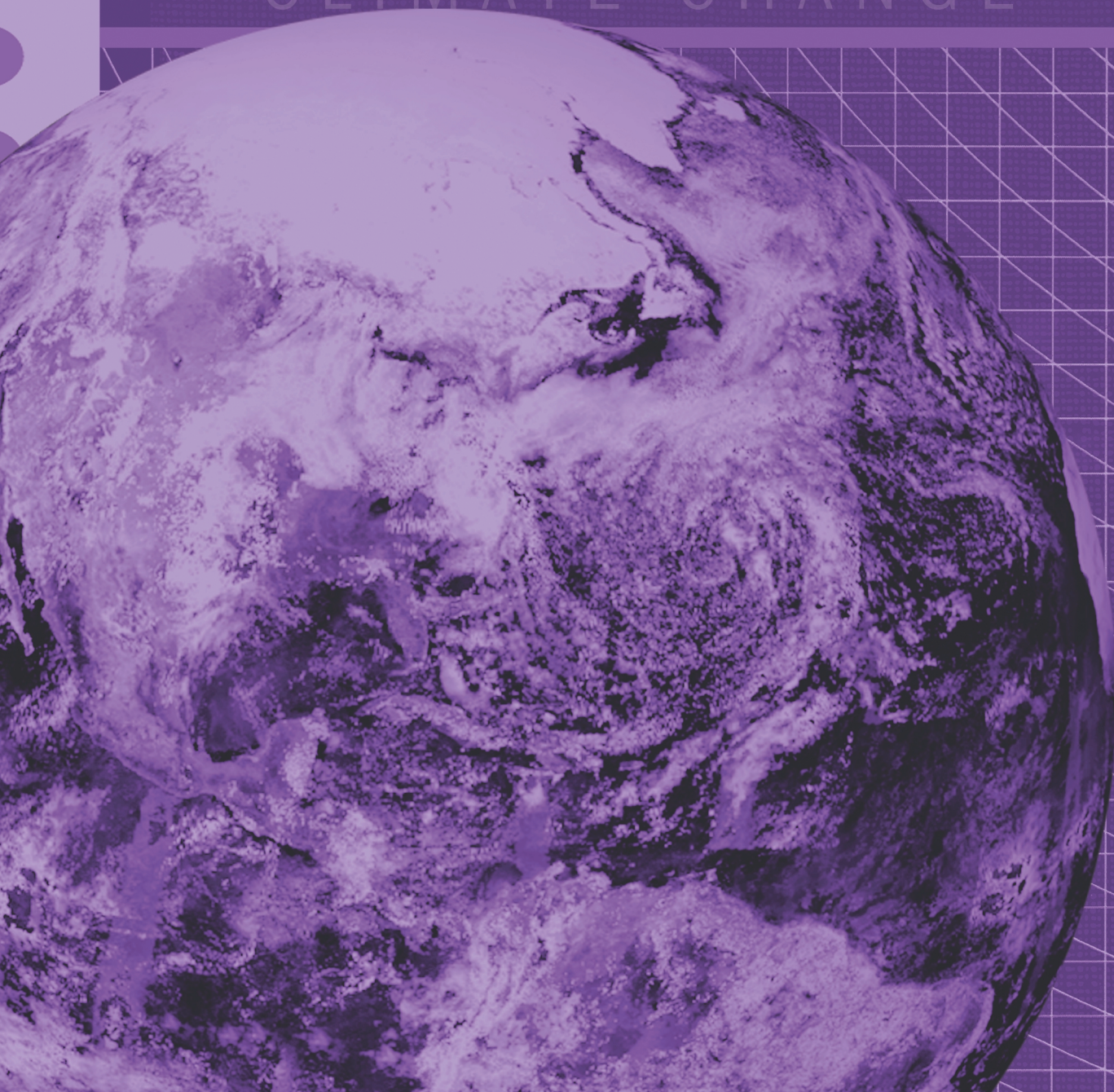


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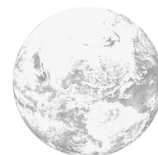
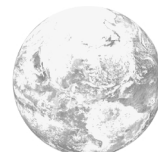
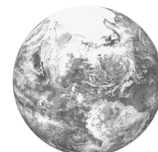




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COMPLETE TABLE OF CONTENTS



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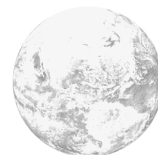
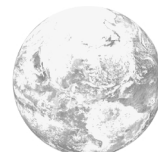
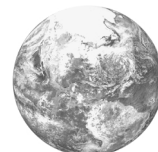
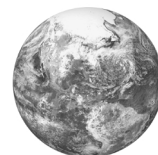
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SECTION 1





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## ACKNOWLEDGEMENTS

This compendium was developed for the American Petroleum Institute by:

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This work was sponsored by the American Petroleum Institute (API), with leadership and direction by Karin Ritter, Regulatory and Scientific Affairs Department. The work was supervised by API's Greenhouse Gas Emissions Methodologies Working Group, chaired by Susann Nordrum of ChevronTexaco, with participation from representatives of BP, ConocoPhillips, EnCana, ExxonMobil, Marathon, Murphy Oil, Shell, Sunoco and Unocal.

The authors would like to acknowledge the API member companies and their representatives on the work group who have contributed valuable time and resources over the past several years. We are particularly indebted to the companies that shared their internal company practices and information, and facilitated the continued enhancement of the Compendium.

# PREFACE

---

The *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* (referred to as the “Compendium”) was initially distributed in April 2001 as a “Pilot Test” version. Since its release, API has reached out to governmental, non-governmental and industry associations to ensure broad peer review. In addition, API initiated a study to evaluate and compare other greenhouse gas estimation protocols and methodologies. These activities were conducted in an effort to better harmonize greenhouse gas emission estimation techniques and enable improved global comparability of emission estimates.

This document represents the second release of the Compendium. The emission factors and methodologies presented here represent the latest information available at the time. Note, however, that estimating greenhouse gas emissions is a relatively new and evolving process. As such, the Compendium is intended to also evolve. There is a process for ongoing review and updates, and revisions will be made at regular intervals to incorporate new information. In the interim, users are encouraged to check the documents referenced within the Compendium for updates.

API welcomes a continuing exchange of information and broad discussion of greenhouse gas emission estimation methodologies from users of the Compendium and other interested parties. Please direct comments to Karin Ritter, Regulatory and Scientific Affairs Department, at API.



# 1.0

## INTRODUCTION

---

The American Petroleum Institute (API) and many of its member companies are developing action plans for addressing global climate concerns and policy issues. These plans often include estimating greenhouse gas (GHG) emissions. Concurrently, national and international bodies are developing or re-writing their guidance on estimating, tracking, and verifying GHG emissions. This document is a compendium of currently recognized methods and provides details for all oil and gas industry segments to enhance consistency in emissions estimation.

This *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* (referred to as the *Compendium*) aims to accomplish the following goals:

- Assemble an expansive collection of relevant emission factors for estimating GHG emissions, based on currently available public documents;
- Outline detailed procedures for conversions between different measurement unit systems, with particular emphasis on implementation of oil and gas industry standards;
- Provide descriptions of the multitude of oil and gas industry operations—in its various segments—and the associated emissions sources that should be considered; and
- Develop emission inventory examples—based on selected facilities from the various segments—to demonstrate the broad applicability of the methodologies.

The overall objective of developing this document is to promote the use of consistent, standardized methodologies for estimating GHG emissions from petroleum industry operations. The resulting *Compendium* documents recognized calculation techniques and emission factors for estimating GHG emissions for oil and gas industry operations. These techniques cover the calculation or estimation of emissions from the full range of industry operations – from exploration and production through refining, to the marketing and distribution of products. The *Compendium* presents and illustrates the use of preferred and alternative calculation approaches for carbon dioxide (CO<sub>2</sub>), methane (CH<sub>4</sub>), and nitrous oxide (N<sub>2</sub>O) emissions for all common emission sources, including combustion, vented, and fugitive. Decision trees are provided to guide the user in selecting an estimation technique based on considerations of materiality, data availability, and

accuracy. API will provide (free of charge) a calculation tool based on the emission estimation methodologies described herein. The tool will be made available at <http://ghg.api.org>.

## **1.1 Background**

The *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* was first distributed in April 2001 (API, 2001). Its initial release as a “road test” or Pilot Version document was geared toward testing its application to project, facility, or corporate level GHG emission inventories. Since that time, comments on the *Compendium* have been received through a number of mechanisms, including industry conferences, workshops, and focussed outreach to other protocol development organizations, particularly those used by the oil and natural gas industry in other regions of the world.

Since the release of the *Compendium* Pilot Version, a focused comparison study was conducted to identify and understand differences among the various emission estimation approaches as applicable to the global oil and gas industry. Results from this comparison study are summarized in Appendix A and serve as the basis for the emission estimation approaches presented in this document<sup>1</sup>. Through collaboration with other industry-related protocol development organizations, this version of the *Compendium* represents industry best practices for estimating GHG emissions.

Also following the release of the *Compendium* Pilot Version, a parallel effort was initiated to promote consistent, credible, and reliable GHG accounting and reporting practices for the oil and gas industry. Developed by a focused team of petroleum industry representatives and led by the International Petroleum Industry Environmental Conservation Association (IPIECA), the Association of Oil and Gas Producers (OGP) and API, the *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions* (referred to as the *Guidelines*) were issued in December 2003 (IPIECA, et. al., 2003). The *Guidelines* build upon other existing protocols for estimating GHG emissions by providing information to address the unique operational arrangements of the petroleum industry.

---

<sup>1</sup> A Synopsis Report of the comparison study is available through the American Petroleum Institute (API): *Toward a Consistent Methodology For Estimating Greenhouse Gas Emissions from Oil and natural Gas Industry Operations*, 22127:10.02, 2002.

The *Compendium* and *Guidelines* are complementary; where the *Compendium* focuses on GHG emission estimation methodologies for industry sources (how to calculate emissions), the *Guidelines* primarily address GHG accounting and reporting questions faced by the industry (how to report emissions). Together, the *Compendium* and *Guidelines* provide comprehensive guidance for the estimation, accounting, and reporting of petroleum industry GHG emissions.

## **1.2 Document Overview**

The *Compendium* is neither a standard nor a recommended practice for the development of emissions inventories. Rather, as the name implies, it represents a compilation of commonly used GHG emission estimation methodologies.

Methodologies outlined in this *Compendium* can be used to guide the estimation of GHG emissions for individual projects, entire facilities or company-wide inventories. The purpose of the GHG analysis, as well as the availability of data, will generally determine the level of detail and the estimation approach to be selected. The methodologies presented here focus on estimating CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions from oil and gas industry operations. This should not imply that emissions of these GHG compounds are necessarily significant for all emission sources or industry operations, as emission rates are highly variable. Rather, these three GHG compounds were selected because they are the most relevant to the oil and gas industry. Other compounds may require evaluation for specific, non-traditional operations, or as new data become available.

The emission estimation approaches presented are believed to be practical for all segments of the oil and gas industry. The operations and facilities addressed range from the well-head to retail outlets, including exploration and production (E&P), refining, marine vessels, pipelines, bulk distribution, other transportation, and retail marketing. The methods presented in this *Compendium* pertain only to emissions from operations and not those that might be attributable to product use. Industry data provided throughout this document list the carbon content fraction for typical fuels in commerce, but no attempt is made to account for hypothetical efficiencies associated with products use.

Transparency is a key issue in developing GHG inventory estimates. It is strongly recommended that any estimation approach utilized should be well annotated, with all input information recorded and careful documentation of the underlying conditions and assumptions. The calculation tool to



be provided by API facilitates such documentation. This level of detail is necessary to track and compare GHG emission information over time and to allow for future revisions as new information becomes available. Moreover, the dynamic nature of oil and gas industry operations, along with changes in estimation procedures, necessitate good narrative descriptions of included operations and equipment, in addition to careful calculations and knowledge of operating procedures.

It is also important to note that emission results can differ, in some cases significantly, depending on the specific approach(es) used to estimate emissions. The *Compendium* and *Guidelines* documents provide guidance for selecting appropriate estimation techniques based on the intended use of the inventory data and the availability of data. Ultimately, however, the use of the information presented in this document is left to the discretion of the user.

### **1.3 Organization**

Section 2.0 of this *Compendium* provides a description of the various industry segments and their interrelation. It sets out a common classification for all devices in the various segments and includes listings of operations and sources that need to be assessed for their CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions. The equipment classification system described in Section 2.0 is summarized in Table 1-1 and includes the major categories, with a representative list of devices that might fall into each of these categories.

Section 3 presents detailed technical considerations and suggestions for developing a consistent emissions estimate. To allow for global use of the estimation approaches, this section of the *Compendium* contains conversion factors, standard gas conditions, and fuel properties for fuels typically found in the oil and gas industry.

Sections 4, 5, and 6 provide the compiled calculation methodologies for combustion sources, vented sources, and fugitive sources, respectively. Each section presents the details of various estimation approaches for each source, device, or operation and also includes example calculations. The methods are organized around the general classification of emission sources and equipment by category, as specified in Section 2. The estimation approaches are, therefore, presented by either equipment or fuel type, and by operational practices. These sections strive to balance the need to make the computational tasks as simple as possible while retaining sufficient accuracy in the final inventory. To accomplish this, the methodology provides options for relying on generic estimation

methods—if applicable—such that specific knowledge of every equipment detail may not be essential. For example, many of the combustion device estimation approaches will be the same regardless of the industry segment in which they occur. However, most of the process vents are specific to an industry segment and reflect a specific operational practice for that part of the oil and gas industry.

**Table 1-1. Proposed Source Classification Approach<sup>2</sup>**

<b>Category</b>	<b>Principal Sources Include:</b>
<b>Combustion Devices</b> <i>Stationary Devices</i> <i>Essential Mobile Sources</i> <i>Indirects</i>	Boilers, heaters, furnaces, reciprocating internal combustion engines and turbines, flares, incinerators, and thermal/catalytic oxidizers Barges, ships, railcars, and trucks for material transport; and planes/helicopters and other company vehicles Off-site generation of electricity, hot water and steam for onsite power and heat
<b>Vented Sources</b> <i>Process Vents</i> <i>Other Venting</i> <i>Maintenance/Turnaround</i> <i>Non-Routine Activities</i>	Hydrogen plants, amine units, glycol dehydrators, fluid catalytic cracking unit and reformer regeneration, flexi-coker coke burn Crude oil, condensate, and petroleum product storage tanks, gas-driven pneumatic devices, chemical injection pumps, exploratory drilling, loading/ballasting/transit, loading racks Decoking of furnace tubes, vessel and gas compressor depressurizing, well and pipeline blowdowns, tank cleaning, painting Pressure relief valves, emergency shut-down devices
<b>Fugitive Sources</b> <i>Fugitive Emissions</i> <i>Other Non-Point Sources</i>	Valves, flanges, connectors, pumps, compressor seal leaks Wastewater treatment, surface impoundments

<sup>2</sup> Note that this *Compendium* uses terms (e.g., “routine,” “maintenance,” “point source”) that may have both a commonplace, non-legal meaning, and a specific, legal meaning. The *Compendium* uses the commonplace, non-legal meanings for these terms and does not use them in their legal sense.

Section 7 presents emission inventory examples for each industry segment. These examples are used to demonstrate methodology and emissions tabulations to help the reader determine the key emission sources for that type of facility. The examples constructed have an abundance of different types of equipment and devices for illustrative purposes, but are not intended to be representative of any specific facility or industry sector.

A detailed glossary for the terminology used throughout this compendium is provided following the main report sections. A separate study to compare the Pilot Version of the Compendium to other industry organization emission estimation protocols is summarized in Appendix A. Appendix B provides additional calculation methodologies and further details for some emission sources. Appendix C contains an analysis of nitrous oxide (N<sub>2</sub>O) emission factors for petroleum industry operations.

## **1.4 References**

American Petroleum Institute (API). *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry*, Pilot Test Version, April 2001. <http://ghg.api.org>  
[Mail Orders of the Compendium: API Publications c/o Global Engineering Documents, 15 Inverness Way East, Mail Stop C303B, Englewood CO 80112-5776]

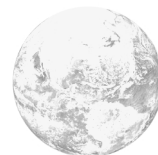
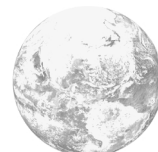
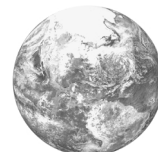
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SECTION 2



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## 2.0

# INDUSTRY DESCRIPTION

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This section presents a description of the oil and gas industry and its segments to give some perspective on the potential sources of greenhouse gas (GHG) emissions. Figure 2-1 presents a graphical overview of the primary industry segments with a rudimentary indication of GHG emission sources. The following subsections describe industry segments and specialty operations and the related GHG emission sources in more detail.

### 2.1 Overview

The oil and gas industry, for the purposes of this document, includes all direct activities related to producing, refining, transporting, and marketing crude oil and associated natural gas, and refined products. Figure 2-1 shows a graphical overview of the industry. The key industry segments include:

- Exploration, Production, and Gas Processing;
- Transportation and Distribution;
- Refining; and
- Retail and Marketing.

These segments are the direct activities within the oil and gas industry that have the potential to emit GHG. Integrated petroleum companies may also have operations associated with electricity and heat/steam generation, mining and minerals, and petrochemical manufacturing. Many of these methodologies are equally applicable to these other operations, but other compounds and process specific emissions must also be considered.

In addition, petroleum processes may also purchase electric power or heat/steam. However, the combustion emissions from these externally generated sources are considered an indirect contributor of GHG emissions. If reported, indirect GHG emissions from external power and heat/steam generation are considered separately from the direct petroleum sector emissions.

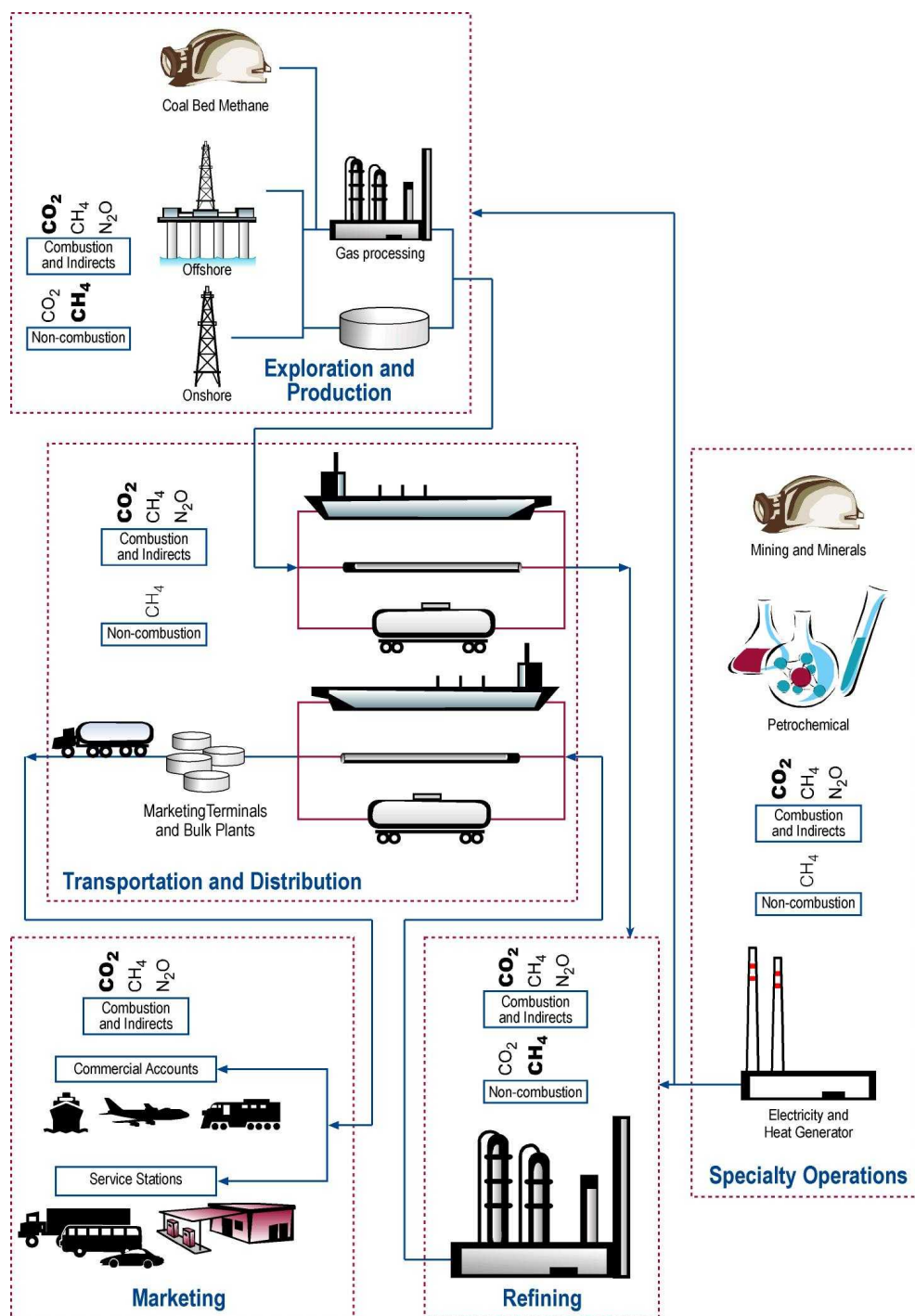


Figure 2-1. Oil and Gas Industry Schematic of GHG Emissions

Note: **CO<sub>2</sub>** and **CH<sub>4</sub>** represent the most significant emission sources; CO<sub>2</sub>, N<sub>2</sub>O and CH<sub>4</sub> represent less significant emission sources. If none are shown, emissions are believed to be negligible. Comparison is based on CO<sub>2</sub> equivalents.



Additional guidance on accounting for indirect emissions is provided in the Section 3.1.1 and Section 7 of the *Guidelines* (IPIECA, et. al, 2003).

Tables 2-1 through 2-6 present expansive checklists of potential GHG emission sources in each primary industry sector, as well as other “specialty” operations that may be part of a petroleum company’s portfolio. These tables also include an indication of whether each source is likely to emit CO<sub>2</sub>, N<sub>2</sub>O, and/or CH<sub>4</sub> and references sections of this document where further details on emission factors and emission calculation methodologies are provided. The sources listed in Tables 2-1 through 2-6 may potentially be located at a facility; however, individual facilities vary and some sources listed in the tables may not be present at all facilities. In addition, although the *Compendium* provides estimation methods for CH<sub>4</sub> and N<sub>2</sub>O, this should not imply that these emissions are necessarily significant or should always be estimated.

The diversity of operations associated with the oil and gas industry presents a challenge in determining which sources of emissions are significant enough to be included in an emissions inventory. The *Guidelines* document defines a tiered structure to help the reader use available time and resources effectively, based on the use of the resulting inventory (IPIECA, et.al.,2003). In addition, both Figure 2-1 and Tables 2-1 through 2-6 present some information on potential prioritization of emission sources. The bold text in Figure 2-1 illustrates where emissions of CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub> are generally considered to be most significant, while the non-bold text indicates that emissions from these sources are possible, but in less significant quantities.

Similarly, Tables 2-1 through 2-6 indicate which specific sources of emissions were considered in preparing this document. Where an “X” is indicated, an emission estimation approach is provided in this document. An empty field indicates that the source was considered but determined to be negligible. An “\*” is listed for some sources of CO<sub>2</sub> emissions in the production segment. This is used to note potential sources of CO<sub>2</sub> emissions for those production streams rich in CO<sub>2</sub>, such as associated gas from enhanced oil recovery. An approach is provided for these sources, but the significance of CO<sub>2</sub> emissions depends on the CO<sub>2</sub> concentration and the source-specific emission rate.

## **2.2 Industry Segment Descriptions**

The oil and gas industry can be divided into the following segments for emission estimates:

- Exploration, production (including coal bed methane production), and gas processing;
- Transportation and distribution (including crude and product transportation, as well as natural gas transmission and distribution);
- Refining; and
- Retail and marketing.

Some petroleum companies may also have specialty operations associated with coal mining and minerals, petrochemical production, and/or electricity and heat/steam generation. For the purpose of this document, the scope of a company's inventory may include any or all of these activities.

### **2.2.1 Exploration, Production, and Gas Processing**

This segment includes the exploration for and extraction of petroleum from underground resources, located either onshore or offshore. Because oil and gas can be produced from the same well, the production segment may include gas handling equipment and processing operations. The checklist of emission sources for this industry segment is provided in Table 2-1.

Exploration primarily involves various geological and geophysical surveys and tests, followed by exploratory drilling in likely areas. The primary emission sources from exploration are the exhausts from internal combustion (IC) engines used in drilling operations and the flaring of gas from a relatively few rank (i.e., remotely located) exploration wells.

If natural gas is available at sufficiently high pressures, it may be used as the motive force to drill wells. In this case, CH<sub>4</sub> would be emitted to the atmosphere, similar to vented releases resulting from diaphragm pumps. Natural gas may also be used to clean sediment that accumulates during drilling, or to unload water from the well. For this use, compressed natural gas is forced down the well bore to build up pressure, and then rapidly released to the surface through the annulus.

**Table 2–1. Potential Greenhouse Gas Emission Sources by Sector:  
Exploration, Production, and Gas Processing<sup>1</sup>**

<b>EXPLORATION AND PRODUCTION</b>	<b>CO<sub>2</sub></b>	<b>N<sub>2</sub>O</b>	<b>CH<sub>4</sub></b>	<b>Section</b>
<b><i>COMBUSTION SOURCES – Stationary Devices</i></b>				
Boilers/Steam Generators	<b>X</b>	<b>X</b>	<b>X</b>	4.1, 4.2, 4.3
Heaters/Treaters	<b>X</b>	<b>X</b>	<b>X</b>	4.1, 4.2, 4.3
Internal Combustion (IC) Engines	<b>X</b>	<b>X</b>	<b>X</b>	4.1, 4.2, 4.3
Turbines	<b>X</b>	<b>X</b>	<b>X</b>	4.1, 4.2, 4.3
Flares	<b>X</b>	<b>X</b>	<b>X</b>	4.4
Incinerators	<b>X</b>	<b>X</b>	<b>X</b>	4.6
<b><i>COMBUSTION SOURCES – Essential Mobile Sources</i></b>				
Planes/helicopters	<b>X</b>	<b>X</b>	<b>X</b>	4.5
Supply boats, barges	<b>X</b>	<b>X</b>	<b>X</b>	4.5
Other company vehicles	<b>X</b>	<b>X</b>	<b>X</b>	4.5
<b><i>COMBUSTION SOURCES – Indirects</i></b>				
Electricity imports	<b>X</b>	<b>X</b>	<b>X</b>	4.7
Process heat/steam imports	<b>X</b>	<b>X</b>	<b>X</b>	4.7
<b><i>VENTED SOURCES – Process Vents</i></b>				
Gas sweetening processes	<b>X</b>		<b>X</b>	5.1
Dehydration processes			<b>X</b>	5.1
<b><i>VENTED SOURCES – Other Venting</i></b>				
Tanks	<b>X</b>		<b>X</b>	5.4
Pneumatic devices	<b>X (*)</b>		<b>X</b>	5.6.1
Chemical injection pumps	<b>X (*)</b>		<b>X</b>	5.6.2
Well testing	<b>X (*)</b>		<b>X</b>	5.6.3
Exploratory drilling	<b>X</b>		<b>X</b>	5.6.3
<b><i>VENTED SOURCES – Maintenance/Turnarounds</i></b>				
Vessel blowdown	<b>X (*)</b>		<b>X</b>	5.7.2
Well workovers	<b>X (*)</b>		<b>X</b>	5.7.2
Compressor starts	<b>X (*)</b>		<b>X</b>	5.7.2
Compressor blowdowns	<b>X (*)</b>		<b>X</b>	5.7.2
Gathering pipeline blowdowns	<b>X (*)</b>		<b>X</b>	5.7.2
<b><i>VENTED SOURCES – Non-routine Activities</i></b>				
Pressure relief valves (PRVs)	<b>X (*)</b>		<b>X</b>	5.7.2
Well tests and blowdowns (when not flared)	<b>X (*)</b>		<b>X</b>	5.7.2
Emergency shutdown (ESD)/ emergency safety blowdown (ESB)	<b>X (*)</b>		<b>X</b>	5.7.2
<b><i>FUGITIVE SOURCES</i></b>				
Equipment component leaks	<b>X (*)</b>		<b>X</b>	6.1

X Document provides an emission estimation approach for these sources.

\*Emission estimation approach is provided, but only applicable to CO<sub>2</sub> rich production streams (e.g., CO<sub>2</sub> flood or enhanced oil recovery). Significance of these sources depends on the CO<sub>2</sub> concentration and source-specific emission rate.

<sup>1</sup> Note that this *Compendium* uses terms (e.g., “routine,” “maintenance,” “point source”) that may have both a commonplace, non-legal meaning, and a specific, legal meaning. The *Compendium* uses the commonplace, non-legal meanings for these terms and does not use them in their legal sense.

The released gas is most often directed to a flare (resulting primarily in CO<sub>2</sub> emissions), or alternatively vented to the atmosphere (releasing CH<sub>4</sub>).

A well that reaches an economically viable oil and/or gas reservoir may then be completed and put into production. There are a number of steps potentially involved in production, such as oil/gas separation, oil/water separation and collection, and storage. In addition, the wellhead itself may have a vent to release casing head gas, which could be a source of both CH<sub>4</sub> and CO<sub>2</sub>.

The balance between CH<sub>4</sub> and CO<sub>2</sub> emissions from the wellhead and associated equipment leaks can be quite variable. Most reservoir gas has less than 5% CO<sub>2</sub> with more than 90% CH<sub>4</sub>; however, exceptions do exist. For example, some enhanced oil recovery (EOR) techniques involve injection of CO<sub>2</sub> into the formation, potentially resulting in significantly larger CO<sub>2</sub> emissions than CH<sub>4</sub> from equipment/process vents and fugitive leaks.

Oil/gas separation and gas processing operations may result in CH<sub>4</sub> losses from oilfield tank vents, dehydrators, amine units, and pneumatic devices. Fugitive equipment leaks may also be a source of CH<sub>4</sub> emissions. Combustion emissions result from reciprocating compressors or turbines used to handle produced gas, where the produced gas may be collected for processing (dehydration and/or sweetening), reinjected to boost reservoir pressure, or in some cases flared. Flaring of produced gas, a potentially significant CO<sub>2</sub> emission source, is generally done only when there is no infrastructure to process the gas or when produced gas volumes are too low to be economically collected and processed.

Offshore oil and gas production operations are similar to onshore operations. Equipment and process configurations are typically the same, although vented and fugitive CH<sub>4</sub> emission sources are generally smaller than onshore operations due to space confinements and personnel considerations associated with platforms. Offshore operations may include combustion emissions from equipment and personnel transport to and from the platforms (supply boats and helicopters) that are not generally associated with onshore operations. Floating Production Storage and Offloading (FPSO) systems, a subset of offshore operations, may also have emissions from storage and offloading capabilities.

In gas processing, high value liquid products are recovered from the gas stream and/or the produced gas is treated to meet pipeline specifications. Process vents from dehydration, gas sweetening, pneumatic devices, and non-routine activities may result in CH<sub>4</sub> emissions. Fugitive equipment leaks are also a source of CH<sub>4</sub> emissions. Combustion sources, such as boilers, heaters, engines, and flares result in CO<sub>2</sub> and N<sub>2</sub>O emissions in much small quantities..

Heat generated by fossil fuel combustion is often used to promote the separation of oil from water, which would result primarily in CO<sub>2</sub> emissions from the heater-treater stack, with small amounts of CH<sub>4</sub> emissions and potentially N<sub>2</sub>O emissions.. The collection and storage of produced oil involves closed pipes running to oil tanks. Fugitive equipment leaks, gas-driven pneumatic devices, and gas-driven valve operators are potential emission sources associated with the collection piping. In the oilfield, oil tanks may have flashing losses as the higher pressure crude oil enters the tank. These flashing losses are often more significant in terms of CH<sub>4</sub> emissions than the normal tank breathing and working losses.

### **2.2.2 Coal Bed Methane Production**

Coal bed methane (CBM) is another method of producing CH<sub>4</sub> (natural gas). The process of coalification, in which swamp vegetation is converted to coal by geological and biological forces, also captures CH<sub>4</sub> in the coal seams and the surrounding rock strata. At the high pressures in the coal seams, the CH<sub>4</sub> either remains adsorbed on the coal surface or is trapped within the coal's porous structure. This CH<sub>4</sub> can be recovered for use or sale, just as associated gas can be recovered from crude production wells.

The emission sources from CBM production are very similar to those from petroleum exploration and production discussed in Section 2.2.1 above. A checklist of possible sources is provided in Table 2-2.

In conventional CBM operations, several gas production wells are drilled from the surface to the coal seam and the pressure in the coal beds is reduced, thereby releasing the CH<sub>4</sub>. GHG emissions result from the IC engines used to drill the production wells. Flaring emissions are not routine but may occur if the natural gas is flared due to process upsets.

Emission sources associated with producing CBM are the same as those associated with conventional natural gas production. The recovered CBM is separated from other contaminants (e.g., formation water, CO<sub>2</sub>) at the surface. Process equipment, such as water tanks, dehydrators, amine units, and/or pneumatic devices result in vented and fugitive emissions through the same mechanisms as conventional natural gas production. Combustion emissions result from compressors used to transport the recovered natural gas.

**Table 2–2. Potential Greenhouse Gas Emission Sources by Sector: Coal bed Methane Production**

<b>COAL BED METHANE PRODUCTION</b>	<b>CO<sub>2</sub></b>	<b>N<sub>2</sub>O</b>	<b>CH<sub>4</sub></b>	<b>Section</b>
<b><i>COMBUSTION SOURCES – Stationary Devices</i></b>				
Boilers/steam generators	X	X	X	4.1, 4.2, 4.3
Internal combustion (IC) engines	X	X	X	4.1, 4.2, 4.3
Turbines	X	X	X	4.1, 4.2, 4.3
Flares	X	X	X	4.4
<b><i>COMBUSTION SOURCES – Essential Mobile Sources</i></b>				
Mining equipment	X	X	X	4.5
Other company vehicles	X	X	X	4.5
<b><i>COMBUSTION SOURCES – Indirects</i></b>				
Electricity imports	X	X	X	4.7
Process heat/steam imports	X	X	X	4.7
<b><i>VENTED SOURCES – Process Vents</i></b>				
Gas sweetening processes	X		X	5.1
Dehydration processes			X	5.1
<b><i>VENTED SOURCES – Other Venting</i></b>				
Water tanks			X	5.4.3
Coal-handling			X	5.6.5
<b><i>VENTED SOURCES – Maintenance/Turnarounds</i></b>				
Vessel blowdown			X	5.7.2
Well workovers			X	5.7.2
Compressor starts			X	5.7.2
Compressor blowdowns			X	5.7.2
Gathering Pipeline Blowdowns			X	5.7.2
<b><i>VENTED SOURCES – Non-routine Activities</i></b>				
Gathering pipeline leaks			X	5.7.2
Pressure relief valves (PRVs)			X	5.7.2
Well tests and blowdowns (when not flared)			X	5.7.2
<b><i>FUGITIVE SOURCES</i></b>				
Equipment component leaks			X	6.1

### **2.2.3 Minerals and Mining Operations**

This segment includes the operation of mines and quarries primarily engaged in mining, mine site development, and preparing metallic and nonmetallic minerals, including coal. The term “mining” is used broadly to include ore extraction, quarrying, and beneficiating (e.g., crushing, grinding, screening, washing, and separating) customarily done at the mine site.

While CBM operations, discussed in the previous section, are considered another method of producing natural gas, this segment consists of minerals and mining operations where natural gas entrained in the produced minerals or located in the surrounding strata is not recovered. Table 2-3 provides a checklist of emission sources associated with this specialized industry segment.

A significant source of GHG emissions from mining operations is combustion emissions (CO<sub>2</sub> and trace amounts of N<sub>2</sub>O). The operations associated with extraction and beneficiation are primarily mechanical and require the use of energy, either generated onsite or imported. Heat may also be required for some mining processes. Combustion emissions also result from the fuel consumed to operate mobile mining equipment. These sources exist for any type of mining operation.

For coal mining, three types of activities release CH<sub>4</sub> to the atmosphere: underground mining, surface mining, and coal handling processes. Where CBM is not recovered, CH<sub>4</sub> emissions from underground coal mines can be significant. Ventilation and degasification systems are used in underground mining to reduce CH<sub>4</sub> concentrations to safe levels by exhausting CH<sub>4</sub> to the atmosphere. Surface coal mining also releases CH<sub>4</sub> to the atmosphere as the coal is exposed, though the emissions are much lower than from underground mines. Finally, a portion of the CH<sub>4</sub> retained in the coal after mining is released to the atmosphere during processing, storage, and transport.

Methane emissions from non-coal mining and mineral operations can occur through the same mechanics as described for coal mining if CH<sub>4</sub> deposits are present.

**Table 2–3. Potential Greenhouse Gas Emission Sources by Sector:  
Minerals and Mining Operations**

<b>MINERALS AND MINING OPERATIONS</b>	<b>CO<sub>2</sub></b>	<b>N<sub>2</sub>O</b>	<b>CH<sub>4</sub></b>	<b>Section</b>
<b><i>COMBUSTION SOURCES – Stationary Devices</i></b>				
Boilers/steam generators	X	X	X	4.1, 4.2, 4.3
Heaters	X	X	X	4.1, 4.2, 4.3
Internal combustion (IC) engines	X	X	X	4.1, 4.2, 4.3
Turbines	X	X	X	4.1, 4.2, 4.3
Flares	X	X	X	4.4
<b><i>COMBUSTION SOURCES – Essential Mobile Sources</i></b>				
Mining equipment	X	X	X	4.5
Other company vehicles	X	X	X	4.5
<b><i>COMBUSTION SOURCES – Indirects</i></b>				
Electricity imports	X	X	X	4.7
Process heat/steam imports	X	X	X	4.7
<b><i>VENTED SOURCES – Process Vents</i></b>				
Ventilation and degasification			X	5.6.5
Surface mining			X	5.6.5
<b><i>VENTED SOURCES – Other Venting</i></b>				
Water Tanks			X	5.4.3
Coal-handling			X	5.6.5

#### **2.2.4 Transportation and Distribution**

The transportation and distribution segment consists of the movement of crude and associated gas from the production segment to refineries or gas processing. It may also include the movement of natural gas or petroleum products to market or distribution centers. As shown in Table 2-3, emission sources include loading and unloading of tank trucks, rail cars, and marine vessels; and transit losses from truck, marine, rail, and pipeline (liquid and gas) transportation.

Transportation and distribution emissions generally result from either losses of the material being transported or from combustion emissions from the motive forces used to transport the material. Product losses may occur either as fugitive equipment leaks or as evaporative losses during loading, unloading, and storage operations. In terms of GHG emissions, only CH<sub>4</sub> emissions result from product losses. The primary potential for CH<sub>4</sub> emissions is from handling crude oil, produced gas, and natural gas. Most refined products do not contain significant amounts of CH<sub>4</sub>.

Emissions of CO<sub>2</sub> and significantly smaller quantities of N<sub>2</sub>O occur in transportation and distribution due to combustion of fuels in IC engines, steam boilers on marine vessels, and



turbines on gas compressors. It is also possible to have smaller amounts of unburned CH<sub>4</sub> emissions when natural gas is used to fire the IC engines or turbines.

**Table 2–4. Potential Greenhouse Gas Emission Sources by Sector:  
Transportation and Distribution**

<b>TRANSPORTATION AND DISTRIBUTION</b>	<b>CO<sub>2</sub></b>	<b>N<sub>2</sub>O</b>	<b>CH<sub>4</sub></b>	<b>Section</b>
<b><i>COMBUSTION SOURCES – Stationary</i></b>				
Turbines	X	X	X	4.1, 4.2, 4.3
Engines	X	X	X	4.1, 4.2, 4.3
Heaters	X	X	X	4.1, 4.2, 4.3
Flares	X	X	X	4.4
Catalytic and thermal oxidizers	X	X	X	4.6
<b><i>COMBUSTION SOURCES – Essential Mobile Sources</i></b>				
Marine, road, or railroad tankers	X	X	X	4.5
Barges	X	X	X	4.5
Planes/helicopters	X	X		4.5
Other company vehicles	X	X		4.5
<b><i>COMBUSTION SOURCES – Indirects</i></b>				
Electricity imports	X	X	X	4.7
Process heat/steam imports	X	X	X	4.7
<b><i>VENTED SOURCES – Process Vents</i></b>				
Storage tanks			X	5.4
Loading/unloading/transit			X	5.5
Pneumatic devices			X	5.6.1
<b><i>VENTED SOURCES – Maintenance/Turnarounds</i></b>				
Pipeline blowdowns			X	5.7.4, 5.7.5
Pigging operations			X	5.7.4
Compressor starts			X	5.7.4
Compressor blowdowns			X	5.7.4
Compressor station blowdowns			X	5.7.4
Vessel blowdowns			X	5.7.4
<b><i>VENTED SOURCES – Non-Routine Activities</i></b>				
Pressure relief valves			X	5.7.4, 5.7.5
Surge tanks			X	5.7.4
<b><i>FUGITIVE SOURCES</i></b>				
Process equipment leaks			X	6.1
Pipeline leaks			X	6.1

### **2.2.5 Refining**

The refining segment consists of all refinery sites that take in crude and produce finished products, such as gasoline. The refining process includes many distillation steps that separate petroleum hydrocarbons into narrower boiling ranges. There are also a number of refining processes that react the hydrocarbons, such as cracking, coking, reforming, alkylation, and isomerization. Hydrogen is often manufactured to support increased hydroprocessing to remove sulfur from petroleum products. Petrochemicals may be manufactured on the refinery site, some by separation and concentration of naturally occurring chemicals in the petroleum and others by reaction to form new materials. Refinery sites may also include manufacturing of lubricating oils, specialty oils, and asphalt.

Table 2-5 provides a checklist of potential GHG emission sources for the refining segment. GHG emissions from refining occur primarily from combustion of fuels to provide the energy needed for the refining processes. Carbon dioxide emissions from boilers, process heaters, turbines, flares, and incinerators are the primary GHG emissions. Nitrous oxide emissions also result from these sources, but in quantities much smaller than CO<sub>2</sub>. When these combustion sources are fired with natural gas or refinery fuel gas, there may also be trace quantities of unburned CH<sub>4</sub> emissions.

The natural gas system, and potentially the refinery fuel gas system, are the only process streams within the refinery with potentially significant CH<sub>4</sub> concentrations. Fugitive CH<sub>4</sub> emissions may result from the piping and components associated with these systems and the combustion equipment fired by these fuels. Preliminary results from an API study on fugitive emissions from refinery fuel gas systems indicate that these emissions appear to be negligible.<sup>2</sup>

There are also a number of specialized process vents that may contribute GHG emissions. Some potential process vents include the fluid catalytic cracker (FCC) regenerator/CO boiler vent; cokers, hydrogen plant vents; and other catalyst regeneration. The FCC vent is primarily a source of CO<sub>2</sub> emissions, although there could be some unburned CH<sub>4</sub> if there is supplemental fuel fired in a CO boiler. The hydrogen plant vent is primarily a source of CO<sub>2</sub> emissions, as are other catalyst regeneration vents.

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<sup>2</sup> Measurements at one refinery resulted in CH<sub>4</sub> fugitive emissions of about 0.1% of the total refinery GHG inventory. Additional testing is planned for early 2004.

Table 2–5. Potential Greenhouse Gas Emission Sources by Sector: Refining

<b>REFINING</b>	<b>CO<sub>2</sub></b>	<b>N<sub>2</sub>O</b>	<b>CH<sub>4</sub></b>	<b>Section</b>
<b><i>COMBUSTION SOURCES – Stationary Devices</i></b>				
Boilers	X	X	X	4.1, 4.2, 4.3
Process heaters	X	X	X	4.1, 4.2, 4.3
Turbines	X	X	X	4.1, 4.2, 4.3
Engines	X	X	X	4.1, 4.2, 4.3
Flares	X	X	X	4.4
Catalytic and thermal oxidizers	X	X	X	4.6
Coke calcining kilns	X	X	X	4.6
Incinerators	X	X	X	4.6
<b><i>COMBUSTION SOURCES – Essential Mobile Sources</i></b>				
Company vehicles	X	X		4.5
<b><i>COMBUSTION SOURCES – Indirects</i></b>				
Electricity imports	X	X	X	4.7
Process heat/steam imports	X	X	X	4.7
<b><i>VENTED SOURCES – Process Vents</i></b>				
Catalytic cracking	X			5.2.1
Catalytic reforming	X			5.2.1
Catalyst regeneration	X			5.2.1, 5.2.4
Thermal cracking				5.2.6
Flexi-coking	X			5.2.3
Delayed coking	X			5.2.3
Steam methane reforming (hydrogen plants)	X			5.2.2
Sulfur recovery units				5.2.6
Asphalt production				5.2.5
<b><i>VENTED SOURCES – Other Venting</i></b>				
Storage tanks				5.4
Pneumatic devices				5.6.1
Loading racks			X	5.5
<b><i>VENTED SOURCES – Maintenance/Turnarounds</i></b>				
Equipment/process blowdowns			X	5.7.6
Heater/boiler tube decoking			X	5.7.6
Compressor starts			X	5.7.6
<b><i>VENTED SOURCES – Non-routine Activities</i></b>				
Pressure relief valves (PRV)	X		X	5.7.6
Emergency shut down (ESD)	X		X	5.7.6
<b><i>FUGITIVE SOURCES</i></b>				
Fuel gas system leaks			X	6.1, B.3
Other process equipment leaks			X	6.1, B.3
Wastewater collection and treating			X	6.2.1
Sludge/solids handling				6.2.1
Cooling towers				6.2.1

### **2.2.6 Petrochemical Manufacturing**

For some companies, operations to produce or manufacture chemicals derived from petroleum-based products are separate from refining operations. The sources of GHG emissions from petrochemical manufacturing, shown in Table 2-6, are similar to the refining segment.

Fossil fuel combustion is the most significant source of GHG emissions from chemical manufacturing, primarily resulting in CO<sub>2</sub> emissions. Trace quantities of nitrous oxide emissions may also occur. Different operating conditions associated with specific petrochemical units, such as the high operating temperatures of olefin units, may result in higher N<sub>2</sub>O combustion emissions than observed at refinery processes. Trace quantities of CH<sub>4</sub> might also be released from combustion equipment as products of incomplete fuel combustion.

As in refineries, when natural gas or plant fuel gas is used to fuel the combustion devices, CH<sub>4</sub> emissions may result from fugitive sources associated with system piping or the combustion equipment itself. Vented and fugitive emissions may also result where significant concentrations of CH<sub>4</sub> is present in other process streams. For some circumstances, CH<sub>4</sub> may be used in petrochemical facilities for purposes other than combustion, such as tank and process vessel blanketing.

Small amounts of GHGs are released during the production of some petrochemicals. This *Compendium* provides CH<sub>4</sub> emission factors associated with the production of five chemicals: carbon black, ethylene, dichloride, styrene, and methanol based on national GHG inventory data (EPA, 2002). In addition, N<sub>2</sub>O emission factors are provided for nitric oxide production and adipic acid production.

**Table 2–6. Potential Greenhouse Gas Emission Sources by Sector:**  
**Petrochemical Manufacturing**

<b>PETROCHEMICAL MANUFACTURING</b>	<b>CO<sub>2</sub></b>	<b>N<sub>2</sub>O</b>	<b>CH<sub>4</sub></b>	<b>Section</b>
<b><i>COMBUSTION SOURCES – Stationary Devices</i></b>				
Boilers	X	X	X	4.1, 4.2, 4.3
Process heaters	X	X	X	4.1, 4.2, 4.3
Turbines	X	X	X	4.1, 4.2, 4.3
Engines	X	X	X	4.1, 4.2, 4.3
Flares	X	X	X	4.4
Catalytic and thermal oxidizers	X	X	X	4.6
Incinerators	X	X	X	4.6
<b><i>COMBUSTION SOURCES – Essential Mobile Sources</i></b>				
Company vehicles				4.5
<b><i>COMBUSTION SOURCES - Indirects</i></b>				
Electricity imports	X	X	X	4.7
Process heat/steam imports	X	X	X	4.7
<b><i>VENTED SOURCES – Process Vents</i></b>				
Catalyst regeneration	X			5.2.4
Steam methane reforming (hydrogen plants)	X			5.2.2
Chemical production	X			5.6.6
<b><i>VENTED SOURCES – Other Venting</i></b>				
Storage tanks			X	5.4
Pneumatic devices				5.6.1
Loading racks			X	5.5.1
<b><i>VENTED SOURCES – Maintenance/Turnarounds</i></b>				
Equipment/process blowdowns			X	5.7.6
Heater/boiler tube decoking			X	5.7.6
Compressor starts			X	5.7.6
<b><i>VENTED SOURCES – Non-routine Activities</i></b>				
Pressure relief valves (PRV)	X		X	5.7.6
Emergency shut down (ESD)	X		X	5.7.6
<b><i>FUGITIVE SOURCES</i></b>				
Fuel gas system leaks			X	6.1
Other process equipment leaks			X	6.1
Wastewater collection and treating			X	6.2
Sludge/solids handling				6.2
Cooling towers				6.2

### 2.2.7 Marketing

The marketing segment includes company owned retail operations and support to customer fueling operations. A checklist of potential GHG emission sources is provided in Table 2-7.

Evaporative emissions of hydrocarbons may occur during fuel transfer or pumping activities, but the concentration of CH<sub>4</sub> or other GHG pollutants is negligible in the refined products.

Therefore, there are generally no significant GHG emissions from these activities. Methane emissions may result from process equipment leaks associated with liquefied natural gas (LNG) or compressed natural gas (CNG) marketing. Indirect emissions associated with onsite electricity usage are a source of CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub> emissions.

**Table 2–7. Potential Greenhouse Gas Emission Sources by Sector:  
Retail and Marketing**

<b>RETAIL AND MARKETING</b>	<b>CO<sub>2</sub></b>	<b>N<sub>2</sub>O</b>	<b>CH<sub>4</sub></b>	<b>Section</b>
<b><i>COMBUSTION SOURCES - Stationary</i></b>				
Thermal oxidizers	X	X		4.6
<b><i>COMBUSTION SOURCES – Essential Mobile Sources</i></b>				
Marine tankers	X	X	X	4.5
Road tankers	X	X	X	4.5
Railroad tankers	X	X	X	4.5
Other company vehicles	X	X	X	4.5
<b><i>COMBUSTION SOURCES – Indirects</i></b>				
Electricity usage	X	X	X	4.7
<b><i>VENTED SOURCES</i></b>				
Service station storage tanks				5.4
<b><i>FUGITIVE SOURCES</i></b>				
Process equipment leaks				6.1

### 2.2.8 Electricity and Heat Generation

Petroleum refining and petrochemical production are energy intensive operations, requiring steady supplies of electricity and often process heat or steam. Steam is also used in enhanced oil recovery or enhanced coal bed methane production. A petroleum company may own and operate energy generation facilities to supply electricity and steam for these operations.

The sources of GHG emissions for electricity and heat generation are shown in Table 2-8. Combustion emissions of CO<sub>2</sub>, and to a lesser extent N<sub>2</sub>O and CH<sub>4</sub>, result from the burning of fossil fuels to operate turbines or boilers. Where natural gas is used to generate electricity or heat, emissions of CH<sub>4</sub> result from process vents and fugitive sources, though these emissions are generally negligible compared to the combustion sources.

Another GHG called sulfur hexafluoride (SF<sub>6</sub>) may be used as an insulator in electrical transmission and distribution systems. Fugitive and process vent emissions of SF<sub>6</sub> can occur from leaks or service activities on substations and circuit breakers. Despite the very high global warming potential of SF<sub>6</sub>, the quantities released are generally so small that the overall contribution of SF<sub>6</sub> to a greenhouse gas inventory is negligible (EPA, 2003).

**Table 2–8. Potential Greenhouse Gas Emission Sources by Sector:  
Electricity and Heat/Steam Generation**

<b>ELECTRICITY AND HEAT/STEAM GENERATION</b>	<b>CO<sub>2</sub></b>	<b>N<sub>2</sub>O</b>	<b>CH<sub>4</sub></b>	<b>Section</b>
<b><i>COMBUSTION SOURCES - Stationary</i></b>				
Turbines	X	X	X	4.1, 4.2, 4.3
Boilers/steam generators	X	X	X	4.1, 4.2, 4.3
<b><i>COMBUSTION SOURCES – Essential Mobile Sources</i></b>				
Company vehicles	X	X	X	4.5
<b><i>VENTED SOURCES</i></b>				
Natural gas distribution process/equipment vents			X	5.7
<b><i>FUGITIVE SOURCES</i></b>				
Natural gas distribution equipment leaks			X	6.1

## 2.3 References

International Petroleum Industry Environmental Conservation Association (IPIECA), International Association of Oil and Gas Producers (OGP), and American Petroleum Institute (API). *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions*, December 2003. <http://www.api.org> and <http://www.ipieca.org>

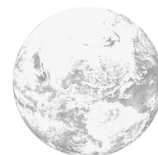
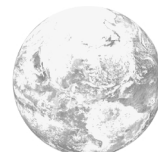
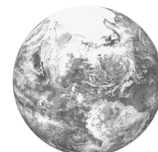
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FEBRUARY 2004

**COMPENDIUM OF GREENHOUSE GAS  
EMISSIONS METHODOLOGIES FOR  
THE OIL AND GAS INDUSTRY**

SECTION 3



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## 3.0

# TECHNICAL CONSIDERATIONS

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### 3.1 Overview

Emissions for a particular source are the product of the source specific emission factor (EF) and the activity factor (AF). An inventory is the sum of all of the emissions for a particular facility or company:

$$\text{Emission Inventory} = \sum_{i=1}^{\text{\# sources}} \text{EF}_i \times \text{AF}_i$$

(Equation 3-1)

Throughout this document it will be important to pay close attention to assumptions and conventions used in defining the emission factors. The listing below highlights some of the key areas where error can be introduced into the computation if not addressed properly.

- **Standard Gas Conditions**—When converting from a volume basis to a mass basis for a gas stream, the standard conditions used in this document are 14.7 psia and 60°F. This is equivalent to 379.3 standard cubic feet (scf)/lbmole or 23,685 cm<sup>3</sup>/gmole.
- **Heating Value Specifications**—When converting between fuel volume and energy, higher heating value (HHV) or gross calorific value is the preferred convention. However, lower heating value (LHV) or net calorific values are also reported.
- **Units**—The format for units presented throughout this document is to use the units directly from the referenced source. This enables the user to easily check for updates from the referenced sources. Each emission factor is then also reported in terms of tonnes<sup>1</sup> per unit of activity, where the unit of activity is expressed in both SI units and units common to US practices. Conversion factors are provided in this section if other units are preferred.
- **Fuel Combustion**—Fuel properties in terms of heating values and carbon content are provided for a variety of fuels in commerce. Carbon dioxide (CO<sub>2</sub>) emissions associated with fossil fuels or refined products are based only on the conversion of carbon to CO<sub>2</sub> and do not account for the efficiency of the combustion device.

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<sup>1</sup> Metric tonnes = 1000 kg = 2204.62 lb.

These and other considerations are more thoroughly discussed in the subsections that follow.

## **3.2 Emission Sources**

Emissions of greenhouse gases (GHG) in the oil and gas industry typically occur from one of the following general source classes: 1) combustion sources; 2) vented sources; and 3) fugitive sources. Some pieces of equipment, such as compressors, may emit under multiple modes – fugitive emissions when pressurized, vented emissions when depressurized for maintenance, and combustion emissions from the driver engines during normal operations. Tables 2-1 through 2-8, shown in Section 2, provide a detailed list of the types of potential emission sources associated with each of the general source classes discussed further in the following subsections.

### **3.2.1 Combustion**

Combustion of carbon-containing fuels in stationary equipment such as engines, burners, heaters, boilers, and flares results in the formation of CO<sub>2</sub> due to the oxidation of carbon. Very small quantities of nitrous oxide (N<sub>2</sub>O) may be formed during fuel combustion by reaction of nitrogen and oxygen. Methane (CH<sub>4</sub>) may also be released in exhaust gases as a result of incomplete fuel combustion.

Stationary combustion sources include the generation of electricity or steam from hydrocarbon fuels, whether this energy is imported (indirect emissions) or generated onsite. Emissions resulting from the combustion of fuel in transportation equipment (i.e., vessels, barges, ships, railcars, and trucks) that are included in the inventory are also categorized as combustion sources.

### **3.2.2 Vented Sources**

Vented sources are defined as releases resulting from normal operations. These include sources such as crude oil, condensate and petroleum product storage tanks, loading/ballasting/transit sources, and loading racks, as well as equipment such as chemical injection pumps and pneumatic devices which release GHG as part of their operation.

Process vents, a subcategory of vented sources, are defined as those sources that produce emissions as a result of some form of chemical transformation or processing step. Examples of these sources

include dehydration, gas sweetening, stream CH<sub>4</sub> reforming units (hydrogen plants), catalytic cracking units, delayed cokers, coke calciners, and others. These sources are generally specific to the particular industry segment.

Depressurizing equipment for maintenance or turnaround activities often results in vented emissions. Similarly, GHG emissions may result from equipment startup activities or from purging equipment prior to repressurization. Other activities classified as maintenance or turnaround emission sources include well workovers, compressor turn-arounds, pipeline pigging operations, and heater/boiler tube decoking.

Other releases included as vented emission sources are non-routine releases from emergency or pressure relieving equipment such as emergency shutdowns (ESD) or emergency safety blowdowns (ESB), pressure relief valves, and surge tanks.

### **3.2.3 Fugitive Sources**

Fugitive emissions are unintentional releases from equipment leaks at sealed surfaces, as well as from underground pipeline leaks. Fugitive emissions are generally low-level leaks of process fluid (gas or liquid) from sealed surfaces, such as packing and gaskets, resulting from the wear of mechanical joints, seals, and rotating surfaces over time. Specific fugitive emission source types include various fittings such as valves, flanges, pump seals, compressor seals, or sampling connections.

## **3.3 Greenhouse Gases**

This document is focused on carbon dioxide (CO<sub>2</sub>), methane (CH<sub>4</sub>), and nitrous oxide (N<sub>2</sub>O) GHG emissions, as these are the most important GHGs emitted from oil and gas industry operations. However, while the Compendium provides emission estimation methods for CH<sub>4</sub> and N<sub>2</sub>O, this should not imply that these emissions are necessarily significant or should always be estimated.

Carbon dioxide is primarily emitted from combustion sources, but may also be emitted from gas production and processing operations through vented and fugitive sources. This is particularly important in operations using or processing CO<sub>2</sub>-rich field gas. For these non-combustion sources, the potential for emitting CO<sub>2</sub> will depend on the CO<sub>2</sub> concentration in the working reservoir, as

well as design and operating practices at facilities. The concentration of CO<sub>2</sub> in commercial natural gas is generally so small that vented and fugitive emissions associated with its use would be negligible compared to those produced from combustion.

Methane emissions can result from any or all of the emission sources described in Section 3.2. Methane is emitted when natural gas leaks from fugitive sources or when natural gas is vented directly during maintenance or emergency procedures. Methane is also found in exhaust gases as a result of incomplete fuel combustion.

Nitrous oxide is produced both naturally, through various biological reactions in the soil and in water, and anthropogenically, through industrial, waste management, and agricultural activities. With respect to oil and gas industry operations, trace amounts of N<sub>2</sub>O may be formed from reactions between nitrogen and oxygen that occur during stationary or mobile source combustion. The quantity of N<sub>2</sub>O formed during combustion varies based on the fuel, equipment, and pollution control device (e.g., catalytic converters installed to reduce motor vehicle emissions can increase N<sub>2</sub>O emissions). As indicated in Section 7 and Appendix C, N<sub>2</sub>O emissions contribute less than 1% of a facility's overall GHG inventory (on a CO<sub>2</sub> Equivalent basis) for the example facilities examined.

### **3.3.1 Global Warming Potentials**

Greenhouse gas inventories are often reported in terms of Carbon Equivalents or Carbon Dioxide Equivalents (CO<sub>2</sub> Eq.), in which all of the GHGs are converted to an equivalent basis relative to their “global warming potential” (GWP). The GWP is a measure of a compound's ability to trap heat over a certain lifetime in the atmosphere, relative to the effects of the same mass of CO<sub>2</sub> released over the same time period. Emissions expressed in equivalent terms highlight the contribution of the various gases to the overall inventory. Therefore, GWP is a useful statistical weighting tool for comparing the heat trapping potential of various gases.

Table 3-1 presents the currently accepted GWP values associated with various compounds recognized as contributing to the greenhouse effect (COP, 2002). According to the Intergovernmental Panel on Climate Change (IPCC), GWPs typically have an uncertainty of ±35 percent (IPCC, 2001). The time interval associated with the GWP value is an area of debate between policy analysts and scientists. For CH<sub>4</sub> and N<sub>2</sub>O, the time interval chosen can have a significant impact because there is a large difference between the lifetime of CH<sub>4</sub> and N<sub>2</sub>O (approximately 12.2 years and 120 years, respectively) and the effective lifetime of CO<sub>2</sub> (200-250

years).<sup>2</sup> Currently, the parties to the United Nations Framework Convention on Climate Change (UNFCCC) have agreed to base GWPs on a 100 year time horizon (EPA, 2003).

The UNFCCC updates the GWP values periodically as new information becomes available. The IPCC published its Third Assessment Report (TAR) in 2001, which presented new GWP values for the second commitment period (after 2012) based on an improved calculation of the radiative forcing and response function of CO<sub>2</sub> (IPCC, 2001). Although the GWPs have been updated by IPCC, the values from the Second Assessment Report (SAR) are applicable through the first commitment period (2008-2012)<sup>3</sup> and are the values applied in the *Compendium*, as shown in Table 3-1. The recommended GWP values from the SAR are highlighted in bold. For comparison, Table 3-1 also includes the GWPs presented in the TAR.

**Table 3-1. Greenhouse Gas and Global Warming Potentials**

Gas	Recommended GWP(UNFCCC, 2002) applicable through 2012	IPCC Revised GWP (IPCC TAR, 2001) applicable after 2012
CO <sub>2</sub>	<b>1</b>	1
CH <sub>4</sub> <sup>a</sup>	<b>21</b>	23
Nitrous Oxide (N <sub>2</sub> O)	<b>310</b>	296
Hydrofluorocarbon (HFC)-23	<b>11,700</b>	12,000
HFC-32	<b>650</b>	550
HFC-125	<b>2,800</b>	3,400
HFC-134a	<b>1,300</b>	1,300
HFC-143a	<b>3,800</b>	4,300
HFC-152a	<b>140</b>	120
HFC-227ea	<b>2,900</b>	3,500
HFC-236fa	<b>6,300</b>	9,400
HFC-4310mee	<b>1,300</b>	1,500
CF <sub>4</sub>	<b>6,500</b>	5,700
C <sub>2</sub> F <sub>6</sub>	<b>9,200</b>	11,900
C <sub>4</sub> F <sub>10</sub>	<b>7,000</b>	8,600
C <sub>6</sub> F <sub>10</sub>	<b>7,400</b>	9,000
SF <sub>6</sub>	<b>23,900</b>	22,200

<sup>a</sup> The GWP of CH<sub>4</sub> includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO<sub>2</sub> is not included.

<sup>2</sup> For example, if a time period of 50 years is selected, the CH<sub>4</sub> GWP would be approximately 34, compared to a GWP of 6.5 for a 500-year integration interval.

<sup>3</sup> This is consistent with UNFCCC reporting guidelines, which require reporting of GHG emissions and reductions using 100-year GWP values that have been identified by IPCC and adopted by the Conference of Parties (COP). As of COP9 in 2003, the UNFCCC COP has not adopted the revised GWPs from the TAR (COP, 2002).



### 3.3.2 Emissions Summaries

This document provides emission factors for CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O only. Nonetheless, there are other recognized GHGs, as listed in Table 3-1. Each user should determine if their emission sources might result in significant emissions of any of the other GHGs. The relative significance of each compound could be assessed both by its overall mass emissions as well as its GWP weighted value.

This section demonstrates how to use the GWP values as a convenient means of aggregating the combined effect of multiple GHGs. In developing emissions summaries, it is important to keep track of the actual mass emissions of all the compounds emitted, in addition to the weighted sum. Also, the inventory should note the GWP value used in the aggregation and allow for revisions to the total emission estimate should the UNFCCC adopt revised GWPs.

Using GWP values, GHG emissions estimates are often expressed in terms of CO<sub>2</sub> Equivalents or Carbon Equivalents for final summation. Although any units of mass may be used to convert GHG emissions to these equivalent bases, the most widely recognized units are tonnes and million metric tonnes (MMT). The equations and an example are provided below.

$$\text{CO}_2 \text{ Equivalents, tonnes} = \sum_{i=1}^{\text{\# Greenhouse Gas Species}} (\text{tonnes}_i \times \text{GWP}_i) \quad (\text{Equation 3-2})$$

$$\text{MMTCE} = \text{CO}_2 \text{ Equivalents, tonnes} \times \frac{\text{MW Carbon}}{\text{MW CO}_2} \times \frac{\text{MMT}}{10^6 \text{ tonnes}} \quad (\text{Equation 3-3})$$

where,

MMTCE = Million Metric Tonnes of Carbon Equivalent  
 MW = molecular weight (MW Carbon = 12; MW CO<sub>2</sub> = 44)

**EXHIBIT 3.1: Sample Calculation for Carbon Equivalents, continued**

$$\left( \frac{8,800,000 \text{ tons CO}_2}{\text{yr}} \times \frac{1 \text{ ton CO}_2 \text{ Equivalents}}{\text{ton CO}_2} + \frac{315,000 \text{ tons CH}_4}{\text{yr}} \times \frac{21 \text{ tons CO}_2 \text{ Equivalents}}{\text{ton CH}_4} \right) \times \frac{\text{tonnes}}{1.10231 \text{ tons}} = 13.98 \times 10^6 \text{ tonnes CO}_2 \text{ Equivalents/yr}$$

Continuing from above, Equation 3-3 can be used to calculate emissions in terms of Carbon Equivalents:

$$\frac{13.98 \times 10^6 \text{ tonnes CO}_2 \text{ Equivalents}}{\text{yr}} \times \frac{12 \text{ tonnes/mole C}}{44 \text{ tonnes/mole CO}_2} \times \frac{\text{MMTCE}}{10^6 \text{ tonnes C}} = \underline{3.81 \text{ MMTCE/yr}}$$

**INPUT DATA:**

A company's GHG inventory reported 8,800,000 tons/yr (i.e., short tons) of CO<sub>2</sub> emissions and 315,000 tons/yr of CH<sub>4</sub> emissions.

**CALCULATION METHODOLOGY:**

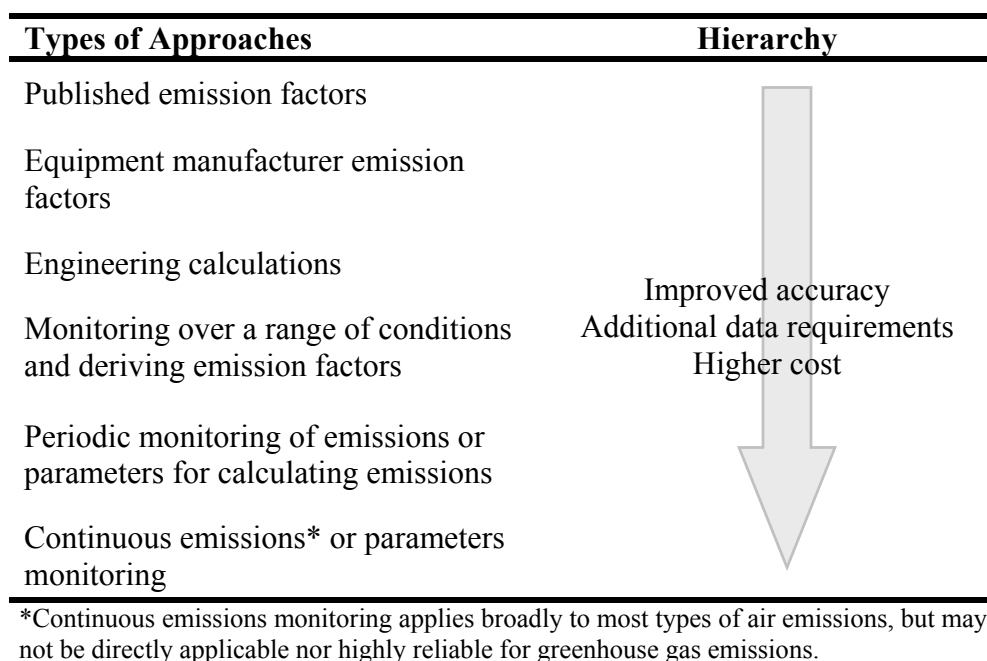
As stated above, the GWP for CH<sub>4</sub> is 21, and the GWP for CO<sub>2</sub> is 1. Using Equation 3-2 above, the emissions are calculated in terms of CO<sub>2</sub> Equivalents. Table 3-2 provides the factor for converting tons to tonnes.

### 3.4 Data Requirements

The availability of any given type of data will generally determine which estimation approach within a target range is selected. For an overall assessment of emissions, published emission factors are generally acceptable. If a more representative, site-specific evaluation is needed and information is available, emission factors may be obtained from equipment manufacturers, engineering calculations, and/or test data. Emissions monitoring is rarely used and is generally not practical for estimating GHG emissions.

Figure 3-1 illustrates the hierarchy associated with the range of available options for emission factor data.

Where possible, this manual provides multiple estimation approaches for each category of emissions. These approaches are generally presented in terms of a preferred approach and alternate approach(es). Decision diagrams are provided to guide the user through the available options where the choice of one approach over another is often dictated by the available data. Additional guidance on selecting estimation methods is provided in the *Guidelines* document, where emission estimation approaches are classified into three tiers based on different uncertainty ranges (IPIECA, et. al, 2003).



**Figure 3-1. Estimation Approaches**

An emissions inventory is time dependent, reflecting conditions at the time the inventory is conducted. As processes or operations change, emission factor values may also change over time. A facility may change an equipment's emission factor by implementing control mechanisms, or may even eliminate a previous emission source through emission reduction activities. In addition, a published data source, such as AP-42 (EPA, 1995 with supplements), may revise emission factors based on new data. As an inventory is updated, emission factor approaches and sources should be reviewed for relevant updates, to ensure its validity.

### 3.5 Data Assumptions

An emission factor represents an average emission rate for a given source, and is generally expressed as a mass or volume of emissions per source type or measure of activity related to the source. For example:

$$\frac{\text{scf CH}_4/\text{yr}}{\text{valve}} \text{ or } \frac{\text{g CO}_2}{\text{L diesel combusted}}$$

This *Compendium* provides emission factors from many different documents. To allow the user to confirm or update an emission factor, detailed references are provided and the reported emission factors are maintained in the units convention from the referenced source. However, to simplify the use of these emission factors, the units convention adopted for this *Compendium* is to express emission factors in terms of metric tonnes of emissions in the numerator, and express the denominator in terms of both US conventional units and SI units. Conversion factors are provided in Section 3.6.

When converting from a volume basis to a mass basis for a gas stream, the standard conditions used in this document are at 14.7 psia and 60°F. Using the ideal gas law:

$$PV = nRT \quad \text{(Equation 3-4)}$$

where,

P = pressure (psia or atm)

V = volume (ft<sup>3</sup> or cm<sup>3</sup>)

n = number of moles

R = gas constant      = 10.73 psi ft<sup>3</sup>/lbmole °R  
                                  = 0.73 atm ft<sup>3</sup>/lbmole °R  
                                  = 82.06 atm cm<sup>3</sup>/gmole K

T = absolute temperature (°R or K)

This equates to 1 lbmole = 379.3 standard cubic feet (scf) at the specified standard conditions of 14.7 psia and 60°F. In metric units, 1 gmole = 23,685 cm<sup>3</sup> (23.685 m<sup>3</sup>/kg-mole) at these same conditions.

Note that there are many different sets of standard or reference conditions, where “standard” often depends on the application or the industry convention. For example, physical properties of gases

are often reported in terms of 0°C and 760 mm Hg (CRC, 1984). To convert a volumetric rate from one set of standard conditions to another, the following equation can be used:

$$V_2 = V_1 \left[ \frac{(P_1)(T_2)}{(P_2)(T_1)} \right] \quad (\text{Equation 3-5})$$

where subscript "2" corresponds to the new set of standard conditions and subscript "1" corresponds to the initial conditions. Note that absolute temperatures (°R or K) are required for this equation. This conversion is demonstrated in Exhibit 3.2.

**EXHIBIT 3.2: Sample Calculation for Converting between Sets of Standard Conditions**

**INPUT DATA:**

The CH<sub>4</sub> emission factor for a pneumatic device was determined to be 345 scfd/device based on the standard conditions of 14.7 psia and 60°F.

- a) What is the emission factor at the EPA reference conditions of 14.73 psia and 298 K (77°F)?
- b) What is the emission factor at 0°C and 760 mm Hg?

**CALCULATION METHODOLOGY (a):**

The ideal gas law requires absolute temperatures. (Note: temperature conversions are provided in Section 3.6.) First, convert 60°F to an absolute basis, in this case Kelvin (K) so it will be on the same basis as the new conditions:

$$\frac{60^\circ\text{F} - 32}{1.8} + 273.15 = 288.7 \text{ K}$$

Using Equation 3-5, calculate the volume for the new standard conditions:

$$V_2 = V_1 \left[ \frac{(P_1)(T_2)}{(P_2)(T_1)} \right]$$
$$V_2 = (345 \text{ scf}) \left[ \frac{(14.7 \text{ psia})(298 \text{ K})}{(14.73 \text{ psia})(288.7 \text{ K})} \right] = \underline{355.4 \text{ scf}}, \text{ at } 14.73 \text{ psia and } 298 \text{ K}$$

**EXHIBIT 3.2: Sample Calculation for Converting between Sets of Standard Conditions, continued**

CALCULATION METHODOLOGY (b):

From Table 3-3, 0°C = 273.15 K. From Table 3-2, 760 mmHg = 14.696 psi

Using Equation 3-5, calculate the emission factor volume corresponding to these new conditions:

$$V_2 = (345 \text{ scf}) \left[ \frac{(14.7 \text{ psia})(273.15 \text{ K})}{(14.696 \text{ psia})(288.7 \text{ K})} \right] = \underline{326.51 \text{ scf}}, \text{ at } 0^\circ \text{C and } 760 \text{ mmHg}$$

This result can be converted to SI units using the conversion factor provided in Table 3-2:

$$326.51 \text{ scf} \times \frac{\text{m}^3}{35.3147 \text{ ft}^3} = \underline{9.2456 \text{ m}^3} \text{ at } 0^\circ \text{C and } 760 \text{ mm Hg}.$$

## 3.6 Units, Conversions, and Fuel Properties

### 3.6.1 General Units Conversions

API Publication 2564 specifies API preferred units for quantities common to the petroleum industry and provides factors for converting customary units to the API-preferred metric units (API, 1998). The API preferred units are consistent with metric practice, as defined by the General Conference on Weights and Measures and significant standards organizations (such as the American Society for Testing and Materials, the American National Standards Institute, and related technical societies). API Publication 2564 served as the basis for the common unit conversion factors provided in Tables 3-2 through 3-4.

In Table 3-2, most of the conversion factors are shown to six or seven significant digits. Those shown to fewer than six significant figures are limited by the precision of the physical property. An asterisk (\*) indicates that the conversion factor is exact, and any succeeding digits would be zeros.

**Table 3-2. Conversion Factors**

	Common US Units	API Preferred SI Units	Other Conversions
<b>Mass</b>		1 kilogram	= 2.20462 pounds (lb) = 1000* grams (g)
	1 pound (lb)	= 0.4535924 kilograms	= 453.5924 grams (g)
	1 short ton (ton)	= 907.1847 kilograms	= 2000* pounds (lb)
	1 metric tonne (tonne)	= 1000* kilograms	= 2204.62 pounds (lb) = 1.10231 tons
<b>Volume</b>		1 cubic meter (m <sup>3</sup> )	= 1000 *liters (L) = 35.3147 cubic feet (ft <sup>3</sup> ) = 264.17 gallons
	1 cubic foot (ft <sup>3</sup> )	= 0.02831685 cubic meters (m <sup>3</sup> )	= 28.31685 liters (L) = 7.4805 gallons
	1 gallon (gal)	= 3.785412×10 <sup>-3</sup> cubic meters (m <sup>3</sup> )	= 3.785412 liters (L)
	1 barrel (bbl)	= 0.1589873 cubic meters (m <sup>3</sup> )	= 158.9873 liters (L) = 42* gallons (gal)
<b>Length</b>		1 meter (m)	= 3.28084 feet = 6.213712×10 <sup>-4</sup> miles
	1 inch (in)	= 0.0254* meters (m)	= 2.54* centimeters
	1 foot (ft)	= 0.3048* meters (m)	
	1 mile	= 1609.344* meters (m)	= 1.609344* kilometers
<b>Power</b>		1 Watt (W)	= 1* joule (J)/second = 9.47817×10 <sup>-4</sup> Btu/second = 1.341×10 <sup>-3</sup> horsepower (hp)
	1 megawatt	10 <sup>6</sup> Watts (W)	= 1000* Joules/second = 1000* kilowatts (10 <sup>3</sup> W)
	1 horsepower (hp)	= 745.6999 Watts (W)	= 0.7456999 kilowatts = 0.707 Btu/second
<b>Energy</b>		1 Joule (J)	= 9.47817×10 <sup>-4</sup> Btu = 2.778×10 <sup>-7</sup> kilowatt-hour = 0.7376 foot-pounds <sub>force</sub>
	1 horsepower-hour (hp-hr)	= 2.68452×10 <sup>6</sup> Joules (J)	= 2544.43 Btu = 0.7457 kilowatt-hour
	1 kilowatt-hour	= 3.6*×10 <sup>6</sup> Joules (J)	= 3412.1 Btu = 1.341 horsepower-hours = 3600* kilo Joules
	1 Btu	= 1055.056 Joules (J)	= 3.930×10 <sup>-4</sup> horsepower-hours = 2.931×10 <sup>-4</sup> kilowatt-hours
	1 million Btu (10 <sup>6</sup> Btu)	= 1.055056×10 <sup>9</sup> Joules (J)	= 1.055056 giga-Joules (10 <sup>9</sup> J) = 293.1 kilowatt-hours
<b>Pressure</b>		1 kilo-Pascal (10 <sup>3</sup> Pa)	= 9.869233×10 <sup>-3</sup> atmosphere (atm)
	1 atmosphere (atm)	= 101.325* kilo-Pascals (10 <sup>3</sup> Pa)	= 14.696 pounds per square inch (psi) = 760 millimeters mercury (mm Hg) @ 0°C
	1 pound per square inch (psi)	= 6.894757 kilo-Pascals (10 <sup>3</sup> Pa)	= 0.06804596 atmosphere (atm)

**Table 3-2. Conversion Factors, Continued**

	Common US Units	API Preferred SI Units	Other Conversions
<b>Heating Value</b>			
Mass basis:	1 Btu/pound	= 2326 Joules/kilogram (J/kg)	
Volume basis:	1 Btu/cubic foot (Btu/ft <sup>3</sup> )	= 37,258.95 Joules/cubic meter (J/m <sup>3</sup> )	= 0.13368 Btu/gallon
Emission Factor:		1 kilogram/giga-Joule (kg/10 <sup>9</sup> J)	= 2.32600 pound/million Btu (lb/10 <sup>6</sup> Btu)
	1 pound/million Btu (lb/10 <sup>6</sup> Btu)	= 0.429923 kilograms/giga-Joule (kg/10 <sup>9</sup> J)	= 0.429923 tonnes/tera-Joule (tonnes/10 <sup>12</sup> J) = 429.923 grams/giga-Joule (g/10 <sup>9</sup> J)

Notes:

\* indicates the conversion factor is exact, any succeeding digits would be zeros.

psig = Gauge pressure.

psia = Absolute pressure (note psia = psig + atmospheric pressure).

**Table 3-3. Temperature Conversions**

Degrees Fahrenheit (°F)	= 1.8 (degrees C) + 32
Degrees Rankine (°R)	= degrees F + 459.7
Degrees Celsius (°C)	= (degrees F – 32)/1.8
Kelvin (K)	= degrees C + 273.15

As shown in Table 3-4, the symbol associated with a particular unit or prefix can have multiple meanings depending on which system of units is used. The distinction between upper case and lower case letters used for the symbol is also important. To minimize confusion, this document expresses units numerically on a log<sub>10</sub> basis (i.e., 10<sup>x</sup>) or spells out the unit name.



**Table 3-4. Unit Prefixes**

SI Units		US Designation	
Unit/Symbol	Factor	Unit/Symbol	Factor
peta (P )	$10^{15}$	quadrillion (Q)	$10^{15}$
tera (T)	$10^{12}$	trillion (T)	$10^{12}$
giga (G)	$10^9$	billion (B)	$10^9$
mega (M)	$10^6$	million (MM)	$10^6$
kilo (k)	$10^3$	thousand (k or M)	$10^3$
hecto (h)	$10^2$		
deka (da)	$10^1$		
deci (d)	$10^{-1}$		
centi (c)	$10^{-2}$		
milli (m)	$10^{-3}$		
micro ( $\mu$ )	$10^{-6}$		
Nano (n)	$10^{-9}$		
Pico (p)	$10^{-12}$		

### 3.6.2 Numeric Format

This document does not maintain a fixed number of significant figures associated with the many numeric values presented. Where emission factors are cited, the *Compendium* provides the same number of significant figures as reported in the emission factor source documents. This enables the user to easily compare values directly with the referenced sources as a check for updated emission factors. In general, a consistent number of significant figures are also reported for the emission factors converted to the unit convention adopted for the *Compendium*.

Numeric round-off, reflecting an appropriate number of significant digits, is considered acceptable only at the final stage of creating an emissions inventory to prevent compounding inaccuracy through the various calculation steps. This practice is reflected in the example calculations in Section 7, where rounded-off results are presented in the summary tables.

### 3.6.3 Fuel Properties

Heating value describes the quantity of energy released when a fuel is completely combusted. The difference between the higher heating value (HHV), also known as gross calorific value, and lower heating value (LHV), also referred to as the net calorific value, is the phase of the water in the

combustion products: water is in the liquid form for HHV and in the vapor form for LHV. The two heating values are related by the following equation:

$$\text{HHV} = \text{LHV} + (n\bar{h})_{H_2O} \quad (\text{Equation 3-6})$$

where:

$n$  is the number of moles of water in the products and  $h$  is the enthalpy of vaporization of water at 25°C

In most cases, choosing between the use of heating values in terms of HHV or LHV is a matter of preference. The HHV convention is commonly used in the US and Canada, while LHV is generally the preference outside North America. The *Compendium* provides fuel heating values and energy-based emission factors in terms of both HHV and LHV. The convention chosen will not impact the emission results, as long as the energy data and emission factors are on the same basis, either HHV or LHV. Errors occur when the conventions are not clearly identified and are combined (e.g., multiplying the energy associated with fuel use, reported on one basis, by an emission factor that is reported on the other basis).

Table 3-5 provides heating values, in terms of both HHV and LHV, and other fuel properties for some common fuel types (EPA(b), 1995; North American Mfg., 1986; CAPP, 2003; Baumeister, et. al., 1978; SANGA™, 2003).

**Table 3-5. Densities, Higher Heating Values, and Carbon Contents for Various Fuels**

Fuel	Typical Density		Higher Heating Value		Lower Heating Value		Carbon, % by wt.
Aviation Gas			$5.05 \times 10^6$ Btu/bbl <sup>d</sup>	$3.35 \times 10^{10}$ J/m <sup>3</sup> <sup>d</sup>	$4.80 \times 10^6$ Btu/bbl	$3.18 \times 10^{10}$ J/m <sup>3</sup>	
Butane (liquid)	4.84 lb/gal <sup>a</sup>	$579.96 \text{ kg/m}^3$ <sup>a</sup>	$4.09 \times 10^6$ Btu/bbl <sup>a</sup>	$2.71 \times 10^{10}$ J/m <sup>3</sup> <sup>a</sup>	$3.89 \times 10^6$ Btu/bbl	$2.58 \times 10^{10}$ J/m <sup>3</sup>	83.6 <sup>b</sup>
Coal, anthracite			12,660 Btu/lb <sup>b</sup> 12,300 Btu/lb <sup>a</sup>	$2.94 \times 10^7$ J/kg <sup>b</sup> $2.86 \times 10^7$ J/kg <sup>a</sup>	12,027 Btu/lb 11,685 Btu/lb	$2.80 \times 10^7$ J/kg $2.72 \times 10^7$ J/kg	80.6 <sup>b</sup>
Coal, bituminous			14,030 Btu/lb <sup>b</sup> 13,000 Btu/lb <sup>a</sup>	$3.26 \times 10^7$ J/kg <sup>b</sup> $3.02 \times 10^7$ J/kg <sup>a</sup>	13,329 Btu/lb 12,350 Btu/lb	$3.10 \times 10^7$ J/kg $2.87 \times 10^7$ J/kg	80.1 <sup>b</sup>
Crude Oil	7.3 lb/gal <sup>a</sup>	$874.73 \text{ kg/m}^3$ <sup>a</sup>	$5.55 \times 10^6$ - $6.40 \times 10^6$ Btu/bbl <sup>d</sup>	$3.68 \times 10^{10}$ - $4.25 \times 10^{10}$ J/m <sup>3</sup> <sup>d</sup>	$5.27 \times 10^6$ - $6.08 \times 10^6$ Btu/bbl	$3.50 \times 10^{10}$ - $4.03 \times 10^{10}$ J/m <sup>3</sup>	83.7 - 86.1 <sup>c</sup>
Diesel	7.1 lb/gal <sup>a</sup>	$850.77 \text{ kg/m}^3$ <sup>a</sup>	$5.75 \times 10^6$ Btu/bbl <sup>a</sup>	$3.82 \times 10^{10}$ J/m <sup>3</sup> <sup>a</sup>	$5.46 \times 10^6$ Btu/bbl	$3.62 \times 10^{10}$ J/m <sup>3</sup>	
Distillate Oil	7.05 lb/gal <sup>a</sup>	$844.78 \text{ kg/m}^3$ <sup>a</sup>	$5.88 \times 10^6$ Btu/bbl <sup>a</sup>	$3.90 \times 10^{10}$ J/m <sup>3</sup> <sup>a</sup>	$5.59 \times 10^6$ Btu/bbl	$3.71 \times 10^{10}$ J/m <sup>3</sup>	#1: 86.6 <sup>b</sup> #2: 87.3 <sup>b</sup>
Ethane (liquid)			$2.79 \times 10^6$ Btu/bbl <sup>d</sup>	$1.85 \times 10^{10}$ J/m <sup>3</sup> <sup>d</sup>	$2.65 \times 10^6$ Btu/bbl	$1.76 \times 10^{10}$ J/m <sup>3</sup>	
Fuel Oil #4	7.59 lb/gal <sup>b</sup>	$909.48 \text{ kg/m}^3$ <sup>b</sup>	$6.01 \times 10^6$ Btu/bbl <sup>b</sup>	$3.99 \times 10^{10}$ J/m <sup>3</sup> <sup>b</sup>	$5.71 \times 10^6$ Btu/bbl	$3.79 \times 10^{10}$ J/m <sup>3</sup>	86.4 <sup>b</sup>
Gasoline	6.17 lb/gal <sup>a</sup>	$739.33 \text{ kg/m}^3$ <sup>a</sup>	$5.46 \times 10^6$ Btu/bbl <sup>a</sup>	$3.62 \times 10^{10}$ J/m <sup>3</sup> <sup>a</sup>	$5.19 \times 10^6$ Btu/bbl	$3.44 \times 10^{10}$ J/m <sup>3</sup>	85.5 <sup>b</sup>
Kerosene	6.76 lb/gal <sup>b</sup>	$810.03 \text{ kg/m}^3$ <sup>b</sup>	$5.67 \times 10^6$ Btu/bbl <sup>a</sup>	$3.76 \times 10^{10}$ J/m <sup>3</sup> <sup>a</sup>	$5.39 \times 10^6$ Btu/bbl	$3.57 \times 10^{10}$ J/m <sup>3</sup>	
Lignite			7,200 Btu/lb <sup>a</sup>	$1.67 \times 10^7$ J/kg <sup>a</sup>	6,840 Btu/lb <sup>a</sup>	$1.59 \times 10^7$ J/kg <sup>a</sup>	
LPG	4.52 lb/gal <sup>b</sup>	$541.62 \text{ kg/m}^3$ <sup>b</sup>	$3.95 \times 10^6$ Btu/bbl <sup>a</sup>	$2.62 \times 10^{10}$ J/m <sup>3</sup> <sup>a</sup>	$3.75 \times 10^6$ Btu/bbl	$2.49 \times 10^{10}$ J/m <sup>3</sup>	
Naptha	5.254 lb/gal <sup>f</sup>						83.08 wt% C <sup>f</sup>
Natural Gas (processed)	1 lb/23.8 ft <sup>3</sup> <sup>c</sup>	$0.6730 \text{ kg/m}^3$ <sup>c</sup>	1,020 Btu/ft <sup>3</sup> <sup>c</sup> 1,004 Btu/ft <sup>3</sup> <sup>d</sup>	$3.80 \times 10^7$ J/m <sup>3</sup> <sup>c</sup> $3.74 \times 10^7$ J/m <sup>3</sup> <sup>d</sup>	918 Btu/ft <sup>3</sup> 903 Btu/ft <sup>3</sup>	$3.42 \times 10^7$ J/m <sup>3</sup> $3.37 \times 10^7$ J/m <sup>3</sup>	76 wt% C <sup>c</sup>
Natural Gas (raw / unprocessed)			1,235 Btu/ft <sup>3</sup> <sup>d</sup>	$4.60 \times 10^7$ J/m <sup>3</sup> <sup>d</sup>	1,111 Btu/ft <sup>3</sup>	$4.14 \times 10^7$ J/m <sup>3</sup>	
Natural Gas Liquids (NGL)			$4.14 \times 10^6$ Btu/bbl <sup>d</sup>	$2.75 \times 10^{10}$ J/m <sup>3</sup> <sup>d</sup>	$3.94 \times 10^6$ Btu/bbl	$2.61 \times 10^{10}$ J/m <sup>3</sup>	
Petroleum Coke			12,690 Btu/lb <sup>b</sup>	$2.95 \times 10^7$ J/kg <sup>b</sup>	12,056 Btu/lb	$2.80 \times 10^7$ J/kg	85.0 <sup>b</sup>
Propane (liquid)	4.24 lb/gal <sup>a</sup>	$508.06 \text{ kg/m}^3$ <sup>a</sup>	$3.80 \times 10^6$ Btu/bbl <sup>a</sup>	$2.52 \times 10^{10}$ J/m <sup>3</sup> <sup>a</sup>	$3.61 \times 10^6$ Btu/bbl	$2.40 \times 10^{10}$ J/m <sup>3</sup>	81.6 <sup>b</sup>
Residual Oil #5	7.93 lb/gal <sup>b</sup>	$950.22 \text{ kg/m}^3$ <sup>b</sup>	$6.30 \times 10^6$ Btu/bbl <sup>b</sup>	$4.18 \times 10^{10}$ J/m <sup>3</sup> <sup>b</sup>	$5.99 \times 10^6$ Btu/bbl	$3.97 \times 10^{10}$ J/m <sup>3</sup>	88.7 <sup>b</sup>
Residual Oil #6	8.45 lb/gal <sup>b</sup>	$1012.53 \text{ kg/m}^3$ <sup>b</sup>	$6.43 \times 10^6$ Btu/bbl <sup>b</sup>	$4.27 \times 10^{10}$ J/m <sup>3</sup> <sup>b</sup>	$6.11 \times 10^6$ Btu/bbl	$4.05 \times 10^{10}$ J/m <sup>3</sup>	88.3 <sup>b</sup>

To convert from HHV to LHV, the assumed conversion for gaseous fuels is  $\text{LHV} = (0.9) \times (\text{HHV})$ ; for solids or liquids the assumed conversion is  $\text{LHV} = (0.95) \times (\text{HHV})$ . Note that the values presented in this table are taken from multiple sources. As a result, the inherent fuel properties and assumptions associated with each fuel may differ.

Sources:

<sup>a</sup> EPA AP-42, Appendix A, *Miscellaneous Data Conversion Factors*, 1995.

<sup>b</sup> *North American Combustion Handbook*, Volume I: Combustion Fuels, Stoichiometry, Heat transfer, Fluid Flow, Third Edition, 1986.

<sup>c</sup> EPA AP-42, Section 1.4, *Natural Gas Combustion*, 1998.

<sup>d</sup> Canadian Association of Petroleum Producers (CAPP), *Calculating Greenhouse Gas Emissions*, Table 1-5, Canadian Association of Petroleum Producers, Publication Number 2003-03, April 2003.

<sup>e</sup> Baumeister, T., Avallone, E.A., and Baumeister III, T. *Marks' Standard Handbook for Mechanical Engineers*, Eighth Edition, Section 7, Table 9, McGraw-Hill Book Company, 1978.

<sup>f</sup> SANGA™ Emissions Estimating System User's Guide, Version 3.0, Section 9.4, January 2003.

**Table 3-6. Power Output to Energy Input Conversions for Prime Movers**

Fuel/Service	Original Units	Converted Units				
	HHV Basis			LHV Basis		
	Btu/kW-hr	Btu/hp-hr	J (input)/ J (output)	Btu/kW-hr	Btu/hp-hr	J (input)/ J (output)
Coal (Anthracite) / Steam Turbine (Boiler)	11,792	8,793	3.456	11,202	8,354	3.283
Coal (Bituminous) / Steam Turbine (Boiler)	9,941	7,413	2.913	9,444	7,042	2.768
Coal (Lignite) / Steam Turbine (Boiler)	10,933	8,153	3.204	10,386	7,745	3.044
Coal (Sub-Bituminous) / Steam Turbine (Boiler)	10,354	7,721	3.034	9,836	7,335	2.883
No. 2 Fuel Oil / Combined Cycle Turbine	12,420	9,262	3.640	11,799	8,799	3.458
No. 2 Fuel Oil / Gas Turbine	14,085	10,503	4.128	13,381	9,978	3.922
No. 2 Fuel Oil / Internal Combustion Engine	10,847	8,089	3.179	10,305	7,684	3.020
No. 2 Fuel Oil / Steam Turbine (Boiler)	8,653	6,453	2.536	8,220	6,130	2.409
Gasoline / Industrial Engine <sup>a</sup>	9,387 (converted)	7,000 (original units)	2.751	8,918	6,650	2.614
Natural Gas / Combined Heat and Power <sup>b</sup>	5,000 - 6,000	3,729 - 4,474	1.465 - 1.758	4,750 – 5,700	3,542 – 4,250	1.392 – 1.671
Natural Gas / Combined Cycle Steam Turbine with Supplemental Firing	10,229	7,628	2.998	9,206	6,865	2.698
Natural Gas / Combined Cycle Single Shaft	8,952	6,676	2.624	8,057	6,008	2.361
Natural Gas / Combined Cycle Combustion Turbine	11,648	8,686	3.414	10,483	7,817	3.072
Natural Gas / Gas Turbine	13,918	10,379	4.079	12,526	9,341	3.671
Natural Gas / Internal Combustion Engine	10,538	7,858	3.088	9,484	7,072	2.780
Natural Gas / Steam Turbine (Boiler)	10,502	7,831	3.078	9,452	7,048	2.770
Liquefied Propane Gas / Gas Turbine	13,503	10,069	3.957	12,828	9,566	3.759
Liquefied Propane Gas / Steam Turbine (Boiler)	14,200	10,589	4.162	13,490	10,059	3.954
Refuse, Bagasses, non-wood / Steam Turbine (Boiler)	13,706	10,221	4.017	13,021	9,710	3.816
Wood and Wood Waste / Steam Turbine (Boiler)	15,725	11,726	4.609	14,939	11,140	4.378
Refinery Gas / Gas Turbine	15,000	11,186	4.396	13,500	10,067	3.956
Refinery Gas / Internal Combustion Engine	14,000	10,440	4.103	12,600	9,396	3.693

Sources:

EIIP, *Guidance for Emissions Inventory Development*, Volume VIII: Estimating Greenhouse Gas Emissions, EIIP Greenhouse Gas Committee, October 1999.

<sup>a</sup> EPA, AP-42, Supplements A, B, and C, Table 3.3-1, October 1996.

<sup>b</sup> Assumed output to input energy conversion based on industry best practice.

### 3.6.4 Conversion from Energy Output to Energy Input

This document has adopted an energy input basis for estimating combustion emissions. This approach is consistent with the actual fuel consumption volumes or mass rates and accounts for the loss in efficiency. Equipment vendors may specify Btu/hp-hr for a particular device to convert between power output and energy input. In the absence of this information, Table 3-6 provides conversion factors for some common combustion sources taken from EIIP (EIIP, 1999). These factors can be used to convert from a rated power output to an estimated energy input. Exhibit 3.3 demonstrates this conversion.

#### **EXHIBIT 3.3: Sample Calculation for Converting from Energy Output to Energy Input Basis Prior to Estimating Emissions**

##### **INPUT DATA:**

A 100-hp gasoline fired internal combustion engine is operated for 8,000 hours at 90% load during the reporting year.

##### **CALCULATION METHODOLOGY:**

The power output is converted to an energy input basis using a conversion factor of 7,000 Btu/hp-hr (HHV basis) from Table 3-6.

$$100 \text{ hp} \times 0.90 \times \frac{8000 \text{ hr}}{\text{yr}} \times \frac{7000 \text{ Btu}}{\text{hp} \cdot \text{hr}} = 5040 \times 10^6 \text{ Btu/yr (HHV)}$$

The calculation is repeated below to illustrate the use of the conversion factor in SI units. First, the power output must be converted to energy output using a conversion factor from Table 3-2.

$$100 \text{ hp} \times 0.90 \times \frac{8000 \text{ hr}}{\text{yr}} \times \frac{2.68452 \times 10^6 \text{ J}}{\text{hp} \cdot \text{hr}} = 1.933 \times 10^{12} \text{ J (output)/yr}$$

Next, the energy output basis is converted to an input basis using a conversion factor of 2.751 J (input) / J (output) from Table 3-6.

$$1.933 \times 10^{12} \text{ J (output)/yr} \times \frac{2.751 \text{ J (input)}}{\text{J (output)}} = 5.318 \times 10^{12} \text{ J (input)/yr (HHV)}$$

### 3.6.5 Conversion from Weight Percents to Mole Percents in Mixtures

Some of the emission estimation methodologies described in Sections 4 through 6 require a material balance approach using fuel compositions on a molar basis. This section describes and illustrates through an exhibit calculation how to convert a fuel composition from a weight basis to a molar basis.

The weight percent composition of a mixture is converted to a mole percent composition by multiplying the individual weight percentages (Wt%<sub>i</sub>) by the ratio of the molecular weight of the mixture (MW<sub>Mixture</sub>) to the individual molecular weights (MW<sub>i</sub>):

$$\text{Mole}\%_i = \text{Wt}\%_i \times \frac{\text{MW}_{\text{Mixture}}}{\text{MW}_i} \quad (\text{Equation 3-7})$$

If complete speciation is available for the mixture, MW<sub>Mixture</sub> can be calculated as the weighted average of the individual molecular weights:

$$\text{MW}_{\text{Mixture}} = \frac{1}{100} \times \sum_{i=1}^{\text{\# compounds}} (\text{Mole}\%_i \times \text{MW}_i) \quad (\text{Equation 3-8})$$

Or, in terms of Wt%:

$$\text{MW}_{\text{Mixture}} = 100 \div \sum_{i=1}^{\text{\# compounds}} \frac{\text{Wt}\%_i}{\text{MW}_i} \quad (\text{Equation 3-9})$$

If complete speciation of the mixture is not available, MW<sub>Mixture</sub> can sometimes be obtained from chemical property tables that list data for common petroleum fractions (e.g., gasoline, No.2 distillate, etc.).

Table 3-7 provides the molecular weight values used in the *Compendium* calculations for various hydrocarbon compounds.

**Table 3-7. Hydrocarbon Molecular Weights**

Compound		Molecular Weight
Methane	CH <sub>4</sub>	16.04
Ethane	C <sub>2</sub> H <sub>6</sub>	30.07
Propane	C <sub>3</sub> H <sub>8</sub>	44.10
Butanes	C <sub>4</sub> H <sub>10</sub>	58.12
Pentanes	C <sub>5</sub> H <sub>12</sub>	72.15
Hexanes	C <sub>6</sub> H <sub>14</sub>	86.18
Heptanes	C <sub>7</sub> H <sub>16</sub>	100.21
Octanes	C <sub>8</sub> H <sub>18</sub>	114.23
C9+	C <sub>9</sub> H <sub>20</sub>	156.31 (MW of C <sub>11</sub> H <sub>24</sub> )

The category "C9+" includes molecules with 9 or more carbon atoms. Because "C9+" includes a group of compounds, an assumption must be made for the molecular weight based on specific knowledge of the liquid. The *Compendium* assumes that the "C9+" is best represented by the C11 alkane. Thus, the molecular weight for C<sub>11</sub>H<sub>24</sub> will be used for "C9+".

The following exhibits illustrate the conversion calculations between weight percent compositions and mole percent compositions.

**EXHIBIT 3.4: Sample Calculation for Converting from Weight Percent to Mole Percent For Known Fuel Analysis**

**INPUT DATA:**

A chemical analysis is taken for a liquid fuel sample. The analysis shows that the sample contains the following compounds on a weight basis. Molecular weights from Table 3-7 are also shown.

<u>Compound</u>	<u>Weight %</u>	<u>Molecular Weight</u>
Methane	0.5	16.04
Ethane	1.0	30.07
Propane	2.0	44.10
Butanes	3.0	58.12
Pentanes	7.0	72.15
Hexanes	10.0	86.18
Heptanes	25.0	100.21
Octanes	30.0	114.23
C9+	21.5	156.31

**EXHIBIT 3.4: Sample Calculation for Converting from Weight Percent to Mole Percent For Known Fuel Analysis, continued**

**CALCULATION METHODOLOGY:**

For this example, the common mass basis of 100 grams of liquid will be used to convert from the weight basis provided above to a molar basis.

First, calculate the molecular weight of the mixture ( $MW_{\text{Mixture}}$ ), using Equation 3-9:

$$MW_{\text{Mixture}} = 100 \div \left( \frac{0.5}{16.04} + \frac{1}{30.07} + \frac{2}{44.10} + \frac{3}{58.12} + \frac{7}{72.15} + \frac{10}{86.18} + \frac{25}{100.21} + \frac{30}{114.23} + \frac{21.5}{156.31} \right) = 97.65$$

Using Equation 3-7, calculate the individual compound mole %'s. For example, for hexane:

$$\text{Mole}\%_{\text{Hexane}} = 10 \times \frac{97.65}{86.18} = 11.33 \%$$

Repeat this calculation for the remaining compounds. The mole% composition results are shown below.

<u>Compound</u>	<u>Weight, grams</u>	<u>Molecular Weight</u>	<u>Mole %</u>
Methane	0.5	16.04	3.04
Ethane	1.0	30.07	3.25
Propane	2.0	44.10	4.43
Butanes	3.0	58.12	5.04
Pentanes	7.0	72.15	9.47
Hexanes	10.0	86.18	11.33
Heptanes	25.0	100.21	24.36
Octanes	30.0	114.23	25.64
C9+	21.5	156.31	13.43
	100		100

The previous example illustrates how to convert the weight fraction of compounds in a liquid fuel mixture to molar fractions. This methodology would also apply to solid and gaseous fuel mixtures. In gaseous mixtures, mole percents and volume percents are often used interchangeably when the mixture is assumed to be an ideal gas.



### EXHIBIT 3.5: Sample Calculation for Converting from Weight Percent to Mole Percent For Unknown Fuel Analysis

#### INPUT DATA:

The molecular weight of a mixture is known to be 97.65 grams/gmole, and the concentration of only the CH<sub>4</sub> is known (0.5 weight % CH<sub>4</sub>). What is the mole % of CH<sub>4</sub>?

#### CALCULATION METHODOLOGY:

Using Equation 3-7:

$$\text{Mole \% of CH}_4 = \frac{0.5 \text{ g CH}_4}{100 \text{ g mixture}} \times \frac{\left( \frac{97.65 \text{ g mixture}}{\text{gmole mixture}} \right)}{\left( \frac{16.04 \text{ g CH}_4}{\text{gmole CH}_4} \right)} = \frac{0.0304 \text{ gmole CH}_4}{\text{gmole mixture}} = 3.04 \text{ mole \% CH}_4$$

Similarly, the CH<sub>4</sub> weight % can be calculated by re-arranging Equation 3-7 if only the mixture molecular weight (97.65 g/gmole) and CH<sub>4</sub> mole percent (3.04 %) are known:

$$\text{Wt. \% of CH}_4 = \frac{3.04 \text{ gmole CH}_4}{100 \text{ gmole mixture}} \times \frac{\left( \frac{16.04 \text{ g CH}_4}{\text{gmole CH}_4} \right)}{\left( \frac{97.65 \text{ g mixture}}{\text{gmole mixture}} \right)} = \frac{0.00499 \text{ g CH}_4}{\text{g mixture}} = 0.5 \text{ wt. \% CH}_4$$

## 3.7 Emission Factor Quality

This *Compendium* reports emission factor quality data where available from the source documents cited. A number of emission factors are taken from two publication series which present different methods of assessing emission factor quality: EPA's AP-42 publication series (EPA, 1995 with Supplements through 2000) and the *Methane Emissions from the Natural Gas Industry* report series (Harrison, et. al, 1996). The different approaches are discussed in this section.

### 3.7.1 Quality Ratings

EPA's AP-42 publication series provides emission factor quality ratings. The Introduction of the Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources characterizes emission factor ratings as follows (EPA, 1995):

- A = Excellent. Emission factor is developed primarily from A- and B-rated source test data taken from many randomly chosen facilities in the industry population. The source category population is sufficiently specific to minimize variability.
- B = Above average. Emission factor is developed primarily from A- or B-rated test data from a moderate number of facilities. Although no specific bias is evident, is not clear if the facilities tested represent a random sample of the industry. As with the A rating, the source category population is sufficiently specific to minimize variability.
- C = Average. Emission factor is developed primarily from A-, B-, and C-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. As with the A rating, the source category population is sufficiently specific to minimize variability.
- D = Below average. Emission factor is developed primarily from A-, B- and C-rated test data from a small number of facilities, and there may be reason to suspect that these facilities do not represent a random sample of the industry. There also may be evidence of variability within the source population.
- E = Poor. Factor is developed from C- and D-rated test data from a very few number of facilities, and there may be reason to suspect that the facilities tested do not represent a random sample of the industry. There also may be evidence of variability within the source category population.
- U = Unrated. Emission factor is developed from source tests which have not been thoroughly evaluated, research papers, modeling data, or other sources that may lack supporting documentation. The data are not necessarily "poor," but there is not enough information to rate the factors according to the rating protocol. "U" ratings are commonly found in L&E documents and FIRE rather than in AP-42.

Combustion emission factors reported in Compendium Section 4.0 which are taken from EPA's AP-42 publications, cite these ratings which correspond to the reported emission factors.

### 3.7.2 Confidence Intervals

The Gas Technology Institute (formerly Gas Research Institute) and EPA conducted a study in the early to mid 1990's to quantify CH<sub>4</sub> emissions from the US natural gas industry. A sampling program was designed to address precision, bias, and accuracy calculations, with an inventory accuracy objective of 0.5% of US production on the basis of a 90% confidence interval (Harrison,

et. al., 1996). A brief summary of the statistical methods employed by the GTI study is provided in this section. Additional details can be found in the documents: *Methane Emissions from the Natural Gas Industry*, Volume 3: General Methodology and Volume 4: Statistical Methodology (Harrison, et. al., 1996; and Williamson, et. al, 1996).

Confidence intervals establish the lower and upper tolerances associated with an estimated number. The confidence interval, expressed as an absolute value, is computed as:

$$\pm t \times \frac{s}{\sqrt{n}} \quad (\text{Equation 3-10})$$

where:

- n = Sample size.
- t = t-value for “n-1” degrees of freedom. This value is obtained from a standard table in most statistics books and is a function of the confidence level (90% for the GRI/EPA study) and the sample size.
- s = standard deviation.

and

$$s = \sqrt{\frac{\sum_{i=1}^n (e_i - e_{\text{avg.}})^2}{n - 1}} \quad (\text{Equation 3-11})$$

$e_i$  represents the  $i$ th emission factor.  
 $e_{\text{avg.}}$  represents the average emission factor.

In *Compendium* Sections 5 and 6, confidence intervals are expressed in terms of precision where emissions factors from the GTI study are cited. Additional details on the derivation of the confidence intervals are provided in Appendix B. Guidance in inventory uncertainties are available from the following sources:

- EPA. *Procedures Manual for Quality Assurance/Quality Control and Uncertainty Analysis*, US Environmental Protection Agency, Office of Atmospheric Programs, EPA 430-R-02-007B, 2000.  
<http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissions.html>
- WRI/WBCSD. *GHG Protocol guidance on uncertainty assessment in GHG inventories and calculating statistical parameter uncertainty* and associated calculation tool.  
<http://www.ghgprotocol.org/standard/tools.htm>

- ISO. *Guide to the Expression of Uncertainty in Measurement*, International Organization for Standardization, Geneva, Switzerland, 1993. <http://www.iso.ch>
- IPCC. *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*. Intergovernmental Panel on Climate Change, 2000. <http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm>

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Baumeister, T., Avallone, E.A., and Baumeister III, T. *Marks' Standard Handbook for Mechanical Engineers*, Eighth Edition, Section 7, Table 9, McGraw-Hill Book Company, 1978. <http://www.mcgraw-hill.com>

Canadian Association of Petroleum Producers (CAPP), *Calculating Greenhouse Gas Emissions*, Table 1-5, Canadian Association of Petroleum Producers, Publication Number 2003-03, April 2003. <http://www.capp.ca>

CRC Press, Inc. *CRC Handbook of Chemistry and Physics*, 65th Edition, 1984. [www.crcpress.com](http://www.crcpress.com)

Emission Inventory Improvement Program (EIIP). *Guidance for Emissions Inventory Development*, Volume VIII: Estimating Greenhouse Gas Emissions, EIIP Greenhouse Gas Committee, October 1999. (Cited Table 1.5-2 for average heat rates for prime movers.) <http://www.epa.gov/ttnchie1/eiip/index.html>

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of the Intergovernmental Panel on Climate Change [Watson, R.T. and the Core Writing Team (eds.)]. Cambridge University Press, Cambridge, United Kingdom, and New York, NY, USA, 2001. <http://www.ipcc.ch/pub/reports.htm>

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United Nations Framework Convention on Climate Change (UNFCCC). *Report of the Conference of the Parties on its eighth session, held at New Delhi from 23 October to 1 November 2002*, Guidelines for the preparation of national communications by Parties included in Annex I to the Convention, part I: UNFCCC reporting guidelines on annual inventories, Decision /CP.8, 2002. [http://unfccc.int/cop8/latest/5\\_sbstal5add1.pdf](http://unfccc.int/cop8/latest/5_sbstal5add1.pdf)

US Environmental Protection Agency. *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources*, AP-42, Section 1.4: Natural Gas Combustion and Appendix A: miscellaneous Data and Conversion Factors, (GPO 055-000-005-001), US EPA Office of Air Quality Planning and Standards, Fifth Edition, January 1995, with Supplements A, B, and C, October 1996, Supplement D, 1998, and Supplement F, 2000. <http://www.epa.gov/ttn/chief/ap42/index.html>

US Environmental Protection Agency. *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources*, AP-42, (GPO 055-000-005-001), US EPA Office of Air Quality Planning and Standards, Supplement D, July 1998. <http://www.epa.gov/ttn/chief/ap42/index.html>

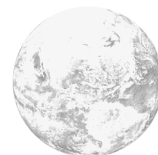
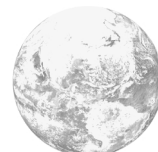
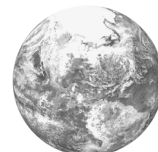
US Environmental Protection Agency. *Inventory of US Greenhouse Gas Emissions and Sinks: 1990 – 2001*. Final Version, EPA 430-R-03-004, US EPA, Washington DC, April 2003. <http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2003.html>

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FEBRUARY 2004

**COMPENDIUM OF GREENHOUSE GAS  
EMISSIONS METHODOLOGIES FOR  
THE OIL AND GAS INDUSTRY**

SECTION 4



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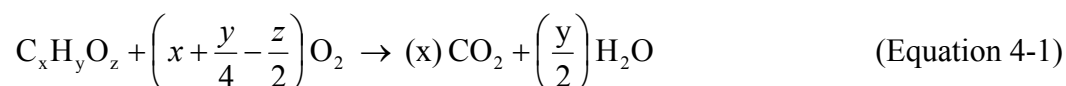
## 4.0

# COMBUSTION EMISSIONS ESTIMATION METHODS

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This section addresses combustion emissions from stationary sources, mobile sources, flares, and other miscellaneous combustion sources. The approaches presented here are applicable to any combustion source utilizing hydrocarbon fuels.

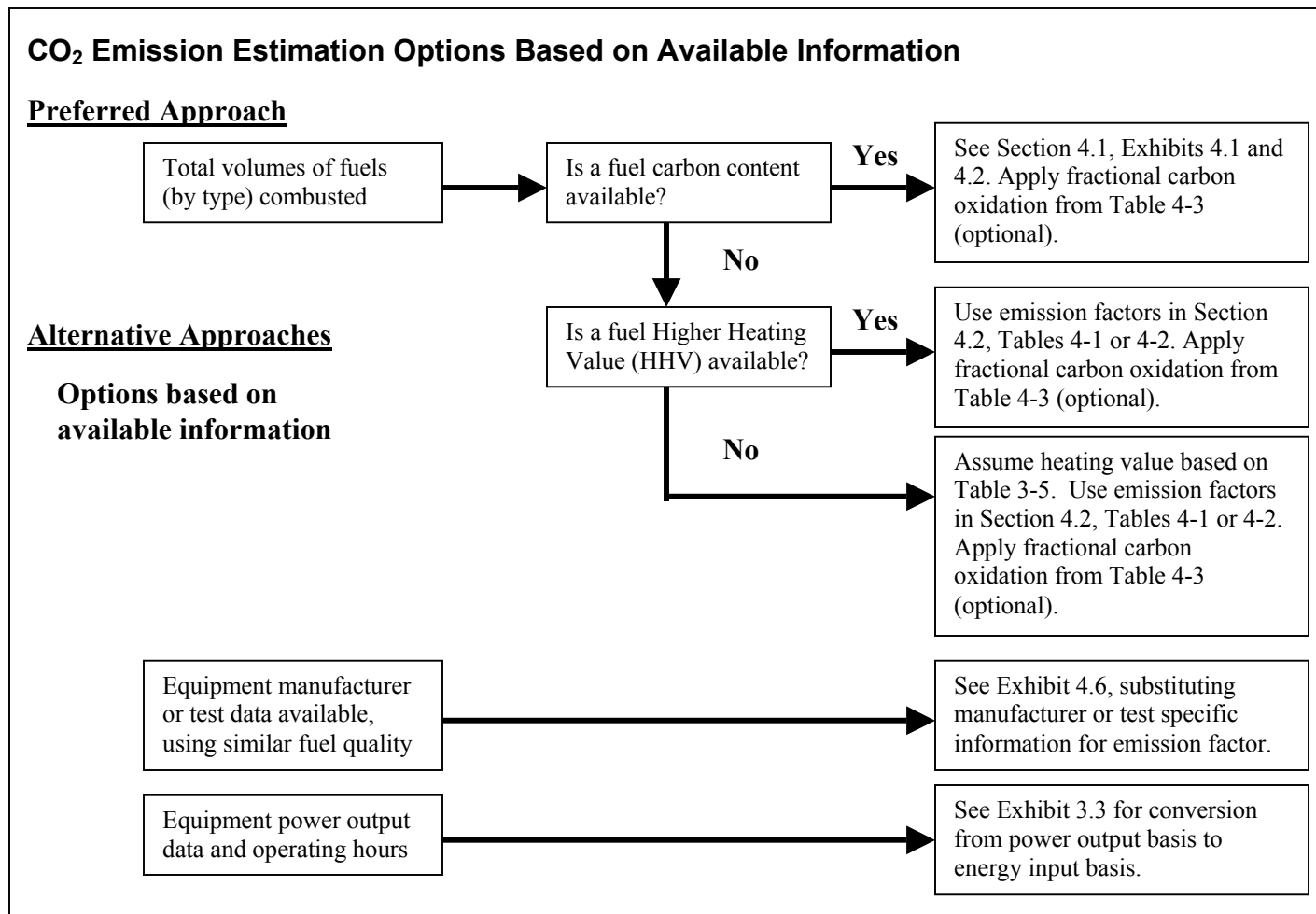
Carbon dioxide (CO<sub>2</sub>), methane (CH<sub>4</sub>), and nitrous oxide (N<sub>2</sub>O) are produced and/or emitted as a result of hydrocarbon combustion. Combustion of hydrocarbons can be represented by the following general reaction, assuming complete combustion:



Carbon dioxide emissions result from the oxidation of the hydrocarbons during combustion. Nearly all of the fuel carbon is converted to CO<sub>2</sub> during the combustion process, and this conversion is relatively independent of the fuel or firing configuration. Methane emissions may result due to incomplete combustion of the fuel gas, which is emitted as unburned CH<sub>4</sub>. Incomplete combustion also results in other products such as carbon monoxide (CO) and volatile organic compounds (VOC).

For petroleum industry operations, N<sub>2</sub>O is formed during combustion by a complex series of reactions. Because its formation is dependent upon many factors, N<sub>2</sub>O emissions can vary widely from unit to unit, and even vary within the same unit based on different operating conditions. Typically the conditions that favor formation of N<sub>2</sub>O also favor CH<sub>4</sub> emissions, such that CH<sub>4</sub> emissions also vary with the type of fuel and firing configuration. Overall, CH<sub>4</sub> and N<sub>2</sub>O emissions from combustion sources are significantly less than CO<sub>2</sub> emissions. (Methane and N<sub>2</sub>O emissions for stationary combustion sources are calculated separately using emission factors. See Section 4.3).

Figure 4-1 provides a decision tree for selecting a stationary combustion calculation approach for estimating CO<sub>2</sub> emissions. The decision tree is presented in terms of a preferred approach and alternative approach(es), based on the type of information available.



**Figure 4-1. Calculating CO<sub>2</sub> Emissions from Stationary Combustion Sources**

For CO<sub>2</sub> emissions from stationary combustion sources, the preferred approach relies on a measurement program to obtain the fuel consumption rate (in terms of mass or volume) and the fuel composition (i.e., carbon content). If such information is not available, manufacturer data, device specific testing, or published emission factors are provided as alternative approaches. In applying published emission factors for estimating CO<sub>2</sub> emissions, emission factors provided in terms of tonnes per quantity of fuel consumed or tonnes per energy consumption of a given fuel are generally more accurate than equipment based emission factors.

For CH<sub>4</sub> emissions, the preferred approach is to use published emission factors which incorporate a default fuel composition and CH<sub>4</sub> destruction efficiency based on the equipment type. These factors are discussed further in Section 4.3 for typical stationary combustion equipment, Section 4.4 for flares, and Section 4.5 for mobile sources.

Published emission factors are also the preferred approach for N<sub>2</sub>O emissions from combustion sources. Where available, average N<sub>2</sub>O emission factors based on reported test data are provided in Section 4.3 for typical stationary combustion equipment, Section 4.4 for flares, and Section 4.5 for mobile sources.

#### **4.1 Fuel Combustion Emissions Estimated from Fuel Composition and Usage**

A material balance approach, based on fuel usage data and fuel carbon analyses, is the preferred technique for estimating emissions from stationary combustion sources. This Compendium has also adopted an assumption of complete combustion (i.e., 100% of the fuel carbon combusts to form CO<sub>2</sub>) as the preferred approach in estimating CO<sub>2</sub> emissions. This assumption applies to most combustion sources, with the exception of flares (see Section 4.4).

Other protocols apply a fractional conversion of carbon to estimate CO<sub>2</sub> emissions from combustion sources. This section addresses the use of carbon oxidation values as an optional, alternative approach.

In addition to estimating CO<sub>2</sub> emissions based on 100% oxidation of fuel carbon,<sup>1</sup> the Compendium estimates CH<sub>4</sub> emissions from combustion sources based on emission factors. This approach does not double count GHG emissions because, under IPCC convention, the global warming potential for CH<sub>4</sub> does not include the indirect conversion of CH<sub>4</sub> to CO<sub>2</sub>.

As illustrated in the following examples, the preferred calculation approach for stationary combustion emissions estimates CO<sub>2</sub> emissions based on fuel composition and consumption rate, independent of the type of equipment. Exhibit 4.1 first demonstrates the scenario where the fuel composition is known. The calculation is also shown for a case where complete composition data are not available, but fuel carbon content and molecular weight are known.

---

<sup>1</sup> The carbon oxidation factor is intended to reflect carbon that is emitted as soot or ash.

**EXHIBIT 4.1(a): Sample Calculation for Fuel Basis (Gas Fuel) Combustion Emissions****INPUT DATA:**

800 million ( $10^6$ ) scf/year of natural gas is burned in a combustion device or group of devices. The gas composition for the fuel is known from measurements. Calculate the annual CO<sub>2</sub> emissions.

**(a) Known: Fuel Composition**

The gas composition is given below. The weight percents of the fuel components are calculated from the molar composition. (See Exhibit 3.4 for a similar example of this conversion.)

	<u>Mole %</u>	<u>MW</u>	<u>Wt% (Calculated)</u>
CO <sub>2</sub>	0.8	44	2.1
CH <sub>4</sub>	95.3	16	90.6
C <sub>2</sub> H <sub>6</sub>	1.7	30	3.0
C <sub>3</sub> H <sub>8</sub>	0.5	44	1.3
C <sub>4</sub> H <sub>10</sub>	0.1	58	0.3
N <sub>2</sub>	1.6	28	2.7
<b>Fuel Mixture</b>	<b>100</b>	<b>16.84</b>	<b>100.0</b>

**CALCULATION METHODOLOGY:**

The carbon content of the fuel mixture is a weighted average of the individual component carbon contents. This is determined by first calculating the wt% carbon of each of the fuel components, which is the molecular weight of carbon (12 lb/lbmole) times the number of moles of carbon and divided by the molecular weight of the compound. This is shown below for ethane (C<sub>2</sub>H<sub>6</sub>).

$$\frac{12 \text{ lb C}}{1 \text{ lbmole C}} \times \frac{2 \text{ lbmoles C}}{1 \text{ lbmole C}_2\text{H}_6} \times \frac{1 \text{ lbmole C}_2\text{H}_6}{30 \text{ lb C}_2\text{H}_6} = \underline{0.8 \text{ lb C/lb C}_2\text{H}_6}$$
$$\times 100\% = \underline{80\% \text{ C}}$$

Applying this approach to the other compounds results in the following:

	<u>Wt% (Calculated)</u>	<u>Carbon Content (Wt% C)</u>
CO <sub>2</sub>	2.1	27.3
CH <sub>4</sub>	90.6	75.0
C <sub>2</sub> H <sub>6</sub>	3.0	80.0
C <sub>3</sub> H <sub>8</sub>	1.3	81.8
C <sub>4</sub> H <sub>10</sub>	0.3	82.8
N <sub>2</sub>	2.7	0
<b>Fuel Mixture</b>	<b>100.0</b>	<b>72.24</b>

**EXHIBIT 4.1(a): Sample Calculation for Fuel Basis (Gas Fuel) Combustion Emissions, continued**

The carbon content of the fuel mixture is then calculated as:

$$\begin{aligned}\text{Wt}\%C_{\text{Mixture}} &= \frac{1}{100} \times \sum_{i=1}^{\text{\# components}} (\text{Wt}\%_i \times \text{Wt}\%C_i) \\ &= \frac{1}{100} \times [(2.1 \times 27.3) + (90.6 \times 75) + (3 \times 80) + (1.3 \times 81.8) + (0.3 \times 82.8) + (2.7 \times 0)] \\ &= \underline{72.24 \text{ Wt}\% C} = 0.7224 \text{ lb C/lb fuel}\end{aligned}$$

Using the information above and the specified fuel usage, the annual CO<sub>2</sub> emissions are calculated as shown:

$$\begin{aligned}\frac{800 \times 10^6 \text{ scf fuel}}{\text{yr}} \times \frac{\text{lbmole}}{379.3 \text{ scf fuel}} \times \frac{16.84 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.7224 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12 \text{ lb C}} \times \frac{\text{lbmole CO}_2}{\text{lbmole C}} \\ \times \frac{44 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = \underline{42,674 \text{ tonnes CO}_2 / \text{yr}}\end{aligned}$$

**EXHIBIT 4.1(b): Sample Calculation for Fuel Basis (Gas Fuel) Combustion Emissions**

**INPUT DATA:**

22 million (10<sup>6</sup>) cubic meters per year of natural gas are burned in a combustion device or group of devices. The molecular weight and carbon content of the gas are known. Calculate the annual CO<sub>2</sub> emissions.

**(b) Known (or assumed): Molecular Weight (MW) and Fuel Carbon Content**

$$\text{MW} = 17.4$$

$$\text{Wt}\% \text{ C} = 76.2$$

**CALCULATION METHODOLOGY:**

Assuming 100% of the carbon in the fuel forms CO<sub>2</sub>, the CO<sub>2</sub> emissions are calculated as shown:

$$\begin{aligned}\frac{22 \times 10^6 \text{ m}^3 \text{ fuel}}{\text{yr}} \times \frac{\text{gmole fuel}}{0.022414 \text{ m}^3 \text{ fuel}} \times \frac{17.4 \text{ g fuel}}{\text{gmole fuel}} \times \frac{76.2 \text{ g C}}{100 \text{ g fuel}} \times \frac{\text{gmole C}}{12 \text{ g C}} \times \frac{\text{gmole CO}_2}{\text{gmole C}} \\ \times \frac{44 \text{ g CO}_2}{\text{gmole CO}_2} \times \frac{\text{tonnes}}{10^6 \text{ g}} = \underline{47,718 \text{ tonnes CO}_2 / \text{yr}}\end{aligned}$$

For a liquid fuel, Exhibit 4.2 demonstrates the preferred emission calculation approach for a case where the fuel carbon content, density, and heating value are known.

#### **EXHIBIT 4.2: Sample Calculation for Fuel Basis (Liquid Fuel) Combustion Emissions**

##### **INPUT DATA:**

4 million ( $10^6$ ) gallons per year of No. 6 residual fuel is burned in a combustion device or group of devices. Calculate the annual CO<sub>2</sub> emissions for a site where detailed fuel information is known.

##### **Known (or assumed): Density and Fuel Carbon Content**

Liquid Density = 8.3 lb/gallon

Wt% C = 92.3

##### **CALCULATION METHODOLOGY:**

The CO<sub>2</sub> emissions are calculated, based on the density and carbon content, as shown:

$$\begin{aligned} \frac{4 \times 10^6 \text{ gal. fuel}}{\text{year}} \times \frac{8.3 \text{ lb fuel}}{\text{gal. fuel}} \times \frac{92.3 \text{ lb C}}{100 \text{ lb fuel}} \times \frac{1 \text{ lbmol C}}{12 \text{ lb C}} \times \frac{1 \text{ lbmol CO}_2}{1 \text{ lbmol C}} \times \frac{44 \text{ lb CO}_2}{1 \text{ lbmol CO}_2} \times \frac{\text{tonnes}}{2204.62 \text{ lb}} \\ = \underline{50,966 \text{ tonnes CO}_2 / \text{yr}} \end{aligned}$$

## **4.2 Fuel Combustion Emissions Estimated on a Fuel Basis for Stationary Sources**

If only the facility fuel consumption rate is known, and a fuel carbon analysis is not available, emission factors based on average fuel compositions can be used to estimate combustion emissions. Table 4-1 lists emission factors for common fuel types used in petroleum operations, while Table 4-2 lists more specialized and less common fuels. These emission factors are appropriate for both external combustion (e.g., boilers and heaters) as well as internal combustion (e.g., engines and turbines).

Note that this approach only provides CO<sub>2</sub> emission factors. Methane and N<sub>2</sub>O emissions from combustion must be calculated separately (See Section 4.3).

**Table 4-1. CO<sub>2</sub> Combustion Emission Factors (Fuel Basis) for Common Industry Fuel Types**

Fuel	Carbon Emission Factor from Original Source Document			CO <sub>2</sub> Emission Factor <sup>a</sup> , US Units		CO <sub>2</sub> Emission Factor <sup>a</sup> , SI Units	
		Emission Factor	Source	tonnes/10 <sup>6</sup> Btu (LHV)	tonnes/10 <sup>6</sup> Btu (HHV)	tonnes/10 <sup>12</sup> J (LHV)	tonnes/10 <sup>12</sup> J (HHV)
Aviation Gas	18.87	MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.0728	0.0692	69.0	65.6
Bitumen	22.0	tonne C/10 <sup>12</sup> J (LHV)	Table 1-1, IPCC, 1996	0.0851	0.0809	80.7	76.6
Coke (Coke Oven/Gas Coke)	29.5	tonne C/10 <sup>12</sup> J (LHV)	Table 1-1, IPCC, 1996	0.1141	0.1084	108.2	102.8
Crude Oil	20.29	MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.0783	0.0744	74.2	70.5
Diesel/Gas Oil	20.2	tonne C/10 <sup>12</sup> J (LHV)	Table 1-1, IPCC, 1996	0.0781	0.0742	74.1	70.4
Distillate Fuel	19.95	MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.0770	0.0732	73.0	69.3
Electric Utility Coal	25.98	MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.1003	0.0953	95.0	90.3
Ethanol	0.07	tonne CO <sub>2</sub> /10 <sup>6</sup> Btu	Texaco, 1999	0.0737	0.0700	69.8	66.3
Flexicoker Low Btu Gas	278	lb CO <sub>2</sub> /10 <sup>6</sup> Btu (LHV)	Petroleum Industry Data	0.1261	0.1135	119.5	107.6
Fuel Oil #4	45.8	lb C/10 <sup>6</sup> Btu	Derived from fuel property data in Table 3-5	0.0802	0.0762	76.0	72.2
Jet Fuel	19.33	MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.0746	0.0709	70.7	67.2
Kerosene/Aviation Kerosene	19.72	MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.0761	0.0723	72.1	68.5
Lignite	26.3	MMTC/10 <sup>15</sup> Btu	Table B2, EIA, 2002	0.1015	0.0964	96.2	91.4
LPG	16.99	MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.0656	0.0623	62.2	59.0
Butane	17.75	MMTC/10 <sup>15</sup> Btu	Table B9, EIA, 2002	0.0685	0.0651	64.9	61.7
Ethane	16.25	MMTC/10 <sup>15</sup> Btu	Table B9, EIA, 2002	0.0627	0.0596	59.4	56.5
Propane	17.2	MMTC/10 <sup>15</sup> Btu	Table B9, EIA, 2002	0.0664	0.0631	62.9	59.8
Motor Gasoline (Petrol)	19.34	MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.0746	0.0709	70.8	67.2
Naphtha (<104°F)	40.0	lb C/10 <sup>6</sup> Btu	Table 1.4-3, EIIP, 1999	0.0700	0.0665	66.4	63.1



**Table 4-1. CO<sub>2</sub> Combustion Emission Factors (Fuel Basis) for Common Industry Fuel Types (continued)**

Fuel	Carbon Emission Factor from Original Source Document		CO <sub>2</sub> Emission Factor <sup>a</sup> , US Units		CO <sub>2</sub> Emission Factor <sup>a</sup> , SI Units	
	Emission Factor	Source	tonnes/10 <sup>6</sup> Btu (LHV)	tonnes/10 <sup>6</sup> Btu (HHV)	tonnes/10 <sup>12</sup> J (LHV)	tonnes/10 <sup>12</sup> J (HHV)
Nat. Gas Liquids	17.2 tonne C/10 <sup>12</sup> J (LHV)	Table 1-1, IPCC, 1996	0.0665	0.0632	63.1	59.9
Natural Gas (Pipeline) <sup>b</sup>	14.47 MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.0590	0.0531	55.9	50.3
Natural Gas (Flared)	14.92 MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.0608	0.0547	57.6	51.9
Other Bituminous Coal	56.0 lb C/10 <sup>6</sup> Btu	Table 1.4-3, EIIP, 1999	0.0980	0.0931	92.9	88.3
Other Oil (>104°F)	44.0 lb C/10 <sup>6</sup> Btu	Table 1.4-3, EIIP, 1999	0.0770	0.0732	73.0	69.4
Pentanes Plus	40.2 lb C/10 <sup>6</sup> Btu	Table 1.4-3, EIIP, 1999	0.0704	0.0669	66.7	63.4
Petroleum Coke	27.85 MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.1075	0.1021	101.9	96.8
Refinery Fuel Gas	139 lb CO <sub>2</sub> /10 <sup>6</sup> Btu (LHV)	Petroleum Industry Data	0.0630	0.0567	59.8	53.8
Residual Fuel	21.49 MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.0829	0.0788	78.6	74.7
Residual Oil #5	46.9 lb C/10 <sup>6</sup> Btu	Derived from fuel property data in Table 3-5	0.0821	0.0780	77.8	73.9
Residual Oil #6	48.7 lb C/10 <sup>6</sup> Btu	Derived from fuel property data in Table 3-5	0.0853	0.0811	80.9	76.8
Special Naphtha	43.8 lb C/10 <sup>6</sup> Btu	Table 1.4-3, EIIP, 1999	0.0767	0.0728	72.7	69.0
Still Gas	38.6 lb C/10 <sup>6</sup> Btu	Table 1.4-3, EIIP, 1999	0.0713	0.0642	67.6	60.8
Sub-bituminous Coal	26.48 MMTC/10 <sup>15</sup> Btu	Table B2, EIA, 2002	0.1022	0.0971	96.9	92.0
Unfinished Oils	44.6 lb C/10 <sup>6</sup> Btu	Table 1.4-3, EIIP, 1999	0.0781	0.0742	74.0	70.3

<sup>a</sup> CO<sub>2</sub> emission factors shown are based on the default Compendium assumption of 100% oxidation. Companies may wish to apply the fractional oxidation values provided in Table 4-3. To convert between higher and lower heating value emission factors, the assumed conversion for gaseous fuels is:

(EF, HHV) = (0.9) × (EF, LHV), and for solids or liquids the assumed conversion is (EF, HHV) = (0.95) × (EF, LHV).

<sup>b</sup> Natural gas carbon coefficient is based on a weighted U.S. national average.

Sources:

Energy Information Administration (EIA). *Emissions of Greenhouse Gases in the United States 2001*, DOE/EIA-0573(2001), December 2002.

Emission Inventory Improvement Program (EIIP). *Guidance for Emissions Inventory Development*, Volume VIII: Estimating Greenhouse Gas Emissions, EIIP Greenhouse Gas Committee, October 1999.

Intergovernmental Panel on Climate Change (IPCC). *Greenhouse Gas Inventory Reference Manual: IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 3, United Nations Environment Programme, the Organization for Economic Co-operation and Development, the International Energy Agency, and the Intergovernmental Panel on Climate Change, 1996.

Texaco Inc. *Establishing Texaco's Emission Inventory – A Guidance Document for Inventory Year 1998*, March 2, 1999.

**Table 4-2. CO<sub>2</sub> Combustion Emission Factors (Fuel Basis) for Specialized Fuel Types**

Fuel	Carbon Emission Factor from Original Source Document		CO <sub>2</sub> Emission Factor <sup>a</sup> , US Units		CO <sub>2</sub> Emission Factor <sup>a</sup> , SI Units	
	Emission Factor	Source	tonnes/10 <sup>6</sup> Btu (LHV)	tonnes/10 <sup>6</sup> Btu (HHV)	tonnes/10 <sup>12</sup> J (LHV)	tonnes/10 <sup>12</sup> J (HHV)
Anthracite	28.26 MMTC/10 <sup>15</sup> Btu	Table B2, EIA, 2002	0.1091	0.1036	103.4	98.2
Asphalt and Road Oil	20.62 MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.0796	0.0756	75.4	71.7
Industrial Coking Coal	25.63 MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.0989	0.0940	93.8	89.1
Lubricants	20.24 MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.0781	0.0742	74.0	70.3
Other Industrial Coal	25.74 MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.0993	0.0944	94.2	89.5
Miscellaneous Petroleum Products and Crude	7.18E-04 tonne C/L	Petroleum Industry Data	9.97E-03 tonnes CO <sub>2</sub> /gal		2.63E-03 tonnes CO <sub>2</sub> /L	
Peat	28.9 tonne C/10 <sup>12</sup> J (LHV)	Table 1-1, IPCC, 1996	0.1118	0.1062	106.0	100.7
Petrochemical Feed	19.37 MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.0748	0.0710	70.9	67.3
Residential/Commercial Coal	26.04 MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.1005	0.0955	95.3	90.5
Shale Oil	20.0 tonne C/10 <sup>12</sup> J (LHV)	Table 1-1, IPCC, 1996	0.0774	0.0735	73.3	69.7
Waxes and Miscellaneous	19.81 MMTC/10 <sup>15</sup> Btu	Table B1, EIA, 2002	0.0765	0.0726	72.5	68.8

<sup>a</sup> CO<sub>2</sub> emission factors shown are based on the default Compendium assumption of 100% oxidation. Companies may wish to apply the fractional oxidation values provided in Table 4-3. To convert between higher and lower heating value emission factors, the assumed conversion for gaseous fuels is: (EF, HHV) = (0.9) × (EF, LHV), and for solids or liquids the assumed conversion is (EF, HHV) = (0.95) × (EF, LHV).

Sources:

Energy Information Administration (EIA). *Emissions of Greenhouse Gases in the United States 2001*, DOE/EIA-0573(2001), December 2002.

Intergovernmental Panel on Climate Change (IPCC). *Greenhouse Gas Inventory Reference Manual: IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 3, United Nations Environment Programme, the Organization for Economic Co-operation and Development, the International Energy Agency, and the Intergovernmental Panel on Climate Change, 1996.

The CO<sub>2</sub> emission factors shown in Tables 4-1 and 4-2 are converted from a carbon basis (mass of carbon emitted per fuel energy input) to a CO<sub>2</sub> basis, assuming all of the carbon is oxidized to form CO<sub>2</sub> (i.e., 100% oxidation). As noted earlier, the carbon oxidation value is intended to reflect unoxidizable carbon that is emitted as a solid in soot or ash. However, some protocols apply different carbon oxidation factors. Table 4-3 lists the values recommended by several protocols for different fuel types.

**Table 4-3. Fraction of Carbon Oxidized for Fuel basis CO<sub>2</sub> Combustion Emission Factors**

Fuel	Fraction of Carbon Fuel Oxidized <sup>a</sup>		
	IPCC, 1996, Vol. 3, Table 1-6	EIA, 2002, Table A3	EIIP, 1999, Vol. VIII, Pg. 1.4-17
Coal	0.98	0.99	0.99
Petroleum Fuels <sup>b</sup>	0.99	0.99	0.99
Natural Gas <sup>c</sup>	0.995	0.995	0.995
Peat for electricity generation	0.99		
LPG		0.995	
Still Gas		0.995	
Flare Gas		1	

<sup>a</sup> The fraction of carbon fuel oxidized should be applied to the CO<sub>2</sub> emission factors provided in Tables 4-1 and 4-2, which reflect the Compendium default assumption of 100% conversion. This Compendium recommends using 100% fractional conversion for conservatism; however, companies may choose to apply the oxidation fractions above.

<sup>b</sup> IPCC labels this category as "Oil and Oil Products".

<sup>c</sup> IPCC labels this category as "Gas".

Sources:

Energy Information Administration (EIA). *Emissions of Greenhouse Gases in the United States 2001*, DOE/EIA-0573(2001), December 2002.

Emission Inventory Improvement Program (EIIP). *Guidance for Emissions Inventory Development*, Volume VIII: Estimating Greenhouse Gas Emissions, EIIP Greenhouse Gas Committee, October 1999.

Intergovernmental Panel on Climate Change (IPCC). *Greenhouse Gas Inventory Reference Manual: IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 3, United Nations Environment Programme, the Organization for Economic Co-operation and Development, the International Energy Agency, and the Intergovernmental Panel on Climate Change, 1996.

Although the Compendium recommends estimating CO<sub>2</sub> emissions from combustion based on 100% conversion of the fuel carbon to CO<sub>2</sub>, companies may choose to apply oxidation fractions to the emission factors provided in Table 4-1 and 4-2. Table 4-3 presents values for the fraction of carbon oxidized to CO<sub>2</sub> from three widely referenced sources. The oxidation factors are generally consistent, with the exception of coal. The Intergovernmental Panel on Climate Change (IPCC) recommends using a value of 0.98 for the fraction of coal oxidized (IPCC, 1996); while the Energy

Information Administration (EIA) and US Environmental Protection Agency (EPA) recommend using a value of 0.99 because coal combustors in the U.S. achieve more complete combustion than the global average reflected in the IPCC value (EIA, 2002; EIIP, 1999). For consistency, it would be appropriate to select an oxidation value corresponding to the same source document cited for the emission factors in Tables 4-1 and 4-2.

Exhibit 4.3 illustrates the use of the fuel-based emission factors for both the 100% oxidation approach, as well as for the use of carbon oxidation factors.

**EXHIBIT 4.3: Sample Calculation for Fuel Basis (Liquid Fuel) Combustion Emissions - Known (or assumed): Higher Heating Value (HHV) only**

**INPUT DATA:**

4 million ( $10^6$ ) gallons per year of No. 6 residual fuel is burned in a combustion device or group of devices. Calculate the annual  $\text{CO}_2$  emissions for a site where detailed fuel information is not available.

**CALCULATION METHODOLOGY:**

If only the fuel type is known, an emission factor can be obtained from Table 4-1. The heating value or energy content must be known or estimated for the fuel type. (Default values are provided in Table 3-5 for some fuels.)

The emission factor for residual fuel oil #6 from Table 4-1 is  $48.7 \text{ lb C}/10^6 \text{ Btu}$  (HHV). Convert this to a  $\text{CO}_2$  basis, applying the Compendium assumption of 100% carbon oxidation:

$$\frac{48.7 \text{ lb C}}{10^6 \text{ Btu}} \times \frac{1 \text{ lbmol C}}{12 \text{ lb C}} \times \frac{1 \text{ lbmol CO}_2}{1 \text{ lbmol C}} \times \frac{44 \text{ lb CO}_2}{1 \text{ lbmol CO}_2} = 178.6 \text{ lb CO}_2 / 10^6 \text{ Btu (HHV)}$$

Next, using the fuel usage data, default emission factor, and default heating value from Table 3-5, calculate the annual  $\text{CO}_2$  emissions based on 100% carbon oxidation.

$$\frac{178.6 \text{ lb CO}_2}{10^6 \text{ Btu}} \times \frac{4 \times 10^6 \text{ gal. fuel}}{\text{year}} \times \frac{\text{bbl fuel}}{42 \text{ gal. fuel}} \times \frac{6.43 \times 10^6 \text{ Btu}}{\text{bbl fuel}} = 109,371,238 \text{ lb CO}_2 / \text{yr}$$

$$\frac{109,371,238 \text{ lb CO}_2}{\text{year}} \times \frac{\text{tonnes}}{2204.62 \text{ lb}} = 49,610 \text{ tonnes CO}_2 / \text{yr}$$

Note the difference between the emission estimate calculated in Exhibit 4.2, where the fuel composition data are known, and this emission estimate based on an emission factor that incorporates a default fuel composition.

**EXHIBIT 4.3: Sample Calculation for Fuel Basis (Liquid Fuel) Combustion Emissions - Known (or assumed): Higher Heating Value (HHV) only, continued**

For comparison and illustrative purposes, the above calculation is repeated incorporating a fraction of carbon oxidized to CO<sub>2</sub>, rather than assuming 100% oxidation. According to Table 4-3, the fraction of carbon oxidized for petroleum fuels is 99%. Thus, the emissions are estimated as shown, incorporating the 99% conversion of fuel carbon to CO<sub>2</sub>:

$$\frac{48.7 \text{ lb C}}{10^6 \text{ Btu}} \times \frac{1 \text{ lbmol C}}{12 \text{ lb C}} \times \frac{0.99 \text{ lbmol CO}_2}{1 \text{ lbmol C}} \times \frac{44 \text{ lb CO}_2}{1 \text{ lbmol CO}_2} = 176.8 \text{ lb CO}_2 / 10^6 \text{ Btu (HHV)}$$

$$\frac{176.8 \text{ lb CO}_2}{10^6 \text{ Btu}} \times \frac{4 \times 10^6 \text{ gal. fuel}}{\text{year}} \times \frac{\text{bbl fuel}}{42 \text{ gal. fuel}} \times \frac{6.43 \times 10^6 \text{ Btu}}{\text{bbl fuel}} = 108,268,952 \text{ lb CO}_2 / \text{yr}$$

$$\frac{108,268,952 \text{ lb CO}_2}{\text{year}} \times \frac{\text{tonnes}}{2204.62 \text{ lb}} = 49,110 \text{ tonnes CO}_2 / \text{yr}$$

With the exception of the IPCC factors, all of the combustion emission factor sources in Tables 4-1 and 4-2 provide emission factors on a higher heating value (HHV) basis. IPCC notes that their emission factors were originally based on gross calorific value, but converted the heating values to net calorific value by assuming LHV is 5% lower than HHV for coal and oil, and 10% lower for natural gas (IPCC, Table 1-17, 1997). The IPCC emission factors in the tables above were converted back to a HHV basis using these same percentages.

Applying IPCC's convention, emission factors in Tables 4-1 and 4-2 that were originally reported on a lower heating value basis were converted to a higher heating value basis using the following equations:<sup>2</sup>

Gaseous Fuels: 
$$EF_{HHV} = (EF_{LHV}) \left( \frac{1-0.1}{1} \right) \text{mass/energy}$$

(Equations 4-2 and 4-3)

Solid/Liquid Fuels: 
$$EF_{HHV} = (EF_{LHV}) \left( \frac{1-0.05}{1} \right) \text{mass/energy}$$

<sup>2</sup> Derivation of these equations is provided in Appendix B.

Equations 4-2 and 4-3 were also used to convert any emission factors originally reported on a higher heating value basis to a lower heating value basis.

The following exhibit illustrates how to convert emission factors on an LHV basis to an HHV. The process for converting from an HHV basis to an LHV basis would be carried out in a similar manner.

**EXHIBIT 4.4:          Sample Calculation for Converting LHV to HHV**

**INPUT DATA:**

IPCC reports the heating value of natural gas liquids as 17.2 tonne C/10<sup>12</sup> J on an LHV basis. Convert to a CO<sub>2</sub> emission factor on an HHV basis.

**CALCULATION METHODOLOGY:**

Convert the heating value to HHV using Equation 4-2 and IPCC's assumption that the LHV for a liquid is 5% lower than the HHV.

$$\left( \frac{17.2 \text{ tonne C}}{10^{12} \text{ J}} \right)_{\text{LHV}} \times \left( \frac{1 - 0.05}{1} \right) = \left( \frac{16.34 \text{ tonne C}}{10^{12} \text{ J}} \right)_{\text{HHV}}$$

The emission factor units can be converted using the conversion factors presented in Table 3-2:

$$\frac{16.34 \text{ tonne C}}{10^{12} \text{ J}} \times \frac{1055.056 \text{ J}}{\text{Btu}} \times \frac{44 \text{ tonne CO}_2 / \text{tonne - mole CO}_2}{12 \text{ tonne C/tonne - mole C}} = 0.0632 \text{ tonnes CO}_2 / 10^6 \text{ Btu}$$

If the fuel input is provided on a volumetric basis (scf/yr, for example), then fuel higher heating value factors given in Table 3-5 can be used to convert the fuel volumetric rate to a fuel fired heat input rate (in Btu/year, for example). Exhibit 4.5 shows how to convert from a volumetric basis to fuel fired heat rate basis and to estimate emissions using the CO<sub>2</sub> emission factors provided in Tables 4-1 and 4-2. The calculation is performed two ways: 1) applying 100% carbon oxidation (Compendium preferred approach); and 2) using the carbon oxidation value suggested in Table 4-3.

**EXHIBIT 4.5: Sample Calculation for Combustion Emissions Fuel Basis with Unknown Carbon Analysis**

**INPUT DATA:**

800 million ( $10^6$ ) scf/year of natural gas is burned in a combustion device. Neither the fuel composition nor the heating value of the fuel is known.

**CALCULATION METHODOLOGY:**

The fuel volumetric rate is converted to heat input rate using a recommended fuel higher heating value (HHV) of 1020 Btu/scf for natural gas, given in Table 3-5 of this document. Thus, the fuel heat input rate is:

$$\frac{800 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1020 \text{ Btu}}{\text{scf}} = 8.16 \times 10^{11} \text{ Btu/yr (HHV)}$$

The CO<sub>2</sub> emission factor for natural gas from Table 4-1 is 0.0531 tonne CO<sub>2</sub>/10<sup>6</sup> Btu, HHV basis (EIIP, 1999).

Next, the CO<sub>2</sub> emissions are calculated applying the preferred Compendium approach of 100% carbon oxidation:

$$\frac{8.16 \times 10^{11} \text{ Btu}}{\text{yr}} \times \frac{0.0531 \text{ tonne CO}_2}{10^6 \text{ Btu}} = 43,330 \text{ tonnes CO}_2/\text{yr}$$

Note the difference between the emission estimate calculated in Exhibit 4.1, where the fuel composition data are known, and this emission estimate based on an emission factor that incorporates a default natural gas composition.

For comparison and illustrative purposes, the above calculation is repeated incorporating the carbon oxidation fraction for natural gas from Table 4-3 rather than assuming 100% oxidation. To demonstrate this calculation, the original source carbon emission factor from Table 4-1 is used.

$$\begin{aligned} \frac{8.16 \times 10^{11} \text{ Btu}}{\text{yr}} \times \frac{14.47 \text{ MMTC}}{10^{15} \text{ Btu}} \times \frac{10^6 \text{ tonne mole C}}{12 \text{ MMTC}} \times \frac{0.995 \text{ tonne mole CO}_2}{\text{tonne mole C}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} \\ = 43,078 \text{ tonnes CO}_2/\text{yr} \end{aligned}$$

### **4.3 Fuel Combustion Emissions Estimated on an Equipment Basis for Stationary Sources**

If the fuel usage is known for the specific type of equipment (i.e., boiler, turbine, IC engine, etc.) or groups of the same equipment, then emission factors can be used to estimate non-CO<sub>2</sub> emissions. This is the preferred approach for CH<sub>4</sub> and N<sub>2</sub>O emissions. Alternatively, these emissions can be assumed to be negligible compared to CO<sub>2</sub> emissions from combustion sources.

Most of the emission factors are taken from EPA's AP-42 Sections 1 and 3 (EPA, AP-42, 1995-2000). These emission factors are updated periodically with the latest factors available at the following Internet address:

<http://www.epa.gov/ttn/chief/ap42.html#chapter>

Note that AP-42 also provides CO<sub>2</sub> emission factors on an equipment basis (EPA, AP-42, 1995-2000). However, these emission factors are inconsistent with the Compendium's preferred approach of estimating CO<sub>2</sub> emissions based on 100% oxidation of the fuel carbon, and the recognition that CO<sub>2</sub> emissions are independent of the type of combustion equipment.

#### **4.3.1 External Combustion Units**

Tables 4-4a and b provide CH<sub>4</sub> and N<sub>2</sub>O emission factors for external combustion devices primarily from EPA's AP-42 (EPA, AP-42, 1995-2000). The few exceptions are additional emission factors for refinery fuel gas-fired heaters from ARPEL (ARPEL, 1998) and for diesel-fired boilers/furnaces from the E&P Forum (E&P Forum, 1994). Also, the wood fuel/wood waste emission factor is from Environment Canada (Environment Canada, 2003). Table 4-4a applies to non-solid fuels while Table 4-4b applies to solid fuels such as coal.

With the exception of fuel gas fired boilers/furnaces/heaters, the emission factors from external combustion are provided on a volume (scf or gallons) of fuel basis for gaseous or liquid fuels and mass (tonnes) of fuel basis for solid fuels. If the fire rate is given on a heat basis, then the heating values for various fuels provided in Table 3-5 of this document can be used to convert the fuel fire rate (energy input basis) to a volumetric basis or mass basis.



**Table 4-4a. Equipment Specific Combustion Emission Factors for Boilers and Furnaces  
(Non-Solid Fuels)**

<b>Original Units</b>					
<b>Source</b>	<b>Methane</b>	<b>Emission Factor Rating<sup>d</sup></b>	<b>Nitrous Oxide</b>	<b>Emission Factor Rating<sup>d</sup></b>	<b>Source (version date)</b>
Boilers/furnaces/heaters - Natural gas					
Controlled	2.3 lb/10 <sup>6</sup> scf	B	0.64 <sup>a</sup> lb/10 <sup>6</sup> scf	E	AP-42 Table 1.4-2 (7/98)
Not controlled			2.2 <sup>b</sup> lb/10 <sup>6</sup> scf		
Boilers/furnaces/heaters - Diesel	7.8E-06 lb/lb	Not available	Not available		E&P Forum, 1994
Heater – Refinery fuel gas (low H <sub>2</sub> -content gas)					
<9.9 10 <sup>6</sup> Btu/hr	0.263 tonne/PJ (HHV)	Not available	Not available		Table 6.4 of ARPEL, 1998
>9.9 10 <sup>6</sup> Btu/hr	0.293 tonne/PJ (HHV)	Not available	Not available		
Heater – Refinery fuel gas (High H <sub>2</sub> -content gas)					
< 9.9 10 <sup>6</sup> Btu/hr	0.193 tonne/PJ (HHV)	Not available	Not available		Table 6.4 of ARPEL, 1998
> 9.9 10 <sup>6</sup> Btu/hr	0.215 tonne/PJ (HHV)	Not available	Not available		
Utility boilers - No. 4,5,6 oil	0.28 lb/1000 gal	A	0.53 lb/1000 gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Industrial boiler - No. 5/6 oil	1.00 lb/1000 gal	A	0.53 lb/1000 gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Industrial boiler - No. 4 or distillate oil	0.052 lb/1000 gal	A	0.26 lb/1000 gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Commercial combustors - No. 5/6 oil	0.475 lb/1000 gal	A	0.53 lb/1000 gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Commercial combustors - No. 4 or distillate	0.216 lb/1000 gal	A	0.26 lb/1000 gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Industrial/commercial boilers – Butane	0.2 lb/1000 gal	E	0.9 lb/1000 gal	E	AP-42 Table 1.5-1 (10/96)
Industrial/commercial Boilers – Propane	0.2 lb/1000 gal	E	0.9 lb/1000 gal	E	AP-42 Table 1.5-1 (10/96)
Residential furnace - Fuel oil	1.78 lb/1000 gal	A	0.05 lb/1000 gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98)

**Table 4-4a. Equipment Specific Combustion Emission Factors for Boilers and Furnaces, continued (Non-Solid Fuels)**

Emission Factors Converted to tonne/gal or tonne/10 <sup>6</sup> Btu (HHV and LHV, as indicated)							
Source	Methane		Emission Factor Rating <sup>d</sup>	Nitrous Oxide		Emission Factor Rating <sup>d</sup>	Source (version date)
Boilers/furnaces/heaters - Natural gas							
Controlled	1.0E-06	tonne/10 <sup>6</sup> Btu (HHV) <sup>c</sup>	B	2.8E-07	tonne/10 <sup>6</sup> Btu (HHV) <sup>a,c</sup>	E	AP-42 Table 1.4-2 (7/98)
	1.1E-06	tonne/10 <sup>6</sup> Btu (LHV) <sup>c</sup>		3.0E-07	tonne/10 <sup>6</sup> Btu (LHV) <sup>a,c</sup>	E	
Not controlled	1.0E-06	tonne/10 <sup>6</sup> Btu (HHV) <sup>c</sup>	B	9.8E-07	tonne/10 <sup>6</sup> Btu (HHV) <sup>b,c</sup>	E	AP-42 Table 1.4-2 (7/98)
	1.1E-06	tonne/10 <sup>6</sup> Btu (LHV) <sup>c</sup>		1.0E-06	tonne/10 <sup>6</sup> Btu (LHV) <sup>b,c</sup>	E	
Boilers/furnaces/heaters - Diesel	7.8E-06	tonne/ tonne		Not available			E&P Forum, 1994
Heater – Refinery fuel gas (low H <sub>2</sub> -content gas)							
< 9.9 10 <sup>6</sup> Btu/hr	2.77E-07	tonne/10 <sup>6</sup> Btu (HHV)	Not available	Not available			Table 6.4 of ARPEL, 1998
	3.08E-07	tonne/10 <sup>6</sup> Btu (LHV)					
≥ 9.9 10 <sup>6</sup> Btu/hr	3.09E-07	tonne/10 <sup>6</sup> Btu (HHV)	Not available	Not available			
	3.43E-07	tonne/10 <sup>6</sup> Btu (LHV)					
Heater – Refinery fuel gas (High H <sub>2</sub> -content gas)							
< 9.9 10 <sup>6</sup> Btu/hr	2.04E-07	tonne/10 <sup>6</sup> Btu (HHV)	Not available	Not available			Table 6.4 of ARPEL, 1998
	2.26E-07	tonne/10 <sup>6</sup> Btu (LHV)					
≥ 9.9 10 <sup>6</sup> Btu/hr	2.27E-07	tonne/10 <sup>6</sup> Btu (HHV)	Not available	Not available			
	2.52E-07	tonne/10 <sup>6</sup> Btu (LHV)					
Utility boilers - No. 4,5,6 oil	1.3E-07	tonne/gal	A	2.4E-07	tonne/gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Industrial boiler - No. 5/6 oil	4.54E-07	tonne/gal	A	2.4E-07	tonne/gal	B	
Industrial boiler - No. 4 or distillate oil	2.4E-08	tonne/gal	A	1.2E-07	tonne/gal	B	
Commercial combustors - No. 5/6 oil	2.15E-07	tonne/gal	A	2.4E-07	tonne/gal	B	
Commercial combustors - No. 4 or distillate	9.80E-08	tonne/gal	A	1.2E-07	tonne/gal	B	
Industrial/commercial boilers – Butane	9.1E-08	tonne/gal	E	4.1E-07	tonne/gal	E	AP-42 Table 1.5-1 (10/96)
Industrial/commercial Boilers – Propane	9.1E-08	tonne/gal	E	4.1E-07	tonne/gal	E	AP-42 Table 1.5-1 (10/96)
Residential furnace - Fuel oil	8.07E-07	tonne/gal	A	2.3E-08	tonne/gal	B	AP-42 Tables 1.3-3 and 1.3-12 (9/98) - errata updated 4/28/0

**Table 4-4a. Equipment Specific Combustion Emission Factors for Boilers and Furnaces, continued (Non-Solid Fuels)**

<b>Emission Factors Converted to tonne/m<sup>3</sup> or tonne/10<sup>12</sup> J (HHV and LHV, as indicated)</b>								
Source		Methane		Emission Factor Rating <sup>d</sup>	Nitrous Oxide		Emission Factor Rating <sup>d</sup>	Source (version date)
Boilers/furnaces/heaters - Natural gas								
Controlled	9.7E-04	tonne/10 <sup>12</sup> J (HHV) <sup>c</sup>	B	2.7E-04	tonne/10 <sup>12</sup> J (HHV) <sup>a,c</sup>	E	AP-42 Table 1.4-2 (7/98)	
	1.1E-03	tonne/10 <sup>12</sup> J (LHV) <sup>c</sup>		2.8E-04	tonne/10 <sup>12</sup> J (LHV) <sup>a,c</sup>	E		
Not controlled	9.7E-04	tonne/10 <sup>12</sup> J (HHV) <sup>c</sup>	B	9.3E-04	tonne/10 <sup>12</sup> J (HHV) <sup>b,c</sup>	E	AP-42 Table 1.4-2 (7/98)	
	1.1E-03	tonne/10 <sup>12</sup> J (LHV) <sup>c</sup>		9.8E-04	tonne/10 <sup>12</sup> J (LHV) <sup>b,c</sup>	E		
Boilers/furnaces/heaters - Diesel		7.8E-06	tonne/ tonne		Not available			E&P Forum, 1994
Heater – Refinery fuel gas (low H <sub>2</sub> -content gas)								
< 9.9 10 <sup>6</sup> Btu/hr	2.63E-04	tonne/10 <sup>12</sup> J (HHV)	Not available	Not available			Table 6.4 of ARPEL, 1998	
	2.92E-04	tonne/10 <sup>12</sup> J (LHV)						
>= 9.9 10 <sup>6</sup> Btu/hr	2.93E-04	tonne/10 <sup>12</sup> J (HHV)	Not available	Not available				
	3.26E-04	tonne/10 <sup>12</sup> J (LHV)						
Heater – Refinery fuel gas (High H <sub>2</sub> -content gas)								
< 9.9 10 <sup>6</sup> Btu/hr	1.93E-04	tonne/10 <sup>12</sup> J (HHV)	Not available	Not available			Table 6.4 of ARPEL, 1998	
	2.14E-04	tonne/10 <sup>12</sup> J (LHV)						
>= 9.9 10 <sup>6</sup> Btu/hr	2.15E-04	tonne/10 <sup>12</sup> J (HHV)	Not available	Not available				
	2.39E-04	tonne/10 <sup>12</sup> J (LHV)						
Utility boilers - No. 4,5,6 oil		3.4E-05	tonne/m <sup>3</sup>	A	6.4E-05	tonne/m <sup>3</sup>	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Industrial boiler - No. 5/6 oil		1.20E-04	tonne/m <sup>3</sup>	A	6.4E-05	tonne/m <sup>3</sup>	B	
Industrial boiler - No. 4 or distillate oil		6.2E-06	tonne/m <sup>3</sup>	A	3.1E-05	tonne/m <sup>3</sup>	B	
Commercial combustors - No. 5/6 oil		5.69E-05	tonne/m <sup>3</sup>	A	6.4E-05	tonne/m <sup>3</sup>	B	
Commercial combustors - No. 4 or distillate		2.59E-05	tonne/m <sup>3</sup>	A	3.1E-05	tonne/m <sup>3</sup>	B	
Industrial/commercial boilers – Butane		2.4E-05	tonne/m <sup>3</sup>	E	1.1E-04	tonne/m <sup>3</sup>	E	AP-42 Table 1.5-1 (10/96)
Industrial/commercial boilers – Propane		2.4E-05	tonne/m <sup>3</sup>	E	1.1E-04	tonne/m <sup>3</sup>	E	AP-42 Table 1.5-1 (10/96)
Residential furnace - Fuel oil		2.13E-04	tonne/m <sup>3</sup>	A	6.0E-06	tonne/m <sup>3</sup>	B	AP-42 Tables 1.3-3 and 1.3-12 (9/98)

Footnotes for Table 4-4a:

<sup>a</sup> The first set of N<sub>2</sub>O emission factors is for a natural gas, controlled low NO<sub>x</sub> burner unit.

<sup>b</sup> The second set of N<sub>2</sub>O emission factors is for uncontrolled natural gas units.

<sup>c</sup> The Btu-based emission factors for natural gas boiler/furnaces/heaters are derived from the volume-based (scf) factor by dividing by 1020 Btu/scf (the default heating value used by AP-42). This factor may be used for other natural gas combustion sources. Gas volumes are based on standard conditions of 60°F and 14.7 psia.

<sup>d</sup>Emission factor rating pertains to the quality of the data; “A” has the best quality while “E” has the poorest quality.

Sources:

Asociacion Regional De Empresas De Petroleo Y Gas Natural EN LatinoAmerica Y El Caribe (ARPEL). *Atmospheric Emissions Inventories Methodologies in the Petroleum Industry*. ARPEL Guideline # ARPELCIDA02AEGUI2298, Prepared by Jaques Whitford Environment Limited, December 1998.

E&P Forum. *Methods for Estimating Atmospheric Emissions from E&P Operations*, The Oil Industry International Exploration and Production Forum, Report No. 2.59/197, September 1994.

US Environmental Protection Agency (EPA). *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources*, AP-42, (GPO 055-000-005-001), US EPA Office of Air Quality Planning and Standards, Fifth Edition, January 1995, with Supplements A, B, and C, 1996; Supplement D, 1998 – errata updated 4/28/00; Supplement E, 1999; and Supplement F, 2000.

**Table 4-4b. Equipment Specific Combustion Emission Factors for Boilers and Furnaces (Solid Fuels)**

<b>Original Units</b>					
<b>Source</b>	<b>Methane</b>	<b>Emission Factor Rating<sup>a</sup></b>	<b>Nitrous Oxide</b>	<b>Emission Factor Rating<sup>a</sup></b>	<b>Source (version date)</b>
Boilers - Bituminous and Sub bituminous Coal					
PC-fired, dry bottom, wall fired	0.04 lb/ton	B	0.03 lb/ton	B	AP-42 Table 1.1-19 (9/98)
PC-fired, dry bottom, tangentially fired	0.04 lb/ton	B	0.08 lb/ton	B	AP-42 Table 1.1-19 (9/98)
PC-fired, wet bottom	0.05 lb/ton	B	0.08 lb/ton	E	AP-42 Table 1.1-19 (9/98)
Cyclone furnace	0.01 lb/ton	B	0.09 lb/ton	E	AP-42 Table 1.1-19 (9/98)
Spreader stoker	0.06 lb/ton	B	0.04 lb/ton	D-E	AP-42 Table 1.1-19 (9/98)
Overfeed stoker	0.06 lb/ton	B	0.04 lb/ton	E	AP-42 Table 1.1-19 (9/98)
Underfeed stoker	0.8 lb/ton	B	0.04 lb/ton	E	AP-42 Table 1.1-19 (9/98)
Fluidized bed combustor	0.06 lb/ton	E	3.5 lb/ton	B	AP-42 Table 1.1-19 (9/98)
Boilers - Lignite					
Atmospheric fluidized bed combustor	Not available	Not available	2.5 lb/ton	E	AP-42 Tables 1.7-1 and 1.7-4 (9/98)
Wood fuel/wood waste	0.05 g/kg	Not available	0.02 g/kg	Not available	Environment Canada, 2003, Table A7-16

**Table 4-4b. Equipment Specific Combustion Emission Factors for Boilers and Furnaces (Solid Fuels)  
(continued)**

<b>Emission Factors Converted to tonne/tonne</b>					
<b>Source</b>	<b>Methane</b>	<b>Emission Factor Rating<sup>a</sup></b>	<b>Nitrous Oxide</b>	<b>Emission Factor Rating<sup>a</sup></b>	<b>Source (version date)</b>
Boilers - Bituminous and Sub bituminous Coal					
PC-fired, dry bottom, wall fired	2.0E-05 tonne/tonne	B	1.5E-05 tonnes/tonne	B	AP-42 Table 1.1-19 (9/98)
PC-fired, dry bottom, tangentially fired	2.0E-05 tonnes/tonne	B	4.0E-05 tonnes/tonne	B	AP-42 Table 1.1-19 (9/98)
PC-fired, wet bottom	2.5E-05 tonnes/tonne	B	4.0E-05 tonnes/tonne	E	AP-42 Table 1.1-19 (9/98)
Cyclone furnace	5.0E-06 tonnes/tonne	B	4.5E-05 tonnes/tonne	E	AP-42 Table 1.1-19 (9/98)
Spreader stoker	3.0E-05 tonnes/tonne	B	2.0E-05 tonnes/tonne	D-E	AP-42 Table 1.1-19 (9/98)
Overfeed stoker	3.0E-05 tonnes/tonne	B	2.0E-05 tonnes/tonne	E	AP-42 Table 1.1-19 (9/98)
Underfeed stoker	4.0E-04 tonnes/tonne	B	2.0E-05 tonnes/tonne	E	AP-42 Table 1.1-19 (9/98)
Fluidized bed combustor	3.0E-05 tonnes/tonne	E	1.8E-03 tonnes/tonne	B	AP-42 Table 1.1-19 (9/98)
Boilers - Lignite					
Atmospheric fluidized bed combustor	Not available	Not available	1.25E-03 tonnes/tonne	E	AP-42 Tables 1.7-1 and 1.7-4 (9/98)
Wood fuel/wood waste	5.0E-05 tonnes/tonne	Not available	2.0E-05 tonnes/tonne	Not available	Environment Canada, 2003, Table A7-16

<sup>a</sup>Emission factor rating pertains to the quality of the data; “A” has the best quality while “E” has the poorest quality.

Sources:

US Environmental Protection Agency (EPA). *Compilation of Air Pollutant Emission Factors*, Volume I: Stationary Point and Area Sources, AP-42, (GPO 055-000-005-001), US EPA Office of Air Quality Planning and Standards, Fifth Edition, January 1995, with Supplements A and B, 1996; Supplement E, 1998.

Environment Canada, *Canada's Greenhouse Gas Inventory 1990-2001*, Greenhouse Gas Division, Environment Canada, August 2003.

An example calculation for CH<sub>4</sub> and N<sub>2</sub>O emissions from an external combustion device follows.

**EXHIBIT 4.6:            Sample Calculation for Combustion Emissions Equipment Basis for External Combustion Device**

**INPUT DATA:**

800 million (10<sup>6</sup>) scf/year of natural gas is burned in a boiler with a low-NO<sub>x</sub> burner. The heating value of the gas is 1032 Btu/scf (HHV). Calculate the CH<sub>4</sub> and N<sub>2</sub>O emissions.

**CALCULATION METHODOLOGY:**

Table 4-4a gives the following emission factors for a natural gas-fired boiler:

$$\text{CH}_4 \text{ EF} = 2.3 \text{ lb CH}_4/10^6 \text{ scf} = 1.0\text{E-}06 \text{ tonne CH}_4/10^6 \text{ Btu (HHV)}$$

$$\text{N}_2\text{O EF} = 2.2 \text{ lb N}_2\text{O}/10^6 \text{ scf} = 2.8\text{E-}07 \text{ tonne N}_2\text{O}/10^6 \text{ Btu (HHV)}$$

Next, the quantity of fuel burned is converted to a Btu basis and then multiplied by the emission factors:

$$\text{CH}_4 : \frac{800 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1032 \text{ Btu}}{\text{scf}} \times \frac{1.0 \times 10^{-6} \text{ tonne CH}_4}{10^6 \text{ Btu}} = \underline{0.82 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{800 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1032 \text{ Btu}}{\text{scf}} \times \frac{2.8 \times 10^{-7} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}} = \underline{0.23 \text{ tonnes N}_2\text{O}/\text{yr}}$$

### **4.3.2      Internal Combustion Units**

Table 4-5 summarizes CH<sub>4</sub> and N<sub>2</sub>O emission factors for internal combustion units from EPA's AP-42 (EPA, AP-42 Supplement F, 2000). These emission factors are given on a fuel input basis, but can be converted from a power output basis using the conversion factors for each type of engine given in Section 3 of this document.

The emission factors provided in Table 4-5 are generic factors that are not model-specific. Model-specific emission factors for several reciprocating engine types are provided in Appendix B. A facility may prefer to use these model-specific emission factors instead of those provided in Table 4-5 if the specific model used is provided in the tables in Appendix B.

Table 4-5. Engines and Turbines Emission Factors

Original Units								
Source	Methane		Emission Factor Rating	CH <sub>4</sub> Reference AP-42 (version date)	Nitrous Oxide		Emission Factor Rating	N <sub>2</sub> O Reference
IC Engine (2 cycle lean) – Natural Gas	1.45	lb/10 <sup>6</sup> Btu (HHV)	C	Table 3.2-1 (7/00)	0.005	lb/10 <sup>6</sup> Btu (HHV) <sup>c</sup>	A	GTI, 2002; API, 1999
IC Engine (4 cycle lean) – Natural Gas	1.25	lb/10 <sup>6</sup> Btu (HHV)	C	Table 3.2-2 (7/00)	0.003	lb/10 <sup>6</sup> Btu (HHV) <sup>c</sup>	A	GTI, 2002; API, 1999
IC Engine (4 cycle rich) – Natural Gas	0.23	lb/10 <sup>6</sup> Btu (HHV)	C	Table 3.2-3 (7/00)	0.001	lb/10 <sup>6</sup> Btu (HHV) <sup>c</sup>	A	GTI, 2002; API, 1999
IC Engine - Gasoline	3.03	lb TOC/ 10 <sup>6</sup> Btu (HHV) <sup>a</sup>	D,E	Table 3.3-1 (10/96)	0.031	g/L (distillate)	Not available	Environment Canada
IC Engine - Diesel	0.36	lb TOC/ 10 <sup>6</sup> Btu (HHV) <sup>a</sup>	D,E	Table 3.3-1 (10/96)	0.4	g/L	Not available	Environment Canada
Large Bore Engine – Diesel (> 600 hp)	0.0081	lb/10 <sup>6</sup> Btu (HHV) <sup>b</sup>	E	Table 3.4-1 ( 10/96)	0.08	g/L	Not available	Environment Canada
IC Engine - 95%Nat Gas/ 5%Diesel	0.6	lb/10 <sup>6</sup> Btu (HHV)	E	Table 3.4-1 (10/96)	Not available			
Turbines (≥ 80% load) – Natural Gas								
Controlled (SCR)	0.0086	lb/10 <sup>6</sup> Btu (HHV)	C	Table 3.1-2a (4/00)	0.03	lb/10 <sup>6</sup> Btu (HHV)	E	GTI, 2002; API, 1999
Not controlled	0.0086	lb/10 <sup>6</sup> Btu (HHV)	C	Table 3.1-2a (4/00)	0.003	lb/10 <sup>6</sup> Btu (HHV)	E	GTI, 2002; API, 1999

<sup>a</sup> If the fuel composition is unknown, TOC factors shown above can be converted to CH<sub>4</sub> emission factors assuming the TOC contains 10 wt% CH<sub>4</sub> in the exhaust gas based on engineering judgment. The emission factors include TOC emissions from the sum of exhaust, evaporative, crankcase, and refueling emissions. Emission factor rating D applies to exhaust emissions; emission factor rating E applies to evaporative, crankcase, and refueling emissions.

<sup>b</sup> Emission factor is based on TOC with 9% CH<sub>4</sub> by weight in the exhaust gas.

<sup>c</sup> N<sub>2</sub>O emissions from 2- and 4-stroke lean burn engines were below detection limits (DL) of 1.5 ppmv. The lb/10<sup>6</sup> Btu values are based on this DL.

<sup>d</sup> LHV emission factor was estimated from the HHV factor assuming the fuel is a gas (i.e., assumed that the HHV Emission Factor = LHV/0.90).



Table 4-5. Engines and Turbines Emission Factors (continued)

Units Converted to US Basis								
Source	Methane		Emission Factor Rating	CH <sub>4</sub> Release AP-42 (version date)	Nitrous Oxide		Emission Factor Rating	N <sub>2</sub> O Reference
IC Engine (2 cycle lean) - Gas	0.00066	tonne/10 <sup>6</sup> Btu (HHV)	C	Table 3.2-1 (7/00)	2.3E-06	tonne/10 <sup>6</sup> Btu (HHV) <sup>c</sup>	A	GTI, 2002; API, 1999
	0.00073	tonne/10 <sup>6</sup> Btu (LHV)			2.5E-06	tonne/10 <sup>6</sup> Btu (LHV) <sup>c</sup>		
IC Engine (4 cycle lean) - Gas	0.00057	tonne/10 <sup>6</sup> Btu (HHV)	C	Table 3.2-2 (7/00)	1.4E-06	tonne/10 <sup>6</sup> Btu (HHV) <sup>c</sup>	A	GTI, 2002; API, 1999
	0.00063	tonne/10 <sup>6</sup> Btu (LHV)			1.5E-06	tonne/10 <sup>6</sup> Btu (LHV) <sup>c</sup>		
IC Engine (4 cycle rich) – Gas	0.00010	tonne/10 <sup>6</sup> Btu (HHV)	C	Table 3.2-3 (7/00)	4.5E-07	tonne/10 <sup>6</sup> Btu (HHV) <sup>c</sup>	A	GTI, 2002; API, 1999
	0.00012	tonne/10 <sup>6</sup> Btu (LHV)			5.0E-07	tonne/10 <sup>6</sup> Btu (LHV) <sup>c</sup>		
IC Engine - Gasoline	0.00137	tonne TOC/10 <sup>6</sup> Btu (HHV) <sup>a</sup>	D, E	Table 3.3-1 (10/96)	1.17E-07	tonne/gal	Not available	Environment Canada
	0.00145	tonne TOC/10 <sup>6</sup> Btu (LHV) <sup>a</sup>						
IC Engine - Diesel	0.00016	tonne TOC/10 <sup>6</sup> Btu (HHV) <sup>a</sup>	D, E	Table 3.3-1 (10/96)	1.51E-06	tonne/gal	Not available	Environment Canada
	0.00017	tonne TOC/10 <sup>6</sup> Btu (LHV) <sup>a</sup>						
Large Bore Engine – Diesel (> 600 hp)	3.7E-06	tonne/10 <sup>6</sup> Btu (HHV) <sup>b</sup>	E	Table 3.4-1 (10/96)	3.03E-07	tonne/gal	Not available	Environment Canada
	3.9E-06	tonne/10 <sup>6</sup> Btu (LHV) <sup>b</sup>						
IC Engine - 95%NG/5%diesel	0.00027	tonne/10 <sup>6</sup> Btu (HHV)	E	Table 3.4-1 (10/96)	Not available			
	0.00030	tonne/10 <sup>6</sup> Btu (LHV) <sup>d</sup>						
Turbines (≥ 80% load) – Natural Gas								
Controlled SCR	3.9E-06	tonne/10 <sup>6</sup> Btu (HHV)	C	Table 3.1-2a (4/00)	1.4E-05	tonne/10 <sup>6</sup> Btu (HHV)	E	GTI, 2002; API, 1999
	4.3E-06	tonne/10 <sup>6</sup> Btu (LHV)			1.5E-05	tonne/10 <sup>6</sup> Btu (LHV)		
Uncontrolled	3.9E-06	tonne/10 <sup>6</sup> Btu (HHV)	C	Table 3.1-2a (4/00)	1.4E-06	tonne/10 <sup>6</sup> Btu (HHV)	E	GTI, 2002; API, 1999
	4.3E-06	tonne/10 <sup>6</sup> Btu (LHV)			1.5E-06	tonne/10 <sup>6</sup> Btu (LHV)		

<sup>a</sup> If the fuel composition is unknown, TOC factors shown above can be converted to CH<sub>4</sub> emission factors assuming the TOC contains 10 wt% CH<sub>4</sub> in the exhaust gas based on engineering judgment. The emission factors include TOC emissions from the sum of exhaust, evaporative, crankcase, and refueling emissions. Emission factor rating D applies to exhaust emissions; emission factor rating E applies to evaporative, crankcase, and refueling emissions.

<sup>b</sup> Emission factor is based on TOC with 9% CH<sub>4</sub> by weight in the exhaust gas.

<sup>c</sup> N<sub>2</sub>O emissions from 2- and 4-stroke lean burn engines were below detection limits (DL) of 1.5 ppmv. The lb/10<sup>6</sup> Btu values are based on this DL.

<sup>d</sup> LHV emission factor was estimated from the HHV factor assuming the fuel is a gas (i.e., assumed that the HHV Emission Factor = LHV/0.90).

Table 4-5. Engines and Turbines Emission Factors (continued)

Units Converted to SI Basis								
Source	Methane		Emission Factor Rating	AP-42 Reference (version date)	Nitrous Oxide		Emission Factor Rating	Reference
IC Engine (2 cycle lean) - Gas	0.623	tonne/10 <sup>12</sup> J (HHV)	C	Table 3.2-1 (7/00)	0.0021	tonne/10 <sup>12</sup> J (HHV) <sup>c</sup>	A	GTI, 2002; API, 1999
	0.693	tonne/10 <sup>12</sup> J (LHV)			0.0024	tonne/10 <sup>12</sup> J (LHV) <sup>c</sup>		
IC Engine (4 cycle lean) - Gas	0.537	tonne/10 <sup>12</sup> J (HHV)	C	Table 3.2-2 (7/00)	0.0013	tonne/10 <sup>12</sup> J (HHV) <sup>c</sup>	A	GTI, 2002; API, 1999
	0.597	tonne/10 <sup>12</sup> J (LHV)			0.0014	tonne/10 <sup>12</sup> J (LHV) <sup>c</sup>		
IC Engine (4 cycle rich) – Gas	0.10	tonne/10 <sup>12</sup> J (HHV)	C	Table 3.2-3 (7/00)	0.0004	tonne/10 <sup>12</sup> J (HHV) <sup>c</sup>	A	GTI, 2002; API, 1999
	0.11	tonne/10 <sup>12</sup> J (LHV)			0.0005	tonne/10 <sup>12</sup> J (LHV) <sup>c</sup>		
IC Engine - Gasoline	1.30	tonne TOC/10 <sup>12</sup> J (HHV) <sup>a</sup>	D, E	Table 3.3-1 (10/96)	0.000031	tonnes/m <sup>3</sup>	Not available	Environment Canada
	1.37	tonne TOC/10 <sup>12</sup> J (LHV) <sup>a</sup>						
IC Engine - Diesel	0.15	tonne TOC/10 <sup>12</sup> J (HHV) <sup>a</sup>	D, E	Table 3.3-1 (10/96)	0.0004	tonnes/m <sup>3</sup>	Not available	Environment Canada
	0.16	tonne TOC/10 <sup>12</sup> J (LHV) <sup>a</sup>						
Large Bore Engine – Diesel (> 600 hp)	0.0035	tonne/10 <sup>12</sup> J (HHV) <sup>b</sup>	E	Table 3.4-1 ( 10/96)	0.00008	tonnes/m <sup>3</sup>	Not available	Environment Canada
	0.0037	tonne/10 <sup>12</sup> J (LHV) <sup>b</sup>						
IC Engine - 95%NG/5%diesel	0.26	tonne/10 <sup>12</sup> J (HHV)	E	Table 3.4-1 (10/96)	Not available			
	0.29	tonne/10 <sup>12</sup> J (LHV) <sup>d</sup>						
Turbines (≥ 80% load) – Natural Gas								
Controlled SCR	0.0037	tonne/10 <sup>12</sup> J (HHV)	C	Table 3.1-2a (4/00)	0.013	tonne/10 <sup>12</sup> J (HHV)	E	GTI, 2002; API, 1999
	0.0041	tonne/10 <sup>12</sup> J (LHV)			0.014	tonne/10 <sup>12</sup> J (LHV)		
Uncontrolled	0.0037	tonne/10 <sup>12</sup> J (HHV)	C	Table 3.1-2a (4/00)	0.0013	tonne/10 <sup>12</sup> J (HHV)	E	GTI, 2002; API, 1999
	0.0041	tonne/10 <sup>12</sup> J (LHV)			0.0014	tonne/10 <sup>12</sup> J (LHV)		

Footnotes a-d are defined on the previous pages.

Sources:

US Environmental Protection Agency (EPA). *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources*, AP-42, (GPO 055-000-005-001), US EPA Office of Air Quality Planning and Standards, Fifth Edition, January 1995, with Supplements A, B, and C, 1996; Supplement D, 1998; Supplement E, 1999; and Supplement F, 2000.

Campbell, L.M. and M. Gundappa. *Characterization of Emissions from Oil and Gas Production Combustion Units*, Draft Report, API, July 1999.

URS. *Nitrous Oxide Emissions from Natural Gas-Fired Reciprocating Internal Combustion Engines*, Draft Memorandum, GTI, January 2002.

Environment Canada, *Canada's Greenhouse Gas Inventory 1990-2001*, Greenhouse Gas Division, Environment Canada, August 2003.

Total organic compound (TOC) emission factors for diesel and gasoline IC engines (shown in Table 4-5) can be converted to CH<sub>4</sub> emissions assuming the exhaust gas TOC contains 10 w% CH<sub>4</sub> based on engineering judgment.

An example calculation for CH<sub>4</sub> and N<sub>2</sub>O emissions from an internal combustion device follows.

**EXHIBIT 4.7:      Sample Calculation for Combustion Emissions Equipment Basis for Internal Combustion Device**

**INPUT DATA:**

A 100-hp gasoline fired internal combustion engine is operated for 8000 hours at 90% load during the reporting year. Calculate the CH<sub>4</sub> and N<sub>2</sub>O emissions from this source.

**CALCULATION METHODOLOGY FOR CH<sub>4</sub>:**

The quantity of fuel burned is multiplied by an equipment specific emission factor from Table 4-5.

Total Organic Compound (TOC) EF = 3.03 lb/10<sup>6</sup> Btu = 0.00137 tonne TOC/10<sup>6</sup> Btu

The exhaust gas TOC is assumed to contain 10 wt% CH<sub>4</sub> based on engineering judgment.

Because the input data is based on power output, a conversion factor is needed to put the fuel consumption on an energy input basis. A conversion factor of 7,000 Btu/hp-hr is taken from Table 3-6. This calculation is shown in Exhibit 3.3 and is repeated below:

$$100 \text{ hp} \times 0.90 \times \frac{8000 \text{ hr}}{\text{yr}} \times \frac{7000 \text{ Btu}}{\text{hp} \cdot \text{hr}} = 5040 \times 10^6 \text{ Btu/yr (HHV)}$$

The emissions are calculated as:

$$\text{CH}_4 : \frac{5040 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.00137 \text{ tonne TOC}}{10^6 \text{ Btu}} \times \frac{0.10 \text{ tonne CH}_4}{\text{tonne TOC}} = \underline{0.69 \text{ tonnes CH}_4/\text{yr}}$$

**CALCULATION METHODOLOGY FOR N<sub>2</sub>O:**

The N<sub>2</sub>O emission factor for gasoline is provided on a volume basis. Table 3-5 provides a default heating value for gasoline, which is used to convert Btu of fuel usage to volume:

$$\text{N}_2\text{O} : \frac{5040 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{\text{bbl}}{5.46 \times 10^6 \text{ Btu}} \times \frac{42 \text{ gal}}{\text{bbl}} = 38,769 \text{ gal gasoline} \times \frac{1.17 \times 10^{-7} \text{ tonne N}_2\text{O}}{\text{gal}} \\ = \underline{0.0045 \text{ tonnes N}_2\text{O/yr}}$$

## 4.4 Flare Emissions<sup>3</sup>

Flares are used in all segments of the oil and gas industry to manage the disposal of hydrocarbon products from routine operations, upsets, or emergencies via combustion. There are a wide variety of flare types used in the industry, ranging from small open-ended pipes at production wellheads, to large horizontal or vertical flares with pilots, such as those at refineries. Emissions of CO<sub>2</sub> and N<sub>2</sub>O are formed as products of combustion, and CH<sub>4</sub> emissions may result due to incomplete combustion or from time periods where there is no flame at the flare tip due to operational problems. Combustion efficiency, and therefore flare performance, is highly variable, primarily dependent on the flame stability. This, in turn, depends on the gas velocity, heat content, and wind conditions.

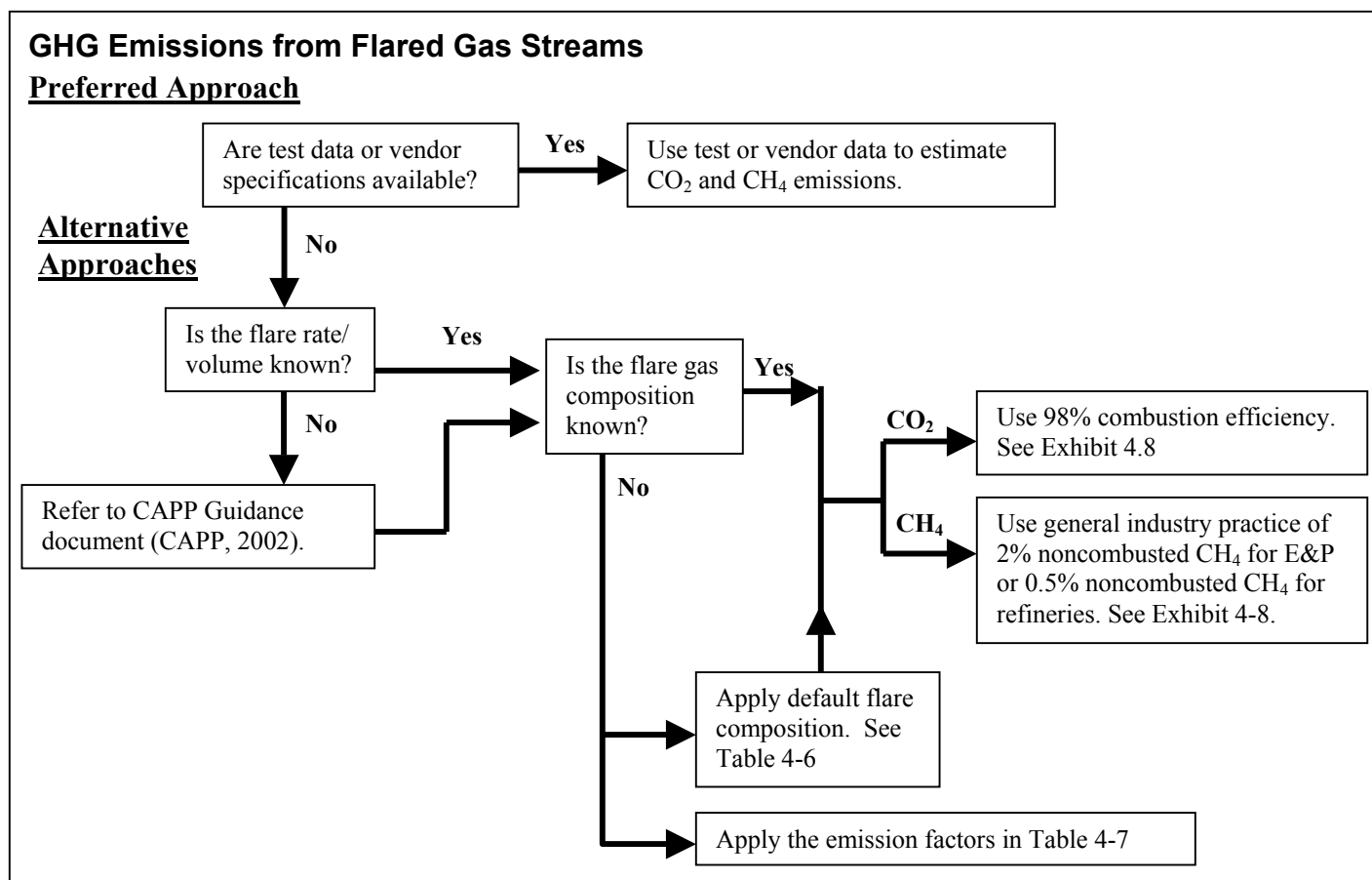
Due to these complexities, detailed examination of flare emissions has been somewhat limited and focussed primarily on refinery flares. General industry practice relies on the widely accepted AP-42 document which states: “properly operated flares achieve at least 98 percent combustion efficiency” (EPA, AP-42 Section 13.5.2, September 1991), where 98% efficiency is consistent with the performance of other control devices. However, increased interest in greenhouse gas and air toxic emissions has prompted recent studies to more accurately characterize emissions from oil and gas industry flares (Ozumba, 2000; Strosher, 1996). Findings from these studies indicate a minimum of 98% combustion efficiency, with much higher efficiencies measured in most situations, and very little, if any, detectable CH<sub>4</sub>.<sup>4</sup>

As shown in Figure 4-2, this *Compendium* recommends test data or vendor specific information as the preferred method for estimating flare emissions from gas streams. In the absence of this information, the alternative emissions calculation approach is based on knowing or estimating the flare gas flow rate and composition. For upstream operations, CAPP provides an approach for quantifying volumes of gas flared at typical upstream oil and gas facilities (CAPP, 2002). Some of the approaches are also applicable to downstream operations. Table 4-6 provides “generic” upstream gas compositions for use only if measured data are unavailable. Keep in mind that flare gas compositions can vary significantly, and the compositions provided in Table 4-6 are not meant to be representative of industry averages or typical values.

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<sup>3</sup> Approaches presented in this section apply to flare combustion emissions. Flares that are not operating (i.e., no flame) are treated as vented sources (see Section 5).

<sup>4</sup> Note that the Strosher flare study reports combustion efficiencies of less than 98% for tests conducted on two production flares without knockout drums.



**Figure 4-2. Calculation Approaches for Gas Flare Emissions**

The general equations for estimating emissions from flares are:

$$\text{CO}_2 \text{ Emissions} = \text{Volume Flared} \times \text{Molar volume} \times \sum \left( \frac{\text{mole Hydrocarbon}}{\text{mole gas}} \times \frac{\text{X mole C}}{\text{mole Hydrocarbon}} \right) \times \text{Combustion efficiency} \left( \frac{0.98 \text{ mole CO}_2 \text{ formed}}{\text{mole C combusted}} \right) \times \text{MW CO}_2$$

$$\text{CH}_4 \text{ Emissions} = \text{Volume Flared} \times \text{CH}_4 \text{ Mole fraction} \times \% \text{ residual CH}_4 \times \text{Molar volume} \times \text{MW CH}_4$$

$$\text{N}_2\text{O Emissions} = \text{Volume Flared} \times \text{N}_2\text{O emission factor}$$

(Equation 4-4)

**Table 4-6. “Generic” Upstream Gas Composition**

Gas Component	Raw or Produced Gas Composition <sup>a</sup>	Gas Processing Plant Gas Composition <sup>b</sup>
	Volume (or mole) %	Volume (or mole) %
CH <sub>4</sub>	80	91.9
Non-methane Hydrocarbon	15 (C <sub>2</sub> H <sub>6</sub> ) 5 (C <sub>3</sub> H <sub>8</sub> )	6.84 (MW unspecified)
N <sub>2</sub>	-	0.68
CO <sub>2</sub>	-	0.58

Sources:

<sup>a</sup> CAPP. *Calculating Greenhouse Gas Emissions*, Guide, 2003-003, Section 1.7.3, April 2003.

<sup>b</sup> IPCC. *IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*, Chapter 2 (Energy), Table 2.16, page 2.87, May 2000.

If measured emissions data are unavailable, CO<sub>2</sub> emissions from flares are based on an estimated 98% combustion efficiency for the conversion of flare gas carbon to CO<sub>2</sub>. This is consistent with published flare emission factors (E&P Forum, 1994), fuel carbon combustion efficiencies (EIA, 2002), control device performance, and results from the more recent flare studies.

For CH<sub>4</sub> emissions from flares, general industry practice assumes 0.5% residual, unburned CH<sub>4</sub> remaining in the flared gas for well designed and operated flares, such as in refineries. For production flares, where greater operational variability exists, CH<sub>4</sub> emissions may be based on an assumed value of 2% noncombusted. These recommendations are believed to be conservative and are supported by published flare emission factors (EIIP Volume II, Table 10.2-1, September 1999) and typical carbon oxidation values from combustion processes (IPCC Table 16, 1996; EIIP, Volume VIII, p. 1.4-17, 1999).

Very little information is available for N<sub>2</sub>O emissions from petroleum industry flares, but these emissions are likely negligible compared to CO<sub>2</sub> emissions from flares. Table 4-7 provides simple emission factors for N<sub>2</sub>O from IPCC (IPCC, 2000). IPCC cites U.S. measurement data for these factors. IPCC also provides CO<sub>2</sub> and CH<sub>4</sub> emission factors for the same flare sources. The refinery CH<sub>4</sub> flare emission factor is from Annex H of the EPA report, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001* (EPA, 2003). These flare emission factors are provided as an alternative to using the generic gas compositions from Table 4-6.

Table 4-7. GHG Emission Factors for Gas Flares

<b>Original Units</b>	<b>Emission Factors</b>			
<b>Flare Source</b>	<b>CO<sub>2</sub></b>	<b>CH<sub>4</sub></b>	<b>N<sub>2</sub>O</b>	<b>Units</b>
Flaring - gas production <sup>a</sup>	1.8E-03	1.1E-05	2.1E-08	Gg/10 <sup>6</sup> m <sup>3</sup> gas production
Flaring - sweet gas processing <sup>a</sup>	2.1E-03	1.3E-05	2.5E-08	Gg/10 <sup>6</sup> m <sup>3</sup> gas receipts
Flaring - sour gas processing <sup>a</sup>	4.6E-03	2.9E-05	5.4E-08	Gg/10 <sup>6</sup> m <sup>3</sup> gas receipts
Flaring - conventional oil production <sup>a</sup>	6.7E-02	5.0E-06 - 2.7E-04	6.4E-07	Gg/1000 m <sup>3</sup> conventional oil production
Flaring - heavy oil production <sup>a</sup>	4.9E-02	5.0E-05 - 2.0E-04	4.6E-07	Gg/1000 m <sup>3</sup> heavy oil production
Flaring - crude bitumen production <sup>a</sup>	2.2E-02	8.8E-05	2.4E-07	Gg/1000 m <sup>3</sup> crude bitumen production
Flaring - Refining <sup>b,c</sup>	No data	0.189	No data	scf/1000 bbl refinery feed
<b>Units Converted to tonnes/10<sup>6</sup> scf or tonnes/1000 bbl</b>				
<b>Flare Source</b>	<b>Emission Factors</b>			<b>Units</b>
	<b>CO<sub>2</sub></b>	<b>CH<sub>4</sub></b>	<b>N<sub>2</sub>O</b>	
Flaring - gas production <sup>a</sup>	5.1E-02	3.1E-04	5.9E-07	tonnes/10 <sup>6</sup> scf gas production
Flaring - sweet gas processing <sup>a</sup>	5.9E-02	3.7E-04	7.1E-07	tonnes/10 <sup>6</sup> scf gas receipts
Flaring - sour gas processing <sup>a</sup>	0.13	8.2E-04	1.5E-06	tonnes/10 <sup>6</sup> scf gas receipts
Flaring - conventional oil production <sup>a</sup>	10.7	7.9E-04 - 4.3E-02	1.0E-04	tonnes/1000 bbl conventional oil production
Flaring - heavy oil production <sup>a</sup>	7.8	7.9E-03 - 3.2E-02	7.3E-05	tonnes/1000 bbl heavy oil production
Flaring - crude bitumen production <sup>a</sup>	3.5	1.4E-02	3.8E-05	tonnes/1000 bbl crude bitumen production
Flaring - Refining <sup>b,c</sup>	No data	3.62E-06	No data	tonnes/1000 bbl refinery feed
<b>Units Converted to tonnes/10<sup>6</sup> m<sup>3</sup> or tonnes/1000 m<sup>3</sup></b>				
<b>Flare Source</b>	<b>Emission Factors</b>			<b>Units</b>
	<b>CO<sub>2</sub></b>	<b>CH<sub>4</sub></b>	<b>N<sub>2</sub>O</b>	
Flaring - gas production <sup>a</sup>	1.8	1.1E-02	2.1E-05	tonnes/10 <sup>6</sup> m <sup>3</sup> gas production
Flaring - sweet gas processing <sup>a</sup>	2.1	1.3E-02	2.5E-05	tonnes/10 <sup>6</sup> m <sup>3</sup> gas receipts
Flaring - sour gas processing <sup>a</sup>	4.6	2.9E-02	5.4E-05	tonnes/10 <sup>6</sup> m <sup>3</sup> gas receipts
Flaring - conventional oil production <sup>a</sup>	67.0	5.0E-03 - 2.7E-01	6.4E-04	tonnes/1000 m <sup>3</sup> conventional oil production
Flaring - heavy oil production <sup>a</sup>	49.0	5.0E-02 - 2.0E-01	4.6E-04	tonnes/1000 m <sup>3</sup> heavy oil production
Flaring - crude bitumen production <sup>a</sup>	22.0	8.8E-02	2.4E-04	tonnes/1000 m <sup>3</sup> crude bitumen production
Flaring - Refining <sup>b,c</sup>	No data	2.28E-05	No data	tonnes/1000 m <sup>3</sup> refinery feed

Sources:

<sup>a</sup>IPCC, *IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*, Chapter 2 (Energy), Table 2.16, May 2000.<sup>b</sup>US Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001*. EPA-430-R-03-004, U.S. Environmental Protection Agency, Washington D.C., April 15, 2003, Annex H, Table H-3.<sup>c</sup>CH<sub>4</sub> emission factors converted from scf or m<sup>3</sup> are based on 60°F and 14.7 psia.

During well testing, produced crude may be flared. Figure 4-3 provides preferred and alternative approaches for estimating emissions associated with liquid flare streams. Here also, the preferred approach is to use data from the well testing contractor. Alternatively, fuel-based emission factors from Table 4-1 or 4-2 can be used to estimate CO<sub>2</sub> emissions, or the average emission factor shown in Table 4-8 can be applied.

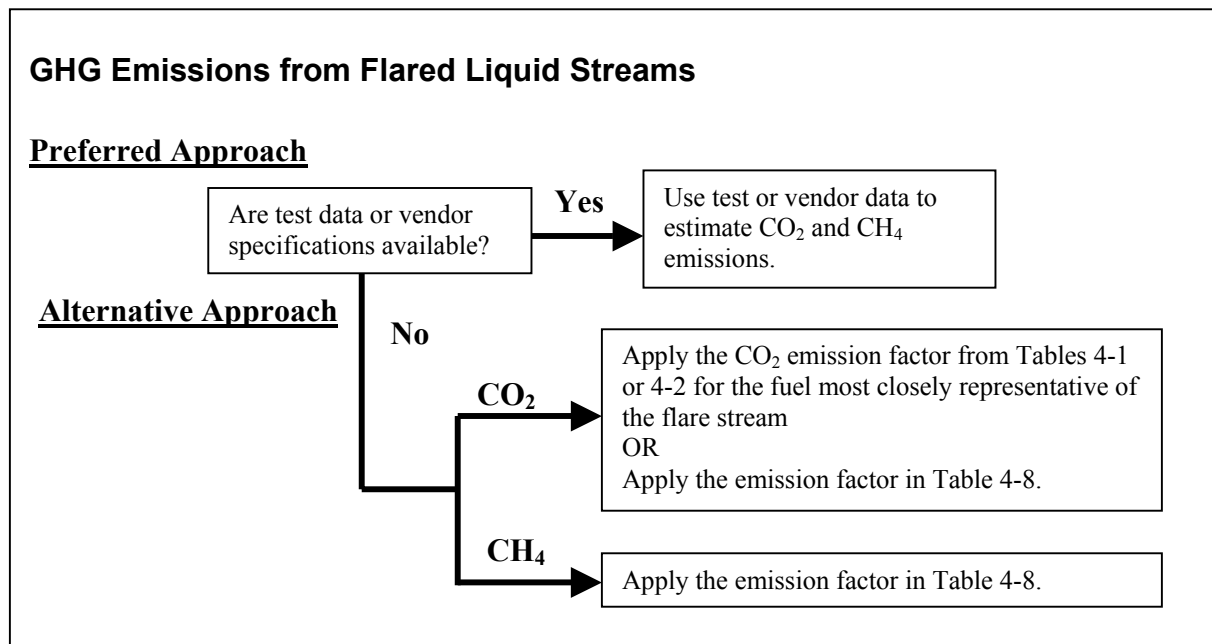


Figure 4-3. Calculation Approaches for Liquid Flare Emissions

Table 4-8. GHG Emission Factors for Liquid Flares

<b>Original Units</b>				
<b>Flare Source</b>	<b>Emission Factors</b>			<b>Units</b>
	<b>CO<sub>2</sub></b>	<b>CH<sub>4</sub></b>	<b>N<sub>2</sub>O</b>	
Upstream liquid flares	3.2×0.95 = 3.04 <sup>a</sup>	0.00033	0.00022	tonnes/tonne oil flared

<sup>a</sup> The CO<sub>2</sub> emission factors is based on the assumption that 95% of the carbon is combusted to form CO<sub>2</sub>.

Source:

OLF Environmental Programme, Report Phase II, Part A, *Emissions to Air*, December 1991.

Referenced in E&P Forum, *Methods for Estimating Atmospheric Emissions from E&P Operations*, Report No. 2.59/197, September 1994.

Note:

Table 3-5 provides a crude density of 7.3 lb/gal or 874.73 kg/m<sup>3</sup> (EPA AP-42, 1998) for converting the emission factor shown in Table 4-8 to a volume basis. However, crude oils can vary significantly. As such, a site specific density is preferred over this default value.



Note that a unique flare situation may exist at production facilities utilizing EOR with CO<sub>2</sub> flood or other CO<sub>2</sub> rich production streams. In this case, the flared gas stream has a high CO<sub>2</sub> content to begin, in addition to CO<sub>2</sub> that is formed from the combustion of associated hydrocarbons. The recommended 98% efficiency may not be applicable to this situation. (See Section 7.1.1 for an example facility producing a CO<sub>2</sub> rich stream.)

Exhibit 4.8 demonstrates emission calculations for flares.

**EXHIBIT 4.8: Sample Calculation for Combustion Emissions from a Gas Flare**

**INPUT DATA:**

A production facility produces 3 million scf/day of natural gas. In a given year, 20 million scf of field gas are flared at the facility. The flare gas composition is unknown.

**ASSUMPTIONS:**

Since test results or vendor data are not available, emissions will be calculated based on the alternative approaches of 98% combustion efficiency for CO<sub>2</sub> emissions and 2% uncombusted CH<sub>4</sub>. The flare gas composition for produced gas, provided in Table 4-6, will be applied in the absence of better data.

**CALCULATION METHODOLOGY:**

For CH<sub>4</sub>, emissions are based on the assumption that 2% of the CH<sub>4</sub> in the flare gas are released uncombusted.

$$\text{CH}_4 : \frac{20 \times 10^6 \text{ scf gas}}{\text{yr}} \times \frac{0.80 \text{ scf CH}_4}{\text{scf gas}} \times \frac{0.02 \text{ scf noncombusted CH}_4}{\text{scf CH}_4 \text{ total}} \times \frac{1 \text{ lbmole CH}_4}{379.3 \text{ scf CH}_4} \times \frac{16 \text{ lb CH}_4}{1 \text{ lbmole CH}_4} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = 6.1 \text{ tonnes CH}_4/\text{yr}$$

For CO<sub>2</sub>, emissions are based on the generic gas composition and the generally accepted 98% combustion efficiency to convert from flare gas carbon to CO<sub>2</sub>.

**EXHIBIT 4.8: Sample Calculation for Combustion Emissions from a Gas Flare, continued**

$$\begin{aligned} \text{CO}_2 : & \frac{20 \times 10^6 \text{ scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \left( \begin{aligned} & \frac{0.80 \text{ lbmole CH}_4}{\text{lbmole gas}} \times \frac{\text{lbmole C}}{\text{lbmole CH}_4} \\ & + \frac{0.15 \text{ lbmole C}_2\text{H}_6}{\text{lbmole gas}} \times \frac{2 \text{ lbmole C}}{\text{lbmole C}_2\text{H}_6} \\ & + \frac{0.05 \text{ lbmole C}_3\text{H}_8}{\text{lbmole gas}} \times \frac{3 \text{ lbmole C}}{\text{lbmole C}_3\text{H}_8} \end{aligned} \right) \\ & \times \frac{0.98 \text{ lbmole CO}_2 \text{ formed}}{\text{lbmole C combusted}} \times \frac{44 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} \\ & = \underline{1,289 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

N<sub>2</sub>O emissions are calculated using the emission factor in Table 4-7. Note that these emission factors are based on the total volume of gas produced at the facility. For comparison purposes, CO<sub>2</sub> and CH<sub>4</sub> emissions are also estimated using the published emission factors.

$$\begin{aligned} \text{N}_2\text{O} : & \frac{3 \times 10^6 \text{ scf gas}}{\text{day}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{5.9 \times 10^{-7} \text{ tonnes N}_2\text{O}}{10^6 \text{ scf gas}} = \underline{6.46 \times 10^{-4} \text{ tonnes N}_2\text{O/yr}} \\ \text{CO}_2 : & \frac{3 \times 10^6 \text{ scf gas}}{\text{day}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{5.1 \times 10^{-2} \text{ tonnes CO}_2}{10^6 \text{ scf gas}} = \underline{55.8 \text{ tonnes CO}_2/\text{yr}} \\ \text{CH}_4 : & \frac{3 \times 10^6 \text{ scf gas}}{\text{day}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{3.1 \times 10^{-4} \text{ tonnes CH}_4}{10^6 \text{ scf gas}} = \underline{0.339 \text{ tonnes CH}_4/\text{yr}} \end{aligned}$$

## 4.5 Mobile/Transportation Combustion Sources

Transportation combustion sources are the engines that provide motive power for vehicles used as part of petroleum operations. Transportation sources may include company fleet vehicles such as cars and trucks used for work-related personnel transport, as well as rail cars, tanker trucks, ships, barges, and pipelines used to transport crude and petroleum products.

The fossil fuel-fired internal combustion engines used in transportation are a significant source of CO<sub>2</sub> emissions. Small quantities of CH<sub>4</sub> and N<sub>2</sub>O are also emitted based on fuel composition, combustion conditions, and post-combustion control technology.

Estimating emissions from mobile sources is complex, requiring detailed information on the types of mobile sources, fuel types, vehicle fleet age, maintenance procedures, operating conditions and frequency, emissions controls, and fuel consumption. EPA has developed a software model, MOBILE Vehicle Emissions Modeling Software<sup>5</sup>, that accounts for these factors in calculating exhaust emissions (CO<sub>2</sub>, HC, CO, NO<sub>x</sub>, particulate matter, and toxics) for gasoline and diesel fueled vehicles. EPA also has a draft emissions model for nonroad equipment and vehicles called NONROAD. However, these approaches are not as accurate for CO<sub>2</sub> emissions and the inputs associated with this level of detail are not easily obtainable.

Figure 4-4 illustrates the methods available for estimating CO<sub>2</sub> emissions from mobile sources. The preferred approach for estimating CO<sub>2</sub> emissions is based on fuel consumption rates and composition data. Alternative approaches apply default fuel data to fuel-based emission factors or emission estimates based on vehicle distance traveled.

The preferred approach for estimating CH<sub>4</sub> and N<sub>2</sub>O emissions from mobile sources is to assume that these emissions are negligible compared to CO<sub>2</sub>. Alternatively, Table 4-9 provides CH<sub>4</sub> and N<sub>2</sub>O emission factors for a number of vehicle and fuel types.

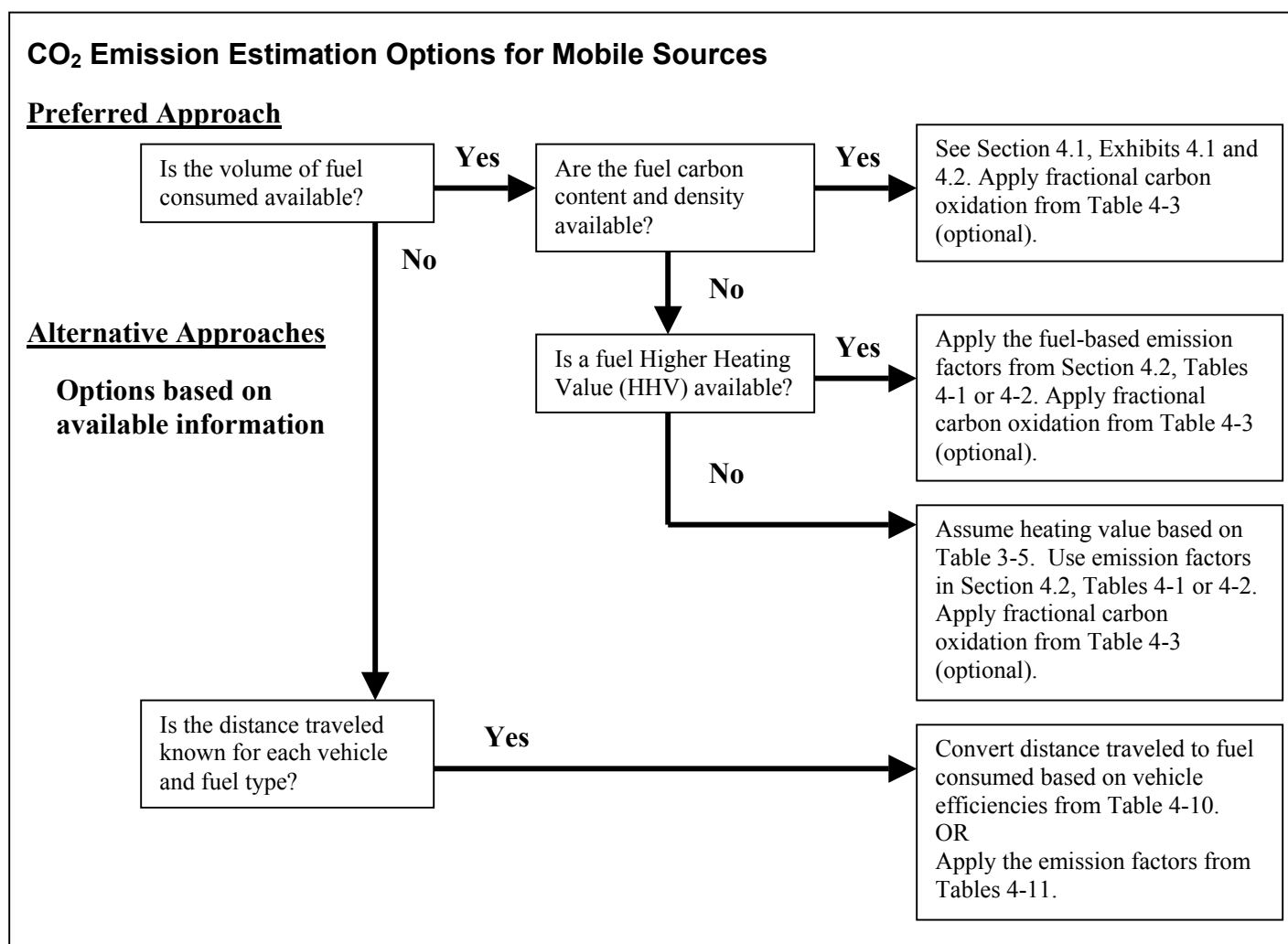
#### **4.5.1 Fuel Consumption Basis**

Approaches for estimating CO<sub>2</sub> emissions from mobile sources are illustrated in Figure 4-4. As presented in Section 4.1 for stationary combustion, the fuel consumption approach for mobile sources is simply based on the volume and type of fuel consumed. If the carbon content of the fuel is known, a material balance approach can be used based on an assumed conversion of carbon in the fuel to CO<sub>2</sub> (typically 100%, as shown in Equation 4-1). This type of calculation is demonstrated in Exhibits 4.1 and 4.2. As a rule of thumb, carbon contents of different fuel types can be approximated from Table 3-5.

If the carbon content is unknown, fuel specific emission factors provided in Table 4-1 can be used. The emission factors are based on the assumption that 100% of the fuel gas hydrocarbons are converted to CO<sub>2</sub>. An example calculation is provided in Exhibit 4.3.

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<sup>5</sup> MOBILE6 is currently available. According to the EPA web site, the Office of Transportation and Air Quality (OTAQ) has been working to develop and release an update to AP-42, "Compilation of Air Pollutant Emission Factors, Volume II: Mobile Sources." The Internet address, [www.epa.gov/oms/ap42.htm](http://www.epa.gov/oms/ap42.htm), provides more details on the status of this work. EPA also has plans to combine the MOBILE and NONROAD models into a new modeling system termed the Multi-scale mOtor Vehicles and equipment Emission System (MOVES). This new system will estimate emissions for on-road and nonroad sources, cover a broad range of pollutants, and allow multiple scale analysis, from fine-scale analysis to national inventory estimation.



**Figure 4-4. Calculation Approaches for Mobile Source CO<sub>2</sub> Emissions**

Methane emissions from transportation fuel consumption can also be estimated using a mass balance and assuming a certain CH<sub>4</sub> destruction efficiency for the CH<sub>4</sub> content of the fuel. Note that gasoline and diesel, the most commonly used transportation fuels, contain negligible amounts of CH<sub>4</sub>. Methane formation from incomplete combustion of these two fuels is also negligible compared to CO<sub>2</sub> formation (EIIP, 1998).

#### 4.5.2 Simplified Emission Factors

Simplified emission factors for mobile source CH<sub>4</sub> and N<sub>2</sub>O emissions are provided in Table 4-9. These mobile source emission factors are taken from Table A7-5 of the report, *Canada's Greenhouse Gas Inventory 1990-2001* (Environment Canada, 2003).

Table 4-9. Mobile Source Combustion Emission Factors

Source <sup>a</sup>	Methane Emission Factor			Nitrous Oxide Emission Factor		
	Original Units, g/L fuel	Converted to tonnes/ 1000 gal fuel	Converted to tonnes/ m <sup>3</sup> fuel	Original Units, g/L fuel	Converted to tonnes/ 1000 gal fuel	Converted to tonnes/ m <sup>3</sup> fuel
<b>On-Road Transport</b>						
<i>Gasoline Fuel</i>						
Light-Duty Gasoline Automobiles (LDGA)						
Tier 1, Three-way catalyst	0.12	4.5E-04	1.2E-04	0.26	9.8E-04	2.6E-04
Tier 0, New Three-way catalyst	0.32	1.2E-03	3.2E-04	0.25	9.5E-04	2.5E-04
Tier 0, Aged Three-way catalyst	0.32	1.2E-03	3.2E-04	0.58	2.2E-03	5.8E-04
Oxidation Catalyst	0.42	1.6E-03	4.2E-04	0.2	7.6E-04	2.0E-04
Non-Catalyst	0.52	2.0E-03	5.2E-04	0.028	1.1E-04	2.8E-05
Light-Duty Gasoline Trucks (LDGT)						
Tier 1, Three-way Catalyst	0.22	8.3E-04	2.2E-04	0.41	1.6E-03	4.1E-04
Tier 0, New Three-way Catalyst	0.41	1.6E-03	4.1E-04	0.45	1.7E-03	4.5E-04
Tier 0, Aged Three-way Catalyst	0.41	1.6E-03	4.1E-04	1	3.8E-03	1.0E-03
Oxidation Catalyst	0.44	1.7E-03	4.4E-04	0.2	7.6E-04	2.0E-04
Non-Catalyst	0.56	2.1E-03	5.6E-04	0.028	1.1E-04	2.8E-05
Heavy-Duty Gasoline Vehicles (HDGV)						
Three-way Catalyst	0.17	6.4E-04	1.7E-04	1	3.8E-03	1.0E-03
Non-Catalyst	0.29	1.1E-03	2.9E-04	0.046	1.7E-04	4.6E-05
Uncontrolled	0.49	1.9E-03	4.9E-04	0.08	3.0E-04	8.0E-05
<i>Diesel Fuel</i>						
Light-Duty Diesel Automobiles (LDDA)						
Advance Control	0.05	1.9E-04	5.0E-05	0.2	7.6E-04	2.0E-04
Moderate Control	0.07	2.6E-04	7.0E-05	0.2	7.6E-04	2.0E-04
Uncontrolled	0.1	3.8E-04	1.0E-04	0.2	7.6E-04	2.0E-04
Light-Duty Diesel Trucks (LDDT)						
Advance Control	0.07	2.6E-04	7.0E-05	0.2	7.6E-04	2.0E-04
Moderate Control	0.07	2.6E-04	7.0E-05	0.2	7.6E-04	2.0E-04
Uncontrolled	0.08	3.0E-04	8.0E-05	0.2	7.6E-04	2.0E-04
Heavy-Duty Diesel Vehicles (HDDV)						
Advance Control	0.12	4.5E-04	1.2E-04	0.08	3.0E-04	8.0E-05
Moderate Control	0.13	4.9E-04	1.3E-04	0.08	3.0E-04	8.0E-05
Uncontrolled	0.15	5.7E-04	1.5E-04	0.08	3.0E-04	8.0E-05
<i>Natural Gas Vehicles</i>	0.022	8.3E-05	2.2E-05	6E-05	2.3E-07	6.0E-08
<i>Propane Vehicles</i>	0.52	2.0E-03	5.2E-04	0.028	1.1E-04	2.8E-05
<b>Off-Road Vehicles</b>						
Other Gasoline Vehicles	2.7	1.0E-02	2.7E-03	0.05	1.9E-04	5.0E-05
Other Diesel Vehicles	0.14	5.3E-04	1.4E-04	1.1	4.2E-03	1.1E-03
<b>Diesel Rail Transportation</b>	0.15	5.7E-04	1.5E-04	1.1	4.2E-03	1.1E-03

**Table 4-9. Mobile Source Combustion Emission Factors (continued)**

Source <sup>a</sup>	Methane Emission Factor			Nitrous Oxide Emission Factor		
	Original Units, g/L fuel	Converted to tonnes/ 1000 gal fuel	Converted to tonnes/ m <sup>3</sup> fuel	Original Units, g/L fuel	Converted to tonnes/ 1000 gal fuel	Converted to tonnes/ m <sup>3</sup> fuel
<b>Marine Transportation</b>						
Gasoline Boats	1.3	4.9E-03	1.3E-03	0.06	2.3E-04	6.0E-05
Diesel Ships	0.15	5.7E-04	1.5E-04	1.00	3.79E-03	1.00E-03
Light Fuel Oil Ships	0.3	1.1E-03	3.0E-04	0.07	2.6E-04	7.0E-05
Heavy Fuel Oil Ships	0.3	1.1E-03	3.0E-04	0.08	3.0E-04	8.0E-05
<b>Air Transportation</b>						
Conventional Aircraft	2.19	8.29E-03	2.19E-03	0.23	8.71E-04	2.3E-04
Jet Aircraft	0.08	3.0E-04	8.0E-05	0.25	9.5E-04	2.5E-04

<sup>a</sup>IPCC provides the following model year information for the following vehicle and control types:

- Non-catalyst controlled gasoline passenger car and light truck: 1973
- Oxidation catalyst controlled gasoline passenger car and light truck: 1978
- Early three-way catalyst controlled gasoline passenger car and light truck: 1983
- Three-way catalyst controlled gasoline passenger car and light truck: 1996

- Uncontrolled heavy-duty gasoline vehicle: 1968
- Non-catalyst controlled heavy-duty gasoline vehicle: 1983
- Three-way catalyst controlled heavy-duty gasoline vehicle: 1996

- Uncontrolled diesel passenger car and light truck: 1978
- Moderate control diesel passenger car and light truck: 1983
- Advanced control diesel passenger car and light truck: 1996

- Uncontrolled heavy-duty diesel vehicle: 1968
- Moderate control heavy-duty diesel vehicle: 1983
- Advanced control heavy-duty diesel vehicle: 1996

Source: Intergovernmental Panel on Climate Change (IPCC). *Greenhouse Gas Inventory Reference Manual: IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 3, United Nations Environment Programme, the Organization for Economic Co-operation and Development, the International Energy Agency, and the Intergovernmental Panel on Climate Change, 1996, Table 1-25.

Source for mobile source combustion emission factors:

Environment Canada, *Canada's Greenhouse Gas Inventory 1990-2001*, Greenhouse Gas Division, Environment Canada, August 2003, Table A7-5.

If the quantity of fuel consumed is unknown for land-based vehicles, the fuel economy factors shown in Table 4-10 can be used to estimate the volumes. These factors are taken from Table 4 of mobile source CO<sub>2</sub> emissions estimation guidance from World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD) (WRI/WBCSD, 2003). Factors provided in Table 3-5 can be used to convert the volume of fuel used to an energy basis.

**Table 4-10. Default Fuel Economy Factors for Different Types of Mobile Sources**

Vehicle Type	Fuel Economy	
	liters/100 km	miles/gallon
New small gas/electric hybrid	4.2	56
Small gas auto, highway	7.3	32
Small gas auto, city	9.0	26
Medium gas auto, highway	7.8	30
Medium gas auto, city	10.7	22
Large gas automobile, highway	9.4	25
Large gas automobile, city	13.1	18
Medium Station wagon, highway	8.7	27
Medium Station wagon, city	11.8	20
Mini Van, highway	9.8	24
Mini Van, city	13.1	18
Large Van, highway	13.1	18
Large Van, city	16.8	14
Mid-size pick-up trucks, highway	10.7	22
Mid-size pick-up Trucks, city	13.8	17
Large pick-up trucks, highway	13.1	18
Large pick-up trucks, city	15.7	15
LPG automobile	11.2	21
Diesel automobile	9.8	24
Gasoline light truck	16.8	14
Gasoline heavy truck	39.2	6
Diesel light truck	15.7	15
Diesel heavy truck	33.6	7
Light motorcycle	3.9	60
Diesel bus	35.1	6.7

Source: World Resources Institute and World Business Council for Sustainable Development (WRI/WBCSD). *Calculating CO<sub>2</sub> Emissions from Mobile Sources. Guidance to calculation worksheets.* Table 4. File: MobileGuidance27May03.doc available through [www.ghgprotocol.org](http://www.ghgprotocol.org), May 2003.

Table 4-11 provides simplified CO<sub>2</sub> emission factors for mobile sources (vehicles) in the United Kingdom based on distance traveled. These emission factors are based on WRI/WBCSD guidance, Tables 5.1, 5.2, and 5.4 (WRI/WBCSD, 2003).

**Table 4-11. Default Distance Based CO<sub>2</sub> Mobile Source Emission Factors for the United Kingdom**

Source	Original Units		Converted to	
	kg CO <sub>2</sub> /miles	kg CO <sub>2</sub> /km	tonne CO <sub>2</sub> /miles	tonne CO <sub>2</sub> /km
Small gasoline (petrol) car, max. 1.4 liter engine	0.28	0.17	0.00028	0.00017
Medium gasoline (petrol) car, 1.4 to 2.1 liter engine	0.36	0.22	0.00036	0.00022
Large gasoline (petrol) car, 2.1 liter engine or larger	0.44	0.27	0.00044	0.00027
Average gasoline (petrol) car	0.33	0.20	0.00033	0.00020
Small diesel car, 2.0 liter engine or smaller	0.19	0.12	0.00019	0.00012
Large diesel car, 2.0 liter engine or larger	0.23	0.14	0.00023	0.00014
Average diesel car	0.20	0.12	0.00020	0.00012
Gasoline (petrol) truck, semi (articulated lorry)	1.3	0.81	0.0013	0.00081
Diesel truck, semi (articulated lorry)	1.5	0.94	0.0015	0.00094
LPG truck, semi (articulated lorry)	0.9	0.53	0.0009	0.00053
Gasoline (petrol) truck, non-semi (rigid lorry)	1.5	0.92	0.0015	0.00092
Diesel truck, non-semi (rigid lorry)	1.7	1.07	0.0017	0.00107
LPG truck, non-semi (rigid lorry)	1.0	0.60	0.0010	0.00060

Source: World Resources Institute and World Business Council for Sustainable Development (WRI/WBCSD). *Calculating CO<sub>2</sub> Emissions from Mobile Sources. Guidance to calculation worksheets.* Tables 5.1, 5.2, and 5.4. File: MobileGuidance27May03.doc available through [www.ghgprotocol.org](http://www.ghgprotocol.org), May 2003.

An example calculation illustrating how to estimate mobile source emissions follows.

#### **EXHIBIT 4.9: Sample Calculation for Combustion Emissions from Mobile Sources**

##### **INPUT DATA:**

A fleet of heavy-duty (HD) diesel trucks travels 1,000,000 miles during the year. The trucks are equipped with advance control systems.



**EXHIBIT 4.9: Sample Calculation for Combustion Emissions from Mobile Sources, continued**

**CALCULATION METHODOLOGY:**

The CH<sub>4</sub> and N<sub>2</sub>O emission factors provided in Table 4-9 are given in terms of volumetric fuel consumed. The fuel usage of the fleet is unknown, so the first step in the calculation is to convert from miles traveled to a volume of diesel fuel consumed basis. This calculation is performed using the default fuel economy factor of 7 miles/gallon for diesel heavy trucks provided in Table 4-10.

$$\frac{1,000,000 \text{ miles}}{\text{yr}} \times \frac{\text{gallons diesel}}{7 \text{ miles}} = 142,857 \text{ gallons diesel consumed/yr}$$

The CH<sub>4</sub> and N<sub>2</sub>O emission factors given in Table 4-9 for "Heavy-Duty Diesel Vehicles, Advance Control" are the following:

CH<sub>4</sub> EF =  $4.5 \times 10^{-4}$  tonne CH<sub>4</sub>/1000 gallons

N<sub>2</sub>O EF =  $3.0 \times 10^{-4}$  tonne N<sub>2</sub>O/1000 gallons

Therefore, CH<sub>4</sub> and N<sub>2</sub>O emissions are calculated as follows:

$$\text{CH}_4 : \frac{142,857 \text{ gallons}}{\text{yr}} \times \frac{4.5 \times 10^{-4} \text{ tonne CH}_4}{1000 \text{ gallons}} = \underline{0.064 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{142,857 \text{ gallons}}{\text{yr}} \times \frac{3.0 \times 10^{-4} \text{ tonne N}_2\text{O}}{1000 \text{ gallons}} = \underline{0.043 \text{ tonnes CO}_2/\text{yr}}$$

Carbon dioxide emissions are estimated using a fuel-based factor provided in Table 4-1. This factor is provided on a heat basis, so the fuel consumption must be converted to an energy input basis. This conversion is carried out using a recommended diesel heating value of  $5.75 \times 10^6$  Btu/bbl (HHV), given in Table 3-5 of this document. Thus, the fuel heat rate is:

$$\frac{142,857 \text{ gal}}{\text{yr}} \times \frac{\text{bbl}}{42 \text{ gal}} \times \frac{5.75 \times 10^6 \text{ Btu}}{\text{bbl}} = 1.96 \times 10^{10} \text{ Btu/yr (HHV)}$$

**EXHIBIT 4.9: Sample Calculation for Combustion Emissions from Mobile Sources, continued**

According to Table 4-1, the fuel basis CO<sub>2</sub> emission factor for diesel fuel (diesel oil) is 0.0742 tonne CO<sub>2</sub>/10<sup>6</sup> Btu (HHV basis).

Therefore, CO<sub>2</sub> emissions are calculated as follows, assuming 100% oxidation of fuel carbon to CO<sub>2</sub>:

$$\text{CO}_2 : \frac{1.96 \times 10^{10} \text{ Btu}}{\text{yr}} \times \frac{0.0742 \text{ tonne CO}_2}{10^6 \text{ Btu}} = \underline{1,454 \text{ tonnes CO}_2/\text{yr}}$$

For comparison and illustrative purposes, CO<sub>2</sub> emissions are estimated using the default distance based emission factor approach assuming the trucks are operated and located in the United Kingdom. The trucks are assumed to be a tractor-trailer type (or “semi” trucks). The emission factor of 0.0015 tonne CO<sub>2</sub>/mile for diesel semi trucks (articulated lorry type) in Table 4-11 is used:

$$\text{CO}_2 : \frac{1,000,000 \text{ miles}}{\text{yr}} \times \frac{0.0015 \text{ tonne CO}_2}{\text{mile}} = \underline{1,500 \text{ tonnes CO}_2/\text{yr}}$$

This sample calculation illustrates that the CH<sub>4</sub> and N<sub>2</sub>O emissions are negligible when compared to CO<sub>2</sub>.

## 4.6 Other Miscellaneous Combustion Source Emissions

Other miscellaneous combustion sources include incinerators, catalytic oxidizers, thermal oxidizers, coke calcining kilns, and exploratory well drilling. Combustion emissions from these sources vary widely from process to process. Thus, there is not a set of published emission factors associated with these equipment/processes. General emission estimate approaches for fuel combustion, combined with site-specific data and/or engineering judgment, are recommended for determining these emissions.

Methane emissions from these sources can be estimated from a mass balance by assuming a certain CH<sub>4</sub> destruction efficiency. The CO<sub>2</sub> emissions can be estimated by mass balance using an assumed conversion of carbon in the fuel gas to CO<sub>2</sub>. Alternatively, the external combustion

emission factors given by fuel usage (described in Section 4.1) can be used for estimating CO<sub>2</sub> emissions.

The following example shows the approach that can be used to estimate CH<sub>4</sub> and CO<sub>2</sub> emissions from an incinerator.

**EXHIBIT 4.10: Sample Calculation for Combustion Emissions – Other Miscellaneous Sources (Incinerator)**

**INPUT DATA:**

An incinerator is used to treat a waste gas stream from an upstream process vessel in a refinery. Previous stack test data have demonstrated that the incinerator achieves at least 98% destruction of the waste gas. The incinerator requires supplemental natural gas (5 million Btu/hr) in order to operate properly. Detailed gas analyses for the waste gas and the supplemental natural gas fuel are not available.

The following is known about the waste gas stream based on process knowledge and/or engineering judgment:

Flow rate: 10 acfm; Pressure: 1 atm; Temperature: 120°F

CH<sub>4</sub> content: 15 mole % (based on engineering design documents)

Heating value: 150 Btu/scf (HHV)

**CALCULATION METHODOLOGY:**

The first step in estimating the waste gas CH<sub>4</sub> emissions is to calculate the CH<sub>4</sub> flow rate in the waste gas stream to the incinerator. The waste gas molar flow rate is calculated using the ideal gas law (Refer to Section 3.5 for more discussion on the ideal gas law):  $PV = nRT$

$$(14.7 \text{ psia})(10 \text{ acfm}) = n \left( \frac{10.73 \text{ psia} \cdot \text{ft}^3}{\text{lbmole} \cdot ^\circ\text{R}} \right) (120 + 459.67 ^\circ\text{R})$$

Solving for the molar flow rate,  $n = 0.0236 \text{ lbmole/min} = 1.416 \text{ lbmole/hr}$ .

The CH<sub>4</sub> flow rate to the incinerator is calculated as:

$$\frac{1.416 \text{ lbmole gas}}{\text{hr}} \times \frac{0.15 \text{ lbmole CH}_4}{\text{lbmole gas}} \times \frac{16 \text{ lb CH}_4}{\text{lbmole CH}_4} = 3.41 \text{ lb CH}_4/\text{hr}$$

**EXHIBIT 4.10: Sample Calculation for Combustion Emissions – Other Miscellaneous Sources (Incinerator), continued**

Assuming 98% destruction of CH<sub>4</sub> in the waste gas and continuous annual operation, the CH<sub>4</sub> emissions from the waste gas are:

$$\frac{3.41 \text{ lb CH}_4}{\text{hr}} \times (1 - 0.98) \times \frac{8760 \text{ hours}}{\text{year}} \times \frac{\text{tonne}}{2205 \text{ lb}} = 0.271 \text{ tonnes CH}_4/\text{yr}$$

Next, the CH<sub>4</sub> emissions from the supplemental fuel combustion gas must be considered. Table 4-4a provides an emission factor of 1.0E-06 tonne CH<sub>4</sub>/10<sup>6</sup> Btu (0.0023 lb CH<sub>4</sub>/10<sup>6</sup> Btu) for external combustion in furnaces or heaters. Thus, the CH<sub>4</sub> emissions from the natural gas combustion are calculated as:

$$\frac{5 \times 10^6 \text{ Btu}}{\text{hr}} \times \frac{1.0 \times 10^{-6} \text{ tonne CH}_4}{10^6 \text{ Btu}} \times \frac{8760 \text{ hr}}{\text{yr}} = 0.044 \text{ tonnes CH}_4/\text{yr}$$

The total of the CH<sub>4</sub> emissions from the waste gas and supplemental natural gas are:

$$\begin{aligned} \text{Total CH}_4 \text{ Emissions} &= \text{Waste Gas Emissions} + \text{Natural Gas Emissions} \\ &= 0.271 \text{ tonne/yr} + 0.044 \text{ tonne/yr} = \underline{0.315 \text{ tonnes CH}_4/\text{yr}} \end{aligned}$$

For CO<sub>2</sub>, Table 4-1 provides a fuel-based combustion emission factor of 0.057 tonnes CO<sub>2</sub>/10<sup>6</sup> Btu (HHV) for refinery fuel gas and 0.0531 tonnes CO<sub>2</sub>/10<sup>6</sup> Btu (HHV) for natural gas. The waste gas flow rate = 10 acfm (note: actual and standard pressures are 14.7 psia). The waste gas firing rate is then calculated by converting to standard conditions of 60°F and applying the specified heating value:

$$\frac{10 \text{ ft}^3}{\text{min}} \times \left( \frac{60 + 459.67^\circ\text{R}}{120 + 459.67^\circ\text{R}} \right) = 8.96 \text{ scfm} \times \frac{60 \text{ min}}{\text{hr}} \times \frac{150 \text{ Btu}}{\text{scf}} = 80,640 \text{ Btu/hr}$$

Next, the CO<sub>2</sub> emissions are calculated for the natural gas and waste gas streams:

$$\text{Natural Gas: } \frac{5.0 \times 10^6 \text{ Btu}}{\text{hr}} \times \frac{0.0531 \text{ tonne CO}_2}{10^6 \text{ Btu}} \times \frac{8760 \text{ hr}}{\text{yr}} = \underline{2,326 \text{ tonnes CO}_2/\text{yr}}$$

$$\text{Waste Gas: } \frac{80,640 \text{ Btu}}{\text{hr}} \times \frac{0.057 \text{ tonne CO}_2}{10^6 \text{ Btu}} \times \frac{8760 \text{ hr}}{\text{yr}} = \underline{40.3 \text{ tonnes CO}_2/\text{yr}}$$

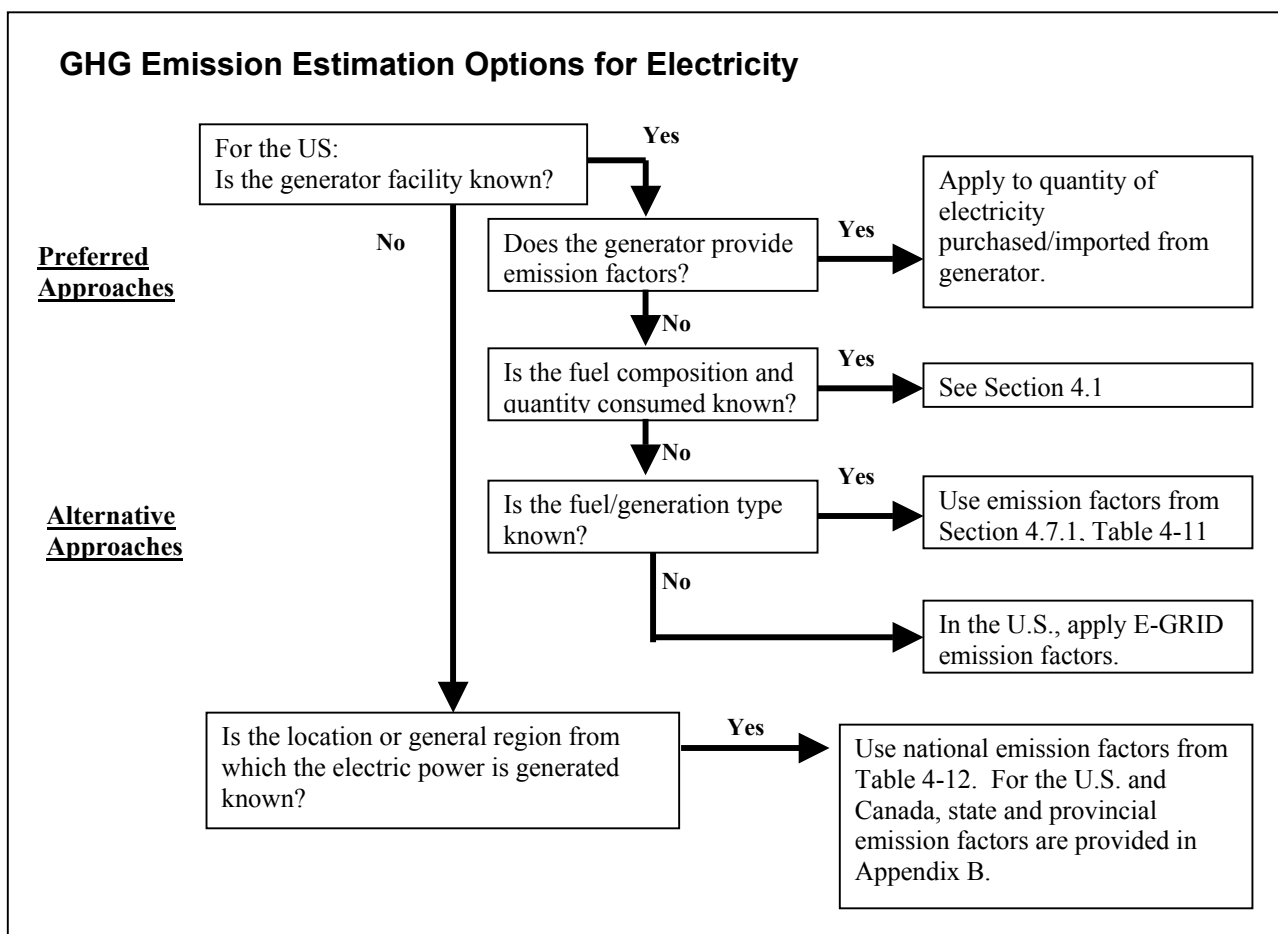
$$\begin{aligned} \text{Total CO}_2 \text{ Emissions} &= \text{Natural Gas Emissions} + \text{Waste Gas Emissions} \\ &= 2,326 \text{ tonnes/yr} + 40.3 \text{ tonnes/yr} = \underline{2,366 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

## 4.7 Emissions Associated with Purchased Energy

Carbon dioxide, CH<sub>4</sub>, and N<sub>2</sub>O are emitted when fuel is combusted to generate electricity or to produce heat or steam. This section provides methodologies for estimating the emissions associated with these activities, where these energy sources are generated offsite and imported or purchased for use onsite.

### 4.7.1 Electric Utility Emissions

As shown in Figure 4-5, the emission estimation approach for purchased or imported electricity varies depending on whether the power was purchased from the grid or from a known generator.



**Figure 4-5. Decision Tree for Purchased Electricity Emissions**

## Electricity from a Known Generator

It is often difficult to track purchased electricity back to the source. For the case where electricity is supplied from a known generator, the preferred approach for estimating combustion emissions associated with purchased or imported electricity is either to use fuel derived emission factors provided by the generator or to estimate emissions based on fuel data using the combustion emission approach presented in Section 4.1. If only general information on the type of fuel and combustion method are known, the U.S. Department of Energy (DOE) provides the following CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emission factors for electricity generation on a power consumed basis (megawatt-hours) (DOE, 1994).

**Table 4-12. Electricity Usage Emission Factors by Method of Generation**

Method of Generation	Carbon Dioxide		Methane		Nitrous Oxide	
	lb/ 10 <sup>6</sup> W-hr	Tonnes/ 10 <sup>6</sup> W-hr	lb/ 10 <sup>6</sup> W-hr	Tonnes/ 10 <sup>6</sup> W-hr	lb/ 10 <sup>6</sup> W-hr	Tonnes/ 10 <sup>6</sup> W-hr
Gas – Combined Cycle	952	0.432	0.015	6.80E-06	0.063	2.86E-05
Gas – Combustion Turbine	1,560	0.708	0.16	7.26E-05	0.24	1.09E-04
Gas – Steam Turbine	968	0.439	0.05	2.27E-05	0	0
Oil – Combined Cycle	1,330	0.603	0.013	5.90E-06	0.268	1.22E-04
Oil – Combustion Turbine	2,150	0.975	0.021	9.53E-06	0.276	1.25E-04
Oil – Steam Turbine	1,452	0.659	0.002	9.07E-07	0	0
Pulverized Coal	1,970	0.894	0.04	1.81E-05	0.34	1.54E-04
Wood Waste Biomass Boiler <sup>b</sup>	3,400	1.542	0.14	6.35E-05	0.55	2.49E-04
Municipal Solid Waste Boiler <sup>a</sup>	3,747	1.700	0.02	9.07E-06	0.55	2.49E-04
Geothermal <sup>c</sup>		0.122				
Renewables (wind, hydro, solar, and nuclear)	0	0	0	0	0	0

Source: US Department of Energy, Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992, Volume I, DOE/PO-0028, Washington, D.C. October 1994.

<sup>a</sup> Under international GHG accounting methods developed by the Intergovernmental Panel on Climate Change, biogenic carbon is considered to be part of the natural carbon balance and it does not add to atmospheric concentrations of CO<sub>2</sub>.

<sup>b</sup> Municipal solid waste normally contains inorganic materials—principally plastics—that contain carbon that is not biogenic. The proportion of plastics in municipal solid waste varies considerably depending on climate, season, socio-economic factors, and waste management practices. As a result, EIA does not estimate a non-biogenic carbon dioxide emission factor for municipal solid waste.

<sup>c</sup>Source: International Geothermal Association (Bertani and Thain, 2001).

Note that these emissions do not include transmission and distribution losses, but are applicable to megawatt-hr of metered electricity usage. Emissions resulting from transmission and distribution losses are accounted for by the entity that owns the transmission or distribution service lines. As

such, any losses that occur downstream of the customer meter are incorporated into the customer's emission inventory by basing the emission estimate on the metered energy usage.

One generation method not assessed by DOE in Table 4-12 is geothermal. Although this is considered a renewable energy source, the geothermal gas can contain high concentrations of CO<sub>2</sub>. The International Geothermal Association conducted a survey to determine CO<sub>2</sub> emissions from geothermal power plants from around the world (Bertani and Thain, 2001). Emission data were collected from 85 geothermal power plants operating in 11 countries, representing 85% of the worldwide geothermal power plant capacity. From this data, the generation-weighted CO<sub>2</sub> emission rate of 122 grams per kilowatt-hr was calculated.

Exhibit 4.11 demonstrates the use of the generation-based emission factors provided in Table 4-12.

**EXHIBIT 4.11: Sample Calculation for Electric Utility (Indirect) Emissions Using Generation-based Emission Factors**

**INPUT DATA:**

A facility purchases 500,000 kilowatt-hrs of electricity during a given year generated from an offsite natural gas combined cycle system.

**CALCULATION METHODOLOGY:**

Table 4-1 provides the following emission factors for natural gas combined cycle:

CO<sub>2</sub> EF = 0.432 tonnes CO<sub>2</sub>/10<sup>6</sup> W-hr

CH<sub>4</sub> EF = 6.80E-06 tonnes CH<sub>4</sub>/10<sup>6</sup> W-hr

N<sub>2</sub>O EF = 2.86-05 tonnes N<sub>2</sub>O/10<sup>6</sup> W-hr

The emission factors are multiplied by the quantity of electricity purchased to calculate the annual emissions, as follows:

$$\text{CO}_2 : \frac{500,000 \text{ kilowatt - hr}}{\text{yr}} \times \frac{1 \text{ megawatt}}{1000 \text{ kilowatt}} \times \frac{0.432 \text{ tonne CO}_2}{\text{megawatt - hr}} = \underline{216 \text{ tonnes CO}_2/\text{yr}}$$

$$\text{CH}_4 : \frac{500,000 \text{ kilowatt - hr}}{\text{yr}} \times \frac{1 \text{ megawatt}}{1000 \text{ kilowatt}} \times \frac{6.80 \times 10^{-6} \text{ tonne CH}_4}{\text{megawatt - hr}} = \underline{0.0034 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{500,000 \text{ kilowatt - hr}}{\text{yr}} \times \frac{1 \text{ megawatt}}{1000 \text{ kilowatt}} \times \frac{2.86 \times 10^{-5} \text{ tonne CO}_2}{\text{megawatt - hr}} = \underline{0.0143 \text{ tonnes N}_2\text{O}/\text{yr}}$$

In the U.S., if the generator of purchased electricity is known but fuel-based data are not available, general emission factors from EPA can be applied. Currently, EPA maintains a database with information from virtually every power plant and company that generates electricity in the U.S. The database is available at the following website:

<http://www.epa.gov/airmarkets/egrid>

The database integrates information from both utility and non-utility companies and provides CO<sub>2</sub> emission rates (in addition to NO<sub>x</sub>, SO<sub>2</sub>, and Hg) in terms of boiler, generator, power plant, electric generating company, parent company, state, power control area, and North American Electric Reliability Council (NERC) region.

Ideally, the emissions would be based on the most detailed information available. For example, if a facility knew that their electricity was primarily supplied by a specific power plant, emissions data at this level would provide the highest accuracy. If company specific information were not available, state or regional grid average values would be appropriate.

Note that the EPA E-GRID database does not currently collect and report CH<sub>4</sub> and N<sub>2</sub>O emissions. The alternative approaches using average or composite grid emission factors (discussed in the next subsection) can be used to estimate CH<sub>4</sub> and N<sub>2</sub>O emissions.

### **Purchased Electricity from an Unknown Generator**

In the case where electricity is imported directly from a third party power supplier, the data to estimate emissions may not be available in all cases. Where data are unavailable, the default approach is to assume that the electricity was supplied from the grid. Regional or national grid emission factors may be available from federal governments. Table 4-13 provides national emission factors from published sources or developed from International Energy Agency (IEA) data. These emission factors are based on electricity generation and do not include transmission or distribution line losses. The approach used to develop the emission factors from IEA data is provided in Appendix B. Appendix B also presents state and provincial emission factors for the U.S. and Canada.



**Table 4-13. International Electric Grid Emission Factors  
Average of 2000 – 2002 Data (Generation Basis)**

<b>tonnes/10<sup>6</sup> W-hr</b>				
<b>Country</b>	<b>CO<sub>2</sub></b>	<b>CH<sub>4</sub></b>	<b>N<sub>2</sub>O</b>	<b>Data Source</b>
Australia	0.754	1.54E-05	1.25E-04	Developed from EIA, 2003 (See Appendix B)
Austria	0.193	4.92E-06	2.95E-05	
Belgium	0.242	4.44E-06	3.23E-05	
Canada	0.222	7.82E-06	4.14E-06	Environment Canada, 2003
Czech Republic	0.647	1.33E-05	1.10E-04	Developed from EIA, 2003 (See Appendix B)
Denmark	0.596	1.20E-05	9.35E-05	
Finland	0.340	1.21E-05	7.73E-05	
France	0.061	1.23E-06	9.05E-06	
Germany	0.521	1.04E-05	8.61E-05	
Greece	0.732	1.26E-05	1.02E-04	
Hungary	0.401	6.38E-06	4.68E-05	
Iceland	0.022	7.53E-10	0.00E+00	
Ireland	0.680	8.92E-06	7.59E-05	
Italy	0.459	5.21E-06	3.06E-05	
Japan	0.381	6.19E-06	4.16E-05	
Korea	0.444	7.47E-06	5.89E-05	
Luxembourg	0.161	3.06E-06	1.96E-05	
Mexico	0.491	4.20E-06	2.42E-05	
Netherlands	0.519	9.70E-06	6.64E-05	
New Zealand	0.155	3.23E-06	1.60E-05	
Norway	0.002	1.48E-07	7.42E-07	
Poland	0.854	1.72E-05	1.45E-04	
Portugal	0.501	8.76E-06	6.29E-05	
Slovak Republic	0.211	4.07E-06	3.07E-05	
Spain	0.411	7.50E-06	5.70E-05	
Sweden	0.030	1.94E-06	9.43E-06	
Switzerland	0.007	4.56E-07	6.37E-06	
Turkey	0.480	7.98E-06	5.53E-05	
UK	0.43	9.27E-06	6.52E-05	DEFRA, 2003
US	0.606	5.03E-06	8.71E-06	EIA, 2002

Sources:

Appendix B provides the approach used to estimate emission factors based on data from the following source:  
International Energy Agency (IEA). *Electricity Information 2002*. IEA Energy Statistics Division, 2002.  
Electricity Emissions Database purchased from <http://www.iea.org>.

DEFRA, *Guidelines for the Measurement and Reporting of Emissions by Direct Participants in the UK Emissions Trading Scheme*, Department for Environment, Food, and Rural Affairs, UKETS(01)05rev2, June 2003.

Energy Information Administration (EIA), *Updated State- and Regional-level Greenhouse Gas Emission Factors for Electricity*, U.S. Department of Energy, EIA, Office of Integrated Analysis and Forecasting, <http://www.eia.doe.gov/oiaf/1605/e-factor.html>, March 2002.

Environment Canada, Electricity generation data provided to URS Corporation on September 16, 2003. Emissions data: Olsen, K., et al. *Canada's Greenhouse Gas Inventory 1990-2001*, Greenhouse Gas Division, Environment Canada, August, 2003. Discussed further in Appendix B.

**Table 4-13. International Electric Grid Emission Factors, continued**  
**Average of 2001 – 2002 Data (Generation Basis)**

tonnes/10 <sup>6</sup> W-hr								
Country	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O		Country	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Algeria	0.438	6.61E-06	2.77E-05		Argentina	0.250	3.99E-06	1.73E-05
Angola	0.243	3.34E-07	0.00E+00		Bolivia	0.222	3.59E-06	1.44E-05
Benin	0.659	9.07E-07	0.00E+00		Brazil	0.064	2.36E-06	1.10E-05
Cameroon	0.010	1.42E-08	0.00E+00		Chile	0.318	7.56E-06	4.81E-05
Congo	0.000	0.00E+00	0.00E+00		Colombia	0.142	3.29E-06	1.88E-05
Democratic Republic of Congo	0.002	3.24E-09	0.00E+00		Costa Rica	0.025	1.94E-07	7.20E-07
Cote d'Ivoire	0.286	3.98E-06	1.65E-05		Cuba	0.619	4.27E-06	1.34E-05
Egypt	0.389	4.68E-06	1.91E-05		Dominican Republic	0.621	1.79E-06	7.15E-06
Eritrea	0.659	9.07E-07	0.00E+00		Ecuador	0.212	2.92E-07	0.00E+00
Ethiopia	0.009	1.04E-08	0.00E+00		El Salvador	0.335	7.51E-07	1.28E-06
Gabon	0.185	1.31E-06	4.71E-06		Guatemala	0.351	1.10E-05	4.85E-05
Ghana	0.080	1.10E-07	0.00E+00		Haiti	0.317	4.37E-07	0.00E+00
Kenya	0.307	4.04E-07	0.00E+00		Honduras	0.252	9.82E-07	2.49E-06
Libya	0.659	9.07E-07	0.00E+00		Jamaica	0.637	1.83E-06	3.75E-06
Morocco	0.772	1.21E-05	1.00E-04		Netherlands Antilles	0.659	9.07E-07	0.00E+00
Mozambique	0.003	4.00E-09	0.00E+00		Nicaragua	0.547	2.36E-06	6.37E-06
Namibia	0.023	1.50E-07	1.09E-06		Panama	0.271	9.72E-07	2.35E-06
Nigeria	0.286	3.82E-06	1.58E-05		Paraguay	0.000	5.19E-08	2.03E-07
Senegal	0.659	9.07E-07	0.00E+00		Peru	0.101	1.05E-06	4.63E-06
South Africa	0.827	1.68E-05	1.43E-04		Trinidad and Tobago	0.430	7.06E-06	2.96E-05
Sudan	0.341	4.69E-07	0.00E+00		Uruguay	0.023	2.60E-07	8.98E-07
United Republic of Tanzania	0.042	3.30E-07	2.48E-06		Venezuela	0.151	1.41E-06	5.55E-06
Togo	0.659	9.07E-07	0.00E+00		Other Latin America	0.550	1.45E-06	2.71E-06
Tunisia	0.453	6.10E-06	2.52E-05					
Zambia	0.005	3.78E-08	2.87E-07					
Zimbabwe	0.515	1.04E-05	8.81E-05					
Other Africa	0.403	5.55E-07	0.00E+00					

Appendix B provides the approach used to estimate emission factors based on data from the following source: International Energy Agency (IEA). *Electricity Information 2002*. IEA Energy Statistics Division, 2002. Electricity Emissions Database purchased from <http://www.iea.org>.

**Table 4-13. International Electric Grid Emission Factors, continued**  
**Average of 2001 – 2002 Data (Generation Basis)**

<b>tonnes/10<sup>6</sup> W-hr</b>							
<b>Country</b>	<b>CO<sub>2</sub></b>	<b>CH<sub>4</sub></b>	<b>N<sub>2</sub>O</b>	<b>Country</b>	<b>CO<sub>2</sub></b>	<b>CH<sub>4</sub></b>	<b>N<sub>2</sub>O</b>
Romania	0.453	7.84E-06	6.11E-05	Bangladesh	0.425	5.89E-06	2.44E-05
Bosnia and Herzegovina	0.456	9.21E-06	7.82E-05	Brunei	0.434	6.76E-06	2.84E-05
Croatia	0.299	3.70E-06	2.58E-05	Hong Kong, China	0.714	1.37E-05	1.05E-04
Former Yugoslav Republic of Macedonia	0.762	1.49E-05	1.26E-04	India	0.721	1.45E-05	1.22E-04
Slovenia	0.321	6.48E-06	5.42E-05	Indonesia	0.569	7.97E-06	5.60E-05
Federal Republic of Yugoslavia	0.546	1.08E-05	9.10E-05	Korea, DPR	0.352	6.80E-06	5.76E-05
Armenia	0.202	3.19E-06	1.34E-05	Malaysia	0.422	5.96E-06	2.71E-05
Azerbaijan	0.514	3.32E-06	1.20E-05	Myanmar	0.302	3.96E-06	1.63E-05
Belarus	0.447	6.40E-06	2.66E-05	Nepal	0.010	1.31E-08	0.00E+00
Estonia	0.850	1.70E-05	1.42E-04	Pakistan	0.395	2.67E-06	1.01E-05
Georgia	0.094	1.30E-06	5.57E-06	Philippines	0.513	7.22E-06	5.97E-05
Kazakhstan	0.703	1.35E-05	1.11E-04	Singapore	0.575	2.67E-06	8.64E-06
Kyrgyzstan	0.058	1.08E-06	7.94E-06	Sri Lanka	0.350	4.82E-07	0.00E+00
Latvia	0.166	2.12E-06	1.18E-05	Chinese Taipei	0.594	9.78E-06	7.87E-05
Lithuania	0.095	9.89E-07	3.95E-06	Thailand	0.500	8.94E-06	5.17E-05
Republic of Moldova	0.445	7.10E-06	3.31E-05	Vietnam	0.274	3.22E-06	2.16E-05
Russia	0.383	6.38E-06	4.21E-05	Other Asia	0.300	4.13E-07	0.00E+00
Tajikistan	0.010	1.59E-07	6.70E-07	People's Republic of China	0.712	1.41E-05	1.19E-04
Turkmenistan	0.432	6.80E-06	2.86E-05	Albania	0.017	2.36E-08	0.00E+00
Ukraine	0.344	6.15E-06	4.69E-05	Bulgaria	0.415	8.14E-06	6.76E-05
Uzbekistan	0.422	5.75E-06	2.69E-05	Cyprus	0.659	9.07E-07	0.00E+00
Bahrain	0.432	6.80E-06	2.86E-05	Gibraltar	0.659	9.07E-07	0.00E+00
Islamic Republic of Iran	0.464	5.34E-06	2.16E-05	Malta	0.659	9.07E-07	0.00E+00
Iraq	0.647	8.91E-07	0.00E+00				
Israel	0.828	1.33E-05	1.11E-04				
Jordan	0.632	1.50E-06	2.89E-06				
Kuwait	0.604	2.32E-06	6.84E-06				
Lebanon	0.626	8.63E-07	0.00E+00				
Oman	0.474	5.72E-06	2.33E-05				
Qatar	0.442	6.53E-06	2.72E-05				
Saudi Arabia	0.576	3.06E-06	1.04E-05				
Syria	0.307	2.83E-06	1.11E-05				
United Arab Emirates	0.450	6.34E-06	2.63E-05				
Yemen	0.659	9.07E-07	0.00E+00				

Appendix B provides the approach used to estimate emission factors based on data from the following source: International Energy Agency (IEA). *Electricity Information 2002*. IEA Energy Statistics Division, 2002. Electricity Emissions Database purchased from <http://www.iea.org>.

#### 4.7.2 Steam/Heat Utility Emissions

Imported steam/heat or steam/heat generated onsite results in GHG emissions due to combustion that occurs to produce the steam. If the method of generation for the steam/heat is known, then the approach to estimate combustion emissions given in Section 4.1 can be used. However, if no information about the steam/heat generation method is known, then a simple approach of assuming that the steam/heat was generated in a natural gas boiler is suggested. A thermal based emission factor for this approach can be developed by dividing a boiler emission factor on a lower heating value (LHV) basis by an assumed boiler efficiency. For example, the LHV natural gas combustion emission factors given in Table 4-2 for CO<sub>2</sub> and Table 4-4a for CH<sub>4</sub> and N<sub>2</sub>O (uncontrolled) can be converted to a thermal basis by dividing by an assumed 92% boiler efficiency, as shown below:

CO <sub>2</sub> Emission Factor	=	$\frac{0.0531 \text{ tonne}/10^6 \text{ Btu}}{0.92}$	= 0.05772 tonne CO <sub>2</sub> /10 <sup>6</sup> Btu (steam/heat energy basis)
CH <sub>4</sub> Emission Factor	=	$\frac{1.11 \times 10^{-6} \text{ tonne}/10^6 \text{ Btu}}{0.92}$	= 1.21 × 10 <sup>-6</sup> tonne CH <sub>4</sub> /10 <sup>6</sup> Btu (steam/heat energy basis)
N <sub>2</sub> O Emission Factor	=	$\frac{3.0 \times 10^{-7} \text{ tonne}/10^6 \text{ Btu}}{0.92}$	= 3.26 × 10 <sup>-7</sup> tonne CO <sub>2</sub> /10 <sup>6</sup> Btu (steam/heat energy basis)

Steam is measured in terms of pressure, temperature, and flow rate. Based on the temperature and pressure of the imported steam and a readily available steam table, the mass quantity of the steam can be converted to an equivalent thermal energy basis using an assumed reference condition of liquid water at 212 °F (100 °C). The steam factors given above can then be applied to determine the CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O indirect emissions from the imported steam.

The calculation exhibit that follows illustrates this simplified approach.

#### EXHIBIT 4.12: Sample Calculation for Steam (Indirect) Emissions

##### INPUT DATA:

A facility purchases 15 million pounds of 600 psig, 700°F steam during a given year. The method of steam generation is unknown.

# **EXHIBIT 4.12: Sample Calculation for Steam (Indirect) Emissions, continued**

## **CALCULATION METHODOLOGY:**

Because the method of steam generation is unknown, the simple approach of assuming the steam was generated in a natural gas boiler with an efficiency of 92% will be used. The first step is to convert the mass of steam generated into an equivalent thermal basis using 212°F saturated water as the reference basis. Using a commonly available steam table, the enthalpy of the steam at the two conditions are:

Steam, 600 psig, 700°F = 1350 Btu/lbm

Saturated Water, 212°F = 180 Btu/lbm

Thus, the equivalent steam thermal energy is:

$$\text{Steam thermal equivalent} = (15 \times 10^6 \text{ lbm/yr})(1350 \text{ Btu/lbm} - 180 \text{ Btu/lbm}) = 1.755 \times 10^{10} \text{ Btu/yr}$$

The emissions can now be estimated using the emission factors presented in the preceding discussion:

$$\text{CO}_2 : \frac{1.755 \times 10^{10} \text{ Btu}}{\text{yr}} \times \frac{0.05772 \text{ tonne}}{10^6 \text{ Btu}} = \underline{1,013 \text{ tonnes CO}_2/\text{yr}}$$

$$\text{CH}_4 : \frac{1.755 \times 10^{10} \text{ Btu}}{\text{yr}} \times \frac{1.21 \times 10^{-6} \text{ tonne}}{10^6 \text{ Btu}} = \underline{0.0212 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{1.755 \times 10^{10} \text{ Btu}}{\text{yr}} \times \frac{3.26 \times 10^{-7} \text{ tonne}}{10^6 \text{ Btu}} = \underline{0.0057 \text{ tonnes N}_2\text{O/yr}}$$

## **4.7.3 Allocation of Cogeneration Emissions**

Cogeneration of electricity and steam, also known as combined heat and power (CHP), is the simultaneous production of electricity and process heat from the same fuel. In these units, the heat produced from the electricity generating process (e.g., from the exhaust systems of gas turbines or from conventional boilers with steam turbines) is captured and used for process steam, hot water heating, space heating, and other thermal needs, or to produce additional electricity. Lower emissions result from these processes because process heat is generated with little or no additional fuel usage. Note that for some processes, additional energy from a secondary combustion unit is required to generate steam. GHG emissions should also be considered from this supplemental combustion source.

Where all or part of the electricity and/or steam/heat produced from the cogeneration facility is transferred, sold, or otherwise used by another entity, it may be necessary to divide the emissions resulting from the CHP among multiple energy streams. The UK Emissions Trading Scheme (DEFRA, 2003), the WRI/WBCSD GHG Protocol Initiative (WRI/WBCSD, 2001), and the California Climate Action Registry (CACR, 2002) have published approaches for allocating emissions between energy streams in cases where these streams are used by two or more different parties. Each of approaches partitions the total emissions resulting from fuel combustion in the cogeneration unit between the electricity and steam energy streams. As a result, the sum of the emissions assigned to the individual energy streams does not exceed the total emissions resulting from the fuel combusted to produce the energy.

These allocation methodologies are discussed further and illustrated through calculation exhibits.

### Efficiency Allocation Approach - UK Emissions Trading Scheme

The UK Emissions Trading Scheme (ETS) bases its allocation on the assumption that the efficiency of heat generation is twice that of electricity generation. The approach applies to emissions associated with the direct import/export of electricity from a combined heat and power (CHP) facility (i.e., via direct contract, not supply to/from grid).

The first step is to calculate the total direct CO<sub>2</sub> emissions from the combustion of natural gas at the cogeneration facility. The second step is to calculate the thermal equivalent of the steam. The mass of steam generated is converted to an equivalent thermal basis using 212°F saturated water as the reference basis. A commonly available steam table provides the enthalpy of the steam at the actual and reference conditions. The third step is to apply the equation for direct electricity or steam imports/exports from cogeneration used in the UK ETS protocol. The equations are provided below.

#### Electricity Emission Factor from Cogeneration Facility:

$$\text{CO}_2 \text{ EF from electricity (lb CO}_2\text{/megawatt - hr)} = \frac{2 \times \text{CO}_2 \text{ direct emissions (tonnes CO}_2\text{)}}{[2 \times \text{Electricity produced (megawatt - hr)}] + \text{Steam produced (megawatt - hr)}}$$

(Equation 4-5)

Steam Emission Factor from Cogeneration Facility:

$$\text{CO}_2 \text{ EF from steam} = \frac{\text{CO}_2 \text{ direct emissions (tonnes CO}_2\text{)}}{[2 \times \text{Electricity produced (megawatt - hr)}] + \text{Steam produced (megawatt - hr)}}$$

(Equation 4-6)

This approach is illustrated in the following exhibit.

**EXHIBIT 4.13: Cogeneration Emissions Allocation – UK ETS Efficiency Allocation Approach**

**INPUT DATA:**

A cogeneration facility operates three natural gas-fired combustion turbines, three heat recovery steam generators with supplemental duct firing capability, and a steam turbine. The combustion turbines and duct burners are the only material sources of GHG emissions associated with the cogeneration plant (i.e., fugitive component emissions are assumed to be negligible).

The cogeneration facility consumes 8,131,500 million Btu of natural gas, producing 3,614,000 million Btu steam and 1,100,600 megawatt-hr of electricity (gross) on an annual basis. A nearby refinery purchases 2,710,000 million Btu of steam and 206,000 megawatt-hr of electricity. The cogeneration facility itself requires 38,500 megawatt-hr to operate (Parasitic load). The net electricity (856,100 megawatt-hrs, metered at the custody transfer point) is sold to the electric grid.

This example applies the UK Emissions Trading System approach to allocating emissions between steam and electricity. Note that the UK ETS program does not currently address CH<sub>4</sub> and N<sub>2</sub>O emissions, but the approach presumably applies to CO<sub>2</sub> equivalent emissions.

**CALCULATION METHODOLOGY:**

Step 1: Direct (On-site) Combustion Emissions from Cogeneration:

For the cogeneration unit, emissions are calculated based on the natural gas consumed using the emission factors in *Compendium* Table 4-1 for CO<sub>2</sub> and Table 4-5 (natural gas turbines) for CH<sub>4</sub> and N<sub>2</sub>O:

$$\text{CO}_2 : 8,131,500 \times 10^6 \text{ Btu} \times \frac{0.0531 \text{ tonnes CO}_2}{10^6 \text{ BTU natural gas}} = 431,782 \text{ tonnes CO}_2$$

**EXHIBIT 4.13: Cogeneration Emissions Allocation – UK ETS Efficiency Allocation Approach, continued**

$$\text{CH}_4 : 8,131,500 \times 10^6 \text{ Btu} \times \frac{3.9 \times 10^{-6} \text{ tonnes CH}_4}{10^6 \text{ BTU natural gas}} = 31.7 \text{ tonnes CH}_4$$

$$\text{N}_2\text{O} : 8,131,500 \times 10^6 \text{ Btu} \times \frac{1.4 \times 10^{-6} \text{ tonnes N}_2\text{O}}{10^6 \text{ BTU natural gas}} = 11.4 \text{ tonnes N}_2\text{O}$$

$$\begin{aligned} \text{CO}_2 \text{ Eq.} : 431,782 + \left( 31.7 \times \frac{21 \text{ tonnes CO}_2 \text{ Eq.}}{\text{tonnes CH}_4} \right) + \left( 11.4 \times \frac{310 \text{ tonnes CO}_2 \text{ Eq.}}{\text{tonnes N}_2\text{O}} \right) \\ = 435,982 \text{ tonnes CO}_2 \text{ Eq.} \end{aligned}$$

Step 2: Steam Thermal Equivalent

The total amount of steam generated from the cogeneration facility needs to be converted from a Btu basis to a megawatt-hr basis. Table 3-2 provides the conversion factor.

The steam thermal equivalent is then:

$$\begin{aligned} 3,614,000 \times 10^6 \text{ Btu steam} \times \frac{2.931 \times 10^{-4} \text{ kilowatt - hr}}{\text{Btu}} \times \frac{\text{megawatt - hr}}{1000 \text{ kilowatt - hr}} \\ = 1,059,263 \text{ megawatt - hr/yr} \end{aligned}$$

Step 3: Calculate Electricity and Steam Emission Factors

The third step is to apply the UK ETS equations (Equations 4-5 and 4-6) for allocating emissions between the electricity and steam energy to generate emission factors.

Electricity allocation:

$$\begin{aligned} & \frac{2 \times \text{CO}_2 \text{ direct emissions (tonnes CO}_2\text{)}}{[2 \times \text{Electricity produced (megawatt - hr)}] + \text{Steam produced (megawatt - hr)}} \\ & = \frac{2 \times 435,982 \text{ tonnes CO}_2 \text{ Eq.}}{[2 \times 1,100,600 \text{ megawatt - hr}_{\text{Electricity}}] + 1,059,263 \text{ megawatt - hr}_{\text{Steam}}} \\ & = 0.267 \text{ tonnes CO}_2 \text{ Eq. /megawatt - hr} \end{aligned}$$



**EXHIBIT 4.13: Cogeneration Emissions Allocation – UK ETS Efficiency Allocation Approach, continued**

Steam allocation:

$$\begin{aligned} & \frac{\text{CO}_2 \text{ direct emissions (tonnes CO}_2\text{)}}{[2 \times \text{Electricity produced (megawatt - hr)}] + \text{Steam produced (megawatt - hr)}} \\ &= \frac{435,982 \text{ tonnes CO}_2 \text{ Eq.}}{[2 \times 1,100,600 \text{ megawatt - hr}_{\text{Electricity}}] + 1,059,263 \text{ megawatt - hr}_{\text{Steam}}} \\ &= 0.134 \text{ tonnes CO}_2 \text{ Eq. /megawatt - hr} \end{aligned}$$

Step 4: Allocate Emissions to Electricity and Steam

The final step is to apply the emission factors to allocate emissions between electricity and steam used for energy onsite (direct emissions) and the exported electricity and steam (indirect emissions).

*CO<sub>2</sub> Equivalent emissions for electricity sold to the refinery:*

$$\frac{0.267 \text{ tonnes CO}_2}{\text{megawatt - hr electricity}} \times 206,000 \text{ megawatt - hr} = 55,002 \text{ tonnes CO}_2 \text{ Eq. (Direct)}$$

*CO<sub>2</sub> Equivalent emissions for electricity sold to the grid:*

$$\frac{0.267 \text{ tonnes CO}_2}{\text{megawatt - hr electricity}} \times 856,100 \text{ megawatt - hr} = 228,579 \text{ tonnes CO}_2 \text{ Eq. (Indirect)}$$

*CO<sub>2</sub> Equivalent emissions for steam sold to the refinery:*

$$\begin{aligned} & 2,710,000 \times 10^6 \text{ Btu steam} \times \frac{2.931 \times 10^{-4} \text{ kilowatt - hr}}{\text{Btu}} \times \frac{\text{megawatt - hr}}{1000 \text{ kilowatt - hr}} \\ &= 794,301 \text{ megawatt - hr/yr} \end{aligned}$$

$$\frac{0.134 \text{ tonnes CO}_2}{\text{MW - hr steam}} \times 794,301 \text{ MW - hr} = 106,436 \text{ tonnes CO}_2 \text{ Eq. (Direct)}$$

Accounting for round-off error, the sum of the emissions assigned to onsite and offsite steam and electricity should equal the total direct emissions from combustion. This is summarized in Table 4-14.

**Table 4-14. Summary of Cogeneration Emissions – UK ETS Efficiency Allocation Approach**

	Emissions, tonnes CO <sub>2</sub> Eq.
<b>Cogeneration Facility – Direct Emissions from Fuel Consumption</b>	435,982
<b>Refinery Emissions</b>	
Purchased electricity	55,002
Purchased Steam	106,410
<b>Emissions Associated with Electricity Sold to the Grid</b>	228,579

### Efficiency Allocation Approach - WRI/WBCSD

WRI/WBCSD presents a slightly different efficiency allocation approach. The equations associated with the WRI/WBCSD efficiency allocation approach are:

$$\text{Emissions}_{\text{Heat}} = \text{Emissions}_{\text{Total}} \times \frac{\frac{\text{Heat Output}}{\text{Efficiency}_{\text{Heat}}}}{\frac{\text{Heat Output}}{\text{Efficiency}_{\text{Heat}}} + \frac{\text{Electricity Output}}{\text{Efficiency}_{\text{Electricity}}}} \quad (\text{Equation 4-7})$$

and

$$\text{Emissions}_{\text{Total}} = \text{Emissions}_{\text{Heat}} + \text{Emissions}_{\text{Electricity}} \quad (\text{Equation 4-8})$$

where:

Emissions <sub>Total</sub>	= total emissions from CHP plant
Emissions <sub>Heat</sub>	= emissions share attributable to heat production
Emissions <sub>Electricity</sub>	= emissions share attributable to electricity production
Efficiency <sub>Heat</sub>	= assumed efficiency of typical heat production
Efficiency <sub>Electricity</sub>	= assumed efficiency of typical power production

Heat Output and Electricity Output are reported in the same units (Joule, Btu or kilowatt-hr).

This approach is demonstrated in Exhibit 4.14. Note that this approach is also preferred by EPA's Climate Leaders Program (EPA, 2003).

# **EXHIBIT 4.14: Cogeneration Emissions Allocation – WRI/WBCSD Efficiency Allocation Approach**

## **INPUT DATA:**

For the same scenario as described in the previous exhibit (Exhibit 4.13), this example applies the WRI/WBCSD Efficiency Allocation approach

The cogeneration facility consumes 8,131,500 million BTU of natural gas, producing 3,614,000 million BTU steam and 1,100,600 megawatt-hr of electricity (gross) on an annual basis. The refinery purchases 2,710,000 million Btu of steam and 206,000 megawatt-hr of electricity. The cogeneration facility itself requires 38,500 megawatt-hr to operate (Parasitic load), with the net electricity (856,100 megawatt-hrs) is sold to the electric grid.

For this example, the efficiency of steam generation is assumed to be 77% and the efficiency of the electricity generation is assumed to be 24%.

## **CALCULATION METHODOLOGY:**

### Step 1: Direct (On-site) Combustion Emissions from Cogeneration:

The total direct emissions are calculated as shown in Exhibit 4.13, resulting in 435,982 tonnes CO<sub>2</sub> equivalent emissions.

### Step 2: Define Power and Heat Production on the Same Units

The electric power output from the cogeneration unit needs to be converted from a megawatt-hr basis to Btu. The conversion factor for is provided in Table 3-2.

$$1,100,600 \text{ megawatt-hr} \times \frac{1000 \text{ kilowatt-hr}}{\text{megawatt-hr}} \times \frac{\text{Btu}}{2.931 \times 10^{-4} \text{ kilowatt-hr}} = 3.755 \times 10^{12} \text{ Btu (Electricity Output)}$$

### Step 3: Calculate the Emissions Allocated to Steam

Estimate the emissions associated with the steam generation by applying Equation 4-7.

$$\text{Emissions}_{\text{Heat}} = 435,982 \text{ tonnes CO}_2 \text{ Eq.} \times \frac{\frac{3,614,000 \times 10^6 \text{ Btu}}{0.77}}{\frac{3,614,000 \times 10^6 \text{ Btu}}{0.77} + \frac{3.755 \times 10^{12} \text{ Btu}}{0.24}}$$

$$\text{Emissions}_{\text{Heat}} = 435,982 \text{ tonnes CO}_2 \text{ Eq.} \times 0.23076 = 100,607 \text{ tonnes CO}_2 \text{ Eq.}$$

**EXHIBIT 4.14: Cogeneration Emissions Allocation – WRI/WBCSD Efficiency Allocation Approach, continued**

Step 4: Calculate the Emissions Allocated to Electricity

Applying Equation 4-8, the emissions allocated to electricity are calculated based on the difference between the total emissions and those allocated to steam.

$$435,982 \text{ tonnes CO}_2 \text{ Eq. (Total)} - 100,607 \text{ tonnes CO}_2 \text{ Eq. (Heat)} \\ = 335,374 \text{ tonnes CO}_2 \text{ Eq. (Electricity)}$$

Step 5: Allocate Emissions for Energy Exports

The total steam and electricity emissions can be estimated for exports based on the ratio of the total electricity and steam generated versus the energy sold.

*CO<sub>2</sub> Equivalent Emissions for electricity sold to the refinery:*

$$335,374 \text{ tonnes CO}_2 \text{ Eq. (Total Electricity)} \times \frac{206,000 \text{ megawatt-hr (Refinery)}}{1,100,600 \text{ megawatt-hr (Total)}} \\ = 62,772 \text{ tonnes CO}_2 \text{ Eq. (Refinery)}$$

*CO<sub>2</sub> Equivalent Emissions for electricity sold to the grid:*

$$335,374 \text{ tonnes CO}_2 \text{ Eq. (Total Electricity)} - 62,772 \text{ tonnes CO}_2 \text{ Eq. (Refinery)} \\ = 272,601 \text{ tonnes CO}_2 \text{ Eq. (Grid)}$$

*CO<sub>2</sub> Equivalent Emissions for steam sold to the refinery:*

$$100,607 \text{ tonnes CO}_2 \text{ Eq. (Total Heat)} \times \frac{2,710,000 \times 10^6 \text{ Btu (Refinery)}}{3,614,000 \times 10^6 \text{ Btu (Total)}} \\ = 75,441 \text{ tonnes CO}_2 \text{ Eq. (Refinery)}$$

The results for the allocation of emissions based on energy efficiency are shown in Table 4-15.

**Table 4-15. Summary of Cogeneration Emissions – WRI/WBCSD Efficiency Allocation Approach**

	Emissions, tonnes CO <sub>2</sub> Eq.
<b>Cogeneration Facility – Direct Emissions from Fuel Consumption</b>	435,982
<b>Refinery Emissions</b>	
Purchased electricity	62,772
Purchased Steam	75,441
<b>Emissions Associated with Electricity Sold to the Grid</b>	272,601

### California Climate Action Registry Efficiency Allocation Approach

The California Climate Action Registry (CCAR, 2003) attributes emissions to heat and electricity production based on a ratio of the energy produced for each type (heat or steam) to the total energy produced (net heat production plus electricity production), where each of the energy streams are expressed in the same units (Btu or Joules).

The equations associated with this approach are:

$$\text{Emissions}_{\text{Heat}} = \text{Emissions}_{\text{Total}} \times \frac{\text{Net Heat Production}}{\text{Net Heat Production} + \text{Electricity Production}} \quad (\text{Equation 4-9})$$

and

$$\text{Emissions}_{\text{Electricity}} = \text{Emissions}_{\text{Total}} \times \frac{\text{Electricity Production}}{\text{Net Heat Production} + \text{Electricity Production}} \quad (\text{Equation 4-10})$$

where:

$\text{Emissions}_{\text{Total}}$	= total emissions from CHP plant in tonnes
$\text{Emissions}_{\text{Heat}}$	= emissions share attributable to heat production in tonnes
$\text{Emissions}_{\text{Electricity}}$	= emissions share attributable to electricity production in tonnes

Net heat production refers to the useful heat that is produced in a CHP less the heat that returns to the boiler as steam condensate. Electricity production is the electrical energy output reported on the same units basis, either Btu or Joules, as heat production.

This approach is similar to the WRI/WBCSD energy efficiency allocation method, accept that the California approach assumes the efficiency is the same for both net heat production and electricity production. An example is provided in Exhibit 4.15.

**EXHIBIT 4.15: Cogeneration Emissions Allocation – California Climate Action Registry Efficiency Allocation Approach**

**INPUT DATA:**

For the same scenario as described in the previous exhibits, this example applies the California Climate Action Registry approach.

The cogeneration facility consumes 8,131,500 million BTU of natural gas, producing 3,614,000 million BTU steam and 1,100,600 megawatt-hr of electricity (gross) on an annual basis. The refinery purchases 2,710,000 million Btu of steam and 206,000 megawatt-hr of electricity. The cogeneration facility itself requires 38,500 megawatt-hr to operate (Parasitic load), with the net electricity (856,100 megawatts) sold to the electric grid.

**CALCULATION METHODOLOGY:**

Step 1: Direct (On-site) Combustion Emissions from Cogeneration:

The total direct emissions are calculated as shown in Exhibit 4.13, resulting in 435,982 tonnes CO<sub>2</sub> equivalent emissions.

Step 2: Define Power and Heat Production on the Same Units

The electric power output from the cogeneration unit needs to be converted from a megawatt-hr basis to Btu. The conversion factor is provided in Table 3-2.

$$1,100,600 \text{ megawatt-hr} \times \frac{1000 \text{ kilowatt-hr}}{\text{megawatt-hr}} \times \frac{\text{Btu}}{2.931 \times 10^{-4} \text{ kilowatt-hr}} = 3.755 \times 10^{12} \text{ Btu (Electricity Output)}$$

Step 3: Calculate the Emissions Allocated to Steam

Estimate the emissions associated with the steam generation by applying Equation 4-9.

$$\text{Emissions}_{\text{Heat}} = 435,982 \text{ tonnes CO}_2 \text{ Eq.} \times \frac{3,614,000 \times 10^6 \text{ Btu}}{3,614,000 \times 10^6 \text{ Btu} + 3.755 \times 10^{12} \text{ Btu}}$$

$$\text{Emissions}_{\text{Heat}} = 435,982 \text{ tonnes CO}_2 \text{ Eq.} \times 0.49 = 213,820 \text{ tonnes CO}_2 \text{ Eq.}$$

**EXHIBIT 4.15: Cogeneration Emissions Allocation – California Climate Action Registry Efficiency Allocation Approach, continued**

Step 4: Calculate the Emissions Allocated to Electricity

The emissions allocated to electricity are calculated based on Equation 4-10.

$$\text{Emissions}_{\text{Electricity}} = 435,982 \text{ tonnes CO}_2 \text{ Eq.} \times \frac{3.755 \times 10^{12} \text{ Btu}}{3,614,000 \times 10^6 \text{ Btu} + 3.755 \times 10^{12} \text{ Btu}}$$

$$\text{Emissions}_{\text{Electricity}} = 435,982 \text{ tonnes CO}_2 \text{ Eq.} \times 0.51 = 222,162 \text{ tonnes CO}_2 \text{ Eq.}$$

Step 5: Allocate Emissions for Energy Exports

The total steam and electricity emissions can be divided among onsite and offsite usage based on the ratio of electricity and steam used onsite versus the energy sold for use offsite.

*CO<sub>2</sub> Equivalent Emissions for electricity sold to the refinery:*

$$\begin{aligned} 222,157 \text{ tonnes CO}_2 \text{ Eq. (Total Electricity)} &\times \frac{206,000 \text{ megawatt-hr (Refinery)}}{1,100,600 \text{ megawatt-hr Total}} \\ &= 41,581 \text{ tonnes CO}_2 \text{ Eq. (Refinery)} \end{aligned}$$

*CO<sub>2</sub> Equivalent Emissions for electricity sold to the grid:*

$$\begin{aligned} 222,157 \text{ tonnes CO}_2 \text{ Eq. (Total Electricity)} &- 41,581 \text{ tonnes CO}_2 \text{ Eq. (Refinery)} \\ &= 180,576 \text{ tonnes CO}_2 \text{ Eq. (Grid)} \end{aligned}$$

*CO<sub>2</sub> Equivalent Emissions for steam sold to the refinery:*

$$\begin{aligned} 213,815 \text{ tonnes CO}_2 \text{ Eq. (Total Heat)} &\times \frac{2,710,000 \times 10^6 \text{ Btu (Refinery)}}{3,614,000 \times 10^6 \text{ Btu Total}} \\ &= 160,332 \text{ tonnes CO}_2 \text{ Eq. (Refinery)} \end{aligned}$$

The results for the allocation of emissions based on energy efficiency are shown in Table 4-16.

**Table 4-16. Summary of Cogeneration Emissions – California Climate Action Registry Efficiency Allocation Approach**

	Emissions, tonnes CO <sub>2</sub> Eq.
<b>Cogeneration Facility – Direct Emissions from Fuel Consumption</b>	435,982
<b>Refinery Emissions</b>	
Purchased electricity	41,582
Purchased Steam	160,335
<b>Emissions Associated with Electricity Sold to the Grid</b>	180,580

### Work Potential Allocation Approach

This approach assigns the emissions to the energy streams in proportion to their contribution to the total work potential, or exergy. The work potential for steam is calculated from the specific enthalpy (H) and specific entropy (S) of the stream. This approach sums the work potential of all streams and allocates the total emissions to the individual streams.

As with the UK ETS method, the first step is to calculate the total direct CO<sub>2</sub> emissions from the combustion of natural gas at the cogeneration facility. The second step is to calculate the work potential of the steam, using 212 °F (100 °C) saturated water as the reference basis, and 700°F (371 °C) and 600 psia (4,137 kilo Pascal) for the process steam. The enthalpy and entropy of the steam can be determined from a steam table at the reference and actual conditions. The work potential of the steam is calculated using the following equations.

In US units:

$$\text{Steam work potential (Btu/lb)} = (H_i - H_{\text{ref}}) - (T_{\text{ref}} + 460) \times (S_i - S_{\text{ref}}) \quad (\text{Equation 4-11})$$

and in SI units:

$$\text{Steam work potential (10}^9 \text{ J/tonne)} = (H_i - H_{\text{ref}}) - (T_{\text{ref}} + 273) \times (S_i - S_{\text{ref}}) \quad (\text{Equation 4-12})$$

where:

$H_i$  = specific enthalpy of the process steam (BTU/lb or 10<sup>3</sup> J/kilogram)

$H_{\text{ref}}$  = specific enthalpy at the reference conditions (BTU/lb or 10<sup>3</sup> J/kilogram)

$T_{\text{ref}}$  = reference temperature (R or K)

$S_i$  = specific entropy of the process steam (BTU/lb R or 10<sup>3</sup> J/kilogram K)

$S_{\text{ref}}$  = specific entropy at the reference conditions (BTU/lb R or 10<sup>3</sup> J/kilogram K)

The third step is to allocate the total emissions from the cogeneration facility in proportion to their work potential, as shown in Equation 4-13.



CO<sub>2</sub> EF from electricity or steam (tonnes CO<sub>2</sub>/megawatt - hr) =

$$\frac{\text{CO}_2 \text{ direct emissions (tonnes CO}_2\text{/yr)}}{\left[ \text{Work potential}_{\text{steam}} \left( \frac{\text{megawatt - hr}}{\text{yr}} \right) + \text{Work potential}_{\text{electricity}} \left( \frac{\text{megawatt - hr}}{\text{yr}} \right) \right]}$$

(Equation 4-13)

This allocation approach is demonstrated in the following exhibit.

**EXHIBIT 4.16: Cogeneration Emissions Allocation –Work Potential Allocation Approach**

This example applies the WRI/WBCSD Work Potential approach to allocating emissions between steam and electricity for the same facility described in Exhibit 4.13.

The cogeneration facility consumes 8,131,500 million Btu of natural gas, producing 3,614,000 million Btu steam at 700 °F and 600 psia and 1,100,600 megawatt-hr of electricity (gross) on an annual basis. The refinery purchases 2,710,000 million Btu of steam and 206,000 MW-hr of electricity. The cogeneration facility itself requires 38,500 megawatt-hr to operate (Parasitic load), with the net electricity (856,100 megawatt-hrs) sold to the electric grid.

**CALCULATION METHODOLOGY:**

Step 1: Direct Emissions from Cogeneration:

Direct emissions are calculated as shown previously, resulting in 435,982 tonnes CO<sub>2</sub> Eq. emissions.

Step 2: Steam Work Potential

Steam work potential requires the enthalpy and entropy of the steam at both actual and reference conditions. These values can be determined using a steam table.

Enthalpy: Steam, 600 psia, 700 °F = 1,350 Btu/lb (H<sub>i</sub>);  
Saturated Water, 212 °F = 180 Btu/lb (H<sub>ref</sub>)

Entropy: Steam, 600 psia, 700 °F = 1.5872 Btu/lb-R (S<sub>i</sub>);  
Saturated Water, 212 °F = 0.31213 Btu/lb-R (S<sub>ref</sub>)

# **EXHIBIT 4.16: Cogeneration Emissions Allocation –Work Potential Allocation Approach, continued**

The work potential of the steam is then calculated using these values:

$$\begin{aligned} \text{Steam work potential (Btu/lb)} &= (H_i - H_{\text{ref}}) - (T_{\text{ref}} + 460) \times (S_i - S_{\text{ref}}) \\ &= (1,350 - 180) \frac{\text{Btu}}{\text{lb}} - \left[ (212 + 460)R \times (1.5872 - 0.31213) \frac{\text{Btu}}{\text{lb} - R} \right] = 313.2 \text{ Btu/lb} \end{aligned}$$

In addition, the steam needs to be expressed on a mass basis to apply the work potential equations.

$$\begin{aligned} 3,614,000 \times 10^6 \text{ Btu steam} \times \left( \frac{\text{lb steam}}{1,350 \text{ Btu}_{\text{steam conditions}} - 180 \text{ Btu}_{\text{reference conditions}}} \right) \\ = 3.089 \times 10^9 \text{ lbs steam} \end{aligned}$$

Next, the mass of steam and the steam work potential are combined and converted to megawatt-hrs:

$$\begin{aligned} 3.089 \times 10^9 \text{ lbs steam/yr} \times \left( \frac{313.2 \text{ Btu}}{\text{lb steam}} \right) \times \frac{2.931 \times 10^{-4} \text{ kilowatt} - \text{hr}}{\text{Btu}} \times \frac{\text{megawatt} - \text{hr}}{1000 \text{ kilowatt} - \text{hr}} \\ = 283,567 \text{ megawatt} - \text{hr/yr} \end{aligned}$$

## Step 3: Calculate Electricity and Steam Emission Factors

The third step is to apply Equation 4-13 for allocating emissions between the electricity and steam energy to generate emission factors.

Allocation =

$$\begin{aligned} &\frac{\text{CO}_2 \text{ direct emissions (tonnes CO}_2\text{/yr)}}{\left[ \text{Work potential}_{\text{steam}} \left( \frac{\text{megawatt} - \text{hr}}{\text{yr}} \right) + \text{Work potential}_{\text{electricity}} \left( \frac{\text{megawatt} - \text{hr}}{\text{yr}} \right) \right]} \\ &= \frac{435,982 \text{ tonnes CO}_2 \text{ Eq.}}{283,567 \text{ megawatt} - \text{hr}_{\text{steam}} + 1,100,600 \text{ megawatt} - \text{hr}_{\text{electricity}}} = 0.315 \text{ tonne CO}_2 \text{ Eq./megawatt} - \text{hr} \end{aligned}$$

## Step 4: Apply Emission Factor to Estimate Emissions

The emissions associated with exported electricity and steam are determined by applying the appropriate MW-hrs to this emission factor.

**EXHIBIT 4.16: Cogeneration Emissions Allocation –Work Potential Allocation Approach, continued**

*CO<sub>2</sub> Equivalent Emissions for electricity sold to the refinery:*

$$\frac{0.315 \text{ tonnes CO}_2}{\text{megawatt - hr electricity}} \times 206,000 \text{ megawatt - hr} = 64,890 \text{ tonnes CO}_2 \text{ Eq. (Refinery)}$$

*CO<sub>2</sub> Equivalent Emissions for electricity sold to the grid:*

$$\frac{0.315 \text{ tonnes CO}_2}{\text{megawatt - hr electricity}} \times 856,100 \text{ megawatt - hr} = 269,672 \text{ tonnes CO}_2 \text{ Eq. (Grid)}$$

*CO<sub>2</sub> Equivalent Emissions for steam sold to the grid:*

$$2,710,000 \times 10^6 \text{ Btu steam} \times \frac{283,567 \text{ megawatt - hr/yr}}{3,614,000 \times 10^6 \text{ Btu steam}} = 212,636 \text{ megawatt - hr/yr}$$

$$\frac{0.315 \text{ tonnes CO}_2}{\text{megawatt - hr steam}} \times 212,636 \text{ megawatt - hr} = 66,980 \text{ tonnes CO}_2 \text{ Eq. (Indirect)}$$

Table 4-17 summarizes the results for the work potential method.

**Table 4-17. Summary of Cogeneration Emissions – Work Potential Allocation Approach**

	Emissions, tonnes CO <sub>2</sub> Eq.
<b>Cogeneration Facility – Direct Emissions from Fuel Consumption</b>	435,982
<b>Refinery Emissions</b>	
Purchased electricity	64,890
Purchased Steam	66,980
<b>Emissions Associated with Electricity Sold to the Grid</b>	269,672

## 4.8 References

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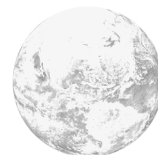
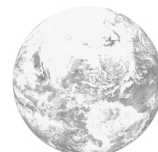
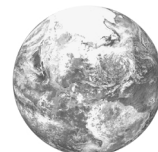
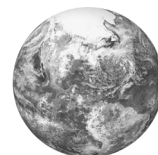
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FEBRUARY 2004

**COMPENDIUM OF GREENHOUSE GAS  
EMISSIONS METHODOLOGIES FOR  
THE OIL AND GAS INDUSTRY**

SECTION 5





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## 5.0

# VENTED EMISSIONS ESTIMATION METHODS

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Vented emissions are releases to the atmosphere as a result of the process or equipment design or operational practices. There are a number of vented emission sources associated with oil and gas industry operations. These vented emissions may come from a variety of non-fired stacks and vents (combustion emissions are covered in Section 4). These emission sources tend to be very specific to the type of operation, therefore this section is organized by segments of the oil and gas industry, with additional subsections for equipment common to more than one industry segment.

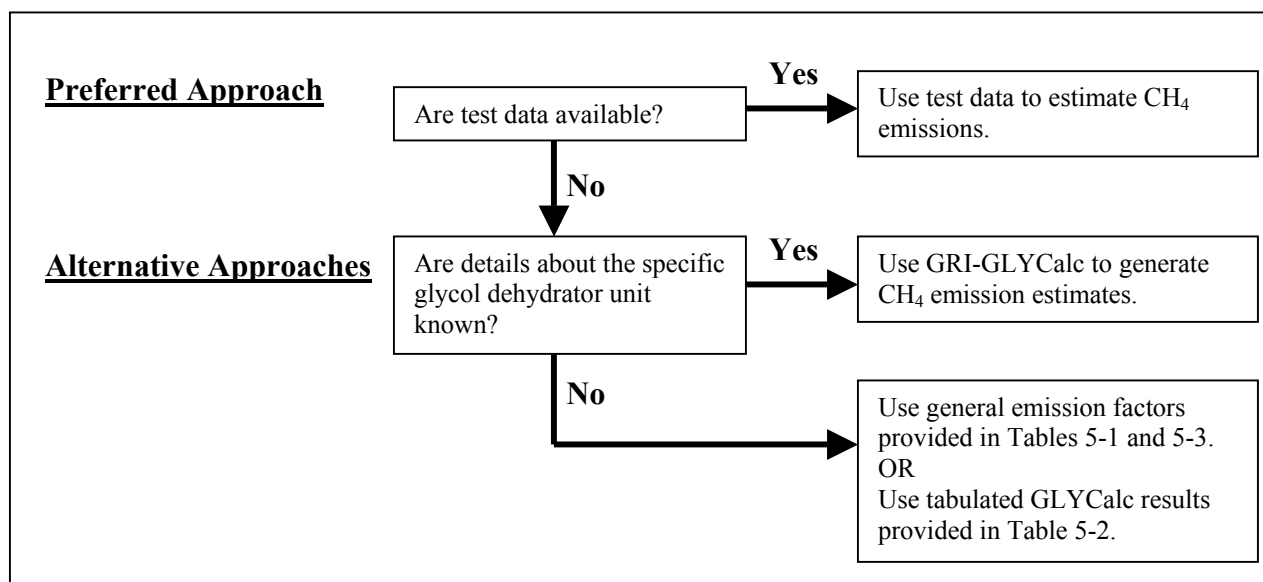
### 5.1 Gas Treatment Processes

#### 5.1.1 Glycol Dehydrator Emissions

Glycol dehydrators are used to remove water from gas streams by contacting the gas with a liquid glycol stream in an absorber. The liquid glycol absorbs the water from the gas stream, and the water is driven from the glycol by heating it in the reboiler (or regenerator). Methane emissions from glycol units occur because a small amount of CH<sub>4</sub> is absorbed by the glycol and driven off to the atmosphere in the glycol regeneration step. Note that combustion emissions from the glycol reboiler are not included in this section, and should be estimated using the combustion techniques presented in Section 4.

Figure 5-1 illustrates the methods available for estimating CH<sub>4</sub> emissions from glycol dehydrators.

Measured test data of the glycol dehydrator vent is the preferred approach for determining the vented emissions. However, such test data may not be available. If detailed information about the site-specific glycol dehydrator unit is known, then a process simulator or other computer software such as GRI-GLYCalc (GRI, 2000) can be used to estimate the emissions. Detailed information to run the GRI-GLYCalc computer simulation includes the wet gas flow rate, wet gas temperature and pressure, existence of a gas-driven glycol pump, wet and dry gas water contents, glycol flow



**Figure 5-1. CH<sub>4</sub> Emissions from Glycol Dehydrators**

rate, use of stripping gas in the regenerator, and the temperature and pressure of the flash tank, if applicable.

If this detailed information is not readily available, then simplified emission factors can be used. These emission factors, provided in Table 5-1, were developed using both site data and computer simulations (Myers, 1996). Table 5-1 also lists the default CH<sub>4</sub> content of the natural gas for the different industry segments that may use glycol dehydration.

Note that the emission factors given in Table 5-1 do not include the emissions from gas-assisted glycol pumps, which can be a significant source of CH<sub>4</sub> emissions. Although the gas-assisted CH<sub>4</sub> emissions are emitted from the regenerator vent, the emission rates were developed as a separate emission source in the GRI/EPA CH<sub>4</sub> emissions study, and are discussed later in this section (Myers and Harrison, 1996; Harrison et al., 1996).

The emission factors in Table 5-1 can be scaled based on the ratio of the site-specific CH<sub>4</sub> content to the default emission factor concentration if the site natural gas has a significantly different CH<sub>4</sub> content from the default basis. Also, if the gas contains significant quantities of CO<sub>2</sub>, the CH<sub>4</sub> emission factors can be adjusted based on the relative concentrations of CH<sub>4</sub> and CO<sub>2</sub> in the gas to estimate the CO<sub>2</sub> emissions. Exhibit 5.1 demonstrates these calculations.

**Table 5-1. Segment Specific Gas Dehydration CH<sub>4</sub> Emission Factors**  
(Excludes Glycol Gas-Assisted Pump Emissions – See Section 5.1.2)

Industry Segment	CH <sub>4</sub> Emission Factor, Original Units	CH <sub>4</sub> Emission Factor, Converted to Tonnes Basis <sup>a</sup>	CH <sub>4</sub> Content Basis for Industry Segment	Precision <sup>b</sup> (+/- %)
Production	275.57 scf/10 <sup>6</sup> scf gas processed	0.0052869 tonnes/10 <sup>6</sup> scf gas processed	78.8 mole %	154
		0.18667 tonnes/10 <sup>6</sup> m <sup>3</sup> gas processed		
Gas processing	121.55 scf/10 <sup>6</sup> scf gas processed	0.0023315 tonnes/10 <sup>6</sup> scf gas processed	87 mole %	202
		0.082338 tonnes/10 <sup>6</sup> m <sup>3</sup> gas processed		
Gas transmission	93.72 scf/10 <sup>6</sup> scf gas processed	0.0017980 tonnes/10 <sup>6</sup> scf gas processed	93.4 mole %	208
		0.06349 tonnes/10 <sup>6</sup> m <sup>3</sup> gas processed		
Gas storage	117.18 scf/10 <sup>6</sup> scf gas processed	0.0022477 tonnes/10 <sup>6</sup> scf gas processed	93.4 mole %	160
		0.079377 tonnes/10 <sup>6</sup> m <sup>3</sup> gas processed		

Source: Myers, D.B. Methane Emissions from the Natural Gas Industry, Volume 14: Glycol Dehydrators, Final Report, GRI-94/0257.31 and EPA-600/R-96-080n, Gas Research Institute and US Environmental Protection Agency, June 1996.

Notes:

<sup>a</sup> CH<sub>4</sub> emission factors converted from scfy are based on 60°F and 14.7 psia.

<sup>b</sup> Precision is based on a 90% confidence interval based on data used to develop the original emission factor.

As an alternative to the industry specific emission factors given above, Table 5-2 provides general glycol dehydrator emission factors developed using GRI-GLYCalc (Texaco, 1999). Unlike the GRI/EPA emission factors, these factors include the emissions contribution from the gas-assisted glycol pump, if present. The emission factors are developed assuming typical operating parameters for a glycol unit with no vent condenser, as a vent condenser does not appreciably affect the CH<sub>4</sub> emissions.

**Table 5-2. GLYCalc Generated Dehydration Methane Emission Factors**  
(Includes Glycol Gas-Assisted Pump Emissions)

Mode of Operation	CH <sub>4</sub> Emission Factor, Original Units	CH <sub>4</sub> Emission Factor, Converted to Tonnes per Gas Processed Basis
Gas pump without a flash separator	82.63 tonne/yr per 10 <sup>6</sup> Nm <sup>3</sup> /day gas processed	0.006410 tonnes/10 <sup>6</sup> scf gas processed
		0.2264 tonnes/10 <sup>6</sup> m <sup>3</sup> gas processed
Gas pump with a flash separator	1.98 tonne/yr per 10 <sup>6</sup> Nm <sup>3</sup> /day gas processed	0.000154 tonnes/10 <sup>6</sup> scf gas processed
		0.00542 tonnes/10 <sup>6</sup> m <sup>3</sup> gas processed
Electric pump without a flash separator	21.46 tonne/yr per 10 <sup>6</sup> Nm <sup>3</sup> /day gas processed	0.001665 tonnes/10 <sup>6</sup> scf gas processed
		0.05879 tonnes/10 <sup>6</sup> m <sup>3</sup> gas processed
Electric pump with a flash separator	1.64 tonne/yr per 10 <sup>6</sup> Nm <sup>3</sup> /day gas processed	0.000127 tonnes/10 <sup>6</sup> scf gas processed
		0.00449 tonnes/10 <sup>6</sup> m <sup>3</sup> gas processed

Source: Texaco, 1999. Based on results from GRI Report No. GRI-98/0073, Investigation of Condenser Efficiency for HAP Control from Glycol Dehydrator Reboiler Vent Streams: Analysis of Data from the EPA 114 Questionnaire and GRI's Condenser Monitoring Program.

Notes:

CH<sub>4</sub> emission factors are based on 60°F and 14.7 psia.

Precision data are not available from this source.

An example calculation for dehydrator CH<sub>4</sub> emissions is given below.

#### **EXHIBIT 5.1: Sample Calculation for Dehydration Processing Vent Emissions**

##### **INPUT DATA:**

A glycol dehydrator at a gas processing plant treats  $25 \times 10^6$  scf/day of gas with a CH<sub>4</sub> molar content of 90% and CO<sub>2</sub> content of 5%. The dehydration unit includes an electric pump but does not include a flash separator.

##### **CALCULATION METHODOLOGY:**

Table 5-1 provides an emission factor specific to gas processing facilities. Because the CH<sub>4</sub> content of this facility differs from the 87% default CH<sub>4</sub> content associated with the emission factor, the calculations include an adjustment for the composition:

$$\begin{aligned}
 \text{CH}_4 : & \frac{25 \times 10^6 \text{ scf}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{0.0023315 \text{ tonne CH}_4}{10^6 \text{ scf}} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \\
 & \times \frac{0.90 \text{ tonne mole CH}_4 \text{ (facility)}}{0.87 \text{ tonne mole CH}_4 \text{ (default)}} \times \frac{16 \text{ tonne CH}_4}{\text{tonne mole CH}_4} = \underline{22.0 \text{ tonnes CH}_4/\text{yr}}
 \end{aligned}$$

**EXHIBIT 5.1: Sample Calculation for Dehydration Processing Vent Emissions, continued**

Because the gas contains a significant amount of CO<sub>2</sub>, emissions of CO<sub>2</sub> are also estimated using the relative CO<sub>2</sub> and CH<sub>4</sub> contents in the gas.

$$\text{CO}_2 : 22.0 \text{ tonnes CH}_4 \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.90 \text{ tonne mole CH}_4} \times \frac{0.05 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{3.36 \text{ tonnes CO}_2/\text{yr}}$$

Alternatively, Table 5-2 provides a CH<sub>4</sub> emission factor of 0.001665 tonnes CH<sub>4</sub>/10<sup>6</sup> scf of gas processed for this type of arrangement. The CH<sub>4</sub> emissions from the dehydrator vent are calculated using this approach as shown below.

$$\text{CH}_4 : \frac{25 \times 10^6 \text{ scf}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{0.001665 \text{ tonne CH}_4}{10^6 \text{ scf}} = \underline{15.19 \text{ tonnes CH}_4/\text{yr}}$$

Note that the results for the two methods presented in Exhibit 5.1 are different. Both are based on field data and computer simulation results. However, different assumptions were used for each study. The primary distinction is that the factors provided in Table 5-1 are classified by industry segment, accounting for the average dehydrator capacity in each industry segment, while the factors in Table 5-2 are based on an average equipment set-up for any industry sector.

**5.1.2 Glycol Pumps**

As demonstrated by the GRI/EPA study, gas-assisted glycol pumps can be a significant source of CH<sub>4</sub> emissions (Myers and Harrison, 1996). Both electric and gas-assisted pumps are used to circulate glycol in the dehydrator system. If a gas-assisted pump is used, the low-pressure glycol is pumped into the absorber by pistons driven by the high-pressure glycol that is entrained with natural gas leaving the absorber. The GRI/EPA CH<sub>4</sub> emissions project estimated the gas-assisted glycol pump emissions separate from the dehydrator vent emissions, though they are emitted from the same vent.

The GRI/EPA study observed that Kimray was a leading manufacturer of gas-assisted glycol pumps. Emission factors were presented in the 1996 GRI/EPA study (Volume 15) based on technical data from Kimray and using assumptions about typical dehydrator operation (Myers and Harrison, 1996). Production and processing Kimray pump CH<sub>4</sub> emissions are given in Table 5-3.



This table also includes the default CH<sub>4</sub> content that can be used for adjusting the emission factors to other CH<sub>4</sub> contents. The GRI/EPA study did not observe any active gas-assisted pumps in the transmission and storage segments, so no emission factors are presented for these industry segments.

**Table 5-3. GRI/EPA Kimray Pump CH<sub>4</sub> Emission Factors**

Segment	CH <sub>4</sub> Emission Factor, Original Units	CH <sub>4</sub> Emission Factor, Converted to Tonnes Basis <sup>a</sup>	CH <sub>4</sub> Content Basis of Factor	Precision <sup>b</sup> (+/- %)
Production	992.0 scf/10 <sup>6</sup> scf gas processed	0.01903 tonnes/10 <sup>6</sup> scf gas processed	78.8 mole %	77.3
		0.6720 tonnes/10 <sup>6</sup> m <sup>3</sup> gas processed		
Processing	177.75 scf/10 <sup>6</sup> scf gas processed	0.0034096 tonnes/10 <sup>6</sup> scf gas processed	87 mole %	56.8
		0.12041 tonnes/10 <sup>6</sup> m <sup>3</sup> gas processed		

Source: Myers, D.B. and M.R. Harrison. Methane Emissions from the Natural Gas Industry, Volume 15: Gas Assisted Glycol Pumps, Final Report, GRI-94/0257.33 and EPA-600/R-96-080o, Gas Research Institute and US Environmental Protection Agency, June 1996.

Notes:

<sup>a</sup> CH<sub>4</sub> emission factors converted from scfy are based on 60°F and 14.7 psia.

<sup>b</sup> Precision is based on a 90% confidence interval based on data used to develop the original emission factor.

An example calculation for glycol dehydrator Kimray pump CH<sub>4</sub> emissions is given below.

#### **EXHIBIT 5.2: Sample Calculation for Dehydration Kimray Vent Emissions**

##### **INPUT DATA:**

From the previous example, a glycol dehydrator at a gas processing plant treats  $25 \times 10^6$  scf/day of gas. This dehydration unit includes a gas-operated pump but does not include a flash separator.

##### **CALCULATION METHODOLOGY:**

The previous example estimated the emissions from the dehydration unit to be 22.01 tonnes CH<sub>4</sub>/yr, excluding the gas-assisted glycol pump. Assuming the pump is a Kimray or similar type, Table 5-3 provides an appropriate emission factor. The CH<sub>4</sub> emissions are calculated by multiplying this emission factor by the annual gas throughput and adjusting for the facility CH<sub>4</sub> concentration, as shown below.

**EXHIBIT 5.2: Sample Calculation for Dehydration Kimray Vent Emissions, continued**

$$\text{CH}_4 : \frac{25 \times 10^6 \text{ scf}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{0.0034096 \text{ tonne CH}_4}{10^6 \text{ scf}} \times \frac{0.90 \text{ tonne mole CH}_4 \text{ (Facility)}}{0.87 \text{ tonne mole CH}_4 \text{ (default)}} = \underline{32.18 \text{ tonnes CH}_4/\text{yr}}$$

CO<sub>2</sub> emissions are calculated by correcting the CH<sub>4</sub> emissions by the ratio of CH<sub>4</sub> to CO<sub>2</sub> in the facility gas.

$$\text{CO}_2 : 32.18 \text{ tonnes CH}_4 \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.90 \text{ tonne mole CH}_4} \times \frac{0.05 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{4.92 \text{ tonnes CO}_2/\text{yr}}$$

Note that because the GRI/EPA factor is used, the Kimray pump emissions should be added to the dehydrator vent emissions estimated in the previous example to obtain the total dehydrator vented emissions:

$$\text{Total dehydrator CH}_4 \text{ emissions} = \frac{22.0 \text{ tonnes CH}_4 / \text{yr}}{\text{(from the dehydrator)}} + \frac{32.18 \text{ tonnes CH}_4 / \text{yr}}{\text{(from the pump)}} = \underline{54.2 \text{ tonnes CH}_4 / \text{yr}}$$

$$\text{Total dehydrator CO}_2 \text{ emissions (excluding combustion emissions)} = \frac{3.36 \text{ tonnes CO}_2 / \text{yr}}{\text{(from the dehydrator)}} + \frac{4.92 \text{ tonnes CO}_2 / \text{yr}}{\text{(from the pump)}} = \underline{8.28 \text{ tonnes CO}_2 / \text{yr}}$$

Alternatively, using the emission factor from Table 5-2 for this type of arrangement, results in the following:

$$\text{CH}_4 : \frac{25 \times 10^6 \text{ scf}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{0.00641 \text{ tonne CH}_4}{10^6 \text{ scf}} = \underline{58.5 \text{ tonnes CH}_4/\text{yr}}$$

**5.1.3 Acid Gas Removal**

Natural gas with high concentrations of acid gas species (H<sub>2</sub>S and CO<sub>2</sub>), referred to as sour gas, must be treated to remove the acid gases to a concentration that meets pipeline corrosion-prevention specifications. Acid Gas Removal (AGR) units remove H<sub>2</sub>S and CO<sub>2</sub> by contacting the sour gas with a liquid solution (typically amines). AGR units have similar equipment as the

dehydrator units (an absorber, liquid circulation pump, and a reboiler to regenerate the absorber liquid). The amine solution can absorb a small amount of CH<sub>4</sub> from the gas, and some CH<sub>4</sub> can be driven off to the atmosphere from the reboiler vent.

Two CH<sub>4</sub> emission factors for AGR vents were developed as part of the 1996 GRI/EPA CH<sub>4</sub> emissions study (Volume 14, page A-13) based on process simulation results for typical unit operations (Myers, 1996). Table 5-4 provides the AGR CH<sub>4</sub> emission factor on both a throughput basis and unit basis. The throughput basis should be used preferentially over the unit basis factor if the volume of gas treated is known.

**Table 5-4. AGR CH<sub>4</sub> Emission Factor**

Source	Methane Emission Factor, Original Units <sup>a</sup>	Methane Emission Factor, Converted to Tonnes Basis <sup>b</sup>	Precision <sup>b</sup> (+/- %)
Acid gas removal (AGR) vent	965 scf/10 <sup>6</sup> scf treated gas	0.0185 tonnes/10 <sup>6</sup> scf treated gas	100
	6083 scfd/AGR unit	0.1167 tonnes/day-AGR unit	105

Source: Myers, D.B. Methane Emissions from the Natural Gas Industry, Volume 14: Glycol Dehydrators, Final Report, GRI-94/0257.31 and EPA-600/R-96-080n, Gas Research Institute and US Environmental Protection Agency, June 1996.

Notes:

<sup>a</sup> CH<sub>4</sub> emission factors converted from scf are based on 60°F and 14.7 psia.

<sup>b</sup> Precision is based on a 90% confidence interval based on data used to develop the original emission factor.

Alternatively, API's AMINECalc provides a mass emission rate of VOCs, which could be converted to CH<sub>4</sub> emissions based on an assumed CH<sub>4</sub> composition. Details on this software are available at the following API web address:

<http://www.api.org/ehs/rh/4679&80.htm>

An example calculation for AGR CH<sub>4</sub> emissions is given below, based on the emission factors in Table 5-4.

### **EXHIBIT 5.3: Sample Calculation for Acid Gas Removal (AGR) Vent Emissions**

#### **INPUT DATA:**

A gas processing plant has one AGR unit. The treated gas throughput of the AGR unit is not known. The facility operates continuously throughout the year (8760 hours/year).

### EXHIBIT 5.3: Sample Calculation for Acid Gas Removal (AGR) Vent Emissions, continued

#### CALCULATION METHODOLOGY:

The AGR unit-based CH<sub>4</sub> emission factor from Table 5-4 is multiplied by the number of AGR units and converted from a daily basis to an annual basis.

$$\text{CH}_4 : (1 \text{ AGR}) \times \frac{0.1167 \text{ tonne CH}_4}{\text{day} - \text{AGR}} \times \frac{365 \text{ day}}{\text{yr}} = \underline{42.60 \text{ tonnes CH}_4/\text{yr}}$$

Note that the treated gas throughput-based CH<sub>4</sub> emission factor could have been used instead of the unit-based factor if the AGR throughput data had been available.

#### 5.1.4 CO<sub>2</sub> Venting from Sour Gas Processing

Sour gas processing can directly vent the CO<sub>2</sub> removed from the sour gas stream to the atmosphere or capture the CO<sub>2</sub> for other uses, such as enhanced oil recovery. For systems that vent the waste CO<sub>2</sub>, emissions can be estimated by material balance using the known throughput and CO<sub>2</sub> concentrations of the inlet and outlet gas streams (CAPP, 2003). Methane emissions from sour gas processing are assumed to be insignificant, but can also be estimated by material balance.

The material balance equation for estimating the CO<sub>2</sub> emissions is:

$$E_{\text{CO}_2} = \left[ \left( \frac{\text{Volume}}{\text{time}} \times \text{CO}_2 \text{ mole\%} \right)_{\text{sour}} - \left( \frac{\text{Volume}}{\text{time}} \times \text{CO}_2 \text{ mole\%} \right)_{\text{sweet}} \right] \times \frac{44}{\text{molar volume conversion}}$$

(Equation 5-1)

where:

$E_{\text{CO}_2}$	=	mass emissions of CO <sub>2</sub> per year (in pounds or kg)
Volume	=	volume of the sour and sweet gas (in scf or m <sup>3</sup> at STP conditions)
Molar volume conversion	=	conversion from molar volume to mass (379.3 scf/lbmole or 23.685 m <sup>3</sup> /kgmole)

This approach is demonstrated in following exhibit.

### EXHIBIT 5.4a: Sample Calculation for CO<sub>2</sub> Venting Emissions from Sour Gas Processing

#### INPUT DATA:

A sour gas processing facility has the following operating parameters:

Unit inlet stream: 150,000 × 10<sup>6</sup> scf/yr sour gas processed with 3.0 mole % CO<sub>2</sub>

Unit outlet stream: 148,500 × 10<sup>6</sup> scf/yr sweet gas produced with 2.0 mole % CO<sub>2</sub>

#### CALCULATION METHODOLOGY:

The CO<sub>2</sub> vented emissions are estimated using the material balance from Equation 5-1. Methane emissions are assumed to be insignificant.

$$E_{\text{CO}_2} = \left[ \left( \frac{\text{Volume}}{\text{time}} \times \text{CO}_2 \text{ mole\%} \right)_{\text{sour}} - \left( \frac{\text{Volume}}{\text{time}} \times \text{CO}_2 \text{ mole\%} \right)_{\text{sweet}} \right] \times \frac{44}{\text{molar volume conversion}}$$

$$\text{CO}_2 = \left( \frac{150,000 \times 10^6 \text{ scf gas}}{\text{yr}} \times \frac{0.030 \text{ scf CO}_2}{\text{scf gas}} \right) - \left( \frac{148,500 \times 10^6 \text{ scf gas}}{\text{yr}} \times \frac{0.020 \text{ scf CO}_2}{\text{scf gas}} \right) \\ \times \frac{\text{lbmole CO}_2}{379.3 \text{ scf CO}_2} \times \frac{44 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonnes}}{2204.62 \text{ lb}} = 80,506 \text{ tonnes/yr CO}_2$$

Alternatively, the acid gas may be sent to an incinerator. In this case, the CO<sub>2</sub> emissions vented from the incinerator can be calculated based on the volume of acid gas to the incinerator and the mole fraction of CO<sub>2</sub> in the acid gas. The material balance equation for this approach is:

$$\text{CO}_2 \text{ emitted} = \left( \frac{\text{Volume}}{\text{time}} \times \text{CO}_2 \text{ mole\%} \right)_{\text{Acid gas}} \times \frac{44}{\text{molar volume conversion}} \quad (\text{Equation 5-2})$$

where:

$E_{\text{CO}_2}$	=	mass emissions of CO <sub>2</sub> per year (in pounds or kg)
Volume	=	volume of the acid gas (in scf or m <sup>3</sup> at STP conditions)
Molar volume conversion	=	conversion from molar volume to mass (379.3 scf/lbmole or 23.685 m <sup>3</sup> /kgmole)

**EXHIBIT 5.4b: Sample Calculation for CO<sub>2</sub> Venting Emissions from Sour Gas Processing****INPUT DATA:**

76,500×10<sup>6</sup> scf/yr of an acid gas stream with 2 mole% CO<sub>2</sub>

**CALCULATION METHODOLOGY:**

The CO<sub>2</sub> vented emissions are estimated using the material balance from Equation 5-2.

$$\text{CO}_2 \text{ emitted} = \left( \frac{\text{Volume}}{\text{time}} \times \text{CO}_2 \text{ mole\%} \right)_{\text{Acid gas}} \times \frac{44}{\text{molar volume conversion}}$$

$$\text{CO}_2 = \left( \frac{76,500 \times 10^6 \text{ scf gas}}{\text{yr}} \times \frac{0.02 \text{ scf CO}_2}{\text{scf gas}} \right) \times \frac{\text{lbmole CO}_2}{379.3 \text{ scf CO}_2} \times \frac{44 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonnes}}{2204.62 \text{ lb}}$$

$$= \underline{80,506 \text{ tonnes/yr CO}_2}$$

**5.2 Refinery Processes**

There are a number of specialized process vents in refineries. Many of these are associated with catalyst regeneration, such as the catalytic cracking regeneration, catalytic reformer regeneration, etc. Others are used to vent a waste material, such as the hydrogen plant. This section will address each vent by process.

**5.2.1 Catalytic Cracking Regenerator**

The catalytic cracking process deposits coke on the catalyst as a byproduct of the reaction. That coke must be burned off to restore the activity of the catalyst. The coke is continuously burned off in the regenerator. This process vent will be a significant source of CO<sub>2</sub> emissions, but CH<sub>4</sub> emissions are likely to be negligible.

Catalytic crackers (FCCUs) are operated in two basic modes:

1. Full, or complete, CO burn mode, where essentially all CO is combusted to CO<sub>2</sub> within the regenerator. The exhaust gas typically contains approximately 2% O<sub>2</sub> and less than 1%

- CO. The hot exhaust gases often pass through a waste heat boiler, operated with or without supplemental fuel, to produce steam prior to exiting through the stack.
2. Partial burn mode, where the regenerator exhaust gas contains less than 1% O<sub>2</sub> and 6-8% CO. The exhaust gases pass through a CO boiler, which completes the combustion of CO to CO<sub>2</sub> external to the FCCU regenerator prior to exiting the stack.

Sometimes an oxidation promoter (e.g., Platinum, Palladium, etc.) is added to the process or is included within the catalyst to assist combustion in “promoted” operation. Where no promoter is used, the operation is referred to as “conventional” or “non-promoted” CO burn. Full or partial CO burn modes can be conventional or promoted.

In some cases, the regenerator off-gas may be controlled with a CO Boiler (to control CO and TOC emissions) if operated in a conventional or partial burn mode or with an electrostatic precipitator or scrubber (to control particulate emissions). When a partial burn unit is operated with a CO Boiler, the unit is equivalent to a full burn unit with respect to CO<sub>2</sub>, CH<sub>4</sub>, and TOC emissions since the combustion of CO to CO<sub>2</sub> is completed. As noted earlier, some catalytic cracking unit (CCU) regenerators are designed to complete the combustion of CO to CO<sub>2</sub> and do not need a CO Boiler. These units may also be equipped with a waste heat boiler that can be fired with supplemental fuel. The CO<sub>2</sub> from the combustion of the supplemental fuel should be accounted for as described in Section 4. The end result is the same, with large emissions of CO<sub>2</sub> and negligible emissions of TOC and CH<sub>4</sub>.

Units operated in partial burn mode with a CO boiler or full burn mode have negligible CH<sub>4</sub> and TOC emissions. This conclusion is supported by test data that showed negligible CH<sub>4</sub> emissions from a full burn regenerator unit (ARPEL, 1998). An FCCU that is not controlled by either a CO Boiler or a regenerator designed for complete combustion would have higher TOC and CH<sub>4</sub> emissions.<sup>1</sup> However, FCCUs are typically not operated in partial burn modes without a CO boiler.

There are two commonly used approaches for estimating the CO<sub>2</sub> and CH<sub>4</sub> emissions from FCCU regeneration:

1. Process calculations based on coke burned; and
2. Process calculations based on air rates and CO/CO<sub>2</sub> concentrations.

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<sup>1</sup> Data presented in Table 6.22 of ARPEL shows CH<sub>4</sub> emission factors of 924 kg/1000 m<sup>3</sup> FCCU feed and 386 kg/1000 m<sup>3</sup> FCCU feed for conventional and partial burn units, respectively, that did not have CO boilers (ARPEL, 1998). However, this type of operation is not typically employed.

These approaches are based on process parameters that are generally monitored or estimated as part of routine refinery operations. Both process calculation approaches should provide equally accurate emission estimates. The user should pick the approach for which the input data are most readily available.

The first approach uses the coke burn rate expressed in mass per year. The coke burned is assumed to proceed completely to CO<sub>2</sub>. Based on this assumption and accounting for the conversion of units, the CO<sub>2</sub> emission rate can then be calculated from the following equation:

$$E_{\text{CO}_2} = \text{CC} \times \text{CF} \times \frac{44 \text{ mass units CO}_2}{12 \text{ mass units C}} \quad (\text{Equation 5-3})$$

where,

$E_{\text{CO}_2}$	=	emissions of CO <sub>2</sub> in units of mass (pounds, kg, tonnes) per year
CC	=	coke burn rate in units of mass per year
CF	=	fraction of carbon in the coke burned
44	=	molecular weight of CO <sub>2</sub>
12	=	molecular weight of carbon (coke is assumed to be carbon)

Equation 5-3 is based on the fundamental principles of complete stoichiometric combustion of the carbon in coke to CO<sub>2</sub>. Using a site-specific carbon fraction of coke will result in the most accurate estimates. In the absence of site-specific carbon fraction of coke data, the user may consult Table 3-5, which contains the properties of various fuels, or assume a carbon fraction of 1.0 to produce a conservatively high estimate.

Another process calculation approach is based on the air blower capacity and flue gas concentration:

$$E_{\text{CO}_2} = (\text{AR} + \text{SOR}) \times (\text{FCO}_2 + \text{FCO}) \times \frac{44}{\text{molar volume conversion}} \times \frac{525,600 \text{ min}}{\text{year}} \quad (\text{Equation 5-4})$$

where,

$E_{\text{CO}_2}$	=	emissions of CO <sub>2</sub> in units of mass (pounds, kg, tonnes) per year
AR	=	air rate in standard cubic feet or cubic meters per minute
SOR	=	supplemental oxygen rate (if used) in standard cubic feet or cubic meters per minute
$\text{FCO}_2$	=	fraction CO <sub>2</sub> in the flue gas (enter “0.12” for 12%, not 12)
FCO	=	fraction CO in the flue gas (enter “0.08” for 8%, not 8)
Molar volume conversion	=	conversion from molar volume to mass (379.3 scf/lbmole or 23.685 m <sup>3</sup> /kgmole)



The other term in Equation 5-4 is a conversion from minutes to years for the time basis.

This equation is based on fundamental principles for calculating the mass of a component from the total stream flow and concentration of the subject component. The concentration term includes both CO and CO<sub>2</sub>, because a partial oxidation regenerator flue gas contains both species, and each mole of CO will become a mole of CO<sub>2</sub> when emitted from the CO Boiler.

A sample calculation for both approaches follows.

#### **EXHIBIT 5.5: Sample Calculation for FCCU Process Calculation Approach**

##### **INPUT DATA:**

Assume a  $6.36 \times 10^3$  m<sup>3</sup> per day catalytic cracking unit has a coke burn rate of 119,750 tonnes per year and a blower air capacity of 2150 m<sup>3</sup>/min. Assume also that the carbon fraction of the coke is 0.93 based on site-specific data, the flue gas concentrations are 11% CO<sub>2</sub> and 9% CO exiting the regenerator, and that a CO Boiler is used for control of that stream. Supplemental firing with natural gas is also employed ( $100 \times 10^6$  Btu/hr, higher heating value basis).

##### **CALCULATION METHODOLOGY:**

Using Equation 5-3, the estimated CO<sub>2</sub> emissions from the regenerator would be:

$$E_{\text{CO}_2} = 119,750 \frac{\text{tonnes Coke Burned}}{\text{year}} \times \frac{0.93 \text{ tonnes C}}{\text{tonnes Coke}} \times \frac{44 \text{ tonnes CO}_2}{12 \text{ tonnes C}} \\ = \underline{408,348 \text{ tonnes CO}_2/\text{year}}$$

Or using the air rate in Equation 5-4 would yield:

$$E_{\text{CO}_2} = \frac{2150 \text{ m}^3}{\text{min}} \times \left( \frac{0.11 \text{ m}^3 \text{ CO}_2}{\text{m}^3 \text{ gas}} + \frac{0.09 \text{ m}^3 \text{ CO}}{\text{m}^3 \text{ gas}} \times \frac{\text{m}^3 \text{ CO}_2}{\text{m}^3 \text{ CO}} \right) \times \frac{44 \text{ kg CO}_2/\text{kgmole CO}_2}{23.685 \text{ m}^3 \text{ CO}_2/\text{kgmole CO}_2} \\ \times \frac{525,600 \text{ min}}{\text{year}} \times \frac{\text{tonnes}}{1000 \text{ kg}} = \underline{419,859 \text{ tonnes CO}_2/\text{year}}$$

**EXHIBIT 5.5: Sample Calculation for FCCU Process Calculation Approach, continued**

Emissions from the supplemental firing of natural gas are also estimated using the approaches presented in Sections 4.2 and 4.3. The emissions from the supplemental firing are in addition to the CO<sub>2</sub> emissions from the FCCU regenerator. The CH<sub>4</sub> and CO<sub>2</sub> emission factors are:

CO<sub>2</sub> EF = 0.0531 tonne CO<sub>2</sub>/10<sup>6</sup> Btu (HHV), from Table 4-1 for pipeline natural gas  
 CH<sub>4</sub> EF = 1.0E-06 tonne CH<sub>4</sub>/10<sup>6</sup> Btu (HHV), from Table 4-4 for natural gas fired boilers

$$\text{CO}_2 : \frac{100 \times 10^6 \text{ Btu}}{\text{hr}} \times \frac{0.0531 \text{ tonne CO}_2}{10^6 \text{ Btu}} \times \frac{8760 \text{ hr}}{\text{yr}} = \underline{46,516 \text{ tonnes CO}_2/\text{yr}}$$

$$\text{CH}_4 : \frac{100 \times 10^6 \text{ Btu}}{\text{hr}} \times \frac{1.0 \times 10^{-6} \text{ tonne CH}_4}{10^6 \text{ Btu}} \times \frac{8760 \text{ hr}}{\text{yr}} = \underline{0.88 \text{ tonnes CH}_4/\text{yr}}$$

The emissions from the FCCU are summarized below. Using the coke burn rate approach for the regenerator contribution (Equation 5-3), the emissions are:

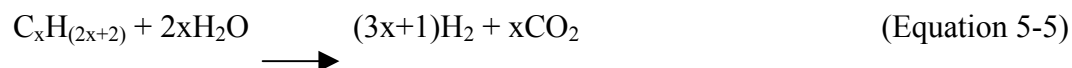
<b>Contribution</b>	<b>CO<sub>2</sub></b>	<b>CH<sub>4</sub></b>
Coke Burn	408,348	Negligible
CO Boiler	46,516	0.88
<b>Total</b>	<b>454,864</b>	<b>0.88</b>

Using the air blower rate approach for the regenerator contribution (Equation 5-4), the emissions are:

<b>Contribution</b>	<b>CO<sub>2</sub></b>	<b>CH<sub>4</sub></b>
Coke Burn	419,859	Negligible
CO Boiler	46,516	0.88
<b>Total</b>	<b>466,375</b>	<b>0.88</b>

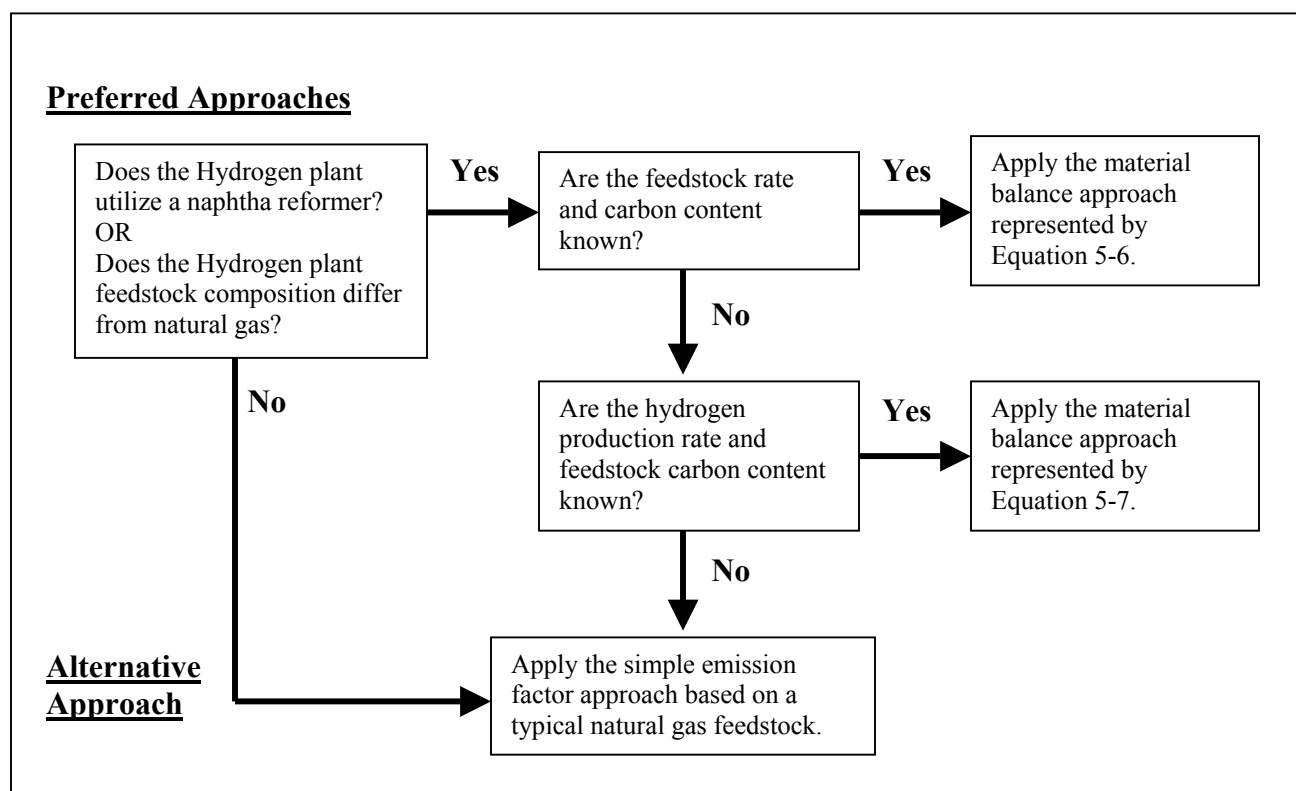
**5.2.2 Refinery Hydrogen Plant**

The hydrogen (H<sub>2</sub>) plant produces significant CO<sub>2</sub> emissions which may be further processed for other uses, or may be vented to the atmosphere. The quantity of CO<sub>2</sub> vented depends on the carbon to hydrogen ratio of the feed gas. In most cases, H<sub>2</sub> is made from CH<sub>4</sub>, but there are some plants that operate with naphtha or refinery fuel gas as the feedstock. The chemical reaction can be expressed as:



This equation shows that a mole of CO<sub>2</sub> is formed for every mole of carbon in the hydrocarbon species. Note that the CO<sub>2</sub> vent stream described by this reaction does not include CO<sub>2</sub> emissions from process heater(s) associated with the H<sub>2</sub> plant. Emissions from the process heaters should be treated like other combustion sources described in Section 4.

Figure 5-2 illustrates the approaches available for estimating CO<sub>2</sub> emissions from a refinery hydrogen plant that vents the CO<sub>2</sub> stream.



**Figure 5-2. CO<sub>2</sub> Emissions from a Refinery Hydrogen Plant**

A rigorous calculation approach, using a specific feed gas composition, can be used to estimate the CO<sub>2</sub> vent rate from the hydrogen plant. The rigorous approach can be based on either the volume of feedstock used or the hydrogen production rate. Both of these methods are discussed in this section, along with examples of their application.

There is also a simpler approach that can be used for steam methane reformers. Simple CO<sub>2</sub> emission factors have been developed from an assumed natural gas feedstock composition. The simple approach should be adequate for most refineries where the feed gas is not much different than natural gas (i.e., predominantly CH<sub>4</sub> with small amounts of other low molecular weight hydrocarbons). However, the simple approach should not be used when naphtha reformers are used at the H<sub>2</sub> plant. The more rigorous approaches can be used for this case or other cases where the feed gas does not resemble natural gas.

The first of the two rigorous approaches is based on a material balance using the feedstock rate and carbon content. Equation 5-6 presents this material balance approach:

$$E_{\text{CO}_2} = \text{FR} \times \text{CF} \times \frac{44 \text{ mass units CO}_2}{12 \text{ mass units C}} \quad (\text{Equation 5-6})$$

where,

$E_{\text{CO}_2}$	=	emissions of CO <sub>2</sub> in units of mass (pounds, kg, tonnes) per year
FR	=	feedstock rate in units of mass per year (feedstock rate excluding H <sub>2</sub> O fed)
CF	=	fraction of carbon in feedstock
44	=	molecular weight of CO <sub>2</sub>
12	=	molecular weight of carbon

The carbon fraction can be estimated using the feedstock composition if it is not explicitly known. Exhibit 5.6(a) demonstrates the approach to estimate the CO<sub>2</sub> emissions from a hydrogen plant using the feedstock rate and carbon content.

**EXHIBIT 5.6(a): Sample Calculation for Hydrogen Plant - Rigorous Approach based on Feedstock Rate and Carbon Content****INPUT DATA:**

A hydrogen plant has a feedstock rate of  $5 \times 10^9$  standard cubic feet per year using feed gas with the following composition:

Methane = 85%, Ethane = 8%, Butane = 3%; the balance is inerts (assume  $N_2$  for the inerts).

**CALCULATION METHODOLOGY:**

The first step is to estimate the carbon content of the feed gas since it is not explicitly provided. Also, the molecular weight of the feed gas must also be estimated since the feed rate must be converted from a volumetric or molar basis to a mass basis. The weight percent for each compound is needed to determine the carbon weight fraction.

These calculations are shown below:

<u>Compound</u>	<u>Mole %</u>	<u>MW</u>	<u>Weight %</u>	<u>Carbon Content (Wt. % C)</u>
Methane	85	16	72.1	75.0
Ethane	8	30	12.7	80.0
Butane	3	58	9.2	82.8
<u>Nitrogen</u>	<u>4</u>	<u>28</u>	<u>5.9</u>	<u>0</u>
<b>Mixture</b>	100	18.86	~100	<b>71.85</b>

The molecular weight of the mixture shown in the table above is estimated using Equation 3-8:

$$MW_{\text{Mixture}} = \frac{1}{100} \times \sum_{i=1}^{\text{\# compounds}} (\text{Mole}\%_i \times MW_i)$$

$$MW_{\text{Mixture}} = \frac{1}{100} \times [(85 \times 16) + (8 \times 30) + (3 \times 58) + (4 \times 28)] = 18.86$$

The weight percent for each compound is estimated using Equation 3-7, rearranged in terms of weight %:

$$\text{Wt}\%_i = \text{Mole}\%_i \times \frac{MW_i}{MW_{\text{mixture}}}$$

For example, the weight percent for  $CH_4$  shown in the table is calculated as:

$$\text{Wt}\%_i = (85) \times \frac{16}{18.86} = 72.1 \text{ weight \% } CH_4$$

**EXHIBIT 5.6(a): Sample Calculation for Hydrogen Plant - Rigorous Approach based on Feedstock Rate and Carbon Content, continued**

The carbon content in weight percent for each chemical species (e.g., CH<sub>4</sub> contains 75.0 wt. % C) is calculated in the same manner as shown in Exhibit 4.1(a) (refer to this exhibit for the calculation). With the individual compound weight percents and carbon contents now estimated, the feed gas mixture carbon content is estimated using the equation presented previously in Exhibit 4.1(a):

$$\text{Wt}\%C_{\text{Mixture}} = \frac{1}{100} \times \sum_{i=1}^{\text{\# components}} (\text{Wt}\%_i \times \text{Wt}\%C_i)$$

$$\text{Wt}\%C_{\text{Mixture}} = \frac{1}{100} \times [(72.1 \times 75.0) + (12.7 \times 80.0) + (9.2 \times 82.8) + (5.9 \times 0)]$$

$$= \underline{71.85 \text{ Wt}\% \text{ C}} = 0.7185 \text{ lb C/lb feed}$$

With the feed stock gas mixture molecular weight and carbon content now defined, the CO<sub>2</sub> vent rate can be calculated using Equation 5-6:

$$E_{\text{CO}_2} = \text{FR} \times \text{CF} \times \frac{44 \text{ mass units CO}_2}{12 \text{ mass units C}}$$

$$E_{\text{CO}_2} = 5,000 \frac{10^6 \text{ scf feed}}{\text{year}} \times \frac{\text{lbmole feed}}{379.3 \text{ scf}} \times \frac{18.86 \text{ lb feed}}{\text{lbmole feed}} \times \frac{0.7185 \text{ lb C}}{\text{lb feed}} \times \frac{44 \text{ lb CO}_2}{12 \text{ lb C}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$= \underline{297,100 \text{ tonnes CO}_2 / \text{yr}}$$

The other rigorous approach is based on the hydrogen production rate rather than the feedstock rate. This second approach involves writing out the chemical reaction shown earlier for each hydrocarbon species in the feed gas and doing a weighted average based on composition data. Using fundamental principles and the stoichiometric ratio of H<sub>2</sub> formed to CO<sub>2</sub> formed, as shown in Equation 5-5, the following equation describes this approach based on the hydrogen production rate.

$$E_{\text{CO}_2} = \text{H}_2\text{R} \times \frac{x \text{ mole CO}_2}{(3x + 1) \text{ mole H}_2} \times \frac{44}{\text{molar volume conversion}} \quad (\text{Equation 5-7})$$

where,

$E_{CO_2}$	=	emissions of $CO_2$ in units of mass (pounds, kg, tonnes) per year
$H_2R$	=	rate of hydrogen production in scf per year
$x$	=	stoichiometry from Equation 5-6
44	=	molecular weight of $CO_2$
Molar volume conversion	=	conversion from molar volume to mass (379.3 scf/lbmole or 23.685 m <sup>3</sup> /kgmole)

This second rigorous approach is based on the hydrogen production rate demonstrated in Exhibit 5.6(b).

There are a few other considerations for hydrogen plant emissions. Some plants sell the  $CO_2$  vent stream, or a portion thereof, and any  $CO_2$  sold should be subtracted from the vented emission estimate. Other plants use a pressure swing adsorption (PSA) step to produce a low-Btu fuel gas that is consumed in the steam reforming furnace. The  $CO_2$  in this low-Btu gas is emitted from the furnace stack, and should still be counted as the hydrogen plant vent stream. The combustion emissions for the  $CH_4$  and  $CO_2$  in the low-Btu gas, along with any supplemental fuels, should be estimated like other combustion sources, as presented in Section 4.

**EXHIBIT 5.6(b): Sample Calculation for Hydrogen Plant - Rigorous Approach based on  $H_2$  Production Rate**

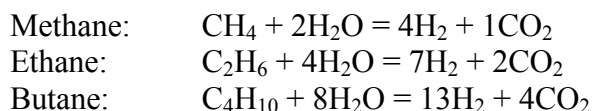
**INPUT DATA:**

A hydrogen plant produces  $13 \times 10^9$  standard cubic feet of hydrogen per year using feed gas with the following composition:

Methane = 85%, Ethane = 8%, Butane = 3%; the balance is inerts.

**CALCULATION METHODOLOGY:**

The first step is to examine the chemical reaction for each compound:



Next, the moles of carbon and hydrogen are determined by multiplying the number of molecules of each by the composition of each compound in feed gas (i.e., methane, ethane, and butane). These results are used to determine the ratio of moles of carbon to moles of  $H_2$ :

**EXHIBIT 5.6(b): Sample Calculation for Hydrogen Plant - Rigorous Approach based on H<sub>2</sub> Production Rate, continued**

Compound	# C Atoms	# H <sub>2</sub> Molecules	Concentration	Moles C	Moles H <sub>2</sub>
Methane	1	4	0.85	0.85	3.4
Ethane	2	7	0.08	0.16	0.56
Butane	4	13	0.03	0.12	0.39
<b>Total Moles</b>				<b>1.13</b>	<b>4.35</b>

The carbon to hydrogen ratio =  $1.13/4.35 = 0.26$

Since each mole of carbon produces 1 mole of CO<sub>2</sub>, the CO<sub>2</sub>/H<sub>2</sub> ratio is also 0.26.

The CO<sub>2</sub> vent rate can then be calculated using Equation 5-7:

$$E_{\text{CO}_2} = 13,000 \frac{10^6 \text{ scf H}_2}{\text{year}} \times \frac{\text{lbmole H}_2}{379.3 \text{ scf}} \times \frac{0.26 \text{ lbmole CO}_2}{\text{lbmole H}_2} \times \frac{44 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$= \underline{177,800 \text{ tonnes CO}_2 / \text{yr}}$$

The simple approach is based on an emission factor of 32,721 pounds of carbon per million standard cubic feet of feedstock (excluding H<sub>2</sub>O fed) or 8,064 pounds of carbon per million standard cubic feet of H<sub>2</sub> produced. These emission factors are shown below:

119,976 lb CO <sub>2</sub> /million scf feedstock
54.42 tonnes CO <sub>2</sub> /million scf feedstock
1,922 tonnes CO <sub>2</sub> /million m <sup>3</sup> H <sub>2</sub> feedstock
29,568 lb CO <sub>2</sub> /million scf H <sub>2</sub> produced
13.41 tonnes CO <sub>2</sub> /million scf H <sub>2</sub> produced
473.6 tonnes CO <sub>2</sub> /million m <sup>3</sup> H <sub>2</sub> produced

These emission factors are based on a stoichiometric conversion per Equation 5-5 for a feed gas with an average natural gas composition. Table 5-5 provides the average natural gas composition



used to derive these factors, which is based on measurements from pipeline-quality gas from 26 US cities (GTI, 1992).

**Table 5-5. Composition of US Pipeline Quality Natural Gas**

Compound	Average Volume %
Methane	93.07
Ethane	3.21
Propane	0.59
Higher hydrocarbons <sup>a</sup>	0.32
Non-hydrocarbons <sup>b</sup>	2.81

Notes:

<sup>a</sup> Higher molecular weight hydrocarbons were represented by C5 in calculating the CO<sub>2</sub> and hydrogen production rates.

<sup>b</sup> The non-hydrocarbons are assumed to contain 0.565 volume % CO<sub>2</sub> based on an average natural gas composition from Perry's Chemical Engineers Handbook.

Sources:

Gas Technology Institute (GTI). Database as documented in W.E. Liss, W.H. Thrasher, G.F. Steinmetz, P. Chowdiah, and A. Atari, "Variability of Natural Gas Composition in Select Major Metropolitan Areas of the United States." GRI-92/0123, March 1992.

Perry and Green. *Perry's Chemical Engineer's Handbook*, Sixth Edition, Table 9-14, 1984.

This simple approach is demonstrated in Exhibit 5.7.

#### **EXHIBIT 5.7: Sample Calculation for Hydrogen Plant Emissions - Simple Approach**

##### **INPUT DATA:**

A hydrogen plant produces  $13 \times 10^9$  standard cubic feet of hydrogen per year.

##### **CALCULATION METHODOLOGY:**

Using the emission factor derived from the average US natural gas composition (discussed in the preceding paragraph), the estimated CO<sub>2</sub> emissions would be:

$$E_{\text{CO}_2} = 13,000 \frac{10^6 \text{ scf H}_2}{\text{year}} \times \frac{13.41 \text{ tonnes CO}_2}{10^6 \text{ scf H}_2} = \underline{174,300 \text{ tonne CO}_2 / \text{yr}}$$

Although rare and not applicable to most refineries, a partial hydrogen generation unit may be used. If such a system is used, site-specific data or engineering judgment must be used to estimate the CO<sub>2</sub> emissions. If site-specific data are not available, one suggested estimation approach is to

ratio the actual hydrogen generation rate for the year to the design basis, and multiply this ratio by the design CO<sub>2</sub> emissions to estimate the actual CO<sub>2</sub> emission rate. Alternatively, a conservative (high) approach would be to assume full conversion and use the simple emission factor or apply Equation 5-7.

### 5.2.3 Cokers

There are several varieties of cokers in use in refineries, including delayed cokers, fluid cokers, and flexi-cokers. No quantitative data have been found to estimate CH<sub>4</sub> emissions from these sources. Delayed cokers will not have CO<sub>2</sub> emissions, other than from their process heaters that are calculated as any other combustion source (see Section 4). Fluid cokers and flexi-cokers may have a CO<sub>2</sub> vent resulting from the coke burner.

The CO<sub>2</sub> emissions from the coke burner are estimated by assuming that all of the carbon in the coke is oxidized to CO<sub>2</sub>. Equation 5-3 presented for catalytic cracking units can also be used for fluid coker or flexi-coker coke burner emissions. This calculation is shown in Exhibit 5.8.

Note that if the coke burner off-gas is exported for recovery of CO<sub>2</sub> or burned as a low-Btu fuel gas the raw CO<sub>2</sub> emissions rate should be adjusted so as not to include those quantities.

#### **EXHIBIT 5.8: Sample Calculation for Fluid Coker**

##### **INPUT DATA:**

A fluid coker combusts  $140 \times 10^6$  pounds per year of coke in the coke burner. The percent H<sub>2</sub> in the coke is known to be 1.5%. On a fraction basis the H<sub>2</sub> would be 0.015. The fraction carbon would be 1 minus the fraction H<sub>2</sub>, or 0.985.

##### **CALCULATION METHODOLOGY:**

Using Equation 5-3, the estimated CO<sub>2</sub> emissions would be:

$$\begin{aligned} E_{\text{CO}_2} &= \frac{140 \times 10^6 \text{ lb Coke}}{\text{year}} \times \frac{0.985 \text{ lb C}}{\text{lb Coke}} \times \frac{44 \text{ lb CO}_2/\text{lbmole}}{12 \text{ lb C/lbmole}} \times \frac{\text{tonne}}{2204.62 \text{ lb}} \\ &= \underline{\underline{229,350 \text{ tonnes CO}_2 / \text{yr}}} \end{aligned}$$

### 5.2.4 Other Catalyst Regeneration

There are a variety of other refinery processes that employ catalysts requiring regeneration. The catalytic reformers and hydroprocessing units fall into this category. Most of these are regenerated intermittently, although a few have continuous regeneration systems. There are no significant CH<sub>4</sub> emissions from any of these regeneration activities. However, the combustion of coke on the spent catalyst results in CO<sub>2</sub> emissions. The CO<sub>2</sub> emissions from intermittent regeneration are not likely to be significant when compared to combustion sources and continuous regeneration.

Using the fundamental principle of complete stoichiometric combustion, CO<sub>2</sub> emissions from intermittent or continuous catalyst regeneration can be estimated by the following equation:

$$E_{\text{CO}_2} = \text{CRR} \times \text{FC} \times \frac{44 \text{ mass units CO}_2/\text{mole}}{12 \text{ mass units C/mole}} \quad (\text{Equation 5-7})$$

where,

$E_{\text{CO}_2}$	=	emissions of CO <sub>2</sub> in tonnes per year
CRR	=	catalyst regeneration rate in tonnes per year
FC	=	weight fraction of carbon on spent catalyst

The emissions approach above can be used for catalytic reformer units (CFUs).

The catalyst regeneration rate (CRR) for an intermittent regeneration operation would be the catalyst inventory in tonnes multiplied by the number of regeneration events per year. An example of this calculation is presented in Exhibit 5.9.

#### **EXHIBIT 5.9: Sample Calculation for Other Intermittent Catalyst Regeneration**

##### **INPUT DATA:**

A hydrotreater has a catalyst inventory of 1000 tonnes and the carbon on the spent catalyst is 7 weight percent (or 0.07 weight fraction). The catalyst is typically regenerated every 9 months, which equates to 12/9 or 1.33 regeneration events per year.

##### **CALCULATION METHODOLOGY:**

Using Equation 5-7, the estimated CO<sub>2</sub> emissions per regeneration would be:

**EXHIBIT 5.9: Sample Calculation for Other Intermittent Catalyst Regeneration, continued**

$$E_{\text{CO}_2} = \frac{1,000 \text{ tonnes catalyst}}{\text{regeneration}} \times \frac{1.33 \text{ regenerations}}{\text{yr}} \times \frac{0.07 \text{ tonne C}}{\text{tonne catalyst}} \times \frac{44 \text{ tonne CO}_2 / \text{tonne mole}}{12 \text{ tonne C/tonne mole}} = \underline{341 \text{ tonnes CO}_2 / \text{yr}}$$

The calculation for a continuous regeneration processes is similar. The catalyst regeneration rate (CRR) in Equation 5-7 is based on the catalyst circulation rate multiplied by the hours of operation. This calculation is illustrated in Exhibit 5.10.

**EXHIBIT 5.10: Sample Calculation for Other Continuous Catalyst Regeneration****INPUT DATA:**

A catalytic reformer operates with a catalyst circulation rate of 10 tonnes per hour and with 4 wt% carbon on the spent catalyst. The unit operates for 8,280 hours per year.

**CALCULATION METHODOLOGY:**

Using Equation 5-7, the estimated CO<sub>2</sub> emissions would be:

$$E_{\text{CO}_2} = \frac{10 \text{ tonnes catalyst}}{\text{hr}} \times \frac{8280 \text{ hr}}{\text{yr}} \times \frac{0.04 \text{ tonne C}}{\text{tonne catalyst}} \times \frac{44 \text{ tonne CO}_2 / \text{tonne mole}}{12 \text{ tonne C/tonne mole}} = \underline{12,144 \text{ tonnes CO}_2 / \text{yr}}$$

**5.2.5 Asphalt Blowing**

Asphalt blowing is used for polymerizing and stabilizing asphalt to increase its resistance to weathering for use in the roofing and shingling industries. This process involves contacting the asphalt oils with heated air. In addition to occurring at refineries, asphalt blowing can also occur at asphalt processing and roofing plants. The exhaust air may be vented directly to the atmosphere,

resulting in CH<sub>4</sub> emissions, or the emissions may be reduced to negligible levels via controls such as vapor scrubbing or incineration (incineration would result in CO<sub>2</sub> emissions).

The preferred approach to estimate the CH<sub>4</sub> and CO<sub>2</sub> emissions from asphalt blowing is based on using site-specific measured data. Thus, measurements of the exhaust gas flow rate and composition are needed for this approach. This approach is the same as the cold process vent approach to estimate emissions described later in this *Compendium* (refer to Section 5.3).

In the absence of site-specific data, a simple emission factor for uncontrolled asphalt blowing is available from AP-42 (EPA, AP-42, Section 5.1.2.10, 1995):

30 kg emissions/megagram blown asphalt (original units)
60 lb emissions/ton blown asphalt (original units)
0.03 tonnes emissions/tonne blown asphalt (converted)

The AP-42 emission factor for asphalt blowing is assumed to be on an air-free basis (AP-42 does not specify this, but notes the factor represents “emissions”).

A gas composition is needed to estimate the CH<sub>4</sub> and CO<sub>2</sub> emissions when using the simple emission factor approach. Site-specific measured data or engineering judgment should be used to estimate the exhaust gas concentrations. In the absence of such data, the following sample calculation includes composition data from the literature (ARPEL, 1998).

#### **EXHIBIT 5.11: Sample Calculation for Asphalt Blowing Emissions**

##### **INPUT DATA:**

Asphalt blowing occurs at a refinery. During the reporting year, 100,000 tons of asphalt are treated with air blowing. The exhaust air is vented to the atmosphere uncontrolled.

##### **CALCULATION METHODOLOGY:**

The annual blown asphalt rate is multiplied by the simple emission factor provided earlier:

**EXHIBIT 5.11: Sample Calculation for Asphalt Blowing Emissions, continued**

$$\text{Gas Emissions: } \frac{100,000 \text{ tons asphalt blown}}{\text{year}} \times \frac{\text{tonnes asphalt}}{1.1023 \text{ tons asphalt}} \times \frac{0.03 \text{ tonnes emissions}}{\text{tonne asphalt}} = 2,722 \text{ tonnes gas emissions/yr}$$

Next, the CH<sub>4</sub> and CO<sub>2</sub> emissions are determined by multiplying the total emission rate by the concentrations in the exhaust stream. Site-specific data should be used for the exhaust stream composition profile. However, such an analysis is not available for this example, so a typical asphalt blowing exhaust composition provided in Table 6.24 of the ARPEL emissions protocol document is used (ARPEL, 1998). This composition is presented on an air-free basis (air made up 97.6% of the sample). The composition presented in ARPEL, which is provided on a molar basis, is shown below, along with the molecular weight of each compound:

Compound	Mole %	Molecular Weight
H <sub>2</sub>	52	2.02
H <sub>2</sub> S	4	34.08
CO	4	28.01
CO <sub>2</sub>	9	44.01
Methane	13	16.04
Ethane	4	30.07
Propane	4	44.10
Butane	4	58.12
Pentanes+	4	72.15

The exhaust emission rate is on a mass basis while the assumed exhaust analysis is on a molar basis, so the exhaust concentration must be converted to a mass basis. First, the exhaust gas molecular weight of the mixture (MW<sub>Mixture</sub>) must be estimated. Equation 3-8 is used to estimate the gas molecular weight of the mixture.

$$MW_{\text{Mixture}} = \frac{1}{100} \times \sum_{i=1}^{\text{\# compounds}} (\text{Mole}\%_i \times MW_i)$$

$$MW_{\text{Mixture}} = \frac{1}{100} \times [(52 \times 2.02) + (4 \times 34.08) + (4 \times 28.01) + (9 \times 44.01) + (13 \times 16.04) + (4 \times 30.07) + (4 \times 44.10) + (4 \times 58.12) + (4 \times 72.15)] = 17.76$$

**EXHIBIT 5.11: Sample Calculation for Asphalt Blowing Emissions, continued**

Next, the weight percents of CH<sub>4</sub> and CO<sub>2</sub> are estimated using Equation 3-7 rearranged in terms of the weight percent (Wt%i):

$$\text{Mole}\%_i = \text{Wt}\%_i \times \frac{\text{MW}_{\text{Mixture}}}{\text{MW}_i} \Rightarrow \text{Wt}\%_i = \text{Mole}\%_i \times \frac{\text{MW}_i}{\text{MW}_{\text{Mixture}}}$$

$$\text{Wt}\%_{\text{CH}_4} = 13 \times \frac{16.04}{17.76} = 11.7 \%$$

$$\text{Wt}\%_{\text{CO}_2} = 9 \times \frac{44.01}{17.76} = 22.3 \%$$

Lastly, the CH<sub>4</sub> and CO<sub>2</sub> emission rates are estimated by multiplying the total gas emission rate by the individual weight concentrations:

$$\text{CH}_4 : \frac{2,722 \text{ tonnes gas}}{\text{year}} \times \frac{11.7 \text{ tonnes CH}_4}{100 \text{ tonnes gas}} = \underline{318 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{CO}_2 : \frac{2,722 \text{ tonnes gas}}{\text{year}} \times \frac{22.3 \text{ tonnes CO}_2}{100 \text{ tonnes gas}} = \underline{607 \text{ tonnes CH}_4/\text{yr}}$$

**5.2.6 Other Refinery Process Vents**

Some additional process vents from refining were considered as potential sources of greenhouse gas emissions, but were subsequently determined to be insignificant. These include:

- Thermal cracking – breaks heavy oil molecules by exposing them to high temperatures; and
- Sulfur recovery units – used to convert hydrogen sulfide recovered from refinery gas streams into elemental sulfur.

In each of these processes, CH<sub>4</sub> emissions are considered negligible. Carbon dioxide emissions would be associated with heating processes, but these emissions would be calculated using the approaches presented for other combustion sources (see Section 4).

### 5.3 Cold Process Vents

“Cold” process vents refer to the vented release of emissions without combustion. As a result, these emission sources are more likely to contain CH<sub>4</sub> than CO<sub>2</sub>. These emission sources may include small, miscellaneous upstream or downstream vents that occur on an intermittent basis, or may encompass an overall process vent such as the venting of associated gas from an isolated crude oil production field.

Due to the wide variability of sources that could be considered cold vents, there are no emission factors or default values for estimating CH<sub>4</sub> and/or CO<sub>2</sub> emissions. A general material balance approach is required, based on source-specific measurements or estimates of the vent rate and concentrations. The material balance equation for an intermittent process vent is:

$$E_x = VR \times F_x \times \frac{MW_x}{\text{molar volume conversion}} \times VT \times n \quad (\text{Equation 5-8})$$

where,

$E_x$	=	emissions of “x” in units of mass (pounds, kg, tonnes) per year
“x”	=	the greenhouse gas compound of interest (CH <sub>4</sub> , or CO <sub>2</sub> for CO <sub>2</sub> rich streams)
VR	=	the vent rate in volume units at STP conditions (scfm or m <sup>3</sup> /min) per event
$F_x$	=	the molar fraction of compound “x” in the vent gas stream
$MW_x$	=	molecular weight of compound “x”
Molar volume conversion	=	conversion from molar volume to mass (379.3 scf/lbmole or 23.685 m <sup>3</sup> /kgmole)
VT	=	the time duration of the venting event in minutes
n	=	the number of events of this type and magnitude annually

This equation calculates the total amount of any compound released during the event. To estimate an annual emission rate, determine the frequency and duration of such venting episodes on a yearly basis using either documentation from actual venting events or averages from past events.

The approach is similar for a continual process vent. In this case the emission estimation equation is:



$$E_x = VR \times F_x \times \frac{MW_x}{\text{molar volume conversion}} \quad (\text{Equation 5-9})$$

where,

$E_x$	=	emissions of “x” in units of mass (pounds, kg, tonnes) per unit of time
“x”	=	the greenhouse gas compound of interest (CH <sub>4</sub> or CO <sub>2</sub> , for CO <sub>2</sub> rich streams)
VR	=	the vent rate in volume units at STP conditions per unit of time (e.g., scfm or m <sup>3</sup> /min)
$F_x$	=	the molar fraction of compound “x” in the vent gas stream
$MW_x$	=	molecular weight of compound “x”
Molar volume conversion	=	Conversion from molar volume to mass (379.3 scf/lbmole or 23.685 m <sup>3</sup> /kgmole)

Examples of these calculations are shown in Exhibit 5.12 (a) and (b)

#### EXHIBIT 5.12(a): Sample Calculation for an Intermittent Process Vent

##### INPUT DATA:

A production facility in a remote location produces 5,200 bbl/day of crude oil. The gas-to-oil ratio (GOR) for the field is 700. The associated gas is generally flared; however, the flare was not operated for a period of 15 days, during which time the gas was vented to the atmosphere. Process knowledge indicates that the gas molar composition is approximately 70% CH<sub>4</sub>, 20% VOC, and 10% CO<sub>2</sub>.

##### CALCULATION METHODOLOGY:

First, calculate the associated gas production rate from the gas-to-oil ratio and the oil production rate.

$$\text{Gas Production Rate} = \text{GOR} \times (\text{Oil production})$$

$$\text{Gas Production Rate} = \frac{700 \text{ scf gas}}{\text{bbl oil}} \times \frac{5,200 \text{ bbl oil}}{\text{day}} \times \frac{\text{day}}{24 \text{ hours}} \times \frac{\text{hour}}{60 \text{ min}} = 2,528 \text{ scf/min}$$

Equation 5-8 provides the approach for calculating the emissions per event. For this example there is one event during the year that lasts 15 days (when no gas flaring occurs).

**EXHIBIT 5.12(a): Sample Calculation for an Intermittent Process Vent, continued**CH<sub>4</sub> Emissions:

$$E_{\text{CH}_4} = \frac{2,528 \text{ scf}}{\text{min}} \times \frac{0.7 \text{ scf CH}_4}{\text{scf gas}} \times \frac{\text{lbmole CH}_4}{379.3 \text{ scf CH}_4} \times \frac{16 \text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{60 \text{ minutes}}{\text{hour}} \times \frac{24 \text{ hours}}{\text{day}} \\ \times \frac{15 \text{ days}}{\text{event}} \times \frac{1 \text{ event}}{\text{year}} \times \frac{\text{tonnes}}{2204.62 \text{ lb}} = \underline{731 \text{ tonnes CH}_4 / \text{year}}$$

CO<sub>2</sub> Emissions:

$$E_{\text{CO}_2} = \frac{2,528 \text{ scf}}{\text{min}} \times \frac{0.1 \text{ scf CO}_2}{\text{scf gas}} \times \frac{\text{lbmole CO}_2}{379.3 \text{ scf CO}_2} \times \frac{44 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{60 \text{ minutes}}{\text{hour}} \times \frac{24 \text{ hours}}{\text{day}} \\ \times \frac{15 \text{ days}}{\text{event}} \times \frac{1 \text{ event}}{\text{year}} \times \frac{\text{tonnes}}{2204.62 \text{ lb}} = \underline{287 \text{ tonnes CO}_2 / \text{year}}$$

Emissions when flaring occurs would be estimated using the approaches described in Section 4.4.

**EXHIBIT 5.12(b): Sample Calculation for a Continuous Process Vent**

INPUT DATA:

The production facility described in part (a) of this exhibit calculation is repeated for the case where no flare is installed at the facility. Thus, annual emissions occur due to continuous venting of the produced associated gas throughout the year.

CALCULATION METHODOLOGY:

Equation 5-9 provides the approach for estimating emissions from a continuous vent. The hourly gas vent flow rate is the same as shown in part a of this exhibit calculation. Thus, the emissions from the continuous venting are estimated based on 8,760 hours per year of operation.

CH<sub>4</sub> Emissions:

$$E_{\text{CH}_4} = \frac{2,528 \text{ scf}}{\text{min}} \times \frac{0.7 \text{ scf CH}_4}{\text{scf gas}} \times \frac{\text{lbmole CH}_4}{379.3 \text{ scf CH}_4} \times \frac{16 \text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{60 \text{ minutes}}{\text{hour}} \times \frac{24 \text{ hours}}{\text{day}} \\ \times \frac{365 \text{ days}}{\text{year}} \times \frac{\text{tonnes}}{2204.62 \text{ lb}} = \underline{17,796 \text{ tonnes CH}_4 / \text{year}}$$

**EXHIBIT 5.12(b): Sample Calculation for a Continuous Process Vent, continued**CO<sub>2</sub> Emissions:

$$E_{\text{CO}_2} = \frac{2,528 \text{ scf}}{\text{min}} \times \frac{0.1 \text{ scf CO}_2}{\text{scf gas}} \times \frac{\text{lbmole CO}_2}{379.3 \text{ scf CO}_2} \times \frac{44 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{60 \text{ minutes}}{\text{hour}} \times \frac{24 \text{ hours}}{\text{day}} \\ \times \frac{365 \text{ days}}{\text{year}} \times \frac{\text{tonnes}}{2204.62 \text{ lb}} = \underline{6,991 \text{ tonnes CO}_2 / \text{year}}$$

**5.4 Storage Tank Emissions****5.4.1 Flashing Losses.**

Where liquids are in contact with a gas phase, high pressures will cause some of the gas to go into solution (i.e., thermodynamic equilibrium between the phases will eventually occur). When the liquid is brought to atmospheric conditions, the solution gas is released through a rapid process called flashing.

Crude oil production tanks (primarily fixed roof tanks) emit CH<sub>4</sub> (and potentially CO<sub>2</sub> for a CO<sub>2</sub> rich stream) through flashing losses, which occur as the crude oil pressure decreases from the separator conditions to atmospheric pressure in the storage tank. Flashing emissions can be significant where there is a significant reduction in pressure. This primarily occurs in production operations. Liquid petroleum storage tanks can also produce emissions through working and standing (breathing) losses, but these emissions are generally insignificant for CH<sub>4</sub> and CO<sub>2</sub> (refer to Section 5.4.2)

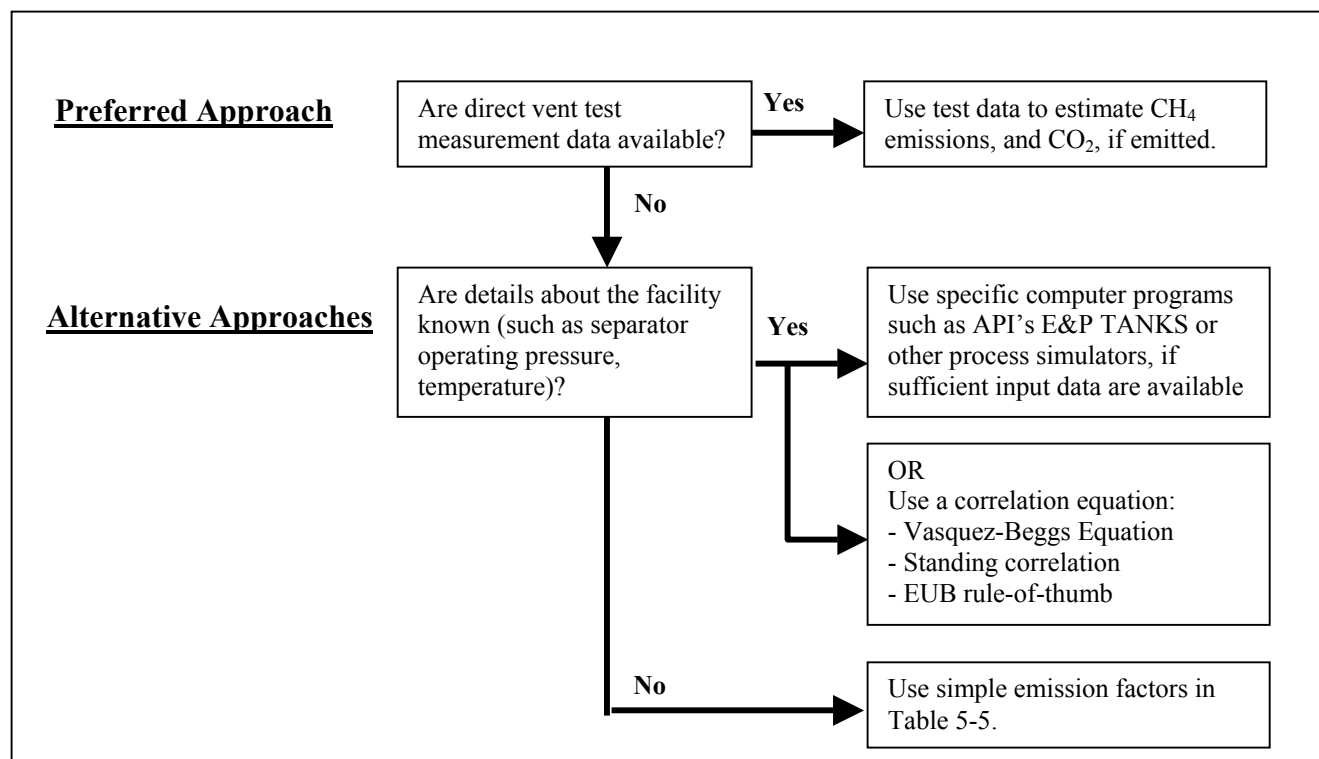
A variety of calculation methods can be used to estimate flashing losses from production storage tanks, as described below.

1. Direct measurements - Tank vent emissions can be measured directly, providing accurate emissions estimates for the measured tanks, but this approach is generally expensive and time consuming for large numbers of tanks.

2. Specific computer programs - API's E&P TANKS program (API, 1997) can be used to estimate flashing losses. However, this model works best when the low-pressure oil analysis (between the separator and storage tank) is known. Other input parameters include: separator pressure and temperature, atmospheric pressure, API gravity and Reid Vapor Pressure of the crude, composition of the crude, and production rate. If these conditions are unknown, assumptions can be made to run the program. Note that the EPA TANKS Program does not account for flashing loss emissions (EPA, 1999).
3. Process simulators - Flashing losses can also be estimated using various professional process simulators, but these models also require detailed model input data that may not be available.
4. Correlation equations – The Vasquez-Beggs Equation (VBE), standing correlation, and the Alberta Energy Utility Board (EUB) rule-of-thumb methods provide computational approaches for estimating tank flashing losses when limited input data are available.
5. Emission factors – Measured emissions from a variety of E&P tanks have been used to develop simple emission factors based on tank throughput.

Figure 5-3 summarizes the above methods for estimating flashing loss emissions. Using measured test data is the preferred approach for determining the flashing loss emissions. However, such test data may not be available. Alternative estimation methods include computer programs or process simulators, if sufficient input data are available. Correlation equations may be used with less input data than the software programs or process simulators require, but some basic process parameters are still needed (such as the separator pressure). A simple emission factor approach is provided if only limited data are available.

The use of correlation equations and emission factors for estimating flashing losses from crude oil storage tanks are discussed in the following subsections. Example calculations are provided for these approaches.



**Figure 5-3. Decision Tree for Crude Oil Flashing Losses**

### Vasquez-Beggs Equation (VBE) (Correlation Equation Approach)

The Texas Natural Resource Conservation Commission (TNRCC), now known as the Texas Commission on Environmental Quality (TCEQ), provides guidance on using the VBE to estimate tank flashing loss emissions from crude oil (TNRCC; Vasquez, 1980):

$$GOR = A \times (G_{\text{flash gas}}) \times (P_{\text{sep}} + 14.7)^B \times \exp\left(\frac{C \times G_{\text{oil}}}{T_{\text{sep}} + 460}\right) \quad (\text{Equation 5-10})$$

where,

GOR	=	Ratio of flash gas production to standard stock tank barrels of oil produced, in scf/bbl oil (barrels of oil corrected to 60°F)
$G_{\text{flash gas}}$	=	Specific gravity of the tank flash gas, where air = 1. A suggested default value for $G_{\text{flash gas}}$ is 1.22 (TNRCC; Vasquez, 1980)
$G_{\text{oil}}$	=	API gravity of stock tank oil at 60°F
$P_{\text{sep}}$	=	Pressure in separator, in psig
$T_{\text{sep}}$	=	Temperature in separator, °F

For  $G_{\text{oil}} \leq 30^\circ\text{API}$ :  $A = 0.0362$ ;  $B = 1.0937$ ; and  $C = 25.724$

For  $G_{\text{oil}} > 30^\circ\text{API}$ :  $A = 0.0178$ ;  $B = 1.187$ ; and  $C = 23.931$

The flash gas emissions estimated by the VBE are in terms of total hydrocarbon. Thus, an estimate must be made of the  $\text{CH}_4$  content in the tank flash gas vent. Two published studies measured flashing loss emissions from tanks, including the tank vent gas composition (Ogle, March 1997/ Ogle, May 1997; Picard, Vol. III, 1992). The average tank vent  $\text{CH}_4$  content was 27.4 volume % from these reports. This value is recommended in the absence of site-specific data. A summary of the results of the two studies is included in Appendix B.

A sample calculation illustrating the use of the VBE applied to flashing loss emissions is provided below.

#### **EXHIBIT 5.13(a): Sample Calculation for Flashing Loss Emissions – Vasquez-Beggs Equation (VBE)**

##### **INPUT DATA:**

An oil and gas production facility produces 71.70 m<sup>3</sup>/day (451 bbl/day) of crude oil with an API gravity of 48.8°. The separator pressure (immediately upstream of the tank) is 197.2 kPa (28.6 psig), and the separator temperature is 44.4°C (112°F). Neither the tank vent  $\text{CH}_4$  content nor the tank vent gas specific gravity is known.

##### **CALCULATION METHODOLOGY:**

The VBE Equation 5-10 will be used to estimate the tank flashing loss emissions. Note that the output from this equation is in units of scf/bbl oil.

The flash gas specific gravity,  $G_{\text{flash gas}}$ , is not known, so the recommended default value of 1.22 will be used. The flash gas vent flow rate is calculated below, using the A, B, and C parameters for an API gravity less than 30:

**EXHIBIT 5.13(a): Sample Calculation for Flashing Loss Emissions – Vasquez-Beggs Equation (VBE), continued**

$$\text{GOR} = A \times (G_{\text{flash gas}}) \times (P_{\text{sep}} + 14.7)^B \times \exp\left(\frac{C \times G_{\text{oil}}}{T_{\text{sep}} + 460}\right)$$

$$\text{GOR} = 0.0178 \times (1.22) \times (28.6 + 14.7)^{1.187} \times \exp\left(\frac{23.931 \times 48.8}{112 + 460}\right) = 14.65 \text{ scf/bbl oil}$$

Next, the output from the Vasquez-Beggs equation is converted to SI units using conversion factors from Table 3-2:

$$\frac{14.65 \text{ scf gas}}{\text{bbl crude}} \times \frac{\text{m}^3 \text{ gas}}{35.3147 \text{ scf gas}} \times \frac{\text{bbl crude}}{0.1589873 \text{ m}^3 \text{ crude}} = \frac{2.61 \text{ m}^3 \text{ gas}}{\text{m}^3 \text{ crude}}$$

The flash gas to oil ratio, GOR, contains gases besides CH<sub>4</sub> and must be multiplied by the tank vent CH<sub>4</sub> content. The tank vent CH<sub>4</sub> content is not known, so the recommended default concentration of 27.4 volume % CH<sub>4</sub> will be used. Thus, the CH<sub>4</sub> emissions are estimated as:

$$\begin{aligned} \frac{2.61 \text{ m}^3 \text{ gas}}{\text{m}^3 \text{ crude}} \times \frac{71.70 \text{ m}^3 \text{ oil}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{\text{kgmol gas}}{23.685 \text{ m}^3} \times \frac{27.4 \text{ kgmol CH}_4}{100 \text{ kgmol gas}} \times \frac{16 \text{ kg CH}_4}{\text{kgmole CH}_4} \times \frac{\text{tonne}}{1000 \text{ kg}} \\ = 12.64 \text{ tonnes CH}_4/\text{yr} \end{aligned}$$

**Standing Correlation (Correlation Equation Approach)**

The Canadian Association of Petroleum Producers (CAPP) document, *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, includes a standing correlation to estimate flashing losses (CAPP, 2002). This correlation is shown in the equation below (with variable letters changed to be consistent with the variables shown for the VBE):

$$\text{GOR} = G_{\text{flash gas}} \times \left( \frac{P}{519.7 \times 10^{-\text{V}_g}} \right)^{1.204} \quad (\text{Equation 5-11})$$

where,

GOR	=	Ratio of flash gas production to oil produced, in m <sup>3</sup> /m <sup>3</sup> oil
G <sub>flash gas</sub>	=	Specific gravity of the tank flash gas, where air = 1. A suggested default value for G <sub>flash gas</sub> is 1.22 (TNRCC; Vasquez, 1980)
P	=	Absolute pressure in vessel of interest, kPa
y <sub>g</sub>	=	$1.225 + 0.00164 \times T - \frac{1.769}{SG_{oil}}$
SG <sub>oil</sub>	=	specific gravity of oil with respect to water = $\frac{141.5}{131.5 + G_{oil}}$
G <sub>oil</sub>	=	API gravity of stock tank oil at 60°F
T	=	Temperature in vessel of interest, K

Note that the units for the standing correlation variables are different than the VBE, so caution should be exercised if both of these methods are used to estimate the flashing losses. For the situation where the crude flash occurs from a separator to an atmospheric tank, the term in parenthesis must be evaluated separately for the separator and the oil storage tank. For this scenario, Equation 5-11 would be expressed as shown:

$$GOR = G_{flash\ gas} \times \left[ \left( \frac{P}{519.7 \times 10^{y_g}} \right)_{Separator}^{1.204} - \left( \frac{P}{519.7 \times 10^{y_g}} \right)_{Storage\ Tank}^{1.204} \right] \quad (\text{Equation 5-12})$$

Similar to the VBE correlation approach, the flash gas emissions estimated using the standing correlation is provided in terms of hydrocarbon and must be converted to a CH<sub>4</sub> emissions basis. As noted earlier, a default of 27.4 volume % CH<sub>4</sub> is assumed in the absence of site-specific data (Ogle, March 1997; Ogle, May 1997; Picard, Vol. III, 1992).

A sample calculation illustrating the use of the standing correlation approach follows.



**EXHIBIT 5.13(b): Sample Calculation for Flashing Loss Emissions – Standing Correlation****INPUT DATA:**

The facility is the same oil and gas production facility described in Exhibit 5.13(a) for the VBE correlation approach. Namely, 451 bbl/day of crude (48.8° API gravity) is produced, and flashing losses occur as the oil flows from a separator at 28.6 psig and 112°F to an atmospheric tank. The atmospheric temperature (and thus the storage tank temperature) is assumed to be 80°F (299.8 K). Note that the atmospheric temperature was not needed for the VBE approach presented earlier.

**CALCULATION METHODOLOGY:**

The standing correlation approach, Equation 5-12, will be used to estimate the tank flashing loss emissions. First, the input parameters must be converted to the proper SI units for use in the equation, using the conversion factors presented in Table 3-2:

$$V_o = \frac{451 \text{ bbl}}{\text{day}} \times \frac{0.1589873 \text{ m}^3}{\text{bbl}} = 71.7 \text{ m}^3 \text{ oil/day}$$

Note that the separator absolute pressure is 43.3 psia (28.6 psig + 14.7 psia) while the tank pressure is 1 atm. Thus, the pressures in kPa are:

$$P_{\text{sep}} = (43.3 \text{ psi}) \times \frac{6.894757 \text{ kPa}}{\text{psi}} = 298.5 \text{ kPa} \quad \text{and} \quad P_{\text{tank}} = (1 \text{ atm}) \times \frac{101.325 \text{ kPa}}{\text{atm}} = 101.3 \text{ kPa}$$

Next, the oil API gravity ( $G_{\text{oil}}$ ) is converted to a specific gravity:

$$SG_{\text{oil}} = \frac{141.5}{131.5 + G_{\text{oil}}} = \frac{141.5}{131.5 + 48.8} = 0.785$$

Next, the parameter,  $y_g$ , can be calculated for both the separator and tank using the oil specific gravity and temperatures in the separator (112°F or 317.6 K) and the tank (80°F or 299.8 K):

$$y_g = 1.225 + 0.00164 \times T - \frac{1.769}{SG_{\text{oil}}}$$

**EXHIBIT 5.13(b): Sample Calculation for Flashing Loss Emissions – Standing Correlation, continued**

$$y_{g, \text{sep}} = 1.225 + (0.00164) \times (317.6) - \frac{1.769}{0.785} = -0.5076$$

$$y_{g, \text{tank}} = 1.225 + (0.00164) \times (299.8) - \frac{1.769}{0.785} = -0.5368$$

Thus, the input parameters for the standing correlation approach have been defined, and are summarized below:

$G_{\text{flash gas}} = 1.22$  (assume the default value in the absence of data)

$P_{\text{sep}} = 298.5$  kPa

$P_{\text{tank}} = 101.3$  kPa

$y_{g, \text{sep}} = -0.5076$

$y_{g, \text{tank}} = -0.5368$

The flash gas vent flow rate is calculated below, using the above parameters, which are shown in the proper units for the equation:

$$\text{GOR} = G_{\text{flash gas}} \times \left[ \left( \frac{P}{519.7 \times 10^{y_g}} \right)_{\text{Separator}}^{1.204} - \left( \frac{P}{519.7 \times 10^{y_g}} \right)_{\text{Storage Tank}}^{1.204} \right]$$

$$\text{GOR} = (1.22) \times \left[ \left( \frac{298.5}{519.7 \times 10^{-0.5076}} \right)_{\text{Separator}}^{1.204} - \left( \frac{101.3}{519.7 \times 10^{-0.5368}} \right)_{\text{Storage Tank}}^{1.204} \right]$$

$$\text{GOR} = 1.802 \text{ m}^3 \text{ gas/m}^3 \text{ oil}$$

The flash gas contains gases besides  $\text{CH}_4$  and must be multiplied by the tank vent  $\text{CH}_4$  content. The tank vent  $\text{CH}_4$  content is not known, so the recommended default concentration of 27.4 volume %  $\text{CH}_4$  will be used. Thus, the  $\text{CH}_4$  emissions are estimated as:

**EXHIBIT 5.13(b): Sample Calculation for Flashing Loss Emissions – Standing Correlation, continued**

$$\frac{1.802 \text{ m}^3 \text{ gas}}{\text{m}^3 \text{ oil}} \times \frac{71.7 \text{ m}^3 \text{ oil}}{\text{day}} \times \frac{35.3147 \text{ ft}^3 \text{ (scf) gas}}{\text{m}^3} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{27.4 \text{ lbmole CH}_4}{100 \text{ lbmole gas}} \times \frac{365 \text{ day}}{\text{yr}} \\ \times \frac{16 \text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = \underline{8.73 \text{ tonnes CH}_4/\text{yr}}$$

**EUB Rule-of-Thumb (Correlation Equation Approach)**

The Canadian Association of Petroleum Producers (CAPP) document, *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, includes the EUB (Energy and Utilities Board) rule-of-thumb approach to estimate flashing losses (CAPP, 2002). CAPP reports that this approach tends to yield conservatively high flashing loss estimates and is recommended for facilities with low oil volumes, established pools, mature pools with declining GOR's, and some heavy oil production facilities (CAPP, 2002). The EUB rule-of-thumb equation is:

$$V_s = 0.0257 \times V_o \times \Delta P \quad (\text{Equation 5-13})$$

where,

- $V_s$  = volume of gas released, in  $\text{m}^3$
- $V_o$  = oil production volume,  $\text{m}^3$
- $\Delta P$  = Pressure drop to atmospheric tank, kPa.

Similar to the VBE and standing correlation approaches, the flash gas emissions estimated using the EUB rule-of-thumb approach is in terms of hydrocarbon and must be converted to a  $\text{CH}_4$  emissions basis. As noted earlier, a default of 27.4 volume %  $\text{CH}_4$  is assumed in the absence of site-specific data (Ogle, March 1997; Ogle, May 1997; Picard, Vol. III, 1992).

A sample calculation illustrating the use of the EUB rule-of-thumb approach follows.

**EXHIBIT 5.13(c): Sample Calculation for Flashing Loss Emissions – EUB Rule-of-Thumb****INPUT DATA:**

The facility is the same oil and gas production facility described in Exhibits 5.13(a) and 5.13(b) for the other two correlation approaches. For illustrative purposes, this exhibit shows how CO<sub>2</sub> emissions would be estimated as well. For this facility, the CO<sub>2</sub> tank vent concentration is assumed to be approximately 4.5 volume %.

**CALCULATION METHODOLOGY:**

The EUB rule-of-thumb approach, Equation 5-13, will be used to estimate the tank flashing loss emissions. First, the input parameters must be converted to the proper SI units for use in the equation, using the conversion factors presented in Table 3-2:

$$V_o = \frac{451 \text{ bbl}}{\text{day}} \times \frac{0.1589873 \text{ m}^3}{\text{bbl}} = 71.7 \text{ m}^3 \text{ oil/day}$$

Note that the separator gauge pressure, 28.6 psig, is equal to the pressure drop from the separator to the atmospheric storage tank (i.e. 43.3 psia - 14.7 psia = 28.6 psi). Thus, the pressure drop in kPa is:

$$\Delta P = (28.6 \text{ psi}) \times \frac{6.894757 \text{ kPa}}{\text{psi}} = 197.2 \text{ kPa}$$

The flash gas vent flow rate is calculated below, using the parameters in the proper units:

$$V_s = 0.0257 \times V_o \times \Delta P$$

$$V_s = 0.0257 \times (71.7) \times (197.2) = 363.4 \text{ m}^3/\text{day}$$

The flash gas contains gases besides CH<sub>4</sub> and must be multiplied by the tank vent CH<sub>4</sub> content. The tank vent CH<sub>4</sub> content is not known, so the recommended default concentration of 27.4 volume % CH<sub>4</sub> will be used. Thus, the CH<sub>4</sub> emissions are estimated as:

$$\begin{aligned} \text{CH}_4 : \frac{363.4 \text{ m}^3 \text{ gas}}{\text{day}} &\times \frac{35.3147 \text{ ft}^3 (\text{scf}) \text{ gas}}{\text{m}^3} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{27.4 \text{ lbmole CH}_4}{100 \text{ lbmole gas}} \times \frac{365 \text{ day}}{\text{yr}} \\ &\times \frac{16 \text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = \underline{24.56 \text{ tonnes CH}_4/\text{yr}} \end{aligned}$$

**EXHIBIT 5.13(c): Sample Calculation for Flashing Loss Emissions – EUB Rule-of-Thumb, continued**

$$\text{CO}_2 : \frac{363.4 \text{ m}^3 \text{ gas}}{\text{day}} \times \frac{35.3147 \text{ ft}^3 (\text{scf}) \text{ gas}}{\text{m}^3} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{4.5 \text{ lbmole CO}_2}{100 \text{ lbmole gas}} \times \frac{365 \text{ day}}{\text{yr}} \\ \times \frac{44 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = \underline{11.09 \text{ tonnes CH}_4/\text{yr}}$$

If sufficient input data are available, users may choose to estimate flashing losses with software programs such as API's E&P TANKS or with process simulators instead of the correlation approaches described above. The results could differ between the software programs/process simulators and the correlation equations due to different assumptions used by each approach. However, if very limited input data are available, then a simple emission factor approach must be used as described in the next subsection.

**Emission Factor Approach For Crude Oil Tank Flashing**

Data from two published studies, one by API/GRI (Ogle, March 1997; Ogle, May 1997) and the other by the Canadian Petroleum Association (Picard, Vol. III, 1992), were used to derive an emission factor for production crude oil storage tanks. A summary of the results of these studies, including development of the average tank CH<sub>4</sub> flashing loss emission factor, is included in Appendix B. The CH<sub>4</sub> emission factor is provided in Table 5-6.

**Table 5-6. Methane Flashing Loss Emission Factors for Crude Oil Storage Tanks**

Source	CH <sub>4</sub> Flashing Loss Emission Factor		Notes
Combined API/GRI and CPA data	1.954	lb/bbl crude	Factor based on separator CH <sub>4</sub> content of 78.8% (vol.); can ratio to other separator concentrations
	8.86E-04	tonnes/bbl crude	
	5.57E-03	tonnes/m <sup>3</sup> crude	

Sources:

Ogle, L.D. *Validation of a Petroleum Production Tank Emission Model*, Final Report, GRI-97/0117. American Petroleum Institute and Gas Research Institute, March 1997.

Ogle, L.D. *Evaluation of a Petroleum Production Tank Emission Model*, Final Report. American Petroleum Institute, Gas Research Institute, and Canadian Association of Petroleum Producers, May 1997.

Picard, D. J., B. D. Ross, and D. W. H. Koon. *Inventory of CH<sub>4</sub> and VOC Emissions from Upstream Oil and Gas Operations in Alberta*, Volume III Results of the Field Validation Program, Canadian Petroleum Association, March 1992, pp. 75-81.

A sample calculation illustrating the use of the simple emission factor is given below.

**EXHIBIT 5.14: Sample Calculation for Tank Flashing Losses - Simple Emission Factor Approach**

**INPUT DATA:**

An oil and gas production facility produces 451 bbl/day of crude oil (same as the previous exhibit). The separator gas (to sales pipeline) CH<sub>4</sub> content is 58 volume %.

**CALCULATION METHODOLOGY:**

The CH<sub>4</sub> flashing losses are calculated using the emission factor provided in Table 5-6. Please note that this emission factor is based on 78.8 mole % CH<sub>4</sub> in the separator gas, so this emission factor must be corrected to 58 mole % based on the composition for this example.

$$\frac{451 \text{ bbl crude}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{8.86 \times 10^{-4} \text{ tonnes CH}_4}{\text{bbl crude}} \times \frac{58 \text{ mole \% CH}_4}{78.8 \text{ mole \% CH}_4} = 107.4 \text{ tonne CH}_4/\text{yr}$$

Exhibits 5.13(a), (b), and (c) demonstrate the use of the VBE, standing, and EUB rule-of-thumb correlation approaches, respectively. Additionally, Exhibit 5.14 demonstrates the use of the simple emission factor approach. These exhibits were based on operating parameters presented in a testing program prepared for API, GRI, and CAPP to evaluate API's E&P TANKS software (Ogle, May 1997). Site number 5 from this study was used for the exhibit calculations. This study presented both measured flashing loss data as well as the results obtained for the test site using E&P TANKS software, version 3.0.

Table 5-7 summarizes tank flashing loss emission estimates for the various approaches presented. As shown, the EUB rule-of-thumb approach results in the highest flashing loss emission estimate for the 3 correlation approaches. This is consistent with information from CAPP, which states that this approach provides conservatively high estimates. The VBE correlation results in emission estimates that are higher than the standing correlation for the exhibit calculation and nearly equivalent to E&P TANKS. The measured emissions were less than all of the correlation approaches except the standing correlation. The simple emission factor was much higher than all of the other approaches; however, it did not rely on many of the input parameters (except for the flow rate and separator gas methane content, which were taken from the Ogle report for site number 5).

**Table 5-7. Summary of Production Tank Flashing Losses Using Different Correlation Equation Approaches**

Correlation	CH <sub>4</sub> Flashing Losses (tonnes/yr)
Vasquez-Beggs Equation (VBE)	12.64
Standing Correlation	8.73
EUB Rule-of-Thumb	24.56
Simple Emission Factor Approach	107.4
E&P TANKS, Version 3.0	12.75 <sup>a,b</sup>
Measured	9.54 <sup>a,b</sup>

<sup>a</sup>Source: Ogle, L.D. *Evaluation of a Petroleum Production Tank Emission Model*, Final Report. American Petroleum Institute, Gas Research Institute, and Canadian Association of Petroleum Producers, May 1997. Based on data for site number 5.

<sup>b</sup>E&P TANKS also uses the pressurized oil composition as an input. Annual emissions for the measured data are estimated from the hourly rate assuming continuous annual operation.

Note that the comparison in Table 5-7 is not comprehensive as it is for only one set of conditions presented at one site. Thus, no conclusion can be drawn with regard to the relative estimates provided by the different approaches. The choice of using the EUB rule-of-thumb versus the VBE or standing correlation depends on the available data; the EUB rule-of-thumb requires less input data than the other two approaches. If sufficient data are available for the VBE or standing correlation approaches, then the choice of one approach over the other is left to the discretion of the user. Users may choose to apply both correlations and conservatively use the approach that provides the highest emission estimate. The simple emission factor should only be used when very limited input data are available (and, thus, the other approaches cannot be used).

### Emissions from Methane Entrained in Condensate

Condensate collected in the production segment may contain entrained CH<sub>4</sub>, which can result in flashing losses as the condensate is brought to atmospheric conditions. Small quantities of condensate may also be collected at transmission compressor stations or in pipeline knockout drums.

The approach to estimate CH<sub>4</sub> emissions from condensate collected in separators or knockout drums is very similar to crude tank flashing losses. The preferred approach is to use direct measurements. In the absence of measured data, alternative estimation methods include process simulators, if sufficient input data are available, or the Vasquez-Beggs Equation or standing correlation, provided the physical properties of the condensate are used instead of the physical

properties for crude oil. The EUB rule-of-thumb correlation or the simple emission factor should not be used for condensate since these approaches do not take into account the condensate physical properties.

#### **5.4.2 Tanks Working/Standing Losses**

Liquid petroleum storage tanks can produce hydrocarbon emissions through working and standing (breathing) losses. These storage tanks include crude oil tanks in production, intermediate tanks at a refinery, and refined product tanks at refineries and in distribution. Tank types include fixed roof tanks as well as floating roof tanks. Working loss emissions occur during filling and emptying of the tanks as evaporative losses occur. Standing losses occur during storage of the liquid, and can result from diurnal temperature changes. Because most of the CH<sub>4</sub> and CO<sub>2</sub> emissions from storage tanks occur due to flashing (refer to Section 5.4.1), working and breathing loss emissions of these pollutants are expected to be very small in production and virtually non-existent in the downstream segments. Thus, the default approach of this Compendium is to assume that tank working and breathing loss emissions are negligible for CH<sub>4</sub> and CO<sub>2</sub>.

However, as an alternative approach, sites may choose to estimate CH<sub>4</sub> and CO<sub>2</sub> emissions due to tank working and standing losses. Chapter 7 of AP-42 provides detailed guidance for estimating tank hydrocarbon working and standing loss emissions (EPA, Supplement D, 1997). The emission estimation equations in Chapter 7 of AP-42 were developed by API (API retains the copyright of the equations but has granted EPA permission to publish them). The API tank emission equations presented in Chapter 7 of AP-42 are also the basis for the TANKS software program (EPA, 1999), which is distributed through the EPA's Technology Transfer Network (TTN). Note that Chapter 7 of AP-42 and the TANKS program do not estimate tank flashing losses. The TANKS software is available on the Internet at:

*<http://www.epa.gov/ttn/chief/software/tanks/index.html>*

Since Chapter 7 of AP-42 and the TANKS program are primarily directed at estimating THC or VOC emissions, the user would have to estimate the total emissions from the tank and then multiply the total emissions by the concentration of CH<sub>4</sub> and/or CO<sub>2</sub> in the tank vent stream. The CH<sub>4</sub> and/or CO<sub>2</sub> concentrations should be based on site test data if they are available (otherwise the site will have to use engineering judgment).



### 5.4.3 Produced Water Tank Emissions

Produced water tank emissions occur in a manner similar to crude oil storage tank flashing losses, though at a smaller relative rate. Methane emissions from produced water tanks are lower than crude tank flashing losses because CH<sub>4</sub> has a stronger affinity for hydrocarbon oil than it does for water. Thus, more CH<sub>4</sub> is dissolved in the oil phase than the water phase.

Direct measurement, process simulation, and general industry emission factors can be used to quantify flashing losses from produced water tanks. However, API's E&P TANKS program (API, 1997) and the Vasquez-Beggs Equation are based on properties specific to crude oil and, therefore, are not applicable to water tanks.

Table 5-8 presents emission factors from produced (salt) water tanks. These emission factors were developed from data presented in Volume 6 of the 1996 GRI/EPA study (Shires and Harrison, 1996). The GRI/EPA study estimated produced water emissions based on process simulator modeling for salt contents of 2, 10, and 20%, and pressures of 50, 250, and 1000 psi. The original emission factors are converted from a total CH<sub>4</sub> mass rate to tonnes CH<sub>4</sub> per volume of produced water based on the national produced water volume used in the original process simulations (Energy Environmental Research Center, 1995).

**Table 5-8. Produced Salt Water Tank Methane Flashing Emission Factors**

Separator Pressure (psi)	Produced Water Salt Content	GRI/EPA Emission Rate, Original Units (10 <sup>6</sup> lb CH <sub>4</sub> /yr)	Water Tank Emission Factor	
			tonnes CH <sub>4</sub> /1000 bbl produced water	tonnes CH <sub>4</sub> /1000 m <sup>3</sup> produced water
<b>50</b>	<b>20%</b>	<b>1.6</b>	<b>0.0015</b>	<b>0.00943</b>
250	20%	10.8	0.00986	0.06202
250	10%	16.4	0.0150	0.09435
250	2%	19.4	0.0177	0.11133
<b>250</b>	<b>Average of 10.7%</b>	<b>--</b>	<b>0.0142<sup>a</sup></b>	<b>0.08923</b>
1000	20%	38.8	0.0354	0.22266
1000	10%	58.7	0.0536	0.33713
1000	2%	69.5	0.0634	0.39877
<b>1000</b>	<b>Average of 10.7%</b>	<b>--</b>	<b>0.0508<sup>a</sup></b>	<b>0.31952</b>

Sources:

Emission factors developed from Table 5-5 of Shires, T.M., and M.R. Harrison. *Methane Emissions from the Natural Gas Industry*, Volume 6: Vented and Combustion Source Summary, Final Report, GRI-94/0257.23 and EPA-600/R-96-080f, Gas Research Institute and US Environmental Protection Agency, June 1996.

Process simulation modeling based on 1990 annual salt water production of 497 million barrels from Energy Environmental Research Center, 1995.

<sup>a</sup> Average of emission factors at 20, 10, and 2% salt.

The Regional Association of Oil and Natural Gas Companies in Latin America and the Caribbean (ARPEL) provides another source of general emission factors for produced water flashing losses (ARPEL, 1998). Table 5-9 presents CH<sub>4</sub> emission factors for produced water from shallow gas wells (76 psi or less). These factors are based on produced water at a temperature of 50°C (122°F). The base emission factor, developed from Chapter 9 of *API Technical Data Book* (API, 1984), is reported to be extremely approximate (ARPEL, 1998).

**Table 5-9. Methane Emission Factors from Produced Water from Shallow Gas Wells**

Source Information	CH <sub>4</sub> Water Tank Emission Factor, Original Units (kg/m <sup>3</sup> produced water)	CH <sub>4</sub> Water Tank Emission Factor
Shallow gas well (76 psi or less, 50°C)	0.036	0.0057 tonnes/1000 bbl produced water 0.036 tonnes/1000 m <sup>3</sup> produced water

Source: Table 3.6 of ARPEL, *Atmospheric Emissions Inventories Methodologies in the Petroleum Industry*. ARPEL Guideline # ARPELCIDA02AEGUI2298, Prepared by Jaques Whitford Environment Limited, December 1998.

A sample calculation illustrating the use of the simple emission factor for produced water emissions is presented below.

**NEW EXHIBIT 5.15: Sample Calculation for Water Tank Emissions – Simple Emission Factor Approach**

**INPUT DATA:**

An oil and gas production facility produces 50 bbl/day of water. The salt content of the water is not known. The separator pressure (immediately upstream of the water tank) is 200 psig.

**CALCULATION METHODOLOGY:**

The CH<sub>4</sub> flashing losses are calculated using the emission factor provided in Table 5-8 for 250 psi. This emission factor should provide a conservative (high) estimate since the actual separator pressure is less than 250 psi (actual pressure is 200 psi). Because the salt content (for a separator pressure 250 psi) of the produced water is unknown, the emission factor provided for the average salt content is used. The CH<sub>4</sub> emissions are estimated as shown below.

$$\frac{50 \text{ bbl water}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{0.0142 \text{ tonnes CH}_4}{1000 \text{ bbl water}} = \underline{0.26 \text{ tonne CH}_4/\text{yr}}$$

#### 5.4.4 Natural Gas Blanketed Tank Emissions

Some tanks are blanketed with natural gas. If the tanks are uncontrolled, CH<sub>4</sub> emissions (and possibly CO<sub>2</sub> emissions, if present in the natural gas) occur as the natural gas is displaced by the liquid pumped into the tanks. The recommended approach for estimating emissions from this source is the material balance equation for cold process vents presented in Section 5.3 (Equation 5-9), converted to an annual basis.

$$E_x = VR \times F_x \times \frac{MW_x}{\text{molar volume conversion}} \quad \text{(Equation 5-9 from Section 5.3)}$$

where,

$E_x$	=	emissions of “x” in units of mass (pounds, kg, tonnes) per unit of time
“x”	=	the greenhouse gas compound of interest (CH <sub>4</sub> or CO <sub>2</sub> , for CO <sub>2</sub> rich streams)
VR	=	the vent rate in volume units at STP conditions per unit of time (e.g., scfm or m <sup>3</sup> /min)
$F_x$	=	the molar fraction of compound “x” in the vent gas stream
$MW_x$	=	molecular weight of compound “x”
Molar volume conversion	=	Conversion from molar volume to mass (379.3 scf/lbmole or 23.685 m <sup>3</sup> /kgmole)

The blanket natural gas is generally charged to the tank intermittently rather than continuously. Thus, the emissions are based on vapor displacement when liquid fills the tank rather than based on a continuous flow of the natural gas to the tank. The vent rate (VR) term in Equation 5-9 is assumed to be the vapor displacement due to filling the tank with liquid. It is the total increase in liquid height, without taking reductions for decreases of the liquid height. Note that filling and emptying a tank simultaneously at the same flow rate would result in no net change in the liquid height, and consequently no displacement of natural gas to the atmosphere. Thus, the volumetric increase in liquid level should be used in the calculation. However, a site may not monitor liquid level changes. In this case, the site may only know liquid throughput rates. This liquid throughput rate should be used for the VR term in the absence of liquid level data. Using the liquid throughput rate to estimate the vapor displacement should provide conservatively high emission estimates since it does not take into account the liquid level affects due to emptying the tank at the same time as filling.

A sample calculation for natural gas blanketed tank emissions is shown below.

**EXHIBIT 5.16: Sample Calculation for Natural Gas Blanketed Tank Emissions****INPUT DATA:**

A natural gas blanketed tank has an annual liquid throughput of 36,500 bbl/year. However, the facility records the tank liquid level, and the total increase in liquid height during the year is 32,000 bbl. The total volumetric increase in liquid height is less than the total throughput since emptying of the tank occurs while filling during some periods of the year. The blanket natural gas contains approximately 82 mole % CH<sub>4</sub> and 1 mole % CO<sub>2</sub>. The estimated annual temperature in the tank vapor space is 75°F.

**CALCULATION METHODOLOGY:**

Equation 5-9 is used to estimate the annual emissions. However, the vent rate (VR) term in the equation is on a standard ft<sup>3</sup> basis (scf), and the annual volumetric rate is on an actual ft<sup>3</sup> basis at 75°F (acf), so the actual vent rate must be converted to standard conditions of 1 atm and 60°F. Equation 3-5 is used to convert from actual to standard conditions. Also, the actual volumetric displacement rate of 32,000 bbl/yr is used instead of the annual liquid throughput of 36,500 bbl/yr since it represents the actual natural gas displaced.

First, the volumetric displacement is converted from barrels to actual cubic feet.

$$\frac{32,000 \text{ bbl}}{\text{yr}} \times \frac{42 \text{ gallons}}{\text{bbl}} \times \frac{\text{ft}^3}{7.4805 \text{ gallons}} = 179,667 \text{ ft}^3 \text{ (at 75°F)}$$

Next, Equation 3-5 is applied to convert from acf to scf (note that the actual and standard conditions are both at 1 atm). Also note that the equation requires absolute temperatures (°R).

$$V_2 = V_1 \left[ \frac{(P_1)(T_2)}{(P_2)(T_1)} \right]$$

$$V_2 = (179,667 \text{ ft}^3) \times \left[ \frac{(1 \text{ atm})(60 + 459.7)}{(1 \text{ atm})(75 + 459.7)} \right] = 174,627 \text{ scf (at 60°F and 1 atm)}$$

Lastly, Equation 5-9 is applied.

$$E_x = \text{VR} \times F_x \times \frac{\text{MW}_x}{\text{molar volume conversion}}$$

**EXHIBIT 5.16: Sample Calculation for Natural Gas Blanketed Tank Emissions, continued**CH<sub>4</sub> Emissions:

$$E_{\text{CH}_4} = \frac{174,627 \text{ scf}}{\text{yr}} \times \frac{0.82 \text{ scf CH}_4}{\text{scf gas}} \times \frac{16 \text{ lb CH}_4/\text{lbmole CH}_4}{379.3 \text{ scf CH}_4/\text{lbmole CH}_4} \times \frac{\text{tonnes}}{2204.62 \text{ lb}} \\ = \underline{2.74 \text{ tonnes CH}_4 / \text{year}}$$

CO<sub>2</sub> Emissions:

$$E_{\text{CO}_2} = \frac{174,627 \text{ scf}}{\text{yr}} \times \frac{0.01 \text{ scf CO}_2}{\text{scf gas}} \times \frac{44 \text{ lb CO}_2/\text{lbmole CO}_2}{379.3 \text{ scf CO}_2/\text{lbmole CO}_2} \times \frac{\text{tonnes}}{2204.62 \text{ lb}} \\ = \underline{0.09 \text{ tonnes CO}_2 / \text{year}}$$

**5.5 Loading, Ballasting, and Transit Loss Emissions**

The transportation sector consists of crude and natural gas transport from the production segment to downstream operations and the transport of refined products from refineries to marketing or distribution centers. Transporting petroleum liquids via tank trucks, rail tank cars, and marine vessels, and the loading of petroleum products into these vessels results in the evaporative losses of the hydrocarbons, which potentially include CH<sub>4</sub>. Methane emissions during loading operations occur as the CH<sub>4</sub> in organic vapors in the cargo tanks are displaced into the atmosphere by the petroleum liquid that is being loaded. Evaporative CH<sub>4</sub> emissions can also occur during marine ballasting operations as crude oil loaded from a marine cargo vessel is replaced by "ballasting" water which can displace hydrocarbon vapors in the marine vessel. Transit losses occur due to a mechanism that is similar to breathing losses associated with storage tanks.

Several approaches are available for estimating emissions from loading, ballasting, and transit operations. In many cases, the specific estimation approach depends on the fuel type, type of information available, and other specific operation conditions. Each of the approaches requires the crude or petroleum fuel CH<sub>4</sub> content to convert from TOC emission factors. The CH<sub>4</sub> content of crude is assumed to be 15 wt%, if site-specific data are not available (EPA, AP-42 Section 5.2, 1995). For petroleum liquids other than crude, the CH<sub>4</sub> content is generally insignificant and is assumed negligible if measured data are not available.

Due to the negligible CH<sub>4</sub> content of most fuels, calculating emissions associated with loading, ballasting, and transit operations is recommended for crude oil and for other petroleum fuels only if the CH<sub>4</sub> content is measurably significant (>1% by weight). This section presents simple calculation approaches for these sources in crude and gasoline service. More detailed methods are provided in Appendix B if warranted by the fuel throughput volume or CH<sub>4</sub> content.

### 5.5.1 Loading Loss Emissions

Table 5-10 provides simplified TOC emission factors for loading loss emissions for crude oil and gasoline (EPA, AP-42 Section 5.2, 1995). This approach only applies to gasoline where the CH<sub>4</sub> content in the fuel is measurably significant (>1% by weight).

Table 5-11 presents TOC emission factors for emissions resulting from gasoline loaded into ships and barges (EPA, AP-42 Table 5.2-2, 1995). Here also, this approach only applies where the CH<sub>4</sub> content in the gasoline is measurably significant (>1% by weight).

An example for gasoline loading is provided in Exhibit B-5, in Appendix B.

#### EXHIBIT 5.17: Sample Calculation for Estimating Loading Loss CH<sub>4</sub> Emissions Using Simplified Emission Factor Approach

##### INPUT DATA:

50,000 bbl/yr of crude oil is loaded into rail tankers via splash loading and dedicated normal service. The crude vapors contain 12 wt% CH<sub>4</sub>.

##### CALCULATION METHODOLOGY:

From Table 5-10, the emission factor corresponding to crude loading losses from rail splash loading, dedicated service is 2.2 tonnes TOC/million gallons loaded. Converting the TOC emissions to CH<sub>4</sub> and applying the annual loading rate, the loading emissions are calculated as follows.

$$\begin{aligned}\text{Loading Emissions} &= \frac{2.2 \text{ tonnes TOC}}{10^6 \text{ gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{50,000 \text{ bbl}}{\text{yr}} \times \frac{12 \text{ tonne CH}_4}{100 \text{ tonne TOC}} \\ &= \underline{0.554 \text{ tonnes CH}_4 / \text{yr}}\end{aligned}$$

**Table 5-10. Simplified TOC Emission Factors for Loading Losses<sup>a</sup>**

Loading Type	Units		Crude Oil <sup>b</sup>	Gasoline <sup>c</sup>
Rail / Truck Loading <sup>d</sup> Submerged Loading - Dedicated normal service	Original	lb TOC/10 <sup>3</sup> gal loaded	2	5
	Units	mg TOC/L loaded	240	590
	Converted	tonne TOC/ 10 <sup>6</sup> gal loaded <sup>f</sup>	0.91	2.23
	Units	tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded <sup>f</sup>	0.240	0.590
Rail / Truck Loading <sup>d</sup> Submerged Loading - Vapor balance service	Original	lb TOC/10 <sup>3</sup> gal loaded	3	8
	Units	mg TOC/L loaded	400	980
	Converted	tonne TOC/ 10 <sup>6</sup> gal loaded <sup>f</sup>	1.51	3.71
	Units	tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded <sup>f</sup>	0.400	0.980
Rail / Truck Loading <sup>d</sup> Splash Loading - Dedicated normal service	Original	lb TOC/10 <sup>3</sup> gal loaded	5	12
	Units	mg TOC/L loaded	580	1,430
	Converted	tonne TOC/ 10 <sup>6</sup> gal loaded <sup>f</sup>	2.20	5.41
	Units	tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded <sup>f</sup>	0.580	1.430
Rail / Truck Loading <sup>d</sup> Splash Loading - Vapor balance service	Original	lb TOC/10 <sup>3</sup> gal loaded	3	8
	Units	mg TOC/L loaded	400	980
	Converted	tonne TOC/ 10 <sup>6</sup> gal loaded <sup>f</sup>	1.51	3.71
	Units	tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded <sup>f</sup>	0.400	0.980
Marine Loading <sup>e</sup> - Ships/ocean barges	Original	lb TOC/10 <sup>3</sup> gal loaded	0.61	See Table 5-11
	Units	mg TOC/L loaded	73	
	Converted	tonne TOC/ 10 <sup>6</sup> gal loaded <sup>f</sup>	0.28	
	Units	tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded <sup>f</sup>	0.073	
Marine Loading <sup>e</sup> - Barges	Original	lb TOC/10 <sup>3</sup> gal loaded	1.0	See Table 5-11
	Units	mg TOC/L loaded	120	
	Converted	tonne TOC/ 10 <sup>6</sup> gal loaded <sup>f</sup>	0.45	
	Units	tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded <sup>f</sup>	0.120	

Source: EPA, AP-42, Section 5, Tables 5.2-5 and 5.2-6, 1995.

<sup>a</sup> The factors shown are for total organic compounds. AP-42 reports that the VOC comprises approximately 85% of the TOC for crude oil. Thus, a good, conservative assumption for the CH<sub>4</sub> content of the TOC is 15% in the absence of site-specific data. The emission factors for gasoline are for both TOC and VOC because AP-42 reports that the methane and ethane content of the loading emissions is negligible for these products.

<sup>b</sup> The example crude oil has an RVP of 5 psia.

<sup>c</sup> The example gasoline has an RVP of 10 psia.

<sup>d</sup> The rail/truck loading emission factors were derived using Equation B-5 assuming a liquid temperature of 60°F.

<sup>e</sup> Marine loading factors based on a loaded liquid temperature of 60°F.

<sup>f</sup> Converted from original emission factors provided in units of mg/L in AP-42. Thus, round-off errors may result in some small differences when converting from the emission factors provided in units of lb/10<sup>3</sup> gallons.

**Table 5-11. TOC Emission Factors for Gasoline Loading at Marine Terminals<sup>a</sup>**

<b>Vessel Tank Condition</b>	<b>Previous Cargo<sup>b</sup></b>			<b>Ships/Ocean Barges<sup>c</sup></b>	<b>Barges<sup>d</sup></b>
Uncleaned	Volatile	Original Units	lb TOC/10 <sup>3</sup> gal loaded	2.6	3.9
			mg TOC/L loaded	315	465
		Converted Units	tonne TOC/ 10 <sup>6</sup> gal loaded <sup>e</sup>	1.19	1.76
			tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded <sup>e</sup>	0.315	0.465
Ballasted	Volatile	Original Units	lb TOC/10 <sup>3</sup> gal loaded	1.7	Barges are not typically ballasted
			mg TOC/L loaded	205	
		Converted Units	tonne TOC/ 10 <sup>6</sup> gal loaded <sup>e</sup>	0.776	
			tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded <sup>e</sup>	0.205	
Cleaned	Volatile	Original Units	lb TOC/10 <sup>3</sup> gal loaded	1.5	No data
			mg TOC/L loaded	180	
		Converted Units	tonne TOC/ 10 <sup>6</sup> gal loaded <sup>e</sup>	0.681	No data
			tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded <sup>e</sup>	0.180	
Gas-freed	Volatile	Original Units	lb TOC/10 <sup>3</sup> gal loaded	0.7	No data
			mg TOC/L loaded	85	
		Converted Units	tonne TOC/ 10 <sup>6</sup> gal loaded <sup>e</sup>	0.322	No data
			tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded <sup>e</sup>	0.085	
Any condition	Non-volatile	Original Units	lb TOC/10 <sup>3</sup> gal loaded	0.7	No data
			mg TOC/L loaded	85	
		Converted Units	tonne TOC/ 10 <sup>6</sup> gal loaded <sup>e</sup>	0.322	No data
			tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded <sup>e</sup>	0.085	
Gas-freed	Any cargo	Original Units	lb TOC/10 <sup>3</sup> gal loaded	No data	2.0
			mg TOC/L loaded		245
		Converted Units	tonne TOC/ 10 <sup>6</sup> gal loaded <sup>e</sup>	No data	0.93
			tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded <sup>e</sup>		0.245
Typical overall situation	Any cargo	Original Units	lb TOC/10 <sup>3</sup> gal loaded	1.8	3.4
			mg TOC/L loaded	215	410
		Converted Units	tonne TOC/ 10 <sup>6</sup> gal loaded <sup>e</sup>	0.814	1.55
			tonne TOC/10 <sup>3</sup> m <sup>3</sup> loaded <sup>e</sup>	0.215	0.410

Source: EPA, AP-42, Section 5, Table 5.2-2, 1995.

<sup>a</sup> The factors shown are for both TOC and VOC because AP-42 reports that the methane and ethane content of the loading emissions is negligible.

<sup>b</sup> "Volatile" cargo refers to those liquids with a vapor pressure greater than 1.5 psia.

<sup>c</sup> AP-42 reports ocean barges (tank compartment depth of ~40 feet) exhibit emission levels similar to tank ships.

<sup>d</sup> Shallow draft barges (tank compartment depth of 10-12 feet) yield higher emissions than ocean barges.

<sup>e</sup> Converted from original emission factors provided in units of mg/L in AP-42. Thus, round-off errors may result in some small differences when converting from the emission factors provided in units of lb/10<sup>3</sup> gallons.



### 5.5.2 Ballasting Emissions

Ballasting operations are used to improve the stability of empty tanker ships after their cargo tanks have been unloaded. After the ships filled with petroleum liquid are unloaded at marine terminals, sea water or "ballast" water is loaded into the empty cargo tank compartment. The ballast water displaces the vapor in the "empty" cargo tank to the atmosphere resulting in ballasting emissions.

Table 5-12 provides average emission factors for estimating TOC emissions from crude ballasting operations (EPA, AP-42 Table 5.2-4, 1995). The emission factors are for total organic compounds (TOC) and should be converted to CH<sub>4</sub> emissions based on the CH<sub>4</sub> content of the ballasting vapors. The factors are categorized according to how full the cargo tank is prior to discharge. The "fully loaded" cargo category applies to those compartments that have a true ullage of less than 5 feet prior to crude discharge ("ullage" refers to the distance between the cargo surface level and the deck level). The "lightered or previously short loaded" category applies to those cargoes that have an arrival ullage of more than 5 feet.

**Table 5-12. Average TOC Emission Factors for Crude Oil Ballasting Operations**

Compartment Condition Before Cargo Discharge	Average TOC Emission Factors, Original Units <sup>a</sup>		Average TOC Emission Factors, Converted to Tonnes <sup>c</sup>	
	lb TOC/10 <sup>3</sup> gal ballast water	mg TOC/L ballast water	Tonne TOC/10 <sup>6</sup> gal ballast water	Tonne TOC/10 <sup>3</sup> m <sup>3</sup> ballast water
Fully loaded <sup>b</sup>	0.9	111	0.420	0.111
Lightered or previously short loaded <sup>c</sup>	1.4	171	0.647	0.171
Typical overall situation <sup>d</sup>	1.1	129	0.488	0.129

Source: EPA, AP-42, Section 5, Table 5.2-4, 1995.

<sup>a</sup> The factors shown are for total organic compounds. The average factors were derived assuming an average crude temperature of 60°F and a crude RVP of 5 psi. AP-42 reports that the VOC comprises an approximate average of 85% of the TOC for crude. Thus, a good assumption for the CH<sub>4</sub> content of the TOC is 15% in the absence of site-specific data.

<sup>b</sup> Based on assumed typical arrival ullage of 0.6 m (2 feet).

<sup>c</sup> Based on assumed typical arrival ullage of 6.1 m (20 feet).

<sup>d</sup> Typical overall situation based on the observation that 70% of tested compartments had been fully loaded before ballasting.

<sup>e</sup> Converted from original emission factors provided in units of mg/L in AP-42. Thus, round-off errors may result in some small differences when converting from the emission factors provided in units of lb/10<sup>3</sup> gallons.

Simplified emission factors for ballasting operations involving gasoline are provided in Table 5-13 (EPA, AP-42 Table 5.2-6, 1995).

**Table 5-13. Simplified TOC Emission Factors for Gasoline Ballasting Losses<sup>a</sup>**

Operation	Gasoline <sup>b</sup>
Tanker Ballasting	
lb TOC/10 <sup>3</sup> gal ballast water	0.8
mg/L ballast water	100
tonne TOC/ 10 <sup>6</sup> gal water <sup>c</sup>	0.379
tonne TOC/10 <sup>3</sup> m <sup>3</sup> water <sup>c</sup>	0.100

Source: EPA, AP-42, Section 5, Table 5.2-6, 1995.

<sup>a</sup> The factors shown are for total organic compounds.

<sup>b</sup> The example gasoline has an RVP of 10 psia

<sup>c</sup> Converted from original emission factors provided in units of mg/L in AP-42. Thus, round-off errors may result in some small differences when converting from the emission factors provided in units of lb/10<sup>3</sup> gallons.

**EXHIBIT 5.18: Sample Calculation for Crude Oil Ballasting Emissions Based on Unknown Ullage**

**INPUT DATA:**

Crude oil (RVP 5) is unloaded from ships at a marine terminal. The annual ballast water throughput is 1 million bbl/year. The ullage of the arriving ships is unknown.

**CALCULATION METHODOLOGY:**

Assuming the ballasting operations at this facility are typical, TOC emissions will be calculated using the emission factor provided in Table 5-12, which is 1.1 lb TOC/10<sup>3</sup> gallons ballast water (0.488 tonnes TOC/10<sup>3</sup> gallons ballast water).

The ballasting emissions are obtained by multiplying the ballasting emission factor by the annual ballast water throughput loaded into the ships. Also, the TOC emissions must be multiplied by the CH<sub>4</sub> content of the vapors to obtain the CH<sub>4</sub> emissions. The CH<sub>4</sub> content of the vapors will conservatively be assumed to be 15 wt% per AP-42 (EPA, AP-42 Section 5.2, 1995). Thus, the CH<sub>4</sub> emissions from the ballasting operations are:

$$\begin{aligned} \text{Ballasting Emissions} &= \frac{1.1 \text{ lb TOC}}{10^3 \text{ gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{1 \times 10^6 \text{ bbl}}{\text{yr}} \times \frac{15 \text{ lb CH}_4}{100 \text{ lb TOC}} \times \frac{\text{tonne}}{2204.62 \text{ lb}} \\ &= \underline{\underline{3.14 \text{ tonnes CH}_4/\text{yr}}} \end{aligned}$$

### 5.5.3 Transit Loss Emissions

In addition to emissions resulting from loading operations and marine ballasting operations, hydrocarbon emissions (potentially including CH<sub>4</sub>) also occur during petroleum transit. The mechanism resulting in transit losses is similar to breathing losses that occur for storage tanks. The conditions that affect transit emissions are the vapor tightness of the cargo vessel, the cargo vessel pressure at the beginning of the trip, the pressure relief valve settings, the liquid vapor pressure, and the degree of vapor saturation in the vapor void space of the cargo tank.

Table 5-14 provides simple transit TOC emission factors for marine transit of crude and gasoline (EPA, AP-42 Section 5.2.2.1.3, 1995). Appendix B provides additional emission factors for gasoline transported by rail or truck if the CH<sub>4</sub> content of the fuel is significantly measurable (>1% by weight) to warrant calculation.

**Table 5-14. Simplified TOC Emission Factors for Marine Transit Losses<sup>a</sup>**

Units		Crude Oil <sup>b</sup>	Gasoline <sup>c</sup>
Original Units	lb TOC/week 10 <sup>3</sup> gal transported mg TOC/week L transported	1.3 150	2.7 320
Converted Units	tonne TOC/week-10 <sup>6</sup> gal transported <sup>d</sup> tonne TOC/week-10 <sup>3</sup> m <sup>3</sup> transported <sup>d</sup>	0.57 0.150	1.21 0.320

Source: EPA, AP-42, Section 5, Tables 5.2-5 and 5.2-6, 1995.

<sup>a</sup> The factors shown are for total organic compounds. AP-42 reports that the VOC comprises approximately 85% of the TOC for crude. Thus, a good, conservative assumption for the CH<sub>4</sub> content of the TOC is 15% in the absence of site-specific data.

<sup>b</sup> The example crude oil has an RVP of 5 psia.

<sup>c</sup> The example gasoline has an RVP of 10 psia.

<sup>d</sup> Converted from original emission factors provided in units of mg/L in AP-42. Thus, round-off errors may result in some small differences when converting from the emission factors provided in units of lb/10<sup>3</sup> gallons.

Exhibit 5.19 illustrates the use of the simple transit emission factors.

### EXHIBIT 5.19: Sample Calculation for Estimating CH<sub>4</sub> Emissions Using Simplified Transit Emission Factors

#### INPUT DATA:

500,000 barrels of crude oil (RVP 5) is transported via ships with an average trip duration of 10 days. The company transports the crude 25 times during the given reporting year.

#### CALCULATION METHODOLOGY:

The transit loss emission factor given in Table 5-14 for crude oil is 1.3 lb TOC/week-1000 gallons transported (0.57 tonne TOC/week-106 gallon transported). The CH<sub>4</sub> content of the vapors is assumed to be 15 wt%.

$$\begin{aligned} \text{Transit Emissions} = & \frac{0.57 \text{ tonne TOC}}{\text{week} - 10^6 \text{ gal transported}} \times \frac{42 \text{ gal}}{\text{bbl}} \times 500,000 \text{ bbl} \times \frac{10 \text{ days}}{\text{trip}} \times \frac{25 \text{ trips}}{\text{yr}} \\ & \times \frac{\text{week}}{7 \text{ days}} \times \frac{15 \text{ lb CH}_4}{100 \text{ lb TOC}} = \underline{64.1 \text{ tonnes CH}_4/\text{yr}} \end{aligned}$$

## 5.6 Other Venting Sources

### 5.6.1 Other Venting Sources: Gas Driven Pneumatic Devices

Natural gas-driven pneumatic devices are a source of CH<sub>4</sub> emissions (and CO<sub>2</sub>, if present in the gas) due to venting the natural gas used to actuate the devices.

Methane emissions from pneumatic devices were evaluated as part of the 1996 GRI/EPA CH<sub>4</sub> emissions study (Shires, 1996). In the production segment, this study observed that most of the pneumatic devices used were valve actuators and controllers that used natural gas pressure as the force for the valve movement. Gas from the valve actuator is vented to the atmosphere during the valve stroke, and gas may also be continuously bled from the valve controller pilot in some pneumatic devices.

Emissions from pneumatic devices in the transmission and processing were also evaluated during the 1996 GRI/EPA CH<sub>4</sub> study (Shires, 1996). In the transmission segment, compressor and storage stations commonly employed gas-operated isolation valves as well as a few continuous

bleed devices. There were essentially no pneumatic devices associated with the pipeline itself. Compressed air was used to power a majority of the pneumatic devices at gas processing plants, though some devices were operated with natural gas. Many processing plants used gas-driven pneumatic controllers on isolation valves for emergency shut-down conditions or for maintenance work.

Distribution pneumatic devices were evaluated as part of a study of Canadian greenhouse gas emissions (Shires, 2001). Some distribution metering and pressure regulating (M&R) stations use gas-operated pneumatic control loops or isolation valves.

The preferred approach for estimating CH<sub>4</sub> emissions (and CO<sub>2</sub> emissions if CO<sub>2</sub> is present in the gas stream) from gas-driven pneumatic devices is to use site-specific device measurements or manufacturer's data. Alternatively, simplified CH<sub>4</sub> emission factors are provided in Table 5-15 for each industry sector.

Table 5-15 also presents the corresponding CH<sub>4</sub> content of the gas used as the basis for the emission factors. The emission factors can be adjusted based on the CH<sub>4</sub> content of the site-specific gas used to drive the devices if the natural gas is significantly different from the default basis. Also, if the pneumatic devices are driven with gas that contains significant quantities of CO<sub>2</sub>, the CH<sub>4</sub> emission factors can be adjusted based on the relative concentrations of CH<sub>4</sub> and CO<sub>2</sub> in the gas to estimate the CO<sub>2</sub> emissions.

In production, the continuous bleed, intermittent bleed, and average pneumatic device emission factors shown in Table 5-15 are taken from the 1996 GRI/EPA report (Volumes 2 and 12) (Harrison, 1996; Shires, 1996). The pneumatic device emission factors from the GRI/EPA reports were derived using vendor and/or measured data for both intermittent and continuous bleed devices. The instrument controller emission factor (pressure unspecified) is taken from a 2002 CAPP document and is based on data collected in Alberta (CAPP, 2002). Other pneumatic device emission factors such as transmitters and controllers are taken from a 2003 CAPP report (CAPP, 2003). The emission factors from the 2003 CAPP document are most appropriate for standard (high bleed) components that were common prior to 1985 and are a function of the device operating pressure (factors are given at 140 kPa or 240 kPa, both gauge pressure).

**Table 5-15. Gas-Driven Pneumatic Device CH<sub>4</sub> Emission Factors**

Device Type	Emission Factor, Original Units		Precision <sup>f</sup> (±%)	CH <sub>4</sub> Emission Factor, Converted to Tonnes Basis <sup>g</sup>	
<b>Production Segment</b>				Based on 78.8 mole% CH <sub>4</sub> <sup>a</sup>	
Continuous bleed <sup>a</sup>	654	scfd gas/device	31	3.608	tonnes/device-yr
Intermittent bleed <sup>a</sup>	323	scfd gas/device	34	1.782	tonnes/device-yr
<i>Production average<sup>a</sup> (if device type is unknown)</i>	345	scfd CH <sub>4</sub> /device	40	2.415	tonnes/device-yr
Transmitter (140 kPag) <sup>b</sup>	0.12	m <sup>3</sup> gas/hr/device	Precision not specified	0.56	tonnes/device-yr
Transmitter (240 kPag) <sup>b</sup>	0.2	m <sup>3</sup> gas/hr/device		0.94	tonnes/device-yr
Controller (140 kPag) <sup>b</sup>	0.6	m <sup>3</sup> gas/hr/device		2.8	tonnes/device-yr
Controller (240 kPag) <sup>b</sup>	0.8	m <sup>3</sup> gas/hr/device		3.7	tonnes/device-yr
Controller (pressure not specified) <sup>c</sup>	0.1996	m <sup>3</sup> gas/hr/device		0.9332	tonnes/device-yr
I/P Transducer (140 kPag) <sup>b</sup>	0.6	m <sup>3</sup> gas/hr/device		2.8	tonnes/device-yr
I/P Transducer (240 kPag) <sup>b</sup>	0.8	m <sup>3</sup> gas/hr/device		3.7	tonnes/device-yr
P/P Positioner (140 kPag) <sup>b</sup>	0.32	m <sup>3</sup> gas/hr/device		1.5	tonnes/device-yr
P/P Positioner (240 kPag) <sup>b</sup>	0.5	m <sup>3</sup> gas/hr/device		2.3	tonnes/device-yr
I/P Positioner (140 kPag) <sup>b</sup>	0.4	m <sup>3</sup> gas/hr/device		1.9	tonnes/device-yr
I/P Positioner (240 kPag) <sup>b</sup>	0.6	m <sup>3</sup> gas/hr/device		2.8	tonnes/device-yr
<b>Processing</b>				Based on 87 mole% CH <sub>4</sub> <sup>a</sup>	
Continuous bleed	497,584	scf gas/device-yr	29	8.304	tonnes/device-yr
Piston valve operator	48	scf gas/device-yr	49	8.010E-04	tonnes/device-yr
Pneumatic/hydraulic valve operator	5,627	scf gas/device-yr	112	0.0939	tonnes/device-yr
Turbine valve operator	67,599	scf gas/device-yr	276	1.128	tonnes/device-yr
<i>Processing average<sup>a</sup> (if device type is unknown)</i>	164,949	scfy gas CH <sub>4</sub> /plant	133	3.160	tonnes/plant-yr
	7.454 <sup>e</sup>	scf CH <sub>4</sub> /MMscf processed		1.430E-04	tonnes/10 <sup>6</sup> scf processed
				5.049E-03	tonnes/10 <sup>6</sup> m <sup>3</sup> processed
<b>Transmission and Storage</b>				Based on 93.4 mole% CH <sub>4</sub> <sup>a</sup>	
Continuous bleed	497,584	scf gas/device-yr	29	8.915	tonnes/device-yr
Pneumatic/hydraulic valve operator	5,627	scf gas/device-yr	112	0.1008	tonnes/device-yr
Turbine valve operator	67,599	scf gas/device-yr	276	1.211	tonnes/device-yr
<i>Transmission or Storage average<sup>a</sup> (if device type is unknown)</i>	162,197	scfy CH <sub>4</sub> /device	44	3.111	tonnes/device-yr
<b>Distribution</b>					
Pneumatic isolation valves <sup>d</sup> based on 93.4 mole% CH <sub>4</sub>	0.366	tonnes CH <sub>4</sub> /device-yr	Precision not specified	0.366	tonnes/device-yr
Pneumatic control loops <sup>d</sup> based on 94.4 mole% CH <sub>4</sub>	3.465	tonnes CH <sub>4</sub> /device-yr	Precision not specified	3.465	tonnes/device-yr
<i>Distribution average<sup>a</sup> (if device type is unknown) based on 94.9 mole% CH<sub>4</sub> weighted ave.</i>	2.941	tonnes/yr/device	Precision not specified	2.941	tonnes/device-yr

## Footnotes for Table 5-15:

### Sources:

<sup>a</sup> Shires, T.M. and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 12: Pneumatic Devices*, Final Report, GRI-94/0257.29 and EPA-600/R-96-080l, Gas Research Institute and US Environmental Protection Agency, June 1996. and Harrison, M.R., L.M. Campbell, T.M. Shires, and R.M. Cowgill. *Methane Emissions from the Natural Gas Industry, Volume 2: Technical Report*, Final Report, GRI-94/0257.1 and EPA-600/R-96-080b, Gas Research Institute and US Environmental Protection Agency, June 1996.

<sup>b</sup> Canadian Association of Petroleum Producers (CAPP), *Calculating Greenhouse Gas Emissions*, Table 1-12, Canadian Association of Petroleum Producers, Publication Number 2003-03, April 2003. Note that the emission factors provided by this source are for the total gas emitted and were converted to a methane basis using the methane content shown in the table. I/P refers to a device that converts electric current to pneumatic pressure. P/P refers to a device that converts pneumatic pressure to pneumatic pressure.

<sup>c</sup> Canadian Association of Petroleum Producers (CAPP), *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, Table 3-4, Canadian Association of Petroleum Producers, Publication Number 2002-0009, May 2002. Factor shown is based on data collected in Alberta, and was converted from a total gas basis to a methane basis using the methane content shown in the table.

<sup>d</sup> Shires, T.M. and C.J. Loughran. *Updated Canadian National Greenhouse Gas Inventory for 1995, Emission Factor Documentation*, Technical Memorandum, August 23, 2001.

<sup>e</sup> Shires, T.M. and C.J. Loughran. *GHGCalc Version 1.0 Emission Factor Documentation*, Draft, Section 5.2.2, November 2001.

<sup>f</sup> Precision based on 90% confidence interval.

<sup>g</sup> CH<sub>4</sub> emission factors converted from scf or m<sup>3</sup> are based on 60°F and 14.7 psia.

The processing segment pneumatic device emission factors in Table 5-15 are primarily taken from the 1996 GRI/EPA report (Volumes 2 and 12) (Harrison, 1996; Shires, 1996). The average processing pneumatic device emission factor on a throughput basis is taken from documentation for GHGCalc Version 1.0 (Shires, November 2001).

The transmission pneumatic device emission factors are also taken from the 1996 GRI/EPA report.

In the distribution segment, the pneumatic isolation valve emission factor is taken from the 1996 GRI/EPA report (Volume 12) (Shires, 1996). The emission factors for pneumatic control loops and average distribution devices are taken from a Canadian greenhouse gas inventory for 1995 (Shires, August 2001).

An example calculation is provided below in Exhibit 5.20 that demonstrates the use of the pneumatic device emission factors.

**EXHIBIT 5.20: Sample Calculation for Gas-Driven Pneumatic Device Emissions****INPUT DATA:**

A gas production facility has 80 natural gas-driven pneumatic devices. The average CH<sub>4</sub> content of the gas is 70 mole %. There is also 9 mole % CO<sub>2</sub> in the gas, so CO<sub>2</sub> emissions from the pneumatic devices are also estimated.

**CALCULATION METHODOLOGY:**

The number of pneumatic devices is multiplied by the emission factor from Table 5-15. The average pneumatic device emission factor for production is used since the type of device is not known. The base pneumatic device CH<sub>4</sub> emission factor is also adjusted from the default basis of 78.8 mole % CH<sub>4</sub> to the site-specific basis of 70 mole % CH<sub>4</sub>. Because the gas contains a significant quantity of CO<sub>2</sub>, emissions of CO<sub>2</sub> are also estimated using the relative CO<sub>2</sub> and CH<sub>4</sub> contents in the gas.

$$\begin{aligned} \text{CH}_4 : & (80 \text{ pneumatic devices}) \times \frac{2.415 \text{ tonne CH}_4}{\text{device - yr}} \times \frac{70 \text{ mole \% CH}_4}{78.8 \text{ mole \% CH}_4} = \underline{171.6 \text{ tonnes CH}_4/\text{yr}} \\ \text{CO}_2 : & (80 \text{ pneumatic devices}) \times \frac{2.415 \text{ tonne CH}_4}{\text{device - yr}} \times \frac{70 \text{ mole \% CH}_4}{78.8 \text{ mole \% CH}_4} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \\ & \times \frac{\text{tonne mole gas}}{0.70 \text{ tonne mole CH}_4} \times \frac{0.09 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{60.68 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

**5.6.2 Other Venting Sources: Gas Driven Chemical Injection Pumps**

Natural gas-driven chemical injection pumps (CIPs) are a source of CH<sub>4</sub> emissions due to venting of the gas used to act on a piston or diaphragm to pump chemicals into the process equipment lines. The CIPs can also be a source of CO<sub>2</sub> emissions if the gas used to drive the pump contains a significant amount of CO<sub>2</sub>.

The 1996 GRI/EPA study observed that gas-powered chemical injection pumps are most commonly found in the production segment where electricity may not be readily available (Shires, 1996). Typical chemicals injected into the process lines include biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers, and hydrogen sulfide (H<sub>2</sub>S) scavengers.



The preferred approach for estimating GHG emissions from CIPs is to use site specific gas usage measurements or manufacturer's data. Alternatively, the simplified emission factors in Table 5-16 can be used to estimate CH<sub>4</sub> emissions from gas-driven CIPs. The factors are given for piston and diaphragm type pumps, and an average emission factor is given if the type of pump is unknown.

The emission factors are taken from three sources: the 1996 GRI/EPA report (Volume 13) (Shires, 1996) and two guidance documents from the Canadian Association of Petroleum Producers (CAPP, 2002; CAPP, 2003). The piston pump emission factor from the GRI report was based on manufacturer's data while the diaphragm pump factor from the GRI report was based on combined manufacturer's data and measurements carried out in Canada. The emission factor for the average CIP in the GRI/EPA study was derived using estimated populations of the piston and diaphragm pumps from site visits conducted in the United States (Shires, 1996). The emission factors from the 2003 CAPP document were based on a separate study of upstream oil and gas operations in Canada and are a function of the pump operating pressure (factors are given at 140 kPa or 240 kPa, both gauge pressure). The average pump factor from the 2002 CAPP guidance document was based on data collected in Alberta.

The CIP emission factors can be adjusted based on the CH<sub>4</sub> content of the site-specific gas used to drive the pumps if the natural gas has a significantly different CH<sub>4</sub> content from the default basis. Also, if the pumps are driven with gas that contains significant quantities of CO<sub>2</sub>, the CH<sub>4</sub> emission factor can be adjusted based on the relative concentrations of CH<sub>4</sub> and CO<sub>2</sub> in the gas to estimate the CO<sub>2</sub> emissions.

An example calculation is given in Exhibit 5.21 that illustrates the use of the CIP emission factors.

**Table 5-16. Gas-Driven Chemical Injection Pump CH<sub>4</sub> Emission Factors**

Type of Chemical Injection Pump	CH <sub>4</sub> Emission Factor, Original Units	Precision <sup>d</sup> ±(%)	CH <sub>4</sub> Emission Factor, Converted to Tonnes Basis <sup>e</sup> Based on 78.8 mole% CH <sub>4</sub> <sup>a</sup>
Piston pumps (207 kPag)	48.9 <sup>a</sup> scfd CH <sub>4</sub> /pump	106%	0.342 tonnes/pump-yr
Piston pumps (140 kPag)	0.04 <sup>b</sup> m <sup>3</sup> gas/hr/pump	Not specified	0.19 tonnes/pump-yr
Piston pumps (240 kPag)	0.06 <sup>b</sup> m <sup>3</sup> gas/hr/pump	Not specified	0.28 tonnes/pump-yr
Diaphragm pumps (pressure unspecified)	446 <sup>a</sup> scfd CH <sub>4</sub> /pump	77%	3.123 tonnes/pump-yr
Diaphragm pumps (140 kPag)	0.4 <sup>b</sup> m <sup>3</sup> gas/hr/pump	Not specified	1.9 tonnes/pump-yr
Diaphragm pumps (240 kPag)	0.6 <sup>b</sup> m <sup>3</sup> gas/hr/pump	Not specified	2.8 tonnes/pump-yr
Average pump (if type not known)	248 <sup>a</sup> scfd CH <sub>4</sub> /pump	83%	1.736 tonnes/pump-yr
	0.3945 <sup>c</sup> m <sup>3</sup> gas/hr/pump	Not specified	1.844 tonnes/pump-yr

Sources:

<sup>a</sup> Shires, T.M. *Methane Emissions from the Natural Gas Industry*, Volume 13: Chemical Injection Pumps, Final Report, GRI-94/0257.30 and EPA-600/R-96-080m, Gas Research Institute and US Environmental Protection Agency, June 1996.

<sup>b</sup> Canadian Association of Petroleum Producers (CAPP), *Calculating Greenhouse Gas Emissions*, Table 1-12, Canadian Association of Petroleum Producers, Publication Number 2003-03, April 2003. Note that the emission factors provided by this source are for the total gas emitted and were converted to a methane basis using the methane content shown in the table.

<sup>c</sup> Canadian Association of Petroleum Producers (CAPP), *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, Table 3-4, Canadian Association of Petroleum Producers, Publication Number 2002-0009, May 2002. Factor shown is based on data collected in Alberta, and was converted from a total gas basis to a methane basis using the methane content shown in the table.

<sup>d</sup> Precision based on 90% confidence interval.

<sup>e</sup> CH<sub>4</sub> emission factors converted from scf or m<sup>3</sup> are based on 60°F and 14.7 psia.

### **EXHIBIT 5.21: Sample Calculation for Gas-Driven Chemical Injection Pump Emissions**

#### **INPUT DATA:**

A gas production facility in the United States has 25 gas-driven chemical injection pumps (CIPs) that are piston type pumps. The average operating pressure for these pumps is 29 psig (200 kPa gauge). The CH<sub>4</sub> content of the gas is not known, but is assumed to be similar to other typical facilities. There is no significant quantity of CO<sub>2</sub> in the gas.

**EXHIBIT 5.21:      Sample Calculation for Gas-Driven Chemical Injection Pump Emissions, continued****CALCULATION METHODOLOGY:**

The number of chemical injection pumps is multiplied by the piston pump emission factor given at 207 kPa (gauge) from Table 5-16. The factor at 207 kPa is chosen because it is based on a US report and is closest to the actual operating pressure of the pumps. The emission factor is not corrected by the gas CH<sub>4</sub> content because the facility is assumed to have a gas CH<sub>4</sub> content similar to other typical facilities.

$$\text{CH}_4 : (25 \text{ CIPs}) \times \frac{0.342 \text{ tonne CH}_4}{\text{pump} - \text{yr}} = \underline{8.55 \text{ tonnes CH}_4/\text{yr}}$$

**5.6.3      Other Venting Sources: Exploratory Drilling and Well Testing**

Methane, or natural gas, may be used for drilling coal seam CH<sub>4</sub> wells, if available at high pressures. In this case, CH<sub>4</sub>, rather than compressed air, is used as the motive force to drill the wells and is emitted back to the atmosphere.

Methane may also be used to clean coal fines (dust) that accumulate in the well. For this use, compressed gas is pumped into the well bore where it builds up pressure over a short duration (20 minutes to one hour). Then the gas is released rapidly to the surface, bringing the coal fines with it, as well as unloading accumulated water. The released gas may be vented or flared.

Emissions from these sources can be calculated based on a material balance approach. The emissions would be recorded either as point sources, if vented to the atmosphere, or combustion sources if vented to a flare. (If vented to a flare, emissions would be calculated as described in Section 4.4.) An example calculation illustrating the material balance approach follows.

# EXHIBIT 5.22: Sample Calculation for Exploratory Drilling or Well Testing

## INPUT DATA:

A coal bed CH<sub>4</sub> site is drilling three new wells with the following duration and gas consumption rates.

	Duration to Drill, days	Gas Consumption, 10 <sup>6</sup> ft <sup>3</sup> /day
Well 1	5	1.5
Well 2	2	1.5
Well 3	5	1.75

An additional 6.76×10<sup>6</sup> scf of gas/well is flared during well testing. The gas contains 10.9 mole% CO<sub>2</sub>, 88.7 mole% CH<sub>4</sub>, and 0.4 mole% other.

## CALCULATION METHODOLOGY:

First, assuming the drilling gas is vented to the atmosphere, calculate the emissions from well drilling. Total volume of gas vented is:

$$\left( \frac{1.5 \times 10^6 \text{ ft}^3}{\text{day}} \times 5 \text{ days} \right)_{\text{Well 1}} + \left( \frac{1.5 \times 10^6 \text{ ft}^3}{\text{day}} \times 2 \text{ days} \right)_{\text{Well 2}} + \left( \frac{1.75 \times 10^6 \text{ ft}^3}{\text{day}} \times 5 \text{ days} \right)_{\text{Well 3}} = 19.25 \times 10^6 \text{ scf gas}$$

The corresponding CH<sub>4</sub> and CO<sub>2</sub> emissions resulting from this vented gas are:

$$\text{CH}_4 : 19.25 \times 10^6 \text{ scf gas} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{0.887 \text{ lbmole CH}_4}{\text{lbmole gas}} \times \frac{16 \text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = 327 \text{ tonnes CH}_4$$

$$\text{CO}_2 : 19.25 \times 10^6 \text{ scf gas} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{0.109 \text{ lbmole CO}_2}{\text{lbmole gas}} \times \frac{44 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = 110 \text{ tonnes CO}_2$$

**EXHIBIT 5.22: Sample Calculation for Exploratory Drilling or Well Testing, continued**

Next, estimate the CO<sub>2</sub> released from flaring the well test gas (see Section 4.4 for details on flaring emissions). We will assume that the “other” components are primarily ethane.

$$\begin{aligned}
 \text{CO}_2 : & \left( \frac{6.76 \times 10^6 \text{ scf gas}}{\text{well}} \times 3 \text{ wells} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \right) \times \left( \frac{0.109 \text{ lbmole C O}_2}{\text{lbmole gas}} + \right. \\
 & \left. \left[ \frac{0.887 \text{ lbmole C (from CH}_4)}{\text{lbmole gas}} + \frac{0.004 \times 2 \text{ lbmole C (from C}_2\text{H}_6)}{\text{lbmole gas}} \right] \times \frac{0.98 \text{ lbmole CO}_2 \text{ formed}}{\text{lbmole C combusted}} \right) \\
 & \times \frac{44 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = \underline{1,050 \text{ tonnes CO}_2}
 \end{aligned}$$
  

$$\begin{aligned}
 \text{CH}_4 : & \frac{6.76 \times 10^6 \text{ scf gas}}{\text{well}} \times 3 \text{ wells} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{0.887 \text{ lbmole CH}_4}{\text{lbmole gas}} \\
 & \times \frac{0.02 \text{ lbmole residual CH}_4}{\text{lbmole CH}_4} \times \frac{16 \text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = \underline{6.9 \text{ tonnes CH}_4}
 \end{aligned}$$

**5.6.4 Other Venting Sources: Casing Gas**

Casing gas venting is associated with crude oil production (typically heavy oil). This venting results in emissions of CH<sub>4</sub> contained in the gas, and possibly CO<sub>2</sub> emissions. Site-specific volumetric flow rate and CH<sub>4</sub> (and CO<sub>2</sub> if present) concentration data should be used to estimate these emissions. However, in the absence of site-specific data, the simplified casing gas vented emission factors presented in Tables 5-17 and 5-18 can be used.

Table 5-17 provides casing gas total hydrocarbon (THC) vented emission factors on an oil production throughput basis. The base THC factors are taken from Canadian Association of Petroleum Producers guidance (CAPP, 2003). The THC factors in CAPP are based on an assumed percentage vented for each type of oil. However, the factors can be adjusted using actual site-specific venting percentages if they are available and different from the defaults shown in the table.

**Table 5-17. Casing Gas Vented CH<sub>4</sub> Emission Factors – Throughput Basis**

Type of Oil	THC Emission Factor, Original Units <sup>a</sup> (m <sup>3</sup> THC/m <sup>3</sup> oil produced)	CH <sub>4</sub> Emission Factor, Converted to Tonnes Basis <sup>b</sup> Based on 78.8 mole% CH <sub>4</sub> <sup>c</sup>	
		(tonnes/1000 bbl oil produced)	(tonnes/1000 m <sup>3</sup> oil produced)
Primary Heavy Oil (63.2% casing gas vented) <sup>d</sup>	37.4	3.17	20.0
Thermal Heavy Oil (4.7% casing gas vented) <sup>d</sup>	2.53	0.215	1.35
Crude Bitumen (18% casing gas vented) <sup>d</sup>	2.3	0.20	1.2

Sources:

<sup>a</sup> Canadian Association of Petroleum Producers (CAPP), *Calculating Greenhouse Gas Emissions*, Table 1-14, Canadian Association of Petroleum Producers, Publication Number 2003-03, April 2003. Note that the emission factors provided by this source are for the total gas emitted and were converted to a methane basis using the methane content shown in the table.

<sup>b</sup> Shires, T.M., and M.R. Harrison. *Methane Emissions from the Natural Gas Industry*, Volume 6: Vented and Combustion Source Summary, Final Report, GRI-94/0257.23 and EPA-600/R-96-080f, Gas Research Institute and US Environmental Protection Agency, June 1996.

<sup>c</sup> CH<sub>4</sub> emission factors converted from scf or m<sup>3</sup> are based on 60°F and 14.7 psia.

<sup>d</sup> Percentage shown is the assumed percent of total casing gas vented. If the actual percent casing gas vented is known, then the factor and percentage shown for each crude type can be used to estimate the methane emission factor for the actual percent casing gas vented if it is different from the default value shown in the table.

If the oil production throughput is not known, then Table 5-18 can be used. This table provides simplified casing gas vented THC emission factors for active and suspended wells based on data in Alberta (CAPP, 2002). The active and suspended well emission rate data were based on 883 and 910 wells, respectively.

The THC emission factors from the two CAPP guidance documents were converted to CH<sub>4</sub> emission factors using a default CH<sub>4</sub> gas content of 78.8 mole % in the production segment according to the GRI/EPA study (Shires, Volume 6, 1996). The casing gas CH<sub>4</sub> emission factors can be adjusted based on the CH<sub>4</sub> content of the site-specific gas if the natural gas has a significantly different CH<sub>4</sub> content from the default basis. Also, if the gas at the site contains significant quantities of CO<sub>2</sub>, the CH<sub>4</sub> emission factor can be adjusted based on the relative concentrations of CH<sub>4</sub> and CO<sub>2</sub> in the gas to estimate the CO<sub>2</sub> emissions.

**Table 5-18. Casing Gas Vented CH<sub>4</sub> Emission Factors – Well Basis**

Source	THC Emission Factor, Original Units <sup>a</sup> (m <sup>3</sup> THC/well-day)	CH <sub>4</sub> Emission Factor, Converted to Tonnes Basis <sup>b</sup> Based on 78.8 mole% CH <sub>4</sub> <sup>c</sup> (tonnes CH <sub>4</sub> /well-day)
Active Wells	37.1	0.0198
Suspended Wells	20.1	0.0107

Sources:

<sup>a</sup> Canadian Association of Petroleum Producers (CAPP), *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, table on page 3-24, Canadian Association of Petroleum Producers, Publication Number 2002-0009, May 2002. Factors shown are based on data collected in Alberta, and were converted from a total gas basis to a methane basis using the methane content shown in the table.

<sup>b</sup> CH<sub>4</sub> emission factors converted from scf or m<sup>3</sup> are based on 60°F and 14.7 psia.

<sup>c</sup> Shires, T.M., and M.R. Harrison. *Methane Emissions from the Natural Gas Industry*, Volume 6: Vented and Combustion Source Summary, Final Report, GRI-94/0257.23 and EPA-600/R-96-080f, Gas Research Institute and US Environmental Protection Agency, June 1996.

An example calculation is given in Exhibit 5.23 that illustrates the use of the casing gas vent emission factors.

### **EXHIBIT 5.23: Sample Calculation for Casing Gas Vented Emissions**

#### **INPUT DATA:**

An oil and gas production facility produces 100 bbl/day of primary heavy crude oil. The facility operates 365 days during the year. The average CH<sub>4</sub> content of the gas is 70 mole %. There is also 9 mole % CO<sub>2</sub> in the gas, so CO<sub>2</sub> emissions from the casing gas are also estimated.

#### **CALCULATION METHODOLOGY:**

The oil throughput is multiplied by the “primary heavy oil” CH<sub>4</sub> emission factor from Table 5-17. The base casing gas CH<sub>4</sub> emission factor is also adjusted from the default basis of 78.8 mole % CH<sub>4</sub> to the site-specific basis of 70 mole % CH<sub>4</sub>. Because the gas contains a significant quantity of CO<sub>2</sub>, emissions of CO<sub>2</sub> are also estimated using the relative CO<sub>2</sub> and CH<sub>4</sub> contents in the gas.

**EXHIBIT 5.23: Sample Calculation for Casing Gas Vented Emissions, continued**

$$\text{CH}_4 : \frac{100 \text{ bbl crude}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{3.17 \text{ tonnes CH}_4}{1000 \text{ bbl crude}} \times \frac{70 \text{ mole \% CH}_4}{78.8 \text{ mole \% CH}_4} = \underline{102.8 \text{ tonnes CH}_4/\text{yr}}$$

$$\begin{aligned} \text{CO}_2 : & \frac{100 \text{ bbl crude}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{3.17 \text{ tonnes CH}_4}{1000 \text{ bbl crude}} \times \frac{70 \text{ mole \% CH}_4}{78.8 \text{ mole \% CH}_4} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \\ & \times \frac{\text{tonne mole gas}}{0.70 \text{ tonne mole CH}_4} \times \frac{0.09 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{36.34 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

**Casing Gas Migration to the Surface**

Casing gas migration can result in CH<sub>4</sub> emissions and possibly CO<sub>2</sub> emissions, if CO<sub>2</sub> is present in the gas. This migration results from the flow of gas around the outside of a well casing. It is typically caused by gas migrating from one or more shallow, low-productivity gas bearing zones that were penetrated during the drilling process or as a result of natural processes within the soil (CAPP, 2002). Similar to the approach for casing gas venting, casing gas migration emissions should be estimated from site-specific measurements. In the absence of site-specific data, the following emission factor from page 3-25 of the CAPP document, *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, can be used (CAPP, 2002):

<p>3.85 m<sup>3</sup> gas/well-day (original units) (CAPP, 2002)</p> <p>0.00206 tonnes CH<sub>4</sub>/well-day (converted)<sup>a</sup></p>
--

<sup>a</sup>Note: the THC factor was converted to a CH<sub>4</sub> emission factor assuming 78.8 mole % CH<sub>4</sub> in the gas according to the GRI/EPA study (Shires, Volume 6, 1996).

The casing gas migration emission factor was based on test data of the “...average vent rate for wells with gas migration problems...” (CAPP, 2002).

An example calculation is given in Exhibit 5.24 that demonstrates the use of the casing gas migration emission factor.



**EXHIBIT 5.24: Sample Calculation for Casing Gas Migration Emissions****INPUT DATA:**

An oil and gas production facility has 3 wells. Sampling data shows that casing gas migration occurs, but the emission rate has not been measured. The average CH<sub>4</sub> content of the gas is 70 mole %. There is also 9 mole % CO<sub>2</sub> in the gas, so CO<sub>2</sub> emissions from the casing gas migration are also estimated.

**CALCULATION METHODOLOGY:**

The number of wells is multiplied by the casing gas migration CH<sub>4</sub> emission factor. The base casing gas migration CH<sub>4</sub> emission factor is also adjusted from the default basis of 78.8 mole % CH<sub>4</sub> to the site-specific basis of 70 mole % CH<sub>4</sub>. Because the gas contains a significant quantity of CO<sub>2</sub>, emissions of CO<sub>2</sub> are also estimated using the relative CO<sub>2</sub> and CH<sub>4</sub> contents in the gas.

$$\begin{aligned} \text{CH}_4 : 3 \text{ wells} \times \frac{0.00206 \text{ tonnes CH}_4}{\text{well-day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{70 \text{ mole \% CH}_4}{78.8 \text{ mole \% CH}_4} &= \underline{2.00 \text{ tonnes CH}_4/\text{yr}} \\ \text{CO}_2 : 3 \text{ wells} \times \frac{0.00206 \text{ tonnes CH}_4}{\text{well-day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{70 \text{ mole \% CH}_4}{78.8 \text{ mole \% CH}_4} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \\ &\times \frac{\text{tonne mole gas}}{0.70 \text{ tonne mole CH}_4} \times \frac{0.09 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{0.71 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

**5.6.5 Other Venting Sources: Coal Mining**

Underground and surface coal mining activities result in CH<sub>4</sub> emissions. These emissions result from activities that occur before, during, and after the mining occurs.

Ventilation systems are used in underground coal mines to maintain safe CH<sub>4</sub> concentrations. These ventilation systems result in significant CH<sub>4</sub> emissions to the atmosphere, although the CH<sub>4</sub> concentration is generally low (usually no more than 1.5%). Some underground coal mines may also use degasification systems to relieve natural gas from the mine. These degasification systems use wells drilled from the surface or boreholes drilled inside the mine. These systems are used before, during, and after mining. Some of the gas from the degasification system may be recovered, thus reducing CH<sub>4</sub> emissions.

Surface coal mines result in CH<sub>4</sub> emissions as the overburden is removed and the coal is exposed, but the emissions are lower than from underground mines. Some CH<sub>4</sub> emissions also occur during the processing, storage, and transportation of the coal (referred to as post-mining activities).

Site-specific measured data should be used to estimate coal mining CH<sub>4</sub> emissions. In the absence of such data, simple emission factors provided in Table 5-19 may be used. These emission factors were developed from data provided in Annex F of the EPA report, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001* (EPA, 2003). The emission factors were derived based on dividing the emissions by the coal production rates provided in the EPA document for the U.S in 2001. Separate emission factors are provided for underground and surface mining. The underground mining emission factor includes contributions from both ventilation and degasification. Coal handling emission factors are also provided.

**Table 5-19. Coal Mining CH<sub>4</sub> Emission Factors**

Activity	Methane Emission Factor		
	scf CH <sub>4</sub> / short ton coal	lb CH <sub>4</sub> / short ton coal	tonnes CH <sub>4</sub> / tonne coal
Underground Mining (Ventilation and Degasification)	250	10.6	0.00528
Underground Post-Mining (coal handling)	76.2	3.22	0.00161
Surface Mining	32.1	1.36	0.000679
Surface Post-Mining (coal handling)	5.35	0.23	0.000113

Source:

US Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001*. EPA-430-R-03-004, U.S. Environmental Protection Agency, Washington D.C., April 15, 2003. (Coal mining methane emission factors derived from 2001 data in Tables F-3, F-5, and F-6).

An example calculation is given in Exhibit 5.25 that illustrates the use of the coal mining CH<sub>4</sub> emission factors.

**EXHIBIT 5.25: Sample Calculation for Coal Mining Emissions****INPUT DATA:**

During a calendar year 200,000 tons of coal are produced from an underground mine.

**CALCULATION METHODOLOGY:**

The annual coal production rate is multiplied by the underground coal mining and coal handling CH<sub>4</sub> emission factors from Table 5-19.

Underground coal mining:

$$\text{CH}_4 : \frac{200,000 \text{ tons}}{\text{year}} \times \frac{\text{tonnes coal}}{1.10231 \text{ tons coal}} \times \frac{0.00528 \text{ tonnes CH}_4}{\text{tonne coal}} = \underline{958 \text{ tonnes CH}_4/\text{yr}}$$

Underground coal handling:

$$\text{CH}_4 : \frac{200,000 \text{ tons}}{\text{year}} \times \frac{\text{tonnes coal}}{1.10231 \text{ tons coal}} \times \frac{0.00161 \text{ tonnes CH}_4}{\text{tonne coal}} = \underline{292 \text{ tonnes CH}_4/\text{yr}}$$

**5.6.6 Other Venting Sources: Chemical Production**

Small amounts of CH<sub>4</sub> are released during the production of some petrochemicals. This section presents simple emission factors, developed from EPA annual inventory data, for the following chemical processes (EPA, 2003):

- Carbon black – made from the incomplete combustion of an aromatic petroleum feedstock. It is most commonly added to rubber to improve strength and abrasion resistance, and the tire industry is the largest consumer.
- Ethylene – used in the production of plastic polymers.
- Ethylene dichloride – an important intermediate in the synthesis of chlorinated hydrocarbons. It is also used as an industrial solvent and fuel additive.
- Styrene – a common precursor in the production of plastics, rubber and resins. Styrene is also used in construction products such as foam insulation, vinyl flooring, and epoxy adhesives.
- Methanol – an alternative transportation fuel as well as a principle ingredient in paints, solvents, refrigerants, and disinfectants. Methanol-based acetic acid is used in making certain plastics and polyester fibers.

Nitrous oxide emissions result from two additional chemical processes: adipic acid and nitric acid production. Adipic acid is used in the manufacture of synthetic fibers, coatings, plastics, urethane foams, elastomers, and synthetic lubricants. Food grade adipic acid is used as a flavor additive. Nitrous oxide is generated as a by-product of nitric acid oxidation in the second stage of a two-stage production process. Nitric acid ( $\text{HNO}_3$ ) is an inorganic compound used primarily to make synthetic commercial fertilizers. It is typically produced by the catalytic oxidation of ammonia, where  $\text{N}_2\text{O}$  is formed as a by-product.

Table 5-20 provides average emission factors for each of the chemical processes described above based on production rate (EPA, 2003). The  $\text{CH}_4$  emission factors are based on material balances of the petrochemical processes. The  $\text{N}_2\text{O}$  emission factors are based on facility data and account for the use of  $\text{N}_2\text{O}$  abatement technologies, such as non-selective catalytic reduction (NSCR). Emissions are estimated by multiplying the chemical production rate by the appropriate emission factor based on the process type, and for  $\text{N}_2\text{O}$ , the abatement method.

**Table 5-20. Chemical Production Emission Factors**

Chemical Production Process	Emission Factor, Original units	Emission Factor, Converted Units
Carbon black	11 kg $\text{CH}_4$ /tonne produced	0.011 tonne $\text{CH}_4$ /tonne produced
Ethylene	1 kg $\text{CH}_4$ /tonne produced	0.001 tonne $\text{CH}_4$ /tonne produced
Ethylene dichloride	0.4 kg $\text{CH}_4$ /tonne produced	0.0004 tonne $\text{CH}_4$ /tonne produced
Styrene	4 kg $\text{CH}_4$ /tonne produced	0.004 tonne $\text{CH}_4$ /tonne produced
Methanol	2 kg $\text{CH}_4$ /tonne produced	0.002 tonne $\text{CH}_4$ /tonne produced
Nitric acid		
- with NSCR	2 kg $\text{N}_2\text{O}$ /tonne produced	0.002 tonne $\text{N}_2\text{O}$ /tonne produced
- without NSCR <sup>a</sup>	9.5 kg $\text{N}_2\text{O}$ /tonne produced	0.0095 tonne $\text{N}_2\text{O}$ /tonne produced
Adipic acid <sup>b</sup>		
- with catalytic abatement	0.015 kg $\text{N}_2\text{O}$ /kg produced	0.015 tonne $\text{N}_2\text{O}$ /tonne produced
- with thermal abatement	0.006 kg $\text{N}_2\text{O}$ /kg produced	0.006 tonne $\text{N}_2\text{O}$ /tonne produced
- without abatement	0.3 kg $\text{N}_2\text{O}$ /kg produced	0.3 tonne $\text{N}_2\text{O}$ /tonne produced

Source: US Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001*. EPA-430-R-03-004, U.S. Environmental Protection Agency, Washington D.C., April 15, 2003.

<sup>a</sup> Note that selective catalytic reduction (SCR) and extended absorption are not known to reduce  $\text{N}_2\text{O}$  emissions.

<sup>b</sup> Thermal abatement is assume to destroy 98% of  $\text{N}_2\text{O}$ , while catalytic abatement is assumed to destroy 85% of  $\text{N}_2\text{O}$ .

## 5.7 Non-Routine Activities

Non-routine emissions involve blowdowns or venting events that result in CH<sub>4</sub> emissions, and possibly CO<sub>2</sub> emissions for CO<sub>2</sub> rich streams. Non-routine emissions are grouped into the following two categories:

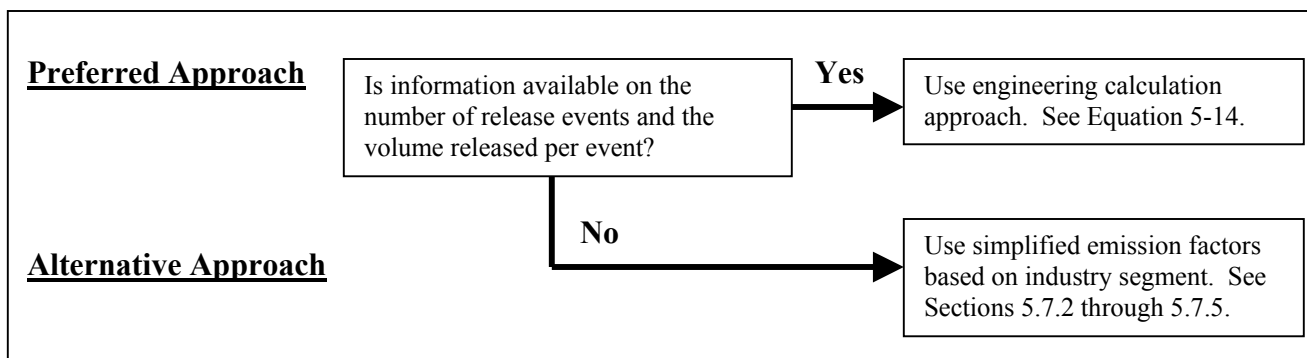
1. Maintenance or turnaround activities that are planned, and
2. Other releases that result from unplanned events.

Maintenance and turnaround activities may cause intentional releases of process gas to the atmosphere to provide a safer work environment. For example, the gas blowdown of process equipment may be necessary to safely perform maintenance work. The blowdown of natural gas from process equipment to the atmosphere results in CH<sub>4</sub>, and possibly CO<sub>2</sub> emissions.

When the process equipment is put back in service following maintenance work, it may be necessary to purge the lines or equipment with process gas to prevent the formation of a flammable mixture of CH<sub>4</sub> and oxygen. An inert gas, such as nitrogen, or natural gas can be used for the purging process. Methane and possibly CO<sub>2</sub> emissions result when natural gas used for purging equipment is vented to the atmosphere.

Emergency or upset conditions are examples of other non-routine releases that can occur throughout the various segments of the oil and gas industry. Often, these conditions automatically trigger the depressurization of process equipment to ensure safe operating conditions. For example, pressure relief valves (PRVs) and emergency shutdown systems (ESDs) are installed to relieve pressure during emergency conditions.

This section provides two methods for estimating non-routine emissions from petroleum operations, as presented in Figure 5-4. The first is based on engineering calculations of the volume released, documentation of the non-routine release events, and the concentration of CH<sub>4</sub> (and CO<sub>2</sub>, if significant) in the gas stream. The second approach is based on simplified emission factors developed from an inventory of company practices or from specific measurement programs. The emission factors for these sources tend to be segment specific, so each industry segment is discussed separately (See Sections 5.7.2 through 5.7.5).



**Figure 5-4. Decision Tree for Non-Routine Activities**

### 5.7.1 Engineering Calculation Approach

Emissions from maintenance activities or emergency conditions can generally be estimated by the following equation:

$$E_{\text{CH}_4 \text{ or CO}_2} = \frac{\text{Gas Volume Released}}{\text{Event}} \times \text{Mole\%}_{\text{CH}_4 \text{ or CO}_2} \times \frac{\# \text{ Events}}{\text{Year}} \times \frac{\text{MW}_{\text{CH}_4 \text{ or CO}_2}}{\text{molar volume conversion}} \quad (\text{Equation 5-14})$$

where,

$$\begin{array}{ll} E_{\text{CH}_4 \text{ or CO}_2} & = \text{emissions of CH}_4 \text{ or CO}_2 \text{ emissions in units of mass} \\ \text{Molar volume} & \text{conversion from molar volume to mass (379.3 scf/lbmole or} \\ \text{conversion} & \text{23.685 m}^3/\text{kgmole @ 60}^\circ\text{F and 14.7 psia)} \end{array}$$

Engineering assumptions may be required to estimate the volume of gas released. For example, the volume released may be based on the internal volume of a piece of equipment or the volume contained within a pipe section (assuming the entire contents are released) and converted from actual cubic feet of gas to standard cubic feet using the density of the gas. For pigging operations, the volume released would be based on the segment of pipeline depressurized plus the volume of the pig catcher or launcher.

The density of the gas can be calculated using an additional term in the gas law, (Equation 3-4):

$$PV = znRT \quad (\text{Equation 5-15})$$

where,

P	=	pressure (psia or atm)
V	=	volume
z	=	compressibility factor, tables for CH <sub>4</sub> and CO <sub>2</sub> are provided in Perry's Chemical Engineer's Handbook Tables 3-172 and 3-166, respectively (Perry, 1984)
N	=	number of moles
R	=	gas constant
T	=	absolute temperature (°R or K)

Rearranging, the equation becomes:

$$n = \frac{PV}{zRT} \quad (\text{Equation 5-16})$$

Using this equation, the moles of gas emitted can be converted to a mass basis by applying the molecular weight of CH<sub>4</sub> or CO<sub>2</sub>. An equation similar to 5-14 results:

$$E_{\text{CH}_4 \text{ or CO}_2} = \frac{\text{Moles Gas Released}}{\text{Event}} \times \text{Mole\%}_{\text{CH}_4 \text{ or CO}_2} \times \text{MW}_{\text{CH}_4 \text{ or CO}_2} \times \frac{\# \text{Events}}{\text{Year}} \quad (\text{Equation 5-17})$$

An example of this approach is demonstrated in Exhibit 5.26.

#### **EXHIBIT 5.26: Sample Calculation for Estimating Non-Routine Emissions**

##### **INPUT DATA:**

A low pressure separator, operating at 100 psig and ambient temperature (~80 °F), is blowdown for maintenance once per year. The vessel dimensions are 4' ID and 10' long. The gas composition in the separator is 90% CH<sub>4</sub> with negligible CO<sub>2</sub>.

##### **CALCULATION METHODOLOGY:**

First, the actual volume of the gas in the vessel is estimated based on the internal dimensions:

$$\text{Actual Volume} = \pi r^2 L = \pi \times \left( \frac{4\text{ft}}{2} \right)^2 \times 10\text{ ft} = 125.7\text{ ft}^3 (\text{actual})$$

**EXHIBIT 5.26: Sample Calculation for Estimating Non-Routine Emissions, continued**

Then, the density of the gas is calculated using Equation 5-16. The compressibility factor for CH<sub>4</sub> is determined to be 0.9864 (Perry, 1984).

$$n = \frac{PV}{zRT} = \frac{(100 \text{ psig} + 14.7) \times (125.7 \text{ ft}^3)}{0.9864 \times 10.73 \frac{\text{psi ft}^3}{\text{lbmole } ^\circ\text{R}} \times 539.7 \text{ } ^\circ\text{R}} = 2.52 \text{ lbmoles gas/blowdown event}$$

Finally, the CH<sub>4</sub> emissions are calculated using Equation 5-17:

$$\begin{aligned} \frac{2.52 \text{ lbmoles gas}}{\text{blowdown event}} \times \frac{0.9 \text{ lbmoles CH}_4}{\text{lbmoles gas}} \times \frac{16 \text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{1 \text{ blowdown}}{\text{yr}} \times \frac{\text{tonne}}{2204.62 \text{ lb}} \\ = 0.0165 \text{ tonne CH}_4 / \text{yr} \end{aligned}$$

The volume (V) of gas blown down in Equation 5-15 is typically based on equipment design specifications for the vessel/pipeline/equipment of interest. In the absence of such design data, the CAPP document, *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, provides guidance on estimating the volumes for several vessel types (CAPP, 2002, Section 3.2.4). These vessel types include horizontal and vertical cylinders and hemispherical and ellipsoidal end caps. The CAPP document also provides volumes per meter of pipeline length for several pipe sizes and schedules (CAPP, 2002, Table 3-8). Refer to this CAPP document for assistance on estimating these vessel volumes.

Use of the gas law is most appropriate for situations where the entire volume of the vessel is blown down, and the gas blow down volume is finite. More rigorous engineering approaches are needed for a blowdown situation where only a portion of the vessel contents are released. A good example of this type of situation is a well blowdown to remove water that has accumulated in the production tubing. The 2002 CAPP document noted earlier provides an engineering approach for these types of blowdowns (CAPP, 2002, Section 3.2.1). The CAPP document also provides a very similar approach for pressure relief valve (PRV) releases (CAPP, 2002, Section 3.2.3).



These approaches are based on modeling the releases as isentropic flow of an ideal gas through a nozzle. This approach requires release parameters such as the open cross-sectional area of the release, wellhead pressure, and the gas specific heat ratio ( $C_p/C_v$ ). These approaches are most appropriate for releases that do not blow down the entire volume of interest. Refer to the CAPP document for more information on this approach, including an example calculation.

The CAPP document also provides a summary of cross-sectional areas for several pipe sizes and schedules (CAPP, 2002, Table 3-6). These areas are useful for applying the isentropic flow equation to estimate the blowdown rates.

### **5.7.2      *Production Related Non-Routine Emissions***

#### **Production Segment Maintenance/Turnaround Activities**

A summary of the  $CH_4$  emission factors from production segment maintenance and turnaround activities is presented in Table 5-21. The majority of these emission factors are taken from the GRI/EPA study (Shires, Volume 7, 1996). Other data sources include a report by Pipeline Systems Incorporated (PSI, 1990) for the gas and oil well workover emission factors, and a Canadian study for the gas well water removal emission factor and a second well clean-up emission factor (Picard, Vol. II, 1992).

The maintenance activities listed in Table 5-21 are non-routine activities that result in intentional releases of gas (including  $CH_4$ ) to the atmosphere. Vessel blowdowns refer to blowdowns of the various production process vessels including separators, dehydrators, and in-line heaters.

Compressor starts are vented emissions of the natural gas used to start the engine. If the compressor is started with air, then there would be no  $CH_4$  emissions from this activity.

Compressor blowdowns occur when the compressor is depressurized to the atmosphere when it is shutdown. Pipeline blowdowns may occur for repair work or when lines are put out of service.

The pipeline "pull-back" (water removal blowdown) emission factor is based on a Canadian report for emissions in Alberta (Picard, Vol. II, 1992). This emission factor was provided on a total gas basis and was converted to a  $CH_4$  emission factor using a default  $CH_4$  gas content of 78.8 mole % in the production segment according to the GRI/EPA study (Shires, Volume 6, 1996). This factor applies to blowdowns on low-pressure (e.g. less than 76 psi) gathering gas system pipelines that have short segments vented briefly (about 10 seconds) to remove accumulated water.

**Table 5-21. Production Segment CH<sub>4</sub> Emission Factors for Maintenance and Turnaround Activities**

Source	CH <sub>4</sub> Emission Factor, Original Units	CH <sub>4</sub> Emission Factor, Converted to Tonnes Basis <sup>c</sup>	CH <sub>4</sub> Content Basis of Factor <sup>d</sup>	Precision <sup>e</sup> (±%)
Vessel blowdowns	78 scfy/vessel	0.0015 tonnes/vessel-yr	78.8 mole %	266%
Compressor starts	8443 scfy/compressor	0.1620 tonnes/compressor-yr	78.8 mole %	157%
Compressor blowdowns	3774 scfy/compressor	0.07239 tonnes/compressor-yr	78.8 mole %	147%
Gas well workovers <sup>a</sup>	2454 scf/workover	0.04707 tonnes/workover	Not given	459%
Oil Well Workovers <sup>a</sup>	96 scf/workover	0.0018 tonnes/workover	Not given	Not available
Gas well water removal (pull back) <sup>b</sup>	0.6 m <sup>3</sup> gas/pull back-well	3.2E-04 tonnes/pull back-well	Not given	Not available
Well clean-ups (low-pressure gas wells)	49,570 scfy/LP well cleaned	0.9508 tonnes/LP well cleaned-yr	78.8 mole %	344%
Well clean-ups - Canada (shallow, <1000 m, low-pressure gas wells) <sup>b</sup>	328 m <sup>3</sup> gas/shallow well-yr	0.175 tonnes/shallow well-yr	78.8 mole % <sup>d</sup>	Not available
Gathering gas pipeline blowdowns	309 scfy/mile	0.00593 tonnes/mile-yr	78.8 mole %	32%
		0.00368 tonne/km-yr		

Primary data source: Shires, T.M. *Methane Emissions from the Natural Gas Industry, Volume 7: Blow and Purge Activities*, Final Report, GRI-94/0257.24 and EPA-600/R-96-080g, Gas Research Institute and US Environmental Protection Agency, June 1996.

<sup>a</sup> Tilkicioglu, B.H. *Annual Methane Emission Estimate of the Natural Gas Systems in the United States*, Phase, Pipeline Systems Incorporated (PSI), September 1990.

<sup>b</sup> Picard, D. J., B. D. Ross, and D. W. H. Koon. *Inventory of CH<sub>4</sub> and VOC Emissions from Upstream Oil and Gas Operations in Alberta*, Volume II Development of the Inventory, Canadian Petroleum Association, March 1992, pp. 30 and 122. Well clean-up emission factor was estimated by dividing emissions data by number of shallow wells.

<sup>c</sup> CH<sub>4</sub> emission factors converted from scf or m<sup>3</sup> are based on 60°F and 14.7 psia. The CH<sub>4</sub> emission factors can be adjusted based on the relative concentrations of CH<sub>4</sub> and CO<sub>2</sub> to estimate CO<sub>2</sub> emissions.

<sup>d</sup> Shires, T.M., and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 6: Vented and Combustion Source Summary*, Final Report, GRI-94/0257.23 and EPA-600/R-96-080f, Gas Research Institute and US Environmental Protection Agency, June 1996.

<sup>e</sup> Precision based on 90% confidence interval.

Well workovers involve pulling the tubing from the well for tube repair work. A small amount of gas is released as the tubing is removed from the open surface casing. Well cleanup is another maintenance activity involving the wells (also referred to as unloading). This activity is used on low-pressure or shallow gas wells that have accumulated liquids (primarily water) in the wellbore. The liquid is purged by allowing the well to flow to atmospheric pressure where gas is discharged to the atmosphere.

For well clean-ups, both U.S. and Canadian emission factors are provided. The U.S. well clean-up emission factor is based on data from the GRI/EPA study (Shires, Volume 7, 1996). The Canadian well clean-up factor is derived from the Alberta emissions study (Picard, Vol. II, 1992). The Canadian well clean-up factor applies to shallow (less than 1000 m deep), low-pressure (less than 290 psi) wells. This emission factor was estimated by dividing the emissions data by the number of shallow wells presented in the Canadian report. The factor was converted from a total gas basis to a CH<sub>4</sub> basis in the same manner as for the pipeline “pull-back” emission factor. The Canadian well clean-up emission factor includes contributions from unassisted blowdowns, swabbing, and coiled tubing clean-outs.

The maintenance emission factors given in Table 5-21 can be adjusted based on the CH<sub>4</sub> content of the site-specific gas, if the natural gas has a significantly different CH<sub>4</sub> content from the default basis (if given). Also, if the facility gas contains significant quantities of CO<sub>2</sub>, the CH<sub>4</sub> emission factor can be adjusted based on the relative concentrations of CH<sub>4</sub> and CO<sub>2</sub> in the gas to estimate the CO<sub>2</sub> emissions.

An example calculation is given below that illustrates the use of the production segment maintenance/turnaround related emission factors.

**EXHIBIT 5.27:      Sample Calculation for Production Maintenance/Turnaround Related Emissions**

**INPUT DATA:**

A gas production field has 10 low-pressure gas wells that send the gas to 5 miles of gathering pipeline. All of the wells required cleaning (or "unloading") and there were 2 well workovers during the year. The field also has 5 process vessels and a compressor. The gas contains 70 mole % CH<sub>4</sub> and 8 mole % CO<sub>2</sub>.

**EXHIBIT 5.27: Sample Calculation for Production Maintenance/Turnaround Related Emissions, continued****CALCULATION METHODOLOGY:**

The equipment count for each maintenance related activity (vessel blowdowns, compressor starts, etc.) is multiplied by the appropriate emission factor from Table 5-21. The emission factors are corrected by the ratio of the site CH<sub>4</sub> content to the emission factor default CH<sub>4</sub> content. The well workover emission factor is not adjusted based on the site gas CH<sub>4</sub> content because the default content for this emission factor is not given.

CO<sub>2</sub> emissions are also estimated because the CO<sub>2</sub> content on the gas is not negligible. Carbon dioxide emissions are determined by adjusting the CH<sub>4</sub> emission factors based on the relative concentrations of CH<sub>4</sub> and CO<sub>2</sub> in the gas.

Vessel blowdowns:

$$\text{CH}_4 : (5 \text{ vessels}) \times \frac{0.0015 \text{ tonne CH}_4}{\text{vessel - yr}} \times \frac{70 \text{ mole \% CH}_4}{78.8 \text{ mole \% CH}_4} = \underline{0.007 \text{ tonnes CH}_4/\text{yr}}$$

$$\begin{aligned} \text{CO}_2 : (5 \text{ vessels}) &\times \frac{0.0015 \text{ tonne CH}_4}{\text{vessel - yr}} \times \frac{70 \text{ mole \% CH}_4}{78.8 \text{ mole \% CH}_4} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \\ &\times \frac{\text{tonne mole gas}}{0.70 \text{ tonne mole CH}_4} \times \frac{0.08 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{0.002 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

Compressor starts:

$$\text{CH}_4 : (1 \text{ compressor}) \times \frac{0.1620 \text{ tonne CH}_4}{\text{compressor - yr}} \times \frac{70 \text{ mole \% CH}_4}{78.8 \text{ mole \% CH}_4} = \underline{0.14 \text{ tonnes CH}_4/\text{yr}}$$

$$\begin{aligned} \text{CO}_2 : (1 \text{ compressor}) &\times \frac{0.1620 \text{ tonne CH}_4}{\text{compressor - yr}} \times \frac{70 \text{ mole \% CH}_4}{78.8 \text{ mole \% CH}_4} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \\ &\times \frac{\text{tonne mole gas}}{0.7 \text{ tonne mole CH}_4} \times \frac{0.08 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{0.045 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

**EXHIBIT 5.27: Sample Calculation for Production Maintenance/Turnaround Related Emissions, continued**

Compressor blowdowns:

$$\text{CH}_4 : (1 \text{ compressor}) \times \frac{0.07239 \text{ tonne CH}_4}{\text{compressor - yr}} \times \frac{70 \text{ mole \% CH}_4}{78.8 \text{ mole \% CH}_4} = \underline{0.064 \text{ tonnes CH}_4/\text{yr}}$$

$$\begin{aligned} \text{CO}_2 : (1 \text{ compressor}) &\times \frac{0.07239 \text{ tonne CH}_4}{\text{compressor - yr}} \times \frac{70 \text{ mole \% CH}_4}{78.8 \text{ mole \% CH}_4} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \\ &\times \frac{\text{tonne mole gas}}{0.70 \text{ tonne mole CH}_4} \times \frac{0.08 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{0.020 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

Gas well workovers:

$$\text{CH}_4 : \frac{2 \text{ well workovers}}{\text{yr}} \times \frac{0.04707 \text{ tonne CH}_4}{\text{workovers}} = \underline{0.094 \text{ tonnes CH}_4/\text{yr}}$$

$$\begin{aligned} \text{CO}_2 : \frac{2 \text{ well workovers}}{\text{yr}} &\times \frac{0.04707 \text{ tonne CH}_4}{\text{workovers}} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.7 \text{ tonne mole CH}_4} \\ &\times \frac{0.08 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{0.030 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

Well clean-ups (low-pressure gas wells cleaned or "unloaded"):

$$\text{CH}_4 : (10 \text{ LP wells cleaned}) \times \frac{0.9508 \text{ tonne CH}_4}{\text{LP well cleaned - yr}} \times \frac{70 \text{ mole \% CH}_4}{78.8 \text{ mole \% CH}_4} = \underline{8.45 \text{ tonnes CH}_4/\text{yr}}$$

$$\begin{aligned} \text{CO}_2 : (10 \text{ LP wells cleaned}) &\times \frac{0.9508 \text{ tonne CH}_4}{\text{LP well cleaned - yr}} \times \frac{70 \text{ mole \% CH}_4}{78.8 \text{ mole \% CH}_4} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \\ &\times \frac{\text{tonne mole gas}}{0.70 \text{ tonne mole CH}_4} \times \frac{0.08 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{2.65 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

**EXHIBIT 5.27: Sample Calculation for Production Maintenance/Turnaround Related Emissions, continued**

Gathering pipeline blowdowns:

$$\begin{aligned} \text{CH}_4 : & (5 \text{ miles}) \times \frac{0.00593 \text{ tonne CH}_4}{\text{mile} \cdot \text{yr}} \times \frac{70 \text{ mole \% CH}_4}{78.8 \text{ mole \% CH}_4} = \underline{0.026 \text{ tonnes CH}_4/\text{yr}} \\ \text{CO}_2 : & (5 \text{ miles}) \times \frac{0.00593 \text{ tonne CH}_4}{\text{mile} \cdot \text{yr}} \times \frac{70 \text{ mole \% CH}_4}{78.8 \text{ mole \% CH}_4} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.70 \text{ tonne mole CH}_4} \\ & \times \frac{0.08 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{0.008 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

### Other Production Segment Releases

A summary of the CH<sub>4</sub> emission factors from other production segment venting releases is given in Table 5-22. These non-routine activities are the result of unplanned events (such as during emergency or upset conditions) that result in releases of gas (including CH<sub>4</sub>, and possibly CO<sub>2</sub>) to the atmosphere. All of the emission factors given in Table 5-22 are taken from the GRI/EPA study (Harrison, 1996; Shires, 1996) except for the oil well blowout emission factor, which is taken from two EPA reports (EPA, 1977; EPA, 1999).

The well blowout emission factor was estimated in a 1999 EPA report assuming that the blowout occurs for 48 hours (a 1977 EPA report provided a range of 15 minutes to 5 months but noted that blowouts typically last a few days) and releases at a rate similar to the gas well production. The gas well production rate was assumed to be 125,000 scfd/well as observed by the GRI/EPA study (Shires, 1996).

The GRI/EPA study developed emission factors for station emergency shutdown (ESD) systems at offshore facilities and for pressure relief valves (PRVs) associated with either onshore or offshore production activities. ESDs are manual or automatic safety systems that shut down and vent all rotating equipment when an emergency is detected. The emission factor is based on an average number of ESD blowdowns vented to the atmosphere on an annual basis. Similarly, the PRV emission factor is based on the average size and duration of release events at production facilities.

**Table 5-22. Production Segment CH<sub>4</sub> Emission Factors for Other Non-Routine Releases**

Source	CH <sub>4</sub> Emission Factor, Original Units	CH <sub>4</sub> Emission Factor, Converted to Tonnes Basis <sup>b</sup>	CH <sub>4</sub> Content Basis of Factor	Precision <sup>c</sup> (±%)
Pressure relief valves releases	34 scfy/PRV	0.00065 tonnes/PRV-yr	78.8 mole %	252%
Gathering gas pipeline mishaps (dig-ins)	669 scfy/mile	0.0128 tonnes/mile-yr 0.00797 tonnes/km-yr	78.8 mole %	1925%
Well blowouts <sup>a</sup>	250,000 scf/blowout	4.795 tonnes/blowout	Not Given	Not available
Offshore emergency shutdown (ESD)	256,888 scfy/platform	4.9276 tonnes/platform-yr	78.8 mole %	200%

Sources:

Shires, T.M. *Methane Emissions from the Natural Gas Industry, Volume 7: Blow and Purge Activities*, Final Report, GRI-94/0257.24 and EPA-600/R-96-080g, Gas Research Institute and US Environmental Protection Agency, June 1996.

<sup>a</sup> US EPA. *Methane Emissions from the U.S. Petroleum Industry*, EPA-600-R-99-010, February 1999.

<sup>b</sup> CH<sub>4</sub> emission factors converted from scf or m<sup>3</sup> are based on 60°F and 14.7 psia. The CH<sub>4</sub> emission factors can be adjusted based on the relative concentrations of CH<sub>4</sub> and CO<sub>2</sub> to estimate CO<sub>2</sub> emissions.

<sup>c</sup> Precision based on 90% confidence interval.

Dig-ins of gathering gas lines in production are unintentional mishaps that result in gas being released to the atmosphere. Gathering crude pipelines (i.e., no gas-associated lines) may emit CH<sub>4</sub>, but dig-in or leak emission factors for these pipelines are not readily available.

As with the maintenance emission factors presented earlier, the other release emission factors can be adjusted based on the CH<sub>4</sub> content of the site-specific gas, if the natural gas has a significantly different CH<sub>4</sub> content from the default basis (if given). Also, if the facility gas contains a significant quantity of CO<sub>2</sub>, the CH<sub>4</sub> emission factor can be adjusted based on the relative concentrations of CH<sub>4</sub> and CO<sub>2</sub> in the gas to estimate the CO<sub>2</sub> emissions.

An example calculation is given below that illustrates the use of emission factors from other production segment non-routine emission sources.

**EXHIBIT 5.28:      Sample Calculation for Other Production Segment Non-routine Emission Sources****INPUT DATA:**

An oil and gas production field has 60 pressure relief valves (PRVs). The gas from the field is transported through 6 miles of gathering pipeline. The site gas has a typical CH<sub>4</sub> content and a negligible amount of CO<sub>2</sub>.

**CALCULATION METHODOLOGY:**

The PRV count and gathering pipeline miles are each multiplied by the appropriate emission factor from Table 5-22. The CH<sub>4</sub> emission factors are not corrected by the site CH<sub>4</sub> content because it is similar to the default concentration associated with the emission factors.

PRVs:

$$\text{CH}_4 : (60 \text{ PRVs}) \times \frac{0.00065 \text{ tonne CH}_4}{\text{PRV} - \text{yr}} = \underline{0.039 \text{ tonnes CH}_4/\text{yr}}$$

Gathering gas pipeline mishaps (Dig-ins):

$$\text{CH}_4 : (6 \text{ miles}) \times \frac{0.0128 \text{ tonne CH}_4}{\text{mile} - \text{yr}} = \underline{0.077 \text{ tonnes CH}_4/\text{yr}}$$

**5.7.3      Gas Processing Related Non-Routine Emissions**

Unlike the production segment, the gas processing segment emission factor is not separated into the categories of "maintenance and turnaround" and "other releases" because of the data used in their development (Shires, 1996). The GRI/EPA study developed emission factors associated with station blowdown practices at gas processing facilities based on similarities between gas processing and transmission station maintenance practices (Shires, 1996). Maintenance blowdowns at gas plants include compressor blowdowns, compressor starts, and other miscellaneous sources.

The processing plant blowdown emission factor is presented in Table 5-23. This emission factor can be adjusted based on the CH<sub>4</sub> content of the site-specific gas if the natural gas has a significantly different CH<sub>4</sub> content from the default basis. Also, if the facility gas contains



significant quantities of CO<sub>2</sub>, the CH<sub>4</sub> emission factor can be adjusted based on the relative concentrations of CH<sub>4</sub> and CO<sub>2</sub> in the gas to estimate the CO<sub>2</sub> emissions.

**Table 5-23. Gas Processing Segment CH<sub>4</sub> Emission Factor for Non-Routine Activities**

Source	CH <sub>4</sub> Emission Factor, Original Units	CH <sub>4</sub> Emission Factor, Converted to Tonnes Basis <sup>a</sup>	CH <sub>4</sub> Content Basis of Factor	Precision <sup>b</sup> (±%)
Gas processing non-routine emissions	184 scf/10 <sup>6</sup> scf processed	3.527E-03 tonne/10 <sup>6</sup> scf processed	87 mole %	Precision not available
		0.1244 tonnes/10 <sup>6</sup> m <sup>3</sup> processed		

Source:

Shires, T.M. and C.J. Loughran. *GHGCalc Version 1.0 Emission Factor Documentation*, Draft, Section 5.1.2, November 2001.

<sup>a</sup> CH<sub>4</sub> emission factors converted from scf or m<sup>3</sup> are based on 60°F and 14.7 psia.

<sup>b</sup> Precision based on 90% confidence interval.

An example is provided in Exhibit 5.29

#### **EXHIBIT 5.29: Sample Calculation for Processing Non-Routine Related Emissions**

##### **INPUT DATA:**

A natural gas processing facility treats 20×10<sup>6</sup> m<sup>3</sup> of gas per day. The facility gas has a typical CH<sub>4</sub> content and a negligible amount of CO<sub>2</sub>. Estimate the blowdown emissions for this facility.

##### **CALCULATION METHODOLOGY:**

The processing plant throughput is multiplied by the emission factor presented in Table 5-23. The CH<sub>4</sub> emission factor is not corrected by the site CH<sub>4</sub> content because the composition is assumed to be consistent with the default emission factor CH<sub>4</sub> content. Carbon dioxide emissions are considered negligible.

Gas processing plant blowdowns:

$$\text{CH}_4 : \frac{20 \times 10^6 \text{ m}^3}{\text{day}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{0.1244 \text{ tonnes CH}_4}{10^6 \text{ m}^3} = \underline{908 \text{ tonnes CH}_4/\text{yr}}$$

### 5.7.4 Transportation Related Non-Routine Emissions

Consistent with the gas processing segment, the transmission segment emission factors include both "maintenance and turnaround" and "other releases" from non-routine activities. A summary of the CH<sub>4</sub> emission factors from the transmission segment non-routine activities is presented in Table 5-24. The emission factors are based on a mixture of US and Canadian data.

The gas compressor station blowdown emission factor is an overall station factor that includes compressor blowdowns, compressor starts, PRV releases, ESD activation, and other non-routine venting (Shires and Loughran, 2001). The vented emission factor for meter and pressure regulating (M&R) stations is based on company data from a Canadian study (URS Corporation, 2001). The gas transmission pipeline venting emission factor is based on transmission pipeline blowdowns due to maintenance activities, such as pipe repairs or pigging operations (Shires and Loughran, 2001).

**Table 5-24. Transmission Segment CH<sub>4</sub> Emission Factors for Non-Routine Activities**

Source	CH <sub>4</sub> Emission Factor, Original Units	CH <sub>4</sub> Emission Factor, Converted to Tonnes Basis <sup>e</sup>	CH <sub>4</sub> Content Basis of Factor	Precision <sup>f</sup> (±%)
Gas compressor station blowdowns <sup>a</sup>	5300 × 10 <sup>3</sup> scfy/station	101.7 tonnes/station-yr	93.4 mole %	52
M&R station blowdowns <sup>b</sup>	0.020 × 10 <sup>6</sup> m <sup>3</sup> /station-yr	13.75 tonnes/station-yr	95 mole %	Not available
Gas transmission pipelines venting/ blowdowns <sup>a</sup>	40,950 scfy/mile	0.7855 tonnes/mile-yr	93.4 mole %	60
		0.4881 tonnes/km-yr		
Gas storage station venting <sup>c</sup>	4359 × 10 <sup>3</sup> scfy/station	83.61 tonnes/station-yr	93.4 mole %	262
Oil pump stations (maintenance) <sup>d</sup>	1.56 lb/yr-station	7.076E-4 tonnes/station-yr	Not given	Not available

Sources:

<sup>a</sup> Shires, T.M. and C.J. Loughran. *GHGCalc Version 1.0 Emission Factor Documentation*, Draft, Section 5.1.3, November 2001. Includes US and Canadian data.

<sup>b</sup> URS Corporation. *Updated Canadian National Greenhouse Gas Inventory for 1995, Emission Factor Documentation*. Technical Memorandum, Final, October 2001.

<sup>c</sup> Shires, T.M. *Methane Emissions from the Natural Gas Industry, Volume 7: Blow and Purge Activities*, Final Report, GRI-94/0257.24 and EPA-600/R-96-080g, Gas Research Institute and US Environmental Protection Agency, June 1996.

<sup>d</sup> Tilkicioglu, B.H and D.R. Winters. *Annual Methane Emission Estimate of the Natural Gas and Petroleum Systems in the United States*. Pipeline Systems Incorporated (PSI), December 1989.

Notes:

<sup>e</sup> CH<sub>4</sub> emission factors converted from scf or m<sup>3</sup> are based on 60°F and 14.7 psia.

<sup>f</sup> Precision based on 90% confidence interval.

Gas storage stations include both below-ground facilities and above-ground liquefied natural gas (LNG) facilities. The storage stations have similar non-routine practices as the compressor stations, and are thus categorized with transmission sector emission factors (Shires, 1996).

The oil pump station emission factor is based on an estimate of annual maintenance activities and an assumed CH<sub>4</sub> content in the crude of 100 ppm (Tilkicioglu and Winters, 1989).

The non-routine emission factors given in Table 5-24 can be adjusted based on the CH<sub>4</sub> content of the site-specific gas, if the natural gas has a significantly different CH<sub>4</sub> content from the default basis (if given). Also, if the facility gas contains significant quantities of CO<sub>2</sub>, the CH<sub>4</sub> emission factor can be adjusted based on the relative concentrations of CH<sub>4</sub> and CO<sub>2</sub> in the gas to estimate the CO<sub>2</sub> emissions.

An example calculation is shown in Exhibit 5.30 that illustrates the use of the transmission segment non-routine emissions.

Note that Table 5-24 does not provide an emission factor for surge or breakout tanks. These tanks are used to provide excess volume to relieve pressure in a liquid pipeline system or to provide temporary storage when switching product lines or performing maintenance on the pipeline system. “Breakout tanks” is the preferred terminology for liquid pipeline operations, while the term “surge tanks” is generally associated with processing.

The tanks are generally open to the atmosphere and could result in flashing losses (working and breathing losses are insignificant). Emissions from these tanks would be estimated using the approaches presented in Section 5.4.1 (flashing losses). If the tank type is unknown, assume a fixed roof tank.

**EXHIBIT 5.30:      Sample Calculation for Transmission Non-Routine Related Emissions**

**INPUT DATA:**

A gas transmission system has 50 miles of gas transmission lines and 2 compressor stations. The natural gas in the transmission system has a typical CH<sub>4</sub> content and a negligible amount of CO<sub>2</sub>.

**EXHIBIT 5.30:      Sample Calculation for Transmission Non-Routine Related Emissions, continued****CALCULATION METHODOLOGY:**

The compressor station count and transmission pipeline miles are each multiplied by the appropriate emission factor from Table 5-23. The CH<sub>4</sub> emission factors are not corrected by the site CH<sub>4</sub> content because the composition is assumed to be consistent with the default emission factor CH<sub>4</sub> content. Carbon dioxide emissions are considered negligible.

Compressor station blowdowns:

$$\text{CH}_4 : (2 \text{ stations}) \times \frac{101.7 \text{ tonne CH}_4}{\text{station} - \text{yr}} = \underline{203.4 \text{ tonnes CH}_4/\text{yr}}$$

Transmission gas pipeline blowdowns:

$$\text{CH}_4 : (50 \text{ miles}) \times \frac{0.7855 \text{ tonne CH}_4}{\text{mile} - \text{yr}} = \underline{39.3 \text{ tonnes CH}_4/\text{yr}}$$

**5.7.5      Distribution Related Non-Routine Emissions**

Distribution segment CH<sub>4</sub> emission factors from non-routine activities are presented in Table 5-25. The meter and pressure regulatory (M&R) station blowdown emission factor and the emission factor for odorizer and gas sampling vents are based on a Canadian study (Shires and Loughran, 2002) while the other emission factors are taken from documentation for GHGCalc Version 1.0 (URS Corporation, 2001).

The M&R Station blowdown emission factor includes emissions from station blowdowns and purges as well as pneumatic isolation valve venting. The pipeline blowdown emission factor is based on gas distribution pipeline blowdowns due to maintenance activities, such as pipe repairs, abandonment, or installation.

**Table 5-25. Gas Distribution Segment CH<sub>4</sub> Emission Factors for Non-Routine Activities**

Source	CH <sub>4</sub> Emission Factor, Original Units	CH <sub>4</sub> Emission Factor, Converted to Tonnes Basis <sup>c</sup>	CH <sub>4</sub> Content Basis of Factor	Precision <sup>d</sup> (±%)
M&R Station maintenance/upsets <sup>a</sup>	4.27 m <sup>3</sup> /station-yr	0.002895 tonnes/station-yr	94.8 mole %	Not available
Odorizer and gas sampling vents <sup>a</sup>	33.59 m <sup>3</sup> /station-yr	0.02275 tonnes/station-yr	94.8 mole %	Not available
Pipeline blowdowns (based on mains and services length) <sup>b</sup>	1680 scfy/mile	0.03223 tonnes/mile-yr 0.02002 tonnes/km-yr	93.4 mole %	95
Pipeline dig-ins (based on mains and services length) <sup>b</sup>	1590 scfy/mile	0.03050 tonnes/mile-yr 0.01895 tonnes/km-yr	93.4 mole %	1922
Pressure relief valves (based on pipeline mains length) <sup>b</sup>	50 scfy/mile	9.591E-4 tonnes/mile-yr 5.959E-4 tonnes/km-yr	93.4 mole %	3914

Sources:

<sup>a</sup> URS Corporation. *Updated Canadian National Greenhouse Gas Inventory for 1995, Emission Factor Documentation*, Technical Memorandum, Final, October 2001.

<sup>b</sup> Shires, T.M. and C.J. Loughran. *GHGCalc Version 1.0 Emission Factor Documentation*, Draft, January 2002

Notes:

<sup>c</sup> CH<sub>4</sub> emission factors converted from scf or m<sup>3</sup> are based on 60°F and 14.7 psia.

<sup>d</sup> Precision based on 90% confidence interval.

Dig-ins are unintentional mishaps that result in gas being released to the atmosphere from main or service distribution gas pipelines.

Similar to the transmission segment, the non-routine emission factors given in Table 5-25 can be adjusted based on the CH<sub>4</sub> content of the site-specific gas, if the natural gas has a significantly different CH<sub>4</sub> content from the default basis. Also, if the facility gas contains significant quantities of CO<sub>2</sub>, the CH<sub>4</sub> emission factor can be adjusted based on the relative concentrations of CH<sub>4</sub> and CO<sub>2</sub> in the gas to estimate the CO<sub>2</sub> emissions.

An example calculation is shown in Exhibit 5.31 that illustrates the use of the distribution segment non-routine emissions.

**EXHIBIT 5.31: Sample Calculation for Distribution Non-Routine Related Emissions****INPUT DATA:**

A gas distribution system has 20 miles of gas distribution main lines and 3 M&R stations. The natural gas in the distribution system has a typical CH<sub>4</sub> content and a negligible amount of CO<sub>2</sub>.

**CALCULATION METHODOLOGY:**

The M&R station count and pipeline miles are each multiplied by the appropriate emission factor from Table 5-25. The CH<sub>4</sub> emission factors are not corrected by the site CH<sub>4</sub> content because the composition is assumed to be consistent with the default emission factor CH<sub>4</sub> content. Carbon dioxide emissions are considered negligible.

**M&R station blowdowns:**

$$\text{CH}_4 : (3 \text{ stations}) \times \frac{0.002895 \text{ tonne CH}_4}{\text{station} - \text{yr}} = \underline{0.0087 \text{ tonnes CH}_4/\text{yr}}$$

**Odorizer and gas sampling vents:**

$$\text{CH}_4 : (3 \text{ stations}) \times \frac{0.02275 \text{ tonne CH}_4}{\text{station} - \text{yr}} = \underline{0.068 \text{ tonnes CH}_4/\text{yr}}$$

**Distribution gas pipeline blowdowns:**

$$\text{CH}_4 : (20 \text{ miles}) \times \frac{0.03223 \text{ tonne CH}_4}{\text{mile} - \text{yr}} = \underline{0.64 \text{ tonnes CH}_4/\text{yr}}$$

**Distribution gas pipeline mishaps (dig-ins):**

$$\text{CH}_4 : (20 \text{ miles}) \times \frac{0.0305 \text{ tonne CH}_4}{\text{mile} - \text{yr}} = \underline{0.61 \text{ tonnes CH}_4/\text{yr}}$$

**Distribution pressure relief valves:**

$$\text{CH}_4 : (20 \text{ miles}) \times \frac{9.591 \times 10^{-4} \text{ tonne CH}_4}{\text{mile} - \text{yr}} = \underline{0.02 \text{ tonnes CH}_4/\text{yr}}$$

**5.7.6 Refining Related Non-Routine Emissions**

Non-routine activities in refineries include equipment or process blowdowns, heater or boiler tube decoking, pressure relief valves, or emergency shut downs. Gas releases from these sources are generally routed to the fuel gas system or to a flare. Therefore, emissions from these sources would be included with the combustion source estimates.

Compressor starts at refineries generally use compressed air. If, however, refinery fuel gas is used to start compressor turbines, the emission factors presented for the production segment can be used to estimate CH<sub>4</sub> emissions, adjusting for the CH<sub>4</sub> composition in the fuel gas. Similarly, production segment emission factors can be used if refinery equipment blowdowns are vented directly to the atmosphere.

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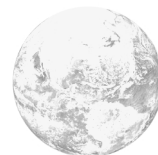
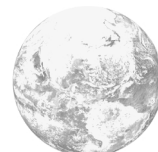
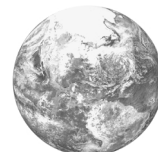
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FEBRUARY 2004

**COMPENDIUM OF GREENHOUSE GAS  
EMISSIONS METHODOLOGIES FOR  
THE OIL AND GAS INDUSTRY**

SECTION 6



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## 6.0

# FUGITIVE EMISSION ESTIMATION METHODS

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Fugitive emissions refer to emissions from equipment leaks, where any pressurized equipment has the potential to leak. These leaks generally occur through valves, flanges, seals, or related equipment. Fugitive emissions also include non-point evaporative sources such as from wastewater treatment, pits, and impoundments. This section presents methods for estimating CH<sub>4</sub> and potentially CO<sub>2</sub> emissions from these fugitive sources.

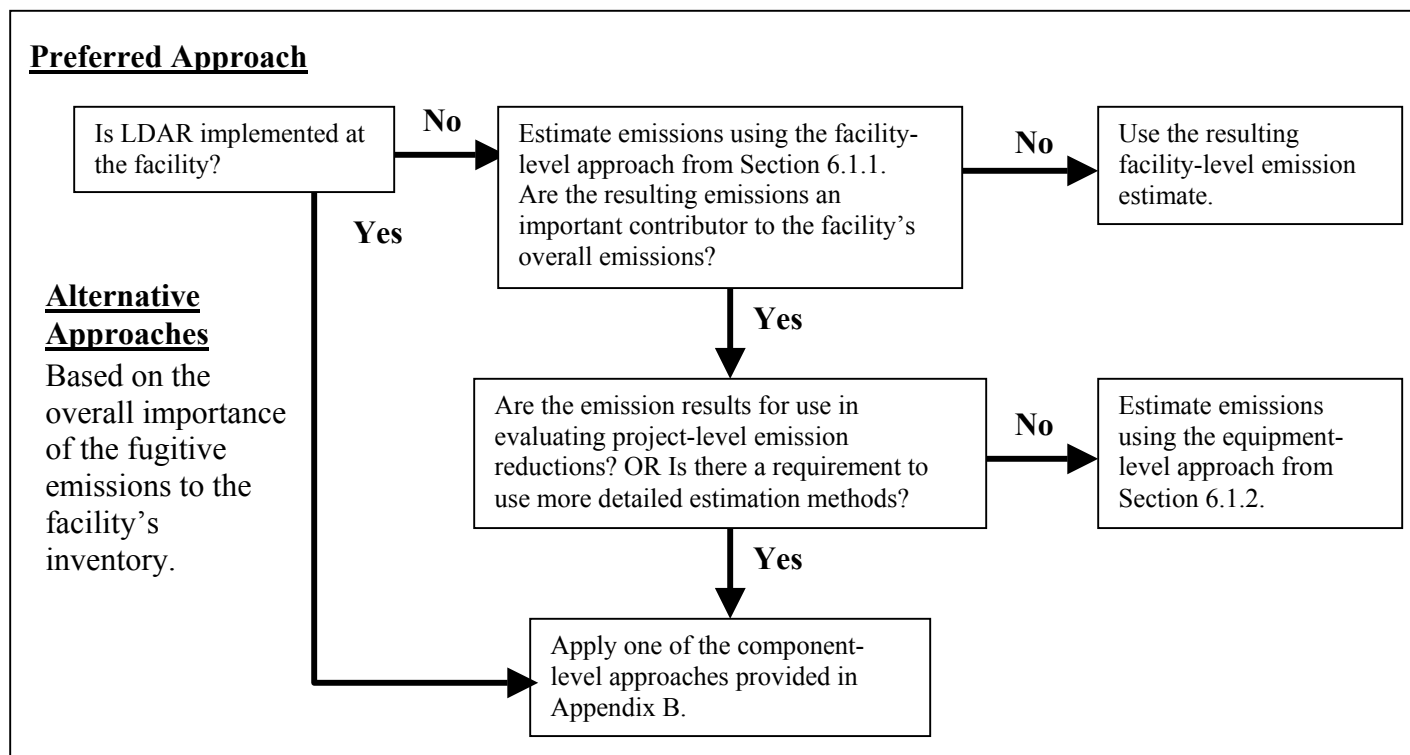
### 6.1 Equipment Leaks

There are a variety of fugitive emission sources related to oil and gas industry operations. The type of fugitive emissions discussed in this subsection are equipment leaks from valves, flanges, pump seals, compressor seals, relief valves, sampling connections, process-drains, open-ended lines, and other miscellaneous component types. There have been numerous documents published outlining the estimation of fugitive emissions, some of which include CH<sub>4</sub>. In comparison, data on fugitive equipment leaks of CO<sub>2</sub> are not generally presented, since CO<sub>2</sub> emissions are more commonly associated with combustion sources. It may be possible to adapt the estimation methods presented for CH<sub>4</sub> to the few petroleum operations for which CO<sub>2</sub> equipment leaks might be of significance, such as with equipment from a CO<sub>2</sub>-enhanced oil production field.

A number of emission factors and correlation equations have been developed for estimating fugitive equipment leak emissions. Many of these approaches require monitoring data and calculations at the component level. The more rigorous component-level approaches are described in Appendix B. The simpler approaches recommended for most greenhouse gas (GHG) fugitive equipment leak emissions are listed below, in order of increasing data requirements and increasing accuracy:

1. Facility-level average emission factors; and
2. Equipment level average emission factors.

When estimating the fugitive equipment leak contribution to a GHG inventory, the simplest method should be used that meets the inventory accuracy needs and for which data are available. Figure 6-1 presents the available options for consideration based on the likely significance of fugitive equipment leaks or the availability of information from a leak detection and repair (LDAR) program. Note that some reporting programs may require the more detailed component-level approaches.



**Figure 6-1. Emission Estimation Approaches for Fugitive Equipment Leaks**

The contribution of fugitive emissions to an overall facility's GHG inventory varies with the type of facility. For example, fugitive CH<sub>4</sub> emissions from a gas processing facility could be a significant element of the total GHG inventory, so the accuracy of the fugitive emissions estimates could be a determining factor in the overall facility inventory. Conversely, refinery fugitive emissions will generally have an insignificant contribution to the total GHG inventory because most refinery streams contain only small amounts of CH<sub>4</sub>. Using a less detailed estimation method for refinery fugitive emissions would generally be acceptable, since the contribution of fugitive emissions would have very little influence on the overall refinery inventory accuracy.



An ongoing API study is testing the hypothesis that CH<sub>4</sub> fugitive emissions from the refinery fuel gas system are negligible. Data from a small, simple refinery configuration indicate that CH<sub>4</sub> fugitive emissions from the fuel gas system represent about 0.1% of the total refinery GHG inventory.<sup>1</sup> Since other large GHG emitting sources have uncertainties within the range of 1% to 5% of the overall GHG inventory, a CH<sub>4</sub> fugitive emission contribution of 0.1% does appear to be negligible.

The selection of a fugitive equipment leaks estimation approach must also consider the data available to support the estimate. The facility-level average emission factor approach requires only identifying the type of facility and knowing its capacity or a count of major equipment. General equipment counts are required for the second approach. Component-level average emission factor approaches, presented in Appendix B, require detailed count of components (such as valves, connections, pump seals, etc.), and for some emissions factors, these component counts will have to be by service type (such as for valves in gas, light liquid, or heavy liquid service). Some of the more rigorous component-level approaches also require monitoring data, in addition to component counts.

Ultimately, accuracy must be balanced against the available data. If the available data will not support an estimate of the needed accuracy, additional data gathering may be required. It is generally not very costly to gather minor component population data to support the third approach. Gathering monitoring data to support the more rigorous approaches is more costly. A decision is required on whether the gains in accuracy justify the cost of additional data gathering.

### **6.1.1 Facility-Level Average Emission Factors Approach**

Applying average facility-level emission factors is the simplest method for estimating CH<sub>4</sub> emissions from petroleum operations. These emission factors are presented in Table 6-1. The user simply needs to know the type of facility and its throughput or major equipment counts to use these factors, such as onshore gas production of 100 million standard cubic feet per day. These facility-level factors were developed by aggregating component emission measurements and activity factors for the facility, primarily for upstream gas industry facilities (Shires, 2002).

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<sup>1</sup> This study plans to test an additional larger, more complex refinery configuration. This testing is scheduled for late first quarter 2004. Results will be available through API soon afterward.

The facility-level approach should provide a reasonable estimate of the fugitive emissions from the facility equipment. The level of accuracy should be sufficient for many facilities, especially if the facility is typical of the industry average. If the facility is atypical or greater accuracy is needed to support emission reduction estimates, then one of the more rigorous approaches should be used.

Downstream facilities, like refineries and marketing terminals, will tend to have insignificant CH<sub>4</sub> fugitive equipment leak emissions. If the average CH<sub>4</sub> content of the refinery fugitive streams is known (or assumed), then the total hydrocarbon (THC) refinery fugitive emission factor provided in Table 6-1 can be used. This THC factor is taken from EMEP/CORINAIR guidance, Group 4 (EEA, 2001), which is based on an inventory of Canadian refineries in 1988 (CPPI and Environment Canada, 1991). The factor must be converted from a THC basis to a CH<sub>4</sub> basis using the site-specific or assumed CH<sub>4</sub> stream content.

Table 6-1 provides separate fugitive emission factors for oil and gas production operations. However, oil and gas can be produced from the same well. For facilities that produce any natural gas, the gas production emission factors should be used. For facilities that do not market the associated gas or only produce crude, the oil production emission factors should be used.

Methane is the primary GHG pollutant from fugitive emissions. The fugitive emission factors provided in Table 6-1 are based on default, average compositions. The default CH<sub>4</sub> content can be replaced with a user-specified gas analysis. In this case, the fugitive CH<sub>4</sub> emission estimates are adjusted by the ratio of the specified gas CH<sub>4</sub> concentration to the default CH<sub>4</sub> concentration. This correction is demonstrated in Exhibit 6.1.

In addition to CH<sub>4</sub>, CO<sub>2</sub> may also be released from fugitive sources if CO<sub>2</sub> is present in the gas stream (e.g., enhance oil recovery operations). Fugitive emission factors for CO<sub>2</sub> do not exist. However, as an approximation, the CH<sub>4</sub> emission factor can be adjusted to account for the CO<sub>2</sub> composition of the gas for fugitive sources other than underground pipelines. This is demonstrated in Exhibit 6.1. Fugitive CO<sub>2</sub> emissions from underground pipelines may also result from the oxidation of CH<sub>4</sub> as it migrates through the soil to the atmosphere. These emission sources are discussed separately in Section 6.1.2.

**Table 6-1. Facility-Level Average Fugitive Emission Factors**

Source	Emission Factor Original Units	Precision ( $\pm$ %) <sup>a</sup>	Gas Content Basis of Factor	Emission Factor <sup>b</sup> Converted Units
<b>Production</b>				
Onshore gas production	57.21 lb CH <sub>4</sub> /10 <sup>6</sup> scf produced	44	78.8 mole % CH <sub>4</sub>	2.595E-02 tonnes CH <sub>4</sub> /scf 9.164E-01 tonnes CH <sub>4</sub> /m <sup>3</sup>
Offshore gas production	22.88 lb CH <sub>4</sub> /10 <sup>6</sup> scf produced	Not available	78.8 mole % CH <sub>4</sub>	1.038E-02 tonnes CH <sub>4</sub> /scf 3.665E-01 tonnes CH <sub>4</sub> /m <sup>3</sup>
Onshore oil production	0.5164 lb CH <sub>4</sub> /bbl produced	Not available	78.8 mole % CH <sub>4</sub>	2.342E-04 tonnes CH <sub>4</sub> /bbl 1.473E-03 tonnes CH <sub>4</sub> /m <sup>3</sup>
Offshore oil production	0.2066 lb CH <sub>4</sub> /bbl produced	Not available	78.8 mole % CH <sub>4</sub>	9.371E-05 tonnes CH <sub>4</sub> /bbl 5.894E-04 tonnes CH <sub>4</sub> /m <sup>3</sup>
<b>Gas processing plants</b>	64.32 lb CH <sub>4</sub> /10 <sup>6</sup> scf processed	69	87 mole % CH <sub>4</sub>	2.918E-02 tonnes CH <sub>4</sub> /scf 1.030E+00 tonnes CH <sub>4</sub> /m <sup>3</sup>
<b>Gas storage stations</b>	1,489,000 lb CH <sub>4</sub> /station	57	93.4 mole % CH <sub>4</sub>	6.754E+02 tonnes CH <sub>4</sub> /station
<b>Gas transmission pipelines</b>				
CH <sub>4</sub> from pipeline leaks	7,923 lb CH <sub>4</sub> /mile-yr	84	93.4 mole % CH <sub>4</sub>	3.594E+00 tonnes CH <sub>4</sub> /mile-yr 2.233E+00 tonnes CH <sub>4</sub> /km-yr
CO <sub>2</sub> from oxidation <sup>c</sup>	7.59 lb CO <sub>2</sub> /mile-yr	65	2 mole % CO <sub>2</sub>	3.443E-03 tonnes CO <sub>2</sub> /mile-yr 2.139E-03 tonnes CO <sub>2</sub> /km-yr
CO <sub>2</sub> from pipeline leaks	466.7 lb CO <sub>2</sub> /mile-yr	84	2 mole % CO <sub>2</sub>	2.117E-01 tonnes CO <sub>2</sub> /mile-yr 1.315E-01 tonnes CO <sub>2</sub> /km-yr
Crude transmission pipelines	Negligible		Negligible	
<b>Gas distribution pipelines</b>				
CH <sub>4</sub> from pipeline leaks	3,551 lb CH <sub>4</sub> /mile-yr	48	93.4 mole % CH <sub>4</sub>	1.611E+00 tonnes CH <sub>4</sub> /mile-yr 1.001E+00 tonnes CH <sub>4</sub> /km-yr
CO <sub>2</sub> from oxidation <sup>c</sup>	1,237 lb CO <sub>2</sub> /mile-yr	69	2 mole % CO <sub>2</sub>	5.611E-01 tonnes CO <sub>2</sub> /mile-yr 3.486E-01 tonnes CO <sub>2</sub> /km-yr
CO <sub>2</sub> from pipeline leaks	235.6 lb CO <sub>2</sub> /mile-yr	45	2 mole % CO <sub>2</sub>	1.069E-01 tonnes CO <sub>2</sub> /mile-yr 6.640E-02 tonnes CO <sub>2</sub> /km-yr
<b>Refining <sup>d</sup></b>	0.53 kg THC/m <sup>3</sup> crude feedstock	Not available		8.43E-05 tonnes THC/bbl feedstock 5.30E-04 tonnes THC/m <sup>3</sup> feedstock

Source: Shires, T.M. and C.J. Loughran. *GHGCalc Version 1.0 Emission Factor Documentation*, Draft, Gas Technology Institute (GTI), January 2002, Tier 1 fugitive emission factors from Table 4-26.

<sup>a</sup> Precision is based on a 90% confidence interval from the data used to develop the original emission factor.

<sup>b</sup> The CH<sub>4</sub> emission factors can be adjusted based on the relative concentrations of CH<sub>4</sub> and CO<sub>2</sub> to estimate CO<sub>2</sub> emissions

<sup>c</sup> A portion of CH<sub>4</sub> emitted from underground pipeline leaks is oxidized to form CO<sub>2</sub>.

<sup>d</sup> Source: European Environment Agency (EEA), *Joint EMEP/CORINAIR Atmospheric Emission Inventory Guidebook*, Third Edition, EEA, Copenhagen, 2001, updated October 2002. Refinery fugitive emission factor from Group 4, page B411-9, which is based on: Canadian Petroleum Products Institute (CPPI) and Environment Canada. *Atmospheric Emissions from Canadian Petroleum Refineries and the Associated Gasoline Distribution System for 1988*, CPPI and Environment Canada, CPPI Report No. 91-7, prepared by B.H. Levelton & Associates Ltd. and RTM Engineering Ltd., 1991. Refinery fugitive emission factor is on a total hydrocarbon (THC) basis and must be converted to a CH<sub>4</sub> basis using a site-specific or assumed CH<sub>4</sub> stream content. However, refineries tend to have insignificant CH<sub>4</sub> fugitive equipment leak emissions.

The following exhibit shows an example of calculations using facility-level average emission factors.

**EXHIBIT 6.1: Sample Calculation for Facility-Level Average Fugitive Emission Factor Approach**

**INPUT DATA:**

An onshore oil production facility has a production throughput of 795 m<sup>3</sup> per day of crude. The CH<sub>4</sub> content of the associated gas is 68 mole %, and the CO<sub>2</sub> content is 4 mole%. Assume that the facility operates continuously throughout the year.

**CALCULATION METHODOLOGY:**

Methane emissions would be calculated using the emission factor for onshore oil production from Table 6-1, and correcting for the actual CH<sub>4</sub> composition of the gas:

$$E_{\text{CH}_4} = \frac{795 \text{ m}^3}{\text{day}} \times \frac{365 \text{ days}}{\text{year}} \times \frac{1.473 \times 10^{-3} \text{ tonne CH}_4}{\text{m}^3} \times \frac{0.68 \text{ tonne mol CH}_4 \text{ actual}}{0.788 \text{ tonne mol CH}_4 \text{ default}} = \underline{369 \text{ tonnes CH}_4 / \text{yr}}$$

CO<sub>2</sub> emissions are calculated by the ratio of CH<sub>4</sub> to CO<sub>2</sub> in the produced gas.

$$E_{\text{CO}_2} = \frac{369 \text{ tonne CH}_4}{\text{yr}} \times \frac{\text{tonne mol CH}_4}{16 \text{ tonne mol CH}_4} \times \frac{\text{tonne mol gas}}{0.68 \text{ tonne mol CH}_4} \times \frac{0.04 \text{ tonne mol CO}_2}{\text{tonne mol gas}} \times \frac{44 \text{ tonne CO}_2}{\text{tonne mol CO}_2} = \underline{59.7 \text{ tonnes CO}_2 / \text{yr}}$$

**6.1.2 Equipment-Level Average Emission Factors Approach**

The equipment-level average emission factor approach allows the fugitive emission estimate to be tailored to a particular facility based on the population of major equipment at the facility. This approach requires more information than the facility-level approach, but results in a slightly more accurate emission estimate than the facility-level approach. It is especially useful when trying to estimate GHG emissions for a planned facility that has not yet been fully designed or for an existing facility where no detailed minor component population data are available.

The data listed in Tables 6-2 through 6-6 were developed from extensive component monitoring and emission measurement data. The minor component emission factor data were then aggregated using activity factors that characterized the number of each minor component per major equipment system. This approach of aggregating individual components into major equipment systems may be appropriate for many GHG emission calculation efforts.

Most of these major equipment emission factors are CH<sub>4</sub>-specific. The default CH<sub>4</sub> concentration for each industry sector is indicated in the table footnotes. Carbon dioxide emissions from buried pipelines are based on an assumed concentration of 2 mole %. The method for estimating the emissions using the major equipment approach is presented in the equation below:

$$E_{\text{CH}_4 \text{ (or CO}_2\text{)}} = F_A \times N \quad \text{(Equation 6-1)}$$

where,

$E_{\text{CH}_4 \text{ (or CO}_2\text{)}}$	=	Emission rate of CH <sub>4</sub> (or CO <sub>2</sub> ) from a population of equipment
$F_A$	=	Applicable average emission factor for the major equipment type
$N$	=	Number of pieces of equipment in the plant/process

Tables 6-2 and 6-3 provide fugitive emission factors for equipment associated with oil and gas exploration and production operations. For facilities where oil and gas are produced from the same well, Figure 6-2 illustrates the boundaries between crude production equipment and natural gas production equipment. Emission factors from Table 6-2 should be applied to counts of equipment associated with crude production, while Table 6-3 emission factors should be applied to natural gas production equipment. For both tables, the CH<sub>4</sub> emission factors are based on an average CH<sub>4</sub> composition of 78.8 mole %. The emission factors can be adjusted to other CH<sub>4</sub> concentrations by the ratio of the actual CH<sub>4</sub> content to the default value. In addition, in the absence of CO<sub>2</sub> specific emission factors, CO<sub>2</sub> emissions can be approximated from the CH<sub>4</sub> emission factors based on the ratio of CO<sub>2</sub> to CH<sub>4</sub> in the produced gas. (These adjustments are demonstrated in Exhibit 6.1.)

The emission factors shown in Table 6-2 for crude production equipment are derived from API Report 4615 *Emission Factors for Oil and Gas Production Operations* (API, 1995). Separate emission factors are provided for heavy versus light crude, since heavier crude has less entrained CH<sub>4</sub> and therefore lower emissions. API Report 4615 designates heavy crude as having an API gravity of less than 20° and light crude as having an API gravity of greater than 20°.

Emission factors provided in Table 6-3 are derived from the GRI/EPA US methane emissions study (Hummel, et. al., 1996). Emission factors for both CH<sub>4</sub> and CO<sub>2</sub> are provided for gathering pipelines. Carbon dioxide emissions from buried pipeline leaks are discussed further at the end of Section 6.1.2.

**Table 6–2. Fugitive Emission Factors for Onshore Crude Production Equipment**

Equipment Basis	Reference CH <sub>4</sub> Emission Factor, Original Units		Precision (± %) <sup>a</sup>	CH <sub>4</sub> Emission Factor <sup>b</sup> , Converted Units	
Oil Wellheads – heavy crude	0.83	scfd/well	30	6.63E-07	tonne/well-hr
Oil Wellheads – light crude	19.58	scfd/well	30	1.56E-05	tonne/well-hr
Separators – heavy crude	0.85	scfd/separator	30	6.79E-07	tonne/separator-hr
Separators – light crude	51.33	scfd/separator	30	4.10E-05	tonne/separator-hr
Heater Treaters - light crude	59.74	scfd/heater	30	4.77E-05	tonne/heater-hr
Headers – heavy crude	0.59	scfd/header	30	4.71E-07	tonne/header-hr
Headers – light crude	202.78	scfd/header	30	1.62E-04	tonne/header-hr
Tanks – light crude	34.4	scfd/tank	30	2.75E-05	tonne/tank-hr
Small Compressors - light crude	46.14	scfd/compressor	100	3.69E-05	tonne/compressor-hr
Large Compressors <sup>c</sup> - light crude	16,360	scfd/compressor	100	1.31E-02	tonne/compressor-hr
Sales Areas	40.55	scfd/area	30	3.24E-05	tonne/area-hr

Source: Harrison, M.R., T.M. Shires, R.A. Baker, and C.J. Loughran. *Methane Emissions from the US Petroleum Industry*, Final Report, EPA 600/R-99-010, US Environmental Protection Agency, 1999.

Notes:

<sup>a</sup> Precision is based on a 90% confidence interval from the data used to develop the original emission factor.

<sup>b</sup> Emission factors converted from scfy are based on 60 °F and 14.7 psia. The average CH<sub>4</sub> concentration associated with these emission factors is 78.8 mole %. If the actual CH<sub>4</sub> content differs from the default value, the emission factors shown above can be adjusted by the ratio of the site CH<sub>4</sub> content to the default concentration.

<sup>c</sup> Large compressors are those with more than 3 stage of compression.

**Table 6–3. Fugitive Emission Factors for Onshore Natural Gas Production Equipment**

<b>Equipment Basis</b>	<b>Reference Emission Factor, Original Units</b>		<b>Precision (± %) <sup>a</sup></b>	<b>Emission Factor<sup>b</sup>, Converted Units</b>	
Gas wellheads	8,208	scfy CH <sub>4</sub> /well	22	1.80E-05	tonne CH <sub>4</sub> /well-hr
Separators	20,171	scfy CH <sub>4</sub> /separator	73	4.42E-05	tonne CH <sub>4</sub> /separator-hr
Gas Heaters	20,978	scfy CH <sub>4</sub> /heater	145	4.59E-05	tonne CH <sub>4</sub> /heater-hr
Small reciprocating gas compressor	97,043	scfy CH <sub>4</sub> /compressor	106	2.12E-04	tonne CH <sub>4</sub> /compressor-hr
Large reciprocating gas compressor <sup>c</sup>	5.55×10 <sup>6</sup>	scfy CH <sub>4</sub> /compressor	169	1.22E-02	tonne CH <sub>4</sub> /compressor-hr
Large reciprocating gas compressor stations <sup>c</sup>	3.088×10 <sup>6</sup>	scfy CH <sub>4</sub> /station	102	6.59E-03	tonne CH <sub>4</sub> /station-hr
Meters/piping	16,072	scfy CH <sub>4</sub> /meter	133	3.52E-05	tonne CH <sub>4</sub> /meter-hr
Dehydrators	20,171	scfy CH <sub>4</sub> /dehydrator	37	4.42E-05	tonne CH <sub>4</sub> /dehydrator-hr
Gathering pipelines	825	lb CH <sub>4</sub> /mile-yr	108	4.27E-05	tonne CH <sub>4</sub> /mile-hr
				2.65E-05	tonne CH <sub>4</sub> /km-hr
CO <sub>2</sub> from oxidation <sup>d</sup>	84.5	lb CO <sub>2</sub> /mile-yr	66	4.38E-06	tonne CO <sub>2</sub> /mile-hr
				2.72E-06	tonne CO <sub>2</sub> /km-hr
CO <sub>2</sub> from pipeline leaks	112.9	lb CO <sub>2</sub> /mile-yr	107	5.85E-06	tonne CO <sub>2</sub> /mile-hr
				3.63E-06	tonne CO <sub>2</sub> /km-hr

Source: Shires, T.M. and C.J. Loughran. *GHGCalc Version 1.0 Emission Factor Documentation*, Draft, Gas Technology Institute, January 2002. Cite data from Sections 4.2.1 and 4.3.1.

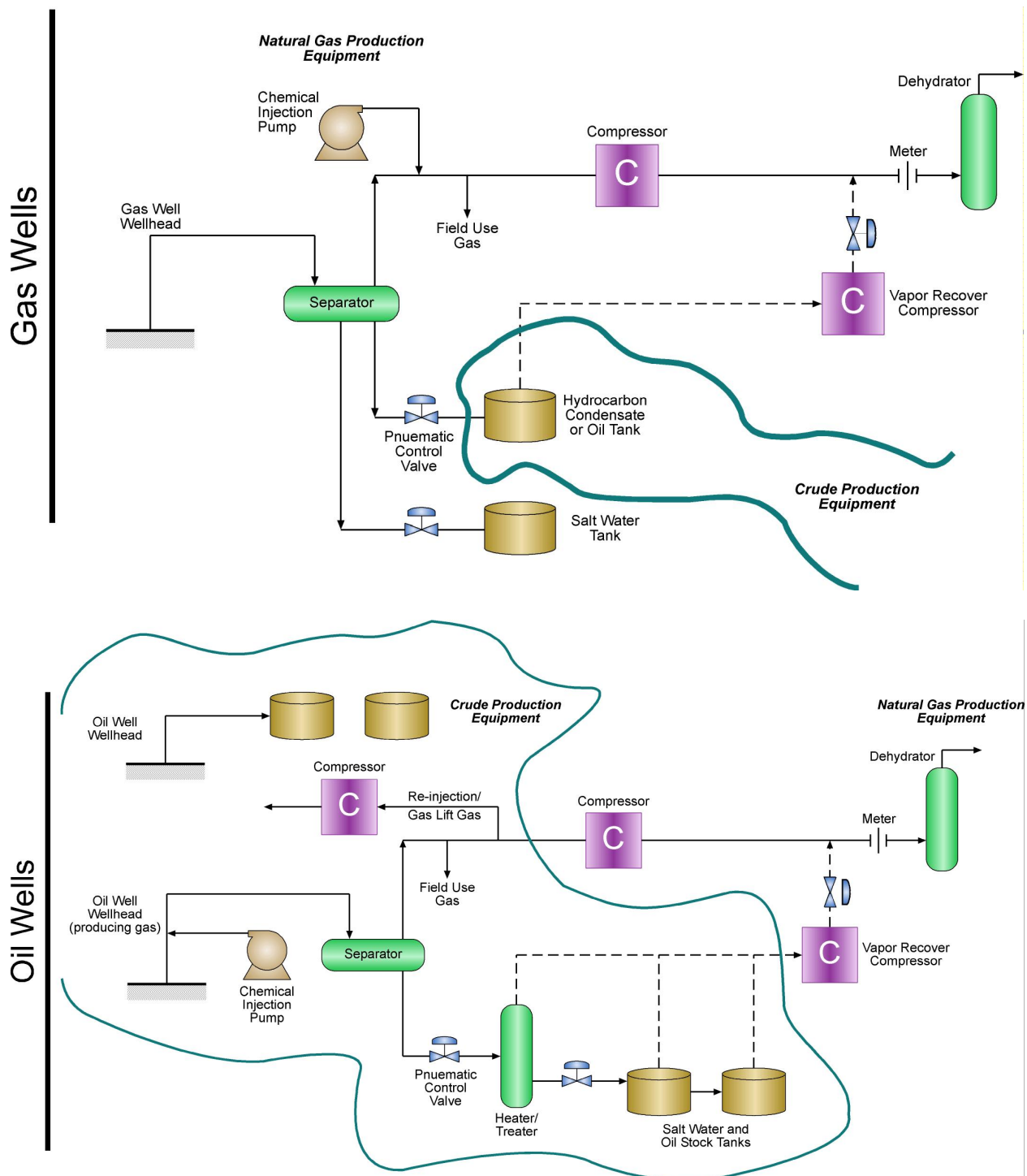
Notes:

<sup>a</sup> Precision is based on a 90% confidence interval from the data used to develop the original emission factor.

<sup>b</sup> Emission factors converted from scfy are based on 60 °F and 14.7 psia. The average CH<sub>4</sub> concentration associated with these emission factors is 78.8 mole %; the average CO<sub>2</sub> concentration (for buried pipelines) is 2 mole %. If the actual concentration differs from the default value, the emission factors shown above can be adjusted by the ratio of the site concentration to the default concentration.

<sup>c</sup> Large compressors are those with more than 3 stage of compression. Large compressor stations are those with five or more compressors.

<sup>d</sup> A portion of CH<sub>4</sub> emitted from underground pipeline leaks is oxidized to form CO<sub>2</sub>.



**Figure 6-2. Boundaries Between Crude and Natural Gas Production Equipment**



Gas processing fugitive emission factors are presented in Table 6-4. The default CH<sub>4</sub> concentration associated with these emission factors is 87 mole %. The emission factors can be adjusted for other CH<sub>4</sub> concentrations by the ratio of the actual CH<sub>4</sub> content to the default value. The emission factors can also be used to estimate CO<sub>2</sub> emissions based on the ratio of CO<sub>2</sub> to CH<sub>4</sub> in the produced gas. (These adjustments are demonstrated in Exhibit 6.1.)

**Table 6–4. Fugitive CH<sub>4</sub> Emission Factors Gas Processing Equipment**

Equipment Basis	Reference CH <sub>4</sub> Emission Factor, Original Units		Precision (± %) <sup>a</sup>	CH <sub>4</sub> Emission Factor <sup>b</sup> , Converted Units
Gas Processing Volume	0.000130563	scf/scf processed	49	2.50E-03 tonne/MMscf processed
				8.84E-02 tonne/10 <sup>6</sup> m <sup>3</sup> processed
Reciprocating Compressors	11,198	scfd/compressor	74	8.95E-03 tonne/compressor-hr
Centrifugal Compressors	21,230	scfd/compressor	39	1.70E-02 tonne/compressor-hr

Source: Shires, T.M. and C.J. Loughran. *GHGCalc Version 1.0 Emission Factor Documentation*, Draft, Gas Technology Institute, January 2002. Cites data from Table 4-6.

Notes:

<sup>a</sup> Precision is based on a 90% confidence interval from the data used to develop the original emission factor.

<sup>b</sup> Emission factors converted from scfy are based on 60 °F and 14.7 psia. The average CH<sub>4</sub> concentration associated with these emission factors is 87 mole %. If the actual CH<sub>4</sub> content differs from the default value, the emission factors shown above can be adjusted by the ratio of the site CH<sub>4</sub> content to the default concentration.

Table 6-5 provides fugitive emission factors for equipment associated with natural gas transmission and storage operations and Table 6-6 provides fugitive emission factors for gas distribution equipment. Carbon dioxide emissions from buried pipeline leaks are discussed further at the end of Section 6.1.2. The default CH<sub>4</sub> concentration for both emission factor tables is 93.4 mole %. The emission factors can be adjusted for other CH<sub>4</sub> concentrations by the ratio of the actual CH<sub>4</sub> content to the default value. The emission factors can also be used to estimate CO<sub>2</sub> emissions based on the ratio of CO<sub>2</sub> to CH<sub>4</sub> in the produced gas. (These adjustments are demonstrated in Exhibit 6.1.)

**Table 6–5. Fugitive Emission Factors Gas Transmission and Storage Equipment**

Equipment Basis	Reference Emission Factor, Original Units		Precision (± %) <sup>a</sup>	Emission Factor <sup>b</sup> , Converted Units	
Compressor Stations	8,778	scfd CH <sub>4</sub> /facility	102	7.02E-03	tonne CH <sub>4</sub> /station-hr
Compressor Stations – Reciprocating	15,205	scfd CH <sub>4</sub> /comp.	65	1.22E-02	tonne CH <sub>4</sub> /compressor-hr
Compressor Stations – Centrifugal	30,305	scfd CH <sub>4</sub> /comp.	34	2.42E-02	tonne CH <sub>4</sub> /compressor-hr
Meter/Reg. Stations	60,010	scf CH <sub>4</sub> /station-yr	80	1.31E-04	tonne CH <sub>4</sub> /station-hr
Gas Transmission Pipeline	23.08	Lb CH <sub>4</sub> /mile-yr	90	1.20E-06	tonne CH <sub>4</sub> /mile-hr
				7.43E-07	tonne CH <sub>4</sub> /km-hr
CO <sub>2</sub> from oxidation <sup>c</sup>	7.59	lb CO <sub>2</sub> /mile-yr	65	3.93E-07	tonne CO <sub>2</sub> /mile-hr
				2.44E-07	tonne CO <sub>2</sub> /km-hr
CO <sub>2</sub> from pipeline leaks	1.522	lb CO <sub>2</sub> /mile-yr	84	7.88E-08	tonne CO <sub>2</sub> /mile-hr
				4.90E-08	tonne CO <sub>2</sub> /km-hr
Oil Pump Stations <sup>d</sup>	1.06	lb CH <sub>4</sub> /mile-yr		5.49E-08	tonne CH <sub>4</sub> /mile-hr
				3.41E-08	tonne CH <sub>4</sub> /km-hr
Storage Stations	21,507	scfd CH <sub>4</sub> /facility	100	1.72E-02	tonne CH <sub>4</sub> /station-hr
Storage – Reciprocating Compressor	21,116	scfd CH <sub>4</sub> /comp.	48	1.69E-02	tonne CH <sub>4</sub> /compressor-hr
Storage – Centrifugal Compressor	30,573	scfd CH <sub>4</sub> /comp.	34	2.44E-02	tonne CH <sub>4</sub> /compressor-hr
Storage Wells	114.5	scfd CH <sub>4</sub> /well	76	9.15E-05	tonne CH <sub>4</sub> /well-hr

Source: Shires, T.M. and C.J. Loughran. *GHGCalc Version 1.0 Emission Factor Documentation*, Draft, Gas Technology Institute, January 2002. Cites data from Table 4-6.

Notes:

<sup>a</sup> Precision is based on a 90% confidence interval from the data used to develop the original emission factor.

<sup>b</sup> Emission factors converted from scfy are based on 60 °F and 14.7 psia. The average CH<sub>4</sub> concentration associated with these emission factors is 93.4 mole %; the average CO<sub>2</sub> concentration (for buried pipelines) is 2 mole %. If the actual concentration differs from the default value, the emission factors shown above can be adjusted by the ratio of the site concentration to the default concentration.

<sup>c</sup> A portion of CH<sub>4</sub> emitted from underground pipeline leaks is oxidized to form CO<sub>2</sub>.

<sup>d</sup> PSI, 1989

**Table 6–6. Fugitive Emission Factors Gas Distribution Equipment**

Equipment Basis	Reference Emission Factor, Original Units		Precision (± %) <sup>a</sup>	Emission Factor <sup>b</sup> , Converted Units	
Customer Meters	129.15	scf/meter-yr	22	2.83E-07	tonne CH <sub>4</sub> /meter-hr
Distribution Meter/Reg. Stations	207,018	scf/station-yr	90	4.53E-04	tonne CH <sub>4</sub> /station-hr
Distribution Pipelines	1,357	lb CH <sub>4</sub> /mile-yr	69	7.03E-05	tonne CH <sub>4</sub> /mile-hr
				4.37E-05	tonne CH <sub>4</sub> /km-hr
CO <sub>2</sub> oxidation EF for distribution pipeline <sup>c</sup>	1,205	lb CO <sub>2</sub> /mile-yr	71	6.24E-05	tonne CO <sub>2</sub> /mile-hr
				3.88E-05	tonne CO <sub>2</sub> /km-hr
CO <sub>2</sub> leaks from distribution pipeline	105.7	lb CO <sub>2</sub> /mile-yr	63	5.47E-06	tonne CO <sub>2</sub> /mile-hr
				3.40E-06	tonne CO <sub>2</sub> /km-hr
Distribution Services	1,200	lb CH <sub>4</sub> /mile-yr	142	6.21E-05	tonne CH <sub>4</sub> /mile-hr
				3.86E-05	tonne CH <sub>4</sub> /km-hr
CO <sub>2</sub> oxidation EF for distribution services <sup>c</sup>	0.64	lb CO <sub>2</sub> /mile-yr	114	3.31E-08	tonne CO <sub>2</sub> /mile-hr
				2.06E-08	tonne CO <sub>2</sub> /km-hr
CO <sub>2</sub> leaks from distribution services	0.758	lb CO <sub>2</sub> /mile-yr	142	3.92E-08	tonne CO <sub>2</sub> /mile-hr
				2.44E-08	tonne CO <sub>2</sub> /km-hr

Source: Shires, T.M. and C.J. Loughran. *GHGCalc Version 1.0 Emission Factor Documentation*, Draft, Gas Technology Institute, January 2002. Cites data from multiple tables.

Notes:

<sup>a</sup> Precision is based on a 90% confidence interval from the data used to develop the original emission factor.

<sup>b</sup> Emission factors converted from scfy are based on 60 °F and 14.7 psia. The average CH<sub>4</sub> concentration associated with these emission factors is 93.4 mole %; the average CO<sub>2</sub> concentration (for buried pipelines) is 2 mole %. If the actual concentration differs from the default value, the emission factors shown above can be adjusted by the ratio of the site concentration to the default concentration.

<sup>c</sup> A portion of CH<sub>4</sub> emitted from underground pipeline leaks is oxidized to form CO<sub>2</sub>.

Exhibit 6.2 presents an example of calculating CH<sub>4</sub> emissions using the major equipment emission factors approach.

**EXHIBIT 6.2: Sample Calculation for Major Equipment Emission Factor Approach****INPUT DATA:**

Assume an onshore gas production field in Texas has 15 gas wellheads, 4 separators, one heater, a small reciprocating compressor, a metering station, and 12 miles of gathering pipelines. The concentration of the produced gas is 79 mole % CH<sub>4</sub> and 2% CO<sub>2</sub>.

**CALCULATION METHODOLOGY:**

The emission factors for a natural gas exploration and production facility are provided in Table 6-3.

$$E_{\text{CH}_4 \text{ wellheads}} = \frac{1.8 \times 10^{-5} \text{ tonnes CH}_4}{\text{hr} \times \text{wellhead}} \times \frac{8760 \text{ hours}}{\text{year}} \times 15 \text{ wellheads} = 2.36 \text{ tonnes CH}_4 / \text{yr}$$

$$E_{\text{CH}_4 \text{ separators}} = \frac{4.42 \times 10^{-5} \text{ tonnes CH}_4}{\text{hr} \times \text{separator}} \times \frac{8760 \text{ hours}}{\text{year}} \times 4 \text{ separators} = 1.55 \text{ tonnes CH}_4 / \text{yr}$$

$$E_{\text{CH}_4 \text{ heaters}} = \frac{4.59 \times 10^{-5} \text{ tonnes CH}_4}{\text{hr} \times \text{heater}} \times \frac{8760 \text{ hours}}{\text{year}} \times 1 \text{ heater} = 0.40 \text{ tonnes CH}_4 / \text{yr}$$

$$E_{\text{CH}_4 \text{ small recip.}} = \frac{2.12 \times 10^{-4} \text{ tonnes CH}_4}{\text{hr} \times \text{small recip.}} \times \frac{8760 \text{ hours}}{\text{year}} \times 1 \text{ small recip.} = 1.86 \text{ tonnes CH}_4 / \text{yr}$$

$$E_{\text{CH}_4 \text{ meter}} = \frac{3.52 \times 10^{-5} \text{ tonnes CH}_4}{\text{hr} \times \text{meter}} \times \frac{8760 \text{ hours}}{\text{year}} \times 1 \text{ meter} = 0.31 \text{ tonnes CH}_4 / \text{yr}$$

$$E_{\text{CH}_4 \text{ gathering pipe}} = \frac{4.27 \times 10^{-5} \text{ tonnes CH}_4}{\text{hr} \times \text{mile}} \times \frac{8760 \text{ hours}}{\text{year}} \times 12 \text{ miles} = 4.49 \text{ tonnes CH}_4 / \text{yr}$$

Total CH<sub>4</sub> emissions are then:

$$\begin{aligned} E_{\text{CH}_4 \text{ total}} &= \frac{2.36 \text{ tonnes}}{\text{yr}} + \frac{1.55 \text{ tonnes}}{\text{yr}} + \frac{0.4 \text{ tonnes}}{\text{yr}} + \frac{1.86 \text{ tonnes}}{\text{yr}} + \frac{0.31 \text{ tonnes}}{\text{yr}} + \frac{4.49 \text{ tonnes}}{\text{yr}} \\ &= \underline{10.97 \text{ tonnes CH}_4 / \text{yr}} \end{aligned}$$

**EXHIBIT 6.2: Sample Calculation for Major Equipment Emission Factor Approach, continued**

CO<sub>2</sub> emissions result from CO<sub>2</sub> present in the gas stream. For non-pipeline sources, it is assumed that the CO<sub>2</sub> leak rate is based on the CH<sub>4</sub> emission rate, but adjusted for the ratio of CO<sub>2</sub> to CH<sub>4</sub> in the gas.

$$E_{\text{CO}_2 \text{ non-pipeline sources}} = \frac{10.97 \text{ tonnes CH}_4}{\text{yr}} \times \frac{\text{tonne mol CH}_4}{16 \text{ tonnes CH}_4} \times \frac{0.02 \text{ tonne mol CO}_2}{0.79 \text{ tonne mol CH}_4} \times \frac{44 \text{ tonnes CO}_2}{\text{tonne mol CO}_2} = 0.76 \text{ tonnes CO}_2 / \text{yr}$$

CO<sub>2</sub> emissions from pipeline leaks are calculated using the emission factor from Table 6-3.

$$E_{\text{CO}_2 \text{ pipeline leaks}} = \frac{5.85 \times 10^{-6} \text{ tonnes CO}_2}{\text{hr} \times \text{mile}} \times \frac{8760 \text{ hours}}{\text{year}} \times 12 \text{ miles} = 0.61 \text{ tonnes CO}_2 / \text{yr}$$

CO<sub>2</sub> emissions also result from pipeline leaks due to the oxidation of CH<sub>4</sub> in the soil.

$$E_{\text{CO}_2 \text{ oxidation}} = \frac{4.38 \times 10^{-6} \text{ tonnes CO}_2}{\text{hr} \times \text{mile}} \times \frac{8760 \text{ hours}}{\text{year}} \times 12 \text{ miles} = 0.46 \text{ tonnes CO}_2 / \text{yr}$$

The total CO<sub>2</sub> emissions from these sources are:

$$E_{\text{CO}_2 \text{ total}} = \frac{0.76 \text{ tonnes}}{\text{yr}} + \frac{0.61 \text{ tonnes}}{\text{yr}} + \frac{0.46 \text{ tonnes}}{\text{yr}} = \underline{1.83 \text{ tonnes CO}_2 / \text{yr}}$$

Total fugitive emissions for this production field, in CO<sub>2</sub> equivalent are:

$$\text{CO}_2 \text{ Equivalent Emissions} = \left( \frac{10.97 \text{ tonnes CH}_4}{\text{yr}} \times \frac{21 \text{ tonnes CO}_2 \text{ Eq.}}{\text{tonne CH}_4} \right) + \frac{1.83 \text{ tonnes CO}_2}{\text{yr}} = \underline{232.2 \text{ tonnes CO}_2 \text{ Eq.} / \text{yr}}$$

## Fugitive Emissions from Buried Pipelines

Carbon dioxide may be emitted from fugitive sources due to the concentration of CO<sub>2</sub> in the gas stream. For buried pipelines, a second source of fugitive CO<sub>2</sub> emissions results. Methane emitted from buried pipelines is partially oxidized to form CO<sub>2</sub> as it passes through the surrounding soil.

The following equations were used in developing the CO<sub>2</sub> emission factors for pipeline fugitive emissions:

### (1) Methane Emissions from Gas Leaks:

$$\text{CH}_4 \text{ Emission Factor} = (\text{Total CH}_4 \text{ leaked}) \times (100 - \% \text{ Soil Oxidation}) \quad (\text{Equation 6-2})$$

Equation 6-2 accounts for the portion of leaked CH<sub>4</sub> that is not oxidized to CO<sub>2</sub>.

### (2) CO<sub>2</sub> Emissions from Methane Oxidation:

$$\text{CO}_2 \text{ EF} = \left( \frac{\text{CH}_4 \text{ Emission}}{\text{Factor}} \right) \times \left( \frac{100}{100 - \% \text{ Soil Oxidation}} \right) \times \left( \frac{\% \text{ Soil Oxidation}}{100} \right) \times \left( \frac{\text{MW CO}_2}{\text{MW CH}_4} \right) \quad (\text{Equation 6-3})$$

Equation 6-3 accounts for the CO<sub>2</sub> formed from the oxidation of leaked CH<sub>4</sub> as the gas migrates through the soil. The second term in the equation corrects the CH<sub>4</sub> emission factor to its "pre-oxidized" form. The third term converts the total moles of CH<sub>4</sub> to moles of CO<sub>2</sub> formed as a result of oxidation. The final term corrects for the molecular weights of CO<sub>2</sub> and CH<sub>4</sub>.

### (3) CO<sub>2</sub> Emissions from Gas Leaks:

$$\text{CO}_2 \text{ EF} = \left( \frac{\text{CH}_4 \text{ Emission}}{\text{Factor}} \right) \times \left( \frac{100}{100 - \% \text{ Soil Oxidation}} \right) \times \left( \frac{\text{default mol\% CO}_2}{\text{default mol\% CH}_4} \right) \times \left( \frac{\text{MW CO}_2}{\text{MW CH}_4} \right) \quad (\text{Equation 6-4})$$

Equation 6-4 accounts for CO<sub>2</sub> that is emitted from pipeline fugitive leaks. This equation starts with the CH<sub>4</sub> emission factor, which is converted to its "pre-oxidized" form by the second term. The third term corrects for the molar ratio of CO<sub>2</sub> to CH<sub>4</sub> in the default gas composition, and the final term corrects for the molecular weights of CO<sub>2</sub> and CH<sub>4</sub>.

Oxidation rates and fugitive emission rates for different pipeline materials (cast iron, protected steel, unprotected steel, copper, and plastic) were measured as part of the GRI/EPA US methane emissions study (Campbell, et. al., 1996). The emission factors shown in Tables 6-1, 6-3, 6-5, and 6-6 are based on average emission rates for the types of pipelines in service in each industry sector. Exhibit 6.2 demonstrates the use of these emission factors for a production facility.

### **6.1.3 Time Basis of Fugitive Equipment Leaks**

All of the fugitive approaches presented in this section and in Appendix B result in estimates of the equipment leak rate over a short time period, such as an hour or a day. Those estimates are multiplied by the number of hours (or days) of annual operation to result in the annual emission estimate. The components subject to fugitive equipment leaks will have the potential to leak any time the line is filled with hydrocarbons, even if not under normal pressure or if the component is idle (such as a pump). For this reason, most equipment leaks are calculated as if they emitted continuously for the full year, or 8760 hours per year. If a facility shuts down and empties the lines for maintenance for a portion of the year, that time can be deducted from the annual operating hours.

## **6.2 Other Fugitive Emissions**

In addition to fugitive equipment leaks, there may be one or more of a variety of other non-point emission sources associated with oil and gas industry operations. These other non-point emission sources include wastewater treating, sludge/solids handling, impoundments, pits, and cooling towers.

These other non-point emission sources will generally not be a significant source of CH<sub>4</sub> or CO<sub>2</sub> emissions. Few specific emission factors for CH<sub>4</sub> or CO<sub>2</sub> from these non-point sources have been found. There are several methods that are used for estimating TOC (or VOC) and compound-specific emissions from these types of sources, and these methods can be adapted to estimate CH<sub>4</sub> or CO<sub>2</sub> if site-specific data are available.

AP-42 provides VOC emission factors for refinery cooling towers (EPA, AP-42 Table 5.1-2, 1995). These factors could be adapted to CH<sub>4</sub> or CO<sub>2</sub> emissions if the corresponding concentrations were known. However, this is not considered a significant source of GHG emissions.

The general method for estimating TOC evaporative emissions from wastewater treating, impoundments, and pits is WATER9. WATER9 is a computer program used to estimate evaporative emissions from wastewater collection and treatment operations. Although CH<sub>4</sub> and CO<sub>2</sub> evaporative emissions from petroleum wastewater are expected to be insignificant, facilities with unique situations can find more information on WATER9 at:

<http://www.epa.gov/ttn/chief/software.html>

The EPA also maintains a hotline for WATER9 at (919) 541-5610.

### **6.2.1 Anaerobic Water Treatment**

Anaerobic water treatment processes produce CH<sub>4</sub>, and to a much lesser degree CO<sub>2</sub> and N<sub>2</sub>O, as byproducts of the digestion of larger organic molecules. Anaerobic water treatment is not common in the oil and gas industry, and it is possible to recover the CH<sub>4</sub> generated for use as a fuel. For these reasons, anaerobic water treating is not considered a significant GHG emission source for the oil and gas industry.

For facilities where CH<sub>4</sub> is not captured from an anaerobic water treatment system, US EPA presents a relatively simple method for estimating CH<sub>4</sub> emissions in AP-42 Section 4.3.5.2. The following equation is used:

$$E_{CH_4} = Q \times \left( \frac{\text{lbBOD}_5}{\text{ft}^3 \text{ wastewater}} \right) \times \left( \frac{0.22 \text{ lbCH}_4}{\text{lbBOD}_5} \right) \times F_{AD} \times 365 \quad (\text{Equation 6-5})$$

where,

$E_{CH_4}$	=	Emission rate of CH <sub>4</sub> in pounds per year
$Q$	=	Wastewater flow rate in cubic feet per day
$BOD_5$	=	Biological oxygen demand measured using the standard five day test
$F_{AD}$	=	Fraction anaerobically digested
365	=	Days per year

A site-specific value for BOD<sub>5</sub> loading should be available from facility wastewater treating staff. If it is not, EPA suggests a default value of 0.25 pounds BOD<sub>5</sub> per cubic foot of wastewater for the oil and gas industry. The fraction anaerobically digested is that part of the wastewater flow that is routed to anaerobic treatment as opposed to aerobic treatment.



Alternatively, the Intergovernmental Panel on Climate Change (IPCC) provides an anaerobic wastewater treatment emissions approach based on chemical oxygen demand (COD) if more detailed information is not available (IPCC, 2000). The COD default factor for maximum CH<sub>4</sub> producing capacity is:

$$0.25 \text{ kg CH}_4/\text{kg COD} = 0.25 \text{ tonne CH}_4/\text{tonne COD}$$

For petroleum refineries, IPCC provides a typical COD production rate of 1 gram of COD per liter of wastewater generation, with the COD value ranging between 0.4 and 1.6 g COD/L.

The emission rate for CO<sub>2</sub> is considered to be negligible compared to the CH<sub>4</sub> emission rate. No equation has been found to estimate these emissions.

An example calculation for CH<sub>4</sub> emissions from anaerobic water treatment follows.

#### **EXHIBIT 6.5: Sample Calculation for Anaerobic Treatment Approach**

##### **INPUT DATA:**

A wastewater treatment system processes 870,000 cubic feet per day, with 10% of the water going to anaerobic treatment. The BOD<sub>5</sub> level of the influent averages 0.3 pounds per cubic foot.

##### **CALCULATION METHODOLOGY:**

Using Equation 6-8, the estimated emissions would be:

$$E_{\text{CH}_4} = 870,000 \frac{\text{ft}^3}{\text{day}} \times \left( \frac{0.3 \text{ lb BOD}_5}{\text{ft}^3 \text{ wastewater}} \right) \times \left( \frac{0.22 \text{ lb CH}_4}{\text{lb BOD}_5} \right) \times 0.1 \times 365 \frac{\text{days}}{\text{year}} \times \frac{\text{tonne}}{2205 \text{ lb}}$$

$$= \underline{950.5 \text{ tonne CH}_4/\text{yr}}$$

Using IPCC's approach and assuming the default COD rate, the estimated emissions would be:

$$E_{\text{CH}_4} = 870,000 \frac{\text{ft}^3}{\text{day}} \times \left( \frac{0.1 \text{ ft}^3 \text{ anaerobic}}{\text{ft}^3 \text{ processed}} \right) \times 365 \frac{\text{days}}{\text{year}} \times \frac{28.32 \text{ L}}{\text{ft}^3} \times \frac{1 \text{ g COD}}{\text{L}} \times \frac{0.25 \text{ g CH}_4}{\text{g COD}} \times \frac{\text{tonne CH}_4}{1 \times 10^6 \text{ g}}$$

$$= \underline{224.8 \text{ tonne CH}_4/\text{yr}}$$

### **6.2.2 Biotreaters**

There are applications in the oil and gas industry where biotreaters (or biofilters) are used in wastewater treating and/or as control devices to remove TOC from vent streams. The CO<sub>2</sub> emissions from biotreaters are expected to be insignificant compared to major sources like combustion. The CO<sub>2</sub> production from biotreaters can be estimated from the feed TOC rate and the biomass conversion efficiency. The produced CO<sub>2</sub> is partially emitted to the air and partially converted to carbonates depending on system pH. In the unusual cases where biotreater emissions may be significant, it would be best to develop the emissions estimates based on the site-specific features of the biotreater and its feed streams.

## **6.3 References**

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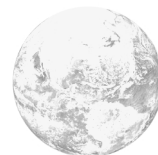
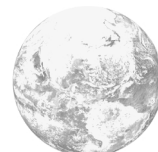
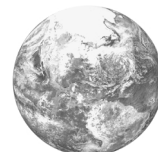
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FEBRUARY 2004

**COMPENDIUM OF GREENHOUSE GAS  
EMISSIONS METHODOLOGIES FOR  
THE OIL AND GAS INDUSTRY**

SECTION 7



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## 7.0

# EMISSION INVENTORY EXAMPLES

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Oil and gas industry facility operations and their associated equipment vary significantly. Their design differs based on performance requirements and site-specific considerations. In general, the resultant greenhouse gas emissions will be determined by:

- Intensity of energy usage;
- Degree of internal capture and reprocessing;
- Installation of end-of-pipe controls; and
- Venting practices.

### 7.1 Exploration and Production

This section provides emission inventory examples for each industry segment to demonstrate the use of emission factors provided in Sections 4, 5 and 6. These examples were not intended to represent some “average” facility or to reflect actual operations. Rather, the examples illustrate emission calculations one might encounter in preparing an emissions inventory, based on hypothetical “data”. For each example, specific, simplifying assumptions about throughput volume, types of equipment utilized, and other design considerations are presented. The examples provide an indication of the significance of a particular source type and relative magnitude of emissions from sources within a given facility. A particular facility may have other emission sources not covered in these examples, or the relative magnitude of its sources might be different due to its design and operating practices. Also, some emission sources indicated in the examples may not be applicable to other facilities.

#### 7.1.1 Onshore Oil Field with High CO<sub>2</sub> Content

**Facility Description:** An onshore oil field in Texas consists of 320 producing oil wells.

**Throughput:** The average daily oil and gas production rates are 6,100 bbl/day and 30×10<sup>6</sup> scf/day, respectively.

**Operations:** The facility operates approximately 343 days per year. The facility gas contains 80 mole % CH<sub>4</sub>, 12 mole % CO<sub>2</sub>, 4.2 mole % C<sub>2</sub>H<sub>6</sub>, 1.3 mole % C<sub>3</sub>H<sub>8</sub>, 0.4 mole % C<sub>4</sub>H<sub>10</sub>, and 2.1 mole % other non-carbon compounds. The facility imports 917 MW-hr from the grid annually.

Tables 7-1 and 7-2 summarize the emission sources associated with this facility. Equipment at the site that have negligible greenhouse gas emissions are also included in Table 7-1.



Table 7-1. Onshore Oil Field (High CO<sub>2</sub> Content) Emissions Sources

Source	No. of Units	Unit Capacity (per unit)	Average Operation (per unit per year)	Annual Activity Factor (all units combined)	CO <sub>2</sub> Emissions (tonnes/yr)	CH <sub>4</sub> Emissions (tonnes/yr)	N <sub>2</sub> O Emissions (tonnes/yr)
<b>Combustion Sources</b>					<b>46,400</b>	<b>155</b>	<b>3.99</b>
Boilers (natural gas)	6			40×10 <sup>6</sup> scf/yr @ 1068 BTU/scf	2,230	0.043	0.012
Heaters/reboilers (natural gas)	3	2×10 <sup>6</sup> Btu/hr	343 days/yr	49,392×10 <sup>6</sup> Btu/yr	2,580	0.049	0.014
Compressor engines – turbines (natural gas fired)	11			250×10 <sup>6</sup> scf/yr @ 1068 BTU/scf	13,900	1.04	3.74
Emergency flare	1			500×10 <sup>6</sup> scf/yr	27,400	153	0.223
Emergency generator IC Engine (diesel fuel)	1	1800 hp (8,089 Btu/hp-hr <sup>a</sup> )	200 hr/yr	2,912 ×10 <sup>6</sup> Btu/yr	216	0.011	0.006
Fire water pump IC engine (diesel fuel)	1	460 hp, 87% load (8,089 Btu/hp-hr <sup>a</sup> )	24 hr/yr	77.7 ×10 <sup>6</sup> Btu/yr	5.76	0.0012	0.0009
<b>Vented Sources</b>					<b>994</b>	<b>2,570</b>	
Dehydration vents (also has Kimray pump emissions)	1	30×10 <sup>6</sup> scf/day gas processed	343	10,290×10 <sup>6</sup> scf/yr gas processed	105	250	
Central tank battery	1 Battery	N/A	Continuous	2,092,300 bbl/yr (6,100 bbl/day, 343 days/yr)	775	1,850	
Chemical storage tank	1	N/A	Continuous	Negligible greenhouse gas (GHG) emissions	0	0	
Naphtha storage tank	1	N/A	Continuous	Negligible GHG emissions	0	0	

**Note, the values shown above are for example only. They do not reflect actual operations.**

Totals may not sum due to independent rounding.

Table 7-1. Onshore Oil Field (High CO<sub>2</sub> Content) Emissions Sources (continued)

Source	No. of Units	Unit Capacity (per unit)	Average Operation (per unit per year)	Activity Factor (all units combined)	CO <sub>2</sub> Emissions (tonnes/yr)	CH <sub>4</sub> Emissions (tonnes/yr)	N <sub>2</sub> O Emissions (tonnes/yr)
<b><i>Vented Sources, continued</i></b>							
Glycol storage tank	1	N/A	Continuous	Negligible GHG emissions	0	0	
Water blowdown tank	1	N/A	Continuous	Negligible GHG emissions	0	0	
Slop oil tank	1	N/A	Continuous	Negligible GHG emissions	0	0	
Amine unit for CO <sub>2</sub> removal	1	30×10 <sup>6</sup> scf/day gas processed	343	10,290×10 <sup>6</sup> scf/yr gas processed		190	
Pneumatic devices	64	N/A	N/A	64 pneumatic devices	64.6	155	
Chemical injection pumps (CIPs)	67	N/A	N/A	67 CIPs	48.6	116	
Vessels	112	N/A	N/A	112 vessels	0.070	0.168	
Compressor starts (non-routine)	11	N/A	N/A	11 compressors	0.745	1.78	
Compressor blowdowns (non-routine)	11	N/A	N/A	11 compressors	0.333	0.796	
Well workovers (non-routine)	24	N/A	N/A	24 well workovers	0.018	0.043	
Pressure relief valves	482	N/A	N/A	482 PRVs	0.131	0.313	
<b><i>Fugitive Sources</i></b>					<b>30.9</b>	<b>75.1</b>	
Fugitives	N/A	N/A	8,760	See Table 5-2	30.9	75.1	
<b><i>Indirect Sources</i></b>					<b>609</b>	<b>0.003</b>	<b>0.006</b>
Electricity consumed				917 MW-hr/yr	609	0.003	0.006

**Note, the values shown above are for example only. They do not reflect actual operations.**

Totals may not sum due to independent rounding.

<sup>a</sup> Engine Btu/hp-hr is presented in Table 3-6 (The turbine Btu/hp-hr factor is based on a natural gas prime-mover unit.)

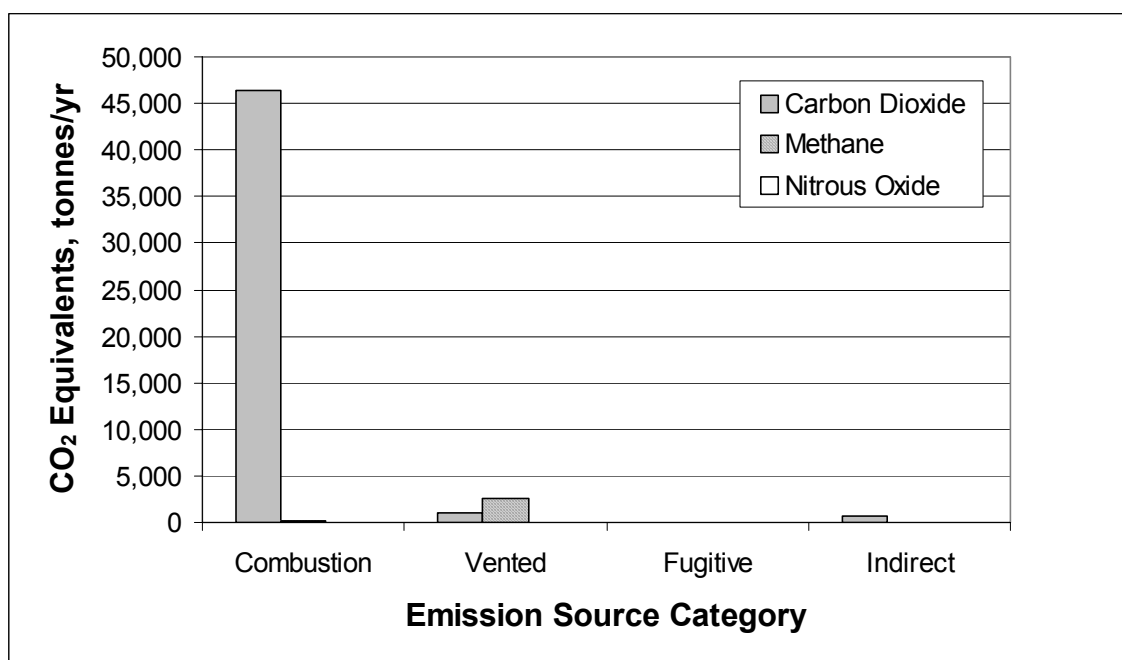
**Table 7-2. Onshore Oil Field (high CO<sub>2</sub> content) Fugitive Emission Sources**

Component	Service	Average Component Count
Valves	Gas	2,100
Valves	Light oil	640
Pump seals	Gas	140
Pump seals	Light oil	45
Connectors	Gas	110
Flanges	Gas	7,700
Flanges	Light oil	2,300
Open-ended lines	Gas	6
Others	Gas	550
Others	Light oil	160

**Note, the values shown above are for example only. They do not reflect actual operations.**

Because the oil field gas contains a relatively high CO<sub>2</sub> content (12 mole %), CO<sub>2</sub> vented emissions are considered. Also, vented emission factors are not corrected from their default CH<sub>4</sub> content of 78.8 mole % to the field gas CH<sub>4</sub> content of 80 mole %. This correction should be carried out if the CH<sub>4</sub> content differs significantly from the default basis (examples are provided in Section 5).

A summary of the emissions (expressed in CO<sub>2</sub> equivalents) for this facility is given in Figure 7-1.

**Figure 7-1. Onshore Oil Field (High CO<sub>2</sub> Content) Summary of Emissions**

## Stationary Combustion Devices – CO<sub>2</sub> Emissions

CO<sub>2</sub> emissions from combustion are calculated using the gas composition approach provided in Section 4.1, as shown:

### EXHIBIT 7.1: On-shore Oil Field (high CO<sub>2</sub> content) – Natural Gas CO<sub>2</sub> Combustion Emissions

Boilers, heater/reboilers, and compressor engines-turbines use natural gas at this facility.

External combustion gas usage :

$$\begin{aligned}
 &= \frac{40 \times 10^6 \text{ scf}}{\text{yr}} + \left( \frac{49,392 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{\text{scf}}{1068 \text{ Btu}} \right) \\
 &= (40 + 46.3) \times 10^6 \text{ scf/yr} \\
 &= 86.3 \times 10^6 \text{ scf/yr}
 \end{aligned}$$

Internal combustion gas usage

$$= 250 \times 10^6 \text{ scf/yr}$$

Fuel composition and carbon content:

	<u>Mole %</u>	<u>MW</u>	<u>Wt% (Calculated)</u>	<u>Carbon Content</u> <u>(wt%C)</u>
CO <sub>2</sub>	12.0	44.01	25.43	27.3
N <sub>2</sub>	2.1	28.01	2.83	0
CH <sub>4</sub>	80.0	16.04	61.78	74.9
C <sub>2</sub> H <sub>6</sub>	4.2	30.07	6.08	79.9
C <sub>3</sub> H <sub>8</sub>	1.3	44.10	2.76	81.7
C <sub>4</sub> H <sub>10</sub>	0.4	58.12	1.12	82.7
<b>Fuel Mixture</b>	<b>100</b>	<b>20.77</b>	<b>100.0</b>	<b>61.24</b>

**EXHIBIT 7.1: On-shore Oil Field (high CO<sub>2</sub> content) – Natural Gas CO<sub>2</sub> Combustion Emissions, continued**

Exhibit 3.4 gives an example of the conversion from weight percent to mole percent. Conversion from weight percent to mole percent is carried out in a similar manner by rearranging Equation 3-7 and using Equation 3-9. Carbon content calculation for an individual component is shown below for ethane (C<sub>2</sub>H<sub>6</sub>).

$$\frac{12.01 \text{ lb C}}{\text{lbmole C}} \times \frac{2 \text{ lbmoles C}}{\text{lbmole C}_2\text{H}_6} \times \frac{\text{lbmole C}_2\text{H}_6}{30.07 \text{ lb C}_2\text{H}_6} = \frac{0.799 \text{ lb C/lb C}_2\text{H}_6}{\times 100\% = \underline{79.9\% \text{ C}}}$$

Carbon content for mixture:

$$\begin{aligned} \text{Wt\%C}_{\text{Mixture}} &= \frac{1}{100} \times \sum_{i=1}^{\text{\# components}} (\text{Wt\%}_i \times \text{Wt\%C}_i) \\ &= \frac{1}{100} \times \left[ (25.43 \times 27.29) + (2.83 \times 0) + (61.78 \times 74.88) + (6.08 \times 79.89) + (2.76 \times 81.71) \right] \\ &= \underline{61.24 \text{ Wt\% C}} = 0.6124 \text{ lb C/lb fuel} \end{aligned}$$

External combustion – natural gas:

$$\begin{aligned} \text{CO}_2 : & \frac{86.3 \times 10^6 \text{ scf fuel}}{\text{yr}} \times \frac{\text{lbmole}}{379.3 \text{ scf fuel}} \times \frac{20.77 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.6124 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}} \\ & \times \frac{\text{lbmole CO}_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = \underline{4,810 \text{ tonnes CO}_2 / \text{yr}} \end{aligned}$$

Internal combustion – natural gas:

$$\begin{aligned} \text{CO}_2 : & \frac{250 \times 10^6 \text{ scf fuel}}{\text{yr}} \times \frac{\text{lbmole}}{379.3 \text{ scf fuel}} \times \frac{20.77 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.6124 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}} \\ & \times \frac{\text{lbmole CO}_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = \underline{13,900 \text{ tonnes CO}_2 / \text{yr}} \end{aligned}$$

CO<sub>2</sub> emissions from diesel combustion are calculated using the diesel emission factor provided in Table 4-1, as shown in the following exhibit.

**EXHIBIT 7.2: On-shore Oil Field (high CO<sub>2</sub> content) – Diesel CO<sub>2</sub> Combustion Emissions**

Diesel firing rate =  $(2,912 + 77.7) \times 10^6 \text{ Btu/yr} = 2989.7 \times 10^6 \text{ Btu/yr}$

$$\text{CO}_2 : \frac{2,989.7 \times 10^6 \text{ Btu}}{\text{year}} \times \frac{0.0742 \text{ tonnes CO}_2}{10^6 \text{ Btu}} = 222 \text{ tonnes CO}_2 / \text{yr}$$

**Stationary Combustion Devices – CH<sub>4</sub> and N<sub>2</sub>O Emissions**

Combustion emission factors for natural gas fired equipment are provided in Table 4-4a for controlled boilers and heaters, and Table 4-5 for controlled turbines.

The diesel operated emergency generator engine (1800 hp unit) emissions are estimated using the "Large Bore Engine - Diesel" emission factors (for engines rated greater than 600 hp) from Table 4-5. The diesel operated fire water pump engine (460 hp unit) emissions are estimated using the "IC Engine - Diesel" emission factors from Table 4-5 for diesel engines rated less than 600 hp. Table 4-5 also provides an assumed CH<sub>4</sub> content of 10 wt% to convert from TOC emissions if the exhaust composition is unknown.

**EXHIBIT 7.3: On-shore Oil Field (High CO<sub>2</sub> Content) – CH<sub>4</sub> and N<sub>2</sub>O Combustion Emissions**

Boilers and Heaters:

$$\begin{aligned} \text{Natural gas firing rate} &= \left( \frac{40 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1068 \text{ Btu}}{\text{scf}} \right) + \frac{49,392 \times 10^6 \text{ Btu}}{\text{yr}} \\ &= (42,720 + 49,392) \times 10^6 \text{ Btu/yr} \\ &= 92,112 \times 10^6 \text{ Btu/yr} \end{aligned}$$

$$\text{CH}_4 : \frac{92,112 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{1.0 \times 10^{-6} \text{ tonne CH}_4}{10^6 \text{ Btu}} = 0.092 \text{ tonnes CH}_4 / \text{yr}$$

$$\text{N}_2\text{O} : \frac{92,112 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{2.8 \times 10^{-7} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}} = 0.026 \text{ tonnes N}_2\text{O} / \text{yr}$$

**EXHIBIT 7.3: On-shore Oil Field (High CO<sub>2</sub> Content) – CH<sub>4</sub> and N<sub>2</sub>O Combustion Emissions, continued**

Turbines:

$$\text{Natural gas firing rate} = \left( \frac{250 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1068 \text{ Btu}}{\text{scf}} \right) = 267,000 \times 10^6 \text{ Btu/yr}$$

$$\text{CH}_4 : \frac{267,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{3.9 \times 10^{-6} \text{ tonne CH}_4}{10^6 \text{ Btu}} = \underline{1.04 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{267,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{1.4 \times 10^{-5} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}} = \underline{3.74 \text{ tonnes N}_2\text{O/yr}}$$

Diesel engine >600 hp (emergency generator):

$$\text{CH}_4 : \frac{2912 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{3.7 \times 10^{-6} \text{ tonne CH}_4}{10^6 \text{ Btu}} = \underline{0.011 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{2912 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{2.2 \times 10^{-6} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}} = \underline{0.006 \text{ tonnes N}_2\text{O/yr}}$$

Diesel engine <600 hp (fire water pump):

From Table 3-5, we obtain the higher heating value for diesel on a volumetric basis.

$$\text{CH}_4 : \frac{77.7 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.00016 \text{ tonne TOC}}{10^6 \text{ Btu}} \times \frac{0.1 \text{ tonne CH}_4}{\text{tonne TOC}} = \underline{0.0012 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{77.7 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{\text{bbl}}{5.75 \times 10^6 \text{ Btu}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{1.51 \times 10^{-6} \text{ tonne N}_2\text{O}}{\text{gal}} = \underline{0.0009 \text{ tonnes N}_2\text{O/yr}}$$

**Combustion Sources – Flares**

Flaring emissions are calculated based on the guidance given in Section 4.4. Based on this guidance, CH<sub>4</sub> emissions are calculated assuming 2% of the CH<sub>4</sub> remains uncombusted, and CO<sub>2</sub>



emissions are based on 98% combustion efficiency. Nitrous oxide emissions are estimated using an emission factor from Table 4-7. Because the flared gas contains a large amount of CO<sub>2</sub>, the CO<sub>2</sub> emissions are estimated as the sum of the CO<sub>2</sub> already present in the gas and the CO<sub>2</sub> that results from the product of flared gas carbon combustion.

#### EXHIBIT 7.4: Onshore Oil Field (High CO<sub>2</sub> Content) Flare Emissions

Assume the flare gas composition is equal to the field gas composition.

$$\text{CH}_4 : \frac{500 \times 10^6 \text{ scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{0.80 \text{ lbmole CH}_4}{\text{lbmole gas}} \times \frac{16.04 \text{ lb CH}_4}{\text{lbmole CH}_4} \\ \times \frac{0.02 \text{ lb noncombusted CH}_4}{\text{lb CH}_4} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = \underline{153 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{6,100 \text{ bbl}}{\text{day}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{1.0 \times 10^{-4} \text{ tonnes N}_2\text{O}}{1,000 \text{ bbl}} = 0.223 \text{ tonnes N}_2\text{O}/\text{yr}$$

$$\text{CO}_2 \text{ in gas} : \frac{500 \times 10^6 \text{ scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{0.12 \text{ lbmole CO}_2}{\text{lbmole gas}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} \\ = \underline{3,160 \text{ tonnes CO}_2/\text{yr}}$$

$$\text{CO}_2 \text{ formed} : \frac{500 \times 10^6 \text{ scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \\ \times \left( \frac{0.80 \text{ lbmol CH}_4}{\text{lbmol gas}} \times \frac{1 \text{ lbmol C}}{\text{lbmol CH}_4} + \frac{0.042 \text{ lbmol C}_2\text{H}_6}{\text{lbmol gas}} \times \frac{2 \text{ lbmol C}}{\text{lbmol C}_2\text{H}_6} \right. \\ \left. + \frac{0.013 \text{ lbmol C}_3\text{H}_8}{\text{lbmol gas}} \times \frac{3 \text{ lbmol C}}{\text{lbmol C}_3\text{H}_8} + \frac{0.004 \text{ lbmol C}_4\text{H}_{10}}{\text{lbmol gas}} \times \frac{4 \text{ lbmol C}}{\text{lbmol C}_4\text{H}_{10}} \right) \\ \times \frac{0.98 \text{ lbmole CO}_2 \text{ formed}}{\text{lbmole C combusted}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} \\ = \underline{24,200 \text{ tonnes CO}_2/\text{yr}}$$

$$\text{CO}_2 \text{ flare emissions} = (\text{CO}_2 \text{ in gas}) + (\text{CO}_2 \text{ formed})$$

$$\text{CO}_2 \text{ flare emissions} = (3,160 \text{ tonnes/yr}) + (24,200 \text{ tonnes/yr}) = \underline{27,400 \text{ tonnes CO}_2/\text{yr}}$$

## Vented Sources - Gas Dehydration

The glycol dehydrator vents are vented to the atmosphere. Methane emissions from the gas dehydrator vents are estimated using the production segment emission factor given in Table 5-1. The Kimray pump emissions are estimated using the production segment emission factor in Table 5-3. For both of these sources, emissions are based on the quantity of gas processed --  $30 \times 10^6$  scf/day, or  $10,290 \times 10^6$  scf/yr (based on 343 days of annual operation). Carbon dioxide emissions are estimated using the facility  $\text{CO}_2$  and default  $\text{CH}_4$  concentrations in the gas, which are 12 mol% and 78.8 mole%, respectively. The facility  $\text{CH}_4$  content of the separator gas is 80 mole %. The difference between the facility  $\text{CH}_4$  content and default content is insignificant, and thus the  $\text{CH}_4$  emissions are not adjusted based on the  $\text{CH}_4$  content. Emission calculations for these sources are provided in Exhibit 7.6.

### EXHIBIT 7.6: Onshore Oil Field (high $\text{CO}_2$ content) Dehydration Processing Vent Emissions

Dehydrator Vents:

$$\begin{aligned}\text{CH}_4 : & (10,290 \times 10^6 \text{ scf/yr processed}) \times \frac{0.0052869 \text{ tonne CH}_4}{10^6 \text{ scf}} = \underline{54.4 \text{ tonnes CH}_4/\text{yr}} \\ \text{CO}_2 : & (10,290 \times 10^6 \text{ scf/yr processed}) \times \frac{0.0052869 \text{ tonne CH}_4}{10^6 \text{ scf}} \times \frac{\text{tonne mole CH}_4}{16.04 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \\ & \times \frac{0.12 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{22.7 \text{ tonnes CO}_2/\text{yr}}\end{aligned}$$

Kimray Pumps:

$$\begin{aligned}\text{CH}_4 : & (10,290 \times 10^6 \text{ scf/yr processed}) \times \frac{0.01903 \text{ tonne CH}_4}{10^6 \text{ scf}} = \underline{195.8 \text{ tonnes CH}_4/\text{yr}} \\ \text{CO}_2 : & (10,290 \times 10^6 \text{ scf/yr processed}) \times \frac{0.01903 \text{ tonne CH}_4}{10^6 \text{ scf}} \times \frac{\text{tonne mole CH}_4}{16.04 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \\ & \times \frac{0.12 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{81.8 \text{ tonnes CO}_2/\text{yr}}\end{aligned}$$

Total emissions from dehydration are:

$$\text{CH}_4 : (54.4 \text{ tonnes CH}_4/\text{yr}) + (195.8 \text{ tonnes CH}_4/\text{yr}) = \underline{250 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{CO}_2 : (22.7 \text{ tonnes CO}_2/\text{yr}) + (81.8 \text{ tonnes CO}_2/\text{yr}) = \underline{105 \text{ tonnes CO}_2/\text{yr}}$$

## Vented Sources - Storage Tanks

Methane emissions from flashing losses are estimated using the simple emission factor provided in Table 5-6, which was derived from combined API/GRI and CPA data. (Note that this simple emission factor approach is used in absence of the more detailed information necessary for the other calculation approaches provided in Section 5.4.1.) Methane emissions from tank standing and working losses are negligible. The tank vents are uncontrolled.

The CH<sub>4</sub> content of the separator gas is 80 mole %. The flashing loss emission factor is based on a default CH<sub>4</sub> separator concentration of 78.8 mole %. The difference between the facility CH<sub>4</sub> content and default content is insignificant, and thus the CH<sub>4</sub> emissions are not adjusted based on the CH<sub>4</sub> content. The CO<sub>2</sub> content in the gas is 12 mole %. Emission calculations are provided in the Exhibit 7.7.

### **EXHIBIT 7.7: Onshore Oil Field (high CO<sub>2</sub> content) Crude Storage Tank Flashing Loss Emissions**

$$\begin{aligned}\text{CH}_4 &: \frac{2,092,300 \text{ bbl}}{\text{yr}} \times \frac{8.86 \times 10^{-4} \text{ tonne CH}_4}{\text{bbl}} = \underline{1,850 \text{ tonnes CH}_4 / \text{yr}} \\ \text{CO}_2 &: \frac{2,092,300 \text{ bbl}}{\text{yr}} \times \frac{8.86 \times 10^{-4} \text{ tonne CH}_4}{\text{bbl}} \times \frac{\text{tonne mole CH}_4}{16.04 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \\ &\quad \times \frac{0.12 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{775 \text{ tonnes CO}_2 / \text{yr}}\end{aligned}$$

## Vented Sources - Acid Gas Removal (Amine Unit Emissions)

Methane emissions from the amine unit are estimated based on the emission factor provided in Table 5-4. This calculation is provided in Exhibit 7.8.

### **EXHIBIT 7.8: Onshore Oil Field (High CO<sub>2</sub> Content) – Acid Gas Removal**

$$\text{CH}_4 : (10,290 \times 10^6 \text{ scf/yr processed}) \times \frac{0.0185 \text{ tonne CH}_4}{10^6 \text{ scf}} = \underline{190 \text{ tonnes CH}_4 / \text{yr}}$$

## Vented Sources - Pneumatics and Chemical Injection Pumps

The pneumatic devices and chemical injection pumps (CIPs) at the facility are actuated by natural gas. Methane emissions from pneumatic device and CIP vents are estimated using CH<sub>4</sub> emission factors presented in Tables 5-15 and 5-16, respectively. The type of pneumatic device and CIP are

not specified, so the "Production Average" device and the "Average Pump" emission factor are used. Carbon dioxide emissions from pneumatic devices and chemical injection pumps are estimated using the known CO<sub>2</sub> and default CH<sub>4</sub> concentrations in the gas (same method as for the tank emissions). These emissions are shown in Exhibit 7.9.

**EXHIBIT 7.9: Onshore Oil Field (high CO<sub>2</sub> content) Pneumatic Device and Chemical Injection Pump Vent Emissions**

Pneumatic Devices:

$$\text{CH}_4 : (64 \text{ pneumatic devices}) \times \frac{2.415 \text{ tonne CH}_4}{\text{device - yr}} = \underline{155 \text{ tonnes CH}_4/\text{yr}}$$

$$\begin{aligned} \text{CO}_2 : (64 \text{ pneumatic devices}) &\times \frac{2.415 \text{ tonne CH}_4}{\text{device - yr}} \times \frac{\text{tonne mole CH}_4}{16.04 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \\ &\times \frac{0.12 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{64.6 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

Chemical Injection Pumps (CIPs):

$$\text{CH}_4 : (67 \text{ CIPs}) \times \frac{1.736 \text{ tonne CH}_4}{\text{CIP - yr}} = \underline{116 \text{ tonnes CH}_4/\text{yr}}$$

$$\begin{aligned} \text{CO}_2 : (67 \text{ CIPs}) &\times \frac{1.736 \text{ tonne CH}_4}{\text{CIP - yr}} \times \frac{\text{tonne mole CH}_4}{16.04 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \\ &\times \frac{0.12 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{48.6 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

**Vented Sources - Maintenance/Turnaround Emissions**

Methane emissions from vessel blowdowns, compressor starts, compressor blowdowns, and oil well workovers are estimated using the emission factors presented in Table 5-21. Carbon dioxide emissions are estimated using the known CO<sub>2</sub> and CH<sub>4</sub> concentrations in the gas. The maintenance emission calculations are shown in Exhibit 7.10.

**Vented Sources – Pressure Relief Valves**

Methane emissions from pressure relief valves (PRV) are estimated using an emission factor from Table 5-22. The CO<sub>2</sub> emissions are estimated using the ratio of the facility gas CO<sub>2</sub> to the default CH<sub>4</sub> content as shown in Exhibit 7.10.

**EXHIBIT 7.10: Onshore Oil Field (high CO<sub>2</sub> content) Maintenance/Turnaround Emissions**

Vessel blowdowns:

$$\text{CH}_4 : (112 \text{ vessels}) \times \frac{0.0015 \text{ tonne CH}_4}{\text{vessel - yr}} = \underline{0.168 \text{ tonnes CH}_4/\text{yr}}$$

$$\begin{aligned} \text{CO}_2 : (112 \text{ vessels}) \times \frac{0.0015 \text{ tonne CH}_4}{\text{vessel - yr}} \times \frac{\text{tonne mole CH}_4}{16.04 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \\ \times \frac{0.12 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{0.070 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

Compressor starts:

$$\text{CH}_4 : (11 \text{ compressors}) \times \frac{0.1620 \text{ tonne CH}_4}{\text{compressor - yr}} = \underline{1.78 \text{ tonnes CH}_4/\text{yr}}$$

$$\begin{aligned} \text{CO}_2 : (11 \text{ compressors}) \times \frac{0.1620 \text{ tonne CH}_4}{\text{compressor - yr}} \times \frac{\text{tonne mole CH}_4}{16.04 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \\ \times \frac{0.12 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{0.745 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

Compressor blowdowns:

$$\text{CH}_4 : (11 \text{ compressors}) \times \frac{0.07239 \text{ tonne CH}_4}{\text{compressor - yr}} = \underline{0.796 \text{ tonnes CH}_4/\text{yr}}$$

$$\begin{aligned} \text{CO}_2 : (11 \text{ compressors}) \times \frac{0.07239 \text{ tonne CH}_4}{\text{compressor - yr}} \times \frac{\text{tonne mole CH}_4}{16.04 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \\ \times \frac{0.12 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{0.333 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

Oil well workovers:

$$\text{CH}_4 : \frac{24 \text{ well workovers}}{\text{yr}} \times \frac{0.0018 \text{ tonne CH}_4}{\text{workovers}} = \underline{0.043 \text{ tonnes CH}_4/\text{yr}}$$

$$\begin{aligned} \text{CO}_2 : \frac{24 \text{ well workovers}}{\text{yr}} \times \frac{0.0018 \text{ tonne CH}_4}{\text{workovers}} \times \frac{\text{tonne mole CH}_4}{16.04 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \\ \times \frac{0.12 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{0.018 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

**EXHIBIT 7.10: Onshore Oil Field (high CO<sub>2</sub> content) Maintenance/Turnaround Emissions, continued**

$$\text{CH}_4 : (482 \text{ PRVs}) \times \frac{0.00065 \text{ tonne CH}_4}{\text{PRV} \cdot \text{yr}} = \underline{0.313 \text{ tonnes CH}_4/\text{yr}}$$

$$\begin{aligned} \text{CO}_2 : (482 \text{ PRVs}) \times \frac{0.00065 \text{ tonne CH}_4}{\text{PRV} \cdot \text{yr}} \times \frac{\text{tonne mole CH}_4}{16.04 \text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.788 \text{ tonne mole CH}_4} \\ \times \frac{0.12 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne CO}_2}{\text{tonne mole CO}_2} = \underline{0.131 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

**Fugitive Sources - Equipment Leaks**

Table 7-3 provides fugitive component counts associated with the high CO<sub>2</sub> content onshore oil field facility. The corresponding average component emission factors are also provided based on the EPA average oil and gas production emission factors given in Table B-14.

**Table 7-3. Onshore Oil Field (High CO<sub>2</sub> Content) Fugitive Emission Factors**

<b>Component</b>	<b>Service</b>	<b>Average Component Count</b>	<b>Component EF, tonnes TOC/comp./hr<sup>a</sup></b>
Valves	Gas	2100	2.63E-06
Valves	Light Oil	640	1.32E-06
Pump Seals	Gas	140	1.95E-07
Pump Seals	Light Oil	45	3.18E-07
Connectors	Gas	110	3.21E-07
Flanges	Gas	7700	1.18E-07
Flanges	Light Oil	2300	7.69E-08
OELs	Gas	6	6.86E-07
Others	Gas	550	9.19E-06
Others	Light Oil	160	7.50E-06

<sup>a</sup> Note that for this example, the TOC weight fraction of the gas stream is not 100%. However, the TOC emissions are not adjusted here, since such an adjustment cancels out when calculating CH<sub>4</sub> emissions as shown in Equation B-9.

Using Equation B-9, methane and carbon dioxide emissions are calculated for each component by multiplying the component emission factor by the component count, the annual hours of operation (8760 hours/year, assuming the equipment remains pressurized year-round), and the weight fraction of either methane or carbon dioxide. The fugitive gas service CH<sub>4</sub> and CO<sub>2</sub> weight

fractions are obtained from Exhibit 7.1. The results for these calculations are shown in Exhibit 7.11. The gas service compositions are conservatively used for the liquid fugitive emissions because the liquid composition is not known. The total fugitive emissions are then the sum of each of the component emissions.

### EXHIBIT 7.11 Onshore Oil Field (High CO<sub>2</sub> Content) Fugitive Emissions

CH<sub>4</sub> wt. % = 61.78 wt. % CH<sub>4</sub>

CO<sub>2</sub> wt. % = 25.43 wt. % CO<sub>2</sub>

Example calculation: Light oil pump seals

$$\text{CH}_4 : (45 \text{ seals}) \times \frac{3.18 \times 10^{-7} \text{ tonne TOC}}{\text{seal} - \text{hr}} \times \frac{8,760 \text{ hr}}{\text{yr}} \times \frac{0.6178 \text{ tonne CH}_4}{\text{tonne TOC}}$$

$$= \underline{0.07 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{CO}_2 : (42 \text{ seals}) \times \frac{3.18 \times 10^{-7} \text{ tonne TOC}}{\text{seal} - \text{hr}} \times \frac{8,760 \text{ hr}}{\text{yr}} \times \frac{0.2543 \text{ tonne CO}_2}{\text{tonne TOC}}$$

$$= \underline{0.032 \text{ tonnes CO}_2/\text{yr}}$$

Component	Service	Average Component Count	Component EF, tonnes TOC/comp. /hr	CH <sub>4</sub> Emissions (tonnes/yr)	CO <sub>2</sub> Emissions (tonnes/yr)
Valves	Gas	2100	2.63E-06	29.9	12.3
Valves	Light oil	640	1.32E-06	4.57	1.88
Pump seals	Gas	140	1.95E-07	0.148	0.061
Pump seals	Light oil	45	3.18E-07	0.077	0.032
Connectors	Gas	110	3.21E-07	0.191	0.079
Flanges	Gas	7700	1.18E-07	4.92	2.02
Flanges	Light oil	2300	7.69E-08	0.957	0.394
OELs	Gas	6	6.86E-07	0.022	0.009
Others	Gas	550	9.19E-06	27.4	11.3
Others	Light oil	160	7.50E-06	6.49	2.67
<b>Total</b>				<b>74.6</b>	<b>30.7</b>

## Indirect Sources - Electricity Consumption

Emissions associated with the electricity purchased by the facility are calculated using emission factors in Table B-4 for Texas. This calculation is demonstrated in the following exhibit.

### **EXHIBIT 7.5: Onshore Oil Field (High CO<sub>2</sub> Content) Electricity Consumption Emissions**

$$\text{CO}_2 : \frac{917 \text{ MW} \cdot \text{hr}}{\text{yr}} \times \frac{0.664 \text{ tonne CO}_2}{\text{MW} \cdot \text{hr}} = \underline{609 \text{ tonnes CO}_2/\text{yr}}$$

$$\text{CH}_4 : \frac{917 \text{ MW} \cdot \text{hr}}{\text{yr}} \times \frac{3.492 \times 10^{-6} \text{ tonne CH}_4}{\text{MW} \cdot \text{hr}} = \underline{0.0032 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{917 \text{ MW} \cdot \text{hr}}{\text{yr}} \times \frac{6.621 \times 10^{-6} \text{ tonne N}_2\text{O}}{\text{MW} \cdot \text{hr}} = \underline{0.0061 \text{ tonnes N}_2\text{O}/\text{yr}}$$

## Facility Summary

Total emissions for this facility are summarized in Table 7-4.



**Table 7-4. Onshore Oil Field (High CO<sub>2</sub> Content) Emissions**

Source Type	Source	Emissions (tonnes/yr)		
		CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Combustion Sources	External combustion	4,800	0.09	0.03
	Internal combustion	14,200	1.05	3.75
	Flares	27,400	153	0.22
	<b>Combustion Total</b>	<b>46,300</b>	<b>155</b>	<b>3.99</b>
Vented sources	Dehydration and Kimray pump vents	105	250	
	Tanks - Flashing losses	775	1,850	
	Amine unit	0	190	
	Pneumatic devices	64.6	155	
	Chemical injection pumps	48.6	116	
	Maintenance / turnaround	1.20	3.03	
	Other non-routine (PRVs)	0.10	0.31	
	<b>Vented Total</b>	<b>994</b>	<b>2,570</b>	
Fugitive Sources	Fugitive components	30.7	74.6	
	<b>Fugitive Total</b>	<b>30.7</b>	<b>74.6</b>	
Indirect Sources	Electricity consumed	609	0	0.01
	<b>Indirect Total</b>	<b>609</b>	<b>0</b>	<b>0.01</b>
<b>TOTAL</b>		<b>48,000</b>	<b>2,790</b>	<b>4.0</b>
<b>Total CO<sub>2</sub> Equivalents</b>		<b>108,000</b>		

Totals may not sum due to independent rounding.

### 7.1.2 Offshore Oil and Gas Production Platform

**Facility Description:** An offshore platform has an average daily production of 1,500 bbl/day crude oil and an average gas production rate of  $16 \times 10^6$  scf/day.

**Operations:** The facility operates continuously throughout the year. The produced gas composition is provided in Table 7-5.

The facility field gas CH<sub>4</sub> content differs from that of the average composition for production facilities. Thus, the venting emission factors need to be corrected from the default CH<sub>4</sub> content. The CO<sub>2</sub> content of the field gas is assumed to be insignificant; therefore, CO<sub>2</sub> vented and fugitive emissions are negligible.

**Table 7-5. Gas Composition for Offshore Production Platform**

Gas Compound	Produced Gas Mole %
Carbon Dioxide	1.09
Nitrogen	2.39
Methane	90.95
Ethane	4
Propane	1.14
i-Butane	0.14
n-Butane	0.16
i-Pentane	0.02
n-Pentane	0.02
n-Hexane	0
Other Hexanes	0.02
C7+	0.07

**Note, the values shown above are for example only. They do not reflect actual operations.**

Table 7-6 provides the fugitive component count for equipment at the offshore facility. The split between oil and gas service for these components is approximately 85% with oil service and the remaining 15% are associated with gas service.

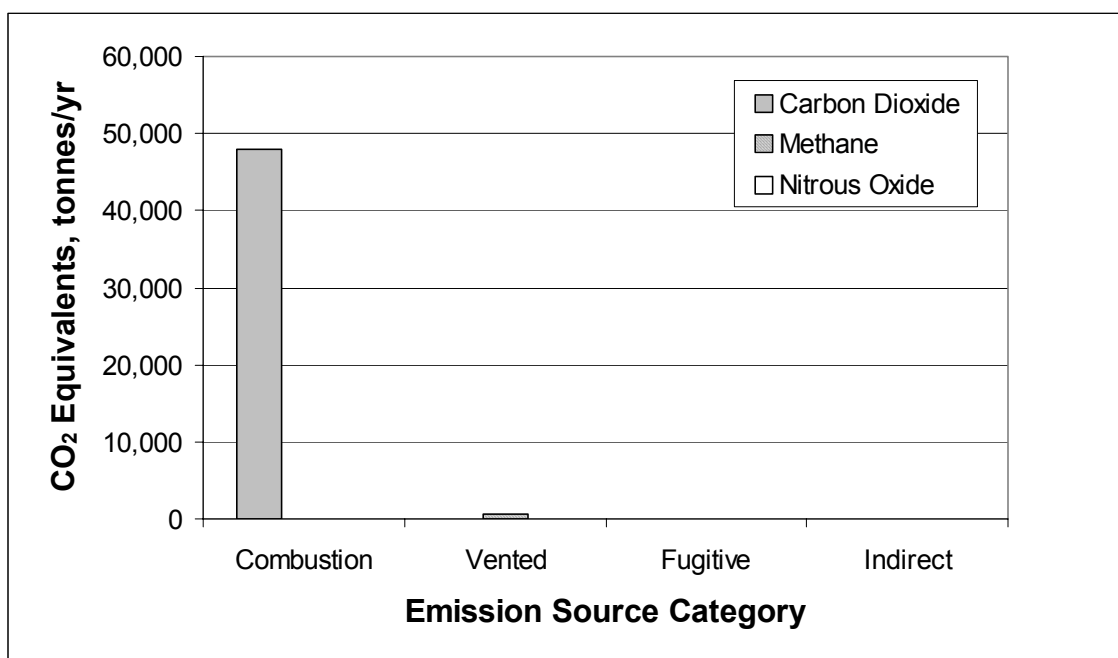
**Table 7-6. Offshore Oil and Gas Production Platform Fugitive Emission Sources**

Component	Service	Average Component Count
Valves	Oil and gas	2,200
Connectors	Oil and gas	8,800
Open-ended lines	Oil and gas	325
Others	Oil and gas	70

**Note, the values shown above are for example only. They do not reflect actual operations.**

Table 7-7 summarizes the emission sources associated with this facility. Equipment at the site that have negligible greenhouse gas emissions are also included in this table.

A summary of the emissions (expressed in CO<sub>2</sub> equivalents) for this offshore facility is given in Figure 7-2.



**Figure 7-2. Offshore Oil and Gas Production Platform  
Summary of Emissions**

**Table 7-7. Offshore Oil and Gas Production Platform Emissions Sources**

Source	No. of Units	Unit Capacity (per unit)	Average Operation (per unit/yr)	Activity Factor (all units combined)	CO <sub>2</sub> Emissions (tonnes/yr)	CH <sub>4</sub> Emissions (tonnes/yr)	N <sub>2</sub> O Emissions (tonnes/yr)
<i>Combustion Sources</i>					47,900	13.8	5.96
Fuel usage – Natural gas boilers/heaters				14,126×10 <sup>3</sup> scf/yr @1065 BTU/scf	784	0.015	0.004
Fuel usage – Natural gas turbines (electricity generation)				470×10 <sup>6</sup> scf/yr @1065 BTU/scf	26,100	2.61	3.920
Fuel usage – Natural gas turbines (compression)				200×10 <sup>6</sup> scf/yr @1065 BTU/scf	11,100	0.83	0.290
Fuel usage – Diesel IC Engines				160,000 gal/yr @ 5.75×10 <sup>6</sup> BTU/bbl	1,630	0.35	0.242
Crane engine (diesel fired)	1	210 hp (7100 Btu/hp-hr <sup>a</sup> )	2,920 hr/yr	4,354×10 <sup>6</sup> Btu/yr	323	0.070	0.048
Crane engine (diesel fired)	1	200 hp (7100 Btu/hp-hr <sup>a</sup> )	2,920 hr/yr	4,146×10 <sup>6</sup> Btu/yr	308	0.066	0.046
Fire water pump IC engine (diesel fuel)	1	280 hp (7000 Btu/hp-hr <sup>a</sup> )	200 hr/yr	392×10 <sup>6</sup> Btu/yr	29	0.006	0.004
Emergency generator, drilling (diesel fired)	2	1000 hp (7000 Btu/hp-hr <sup>a</sup> )	200 hr/yr	2,800×10 <sup>6</sup> Btu/yr	208	0.010	0.0062
Emergency generator, production (diesel fired)	1	1800 hp (7000 Btu/hp-hr <sup>a</sup> )	200 hr/yr	2,520×10 <sup>6</sup> Btu/yr	187	0.009	0.0055
Forklift (diesel engine)	1	2400 hp (7000 Btu/hp-hr <sup>a</sup> )	1,100 hr/yr	18,480×10 <sup>6</sup> Btu/yr	1,370	0.068	0.041
Whittaker escape capsule (diesel engine)	1	3000 hp (7000 Btu/hp-hr <sup>a</sup> )	200 hr/yr	4,200×10 <sup>6</sup> Btu/yr	312	0.015	0.0092
Supply boat (diesel engine)	1	5000 hp (7500 Btu/hp-hr <sup>a</sup> )	1100 hr/yr	41,250×10 <sup>6</sup> Btu/yr	3,060	0.172	1.14
Supply boat (diesel engine)	1	5000 hp (7500 Btu/hp-hr <sup>a</sup> )	110 hr/yr	4,125×10 <sup>6</sup> Btu/yr	306	0.017	0.114

**Note, the values shown above are for example only. They do not reflect actual operations.**

Totals may not sum due to independent rounding.

**Table 7-7. Offshore Oil and Gas Production Platform Emissions Sources (continued)**

Source	No. of Units	Unit Capacity (per unit)	Average Operation (per unit per year)	Activity Factor (all units combined)	CO <sub>2</sub> Emissions (tonnes/yr)	CH <sub>4</sub> Emissions (tonnes/yr)	N <sub>2</sub> O Emissions (tonnes/yr)
Helicopters (aviation fuel)	N/A	650 lb fuel/hr	912.5 hr/yr (50 min/trip, 1095 trips)	11,845×10 <sup>6</sup> Btu/yr <sup>b</sup>	820	0.817	0.086
Flare - Purge and pilot	1	N/A	8,760 hr/yr	395,000 scf/yr	21	0.14	0.003 (Flare total)
Flare - planned other	1	N/A	1 hr/yr	1.7×10 <sup>6</sup> scf/yr	92	0.59	
Flare - Planned continuous	1	N/A	1 hr/yr	3.1×10 <sup>6</sup> scf/yr	169	1.08	
Flare - Unplanned	1	N/A	1 hr/yr	20×10 <sup>6</sup> scf/yr	1,088	6.98	
<i>Vented Sources</i>						680	
Tank battery	N/A	N/A	Continuous Emissions	547,500 bbl/yr (1,500 bbl/day)		485	
Dehydration vents (also has Kimray pump emissions)	1	16×10 <sup>6</sup> scf/day gas processed	365	5,840×10 <sup>6</sup> scf/yr		164	
Pneumatic devices	7	N/A	N/A	7 pneumatic devices		19.5	
Chemical injection pumps	2	N/A	N/A	2 CIPs		4.01	
Vessels	9	N/A	N/A	9 vessels		0.016	
Compressor starts (non-routine)	6	N/A	N/A	6 compressors		1.12	
Compressor blowdowns (non-routine)	6	N/A	N/A	6 compressors		0.501	
Emergency shutdowns	N/A	N/A	N/A	1 platform		5.69	
Pressure Relief Valves	175	N/A	N/A	175 PRVs		0.13	

**Note, the values shown above are for example only. They do not reflect actual operations.**

Totals may not sum due to independent rounding.

**Table 7-7. Offshore Oil and Gas Production Platform Emissions Sources (continued)**

Source	No. of Units	Unit Capacity (per unit)	Average Operation (per unit per year)	Activity Factor (all units combined)	CO <sub>2</sub> Emissions (tonnes/yr)	CH <sub>4</sub> Emissions (tonnes/yr)	N <sub>2</sub> O Emissions (tonnes/yr)
<i>Fugitive Sources</i>						65.0	
Fugitives (equipment leaks)	N/A	N/A	8,760 hr/yr	See Table 7-6		65.0	
Sumps	3	N/A	Continuous	Negligible greenhouse gas (GHG) emissions		~0	
Wastewater tanks (open)	2	N/A	Continuous	Negligible GHG emissions		~0	
Mud cuttings roll-off bins	N/A	N/A	Continuous	Negligible GHG emissions		~0	
<i>Indirect Sources</i>							
None							

**Note, the values shown above are for example only. They do not reflect actual operations.**

Totals may not sum due to independent rounding.

<sup>a</sup> Engine Btu/hp-hr based on test data or manufacturer's data.

<sup>b</sup> Estimated heat rate using data for kerosene because data for aviation fuel not given (for kerosene, used density = 6.76 lb/gal, heating value = 5.67x10<sup>6</sup> Btu/bbl per Section 3).

Stationary Combustion Devices – CO<sub>2</sub> Emissions

CO<sub>2</sub> emissions from equipment burning natural gas are calculated using the gas composition approach provided in Section 4.1, as shown in the following exhibit.

**EXHIBIT 7.12: Offshore Oil and Gas Production Platform – Natural Gas CO<sub>2</sub> Combustion Emissions**

Boilers/heaters and turbines use natural gas at this facility.

External combustion gas usage:  
=  $14.1 \times 10^6$  scf/yr

Internal combustion gas usage:  
=  $(470 + 200) \times 10^6$  scf/yr =  $670 \times 10^6$  scf/yr

Fuel composition and carbon content:

	<u>Mole %</u>	<u>MW</u>	<u>Wt% (Calculated)</u>	<u>Carbon Content (wt%C)</u>
CO <sub>2</sub>	1.09	44.01	2.71	27.3
N <sub>2</sub>	2.39	28.01	3.77	0
CH <sub>4</sub>	90.95	16.04	82.26	74.9
C <sub>2</sub> H <sub>6</sub>	4	30.07	6.78	79.9
C <sub>3</sub> H <sub>8</sub>	1.14	44.10	2.83	81.7
<i>i</i> -C <sub>4</sub> H <sub>10</sub>	0.14	58.12	0.46	82.7
<i>n</i> -C <sub>4</sub> H <sub>10</sub>	0.16	58.12	0.52	82.7
<i>i</i> -C <sub>5</sub> H <sub>12</sub>	0.02	72.15	0.08	83.2
<i>n</i> -C <sub>5</sub> H <sub>12</sub>	0.02	72.15	0.08	83.2
<i>i</i> -C <sub>6</sub> H <sub>14</sub>	0	86.18	0	83.6
Other C <sub>6</sub>	0.02	86.18	0.10	83.6
C <sub>7</sub> +	0.07	100.20	0.40	83.9
<b>Fuel Mixture</b>	<b>100</b>	<b>17.74</b>	<b>100.0</b>	<b>71.43</b>

Carbon content calculation for an individual component is shown below for ethane (C<sub>2</sub>H<sub>6</sub>).

$$\frac{12.01 \text{ lb C}}{\text{lbmole C}} \times \frac{2 \text{ lbmoles C}}{\text{lbmole C}_2\text{H}_6} \times \frac{\text{lbmole C}_2\text{H}_6}{30.07 \text{ lb C}_2\text{H}_6} = 0.799 \text{ lb C/lb C}_2\text{H}_6$$

$$\times 100\% = \underline{79.9\% \text{ C}}$$

**EXHIBIT 7.12: Offshore Oil and Gas Production Platform – Natural Gas CO<sub>2</sub> Combustion Emissions, continued**

Carbon content for mixture:

$$\begin{aligned} \text{Wt}\%C_{\text{Mixture}} &= \frac{1}{100} \times \sum_{i=1}^{\text{\# components}} (\text{Wt}\%_i \times \text{Wt}\%C_i) \\ &= \frac{1}{100} \times \left[ (2.71 \times 27.3) + (3.77 \times 0) + (82.26 \times 74.9) + (6.78 \times 79.9) + (2.83 \times 81.7) + (0.46 \times 82.7) \right. \\ &\quad \left. + (0.52 \times 82.7) + (0.08 \times 83.2) + (0.08 \times 83.2) + (0 \times 83.6) + (0.10 \times 83.6) + (0.40 \times 83.9) \right] \\ &= \underline{71.43 \text{ Wt}\%C} = 0.7143 \text{ lb C/lb fuel} \end{aligned}$$

External combustion:

$$\begin{aligned} \text{CO}_2 : \frac{14.1 \times 10^6 \text{ scf fuel}}{\text{yr}} &\times \frac{\text{lbmole}}{379.3 \text{ scf fuel}} \times \frac{17.74 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.7143 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}} \\ &\times \frac{\text{lbmole CO}_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = \underline{783 \text{ tonnes CO}_2 / \text{yr}} \end{aligned}$$

Internal combustion:

$$\begin{aligned} \text{CO}_2 : \frac{670 \times 10^6 \text{ scf fuel}}{\text{yr}} &\times \frac{\text{lbmole}}{379.3 \text{ scf fuel}} \times \frac{17.74 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.7143 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}} \\ &\times \frac{\text{lbmole CO}_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = \underline{37,200 \text{ tonnes CO}_2 / \text{yr}} \end{aligned}$$

CO<sub>2</sub> emissions from diesel combustion are calculated using the diesel emission factor provided in Table 4-1, as shown in the following exhibit.

**EXHIBIT 7.13: Offshore Oil and Gas Production Platform – Diesel CO<sub>2</sub> Combustion Emissions**

$$\begin{aligned} \text{Diesel firing rate} &= \left( \frac{160,000 \text{ gal}}{\text{yr}} \times \frac{\text{bbl}}{42 \text{ gal}} \times \frac{5.75 \times 10^6 \text{ Btu}}{\text{bbl}} \right) \\ &+ (4,354 + 4,146 + 392 + 2,800 + 2,520 + 18,480 + 4,200) \times 10^6 \text{ Btu/yr} \\ &= 58,797 \times 10^6 \text{ Btu/yr} \end{aligned}$$

$$\text{CO}_2 : \frac{58,797 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.0742 \text{ tonne CO}_2}{10^6 \text{ Btu}} = \underline{4,360 \text{ tonnes CO}_2 / \text{yr}}$$



## Stationary Combustion Devices – CH<sub>4</sub> and N<sub>2</sub>O Emissions

Combustion emission factors for natural gas fired equipment are provided in Table 4-4a for controlled boilers and heaters, and Table 4-5 for uncontrolled turbines.

Table 4-4a provides TOC emission factors for IC engines burning diesel. The emissions from diesel fired equipment rated less than 600 hp per unit (crane engines and fire water pump) are also estimated using this emission factor. The emissions from diesel fired equipment rated greater than 600 hp per unit (emergency generators, forklift, and Whittaker escape capsule) are estimated using the "Large Bore Engine - Diesel" emission factors (for engines rated greater than 600 hp) from Table 4-4a. All of the engines, except for the supply boats and helicopters, are estimated using the factors in Table 4-4a, as shown below (boat and helicopter emissions are described later in this section). Table 4-4a also provides an assumed CH<sub>4</sub> content of 10 wt% to convert from TOC emissions if the exhaust CH<sub>4</sub> composition is unknown.

Exhibit 7.14 demonstrates the non-CO<sub>2</sub> emission calculations for stationary combustion equipment.

### **EXHIBIT 7.14: Offshore Oil and Gas Production Platform Engines - CH<sub>4</sub> and N<sub>2</sub>O Combustion Emissions**

#### Natural Gas Boilers and Heaters

$$\text{CH}_4 : \frac{14.1 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{2.3 \text{ lb CH}_4}{10^6 \text{ scf}} \times \frac{1 \text{ tonne}}{2,204.62 \text{ lb}} = \underline{0.01 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{14.1 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{0.64 \text{ lb N}_2\text{O}}{10^6 \text{ scf}} \times \frac{1 \text{ tonne}}{2,204.62 \text{ lb}} = \underline{0.004 \text{ tonnes N}_2\text{O}/\text{yr}}$$

#### Natural Gas Turbines – Compression:

$$\text{CH}_4 : \frac{200 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1065 \text{ Btu}}{\text{scf}} \times \frac{0.0086 \text{ lb CH}_4}{10^6 \text{ Btu}} \times \frac{1 \text{ tonne}}{2,204.62 \text{ lb}} = \underline{0.83 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{200 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1065 \text{ Btu}}{\text{scf}} \times \frac{0.003 \text{ lb N}_2\text{O}}{10^6 \text{ Btu}} \times \frac{1 \text{ tonne}}{2,204.62 \text{ lb}} = \underline{0.29 \text{ tonnes N}_2\text{O}/\text{yr}}$$

**EXHIBIT 7.14: Offshore Oil and Gas Production Platform Engines - CH<sub>4</sub> and N<sub>2</sub>O Combustion Emissions, continued**

Natural Gas Turbines – Electricity Generation:

$$\text{CH}_4 : \frac{470 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1065 \text{ Btu}}{\text{scf}} \times \frac{\text{kW} - \text{hr}}{13,918 \text{ Btu}} \times \frac{1 \text{ MW} - \text{hr}}{1,000 \text{ kW} - \text{hr}} \times \frac{7.26 \times 10^{-5} \text{ tonnes CH}_4}{\text{MW} - \text{hr}}$$

$$= \underline{2.61 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{470 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1065 \text{ Btu}}{\text{scf}} \times \frac{\text{kW} - \text{hr}}{13,918 \text{ Btu}} \times \frac{1 \text{ MW} - \text{hr}}{1,000 \text{ kW} - \text{hr}} \times \frac{1.09 \times 10^{-4} \text{ tonnes N}_2\text{O}}{\text{MW} - \text{hr}}$$

$$= \underline{3.92 \text{ tonnes N}_2\text{O}/\text{yr}}$$

Diesel engines <600 hp:

The firing rates for the diesel IC engines, crane engines, and fire water pump are summed together, as shown:

$$\text{Diesel firing rate} = (21,905 + 4,354 + 4,146 + 392) \times 10^6 \text{ Btu/yr} = 30,797 \times 10^6 \text{ Btu/yr}$$

$$\text{CH}_4 : \frac{30,797 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.00016 \text{ tonne TOC}}{10^6 \text{ Btu}} \times \frac{0.1 \text{ tonne CH}_4}{\text{tonne TOC}} = \underline{0.49 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{30,797 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{\text{bbl diesel}}{5.75 \times 10^6 \text{ Btu}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{1.51 \times 10^{-6} \text{ tonne N}_2\text{O}}{\text{gal diesel}} = \underline{0.34 \text{ tonnes N}_2\text{O}/\text{yr}}$$

Diesel engines >600 hp:

The firing rates for the emergency generators, forklift, and Whittaker escape capsule are summed together, as shown:

$$\text{Diesel firing rate} = (2,800 + 2,520 + 18,480 + 4,200) \times 10^6 \text{ Btu/yr} = 28,000 \times 10^6 \text{ Btu/yr}$$

$$\text{CH}_4 : \frac{28,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{3.7 \times 10^{-6} \text{ tonne CH}_4}{10^6 \text{ Btu}} = \underline{0.104 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{28,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{2.2 \times 10^{-6} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}} = \underline{0.062 \text{ tonnes N}_2\text{O}/\text{yr}}$$

## Combustion Sources – Mobile Sources

The diesel fired supply boat and aviation gas fired helicopter engine CO<sub>2</sub> emissions are estimated using the fuel basis "gas/diesel oil" and "aviation gas" emission factors, respectively, given in Table 4-1. CH<sub>4</sub> or N<sub>2</sub>O emission factors are obtained from Table 4-9. The emission factors for diesel ships and conventional aircraft are used for the supply boat and the helicopter, respectively. Heating values for diesel fuel and aviation gas are obtained from Table 3-5. The boat and helicopter emission calculations are shown in Exhibit 7.15.

**EXHIBIT 7.15: Offshore Oil and Gas Production Platform Engines (Boats and Helicopters) Combustion Emissions**

Boats:

The total firing rate of the boat engines is:

$$\text{Diesel firing rate} = (41,250 + 4,125) \times 10^6 \text{ Btu/yr} = 45,375 \times 10^6 \text{ Btu/yr}$$

$$\text{CO}_2 : \frac{45,375 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.0742 \text{ tonne CO}_2}{10^6 \text{ Btu}} = \underline{3,370 \text{ tonnes CO}_2/\text{yr}}$$

$$\text{CH}_4 : \frac{45,375 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{\text{bbl}}{5.75 \times 10^6 \text{ Btu}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{0.00057 \text{ tonne CH}_4}{1000 \text{ gal}} = \underline{0.189 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{45,375 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{\text{bbl}}{5.75 \times 10^6 \text{ Btu}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{0.00379 \text{ tonne N}_2\text{O}}{1000 \text{ gal}} = \underline{1.26 \text{ tonnes N}_2\text{O}/\text{yr}}$$

Helicopters:

The total firing rate of the helicopter engines is  $11,845 \times 10^6$  Btu/yr (aviation gas fired)

$$\text{CO}_2 : \frac{11,845 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.0692 \text{ tonne CO}_2}{10^6 \text{ Btu}} = \underline{820 \text{ tonnes CO}_2/\text{yr}}$$

$$\text{CH}_4 : \frac{11,845 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{\text{bbl}}{5.05 \times 10^6 \text{ Btu}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{0.000829 \text{ tonne CH}_4}{1000 \text{ gal}} = \underline{0.817 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{11,845 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{\text{bbl}}{5.05 \times 10^6 \text{ Btu}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{0.000871 \text{ tonne N}_2\text{O}}{1000 \text{ gal}} = \underline{0.086 \text{ tonnes N}_2\text{O}/\text{yr}}$$

## Combustion Sources – Flares

Based on the guidance given in Section 4.4, CH<sub>4</sub> emissions from flares are calculated assuming 2% of the CH<sub>4</sub> remains uncombusted, and CO<sub>2</sub> emissions are based on 98% combustion efficiency. CO<sub>2</sub> in the flare gas before combustion is neglected because the CO<sub>2</sub> concentration is low. Nitrous oxide emissions are estimated using emission factors from Table 4-7. The flaring emissions are shown in Exhibit 7.16.

### EXHIBIT 7.16: Offshore Oil and Gas Production Platform Flare Emissions

Natural gas firing rate =  $(0.395 + 1.7 + 3.1 + 20) \times 10^6 \text{ scf/yr} = 25.195 \times 10^6 \text{ scf/yr}$

$$\text{CO}_2 : \frac{25.195 \times 10^6 \text{ scf gas}}{\text{yr}} \times \frac{\text{lbmol gas}}{379.3 \text{ scf gas}} \times \frac{17.74 \text{ lb gas}}{\text{lbmol gas}} \times \frac{0.7143 \text{ lb C}}{\text{lb gas}} \times \frac{\text{lbmol C}}{12.01 \text{ lb C}} \\ \times \frac{0.98 \text{ lbmol CO}_2}{\text{lbmol C}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmol CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = 1,370 \text{ tonnes CO}_2$$

$$\text{CH}_4 : \frac{25.195 \times 10^6 \text{ scf gas}}{\text{yr}} \times \frac{\text{lbmol gas}}{379.3 \text{ scf gas}} \times \frac{0.9095 \text{ lbmol CH}_4}{\text{lbmol gas}} \times \frac{0.02 \text{ nonconformed lbmol CH}_4}{\text{lbmol total CH}_4} \\ \times \frac{16.04 \text{ lb CH}_4}{\text{lbmol CH}_4} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = 8.79 \text{ tonnes CH}_4$$

$$\text{N}_2\text{O} : \frac{16 \times 10^6 \text{ scf gas produced}}{\text{day}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{5.90 \times 10^{-7} \text{ tonnes N}_2\text{O}}{10^6 \text{ scf gas produced}} = 0.003 \text{ tonnes N}_2\text{O/yr}$$

Note that the N<sub>2</sub>O emissions factor is based on gas produced, not gas flared.

## Vented Sources – Storage Tanks

Methane emissions from flashing losses are estimated using the simple emission factor provided in Table 5-6. Methane emissions from tank standing and working losses are negligible. The tank vents are uncontrolled. Emission calculations are provided below.

### EXHIBIT 7.17: Offshore Oil and Gas Production Platform Crude Storage Tank Flashing Loss Emissions

$$\text{CH}_4 : \frac{547,500 \text{ bbl}}{\text{yr}} \times \frac{8.86 \times 10^{-4} \text{ tonne CH}_4}{\text{bbl}} = \underline{485 \text{ tonnes CH}_4/\text{yr}}$$

### Vented Sources - Gas Dehydration

The glycol dehydrator vents are vented to the atmosphere. Methane emissions from the gas dehydrator vents are estimated using the production segment emission factor given in Table 5-1. The Kimray pump emissions are estimated using the production segment emission factor in Table 5-3. For both of these sources, emissions are based on the annual quantity of gas processed. The emission calculation also includes a ratio factor to correct the emission factor from a default basis of 78.8 mol% CH<sub>4</sub> to the site-specific CH<sub>4</sub> content of 90.95 mol%. Emission calculations for these sources are provided in Exhibit 7.18.

#### **EXHIBIT 7.18: Offshore Oil and Gas Production Platform Dehydration Processing Vent Emissions**

Dehydrator Vents:

$$\text{CH}_4 : \frac{5,840 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{0.005287 \text{ tonne CH}_4}{10^6 \text{ scf}} \times \frac{90.95 \text{ mol\% CH}_4 \text{ at site}}{78.8 \text{ mol\% CH}_4 \text{ generic}} = \underline{35.6 \text{ tonnes CH}_4/\text{yr}}$$

Kimray Pumps:

$$\text{CH}_4 : \frac{5,840 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{0.01983 \text{ tonne CH}_4}{10^6 \text{ scf}} \times \frac{90.95 \text{ mol\% CH}_4 \text{ at site}}{78.8 \text{ mol\% CH}_4 \text{ generic}} = \underline{128 \text{ tonnes CH}_4/\text{yr}}$$

### Vented Sources – Pneumatics and Chemical Injection Pumps

The pneumatic devices and chemical injection pumps at the facility are actuated by natural gas. Methane emissions from pneumatic device and chemical injection pump vents are estimated using CH<sub>4</sub> emission factors presented in Tables 5-15 and 5-16, respectively. The type of pneumatic devices and chemical injection pumps are not specified, so the "Production Average" device and the "Average Pump" emission factor are used. These emissions are shown in Exhibit 7-19.

#### **EXHIBIT 7.19: Offshore Oil and Gas Production Platform Pneumatic Device and Chemical Injection Pump Vent Emissions**

Pneumatic Devices:

$$\text{CH}_4 : (7 \text{ pneumatic devices}) \times \frac{2.415 \text{ tonne CH}_4}{\text{device} \cdot \text{yr}} \times \frac{90.95 \text{ mol\% CH}_4 \text{ at site}}{78.8 \text{ mol\% CH}_4 \text{ generic}} = \underline{19.5 \text{ tonnes CH}_4/\text{yr}}$$

**EXHIBIT 7.19: Offshore Oil and Gas Production Platform Pneumatic Device and Chemical Injection Pump Vent Emissions, continued**

Chemical Injection Pumps (CIPs):

$$\text{CH}_4 : (2 \text{ CIPs}) \times \frac{1.736 \text{ tonne CH}_4}{\text{CIP - yr}} \times \frac{90.95 \text{ mol\% CH}_4 \text{ at site}}{78.8 \text{ mol\% CH}_4 \text{ generic}} = \underline{4.01 \text{ tonnes CH}_4/\text{yr}}$$

**Vented Sources – Maintenance/Turnaround Emissions**

Methane emissions from vessel blowdowns, compressor starts, and compressor blowdowns are estimated using the emission factors presented in Table 5-21, as shown in the following exhibit.

**EXHIBIT 7.20: Offshore Oil and Gas Production Platform Maintenance/Turnaround Emissions**

$$\text{CH}_4 : (9 \text{ vessels}) \times \frac{0.0015 \text{ tonne CH}_4}{\text{vessel - yr}} \times \frac{90.95 \text{ mol\% CH}_4 \text{ at site}}{78.8 \text{ mol\% CH}_4 \text{ generic}} = \underline{0.016 \text{ tonnes CH}_4/\text{yr}}$$

Compressor starts:

$$\text{CH}_4 : (6 \text{ compressors}) \times \frac{0.162 \text{ tonne CH}_4}{\text{compressor - yr}} \times \frac{90.95 \text{ mol\% CH}_4 \text{ at site}}{78.8 \text{ mol\% CH}_4 \text{ generic}} = \underline{1.12 \text{ tonnes CH}_4/\text{yr}}$$

Compressor blowdowns:

$$\text{CH}_4 : (6 \text{ compressors}) \times \frac{0.07329 \text{ tonne CH}_4}{\text{compressor - yr}} \times \frac{90.95 \text{ mol\% CH}_4 \text{ at site}}{78.8 \text{ mol\% CH}_4 \text{ generic}} = \underline{0.50 \text{ tonnes CH}_4/\text{yr}}$$

**Vented Sources – Offshore Emergency Shutdown Systems**

Methane emissions from emergency shutdown systems (ESDs) are estimated using an emission factor from Table 5-22, as shown in Exhibit 7.21.

## Vented Sources – Pressure Relief Valves

Methane emissions from pressure relief valves (PRV) are estimated using an emission factor from Table 5-22. Estimation of these emissions are also shown in Exhibit 7.21.

### EXHIBIT 7.21: Offshore Oil and Gas Production Platform Non-Routine (ESD release) Emissions

ESD System:

$$\text{CH}_4 : (1 \text{ platform}) \times \frac{4.9276 \text{ tonne CH}_4}{\text{platform - yr}} \times \frac{90.95 \text{ mol\% CH}_4 \text{ at site}}{78.8 \text{ mol\% CH}_4 \text{ generic}} = \underline{5.69 \text{ tonnes CH}_4/\text{yr}}$$

PRV Releases:

$$\text{CH}_4 : (175 \text{ PRVs}) \times \frac{0.00065 \text{ tonne CH}_4}{\text{PRV - yr}} \times \frac{90.95 \text{ mol\% CH}_4 \text{ at site}}{78.8 \text{ mol\% CH}_4 \text{ generic}} = \underline{0.13 \text{ tonnes CH}_4/\text{yr}}$$

## Fugitive Sources: Equipment Leaks

Table 7-8 provides fugitive component emissions associated with this offshore production facility. The corresponding component emission factors are given in Table B-13.

**Table 7-8. Offshore Oil and Gas Production Platform Fugitive Emission Estimate**

Component	Service	Average Component Count	Component EF (tonnes TOC/comp./hr)	Weight % CH <sub>4</sub>
Valves	Light oil	1870	2.5E-06	82.3
	Gas	330	4.5E-06	82.3
Connectors	Light oil	7480	2.1E-07	82.3
	Gas	1320	2.0E-07	82.3
OELs	Light oil	276	1.4E-06	82.3
	Gas	49	2.0E-06	82.3
Others	Light oil	60	7.5E-06	82.3
	Gas	10	8.8E-06	82.3



The TOC emission factors are converted to a CH<sub>4</sub> basis using the facility gas composition. For conservatism, the CH<sub>4</sub> natural gas concentration is assumed for the liquid streams. Emissions are calculated for each component by multiplying the component emission factor by the component count and the annual hours of operation (8,760 hours/year). The total fugitive emissions are then the sum of each of the component emissions. This is shown in the exhibit below.

**EXHIBIT 7.22: Offshore Oil and Gas Production Platform Fugitive Emissions**

Component	Service	Average Component Count	Comp. EF (tonnes CH <sub>4</sub> /comp./hr)	Emissions (tonnes CH <sub>4</sub> /yr)
Valves	Oil	1870	2.06E-06	33.8
	Gas	330	3.70E-06	10.7
Connectors	Oil	7480	1.73E-07	11.3
	Gas	1320	1.65E-07	1.91
OELs	Oil	276	1.15E-06	2.78
	Gas	49	1.65E-06	0.71
Others	Oil	60	6.17E-06	3.24
	Gas	10	7.24E-06	0.63
			<b>TOTAL</b>	<b>65.0</b>

## Facility Summary

Total emissions for this facility are summarized in Table 7-9.

**Table 7-9. Offshore Oil and Gas Production Platform Emissions**

Source Type	Source	Emissions (tonnes/yr)		
		CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Combustion	External combustion	784	0.01	0.02
	Internal combustion	45,700	5.0	5.94
	Flares	1,370	8.8	0.00
	<b>Combustion Total</b>	<b>47,900</b>	<b>13.8</b>	<b>5.96</b>
Vented sources	Tanks - flashing losses	0	485	
	Dehydration and Kimray pump vents	0	164	
	Pneumatics and chemical injection pumps	0	23.5	
	Maintenance/turnaround	0	1.64	
	Other non-routine (ESD and PRV)	0	5.82	
	<b>Vented Total</b>	<b>0</b>	<b>680</b>	
Fugitive Sources	Fugitive components	0	65.0	
	<b>Fugitive Total</b>	<b>0</b>	<b>65.0</b>	
Indirect Sources	None	0	0	0
	<b>Indirect Total</b>	<b>0</b>	<b>0</b>	<b>0</b>
<b>TOTAL</b>		<b>47,900</b>	<b>759</b>	<b>5.96</b>
<b>Total CO<sub>2</sub> Equivalents</b>		<b>65,700</b>		

Totals may not sum due to independent rounding.

### 7.1.3 Natural Gas Processing Plant

**Facility Description:** The facility consists of a natural gas processing plant.

**Throughput:** The plant processes  $800 \times 10^6$  scf/day of gas.

**Operations:** Compositions of the produced and processed gas streams are provided in Table 7-10.

**Table 7-10. Gas Composition for Natural Gas Processing Plant**

Gas Compound	Produced Gas Mole %	Processed Gas Mole %
Hydrogen Sulfide	1.13	0.02
Carbon Dioxide	3.5	2.0
Nitrogen	2.39	1.2
Methane	70	90
Ethane	12.5	4.7
Propane	5.1	1.2
Butanes	3.7	.5
Pentanes	0.76	.3
C6+	0.92	.08

**Note, the values shown above are for example only. They do not reflect actual operations.**

The facility field gas CH<sub>4</sub> content does not differ significantly from that of a typical processing facility. Thus, the venting emission factors do not need to be corrected from the default CH<sub>4</sub> content.

Tables 7-11 and 7-12 summarize the emission sources associated with this facility.

Table 7-11. Natural Gas Processing Emission Sources

Source	No. of Units	Unit Capacity (per unit)	Average Operation per unit per year	Activity Factor (all units combined)	CO <sub>2</sub> Emissions (tonnes/yr)	CH <sub>4</sub> Emissions (tonnes/yr)	N <sub>2</sub> O Emissions (tonnes/yr)
<b>Combustion Sources</b>					<b>512,000</b>	<b>96.7</b>	<b>11.9</b>
Auxiliary boilers (natural gas fired)	2	130×10 <sup>6</sup> Btu/hr	8400 hr/yr	2,184,000×10 <sup>6</sup> Btu/yr	123,000	2.18	0.61
Hot oil heaters (natural gas fired)	2	80×10 <sup>6</sup> Btu/hr	8400 hr/yr	1,344,000×10 <sup>6</sup> Btu/yr	75,600	1.34	0.38
Gas turbines for recompression (natural gas fired)	2	36,300 hp, 46% load (10,379 Btu/hp-hr <sup>a</sup> )	8665 hr/yr	3.00 ×10 <sup>12</sup> Btu/yr	169,000	11.7	4.20
Gas turbines for electrical generation (natural gas fired)	2	35,900 hp output 46% load (0.7457 kW/hp <sup>b</sup> )	8665 hr/yr	213,410 MW-hr/yr output	92,200	1.45	6.10
Flare - pilot (dry gas, low sulfur)	1	0.0072×10 <sup>6</sup> scf/day (average use)	365 day/yr	2.63×10 <sup>6</sup> scf/yr	148	0.91	0.44 (Total)
Emergency flare (acid gas, low pressure)	1	10×10 <sup>6</sup> scf/day (average use)	156 hr/yr	65×10 <sup>6</sup> scf/yr	4,630	17.5	
Emergency flare (acid gas, high pressure)	1	35×10 <sup>6</sup> scf/day (average use)	156 hr/yr	227.5×10 <sup>6</sup> scf/yr	16,200	61.1	
Tail gas incinerator (combusts acid gas)	2	35 ×10 <sup>6</sup> Btu/hr	8400 hr/yr	588,000×10 <sup>6</sup> Btu/yr	31,200	0.59	0.165
Emergency fire water pump IC engines (diesel fired)	2	460 hp 87% load (8089 Btu/hp-hr <sup>a</sup> )	24 hr/yr	155 ×10 <sup>6</sup> Btu/yr	11.5	0.003	0.002
Emergency fire water pump IC engines (diesel fired)	2	425 hp 92% load (8089 Btu/hp-hr <sup>a</sup> )	24 hr/yr	152 ×10 <sup>6</sup> Btu/yr	11.3	0.002	0.002

**Note, the values shown above are for example only. They do not reflect actual operations.**

Totals may not sum due to independent rounding.

Table 7-11. Natural Gas Processing Emission Sources (continued)

Source	No. of Units	Unit Capacity (per unit)	Average Operation (per unit per year)	Activity Factor (all units combined)	CO <sub>2</sub> Emissions (tonnes/yr)	CH <sub>4</sub> Emissions (tonnes/yr)	N <sub>2</sub> O Emissions (tonnes/yr)
<i>Vented Sources</i>					299,000	4,110	
Dehydration vents (also has Kimray pump emissions)	1	800×10 <sup>6</sup> scf/day gas processed	365 day/yr	292,000×10 <sup>6</sup> scf/yr gas processed	230	1,680	
Gas processing /sour gas treating					299,000	1,400	
Inlet	N/A	800×10 <sup>6</sup> scf/day 3.5 mole% CO <sub>2</sub>	365 day/yr	292,000×10 <sup>6</sup> scf/yr 3.5 mole % CO <sub>2</sub>			
Outlet	N/A	622×10 <sup>6</sup> scf/day 2.0 mole % CO <sub>2</sub> <sup>c</sup>	365 day/yr	227,100×10 <sup>6</sup> scf/yr 2.0 mole% CO <sub>2</sub>			
Condensate storage tanks	3 tanks	1,200,000 bbl/yr/tank (average use)	Continuous (365 day/yr)	3,600,000 bbl/yr	~0	~0	
LPG marine loading	N/A	300,000 bbl/load	12 /yr	3,600,000 bbl/yr	~0	~0	
C <sub>5</sub> + marine loading	N/A	300,000 bbl/load	12 /yr	3,600,000 bbl/yr	~0	~0	
Propane marine loading	N/A	175,000 bbl/load	12 /yr	2,100,000 bbl/yr	~0	~0	
Butane marine loading	N/A	125,000 bbl/load	12 /yr	1,500,000 bbl/yr	~0	~0	
Compressor starts	4	N/A	N/A	4 <sup>d</sup> compressors / turbines	Included in maintenance blowdowns	Included in maintenance blowdowns	
Compressor blowdowns	2	N/A	N/A	2 <sup>d</sup> compressors	Included in maintenance blowdowns	Included in maintenance blowdowns	
Processing maintenance blowdowns	N/A	N/A	N/A	1 processing plant		1,030	

**Note, the values shown above are for example only. They do not reflect actual operations.**

Totals may not sum due to independent rounding.

Table 7-11. Natural Gas Processing Emission Sources (continued)

Source	No. of Units	Unit Capacity (per unit)	Average Operation (per unit per year)	Activity Factor (all units combined)	CO <sub>2</sub> Emissions (tonnes/yr)	CH <sub>4</sub> Emissions (tonnes/yr)	N <sub>2</sub> O Emissions (tonnes/yr)
<i>Fugitive Sources</i>					0	128	
Fugitives	N/A	N/A	N/A	See Table 7-12	~0	128	
<i>Indirect Sources</i>							
None							

**Note, the values shown above are for example only. They do not reflect actual operations.**

Totals may not sum due to independent rounding.

<sup>a</sup> Engine btu/hp-hr presented in Table 3-6 (the turbine btu/hp-hr factor is based on a natural gas prime mover unit).

<sup>b</sup> Conversion factor from hp output to kW output presented in Table 3-2.

<sup>c</sup> Outlet gas flow rate calculated assuming 90% CH<sub>4</sub>, 2% CO<sub>2</sub>, and negligible H<sub>2</sub>S.

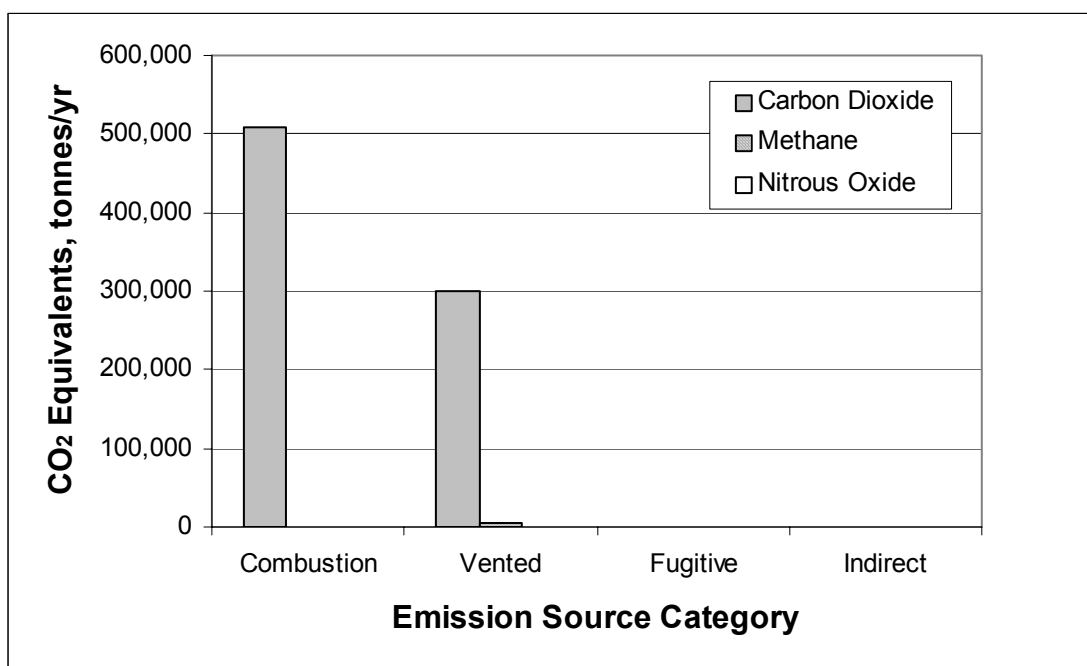
<sup>d</sup> Compressor starts are based on a count of the internal combustion drivers (including turbine-driven electric generators) because the compressor starts are emissions of fuel gas associated with starting the engine. Compressor blowdowns are based on the number of compressor units that could potentially be depressurized, and thus does not include turbine-driven electrical generator units.

**Table 7-12. Natural Gas Processing Fugitive Emission Sources**

Component	Service	Average Component Count
Valves	Gas	730
Valves	Liquid	3,700
Pump seals	Liquid	90
Flanges	Gas	2,900
Flanges	Liquid	14,700
Compressor seals	Gas	20

Note, the values shown above are for example only. They do not reflect actual operations.

A summary of the emissions (expressed in CO<sub>2</sub> equivalents) for this gas processing facility is given in Figure 7-3.

**Figure 7-3. Natural Gas Processing Summary of Emissions**



## Stationary Combustion Devices – CO<sub>2</sub> Emissions

CO<sub>2</sub> emissions from natural gas combustion are calculated using the gas composition approach provided in Section 4.1. CO<sub>2</sub> emissions from the diesel pumps are calculated using the diesel emission factor provided in Table 4-1. The CO<sub>2</sub> combustion emissions from electricity generation from the turbine are estimated using the “Gas-Combined Cycle” emission factor from Table 4-12. Calculated emissions for both fuel types are shown in Exhibit 7.23.

### EXHIBIT 7.23: Natural Gas Processing - CO<sub>2</sub> Combustion Emissions

#### (a) Auxiliary boilers, hot oil heaters, and gas turbines for recompression.

External combustion gas usage:

$$= \left[ \left( 2 \text{ boilers} \times \frac{130 \times 10^6 \text{ Btu}}{\text{boiler}} \times \frac{8,400 \text{ hr}}{\text{yr}} \right) + \left( 2 \text{ heaters} \times \frac{80 \times 10^6 \text{ Btu}}{\text{heater}} \times \frac{8,400 \text{ hr}}{\text{yr}} \right) \right] \times \frac{\text{scf}}{1,020 \text{ Btu}}$$

$$= 3,459 \times 10^6 \text{ scf/yr}$$

Internal combustion gas usage:

$$= \left( 2 \text{ turbines} \times \frac{36,300 \text{ hp}}{\text{turbine}} \times 0.46 \text{ load} \times \frac{10,379 \text{ Btu}}{\text{hp} \cdot \text{hr}} \times \frac{8,665 \text{ hr}}{\text{yr}} \right) \times \frac{\text{scf}}{1,020 \text{ Btu}}$$

$$= 2,944 \times 10^6 \text{ scf/yr}$$

Fuel composition and carbon content:

#### Produced Gas

	<u>Mole %</u>	<u>MW</u>	<u>Wt% (Calculated)</u>	<u>Carbon Content</u> <u>(wt% C)</u>
H <sub>2</sub> S	1.13	34.08	1.65	0.0
CO <sub>2</sub>	3.5	44.01	6.60	27.3
N <sub>2</sub>	2.39	28.01	2.87	0.0
CH <sub>4</sub>	70	16.04	48.14	74.9
C <sub>2</sub> H <sub>6</sub>	12.5	30.07	16.12	79.9
C <sub>3</sub> H <sub>8</sub>	5.1	44.10	9.64	81.7
C <sub>4</sub> H <sub>10</sub>	3.7	58.12	9.22	82.7
C <sub>5</sub> H <sub>12</sub>	0.76	72.15	2.35	83.2
C <sub>6</sub> +	0.92	86.18	3.40	83.6
<b>Fuel Mixture</b>	<b>100</b>	<b>23.32</b>	<b>100.0</b>	<b>71.03</b>

**EXHIBIT 7.23: Natural Gas Processing - CO<sub>2</sub> Combustion Emissions, continued****Processed Gas**

	<u>Mole %</u>	<u>MW</u>	<u>Wt% (Calculated)</u>	<u>Carbon Content (wt%C)</u>
H <sub>2</sub> S	0.02	34.08	0.04	0.0
CO <sub>2</sub>	2	44.01	4.84	27.3
N <sub>2</sub>	1.2	28.01	1.85	0.0
CH <sub>4</sub>	90	16.04	79.42	74.9
C <sub>2</sub> H <sub>6</sub>	4.7	30.07	7.77	79.9
C <sub>3</sub> H <sub>8</sub>	1.2	44.10	2.91	81.7
C <sub>4</sub> H <sub>10</sub>	0.5	58.12	1.60	82.7
C <sub>5</sub> H <sub>12</sub>	0.3	72.15	1.19	83.2
C6+	0.08	86.18	0.38	83.6
<b>Fuel Mixture</b>	<b>100</b>	<b>18.18</b>	<b>100.0</b>	<b>72.01</b>

Exhibit 4-1(a) details how to calculate carbon content for individual components and for mixtures.

Processed gas is used for combustion.

$$\text{CO}_2 : \frac{6,405 \times 10^6 \text{ scf fuel}}{\text{yr}} \times \frac{\text{lbmole}}{379.3 \text{ scf fuel}} \times \frac{18.18 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.7201 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}} \\ \times \frac{\text{lbmole CO}_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = \underline{367,400 \text{ tonnes CO}_2 / \text{yr}}$$

**(b) Gas turbines for electricity generation**

$$\text{Electricity generation} = 2 \text{ turbines} \times \frac{35,900 \text{ hp}}{\text{turbine}} \times 0.46 \text{ load} \times \frac{0.7457 \text{ kW}}{\text{hp}} \times \frac{1 \text{ MW}}{1,000 \text{ kW}} \\ \times \frac{8,665 \text{ hr}}{\text{yr}} = 213,400 \text{ MW} \cdot \text{hr/yr}$$

$$\text{CO}_2 : 213,400 \text{ MW} \cdot \text{hr/yr} \times \frac{0.432 \text{ tonnes CO}_2}{\text{MW} \cdot \text{hr}} = 92,200 \text{ tonnes CO}_2 / \text{yr}$$

**EXHIBIT 7.23: Natural Gas Processing - CO<sub>2</sub> Combustion Emissions, continued****(c) Diesel emergency fire water pumps**

$$\begin{aligned} \text{Diesel firing rate} = & \left( 2 \text{ pumps} \times \frac{460 \text{ hp}}{\text{pump}} \times 0.87 \text{ load} \times \frac{8,089 \text{ Btu}}{\text{hp} \cdot \text{hr}} \times \frac{24 \text{ h}}{\text{yr}} \right) \\ & + \left( 2 \text{ pumps} \times \frac{425 \text{ hp}}{\text{pump}} \times 0.92 \text{ load} \times \frac{8,089 \text{ Btu}}{\text{hp} \cdot \text{hr}} \times \frac{24 \text{ h}}{\text{yr}} \right) = 307 \times 10^6 \text{ Btu / yr} \end{aligned}$$

$$\text{CO}_2 : \frac{307 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.0742 \text{ tonnes CO}_2}{10^6 \text{ Btu}} = 22.8 \text{ tonnes CO}_2 / \text{yr}$$

$$\text{Total CO}_2 = (367,400 + 92,200 + 22.8) \text{ tonnes CO}_2/\text{yr} = 459,600 \text{ tonnes CO}_2 / \text{yr}$$

**Stationary Combustion Devices – CH<sub>4</sub> and N<sub>2</sub>O Emissions**

Combustion emission factors for natural gas fired equipment are provided in Table 4-4a for controlled boilers and heaters, and Table 4-5 for uncontrolled turbines. The electricity generation turbine emission factors are taken from Table 4-12 for “gas-Combined Cycle” units.

**EXHIBIT 7.24: Natural Gas Processing Engines Combustion Emissions**

Boilers and Heaters:

$$\begin{aligned} \text{Natural gas firing rate} = & \left[ (2 \text{ boilers} \times \frac{130 \times 10^6 \text{ Btu}}{\text{boiler}} \times \frac{8,400 \text{ hr}}{\text{yr}}) \right. \\ & \left. + (2 \text{ heaters} \times \frac{80 \times 10^6 \text{ Btu}}{\text{heater}} \times \frac{8,400 \text{ hr}}{\text{yr}}) \right] \\ = & 3,528,000 \times 10^6 \text{ Btu/yr} \end{aligned}$$

$$\text{CH}_4 : \frac{3,528,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{1.00 \times 10^{-6} \text{ tonne CH}_4}{10^6 \text{ Btu}} = \underline{3.53 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{3,528,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{2.80 \times 10^{-7} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}} = \underline{0.988 \text{ tonnes N}_2\text{O/yr}}$$

**EXHIBIT 7.24: Natural Gas Processing Engines Combustion Emissions, continued**

Diesel engines:

Table 4-5 provides an assumed CH<sub>4</sub> content of 10 wt% to convert from TOC emissions if the exhaust composition is unknown.

$$\text{CH}_4 : \frac{307 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.00016 \text{ tonne TOC}}{10^6 \text{ Btu}} \times \frac{0.1 \text{ tonne CH}_4}{\text{tonne TOC}} = \underline{0.005 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{307 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{\text{bbl diesel}}{5.75 \times 10^6 \text{ Btu}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{1.51 \times 10^{-6} \text{ tonne N}_2\text{O}}{\text{gal diesel}} = \underline{0.0034 \text{ tonnes N}_2\text{O}/\text{yr}}$$

Turbines for recompression:

$$\text{CH}_4 : \frac{3.00 \times 10^{12} \text{ Btu}}{\text{yr}} \times \frac{3.9 \times 10^{-6} \text{ tonne CH}_4}{10^6 \text{ Btu}} = \underline{11.7 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{3.00 \times 10^{12} \text{ Btu}}{\text{yr}} \times \frac{1.4 \times 10^{-6} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}} = \underline{4.19 \text{ tonnes N}_2\text{O}/\text{yr}}$$

Gas combustion turbine for electrical generation:

$$\text{CH}_4 : \frac{213,410 \text{ MW} \cdot \text{hr}}{\text{yr}} \times \frac{6.80 \times 10^{-6} \text{ tonne CH}_4}{\text{MW} \cdot \text{hr}} = \underline{1.45 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{213,410 \text{ MW} \cdot \text{hr}}{\text{yr}} \times \frac{2.86 \times 10^{-5} \text{ tonne N}_2\text{O}}{\text{MW} \cdot \text{hr}} = \underline{6.10 \text{ tonnes N}_2\text{O}/\text{yr}}$$

**Combustion Sources – Flares**

Based on the guidance provided in Section 4.4, CH<sub>4</sub> emissions from flares are calculated assuming 2% of the CH<sub>4</sub> remains uncombusted, and CO<sub>2</sub> emissions are based on 98% combustion efficiency. Nitrous oxide emissions are estimated using emission factors from Table 4-7. The flaring emissions are shown in Exhibit 7.25. For completeness, the CO<sub>2</sub> emissions from flaring the sour gas are estimated by taking into account the CO<sub>2</sub> already present in the gas. However, this contribution is small compared to the CO<sub>2</sub> formed from combustion of the hydrocarbon compounds.

**EXHIBIT 7.25: Natural Gas Processing Flare Emissions****Methane Emissions:***(a) Pilot gas (processed gas) flaring*

$$\text{CH}_4 : \frac{2,628,000 \text{ scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{0.9 \text{ lbmole CH}_4}{\text{lbmole gas}} \times \frac{16.04 \text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{0.02 \text{ lb noncombusted CH}_4}{\text{lb CH}_4} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = 0.91 \text{ tonnes CH}_4/\text{yr}$$

*(b) Sour gas flaring*

$$\text{CH}_4 : \frac{(65,000,000 + 227,500,000) \text{ scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{0.7 \text{ lbmole CH}_4}{\text{lbmole gas}} \times \frac{16.04 \text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{0.02 \text{ lb noncombusted CH}_4}{\text{lb CH}_4} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = 78.5 \text{ tonnes CH}_4/\text{yr}$$

**Nitrous Oxide Emissions**

N<sub>2</sub>O emission factor from Table 4-7 is based on gas receipts and will represent N<sub>2</sub>O emissions for all flares. Therefore, we use the sour gas emission factor to obtain a conservative estimate.

$$\text{Natural Gas Receipts} = 800 \times 10^6 \text{ scf/day} \times \frac{365 \text{ days}}{\text{yr}} = 292,000 \times 10^6 \text{ scf/yr}$$

$$\text{N}_2\text{O} : \frac{292,000 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1.50 \times 10^{-6} \text{ tonnes N}_2\text{O}}{10^6 \text{ scf gas receipts}} = 0.44 \text{ tonnes N}_2\text{O/yr}$$

**Carbon Dioxide Emissions***(a) Pilot gas (processed gas) flaring*

$$\text{CO}_2 \text{ in gas} : \frac{2,628,000 \text{ scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{0.02 \text{ lbmol CO}_2}{\text{lbmol gas}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = 2.8 \text{ tonnes CO}_2/\text{yr}$$

**EXHIBIT 7.25: Natural Gas Processing Flare Emissions, continued**

$$\begin{aligned}
 \text{CO}_2 \text{ formed} &: \frac{2.628 \times 10^6 \text{ scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \\
 &\times \left( \begin{aligned} &\frac{0.90 \text{ lbmol CH}_4}{\text{lbmol gas}} \times \frac{1 \text{ lbmol C}}{\text{lbmol CH}_4} + \frac{0.047 \text{ lbmol C}_2\text{H}_6}{\text{lbmol gas}} \times \frac{2 \text{ lbmol C}}{\text{lbmol C}_2\text{H}_6} \\ &+ \frac{0.012 \text{ lbmol C}_3\text{H}_8}{\text{lbmol gas}} \times \frac{3 \text{ lbmol C}}{\text{lbmol C}_3\text{H}_8} + \frac{0.005 \text{ lbmol C}_4\text{H}_{10}}{\text{lbmol gas}} \times \frac{4 \text{ lbmol C}}{\text{lbmol C}_4\text{H}_{10}} \\ &+ \frac{0.003 \text{ lbmol C}_5\text{H}_{12}}{\text{lbmol gas}} \times \frac{5 \text{ lbmol C}}{\text{lbmol C}_5\text{H}_{12}} + \frac{0.0008 \text{ lbmol C}_6\text{H}_{14}}{\text{lbmol gas}} \times \frac{6 \text{ lbmol C}}{\text{lbmol C}_6\text{H}_{14}} \end{aligned} \right) \\
 &\times \frac{0.98 \text{ lbmole CO}_2 \text{ formed}}{\text{lbmole C combusted}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} \\
 &= \underline{1450 \text{ tonnes CO}_2/\text{yr}}
 \end{aligned}$$

$$\text{CO}_2 \text{ flare emissions} = (\text{CO}_2 \text{ in gas flared}) + (\text{CO}_2 \text{ formed})$$

$$\text{CO}_2 \text{ flare emissions} = (2.8 \text{ tonnes/yr}) + (145 \text{ tonnes/yr}) = \underline{148 \text{ tonnes CO}_2/\text{yr}}$$

*(b) Sour gas flaring*

$$\begin{aligned}
 \text{CO}_2 \text{ in gas} &: \frac{(35,000,000 + 227,500,000) \text{ scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{0.035 \text{ lbmole CO}_2}{\text{lbmole gas}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \\
 &\times \frac{\text{tonne}}{2204.62 \text{ lb}} = \underline{539 \text{ tonnes CO}_2/\text{yr}}
 \end{aligned}$$

**EXHIBIT 7.25: Natural Gas Processing Flare Emissions, continued**

$$\begin{aligned}
 \text{CO}_2 \text{ formed} &: \frac{(65,000,000 + 227,500,000) \text{ scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \\
 &\times \left( \begin{aligned} &\frac{0.70 \text{ lbmol CH}_4}{\text{lbmol gas}} \times \frac{1 \text{ lbmol C}}{\text{lbmol CH}_4} + \frac{0.124 \text{ lbmol C}_2\text{H}_6}{\text{lbmol gas}} \times \frac{2 \text{ lbmol C}}{\text{lbmol C}_2\text{H}_6} \\ &+ \frac{0.051 \text{ lbmol C}_3\text{H}_8}{\text{lbmol gas}} \times \frac{3 \text{ lbmol C}}{\text{lbmol C}_3\text{H}_8} + \frac{0.037 \text{ lbmol C}_4\text{H}_{10}}{\text{lbmol gas}} \times \frac{4 \text{ lbmol C}}{\text{lbmol C}_4\text{H}_{10}} \\ &+ \frac{0.0076 \text{ lbmol C}_5\text{H}_{12}}{\text{lbmol gas}} \times \frac{5 \text{ lbmol C}}{\text{lbmol C}_5\text{H}_{12}} + \frac{0.0092 \text{ lbmol C}_6\text{H}_{14}}{\text{lbmol gas}} \times \frac{6 \text{ lbmol C}}{\text{lbmol C}_6\text{H}_{14}} \end{aligned} \right) \\
 &\times \frac{0.98 \text{ lbmole CO}_2 \text{ formed}}{\text{lbmole C combusted}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} \\
 &= \underline{20,250 \text{ tonnes CO}_2/\text{yr}}
 \end{aligned}$$

$$\text{CO}_2 \text{ flare emissions} = (\text{CO}_2 \text{ in gas flared}) + (\text{CO}_2 \text{ formed})$$

$$\text{CO}_2 \text{ flare emissions} = (539 \text{ tonnes/yr}) + (20,250 \text{ tonnes/yr}) = \underline{20,800 \text{ tonnes CO}_2/\text{yr}}$$

**Combustion Sources – Incinerators**

Incinerator emissions result from both combustion emissions and from the untreated portion of the waste gas. The treatment efficiency of the waste gas is typically 98%. Because the waste gas composition is unknown, only combustion emissions are estimated for the incinerators for this facility. The CH<sub>4</sub> and N<sub>2</sub>O emissions are estimated using the controlled boiler/furnace emission factor given in Table 4-4a, and the CO<sub>2</sub> emissions are estimated using the fuel specific factors given in Table 4-1.

**EXHIBIT 7.26: Natural Gas Processing Tail Gas Incinerator Emissions**

$$\text{CH}_4 : \frac{588,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{1.0 \times 10^{-6} \text{ tonne CH}_4}{10^6 \text{ Btu}} = \underline{0.588 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{588,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{2.8 \times 10^{-7} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}} = \underline{0.165 \text{ tonnes N}_2\text{O}/\text{yr}}$$

$$\text{CO}_2 : \frac{588,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.0531 \text{ tonne CO}_2}{10^6 \text{ Btu}} = \underline{31,200 \text{ tonnes CO}_2/\text{yr}}$$

**Vented Sources – Gas Dehydration**

The glycol dehydrator vent is vented to the atmosphere. Methane emissions from the gas dehydrator vent are estimated using the gas processing-specific emission factor given in Table 5-1. The Kimray pump CH<sub>4</sub> emissions are estimated using the gas processing-specific emission factor in Table 5-3. Carbon dioxide emissions are estimated based on the ratio of CO<sub>2</sub> to CH<sub>4</sub> in the gas. The dehydration process emissions are estimated as shown in Exhibit 7.27.

**EXHIBIT 7.27: Natural Gas Processing Dehydration Process Vent Emissions**

The amount of gas dehydrated is 800×10<sup>6</sup> scf/day, or 292,000×10<sup>6</sup> scf/yr (based on 365 days of annual operation). The dehydrator and Kimray pump vent emissions are based on the quantity of gas processed.

Dehydrator Vent:

$$\text{CH}_4 : (292,000 \times 10^6 \text{ scf/yr processed}) \times \frac{0.0023315 \text{ tonne CH}_4}{10^6 \text{ scf}} = \underline{681 \text{ tonnes CH}_4/\text{yr}}$$

$$\begin{aligned} \text{CO}_2 : (292,000 \times 10^6 \text{ scf/yr processed}) &\times \frac{0.0023315 \text{ tonne CH}_4}{10^6 \text{ scf}} \times \frac{\text{tonne mole CH}_4}{16.01 \text{ tonne CH}_4} \times \frac{0.035 \text{ tonne mole CO}_2}{0.7 \text{ tonne mole CH}_4} \\ &= \times \frac{44.01 \text{ tonnes CO}_2}{\text{tonne mole CO}_2} = \underline{93.6 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$



**EXHIBIT 7.27: Natural Gas Processing Dehydration Process Vent Emissions, continued****Kimray Pumps:**

$$\begin{aligned}
 \text{CH}_4 : & \quad (292,000 \times 10^6 \text{ scf/yr processed}) \times \frac{0.0034096 \text{ tonne CH}_4}{10^6 \text{ scf}} = \underline{996 \text{ tonnes CH}_4/\text{yr}} \\
 \text{CO}_2 : & \quad (292,000 \times 10^6 \text{ scf/yr processed}) \times \frac{0.0034096 \text{ tonne CH}_4}{10^6 \text{ scf}} \times \frac{\text{tonne mole CH}_4}{16.01 \text{ tonne CH}_4} \times \frac{0.035 \text{ tonne mole CO}_2}{0.7 \text{ tonne mole CH}_4} \\
 & \quad = \times \frac{44.01 \text{ tonnes CO}_2}{\text{tonne mole CO}_2} = \underline{137 \text{ tonnes CO}_2/\text{yr}}
 \end{aligned}$$

**Vented Sources – CO<sub>2</sub> Venting from Sour Gas Processing**

Carbon dioxide and CH<sub>4</sub> emissions from sour gas processing are estimated by material balance using the known throughput and CO<sub>2</sub> concentrations of the inlet and outlet gas streams as described in Section 5.1.4. This vent is uncontrolled and vented to the atmosphere. As industry operating practices change in the future, this vent stream may be captured and thus may no longer be an emissions source.

**EXHIBIT 7.28: CO<sub>2</sub> Venting Emissions from Sour Gas Processing**

Unit inlet (sour) stream: 292,000×10<sup>6</sup> scf/yr gas throughput, 3.5 mole % CO<sub>2</sub>

Unit outlet (sweet) stream: 227,030×10<sup>6</sup> scf/yr gas throughput, 2.0 mole % CO<sub>2</sub>

The vented gas is not captured (vented to the atmosphere)

$$\text{CO}_2 \text{ emitted} = (\text{CO}_2)_{\text{inlet}} - (\text{CO}_2)_{\text{outlet}} = (\text{CO}_2)_{\text{sour}} - (\text{CO}_2)_{\text{sweet}}$$

$$\begin{aligned}
 \text{CO}_2 = & \quad \left( \frac{292,000 \times 10^6 \text{ scf gas}}{\text{yr}} \right) \left( \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \right) \left( \frac{0.035 \text{ lbmole CO}_2}{\text{lbmole gas}} \right) \left( \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \right) \left( \frac{\text{tonnes}}{2204.62 \text{ lb}} \right) \\
 & \quad - \left( \frac{227,030 \times 10^6 \text{ scf gas}}{\text{yr}} \right) \left( \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \right) \left( \frac{0.02 \text{ lbmole CO}_2}{\text{lbmole gas}} \right) \left( \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \right) \left( \frac{\text{tonnes}}{2204.62 \text{ lb}} \right) \\
 & \quad = \underline{299,000 \text{ tonnes CO}_2/\text{yr}}
 \end{aligned}$$

**EXHIBIT 7.28: CO<sub>2</sub> Venting Emissions from Sour Gas Processing, continued**

$$\text{CH}_4 \text{ emitted} = (\text{CH}_4)_{\text{inlet}} - (\text{CH}_4)_{\text{outlet}} = (\text{CH}_4)_{\text{sour}} - (\text{CH}_4)_{\text{sweet}}$$

$$\begin{aligned} \text{CH}_4 = & \left( \frac{292,000 \times 10^6 \text{ scf gas}}{\text{yr}} \right) \left( \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \right) \left( \frac{0.70 \text{ lbmole CH}_4}{\text{lbmole gas}} \right) \left( \frac{16.04 \text{ lb CH}_4}{\text{lbmole CH}_4} \right) \left( \frac{\text{tonnes}}{2204.62 \text{ lb}} \right) \\ & - \left( \frac{227,030 \times 10^6 \text{ scf gas}}{\text{yr}} \right) \left( \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \right) \left( \frac{0.90 \text{ lbmole CO}_2}{\text{lbmole gas}} \right) \left( \frac{16.04 \text{ lb CH}_4}{\text{lbmole CH}_4} \right) \left( \frac{\text{tonnes}}{2204.62 \text{ lb}} \right) \\ & = 1,400 \text{ tonnes CH}_4/\text{yr} \end{aligned}$$

**Vented Sources – Storage Tanks**

Methane emissions from flashing losses are assumed to be negligible at this processing facility because the pressure reduction associated with flashing emissions are assumed to occur upstream in production.

Tank storage of LPG, propane, and butane is assumed to have negligible CH<sub>4</sub> emissions as these processed liquids contain insignificant quantities of CH<sub>4</sub>. Also, these liquids are typically stored in pressurized vessels that do not vent to the atmosphere. Methane emissions from the standing and working losses from the condensate tanks are also assumed to be negligible.

**Vented Sources – Loading Operations**

The marine loading of LPG, C<sub>5</sub>+, propane, and butane is assumed to have negligible CH<sub>4</sub> emissions as these processed liquids should have insignificant quantities of CH<sub>4</sub> by the time they are loaded out.

**Vented Sources: Maintenance/Turnaround Emissions**

Methane emissions from processing maintenance/non-routine activities are estimated using the emission factor presented in Table 5-23. This overall emission factor includes CH<sub>4</sub> emissions from compressor/turbine starts, compressor blowdowns, miscellaneous vessel blowdowns, and pressure relief valves. The maintenance/non-routine emission calculation is shown in Exhibit 7.29.

**EXHIBIT 7.29: Natural Gas Processing Maintenance/Turnaround Emissions**

Processing maintenance blowdowns:

$$\text{CH}_4 : \frac{800 \times 10^6 \text{ scf}}{\text{day}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{0.003527 \text{ tonne CH}_4}{10^6 \text{ scf}} = 1,030 \text{ tonnes CH}_4 / \text{yr}$$

**Fugitive Sources: Equipment Leaks**

Table 7-13 provides fugitive component counts associated with the gas processing facility. The corresponding average component emission factors are also provided based on the average gas plant emission factors given in Table B-15. The CH<sub>4</sub> composition of 56.4 wt% for the entire facility is based on the suggested default composition given in Table B-25. Note that the API average emissions factors and recommended CH<sub>4</sub> content are not service (liquid or gas) specific.

**Table 7-13. Natural Gas Processing Fugitive Emission Estimate**

Component	Service	Average Component Count	Component EF (tonnes TOC/comp./hr)	Weight % CH <sub>4</sub>
Valves	Liquid and gas	4430	3.86E-06	56.4
Pump seals	Liquid	90	1.15E-05	56.4
Flanges	Liquid and gas	17,600	4.38E-07	56.4
Others (compressor seals)	Gas	20	4.86E-06	56.4

The TOC emission factors are converted to a CH<sub>4</sub> basis. Emissions are calculated for each component by multiplying the component emission factor by the component count and the annual hours of operation (8,760 hours/year). The total fugitive emissions are then the sum of each of the component emissions. This is shown below.

**EXHIBIT 7.30: Natural Gas Processing Fugitive Emissions**

<b>Component</b>	<b>Service</b>	<b>Average Component Count</b>	<b>Comp. EF (tonnes CH<sub>4</sub>/comp./hr)</b>	<b>Emissions, tonnes CH<sub>4</sub>/yr</b>
Valves	Liquid and gas	4430	2.18E-06	84.5
Pump seals	Liquid	90	6.49E-06	5.11
Flanges	Liquid and gas	17,600	2.47E-07	38.1
Others	Gas	20	2.74E-06	0.48
			<b>TOTAL</b>	<b>128</b>

## Facility Summary

Total emissions for this facility are summarized in Table 7-14.

**Table 7-14. Natural Gas Processing Emissions**

<b>Source Type</b>	<b>Source</b>	<b>Emissions (tonnes/yr)</b>		
		<b>CO<sub>2</sub></b>	<b>CH<sub>4</sub></b>	<b>N<sub>2</sub>O</b>
Combustion Sources	External combustion	198,000	3.5	0.99
	Internal combustion	261,000	13.2	10.3
	Flares	21,000	79.5	0.438
	Incinerators	31,200	0.6	0.167
	<b>Combustion Total</b>	<b>512,000</b>	<b>96.7</b>	<b>11.9</b>
Vented sources	Dehydration and Kimray pump vents	230	1,680	
	Sour gas processing	299,000	1,400	
	Condensate tanks	0	0	
	Maintenance / turnaround	0	1,030	
	<b>Vented Total</b>	<b>299,000</b>	<b>4,110</b>	
Fugitive Sources	Fugitive components	0	128	
	<b>Fugitive Total</b>	<b>0</b>	<b>128</b>	
Indirect Sources	None	0	0	0
	<b>Indirect Total</b>	<b>0</b>	<b>0</b>	<b>0</b>
<b>TOTAL</b>		<b>811,000</b>	<b>4,330</b>	<b>11.9</b>
<b>Total CO<sub>2</sub> Equivalents</b>		<b>906,000</b>		

Totals may not sum due to independent rounding.

## 7.2 Transportation

### 7.2.1 Production Gathering Compressor Station

**Facility Description:** A 3,400-hp gathering compressor station, located in Oklahoma, operates four reciprocating compressors. 80 miles of gathering pipelines are associated with this compressor station.

**Operations:** The facility operates continuously throughout the year. Heat rates for the compressors are based on manufacturer's data and test data. The composition of the field fuel gas is used to operate the compressors is provided in Table 7-15. Because there is an insignificant amount of CO<sub>2</sub> in the field gas, CO<sub>2</sub> vented emissions are negligible.

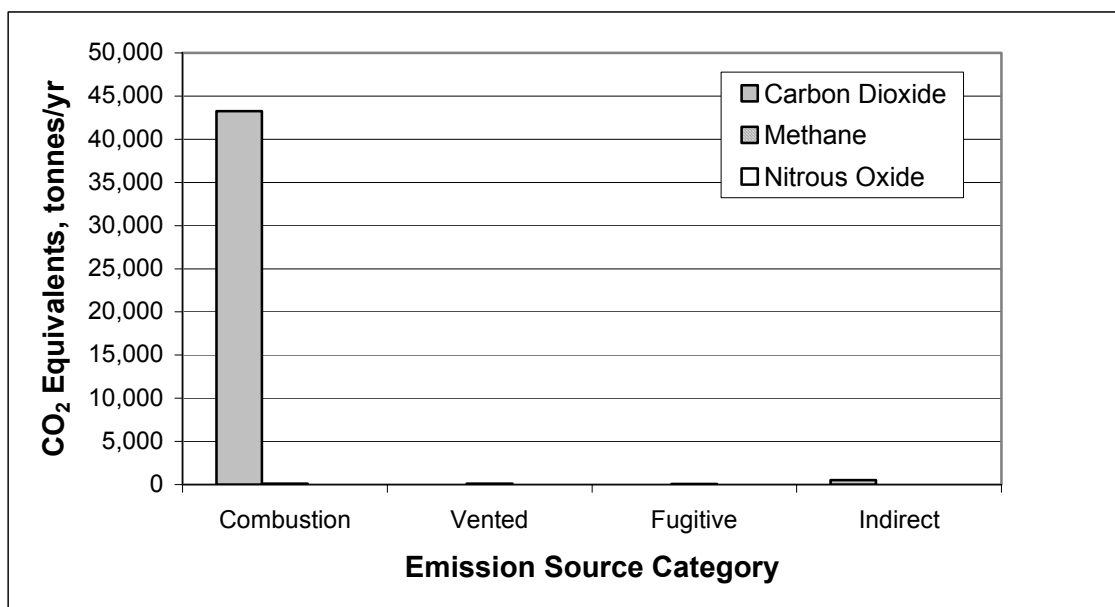
**Table 7-15. Gas Composition for Production Gathering Compressor Station**

Gas Compound	Produced Gas Mole %
Carbon Dioxide	0.8
Nitrogen	1.8
Methane	83
Ethane	8
Propane	5
Butanes	1
Pentanes	0.3
C6+	0.1
Heating Value	1165 BTU/scf

**Note, the values shown above are for example only. They do not reflect actual operations.**

Details on the emission sources associated with this facility are provided in Tables 7-16 and 7-17.

A summary of the emissions (expressed in CO<sub>2</sub> equivalents) for this gas processing facility is given in Figure 7-4.



**Figure 7-4. Production Gathering Compressor Station Summary of Emissions**

**Table 7-16. Production Gathering Compressor Station Combustion and Vented Sources**

Source	Number of Units	Total Capacity (all units combined)	Engine Btu/hp-hr	Activity Factor (all units combined)	CO <sub>2</sub> Emissions (tonnes/yr)	CH <sub>4</sub> Emissions (tonnes/yr)	N <sub>2</sub> O Emissions (tonnes/yr)
<i>Combustion Sources</i>					43,300	125	0.432
4 stroke, rich burn engines (natural gas fired)	3	2200 hp	10,600 <sup>a</sup>	612,850×10 <sup>6</sup> Btu/yr – continuous operation	36,600	61.3	0.276
4 stroke, lean burn engine (natural gas fired)	1	1200 hp	10,600 <sup>a</sup>	111,427×10 <sup>6</sup> Btu/yr – continuous operation	6,660	63.5	0.156
<i>Vented Sources</i>					~0	103	
Pneumatic devices	40	N/A	N/A	40 pneumatic devices	~0	102	
Compressor starts	4	N/A	N/A	4 compressors	~0	0.68	
Compressor blowdowns	4	N/A	N/A	4 compressors	~0	0.30	
Pressure relief valves	14			14 PRVs	~0	0.0096	
Pipeline: Blowdowns	80 miles	N/A	N/A	80 miles of pipeline	~0	0.50	
<i>Fugitive Sources</i>					2.87	56.2	
Equipment Leaks	N/A	N/A	N/A	See Table 7-16	~0	24.6	
Pipeline: Leakage Oxidation	80 miles				1.64 (leaks) 1.23 (oxidation)	31.5 (leaks)	
<i>Indirect Sources</i>					531	0.0034	0.0069
Electricity purchased				680 MW-hr/yr	531	0.0034	0.0069

**Note, the values shown above are for example only. They do not reflect actual operations.**

Totals may not sum due to independent rounding.

<sup>a</sup> Engine Btu/hp-hr based on test data or manufacturer's data.

**Table 7-17. Production Gathering Compressor Station Fugitive Emission Sources**

<b>Component</b>	<b>Service</b>	<b>Average Component Count</b>
Valves	Gas	675
Control valves	Gas	30
Connectors	Gas	3,000
Open-ended lines	Gas	60
Compressor seals	Gas	15
Pressure relief valves	Gas	15

**Note, the values shown above are for example only. They do not reflect actual operations.**

### Stationary Combustion Devices – CO<sub>2</sub> Emissions

CO<sub>2</sub> emissions from natural gas combustion are calculated using the gas composition approach provided in Section 4.1, as shown:

#### **EXHIBIT 7.31: Production Gathering Compressor Station – Natural Gas CO<sub>2</sub> Combustion Emissions**

##### **Natural gas fired engines (rich burn and lean burn)**

Calculate natural gas rate:

$$\begin{aligned}
 \text{Natural gas firing rate} &= \left[ (3 \text{ rich burn} \times \frac{2,200 \text{ hp}}{\text{engine}} \times \frac{10,600 \text{ Btu}}{\text{hp} \cdot \text{hr}} \times \frac{8,760 \text{ hr}}{\text{yr}}) \right. \\
 &\quad \left. + (1 \text{ lean burn} \times \frac{1,200 \text{ hp}}{\text{engine}} \times \frac{10,600 \text{ Btu}}{\text{hp} \cdot \text{hr}} \times \frac{8,760 \text{ hr}}{\text{yr}}) \right] \times \frac{\text{scf}}{1,065 \text{ Btu}} \\
 &= 680 \times 10^6 \text{ scf/yr}
 \end{aligned}$$



**EXHIBIT 7.31: Production Gathering Compressor Station – Natural Gas CO<sub>2</sub> Combustion Emissions, continued**

Fuel composition and carbon content:

	<u>Mole %</u>	<u>MW</u>	<u>Wt% (Calculated)</u>	<u>Carbon Content (wt%C)</u>
CO <sub>2</sub>	0.8	44.01	1.79	27.3
N <sub>2</sub>	1.8	28.01	2.56	0.0
CH <sub>4</sub>	83.0	16.04	67.70	74.9
C <sub>2</sub> H <sub>6</sub>	8.0	30.07	12.23	79.9
C <sub>3</sub> H <sub>8</sub>	5.0	44.10	11.21	81.7
C <sub>4</sub> H <sub>10</sub>	1.0	58.12	2.96	82.7
C <sub>5</sub> H <sub>12</sub>	0.3	72.15	1.10	83.2
C6+	0.1	86.18	0.44	83.6
<b>Fuel Mixture</b>	<b>100</b>	<b>19.66</b>	<b>100.0</b>	<b>73.85</b>

Exhibit 4-1(a) details how to calculate carbon content for individual components and for mixtures.

$$\text{CO}_2 : \frac{680 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{\text{lbmole}}{379.3 \text{ scf fuel}} \times \frac{19.66 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.7385 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}} \\ \times \frac{\text{lbmole CO}_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = \underline{43,300 \text{ tonnes CO}_2 / \text{yr}}$$

**Stationary Combustion Devices – CH<sub>4</sub> and N<sub>2</sub>O Emissions**

Combustion emission factors for natural gas fired engines are provided in Table 4-5.

**EXHIBIT 7.32: Production Gathering Compressor Station – CH<sub>4</sub> and N<sub>2</sub>O Emissions**

Emissions from 4 stroke, rich burn engines:

$$\text{CH}_4 : \frac{612,850 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.00010 \text{ tonne CH}_4}{10^6 \text{ Btu}} = \underline{61.3 \text{ tonnes CH}_4 / \text{yr}}$$

$$\text{N}_2\text{O} : \frac{612,850 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{4.50 \times 10^{-7} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}} = \underline{0.267 \text{ tonnes N}_2\text{O} / \text{yr}}$$

**EXHIBIT 7.32: Production Gathering Compressor Station – CH<sub>4</sub> and N<sub>2</sub>O Emissions, continued**

Emissions from the 4 stroke, lean burn engine:

$$\text{CH}_4 : \frac{111,427 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.00057 \text{ tonne CH}_4}{10^6 \text{ Btu}} = \underline{63.5 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{111,427 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{1.40 \times 10^{-6} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}} = \underline{0.156 \text{ tonnes N}_2\text{O}/\text{yr}}$$

**Vented Sources – Pneumatic Devices**

The pneumatic devices at the facility are actuated by natural gas. Methane emissions from pneumatic device vents are estimated using the "Production" segment average CH<sub>4</sub> emission factor presented in Table 5-15, as shown in Exhibit 7.34.

**EXHIBIT 7.34: Production Gathering Compressor Station - Pneumatic Device Vent Emissions**

$$\text{CH}_4 : (40 \text{ pneumatic devices}) \times \frac{2.415 \text{ tonne CH}_4}{\text{device} - \text{yr}} \times \frac{83.0 \text{ mol\% CH}_4 \text{ at site}}{78.8 \text{ mol\% CH}_4 \text{ generic}} = \underline{102 \text{ tonnes CH}_4/\text{y}}$$

**Vented Sources: Maintenance/Turnaround Emissions**

Methane emissions from compressor starts, compressor blowdowns, and production gathering pipeline blowdowns are estimated using the production segment emission factors presented in Table 5-21. The maintenance emission calculations are shown in Exhibit 7.35.

**EXHIBIT 7.35:      Production Gathering Compressor Station  
Maintenance/Turnaround Emissions**

Compressor starts:

$$\text{CH}_4 : (4 \text{ compressors}) \times \frac{0.1620 \text{ tonne CH}_4}{\text{compressor - yr}} \times \frac{83.0 \text{ mol\% CH}_4 \text{ at site}}{78.8 \text{ mol\% CH}_4 \text{ generic}} = \underline{0.68 \text{ tonnes CH}_4/\text{yr}}$$

Compressor blowdowns:

$$\text{CH}_4 : (4 \text{ compressors}) \times \frac{0.07239 \text{ tonne CH}_4}{\text{compressor - yr}} \times \frac{83.0 \text{ mol\% CH}_4 \text{ at site}}{78.8 \text{ mol\% CH}_4 \text{ generic}} = \underline{0.30 \text{ tonnes CH}_4/\text{yr}}$$

Pipeline blowdown venting (for 80 miles of gathering pipelines):

$$\text{CH}_4 : (80 \text{ miles}) \times \frac{0.00593 \text{ tonne CH}_4}{\text{mile - yr}} \times \frac{83.0 \text{ mol\% CH}_4 \text{ at site}}{78.8 \text{ mol\% CH}_4 \text{ generic}} = \underline{0.50 \text{ tonnes CH}_4/\text{yr}}$$

**Vented Sources: Other Releases**

Methane emissions from pressure relief valves (PRVs) are estimated using an emission factor presented in Table 5-22. This non-routine emission calculation is shown below:

**EXHIBIT 7.36:      Production Gathering Compressor Station Non-Routine Emissions**

Pressure relief valves:

$$\text{CH}_4 : (14 \text{ PRVs}) \times \frac{0.00065 \text{ tonne CH}_4}{\text{PRV - yr}} \times \frac{83.0 \text{ mol\% CH}_4 \text{ at site}}{78.8 \text{ mol\% CH}_4 \text{ generic}} = \underline{0.0096 \text{ tonnes CH}_4/\text{yr}}$$

**Fugitive Sources: Equipment Leaks**

Table 7-18 provides fugitive component emissions associated with the gathering compressor facility. The corresponding average component emission factors are also provided based on the EPA average oil and gas production emission factors given in Table B-14. The gas service CH<sub>4</sub> composition of 67.7 wt% is based on field test analyses for the facility.

**Table 7-18. Production Gathering Compressor Station  
Fugitive Emission Estimate**

Component	Service	Average Component Count	Component EF, tonnes TOC/comp./hr	Weight % CH <sub>4</sub>
Valves	Gas	675	4.5E-06	67.7
Control Valves	Gas	30	4.5E-06	67.7
Connectors	Gas	3,000	2.0E-07	67.7
Open-Ended Lines	Gas	60	2.0E-06	67.7
Compressor Seals	Gas	15	8.8E-06	67.7
Pressure Relief Valves	Gas	15	8.8E-06	67.7

The TOC emission factors are converted to a CH<sub>4</sub> basis. Emissions are calculated for each component by multiplying the component emission factor by the component count and the annual hours of operation (8,760 hours/year). The total fugitive emissions are then the sum of each of the component emissions. This is shown in Exhibit 7.37.

**EXHIBIT 7.37: Production Gathering Compressor Station Fugitive Emissions**

Compressor seals and pressure relief valves (PRVs) are grouped in the “Other” category. Control valves are included with the other valve components.

Component	Service	Average Component Count	Comp. EF (tonnes CH <sub>4</sub> /comp./hr)	Emissions, tonnes CH <sub>4</sub> /yr
Valves	Gas	705	3.05E-06	18.8
Connectors	Gas	3000	1.35E-07	3.56
Open-ended lines	Gas	60	1.35E-06	0.71
Other	Gas	30	5.96E-06	1.57
			<b>TOTAL</b>	<b>24.6</b>

Pipeline leaks also result in fugitive emissions, including CO<sub>2</sub> emissions due to soil oxidation. Emission factors for these sources are provided in Table 6-5. These calculations are demonstrated in the following exhibit.

**EXHIBIT 7.38: Production Gathering Compressor Station Non-Routine Emissions**

Pipeline leak emissions (for 80 miles of gathering pipelines):

$$\text{CH}_4 : (80 \text{ miles}) \times \frac{4.27 \times 10^{-5} \text{ tonne CH}_4}{\text{mi} - \text{hr}} \times \frac{8,760 \text{ hr}}{\text{year}} \times \frac{0.83 \text{ moles CH}_4 \text{ actual}}{0.788 \text{ moles CH}_4 \text{ default}} = \underline{31.5 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{CO}_2 \text{ (leaks)} : (80 \text{ miles}) \times \frac{5.85 \times 10^{-6} \text{ tonne CO}_2}{\text{mi} - \text{hr}} \times \frac{8,760 \text{ hr}}{\text{year}} \times \frac{0.008 \text{ moles CO}_2 \text{ actual}}{0.02 \text{ moles CO}_2 \text{ default}} = \underline{1.64 \text{ tonnes CO}_2/\text{yr}}$$

$$\text{CO}_2 \text{ (oxidation)} : (80 \text{ miles}) \times \frac{4.38 \times 10^{-6} \text{ tonne CO}_2}{\text{mi} - \text{hr}} \times \frac{8,760 \text{ hr}}{\text{year}} \times \frac{0.008 \text{ moles CO}_2 \text{ actual}}{0.02 \text{ moles CO}_2 \text{ default}} = \underline{1.23 \text{ tonnes CO}_2/\text{yr}}$$

**Indirect Sources - Electricity Consumption**

Emissions associated with the electricity purchased by the facility are calculated using emission factors in Table B-4 for Oklahoma. This calculation is demonstrated in the following exhibit.

**EXHIBIT 7.33 Production Gathering Compressor Station - Electricity Consumption Emissions**

$$\text{CO}_2 : \frac{680 \text{ MW} - \text{hr}}{\text{yr}} \times \frac{0.781 \text{ tonne CO}_2}{\text{MW} - \text{hr}} = \underline{531 \text{ tonnes CO}_2/\text{yr}}$$

$$\text{CH}_4 : \frac{680 \text{ MW} - \text{hr}}{\text{yr}} \times \frac{4.989 \times 10^{-6} \text{ tonne CH}_4}{\text{MW} - \text{hr}} = \underline{0.0034 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{680 \text{ MW} - \text{hr}}{\text{yr}} \times \frac{1.011 \times 10^{-5} \text{ tonne N}_2\text{O}}{\text{MW} - \text{hr}} = \underline{0.0069 \text{ tonnes N}_2\text{O}/\text{yr}}$$

**Facility Summary**

Total emissions for this facility are summarized in Table 7-19.

**Table 7-19. Production Gathering Compressor Station Emissions**

Source Type	Source	Emissions (tonnes/yr)		
		CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Combustion Sources	Engines	43,300	125	0.432
	<b>Combustion Total</b>	<b>43,300</b>	<b>125</b>	<b>0.432</b>
Vented sources	Pneumatic devices	0	102	
	Maintenance/turnaround	0	1.49	
	Other non-routine	0	0.01	
	<b>Vented Total</b>	<b>0</b>	<b>103</b>	
Fugitive Sources	Fugitive components	2.87	56.2	
	<b>Fugitive Total</b>	<b>2.87</b>	<b>56.2</b>	
Indirect Sources	Electricity	531	0.003	0.007
	<b>Indirect Total</b>	<b>531</b>	<b>0.003</b>	<b>0.007</b>
<b>TOTAL</b>		<b>43,800</b>	<b>284</b>	<b>0.439</b>
<b>Total CO<sub>2</sub> Equivalents</b>		<b>49,900</b>		

Totals may not sum due to independent rounding.

### 7.2.2 Marketing Terminal

**Facility Description:** A marketing terminal facility, located in New York, includes a main pump station with a loading capacity of 90 tank trucks per day (typically 10,000 gallon tankers).

**Throughput:** The terminal has an annual 300,000,000 gallon loading rack throughput.

**Operations:** The loading rack emissions are controlled by a vapor combustor unit.

Emission sources associated with the facility operations are summarized in Tables 7-20 and 7-21.

**Table 7-20. Marketing Terminal Combustion and Vented Emission Sources**

Source	Activity Factor	CO <sub>2</sub> Emissions (tonnes/yr)	CH <sub>4</sub> Emissions (tonnes/yr)	N <sub>2</sub> O Emissions (tonnes/yr)
<b>Combustion</b>		<b>19,900</b>	<b>0.402</b>	<b>0.191</b>
Heater – Natural Gas	235,000 × 10 <sup>6</sup> Btu/yr	12,500	0.235	0.0658
Heater – Diesel	4,500 bbl/yr	1,920	0.005	0.0227
Auxiliary fire pump – Diesel	12.5 gallons/hr (assume 200 hours/yr operation)	70.1	0.015	0.0104
Auxiliary generator – Diesel	22 gallons/hr (assume 200 hours/yr operation)			
Road tanker transport - Diesel operated	300,000 gallons/yr	3,050	0.147	0.090
Vapor combustor unit (VCU)	Pilot: 6000 gal propane/yr Gasoline loading 200 gallons/yr	34.3 2,330	~0	0.0025
<b>Vented Sources</b>		<b>~0</b>	<b>~0</b>	
Gasoline storage tank – Internal floating roof (IFR)	700×10 <sup>6</sup> gallons/yr	~0	~0	
Diesel storage tank – IFR	450×10 <sup>6</sup> gallons/yr	~0	~0	
Jet fuel storage tank – IFR	10×10 <sup>6</sup> gallons/yr	~0	~0	
Gasoline rail car/tank car loading/transit	200×10 <sup>6</sup> gallons/yr	~0 (transit) <sup>a</sup>	~0 (transit) <sup>a</sup>	
Diesel rail car/tank car loading/transit	120×10 <sup>6</sup> gallons/yr	~0 (transit) <sup>a</sup>	~0 (transit) <sup>a</sup>	
Jet fuel rail car/tank car loading/transit	2×10 <sup>6</sup> gallons/yr	~0 (transit) <sup>a</sup>	~0 (transit) <sup>a</sup>	
<b>Fugitive Sources</b>		<b>0</b>	<b>0</b>	
Fugitive equipment leaks	See Table 7-20	Negligible	Negligible	
<b>Indirect Sources</b>		<b>5,770</b>	<b>0.116</b>	<b>0.035</b>
Electricity purchased and consumed	1100 MW-hr/yr	428	0.004	0.0044
Steam purchased and consumed	97,600 × 10 <sup>9</sup> J/yr	5,340	0.112	0.0302

**Note, the values shown above are for example only. They do not reflect actual operations.**

Totals may not sum due to independent rounding.

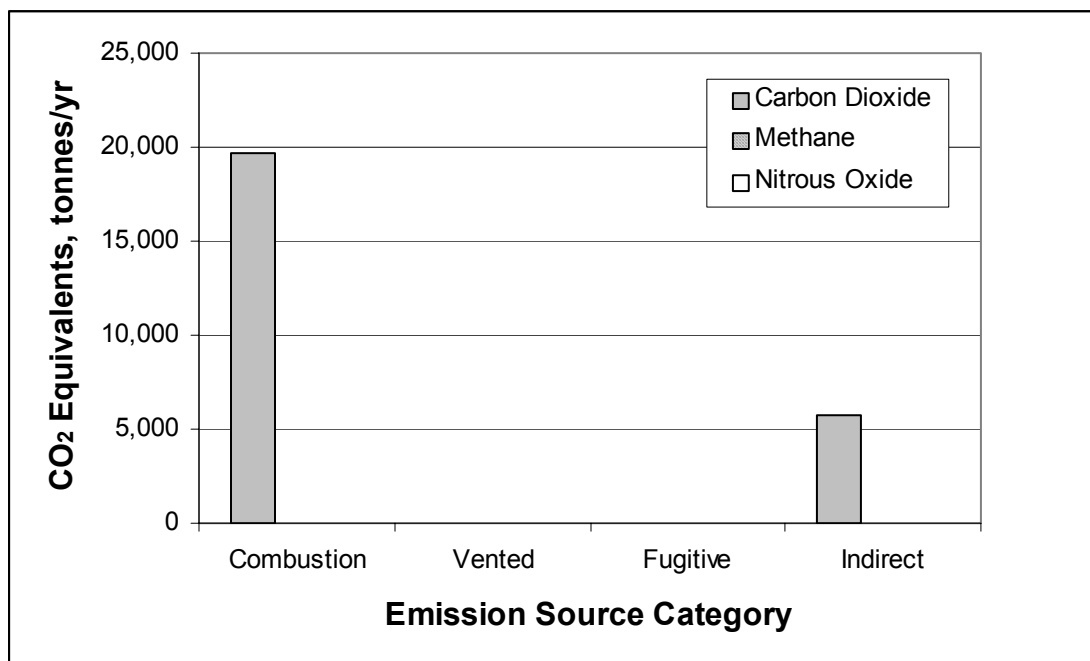
<sup>a</sup> Loading emissions are controlled by the vapor combustor unit (VCU). However, CH<sub>4</sub> emissions from loading operations are negligible due to the insignificant quantity of CH<sub>4</sub> in the loaded liquids.

**Table 7-21. Marketing Terminal Fugitive Emission Sources**

Component	Service	Average Component Count
Valves	Gas	30
Valves	Light liquid	390
Valves	Heavy liquid	50
Pump seals	Light liquid	25
Pump seals	Heavy liquid	3
Connectors/flanges	Gas	190
Connectors/flanges	Light liquid	3,100
Connectors/flanges	Heavy liquid	350
Open-ended lines	Gas	4
Open-ended lines	Light liquid	20
Open-ended lines	Heavy liquid	3
Pressure relief valves	Gas	1
Pressure relief valves	Light liquid	2

**Note, the values shown above are for example only. They do not reflect actual operations.**

A summary of the emissions (expressed in CO<sub>2</sub> equivalents) for this facility is given in Figure 7-5.

**Figure 7-5. Marketing Terminal Summary of Emissions**



## Stationary Combustion Devices – CO<sub>2</sub> Emissions

CO<sub>2</sub> emissions from natural gas and diesel combustion are calculated using the fuel-based emission factors provided in Table 4-1. These calculations are demonstrated in Exhibit 7.39

### EXHIBIT 7.39: Marketing Terminal –CO<sub>2</sub> Combustion Emissions

Natural gas heater:

$$\text{CO}_2 : \frac{235,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.0531 \text{ tonnes CO}_2}{10^6 \text{ Btu}} = 12,500 \text{ tonnes CO}_2 / \text{yr}$$

Diesel heater:

$$\text{Diesel firing rate} = \frac{4,500 \text{ bbl}}{\text{yr}} \times \frac{5.75 \times 10^6 \text{ Btu}}{\text{bbl}} = 25,875 \times 10^6 \text{ Btu/yr}$$

$$\text{CO}_2 : \frac{25,875 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.0742 \text{ tonnes CO}_2}{10^6 \text{ Btu}} = 1,920 \text{ tonnes CO}_2 / \text{yr}$$

Diesel Engines:

$$\begin{aligned} \text{CO}_2 : \left( \frac{12.5 + 22 \text{ gallons}}{\text{hr}} \right) \times \frac{200 \text{ hr}}{\text{yr}} \times \frac{\text{bbl}}{42 \text{ gallons}} \times \frac{5.75 \times 10^6 \text{ Btu}}{\text{bbl}} \times \frac{0.0742 \text{ tonne CO}_2}{10^6 \text{ Btu}} \\ = \underline{70.1 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

## Stationary Combustion Devices – CH<sub>4</sub> and N<sub>2</sub>O Emissions

Combustion emission factors for natural gas and diesel equipment are provided in Table 4-4a for controlled boilers and heaters, and Table 4-5 for engines. The distillate oil N<sub>2</sub>O emission factor from Table 4-4a is used in the absence of the diesel N<sub>2</sub>O factor. Table 4-5 provides an assumed CH<sub>4</sub> content of 10 wt% to convert from TOC emissions if the exhaust composition is unknown. The diesel heating value and density are provided in Table 3-5.

**EXHIBIT 7.40: Marketing Terminal – CH<sub>4</sub> and N<sub>2</sub>O Emissions**

Natural gas heater:

$$\text{CH}_4 : \frac{235,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{1.0 \times 10^{-6} \text{ tonnes CH}_4}{10^6 \text{ Btu}} = 0.235 \text{ tonnes CH}_4 / \text{yr}$$

$$\text{N}_2\text{O} : \frac{235,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{2.80 \times 10^{-7} \text{ tonnes N}_2\text{O}}{10^6 \text{ Btu}} = 0.0658 \text{ tonnes N}_2\text{O} / \text{yr}$$

Diesel heater:

$$\text{CH}_4 : \frac{4,500 \text{ bbl}}{\text{yr}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{7.1 \text{ lb}}{\text{gal}} \times \frac{\text{tonne}}{2,204.62 \text{ lb}} \times \frac{7.80 \times 10^{-6} \text{ tonnes CH}_4}{\text{tonnes diesel}} = 0.005 \text{ tonnes CH}_4 / \text{yr}$$

$$\text{N}_2\text{O} : \frac{4,500 \text{ bbl}}{\text{yr}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{1.2 \times 10^{-7} \text{ tonnes N}_2\text{O}}{\text{gal}} = 0.0023 \text{ tonnes N}_2\text{O} / \text{yr}$$

Diesel engines:

$$\begin{aligned} \text{CH}_4 : \left( \frac{12.5 + 22 \text{ gallons}}{\text{hr}} \right) \times \frac{200 \text{ hr}}{\text{yr}} \times \frac{\text{bbl}}{42 \text{ gallons}} \times \frac{5.75 \times 10^6 \text{ Btu}}{\text{bbl}} \times \frac{0.00016 \text{ tonne TOC}}{10^6 \text{ Btu}} \\ \times \frac{0.1 \text{ tonne CH}_4}{\text{tonne TOC}} = \underline{0.015 \text{ tonnes CH}_4/\text{yr}} \end{aligned}$$

$$\text{N}_2\text{O} : \left( \frac{12.5 + 22 \text{ gallons}}{\text{hr}} \right) \times \frac{200 \text{ hr}}{\text{yr}} \times \frac{1.51 \times 10^{-6} \text{ tonne N}_2\text{O}}{\text{gal}} = \underline{0.0104 \text{ tonnes N}_2\text{O}/\text{yr}}$$

**Combustion Sources – Vapor Combustor Unit (VCU)**

The loading rack emissions are controlled by a vapor combustor, which results in CO<sub>2</sub> emissions due to combustion of the captured hydrocarbon vapors. Methane emissions are assumed to be negligible due to the low CH<sub>4</sub> content in the fuels being loaded.

The captured hydrocarbon rates from the loading operation are estimated using the simplified total organic compound (TOC) emission factors given in Table 5-10, assuming submerged loading and vapor balance service for gasoline. Table 5-10 does not contain emissions factors for diesel and jet fuel; therefore, only calculations for gasoline are included. Next, the VCU CO<sub>2</sub> emissions are

estimated using the carbon content of the loaded liquid given in Table 3-5 and assuming complete combustion to CO<sub>2</sub>. The CO<sub>2</sub> emissions from burning propane for the pilot are estimated using the fuel basis propane emission factor given in Table 4-1. N<sub>2</sub>O emissions from the propane pilot are calculated using emissions factors from Table 4-4a. The VCU emission calculation is given in Exhibit 7.41

#### EXHIBIT 7.41: Marketing Terminal - Vapor Combustor Emissions

First, the hydrocarbon vent rates to the VCU must be estimated using the emission factors given in Table 5-10 assuming submerged loading and vapor balance service for gasoline.

Gasoline:

$$\frac{200 \times 10^6 \text{ gallons}}{\text{yr}} \times \frac{3.71 \text{ tonne TOC}}{10^6 \text{ gallons loaded}} = 742 \text{ tonnes TOC/yr}$$

Next, the CO<sub>2</sub> emission rates are estimated using the carbon content of gasoline given in Table 3-5.

Gasoline:

$$\text{CO}_2 : \frac{742 \text{ tonnes TOC}}{\text{yr}} \times \frac{0.855 \text{ tonne C}}{\text{tonne TOC}} \times \frac{44.01 \text{ tonne CO}_2}{12.01 \text{ tonne C}} = 2,325 \text{ tonnes CO}_2/\text{yr}$$

The CO<sub>2</sub> emissions from burning propane for the pilot are estimated using the fuel heating value from Table 3-5 and the CO<sub>2</sub> fuel basis emission factor from Table 4-1.

$$\text{CO}_2 : \frac{6000 \text{ gal}}{\text{yr}} \times \frac{\text{bbl}}{42 \text{ gal}} \times \frac{3.80 \times 10^6 \text{ Btu}}{\text{bbl}} \times \frac{0.0631 \text{ tonne CO}_2}{10^6 \text{ Btu}} = 34.3 \text{ tonnes CO}_2/\text{yr}$$

Thus, the total CO<sub>2</sub> emissions from the vapor combustor are:

$$\begin{aligned} \text{Total CO}_2 : & 2,325 \text{ tonnes CO}_2/\text{yr} + 34.3 \text{ tonnes CO}_2/\text{yr} \\ & = \underline{2,360 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

N<sub>2</sub>O (from pilot):

$$\text{N}_2\text{O} : \frac{6,000 \text{ gal}}{\text{yr}} \times \frac{4.10 \times 10^{-7} \text{ tonnes N}_2\text{O}}{\text{gal}} = 0.0025 \text{ tonnes N}_2\text{O/yr}$$

## Combustion Sources – Road Tankers

The mobile source combustion emissions from road tankers are estimated using the emission factor for the heavy-duty diesel operated road tanker with moderate control given in Table 4-9. The mobile source emissions are given in Exhibit 7.42.

### **EXHIBIT 7.42:      Marketing Terminal - Associated Mobile Source Combustion (Diesel Road Tankers) Emissions**

The diesel heating value is given in Table 3-5. Thus, the heat rate is:

$$\frac{300,000 \text{ gal}}{\text{yr}} \times \frac{\text{bbl}}{42 \text{ gal}} \times \frac{5.75 \times 10^6 \text{ Btu}}{\text{bbl}} = 4.107 \times 10^{10} \text{ Btu/yr}$$

The CH<sub>4</sub> and N<sub>2</sub>O emission factors are given in Table 4-9 using “moderate control, heavy duty diesel vehicles.” The CO<sub>2</sub> emissions are based on a factor from Table 4-1. Thus, the CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O emissions are:

$$\text{CO}_2 : \frac{4.107 \times 10^{10} \text{ Btu}}{\text{yr}} \times \frac{0.0742 \text{ tonne CO}_2}{10^6 \text{ Btu}} = \underline{3,050 \text{ tonnes CO}_2/\text{yr}}$$

$$\text{CH}_4 : \frac{300,000 \text{ gal}}{\text{yr}} \times \frac{0.00049 \text{ tonne CH}_4}{1000 \text{ gal}} = \underline{0.147 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{300,000 \text{ gal}}{\text{yr}} \times \frac{0.0003 \text{ tonne N}_2\text{O}}{1000 \text{ gal}} = \underline{0.090 \text{ tonnes N}_2\text{O/yr}}$$

## Vented Sources – Storage Tanks

Methane emissions from gasoline, diesel, and jet fuel storage tanks (working and breathing losses) are negligible because these fuels contain negligible amounts of CH<sub>4</sub>.

## Vented Sources – Loading and Transit Operations

Tables 5-10 and 5-14 provide TOC loading and transit emission factors, respectively, for the fuel types at this facility, but note that the fuels contain negligible amounts of CH<sub>4</sub>. Therefore, no CH<sub>4</sub> emissions result from gasoline, diesel, or jet fuel loading or transit operations. Also, the loading

vent emissions are controlled by the vapor combustor unit (VCU). The CO<sub>2</sub> emissions resulting from the combustion from this unit are estimated under stationary combustion devices given earlier in this section.

### Fugitive Sources: Equipment Leaks

Table 7-21 provides fugitive component counts associated with the marketing terminal equipment. The marketing terminal fugitive streams are assumed to have a negligible CH<sub>4</sub> content because the products have been refined. Thus, CH<sub>4</sub> fugitive emissions are not estimated.

### Indirect Sources - Electricity Consumption

Emissions associated with the electricity purchased by the facility are calculated using emission factors in Table B-4 for New York. This calculation is demonstrated in the following exhibit.

#### **EXHIBIT 7.43      Marketing Terminal – Electricity Consumption Emissions**

$$\text{CO}_2 : \frac{1,100 \text{ MW} \cdot \text{hr}}{\text{yr}} \times \frac{0.389 \text{ tonne CO}_2}{\text{megawatt} \cdot \text{hr}} = \underline{428 \text{ tonnes CO}_2/\text{yr}}$$

$$\text{CH}_4 : \frac{1,100 \text{ MW} \cdot \text{hr}}{\text{yr}} \times \frac{3.673 \times 10^{-6} \text{ tonne CH}_4}{\text{megawatt} \cdot \text{hr}} = \underline{0.004 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{1,100 \text{ MW} \cdot \text{hr}}{\text{yr}} \times \frac{4.036 \times 10^{-6} \text{ tonne N}_2\text{O}}{\text{megawatt} \cdot \text{hr}} = \underline{0.0044 \text{ tonnes N}_2\text{O}/\text{yr}}$$

### Indirect Sources - Steam Consumption

Emissions associated with the steam purchased by the facility are calculated using the approach described in Section 4.7.2, as demonstrated in the following exhibit.

#### EXHIBIT 7.44 Marketing Terminal – Steam Consumption Emissions

Because no information about the steam production is known, we assume a 92% efficient natural gas boiler and use the emission factors provided in Section 4.7.2.

$$\text{Steam energy} = \frac{97,600 \times 10^9 \text{ J}}{\text{yr}} \times \frac{\text{Btu}}{1,055.056 \text{ J}} = 92,507 \times 10^6 \text{ Btu/yr}$$

$$\text{CO}_2 : \frac{92,507 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.05772 \text{ tonne CO}_2}{10^6 \text{ Btu}} = \underline{5,340 \text{ tonnes CO}_2/\text{yr}}$$

$$\text{CH}_4 : \frac{92,507 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{1.21 \times 10^{-6} \text{ tonne CH}_4}{10^6 \text{ Btu}} = \underline{0.112 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{92,507 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{3.26 \times 10^{-7} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}} = \underline{0.0302 \text{ tonnes N}_2\text{O/yr}}$$

#### Facility Summary

Total emissions for this facility are summarized in Table 7-22.

**Table 7-22. Marketing Terminal Emissions**

Source Type	Source	Emissions (tonnes/yr)		
		CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Combustion Sources	External combustion (heaters)	14,400	0.240	0.088
	Internal combustion (engines)	70	0.015	0.011
	Mobile source (tankers)	3,050	0.147	0.090
	VCU (vapor combustor)	2,360	0	0.002
	<b>Combustion Total</b>	<b>19,900</b>	<b>0.402</b>	<b>0.191</b>
Vented sources	Storage tanks	0	0	
	Loading / transit	0	0	
	<b>Vented Total</b>	<b>0</b>	<b>0</b>	
Fugitive Sources	Fugitive components	Negligible	Negligible	
	<b>Fugitive Total</b>	<b>0</b>	<b>0</b>	
Indirect Sources	Electricity consumed	428	0.004	0.0044
	Steam consumed	5,340	0.112	0.0302
	<b>Indirect Total</b>	<b>5,770</b>	<b>0.116</b>	<b>0.0346</b>
<b>TOTAL</b>		<b>25,600</b>	<b>0.518</b>	<b>0.226</b>
<b>Total CO<sub>2</sub> Equivalents</b>		<b>25,700</b>		

Totals may not sum due to independent rounding.

## 7.3 Refining

### 7.3.1 Refinery

**Facility Description:** The facility in the UK consists of an oil refinery with a hydrogen plant. The refinery also has a catalytic cracking unit.

**Throughput:** The refinery has a capacity of 250,000 bbl crude/day. For the inventory year, Table 7-23 summarizes the feed streams to the hydrogen plant.

**Operations:** The combustion sources are fired with either refinery fuel gas or natural gas. The refinery fuel gas has a heating value of 1,119 Btu/scf; the natural gas has a heating value of 1,050 Btu/scf. The average molecular weight and heating value of gas flared is 72 lb/lbmole and 4,009 Btu/scf, respectively based on assuming the properties of pentane. The facility imported 76,000 megawatt (MW) hours of electricity for the inventory year.

The refinery has the emission sources listed in Table 7-24.

**Table 7-23. Hydrogen Plant Feed Streams**

Gas Compound	Volume %	
	Natural Gas	Refinery Fuel Gas
Carbon Dioxide	0.6	
Nitrogen	0.5	
Hydrogen		30
Methane	94.4	35
Ethane	3.4	31
Propane	0.6	3
Butanes	0.5	1
Pentanes		
C6+		
Feed Rate 10 <sup>6</sup> scfy	6,600	4,000

Note, the values shown above are for example only. They do not reflect actual operations.

**Table 7-24. Refinery Emissions Sources**

Source	No. of Units	Activity Factor (total)	CO <sub>2</sub> Emissions (tonnes/yr)	CH <sub>4</sub> Emissions (tonnes/yr)	N <sub>2</sub> O Emissions (tonnes/yr)
<i>Vented Sources</i>			<b>2,570,000</b>	<b>0</b>	<b>0</b>
Hydrogen plant – natural gas feed	N/A	6,600×10 <sup>6</sup> scfy	367,000		
Hydrogen plant – refinery fuel gas feed	N/A	4,000×10 <sup>6</sup> scfy	232,000		
FCCU regenerator	1	16,500,000×10 <sup>6</sup> Btu/yr, coke consumed (coke contains ~91 wt% carbon)	1,970,000		
Crude tanks	Not Given	91.25×10 <sup>6</sup> bbl/yr	0	0	
Maintenance/Turnaround activities	N/A	N/A	Included w/ Flaring	Included w/ Flaring	
<i>Fugitive Sources</i>			<b>0</b>	<b>0</b>	
Fugitives	N/A	See Table 7-25	Negligible	Negligible	
<i>Indirect Sources</i>			<b>32,700</b>	<b>0.705</b>	<b>4.96</b>
Imported electricity		76,000×10 <sup>6</sup> W-hr/yr	32,700	0.705	4.96

Note, the values shown above are for example only. They do not reflect actual operations. Totals may not sum due to independent rounding.



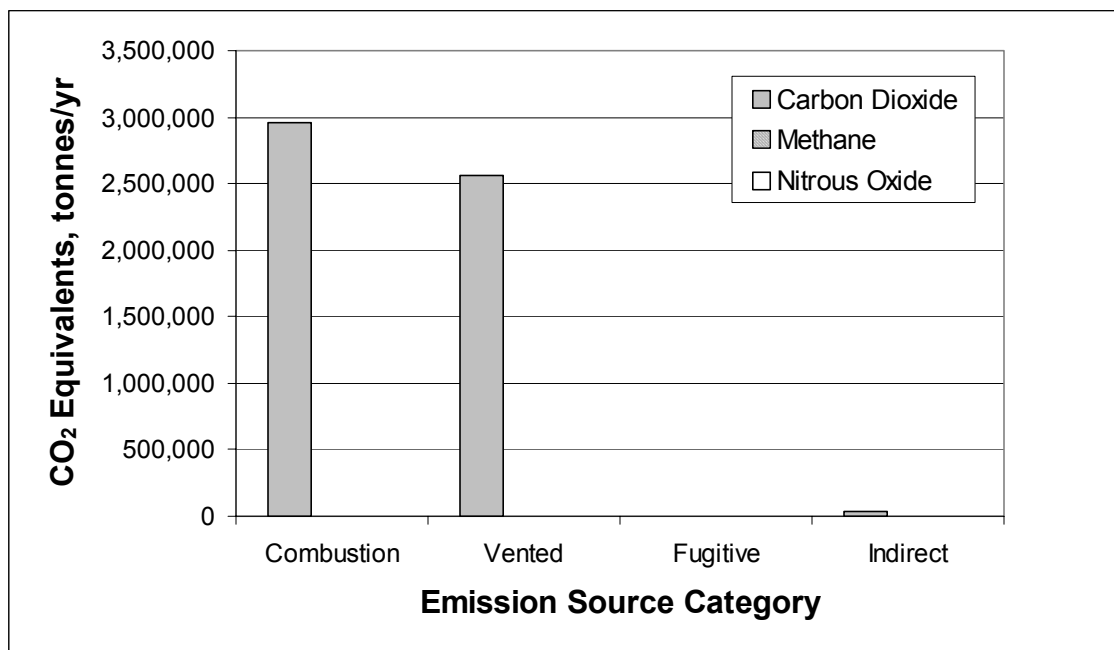
Table 7-24. Refinery Emissions Sources, continued

Source	No. of Units	Average Firing Rate per unit (10 <sup>6</sup> Btu/hr)	Average Operating Hours per Unit (hr/yr)	Activity Factor (total)	CO <sub>2</sub> Emissions (tonnes/yr)	CH <sub>4</sub> Emissions (tonnes/yr)	N <sub>2</sub> O Emissions (tonnes/yr)
<b>Combustion Sources</b>					<b>2,960,000</b>	<b>482</b>	<b>114</b>
Power (steam) boilers (refinery fuel gas)	10	280	8,000	22,400,000×10 <sup>6</sup> Btu/yr	1,160,000	5.08	6.27
Process heaters (refinery fuel gas)	40	70	7,800	21,840,000×10 <sup>6</sup> Btu/yr	1,130,000	4.96	6.12
FCCU CO boiler (refinery fuel gas)	1	175	8,700	1,522,500×10 <sup>6</sup> Btu/yr	78,800	0.35	0.426
IC engines (natural gas)	10	12 (Average design of 1060 hp/unit)	5,600	672,000×10 <sup>6</sup> Btu/yr	35,600	444	1.55
Gas turbines (natural gas)	3	280	8,500	7,140,000×10 <sup>6</sup> Btu/yr	378,000	27.8	100.
Flaring	Not Given	Not Given	Not Given	2,400,000×10 <sup>6</sup> Btu/yr	154,000	0.330	
Incinerators (sulfur recovery unit, tail gas treatment unit)	4	10	8,600	344,000×10 <sup>6</sup> Btu/yr	19,500	0.078	0.096

**Note, the values shown above are for example only. They do not reflect actual operations.**

Totals may not sum due to independent rounding.

A summary of the emissions (expressed in CO<sub>2</sub> equivalents) for this facility is given in Figure 7-6.



**Figure 7-6. Refinery Summary of Emissions**

### Stationary Combustion Devices – CO<sub>2</sub> Emissions

CO<sub>2</sub> emissions from combustion are calculated using the gas composition approach provided in Section 4.1. These calculations are demonstrated in Exhibit 7.45

**EXHIBIT 7.45: Refinery –CO<sub>2</sub> Combustion Emissions**

Fuel composition and carbon content:

**Natural Gas:**

	<u>Mole %</u>	<u>MW</u>	<u>Wt% (Calculated)</u>	<u>Carbon Content (wt%C)</u>
CO <sub>2</sub>	0.6	44.01	1.54	0.0
N <sub>2</sub>	0.5	28.01	0.82	27.3
H <sub>2</sub>	0	2.02	0	0.0
CH <sub>4</sub>	94.4	16.04	88.43	74.9
C <sub>2</sub> H <sub>6</sub>	3.4	30.07	5.97	79.9
C <sub>3</sub> H <sub>8</sub>	0.6	44.10	1.55	81.7
C <sub>4</sub> H <sub>10</sub>	0.5	58.12	1.70	82.7
C <sub>5</sub> H <sub>12</sub>	0	72.15	0	83.2
C6+	0	86.18	0	83.6
<b>Fuel Mixture</b>	<b>100</b>	<b>17.12</b>	<b>100.0</b>	<b>74.07</b>

**Refinery Fuel Gas**

	<u>Mole %</u>	<u>MW</u>	<u>Wt% (Calculated)</u>	<u>Carbon Content (wt%C)</u>
CO <sub>2</sub>	0	44.01	0	0.0
N <sub>2</sub>	0	28.01	0	27.3
H <sub>2</sub>	30	2.02	3.47	0.0
CH <sub>4</sub>	35	16.04	32.18	74.9
C <sub>2</sub> H <sub>6</sub>	31	30.07	53.43	79.9
C <sub>3</sub> H <sub>8</sub>	3	44.10	7.58	81.7
C <sub>4</sub> H <sub>10</sub>	1	58.12	3.33	82.7
C <sub>5</sub> H <sub>12</sub>	0	72.15	0	83.2
C6+	0	86.18	0	83.6
<b>Fuel Mixture</b>	<b>100</b>	<b>17.45</b>	<b>100.0</b>	<b>75.73</b>

Exhibit 4-1(a) details how to calculate carbon content for individual components and for mixtures.

**Internal Combustion**

Natural gas firing rate

$$\begin{aligned}
 &= (10 \text{ IC engines} \times \frac{12 \times 10^6 \text{ Btu}}{\text{engine}} \times \frac{5,600 \text{ hr}}{\text{yr}}) + (3 \text{ turbines} \times \frac{280 \times 10^6 \text{ Btu}}{\text{turbine}} \times \frac{8,500 \text{ hr}}{\text{yr}}) \\
 &= (672,000 + 7,140,000) \times 10^6 \text{ Btu/yr} \\
 &= 7,812,000 \times 10^6 \text{ Btu/yr}
 \end{aligned}$$

**EXHIBIT 7.45: Refinery –CO<sub>2</sub> Combustion Emissions, continued**

The higher heating value for the natural gas is 1,050 Btu/scf.

$$\frac{7,812,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{\text{scf}}{1,050 \text{ Btu}} = 7,440 \times 10^6 \text{ scf/yr}$$

$$\begin{aligned} \text{CO}_2 : & \frac{7,440 \times 10^6 \text{ scf fuel}}{\text{yr}} \times \frac{\text{lbmole}}{379.3 \text{ scf fuel}} \times \frac{17.12 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.7407 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}} \\ & \times \frac{\text{lbmole CO}_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = \underline{413,000 \text{ tonnes CO}_2 / \text{yr}} \end{aligned}$$

*External Combustion*

Refinery fuel gas firing rate

$$\begin{aligned} & = (10 \text{ steam boilers} \times \frac{280 \times 10^6 \text{ Btu}}{\text{boiler}} \times \frac{8,000 \text{ hr}}{\text{yr}}) + (40 \text{ heaters} \times \frac{70 \times 10^6 \text{ Btu}}{\text{heater}} \times \frac{7,800 \text{ hr}}{\text{yr}}) \\ & \quad + (1 \text{ FCCU CO boiler} \times \frac{175 \times 10^6 \text{ Btu}}{\text{FCCU CO boiler}} \times \frac{8,700 \text{ hr}}{\text{yr}}) \\ & = (22,400,000 + 21,840,000 + 1,522,500) \times 10^6 \text{ Btu} \\ & = 45,762,500 \times 10^6 \text{ Btu/yr} \end{aligned}$$

The higher heating value for refinery fuel gas is 1,119 Btu/scf.

$$\frac{45,762,500 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{\text{scf}}{1,119 \text{ Btu}} = 40,895.9 \times 10^6 \text{ scf/yr}$$

$$\begin{aligned} \text{CO}_2 : & \frac{40,895.9 \times 10^6 \text{ scf fuel}}{\text{yr}} \times \frac{\text{lbmole}}{379.3 \text{ scf fuel}} \times \frac{17.45 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.7573 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}} \\ & \times \frac{\text{lbmole CO}_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = \underline{2,370,000 \text{ tonnes CO}_2 / \text{yr}} \end{aligned}$$

Stationary Combustion Devices – CH<sub>4</sub> and N<sub>2</sub>O Emissions

Combustion emission factors for natural gas and refinery fuel gas equipment are provided in Table 4-4a for controlled boilers and heaters. N<sub>2</sub>O emission factors for controlled natural gas heaters are used in the absence of refinery fuel gas emission factors. External combustion emissions come from the steam boilers, the process heaters, and the FCCU CO boiler.

Internal combustion emissions come from the natural gas engines and the turbines. Emission factors are provided in Table 4-5. The IC engines are assumed to be 2-cycle lean burn engines. Exhibit 7.46 demonstrates the emission estimates for these sources.

**EXHIBIT 7.46: Refinery – CH<sub>4</sub> and N<sub>2</sub>O Combustion Emissions***External Combustion*

The “Heater – Refinery fuel gas (High H<sub>2</sub>-content gas)” emissions factor from Table 4-4a is used.

$$\text{CH}_4 : \frac{45,762,500 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{2.27 \times 10^{-7} \text{ tonne CH}_4}{10^6 \text{ Btu}} = \underline{10.4 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{45,762,500 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{2.8 \times 10^{-7} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}} = \underline{12.8 \text{ tonnes N}_2\text{O}/\text{yr}}$$

*Internal Combustion*

Natural Gas IC Engines:

$$\text{CH}_4 : \frac{672,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.00066 \text{ tonne CH}_4}{10^6 \text{ Btu}} = \underline{444 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{672,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{2.3 \times 10^{-6} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}} = \underline{1.55 \text{ tonnes N}_2\text{O}/\text{yr}}$$

Natural Gas Turbines:

Controlled (SCR) emission factors are used.

$$\text{CH}_4 : \frac{7,140,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{3.9 \times 10^{-6} \text{ tonne CH}_4}{10^6 \text{ Btu}} = \underline{27.8 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{7,140,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{1.4 \times 10^{-5} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}} = \underline{100. \text{ tonnes N}_2\text{O}/\text{yr}}$$

## Combustion Sources – Flares

The flaring emissions are determined based on the guidance in Section 4.4. CH<sub>4</sub> emissions are based on the emission factor given in Table 4-7, and CO<sub>2</sub> emissions are based on 98% combustion efficiency.

The molecular weight of the flared gas is approximately 72, and the heating value is approximately 4009 Btu/scf, which are based on assuming the properties of pentane for the gas flared. Also, the carbon content of the flared gas is assumed to be 83.24 wt% carbon, based on the assumption that the flared gas is mostly pentane.

### EXHIBIT 7.47: Refinery Flare Emissions

The CH<sub>4</sub> flaring emission factor is based on the barrels of crude feed to the refinery.

$$\text{CH}_4 : \frac{250,000 \text{ bbl}}{\text{day}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{3.62 \times 10^{-6} \text{ tonne CH}_4}{1000 \text{ bbl}} = \underline{0.330 \text{ tonnes CH}_4/\text{yr}}$$

The CO<sub>2</sub> flaring emissions are based on the quantity of gas flared and 98% combustion efficiency.

$$\begin{aligned} \text{CO}_2 : & \frac{2,400,000 \times 10^6 \text{ Btu gas}}{\text{yr}} \times \frac{\text{scf}}{4009 \text{ Btu}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{72 \text{ lb gas}}{\text{lbmole gas}} \times \frac{0.8324 \text{ lb C}}{\text{lb gas}} \\ & \times \frac{\text{lbmole C}}{12.01 \text{ lb C}} \times \frac{0.98 \text{ lbmole CO}_2 \text{ formed}}{\text{lbmole C combusted}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} \\ & = \underline{154,000 \text{ tonnes CO}_2/\text{yr}} \end{aligned}$$

## Combustion Sources – Incinerators

Incinerator emissions result from both combustion emissions and from the untreated portion of the waste gas. The treatment efficiency of the waste gas is typically 98%. Because the waste gas composition is unknown, only combustion emissions are estimated for the incinerators for this example. The CH<sub>4</sub> emissions are estimated using the “Heater – Refinery fuel gas (High H<sub>2</sub> content)” emission factors given in Table 4-4a. To be conservative, the N<sub>2</sub>O emission factor for the natural gas boiler/heater in Table 4-4a is used in the absence of a refinery fuel N<sub>2</sub>O factor. The CO<sub>2</sub> emissions are estimated using the fuel specific emission factor for refinery fuel gas given in Table 4-1.

**EXHIBIT 7.48: Refinery Incinerator Emissions**

$$\text{CH}_4 : \frac{344,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{2.27 \times 10^{-7} \text{ tonne CH}_4}{10^6 \text{ Btu}} = \underline{0.078 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{344,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{2.8 \times 10^{-7} \text{ tonne CH}_4}{10^6 \text{ Btu}} = \underline{0.096 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{CO}_2 : \frac{344,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.0567 \text{ tonne CO}_2}{10^6 \text{ Btu}} = \underline{19,500 \text{ tonnes CO}_2/\text{yr}}$$

**Vented Emissions – Hydrogen Plant**

Carbon dioxide emissions from the hydrogen plant are estimated based on the feed rate and compositions of the three streams specified in Table 7-23 using Equation 5-6. These emission calculations are demonstrated in Exhibit 7.50

**EXHIBIT 7.50: Refinery – Hydrogen Plant Emissions**

Fuel composition and carbon content:

From Exhibit 7.45,

Natural gas MW = 17.12

Natural gas wt%C = 74.07

Refinery fuel gas MW = 17.45

Refinery fuel gas wt%C = 75.73

Exhibit 4-1(a) details how to calculate carbon content for individual components and for mixtures.

Feed rates to hydrogen plant:

Natural gas = 6,600 MMscf/yr

Refinery fuel gas = 4,000 MMscf/yr

**EXHIBIT 7.50: Refinery – Hydrogen Plant Emissions, continued**

Equation 5-6 is used to estimate the CO<sub>2</sub> hydrogen plant emissions.

Natural gas:

$$\text{CO}_2 : \frac{6,600 \times 10^6 \text{ scf fuel}}{\text{yr}} \times \frac{\text{lbmole}}{379.3 \text{ scf fuel}} \times \frac{17.12 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.7407 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}} \\ \times \frac{1 \text{ lbmole CO}_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = 367,000 \text{ tonnes CO}_2 / \text{yr}$$

Refinery fuel gas:

$$\text{CO}_2 : \frac{4,000 \times 10^6 \text{ scf fuel}}{\text{yr}} \times \frac{\text{lbmole}}{379.3 \text{ scf fuel}} \times \frac{17.45 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.7573 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}} \\ \times \frac{1 \text{ lbmole CO}_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = 232,000 \text{ tonnes CO}_2 / \text{yr}$$

$$\text{Total CO}_2 = (367,000 + 232,000) \text{ tonnes CO}_2 = 598,000 \text{ tonnes CO}_2$$

**Vented Emissions – Catalytic Cracking Regenerator Vent**

Carbon dioxide emissions from the catalytic cracking regenerator vent are estimated using the coke burn rate and Equation 5-3, as shown below. The CH<sub>4</sub> emissions are assumed to be negligible from this source.

**EXHIBIT 7.51: Refinery Catalytic Cracking Regenerator Vent**

First, the coke burn rate in Btu/year must be converted to a mass basis using the default coke heating value given in Table 3-5.

$$\text{Coke burn rate} : \frac{16,500,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{\text{lb}}{12,690 \text{ Btu}} \times \frac{\text{tonnes}}{2204.62 \text{ lb}} \\ = 589,778 \text{ tonnes Coke Burned / yr}$$



### **EXHIBIT 7.51: Refinery Catalytic Cracking Regenerator Vent, continued**

The CO<sub>2</sub> emissions are estimated using Equation 4.2-2. The fraction of carbon in the coke is approximately 0.91.

$$\text{CO}_2 : \frac{589,778 \text{ tonnes Coke Burned}}{\text{yr}} \times \frac{0.91 \text{ lb C}}{\text{lb Coke}} \times \frac{44.01 \text{ lb CO}_2}{12.01 \text{ lb C}} = \underline{1,970,000 \text{ tonnes CO}_2 / \text{yr}}$$

#### **Vented Sources – Storage Tanks**

Methane emissions from storage tank standing and working losses are negligible because the liquids stored in the refinery have a negligible CH<sub>4</sub> content.

#### **Vented Sources – Loading and Transit Operations**

Tables 5-10 and 5-14 provide TOC loading and transit emission factors, respectively, for various refined fuel types, but note that the fuels contain negligible amounts of CH<sub>4</sub>. Therefore, no CH<sub>4</sub> or CO<sub>2</sub> emissions result from loading or transit of refined products (gasoline, diesel, jet fuel, etc.).

#### **Vented Sources: Maintenance/Turnaround Emissions**

As noted in Section 5.7.6, non-routine related activities at refineries typically vent to the fuel gas system or a flare. Thus, these activities are included with the flare emissions presented in Exhibit 7.47.

#### **Fugitive Sources: Equipment Leaks**

The CH<sub>4</sub> content of non-fuel gas systems components is generally very small or non-detectable, as most of the CH<sub>4</sub> has flashed off by the time the crude reaches the refinery. In addition, preliminary results from an API study indicate that the contribution to greenhouse gas emissions from fuel gas system components is less than 0.1%. Thus, CH<sub>4</sub> emissions for the refinery fugitive components are negligible.

#### **Indirect Sources - Electricity Consumption**

Emissions associated with the electricity purchased by the facility are calculated using emission factors in Table 4-13 for the UK. This calculation is demonstrated in the following exhibit.

**EXHIBIT 7.49 Hydrogen Plant – Electricity Consumption Emissions**

$$\text{CO}_2 : \frac{76,000 \text{ MW} \cdot \text{hr}}{\text{yr}} \times \frac{0.43 \text{ tonne CO}_2}{\text{megawatt} \cdot \text{hr}} = \underline{32,700 \text{ tonnes CO}_2/\text{yr}}$$

$$\text{CH}_4 : \frac{76,000 \text{ MW} \cdot \text{hr}}{\text{yr}} \times \frac{9.27 \times 10^{-6} \text{ tonne CH}_4}{\text{megawatt} \cdot \text{hr}} = \underline{0.70 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{76,000 \text{ MW} \cdot \text{hr}}{\text{yr}} \times \frac{6.52 \times 10^{-5} \text{ tonne N}_2\text{O}}{\text{megawatt} \cdot \text{hr}} = \underline{4.96 \text{ tonnes N}_2\text{O}/\text{yr}}$$

**Facility Summary**

Total emissions for this case are summarized in Table 7-26.

**Table 7-25. Refinery Emissions**

Source Type	Source	Emissions (tonnes/yr)		
		CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Combustion Sources	External combustion	2,370,000	10.4	12.8
	Internal combustion	413,000	471	102
	Flares	154,000	0.33	
	Incinerators	19,500	0.08	0.10
	<b>Combustion Total</b>	<b>2,960,000</b>	<b>482</b>	<b>114</b>
Vented sources	Hydrogen plant vents	598,000	0	
	Catalytic cracking regeneration vent	1,970,000	0	
	Storage tanks	0	0	
	Loading / transit	0	0	
	<b>Vented Total</b>	<b>2,570,000</b>	<b>0</b>	
Fugitive Sources	Fugitive components	Negligible	Negligible	
	<b>Fugitive Total</b>	<b>0</b>	<b>0</b>	
Indirect Sources	Electricity purchased	32,700	0.70	4.96
	<b>Indirect Total</b>	<b>32,700</b>	<b>0.70</b>	<b>4.96</b>
<b>TOTAL</b>		<b>5,550,000</b>	<b>483</b>	<b>119</b>
<b>Total CO<sub>2</sub> Equivalents</b>		<b>5,600,000</b>		

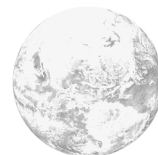
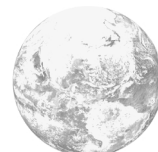
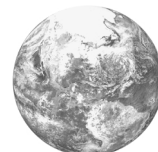
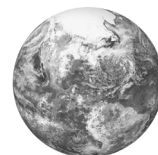
Totals may not sum due to independent rounding.

FEBRUARY 2004

**COMPENDIUM OF GREENHOUSE GAS  
EMISSIONS METHODOLOGIES FOR  
THE OIL AND GAS INDUSTRY**

APPENDIX A

PROTOCOL COMPARISON  
SUMMARY



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# A.

## PROTOCOL COMPARISON SUMMARY

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### A.1 Overview

The *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* (referred to as the *Compendium*) is a compilation of recognized emission factors and emission estimation techniques applicable to oil and gas industry operations. The early stages of the API Compendium development project included the review and comparison of the following Greenhouse Gas (GHG) emissions estimation protocols and inventory reports:

1. American Petroleum Institute (API). *Methane and Carbon Dioxide Emission Estimates from U.S. Petroleum Sources*, January 1997.
2. Canadian Association of Petroleum Producers (CAPP). *Global Climate Change Voluntary Challenge Guide*, June 2000.
3. E&P Forum [more recently named the Offshore Gas Producers (OGP)]. *Methods for Estimating Atmospheric Emissions from E&P Operations*, September 1994.
4. Emission Inventory Improvement Program (EIIP). *Guidance for Emissions Inventory Development*, 1999.
5. US Environmental Protection Agency (EPA). *Methane Emissions from the U.S. Petroleum Industry*, February 1999.
6. Gas Research Institute (GRI) and EPA. *Methane Emissions from the Natural Gas Industry*, June 1996.
7. Intergovernmental Panel on Climate Change (IPCC). *Greenhouse Gas Inventory Reference Manual: IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 3, 1997.
8. Canadian Petroleum Association (CPA). *A Detailed Inventory of CH<sub>4</sub> and VOC Emissions from Upstream Oil and Gas Operations in Alberta*, Volumes I-III, March 1992.
9. US Department of Energy (DOE). *Instructions for Form EIA 1605 Voluntary Reporting of Greenhouse Gases*, 1997.
10. US Environmental Protection Agency. *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources*, AP-42, (GPO 055-000-005-001), 2000.

In updating the Compendium, a more detailed comparison study was conducted to identify and understand differences among various existing and newly developed emission estimation guidance documents. This Appendix summarizes the results from a qualitative and quantitative comparison

of the *Compendium* to other publicly available GHG emission estimation methodology documents from the oil and gas industry, governmental, and non-governmental organizations.<sup>1</sup> This study supports API's objective of building consensus among GHG emission estimation approaches for the oil and gas industry.

The qualitative review examined the scope and data sources associated with the emission factors in each document. Summary tables provide comparisons of the protocols by emission type: combustion, point (vented sources), non-point (fugitive sources), non-routine (also vented sources), and indirect.

A quantitative review of several key protocols was conducted for the purpose of comparing numeric results with results obtained from using the *Compendium* methodologies. This quantitative analysis applied carbon dioxide (CO<sub>2</sub>) and methane (CH<sub>4</sub>) emission factors from the protocol documents to six case studies included in the Pilot Version *Compendium* (API, 2001). The quantitative analysis also included a comparison of fuel based CO<sub>2</sub> combustion emission factors for several of the protocols.

The qualitative and quantitative reviews revealed differences in emission factors, estimation methodologies, and resulting emission estimates. Key contributors to these differences include:

- Assumed or default fuel properties;
- Omitted emission sources;
- Outdated data sources used as the basis for emission factors; and
- Broad, generalized emission factors develop from grouping multiple emission sources together.

In addition, many of the protocols do not provide sufficient documentation on the derivation of the emissions factors, which is necessary to apply the factors appropriately and compare emission results among different methodologies.

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<sup>1</sup> Additional details on the comparison study are available in the following report: American Petroleum Institute (API), *Toward a Consistent Methodology for Estimating Greenhouse Gas Emissions from Oil and Natural Gas Industry Operations*, Synopsis Report, 2002.

## A.2 Qualitative Comparison Summary

Many of the sources examined in the early stages of developing the Pilot Version of the *Compendium* have since been updated. In addition, several new greenhouse gas emission protocol documents are now available. The following documents were reviewed on a qualitative basis to examine differences between their emission estimation approaches and those provided in the *Compendium*.

1. Australian Greenhouse Office (AGO), *Workbook for Fuel Combustion Activities* (AGO a, 1999) and *Workbook for Fugitive Fuel Emissions (Fuel Production, Transmission, Storage, and Distribution)* (AGO b, 1999);
2. Australian Petroleum Production and Exploration Association (APPEA), *Greenhouse Challenge Report* (APPEA, 2000);
3. Canadian Association of Petroleum Producers (CAPP), *Calculating Greenhouse Gas Emissions* (CAPP a, 2003);
4. Canadian Association of Petroleum Producers (CAPP), *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities* (CAPP b, 2003);
5. Canadian Industrial Energy End-Use Data and Analysis Centre (CIEEDAC) memorandum on “Guide for the Consumption of Energy Survey” (CIEEDAC, 2000);
6. Environmental Protection Agency (EPA), *Emission Inventory Improvement Program* (EIIP, 1999);
7. European Environment Agency (EEA), *EMEP/CORINAIR Emission Inventory Guidebook* (EEA, 2002);
8. Exploration and Production Forum (E&P Forum) *Methods for Estimating Atmospheric Emissions from E&P Operations* (E&P Forum, 1994);
9. Intergovernmental Panel on Climate Change (IPCC), *Guidelines for National Greenhouse Gas Inventories* (IPCC, 1997; UNECE/EMEP, 1999; IPCC, 2001);
10. Regional Association of Oil and Natural Gas Companies in Latin America and the Caribbean (ARPEL), *Atmospheric Emissions Inventories Methodologies in the Petroleum Industry* (ARPEL, 1998);
11. UK Emissions Trading Scheme (DEFRA, 2003);
12. UK Offshore Operators Association Limited, *Guidelines for the Compilation of an Atmospheric Emissions Inventory* (UKOOA, 2002); and
13. World Resources Institute and World Business Council for Sustainable Development, *The Greenhouse Gas Protocol* (WRI/WBCSD, 2001) and calculation tools for Stationary and Mobile Combustion Sources (WRI/WBCSD, 2003).

More detailed citations and web links for these documents are provided in the reference section for this appendix.



A qualitative review of each of the protocol documents is presented in the following subsections. The analysis is focussed on the following parameters:

1. Scope of the document relative to the oil and gas industry;
2. Root source of emission factor data; and
3. Additional or omitted emission sources compared to those presented in the *Compendium*.

Table A-1 summarizes the comparison of the protocols for each of these key points. In addition, Table A-2 examines emission sources presented in each of the other protocol documents against the source categories provided in the *Compendium*: combustion sources (including indirect emissions), vented sources, and fugitive sources.

**Table A-1. Summary Protocol Comparison**

<b>Protocol and Publication Date</b>	<b>Scope (relative to Oil/Gas Industry)</b>	<b>Root Data Source(s)</b>	<b>Other Details</b>	<b>Overall Comparison to the <i>Compendium</i></b>
Australian Greenhouse Challenge Report (APPEA, 2000)	Covers exploration and production operations, and transport/loading.	Cites E&P Forum (1994) for emission factors.	Emission factor units are not defined.	See comments for E&P Forum.
Australian Greenhouse Office (AGO, 1999)	Workbooks 1.1 and 2.1 address sources relevant to oil/gas industry.	Combustion emissions are based on IPCC approach. 1994 version of document provided approaches for non-combustion emissions based on E&P Forum and IPCC, 1997. Current version reports national inventory results only.	Expresses energy data in terms of gross calorific value (HHV). IPCC factors are converted to HHV basis using Australian heating values.	Combustion emissions are consistent with the <i>Compendium</i> fuel based approach. Non-combustion emissions are reported in tonnes/yr with no published details on emission factor basis.
Canadian Industrial Energy End-Use Data and Analysis Centre (CIEEDAC, 2000)	Addresses refinery CO <sub>2</sub> combustion emissions only.	Default emission factors cite Environment Canada inventory data from 1992 with updates in 1995.	Fuel data reported in HHV. Provides means to record electricity and steam transfers, but does not calculate emissions.	Comparable for combustion emission sources in refineries.
CAPP Guides for Calculating GHG Emissions and Estimating Venting and Flaring Volumes (CAPP, 2003)	Developed to support petroleum company submittals to Canada's Voluntary Challenge Registry. Focus is on upstream activities.	Equipment based combustion emission factors cite EPA AP-42, 1995. Manufacturer data provided for IC engines. Canadian fuel heating values provided. Non-combustion emission factors are generally based on Canadian-specific measurement programs.	Expresses energy data in terms of HHV.	Combustion sources are consistent with <i>Compendium</i> . Non-combustion sources are also comparable to the <i>Compendium</i> . Canadian specific data have been incorporated into the <i>Compendium</i> .
European Environment Agency Emission Inventory Guidebook (EEA, 2002).	Broadly focussed on atmospheric emissions. Does address GHG emissions and petroleum industry operations.	Cites data from numerous sources, primarily documents from early 1990's. EPA AP-42 4 <sup>th</sup> edition (1990) is cited for combustion sources. E&P Forum, UKOOA, and Canadian data cited for non-combustion sources.	Expresses energy data in terms of LHV.	Emission factor methodologies are generally consistent with the <i>Compendium</i> , though many of the data sources are outdated.

EF = emission factor.

Table A-1. Summary Protocol Comparison, continued

Protocol and Publication Date	Scope (relative to Oil/Gas Industry)	Root Data Source(s)	Other Details	Overall Comparison to API Compendium
Emission Inventory Improvement Program (EIIP, 1999)	Volume VIII, Chapters 1, 3, and 14; and Volume II Chapter 10 address sources relevant to oil/gas industry.	Provides fuel based combustion emission factors citing EIA, 1996 and EPA AP-42, 1995. Non-combustion emission factors rolled up to broad operational factors, cite IPCC, 1997 and GRI/EPA, 1996.	Energy data associated with CO <sub>2</sub> emissions are expressed in gross calorific values (HHV). Energy data associated with CH <sub>4</sub> emissions are expressed in net calorific values (LHV).	Combustion EFs consistent with the <i>Compendium</i> approaches. Non-combustion EFs are not source specific and generally reported in terms of overall processes or operations. Several of the more detailed emission calculation approaches were incorporated into the <i>Compendium</i> .
E&P Forum's <i>Methods for Estimating Atmospheric Emissions from E&amp;P Operations</i> September 1994.	Covers exploration and production operations, and gas processing.	For combustion, generally cites EPA AP-42, 1986 or E&P Forum internal data. For fugitives, cites API "Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations" 1993. Provides limited venting data.	Provides methodologies for five calculation tiers. Emission factors provided in Tiers 2, 3, and 4 are most comparable to the <i>Compendium</i> . Provides data for multiple countries.	Generally outdated with respect to US data.
IPCC's <i>Guidelines for National Greenhouse Gas Inventories</i> (IPCC, 1997). Non-combustion emissions are updated in IPCC uncertainty document (IPCC, 2001).	Energy chapter covers sources relevant to oil/gas industry. Oil refining is not included in the uncertainty document.	For combustion, equipment based approach cites EPA AP-42, 1995. Fuel based approach uses International Energy Association (IEA) Statistics. IPCC, 2001 provides non-combustion emission factor ranges for broad source categories citing the 1999 version of the CAPP Calculation Guide; GRI/EPA, 1996; and EPA, 1999.	All energy data are expressed in net calorific values (i.e., lower heating value, LHV) converted from a higher heating value (HHV) basis.	Equipment based combustion sources are outdated. Fuel based approach is consistent with the <i>Compendium</i> . Vented/fugitive emission factors are not source specific and generally reported in terms of overall processes or operations.

**Table A-1. Summary Protocol Comparison, continued**

<b>Protocol and Publication Date</b>	<b>Scope (relative to Oil/Gas Industry)</b>	<b>Root Data Source(s)</b>	<b>Other Details</b>	<b>Overall Comparison to API Compendium</b>
Latin American /Caribbean Methodology Document (ARPEL, 1998)	Covers exploration/drilling, production, processing, refining, product distribution, and service stations. Also includes marine terminals and road construction vehicles.	Combustion sources cite EPA (Stationary Internal Combustion Sources and External Combustion Sources, April 1993) and CAPP (Guide to Voluntary Challenge, June 1995). Fugitive EFs cite API 4615 and API 4612. Tank emissions cite API 2517, API 2518, API 2519 and API Technical Data Book.	Provides good descriptions of industry activities. Expresses fuel energy data in terms of HHV and LHV.	Generally comparable to the <i>Compendium</i> in terms of specific sources included. Combustion emissions are comparable to the <i>Compendium</i> equipment based approach, though may be outdated. Some emission factor sources are outdated. Some methodologies lack detail to assess approach.
UK Offshore Operators Guidelines for Compilation of an Atmospheric Emissions Inventory (UKOOA, 2002)	Includes exploration activities, offshore production, and onshore processing.	Cites E&P Forum and EPA's AP-42. Other data developed from UKOOA. Fugitive emission factors based on API 4615.	Provides tiered approach similar to E&P Forum. Combustion emission factors are provided on a mass basis.	Emission factors based on UK data were incorporated into the <i>Compendium</i> .
The GHG Protocol Stationary Combustion and Mobile combustion Tools (WRI/WBCSD, 2003).	Currently does not address emissions specific to oil/gas operations. Provides CO <sub>2</sub> emission estimation tools for combustion and indirect sources.	Provides fuel based CO <sub>2</sub> emission factors from a number of different sources and in different unit conventions. HHV factors cite EIA, 2001.	Specifically addresses emissions from combined heat and power processes. Provides emission factors in terms of both HHV and LHV.	Combustion emissions are consistent with the <i>Compendium</i> fuel based approach. Indirect emission factors combine electricity and steam generation.
UK Emission Trading Scheme (DEFRA, 2001)	Includes on-site combustion of fossil fuels and on-site consumption of electricity, heat and steam. Include CH <sub>4</sub> emissions from offshore operations.	Provides combustion emission factors for CO <sub>2</sub> based on energy generation and input basis. Cites DEFRA environmental reporting guidelines and UKOOA Guidelines.	Provides methodology for treating imported or exported emissions from CHP. Expresses energy data in terms of LHV.	Combustion emissions are comparable to the <i>Compendium</i> fuel based approach, but fuel types vary somewhat.

Table A-2. Protocol Summary Comparison by Source Type

Protocol/ Boundaries	Combustion	Vented	Fugitive	Indirect Emissions
<b>Australian Greenhouse Challenge Report (APPEA, 2000)</b>				
Cites E&P Forum 1994 for EFs. Provides EFs for CO <sub>2</sub> , CH <sub>4</sub> , VOC, N <sub>2</sub> O, NO <sub>x</sub> , and CO.	<b>Includes:</b> Equipment specific EFs in terms of tonnes/tonne of fuel combusted. Approaches also provided for flares, and mobile sources. <b>Does not include:</b> refinery specific EFs.	<b>Includes:</b> Direct vents from drilling operations, compressor seal gas, acid gas removal, and “other process venting” based only on gas volume released. <b>Does not include:</b> average CH <sub>4</sub> content of gas, tank flashing losses, pneumatic devices, chemical injection pumps, and gas dehydration. Units of emission factors are not indicated.	Classifies tank working losses as fugitive emissions. Provides EFs for category called “general leaks” under fugitives. <b>Does not include:</b> component based EFs. Units of EFs are not indicated.	<b>Includes:</b> Power generation by diesel engine, diesel turbine, natural gas engine, and natural gas turbine. <b>Does not include:</b> steam imports/ exports. Units of EFs are not indicated.
<b>Australian Greenhouse Office (AGO, 2000)</b>				
Cites IPCC Reference and Detailed Technology methodologies. Provides EFs for CO <sub>2</sub> , CH <sub>4</sub> , N <sub>2</sub> O, NO <sub>x</sub> , CO, and NMVOCs.	States that EFs are converted from IPCC factors to HHV basis using Australian gross calorific values. <b>Includes:</b> Fuel-based and equipment based EFs. <b>Does not include:</b> refinery specific EFs.	<b>Includes:</b> Production venting and flaring based on APPEA recommendations. Refinery venting/flaring emissions are based on E&P Forum emission factors. <b>Does not include:</b> source specific EFs.	<b>Includes:</b> Non venting emissions in production based on APPEA data. Storage tank emissions in production are assumed to be zero. Other non-venting emissions are primarily based on IPCC. Also includes Australian-based data for transmission and distribution. <b>Does not include:</b> source specific Efs	<b>Includes:</b> EFs for each State/Territory power station based on primary fuel and also secondary fuels for some stations. <b>Does not include:</b> steam imports/ exports.

EF = emission factor

Table A-2. Protocol Summary Comparison by Source Type, continued

Protocol/ Boundaries	Combustion	Vented	Fugitive	Indirect Emissions
Canadian Industrial Energy End-Use Data and Analysis Centre (CIEEDAC, 2000)				
Cites Environment Canada 1992, with updates in 1995. Provides EFs for CO <sub>2</sub> only.	<b>Includes:</b> Fuel based EFs and refinery specific EFs. <b>Does not include:</b> engines, turbines, heaters. Provides fuel energy data in terms of HHV from Statistics Canada.	Not addressed in this document.		Tracks energy associated with electricity and steam inputs and consumption but does not calculate associated emissions.
CAPP Guides for Calculating GHG Emissions and Estimating Venting and Flaring Volumes (CAPP, 2003)				
Non-combustion approaches are generally limited to upstream operations. Provides EFs for CO <sub>2</sub> , CH <sub>4</sub> , NOx, and N <sub>2</sub> O (derived from NOx).	<b>Includes:</b> Fuel-based and equipment based EFs for stationary combustion sources. Includes mobile source emission factors.	<b>Includes:</b> EFs or estimation approaches for upstream sources. <b>Does not include:</b> downstream operations (outside CAPP boundaries).	<b>Includes:</b> Component based fugitive EFs for vapor service in oil and gas production facilities. Comparable with <i>Compendium</i> . <b>Does not include:</b> liquid service or downstream EFs.	<b>Includes:</b> CO <sub>2</sub> EFs for Canadian provinces. <b>Does not include:</b> steam imports/ exports.
European Environment Agency Emission Inventory Guidebook (EEA, 2002).				
Developed as guidance for reporting emissions associated with activities under the Selected Nomenclature for Air Pollution (SNAP97). Provides emission factors for CO <sub>2</sub> , CH <sub>4</sub> , N <sub>2</sub> O, NOx, CO, PM, and NMVOCs.	<b>Includes:</b> Fuel-based and equipment-based CO <sub>2</sub> , CH <sub>4</sub> , and N <sub>2</sub> O EFs for stationary combustion sources. Also includes mobile source emission factors.	<b>Includes:</b> General upstream emission factors (production basis). For downstream, includes FCC, sulfur recovery, asphalt blowing, loading/ballasting. <b>Does not include:</b> Source specific EFs for upstream. Downstream does not include Hydrogen plants.	<b>Includes:</b> Component based fugitive EFs from EPA and equipment based factors from Canada. Comparable with <i>Compendium</i> .	Not addressed in this document, except through stationary combustion equipment emissions.

Table A-2. Protocol Summary Comparison by Source Type, continued

Protocol/ Boundaries	Combustion	Vented	Fugitive	Indirect Emissions
<b>EPA Emission Inventory Improvement Program (EIIP), October 1999</b>				
Developed for preparing state inventories. Provides EF methodologies for CO <sub>2</sub> , CH <sub>4</sub> , and N <sub>2</sub> O relative to oil and gas industry operations.	The <i>Compendium</i> references EIIP for CO <sub>2</sub> emissions from combustion fuel basis approach. <b>Includes:</b> CH <sub>4</sub> EFs on an equipment basis; consistent with the <i>Compendium</i> ; mobile source EFs on vehicle mile travel basis, which requires unit conversion for comparison to the <i>Compendium</i> . <b>Does not include:</b> refinery specific EFs.	<b>Includes:</b> Facility-wide CH <sub>4</sub> EFs, generally reported in terms of overall processes or operations. <b>Does not include:</b> source specific EFs.	<b>Includes:</b> Facility-wide CH <sub>4</sub> EFs, generally reported in terms of overall processes or operations. <b>Does not include:</b> source specific EFs.	Provides a US national average emission factor of 0.36 lb C/kW-hr of electricity generated for use with state net imports of electricity. <b>Does not include:</b> steam imports/ exports.
<b>E&amp;P Forum, September 1994</b>				
Covers E&P operations only. Provides 5 Tiers of emission factors. Provides EFs for different countries. Provides EFs for CO <sub>2</sub> , CH <sub>4</sub> , NO <sub>x</sub> , CO, and VOCs.	CO <sub>2</sub> and CH <sub>4</sub> emissions – Fuel consumed basis. Comparable to the <i>Compendium</i> with some unit conversions. <b>Includes:</b> Fuel-based and equipment based EFs. <b>Does not include:</b> refinery specific EFs (outside the boundaries of E&P Forum).	<b>Includes:</b> Working losses from tanks; loading losses. <b>Does not include:</b> tank flashing losses; pneumatic devices; chemical injection pumps; dehydrators.	<b>Includes:</b> Component based fugitive EFs for upstream operations. Comparable with the <i>Compendium</i> . <b>Does not include:</b> downstream EFs.	Not addressed.

Table A-2. Protocol Summary Comparison by Source Type, continued

Protocol/ Boundaries	Combustion	Vented	Fugitive	Indirect Emissions
<b>IPCC Guidelines for National Inventories (IPCC, Volume 3, 1997; IPCC, 2001)</b>				
Developed for preparing national inventories. Manual provides two calculations tiers and references another methodology as a 3 <sup>rd</sup> tier. Provides EFs for CO <sub>2</sub> , CH <sub>4</sub> , N <sub>2</sub> O, NO <sub>x</sub> , CO, and NMVOC.	All energy data are expressed in terms of net calorific values. <b>Includes:</b> Tier 1 EFs in terms of kg per TJ of consumption fuel; Tier 2 EFs based on fuel type and equipment type. <b>Does not include:</b> Refinery specific EFs.	Tier 1 approach provides range of emission factors for three broad categories of emissions. Tier 2 provides mass balance equations for oil production, crude oil transportation and refining, and exploration and drilling losses. Tier 3 suggests source specific emission estimation. <b>Does not include:</b> source specific EFs.	<b>Includes:</b> Equipment based, Tier 2 combustion emission factors for electricity and steam generation equipment. <b>Does not include:</b> import/ export issues.	
<b>Latin American/Caribbean Methodology Document (ARPEL, 1998)</b>				
Provides EFs for CO <sub>2</sub> , CH <sub>4</sub> , NO <sub>x</sub> , CO, SO <sub>x</sub> , NMHC, BTEX, and particulates. Addresses emission methodologies by source for each industry sector. Covers exploration/drilling through product distribution and service stations.	Cites EPA (Stationary Internal Combustion Sources and External Combustion Sources, April 1993) and CAPP (Guide to Voluntary Challenge, June 1995). Provides fuel heating values in terms of gross and net. <b>Includes:</b> Combustion emission factors on an equipment basis for upstream and downstream operations. <b>Does not include:</b> turbines.	<b>Includes:</b> Detailed emission estimate methodologies for tanks and loading/ transit; pneumatic devices, chemical injection pumps, drilling, diesel storage, produced water, pipeline pigging, casing gas, and asphalt blowing. <b>Does not include:</b> some maintenance or non-routine emission events	<b>Includes:</b> Component based fugitive emission factors. Gas plant EFs (from API 4615) are provided for onshore fugitive sources.	Not addressed.



Table A-2. Protocol Summary Comparison by Source Type, continued

Protocol/ Boundaries	Combustion	Vented	Fugitive	Indirect Emissions
<b>UK Offshore Operators Guidelines for Compilation of an Atmospheric Emissions Inventory (UKOOA, 2002)</b>				
Developed to provide guidance for operators reporting emissions to UKOOA. Provides EFs for CO <sub>2</sub> , CH <sub>4</sub> , N <sub>2</sub> O, NO <sub>x</sub> , SO <sub>2</sub> , CO, and NMVOCs.	<b>Includes:</b> preference for combustion emissions based on fuel composition data. Tier 2 provides EFs for gas consumption, distillate consumption, and flaring. Tier 3 provides equipment-based factors, well testing, and mobile sources.	<b>Includes:</b> Emission factors for cold venting, tanks, and loading. Text describes calculation of other process vents. <b>Does not include:</b> tank flashing, pneumatic devices, dehydrators, maintenance, and non-routine emissions	Includes component-level EFs and component counts	Not addressed.
<b>The Greenhouse Gas Protocol and Calculation Tools (WRI/WBCSD, 2001 and 2003)</b>				
Currently, does not address emissions specific to oil and natural gas industry operations. Includes only CO <sub>2</sub> emissions.	<b>Includes:</b> CO <sub>2</sub> EFs from a number of sources in different unit conventions. Notes that the tool should not be used for gas flaring or gas fired IC engines. A separate calculation tool is provided for CO <sub>2</sub> emissions from mobile sources. <b>Does not include:</b> Equipment based EFs, or CH <sub>4</sub> emissions from combustion.	Not addressed at this time for oil and natural gas industry operations.		<b>Includes:</b> Preferred approach based on supplier data or actual fuel and generation technology. Provides published EFs and country specific CO <sub>2</sub> EFs. Note that these EFs combine emissions due to heat and power. Provides two methods for estimating emissions from combined heat and power (CHP) plants.
<b>UK Emissions Trading Scheme (DEFRA, 2003)</b>				
Scope includes: On-site combustion of fossil fuels; On-site consumption of electricity generated on-site or off-site; and On-site consumption of heat or steam generated on-site or off-site. Includes CO <sub>2</sub> and for some sources CH <sub>4</sub> .	<b>Includes:</b> CO <sub>2</sub> EFs for fuel-based energy generation (kgCO <sub>2</sub> /kWh) and conversion factors for kWh/tonne, L/tonne, and kWh/L. <b>Does not include:</b> Equipment based EFs, or CH <sub>4</sub> emissions from combustion.	CO <sub>2</sub> process emissions do not currently address petroleum downstream processes. Cites UKOOA Guidelines for CH <sub>4</sub> and CO <sub>2</sub> emissions from offshore E&P operations.	Not addressed in this document.	<b>Includes:</b> One EF for all electricity from the public supply network; methodology for treating imported or exported emissions from combined heat and power (CHP). <b>Does not include:</b> Regional or utility based EFs for electricity.

## A.3 Quantitative Comparison

### A.3.1 CO<sub>2</sub> Combustion Emission Factors

One of the key technical considerations presented in the *Compendium* is the specification of energy in terms of fuel higher and lower heating values (HHV and LHV). Gross calorific value, or HHV, is the convention most commonly used in the US and Canada. Other protocol documents report fuel data in terms of net or lower heating values (LHV). In some documents, the convention is not explicitly stated and if applied inappropriately, can result in a 5-10% error in the stated emissions.

Tables A-3 and A-4 compare fuel combustion CO<sub>2</sub> emission factors from several protocol documents to those factors reported in the *Compendium*. All of the emission factors shown are reported in HHV or have been converted to HHV to evaluate potential differences on a consistent basis.

**Table A-3. Comparison of CO<sub>2</sub> Combustion Emission Factors (Fuel Basis) for Common Industry Fuel Types**

Fuel Types	Tonnes CO <sub>2</sub> /MMBTU (HHV)					
	Compendium CO <sub>2</sub> Emission Factor <sup>2</sup>	AGO Workbook 1.1 (Table 4)	IPCC Volume 3 (Table 1-1)	DEFRA, Protocol A1	WRI/WBCSD <sup>3</sup>	CIEEDAC
Aviation Gas	0.0692	0.0717		0.0703	0.0693	
Bitumen	0.0809	0.0851	0.0808	0.0879	0.0931	
Coke (Coke Oven/Gas Coke)	0.1084	0.1260	0.1083	0.0879	0.1083	0.0893
Crude Oil	0.0744		0.0734	0.0703		
Distillate Fuel	0.0732	0.0718		0.0703	0.0732	0.0750
Electric Utility Coal	0.0953	0.0966		0.0879		
Ethanol	0.0700					
Flexicoker Low Btu Gas	0.1135					
Gas/Diesel Oil	0.0742	0.0735	0.0742	0.0732	0.0732	

<sup>2</sup> Primarily taken from EIIP, 1999.

<sup>3</sup> Cites heating value and other fuel property conversion factors from EIA, *Annual Energy Review*, US Department of Energy, 2000.

**Table A-3. Comparison of CO<sub>2</sub> Combustion Emission Factors (Fuel Basis)  
for Common Industry Fuel Types, continued**

Fuel Types	Tonnes CO <sub>2</sub> /MMBTU HHV					
	<i>Compendium</i> CO <sub>2</sub> Emission Factor	AGO Workbook 1.1 (Table 4)	IPCC Volume 3 (Table 1-1)	DEFRA, Protocol A1	WRI/ WBCSD	CIEEDAC
Jet Fuel	0.0709	0.0717		0.0703	0.0709	
Kerosene/Aviation Kerosene	0.0723	0.0735	0.0716	0.0703	0.0724	
Lignite	0.0964		0.1013		0.0977	
LPG	0.0623	0.0626	0.0632	0.0615	0.0631	
Butane	0.0651					0.0649
Ethane	0.0596		0.0617	0.0586		
Propane	0.0631				0.0631	0.0632
Misc. Petroleum Products and Crude	0.0721	0.0723		0.0703		
Motor Gasoline	0.0709		0.0694	0.0703	0.0710	
Naphtha (<104°F)	0.0665	0.0696	0.0734	0.0761		
Nat Gas Liquids	0.0632		0.0632			
Natural Gas	0.0531	0.0542	0.0532	0.0556	0.0531	0.0520
Other Bituminous Coal	0.0931		0.0947	0.0879	0.0931	
Other Oil (>104°F)	0.0732		0.0734			
Pentanes Plus	0.0669					
Petroleum Coke	0.1021	0.1260	0.1010	0.0879	0.1021	0.0987
Refinery Fuel Gas	0.0567	0.0718		0.0586		0.0566
Residual Fuel	0.0788	0.0718	0.0775	0.0703	0.0789	
Special Naphtha	0.0728					
Still Gas	0.0642					
Sub-bituminous Coal	0.0971		0.0962	0.0879	0.0965	
Unfinished Oils	0.0742					

**Table A-4. CO<sub>2</sub> Comparison of CO<sub>2</sub> Combustion Emission Factors (Fuel Basis) for Specialized Fuel Types**

Fuel	Tonnes CO <sub>2</sub> /MMBTU HHV				
	Compendium CO <sub>2</sub> Emission Factor	AGO Workbook 1.1 (Table 4)	IPCC Volume 3 (Table 1-1)	DEFRA, Protocol A1	WRI/WBCSD
Anthracite	0.103				0.1032
Asphalt and Road Oil	0.0757				
Industrial Coking Coal	0.0937	0.0980		0.0879	
Industrial Sector "Other"	0.0573				
Lubricants	0.0742		0.0734		0.0734
Other Industrial Coal	0.094	0.0931		0.0879	
Peat	0.106		0.1061		0.1061
Petrochemical Feed	0.0710		0.0734		
Residential/Commercial Coal	0.0953			0.0879	
Shale Oil	0.0735		0.0734	0.0703	
Waxes and Miscellaneous	0.0726				

There are some significant differences in the fuel-based CO<sub>2</sub> emission factors shown in Tables A-3 and A-4. Approximately half of the fuel types show a difference of greater than 5% from the *Compendium* emission factors, with the most significant differences associated with refinery fuel gas and petroleum coke. There also does not seem to be any general trends in the documents compared to the *Compendium*. Each of the documents provides some emission factors that are lower and some that are higher than those reported in the *Compendium*, with no particular document reporting values most similar to the *Compendium* factors.

This comparison indicates that fuel specific data (composition, heating value, density, etc.) are going to provide the most accurate results. Due to potentially significant variances in fuel properties, general published emission factors should be used with caution.

Another parameter to consider when using CO<sub>2</sub> combustion emission factors is the fractional conversion of carbon to CO<sub>2</sub> (or fraction oxidized). Two general conventions are used to address the fraction of carbon that is converted to CO<sub>2</sub> during combustion. One assumes that all of the carbon is oxidized during the combustion process and emitted as CO<sub>2</sub>. For the *Compendium*, this convention applies to the preferred approach for stationary combustion sources, with the exception of flares. This is also the convention adopted by WRI/WBCSD. The second approach, used by

IPCC and EIIP, applies a fractional conversion for different fuel types (generally, 99.5% for natural gas and 99% for petroleum fuels and coal. This conversion is applied as a correction to the emission factors shown in Tables 4-1 and 4-2, based on the following equation:

$$\text{CO}_2 \text{ Emissions (tonnes)} = \frac{\text{Fuel Consumption (BTU)}}{\text{CO}_2 \text{ Emission Factor}} \left( \frac{\text{tonnes CO}_2}{\text{BTU}} \right) \times \frac{\text{Fraction Oxidized}}{\text{Fraction Oxidized}}$$

Given the high oxidation of carbon from most combustion sources, the slight difference resulting from the application of the fraction oxidized has less influence on the final CO<sub>2</sub> emission estimates than the fuel specific data used to develop the emission factors in Tables A-3 and A-4.

## **A.4 Conclusions**

The main conclusion from this review of greenhouse gas emission estimation protocols is that there can be differences, in some cases significant, in the results depending on the approach used to calculate emissions. For example, updates to emission factors published in AP-42 have resulted in significant changes to the CH<sub>4</sub> emission factors.

Transparency is also a key issue. Many of the protocol documents do not provide enough detail to understand the derivation of the emission factors. Careful documentation of the underlying conditions and assumptions is necessary for ensuring that information provided by the protocols is used appropriately.

The primary contributors to the differences observed in the results of the quantitative comparison among the various protocols include:

- Omission of emission source types from some of the protocols,
- Differences in emission factors, particularly CH<sub>4</sub>, which are a result of the sources referenced or version of the source cited, and
- Different “tiers” or levels of emission factors - some of the protocols roll several emission sources into one emission factor.

Other conclusions from this comparison effort are:

1. General fuel based emission factors provided in the protocol documents include assumed “average” fuel properties, which are often not documented. Use of fuel specific data eliminates the potential for variability.

2. Combustion emissions are presented on either a higher heating value basis (HHV) or a lower heating value (LHV) basis. Some of the protocols do not clearly indicate which basis is used, and the reader must delve deeply into the text to find the basis. Also, EIIP is not consistent in its basis; fuel-based combustion emission factors are on a higher heating value basis (Volume VIII, Chapter 1) while the equipment-based combustion emission factors are on a lower heating value basis (Volume VIII, Chapter 14).
3. Using a single emission factor, which represents some compilation of emission sources, generally underestimates emissions due to the exclusion of some sources. Basing an inventory on the summation of source specific emission factors clearly shows which source types are included.
4. Methane emissions are not included in the WRI/WBCSD and CIEEDAC documents. Methane emissions from non-routine activities are not included in most of the emission estimation documents. General (rather than source specific) CH<sub>4</sub> emission factors are provided in the EIIP and IPCC protocols.
5. Use of the ARPEL protocol would underestimate combustion emissions for facilities with turbines, since this source is not included in the ARPEL protocol.
6. Emission estimates for facilities with production tanks will be underestimated for the E&P Forum, EIIP, and IPCC protocols because flashing losses do not appear to be included in these protocols.
7. The *Compendium*, CAPP, and ARPEL address pneumatic device, chemical injection pump emissions and dehydrator vent emissions. The remaining protocols reviewed do not address these sources, which can be important for upstream sources.
8. Indirect emissions from electricity usage are not included for four of the protocols (EEA, E&P Forum, UKOOA and ARPEL). Indirect emissions from steam imports or exports are addressed by the *Compendium*, EIIP, WRI/WBCSD, DEFRA, and CIEEDAC, but are not included in the remaining protocols.
9. Significant variation in CH<sub>4</sub> emissions from combustion sources occurs due to different versions of AP-42.

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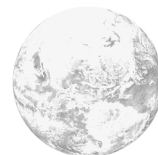
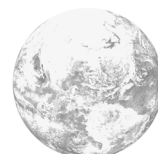
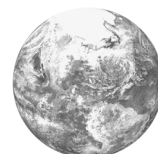
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FEBRUARY 2004

**COMPENDIUM OF GREENHOUSE GAS  
EMISSIONS METHODOLOGIES FOR  
THE OIL AND GAS INDUSTRY**

APPENDIX B

ADDITIONAL CALCULATION  
APPROACHES



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## B. ADDITIONAL CALCULATION APPROACHES

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### B.1 Combustion Sources

#### ***B.1.1 Combustion Emissions Based on Equipment Manufacturer Data (Canadian)***

Section 4.3.2 presents generic emission factors for internal combustion units. Tables B-1 and B-2 provide model-specific combustion emission factors for CH<sub>4</sub> and CO<sub>2</sub>. These model-specific factors may be useful if a facility uses these specific types of engine drivers. Table B-1 applies to Waukesha reciprocating units and is taken from Table 1-7 of the CAPP document, Calculating Greenhouse Gas Emissions (CAPP, 2003). Table B-2 is appropriate for CAT reciprocating engines, and is taken from Table 1-8 of the CAPP document (CAPP, 2003).

The emission factors in Tables B-1 and B-2 are given on power output basis, but can be converted from a fuel input basis using the conversion factors for each type of engine given in Section 3 of this document. If available, model-specific conversion factors are preferred over the generic factors in Section 3. CAPP states that thermal efficiencies (higher heating value basis) for reciprocating engines are typically in the range of 28 to 31% for naturally aspirated engines and 31 to 36% for lean burn engines based on Waukesha engine specifications (CAPP, 2003). For gas-fired turbines, CAPP reports typical thermal efficiencies (HHV basis) of 24 to 30% based on Solar and GE manufacturer data (CAPP, 2003).

Carbon dioxide emission factors were not provided for several of the engine models shown in Tables B-1 and B-2. For these models, the user may want to use the generic fuel-basis CO<sub>2</sub> emission factors provided earlier in Section 4.2. Also, model-specific N<sub>2</sub>O emission factors are not available.

**Table B–1. Waukesha Reciprocating Engines Combustion Emission Factors**

Model	Carburetor Setting	Excess Air Ratio	Methane		Carbon Dioxide	
			Original Units, g/kW-hr	tonnes/kW-hr	Original Units, g/kW-hr	tonnes/kW-hr
AT25GL	Standard	1.74	9.39	9.39E-06	580.8	5.808E-04
AT27GL	Standard	1.74	6.03	6.03E-06	Not Given	Not Given
	Ultra Lean	2.00	4.16	4.16E-06	526.9	5.269E-04
VHP G, GSI	Lowest manifold	0.97	2.61	2.61E-06	581.29	5.8129E-04
	Equal NOx & CO	0.99	2.61	2.61E-06	581.29	5.8129E-04
	Catalytic Converter	0.99	2.28	2.28E-06	581.29	5.8129E-04
	Standard	1.06	1.68	1.68E-06	581.29	5.8129E-04
VHP 3524 GSI	Equal NOx & CO	0.99	1.14	1.14E-06	576.13	5.7613E-04
VHP 7044 GSI	Catalytic Converter	0.99	1.07	1.07E-06	573.7	5.737E-04
	Standard	1.06	0.80	8.0E-07	Not Given	Not Given
VHP 5794 GSI	Equal NOx & CO	0.99	3.42	3.42E-06	568.7	5.687E-04
	Catalytic Converter	0.99	3.29	3.29E-06	Not Given	Not Given
	Standard	1.06	2.75	2.75E-06	Not Given	Not Given
VHP GL	Standard	1.74	6.03	6.03E-06	592.3	5.923E-04
VGF Model G	Lowest manifold	0.97	2.28	2.28E-06	575.0	5.750E-04
	Equal NOx & CO	0.98	2.28	2.28E-06	Not Given	Not Given
	Catalytic Converter	0.99	2.28	2.28E-06	Not Given	Not Given
	Standard	1.12	1.41	1.41E-06	Not Given	Not Given
VGF Model GSID	Catalytic Converter	0.99	1.68	1.68E-06	575.0	5.750E-04
VGF GL, GLD 11:1 CR	Std.: high speed turbo	1.53	5.7	5.7E-06	575.0	5.750E-04
	T.A. Luft emissions	1.59	4.09	4.09E-06	Not Given	Not Given
VGF GL 8.7:1 CR	Std.: high speed turbo	1.53	4.09	4.09E-06	575.0	5.750E-04
VSG G, GSI, GSID	Lowest manifold	0.97	3.42	3.42E-06	566.8	5.668E-04
	Equal NOx & CO	0.98	3.42	3.42E-06	Not Given	Not Given
	Catalytic Converter	0.99	3.08	3.08E-06	Not Given	Not Given
	Standard	1.10	2.28	2.28E-06	Not Given	Not Given
F1197G G	Lowest manifold	0.97	3.35	3.35E-06	Not Given	Not Given
	Equal NOx & CO	1.0	2.61	2.61E-06	Not Given	Not Given
	Catalytic Converter	0.99	2.61	2.61E-06	Not Given	Not Given
	Standard	1.06	1.27	1.27E-06	Not Given	Not Given
F8176 G	Lowest manifold	0.97	2.61	2.61E-06	Not Given	Not Given
	Equal NOx & CO	1.0	2.28	2.28E-06	Not Given	Not Given
	Catalytic Converter	0.99	2.28	2.28E-06	Not Given	Not Given
	Standard	1.06	2.28	2.28E-06	Not Given	Not Given

Note: All data in this table are based on maximum horsepower and engine speed. "Lowest manifold" setting refers to best power setting while "Standard" setting refers to best economy setting.

Source:

Canadian Association of Petroleum Producers (CAPP), *Calculating Greenhouse Gas Emissions*, Table 1-7, Canadian Association of Petroleum Producers, Publication Number 2003-03, April 2003.



**Table B–2. CAT Reciprocating Engines Combustion Emission Factors**

Model	Power	Speed	% O <sub>2</sub>	Carbon Dioxide	
	kW	rpm		Original Units, g/kWh	tonnes/kW-hr
3412 SITA	447	1800	1.5	436	4.36E-04
3508 SITA	384	1200	7.7	574	5.74E-04
3508 SITA	470	1400	8.0	590	5.90E-04
3512 SITA	604	1200	8.2	579	5.79E-04
3512 SITA	705	1400	7.7	595	5.95E-04
3516 SITA	809	1200	8.3	567	5.67E-04
3516 SITA	943	1200	7.9	581	5.81E-04
3606 SITA	1242	1000	12.3	347	3.47E-04
3608 SITA	1659	1000	12.3	347	3.47E-04
3612 SITA	2487	1000	12.3	347	3.47E-04
3616 SITA	3315	1000	12.3	347	3.47E-04
G398 TALCR	522	1200	2.0	Not Given	Not Given
G398 TAHCR	522	1200	2.0	Not Given	Not Given
Catalyst	522	1200	0.5	Not Given	Not Given
G398 TAHCR 32C (low emissions)	522	1200	6.2	Not Given	Not Given

Source:

Canadian Association of Petroleum Producers (CAPP), *Calculating Greenhouse Gas Emissions*, Table 1-7,  
Canadian Association of Petroleum Producers, Publication Number 2003-03, April 2003.

Exhibit B.1 illustrates the use of the model-specific CH<sub>4</sub> and CO<sub>2</sub> combustion emission factors.

### **EXHIBIT B.1: Sample Calculation for Combustion Emissions Model-Specific Basis for Internal Combustion Device**

#### **INPUT DATA:**

A 500-kW Waukesha Model AT25GL internal combustion engine is operated for 1000 hours at 90% load during the reporting year. The unit uses a “standard” carburetor setting. Calculate the CH<sub>4</sub> and CO<sub>2</sub> emissions from this source.

#### **CALCULATION METHODOLOGY:**

The engine power output is multiplied by the model specific emission factors from Table B-1. Note that an emission factor for N<sub>2</sub>O for this engine type is not available.

**EXHIBIT B.1: Sample Calculation for Combustion Emissions Model-Specific Basis for Internal Combustion Device, continued**

The annual power output from the unit is calculated as:

$$500 \text{ kW} \times 0.90 \times \frac{1000 \text{ hr}}{\text{yr}} = 450,000 \text{ kW} \cdot \text{hr/yr}$$

The emissions are calculated as:

$$\text{CH}_4 : \frac{450,000 \text{ kW} \cdot \text{hr}}{\text{yr}} \times \frac{9.39 \times 10^{-6} \text{ tonne CH}_4}{\text{kW} \cdot \text{hr}} = \underline{4.2 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{CO}_2 : \frac{450,000 \text{ kW} \cdot \text{hr}}{\text{yr}} \times \frac{5.808 \times 10^{-4} \text{ tonne CO}_2}{\text{kW} \cdot \text{hr}} = \underline{261 \text{ tonnes CO}_2/\text{yr}}$$

**B.1.2 Methodology for Converting Between LHV and HHV Bases**

Heating value describes the quantity of energy released when a fuel is completely combusted. The difference between gross or higher heating value (HHV) and net or lower heating value (LHV) is the phase of the water in the combustion products: water is in the liquid form for HHV and in the vapor form for LHV. The two heating values are related by the following equation:

$$\text{HHV} = \text{LHV} + (n\bar{h})_{\text{H}_2\text{O}} \quad (\text{Equation B-1})$$

where,

- $n$  is the number of moles of water in the products and  $h$  is the enthalpy of vaporization of water at 25°C.
- Higher heating value (HHV), also referred to as gross calorific value, accounts for condensation of water vapor from the combustion process – the convention commonly used in EPA and DOE documents; and
- Lower heating value (LHV) or net calorific value, includes water in the vapor phase – the convention used by IPCC and other international sources.

Derivation of the emission factor conversion is provided below for a solid fuel.

Starting with the IPCC assumption for a solid-based fuel:

$$\text{LHV} \left( \frac{\text{energy}}{\text{mass}} \right) = \text{HHV} \left( \frac{\text{energy}}{\text{mass}} \right) - 5\% \text{ HHV} \left( \frac{\text{energy}}{\text{mass}} \right)$$

$$\text{LHV} \left( \frac{\text{energy}}{\text{mass}} \right) = \text{HHV} \left( \frac{\text{energy}}{\text{mass}} \right) (1 - 0.05) = 0.95 \text{ HHV} \left( \frac{\text{energy}}{\text{mass}} \right)$$

The heating value is converted to an emission factor as shown:

$$\text{EF} \left( \frac{\text{mass CO}_2}{\text{energy}} \right) =$$

$$\frac{\text{X mass C}}{\text{mass fuel}} \times \frac{\text{mol C}}{12 \text{ mass units C}} \times \frac{\text{mol CO}_2}{\text{mol C}} \times \frac{44 \text{ mass units CO}_2}{\text{mol CO}_2} \times \frac{\text{mass fuel}}{\text{energy fuel}}$$

(Carbon content)      (MW Carbon)      (Carbon Oxidation)      (MW CO<sub>2</sub>)      (1/Heating value)

For an emission factor in terms of higher heating value:

$$\text{EF} \left( \frac{\text{mass CO}_2}{\text{energy}} \right)_{\text{HHV}} = \frac{(44\text{X}/12) \text{ mass CO}_2}{\text{mass fuel}} \times \frac{1}{\text{HHV}} \left( \frac{\text{mass fuel}}{\text{energy}} \right)$$

Likewise, for an emission factor in terms of lower heating value:

$$\text{EF} \left( \frac{\text{mass CO}_2}{\text{energy}} \right)_{\text{LHV}} = \frac{(44\text{X}/12) \text{ mass CO}_2}{\text{mass fuel}} \times \frac{1}{\text{LHV}} \left( \frac{\text{mass fuel}}{\text{energy}} \right)$$

To convert from a HHV-based emission factor to LHV:

$$\text{EF} \left( \frac{\text{mass CO}_2}{\text{energy}} \right)_{\text{LHV}} = \frac{(44\text{X}/12) \text{ mass CO}_2}{\text{mass fuel}} \times \frac{1}{\text{LHV}} \left( \frac{\text{mass fuel}}{\text{energy}} \right) \times \frac{\text{LHV}}{0.95 \text{ HHV}}$$

or expressed more simply:

$$\text{EF}_{\text{LHV}} = \frac{\text{EF}_{\text{HHV}}}{0.95}$$

The same approach would apply for a liquid fuel, except that the heating value of a liquid fuel is typically reported in terms of energy per volume. The fuel carbon content may be available on a mass, volume, or molar basis. As long as the units are internally consistent, the resulting equation

to convert from LHV to HHV is the same as presented for the solid fuels. This is illustrated in the following.

Starting with the IPCC assumption for a liquid-based fuel:

$$\text{LHV}\left(\frac{\text{energy}}{\text{volume}}\right) = \text{HHV}\left(\frac{\text{energy}}{\text{volume}}\right) - 5\% \text{ HHV}\left(\frac{\text{energy}}{\text{volume}}\right)$$

$$\text{LHV}\left(\frac{\text{energy}}{\text{volume}}\right) = \text{HHV}\left(\frac{\text{energy}}{\text{volume}}\right) (1 - 0.05) = 0.95 \text{ HHV}\left(\frac{\text{energy}}{\text{volume}}\right)$$

The heating value is converted to an emission factor, similar to the approach shown for a solid fuel. Additional unit conversions and a fuel density may be required to convert the units appropriately:

$$\text{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right) = \frac{\text{mass fuel}}{\text{volume fuel}} \times \frac{X \text{ mass C}}{\text{mass fuel}} \times \frac{\text{mol C}}{12 \text{ mass units C}} \times \frac{\text{mol CO}_2}{\text{mol C}}$$

(Fuel density)    (Carbon content)    (MW Carbon)    (Carbon Oxidation)

$$\times \frac{44 \text{ mass units CO}_2}{\text{mol CO}_2} \times \frac{\text{volume fuel}}{\text{energy fuel}}$$

(MW CO<sub>2</sub>)    (1/Heating value)

For an emission factor in terms of higher heating value:

$$\text{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right)_{\text{HHV}} = \text{density}\left(\frac{\text{mass fuel}}{\text{volume fuel}}\right) \times \frac{(44X/12) \text{ mass CO}_2}{\text{mass fuel}} \times \frac{1}{\text{HHV}}\left(\frac{\text{volume fuel}}{\text{energy}}\right)$$

Likewise, for an emission factor in terms of lower heating value:

$$\text{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right)_{\text{LHV}} = \text{density}\left(\frac{\text{mass fuel}}{\text{volume fuel}}\right) \times \frac{(44X/12) \text{ mass CO}_2}{\text{mass fuel}} \times \frac{1}{\text{LHV}}\left(\frac{\text{volume fuel}}{\text{energy}}\right)$$

To convert from a HHV-based emission factor to LHV:

$$\text{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right)_{\text{LHV}} = \text{density}\left(\frac{\text{mass fuel}}{\text{vol. fuel}}\right) \times \frac{(44X/12) \text{ mass CO}_2}{\text{mass fuel}} \times \frac{1}{\text{LHV}}\left(\frac{\text{vol. fuel}}{\text{energy}}\right) \times \frac{\text{LHV}}{0.95 \text{ HHV}}$$

or expressed more simply:  $\text{EF}_{\text{LHV}} = \frac{\text{EF}_{\text{HHV}}}{0.95}$

A gas fuel would be treated like a liquid fuel, except that the LHV is 10% lower than the HHV, as shown:

$$\begin{aligned} \text{LHV} \left( \frac{\text{energy}}{\text{volume}} \right) &= \text{HHV} \left( \frac{\text{energy}}{\text{volume}} \right) - 10\% \text{ HHV} \left( \frac{\text{energy}}{\text{volume}} \right) \\ \text{LHV} \left( \frac{\text{energy}}{\text{volume}} \right) &= \text{HHV} \left( \frac{\text{energy}}{\text{volume}} \right) (1 - 0.10) = 0.90 \text{ HHV} \left( \frac{\text{energy}}{\text{volume}} \right) \end{aligned}$$

Following the same approach as shown for the liquid fuel, the emission factor conversion for a gas fuel is:

$$\text{EF}_{\text{LHV}} = \frac{\text{EF}_{\text{HHV}}}{0.90}$$

### **B.1.3 Development of International Electricity Grid Emission Factors**

Composite grid emission factors can be developed using a weighted average approach if the electric contribution of the various generation and fuel types are known. The calculation approach is demonstrated for international grid emission factors, but can be applied to any geographic region.

The International Energy Administration (IEA) provides annual electric generation data (data for OECD countries is summarized in Table B-3) (IEA, 2002). This information can be combined with the emission factors from Table 4-12 using a weighted average basis. This weighted average approach is represented by Equation B-2:

$$\begin{aligned} \text{National Electric EF} &= \\ \sum \left[ \frac{10^{12} \text{ W - hr for Fuel Type}_i}{10^{12} \text{ W - hr Total}} \times \text{Base EF for Fuel/Generation Type}_i \left( \frac{\text{tonnes}}{10^6 \text{ W - hr}} \right) \right] \end{aligned}$$

(Equation B-2)

where, EF = emission factor

Table 4-12 footnotes the municipal solid waste boiler and wood waste biomass boiler emission factors, indicating that these sources are carbon neutral. This is consistent with policies adopted by IPCC and EPA, where CO<sub>2</sub> emissions resulting from biomass combustion are not included based on the assumption that biogenic carbon emitted is offset by the growth of new biomass. Therefore, in developing the grid emission factors, zero CO<sub>2</sub> emissions are applied for these sources. However, the CH<sub>4</sub> and N<sub>2</sub>O emission factors from Table 4-12 are included in the calculations.

Additional IEA information provides the electrical capacity of each country within the Organization for Economic Co-operation and Development (OECD) (IEA, 2002). For the purpose of developing international grid emission factors for the Compendium, this information was used to assign appropriate emission factors from Table 4-1 to the fuel types. The IEA information indicates that the majority of the electrical capacity for the OECD countries is generated by steam turbines, followed by combined cycle. In calculating the national emission factors, the oil steam turbine emission factor is applied to electric generation by oil fuels and the gas combined cycle emission factor is applied to electric generation by gas fuels. As mentioned previously, the wood waste biomass emission factors for CO<sub>2</sub> are not included, but the CH<sub>4</sub> and N<sub>2</sub>O emission factors are applied to electricity generation by combustible renewables. Similarly, the CO<sub>2</sub> emissions from municipal solid waste are zero, while the DOE CH<sub>4</sub> and N<sub>2</sub>O emission factors are applied to this electric generation. The municipal solid waste boiler emission factors are also applied to the “industrial waste” and “other fuels and waste” categories of electric generation.

Calculation of the national emission factors is illustrated below for Italy.

**Exhibit B.2                      Electricity Emission Factor Development for Italy – Generation Based Approach**

**CALCULATION METHODOLOGY:**

Table B-3 provides the year 2002 fuel mix for electricity production in Italy. Table 4-12 provides the emission factors for different electricity generation types (DOE, 1994). Applying Equation B-2, the weighted emission factors are calculated by multiplying the ratio of the electricity generation of each fuel to the overall generation (from Table B-3) by the base emission factor (from Table 4-12), then summing for all of the fuel types. This is shown for CO<sub>2</sub>:

**Exhibit B.2 Electricity Emission Factor Development for Italy – Generation Based Approach, continued**

$$\begin{aligned} \text{Weighted CO}_2 \text{ EF} = & \left( \frac{0.127 \times 10^{12} \text{ Whr}_{\text{coal}}}{10^{12} \text{ Whr}_{\text{Total}}} \times \frac{0.894 \text{ tonnes CO}_2}{10^6 \text{ W-hr}} \right) \\ & + \left( \frac{0.269 \times 10^{12} \text{ Whr}_{\text{oil}}}{10^{12} \text{ Whr}_{\text{Total}}} \times \frac{0.659 \text{ tonnes CO}_2}{10^6 \text{ W-hr}} \right) + \left( \frac{0.401 \times 10^{12} \text{ Whr}_{\text{gas}}}{10^{12} \text{ Whr}_{\text{Total}}} \times \frac{0.432 \text{ tonnes CO}_2}{10^6 \text{ W-hr}} \right) \\ & + \left( \frac{0.004 \times 10^{12} \text{ Whr}_{\text{solid biomass \& biogas}}}{10^{12} \text{ Whr}_{\text{Total}}} \times \frac{0 \text{ tonnes CO}_2}{10^6 \text{ W-hr}} \right) + \left( \frac{0.002 \times 10^{12} \text{ Whr}_{\text{industrial waste}}}{10^{12} \text{ Whr}_{\text{Total}}} \times \frac{1.700 \text{ tonnes CO}_2}{10^6 \text{ W-hr}} \right) \\ & + \left( \frac{0.005 \times 10^{12} \text{ Whr}_{\text{municipal waste}}}{10^{12} \text{ Whr}_{\text{Total}}} \times \frac{0 \text{ tonnes CO}_2}{10^6 \text{ W-hr}} \right) + \left( \frac{0.016 \times 10^{12} \text{ Whr}_{\text{geothermal}}}{10^{12} \text{ Whr}_{\text{Total}}} \times \frac{0.122 \text{ tonnes CO}_2}{10^6 \text{ W-hr}} \right) \\ & + \left( \frac{0.177 \times 10^{12} \text{ Whr}_{\text{renewables}}}{10^{12} \text{ Whr}_{\text{Total}}} \times \frac{0 \text{ tonnes CO}_2}{10^6 \text{ W-hr}} \right) + \left( \frac{0 \times 10^{12} \text{ Whr}_{\text{other}}}{10^{12} \text{ Whr}_{\text{Total}}} \times \frac{1.700 \text{ tonnes CO}_2}{10^6 \text{ W-hr}} \right) \end{aligned}$$

Weighted CO<sub>2</sub> EF =

$$\left[ \begin{aligned} & \left( 0.113 \frac{\text{tonnes CO}_2}{10^6 \text{ W-hr}} \right)_{\text{coal}} + \left( 0.177 \frac{\text{tonnes CO}_2}{10^6 \text{ W-hr}} \right)_{\text{oil}} + \left( 0.173 \frac{\text{tonnes CO}_2}{10^6 \text{ W-hr}} \right)_{\text{gas}} \\ & + \left( 0 \frac{\text{tonnes CO}_2}{10^6 \text{ W-hr}} \right)_{\text{biogas \& solid biomass}} + \left( 0.0034 \frac{\text{tonnes CO}_2}{10^6 \text{ W-hr}} \right)_{\text{industrial waste}} + \left( 0 \frac{\text{tonnes CO}_2}{10^6 \text{ W-hr}} \right)_{\text{municipal waste}} \\ & + \left( 0.0020 \frac{\text{tonnes CO}_2}{10^6 \text{ W-hr}} \right)_{\text{geothermal}} + \left( 0 \frac{\text{tonnes CO}_2}{10^6 \text{ W-hr}} \right)_{\text{renewables}} + \left( 0 \frac{\text{tonnes CO}_2}{10^6 \text{ W-hr}} \right)_{\text{other}} \end{aligned} \right]$$

**Weighted CO<sub>2</sub> EF = 0.468 tonnes CO<sub>2</sub>/10<sup>6</sup> W-hr**

**Exhibit B.2 Electricity Emission Factor Development for Italy – Generation Based Approach, continued**

Fuel/ Generation Type	% Contribution to Electricity Generation	Tonnes/ 10 <sup>6</sup> W-hr					
		Base CO <sub>2</sub> EF	Weighted CO <sub>2</sub> EF	Base CH <sub>4</sub> EF	Weighted CH <sub>4</sub> EF	Base N <sub>2</sub> O EF	Weighted N <sub>2</sub> O EF
Coal	12.7	0.894	0.113	1.814E-5	2.303E-6	1.542E-4	1.958E-5
Oil	26.9	0.659	0.177	9.072E-7	2.440E-7	0	0
Gas	40.1	0.432	0.173	6.804E-6	2.728E-6	2.858E-5	1.146E-5
Biogas & Solid Biomass	0.4	0	0	6.350E-5	2.540E-7	2.495E-4	9.98E-7
Industrial Waste	0.2	1.700	0.003	9.072E-6	1.814E-8	2.495E-4	4.99E-7
Municipal waste	0.5	0	0	9.072E-6	4.536E-8	2.495E-4	1.247E-6
Geothermal	1.6	0.122	0.0020	0	0	0	0
Wind, Hydro, Solar & Nuclear	17.7	0	0	0	0	0	0
Other fuels	0	1.700	0	9.072E-6	0	2.495E-4	0
<b>TOTAL</b>	<b>100</b>	<b>--</b>	<b>0.468</b>	<b>--</b>	<b>5.59E-06</b>	<b>--</b>	<b>3.38E-5</b>

The resulting 2002 weighted average emission factors for Italy are:

CO<sub>2</sub> = 0.468 tonnes/10<sup>6</sup> W-hr

CH<sub>4</sub> = 5.59E-06 tonnes/10<sup>6</sup> W-hr

N<sub>2</sub>O = 3.38E-05 tonnes/10<sup>6</sup> W-hr

The same approach was used to estimate “grid” emission factors for the years 2000 and 2001. The results shown in Table 4-13 are an average of the three years for OECD countries, and an average of 2000 and 2001 data for non-OECD countries (2002 data are not currently available for the non-OECD countries).

The Greenhouse Gas Protocol by the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD) (WRI/WBCSD, 2001) also reports emission factors from imported energy by country based on other information from IEA. The user should note, however, that the emission factors provided by WRI/WBCSD are based on fuel consumption and generation methods to produce both electricity and heat. For these emission factors, the total CO<sub>2</sub> emissions are derived from the national fuel usage, carbon content and heating value of the fuel, and divided by the sum of energy output from both electricity and heat. The actual mix of generation methods and fuels used for electricity versus heat can differ significantly within a country, such that these emission factors may not be appropriate for calculating emissions associated with electricity usage only. Therefore, the IEA data developed specifically from electricity generation information is recommended over the WRI/WBCSD published emission factors.



**Table B–3. Summary of Year 2002 Electricity Generation Information for OECD Countries**

Country	Total Generation,	Coal	Oil	Gas	Geothermal	Wind, hydro, solar & nuclear	Solid biomass & biogas	Industrial waste	Municipal waste	Other fuels and waste
	10 <sup>12</sup> W-hr	% Generation								
Australia	223.2	76.7	1.3	13.1	0.0	7.7	1.1	0.0	0.0	0.0
Austria	62.46	13.2	3.8	17.9	0.0	61.4	3.3	0.4	0.1	0.0
Belgium	82.06	12.9	1.0	24.4	0.0	59.6	0.4	0.7	1.0	0.0
Canada	566.18	20.1	2.9	6.2	0.0	69.6	1.2	0.0	0.0	0.0
Czech Republic	76.35	65.5	0.5	4.9	0.0	28.3	0.6	0.2	0.0	0.0
Denmark	38.62	47.3	10.2	23.3	0.0	12.7	3.0	0.0	3.5	0.0
Finland	75.23	17.4	2.2	14.1	0.0	44.1	13.0	0.4	0.3	8.4
France	559.64	4.1	1.3	3.9	0.0	90.1	0.3	0.0	0.3	0.0
Germany	582.79	50.4	1.0	10.9	0.0	35.6	0.5	0.9	0.6	0.0
Greece	50.74	61.5	16.6	13.3	0.0	8.3	0.2	0.2	0.0	0.0
Hungary	36.09	24.7	7.8	28.1	0.0	39.2	0.0	0.0	0.2	0.0
Iceland	8.41	0.0	0.1	0.0	17.0	82.9	0.0	0.0	0.0	0.0
Ireland	24.63	27.6	14.7	42.3	0.0	6.7	0.3	0.0	0.0	8.3
Italy	283.66	12.7	26.9	40.1	1.6	17.7	0.4	0.2	0.5	0.0
Japan	1097.02	20.9	14.0	27.8	0.3	35.3	1.2	0.0	0.5	0.0
Korea	306.56	31.9	13.8	13.5	0.0	40.6	0.0	0.0	0.1	0.0
Luxembourg	3.55	0.0	0.0	69.9	0.0	28.5	0.3	0.0	1.4	0.0
Mexico	215.15	11.9	36.9	32.3	2.5	16.1	0.2	0.0	0.0	0.0
Netherlands	96.29	24.5	2.1	64.3	0.0	5.4	1.1	0.0	2.6	0.0
New Zealand	39.51	3.8	0.0	25.6	6.3	63.1	1.1	0.0	0.0	0.0
Norway	130.61	0.0	0.0	0.4	0.0	99.4	0.2	0.0	0.0	0.0
Poland	144.08	92.4	1.9	2.3	0.0	2.7	0.4	0.2	0.0	0.0
Portugal	46.07	33.1	24.8	19.8	0.2	18.6	2.4	0.0	1.1	0.0
Slovak Republic	32.37	16.4	1.9	8.7	0.0	72.5	0.4	0.0	0.0	0.0

**Table B–3. Summary of Year 2002 Electricity Generation Information for OECD Countries, continued**

Country	Total Generation,	Coal	Oil	Gas	Geothermal	Wind, hydro, solar & nuclear	Solid biomass & biogas	Industrial waste	Municipal waste	Other fuels and waste
	10 <sup>12</sup> W-hr	% Generation								
Spain	245.51	33.1	11.6	13.7	0.0	40.0	1.4	0.0	0.2	0.0
Sweden	147.57	1.6	1.9	0.8	0.0	92.2	3.0	0.1	0.2	0.1
Switzerland	67.06	0.0	0.1	1.5	0.0	95.6	0.3	0.0	2.4	0.0
Turkey	129.39	24.3	8.3	41.1	0.1	26.1	0.1	0.0	0.0	0.0
United Kingdom	385.21	32.2	1.6	39.5	0.0	25.2	1.1	0.0	0.4	0.0
United States	3970.33	49.3	2.4	18.3	0.4	27.8	1.1	0.2	0.4	0.0
OECD Total	9726.3	36.1	5.9	18.7	0.3	37.2	1.1	0.2	0.4	0.1
OECD Europe	3308.35	27.7	5.4	18.2	0.2	46.5	1.1	0.2	0.5	0.3
OECD Pacific	1666.3	30.0	12.0	23.1	0.3	33.2	0.9	0.0	0.3	0.0
OECD North America	4751.65	44.2	4.1	17.5	0.4	32.2	1.1	0.2	0.3	0.0

Source: IEA Electricity Information Database, “Gross Electricity Production by Fuel” (IEA, 2002).

### B.1.4 U.S. and Canadian Regional Electricity Grid Emission Factors

In the U.S., the Department of Energy's (DOE) Energy Information Administration (EIA) provides emission factors based on electric generation from utilities, non-utilities, and industrial cogenerators for a three-year (1998 through 2000) rolling average<sup>1</sup> (EIA, 2002). These are summarized in Table B-4.

**Table B-4. Average US Electricity Usage Emission Factors by State**

Location	Carbon Dioxide (CO <sub>2</sub> )		Methane (CH <sub>4</sub> )		Nitrous Oxide (N <sub>2</sub> O)	
	short tons/ 10 <sup>6</sup> W-hr	tonnes/ 10 <sup>6</sup> W-hr	lb/ 10 <sup>6</sup> W-hr	tonnes/ 10 <sup>6</sup> W-hr	lb/ 10 <sup>6</sup> W-hr	tonnes/ 10 <sup>6</sup> W-hr
Alabama	0.656	0.595	0.0137	6.213E-06	0.0223	1.011E-05
Alaska	0.690	0.626	0.0068	3.084E-06	0.0089	4.036E-06
Arizona	0.525	0.476	0.0068	3.084E-06	0.0154	6.984E-06
Arkansas	0.643	0.583	0.0125	5.669E-06	0.0203	9.206E-06
California	0.303	0.275	0.0067	3.039E-06	0.0037	1.678E-06
Colorado	0.963	0.873	0.0127	5.760E-06	0.0289	1.311E-05
Connecticut	0.471	0.427	0.0174	7.891E-06	0.0120	5.442E-06
Delaware	0.915	0.830	0.0123	5.578E-06	0.0227	1.029E-05
Florida	0.697	0.632	0.0150	6.803E-06	0.0180	8.163E-06
Georgia	0.683	0.620	0.0129	5.850E-06	0.0226	1.025E-05
Hawaii	0.831	0.754	0.0214	9.705E-06	0.0183	8.299E-06
Idaho	0.014	0.013	0.0080	3.628E-06	0.0033	1.497E-06
Illinois	0.582	0.528	0.0082	3.719E-06	0.0180	8.163E-06
Indiana	1.038	0.941	0.0143	6.485E-06	0.0323	1.465E-05
Iowa	0.941	0.854	0.0138	6.259E-06	0.0298	1.351E-05
Kansas	0.842	0.764	0.0112	5.079E-06	0.0254	1.152E-05
Kentucky	1.004	0.911	0.0140	6.349E-06	0.0321	1.456E-05
Louisiana	0.589	0.534	0.0094	4.263E-06	0.0112	5.079E-06
Maine	0.426	0.386	0.0565	2.562E-05	0.0270	1.224E-05
Maryland <sup>a</sup>	0.683	0.620	0.0118	5.351E-06	0.0206	9.342E-06
Massachusetts	0.639	0.580	0.0174	7.891E-06	0.0159	7.211E-06
Michigan	0.790	0.717	0.0146	6.621E-06	0.0250	1.134E-05
Minnesota	0.762	0.691	0.0157	7.120E-06	0.0247	1.120E-05
Mississippi	0.647	0.587	0.0132	5.986E-06	0.0165	7.483E-06
Missouri	0.920	0.834	0.0126	5.714E-06	0.0288	1.306E-05
Montana	0.717	0.650	0.0108	4.898E-06	0.0227	1.029E-05
Nebraska	0.700	0.635	0.0095	4.308E-06	0.0219	9.932E-06
Nevada	0.759	0.688	0.0090	4.082E-06	0.0195	8.844E-06
New Hampshire	0.341	0.309	0.0172	7.800E-06	0.0141	6.395E-06
New Jersey	0.353	0.320	0.0077	3.492E-06	0.0079	3.583E-06

<sup>1</sup> DOE EIA data reported for the three-year average 1997-1999 included only electric utilities.

**Table B-4. Average US Electricity Usage Emission Factors by State, continued**

Location	Carbon Dioxide (CO <sub>2</sub> )		Methane (CH <sub>4</sub> )		Nitrous Oxide (N <sub>2</sub> O)	
	short tons/ 10 <sup>6</sup> W-hr	tonnes/ 10 <sup>6</sup> W-hr	lb/ 10 <sup>6</sup> W-hr	tonnes/ 10 <sup>6</sup> W-hr	lb/ 10 <sup>6</sup> W-hr	tonnes/ 10 <sup>6</sup> W-hr
New Mexico	1.009	0.915	0.0131	5.941E-06	0.0296	1.342E-05
New York	0.429	0.389	0.0081	3.673E-06	0.0089	4.036E-06
North Carolina	0.621	0.563	0.0105	4.762E-06	0.0203	9.206E-06
North Dakota	1.121	1.017	0.0147	6.667E-06	0.0339	1.537E-05
Ohio	0.900	0.816	0.0130	5.896E-06	0.0288	1.306E-05
Oklahoma	0.861	0.781	0.0110	4.989E-06	0.0223	1.011E-05
Oregon	0.141	0.128	0.0033	1.497E-06	0.0034	1.542E-06
Pennsylvania	0.632	0.573	0.0107	4.853E-06	0.0203	9.206E-06
Rhode Island	0.526	0.477	0.0068	3.084E-06	0.0047	2.132E-06
South Carolina	0.417	0.378	0.0091	4.127E-06	0.0145	6.576E-06
South Dakota	0.399	0.362	0.0053	2.404E-06	0.0121	5.488E-06
Tennessee	0.648	0.588	0.0105	4.762E-06	0.0212	9.615E-06
Texas	0.732	0.664	0.0077	3.492E-06	0.0146	6.621E-06
Utah	0.967	0.877	0.0134	6.077E-06	0.0308	1.397E-05
Vermont	0.014	0.013	0.0096	4.354E-06	0.0039	1.769E-06
Virginia	0.582	0.528	0.0137	6.213E-06	0.0192	8.707E-06
Washington	0.123	0.112	0.0037	1.678E-06	0.0040	1.814E-06
West Virginia	0.988	0.896	0.0137	6.213E-06	0.0316	1.433E-05
Wisconsin	0.821	0.745	0.0138	6.259E-06	0.0260	1.179E-05
Wyoming	1.073	0.973	0.0147	6.667E-06	0.0338	1.533E-05
<b>US Average</b>	<b>0.668</b>	<b>0.606</b>	<b>0.0111</b>	<b>5.034E-06</b>	<b>0.0192</b>	<b>8.707E-06</b>

Source: Energy Information Administration (EIA), *Updated State- and Regional-level Greenhouse Gas Emission Factors for Electricity*, U.S. Department of Energy, EIA, Office of Integrated Analysis and Forecasting, <http://www.eia.doe.gov/oiaf/1605/e-factor.html>, March 2002.

<sup>a</sup> Includes the District of Columbia.

Similarly, Environment Canada collects information on electricity generation for each province. Table B-5 provides emission factors for the average of years 1999 through 2001. These emission factors were calculated by dividing electricity emissions data by the power usage, based on data provided by Environment Canada (Ha, 2003; Olsen, 2003). These emission factors include electricity generation from both utility and industrial emission sources.

**Table B-5. Average Canadian Electricity Usage Emission Factors by Province (1999-2001 data)**

Location	Carbon Dioxide (CO <sub>2</sub> )	Methane (CH <sub>4</sub> )	Nitrous Oxide (N <sub>2</sub> O)
	tonnes/ 10 <sup>6</sup> W-hr	tonnes/ 10 <sup>6</sup> W-hr	tonnes/ 10 <sup>6</sup> W-hr
Newfoundland	0.0283	3.14E-07	6.28E-07
Prince Edward Island	1.207	Not Given	Not Given
Nova Scotia	0.728	7.21E-06	1.07E-05
New Brunswick	0.447	4.98E-06	8.42E-06
Quebec	0.00338	1.35E-07	7.70E-08
Ontario	0.264	1.09E-05	4.33E-06
Manitoba	0.0216	3.22E-07	4.29E-07
Saskatchewan	0.846	2.92E-05	1.93E-05
Alberta	0.876	2.92E-05	1.62E-05
British Columbia	0.0341	6.65E-06	8.69E-07
Yukon, Northwest Territories, and Nunavut	0.304	Not Given	3.31E-05
<b>Canada Average</b>	<b>0.222</b>	<b>7.82E-06</b>	<b>4.14E-06</b>

Sources:

Electricity generation data: Ha, Chia. Environment Canada, data provided to URS Corporation on September 16, 2003.

Emissions data: Olsen, K., et al. *Canada's Greenhouse Gas Inventory 1990-2001*, Greenhouse Gas Division, Environment Canada, August 2003.

An example calculation illustrating how to estimate electricity related CO<sub>2</sub>, CH<sub>4</sub> and N<sub>2</sub>O emissions using state or provincial emission factors follows.

**EXHIBIT B.3: Sample Calculation for Electric Utility (Indirect) Emissions Using State Emission Factors**

**INPUT DATA:**

A facility in Louisiana purchases 500,000 kilowatt-hr of electricity during a given year. The method of electricity generation is unknown, but the electricity is produced in Louisiana.

**CALCULATION METHODOLOGY:**

Table B-4 provides the following CH<sub>4</sub> and CO<sub>2</sub> emission factors for Louisiana:

CO<sub>2</sub> EF = 0.534 tonnes CO<sub>2</sub>/10<sup>6</sup> W-hr

CH<sub>4</sub> EF = 4.263E-06 tonnes CH<sub>4</sub>/10<sup>6</sup> W-hr

N<sub>2</sub>O EF = 5.079-06 tonnes N<sub>2</sub>O/10<sup>6</sup> W-hr

The emission factors are multiplied by the quantity of electricity purchased by the plant to calculate the annual emissions, as follows:

$$\text{CO}_2 : \frac{500,000 \text{ kilowattW - hr}}{\text{yr}} \times \frac{1 \text{ megawatt}}{1000 \text{ kilowatt}} \times \frac{0.534 \text{ tonne CO}_2}{\text{megawatt - hr}} = \underline{267 \text{ tonnes CO}_2/\text{yr}}$$

$$\text{CH}_4 : \frac{500,000 \text{ kilowatt - hr}}{\text{yr}} \times \frac{1 \text{ megawatt}}{1000 \text{ kilowatt}} \times \frac{4.263 \times 10^{-6} \text{ tonne CH}_4}{\text{megawatt - hr}} = \underline{0.0021 \text{ tonnes CH}_4/\text{yr}}$$

$$\text{N}_2\text{O} : \frac{500,000 \text{ kilowatt - hr}}{\text{yr}} \times \frac{1 \text{ megawatt}}{1000 \text{ kilowatt}} \times \frac{5.079 \times 10^{-6} \text{ tonne CO}_2}{\text{megawatt - hr}} = \underline{0.0025 \text{ tonnes N}_2\text{O}/\text{yr}}$$

Other sources of information related to energy generation emissions in the US include the following:

- 1) Electric generation provided by non-utilities -  
[http://www.eia.doe.gov/cneaf/electricity/st\\_profiles/toc.html](http://www.eia.doe.gov/cneaf/electricity/st_profiles/toc.html)
- 2) Electric generation by fuel type and fuel consumption rates for each major US electricity producer – <http://www.eia.doe.gov/cneaf/electricity/epm/epm56pl.html>

## B.2 Vented Sources

### B.2.1 Tank Flashing

A simplified CH<sub>4</sub> emission factor was derived from combining flashing loss measurement data from two separate measurement programs (Ogle, March 1997/Ogle, May 1997; Picard, 1992). The measurement programs involved gas streams with varying CH<sub>4</sub> contents. In order to combine the measurements, each was converted to a common production segment CH<sub>4</sub> concentration of 78.8% (Shires, 1996). The measurement data and conversion calculations are summarized in Table B-6.

**Table B-6. Tank Flashing Loss Emission Factor Development**

	Oil Fill Rate, bbl/day	CH <sub>4</sub> Emissions, scf/hr <sup>a</sup>	Separator Mol % CH <sub>4</sub>	CH <sub>4</sub> EF, scf/bbl	Normalized CH <sub>4</sub> EF, scf/bbl/sep-% CH <sub>4</sub>
<b>Canadian Measurements<sup>b</sup></b>					
1	34.6	4.98	75.91	3.45	0.045
2	69.2	128	81.78	44.5	0.544
3	2717	5.32	69.99	0.05	0.001
4	34.6	9.32	75.91	6.46	0.085
5	1413	376	88.16	6.38	0.072
<i>Canadian Average</i>			78.35	12.16	0.15
<b>API Measurements<sup>c</sup></b>					
1	188	179	57.91	22.8	0.394
2	1600	572	24.81	8.59	0.346
3	438	19.7	49.61	1.08	0.022
4	259	35.5	80.63	3.29	0.041
5	451	56.8	58.00	3.03	0.052
6	12	73.0	No Data – assume average of 54.19	146	2.69
7	60	371		148	2.74
<i>API Average</i>			54.19	47.6	0.90
<b>Combined Average</b>				<b>32.84</b>	<b>0.586</b>
<b>Corrected Emission Factor, scf CH<sub>4</sub>/bbl<sup>d</sup></b>				<b>46.18</b>	
<b>Corrected Emission Factor, lb CH<sub>4</sub>/bbl<sup>d</sup></b>				<b>1.954</b>	
<b>Corrected Emission Factor, tonnes CH<sub>4</sub>/bbl<sup>d</sup></b>				<b>8.86E-04</b>	
<b>Corrected Emission Factor, tonnes CH<sub>4</sub>/m<sup>3</sup> oil<sup>d</sup></b>				<b>5.57E-03</b>	

Footnotes for Table B-6:

<sup>a</sup> Corrected to 60°F and 1 atm.

<sup>b</sup> Source: Picard, D. J., B. D. Ross, and D. W. H. Koon. *A Detailed Inventory of CH<sub>4</sub> and VOC Emissions from Upstream Oil and Gas Operations in Alberta*, Volume III Results of the Field Validation Program, Canadian Petroleum Association, March 1992, pp. 75-81.

<sup>c</sup> Source: Ogle, L.D. *Validation of a Petroleum Production Tank Emission Model*, Final Report, GRI-97/0117. American Petroleum Institute and Gas Research Institute, March 1997 (emission and production rates).

and

Ogle, L.D. *Evaluation of a Petroleum Production Tank Emission Model*, Final Report. American Petroleum Institute, Gas Research Institute, and Canadian Association of Petroleum Producers, May 1997 (separator CH<sub>4</sub> concentration).

<sup>d</sup> Corrected to average CH<sub>4</sub> concentration for natural gas industry production operations of 78.8%. Source for 78.8% CH<sub>4</sub> concentration:

Shires, T.M., and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 6: Vented and Combustion Source Summary*, Final Report, GRI-94/0257.23 and EPA-600/R-96-080f, Gas Research Institute and US Environmental Protection Agency, June 1996.

## **B.2.2 Loading, Ballasting, and Transit Loss Emissions**

Section 5.5 of the Compendium presents the simple calculation approaches for loading, ballasting, and transit loss emissions. This appendix section provides more detailed calculation approaches.

### **Loading Loss Emissions**

Figures B-1 and B-2 provide guidance for selecting among the available techniques for estimating loading losses. Figure B-1 applies to crude, while Figure B-2 applies to other petroleum fuels.

For all of the loading loss emission estimates, the fuel CH<sub>4</sub> content is required to convert from the TOC emission factors provided in this section. The CH<sub>4</sub> content of crude is assumed to be 15 percent by weight (wt%), if site-specific data are not available (EPA, AP-42 Section 5.2, 1995). For petroleum liquids other than crude, the CH<sub>4</sub> content is generally insignificant and is assumed negligible if measured data are not available. As shown in Figure B-2, loading loss emission calculations are only required for gasoline if the CH<sub>4</sub> content is measurably significant (> 1% by weight).



### Options Based on Fuel Type and Available

#### Crude:

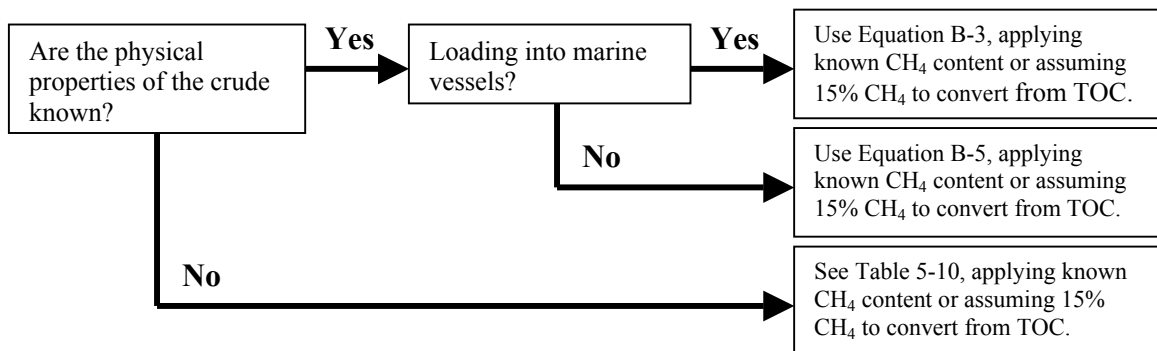


Figure B-1. Decision Tree for Crude Loading Losses

### Options Based on Fuel Type and Available Information

#### Other Fuels (Gasoline):

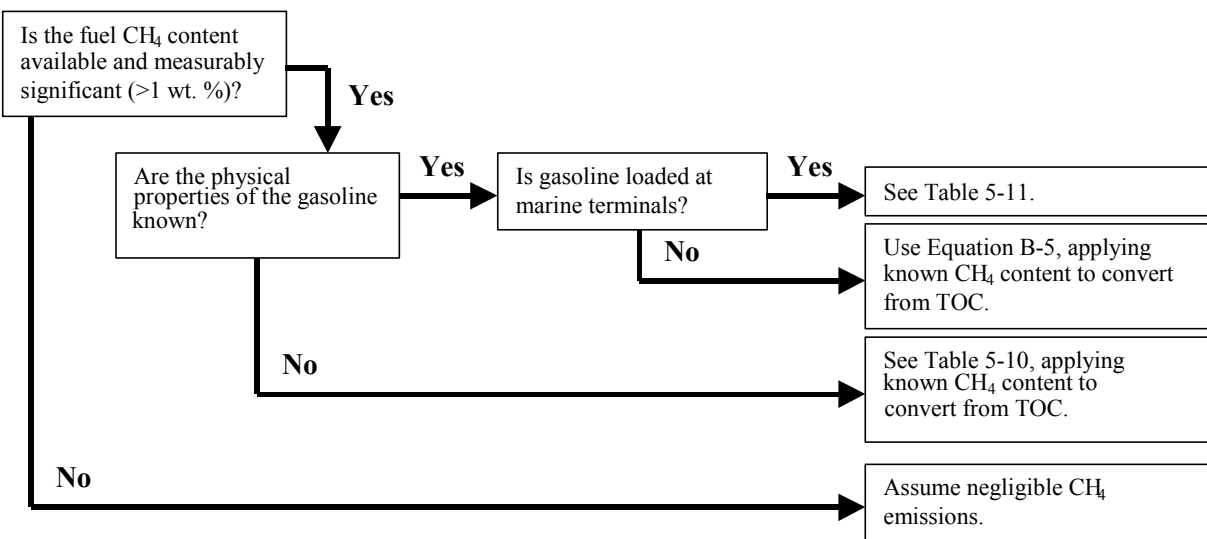


Figure B-2. Decision Tree for Gasoline Liquid Loading Losses

For crude oil loaded into ships and ocean barges, Equation B-3, below, is applicable (EPA, AP-42, Section 5.2, 1995).

$$C_L = C_A + C_G \quad (\text{Equation B-3})$$

where,

- $C_L$  = total loading loss TOC emission factor, lb/10<sup>3</sup> gallon of crude oil loaded
- $C_A$  = arrival emission factor, from vapors in the empty tank vessel before loading, lb/10<sup>3</sup> gallon loaded; given in Table B-7 below
- $C_G$  = emission factor for emissions generated during loading, lb/10<sup>3</sup> gallon; given by Equation B-4 below

Equation B-3 gives an emission factor for total organic compounds (TOC) emitted during marine vessel loading of crude oil. AP-42 reports that the VOC comprises 55-100 wt% of the TOC, with a typical value of 85%. Thus, a good assumption for the CH<sub>4</sub> content of the TOC is 15 wt% in the absence of site-specific data. This assumption is conservative because the non-VOC portion of the TOC includes both methane and ethane; thus, assuming that the CH<sub>4</sub> comprises 15 wt% of the TOC is conservative because the ethane portion is not accounted for.

Equation B-4 provides the calculation for the factor  $C_G$  (EPA, AP-42 Section 5.2, Equation 3, 1995).

$$C_G = 1.84 \times (0.44 P - 0.42) \times \left( \frac{M G}{T} \right) \quad (\text{Equation B-4})$$

where,

- $P$  = true vapor pressure of crude oil loaded, psia
- $M$  = molecular weight of the vapors, lb/lb-mole
- $G$  = vapor growth factor = 1.02, dimensionless
- $T$  = temperature of the vapors, °R (°R = °F + 459.7)

The arrival factor,  $C_A$ , in the expression above is presented in Table B-7 below.

**Table B-7. Average Arrival TOC Emission Factor,  $C_A$ , for the Crude Oil Marine Vessel Loading Emission Factor Equation**

Ship/Ocean Barge Tank Condition	Previous Cargo <sup>b</sup>	Arrival Emission Factor, $C_A$		
		Original Units	Converted Units	
		lb TOC/10 <sup>3</sup> gallon <sup>a</sup>	tonnes TOC/gal	tonnes TOC/m <sup>3</sup>
Uncleaned	Volatile	0.86	0.39	103
Ballasted	Volatile	0.46	0.21	5.9
Cleaned or gas-freed	Volatile	0.33	0.15	1.1
Any condition	Non-volatile	0.33	0.15	0.57

Source: EPA, AP-42, Section 5.2.

<sup>a</sup> The factors shown are for total organic compounds. AP-42 reports that the VOC comprises 55-100% of the TOC, with a typical value of 85%. Thus, a good, conservative assumption for the CH<sub>4</sub> content of the TOC is 15% in the absence of site-specific data.

<sup>b</sup> "Volatile" cargo refers to those cargoes with a vapor pressure greater than 1.5 psia.

Physical properties such as the true vapor pressure of the fuel (P), Reid Vapor Pressure (RVP), and the molecular weight of the vapors (M) are required inputs for this approach. Several sources are available for this information, such as Perry's Chemical Engineering Handbook (Perry, 1984) and the CRC (CRC Press, 1984). Table B-8 provides these properties for some select petroleum liquids based on the average ambient temperature of the facility (EPA, AP-42 Supplement A, 1996). Average temperature information for a specific location can be found at a number of Internet sites, such as:

www.worldclimate.com  
 www.weatherbase.com  
 www.ncdc.noaa.gov

**Table B-8. Properties of Select Petroleum Liquids**

Petroleum Liquid	Vapor Molecular Weight at 60°F, (lb/lbmole)	Condensed Vapor Density at 60°F, (lb/gal)	Liquid Density 60°F, (lb/gal)	True Vapor Pressure (psi)						
				40°F	50°F	60°F	70°F	80°F	90°F	100°F
Gasoline RVP 13	62	4.9	5.6	4.7	5.7	6.9	8.3	9.9	11.7	13.8
Gasoline RVP 10	66	5.1	5.6	3.4	4.2	5.2	6.2	7.4	8.8	10.5
Gasoline RVP 7	68	5.2	5.6	2.3	2.9	3.5	4.3	5.2	6.2	7.4
Crude oil RVP 5	50	4.5	7.1	1.8	2.3	2.8	3.4	4.0	4.8	5.7

Petroleum Liquid	Vapor Molecular Weight at 15.6°C, (kg/kgmole)	Condensed Vapor Density at 15.6°C, (kg/m <sup>3</sup> )	Liquid Density 60°F, (kg/m <sup>3</sup> )	True Vapor Pressure (10 <sup>3</sup> Pa)						
				4.4°C	10.0°C	15.6°C	21.1°C	26.7°C	32.2°C	37.8°C
Gasoline RVP 13	62	587	671	32.4	39.3	47.6	57.2	68.3	80.7	95.1
Gasoline RVP 10	66	611	671	23.4	29.0	35.9	42.7	51.0	60.7	72.4
Gasoline RVP 7	68	623	671	15.9	20.0	24.1	29.6	35.9	42.7	51.0
Crude oil RVP 5	50	539	851	12.4	15.9	19.3	23.4	27.6	33.1	39.3

Source: EPA, AP-42, Table 7.1-2, February 1996.

Exhibit B.4 illustrates the use of the equation for estimating marine vessel crude oil loading loss emissions.

**EXHIBIT B.4: Sample Calculation for Estimating Crude Oil Marine Loading Loss CH<sub>4</sub> Emissions Using Equations B-3 and B-4**

**INPUT DATA:**

50,000 bbl/yr of crude oil with a Reid Vapor Pressure (RVP) of 5 is loaded into ships at a marine terminal. The ships are not cleaned prior to loading. The previous cargo in the ships was also crude oil (RVP 5).

**EXHIBIT B.4: Sample Calculation for Estimating Crude Oil Marine Loading Loss CH<sub>4</sub> Emissions Using Equations B-3 and B-4, continued**

**CALCULATION METHODOLOGY:**

The average ambient temperature at the facility is 70°F (529.7°R) based on average annual meteorological data. The crude oil molecular weight and vapor pressure are estimated using data provided in Table B-8 for crude oil with an RVP of 5 psi:

$$M = 50 \text{ lb/lbmole}$$

$$P = 3.4 \text{ psia (per AP-42 at 70°F)}$$

Using Equation B-4, the vapor growth factor,  $G$ , is 1.02 and the “generated emission factor” or  $C_G$  is calculated as:

$$C_G = 1.84 \times (0.44 P - 0.42) \times \left( \frac{M G}{T} \right)$$

$$C_G = 1.84 \times [(0.44)(3.4) - 0.42] \times \left( \frac{(50)(1.02)}{529.7} \right)$$

$$C_G = 0.19 \text{ lb TOC}/10^3 \text{ gal crude}$$

Next, the "arrival" emission factor,  $C_A$ , is read from Table B-7. Because the crude (previous cargo) has a vapor pressure greater than 1.5 psia, it is classified as "volatile." Thus, for "uncleaned" ships, Table B-7 gives a  $C_A$  factor of 0.86 lb TOC/10<sup>3</sup> gallons of crude loaded. With the factors  $C_A$  and  $C_G$  now defined, the total loading loss factor,  $C_L$ , can be estimated using Equation B-3:

$$C_L = C_A + C_G$$

$$C_L = (0.86 \text{ lb TOC}/10^3) + (0.19 \text{ lb TOC}/10^3) = 1.05 \text{ lb TOC}/10^3 \text{ gallons crude loaded}$$

The last step in the calculation is to estimate the loading loss emissions by multiplying the loading loss emission factor,  $C_L$ , by the annual crude throughput loaded into the ships. Also, the TOC must be multiplied by the CH<sub>4</sub> content of the vapors to obtain the CH<sub>4</sub> emissions. Because a specific CH<sub>4</sub> content is not available, 15% by weight is assumed, per Table B-7. Thus, the CH<sub>4</sub> emissions from the crude oil ship loading are:

$$\begin{aligned} \text{Loading Emissions} &= \frac{1.05 \text{ lb TOC}}{10^3 \text{ gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{50,000 \text{ bbl}}{\text{yr}} \times \frac{15 \text{ lb CH}_4}{100 \text{ lb TOC}} \times \frac{\text{tonne}}{2204.62 \text{ lb}} \\ &= \underline{0.15 \text{ tonnes CH}_4/\text{yr}} \end{aligned}$$

The emission estimate technique for CH<sub>4</sub> losses from gasoline loading at marine terminals is discussed below for sites where the CH<sub>4</sub> content is measurably significant (> 1% by weight). For sites where the CH<sub>4</sub> content is unknown, these emissions are assumed to be negligible (EPA, AP-42 Section 5.2, 1995). Table 5-11 in Section 5.5.1 presents TOC emission factors for emissions resulting from gasoline loaded into ships and barges (EPA, AP-42 Table 5.2-2, 1995).

A sample calculation illustrating the use of the marine gasoline loading emission factors is presented in Exhibit B.5. In this sample calculation, the CH<sub>4</sub> content of the gasoline vapors was assumed to be 2 weight percent for illustrative purposes. In practice, the actual CH<sub>4</sub> content of gasoline loading vapors is expected to be negligible.

**EXHIBIT B.5:      Sample Calculation for Estimating Gasoline Marine Loading Loss CH<sub>4</sub> Emissions**

**INPUT DATA:**

50,000 bbl/yr of gasoline (RVP 7) is loaded into ships and ocean barges at a marine terminal. The ships are cleaned prior to loading, and the previous cargo was also gasoline, RVP 7. The average ambient temperature at the terminal is 70°F. The CH<sub>4</sub> content of the gasoline loading vapors is conservatively assumed to be 2 weight percent (actual gasoline CH<sub>4</sub> content of gasoline loading vapors is expected to be negligible but was assumed to be 2 weight percent for the purposes of this sample calculation).

**CALCULATION METHODOLOGY:**

Based on an average ambient temperature, the gasoline (RVP 7) vapor pressure is 4.3 psia, per Table B-8. Because the vapor pressure is greater than 1.5 psia, the previous cargo is classified as "volatile". For clean ships and ocean barges previously storing volatile gasoline, the loading loss emission factor given in Table 5-11 is 0.681 tonne TOC/10<sup>6</sup> gallon loaded.

The loading loss emissions are calculated using the assumed gasoline CH<sub>4</sub> content of 2 weight percent as shown below:

$$\begin{aligned}\text{Loading Emissions} &= \frac{0.681 \text{ tonne TOC}}{10^6 \text{ gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{50,000 \text{ bbl}}{\text{yr}} \times \frac{2 \text{ lb CH}_4}{100 \text{ lb TOC}} \\ &= \underline{0.03 \text{ tonnes CH}_4/\text{yr}}\end{aligned}$$

A general equation is provided for estimating loading losses for all petroleum liquids, including crude and gasoline, into tank trucks and rail cars (EPA, AP-42 Section 5.2, 1995). This equation also applies to marine vessel loading for petroleum liquids other than crude and gasoline. AP-42 provides an accuracy estimate of  $\pm 30\%$  associated with this approach.

$$L_L = 12.46 \frac{S \times P \times M}{T} \times \left( 1 - \frac{\text{control efficiency, \%}}{100} \right) \quad (\text{Equation B-5})$$

where,

- $L_L$  = loading loss emission factor, lb/10<sup>3</sup> gallon of liquid loaded; this factor is for total organic compounds (TOC)
- $S$  = saturation factor, given in Table B-9 below
- $P$  = liquid true vapor pressure, psia (See Table B-8)
- $M$  = molecular weight of the vapors, lb/lb-mole (see Table B-8)
- $T$  = temperature of bulk liquid loaded, °R (°R = °F + 459.7)

**Table B-9. Saturation, S, Factors for Estimating Loading Losses**

Cargo Carrier Type	Mode of Operation	S Factor
Tank trucks and rail tank cars	Submerged loading of a clean cargo tank	0.50
	Submerged loading: dedicated normal service	0.60
	Submerged loading: dedicated vapor balance service	1.00
	Splash loading of a clean cargo tank	1.45
	Splash loading: dedicated normal service	1.45
	Splash loading: dedicated vapor balance service	1.00
Marine vessels <sup>a</sup>	Submerged loading: ships	0.2
	Submerged loading: barges	0.5

Source: EPA AP-42, Section 5.2, January 1995.

<sup>a</sup> Marine vessel saturation factor shown above is not applicable for gasoline and crude oil loading. For marine loading of crude oil, use Equations B-3 and B-4, and Table B-7. For marine loading of gasoline, refer to Table 5-11.

The control efficiency term is included in the loading loss emission factor equation because some loading operations are controlled using various collection systems, such as Vapor Recovery Units (VRU). If applicable, the overall estimated control efficiency for the particular control system should be used.

A sample calculation illustrating the use of Equation B-5 for estimating loading loss emission follows.

# **EXHIBIT B.6: Sample Calculation for Estimating Loading Loss CH<sub>4</sub> Emissions Using General Equation Approach**

## **INPUT DATA:**

100 bbl/day of crude oil (RVP 5) is loaded into tank trucks from an oil tank battery. The tank truck loading type is submerged and dedicated normal service of the truck is utilized. No control devices are used to minimize emissions. The average ambient temperature at this facility is 70 °F.

## **CALCULATION METHODOLOGY:**

Table B-8 is used to determine the physical properties of the crude oil based on the average ambient temperature.

M = 50 lb/lbmole

P = 3.4 psia (per AP-42 at 70°F)

The saturation factor, S, is 0.6 per Table B-9 for submerged fill, dedicated normal service of the tank truck.

Using Equation B-5, the TOC loading loss emission factor is calculated as:

$$L_L = 12.46 \frac{S \times P \times M}{T} \times \left( 1 - \frac{\text{control efficiency, \%}}{100} \right)$$

$$L_L = 12.46 \frac{(0.6) \times (3.4) \times (50)}{529.7} \times \left( 1 - \frac{0\%}{100} \right)$$

$$L_L = 2.40 \text{ lb TOC}/10^3 \text{ gal}$$

The last step in the calculation is to estimate the loading loss emissions by multiplying the loading loss emission factor,  $L_L$ , by the annual crude throughput loaded. Also, the TOC must be multiplied by the CH<sub>4</sub> content of the vapors to obtain the CH<sub>4</sub> emissions. The CH<sub>4</sub> content of the vapors will conservatively be assumed to be 15 wt%. Thus, the CH<sub>4</sub> emissions from the crude oil loading are:

$$\begin{aligned} \text{Loading Emissions} &= \frac{2.40 \text{ lb TOC}}{10^3 \text{ gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{36,500 \text{ bbl}}{\text{yr}} \times \frac{15 \text{ lb CH}_4}{100 \text{ lb TOC}} \times \frac{\text{tonne}}{2204.62 \text{ lb}} \\ &= \underline{0.25 \text{ tonnes CH}_4/\text{yr}} \end{aligned}$$

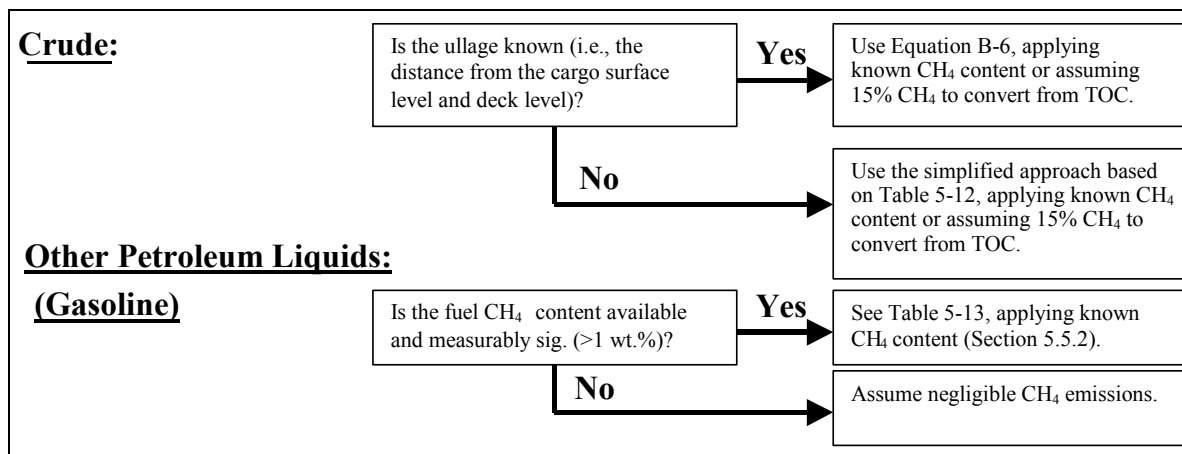
In addition to the detailed methods presented above for loading loss emissions, Table 5-10 provides simplified TOC emission factors for loading loss emissions for various petroleum liquids (refer to Section 5.5.1 for this table and a sample calculation using these emission factors). These



simplified loading loss emission factors should be used when specific input data for using Equations B-3 through B-5 above are not available.

## Ballasting Emissions

Ballasting operations are used to improve the stability of empty tanker ships after their cargo tanks have been unloaded. After the ships filled with petroleum liquid are unloaded at marine terminals, sea water or "ballast" water is loaded into the empty cargo tank compartment. The ballast water displaces the vapor in the "empty" cargo tank to the atmosphere resulting in ballasting emissions. Figure B-3 illustrates the calculation options available for ballasting emissions based on the petroleum liquid type and available information.



**Figure B-3. Decision Tree for Petroleum Liquid Ballasting Emissions**

Ballasting emissions from crude oil ships and ocean barges can be estimated using the following equation (EPA, AP-42 Section 5.2, Equation 4, 1995), developed from test data. This equation results in a TOC emission rate that is converted to CH<sub>4</sub> emissions based on the CH<sub>4</sub> content of the vapors.

$$L_B = 0.31 + 0.20 P + 0.01 P U_A \quad (\text{Equation B-6})$$

where,

$L_B$  = ballasting TOC emission factor, lb/10<sup>3</sup> gallon of ballast water

$P$  = true vapor pressure of crude oil unloaded, psia

$U_A$  = arrival cargo true ullage, prior to dockside discharge, feet; note: "ullage" refers to the distance between the cargo surface level and the deck level

The vapor pressure of the discharged crude oil must be known to calculate the ballasting emissions using the equation above. This can be determined from Table B-8 using the average ambient temperature of the facility.

A sample calculation for estimating crude oil ballasting emissions is shown below.

**EXHIBIT B.7: Sample Calculation for Crude Oil Ballasting Emissions Based on Known Ullage**

**INPUT DATA:**

Crude oil (RVP 5) is unloaded from ships at a marine terminal. The annual ballast water throughput is 1 million bbl/year and the average ullage of the arriving ships loaded with crude is 5 feet (distance from deck level to the crude oil surface level). The average ambient temperature at the facility is 70°F (529.7°R) based on average annual meteorological data.

**CALCULATION METHODOLOGY:**

Using the average ambient temperature and Table B-8, the crude oil vapor pressure is 3.4 psia at 70°F. The ballasting TOC emission factor is calculated using Equation B-6:

$$L_B = 0.31 + 0.20 P + 0.01 P U_A$$

$$L_B = 0.31 + (0.20 \times 3.4 \text{ psia}) + (0.01 \times 3.4 \text{ psia} \times 5 \text{ ft})$$

$$L_B = 1.16 \text{ lb TOC}/10^3 \text{ gallons ballast water}$$

The ballasting emissions are obtained by multiplying the ballasting emission factor,  $L_B$ , by the annual ballast water throughput loaded into the ships. Also, the TOC emissions must be multiplied by the  $\text{CH}_4$  content of the vapors to obtain the  $\text{CH}_4$  emissions. The  $\text{CH}_4$  content of the vapors will conservatively be assumed to be 15 wt% per AP-42 (EPA, AP-42 Section 5.2, 1995). Thus, the  $\text{CH}_4$  emissions from the ballasting operations are:

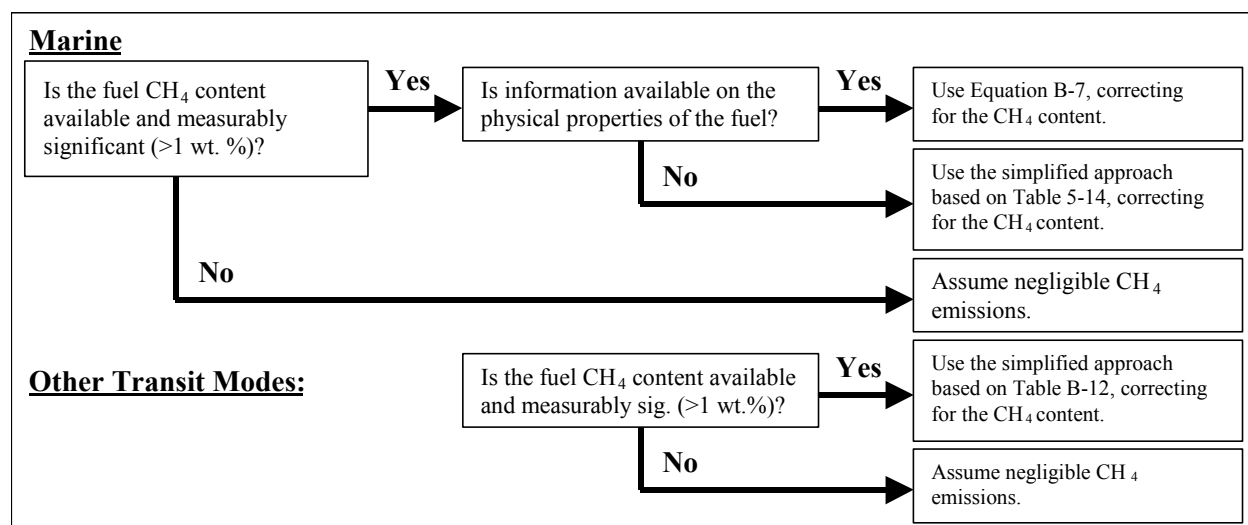
$$\begin{aligned} \text{Ballasting Emissions} &= \frac{1.16 \text{ lb TOC}}{10^3 \text{ gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{1 \times 10^6 \text{ bbl}}{\text{yr}} \times \frac{15 \text{ lb CH}_4}{100 \text{ lb TOC}} \times \frac{\text{tonne}}{2204.62 \text{ lb}} \\ &= 3.31 \text{ tonnes CH}_4/\text{yr} \end{aligned}$$

If the cargo ullage is unknown and data are not available to estimate the crude vapor pressure, then average ballasting emission factors can be used to estimate ballasting emissions (EPA, AP-42 Table 5.2-4, 1995). These emission factors are provided in Table 5-12 in Section 5.5.2 (refer to Section 5.5.2 for a sample calculation as well).

The non-VOC (i.e., CH<sub>4</sub> and C<sub>2</sub>H<sub>6</sub>) portion of TOC emissions from other petroleum liquids is generally considered negligible (EPA, AP-42 Section 5.2, 1995). In addition, ballasting emissions factors are not available for fuels other than gasoline due to limited data. If, however, the CH<sub>4</sub> content of gasoline ballasting vapors is measurably significant (> 1% by weight), Table 5-13 in Section 5.5.2 provides simple emission factors.

## Transit Loss Emissions

In addition to emissions resulting from petroleum loading operations and marine ballasting operations, emissions also occur during petroleum transit. The mechanism resulting in transit losses is similar to breathing losses that occur for storage tanks. (Note that CH<sub>4</sub> and CO<sub>2</sub> emissions from tank breathing and working losses are considered negligible.) Figure B-4 illustrates the calculation approach for transit emissions.



**Figure 0-4. Decision Tree for Petroleum Liquid Transit Emissions**

For transit by marine vessel (i.e., ships and barges), Equation B-7 provides an emission estimate based on experimental tests on ships and barges (EPA, AP-42 Section 5.2, 1995).

$$L_T = 0.1 P W \quad \text{(Equation B-7)}$$

where,

- $L_T$  = ship and barge transit loss TOC emission factor, lb/week-10<sup>3</sup> gallon transported
- $P$  = true vapor pressure of the liquid transported, psia
- $W$  = density of the condensed vapors, lb/gal

The equation above provides a TOC emission factor, which is converted to CH<sub>4</sub> based on the concentration of CH<sub>4</sub> in the fuel vapors. If the CH<sub>4</sub> concentration for crude is unknown, a typical value of 15 wt% can be assumed. For other petroleum liquids, the CH<sub>4</sub> content is assumed negligible in the absence of measured data. The vapor pressure (P) and vapor density (W) factors in Equation B-7 can be estimated from Table B-8 based on the average ambient temperature of the facility.

An exhibit calculation demonstrating the use of Equation B-7 in estimating transit loss emissions is shown in Exhibit B.8.

**EXHIBIT B.8: Sample Calculation for Estimating Marine Transit Loss Emissions Associated with Crude Oil Transportation**

**INPUT DATA:**

500,000 barrels of crude oil (RVP 5) are transported via ships with an average trip duration of 10 days. The company transports crude 25 times during the given reporting year. The average ambient temperature at the facility is 70°F (529.7°R) based on average annual meteorological data.

**CALCULATION METHODOLOGY:**

From Table B-8, the vapor pressure and condensed vapor density of RVP 5 crude oil are:

$$P = 3.4 \text{ psia (70°F)} \quad W = 4.5 \text{ lb/gal}$$

Using Equation B-7, the ship transit loss TOC emission factor is calculated as shown below:

$$L_T = 0.1 P W = (0.1) \times (3.4 \text{ psi}) \times (4.5 \text{ lb/gal}) = 1.53 \text{ lb TOC/week} - 10^3 \text{ gal transported}$$

The transit loss emissions are obtained by multiplying the transit emission factor,  $L_T$ , by the duration of transport and the quantity of crude transported. Also, the TOC must be multiplied by the CH<sub>4</sub> content of the vapors to obtain the CH<sub>4</sub> emissions. The CH<sub>4</sub> content of the vapors will conservatively be assumed to be 15 wt%. Thus, the CH<sub>4</sub> emissions from the transit operations are estimated as:

$$\begin{aligned} \text{Transit Emissions} &= \frac{1.53 \text{ lb TOC}}{\text{week} - 10^3 \text{ gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times 500,000 \text{ bbl} \times \frac{10 \text{ days}}{\text{trip}} \times \frac{25 \text{ trips}}{\text{year}} \times \frac{\text{week}}{7 \text{ days}} \\ &\quad \times \frac{15 \text{ lb CH}_4}{100 \text{ lb TOC}} \times \frac{\text{tonne}}{2204.62 \text{ lb}} = \underline{78.1 \text{ tonnes CH}_4/\text{yr}} \end{aligned}$$

Table 5-14 in Section 5.5.3 provides simple transit TOC emission factors for marine transit of crude oil or gasoline (refer to Section 5.5.3 for a sample calculation as well). Gasoline transit TOC emission factors via rail or truck transit are provided in Table B-10 (EPA, AP-42 Section 5.2.2.1.3, 1995). The emission factors in Table B-10 should only be used if the CH<sub>4</sub> content of the gasoline vapor are significantly measurable (> 1% by weight).

The conditions that affect transit emissions are the vapor tightness of the cargo vessel, the cargo vessel pressure at the beginning of the trip, the pressure relief valve settings, the liquid vapor pressure, and the degree of vapor saturation in the vapor void space of the cargo tank. The rail and truck tanker emission factors are reported as a range for both "typical" and "extreme" conditions, where the "extreme" factors correspond to conditions that would result in maximum emissions. Note also that the rail and truck emission factors are reported in terms of mass of TOC per volume transported. Estimating emissions for these sources also requires the number of trips taken during the reporting year.

**Table B-10. Simplified TOC Emission Factors for Rail/Truck Gasoline Transit Losses<sup>a</sup>**

Loading Type	Gasoline <sup>b</sup>
<i>Loaded with Product</i>	
Typical Operation	
Original Units	
lb TOC/10 <sup>3</sup> gal transported	0 - 0.01
mg TOC/L transported	0 - 1.0
Converted Units	
tonne TOC/10 <sup>6</sup> gal transported <sup>c</sup>	0 - 0.0038
tonne TOC/10 <sup>3</sup> m <sup>3</sup> transported <sup>c</sup>	0 - 0.0010
Extreme Operation	
Original Units	
lb TOC/10 <sup>3</sup> gal transported	0 - 0.08
mg TOC/L transported	0 - 9.0
Converted Units	
tonne TOC/10 <sup>6</sup> gal transported <sup>c</sup>	0 - 0.034
tonne TOC/10 <sup>3</sup> m <sup>3</sup> transported <sup>c</sup>	0 - 0.0090
<i>Return with Vapor</i>	
Typical Operation	
Original Units	
lb TOC/10 <sup>3</sup> gal transported	0 - 0.11
mg TOC/L transported	0 - 13.0
Converted Units	
tonne TOC/10 <sup>6</sup> gal transported <sup>c</sup>	0 - 0.049
tonne TOC/10 <sup>3</sup> m <sup>3</sup> transported <sup>c</sup>	0 - 0.0130
Extreme Operation	
Original Units	
lb TOC/10 <sup>3</sup> gal transported	0 - 0.37
mg TOC/L transported	0 - 44.0
Converted Units	
tonne TOC/10 <sup>6</sup> gal transported <sup>c</sup>	0 - 0.167
tonne TOC/10 <sup>3</sup> m <sup>3</sup> transported <sup>c</sup>	0 - 0.0440

Source: EPA, AP-42, Section 5, Table 5.2-5, 1995.

<sup>a</sup> The emission factors for the other products listed above are for both TOC and VOC because AP-42 reports that the CH<sub>4</sub> and C<sub>2</sub>H<sub>6</sub> content of the loading emissions is negligible for gasoline.

<sup>b</sup> The example gasoline has an RVP of 10 psia.

<sup>c</sup> Converted from original emission factors provided in units of mg/L in AP-42. Thus, round-off errors may result in some small differences when converting from the emission factors provided in units of lb/10<sup>3</sup> gallons.

Exhibit B.9 illustrates the use of the simple transit emission factors. In this sample calculation, the CH<sub>4</sub> content of the gasoline vapors was assumed to be 2 weight percent for illustrative purposes. In practice, the actual CH<sub>4</sub> content of gasoline transit vapors is expected to be negligible.

**EXHIBIT B.9: Sample Calculation for Estimating CH<sub>4</sub> Emissions Using Simplified Rail/Truck Transit Emission Factors**

**INPUT DATA:**

8,000 gallons of gasoline (RVP 10) is transported via truck (8,000 gallons per trip). The company transports gasoline 100 times during the given reporting year. The CH<sub>4</sub> content of the gasoline vapors is conservatively assumed to be 2 weight percent (actual gasoline CH<sub>4</sub> content of transit vapors is expected to be negligible but was assumed to be 2 weight percent for the purposes of this sample calculation).

**CALCULATION METHODOLOGY:**

The transit loss emission factor given in Table B-10 for the truck when loaded with product for typical operation is 0-0.01 lb TOC/1000 gallons transported (0-0.0038 tonne TOC/10<sup>6</sup> gallon transported). For conservatism, the upper bound factor is used. Thus, the transit emissions when loaded with product are:

$$\begin{aligned}\text{Transit, Loaded} &= \frac{0.0038 \text{ tonne TOC}}{10^6 \text{ gal transported}} \times \frac{8000 \text{ gal}}{\text{trip}} \times \frac{100 \text{ trips}}{\text{yr}} \times \frac{2 \text{ lb CH}_4}{100 \text{ lb TOC}} \\ &= \underline{0.0001 \text{ tonnes CH}_4 / \text{yr}}\end{aligned}$$

Similar, the transit emissions of the truck when returning with vapor are estimated. The transit loss emission factor given in Table B-10 for the truck with vapor for typical operation is 0-0.11 lb TOC/1000 gallons transported (0-0.049 tonne TOC/10<sup>6</sup> gallon transported). For conservatism, the upper bound factor is used. Thus, the transit emissions when loaded with product are:

$$\begin{aligned}\text{Transit, Loaded} &= \frac{0.049 \text{ tonne TOC}}{10^6 \text{ gal transported}} \times \frac{8000 \text{ gal}}{\text{trip}} \times \frac{100 \text{ trips}}{\text{yr}} \times \frac{2 \text{ lb CH}_4}{100 \text{ lb TOC}} \\ &= \underline{0.0008 \text{ tonnes CH}_4 / \text{yr}}\end{aligned}$$

## **B.3 Fugitive Sources**

This section presents component-level estimation methods for CH<sub>4</sub> and CO<sub>2</sub> fugitive emissions from equipment leaks that are more rigorous than the methods presented in Section 6.1. These approaches are likely to be overly complicated for most greenhouse gas (GHG) emissions estimates, but they have been included here for completeness.

The additional approaches available for estimating fugitive equipment leak emissions, in order of increasing data requirements and increasing accuracy are:

1. Average emission factors approach;
2. Screening ranges approach;
3. Correlation approach; and
4. Unit-Specific correlation approach.

Applicable to all of these approaches, the CH<sub>4</sub> composition of the fugitive stream and the population of fugitive components must be known. Following the discussion of the different estimation approaches, “generic” compositions are provided for estimating CH<sub>4</sub> emissions from fugitive sources, when site specific speciation data are not available. “Generic” component counts are also provided for different equipment and process types.

### **B.3.1 Component-Level Average Emission Factors Approach**

The component-level average emission factor approach estimates emissions based on the number of components in the facility. The component-level average emission factor approach should provide acceptable accuracy for most GHG emission work. Where no monitoring data are available, it provides the most accurate estimate available, since it is based on site-specific component population data. It should be noted that the component-level average emission factors were developed for estimating total organic compounds (TOC), also referred to as total hydrocarbon compounds (THC), or volatile organic compounds (VOC), rather than CH<sub>4</sub>. This section also includes a methodology for estimating the CH<sub>4</sub> portion of the fugitive equipment leak emissions, based on either site-specific data or on defaults by type of facility.

For some emission factors, component counts are required for each service category, such as valves in gas, light liquid, or heavy liquid service. Gas service is defined as any material that is in a gaseous or vapor state at process conditions. Light liquid service is defined as naphtha and more



volatile petroleum liquids. Alternately, light liquid service may be defined as any material in a liquid state in which the sum of the concentration of individual constituents with a vapor pressure over 0.3 kPa at 20°C is greater than or equal to 20 weight percent. A heavy liquid is any liquid that is not in gas/vapor or light liquid service, which would generally include kerosene and less volatile petroleum liquids.

EPA provides the following equation to estimate TOC mass emissions for a given component type:

$$E_{\text{TOC}} = F_A \times \text{WF}_{\text{TOC}} \times N \quad (\text{Equation B-8})$$

where,

$E_{\text{TOC}}$	=	Emission rate of TOC from all components of a given type in the stream
$F_A$	=	Average emission factor for the component type from the applicable tables
$\text{WF}_{\text{TOC}}$	=	Average weight fraction TOC in the stream (if unknown assume 1.0)
$N$	=	Number of components of the given type in the stream

The emission factors were developed for streams composed completely of TOC (i.e., no water vapor, CO<sub>2</sub>, nitrogen compounds, etc.). The weight fraction concentration of TOC within the equipment is needed because equipment with higher TOC concentrations tend to have higher TOC leak rates. When using the average emission factor approach for streams that are not 100% TOC, such as for E&P operations, the components should be grouped according to the TOC weight fraction, prior to applying Equation B-8.

On the same basis, Equation B-8 can be restated in terms of CH<sub>4</sub> emissions ( a constituent of TOC) by replacing the TOC weight fraction with the weight fraction of CH<sub>4</sub> (WF<sub>CH<sub>4</sub></sub>). The derivation from Equation B-9 is shown below:

$$E_{\text{TOC}} = F_A \times \text{WF}_{\text{TOC}} \times N \qquad E_{\text{CH}_4} = E_{\text{TOC}} \times \frac{\text{WF}_{\text{CH}_4}}{\text{WF}_{\text{TOC}}}$$

Combining these equations, the weight fraction of TOC cancels out.

$$E_{\text{CH}_4} = (F_A \times \text{WF}_{\text{TOC}} \times N) \times \frac{\text{WF}_{\text{CH}_4}}{\text{WF}_{\text{TOC}}} \quad (\text{Equation B-9})$$
$$E_{\text{CH}_4} = F_A \times \text{WF}_{\text{CH}_4} \times N$$

where,

$E_{CH_4}$	=	Emission rate of CH <sub>4</sub> from all components of a given type in the stream
$F_A$	=	Average emission factor for the component type from the applicable tables
$WF_{CH_4}$	=	Average weight fraction of CH <sub>4</sub>
$N$	=	Number of components of the given type in the stream

The refinery component-level average emission factors, shown in Table B-12, are expressed as volatile organic compounds (VOC), where  $VOC = TOC - CH_4$ . A slightly different approach is applied to estimate CH<sub>4</sub> emissions for refinery sources. The emission factor,  $F_A$ , must be adjusted to account for all organic compounds in the stream because the refinery factors are expressed in non-CH<sub>4</sub> (VOC) organic compounds. The equation below illustrates the emission factor adjustment that corrects the VOC emission factor back to a CH<sub>4</sub> basis:

$$E_{CH_4} = F_{A\ VOC} \times \frac{WF_{CH_4}}{WF_{TOC} - WF_{CH_4}} \times N \quad (\text{Equation B-10})$$

where,

$E_{CH_4}$	=	Emission rate of CH <sub>4</sub> from all components of a given type in the stream
$F_{A\ VOC}$	=	Average emission factor (as VOC)
$WF_{TOC}$	=	Average weight fraction TOC in the stream
$WF_{CH_4}$	=	Weight fraction of CH <sub>4</sub> in the TOC
$N$	=	Number of components of the given type in the stream

When applied to refineries, the correction should only be applied to components containing a mixture of CH<sub>4</sub> and organic compounds. The maximum CH<sub>4</sub> concentration correction should not exceed 10 weight percent, even if a stream contains more than 10 weight percent CH<sub>4</sub>. This limitation generally is not an issue for refinery streams because they contain very little CH<sub>4</sub>. The exception would be for a fuel gas system, in which case the gas service emission factors from Table B-11 may be more representative and applicable to the higher CH<sub>4</sub> concentrations.

EPA average emission factors for oil and gas production facilities are provided in Table B-11 (EPA, 1995) and Table B-12 provides emission factors for refineries. Although these emission factors are reported in terms of individual components, the average emission factor approach is intended for application to a population of components. Note also that the emission factors in Tables B-11 and B-12 are service specific.

**Table B-11. EPA Average Oil and Gas Production Emission Factors**

<b>Component – Service</b>	<b>Emission Factor, Original Units, kg gas/hr/component</b>	<b>Emission Factor, Converted to tonne gas/hr/component</b>
Valves – Gas	4.5E-03	4.5E-06
Valves - Heavy Oil	8.4E-06	8.4E-09
Valves - Light Oil	2.5E-03	2.5E-06
Valves - Water/Oil	9.8E-05	9.8E-08
Connectors - Gas service	2.0E-04	2.0E-07
Connectors - Heavy Oil	7.5E-06	7.5E-09
Connectors - Light Oil	2.1E-04	2.1E-07
Connectors - Water/Oil	1.1E-04	1.1E-07
Flanges – Gas	3.9E-04	3.9E-07
Flanges - Heavy Oil	3.9E-07	3.9E-10
Flanges - Light Oil	1.1E-04	1.1E-07
Flanges - Water/Oil	2.9E-06	2.9E-09
Open-ended Lines – Gas	2.0E-03	2.0E-06
Open-ended Lines - Heavy Oil	1.4E-04	1.4E-07
Open-ended Lines – Light Oil	1.4E-03	1.4E-06
Open-ended Lines - Water/Oil	2.5E-04	2.5E-07
Pump Seals – Gas	2.4E-03	2.4E-06
Pump Seals – Light Oil	1.3E-02	1.3E-05
Pump Seals – Water/Oil	2.4E-05	2.4E-08
Others – Gas	8.8E-03	8.8E-06
Others – Heavy Oil	3.2E-05	3.2E-08
Others – Light Oil	7.5E-03	7.5E-06
Others – Water/Oil	1.4E-02	1.4E-05

Source: US Environmental Protection Agency (EPA). *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-4.

**Table B-12. EPA Average Refinery Emission Factors**

<b>Component - Service</b>	<b>Emission Factor, Original Units, kg VOC/hr/comp.</b>	<b>Emission Factor, Converted to tonne VOC/hr/comp.</b>
Valves – Gas	2.68E-02	2.68E-05
Valves – Light Liquid	1.09E-02	1.09E-05
Valves – Heavy Liquid	2.3E-04	2.3E-07
Pump Seals - Light Liquid	1.14E-01	1.14E-04
Pump Seals - Heavy Liquid	2.1E-02	2.1E-05
Compressor Seals - Gas	6.36E-01	6.36E-04
Pressure Relief Valves - Gas	1.6E-01	1.6E-04
Connectors – All	2.5E-04	2.5E-07
Open-ended Lines – All	2.3E-03	2.3E-06
Sampling Connections – All	1.50E-02	1.50E-05

Source: US Environmental Protection Agency (EPA). *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-2.

Note: These emission factors were developed from testing performed in the 1970s and represent average emissions from uncontrolled components (i.e., components that are not subject to leak detection and repair programs). These emission factors can be converted to a CH<sub>4</sub> basis using Equation B-10.

The emission factors provided in Tables B-13 through B-17 are facility-specific and not service-specific. For example, a heavy-crude production facility should use the heavy-crude emission factors provided in Table B-14 for all streams including any gas streams at the site. Thus, the gas production emission factors would not be used to estimate gaseous stream fugitive emissions at the heavy-crude production facility. Note also that these emission factors can be converted to a CH<sub>4</sub> basis using Equation B-9.

**Table B-13. API Offshore Fugitive Emission Average Factors**

<b>Average Component Factors</b>	<b>Emission Factor, lb TOC/day/comp.</b>	<b>Emission Factor, tonne TOC/component-hr</b>
Valves	0.027	5.14E-07
Pump Seals	0.010	1.95E-07
Others	0.367	6.94E-06
Connectors	0.006	1.08E-07
Flanges	0.010	1.97E-07
Open-ended Lines	0.054	1.01E-06

Source: American Petroleum Institute (API). *Emission Factors for Oil and Gas Production Operations*, API Publication Number 4615, Health and Environmental Sciences Department, January, 1995, Table ES-1.

**Table B-14. API Oil and Gas Production Average Emission Factors**

Component – Facility Type	Emission Factor (lb TOC/day/component)	Emission Factor (tonne TOC/component-hr)
Valves – Gas Production	1.39E-01	2.63E-06
Valves – Heavy Crude Production	6.86E-04	1.30E-08
Valves – Light Crude Production	7.00E-02	1.32E-06
Connectors – Gas Production	1.70E-02	3.21E-07
Connectors – Heavy Crude Production	4.22E-04	7.98E-09
Connectors – Light Crude Production	8.66E-03	1.64E-07
Flanges – Gas Production	6.23E-03	1.18E-07
Flanges – Heavy Crude Production	1.16E-03	2.19E-08
Flanges – Light Crude Production	4.07E-03	7.69E-08
Open-ended Lines – Gas Production	3.63E-02	6.86E-07
Open-ended Lines - Heavy Crude Production	8.18E-03	1.55E-07
Open-ended Lines – Light Crude Production	6.38E-02	1.21E-06
Pump Seals – Gas Production	1.03E-02	1.95E-07
Pump Seals – Light Crude Production	1.68E-02	3.18E-07
Others – Gas Production	4.86E-01	9.19E-06
Others – Heavy Crude Production	3.70E-03	6.99E-08
Others – Light Crude Production	3.97E-01	7.50E-06

Source: American Petroleum Institute (API). *Emission Factors for Oil and Gas Production Operations*, API Publication Number 4615, Health and Environmental Sciences Department, January, 1995, Table ES-1.

**Table B-15. API Gas Plant Average Emission Factors**

Component	Emission Factor, lb TOC/day/comp.	Emission Factor, tonne TOC/component-hr
Valves	0.204	3.86E-06
Pump Seals	0.609	1.15E-05
Others	0.257	4.86E-06
Connectors	0.015	2.74E-07
Flanges	0.023	4.38E-07
Open-ended Lines	0.055	1.03E-06

Source: American Petroleum Institute (API). *Emission Factors for Oil and Gas Production Operations*, API Publication Number 4615, Health and Environmental Sciences Department, January, 1995, Table ES-1.

**Table B-16. Gas Transmission and Storage Average Emission Factors**

Component	Emission Factor, kg THC/hr/comp.	Emission Factor, tonne TOC/component-hr
Valves	0.00214	2.14E-06
Control valves	0.01969	1.97E-05
Connectors	0.00027	2.70E-07
Compressor Seals – Reciprocating	0.66160	6.62E-04
Compressor Seals – Centrifugal	0.81390	8.14E-04
Pressure Relief Valves	0.27950	2.80E-04
Open-Ended Lines (OEL)	0.08355	8.36E-05
OEL - Station Blowdown	0.93690	9.37E-04
OEL - Depressurized Reciprocating	2.34700	2.35E-03
OEL - Depressurized Centrifugal	0.73340	7.33E-04
Orifice Meter	0.00333	3.33E-06
Other Gas Meter	0.00001	9.06E-09

Source: Picard, D. J., B. D. Ross, and D. W. H. Koon. A Detailed Inventory of CH<sub>4</sub> and VOC Emissions from Upstream Oil and Gas Operations in Alberta, Volume II, Canadian Petroleum Association, March 1992.

**Table B-17. Additional Oil and Gas Facility Average Emission Factors**

Component, service	Emission Factor, kg THC/comp/hr	Emission Factor, tonnes/component-hr
Valves – gas facility – sweet	4.35E-02	4.35E-05
Valves – gas facility – sour	5.18E-03	5.18E-06
Valves - oil facility - all services	1.42E-02	1.42E-05
Flange/Connector - gas facility – sweet	2.53E-03	2.53E-06
Flange/Connector - gas facility – sour	3.10E-04	3.10E-07
Flange/Connector - oil facility – sweet	7.90E-04	7.90E-07
Connectors - All services - Oil facility	4.80E-04	4.80E-07
Compressor Seals	8.05E-01	8.05E-04
Pressure Relief Valves	1.21E-01	1.21E-04
Open Ended Lines	3.73E-03	3.73E-06
Pump Seals – Light Oil	2.14E-02	2.14E-05

Source: Picard, D. J., B. D. Ross, and D. W. H. Koon. A Detailed Inventory of CH<sub>4</sub> and VOC Emissions from Upstream Oil and Gas Operations in Alberta, Volume II, Canadian Petroleum Association, March 1992.

An example calculation illustrating the use of the component-level fugitive emission factors follows.

**EXHIBIT B.10: Sample Calculation for Non-Refinery Component-Level Average Fugitive Emission Factor Approach**

**INPUT DATA:**

There are 100 gas valves in a stream at a production site that contains 80 weight percent non-CH<sub>4</sub> hydrocarbons, 10 weight percent water vapor, and 10 weight percent CH<sub>4</sub>.

**CALCULATION METHODOLOGY FOR NON-REFINERY CASE:**

CH<sub>4</sub> emissions would be calculated using Equation B-9 and the average emission factor for valves in Table B-11 as follows.

$$\begin{aligned} E_{\text{CH}_4} &= 4.5 \times 10^{-6} \frac{\text{tonne gas}}{\text{hr} \times \text{valve}} \times \frac{0.1 \text{ tonne CH}_4}{\text{tonne gas}} \times \frac{8760 \text{ hr}}{\text{yr}} \times 100 \text{ valves} \\ &= \underline{0.394 \text{ tonnes CH}_4 / \text{yr}} \end{aligned}$$

The next exhibit shows an example of the same calculation, except that the 100 gas valves are assumed to be in a refinery. This requires a conversion of the refinery emission factors from a VOC basis to a TOC basis, and then the remaining calculations follow the same pattern.

**EXHIBIT B.11: Sample Calculation for Refinery Component-Level Average Fugitive Emission Factor Approach**

**INPUT DATA:**

Assume the 100 gas valves from the previous exhibit are at a refinery.

**CALCULATION METHODOLOGY FOR REFINERY CASE:**

Before applying Equation B-10, the CH<sub>4</sub> weight fraction in the TOC stream is needed.

$$WF_{\text{CH}_4} = \frac{0.1 \text{ kg CH}_4 / \text{kg gas}}{(1 - 0.1 \text{ kg H}_2\text{O} / \text{kg gas})} = 0.111 \frac{\text{kg CH}_4}{\text{kg TOC}}$$

The CH<sub>4</sub> emissions can then be calculated using Equation B-10 and the average emission factor for valves from Table B-12:

$$E_{\text{CH}_4} = \frac{2.68 \times 10^{-5} \text{ tonne VOC}}{\text{hr} \times \text{valve}} \times \frac{0.111 \text{ tonne CH}_4/\text{tonne TOC}}{(0.9 \text{ tonne TOC} / \text{tonne gas} - 0.111 \text{ tonne CH}_4/\text{tonne TOC})} \\ \times \frac{8760 \text{ hours}}{\text{yr}} \times 100 \text{ valves} = \underline{3.30 \text{ tonnes CH}_4 / \text{yr}}$$

Note that the same 100 gas valves generate emission estimates that are different by more than a factor of 8 depending on whether they are at a refinery or a production (or gas processing) site.

### B.3.2 Screening Range Factor Approach

The screening range factor approach, also called the leak/no-leak approach, is based on monitoring data that have been categorized into two or more ranges. Monitoring data are broken into categories of “leakers”, with US EPA Reference Method 21 readings greater than or equal to 10,000 ppmv, and “non-leakers” with readings less than 10,000 ppmv. Each of these categories is assigned an emission factor. The 10,000 ppmv break point is based on early leak definitions, such as in 40 CFR 60 Subpart VV. This criterion for separating leakers from non-leakers may not coincide with the leak definition required by local regulations that apply to each facility, but it is the only level for which there is any significant amount of mass emission data to develop screening range factors. The screening range approach should be more accurate than previously presented approaches because it is based on a site-specific percent “leaking” measurement. This approach could be appropriate for facilities that are already collecting monitoring data for a leak detection and repair program, or would be willing to do so to improve their emission estimates.

When using the screening range factor approach, the components should be grouped into “streams” where all the components have approximately the same TOC weight fraction and monitoring readings within the same category. The following equation is used in the calculations:

$$E_{\text{TOC}} = (F_G \times N_G) + (F_L \times N_L) \quad (\text{Equation B-11})$$

where,

- $E_{\text{TOC}}$  = Emission rate of TOC from all components of a given type in the stream.
- $F_G$  = Emission factor for components with screening values greater than or equal to 10,000 ppmv
- $N_G$  = Number of components with screening values greater than or equal to 10,000 ppmv
- $F_L$  = Emission factor for components with screening values less than or equal to 10,000 ppmv



$N_L$  = Number of components with screening values less than or equal to 10,000 ppmv.

Methane emissions can be estimated from the TOC emission factors using Equation B-9. The refinery screening range factors are given in VOC rather than TOC. Equation B-10 presents the correction for refinery emission factors from a VOC to a CH<sub>4</sub> basis.

Tables B-18 through B-21 present screening emission factors for different industry segments. Note that Table B-19 provides facility specific emission factors, while the other tables are service specific.

**Table B-18. EPA Oil and Gas Production Screening Factors**

Component – Service	Emission Factor, kg TOC/hr/comp.		Emission Factor, tonne TOC/component-hr	
	<10,000 ppmv	>=10,000 ppmv	<10,000 ppmv	>=10,000 ppmv
Valves – Gas	2.5E-05	9.8E-02	2.5E-08	9.8E-05
Valves – Light Oil	1.9E-05	8.7E-02	1.9E-08	8.7E-05
Valves – Water/Oil	9.7E-06	6.4E-02	9.7E-09	6.4E-05
Valves – Heavy Oil	8.4E-06	NA <sup>1</sup>	8.4E-09	NA <sup>1</sup>
Pump Seals – Gas	3.5E-04	7.4E-02	3.5E-07	7.4E-05
Pump Seals - Light Oil	5.1E-04	1.0E-01	5.1E-07	1.0E-04
Pump Seals - Water/Oil	2.4E-05	NA <sup>1</sup>	2.4E-08	NA <sup>1</sup>
Others – Gas	1.2E-04	8.9E-02	1.2E-07	8.9E-05
Others – Light Oil	1.1E-04	8.3E-02	1.1E-07	8.3E-05
Others – Water/Oil	5.9E-05	6.9E-02	5.9E-08	6.9E-05
Others – Heavy Oil	3.2E-05	NA <sup>1</sup>	3.2E-08	NA <sup>1</sup>
Connectors – Gas	1.0E-05	2.6E-02	1.0E-08	2.6E-05
Connectors - Light Oil	9.7E-06	2.6E-02	9.7E-09	2.6E-05
Connectors - Water/Oil	1.0E-05	2.8E-02	1.0E-08	2.8E-05
Connectors - Heavy Oil	7.5E-06	NA <sup>1</sup>	7.5E-09	NA <sup>1</sup>
Flanges – Gas	5.7E-06	8.2E-02	5.7E-09	8.2E-05
Flanges – Light Oil	2.4E-06	7.3E-02	2.4E-09	7.3E-05
Flanges – Heavy Oil	3.9E-07	NA <sup>1</sup>	3.9E-10	NA <sup>1</sup>
Flanges – Water/Oil	2.9E-06	NA <sup>1</sup>	2.9E-09	NA <sup>1</sup>
Open-ended Line – Gas	1.5E-05	5.5E-02	1.5E-08	5.5E-05
Open-ended Line – Heavy Oil	7.2E-06	3.0E-02	7.2E-09	3.0E-05
Open-ended Line – Light Oil	1.4E-05	4.4E-02	1.4E-08	4.4E-05
Open-ended Line – Water/Oil	3.5E-06	3.0E-02	3.5E-09	3.0E-05

Source: US Environmental Protection Agency (EPA). *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-8.

<sup>1</sup> NA means that there were not sufficient examples of that emission category found to develop an emission factor.

**Table B-19. API Oil and Gas Production and Processing Screening Factors**

Component – Facility Type	Emission Factor, lb TOC/day/comp.		Emission Factor, tonne TOC/component-hr	
	<10,000 ppmv	>=10,000 ppmv	<10,000 ppmv	>=10,000 ppmv
Valves – All Facility Types	NA <sup>1</sup>	3.381	NA <sup>1</sup>	6.4E-05
Valves – Gas Production	1.63E-03	3.381	3.1E-08	6.4E-05
Valves – Light Crude Production	1.11E-03	3.381	2.1E-08	6.4E-05
Valves – Heavy Crude Production	6.95E-04	3.381	1.3E-08	6.4E-05
Valves – Offshore Production	8.5E-04	3.381	1.61E-08	6.4E-05
Valves – Gas Processing	1.81E-03	3.381	3.42E-08	6.4E-05
Connectors – All Facility Types	NA <sup>1</sup>	1.497	NA <sup>1</sup>	2.8E-05
Connectors - Gas Production	6.33E-04	1.497	1.2E-08	2.8E-05
Connectors - Light Crude Prod.	5.25E-04	1.497	9.9E-09	2.8E-05
Connectors - Heavy Crude Prod.	4.41E-04	1.497	8.3E-09	2.8E-05
Connectors - Offshore Production	5.11E-04	1.497	9.66E-09	2.8E-05
Connectors - Gas Processing	5.76E-04	1.497	1.09E-08	2.8E-05
Flanges – All Facility Types	NA <sup>1</sup>	4.490	NA <sup>1</sup>	8.5E-05
Flanges – Gas Production	1.30E-03	4.490	2.5E-08	8.5E-05
Flanges – Light Crude Production	1.24E-03	4.490	2.3E-08	8.5E-05
Flanges – Heavy Crude Production	1.19E-03	4.490	2.2E-08	8.5E-05
Flanges – Offshore Production	1.33E-03	4.490	2.51E-08	8.5E-05
Flanges – Gas Processing	1.44E-03	4.490	2.72E-08	8.5E-05
Open-ended Lines – All Facilities	NA <sup>1</sup>	1.600	NA <sup>1</sup>	3.0E-05
Open-ended Lines - Gas Production	1.26E-03	1.600	2.4E-08	3.0E-05
Open-ended Lines - Light Crude Production	1.50E-03	1.600	2.8E-08	3.0E-05
Open-ended Lines - Heavy Crude Production	8.86E-04	1.600	1.7E-08	3.0E-05
Open-ended Lines - Offshore Production	9.4E-04	1.600	1.78E-08	3.0E-05
Open-ended Lines - Gas Processing	1.62E-03	1.600	3.06E-08	3.0E-05
Pump Seals – All Facilities	NA <sup>1</sup>	3.905	NA <sup>1</sup>	7.4E-05
Pump Seals – Gas Production	1.03E-02	3.905	1.9E-07	7.4E-05
Pump Seals - Heavy Crude Prod.	No data	3.905	No data	7.4E-05
Pump Seals - Light Crude Prod.	1.68E-02	3.905	3.2E-07	7.4E-05
Pump Seals – Offshore Production	1.03E-02	3.905	1.95E-07	7.4E-05
Pump Seals – Gas Processing	4.3E-02	3.905	8.13E-07	7.4E-05
Others – All Facilities	NA <sup>1</sup>	3.846	NA <sup>1</sup>	7.3E-05
Others – Gas Production	7.92E-03	3.846	1.5E-07	7.3E-05
Others – Heavy Crude Production	3.67E-03	3.846	6.9E-08	7.3E-05
Others – Light Crude Production	9.01E-03	3.846	1.7E-07	7.3E-05
Others – Offshore Production	3.76E-03	3.846	7.11E-08	7.3E-05
Others – Gas Processing	9.09E-03	3.846	1.72E-07	7.3E-05

Source: American Petroleum Institute (API). *Emission Factors for Oil and Gas Production Operations*, API Publication No. 4615, Health and Environmental Sciences Department, January 1995, Table ES-2.

<sup>1</sup> NA means not available on the “all facilities” basis. The emission factors for leaking components were developed as a single factor across all facility types. The emission factors for non-leaking components, however, were developed for each facility type.

**Table B-20. Marketing Terminal Screening Range Factors**

Component – Service	Emission Factor, kg TOC/hr/comp.		Emission Factor, tonne TOC/hr/comp.	
	<10,000 ppmv	≥10,000 ppmv	<10,000 ppmv	≥10,000 ppmv
Valves – LL	1.5E-05	2.3E-02	1.50E-08	2.30E-05
Valves – Gas	1.3E-05	NA <sup>1</sup>	1.30E-08	NA <sup>1</sup>
Pump Seals – LL	2.4E-04	7.7E-02	2.40E-07	7.70E-05
Others – LL	2.4E-05	3.4E-02	2.40E-08	3.40E-05
Others – Gas	1.2E-04	NA <sup>1</sup>	1.20E-07	NA <sup>1</sup>
Connectors <sup>2</sup> – Gas	5.9E-06	3.4E-02	5.90E-09	3.40E-05
Connectors <sup>2</sup> – LL	7.2E-06	6.5E-03	7.20E-09	6.50E-06

Source: US Environmental Protection Agency (EPA). *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-7.

<sup>1</sup> NA means not available.

<sup>2</sup> Connectors includes both flanges and other types of connectors.

**Table B-21. Refinery Screening Factors**

Component – Service	Emission Factor (kg VOC/hr/comp.)		Emission Factor (tonne VOC/hr/comp.)	
	<10,000 ppmv	≥10,000 ppmv	<10,000 ppmv	≥10,000 ppmv
Valves – Gas	6.00E-04	2.63E-01	6.00E-07	2.63E-04
Valves – LL	1.70E-03	8.52E-02	1.70E-06	8.52E-05
Valves – HL	2.30E-04	2.30E-04	2.30E-07	2.30E-07
Pump Seals – LL	1.20E-02	4.37E-01	1.20E-05	4.37E-04
Pump Seals – HL	1.35E-02	3.89E-01	1.35E-05	3.89E-04
Compressor Seals – Gas	8.94E-02	1.61E+00	8.94E-05	1.61E-03
Pressure Relief Valve – Gas	4.47E-02	1.69E+00	4.47E-05	1.69E-03
Connectors, All Services	6.00E-04	3.75E-02	6.00E-07	3.75E-05
Open-Ended Lines – All	1.50E-03	1.20E-02	1.50E-06	1.20E-05

Source: US Environmental Protection Agency (EPA). *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-6.

## EXHIBIT B.12: Sample Calculation for Screening Factor Approach

### INPUT DATA:

Assume that there are 100 valves in gas service at a gas production facility and that there is no stream composition data available. Five of the valves had a screening value of >10,000 ppmv, and the remaining 95 valves had a screening factor of <10,000 ppmv.

### ASSUMPTIONS:

Because no plant-specific stream composition data is available, the composition data will be taken from Table B-26 (presented in Section B.3.5). The CH<sub>4</sub> composition for a sweet gas facility, with components in gas service is 91.8796 mole %, or 84.1609 weight %.

### CALCULATION METHODOLOGY:

TOC emissions would be calculated using Equation B-11 and the “Valves-Gas” screening factor values from Table B-18 as follows:

For components screening  $\geq 10,000$  ppmv:

$$E_{\text{TOC} > 10000} = 9.8 \times 10^{-5} \frac{\text{tonne}}{\text{hr} \times \text{valve}} \times 5 \text{ valves} = 4.9 \times 10^{-4} \frac{\text{tonne TOC}}{\text{hr}}$$

For components screening <10,000 ppmv:

$$E_{\text{TOC} < 10000} = 2.5 \times 10^{-8} \frac{\text{tonne}}{\text{hr} \times \text{valve}} \times 95 \text{ valves} = 2.4 \times 10^{-6} \frac{\text{tonne TOC}}{\text{hr}}$$

The combined valve emissions are:

$$E_{\text{TOC Total}} = 4.9 \times 10^{-4} + 2.4 \times 10^{-6} = 4.92 \times 10^{-4} \frac{\text{tonne TOC}}{\text{hr}}$$

Methane emissions would then be calculated by applying the CH<sub>4</sub> composition, expressed as weight fraction:

$$\begin{aligned} E_{\text{CH}_4} &= E_{\text{TOC Total}} \times \text{WF}_{\text{CH}_4} = 4.92 \times 10^{-4} \frac{\text{tonne TOC}}{\text{hr}} \times 0.841609 \frac{\text{tonne CH}_4}{\text{tonne TOC}} \times \frac{8760 \text{ hr}}{\text{yr}} \\ &= \underline{3.6 \text{ tonnes CH}_4 / \text{yr}} \end{aligned}$$

Alternatively, CH<sub>4</sub> emissions can be calculated using the production emission factors from Table B-19 and gas composition data from Table B-26 (presented in Section B.3.5).

For components screening  $\geq 10,000$  ppmv:

$$E_{\text{TOC} > 10000} = 6.4 \times 10^{-5} \frac{\text{tonne}}{\text{hr} \times \text{valve}} \times 5 \text{ valves} = 3.2 \times 10^{-4} \frac{\text{tonne TOC}}{\text{hr}}$$

### EXHIBIT B.12: Sample Calculation for Screening Factor Approach, continued

For components screening <10,000 ppmv:

$$E_{\text{TOC} < 10000} = 3.1 \times 10^{-8} \frac{\text{tonne}}{\text{hr} \times \text{valve}} \times 95 \text{ valves} = 2.94 \times 10^{-6} \frac{\text{tonne TOC}}{\text{hr}}$$

The combined valve emissions are:

$$E_{\text{TOC Total}} = 3.2 \times 10^{-4} + 2.94 \times 10^{-6} = 3.23 \times 10^{-4} \frac{\text{tonne TOC}}{\text{hr}}$$

Methane emissions would then be calculated by applying the CH<sub>4</sub> composition from Table B-26, for gas production facilities (0.92 weight fraction).

$$\begin{aligned} E_{\text{CH}_4} &= E_{\text{TOC Total}} \times \text{WF}_{\text{CH}_4} = 3.23 \times 10^{-4} \frac{\text{tonne TOC}}{\text{hr}} \times 0.92 \frac{\text{tonne CH}_4}{\text{tonne TOC}} \times \frac{8760 \text{ hr}}{\text{yr}} \\ &= \underline{2.6 \text{ tonnes CH}_4 / \text{yr}} \end{aligned}$$

### B.3.3 Correlation Approach

The correlation approach predicts the mass emission rate as a function of the screening value for a particular equipment type. The screening value to leak rate correlations were developed based on data collected from petroleum industry units, including refineries, marketing terminals, and oil and gas production operations. The key difference between this approach and those previously discussed is that the user must estimate the emission rate for each component individually, rather than in large groups. This is generally only practical when the site maintains a specialized database that records Leak Detection and Repair (LDAR) activities and calculates the emission rates, although a facility with few components could use a spreadsheet to estimate emissions by the correlation approach. The specialized databases are common in refineries, but uncommon in other oil and gas industry facilities. While refineries have the database to support emission estimating by correlations, the CH<sub>4</sub> composition of refinery fugitive equipment leak emissions is generally negligible (with the exception of the fuel gas system, which is not commonly covered by the LDAR database). The types of facilities that are likely to have significant CH<sub>4</sub> fugitive equipment leaks will generally not have access to routine monitoring data and/or a specialized database to allow use of the correlation approach. If monitoring data and the means to make the correlation calculations on an individual component basis are available, the correlation approach will provide

more accurate estimates of equipment leak emissions than the other methods presented. It will have to be a site-specific decision whether the cost to achieve this level of accuracy is justified for GHG emission estimating.

The correlation equations apply to the entire range of the analyzer used for monitoring. The form of the correlation is:

$$E_{\text{TOC}} = A \times \text{SV}^B \quad (\text{Equation B-12})$$

where:

$E_{\text{TOC}}$	=	emission rate expressed as kg of TOC/hour
$A$ and $B$	=	constants developed in the correlation fitting
$\text{SV}$	=	screening value in ppmv estimated according to US EPA Method 21

The correlation equations do not directly allow for estimating the emissions for components whose monitoring value is below the lower limit of detection of the analyzer (often called “default zero”) or above the upper limit of detection (often called “pegged”). Default zero and pegged emission factors are used for these types of readings as an adjunct to the correlation equations. These default zero or pegged emission factors are applied as in the following equation:

$$E_{\text{TOC}} = F_A \times N \quad (\text{Equation B-13})$$

where,

$F_A$	=	the applicable default zero or pegged emission factor
$N$	=	the number of components found to be default zeros or pegged components

The Tables B-22 through B-24 present the correlation equations, the default zero emission factors, and the pegged emission factors.

**Table B-22. Petroleum Industry Leak Rate/Screening Value (SV) Correlations**

Equipment Type	Correlation Equation (Leak Rate in kg TOC/hr/component)
Valves	Leak Rate = $2.29\text{E-}06 \times (\text{SV})^{0.746}$
Pump Seals	Leak Rate = $5.03\text{E-}05 \times (\text{SV})^{0.610}$
Connectors	Leak Rate = $1.53\text{E-}06 \times (\text{SV})^{0.735}$
Flanges	Leak Rate = $4.61\text{E-}06 \times (\text{SV})^{0.703}$
Open-Ended Lines	Leak Rate = $2.20\text{E-}06 \times (\text{SV})^{0.704}$
Others *	Leak Rate = $1.36\text{E-}05 \times (\text{SV})^{0.589}$

Source: US Environmental Protection Agency (EPA). *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-10.

\* Other equipment type was derived from instruments, loading arms, pressure relief valves, stuffing boxes, and vents. This type should be applied to any refinery equipment other than valves, pump seals, connectors, flanges, or open-ended lines.

**Table B-23. Default-Zero Values: Petroleum Industry**

Equipment Type	Default-zero Emission Factors	
	kg TOC/hr/component	Tonne TOC/hr/component
Valves	7.8E-06	7.8E-09
Pump Seals	2.4E-05	2.4E-08
Connectors	7.5E-06	7.5E-09
Flanges	3.1E-07	3.1E-10
Open-Ended Lines	2.0E-06	2.0E-09
Others*	4.0E-06	4.0E-09

Source: US Environmental Protection Agency (EPA). *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-12.

\* Other equipment type was derived from instruments, loading arms, pressure relief valves, stuffing boxes, and vents. This type should be applied to any equipment other than valves, pump seals, connectors, flanges, or open-ended lines.

**Table B-24. Pegged Emission Rates for the Petroleum Industry**

Equipment Type	10,000 ppm Pegged Emission Factor		100,000 ppm Pegged Emission Factor	
	kg TOC/hr /component	Tonne TOC/hr /component	kg TOC/hr /component	Tonne TOC/hr /component
Valves	0.064	6.4E-05	0.140	1.4E-04
Pump Seals	0.074	7.4E-05	0.160	1.6E-04
Connectors	0.028	2.8E-05	0.030	3.0E-05
Flanges	0.085	8.5E-05	0.084	8.4E-05
Open-Ended Lines	0.030	3.0E-05	0.079	7.9E-05
Others*	0.073	7.3E-05	0.110	1.1E-04

Source: US Environmental Protection Agency (EPA). *Protocol for Equipment Leak Emission Estimates*, EPA-453/R-95-017, EPA Office of Air Quality Planning and Standards, November 1995, Table 2-4.

\*The other equipment type was developed for instruments, loading arms, pressure relief valves, stuffing boxes, vents, compressors, dump lever arms, diaphragms, drains, hatches, meters and polished rods.

“Other” does not apply to valves, pump seals, flanges, connectors, or open-ended lines.

It should be noted that the 10,000 ppmv pegged emission rate was based on components that screened at greater than or equal to 10,000 ppmv. It is quite possible that many of those components would have screened at greater than 100,000 ppmv if a dilution probe had been available to make the measurement. Because of this overlap of data, some pegged emission factors at the 10,000 and 100,000 ppmv levels are similar.

It should also be noted that only two data points were available for the pump seal 100,000 pegged emission rate. Rather than base an emission factor on this small amount of data, a ratio between the 10,000 and 100,000 ppmv emission factors for all the other equipment types was developed. This ratio was used to extrapolate the 100,000 ppmv emission factor for pumps from the 10,000 ppmv emission factor.

### **EXHIBIT B.13: Sample Calculation for the Correlation Approach**

#### **INPUT DATA:**

Assume there are 100 flanges in a gas plant and that no composition data are available. Ninety-five of the flanges had a screening value of non-detect, 4 flanges had a screening value of 7,950 ppmv, and the remaining 1 flange had a screening factor of >10,000 ppmv (note: these example monitoring data have been simplified to make the example easier to follow).



**EXHIBIT B.13: Sample Calculation for the Correlation Approach, continued**

**ASSUMPTIONS:**

Because no plant-specific composition data are available, the composition data will be taken from Table B-26 (presented in Section B.3.5). The default CH<sub>4</sub> concentration is 56.4%, or a weight fraction of 0.564.

**CALCULATION METHODOLOGY:**

TOC emissions are calculated using Equations B-12 and B-13:

From Table B-24, emissions from default zeros are:

$$E_{\text{TOC}} = 3.1 \times 10^{-7} \frac{\text{kg}}{\text{hr} \times \text{flange}} \times 95 \text{ flanges} = 2.95 \times 10^{-5} \frac{\text{kg TOC}}{\text{hr}}$$

From Table B-23, emissions within the correlation range are:

$$E_{\text{TOC}} = 4.61 \times 10^{-6} \times (7950)^{0.703} \frac{\text{kg TOC}}{\text{hr} \times \text{flange}} \times 4 \text{ flanges} = 1.02 \times 10^{-2} \frac{\text{kg TOC}}{\text{hr}}$$

From Table B-25, emissions from pegged components are:

$$E_{\text{TOC}} = 0.085 \frac{\text{kg}}{\text{hr} \times \text{flange}} \times 1 \text{ flange} = 8.5 \times 10^{-2} \frac{\text{kg TOC}}{\text{hr}}$$

Summing these results, the total TOC emissions are:

$$E_{\text{TOC}} = (2.95 \times 10^{-5} + 1.02 \times 10^{-2} + 8.5 \times 10^{-2}) = 9.5 \times 10^{-2} \frac{\text{kg TOC}}{\text{hr}}$$

The CH<sub>4</sub> emissions are calculated using Equation B-9:

$$\begin{aligned} E_{\text{CH}_4} &= E_{\text{TOC}} \times \frac{\text{WF}_{\text{CH}_4}}{\text{WF}_{\text{TOC}}} = 9.5 \times 10^{-2} \frac{\text{kg TOC}}{\text{hr}} \times \frac{0.564 \text{ kg CH}_4}{\text{kg TOC}} \times \frac{\text{tonne CH}_4}{1000 \text{ kg CH}_4} \times \frac{8760 \text{ hr}}{\text{yr}} \\ &= \underline{0.47 \text{ tonne CH}_4/\text{yr}} \end{aligned}$$

### **B.3.4 Unit-Specific Correlations**

The previous subsection described the use of leak rate/screening value correlations using methodologies that have been published for general petroleum industry use. It is also possible to develop unit-specific and/or site-specific correlations that can be used in the same manner. Developing unit-specific correlations requires the collection of screening values and measured mass emissions for a subset of components from the subject process unit. These data must then be statistically analyzed to develop the correlation equations. An in-depth description of the Unit-Specific Correlation Approach may be found in the *EPA Protocol for Equipment Leak Emission Estimates*, Section 2.3.4 (EPA, 1995). This approach can be quite expensive. An existing unit-specific correlation (if available) may be used for the subject process, but it would seldom be justified to try to develop unit-specific correlations to support GHG emission estimates.

### **B.3.5 Methane-Specific Data for Emission Rate Calculations**

Most fugitive emission factors are for total hydrocarbons (THC), total organic compounds (TOC), or volatile organic compounds (VOC). Methane emissions are included as part of the emissions from THC and TOC emission factors, but are excluded from VOC emission factors. It will be necessary to make some additional calculations to estimate CH<sub>4</sub> emissions from these types of emission factors. Calculating CH<sub>4</sub> fugitive emissions from THC or TOC emission factors is done using Equations B-9 and B-10, and requires composition data. The best source of composition data is test data specific to the facility. If plant-specific test data are unavailable, Table B-25 provides “generic” data on average CH<sub>4</sub> fractions of fugitive emissions from various oil and gas industry operations. The composition data in Table B-25 are taken from API Publication 4615 (API, 1995).

Note that the weight fractions of CH<sub>4</sub> in Table B-25 are not specified by the type of service (gas, light liquid or heavy liquid), but are instead the weight fraction of CH<sub>4</sub> in the aggregated emissions from many different streams associated with the type of operation. These composition data are best applied to API 4615 component emission factors provided in Tables B-13 through B-15.

**Table B-25. “Generic” Weight Fraction of THC Emissions in each Category**

Compound	Onshore Operations				Offshore Oil and Gas Wt. Fraction
	Light Crude Wt. Fraction	Heavy Crude Wt. Fraction	Gas Production Wt. Fraction	Gas Plant Wt. Fraction	
Methane	0.613	0.942	0.920	0.564	0.791
NMHC <sup>a</sup>	0.387	0.058	0.080	0.436	0.210
VOC <sup>b</sup>	0.292	0.030	0.035	0.253	0.110
C6+	0.02430	0.00752	0.00338	0.00923	0.00673
Benzene	0.00027	0.00935	0.00023	0.00123	0.00133
Toluene	0.00075	0.00344	0.00039	0.00032	0.00089
Ethylbenzene	0.00017	0.00051	0.00002	0.00001	0.00016
Xylenes	0.00036	0.00372	0.00010	0.00004	0.00027

Source: American Petroleum Institute (API). *Emission Factors for Oil and Gas Production Operations*, API Publication No. 4615, Health and Environmental Sciences Department, January 1995, Table ES-4.

<sup>a</sup> NMHC = Non-methane hydrocarbon.

<sup>b</sup> VOC = Propane and heavier hydrocarbon.

Additionally, Table B-26 provides generic fugitive stream composition data based on a Canadian study of upstream oil and gas operations in Alberta (Picard, Vol. II, 1992). Unlike the data in Table B-25, the composition data in Table B-26 are specified by gas or liquid service. These compositions are best applied to the EPA Protocol emission factors shown in Table B-11, which are provided on a component-service basis. Note that EMEP/CORINAIR guidance (Group 5, Tables 8.31 and 8.32) recommends using the Canadian composition data (EEA, 2001).

The usage of the compositions provided in Table B-26 are described below.

- Dry gas profile is applied to low-pressure gas gathering systems and to gas batteries;
- Sweet gas profiles are used for dehydrated gas gathering systems and sweet gas processing plants;
- Sour gas profiles are dedicated to heated gas gathering systems and to sour gas processing plants; however, all fuel gas is assumed to be sweet;
- The natural gas profile is used for natural gas transmission systems;
- Conventional oil, heavy oil, and crude bitumen profiles are applied to corresponding production and battery facilities. Heavy liquid service composition data also applies to vapors from storage tanks.

**Table B-26. “Generic” Production (Canadian) Composition in each Category**

Compound	Dry Gas - Gas Service		Sweet Gas - Gas Service		Sweet Gas – Light Liquid Service		Sour Gas - Gas Service		Sour Gas – Light Liquid Service		Natural Gas	
	Mole % <sup>a</sup>	Weight % <sup>b</sup>	Mole % <sup>a</sup>	Weight % <sup>b</sup>	Mole % <sup>a</sup>	Weight % <sup>b</sup>	Mole % <sup>a</sup>	Weight % <sup>b</sup>	Mole % <sup>a</sup>	Weight % <sup>b</sup>	Mole % <sup>a</sup>	Weight % <sup>b</sup>
N <sub>2</sub>	1.0914	1.8618	0.6793	1.0866	0.0000	0.0000	0.6552	1.0140	0.0000	0.0000	0.6793	1.0866
CO <sub>2</sub>	0.2674	0.7167	0.5814	1.4612	0.0000	0.0000	0.5608	1.3637	0.0000	0.0000	0.5814	1.4612
H <sub>2</sub> S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	3.5460	6.6772	0.0000	0.0000	0.0000	0.0000
C <sub>1</sub>	97.4524	95.1997	91.8796	84.1609	0.0000	0.0000	88.6210	78.5410	0.0000	0.0000	91.8796	84.1609
C <sub>2</sub>	1.1439	2.0949	5.4263	9.3180	6.2600	3.8133	5.2339	8.6959	6.2600	3.8133	5.4263	9.3180
C <sub>3</sub>	0.0389	0.1045	1.0490	2.6418	60.4300	53.9867	1.0118	2.4654	60.4300	53.9867	1.0490	2.6418
i-C <sub>4</sub>	0.0018	0.0064	0.1291	0.4285	10.9300	12.8689	0.1245	0.3998	10.9300	12.8689	0.1291	0.4285
n-C <sub>4</sub>	0.0034	0.0120	0.1949	0.6469	16.4000	19.3092	0.1880	0.6037	16.4000	19.3092	0.1949	0.6469
i-C <sub>5</sub>	0.0004	0.0018	0.0254	0.1047	1.6600	2.4263	0.0245	0.0977	1.6600	2.4263	0.0254	0.1047
n-C <sub>5</sub>	0.0005	0.0022	0.0296	0.1220	1.4300	2.0901	0.0286	0.1140	1.4300	2.0901	0.0296	0.1220
C <sub>6</sub>	0.0000	0.0000	0.0060	0.0295	1.2000	2.0950	0.0058	0.0276	1.2000	2.0950	0.0060	0.0295
C <sub>7+</sub>	0.0000	0.0000	0.0000	0.0000	1.6800	3.4105	0.0000	0.0000	1.6800	3.4105	0.0000	0.0000
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Picard, D. J., B. D. Ross, and D. W. H. Koon. *A Detailed Inventory of CH<sub>4</sub> and VOC Emissions from Upstream Oil and Gas Operations in Alberta*, Volume II Development of the Inventory, Canadian Petroleum Association, March 1992, Tables 12 through 15.

<sup>a</sup> Original composition provided in mole percent on a moisture-free (dry) basis.

<sup>b</sup> Compositions are converted from mole percents to weight percents using the approach described in Section 3.6.5 of this Compendium.

**Table B-26. “Generic” Production (Canadian) Composition in each Category, continued**

Compound	Conventional Oil - Gas Service		Conventional Oil - Light Liquid Service		Heavy Oil (Primary) - Gas Service		Heavy Oil (Primary) - Vapor/Heavy Liquid Service		Heavy Oil (Thermal) - Gas Service		Heavy Oil (Thermal) - Vapor/Heavy Liquid Service		Crude Bitumen - Gas/Vapor/Heavy Liquid Service	
	Mole % <sup>a</sup>	Weight % <sup>b</sup>	Mole % <sup>a</sup>	Weight % <sup>b</sup>	Mole % <sup>a</sup>	Weight % <sup>b</sup>	Mole % <sup>a</sup>	Weight % <sup>b</sup>	Mole % <sup>a</sup>	Weight % <sup>b</sup>	Mole % <sup>a</sup>	Weight % <sup>b</sup>	Mole % <sup>a</sup>	Weight % <sup>b</sup>
N <sub>2</sub>	0.6190	0.7723	13.9989	8.8634	0.1817	0.3030	6.3477	8.9367	0.1932	0.1767	3.3516	3.0550	0.0000	0.0000
CO <sub>2</sub>	5.2430	10.2775	0.3303	0.3286	0.0859	0.2251	0.6892	1.5246	2.6094	3.7488	16.1140	23.0785	22.0000	41.5263
H <sub>2</sub> S	0.0000	0.0000	0.0000	0.0000	0.0001	0.0002	0.0000	0.0000	0.0150	0.0167	0.1439	0.1596	0.0000	0.0000
C <sub>1</sub>	73.2524	52.3339	10.0100	3.6294	98.0137	93.6014	87.2337	70.3291	72.9361	38.1894	66.6600	34.7954	70.0000	48.1562
C <sub>2</sub>	11.9708	16.0329	15.7274	10.6902	0.9062	1.6224	2.2616	3.4182	1.9370	1.9013	0.9490	0.9286	8.0000	10.3175
C <sub>3</sub>	5.3198	10.4494	24.1601	24.0842	0.0408	0.1071	0.1905	0.4223	3.0956	4.4564	0.5394	0.7741	0.0000	0.0000
i-C <sub>4</sub>	0.8778	2.2724	6.6404	8.7240	0.0564	0.1952	0.1324	0.3868	1.0807	2.0503	0.1922	0.3635	0.0000	0.0000
n-C <sub>4</sub>	1.7027	4.4078	16.6022	21.8115	0.0351	0.1215	0.1137	0.3321	2.3889	4.5323	0.3678	0.6956	0.0000	0.0000
i-C <sub>5</sub>	0.3570	1.1473	4.2113	6.8683	0.0501	0.2152	0.1400	0.5077	1.9994	4.7090	0.4541	1.0662	0.0000	0.0000
n-C <sub>5</sub>	0.3802	1.2218	4.5447	7.4120	0.0433	0.1860	0.1230	0.4461	2.2733	5.3541	0.5829	1.3686	0.0000	0.0000
C <sub>6</sub>	0.2446	0.9389	2.9655	5.7770	0.0927	0.4756	0.3494	1.5135	5.8086	16.3408	2.1914	6.1458	0.0000	0.0000
C <sub>7</sub> +	0.0327	0.1460	0.7997	1.8115	0.4940	2.9473	2.4188	12.1831	5.6628	18.5242	8.4539	27.5689	0.0000	0.0000
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Source: Picard, D. J., B. D. Ross, and D. W. H. Koon. *A Detailed Inventory of CH<sub>4</sub> and VOC Emissions from Upstream Oil and Gas Operations in Alberta*, Volume II Development of the Inventory, Canadian Petroleum Association, March 1992, Tables 12 through 15.

<sup>a</sup> Original composition provided in mole percent on a moisture-free (dry) basis.

<sup>b</sup> Compositions converted from mole percents to weight percents using the approach described in Section 3.6.5 of this Compendium.

Methane contributions to fugitive emissions from downstream operations are generally negligible. However, if a specific downstream operation has potentially significant CH<sub>4</sub> fugitive emissions, then the CH<sub>4</sub> weight fraction should be characterized using plant-specific data. In the absence of plant-specific composition data, Table B-27 provides “generic” compositions for refinery fugitive streams based on data taken from the EPA’s SPECIATE computer database program, Version 3.2 (EPA, 2002). Although the EPA compositions are not specific to the type of service, these compositions can be applied to the refinery emission factors provided in Table B-12. Note that EMEP/CORINAIR guidance (Group 4, Tables 9.5 through 9.8) recommends using these EPA generic composition data from the SPECIATE program for downstream operations (EPA, 2002).

### **B.3.6 Generic Component Counts**

When using the component-level average emission factors, site-specific data should be used for the component counts.<sup>2</sup> If site-specific counts are not available, then component counts may be estimated based on counts for similar facilities within the organization. In the absence of component counts from other similar facilities within the organization, Table B-28 provides generic component counts for onshore oil production facilities, and Table B-29 provides generic counts for onshore gas production, onshore gas processing, and offshore oil and gas production platform facilities. These generic counts provide the number of components per piece of process equipment or process type. The counts are not split according to liquid or vapor service, so equipment with components in both liquid and vapor service (e.g. separators, dehydrator) could be assumed to have components that are 50% in liquid service and 50% in vapor service. The generic fugitive component counts are taken from a CAPP report (CAPP, 2003), which is based on API Publication 4589 (API, 1993). The generic counts were based on a study of 20 different sites.

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<sup>2</sup> The UK Offshore Operators Association Limited (UKOOA) provides adjustment factors that can be applied to the emission calculation based on the age of the facility. These factors are 1.0 if built after 1988, 1.3 if built between 1980 and 1988, and 1.5 if built before 1980 (UKOOA, 2002). Thus, these factors would be applied to the component count times the component emission factor to adjust the emission estimate [i.e.  $E_{CH_4} = FA \times WF_{CH_4} \times N \times (\text{age correction})$ ]. However, using these adjustment factors is optional, and the facility should evaluate whether they are representative for their operations. These factors should only be used for onshore exploration and production facilities where an LDAR program is not used. Thus, downstream facilities such as a refinery should not use these factors.

**Table B-27. “Generic” Refinery Composition by Component Type**

<b>Compound</b>	<b>Compressor Seals, Refinery Gas, Weight %</b>	<b>PRV, Liquefied Petroleum Gas, Weight %</b>	<b>Pipe/Valve Flanges Weight %</b>	<b>Pump Seals Weight %</b>
Methane	13.3		28.6	3.3
Ethane	5.6	4.1	5.8	1.2
Propane	16	90.4	11.5	3.7
Propylene	8.8	5.1	0.1	
n-Butane	23.2		18.3	8.1
i-Butane	10	0.4	7.4	0.8
1-Butene	1.2			
n-Pentane	7.6		7.7	11.1
Isomers of Pentane	8.6		7.8	6.6
n-Hexane	4.6		3.4	11
Isomers of Hexane	1		1.6	5.5
n-Heptane			1.4	8.5
Isomers of Heptane	0.1		0.8	4.1
C-7 Cycloparaffins			0.2	1.1
n-Octane			1.8	12
Isomers of Octane			0.4	2.8
C-8 Cycloparaffins				0.1
n-Nonane			0.6	3.9
Isomers of Nonane			0.5	3.1
C-9 Cycloparaffins			0.1	0.8
n-Decane			0.8	5.1
Isomers of Decane			0.3	1.9
Cyclohexane			0.1	0.5
Isomers of Xylene			0.2	1.3
Benzene			0.1	0.5
Toluene			0.5	3
Total	100	100	100	100
<b>Data Quality Rating<sup>a</sup></b>	D	C	C	C
<b>EPA SPECIATE Program Profile Number</b>	0039	0047	0316	0321

Source: US Environmental Protection Agency (EPA). SPECIATE Version 3.2, computer program, US Environmental Protection Agency, Technology Transfer Network, Clearinghouse for Inventories & Emission Factors (CHIEF), November 2002.

<sup>a</sup>Quality rating pertains to the quality of the data; “A” has the best quality while “E” has the poorest quality.

**Table B-28. “Generic” Fugitive Counts for Onshore Oil Production Facilities (per Equipment/Process Type)**

Equipment/ Process	Light Onshore Oil Production <sup>a</sup>					Heavy Onshore Oil Production <sup>a</sup>				
	Connectors	Valves	Open-Ended Lines	Compressor Seals	PRVs	Connectors	Valves	Open-Ended Lines	Compressor Seals	PRVs
Well	53	13	2		1	44	8	3		
Header	389	109	4			108	17	4		3
Heater	146	28	3							
Separator	111	24	3		1	41	10	2		
Chiller	94	25	1							
Meter	91	21	4							
Dehydrator	119	26								
Sulfur	109	34	7							
Compressor	163	34	2	1						
Scrubber	105	22	3							
Flare	114	35	5							

Sources:

Canadian Association of Petroleum Producers (CAPP). *Calculating Greenhouse Gas Emissions*, Guide, Canadian Association of Petroleum Producers, Publication Number 2003-0003, April 2003, Tables 1-15 through 1-19, which are based on:

American Petroleum Institute (API). *Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations*, API Publication No. 4589, Health and Environmental Sciences Department, December 1993.

<sup>a</sup> Light oil refers to crude with an API gravity of 20° or more, while heavy oil refers to crude with an API gravity less than 20°.



**Table B-29. “Generic” Fugitive Counts for Gas Production, Gas Processing, and Offshore Facilities (per Equipment/Process Type)**

Equipment/ Process	Gas Production					Gas Processing Plants					Offshore Oil and Gas Production Platforms				
	Connectors	Valves	Open-Ended Lines	Compressor Seals	PRVs	Connectors	Valves	Open-Ended Lines	Compressor Seals	PRVs	Connectors	Valves	Open-Ended Lines	Compressor Seals	PRVs
Well	60	16	3								195	61	20		
Header	105	26	4			145	38	4			310	82	14		2
Heater	147	22	4		2						197	45	4		2
Separator	160	30	5		3	48	17	3			299	81	11		1
Filter	122	19	3								269	42	8		2
Meter	55	13	2		2	160	41	13		2	383	84	10		4
Dehydrator	155	31	5			105	25	3		2	210	46	5		1
Fractionation						81	23	2		1					
Sulfur						144	42	3							
Compressor	195	31	5	2	3	129	26	2	3	4	417	88	12	2	3
Vapor Recovery	78	10	3								162	41	8		1
Scrubber	120	24	2		2	81	23	2			177	39	5		1
Flare						221	71	1			376	74	11		1

Sources:

Canadian Association of Petroleum Producers (CAPP). *Calculating Greenhouse Gas Emissions*, Guide, Canadian Association of Petroleum Producers, Publication Number 2003-0003, April 2003, Tables 1-15 through 1-19, which are based on:

American Petroleum Institute (API). *Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations*, API Publication No. 4589, Health and Environmental Sciences Department, December 1993.

## **B.4 Calculating Precision Values**

As discussed in *Compendium* Section 3.7, the GRI/EPA methane emissions study developed 90% confidence intervals for each emission source (Williamson, et. al., 1996). Sections 5 and 6 of the *Compendium* cite many emission factors directly from this study or derived from this study. This section provides additional information on the derivation of the precision factors associated with these emission factors.

The uncertainty associated with emission factor derivations from the GRI/EPA study is calculated as follows:

$$\text{Tol(EF) (\%)} = \frac{100\% \times \text{Tol(EF)}}{\text{EF}} \quad (\text{Equation B-14})$$

This equation expresses the tolerance of the emission factor in terms of a percentage (%), referred to as the “90% confidence half width” or “90% confidence interval.” The half width or interval establishes the lower and upper tolerances of the estimate. There is only a 5% chance that the true value falls below the lower limit of the confidence interval. There is also a 5% chance that the true value falls above the upper limit interval. Thus, there is a combined 10% chance that the true value falls outside the confidence interval.

An emission factor describes the emission rate associated with a given emission source. Both sampling and measurement errors contribute to the error in the estimate of the emission factor. An activity factor is the population of emission sources or activities resulting in emissions, such that the emission rate for a given source type is defined as:

$$\text{Emission Rate} = \text{Emission Factor (EF)} \times \text{Activity Factor (AF)} \quad (\text{Equation B-15})$$

The uncertainty associated with activity factors is calculated in a manner similar to emission factors, though slightly more complex.

All activity values are related to a known value. On a national basis, source data for the GRI/EPA study was generally a published production or throughput rate. On a company basis, the activity

value may be derived from measurements, in which case the uncertainty approach above (Equations B-14 and B15) would apply.

Company activity data may also be estimated by sampling a subset population and relating this subset to a total value based on some known value. This extrapolation method was used for estimating national emissions in the GRI/EPA methane study (Harrison, et. al., 1996).

To summarize the extrapolation method, an activity factor from a portion or sample of the total must be scaled up to the total. The selected scale-up method uses a ratio of another activity factor that is both known for the sample set and for the total, such as pipeline length in transmission. This known activity factor is called an extrapolation parameter (EP). The sample activity factor is divided by the extrapolation parameter sum for the sample set, producing a ratio that can be designated  $(AF/EP)_{\text{sample}}$ . Next, to scale the sample activity factor to a total, this AF ratio was multiplied by the known total value for the extrapolation parameter,  $(EP)_{\text{total}}$ . This product yields the extrapolated total value, as illustrated in the following equations:

$$\left( \frac{AF}{EP} \right)_{\text{sample}} \times EP_{\text{total}} = AF_{\text{total}} \quad (\text{Equation B-16})$$

$$\left( \frac{AF}{EP} \right)_{\text{sample}} = \frac{\sum_{i=1}^n AF_i}{\sum_{i=1}^n EP_i} \quad (\text{Equation B-17})$$

where:

n = the number of individual data points sampled (i) in the data set.

A more complex equation is applied to approximate the tolerance associated with  $AF_{\text{total}}$ :

$$\text{Tol}(AF)_{\text{total}} = \frac{N^2(1-f)}{n(n-1)} \sum_{i=1}^n \left[ AF_{\text{sample}} - \left( \frac{AF}{EP} \right)_{\text{sample}} \times EP_{\text{sample}} \right]^2 \quad (\text{Equation B-18})$$

where:

N = the total number of data points and f = sampling fraction, n/N

### **B.4.1 Error Propagation**

The error bounds of two numbers can be propagated to determine a combined error bound based on addition/subtraction and/or multiplication/division. Error propagation techniques for the sum and product of two numbers were required in the GRI/EPA methane study to develop the national emission estimates. Details on the derivation of the statistical calculations used throughout that study are available in a separate report (Williamson, et. al., 1996). Error propagation techniques used in developing uncertainty estimates associated with emission factors derived from the GRI/EPA study are summarized below.

#### **Error propagation in summation**

The expression used for calculating the propagated error associated with summed values accounts for the fact that the values were derived from different data and were unrelated (i.e., uncorrelated). For these uncorrelated values, the error bound (90% confidence half width) of a sum is the “square root of the sum of the squares” using the absolute errors of the values being summed. For example, if the confidence bound of the value A is expressed as “a” (in absolute terms from Equation 3-10) and the confidence bound of the value B is expressed as “b”, then the error for the sum of A and B is:

$$\text{Absolute error of } (A + B) = \sqrt{a^2 + b^2} \quad (\text{Equation B-20})$$

#### **Error propagation in division**

The GRI/EPA methane study developed an expression for calculating the propagated error associated with the product of two values based on the absolute error of the terms being multiplied. This approach was selected because it provided slightly larger (i.e., more conservative) error bounds (Williamson, et. al., 1996).

The alternative approach considered, and cited in many publications on error analysis, uses the relative error or fractional uncertainty of the values being multiplied or divided. Where the absolute error of value A is defined through Equation 3-10 as “a”, the relative error is expressed as a fraction based on the following equation:

$$\frac{a}{A} \quad (\text{Equation B-21})$$

The relative error can also be multiplied by 100% to express it in terms of a percentage.

The error propagation equation for two values divided (or multiplied) is then based on the “square root of the sum of the squares” using the relative errors (Skoog and West, 1982). For example, suppose that  $A \div B = C$ , then the propagated error for C (expressed as a relative error) is:

$$\begin{aligned} \text{90\% Confidence Interval} \\ \text{for } C = A \div B \end{aligned} = \frac{c}{C} \times 100\% = 100\% \times \sqrt{\left(\frac{a}{A}\right)^2 + \left(\frac{b}{B}\right)^2} \quad (\text{Equation B-22})$$

These techniques were used to develop precision values cited from the following reports:

- Harrison, M.R., T.M. Shires, R.A. Baker, and C.J. Loughran. *Methane Emissions from the US Petroleum Industry*, Final Report, EPA-600/R-99-010. US Environmental Protection Agency, February 1999; and
- Shires, T.M. and C.J. Loughran. *GHGCalc Version 1.0 Emission Factor Documentation*, Draft, January 2002.

## **B.5 References**

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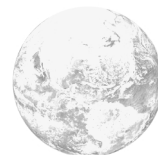
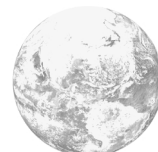
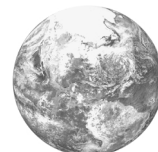
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FEBRUARY 2004

**COMPENDIUM OF GREENHOUSE GAS  
EMISSIONS METHODOLOGIES FOR  
THE OIL AND GAS INDUSTRY**

APPENDIX C

NITROUS OXIDE  
EMISSIONS STUDY





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## C. NITROUS OXIDE EMISSIONS STUDY

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### C.1 Introduction

This appendix describes the results of a study to identify and evaluate N<sub>2</sub>O emissions data and emission estimation methodologies for major sources of N<sub>2</sub>O emissions in the oil and gas industry. A literature search of available publications on N<sub>2</sub>O emissions data was performed and the data reviewed and compared. Currently used emission factors by US and international agencies were also reviewed. Table C-1 lists recommended N<sub>2</sub>O emissions factors that are based on the reviewed data for typical emissions sources in the oil and gas industry. Based on these emission factors, the relative contributions of N<sub>2</sub>O emissions to total GHG emissions for typical oil and gas industry operations were evaluated.

This section contains an introduction including sources of N<sub>2</sub>O emissions from the oil and gas industry, N<sub>2</sub>O formation/destruction kinetics and N<sub>2</sub>O measurement methods. A review of N<sub>2</sub>O emission factors is included in Section C.2. Estimates of N<sub>2</sub>O emissions from typical oil and gas industry operations are discussed in Section C.3.

#### C.1.1 Background

While CO<sub>2</sub> is the primary gas associated with global climate change, there is concern on the role of other trace gas species (e.g., N<sub>2</sub>O). N<sub>2</sub>O is a strong absorber of infrared radiation, therefore, increased N<sub>2</sub>O concentrations in the troposphere could lead to more retention of long wavelength radiation emitted from the surface of the earth.

In a recent Department of Energy (DOE) Energy Information Administration report (EIA, 2003), annual emissions of N<sub>2</sub>O in the US for 2001 were estimated at 424.6 Tg (Teragram = 10<sup>9</sup> Kg) CO<sub>2</sub>e (carbon dioxide equivalent) which is 7 percent higher than in the base year 1990. Agricultural activities including soil and manure management accounted for almost 75 percent of the 2001 estimate. The second largest source of anthropogenic N<sub>2</sub>O emissions is energy consumption, which includes mobile source combustion and stationary source combustion from electric utility,

industrial, and residential energy use. Energy consumption accounts for about 16 percent of the total N<sub>2</sub>O emissions estimate for 2001.

A breakdown of N<sub>2</sub>O emissions from energy use indicates that mobile source combustion accounts for almost 80 percent of N<sub>2</sub>O emissions from energy use (i.e., 13 percent of U.S. N<sub>2</sub>O emissions). N<sub>2</sub>O emissions from motor vehicles are caused primarily by the conversion of NO<sub>x</sub> into N<sub>2</sub>O by vehicle catalytic converters. For stationary sources, coal-fired combustion accounts for two-thirds of total N<sub>2</sub>O emissions, with electric utilities accounting for two-thirds of all stationary source combustion.

The oil and gas industry includes all direct activities related to producing, refining, transporting, and marketing crude oil and associated natural gas, and refined products. Potential sources of GHG emissions from this industry are discussed in Section 2 of the API Compendium. These can be classified broadly as combustion sources (includes stationary and mobile sources), vented sources (includes process vents, tanks, etc.), and fugitive sources.

Based on a knowledge of these processes, composition and properties of the gas streams, and published literature, only combustion sources appear to have the potential for N<sub>2</sub>O formation and emissions. Combustion sources in the oil and gas industry include:

- Boilers;
- Heaters/treaters;
- Combustion turbines;
- Internal combustion engines;
- Mobile sources (Road/Rail/Marine tankers, Barges, etc.); and
- Flares.

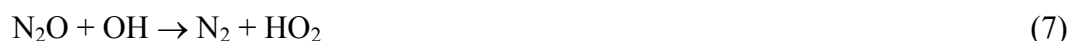
### **C.1.2     N<sub>2</sub>O Formation/Destruction Kinetics**

Nitrous oxide formation and destruction during the combustion of gaseous and liquid fuels is controlled by gas phase N<sub>2</sub>O chemistry. Gas phase formation/destruction of N<sub>2</sub>O during combustion is strongly linked to nitric oxide kinetics, (de Soete, and Sharp, 1991):

Key reactions for N<sub>2</sub>O formation include:



Reactions 2 and 4 are the predominant mechanisms for  $\text{N}_2\text{O}$  formation during combustion. The formation of  $\text{N}_2\text{O}$  is counterbalanced by its very fast destruction by H or OH radicals, according to the following reactions:



To a smaller extent,  $\text{N}_2\text{O}$  is destroyed by thermal decomposition represented by,



In premixed gas flames,  $\text{N}_2\text{O}$  is primarily formed in the oxidation zone, or flame front, but is readily destroyed due to the relatively high concentration of H radicals. Therefore, the  $\text{N}_2\text{O}$  emissions from premixed gas flames are found experimentally to be very small (generally less than 1 ppm). However, any mechanisms which decrease the H atom concentration in the  $\text{N}_2\text{O}$  formation zone are expected to increase emissions, including:

- Lowering the combustion temperature;
- Air or fuel staging, where the secondary air or air/fuel mixture is introduced in low temperature zones; and
- Injection of ammonia, urea, or other amine or cyanide species into the exhaust stream, especially at relatively low temperatures.

At temperatures well below 1000 K (1340 deg F), the reactivity of HCN is weak and almost no NCO or  $\text{N}_2\text{O}$  is formed. Maximum  $\text{N}_2\text{O}$  production occurs around 1000 K. At temperatures higher than 1200 K (1700 F), larger concentrations of H and OH radicals are produced resulting in the destruction of  $\text{N}_2\text{O}$  according to equations 6 and 7.

### **C.1.3     *N<sub>2</sub>O Emissions from Catalytic Reduction Systems***

N<sub>2</sub>O emissions from catalytic reduction systems for NO<sub>x</sub> or hydrocarbons are governed by catalytic heterogeneous reaction chemistry. Intermediate N<sub>2</sub>O formation during catalytic NO<sub>x</sub> reduction has been documented from catalytic converters on gasoline engines in the automotive industry and selective catalytic reduction (SCR) systems (de Soete, G. and B. Sharp, 1991). In the presence of reducing agents (e.g., CO and H<sub>2</sub>), the reduction of NO<sub>x</sub> generally occurs at lower temperatures than that of N<sub>2</sub>O. At low catalyst operating temperatures adequate for NO<sub>x</sub> reduction, the temperatures may be too low for complete N<sub>2</sub>O reduction to occur. Therefore, N<sub>2</sub>O emissions from a catalyst system will likely increase at lower catalyst operating temperatures.

N<sub>2</sub>O can also be formed across noble metal catalysts, typically used for non-selective catalytic reduction (NSCR) systems. Based on data collected for gasoline-fueled engines, the N<sub>2</sub>O emissions from catalyst equipped engines are substantially higher than uncontrolled engines, and emissions from aged catalysts appear to be higher than new catalysts, as follows (de Soete, G. and B. Sharp, 1991):

- New catalysts emit 4 to 5 times more N<sub>2</sub>O than uncontrolled engines; and
- Aged catalysts emit 10 to 17 times more N<sub>2</sub>O than uncontrolled engines, or 2 to 4 times more N<sub>2</sub>O than new catalysts.

For SCR systems that operate under overall oxidizing conditions, N<sub>2</sub>O is formed as a secondary reaction product from ammonia (or other SCR reagents such as, urea or cyanuric acid) and NO. Both NO and N<sub>2</sub>O are reduced on the catalyst metal sites, however, the optimum temperature window required for NO reduction across vanadium or noble metal catalysts, is not optimum for N<sub>2</sub>O reduction. This results in higher N<sub>2</sub>O emissions downstream of these catalysts.

### **C.1.4     *N<sub>2</sub>O Sampling Methods***

N<sub>2</sub>O emissions from combustion sources have been measured using a variety of methodologies including grab sampling and on-line monitoring techniques. In grab sampling, flue gas samples are collected in containers (usually tedlar bags) and subsequently analyzed using gas chromatography (GC). On-line monitoring methods include non-dispersive infrared (NDIR), Fourier transform infrared (FTIR), and GC techniques.

Grab sampling methods are easy to implement and less expensive than other techniques and were used widely in the early 1980s, in part, because other sampling techniques were as yet undeveloped or expensive to implement. However, the integrity of the samples collected in this manner are compromised under typical combustion flue gas conditions.

Early studies (prior to 1988) that used this sampling technique reported substantial levels of N<sub>2</sub>O from systems fired with residual oil or coal, with levels proportional to NO<sub>x</sub> emissions. It was later determined that the high levels of N<sub>2</sub>O measured from these sources were an artifact of the sampling procedure, through reaction of SO<sub>2</sub>, NO, and H<sub>2</sub>O to form N<sub>2</sub>O in the sample containers stored at room temperature (Muzio, L.J. and J.C. Kramlich, 1988; Muzio, L.J. et al., 1989). These effects can be minimized by sample conditioning techniques that minimize N<sub>2</sub>O formation in the contained samples.

N<sub>2</sub>O emissions can be measured using on-line real time analyzers based on infrared radiation absorption. This includes NDIR systems that are capable of monitoring N<sub>2</sub>O emission at several ppm level. These systems are susceptible to interferences from other compounds present in the gases that also absorb IR radiation at similar wavelength as N<sub>2</sub>O. However, these interferences can be minimized through the use of elaborate conditioning systems as well as electronic background correction. (Ryan and Linak). FTIR spectroscopy is capable of monitoring multiple wavelengths making it suitable for real-time, multi-component monitoring of combustion gases.

Another common method used to measure N<sub>2</sub>O emissions in through the use of a GC coupled with electron capture detection (ECD) with detection levels less than 300 ppb (parts per billion). Other detection methods with GC include thermal conductivity detection (TCD) and mass spectroscopy (MS). Although GC methods do not allow continuous real time measurements, they are typically easy to construct and operate and relatively inexpensive (Ryan and Linak).

## **C.2 N<sub>2</sub>O Emissions From Combustion Sources**

### **C.2.1 Literature Search and Review**

An exhaustive search of the published literature was performed to identify N<sub>2</sub>O emission measurements and emissions factors currently in use in the U.S. and abroad. It included searching on-line database including National Technical Information Service (NTIS), Engineering Index, Science Direct, Applied Science and Technology, Cambridge Scientific Abstracts, etc.

Additionally, relevant publications of US and international agencies were obtained and reviewed. These include:

- USEPA, AP-42 Emission factors;
- USEPA Climate Leaders program;
- USDOE publications;
- WRI/WBCSD publications; and
- International agency publications (e.g., UNFCCC, Environment Canada, European Environmental Agency, etc.).

The on-line searches were supplemented by manual searches of relevant published literature (e.g., recent symposia proceedings or publications) and contacts with oil and gas industry and regulatory agency representatives for relevant N<sub>2</sub>O data.

The literature search focused on recent data (typically post 1988) to avoid data that may be affected by the sampling artifact as discussed in the previous section. The data obtained were reviewed to identify the sampling procedure and the reported test conditions (equipment type, fuel type, operating load, etc.). The data were compiled in tables based on fuel and equipment type as discussed in the following section.

### **C.2.2     *N<sub>2</sub>O Emission Measurements and Emission Factors***

The N<sub>2</sub>O emissions data obtained from a review of the literature are summarized in Tables C-2 through C-7 for the various sources applicable to the oil and gas industry. For stationary sources, only measurements made by on-line sampling techniques were included. This ensures that the data are not influenced by the sampling artifact introduced by grab sampling methods. Further, measurements made prior to 1988 (when the sampling errors introduced by grab sampling were detected) are not included in these tables. Each table lists the equipment type (i.e. industrial boiler, gas turbine, etc.), equipment size, N<sub>2</sub>O emissions in the units of measure as originally reported by the data source and also expressed on a lb/10<sup>6</sup> Btu basis (HHV), exhaust O<sub>2</sub> concentration, and the source of the data.



## Residual Oil-fired Boilers

Uncontrolled boilers: N<sub>2</sub>O emissions data for residual oil-fired boilers are shown in Table C-2. The emission factors range between 0 and 0.033 lb/10<sup>6</sup> Btu. Linak et al conducted laboratory-scale tests on two units on a 2.5 10<sup>6</sup> Btu/hr gas/oil-fired package boiler and a 2 10<sup>6</sup> Btu/hr gas/oil-fired package boiler simulator capable of air staging for NO<sub>x</sub> emissions control. They used extractive sampling followed by on-line N<sub>2</sub>O analysis by GC/ECD. Measured N<sub>2</sub>O concentrations during residual oil firing were 1.3 ppm (0.002 lb/10<sup>6</sup> Btu) on the 2.5 10<sup>6</sup> Btu/hr boiler and 0.73 ppm (0.001 lb/10<sup>6</sup> Btu) on the 2 10<sup>6</sup> Btu/hr unit without air staging.

Muzio et al. conducted tests on utility sized boilers (110 –215 MW). N<sub>2</sub>O concentrations of 1 ppm (0.001 lb/10<sup>6</sup> Btu) were measured using an on-line NDIR analyzer. DeSoete and Sharp reviewed N<sub>2</sub>O data from tests conducted in the US, Europe and Japan. Based on results from 36 facilities, N<sub>2</sub>O emissions ranged from 0 to 4.9 ppm (0.001 to 0.006 lb/10<sup>6</sup> Btu). The measurements were based mainly on ECD chromatography. Korhonen et al. measured N<sub>2</sub>O emissions from a 65 MW (thermal) boiler at 50 and 75 percent load using an NDIR analyzer. Measured values were below 2 ppm (<0.003 lb/10<sup>6</sup> Btu).

Emission factors currently in use or recommended by US and international agencies were also reviewed. The US EPA AP-42 emission factor was revised in 1998 and corrected in April 2000 to 0.53 lb/1000 gal (0.0035 lb/10<sup>6</sup> Btu). The EPA emission factor is based on six tests at four facilities. It appears that this emission factor is based on the mean value of the test dataset as evidenced from the work of Peer et al. Environment Canada's Greenhouse gas inventory uses an emission factor of 0.064 g/L (0.0036 lb/10<sup>6</sup> Btu), which is based on a GHG emission factor study, completed in August 2000. This study cites the USEPA's AP-42 as the source of its emission factor.

Data from the Core Inventory of Air Emissions in Europe (CORINAIR90) show a range of N<sub>2</sub>O emission factors between 0.6 – 14.8 g/GJ (LHV basis) which equates to 0.001 – 0.033 lb/10<sup>6</sup> Btu on a HHV basis. Based on this and other data, the IPCC, in its revised guidelines for national greenhouse gas inventories, proposed a N<sub>2</sub>O emission factor for fuel oil (residual and distillate) of 0.6 kg/TJ (LHV basis). This equates to 0.0014 lb/10<sup>6</sup> Btu (HHV basis). The IPCC recommended value appears to be at the low end of the range reported in the CORINAIR90 database. More recently the USEPA Climate Leaders program has also adopted this emission factor (0.57 kg/TJ-HHV basis) as its default emission factor.

A comparison of the emissions factors derived from the data in Table C-2 indicates one group of data around  $0.001 \text{ lb}/10^6 \text{ Btu}$ , another cluster around  $0.003 \text{ lb}/10^6 \text{ Btu}$  and at the upper end of the range  $0.006 \text{ lb}/10^6 \text{ Btu}$  or greater. At the low end of this range is the IPCC factor which is based, in part, on the CORINAIR database. The factor is at the low-end of the range in the CORINAIR90 database. The AP-42 factor of  $0.0035 \text{ lb}/10^6 \text{ Btu}$  is close to the mid-range value of the De Soete data. The EPA and the De Soete datasets reflect measurements made on a large number of units (a total of 40 facilities). Therefore an  $\text{N}_2\text{O}$  emission factor of  $0.0035 \text{ lb}/10^6 \text{ Btu}$  is recommended for uncontrolled residual oil-fired boilers.

Controlled Boilers:  $\text{N}_2\text{O}$  emissions data for residual oil-fired boilers equipped with air-staging and with selective non catalytic reduction (SNCR) for  $\text{NO}_x$  control are also presented in Table C-2. Linak et al.'s measured  $\text{N}_2\text{O}$  emissions of 0.26 ppm ( $0.0004 \text{ lb}/10^6 \text{ Btu}$ ) on a  $2 \times 10^6 \text{ Btu/hr}$  boiler simulator. Although, these values are lower than without air staging on the same combustor, the  $\text{N}_2\text{O}$  data are very close to the instrument's detection limit for accurate comparison.

Muzio et al. measured substantially higher  $\text{N}_2\text{O}$  emissions on a 110 MW utility boiler equipped with selective noncatalytic reduction (SNCR) for  $\text{NO}_x$  control. The tests were conducted at a urea/ $\text{NO}_x$  molar ratio of 2.  $\text{N}_2\text{O}$  concentrations ranged between 10 and 23 ppm ( $0.011 - 0.025 \text{ lb}/10^6 \text{ Btu}$ ). The higher emissions can be explained from the gas phase reaction chemistry discussed in Section 1. In the optimum temperature window required for the control of NO, urea decomposes and transforms to NH and NCO each of which reacts with NO as described by equations (2) and (4) to form  $\text{N}_2\text{O}$ . Since  $\text{N}_2\text{O}$  is formed from both the injected nitrogen reagent and NO, the quantity of  $\text{N}_2\text{O}$  formed is dependent on the NO concentration in the stack gas as well as the reagent-to-NO injection ratio.  $\text{N}_2\text{O}$  emissions from urea injection are typically higher than from ammonia injection (DeSoete et al., 1993).

### Distillate oil-fired boilers

Emission factors for  $\text{N}_2\text{O}$  emissions from distillate oil-fired boilers are shown in Table C-3. Emission factors range between  $0.0004$  and  $0.002 \text{ lb}/10^6 \text{ Btu}$ . At the low end of this range is the measurement of Linak et al. They measured  $\text{N}_2\text{O}$  concentrations of 0.3 ppm ( $0.0004 \text{ lb}/10^6 \text{ Btu}$ ) on a  $2.5 \times 10^6 \text{ Btu/hr}$  package boiler and the boiler simulator without air staging. The AP-42 emission factor is  $0.26 \text{ lb}/1000 \text{ gal}$  ( $0.0017 \text{ lb}/10^6 \text{ Btu}$ ) per the April 2000 correction. This factor is based on fourteen source tests conducted at six facilities and is the mean value of the test data as reflected in the report by Peer et al. Environment Canada's Greenhouse gas inventory uses an emission factor of  $0.031 \text{ g/L}$  ( $0.0017 \text{ lb}/10^6 \text{ Btu}$ ), which is based on the USEPA's AP-42 emission

factor. As discussed under residual oil-fired boilers, the IPCC emissions factor of 0.0014 lb/10<sup>6</sup> Btu is also recommended for distillate-fuel fired boilers and has been adopted by the USEPA Climate Leaders program.

N<sub>2</sub>O emissions with air staging on the 2 10<sup>6</sup> Btu/hr boiler simulator are similar to values measured without air staging.

Except for the emission factors from the laboratory-scale boiler and boiler simulator, N<sub>2</sub>O emission factors are consistent ranging between 0.001 – 0.002. The AP-42 factor of 0.0017 lb/10<sup>6</sup> Btu is based on fourteen source tests and is recommended for estimating N<sub>2</sub>O emissions from distillate-oil fired boilers.

### **Natural Gas-fired Boilers**

Uncontrolled Boilers: Emission factors for N<sub>2</sub>O emissions from natural gas-fired boilers are shown in Table C-4. Emission factors range between 0.0003 lb/10<sup>6</sup> Btu to 0.006 lb/10<sup>6</sup> Btu. Linak et al. measured N<sub>2</sub>O concentrations of <0.24 ppm (<0.0003 lb/10<sup>6</sup> Btu) from a 2.5 10<sup>6</sup> Btu/hr package boiler firing natural gas and 0.72 ppm (0.001 lb/10<sup>6</sup> Btu) on the boiler simulator without air staging. N<sub>2</sub>O levels of 1-2 ppm (0.0012 - 0.0023 lb/10<sup>6</sup> Btu) were measured by Muzio et al. on utility size boilers (215-750 MW).

The AP-42 emission factor is 2.2 lb/10<sup>6</sup> scf (0.002 lb/10<sup>6</sup> Btu based on a HHV of 1020 Btu/scf). The AP-42 factors are based on five source tests on large wall-fired boilers (100 10<sup>6</sup> Btu/hr). Peer et al. report a mean value of 0.452 g/GJ (0.001 lb/10<sup>6</sup> Btu). Environment Canada's greenhouse gas inventory uses an emission factor of 0.035 g/m<sup>3</sup> (0.002 lb/10<sup>6</sup> Btu), which is based on the USEPA's AP-42 emission factor.

The CORINAIR90 database N<sub>2</sub>O emission factors range between 0.1 to 3 g/GJ (0.0002 – 0.006 lb/10<sup>6</sup> Btu). The IPCC recommended value of 0.1 kg/TJ (LHV basis) appears to be at the low end of the range reported in the CORINAIR90 database. The USEPA Climate Leaders program has also adopted this emission factor (0.09 kg/TJ-HHV basis) as its default emission factor.

The data in Table C-4 reflect two levels of N<sub>2</sub>O emission factors that differ by one order of magnitude. At the low end is the emission factor of 0.0002 lb/10<sup>6</sup> Btu that is the default factor adopted by the IPCC. The IPCC factor is based, in part, on the CORINAIR90 database. However,

this level is at the low-end of the range of the CORINAIR90 factors as shown in Table C-4. At the higher end of the range shown in Table 4 are factors proposed by AP-42 and source tests on large boilers. The AP-42 factor is based on five source tests conducted on industrial size boilers and its value is near the mid-range of the CORINAIR90 database. Therefore the AP-42 N<sub>2</sub>O emission factor of 0.002 lb/10<sup>6</sup> Btu is recommended for estimating emissions from natural gas-fired boilers.

Controlled Boilers: Linak et al. tested their 2 10<sup>6</sup> Btu/hr boiler simulator with LNB on natural gas. Measured N<sub>2</sub>O concentrations were below the detection limit < 0.24 ppm (< 0.0003 lb/10<sup>6</sup> Btu). The USEPA's AP-42 emission factor based on testing a gas-fired boiler with LNB is 0.64 lb/10<sup>6</sup> scf (0.0006 lb/10<sup>6</sup> Btu).

### Combustion Turbines

Emission factors for N<sub>2</sub>O emissions from combustion turbines are shown in Table C-5. De Soete summarized N<sub>2</sub>O measurements on two turbines, rated at 44 MW and 35 MW electric. The 44 MW turbine was tested with natural gas and fuel oil as fuel. Reported values of N<sub>2</sub>O emissions were similar for natural gas and fuel oil firing and ranged between 0.2 to 0.4 ppmvd measured @ 16 percent O<sub>2</sub> (0.0008 – 0.0017 lb/10<sup>6</sup> Btu).

Tests were conducted at various loads on the 35 MW turbine firing natural gas only. The turbine was equipped with water injection for NO<sub>x</sub> emissions control. At full load and without water injection, N<sub>2</sub>O emissions ranged between 1.4 to 1.9 ppmvd measured at 16 percent O<sub>2</sub> (0.006 – 0.008 lb/10<sup>6</sup> Btu). N<sub>2</sub>O emissions generally decreased at lower loads (20 – 90 percent of full load) ranging between 0.5 – 1.8 ppmvd (0.002 – 0.008 lb/10<sup>6</sup> Btu). With water injection N<sub>2</sub>O emissions ranged between 0.95 – 1.4 ppmvd (0.004 – 0.006 lb/10<sup>6</sup> Btu) at full load and between 0.75 – 1.65 ppmvd (0.003 – 0.007) at lower loads (80 – 90 percent of full load).

Korhonen measured N<sub>2</sub>O emissions from two combined cycle gas turbines. The first was rated at 155 MW (thermal) and operated at 47 percent of full load. The other was rated at 120 MW (thermal) and was operated at 100 percent load and 115 percent of full load with supplementary firing. Measured values in all cases were below 2 ppm @ 15 percent O<sub>2</sub> (< 0.007 lb/10<sup>6</sup> Btu).

The USEPA AP-42 emission factor is 0.003 lb/10<sup>6</sup> Btu. This is based on limited tests performed on a single turbine equipped with water injection. Environment Canada's Greenhouse gas inventory uses an emission factor is 0.049 g/m<sup>3</sup> (0.003 lb/10<sup>6</sup> Btu), based on the USEPA's AP-42 emission factor.

The CORINAIR90 database N<sub>2</sub>O emission factors for gas turbines range between 2 to 3 g/GJ (0.004 – 0.006 lb/10<sup>6</sup> Btu). The IPCC and the USEPA Climate Leaders program default N<sub>2</sub>O emission factors are based on fuel type and are not equipment type specific. Therefore the emission factors listed for distillate oil- and natural gas-fired boilers also apply to combustion turbines fired with these fuels.

The limited data in Table C-5 indicates that an appropriate emission factor for combustion turbines may be in the range of 0.004 - 0.005 lb/10<sup>6</sup> Btu. The AP-42 emission factor is 0.003 lb/10<sup>6</sup> Btu that is also adopted by Environment Canada. The IPCC default factor for all gas-fired equipment is 0.0002 lb/10<sup>6</sup> Btu which is substantially lower than the data in Table C-5. Since the test data in Table C-5 are inadequate to independently derive an emission factor for combustion turbines, the recommended N<sub>2</sub>O emission factor is the AP-42 value of 0.003 lb/10<sup>6</sup> Btu.

### **Stationary Gas-fired Reciprocating Engines**

N<sub>2</sub>O emissions from stationary gas-fired reciprocating engines are shown in Table C-6. The data were collected as part of a comprehensive GTI (formerly GRI) and GTI/API measurement program to characterize air toxics emissions from sources in the natural gas industry. The primary measurement method used for data collection was extractive Fourier transform infrared (FTIR) spectroscopy, which also measures N<sub>2</sub>O as part of the analytical matrix. On some engines that were equipped with catalysts measurements were made both upstream and downstream of the catalysts. These data represent a total of 45 reciprocating IC engines and are classified under the following engine types:

- 4-stroke, rich-burn engines (3 units with NSCR catalysts);
- 4-stroke, lean-burn engines (one with an SCR and another with an oxidation catalyst); and
- 2-stroke engines (one with an oxidation catalyst).

### ***N<sub>2</sub>O Emissions from Engines Without Catalytic Controls or Upstream of Catalysts***

Among the 4-stroke rich burn engines, two engines were tested with a long path FTIR system that had a detection limit for N<sub>2</sub>O of 0.5 ppmv. Measured values were 1.4 ppm (0.0014 lb/10<sup>6</sup> Btu) on one engine firing pipeline quality natural gas and ranged between 0.8 – 1.3 ppm (0.0009 – 0.0014 lb/10<sup>6</sup> Btu) on another engine firing field gas. For the remaining engines that were tested with a shorter path length FTIR (N<sub>2</sub>O detection limit = 1.5 ppmv), the N<sub>2</sub>O emissions were below the

detection limit of the FTIR system regardless of engine or fuel type (i.e., pipeline or field gas). Using the FTIR detection limit as an upperbound on emissions, N<sub>2</sub>O emissions were calculated to be <0.002 lb/10<sup>6</sup> Btu for 4-stroke rich burn engines, <0.003 lb/10<sup>6</sup> Btu for 4-stroke lean burn engines, and <0.005 lb/10<sup>6</sup> Btu for 2-stroke engines.

Among other sources of data, N<sub>2</sub>O emissions for stationary gas-fired engines in the CORINAIR90 database range between 1 to 3 g/GJ (0.002 – 0.006 lb/10<sup>6</sup> Btu) for pipeline gas, and 2.5 g/GJ (0.005 lb/10<sup>6</sup> Btu) for refinery gas.

Recommended uncontrolled N<sub>2</sub>O emission factors are 0.002 lb/10<sup>6</sup> Btu for 4-stroke rich burn engines, 0.003 lb/10<sup>6</sup> Btu for 4-stroke lean burn engines, and 0.005 lb/10<sup>6</sup> Btu for 2-stroke engines.

### ***Impact of Catalytic Controls on N<sub>2</sub>O Emissions from Reciprocating Engines***

**NSCR.** Levels of N<sub>2</sub>O measured downstream of NSCR catalyst systems were consistently higher than the uncontrolled emissions levels, as shown in Table C-6. For the first engine tested at 644 hp, the emissions levels of N<sub>2</sub>O measured downstream of the NSCR catalyst ranged from 2.4 to 2.6 ppmvd (0.002 – 0.003 lb/10<sup>6</sup> Btu), compared to 1.4 ppmvd upstream of the catalyst. Reduction of total NO<sub>x</sub> (i.e., NO and NO<sub>2</sub>) across the catalyst exceeded 99 percent. Exhaust temperatures upstream of the catalyst were measured at 796°F.

On another engine, N<sub>2</sub>O emission levels downstream of the NSCR catalyst were around 5 ppmvd (0.0052 lb/10<sup>6</sup> Btu). These N<sub>2</sub>O levels downstream of the catalyst are 4-6 times higher than the uncontrolled levels of 0.8 to 1.3 ppmvd. Exhaust temperatures upstream of the catalyst ranged from around 830-940°F, depending on engine operating conditions.

Substantially higher levels of N<sub>2</sub>O were measured downstream of the NSCR catalyst on a third engine firing field gas. N<sub>2</sub>O levels ranged between 120 to 144 ppmvd (0.121 – 0.146 lb/10<sup>6</sup> Btu). N<sub>2</sub>O levels upstream of the NSCR catalyst were below the FTIR detection limit of around 1.5 ppmv. Therefore, the N<sub>2</sub>O emissions downstream of the catalyst are nominally 80-95 times higher than uncontrolled levels. Exhaust temperatures upstream of the catalyst were measured at around 774°F, which is lower than the two other NSCR catalyst systems tested (796 and 830-940°F, respectively). The lower operating temperature of the NSCR catalyst system on this engine may have contributed to the elevated N<sub>2</sub>O emissions, as has previously been documented for automotive catalyst systems (de Soete, G. and B. Sharp, 1991). Data available for automotive catalytic converters also indicate that N<sub>2</sub>O emissions increase as the catalyst ages. Although no

data are available on the age of the NSCR catalyst systems tested, the catalyst age may also have some influence on N<sub>2</sub>O emissions levels.

**SCR.** On the 4-stroke lean burn engine equipped with an SCR catalyst, N<sub>2</sub>O emissions downstream of the SCR catalyst were 16-17 ppmvd (0.031 – 0.033 lb/10<sup>6</sup> Btu), as shown in Table C-6. N<sub>2</sub>O levels upstream of the SCR catalyst ammonia injection grid were below the FTIR detection limit of around 1.5 ppmv. Therefore, these N<sub>2</sub>O levels downstream of the SCR catalyst are nominally around 10 times higher than uncontrolled levels. These data are consistent with results from previous laboratory research studies which indicate an increase in N<sub>2</sub>O emissions for SCR systems (de Soete, G. and B. Sharp, 1991).

**Oxidation Catalysts.** Two engines equipped with oxidation catalysts for CO reduction were tested as part of the GTI programs. Levels of N<sub>2</sub>O upstream and downstream of the oxidation catalyst for both engines were below the FTIR detection limit of 1.5 ppmv.

### **C.2.3      *Mobile Source Emission Factors***

Several studies have been conducted on on-road mobile source emissions and on the development of emission factors for this source category. Although the revised 1996 IPCC guidelines include the USEPA emission factors, the N<sub>2</sub>O emission factors have been revised more recently (Michaels, 1998) and supersede the IPCC N<sub>2</sub>O emission factors. These revised factors coupled with more recent studies (Lipman and DeLucci, 1999) form the basis of the factors used in Canada's Greenhouse Gas Inventory database.

The on-road source emission factors used in the development of Canada's Greenhouse Gas Inventory (Environment Canada, 2002) is shown in Table C-7. The table includes emission factors expressed as g/L fuel (as originally listed) and also expressed in units of tonne/1000gal. Table C-7 also includes emission factors for off-road vehicles, and marine and air transportation obtained from the Canadian Inventory.

### **C.2.4      *Other Combustion Sources***

Other combustion sources include well testing and flaring used to incinerate sweet and sour gas streams in production and gas processing facilities and refineries. Smaller flares may be found at marketing terminals. The IPCC has developed emission factors based on work done by the

Canadian Association of Petroleum Producers (CAPP), GTI, and the USEPA. These factors are reproduced in Table C-8.

### **C.3 N<sub>2</sub>O Emissions From Typical Oil And Gas Industry Operations**

To assess the relative contributions of N<sub>2</sub>O emissions over total GHG emissions for typical oil and gas industry operations, N<sub>2</sub>O emissions from model facilities were estimated based on the emission factors developed in the previous section. The mix of equipment types and equipment sizes for these facilities is presented in Section 7 of the API Compendium.

The results are presented in Tables C-9 through C-15. The model facilities that were evaluated include:

- On-shore oil and gas production facility;
- Off-shore oil and gas production facility;
- Natural gas processing facility;
- Production gathering compressor station;
- Marketing terminal; and
- Refinery

For each facility, only sources of N<sub>2</sub>O emissions are shown in each table. The process vents and other equipment and processes that do not discharge N<sub>2</sub>O emissions are not included. However, those sources could be major emitters of other GHG emissions (i.e. CO<sub>2</sub> and CH<sub>4</sub>) and are included in the calculation of the total GHG emission footprint for the facility.

To evaluate the effect of catalytic controls, results for both controlled and uncontrolled (i.e., does not include catalytic controls for NO<sub>x</sub> or other hydrocarbons) combustion sources are shown for the on-shore oil and gas production facility (Table C-9). The gas turbine located for this facility was assumed to be equipped with SCR for NO<sub>x</sub> emission control. The N<sub>2</sub>O emission factor for this unit with SCR was assumed to be ten times higher than the emission factor for the uncontrolled gas turbine based on the data from the previous section. The N<sub>2</sub>O emission results with SCR on the turbine are also included in Table C-9.



Tables C-15 summarizes the GHG emission estimates for each model facility. Estimates of CO<sub>2</sub> and CH<sub>4</sub> emissions were obtained from Section 7 of the API Compendium. N<sub>2</sub>O emissions range between a low of 0.2 tonne/yr for the marketing terminal to 115 tonnes/yr for the refinery, which equates to 59 – 35,545 tonnes/yr on a CO<sub>2</sub>e basis.

In terms of the contribution of N<sub>2</sub>O emissions to the total greenhouse gas inventory, Table C-15 shows N<sub>2</sub>O emissions to be less than 5% for all of the facilities, and less than 1% for most of the scenarios examined. The addition of NO<sub>x</sub> controls on the gas turbine and heaters/boilers for the two production facilities increases N<sub>2</sub>O emissions from 0.7 to 4.0 tonnes/yr for the onshore oil field example facility and from 6.25 to 8.85 tonnes/yr for the offshore production facility.

## **C.4 Conclusions**

About 75 percent of N<sub>2</sub>O emissions in the US are from agricultural activities. Stationary combustion sources account for about 3 percent of the US total with two-thirds of stationary combustion N<sub>2</sub>O resulting from coal combustion. N<sub>2</sub>O emissions from the oil and gas industry are predominantly from stationary source combustion of oil and gas. These include boilers, heaters, engines, and turbines. Emissions from mobile sources used in the transport of crude and refined products also contribute to the emissions total.

A review of available data on N<sub>2</sub>O emissions from stationary combustion sources indicates wide variability in the emissions measurements and emission factors for each fuel/source type. However, the data indicate that N<sub>2</sub>O emissions from uncontrolled stationary sources are small (< 5 ppm). Higher levels of N<sub>2</sub>O emissions were measured across catalyst systems or when nitrogen compounds (such as ammonia or urea) are injected in the flue gas for NO<sub>x</sub> control. There were also differences in default N<sub>2</sub>O emission factor being recommended. Some agencies have adopted a single emissions factor based on fuel type only. Based on the available data, N<sub>2</sub>O emissions factors for use by the oil and gas industry were recommended.

Based on recommended emission factors, N<sub>2</sub>O emissions were estimated for model facilities that represent example oil and gas industry operations. These include: production, processing, gathering, marketing, and refining. Based on the mix of equipment developed for the API Compendium, N<sub>2</sub>O emissions were estimated to be less than 3 percent of the total GHG emissions from each model facility with uncontrolled sources (i.e., not accounting for the effect of SCR

system at the oil and gas production facility). The addition of NO<sub>x</sub> controls increases N<sub>2</sub>O emissions by an order of magnitude for SCR on gas turbines and increases N<sub>2</sub>O emissions by a factor of 3.5 for natural gas-fired heaters/boilers.

## **C.5 References**

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**Table C-1. Emission Factors Recommended for Oil and Gas Industry Sources**

Emission Source	N <sub>2</sub> O Emission Factor		Reference
	Original Units	Converted Units	
Residual Oil-fired Boilers and Heaters	0.53 lb/1000 gal	$2.4 \times 10^{-7}$ tonne/gal	AP-42 Table 1.3-8 – errata updated 4/28/00
Distillate Oil-fired Boilers and Heaters	0.26 lb/1000 gal	$1.2 \times 10^{-7}$ tonne/gal	
Natural Gas-fired Boilers and Heaters			
Controlled	0.64 lb/10 <sup>6</sup> scf	$2.8 \times 10^{-7}$ tonne/10 <sup>6</sup> Btu (HHV)	AP-42 Table 1.4-2 (7/98)
Uncontrolled	2.2 lb/10 <sup>6</sup> scf	$9.8 \times 10^{-7}$ tonne/10 <sup>6</sup> Btu (HHV)	AP-42 Table 1.4-2 (7/98)
Natural Gas Combustion Turbines			
Controlled (SCR)	0.03 lb/10 <sup>6</sup> Btu	$1.4 \times 10^{-5}$ tonne/10 <sup>6</sup> Btu (HHV)	GTI, 2002; API, 1999
Uncontrolled	0.003 lb/10 <sup>6</sup> Btu	$1.4 \times 10^{-6}$ tonne/10 <sup>6</sup> Btu (HHV)	GTI, 2002; API, 1999
Stationary Gas-fired IC Engines (without catalyst controls)			
4-stroke rich burn	0.001 lb/10 <sup>6</sup> Btu (HHV)	$4.5 \times 10^{-7}$ tonne/10 <sup>6</sup> Btu (HHV)	GTI, 2002; API, 1999
4-stroke lean burn	0.003 lb/10 <sup>6</sup> Btu (HHV)	$1.4 \times 10^{-6}$ tonne/10 <sup>6</sup> Btu (HHV)	GTI, 2002; API, 1999
2-stroke	0.005 lb/10 <sup>6</sup> Btu (HHV)	$2.3 \times 10^{-6}$ tonne/10 <sup>6</sup> Btu (HHV)	GTI, 2002; API, 1999
Gasoline IC Engines	0.031 g/L (distillate)	$1.17 \times 10^{-7}$ tonne/gal	Environment Canada
Diesel IC Engines	0.4 g/L	$1.51 \times 10^{-6}$ tonne/gal $1.1 \times 10^{-5}$ tonne/10 <sup>6</sup> Btu (HHV)	Environment Canada
Large Bore Diesel Engine (> 600 hp)	0.08 g/L	$3.03 \times 10^{-7}$ tonne/gal $2.2 \times 10^{-6}$ tonne/10 <sup>6</sup> Btu (HHV)	Environment Canada

Sources:

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Environment Canada, Canada's Greenhouse Gas Inventory 1990-2001, Greenhouse Gas Division, Environment Canada, August 2003.

Table C-2. N<sub>2</sub>O Emissions and Emission Factors for Residual Oil Fired Boilers

Source Description	Size/Capacity	N <sub>2</sub> O Emissions/Factor		O <sub>2</sub>	NO <sub>x</sub>	Data Source
		(as reported)	(lb/10 <sup>6</sup> Btu)	(%)	ppm	
<i>Uncontrolled Units</i>						
Package Boiler	2.5 10 <sup>6</sup> Btu/hr	1.3 ppm	0.0018	4.4	189	Linak, et al., 1990
Package Boiler Simulator	2.0 10 <sup>6</sup> Btu/hr	0.73 ppm	0.0009	4.1	682	Linak, et al., 1990
Utility Boiler	215 MW	1 ppm	0.0011	3	268	Muzio, et al., 1990
Utility Boiler	110 MW	1 ppm	0.0011	3	291	Muzio, et al., 1990
Various	--	0 - 4.9 ppm	0 – 0.006	3	--	De Soete, 1993
Industrial boiler	various	0.53 lb/1000 gal	0.0035	--	--	U.S. EPA, AP-42, 1998, Errata
Industrial/Utility	various	1.527 g/GJ	0.0035	--	--	Peer et al., 1995
various	--	0.6 kg/TJ	0.0014	NA	--	Revised 1996 IPCC Guidelines, 1997
Industrial boiler	--	0.064 g/L	0.0036	NA	--	Canada's GHG Inventory, June 2002
Boiler	65 MW-thermal	< 2 g/L	< 0.0027	4.6		Korhonen, S., et al., 2001
Boiler	65 MW-thermal	< 2 g/L	< 0.0026	4		Korhonen, S., et al., 2001
Various	--	0.6 - 14.8 g/GJ	0.0014 - 0.033	NA	--	EMEP/CORINAIR90
Various	--	0.57 kg/TJ	0.0014	NA	--	USEPA Climate Leaders
<i>Air Staging</i>						
Package Boiler Simulator	2.0 10 <sup>6</sup> Btu/hr	0.26 ppm	0.0004	5.4	60	Linak, et al., 1990
<b>Selective Noncatalytic reduction</b>						
Utility Boiler	110 MW	10 – 23 ppm	0.011 – 0.025			Muzio, et al., 1990

Table C-3. N<sub>2</sub>O Emissions and Emission Factors for Distillate Oil Fired Boilers

Source Description	Size/Capacity	N <sub>2</sub> O Emissions/Factor		O <sub>2</sub>	NO <sub>x</sub>	Data Source
		(as reported)	(lb/10 <sup>6</sup> Btu)	(%)	ppm	
Package Boiler	2.5 10 <sup>6</sup> Btu/hr	0.3 ppm	0.0004	4.4	105	Linak, W.P., et al., 1990
Package Boiler Simulator	2.0 10 <sup>6</sup> Btu/hr	0.27 ppm	0.0004	6.0	536	Linak, W.P., et al., 1990
Various	--	0.57 kg/TJ	0.0014	--	--	USEPA Climate Leaders
Industrial/commercial boiler	--	0.26 lb/1000 gal	0.0017	--	0.26	U.S. EPA, AP-42, Sept. 1998.-Errata.
All	--	0.6 kg/TJ	0.0014	--	--	Revised 1996 IPCC Guidelines, 1997
Industrial boiler	--	0.031 g/L	0.0017	--	0.031	Canada's GHG Inventory, June 2002
Industrial/Utility	various	0.792 g/GJ	0.0018	--	--	Peer et al., 1995
<b>Air Staging</b>						
Package Boiler Simulator	2.0 10 <sup>6</sup> Btu/hr	< 0.24 ppm	< 0.0003	6.1	64	Linak, W.P., et al., 1990

**Table C-4. N<sub>2</sub>O Emissions and Emission Factors for Natural Gas Fired Boilers**

Source Description	Size/Capacity	Calculated Emission Factor		O <sub>2</sub> (%)	NO <sub>x</sub> ppm	Reference
		N <sub>2</sub> O Level				
		(as reported)	(lb/10 <sup>6</sup> Btu)			
Package Boiler	2.5 10 <sup>6</sup> Btu/hr	< 0.24 ppm	< 0.00031	4.4	62	Linak, et al., 1990
Package Boiler Simulator	2.0 10 <sup>6</sup> Btu/hr	0.72 ppm	0.0009	4.6	638	Linak, et al., 1990
Utility boiler	215 - 750 10 <sup>6</sup> Btu/hr	2 ppm	0.0024	3	120	Muzio, et al., 1990
Utility boiler	215 - 750 10 <sup>6</sup> Btu/hr	2 ppm	0.0024	3	142	Muzio, et al., 1990
Utility boiler	215 - 750 10 <sup>6</sup> Btu/hr	1 ppm	0.0012	3	58	Muzio, et al., 1990
Industrial/commercial boiler	--	2.2 lbs/10 <sup>6</sup> scf	0.0022	--	--	U.S. EPA, (AP-42), 5th Edition, Section 1.4, Table 1.4-2, July 1998.
Industrial/commercial boiler	various	0.452 g/GJ	0.001	--	--	Peer et al., 1995
Industrial Boiler	--	0.035 g/m <sup>3</sup>	0.002	--	--	Canada's GHG Inventory, June 2002
Various	--	0.1 - 3.0 g/GJ	0.0002 - 0.006	--	--	EMEP/CORINAIR90
Various	--	0.1 kg/TJ	0.0002	--	--	Revised IPCC Guidelines
Various	--	0.09 kg/TJ	0.0002	--	--	USEPA Climate Leaders
<b>Air Staging</b>						
Package Boiler Simulator	2.0 10 <sup>6</sup> Btu/hr	< 0.24 ppm	0.0003	4.6	50	Linak, et al., 1990
Industrial/commercial boiler	--	0.64 lb/10 <sup>6</sup> scf	0.0006	--	--	U.S. EPA, (AP-42), 5th Edition, Section 1.4, Table 1.4-2, July 1998.

Table C-5. N<sub>2</sub>O Emissions and Emission Factors for Combustion Turbines

Source Description	Fuel Type	Size	N <sub>2</sub> O Emissions		O <sub>2</sub> (%)	Comments	Reference
			(as reported)	(lb/10 <sup>6</sup> Btu)			
Turbine	Natural gas and fuel oil	44 MW	0.2 - 0.4 ppmvd	0.0008 - 0.0017	16	Similar range in N <sub>2</sub> O values for gas and oil firing	De Soete, et al., 1993
Turbine	Natural gas	35 MW	1.4 - 1.9 ppmvd	0.006 - 0.008	16	no WI 100% load	De Soete, et al., 1993
Turbine	Natural gas	35 MW	0.5 - 1.3 ppmvd	0.0039	16	no WI 90% load	De Soete, et al., 1993
Turbine	Natural gas	35 MW	0.75 ppmvd	0.0032	16	no WI 80% load	De Soete, et al., 1993
Turbine	Natural gas	35 MW	0.8 ppmvd	0.0035	16	no WI 60% load	De Soete, et al., 1993
Turbine	Natural gas	35 MW	1.8 ppmvd	0.0078	16	no WI 41% load	De Soete, et al., 1993
Turbine	Natural gas	35 MW	0.65 ppmvd	0.0028	16	no WI 20% load	De Soete, et al., 1993
Turbine	Natural gas	35 MW	0.95 - 1.4 ppmvd	0.004 - 0.006	16	w. WI 100% load	De Soete, et al., 1993
Turbine	Natural gas	35 MW	0.95 - 1.65 ppmvd	0.004 - 0.007	16	w. WI 90% load	De Soete, et al., 1993
Turbine	Natural gas	35 MW	0.95 - 1.65 ppmvd	0.003	16	w. WI 80% load	De Soete, et al., 1993
Turbine	Natural gas	--	0.003 lb/10 <sup>6</sup> Btu	0.003	--	Based on limited tests of single turbine with water-steam injection.	USEPA AP-42, 5th Edition,, Section 3.1, Table 3.1-2a, Apr. 2000.
Combined Cycle Gas Turbine 1	Natural gas	155 MW (thermal)	< 2 ppm	< 0.0068	14.7	47 % load	Korhonen, et al., 2001
Combined Cycle Gas Turbine 2	Natural gas	120 MW (thermal)	< 2 ppm	< 0.0071	14.9	100 % load	Korhonen, et al., 2001
Combined Cycle Gas Turbine 2	Natural gas	138 MW (thermal)	< 2 ppm	0.006	13.9	115 % load (with supplementary firing)	Korhonen, et al., 2001
Turbine	Natural gas	--	2 - 3 g/GJ	0.004 - 0.006	--	--	EMEP/CORINAIR 90
Various	Natural gas	--	0.049 g/m <sup>3</sup>	0.003	--	--	Canada's GHG Inventory, June 2002



Table C-6. N<sub>2</sub>O Emission and Emission Factors for Gas Fired Stationary Engines<sup>1</sup>

Fuel Type Units	Measurement Method	No. of Engines Tested	N <sub>2</sub> O Emissions/Factor		O <sub>2</sub> (%)	Upstream Catalyst Temperature
			(as reported)	(lb/10 <sup>6</sup> Btu)		
Uncontrolled or Upstream of Catalyst						
4-Stroke Rich Burn						
Pipeline	FTIR	1	1.4 ppmvd	0.0014	0.4	--
Field gas	FTIR	1	0.8 – 1.3 ppmvd	0.0012	1.15	--
Field gas	FTIR	1	< 1.5 ppmvd	< 0.0015	0.01	--
Field gas	FTIR	2	< 1.5 ppmvd	< 0.0016	1	--
Pipeline	FTIR	3	< 1.5 ppmvd	< 0.0016	1	--
4-Stroke Lean Burn						
Pipeline	FTIR	1	< 1.5 ppmvd	< 0.0029	10	--
Field gas	FTIR	1	< 1.5 ppmvd	< 0.0029	10	--
Pipeline	FTIR	5	< 1.5 ppmvd	< 0.0032	11	--
Field gas	FTIR	2	< 1.5 ppmvd	< 0.0032	11	--
2-Stroke Lean Burn						
Pipeline	FTIR	20	< 1.5 ppmvd	< 0.0054	15	--
Field gas	FTIR	1	< 1.5 ppmvd	< 0.0054	15	--
2-Stroke Clean Burn						
Pipeline	FTIR	5	< 1.5 ppmvd	< 0.0054	15	--
Various						
Pipeline <sup>2</sup>	--	--	1 - 3 g/GJ	0.002 - 0.006	--	--
Refinery <sup>2</sup>	--	--	2.5 g/GJ	0.005	--	--
Downstream of Catalytic Systems						
4-Stroke Rich Burn (NSCR Catalyst)						
Pipeline	FTIR	1	2.4 - 2.6 ppmvd	0.0024 - 0.0026	0.05	796 °F
Field gas	FTIR	1	5 ppmvd	0.0052	0.4	830 – 940 °F
Field gas	FTIR	1	120 - 144 ppmvd	0.121 - 0.146	0.01	774 °F
4-Stroke Lean Burn (SCR Catalyst)						
Pipeline	FTIR	1	16 - 17 ppmvd	0.031 - 0.033	10	--
2 and 4-Stroke (CO Oxidation Catalyst)						
Pipeline <sup>3</sup>	FTIR	--	< 1.5 ppmvd	< 0.005	--	--
Field gas <sup>4</sup>	FTIR	--	< 1.5 ppmvd	< 0.003	--	--

<sup>1</sup>Reference: URS-GTI memorandum, 2002, unless otherwise indicated<sup>2</sup>Reference: EMEP/CORINAIR (CORINAIR90 database)<sup>3</sup>2-Stroke Lean Burn<sup>4</sup>4-Stroke Lean Burn

**Table C-7. N<sub>2</sub>O Emission Factors for Mobile Combustion Sources  
(Environment Canada, 2002)**

Use	N <sub>2</sub> O Emission Factor	
	g/L Fuel	tonne/1000 gal Fuel
<b>On-Road Transport</b>		
<i>Gasoline</i>		
Light-Duty Gasoline Automobiles (LDGA)		
Tier 1, Three-way Catalyst	0.26	9.84E-04
Tier 0, New Three-way Catalyst	0.25	9.46E-04
Tier 0, Aged Three-way Catalyst	0.58	2.20E-03
Oxidation Catalyst	0.2	7.57E-04
Non-Catalyst	0.028	1.06E-04
Light-Duty Gasoline Truck (LDGT)		
Tier 1, Three-way Catalyst	0.41	1.55E-03
Tier 0, New Three-way Catalyst	0.45	1.70E-03
Tier 0, Aged Three-way Catalyst	1	3.79E-03
Oxidation Catalyst	0.2	7.57E-04
Non-Catalyst	0.028	1.06E-04
Heavy-Duty Gasoline Vehicles (HDGV)		
Three-way Catalyst	1	3.79E-03
Non-Catalyst	0.046	1.74E-04
Uncontrolled	0.08	3.03E-04
Motorcycles		
Non-Catalytic Controlled	0.046	1.74E-04
Uncontrolled	0.046	1.74E-04
<i>Diesel</i>		
Light-Duty Diesel Automobiles (LDDA)		
Advance Control	0.2	7.57E-04
Moderate Control	0.2	7.57E-04
Uncontrolled	0.2	7.57E-04
Light-Duty Trucks (LDDT)		
Advance Control	0.2	7.57E-04
Moderate Control	0.2	7.57E-04
Uncontrolled	0.2	7.57E-04
Heavy-Duty Diesel Vehicles (HDDV)		
Advance Control	0.08	3.03E-04
Moderate Control	0.08	3.03E-04
Uncontrolled	0.08	3.03E-04
<i>Natural Gas Vehicles</i>	6E-05	2.27E-07
<i>Propane Vehicles</i>	0.028	1.06E-04
<b>On-Road Vehicles</b>		
Other Gasoline Vehicles	0.05	1.89E-04
Other Diesel Vehicles	1.1	4.16E-03
Diesel Rail Transportation	1.1	4.16E-03
<b>Marine Transportation</b>		
Gasoline Boats	0.06	2.27E-04
Diesel Ships	1.00	3.79E-03
Light Fuel Oil Ships	0.07	2.65E-04
Heavy Fuel Oil Ships	0.08	3.03E-04
<b>Air Transportation</b>		
Conventional Aircraft	0.23	8.71E-04
Jet Aircraft	0.25	9.46E-04

**Table C-8. N<sub>2</sub>O Emission Factors for Other Oil and Gas Industry Activities<sup>1</sup>**

<b>Activity</b>	<b>N<sub>2</sub>O Emission Factor</b>	<b>Units</b>
Well Testing	6.80E-08	Gg per number of wells drilled
LPG Transport	2.20E-09	Gg/1000 m <sup>3</sup> LPG
Flaring - gas production	2.10E-08	Gg/10 <sup>6</sup> m <sup>3</sup> production
Flaring - sweet gas processing	2.50E-08	Gg/10 <sup>6</sup> m <sup>3</sup> receipts
Flaring - sour gas processing	5.40E-08	Gg/10 <sup>6</sup> m <sup>3</sup> receipts
Flaring - deep-cut extraction plants	1.20E-08	Gg/10 <sup>6</sup> m <sup>3</sup> receipts
Flaring - conventional oil production	6.40E-07	Gg/1000 m <sup>3</sup> production
Flaring - heavy oil production	4.60E-07	Gg/1000 m <sup>3</sup> production

<sup>1</sup>Source: Intergovernmental Panel on Climate Change, IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories, Chapter 2 (Energy), Table 2-16, 2000.

**Table C-9. Onshore Oil Field N<sub>2</sub>O Emissions**

Emission Source	Activity Factor	Emission Factor	Units	Nitrous Oxide Emissions (Not Controlled)		Nitrous Oxide Emissions (Controlled)	
				tonnes/yr	tonnes CO <sub>2</sub> e/yr	tonnes/yr	tonnes CO <sub>2</sub> e/yr
Gas Boilers (controlled)	40×10 <sup>6</sup> scf/yr @ 1068 BTU/scf	2.8×10 <sup>-7</sup>	tonnes/10 <sup>6</sup> Btu (HHV)			0.012	3.71
Gas Boilers (not controlled)	=42,700×10 <sup>6</sup> Btu/yr	9.8×10 <sup>-7</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.042	13.0		
Gas Heaters/Reboilers (controlled)	49,392×10 <sup>6</sup> Btu/yr	2.8×10 <sup>-7</sup>	tonnes/10 <sup>6</sup> Btu (HHV)			0.014	4.34
Gas Heaters/Reboilers (not controlled)		9.8×10 <sup>-7</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.048	15		
Diesel Engine 1800 hp generator	2,912 ×10 <sup>6</sup> Btu/yr	2.2×10 <sup>-6</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.006	1.86	0.006	1.86
Diesel Engine 460 hp fire pump	77.7 ×10 <sup>6</sup> Btu/yr	1.1×10 <sup>-5</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.00085	0.26	0.0009	0.28
Gas Turbines 2-3394 hp comp. Engines OR	250×10 <sup>6</sup> scf/yr @ 1068 BTU/scf 267,000×10 <sup>6</sup> Btu/yr	1.4×10 <sup>-6</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.374	115.9		
Gas Turbines-with SCR 2-3394 hp comp. Engines	250×10 <sup>6</sup> scf/yr @ 1068 BTU/scf = 267,000×10 <sup>6</sup> Btu/yr	1.4×10 <sup>-5</sup>	tonnes/10 <sup>6</sup> Btu (HHV)			3.738	1,158
Emergency Flare	500×10 <sup>6</sup> scf/yr flared 6,100 bbl crude/day	1.0×10 <sup>-4</sup>	tonnes/1000 bbl crude produced	0.223	69.02	0.223	69.02
<b>Total N<sub>2</sub>O Emissions</b>				<b>0.693</b>	<b>215</b>	<b>3.994</b>	<b>1,238</b>

Table C-10. Offshore Oil and Gas Platform N<sub>2</sub>O Emissions

Emission Source	Activity Factor	Nitrous Oxide Emissions					
		Emission Factor	Units	Uncontrolled		Controlled	
				Tonnes/yr	tonnes CO <sub>2</sub> e/yr	tonnes/yr	tonnes CO <sub>2</sub> e/yr
Fuel usage – Natural gas boilers/heaters	14.126×10 <sup>6</sup> scf/yr = 15,044×10 <sup>6</sup> Btu/yr	2.8×10 <sup>-7</sup> 9.8×10 <sup>-7</sup>	tonnes/10 <sup>6</sup> Btu (HHV) tonnes/10 <sup>6</sup> Btu (HHV)	0.0147	4.57	0.004	1.23
Fuel usage – Natural gas turbines (electricity generation)	35,964 MW-hr	1.09×10 <sup>-4</sup>	Tonnes/megawatt-hr	3.92	1,215	3.92	1,215
Fuel usage – Natural gas turbines	200×10 <sup>6</sup> scf/yr @1065 BTU/scf	1.4×10 <sup>-5</sup> 1.4×10 <sup>-6</sup>	tonnes/10 <sup>6</sup> Btu (HHV) tonnes/10 <sup>6</sup> Btu (HHV)	0.298	89.9	2.98	899
Fuel usage – Diesel IC Engines	160,000 gal/yr	1.51×10 <sup>-6</sup>	tonne/gal	0.242	74.9	0.242	74.9
Diesel Engine <600 hp (210 hp crane engine)	4,354×10 <sup>6</sup> Btu/yr	1.1×10 <sup>-5</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.048	14.9	0.048	14.9
Diesel Engine <600 hp (197 hp crane engine)	4,146×10 <sup>6</sup> Btu/yr	1.1×10 <sup>-5</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.0457	14.2	0.0457	14.2
Diesel Engine <600 hp (280 hp fire pump)	392×10 <sup>6</sup> Btu/yr	1.1×10 <sup>-5</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.0043	1.34	0.0043	1.34
Diesel Engine >600 hp (2-1000 hp emergency generators)	2,800×10 <sup>6</sup> Btu/yr	2.2×10 <sup>-6</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.0062	1.9	0.0062	1.9
Diesel Engine >600 hp (1800 hp emergency generator)	2,520×10 <sup>6</sup> Btu/yr	2.2×10 <sup>-6</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.0055	1.72	0.0055	1.72
Diesel Engine >600 hp (2400 hp forklift)	18,480×10 <sup>6</sup> Btu/yr	2.2×10 <sup>-6</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.0407	12.6	0.0407	12.6
Diesel Engine >600 hp (3000 hp escape capsule)	4,200×10 <sup>6</sup> Btu/yr	2.2×10 <sup>-6</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.0092	2.86	0.0092	2.86
Diesel Engine (5000 hp supply boat)	41,250×10 <sup>6</sup> Btu/yr	2.77×10 <sup>-5</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	1.14	354	1.14	354
Diesel Engine (5000 hp supply boat)	4,125×10 <sup>6</sup> Btu/yr	2.77×10 <sup>-5</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.114	35.4	0.114	35.4
Aviation Fuel – Helicopters (assume)	11,845×10 <sup>6</sup> Btu/yr = 94,878 gal	8.71×10 <sup>-4</sup>	tonnes/1000 gal	0.086	26.7	0.086	26.7
Flare - Processed Gas and Sour gas	24.8×10 <sup>6</sup> scf/yr 16×10 <sup>6</sup> scf/day gas produced	5.9×10 <sup>-7</sup>	tonnes/10 <sup>6</sup> scf	0.0034	1.07	0.0034	1.07
<b>Total N<sub>2</sub>O Emissions</b>				<b>5.96</b>	<b>1,848</b>	<b>8.64</b>	<b>2,680</b>

**Table C-11. Natural Gas Processing Facility N<sub>2</sub>O Emission**

Emission Source	Activity Factor	Nitrous Oxide Emissions			
		Emission Factor	Units	tonnes/yr	tonnes CO <sub>2</sub> e/yr
Auxiliary Boilers (Natural Gas) – controlled	2,184,000×10 <sup>6</sup> Btu/yr	2.8×10 <sup>-7</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.61	190
Hot Oil Heaters (Natural Gas) - controlled	1,344,000×10 <sup>6</sup> Btu/yr	2.8×10 <sup>-7</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.38	117
Diesel Engine (2-460 hp fire pump engines)	155.4×10 <sup>6</sup> Btu/yr	1.1×10 <sup>-5</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.0017	0.53
Diesel Engine (2-425 hp fire pump engines)	151.8×10 <sup>6</sup> Btu/yr	1.1×10 <sup>-5</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.0017	0.52
Gas Turbines (2-36,200 hp comp. engines) - uncontrolled	3.0×10 <sup>12</sup> Btu/yr	1.4×10 <sup>-6</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	4.2	1,300
Gas Turbines (2-35,925 hp for electrical generation, 46% load, 8665 hr/yr per unit)	213,410×10 <sup>6</sup> W-hr output	2.86×10 <sup>-5</sup>	tonne/megawatt-hr	6.10	1,891
Flares - Pilot (sweet, dry gas and Sour Gas)	314.64×10 <sup>6</sup> scf/yr flared 800×10 <sup>6</sup> scf/day receipts	1.5×10 <sup>-6</sup>	tonnes/10 <sup>6</sup> scf gas receipts	0.44	136
Incinerator (tail gas incin., 2 units – waste composition unknown) - controlled	588,000×10 <sup>6</sup> Btu/yr	2.8×10 <sup>-7</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.165	51.0
<b>Total N<sub>2</sub>O Emissions</b>				<b>11.9</b>	<b>3,690</b>

**Table C-12. Production Gathering Station Facility N<sub>2</sub>O Emission**

Emission Source	Activity Factor	Nitrous Oxide Emissions			
		Emission Factor	Units	tonnes/ yr	tonnes CO <sub>2</sub> e/yr
Gas engines, 4 stroke rich (3-2200 hp units)	612,850×10 <sup>6</sup> Btu/yr	4.5×10 <sup>-7</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.274	85.5
Gas engines, 4 stroke lean (1-1200 hp unit)	111,427×10 <sup>6</sup> Btu/yr	1.4×10 <sup>-6</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.155	48.3
<b>Total N<sub>2</sub>O Emissions</b>				<b>0.432</b>	<b>134</b>

**Table C-13. Marketing Terminal Facility N<sub>2</sub>O Emission**

Emission Source	Activity Factor	Nitrous Oxide Emissions			
		Emission Factor	Units	tonnes/yr	tonnes CO <sub>2</sub> e/yr
Natural Gas Heater – controlled	235,000×10 <sup>6</sup> Btu	2.8×10 <sup>-7</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.0658	20.4
Diesel Heater	25,875×10 <sup>6</sup> Btu 4,500 bbl	1.2×10 <sup>-7</sup>	tonnes/gal	0.0227	7.03
Diesel Engine (fire pump engine)	2,500 gal/yr	1.51×10 <sup>-6</sup>	tonnes/gal	0.0038	1.17
Diesel Engine (fire pump engine)	4,400 gal/yr	1.51×10 <sup>-6</sup>	tonnes/gal	0.0066	2.06
Diesel Operated HD Road Tankers	300,000 gal/yr	3×10 <sup>-4</sup>	tonnes/1000 gal	0.09	27.9
Vapor Combustor - Propane Pilot	6,000 gal/yr	4.1×10 <sup>-7</sup>	tonnes/gal	0.0025	0.76
<b>Total N<sub>2</sub>O Emissions</b>				<b>0.191</b>	<b>59.3</b>

**Table C-14. Refinery N<sub>2</sub>O Emission**

Emission Source	Activity Factor	Nitrous Oxide Emissions			
		Emission Factors	Units	tonnes/yr	tonnes CO <sub>2</sub> e/yr
Power (steam) Boilers - Fuel Gas Fired	22,400,000 10 <sup>6</sup> Btu/yr	2.8×10 <sup>-7 a</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	6.272	1,944
Process Heaters - Fuel Gas Fired	21,840,000 10 <sup>6</sup> Btu/yr	2.8×10 <sup>-7 a</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	6.115	1,896
FCCU CO Boiler (supplemental fuel gas)	1,522,500 10 <sup>6</sup> Btu/yr	2.8×10 <sup>-7 a</sup>	tonnes/10 <sup>6</sup> Btu (HHV)	0.426	133
Gas engines, 2 cycle lean (Natural Gas Fired, 10 units, 1060 avg. hp each)	672,000 10 <sup>6</sup> Btu/yr	2.3×10 <sup>-6</sup>		1.546	480
Gas Turbines (Natural Gas Fired, 3 units) - controlled	7,140,000 10 <sup>6</sup> Btu/yr	1.4×10 <sup>-5</sup>		99.96	30,988
Flaring	250,000 bbl crude/day 2,390,540 10 <sup>6</sup> Btu/yr	No N <sub>2</sub> O emission factor			
Incinerators (sulfur recovery and tail gas incin. - waste composition unknown)	344,000 10 <sup>6</sup> Btu/yr	0.0022		0.096	29.8
<b>Total N<sub>2</sub>O Emissions</b>				<b>114.4</b>	<b>35,471</b>

<sup>a</sup> Applies emission factors for controlled natural gas fired boiler/heaters

**Table C-15. Summary of Total Greenhouse Gas Emission from Model Facilities – All Sources**

Facility	tonnes CO <sub>2</sub>	tonnes CH <sub>4</sub>	CH <sub>4</sub> Emissions Expressed as CO <sub>2</sub> e	Tonnes N <sub>2</sub> O	N <sub>2</sub> O Emissions Expressed as CO <sub>2</sub> e	Total tonnes CO <sub>2</sub> e	Contribution of N <sub>2</sub> O to Total CO <sub>2</sub> e Emissions (percent)
			tonnes CH <sub>4</sub> (e)		tonnes N <sub>2</sub> O(e)		N <sub>2</sub> O (e)/ CO <sub>2</sub> e × 100
Onshore Oil Field (uncontrolled)	48,000	2,790	58,590	0.70	217	106,800	0.20
Onshore Oil Field (controlled)	48,000	2,790	58,590	4.0	1,240	107,800	1.15
Offshore O&G Production (uncontrolled)	47,900	759	15,900	5.96	1,850	65,650	2.8
Offshore O&G Production (controlled)	47,900	759	15,900	8.64	2,680	66,480	4.0
Natural Gas Processing	811,000	4,330	90,900	11.9	3,690	906,000	0.41
Production Gathering Compressor Station	43,800	284	5,960	0.439	136	49,900	0.27
Marketing Terminal	25,600	0.518	10.9	0.226 <sup>a</sup>	70.1	25,700	0.27
Refinery	5,550,000	483	10,100	119 <sup>a</sup>	36,900	5,600,000	0.66

The equipment mix for each of these facilities is taken from Section 7 of the *Compendium*.

A GWP of 21 and 310 were used to calculate CH<sub>4</sub> (e) and N<sub>2</sub>O (e) emissions, respectively.

<sup>a</sup> Includes N<sub>2</sub>O emissions from purchased electricity and steam. Details are provided in Section 7.



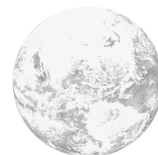
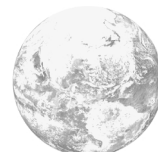
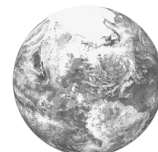


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FEBRUARY 2004

**COMPENDIUM OF GREENHOUSE GAS  
EMISSIONS METHODOLOGIES FOR  
THE OIL AND GAS INDUSTRY**

GLOSSARY



# GLOSSARY

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## ***Accuracy***

A measure of the total error associated with a data value, accounting for both random and bias errors.

## ***Activity Factor***

The numeric value representing any action or operation that causes or influences the release of greenhouse gas emissions (e.g., amount of fuel consumed or counts of emission sources); absolute greenhouse gas emissions result when related to the rate of emissions from the action.

## ***API Gravity***

A scale used to reflect the specific gravity (SG) of a fluid such as crude oil, water, or natural gas. The API gravity is calculated as  $^{\circ}\text{API} = (141.5/\text{SG}) - 131.5$ . The API gravity is calculated with the specific gravity at 60°F. Typical oils have an API gravity ranging from 25° to 35°. Light oils range from 35° to 45°, while heavy oils are less than 25°.

## ***Ballasting Emissions***

Evaporative emissions associated with the unloading of petroleum liquids at marine terminals. The emissions occur when vapor-laden air in an “empty” cargo tank is displaced to the atmosphere by ballast water being pumped into the tank to improve the stability of the marine tanker.

## ***Bitumen***

A thick, black, high-sulfur, heavy oil extracted from tar sand and then upgraded to synthetic fuel oil.

## ***Bituminous Coal***

A dense, black, soft coal, often with well defined bands of bright and dull material. The most common coal, with moisture content usually less than 20 percent. Used for generating electricity, making coke, and space heating.

## ***Bunker Fuel***

Fuel supplied to ships (marine bunker fuel) and aircraft (aviation bunker fuel) consisting primarily of residual and distillate fuels for marine sources and jet fuel for aviation sources. Thus, the CO<sub>2</sub> emission factors listed in Table 4-1 can be used for marine and aviation bunker fuels.

### ***Carbon Dioxide (CO<sub>2</sub>)***

A colorless, odorless, non-poisonous gas that is a normal component of ambient air. Carbon dioxide is a product of fossil fuel combustion. Although CO<sub>2</sub> does not directly impair human health, it is a greenhouse gas that traps terrestrial (i.e. infrared) radiation and contributes to the potential for global warming.

### ***Carbon Equivalent***

Determined by first multiplying the total mass of a greenhouse gas species by the global warming potential for that species, which converts the units to a mass of CO<sub>2</sub> basis. Then the CO<sub>2</sub> mass units are converted to carbon based on the molecular weight ratio of carbon to CO<sub>2</sub>. Exhibit 3.1 provides an example of this calculation.

### ***CO<sub>2</sub> Equivalent***

The mass of a greenhouse gas species multiplied by the global warming potential (GWP) for that species. It is used to evaluate emissions of different greenhouse gases on a common basis—the mass of CO<sub>2</sub> emitted that would have an equivalent warming effect.

### ***Coal***

A black or brownish-black solid, combustible substance formed by the anaerobic partial decomposition of vegetation. The rank of coal, which includes anthracite, bituminous coal, sub-bituminous coal, and lignite, is based on fixed carbon, volatile matter, and heating value.

### ***Co-generation unit/Combined Heat and Power (CHP)***

A facility producing both electricity and steam/heat using the same fuel supply.

### ***Commercial Combustor***

Refers to commercial boilers/furnaces with Source Classification Codes (SCC) 1-03-004-01/02/03/04 and 1-03-005-01/02/03/04.

### ***Condensate***

Liquid hydrocarbons of very light crude composition that occur as a gas under subsurface reservoir conditions (high temperature and pressure) and condense into liquid upon production and surface conditions.

### ***Direct Emissions***

Greenhouse gas emissions from sources that are owned or controlled by the company.

### ***Distillate Oil***

Distillate oils are more volatile and less viscous than residual oils. They have negligible nitrogen and ash contents and usually contain less than 0.3 percent sulfur (by weight). Distillate oils are used mainly in domestic and small commercial applications, and include kerosene and diesel fuels. Oil grade Nos. 1 and 2 are distillate oils. Oil grade No.4 is either distillate oil or a mix of distillate and residual oils.

### ***Downstream***

Operations involving the refining, processing, distribution and marketing of products derived from oil and gas, including service stations.

### ***Emission Factor***

The emission rate for a particular emission source per unit of the source, when related to the activity data (e.g., amount of fuel consumed or counts of emission sources) results in absolute greenhouse gas emissions.

### ***Emissions***

The intentional or unintentional release of greenhouse gases into the atmosphere.

### ***Enhanced Oil Recovery (EOR)***

Artificial methods used to recover more oil after primary production by the natural reservoir drive and, possibly, water-flooding. Common EOR methods include thermal (cyclic steam stimulation, steam-flooding, and in-situ combustion), chemical (polymer, micellarpolymer, and alkaline flooding), and gas miscible (cyclic, carbon-dioxide stimulation, carbon-dioxide flooding, and nitrogen flooding). Due to potentially high CO<sub>2</sub> concentrations associated with EOR operations, CO<sub>2</sub> emissions from vented and fugitive sources should be considered in a greenhouse gas inventory.

### ***External Combustion Device***

External combustion devices include boilers, heaters, and furnaces. These include steam/electric generating plants, industrial boilers, process heating and space heating, and other commercial and domestic combustion units.

### ***Floating Production and Storage Offloading (FPSO) System***

Similar to an offshore production platform, except that FPSO's are mobile. FPSO's combine production, crude oil storage, and offloading. They may also include gas processing.

### ***Fugitive Emissions***

Releases of greenhouse gases from pressurized equipment, such as joints, seals, packings, and gaskets. Fugitive emissions also include evaporative or non-point sources, such as wastewater treatment.

### ***Global Warming Potential (GWP)***

An index used to relate the level of emissions of various greenhouse gases to a common measure. The GWP is defined as the ratio of the amount of global warming or radiative forcing produced by a given gas relative to the global warming produced by the reference gas CO<sub>2</sub>, for a specified time period. As the reference gas, CO<sub>2</sub> has a GWP value of 1. The current GWP for methane is 21, based on a 100-year time period, as recommended by the Intergovernmental Panel for Climate Change (EPA, 1998). Therefore, one mass unit of methane has the same impact on global warming as 21 mass units of carbon dioxide over a 100-year time period.

### **Greenhouse Gas (GHG)**

Any gas that absorbs infrared radiation in the atmosphere. Greenhouse gases include water vapor, carbon dioxide, methane, nitrous oxide (N<sub>2</sub>O), hydrochlorofluorocarbons (HCFCs), ozone (O<sub>3</sub>), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF<sub>6</sub>).

### **Heating Value**

The amount of energy released when a fuel is burned completely. (See also HHV and LHV).

### **HHV**

Higher Heating Value or Gross Calorific Value. The quantity of heat produced by the complete combustion of a unit volume or weight of fuel assuming that the produced water is completely condensed (liquid state) and the heat is recovered.

### **Indirect Emissions**

The release of greenhouse gas emissions as a consequence of operations of the reporting company, but physically occurring at sources owned or operated by another organization (e.g., purchased electricity).

### **Internal Combustion Engines**

An internal combustion (IC) engine uses the burning of the air-fuel mixture to provide mechanical shaft power. The major types of IC engines used in petroleum operations are gas turbines and reciprocating engines. Most stationary internal combustion engines are used to generate electric power, to pump gas or other fluids, or to compress air for pneumatic machinery.

### **Industrial Boiler**

Refers to Source Classification Codes (SCC) 1-02-004-01/02/03/04 and 1-02-005-01/02/03/04.

### **LHV**

Lower Heating Value or Net Calorific Value. The quantity of heat produced by the complete combustion of a unit volume or weight of fuel assuming that the produced water remains as a vapor and the heat of the vapor is not recovered. The difference between the HHV and LHV is the latent heat of vaporization of the product water (i.e., the LHV is reduced by the enthalpy needed to vaporize liquid water).

### **Liquefied Natural Gas (LNG)**

Natural gas converted to a liquid form by cooling to a very low temperature.

### **Liquefied Petroleum Gas (LPG)**

Ethane, ethylene, propane, propylene, normal butane, butylene, and isobutane liquids produced at refineries or natural gas processing plants.

### **Loading Emissions**

The hydrocarbon vapors residing in “empty” cargo tanks that are displaced to the atmosphere by liquids being loaded into the tanks.

### **Methane (CH<sub>4</sub>)**

A hydrocarbon that is a greenhouse gas. Methane is released to the atmosphere through anaerobic (without air) decomposition of waste, animal digestion, production and distribution of natural gas and petroleum, coal production, and incomplete fossil fuel combustion. The molecular weight of methane used in the *Compendium* is 16.04.

### **Mobile Combustion Sources**

Emissions from engines providing the motive power for vehicles or marine vessels used in the transport of feedstock or product, or in the work-related transport of company personnel.

### **Natural Gas Liquids**

Hydrocarbons in natural gas that are separated as liquids from the gas. Includes natural gas plant liquids and lease condensate.

### **Non-Point Sources**

An emission category that includes fugitive equipment leaks as well as other sources which generally produce emissions over a large surface area (e.g., waste water treatment systems and impoundments/pits).

### **Petrochemicals**

The manufacture, distribution, and marketing of chemical products derived from oil and gas.

### **Point Sources**

An emission category that includes releases to the atmosphere that occur through stacks, vents, ducts, tailpipes, or other confined streams.

### **Precision**

A measure of the degree of random variability associated with a data value.

### **Process Vents**

A subcategory of point sources that produce emissions as a result of some form of chemical transformation or processing step.

### **Reciprocating Engine**

An engine that uses the up and down motion of pistons in a cylinder to drive a crankshaft.

### **Reid Vapor Pressure (RVP)**

A measure of the tendency of a liquid to vaporize. RVP is the pressure of the vapor portion of a liquid plus the enclosed air plus the water vapor under standard conditions, measured in pounds per square inch (psi) at 100°F.

### **Renewable Energy**

Energy taken from sources that are inexhaustible (e.g., wind, water, solar, geothermal, and biofuels).

### ***Residual Oils***

Residual oils are produced from the residue remaining after the lighter fractions (gasoline, kerosene, and distillate oils) have been removed from the crude oil. As a result, they contain significant quantities of ash, nitrogen, and sulfur. Residual oils are used primarily in utility, industrial, and large commercial applications. Oil grade Nos. 5 and 6 are residual oils.

### ***Source***

Any physical unit or process that releases greenhouse gases into the atmosphere.

### ***Standard Conditions***

For the purpose of this document, standard conditions for converting gas flow rates between mass and volume bases are 14.7 psia and 60°F.

### ***Stationary Combustion Sources***

Stationary combustion sources include boilers, heaters, turbines, and engines.

### ***Ton***

A short ton is equivalent to 2,000 US pounds.

### ***Tonnes***

A metric tonne is equivalent to 1,000 kg and 2,205 US pounds. Metric tonnes are the standard convention for reporting greenhouse gas equivalent emissions used by IPCC and other international climate change organizations.

### ***Total Organic Compound (TOC)***

Used in AP-42 to indicate all VOCs and all exempted organic compounds including methane, ethane, chlorofluorocarbons, toxics and hazardous air pollutants, aldehydes, and semivolatile compounds.

### ***Total Hydrocarbons (THC)***

Used interchangeably with the term TOC in this document. THC sometimes refers to hydrocarbon compounds that are measured using a Flame Ionization Detector (FID) of a gas chromatograph (GC).

### ***Turbine***

A motor consisting of a rotating shaft with propellers or blades that are driven by a fluid.

### ***Uncertainty***

The range around a reported value in which the true value can be expected to fall.

### ***Upstream***

Operations involving the exploration, development, and production of oil and gas.

***Utility Boiler***

Refers to Source Classification Codes (SCC) 1-01-004-01/04/05/06 and 1-01-005-04/05.

***Volatile Organic Compound (VOC)***

Any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric chemical reactions (40 CFR 51.100, April 9, 1998). Pollutants commonly classified as VOC encompass a wide spectrum of volatile organic compounds that are photochemically reactive in the atmosphere. Compounds deemed to have “negligible photochemical reactivity” and therefore excluded include methane, ethane, methylene chloride, methyl chloroform, many chlorofluorocarbons, and certain classes of perfluorocarbons.





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