
- Carbon content = 85.6 percent (see table 11). CO_2 emission factor = 259(C) lb/10^3 gal distillate oil.
- Sulfur content = 0.6 percent by weight[25] (mid-point of sulfur content reported in AP-42, and shown in Table 11).
- Control efficiencies = Not applicable, boiler is uncontrolled. AP-42 factors represent uncontrolled emissions.

The AP-42 emission factor for CO_2 is dependent on the carbon percentage of the fuel. The calculation of uncontrolled CO_2 emissions is given below:

Uncontrolled AP-42 emission factor = 259(C) lb CO_2 /10^3 gallon distillate oil

Where: C = weight percent carbon content of fuel
percent carbon for distillate oil = 85.6 percent
Uncontrolled CO_2 emissions = 259(85.6) = 22,170 lb CO_2/10^3 gallon distillate oil

The results of the emission factor conversions of AP-42 emission factors for a distillate oil-fired boiler into units of kg/kJ and lb/MMBtu, and calculation of emission rates (Mg/yr, ton/yr) are shown in table 16. As with the natural gas boiler example given above, it is important to adjust uncontrolled EFs (see equation 4) with the appropriate control efficiency in situations where an air pollution control is required or in use. AP-42 contains information on pollution control efficiencies for common control technologies.[23]

TABLE 16. DISTILLATE OIL-FIRED BOILER: SUMMARY OF EMISSION FACTORS AND EMISSION RATES

Compound	Emission Factor		Emission Rate	
	kg/kJ	lb/MMBtu	Mg/yr	Ton/yr
Criteria Pollutants/Ozone Precursors				
Carbon Monoxide	1.54×10^{-8}	3.57×10^{-2}	3.45	3.80
Nitrogen Oxides	6.15×10^{-8}	0.143	13.8	15.2
NMOC	1.05×10^{-9}	2.43×10^{-3}	0.235	0.259
Sulfur Dioxide	2.62×10^{-7}	0.609	58.8	64.8
Greenhouse Gases				
Carbon Dioxide	6.81×10^{-5}	158	15,278	16,830
Methane	6.64×10^{-10}	1.54×10^{-3}	0.149	0.164

4.4 Example LFG Control and Utilization Comparison Summary

Comparisons of emission factors and annual emission estimates developed in the previous three Sections are presented in tables 17 through 21. The values presented in these tables should not be construed to represent typical emissions for each listed industry nor should they be considered to represent the typical differences in emissions between utilization options or alternative energy sources. The values presented in the tables below and the differences between the various sources could change significantly depending on site-specific conditions. The tables are presented in order to illustrate how the estimates developed in the previous Sections can be presented to decision makers.

Table 17 provides a summary of emission factors developed in the previous two Sections for the electricity generating utilization options and applicable energy alternatives. As discussed earlier, the EFs derived for LFG control/utilization (i.e., EF_{col}) only include emissions associated with the collected LFG. Table 18 summarizes the annual emissions for these sources and also a flare control. Annual emission estimates are based on an equivalent energy input to all sources (26.15 MMBtu/hr). Finally, an estimate of the annual power produced for each source based on this equivalent energy input is provided.

TABLE 17. COMPARISON OF LFG UTILIZATION AND ALTERNATIVE ENERGY SOURCE EMISSION FACTORS

Pollutant	Emission Factor (lb/kWh)			
	LFG Utilization		Alternative Energy Source	
	RIC Engine	Gas Turbine	Coal-Fired Steam Power Plant	Natural Gas Turbine Power Plant
CO	45.8×10^{-4}	13.6×10^{-4}	1.99×10^{-4}	1.22×10^{-4}
NO_x	23.7×10^{-4}	13.5×10^{-4}	64.8×10^{-4}	4.35×10^{-4}
NMOC	9.30×10^{-5}	13.4×10^{-5}	2.39×10^{-5}	4.64×10^{-5}
SO_2	16.2×10^{-5}	23.2×10^{-5}	908×10^{-5}	1.11×10^{-5}
CO_2	2.04	2.95	1.94	1.63
CH_4	40.7×10^{-5}	58.6×10^{-5}	1.59×10^{-5}	20.3×10^{-5}

Tables 19 and 20 provide a similar comparison for an LFG boiler with two alternative energy sources. The emission factors and annual emission estimates for the LFG boiler have been adjusted upward by 12 percent as discussed in Section 3.1 to account for the lower heat output typically encountered with the use of LFG fuel.

Table 21 provides a comparison of annual uncontrolled versus controlled emissions from the example landfill. The annual emissions differ from those presented in the tables above since emissions from both collected and uncollected LFG are included (i.e., assumptions include 90 percent of the landfill under the influence of the collection system which operates at 75 percent efficiency).

TABLE 18. COMPARISON OF ANNUAL EMISSIONS: LFG CONTROL/UTILIZATION AND ALTERNATIVE ENERGY SOURCES

Pollutant	Annual Emissions (ton/yr)*				
	Flare/LFG Control	RIC Engine/ LFG Utilization**	Gas Turbine/ LFG Utilization**	Coal-Fired Steam Power Plant	Natural Gas Turbine Power Plant
CO	18.7	50.6	11.6	2.05	0.89
NO_x	10.1	26.2	10.8	66.7	3.20
NMOC	2.65	1.08	1.08	0.25	0.34
SO_2	1.81	1.87	1.87	93.4	0.08
CO_2	23,315	22,684	22,791	20,026	11,930
CH_4†	4.57	4.71	4.71	0.16	1.49
Annual Energy Produced (kWh)	0	2.15×10^7	1.50×10^7	2.06×10^7	1.47×10^7

* Based on 26.15 MMBtu/hr heat input, 3 percent down-time for flare, 7 percent down-time for all other sources.
** Includes emissions from flare backup during 7 percent system down-time.
† Emission estimates for CH_4 are significantly higher for the LFG control/utilization due to the default combustion efficiency of 99.9 percent. In reality, these systems can likely achieve efficiencies of greater than 99.99 percent.

TABLE 19. COMPARISON OF LFG UTILIZATION AND ALTERNATIVE ENERGY SOURCE EMISSION FACTORS

Pollutant	Emission Factor (lb/MMBtu)		
	LFG Boiler*	Alternative Energy Source	
		Natural Gas-Fired Boiler	Distillate Fuel-Fired Boiler
CO	6.27×10^{-3}	33.3×10^{-3}	35.7×10^{-3}
NO_x	3.24×10^{-2}	13.3×10^{-2}	14.3×10^{-2}
NMOC	10.7×10^{-3}	2.65×10^{-3}	2.43×10^{-3}
SO_2	183×10^{-4}	5.71×10^{-4}	6090×10^{-4}
CO_2	235	114	158
CH_4	4.67×10^{-3}	2.87×10^{-3}	1.54×10^{-3}

* EFs have been adjusted upward 12 percent to reflect lower heat output with the use of LFG. Conservative combustion efficiencies for NMOC (98%) and CH_4 (99.9%) were assumed.

TABLE 20. COMPARISON OF ANNUAL EMISSIONS: BOILER LFG CONTROL AND ALTERNATIVE ENERGY SOURCES

Pollutant	Annual Emissions (ton/yr)*			
	Flare/LF Gas Control	Landfill Gas Fired Boiler	Natural Gas Fired Boiler	Distillate Fuel Fired Boiler
CO	18.7	1.94	3.55	3.80
NO_x	10.1	3.77	14.2	15.2
NMOC	2.65	1.08	0.282	0.259
SO_2	1.81	1.87	6.09×10^{-2}	64.8
CO_2	23,315	22,791	12,143	16,830
CH_4**	145.6	4.71	0.306	0.164

* Based on 26.15 MMBtu/hr heat input, 3 percent down-time for flare, 7 percent down-time for all other sources.

** Emission estimates for CH_4 are significantly higher for the LFG control/utilization due to the default combustion efficiency of 99.9 percent. In reality, these systems can likely achieve efficiencies of greater than 99.99 percent.

TABLE 21. COMPARISON OF ANNUAL EMISSIONS: UNCONTROLLED VERSUS CONTROLLED LANDFILL

Pollutant	Annual Emissions (ton/yr)*				
	Uncontrolled Landfill	Flare/LFG Control	RIC Engine/ LFG Utilization	Gas Turbine/ LFG Utilization	Boiler/ LFG Control
CO	N/A	18.7	50.6	11.6	1.94
NO_x	N/A	10.1	26.2	10.8	3.77
NMOC	79.7	28.5	27.0	27.0	27.0
SO_2	N/A	1.81	1.87	1.87	1.87
CO_2	15,682	28,412	27,781	27,888	27,888
CH_4	6,970	2,411	2,270	2,270	2,270

* Includes emissions from collected and uncollected LFG.

N/A Not applicable. Emissions of this compound are only associated with the combustion of LFG.

5. ISSUES REQUIRING ADDITIONAL ANALYSIS

Refinements to the data presented in this document and supporting documentation will likely take place in the near future, as new data are made available to EPA by industry and the regulated community. A revision to the AP-42 section on landfills is expected within the next 1 to 2 years. Additional data will be needed to refine the estimates of key factors such as the default concentrations of LFG constituents (in AP-42). Also, defaults for secondary compound emission factors and primary pollutant control efficiencies presented here and in AP-42 require refinement.

An assessment of primary and secondary hazardous air pollutants (HAPs) may be required as part of a LFG control/utilization impacts assessment. AP-42 contains some information on determining emissions of primary HAPs (e.g., toluene, trichloroethane) from landfills, but none on secondary HAPs from control/utilization projects (e.g., polycyclic aromatic hydrocarbons, formaldehyde).[3] In addition, HAP emissions data for comparison energy projects are often lacking in AP-42. Supplemental data on HAP emissions for LFG control/utilization and comparison energy projects may be found in EPA's FIRE data base.[28]

Emissions data for emerging LFG utilization technologies are lacking. Technologies currently undergoing field demonstrations include the conversion of LFG to compressed natural gas for vehicle fuel, conversion of LFG to methanol for use either as an industrial feedstock or vehicle fuel, and processing of LFG to provide methane for use in fuel cells to generate electricity. Also, sterling and organic rankine cycle engines, are also being reviewed as potential technologies for the utilization of LFG.

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