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

AUGUST 2009

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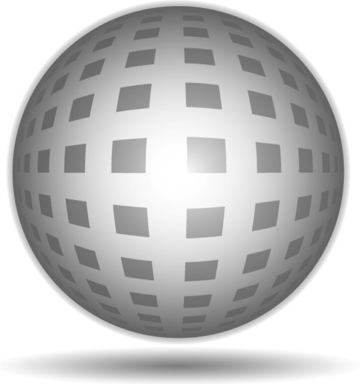

Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry

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August 2009

ACKNOWLEDGEMENTS

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PREFACE

The API *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry* (referred to as the "API *Compendium*") was initially distributed in June 2001 as a "Pilot Test" version. Since the initial 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 to better harmonize greenhouse gas emission estimation techniques and enable improved global comparability of emission estimates.

This document represents the third release of the API *Compendium*. The emission factors and methodologies presented here represent the latest information available at the time this document was published. Note, however, that estimating greenhouse gas emissions is an evolving process. As such, the API *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 API *Compendium* for updates.**

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

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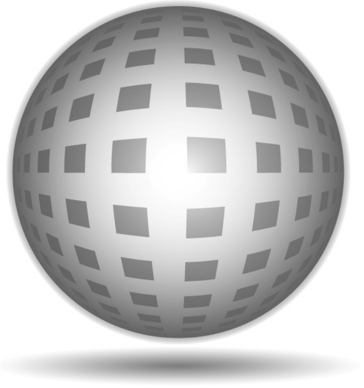
SECTION 1
INTRODUCTION



Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry

Section 1 - Introduction

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1.0
INTRODUCTION

The American Petroleum Institute (API) and many of its member companies are implementing action plans for addressing greenhouse gas (GHG) concerns and policy issues. Concurrently, local, regional, national and international bodies are developing or revising their guidance on estimating, reporting, and verifying GHG emissions. This document is a compendium of currently recognized methods and provides details for all oil and natural gas industry segments to enhance consistency in emissions estimation.

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

- Assemble an expansive collection of relevant emission factors and methodologies 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 natural gas industry standards;
- Provide descriptions of the multitude of oil and natural gas industry operations—in its various segments—and the associated GHG emissions sources that should be considered; and
- Develop emission inventory examples—based on selected facilities from various oil and natural gas industry operations—to demonstrate the broad applicability of the methodologies.

The overall objective of this document is to promote the use of consistent, standardized methodologies for estimating GHG emissions from oil and natural gas industry operations[1]. As a result, this API *Compendium* recognizes calculation techniques and emission factors for estimating GHG emissions for oil and natural 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 API *Compendium* presents and illustrates the use of emission estimation methods for carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons

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[1] Although the API *Compendium* was derived for oil and natural gas industry operations, the methodologies presented in the API *Compendium* can be used by other industries, particularly those that utilize fossil fuels.

(PFCs), and sulfur hexafluoride (SF_6) for all common emission sources, including combustion, vented, and fugitive. Decision trees are provided to guide the user in selecting a calculation or estimation technique that is based on considerations of materiality, data availability, and accuracy. **METHODOLOGIES REQUIRED BY REGULATIONS TAKE PRECEDENCE OVER THE OPTIONS PROVIDED IN THE DECISION TREES.**

1.1 Background

The API *Compendium* was first released 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 API *Compendium* have been received through a number of mechanisms, including industry conferences, workshops, and focused outreach to other protocol development organizations, particularly those used by the oil and natural gas industry in other regions of the world. Through collaboration with other industry-related protocol development organizations, this version of the API *Compendium* represents industry best practices for estimating GHG emissions.

Also following the release of the API *Compendium* Pilot Version, a parallel effort was initiated to promote consistent, credible, and reliable GHG accounting and reporting practices for the oil and natural gas industry. A team of oil and natural gas industry representatives led by the International Petroleum Industry Environmental Conservation Association (IPIECA), the Association of Oil and Gas Producers (OGP) and API, issued the *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions* (referred to as the *Guidelines*) 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 oil and natural gas industry.

In 2007, API launched an initiative to develop guidelines for quantifying uncertainty associated with GHG emission inventories. API, Conservation of Clean Air and Water in Europe (CONCAWE), and IPIECA convened an international workshop on the topic on January 16, 2007, in Brussels, Belgium, as the first step in the process of addressing inventory uncertainty and accuracy issues (API and IPIECA, 2007). The document *Addressing Uncertainty in Oil & Natural Gas Industry Greenhouse Gas Inventories: Technical Considerations and Calculation Methods* (referred to here as the *Uncertainty Document*) was developed as a result, with the purpose of augmenting existing industry guidance and providing technically valid approaches applicable for use by the global oil and natural gas industry to improve GHG emissions estimation robustness and data quality (API, CONCAWE, IPIECA, 2009).

The API *Compendium*, *Guidelines*, and *Uncertainty Document* are complementary; where the API *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), and the *Uncertainty Document* addresses the confidence intervals for the inventory results. Combined, the API *Compendium*, *Guidelines*, and *Uncertainty Document* provide comprehensive guidance for the estimation, accounting, and reporting of oil and natural gas industry GHG emissions.

In addition, API provides (free of charge) the SANGEA™ Emissions Estimating System, an automated, electronic data management information system based on the emission estimation methodologies described in the API *Compendium*. SANGEA™ was designed to assist oil and natural gas companies with estimating, managing, and reporting GHG emissions, and can also be used to track energy consumption and criteria pollutant emissions. SANGEA™ is available at http://ghg.api.org.

1.2 Document Overview

The API *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 API *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 address the estimation of all six GHG species or families of gases (CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6) from oil and natural gas industry operations. This should not imply that emissions of all these GHG compounds are necessarily significant for all emission sources or industry operations, as their presence varies highly and depends on source design and operational practice. The emission estimation approaches presented are believed to be practical for all segments of the oil and natural 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 API *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 product use.

Transparency is a key issue in developing GHG inventory estimates. It is strongly recommended that any estimation approach used should be well annotated, with all input information recorded and careful documentation of the underlying conditions and assumptions. The SANGEA™ calculation tool provided by API may assist in facilitating 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 natural 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 API *Compendium*, *Guidelines*, and *Uncertainty Document* provide guidance for selecting appropriate estimation techniques based on the intended use of the inventory data and the availability of required input data. Beyond regulatory requirements, the use of the information presented in this document is left to the discretion of the user.

1.3 Organization

Section 2 of this API *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 GHG emissions, with a focus on CO_2, CH_4, and N_2O emissions because these are the most relevant to oil and natural gas industry operations. The equipment classification system described in Section 2 is summarized in Table 1-1 and includes the major emission categories, with a representative list of devices that might fall into each of these categories.

Indirect emissions are emissions that are a consequence of activities of the reporting company but which result from sources owned or controlled by another party. All other sources identified in Table 1-1 are considered direct emissions, which result from sources owned or controlled by the reporting company. For transparency, if reported, indirect emissions should be reported separately from direct emissions. More information on the differences and reporting of direct and indirect emissions can be found in the *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions* (IPIECA, 2003).

Table 1-1. Proposed Source Classification Approach[a]

Category	**Principal Sources Include:**
Direct Emissions	
Combustion Sources	
Stationary Devices	Boilers, heaters, furnaces, reciprocating internal combustion engines and turbines, flares, incinerators, and thermal/catalytic oxidizers
Mobile Sources	Barges, ships, railcars, and trucks for material transport; planes/helicopters and other company vehicles for personnel transport; forklifts, all terrain vehicles, construction equipment, and other off-road mobile equipment
Process Emissions and Vented Sources[b,c]	
Process Emissions	Hydrogen plants, amine units, glycol dehydrators, fluid catalytic cracking unit and reformer regeneration, and flexi-coker coke burn
Other Venting	Crude oil, condensate, and oil and natural gas product storage tanks, gas-blanketed water and chemical tanks, underground drain tanks, gas-driven pneumatic devices, gas samplers, chemical injection pumps, exploratory drilling, loading/ballasting/transit, and loading racks
Maintenance/Turnaround	Decoking of furnace tubes, well unloading, vessel and gas compressor depressurizing, compressor starts, gas sampling, and pipeline blowdowns
Non-Routine Activities	Pressure relief valves, PCVs, fuel supply unloading valves, and emergency shut-down devices
Fugitive Sources[d]	
Fugitive Emissions	Valves, flanges, connectors, pumps, compressor seal leaks, and catadyne heaters
Other Non-Point Sources	Wastewater treatment and surface impoundments
Indirect Emissions	
Electricity	Off-site generation of electricity for on-site power
Steam/Heat	Off-site generation of hot water and steam for on-site heat
District Cooling	Off-site gaseous pressurization (compression) for on-site cooling

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

[b] Vented emissions are intentional or designed into the process or technology to occur during normal operations.

[c] The above categories of emissions are broad listings intended to give an indication of the emission sources in the oil and natural gas industry. Note that some regulatory and/or voluntary reporting programs classify the categories differently, including what sources are included under the vented, process, and fugitive categories.

[d] Fugitive emissions can be individually found and “fixed” to make the emissions “near zero.”

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 API *Compendium* contains conversion factors, standard gas conditions, and fuel properties for fuels typically found in the oil and natural gas industry. It also introduces key statistical calculation methods for assessing uncertainty ranges for GHG emissions from applicable sources. A discussion on emission factor quality and inventory accuracy is also provided in Section 3.

Sections 4, 5, and 6 provide the compiled calculation methodologies for direct emission sources: combustion devices, process and operational venting, and fugitive emission 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 natural gas industry. Examples are provided throughout the API *Compendium* to demonstrate calculation methodologies. Examples may be used multiple times throughout the document, and are intended to be as realistic as possible.

Section 7 presents methods that are applicable for estimating indirect GHG emissions from sources that provide power, heat and steam, and cooling. In the case of indirect emissions from power generating activities, the methods rely on average EFs based on national compilation, such as eGrid[2] in the US and the International Energy Agency (IEA) for sources out of the US. The section also describes different methods, recommended by diverse programs, for the allocation of GHG emissions between the power and heat/steam generation aspects of Combined Heat and Power (CHP) installations.

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[2] EPA maintains a database with information from power plants and electricity generators. The database is available at the following website: http://www.epa.gov/cleanenergy/egrid/index.htm (accessed June 19, 2009).

Section 8 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. The results presented also feature the calculated uncertainty ranges in order to demonstrate the implementation of the statistical calculation methods to a facility inventory.

A detailed glossary for the terminology used throughout this compendium is provided following the main report sections. Appendices A, B, C, and D provide additional calculation methodologies and further details for emission sources covered in Sections 4, 5, 6, and 7, respectively. Appendix E provides fuel speciation details to support combustion and non-combustion emission estimation. Appendix F contains an analysis of fugitive CH_4 emissions from refinery 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://www.api.org/ehs/climate/new/upload/2004_COMPENDIUM.pdf, accessed May 1, 2009. [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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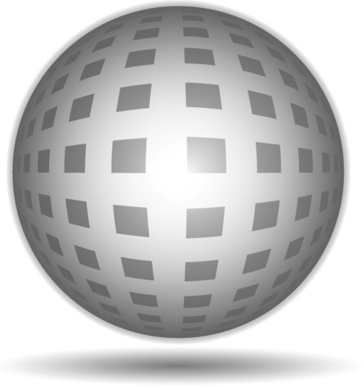
SECTION 2
INDUSTRY DESCRIPTION



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Section 2 – Industry Description

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2.0
INDUSTRY DESCRIPTION

This section presents a description of the oil and natural gas industry and its segments to give some perspective on the potential sources of 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

For the purposes of this document, the oil and natural gas industry 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 natural gas industry that have the potential to emit GHG. Integrated petroleum companies may also have operations associated with energy generation (electricity, heat/steam generation, or cooling), mining and minerals, petrochemical manufacturing, and/or carbon capture and geological storage.

Note: The relative scale of the primary GHGs of interest (CO_2, CH_4, and N_2O) are indicated in Figure 2-1. **Carbon dioxide** and **CH_4** (in bold font) represent the most significant emission sources; CO_2, N_2O and CH_4 (in regular font) represent less significant emission sources. If none are shown, emissions are believed to be negligible. The comparison is based on CO_2 equivalents.

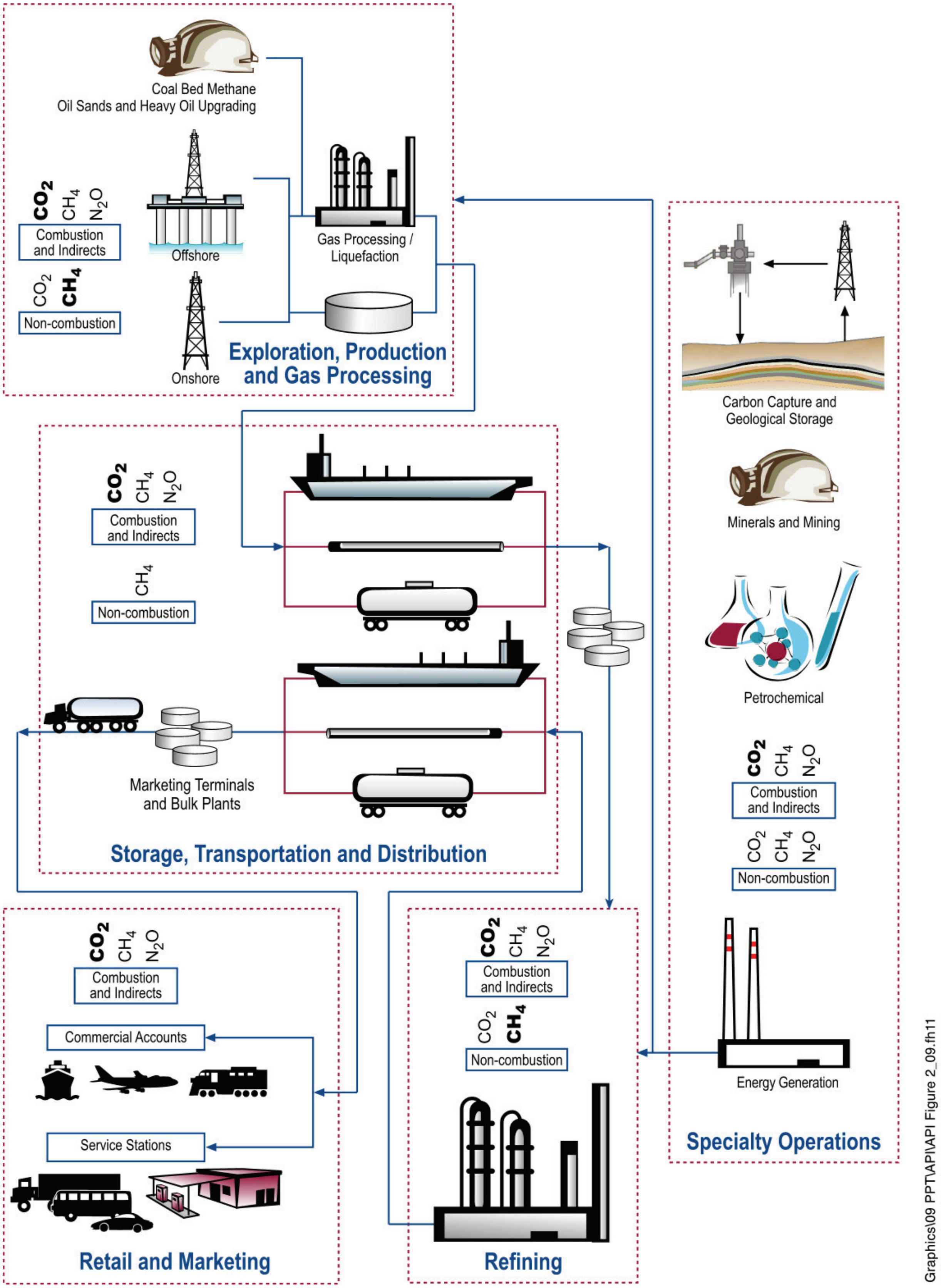

Figure 2-1. Oil and Natural Gas Industry Schematic of GHG Emissions

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. Indirect GHG emissions from external power and heat/steam generation are reported separately from the direct petroleum sector emissions. Additional guidance on accounting for indirect emissions is provided in Sections 3.2.2 and Section 7 of the *Guidelines* (IPIECA, et. al, 2003).

Tables 2-1 through 2-13 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_2, N_2O, and/or CH_4 and reference sections of this document where further details on emission factors and emission calculation methodologies are provided. The sources listed in Tables 2-1 through 2-13 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.

Tables 2-1 through 2-13 also indicate which specific sources of emissions were considered in preparing this document. The "X" is used to designate which GHG species may be emitted from the source identified, for which estimation methodologies are provided in the API *Compendium*. An "*" is listed for some sources of CO_2 emissions in the production segment and CH_4 emissions associated with CCS processes. This is used to note potential sources of CO_2 emissions for those production streams rich in CO_2, such as associated gas from enhanced oil recovery or where CH_4 may be present in gas streams associated with CCS. An approach is provided for these sources, but the significance of CO_2 emissions depends on the CO_2 concentration and the source-specific emission rate.

In addition, SF_6, PFCs, and HFCs are also greenhouse gases with global warming potentials several hundred to several thousand times larger than that of CO_2. Sulfur hexafluoride may be used by oil and natural gas companies that operate electric transmission equipment or as a tracer gas to detect pipeline leaks. As a result of using substitutes for ozone-depleting substances (ODSs), air conditioning (mobile and stationary), refrigeration, and fire suppression equipment are potential sources of HFC and PFC emissions. Although the API *Compendium* provides estimation methods for non-CO_2 emissions, this should not imply that these emissions are necessarily significant.

The diversity of operations associated with the oil and natural gas industry presents a challenge in determining the relative contribution of the many different emission sources. The *Guidelines* document provides some considerations to help the reader use available time and resources effectively (IPIECA, et. al., 2003). In addition, Figure 2-1 and Tables 2-1 through 2-13 present some information on potential prioritization of emission sources.

2.2 Industry Segment Descriptions

In this API *Compendium*, the oil and natural gas industry is divided into the following categories for the purpose of describing applicable emission estimation methodologies:

- Exploration and production;
- Oil sands and heavy oil upgrading;
- Coal bed methane production;
- Gas processing;
- Carbon capture and geological storage;
- Natural gas storage and (liquified natural gas) LNG operations;
- Liquid transportation and distribution;
- Natural gas transmission and distribution;
- Refining;
- Petrochemical manufacturing;
- Minerals and mining operations;
- Retail and marketing; and
- Energy generation (including electricity, heat/steam, and cooling).

For the purpose of this document, the scope of a company's inventory may include any or all of these activities. The following subsections describe emission sources associated with each of these categories of operations.

2.2.1 Conventional Exploration and Production

This segment includes the exploration for and extraction of petroleum from underground reservoirs, located either onshore or offshore. Because oil and natural gas can be produced from the same well, the production segment may include gas handling equipment and processing operations. A 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 exhaust from internal combustion (IC) engines used in drilling operations; the venting or flaring of gas associated with well testing or completions; and mobile source emissions associated with equipment used at the well site and to transport personnel and equipment to/from the site.

If natural gas is available at sufficiently high pressures, it may be used as the motive force to drill wells. In this case, CH_4 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 well annulus. The released gas is most often directed to a flare (resulting primarily in CO_2 emissions), or alternatively vented to the atmosphere (releasing CH_4).

Table 2–1. Potential Greenhouse Gas Emission Sources by Sector: Conventional Exploration and Production

EXPLORATION AND PRODUCTION	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1-4.4, 4.5.1
Dehydrator reboilers	X	X	X	4.1-4.4, 4.5.1
Heaters/treaters	X	X	X	4.1-4.4, 4.5.1
Internal combustion (IC) engine generators	X	X	X	4.1-4.4, 4.5.1
Fire pumps	X	X	X	4.1-4.4, 4.5.2
Reciprocating compressor drivers	X	X	X	4.1-4.4, 4.5.2
Turbine electric generators	X	X	X	4.1-4.4, 4.5.2
Turbine/centrifugal compressor drivers	X	X	X	4.1-4.4, 4.5.2
Well drilling	X	X	X	4.1-4.4, 4.5.2
Flares	X	X	X	4.6
Incinerators	X	X	X	4.7
COMBUSTION SOURCES – Mobile Sources				4.8
Mobile drilling equipment	X	X	X	4.8
Other company vehicles	X	X	X	4.8
Planes/helicopters	X	X	X	4.8
Supply boats, barges	X	X	X	4.8
Site preparation, construction, and excavation	X	X	X	4.8
INDIRECT SOURCES				7.0
Electricity imports	X	X	X	7.1
Process heat/steam imports	X	X	X	7.1
Cogeneration	X	X	X	7.2
VENTED SOURCES – Process Vents				5.0
Dehydration processes			X	5.1
Dehydrator Kimray pumps			X	5.1
Gas sweetening processes	X		X	5.1

Table 2–1. Potential Greenhouse Gas Emission Sources by Sector: Exploration and Production, continued

EXPLORATION AND PRODUCTION	CO_2	N_2O	CH_4	**Section**
VENTED SOURCES – Other Venting				5.3-5.6
Storage tanks and drain vessels	X (*)		X	5.4
Exploratory drilling	X (*)		X	5.6
Well testing and completions	X (*)		X	5.6
Pneumatic devices	X (*)		X	5.6.1
Chemical injection pumps	X (*)		X	5.6.2
Gas sampling and analysis	X (*)		X	5.7.1
VENTED SOURCES – Maintenance/Turnarounds				5.6-5.7
Mud degassing	X (*)		X	5.6.3
Low pressure gas well casing	X (*)		X	5.6.5
Compressor blowdowns	X (*)		X	5.7.2
Compressor starts	X (*)		X	5.7.2
Gathering pipeline blowdowns	X (*)		X	5.7.2
Vessel blowdown	X (*)		X	5.7.2
Well completions	X (*)		X	5.7.2
Well unloading and workovers	X (*)		X	5.7.2
VENTED SOURCES – Non-routine Activities				5.7-5.8
Emergency shutdown (ESD)/ emergency safety blowdown (ESB)	X (*)		X	5.7.2
Pressure relief valves (PRVs)	X (*)		X	5.7.2
Well blowouts (when not flared)	X (*)		X	5.7.2
Fire Suppression				5.8
FUGITIVE SOURCES				6.0
Equipment component leaks	X (*)		X	6.1
Wastewater treatment	X		X	6.2
Air Conditioning/Refrigeration				6.3

Footnotes:
Note that this API *Compendium* uses terms (e.g., "routine," "maintenance," "point source") that may have both a commonplace, non-legal meaning, and a specific, legal meaning. The API *Compendium* uses the commonplace, non-legal meanings for these terms and does not use them in their legal sense.
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.
*Emission estimation approach is provided, but only applicable to CO_2-rich production streams (e.g., CO_2 flood or enhanced oil recovery). Significance of these sources depends on the CO_2 concentration and source-specific emission rate.

A well that reaches an economically viable oil and/or natural gas reservoir may then be completed and put into production. A number of steps are 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_4 and CO_2.

The balance between CH_4 and CO_2 emissions from the wellhead and associated equipment leaks can be quite variable. Most reservoir gas has less than 5% CO_2 (mole percent) and a CH_4 content greater than 80%; however, exceptions do exist. For example, in Canada, most wellhead natural gas is below 90% CH_4. Also, some enhanced oil recovery (EOR) techniques involve injection of CO_2 into the formation, potentially resulting in significantly larger CO_2 emissions than CH_4 from equipment/process vents and fugitive leaks. Carbon dioxide injection, as part of a carbon capture and geological storage (CCS) operation, is addressed in more detail in Section 2.2.5.

Oil/gas separation and gas treatment operations may result in CH_4 losses from oilfield tank vents, dehydrators, amine units, and pneumatic devices. Fugitive equipment leaks may also be a source of CH_4 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 may occur in emergency situations when pressure must be relieved from process vessels and equipment in order to avoid an unsafe condition or catastrophic failure, 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 natural gas production operations are similar to onshore operations. Equipment and process configurations are typically the same, although vented and fugitive CH_4 emission sources are generally smaller than for onshore operations due to tight space confinements on platforms and increased emphasis on personnel safety and risk/loss prevention. 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.

2.2.2 Oil Sands and Heavy Oil Upgrading

This segment includes the non-conventional extraction of heavy oil in the form of bitumen from sand deposits, and the subsequent conversion of the bitumen to synthetic crude oil. Oil sands (sometimes called tar sands) are naturally occurring mixtures of clay, sand, water, and bitumen. Bitumen can be separated from the oil sands through multiple methods: surface mining and extraction, or in-situ recovery. The bitumen is then upgraded, removing carbon and adding hydrogen to produce synthetic crude oil.

Oil sands GHG emission sources vary by operation but can include mining activities (mobile equipment), fine tailings ponds, combustion sources, hydrogen generation, sulfur recovery, and equipment leak sources. A detailed overview of the oil sands and heavy oil upgrading process can be found in the document *CH_4 and VOC Emissions from the Canadian Upstream Oil and Gas Industry Volume 3: Organic and Common-Pollutant Emissions by the Canadian Oilsands Industry and from Heavy Oil Upgrading Facilities* (CAPP, 1999).

A checklist of emission sources for this industry segment is provided in Table 2-2.

Table 2–2. Potential Greenhouse Gas Emission Sources by Sector: Oil Sands and Heavy Oil Upgrading

EXPLORATION AND PRODUCTION	**CO_2**	**N_2O**	**CH_4**	**Section**
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/heaters	X	X	X	4.1-4.4, 4.5.1
Fire pumps	X	X	X	4.1-4.4, 4.5.2
Fire pumps	X	X	X	4.1-4.4, 4.5.2
Internal combustion (IC) engine generators	X	X	X	4.1-4.4, 4.5.2
Reciprocating compressor drivers	X	X	X	4.1-4.4, 4.5.2
Turbine electric generators	X	X	X	4.1-4.4, 4.5.2
Turbine/centrifugal compressor drivers	X	X	X	4.1-4.4, 4.5.2
Turbines	X	X	X	4.1-4.4, 4.5.2
Mining equipment	X	X	X	4.1-4.5
Flares	X	X	X	4.6
Catalytic oxidizers	X			4.7
Incinerators	X	X	X	4.7
COMBUSTION SOURCES – Mobile Sources				4.8
Mining equipment	X	X	X	4.8
Other company vehicles	X	X	X	4.8
Planes/helicopters	X	X	X	4.8
Site preparation, construction, and excavation	X	X	X	4.8
INDIRECT SOURCES				7.0
Electricity imports	X	X	X	7.1
Process heat/steam imports	X	X	X	7.1
VENTED SOURCES – Process Vents				5.0
Flue gas desulfurization process vents	X			5.1.5
Sulfur recovery units	X			5.1.5
Catalytic cracking	X			5.2.1
Catalyst regeneration	X			5.2.1, 5.2.4
Steam methane reforming (hydrogen plants)	X			5.2.2
Delayed coking	X			5.2.3
Flexi-coking	X			5.2.3, 5.2.6
Catalytic reforming	X			5.2.4
Thermal cracking	X			5.2.6
Ventilation and degasification			X	5.3
Ash processing unit			X	5.3
Surface mining			X	NA
VENTED SOURCES – Other Venting				5.3-5.6
Storage tanks			X	5.4
Water tanks			X	5.4.3
Loading racks			X	5.5
Sand-handling			X	5.3
Pneumatic devices			X	5.6.1
Casing gas vents			X	5.6.4, 5.6.5

Table 2–2. Potential Greenhouse Gas Emission Sources by Sector: Oil Sands and Heavy Oil Upgrading, continued

EXPLORATION AND PRODUCTION	**CO_2**	**N_2O**	**CH_4**	**Section**
VENTED SOURCES – Maintenance/Turnarounds				5.7
Compressor blowdowns			X	5.7
Compressor starts			X	5.7
Equipment/process blowdowns			X	5.7
Heater/boiler tube decoking			X	5.7
Vessel blowdown			X	5.7
VENTED SOURCES – Non-routine Activities				5.7-5.8
Emergency shut down (ESD)			X	5.7
Pressure relief valves (PRVs)			X	5.7
Fire suppression				5.8
FUGITIVE SOURCES				6.0
Equipment component leaks	X		X	6.1
Wastewater treatment	X		X	6.1
Sludge/solids handling			X	6.2
Wastewater collection and treating			X	6.2
Air conditioning/refrigeration				6.3
Exposed mine faces			X	NA
Tailing ponds			X	NA

Footnotes:
Note that this API *Compendium* uses terms (e.g., “routine,” “maintenance,” “point source”) that may have both a commonplace, non-legal meaning, and a specific, legal meaning. The API *Compendium* uses the commonplace, non-legal meanings for these terms and does not use them in their legal sense.
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.
NA indicates a souce specific GHG estimation methodology or emission factor is not currently available.

Emissions from oil sands mining operations result from the volatilization of CH_4 entrained in the oil sands during mining and mine dewatering, from exposed mine faces, and during transport and handling of the ore and oil sands. Unlike coal mining, for which emission factors are presented in Section 5, oil sands mining activities currently do not have published emission factors. Site-specific data should be used to account for these emissions.

The largest source of CH_4 emissions from oil sands operations are tailing ponds. The processes resulting in emissions from tailing ponds are currently being studied; however, it appears that the emissions are due to microbial degradation of hydrocarbons in the tailings. As a result, the emissions from tailings ponds are highly site specific. There currently are no emission factors available for estimating emissions from tailings and therefore site specific data or measurements should be used for estimating these emissions.

The processes involved in bitumen upgrading include coking and hydroprocessing; these emission sources are discussed in more detail in Section 2.2.8 (Refining). Upgrading facilities may also have cogeneration and utility plants for which emissions may need to be allocated using a methodology provided in Section 7. Sulfur recovery units or limestone-based flue gas desulfurization plants may also be used to remove sulfur from process streams.

2.2.3 Coal Bed Methane Production

Coal bed methane (CBM) is another method of producing CH_4 (natural gas). The process of coalification, in which swamp vegetation is converted to coal by geological and biological forces, also captures CH_4 in the coal seams and the surrounding rock strata. At the high pressures in the coal seams, the CH_4 either remains adsorbed on the coal surface or is trapped within the coal's porous structure. This CH_4 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. A checklist of possible sources is provided in Table 2-3.

Table 2–3. Potential Greenhouse Gas Emission Sources by Sector: Coal Bed Methane Production

COAL BED METHANE PRODUCTION	CO_2	N_2O	CH_4	**Section**
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1-4.4, 4.5.1
Dehydrator reboilers	X	X	X	4.1-4.4, 4.5.1
Fire pumps	X	X	X	4.1-4.4, 4.5.2
Internal combustion (IC) engines and generators	X	X	X	4.1-4.4, 4.5.2
Reciprocating compressor drivers	X	X	X	4.1-4.4, 4.5.2
Turbine electric generators	X	X	X	4.1-4.4, 4.5.2
Turbine/centrifugal compressor drivers	X	X	X	4.1-4.4, 4.5.2
Flares	X	X	X	4.6
COMBUSTION SOURCES – Mobile Sources				4.8
Mining equipment	X	X	X	4.8
Other company vehicles	X	X	X	4.8
Site preparation, construction, and excavation	X	X	X	4.8
INDIRECT SOURCES				7.0
Electricity imports	X	X	X	7.1
Process heat/steam imports	X	X	X	7.1
VENTED SOURCES – Process Vents				5.0
Dehydration processes			X	5.1
Dehydrator Kimray pump			X	5.1
Gas sweetening processes	X		X	5.1
VENTED SOURCES – Other Venting				5.3-5.6
Water handling, tanks			X	5.4
Coal seam drilling and well testing			X	5.6.6
Coal handling			X	5.6.7

Table 2–3. Potential Greenhouse Gas Emission Sources by Sector: Coal Bed Methane Production, continued

COAL BED METHANE PRODUCTION	CO_2	N_2O	CH_4	Section
VENTED SOURCES – Maintenance/Turnarounds				5.7
Gas sampling and analysis			X	5.7.1
Compressor starts and blowdowns			X	5.7.2
Gathering pipeline blowdowns			X	5.7.2
Vessel blowdowns			X	5.7.2
Well workovers			X	5.7.2
VENTED SOURCES – Non-routine Activities				5.7-5.8
Gathering pipeline leaks			X	5.7.2
Pressure relief valves (PRVs)			X	5.7.2
Well blowdowns (when not flared)			X	5.7.2
Fire suppression				5.8
FUGITIVE SOURCES				6.0
Equipment component leaks			X	6.1
Wastewater treatment	X		X	6.2
Air conditioning/refrigeration				6.3

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

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_4. GHG emissions result from the engines used to drill the production wells. Flaring emissions are not routine but may occur if the natural gas is flared prior to tying into a production facility or due to process upsets.

Emission sources associated with producing CBM are largely the same as those associated with conventional natural gas production. The recovered CBM is separated from other contaminants (e.g., formation water, CO_2) at the surface. Process equipment, such as separators, 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.

2.2.4 Gas Processing

This segment includes processing operations. The checklist of emission sources for this industry segment is provided in Table 2-4.

Table 2–4. Potential Greenhouse Gas Emission Sources by Sector: Processing

PROCESSING	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1-4.4, 4.5.1
Dehydrator reboilers	X	X	X	4.1-4.4, 4.5.1
Heaters/treaters	X	X	X	4.1-4.4, 4.5.1
Fire pumps	X	X	X	4.1-4.4, 4.5.2
Internal combustion (IC) engine generators	X	X	X	4.1-4.4, 4.5.2
Reciprocating compressor drivers	X	X	X	4.1-4.4, 4.5.2
Turbine electric generators	X	X	X	4.1-4.4, 4.5.2
Turbine/centrifugal compressor drivers	X	X	X	4.1-4.4, 4.5.2
Flares	X	X	X	4.6
Catalytic and thermal oxidizers	X			4.7
Incinerators	X	X	X	4.7
COMBUSTION SOURCES – Mobile Sources				4.8
Other company vehicles	X	X	X	4.8
Planes/helicopters	X	X	X	4.8
Supply boats, barges	X	X	X	4.8
INDIRECT SOURCES				7.0
Electricity imports	X	X	X	7.1
Process heat/steam imports	X	X	X	7.1
VENTED SOURCES – Process Vents				5.0
Dehydration processes	X (*)		X	5.1
Dehydrator Kimray pumps	X (*)		X	5.1
Gas sweetening processes	X (*)		X	5.1
Sulfur recovery units	X			5.1.5
VENTED SOURCES – Other Venting				5.3-5.6
Storage tanks and drain vessels	X (*)		X	5.4
Pneumatic devices	X (*)		X	5.6.1
Chemical injection pumps	X (*)		X	5.6.2
VENTED SOURCES – Maintenance/Turnarounds				5.7
Gas sampling and analysis	X (*)		X	5.7.1
Compressor blowdowns	X (*)		X	5.7.3
Compressor starts	X (*)		X	5.7.3
Vessel blowdown	X (*)		X	5.7.3
VENTED SOURCES – Non-routine Activities				5.7-5.8
Emergency shutdown (ESD)/ emergency safety blowdown (ESB)	X (*)		X	5.7.3
Pressure relief valves (PRVs)	X (*)		X	5.7.3
Fire suppression				5.8
FUGITIVE SOURCES				6.0
Equipment component leaks	X (*)		X	6.1
Wastewater treatment	X		X	6.2
Air conditioning/refrigeration				6.3

Footnotes:

X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

*Emission estimation approach is provided, but only applicable to CO_2-rich streams. Significance of these sources depends on the CO_2 concentration and source-specific emission rate.

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_4 emissions. Fugitive equipment leaks are also a source of CH_4 emissions. Combustion sources, such as boilers, heaters, engines, and flares result in CO_2 emissions, as well as smaller quantities of N_2O and CH_4 emissions.

Offshore operations may include oil and natural gas processing.

2.2.5 Carbon Capture and Geological Storage

Carbon dioxide capture and geological storage refers to the chain of processes used to collect or capture a CO_2 gas stream, transport the CO_2 to a storage location, and inject the CO_2 into a geological formation[1] for long-term isolation from the atmosphere.

In the capture step, CO_2 is separated from other gaseous products, compressed to facilitate efficient transportation, and when necessary, conditioned for transport (e.g., by dehydration). Captured CO_2 is then transported from the point of capture to the storage site. Pipelines are the most common method for transporting CO_2; however, bulk transport of CO_2 by ship, truck, and rail occurs on a much smaller scale. Once at the storage site, the CO_2 may be additionally compressed and then injected into the storage reservoir. Carbon dioxide is retained in geologic structural and stratigraphic traps (e.g., depleted oil and natural gas reservoirs without enhanced hydrocarbon recovery).

Emissions from CCS activities may occur during each of the CCS phases. The operations associated with the capture phase require the use of energy (fossil fuel consumption and/or purchased electricity), resulting in combustion and/or indirect emissions. Vented and fugitive emissions may result from equipment used as part of the capture process. A small amount of emissions may also be released in the form of residual (uncaptured) CO_2 and CH_4. Transportation-related process losses may occur either as fugitive equipment leaks or as evaporative losses during maintenance, emergency releases, intermediate storage, and loading/offloading. Combustion or indirect emissions will also occur from energy consumption to compress and move the CO_2 between the capture and storage locations. Storage emissions include vented, fugitive, combustion, and indirect emissions from equipment and associated energy requirements at the injection site. In addition, emissions may result from physical leaks from the storage site, uncaptured CO_2 co-produced with oil and/or gas, and enhanced hydrocarbon recovery operations.

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[1] For the purpose of this API *Compendium,* geological storage reservoirs explicitly exclude ocean sequestration.

Nitrous oxide and CH_4 emissions may also occur from the operation of combustion-driven equipment and purchased electricity. Table 2-5 provides a checklist of emission sources associated with CCS processes.

Table 2–5. Potential Greenhouse Gas Emission Sources by Sector: Carbon Capture and Geological Storage

CCS	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1-4.4, 4.5.1
Dehydrator reboilers	X	X	X	4.1-4.4, 4.5.1
Heaters/treaters	X	X	X	4.1-4.4, 4.5.1
Fire pumps	X	X	X	4.1-4.4, 4.5.2
Internal combustion (IC) engine generators	X	X	X	4.1-4.4, 4.5.2
Reciprocating compressor drivers	X	X	X	4.1-4.4, 4.5.2
Turbine/centrifugal compressor drivers	X	X	X	4.1-4.4, 4.5.2
Turbine electric generators	X	X	X	4.1-4.4, 4.5.2
Well drilling	X	X	X	4.1-4.4, 4.5.2
Flares	X	X	X	4.6
Incinerators	X	X	X	4.7
COMBUSTION SOURCES – Mobile Sources				4.8
Marine, road or railroad tankers	X	X	X	4.8
Other company vehicles	X	X	X	4.8
Planes/helicopters	X	X	X	4.8
INDIRECT SOURCES				7.0
Electricity imports	X	X	X	7.1
VENTED SOURCES – Process Vents				5.0
Dehydration processes	X		X (*)	5.1
Dehydrator Kimray pumps	X		X (*)	5.1
Gas sweetening processes	X		X (*)	5.1
VENTED SOURCES – Other Venting				5.3-5.6
Intermediate storage	X		X (*)	5.4
Storage tanks	X		X (*)	5.4
Loading/unloading/transit	X		X (*)	5.5
Pneumatic devices	X		X (*)	5.6.1
Chemical injection pumps	X		X (*)	5.6.2
VENTED SOURCES – Maintenance/Turnarounds				5.7
Maintenance	X		X (*)	5.7
Gas sampling and analysis	X		X (*)	5.7.1
Compressor blowdowns	X		X (*)	5.7.2
Compressor starts	X		X (*)	5.7.2
Pipeline blowdowns	X		X (*)	5.7.2
Vessel blowdown	X		X (*)	5.7.2
VENTED SOURCES – Non-routine Activities				5.7-5.8
Emergency releases	X		X (*)	5.7
Fire suppression				5.8

Table 2–5. Potential Greenhouse Gas Emission Sources by Sector: Carbon Capture and Geological Storage, continued

CCS	**CO_2**	**N_2O**	**CH_4**	**Section**
FUGITIVE SOURCES				6.0
Well leakage	X		X (*)	6.1
Equipment and pipeline leaks	X		X (*)	6.1
Wastewater treatment	X		X (*)	6.2
Air conditioning/refrigeration				6.3
Fugitive emissions from ships	X		X (*)	NA
Physical leakage from geological formations	X		X (*)	NA

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.
* Significance of these sources depends on the CH_4 concentration and source-specific emission rate.

2.2.6 Natural Gas Storage and LNG Operations

Natural gas storage facilities are used to store natural gas produced during off-peak times (usually summer) so that gas can be delivered during peak demand. Storage facilities can be below or above ground. Above ground facilities liquefy the gas by super cooling and then storing the LNG in heavily insulated tanks. Below-ground facilities compress and store natural gas in the vapor phase in one of several formations: 1) spent gas production fields, 2) aquifers, or 3) salt caverns.

Of the approximate 113 active LNG facilities in the United States, 57 are peak-shaving facilities (IELE, 2003). The other LNG facilities include marine terminals (eight import terminals and one export terminal in the U.S.), storage facilities, and operations involved in niche markets such as LNG vehicle fuel. Worldwide, there are 17 LNG export (liquefaction) terminals and 40 import (regasification) terminals (IELE, 2003).

LNG is commonly transported long distances in double-hulled ships specifically designed to handle the low temperature of LNG. These carriers are insulated to limit the amount of LNG that boils off or evaporates. This boil-off gas is sometimes used to supplement fuel for the carriers. Worldwide, 136 ships currently transport more than 120 million metric tons of LNG every year. (IELE, 2003).

During ship unloading operations, a portion of the boil-off gas is returned to the ship to compensate for the volume of liquid pumped out to maintain the ship's tank pressure. Boil-off gas that is not returned to the ship is compressed, condensed by direct contact with LNG, and then combined with the send-out natural gas prior to being pumped up to pipeline pressure in the send-out pumps.

When LNG is received at a terminal, it is transferred to double-walled, insulated storage tanks that are built specifically to hold LNG. These tanks can be found above or below ground and keep the liquid at a low temperature to minimize the amount of evaporation. If tank LNG vapors are not released, the pressure and temperature within the tank will continue to rise. LNG is characterized as a cryogen, a liquefied gas kept in its liquid state at very low temperatures. The temperature within the tank remains nearly constant if the pressure is kept constant by allowing the boil off gas to escape from the tank. This is known as auto-refrigeration. The boil-off gas is collected and used as a fuel source in the facility or on the tanker transporting/ unloading it. When natural gas is needed, the LNG is warmed to a point where it converts back to its gaseous state. This is accomplished using a regasification process involving heat exchangers.

Table 2-6 lists potential emission sources associated with natural gas storage and LNG operations. Methane emission factors for LNG vents and fugitive sources are not well developed. LNG systems are designed to avoid contact with the outside air, which would gasify the LNG. Thus, great effort is taken to prevent vented and fugitive losses. Vapor recovery systems are used to capture boil-off gas and re-route it for use as a fuel or to the send-out natural gas pipeline. In an emergency, flares are available to burn the CH_4 rather than release it to the atmosphere. Once the CH_4 is vaporized, emission factors applicable to natural gas storage or pipeline operations apply.

Table 2–6. Potential Greenhouse Gas Emission Sources by Sector: Natural Gas Storage and LNG Operations

Natural Gas Storage and LNG Operations	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1-4.4, 4.5.1
Dehydrator reboilers	X	X	X	4.1-4.4, 4.5.1
Heaters and heat exchangers	X	X	X	4.1-4.4, 4.5.1
Fire pumps	X	X	X	4.1-4.4, 4.5.2
Internal combustion (IC) engine generators	X	X	X	4.1-4.4, 4.5.2
Pump engines	X	X	X	4.1-4.4, 4.5.2
Reciprocating compressor drivers	X	X	X	4.1-4.4, 4.5.2
Turbine electric generators	X	X	X	4.1-4.4, 4.5.2
Turbine/centrifugal compressor drivers	X	X	X	4.1-4.4, 4.5.2
Flares	X	X	X	4.6
Catalyst and thermal oxidizers	X			4.7
Incinerators	X	X	X	4.7
Vapor combustion units (VCU)	X			4.7

Table 2–6. Potential Greenhouse Gas Emission Sources by Sector: Natural Gas Storage and LNG Operations, continued

Natural Gas Storage and LNG Operations	CO_2	N_2O	CH_4	**Section**
COMBUSTION SOURCES – Mobile Sources				4.8
Marine vessels	X	X	X	4.8
Other company vehicles	X	X	X	4.8
INDIRECT SOURCES				7.0
Electricity imports	X	X	X	7.1
Process heat/steam imports	X	X	X	7.1
VENTED SOURCES – Process Vents				5.0
Dehydration processes			X	5.1
Dehydrator Kimray pumps			X	5.1
Gas treatment processes	X		X	5.1
VENTED SOURCES – Other Venting				5.3-5.6
Gas sampling and analysis			X	5.3
LNG cold box			X	5.3
Gas sampling and analysis			X	5.3
Revaporization			X	5.34
VENTED SOURCES – Other Venting, continued				5.3-5.6
Storage tanks			X	5.4
Loading/unloading/transit			X	5.5
Pneumatic devices			X	5.6.1
Chemical injection pumps			X	5.6.2
Chemical injection pumps			X	5.6.2
VENTED SOURCES – Maintenance/Turnarounds				5.7
Compressor blowdowns			X	5.7.4
Compressor starts			X	5.7.4
Pipeline blowdowns			X	5.7.4
Vessel blowdown			X	5.7.4
Compressor station venting			X	5.7.4
Storage station venting			X	5.7.4
VENTED SOURCES – Non-routine Activities				5.7-5.8
Emergency shutdown (ESD)/ emergency safety blowdown (ESB)			X	5.7.4
Pressure relief valves (PRVs)			X	5.7.4
Fire suppression				5.8
FUGITIVE SOURCES				6.0
Pipeline leaks			X	6.1
Process equipment leaks			X	6.1
Storage wellheads			X	6.1
Vapor handling system			X	6.1
Wastewater treatment	X		X	6.2
Air conditioning/refrigeration				6.3

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

2.2.7 Transportation and Distribution

The transportation and distribution segment consists of the movement of crude and associated gas from the production segment to refineries. It also includes the movement of natural gas or petroleum products to market or distribution centers. Emission sources for transportation and distribution are shown in Tables 2-7 and 2-8 for liquid petroleum products and natural gas, respectively. Emission sources include loading and unloading of tank trucks, rail cars, and marine vessels; and transit losses from truck, marine, rail, and pipeline 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_4 emissions result from product losses. The primary potential for CH_4 emissions is from handling ‘live’ crude oil (crude oil which has not yet reached atmospheric pressure), produced gas, and natural gas. Transportation of ‘live’ crude oil and produced gas should be accounted for through the use of gathering pipelines, which are addressed in Section 2.2.1, Conventional Exploration and Production. Table 2-7 addresses transportation of other liquid products. However, most refined products and ’weathered’ crude oil do not contain CH_4, as shown by the compositions presented in Appendix E. Table 2-8 addresses the transportation of natural gas. Transportation of liquefied natural gas is addressed in Section 2.2.6, Natural Gas Storage and LNG Operations.

Emissions of CO_2 and significantly smaller quantities of N_2O 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 small amounts of unburned CH_4 emissions when natural gas is used to fire the IC engines or turbines.

In addition, SF_6 emissions may occur if SF_6 is used as a tracer gas to detect pipeline leaks. On a CO_2 equivalent basis, these may be a large emission source for some pipeline operations.

Table 2–7. Potential Greenhouse Gas Emission Sources by Sector: Liquid Transportation and Distribution

LIQUID TRANSPORTATION AND DISTRIBUTION	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES – Stationary				4.0
Reciprocating compressor drivers	X	X	X	4.1
Turbine electric generators	X	X	X	4.1
Turbine/centrifugal compressor drivers	X	X	X	4.1
Boilers/steam generators	X	X	X	4.1-4.4, 4.5.1
Heaters	X	X	X	4.1-4.4, 4.5.1
Fire pumps	X	X	X	4.1-4.4, 4.5.2
Internal combustion (IC) engine generators	X	X	X	4.1-4.4, 4.5.2
Pumps	X	X	X	4.1-4.4, 4.5.2
Flares	X	X	X	4.6
Catalyst and thermal oxidizers	X	X		4.7
Incinerators	X	X		4.7
Vapor combustion units	X	X	X	4.7
COMBUSTION SOURCES – Mobile Sources				4.8
Barges	X	X	X	4.8
Marine, road, or railroad tankers	X	X	X	4.8
Other company vehicles	X	X	X	4.8
Planes/helicopters	X	X	X	4.8
INDIRECT SOURCES				7.0
Electricity imports	X	X	X	7.1
Process heat/steam imports	X	X	X	7.1
VENTED SOURCES – Process Vents				5.0
Storage tanks			X	5.4
Loading/unloading/transit			X	5.5
Pneumatic devices			X	5.6.1
VENTED SOURCES – Maintenance/Turnarounds				5.7-5.8
Pump station maintenance			X	5.7.4
VENTED SOURCES – Non-Routine Activities				5.7-5.8
Breakout/surge tanks			X	5.7.4
Fire suppression				5.8
FUGITIVE SOURCES				6.0
Pipeline leaks			X	6.1
Process equipment leaks			X	6.1
Wastewater treatment	X		X	6.2
Air conditioning/refrigeration				6.3
Leak detection (SF_6 Emissions)				6.3.3

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

Table 2–8. Potential Greenhouse Gas Emission Sources by Sector: Natural Gas Transmission and Distribution

NATURAL GAS TRANSMISSION AND DISTRIBUTION	**CO_2**	**N_2O**	**CH_4**	**Section**
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1-4.4, 4.5.1
Dehydrator reboilers	X	X	X	4.1-4.4, 4.5.1
Heaters	X	X	X	4.1-4.4, 4.5.1
Fire pumps	X	X	X	4.1-4.4, 4.5.2
Internal combustion (IC) engine generators	X	X	X	4.1-4.4, 4.5.2
Reciprocating compressor drivers	X	X	X	4.1-4.4, 4.5.2
Turbine electric generators	X	X	X	4.1-4.4, 4.5.2
Turbine/centrifugal compressor drivers	X	X	X	4.1-4.4, 4.5.2
Flares	X	X	X	4.6
Catalyst and thermal oxidizers	X			4.7
Incinerators	X	X	X	4.7
COMBUSTION SOURCES – Mobile Sources				4.8
Other company vehicles	X	X	X	4.8
Planes/helicopters	X	X	X	4.8
INDIRECT SOURCES				7.0
Electricity imports	X	X	X	7.1
Process heat/steam imports	X	X	X	7.1
VENTED SOURCES – Process Vents				5.0
Dehydration processes			X	5.1
Dehydrator Kimray pumps			X	5.1
Gas treatment processes	X		X	5.1
VENTED SOURCES – Other Venting				5.3-5.6
Gas sampling and analysis			X	5.3
Storage tanks			X	5.4
Loading/unloading/transit			X	5.5
Pneumatic devices			X	5.6.1
Chemical injection pumps			X	5.6.2
VENTED SOURCES – Maintenance/Turnarounds				5.7
Compressor blowdowns			X	5.7.4
Compressor starts			X	5.7.4
Compressor station blowdowns			X	5.7.4
Pig traps and drips			X	5.7.4
Vessel blowdown			X	5.7.4
Pipeline blowdowns			X	5.7.4, 5.7.5
VENTED SOURCES – Non-routine Activities				5.7-5.8
Metering and Pressure Regulating (M&R) station upsets			X	5.7.4, 5.7.5
Pressure relief valves (PRVs)			X	5.7.4, 5.7.5
Pipeline dig-ins			X	5.7.5
Fire suppression				5.8

Table 2–8. Potential Greenhouse Gas Emission Sources by Sector: Natural Gas Transmission and Distribution, continued

NATURAL GAS TRANSMISSION AND DISTRIBUTION	CO_2	N_2O	CH_4	Section
FUGITIVE SOURCES				6.0
Pipeline leaks			X	6.1
Process equipment leaks			X	6.1
Wastewater treatment			X	6.2
Air conditioning/refrigeration				6.3

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

2.2.8 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 2-9 provides a checklist of potential GHG emission sources for the refining segment. Greenhouse gas 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 those of CO_2. When these combustion sources are fired with natural gas or refinery fuel gas, there may also be trace quantities of unburned CH_4 emissions.

The natural gas system, and potentially the refinery fuel gas system, are the only process streams within the refinery with potentially significant CH_4 concentrations. Fugitive CH_4 emissions may result from the piping and components associated with these systems and the combustion equipment fired by these fuels. Results from an API study on fugitive emissions from refinery fuel gas systems indicate that these emissions appear to be negligible.[2] The results from this study are presented in Appendix F.

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[2] Methane emissions data gathering and analyses were conducted for two refineries: a small simple refinery and a larger, more complex refinery. The estimated CH_4 fugitive emissions represent about 0.11% of the total GHG inventory for the small/simple refinery and about 0.19% of the GHG inventory for the large/complex refinery.

A number of specialized process vents also 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_2 emissions, although there could be some unburned CH_4 if supplemental fuel is fired in a CO boiler. The hydrogen plant vent is primarily a source of CO_2 emissions, as are other catalyst regeneration vents.

Table 2–9. Potential Greenhouse Gas Emission Sources by Sector: Refining

REFINING	**CO_2**	**N_2O**	**CH_4**	**Section**
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1-4.4, 4.5.1
Heaters	X	X	X	4.1-4.4, 4.5.1
Fire pumps	X	X	X	4.1-4.4, 4.5.2
Internal combustion (IC) engine generators	X	X	X	4.1-4.4, 4.5.2
Pumps	X	X	X	4.1-4.4, 4.5.2
Reciprocating compressor drivers	X	X	X	4.1-4.4, 4.5.2
Turbine electric generators	X	X	X	4.1-4.4, 4.5.2
Turbine/centrifugal compressor drivers	X	X	X	4.1-4.4, 4.5.2
Flares	X	X	X	4.6
Catalyst and thermal oxidizers	X			4.7
Incinerators	X	X	X	4.7
Coke calcining kilns	X	X	X	4.7
COMBUSTION SOURCES – Mobile Sources				4.8
Company vehicles	X	X	X	4.8
INDIRECT SOURCES				7.0
Electricity imports	X	X	X	7.1
Process heat/steam imports	X	X	X	7.1
VENTED SOURCES – Process Vents				5.0
Sulfur recovery units	X			5.1.5
Catalytic cracking	X			5.2.1
Catalytic reforming	X			5.2.1
Catalyst regeneration	X			5.2.1, 5.2.4
Steam methane reforming (hydrogen plants)	X			5.2.2
Delayed coking	X			5.2.3
Flexi-coking	X			5.2.3
Asphalt production			X	5.2.5
Thermal cracking	X			5.2.6
VENTED SOURCES – Other Venting				5.3-5.6
Storage tanks				5.4
Loading racks				5.5
Pneumatic devices				5.6.1

Table 2–9. Potential Greenhouse Gas Emission Sources by Sector: Refining, continued

REFINING	CO_2	N_2O	CH_4	Section
VENTED SOURCES – Maintenance/Turnarounds				5.7
Compressor starts				5.7.6
Equipment/process blowdowns				5.7.6
Heater/boiler tube decoking	X			5.7.6
VENTED SOURCES – Non-routine Activities				5.7-5.8
Emergency shut down (ESD)				5.7.6
Pressure relief valves (PRVs)				5.7.6
Fire suppression				5.8
FUGITIVE SOURCES				6.0
Fuel gas system leaks			X	6.1
Other process equipment leaks				6.1
Sludge/solids handling				6.2.1
Wastewater collection and treating	X		X	6.2.1
Air conditioning/refrigeration				6.3

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

2.2.9 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 2-10, are similar to those of the refining segment.

Table 2–10. Potential Greenhouse Gas Emission Sources by Sector: Petrochemical Manufacturing

PETROCHEMICAL MANUFCTURING	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1-4.4, 4.5.1
Heaters	X	X	X	4.1-4.4, 4.5.1
Fire pumps	X	X	X	4.1-4.4, 4.5.2
Internal combustion (IC) engine generators	X	X	X	4.1-4.4, 4.5.2
Pumps	X	X	X	4.1-4.4, 4.5.2
Reciprocating compressor drivers	X	X	X	4.1-4.4, 4.5.2
Turbine electric generators	X	X	X	4.1-4.4, 4.5.2
Turbine/centrifugal compressor drivers	X	X	X	4.1-4.4, 4.5.2
Flares	X	X	X	4.6
Catalyst and thermal oxidizers	X			4.7
Incinerators	X	X	X	4.7

Table 2–10. Potential Greenhouse Gas Emission Sources by Sector: Petrochemical Manufacturing, continued

PETROCHEMICAL MANUFCTURING	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES – Mobile Sources				4.8
Company vehicles	X	X	X	4.8
INDIRECT SOURCES				7.0
Electricity imports	X	X	X	7.1
Process heat/steam imports	X	X	X	7.1
VENTED SOURCES – Process Vents				5.0
Catalyst regeneration	X			5.2.1, 5.2.4
Steam methane reforming (hydrogen plants)	X			5.2.2
Chemical production	X	X	X	5.6.8
VENTED SOURCES – Other Venting				5.3-5.6
Storage tanks			X	5.4
Loading racks			X	5.5.1
Pneumatic devices				5.6.1
VENTED SOURCES – Maintenance/Turnarounds				5.7
Compressor starts				5.7.6
Equipment/process blowdowns				5.7.6
Heater/boiler tube decoking				5.7.6
VENTED SOURCES – Non-routine Activities				5.7-5.8
Emergency shut down (ESD)				5.7.6
Pressure relief valves (PRVs)				5.7.6
Fire suppression				5.8
FUGITIVE SOURCES				6.0
Fuel gas system leaks			X	6.1
Other process equipment leaks				6.1
Sludge/solids handling				6.2
Wastewater collection and treating	X		X	6.2
Air conditioning/refrigeration				6.3

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

Fossil fuel combustion is the most significant source of GHG emissions from chemical manufacturing, primarily resulting in CO_2 emissions. Trace quantities of N_2O 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_2O combustion emissions than observed at refinery processes. Trace quantities of CH_4 also might be released from combustion equipment as a product of incomplete fuel combustion.

As in refineries, when natural gas or plant fuel gas is used to fuel the combustion devices, CH_4 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_4 are present in other process streams. In some circumstances, CH_4 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 API *Compendium* provides CH_4 emission factors associated with the production of five chemicals: carbon black, ethylene, ethylene dichloride, styrene, and methanol, based on national GHG inventory data (EPA, 2009). In addition, N_2O emission factors are provided for nitric oxide production and adipic acid production.

2.2.10 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 Section 2.2.3, 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 2-11 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_2 and trace amounts of CH_4 and N_2O). 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.

Table 2–11. Potential Greenhouse Gas Emission Sources by Sector: Minerals and Mining Operations

MINERALS AND MINING OPERATIONS	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES – Stationary Devices				4.0
Boilers/steam generators	X	X	X	4.1-4.4, 4.5.1
Heaters	X	X	X	4.1-4.4, 4.5.1
Fire pumps	X	X	X	4.1-4.4, 4.5.2
Internal combustion (IC) engines	X	X	X	4.1-4.4, 4.5.2
Turbines	X	X	X	4.1-4.4, 4.5.2
Flares	X	X	X	4.6
Catalytic oxidizers	X			4.7
Incinerators	X	X	X	4.7

Table 2–11. Potential Greenhouse Gas Emission Sources by Sector: Minerals and Mining Operations, continued

MINERALS AND MINING OPERATIONS	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES – Mobile Sources				4.8
Mining equipment	X	X	X	4.8
Other company vehicles	X	X	X	4.8
Site preparation, construction, and excavation	X	X	X	4.8
INDIRECT SOURCES				7.0
Electricity imports	X	X	X	7.1
Process heat/steam imports	X	X	X	7.1
VENTED SOURCES – Process Vents				5.0
Surface mining			X	5.6
Ventilation and degasification			X	5.6
VENTED SOURCES – Other Venting				5.3-5.6
Water tanks			X	5.4
Coal seam drilling and well testing			X	5.6.6
Coal-handling			X	5.6.6, 5.6.7
VENTED SOURCES – Non-routine Activities				5.8
Fire suppression				5.8
FUGITIVE SOURCES				6.0
Equipment and pipeline leaks	X		X	6.1
Wastewater treatment			X	6.2
Air conditioning/refrigeration				6.3

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

For coal mining, three types of activities release CH_4 to the atmosphere: underground mining, surface mining, and coal handling processes. Where mining gases are not recovered, CH_4 emissions from underground coal mines can be significant. Ventilation and degasification systems are used in underground mining to reduce CH_4 concentrations to safe levels by exhausting CH_4 to the atmosphere. Surface coal mining also releases CH_4 to the atmosphere as the coal is exposed, though the emissions are generally much lower than from underground mines. Finally, a portion of the CH_4 retained in the coal after mining may be 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 those described for coal mining if CH_4 deposits are present.

2.2.11 Retail and Marketing

The retail and marketing segment includes company-owned retail operations and support to customer fueling operations. A checklist of potential GHG emission sources is provided in Table 2-12.

Table 2–12. Potential Greenhouse Gas Emission Sources by Sector: Retail and Marketing

RETAIL AND MARKETING	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES - Stationary				4.0
Boilers/steam generators	X	X	X	4.1-4.4, 4.5.1
Heaters	X	X	X	4.1-4.4, 4.5.1
Thermal oxidizers	X			4.76
COMBUSTION SOURCES – Mobile Sources				4.8
Marine tankers	X	X	X	4.8
Other company vehicles	X	X	X	4.8
Railroad tankers	X	X	X	4.8
Road tankers	X	X	X	4.8
INDIRECT SOURCES				7.0
Electricity usage	X	X	X	7.1
VENTED SOURCES				5.0
Service station storage tanks				5.4
VENTED SOURCES – Non-routine Activities				5.8
Fire suppression				5.8
FUGITIVE SOURCES				6.0
Process equipment leaks				6.1
Air conditioning/refrigeration				6.3

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

Evaporative emissions of hydrocarbons may occur during fuel transfer or pumping activities, but the concentration of CH_4 or other GHGs is negligible in the refined products as shown by the compositions presented in Appendix E. Therefore, there generally are no significant GHG emissions from these activities. Methane emissions may result from process equipment leaks associated with LNG or compressed natural gas (CNG) marketing. Indirect emissions associated with onsite electricity usage are a source of CO_2, N_2O, and CH_4 emissions.

2.2.12 Energy Generation

Oil and natural gas industry operations are energy intensive, requiring steady supplies of electricity and often process heat, steam, or cooling. 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 energy generation operations are shown in Table 2-13. Combustion emissions of CO_2, and to a lesser extent N_2O and CH_4, result from the burning of fossil fuels to operate turbines, boilers, or compressors. Where natural gas is used to generate energy, emissions of CH_4 may result from process vents and fugitive sources, though these emissions are generally small compared to the combustion sources.

Table 2–13. Potential Greenhouse Gas Emission Sources by Sector: Electricity and Heat/Steam Generation

ELECTRICITY AND HEAT/STEAM GENERATION	CO_2	N_2O	CH_4	Section
COMBUSTION SOURCES - Stationary				4.0
Turbine electric generators	X	X	X	4.1-4.4, 4.5.1
Boilers/steam generators	X	X	X	4.1-4.4, 4.5.2
Internal combustion (IC) engine generators	X	X	X	4.1-4.4, 4.5.2
COMBUSTION SOURCES – Mobile Sources				4.8
Company vehicles	X	X	X	4.8
VENTED SOURCES				5.0
Natural gas venting (maintenance on fuel line to natural gas fuel sources)	X		X	5.7.1
VENTED SOURCES – Other Venting				5.3-5.6
Fire suppression				5.8
FUGITIVE SOURCES				6.0
Natural gas equipment leaks (natural gas fuel line)	X		X	6.1.3
Air conditioning/refrigeration				6.3

Footnotes:
X Indicates if CO_2, CH_4, or N_2O emissions may result from the source.

As mentioned previously, SF_6 may be used as an insulator in electrical transmission and distribution systems. Fugitive and process vent emissions of SF_6 can occur from leaks or service activities on gas-insulated substations, circuit breakers, and other switchgear. Fugitive emissions of SF_6 can escape from gas-insulated equipment through seals, especially from older equipment. Sulfur hexafluoride can also be released during equipment manufacturing, installation, servicing, and disposal. Despite the very high global warming potential of SF_6, the quantities released as a result of oil and natural gas industry operations generally are very small.

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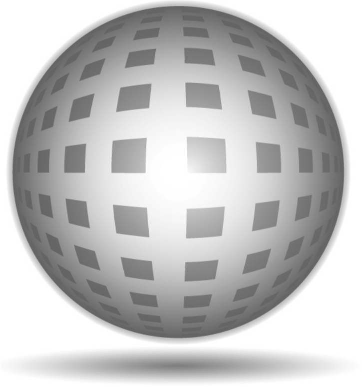
AMERICAN PETROLEUM INSTITUTE

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

AUGUST 2009

SECTION 3
TECHNICAL CONSIDERATIONS



Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry

Section 3 – Technical Considerations

August 2009

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3.0
TECHNICAL CONSIDERATIONS

3.1 Overview

In general, 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:

$$\text{Emission Inventory} = \sum_{i=1}^{\#\,\text{sources}} \text{EF}_i \times \text{AF}_i \qquad \text{(Equation 3-1)}$$

where

Emissions Inventory = total emissions for a company or facility;

EF_i = emission factor for source *i*; and

AF_i = activity factor for source *i*.

Throughout this document it is important to note 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 conventions are 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 pounds per square inch (psia) and 60 degrees Fahrenheit (°F) (equivalent to 101.325 kilo-Pascals absolute (kPaa) and 15.6 degrees Celsius (°C) in metric units). This is equivalent to 379.3 standard cubic feet (scf)/lb-mole (836.2 scf/kg-mole) or 23,685 cubic centimeters (cm^3)/g-mole.
- Heating Value Specifications—When converting between fuel volume and energy, HHV or gross calorific value is the preferred convention. However, LHV or net calorific values are also reported.
- Units—Throughout this document, units are presented in the same convention used in 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[1] per unit of activity, where the unit of activity is expressed in both the International System of Units (SI units) and

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[1] Metric tonne = 1000 kg = 2204.62 lb.

U.S. customary units (USC). Conversion factors are provided in Table 3-4 if other units are desired.

- Fuel Combustion—Fuel properties in terms of heating values and carbon content are provided for a variety of fuels in commerce. Carbon dioxide emissions associated with the combustion of fossil fuels or refined products are based on the conversion of 100% of the fuel carbon to CO_2.

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

3.2 Emission Sources

Emissions of GHG in the oil and natural gas industry typically occur from one of the following general source classes: 1) combustion sources, including both stationary devices and mobile equipment; 2) process emissions and vented sources; 3) fugitive sources; and 4) indirect sources. Some pieces of equipment, such as compressors, may emit under multiple classes − fugitive emissions when pressurized, vented emissions when depressurized for maintenance, and combustion emissions from the driver engines during normal operations. Tables 2-1 through 2-13, 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, flares, and incinerators results in the formation of CO_2 due to the oxidation of carbon. 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. Very small quantities of N_2O may be formed during fuel combustion by reaction of nitrogen and oxygen. Methane may also be released in exhaust gases as a result of incomplete fuel combustion.

3.2.2 Process Emissions and Vented Sources

Vented sources occur as releases resulting from normal operations, maintenance and turnaround activities, and emergency and other non-routine events. These include sources such as crude oil, condensate, oil, and gas product storage tanks; blanket fuel gas from produced water or chemical storage tanks; loading/ballasting/transit sources, and loading racks; as well as equipment such as chemical injection pumps and pneumatic devices that release GHGs (CH_4 and potentially CO_2) 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, hydrogen plants (often referred to as steam reformers), naphtha reformers, 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 may result in vented emissions. Similarly, GHG emissions may result from equipment startup activities or from purging equipment prior to repressurization. Examples of other maintenance or turnaround activities classified as venting sources are 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 (PRV), and breakout/surge tanks (described in Section 5.7.4).

3.2.3 Fugitive Sources

Fugitive emissions are unintentional releases from piping components and equipment leaks at sealed surfaces, as well as from underground pipeline leaks. Fugitive emissions are usually low-volume 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 components and fittings such as valves, flanges, pump seals, compressor seals, PRVs, or sampling connections. Fugitive emissions also include non-point evaporative sources such as from wastewater treatment, pits, and impoundments.

3.2.4 Indirect Sources

Indirect emissions are emissions that are a consequence of activities of the reporting company but which result from sources owned or controlled by another party (IPIECA, 2003). This category includes emissions from the combustion of hydrocarbon fuels to generate electricity, heat, steam, or cooling, where this energy is imported or purchased.

3.3 Greenhouse Gases

This document is focused on CO_2, CH_4, and N_2O GHG emissions because these are the most prevalent GHGs emitted from oil and natural gas industry operations. However, while the API *Compendium* provides emission estimation methods for all six internationally recognized GHGs or classes of GHGs (CO_2, CH_4, N_2O, SF_6, HFCs, and PFCs), this should not imply that all of the GHGs are necessarily significant.

Carbon dioxide is primarily emitted from combustion sources, but may also be emitted from gas production, processing, refining, and CCS operations through some vented and fugitive sources. This is particularly important in operations using or processing CO_2-rich field gas. For these non-combustion sources, the potential for emitting CO_2 will depend on the CO_2 concentration associated with the emission source, as well as design and operating practices at facilities. The concentration of CO_2 in commercial natural gas is generally small (< 2% by pipeline specifications), such that vented and fugitive emissions associated with its use are small compared to emissions produced from combustion. However, vented and fugitive CO_2 emissions from CCS operations may be more significant than those from natural gas systems, but still small compared to CO_2 combustion emissions.

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 emission 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 natural gas industry operations, trace amounts of N_2O may be formed from reactions between nitrogen and oxygen that occur during stationary or mobile source combustion. The quantity of N_2O 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_2O emissions). Depending on the facility type (i.e. compressor station or gas plant) and the proliferation (and model/type) of reciprocating engines at a particular upstream facility, N_2O emissions can be more than 2% of the total facility GHG emissions inventory, on a CO_2e basis. As indicated in Section 8, N_2O emissions contribute less than 1% of a refinery's overall GHG inventory (on a CO_2e basis).

Air conditioning (mobile and stationary), refrigeration (including large process equipment such as chillers), and fire suppression equipment are potential sources of HFC and PFC emissions. Sulfur hexafluoride is most often used for circuit breaker applications in the electric power industry, but may also be used as a tracer gas for pipeline leak detection.

3.3.1 Global Warming Potentials

Greenhouse gas inventories are often reported in terms of Carbon Equivalents or Carbon Dioxide Equivalents (CO_2e), 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_2 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 (United Nations Framework Convention on Climate (UNFCCC), 2002). According to the Intergovernmental Panel on Climate Change (IPCC), GWPs typically have an uncertainty of ±35 percent (IPCC, 2007b). The time interval associated with the GWP value is an area of debate between policy analysts and scientists. For CH_4 and N_2O, the time interval chosen can have a significant impact because there is a large difference between the lifetime of CH_4 and N_2O (approximately 12.2 years and 120 years, respectively) and the effective lifetime of CO_2 (200-250 years). Currently, the parties to the UNFCCC have agreed to base GWPs on a 100-year time horizon (IPCC, 2007).[2]

The UNFCCC updates the GWP values periodically as new information becomes available. The IPCC published the Third Assessment Report (TAR) in 2001 (IPCC, 2001), and the Fourth Assessment Report (AR4) in 2007 (IPCC, 2007b). Both reports present new GWP values for the second commitment period (after 2012) based on improved calculations of the radiative forcing and response function of CO_2. 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)[3] and are the values applied in the API *Compendium*, as shown in Table 3-1.

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[2] For example, using the recommended GWP and selecting a time period of 50 years, the CH_4 GWP would be approximately 34, compared to a GWP of 6.5 for a 500-year integration interval.

[3] 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) (UNFCCC, 2002). As of COP12 in 2006, the UNFCCC COP has not adopted the revised GWPs from the TAR.

For comparison, Table 3-1 also includes the GWPs presented in the AR4.

Table 3-1. Greenhouse Gas and Global Warming Potentials

Gas	Recommended GWP (UNFCCC, 2002) applicable through 2012	IPCC Revised GWP (IPCC AR4, 2007) applicable after 2012
CO_2	1	1
CH_4 [a]	21	25
N_2O	310	298
Hydrofluorocarbons (HFCs)		
HFC-23	11,700	14,800
HFC-32	650	675
HFC-41	150	97 [b]
HFC-125	2,800	3,500
HFC-134	1,000	1,100 [b]
HFC-134a	1,300	1,430
HFC-143	300	330 [b]
HFC-143a	3,800	4,470
HFC-152		43 [b]
HFC-152a	140	124
HFC-161		12 [b]
HFC-227ea	2,900	3,220
HFC-236cb		1,300 [b]
HFC-236ea		1,200 [b]
HFC-236fa	6,300	9,810
HFC-245ca	560	640 [b]
HFC-245fa		1,030
HFC-43-10mee	1,300	1,640
HFC-365mfc		794
Perfluorinated compounds		
CF_4	6,500	7,390
C_2F_6	9,200	12,200
C_3F_8	7,000	8,830
$c\text{-}C_4F_8$	8,700	10,300
C_4F_{10}	7,000	8,860
C_5F_{12}	7,500	9,160
C_6F_{14}	7,400	9,300
$C_{10}F_{18}$		>7,500
NF_3		17,200
SF_6	23,900	22,800
SF_5CF_3		17,700

Table 3-1. Greenhouse Gas and Global Warming Potentials, continued

Gas	Recommended GWP (UNFCCC, 2002) applicable through 2012	IPCC Revised GWP (IPCC AR4, 2007) applicable after 2012
Fluorinated ethers		
HFE-125		14,900
HFE-134		6,320
HFE-143a		756
HCFE-235da2		350
HFE-245cb2		708
HFE-245fa2		659
HFE-254cb2		359
HFE-347mcc3		575
HFE-347pcf2		580
HFE-356pcc3		110
HFE-449sl (HFE-7100)		297
HFE-569sf2 (HFE-7200)		59
HFE-43-10pccc124 (H-Galden 1040x)		1,870
HFE-236ca12 (HG-10)		2,800
HFE-338pcc13 (HG-01)		1,500
Perfluoropolyethers		
PFPMIE		10,300
Hydrocarbons and other compounds – Direct Effects		
Dimethylether		1
Methylene chloride		8.7
Methyl chloride		13

Footnotes and Sources:

[a] The GWP of CH_4 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_2 is not included.

[b] GWP values are taken from the IPCC Third Assessment Report (IPCC TAR, 2001). Values were not provided for these compounds in the Fourth Assessment Report.

3.3.2 Emissions Summaries

This document presents emission factors for CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6 for emission sources of interest to oil and natural gas industry operations. 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 and sources of all the GHG compounds emitted, and report them individually, in addition to the weighted sum expressed as CO_2e. 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 emission estimates are often expressed in terms of CO_2e 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 for calculating CO_2e and Carbon Equivalents are provided below.

$$CO_2e\text{, tonnes} = \sum_{i=1}^{\#\text{ Greenhouse Gas Species}} (\text{tonnes}_i \times GWP_i) \qquad \text{(Equation 3-2)}$$

where
CO_2e = carbon dioxide equivalent emissions (tonnes);
tonnes_i = GHG emissions of pollutant *i* (tonnes); and
GWP_i = global warming potential of pollutant *i*, presented in Table 3-1 (tonnes CO_2e per tonne *i*).

$$\text{MMTCE} = CO_2e\text{, tonnes} \times \frac{\text{MW Carbon}}{\text{MW } CO_2} \times \frac{\text{MMTCE}}{10^6 \text{ tonnes Carbon}} \qquad \text{(Equation 3-3)}$$

where
MMTCE = Million Metric Tonnes of Carbon Equivalent, and
MW = molecular weight (MW Carbon = 12; MW CO_2 = 44).

Exhibit 3.1 demonstrates these calculations.

EXHIBIT 3.1: Sample Calculation for Carbon Equivalents

INPUT DATA:
A company's GHG inventory reported 8,800,000 tons/yr (i.e., short tons) of CO_2 emissions and 315,000 tons/yr of CH_4 emissions. What are the company's total CO_2 equivalent and carbon equivalent emissions for the GHG inventory (E_{CO_2e} and E_{CE})?

CALCULATION METHODOLOGY:
1. *Calculate* E_{CO_2e}. Equation 3-2 is used to calculate emissions in terms of CO_2e. As shown in Table 3-1, the GWP for CH_4 is 21, and the GWP for CO_2 is 1. (Note that Table 3-4 provides the tons to tonnes conversion factor.)

$$E_{CO_2e} = \left[\left(\frac{8{,}800{,}000 \text{ tons } CO_2}{\text{yr}} \times \frac{1 \text{ ton } CO_2e}{\text{ton } CO_2}\right) + \left(\frac{315{,}000 \text{ tons } CH_4}{\text{yr}} \times \frac{21 \text{ tons } CO_2e}{\text{ton } CH_4}\right)\right] \times \frac{\text{tonnes}}{1.10231 \text{ tons}}$$

$$\underline{E_{CO_2e} = 13.98 \times 10^6 \text{ tonnes } CO_2e/\text{yr}}$$

EXHIBIT 3.1: Sample Calculation for Carbon Equivalents, continued

2. *Calculate E_{CE}.* Equation 3-3 is used to convert CO_2e emissions to carbon equivalents.

$$E_{CE} = \frac{13.98\times10^6 \text{ tonnes } CO_2e}{\text{yr}} \times \frac{12 \text{ tonnes C/mole C}}{44 \text{ tonnes } CO_2e\text{/mole } CO_2e} \times \frac{\text{mole C}}{\text{mole } CO_2e} \times \frac{\text{MMTCE}}{10^6 \text{ tonnes C}}$$

$$\underline{E_{CE} = 3.81 \text{ MMTCE/yr}}$$

Note that in the calculation above, the term "mole C/mole CO_2e" is shown to demonstrate the unit conversion. However, this term is not shown in Equation 3-3 or elsewhere in this document, as the term equates to 1.

3.4 Data Requirements

For many GHG emission sources, there are multiple options for determining the emissions, often with different accuracies. Table 3-2 illustrates the range of available options for estimating GHG emissions and associated considerations.

Table 3-2. Emission Estimation Approaches – General Considerations

Types of Approaches	General Considerations
Published emission factors	• Accounts for average operations or conditions • Simple to apply • Requires understanding and proper application of measurement units and underlying standard conditions • Accuracy depends on the representativeness of the factor relative to the actual emission source • Accuracy can vary by GHG constituents (i.e., CO_2, CH_4, and N_2O)
Equipment manufacturer emission factors	• Tailored to equipment-specific parameters • Accuracy depends on the representativeness of testing conditions relative to actual operating practices and conditions • Accuracy depends on adhering to manufacturers inspection, maintenance and calibration procedures • Accuracy depends on adjustment to actual fuel composition used on-site • Addition of after-market equipment/controls will alter manufacturer emission factors
Engineering calculations	• Accuracy depends on simplifying assumptions that may be contained within the calculation methods • May require detailed data

Table 3-2. Emission Estimation Approaches – General Considerations, continued

Types of Approaches	General Considerations
Process simulation or other computer modeling	• Accuracy depends on simplifying assumptions that may be contained within the computer model methods • May require detailed input data to properly characterize process conditions • May not be representative of emissions that are due to operations outside the range of simulated conditions
Monitoring over a range of conditions and deriving emission factors	• Accuracy depends on representativeness of operating and ambient conditions monitored relative to actual emission sources • Care should be taken when correcting to represent the applicable standard conditions • Equipment, operating, and maintenance costs must be considered for monitoring equipment
Periodic or continuous [a] monitoring of emissions or parameters [b] for calculating emissions	• Accounts for operational and source specific conditions • Can provide high reliability if monitoring frequency is compatible with the temporal variation of the activity parameters • Instrumentation not available for all GHGs or applicable to all sources • Equipment, operating, and maintenance costs must be considered for monitoring equipment

Footnotes and Sources:
[a] Continuous emissions monitoring applies broadly to most types of air emissions, but may not be directly applicable nor highly reliable for GHG emissions.
[b] Parameter monitoring may be conducted in lieu of emissions monitoring to indicate whether a source is operating properly. Examples of parameters that may be monitored include temperature, pressure and load.

As presented throughout the API *Compendium*, published emission factors are available from a variety of sources, including IPCC, EPA, Energy Information Administration (EIA), Gas Research Institute (GRI) and other widely available sources.

Where possible, this manual provides multiple estimation approaches for each category of emissions. 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 (IPIECA, et. al, 2003). Ideally, the methodologies need to be consistent with the contribution of the particular emission source to the overall inventory. However, **methodologies required by regulations take precedence over the options provided in the decision trees or the *Guidelines* document.**

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 their 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 API *Compendium* compiles emission factors from many different data sources. 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 API *Compendium* is to express emission factors in terms of metric tonnes of emissions in the numerator, and express the denominator in terms of both U.S. customary 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[4] (or 101.325 kPaa and 15.6°C in metric). Using the ideal gas law:

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

where

P = pressure (psia or atm);
V = volume (ft^3, cm^3, or m^3);
n = number of moles;
R = gas constant = 10.73 psi ft^3/lbmole degree Rankine (°R),
= 0.73 atm ft^3/lbmole °R,
= 82.06 atm cm^3/gmole Kelvin (K),
= 8.3145 Pa m^3/gmole K; and
T = absolute temperature (°R or K).

At standard conditions as defined for the API *Compendium*, 1 lbmole = 379.3 scf. In metric units, 1 gmole = 23,685 cm^3 (23.685 m^3/kg-mole) at these same conditions.

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[4] 60°F and 14.7 psia are also consistent with standard conditions in American Society of Testing and Materials (ASTM) D3588-98 (1998, Reapproved 2003) and API Manual of Petroleum Measurement Standards, Chapter 14, Section 5 (January 1991, Reaffirmed March 2002).

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). Table 3-3 provides molar volume conversions for commonly used gas conditions.

Table 3-3. Commonly Used Molar Volume Conversions [a]

	Molar Volume Conversion		
Temperature	**(scf/lb-mole)**	**(scf/kg-mole)**	**(m^3/kg-mole)**
0 °C	359.0	791.5	22.41
15 °C	378.8	835.0	23.64
20 °C	385.3	849.5	24.06
25 °C	391.9	864.0	24.47
60 °F [b]	379.3	836.2	23.68
68 °F	385.3	849.5	24.06
70 °F	386.8	852.7	24.15

Footnotes and Sources:

[a] All molar volume conversions at 1 atm (14.7 psia).

[b] API *Compendium* standard conditions

To convert a volumetric rate from one set of standard conditions to another, the following equation can be used. Note that absolute temperatures (°R or K) are required for this equation.

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

where

Subscript 1 = initial conditions for variable V, P, or T, and

Subscript 2 = new set of standard conditions for variable V, P, or T.

This conversion is demonstrated in Exhibit 3.2.

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

INPUT DATA:

The CH_4 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. What is the emission factor at the EPA reference conditions of 101.3 kPa and 293 K (68°F), as shown in 40 CFR 60.1 and 63.1? What is the emission factor at 0°C and 760 mm Hg in both U.S. customary and SI units?

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

CALCULATION METHODOLOGY:

1. *Calculate the emission factor at 101.3 kPa and 293K.* To convert the gas volumetric rate between different temperature and pressure conditions, the ideal gas law derivation shown in Equation 3-5 will be used. Because the ideal gas law requires absolute temperatures, the standard condition of 60°F must be converted to an absolute basis. In this case, the temperature will be converted from °F to K so it will be on the same basis as the new conditions. (Note that temperature conversions are provided in Section 3.6.)

$$T_{abs} = \frac{60°F - 32}{1.8} + 273.15$$

$$\underline{T_{abs} = 288.7\ \text{K}}$$

The new emission factor is then calculated using Equation 3-5 for the new standard conditions:

$$EF = \left(345\ \frac{\text{scfd}}{\text{device}}\right) \times \left[\frac{(14.7\ \text{psia}) \times (293\ \text{K})}{(101.3\ \text{kPa}) \times \dfrac{(14.696\ \text{psia})}{(101.325\ \text{kPa})} \times (288.7\ \text{K})}\right]$$

$$\underline{EF = 350.3\ \frac{\text{scfd}}{\text{device}},\ \text{at 101.3 kPa and 293 K}}$$

2. *Calculate the emission factor at 760 mm Hg and 0°C.* As shown in calculation step 1 of this exhibit, the new temperature must be on an absolute basis, and the units at the current and new conditions must be the same for temperature and pressure, respectively. From Table 3-5, 0°C equals 273.15 K; from Table 3-4, 760 mm Hg equals 14.696 psia.

The new emission factor is calculated using Equation 3-5 for these new conditions.

$$EF_{US} = \left(345\ \frac{\text{scfd}}{\text{device}}\right) \times \left[\frac{(14.7\ \text{psia}) \times (273.15\ \text{K})}{(14.696\ \text{psia}) \times (288.7\ \text{K})}\right]$$

$$\underline{EF_{US} = 326.51\ \frac{\text{scfd}}{\text{device}},\ \text{at } 0^{\circ}\text{C and 760 mm Hg}}$$

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

This result can be converted to SI units using the volumetric conversion factor provided in Table 3-4:

$$EF_{SI} = 326.51 \frac{\text{scfd}}{\text{device}} \times \frac{\text{m}^3}{35.3147\ \text{ft}^3}$$

$$EF_{SI} = 9.2456 \frac{\text{m}^3}{\text{day-device}}, \text{ at } 0^{\circ}\text{C and } 760 \text{ mm Hg}$$

3.6 Conversions, Numeric Format, and Fuel Properties

3.6.1 General Units Conversions

API *Manual of Petroleum Measurement Standards* (*MPMS*) Chapter 15 specifies API-preferred units for quantities common to the oil and natural gas industry, and provides factors for converting customary units to the API-preferred metric units (API, 2001). 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). MPMS Chapter 15 served as the basis for the common unit conversion factors provided in Tables 3-3 through 3-6.

In Table 3-4, most of the conversion factors are shown with up to seven significant digits. Those shown to fewer than six significant figures are limited by the uncertainty of the measurement of the physical property. An asterisk (*) indicates that the conversion factor is exact, and any succeeding digits would be zeros.

Table 3-4. Conversion Factors

	Common US Units	API-Preferred SI Units	Other Conversions
Mass		1 kilogram	= 2.20462 pounds (lb) = 1000* grams (g) = 0.001 metric tonnes (tonne)
	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

Table 3-4. Conversion Factors, continued

	Common US Units	API-Preferred SI Units	Other Conversions
Volume		1 cubic meter (m^3)	= 1000 *liters (L) = 35.3147 cubic feet (ft^3) = 264.172 gallons
	1 cubic foot (ft^3)	= 0.02831685 cubic meters (m^3)	= 28.31685 liters (L) = 7.4805 gallons
	1 gallon (gal)	3.785412×10^{-3} cubic meters (m^3)	= 3.785412 liters (L)
	1 barrel (bbl)	= 0.1589873 cubic meters (m^3)	= 158.9873 liters (L) = 42* gallons (gal)
Length		1 meter (m)	= 3.28084 feet = 6.213712×10^{-4} 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
Power		1 Watt (W)	= 1* joule (J)/second = 9.47817×10^{-4} Btu/second = 1.34102×10^{-3} horsepower (hp)
	1 megawatt	10^6 Watts (W)	= 10^6* Joules/second = 1000* kilowatts (10^3 W)
	1 horsepower (hp)	= 745.6999 Watts (W)	= 0.7456999 kilowatts = 0.706787 Btu/second
Energy		1 Joule (J) 0.001 kilo Joules (kJ)	= 9.47817×10^{-4} Btu = 2.778×10^{-7} kilowatt-hour = 0.737562 foot-pounds$_{\text{force}}$
	1 horsepower-hour (hp-hr)	= 2.68452×10^6 Joules (J)	= 2544.43 Btu = 0.7456999 kilowatt-hour
	1 kilowatt-hour	= 3.6*×10^6 Joules (J)	= 3412.14 Btu = 1.34102 horsepower-hours = 3600* kilo-Joules
	1 Btu	= 1055.056 Joules (J)	= 3.93015×10^{-4} horsepower-hours = 2.93071×10^{-4} kilowatt-hours
	1 million Btu (10^6 Btu)	= 1.055056×10^9 Joules (J)	= 1.055056 giga-Joules (10^9 J) = 293.071 kilowatt-hours
	1 therm	= 1.055056×10^8 Joules (J)	= 100,000 Btu = 29.3071 kilowatt-hours
Pressure		1 kilo-Pascal (10^3 Pa)	= 9.869233×10^{-3} atmosphere (atm)
	1 atmosphere (atm)	= 101.325* kilo-Pascals (10^3 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 (10^3 Pa)	= 0.06804596 atmosphere (atm)

Table 3-4. Conversion Factors, continued

	Common US Units	API Preferred SI Units	Other Conversions
Heating Value			
Mass basis:	1 Btu/pound	= 2326.000 Joules/kilogram (J/kg)	
Volume basis:	1 Btu/cubic foot (Btu/ft^3)	= 37,258.95 Joules/cubic meter (J/m^3)	= 0.133681 Btu/gallon
Emission Factor:		1 kilogram/giga-Joule ($kg/10^9$ J)	= 2.32600 pound/million Btu ($lb/10^6$ Btu)
	1 pound/million Btu ($lb/10^6$ Btu)	= 0.429923 kilograms/giga-Joule ($kg/10^9$ J)	= 0.429923 tonnes/tera-Joule ($tonnes/10^{12}$ J) = 429.923 grams/giga-Joule ($g/10^9$ J)
Barrels of Oil Equivalent (BOE)			
All Fuel Types	1 BOE	= $6.12x10^9$ J	= $5.8x10^6$ Btu
			= 2279.49 horsepower-hours
			= 1699.81 kilowatt-hours
Natural Gas	1 BOE	= 159.920 m^3	= 5,647.52 ft^3
Note: The BOE volume equivalent for natural gas was calculated by dividing the 5.8E+06 Btu/BOE by the heating value of natural gas (pipeline quality) from Table 3-8 (1,027 Btu/scf).			
Natural Gas Liquids	1 BOE	= 0.231327 m^3	= 1.455 bbl = 231.327 L = 61.11 gal = 8.16992 ft^3

Footnotes:
* indicates the conversion factor is exact; any succeeding digits would be zeros.
psig = Gauge pressure.
psia = Absolute pressure (note psia = psig + atmospheric pressure).

Table 3-5. 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 3-6, 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 $\log_{10}$ basis (i.e., 10^x) or spells out the unit name.

Table 3-6. Unit Prefixes

SI Units		U.S. 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 (μ)	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 API *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 is also reported for the emission factors converted to the unit convention adopted for the API *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 8, 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 heating value per unit volume of a fuel is calculated as the volume- or mass-weighted average of the heat generated in the combustion of the individual components of the gas. While inert compounds (e.g., nitrogen, CO_2) have a zero heat of combustion, the heat of combustion of hydrocarbons per volume or mass increases with the addition of carbon atoms to the hydrocarbon chain. For example, a fuel that is rich in ethane and heavier components will have a greater HHV than a fuel that contains an increased amount of inert compounds and less ethane and heavier components. While a change in HHV is an indicator of composition change, it may not always be a sufficient index of combustion behavior since two fuels of the same heating values can have different compositions and combustion characteristics. However, when using pipeline quality natural gas as the fuel source, HHV may be used as an indicator of fuel carbon content and emissions index.

The difference between the HHV, also known as gross calorific value, and 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:

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

where

n = the number of moles of water in the products;
h = the enthalpy of vaporization of water at 25°C;
HHV = higher heating value, also referred to as gross calorific value, accounts for condensation of water vapor from the combustion process – the convention commonly used in EPA and U.S. Department of Energy (DOE) documents; and
LHV = lower heating value or net calorific value, which includes water in the vapor phase – the convention used by IPCC and other international sources.

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 U.S. and Canada, while LHV is generally the preference outside North America. The API *Compendium* provides fuel heating values and energy-based emission factors in terms of both HHV and LHV. In general, emission factors taken from U.S. and Canadian references are in terms of HHV: factors from outside North America are in terms of LHV. Section 4.2 provides a detailed discussion of the method used throughout the API *Compendium* for conversion between LHV and HHV. 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 3-7 provides the molecular weight and heating values used in the API *Compendium* calculations for various hydrocarbon compounds[5]. The category "C9+" includes molecules with nine 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 API *Compendium* assumes that the "C9+" is best represented by the C11 alkanes. Thus, the molecular weight for $C_{11}H_{24}$ will be used for "C9+."

Table 3-7. Hydrocarbon Molecular Weights and Gross Heating Values

Compound		**Molecular Weight**	**Ideal Gross Heating Value, 60°F, 1 atm [a]**	
			(Btu/scf)	**(MJ/standard m^3)**
Methane	CH_4	16.04	1009.7	37.620
Ethane	C_2H_6	30.07	1768.8	65.904
Propane	C_3H_8	44.10	2517.5	93.799
n-Butane	C_4H_{10}	58.12	3262.1	121.54
n-Pentane	C_5H_{12}	72.15	4009.6	149.39
n-Hexane	C_6H_{14}	86.18	4756.2	177.21
n-Heptane	C_7H_{16}	100.20	5502.8	205.03
Octanes	C_8H_{18}	114.23	6248.9 [b]	232.83
C9+		156.31 (MW of $C_{11}H_{24}$)	8488.46 [c] (HHV of $C_{11}H_{24}$, gas)	316.27
Carbon Dioxide	CO_2	44.01	N/A	

Footnotes and Sources:

[a] Data taken from API *MPMS* Chapter 14, Section 5, Table 1 (API, 2002), unless otherwise noted.

[b] Gas Processors Suppliers Association *Engineering Data Book* (GPSA, 1987) Figure 23-2, for n- Octane.

[c] *Perry's Chemical Engineers' Handbook* (Perry, 1984) Table 3-207.

Table 3-8 provides heating values, in terms of both HHV and LHV, typical densities, and carbon contents by weight percent for some common fuel types. Note that using the carbon content of a liquid fuel (for example, gasoline) in the place of the carbon content of the vapor phase is a simplifying assumption that will overestimate emissions. In reality, the carbon content of the vapor phase will be lower than the carbon content of the liquid phase because vapors contain lighter hydrocarbons that are able to volatilize easier than heavier hydrocarbons.

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[5] Unless otherwise noted, data in Table 3-7 is taken from the *Manual of Petroleum Measurement Standards* (API, 2002); however, there are many other references that provide these data. Alternate information sources include: *Perry's Chemical Engineers' Handbook*, the Gas Processors Suppliers Association (GPSA) *Engineering Data Book*, and ASTM International.

Table 3-8. Densities, Higher Heating Values, and Carbon Contents for Various Fuels

Fuel	Typical Density		Higher Heating Value		Lower Heating Value		Carbon, % by wt.
Acetylene	0.0686 lb/ft^3 [a]	1.10 kg/m^3	1.47×10^{3} Btu/ft^3 [a]	5.49×10^{7} J/m^3	1.33×10^{3} Btu/ft^3	4.97×10^{7} J/m^3	92.3
Asphalt and Road Oil	8.61 lb/gal [b]	1032.09 kg/m^3	6.64×10^{6} Btu/bbl [b]	4.40×10^{10} J/m^3	6.30×10^{6} Btu/bbl	4.18×10^{10} J/m^3	83.47 [b]
Aviation Gas	5.89 lb/gal [b]	705.74 kg/m^3	5.05×10^{6} Btu/bbl [b]	3.35×10^{10} J/m^3	4.80×10^{6} Btu/bbl	3.18×10^{10} J/m^3	85.00 [b]
Butane (liquid)	4.86 lb/gal	582.93 kg/m^3	4.33×10^{6} Btu/bbl [b]	2.87×10^{10} J/m^3	4.11×10^{6} Btu/bbl	2.73×10^{10} J/m^3	82.8 [b]
Coal, anthracite	No data [c]	No data	1.13×10^{4} Btu/lb [c]	2.63×10^{7} J/kg	1.07×10^{4} Btu/lb	2.49×10^{7} J/kg	No data [c]
Coal, bituminous	No data [c]	No data	1.19×10^{4} Btu/lb [c]	2.78×10^{7} J/kg	1.13×10^{4} Btu/lb	2.64×10^{7} J/kg	No data [c]
Crude Oil	7.29 lb/gal [b]	873.46 kg/m^3	5.80×10^{6} Btu/bbl [b]	3.85×10^{10} J/m^3	5.51×10^{6} Btu/bbl	3.66×10^{10} J/m^3	84.8 [b]
Distillate Oil (Diesel)	7.07 lb/gal [b]	847.31 kg/m^3	5.83×10^{6} Btu/bbl [b]	3.87×10^{10} J/m^3	5.53×10^{6} Btu/bbl	3.67×10^{10} J/m^3	86.34 [b]
Ethane (liquid)	3.11 lb/gal	372.62 kg/m^3	2.92×10^{6} Btu/bbl [b]	1.94×10^{10} J/m^3	2.77×10^{6} Btu/bbl	1.84×10^{10} J/m^3	80.0 [b]
Fuel Oil #4	7.59 lb/gal [d]	909.48 kg/m^3	6.01×10^{6} Btu/bbl [d]	3.99×10^{10} J/m^3	5.71×10^{6} Btu/bbl	3.79×10^{10} J/m^3	86.4 [d]
Isobutane	4.69 lb/gal	561.59 kg/m^3	4.16×10^{6} Btu/bbl [b]	2.76×10^{10} J/m^3	3.95×10^{6} Btu/bbl	2.62×10^{10} J/m^3	82.8 [b]
Jet Fuel	6.81 lb/gal [b]	815.56 kg/m^3	5.67×10^{6} Btu/bbl [b]	3.76×10^{10} J/m^3	5.39×10^{6} Btu/bbl	3.57×10^{10} J/m^3	86.30 [b]
Kerosene	6.83 lb/gal [b]	818.39 kg/m^3	5.67×10^{6} Btu/bbl [b]	3.76×10^{10} J/m^3	5.39×10^{6} Btu/bbl	3.57×10^{10} J/m^3	86.01 [b]
Lignite	No data [c]	No data	6.43×10^{3} Btu/lb [c]	1.50×10^{7} J/kg	6.11×10^{3} Btu/lb	1.42×10^{7} J/kg	No data [c]
LPG [e]	See footnote e						
Lubricants	7.52 lb/gal [b]	900.70 kg/m^3	6.07×10^{6} Btu/bbl [b]	4.02×10^{10} J/m^3	5.76×10^{6} Btu/bbl	3.82×10^{10} J/m^3	85.80 [b]
Miscellaneous Product [f]	7.29 lb/gal [b]	873.46 kg/m^3	5.80×10^{6} Btu/bbl [b]	3.85×10^{10} J/m^3	5.51×10^{6} Btu/bbl	3.65×10^{10} J/m^3	85.49 [b]
Motor Gasoline [g]	6.20 lb/gal [b]	742.39 kg/m^3	5.25×10^{6} Btu/bbl [b]	3.49×10^{10} J/m^3	4.99×10^{6} Btu/bbl	3.31×10^{10} J/m^3	86.60 [b]
Natural Gas (processed)	0.042 lb/ft^3 [h]	0.6728 kg/m^3	1,020 Btu/ft^3 [h] 1,004 Btu/ft^3 1,027 Btu/ft^3 [c]	3.80×10^{7} J/m^3 3.74×10^{7} J/m^3 [h] 3.83×10^{7} J/m^3	918 Btu/ft^3 903 Btu/ft^3 924 Btu/ft^3	3.42×10^{7} J/m^3 3.37×10^{7} J/m^3 3.44×10^{7} J/m^3	76 wt% C [h]
Natural Gas (raw / unprocessed)			1,235 Btu/ft^3	4.60×10^{7} J/m^3 [h]	1,111 Btu/ft^3	4.14×10^{7} J/m^3	
Natural Gas Liquids (NGL) [e]	See footnote e						
Natural Gasoline [f]	5.54 lb/gal [b]	663.70 kg/m^3	4.62×10^{6} Btu/bbl [b]	3.07×10^{10} J/m^3	4.39×10^{6} Btu/bbl	2.91×10^{10} J/m^3	83.70 [b]
Pentanes Plus	5.54 lb/gal [b]	663.70 kg/m^3	4.62v10^{6} Btu/bbl [b]	3.07×10^{10} J/m^3	4.39×10^{6} Btu/bbl	2.91×10^{10} J/m^3	83.70 [b]
Petrochemical Feedstocks	5.95 lb/gal [b]	712.49 kg/m^3	5.25×10^{6} Btu/bbl [b, j]	3.48×10^{10} J/m^3	4.99×10^{6} Btu/bbl	3.31×10^{10} J/m^3	84.11 [b]
Petroleum Coke [f]	No data [b]	No data	6.02×10^{6} Btu/bbl [b]	4.00×10^{10} J/m^3	5.72×10^{6} Btu/bbl	3.80×10^{10} J/m^3	92.28 [b]

Table 3-8. Densities, Higher Heating Values, and Carbon Contents for Various Fuels, continued

Fuel	Typical Density		Higher Heating Value		Lower Heating Value		Carbon, % by wt.
Petroleum Waxes	6.76 lb/gal [b]	809.50 kg/m^3	5.54×10^{6} Btu/bbl [b]	3.67×10^{10} J/m^3	5.26×10^{6} Btu/bbl	3.49×10^{10} J/m^3	85.29 [b]
Propane (gas) [k]	0.12 lb/ft^3	1.90 kg/m^3	2,516.1 Btu/ft^3 [a]	9.37×10^{7} J/m^3	2,314.9 Btu/ft^3 [a]	8.63×10^{7} J/m^3	81.8 [b]
Propane (liquid)	4.22 lb/gal	505.61 kg/m^3	3.82×10^{6} Btu/bbl [b]	2.54×10^{10} J/m^3	3.63×10^{6} Btu/bbl	2.41×10^{10} J/m^3	81.8 [b]
Residual Oil #5	7.93 lb/gal [d]	950.22 kg/m^3	6.30×10^{6} Btu/bbl [d]	4.18×10^{10} J/m^3 [d]	5.99×10^{6} Btu/bbl	3.97×10^{10} J/m^3	88.7 [d]
Residual Oil #6 [l]	8.29 lb/gal [b]	992.98 kg/m^3	6.29×10^{6} Btu/bbl [b]	4.17×10^{10} J/m^3 [b]	5.97×10^{6} Btu/bbl	3.96×10^{10} J/m^3	85.68 [b]
Special Naphtha	6.46 lb/gal [b]	774.49 kg/m^3	5.25×10^{6} Btu/bbl [b]	3.48×10^{10} J/m^3	4.99×10^{6} Btu/bbl	3.31×10^{10} J/m^3	84.76 [b]
Still Gas	No data [b]	No data	6.00×10^{6} Btu/bbl [b]	3.98×10^{10} J/m^3	5.70×10^{6} Btu/bbl	3.78×10^{10} J/m^3	No data [b]
Unfinished Oils [f]	7.29 lb/gal [b]	873.46 kg/m^3	5.83×10^{6} Btu/bbl [b]	3.87×10^{10} J/m^3	5.53×10^{6} Btu/bbl	3.67×10^{10} J/m^3	85.49 [b]

All LHVs were derived from HHVs. To convert from HHV to LHV, the assumed conversion for gaseous fuels is LHV = (0.9) × (HHV); for solids or liquids the assumed conversion is LHV = (0.95) × (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. Values in original source units are footnoted; additional values are derived from original source values.

Footnotes and Sources:

[a] Gas Processors Suppliers Association, *Engineering Data Book*, Volume II, 1987.

[b] Energy Information Administration, *Documentation for Emissions of Greenhouse Gases in the United States 2006*, Tables 6-5 and 6-7, October 2008. Densities provided as API gravity or bbl/tonne and converted.

[c] U.S. Environmental Protection Agency (EPA), *Inventory of U.S. Greenhouse Gas Emissions and Sinks*: 1990-2007, Annexes, Table A-251, April 15, 2009.

[d] *North American Combustion Handbook*, *Volume I: Combustion Fuels, Stoichiometry, Heat transfer, Fluid Flow*, ISBN 0-9601596-2-2, Third Edition, Cleveland, Ohio, 1986.

[e] LPG and NGL are blends of multiple hydrocarbons (e.g., ethane, propane, isobutene), each with its own heat content, density and carbon content. Mixture properties should be calculated using the methods described in Section 3.6.4.

[f] Term defined in the Glossary.

[g] Motor gasoline includes conventional gasoline, all types of oxygenated gasoline (including gasohol), and reformulated gasoline, but excludes aviation gasoline.

[h] EPA AP-42, Section 1.4, *Natural Gas Combustion*, 1998.

[i] Canadian Association of Petroleum Producers (CAPP), *Calculating Greenhouse Gas Emissions*, Table 1-5, Canadian Association of Petroleum Producers, Publication Number 2003-03, April 2003.

[j] Parameters presented are for naphthas with a boiling temperature of less than 400° F. Petrochemical feedstocks with higher boiling points are assumed to have the same characteristics as distillate fuel.

[k] Calculated using methodology provided in API *Measurement of Petroleum Measurement Standards*, Chapter 14 - *Natural Gas Fluids Measurement*, Section 5 – *Calculation of Gross Heating Value*, Specific Gravity and Compressibility of Natural Gas Mixtures from Compositional Analysis, ANSI/API 14.5-1981, First Edition, January 1981, Reaffirmed March 2002.

[l] Values shown are for residual fuel, which is defined in the text of the reference document as No. 6 fuel oil.

Table 3-9 provides carbon contents for natural gas according to heating value ranges. Note that in the United States, pipeline quality natural gas has a HHV greater than 970 Btu/scf but less than 1,100 Btu/scf (EPA, 2009). Gas with heating values outside this range should be not be classified as natural gas, but could instead be classified as produced gas, refinery gas, associated gas, or process gas. Lower heating value gases tend to have a higher content of inert gases, while higher heating value gases tend to have a higher content of natural gas liquids, both of which affect the carbon content of the gas (EPA, 2009).

Table 3-9. Natural Gas Carbon Contents by Heating Value

Higher Heating Value	Carbon Content, g C/1000 BTU [a]	Higher Heating Value	Carbon Content, g C/1000 BTU [b]
GRI Full Sample [c]	14.51	1,100 to 1,125 Btu/scf	15.07
Greater than 1,000 Btu/scf	14.47	1,125 to 1,150 Btu/scf	15.09
1,025 to 1,035 Btu/scf	14.45	1,150 to 1,175 Btu/scf	15.15
975 to 1,000 Btu/scf	14.73	1,175 to 1,200 Btu/scf	15.27
1,000 to 1,025 Btu/scf	14.43	1,200 to 1,225 Btu/scf	15.38
1,025 to 1,050 Btu/scf	14.47	1,225 to 1,250 Btu/scf	15.52
1,050 to 1,075 Btu/scf	14.58	Greater than 1,250 Btu/scf	16.33
1,075 to 1,100 Btu/scf	14.65		
Weighted National Average [d]	14.47		

Footnotes and Sources:

[a] Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks*: 1990-2007, Annex A, Table A-38, April 15, 2009.

[b] Based on data from worldwide LNG operations and U.S. produced gas with high heating values. The gas compositions included in this analysis did not include H_2.

[c] The "GRI Full Sample" value represents the average of 6,743 samples of pipeline-quality natural gas from utilities and/or pipeline companies in 26 cities located in 19 states.

[d] The national average was weighted by applying the carbon content associated with the average heat content of natural gas consumed in each state by the portion of national natural gas consumption represented by that state.

3.6.4 Fuel Mixture Conversions

Fuel properties for mixtures vary, particularly for non-commercial fuels associated with diverse oil and natural gas industry operations. This section describes and illustrates how to estimate fuel mixture data from pure component data, how to convert a fuel composition from a weight basis to a molar basis, and how to convert between different sampling bases.

The weight percent composition of a mixture is converted to a mole percent composition by multiplying the individual weight percentages by the ratio of the molecular weight of the mixture to the individual molecular weights:

$$\mathrm{Mole\%_i} = \mathrm{Wt\%_i} \times \frac{\mathrm{MW_{Mixture}}}{\mathrm{MW_i}} \qquad \text{(Equation 3-7)}$$

where

$\mathrm{Mole\%_i}$ = molar or volume percent of constituent *i;*
$\mathrm{Wt\%_i}$ = weight or mass percent of constituent *i;*
$\mathrm{MW_{Mixture}}$ = molecular weight of mixture; and
$\mathrm{MW_i}$ = molecular weight of constituent *i.*

If complete speciation is available for the mixture, $\mathrm{MW_{Mixture}}$ can be calculated as the weighted average of the individual molecular weights:

$$\mathrm{MW_{Mixture}} = \frac{1}{100} \times \sum_{\mathrm{i=1}}^{\#\,\mathrm{compounds}} \left(\mathrm{Mole\%_i} \times \mathrm{MW_i}\right) \qquad \text{(Equation 3-8)}$$

Or, in terms of Wt%:

$$\mathrm{MW_{Mixture}} = 100 \div \sum_{\mathrm{i=1}}^{\#\,\mathrm{compounds}} \frac{\mathrm{Wt\%_i}}{\mathrm{MW_i}} \qquad \text{(Equation 3-9)}$$

If complete speciation of the mixture is not available, $\mathrm{MW_{Mixture}}$ can sometimes be obtained from chemical property tables that list data for common oil and gas fractions (e.g., gasoline, No.2 distillate, etc.). Molecular weight values used in the API *Compendium* calculations for various hydrocarbon compounds can be found in Table 3-7.

Exhibits 3.3 and 3.4 illustrate the conversion calculations between weight percent compositions and mole percent compositions.

EXHIBIT 3.3: 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.

Compound	Weight %	Molecular Weight
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	100.20
Octanes	30.0	114.23
C9+	21.5	156.31

Convert the sample analysis to a mass basis.

CALCULATION METHODOLOGY:

The equation to convert from individual compound mole% to wt% (Equation 3-7) requires the molecular weight of the mixture ($MW_{Mixture}$), which is calculated using Equation 3-9:

$$MW_{Mixture} = 100 \div \left(\frac{0.5}{16.04} + \frac{1.0}{30.07} + \frac{2.0}{44.10} + \frac{3.0}{58.12} + \frac{7.0}{72.15} + \frac{10.0}{86.18} + \frac{25.0}{100.20} + \frac{30.0}{114.23} + \frac{21.5}{156.31} \right)$$

$$\underline{MW_{Mixture} = 97.64}$$

Equation 3-7 is then used to calculate the individual compound mole %. For example, for hexane:

$$Mole\%_{Hexane} = 10.0 \times \frac{97.64}{86.18}$$

$$\underline{Mole\%_{Hexane} = 11.33\%}$$

Repeating this calculation for the remaining compounds results in the mole% compositions shown in Exhibit 3.3.

EXHIBIT 3.3: Sample Calculation for Converting from Weight Percent to Mole Percent For Known Fuel Analysis, continued

Compound	Weight %	Molecular Weight	Mole %
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	100.20	24.36
Octanes	30.0	114.23	25.64
C9+	21.5	156.31	13.43
Total	**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 3.4: 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 CH_4 is known (0.5 weight % CH_4). What is the mole % CH_4? To confirm the solution, recalculate the weight % CH_4 using the calculated mole%.

CALCULATION METHODOLOGY:
1. *Calculate the mole% CH_4.* The mole% CH_4 is calculated using Equation 3-7:

$$\text{Mole\%}_{CH_4} = \frac{0.5 \text{ g } CH_4}{100 \text{ g mixture}} \times \frac{\left(\frac{97.65 \text{ g mixture}}{\text{gmole mixture}}\right)}{\left(\frac{16.04 \text{ g } CH_4}{\text{gmole } CH_4}\right)} = \frac{0.0304 \text{ gmole } CH_4}{\text{gmole mixture}}$$

$\underline{\text{Mole\%}_{CH_4} = 3.04 \text{ mole \% } CH_4}$

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

2. *Confirm the solution.* If only the mixture molecular weight and CH_4 mole percent are known, the CH_4 weight % is calculated by re-arranging Equation 3-7:

$$\text{Wt.\%}_{CH_4} = \frac{3.04\ \text{gmole}\ CH_4}{100\ \text{gmole mixture}} \times \frac{\left(\dfrac{16.04\ \text{g}\ CH_4}{\text{gmole}\ CH_4}\right)}{\left(\dfrac{97.65\ \text{g mixture}}{\text{gmole mixture}}\right)} = \frac{0.00499\ \text{g}\ CH_4}{\text{g mixture}}$$

$$\text{Wt.\%}_{CH_4} = 0.5\ \text{wt. \%}\ CH_4$$

Gas composition and physical property data can be represented on several different bases, including as a wet or dry gas, or in an ideal or real state. Wet gas refers to the presence of liquid hydrocarbons and/or water in the gas. Natural gas at the wellhead is often referred to as wet for this reason. Dry gas refers to a lack of liquid hydrocarbons or water in the gas. Pipeline quality gas is often referred to as dry since the bulk of the liquid hydrocarbons and water have been removed. Ideal gas refers to a gas that follows the principles of the ideal gas law (particles have negligible volume and no intermolecular forces), which is adequate for many engineering calculations over a wide range of conditions.[6]

Gas properties can be converted between wet and dry, or ideal and real bases. Described below are the conversions for heating values.

Some methods for measuring heating values are based upon the gas being saturated with water (wet gas basis), while other methods are based upon the gas not having a significant amount of vapor (dry gas basis). If a water-saturated gas sample is analyzed on a dry gas basis, it must be converted to account for the fact that water has displaced some gas and thus has lowered the heating value. If the heating value of the mixture is known, Equation 3-10 can be used to determine the adjusted heating value.

$$HV_{wet} = (1\text{-}x_{liq})HV_{dry} \qquad \text{(Equation 3-10)}$$

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[6] At high pressures and low temperatures, all gases deviate from ideal behavior and more complex equations of state are needed.

where

HV_{wet} = ideal gas heating value of the mixture, per unit volume, on a wet gas basis;
x_{liq} = mole fraction of water or liquid hydrocarbons in the gas; and
HV_{dry} = ideal gas heating value of the mixture, per unit volume, on a dry gas basis.

Equation 3-11 is applied when the heating value of the wet gas mixture is not known. For this equation, water is not included in the N components of summation.

$$HV_{wet} = (1 - x_w) \sum_{i=1}^{N} x_i HV_{i,dry} \qquad \text{(Equation 3-11)}$$

where

N = number of components in the summation;
x_i = mole fraction of constituent *i* in the gas;
x_w = mole fraction of water or liquid hydrocarbons in the gas; and
$HV_{i,dry}$ = ideal gas gross heating value of constituent *i*, per unit volume, on a dry gas basis.

It is important to note that the equations above are sufficient for GHG emission estimation purposes and are commonly used for custody transfer conditions (ASTM, 2003). More detailed equations are available if it is necessary to account for the complete conversion for the effect of water on heating value, including the effect of relative humidity (ASTM, 2003). However, this added calculation complexity improves the accuracy of the estimates only slightly.

Exhibit 3.5 illustrates how to estimate the gas mixture gross heating value on a dry basis, and then how to convert it to a wet basis using the equations provided above.

EXHIBIT 3.5: Sample Calculation for Converting from Dry Gas Basis to Wet Gas Basis For Known Gas Analysis

INPUT DATA:
A chemical analysis is taken on a dry basis for a wet gas sample. The analysis shows that the sample contains the following compounds on a weight basis. Heating values from Table 3-7 are also shown. Calculate the heating value on a wet basis.

EXHIBIT 3.5: Sample Calculation for Converting from Dry Gas Basis to Wet Gas Basis For Known Gas Analysis, continued

Compound	Mol Fraction	Heating Value (Btu/scf)
Methane	2.99	1009.7
Ethane	3.19	1768.8
Propane	4.35	2517.5
Butanes	4.95	3262.1
Pentanes	9.30	4009.6
Hexanes	11.13	4756.2
Heptanes	23.94	5502.8
Octanes	25.19	6248.9
C9+	13.20	8488.46
Water	1.74	--

CALCULATION METHODOLOGY:
To adjust the heating value to a wet basis, the contribution of each compound towards the mixture's heating value ($x_i HV_{i,dry}$) must be calculated. This calculation is performed below, for methane:

$$\left[x_i HV_{i,dry}\right]_{Methane} = \frac{2.99}{100} \times 1009.7 \text{ Btu/scf}$$

$$\left[x_i HV_{i,dry}\right]_{Methane} = 30.16 \text{ Btu/scf}$$

Repeating this calculation for the remaining compounds results in the heating value contributions shown below.

Compound	Mole Fraction	$x_i HV_i$ (Heating Value Contribution)
Methane	2.99	30.16
Ethane	3.19	56.48
Propane	4.35	109.58
Butanes	4.95	161.54
Pentanes	9.30	373.09
Hexanes	11.13	529.48
Heptanes	23.94	1317.10
Octanes	25.19	1574.28
C9+	13.20	1120.12
Water	1.74	--

EXHIBIT 3.5: Sample Calculation for Converting from Dry Gas Basis to Wet Gas Basis For Known Gas Analysis, continued

The heating value is then adjusted to a wet basis using Equation 3-11.

$$HV_{wet} = (1-x_w)\sum_{i=1}^{N} x_i\, HV_{i,dry}$$

$$HV_{wet} = \left(1-\frac{1.74}{100}\right)\begin{bmatrix}30.16+56.48+109.58+161.54+373.09+529.48 \\ +1317.10+1574.28+1120.12\end{bmatrix}$$

$$\underline{HV_{wet} = 2532.49 \text{ Btu/scf}}$$

Ideal gas heating values are calculated from the molar composition and ideal gas heating values of the components of the fuel. The heating value can then be adjusted based on Equation 3-12 using a compressibility factor, which is a measure of how much the real gas deviates from the ideal gas. A complete description of how to calculate the compressibility factor can be found in *Calculation of Gross Heating Value, Specific Gravity, and Compressibility of Natural Gas Mixtures from Compositional Analysis* (API, 2002).

$$HV_r = \frac{HV}{Z} \qquad \text{(Equation 3-12)}$$

where

HV = ideal gas heating value;
HV_r = real gas heating value; and
Z = compressibility factor, notes tables for CH_4 and CO_2 are provided in *Perry's Chemical Engineer's Handbook*, Tables 3-172 and 3-166, respectively (Perry, 1984).

3.7 Emission Estimation Quality

Uncertainty is used to characterize the dispersion of values that could be reasonably attributed to a measured quantity (IPCC, 2000). Conducting an uncertainty analysis is recognized as an important step in prioritizing future work and improving the overall quality of an inventory (EPA, 2009).

Data quality and the uncertainty associated with such data are of increasing importance when developing GHG emission inventories. The uncertainty intervals associated with emission rates, activity data or emission factors are characterized by the dispersion of the respective measurement values that were used to derive them initially. Therefore, estimating uncertainties in emission inventories is based on the characteristics of the variable(s) of interest (input quantity), as estimated from the applicable data set. Such uncertainties will depend both on the accuracy and representativeness of direct measurements, and the assumed probability distributions for the key parameters used for aggregating the overall emissions inventory.

The overall uncertainty associated with a GHG inventory is driven primarily by the uncertainty associated with the largest (“key”) sources of emissions. Although very high levels of uncertainty may be associated with some sources, their overall impact on the uncertainty of entity-wide emissions, or that of a specific installation, may often be very small. In turn, the uncertainty associated with each individual source depends on the quality and availability of sufficient data to estimate emissions and/or on the ability to measure emissions and properly account for measurement variability.

This section provides a description of calculation approaches for statistical assessment of uncertainty and its aggregation (Section 3.7.1) to allow users to quantify the uncertainty associated with their own inventories. This section also addresses different methods of assessing data quality that are either based on calculated uncertainty intervals from raw measurement data (Section 3.7.2) such as for the GRI/EPA methane emissions study (Harrison, et al, 1996), or originally reported quality indicators for emission factors (Section 3.7.3). Calculated aggregated uncertainties for selected example facilities are provided in Section 8.

3.7.1 General Statistical Approach to Calculating Uncertainty

Uncertainties associated with GHG emission inventories are the result of three main processes:

1. Incomplete, unclear or faulty definitions of emission sources;
2. Natural variability of the process that produces the emissions; and
3. Models, or equations, used to quantify emissions for the process or quantity under consideration.

When assessing the process or quantity under consideration, uncertainties could be attributable to one or more factors such as: sampling, measuring, incomplete reference data, or inconclusive expert judgment. The uncertainty associated with total annual emissions is comprised of several components of uncertainty, of which measurement uncertainty is but one. To the extent that measurement and accounting errors can be minimized, such action will have a direct influence on reducing the overall uncertainty associated with emission inventories.

The goal of conducting a detailed uncertainty assessment is two fold:

1. Provide a quantitative assessment of the confidence intervals for the emissions calculated; and
2. Highlight areas of high uncertainty where targeted data collection efforts could lead to material improvement of the emission assessment.

This section provides a brief overview of statistical methods and concepts applicable to conducting an uncertainty assessment for a facility- or entity-wide GHG inventory. Additional details of the technical considerations and calculation methods, including calculation examples, are available in a separate API publication: *Addressing Uncertainty in Oil & Natural Gas Industry Greenhouse Gas Inventories: Technical Considerations and Calculation Methods* (referred to as the *Uncertainty Document*; API, 2009). Both in this section as well as the *Uncertainty Document* the statistical analysis of uncertainty is not viewed as a mean unto itself but as a tool for phasing-in data quality improvements.

Calculation Methods Basics

At the most basic level, a GHG inventory is comprised of calculated and estimated emissions from individual emission sources. Emission information typically is obtained either through direct on-site measurement of emissions, or the combination of measured or published emission factors and some measure of the activity that results in the emission (referred to as the activity factor). Emissions from multiple sources are then aggregated to produce the inventory. The quantification of the uncertainty associated with such calculations or estimates should be applied at the emission source level (or grouping of similar emission sources) and then propagated to the total inventory (as discussed in Section 2.5 of the *Uncertainty Document*).

An emission factor describes the emission rate associated with a given emission source. Emission factors may be either based on site-specific measurements or based on published values that were derived from averaging a variety of measurements. Activity factors are generally a measured quantity, such as a count of equipment or measure of fuel consumed. Sampling uncertainty, measurement uncertainty, and process variability are types of uncertainties that may apply to emission factors and activity factors.

Quantifying the uncertainty for a GHG inventory involves mathematically combining individual sources of uncertainty to establish an estimate of the overall uncertainty. The general steps for quantifying uncertainty are:

1) Determine uncertainty for activity data;
2) Determine uncertainty for emission factor data; and
3) Aggregate uncertainties.

There are four general equations for aggregating uncertainty that are used in this document and the *Uncertainty Document* for compiling the uncertainty associated with a GHG inventory.

Consider two quantities that can be measured: X and Y. The uncertainty for these values can be expressed on an absolute basis as $\pm U_X$ and $\pm U_Y$, respectively. Uncertainty may also be expressed on a relative basis, generally reported as a percentage:

$\pm 100\left(\frac{U_X}{X}\right)\%$ or $\pm 100\left(\frac{U_Y}{Y}\right)\%$, respectively.

Depending on the uncertainty propagation equation, the absolute or relative uncertainty value may be required. In addition, selection of the propagation equation also depends on whether the uncertainties associated with the individual uncertainty parameters are independent or correlated. The uncertainties in two quantities are considered independent if they were estimated by entirely separate processes and there was no common source of uncertainty. The correlation or covariance of uncertainty terms is addressed through an additional term in the propagation equations, discussed further below. Note that where more than two uncertainty parameters are related, a Monte Carlo simulation is recommended for aggregating the uncertainties (IPCC, 2000). Additional information on Monte Carlo simulations is provided by IPCC (IPCC, 2006).

Error Propagation for a Sum (or Difference)

Two potential equations are used for computing the total uncertainty from the addition or subtraction of two or more measured quantities. The selection between the two equations depends on whether or not the uncertainties associated with the measured quantities, X and Y, are correlated.

For uncertainties that are mutually independent, or uncorrelated (i.e., the uncertainty terms are not related to each other), the aggregated error is calculated as the “square root of the sum of the squares” using the absolute errors, as shown in Equation 3-13.

$$U(abs)_{X+Y+\ldots+N} = \sqrt{U_X^2 + U_Y^2 + \ldots + U_N^2} \qquad \text{(Equation 3-13)}$$

where, U(*abs*) refers to the absolute uncertainty.

The absolute uncertainty values are used in the equations, and the resulting aggregated uncertainty ($U(abs)_{X+Y+\ldots+N}$) is also on an absolute basis.

For two uncertainty parameters that are related to each other, the equation becomes:

$$U(abs)_{Correlated\ X+Y} = \sqrt{U_X^2 + U_Y^2 + 2r(U_X \times U_Y)} \qquad \text{(Equation 3-14)}$$

where, r is the correlation coefficient between U_X and U_Y.

Error Propagation for a Product (or Quotient)

The equation for propagating uncertainties from the product or quotient of two or more measured and independent quantities is similar to Equation 3-13. However, in this case the relative uncertainties are used, as shown in Equation 3-15. When multiplied by 100, the resulting combined uncertainty ($U(Rel)_{X\times Y\times N}$) is expressed as a percentage.

$$U(rel)_{X\times Y\times\ldots\times N} = U(rel)_{X\div Y\div\ldots\div N} = \sqrt{\left(\frac{U_X}{X}\right)^2 + \left(\frac{U_Y}{Y}\right)^2 + \ldots + \left(\frac{U_N}{N}\right)^2} \qquad \text{(Equation 3-15)}$$

Equation 3-16 is used to estimate the uncertainty of a product or quotient of two parameters (X and Y) where the uncertainties are correlated and positive values. Here also, relative uncertainty values are used in the equation and the resulting combined uncertainty is on a relative basis.

$$U(rel)_{Correlated\ X\times Y} = \sqrt{\left(\frac{U_X}{X}\right)^2 + \left(\frac{U_Y}{Y}\right)^2 + 2r\left(\frac{U_X}{X} \times \frac{U_Y}{Y}\right)} \qquad \text{(Equation 3-16)}$$

Combining Uncertainties

It may be necessary to combine multiple uncertainty parameters associated with a single measured value, such as combining uncertainties for precision and bias. For uncertainty parameters that are independent, the combined uncertainty is calculated using the absolute uncertainties as shown in

Equation 3-13. Similarly, for uncertainty parameters that are related to each other, Equation 3-14 applies.

Correlation Coefficient

The correlation coefficient, r, used in Equations 3-14 and 3-16, is a number between -1 and 1, which measures the linear relationship between the uncertainties of two measured parameters. The value of r is zero when the parameters are independent. As stated previously, once the uncertainty propagation exceeds two terms and covariance occurs, the use of the Monte Carlo approach is preferable.

For two terms that might be correlated, the uncertainties are plotted against each other. For the purpose of this discussion, U_X represents the uncertainties of one variable plotted along the x-axis, and U_Y represents the uncertainties of the second variable plotted on the y-axis. The correlation coefficient, r, is determined by a linear regression of the U_X and U_Y values.

If one suspects that the uncertainty parameters are correlated, but data are not available to plot or calculate the correlation coefficient, the following rule-of-thumb values could be applied, using expert judgment (Franzblau, 1958)[7]:

r = 0: no correlation, the data are independent;
r = ±0.2: weak correlation;
r = ±0.5: medium correlation;
r = ±0.8: strong correlation; and
r = ±1: perfect correlation, the data fall on a straight line.

Additional details are provided in the *Uncertainty Document*.

3.7.2 Confidence Intervals from GRI/EPA Study

The GRI (currently known as the Gas Technology Institute) and EPA conducted a study in the early to mid 1990s to quantify CH_4 emissions from the U.S. natural gas industry. A sampling program was designed to address uncertainty, bias, and accuracy calculations, with an inventory accuracy objective of 0.5% of U.S. natural gas production on the basis of a 90% confidence interval (Harrison, et. al., 1996). Details on the statistical methods employed by the GRI/EPA study can be found in the documents: *Methane Emissions from the Natural Gas Industry*,

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[7] http://irp.savstate.edu/irp/glossary/correlation.html

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 limits within which the true value of an estimated number might be found for a given probability level. For the emission factors derived from the GRI/EPA study, the confidence intervals were determined from a sample of measurements, and the relative uncertainty defined as the ratio of the calculated confidence interval and the sample mean. Mathematically, the relative uncertainty is expressed as:

$$U(rel) = \pm t \times \frac{s(x)/\sqrt{n}}{\bar{x}} \times 100\% \qquad \text{(Equation 3-17)}$$

where

U(*rel*) = relative uncertainty;
t = student's t-distribution for "n-1" degrees of freedom, which gives a 95% confidence interval. This value is obtained from a standard table in most statistics books;
s(x) = standard deviation of the data set, calculated in Equation 3-18;
n = sample size for the set of data; and
$\bar{x}$ = mean (average) for the set of data.

$$s(x) = \sqrt{\frac{1}{n-1}\sum_{i=1}^{n}\left(x_i - \bar{x}\right)^2} \qquad \text{(Equation 3-18)}$$

where

$\bar{x}$ = mean (average) for the set of data;
x_i = i^{th} observation in the set of data; and
n = sample size for the set of data.

In Sections 5 and 6, confidence intervals are expressed in terms of uncertainty where emissions factors from the GRI/EPA study are cited. However, the values reported in this API *Compendium* have been updated to a 95% confidence interval to be more consistent with current statistical reporting practices. A 95% confidence interval indicates that there is a 5% chance that the true value falls outside the confidence interval.

3.7.3 Quality Ratings

EPA's AP-42 publication series and emission factor database (FIRE[8]) provide emission factor quality ratings. The *Introduction of the Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources* (EPA, 1995) and FIRE characterize emission factor ratings as follows:

A = Excellent. Emission factor is developed primarily from A and B-rated source test data[9] 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, 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.

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 low 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 that 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 locating and estimating documents and FIRE rather than in AP-42.

The combustion emission factors reported in Section 4, which are taken from EPA's AP-42 publications, cite these ratings.

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[8] FIRE is the EPA's emission factor database. FIRE includes emission factors from AP-42 (including AP-42 supplements) and locating and estimating documents, as well as revoked emission factors. The latest version of FIRE (WebFIRE, December 2005) can be found online at: http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main, accessed January 13, 2009.

[9] For descriptions of source test data ratings, see *Introduction to AP-42 Volume 1*, page 9 (EPA, 1995).

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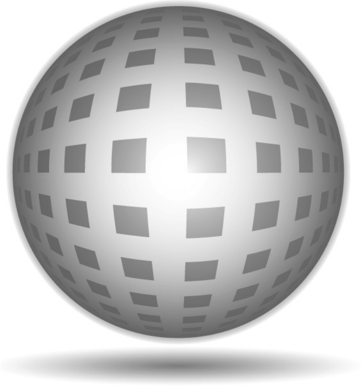
AMERICAN PETROLEUM INSTITUTE

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

AUGUST 2009

SECTION 4

COMBUSTION EMISSIONS ESTIMATION METHODS



Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry

Section 4 - Combustion Emissions Estimation Methods

August 2009

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4.0
COMBUSTION EMISSIONS ESTIMATION METHODS

This section addresses combustion emissions from stationary sources, mobile sources, flares, and other miscellaneous combustion sources. The approaches presented here are applicable to any fossil fuel-based combustion source.

Carbon dioxide, CH_4, and N_2O are produced and/or emitted as a result of combustion. Combustion of hydrocarbons can be represented by the following general reaction, assuming complete combustion:

$$\mathrm{C_xH_yO_z} + \left(x + \frac{y}{4} - \frac{z}{2} \right) \mathrm{O_2} \rightarrow (x)\ \mathrm{CO_2} + \left(\frac{y}{2} \right) \mathrm{H_2O} \qquad \text{(Equation 4-1)}$$

where

x = stoichiometric coefficient for carbon;
y = stoichiometric coefficient for hydrogen; and
z = stoichiometric coeffieicnt for oxygen.

Carbon dioxide emissions result from the oxidation of the hydrocarbons during combustion. Nearly all of the fuel carbon is converted to CO_2 during the combustion process, and this conversion is relatively independent of the fuel or firing configuration. Methane emissions may result from the incomplete combustion of the fuel, which is emitted as unburned CH_4. Incomplete combustion also results in other products such as carbon monoxide (CO) and volatile organic compounds (VOC)[1].

For petroleum industry operations, N_2O is formed during combustion by a complex series of reactions. Because its formation is dependent upon many factors, N_2O emissions can vary widely from unit to unit, and even vary within the same unit for different operating conditions. Typically the conditions that favor formation of N_2O also favor CH_4 emissions; these CH_4 emissions also vary with the type of fuel and firing configuration. Overall, CH_4 and N_2O emissions from combustion sources are significantly less than CO_2 emissions, on a CO_2 equivalent basis.

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[1] VOC excludes non-reactive hydrocarbons, such as methane and ethane. The definition of VOC is provided in the Glossary.

(Methane and N_2O emissions for stationary combustion sources are calculated separately using emission factors. See Section 4.5).

Because emissions from combustion sources comprise such a large part of a GHG inventory, it is important to understand the accuracy of the data used in the calculations. For example, fuel measurement data can be taken from flow meters, the accuracy of which can be affected by calibrations, inspection, and maintenance. Fuel composition can vary over time so emissions calculated using carbon content may or may not be representative, depending on the frequency of the sampling data and the variability of the fuel's composition. The accuracy of calculated emissions depends on the accuracy of the input data. Table 4-1 illustrates the range of available options for estimating combustion GHG emissions and associated considerations.

Table 4-1. Emission Estimation Approaches – GHG and Source-Specific Considerations for Combustion Sources

Types of Approaches	CO_2 Emissions	CH_4, N_2O Combustion Emissions
Published emission factors	• Based on "average" fuel carbon content • Commodity fuels generally have consistent compositions	• Based on "average" equipment characteristics • Uncertainty is consistent with generally low contribution to overall emissions
Equipment manufacturer emission factors	• CO_2 emissions are related more to fuel type than equipment characteristics • Manufacturer published emission factors are based on engine type, air/fuel ratio, and fuel type	• Emissions are closely related to equipment characteristics
Engineering calculations	• Highly reliable for many emission sources but dependent on methodology used and assumptions made • May require detailed input data	• Limited application for oil and natural gas industry operations (e.g., flares)
Monitoring over a range of conditions and deriving emission factors		
Periodic or continuous monitoring of emissions or parameters for calculating emissions	• Generally not practical for oil and natural gas operations given the substantial number of emission sources	• Not practical given the number of emission sources and the low contribution to overall emissions

Figure 4-1 provides a decision tree for selecting a stationary combustion calculation approach for estimating CO_2 emissions for all stationary combustion sources except flares (see Section 4.6).

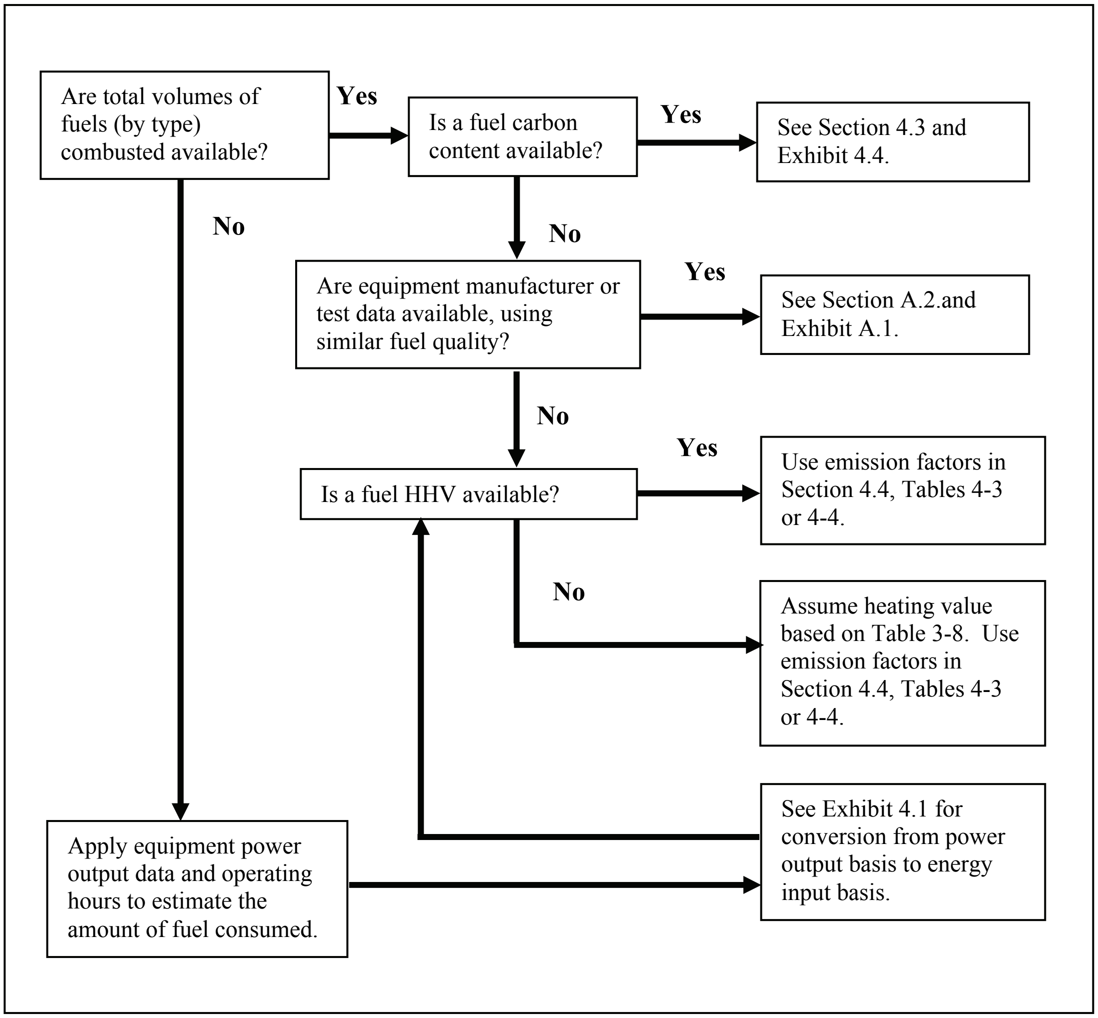

Figure 4-1. Calculating CO_2 Emissions from Stationary Combustion Sources (Not Including Flares)

Figure 4-1 provides several options based on the type of information available, such as volume of fuel combusted, fuel carbon content or HHV, equipment manufacturer or test data, and equipment power output data and operating hours. However, methodologies required by regulations take precedence over the options provided in the decision trees.

For CO_2 emissions from stationary combustion sources, the first 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 other estimation methods. A methodology for calculating fuel consumption is provided in Section 4.1 where metered fuel use is not available. Where volumes of fuel combusted are not available, the volume can be estimated based on the energy output of the combustion equipment, which is dependent on the equipment rating, efficiency, and hours of operation.

The emission factors provided in this section are provided on a HHV basis. Emission factors published by IPCC were originally on a LHV basis, but were converted to a HHV basis using the methodology described in Section 4.2.

Published emission factors for CO_2 provided in terms of tonnes per quantity of fuel consumed or tonnes per energy consumption of a given fuel are recognized as sufficient for estimating CO_2 emissions, as CO_2 emissions do not vary based on combustion technology (IPCC, 2006).

Methane emissions are estimated using published emission factors that incorporate a default fuel composition and CH_4 destruction efficiency based on the equipment type. These factors are discussed further in Section 4.5 for typical stationary combustion equipment, Section 4.6 for flares, and Section 4.8 for mobile sources. Where available, manufacturer supplied CH_4 emission factors may also be used.

Published emission factors are also used for estimating N_2O emissions from combustion sources. Where available, average N_2O emission factors based on reported test data are provided in Section 4.5 for typical stationary combustion equipment, Section 4.6 for flares, and Section 4.8 for mobile sources. Where available, manufacturer supplied N_2O emission factors may also be used.

Care must be taken to avoid double counting or underestimating emissions. In particular, fuel meters must be properly associated with the sources for which the emissions are being estimated, and fuel consumption should be accounted for all sources. For example, some refinery fuel gas sources may use supplemental natural gas as a fuel source. However, if emissions from the supplemental natural gas are already accounted for at a point further upstream, they should not be associated with the individual source because this would be double counting. In this case, measuring fuel consumption at a central header is desired unless equipment specific emission rates are needed. In addition, at a refinery, fuels are often metered at individual sources, but not all sources may be metered. In such a case, not all emissions would be accounted for using just the metered fuel rates.

4.1 Estimating Fuel Consumption Data from Energy Output or Volumetric Flow

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. Using actual fuel consumption data is the API *Compendium* preferred method for estimating combustion emissions; this section describes methods for estimating fuel consumption, if actual consumption data are not available. Inclusion of all fuel streams is essential when using fuel volumes for determining GHG emissions.

4.1.1 Estimating Fuel Consumption from Equipment Data

For some locations, measured fuel data are not available. In this situation, equipment fuel consumption rates are estimated by converting energy output to energy input. Required data for this approach are:

1. Equipment rating (horsepower). Actual horsepower is more accurate, but manufacturer or maximum horsepower and load can be used to estimate fuel usage, recognizing that these ratings will overestimate emissions.

2. Operating hours. If monthly operating hours are available, total operating hours can be calculated using Equation 4-2.

$$\mathrm{OT} = \sum_{i=1}^{\#\,\mathrm{Months}} \left(\frac{\mathrm{Total\ hours}}{\mathrm{Month}} \right)_i \qquad \text{(Equation 4-2)}$$

where

OT = annual operating time (hr/year).

Alternatively, if runtime is tracked as a percent, Equation 4-3 can be used to calculate total operating hours.

$$\mathrm{OT} = \sum_{i=1}^{\#\,\mathrm{Months}} \left(\frac{\mathrm{Default\ runtime}}{100} \times \frac{\mathrm{Total\ hours}}{\mathrm{Month}} \right)_i \qquad \text{(Equation 4-3)}$$

Finally, if downtime hours are tracked instead of runtime, total operating hours can be calculated using Equation 4-4.

$$\mathrm{OT} = \sum_{i=1}^{\#\,\mathrm{Months}} \left(\frac{\text{Total Hours}}{\text{Month}} - \frac{\text{Downtime hours}}{\text{Month}} \right)_i \qquad \text{(Equation 4-4)}$$

3. **Equipment thermal efficiency**. This is provided in terms of heat input per energy output (Btu/hp-hr). Equipment vendors may specify a Btu/hp-hr conversion factor for a particular device to convert between power output and energy input. In the absence of this information, Table 4-2 provides power conversion factors for some common combustion sources. These factors can be used to convert from a rated power output to an estimated energy input.

4. **Fuel properties.** Regardless of fuel type (gas or liquid), the heating value and carbon content of the fuel will be needed. If the fuel being combusted is a liquid, the density of the fuel will also be needed. It is important to use the same heating value basis (i.e., HHV or LHV) for both thermal efficiency and fuel property.

Using this approach, fuel usage is calculated on an equipment basis by combining the data identified in Items 1 through 4 above, as shown in Equation 4-5:

$$\mathrm{FC} = \mathrm{ER} \times \mathrm{LF} \times \mathrm{OT} \times \mathrm{ETT} \times \frac{1}{\mathrm{HV}} \qquad \text{(Equation 4-5)}$$

where

FC = annual fuel consumed (volume/yr);
ER = equipment rating (hp, kW, or J);
LF = equipment load factor (fraction);
OT = annual operating time (hr/yr);
ETT = equipment thermal efficiency (Btu $_{\text{input}}$/hp-hr $_{\text{output}}$, Btu $_{\text{input}}$/kW-hr $_{\text{output}}$, or J $_{\text{input}}$/J $_{\text{output}}$).; and
HV = fuel heating value (energy/volume).

Alternatively, some emission factors are reported on an energy input basis. The energy input is calculated using Equation 4-6.

$$E_{in} = \mathrm{ER} \times \mathrm{LF} \times \mathrm{OT} \times \mathrm{ETT} \qquad \text{(Equation 4-6)}$$

where

E_{in} = energy input (Btu, J);
ER = equipment rating (hp, kW, or J);
LF = equipment load factor (fraction);
OT = annual operating time (hr/yr); and
ETT = equipment thermal efficiency (Btu $_{\text{input}}$/hp-hr $_{\text{output}}$, Btu $_{\text{input}}$/kW-hr $_{\text{output}}$, or J $_{\text{input}}$/J $_{\text{output}}$).

Table 4-2. Energy Conversions by Generator Type

		Original Units	Converted Units				
			HHV Basis		LHV Basis [e]		
Generator Type	**Fuel Type**	**Btu/kW-hr**	**Btu/hp-hr**	**J (input)/ J (output)**	**Btu/kW-hr**	**Btu/hp-hr**	**J (input)/ J (output)**
Advanced Combustion Turbine [a]	Not Specified	9,289	6,927	2.722			
Advanced Gas / Oil Combined Cycle [a]	Not Specified	6,752	5,035	1.979			
Advanced Gas / Oil Combined Cycle with Carbon Sequestration [a]	Not Specified	8,613	6,423	2.524			
Biomass [a]	Not Specified	8,911	6,645	2.612			
Combined Heat and Power [c]	Natural Gas	5,000 – 6,000	3,729 – 4,474	1.465 – 1.758	4,750 – 5,700	3,542 – 4,250	1.392 – 1.671
Combined Cycle Single Shaft [b]	Natural Gas	8,952	6,676	2.624	8,057	6,008	2.361
Combined Cycle Steam Turbine with Supplemental Firing [b]	Natural Gas	10,229	7,628	2.998	9,206	6,865	2.698
Conventional Combustion Turbine [a]	Not Specified	10,833	8,078	3.175			
Conventional Gas / Oil Combined Cycle [a]	Not Specified	7,196	5,366	2.109			
Distributed Generation – Baseload [a]	Not Specified	9,200	6,860	2.696			
Distributed Generation – Peak [a]	Not Specified	10,257	7,649	3.006			
Fuel Cells [a]	Not Specified	7,930	5,913	2.324			
Gas Turbine [b]	Liquefied Propane Gas	13,503	10,069	3.957	12,828	9,566	3.759
	Natural Gas	13,918	10,379	4.079	12,526	9,341	3.671
	Refinery Gas	15,000	11,186	4.396	13,500	10,067	3.956
Geothermal [a]	Not Specified	35,376	26,380	10.368			
Integrated Coal-Gasification Combined Cycle [a]	Not Specified	8,765	6,536	2.569			
Integrated Coal-Gasification Combined Cycle with Carbon Sequestration [a]	Not Specified	10,781	8,039	3.160			
Internal Combustion Engine	Gasoline [d]	9,387 (converted)	7,000 (original units)	2.751	8,918	6,650	2.614
	Natural Gas [b]	10,538	7,858	3.088	9,484	7,072	2.780
	No. 2 Fuel Oil [b]	10,847	8,089	3.179	10,305	7,684	3.020
	Refinery Gas [b]	14,000	10,440	4.103	12,600	9,396	3.693

Table 4-2. Energy Conversions by Generator Type, continued

		Original Units	Converted Units				
		HHV Basis			LHV Basis [e]		
Generator Type	**Fuel Type**	**Btu/kW-hr**	**Btu/hp-hr**	**J (input)/ J (output)**	**Btu/kW-hr**	**Btu/hp-hr**	**J (input)/ J (output)**
Scrubbed Coal – New [a]	Not Specified	9,200	6,860	2.696			
Steam Turbine (Boiler) [b]	Coal (Anthracite)	11,792	8,793	3.456	11,202	8,354	3.283
	Coal (Bituminous)	9,941	7,413	2.913	9,444	7,042	2.768
	Coal (Lignite)	10,933	8,153	3.204	10,386	7,745	3.044
	Coal (Sub-Bituminous)	10,354	7,721	3.034	9,836	7,335	2.883
	Liquefied Propane Gas	14,200	10,589	4.162	13,490	10,059	3.954
	Natural Gas	10,502	7,831	3.078	9,452	7,048	2.770
	No. 2 Fuel Oil	8,653	6,453	2.536	8,220	6,130	2.409
	Refuse, Bagasses, non-wood	13,706	10,221	4.017	13,021	9,710	3.816
	Wood and Wood Waste	15,725	11,726	4.609	14,939	11,140	4.378

Footnotes and Sources:

[a] Energy Information Administration (EIA), *Assumptions to the Annual Energy Outlook 2008*, Table 38: Heat Rate In 2007, June 2008. Fuel type is not specified; assume heat rate is the same for all fuel types.

[b] Emission Inventory Improvement Program (EIIP), *Guidance for Emissions Inventory Development*, *Volume VIII: Estimating Greenhouse Gas Emissions*, EIIP Greenhouse Gas Committee, October 1999, Table 1.5-2.

[c] Assumed output to input energy conversion based on industry best practice.

[d] EPA, AP-42, Supplements A, B, and C, Table 3.3-1, October 1996.

[e] For generator types where fuel type is not specified, HHV basis values should be multiplied by 0.90 (for gaseous fuels) or 0.95 (for solid or liquid fuels) to convert to LHV basis values, as appropriate for the fuel(s) being used.

Exhibit 4.1 demonstrates this conversion.

EXHIBIT 4.1: Sample Calculation for Converting from Energy Output to Energy Input Basis Prior to Estimating Emissions

INPUT DATA:
A 100-hp gasoline-fired IC engine is operated for 8,000 hours at 90% load during the reporting year. Calculate the energy input (E_{in}) in both U.S. customary and SI units, on an HHV basis.

CALCULATION METHODOLOGY:
1. *Calculate E_{In} in U.S. customary units.* The power output is converted to an energy input basis using a conversion factor of 7,000 Btu/hp-hr (HHV basis) from Table 4-2.

$$E_{\text{In, US}} = 100 \text{ hp} \times 0.90 \times \frac{8000 \text{ hr}}{\text{yr}} \times \frac{7000 \text{ Btu}}{\text{hp-hr}}$$

$$\underline{E_{\text{In, US}} = 5.04 \times 10^{9} \text{ Btu/yr, HHV}}$$

2. *Calculate E_{In} in SI units.* The SI conversion factors presented in Table 4-2 are in units of J (input)/J (output). To convert the power output to energy input on an SI basis, the power output (P) must first be converted to energy output using a conversion factor from Table 3-4.

$$P = 100 \text{ hp} \times 0.90 \times \frac{8000 \text{ hr}}{\text{yr}} \times \frac{2.68452 \times 10^{6} \text{ J}}{\text{hp-hr}}$$

$$\underline{P = 1.933 \times 10^{12} \text{ J (output)/yr}}$$

Next, the energy output basis is converted to an input basis using a conversion factor of 2.751 J (input) / J (output) (HHV basis) from Table 4-2.

$$E_{\text{In, SI}} = \frac{1.933 \times 10^{12} \text{ J (output)}}{\text{yr}} \times \frac{2.751 \text{ J (input)}}{\text{J (output)}}$$

$$\underline{E_{\text{In, SI}} = 5.318 \times 10^{12} \text{ J (input)/yr (HHV)}}$$

4.1.2 Conversion from Volumetric Flow Rate to Energy Input

If the fuel input is provided on a volumetric basis (scf/yr, for example), then fuel HHV factors given in Table 3-8 can be used to convert the fuel volumetric rate to a fuel-fired heat input rate (in Btu/year, for example). Exhibit 4.2 demonstrates this conversion.

EXHIBIT 4.2: 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. Calculate the energy input (E_{In}) on an HHV basis.

CALCULATION METHODOLOGY:
The fuel volumetric rate is converted to heat input rate using a recommended HHV of 1020 Btu/scf for natural gas, provided in Table 3-8. Thus, the fuel heat input rate is:

$$E_{In} = \frac{800 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1020 \text{ Btu}}{\text{scf}}$$

$$\underline{E_{In} = 8.16 \times 10^{11} \text{ Btu/yr (HHV)}}$$

4.2 Conversion Between Gross and Net Heating Value

With the exception of the IPCC (IPCC, 2007), all of the combustion emission factor sources used in this section provide emission factors on a 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 the LHV is 5% lower than the HHV for coal and oil, and 10% lower for natural gas (IPCC, Volume 2, Chapter 2, Table 2.6, 2007). 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 that were originally reported on a LHV basis were converted to a HHV basis using Equations 4-7 (for gaseous fuels) and 4-8 (for solid/liquid fuels).[2]

For gaseous fuels,

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[2] Derivation of these equations (as noted in the footnotes to certain tables in this section) is provided in Appendix A.

$$EF_{HHV} = EF_{LHV} \times \left(\frac{1-0.1}{1} \right) \qquad \text{(Equation 4-7)}$$

where

EF = Emission factor, mass or energy basis.

For solid or liquid fuels:

$$EF_{HHV} = EF_{LHV} \times \left(\frac{1-0.05}{1} \right) \qquad \text{(Equation 4-8)}$$

Equations 4-7 and 4-8 were also used to convert any emission factors originally reported on a HHV basis to a LHV basis. For most stationary combustion sources, emission factors throughout Section 4 are presented on both a LHV basis and a HHV basis.

Exhibit 4.3 illustrates how to convert emission factors on an LHV basis to an HHV basis. The process for converting from an HHV basis to an LHV basis would be carried out in a similar manner.

EXHIBIT 4.3: Sample Calculation for Converting LHV to HHV

INPUT DATA:
IPCC reports the carbon factor of natural gas liquids as 17.5 kg C/GJ (17.5 tonne/10^{12} J) on an LHV basis (as shown in Table 4-3). Convert the carbon factor to a CO_2 emission factor (tonnes/Btu) on an HHV basis.

CALCULATION METHODOLOGY:
The first step in calculating the CO_2 emission factor is to convert the carbon factor to a HHV basis using Equation 4-8 and IPCC's assumption that the LHV for a liquid is 5% lower than the HHV. The conversion is shown below.

$$EF_{HHV} = \left(\frac{17.5 \text{ tonne C}}{10^{12} \text{ J}} \right)_{LHV} \times \left(\frac{1\text{-}0.05_{LHV}}{1_{HHV}} \right) = \left(\frac{16.63 \text{ tonne C}}{10^{12} \text{ J}} \right)_{HHV}$$

The carbon emission factor is then converted to a CO_2 emission factor using the compound molecular weights and the conversion factors presented in Table 3-4:

$$EF_{CO_2} = \frac{16.63 \text{ tonne C}}{10^{12}\text{J}} \times \frac{1055.056 \text{ J}}{\text{Btu}} \times \frac{44 \text{ tonne } CO_2\text{/tonne-mole } CO_2}{12 \text{ tonne C/tonne-mole C}}$$

$$\underline{EF_{CO_2} = 0.0643 \text{ tonnes } CO_2/10^6 \text{ Btu}}$$

4.3 Fuel Combustion Emissions Estimated from Fuel Composition and Usage

This section discusses estimating CO_2 emissions from fuel combustion. A material balance approach, based on fuel usage data and fuel carbon analyses, is the most reliable method for estimating emissions from stationary combustion sources. This approach applies to the combustion of any fuel, though fuel carbon analyses are likely more readily available for produced or purchased gas streams than for refinery gas, liquid or solid fuels.

The carbon content of a 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. This is accomplished by multiplying the molecular weight of carbon by the number of moles of carbon and dividing by the molecular weight of the compound. This is shown in Equation 4-9.

$$\mathrm{Wt\%C_{Cj}} = \frac{\frac{12\ \mathrm{lb\ C}}{\mathrm{lbmole\ C}} \times \frac{\mathrm{X\ lbmole\ C}}{\mathrm{lbmole\ Cj}}}{\mathrm{MW_{Cj}}\left(\frac{\mathrm{lb}}{\mathrm{lbmole}}\right)} \times 100\% \qquad \text{(Equation 4-9)}$$

where

$\mathrm{Wt\%\ C_{Cj}}$ = carbon content of individual hydrocarbon compound on a mass percent basis;
j = any hydrocarbon compound $C_xH_yO_z$ from Equation 4-1;
12 = molecular weight of carbon;
X = Stoichiometric coefficient for carbon (for example X=3 for pentane, C_3H_8); and
$\mathrm{MW_{C_XY}}$ = molecular weight of individual hydrocarbon compound.

The carbon content of the fuel mixture can then be calculated using Equation 4-10.

$$\mathrm{Wt\%C_{Mixture}} = \frac{1}{100} \times \sum_{i=1}^{\#\ \mathrm{components}} \left(\mathrm{Wt\%_i} \times \mathrm{Wt\%C_i}\right) \qquad \text{(Equation 4-10)}$$

where

$\mathrm{Wt\%\ C_{Mixture}}$ = carbon content of mixture, on mass percent basis;
$\mathrm{Wt\%_i}$ = weight percent of component *i*; and
$\mathrm{Wt\%C_i}$ = carbon content of component *i* on a weight percent basis, calculated using Equation 4-9.

The API *Compendium* has also adopted an assumption of complete combustion (i.e., 100% of the fuel carbon combusts to form CO_2) in estimating CO_2 emissions. This assumption applies to most combustion sources, with the exception of flares (see Section 4.6).

In addition to estimating CO_2 emissions based on 100% oxidation of fuel carbon, the API *Compendium* estimates CH_4 emissions from combustion sources based on emission factors. This approach accounts for potential emissions of CH_4 (which has a higher GWP than CO_2), which may exist in the atmosphere before CH_4 is completely oxidized to form CO_2. Additional information on atmospheric oxidation of emissions is provided in Appendix E.

Emissions of CO_2 are calculated using a mass balance approach. The equations are slightly different depending on whether the fuel combusted is a gas, liquid, or solid. For combustion of gaseous fuels, CO_2 emissions can be calculated using Equation 4-11, assuming 100% oxidation:

$$E_{CO_2} = FC \times \frac{1}{\text{molar volume conversion}} \times MW_{Mixture} \times Wt\%\, C_{Mixture} \times \frac{44}{12} \qquad \text{(Equation 4-11)}$$

where

E_{CO_2} = mass emissions of CO_2 (lb or kg);
FC = fuel consumed (scf or m^3);
Molar volume conversion = conversion from molar volume to mass (379.3 scf/lbmole or 23.685 m^3/kgmole);
$MW_{Mixture}$ = molecular weight of mixture; and
$\frac{44}{12}$ = stoichiometric conversion of C to CO_2.

Carbon dioxide emissions from the combustion of liquid fuels can be calculated using Equation 4-12, assuming 100% oxidation:

$$E_{CO_2} = FC \times D \times Wt\%\, C_{Mixture} \times \frac{44}{12} \qquad \text{(Equation 4-12)}$$

where

FC = fuel consumed (gal or m^3); and
D = fuel density (lb/gal or kg/m^3).

Similarly, emissions from the combustion of solid fuels are calculated using Equation 4-13, assuming 100% oxidation.

$$E_{CO_2} = FC \times Wt\%\, C_{Mixture} \times \frac{44}{12} \qquad \text{(Equation 4-13)}$$

where

FC = fuel consumed in mass units (lb, kg, tonnes).

The following examples illustrate the calculation approach for stationary combustion CO_2 emissions based on fuel composition and consumption rate, independent of the type of equipment. Exhibit 4.4(a) first demonstrates the scenario where the fuel composition is known and used directly to derive the fuel carbon content. The calculation is also shown [Exhibit 4.4(b)] for a case where complete composition data are not available, but fuel carbon content and molecular weight are known (or default values are applied).

EXHIBIT 4.4(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 and is given below. The weight percents of the fuel components have been calculated from the molar composition. (See Exhibit 3.4 for a similar example of this conversion.)

	Mole %	MW	Wt% (Calculated)
CO_2	0.8	44	2.1
CH_4	95.3	16	90.6
C_2H_6	1.7	30	3.0
C_3H_8	0.5	44	1.3
C_4H_{10}	0.1	58	0.3
N_2	1.6	28	2.7
Fuel Mixture	**100**	**16.84**	**100.0**

Calculate the annual CO_2 emissions.

CALCULATION METHODOLOGY:
The first step in calculating the CO_2 emissions is calculating the carbon content of the fuel mixture, as shown in Equation 4-10. To use Equation 4-10, the carbon contents of the individual constituents must be calculated using Equation 4-9. This is shown below for ethane (C_2H_6).

$$Wt\%C_{C_2H_6} = \frac{12 \text{ lb C}}{\text{lbmole C}} \times \frac{2 \text{ lbmoles C}}{\text{lbmole } C_2H_6} \times \frac{\text{lbmole } C_2H_6}{30 \text{ lb } C_2H_6} = \underline{0.8 \text{ lb C/lb } C_2H_6}$$

$$\underline{Wt\%C_{C_2H_6} = 80\% \text{ C}}$$

EXHIBIT 4.4(b): Sample Calculation for Fuel Basis (Gas Fuel) Combustion Emissions

CALCULATION METHODOLOGY:
To calculate the CO_2 emissions, the fuel consumption is converted to a mass basis using the volumetric conversions presented in Section 3. The molecular weight and carbon content of the gas are then used to convert the mass of gas combusted to a mass of carbon combusted. The CO_2 emissions are calculated below:

$$E_{CO_2} = \frac{22\times10^6 \text{ m}^3 \text{ fuel}}{\text{yr}} \times \frac{10^6 \text{ cm}^3 \text{ fuel}}{\text{m}^3 \text{ fuel}} \times \frac{\text{gmole fuel}}{23{,}685 \text{ cm}^3 \text{ fuel}} \times \frac{17.4 \text{ g fuel}}{\text{gmole fuel}} \times \frac{76.2 \text{ g C}}{100 \text{ g fuel}} \times \frac{\text{gmole C}}{12 \text{ g C}}$$

$$\times \frac{\text{gmole } CO_2}{\text{gmole C}} \times \frac{44 \text{ g } CO_2}{\text{gmole } CO_2} \times \frac{\text{tonnes}}{10^6 \text{ g}}$$

$$\underline{E_{CO_2} = 45{,}157 \text{ tonnes } CO_2/\text{yr}}$$

For a liquid fuel, Exhibit 4.5 demonstrates the emission calculation approach for a case where the fuel carbon content, density, and heating value are known.

EXHIBIT 4.5: 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. The density of the residual fuel is 8.3 lb/gallon; the wt% carbon of the fuel is 92.3%. Calculate the annual CO_2 emissions for a site where detailed fuel information is known (or default values are applied).

CALCULATION METHODOLOGY:
The CO_2 emissions are calculated based on the density and carbon content, as shown below.

$$E_{CO_2} = \frac{4\times10^6 \text{ gal fuel}}{\text{year}} \times \frac{8.3 \text{ lb fuel}}{\text{gal fuel}} \times \frac{92.3 \text{ lb C}}{100 \text{ lb fuel}} \times \frac{\text{lbmole C}}{12 \text{ lb C}} \times \frac{1 \text{ lbmole } CO_2}{1 \text{ lbmole C}} \times \frac{44 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonnes}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 50{,}966 \text{ tonnes } CO_2/\text{yr}}$$

4.4 Fuel Combustion Emissions Estimated on a Fuel Basis for Stationary Sources

As illustrated in the decision tree (Figure 4-1), if fuel carbon analyses are not available, emissions from fuel combustion may be estimated using default average fuel compositions. In addition, although this API *Compendium* has adopted an assumption of complete combustion in estimating CO_2 emissions, other protocols may apply a fractional conversion of carbon to estimate CO_2 emissions from combustion sources.[3] This section addresses the use of average fuel compositions and carbon oxidation values as an optional approach.

4.4.1 Emission Estimation Using Default Average Fuel Composition

If only the facility fuel consumption rate is known, and a fuel carbon analysis is not available, emission factors based on default average fuel compositions can be used to estimate combustion emissions. Table 4-3 lists CO_2 emission factors for common fuel types used in petroleum operations, while Table 4-4 lists CO_2 emission factors for more specialized and less common fuels. Similar factors are provided in Tables 4-5 and 4-6 for CH_4 and N_2O. 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 the use of fuel based CH_4 and N_2O emission factors does not take into account other factors which influence CH_4 and N_2O emissions, such as combustion and control technologies. The methodology for calculating CH_4 and N_2O emissions by equipment type is provided in Section 4.5.

4.4.2 Carbon Oxidation Values

The CO_2 emission factors shown in Tables 4-3 and 4-4 are converted from a carbon basis (mass of carbon emitted per fuel energy input) to a CO_2 basis, assuming all of the fuel carbon is oxidized to form CO_2 (i.e., 100% oxidation). As noted earlier, the carbon oxidation value reflects unoxidizable carbon that is emitted as a solid in soot or ash. In the past, some protocols have assumed that only a fraction of carbon emitted is oxidized; however, the 100% oxidation assumption is a common approach, adopted by the IPCC (2006), EIA (2008b) and EPA (2008). EIA notes that "unless the carbon is consciously sequestered, it is likely to oxidize over the next 100 years" (EIA, 2007).

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[3] The carbon oxidation factor is intended to reflect carbon that is emitted as soot or ash.

Table 4-3. CO_2 Combustion Emission Factors (Fuel Basis) for Common Industry Fuel Types

Fuel	Carbon Emission Factor from Original Source Document			CO_2 Emission Factor [a, b], US Units		CO_2 Emission Factor [a,b], SI Units	
	Emission Factor		Source[c]	tonnes/10^6 Btu (LHV)	tonnes /10^6 Btu (HHV)	tonnes /10^{12} J (LHV)	tonnes /10^{12} J (HHV)
Aviation Gas	18.87	MMTC/10^{15} Btu; Tg C/10^{15} Btu; kg C/MMBtu	Table 6-1, EIA, 2008; Table A-34, EPA, 2009; Table 12.1, TCR, 2008.	0.0728	0.0692	69.0	65.6
Bitumen	22.0	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007.	0.0851	0.0809	80.7	76.6
Coke	31.00	kg C/MMBtu	Table B-1, EPA, 2008; Table 12.1, TCR, 2008.	0.1199	0.1139	113.7	108.0
Coke (Coke Oven/Lignite/Gas)	29.2	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007.	0.1130	0.1073	107.1	101.7
Crude Oil	20.33	MMTC/10^{15} Btu; Tg C/10^{15} Btu; kg C/MMBtu	Table 6-1, EIA, 2008; Table A-34, EPA, 2009; Table 12.1, TCR, 2008.	0.0785	0.0745	74.4	70.7
Distillate Fuel (#1,2,4)	19.95	MMTC/10^{15} Btu or Tg C/10^{15} Btu; kg C/MMBtu	Table 6-1, EIA, 2008; Table A-34, EPA, 2009; Table 12.1, TCR, 2008.	0.0770	0.0732	73.0	69.3
Electric Utility Coal	No Data [c]		Table 6-1, EIA, 2008.	0.0997	0.0947	94.5	89.8
	25.76	Tg C/10^{15} Btu; kg C/MMBtu	Table A-35, EPA, 2009; Table 12.1, TCR, 2008.	0.0994	0.0945	94.2	89.5
Ethanol [d]	19.3	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007.	0.0747	0.0709	70.8	67.2
Flexicoker Low Btu Gas	278	lb CO_2/10^6 Btu (LHV)	Petroleum Industry Data.	0.1261	0.1135	119.5	107.6
Fuel Oil #4	45.8	lb C/10^6 Btu	Derived from fuel property data in Table 3-8.	0.0802	0.0762	76.0	72.2
Gas/Diesel Oil [e]	20.2	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007.	0.0781	0.0742	74.1	70.4
Jet Fuel	19.33	MMTC/10^{15} Btu; Tg C/10^{15} Btu; kg C/MMBtu	Table 6-1, EIA, 2008; Table A-34, EPA, 2009; Table 12.1, TCR, 2008.	0.0746	0.0709	70.7	67.2
Kerosene	19.72	MMTC/10^{15} Btu; Tg C/10^{15} Btu; kg C/MMBtu	Table 6-1, EIA, 2008; Table A-34, EPA, 2009; Table 12.1, TCR, 2008.	0.0761	0.0723	72.1	68.5
Lignite	26.30	MMTC/10^{15} Btu; kg C/MMBtu	Table 6-2, EIA, 2008; Table B-1, EPA, 2008; Table 12.1, TCR, 2008.	0.1015	0.0964	96.2	91.4
Liquefied Petroleum Gas (LPG)	No Data [c]		Table 6-1, EIA, 2008.	0.0656	0.0623	62.1	59.0
	17.23	kg C/MMBtu	Table B-1, EPA, 2008; Table 12.1, TCR, 2008.	0.0665	0.0632	63.0	59.9

Table 4-3. CO_2 Combustion Emission Factors (Fuel Basis) for Common Industry Fuel Types, continued

	Carbon Emission Factor from Original Source Document			CO_2 Emission Factor [a, b], US Units		CO_2 Emission Factor [a, b], SI Units	
Fuel	Emission Factor		Source	tonnes /10^6 Btu (LHV)	tonnes /10^6 Btu (HHV)	tonnes /10^{12} J (LHV)	tonnes /10^{12} J (HHV)
Butane (normal)	17.71	MMTC/10^{15} Btu	Table 1-5, EIA, 2008.	0.0684	0.0649	64.8	61.5
	17.72	Tg C/10^{15} Btu; kg C/MMBtu	Table A-42, EPA, 2009; Table 12.1, TCR, 2008.	0.0684	0.0650	64.8	61.6
Ethane	16.25	MMTC/10^15 Btu; Tg C/10^15 Btu; kg C/MMBtu	Table 1-5, EIA, 2008; Table A-42, EPA, 2009; Table 12.1, TCR, 2008.	0.0627	0.0596	59.4	56.5
Isobutane	17.75	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 1-5, EIA, 2008; Table A-42, EPA, 2009.	0.0685	0.0651	64.9	61.7
Propane	17.20	MMTC/10^{15} Btu; Tg C/10^{15} Btu; kg C/MMBtu	Table 1-5, EIA, 2008; Table A-42, EPA, 2009; Table 12.1, TCR, 2008.	0.0664	0.0631	62.9	59.8
Miscellaneous Product [e,f]	No Data [c]		Table 6-1, EIA, 2008.	0.0785	0.0745	74.4	70.7
Motor Gasoline (Petrol)	19.33	MMTC/10^{15} Btu; Tg C/10^{15} Btu; kg C/MMBtu	Table 6-1, EIA, 2008; Table A-34, EPA, 2009; Table 12.1, TCR, 2008.	0.0746	0.0709	70.7	67.2
Naphtha (<401°F)	18.14	Tg C/10^{15} Btu; kg C/MMBtu	Table A-34, EPA, 2009; Table 12.1, TCR, 2008.	0.0700	0.0665	66.4	63.0
Nat. Gas Liquids	17.5	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007.	0.0677	0.0643	64.2	61.0
Natural Gas (Pipeline) [g]	14.47	MMTC/10^{15} Btu; kg C/MMBtu	Table 6-1, EIA, 2007; Table B-1, EPA, 2008; Table 12.1, TCR, 2008.	0.0590	0.0531	55.9	50.3
Natural Gas (Flared – 1,130 Btu/scf basis) [h]	No Data [c]		Table 6-1, EIA, 2008.	0.0608	0.0547	57.6	51.9
Other Bituminous Coal	25.8	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007.	0.0998	0.0948	94.6	89.9
Other Oil (>401°F)	19.95	Tg C/10^{15} Btu; kg C/MMBtu	Table A-34, EPA, 2009; Table 12.1, TCR, 2008.	0.0770	0.0732	73.0	69.3
Pentanes Plus	18.24	Tg C/10^{15} Btu; kg C/MMBtu	Table A-34, EPA, 2009; Table 12.1, TCR, 2008.	0.0704	0.0669	66.7	63.4
Petroleum Coke [i]	27.85	MMTC/10^{15} Btu; Tg C/10^{15} Btu; kg C/MMBtu	Table 6-1, EIA, 2008; Table A-34, EPA, 2009; Table 12.1, TCR, 2008.	0.1075	0.1021	101.9	96.8
Refinery Gas	15.7	kg C/10^9 J (LHV)	Table 1.3, IPCC, 2007.	0.0607	0.0547	57.6	51.8

Table 4-3. CO_2 Combustion Emission Factors (Fuel Basis) for Common Industry Fuel Types, continued

	Carbon Emission Factor from Original Source Document			CO_2 Emission Factor [a, b], US Units		CO_2 Emission Factor [a, b], SI Units	
Fuel	**Emission Factor**		**Source**	**tonnes /10^6 Btu (LHV)**	**tonnes /10^6 Btu (HHV)**	**tonnes /10^{12} J (LHV)**	**tonnes /10^{12} J (HHV)**
Residual Oil #5	46.9	lb C/10^6 Btu	Derived from fuel property data in Table 3-8.	0.0821	0.0780	77.8	73.9
Residual Oil #6[j]	21.49	MMTC/10^{15} Btu; Tg C/10^{15} Btu; kg C/MMBtu	Table 6-1, EIA, 2008; Table A-34, EPA, 2009; Table 12.1, TCR, 2008.	0.0829	0.0788	78.6	74.7
Special Naphtha	19.86	Tg C/10^{15} Btu; kg C/MMBtu	Table A-34, EPA, 2009; Table 12.1, TCR, 2008.	0.0767	0.0728	72.7	69.0
Still Gas	17.51	Tg C/10^{15} Btu; kg C/MMBtu	Table A-34, EPA, 2009; Table 12.1, TCR, 2008.	0.0713	0.0642	67.6	60.9
Sub-bituminous Coal	26.48	MMTC/10^{15} Btu; Tg C/10^{15} Btu; kg C/MMBtu	Table 6-2, EIA, 2008; Table A-35, EPA, 2009; Table 12.1, TCR, 2008.	0.1022	0.0971	96.9	92.0
Unfinished Oils [e,f]	20.33	MMTC/10^{15} Btu; Tg C/10^{15} Btu; kg C/MMBtu	Table 6-1, EIA, 2008; Table A-34, EPA, 2009; Table 12.1, TCR, 2008.	0.0785	0.0745	74.4	70.7

Footnotes and Sources:

Energy Information Administration (EIA). *Documentation for Emissions of Greenhouse Gases in the United States 2006*, DOE/EIA-0638(2006), October 2008.

Energy Information Administration (EIA). *Emissions of Greenhouse Gases in the United States* 1987-1992, DOE/EIA-0573, October 1994.

U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007,* Annexes, April 15, 2009.

U.S. Environmental Protection Agency (EPA). Climate Leaders. *Greenhouse Gas Inventory Protocol Core Module Guidance: Direct Emissions from Stationary Combustion Sources*. EPA 430-K-08-003, May 2008 (2008).

Intergovernmental Panel on Climate Change (IPCC). *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 2, Chapter 1, 2006 Revised April 2007.

The Climate Registry (TCR). *General Reporting Protocol,* Version 1.1, May 2008.

[a] CO_2 emission factors shown are based on the default API *Compendium* assumption of 100% oxidation.

[b] 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).

[c] Factors from EIA, 2008 Tables 6-1 and 6-2 are presented in 10^6 tonne/10^{15} Btu.

[d] Theoretical number. Under international GHG accounting methods developed by the IPCC, biogenic carbon is considered to be part of the natural carbon balance and does not add to atmospheric concentrations of CO_2.

[e] Term is defined in the Glossary.

[f] Carbon content assumed to be the same as for Crude Oil (EIA, 2007).

[g] Natual gas carbon coefficient is based on a weighted U.S. national average.

[h] Flared gas is assumed to be rich associated gas, with an energy content of 1,130 Btu/scf. Factor does not apply to higher heating value gases such as associated gas (raw inlet gas) with heating values of 1300-1400 Btu/scf (EIA, 1994).

[i] Note that catalyst coke is not the same as petroleum coke/marketable coke. Catalyst coke refers to coke formed on catalysts while petroleum/marketable coke is coke that is the “final product of thermal decomposition in the condensation process in cracking” (EIA, 2008b). Carbon dioxide emissions from catalyst coke are discussed in Section 5.

[j] Values are defined in reference documents as for both residual fuel oil No. 5 and residual fuel oil No. 6.

Table 4-4. CO_2 Combustion Emission Factors (Fuel Basis) for Specialized Fuel Types

Fuel	Carbon Emission Factor from Original Source Document			CO_2 Emission Factor [a, b], US Units		CO_2 Emission Factor [a, b], SI Units	
	Emission Factor		Source[c]	tonnes /10^6 Btu (LHV)	tonnes /10^6 Btu (HHV)	tonnes /10^{12} J (LHV)	tonnes /10^{12} J (HHV)
Anthracite Coal	28.26	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-2, EIA, 2008; Table A-35, EPA, 2009; Table 12.1, TCR, 2008.	0.1091	0.1036	103.4	98.2
Asphalt and Road Oil	20.62	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-1, EIA, 2008; Table A-34, EPA, 2009; Table 12.1, TCR, 2008.	0.0796	0.0756	75.4	71.7
Bituminous Coal	25.49	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-2, EIA, 2008; Table A-35, EPA, 2009; Table 12.1, TCR, 2008.	0.0984	0.0935	93.2	88.6
Industrial Coking Coal		No Data [c]	Table 6-1, EIA, 2008.	0.0986	0.0937	93.5	88.8
Lubricants	20.24	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-1, EIA, 2008; Table A-34, EPA, 2009; Table 12.1, TCR, 2008.	0.0781	0.0742	74.0	70.3
Oil Shale and Tar Sands	29.1	kg C/GJ (LHV)	Table 1.3, IPCC, 2007.	0.113	0.107	106.7	101.4
Other Industrial Coal		No Data [c]	Table 6-1, EIA, 2008.	0.0989	0.0940	93.8	89.1
	25.63	Tg C/10^{15} Btu	Table A-35, EPA, 2009; Table 12.1, TCR, 2008.	0.0989	0.0940	93.8	89.1
Peat	28.9	kg C/GJ (LHV)	Table 1.3, IPCC, 2007.	0.1118	0.1062	106.0	100.7
Petrochemical Feedstocks	19.37	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-1, EIA, 2008; Table A-34, EPA, 2009; Table 12.1, TCR, 2008.	0.0748	0.0710	70.9	67.3
Residential/Commercial Coal		No Data [c]	Table 6-1, EIA, 2008.	0.1004	0.0953	95.1	90.4
	26.00	Tg C/10^{15} Btu	Table A-35, EPA, 2009; Table 12.1, TCR, 2008.	0.1004	0.0953	95.1	90.4
Shale Oil	20.0	kg C/GJ (LHV)	Table 1.3, IPCC, 2007.	0.0774	0.0735	73.3	69.7
Petroleum Waxes	19.81	MMTC/10^{15} Btu; Tg C/10^{15} Btu	Table 6-1, EIA, 2008; Table A-34, EPA, 2009; Table 12.1, TCR, 2008.	0.0765	0.0726	72.5	68.8
Tires/Tire Derived Fuel	86.0	kg CO_2/MMBtu	Appendix H, EIA, 2007b.	0.0905	0.0860	85.8	81.5
Waste Oil [c]	9.98	kg CO_2/gal	Appendix H, EIA, 2007b.	No data			

Footnotes and Sources:

Energy Information Administration (EIA). *Documentation for Emissions of Greenhouse Gases in the United States 2006* , DOE/EIA-0638(2006), October 2008.

Energy Information Administration (EIA). *Instructions for Form EIA-1605,* OMDB No. 1905-0194, October 2007 (2007b).

Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, Annexes, April 15, 2009.

Intergovernmental Panel on Climate Change (IPCC). *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 2, Chapter 1, 2006 Revised April 2007.

The Climate Registry (TCR). *General Reporting Protocol,* Version 1.1, May 2008.

[a] CO_2 emission factors shown are based on the default API *Compendium* assumption of 100% oxidation.

[b] 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).

[c] Factors from EIA, 2008 Tables 6-1 and 6-2 are presented in 10^6 tonne/10^{15} Btu.

Table 4-5. CH_4 and N_2O Combustion Emission Factors (Fuel Basis) for Common Industry Fuel Types [a]

	CH_4 Emission Factor [b], US Units		CH_4 Emission Factor [b], SI Units		N_2O Emission Factor [b], US Units		N_2O Emission Factor [b], SI Units	
Fuel	**tonnes /10^6 Btu (LHV)**	**tonnes /10^6 Btu (HHV)**	**tonnes /10^{12} J (LHV)**	**tonnes /10^{12} J (HHV)**	**tonnes /10^6 Btu (LHV)**	**tonnes /10^6 Btu (HHV)**	**tonnes /10^{12} J (LHV)**	**tonnes /10^{12} J (HHV)**
Aviation Gasoline/Jet Gasoline	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Biogasoline	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Biodiesels	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Bitumen	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Coke Oven and Lignite Coke	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.58E-06	1.50E-06	1.50E-03	1.42E-03
Crude Oil	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Ethane	1.06E-06	1.00E-06	1.00E-03	9.50E-04	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Gas Coke	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.06E-07	1.00E-07	1.00E-04	9.50E-05
Gas/Diesel Oil	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Jet Gasoline	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Jet Kerosene	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Lignite	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.58E-06	1.50E-06	1.50E-03	1.42E-03
LPG	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.06E-07	1.00E-07	1.00E-04	9.50E-05
Motor Gasoline	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Naphtha	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Natural Gas	1.06E-06	9.50E-07	1.00E-03	9.00E-04	1.06E-07	9.50E-08	1.00E-04	9.00E-05
Natural Gas Liquids	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Other Biogas	1.06E-06	9.50E-07	1.00E-03	9.00E-04	1.06E-07	9.50E-08	1.00E-04	9.00E-05
Other Kerosene	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Other Liquid Biofuels	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Other Petroleum Products	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Other Primary Solid Biomass	3.17E-05	3.01E-05	3.00E-02	2.85E-02	4.22E-06	4.01E-06	4.00E-03	3.80E-03
Paraffin Waxes	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Petroleum Coke	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Residual Fuel Oil	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Sub-Bituminous Coal	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.58E-06	1.50E-06	1.50E-03	1.42E-03
Wood/Wood Waste	3.17E-05	3.01E-05	3.00E-02	2.85E-02	4.22E-06	4.01E-06	4.00E-03	3.80E-03

Footnotes and Sources:

[a] Intergovernmental Panel on Climate Change (IPCC). *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 2, Chapter 2, Table 2.2, 2006 Revised April 2007.

[b] Converted from original units of kg/TJ (LHV). 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).

Table 4-6. CH$_4$ and N$_2$O Combustion Emission Factors (Fuel Basis) for Specialized Fuel Types [a]

Fuel	CH$_4$ Emission Factor [b], US Units		CH$_4$ Emission Factor [b], SI Units		N$_2$O Emission Factor [b], US Units		N$_2$O Emission Factor [b], SI Units	
	tonnes /10^6 Btu (LHV)	tonnes /10^6 Btu (HHV)	tonnes /10^{12} J (LHV)	tonnes /10^{12} J (HHV)	tonnes /10^6 Btu (LHV)	tonnes /10^6 Btu (HHV)	tonnes /10^{12} J (LHV)	tonnes /10^{12} J (HHV)
Anthracite	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.58E-06	1.50E-06	1.50E-03	1.42E-03
Charcoal	2.11E-04	2.00E-04	2.00E-01	1.90E-01	4.22E-06	4.01E-06	4.00E-03	3.80E-03
Coal Tar	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.58E-06	1.50E-06	1.50E-03	1.42E-03
Coke Oven Gas	1.06E-06	9.50E-07	1.00E-03	9.00E-04	1.06E-07	9.50E-08	1.00E-04	9.00E-05
Coking Coal	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.58E-06	1.50E-06	1.50E-03	1.42E-03
Landfill Gas	1.06E-06	9.50E-07	1.00E-03	9.00E-04	1.06E-07	9.50E-08	1.00E-04	9.00E-05
Lubricants	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Oil Shale and Tar Sands	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.58E-06	1.50E-06	1.50E-03	1.42E-03
Other Bituminous Coal	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.58E-06	1.50E-06	1.50E-03	1.42E-03
Peat	1.06E-06	1.00E-06	1.00E-03	9.50E-04	1.58E-06	1.50E-06	1.50E-03	1.42E-03
Refinery Feedstocks	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Refinery Gas	1.06E-06	9.50E-07	1.00E-03	9.00E-04	1.06E-07	9.50E-08	1.00E-04	9.00E-05
Shale Oil	3.17E-06	3.01E-06	3.00E-03	2.85E-03	6.33E-07	6.01E-07	6.00E-04	5.70E-04
Sludge Gas	1.06E-06	9.50E-07	1.00E-03	9.00E-04	1.06E-07	9.50E-08	1.00E-04	9.00E-05
Waste Oils	3.17E-05	3.01E-05	3.00E-02	2.85E-02	4.22E-06	4.01E-06	4.00E-03	3.80E-03

Footnotes and Sources:

[a] Intergovernmental Panel on Climate Change (IPCC). *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 2, Chapter 2, Table 2.2, 2006 Revised April 2007.

[b] Converted from original units of kg/TJ (LHV). 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).

Exhibit 4.6 illustrates the use of the fuel-based emission factors for the 100% oxidation approach. Note the difference between the emission estimate calculated in Exhibit 4.5, where the fuel composition data are known, and Exhibit 4.6, where CO_2 emissions are calculated based on an emission factor that incorporates a default fuel composition.

EXHIBIT 4.6: 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 CO_2 emissions, CH_4, and N_2O emissions.

CALCULATION METHODOLOGY:
1. *Calculate the CO_2 emissions.* If only the fuel type is known, an emission factor can be obtained from Table 4-3. Although the carbon emission factors presented in Table 4-3 have already been converted to CO_2 emission factors, the CO_2 emission factor for residual fuel oil #6 is re-calculated from the carbon emission factor as a demonstration in this exhibit. From Table 4-3, the carbon emission factor for residual fuel oil #6 is 21.49 MMTC/10^{15} Btu (10^6 tonne C/10^{15} Btu) (HHV). This factor is converted to a CO_2 basis as shown below:

$$EF_{CO_2} = \frac{21.49 \text{ MMTC}}{\text{QBtu}} \times \frac{10^6 \text{ tonne C}}{\text{MMTC}} \times \frac{2204.62 \text{ lb C}}{\text{tonne C}} \times \frac{\text{QBtu}}{10^{15} \text{ Btu}} \times \frac{10^6 \text{ Btu}}{\text{MMBtu}} \times$$

$$\frac{\text{lbmole C}}{12 \text{ lb C}} \times \frac{1 \text{ lbmole } CO_2}{1 \text{ lbmole C}} \times \frac{44 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne } CO_2}{2204.62 \text{ lb } CO_2}$$

$$EF_{CO_2} = 0.0788 \text{ tonnes } CO_2/10^6 \text{ Btu (HHV)}$$

Because the emission factor is on an energy basis, the fuel consumption must be converted to energy consumption using the heating value or energy content for the fuel type. (Default heating values are provided in Table 3-8 for some fuels.) The annual CO_2 emissions are calculated using the fuel usage data, default emission factor, and default heating value from Table 3-8.

$$E_{CO_2} = \frac{173.72 \text{ lb } CO_2}{10^6 \text{ Btu}} \times \frac{4\times10^6 \text{ gal fuel}}{\text{year}} \times \frac{\text{bbl fuel}}{42 \text{ gal fuel}} \times \frac{6.29\times10^6 \text{ Btu}}{\text{bbl fuel}} \times \frac{\text{tonnes}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 47{,}204 \text{ tonnes } CO_2/\text{yr}}$$

2. *Calculate the CH_4 and N_2O emissions.* Methane and N_2O emissions are calculated using the emission factors for residual fuel oil in Table 4-5.

EXHIBIT 4.6: Sample Calculation for Fuel Basis (Liquid Fuel) Combustion Emissions - Known (or assumed): Higher Heating Value (HHV) only, continued

$$E_{CH_4} = \frac{3.01\times10^{-6}\ \text{tonne CH}_4}{10^6\ \text{Btu}} \times \frac{4\times10^6\ \text{gal fuel}}{\text{year}} \times \frac{\text{bbl fuel}}{42\ \text{gal fuel}} \times \frac{6.29\times10^6\ \text{Btu}}{\text{bbl fuel}}$$

$$\underline{E_{CH_4} = 1.80\ \text{tonne CH}_4/\text{yr}}$$

$$E_{N_2O} = \frac{6.01\times10^{-7}\ \text{tonne N}_2\text{O}}{10^6\ \text{Btu}} \times \frac{4\times10^6\ \text{gal fuel}}{\text{year}} \times \frac{\text{bbl fuel}}{42\ \text{gal fuel}} \times \frac{6.29\times10^6\ \text{Btu}}{\text{bbl fuel}}$$

$$\underline{E_{N_2O} = 0.36\ \text{tonne N}_2\text{O/yr}}$$

4.5 Fuel Combustion Emissions Estimated on an Equipment Basis for Stationary Sources

If the fuel usage is known for the specific type of equipment (e.g., boiler, turbine, IC engine, etc.) or groups of the same equipment, then emission factors can be used to estimate non-CO_2 emissions (CH_4 and N_2O).

Other GHG reporting protocol documents may provide CO_2 emission factors for stationary combustion on an equipment basis. However, these emission factors are inconsistent with the API *Compendium's* approach of estimating CO_2 emissions based on 100% oxidation of the fuel carbon, and the recognition that CO_2 emissions are independent of the type of combustion equipment. Most of the emission factors are taken from EPA's AP-42 (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[4].

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[4] Accessed January 7, 2009.

4.5.1 External Combustion Units

Tables 4-7 and 4-8 provide CH_4 and N_2O emission factors for external combustion devices. Factors in Tables 4-7 and 4-8 are 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 Asociacion Regional De Empresas De Petroleo Y Gas Natural EN LatinoAmerica Y El Caribe (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, 2007). Table 4-7 applies to liquid and gaseous fuels while Table 4-8 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 firing rate is given on a volume or mass basis, the heating values for various fuels provided in Table 3-8 of this document can be used to convert the fuel firing rate (energy input basis) to an energy basis.

An example calculation for CH_4 and N_2O emissions from an external combustion device is shown in Exhibit 4.7.

EXHIBIT 4.7: Sample Calculation for Combustion Emissions Equipment Basis for External Combustion Device

INPUT DATA:
800 million (10^6) scf/year of natural gas is burned in a boiler with a low-NO_x burner. The heating value of the gas is 1032 Btu/scf (HHV). Calculate the CH_4 and N_2O emissions.

CALCULATION METHODOLOGY:
Methane and N_2O emissions are calculated by converting the quantity of fuel burned to a Btu basis and multiplying the result by the emission factors provided in Table 4-7.

$$E_{CH_4} = \frac{800\times10^6 \text{ scf}}{\text{yr}} \times \frac{1032 \text{ Btu}}{\text{scf}} \times \frac{1.0\times10^{-6} \text{ tonne CH}_4}{10^6 \text{ Btu}} = \underline{0.83 \text{ tonnes CH}_4\text{/yr}}$$

$$E_{N_2O} = \frac{800\times10^6 \text{ scf}}{\text{yr}} \times \frac{1032 \text{ Btu}}{\text{scf}} \times \frac{2.8\times10^{-7} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}} = \underline{0.23 \text{ tonnes N}_2\text{O/yr}}$$

Table 4-7. Equipment-Specific Combustion Emission Factors for Boilers and Furnaces (Gas and Liquid Fuels)

Original Units

Source	**Methane**		**Emission Factor Rating [d]**	**Nitrous Oxide**		**Emission Factor Rating [d]**	**Source (version date)**
Boilers/furnaces/heaters – Natural gas							
Controlled	2.3	lb/10^6 scf	B	0.64[a]	lb/10^6 scf [a]	E	AP-42 Table 1.4-2 (7/98)
Not controlled				2.2[b]	lb/10^6 scf [b]		
Boilers/furnaces/heaters – Diesel	7.8E-06	lb/lb	Not available	Not available			E&P Forum, 1994
Heater – Refinery fuel gas (low H_2-content gas)							
< 9.9 x 10^6 Btu/hr	0.263	tonne/PJ (HHV)	Not available	Not available			Table 6.4 of ARPEL, 1998
9.9 – 99 x 10^6 Btu/hr	0.293	tonne/PJ (HHV)	Not available	0.035	tonne/PJ (HHV)	Not available	
>99 x 10^6 Btu/hr	0.293	tonne/PJ (HHV)	Not available	Not available			
Heater – Refinery fuel gas (High H_2-content gas)							
< 9.9 x 10^6 Btu/hr	0.193	tonne/PJ (HHV)	Not available	Not available			Table 6.4 of ARPEL, 1998
9.9 – 99x10^6 Btu/hr	0.215	tonne/PJ (HHV)	Not available	0.035	tonne/PJ (HHV)	Not available	
> 99 x 10^6 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/Propane	0.2	lb/1000 gal	E	0.9	lb/1000 gal	E	AP-42 Table 1.5-1 (07/08)
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 4-7. Equipment-Specific Combustion Emission Factors for Boilers and Furnaces (Gas and Liquid Fuels), continued

Emission Factors Converted to tonne/gal or tonne/10^6 Btu (HHV and LHV, as indicated)

Source	Methane	Emission Factor Rating [d]	Nitrous Oxide	Emission Factor Rating [d]	Source (version date)
Boilers/furnaces/heaters – Natural gas					
Controlled	1.0E-06 tonne/10^6 Btu (HHV)[c] 1.1E-06 tonne/10^6 Btu (LHV)[c]	B	2.8E-07 tonne/10^6 Btu (HHV) [a,c] 3.0E-07 tonne/10^6 Btu (LHV) [a,c]	E E	AP-42 Table 1.4-2 (7/98)
Not controlled	1.0E-06 tonne/10^6 Btu (HHV)[c] 1.1E-06 tonne/10^6 Btu (LHV)[c]	B	9.8E-07 tonne/10^6 Btu (HHV) [b,c] 1.0E-06 tonne/10^6 Btu (LHV) [b,c]	E E	AP-42 Table 1.4-2 (7/98)
Boilers/furnaces/heaters – Diesel	7.8E-06 tonne/ tonne	Not available	Not available		E&P Forum, 1994
Heater – Refinery fuel gas (low H_2-content gas)					
< 9.9 x 10^6 Btu/hr	2.77E-07 tonne/10^6 Btu (HHV) 3.08E-07 tonne/10^6 Btu (LHV)	Not available	Not available		Table 6.4 of ARPEL, 1998
9.9 – 99 x 10^6 Btu/hr	3.09E-07 tonne/10^6 Btu (HHV) 3.43E-07 tonne/10^6 Btu (LHV)	Not available	3.69E-08 tonne/10^6 Btu (HHV) 4.10E-08 tonne/10^6 Btu (LHV)	Not available	
> 99 x 10^6 Btu/hr	3.09E-07 tonne/10^6 Btu (HHV) 3.43E-07 tonne/10^6 Btu (LHV)	Not available	Not available		
Heater – Refinery fuel gas (High H_2-content gas)					
< 9.9 x 10^6 Btu/hr	2.04E-07 tonne/10^6 Btu (HHV) 2.26E-07 tonne/10^6 Btu (LHV)	Not available	Not available		Table 6.4 of ARPEL, 1998
9.9 – 99 x 10^6 Btu/hr	2.27E-07 tonne/10^6 Btu (HHV) 2.52E-07 tonne/10^6 Btu (LHV)	Not available	3.69E-08 tonne/10^6 Btu (HHV) 4.10E-08 tonne/10^6 Btu (LHV)	Not available	
> 99 x 10^6 Btu/hr	2.27E-07 tonne/10^6 Btu (HHV) 2.52E-07 tonne/10^6 Btu (LHV)	Not available	Not available		
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	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Industrial boiler – No. 4 or distillate oil	2.4E-08 tonne/gal	A	1.2E-07 tonne/gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00

Table 4-7. Equipment-Specific Combustion Emission Factors for Boilers and Furnaces (Gas and Liquid Fuels), continued

Emission Factors Converted to tonne/gal or tonne/10^6 Btu (HHV and LHV, as indicated), continued

Source	Methane	Emission Factor Rating [d]	Nitrous Oxide	Emission Factor Rating [d]	Source (version date)
Commercial combustors – No. 5/6 oil	2.15E-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
Commercial combustors – No. 4 or distillate	9.80E-08 tonne/gal	A	1.2E-07 tonne/gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98) - errata updated 4/28/00
Industrial/commercial boilers – Butane/Propane	9.1E-08 tonne/gal	E	4.1E-07 tonne/gal	E	AP-42 Table 1.5-1 (07/08)
Residential furnace – Fuel oil	8.07E-07 tonne/gal	A	2.3E-08 tonne/gal	B	AP-42 Tables 1.3-3 and 1.3-8 (9/98)

Emission Factors Converted to tonne/m^3 or tonne/10^{12} J (HHV and LHV, as indicated)

Source	Methane	Emission Factor Rating [d]	Nitrous Oxide	Emission Factor Rating [d]	Source (version date)
Boilers/furnaces/heaters – Natural gas					
Controlled	9.7E-04 tonne/10^{12} J (HHV)[c] 1.1E-03 tonne/10^{12} J (LHV)[c]	B	2.7E-04 tonne/10^{12} J (HHV) [a,c] 2.8E-04 tonne/10^{12} J (LHV) [a,c]	E E	AP-42 Table 1.4-2 (7/98)
Not controlled	9.7E-04 tonne/10^{12} J (HHV)[c] 1.1E-03 tonne/10^{12} J (LHV)[c]	B	9.3E-04 tonne/10^{12} J (HHV) [b,c] 9.8E-04 tonne/10^{12} J (LHV) [b,c]	E E	AP-42 Table 1.4-2 (7/98)
Boilers/furnaces/heaters – Diesel	7.8E-06 tonne/ tonne	Not available	Not available		E&P Forum, 1994
Heater – Refinery fuel gas (low H_2-content gas)					
< 9.9 x 10^6 Btu/hr	2.63E-04 tonne/10^{12} J (HHV) 2.92E-04 tonne/10^{12} J (LHV)	Not available	Not available		Table 6.4 of ARPEL, 1998
9.9 – 99 x 10^6 Btu/hr	2.93E-04 tonne/10^{12} J (HHV) 3.26E-04 tonne/10^{12} J (LHV)	Not available	3.50E-05 tonne/10^{12} J (HHV) 3.89E-05 tonne/10^{12} J (LHV)	Not available	
> 99 x 10^6 Btu/hr	2.93E-04 tonne/10^{12} J (HHV) 3.26E-04 tonne/10^{12} J (LHV)	Not available	Not available		

Table 4-7. Equipment-Specific Combustion Emission Factors for Boilers and Furnaces (Gas and Liquid Fuels), continued

Emission Factors Converted to tonne/m^3 or tonne/10^{12} J (HHV and LHV, as indicated)

Source	Methane	Emission Factor Rating [d]	Nitrous Oxide	Emission Factor Rating [d]	Source (version date)
Heater – Refinery fuel gas (High H_2-content gas)					
< 9.9 x 10^6 Btu/hr	1.93E-04 tonne/10^{12} J (HHV) 2.14E-04 tonne/10^{12} J (LHV)	Not available	Not available		Table 6.4 of ARPEL, 1998
9.9 - 99 x 10^6 Btu/hr	2.15E-04 tonne/10^{12} J (HHV) 2.39E-04 tonne/10^{12} J (LHV)	Not available	3.50E-05 tonne/10^{12} J (HHV) 3.89E-05 tonne/10^{12} J (LHV)	Not available	
> 99 x 10^6 Btu/hr	2.15E-04 tonne/10^{12} J (HHV) 2.39E-04 tonne/10^{12} J (LHV)	Not available	Not available		
Utility boilers – No. 4,5,6 oil	3.4E-05 tonne/m^3	A	6.4E-05 tonne/m^3	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^3	A	6.4E-05 tonne/m^3	B	
Industrial boiler – No. 4 or distillate oil	6.2E-06 tonne/m^3	A	3.1E-05 tonne/m^3	B	
Commercial combustors – No. 5/6 oil	5.69E-05 tonne/m^3	A	6.4E-05 tonne/m^3	B	
Commercial combustors – No. 4 or distillate	2.59E-05 tonne/m^3	A	3.1E-05 tonne/m^3	B	
Industrial/commercial boilers – Butane/Propane	2.4E-05 tonne/m^3	E	1.1E-04 tonne/m^3	E	AP-42 Table 1.5-1 (07/08)
Residential furnace – Fuel oil	2.13E-04 tonne/m^3	A	6.0E-06 tonne/m^3	B	AP-42 Tables 1.3-3 and 1.3-12 (9/98)

Footnotes and 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.

U.S. Environmental Protection Agency (EPA). *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources,* AP-42, (GPO 055-000-005-001), U.S. 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.

[a] Emission factor is for a natural gas, controlled low-NOx burner unit.

[b] Emission factor is for uncontrolled natural gas units.

[c] 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.

[d] Emission factor rating pertains to the quality of the data; "A" has the best quality while "E" has the poorest quality.

Table 4-8. Equipment-Specific Combustion Emission Factors for Boilers and Furnaces (Solid Fuels) [a]

Original Units					
Source	**Methane**	**Emission Factor Rating [b]**	**Nitrous Oxide**	**Emission Factor Rating [b]**	**Source (version date)**
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	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, 2008, Table A12-19

Table 4-8. Equipment-Specific Combustion Emission Factors for Boilers and Furnaces (Solid Fuels) [a], continued

Emission Factors Converted to tonne/tonne					
Source	**Methane**	**Emission Factor Rating [b]**	**Nitrous Oxide**	**Emission Factor Rating [b]**	**Source (version date)**
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	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, 2008, Table A12-19

Footnotes and Sources:

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

Environment Canada, *National Inventory Report: Greenhouse Gas Sources and Sinks in Canada 1990-2006*, Greenhouse Gas Division, Environment Canada, April 2008.

[b] Emission factor rating pertains to the quality of the data; "A" has the best quality while "E" has the poorest quality.

4.5.2 Internal Combustion Units

Table 4-9 summarizes CH_4 and N_2O emission factors for IC units. These emission factors are given on a fuel input basis, but can be converted to a power output basis using the conversion factors for each type of engine given in Table 4-2.

The emission factors provided in Table 4-9 are generic factors, not model-specific. Model-specific emission factors for several Waukesha and CAT reciprocating engine models are provided in Appendix A.

Total organic compound (TOC) emission factors for diesel and gasoline IC engines (shown in Table 4-9) can be converted to CH_4 emission factors assuming the exhaust gas TOC contains 9 wt% CH_4 (based on AP-42, 10/96).

Table 4-9. Engines and Turbines Emission Factors

Original Units

Source	Methane		Emission Factor Rating	CH_4 Reference	Nitrous Oxide		Emission Factor Rating	N_2O Reference
IC Engines								
2 cycle lean – Natural Gas	1.45	lb/10^6 Btu (HHV)	C	AP-42, Table 3.2-1 (7/00)	Refer to Table 4-5			
4 cycle lean – Natural Gas	1.25	lb/10^6 Btu (HHV)	C	AP-42, Table 3.2-2 (7/00)				
4 cycle rich – Natural Gas	0.23	lb/10^6 Btu (HHV)	C	AP-42, Table 3.2-3 (7/00)				
Gasoline	3.03	lb TOC/ 10^6 Btu (HHV) [a]	D,E	AP-42, Table 3.3-1 (10/96)				
Diesel	0.36	lb TOC/ 10^6 Btu (HHV) [a]	D,E	AP-42, Table 3.3-1 (10/96)				
Large Bore–Diesel (> 600 hp)	0.0081	lb/10^6 Btu (HHV) [b]	E	AP-42, Table 3.4-1 (10/96)				
Dual Fuel (95% Nat Gas/ 5%Diesel)	0.6	lb/10^6 Btu (HHV)	E	AP-42, Table 3.4-1 (10/96)				
Turbines (≥ 80% load) – Natural Gas								
Uncontrolled	0.0086	lb/10^6 Btu (HHV)	C	AP-42, Table 3.1-2a (4/00)	0.003	lb/10^6 Btu (HHV) [c]	E	AP-42, Table 3.1-2a (4/00)

Table 4-9 Engines and Turbines Emission Factors, continued

Units Converted to US Basis								
Source	**Methane**		**Emission Factor Rating**	**CH_4 Reference**	**Nitrous Oxide**		**Emission Factor Rating**	**N_2O Reference**
IC Engines								
2 cycle lean – Natural Gas	0.00066	tonne/10^6 Btu (HHV)	C	AP-42, Table 3.2-1 (7/00)	Refer to Table 4-5			
	0.00073	tonne/10^6 Btu (LHV)						
4 cycle lean – Natural Gas	0.00057	tonne/10^6 Btu (HHV)	C	AP-42, Table 3.2-2 (7/00)				
	0.00063	tonne/10^6 Btu (LHV)						
4 cycle rich – Natural Gas	0.00010	tonne/10^6 Btu (HHV)	C	AP-42, Table 3.2-3 (7/00);				
	0.00012	tonne/106 Btu (LHV)						
Gasoline	0.00137	tonne TOC/10^6 Btu (HHV) [a]	D, E	AP-42, Table 3.3-1 (10/96)				
	0.00145	tonne TOC/10^6 Btu (LHV) [a]						
Diesel	0.00016	tonne TOC/10^6 Btu (HHV) [a]	D, E	AP-42, Table 3.3-1 (10/96)				
	0.00017	tonne TOC/10^6 Btu (LHV) [a]						
Large Bore – Diesel (> 600 hp)	3.7E-06	tonne/10^6 Btu (HHV) [b]	E	AP-42, Table 3.4-1 (10/96)				
	3.9E-06	tonne/10^6 Btu (LHV) [b]						
Dual Fuel (95% NG/5% diesel)	0.00027	tonne/10^6 Btu (HHV)	E	AP-42, Table 3.4-1 (10/96)				
	0.00030	tonne/10^6 Btu (LHV) [d]						
Turbines (≥ 80% load) – Natural Gas								
Uncontrolled	3.9E-06	tonne/10^6 Btu (HHV)	C	AP-42, Table 3.1-2a (4/00)	1.4E-06	tonne/10^6 Btu (HHV) [c]	E	AP-42, Table 3.1-2a (4/00)
	4.3E-06	tonne/10^6 Btu (LHV)			1.5E-06	tonne/10^6 Btu (LHV) [c]		
IC Engines								
2 cycle lean – Natural Gas	0.623	tonne/10^{12} J (HHV)	C	AP-42, Table 3.2-1 (7/00)	Refer to Table 4-5			
	0.693	tonne/10^{12} J (LHV)						
4 cycle lean – Natural Gas	0.537	tonne/10^{12} J (HHV)	C	AP-42, Table 3.2-2 (7/00)				
	0.597	tonne/10^{12} J (LHV)						

Table 4-9 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 Engines, continued								
4 cycle rich – Natural Gas	0.10	tonne/10^{12} J (HHV)	C	AP-42, Table 3.2-3 (7/00)	Refer to Table 4-5			
	0.11	tonne/10^{12} J (LHV)						
Gasoline	1.30	tonne TOC/10^{12} J (HHV) [a]	D, E	AP-42, Table 3.3-1 (10/96)				
	1.37	tonne TOC/10^{12} J (LHV) [a]						
Diesel	0.15	tonne TOC/10^{12} J (HHV) [a]	D, E	AP-42, Table 3.3-1 (10/96)				
	0.16	tonne TOC/10^{12} J (LHV) [a]						
Large Bore – Diesel (> 600 hp)	0.0035	tonne/10^{12} J (HHV) [b]	E	AP-42, Table 3.4-1 (10/96)				
	0.0037	tonne/10^{12} J (LHV) [b]						
Dual Fuel (95% NG/5% diesel)	0.26	tonne/10^{12} J (HHV)	E	AP-42, Table 3.4-1 (10/96)				
	0.29	tonne/10^{12} J (LHV) [d]						
Turbines (≥ 80% load) – Natural Gas								
Uncontrolled	0.0037	tonne/10^{12} J (HHV)	C	AP-42, Table 3.1-2a (4/00)	0.0013	tonne/10^{12} J (HHV) [c]	E	AP-42, Table 3.1-2a (4/00)
	0.0041	tonne/10^{12} J (LHV)			0.0014	tonne/10^{12} J (LHV) [c]		

Footnotes and Sources:

U.S. Environmental Protection Agency (EPA). *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources,* AP-42, (GPO 055-000-005-001), U.S. 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.

[a] If the fuel composition is unknown, TOC factors shown above can be converted to CH_4 emission factors assuming the TOC contains 9 wt% CH_4 in the exhaust gas based on AP-42 (10/96). 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.

[b] Emission factor is based on TOC with 9% CH_4 by weight in the exhaust gas (based on AP-42, 10/96).

[c] Emission factor is based on limited source tests on a single turbine with water-steam injection.

[d] Emission factor was estimated assuming the fuel is a gas (i.e., assumed that HHV = LHV×0.90).

Exhibit 4.8 shows an example calculation for CH_4 and N_2O emissions from an internal combustion device.

EXHIBIT 4.8: Sample Calculation for Combustion Emissions Equipment Basis for Internal Combustion Device

INPUT DATA:
A 100-hp gasoline-fired IC engine is operated for 8000 hours at 90% load during the reporting year. Calculate the CH_4 and N_2O emissions from this source.

CALCULATION METHODOLOGY FOR CH_4:
1. *Calculate CH_4 emissions.* Because the equipment-specific CH_4 emission factor presented in Table 4-9 is on an energy input basis, the power output must be converted to energy input (E_{In}) basis. A conversion factor of 7,000 Btu/hp-hr is taken from Table 4-2. This calculation is shown in Exhibit 4.1 and is repeated below.

$$E_{In} = 100 \text{ hp} \times 0.90 \times \frac{8000 \text{ hr}}{\text{yr}} \times \frac{7000 \text{ Btu}}{\text{hp-hr}}$$

$$E_{In} = 5040 \times 10^6 \text{ Btu/yr (HHV)}$$

The emission factor presented in Table 4-9 for CH_4 is actually a factor for TOC. The exhaust gas TOC is assumed to contain 9 wt% CH_4 based on AP-42. The CH_4 emissions are calculated as:

$$E_{CH_4} = \frac{5040 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.00137 \text{ tonne TOC}}{10^6 \text{ Btu}} \times \frac{0.09 \text{ tonne } CH_4}{\text{tonne TOC}}$$

$$\underline{E_{CH_4} = 0.62 \text{ tonnes } CH_4/\text{yr}}$$

2. *Calculate N_2O emissions.* The N_2O emission factor for gasoline is provided on a volume basis. Nitrous oxide emissions are calculated by multiplying the emission factor provided in Table 4-9 by the quantity of energy consumed.

$$E_{N_2O} = \frac{5040 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{6.01 \times 10^{-7} \text{ tonne } N_2O}{10^6 \text{ Btu}}$$

$$\underline{E_{N_2O} = 0.00303 \text{ tonnes } N_2O/\text{yr}}$$

4.6 Flare Emissions

Flares are used in all segments of the oil and natural gas industry to manage the disposal of unrecoverable natural gas via combustion of hydrocarbon products from routine operations, upsets, or emergencies. A wide variety of flare types are used in the industry, ranging from small open-ended pipes at production wellheads, to large horizontal or vertical flares with pilots and air- or steam-assist, such as those at refineries. Emissions of CO_2 and N_2O are formed as products of combustion, and CH_4 emissions may result from incomplete combustion or from time periods where there is no flame at the flare tip due to operational problems.[5] Combustion efficiency, and therefore flare performance, is highly variable, primarily dependent on the flame stability. The flame stability, in turn, depends on the gas exit velocity, stack diameter, heat content, and wind conditions (Johnson et al., 2002).

Due to these complexities, detailed examination of flare emissions has been somewhat limited and focused primarily on refinery flares. Unless regulatory requirements dictate otherwise, 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, Reformatted January 1995), where 98% efficiency is consistent with the performance of other control devices. However, increased interest in GHG and air toxic emissions has prompted studies to more accurately characterize emissions from oil and natural gas industry flares (Ozumba, 2000; Strosher, 1996). Findings from these studies indicate a minimum of 98% combustion efficiency, with much higher efficiencies (≥ 99.5%) measured in most situations, and very little, if any, detectable CH_4.[6] These findings are also consistent with the results of a study conducted by the International Flare Consortium (IFC) to compare and contrast flare efficiency findings (IFC, 2003). Combustion of flared gases is currently being studied; best available data should be used when determining flare efficiency.

As shown in Figure 4-2, this API *Compendium* recommends test data or vendor-specific information, such as flare combustion efficiency for estimating flare emissions from gas streams because this information is of higher quality than the default 98% combustion efficiency. However, this information may only be available for a small number of flares. In the absence of this information, emissions are calculated on the basis of knowing or estimating the flare gas flow

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[5] Flares that are not operating (i.e., no flame) are treated as vented sources (see Section 5).

[6] Note that the Strosher flare study reports combustion efficiencies of less than 98% for tests conducted on two production flares without knockout drums.

rate and composition. For upstream operations, CAPP provides an approach for quantifying volumes of gas flared at typical upstream oil and natural gas facilities (CAPP, 2002). Some of the approaches are also applicable to downstream operations.

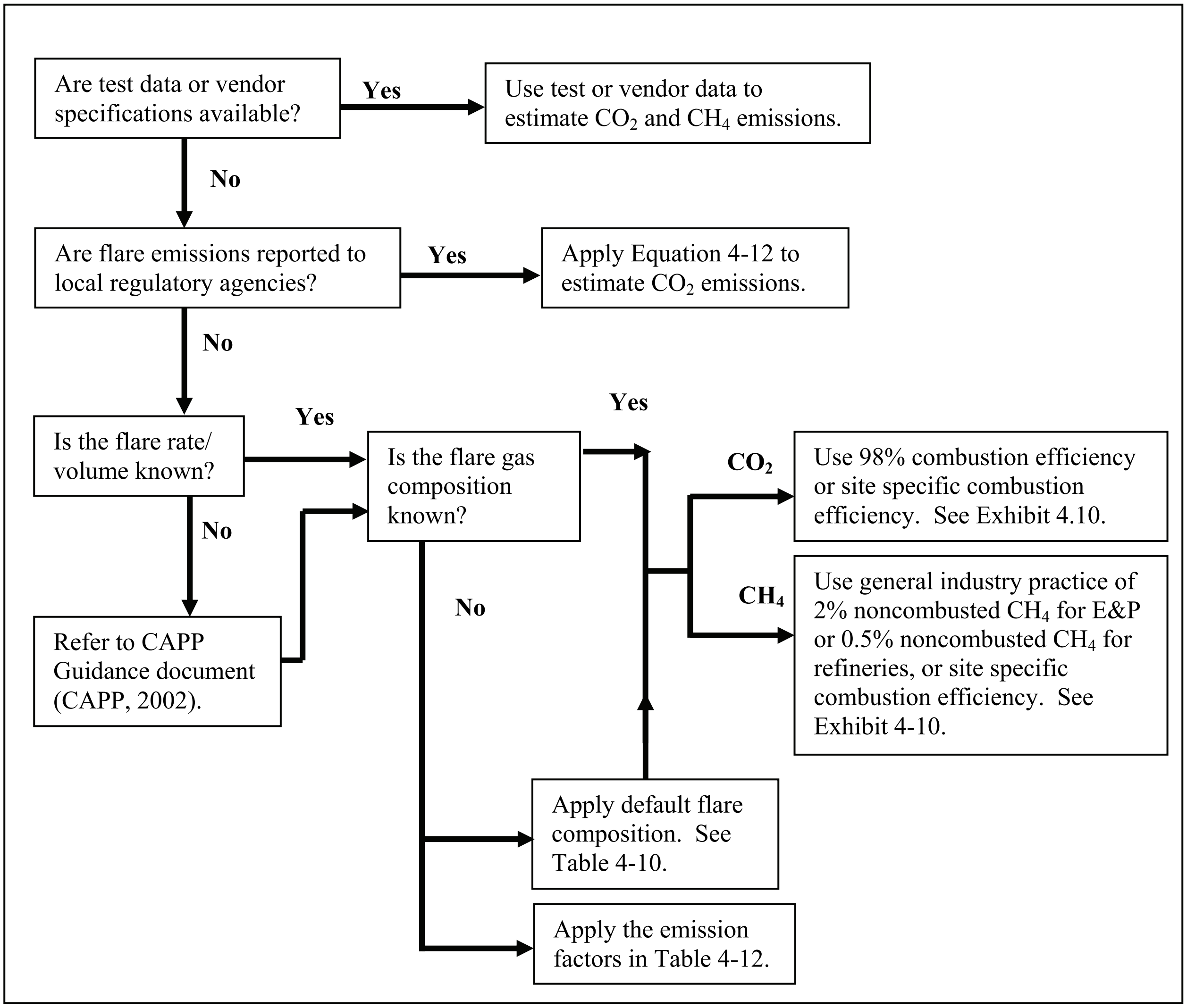

Figure 4-2. Calculation Approaches for Gas Flare Emissions

Table 4-10 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 4-10 are not meant to be representative of industry averages or typical values.

Table 4-10. "Generic" Upstream Gas Composition

Gas Component	Raw or Produced Gas Composition [a] Volume (or mole) %	Gas Processing Plant Gas Composition [b] Volume (or mole) %
CH_4	80	91.9
Non-methane hydrocarbon	15 (C_2H_6) 5 (C_3H_8)	6.84 (MW unspecified)
N_2	-	0.68
CO_2	-	0.58

Footnotes and Sources:

[a] CAPP. *Calculating Greenhouse Gas Emissions*, Guide, 2003-003, Section 1.7.3, April 2003. More detailed speciation profiles can be found in *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulfide (H_2S) Emissions by the Upstream Oil and Gas Industry*, *Volume 3: Methodology for Greenhouse Gases*. (CAPP, 2004)

[b] IPCC. *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 2, Chapter 4 (Fugitive Emissions), Table 4.2.4, 2006 Revised November 2008.

If the volume of hydrocarbons at the flare outlet is known, Equation 4-14 can be used to calculate CO_2 emissions:

$$E_{CO_2} = \left(HC \times CF_{HC} \times \frac{FE}{1\text{-}FE} \times \frac{44}{12} \right) + M_{CO_2} \qquad \text{(Equation 4-14)}$$

where

E_{CO_2} = CO_2 mass emission rate;
HC = flare hydrocarbon mass emission rate (from the flare);
CF_{HC} = carbon weight fraction in hydrocarbon;
FE = flare destruction efficiency;
44/12 = C to CO_2 conversion factor; and
M_{CO_2} = mass of CO_2 in flared stream based on CO_2 composition of the stream.

If measured emissions data are unavailable, CO_2 emissions from flares are based on an estimated 98% combustion efficiency for the conversion of the flare gas carbon to CO_2, as shown in Equation 4-15. This is consistent with published flare emission factors (E&P Forum, 1994), control device performance, and results from the more recent flare studies.

$$E_{CO_2} = \frac{\text{Volume}}{\text{flared}} \times \frac{\text{Molar volume}}{\text{conversion}} \times \text{MW } CO_2 \times \frac{\text{mass}}{\text{conversion}} \times$$

$$\left[\sum \left(\frac{\text{mole Hydrocarbon}}{\text{mole gas}} \times \frac{A \text{ mole C}}{\text{mole Hydrocarbon}} \times \frac{0.98 \text{ mole } CO_2 \text{ formed}}{\text{mole C combusted}} \right) + \frac{B \text{ mole } CO_2}{\text{mole gas}} \right]$$

(Equation 4-15)

where

Molar volume conversion = conversion from molar volume to mass (379.3 scf/lbmole or 23.685 m^3/kgmole);
MW CO_2 = CO_2 molecular weight;
Mass conversion = tonnes/2204.62lb or tonne/1000 kg;
A = the number of moles of Carbon for the particular hydrocarbon; and
B = the moles of CO_2 present in the flared gas stream.

Note that in both Equations 4-14 and 4-15, CO_2 present in the stream to the flare is emitted directly as CO_2. Neither the destruction efficiency nor the conversion of flare gas carbon to CO_2 apply to the CO_2 already contained in the flared stream.

For CH_4 emissions from flares, general industry practice assumes 0.5% residual, unburned CH_4 remaining in the flared gas for well designed and operated flares, such as in refineries. For production flares, where greater operational variability exists, CH_4 emissions may be based on an assumed value of 2% noncombusted. These recommendations are supported by published flare emission factors (EIIP Volume II, Table 10.2-1, September 1999) and endorsed by IPCC (IPCC, Volume 2, Chapter 4, 2006).[7] In the natural gas transmission, storage, and distribution sectors, flares are assumed to be similar to production flares (INGAA, Section 2.4, 2005).

The general equation for CH_4 emissions from flares is:

$$E_{CH_4} = V \times CH_4 \text{ Mole fraction} \times \% \text{ residual } CH_4 \times \frac{1}{\text{molar volume conversion}} \times MW_{CH_4}$$

(Equation 4-16)

where

E_{CH_4} = emissions of CH_4 (lb);
V = volume Flared (scf);
% residual CH_4 = noncombusted fraction of flared stream (default =0.5% or 2%);
Molar volume conversion = conversion from molar volume to mass, (379.3 scf/lbmole or 23.685 m^3/kgmole); and
MW CH_4 = CH_4 molecular weight.

Very little information is available for N_2O emissions from petroleum industry flares, but these emissions are likely negligible compared to CO_2 emissions from flares. Equation 4-17 provides a simple emission factor approach, based on N_2O emission factors provided in Tables 4-11 and 4-12 (IPCC, 2007). Factors provided in Table 4-11 should be applied to systems designed, operated and maintained to North American/Western European standards; Table 4-12 applies to systems in

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[7] The revised IPCC methodology (IPCC, 2006) cites the API *Compendium* (API, 2004) as the reference for the 98% combustion efficiency of flared natural gas (IPCC, 2006, Volume 2, Chapter 4).

developing countries and countries with economies in transition. IPCC also provides CO_2 and CH_4 emission factors for the same flare sources.[8] These flare emission factors are based on the volume of production or throughput for different types of petroleum operations and are provided as an alternative to using the generic gas compositions from Table 4-10.

$$E_{N_2O} = V \times EF_{N_2O} \qquad \text{(Equation 4-17)}$$

where

E_{N_2O} = emissions of N_2O;

V = volume produced or refined (m^3, scf, or bb); and

EF_{N_2O} = N_2O emission factor.

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[8] The refinery CH_4 flare emission factor is from Annex 3 of the EPA report, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007* (EPA, 2009).

Table 4-11. GHG Emission Factors for Gas Flares in Developed Countries [a]

Original Units							
Flare Source	**Emission Factors**						
	CO_2	**Uncertainty [b] (%)**	**CH_4**	**Uncertainty [b] (%)**	**N_2O**	**Uncertainty [b] (%)**	**Units**
Flaring - gas production [c]	1.2E-03	±25	7.6E-07	±25	2.1E-08	-10 to +1000	Gg/10^6 m^3 gas production
Flaring - sweet gas processing	1.8E-03	±25	1.2E-06	±25	2.5E-08	-10 to +1000	Gg/10^6 m^3 raw gas feed
Flaring - sour gas processing	3.6E-03	±25	2.4E-06	±25	5.4E-08	-10 to +1000	Gg/10^6 m^3 raw gas feed
Flaring - conventional oil production	4.1E-02	±50	2.5E-05	±50	6.4E-07	-10 to +1000	Gg/10^3 m^3 conventional oil production
Flaring - heavy oil/cold bitumen production	2.2E-02	±75	1.4E-04	±75	4.6E-07	-10 to +1000	Gg/10^3 m^3 heavy oil production
Flaring - thermal oil production	2.7E-02	±75	1.6E-05	±75	2.4E-07	-10 to +1000	Gg/10^3 m^3 thermal bitumen production
Flaring – refining [d, e]	No data	No data	0.189	No data	No data	No data	scf/10^3 bbl refinery feed
Units Converted to tonnes/10^6 scf or tonnes/1000 bbl							
Flare Source	**Emission Factors**						
	CO_2	**Uncertainty [b] (%)**	**CH_4**	**Uncertainty [b] (%)**	**N_2O**	**Uncertainty [b] (%)**	**Units**
Flaring - gas production [c]	3.4E-02	±25	2.2E-05	±25	5.9E-07	-10 to +1000	tonnes/10^6 scf gas production
Flaring - sweet gas processing	5.1E-02	±25	3.4E-05	±25	7.1E-07	-10 to +1000	tonnes/10^6 scf raw gas feed
Flaring - sour gas processing	0.10	±25	6.8E-05	±25	1.5E-06	-10 to +1000	tonnes/10^6 scf raw gas feed
Flaring - conventional oil production	6.5	±50	4.0E-03	±50	1.0E-04	-10 to +1000	tonnes/10^3 bbl conventional oil production
Flaring - heavy oil/cold bitumen production	3.5	±75	2.2E-02	±75	7.3E-05	-10 to +1000	tonnes/10^3 bbl heavy oil production
Flaring - thermal oil production	4.3	±75	2.5E-03	±75	3.8E-05	-10 to +1000	tonnes/10^3 bbl thermal bitumen production
Flaring - refining [d, e]	No data	No data	3.63E-06	No data	No data	No data	tonnes/10^3 bbl refinery feed

Table 4-11. GHG Emission Factors for Gas Flares in Developed Countries [a], continued

Units Converted to tonnes/10^6 m^3 or tonnes/1000 m^3							
	Emission Factors						
Flare Source	**CO_2**	**Uncertainty [b] (%)**	**CH_4**	**Uncertainty [b] (%)**	**N_2O**	**Uncertainty [b] (%)**	**Units**
Flaring - gas production [c]	1.2	±25	7.6E-04	±25	2.1E-05	-10 to +1000	tonnes/10^6 m^3 gas production
Flaring - sweet gas processing	1.8	±25	1.2E-03	±25	2.5E-05	-10 to +1000	tonnes/$10^6 m^3$ raw gas feed
Flaring - sour gas processing	3.6	±25	2.4E-03	±25	5.4E-05	-10 to +1000	tonnes/$10^6 m^3$ raw gas feed
Flaring - conventional oil production	41.0	±50	2.5E-02	±50	6.4E-04	-10 to +1000	tonnes/10^3 m^3 conventional oil production
Flaring - heavy oil/cold bitumen production	22.0	±75	1.4E-01	±75	4.6E-04	-10 to +1000	tonnes/10^3 m^3 heavy oil production
Flaring - thermal oil production	27.0	±75	1.6E-02	±75	2.4E-04	-10 to +1000	tonnes/10^3 m^3 thermal bitumen production
Flaring – refining [d, e]	No data	No data	2.28E-05	No data	No data	No data	tonnes/10^3 m^3 refinery feed

Footnotes and Sources:

[a] IPCC, *2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Chapter 4 (Fugitive Emissions)*, Table 4.2.4, 2006 Revised November 2008.

[b] Uncertainty based on a 95% confidence interval (IPCC, Volume 2, Chapter 4, Section 4.2.2.7.2, 2006 Revised November 2008).

[c] IPCC reports that flared volumes should be used to estimate flare emissions instead of the above emission factors when such data are available. IPCC reports that flared volume based emission factors are 0.012, 2.0 and 0.000023 Gg/10^6 m^3 of gas flared for CH_4, CO_2, and N_2O, respectively, based on a flaring efficiency of 98% and a typical gas analysis at a gas processing plant (91.9% CH_4, 0.58% CO_2, 0.68% N_2 and 6.84% non-CH_4 hydrocarbons, by volume).

[d] U.S. Environmental Protection Agency (EPA*). Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, Table A-127, April 15, 2009.

[e] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia.

Table 4-12. GHG Emission Factors for Gas Flares in Developing Countries and Countries with Economies in Transition [a]

Original Units

Flare Source	Emission Factors CO_2	Uncertainty [b] (%)	CH_4	Uncertainty [b] (%)	N_2O	Uncertainty [b] (%)	Units
Flaring - gas production [c]	1.2E-03 – 1.6E-03	±75	7.6E-07 – 1.0E-06	±75	2.1E-08 – 2.9E-08	-10 to +1000	Gg/10^6 m^3 gas production
Flaring - sweet gas processing	1.8E-03 – 2.5E-03	±75	1.2E-06 – 1.6E-06	±75	2.5E-08 – 3.4E-08	-10 to +1000	Gg/10^6 m^3 raw gas feed
Flaring - sour gas processing	3.6E-03 – 4.9E-03	±75	2.4E-06 – 3.3E-06	±75	5.4E-08 – 7.4E-08	-10 to +1000	Gg/10^6 m^3 raw gas feed
Flaring - conventional oil production	4.1E-02 – 5.6E-02	±75	2.5E-05 – 3.4E-05	±75	6.4E-07 – 8.8E-07	-10 to +1000	Gg/10^3 m^3 conventional oil production
Flaring - heavy oil/cold bitumen production	2.2E-02 – 3.0E-02	-67 to +150	1.4E-04 – 1.9E-04	-67 to +150	4.6E-07 – 6.3E-07	-10 to +1000	Gg/10^3 m^3 heavy oil production
Flaring - thermal oil production	2.7E-02 – 3.7E-02	-67 to +150	1.6E-05 – 2.2E-05	-67 to +150	2.4E-07 – 3.3E-07	-10 to +1000	Gg/10^3 m^3 thermal bitumen production

Units Converted to tonnes/10^6 scf or tonnes/1000 bbl

Flare Source	Emission Factors CO_2	Uncertainty [b] (%)	CH_4	Uncertainty [b] (%)	N_2O	Uncertainty [b] (%)	Units
Flaring - gas production [c]	3.4E-02 – 4.5E-02	±75	2.2E-05 – 2.8E-05	±75	5.9E-07 – 8.2E-07	-10 to +1000	tonnes/10^6 scf gas production
Flaring - sweet gas processing	5.1E-02 – 7.1E-02	±75	3.4E-05 – 4.5E-05	±75	7.1E-07 – 9.6E-07	-10 to +1000	tonnes/10^6 scf raw gas feed
Flaring - sour gas processing	0.10 – 0.14	±75	6.8E-05 – 9.3E-05	±75	1.5E-06 – 2.1E-06	-10 to +1000	tonnes/10^6 scf raw gas feed
Flaring - conventional oil production	6.5 – 8.9	±75	4.0E-03 – 5.4E-03	±75	1.0E-04 – 1.4E-04	-10 to +1000	tonnes/10^3 bbl conventional oil production
Flaring - heavy oil/cold bitumen production	3.5 – 4.8	-67 to +150	2.2E-02 – 3.0E-02	-67 to +150	7.3E-05 – 1.0E-04	-10 to +1000	tonnes/10^3 bbl heavy oil production
Flaring - thermal oil production	4.3 – 5.9	-67 to +150	2.5E-03 – 3.5E-03	-67 to +150	3.8E-05 – 5.2E-05	-10 to +1000	tonnes/10^3 bbl thermal bitumen production

Table 4-12. GHG Emission Factors for Gas Flares in Developing Countries and Countries with Economies in Transition [a], continued

Units Converted to tonnes/10^6 m^3 or tonnes/1000 m^3

	Emission Factors						
Flare Source	**CO_2**	**Uncertainty [b] (%)**	**CH_4**	**Uncertainty [b] (%)**	**N_2O**	**Uncertainty [b] (%)**	**Units**
Flaring - gas production [c]	1.2 – 1.6	±75	7.6E-04 – 1.0E-03	±75	2.1E-05 – 2.9E-05	-10 to +1000	tonnes/10^6 m^3 gas production
Flaring - sweet gas processing	1.8 – 2.5	±75	1.2E-03 – 1.6E-03	±75	2.5E-05 – 3.4E-05	-10 to +1000	tonnes/10^{6}m^3 raw gas feed
Flaring - sour gas processing	3.6 – 4.9	±75	2.4E-03 – 3.3E-03	±75	5.4E-05 – 7.4E-05	-10 to +1000	tonnes/10^{6}m^3 raw gas feed
Flaring - conventional oil production	41.0 – 56.0	±75	2.5E-02 – 3.4E-02	±75	6.4E-04 – 8.8E-04	-10 to +1000	tonnes/10^3 m^3 conventional oil production
Flaring - heavy oil/cold bitumen production	22.0 – 30.0	-67 to +150	1.4E-01 – 1.9E-01	-67 to +150	4.6E-04 – 6.3E-04	-10 to +1000	tonnes/10^3 m^3 heavy oil production
Flaring - thermal oil production	27.0 – 37.0	-67 to +150	1.6E-02 – 2.2E-02	-67 to +150	2.4E-04 – 3.3E-04	-10 to +1000	tonnes/10^3 m^3 thermal bitumen production

Footnotes and Sources:

[a] IPCC, *2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Chapter 4 (Fugitive Emissions)*, Table 4.2.5, 2006 Revised November 2008.

[a] Uncertainty based on a 95% confidence interval (IPCC, Volume 2, Chapter 4, Section 4.2.2.7.2, 2006 Revised November 2008).

[c] IPCC reports that flared volumes should be used to estimate flare emissions instead of the above emission factors when such data are available. IPCC reports that flared volume based emission factors are 0.012, 2.0 and 0.000023 Gg/10^6 m^3 of gas flared for CH_4, CO_2, and N_2O, respectively, based on a flaring efficiency of 98% and a typical gas analysis at a gas processing plant (91.9% CH_4, 0.58% CO_2, 0.68% N_2 and 6.84% non-CH_4 hydrocarbons, by volume).

Exhibit 4.9 demonstrates emission calculations for gas flares when the volume to the flare is known.

EXHIBIT 4.9: Sample Calculation for Combustion Emissions from a Gas Flare – Known Flared Volume

INPUT DATA:
A production facility in a developed country 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: 12 mole% CO_2, 2.1 mole% N_2, 80 mole% CH_4, 4.2 mole% C_2H_6, 1.3 mole% C_3H_8, and 0.4 mole% C_4H_{10}. The volume of the pilot stream combusted is included in the volume of the field gas flared.

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_2 emissions and 2% uncombusted CH_4.

CALCULATION METHODOLOGY:
Methane emissions are based on the assumption that 2% of the CH_4 in the flare gas is released uncombusted.

$$E_{CH_4}: \frac{20\times10^6 \text{ scf gas}}{\text{yr}} \times \frac{0.80 \text{ scf CH}_4}{\text{scf gas}} \times \frac{0.02 \text{ scf noncombusted CH}_4}{\text{scf CH}_4\text{total}}$$

$$\times \frac{\text{lbmole CH}_4}{379.3 \text{ scf CH}_4} \times \frac{16 \text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$E_{CH_4} = \underline{6.1 \text{ tonnes CH}_4\text{/yr}}$$

Carbon dioxide emissions are based on the facility gas composition and the generally accepted 98% combustion efficiency to convert from flare gas carbon to CO_2.

EXHIBIT 4.9: Sample Calculation for Combustion Emissions from a Gas Flare, continued

$$E_{CO_2}: \frac{20\times 10^6 \text{ scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times$$

$$\left[\left(\begin{array}{l} \frac{0.80 \text{ lbmole } CH_4}{\text{lbmole gas}} \times \frac{1 \text{ lbmole C}}{\text{lbmole } CH_4} \\ + \frac{0.042 \text{ lbmole } C_2H_6}{\text{lbmole gas}} \times \frac{2 \text{ lbmole C}}{\text{lbmole } C_2H_6} \\ + \frac{0.013 \text{ lbmole } C_3H_8}{\text{lbmole gas}} \times \frac{3 \text{ lbmole C}}{\text{lbmole } C_3H_8} \\ + \frac{0.004 \text{ lbmole } C_4H_{10}}{\text{lbmole gas}} \times \frac{4 \text{ lbmole C}}{\text{lbmole } C_4H_{10}} \end{array} \right) \times \frac{0.98 \text{ lbmole } CO_2 \text{ formed}}{\text{lbmole C combusted}} + \frac{0.12 \text{ lbmole } CO_2}{\text{lbmole gas}} \right] \times \frac{44 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$E_{CO_2} = \underline{1,095 \text{ tonnes } CO_2/\text{yr}}$$

N_2O emissions are calculated using the emission factor for "Flaring - gas production" in Table 4-11. Note that these emission factors are based on the total volume of gas produced at the facility. For comparison purposes, CO_2 and CH_4 emissions are also estimated using the published emission factors for "Flaring - gas production."

$$E_{N_2O}: \frac{3\times 10^6 \text{ scf gas}}{\text{day}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{5.9\times 10^{-7} \text{ tonnes } N_2O}{10^6 \text{ scf gas}} = \underline{6.46\times 10^{-4} \text{ tonnes } N_2O/\text{yr}}$$

$$E_{CO_2}: \frac{3\times 10^6 \text{ scf gas}}{\text{day}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{3.4\times 10^{-2} \text{ tonnes } CO_2}{10^6 \text{ scf gas}} = \underline{37.23 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CH_4}: \frac{3\times 10^6 \text{ scf gas}}{\text{day}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{2.2\times 10^{-5} \text{ tonnes } CH_4}{10^6 \text{ scf gas}} = \underline{0.024 \text{ tonnes } CH_4/\text{yr}}$$

Exhibit 4.10 demonstrates an example calculation for GHG emissions from a gas flare when the VOC emissions from the flare are known, but the flow rate to the flare is not known.

EXHIBIT 4.10: Sample Calculation for Gas Flare Combustion Emissions – Known Flare Emissions

INPUT DATA:
A gas flare is estimated to emit 2.21 tons of VOC during the reporting year. The average analysis of the gas stream to the flare is shown below. The flare destruction efficiency is 98%. Calculate the CO_2, CH_4, and N_2O emissions from this source.

Compound	Weight %
Methane	2.73
Ethane	0.85
Propane	1.35
Butanes	0.99
Pentanes	0.83
C6+	2.16
Carbon Dioxide	90.43
Inerts (as N_2)	0.66

VOC Weight % = 5.33
Hydrocarbon Weight % = 8.91

1. *Calculate CO_2 emissions.* The first step in calculating the CO_2 emissions is calculating the carbon content of the hydrocarbon mixture, as shown in Equation 4-10. The fuel sample must first be normalized to exclude CO_2 and inerts. Then, the carbon contents of the individual constituents must be calculated using Equation 4-9. This is shown below for ethane (C_2H_6).

$$\mathrm{Wt\%C}_{C_2H_6} = \frac{12 \text{ lb C}}{\text{lbmole C}} \times \frac{2 \text{ lbmoles C}}{\text{lbmole } C_2H_6} \times \frac{\text{lbmole } C_2H_6}{30.07 \text{ lb } C_2H_6} = \underline{0.80 \text{ lb C/lb } C_2H_6}$$

$$\mathrm{Wt\%C}_{C_2H_6} = 80\% \text{ C}$$

Repeating this calculation for the rest of the sample results in the following:

	Adjusted Wt%	Carbon Content (Wt% C)
Methane	30.64	74.8%
Ethane	9.54	79.8%
Propane	15.15	81.6%
Butanes	11.11	82.6%
Pentanes	9.32	83.2%
C6+	24.24	83.5%
Carbon Dioxide	0	27.3%
Inerts (as N_2)	0	0.0%
Fuel Mixture	**100**	**80.08%**

EXHIBIT 4.10: Sample Calculation for Gas Flare Combustion Emissions – Known Flare Emissions, continued

The carbon content of the fuel mixture is then calculated using Equation 4-10.

$$\text{Wt\%C}_{\text{Mixture}} = \frac{1}{100} \times \begin{bmatrix} (30.64 \times 74.8) + (9.54 \times 79.8) + (15.15 \times 81.6) + (11.11 \times 82.6) \\ + (9.32 \times 83.2) + (24.24 \times 83.5) + (0 \times 27.3) + (0 \times 0) \end{bmatrix}$$

$\text{Wt\%C}_{\text{Mixture}}$ = 80.08 Wt%C (alternately presented as 0.8008 lb C/lb fuel)

Because the estimated VOC emission rate from the flare is known, Equation 4-14 will be used to calculate CO_2 emissions from the flare. To use Equation 4-14, the VOC emissions must be converted to total hydrocarbon emissions, and the mass of the carbon dioxide released must be calculated:

$$E_{HC} = \frac{2.21 \text{ tons VOC}}{\text{yr}} \times \frac{100 \text{ lb gas}}{5.33 \text{ lbVOC}} \times \frac{8.91 \text{ lb hydrocarbon}}{100 \text{ lb gas}}$$

E_{HC} = 3.69 tons hydrocarbon from the flare/yr

$$M_{CO_2} = \frac{2.21 \text{ tons VOC}}{\text{yr}} \times \frac{100 \text{ lb gas}}{5.33 \text{ lbVOC}} \times \frac{90.43 \text{ lb } CO_2}{100 \text{ lb gas}}$$

$M_{CO_2} = 37.50 \text{ tons } CO_2/\text{yr}$

Equation 4-14 is then used to calculate CO_2 emissions.

$$E_{CO_2} = \begin{bmatrix} \left(\frac{3.69 \text{ tons hydrocarbon}}{\text{yr}} \times \frac{0.8008 \text{ ton C}}{\text{ton hydrocarbon}} \times \frac{0.98}{1 - 0.98} \times \frac{44 \text{ ton } CO_2}{12 \text{ ton C}} \right) \\ + \frac{37.50 \text{ tons } CO_2}{\text{yr}} \end{bmatrix} \times \frac{\text{tonne}}{1.10231 \text{ ton}}$$

$E_{CO_2} = 515.7 \text{ tonnes } CO_2/\text{yr}$

EXHIBIT 4.10: Sample Calculation for Gas Flare Combustion Emissions – Known Flare Emissions, continued

2. *Calculate CH_4 emissions.* Methane emissions are calculated using Equation 4-16, which is modified to reflect the fact that the mass flared is known:

$$E_{CH_4} = (\text{Mass Flared}) \times (\text{CH}_4 \text{ Weight fraction}) \times (\% \text{ residual CH}_4)$$

$$E_{CH_4} = \frac{3.69 \text{ tons hydrocarbon}}{\text{yr}} \times \frac{1}{1 - 0.98} \times \frac{100 \text{ tons gas}}{8.91 \text{ tons hydrocarbon}} \times \frac{2.73 \text{ tons CH}_4}{100 \text{ tons gas}} \times (1 - 0.98) \times \frac{\text{tonne}}{1.10231 \text{ ton}}$$

$$\underline{E_{CH_4} = 1.03 \text{ tonnes CH}_4/\text{yr}}$$

3. *Calculate N_2O emissions.* Nitrous oxide emissions are calculated using the natural gas fuel based emission factor from Table 4-5. The use of the emission factor requires the quantity of fuel combusted on a heat basis, which requires the higher heating value of the fuel. The fuel heating value is calculated using Equation 3-11. Note that to use Equation 3-11, the adjusted fuel speciation data is converted from weight % to mole % (as shown in Equation 3-7), using the molecular weight of the mixture on a hydrocarbon basis.

The molecular weight of the mixture is calculated using Equation 3-9.

$$MW_{\text{Mixture}} = 100 \div \begin{bmatrix} (30.64 \div 16.04) + (9.54 \div 30.07) + (15.15 \div 44.10) + (11.11 \div 58.12) \\ + (9.32 \div 72.15) + (24.24 \div 86.18) + (0 \div 44.01) + (0 \div 28.01) \end{bmatrix}$$

$$MW_{\text{Mixture}} = 31.52 \text{ lb/lbmole}$$

The conversion from weight % to mole % is shown below for C_2H_6.

$$\text{Mole\%}_{C_2H_6} = \frac{\dfrac{9.54 \text{ lb C}_2\text{H}_6}{100 \text{ lb gas}} \times \dfrac{31.52 \text{ lb gas}}{\text{lbmole gas}}}{\dfrac{30.07 \text{ lb C}_2\text{H}_6}{\text{lbmole C}_2\text{H}_6}} = \underline{10.00 \text{ lbmole C}_2\text{H}_6/100 \text{ lbmole gas}}$$

$$\text{Mole\%}_{C_2H_6} = 10.00\%$$

Repeating this calculation for the rest of the sample results in the calculations in Exhibit 4.10.

EXHIBIT 4.10: Sample Calculation for Gas Flare Combustion Emissions – Known Flare Emissions, continued

	Molecular Weight	Adjusted Mol%	Heating Value (Btu/scf)
Methane	16.04	60.21	1009.7
Ethane	30.07	10.00	1768.8
Propane	44.10	10.83	2517.5
Butanes	58.12	6.03	3262.1
Pentanes	72.15	4.07	4009.6
C6+	86.18	8.87	4756.2
Carbon Dioxide	44.01	0.00	0
Inerts (as N_2)	28.01	0.00	0
Fuel Mixture	**31.52**	**100**	**1838.9**

The heating value of the mixture is calculated below.

$$HHV_{Mixture}=\left[\begin{array}{l}\left(\frac{60.21}{100}\times 1009.7\right)+\left(\frac{10.00}{100}\times 1768.8\right)+\left(\frac{10.83}{100}\times 2517.5\right)+\left(\frac{6.03}{100}\times 3262.1\right)\\ +\left(\frac{4.07}{100}\times 4009.6\right)+\left(\frac{8.87}{100}\times 4756.2\right)+(0\times 0)+(0\times 0)\end{array}\right]$$

$HHV_{Mixture}$ = 1838.9 Btu/scf

$$E_{N_2O}=(\text{Volume Hydrocarbon Flared})\times(\text{Heating Value})\times(N_2O\text{ emission factor})$$

$$E_{N_2O}=\frac{3.69\text{ tons hydrocarbon}}{\text{yr}}\times\frac{2{,}000\text{ lb}}{\text{ton}}\times\frac{\text{lbmole hydrocarbon}}{31.52\text{ lb hydrocarbon}}\times\frac{379.3\text{ scf}}{\text{lbmole}}\times\frac{1}{1-0.98}\times\frac{1838.9\text{ Btu}}{\text{scf}}\times\frac{9.50\times 10^{-8}\text{ tonnes }N_2O}{10^6\text{ Btu}}$$

E_{N_2O} = 7.76×10^{-4} tonnes N_2O/yr

4.7 Incinerators, Oxidizers, and Vapor Combustion Units

Incinerators, thermal and catalytic oxidizers, and vapor combustion units (VCUs) may be used as control devices or to combust waste fuels. Carbon dioxide emissions from hydrocarbons in the combusted stream can be estimated by mass balance using an assumed conversion of carbon in the fuel gas to CO_2 or based on the control efficiency of the unit. Alternatively, the external combustion emission factors given by fuel usage (described in Section 4.4) can be used for estimating CO_2 emissions. Carbon dioxide present in the stream is emitted directly as CO_2. Methane emissions from these sources can be estimated from a mass balance by assuming a certain CH_4 destruction efficiency. Nitrous oxide emissions can be estimated by applying an emission factor from Table 4-7, assuming the control device is similar to a heater.

The following example shows the approach that can be used to estimate CO_2, CH_4, and N_2O emissions from a thermal oxidizer.

EXHIBIT 4.11: Sample Calculation for Combustion Emissions – Thermal Oxidizer

INPUT DATA:
A thermal oxidizer is used to control emissions from crude oil loading at a terminal. Previous stack test data have demonstrated that the oxidizer achieves at least 99% destruction of the oil vapors. The thermal oxidizer does not require supplemental fuel to operate properly.

The following is known about the loading operations based on process knowledge and/or engineering judgment:

Loading throughput: 4,122,487 bbl crude
Loading loss: 1.23 lb VOC/1000 gal

Compound	Molecular Weight	Mole %	Wt %	lb C/lb	Contribution to Mixture C Content
Benzene (C_6H_6)	78.11	1.28	2.12	0.92	1.96
Butane (C_4H_{10})	58.12	59.80	73.58	0.83	60.77
Cyclohexane (C_6H_{12})	84.16	1.04	1.86	0.86	1.59
Ethylbenzene (C_8H_{10})	106.16	0.07	0.15	0.79	0.12
Hexane (C_6H_{14})	86.17	3.77	6.88	0.84	5.75
Toluene (C_7H_8)	92.13	0.15	0.29	0.91	0.27
Xylene (C_8H_{10})	106.16	0.05	0.11	0.90	0.10
Methane (CH_4)	16.04	22.08	7.50	0.75	5.61
Ethane (C_2H_6)	30.07	11.78	7.50	0.80	5.99
	47.23	100	100		82.15

EXHIBIT 4.11: Sample Calculation for Combustion Emissions – Thermal Oxidizer, continued

Calculate the CO_2 and CH_4 emissions. (Note, there are no published N_2O emission factors for the combustion of crude vapors.)

CALCULATION METHODOLOGY:
1. *Calculate CO_2 emissions.* The first step in estimating the oxidizer CO_2 emissions is to calculate the TOC flow rate to the incinerator. TOC emissions are calculated from VOC loading loss by assuming that VOC comprises 85% of TOC in crude oil (AP-42, Section 5.2, January 1995).

$$E_{TOC} = \frac{4{,}122{,}487\ \text{bbl}}{\text{yr}} \times \frac{42\ \text{gal}}{\text{bbl}} \times \frac{1.23\ \text{lb VOC}}{1000\ \text{gal crude}} \times \frac{\text{lb TOC}}{0.85\ \text{lb VOC}}$$

$$E_{TOC} = 250{,}550\ \text{lb TOC/yr}$$

The second step is to convert TOC flow rate to CO_2 emissions, using the fuel carbon content and oxidizer combustion efficiency.

$$E_{CO_2} = \frac{250{,}550\ \text{lb TOC}}{\text{yr}} \times \frac{0.8215\ \text{lb C}}{\text{lb TOC}} \times \frac{44\ \text{lb CO}_2}{12\ \text{lb C}} \times \frac{0.99\ \text{lb CO}_2\ \text{formed}}{\text{lb CO}_2\ \text{combusted}} \times \frac{\text{tonne}}{2204.62\ \text{lb}}$$

$$\underline{E_{CO_2} = 338.9\ \text{tonnes CO}_2\text{/yr}}$$

2. *Calculate CH_4 emissions.* Methane emissions are calculated by multiplying the uncombusted portion of the oxidizer crude oil feed by the CH_4 content of the crude (wt%), as shown below:

$$E_{CH_4} = \frac{250{,}550\ \text{lb TOC}}{\text{yr}} \times \frac{0.075\ \text{lb CH}_4}{\text{lb TOC}} \times \frac{(1\text{-}0.99)\ \text{lb CH}_4\ \text{emitted}}{\text{lb CH}_4\ \text{combusted}} \times \frac{\text{tonne}}{2204.62\ \text{lb}}$$

$$\underline{E_{CH_4} = 0.085\ \text{tonnes CH}_4\text{/yr}}$$

4.8 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 forklifts and other construction and maintenance equipment, rail cars, tanker trucks, ships, and barges used to transport crude and petroleum products, and mobile trucks and shovels used in oil sand mining operations.

The fossil fuel-fired IC engines used in transportation are a source of CO_2 emissions. Small quantities of CH_4 and N_2O are also emitted based on fuel composition, combustion conditions, and post-combustion control technology.

Estimating emissions from mobile sources can be 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[9], that accounts for these factors in calculating exhaust emissions (CO_2, HC, CO, NO_x, particulate matter, and toxics) for gasoline- and diesel-fueled vehicles. EPA has a similar emissions model for nonroad engines, equipment, and vehicles called NONROAD, and a draft emissions model for both on-road and nonroad vehicles called MOVES. [10]

Figure 4-3 illustrates the methods available for estimating CO_2 emissions from mobile sources. The approaches for estimating CO_2 emissions range from the use of fuel consumption rates and composition data to applying default fuel data to fuel-based emission factors or emission estimates based on vehicle distance traveled. Methane and N_2O emission factors are discussed separately.

Operators reporting under regulations with specific methodologies for mobile source combustion (e.g. California's *Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*, CARB, 2008) should use the approaches and default emission factors defined in the regulations rather than the approaches provided in this section.

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[9] MOBILE6 is currently available.

[10] Motor Vehicle Emission Simulator (MOVES). This new system will estimate emissions for on-road and non-road sources, cover a broad range of pollutants, and allow multiple scale analysis, from fine-scale analysis to national inventory estimation. http://www.epa.gov/oms/ngm.htm, accessed February 2, 2009.

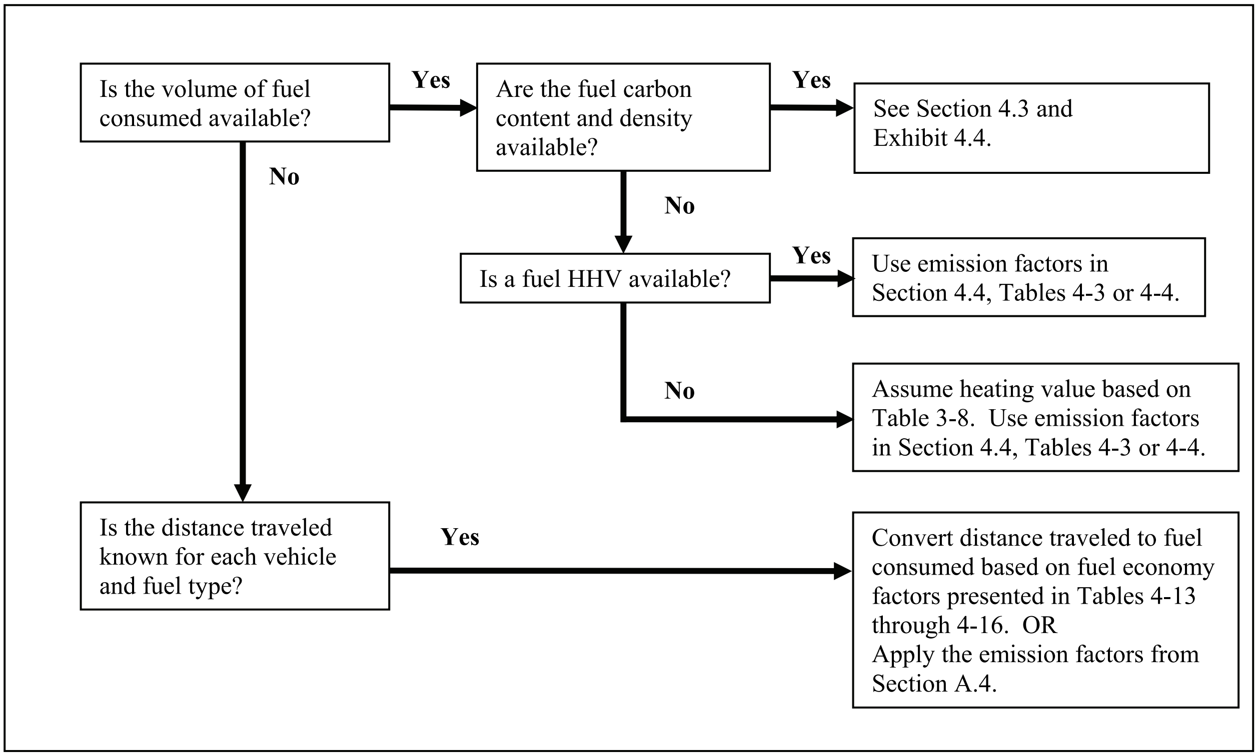

Figure 4-3. Calculation Approaches for Mobile Source CO_2 Emissions

4.8.1 Fuel Consumption Basis

Carbon Dioxide Emissions

As presented in Section 4.1 for stationary combustion, the fuel consumption approach for mobile sources is simply based on the volume of fuel combusted and either the carbon content of the fuel or the HHV. 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_2 (default of 100%). This type of calculation is demonstrated in Exhibits 4.4 and 4.5. As a rule of thumb, the carbon contents of different fuel types can be approximated from Table 3-8.

If the carbon content is unknown, fuel-specific emission factors provided in Table 4-3 can be used. These emission factors are based on the assumption that 100% of the fuel gas hydrocarbons is converted to CO_2. An example calculation is provided in Exhibit 4.6.

Some mobile sources combust biofuels such as ethanol and biodiesel, or biofuel blends such as E85 (85% ethanol and 15% gasoline) and B20 (20% biodiesel and 90% diesel). Combustion of biofuel blends results in emissions of both biogenic CO_2 and fossil-fuel CO_2. Both types of emissions must be calculated separately, since under international GHG accounting methods developed by the IPCC, biogenic carbon is considered to be part of the natural carbon balance and does not add to atmospheric concentrations of CO_2 (IPCC, 2006).

Automobiles/Passenger Vehicles

If the quantity of fuel consumed is unknown for land-based vehicles, fuel economy factors can be used to estimate the volumes. The most accurate fuel economy factors are vehicle- or model-specific. Fuel economy factors for vehicles sold in the U.S. from 1985 to the present can be obtained from the following EPA and DOE sponsored website:

http://www.fueleconomy.gov/feg/findacar.htm[11]

In the absence of vehicle- or model-specific information, the economy factors shown in Table 4-14 can be used. Factors provided in Table 3-8 can be used to convert the volume of fuel used to an energy basis.

Diesel Freight

Fuel economy factors for diesel freight are based on the type of truck (semi-truck/articulated lorry, non-semi truck/rigid lorry)[12] and the percent weight laden. Average truck fuel economy (in liters/km) can be calculated using the following equations (Defra, 2005):

$$\text{Fuel Economy}_{\text{Non-Semi Truck/Rigid Lorry}}(\text{liters/km})=0.236+0.104\times\frac{\%\text{ weight laden}}{100} \qquad \text{(Equation 4-18)}$$

where

% weight laden = the extent to which the vehicle is loaded to its maximum carrying capacity.

$$\text{Fuel Economy}_{\text{Semi Truck/Articulated Lorry}}(\text{liters/km})=0.311+0.137\times\frac{\%\text{ weight laden}}{100} \qquad \text{(Equation 4-19)}$$

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[11] Note that the EPA has recently revised its methodology for calculating fuel economy factors to reflect current operating conditions. Model year 2008 and later vehicles have fuel economies calculated using the new methodology. Fuel economy factors for model years 2007 and earlier have also been revised, and can be compared to the original MPG estimates. For such model years, the "Estimated New EPA MPG" should be used instead of the "Official EPA Window Sticker MPG". Link accessed January 7, 2009

[12] A semi truck/articulated lorry is a truck with two or more sections connected by a pivoting bar (e.g., tractor pulling a trailer). A non-semi truck/rigid lorry is a truck with a load bearing frame.

Table 4-13. Default Fuel Economy Factors for Different Types of Mobile Sources

Vehicle Type	Fuel Economy [a] liters/ 100 km	Fuel Economy [a] miles/ gallon	Vehicle Type	Fuel Economy [a] liters/ 100 km	Fuel Economy [a] miles/ gallon
New small gas/electric hybrid	4.2	56	Mid-size pick-up trucks, highway	10.7	22
Small gas auto, highway	7.3	32	Mid-size pick-up trucks, city	13.8	17
Small gas auto, city	9.0	26	Large pick-up trucks, highway	13.1	18
Medium gas auto, highway	7.8	30	Large pick-up trucks, city	15.7	15
Medium gas auto, city	10.7	22	LPG automobile	11.2	21
Large gas automobile, highway	9.4	25	Diesel automobile	9.8	24
Large gas automobile, city	13.1	18	Gasoline light truck	16.8	14
Medium station wagon, highway	8.7	27	Gasoline heavy truck	39.2	6
Medium station wagon, city	11.8	20	Diesel light truck	15.7	15
Mini van, highway	9.8	24	Diesel heavy truck	33.6	7
Mini van, city	13.1	18	Light motorcycle	3.9	60
Large van, highway	13.1	18	Diesel bus	35.1	6.7
Large van, city	16.8	14	Rail – domestic freight [b]	337 Btu/ton-mile	
Air Travel – domestic carrier (jet fuel, kerosene) [b]	--	0.38			

Footnotes and Sources:

[a] World Resources Institute and World Business Council for Sustainable Development (WRI/WBCSD). *Calculating CO_2 Emissions from Mobile Sources. Guidance to calculation worksheets v1.3.* Table 4. March 2005. File: co2-mobile.pdf available through www.ghgprotocol.org, October 2007.

[b] EPA, Climate Leaders *Greenhouse Gas Inventory Protocol Core Module Guidance: Direct Emissions from Mobile Combustion Sources*, Table 4, May 2008.

Fuel economies for multiple operational settings are provided in Table 4-15. If the % weight laden is unknown, 50% weight laden should be used as an average figure (Defra, 2005).

Table 4-14. Default Fuel Economy Factors for Diesel Freight Mobile Sources [a]

Truck Type	% Weight Laden	Fuel Economy liters/km	Fuel Economy gallons/mile
Non-Semi truck (Rigid Lorry)	0%	0.236	0.100
	25%	0.262	0.111
	50%	0.288	0.122
	75%	0.314	0.133
	100%	0.340	0.145
Semi truck (articulated lorry)	0%	0.311	0.132
	25%	0.345	0.147
	50%	0.379	0.161
	75%	0.414	0.176
	100%	0.448	0.190

Footnote and Source:

[a] Department for Environment, Food and Rural Affairs (Defra). *Guidelines for company reporting on Greenhouse Gas Emissions, Annexes updated July 2005*, Table 10.

Marine Vessels

Marine vessel fuel consumption is based on the type of vessel and the gross registered tonnage. Average marine vessel fuel consumption is presented in Table 4-16. Although the figures presented in Table 4-15 are not engine specific, fuel consumption will vary by engine (i.e., main engines consume more fuel than auxiliary engines). In the event that equipment-specific data are used to calculate emissions, fuel consumption should be split among engine types using the consumption percentages presented in Table 4-16.

Table 4-15. Default Fuel Consumption for Marine Vessels [a]

Ship type	Average Consumption (tonne/day)	Consumption at Full Power (tonne/day) [b]
Solid bulk carriers	33.8	20.186 + (0.00049 x GRT)
Liquid bulk carriers	41.8	14.685 + (0.00079 x GRT)
General cargo	21.3	9.8197 + (0.00143 x GRT)
Container	65.9	8.0552 + (0.00235 x GRT)
Passenger/roll-on/roll-off (Ro-Ro)/cargo	32.3	12.834 + (0.00156 x GRT)
High speed ferry	80.4	39.483 + (0.00972 x GRT)
Inland cargo	21.3	9.8197 + (0.00143 x GRT)
Tugs	14.4	5.6511 + (0.01048 x GRT)
Other ships	26.4	9.7126 + (0.00091 x GRT)
All ships	32.8	16.263 + (0.001 x GRT)

Footnotes and Sources:

[a] IPCC, *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, *Volume 2, Chapter 3 (Mobile Combustion),* Table 3.5.6, 2006.

[b] Fuel consumption is a function of Gross Registered Tonnage (GRT), a measure of the total internal volume of a vessel.

Table 4-16. Default Fuel Consumption by Engine Type [a]

Ship Type	Main Engine Consumption (%)	Avg. Number of Aux. Engines Per Vessel	Aux. Engine Consumption (%)
Bulk carriers	98%	1.5	2%
Combination carriers	99%	1.5	1%
Container vessels	99%	2	1%
Dry cargo vessels	95%	1.5	5%
Offshore vessels	98%	1	2%
Ferries/passenger vessels	98%	2	2%
Reefer vessels	97%	2	3%
RoRo vessels	99%	1.5	1%
Tankers	99%	1.5	1%
Miscellaneous vessels	98%	1	2%
Totals	98%		2%

Footnote and Source:

[a] IPCC, *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, *Volume 2, Chapter 3 (Mobile Combustion)*, Table 3.5.5, 2006.

Methane and Nitrous Oxide Emissions

Methane emissions from transportation fuel consumption can also be estimated using a mass balance and assuming a certain CH_4 destruction efficiency for the CH_4 content of the fuel. Methane formation from the combustion of gasoline and diesel, the most commonly used transportation fuels, typically only contributes around 1% of CO_2 equivalent emissions from the road transport sector; nitrous oxide emissions are not much higher, contributing only 2-3% of CO_2 equivalent emissions (IPCC, 2006).

Simplified emission factors for CH_4 and N_2O emissions from automobiles and other passenger vehicles are provided in Table 4-17.

Table 4-17. Mobile Source Combustion Emission Factors [a]

Source (Original Units) [b]	Methane Emission Factor			Nitrous Oxide Emission Factor		
	Original Value	**Converted to tonnes/ 1000 gal fuel**	**Converted to tonnes/ m^3 fuel**	**Original Value**	**Converted to tonnes/ 1000 gal fuel**	**Converted to tonnes/ m^3 fuel**
On-Road Transport						
Gasoline Fuel						
Light-duty gasoline vehicles (LDGV)						
Tier 1 (g/L)	0.12	4.5E-04	1.2E-04	0.16	6.1E-04	1.6E-04
Tier 0 (g/L)	0.32	1.2E-03	3.2E-04	0.66	2.5E-03	6.6E-04
Oxidation catalyst (g/L)	0.52	2.0E-03	5.2E-04	0.2	7.6E-04	2.0E-04
Non-catalytic controlled (g/L)	0.46	1.7E-03	4.6E-04	0.028	1.1E-04	2.8E-05
Light-duty gasoline trucks (LDGT)						
Tier 1 (g/L)	0.13	4.9E-04	1.3E-04	0.25	9.5E-04	2.5E-04
Tier 0 (g/L)	0.21	7.9E-04	2.1E-04	0.66	2.5E-03	6.6E-04
Oxidation catalyst (g/L)	0.43	1.6E-03	4.3E-04	0.20	7.6E-04	2.0E-04
Non-catalytic controlled (g/L)	0.56	2.1E-03	5.6E-04	0.028	1.1E-04	2.8E-05
Heavy-duty gasoline vehicles (HDGV)						
Three-way catalyst (g/L)	0.068	2.6E-04	6.8E-05	0.20	7.6E-04	2.0E-04
Non-catalytic controlled (g/L)	0.29	1.1E-03	2.9E-04	0.047	1.8E-04	4.7E-05
Uncontrolled (g/L)	0.49	1.9E-03	4.9E-04	0.084	3.2E-04	8.4E-05
Motorcycles						
Non-catalytic controlled (g/L)	1.4	5.3E-03	1.4E-03	0.045	1.7E-04	4.5E-05
Uncontrolled (g/L)	2.3	8.7E-03	2.3E-03	0.048	1.8E-04	4.8E-05
Diesel Fuel						
Light-duty diesel vehicles (LDDV)						
Advance control (g/L)	0.051	1.9E-04	5.1E-05	0.22	8.3E-04	2.2E-04
Moderate control (g/L)	0.068	2.6E-04	6.8E-05	0.21	7.9E-04	2.1E-04
Uncontrolled (g/L)	0.10	3.8E-04	1.0E-04	0.16	6.1E-04	1.6E-04

Table 4-17. Mobile Source Combustion Emission Factors, continued

	Methane Emission Factor			**Nitrous Oxide Emission Factor**		
Source [b]	**Original Value**	**Converted to tonnes/ 1000 gal fuel**	**Converted to tonnes/ m^3 fuel**	**Original Value**	**Converted to tonnes/ 1000 gal fuel**	**Converted to tonnes/ m^3 fuel**
Heavy-Duty Diesel Vehicles (HDDV)						
Advance Control (g/L)	0.12	4.5E-04	1.2E-04	0.082	3.1E-04	8.2E-05
Moderate Control (g/L)	0.14	5.3E-04	1.4E-04	0.082	3.1E-04	8.2E-05
Uncontrolled (g/L)	0.15	5.7E-04	1.5E-04	0.075	2.8E-04	7.5E-05
Natural Gas Vehicles (g/L)	0.009	3.4E-05	9.0E-06	6E-05	2.3E-07	6.0E-08
Propane Vehicles (g/L)	0.64	2.4E-03	6.4E-04	0.028	1.1E-04	2.8E-05
Off-Road Vehicles						
Gasoline Construction (g/gallon) [c]	0.5	5.0E-04	1.3E-04	0.22	2.2E-04	5.8E-05
Diesel Construction (g/gallon)[c]	0.58	5.8E-04	1.5E-04	0.26	2.6E-04	6.9E-05
Heavy-Duty Diesel Vehicles (HDDV)						
Advance Control (g/L)	0.12	4.5E-04	1.2E-04	0.082	3.1E-04	8.2E-05
Moderate Control (g/L)	0.14	5.3E-04	1.4E-04	0.082	3.1E-04	8.2E-05
Uncontrolled (g/L)	0.15	5.7E-04	1.5E-04	0.075	2.8E-04	7.5E-05
Other small utility gasoline (g/gallon) [c]	0.5	5.0E-04	1.3E-04	0.22	2.2E-04	5.8E-05
Other large utility gasoline (g/gallon) [c]	0.5	5.0E-04	1.3E-04	0.22	2.2E-04	5.8E-05
Other large utility diesel (g/gallon) [c]	0.58	5.8E-04	1.5E-04	0.26	2.6E-04	6.9E-05
Other gasoline vehicles (g/L)	2.7	1.0E-02	2.7E-03	0.050	1.9E-04	5.0E-05
Other diesel vehicles (g/L)	0.15	5.7E-04	1.5E-04	1.1	4.2E-03	1.1E-03
Diesel Rail Transportation (g/L)	0.15	5.7E-04	1.5E-04	1.1	4.2E-03	1.1E-03
Marine Transportation Gasoline boats (g/L)	1.3	4.9E-03	1.3E-03	0.066	2.5E-04	6.6E-05
Diesel ships (g/L)	0.15	5.7E-04	1.5E-04	1.1	4.2E-03	1.1E-03
Light fuel oil ships (g/L)	0.26	9.8E-04	2.6E-04	0.073	2.8E-04	7.3E-05
Heavy fuel oil ships (g/L)	0.28	1.1E-03	3.8E-04	0.079	3.0E-04	7.9E-05
Air Transportation Conventional aircraft (Aviation gasoline) (g/L)	2.2	8.3E-03	2.2E-03	0.23	8.7E-04	2.3E-04
Jet aircraft (Aviation turbo fuel) (g/L)	0.080	3.0E-04	8.0E-05	0.23	8.7E-04	2.3E-04

Footnotes and Sources for Table 4-17:

[a] Implementation dates for vehicle control technologies vary by model year. For a full description of implementation dates for Canadian vehicle control technologies, see Figure A2-2 and Table A2-4, *National Inventory Report: Greenhouse Gas Sources and Sinks in Canada, 1990-2006* (Environment Canada, 2008).

[b] Environment Canada, *National Inventory Report: Greenhouse Gas Sources and Sinks in Canada, 1990-2006*, April 2008, Table A12-7, unless otherwise noted. Original units are g/L fuel.

[c] The Climate Registry General Reporting Protocol Version 1.0, March 2008, Table 13.6. Original units are g/gallon fuel.

An example calculation illustrating how to estimate vehicle emissions is shown in Exhibit 4.12.

EXHIBIT 4.12: Sample Calculation for Combustion Emissions from Vehicles

INPUT DATA:
A fleet of heavy-duty (HD) diesel freight trucks travels 1,000,000 miles during the year. The trucks are equipped with advance control systems. Calculate the CO_2, CH_4, and N_2O emissions.

EXHIBIT 4.12: Sample Calculation for Combustion Emissions from Vehicles, continued

CALCULATION METHODOLOGY:
The CO_2, CH_4 and N_2O emission factors provided in Table 4-17 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 4-13.

$$\text{Fuel Consumed} = \frac{1{,}000{,}000 \text{ miles}}{\text{yr}} \times \frac{\text{gal diesel}}{7 \text{ miles}} = 142{,}857 \text{ gal diesel/yr}$$

1. *Calculate the CO_2 emissions.* Carbon dioxide emissions are estimated using a fuel-based factor provided in Table 4-3. 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 5.83×10^6 Btu/bbl (HHV), given in Table 3-8 of this document. Thus, the fuel heat rate is:

$$\text{Fuel Consumed} = \frac{142{,}857 \text{ gal}}{\text{yr}} \times \frac{\text{bbl}}{42 \text{ gal}} \times \frac{5.83 \times 10^6 \text{ Btu}}{\text{bbl}} = 1.98 \times 10^{10} \text{ Btu/yr (HHV)}$$

CO_2 emissions are calculated as using the fuel basis CO_2 emission factor for diesel fuel ("Gas/Diesel Oil") provided in Table 4-3, assuming 100% oxidation of fuel carbon to CO_2:

$$E_{CO_2} = \frac{1.98 \times 10^{10} \text{ Btu}}{\text{yr}} \times \frac{0.0732 \text{ tonne } CO_2}{10^6 \text{ Btu}}$$

$$\underline{E_{CO_2} = 1{,}449 \text{ tonnes } CO_2\text{/yr}}$$

2. *Calculate the CH_4 and N_2O emissions.* Methane and N_2O emissions are calculated using the CH_4 and N_2O emission factors provided in Table 4-17 for "Heavy-Duty Diesel Vehicles, Advance Control."

$$E_{CH_4} = \frac{142{,}857 \text{ gal}}{\text{yr}} \times \frac{4.5 \times 10^{-4} \text{ tonne } CH_4}{1000 \text{ gal}}$$

$$\underline{E_{CH_4} = 0.064 \text{ tonnes } CH_4\text{/yr}}$$

EXHIBIT 4.12: Sample Calculation for Combustion Emissions from Vehicles, continued

$$E_{N_2O} = \frac{142{,}857 \text{ gal}}{\text{yr}} \times \frac{3.1\times10^{-4} \text{ tonne } N_2O}{1000 \text{ gal}}$$

$$\underline{E_{N_2O} = 0.044 \text{ tonnes } CO_2/\text{yr}}$$

This sample calculation illustrates that the CH_4 and N_2O emissions are small when compared to CO_2.

An example calculation illustrating how to estimate marine vessel emissions is shown in Exhibit 4.13.

EXHIBIT 4.13: Sample Calculation for Combustion Emissions from Marine Vessels

INPUT DATA:
A fleet of 17 diesel-powered tankers operated 90 percent of the year at sea. The fuel consumption and Gross Registered Tonnage for each ship is unknown. Calculate the CO_2, CH_4, and N_2O emissions.

CALCULATION METHODOLOGY:
1. *Calculate the CO_2 emissions.* The fuel usage of the fleet is unknown so the first step in the calculation is to convert from days of operation to a volume of diesel fuel consumed basis. This calculation is performed using the default fuel economy factor provided in Table 4-15 for liquid bulk carriers. Note that the fuel economy factor is in terms of tonnes/day, and must be converted to a volume basis using the density of the fuel provided in Table 3-8 (for "Distillate Oil").

$$\text{Fuel Consumed} = 17 \text{ tankers} \times 0.9 \times \frac{365 \text{ days}}{\text{yr}} \times \frac{41.8 \text{ tonnes diesel}}{\text{day-tanker}} \times \frac{m^3}{847.31 \text{ kg diesel}} \times \frac{1000 \text{ kg}}{\text{tonne}}$$

$$\text{Fuel Consumed} = 275{,}498 \text{ m}^3 \text{ diesel consumed/yr}$$

Carbon dioxide emissions are estimated using a fuel-based factor provided in Table 4-3. 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 3.87×10^{10} J/m^3 (HHV) (for "Distillate Oil"), provided in Table 3-8.

EXHIBIT 4.14: Sample Calculation for Combustion Emissions from Marine Vessels, continued

$$\text{Fuel consumed} = \frac{275{,}498\ \text{m}^3}{\text{yr}} \times \frac{3.87\times10^{10}\ \text{J}}{\text{m}^3} = 1.07\times10^{16}\ \text{J/yr (HHV)}$$

Carbon dioxide emissions are calculated using the fuel basis CO_2 emission factor for diesel fuel ("Distillate Fuel") shown in Table 4-3, assuming 100% oxidation of fuel carbon to CO_2:

$$E_{CO_2} = \frac{1.07\times10^{16}\ \text{J}}{\text{yr}} \times \frac{69.3\ \text{tonne CO}_2}{10^{12}\ \text{J}}$$

$$\underline{E_{CO_2} = 738{,}861\ \text{tonnes CO}_2/\text{yr}}$$

2. *Calculate the CH_4 and N_2O emissions.* Methane and N_2O emissions are calculated using the CH_4 and N_2O emission factors provided in Table 4-17 for "Diesel Ships."

$$E_{CH_4} = \frac{275{,}498\ \text{m}^3}{\text{yr}} \times \frac{1.5\times10^{-4}\ \text{tonne CH}_4}{\text{m}^3}$$

$$\underline{E_{CH_4} = 41.32\ \text{tonnes CH}_4/\text{yr}}$$

$$E_{N_2O} = \frac{275{,}498\ \text{m}^3}{\text{yr}} \times \frac{1.1\times10^{-3}\ \text{tonne N}_2\text{O}}{\text{m}^3}$$

$$\underline{E_{N_2O} = 303.05\ \text{tonnes N}_2\text{O/yr}}$$

4.8.2 Operational Basis

If mobile source fuel consumption is not available, or operational parameters cannot be used in such a way as to obtain fuel consumed, the alternate method for calculating emissions from mobile sources is to use operational data, such as distance traveled or power output. This method is described in detail in Appendix A.

4.9 Other Miscellaneous Combustion Source Emissions

Other miscellaneous combustion sources include coke calcining kilns and welding.[13] 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 estimation 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_4 destruction efficiency. Carbon dioxide emissions can be estimated by mass balance using an assumed conversion of carbon in the fuel gas to CO_2. Alternatively, the external combustion emission factors given by fuel usage (described in Section 4.4) can be used for estimating CO_2 emissions. For some sources, N_2O emissions can be estimated by applying an emission factor from Tables 4-7 through 4-9. However, the factors provided in Tables 4-7 through 4-9 may not be applicable for all miscellaneous combustion sources.

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[13] Welding processes may involve the combustion of a supplemental fuel (e.g., acetylene).

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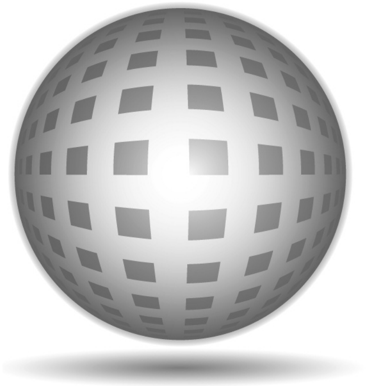
AMERICAN PETROLEUM INSTITUTE

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

AUGUST 2009

SECTION 5

PROCESS AND VENTED EMISSIONS ESTIMATION METHODS



Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry

Section 5 - Process and Vented Emission Estimation Methods

August 2009

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5.0 PROCESS AND VENTED EMISSIONS ESTIMATION METHODS

Vented emissions are releases to the atmosphere as a result of the process or equipment design or operational practices. A number of vented emission sources are associated with oil and natural gas industry operations. 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 natural gas industry, with additional subsections for equipment common to more than one industry segment. Table 5-1 illustrates the range of available options for estimating vented GHG emissions and associated considerations. To optimize cost effectiveness and reporting efficiency, facility operators may choose to use a mix of estimation approaches. It is important to document the estimation method used for each vent source.

Table 5-1. Emission Estimation Approaches – GHG and Source Specific Considerations for Vented Sources

Types of Approaches	**CH_4 Non-combustion Emissions**	**CO_2 Emissions**	**PFC and HFC Emissions**
Published emission factors	• Based on "average" equipment and emission source characteristics	• Limited emission factors specific to non-combustion CO_2 emissions • May be scaled from CH_4 emission factors	• Simplified estimation based on "average" equipment and emission source characteristics are consistent with low contribution to overall emissions
Equipment manufacturer emission factors	• Highly reliable for specific emission sources • Requires tracking number of equipment by type and utilization	• CO_2 emissions may be scaled from other non-combustion emission factors based on gas composition	
Engineering calculations	• Highly reliable for specific emission sources • May require detailed input data	• Highly reliable for many emission sources • May require detailed input data	• Material balance methods provide good reliability. • Requires data tracking

Table 5-1. Emission Estimation Approaches – GHG and Source Specific Considerations for Vented Sources, continued

Types of Approaches	CH_4 Non-combustion Emissions	CO_2 Non-Combustion Emissions	PFC and HFC Emissions
Monitoring over a range of conditions and deriving emission factors	• Highly reliable for specific emission sources • Generally not practical given the substantial number of emission sources	• Generally not practical given the low contribution to overall emissions	• Generally not practical given the low contribution to overall emissions
Periodic or continuous monitoring of emissions or parameters for calculating emissions	• Highly reliable for specific emission sources • Generally not practical given the substantial number of emission sources	• Not practical given the number of emission sources and the low contribution to overall emissions	• Not practical given the number of emission sources and the low contribution to overall emissions

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 the glycol in the reboiler (or regenerator). A small amount of CH_4 is absorbed by the glycol and driven off to the atmosphere in the glycol regeneration step. A stripping gas may also be introduced into the regenerator to help strip water and other absorbed compounds out of the glycol. Methane emissions from uncontrolled glycol dehydration units occur because the CH_4 removed from the glycol stream passes directly through the regenerator and is vented to the atmosphere.

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. Similarly, dehydration vents routed to a flare or other combustion control device should be estimated using the techniques presented in Section 4.

Figure 5-1 illustrates the methods available for estimating CH_4 emissions from glycol dehydrators, starting with using test data. However, such test data may not be available. If detailed information about the site-specific glycol dehydrator unit is known, a process simulator or other computer software such as GRI-GLYCalc^{TM} (GRI, 2000) can be used to estimate the emissions. Detailed information needed to run the GRI-GLYCalc^{TM} computer simulation includes: wet gas hydrocarbon composition, wet gas flow rate, wet gas temperature and pressure, existence of a gas-driven glycol pump, wet and dry gas water contents, glycol flow rate, use of stripping gas flowrate to the regenerator, and the temperature and pressure of the flash tank, if present.

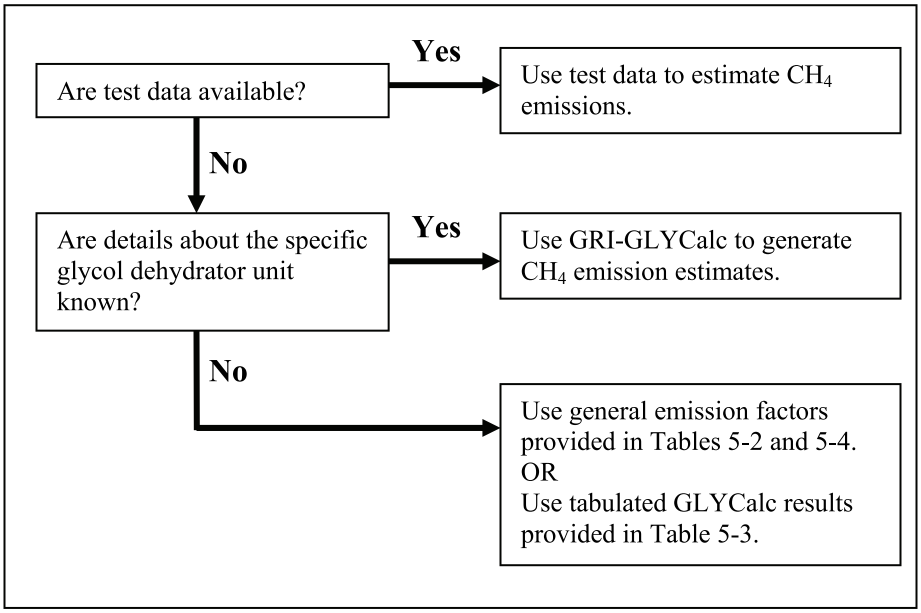

Figure 5-1. CH_4 Emissions from Glycol Dehydrators

If this information is not readily available, simplified emission factors can be used. These emission factors, provided in Table 5-2, were developed using both site data and computer simulations (Myers, 1996). Table 5-2 also lists the default CH_4 content of the natural gas for the different industry segments that may use glycol dehydration. The default CH_4 content and associated uncertainties for each industry segment are provided in Table E-4.

Table 5-2. Segment Specific Uncontrolled Gas Dehydration CH_4 Emission Factors

Excludes Glycol Gas-Assisted Pump Emissions – See Section 5.1.2

Industry Segment	CH_4 Emission Factor [a], Original Units	CH_4 Emission Factor [b], Converted to Tonnes Basis	CH_4 Content Basis for Industry Segment	Uncertainty [c] (+/- %)
Production	275.57 scf/10^6 scf gas processed	0.0052859 tonnes/10^6 scf gas processed	78.8 mole %	191
		0.18667 tonnes/10^6 m^3 gas processed		
Gas processing	121.55 scf/10^6 scf gas processed	0.0023315 tonnes/10^6 scf gas processed	86.8 mole %	249
		0.082338 tonnes/10^6 m^3 gas processed		
Gas transmission	93.72 scf/10^6 scf gas processed	0.001798 tonnes/10^6 scf gas processed	93.4 mole %	257
		0.06349 tonnes/10^6 m^3 gas processed		
Gas storage	117.18 scf/10^6 scf gas processed	0.0022477 tonnes/10^6 scf gas processed	93.4 mole %	197
		0.079377 tonnes/10^6 m^3 gas processed		

Footnotes and Sources:

[a] 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 U.S. Environmental Protection Agency, June 1996.

[b] CH_4 emission factors converted from scfy are based on 60°F and 14.7 psia.

[c] Uncertainty is based on a 95% confidence interval; however, because the data used to calculate the reference emission factor were unavailable, the uncertainty at a 95% confidence interval was calculated based on the uncertainty at a 90% confidence interval presented in the source, assuming a data set size of 10.

The emission factors in Table 5-2 can be scaled based on the ratio of the site-specific CH_4 content to the default emission factor concentration if the site natural gas has a significantly different CH_4 content from the default basis. Also, if the gas contains significant quantities of CO_2, the CH_4 emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions. Exhibit 5.1 demonstrates these calculations.

Note that the emission factors given in Table 5-2 do not include the emissions from gas-assisted glycol pumps, which can be a significant source of CH_4 emissions. Although the CH_4 from gas-assisted pumps are emitted through the regenerator vent, the emission rates were developed as a separate emission source in the GRI/EPA CH_4 emissions study, and are discussed in Section 5.1.2 (Myers and Harrison, 1996; Harrison et al., 1996).

Some glycol dehydrators use flash tanks, also referred to as flash separators. Flash tanks are used to drop the glycol line pressure, causing most of the light hydrocarbons in the glycol to flash into the vapor phase. If left uncontrolled, vapors from the flash tank can be a significant source of CH_4

emissions. However, flash gas is most often routed to the regenerator burner as fuel, significantly reducing CH_4 emissions from the regenerator vent. The uncontrolled emission factors presented in Table 5-2 would overestimate emissions from a glycol dehydration system with a flash tank separator that routes the flash gas to a vapor recovery system. Emission factors that reflect the use of flash separators are discussed below.

As an alternative to the industry-specific emission factors given above, Table 5-3 provides general glycol dehydrator emission factors developed using GRI-GLYCalc^{TM} (Texaco, 1999). Unlike the GRI/EPA emission factors, these factors include the emissions contribution from the gas-assisted glycol pump, if present, and account for the presence of a flash separator. The emission factors are developed assuming typical operating parameters for a glycol unit with no vent condenser, because a vent condenser does not appreciably affect the CH_4 emissions. Factors are provided for gas and electric glycol pumps, with and without flash separators.

Table 5-3. GRI-GLYCalc^{TM}-Generated Dehydration Methane Emission Factors

Includes Glycol Gas-Assisted Pump Emissions

Mode of Operation	CH_4 Emission Factor [a,b], Original Units	CH_4 Emission Factor [c], Converted to Tonnes per Gas Processed Basis
Gas pump without a flash separator	82.63 tonne/yr per 10^6 Nm^3/day gas processed	0.006410 tonnes/10^6 scf gas processed
		0.2264 tonnes/10^6 m^3 gas processed
Gas pump with a flash separator	1.98 tonne/yr per 10^6 Nm^3/day gas processed	0.000154 tonnes/10^6 scf gas processed
		0.00542 tonnes/10^6 m^3 gas processed
Electric pump without a flash separator	21.46 tonne/yr per 10^6 Nm^3/day gas processed	0.001665 tonnes/10^6 scf gas processed
		0.05879 tonnes/10^6 m^3 gas processed
Electric pump with a flash separator	1.64 tonne/yr per 10^6 Nm^3/day gas processed	0.000127 tonnes/10^6 scf gas processed
		0.00449 tonnes/10^6 m^3 gas processed

Footnotes and Sources:

[a] 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*.

[b] Uncertainty data are not available from this source.

[c] CH_4 emission factors are based on 60°F and 14.7 psia.

Some dehydrators also introduce stripping gas in the regenerator to help strip water and other absorbed compounds out of the glycol by increasing the vapor flow rate in the reboiler still. Three types of stripping gas are typically used: dry natural gas from the absorber, flash gas from the flash separator, or nitrogen. Any CH_4 in the stripping gas will pass directly through the regenerator; therefore, the use of dry natural gas will increase CH_4 emissions from the regenerator. GLYCalc should be used to estimate CH_4 emissions in this situation, as the default approaches presented in this subsection do not account for the use of stripping gas. The emission factors presented in Tables 5-2 or 5-3 may be used to estimate emissions from the dehydrator if flash gas or nitrogen is used as the stripping gas, as CH_4 emissions will not be increased.

An example calculation for dehydrator CH_4 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 × 10^6 scf/day of gas with a CH_4 molar content of 90% and CO_2 content of 5%. The dehydration unit includes an electric pump but does not include a flash separator. The glycol circulation rate is 200 gallons/hr, and the contactor pressure is 600 psig. Stripping gas is not used in the process. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:
1. *Calculate the CH_4 emissions.* Emissions are calculated using an emission factor specific to gas processing facilities, taken from Table 5-2. Because the CH_4 content of this facility differs from the 86.8% default CH_4 content associated with the emission factor presented in Table E-4, the calculations include an adjustment for the composition:

$$E_{CH_4} = \frac{25\times10^6 \text{ scf}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{0.0023315 \text{ tonne CH}_4}{10^6 \text{ scf}} \times \frac{\text{tonne mole CH}_4}{16 \text{ tonne CH}_4}$$
$$\times \frac{0.90 \text{ tonne mole CH}_4 \text{ (facility)}}{0.868 \text{ tonne mole CH}_4\text{(default)}} \times \frac{16 \text{ tonne CH}_4}{\text{tonne mole CH}_4}$$

$$\underline{E_{CH_4} = 22.06 \text{ tonnes CH}_4/\text{yr}}$$

Alternatively, Table 5-3 provides a CH_4 emission factor of 0.001665 tonnes $CH_4/10^6$ scf of gas processed for this type of arrangement. The CH_4 emissions from the dehydrator vent are calculated using this approach as shown below.

$$E_{CH_4} = \frac{25\times10^6 \text{ scf}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{0.001665 \text{ tonne CH}_4}{10^6 \text{ scf}}$$

$$\underline{E_{CH_4} = 15.19 \text{ tonnes CH}_4/\text{yr}}$$

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

2. *Calculate the CO_2 emissions*. Emissions of CO_2 are estimated from the CH_4 emissions using the relative CO_2 and CH_4 contents in the gas.

$$E_{CO_2} = 22.06 \text{ tonnes } CH_4 \times \frac{\text{tonne mole } CH_4}{16 \text{ tonne } CH_4} \times \frac{\text{tonne mole gas}}{0.90 \text{ tonne mole } CH_4} \times \frac{0.05 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2} = 3.37 \text{ tonnes } CO_2\text{/yr}} \quad \left(\begin{array}{l}\text{or 2.32 tonnes } CO_2\text{/yr if based on the alternative} \\ CH_4 \text{ approach using Table 5-3.}\end{array}\right)$$

Note that the CH_4 emission 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 5-2 are classified by industry segment, accounting for the average dehydrator capacity in each industry segment, while the factors in Table 5-3 are based on an average equipment set-up for any industry sector. In addition, uncertainty data are not available for the emission factors provided in Table 5-3.

5.1.2 Glycol Pumps

As demonstrated by the GRI/EPA study, gas-assisted glycol pumps can be a significant source of CH_4 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 leaving the absorber. This high pressure glycol contains some entrained gas from the absorber. The GRI/EPA CH_4 emissions project estimated the gas-assisted glycol pump emissions separately from the dehydrator vent emissions, although they are emitted from the same vent.

The GRI/EPA study noted that Kimray was a leading manufacturer of gas-assisted glycol pumps. Emission factors were presented in this 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_4 emissions are given in Table 5-4. This table also includes the default CH_4 content that can be used for adjusting the emission factors to other CH_4 contents. The default CH_4 content and associated uncertainties for each industry segment are provided in Table E-4. 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 5-4. GRI/EPA Kimray Pump CH_4 Emission Factors

Industry Segment	CH_4 Emission Factor [a], Original Units	CH_4 Emission Factor [b], Converted to Tonnes Basis	CH_4 Content Basis for Industry Segment	Uncertainty [c] (+/- %)
Production	992.0 scf/10^6 scf gas processed	0.01903 tonnes/10^6 scf gas processed 0.6720 tonnes/10^6 m^3 gas processed	78.8 mole %	82.8
Processing	177.75 scf/10^6 scf gas processed	0.0034096 tonnes/10^6 scf gas processed 0.12041 tonnes/10^6 m^3 gas processed	86.8 mole %	61.5

Footnotes and Sources:

[a] 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 U.S. Environmental Protection Agency, June 1996.

[b] CH_4 emission factors converted from scfy are based on 60°F and 14.7 psia.

[c] Uncertainty is based on a 95% confidence interval; however, because the data used to calculate the reference emission factor were unavailable, the uncertainty at a 95% confidence interval was calculated based on the uncertainty at a 90% confidence interval presented in the source assuming a data set size of 10.

An example calculation for glycol dehydrator Kimray pump CH_4 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 25×10^6 scf/day of gas. This dehydration unit includes a gas-operated pump but does not include a flash separator. Calculate the vented emissions from the pump and from the dehydrator as a whole.

CALCULATION METHODOLOGY:
1. *Calculate emissions from the pump.* Assuming the pump is a Kimray or similar type, Table 5-4 provides an appropriate emission factor. The CH_4 emissions are calculated by multiplying this emission factor by the annual gas throughput and adjusting for the facility CH_4 concentration, as shown below.

$$E_{CH_4,pump} = \frac{25\times10^6 \text{ scf}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{0.0034096 \text{ tonne CH}_4}{10^6 \text{ scf}} \times \frac{0.90 \text{ tonne mole CH}_4 \text{ (facility)}}{0.868 \text{ tonne mole CH}_4 \text{ (default)}}$$

$$\underline{E_{CH_4,pump} = 32.26 \text{ tonnes CH}_4/\text{yr}}$$

EXHIBIT 5.2: Sample Calculation for Dehydration Kimray Vent Emissions, continued

CO_2 emissions are calculated by correcting the CH_4 emissions by the ratio of CH_4 to CO_2 in the facility gas.

$$E_{CO_2,pump} = 32.26 \text{ tonnes } CH_4 \times \frac{\text{tonne mole } CH_4}{16 \text{ tonne } CH_4} \times \frac{\text{tonne mole gas}}{0.90 \text{ tonne mole } CH_4} \times \frac{0.05 \text{ tonne mole } CO_2}{\text{tonne mole gas}}$$
$$\times \frac{44 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2,pump} = 4.93 \text{ tonnes } CO_2/\text{yr}}$$

2. *Calculate total dehydrator emissions.* The previous example estimated the emissions from the dehydration unit to be 22.06 tonnes CH_4/yr, excluding the gas-assisted glycol pump. 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:

$$E_{CH_4,total} = 22.06 \text{ tonnes } CH_4 / \text{yr (from the dehydrator)} + 32.26 \text{ tonnes } CH_4 / \text{yr (from the pump)}$$

$$\underline{E_{CH_4,total} = 54.3 \text{ tonnes } CH_4 / \text{yr}}$$

$$E_{CO_2,total} = 3.37 \text{ tonnes } CO_2/\text{yr (from the dehydrator)} + 4.93 \text{ tonnes } CO_2/\text{yr (from the pump)}$$

$$\underline{E_{CO_2,total} = 8.30 \text{ tonnes } CO_2/\text{yr}}$$

Alternatively, using the emission factor from Table 5-2 for this type of arrangement results in the following CH_4 emissions:

$$E_{CH_4,total} = \frac{25\times10^6 \text{scf}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{0.00641 \text{ tonne } CH_4}{10^6 \text{ scf}}$$

$$\underline{E_{CH_4,total} = 58.5 \text{ tonnes } CH_4/\text{yr}}$$

These emissions could then be used to calculate CO_2 emissions, using the ratio of CH_4 to CO_2 in the facility gas.

5.1.3 Desiccant Dehydrators

Desiccant dehydrators have lower CH_4 (and CO_2) emissions than glycol-based systems. Desiccant systems remove the moisture in the gas by passing the wet gas through a drying bed of desiccant tablets (e.g., salts such as calcium, potassium, or lithium chlorides). Molecular sieves can also be used as the desiccant in these systems. Molecular sieves selectively adsorb acid gas molecules of smaller diameter than methane, and can be used for both gas dehydration and acid gas treatment.

Portable desiccant dehydrators can also be used during maintenance activities when the glycol dehydrator that is normally used has to be shut down. For example, low pressure wells may be vented to the atmosphere during maintenance activities because it can be difficult to resume flow if the wells are shut in (EPA Gas STAR, PRO Fact Sheet No. 207, October 2004). However, the portable desiccant system can be used in place of the glycol dehydrator system, thus avoiding having to vent the low pressure well to the atmosphere.

Since the desiccant dehydrator systems are fully enclosed, emissions only occur when the vessel is opened to change out the desiccant tablets. The emissions from these desiccant dehydrators can be estimated based on the internal volume of the dehydrator, as shown in the following:

$$\mathrm{GLD} = \frac{\mathrm{H} \times \mathrm{D}^2 \times \pi \times \mathrm{P}_2 \times \mathrm{G} \times \mathrm{N}}{4 \times \mathrm{P}_1} \qquad \text{(Equation 5-1)}$$

where

GLD = gas loss from desiccant dehydrator, scf/yr;
H = dehydrator vessel height, ft;
D = dehydrator vessel inside diameter, ft;
P_2 = gas pressure, psia;
P_1 = atmospheric pressure, 14.7 psia;
G = fraction of packed vessel volume that is gas; and
N = number of desiccant change outs per year.

An example calculation for desiccant dehydrator emissions is shown in Exhibit 5.3. The example is based on Exhibit 12 presented in the November 2003 EPA Gas STAR Lessons Learned document, *Replacing Glycol Dehydrators with Desiccant Dehydrators*.

EXHIBIT 5.3: Sample Calculation for Desiccant Dehydration Venting

INPUT DATA:
A desiccant dehydrator at a gas processing plant has a vessel height of 6.40 feet and an inside diameter of 1.60 feet. The pressure of the gas inside the vessel is 450 psig (464.7 psia). The desiccant material is refilled 52 times annually. The vessel is assumed to be 45% packed. The CH_4 and CO_2 molar contents are 90% and 5%, respectively. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:
The gas vented from the desiccant dehydrator vessel is estimated using Equation 5-1.

$$\text{GLD} = \frac{(6.40\text{ ft}) \times (1.60\text{ ft})^2 \times (3.1416) \times (464.7\text{ psia}) \times (0.45) \times 52}{4 \times (14.7\text{ psia})}$$

$$\underline{\text{GLD} = 9{,}519\text{ scf/yr (total gas)}}$$

The CH_4 and CO_2 emissions are then estimated using the gas molar contents:

$$E_{CH_4} = \frac{9{,}519\text{ scf}}{\text{yr}} \times \frac{0.90\text{ scf CH}_4}{\text{scf gas}} \times \frac{\text{lbmole CH}_4}{379.3\text{ scf CH}_4} \times \frac{16\text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonnes}}{2204.62\text{ lb}}$$

$$\underline{E_{CH_4} = 0.16\text{ tonnes CH}_4\text{/year}}$$

$$E_{CO_2} = \frac{9{,}519\text{ scf}}{\text{yr}} \times \frac{0.05\text{ scf CO}_2}{\text{scf gas}} \times \frac{\text{lbmole CO}_2}{379.3\text{ scf CO}_2} \times \frac{44\text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonnes}}{2204.62\text{ lb}}$$

$$\underline{E_{CO_2} = 0.025\text{ tonnes CO}_2\text{/yr}}$$

5.1.4 Other Glycol Dehydrator Alternatives

Methods of reducing CH_4 emissions range from operational alterations to technological alternatives. Operational alterations, such as optimizing glycol circulation rates or installing electric pumps, have been shown to reduce, but not eliminate, CH_4 emissions. Technological alternatives include replacing glycol dehydrators with desiccant dehydrators (discussed in Section 5.1.3), separators, and in-line heaters, or methanol injection units.

The use of separators and in-line heaters for water removal is a two-step process. First, the gas is expanded in a cyclone. This expansion lowers the temperature of the gas, enhancing water condensation and separation. Then the gas is reheated to restore it to a dew point below conditions in the pipeline system. Vented emissions from the separator should be calculated using an engineering approach. Combustion emissions from the line heater should be calculated using the methodology described in Section 4.

Methanol injection units are an efficient method for controlling gas hydrate formation in the lines. While methanol may absorb some of the water in the gas, its primary function is to act as a hydrate inhibitor. Methanol injection lowers the temperature at which hydrates can form, thereby reducing gas hydrate formation. Unlike glycol dehydration, methanol injection requires no regeneration, thus eliminating vented emissions.

5.1.5 Acid Gas Removal/Sulfur Recovery Units

Natural gas with high concentrations of acid gas species (H_2S and CO_2), referred to as sour gas, must be treated to reduce the acid gases to a concentration that meets pipeline corrosion-prevention specifications. Acid Gas Removal (AGR) units remove H_2S and CO_2 by contacting the sour gas with a liquid solution (typically amines). AGR units have similar equipment to those in the dehydrator units (an absorber, liquid circulation pump, and a reboiler to regenerate the absorber liquid).

Sulfur Recovery Units (SRUs) can also be used to recover elemental sulfur from H_2S. A byproduct of natural gas processing or crude oil refining, H_2S is converted to elemental sulfur through the use of a recovery process. The most common process is the Claus process, in which the H_2S undergoes catalytic oxidation in a two-step process. The Claus process consists of a thermal process and a catalytic process, both of which form elemental sulfur through the conversion of H_2S to sulfur and water. During the oxidation process, side reactions occur then produce other compounds including CO_2.

Methane Emissions

The amine solution associated with AGR units can absorb a small amount of CH_4 from the gas, and some CH_4 can be driven off to the atmosphere from the reboiler vent. In closed amine systems, the reboiler vent is directed to the facility flare and no methane venting occurs. Figure 5-2 shows the approaches available to estimate CH_4 emissions from AGR units, which is dictated by whether specific information is known about the sour gas, such as temperature and pressure.

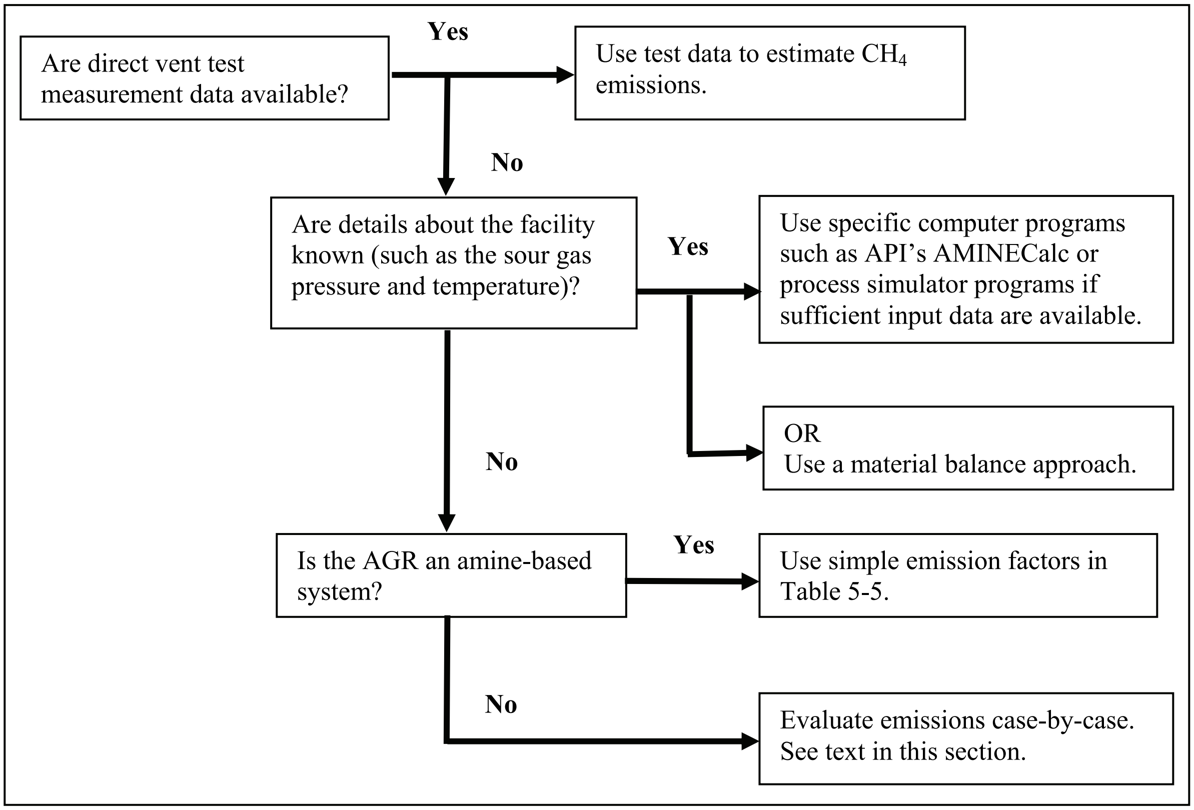

Figure 5-2. CH_4 Emissions from Acid Gas Removal (AGR) Units

Emissions from AGR unit vents routed to a flare or other control device should be estimated using the techniques presented in Section 4. For uncontrolled AGR units, two CH_4 emission factors for AGR vents were developed as part of the 1996 GRI/EPA CH_4 emissions study (Volume 14, page A-13) based on process simulation results for typical unit operations of a diethanol amine (DEA) unit (Myers, 1996). Table 5-5 provides the AGR CH_4 emission factor on both a throughput basis and unit basis. The throughput basis should be used over the unit basis factor if the volume of treated gas is known.

Table 5-5. Uncontrolled AGR CH_4 Emission Factor

Source	Methane Emission Factor [a], Original Units	Methane Emission Factor [b], Converted to Tonnes Basis	Uncertainty [c] (+/- %)
AGR vent	965 scf/10^6 scf treated gas	0.0185 tonnes/10^6 scf treated gas 0.654 tonnes/10^6 m^3 treated gas	119
	33,794 scfd/AGR unit	0.6482 tonnes/day-AGR unit	125

Footnotes and Sources:

[a] 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 U.S. Environmental Protection Agency, June 1996. Based on a DEA unit.

[b] CH_4 emission factors converted from scf are based on 60°F and 14.7 psia.

[c] Uncertainty is based on a 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

Alternatively, API's AMINECalc can be used to estimate CH_4 for amine units. Details on this software are available at the following API web address by searching for API Publication Number 4679:

http://www.api.org/

As an alternative to running AMINECalc, emissions from AGR units could also be calculated using a mass balance approach, such as described in Section 5.7.1.

There are other acid gas removal technologies besides amine units, including the Morphysorb® process, Kvaerner Membrane technology, and the Molecular Gate® process, the latter of which involves the use of molecular sieves. These technologies are reported to reduce CH_4 emissions, although published emission factors are not available (EPA Gas STAR, August 2007).

An example calculation for AGR CH_4 emissions is given in Exhibit 5.4, based on the emission factors in Table 5-5.

EXHIBIT 5.4: Sample Calculation for AGR Vent Emissions

INPUT DATA:
A gas processing plant has one amine-based AGR unit that vents to atmosphere. The treated gas throughput of the AGR unit is not known. The facility operates continuously throughout the year (8760 hours/year). Calculate the CH_4 emissions.

CALCULATION METHODOLOGY:
The AGR unit-based CH_4 emission factor from Table 5-5 is multiplied by the number of AGR units and converted from a daily basis to an annual basis.

EXHIBIT 5.4: Sample Calculation for AGR Vent Emissions, continued

$$E_{CH_4} = (1\ \text{AGR}) \times \frac{0.6482\ \text{tonne CH}_4}{\text{day-AGR}} \times \frac{365\ \text{day}}{\text{yr}}$$

$$\underline{E_{CH_4} = 236.6\ \text{tonnes CH}_4/\text{yr}}$$

Note that the treated gas throughput-based CH_4 emission factor could have been used instead of the unit-based factor if the AGR throughput data had been available.

Carbon Dioxide Emissions

Sour gas processing or sulfur recovery units can directly vent the CO_2 removed from the sour gas stream to the atmosphere or capture the CO_2 for other uses, such as enhanced oil recovery. For systems that vent the waste CO_2 (for example, amine units), emissions can be estimated by material balance using the known throughput and CO_2 concentrations of the inlet and outlet gas streams as shown in the following equation (CAPP, 2003).

$$E_{CO_2} = \left[\left(\frac{\text{Volume}}{\text{time}} \times CO_2\ \text{mole\%}\right)_{\text{sour}} - \left(\frac{\text{Volume}}{\text{time}} \times CO_2\ \text{mole\%}\right)_{\text{sweet}}\right] \times \frac{44}{\text{molar volume conversion}}$$

(Equation 5-2)

where

E_{CO_2} = mass emissions of CO_2 per year (in pounds or kg);

Volume = volume of the sour and sweet gas (in scf or m^3 at STP conditions);

sour = refers to the untreated sour inlet raw gas. Acid gas is typically comprised of CO_2 and H_2S;

sweet = refers to the treated gas after the H_2S and CO_2 have been removed (typically sales gas or pipeline quality gas);

CO_2 mole% = molar (or volume) concentrations of the sour and sweet gas. If the sweet gas concentration is unknown, 0% can be applied as a simplifying assumption, recognizing that this will likely overestimate emissions. Note, pipeline gas specifications typically limit CO_2 concentrations to 2% or less; and

Molar volume conversion = conversion from molar volume to mass (379.3 scf/lbmole or 23.685 m^3/kgmole).

The accuracy of Equation 5-2 is highly dependent on the consistency of the CO_2 concentration in the inlet raw gas and sales gas streams. To improve the accuracy of this method, a volume weighted-average CO_2 concentration should be determined (especially for the inlet gas) using a range of gas sample data.

Note that technologies such as the Molecular Gate® process that remove CO_2 and route the CO_2-rich tail gas stream to the fuel gas system must properly account for the CO_2 emissions. This would involve using the above material balance approach to account for the CO_2 emissions from the acid gas treatment that should be combined with CO_2 formed from combustion that is estimated using the approaches in Section 4 (i.e., the CO_2 removed by the acid gas treatment process gets emitted from the combustion stack with the CO_2 formed from combustion). Care should be taken not to double count these emissions. If the tail gas stream from the Molecular Gate® process is vented, the material balance approach should properly account for the vented CO_2 emissions.

Estimating vented CO_2 emissions from sour gas processing is demonstrated in Exhibit 5.5.

EXHIBIT 5.5: Sample Calculation for CO_2 Venting Emissions from Sour Gas Processing

INPUT DATA:
A amine-based sour gas processing facility has the following operating parameters:
Unit inlet stream: 150,000 $\times 10^6$ scf/yr sour gas processed with 3.0 mole % CO_2
Unit outlet stream: 148,500 $\times 10^6$ scf/yr sweet gas produced with 2.0 mole % CO_2

Calculate the vented CO_2 emissions.

CALCULATION METHODOLOGY:
The CO_2 vented emissions are estimated using the material balance from Equation 5-2.

$$E_{CO_2} = \left(\frac{150{,}000 \times 10^6 \text{ scf gas}}{\text{yr}} \times \frac{0.030 \text{ scf } CO_2}{\text{scf gas}} \right) - \left(\frac{148{,}500 \times 10^6 \text{ scf gas}}{\text{yr}} \times \frac{0.020 \text{ scf } CO_2}{\text{scf gas}} \right)$$

$$\times \frac{\text{lbmole } CO_2}{379.3 \text{ scf } CO_2} \times \frac{44 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonnes}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 80{,}506 \text{ tonnes/yr } CO_2}$$

EXHIBIT 5.5: Sample Calculation for CO_2 Venting Emissions from Sour Gas Processing, continued

Methane emissions are estimated by applying the emission factor from Table 5-5.

$$E_{CH_4} = \frac{150{,}000 \times 10^6 \text{ scf gas}}{\text{yr}} \times \frac{0.0185 \text{ tonnes } CH_4}{10^6 \text{ scf gas}}$$

$$\underline{E_{CH_4} = 2{,}775 \text{ tonnes/yr } CH_4}$$

Carbon dioxide emissions from SRUs that route the sulfur plant tailgas to a thermal oxidizer can also be calculated using a mass balance approach, such as provided in Equation 5-3. Carbon dioxide emissions from SRUs utilizing an amine unit should be calculated using Equation 5-2.

$$E_{CO_2} = FR \times \frac{MW_{CO_2}}{\text{molar volume conversion}} \times MF \times \frac{\text{tonne}}{2204.62 \text{ lb}} \qquad \text{(Equation 5-3)}$$

where

E_{CO_2} = CO_2 emissions (tonnes/yr);
FR = volumetric flow rate of acid gas to SRU (scf/yr);
MW_{CO_2} = molecular weight of CO_2 (44 lb/lb-mole);
Molar Volume Conversion = conversion from molar volume to mass (379.3 scf/lbmole); and
MF = molecular fraction of CO_2 in sour gas, based on site data.

5.2 Refinery Processes Vents

There are a number of specialized process vents in refineries that emit GHG emissions. Many of these are associated with catalyst regeneration, such as catalytic cracking regeneration, catalytic reformer regeneration, etc. Others are used to vent a by-product material, such as the hydrogen plant. This section will address each vent by process.

5.2.1 Catalytic Cracking Regenerator

The catalytic cracking processes deposit coke on the catalyst as a byproduct of the reaction. That coke must be burned off to restore the activity of the catalyst. Similarly, the thermal cracking process referred to as fluid coking utilizes a fluidized solids technique to remove carbon (coke) for continuous conversion of heavy, low-grade oils into lighter products. The coke is continuously burned off in the regenerator. This process vent may be a significant source of CO_2 emissions.

Fluid catalytic cracking units (FCCUs) are operated in two basic modes:

1. Full, or complete, CO burn mode, where essentially all CO is combusted to CO_2 within the regenerator. The exhaust gas typically contains approximately 2% O_2 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 typically contains less than 1% O_2 and 6-8% CO (though these compositions can vary). The exhaust gases pass through a CO boiler, which completes the combustion of CO to CO_2 external to the FCCU regenerator before the gases exit 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 full or partial burn mode and/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_2, CH_4, and TOC emissions since the combustion of CO to CO_2 is completed. As noted earlier, some catalytic cracking unit (CCU) regenerators are designed to complete the combustion of CO to CO_2 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_2 from the combustion of the supplemental fuel should be accounted for as described in Section 4.

Units operated in partial burn mode with a CO boiler or full burn mode have negligible CH_4 and TOC emissions. This conclusion is supported by test data that showed negligible CH_4 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 CH_4 emissions.[1] However, FCCUs are typically not operated in partial burn modes without a CO boiler.

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[1] Data presented in Table 6.22 of ARPEL shows CH_4 emission factors of 924 kg/1000 m^3 FCCU feed and 386 kg/1000 m^3 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.

Figure 5-3 provides the decision tree for FCCU regeneration. Note that the coke burn rate (or air blower capacity) is used for all the CO_2 emission calculation approaches discussed in this section. There are two commonly used approaches for estimating the CO_2 and CH_4 emissions from FCCU regeneration.

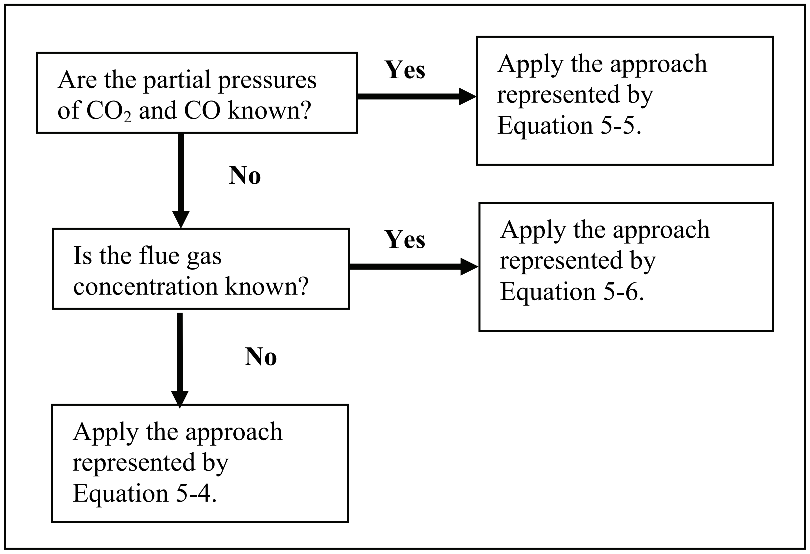

Figure 5-3. CO_2 Emissions from Fluid Catalytic Cracking Units (FCCU)

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_2. Based on this assumption and accounting for the conversion of units, the CO_2 emission rate can be calculated from the following equation:

$$E_{CO_2} = CC_{Avg} \times CF \times \frac{44 \text{ mass units } CO_2\text{/mole}}{12 \text{ mass units C/mole}} \qquad \text{(Equation 5-4)}$$

where

E_{CO_2} = emissions of CO_2 in units of mass (pounds, kg, tonnes) per year;
CC = daily average coke burn rate in units of mass per year;
CF = fraction of carbon in the coke burned (if unknown, default = 1);
44 = molecular weight of CO_2; and
12 = molecular weight of carbon (coke is assumed to be carbon).

Equation 5-4 is based on the fundamental principles of complete stoichiometric combustion of the carbon in coke to CO_2. 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 3-8, which contains the properties of various fuels, or assume a carbon fraction of 1.0 as a simplifying assumption, recognizing that this will overestimate emissions.

The coke burn rate can be calculated using the "K_1, K_2, K_3 approach" provided in EPA Rule 40 CFR 63, Subpart UUU. However, the coke burn equation can be reduced to Equation 5-5. The equation derivation is provided in Appendix B.

$$E_{CO_2} = \left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO}\right)\right] \times \frac{44 \text{ mass units } CO_2\text{/mole}}{12 \text{ mass units C/mole}} \times H \qquad \text{(Equation 5-5)}$$

where

E_{CO_2} = emissions of CO_2 (lb/year or kg/year);
K_1 = carbon conversion factor burn term (0.0186 lb-min/hr-dscf-% or 0.2982 kg-min/hr-dscm-, given in Table B-2%);
Q_r = volumetric flow rate of exhaust gas before entering the emission control system, calculated using Equation B-2 (dscf/min or dscm/min);
P_{CO_2} and P_{CO} = percent CO_2 and CO concentrations, respectively, in regenerator exhaust, percent by volume (dry basis); and
H = annual operating time (hrs/yr); 8760 hrs/yr if operating continuously throughout the year.

Another process calculation approach is based on the air blower capacity and flue gas concentration:

$$E_{CO_2} = \left(AR + SOR\right) \times \left(FCO_2 + FCO\right) \times \frac{44}{\text{molar volume conversion}} \times H \qquad \text{(Equation 5-6)}$$

where

E_{CO_2} = emissions of CO_2 in units of mass (pounds, kg, tonnes) per year;
AR = air rate in standard cubic feet or cubic meters per minute, on a dry basis;
SOR = supplemental oxygen rate (if used) in standard cubic feet or cubic meters per minute, on a dry basis;
FCO_2 = fraction CO_2 in the flue gas, on a dry basis (enter "0.12" for 12%, not 12);
FCO = fraction CO in the flue gas, on a dry basis (enter "0.08" for 8%, not 8);
Molar volume conversion = conversion from molar volume to mass (379.3 scf/lbmole or 23.685 m^3/kgmole); and
H = annual operating time (min/yr); 525,600 min/yr if operating continuously throughout the year.

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_2, because a partial oxidation regenerator flue gas contains both species, and each mole of CO will become a mole of CO_2 when emitted from the CO boiler.

A sample calculation for the approaches is provided in Exhibit 5.6.

EXHIBIT 5.6: Sample Calculation for FCCU Process Calculation Approach

INPUT DATA:
Assume a 6.36×10^3 m^3 per day catalytic cracking unit has a coke burn rate of 119,750 tonnes per year and a blower air capacity of 2150 m^3/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_2 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 (100×10^6 Btu/hr, higher heating value basis). Calculate the regenerator CO_2 emissions using Equations 5-4, 5-5, and 5-6. Calculate the emissions from supplemental firing of natural gas. Summarize the FCCU emissions.

CALCULATION METHODOLOGY:

1. *Calculate the CO_2 emissions using Equation 5-4.* Using Equation 5-4, the estimated CO_2 emissions from the regenerator would be:

$$E_{CO_2} = 119{,}750 \frac{\text{tonnes Coke Burned}}{\text{year}} \times \frac{0.93 \text{ tonnes C}}{\text{tonnes Coke}} \times \frac{44 \text{ tonnes } CO_2}{12 \text{ tonnes C}}$$

$$\underline{E_{CO_2} = 408{,}348 \text{ tonnes } CO_2/\text{year}}$$

2. *Calculate the CO_2 emissions using Equation 5-5.* Using the air rate in Equation 5-5, the CO_2 emission estimate is:

$$E_{CO_2} = \left[\frac{0.2982 \text{ kg - min}}{\text{hr - dscm \%}} \times \frac{2{,}150 \text{ dscm}}{\text{min}} \times \left(11\% + 9\%\right)\right] \times \frac{44}{12} \times \frac{\text{tonne}}{1{,}000 \text{ kg}} \times \frac{8760 \text{ hr}}{\text{yr}}$$

$$\underline{E_{CO_2} = 411{,}862 \text{ tonnes } CO_2/\text{yr}}$$

EXHIBIT 5.5: Sample Calculation for FCCU Process Calculation Approach, continued

3. *Calculate the CO_2 emissions using Equation 5-6.* Using the air rate in Equation 5-6 yields:

$$E_{CO_2} = \frac{2150\ m^3}{min} \times \left(\frac{0.11\ m^3\ CO_2}{m^3\ gas} + \frac{0.09\ m^3\ CO}{m^3\ gas} \times \frac{m^3\ CO_2}{m^3\ CO} \right) \times \frac{44\ kg\ CO_2/kgmole\ CO_2}{23.685\ m^3\ CO_2/kgmole\ CO_2}$$

$$\times \frac{525{,}600\ min}{year} \times \frac{tonnes}{1000\ kg}$$

$$\underline{E_{CO_2} = 419{,}859\ tonnes\ CO_2/year}$$

4. *Calculate the emissions from supplemental natural gas firing.* The emissions from the supplemental firing are in addition to the CO_2 emissions from the FCCU regenerator. Emissions from the supplemental firing of natural gas are estimated using the approaches presented in Section 4. The CO_2 emission factor was taken from Table 4-3 for pipeline natural gas. The CH_4 and N_2O emission factors were taken from Table 4-7 for natural gas-fired boilers.

$$E_{CO_2} = \frac{100 \times 10^6\ Btu}{hr} \times \frac{0.0531\ tonne\ CO_2}{10^6 Btu} \times \frac{8760\ hr}{yr}$$

$$\underline{E_{CO_2} = 46{,}516\ \ tonnes\ CO_2\ /\ yr}$$

$$E_{CH_4} = \frac{100 \times 10^6\ Btu}{hr} \times \frac{1.0 \times 10^{-6}\ tonne\ CH_4}{10^6\ Btu} \times \frac{8760\ hr}{yr}$$

$$\underline{E_{CH_4} = 0.88\ tonnes\ CH_4\ /\ yr}$$

$$E_{N_2O} = \frac{100 \times 10^6\ Btu}{hr} \times \frac{9.8 \times 10^{-7}\ tonne\ N_2O}{10^6\ Btu} \times \frac{8760\ hr}{yr}$$

$$\underline{E_{N_2O} = 0.86\ tonnes\ N_2O\ /\ yr}$$

EXHIBIT 5.6: Sample Calculation for FCCU Process Calculation Approach, continued

5. *Summarize the FCCU emissions.* The emissions from the FCCU are summarized below.

	Contribution	CO_2	CH_4	N_2O
Coke burn rate approach (Equation 5-4)	Coke Burn	408,348		
	CO Boiler	46,516	0.88	0.86
	Total	**454,149**	**0.88**	**0.86**
"K_1, K_2, K_3" approach (Equation 5-5),	**Contribution**	**CO_2**	**CH_4**	**N_2O**
	Coke Burn	411,862		
	CO Boiler	46,516	0.88	0.86
	Total	**458,663**	**0.88**	**0.86**
Air blower rate approach (Equation 5-6)	**Contribution**	**CO_2**	**CH_4**	**N_2O**
	Coke Burn	419,859		
	CO Boiler	46,516	0.88	0.86
	Total	**466,660**	**0.88**	**0.86**

5.2.2 Refinery Hydrogen Plant

Refinery hydrogen plants, often referred to as steam reformers, react hydrocarbons with steam (H_2O) to produce H_2 through a multiple step process involving catalytic reforming followed by water-gas-shift and CO_2 removal. Steam reformers are not to be confused with naphtha reformers, the emissions from which are discussed in Section 5.2.4. The quantity of H_2 generated depends on the carbon-to-hydrogen ratio of the feed gas and the steam-to-carbon ratio. In most cases, H_2 is made from natural gas, but there are some plants that operate with naphtha or refinery fuel gas as the feedstock. The overall chemical reaction can be expressed as:

$$C_xH_{(2x+2)} + 2xH_2O \rightarrow (3x+1)H_2 + xCO_2 \qquad \text{(Equation 5-7)}$$

This equation shows that a mole of CO_2 is formed for every mole of carbon in the hydrocarbon species. Note that the CO_2 generated by this reaction does not include CO_2 emissions from process heater(s) associated with the H_2 plant. Emissions from the process heaters should be treated like other combustion sources described in Section 4.

After the shift reactor, hydrogen must be separated from the syngas. Older hydrogen plants purify the raw hydrogen using wet scrubbing followed by methanation. The wet scrubbing unit generates a nearly pure stream of CO_2 which may be further processed for other uses (including being sold as a product), or may be vented directly to the atmosphere. Some plants may monitor the flow rate and composition of the vent stream from the hydrogen plant; in this situation, these data can be used to estimate the vented emissions from the hydrogen plant.

Modern hydrogen plants use a cyclical pressure swing adsorption (PSA) unit instead of wet scrubbing to remove impurities (CO_2, CO, CH_4) from raw hydrogen exiting the shift reactor. Compared to older units, which are typically able to produce hydrogen of 90% to 98% purity, PSA units are capable of producing hydrogen with a purity of greater than 99% (Kunz et al., n.d.). The PSA purge or tail gas is a low-Btu fuel gas consisting mostly of CO_2, CO, and CH_4, and some H_2. The purge gas is then routed to the reformer furnace. The purge gas is noted to provide 50 to 90% of the heat input to the furnace, for one example process (UOP, 2002). Because the purge gas is sent to the reformer furnace, hydrogen plants with a PSA unit emit all GHGs as reformer furnace flue gas.

GHG emissions from combustion of the low-Btu gas, along with any supplemental fuels, should be estimated like other combustion sources, as presented in Section 4. Due to the variable composition of the PSA purge gas stream, the material balance approach is suggested for estimating emissions from the combustion of the PSA purge gas. Site specific data (e.g., PSA purge gas flow rate and composition) should be used in the material balance approach, due to the fact that the carbon content of the PSA purge gas is not similar to the carbon content of other typical fuels such as natural gas. For plants with a PSA unit, careful accounting must be taken to avoid representing emissions as from both the reaction process (conversion to CO_2 in the reformer and shift reactor) and from combustion of supplemental fuel sent to reformer furnace.

Hydrogen plants are often the preferred source of CO_2 for industrial uses (food and beverage, dry ice, etc.). Traditionally, hydrogen plants with wet scrubbing purification are desirable for this as the wet scrubbing purification process produces a near pure CO_2 stream. Where this type of plant is not available, operators of a PSA type hydrogen plant may choose to add a CO_2 removal step in conjunction with the PSA to capture a portion of the process CO_2 for offsite use. The CO_2 removed in this step should be calculated and included in emissions reporting.

Figure 5-4 illustrates the approaches for estimating CO_2 emissions from a refinery hydrogen plant.

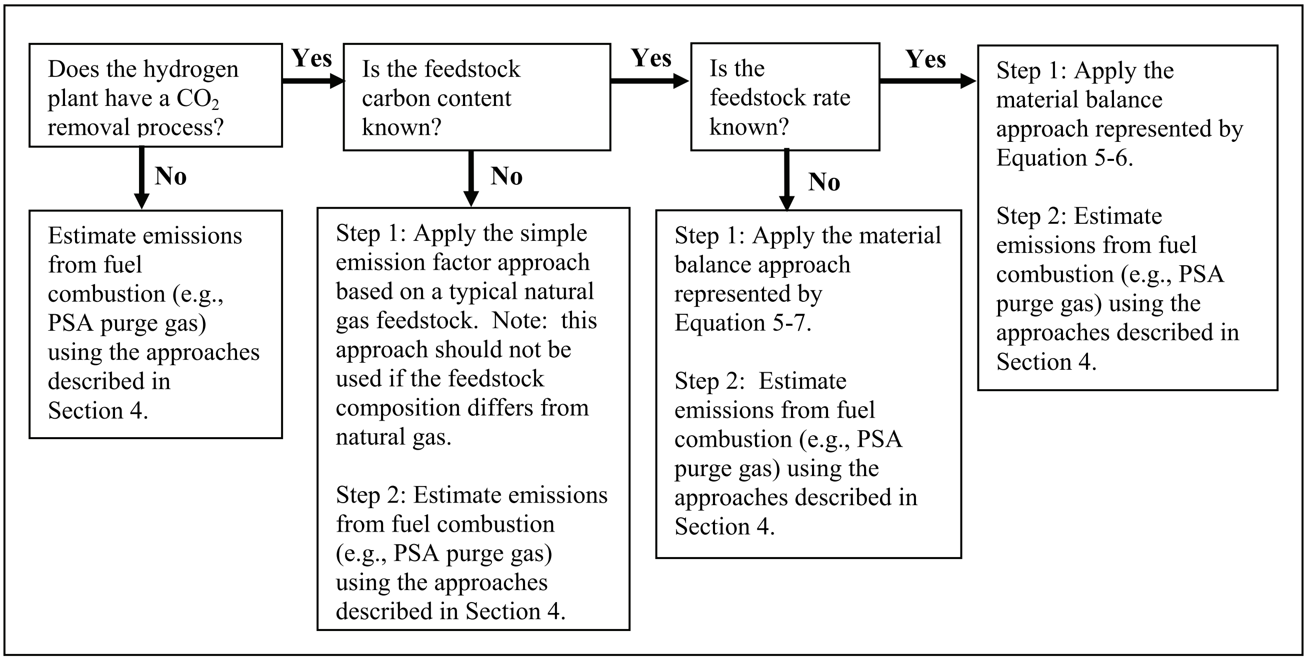

Figure 5-4. CO_2 Emissions from a Refinery Hydrogen Plant

A rigorous calculation approach, using a specific feed gas composition, can be used to estimate vented CO_2 emissions 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 hydrogen plants. Simple CO_2 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_4 with small amounts of other low molecular weight hydrocarbons). However, the more rigorous approaches should be used when naphtha reformers are used at the H_2 plant 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 5-8 presents this material balance approach:

$$E_{CO_2} = FR \times CF \times \frac{44 \text{ mass units } CO_2/\text{mole}}{12 \text{ mass units C/mole}} \qquad \text{(Equation 5-8)}$$

where

E_{CO_2} = emissions of CO_2 in units of mass (pounds, kg, tonnes) per year;

FR = feedstock rate in units of mass per year (feedstock rate excluding H_2O fed);
CF = Weight fraction of carbon in feedstock;
44 = molecular weight of CO_2; and
12 = molecular weight of carbon.

The carbon fraction can be estimated using the feedstock composition if it is not explicitly known. Note that if the fraction of carbon in the feedstock (CF) includes carbon accounted for through other end uses (e.g., combustion of PSA purge gas), these emissions will be double counted. To avoid double counting, the quantity of carbon accounted for elsewhere should be subtracted from the feedstock rate. Exhibit 5.7(a) demonstrates the approach to estimate the CO_2 emissions from a hydrogen plant using the feedstock rate and carbon content.

EXHIBIT 5.7(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 5×10^9 standard cubic feet per year (scf/yr) using feed gas with the following composition (molar basis):

CH_4 = 85%, C_2H_6 = 8%, C_4H_{10}= 3%; the balance is inerts (assume N_2 for the inerts).

Calculate the CO_2 emissions.

CALCULATION METHODOLOGY:
Carbon dioxide emissions are calculated using Equation 5-8. The first step in calculating the CO_2 emissions is to estimate the carbon content of the feed gas since it is not explicitly provided. In order to calculate the carbon content of the feed gas, the molecular weight of the mixture, weight percents of the individual components, and individual carbon contents must be calculated.

The molecular weight of the mixture shown in the table below is estimated using Equation 3-8, as demonstrated in Exhibit 3.3. The weight percent for each compound is estimated using Equation 3-7, rearranged in terms of weight %. This calculation is demonstrated in Exhibit 3.4.

The carbon content in weight percent for each chemical species is calculated using Equation 4-9. Once the individual compound weight percents and carbon contents have been estimated, the feed gas mixture carbon content is estimated using Equation 4-10. These conversions are demonstrated in Exhibit 4.4(a).

EXHIBIT 5.7(a): Sample Calculation for Hydrogen Plant - Rigorous Approach based on Feedstock Rate and Carbon Content, continued

The results of these calculations are shown below.

Compound	Mole %	MW	Weight %	Carbon Content (Wt. % C)
CH_4	85	16	72.1	75.0
C_2H_6	8	30	12.7	80.0
C_4H_{10}	3	58	9.2	82.8
N_2	4	28	5.9	0
Mixture	100	18.86	~100	**71.85**

After the feed stock gas mixture molecular weight and carbon content are defined, the CO_2 vent rate can be calculated using Equation 5-8:

$$E_{CO_2} = 5{,}000 \frac{10^6 \text{ scf feed}}{\text{year}} \times \frac{\text{lbmole feed}}{379.3 \text{ scf}} \times \frac{18.86 \text{ lb feed}}{\text{lbmole feed}} \times \frac{0.7185 \text{ lb C}}{\text{lb feed}} \times \frac{44 \text{ lb CO}_2}{12 \text{ lb C}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 297{,}100 \text{ tonnes CO}_2\text{/yr}}$$

The other rigorous approach is based on the H_2 production rate rather than the feedstock rate. This second approach applies the stoichiometric ratio of H_2 formed to CO_2 formed, as shown in Equation 5-9 based on re-arranging Equation 5-7. For this approach, it is important to apply the total hydrogen production rate prior to any process slip stream to avoid underestimating emissions.

It is important to note that when refinery gas is used as a feedstock, Equation 5-9 should not be used (without modification). Refinery fuel gas typically contains hydrogen, and this "free" hydrogen passes through the process without producing any attendant CO_2 emissions. Thus, this methodology based on hydrogen production rate would tend to overestimate CO_2 emissions when refinery fuel containing hydrogen is used as a feedstock.

$$E_{CO_2} = H_2R \times \frac{x \text{ mole CO}_2}{(3x+1) \text{ mole H}_2} \times \frac{44}{\text{molar volume conversion}} \qquad \text{(Equation 5-9)}$$

where

E_{CO_2} = emissions of CO_2 in units of mass (pounds, kg, tonnes) per year;
H_2R = rate of hydrogen production in units of volume (scf, m^3) per year;

x = stoichiometry from Equation 5-7;
44 = molecular weight of CO_2; and
Molar volume conversion = conversion from molar volume to mass (379.3 scf/lbmole or 23.685 m^3/kgmole).

This second rigorous approach is demonstrated in Exhibit 5.7(b).

EXHIBIT 5.7(b): Sample Calculation for Hydrogen Plant - Rigorous Approach based on H_2 Production Rate

INPUT DATA:
A hydrogen plant produces 13×10^9 standard cubic feet of hydrogen per year using feed gas with the following composition:

CH_4 = 85%, C_2H_6 = 8%, C_4H_{10}= 3%; the balance is inerts.

Calculate the CO_2 emissions.

CALCULATION METHODOLOGY:
The first step is to examine the chemical reaction for each compound:

CH_4: $CH_4+2H_2O = 4H_2+1CO_2$
C_2H_6: $C_2H_6+4H_2O = 7H_2+2CO_2$
C_4H_{10}: $C_4H_{10}+8H_2O = 13H_2+4CO_2$

Next, the moles of carbon and hydrogen are determined by multiplying the number of molecules of each in each compound by the composition of each compound in the feed gas (i.e., CH_4, C_2H_6, and C_4H_{10}). These results are used to determine the ratio of moles of carbon to moles of H_2, and are shown in the table below.

Compound	# C Atoms	# H_2 Molecules	Concentration	Moles C	Moles H_2
CH_4	1	4	0.85	0.85	3.4
C_2H_6	2	7	0.08	0.16	0.56
C_4H_{10}	4	13	0.03	0.12	0.39
Total Moles				**1.13**	**4.35**

EXHIBIT 5.7(b): Sample Calculation for Hydrogen Plant - Rigorous Approach based on H_2 Production Rate, continued

To use Equation 5-9, the carbon to hydrogen ratio must be calculated. The carbon to hydrogen ratio is calculated by dividing the total moles C by the total moles H_2 (1.13/4.35 = 0.26). Since each mole of carbon produces 1 mole of CO_2, the CO_2/H_2 ratio is the same as the C/H_2 ratio (0.26).

The CO_2 vent rate can then be calculated using Equation 5-9:

$$E_{CO_2} = 13{,}000 \frac{10^6 \text{ scf } H_2}{\text{year}} \times \frac{\text{lbmole } H_2}{379.3 \text{ scf}} \times \frac{0.26 \text{ lbmole } CO_2}{\text{lbmole } H_2} \times \frac{44 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 177{,}800 \text{ tonnes } CO_2/\text{yr}}$$

A simpler approach to estimate CO_2 emissions from hydrogen plants with a CO_2 vent is to use default emission factors that are based on either feedstock consumption or hydrogen production. These emission factors are based on a stoichiometric conversion (as shown in Equation 5-7) for a feed gas with an average natural gas composition. Table 5-6 provides the average natural gas composition used to derive these factors, which is based on measurements from pipeline-quality gas from 26 U.S. cities (GTI, 1992).

Table 5-6. Composition of U.S. Pipeline-Quality Natural Gas

Compound	Average Volume % [a,b]
CH_4	93.07
C_2H_6	3.21
C_3H_8	0.59
Higher hydrocarbons [c]	0.32
Non-hydrocarbons [d]	2.81

Footnotes and Sources:

[a] 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.

[b] Perry and Green. *Perry's Chemical Engineer's Handbook*, Sixth Edition, Table 9-14, 1984.

[c] Higher molecular weight hydrocarbons were represented by C5 in calculating the CO_2 and H_2 production rates.

[d] The non-hydrocarbons are assumed to contain 0.565 volume % CO_2 based on an average natural gas composition from Perry's Chemical Engineers Handbook.

Please note that if the feed is different from pipeline-quality natural gas, the emission factors for the simple approach will overestimate emissions due to the assumed higher carbon content of natural gas. In such an event, the stoichiometric conversion presented in Equation 5-7 should be used instead. This simple approach is demonstrated in Exhibit 5.8.

The simple approach is based on an emission factor of 32,721 pounds of carbon per million standard cubic feet of feedstock (excluding H_2O) or 8,064 pounds of carbon per million standard cubic feet of H_2 produced. These emission factors are shown below:

119,976 lb $CO_2/10^6$ scf feedstock	29,568 lb $CO_2/10^6$ scf H_2 produced
54.42 tonnes $CO_2/10^6$ scf feedstock	13.41 tonnes $CO_2/10^6$ scf H_2 produced
1,922 tonnes $CO_2/10^6$ m^3 feedstock	473.6 tonnes $CO_2/10^6$ m^3 H_2 produced

EXHIBIT 5.8: Sample Calculation for Hydrogen Plant Emissions - Simple Approach

INPUT DATA:
A hydrogen plant produces 13×10^9 standard cubic feet of hydrogen per year. Calculate the CO_2 emissions.

CALCULATION METHODOLOGY:
Carbon dioxide emissions are calculated using the emission factor derived from the average U.S. natural gas composition.

$$E_{CO_2} = 13{,}000 \frac{10^6 \text{ scf } H_2}{\text{year}} \times \frac{13.41 \text{ tonnes } CO_2}{10^6 \text{ scf } H_2}$$

$$\underline{E_{CO_2} = 174{,}300 \text{ tonne } CO_2/\text{yr}}$$

Although rare and not applicable to most refineries, a partial H_2 generation unit may be used (i.e., where only a portion of the H_2 available in the hydrocarbon stream is converted to H_2). If such a system is used, site-specific data or engineering judgment must be used to estimate the CO_2 emissions. If site-specific data are not available, one suggested estimation approach is to ratio the actual H_2 generation rate for the year to the design basis, and multiply this ratio by the design CO_2 emissions to estimate the actual CO_2 emission rate. Alternatively, a simplifying assumption would be to assume full conversion and use the simple emission factor or apply Equation 5-9, recognizing that this will overestimate emissions.

5.2.3 Cokers

Several varieties of cokers are used in refineries, including delayed cokers, flexi-cokers, and fluid cokers. No quantitative data have been found to estimate CH_4 emissions from these sources. Delayed cokers will not have CO_2 emissions other than from their process heaters that are calculated as any other combustion source (as described in Section 4). Flexi-cokers produce a low-Btu gas that is combusted through a fuel gas system or a flare, and also will not have CO_2 emissions other than those calculated for the combustion sources described in Section 4.

Carbon dioxide emissions from the coke burner are estimated by assuming that all of the carbon in the coke is oxidized to CO_2, as shown in Equation 5-4. Equation 5-4 can also be used for flexi-coker emissions, provided that the combustion of the low-Btu gas is not otherwise accounted for. An example calculation for a fluid coker is shown in Exhibit 5.9.

Note that if the coke burner off-gas is exported for recovery of CO_2, direct CO_2 emissions from the coker may be eliminated or reduced. As stated previously, if the coke burner off-gas is burned as a low-Btu fuel gas, the CO_2 present in the stream may be counted as a combustion exhaust emission.

EXHIBIT 5.9: Sample Calculation for Fluid Coker

INPUT DATA:
A fluid coker combusts 140×10^6 pounds per year of coke in the coke burner. The weight percent H_2 in the coke is known to be 1.5% (0.015 on a fraction basis). Calculate the CO_2 emissions.

CALCULATION METHODOLOGY:
The carbon fraction is equal to 1 minus the non-hydrocarbon fraction. In this example, the carbon fraction is assumed to be equal to 1 minus the fraction H_2, or 0.985. Using Equation 5-4, the estimated CO_2 emissions are:

$$E_{CO_2} = \frac{140\times10^6 \text{ lb Coke}}{\text{year}} \times \frac{0.985 \text{ lb C}}{\text{lb Coke}} \times \frac{44 \text{ lb CO}_2\text{/lbmole}}{12 \text{ lb C/lbmole}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 229{,}350 \text{ tonnes CO}_2\text{/yr}}$$

5.2.4 Other Catalyst Regeneration

A variety of other refinery processes employ catalysts that require regeneration (e.g., naphtha reformers). 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_4 emissions from any of these regeneration activities. However, the combustion of coke on the spent catalyst results in CO_2 emissions. The CO_2 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_2 emissions from intermittent or continuous catalyst regeneration can be estimated by Equation 5-10. Equation 5-10 can also be used for catalytic reformer units (CRUs). Emissions from all other coke can be calculated assuming complete conversion to CO_2. A default carbon content for petroleum coke is presented in Table 3-8; all other coke can be assumed to be 100% carbon.

$$E_{CO_2} = CRR \times H \times \left(FC_{spent} - FC_{regen}\right) \times \frac{44 \text{ mass units } CO_2\text{/mole}}{12 \text{ mass units C/mole}} \qquad \text{(Equation 5-10)}$$

where

E_{CO_2} = emissions of CO_2 in tonnes per year;
CRR = catalyst regeneration rate in tonnes per hour;
H = hours that the regenerator was operational during the year (hrs/yr);
FC_{spent} = weight fraction of carbon on spent catalyst; and
FC_{regen} = weight fraction of carbon on regenerated catalyst.

In the absence of site specific data, FC_{regen} can be assumed to be zero, recognizing that this will overestimate emissions. 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. Calculate the CO_2 emissions.

CALCULATION METHODOLOGY:
Using Equation 5-10, the estimated CO_2 emissions are calculated as follows:

EXHIBIT 5.10: Sample Calculation for Other Continuous Catalyst Regeneration, continued

$$E_{CO_2} = \frac{10 \text{ tonnes catalyst}}{\text{hr}} \times \frac{8280 \text{ hr}}{\text{yr}} \times \frac{0.04 \text{ tonne C}}{\text{tonne catalyst}} \times \frac{44 \text{ tonne } CO_2\text{/tonne mole}}{12 \text{ tonne C/tonne mole}}$$

$$\underline{E_{CO_2} = 12{,}144 \text{ tonnes } CO_2\text{/yr}}$$

Similarly, 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.

$$E_{CO_2} = CRR \times N \times \left(FC_{spent} - FC_{regen}\right) \times \frac{44 \text{ mass units } CO_2\text{/mole}}{12 \text{ mass units C/mole}} \qquad \text{(Equation 5-11)}$$

where

E_{CO_2} = emissions of CO_2 in tonnes per year;
N = number of regeneration cycles per year;
CRR = catalyst regeneration rate in tonnes per cycle;
FC_{spent} = weight fraction of carbon on spent catalyst; and
FC_{regen} = weight fraction of carbon on regenerated catalyst.

An example of this calculation is presented in Exhibit 5.11.

EXHIBIT 5.11: 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 regenerated twice a year, on average.

Calculate the CO_2 emissions.

CALCULATION METHODOLOGY:
The estimated CO_2 emissions are calculated using Equation 5-11.

$$E_{CO_2} = \frac{1{,}000 \text{ tonnes catalyst}}{\text{regeneration}} \times \frac{2 \text{ regenerations}}{\text{yr}} \times \frac{0.07 \text{ tonne C}}{\text{tonne catalyst}} \times \frac{44 \text{ tonne } CO_2\text{/tonne mole}}{12 \text{ tonne C/tonne mole}}$$

$$\underline{E_{CO_2} = 513 \text{ tonnes } CO_2\text{/yr}}$$

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 some refineries, asphalt blowing can also occur at asphalt processing and roofing plants. The exhaust air may be vented directly to the atmosphere, or the emissions may be controlled such as through vapor scrubbing or incineration (incineration would result in CO_2 emissions). Emissions of CO_2 and CH_4 from asphalt blowing are considered very small, because the majority of light hydrocarbons are removed during distillation (IPCC, 2006; EEA, 2007). However, emissions can be calculated using site-specific data or default emission factors.

The rigorous approach to estimating CH_4 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 estimation method. This approach is the same as the cold process vent approach to estimating emissions described later in this API *Compendium* (refer to Section 5.3).

A simple emission factor for uncontrolled asphalt blowing is available from AP-42 (EPA, AP-42, Section 5.1.2.10, 1995). 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_4 emissions when using the simple emission factor approach. Site-specific measured data or engineering judgment may be used to estimate the exhaust gas concentrations. In the absence of such data, the CH_4 and CO_2 emission factors provided in Table 5-7 can be used:

Table 5-7. Default Asphalt Blowing Emission Factors

Emission Factor	Factor	Units	Source
Total Emissions	30	kg/Mg blown asphalt	AP-42
	60	lb emissions/ton blown asphalt	AP-42
	0.03	tonnes emissions/tonne blown asphalt	Derived from AP-42 factor
CH_4	5.55E-04	tonne CH_4/bbl asphalt blown	Derived using Dimpfl CH_4 composition (13% CH_4 on an air-free basis)
	3.49E-03	tonne CH_4/m^3 asphalt blown	
	3.07E-03	tonne CH_4/ton asphalt blown	
	3.38E-03	tonne CH_4/tonne asphalt blown	
CO_2	1.01E-03	tonne CO_2/bbl asphalt blown	Derived using Dimpfl CO_2 composition (9% CO_2 on an air-free basis)
	6.38E-03	tonne CO_2/m^3 asphalt blown	
	5.61E-03	tonne CO_2/ton asphalt blown	
	6.19E-03	tonne CO_2/tonne asphalt blown	

Sources:
EPA, AP-42, Section 5.2.1.10, 1995
Dimpfl, L.H., "Study Gives Insight Into Asphalt Tank Explosions", *Oil and Gas Journal*, December 1980

The emission factors above were derived from asphalt blowing exhaust composition data presented in an Oil & Gas Journal article (Dimpfl, 1980)[2]. If site-specific exhaust stream data are available, emission factors should be derived in a similar fashion. The derivation of these factors is provided in Appendix B.

In the absence of site-specific data, controlled CH_4 and CO_2 emissions can be calculated using a mass balance approach, as shown in the following equations:

$$E_{CH_4} = \left(Q \times EF_{CH_4}\right) \times \left(1\text{-}DE\right) \qquad \text{(Equation 5-12)}$$

where

E_{CH_4} = CH_4 emissions (metric tonnes/yr);
Q = quantity of asphalt blown (bbl/yr or ton/yr);
EF_{CH_4} = CH_4 Emission factor from Table 5-7 (tonne/bbl or tonne/ton); and
DE = control measure destruction efficiency (default DE = 98%, expressed as 0.98).

$$E_{CO_2} = \left(Q \times EF_{CO_2}\right) + \left(Q \times EF_{CH_4} \times DE \times \frac{44 \text{ mass units } CO_2\text{/mole}}{16 \text{ mass units C/mole}}\right) \qquad \text{(Equation 5-13)}$$

where

E_{CO_2} = CO_2 emissions (metric tonnes/yr);
Q = quantity of asphalt blown (bbl/yr or ton/yr);
EF_{CO_2} = CO_2 Emission factor from Table 5-7 (tonne/bbl or tonne/ton);
EF_{CH_4} = CH_4 Emission factor from Table 5-7 (tonne/bbl or tonne/ton);
DE = control measure destruction efficiency (default DE = 98%, expressed as 0.98); and
44/16 = CH_4 to CO_2 conversion factor.

Note that the second terms of Equations 5-12 and 5-13 should only be used to calculate emissions from asphalt blowing when vented emissions are routed to a combustion control device. Also note that the first term in Equation 5-13 represents the vented CO_2 emissions while the second term reflects CO_2 emissions from combustion.

Exhibit 5.12 provides an example calculation for asphalt blowing emissions.

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[2] The same speciation, presented on an air-free basis is also reported in ARPEL, *Atmospheric Emissions Inventories Methodologies in the Petroleum Industry*, Table 6.24, 1998.

EXHIBIT 5.12: 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. A site-specific exhaust stream composition profile is not available. The exhaust air is vented to the atmosphere uncontrolled. Calculate the CO_2 and CH_4 emissions.

CALCULATION METHODOLOGY:
Carbon dioxide and CH_4 emissions are calculated by multiplying the annual blown asphalt rate by the CO_2 and CH_4 emission factors provided in Table 5-7.

$$E_{CO_2} = \frac{100{,}000 \text{ tons asphalt blown}}{\text{year}} \times \frac{5.61\text{E-03 tonne } CO_2}{\text{ton asphalt blown}}$$

$$\underline{E_{CO_2} = 561 \text{ tonnes } CO_2 \text{ emissions/yr}}$$

$$E_{CH_4} = \frac{100{,}000 \text{ tons asphalt blown}}{\text{year}} \times \frac{3.07\text{E-03 tonne } CH_4}{\text{ton asphalt blown}}$$

$$\underline{E_{CH_4} = 307 \text{ tonnes } CH_4 \text{ emissions/yr}}$$

5.2.6 Other Refinery Process Vents

Coke calcining operations, which convert green coke to almost pure carbon by heating the green coke and evaporating moisture and volatiles, may produce CO_2 emissions. Carbon dioxide emissions should be calculated using engineering approaches such as material balances that incorporate site-specific values such as the CO_2 content of the exhaust gas.

Emissions from coke drums may occur as a result of unquenched hot spots in the coke. When air is introduced, oxidation of the carbon may occur, resulting in emissions of CO_2. Coke drum blowdowns can also result in emissions, which may be routed to a flare. If the emissions are routed to a flare, flared emissions should be calculated using the methodology provided in Section 4.6. Vented emissions from coke drum blowdowns can be calculated using a mass balance approach, such as that described in Section 5.3 for cold process vents.

The process vents from thermal cracking, such as flexi-coking, were also considered as a potential source of GHG emissions. Thermal cracking, which breaks heavy oil molecules by exposing them to high temperatures, does not produce CH_4 emissions. Carbon dioxide emissions would be associated with the heating process, but these emissions would be calculated using the approaches presented for other combustion sources (see Section 4).

Emissions from other refinery process vents not addressed in the API *Compendium* should be estimated using an engineering approach.

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_4 than CO_2. 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_4 and/or CO_2 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 as follows:

$$E_x = VR \times F_x \times \frac{MW_x}{\text{molar volume conversion}} \times VT \times n \qquad \text{(Equation 5-14)}$$

where

E_x = emissions of "x" in units of mass (pounds, kg, tonnes) per year;
"x" = the GHG compound of interest (CH_4, or CO_2 for CO_2 rich streams);
VR = the vent rate in volume units at STP conditions (scfm or m^3/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^3/kgmole);
VT = the time duration of the venting event in minutes; and
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 as follows:

$$E_x = VR \times F_x \times \frac{MW_x}{\text{molar volume conversion}} \qquad \text{(Equation 5-15)}$$

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_4 or CO_2, for CO_2 rich streams);
VR= the vent rate in volume units at STP conditions per unit of time (e.g., scfm or m^3/min);
F_x= the molar fraction of compound "x" in the vent gas stream;
MW_x= molecular weight of compound "x"; and
Molar volume conversion= Conversion from molar volume to mass (379.3 scf/lbmole or 23.685 m^3/kgmole.

Examples of these calculations are shown in Exhibit 5.13 (a) and (b)

EXHIBIT 5.13(a): Sample Calculation for an Intermittent Process Vent

INPUT DATA:
A production facility in a remote location produces 5,200 barrels per day (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_4, 20% VOC, and 10% CO_2. Calculate the CH_4 and CO_2 emissions from the vented associated gas.

CALCULATION METHODOLOGY:
To calculate the vented associated gas emissions, the associated gas production rate (GPR) must be calculated from the GOR and the oil production rate.

$$\text{GPR} = \text{GOR} \times (\text{Oil production})$$

$$\text{GPR} = \frac{700 \text{ scf gas}}{\text{bbl oil}} \times \frac{5{,}200 \text{ bbl oil}}{\text{day}} \times \frac{\text{day}}{24 \text{ hours}} \times \frac{\text{hour}}{60 \text{ min}}$$

GPR = 2,528 scf/min

Equation 5-14 is used to calculate emissions per event. For this example there is one event during the year that lasts 15 days.

EXHIBIT 5.13(a): Sample Calculation for an Intermittent Process Vent, continued

$$E_{CH_4} = \frac{2{,}528\text{ scf}}{\text{min}} \times \frac{0.7\text{ scf CH}_4}{\text{scf gas}} \times \frac{\text{lbmole CH}_4}{379.3\text{ scf CH}_4} \times \frac{16\text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{60\text{ minutes}}{\text{hour}} \times \frac{24\text{ hours}}{\text{day}} \times \frac{15\text{ days}}{\text{event}} \times \frac{1\text{ event}}{\text{year}} \times \frac{\text{tonnes}}{2204.62\text{ lb}}$$

$$\underline{E_{CH_4} = 731\text{ tonnes CH}_4\text{/year}}$$

$$E_{CO_2} = \frac{2{,}528\text{ scf}}{\text{min}} \times \frac{0.1\text{ scf CO}_2}{\text{scf gas}} \times \frac{\text{lbmole CO}_2}{379.3\text{ scf CO}_2} \times \frac{44\text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{60\text{ minutes}}{\text{hour}} \times \frac{24\text{ hours}}{\text{day}} \times \frac{15\text{ days}}{\text{event}} \times \frac{1\text{ events}}{\text{year}} \times \frac{\text{tonnes}}{2204.62\text{ lb}}$$

$$\underline{E_{CO_2} = 287\text{ tonnes CO}_2\text{/year}}$$

Emissions from flaring of the associated gas would be estimated using the approaches described in Section 4.4.

EXHIBIT 5.13(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. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:
Equation 5-15 provides the approach for estimating emissions from a continuous vent. The gas vent flow rate is the same hourly rate 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.

$$E_{CH_4} = \frac{2{,}528\text{ scf}}{\text{min}} \times \frac{0.7\text{ scf CH}_4}{\text{scf gas}} \times \frac{\text{lbmole CH}_4}{379.3\text{ scf CH}_4} \times \frac{16\text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{60\text{ minutes}}{\text{hour}} \times \frac{24\text{ hours}}{\text{day}} \times \frac{365\text{ days}}{\text{year}} \times \frac{\text{tonnes}}{2204.62\text{ lb}}$$

$$\underline{E_{CH_4} = 17{,}796\text{ tonnes CH}_4\text{/year}}$$

EXHIBIT 5.13(b): Sample Calculation for a Continuous Process Vent, continued

$$E_{CO_2} = \frac{2{,}528 \text{ scf}}{\text{min}} \times \frac{0.1 \text{ scf } CO_2}{\text{scf gas}} \times \frac{\text{lbmole } CO_2}{379.3 \text{ scf } CO_2} \times \frac{44 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{60 \text{ minutes}}{\text{hour}} \times \frac{24 \text{ hours}}{\text{day}}$$

$$\times \frac{365 \text{ days}}{\text{year}} \times \frac{\text{tonnes}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 6{,}991 \text{ tonnes } CO_2/\text{year}}$$

5.4 Storage Tank Emissions

5.4.1 Crude 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_4 (and potentially CO_2 for a CO_2 -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; however, flashing emissions can also occur from oil pipeline pigging. Once crude oil reaches atmospheric pressure and the volatile CH_4 has flashed off, the crude is considered "weathered" or stabilized. Unless site-specific data indicate otherwise, "weathered" crude is assumed to have no CH_4.[3]

Liquid petroleum storage tanks can also produce emissions through working and standing (breathing) losses; these emissions are described in Section 5.4.2.

A variety of calculation methods can be used to estimate flashing losses from production storage tanks and oil pipeline pigging, described as follows.

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[3] Refer to Appendix E for more information on the CH_4 content of "weathered" crude and other petroleum products.

1. Direct vent 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. Laboratory measurements of the GOR from a pressurized liquid sample – Laboratory measurements can be made of the GOR of a pressurized liquid crude oil sample from the gas/oil separator. The GHG emissions can be estimated by multiplying the GOR by the crude oil throughput, and then applying the CH_4 and/or CO_2 composition to the total gas rate to estimate the CH_4 and/or CO_2 emissions.
3. Specific computer programs – API's E&P TANK 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).
4. 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.
5. 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.
6. Chart approach – A simple chart taken from an EPA Gas STAR Lessons Learned presentation provides an estimate for flashing losses based on the separator pressure and oil API gravity. The chart was developed from empirical flash data from laboratory studies and field measurements (EPA, Lessons Learned – Installing Vapor Recovery Units on Crude Oil Storage Tanks, October 2003).
7. Emission factors – Measured emissions from a variety of E&P tanks have been used to develop simple emission factors based on tank throughput.

Figure 5-5 summarizes the above methods for estimating flashing loss emissions. Using measured test data is the most rigorous approach for determining the flashing loss emissions. However, such test data may not be available. Other estimation methods include computer programs or process simulators, if sufficient input data are available. Correlation equations and the chart approach 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.

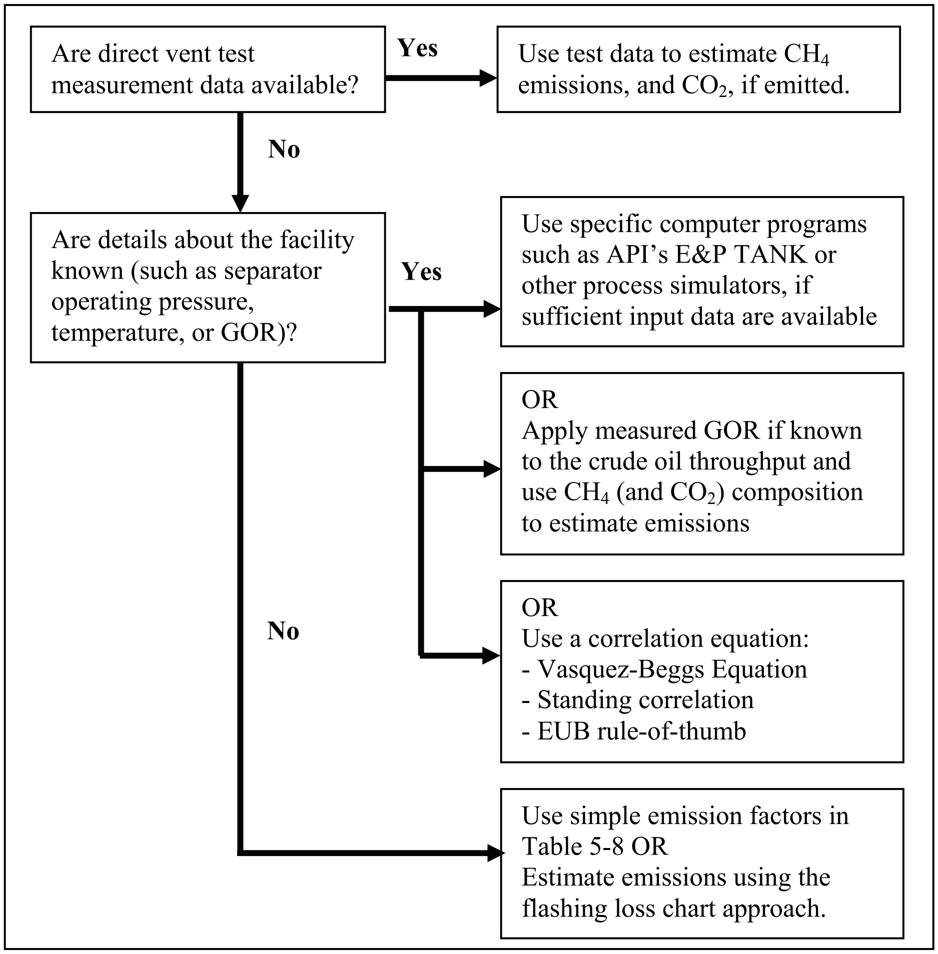

Figure 5-5. Decision Tree for Crude Oil Flashing Losses

Estimated flashing losses should be adjusted for any vapor recovery methods that may be employed. These vapor recovery methods include capturing the flash gas and sending it back to the sales gas line, or routing the flash gas to a control device such as a flare or vapor combustion unit. If vapor recovery is used, then the flashing losses should be estimated using the above approaches, incorporating the collection efficiency as appropriate to estimate the uncollected emissions. If a flare or vapor combustion unit is used to control the flashing losses, then the methods described in Sections 4.6 and 4.7 should be used to estimate the controlled flash gas combustion emission rates.

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.

Vasquez-Beggs Equation (VBE) (Correlation Equation Approach)

The Oklahoma Department of Environmental Quality provides guidance on using the VBE to estimate tank flashing loss emissions from crude oil (OK DEQ, 2004; EIIP, 1999; Vasquez, 1980). The first step in calculating the flashing loss emissions is to calculate the specific gravity of the gas at 100 psig, as shown in Equation 5-16:

$$SG_X = SG_i \times \left[1.0 + 0.00005912 \times API \times T_i \times Log\left(\frac{P_i + 14.7}{114.7} \right) \right] \qquad \text{(Equation 5-16)}$$

where

SG_X = dissolved gas gravity at 100 psig;
SG_i = dissolved gas gravity at initial conditions, where air = 1. A suggested default value for SG_i is 0.90 (OK DEQ, 2004);
API = API gravity of liquid hydrocarbon at final condition;
T_i = temperature of initial conditions (°F); and
P_i = pressure of initial conditions (psig).

The flash GOR is then calculated using Equation 5-17:

$$R_S = C_1 \times SG_X \times (P_i + 14.7)^{C_2} \times \exp\left(\frac{C_3 \times API}{T_i + 460} \right) \qquad \text{(Equation 5-17)}$$

where

R_S = ratio of flash gas production to standard stock tank barrels of oil produced, in scf/bbl oil (barrels of oil corrected to 60°F);
SG_X = dissolved gas gravity, adjusted to 100 psig. Calculated using Equation 5-16;
P_i = pressure in separator, in psig;
API = API gravity of stock tank oil at 60°F; and
T_i = temperature in separator, °F.

For API ≤ 30°API: $C_1 = 0.0362$; $C_2 = 1.0937$; and $C_3 = 25.724$

For API > 30°API: $C_1 = 0.0178$; $C_2 = 1.187$; and $C_3 = 23.931$

The flash gas emissions estimated by the VBE are in terms of total hydrocarbon. Thus, an estimate must be made of the 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 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 in Exhibit 5.14(a) below.

EXHIBIT 5.14(a): Sample Calculation for Flashing Loss Emissions –VBE

INPUT DATA:
An oil and gas production facility produces 71.70 m^3/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 gauge (28.6 psig), and the separator temperature is 44.4°C (112°F). Neither the tank vent CH_4 content nor the tank vent gas specific gravity is known. Flashing losses are not controlled by a vapor recovery system. Calculate flashing loss emissions using the VBE approach.

CALCULATION METHODOLOGY:
The first step is to calculate the flash gas specific gravity adjusted to 100 psig, as shown in Equation 5-16. The flash gas specific gravity at initial conditions, SG_i, is not known, so the recommended default value of 0.90 will be used.

$$SG_X = 0.90 \times \left[1.0 + 0.00005912 \times 48.8 \times 112 \times \text{Log}\left(\frac{28.6+14.7}{114.7}\right)\right]$$

$$SG_X = 0.78$$

The flash gas vent flow rate is calculated below, using the C_1, C_2, and C_3 parameters for an API gravity greater than 30. Note that the output from this equation is in units of scf/bbl oil. The flash GOR is calculated below, as shown in Equation 5-17.

$$R_S = 0.0178 \times (0.78) \times (28.6+14.7)^{1.187} \times \exp\left(\frac{23.931 \times 48.8}{112+460}\right)$$

$$R_S = 9.33 \text{ scf/bbl oil}$$

Next, the output from the Vasquez-Beggs equation is converted to SI units using conversion factors from Table 3-4:

$$R_S = \frac{9.33 \text{ scf gas}}{\text{bbl crude}} \times \frac{\text{m}^3 \text{ gas}}{35.3147 \text{ scf gas}} \times \frac{\text{bbl crude}}{0.1589873 \text{ m}^3 \text{ crude}}$$

$$R_S = \frac{1.66 \text{ m}^3 \text{ gas}}{\text{m}^3 \text{ crude}}$$

EXHIBIT 5.14(a): Sample Calculation for Flashing Loss Emissions –VBE, continued

The flash gas contains gases besides CH_4 and thus the R_S must be multiplied by the tank vent CH_4 content. The tank vent CH_4 content is not known, so the recommended default concentration of 27.4 volume % CH_4 will be used. Thus, the CH_4 emissions are estimated as:

$$E_{CH_4} = \frac{1.66 \text{ m}^3 \text{ gas}}{\text{m}^3 \text{ crude}} \times \frac{71.70 \text{ m}^3 \text{ oil}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{\text{kgmole gas}}{23.685 \text{ m}^3} \times \frac{27.4 \text{ kgmole CH}_4}{100 \text{ kgmole gas}} \times \frac{16 \text{ kg CH}_4}{\text{kgmole CH}_4} \times \frac{\text{tonne}}{1000 \text{ kg}}$$

$$\underline{E_{CH_4} = 8.04 \text{ tonnes CH}_4/\text{yr}}$$

Standing Correlation (Correlation Equation Approach)

The 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 Equation 5-18.

$$\text{GOR} = G_{\text{flash gas}} \times \left(\frac{P}{519.7 \times 10^{y_g}} \right)^{1.204} \qquad \text{(Equation 5-18)}$$

where

GOR = ratio of flash gas production to oil produced, in m^3/m^3 oil;

$G_{\text{flash gas}}$ = specific gravity of the tank flash gas, where air = 1. A suggested default value for $G_{\text{flash gas}}$ is 0.90 (OK DEQ, 2004);

P = absolute pressure in vessel of interest, kPa;

$y_g = 1.225 + 0.00164 \times T - \frac{1.769}{SG_{oil}}$;

SG_{oil} = specific gravity of oil with respect to water = $\frac{141.5}{131.5 + G_{Oil}}$;

G_{oil} = API gravity of stock tank oil at 60°F; and

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 5-18 would be expressed as shown:

$$GOR = G_{\text{flash gas}} \times \left[\left(\frac{P}{519.7 \times 10^{y_g}} \right)_{\text{Separator}}^{1.204} - \left(\frac{P}{519.7 \times 10^{y_g}} \right)_{\text{Storage Tank}}^{1.204} \right]$$ (Equation 5-19)

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_4 emissions basis. As noted earlier, a default of 27.4 volume % 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 standing correlation approach follows in Exhibit 5.14(b):

EXHIBIT 5.14(b): Sample Calculation for Flashing Loss Emissions – Standing Correlation

INPUT DATA:
The facility is the same oil and natural gas production facility described in Exhibit 5.14(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.) Flashing losses are not controlled by a vapor recovery system. Calculate the flashing loss emissions using the standing correlation approach.

CALCULATION METHODOLOGY:

The standing correlation approach, Equation 5-19, 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 3-4:

$$V_o = \frac{451 \text{ bbl}}{\text{day}} \times \frac{0.1589873 \text{ m}^3}{\text{bbl}} = 71.7 \text{ m}^3 \text{ oil/day}$$

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 outline in Exhibit 5.14(b).

EXHIBIT 5.14(b): Sample Calculation for Flashing Loss Emissions – Standing Correlation, continued

$$P_{sep} = (43.3\text{ psi}) \times \frac{6.894757\text{ kPa}}{\text{psi}} = \underline{298.5\text{ kPa}}$$

$$P_{tank} = (1\text{ atm}) \times \frac{101.325\text{ kPa}}{\text{atm}} = \underline{101.3\text{ kPa}}$$

Next, the oil API gravity (G_{oil}) is converted to a specific gravity:

$$SG_{oil} = \frac{141.5}{131.5 + G_{oil}} = \frac{141.5}{131.5 + 48.8} = \underline{0.785}$$

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):

$$y_{g,\ sep} = 1.225 + (0.00164) \times (317.6) - \frac{1.769}{0.785} = -0.5076$$

$$y_{g,\ tank} = 1.225 + (0.00164) \times (299.8) - \frac{1.769}{0.785} = -0.5368$$

Thus, the input parameters for the standing correlation approach have been defined, and are summarized below:

$G_{flash\ gas} = 0.90$ (assume the default value in the absence of data)
$P_{sep} = 298.5$ kPa
$P_{tank} = 101.3$ kPa
$y_{g,\ sep} = -0.5076$
$y_{g,\ tank} = -0.5368$

The flash gas vent flow rate is calculated below, using Equation 5-19 and the above parameters.

$$GOR = (0.90) \times \left[\left(\frac{298.5}{519.7 \times 10^{-0.5076}} \right)_{\text{Separator}}^{1.204} - \left(\frac{101.3}{519.7 \times 10^{-0.5368}} \right)_{\text{Storage Tank}}^{1.204} \right] = 1.329\text{ m}^3\text{ gas/m}^3\text{ oil}$$

EXHIBIT 5.14(b): Sample Calculation for Flashing Loss Emissions – Standing Correlation, continued

The flash gas contains gases besides CH_4 and must be multiplied by the tank vent CH_4 content. The tank vent CH_4 content is not known, so the recommended default concentration of 27.4 volume % CH_4 will be used. Thus, the CH_4 emissions are estimated as:

$$E_{CH_4} = \frac{1.329\ \text{m}^3\ \text{gas}}{\text{m}^3\ \text{oil}} \times \frac{71.7\ \text{m}^3\ \text{oil}}{\text{day}} \times \frac{35.3147\ \text{ft}^3\ \text{(scf) gas}}{\text{m}^3} \times \frac{\text{lbmole gas}}{379.3\ \text{scf gas}} \times \frac{27.4\ \text{lbmole CH}_4}{100\ \text{lbmole gas}}$$

$$\times \frac{365\ \text{day}}{\text{yr}} \times \frac{16\ \text{lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne}}{2204.62\ \text{lb}}$$

$$\underline{E_{CH_4} = 6.44\ \text{tonnes CH}_4/\text{yr}}$$

EUB Rule-of-Thumb (Correlation Equation Approach)

The CAPP document, *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, includes the EUB rule-of-thumb approach to estimate flashing losses (CAPP, 2002). CAPP reports that this approach tends to yield flashing loss estimates biased high and is recommended for facilities with low oil volumes, established pools, mature pools with declining GORs, and some heavy oil production facilities (CAPP, 2002). The EUB rule-of-thumb equation is:

$$V_s = 0.0257 \times V_o \times \Delta P \qquad \text{(Equation 5-20)}$$

where

V_s = volume of gas released, in m^3;
V_o = oil production volume, m^3; and
ΔP = 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 are in terms of hydrocarbon and must be converted to a CH_4 emissions basis. As noted earlier, a default of 27.4 volume % 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 in Exhibit 5.14(c).

EXHIBIT 5.14(c): Sample Calculation for Flashing Loss Emissions – EUB Rule-of-Thumb

INPUT DATA:
The facility is the same oil and natural 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_2 emissions would be estimated as well. For this facility, the CO_2 tank vent concentration is assumed to be approximately 4.5 volume %. Calculate the flashing loss emissions using the EUB rule-of-thumb approach.

CALCULATION METHODOLOGY:
Equation 5-20 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 3-4:

$$V_o = \frac{451 \text{ bbl}}{\text{day}} \times \frac{0.1589873 \text{ m}^3}{\text{bbl}} = 71.7 \text{ m}^3 \text{ oil/day}$$

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:

$$V_s = 0.0257 \times (71.7) \times (197.2) = 363.4 \text{ m}^3/\text{day}$$

The flash gas contains gases besides CH_4 and must be multiplied by the tank vent CH_4 content. The tank vent CH_4 content is not known so the recommended default concentration of 27.4 volume % CH_4 will be used. Thus, the CH_4 emissions are estimated as:

$$E_{CH_4} = \frac{363.4 \text{ m}^3 \text{ gas}}{\text{day}} \times \frac{35.3147 \text{ ft}^3 \text{ (scf) gas}}{\text{m}^3} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{27.4 \text{ lbmole CH}_4}{100 \text{ lbmole gas}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{16 \text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CH_4} = 24.56 \text{ tonnes CH}_4/\text{yr}}$$

EXHIBIT 5.14(c): Sample Calculation for Flashing Loss Emissions – EUB Rule-of-Thumb, continued

$$E_{CO_2} = \frac{363.4\ \text{m}^3\ \text{gas}}{\text{day}} \times \frac{35.3147\ \text{ft}^3\ \text{(scf) gas}}{\text{m}^3} \times \frac{\text{lbmole gas}}{379.3\ \text{scf gas}} \times \frac{4.5\ \text{lbmole CO}_2}{100\ \text{lbmole gas}} \times \frac{365\ \text{day}}{\text{yr}}$$

$$\times \frac{44\ \text{lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62\ \text{lb}}$$

$$\underline{E_{CO_2} = 11.09\ \text{tonnes CH}_4/\text{yr}}$$

Flashing Loss Chart Based on API Gravity and Pressure

The EPA Gas STAR program provides a chart that can be used to estimate crude oil flashing losses. The chart provides the flash gas volume-to-oil ratio from the crude oil tank as a function of the crude oil API gravity and pressure of the separator immediately upstream of the tank. Gas STAR reports that the graph was constructed using empirical flash data from laboratory studies and field measurements (EPA, Lessons Learned – Installing Vapor Recovery Units on Crude Oil Storage Tanks, October 2003). The flashing loss chart is presented in Figure 5-6 and is taken from a Gas STAR Lessons Learned presentation (EPA, August 2007).

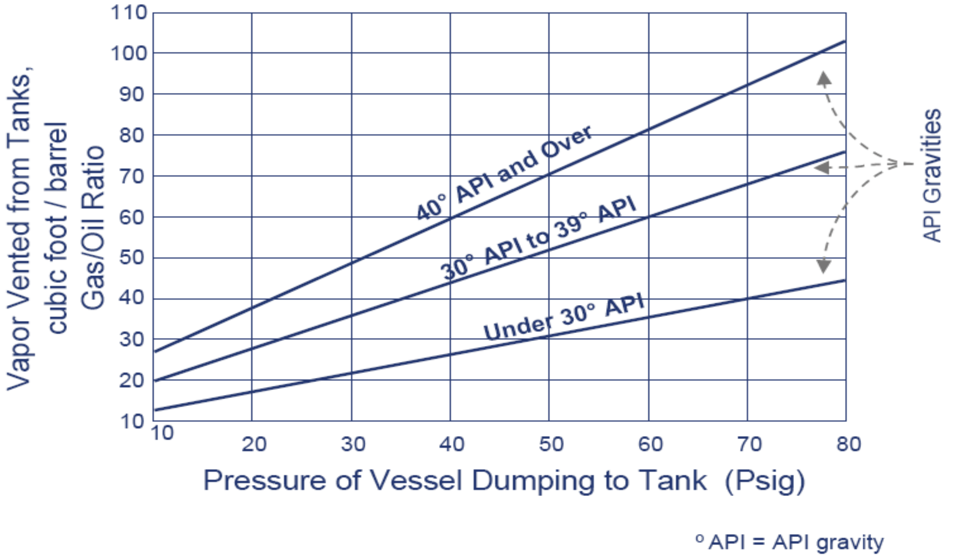

Figure 5-6. Flashing Losses Chart

Source for chart: U.S. Environmental Protection Agency (EPA). *Vapor Recovery Tower/VRU Configuration*, Lessons Learned from Natural Gas STAR, Occidental Petroleum Corporation and California Independent Petroleum Association, Producers Technology Transfer Workshop, Long Beach, California, August 21, 2007. http://www.epa.gov/gasstar/documents/vrt_vru_configuration_08_21_07.pdf

A sample calculation illustrating the use of the chart taken from EPA Gas STAR to estimate flashing losses is given below in Exhibit 5.15.

EXHIBIT 5.15: Sample Calculation for Tank Flashing Losses – Chart Approach

INPUT DATA:
The facility is the same oil and natural 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 separator and the tank temperatures are not needed for the chart approach. Calculate the CH_4 emissions using the chart approach.

CALCULATION METHODOLOGY:
The chart provided in Figure 5-6 will be used to estimate the tank flashing loss emissions. Given a separator pressure of 28.6 psig, and an API gravity of 48.8°, Figure 5-6 shows that the flash vapor-to-oil ratio is approximately 47 scf/bbl (reading on the line indicated in the chart as "40° API and Over"). Thus, the GOR is:

GOR = 47 scf/bbl

The flash gas contains gases besides CH_4 and must be multiplied by the tank vent CH_4 content. The tank vent CH_4 content is not known so the recommended default concentration of 27.4 volume % CH_4 will be used. Thus, the CH_4 emissions are estimated by multiplying the GOR by the oil production rate (assuming 365 days/yr of operation) and the assumed CH_4 concentration in the tank flash gas, as shown below:

$$E_{CH_4} = \frac{47\text{ scf gas}}{\text{bbl crude}} \times \frac{451\text{ bbl oil}}{\text{day}} \times \frac{365\text{ day}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3\text{ scf}} \times \frac{27.4\text{ lbmole CH}_4}{100\text{ lbmole gas}} \times \frac{16\text{ lb CH}_4}{\text{lbmole CH}_4} \times \frac{\text{tonne}}{2204.62\text{ lb}}$$

$$\underline{E_{CH_4} = 40.6\text{ tonnes CH}_4\text{/yr}}$$

Flashing Losses from Computer Software Programs

If sufficient input data are available, users may choose to estimate flashing losses with software programs such as API's E&P TANK 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 or chart approach due to different assumptions used by each approach. However, if very limited input data are available, 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_4 flashing loss emission factor, is included in Appendix B. The CH_4 emission factor is provided in Table 5-8.

Table 5-8. Methane Flashing Loss Emission Factors for Crude Oil Storage Tanks

Source	CH_4 Flashing Loss Emission Factor [a,b,c]		Uncertainty[d] (±)	Notes
Combined API/GRI and CPA data	1.954 8.86E-04 5.57E-03	lb/bbl crude tonnes/bbl crude tonnes/m^3 crude	110	Factor based on separator CH_4 content of 78.8% (vol.); can ratio to other separator concentrations

Footnotes and Sources:

[a] 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.

[b] 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.

[c] Picard, D. J., B. D. Ross, and D. W. H. Koon. *Inventory of CH_4 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.

[d] Uncertainty based on a 95% confidence interval.

A sample calculation illustrating the use of the simple emission factor is given below in Exhibit 5.16.

EXHIBIT 5.16: Sample Calculation for Tank Flashing Losses - Simple Emission Factor Approach

INPUT DATA:
An oil and natural gas production facility produces 451 bbl/day of crude oil (same as the previous exhibit). The separator gas (to sales pipeline) CH_4 content is 58 volume %. Calculate the CH_4 emissions using the simple emission factor.

EXHIBIT 5.16: Sample Calculation for Tank Flashing Losses - Simple Emission Factor Approach, continued

CALCULATION METHODOLOGY:
The CH_4 flashing losses are calculated using the emission factor provided in Table 5-8. Please note that this emission factor is based on 78.8 mole % CH_4 in the separator gas, so this emission factor must be corrected to 58 mole % based on the composition for this example.

$$E_{CH_4} = \frac{451 \text{ bbl crude}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{8.86 \times 10^{-4} \text{ tonnes } CH_4}{\text{bbl crude}} \times \frac{58 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4}$$

$$\underline{E_{CH_4} = 107.4 \text{ tonne } CH_4/\text{yr}}$$

Exhibits 5.14(a), (b), and (c) demonstrate the use of the VBE, standing, and EUB rule-of-thumb correlation approaches, respectively. Additionally, Exhibits 5.15 and 5.16 demonstrate the use of the chart and simple emission factor approaches, respectively. These exhibits were based on operating parameters presented in a testing program prepared for API, GRI, and CAPP to evaluate API's E&P TANK 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 TANK software, version 3.0.

Table 5-9 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 three correlation approaches. This is consistent with information from CAPP, which states that this approach provides estimates biased high. The VBE correlation results in an emission estimate that is higher than the standing correlation for the exhibit calculation. The measured emission estimate is less than all of the correlation approaches except the standing correlation. The chart approach yields an estimate that is higher than the correlation approaches but less than the simple emission factor approach. The simple emission factor approach provides an estimate that is 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 CH_4 content, which were taken from the Ogle report for site number 5).

Table 5-9. Summary of Production Tank Flashing Losses Using Different Correlation Equation Approaches

Correlation	CH_4 Flashing Losses (tonnes/yr)
Vasquez-Beggs Equation (VBE)	8.04 [a]
Standing Correlation	6.44 [b]
EUB Rule-of-Thumb	24.56 [c]
Chart Approach	40.6 [d]
Simple Emission Factor Approach	107.4 [e]
E&P TANK, Version 3.0	12.75 [f,g]
Measured	9.54 [f,g]

Footnotes and Sources:

[a] Calculation shown in Exhibit 5.13(a).

[b] Calculation shown in Exhibit 5.13(b).

[c] Calculation shown in Exhibit 5.13(c).

[d] Calculation shown in Exhibit 5.14.

[e] Calculation shown in Exhibit 5.15.

[f] 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.

[g] E&P TANK 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 5-9 is not comprehensive because 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 for this single example. However, Gas STAR notes that the chart approach will provide estimates that have an uncertainty of ± 50% (EPA, August 2007). Gas STAR also notes that the E&P TANK software and VBE approach provide emission estimates that are ± 20%, while measured data using recording manometer and well tester or ultrasonic meter over several cycles will provide estimates that are ± 5%. Derivation of the simple emission factor (provided in Appendix B) results in an uncertainty of ± 110%.

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, the choice of one approach over the other is left to the discretion of the user. 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_4, 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.

Methane emissions from condensate flashing in the production segment are calculated in a manner very similar to crude tank flashing losses. The most rigorous approach is to use direct measurements. In the absence of measured data, other estimation methods include process simulators, if sufficient input data are available, or the VBE or standing correlation, provided the physical properties of the condensate are used instead of the physical properties for crude oil. However, the EUB rule-of-thumb correlation should not be used for condensate since this approach does not take into account the condensate physical properties. A default emission factor for production condensate flashing was derived from a measurement program conducted in east Texas for the Houston Advanced Research Center (Hendler et al., 2006), and is presented below. The development of this CH_4 emission factor is presented in Appendix B.

Production Condensate Flashing Default Emission Factor

5.068 lb CH_4/bbl condensate ±101%[a]

2.30×10^{-3} tonnes CH_4/bbl condensate ±101%[a]

1.45×10^{-2} tonnes CH_4/m^3 condensate ±101%[a]

[a] Uncertainty based on a 95% confidence interval.

Methane emissions from condensate flashing in the transmission segment can also be calculated with a simplified flashing loss emission factor. The emission factor was derived from EPA GasSTAR PRO Fact Sheet No. 504, and is presented below (EPA, 2004).

Transmission Condensate Flashing Default Emission Factor

160,000 scf CH_4 per year/1.75×10^{9} bbl-day (original data)

5.29×10^{-12} tons CH_4/bbl (converted)

4.80×10^{-12} tonnes CH_4/bbl (converted)

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 and intermediate tanks at a refinery. Tank types include fixed roof tanks as well as floating roof tanks. Working loss emissions occur during the filling and emptying of the tanks as evaporative losses occur and vapor space is displaced. Standing losses occur during storage of the liquid, and can result from diurnal temperature changes.

Because most of the CH_4 and CO_2 emissions from crude storage tanks occur as a result of flashing (refer to Section 5.4.1), working and breathing loss emissions of these gases are very small in production and virtually non-existent in the downstream segments. Unless site-specific data indicate otherwise, "weathered" crude and other refined petroleum products are assumed to contain no CH_4 or CO_2. Therefore, it is also assumed that there are no CH_4 or CO_2 emissions from the working and breathing losses of tanks containing "weathered" crude or other refined petroleum products. This assumption is described in more detail in Appendix E.

EPA provides a methodology for estimating tank hydrocarbon emissions (as total hydrocarbon [THC] or VOC) due to tank working and standing losses, where sites choose to estimate CH_4 and CO_2 emissions from this source. EPA's methodology can be found in Chapter 7 of AP-42 (EPA, Supplement D, 1998).[4] This methodology also forms the basis for the TANKS software program (EPA, 1999).[5]

EPA's methodology is primarily directed at estimating THC or VOC. The user would have to estimate the total emissions from the tank and then multiply the total emissions by the concentration of CH_4 and/or CO_2 in the tank vent stream. The CH_4 and/or CO_2 concentrations should be based on site data if they are available.

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_4 has a stronger affinity for hydrocarbon oil than it does for water. Thus, more CH_4 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 TANK program (API, 1997) and the VBE are based on properties specific to crude oil and, therefore are not applicable to water tanks.

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[4] 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).

[5] The TANKS software is available on the Internet at: http://www.epa.gov/ttn/chief/software/tanks/index.html

Table 5-10 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_4 mass rate to tonnes CH_4 per volume of produced water based on the national produced water volume used in the original process simulations (Energy Environmental Research Center, 1995).

Table 5-10. Produced Salt Water Tank Methane Flashing Emission Factors

Separator Pressure (psi)	Produced Water Salt Content	GRI/EPA Emission Rate [a], Original Units (10^6 lb CH_4/yr)	Water Tank Emission Factor	
			tonnes CH_4 /1000 bbl produced water [b]	tonnes CH_4 /1000 m^3 produced water
50	**20%**	**1.6**	**0.0015**	**0.009185**
250	20%	10.8	0.00986	0.06200
250	10%	16.4	0.0150	0.09414
250	2%	19.4	0.0177	0.11137
250	**Average of 10.7% [c]**	**--**	**0.0142**	**0.08917**
1000	20%	38.8	0.0354	0.22273
1000	10%	58.7	0.0536	0.33697
1000	2%	69.5	0.0634	0.39896
1000	**Average of 10.7% [c]**	**--**	**0.0508**	**0.31955**

Footnotes and Sources:

[a] 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 U.S. Environmental Protection Agency, June 1996.

[b] Process simulation modeling based on 1990 annual salt water production of 497 million barrels from Energy Environmental Research Center, 1995.

[c] Average of emission factors at 20, 10, and 2% salt.

The ARPEL provides another source of general emission factors for produced water flashing losses (ARPEL, 1998). Table 5-11 presents CH_4 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 the *API Technical Data Book* (API, 1984), is reported to be extremely approximate (ARPEL, 1998).

Table 5-11. Methane Emission Factors from Produced Water from Shallow Gas Wells

Source Information	CH_4 Water Tank Emission Factor [a], Original Units (kg/m^3 produced water)	CH_4 Water Tank Emission Factor, Converted to Tonnes Basis
Shallow gas well (76 psi or less, 50°C)	0.036	0.0057 tonnes/1000 bbl produced water 0.036 tonnes/1000 m^3 produced water

Footnotes and Sources:

[a] 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 in Exhibit 5.17.

EXHIBIT 5.17: Sample Calculation for Water Tank Emissions – Simple Emission Factor Approach

INPUT DATA:
An oil and natural 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. Calculate the CH_4 emissions.

CALCULATION METHODOLOGY:
The CH_4 flashing losses are calculated using the emission factor provided in Table 5-10 for 250 psi. It is recognized that this emission factor biases the estimate high since the actual separator pressure is less than 250 psi. Because the salt content of the produced water is unknown, the emission factor provided for the average salt content is used. The CH_4 emissions are estimated as shown below.

$$E_{CH_4} = \frac{50 \text{ bbl water}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{0.0142 \text{ tonnes } CH_4}{1000 \text{ bbl water}}$$

$$\underline{E_{CH_4} = 0.26 \text{ tonne } CH_4/\text{yr}}$$

5.4.4 Natural Gas Blanketed Tank Emissions

Some tanks are blanketed with natural gas to prevent air from collecting in the headspace. Blanket gas may be used for tank storage of: crude, condensate, produced water, glycol, amine and other bulk chemicals. If the blanket gas supply is taken downstream of the total fuel gas meter, then the vented blanket gas volume must be subtracted from the total fuel gas volume (used to determine combustion emissions).

If the tanks are uncontrolled (i.e., the vapor space vents to atmosphere), CH_4 emissions (and possibly CO_2 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 5-15), converted to an annual basis.

$$E_x = VR \times F_x \times \frac{MW_x}{\text{molar volume conversion}}$$ (Equation 5-15 from Section 5.3)

where

E_x = emissions of "x" in units of mass (pounds, kg, tonnes) per unit of time;
"x" = the GHG compound of interest (CH_4 or CO_2, for CO_2 rich streams);
VR = the vent rate in volume units at STP conditions per unit of time (e.g., scfm or m^3/min);
F_x = the molar fraction of compound "x" in the vent gas stream;
MW_x = molecular weight of compound "x"; and
Molar volume conversion = Conversion from molar volume to mass (379.3 scf/lbmole or 23.685 m^3/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 5-19 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 in 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 can be used for the VR term in the absence of liquid level data, recognizing that this will likely overestimate emissions since it does not take into account the liquid level effects caused by emptying the tank at the same time as filling.

A sample calculation for natural gas blanketed tank emissions is shown below in Exhibit 5.18.

EXHIBIT 5.18: 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 simultaneously filling during some periods of the year. The blanket natural gas contains approximately 82 mole % CH_4 and 1 mole % CO_2. The estimated annual temperature in the tank vapor space is 75°F. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:
Equation 5-15 is used to estimate the annual emissions. However, the VR term in the equation is on a standard ft^3 basis (scf), and the annual volumetric rate is on an actual ft^3 basis at 75°F (acf), so the actual vent rate must be converted to standard conditions of 1 atm and 60°F.

EXHIBIT 5.18: Sample Calculation for Natural Gas Blanketed Tank Emissions, continued

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.

$$V = \frac{32{,}000\text{ bbl}}{\text{yr}} \times \frac{42\text{ gal}}{\text{bbl}} \times \frac{\text{ft}^3}{7.4805\text{ gal}} = 179{,}667\text{ ft}^3 \text{ (at 75°F)}$$

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).

$$V_{scf} = (179{,}667\text{ ft}^3) \times \left[\frac{(1\text{ atm})\,(60 + 459.7)}{(1\text{ atm})\,(75 + 459.7)}\right] = 174{,}627\text{ scf (at 60°F and 1 atm)}$$

Lastly, Equation 5-15 is used to calculate the emissions.

CH_4 Emissions:

$$E_{CH_4} = \frac{174{,}627\text{ scf}}{\text{yr}} \times \frac{0.82\text{ scf }CH_4}{\text{scf gas}} \times \frac{16\text{ lb }CH_4/\text{lbmole }CH_4}{379.3\text{ scf }CH_4/\text{lbmole }CH_4} \times \frac{\text{tonnes}}{2204.62\text{ lb}}$$

$$\underline{E_{CH_4} = 2.74\text{ tonnes }CH_4/\text{yr}}$$

CO_2 Emissions:

$$E_{CO_2} = \frac{174{,}627\text{ scf}}{\text{yr}} \times \frac{0.01\text{ scf }CO_2}{\text{scf gas}} \times \frac{44\text{ lb }CO_2/\text{lbmole }CO_2}{379.3\text{ scf }CO_2/\text{lbmole }CO_2} \times \frac{\text{tonnes}}{2204.62\text{ lb}}$$

$$\underline{E_{CO_2} = 0.09\text{ tonnes }CO_2/\text{yr}}$$

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 evaporative losses of the hydrocarbons. Hydrocarbon emissions occur during loading operations as the organic vapors in the cargo tanks are displaced into the atmosphere by the petroleum liquid that is being loaded. Evaporative hydrocarbon emissions can also occur during marine ballasting operations as crude oil loaded from a marine cargo vessel is replaced by "ballasting" water then can displace hydrocarbon vapors in the marine vessel. Transit losses occur due to a mechanism that is similar to storage tank breathing losses.

Due to the fact that there is no CH_4 or CO_2 in most petroleum products (including "weathered" crude), calculating evaporative emissions associated with loading, ballasting, and transit operations is recommended only for "live" crude oil or if measured CH_4 or CO_2 content data are available for "weathered" crude or other petroleum vapors. (Refer to Appendix E for more information on the CH_4 and CO_2 content of "weathered" crude and other petroleum products.) This section presents simple calculation approaches for these activities in crude service. More detailed methods and approaches for loading, ballasting, and transit operations for crude oil are provided in Appendix B.

Several approaches are available for estimating emissions from loading, ballasting, and transit operations. In many cases, the specific estimation approach depends on the type of liquid, type of information available, and other specific operation conditions. Each of the approaches calculates TOC emissions, which requires a vapor phase CH_4 (or CO_2, if present) content to convert to CH_4 (or CO_2) emissions. The vapor phase CH_4 content of "live" crude oil is assumed to be 15 wt% if site-specific data are not available, recognizing that this will overestimate emissions (EPA, AP-42 Section 5.2, 2008). Equations for calculating CH_4 emissions from TOC emission factors are provided in Section 6.1.3. As mentioned earlier, "weathered" crude and other petroleum products contain no CH_4 or CO_2, and thus would have no evaporative losses of CH_4 or CO_2.

Note that if loading losses are routed to a combustion device such as a thermal oxidizer or VCU, the mass of vapors sent to the combustion device can be estimated using the methodology described in this section. Emissions from the combustion of the vapor should be calculated using the methodology described in Section 4.

5.5.1 Loading Loss Emissions

Table 5-12 provides simplified TOC emission factors for loading loss emissions for crude oil (EPA, AP-42 Section 5.2, 2008). TOC emissions should be converted to CH_4 (or CO_2, if present) emissions based on the CH_4 (or CO_2) content of the loading vapors.

Table 5-12. Simplified TOC Emission Factors for Loading Losses

Loading Type	Units		Crude Oil [a,b,c]
Rail / Truck Loading [d] Submerged Loading – Dedicated normal service	Original Units	lb TOC/10^3 gal loaded mg TOC/L loaded	2 240
	Converted Units [e]	tonne TOC/ 10^6 gal loaded tonne TOC/10^3 m^3 loaded	0.91 0.240
Rail / Truck Loading [d] Submerged Loading – Vapor balance service	Original Units	lb TOC/10^3 gal loaded mg TOC/L loaded	3 400
	Converted Units [e]	tonne TOC/ 10^6 gal loaded tonne TOC/10^3 m^3 loaded	1.51 0.400
Rail / Truck Loading [d] Splash Loading – Dedicated normal service	Original Units	lb TOC/10^3 gal loaded mg TOC/L loaded	5 580
	Converted Units [e]	tonne TOC/ 10^6 gal loaded tonne TOC/10^3 m^3 loaded	2.20 0.580
Rail / Truck Loading [d] Splash Loading – Vapor balance service	Original Units	lb TOC/10^3 gal loaded mg TOC/L loaded	3 400
	Converted Units [e]	tonne TOC/ 10^6 gal loaded tonne TOC/10^3 m^3 loaded	1.51 0.400
Marine Loading [f] – Ships/ocean barges	Original Units	lb TOC/10^3 gal loaded mg TOC/L loaded	0.61 73
	Converted Units [e]	tonne TOC/ 10^6 gal loaded tonne TOC/10^3 m^3 loaded	0.28 0.073
Marine Loading [f] – Barges	Original Units	lb TOC/10^3 gal loaded mg TOC/L loaded	1.0 120
	Converted Units [e]	tonne TOC/ 10^6 gal loaded tonne TOC/10^3 m^3 loaded	0.45 0.120

Footnotes and Sources:

[a] 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 simplifying assumption for the CH_4 content of the TOC is 15% in the absence of site-specific data, recognizing that this will likely overestimate emissions.

[b] EPA, AP-42, Section 5, Tables 5.2-5 and 5.2-6, 2008.

[c] The example crude oil has an RVP of 5 psia.

[d] The rail/truck loading emission factors were derived using Equation B-5 assuming a liquid temperature of 60°F.

[e] 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/10^3 gallons.

[f] Marine loading factors based on a loaded liquid temperature of 60°F.

Exhibit 5.19 provides a sample calculation illustrating the use of the loading loss emission factors for crude oil loading.

EXHIBIT 5.19: Sample Calculation for Estimating Loading Loss CH_4 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_4. Calculate the CH_4 emissions.

CALCULATION METHODOLOGY:
From Table 5-12, the emission factor corresponding to crude loading losses from rail splash loading, dedicated service is 2.20 tonnes TOC/million gallons loaded. The loading emissions are calculated by converting the TOC emissions to CH_4 and applying the annual loading rate, as shown below:

$$E_{CH_4} = \frac{2.20 \text{ tonnes TOC}}{10^6 \text{ gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{50{,}000 \text{ bbl}}{\text{yr}} \times \frac{12 \text{ tonne } CH_4}{100 \text{ tonne TOC}}$$

$$\underline{E_{CH_4} = 0.554 \text{ tonnes } CH_4 / \text{yr}}$$

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 5-13 provides average emission factors for estimating TOC emissions from crude ballasting operations (EPA, AP-42 Table 5.2-4, 2008).

The emission factors are for TOC and should be converted to CH_4 (or CO_2, if present) emissions based on the CH_4 (or CO_2) 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.

Exhibit 5.20 demonstrates the use of the crude oil ballasting emission factors.

Table 5-13. Average TOC Emission Factors for Crude Oil Ballasting Operations

Compartment Condition Before Cargo Discharge	Average TOC Emission Factors [a,b], Original Units		Average TOC Emission Factors [c], Converted to Tonnes	
	lb TOC/10^3 gal ballast water	**mg TOC/L ballast water**	**tonne TOC/10^6 gal ballast water**	**tonne TOC/10^3 m^3 ballast water**
Fully loaded [d]	0.9	111	0.420	0.111
Lightered or previously short loaded [e]	1.4	171	0.647	0.171
Typical overall situation [f]	1.1	129	0.488	0.129

Footnotes and Sources:

[a] EPA, AP-42, Section 5, Table 5.2-4, 2008.

[b] 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 simplifying assumption for the CH_4 content of the TOC is 15% in the absence of site-specific data, recognizing that this will likely overestimate emissions.

[c] 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/10^3 gallons.

[d] Based on assumed typical arrival ullage of 0.6 m (2 feet).

[e] Based on assumed typical arrival ullage of 6.1 m (20 feet).

[f] Typical overall situation based on the observation that 70% of tested compartments had been fully loaded before ballasting.

EXHIBIT 5.20: 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. Calculate the CH_4 emissions, assuming that the ballasting operations at this facility are typical.

CALCULATION METHODOLOGY:
TOC emissions are calculated using the emission factor provided in Table 5-13.

The ballasting TOC emissions are calculated by multiplying the ballasting emission factor by the annual ballast water throughput loaded into the ships. The TOC emissions must be multiplied by the CH_4 content of the vapors to obtain the CH_4 emissions. As a simplifying assumption, the CH_4 content of the vapors will be assumed to be 15 wt% per AP-42 (EPA, AP-42 Section 5.2, 2008). Thus, the CH_4 emissions from the ballasting operations are:

$$E_{CH_4} = \frac{1.1 \text{ lb TOC}}{10^3 \text{gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{1\times10^6 \text{ bbl}}{\text{yr}} \times \frac{15 \text{ lb } CH_4}{100 \text{ lb TOC}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CH_4} = 3.14 \text{ tonnes } CH_4/\text{yr}}$$

5.5.3 Transit Loss Emissions

In addition to emissions resulting from loading operations and marine ballasting operations, hydrocarbon emissions 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 oil (EPA, AP-42 Section 5.2.2.1.3, 2008).

Table 5-14. Simplified TOC Emission Factors for Marine Transit Losses

Units		Crude Oil [a,b,c]
Original Units	lb TOC/week-10^3 gal transported mg TOC/week-L transported	1.3 150
Converted Units [d]	tonne TOC/week-10^6 gal transported tonne TOC/week-10^3 m^3 transported	0.57 0.150

Footnotes and Sources:

[a] The factors shown are for TOCs. AP-42 reports that the VOC comprises approximately 85% of the TOC for crude. Thus, a simplifying assumption for the CH_4 content of the TOC is 15% in the absence of site-specific data, recognizing that this will likely overestimate emissions.

[b] EPA, AP-42, Section 5, Table 5.2-6, 2008.

[c] The example crude oil has an RVP of 5 psia.

[d] 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/10^3 gallons.

Alternatively, the Australian Government Department of Climate Changes provides the following CO_2e emission factor for crude oil transport (Australian Government, 2008):

7.3E-04 tonne CO_2e/tonne crude transported

Exhibit 5.21 illustrates the use of the simple crude oil transit emission factors.

EXHIBIT 5.21: Sample Calculation for Estimating CH_4 Emissions Using Simplified Transit Emission Factors

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 the crude 25 times during the given reporting year. Calculate the CH_4 emissions using the AP-42 emission factors.

EXHIBIT 5.21: Sample Calculation for Estimating CH_4 Emissions Using Simplified Transit Emission Factors, continued

CALCULATION METHODOLOGY:
Transit loss emissions are calculated by multiplying the transit loss emission factor given in Table 5-14 for crude oil, by the volume transported and the CH_4 content of the vapors. As a simplifying assumption, the CH_4 content of the vapors is assumed to be 15 wt% (EPA, AP-42 Section 5.2, 2008).

$$E_{CH_4} = \frac{0.57 \text{ tonne TOC}}{\text{week-}10^6 \text{ gal transported}} \times \frac{42 \text{ gal}}{\text{bbl}} \times 500{,}000 \text{ bbl} \times \frac{10 \text{ days}}{\text{trip}} \times \frac{25 \text{ trips}}{\text{yr}} \times \frac{\text{week}}{7 \text{ days}} \times \frac{15 \text{ lb } CH_4}{100 \text{ lb TOC}}$$

$$\underline{E_{CH_4} = 64.1 \text{ tonnes } CH_4/\text{yr}}$$

5.6 Other Venting Sources

5.6.1 Gas-Driven Pneumatic Devices

Natural gas-driven pneumatic devices are a source of CH_4 emissions (and CO_2, if present in the gas). Pneumatic devices may be designed to vent gas continuously (such as when designed with a pilot gas stream) or intermittently (i.e., only when actuated). Low vent and no vent pneumatic devices may also be used. Pneumatic devices may also be operated using compressed air.

If fuel gas is used as the pneumatic gas and is taken downstream of the total fuel gas meter, then the vented gas volume must be subtracted from the total fuel gas volume (used to determine combustion emissions).

Methane emissions from pneumatic devices were evaluated as part of the 1996 GRI/EPA CH_4 emissions study (Shires, 1996). This study observed that most of the pneumatic devices used in the production segment 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 segments were also evaluated during the 1996 GRI/EPA CH_4 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 most rigorous approach for estimating CH_4 emissions (and CO_2 emissions if CO_2 is present in the gas stream) from gas-driven pneumatic devices is to use site-specific device measurements or manufacturers' data.[6] Another rigorous approach to calculate the emissions from a high or continuous bleed pneumatic device is to calculate the volume of gas vented as shown in Equation 5-21 (GPSA, 1987, Equation 3-12).

$$V = 16{,}330 \times \left[1 + \left(\frac{d}{D}\right)^4\right] \times d^2 \times \sqrt{H \times \left[29.32 + \left(0.3 \times H\right)\right]} \times \sqrt{\frac{520}{460 + T_f}} \times \sqrt{\frac{1.0000}{G}} \qquad \text{(Equation 5-21)}$$

where

V = gas flow rate, scf/day

d = orifice diameter, in

D = pipe/tubing inner diameter, in

H = pressure, inches Hg

T_f = gas temperature, °R

G = specific gravity at 60 °F, unitless

After calculating the volume of gas loss, CH_4 and CO_2 emissions can then be calculated using the CH_4 and CO_2 content of the gas, such as described in Section 5.7.1.

Alternatively, simplified CH_4 emission factors are provided in Table 5-15 for each industry sector. Table 5-15 presents the corresponding CH_4 content of the gas used as the basis for the emission

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[6] Note, manufacturer emission rates tend to be lower than emissions observed for the same devices in the field due to actual operating conditions and maintenance practices.

factors. The emission factors can be adjusted based on the CH_4 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_2, the CH_4 emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 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, Canada (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_4 Emission Factors

Device Type	Emission Factor [a], Original Units	Uncertainty [b] (±%)	Emission Factor [c], Converted to Tonnes Basis
Production Segment			Based on 78.8 mole% CH_4[a]
Continuous bleed [a]	654 scfd gas/device	40.3	3.608 tonnes/device-yr
Continuous bleed, low/no-bleed [d]	33.4 scfd gas/device	107	0.184 tonnes/device-yr
Continuous bleed, high-bleed [d]	896 scfd gas/device	33.1	4.941 tonnes/device-yr
Intermittent bleed [a]	323 scfd gas/device	41.2	1.782 tonnes/device-yr
Production average[a] *(if device type is unknown)*	*345 scfd CH_4/device*	*49.5*	*2.415 tonnes/device-yr*
Transmitter (140 kPag) [e]	0.12 m^3 gas/hr/device	Uncertainty not specified	0.56 tonnes/device-yr
Transmitter (240 kPag) [e]	0.2 m^3 gas/hr/device		0.94 tonnes/device-yr
Controller (140 kPag) [e]	0.6 m^3 gas/hr/device		2.8 tonnes/device-yr
Controller (240 kPag) [e]	0.8 m^3 gas/hr/device		3.7 tonnes/device-yr
Controller (pressure not specified) [f]	0.1996 m^3 gas/hr/device		0.9333 tonnes/device-yr
I/P Transducer (140 kPag) [e]	0.6 m^3 gas/hr/device		2.8 tonnes/device-yr
I/P Transducer (240 kPag) [e]	0.8 m^3 gas/hr/device		3.7 tonnes/device-yr
P/P Positioner (140 kPag) [e]	0.32 m^3 gas/hr/device		1.5 tonnes/device-yr

Table 5-15. Gas-Driven Pneumatic Device CH_4 Emission Factors, continued

Device Type	Emission Factor [a], Original Units	Uncertainty [b] (±%)	CH_4 Emission Factor [c], Converted to Tonnes Basis
Production Segment, continued			Based on 78.8 mole% CH_4[a]
P/P Positioner (240 kPag) [e]	0.5 m^3 gas/hr/device		2.3 tonnes/device-yr
I/P Positioner (140 kPag) [e]	0.4 m^3 gas/hr/device		1.9 tonnes/device-yr
I/P Positioner (240 kPag) [e]	0.6 m^3 gas/hr/device		2.8 tonnes/device-yr
Processing			Based on 86.8 mole% CH_4[a]
Continuous bleed	497,584 scf gas/device-yr	35.5	8.304 tonnes/device-yr
Piston valve operator	48 scf gas/device-yr	60.9	8.010E-04 tonnes/device-yr
Pneumatic/hydraulic valve operator	5,627 scf gas/device-yr	134	0.0939 tonnes/device-yr
Turbine valve operator	67,599 scf gas/device-yr	407	1.128 tonnes/device-yr
Processing average (if device type is unknown)	*164,949 scf CH_4/plant-yr*	*170*	*3.164 tonnes/plant-yr*
	7.431[g] scf CH_4/MMscf processed		*1.425E-04 tonnes/10^6 scf processed* *5.034E-03 tonnes/10^6 m^3 processed*
Transmission and Storage			Based on 93.4 mole% CH_4[a]
Continuous bleed	497,584 scf gas/device-yr	35.5	8.915 tonnes/device-yr
Pneumatic/hydraulic valve operator	5,627 scf gas/device-yr	134	0.1008 tonnes/device-yr
Turbine valve operator	67,599 scf gas/device-yr	407	1.211 tonnes/device-yr
Transmission or Storage average (if device type is unknown)	*162,197 scf CH_4/device-yr*	*96.3*	*3.111 tonnes/device-yr*
Distribution			
Pneumatic isolation valves [h] based on 93.4 mole% CH_4	0.366 tonnes CH_4/device-yr	Uncertainty not specified	0.366 tonnes/device-yr
Pneumatic control loops [h] based on 94.4 mole% CH_4	3.465 tonnes CH_4/device-yr		3.465 tonnes/device-yr
Distribution average (if device type is unknown) based on 94.9 mole% CH4 weighted avg.	*2.941 tonnes CH_4/device-yr*		*2.941 tonnes/device-yr*

Footnotes and Sources:

[a] 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 U.S. 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 U.S. Environmental Protection Agency, June 1996. The average CH_4 concentration associated with these emission factors is provided in Table E-4.

[b] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[c] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia.

[d] High-bleed devices refer to devices with leak rates greater than 6 scf/hr while low-bleed devices are 6 scf/hr or lower. Developed from data used for Volume 12 of the GRI/EPA natural gas industry CH_4 emissions study (Shires, 1996). Refer to Appendix B for the development of these emission factors.

[e] 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 CH_4 basis using the CH_4 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.

[f] 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 CH_4 basis using the CH_4 content shown in the table.

[g] Shires, T.M. and C.J. Loughran. *Updated Canadian National Greenhouse Gas Inventory for 1995, Emission Factor Documentation*, *Technical Memorandum*, August 23, 2001.

[h] Derived from estimated processing pneumatic devices vented CH_4 emissions (0.1196 ± 133% Bscf/YR) (Harrison, et al., Vol 2, 1996), and estimated annual gas processed (16,450.855 Bscf/YR (DOE, 1993)).

The production sector continuous bleed device emission factor was further split out according to whether the device is high-bleed or low-bleed, based on the amount of gas vented when the device is not actuating. The EPA Gas STAR program defines a pneumatic device that bleeds more than 6 scfh as a “high-bleed” device, with “low-bleed”/“no-bleed” devices venting less than 6 scfh (EPA Gas STAR, Lessons Learned, July 2003). Therefore, the same data set that was used to develop the production sector continuous bleed device emission factor for the 1996 GRI/EPA study (Volume 12) was also used to develop the high- and low-bleed device emission factors by stratifying the data according to whether the leak rate is greater than or less than 6 scfh. The development of these emission factors is provided in Appendix B.

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 derived from estimated processing devices’ vented CH_4 emissions (Harrison, et al., Vol 2, 1996) and estimated annual gas processed (DOE, 1993).

The transmission pneumatic device emission factors are also taken from the 1996 GRI/EPA report (Shires, 1996).

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 GHG inventory for 1995 (Shires, 2001).

An example calculation is provided below in Exhibit 5.22 that demonstrates the use of the pneumatic device emission factors.

EXHIBIT 5.22: Sample Calculation for Gas-Driven Pneumatic Device Emissions

INPUT DATA:
A gas production facility has 80 natural gas-driven pneumatic devices. The average CH_4 content of the gas is 70 mole %. There is also 9 mole % CO_2 in the gas so CO_2 emissions from the pneumatic devices are also estimated. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:
Emissions are calculated by multiplying the number of pneumatic devices 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.

EXHIBIT 5.22: Sample Calculation for Gas-Driven Pneumatic Device Emissions, continued

The base pneumatic device CH_4 emission factor is also adjusted from the default basis provided in Table E-4 of 78.8 mole % CH_4 to the site-specific basis of 70 mole % CH_4. Because the gas contains a significant quantity of CO_2, emissions of CO_2 are also estimated using the relative CO_2 and CH_4 contents in the gas.

$$E_{CH_4} = 80 \text{ pneumatic devices} \times \frac{2.415 \text{ tonne } CH_4}{\text{device - yr}} \times \frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4}$$

$$\underline{E_{CH_4} = 171.6 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = 80 \text{ pneumatic devices} \times \frac{2.415 \text{ tonne } CH_4}{\text{device - yr}} \times \frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4} \times \frac{\text{tonne mole } CH_4}{16 \text{ tonne } CH_4}$$
$$\times \frac{\text{tonne mole gas}}{0.70 \text{ tonne mole } CH_4} \times \frac{0.09 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2} = 60.68 \text{ tonnes } CO_2/\text{yr}}$$

5.6.2 Gas-Driven Chemical Injection Pumps

Natural gas-driven chemical injection pumps (CIPs) are a source of CH_4 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_2 emissions if the gas used to drive the pump contains a significant amount of CO_2.

If fuel gas is used as the pneumatic gas and is taken downstream of the total fuel gas meter, then the vented gas volume must be subtracted from the total fuel gas volume (used to determine combustion emissions).

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 H_2S scavengers.

The most rigorous approach for estimating GHG emissions from CIPs is to use site-specific gas usage measurements or manufacturer data. Another rigorous approach is to calculate the volume of natural gas emitted from the volume of liquid pumped. The volume of natural gas emissions from a pneumatic pump is a function of the amount of liquid pumped (displacement volume), the liquid outlet pressure from the pump, the gas pressure and temperature used as the pneumatic power gas, and the "mechanical efficiency loss" across the pump. In manufacturers information this relationship is typically described using a set of "pump curves." However it can be described mathematically using Equation 5-22.

$$V_G = \left(\frac{P_O + P_A}{14.7}\right) \times \left(\frac{T_A}{459.7 + T_G}\right) \times V_L \times [1 + I] \qquad \text{(Equation 5-22)}$$

where

V_G = gas loss from natural gas driven pneumatic pump, scf/yr;
P_O = outlet pressure from the pump, psig;
P_A = atmospheric pressure, psig;
14.7 = atmospheric pressure, psig;
T_A = atmospheric temperature, °R;
459.7 = conversion from °F to °R;
T_G = gas temperature, °F;
V_L = volume of liquid pumped, ft^3/yr, from measurement data or calculated using equation 5-2; and
(1 + I) = manufacturer-specific pump inefficiency, or assumed default of 30%.

The volume of liquid pumped in Equation 5-22 can be calculated as shown in Equation 5-23.

$$V_L = \frac{V_S}{7.48} \times N \times T \qquad \text{(Equation 5-23)}$$

where

V_S = volume of liquid pumped per stroke, gal/stroke;
7.48 = conversion from gal to scf;
N = number of strokes/min; and
T = annual operational time, min/year.

After calculating the volume of gas loss, CH_4 and CO_2 emissions can then be calculated using the CH_4 and CO_2 content of the gas, such as described in Section 5.7.1.

Alternatively, the simplified emission factors in Table 5-16 can be used to estimate CH_4 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.

Table 5-16. Gas-Driven Chemical Injection Pump CH_4 Emission Factors

Type of Chemical Injection Pump	**Emission Factor, Original Units**	**Uncertainty [a] (±%)**	**CH_4 Emission Factor, Converted to Tonnes Basis [b]** Based on 78.8 mole% CH_4 [c]
Piston pumps (207 kPag)	48.9 [c] scfd CH_4/pump	141	0.342 tonnes/pump-yr
Piston pumps (140 kPag)	0.04 [d] m^3 gas/hr/pump	Not specified	0.19 tonnes/pump-yr
Piston pumps (240 kPag)	0.06 [d] m^3 gas/hr/pump	Not specified	0.28 tonnes/pump-yr
Diaphragm pumps (pressure unspecified)	446 [c] scfd CH_4/pump	99	3.121 tonnes/pump-yr
Diaphragm pumps (140 kPag)	0.4 [d] m^3 gas/hr/pump	Not specified	1.9 tonnes/pump-yr
Diaphragm pumps (240 kPag)	0.6 [d] m^3 gas/hr/pump	Not specified	2.8 tonnes/pump-yr
Average pump (if type not known)	248 [c] scfd CH_4/pump	108	1.737 tonnes/pump-yr
	0.3945 [e] m^3 gas/hr/pump	Not specified	1.845 tonnes/pump-yr

Footnotes and Sources for Table 5-16:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia.

[c] 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 U.S. Environmental Protection Agency, June 1996. The average CH_4 concentration associated with these emission factors is provided in Table E-4.

[d] 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 CH_4 basis using the CH_4 content shown in the table.

[e] 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 CH_4 basis using the CH_4 content shown in the table.

The emission factors are taken from three sources: the 1996 GRI/EPA report (Volume 13) (Shires, 1996) and two guidance documents from the CAPP (CAPP, 2002; CAPP, 2003). The piston pump emission factor from the GRI/EPA report was based on the manufacturer's data while the diaphragm pump factor from the GRI/EPA report was based on a combination of manufacturer 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 natural 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_4 content of the site-specific gas used to drive the pumps if the natural gas has a significantly different CH_4 content from the default basis. Also, if the pumps are driven with gas that contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

An example calculation is given in Exhibit 5.23 that illustrates the use of the CIP emission factors.

EXHIBIT 5.23: Sample Calculation for Gas-Driven Chemical Injection Pump Emissions

INPUT DATA:
A gas production facility in the United States has 25 gas-driven CIPs that are piston type pumps. The average operating pressure for these pumps is 32.6 psig (200 kPa gauge). The CH_4 content of the gas is not known, but is assumed to be similar to other typical facilities. There is no significant quantity of CO_2 in the gas. Calculate the CH_4 emissions.

CALCULATION METHODOLOGY:
Emissions are calculated by multiplying the number of chemical injection pumps by the appropriate piston pump emission factor from Table 5-16. The actual operating pressure falls between the piston pump factor at 207 kPa and the piston pump factor at 240 kPa, so the factor at 207 kPa is chosen because it is based on a U.S. report. The emission factor is not corrected by the gas CH_4 content because the facility is assumed to have a gas CH_4 content similar to other typical facilities. Emissions are calculated as shown below:

$$E_{CH_4} = (25\text{ CIPs}) \times \frac{0.342\text{ tonne } CH_4}{\text{pump - yr}}$$

$$\underline{E_{CH_4} = 8.55\text{ tonnes } CH_4/\text{yr}}$$

5.6.3 Mud Degassing

During well drilling operations, drilling fluid (otherwise known as drilling mud) is used for many important purposes, including lubricating and cooling the drill bit, carrying cuttings away from the drill bit, and maintaining desired pressure within the well. During these operations, gas from the well bore may become entrained in the mud, requiring the mud to be degassed. During mud degassing, gases entrained in the mud are separated from the mud and vented directly to the atmosphere. This venting results in emissions of CH_4 contained in the gas, and possibly CO_2 emissions. Site-specific CH_4 (and CO_2 if present) concentration data should be used to estimate these emissions. However, in the absence of site-specific data, the simplified mud degassing emission factors presented in Table 5-17 can be used.

Table 5-17 provides mud degassing THC vented emission factors on a drilling day basis. The base THC factors are taken from U.S. Department of the Interior, Minerals Management Service guidance (Wilson et al., 2007). The CH_4 factors are derived from the THC factors based on an assumed CH_4 concentration. However, the factors can be adjusted using actual site-specific concentrations if they are available and different from the defaults shown in the table.

Table 5-17. Mud Degassing Vented CH_4 Emission Factors

Mud Type	THC Emission Factor [a], Original Units (lb THC/drilling day)	CH4 Emission Factor [b], Converted to Tonnes Basis (tonnes CH_4/drilling day)
Water-based Mud	881.84	0.2605
Oil-based Mud	198.41	0.0586
Synthetic Mud	198.41	0.0586

Footnotes and Sources:

[a] Wilson, Darcy, Richard Billings, Regi Oommen, and Roger Chang, Eastern Research Group, Inc. *Year 2005 Gulfwide Emission Inventory Study*, U.S. Department of the Interior, Minerals Management Services, Gulf of Mexico OCS Region, New Orleans, December 2007, Section 5.2.10.

[b] Based on gas content of 65.13 weight percent CH_4, derived from sample data provided in the original source of the emission factors. Original sample data is as follows, in terms of mole%: 83.85% CH_4, 5.41% C_2H_6, 6.12% C_3H_8, 3.21% C_4H_{10}, and 1.40% C_5H_{12} (Wilson et al., 2007).

An example calculation is given in Exhibit 5.24 to illustrate the use of the mud degassing emission factors.

EXHIBIT 5.24: Sample Calculation for Mud Degassing Vented Emissions

INPUT DATA:
An oil and natural gas production facility performed well drilling activities with water-based mud 85 days during the year. The average CH_4 content of the gas is 70 mole %; there is also 9 mole % CO_2 in the gas. Calculate the CH_4 and CO_2 emissions.

EXHIBIT 5.24: Sample Calculation for Mud Degassing Vented Emissions, continued

CALCULATION METHODOLOGY:
Emissions are calculated by multiplying the number of days of drilling activities by the CH_4 emission factor from Table 5-17. The base mud degassing vented CH_4 emission factor is adjusted from the default basis of 83.85 mole% CH_4 to the site-specific basis of 70 mole % CH_4. Because the gas contains a significant quantity of CO_2, emissions of CO_2 are also estimated using the relative CO_2 and CH_4 contents in the gas.

$$E_{CH_4} = \frac{85\text{ day}}{\text{yr}} \times \frac{0.2605\text{ tonnes }CH_4}{\text{day}} \times \frac{70\text{ mole \% }CH_4}{83.85\text{ mole \% }CH_4}$$

$$\underline{E_{CH_4} = 18.49\text{ tonnes }CH_4/\text{yr}}$$

$$E_{CO_2} = \frac{85\text{ day}}{\text{yr}} \times \frac{0.2605\text{ tonnes }CH_4}{\text{day}} \times \frac{70\text{ mole \% }CH_4}{83.85\text{ mole \% }CH_4} \times \frac{\text{tonne mole }CH_4}{16\text{ tonne }CH_4}$$
$$\times \frac{\text{tonne mole gas}}{0.70\text{ tonne mole }CH_4} \times \frac{0.09\text{ tonne mole }CO_2}{\text{tonne mole gas}} \times \frac{44\text{ tonne }CO_2}{\text{tonne mole }CO_2}$$

$$\underline{E_{CO_2} = 6.54\text{ tonnes }CO_2/\text{yr}}$$

5.6.4 Heavy Oil and Crude Bitumen Casing Gas Vents

Casing gas vents are a particular concern for heavy oil and crude bitumen wells. Heavy oil wells are relatively shallow (typically 300 to 900 m deep) and, thus are characterized by low reservoir pressures (typically 4000 kPa or less). To achieve reasonable flow potential, it is necessary to relieve gas pressure from the well bore. The wells are not usually equipped with a production packer (a device that isolates the annulus from the formation), which allows the well pressure to be controlled using the casing vent. Because of the low volumes of gas associated with primary heavy oil casing gas, the gas may be vented directly to atmosphere. For thermal heavy oil projects, the gas is usually flared or conserved because of the potential for H_2S in the gas.

Casing gas venting associated with heavy oil production may result in emissions of CH_4 contained in the gas, and possibly CO_2 emissions. Site-specific volumetric flow rate and CH_4 concentration data (and CO_2 if present) provide the most rigorous estimation of these emissions. However, in the absence of site-specific data, the simplified casing gas vented emission factors presented in Tables 5-18 and 5-19 can be used.

Table 5-18 provides casing gas THC vented emission factors on a heavy oil production throughput basis. The base THC factors are taken from 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 5-18. Heavy Oil and Crude Bitumen Casing Gas Vented CH_4 Emission Factors – Throughput Basis

Type of Oil	THC Emission Factor [a], Original Units (m^3 THC/m^3 oil produced)	CH_4 Emission Factor [b], Converted to Tonnes Basis Based on 78.8 mole% CH_4 [c]	
		(tonnes/1000 bbl oil produced)	(tonnes/1000 m^3 oil produced)
Primary Heavy Oil (63.2% casing gas vented) [d]	37.4	3.17	20.0
Thermal Heavy Oil (4.7% casing gas vented) [d]	2.53	0.215	1.35
Crude Bitumen (18% casing gas vented) [d]	2.3	0.20	1.2

Footnotes and Sources:

[a] 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 CH_4 basis using the CH_4 content shown in the table.

[b] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia.

[c] 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 U.S. Environmental Protection Agency, June 1996.

[d] Percentage shown is the assumed percent of total casing gas vented. If the actual percent casing gas vented is known, the factor and percentage shown for each crude type can be used to estimate the CH_4 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, Table 5-19 can be used. This table provides simplified casing gas vented THC emission factors for active and suspended wells based on data from Alberta, Canada (CAPP, 2002). The active and suspended well emission rate data were based on 883 and 910 wells, respectively.

Table 5-19. Heavy Oil and Crude Bitumen Casing Gas Vented CH_4 Emission Factors – Well Basis

Source	THC Emission Factor [a], Original Units (m^3 THC/well-day)	CH_4 Emission Factor [b], Converted to Tonnes Basis Based on 78.8 mole% CH_4 [c] (tonnes CH_4/well-day)
Active Wells	37.1	0.0198
Suspended Wells	20.1	0.0107

Footnotes and Sources:

[a] 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 CH_4 basis using the CH_4 content shown in the table.

[b] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia.

[c] 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 U.S. Environmental Protection Agency, June 1996.

The THC emission factors from the two CAPP guidance documents were converted to CH_4 emission factors using a default CH_4 gas content of 78.8 mole % in the production segment provided in Table E-4. The casing gas CH_4 emission factors can be adjusted based on the CH_4 content of the site-specific gas if the natural gas has a CH_4 content significantly different from the default basis. Also, if the gas at the site contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

An example calculation is given in Exhibit 5.25 that illustrates the use of the casing gas vent emission factors.

EXHIBIT 5.25: Sample Calculation for Heavy Oil Casing Gas Vented Emissions

INPUT DATA:
An oil and natural gas production facility produces 100 bbl/day of primary heavy crude oil. The facility operates 365 days a year. The average CH_4 content of the gas is 70 mole %; there is also 9 mole % CO_2 in the gas. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:
Emissions are calculated by multiplying the oil throughput by the "primary heavy oil" CH_4 emission factor from Table 5-18. The base casing gas CH_4 emission factor is also adjusted from the default basis provided in Table E-4 of 78.8 mole % CH_4 to the site-specific basis of 70 mole % CH_4. Because the gas contains a significant quantity of CO_2, emissions of CO_2 are also estimated using the relative CO_2 and CH_4 contents in the gas.

$$E_{CH_4} = \frac{100 \text{ bbl crude}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{3.17 \text{ tonnes } CH_4}{1000 \text{ bbl crude}} \times \frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4}$$

$$\underline{E_{CH_4} = 102.8 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = \frac{100 \text{ bbl crude}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{3.17 \text{ tonnes } CH_4}{1000 \text{ bbl crude}} \times \frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4} \times \frac{\text{tonne mole } CH_4}{16 \text{ tonne } CH_4}$$
$$\times \frac{\text{tonne mole gas}}{0.70 \text{ tonne mole } CH_4} \times \frac{0.09 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2} = 36.34 \text{ tonnes } CO_2/\text{yr}}$$

5.6.5 Low-Pressure Gas Well Casing Vents

Casing gas migration from low-pressure natural gas wells can result in CH_4 emissions and possibly CO_2 emissions, if CO_2 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 crude oil casing gas venting, site-specific measurements provide the most rigorous estimate of low-pressure gas well casing emissions. 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):

3.85 m^3 gas/well-day (original units) (CAPP, 2002)
0.00206 tonnes CH_4/well-day (converted)[a]

[a]Note: the THC factor was converted to a CH_4 emission factor assuming 78.8 mole % CH_4 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 5.26 that demonstrates the use of the gas well casing emission factor.

EXHIBIT 5.26: Sample Calculation for Low-Pressure Casing Gas Migration Emissions

INPUT DATA:
An oil and natural gas production facility has three low pressure wells. Sampling data show that casing gas migration occurs, but the emission rate has not been measured. The average CH_4 content of the gas is 70 mole %; there is also 9 mole % CO_2 in the gas. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:
Emissions are calculated by multiplying the number of wells by the casing gas migration CH_4 emission factor. The base casing gas migration CH_4 emission factor is also adjusted from the default basis provided in Table E-4 of 78.8 mole % CH_4 to the site-specific basis of 70 mole % CH_4. Because the gas contains a significant quantity of CO_2, emissions of CO_2 are also estimated using the relative CO_2 and CH_4 contents in the gas.

EXHIBIT 5.26: Sample Calculation for Low-Pressure Casing Gas Migration Emissions, continued

$$E_{CH_4} = 3 \text{ wells} \times \frac{0.00206 \text{ tonnes } CH_4}{\text{well-day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4}$$

$$\underline{E_{CH_4} = 2.00 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = 3 \text{ wells} \times \frac{0.00206 \text{ tonnes } CH_4}{\text{well-day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4} \times \frac{\text{tonne mole } CH_4}{16 \text{ tonne } CH_4}$$
$$\times \frac{\text{tonne mole gas}}{0.70 \text{ tonne mole } CH_4} \times \frac{0.09 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2} = 0.71 \text{ tonnes } CO_2/\text{yr}}$$

5.6.6 Coal Seam Exploratory Drilling and Well Testing

Methane, or natural gas, may be used for drilling coal seam CH_4 wells, if available at high pressures. In this case, CH_4, 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 or 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 4.6.) An example calculation illustrating the material balance approach follows in Exhibit 5.27.

EXHIBIT 5.27: Sample Calculation for Exploratory Drilling or Well Testing

INPUT DATA:
A coal bed CH_4 site is drilling three new wells with the following duration and gas consumption rates:

	Duration to Drill, days	Gas Consumption, 10^6 ft^3/day
Well 1	5	1.5
Well 2	2	1.5
Well 3	5	1.75

An additional 6.76×10^6 scf of gas per well is flared during well testing. The gas contains 10.9 mole% CO_2, 88.7 mole% CH_4, and 0.4 mole% other. Calculate the vented and flared emissions.

CALCULATION METHODOLOGY:
1. *Calculate the vented emissions.* Assuming the drilling gas is vented to the atmosphere, the total volume of gas vented is:

$$V = \left(\frac{1.5\times10^6\ \text{ft}^3}{\text{day}}\times 5\ \text{days}\right)_{\text{Well 1}} + \left(\frac{1.5\times10^6\ \text{ft}^3}{\text{day}}\times 2\ \text{days}\right)_{\text{Well 2}} + \left(\frac{1.75\times10^6\ \text{ft}^3}{\text{day}}\times 5\ \text{days}\right)_{\text{Well 3}}$$

$$V = 19.25\times10^6\ \text{scf gas}$$

The corresponding CH_4 and CO_2 emissions resulting from this vented gas are:

$$E_{CH_4} = 19.25\times10^6\ \text{scf gas}\times\frac{\text{lbmole gas}}{379.3\ \text{scf gas}}\times\frac{0.887\ \text{lbmole CH}_4}{\text{lbmole gas}}\times\frac{16\ \text{lb CH}_4}{\text{lbmole CH}_4}\times\frac{\text{tonne}}{2204.62\ \text{lb}}$$

$$\underline{E_{CH_4} = 327\ \text{tonnes CH}_4}$$

$$E_{CO_2} = 19.25\times10^6\ \text{scf gas}\times\frac{\text{lbmole gas}}{379.3\ \text{scf gas}}\times\frac{0.109\ \text{lbmole CO}_2}{\text{lbmole gas}}\times\frac{44\ \text{lb CO}_2}{\text{lbmole CO}_2}\times\frac{\text{tonne}}{2204.62\ \text{lb}}$$

$$\underline{E_{CO_2} = 110\ \text{tonnes CO}_2}$$

2. *Calculate the emissions released from flaring the well test gas.* Details on flaring emissions are provided in Section 4.6. We will assume that the "other" components in the gas analysis are primarily ethane. Emissions are calculated assuming the default 98% combustion efficiency. Emissions are calculated as follows.

EXHIBIT 5.27: Sample Calculation for Exploratory Drilling or Well Testing, continued

$$E_{CO_2} = \left(\frac{6.76\times10^6 \text{ scf gas}}{\text{well}} \times 3 \text{ wells} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \right) \times \left(\frac{0.109 \text{ lbmole } CO_2}{\text{lbmole gas}} + \left[\frac{0.887 \text{ lbmole C (from } CH_4)}{\text{lbmole gas}} + \frac{0.004\times2 \text{ lbmole C (from } C_2H_6)}{\text{lbmole gas}} \right] \times \frac{0.98 \text{ lbmole } CO_2 \text{ formed}}{\text{lbmole C combusted}} \right) \times \frac{44 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 1{,}050 \text{ tonnes } CO_2}$$

$$E_{CH_4} = \frac{6.76\times10^6 \text{ scf gas}}{\text{well}} \times 3 \text{ wells} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{0.887 \text{ lbmole } CH_4}{\text{lbmole gas}} \times \frac{0.02 \text{ lbmole residual } CH_4}{\text{lbmole } CH_4} \times \frac{16 \text{ lb } CH_4}{\text{lbmole } CH_4} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CH_4} = 6.9 \text{ tonnes } CH_4}$$

5.6.7 Coal Mining

Underground and surface coal mining activities produce CH_4 emissions as a result of activities that occur before, during, and after mining.

Ventilation systems are used in underground coal mines to maintain safe CH_4 concentrations. These ventilation systems can result in significant gas volumes released to the atmosphere, although the CH_4 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_4 emissions. Emissions from flared coal mine waste gas should be calculated using the methodology described in Section 4 (e.g., material balance approach).

Surface coal mines result in CH_4 emissions as the overburden is removed and the coal is exposed, but the emissions are lower than from underground mines. Some CH_4 emissions also occur during the processing, storage, and transportation of the coal (referred to as post-mining activities).

Site-specific data provide the most rigorous estimate of coal mining CH_4 emissions. In the absence of such data, simple emission factors provided in Table 5-20 or Table 5-21 may be used. The emission factors in Table 5-20 were developed from data provided in the Annexes of the EPA report, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006* (EPA, 2009). The emission factors were derived by dividing the U.S. coal mining CH_4 emissions by the U.S. coal production rates. Factors were derived for 2005 through 2007. Separate emission factors are provided for underground and surface mining, and for coal handling. The underground mining emission factor includes contributions from both ventilation and degasification. The derivations of the emission factors shown in Table 5-20, as well as coal mining factors by U.S. coal supply region are provided in Appendix B. Emission factors for Australian mining operations are provided in Table 5-21. Additional emission factors for decommissioned underground mines in Australia are provided in the Australian Government, Department of Climate Change, *National Greenhouse Accounts (NGA) Factors*, November 2008.

Table 5-20. Average U.S. Coal Mining CH_4 Emission Factors

	Emission Factor [a], Original Units			**Emission Factor, Converted Units**					
	scf CH_4/ short ton coal			**tonne CH_4/ short ton coal**			**tonne CH_4/ tonne coal**		
Activity	**2005**	**2006**	**2007**	**2005**	**2006**	**2007**	**2005**	**2006**	**2007**
Underground Mining (Ventilation and Degasification)	241	248	242	0.00463	0.00476	0.00463	0.00511	0.00524	0.00511
Underground Post-Mining (coal handling)	43.4	41.8	42.6	0.000833	0.000801	0.000818	0.000918	0.000883	0.000902
Surface Mining	43.3	43.6	42.8	0.000830	0.000836	0.000822	0.000915	0.000922	0.000906
Surface Post-Mining (coal handling)	6.56	7.47	7.56	0.000126	0.000143	0.000145	0.000139	0.000158	0.000160

Footnotes and Sources:

[a] Derived from data presented in: U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007, Annexes*, April 15, 2009. See derivation in Appendix B.

Table 5-21. Australian Coal Mining CH_4 Emission Factors

State	tonnes CO_2e/ tonne run-of-mine coal extracted [a]	tonnes CH_4/ tonne run-of-mine coal extracted
Open Cut Coal Extraction, by State		
New South Wales	0.045	0.945
Victoria	0.0007	0.0147
Queensland	0.017	0.357
Western Australia	0.017	0.357
South Australia	0.0007	0.0147
Tasmania	0.014	0.294
Coal Extraction, by Mine Type		
Gassy Mine	0.305	6.405
Non-gassy mine	0.008	0.168
Post-Mining		
Gassy Mine	0.014	0.294

Footnote and Source:

[a] Australian Government, Department of Climate Change, *National Greenhouse Accounts (NGA) Factors*, Section 2.4.1, November 2008. Original units are tonnes CO_2^{-eq}/tonne run-of-mine coal.

An example calculation is given in Exhibit 5.28 that illustrates the use of the coal mining CH_4 emission factors.

EXHIBIT 5.28: Sample Calculation for Coal Mining Emissions

INPUT DATA:
During 2007, 200,000 tons of coal are produced from an underground mine in the U.S. Calculate the CH_4 emissions.

CALCULATION METHODOLOGY:
Emissions from coal mining include both mining emissions and coal handling emissions. Emissions are calculated by multiplying the annual coal production rate by the underground coal mining and coal handling CH_4 emission factors from Table 5-20.

Emissions from underground coal mining are:

$$E_{CH_4,\text{mining}} = \frac{200{,}000 \text{ tons}}{\text{year}} \times \frac{\text{tonnes coal}}{1.10231 \text{ tons coal}} \times \frac{0.00511 \text{ tonnes } CH_4}{\text{tonne coal}}$$

$$\underline{E_{CH_4,\text{mining}} = 927.14 \text{ tonnes } CH_4/\text{yr}}$$

EXHIBIT 5.28: Sample Calculation for Coal Mining Emissions, continued

Emissions from underground coal handling are:

$$E_{CH_4,handling} = \frac{200{,}000 \text{ tons}}{\text{year}} \times \frac{\text{tonnes coal}}{1.10231 \text{ tons coal}} \times \frac{0.00090 \text{ tonnes } CH_4}{\text{tonne coal}}$$

$$\underline{E_{CH_4,handling} = 163.29 \text{ tonnes } CH_4/\text{yr}}$$

Total emissions from coal mining are:

$$E_{CH_4,total} = E_{CH_4,mining} + E_{CH_4,handling} = 927.14 + 163.29 \text{ tonnes } CH_4/\text{yr}$$

$$\underline{E_{CH_4,total} = 1{,}090.43 \text{ tonnes } CH_4/\text{yr}}$$

5.6.8 Chemical Production

Small amounts of CH_4 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, 2009):

- Carbon black – made from the incomplete combustion of an aromatic petroleum or coal-based 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 plastics such as polymers.
- Ethylene dichloride – an important intermediate in the synthesis of chlorinated hydrocarbons. It is also used as an industrial solvent and fuel additive.
- Methanol – an alternative transportation fuel as well as a principal 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 (HNO_3) is an inorganic compound used primarily to make synthetic commercial fertilizers. It is typically produced by the catalytic oxidation of ammonia, where N_2O is formed as a by-product.

Table 5-22 provides average emission factors for each of the chemical processes described above based on production rate (EPA, 2009). The CH_4 emission factors are based on material balances of the petrochemical processes. The N_2O emission factors are based on facility data and account for the use of N_2O 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 N_2O, the abatement method.

Table 5-22. Chemical Production Emission Factors

Chemical Production Process	**Emission Factor [a], Original units**	**Emission Factor, Converted Units**
Carbon black	11 kg CH_4/tonne produced	0.011 tonne CH_4/tonne produced
Ethylene	1 kg CH_4/tonne produced	0.001 tonne CH_4/tonne produced
Ethylene dichloride	0.4 kg CH_4/tonne produced	0.0004 tonne CH_4/tonne produced
Methanol	2 kg CH_4/tonne produced	0.002 tonne CH_4/tonne produced
Nitric acid		
- with NSCR	2 kg N_2O/tonne produced	0.002 tonne N_2O/tonne produced
- without NSCR [b]	9 kg N_2O/tonne produced	0.009 tonne N_2O/tonne produced
Adipic acid		
- with catalytic abatement [c]	0.053 kg N_2O/kg produced	0.053 tonne N_2O/tonne produced
- with thermal abatement [d]	0.013 kg N_2O/kg produced	0.013 tonne N_2O/tonne produced
- without abatement	0.3 kg N_2O/kg produced	0.3 tonne N_2O/tonne produced

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, April 15, 2009, pgs 4-20, 4-22, and 4-26.

[b] Note that selective catalytic reduction (SCR) and extended absorption are not known to reduce N_2O emissions.

[c] Catalytic abatement is assumed to have a destruction efficiency of 92.5% of N_2O and a utility factor of 89% (IPCC, 2006).

[d] Thermal abatement is assumed to have a destruction efficiency of 98.5% of N_2O and a utility factor of 97% (EPA, 2009).

5.7 Non-Routine Activities

Non-routine emissions involve venting events that result in CH_4 emissions, and possibly CO_2 emissions for CO_2-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_4, and possibly CO_2 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_4 and oxygen. An inert gas, such as nitrogen or natural gas, can be used for the purging process. Methane and possibly CO_2 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 natural gas industry. Often, these conditions automatically trigger the depressurization of process equipment to ensure safe operating conditions. For example, PRVs and 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 5-7. The first is based on engineering calculations of the volume released, documentation of the non-routine release events, and the concentration of CH_4 (and CO_2, 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 5.7.6).

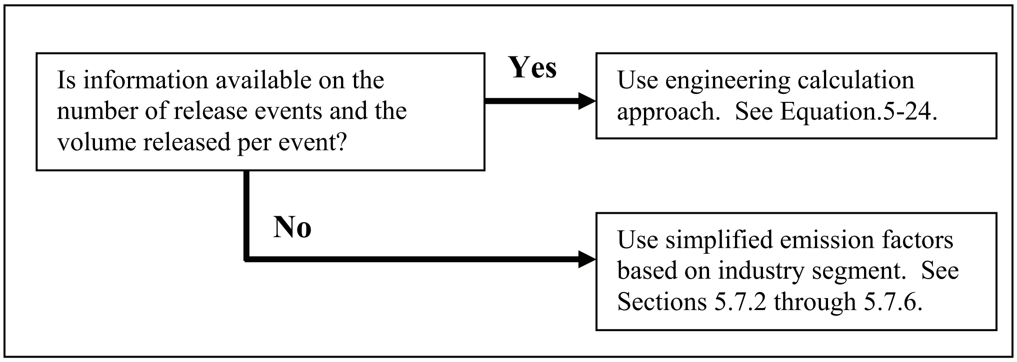

Figure 5-7. Decision Tree for Non-Routine Activities

5.7.1 Engineering Calculation Approach

Emissions from maintenance activities or emergency conditions (e.g., well water removal or offshore emergency shutdowns) can generally be estimated by the following equation:

$$E_{CH_4 \text{ or } CO_2} = \frac{\text{Gas Volume Released}}{\text{Event}} \times \text{Mole\%}_{CH_4 \text{ or } CO_2} \times \frac{\#\text{Events}}{\text{Year}} \times \frac{MW_{CH_4 \text{ or } CO_2}}{\text{molar volume conversion}}$$

(Equation 5-24)

where

$E_{CH_4 \text{ or } CO_2}$ = emissions of CH_4 or CO_2 emissions in units of mass, and

Molar volume conversion = conversion from molar volume to mass (379.3 scf/lbmole or 23.685 m^3/kgmole @ 60°F and 14.7 psia).

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 gas pipeline pigging operations, the volume released would be based on the segment of pipeline depressurized plus the volume of the pig catcher or launcher. Note that emissions associated with oil pipeline pigging operations should be calculated in a manner similar to emissions from crude tank flashing, which is described in Section 5.4.1.

The density of the gas can be calculated using an additional term in the gas law, presented in Section 3.5, Equation 3-4:

$$PV = znRT \qquad \text{(Equation 5-25)}$$

where

P = pressure (psia or atm);
V = volume;
z = compressibility factor, tables for CH_4 and CO_2 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; and
T = absolute temperature (°R or K).

Rearranging, the equation becomes:

$$n = \frac{PV}{zRT} \qquad \text{(Equation 5-26)}$$

Using this equation, the moles of gas emitted can be converted to a mass basis by applying the molecular weight of CH_4 or CO_2 as shown in Equation 5-27.

$$E_{CH_4 \text{ or } CO_2} = \frac{\text{Moles Gas Released}}{\text{Event}} \times \text{Mole\%}_{CH_4 \text{ or } CO_2} \times MW_{CH_4 \text{ or } CO_2} \times \frac{\text{\#Events}}{\text{Year}} \qquad \text{(Equation 5-27)}$$

An example of this approach is demonstrated in Exhibit 5.29.

EXHIBIT 5.29: Sample Calculation for Estimating Non-Routine Emissions

INPUT DATA:
The volume of gas vented from a vessel (e.g., a separator) must take into account whether or not the fluids contained within the vessel will need to be removed to perform the desired maintenance activity. For example, a low pressure separator, operating at 100 psig and ambient temperature (~80 °F), that is blown down to replace a gauge or a relief valve will likely leave the fluid levels intact and remove only the gas. The vessel dimensions are 4 ft in diameter and 10 ft long. The gas composition in the separator is 90% CH_4 with no CO_2. Calculate the CH_4 emissions assuming that the liquid volume occupies 1/3 of the vessel.

CALCULATION METHODOLOGY:
The first step in calculating emissions is to calculate the total volume (V_T) of the vessel in the separator. The actual volume is estimated based upon the internal dimensions:

$$V = \pi r^2 L = \pi \times \left(\frac{4\text{ft}}{2}\right)^2 \times 10 \text{ ft (actual)} = 125.7 \text{ ft}^3 \text{(actual)}$$

The volume of gas (VG) released is a fraction of this total volume as defined by:

$$V_G = (V_t - V_L)/V_T = \left(125.7 - \left[\frac{1}{3} \times 125.7\right]\right)/125.7 = 83.8 \text{ ft}^3 \ (\text{estimated})$$

The moles of gas released is then calculated using Equation 5-26. The compressibility factor for CH_4 is determined to be 0.9864 (Perry, 1984).

EXHIBIT 5.29: Sample Calculation for Estimating Non-Routine Emissions, continued

$$n = \frac{(100 \text{ psig} + 14.7) \times \left(83.8 \text{ ft}^3\right)}{0.9864 \times 10.73 \dfrac{\text{psi ft}^3}{\text{lbmole } ^\circ\text{R}} \times 539.7 \ ^\circ\text{R}} = 1.68 \text{ lbmoles gas/blowdown event}$$

Finally, the CH_4 emissions are calculated using Equation 5-27:

$$E_{CH_4} = \frac{1.68 \text{ lbmoles gas}}{\text{blowdown event}} \times \frac{0.9 \text{ lbmoles } CH_4}{\text{lbmoles gas}} \times \frac{16 \text{ lb } CH_4}{\text{lbmole } CH_4} \times \frac{1 \text{ blowdown}}{\text{yr}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CH_4} = 0.011 \text{ tonne } CH_4/\text{yr}}$$

The volume (V) of gas released in Equation 5-25 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. Standard engineering equations for estimating internal volumes may be applied and are described in the CAPP document referenced above. The CAPP document also provides volumes per meter of pipeline length for several pipe sizes and schedules (CAPP, 2002, Table 3-8). These volumes are provided in Appendix B.

Use of the gas law is most appropriate for situations where the entire volume of the vessel is blown down and the volume of gas released is finite. More rigorous engineering approaches are needed for a blowdown situation where only a portion of the vessel contents is released.

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 5-23. Note that some of the factors presented in Table 5-23 are provided on an equipment count basis, not a per-event basis. The majority of these emission factors are taken from the GRI/EPA study (Shires, Volume 7, 1996). The gas and oil well workover emission factors are taken from a report by Pipeline Systems Incorporated (PSI, 1990). Gas well completion data are taken from an Energy Information Administration report (EIA, 2001).

Table 5-23. Production Segment CH_4 Emission Factors for Maintenance and Turnaround Activities

Source	CH_4 Emission Factor [a], Original Units	CH_4 Emission Factor [b], Converted to Tonnes Basis	CH_4 Content Basis of Factor [c]	Uncertainty [d] (±%)
Vessel blowdowns	78 scfy/vessel	0.0015 tonnes/vessel-yr	78.8 mole %	326
Compressor starts [e]	8,443 scfy/compressor	0.1620 tonnes/ compressor-yr	78.8 mole %	190
Compressor blowdowns	3,774 scfy/compressor	0.07239 tonnes/ compressor-yr	78.8 mole %	179
Gas well workovers [f] (tubing maintenance)	2,454 scf/workover	0.04707 tonnes/workover	Not given	924
Oil well workovers [f] (tubing maintenance)	96 scf/workover	0.0018 tonnes/workover	Not given	Not available
Gathering gas pipeline blowdowns	309 scfy/mile	0.00593 tonnes/mile-yr 0.00368 tonne/km-yr	78.8 mole %	39.5
Onshore gas well completion [g]	$1,712\times10^3$ scf/ completion-day	25.9 tonne/completion-day	78.8 mole %	Not available
Offshore gas well completion [g]	$\sim8,700\times10^3$ scf/ completion-day	131.5 tonne/completion-day	78.8 mole %	Not available
Oil pump stations (maintenance) [h]	1.56 lb/yr-station	7.076E-04 tonnes/station-yr	Not given	Not available

Footnotes and Sources:

[a] 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 U.S. Environmental Protection Agency, June 1996.

[b] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia. The CH_4 emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 to estimate CO_2 emissions.

[c] 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 U.S. Environmental Protection Agency, June 1996.

[d] Uncertainty based on a 95% confidence interval.

[e] An EPA Gas STAR paper on engine starts reports that typical production compressor engine start-ups vent 1,000 to 5,000 scf of gas with each start-up attempt (EPA Gas STAR, PRO Fact Sheet No. 101, September 2004). This equates to 0.015 to 0.076 tonnes CH_4/start-up attempt assuming 78.8 mole % CH_4 in the gas.

[f] Factor taken from: Tilkicioglu, B.H. *Annual Methane Emission Estimate of the Natural Gas Systems in the United States*, Phase II, Pipeline Systems Incorporated (PSI), September 1990. An EPA Gas STAR paper on installing plunger lift systems in gas wells presents a gas well workover emission factor of 2000 scf CH_4/workover, which equates to 0.0384 tonnes CH_4/workover (EPA Gas STAR, Lessons Learned - Installing Plunger Lift Systems in Gas Wells, October 2003). Gas STAR also reports that the number of gas well workovers conducted in a year typically ranges from 1 to 15.

[g] EIA, U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply, December 2001. Cites data for initial rates of production for completions in 2000. Offshore factor interpolated from chart "Initial Flow Rates of New Natural Gas Well Completions, 1985-2000." The total gas basis was converted to a CH_4 basis assuming 78.8 mole % CH_4 in production using the GRI/EPA average CH_4 composition for production operations.

[h] 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.

The maintenance emission factors given in Table 5-23 can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

The maintenance activities listed in Table 5-23 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, 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.

Well workovers refer to activities performed to restore or increase production. Workover activities involve pulling the tubing from the well to repair tubing corrosion or other downhole equipment problems. If the well has positive pressure at the surface, the well is “killed” by replacing the gas and oil in the column with a heavier fluid, such as mud or water, to stop the flow of oil and natural gas. A small amount of gas is released as the tubing is removed from the open surface casing. Derivation of the GRI/EPA emission factors for well workovers was based on data from a limited number of production fields collected by Pipeline Systems Incorporated (PSI, 1990).

Well completions are associated with the final step of the well drilling. After a well is drilled, the well bore and reservoir near the well have to be cleaned. This is accomplished by producing the well to pits or tanks where sand, cuttings, and other reservoir fluids are collected for disposal. This step is also useful to evaluate the well production rate to properly size the production equipment. The vented gas well completion CH_4 emission factors were derived based on the initial rates of production in 2000 (EIA, 2001). Actual data on the volume of gas vented due to completion activities would provide a more rigorous emission estimate. The emission factors from Table 5-23 may be used when producing the wells to pits or tanks after the completion, in the absence of such data. The natural gas from the completion process can either be vented to the atmosphere or flared. Note that if well completion gas is flared, emissions should be calculated using the combusting methodology discussed in Section 4.6.

A method known as “green completions” may be utilized where the well completion gas is captured by temporary equipment brought to the site to clean up the gas to the point that it can be sent to the sales line, thus avoiding vented emissions. If green completion methods are used to recover any of the well completion emissions, the uncontrolled (vented) CH_4 emission factor must be multiplied by the non-recovered fraction associated with the green completion method. The percent recovery via green completions should be based on site-specific data.

The oil pump station emission factor is based on an estimate of annual maintenance activities and an assumed CH_4 content of 100 ppm in the crude (Tilkicioglu and Winters, 1989).

An example calculation is given in Exhibit 5.30 below that illustrates the use of the production segment maintenance/turnaround-related emissions factors.

EXHIBIT 5.30: Sample Calculation for Production Maintenance/Turnaround-Related Emissions

INPUT DATA:
A gas production field has 10 low-pressure gas wells that send produced gas through 5 miles of gathering pipeline. All of the wells required unloading and there were two well workovers during the year. The field also has five process vessels and a compressor. The gas contains 70 mole % CH_4 and 8 mole % CO_2. Calculate the maintenance/turnaround-related emissions, by activity.

CALCULATION METHODOLOGY:
The equipment count for each maintenance related activity (vessel blowdowns, compressor starts, etc.) is multiplied by the appropriate emission factor from Table 5-23. The emission factors are corrected by the ratio of the site CH_4 content to the emission factor default CH_4 content. The well workover emission factor is not adjusted based on the site gas CH_4 content because the default content for this emission factor is not given. Carbon dioxide emissions are also estimated to account for the CO_2 content of the gas. Carbon dioxide emissions are determined by adjusting the CH_4 emission factors based on the relative concentrations of CH_4 and CO_2 in the gas.

Emissions are calculated below, by maintenance activity.

Vessel blowdowns:

$$E_{CH_4} = 5 \text{ vessels} \times \frac{0.0015 \text{ tonne } CH_4}{\text{vessel - yr}} \times \frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4}$$

$$\underline{E_{CH_4} = 0.007 \text{ tonnes } CH_4/\text{yr}}$$

EXHIBIT 5.30: Sample Calculation for Production Maintenance/Turnaround-Related Emissions, continued

$$E_{CO_2} = 5 \text{ vessels} \times \frac{0.0015 \text{ tonne } CH_4}{\text{vessel - yr}} \times \frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4} \times \frac{\text{tonne mole } CH_4}{16 \text{ tonne } CH_4}$$
$$\times \frac{\text{tonne mole gas}}{0.70 \text{ tonne mole } CH_4} \times \frac{0.08 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2} = 0.002 \text{ tonnes } CO_2/\text{yr}}$$

Compressor starts:

$$E_{CH_4} = 1 \text{ compressor} \times \frac{0.1620 \text{ tonne } CH_4}{\text{compressor - yr}} \times \frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4}$$

$$\underline{E_{CH_4} = 0.14 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = 1 \text{ compressor} \times \frac{0.1620 \text{ tonne } CH_4}{\text{compressor - yr}} \times \frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4} \times \frac{\text{tonne mole } CH_4}{16 \text{ tonne } CH_4}$$
$$\times \frac{\text{tonne mole gas}}{0.7 \text{ tonne mole } CH_4} \times \frac{0.08 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2} = 0.045 \text{ tonnes } CO_2/\text{yr}}$$

Compressor blowdowns:

$$E_{CH_4} = 1 \text{ compressor} \times \frac{0.07239 \text{ tonne } CH_4}{\text{compressor - yr}} \times \frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4}$$

$$\underline{E_{CH_4} = 0.064 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = 1 \text{ compressor} \times \frac{0.07239 \text{ tonne } CH_4}{\text{compressor - yr}} \times \frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4} \times \frac{\text{tonne mole } CH_4}{16 \text{ tonne } CH_4}$$
$$\times \frac{\text{tonne mole gas}}{0.70 \text{ tonne mole } CH_4} \times \frac{0.08 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2} = 0.020 \text{ tonnes } CO_2/\text{yr}}$$

EXHIBIT 5.30: Sample Calculation for Production Maintenance/Turnaround-Related Emissions, continued

Gas well workovers:

$$E_{CH_4} = \frac{2\text{ well workovers}}{\text{yr}} \times \frac{0.04707\text{ tonne CH}_4}{\text{workovers}}$$

$$\underline{E_{CH_4} = 0.094\text{ tonnes CH}_4/\text{yr}}$$

$$E_{CO_2} = \frac{2\text{ well workovers}}{\text{yr}} \times \frac{0.04707\text{ tonne CH}_4}{\text{workovers}} \times \frac{\text{tonne mole CH}_4}{16\text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.7\text{ tonne mole CH}_4}$$
$$\times \frac{0.08\text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44\text{ tonne CO}_2}{\text{tonne mole CO}_2}$$

$$\underline{E_{CO_2} = 0.030\text{ tonnes CO}_2/\text{yr}}$$

Gathering pipeline blowdowns:

$$E_{CH_4} = 5\text{ miles} \times \frac{0.00593\text{ tonne CH}_4}{\text{mile-yr}} \times \frac{70\text{ mole \% CH}_4}{78.8\text{ mole \% CH}_4}$$

$$\underline{E_{CH_4} = 0.026\text{ tonnes CH}_4/\text{yr}}$$

$$E_{CO_2} = 5\text{ miles} \times \frac{0.00593\text{ tonne CH}_4}{\text{mile - yr}} \times \frac{70\text{ mole \% CH}_4}{78.8\text{ mole \% CH}_4} \times \frac{\text{tonne mole CH}_4}{16\text{ tonne CH}_4} \times \frac{\text{tonne mole gas}}{0.70\text{ tonne mole CH}_4}$$
$$\times \frac{0.08\text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44\text{ tonne CO}_2}{\text{tonne mole CO}_2}$$

$$\underline{E_{CO_2} = 0.008\text{ tonnes CO}_2/\text{yr}}$$

With the exception of gas well completions, emission factors are not provided in this subsection for well activities and events that can be calculated based on field data. Such activities include:

1. CO_2 well stimulation. Emissions from CO_2 well stimulation should be calculated using an engineering approach. In the absence of site-specific data, a simplifying assumption is

that the entire volume of CO_2 purchased for well stimulation is released to the atmosphere.

2. Well unloading. Emissions from well unloading should be calculated using an engineering approach.
3. Well blowouts. Well blowouts are very rare, unplanned events. Well blowouts result in uncontrolled releases, the emissions from which can be calculated using well test data or production data and duration.

Well unloading (also referred to as well blowdowns) is sometimes performed to remove water that has accumulated in the tubing. During well unloading, the well is opened to the atmosphere; downhole pressure then forces water out of the tubing. The quantity of gas vented from well unloading depends on the duration of the unloading, which can be calculated based on field conditions (formation, depth, etc.) Methane and CO_2 emissions from well unloading can be estimated using an engineering approach based on the ideal gas law equation. Assuming a standard gas temperature of 60°F, the casing diameter, well depth, shut-in pressure, species concentration, and species molecular weight can be substituted into the ideal gas law equation and rearranged in terms of the mass emission rate as shown in the following equation:

$$\begin{aligned} E_{\mathrm{CH_4\ or\ CO_2}} &= (9.781\times10^{-7})\times\left(\frac{1}{z}\right)\times(\mathrm{D_{casing}})^2\times(\mathrm{Depth})\times(\mathrm{P})\times(\mathrm{CH_4\ or\ CO_2\ mole\ fraction}) \\ &\times(\mathrm{MW_{CH_4\ or\ CO_2}})\times\left(\frac{\#\ \mathrm{Blowdowns}}{\mathrm{Year}}\right)\times\frac{\mathrm{tonnes}}{2204.62\ \mathrm{lb}} \end{aligned}$$

(Equation 5-28)

where

$E_{\mathrm{CH_4\ or\ CO_2}}$ = CH_4 or CO_2 emissions (tonnes/year);
z = compressibility factor, tables for CH_4 and CO_2 are provided in *Perry's Chemical Engineer's Handbook*, Tables 3-172 and 3-166, respectively (Perry, 1984). Assumed to be 1 for an ideal gas;
D_{casing} = casing diameter (inches);
Depth = well depth (feet);
P = shut-in pressure (psig);
MW_{CH_4} = molecular weight of CH_4 (16 lb/lb-mole); and
MW_{CO_2} = molecular weight of CO_2 (44 lb/lb-mole).

A more detailed method for estimating emissions from well unloading is provided in Appendix B. Note that emissions from well unloading include emissions from well workover activities; applying the engineering approach and the well workover emission factor provided in Table 5-23 may overestimate emissions from this activity. Exhibit 5.31 illustrates the use of the engineering equation to estimate well unloading emissions.

EXHIBIT 5.31: Sample Calculation for Estimating Well Unloading Emissions

INPUT DATA:
A well is unloaded once per month (or a total of 12 times per year). The casing diameter is 10 inches, the well depth is 12,000 feet, and the shut-in pressure is 250 psig. The gas that is vented contains approximately 80 mole % CH_4 and 3 mole % CO_2. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:
The unloaded gas is assumed to be ideal (i.e., z is taken to be 1). The CH_4 emissions are estimated using Equation 5-28:

$$E_{CH_4} = (9.781\times10^{-7})\times\left(\frac{1}{1}\right)\times(10)^2\times(12{,}000)\times(250)\times(0.80)\times(16)\times\left(\frac{12\text{ Blowdowns}}{\text{Year}}\right)\times\frac{\text{tonnes}}{2204.62\text{ lb}}$$

$$\underline{E_{CH_4} = 20.44\text{ tonnes }CH_4/\text{yr}}$$

Similarly, CO_2 emissions are estimated using the same equation as used for CH_4, with the concentration and molecular weight for CO_2 substituted into the equation:

$$E_{CO_2} = (9.781\times10^{-7})\times\left(\frac{1}{1}\right)\times(10)^2\times(12{,}000)\times(250)\times(0.03)\times(44)\times\left(\frac{12\text{ Blowdowns}}{\text{Year}}\right)\times\frac{\text{tonnes}}{2204.62\text{ lb}}$$

$$\underline{E_{CO_2} = 2.11\text{ tonnes }CO_2/\text{yr}}$$

Other Production Segment Releases

A summary of the CH_4 emission factors from other production segment venting releases is given in Table 5-24. 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_4, and possibly CO_2) to the atmosphere. All of the emission factors given in Table 5-25 are taken from the GRI/EPA study (Harrison, 1996; Shires, 1996), and are provided on an equipment count basis.

The GRI/EPA study developed emission factors for station ESD systems at offshore facilities and for 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 GRI/EPA study developed a PRV emission factor based on the average size and duration of release events at production facilities. The amount of gas released through a PRV is highly dependent on upstream gas pressure and valve size. A more detailed estimation method for PRV releases is provided in Appendix B (CAPP, 2002, Section 3.2.3).

Table 5-24. Production Segment CH_4 Emission Factors for Other Non-Routine Releases

Source	CH_4 Emission Factor [a], Original Units	CH_4 Emission Factor [b], Converted to Tonnes Basis	CH_4 Content Basis of Factor	Uncertainty [c] (±%)
Pressure relief valves releases	34 scfy/PRV	0.00065 tonnes/PRV-yr	78.8 mole %	310
Gathering gas pipeline mishaps (dig-ins)	669 scfy/mile	0.0128 tonnes/mile-yr 0.00797 tonnes/km-yr	78.8 mole %	2,350
Offshore emergency shutdown (ESD)	256,888 scfy/platform	4.9276 tonnes/platform-yr	78.8 mole %	276

Footnotes and Sources:

[a] 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 U.S. Environmental Protection Agency, June 1996.

[b] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia. The CH_4 emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 to estimate CO_2 emissions.

[c] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

Dig-ins of gathering gas lines in production are unintentional mishaps that result in gas being released to the atmosphere. Gathering crude pipelines may emit CH_4, entrained in the crude at pipeline pressure, 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_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis (if given). Also, if the facility gas contains a significant quantity of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

An example calculation is given in Exhibit 5.32 that illustrates the use of emission factors from other production segment non-routine emission sources.

EXHIBIT 5.32: Sample Calculation for Other Production Segment Non-routine Emission Sources

INPUT DATA:
An oil and natural gas production field has 60 PRVs. The gas from the field is transported through 6 miles of gathering pipeline. The site gas has a typical CH_4 content and no CO_2. Calculate the non-routine emissions by activity.

CALCULATION METHODOLOGY:
The PRV count and gathering pipeline miles are each multiplied by the appropriate emission factor from Table 5-24. The CH_4 emission factors are not corrected by the site CH_4 content because it is similar to the default concentration associated with the emission factors. Emissions are calculated below, by activity.

PRV releases:

$$E_{CH_4} = 60 \text{ PRVs} \times \frac{0.00065 \text{ tonne } CH_4}{\text{PRV-yr}}$$

$$\underline{E_{CH_4} = 0.039 \text{ tonnes } CH_4/\text{yr}}$$

Gathering gas pipeline mishaps (Dig-ins):

$$E_{CH_4} = 6 \text{ miles} \times \frac{0.0128 \text{ tonne } CH_4}{\text{mile-yr}}$$

$$\underline{E_{CH_4} = 0.077 \text{ tonnes } CH_4/\text{yr}}$$

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 5-25. This emission factor can be adjusted based on the CH_4 content of the site-specific gas if the natural gas has a significantly different CH_4 content from the default basis. Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

Table 5-25. Gas Processing Segment CH_4 Emission Factor for Non-Routine Activities

Source	CH_4 Emission Factor [a], Original Units	CH_4 Emission Factor [b], Converted to Tonnes Basis	CH_4 Content Basis of Factor	Uncertainty [c] (±%)
Gas processing non-routine emissions	184 scf/10^6 scf processed	3.524E-03 tonne/10^6 scf processed 0.1244 tonnes/10^6 m^3 processed	86.8 mole %	Not available

Footnotes and Sources:

[a] Derived from estimated processing blowdown vented methane emissions (2.9475 Bscf/yr, [Harrison et al., Vol. 2, 1996]) and estimated annual gas processed (16,045.855 Bscf/yr [DOE, 1993]).

[b] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia. The average CH_4 concentration associated with these emission factors is provided in Table E-4. The CH_4 emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 to estimate CO_2 emissions.

[c] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

Due to the hazards associated with H_2S, venting of sour gas is generally avoided/prohibited. Where the sour gas stream is routed to a combustion control device, the methodologies provided in Section 4.7 should be applied.

An example is provided in Exhibit 5.33.

EXHIBIT 5.33: Sample Calculation for Processing Non-Routine Related Emissions

INPUT DATA:
A natural gas processing facility treats 20×10^6 m^3 of gas per day. The facility gas has a typical CH_4 content and no CO_2. Estimate the blowdown emissions for this facility.

CALCULATION METHODOLOGY:
The processing plant throughput is multiplied by the emission factor presented in Table 5-25. The CH_4 emission factor is not corrected by the site CH_4 content because the composition is assumed to be consistent with the default emission factor CH_4 content.

Gas processing plant blowdowns:

$$CH_4: \frac{20\times10^6\ m^3}{day}\times\frac{365\ days}{yr}\times\frac{0.1244\ tonnes\ CH_4}{10^6\ m^3} = \underline{908\ tonnes\ CH_4/yr}$$

5.7.4 Transmission Related Non-Routine Emissions

Transmission related non-routine emissions are associated primarily with natural gas and LNG systems, since the distribution of petroleum liquids is primarily associated with refined liquids that do not contain CH_4. Transmission of "live" crude should be accounted for through the use of gathering pipelines, which are addressed in Section 5.7.2.

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_4 emission factors from the transmission segment non-routine activities is presented in Table 5-26. Note that the factors shown in Table 5-26 are provided on an equipment/facility count basis, not a per-event basis. The emission factors are based on a mixture of U.S. 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).

Gas storage stations include both below-ground facilities and above-ground LNG facilities. The storage stations have similar non-routine practices to those of compressor stations, and are thus categorized with transmission sector emission factors (Shires, 1996).

The miscellaneous factor includes M&R, odorizer, drips[7], sampling, pigging, and dehydrators. These miscellaneous activities can be quite variable so using a material balance equation approach would provide a better emission estimate. For example, emissions of CH_4 (and CO_2 if present in the gas) released from drips could be estimated based on the volume of gas entrained in the liquid and the liquid quantity captured. Any other gas venting from this operation would also be estimated using a material balance approach based on how the separation takes place, if such gas venting occurs.

The non-routine emission factors given in Table 5-26 can be adjusted based on the CH_4 content of the site-specific gas if the natural gas has a significantly different CH_4 content from the default

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[7] Pipeline drips involve removing liquids in gas pipelines using in-line separators.

basis (if given). Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

Table 5-26. Transmission Segment CH_4 Emission Factors for Non-Routine Activities

Source	CH_4 Emission Factor, Original Units	CH_4 Emission Factor [a], Converted to Tonnes Basis	CH_4 Content Basis of Factor	Uncertainty [b] (±%)
Compressor blowdowns [c]	$2,457 \times 10^3$ scfy/station	47.14 tonnes/station-yr	93.4 mole%	168
Gas compressor station blowdowns [d,e]	$5,300 \times 10^3$ scfy/station	101.7 tonnes/station-yr	93.4 mole %	64.3
Engine starts [c]	$1,515 \times 10^3$ scfy/station	29.06 tonnes/station-yr	93.4 mole%	130
PRV lifts [c]	192×10^3 scfy/station	3.68 tonnes/station-yr	93.4 mole%	100 [f]
ESD activation [c]	415×10^3 scfy/station	7.97 tonnes/station-yr	93.4 mole%	346
M&R station blowdowns [g]	0.020×10^6 m^3/sation-yr	13.75 tonnes/station-yr	95 mole %	Not available
Miscellaneous (includes M&R, odorizer, drips, sampling, pigging, dehydrators) [c]	$1,134 \times 10^3$ scfy/station	21.75 tonnes/station-yr	93.4 mole%	43.3
Gas transmission pipelines venting/blowdowns [d,e]	40,950 scfy/mile	0.7855 tonnes/mile-yr	93.4 mole %	73.3
		0.4881 tonnes/km-yr		
Gas storage station venting [h]	$4,359 \times 10^3$ scfy/station	83.61 tonnes/station-yr	93.4 mole %	334

Footnotes and Sources:

[a] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia. The CH_4 emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 to estimate CO_2 emissions.

[b] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[c] Developed from data used for the June 1996 GRI/EPA methane emissions study. Emission factors are based on averaging data by site. The average CH_4 concentration associated with these emission factors is provided in Table E-4.

[d] See derivation in Appendix B.

[e] Radian International. *1995 Air Emissions Inventory of the Canadian Natural Gas Industry*, *Final Report*, Canadian Gas Association Standing Committee on Environment, September 1997.

[f] Based on engineering judgement.

[g] URS Corporation. *Updated Canadian National Greenhouse Gas Inventory for 1995, Emission Factor Documentation. Technical Memorandum*, Final, October 2001.

[h] 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 U.S. Environmental Protection Agency, June 1996. The average CH_4 concentration associated with these emission factors is provided in Table E-4.

An example calculation shown in Exhibit 5.34 illustrates the use of the transmission segment non-routine emissions.

Note that Table 5-27 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 storage tanks in liquid pipeline operations, while the term “surge tanks” is generally associated with processing or pipeline pressure relief applications.

In oil field operations, these tanks are generally open to the atmosphere and could result in flashing losses (working and breathing losses are significantly smaller that flashing losses). Emissions from these tanks would be estimated using the approaches presented in Section 5.4.1 (flashing losses). If the tank type is unknown, a simplifying assumption is to estimate flashing losses for a fixed roof tank.

In pipeline operations, these pipeline tanks typically would not experience flashing losses and would likely have a floating roof to control emissions. Emissions from these tanks would be estimated using the approaches presented in Section 5.4.2 (working/standing losses).

EXHIBIT 5.34: Sample Calculation for Transmission Non-Routine Related Emissions

INPUT DATA:
A gas transmission system has 50 miles of gas transmission lines and two compressor stations. The natural gas in the transmission system has a typical CH_4 content and no CO_2. Calculate the non-routine emissions, by activity.

CALCULATION METHODOLOGY:
The compressor station count and transmission pipeline miles are each multiplied by the appropriate emission factor from Table 5-26. The CH_4 emission factors are not corrected by the site CH_4 content because the composition is assumed to be consistent with the default emission factor CH_4 content. As noted above, the gas for this exhibit does not contain CO_2.

Compressor station blowdowns:

$$E_{CH_4} = 2 \text{ stations} \times \frac{101.7 \text{ tonne } CH_4}{\text{station-yr}}$$

$$\underline{E_{CH_4} = 203.4 \text{ tonnes } CH_4/\text{yr}}$$

Transmission gas pipeline blowdowns:

$$E_{CH_4} = 50 \text{ miles} \times \frac{0.7855 \text{ tonne } CH_4}{\text{mile-yr}}$$

$$\underline{E_{CH_4} = 39.3 \text{ tonnes } CH_4/\text{yr}}$$

5.7.5 Distribution Related Non-Routine Emissions

Distribution related non-routine emissions are associated with natural gas systems, since the distribution of petroleum liquids is primarily associated with refined liquids that do not contain CH_4. Distribution segment CH_4 emission factors from non-routine activities are presented in Table 5-27. Note that the factors shown in Table 5-27 are provided on an equipment/facility count basis, not a per-event basis. The 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, 2001) while the other emission factors are taken from the GRI/EPA Study Volume 2 (Harrison, et al., 1996).

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 5-27. Gas Distribution Segment CH_4 Emission Factors for Non-Routine Activities

Source	CH_4 Emission Factor, Original Units	CH_4 Emission Factor [a], Converted to Tonnes Basis	CH_4 Content Basis of Factor	Uncertainty [b] (±%)
M&R Station maintenance/upsets [c]	4.27 m^3/station-yr	0.002895 tonnes/station-yr	94.8 mole %	Not available
Odorizer and gas sampling vents [c]	33.59 m^3/station-yr	0.02275 tonnes/station-yr	94.8 mole %	Not available
Pipeline blowdowns (based on mains and services length) [d,e]	1,679 scfy/mile	0.03220 tonnes/mile-yr 0.02001 tonnes/km-yr	93.4 mole %	117
Pipeline mishaps (dig-ins) (based on mains and services length) [f]	1,585 scfy/mile	0.03040 tonnes/mile-yr 0.01889 tonnes/km-yr	93.4 mole %	2,600
Pressure relief valves (based on pipeline mains length) [f]	50 scfy/mile	9.591E-04 tonnes/mile-yr 5.959E-04 tonnes/km-yr	93.4 mole %	19,300

Footnotes and Sources:

[a] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia.

[b] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

c URS Corporation. *Updated Canadian National Greenhouse Gas Inventory for 1995, Emission Factor Documentation*, *Technical Memorandum*, Final, October 2001.

[d] See derivation in Appendix B.

[e] Radian International. *1995 Air Emissions Inventory of the Canadian Natural Gas Industry*, Final Report, Canadian Gas Association Standing Committee on Environment, September 1997.

[f] Harrison et.al., *Methane Emissions from the Natural Gas Industry Volume 2*, June 1996.

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 5-27 can be adjusted based on the CH_4 content of the site-specific gas, if the natural gas has a significantly different CH_4 content from the default basis. Also, if the facility gas contains significant quantities of CO_2, the CH_4 emission factor can be adjusted based on the relative concentrations of CH_4 and CO_2 in the gas to estimate the CO_2 emissions.

An example calculation shown in Exhibit 5.35 illustrates the use of the distribution segment non-routine emissions.

EXHIBIT 5.35: Sample Calculation for Distribution Non-Routine Related Emissions

INPUT DATA:
A gas distribution system has 20 miles of gas distribution main lines and three M&R stations. The natural gas in the distribution system has a typical CH_4 content and a no CO_2. Calculate the non-routine emissions, by activity type.

CALCULATION METHODOLOGY:
The M&R station count and pipeline miles are each multiplied by the appropriate emission factor from Table 5-27. The CH_4 emission factors are not corrected by the site CH_4 content because the composition is assumed to be consistent with the default emission factor CH_4 content. As noted above, the gas for this exhibit does not contain CO_2. Emissions are calculated below, by activity type.

M&R station blowdowns:

$$E_{CH_4} = 3 \text{ stations} \times \frac{0.002895 \text{ tonne CH}_4}{\text{station-yr}}$$

$$\underline{E_{CH_4} = 0.0087 \text{ tonnes CH}_4/\text{yr}}$$

Odorizer and gas sampling vents:

$$E_{CH_4} = 3 \text{ stations} \times \frac{0.02275 \text{ tonne CH}_4}{\text{station-yr}}$$

$$\underline{E_{CH_4} = 0.068 \text{ tonnes CH}_4/\text{yr}}$$

EXHIBIT 5.35: Sample Calculation for Distribution Non-Routine Related Emissions, continued

Distribution gas pipeline blowdowns:

$$E_{CH_4} = 20 \text{ miles} \times \frac{0.03220 \text{ tonne } CH_4}{\text{mile-yr}}$$

$$\underline{E_{CH_4} = 0.64 \text{ tonnes } CH_4/\text{yr}}$$

Distribution gas pipeline mishaps (dig-ins):

$$E_{CH_4} = 20 \text{ miles} \times \frac{0.03040 \text{ tonne } CH_4}{\text{mile-yr}}$$

$$\underline{E_{CH_4} = 0.61 \text{ tonnes } CH_4/\text{yr}}$$

Distribution pressure relief valves:

$$E_{CH_4} = 20 \text{ miles} \times \frac{9.591 \times 10^{-4} \text{ tonne } CH_4}{\text{mile-yr}}$$

$$\underline{E_{CH_4} = 0.02 \text{ tonnes } CH_4/\text{yr}}$$

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. However, if refinery fuel gas is used to start compressor turbines, the emission factors presented for the production segment can be used to estimate CH_4 emissions, adjusting for the CH_4 composition in the fuel gas. Similarly, production segment emission factors can be used if refinery equipment blowdowns are vented directly to the atmosphere.

5.8 Fire Suppressant Emissions

The use of fire suppression equipment may result in high GWP emissions as a result of using substitutes for ODSs. The GHGs of concern from such fire suppression equipment are typically HFCs or PFCs. The global warming potentials for such HFCs and PFCs are typically several thousand times larger than for CO_2. Carbon dioxide may also be used as a fire suppressant.

To estimate fire extinguisher emissions, a material balance approach, such as provided by Equation 5-29 (EPA, 2006), should be used. The material balance should consider the amount of fire suppressant released in each event, the number of events annually, and the composition of the particular GHG in the fire suppressant. Emissions from fuel burned during fires should be calculated using the methodology described in Section 4.

$$E_j = r \times \sum_{i=1}^{k} Q_{C_{j+1}} \qquad \text{(Equation 5-29)}$$

where
E_j = total emissions of chemical released in year j, by weight;
r = percentage of total chemical in operation released to the atmosphere;
Q_C = quantity of chemical used in new fire extinguishing equipment one lifetime (k) ago (e.g., j – k +1), by weight;
i = counter, from 1 to lifetime (k);
j = year of emissions; and
k = average lifetime of the equipment.

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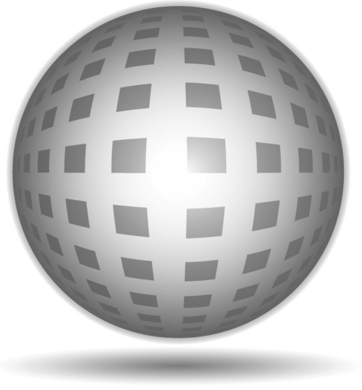
AMERICAN PETROLEUM INSTITUTE

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

AUGUST 2009

SECTION 6

FUGITIVE EMISSIONS ESTIMATION METHODS



Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry

Section 6 – Fugitive Emissions Estimation Methods

August 2009

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6.0
FUGITIVE EMISSION ESTIMATION METHODS

Fugitive emissions refer to unintentional emissions from equipment leaks. Any pressurized equipment has the potential to leak; these leaks generally occur through valves, flanges, seals, or related equipment associated with "live" crude or gas system components. Leaks from equipment used in association with "weathered" crude or other refined oil and natural gas products will not emit CH_4 or CO_2, because "weathered" crude and refined oil and natural gas products do not contain CH_4 or CO_2.[1]

Fugitive emissions also come from non-point evaporative sources, such as from wastewater treatment, pits, impoundments, and mine tailing pond surface emissions. This section presents methods for estimating CH_4 and potentially CO_2 emissions from these fugitive sources. Table 6-1 illustrates the range of available options for estimating fugitive GHG emissions and associated considerations.

Table 6-1. Emission Estimation Approaches – GHG and Source-Specific Considerations for Fugitive Sources

Types of Approaches	CH_4 Non-combustion Emissions	CO_2 Emissions	PFC, HFC, SF_6 Emissions
Published emission factors	• Based on "average" equipment and emission source characteristics	• Limited emission factors specific to non-combustion CO_2 emissions • May be scaled from CH_4 emission factors	• Simplified estimations are based on average equipment and emission source characteristics are consistent with low contribution to overall emissions
Engineering calculations	• Highly reliable for specific emission sources • May require detailed input data	• Highly reliable for many emission sources • May require detailed input data	• Material balance methods provide good reliability • Requires data tracking

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[1] For more information, see Appendix E.

Table 6-1. Emission Estimation Approaches – GHG and Source Specific Considerations for Fugitive Sources, continued

Types of Approaches	CH_4 Non-combustion Emissions	CO_2 Emissions	PFC, HFC, SF_6 Emissions
Monitoring over a range of conditions and deriving emission factors	• Highly reliable for specific emission sources • Generally not practical given the substantial number of emission sources	• Generally not practical given the low contribution to overall emissions	• Generally not practical given the low contribution to overall emissions
Periodic or continuous monitoring of emissions or parameters for calculating emissions	• Highly reliable for specific emission sources • Generally not practical given the substantial number of emission sources	• Not practical given the number of emission sources and the low contribution to overall emissions	• Not practical given the number of emission sources and the low contribution to overall emissions

6.1 Equipment Leaks

A variety of fugitive emission sources are related to oil and natural 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_4. In comparison, data on fugitive equipment leaks of CO_2 are not generally presented because CO_2 emissions are more commonly associated with combustion sources. It may be possible to adapt the estimation methods presented for CH_4 to the few oil and natural gas operations for which CO_2 equipment leaks might be of significance, such as with equipment from a CO_2-enhanced oil production field. This is addressed further as related to specific emission sources.

A number of emission factors and correlation equations have been developed for estimating fugitive equipment leak emissions for VOC and TOC, for example, EPA Method 21. Many of these approaches require monitoring data and calculations at the component level. The simpler approaches recommended for most GHG fugitive equipment leak emissions are listed below, in order of increasing data requirements and increasing accuracy:

1. Facility-level average emission factors;

2. Equipment-level average emission factors;
3. Component-level average emission factors; and
4. Component-level measurement approaches.

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 overall contribution of the fugitive emissions to the entity's inventory or the availability of information from a component count program [e.g., leak detection and repair (LDAR)]. However, **methodologies required by regulations take precedence over the options provided in the decision trees.**

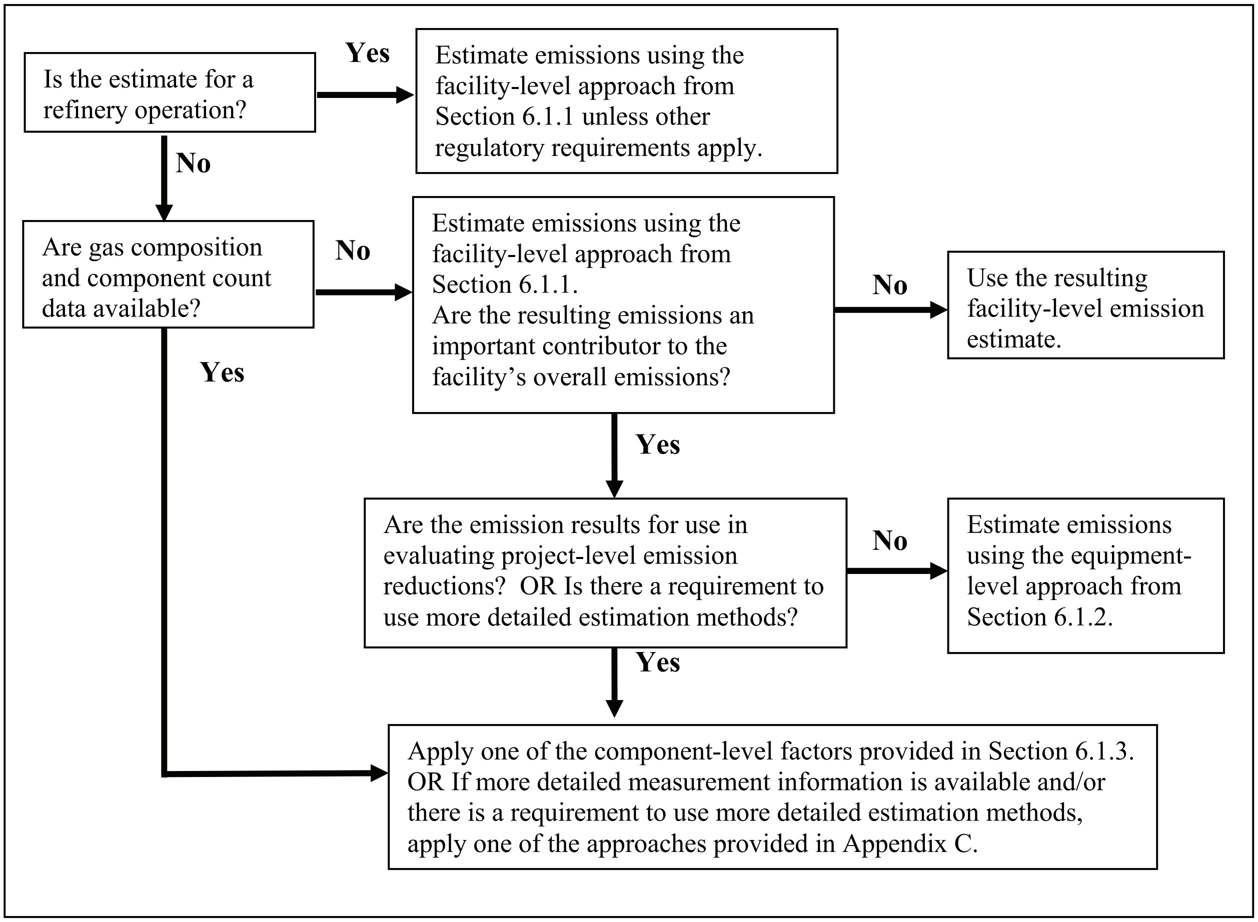

Figure 6-1. Emission Estimation Approaches for Fugitive Equipment Leaks

The contribution of fugitive emissions to an overall facility's GHG inventory varies with the type of facility. For example, fugitive CH_4 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_4 (refer to Appendix E for more information). Using a less detailed estimation method for refinery fugitive emissions would generally be acceptable because the contribution of fugitive emissions would have very little influence on the overall refinery inventory accuracy.

API conducted a study to quantitatively assess the contribution of fugitive CH_4 emissions from equipment leaks to overall refinery GHG emissions. Emissions were estimated based on component counts in natural gas and refinery fuel gas service, using average emission factors for components in gas service provided by EPA (EPA, 1995). Fugitive CH_4 emissions were calculated for two refineries:

- A smaller fuels refinery with a rated capacity between 50,000 and 90,000 bbl feed/day; and
- A larger refinery/petrochemical complex with a rated capacity between 100,000 and 199,000 bbl feed/day.

Results indicated that CH_4 emissions from equipment leaks represent 0.11% of total GHG emissions for the smaller refinery and 0.19% of total emissions for the large refinery. Since other large GHG emitting sources have uncertainties within the range of 1% to 5% of the overall GHG inventory, a CH_4 fugitive emission contribution of 0.1% appears to be negligible. A summary report on the study is provided in Appendix F.

The selection of a fugitive equipment leak estimation approach must also consider the data available to support the estimate. Most fugitive estimation methods require a site-specific gas composition to convert from a TOC, VOC, or default CH_4 concentration basis. 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 require a 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 (presented in Appendix C) 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. A balance needs to be made as to whether the gains in accuracy justify the cost of additional data gathering.

Methodologies need to be consistent with the contribution of particular sources to the overall inventory.

6.1.1 Facility-Level Average Emission Factors Approach

Methane is the primary GHG in fugitive leak emissions. Applying average facility-level emission factors is the simplest method for estimating CH_4 emissions from oil and natural gas operations. 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 in million standard cubic feet per day (scfd). These facility-level factors were developed by aggregating component emission measurements and activity factors for a "typical" facility, primarily for upstream gas industry facilities. Facility-level emission factors are presented in Table 6-2.

Table 6-2 provides separate fugitive emission factors for oil and natural gas production operations. However, oil and natural gas can be produced from the same well. For facilities that produce any natural gas or are equipped similarly to the gas well schematic shown in Figure 6-2, the gas production emission factors should be used. For facilities that do not market the associated gas, or produce only crude or are equipped similar to the oil well schematic shown in Figure 6-2, the oil production emission factors should be used.

For refineries, 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. If the facility is atypical of the industry average or greater accuracy is needed to support emission reduction estimates, one of the more rigorous approaches should be used. In addition, methodologies required by regulations take precedence over the options outlined in Figure 6-1.

Fugitive equipment leaks at refineries or marketing terminals may occur from equipment handling natural gas or fuel gas. However, leaks from equipment used in association with "weathered" crude or other refined oil and natural gas products will not emit CH_4 or CO_2, because "weathered" crude and refined oil and natural gas products do not contain CH_4 or CO_2.[2]

In the absence of site-specific data for refineries, the emission factors provided in Table 6-2 may be used to estimate CH_4 fugitive emissions from fuel gas and natural gas systems. These emission factors were derived from data presented in the refinery CH_4 fugitive emissions study provided in Appendix F. The study was conducted at two refineries: one with a capacity of 50,000 to 99,000

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[2] For more information, see Appendix E.

bbl feed/day and the other one with a capacity of 100,000 to 199,000 bbl feed/day. The simple, refinery facility-level fugitive emission factors for the fuel gas and natural gas systems were estimated by dividing the CH_4 emission rates from the study by the refinery feed rate capacities. The mid-point of the range of the capacities was used when deriving the emission factors. Since these emission factors were derived from very limited data, they should be used with caution because the fugitive emissions are likely to be highly variable depending on the refinery. However, as noted earlier in Section 6.1, refinery CH_4 fugitive emissions represent a very small fraction of the total GHG emissions based on the data provided in Appendix F.

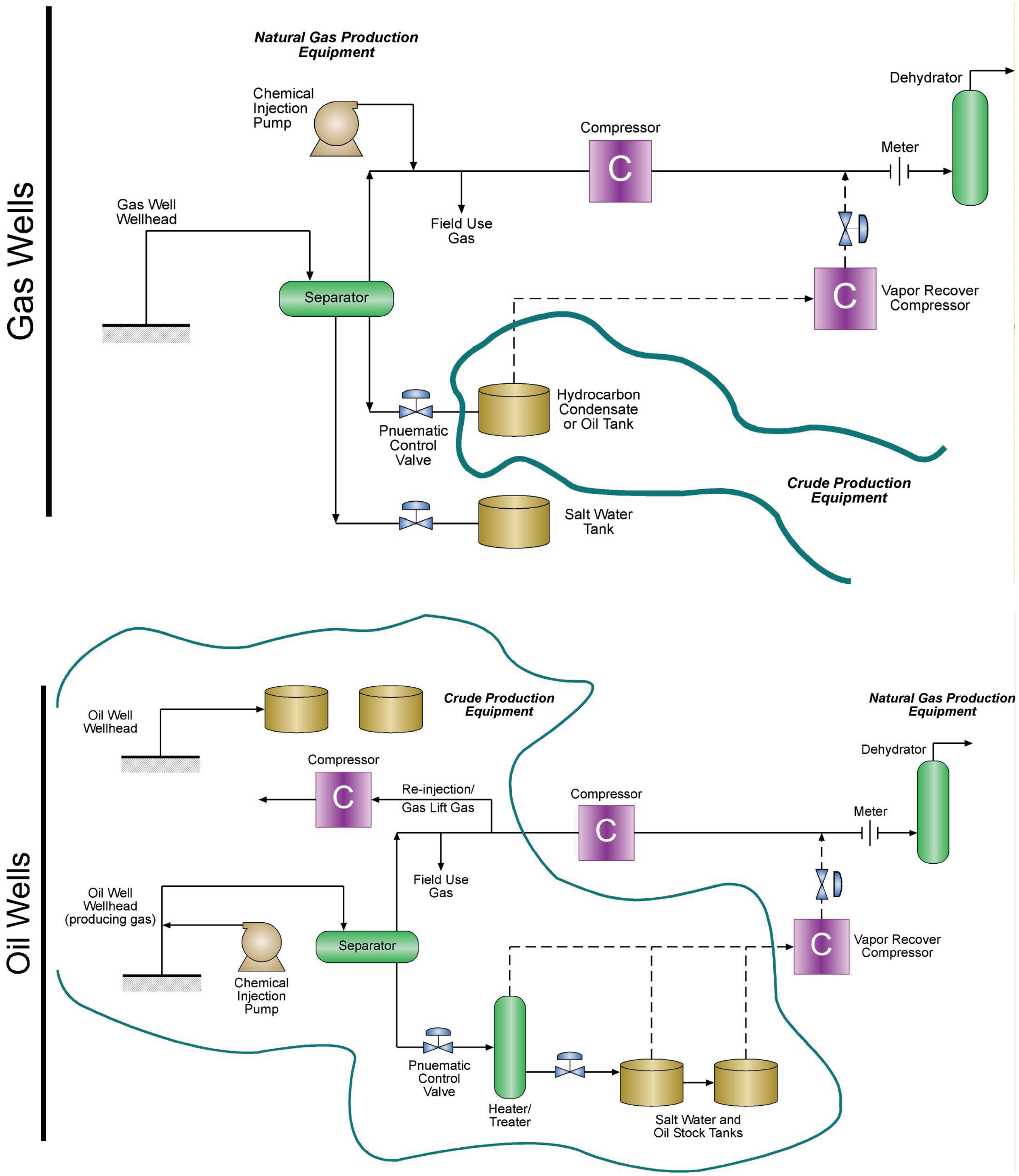

Figure 6-2. Boundaries Between Crude and Natural Gas Production Equipment

Table 6-2. Facility-Level Average Fugitive Emission Factors

Source	Emission Factor Original Units	Uncertainty [a] (± %)	Gas Content Basis of Factor	Emission Factor [b] Converted Units	Factor Reference
Production					
Onshore oil production	0.5173 lb CH_4/bbl produced	95.5	78.8 mole % CH_4	2.346E-04 tonnes CH_4/bbl produced 1.476E-03 tonnes CH_4/m^3 produced	EPA petroleum methane emissions study; see derivation in Appendix C
Offshore oil production	0.2069 lb CH_4/bbl produced	Not available	78.8 mole % CH_4	9.386E-05 tonnes CH_4/bbl produced 5.903E-04 tonnes CH_4/m^3 produced	Assumed to be 40% of the onshore oil production emission factor
Onshore gas production	57.33 lb $CH_4/10^6$scf produced	52.9	78.8 mole % CH_4	2.601E-02 tonnes $CH_4/10^6$ scf produced 9.184E-01 tonnes $CH_4/10^6\ m^3$ produced	GRI/EPA Study, Vol. 2; see derivation in Appendix C
Offshore gas production	22.93 lb $CH_4/10^6$scf produced	Not available	78.8 mole % CH_4	1.040E-02 tonnes $CH_4/10^6$ scf produced 3.673E-01 tonnes $CH_4/10^6\ m^3$ produced	Assumed to be 40% of the onshore gas production emission factor
Gas processing plants	64.43 lb $CH_4/10^6$scf processed	82.2	86.8 mole % CH_4	2.922E-02 tonnes $CH_4/10^6$ scf processed 1.032E+00 tonnes $CH_4/10^6\ m^3$ processed	GRI/EPA Study, Vol. 2; see derivation in Appendix C
Gas storage stations	1,491,936 lb CH_4/station-yr	74.7	93.4 mole % CH_4	6.767E+02 tonnes CH_4/ station-yr	GRI/EPA Study, Vol. 2; see derivation in Appendix C
Gas transmission pipelines					
CH_4 from pipeline leaks	7,928 lb CH4/mile-yr	113	93.4 mole % CH_4	3.596E+00 tonnes CH_4/mile-yr 2.235E+00 tonnes CH_4/km-yr	GRI/EPA Study, Vols. 2 and 9; see derivation in Appendix C
CO_2 from oxidation [c]	7.59 lb CO_2/mile-yr	70.3	2 mole % CO_2	3.443E-03 tonnes CO_2/mile-yr 2.140E-03 tonnes CO_2/km-yr	GRI/EPA Study, Vols. 2 and 9; see derivation in Appendix C
CO_2 from pipeline leaks [d]	466.0 lb CO_2/mile-yr	113	2 mole % CO_2	2.114E-01 tonnes CO_2/mile-yr 1.313E-01 tonnes CO_2/km-yr	GRI/EPA Study, Vols. 2 and 9; see derivation in Appendix C
Crude transmission pipelines [e]	Not applicable				

Table 6-2. Facility-Level Average Fugitive Emission Factors, continued

Source	Emission Factor, Original Units	Uncertainty [a] (± %)	Gas Content Basis of Factor	Emission Factor [b], Converted Units	Factor Reference
Gas distribution pipelines					
CH_4 from pipeline leaks	3,557 lb CH_4/mile-yr	62.7	93.4 mole % CH_4	1.613E+00 tonnes CH_4/mile-yr 1.002E+00 tonnes CH_4/km-yr	GRI/EPA Study, Vols. 2 and 9; see derivation in Appendix C
CO_2 from oxidation [c]	1,236 lb CO_2/mile-yr	76.6	2 mole % CO_2	5.606E-01 tonnes CO_2/mile-yr 3.484E-01 tonnes CO_2/km-yr	GRI/EPA Study, Vols. 2 and 9; see derivation in Appendix C
CO_2 [d] from pipeline leaks	235.4 lb CO_2/mile-yr	74.4	2 mole % CO_2	1.068E-01 tonnes CO_2/mile-yr 6.636E-02 tonnes CO_2/km-yr	GRI/EPA Study, Vols. 2 and 9; see derivation in Appendix C
Refining [f]					Derived from data provided in Appendix F. Mid range capacity was assumed to convert emissions to a throughput basis
Fuel gas system – 50,000 to 99,000 bbl/day refinery	10.2 tonnes CH_4/yr (fuel gas + make gas	Not available	Not available	3.75E-07 tonnes CH_4/bbl feedstock 2.36E-06 tonnes CH_4/m^3 feedstock	
Fuel gas system – 100,000 to 199,000 bbl/day refinery	77 tonnes CH_4/yr	Not available	Not available	1.41E-06 tonnes CH_4/bbl feedstock 8.88E-06 tonnes CH_4/m^3 feedstock	
Natural gas system – 50,000 to 99,000 bbl/day refinery	26 tonnes CH_4/yr	Not available	Not available	9.56E-07 tonnes CH_4/bbl feedstock 6.01E-06 tonnes CH_4/m^3 feedstock	
Natural gas system – 100,000 to 199,000 bbl/day refinery	55 tonnes CH_4/yr	Not available	Not available	1.01E-06 tonnes CH_4/bbl feedstock 6.34E-06 tonnes CH_4/m^3 feedstock	

Footnotes and Sources:

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 U.S. Environmental Protection Agency, June 1996.

Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas* Industry, *Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

Harrison, M.R., T.M. Shires, R.A. Baker, and C.J. Loughran. *Methane Emissions from the U.S. Petroleum Industry*, Final Report, EPA-600/R-99-010. U.S. Environmental Protection Agency, February 1999.

API refinery CH_4 fugitive emissions study provided in Appendix F.

[a] Uncertainty is based on a 95% confidence interval from the data used to develop the original emission factor.

[b] The emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 to estimate CO_2 emissions.

[c] A portion of CH_4 emitted from underground pipeline leaks is oxidized to form CO_2.

[d] Combines CO_2 emissions from equipment and pipleines based on a concentration of 2 mole % CO_2 in the pipeline gas.

Footnotes and Sources for Table 6-2, continued:

[e] As discussed in Section 5, only "live" crude will contain CH_4 (and possibly CO_2). Weathered crude (crude which has reached atmospheric pressure) contains no CH_4 or CO_2. See Appendix E for further discussion on the CH_4 and CO_2 content of "weathered" crude and other oil and natural gas products. If transmission pipelines are used to transport "live" crude oil, CH_4 (and CO_2, if present) emissions should be calculated using engineering judgment.

[f] Refinery fugitive CH_4 emission factors were derived from data from an API refinery CH_4 fugitive emissions study provided in Appendix F . The estimated refinery fugitive CH_4 emission rates from the study for the fuel gas and natural gas systems were divided by the refinery feed capacity for the two refineries in the study, a 50,000 to 99,000 bbl/day "single train (multiply HDS)" refinery and a 100,000 to 199,000 bbl/day "old multi-train refinery." The mid-point of the range of the refinery capacities was assumed when deriving the emission factors (i.e., the estimated CH_4 fugitive emission rates were divided by 74,500 bbl feed/day for the smaller refinery and by 149,500 bbl feed/day for the larger refinery). Refer to Appendix F for the data used to estimate the emission factors.

In addition to CH_4, CO_2 also may be released from fugitive sources if CO_2 is present in the gas stream (e.g., enhanced oil recovery operations and some gas production operations). Fugitive emission factors specific to CO_2 are limited in current, publicly available studies. As an approximation, the CH_4 emission factor can be adjusted to account for the CO_2 composition of the gas for fugitive sources other than underground pipelines. This conversion is shown in the following equation and demonstrated in Exhibit 6.1.

$$CO_2\ EF = CH_4EF \times \left(\frac{MW\ CO_2}{MW\ CH_4}\right) \times \left(\frac{mole\%\ CO_2}{mole\%\ CH_4}\right) \qquad \text{(Equation 6-1)}$$

or

$$CO_2\ \text{Emissions (tonnes/yr)} = CH_4\ \text{Emissions (tonnes/yr)} \times \left(\frac{MW\ CO_2}{MW\ CH_4}\right) \times \left(\frac{mole\%\ CO_2}{mole\%\ CH_4}\right) \qquad \text{(Equation 6-2)}$$

where

EF = emission factor (mass/activity); and
MW = molecular weight (tonne/tonne-mole).

Fugitive emissions from leaks associated with pipeline transport of CO_2 are discussed in Section 6.1.4. Fugitive emissions from natural gas pipelines originate from two sources: (1) gas leaks that result in CH_4 and CO_2 emissions in proportion to the gas composition and (2) the partial oxidation of CH_4 as it migrates through the soil. The degree of oxidation depends on factors such as the depth of cover, soil composition, and leak rate, which is a function of pipeline material. Both types of CO_2 emissions are shown in the tables in this subsection.

Oxidation rates for different soil characteristics and fugitive leak rates for different pipeline materials (cast iron, protected steel, unprotected steel, copper, and plastic) were measured as part of the GRI/EPA U.S. methane emissions study (Campbell, et al., 1996). Equations 6-3 through 6-5 were used in developing the CO_2 emission factors for pipeline fugitive emissions. Equation 6-3 accounts for the portion of leaked CH_4 that is not oxidized to CO_2.

$$EF_{CH_4} = \left(\text{Total } CH_4 \text{ leaked}\right) \times \left(100 - \%\ \text{Soil Oxidation}\right) \qquad \text{(Equation 6-3)}$$

where

EF_{CH_4} = emission factor for CH_4 emissions from pipeline fugitive leaks.

Equation 6-4 accounts for the CO_2 formed from the oxidation of leaked CH_4 as the gas migrates through the soil.

$$EF_{CO_2,\,Oxid.} = EF_{CH_4} \times \left(\frac{100}{100\text{-\% Soil Oxidation}}\right) \times \left(\frac{\text{\% Soil Oxidation}}{100}\right) \times \left(\frac{\text{MW CO}_2}{\text{MW CH}_4}\right) \qquad \text{(Equation 6-4)}$$

where

$EF_{CO_2,\,Oxid}$ = emission factor for CO_2 emissions from methane oxidation of leaked CH_4;

$\left(\frac{100}{100\text{-\% Soil Oxidation}}\right)$ = CH_4 emission factor correction to its "pre-oxidized" form;

$\left(\frac{\text{\% Soil Oxidation}}{100}\right)$ = conversion from total moles of CH_4 to moles of CO_2 formed as a result of oxidation; and

$\left(\frac{\text{MW CO}_2}{\text{MW CH}_4}\right)$ = conversion from molar basis to mass basis.

Equation 6-5 accounts for CO_2 that is emitted from pipeline fugitive leaks. This equation starts with the CH_4 emission factor, which is converted to its "pre-oxidized" form by the second term. The third term corrects for the molar ratio of CO_2 to CH_4 in the default gas composition, and the final term corrects for the molecular weights of CO_2 and CH_4.

$$EF_{CO_2,\,Leak} = EF_{CH_4} \times \left(\frac{100}{100\text{-\% Soil Oxidation}}\right) \times \left(\frac{\text{default mole\% CO}_2}{\text{default mole\% CH}_4}\right) \times \left(\frac{\text{MW CO}_2}{\text{MW CH}_4}\right) \qquad \text{(Equation 6-5)}$$

where

$EF_{CO_2,\,Leak}$ = emission factor for CO_2 emissions from pipeline fugitive leaks; and

$\left(\frac{\text{default mol\% CO}_2}{\text{default mol\% CH}_4}\right)$ = conversion from total moles of CH_4 to moles of CO_2, based on default molar concentrations for the gas.

The emission factors shown in Tables 6-2, 6-4, 6-6, 6-7, and 6-9 through 6-11 are based on average emission rates for the types of pipelines in service in each industry sector. The fugitive emission factors are based on default, average compositions. The default CH_4 or CO_2 content provided in Table E-4 can be replaced with a user-specified gas analysis. In this case, the fugitive emission estimates are adjusted by the ratio of the specified gas CH_4 or CO_2 concentration to the default CH_4 or CO_2 concentration provided in Table E-4. This correction is demonstrated in Exhibit 6.1.

Exhibit 6.1 demonstrates the use of 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^3 per day of crude. The CH_4 content of the associated gas is 68 mole %, and the CO_2 content is 4 mole%. Assume that the facility operates continuously throughout the year. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:
Methane emissions are calculated using the emission factor for onshore oil production from Table 6-2, and correcting for the actual CH_4 composition of the gas. CO_2 emissions are calculated by the ratio of CH_4 to CO_2 in the produced gas.

$$E_{CH_4} = \frac{795\ m^3}{day} \times \frac{365\ days}{year} \times \frac{1.476\times10^{-3}\ tonne\ CH_4}{m^3} \times \frac{0.68\ tonne\ mol\ CH_4\ actual}{0.788\ tonne\ mol\ CH_4\ default}$$

$$\underline{E_{CH_4} = 370\ tonnes\ CH_4/yr}$$

$$E_{CO_2} = \frac{370\ tonne\ CH_4}{yr} \times \frac{tonne\ mol\ CH_4}{16\ tonne\ CH_4} \times \frac{tonne\ mol\ gas}{0.68\ tonne\ mol\ CH_4} \times \frac{0.04\ tonne\ mol\ CO_2}{tonne\ mol\ gas} \times \frac{44\ tonne\ CO_2}{tonne\ mol\ CO_2}$$

$$\underline{E_{CO_2} = 59.8\ tonnes\ CO_2/yr}$$

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 6-3 through 6-8 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_4-specific. The default CH_4 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:

$$E_{CH_4\ (or\ CO_2)} = F_{A\ (CH_4\ or\ CO_2)} \times N \qquad \text{(Equation 6-6)}$$

where

$E_{CH_4\ (or\ CO_2)}$ = emission rate of CH_4 (or CO_2) from a population of equipment;
$F_{A\ (CH_4\ or\ CO_2)}$ = applicable average CH_4 or CO_2 emission factor for the major equipment type A; and
N = number of pieces of equipment in the plant/process.

Tables 6-3 and 6-4 provide fugitive emission factors for equipment associated with oil and natural gas exploration and production operations. For facilities where oil and natural gas are produced from the same well, Figure 6-2 illustrates the boundaries between crude production equipment and natural gas production equipment. The emission factors were developed for separate assessments of natural gas sector equipment versus oil and natural gas industry equipment (Harrison, 1999 and Shires, 2002). Emission factors from Table 6-3 should be applied to counts of equipment associated with crude production and configured similar to the oil well schematic shown in Figure 6-2. Likewise,

Table 6-4 emission factors should be applied to natural gas production equipment configured similar to the gas well schematic shown in Figure 6-2. Equipment with minimal to no gas handling should use the emission factors for crude production equipment.

For both Tables 6-3 and 6-4, the CH_4 emission factors are based on an average CH_4 composition of 78.8 mole % as provided in Table E-4. The emission factors can be adjusted to other CH_4 concentrations by the ratio of the actual CH_4 content to the default value. In addition, in the absence of CO_2-specific emission factors, CO_2 emissions can be approximated from the CH_4 emission factors based on the ratio of CO_2 to CH_4 in the produced gas. (These adjustments are demonstrated in Exhibit 6.1.)

Table 6-3. Fugitive Emission Factors for Onshore Crude Production Equipment

Equipment Basis	Reference CH_4 Emission Factor [a], Original Units		Uncertainty [b] (± %)	CH_4 Emission Factor [c], 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
Oil pump stations [d]	1.06	lb CH_4/mile-yr		5.49E-08 3.41E-08	tonne CH_4/mile-hr tonne CH_4/km-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	4.72E-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 [e] – 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

Footnotes and Sources:

[a] Harrison, M.R., T.M. Shires, R.A. Baker, and C.J. Loughran. *Methane Emissions from the U.S. Petroleum Industry*, Final Report, EPA 600/R-99-010, U.S. Environmental Protection Agency, 1999.

b Uncertainty was assumed based on engineering judgement (Harrison, et al., 1999).

[c] Emission factors converted from scf are based on 60 °F and 14.7 psia. The average CH_4 concentration associated with these emission factors provided in Table E-4 is 78.8 mole %. If the actual CH_4 content differs from the default value, the emission factors shown above can be adjusted by the ratio of the site CH_4 content to the default concentration.

[d] PSI, 1989.

[e] Large compressors are those with more than three stages of compression.

The emission factors shown in Table 6-3 for crude production equipment are derived from API Report 4615 *Emission Factors for Oil and Gas Production Operations* (API, 1995) and average component counts per equipment (Harrison et al., 1999). Separate emission factors are provided for heavy versus light crude, since heavier crude has less entrained CH_4 and therefore lower emissions. API Report 4638, *Calculation Workbook For Oil and Gas Production Equipment Fugitive Emissions*, designates heavy crude as having an API gravity of less than 20° and light crude as having an API gravity of greater than 20° (API, 1996). Please note that the EPA defines light and heavy crude according to vapor pressure.[3] EPA component-level emission factors are provided in Section 6.1.3.

Emission factors provided in Table 6-4 are derived from the GRI/EPA U.S. methane emissions study (Harrison, et al., 1996). Emission factors for both CH_4 and CO_2 are provided for gathering pipelines. Carbon dioxide emissions from buried pipeline leaks are discussed further at the end of

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[3] EPA defines gas/vapor service as material in a gaseous state at operating conditions; light crude as material in a liquid state in which the sum of the concentration of individual constituents with a vapor pressure over 0.3 kilopascals (kPa) at 20 °C is greater than or equal to 20 weight percent; and heavy crude as not in gas/vapor service or light liquid service (EPA, *Protocol for Equipment Leak Emission Estimates*, 1995).

Section 6.1.2. The derivation of all the emission factors presented in Table 6-4 can be found in Appendix C.

Table 6–4. Fugitive Emission Factors for Onshore Natural Gas Production Equipment

Equipment Basis	Reference Emission Factor [a,b], Original Units		Uncertainty [c] (± %)	Emission Factor [d], Converted Units	
Gas wellheads [e]	8,217	scfy CH_4/well	25.7	1.80E-05	tonne CH_4/well-hr
Separators [e]	20,174	scfy CH_4/separator	87.9	4.42E-05	tonne CH_4/separator-hr
Gas heaters [e]	20,985	scfy CH_4/heater	173	4.60E-05	tonne CH_4/heater-hr
Small reciprocating gas compressor [e]	97,023	scfy CH_4/compressor	127	2.12E-04	tonne CH_4/compressor-hr
Large reciprocating gas compressor [e,f]	5.55E+06	scfy CH_4/compressor	202	1.22E-02	tonne CH_4/compressor-hr
Large reciprocating gas compressor stations [f, g]	8,247	scfy CH_4/station	126	6.59E-03	tonne CH_4/station-hr
Meters/piping [e]	16,073	scfy CH_4/meter	159	3.52E-05	tonne CH_4/meter-hr
Dehydrators [e]	32,561	scfy CH_4/dehydrator	45.1	7.13E-05	tonne CH_4/dehydrator-hr
Gathering pipelines [e,h]	826	lb CH_4/mile-yr	113	4.28E-05 2.66E-05	tonne CH_4/mile-hr tonne CH_4/km-hr
CO_2 from oxidation [e,i]	84.7	lb CO_2/mile-yr	70.2	4.38E-06 2.72E-06	tonne CO_2/mile-hr tonne CO_2/km-hr
CO_2 from pipeline leaks [e]	112.8	lb CO_2/mile-yr	114	5.84E-06 3.63E-06	tonne CO_2/mile-hr tonne CO_2/km-hr

Footnotes and Sources:

[a] 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 U.S. Environmental Protection Agency, June 1996.

[b] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Uncertainty is based on a 95% confidence interval from the data used to develop the original emission factor.

[d] Emission factors converted from scfy are based on 60 °F and 14.7 psia. The average CH_4 concentration associated with these emission factors provided in Table E-4 is 78.8 mole %; the average CO_2 concentration (for buried pipelines) also provided in Table E-4 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.

[e] Emission factor derivation provided in Appendix C.

[f] Large compressors are those with more than 3 stage of compression. Large compressor stations are those with five or more compressors.

[g] Because the data used to calculate the reference emission factor was unavailable, the Uncertainty at a 95% confidence interval was calculated based on the Uncertainty at a 90% confidence interval presented in the source assuming a data set size of ten.

[h] More detailed gathering pipeline fugitive emission factors are presented in Appendix C.

[i] A portion of CH_4 emitted from underground pipeline leaks is oxidized to form CO_2.

Gas processing fugitive emission factors are presented in Table 6-5. These emission factors are taken or derived from the GRI/EPA U.S. methane emissions study (Harrison, et al., 1996). The default CH_4 concentration associated with these emission factors provided in Table E-4 is 86.8 mole %. The emission factors can be adjusted for other CH_4 concentrations by the ratio of the actual CH_4 content to the default value. The emission factors can also be used to estimate CO_2 emissions based on the ratio of CO_2 to CH_4 in the produced gas. (These adjustments are demonstrated in Exhibit 6.1.)

Table 6–5. Fugitive CH_4 Emission Factors for Natural Gas Processing Equipment

Equipment Basis	**Reference CH_4 Emission Factor [a,b], Original Units**		**Uncertainty [c] (± %)**	**CH_4 Emission Factor [d], Converted Units**	
Gas processing volume [e]	130.563	scf/MMscf processed	58.1	2.50E-03	tonne/MMscf processed
				8.84E-02	tonne/10^6 m^3 processed
Reciprocating compressors	11,198	scfd/compressor	95.2	8.95E-03	tonne/compressor-hr
Centrifugal compressors	21,230	scfd/compressor	51.8	1.70E-02	tonne/compressor-hr

Footnotes and Sources:

[a] 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 U.S. Environmental Protection Agency, June 1996.

[b] Hummel, K.E., L.M. Campbell, and M.R. Harrison. *Methane Emissions from the Natural Gas Industry*, *Volume 8: Equipment Leaks,* Final Report, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Uncertainty is based on a 95% confidence interval from the data used to develop the original emission factor.

[d] Emission factors converted from scfy are based on 60 °F and 14.7 psia. The average CH_4 concentration associated with these emission factors provided in Table E-4 is 86.8 mole %. If the actual CH_4 content differs from the default value, the emission factors shown above can be adjusted by the ratio of the site CH_4 content to the default concentration.

[e] See derivation in Appendix C.

Table 6-6 provides fugitive emission factors for equipment associated with natural gas transmission and storage operations and Table 6-7 provides fugitive emission factors for gas distribution equipment. Table 6-8 provides fugitive emission factors for distribution M&R stations. Carbon dioxide emissions from buried pipeline leaks are discussed further at the end of Section 6.1.2. The default CH_4 concentration for these emission factor tables provided in Table E-4 is 93.4 mole %. The emission factors can be adjusted for other CH_4 concentrations by the ratio of the actual CH_4 content to the default value. The emission factors can also be used to estimate CO_2 emissions based on the ratio of CO_2 to CH_4 in the produced gas. (These adjustments are demonstrated in Exhibit 6.1.)

Table 6–6. Fugitive Emission Factors for Natural Gas Transmission and Storage Equipment

Equipment Basis	**Reference Emission Factor [a,b], Original Units**		**Uncertainty [c] (± %)**	**Emission Factor [d], Converted Units**	
Compressor stations	8,778	scfd CH_4/station	126	7.02E-03	tonne CH_4/station-hr
Compressor stations – reciprocating compressor	15,205	scfd CH_4/comp.	84.2	1.22E-02	tonne CH_4/compressor-hr
Compressor stations – centrifugal compressor	30,305	scfd CH_4/comp.	45.7	2.42E-02	tonne CH_4/compressor-hr
Meter/Reg. stations [e]	60,011	scf CH_4/station-yr	1,500 [f]	1.31E-04	tonne CH_4/station-hr
M&R stations – farm taps or direct sales	31.2	scfd CH_4/station	97.6	2.49E-05	tonne/station-hr
M&R stations – transmission interconnects	3,984	scfd CH_4/station	96.1	3.18E-03	tonne/station-hr

Table 6–6. Fugitive Emission Factors for Natural Gas Transmission and Storage Equipment, continued

Equipment Basis	Reference Emission Factor [a,b], Original Units		Uncertainty [c] (± %)	Emission Factor [d], Converted Units	
Gas transmission pipeline [e]	23.12	lb CH_4/mile-yr	94.7	1.20E-06 7.44E-07	tonne CH_4/mile-hr tonne CH_4/km-hr
CO_2 from oxidation [e,g]	7.59	lb CO_2/mile-yr	70.3	3.93E-07 2.44E-07	tonne CO_2/mile-hr tonne CO_2/km-hr
CO_2 from pipeline leaks [e]	1.52	lb CO_2/mile-yr	90.1	7.88E-08 4.89E-08	tonne CO_2/mile-hr tonne CO_2/km-hr
Storage stations	21,507	scfd CH_4/station	132	1.72E-02	tonne CH_4/station-hr
Storage – reciprocating compressor	21,116	scfd CH_4/comp.	60.4	1.69E-02	tonne CH_4/compressor-hr
Storage – centrifugal compressor	30,573	scfd CH_4/comp.	39.0	2.44E-02	tonne CH_4/compressor-hr
Storage wells	114.5	scfd CH_4/well	76.0	9.15E-05	tonne CH_4/well-hr

Footnotes and Sources:

[a] 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 U.S. Environmental Protection Agency, June 1996.

[b] Campbell, L.M. and B.E. Stapper. *Methane Emissions from the Natural Gas Industry, Volume 10: Metering and Pressure Regulating, Stations in Natural Gas, and Transmission and Distribution,* Final Report, GRI-94/0257.27 and EPA-600/R-96-080j. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Uncertainty is based on a 95% confidence interval from the data used to develop the original emission factor.

[d] Emission factors converted from scf are based on 60 °F and 14.7 psia. The average CH_4 concentration associated with these emission factors provided in Table E-4 is 93.4 mole %; the average CO_2 concentration (for buried pipelines) also provided in Table E-4 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.

[e] Emission factor derivation is provided in Appendix C.

[f] Uncertainty range (0 – 900,158 scf CH_4/station-yr)

[g] A portion of CH_4 emitted from underground pipeline leaks is oxidized to form CO_2.

Table 6–7. Fugitive Emission Factors for Gas Distribution Equipment

Equipment Basis	Reference Emission Factor [a,b], Original Units		Uncertainty [c] (± %)	Emission Factor [d], Converted Units	
Customer meters [e]	129.15	scf/meter-yr	24.6	2.83E-07	tonne CH_4/meter-hr
Commercial/industrial meters	47.9	scf/meter-yr	47.1	1.05E-07	tonne CH_4/meter-hr
Residential meters	138.5	scf/meter-yr	20.6	3.03E-07	tonne CH_4/meter-hr
Distribution meter/reg. stations [e]	207,018	scf/station-yr	111	4.53E-04	tonne CH_4/station-hr
Distribution pipelines [e]	1,359	lb CH_4/mile-yr	71.4	7.04E-05 4.37E-05	tonne CH_4/mile-hr tonne CH_4/km-hr
CO_2 from oxidation [e,f]	1,204	lb CO_2/mile-yr	78.7	6.24E-05 3.87E-05	tonne CO_2/mile-hr tonne CO_2/km-hr
CO_2 from pipeline leaks [e]	105.6	lb CO_2/mile-yr	67.7	5.47E-06 3.40E-06	tonne CO_2/mile-hr tonne CO_2/km-hr
Distribution services (mileage basis) [e]	1,067	lb CH_4/mile-yr	140	5.53E-05 3.43E-05	tonne CH_4/mile-hr tonne CH_4/km-hr
CO_2 from oxidation [e,f]	54.4	lb CO_2/mile-yr	115	2.82E-06 1.75E-06	tonne CO_2/mile-hr tonne CO_2/km-hr

Table 6–7. Fugitive Emission Factors for Gas Distribution Equipment, continued

Equipment Basis	Reference Emission Factor [a,b], Original Units		Uncertainty [c] (± %)	Emission Factor [d], Converted Units	
CO_2 from service leaks [e]	63.9	lb CO_2/mile-yr	140	3.31E-06 2.05E-06	tonne CO_2/mile-hr tonne CO_2/km-hr
Distribution services (service basis) [e]	12.7	lb CH_4/service-yr	140	6.55E-07	tonne CH_4/service-hr
CO_2 from oxidation [e,f]	0.65	lb CO_2/service-yr	115	3.34E-08	tonne CO_2/service-hr
CO_2 from service leaks [e]	0.76	lb CO_2/service-yr	140	3.92E-08	tonne CO_2/service-hr

Footnotes and Sources:

[a] 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 U.S. Environmental Protection Agency, June 1996.

[b] Hummel, K.E., L.M. Campbell, and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*, Final Report, GRI-94/0257.1 and EPA-600/R-96-080b. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Uncertainty is based on a 95% confidence interval from the data used to develop the original emission factor.

[d] Emission factors converted from scf are based on 60 °F and 14.7 psia. The average CH_4 concentration associated with these emission factors provided in Table E-4 is 93.4 mole %; the average CO_2 concentration (for buried pipelines) also provided in Table E-4 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.

[e] Emission factor derivation provided in Appendix C. Additional distribution service factors (on a service basis) are presented in Appendix C.

[f] A portion of CH_4 emitted from underground pipeline leaks is oxidized to form CO_2.

Table 6–8. Fugitive Emission Factors for Distribution M&R Stations

Equipment Basis	Reference Emission Factor [a], Original Units		Uncertainty [b] (± %)	Emission Factor, Converted Units	
M&R >300 psig	179.8	scf CH_4/station-hr	46.9	30.2	tonne CH_4/station-yr
M&R 100 - 300 psig	95.6	scf CH_4/station-hr	143	16.1	tonne CH_4/station-yr
M&R <100 psig	4.31	scf CH_4/station-hr	334	0.72	tonne CH_4/station-yr
Regulating >300 psig	161.9	scf CH_4/station-hr	70.9	27.2	tonne CH_4/station-yr
R-Vault >300 psig	1.30	scf CH_4/station-hr	246	0.22	tonne CH_4/station-yr
Regulating 100 - 300 psig	40.5	scf CH_4/station-hr	83.1	6.81	tonne CH_4/station-yr
R-Vault 100 - 300 psig	0.180	scf CH_4/station-hr	116	3.02E-02	tonne CH_4/station-yr
Regulating 40 - 100 psig	1.04	scf CH_4/station-hr	93.2	0.17	tonne CH_4/station-yr
R-Vault 40 - 100 psig	0.0865	scf CH_4/station-hr	79.9	1.45E-02	tonne CH_4/station-yr
Regulating <40 psig	0.133	scf CH_4/station-hr	172	2.23E-02	tonne CH_4/station-yr

Footnotes and Sources:

[a] Campbell, L. M. and B. E. Stapper. *Methane Emissions from the Natural Gas Industry, Volume 10: Metering and Pressure Regulating Stations in Natural Gas Transmission and Distribution,* Final Report, GRI-94/0257.27 and EPA 600/R-96-080j. Gas Research Institute and U. S. Environmental Protection Agency, June 1996.

[b] Uncertainty is based on a 95% confidence interval based on the original data found in the source.

Exhibit 6.2 presents an example of calculating CH_4 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 has 15 gas wellheads, 4 separators, a heater, a small reciprocating compressor, a metering station, and 12 miles of gathering pipelines. The equipment operated continuously for the reporting year. The concentration of the produced gas is 79 mole % CH_4 and 2% CO_2. Calculate total CH_4, CO_2, and CO_2e emissions.

CALCULATION METHODOLOGY:
1. *Calculate CH_4 emissions.* The emission factors for a natural gas exploration and production facility are provided in Table 6-4. Emissions are calculated below, by equipment type. Because the facility CH_4 content is approximately the same as the default composition associated with the emissions factors, no adjustment for CH_4 is made.

$$E_{CH_4,\text{ wellheads}} = \frac{1.80\times10^{-5}\text{ tonnes CH}_4}{\text{hr}\times\text{wellhead}}\times\frac{8760\text{ hours}}{\text{year}}\times15\text{ wellheads}$$

$$\underline{E_{CH_4,\text{ wellheads}} = 2.36\text{ tonnes CH}_4\text{ / yr}}$$

$$E_{CH_4,\text{ separators}} = \frac{4.42\times10^{-5}\text{ tonnes CH}_4}{\text{hr}\times\text{ separator}}\times\frac{8760\text{ hours}}{\text{year}}\times4\text{ separators}$$

$$\underline{E_{CH_4,\text{ separators}} = 1.55\text{ tonnes CH}_4\text{ / yr}}$$

$$E_{CH_4,\text{ heaters}} = \frac{4.60\times10^{-5}\text{ tonnes CH}_4}{\text{hr}\times\text{heater}}\times\frac{8760\text{ hours}}{\text{year}}\times1\text{ heater}$$

$$\underline{E_{CH_4,\text{ heaters}} = 0.40\text{ tonnes CH}_4\text{ / yr}}$$

$$E_{CH_4,\text{ small recips.}} = \frac{2.12\times10^{-4}\text{ tonnes CH}_4}{\text{hr}\times\text{small recip.}}\times\frac{8760\text{ hours}}{\text{year}}\times1\text{ small recip.}$$

$$\underline{E_{CH_4,\text{ small recips.}} = 1.86\text{ tonnes CH}_4\text{/yr}}$$

EXHIBIT 6.2: Sample Calculation for Major Equipment Emission Factor Approach, continued

$$E_{CH_4,\text{ meter}} = \frac{3.52\times10^{-5}\text{ tonnes CH}_4}{\text{hr}\times\text{meter}}\times\frac{8760\text{ hours}}{\text{year}}\times1\text{ meter}$$

$$\underline{E_{CH_4,\text{ meter}} = 0.31\text{ tonnes CH}_4\text{ / yr}}$$

$$E_{CH_4,\text{ gathering pipe}} = \frac{4.28\times10^{-5}\text{ tonnes CH}_4}{\text{hr}\times\text{mile}}\times\frac{8760\text{ hours}}{\text{year}}\times12\text{ miles}$$

$$\underline{E_{CH_4,\text{ gathering pipe}} = 4.50\text{ tonnes CH}_4\text{ / yr}}$$

Total CH_4 emissions are calculated by summing the individual equipment CH_4 emissions, as shown below.

$$E_{CH_4,\text{ total}} = \frac{2.36\text{ tonnes}}{\text{yr}}+\frac{1.55\text{ tonnes}}{\text{yr}}+\frac{0.40\text{ tonnes}}{\text{yr}}+\frac{1.86\text{ tonnes}}{\text{yr}}+\frac{0.31\text{ tonnes}}{\text{yr}}$$

$$\underline{E_{CH_4,\text{ total}} = 6.48\text{ tonnes CH}_4\text{ / yr}}$$

2. *Calculate CO_2 emissions.* CO_2 emissions result from CO_2 present in the gas stream. For non-pipeline sources, it is assumed that the CO_2 leak rate is based on the CH_4 emission rate, but adjusted for the ratio of CO_2 to CH_4 in the gas.

$$E_{CO_2,\text{ non-pipeline sources}} = \frac{6.48\text{ tonnes CH}_4}{\text{yr}}\times\frac{\text{tonne mole CH}_4}{16\text{ tonnes CH}_4}\times\frac{0.02\text{ tonne mole CO}_2}{0.79\text{ tonne mole CH}_4}\times\frac{44\text{ tonnes CO}_2}{\text{tonne mole CO}_2}$$

$$\underline{E_{CO_2,\text{ non-pipeline sources}} = 0.45\text{ tonnes CO}_2\text{/yr}}$$

CO_2 emissions from pipeline leaks and from the oxidation of CH_4 in the soil are calculated using the emission factors from Table 6-4.

$$E_{CO_2,\text{ pipeline leaks}} = \frac{5.84\times10^{-6}\text{ tonnes CO}_2}{\text{hr}\times\text{mile}}\times\frac{8760\text{ hours}}{\text{year}}\times12\text{ miles}$$

$$\underline{E_{CO_2,\text{ pipeline leaks}} = 0.61\text{ tonnes CO}_2\text{ / yr}}$$

EXHIBIT 6.2: Sample Calculation for Major Equipment Emission Factor Approach, continued

$$E_{CO_2,\text{ oxidation}} = \frac{4.38\times10^{-6}\text{ tonnes CO}_2}{\text{hr}\times\text{mile}}\times\frac{8760\text{ hours}}{\text{year}}\times12\text{ miles}$$

$$\underline{E_{CO_2,\text{ oxidation}} = 0.46\text{ tonnes CO}_2\text{ / yr}}$$

The total CO_2 emissions from these sources are calculated by summing the individual source CO_2 emissions, as shown below:

$$E_{CO_2,\text{ total}} = \frac{0.45\text{ tonnes}}{\text{yr}}+\frac{0.61\text{ tonnes}}{\text{yr}}+\frac{0.46\text{ tonnes}}{\text{yr}}$$

$$\underline{E_{CO_2,\text{ total}} = 1.52\text{ tonnes CO}_2\text{/yr}}$$

3. *Calculate CO_2e emissions.* Total fugitive emissions for this production field, in CO_2 equivalent are calculated using Equation 3-2.

$$E_{CO_2e} = \left(\frac{6.48\text{ tonnes CH}_4}{\text{yr}}\times\frac{21\text{ tonnes CO}_2\text{e}}{\text{tonne CH}_4}\right)+\frac{1.52\text{ tonnes CO}_2}{\text{yr}}$$

$$\underline{E_{CO_2e} = 137.60\text{ tonnes CO}_2\text{e/yr}}$$

Table 6-9 provides more detailed pipeline leak emission factors for transmission pipelines that include both CH_4 and CO_2 emissions. The derivation of these emission factors is provided in Appendix C.

Table 6–9. More Detailed Fugitive Emission Factors for Natural Gas Transmission Equipment

Source	Emission Factor [a,b], Original Units		Uncertainty [c] (±%)	Emission Factor [d], Converted Units	
Cast iron pipeline	10,096	lb CH_4/mile-yr	77.0	4.5794 2.8455	tonne CH_4/mile-yr tonne CH_4/km-yr
CO_2 from oxidation [e]	18,699	lb CO_2/mile-yr	81.0	8.4817 5.2703	tonne CO_2/mile-yr tonne CO_2/km-yr
CO_2 from pipeline leaks	993.6	lb CO_2/mile-yr	81.1	0.4507 0.2800	tonne CO_2/mile-yr tonne CO_2/km-yr

Table 6–9. More Detailed Fugitive Emission Factors for Natural Gas Transmission Equipment, continued

Source	Emission Factor [a,b], Original Units		Uncertainty [c] (±%)	Emission Factor [d], Converted Units	
Plastic pipeline	22.55	lb CH_4/mile-yr	233	0.01023 0.00636	tonne CH_4/mile-yr tonne CH_4/km-yr
CO_2 from oxidation [e]	1.263	lb CO_2/mile-yr	234	0.0005728 0.0003559	tonne CO_2/mile-yr tonne CO_2/km-yr
CO_2 from pipeline leaks	1.352	lb CO_2/mile-yr	234	0.0006133 0.0003811	tonne CO_2/mile-yr tonne CO_2/km-yr
Protected steel pipeline	15.16	lb CH_4/mile-yr	139	0.006874 0.004272	tonne CH_4/mile-yr tonne CH_4/km-yr
CO_2 from oxidation [e]	1.286	lb CO_2/mile-yr	141	0.0005833 0.0003625	tonne CO_2/mile-yr tonne CO_2/km-yr
CO_2 from pipeline leaks	0.9180	lb CO_2/mile-yr	141	0.0004164 0.0002587	tonne CO_2/mile-yr tonne CO_2/km-yr
Unprotected steel pipeline	275.9	lb CH_4/mile-yr	146	0.1251 0.0778	tonne CH_4/mile-yr tonne CH_4/km-yr
CO_2 from oxidation [e]	13.87	lb CO_2/mile-yr	148	0.006293 0.003910	tonne CO_2/mile-yr tonne CO_2/km-yr
CO_2 from pipeline leaks	16.51	lb CO_2/mile-yr	148	0.007487 0.004652	tonne CO_2/mile-yr tonne CO_2/km-yr

Footnotes and Sources:

[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines,* Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[b] Emission factor derivations are provided in Appendix C.

[c] Uncertainty based on a 95% confidence interval from the data used to develop the original emission factor.

[d] The average CH_4 concentration associated with these emission factors provided in Table E-4 is 93.4 mole %; the average CO_2 concentration (for buried pipelines) also provided in Table E-4 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.

[e] A portion of CH_4 emitted from underground pipeline leaks is oxidized to form CO_2.

Table 6-10 includes some additional, more detailed distribution segment equipment-level emission factors. These are similar to the level of detail shown in the Table 6-9 for the transmission segment. The pipeline leak emission factors were derived from the GRI/EPA methane emissions project (Campbell, et al., Volume 9, 1996). The factor derivation is provided in Appendix C.

Table 6–10. More Detailed Fugitive Emission Factors for Natural Gas Distribution Equipment

Source	Emission Factor [a,b], Original Units		Uncertainty [c] (±%)	Emission Factor, Converted Units	
Cast iron pipeline, main length	10,096	lb CH_4/mile-yr	77.0	4.579 2.845	tonne CH_4/mile-yr tonne CH_4/km-yr
CO_2 from oxidation [d]	18,699	lb CO_2/mile-yr	81.0	8.482 5.270	tonne CO_2/mile-yr tonne CO_2/km-yr
CO_2 from pipeline leaks	993.6	lb CO_2/mile-yr	81.1	0.4507 0.2800	tonne CO_2/mile-yr tonne CO_2/km-yr
Plastic pipeline, main length	694.2	lb CH_4/mile-yr	260	0.3149 0.1956	tonne CH_4/mile-yr tonne CH_4/km-yr
CO_2 from oxidation [d]	38.87	lb CO_2/mile-yr	261	0.01763 0.01096	tonne CO_2/mile-yr tonne CO_2/km-yr
CO_2 from pipeline leaks	41.62	lb CO_2/mile-yr	261	0.01888 0.01173	tonne CO_2/mile-yr tonne CO_2/km-yr
Protected steel pipeline, main length	129.7	lb CH_4/mile-yr	128	0.05883 0.03655	tonne CH_4/mile-yr tonne CH_4/km-yr
CO_2 from oxidation [d]	11.01	lb CO_2/mile-yr	130	0.004992 0.003102	tonne CO_2/mile-yr tonne CO_2/km-yr
CO_2 from pipeline leaks	7.856	lb CO_2/mile-yr	130	0.003563 0.002214	tonne CO_2/mile-yr tonne CO_2/km-yr
Unprotected steel pipeline, main length	4,660	lb CH_4/mile-yr	133	2.114 1.313	tonne CH_4/mile-yr tonne CH_4/km-yr
CO_2 from oxidation [d]	234.4	lb CO_2/mile-yr	135	0.1063 0.0661	tonne CO_2/mile-yr tonne CO_2/km-yr
CO_2 from pipeline leaks	278.8	lb CO_2/mile-yr	135	0.1265 0.0786	tonne CO_2/mile-yr tonne CO_2/km-yr
Copper pipeline, services	10.76	lb CH_4/service-yr	172	0.004878	tonne CH_4/service-yr
CO_2 from oxidation [d]	0	lb CO_2/service-yr	N/A	0	tonne CO_2/service-yr
CO_2 from pipeline leaks	0.6319	lb CO_2/service-yr	174	0.0002866	tonne CO_2/service-yr
Plastic pipeline, services	0.3932	lb CH_4/service-yr	234	0.0001784	tonne CH_4/service-yr
CO_2 from oxidation [d]	0.2903	lb CO_2/service-yr	235	0.0001317	tonne CO_2/service-yr
CO_2 from pipeline leaks	0.02932	lb CO_2/service-yr	235	0.00001330	tonne CO_2/service-yr
Protected steel pipeline, services	7.464	lb CH_4/service-yr	178	0.003385	tonne CH_4/service-yr
CO_2 from oxidation [d]	0.5467	lb CO_2/service-yr	180	0.0002480	tonne CO_2/service-yr
CO_2 from pipeline leaks	0.4502	lb CO_2/service-yr	180	0.0002042	tonne CO_2/service-yr
Unprotected steel pipeline, services	71.92	lb CH_4/service-yr	185	0.03262	tonne CH_4/service-yr
CO_2 from oxidation [d]	2.195	lb CO_2/service-yr	186	0.0009956	tonne CO_2/service-yr
CO_2 from pipeline leaks	4.273	lb CO_2/service-yr	186	0.001938	tonne CO_2/service-yr

Footnotes and Sources:

[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[b] The average CH_4 concentration associated with these emission factors provided in Table E-4 is 93.4 mole %; the average CO_2 concentration (for buried pipelines) also provided in Table E-4 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.

[c] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

[d] A portion of CH_4 emitted from underground pipeline leaks is oxidized to form CO_2.

Early plastic pipes (pre-1982) were more susceptible to leakage than plastic pipes manufactured after 1982 that were built to the American Society of Testing and Materials (ASTM) D2837 standards. Factors such as brittle cracking may have contributed to the higher pipeline leaks from plastic pipelines manufactured prior to 1982. Using data from the 1996 GRI/EPA study (Campbell, et al., 1996) and data from Southern California Gas Company (SoCal, 1993), separate buried plastic pipeline fugitive leak emission factors were developed for pre-1982 plastic pipes and post-1982 (ASTM 2837) plastic pipelines.

Table 6-11 provides emission factors for plastic pipelines disaggregated on the basis of whether the pipes were manufactured before or after 1982. These emission factors are provided on both a leak basis and pipeline mileage basis. More detailed information on the derivation of these factors are provided in Appendix C.

Table 6–11. Fugitive Emission Factor from Underground Plastic Pipelines by Construction Year

	Leak Based Emission Factors [a,b,c,d]				Pipeline Length Based Emission Factors [a,b,c,d]					
	Pre-1982		Post-1982 (ASTM D2837)		Pre-1982			Post-1982 (ASTM D2837)		
Source	(tonnes/leak-yr)[e]	Uncertainty (± %)[f]	(tonnes/leak-yr)[e]	Uncertainty (± %)[f]	(tonnes/mi-yr)[e,g]	(tonnes/km-yr)[e,g]	Uncertainty (± %)[f,h]	(tonnes/mi-yr)[e,g]	(tonnes/km-yr)[e,g]	Uncertainty (± %)[f,h]
Production[i]										
CH_4 from pipeline leaks	0.830	164	0.140	37	0.180	0.112	245	0.030	0.019	108
CO_2 from pipeline leaks	0.111	157	0.019	26	0.024	0.015	236	0.0041	0.003	101
CO_2 from oxidation[l]	0.046	164	0.0078	37	0.010	0.006	245	0.0017	0.001	108
Transmission[j]										
CH_4 from pipeline leaks	0.983	164	0.166	36	0.0053	0.003	249	0.00089	0.001	110
CO_2 from pipeline leaks	0.059	157	0.010	26	0.00031	0.000	241	0.000053	0.000	104
CO_2 from oxidation[l]	0.055	164	0.0093	36	0.00029	0.000	249	0.000050	0.000	110
Distribution, Main[k]										
CH_4 from pipeline leaks	0.983	164	0.166	36	0.162	0.100	324	0.027	0.017	159
CO_2 from pipeline leaks	0.059	157	0.010	26	0.010	0.006	313	0.0016	0.001	153
CO_2 from oxidation[l]	0.055	164	0.0093	36	0.009	0.006	324	0.0015	0.001	159

Footnotes and Sources:

[a] Emission factors derived from data presented in the 1996 GRI/EPA Study and from Southern California Gas Company (SoCal); refer to Appendix C for more details.

[b] Campbell, L. M., M. V. Campbell, and D. L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA 600/R-96-080i. Gas Research Institute and U. S. Environmental Protection Agency, June 1996.

[c] Southern California Gas Company (SoCal). *A Study of the 1991 Unaccounted-for Gas Volume at the Southern Gas Company*, April 1993.

[d] The SoCal data were taken from: California Energy Commission (CEC). *Evaluation of Oil and Gas Sector Greenhouse Gas Emissions Estimation and Reporting,* California Energy Commission, Consultant Report, Final Draft, April 14, 2006.

[e] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia.

[f] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

[g] Leak based emission factors were converted to miles basis based on the leak/miles ratio taken from data presented in Volume 9 of the 1996 GRI/EPA study. Equivalent leaks and pipeline miles were not provided by year of construction, so this conversion was based on the total U.S. leaks and miles of pipeline. Factors were then converted to kilometer basis.

[h] Because the data used to calculate the activity factor for the referenced emission was unavailable, the Uncertainty at a 95% confidence interval was calculated from the reported 90% confidence interval assuming a data set size of ten.

[i] Production sector emission factors are based on a gas composition provided in Table E-4 of 78.8 mole % CH_4 and 3.78% CO_2 . Leak-based emission factors were converted to miles basis using 6,467 +/- 76.0% equivalent leaks from page B-13 and 29,862 +/-10% miles of gathering pipeline from Table 8-9 of Volume 9 of the 1996 GRI/EPA study.

[j] Transmission sector emission factors are based on a gas composition provided in Table E-4 of 93.4 mole % CH_4 and 2.0 mole % CO_2. Leak-based emission factors were converted to miles basis using 14 +/- 78.6% equivalent leaks and 2621 +/-10% miles of transmission pipeline from Table 8-7 of Volume 9 of the 1996 GRI/EPA study.

[k] Distribution sector emission factors are based on a gas composition provided in Table E-4 of 93.4 mole % CH_4 and 2.0 mole % CO_2. Leak-based emission factors were converted to miles basis using 49,226 +/- 117.9% equivalent leaks from Table 8-6 and 299,421 +/-5% miles of distribution pipeline from Table 8-4 of Volume 9 of the 1996 GRI/EPA study.

[l] A portion of CH_4 emitted from underground pipeline leaks is oxidized to form CO_2. The conversion in the table above was based on 2.0% (+/- 25%) soil oxidation for plastic pipelines taken from Table 8-2 of Volume 9 of the GRI/EPA study.

6.1.3 Component-Level Average Emission Factors Approach

The component-level average emission factor approach is based on the number of components in the facility. Where no monitoring data are available, this approach provides a more accurate estimation than equipment or facility level emission factors, 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 TOC, also referred to as THC, or VOC, rather than CH_4. This section includes a methodology for converting the TOC-based emission factors to CH_4 fugitive equipment leak emissions, based on either site-specific data or on default composition 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. According to EPA (EPA, 1995), gas service is any material that is in a gaseous or vapor state at process conditions. Light liquid service is 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, which generally includes naphtha and more volatile oil and natural gas liquids. A heavy liquid is any liquid that is not in gas/vapor or light liquid service, which would generally include kerosene and less volatile oil and natural gas liquids.

EPA provides the following equation to estimate TOC mass emissions for a given component type:

$$E_{TOC}=FA\times WF_{TOC}\times N \qquad \text{(Equation 6-7)}$$

where

E_{TOC} = emission rate of TOC from all components of a given type in the stream;
F_A = average emission factor for the component type A from the applicable tables;
WF_{TOC} = average weight fraction TOC in the stream (if unknown assume 1.0); and
N = number of components of the given type in the stream.

The weight fraction concentration of TOC within the equipment is needed because equipment with higher TOC concentrations tends to have higher TOC leak rates. When using the average emission factor approach for streams with different TOC concentrations, the components should be grouped according to the TOC weight fraction, prior to applying Equation 6-7.

On the same basis, Equation 6-8 can be restated in terms of CH_4 emissions (a constituent of TOC) by replacing the TOC weight fraction with the weight fraction of CH_4 (WF_{CH4}). The derivation is shown below:

$$E_{TOC} = F_A \times WF_{TOC} \times N$$

(Equation 6-8)

$$E_{CH_4} = E_{TOC} \times \frac{WF_{CH_4}}{WF_{TOC}}$$

Combining these equations, the weight fraction of TOC cancels out, resulting in an equation stated in terms of CH_4 emissions, as shown for Equation 6-9.

$$E_{CH_4} = (F_A \times WF_{TOC} \times N) \text{ x } \frac{WF_{CH_4}}{WF_{TOC}}$$

(Equation 6-9)

$$E_{CH_4} = F_A \times WF_{CH_4} \times N$$

where

E_{CH_4} = emission rate of CH_4 from all components of a given type in the stream; and

WF_{CH_4} = average weight fraction of CH_4.

EPA average emission factors for oil and natural gas production facilities are provided in Table 6-12 (EPA, 1995). 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 Table 6-12 are service specific.

Please note that unlike EPA, 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°. The emission factors provided in Tables 6-13, 6-14, and 6-16 are facility-specific and not service-specific. For example, a heavy-crude production facility should use the heavy-crude emission factors provided in Table 6-14 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_4 basis using Equation 6-9.

Table 6-12. EPA Average Oil and Natural Gas Production Emission Factors

Component – Service [a]	Emission Factor, Original Units [b], kg gas/hr/component	Emission Factor, Converted to tonne gas/hr/component
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	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

Footnotes and Sources:

a EPA defines light liquids as liquids for which the sum of the concentration of individual constituents with a vapor pressure over 0.3 kPa at 20 °C is greather than or equal to 20 weight percent. EPA defines heavy liquids as liquids not in gas/vapor or light liquid service.

[b] U.S. 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 6-13 provides average fugitive emission factors for offshore facilities.

Table 6-13. API Average Offshore Fugitive Emission Factors

Component	Emission Factor, Original Units [a], lb TOC/day/comp.	Emission Factor, Converted to tonne TOC/component-hr
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

Footnote and Source:

[a] 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.

Average oil and natural gas production emission factors are provided in Table 6-14.

Table 6-14. API Oil and Natural Gas Production Average Emission Factors

Component – Facility Type [a]	Emission Factor [b], Original Units, lb TOC/day/component	Emission Factor, Converted to 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

Footnotes and Sources:

[a] These emission factors are facility specific, not service specific. For example, a facility producing light crude would apply the light crude production emission factors regardless of service type. API Publication 4615 defines light crude as oil with an API gravity of 20 or more, and heavy crude as oil with an API gravity of less than 20.

[b] 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.

Tables 6-21 and 6-22 provides additional oil and natural gas production facility average emission factors.

Table 6-15 presents natural gas plant, gathering compressor station, and well site average THC emissions factors based on a comprehensive measurement program, conducted to determine cost-effective directed inspection and maintenance (DI&M) control opportunities (EPA, 2006). This report presents fugitive emission factors from two phases of site measurements. Phase I of the program was conducted at four gas processing plants in the Western U.S. during 2000. Phase II of the program was conducted at five gas processing plants, seven gathering compressor stations, and 12 well sites during 2004 and 2005. The report presents aggregate emission factors from gas plants, gathering compressor stations and well sites for Phase II of the study, rather than separate emission factors for each sector. The report also shows that the measured THC emission rates from the leaking components during Phase II of the study were 1348 tonnes/facility-yr for gas plants, 131 tonnes/facility-yr for gathering compressor stations, and 8 tonnes/facility-yr for well sites. Based on the counts of the facilities and measured leak rates, the measured THC leak rates were approximately comprised of 86.9% from gas plants, 11.8% from gathering compressor stations, and 1.2% from well sites.

Table 6-15. Natural Gas Plant, Gathering Compressor Station, and Well Site Average Emission Factors

	Phase I (Gas Plants)[b]		**Phase II (Gas Plants, Gathering Compressor Stations, and Well Sites)[c]**	
Component	**Average THC Emission Factor[a], Original Units, kg/hr/source**	**Average THC Emission Factor, Converted to tonne/hr/source**	**Average THC Emission Factor[a], Original Units, kg/hr/source**	**Average THC Emission Factor, Converted to tonne/hr/source**
Connectors	2.22E-03	2.22E-06	3.30E-03	3.30E-06
Block Valves	1.10E-02	1.10E-05	1.47E-02	1.47E-05
Control Valves	4.85E-02	4.85E-05	3.73E-02	3.73E-05
Pressure Relief Valves (PRV)	6.73E-02	6.73E-05	4.70E-04	4.70E-07
Pressure Regulators	1.74E-02	1.74E-05	6.31E-03	6.31E-06
Orifice Meters	3.58E-03	3.58E-06	2.70E-03	2.70E-06
Crank Case Vents	8.83E-01	8.83E-04	1.20E-01	1.20E-04
Open-Ended Lines (OEL)	5.18E-02	5.18E-05	2.39E-01	2.39E-04
Compressor Seals[d]	8.52E-01	8.52E-04	5.20E-01	5.20E-04

Footnotes and Sources:

[a] U.S. Environmental Protection Agency (EPA). *EPA Phase II Aggregate Site Report: Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites, Technical Report*, prepared by National Gas Machinery Laboratory, Clearstone Engineering, Ltd., and Innovative Environmental Solutions, Inc., March 2006, Table 4.

[b] Phase I of the study was based on surveys at four gas processing facilities in the Western U.S. completed during the 4th quarter of 2000.

[c] Phase II of the study was based on surveys at five gas processing plants, seven gathering compressor stations, and 12 well sites during the first quarter of 2004 and second quarter of 2005. Table 3 of the above referenced report shows that the measured THC emission rates from the leaking components were 1348 tonnes/facility-yr for gas plants, 131 tonnes/facility-yr for gathering compressor stations, and 8 tonnes/facility-yr for well sites. Based on the counts of the facilities and measured leak rates, the measured leak rates were comprised of 86.9% from gas plants, 11.8% from gathering compressor stations, and 1.2% from well sites.

[d] Compressor seals component category accounts for emissions from individual compressor seals. As compressor seal leakage was typically measured from common vent and drain lines, emissions have been divided evenly among the seals on units with detected leakage.

Table 6-16, below, provides average natural gas plant emission factors.

Table 6-16. API Natural Gas Plant Average Emission Factors

Component	**Emission Factor, Original Units [a], lb TOC/day/comp.**	**Emission Factor, Converted to tonne TOC/component-hr**
Valves	2.04E-01	3.86E-06
Pump seals	6.09E-01	1.15E-05
Others	2.57E-01	4.86E-06
Connectors	1.45E-02	2.74E-07
Flanges	2.32E-02	4.38E-07
Open-ended lines	5.46E-02	1.03E-06

Footnote and Source:

[a] 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 6-17 provides natural gas transmission compressor station component emission factors for main line pressure (500-1000 psi) and fuel gas pressure (70 – 100 psi) as determined for components located on and off compressors (Howard, et al., 1999). The emission factors are based on leak rate measurements taken at 13 compressor stations in the U.S. and Canada from 1995 to 1997.

Table 6-17. Natural Gas Transmission Compressor Station Component Emission Factors

	ON COMPRESSOR			OFF COMPRESSOR		
Component	**Reference Emission Factor[a], Original Units, Mcf/yr/ source**	**Uncertainty[b] (± %)**	**Emission Factor[c], Converted to tonne CH_4/hr/ source**	**Reference Emission Factor[a], Original Units, Mcf/yr/ source**	**Uncertainty[b] (± %)**	**Emission Factor[c], Converted to tonne CH_4/hr/ source**
MAIN LINE PRESSURE (500 to 1000 psi)						
Ball/Plug Valves	0.64	163	1.31E-06	5.33	70	1.09E-05
Blowdown Valves	--	--	--	207.5	83	4.24E-04
Compressor Cylinder Joints	9.9	112	2.02E-05	--	--	--
Packing Seals - Running	865	29	1.77E-03	--	--	--
Packing Seals - Idle	1266	44	2.59E-03	--	--	--
Compressor Valves	4.1	93	8.39E-06	--	--	--
Control Valves	--	--	--	4.26	167	8.71E-06
Flanges	0.81	110	1.66E-06	0.32	66	6.54E-07
Gate Valves	--	--	--	0.61	70	1.25E-06
Loader Valves	17.2	33	3.52E-05	--	--	--
Open-Ended Lines (OEL)	--	--	--	81.8	97	1.67E-04
Pressure Relief Valves (PRV)	--	--	--	57.5	110	1.18E-04
Regulators	--	--	--	0.2	105	4.09E-07
Starter Gas Vents	--	--	--	40.8	106	8.34E-05
Threaded Connectors	0.74	62	1.51E-06	0.6	50	1.23E-06
Centrifugal Seals - Dry	--	--	--	62.7	106	1.28E-04
Centrifugal Seals - Wet	--	--	--	278	--	5.69E-04
Unit Valves	--	--	--	3566	--	7.29E-03
FUEL GAS PRESSURE (70 to 100 psi)						
Ball/Plug Valves	0.1	100	2.05E-07	0.51	73	1.04E-06
Control Valves	--	--	--	2.46	158	5.03E-06
Flanges	--	--	--	0.2	95	4.09E-07
Fuel Valves	27.6	49	5.64E-05	--	--	--
Gate Valves	--	--	--	0.43	84	8.79E-07
Open-Ended Lines (OEL)	--	--	--	2.53	87	5.17E-06
Pneumatic Vents	--	--	--	76.6	154	1.57E-04
Regulators	--	--	--	4.03	99	8.24E-06
Threaded Connectors	1.21	137	2.47E-06	0.32	50	6.54E-07

Footnotes and Sources:

[a] Howard, T., R. Kantamaneni, and G. Jones. *Cost Effective Leak Mitigation at Natural Gas Transmission Compressor Stations*, *Final Report*. PRC International, Gas Research Institute, and U.S. EPA Natural Gas STAR Program, August 1999, Tables 3 and 4.

[b] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

[c] Emission factors converted from scf are based on 60°F and 14.7 psia. The total gas emission factors were converted to a CH_4 basis assuming a default CH_4 concentration associated with the transmission sector of 93.4 mole % (provided in Table E-4).

Tables 6-18 through 6-22 provide emission factors and uncertainty values based on data developed in Canada. Average natural gas transmission and storage emission factors are presented in Table 6-18.

Table 6-18. Natural Gas Transmission and Storage Average Emission Factors

Component	Emission Factor [a], kg THC/hr/comp.	Emission Factor, tonne TOC/component-hr	Uncertainty [b] (± %)
Block valves	0.002140	2.14E-06	40.1
Control valves	0.01969	1.97E-05	70.2
Connectors	0.0002732	2.73E-07	19.0
Compressor seals – reciprocating	0.6616	6.62E-04	38.9
Compressor seals – centrifugal	0.8139	8.14E-04	71.5
Pressure relief valves	0.2795	2.80E-04	+127 / -100
Open-ended lines (OEL)	0.08355	8.36E-05	53.0
OEL - station or pressurized compressor blowdown system [c]	0.9369	9.37E-04	61.6
OEL – depressurized reciprocating (comp. blowdown system)	2.347	2.35E-03	+67.5 / -67.6
OEL – depressurized centrifugal (comp. blowdown system)	0.7334	7.33E-04	+103 / -100
OEL – overall pressurized/ depressurized reciprocating [d] (comp. blowdown system)	1.232	1.23E-03	Not available
OEL – overall pressurized/ depressurized centrifugal [d] (comp. blowdown system)	0.7945	7.94E-04	Not available
Orifice meter	0.003333	3.33E-06	+40.5 / -40.6
Other gas meter	0.000009060	9.06E-09	+116 / -100

Footnotes and Sources:

[a] D.J.Picard, M. Stribrny, and M.R. Harrison. *Handbook for Estimating Methane Emissions from Canadian Natural Gas Systems*. GTC Program #3. Environmental Technologies, May 25, 1998, Table 4.

[b] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

[c] The compressor type is not specified. The emission factor is assumed to apply to either reciprocating or centrifugal compressor types or stations.

[d] Overall OEL average emission factors that account for the time that the compressor unit is pressurized and depressurized during the year have been estimated using the annual fractions of the modes of operation taken from Table 4-20 of Volume 8 of the GRI/EPA methane emissions study (Hummel, et al., 1996). The percentages from the GRI/EPA study are 79.1% pressurized/20.9% depressurized for reciprocating compressors and 30% pressurized/70% depressurized for centrifugal compressors. Therefore, these percentages were applied to the base pressurized and depressurized emission factors provided in the table above to develop overall factors that represent annual average emission factors converted to an hourly basis.

Table 6-19 provided average emission factors for natural gas distribution meter/regulator stations.

Table 6-19. Natural Gas Distribution Meter/Regulator Stations Average Emission Factors

Component	Emission Factor [a], kg THC/hr/comp.	Emission Factor, tonne TOC/component-hr	Uncertainty [b] (± %)
Valves	0.00111	1.11E-06	+162 / -100
Control valves	0.01969	1.97E-05	70.2
Connectors	0.00011	1.10E-07	+92.0 / -92.1
Pressure relief valves	0.01665	1.67E-05	+138/-100
Open-ended lines (OEL)	0.08355	8.36E-05	53.0
OEL – station blowdown	0.9369	9.37E-04	61.6
Orifice meter	0.00333	3.33E-06	+40.5 / -40.6
Other gas meter	0.00001	9.06E-09	+116/-100

Footnotes and Sources:

[a] Ross, B.D. and D.J. Picard, *Measurement of Methane Emissions from Western Canadian Natural Gas Facilities*, Gas Technology Canada, GTC Program #3, Environment Technology Program, September, 1996.

[b] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

Average emission factors for natural gas distribution commercial and residential sites are provided in Table 6-20.

Table 6-20. Natural Gas Distribution Commercial and Residential Sites Average Emission Factors

Component	Emission Factor [a], kg THC/hr/comp.	Emission Factor, tonne TOC/component-hr	Uncertainty [b] (± %)
Valves	0.000003	3.33E-09	48.3
Connectors	0.000007	6.78E-09	+131 / -100
Pressure relief valves	0.000272	2.72E-07	+200 / -100
Open-ended lines (OEL)	0.083550	8.36E-05	53.0
Orifice meter	0.003333	3.33E-06	+40.5 / -40.6
Other gas meter	0.000009	9.06E-09	+116 / -100

Footnotes and Sources:

[a] Picard, D. J., B. D. Ross, and D. W. H. Koon. *A Detailed Inventory of CH_4 and VOC Emissions from Upstream Oil and Gas Operations in Alberta*, Volume II, Canadian Petroleum Association, March 1992.

[b] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

Table 6-21. Additional Natural Gas Facility Average Emission Factors

Component – Service	Emission Factor [a], kg THC/comp/hr	Emission Factor, tonnes THC/component-hr	Uncertainty [b] (± %)
Valves - fuel gas	2.81E-03	2.81E-06	±17
Valves - light liquid	3.52E-03	3.52E-06	±19
Valves - gas/vapor - all	2.46E-03	2.46E-06	±15
Valves - gas/vapor - sour	1.16E-03	1.16E-06	±31
Valves - gas/vapor - sweet	2.81E-03	2.81E-06	±17
Connectors - fuel gas	8.18E-04	8.18E-07	±32
Connectors - light liquid	5.51E-04	5.51E-07	+111/-90
Connectors - gas/vapor - all	7.06E-04	7.06E-07	±31
Connectors - gas/vapor - sour	1.36E-04	1.36E-07	±72
Connectors - gas/vapor - sweet	8.18E-04	8.18E-07	±32
Control valves - fuel gas	1.62E-02	1.62E-05	±27
Control valves - light liquid	1.77E-02	1.77E-05	±45
Control valves - gas/vapor - all	1.46E-02	1.46E-05	±23
Control valves - gas/vapor - sour	9.64E-03	9.64E-06	±4
Control valves - gas/vapor - sweet	1.62E-02	1.62E-05	±27
Pressure relief valves - fuel gas and gas/vapor	1.70E-02	1.70E-05	±98
Pressure relief valves - light liquid	5.39E-03	5.39E-06	±80
Pressure regulators - fuel gas and gas/vapor	8.11E-03	8.11E-06	+238/-72
Pressure regulators - gas/vapor - sour	4.72E-05	4.72E-08	+126/-74
Pressure regulators - gas/vapor - sweet	8.39E-03	8.39E-06	+239/-72
Open ended lines - fuel gas	4.67E-01	4.67E-04	+172/-58
Open ended lines - light liquid	1.83E-02	1.83E-05	+127/-79
Open ended lines - gas/vapor - all	4.27E-01	4.27E-04	+161/-62
Open ended lines - gas/vapor - sour	1.89E-01	1.89E-04	+127/-79
Open ended lines - gas/vapor - sweet	4.67E-01	4.67E-04	+172/-58
Chemical injection pumps - fuel gas and gas/vapor	1.62E-01	1.62E-04	±60
Compressor seals - fuel gas and gas/vapor	7.13E-01	7.13E-04	±36
Compressor starts - fuel gas	6.34E-03	6.34E-06	±25
Controllers - fuel gas and gas/vapor	2.38E-01	2.38E-04	±27
Pump seals - light liquid	2.32E-02	2.32E-05	+136/-74

Footnotes and Sources:

[a] Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004.

[b] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

Table 6-22. Additional Oil Facility Average Emission Factors

Component – Service	Emission Factor [a], kg THC/comp/hr	Emission Factor, tonnes THC/component-hr	Uncertainty [b] (± %)
Valves - fuel gas and gas/vapor	1.51E-03	1.51E-06	±79
Valves - heavy liquid	8.40E-06	8.40E-09	±19
Valves - light liquid	1.21E-03	1.21E-06	±19
Connectors - fuel gas and gas/vapor	2.46E-03	2.46E-06	±15
Connectors - heavy liquid	7.50E-06	7.50E-09	+111/-90
Connectors - light liquid	1.90E-04	1.90E-07	+111/-90
Control valves - fuel gas and gas/vapor	1.46E-02	1.46E-05	±21
Control valves - light liquid	1.75E-02	1.75E-05	±44
Pressure relief valves - fuel gas and gas/vapor	1.63E-02	1.63E-05	±80
Pressure relief valves - heavy liquid	3.20E-05	3.20E-08	±80
Pressure relief valves - light liquid	7.50E-02	7.50E-05	±80
Pressure regulators - fuel gas and gas/vapor	6.68E-03	6.68E-06	+238/-72
Open ended lines - fuel gas and gas/vapor	3.08E-01	3.08E-04	+129/-78
Open ended lines - light liquid	3.73E-03	3.73E-06	+127/-79
Chemical injection pumps - fuel gas and gas/vapor	1.62E-01	1.62E-04	±60
Compressor seals - fuel gas and gas/vapor	8.05E-01	8.05E-04	±36
Compressor starts - fuel gas	6.34E-03	6.34E-06	±25
Controllers - fuel gas and gas/vapor	2.38E-01	2.38E-04	±27
Pump seals - heavy liquid	3.20E-05	3.20E-08	+136/-74
Pump seals - light liquid	2.32E-02	2.32E-05	+136/-74

Footnotes and Sources:

[a] Clearstone Engineering Ltd.. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry,* Volume 5, September 2004.

[b] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

An example calculation illustrating the use of the component-level fugitive emission factors is provided in Exhibit 6.3.

EXHIBIT 6.3: Sample Calculation for Non-Refinery Component-Level Average Fugitive Emission Factor Approach

INPUT DATA:

There are 100 gas valves, 250 flanges, 3 pressure relief valves, and 2 open ended lines in a stream at a production site that contains 80 weight percent non-CH_4 hydrocarbons, 10 weight percent water vapor, and 10 weight percent CH_4. Calculate the CH_4 emissions.

EXHIBIT 6.3: Sample Calculation for Non-Refinery Component-Level Average Fugitive Emission Factor Approach, continued

CALCULATION METHODOLOGY FOR NON-REFINERY CASE:
CH_4 emissions would be calculated using Equation 6-9 and the average emission factor for valves in Table 6-12 as follows.

Valves:

$$E_{CH_4} = \frac{4.5\times10^{-6}\ \text{tonne gas}}{\text{hr}\times\text{valve}} \times \frac{0.1\ \text{tonne CH}_4}{\text{tonne gas}} \times \frac{8760\ \text{hr}}{\text{yr}} \times 100\ \text{valves}$$

$$\underline{E_{CH_4} = 0.394\ \text{tonnes CH}_4/\text{yr}}$$

Flanges:

$$E_{CH_4} = \frac{3.9\times10^{-7}\ \text{tonne gas}}{\text{hr}\times\text{flange}} \times \frac{0.1\ \text{tonne CH}_4}{\text{tonne gas}} \times \frac{8760\ \text{hr}}{\text{yr}} \times 250\ \text{flange}$$

$$\underline{E_{CH_4} = 0.0854\ \text{tonnes CH}_4/\text{yr}}$$

PRVs:

$$E_{CH_4} = \frac{8.8\times10^{-6}\ \text{tonne gas}}{\text{hr}\times\text{PRV}} \times \frac{0.1\ \text{tonne CH}_4}{\text{tonne gas}} \times \frac{8760\ \text{hr}}{\text{yr}} \times 3\ \text{PRVs}$$

$$\underline{E_{CH_4} = 0.0231\ \text{tonnes CH}_4/\text{yr}}$$

OELs:

$$E_{CH_4} = \frac{2.0\times10^{-6}\ \text{tonne gas}}{\text{hr}\times\text{OEL}} \times \frac{0.1\ \text{tonne CH}_4}{\text{tonne gas}} \times \frac{8760\ \text{hr}}{\text{yr}} \times 2\ \text{OELs}$$

$$\underline{E_{CH_4} = 0.00350\ \text{tonnes CH}_4/\text{yr}}$$

6.1.4 Emissions from CO_2 Transport

Fugitive emissions from the pipeline transport of CO_2, such as for EOR operations, occur in a similar fashion to fugitive emissions from the pipeline transport of natural gas. IPCC provides a methodology to convert CH_4 emission factors on a mass basis to CO_2 emission factors (IPCC, 2006) for CO_2 pipelines. The methodology is based on the pressure drop through a pipe, and is shown in Equation 6-10. The derivation of this equation is provided in Appendix C, Section C.3.8.

$$EF_{CO_2} = EF_{CH_4} \times \sqrt{\frac{44}{16}} \qquad \text{(Equation 6-10)}$$

where

$\sqrt{\frac{44}{16}}$ = mass basis CH_4 to CO_2 conversion; and

EF_{CH_4} = CH_4 natural gas pipeline leak emission factor provided earlier in this section.

Equation 6-10 should be applied to estimate CO_2 emissions from CO_2 pipelines. For CO_2-based equipment other than pipelines, CO_2 fugitive emissions can be estimated based on the CH_4 emission factor by applying Equation 6-1.

6.1.5 Time Basis of Fugitive Equipment Leaks

All of the fugitive approaches presented in this section and in Appendix C 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 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 depressurizes equipment for maintenance for a portion of the year, that time can be deducted from the annual operating hours. Depressurized equipment that is free of hydrocarbons (e.g. purged with air) would also not have fugitive emissions; that time can be deducted from the annual operating hours as well.

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 natural gas industry operations. These other non-point emission sources include wastewater treating, sludge/solids handling, impoundments, pits, mine tailing ponds, and cooling towers.

These other non-point emission sources will generally not be a significant source of CH_4 or CO_2 emissions. Few specific emission factors for CH_4 or CO_2 from these non-point sources have been found. Several methods 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_4 or CO_2 if site-specific composition data are available.

6.2.1 Wastewater Treatment

Wastewater treatment can be a source of CH_4 when treated or disposed of anaerobically. Under aerobic conditions, it can be a source of N_2O and CO_2 emissions that are byproducts of the digestion of larger organic molecules. However, CO_2 emissions from wastewater are generally disregarded because most are of biogenic origin (IPCC, 2006).

Figure 6-3 provides a decision tree for different methodologies available to estimate emissions from wastewater treatment. These approaches are based on the volume of wastewater processed, Biochemical or Biological Oxygen Demand (BOD) or Chemical Oxygen Demand (COD) data, contribution significance of resulting emissions to overall emissions, and availability of data to run the WATER9 program.[4] Anaerobic and aerobic treatments are discussed separately in the following subsections.

In some cases, vapors from wastewater treatment may be controlled through a combustion device or may be captured and routed to a gas disposal well. Emissions from wastewater vents routed to a combustion control device should be estimated using the techniques presented in Section 4. Alternatively, if vapors are captured, a capture efficiency should be applied to the emission estimation approaches presented in this subsection.

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[4] http://www.epa.gov/ttn/chief/software/water/index.html. Accessed January 15, 2009. The EPA also maintains a hotline for WATER9 at (919) 541-3608 or (919) 541-3154.

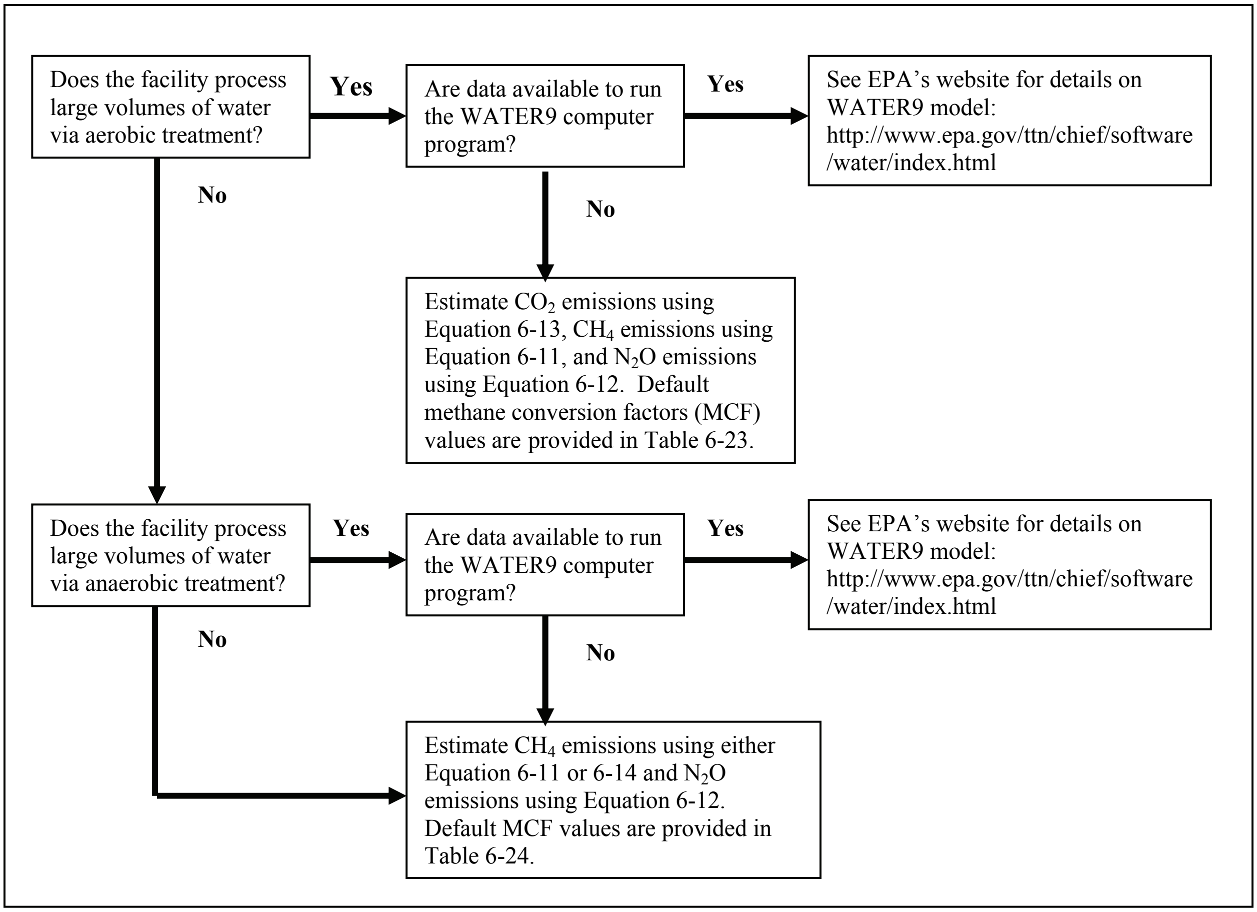

Figure 6-3. Wastewater Treatment

A general method for estimating TOC evaporative emissions from wastewater treating, impoundments, and pits is available in the computer program WATER9. Although CH_4 and CO_2 evaporative emissions from oil and natural gas wastewater are expected to be insignificant, facilities with unique situations can find more information on WATER9 at:

http://www.epa.gov/ttn/chief/software/water/index.html

IPCC provides a detailed method for estimating emissions from wastewater treatment (IPCC, 2006). This approach can be applied to aerobic or anaerobic wastewater treatment. Methane emissions from industrial wastewater are calculated using Equation 6-11.[5]

$$E_{CH_4} = [(P \times W \times COD)\text{-}S] \times B \times MCF \times 0.001 \qquad \text{(Equation 6-11)}$$

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[5] Equation 6-10 combines Equations 6-4, 6-5, and 6-6 in *2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5, Chapter 6: Wastewater Treatment and Discharge* (IPCC, 2006).

where

E_{CH_4} = emission rate of CH_4 (tonnes/yr);
P = product generated (ton product/yr);
W = wastewater generation rate (m^3/ton product);
COD = average chemical oxygen demand of the wastewater (kg/m^3);
S = organic component removed as sludge (kg COD/yr);
B = methane generation capacity (B = 0.25 kg CH_4/kg COD);
MCF = methane conversion factor (Table 6-23 for aerobic treatment, Table 6-24 for anaerobic treatment); and
0.001 = conversion factor (kg to metric tonnes).

Note that if the volume of wastewater treated is known, the term P × W in Equation 6-11 can be replaced directly with the volume treated (m^3/yr).

IPCC provides the following COD default factors and ranges for maximum CH_4 producing capacity for oil and natural gas refineries and the organic chemical industry (IPCC, 2006):

1. For oil and natural gas refineries, a typical COD production rate of 1 kg COD per m^3 of wastewater generation, with the COD value ranging between 0.4 and 1.6 kg COD/m^3.

2. For the organic chemical industry, a typical COD production rate of 3 kg COD per m^3 of wastewater generation, with the COD value ranging between 0.8 and 5 kg COD/m^3.

IPCC also provides default factors and ranges for wastewater generation rates associated with the oil and natural gas refineries and the organic chemical industry (IPCC, 2006):

1. For oil and natural gas refineries, the typical wastewater generation rate is 0.6 m^3/ton product, with the generation rate ranging between 0.3 and 1.2 m^3/ton product.

2. For the organic chemical industry, the typical wastewater generation rate is 67 m^3/ton product, with a range between 0 and 400 m^3/ton product.

Default MCF values are provided in Table 6-23 for aerobic treatment and 6-24 for anaerobic treatment.

Table 6-23. Default MCF Values for Aerobic Industrial Wastewater Treatment

Type of Treatment	Comments	Default MCF	MCF Range
Aerobic treatment plant	Well maintained, some CH_4 may be emitted from settling basins	0	0—0.1
	Not well maintained, overloaded	0.3	0.2—0.4

Source:
IPCC, 2006 IPCC *Guidelines for National Greenhouse Gas Inventories, Volume 5, Chapter 6: Wastewater Treatment and Discharge*, 2006.

Table 6-24. Default MCF Values for Anaerobic Industrial Wastewater Treatment

Type of Treatment	Comments	Default MCF	MCF Range
Anaerobic digester for sludge	CH_4 recovery not considered here	0.8	0.8—1.0
Anaerobic reactor	CH_4 recovery not considered here	0.8	0.8—1.0
Anaerobic shallow lagoon	Depth less than 2 meters	0.2	0—0.3
Anaerobic deep lagoon	Depth more than 2 meters	0.8	0.8—1.0

Source:
IPCC, 2006 IPCC *Guidelines for National Greenhouse Gas Inventories, Volume 5, Chapter 6: Wastewater Treatment and Discharge*, 2006.

For either aerobic or anaerobic wastewater, N_2O emissions are calculated using Equation 6-12. Note that the default emission factor for N_2O (0.005 kg N_2O-N/kg N) is a factor for domestic wastewater nitrogen effluent (IPCC, 2006), but is assumed to be applicable for wastewater applications at oil and natural gas facilities.

$$E_{N_2O} = Q \times N \times EF_{N_2O} \times \frac{44}{28} \times 0.001 \qquad \text{(Equation 6-12)}$$

where

E_{N_2O} = emission rate of N_2O (tonnes/yr);
Q = volume of wastewater treated (m^3/yr);
N = average concentration of N in effluent (kg N/m^3);
EF_{N_2O} = emission factor for N_2O from discharged wastewater (0.005 kg N_2O-N/kg N);
44/28 = conversion factor (kg N_2O-N to kg N_2O); and
0.001 = conversion factor (kg to metric tonnes).

Aerobic Wastewater Treatment

Aerobic wastewater treatment is more common in oil and natural gas industry operations than anaerobic treatment. In aerobic conditions, bacteria consume organic material and convert it to CO_2. According to IPCC, the generation of CO_2 from aerobic wastewater treatment is not included as part of a GHG inventory because the carbon is viewed as part of the biogenic cycle (IPCC, 2006). However, in oil and natural gas operations, oil and natural gas-based organic material in the wastewater would not be considered biogenic, just as the oil and natural gas organic material that is combusted or released through vented and fugitive sources is not biogenic.

Carbon dioxide emissions from aerobic wastewater are produced through two mechanisms: the oxidation of organic material to produce new bacterial cells, and endogenous respiration. The oxidation of carbonaceous organic material is represented by measuring the biochemical oxidation (BOD). Assuming that the ultimate BOD removed is represented by $BOD_5/0.7$,[6] the following equation can be used to estimate CO_2 emissions from aerobic wastewater treatment:

$$E_{CO_2} = \text{WW Flow} \times \frac{3.785412\text{ L}}{\text{gal}} \times \frac{BOD_5}{0.7} \times \frac{44}{32} \times \frac{\text{tonne}}{10^9\text{ mg}} \quad \text{(Equation 6-13)}$$

where

E_{CO_2} = emission rate of CO_2 (tonnes/yr);
WW Flow = wastewater flow rate (10^6 gallons/yr);
$BOD_5/0.7$ = approximation of the ultimate BOD (mg/L); and
44/32 = oxygen to CO_2 conversion factor.

Methane and N_2O emissions from aerobic wastewater treatment are calculated using Equations 6-11 and 6-12, respectively (IPCC, 2006). For CH_4 however, aerobic conversion factors are provided in Table 6-23.

EXHIBIT 6.5: Sample Calculation for Aerobic Treatment Approach

INPUT DATA:
A well-maintained aerobic wastewater treatment system processes 5 million gallons per day with a BOD removal of 120 mg/L (BOD_5). Estimate the CO_2 emissions.

CALCULATION METHODOLOGY:
1. *Calculate CO_2 emissions using Equation 6-13.*

$$E_{CO_2} = \text{WW Flow} \times \frac{3.785412\text{ L}}{\text{gal}} \times \frac{BOD_5}{0.7} \times \frac{44}{32} \times \frac{\text{tonne}}{10^9\text{ mg}}$$

$$= \frac{5\times10^6\text{ gal}}{\text{day}} \times \frac{365\text{ days}}{\text{yr}} \times \frac{3.785412\text{ L}}{\text{gal}} \times \frac{120\text{ mg/L}}{0.7} \times \frac{44}{32} \times \frac{\text{tonne}}{10^9\text{ mg}}$$

$$= \underline{1,628\text{ tonnes } CO_2\text{ / yr}}$$

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[6] The factor "BOD5/0.7" represents an estimate of the total or ultimate BOD, L (i.e., the total or ultimate first-stage BOD initially present). The BOD5 and ultimate BOD (L) are related by the following equation: BOD5 = L (1 - e^-kt), where k is the reaction rate constant and t is time of the BOD remaining in the water (Metcalf and Eddy, 1991). For wastewater, a typical value of 0.23 day^-1 at 68°F is provided by a common wastewater engineering handbook (Metcalf and Eddy, 1991). Therefore, the equation for the ultimate BOD with the values substituted is L = BOD5/[1-e^-(0.23)(5)] = BOD5/0.7.

Anaerobic Wastewater Treatment

Anaerobic water treatment is not common in the oil and natural gas industry, and it is possible to recover the CH_4 generated for use as a fuel. For these reasons, anaerobic water treating is not considered a significant GHG emission source for the oil and natural gas industry.

Methane and N_2O emissions from anaerobic wastewater treatment can be calculated using Equations 6-11 and 6-12, respectively. Table 6-24 provides default CH_4 conversion factors for anaerobic wastewater treatment for use with Equation 6-11.

Alternatively, EPA presents a relatively simple method for estimating CH_4 emissions for facilities where CH_4 is not captured from an anaerobic water treatment system (EPA AP-42 Section 4.3.5.2, 1998). The following equation applies:

$$E_{CH_4} = Q \times \left(\frac{\text{lb BOD}_5}{\text{ft}^3 \text{wastewater}} \right) \times \left(\frac{0.22 \text{ lb CH}_4}{\text{lb BOD}_5} \right) \times F_{AD} \times 365 \qquad \text{(Equation 6-14)}$$

where

E_{CH_4} = emission rate of CH_4 in pounds per year;
Q = wastewater flow rate in cubic feet per day;
BOD_5 = biochemical oxygen demand measured using the standard five day test;
F_{AD} = fraction anaerobically digested; and
365 = days per year.

A site-specific value for BOD_5 loading should be available from facility wastewater treating staff. If it is not, EPA suggests a default value of 0.25 pounds BOD_5 per cubic foot of wastewater for the oil and natural gas industry. The fraction anaerobically digested is that part of the wastewater flow that is routed to anaerobic treatment rather than aerobic treatment.

The emission rate for CO_2 from anaerobic water treatment is considered to be negligible compared to the CH_4 emission rate. No equation or emission factors have been found to estimate these emissions.

An example calculation for CH_4 emissions from anaerobic water treatment follows in Exhibit 6.6.

EXHIBIT 6.6: 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 (anaerobic shallow lagoon). The BOD_5 level of the influent averages 0.3 pounds per cubic foot. Calculate the CH_4 emissions using Equation 6-14 and the IPCC approach.

CALCULATION METHODOLOGY:
1. *Calculate CH_4 emissions using Equation 6-14.* Using Equation 6-14, the estimated emissions are:

$$E_{CH_4} = 870{,}000 \frac{\text{ft}^3}{\text{day}} \times \left(\frac{0.1 \text{ ft}^3 \text{ anaerobic}}{\text{ft}^3 \text{processed}}\right) \times \left(\frac{0.3 \text{ lb BOD}_5}{\text{ft}^3 \text{wastewater}}\right) \times \left(\frac{0.22 \text{ lb CH}_4}{\text{lb BOD}_5}\right) \times 365 \frac{\text{days}}{\text{year}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CH_4} = 950.7 \text{ tonne CH}_4\text{/yr}}$$

2. *Calculate CH_4 emissions using IPCC's approach.* Using IPCC's approach (Equation 6-11), assuming the default COD rate for a refinery (1 kg COD per m^3 of wastewater) and the default MCF from Table 6-24 (0.2), the estimated emissions are calculated as follows:

$$E_{CH_4} = 870{,}000 \frac{\text{ft}^3}{\text{day}} \times \left(\frac{0.1 \text{ ft}^3 \text{ anaerobic}}{\text{ft}^3 \text{processed}}\right) \times 365 \frac{\text{days}}{\text{year}} \times \frac{\text{m}^3}{35.3147 \text{ ft}^3} \times \frac{1 \text{ kg COD}}{\text{m}^3} \times \frac{0.25 \text{ kg CH}_4}{\text{kg COD}} \times 0.2 \times \frac{0.001 \text{ tonne CH}_4}{\text{kg CH}_4}$$

$$\underline{E_{CH_4} = 44.96 \text{ tonne CH}_4\text{/yr}}$$

6.2.2 Biotreaters

There are applications in the oil and natural gas industry where biotreaters (or biofilters) are used in treating wastewater and/or as control devices to remove TOC from vent streams. The CO_2 emissions from biotreaters are expected to be insignificant compared to major sources like combustion. The CO_2 production from biotreaters can be estimated from the feed TOC rate and the biomass conversion efficiency. The produced CO_2 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 Fluorinated Fugitive Emissions

In addition to fugitive emission sources of CH_4 or CO_2, there may be equipment or operations associated with oil and natural gas industry activities that result in emissions of CFCs, HCFCs, HFCs, PFCs, and SF_6. Chlorofluorcarbons and HCFCs are regulated under the Montreal Protocol, and are not typically included in a GHG inventory. However, HFCs, PFCs, and SF_6 are accounted for under most GHG registry programs. Potential fugitive emission sources of HFC emissions for the oil and natural gas industry are leakage from the operation of chillers and air conditioning equipment, including air conditioning for mobile sources. Emissions of SF_6 may result from electrical transmission and distribution equipment, and from the use of SF_6 as a tracer gas to detect leaks.

Emissions of fluorinated substances and SF_6 can be calculated using either a mass balance approach or default operating emission factors. When using the mass balance approach, emissions are commonly reported during the year of recharge, even though fugitive emissions of these substances can occur over multiple years.

6.3.1 Emissions from Air Conditioning and Refrigeration Equipment

Emissions from refrigeration and air conditioning equipment are expected to be very small for oil and natural gas industry operations. This section discusses emissions from the operation of air conditioning and refrigeration equipment. Although emissions can also occur from the manufacture and disposal of fluorinated substances, these activities are generally not conducted as part of oil and natural gas operations.[7] Figure 6-4 provides a decision tree for estimating refrigerant emissions based on the contribution of these emissions to the entity's inventory.[8]

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[7] An additional calculation methodology for the manufacture, installation, or disposal of refrigeration and air conditioning equipment can be found in the following references: EPA, *Climate Leaders Greenhouse Gas Inventory Protocol, Core Module Guidance: Direct HFC and PFC Emissions from Use of Refrigeration and Air Conditioning Equipment,* (EPA, 2008); IPCC, *2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3 Chapter 7: Emissions of Fluorinated Substitutes of Fluorinated Substitutes for Ozone Depleting Substances* (IPCC, 2006); and WRI/ WBCSD, *Calculating HFC and PFC Emissions from the Manufacturing, Installation, Operation and Disposal of Refrigeration & Air-conditioning Equipment (Version 1.0) Guide to Calculation Worksheets,* (WRI/WBCSD,

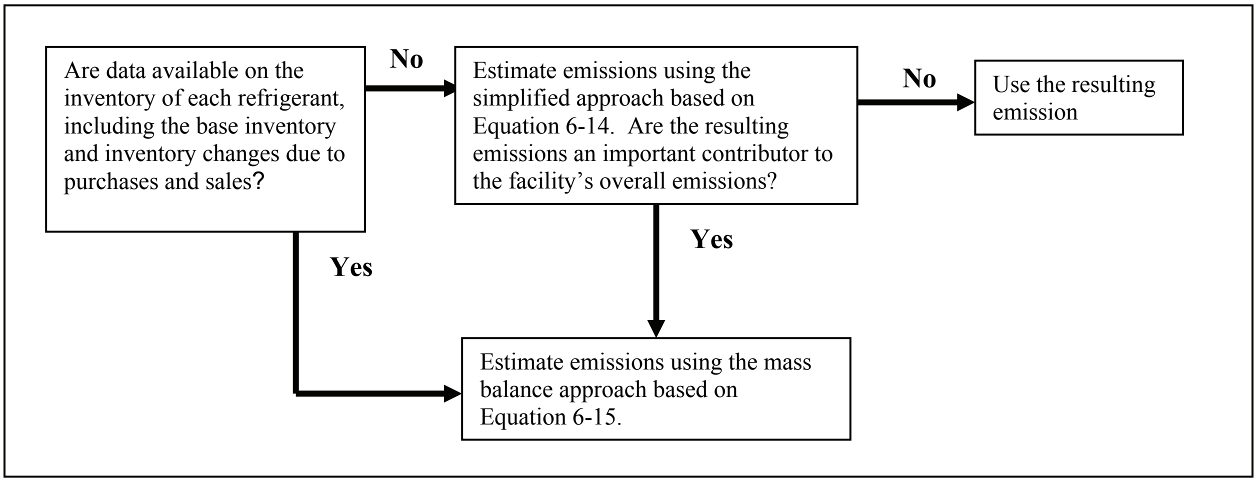

Figure 6-4. Refrigerant Emissions

A simplified estimation method for refrigerant emissions is based on knowing the type of refrigerant and type of equipment. Annual emissions are estimated by adjusting the total charge capacity of the equipment by an annual default leak rate, as shown in Equation 6-15 (WRI/WBCSD, 2005).

$$E_{\text{Refridgerants}} = \text{Equipment Charge (kg)} \times EF_{\text{Operating}} \times \frac{\text{tonne}}{1000\text{ kg}} \qquad \text{(Equation 6-15)}$$

where

$E_{\text{Refrigerant}}$ = emission rate of the PFC or HFC from refrigeration equipment;
Equipment Charge = total full charge of equipment (kg); and
$EF_{\text{Operating}}$ = EF associated with the operating phase of the equipment.

Table 6-25 provides the default equipment capacities and operating leak rates for common types of refrigeration equipment. This assumes that the installation and disposal of the refrigeration or air conditioning equipment is not conducted by the oil and natural gas entity. Where this assumption is not valid, refer to Volume 3, Chapter 7 of the IPCC Guidelines (IPCC, 2007) for additional factors to include in the emission estimation approach.

Refrigerant emissions are then converted to CO_2e by applying the appropriate global warming potential factors provided in Table 3-1 or Table 6-26 for refrigerant blends.

January 2005).

[8] The methodology described in this subsection is consistent with the methodology described in The Climate Registry (TCR, 2008).

Table 6-25. Default Operating Emission Factors for Refrigeration / Air Conditioning Equipment

Type of Equipment	Capacity (kg)	Operating Emission Factor (% of capacity/year)
Domestic refrigeration	0.05 – 0.5	0.5%
Stand-alone commercial applications	0.2 – 6	15%
Medium & large commercial refrigeration	50 – 2,000	35%
Transport refrigeration	3 – 8	50%
Industrial refrigeration including cold storage	10 – 10,000	25%
Chillers	10 – 2,000	15%
Residential and commercial A/C, including heat pumps	0.5 – 100	10%
Mobile air conditioning	0.5 – 1.5	20%

Source:
IPCC, *2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3, Chapter 7: Emissions of Fluorinated Substitutes for Ozone Depleting Substances*, Table 7-9, 2007. Operating emission factors are the high end of the reported range.

Table 6-26. Global Warming Potentials for Refrigeration Blends

Refrigerant Blend	Global Warming Potential	Refrigerant Blend	Global Warming Potential	Refrigerant Blend	Global Warming Potential
R-401A	18	R-409A	0	R-419A	2,403
R-401B	15	R-409B	0	R-420A	1,144
R-401C	21	R-410A	1,725	R-500	37
R-402A	1,680	R-410B	1,833	R-501	0
R-402B	1,064	R-411A	15	R-502	0
R-403A	1,400	R-411B	4	R-503	4,692
R-403B	2,730	R-412A	350	R-504	313
R-404A	3,260	R-413A	1,774	R-505	0
R-406A	0	R-414A	0	R-506	0
R-407A	1,770	R-414B	0	R-507 or R-507A	3,300
R-407B	2,285	R-415A	25	R-508A	10,175
R-407C	1,526	R-415B	105	R-508B	10,350
R-407D	1,428	R-416A	767	R-509 or R-509A	3,920
R-407E	1,363	R-417A	1,955		
R-408A	1,944	R-418A	4		

Source:
WRI/WBCSD GHG Protocol Initiative. *Calculating HFC and PFC Emissions from the Manufacturing, Installation, Operation and Disposal of Refrigeration & Air Conditioning Equipment: Guide to Calculation Worksheets*, Version 1.0, 2005. Taken from ASHRAE Standard 34.

Where refrigerant emissions are a significant part of an entity's GHG inventory (defined by most reporting programs as larger than 5% of the inventory), emissions from air conditioning equipment can be calculated using a mass balance approach, as shown in the following equation (WRI/WBCSD, 2005):

$$E_{FC_i} = S_{E,i} - S_{B,i} + P_i - S_i + \Delta C_i \quad \text{(Equation 6-16)}$$

where

$E_{FC,i}$ = emission rate of fluorinated compound or refrigerant mixture *i;*
$S_{E,i}$ = quantity of refrigerant *i* in storage at the end of the year;
$S_{B,i}$ = quantity of refrigerant *i* in storage at the beginning of the year;
P_i = purchases/acquisitions of refrigerant *i* during the year;
S_i = sales/disbursements of refrigerant *i* during the year; and
ΔC_i = net change in total equipment volume for refrigerant i.

Equation 6-16 should be applied to each type of refrigerant or mixture used. Care should be taken that releases are not double counted (e.g., from reporting both refrigerant blend and individual refrigerant use). Emissions from refrigerant recharges should be accounted for in the year the recharge occurred. An example calculation for HFC emissions from air conditioning equipment is shown in Exhibit 6.7.

EXHIBIT 6.7: Sample Calculation for Air Conditioning HFC Emissions

INPUT DATA:
An oil and natural gas industry company owns and operates 680 vehicles utilizing Freon-134a (otherwise known as R-134a or HFC-134a). The vehicles range from small passenger vehicles to heavy-duty transport vehicles. Calculate the emissions by pollutant and as CO_2e.

CALCULATION METHODOLOGY:
Because the specific capacity of the vehicles is unknown, it is assumed that the median capacity of the vehicles is equal to the high-range capacity listed in Table 6-25. Using Equation 6-15, the estimated emissions would be:

$$E_{R\text{-}134a} = 680\text{ vehicles} \times \frac{1.5\text{ kg}}{\text{vehicle}} \times 0.2 \times \frac{\text{tonne}}{1000\text{ kg}}$$

$$\underline{E_{R\text{-}134a} = 0.204\text{ tonnes R-134a}}$$

$$E_{CO_2e} = 0.204\text{ tonnes R-134a} \times \frac{1300\text{ tonne }CO_2e}{\text{tonne R-134a}}$$

$$\underline{E_{CO_2e} = 265.2\text{ tonne }CO_2e}$$

6.3.2 Electrical Equipment

Electrical transmission and distribution systems may use SF_6 as an insulator or interrupter, due to its dielectric strength. Sulfur hexafluoride may be found in substations, circuit breakers, and switchgears. A potential source of SF_6 emissions in the oil and natural gas industry is equipment leaks (e.g., through seals) and servicing of electrical transmission and distribution equipment, where an oil and natural gas company operates this equipment.

Electrical equipment-based SF_6 emissions can be calculated using either Equation 6-17 or 6-18. Equation 6-16 is appropriate in instances where electrical equipment that use SF_6 have been in use for 10-20 years or more, and emissions from sealed-pressure systems are likely to be negligible. Equation 6-17 is appropriate for sealed-pressure equipment and all types of equipment where electrical equipment has been used for less than 10-20 years.

$$E_{SF_6} = (Q_{Recharge} - Q_{Recovered}) \qquad \text{(Equation 6-17)}$$

$$E_{SF_6} = (Q_{Recharge} - Q_{Recovered}) \times \sum C \times EF \qquad \text{(Equation 6-18)}$$

where

E_{SF_6} = annual emissions of SF_6;
$Q_{Recharge}$ = SF_6 used to recharge closed pressure equipment at servicing;
$Q_{Recovered}$ = SF_6 recovered from closed pressure equipment at servicing;
C = nameplate capacity of equipment installed, excluding equipment covered in ($Q_{Recharge} - Q_{Recovered}$); and
EF = usage based emission factor (see Table 6-27).

Usage-based emission factors for SF_6 emissions from electrical equipment are provided in Table 6-27.

Table 6–27. Usage-Based Fugitive Emission Factors for Electrical Equipment

Equipment	Region/Country	Reference Factor[a,b], Units	
Sealed pressure electrical equipment (MV Switchgear)	Europe	0.002	Fraction per year of nameplate capacity of all equipment installed
	Japan	0.007	
Closed pressure electrical equipment	Europe	0.026	
	Japan	0.007	
	U.S.	0.14[c]	
Gas insulated transformers	Japan	0.007	

Footnotes and Sources:
[a] IPCC. *2006 IPCC Guidelines for National Greenhouse Gas Inventories,* Volume 3, Chapter 8, April 2007, Tables 8.2 through 8.4.
[b] Factors include leakage, major failures/arc faults and maintenance losses. Factors reflect the practices and technologies in place in 1995.
[c] Includes emissions from installation.

SF_6 emissions from electrical transmission and distribution can be calculated using Equation 6-19. Distance-based emission factors for SF_6 emissions from electrical transmission and distribution are provided in Table 6-28.

$$E_{SF_6} = TD \times EF \qquad \text{(Equation 6-19)}$$

where

E_{SF_6} = annual emissions of SF_6;

TD = transmission distance (mi), for lines carrying voltage at or above 34.5 kV; and

EF = distance based emission factor.

Table 6–28. Distance-Based Fugitive Emission Factors for Electrical Transmission and Distribution

Emission Basis	Reference Emission Factor [a], Original Units		Emission Factor, Converted Units	
Less than 10,000 transmission miles	0.89	kg SF_6/mi-yr	8.90E-04	tonne SF_6/mi-yr
			5.53E-04	tonne SF_6/km-yr
More than 10,000 transmission miles	0.58	kg SF_6/mi-yr	5.80E-04	tonne SF_6/mi-yr
			3.60E-04	tonne SF_6/km-yr

Footnote and Source::

[a] EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, April 2009, pg. 4-69.

Exhibit 6.8 presents an example of calculating SF_6 emissions using the major equipment emission factors approach.

EXHIBIT 6.8: Sample Calculation for Electrical Equipment Emissions

INPUT DATA:

A company specializing in the delivery of natural gas and electricity operates 135 miles of electric transmission and distribution lines (at or above 34.5 kV), with various electrical equipment used to support electric transmission and distribution. The company uses SF_6 for electrical insulation and current interruption.

Service records for the past year indicate that a total of 79,878 lb SF_6 was used to recharge electrical equipment, while a total of 79,480 lb SF_6 was recovered from electrical equipment. Calculate the SF_6 and CO_2e emissions using both the equipment usage methodology and transmission mileage methodology, for comparison purposes.

EXHIBIT 6.8: Sample Calculation for Electrical Equipment Emissions, continued

CALCULATION METHODOLOGY:

1. *Calculate emissions associated with the equipment.* Emissions of SF_6 are calculated using a material balance.

$$E_{SF_6} = \frac{(79{,}878 - 79{,}480)\text{ lb}}{\text{yr}} \times \frac{\text{tonne}}{2204.62\text{ lb}} = \underline{0.18\text{ tonne SF}_6\text{ / yr}}$$

CO_2e emissions are calculated using Equation 3-2.

$$E_{CO_2e} = \frac{0.18\text{ tonne SF}_6}{\text{yr}} \times \frac{23{,}900\text{ tonne CO}_2}{\text{tonne SF}_6}$$

$$\underline{E_{CO_2e} = 4{,}314.67\text{ tonne CO}_2\text{e}}$$

2. *Calculate emissions using associated with transmission mileage.* Using Equation 6-19 (for mileage based emissions) and the global warming potential from Table 3-1, the estimated emissions would be:

$$E_{SF_6} = 135\text{ miles} \times \frac{0.89\text{ kg}}{\text{mile-yr}} \times \frac{\text{tonne}}{1000\text{ kg}} = 0.12\text{ tonne SF}_6\text{/yr}$$

CO_2e. emissions are calculated using Equation 3-2.

$$E_{CO_2e} = \frac{0.12\text{ tonne SF}_6}{\text{yr}} \times \frac{23{,}900\text{ tonne CO}_2}{\text{tonne SF}_6}$$

$$\underline{E_{CO_2e} = 2{,}839.32\text{ tonne CO}_2}$$

Note the difference between the emissions calculated with the two methods. As with any methodology, a mass balance approach will be more accurate than the use of emission factors.

6.3.3 SF_6 Emissions from Pipeline Operations

Natural gas pipeline operations may use SF_6 as a tracer gas to detect leaks. Emissions from these activities can be determined using a mass balance approach, similar to that shown for refrigerant emissions:

$$E_{SF_6} = S_E - S_B + P - S + \Delta C \qquad \text{(Equation 6-20)}$$

where

E_{SF_6} = emission rate of SF_6;
S_E = quantity of SF_6 in storage at the end of the year;
S_B = quantity of SF_6 in storage at the beginning of the year;
P = purchases/acquisitions of SF_6 during the year;
S = sales/disbursements of SF_6 during the year; and
ΔC = net change in total equipment SF_6 volume.

Alternatively, SF_6 emissions can be determined by scaling pipeline fugitive CH_4 emissions based on the relative concentration of SF_6 in the gas compared to CH_4, similar to the adjustment shown in Equation 6-1 for CO_2 emissions.

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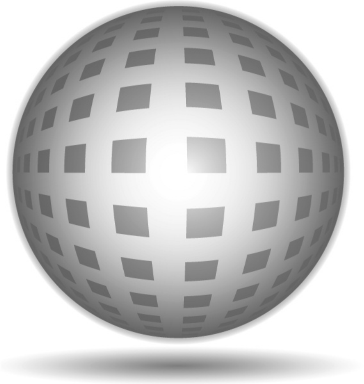
AMERICAN PETROLEUM INSTITUTE

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

AUGUST 2009

SECTION 7

INDIRECT EMISSIONS ESTIMATION METHODS



Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry

Section 7 – Indirect Emissions Estimation Methods

August 2009

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7.0 INDIRECT EMISSIONS ESTIMATION METHODS

Indirect emissions are emissions that are a consequence of activities of the reporting company, but which result from sources owned or controlled by another party (IPIECA, 2003). This section addresses indirect emissions from the purchase of energy, the largest source of indirect emissions for the oil and natural gas industry. Carbon dioxide, CH_4, and N_2O are emitted when fuel is combusted to generate electricity or to produce heat, steam, or cooling water. This section provides methodologies for estimating the emissions associated with these activities, where these energy sources are generated off site and purchased for use on site. In addition, this section addresses the allocation of emissions among co-produced streams, such as those associated with the cogeneration of electricity and steam. For transparency, indirect energy emissions, also referred to as Scope 2, should be reported separately from direct emissions (WRI, 2005).

7.1 Emissions Associated with Purchased or Imported Energy

Figure 7-1 provides a decision tree for selecting an approach for estimating emissions associated with purchased electricity. As shown, 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.

7.1.1 Electricity from a Known Generator

It is often difficult to track purchased electricity back to the source. However, where electricity is supplied from a known generator, emissions associated with purchased or imported electricity can be based on fuel-derived emission factors provided by the generator or fuel data using the combustion emission approach presented in Section 4.3. Figure 7-1 depicts several approaches to estimate indirect emissions from electricity. These approaches are based on having generation facility data such as publicly reported emissions factors, fuel composition and quantity consumed, and fuel/generation type, or knowing the region from which the electricity is generated. If only general information is available on the type of fuel and combustion method, Table 7-1 provides CO_2, CH_4, and N_2O emission factors for electricity generation on a power consumed basis (megawatt-hours) from the U.S. EIA or the U.S. DOE (EIA, 2007; DOE, 1994).

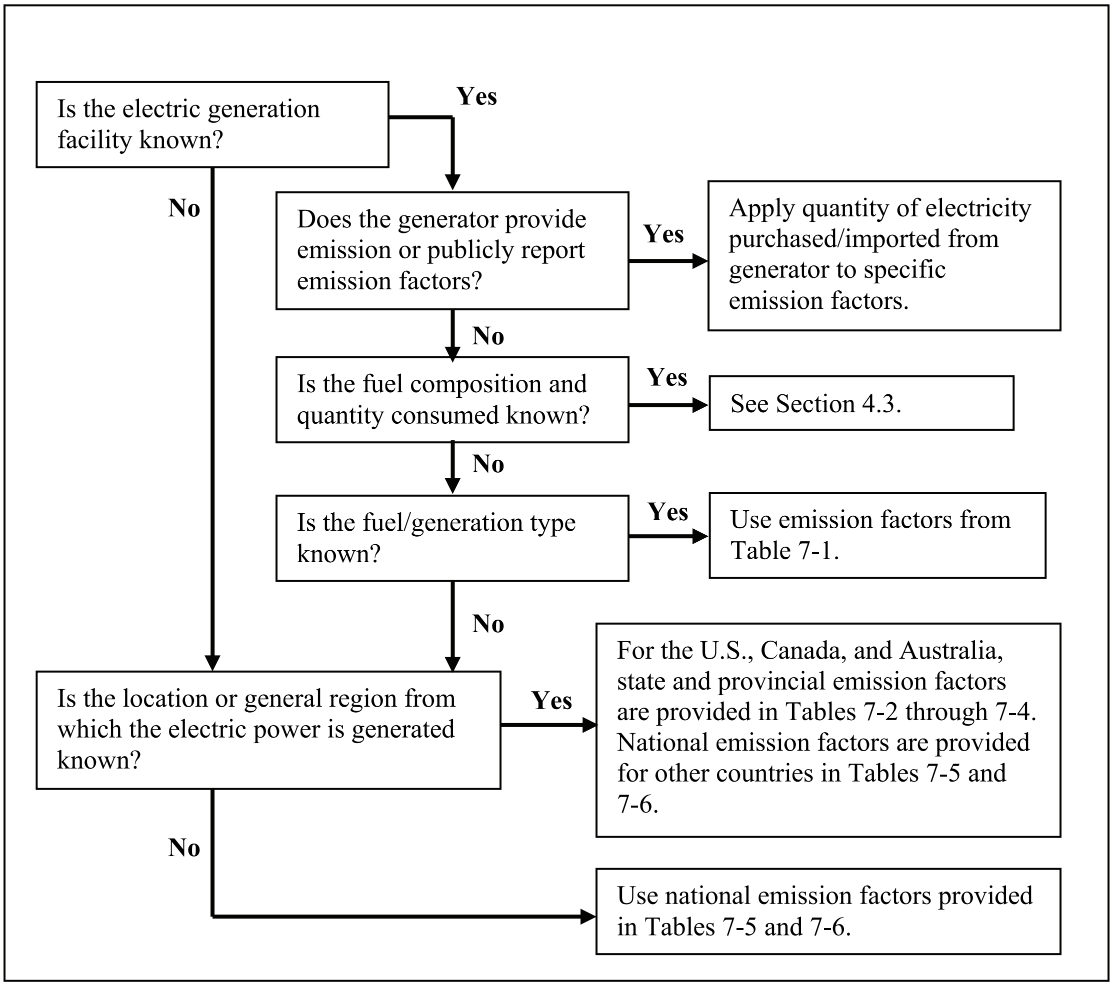

Figure 7-1. Decision Tree for Purchased Electricity Emissions

Table 7-1. Electricity Usage Emission Factors by Method of Generation

		Carbon Dioxide [a]		Methane [b]		Nitrous Oxide [b]	
Method of Generation	**Fuel Type**	**lb/ 10^6 W-hr**	**tonnes/ 10^6 W-hr**	**lb/ 10^6 W-hr**	**tonnes/ 10^6 W-hr**	**lb/ 10^6 W-hr**	**tonnes/ 10^6 W-hr**
Advanced combustion turbine	Natural Gas	1,102.31	0.50	No Data			
	Distillate Oil	1,499.14	0.68	No Data			
	Residual Oil	1,609.37	0.73	No Data			
Advanced gas / oil combined cycle	Natural Gas	815.71	0.37	No Data			
	Distillate Oil	1,124.36	0.51	No Data			
	Residual Oil	1,212.54	0.55	No Data			
Combined cycle [c]	Natural Gas	881.85	0.40	0.015	6.80E-06	0.063	2.86E-05
	Distillate Oil	1,190.49	0.54	0.013	5.90E-06	0.268	1.22E-04
	Residual Oil	1,300.73	0.59	0.013	5.90E-06	0.268	1.22E-04
Combustion turbine [d]	Natural Gas	1,278.68	0.58	0.16	7.26E-05	0.24	1.09E-04
	Distillate Oil	1,741.65	0.79	0.021	9.53E-06	0.276	1.25E-04
	Residual Oil	1,873.93	0.85	0.021	9.53E-06	0.276	1.25E-04
Distributed generation - baseload	Natural Gas	1,102.31	0.50	No Data			
	Distillate Oil	1,499.14	0.68	No Data			
	Residual Oil	1,609.37	0.73	No Data			
Distributed generation - peak	Natural Gas	1,212.54	0.55	No Data			
	Distillate Oil	1,653.47	0.75	No Data			
	Residual Oil	1,785.74	0.81	No Data			
Fuel cells	Natural Gas	881.85	0.40	No Data			
Geothermal – unspecified		268.96	0.122 [e]	No Data			
Geothermal – all, including binary		180 [f]	0.0816	1.66E-03 [f]	7.53E-07	No Data	
Geothermal – flash/dry steam		56.7	0.0257	No Data			
Integrated coal – gasification combined cycle	Coal	1,653.47	0.75	No Data			
Municipal solid waste boiler [g]		3,747	1.70	0.02	9.07E-06	0.55	2.49E-04
Pulverized coal	Coal	1,970	0.89	0.04	1.81E-05	0.34	1.54E-04
Renewables (wind, hydro, solar, and nuclear)		0	0	0	0	0	0
Scrubbed coal	Coal	1,851.88	0.84	No Data			
Steam turbine	Natural Gas	968	0.44	0.05	2.27E-05	0	0
	Oil	1,452	0.66	0.002	9.07E-07	0	0
Wood waste biomass boiler [h]		3,400	1.54	0.14	6.35E-05	0.55	2.49E-04

Footnotes and Sources:

[a] Emission factors taken from U.S. Energy Information Administration, *Technical Guidelines Voluntary Reporting of Greenhouse Gases (1605(b)) Program*, Table 1.F.3, January 2007, unless otherwise noted. Only CO_2 emission factors are available for these Generator Types.

[b] U.S. 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, Appendix B, DOE/PO-0028*, Washington, DC, October 1994.

[c] Gas - Combined Cycle CH_4 and N_2O factors used for Natural Gas; Oil - Combined Cycle CH_4 and N_2O factors used for both distillate oil and residual oil.

[d] Gas - Combustion Turbine CH_4 and N_2O factors used for Natural Gas; Oil - Combustion Turbine CH_4 and N_2O factors used for both distillate oil and residual oil.

[e] Factor for unspecified plant type. Source: International Geothermal Association (Bertani and Thain, 2001).

[f] Factors for all geothermal plant types (including binary). Source: Geothermal Resources Council (Bloomfield and Moore, 1999).

[g] 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 CO_2 emission factor for municipal solid waste.

[h] Under international GHG accounting methods developed by the IPCC, biogenic carbon is considered to be part of the natural carbon balance and does not add to atmospheric concentrations of CO_2.

Note that these emission factors 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. Exhibit 7.1 demonstrates the use of the generation-based emission factors provided in Table 7-1.

EXHIBIT 7.1: 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. Calculate the CO_2, CH_4, and N_2O emissions.

CALCULATION METHODOLOGY:
Emission factors for a natural gas combined-cycle system are provided in Table 7-1. The emission factors are multiplied by the quantity of electricity purchased to calculate the annual emissions, as follows:

$$E_{CO_2} = \frac{500{,}000 \text{ kilowatt-hr}}{\text{yr}} \times \frac{1 \text{ megawatt}}{1000 \text{ kilowatt}} \times \frac{0.40 \text{ tonne } CO_2}{\text{megawatt-hr}}$$

$$\underline{E_{CO_2} = 200 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CH_4} = \frac{500{,}000 \text{ kilowatt-hr}}{\text{yr}} \times \frac{1 \text{ megawatt}}{1000 \text{ kilowatt}} \times \frac{6.80 \times 10^{-6} \text{ tonne } CH_4}{\text{megawatt-hr}}$$

$$\underline{E_{CH_4} = 0.0034 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{500{,}000 \text{ kilowatt-hr}}{\text{yr}} \times \frac{1 \text{ meagwatt}}{1000 \text{ kilowatt}} \times \frac{2.86 \times 10^{-5} \text{ tonne } CO_2}{\text{megawatt-hr}}$$

$$\underline{E_{N_2O} = 0.0143 \text{ tonnes } N_2O/\text{yr}}$$

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

http://www.epa.gov/cleanenergy/egrid/index.htm[1]

The database is a comprehensive inventory of environmental attributes of electric power systems, integrating information from both utility and non-utility companies. eGRID is based on available plant-specific data for all U.S. electricity generating plants that provide power to the electric grid and report data to the U.S. government. The database provides CO_2 emission rates (in addition to NOx, SO_2, 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. Recently, eGRID added CH_4 and N_2O emissions rates.

Ideally, the emissions would be based on the most detailed information available. For example, if a facility knew that the 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.

7.1.2 Purchased Electricity from an Unknown Generator – State or Regional Basis

In the case where electricity is imported directly from a third party power supplier, generation and fuel information may not be available in all cases. Where the detailed 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.

Since electric transmission and distribution lines do not adhere to state boundaries, it is often difficult to identify a specific generation source. In the U.S., the EPA's eGRID database provides GHG emission factors based on electric generation from all electricity generating plants that provide power to the electric grid and report to the U.S. government. eGRID subregions are subsets of NERC regions, with similar emissions and resource mix characteristics. eGRID emission factors are summarized in Table 7-2, with the corresponding subregions illustrated in Figure 7-2. Subregions can also be determined by ZIP code using the EPA Power Profiler Tool, which can be found at the following address:
http://www.epa.gov/cleanenergy/powerprofiler.htm[2]

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[1] Accessed June 19, 2009.
[2] Accessed June 19, 2009.

Table 7-2. Average U.S. Electricity Usage Emission Factors by eGRID Subregion - 2005 [a]

eGRID Subregion Acronym	eGRID Subregion Name	CO_2 Output Emission Rate			CH_4 Output Emission Rate			N_2O Output Emission Rate		
		(lb/MWh)	(ton/MWh)	(tonne/MWh)	(lb/MWh)	(ton/MWh)	(tonne/MWh)	(lb/MWh)	(ton/MWh)	(tonne/MWh)
AKGD	ASCC Alaska Grid	1,232.36	0.616	0.559	0.0256	1.28E-05	1.16E-05	0.00651	3.26E-06	2.95E-06
AKMS	ASCC Miscellaneous	498.86	0.249	0.226	0.02075	1.04E-05	9.41E-06	0.00408	2.04E-06	1.85E-06
AZNM	WECC Southwest	1,311.05	0.656	0.595	0.01745	8.73E-06	7.92E-06	0.01794	8.97E-06	8.14E-06
CAMX	WECC California	724.12	0.362	0.328	0.03024	1.51E-05	1.37E-05	0.00808	4.04E-06	3.67E-06
ERCT	ERCOT All	1,324.35	0.662	0.601	0.01865	9.33E-06	8.46E-06	0.01511	7.56E-06	6.85E-06
FRCC	FRCC All	1,318.57	0.659	0.598	0.04592	2.30E-05	2.08E-05	0.01694	8.47E-06	7.68E-06
HIMS	HICC Miscellaneous	1,514.92	0.757	0.687	0.31468	1.57E-04	1.43E-04	0.04688	2.34E-05	2.13E-05
HIOA	HICC Oahu	1,811.98	0.906	0.822	0.10947	5.47E-05	4.97E-05	0.02362	1.18E-05	1.07E-05
MROE	MRO East	1,834.72	0.917	0.832	0.02759	1.38E-05	1.25E-05	0.03036	1.52E-05	1.38E-05
MROW	MRO West	1,821.84	0.911	0.826	0.028	1.40E-05	1.27E-05	0.03071	1.54E-05	1.39E-05
NEWE	NPCC New England	927.68	0.464	0.421	0.08649	4.32E-05	3.92E-05	0.01701	8.51E-06	7.72E-06
NWPP	WECC Northwest	902.24	0.451	0.409	0.01913	9.57E-06	8.68E-06	0.0149	7.45E-06	6.76E-06
NYCW	NPCC NYC/Westchester	815.45	0.408	0.370	0.03602	1.80E-05	1.63E-05	0.00546	2.73E-06	2.48E-06
NYLI	NPCC Long Island	1,536.80	0.768	0.697	0.11541	5.77E-05	5.23E-05	0.01809	9.05E-06	8.21E-06
NYUP	NPCC Upstate NY	720.80	0.360	0.327	0.02482	1.24E-05	1.13E-05	0.01119	5.60E-06	5.08E-06
RFCE	RFC East	1,139.07	0.570	0.517	0.03027	1.51E-05	1.37E-05	0.01871	9.36E-06	8.49E-06
RFCM	RFC Michigan	1,563.28	0.782	0.709	0.03393	1.70E-05	1.54E-05	0.02717	1.36E-05	1.23E-05
RFCW	RFC West	1,537.82	0.769	0.698	0.01823	9.12E-06	8.27E-06	0.02571	1.29E-05	1.17E-05
RMPA	WECC Rockies	1,883.08	0.942	0.854	0.02288	1.14E-05	1.04E-05	0.02875	1.44E-05	1.30E-05
SPNO	SPP North	1,960.94	0.980	0.889	0.02382	1.19E-05	1.08E-05	0.03209	1.60E-05	1.46E-05
SPSO	SPP South	1,658.14	0.829	0.752	0.02498	1.25E-05	1.13E-05	0.02261	1.13E-05	1.03E-05
SRMV	SERC Mississippi Valley	1,019.74	0.510	0.463	0.02431	1.22E-05	1.10E-05	0.01171	5.86E-06	5.31E-06
SRMW	SERC Midwest	1,830.51	0.915	0.830	0.02115	1.06E-05	9.59E-06	0.0305	1.53E-05	1.38E-05
SRSO	SERC South	1,489.54	0.745	0.676	0.02627	1.31E-05	1.19E-05	0.02547	1.27E-05	1.16E-05
SRTV	SERC Tennessee Valley	1,510.44	0.755	0.685	0.02005	1.00E-05	9.09E-06	0.02564	1.28E-05	1.16E-05
SRVC	SERC Virginia/Carolina	1,134.88	0.567	0.515	0.02377	1.19E-05	1.08E-05	0.01979	9.90E-06	8.98E-06
U.S. Average		**1,347.05**	**0.674**	**0.611**	**0.046**	**2.29E-05**	**2.08E-05**	**0.0206**	**1.03E-05**	**9.33E-06**

Footnotes and Source:

[a] U.S. EPA. *eGRID2007 Version 1.1 Year 2005 GHG Annual Output Emission Rates*, December 2008. Emission factors were converted from units of lb/MWh to units of ton/MWh and tonne/MWh. 2005 was the most recent year for which emission factors were available, as of the time of publication. U.S. Average factors are derived.

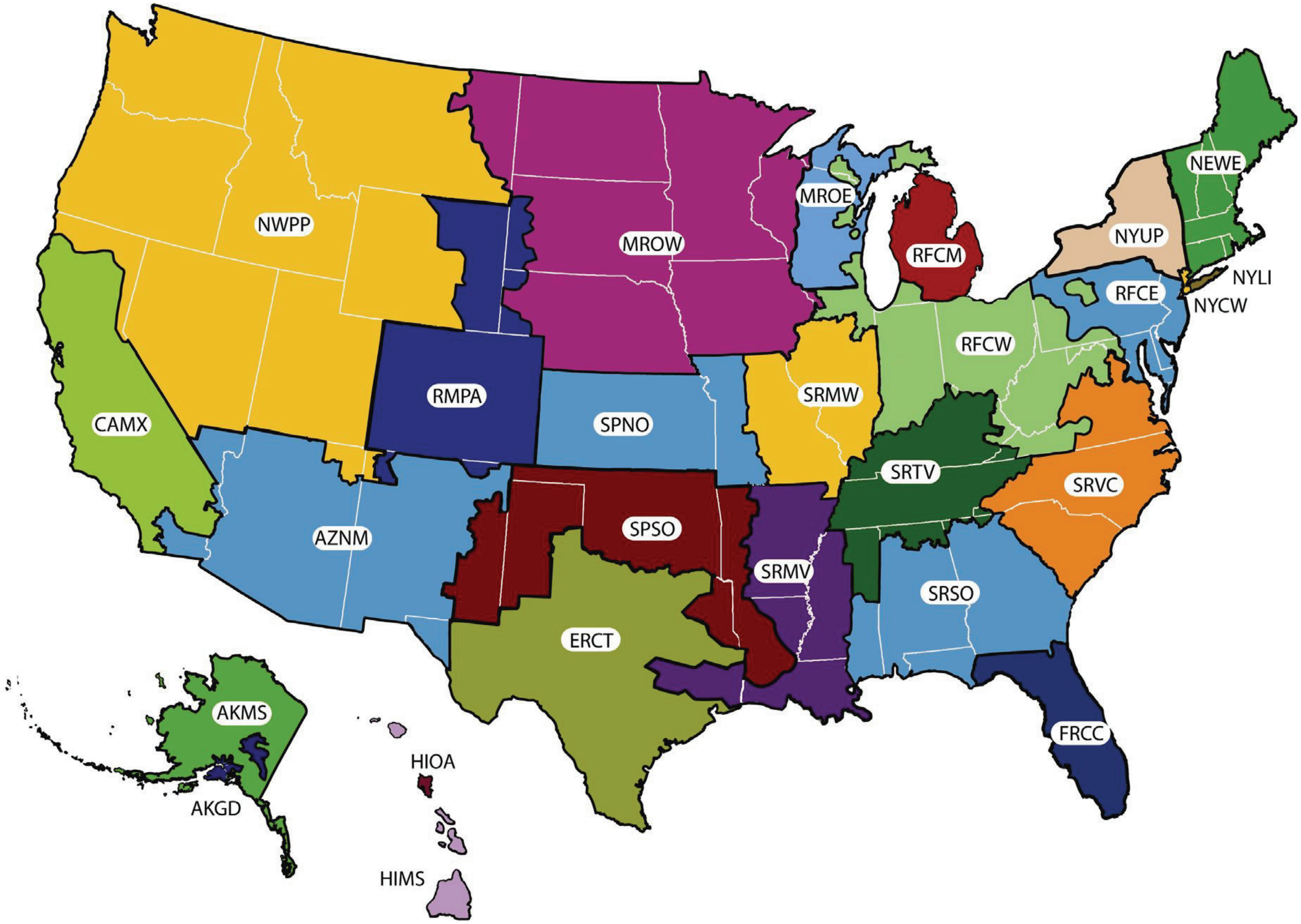

Figure 7-2. eGRID Subregion Map

Source:
U.S. EPA. *eGRID2007 Version 1.1 Year 2005 GHG Annual Output Emission Rates*, December 2008.

Note that these emission factors are for the year 2005, the most current data at the time of publication. When possible, electric grid emission factors corresponding to the emissions inventory year should be applied. The most recent eGRID information can be found online at:

http://www.epa.gov/cleanenergy/egrid/index.htm[3]

The EIA provides additional information related to energy generation emissions in the U.S., such as electric generation by independent power producers, and electric generation by fuel type[4].

The Australian Government publishes emission factors for purchased electricity according to state, territory, or grid description, as shown in Table 7-3.

Table 7-3. Average Australian Electricity Usage Emission Factors

Location	CO_2 Equivalent (CO_2 eq.) [a] tonnes/10^6 W-hr
New South Wales and Australian Capital Territory	0.89
Victoria	1.22
Queensland	0.91
South Australia	0.84
South West Interconnected System in Western Australia	0.87
Tasmania	0.12
Northern Territory	0.69
Australia Average	**0.79**

Footnote and Source:

[a] Australian Government, Department of Climate Change, *National Greenhouse Accounts (NGA) Factors*, Table 5, November 2008. Original source units are kg/kW-hr. Australia Average factors are derived.

Environment Canada provides emission factors for purchased electricity according to province. These factors are shown in Table 7-4.

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[3] Accessed June 19, 2009.

[4] http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html, accessed June 19, 2009.

Table 7-4. Average Canadian Electricity Usage Emission Factors by Province (2006 data) [a]

	CO_2		CH_4		N_2O	
Location	**g/ kW-hr**	**tonnes/ MW hr**	**g/ MW hr**	**tonnes/ MW hr**	**g/ MW-hr**	**tonnes/ MW-hr**
Newfoundland	10	0.010	0.00	0.00E+00	0.29	2.90E-07
Prince Edward Island	150	0.150	1.90	1.90E-06	3.06	3.06E-06
Nova Scotia	730	0.730	14.76	1.48E-05	9.71	9.71E-06
New Brunswick	350	0.350	17.14	1.71E-05	6.71	6.71E-06
Quebec	10	0.010	1.43	1.43E-06	0.16	1.60E-07
Ontario	180	0.180	9.05	9.05E-06	3.19	3.19E-06
Manitoba	10	0.010	0.48	4.80E-07	0.26	2.60E-07
Saskatchewan	800	0.800	36.19	3.62E-05	18.58	1.86E-05
Alberta	920	0.920	27.62	2.76E-05	17.23	1.72E-05
British Columbia	20	0.020	4.29	4.29E-06	0.48	4.80E-07
Yukon, Northwest Territories and Nunavut	80	0.080	3.81	3.81E-06	11.39	1.14E-05
Canada Average	**296.36**	**0.296**	**10.61**	**1.06E-05**	**6.46**	**6.46E-06**

Footnote and Source:

[a] Environment Canada, Energy Section, Greenhouse Gas Division. (Cited by The Cilmate Registry, *General Reporting Protocol*, *Version 1.1, Updates and Clarifications*, April 27, 2009.) Factors do not include emissions from transmission and distribution losses. Emission factors were converted from units of g/kW-hr or g/MW-hr to units of tonne/MW-hr. Canada Average factors are derived.

An example calculation illustrating how to estimate electricity-related CO_2, CH_4 and N_2O emissions using regional or provincial emission factors follows in Exhibit 7.2.

EXHIBIT 7.2: Sample Calculation for Electric Utility (Indirect) Emissions Using State Emission Factors

INPUT DATA:
A facility in Colorado purchases 500,000 kilowatt-hr of electricity during a given year. The method of electricity generation is unknown, but the electricity is produced in Colorado. Calculate the annual CO_2, CH_4 and N_2O emissions.

CALCULATION METHODOLOGY:
From Figure 7-2, the only eGRID subregion serving Colorado is RMPA. With this knowledge, emission factors are taken from Table 7-2 for eGRID subregion RMPA. Annual emissions are calculated by multiplying the emission factors by the quantity of electricity purchased by the plant, as follows:

$$E_{CO_2} = \frac{500{,}000 \text{ kilowattW-hr}}{\text{yr}} \times \frac{1 \text{ megawatt}}{1000 \text{ kilowatt}} \times \frac{0.854 \text{ tonne } CO_2}{\text{megawatt-hr}}$$

$$\underline{E_{CO_2} = 427 \text{ tonnes } CO_2/\text{yr}}$$

EXHIBIT 7.2: Sample Calculation for Electric Utility (Indirect) Emissions Using State Emission Factors, continued

$$E_{CH_4} = \frac{500{,}000 \text{ kilowatt-hr}}{\text{yr}} \times \frac{1 \text{ megawatt}}{1000 \text{ kilowatt}} \times \frac{1.04 \times 10^{-5} \text{ tonne } CH_4}{\text{megawatt-hr}}$$

$$\underline{E_{CH_4} = 0.0052 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{500{,}000 \text{ kilowatt-hr}}{\text{yr}} \times \frac{1 \text{ megawatt}}{1000 \text{ kilowatt}} \times \frac{1.30 \times 10^{-5} \text{ tonne } CO_2}{\text{megawatt-hr}}$$

$$\underline{E_{N_2O} = 0.0065 \text{ tonnes } N_2O/\text{yr}}$$

7.1.3 Purchased Electricity from an Unknown Generator – National Basis

Tables 7-5 and 7-6 provide national emission factors from published sources or developed from IEA data. Table 7-5 is applicable to Organization for Economic Co-operation and Development (OECD) member countries, whereas Table 7-6 is applicable to Non-OECD countries. These emission factors are based on electricity generation only and do not include district heating or transmission/ distribution line losses.

The emission factors presented in Tables 7-5 and 7-6 were derived from data provided in the IEA's *Electricity Information 2007*, which contains electricity generation data for OECD countries for the years 1960 through 2005, and data provided in IEA's *Electricity Information 2007 Edition: Documentation for Beyond 2020 Files*, which contains electricity generation data for non-OECD countries for 2005 and electricity generation data for OECD countries for 2006 (IEA, 2007a and 2007b). The factors provided in Table 7-5 (for OECD countries) are for the years 2003 through 2006, continuing where the emission factors in the previous version of the API *Compendium* ended (Appendix D provides the 2000-2002 emission factors from the previous API *Compendium*). Emission factors for non-OECD member countries are for 2005 only (Appendix D provides the 2001-2002 emission factors from the previous API *Compendium*). The approach used to develop the emission factors from IEA data is provided in Appendix D.

Table 7-5. OECD Member Country International Electric Grid Emission Factors (Generation Basis) [a]

tonnes/10^6 W-hr															
	2003 Weighted Emission Factors			**2004 Weighted Emission Factors**			**2005 Weighted Emission Factors**			**2006 Weighted Emission Factors**			**2003-2006 Average Weighted Emission Factors**		
Country	**CO_2**	**N CH_4**	**$_2O$**	**CO_2**	**N CH_4**	**$_2O$**	**CO_2**	**N CH_4**	**$_2O$**	**CO_2**	**N CH_4**	**$_2O$**	**CO_2**	**N CH_4**	**$_2O$**
Australia	0.709	2.01E-05	1.30E-04	0.718	2.00E-05	1.33E-04	0.722	1.99E-05	1.34E-04	0.718	1.98E-05	1.33E-04	0.717	2.00E-05	1.32E-04
Austria	0.240	1.26E-05	4.69E-05	0.219	1.18E-05	4.39E-05	0.219	1.29E-05	4.41E-05	0.222	1.37E-05	4.73E-05	0.225	1.27E-05	4.55E-05
Belgium	0.243	1.37E-05	4.27E-05	0.244	1.38E-05	4.32E-05	0.234	1.43E-05	4.28E-05	0.236	1.44E-05	4.32E-05	0.239	1.41E-05	4.30E-05
Canada [b]	N/A												0.296	1.06E-05	6.46E-06
Czech Republic	0.530	1.29E-05	9.93E-05	0.518	1.29E-05	9.78E-05	0.522	1.30E-05	9.87E-05	0.512	1.34E-05	9.69E-05	0.520	1.31E-05	9.82E-05
Denmark	0.591	2.13E-05	1.21E-04	0.529	2.20E-05	1.14E-04	0.496	2.19E-05	1.14E-04	0.565	2.16E-05	1.22E-04	0.545	2.17E-05	1.18E-04
Finland	0.434	1.89E-05	9.93E-05	0.371	1.80E-05	9.09E-05	0.272	1.74E-05	7.65E-05	0.375	1.95E-05	9.67E-05	0.363	1.85E-05	9.09E-05
France	0.066	2.73E-06	1.32E-05	0.063	2.72E-06	1.27E-05	0.070	3.00E-06	1.39E-05	0.063	2.83E-06	1.26E-05	0.065	2.82E-06	1.31E-05
Germany	0.494	1.44E-05	9.31E-05	0.480	1.44E-05	9.06E-05	0.469	1.49E-05	9.09E-05	0.452	1.53E-05	9.01E-05	0.474	1.48E-05	9.12E-05
Greece	0.670	1.74E-05	1.18E-04	0.667	1.79E-05	1.17E-04	0.664	1.73E-05	1.17E-04	0.647	1.68E-05	1.14E-04	0.662	1.73E-05	1.16E-04
Hungary	0.424	1.93E-05	7.16E-05	0.387	1.99E-05	6.95E-05	0.341	2.04E-05	6.76E-05	0.351	2.05E-05	6.71E-05	0.376	2.00E-05	6.89E-05
Iceland	0.013	1.29E-07	6.97E-08	0.013	1.47E-07	1.04E-07	0.015	1.77E-07	1.72E-07	0.021	2.06E-07	9.94E-08	0.016	1.65E-07	1.11E-07
Ireland	0.657	2.65E-05	1.04E-04	0.630	2.60E-05	1.00E-04	0.341	1.47E-05	6.33E-05	0.612	2.53E-05	9.66E-05	0.560	2.31E-05	9.10E-05
Italy	0.497	2.10E-05	7.84E-05	0.476	2.24E-05	7.76E-05	0.486	1.60E-05	8.96E-05	0.473	2.50E-05	7.74E-05	0.483	2.11E-05	8.07E-05
Japan	0.421	1.71E-05	7.29E-05	0.406	1.63E-05	7.07E-05	0.432	1.55E-05	7.92E-05	0.397	1.60E-05	6.90E-05	0.414	1.62E-05	7.30E-05
Korea	0.433	1.33E-05	7.48E-05	0.441	1.47E-05	7.60E-05	0.667	2.41E-05	1.06E-04	0.437	1.49E-05	7.57E-05	0.494	1.67E-05	8.31E-05
Luxembourg	0.349	2.90E-05	5.40E-05	0.368	3.07E-05	5.69E-05	0.475	2.47E-05	7.76E-05	0.362	3.03E-05	5.66E-05	0.388	2.87E-05	6.13E-05

Table 7-5. OECD Member Country International Electric Grid Emission Factors (Generation Basis), [a] continued

tonnes/10^6 W-hr

Country	2003 Weighted Emission Factors			2004 Weighted Emission Factors			2005 Weighted Emission Factors			2006 Weighted Emission Factors			2003-2006 Average Weighted Emission Factors		
	CO_2	N CH_4	$_2O$	CO_2	N CH_4	$_2O$	CO_2	NCH_4	$_2O$	CO_2	N CH_4	$_2O$	CO_2	N CH_4	$_2O$
Mexico	0.506	2.03E-05	8.01E-05	0.489	2.01E-05	7.64E-05	0.412	1.58E-05	7.21E-05	0.486	2.06E-05	7.63E-05	0.473	1.92E-05	7.63E-05
Netherlands	0.529	3.05E-05	9.44E-05	0.519	3.11E-05	9.38E-05	0.428	1.44E-05	7.40E-05	0.503	3.14E-05	9.69E-05	0.495	2.68E-05	8.98E-05
New Zealand	0.198	1.27E-05	3.36E-05	0.172	9.74E-06	3.05E-05	0.363	3.03E-05	5.62E-05	0.212	1.23E-05	3.72E-05	0.236	1.63E-05	3.94E-05
Norway	0.003	3.21E-07	1.33E-06	0.003	3.48E-07	1.37E-06	0.492	1.95E-05	7.79E-05	0.003	3.67E-07	1.29E-06	0.125	5.13E-06	2.05E-05
Poland	0.796	1.83E-05	1.48E-04	0.791	1.84E-05	1.47E-04	0.506	3.14E-05	9.72E-05	0.790	1.88E-05	1.49E-04	0.721	2.17E-05	1.35E-04
Portugal	0.428	1.47E-05	8.13E-05	0.485	1.90E-05	9.11E-05	0.220	1.25E-05	3.89E-05	0.447	1.82E-05	8.51E-05	0.395	1.61E-05	7.41E-05
Slovak Republic	0.218	7.43E-06	3.89E-05	0.216	7.28E-06	3.78E-05	0.002	2.75E-07	9.73E-07	0.199	6.60E-06	3.51E-05	0.159	5.40E-06	2.82E-05
Spain	0.375	1.27E-05	6.73E-05	0.394	1.44E-05	6.92E-05	0.359	1.47E-05	6.67E-05	0.382	1.78E-05	6.94E-05	0.377	1.49E-05	6.81E-05
Sweden	0.048	3.25E-06	1.63E-05	0.028	3.54E-06	1.73E-05	0.486	1.61E-05	8.91E-05	0.029	3.96E-06	1.80E-05	0.147	6.72E-06	3.52E-05
Switzerland	0.015	1.01E-06	8.34E-06	0.016	1.05E-06	8.88E-06	0.455	1.60E-05	8.04E-05	0.018	1.15E-06	1.04E-05	0.126	4.80E-06	2.70E-05
Turkey	0.451	2.27E-05	7.26E-05	0.422	2.10E-05	6.83E-05	0.438	1.56E-05	8.00E-05	0.460	2.26E-05	7.49E-05	0.443	2.05E-05	7.40E-05
United Kingdom [c]	N/A	2.23E-05	8.63E-05	N/A	2.32E-05	8.67E-05	N/A	1.86E-05	1.48E-04	N/A	2.23E-05	9.14E-05	0.581	2.16E-05	1.03E-04
United States [d]	N/A												0.611	2.08E-05	9.33E-06

Footnotes and Sources:

N/A – Not available.

[a] All factors developed from International Energy Agency (IEA) *Electricity Information 2007*, 2007 and *Electricity Information 2007 Edition: Documentation for Beyond 2020 Files*, 2007 with the exception of factors for countries identified in footnotes b – d. Appendix D provides the approach used to estimate emission factors. For all years except 2006, emissions from "Other" Fuel Types (e.g. Fuel Cells) have been calculated using the Fuel Cell emission factor (provided in Table 7-1). However, data for 2006 is preliminary (taken from IEA's *Documentation for Beyond 2020 Files* instead of database), and thus the "Other" category could not be split from the "Solar, Wind, Chemical, Other" category for that year.

[b] Environment Canada, Energy Section, Greenhouse Gas Division. (Cited by The Cilmate Registry (TCR), *General Reporting Protocol, Version 1.1, Updates and Clarifications*, April 27, 2009.) Factors do not include emissions from transmission and distribution losses. Emission factors were converted from units of g/kW-hr or g/MW-hr to units of tonne/MW-hr. Canada Average factors are derived.

[c] Defra, *Guidelines to Defra's GHG conversion factors for company reporting, Annexes updated April 2008*, Department for Environment, Food, and Rural Affairs, April 2008. CO_2 emission factor is taken from Defra and is average for 1990-2006. CH_4 and N_2O factors derived from IEA data (IEA, 2007), using methodology described in Appendix D.

[d] U.S. EPA, *eGRID2007 Version 1.1 Year 2005 GHG Annual Output Emission Rates*, December 2008. Factors are U.S. average; factors for individual years are not available.

Table 7-6. Non-OECD Member Country International Electric Grid Emission Factors (Generation Basis)[a]

tonnes/10^6 W-hr											
	2005 Weighted Emission Factors				**2005 Weighted Emission Factors**				**2005 Weighted Emission Factors**		
Country	**CO_2**	**N CH_4**	**$_2O$**	**Country**	**CO_2**	**N CH_4**	**$_2O$**	**Country**	**CO_2**	**N CH_4**	**$_2O$**
Africa				**Africa (cont.)**				**Latin America (cont.)**			
Algeria	0.480	3.83E-05	6.82E-05	Namibia	0.025	2.90E-07	3.77E-06	Costa Rica	0.033	7.75E-07	5.04E-06
Angola	0.233	2.17E-06	3.38E-05	Nigeria	0.345	2.21E-05	4.93E-05	Cuba	0.665	7.43E-06	1.01E-04
Benin	0.682	6.35E-06	9.87E-05	Senegal	0.552	7.21E-06	8.47E-05	Dominican Republic	0.593	6.96E-06	9.03E-05
Botswana	0.826	1.80E-05	1.54E-04	South Africa	0.773	1.70E-05	1.44E-04	Ecuador	0.317	5.65E-06	4.57E-05
Cameroon	0.038	3.53E-07	5.48E-06	Sudan	0.477	4.44E-06	6.91E-05	El Salvador	0.307	3.13E-06	4.31E-05
Congo	0.000	0.00E+00	0.00E+00	United Republic of Tanzania	0.288	3.02E-06	4.27E-05	Guatemala	0.330	1.21E-05	8.22E-05
Democratic Republic of Congo	0.002	1.71E-08	2.66E-07	Togo	0.417	3.88E-06	6.03E-05	Haiti	0.353	3.29E-06	5.11E-05
Côte d'Ivoire	0.359	2.94E-05	5.10E-05	Tunisia	0.493	3.64E-05	7.02E-05	Honduras	0.454	5.02E-06	6.88E-05
Egypt	0.452	3.04E-05	6.44E-05	Zambia	0.005	6.90E-08	7.87E-07	Jamaica	0.659	6.99E-06	9.87E-05
Eritrea	0.682	6.35E-06	9.87E-05	Zimbabwe	0.357	7.81E-06	6.65E-05	Netherlands Antilles	0.682	6.35E-06	9.87E-05
Ethiopia	0.005	4.43E-08	6.88E-07	Other Africa [b]	0.386	4.51E-06	5.89E-05	Nicaragua	0.484	8.06E-06	8.30E-05
Gabon	0.294	8.75E-06	4.40E-05	**Latin America**				Panama	0.244	2.49E-06	3.61E-05
Ghana	0.147	1.37E-06	2.12E-05	Argentina	0.305	2.24E-05	4.71E-05	Paraguay	0.000	0.00E+00	0.00E+00
Kenya	0.212	5.36E-06	4.24E-05	Bolivia	0.270	1.59E-05	4.67E-05	Peru	0.129	5.34E-06	2.12E-05
Libya	0.626	1.57E-05	9.03E-05	Brazil	0.060	4.94E-06	1.80E-05	Trinidad and Tobago	0.482	3.97E-05	6.93E-05
Morocco	0.734	1.40E-05	1.30E-04	Chile	0.306	1.63E-05	5.42E-05	Uruguay	0.085	1.12E-06	1.36E-05
Mozambique	0.001	3.47E-08	1.26E-07	Colombia	0.133	7.55E-06	2.44E-05	Venezuela	0.147	6.87E-06	2.11E-05

Table 7-6. Non-OECD Member Country International Electric Grid Emission Factors (Generation Basis),[a] continued

tonnes/10^6 W-hr

Country	2005 Weighted Emission Factors			Country	2005 Weighted Emission Factors			Country	2005 Weighted Emission Factors		
	CO_2	N CH_4	$_2O$		CO_2	N CH_4	$_2O$		CO_2	N CH_4	$_2O$
Latin America (cont.)				**Asia (cont.)**				**Non-OECD Europe (cont.)**			
Other Latin America[c]	0.584	6.02E-06	8.67E-05	Singapore	0.534	3.12E-05	7.64E-05	Gibraltar	0.682	6.35E-06	9.87E-05
Asia				Sri Lanka	0.414	3.85E-06	5.98E-05	Kazakhstan	0.684	1.75E-05	1.23E-04
Bangladesh	0.469	3.52E-05	6.68E-05	Thailand	0.515	3.31E-05	8.51E-05	Kyrgyzstan	0.076	4.43E-06	1.21E-05
Brunei Darussalam	0.485	3.93E-05	6.90E-05	Vietnam	0.356	1.86E-05	5.68E-05	Latvia	0.147	1.27E-05	2.35E-05
Cambodia	0.651	6.06E-06	9.42E-05	Other Asia[d]	0.407	3.79E-06	5.89E-05	Lithuania	0.117	8.28E-06	1.67E-05
Chinese Taipei	0.570	1.74E-05	1.04E-04	**Non-OECD Europe**				Malta	0.682	6.35E-06	9.87E-05
Hong Kong (China)	0.700	2.60E-05	1.22E-04	Albania	0.009	8.17E-08	1.27E-06	Republic of Moldova	0.476	3.90E-05	6.77E-05
India	0.642	1.65E-05	1.17E-04	Armenia	0.140	1.15E-05	1.99E-05	Romania	0.407	1.35E-05	7.14E-05
Indonesia	0.625	1.49E-05	1.04E-04	Azerbaijan	0.470	2.48E-05	6.73E-05	Russia	0.385	2.17E-05	6.09E-05
Democratic People's Republic of Korea	0.348	7.31E-06	6.38E-05	Belarus	0.501	3.68E-05	7.13E-05	Serbia and Montenegro	0.548	1.22E-05	1.01E-04
Malaysia	0.548	3.04E-05	8.77E-05	Bosnia and Herzegovina	0.471	1.02E-05	8.74E-05	Slovenia	0.303	7.71E-06	5.76E-05
Mongolia	0.824	1.78E-05	1.53E-04	Bulgaria	0.375	9.34E-06	6.86E-05	Tajikistan	0.011	9.29E-07	1.61E-06
Myanmar	0.263	1.65E-05	3.76E-05	Croatia	0.327	1.02E-05	5.38E-05	Turkmenistan	0.483	3.97E-05	6.87E-05
Nepal	0.000	0.00E+00	0.00E+00	Cyprus	0.682	6.35E-06	9.87E-05	Ukraine	0.312	1.22E-05	5.42E-05
Pakistan	0.352	1.88E-05	5.05E-05	Estonia	0.794	1.97E-05	1.47E-04	Uzbekistan	0.465	2.90E-05	6.80E-05
People's Republic of China	0.671	1.49E-05	1.24E-04	Former Yugoslav Republic of Macedonia	0.650	1.42E-05	1.21E-04	**Middle East**			
Philippines	0.455	1.76E-05	7.28E-05	Georgia	0.071	5.35E-06	1.01E-05	Bahrain	0.483	3.97E-05	6.87E-05

Table 7-6. Non-OECD Member Country International Electric Grid Emission Factors (Generation Basis),[a] continued

tonnes/10^6 W-hr

Country	2005 Weighted Emission Factors		
	CO$_2$	N CH$_4$	$_2$O
Middle East (cont.)			
Islamic Republic of Iran	0.476	3.01E-05	6.80E-05
Iraq	0.672	6.25E-06	9.72E-05
Israel	0.763	1.85E-05	1.35E-04
Jordan	0.564	2.54E-05	8.09E-05
Kuwait	0.647	1.23E-05	9.33E-05
Lebanon	0.611	5.69E-06	8.85E-05
Oman	0.519	3.37E-05	7.41E-05
Qatar	0.483	3.97E-05	6.87E-05
Saudi Arabia	0.585	2.27E-05	8.40E-05
Syria	0.541	1.81E-05	7.78E-05
United Arab Emirates	0.488	3.90E-05	6.94E-05
Yemen	0.682	6.35E-06	9.87E-05

Footnotes and Sources:

[a] International Energy Agency (IEA). *Electricity Information 2007 Edition: Documentation for Beyond 2020 Files*. IEA Energy Statistics Division, 2007. Electricity Emissions Database purchased from http://www.iea.org. All factors developed from IEA (IEA, 2007). Appendix D provides the approach used to estimate the emission factors. Emissions from "Other" Fuel Types (e.g. Fuel Cells) could not be split from the "Solar, Wind, Chemical, Other" category.

[b] Other Africa includes: Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Mauritius, Niger, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland, and Uganda.

[c] Other Latin America includes: Antigua and Barbuda, Bahamas, Barbados, Belize, Bermuda, Dominica, French Fuiana, Grenada, Guadeloupe, Guyana, Martinique, St. Kitts and Nevis, Saint Lucia, St. Vincent and Grenadines, and Suriname.

[d] Other Asia includes: Afghanistan, Bhutan, Fiji, French Polynesia, Kiribati, Laos, Macao, Maldives, New Caledonia, Papua New Guinea, Samoa, Solomon Islands, East Timor, Tongoa, and Vanuatu.

In the United States, Canada, and Australia, regional data should be used over national emission factors. If the applicable region or province is not known, country averages are also presented in Table 7-5. Emission factors for the United States are taken from eGRID (EPA, 2009). Emission factors for Canada were taken from Environment Canada (TCR, 2009). The CO_2 emission factor for the United Kingdom is taken from the Department for Environment, Food, and Rural Affairs, *Guidelines to Defra's GHG conversion factors for company reporting, Annexes* (Defra, 2008); the CH_4 and N_2O emission factors for the United Kingdom were derived from IEA.

7.1.4 Renewable Energy

Footnotes to Table 7-1 address some unique characteristics for electricity generated from renewable energy sources. Although a CO_2 emission factor is provided for wood waste biomass, by GHG emission accounting convention, CO_2 emissions from combustion of biogenic fuels[5] are not considered anthropogenic under the Framework Convention on Climate Change[6]. Rather, these emissions are presumed to be carbon neutral, meaning that CO_2 emissions resulting from the combustion of wood waste are offset by the CO_2 absorbed from the atmosphere prior to harvesting the tree. Carbon dioxide emissions from biomass should not be included in either direct or indirect emissions. However, the combustion of biomass does result in net additions of CH_4 and N_2O to the atmosphere. These emissions should be accounted for.

For municipal solid waste, the waste may contain plastics, synthetic textiles, rubber, yard waste, and paper products; with the proportion varying considerably depending on location, season, and waste management practices. An emission factor should be derived based on the anthropogenic carbon contained in the solid waste. If plant-specific estimates of the waste stream composition are not available, the EIA has developed a default emission factor of 919 lbs CO_2 per short ton of municipal solid waste, or 92 lbs CO_2 per million Btu (assuming a municipal solid waste energy content of 5,000 Btu/lb) (DOE, 2007).

Geothermal Energy

Geothermal energy is a renewable resource that utilizes heat and steam produced in the earth's core for heating and energy generation. The three primary uses of geothermal energy are: direct use and district heating systems, electricity generation, and geothermal heat pumps. GHG emissions do

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[5] Biogenic carbon refers to carbon that was recently contained in living and breathing tissues (WRI/WBSCD GHG Protocol, Stations Combustion Guidance, July 2005).

[6] http://unfccc.int/essential_background/glossary/items/3666.php, accessed April 30, 2009.

result from geothermal electricity generation; however, compared to other methods of generation, emissions from geothermal power plants are very low.

There are three basic types of geothermal power plants: dry steam plants, flash steam plants, and binary power plants. Dry and flash steam plants use the geothermal steam (or geothermal hot water converted to steam) to drive generator turbines. When the steam cools, it is converted to water and injected back into the ground to be used again. In both dry and flash steam plants, the gases contained in the geothermal streams do not condense at the turbine exhaust outlet and so are released to the atmosphere. Binary power plants use geothermal hot water to heat another liquid, which is then vaporized and used to drive the generator turbines. Binary plants do not expose the geothermal stream to the atmosphere, so the non-condensable gases contained in the geothermal streams are not released.

The emission factors provided in Table 7-1 for geothermal energy generation are taken from three separate sources. The International Geothermal Association conducted a survey to determine CO_2 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. Bloomfield and Moore (Bloomfield and Moore, 1999) conducted a survey of data from geothermal operators, utilities, and U.S. state air-quality boards. The primary sources of data were the operators of dry steam and flash plants, although the emission rate is for all geothermal plants (including binary power plants). The EIA emission factor is based on EIA estimates.

7.1.5 Steam/Heat Utility Emissions

Imported steam/heat or steam/heat generated on site results in GHG emissions due to combustion that occurs to produce the steam. If the method of generation for the steam/heat is known, the approach to estimate combustion emissions given in Sections 4.3 through 4.5 can be used.

To estimate GHG emissions from imported steam or district heating, or where information about the steam/heat generator is unknown, 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 4-3 for CO_2 and Table 4-7 for CH_4 and N_2O (controlled) can be converted to a thermal basis by dividing by an assumed 92% boiler efficiency, shown below as follows. The assumed 92% boiler efficiency does not account for steam transport losses. The efficiency should be reduced to account for inefficiencies in transporting the steam for the specific application.

$$\begin{aligned}
\text{CO}_2 \text{ Emission Factor } &= \frac{5.90\times10^{-2} \text{ tonne/}10^6 \text{ Btu}}{0.92} \\
&= 6.41\times10^{-2} \text{ tonne CO}_2/10^6 \text{ Btu (steam/heat energy basis, LHV)} \\
&= \frac{6.41\times10^{-2} \text{ tonne CO}_2}{10^6 \text{ Btu}} \times \frac{\text{Btu}}{1055.056 \text{ J}} \\
&= 6.08\times10^{-5} \text{ tonne CO}_2/10^6 \text{ J (steam/heat energy basis, LHV)}
\end{aligned}$$

$$\begin{aligned}
\text{CH}_4 \text{ Emission Factor } &= \frac{1.1\times10^{-6} \text{ tonne/}10^6 \text{ Btu}}{0.92} \\
&= 1.20\times10^{-6} \text{ tonne CH}_4/10^6 \text{ Btu (steam/heat energy basis, LHV)} \\
&= \frac{1.20\times10^{-6} \text{ tonne CH}_4}{10^6 \text{ Btu}} \times \frac{\text{Btu}}{1055.056 \text{ J}} \\
&= 1.14\times10^{-9} \text{ tonne CH}_4/10^6 \text{ J (steam/heat energy basis, LHV)}
\end{aligned}$$

$$\begin{aligned}
\text{N}_2\text{O Emission Factor } &= \frac{3.0\times10^{-7} \text{ tonne/}10^6 \text{ Btu}}{0.92} \\
&= 3.26\times10^{-7} \text{ tonne N}_2\text{O/}10^6 \text{ Btu (steam/heat energy basis, LHV)} \\
&= \frac{3.26\times10^{-7} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}} \times \frac{\text{Btu}}{1055.056 \text{ J}} \\
&= 3.09\times10^{-10} \text{ tonne N}_2\text{O/}10^6 \text{ J (steam/heat energy basis, LHV)}
\end{aligned}$$

The quantity of steam consumed may be expressed in energy units or mass units. Where steam consumption is measured in mass units, the pressure and temperature of the steam are needed to convert to an equivalent energy basis. As demonstrated by Equation 7-1, the mass quantity of the steam is converted to an equivalent thermal energy basis by quantifying the difference in enthalpy at the temperature and pressure of the steam compared to a reference condition of saturated water at 212°F (100°C).

$$\text{Steam Thermal Equivalent} = \text{Mass steam} \times (\text{Enthalpy}_{\text{Actual}} - \text{Enthalpy}_{\text{Reference}}) \qquad \text{Equation 7-1}$$

The enthalpy of the steam at actual and reference conditions can be found in standard steam tables. The steam factors given above can then be applied to determine the CO_2, CH_4, and N_2O indirect emissions from the imported steam.

Exhibit 7.3 illustrates this simplified approach.

EXHIBIT 7.3: 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. Calculate the emissions.

CALCULATION METHODOLOGY:
Because the method of steam generation is unknown, the simple approach of assuming that the steam was generated in a natural gas boiler with an efficiency of 92% is used. The efficiency is reduced further by 10% to account for the steam transport losses. 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 thermodynamic 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 are now estimated using the emission factors presented in the preceding discussion:

$$E_{CO_2} = \frac{1.755\times10^{10} \text{ Btu}}{\text{yr}} \times \frac{5.90\times10^{-2} \text{ tonne } CO_2}{10^6 \text{ Btu}} \times \frac{1}{(0.92-0.10)}$$

$$\underline{E_{CO_2} = 1{,}263 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CH_4} = \frac{1.755\times10^{10} \text{ Btu}}{\text{yr}} \times \frac{1.10\times10^{-6} \text{ tonne } CH_4}{10^6 \text{ Btu}} \times \frac{1}{(0.92-0.10)}$$

$$\underline{E_{CH_4} = 0.0235 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{1.755\times10^{10} \text{ Btu}}{\text{yr}} \times \frac{3.0\times10^{-7} \text{ tonne } N_2O}{10^6 \text{ Btu}} \times \frac{1}{(0.92-0.10)}$$

$$\underline{E_{N_2O} = 0.0064 \text{ tonnes } N_2O/\text{yr}}$$

7.1.6 District Cooling Water Emissions

Similar to purchased heat or steam, facilities may also purchase cooling water or chilled water. Chilled water is typically generated by pressurizing a gaseous substance with a compressor and then allowing the substance to return to standard pressure. When the pressure is released from the gas, it absorbs thermal energy as it expands, lowering the temperature. The compressor system that produces the cooling water may be driven by electricity or fossil fuel combustion. Thus, the estimate of indirect emissions is similar to that of purchased heat or steam. Indirect emissions from district cooling for a given facility represent the share of the total cooling demand from the cooling plant to the facility, multiplied by the total GHG emissions generated by the cooling plant. The quantity of cooling water may be expressed in energy units (Btu or J), or in units of mass-hours (e.g. ton-hours, where 1 ton-hour = 12,000 BTUs). Equation 7-2 is used to determine the energy input resulting from a facility's cooling demand.

$$\text{Energy Input (MMBtu or J)} = \frac{\text{Cooling Demand (MMBtu or J)}}{\text{COP}}$$

Equation 7-2

where

COP = Coefficient of Performance, which is based on the type of chiller.

The COP for common types of chillers is provided in Table 7-7.

Table 7-7. Typical Chiller Coefficients of Performance

Equipment Type	Coefficient of Performance (COP) [a]	Energy Source
Absorption Chiller	0.8	Natural Gas
Engine-driven Compressors	1.2	Natural Gas
Electric-driven Compressor	4.2	Electricity

Footnote and Source:

[a] California Climate Action Registry (CCAR). *California Climate Action Registry General Reporting Protocol: Reporting Entity-Wide Greenhouse Gas Emissions*, Version 3.1, January 2009.

For cooling plants that use absorption chillers or natural gas-driven compressors, emissions are estimated based on the energy input determined from Equation 7-2 and the natural gas combustion emission factor from Table 4-3. For cooling plants that use electric-driven compression, the energy input from Equation 7-2 must be converted to megawatt – hour (MW-hr) (1 MW-hr = 3.4121 10^6BTU from Table 3-4) to apply the emission factors presented in Sections 7.1.1 through 7.1.3.

7.2 Allocation of Emissions Among Energy Streams

In ongoing efforts to improve energy efficiency, many operations co-produce energy streams or utilize excess process heat for energy generation. Processes that simultaneously produce energy streams used by two or more different parties present a special case for estimating GHG emissions. This includes the cogeneration of electricity and heat/steam, as well as operations that produce heat (steam) and other product streams (hydrogen or coke). For these processes, attributing total GHG emissions to each product stream would result in double counting emissions.

The general process for estimating emissions from co-produced streams is:

1. Obtain the total GHG emissions associated with the generation of all energy and product streams;
2. Determine emissions or emission factors attributable to net energy and product stream energy content using one of the methods discussed below;
3. Calculate GHG emissions (CO_2, CH_4, and N_2O) associated with your entity's portion of the energy or product streams; and
4. Convert to units of CO_2 equivalent emissions.

Data required for the allocation approaches presented in this section include the quantity of fuel consumed, quantity of energy streams generated and sold, electricity generated and sold, energy content of product streams generated and sold, and for the WRI/WBCSD efficiency allocation approach, the efficiencies of heat and power production (although default efficiencies may also be used).

7.2.1 Cogeneration of Electricity and Steam

Cogeneration of electricity and steam, also known as 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 electricity and/or steam/heat produced from the cogeneration facility is transferred, sold, or otherwise used by two or more entities, GHG accounting may require allocating the emissions resulting from the CHP among the energy streams. Several registries and GHG reporting programs; have published approaches for allocating emissions between energy streams in cases where these streams are used by two or more different parties (CCAR, 2008; Defra, 2008b; DOE, 2007; TCR, 2008; and WRI/WBCSD, 2006). The three most common methods are:

1. *Efficiency method:* GHG emissions are allocated based on the energy input used to produce the separate steam and electricity products;
2. *Energy content method:* GHG emissions are allocated based on the energy content of the output steam and electricity products; and
3. *Work potential method:* GHG emissions are allocated based on the contribution to the total work potential of the steam and electricity products.

These approaches apply to emissions associated with the direct import/export of electricity from a CHP facility. Each approach 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 is equivalent to the total emissions resulting from the fuel combusted to produce the energy. These allocation methodologies are discussed further and illustrated through calculation exhibits.

GHG emissions from cogeneration plants could also be allocated based on:

- The economic value of the steam and electricity products;
- Allocating 100% of GHG emissions to electricity production (steam production is emissions free);
- Allocating 100% of GHG emissions to steam production (electricity production is emissions free);
- Allocating savings to electricity production (electricity emissions equal total emissions less emissions from conventional steam production, and steam emissions equal emissions of conventional steam production);
- Allocating savings to steam production (steam emissions equal total emissions less emissions from conventional electricity production, and electricity emissions equal emissions of conventional electricity production); or
- Allocating emissions according to a contractual agreement or other understanding between the parties.

Efficiency Allocation Method

The efficiency method allocates GHG emissions according to the amount of fuel energy used to produce each output energy stream. Allocation is based on the assumption that the conversion of fuel energy to steam is more efficient than converting fuel to electricity.

To apply the efficiency allocation method, the first step is to calculate the total direct CO_2 emissions from the combustion of fuel (generally 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 allocation equation to the electricity and steam streams. Two allocation methods are presented: one from the UK Emissions Trading Scheme (ETS) and a second from the WRI/WBCSD.

The UK ETS allocation approach is based on the assumption that the efficiency of heat generation is twice that of electricity generation (Defra, 2008b).[7] The equations are provided below.

Electricity Emission Factor from Cogeneration Facility:

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

(Equation 7-3)

Steam Emission Factor from Cogeneration Facility:

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

(Equation 7-4)

This approach is illustrated in the Exhibit 7.4.

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[7] As of this printing, EU ETS does not currently address the allocation of emissions from cogeneration units. This topic is noted for consideration in Phase III (post-2012).

EXHIBIT 7.4: Cogeneration Emissions Allocation – UK ETS Efficiency Allocation Method

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 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 also consumes 38,500 megawatt-hr of electricity to operate (referred to as the Parasitic load). The net electricity (856,100 megawatt-hrs, metered at the custody transfer point) is sold to the electric grid.

Using the UK ETS Efficiency Allocation Method, calculate the cogeneration facility emissions, refinery emissions, and emissions associated with electricity sold to the grid.

CALCULATION METHODOLOGY:
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_4 and N_2O emissions, but the approach presumably applies to CO_2 equivalent emissions.

<u>Step 1: Combustion Emissions from Cogeneration</u>:
For the cogeneration unit, emissions are calculated based on the natural gas consumed using the emission factors in Table 4-3 for CO_2 and Table 4-7 (natural gas turbines) for CH_4 and N_2O:

$$E_{CO_2} = 8{,}131{,}500 \times 10^6 \text{ Btu} \times \frac{0.0531 \text{ tonnes } CO_2}{10^6 \text{ Btu natural gas}}$$

$$\underline{E_{CO_2} = 431{,}783 \text{ tonnes } CO_2}$$

$$E_{CO_2e} = 431{,}783 + \left(31.7 \times \frac{21 \text{ tonnes } CO_2e}{\text{tonnes } CH_4}\right) + \left(11.4 \times \frac{310 \text{ tonnes } CO_2e}{\text{tonnes } N_2O}\right)$$

$$\underline{E_{CO_2e} = 435{,}983 \text{ tonnes } CO_2e \text{ (Direct, Cogen)}}$$

EXHIBIT 7.4: Cogeneration Emissions Allocation – UK ETS Efficiency Allocation Method, continued

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. The conversion factor is provided in Table 3-2.

The steam thermal equivalent ($S_{Eq.}$) is calculated below:

$$S_{Eq} = 3{,}614{,}000 \times 10^6 \text{ Btu steam} \times \frac{2.931 \times 10^{-4} \text{ kilowatt-hr}}{\text{Btu}} \times \frac{\text{meagwatt-hr}}{1000 \text{ kilowatt-hr}}$$

$$S_{Eq} = 1{,}059{,}263 \text{ megawatt-hr/yr}$$

Step 3: Calculate Electricity and Steam Emission Factors

The third step is to apply the UK ETS equations (Equations 7-3 and 7-4) for allocating emissions between the electricity and steam energy to generate emission factors.

Electricity allocation ($E_{Electricity}$):

$$E_{Electricity} = \frac{2 \times 435{,}982 \text{ tonnes } CO_2e}{\left[2 \times 1{,}100{,}600 \text{ megawatt} - \text{hr}_{Electricity}\right] + 1{,}059{,}263 \text{ megawatt-hr}_{Steam}}$$

$$E_{Electricity} = 0.267 \text{ tonnes } CO_2e \text{ /megawatt-hr}$$

Steam allocation (E_{Steam}):

$$E_{Steam} = \frac{435{,}983 \text{ tonnes } CO_2e}{\left[2 \times 1{,}100{,}600 \text{ megawatt} - \text{hr}_{Electricity}\right] + 1{,}059{,}263 \text{ megawatt-hr}_{Steam}}$$

$$E_{Steam} = 0.134 \text{ tonnes } CO_2e \text{ /megawatt-hr}$$

Step 4: Allocate Emissions to Electricity and Steam

Emissions are allocated between electricity and steam used for energy on site (direct emissions) and the exported electricity and steam (indirect emissions) by applying the emission factors calculated in Step 3.

CO_2 Equivalent emissions for electricity sold to the refinery ($E_{Elec,\ refinery}$):

$$E_{Elec,\ refinery} = \frac{0.267 \text{ tonnes } CO_2}{\text{megawatt-hr electricity}} \times 206{,}000 \text{ megawatt-hr}$$

$$E_{Elec,\ refinery} = 55{,}002 \text{ tonnes } CO_2e \text{ (Direct, Cogen; Indirect, Refinery)}$$

EXHIBIT 7.4: Cogeneration Emissions Allocation – UK ETS Efficiency Allocation Method, continued

CO_2 Equivalent emissions for electricity sold to the grid ($E_{Elec,\ grid}$):

$$E_{\text{Elec, grid}} = \frac{0.267 \text{ tonnes CO}_2}{\text{megawatt-hr electricity}} \times 856{,}100 \text{ megawatt-hr}$$

$$E_{\text{Elec, grid}} = 228{,}579 \text{ tonnes CO}_2\text{e (Direct, Cogen; Indirect, Grid Consumer)}$$

CO_2 Equivalent emissions for steam sold to the refinery ($E_{Steam,\ ref}$):

$$E_{\text{Steam, Ref}} = 2{,}710{,}000 \times 10^6 \text{ Btu steam} \times \frac{2.931 \times 10^{-4} \text{ kW-hr}}{\text{Btu}} \times \frac{\text{MW-hr}}{1000 \text{ kW-hr}} \times \frac{0.134 \text{ tonnes CO}_2}{\text{MW-hr steam}}$$

$$E_{\text{Steam, ref}} = 106{,}436 \text{ tonnes CO}_2\text{e (Direct, Cogen; Indirect, Refinery)}$$

Step 5: Calculate Net Cogeneration Facility Emissions

Net cogeneration facility emissions are calculated by subtracting emissions from steam and electricity sold to the refinery and electricity sold to the grid from the total emissions calculated in Step 1.

Net Cogeneration Facility CO_2 Emissions (E_{Net}):

$$E_{\text{Net}} = 435{,}983 \text{ tonnes CO}_2\text{e} - \left(55{,}002 + 228{,}579 + 106{,}436\right) \text{tonnes CO}_2\text{e}$$

$$E_{\text{Net}} = 45{,}966 \text{ tonnes CO}_2\text{e (Direct, Cogen)}$$

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 the table below.

Summary of Cogeneration Emissions – UK ETS Efficiency Allocation Method

	Emissions, tonnes CO_2e	
Cogeneration Facility (Direct, Cogen)		
Direct Emissions from Fuel Consumption	435,983	
Emissions Associated with Electricity Sold to the Grid (Direct, Cogen, and Indirect, Grid Consumer)	228,579	Sums to 435,938
Net Facility Emissions	45,966	
Refinery Emissions (Direct, Cogen; Indirect, Refinery)		
Purchased electricity	55,002	
Purchased Steam	106,436	

WRI/WBCSD presents a slightly different efficiency allocation approach (WRI/WBCSD, 2006), which relies on actual efficiencies of heat and power production or assumed values. The equations associated with the WRI/WBCSD efficiency allocation approach are:

$$\text{Emissions}_{\text{Heat}} = \text{Emissions}_{\text{Total}} \times \frac{\dfrac{\text{Heat Output}}{\text{Efficiency}_{\text{Heat}}}}{\dfrac{\text{Heat Output}}{\text{Efficiency}_{\text{Heat}}} + \dfrac{\text{Electricity Output}}{\text{Efficiency}_{\text{Electricity}}}} \qquad \text{(Equation 7-5)}$$

and

$$\text{Emissions}_{\text{Total}} = \text{Emissions}_{\text{Heat}} + \text{Emissions}_{\text{Electricity}} \qquad \text{(Equation 7-6)}$$

where

$\text{Emissions}_{\text{Total}}$ = total emissions from CHP plant;
$\text{Emissions}_{\text{Heat}}$ = emissions share attributable to heat production;
$\text{Emissions}_{\text{Electricity}}$ = emissions share attributable to electricity production;
$\text{Efficiency}_{\text{Heat}}$ = actual or assumed efficiency of typical heat production; and
$\text{Efficiency}_{\text{Electricity}}$ = actual or assumed efficiency of typical power production.

Heat output and electricity output are reported in the same units (Joule, Btu or kilowatt-hr). Where actual efficiencies are not available, EPA's Climate Leaders reporting guidelines provide default values for U.S. operations of 35% efficiency for electricity production and 80% efficiency for heat production (EPA, 2008). It should be noted that the use of default efficiency values may violate the energy balance constraints of some cogeneration systems. However, the impact on the emission estimates should be minimal since the total emissions are still allocated between the energy outputs.

This efficiency allocation approach using Equations 7-5 and 7-6 is demonstrated in Exhibit 7.5. Note that this approach is also preferred by EPA's Climate Leaders Program (EPA, 2008), The Climate Registry (TCR, 2008), DOE's 1605(b) program (DOE, 2007), and California's Air Resources Board (CARB, 2008) for Topping Cycle Plants[8].

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[8] Note that Topping Cycle Plants, which generate electricity at the start of the cycle and use the resulting heat or steam for a process stream, are different than Bottoming Cycle Plants, which use steam or heat from a process stream to generate electricity at the end of the cycle.

EXHIBIT 7.5: Cogeneration Emissions Allocation – WRI/WBCSD Efficiency Allocation Method

INPUT DATA:
For the same scenario as described in the previous exhibit (Exhibit 7.4), 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) sold to the electric grid.

For this example, the efficiency of steam generation is assumed to be 80% and the efficiency of the electricity generation is assumed to be 33% based on the default values suggested by Climate Leaders.

Using the WRI/WBCSD Efficiency Allocation Approach, calculate the cogeneration facility emissions, refinery emissions, and emissions associated with electricity sold to the grid.

CALCULATION METHODOLOGY:
Step 1: Combustion Emissions from Cogeneration:
The total direct emissions are calculated as shown in Exhibit 7.4, resulting in 435,983 tonnes CO_2e emissions (Direct, Cogen).

Step 2: Define Power and Heat Production on the Same Units
The electric power output (P) from the cogeneration unit needs to be converted from a megawatt-hr basis to Btu. The conversion factor is provided in Table 3-4.

$$P = 1{,}100{,}600 \text{ megawatt-hr} \times \frac{1000 \text{ kilowatt-hr}}{\text{megawatt-hr}} \times \frac{\text{Btu}}{2.931 \times 10^{-4} \text{ kilowatt-hr}}$$

$$P = 3.755 \times 10^{12} \text{ Btu (Electricity Output)}$$

Step 3: Calculate the Emissions Allocated to Steam
Estimate the emissions associated with the steam generation by applying Equation 7-5.

EXHIBIT 7.5: Cogeneration Emissions Allocation – WRI/WBCSD Efficiency Allocation Method, continued

$$E_{\text{Heat}} = 435{,}983 \text{ tonnes } CO_2e \times \frac{\dfrac{3{,}614{,}000 \times 10^6 \text{ Btu}}{0.80}}{\dfrac{3{,}614{,}000 \times 10^6 \text{ Btu}}{0.80} + \dfrac{3.755 \times 10^{12} \text{ Btu}}{0.33}}$$

$$E_{\text{Heat}} = 435{,}983 \text{ tonnes } CO_2e \times 0.284186$$

$$E_{\text{Heat}} = 123{,}900.2 \text{ tonnes } CO_2e$$

<u>Step 4: Calculate the Emissions Allocated to Electricity</u>
Applying Equation 7-6, the emissions allocated to electricity are calculated based on the difference between the total emissions and those allocated to steam.

$E_{\text{Electricity}}$ = 435,983 tonnes CO_2e (Total) – 123,900.2 tonnes CO_2e (Heat)

$E_{\text{Electricity}}$ = 312,092.8 tonnes CO_2e (Electricity)

<u>Step 5: Allocate Emissions for Energy Exports</u>
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_2 Equivalent Emissions for electricity sold to the refinery ($E_{Elec,\ ref}$):

$$E_{\text{Elec, ref}} = 312{,}082.8 \text{ tonnes } CO_2e \text{ (Total Electricity)} \times \frac{206{,}000 \text{ megawatt-hr (Refinery)}}{1{,}100{,}600 \text{ megawatt-hr (Total)}}$$

$$E_{\text{Elec, ref}} = 58{,}412.7 \text{ tonnes } CO_2e \text{ (Direct, Cogen; Indirect, Refinery)}$$

CO_2 Equivalent Emissions for electricity sold to the grid ($E_{Elec,\ grid}$):

$E_{\text{Elec, grid}}$ =312,082.8 tonnes CO_2e (Total Electricity) – 58,412.7 tonnes CO_2e (Refinery)

$E_{\text{Elec, grid}}$ = 253,670.1 tonnes CO_2e (Direct, Cogen; Indirect, Grid Consumer)

EXHIBIT 7.5: Cogeneration Emissions Allocation – WRI/WBCSD Efficiency Allocation Method, continued

CO_2 Equivalent Emissions for steam sold to the refinery ($E_{Steam,\ ref}$):

$$E_{\text{Steam, ref}} = 123{,}900.2 \text{ tonnes CO}_2\text{e (Total Heat)} \times \frac{2{,}710{,}000 \times 10^6 \text{ Btu (Refinery)}}{3{,}614{,}000 \times 10^6 \text{ Btu (Total)}}$$

$$E_{\text{Steam, ref}} = 92{,}908 \text{ tonnes CO}_2\text{e (Direct, Cogen; Indirect, Refinery)}$$

Step 6: Calculate Net Cogeneration Facility Emissions

Net cogeneration facility emissions are calculated by subtracting emissions from steam and electricity sold to the refinery and electricity sold to the grid from the total emissions calculated in Step 1.

Net Cogeneration Facility CO_2 Emissions (E_{Net}):

$$E_{\text{Net}} = 435{,}983 \text{ tonnes CO}_2\text{e} - \left(58{,}412.7 + 253{,}670.1 + 92{,}908 \text{ tonnes CO}_2\text{e}\right)$$

$$E_{\text{Net}} = 30{,}992.2 \text{ tonnes CO}_2\text{e (Direct, Cogen)}$$

The results for the allocation of emissions based on energy efficiency are shown in the table below.

Summary of Cogeneration Emissions – WRI/WBCSD Efficiency Allocation Method

	Emissions, tonnes CO_2e	
Cogeneration Facility (Direct, Cogen)		
Direct Emissions from Fuel Consumption	435,983	
Emissions Associated with Electricity Sold to the Grid (Direct, Cogen, and Indirect, Grid Consumer)	253,670	Sums to 435,983
Net Facility Emissions	30,992	
Refinery Emissions (Direct, Cogen; Indirect, Refinery)		
Purchased electricity	58,413	
Purchased Steam	92,908	

Energy Content Method

The energy content method allocates emissions based on the amount of useful energy contained in each energy output stream. The energy content of the electrical power is simply the amount of electricity produced by the system (converted to units of Btu or Joules). The energy content of the steam (or hot water) is equivalent to the energy content of the output stream less any energy in the returned condensate. Losses due to inefficient use of either the electricity or steam outputs are not considered. This allocation method is particularly well suited for applications where steam is used for process heat, but may not be appropriate where heat is used for mechanical work because it may overstate the amount of useful energy in the heat, resulting in a low emission factor associated with the heat stream.

This approach starts with obtaining the total fuel consumption emissions associated with generating the heat and steam. For electricity, the energy content is equal to the energy output, converted to units consistent with the steam energy (Btu or Joules). The energy content of the steam is calculated by applying Equation 7-1.

For steam, only the fraction of the total energy in the steam (or hot water) that can be used for process heating is considered. It is also assumed that the steam is used for indirect heating, with condensates returned to the CHP system. If the condensates are not returned or if a hot water output stream is considered in the allocation, different reference conditions than shown below should be applied (e.g., the temperature and pressure of boiler feed water).

The values of enthalpy at the actual and reference conditions can be found in standard steam tables. The reference conditions of 212°F (100°C) and 1 atm (101.325 kilo-Pascals) correspond to condensates returned to the CHP.

The emissions allocated to the individual energy streams are then calculated as:

$$\text{Emissions}_{\text{Heat/Steam}} = \text{Emissions}_{\text{Total}} \times \frac{\text{Energy}_{\text{Heat/Steam}}}{\text{Energy}_{\text{Heat/Steam}} + \text{Energy}_{\text{Electricity}}} \qquad \text{(Equation 7-7)}$$

$$\text{Emissions}_{\text{Electricity}} = \text{Emissions}_{\text{Total}} \times \frac{\text{Energy}_{\text{Electricity}}}{\text{Energy}_{\text{Heat/Steam}} + \text{Energy}_{\text{Electricity}}} \qquad \text{(Equation 7-8)}$$

An example is provided in Exhibit 7.6. The basis for this calculation method was from Annex E of the National Council for Air and Stream Improvement (NCASI) report *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills* (November 2002). This approach has since been included in WRI/WBCSD's *Allocation of GHG Emissions from a Combined Heat and Power (CHP) Plant*, Guide to Calculation Worksheets, v1.0 (September, 2006).

EXHIBIT 7.6: Cogeneration Emissions Allocation – WRI/WBCSD Energy Content Method

INPUT DATA:
For the same scenario as described in the previous exhibits, this example applies the energy content approach.

The cogeneration facility consumes 8,131,500 million Btu of natural gas, producing 3,089 million pounds of 600 psig and 700 °F 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 also consumes 38,500 megawatt-hr of electricity to operate (referred to as the Parasitic load), with the net electricity (856,100 megawatts) sold to the electric grid.

Using the Energy Content Method, calculate the cogeneration facility emissions, refinery emissions, and emissions associated with electricity sold to the grid.

CALCULATION METHODOLOGY:

Step 1: Combustion Emissions from Cogeneration:
The total direct emissions are calculated as shown in Exhibit 7.4, resulting in 435,983 tonnes CO_2e emissions (Direct, Cogen).

Step 2: Calculate the Energy Associated with the Electricity

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

$$P = 1{,}100{,}600 \text{ megawatt-hr} \times \frac{1000 \text{ kilowatt-hr}}{\text{megawatt-hr}} \times \frac{\text{Btu}}{2.931 \times 10^{-4} \text{ kilowatt-hr}}$$

$$P = 3.755 \times 10^{12} \text{ Btu (Electricity Output)}$$

Step 3: Calculate the Energy Associated with the Steam

Estimate the emissions associated with the steam generation by applying Equation 7-1.

EXHIBIT 7.6: Cogeneration Emissions Allocation – WRI/WBCSD Energy Content Method, continued

$$\text{Energy}_{\text{Steam}} = (3{,}089\times10^{6}\ \text{lbm/yr})\ (1350\ \text{Btu/lbm-}180\ \text{Btu/lbm})$$

$$\text{Energy}_{\text{Steam}} = 3.614\times10^{12}\ \text{Btu/yr}$$

Step 4: Calculate the Emissions Allocated to Electricity

The emissions allocated to electricity are calculated based on Equation 7-8.

$$E_{\text{Elec}} = 435{,}983\ \text{tonnes}\ CO_2e\times\frac{3.755\times10^{12}\ \text{Btu}_{\text{Electricity}}}{3.614\times10^{12}\ \text{Btu}_{\text{Steam}}+3.755\times10^{12}\ \text{Btu}_{\text{Electricity}}}$$

E_{Elec} = 222,163 tonnes CO_2e

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 on site versus the energy sold for use off site.

CO_2 Equivalent Emissions for electricity sold to the refinery ($E_{Elec,\ ref}$):

$$E_{\text{Elec, ref}} = 222{,}163\ \text{tonnes}\ CO_2e\ \text{(Total Electricity)}\times\frac{206{,}000\ \text{megawatt-hr (Refinery)}}{1{,}100{,}600\ \text{megawatt-hr Total}}$$

$E_{\text{Elec, ref}}$ = 41,582 tonnes CO_2e (Direct, Cogen; Indirect, Refinery)

CO_2 Equivalent Emissions for electricity sold to the grid ($E_{Elec,\ grid}$):

$E_{\text{Elec, grid}}$ = 222,163 tonnes CO_2e (Total Electricity) – 41,582 tonnes CO_2e (Refinery)

$E_{\text{Elec, grid}}$ = 180,581 tonnes CO_2e (Direct, Cogen; Indirect, Grid Consumer)

CO_2 Equivalent Emissions for steam sold to the refinery ($E_{Steam\ ,ref}$):

E_{Steam} = 435,983 tonnes CO_2e (Total)-222,163 tonnes CO_2e (Electricity)

E_{Steam} = 213,980 tonnes CO_2e (Direct, Cogen)

$$E_{\text{Steam,ref}} = 213{,}820\ \text{tonnes}\ CO_2e\ \text{(Total Steam)}\times\frac{2{,}710{,}000\times10^{6}\ \text{Btu (Refinery)}}{3{,}614{,}000\times10^{6}\ \text{Btu Total}}$$

$E_{\text{Steam,ref}}$ = 160,335 tonnes CO_2e (Direct, Cogen; Indirect, Refinery)

EXHIBIT 7.6: Cogeneration Emissions Allocation – WRI/WBCSD Energy Content Method, continued

Step 6: Calculate Net Cogeneration Facility Emissions
Net cogeneration facility emissions are calculated by subtracting emissions from steam and electricity sold to the refinery and electricity sold to the grid from the total emissions calculated in Step 1.

Net Cogeneration Facility CO_2 Emissions (E_{Net}):

$$E_{Net} = 435{,}983 \text{ tonnes } CO_2e - \left(41{,}582 + 180{,}581 + 160{,}335 \text{ tonnes } CO_2e\right)$$

$$E_{Net} = 53{,}485 \text{ tonnes } CO_2e \text{ (Direct, Cogen)}$$

The results for the allocation of emissions based on energy efficiency are shown in the table below.

Summary of Cogeneration Emissions – Energy Content Approach

	Emissions, tonnes CO_2e	
Cogeneration Facility (Direct, Cogen)		
Direct Emissions from Fuel Consumption	435,983	
Emissions Associated with Electricity Sold to the Grid (Direct, Cogen, and Indirect, Grid Consumer)	180,581	Sums to 435,983
Net Facility Emissions	53,485	
Refinery Emissions (Direct, Cogen; Indirect, Refinery)		
Purchased electricity	41,582	
Purchased Steam	160,335	

Work Potential Allocation Method

This method allocates emissions based on the useful energy represented by the electric power and heat, and defines useful energy on the ability of heat to perform work. This method assumes that the useful energy in steam corresponds to the maximum amount of work that could be done by the steam in an open (flow) steady state and thermodynamically reversible process. This method is most appropriate when heat is to be used for producing mechanical work.

In applications where steam is used for process heat, the useful energy in the steam corresponds to the heat content of the steam, or its enthalpy. As a result, the work potential method would underestimate the amount of useful energy in the steam and should not be used.

The work potential for steam is calculated from the specific enthalpy (H) and specific entropy (S) of the steam. This approach sums the work potential of all streams and allocates the total emissions to the individual streams.

As with the other allocation methods, the first step is to calculate the total direct 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. 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 U.S. units:

$$\text{Steam work potential (Btu/lb)} = (H_i - H_{ref}) - (T_{ref} + 460) \times (S_i - S_{ref}) \qquad \text{(Equation 7-9)}$$

In SI units:

$$\text{Steam work potential } (10^9 \text{ J/tonne}) = (H_i - H_{ref}) - (T_{ref} + 273) \times (S_i - S_{ref}) \qquad \text{(Equation 7-10)}$$

where

H_i = specific enthalpy of the process steam (Btu/lb or 10^3 J/kilogram);
H_{ref} = specific enthalpy at the reference conditions (BTU/lb or 10^3 J/kilogram);
T_{ref} = reference temperature (°F or °C);
S_i = specific entropy of the process steam (Btu/lb R or 10^3 J/kilogram K); and
S_{ref} = specific entropy at the reference conditions (Btu/lb R or 10^3 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 7-11.

$$\text{CO}_2 \text{ EF from electricity or steam (tonnes CO}_2\text{/megawatt - hr)} = \frac{\text{CO}_2 \text{ direct emissions (tonnes CO}_2\text{/yr)}}{\left[\text{Work potential}_{\text{steam}}\left(\frac{\text{megawatt - hr}}{\text{yr}}\right) + \text{Work potential}_{\text{electricity}}\left(\frac{\text{megawatt - hr}}{\text{yr}}\right)\right]} \qquad \text{(Equation 7-11)}$$

This allocation approach is demonstrated in Exhibit 7.7. This approach is referenced by WRI/WBCSD (WRI/WBCSD, 2006).

EXHIBIT 7.7: Cogeneration Emissions Allocation –Work Potential Allocation Method

This example applies the Work Potential Allocation method to allocating emissions between steam and electricity for the same facility described in Exhibit 7.4.

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 also consumes 38,500 megawatt-hr of electricity to operate (referred to as the Parasitic load), with the net electricity (856,100 megawatt-hrs) sold to the electric grid.

Using the Work Potential Allocation method, calculate the cogeneration facility emissions, refinery emissions, and emissions associated with electricity sold to the grid.

CALCULATION METHODOLOGY:

Step 1: Combustion Emissions from Cogeneration:
Direct emissions are calculated as shown in Exhibit 7.4, resulting in 435,983 tonnes CO_2e emissions (Direct, Cogen).

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_i);
Saturated Water, 212°F = 180 Btu/lb (H_{ref})

Entropy: Steam, 600 psia, 700°F = 1.5872 Btu/lb-R (S_i);
Saturated Water, 212°F = 0.31213 Btu/lb-R (S_{ref})

The work potential of the steam (SWP) is calculated using these values and Equation 7-9:

$$\text{SWP} = (1{,}350\text{-}180)\frac{\text{Btu}}{\text{lb}} - \left[\left(212+460\right)\text{R}\times\left(1.5872\text{-}0.31213\right)\frac{\text{Btu}}{\text{lb-R}}\right]$$

SWP = 313.2 Btu/lb

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

EXHIBIT 7.7: Cogeneration Emissions Allocation –Work Potential Allocation Method, continued

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

$$M_S = 3.089 \times 10^9 \text{ lbs steam}$$

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

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

$$S = 283{,}567 \text{ megawatt-hr/yr}$$

Step 3: Calculate Electricity and Steam Emission Factors

The third step is to apply Equation 7-11 for allocating emissions between the electricity and steam energy to generate emission factors.

$$EF = \frac{435{,}983 \text{ tonnes } CO_2e}{283{,}567 \text{ megawatt-hr}_{\text{steam}} + 1{,}100{,}600 \text{ megawatt-hr}_{\text{electricity}}}$$

$$EF = 0.315 \text{ tonne } CO_2\text{e/megawatt-hr}$$

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.

CO_2 Equivalent Emissions for electricity sold to the refinery ($E_{Elec,\ ref}$):

$$E_{\text{Elec, ref}} = \frac{0.315 \text{ tonnes } CO_2}{\text{megawatt-hr electricity}} \times 206{,}000 \text{ megawatt-hr}$$

$$E_{\text{Elec, ref}} = 64{,}890 \text{ tonnes } CO_2\text{e (Direct, Cogen; Indirect, Refinery)}$$

EXHIBIT 7.7: Cogeneration Emissions Allocation – Work Potential Allocation Method, continued

CO_2 Equivalent Emissions for electricity sold to the grid ($E_{Elec,\ grid}$):

$$E_{\text{Elec, grid}} = \frac{0.315 \text{ tonnes } CO_2}{\text{megawatt-hr electricity}} \times 856{,}100 \text{ megawatt-hr}$$

$$E_{\text{Elec, grid}} = 269{,}672 \text{ tonnes } CO_2\text{e (Direct, Cogen; Indirect, Grid)}$$

CO_2 Equivalent Emissions for steam sold to the refinery ($E_{Steam,\ ref}$):

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

$$E_{\text{Steam, ref}} = 212{,}636 \text{ megawatt-hr/yr}$$

$$E_{\text{Steam, ref}} = \frac{0.315 \text{ tonnes } CO_2}{\text{megawatt-hr steam}} \times 212{,}636 \text{ megawatt-hr}$$

$$E_{\text{Steam, ref}} = 66{,}980 \text{ tonnes } CO_2\text{e (Direct, Cogen; Indirect, Refinery)}$$

Step 5: Calculate Net Cogeneration Facility Emissions

Net cogeneration facility emissions are calculated by subtracting emissions from steam and electricity sold to the refinery, and electricity sold to the grid from the total emissions calculated in Step 1.

Net Cogeneration Facility CO_2 Emissions (E_{Net}):

$$E_{\text{Net}} = 435{,}983 \text{ tonnes } CO_2\text{e-}\left(64{,}890\text{+}269{,}672\text{+}66{,}980 \text{ tonnes } CO_2\text{e}\right)$$

$$E_{\text{Net}} = 34{,}441 \text{ tonnes } CO_2\text{e (Direct, Cogen)}$$

The following table summarizes the results for the work potential method.

EXHIBIT 7.7: Cogeneration Emissions Allocation – Work Potential Allocation Method, continued

Summary of Cogeneration Emissions – Work Potential Allocation Method

	Emissions, tonnes CO_2e	
Cogeneration Facility (Direct, Cogen)		
Direct Emissions from Fuel Consumption	435,983	
Emissions Associated with Electricity Sold to the Grid (Direct, Cogen, and Indirect, Grid Consumer)	269,672	Sums to 435,983
Net Facility Emissions	34,441	
Refinery Emissions (Direct, Cogen; Indirect, Refinery)		
Purchased electricity	64,890	
Purchased Steam	66,980	

7.2.2 Cogeneration Within An Entity

In cases where the energy streams from a cogeneration unit are consumed by the same entity that produced the energy streams, there is no need to allocate emissions among the streams. Direct emissions from the combustion of fuels to generate the energy streams are accounted for as direct emissions in the entity's inventory.

There may, however, be situations within an entity where the energy streams cogenerated by one facility are consumed by one or more other facilities owned or operated by the entity. Within the entity's boundary, these emissions should be accounted for as direct emissions (Scope 1 per The GHG Protocol; WRI/WBCSD, 2004). The facility that purchases or consumes the electricity or heat output streams should not also account for the emissions associated with these streams as indirect emissions.

7.2.3 Cogeneration of Product Streams and Heat

Other processes associated with oil and natural gas industry operations (e.g., hydrogen and coke production) co-produce product streams with heat/steam. The basic principles demonstrated above can be applied to allocate emissions based on the energy content of the output streams and products.

For example, the energy content method presented in Section 7.2.1 can be applied to allocate emissions based on the amount of energy in the steam and the Btu content of the produced coke or hydrogen.

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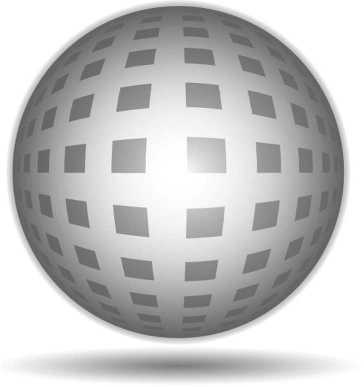
AMERICAN PETROLEUM INSTITUTE

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

AUGUST 2009

SECTION 8

EMISSION INVENTORY EXAMPLES



Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry

Section 8 – Emission Inventory Examples

August 2009

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8.0 EMISSION INVENTORY EXAMPLES

Oil and natural gas industry facility operations and their associated equipment vary significantly. The designs of these operations and equipment differ based on performance requirements and site-specific considerations. In general, the resultant GHG emissions will be determined by:

- Intensity of energy usage;
- Degree of internal capture and reprocessing;
- Installation of end-of-pipe controls; and
- Venting practices.

This section provides emission inventory examples for each industry segment to demonstrate the use of the emission factors provided in Sections 3 through 7. These examples are 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 are meant to be inclusive of all GHG emission source types for a given facility type; however, in actual operations, a particular facility may have other emission sources not covered in these examples. Similarly, some emission sources indicated in the examples may not be applicable to other facilities.

The examples provide an indication of the significance of a particular source type and relative magnitude of emissions from sources within a given facility. In reality, for a particular facility, the relative magnitude of its GHG emission sources might be different due to its design and operating practices. Exclusion of an emission source is not meant to be an indicator of emissions insignificance, and should not be construed as an indicator de minimis.

Uncertainty values (± %) were calculated for all examples using the guidance presented in Section 3. All uncertainty data presented in this section are based on a 95% confidence interval. Assumptions were made where uncertainty values were not available for the emission factors or fuel-based data presented in Section 3 through 7; these assumptions are documented in the text. Step-by-step calculation of the uncertainty values for the Onshore Oil Field subsection is provided in detail in the API Uncertainty document (API, Concawe, and IPIECA, 2009).

8.1 Exploration and Production

8.1.1 Onshore Oil Field with High CO_2 Content

Facility Description: An onshore oil field in Texas consists of 320 producing oil wells.

Throughput: The average daily oil and natural gas production rates are 6,100 bbl/day and 30×10^6 scf/day, respectively.

Operations: The facility operates approximately 343 days per year. The facility imports 917 MW-hr annually from the eGRID subregion "ERCOT All." The facility gas composition is presented in Table 8-1 and results in a heating value of 928 Btu/scf. The uncertainty for the heating value is ± 4%, based on engineering judgment.

Table 8-1. Gas Composition for Onshore Oil Field (High CO_2 Content)

Gas Compound	Produced Gas Mole %	Uncertainty [a] (±%)
CO_2	12	4
N_2	2.1	4
CH_4	80	4
C_2H_6	4.2	4
C_3H_8	1.3	4
C_4H_{10}	0.4	4

Footnote:

[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

Note: the values shown above are for example only. They do not reflect average operations.

Tables 8-2 and 8-3 summarize the emission sources associated with this facility. Equipment at the site that do not have GHG emissions are also included in Table 8-2.

Table 8-2. Onshore Oil Field (High CO_2 Content) Emissions Sources

Source	Fuel/Refrigerant	No. of Units	Uncertainty[a] (±%)	Unit Capacity (per unit)	Uncertainty[a] (±%)	Average Operation (per unit per year)	Uncertainty[a] (±%)	Annual Activity Factor (all units combined)	Uncertainty[a] (±%)
Combustion Sources									
Boilers	Produced Gas	6	0	N/A		N/A		40×10^6 scf/yr	15
Heaters/reboilers	Produced Gas	3	0	2×10^6 Btu/hr	5	343 days/yr	2	53.2×10^6 scf/yr	6.71
Compressor engines – turbines	Produced Gas	11	0	N/A		N/A		250×10^6 scf/yr	15
Emergency flare	Produced Gas	1	0	N/A		N/A		500×10^6 scf/yr	15
Emergency generator IC engine	Diesel	1	0	1800 hp	5	200 hr/yr	10	$2{,}912\times10^6$ Btu/yr	12.3
Fire water pump IC engine	Diesel	1	0	460 hp	5	24 hr/yr; 87% load	10; 20	77.7×10^6 Btu/yr	13.2
Fleet vehicles (trucks)	Gasoline	5	0	N/A		40,000 mi/yr ea.	15	N/A	
Vented Sources									
Dehydration vents (also has Kimray pump emissions)	Produced Gas	1	0	30×10^6 scf/day	5	343 days/yr	2	$10{,}290\times10^6$ scf/yr	5.39
Central tank battery	Crude Oil	1	0	6,100 bbl/day	5	343 days/yr	2	2,092,300 bbl/yr	5.39
Storage tanks	Chemical	1	0	N/A		N/A		N/A	
	Naphtha	1	0	N/A		N/A		N/A	
	Glycol	1	0	N/A		N/A		N/A	
Water blowdown tank	N/A	1	0	N/A		N/A		N/A	
Slop oil tank	Slop Oil	1	0	N/A		N/A		N/A	
Amine unit for CO_2 removal									
Inlet	Produced Gas	N/A		30×10^6 scf/day	5	343 days/yr	2	$10{,}290\times10^6$ scf/yr	5.39
Outlet	Outlet Gas (0.5 mole% CO_2)	N/A		N/A		N/A		$8{,}997\times10^6$ scf/yr	5
Pneumatic devices	Produced Gas	64	5	N/A		N/A		64 pneumatic devices	5

Table 8-2. Onshore Oil Field (High CO_2 Content) Emissions Sources, continued

Source	**Fuel/Refrigerant**	**No. of Units**	**Uncertainty[a] (±%)**	**Unit Capacity (per unit)**	**Uncertainty[a] (±%)**	**Average Operation (per unit per year)**	**Uncertainty[a] (±%)**	**Annual Activity Factor (all units combined)**	**Uncertainty[a] (±%)**
Vented Sources, continued									
CIPs	Produced Gas	67	5	N/A		N/A		67 CIPs	5
Vessel blowdowns (non-routine)	Produced Gas	112	0	N/A		N/A		112 vessels	0
Compressor starts (non-routine)	Produced Gas	11	0	N/A		N/A		11 compressors	0
Compressor blowdowns (non-routine)	Produced Gas	11	0	N/A		N/A		11 compressors	0
Well workovers (non-routine)	Produced Gas	24	0	N/A		N/A		24 well workovers	0
PRVs	Produced Gas	482	1	N/A		N/A		482 PRVs	1
Fugitive Sources									
Equipment leaks	Produced Gas	N/A		N/A		8,760 hr/yr	0	See Table 8-3	
Fleet vehicle refrigeration	R-134a	5 trucks	0	N/A		N/A		Unknown	
Indirect Sources									
Electricity consumed	N/A	N/A		N/A		N/A		917 MW-hr/yr	2

Footnote:

[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

Note: the values shown above are for example only. They do not reflect average operations.

Table 8-3. Onshore Oil Field (High CO_2 Content) Fugitive Emission Sources

Component	Service	Average Component Count	Uncertainty [a] (±%)
Valves	Liquid and Gas	2,740	75
Pump seals	Liquid and Gas	185	75
Connectors	Gas	110	75
Flanges	Liquid and Gas	10,000	75
Open-ended lines	Gas	6	75
Others	Liquid and Gas	710	75

Footnote:
[a] Uncertainty is based on engineering judgment at a 95% confidence interval.
Note: the values shown above are for example only. They do not reflect average operations.

The remainder of this subsection presents emission calculations for the sources identified in Tables 8-2 and 8-3, and a summary of facility emissions (presented at the end of this subsection).

Stationary Combustion Devices – CO_2 Emissions

Natural Gas Combustion

Boilers, heater/reboilers, and compressor engines-turbines use natural gas at this facility. Carbon dioxide emissions from combustion are calculated using the gas composition approach provided in Section 4.3.

The first step in calculating CO_2 emissions is to determine the total volume of fuel combusted (V) at the facility. Total fuel consumption is shown below, by equipment type.

Boilers and heaters:

$$V = \frac{40\times10^{6}\ \text{scf}}{\text{yr}} + \left(3\ \text{Units}\times\frac{2\times10^{6}\ \text{Btu}}{\text{hr-unit}}\times\frac{24\ \text{hr}}{\text{day}}\times\frac{343\ \text{days}}{\text{yr}}\times\frac{\text{scf}}{928\ \text{Btu}}\right) = 93.2\times10^{6}\ \text{scf/yr}$$

Turbines

Turbine fuel consumption (presented in Table 8-2):

$$V = 250\times10^{6}\ \text{scf/yr}$$

Carbon dioxide emissions from equipment burning natural gas are calculated using the gas composition approach provided in Section 4.3. First, the fuel analysis is converted from a molar basis to a mass basis, as shown in Exhibits 3.3 and 3.4. The molecular weight of the mixture is calculated below, using Equation 3-8:

$$MW_{\text{Mixture}} = \begin{bmatrix} (12.0\times44.01)+(2.1\times28.01)+(80\times16.04) \\ +(4.2\times30.07)+(1.3\times44.10)+(0.4\times58.12) \end{bmatrix} \div 100 = 20.77\text{ lb/mole}$$

The individual weight percents are then calculated by rearranging Equation 3-7. The calculation is shown below for CH_4.

$$\text{Wt.\%}_{CH_4} = \frac{80\text{ lbmole }CH_4}{100\text{ lbmole mixture}} \times \frac{\left(\frac{16.04\text{ lb }CH_4}{\text{lbmole }CH_4}\right)}{\left(\frac{20.77\text{ lb mixture}}{\text{lbmole mixture}}\right)} = \frac{0.6178\text{ lb }CH_4}{\text{lb mixture}} = 61.78\text{ wt. \% }CH_4$$

To calculate emissions, the carbon content of the fuel composition provided in Table 8-1 is determined. The first step is to calculate the carbon content of the individual components, using Equation 4-9. The carbon content calculation for an individual component is shown below for ethane (C_2H_6).

$$\text{Wt\% }C_{C_2H_6} = \frac{12.01\text{ lb C}}{\text{lbmole C}} \times \frac{2\text{ lbmoles C}}{\text{lbmole }C_2H_6} \times \frac{\text{lbmole }C_2H_6}{30.07\text{ lb }C_2H_6} \times 100\% = 79.9\%\text{ C}$$

After the calculation has been performed for all constituents, the carbon content for the mixture is calculated using Equation 4-10, as shown below:

$$\text{Wt\% }C_{\text{Mixture}} = \frac{1}{100} \times \begin{bmatrix} (25.43\times27.3)+(2.83\times0)+(61.78\times74.9) \\ +(6.08\times79.9)+(2.76\times81.7)+(1.12\times82.7) \end{bmatrix} = 61.24\text{ Wt\% C} = 0.6124\text{ lb C/lb fuel}$$

Completing the calculations for the fuel analysis presented in Table 8-1 results in the fuel mixture molecular weight and carbon content as follows.

Compound	Mole %	MW	Wt% (Calculated)	Uncertainty [a] (±%)	Compound Carbon Content (wt%C)	Mixture Carbon Content (wt%C)	Uncertainty [a] (±%)
CO_2	12.0	44.01	25.43	4.82	27.3		4.82
N_2	2.1	28.01	2.83	4.82	0	6.94	NA
CH_4	80.0	16.04	61.78	4.82	74.9	0	4.82
C_2H_6	4.2	30.07	6.08	4.82	79.9	46.3	4.82
C_3H_8	1.3	44.10	2.76	4.82	81.7	4.86	4.82
C_4H_{10}	0.4	58.12	1.12	4.82	82.7	2.26	4.82
						0.925	
Fuel Mixture	**100**	**20.77 ±2.69%[a]**	**100.0**			**61.24**	**3.71**

Footnote:
[a] Uncertainty is at a 95% confidence interval.

Carbon dioxide emissions can then be calculated using a mass balance approach. Emissions are calculated below, by equipment type.

Boilers and Heaters:

$$E_{CO_2} = \frac{93.2\times10^6 \text{scf fuel}}{\text{yr}} \times \frac{\text{lbmole fuel}}{379.3 \text{ scf fuel}} \times \frac{20.77 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.6124 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}} \times \frac{\text{lbmole } CO_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 5{,}200 \text{ tonnes } CO_2/\text{yr}}$$

Turbines:

$$E_{CO_2} = \frac{250\times10^6 \text{ scf fuel}}{\text{yr}} \times \frac{\text{lbmole fuel}}{379.3 \text{ scf fuel}} \times \frac{20.77 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.6124 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}} \times \frac{\text{lbmole } CO_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 13{,}900 \text{ tonnes } CO_2/\text{yr}}$$

Diesel Combustion

Carbon dioxide emissions from diesel combustion are calculated using the diesel emission factor provided in Table 4-3, assuming an uncertainty of ±10% based on engineering judgment. Because the emission factor is provided on a energy input basis, the equipment ratings are converted to volume of fuel consumed on a energy input basis using the conversion factors provided in Table 4-2, assuming an uncertainty of ±5% based on engineering judgment. Diesel combustion CO_2 emissions are calculated below.

$$V = \left(1 \text{ Unit} \times \frac{1{,}800 \text{ hp}}{\text{unit}} \times \frac{8{,}089 \text{ Btu}}{\text{hp-hr}} \times \frac{200 \text{ hr}}{\text{yr}}\right) + \left(1 \text{ Unit} \times \frac{460 \text{ hp}}{\text{unit}} \times 0.87 \times \frac{8{,}089 \text{ Btu}}{\text{hp-hr}} \times \frac{24 \text{ hr}}{\text{yr}}\right) = 2989.7 \times 10^6 \text{ Btu/yr}$$

$$E_{CO_2} = \frac{2{,}989.7 \times 10^6 \text{ Btu}}{\text{year}} \times \frac{0.0732 \text{ tonnes } CO_2}{10^6 \text{ Btu}}$$

$$\underline{E_{CO_2} = 219 \text{ tonnes } CO_2\text{/yr}}$$

Stationary Combustion Devices – CH_4, N_2O, and CO_2e Emissions

Natural Gas Combustion

Methane and N_2O combustion emission factors for natural gas-fired equipment are provided in Table 4-7 for controlled boilers and heaters, and Table 4-9 for uncontrolled turbines, assuming an uncertainty of ±25% for all CH_4 emission factors and ±150% for all N_2O emission factors based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Emissions are calculated below, by equipment type.

Boilers and Heaters:

$$V = \left(\frac{40 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{928 \text{ Btu}}{\text{scf}}\right) + \left(3 \text{ Units} \times \frac{2 \times 10^6 \text{ Btu}}{\text{hr-unit}} \times \frac{24 \text{ hr}}{\text{day}} \times \frac{343 \text{ days}}{\text{yr}}\right) = 86{,}512 \times 10^6 \text{ Btu/yr}$$

$$E_{CH_4} = \frac{86{,}512 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{1.0 \times 10^{-6} \text{ tonne } CH_4}{10^6 \text{ Btu}}$$

$$\underline{E_{CH_4} = 0.0865 \text{ tonnes } CH_4\text{/yr}}$$

$$E_{N_2O} = \frac{86{,}512\times10^6 \text{ Btu}}{\text{yr}} \times \frac{2.8\times10^{-7} \text{ tonne } N_2O}{10^6 \text{ Btu}}$$

$$\underline{E_{N_2O} = 0.0242 \text{ tonnes } N_2O/\text{yr}}$$

$$E_{CO_2e} = \frac{5{,}200 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{0.0865 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right)$$
$$+ \left(\frac{0.0242 \text{ tonne } N_2O}{\text{yr}} \times \frac{310 \text{ tonne } CO_2e}{\text{tonne } N_2O}\right)$$

$$\underline{E_{CO_2e} = 5{,}210 \text{ tonne } CO_2e/\text{yr}}$$

Turbines:

$$V = \left(\frac{250\times10^6 \text{ scf}}{\text{yr}} \times \frac{928 \text{ Btu}}{\text{scf}}\right) = 232{,}000\times10^6 \text{ Btu/yr}$$

$$E_{CH_4} = \frac{232{,}000\times10^6 \text{ Btu}}{\text{yr}} \times \frac{3.9\times10^{-6} \text{ tonne } CH_4}{10^6 \text{ Btu}}$$

$$\underline{E_{CH_4} = 0.905 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{232{,}000\times10^6 \text{ Btu}}{\text{yr}} \times \frac{1.4\times10^{-6} \text{ tonne } N_2O}{10^6 \text{ Btu}}$$

$$\underline{E_{N_2O} = 0.325 \text{ tonnes } N_2O/\text{yr}}$$

$$E_{CO_2e} = \frac{13{,}900 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{0.905 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right) + \left(\frac{0.325 \text{ tonne } N_2O}{\text{yr}} \times \frac{310 \text{ tonne } CO_2e}{\text{tonne } N_2O}\right)$$

$$\underline{E_{CO_2e} = 14{,}100 \text{ tonne } CO_2e/\text{yr}}$$

Diesel Combustion

The diesel-operated emergency generator emissions are estimated using the "Large Bore Engine – Diesel" emission factors (for engines rated greater than 600 hp) from Table 4-9. Because the emission factor is provided on a energy input basis, the equipment ratings are converted to volume of fuel consumed on a energy input basis using the conversion factors provided in Table 4-2, assuming an uncertainty of ±5% based on engineering judgment. The diesel-operated fire water pump emissions are estimated using the "IC Engine – Diesel" emission factors from Table 4-9 (for diesel engines rated less than 600 hp). An uncertainty of ±25% was assumed for all CH_4 emission factors and an uncertainty of ±150% was assumed for all N_2O emission factors based on engineering judgment. Table 4-9 also provides an assumed CH_4 content of 9 wt% to convert from TOC emissions if the exhaust composition is unknown, assuming the uncertainty of the TOC emission factor is ±25%, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Because diesel CO_2 emissions are calculated by fuel type, diesel CO_2e emissions are also calculated by fuel type. Emissions are calculated below, by equipment type.

Diesel engine >600 hp (emergency generator):

$$E_{CH_4} = 1\text{ Unit} \times \frac{1{,}800\text{ hp}}{\text{unit}} \times \frac{8{,}089\text{ Btu}}{\text{hp-hr}} \times \frac{200\text{ hr}}{\text{yr}} \times \frac{3.7\times 10^{-6}\text{ tonne CH}_4}{10^6\text{ Btu}}$$

$$\underline{E_{CH_4} = 0.0108\text{ tonnes CH}_4/\text{yr}}$$

$$E_{N_2O} = 1\text{ Unit} \times \frac{1{,}800\text{ hp}}{\text{unit}} \times \frac{8{,}089\text{ Btu}}{\text{hp-hr}} \times \frac{200\text{ hr}}{\text{yr}} \times \frac{6.01\times 10^{-7}\text{ tonne N}_2\text{O}}{10^6\text{ Btu}}$$

$$\underline{E_{N_2O} = 0.00175\text{ tonnes N}_2\text{O/yr}}$$

Diesel engine <600 hp (fire water pump):

$$E_{CH_4} = 1\text{ Unit} \times \frac{460\text{ hp}}{\text{unit}} \times 0.87\text{ load} \times \frac{8{,}089\text{ Btu}}{\text{hp-hr}} \times \frac{24\text{ hr}}{\text{yr}} \times \frac{0.00016\text{ tonne TOC}}{10^6\text{ Btu}} \times \frac{0.09\text{ tonne CH}_4}{\text{tonne TOC}}$$

$$\underline{E_{CH_4} = 0.00112\text{ tonnes CH}_4/\text{yr}}$$

$$E_{N_2O} = 1\ \text{Unit} \times \frac{460\ \text{hp}}{\text{unit}} \times 0.87\ \text{load} \times \frac{8{,}089\ \text{Btu}}{\text{hp-hr}} \times \frac{24\ \text{hr}}{\text{yr}} \times \frac{6.01\times10^{-7}\ \text{tonne N}_2\text{O}}{10^6\ \text{Btu}}$$

$$\underline{E_{N_2O} = 0.0000467\ \text{tonnes N}_2\text{O/yr}}$$

Diesel CO$_2$e Emissions:

$$E_{CO_2e} = \frac{219\ \text{tonne CO}_2}{\text{yr}} + \left(\frac{0.0108\ \text{tonne CH}_4}{\text{yr}} + \frac{0.00112\ \text{tonne CH}_4}{\text{yr}}\right) \times \frac{21\ \text{tonne CO}_2\text{e}}{\text{tonne CH}_4}$$
$$+ \left(\frac{0.00175\ \text{tonne N}_2\text{O}}{\text{yr}} + \frac{0.0000467\ \text{tonne N}_2\text{O}}{\text{yr}}\right) \times \frac{310\ \text{tonne CO}_2\text{e}}{\text{tonne N}_2\text{O}}$$

$$\underline{E_{CO_2e} = 220\ \text{tonne CO}_2\text{e/yr}}$$

Combustion Sources – Flares

Flaring emissions are calculated based on the guidance given in Section 4.6, which states CO_2 emissions are based on 98% combustion efficiency and CH_4 emissions are calculated assuming that 2% of the CH_4 remains uncombusted. A ±20% uncertainty is assumed for both, based on engineering judgment. Carbon dioxide emissions are estimated as the sum of the CO_2 already present in the gas and the CO_2 that results from the product of flared gas carbon combustion. Nitrous oxide emissions are estimated using an emission factor from Table 4-11, assuming an uncertainty of ±200%, based on engineering judgment. It is assumed that the flare gas composition is equal to the field gas composition. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs.

Carbon dioxide emissions:

$$E_{CO_2} = \frac{500\times10^6\ \text{scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3\ \text{scf gas}} \times \frac{44.01\ \text{lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62\ \text{lb}}$$

$$\times \left[\begin{array}{l} \left(\begin{array}{l} \frac{0.80\ \text{lbmole CH}_4}{\text{lbmole gas}} \times \frac{1\ \text{lbmole C}}{\text{lbmole CH}_4} + \frac{0.042\ \text{lbmole C}_2\text{H}_6}{\text{lbmole gas}} \times \frac{2\ \text{lbmole C}}{\text{lbmol C}_2\text{H}_6} \\ + \frac{0.013\ \text{lbmole C}_3\text{H}_8}{\text{lbmole gas}} \times \frac{3\ \text{lbmol C}}{\text{lbmole C}_3\text{H}_8} + \frac{0.004\ \text{lbmole C}_4\text{H}_{10}}{\text{lbmole gas}} \times \frac{4\ \text{lbmole C}}{\text{lbmole C}_4\text{H}_{10}} \end{array} \right) \\ \times \frac{0.98\ \text{lbmole CO}_2\ \text{formed}}{\text{lbmole C combusted}} + \frac{0.12\ \text{lbmole CO}_2}{\text{lbmole gas}} \end{array} \right]$$

$\underline{E_{CO_2} = 27{,}400\ \text{tonnes CO}_2/\text{yr}}$

Methane, N_2O, and CO_2e emissions:

$$E_{CH_4} = \frac{500\times10^6\text{scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3\ \text{scf gas}} \times \frac{0.80\ \text{lbmole CH}_4}{\text{lbmole gas}} \times \frac{16.04\ \text{lb CH}_4}{\text{lbmole CH}_4}$$

$$\times \frac{0.02\ \text{lb uncombusted CH}_4}{\text{lb CH}_4} \times \frac{\text{tonne}}{2204.62\ \text{lb}}$$

$\underline{E_{CH_4} = 153\ \text{tonnes CH}_4/\text{yr}}$

$$E_{N_2O} = \frac{6{,}100\ \text{bbl}}{\text{day}} \times \frac{365\ \text{days}}{\text{yr}} \times \frac{1.0\times10^{-4}\ \text{tonnes N}_2\text{O}}{1{,}000\ \text{bbl}}$$

$\underline{E_{N_2O} = 0.223\ \text{tonnes N}_2\text{O/yr}}$

$$E_{CO_2e} = \frac{27{,}400\ \text{tonne CO}_2}{\text{yr}} + \left(\frac{153\ \text{tonne CH}_4}{\text{yr}} \times \frac{21\ \text{tonne CO}_2\text{e}}{\text{tonne CH}_4} \right)$$

$$+ \left(\frac{0.223\ \text{tonne N}_2\text{O}}{\text{yr}} \times \frac{310\ \text{tonne CO}_2\text{e}}{\text{tonne N}_2\text{O}} \right)$$

$\underline{E_{CO_2e} = 30{,}700\ \text{tonne CO}_2\text{e/yr}}$

Combustion Sources – Fleet Vehicles

The calculations for fleet vehicle emissions are demonstrated below. The fuel-based emission factor for CO_2 is presented in Table 4-3 for motor gasoline, assuming an uncertainty of ±10%, based on engineering judgment. Because the emission factor for CO_2 is in units of tonne CO_2 per MMBtu, the volume of fuel consumed is converted to energy input using the heating value of gasoline (provided in Table 3-8), assuming an uncertainty of ±5%, based on engineering judgment. The emission factors for CH_4 and N_2O are provided in Table 4-17; the vehicles are assumed to be Tier 1. The uncertainty for both the CH_4 and N_2O emission factors is assumed to be ±150%, based on engineering judgment. The fuel economy is taken from Table 4-13, for gasoline light trucks, assuming an uncertainty of ±5%, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs.

$$\mathrm{V} = \frac{40{,}000\ \mathrm{mi}}{\mathrm{yr\text{-}truck}} \times \frac{\mathrm{gal}}{14\ \mathrm{mi}} \times \frac{\mathrm{bbl}}{42\ \mathrm{gal}} \times \frac{5.25 \times 10^6\ \mathrm{Btu}}{\mathrm{bbl}} = 1{,}790 \times 10^6\ \mathrm{Btu/yr\text{-}truck}$$

$$\mathrm{E}_{\mathrm{CO_2}} = 5\ \mathrm{trucks} \times \frac{1{,}790 \times 10^6\ \mathrm{Btu}}{\mathrm{yr\text{-}truck}} \times \frac{0.0709\ \mathrm{tonne\ CO_2}}{1 \times 10^6\ \mathrm{Btu}}$$

$$\underline{\mathrm{E}_{\mathrm{CO_2}} = 127\ \mathrm{tonne\ CO_2/yr}}$$

$$\mathrm{E}_{\mathrm{CH_4}} = 5\ \mathrm{trucks} \times \frac{40{,}000\ \mathrm{mi}}{\mathrm{yr\text{-}truck}} \times \frac{\mathrm{gal}}{14\ \mathrm{mi}} \times \frac{4.5 \times 10^{-4}\mathrm{tonne\ CH_4}}{\mathrm{Mgal}} \times \frac{\mathrm{Mgal}}{1000\ \mathrm{gal}}$$

$$\underline{\mathrm{E}_{\mathrm{CH_4}} = 0.00643\ \mathrm{tonne\ CH_4/yr}}$$

$$\mathrm{E}_{\mathrm{N_2O}} = 5\ \mathrm{trucks} \times \frac{40{,}000\ \mathrm{mi}}{\mathrm{yr\text{-}truck}} \times \frac{\mathrm{gal}}{14\ \mathrm{mi}} \times \frac{6.1 \times 10^{-4}\mathrm{tonne\ N_2O}}{\mathrm{Mgal}} \times \frac{\mathrm{Mgal}}{1000\ \mathrm{gal}}$$

$$\underline{\mathrm{E}_{\mathrm{N_2O}} = 0.00871\ \mathrm{tonne\ N_2O/yr}}$$

$$E_{CO_2e} = \frac{127 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{0.00643 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4} \right) + \left(\frac{0.00871 \text{ tonne } N_2O}{\text{yr}} \times \frac{310 \text{ tonne } CO_2e}{\text{tonne } N_2O} \right)$$

$$\underline{E_{CO_2e} = 129 \text{ tonne } CO_2e/\text{yr}}$$

Vented Sources - Gas Dehydration

Dehydration emissions are from the dehydrator vents and Kimray pumps. Methane emissions from the dehydrator vents are estimated using the production segment emission factor and associated uncertainties given in Table 5-2. The Kimray pump emissions are estimated using the production segment emission factor and associated uncertainties in Table 5-4. For both of these sources, emissions are based on the quantity of gas processed. Methane emissions are adjusted based on the facility CH_4 content. The default CH_4 content and associated uncertainty are provided in Table E-4. Carbon dioxide emissions are estimated by using a ratio of the facility CO_2 and default CH_4 concentrations in the gas. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs.

$$EF_{CH_4} = \left(EF_{\text{Dehydrator vents}}\right) + \left(EF_{\text{Kimray pumps}}\right)$$

$$EF_{CH_4} = \left(\frac{0.0052859 \text{ tonne } CH_4}{10^6 \text{ scf}} \right) + \left(\frac{0.01903 \text{ tonne } CH_4}{10^6 \text{ scf}} \right) = 0.024326 \text{ tonne } CH_4 / 10^6 \text{ scf}$$

$$E_{CH_4} = \frac{30 \times 10^6 \text{ scf}}{\text{day gas processed}} \times \frac{343 \text{ day}}{\text{yr}} \times \frac{0.80 \text{ tonne mole } CH_4 \text{ (facility)}}{0.788 \text{ tonne mole } CH_4 \text{ (default)}} \times \frac{0.024326 \text{ tonne } CH_4}{10^6 \text{scf}}$$

$$\underline{E_{CH_4} = 254 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = \frac{30\times10^6 \text{ scf}}{\text{day gas processed}} \times \frac{343 \text{ day}}{\text{yr}} \times \frac{0.024326 \text{ tonne CH}_4}{10^6\text{scf}} \times \frac{\text{tonne mole CH}_4}{16.04 \text{ tonne CH}_4} \times \frac{0.80 \text{ tonne mole CH}_4 \text{ (facility)}}{0.788 \text{ tonne mole CH}_4 \text{ (default)}}$$
$$\times \frac{\text{tonne mole gas}}{0.8 \text{ tonne mole CH}_4} \times \frac{0.12 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne CO}_2}{\text{tonne mole CO}_2}$$

$$\underline{E_{CO_2} = 105 \text{ tonnes CO}_2\text{/yr}}$$

$$E_{CO_2e} = \frac{105 \text{ tonne CO}_2}{\text{yr}} + \left(\frac{254 \text{ tonne CH}_4}{\text{yr}} \times \frac{21 \text{ tonne CO}_2\text{e}}{\text{tonne CH}_4}\right)$$

$$\underline{E_{CO_2e} = 5{,}440 \text{ tonne CO}_2\text{e/yr}}$$

Vented Sources - Storage Tank Flashing

Methane emissions from flashing losses are estimated using the simple emission factor provided in Table 5-8, in the absence of the more detailed information necessary for the other calculation approaches provided in Section 5.4.1. The uncertainty for the CH_4 emission factor is assumed to be ±90% based on engineering judgment. Methane emissions are adjusted based on the facility CH_4 content. The default CH_4 content and associated uncertainty are provided in Table E-4. Carbon dioxide emissions are calculated by using a ratio of the facility CH_4 and CO_2 contents. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Emissions from storage tank flashing are calculated below.

$$E_{CH_4} = \frac{6{,}100 \text{ bbl}}{\text{day}} \times \frac{343 \text{ day}}{\text{yr}} \times \frac{0.80 \text{ tonne mole CH}_4 \text{ (facility)}}{0.788 \text{ tonne mole CH}_4 \text{ (default)}} \times \frac{8.86\times10^{-4} \text{tonne CH}_4}{\text{bbl}}$$

$$\underline{E_{CH_4} = 1{,}880 \text{ tonnes CH}_4\text{/yr}}$$

$$E_{CO_2} = \frac{6{,}100 \text{ bbl}}{\text{day}} \times \frac{343 \text{ day}}{\text{yr}} \times \frac{8.86\times 10^{-4} \text{tonne CH}_4}{\text{bbl}} \times \frac{\text{tonne mole CH}_4}{16.04 \text{ tonne CH}_4} \times \frac{0.80 \text{ tonne mole CH}_4 \text{ (facility)}}{0.788 \text{ tonne mole CH}_4 \text{ (default)}}$$
$$\times \frac{\text{tonne mole gas}}{0.8 \text{ tonne mole CH}_4} \times \frac{0.12 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne CO}_2}{\text{tonne mole CO}_2}$$

$$\underline{E_{CO_2} = 775 \text{ tonnes CO}_2\text{/yr}}$$

$$E_{CO_2e} = \frac{775 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{1{,}880 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4} \right)$$

$$\underline{E_{CO_2e} = 40{,}300 \text{ tonne } CO_2e/\text{yr}}$$

Vented Sources – Other Storage Tank Emissions

There are no GHG emissions from the other tanks at the facility (chemical tank, naphtha tank, etc.) because the materials do not contain GHG constituents.

Vented Sources - Acid Gas Removal (Amine Unit Emissions)

Methane emissions from the amine unit are estimated based on the emission factor and associated uncertainties provided in Table 5-5 and the quantity of gas processed. Methane emissions are adjusted based on the facility CH_4 content. The default CH_4 content and associated uncertainty are provided in Table E-4. Carbon dioxide emissions are calculated using Equation 5-2. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Amine unit emissions are calculated below.

$$E_{CH_4} = \frac{30\times10^6 \text{ scf}}{\text{day processed}} \times \frac{343 \text{ day}}{\text{yr}} \times \frac{0.0185 \text{ tonne } CH_4}{10^6 \text{ scf}} \times \frac{0.80 \text{ tonne mole } CH_4 \text{ (facility)}}{0.788 \text{ tonne mole } CH_4 \text{ (default)}}$$

$$\underline{E_{CH_4} = 193 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = \left[\left(\frac{30\times10^6 \text{ scf}}{\text{day processed}} \times \frac{343 \text{ day}}{\text{yr}} \times 12 \text{ mole\% } CO_2 \right)_{\text{sour}} - \left(\frac{8{,}997\times10^6 \text{ scf}}{\text{yr}} \times 0.5 \text{ mole\% } CO_2 \right)_{\text{sweet}} \right] \times \frac{44 \frac{\text{lb}}{\text{lbmole}}}{379.3 \frac{\text{scf}}{\text{lbmole}}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 62{,}600 \text{ tonne } CO_2/\text{yr}}$$

$$E_{CO_2e} = 62{,}600 \text{ tonne } CO_2/\text{yr} + \left(\frac{190 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2\text{e}}{\text{tonne } CH_4}\right)$$

$$\underline{E_{CO_2e} = 66{,}700 \text{ tonne } CO_2\text{e/yr}}$$

Vented Sources - Pneumatics and CIPs

The pneumatic devices and CIPs at the facility are actuated by natural gas. Methane emissions from pneumatic devices and CIP vents are estimated using CH_4 emission factors and associated uncertainties 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. Methane emissions are adjusted based on the facility CH_4 content. The default CH_4 content and associated uncertainty are provided in Table E-4. Carbon dioxide emissions are calculated by using a ratio of the facility CH_4 and CO_2 contents. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Emissions are calculated below, by equipment type.

Pneumatic Devices:

$$E_{CH_4} = (64 \text{ pneumatic devices}) \times \frac{0.80 \text{ tonne mole } CH_4 \text{ (facility)}}{0.788 \text{ tonne mole } CH_4 \text{ (default)}} \times \frac{2.415 \text{ tonne } CH_4}{\text{device - yr}}$$

$$\underline{E_{CH_4} = 157 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = (64 \text{ pneumatic devices}) \times \frac{2.415 \text{ tonne } CH_4}{\text{device - yr}} \times \frac{\text{tonne mole } CH_4}{16.04 \text{ tonne } CH_4} \times \frac{0.80 \text{ tonne mole } CH_4 \text{ (facility)}}{0.788 \text{ tonne mole } CH_4 \text{ (default)}}$$
$$\times \frac{\text{tonne mole gas}}{0.8 \text{ tonne mole } CH_4} \times \frac{0.12 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2} = 64.6 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CO_2e} = \frac{64.6 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{157 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2\text{e}}{\text{tonne } CH_4}\right)$$

$$\underline{E_{CO_2e} = 3{,}360 \text{ tonne } CO_2\text{e/yr}}$$

CIPs:

$$E_{CH_4} = (67\text{ CIPs}) \times \frac{1.736\text{ tonne CH}_4}{\text{CIP - yr}} \times \frac{0.80\text{ tonne mole CH}_4\text{ (facility)}}{0.788\text{ tonne mole CH}_4\text{ (default)}}$$

$$\underline{E_{CH_4} = 118\text{ tonnes CH}_4/\text{yr}}$$

$$E_{CO_2} = (67\text{ CIPs}) \times \frac{1.736\text{ tonne CH}_4}{\text{CIP - yr}} \times \frac{\text{tonne mole CH}_4}{16.04\text{ tonne CH}_4} \times \frac{0.80\text{ tonne mole CH}_4\text{ (facility)}}{0.788\text{ tonne mole CH}_4\text{ (default)}}$$
$$\times \frac{\text{tonne mole gas}}{0.8\text{ tonne mole CH}_4} \times \frac{0.12\text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01\text{ tonne CO}_2}{\text{tonne mole CO}_2}$$

$$\underline{E_{CO_2} = 48.6\text{ tonnes CO}_2/\text{yr}}$$

$$E_{CO_2e} = \frac{48.6\text{ tonne CO}_2}{\text{yr}} + \left(\frac{118\text{ tonne CH}_4}{\text{yr}} \times \frac{21\text{ tonne CO}_2\text{e}}{\text{tonne CH}_4}\right)$$

$$\underline{E_{CO_2e} = 2{,}530\text{ tonne CO}_2\text{e/yr}}$$

Vented Sources - Maintenance/Turnaround Emissions

Methane emissions from vessel blowdowns, compressor starts, compressor blowdowns, and oil well workovers are estimated using the emission factors and associated uncertainties presented in Table 5-23. The uncertainty for the well workovers emission factor is assumed to be ±300% based on engineering judgment. Methane emissions are adjusted based on the facility CH_4 content. The default CH_4 content and associated uncertainty are provided in Table E-4. Carbon dioxide emissions are estimated using the known CO_2 and CH_4 concentrations in the gas. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Maintenance emission calculations are shown below, by activity type.

Vessel blowdowns:

$$E_{CH_4} = (112\text{ vessels}) \times \frac{0.0015\text{ tonne CH}_4}{\text{vessel - yr}} \times \frac{0.80\text{ tonne mole CH}_4\text{ (facility)}}{0.788\text{ tonne mole CH}_4\text{ (default)}}$$

$$\underline{E_{CH_4} = 0.171\text{ tonnes CH}_4/\text{yr}}$$

$$E_{CO_2} = (112 \text{ vessels}) \times \frac{0.0015 \text{ tonne CH}_4}{\text{vessel - yr}} \times \frac{\text{tonne mole CH}_4}{16.04 \text{ tonne CH}_4} \times \frac{0.80 \text{ tonne mole CH}_4 \text{ (facility)}}{0.788 \text{ tonne mole CH}_4 \text{ (default)}}$$
$$\times \frac{\text{tonne mole gas}}{0.8 \text{ tonne mole CH}_4} \times \frac{0.12 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne CO}_2}{\text{tonne mole CO}_2}$$

$$\underline{E_{CO_2} = 0.0702 \text{ tonnes CO}_2\text{/yr}}$$

$$E_{CO_2e} = \frac{0.0702 \text{ tonne CO}_2}{\text{yr}} + \left(\frac{0.171 \text{ tonne CH}_4}{\text{yr}} \times \frac{21 \text{ tonne CO}_2\text{e}}{\text{tonne CH}_4} \right)$$

$$\underline{E_{CO_2e} = 3.65 \text{ tonne CO}_2\text{e/yr}}$$

Compressor starts:

$$E_{CH_4} = (11 \text{ compressors}) \times \frac{0.1620 \text{ tonne CH}_4}{\text{compressor - yr}} \times \frac{0.80 \text{ tonne mole CH}_4 \text{ (facility)}}{0.788 \text{ tonne mole CH}_4 \text{ (default)}}$$

$$\underline{E_{CH_4} = 1.81 \text{ tonnes CH}_4\text{/yr}}$$

$$E_{CO_2} = (11 \text{ compressors}) \times \frac{0.1620 \text{ tonne CH}_4}{\text{compressor - yr}} \times \frac{\text{tonne mole CH}_4}{16.04 \text{ tonne CH}_4} \times \frac{0.80 \text{ tonne mole CH}_4 \text{ (facility)}}{0.788 \text{ tonne mole CH}_4 \text{ (default)}}$$
$$\times \frac{\text{tonne mole gas}}{0.8 \text{ tonne mole CH}_4} \times \frac{0.12 \text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne CO}_2}{\text{tonne mole CO}_2}$$

$$\underline{E_{CO_2} = 0.745 \text{ tonnes CO}_2\text{/yr}}$$

$$E_{CO_2e} = \frac{0.745 \text{ tonne CO}_2}{\text{yr}} + \left(\frac{1.81 \text{ tonne CH}_4}{\text{yr}} \times \frac{21 \text{ tonne CO}_2\text{e}}{\text{tonne CH}_4} \right)$$

$$\underline{E_{CO_2e} = 38.7 \text{ tonne CO}_2\text{e/yr}}$$

Compressor blowdowns:

$$E_{CH_4} = (11 \text{ compressors}) \times \frac{0.07239 \text{ tonne CH}_4}{\text{compressor - yr}} \times \frac{0.80 \text{ tonne mole CH}_4 \text{ (facility)}}{0.788 \text{ tonne mole CH}_4 \text{ (default)}}$$

$$\underline{E_{CH_4} = 0.808 \text{ tonnes CH}_4\text{/yr}}$$

$$E_{CO_2} = (11\ \text{compressors}) \times \frac{0.07239\ \text{tonne CH}_4}{\text{compressor - yr}} \times \frac{\text{tonne mole CH}_4}{16.04\ \text{tonne CH}_4} \times \frac{0.80\ \text{tonne mole CH}_4\ \text{(facility)}}{0.788\ \text{tonne mole CH}_4\ \text{(default)}}$$

$$\times \frac{\text{tonne mole gas}}{0.8\ \text{tonne mole CH}_4} \times \frac{0.12\ \text{tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01\ \text{tonne CO}_2}{\text{tonne mole CO}_2}$$

$$\underline{E_{CO_2} = 0.333\ \text{tonnes CO}_2/\text{yr}}$$

$$E_{CO_2e} = \frac{0.333\ \text{tonne CO}_2}{\text{yr}} + \left(\frac{0.808\ \text{tonne CH}_4}{\text{yr}} \times \frac{21\ \text{tonne CO}_2\text{e}}{\text{tonne CH}_4} \right)$$

$$\underline{E_{CO_2e} = 17.3\ \text{tonne CO}_2\text{e/yr}}$$

Oil well workovers:

$$E_{CH_4} = \frac{24\ \text{well workovers}}{\text{yr}} \times \frac{0.0018\ \text{tonne CH}_4}{\text{workovers}} \times \frac{0.80\ \text{tonne mole CH}_4\ \text{(facility)}}{0.788\ \text{tonne mole CH}_4\ \text{(default)}}$$

$$\underline{E_{CH_4} = 0.0439\ \text{tonnes CH}_4/\text{yr}}$$

$$E_{CO_2} = \frac{24\ \text{well workovers}}{\text{yr}} \times \frac{0.0018\ \text{tonne CH}_4}{\text{workovers}} \times \frac{\text{tonne mole CH}_4}{16.04\ \text{tonne CH}_4} \times \frac{0.80\ \text{tonne mole CH}_4\ \text{(facility)}}{0.788\ \text{tonne mole CH}_4\ \text{(default)}}$$

$$\times \frac{\text{tonne mole gas}}{0.8\ \text{tonne mole CH}_4} \times \frac{0.12\ \text{tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01\ \text{tonne CO}_2}{\text{tonne mole CO}_2}$$

$$\underline{E_{CO_2} = 0.0181\ \text{tonnes CO}_2/\text{yr}}$$

$$E_{CO_2e} = \frac{0.0181\ \text{tonne CO}_2}{\text{yr}} + \left(\frac{0.0439\ \text{tonne CH}_4}{\text{yr}} \times \frac{21\ \text{tonne CO}_2\text{e}}{\text{tonne CH}_4} \right)$$

$$\underline{E_{CO_2e} = 0.939\ \text{tonne CO}_2\text{e/yr}}$$

Vented Sources – PRVs

Methane emissions from PRVs are estimated using the PRV emission factor and corresponding uncertainty from Table 5-24. Methane emissions are adjusted based on the facility CH_4 content.

The default CH_4 content and associated uncertainty are provided in Table E-4. The CO_2 emissions are estimated using the ratio of the facility gas CO_2 to the default CH_4 content. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. PRV emissions are calculated below.

$$E_{CH_4} = (482\ \text{PRVs}) \times \frac{0.00065\ \text{tonne}\ CH_4}{\text{PRV - yr}} \times \frac{0.80\ \text{tonne mole}\ CH_4\ \text{(facility)}}{0.788\ \text{tonne mole}\ CH_4\ \text{(default)}}$$

$$\underline{E_{CH_4} = 0.318\ \text{tonnes}\ CH_4/\text{yr}}$$

$$E_{CO_2} = (482\ \text{PRVs}) \times \frac{0.00065\ \text{tonne}\ CH_4}{\text{PRV - yr}} \times \frac{\text{tonne mole}\ CH_4}{16.04\ \text{tonne}\ CH_4} \times \frac{0.80\ \text{tonne mole}\ CH_4\ \text{(facility)}}{0.788\ \text{tonne mole}\ CH_4\ \text{(default)}}$$
$$\times \frac{\text{tonne mole gas}}{0.8\ \text{tonne mole}\ CH_4} \times \frac{0.12\ \text{tonne mole}\ CO_2}{\text{tonne mole gas}} \times \frac{44.01\ \text{tonne}\ CO_2}{\text{tonne mole}\ CO_2}$$

$$\underline{E_{CO_2} = 0.131\ \text{tonnes}\ CO_2/\text{yr}}$$

$$E_{CO_2e} = 0.131\ \text{tonne}\ CO_2/\text{yr} + \left(\frac{0.318\ \text{tonne}\ CH_4}{\text{yr}} \times \frac{21\ \text{tonne}\ CO_2e}{\text{tonne}\ CH_4} \right)$$

$$\underline{E_{CO_2e} = 6.81\ \text{tonne}\ CO_2e/\text{yr}}$$

Fugitive Sources - Equipment Leaks

Table 8-4 provides average component emission factors associated with the high CO_2 content onshore oil field facility. The emission factors are based on the API average oil and natural gas production emission factors given in Table 6-14. Because factors are taken from API 4615, the weight fraction of CH_4 is taken from Table C-6 for light crude, assuming an uncertainty of ±15% based on engineering judgment. Note that Table C-6 does not provide CO_2 speciation data; therefore, these emission are not calculated.

Table 8-4. On-Shore Oil Field (High CO_2 Content) Fugitive Emission Factors

Component	Service	Component EF, tonnes TOC/comp./hr [a]	Uncertainty [b] (±%)
Valves	Liquid and Gas	1.32E-06	100
Pump seals	Liquid and Gas	3.18E-07	100
Connectors	Gas	1.64E-07	100
Flanges	Liquid and Gas	7.69E-08	100
OELs	Gas	1.21E-06	100
Others	Liquid and Gas	7.50E-06	100

Footnotes:

[a] 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_4 emissions as shown in Equation 6-9.

[b] Uncertainty based on engineering judgment at a 95% confidence interval.

Using Equation 6-9, CH_4 emissions are calculated for each component by multiplying the component emission factor by the component count, the annual hours of operation (8,760 hours/year, assuming that the equipment remains pressurized year-round), and the weight fraction of CH_4. As a simplifying assumption, the gas service compositions are used for the liquid fugitive emissions because the liquid composition is not known, recognizing that this overestimates emissions. The total fugitive emissions are then the sum of each of the component emissions. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs.

An example calculation for liquid and gas pump seals is shown below.

$$E_{CH_4} = (185 \text{ pump seals}) \times \frac{3.18 \times 10^{-7} \text{ tonne TOC}}{\text{seal - hr}} \times \frac{8{,}760 \text{ hr}}{\text{yr}} \times \frac{0.613 \text{ tonne } CH_4}{\text{tonne TOC}}$$

$$\underline{E_{CH_4} = 0.316 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2e} = \frac{0.316 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}$$

$$\underline{E_{CO_2e} = 6.63 \text{ tonne } CO_2e/\text{yr}}$$

Completing the calculations for the rest of the components results in the emissions shown in Table 8-5.

Table 8-5. On-Shore Oil Field (High CO_2 Content) Fugitive Emissions

Component	Service	CH_4 Emissions (tonnes/yr)	Uncertainty [a] (±%)	CO_2e Emissions (tonnes/yr)	Uncertainty [a] (±%)
Valves	Liquid and Gas	19.4	126	408	126
Pump seals	Liquid and Gas	0.316	126	6.63	126
Connectors	Gas	0.0969	126	2.03	126
Flanges	Liquid and Gas	4.13	126	86.7	126
OELs	Gas	0.0390	126	0.819	126
Others	Liquid and Gas	28.6	126	600	126
Total[b]		**52.6**	**83.3**	**1,105**	**83.3**

Footnotes:

[a] Uncertainty is at a 95% confidence interval.

[b] Totals may not sum due to independent rounding.

Note: the values shown above are for example only. They do not reflect average operations.

Fugitive Sources – Fleet Vehicle Refrigeration

Because the actual vehicle refrigerant capacities are unknown, the capacity is assumed to be the midpoint of the range presented in Table 6-25 for mobile air conditioning, assuming an uncertainty of ±100%, based on engineering judgment. The percentage of capacity emitted per year is also taken from Table 6-25, assuming an uncertainty of ±50%, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWP provided in Table 3-1 (for HFC-134a). There are no uncertainties for any of the GWPs. The calculations for fleet vehicle refrigeration emissions are shown below.

$$E_{R-134a} = 5 \text{ vehicles} \times \frac{1.0 \text{ kg}}{\text{vehicle}} \times 0.20 \text{ capacity} \times \frac{\text{tonne R-134a}}{1000 \text{ kg}}$$

$$\underline{E_{R-134a} = 0.00100 \text{ tonne R-134a/yr}}$$

$$E_{CO_2e} = \frac{0.00100 \text{ tonne R-134a}}{\text{yr}} \times \frac{1300 \text{ tonne } CO_2e}{\text{tonne R-135a}}$$

$$\underline{E_{CO_2e} = 1.30 \text{ tonne } CO_2e/\text{yr}}$$

Indirect Sources - Electricity Consumption

Emissions associated with the electricity purchased by the facility are calculated using emission factors in Table 7-2 for eGRID subregion ERCOT All. The uncertainties for the emission factors are assumed to be ±10% for CO_2 and ±100% for CH_4 and N_2O, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs.

$$E_{CO_2} = \frac{917 \text{ MW-hr}}{\text{yr}} \times \frac{0.601 \text{ tonne } CO_2}{\text{MW-hr}}$$

$$\underline{E_{CO_2} = 551 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CH_4} = \frac{917 \text{ MW-hr}}{\text{yr}} \times \frac{8.46 \times 10^{-6} \text{ tonne } CH_4}{\text{MW-hr}}$$

$$\underline{E_{CH_4} = 0.00776 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{917 \text{ MW-hr}}{\text{yr}} \times \frac{6.85 \times 10^{-6} \text{ tonne } N_2O}{\text{MW-hr}}$$

$$\underline{E_{N_2O} = 0.00628 \text{ tonnes } N_2O/\text{yr}}$$

$$E_{CO_2e} = \frac{551 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{0.00776 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right) + \left(\frac{0.00628 \text{ tonne } N_2O}{\text{yr}} \times \frac{310 \text{ tonne } CO_2e}{\text{tonne } N_2O}\right)$$

$$\underline{E_{CO_2e} = 553 \text{ tonne } CO_2e/\text{yr}}$$

Facility Summary

Total emissions for this facility are summarized in Table 8-6. A summary of the emissions for this facility is given in Figure 8-1.

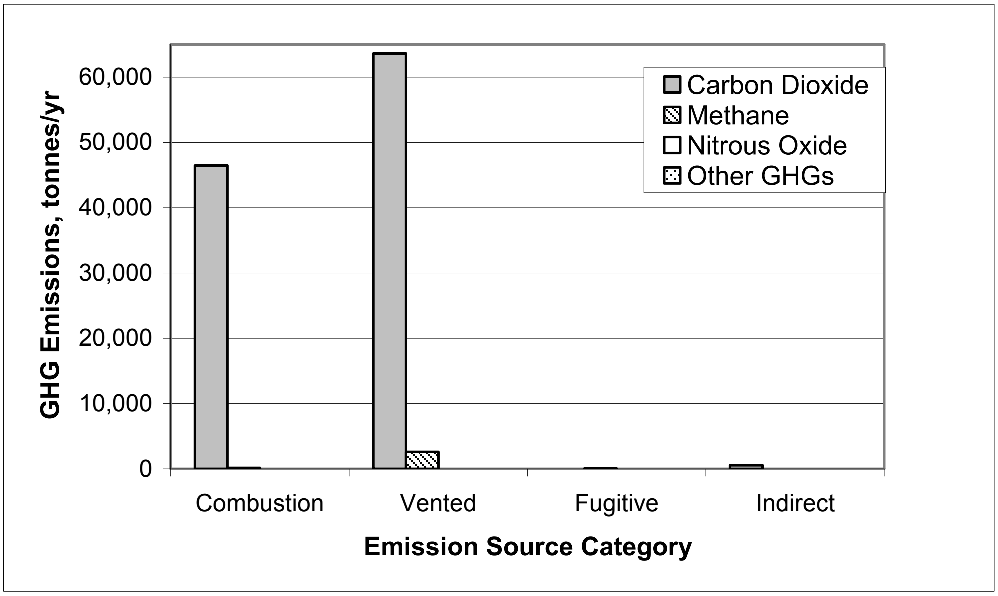


Figure 8-1. Onshore Oil Field (High CO_2 Content) Summary of Emissions

Table 8-6. On-Shore Oil Field (High CO_2 Content) Emissions

Source	CO_2 N		CH_4		$_2$O		CO_2e	
	Emissions (tonnes/yr)	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**
Combustion Sources	**46,800**	**14.5**	**154**	**25.2**	**0.582**	**114**	**49,900**	**13.7**
Boilers	5,200	8.78	0.0865	26.1	0.0242	150	5,210	8.77
Heaters/reboilers								
Compressor engines – turbines	13,900	15.7	0.905	29.4	0.325	151	14,100	15.6
Emergency flare	27,400	23.4	153	25.3	0.223	200	30,700	21.1
Emergency generator IC engine	219	15.6	0.0108	27.8	0.00175	151	220	15.5
Fire water pump IC engine			0.00112	106	0.0000467	151		
Fleet vehicles	127	19.4	0.00643	151	0.00871	151	129	19.2
Vented Sources	**63,600**	**6.95**	**2,610**	**66.5**	**N/A**		**118,300**	**31.0**
Dehydration vents (also has Kimray pump emissions)	105	77.5	254	77.5	N/A		5,440	76.0
Central tank battery	775	90.4	1,880	90.4	N/A		40,300	88.7
Chemical storage tank	No greenhouse gas (GHG) emissions							
Naphtha storage tank	No GHG emissions							

Table 8-6. On-Shore Oil Field (High CO$_2$ Content) Emissions, continued

Source	CO$_2$ N		CH$_4$		$_2$O		CO$_2$e	
	Emissions (tonnes/yr)	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**
Vented Sources, continued	**63,600**	**6.95**	**2,610**	**66.5**	**N/A**	**118,300**	**31.0**	**63,600**
Glycol storage tank	No GHG emissions							
Water blowdown tank	No GHG emissions							
Slop oil tank	No GHG emissions							
Amine unit for CO$_2$ removal	62,600	6.97	193	119	N/A		66,700	9.77
Pneumatic devices	64.6	50.2	157	50.2	N/A		3,360	49.2
CIPs	48.6	108	118	108	N/A		2,530	106
Vessel blowdowns (non-routine)	0.0702	326	0.171	326	N/A		3.65	319
Compressor starts (non-routine)	0.745	190	1.81	190	N/A		38.7	187
Compressor blowdowns (non-routine)	0.333	179	0.808	179	N/A		17.3	175
Well workovers (non-routine)	0.0181	300	0.0439	300	N/A		0.939	294
PRVs	0.131	310	0.318	310	N/A		6.81	304
Fugitive Sources	**N/A**		**52.6**	**83.3**	**N/A**		**1,100**	**83.2**
Equipment leaks	N/A		52.6	83.3	N/A		1,100	83.3
Fleet vehicle refrigeration, R-314a	N/A		N/A		N/A		1.30	112
Indirect Sources	**551**	**10.2**	**0.00776**	**100**	**0.00628**	**100**	**553**	**10.2**
Electricity consumed	551	10.2	0.00776	100	0.00628	100	553	10.2
TOTAL - Direct [b]	**110,500**	**7.33**	**2,820**	**61.7**	**0.582**	**114**	**169,700**	**22.0**
TOTAL - Indirect [b]	**551**	**10.2**	**0.00776**	**100**	**0.00628**	**100**	**553**	**10.2**
TOTAL [b]	**111,00**	**7.29**	**2,820**	**61.7**	**0.588**	**113**	**170,300**	**21.9**

Footnotes:

[a] Uncertainty is at a 95% confidence interval.

[b] Totals may not sum due to independent rounding.

Note: the values shown above are for example only. They do not reflect average operations.

8.1.2 Offshore Oil and Natural 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 16×10^6 scf/day.

Operations: The facility operates continuously throughout the year. The produced gas composition is provided in Table 8-7 which results in a heating value of 1,033 Btu/scf. An uncertainty of ±4% is assumed for both the composition and heating value, based on engineering judgment.

Table 8-7. Gas Composition for Offshore Production Platform

Gas Compound	Produced Gas Mole %	Uncertainty[a] (±%)
CO_2	1.09	4
N_2	2.39	4
CH_4	90.95	4
C_2H_6	4	4
C_3H_8	1.14	4
i-C_4H_{10}	0.14	4
n-C_4H_{10}	0.16	4
i-C_5H_{12}	0.02	4
n-C_5H_{12}	0.02	4
C_6H_{14}	0	4
Other C_6	0.02	4
C_7H_{16}	0.07	4

Footnote:
[a] Uncertainty is based on engineering judgment at a 95% confidence interval.
Note: the values shown above are for example only. They do not reflect actual operations.

Table 8-8 summarizes the emission sources associated with this facility. Equipment at the site that does not have GHG emissions is also included in this table.

Table 8-8. Offshore Oil and Natural Gas Production Platform Emissions Sources

Source	Fuel Type	No. of Units	Uncertainty [a] (±%)	Unit Capacity (per unit)	Uncertainty [a] (±%)	Average Operation (per unit/yr)	Uncertainty [a] (±%)	Activity Factor (all units combined)	Uncertainty [a] (±%)
Combustion Sources									
Boilers/heaters	Produced Gas	N/A		N/A		N/A		$14{,}126\times10^3$ scf/yr	20
Gas turbines (electricity generation)	Produced Gas	N/A		N/A		N/A		470×10^6 scf/yr	20
Gas turbines (compression)	Produced Gas	N/A		N/A		N/A		200×10^6 scf/yr	20
IC engines	Diesel	N/A		N/A		N/A		160,000 gal/yr	10
Crane engine	Diesel	1	0	210 hp; 7100 Btu/hp-hr[a]	5; 5	2,920 hr/yr	15	$4{,}354\times10^6$ Btu/yr	16.6
Crane engine	Diesel	1	0	200 hp; 7100 Btu/hp-hr[a]	5; 5	2,920 hr/yr	15	$4{,}146\times10^6$ Btu/yr	16.6
Fire water pump IC engine	Diesel	1	0	280 hp; 7000 Btu/hp-hr[a]	5; 5	200 hr/yr	15	392×10^6 Btu/yr	16.6
Emergency generator, drilling	Diesel	2	0	1000 hp; 7000 Btu/hp-hr[a]	10; 5	200 hr/yr	15	$2{,}800\times10^6$ Btu/yr	18.7
Emergency generator, production	Diesel	1	0	1800 hp; 7000 Btu/hp-hr[a]	10; 5	200 hr/yr	15	$2{,}520\times10^6$ Btu/yr	18.7
Forklift	Diesel	1	0	2400 hp; 7000 Btu/hp-hr[a]	10; 5	1,100 hr/yr	15	$18{,}480\times10^6$ Btu/yr	18.7
Whittaker escape capsule	Diesel	1	0	3000 hp; 7000 Btu/hp-hr[a]	10; 5	200 hr/yr	15	$4{,}200\times10^6$ Btu/yr	18.7
Supply boat	Diesel	1	0	5000 hp 7500 Btu/hp-hr[a]	10; 5	1100 hr/yr	20	$41{,}250\times10^6$ Btu/yr	22.9
Supply boat	Diesel	1	0	5000 hp; 7500 Btu/hp-hr[a]	10; 5	110 hr/yr	20	$4{,}125\times10^6$ Btu/yr	22.9

Table 8-8. Offshore Oil and Natural Gas Production Platform Emissions Sources, continued

Source	Fuel Type	No. of Units	Uncertainty [a] (±%)	Unit Capacity (per unit)	Uncertainty [a] (±%)	Average Operation (per unit/yr)	Uncertainty [a] (±%)	Activity Factor (all units combined)	Uncertainty [a] (±%)
Helicopters	Aviation Gas	N/A		650 lb fuel/hr	10	50 min/trip, 1095 trips	20	$12,108\times10^{6}$ Btu/yr	22.4
Flare - purge and pilot	Produced Gas	1	0	N/A		N/A		395,000 scf/yr	20
Flare - planned other	Produced Gas	1	0	N/A		N/A		1.7×10^{6} scf/yr	20
Flare - planned continuous	Produced Gas	1	0	N/A		N/A		3.1×10^{6} scf/yr	20
Flare - unplanned	Produced Gas	1	0	N/A		N/A		20×10^{6} scf/yr	20
Vented Sources									
Tank battery	N/A	N/A		N/A		Continuous		547,500 bbl/yr (1,500 bbl/day)	20
Dehydration vents (also has Kimray pump emissions)	N/A	1	0	16×10^{6} scf/day gas processed	5	365 day/yr	0	$5,840\times10^{6}$ scf/yr	5
Pneumatic devices	N/A	7	0	N/A		N/A		7 pneumatic devices	0
CIPs	N/A	2	0	N/A		N/A		2 CIPs	0
Vessel blowdowns (non-routine)	N/A	9	0	N/A		N/A		9 vessels	0
Compressor starts (non-routine)	N/A	6	0	N/A		N/A		6 compressors	0
Compressor blowdowns (non-routine)	N/A	6	0	N/A		N/A		6 compressors	0
Emergency shutdowns	N/A	N/A		N/A		N/A		1 platform	0
PRVs	N/A	175	10	N/A		N/A		175 PRVs	10

Table 8-8. Offshore Oil and Natural Gas Production Platform Emissions Sources, continued

Source	Fuel Type	No. of Units	Uncertainty [a] (±%)	Unit Capacity (per unit)	Uncertainty [a] (±%)	Average Operation (per unit/yr)	Uncertainty [a] (±%)	Activity Factor (all units combined)	Uncertainty [a] (±%)
Fugitive Sources									
Equipment leaks	N/A	N/A		N/A		8,760 hr/yr	0	See Table 8-9	
Sumps	N/A	3	0	N/A		N/A		N/A	
Mud cuttings roll-off bins	N/A	N/A		N/A		N/A		N/A	
Indirect Sources									
None									

Footnotes:

[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

[b] Although some offshore oil and natural gas production platform PRVs may be tied into a flare system, the PRVs for this facility are not tied into the flare system.

Note: the values shown above are for example only. They do not reflect average operations.

Table 8-9 provides the fugitive component count for equipment at the offshore facility. The split between oil and natural gas service for these components is approximately 85% with oil service and the remaining 15% associated with gas service.

Table 8-9. Offshore Oil and Natural Gas Production Platform Fugitive Emission Sources

Component	Service	Average Component Count	Uncertainty [a] (±%)
Valves	Light oil	1870	75
	Gas	330	75
Connectors	Light oil	7480	75
	Gas	1320	75
OELs	Light oil	276	75
	Gas	49	75
Others	Light oil	60	75
	Gas	10	75

Footnote:

[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

Note: the values shown above are for example only. They do not reflect average operations.

Table 8-10 provides the fugitive component liquid composition for equipment at the offshore facility.

Table 8-10. Offshore Oil and Natural Gas Production Platform Fugitive Liquid Weight Percents

Compound	Liquid Weight %	Uncertainty [a] (±%)
CO_2	0.315	4
CH_4	1.19	4
C_2H_6	1.45	4
C_3H_8	3.25	4
C_4H_{10}	6.05	4
C_5H_{12}	7.89	4
C_6H_{14}	9.31	4
C_7H_{16}	22.95	4
C_8H_{18}	9.23	4
C_9H_{20}	6.39	4
$C_{10}H_{22}$	17.21	4
C_6H_6	0.964	4
C_7H_8	4.36	4
C_8H_{10}	0.196	4
C_8H_{10}	9.26	4

Footnote:

[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

Note: the values shown above are for example only. They do not reflect average operations.

The remainder of this subsection presents emission calculations for the sources identified in Table 8-8 and a summary of facility emissions (presented at the end of this subsection).

Stationary Combustion Devices – CO_2 Emissions

Natural Gas Combustion

The first step in calculating CO_2 emissions is to determine the total volume of fuel combusted (V) at the facility. This calculation is shown below, by equipment type.

Boilers and heaters:

Boilers and heaters fuel consumption is presented in Table 8-8.

$$V = 14.126 \times 10^6 \text{ scf / yr}$$

Turbines:

$$V = (470 + 200) \times 10^6 \text{ scf / yr} = 670 \times 10^6 \text{ scf / yr}$$

Carbon dioxide emissions from equipment burning natural gas are calculated using the gas composition approach provided in Section 4.3. First, the fuel analysis is converted from a molar basis to a mass basis, as shown in Exhibits 3.3 and 3.4. The molecular weight of the mixture is calculated below, using Equation 3-8:

$$MW_{\text{Mixture}} = \begin{bmatrix} (1.09\times44.01)+(2.39\times28.01)+(90.95\times16.04) \\ +(4\times30.07)+(1.14\times44.10)+(0.14\times58.12) \\ +(0.16\times58.12)+(0.02\times72.15)+(0.02\times72.15) \\ +(0\times86.18)+(0.02\times86.18)+(0.07\times100.20) \end{bmatrix} \div 100 = 17.73 \text{ lb/mole}$$

The individual weight percents are then calculated by rearranging Equation 3-7. The calculation is shown as follows for CH_4.

$$\text{Wt.\%}_{CH_4} = \frac{90.95 \text{ lbmole } CH_4}{100 \text{ lbmole mixture}} \times \frac{\left(\dfrac{16.04 \text{ lb } CH_4}{\text{lbmole } CH_4}\right)}{\left(\dfrac{17.73 \text{ lb mixture}}{\text{lbmole mixture}}\right)} = \frac{0.8226 \text{ lb } CH_4}{\text{lb mixture}} = 82.26 \text{ wt. \% } CH_4$$

To calculate emissions, the carbon content of the fuel composition provided in Table 8-7 is calculated. The first step is to calculate the carbon content of the individual components, using Equation 4-9. The carbon content calculation for an individual component is shown below for ethane (C_2H_6).

$$\text{Wt\% } C_{C_2H_6} = \frac{12.01 \text{ lb C}}{\text{lbmole C}} \times \frac{2 \text{ lbmoles C}}{\text{lbmole } C_2H_6} \times \frac{\text{lbmole } C_2H_6}{30.07 \text{ lb } C_2H_6} \times 100\% = 79.9\% \text{ C}$$

After the calculation has been performed for all constituents, the carbon content for the mixture is calculated using Equation 4-10, as shown below:

$$\text{Wt\% } C_{\text{Mixture}} = \frac{1}{100} \times \begin{bmatrix} (2.71 \times 27.3) + (3.77 \times 0) + (82.26 \times 74.9) + (6.78 \times 79.9) + (2.83 \times 81.7) + (0.46 \times 82.7) \\ + (0.52 \times 82.7) + (0.08 \times 83.2) + (0.08 \times 83.2) + (0 \times 83.6) + (0.10 \times 83.6) + (0.40 \times 83.9) \end{bmatrix}$$

$$= 71.43 \text{ Wt\% C} = 0.7143 \text{ lb C/lb fuel}$$

Completing the calculations for the fuel analysis results in the fuel mixture molecular weight and carbon content below:

Compound	Mole %	MW	Wt% (Calculated)	Uncertainty[a] (±%)	Compound Carbon Content (wt%C)	Mixture Carbon Content (wt%C)	Uncertainty[a] (±%)
CO_2	1.09	44.01	2.71	5.19	27.3	0.738	5.19
N_2	2.39	28.01	3.77	5.19	0	0	NA
CH_4	90.95	16.04	82.26	5.19	74.9	61.6	5.19
C_2H_6	4	30.07	6.78	5.19	79.9	5.42	5.19
C_3H_8	1.14	44.10	2.83	5.19	81.7	2.32	5.19
i-C_4H_{10}	0.14	58.12	0.46	5.19	82.7	0.379	5.19
n-C_4H_{10}	0.16	58.12	0.52	5.19	82.7	0.434	5.19
i-C_5H_{12}	0.02	72.15	0.08	5.19	83.2	0.0677	5.19
n-C_5H_{12}	0.02	72.15	0.08	5.19	83.2	0.0677	5.19
i-C_6H_{14}	0	86.18	0	NA	83.6	0	NA
Other C6	0.02	86.18	0.10	5.19	83.6	0.0813	5.19
C7+	0.07	100.20	0.40	5.19	83.9	0.332	5.19
Fuel Mixture	**100**	**17.74 ±3.31%[a]**	**100.0**			**71.43**	**4.50**

Footnote:

[a] Uncertainty is at a 95% confidence interval.

Carbon dioxide emissions can then be calculated using a mass balance approach. Emissions are calculated below, by equipment type.

Boilers and heaters:

$$E_{CO_2} = \frac{14.126\times10^6 \text{ scf fuel}}{\text{yr}} \times \frac{\text{lbmole}}{379.3 \text{ scf fuel}} \times \frac{17.74 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.7143 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}} \times \frac{\text{lbmole CO}_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 784 \text{ tonnes CO}_2 / \text{yr}}$$

Turbines:

$$E_{CO_2} = \frac{670\times10^6 \text{ scf fuel}}{\text{yr}} \times \frac{\text{lbmole}}{379.3 \text{ scf fuel}} \times \frac{17.74 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.7143 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}} \times \frac{\text{lbmole CO}_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 37{,}200 \text{ tonnes CO}_2 / \text{yr}}$$

Diesel Combustion

Carbon dioxide emissions from diesel combustion are calculated using the diesel emission factor provided in Table 4-3, assuming an uncertainty of ±10% based on engineering judgment. Because the emission factor is provided on a energy input basis, the volume of fuel consumed is converted to a energy input using the heating value of the fuel, provided in Table 3-8, or using the power output to energy input conversion factors, presented in Table 4-2. The uncertainty of the heating value of the fuel in Table 3-8 is assumed to be ±5% based on engineering judgment.

$$\begin{aligned}
V = &\left(\frac{160{,}000\text{ gal}}{\text{yr}}\times\frac{\text{bbl}}{42\text{ gal}}\times\frac{5.75\times10^{6}\text{ Btu}}{\text{bbl}}\right)\\
&+\left(1\text{ unit}\times\frac{210\text{ hp}}{\text{unit}}\times\frac{7{,}100\text{ Btu}}{\text{hp-hr}}\times\frac{2{,}920\text{ hr}}{\text{yr}}\times\frac{10^{6}\text{ Btu}}{1{,}000{,}000\text{ Btu}}\right)\\
&+\left(1\text{ unit}\times\frac{200\text{ hp}}{\text{unit}}\times\frac{7{,}100\text{ Btu}}{\text{hp-hr}}\times\frac{2{,}920\text{ hr}}{\text{yr}}\times\frac{10^{6}\text{ Btu}}{1{,}000{,}000\text{ Btu}}\right)\\
&+\left(1\text{ unit}\times\frac{280\text{ hp}}{\text{unit}}\times\frac{7{,}000\text{ Btu}}{\text{hp-hr}}\times\frac{200\text{ hr}}{\text{yr}}\times\frac{10^{6}\text{ Btu}}{1{,}000{,}000\text{ Btu}}\right)\\
&+\left(2\text{ units}\times\frac{1{,}000\text{ hp}}{\text{unit}}\times\frac{7{,}000\text{ Btu}}{\text{hp-hr}}\times\frac{200\text{ hr}}{\text{yr}}\times\frac{10^{6}\text{ Btu}}{1{,}000{,}000\text{ Btu}}\right)\\
&+\left(1\text{ unit}\times\frac{1{,}800\text{ hp}}{\text{unit}}\times\frac{7{,}000\text{ Btu}}{\text{hp-hr}}\times\frac{200\text{ hr}}{\text{yr}}\times\frac{10^{6}\text{ Btu}}{1{,}000{,}000\text{ Btu}}\right)\\
&+\left(1\text{ unit}\times\frac{2{,}400\text{ hp}}{\text{unit}}\times\frac{7{,}000\text{ Btu}}{\text{hp-hr}}\times\frac{1{,}100\text{ hr}}{\text{yr}}\times\frac{10^{6}\text{ Btu}}{1{,}000{,}000\text{ Btu}}\right)\\
&+\left(1\text{ unit}\times\frac{3{,}000\text{ hp}}{\text{unit}}\times\frac{7{,}000\text{ Btu}}{\text{hp-hr}}\times\frac{200\text{ hr}}{\text{yr}}\times\frac{10^{6}\text{ Btu}}{1{,}000{,}000\text{ Btu}}\right) = 58{,}797\times10^{6}\text{ Btu/yr}
\end{aligned}$$

$$E_{CO_2} = \frac{58{,}797\times10^{6}\text{ Btu}}{\text{yr}}\times\frac{0.0732\text{ tonne CO}_2}{10^{6}\text{ Btu}}$$

$$\underline{E_{CO_2} = 4{,}300\text{ tonnes CO}_2/\text{yr}}$$

Stationary Combustion Devices – CH_4, N_2O, and CO_2e Emissions

Natural Gas Combustion

Combustion emission factors for natural gas-fired equipment are provided in Table 4-7 for controlled boilers and heaters, and Table 4-9 for uncontrolled turbines. Emission factors for electricity generating natural gas-fired turbines are provided in Table 7-1. For the electricity generating natural gas-fired turbines, a power output to fuel input factor of 10,833 Btu/kW-hr is taken from Table 4-2 assuming a "Conventional Combustion Turbine." An uncertainty of 30% is assumed for this conversion power, based on engineering judgment. The uncertainties are assumed to be ±25% for all CH_4 emission factors and ±150% for all N_2O emission factors, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Because natural gas turbine CO_2 emissions are calculated together (not calculated separately as electricity generation turbine and compression turbine CO_2 emissions), natural gas turbine CO_2e emissions are also calculated together.

Boilers and Heaters:

$$E_{CH_4} = \frac{14.126\times10^6\ \text{scf}}{\text{yr}} \times \frac{2.3\ \text{lb CH}_4}{10^6\ \text{scf}} \times \frac{1\ \text{tonne}}{2{,}204.62\ \text{lb}}$$

$$\underline{E_{CH_4} = 0.0147\ \text{tonnes CH}_4\text{/yr}}$$

$$E_{N_2O} = \frac{14.126\times10^6\ \text{scf}}{\text{yr}} \times \frac{0.64\ \text{lb N}_2\text{O}}{10^6\ \text{scf}} \times \frac{1\ \text{tonne}}{2{,}204.62\ \text{lb}}$$

$$\underline{E_{N_2O} = 0.00410\ \text{tonnes N}_2\text{O/yr}}$$

$$E_{CO_2e} = \frac{784\ \text{tonne CO}_2}{\text{yr}} + \left(\frac{0.0147\ \text{tonne CH}_4}{\text{yr}} \times \frac{21\ \text{tonne CO}_2\text{e}}{\text{tonne CH}_4}\right) + \left(\frac{0.00410\ \text{tonne N}_2\text{O}}{\text{yr}} \times \frac{310\ \text{tonne CO}_2\text{e}}{\text{tonne N}_2\text{O}}\right)$$

$$\underline{E_{CO_2e} = 786\ \text{tonne CO}_2\text{e/yr}}$$

Turbines – Electricity Generation:

$$E_{CH_4} = \frac{470\times10^6\ \text{scf}}{\text{yr}} \times \frac{1033\ \text{Btu}}{\text{scf}} \times \frac{\text{kW}-\text{hr}}{10{,}833\ \text{Btu}} \times \frac{1\ \text{MW-hr}}{1{,}000\ \text{kW-hr}} \times \frac{7.26\times10^{-5}\ \text{tonnes CH}_4}{\text{MW-hr}}$$

$$\underline{E_{CH_4} = 3.25\ \text{tonnes CH}_4\text{/yr}}$$

$$E_{N_2O} = \frac{470\times10^6\ \text{scf}}{\text{yr}} \times \frac{1033\ \text{Btu}}{\text{scf}} \times \frac{\text{kW}-\text{hr}}{10{,}833\ \text{Btu}} \times \frac{1\ \text{MW-hr}}{1{,}000\ \text{kW-hr}} \times \frac{1.09\times10^{-4}\ \text{tonnes N}_2\text{O}}{\text{MW-hr}}$$

$$\underline{E_{N_2O} = 4.89\ \text{tonnes N}_2\text{O/yr}}$$

Turbines – Compression:

$$E_{CH_4} = \frac{200\times10^6 \text{ scf}}{\text{yr}} \times \frac{1033 \text{ Btu}}{\text{scf}} \times \frac{0.0086 \text{ lb CH}_4}{10^6 \text{ Btu}} \times \frac{1 \text{ tonne}}{2{,}204.62 \text{ lb}}$$

$$\underline{E_{CH_4} = 0.806 \text{ tonnes CH}_4\text{/yr}}$$

$$E_{N_2O} = \frac{200\times10^6 \text{ scf}}{\text{yr}} \times \frac{1033 \text{ Btu}}{\text{scf}} \times \frac{0.003 \text{ lb N}_2\text{O}}{10^6 \text{ Btu}} \times \frac{1 \text{ tonne}}{2{,}204.62 \text{ lb}}$$

$$\underline{E_{N_2O} = 0.281 \text{ tonnes N}_2\text{O/yr}}$$

Turbines – CO_2e:

$$E_{CO_2e} = \frac{37{,}200 \text{ tonne CO}_2}{\text{yr}} + \left(\frac{0.806 \text{ tonne CH}_4}{\text{yr}} \times \frac{21 \text{ tonne CO}_2\text{e}}{\text{tonne CH}_4}\right) + \left(\frac{3.25 \text{ tonne CH}_4}{\text{yr}} \times \frac{21 \text{ tonne CO}_2\text{e}}{\text{tonne CH}_4}\right)$$
$$+ \left(\frac{0.281 \text{ tonne N}_2\text{O}}{\text{yr}} \times \frac{310 \text{ tonne CO}_2\text{e}}{\text{tonne N}_2\text{O}}\right) + \left(\frac{4.89 \text{ tonne N}_2\text{O}}{\text{yr}} \times \frac{310 \text{ tonne CO}_2\text{e}}{\text{tonne N}_2\text{O}}\right)$$

$$\underline{E_{CO_2e} = 38{,}900 \text{ tonne CO}_2\text{e/yr}}$$

Diesel Combustion Emissions

The first step in calculating diesel combustion CH_4 and N_2O emissions is to sum the firing rates for two groups of equipment: equipment <600 hp per unit and equipment >600 hp per unit. The firing rates are then multiplied by the appropriate CH_4 and N_2O emission factors, presented in Table 4-9. Because the emission factor is provided on a energy input basis, the volume of fuel consumed is converted to a energy input using the heating value of the fuel, provided in Table 3-8, assuming an uncertainty of ±5%, based on engineering judgment. Table 4-9 provides emission factors for IC engines burning diesel, which are used to estimate emissions from diesel-fired equipment rated less than 600 hp per unit (crane engines and fire water pump). The emissions from diesel-fired equipment rated greater than 600 hp per unit (emergency generators, forklifts, and Whittaker escape capsules) are estimated using the "Large Bore Engine – Diesel" emission factors (for engines rated greater than 600 hp) from Table 4-9. Table 4-9 also provides an assumed CH_4

content of 9 wt% to convert from TOC emissions if the exhaust CH_4 composition is unknown. The uncertainties are assumed to be ±25% for all CH_4 and TOC emission factors and ±150% for all N_2O emission factors, based on engineering judgment. An uncertainty of ±100% is assumed for the TOC to CH_4 conversion, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Because diesel CO_2 emissions are calculated by fuel type, diesel CO_2e emissions are also calculated by fuel type. Emissions are calculated below, by equipment type. Emissions from the boat and helicopter are described under "Combustion Sources – Mobile Sources."

Diesel engines <600 hp:

$$\text{V} = \left(\frac{160{,}000\text{ gal}}{\text{yr}} \times \frac{\text{bbl}}{42\text{ gal}} \times \frac{5.75 \times 10^6\text{ Btu}}{\text{bbl}}\right) = 21{,}905 \times 10^6\text{ Btu/yr}$$

$$\begin{aligned}\text{Diesel firing rate } &= 21{,}905 \times 10^6\text{ Btu/yr} + \left(210\text{ hp} \times \frac{7{,}100\text{ Btu}}{\text{hp-hr}} \times \frac{2920\text{ hr}}{\text{yr}} \times \frac{10^6\text{ Btu}}{1{,}000{,}000\text{ Btu}}\right) \\ &+ \left(200\text{ hp} \times \frac{7{,}100\text{ Btu}}{\text{hp-hr}} \times \frac{2920\text{ hr}}{\text{yr}} \times \frac{10^6\text{ Btu}}{1{,}000{,}000\text{ Btu}}\right) \\ &+ \left(280\text{ hp} \times \frac{7{,}000\text{ Btu}}{\text{hp-hr}} \times \frac{200\text{ hr}}{\text{yr}} \times \frac{10^6\text{ Btu}}{1{,}000{,}000\text{ Btu}}\right) = 30{,}800 \times 10^6\text{ Btu/yr}\end{aligned}$$

$$E_{CH_4} = \frac{30{,}800 \times 10^6\text{ Btu}}{\text{yr}} \times \frac{0.00016\text{ tonne TOC}}{10^6\text{Btu}} \times \frac{0.09\text{ tonne CH}_4}{\text{tonne TOC}}$$

$$\underline{E_{CH_4} = 0.443\text{ tonnes CH}_4\text{/yr}}$$

$$E_{N_2O} = \frac{30{,}800 \times 10^6\text{ Btu}}{\text{yr}} \times \frac{6.01 \times 10^{-7}\text{ tonne N}_2\text{O}}{10^6\text{ Btu}}$$

$$\underline{E_{N_2O} = 0.0185\text{ tonnes N}_2\text{O/yr}}$$

Diesel engines >600 hp:

$$\text{Diesel firing rate } = \left(2 \text{ units} \times \frac{1{,}000 \text{ hp}}{\text{Unit}} \times \frac{7{,}000 \text{ Btu}}{\text{hp-hr}} \times \frac{200 \text{ hr}}{\text{yr}}\right) + \left(1{,}800 \text{ hp} \times \frac{7{,}000 \text{ Btu}}{\text{hp-hr}} \times \frac{200 \text{ hr}}{\text{yr}}\right)$$

$$+ \left(2{,}400 \text{ hp} \times \frac{7{,}000 \text{ Btu}}{\text{hp-hr}} \times \frac{1{,}100 \text{ hr}}{\text{yr}}\right) + \left(3{,}000 \text{ hp} \times \frac{7{,}000 \text{ Btu}}{\text{hp-hr}} \times \frac{200 \text{ hr}}{\text{yr}}\right) = 28{,}000 \times 10^6 \text{ Btu/yr}$$

$$E_{CH_4} = \frac{28{,}000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{3.7 \times 10^{-6} \text{ tonne } CH_4}{10^6 \text{ Btu}}$$

$$\underline{E_{CH_4} = 0.103 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{28{,}000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{6.01 \times 10^{-7} \text{ tonne } N_2O}{10^6 \text{ Btu}}$$

$$\underline{E_{N_2O} = 0.0168 \text{ tonnes } N_2O/\text{yr}}$$

Diesel Combustion CO_2e Emissions:

$$E_{CO_2e} = \frac{4{,}300 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{0.443 \text{ tonne } CH_4}{\text{yr}} + \frac{0.103 \text{ tonne } CH_4}{\text{yr}}\right) \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}$$

$$+ \left(\frac{0.0185 \text{ tonne } N_2O}{\text{yr}} + \frac{0.0168 \text{ tonne } N_2O}{\text{yr}}\right) \times \frac{310 \text{ tonne } CO_2e}{\text{tonne } N_2O}$$

$$\underline{E_{CO_2e} = 4{,}300 \text{ tonne } CO_2e/\text{yr}}$$

Combustion Sources – Mobile Sources

The diesel-fired supply boat and aviation gas-fired helicopter engine CO_2 emissions are estimated using the fuel basis "gas/diesel oil" and "aviation gas" emission factors, respectively, given in Table 4-3, assuming an uncertainty of ±10% for all CO_2 emission factors, based on engineering judgment. Methane and N_2O emission factors are obtained from Table 4-17, assuming an uncertainty of ±25% for CH_4 emission factors and ±150% for N_2O emission factors. 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 3-8, assuming an uncertainty of ±5%, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Emission calculations are shown below, by equipment type.

Boats:

$$\text{Diesel firing rate } = \left(5{,}000\text{ hp} \times \frac{7{,}500\text{ Btu}}{\text{hp-hr}} \times \frac{1{,}100\text{ hr}}{\text{yr}}\right) + \left(5{,}000\text{ hp} \times \frac{7{,}500\text{ Btu}}{\text{hp-hr}} \times \frac{110\text{ hr}}{\text{yr}}\right) = 45{,}400 \times 10^6\text{ Btu/yr}$$

$$E_{CO_2} = \frac{45{,}400\ \times 10^6\text{ Btu}}{\text{yr}} \times \frac{0.0732\text{ tonne }CO_2}{10^6\text{ Btu}}$$

$$\underline{E_{CO_2} = 3{,}320\text{ tonnes }CO_2/\text{yr}}$$

$$E_{CH_4} = \frac{45{,}400 \times 10^6\text{ Btu}}{\text{yr}} \times \frac{\text{bbl}}{5.75 \times 10^6\text{ Btu}} \times \frac{42\text{ gal}}{\text{bbl}} \times \frac{5.7 \times 10^{-4}\text{ tonne }CH_4}{1000\text{ gal}}$$

$$\underline{E_{CH_4} = 0.189\text{ tonnes }CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{45{,}400\ \times 10^6\text{ Btu}}{\text{yr}} \times \frac{\text{bbl}}{5.83 \times 10^6\text{ Btu}} \times \frac{42\text{ gal}}{\text{bbl}} \times \frac{4.2 \times 10^{-3}\text{ tonne }N_2O}{1000\text{ gal}}$$

$$\underline{E_{N_2O} = 1.37\text{ tonnes }N_2O/\text{yr}}$$

$$E_{CO_2e} = \frac{3{,}320\text{ tonne }CO_2}{\text{yr}} + \left(\frac{0.189\text{ tonne }CH_4}{\text{yr}} \times \frac{21\text{ tonne }CO_2e}{\text{tonne }CH_4}\right) + \left(\frac{1.37\text{ tonne }N_2O}{\text{yr}} \times \frac{310\text{ tonne }CO_2e}{\text{tonne }N_2O}\right)$$

$$\underline{E_{CO_2e} = 3{,}750\text{ tonne }CO_2e/\text{yr}}$$

Helicopters:

$$\text{Firing rate} = 1095\ \text{Trips} \times \frac{50\ \text{min}}{\text{Trip}} \times \frac{\text{hr}}{60\ \text{min}} \times \frac{650\ \text{lb fuel}}{\text{hr}} \times \frac{\text{gal}}{5.89\ \text{lb fuel}} \times \frac{0.0037854\ \text{m}^3}{\text{gal}}$$

$$\times \frac{\text{bbl}}{0.15898\ \text{m}^3} \times \frac{5.05 \times 10^6\ \text{Btu}}{\text{bbl}} = 12{,}108 \times 10^6\ \text{Btu/yr}$$

$$E_{CO_2} = \frac{12{,}108 \times 10^6\ \text{Btu}}{\text{yr}} \times \frac{0.0692\ \text{tonne CO}_2}{10^6\ \text{Btu}}$$

$$\underline{E_{CO_2} = 838\ \text{tonnes CO}_2/\text{yr}}$$

$$E_{CH_4} = \frac{12{,}108 \times 10^6\ \text{Btu}}{\text{yr}} \times \frac{\text{bbl}}{5.05 \times 10^6\ \text{Btu}} \times \frac{42\ \text{gal}}{\text{bbl}} \times \frac{8.3 \times 10^{-3}\ \text{tonne CH}_4}{1000\ \text{gal}}$$

$$\underline{E_{CH_4} = 0.836\ \text{tonnes CH}_4/\text{yr}}$$

$$E_{N_2O} = \frac{12{,}108 \times 10^6\ \text{Btu}}{\text{yr}} \times \frac{\text{bbl}}{5.05 \times 10^6\ \text{Btu}} \times \frac{42\ \text{gal}}{\text{bbl}} \times \frac{8.7 \times 10^{-4}\ \text{tonne N}_2\text{O}}{1000\ \text{gal}}$$

$$\underline{E_{N_2O} = 0.0876\ \text{tonnes N}_2\text{O/yr}}$$

$$E_{CO_2e} = \frac{838\ \text{tonne CO}_2}{\text{yr}} + \left(\frac{0.836\ \text{tonne CH}_4}{\text{yr}} \times \frac{21\ \text{tonne CO}_2\text{e}}{\text{tonne CH}_4}\right)$$

$$+ \left(\frac{0.0876\ \text{tonne N}_2\text{O}}{\text{yr}} \times \frac{310\ \text{tonne CO}_2\text{e}}{\text{tonne N}_2\text{O}}\right)$$

$$\underline{E_{CO_2e} = 883\ \text{tonne CO}_2\text{e/yr}}$$

Combustion Sources – Flares

Based on the guidance given in Section 4.6, CO_2 emissions are calculated using a 98% combustion efficiency and CH_4 emissions from flares are calculated assuming that 2% of the CH_4 remains uncombusted. An uncertainty of ±20% is assumed for both the CO_2 combustion efficiency and uncombusted percent CH_4, based on engineering judgment. Carbon dioxide emissions are estimated as the sum of the CO_2 already present in the gas and the CO_2 that results from the product of flared gas carbon combustion. Nitrous oxide emissions are estimated using emission factors from Table 4-11, assuming an uncertainty of ±150%, based on engineering judgment. Note that the N_2O emissions factor is based on gas produced, not gas flared. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs.

$$\text{Natural gas firing rate } = (0.395+1.7+3.1+20)\times 10^6 \text{ scf/yr} = 25.195 \times 10^6 \text{ scf/yr}$$

Carbon dioxide emissions:

$$\begin{aligned}
E_{CO_2} = {} & \frac{25.195\times 10^6 \text{ scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{44.01 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}} \\
& \times \left[\begin{aligned}
& \left(\begin{aligned}
& \frac{0.9095 \text{ lbmole } CH_4}{\text{lbmole gas}} \times \frac{1 \text{ lbmole C}}{\text{lbmole } CH_4} + \frac{0.04 \text{ lbmole } C_2H_6}{\text{lbmole gas}} \times \frac{2 \text{ lbmole C}}{\text{lbmole } C_2H_6} \\
& + \frac{0.0114 \text{ lbmole } C_3H_8}{\text{lbmole gas}} \times \frac{3 \text{ lbmole C}}{\text{lbmole } C_3H_8} + \frac{0.0014 \text{ lbmole } C_4H_{10}}{\text{lbmole gas}} \times \frac{4 \text{ lbmole C}}{\text{lbmole } C_4H_{10}} \\
& + \frac{0.0002 \text{ lbmole } C_5H_{12}}{\text{lbmole gas}} \times \frac{5 \text{ lbmole C}}{\text{lbmole } C_5H_{12}} + \frac{0 \text{ lbmole } C_6H_{14}}{\text{lbmole gas}} \times \frac{6 \text{ lbmole C}}{\text{lbmole } C_6H_{14}} \\
& + \frac{0.0002 \text{ lbmole Other } C_6}{\text{lbmole gas}} \times \frac{6 \text{ lbmole C}}{\text{lbmole Other } C_6} + \frac{0.0007 \text{ lbmole C7+}}{\text{lbmole gas}} \times \frac{7 \text{ lbmole C}}{\text{lbmole C7+}}
\end{aligned} \right) \\
& \frac{0.98 \text{ lbmole } CO_2}{\text{lbmole C combusted}} + \frac{0.0102 \text{ lbmole } CO_2}{\text{lbmole gas}}
\end{aligned} \right]
\end{aligned}$$

$$\underline{E_{CO_2} = 1{,}370 \text{ tonnes } CO_2/\text{yr}}$$

Methane, N_2O and CO_2e emissions:

$$\begin{aligned}
E_{CH_4} = {} & \frac{25.195\times 10^6 \text{ scf gas}}{\text{yr}} \times \frac{\text{lbmol gas}}{379.3 \text{ scf gas}} \times \frac{0.9095 \text{ lbmole } CH_4}{\text{lbmole gas}} \times \frac{0.02 \text{ uncombusted lbmole } CH_4}{\text{lbmole total } CH_4} \\
& \times \frac{16.04 \text{ lb } CH_4}{\text{lbmole } CH_4} \times \frac{\text{tonne}}{2204.62 \text{ lb}}
\end{aligned}$$

$$\underline{E_{CH_4} = 8.79 \text{ tonnes } CH_4}$$

$$E_{N_2O} = \frac{16\times10^{6}\text{ scf gas produced}}{\text{day}} \times \frac{365\text{ days}}{\text{yr}} \times \frac{5.90\times10^{-7}\text{ tonnes }N_2O}{10^{6}\text{ scf gas produced}}$$

$$\underline{E_{N_2O} = 0.00345\text{ tonnes }N_2O/\text{yr}}$$

$$E_{CO_2e} = \frac{1{,}370\text{ tonne }CO_2}{\text{yr}} + \left(\frac{8.79\text{ tonne }CH_4}{\text{yr}} \times \frac{21\text{ tonne }CO_2e}{\text{tonne }CH_4}\right) + \left(\frac{0.000345\text{ tonne }N_2O}{\text{yr}} \times \frac{310\text{ tonne }CO_2e}{\text{tonne }N_2O}\right)$$

$$\underline{E_{CO_2e} = 1{,}560\text{ tonne }CO_2e/\text{yr}}$$

Vented Sources – Storage Tank Flashing

Methane emissions from flashing losses are estimated using the simple emission factor provided in Table 5-8, assuming an uncertainty of ±200%, based on engineering judgment. Methane emissions are adjusted based on the facility CH_4 content. The default CH_4 content and associated uncertainty are provided in Table E-4. Carbon dioxide emissions are calculated by using a ratio of the facility CH_4 and CO_2 contents. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Emissions are calculated below.

$$E_{CH_4} = \frac{1{,}500\text{ bbl}}{\text{day}} \times \frac{365\text{ day}}{\text{yr}} \times \frac{8.86\times10^{-4}\text{tonne }CH_4}{\text{bbl}} \times \frac{0.9095\text{ tonne mole }CH_4\ (\text{facility})}{0.788\text{ tonne mole }CH_4\ (\text{default})}$$

$$\underline{E_{CH_4} = 560\text{ tonnes }CH_4/\text{yr}}$$

$$E_{CO_2} = \frac{1{,}500\text{ bbl}}{\text{day}} \times \frac{365\text{ day}}{\text{yr}} \times \frac{8.86\times10^{-4}\text{tonne }CH_4}{\text{bbl}} \times \frac{\text{tonne mole }CH_4}{16.04\text{ tonne }CH_4} \times \frac{0.9095\text{ tonne mole }CH_4\,(\text{facility})}{0.788\text{ tonne mole }CH_4\,(\text{default})}$$
$$\times \frac{\text{tonne mole gas}}{0.9095\text{ tonne mole }CH_4} \times \frac{0.0109\text{ tonne mole }CO_2}{\text{tonne mole gas}} \times \frac{44.01\text{ tonne }CO_2}{\text{tonne mole }CO_2}$$

$$\underline{E_{CO_2} = 18.4\text{ tonnes }CO_2/\text{yr}}$$

$$E_{CO_2e} = 18.4 \text{ tonne } CO_2/\text{yr} + \left(\frac{560 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4} \right)$$

$$\underline{E_{CO_2e} = 11{,}800 \text{ tonne } CO_2e/\text{yr}}$$

Vented Sources – Other Storage Tank Emissions

Because “weathered” crude contains no CH_4 or CO_2, there are no CH_4 or CO_2 emissions from the tank battery standing and working losses.

Vented Sources - Gas Dehydration

Methane emissions from the gas dehydrator vents are estimated using the production segment emission factor and uncertainty given in Table 5-2. The Kimray pump emissions are estimated using the production segment emission factor and uncertainty in Table 5-4. For both of these sources, emissions are based on the annual quantity of gas processed. Methane emissions are adjusted based on the facility CH_4 content. The default CH_4 content and associated uncertainty are provided in Table E-4. Carbon dioxide emissions are calculated by using a ratio of the facility CH_4 and CO_2 contents. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Emissions are calculated below.

$$EF_{CH_4} = \left(EF_{\text{Dehydrator vents}}\right) + \left(EF_{\text{Kimray pumps}}\right)$$

$$EF_{CH_4} = \left(\frac{0.0052859 \text{ tonne } CH_4}{10^6 \text{ scf}} \right) + \left(\frac{0.01903 \text{ tonne } CH_4}{10^6 \text{ scf}} \right) = 0.024326 \text{ tonne } CH_4 / 10^6 \text{ scf}$$

$$E_{CH_4} = \frac{16 \times 10^6 \text{ scf}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{0.9095 \text{ tonne mole } CH_4 \text{ (facility)}}{0.788 \text{ tonne mole } CH_4 \text{ (default)}} \times \frac{0.024326 \text{ tonne } CH_4}{10^6 \text{ scf}}$$

$$\underline{E_{CH_4} = 164 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = \frac{16\times10^6\ \text{scf}}{\text{day}} \times \frac{365\ \text{day}}{\text{yr}} \times \frac{0.024326\ \text{tonne CH}_4}{10^6\ \text{scf}} \times \frac{\text{tonne mole CH}_4}{16.04\ \text{tonne CH}_4} \times \frac{0.9095\ \text{tonne mole CH}_4\ (\text{facility})}{0.788\ \text{tonne mole CH}_4\ (\text{default})}$$
$$\times \frac{\text{tonne mole gas}}{0.9095\ \text{tonne mole CH}_4} \times \frac{0.0109\ \text{tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01\ \text{tonne CO}_2}{\text{tonne mole CO}_2}$$

$\underline{E_{CO_2} = 5.39\ \text{tonnes CO}_2/\text{yr}}$

$$E_{CO_2e} = \frac{5.39\ \text{tonne CO}_2}{\text{yr}} + \left(\frac{164\ \text{tonne CH}_4}{\text{yr}} \times \frac{21\ \text{tonne CO}_2\text{e}}{\text{tonne CH}_4}\right)$$

$\underline{E_{CO_2e} = 3,450\ \text{tonne CO}_2\text{e/yr}}$

Vented Sources – Pneumatics and CIPs

The pneumatic devices and CIPs at the facility are actuated by natural gas. Methane emissions from pneumatic device and CIP vents are estimated using CH_4 emission factors and uncertainties presented in Tables 5-15 and 5-16, respectively. The type of pneumatic devices and CIPs are not specified, so the "Production Average" device and the "Average Pump" emission factor are used. Methane emissions are adjusted based on the facility CH_4 content. The default CH_4 content and associated uncertainty are provided in Table E-4. Carbon dioxide emissions are calculated by using a ratio of the facility CH_4 and CO_2 contents. Emissions are calculated below, by equipment type.

Pneumatic Devices:

$$E_{CH_4} = (7\ \text{pneumatic devices}) \times \frac{2.415\ \text{tonne CH}_4}{\text{device - yr}} \times \frac{0.9095\ \text{tonne mole CH}_4\ (\text{facility})}{0.788\ \text{tonne mole CH}_4\ (\text{default})}$$

$\underline{E_{CH_4} = 19.5\ \text{tonnes CH}_4/\text{yr}}$

$$E_{CO_2} = (7\ \text{pneumatic devices}) \times \frac{2.415\ \text{tonne CH}_4}{\text{device - yr}} \times \frac{\text{tonne mole CH}_4}{16.04\ \text{tonne CH}_4} \times \frac{0.9095\ \text{tonne mole CH}_4\ (\text{facility})}{0.788\ \text{tonne mole CH}_4\ (\text{default})}$$
$$\times \frac{\text{tonne mole gas}}{0.9095\ \text{tonne mole CH}_4} \times \frac{0.0109\ \text{tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01\ \text{tonne CO}_2}{\text{tonne mole CO}_2}$$

$\underline{E_{CO_2} = 0.642\ \text{tonnes CO}_2/\text{yr}}$

$$E_{CO_2e} = 0.642 \text{ tonnes } CO_2/\text{yr} + \left(\frac{19.5 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4} \right)$$

$$\underline{E_{CO_2e} = 410 \text{ tonne } CO_2e/\text{yr}}$$

CIPs:

$$E_{CH_4} = (2 \text{ CIPs}) \times \frac{1.736 \text{ tonne } CH_4}{\text{CIP - yr}} \times \frac{0.9095 \text{ tonne mole } CH_4 \left(\text{facility}\right)}{0.788 \text{ tonne mole } CH_4 \left(\text{default}\right)}$$

$$\underline{E_{CH_4} = 4.01 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = (2 \text{ CIPs}) \times \frac{1.736 \text{ tonne } CH_4}{\text{CIP - yr}} \times \frac{\text{tonne mole } CH_4}{16.04 \text{ tonne } CH_4} \times \frac{0.9095 \text{ tonne mole } CH_4 \left(\text{facility}\right)}{0.788 \text{ tonne mole } CH_4 \left(\text{default}\right)}$$
$$\times \frac{\text{tonne mole gas}}{0.9095 \text{ tonne mole } CH_4} \times \frac{0.0109 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2} = 0.132 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CO_2e} = 0.132 \text{ tonnes } CO_2/\text{yr} + \left(\frac{4.01 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4} \right)$$

$$\underline{E_{CO_2e} = 84.3 \text{ tonne } CO_2e/\text{yr}}$$

Vented Sources – Maintenance/Turnaround Emissions

Methane emissions from vessel blowdowns, compressor starts, and compressor blowdowns are estimated using the emission factors and uncertainties presented in Table 5-23. Note that the factors are provided on an equipment count basis, not a per-event basis. Methane emissions are adjusted based on the facility CH_4 content. The default CH_4 content and associated uncertainty are provided in Table E-4. Carbon dioxide emissions are calculated by using a ratio of the facility CH_4 and CO_2 contents. Emissions are calculated as follows, by activity type.

Vessel blowdowns:

$$E_{CH_4} = (9 \text{ vessels}) \times \frac{0.0015 \text{ tonne } CH_4}{\text{vessel-yr}} \times \frac{0.9095 \text{ tonne mole } CH_4 \left(\text{facility}\right)}{0.788 \text{ tonne mole } CH_4 \left(\text{default}\right)}$$

$$\underline{E_{CH_4} = 0.0156 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = (9 \text{ vessels}) \times \frac{0.0015 \text{ tonne } CH_4}{\text{vessel-yr}} \times \frac{\text{tonne mole } CH_4}{16.04 \text{ tonne } CH_4} \times \frac{0.9095 \text{ tonne mole } CH_4 \left(\text{facility}\right)}{0.788 \text{ tonne mole } CH_4 \left(\text{default}\right)} \times \frac{\text{tonne mole gas}}{0.9095 \text{ tonne mole } CH_4} \times \frac{0.0109 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2} = 0.000512 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CO_2e} = 0.000512 \text{ tonnes } CO_2/\text{yr} + \left(\frac{0.0156 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right)$$

$$\underline{E_{CO_2e} = 0.328 \text{ tonne } CO_2e/\text{yr}}$$

Compressor starts:

$$E_{CH_4} = (6 \text{ compressors}) \times \frac{0.1620 \text{ tonne } CH_4}{\text{compressor - yr}} \times \frac{0.9095 \text{ tonne mole } CH_4 \left(\text{facility}\right)}{0.788 \text{ tonne mole } CH_4 \left(\text{default}\right)}$$

$$\underline{E_{CH_4} = 1.12 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = (6 \text{ compressors}) \times \frac{0.1620 \text{ tonne } CH_4}{\text{compressor - yr}} \times \frac{\text{tonne mole } CH_4}{16.04 \text{ tonne } CH_4} \times \frac{0.9095 \text{ tonne mole } CH_4 \left(\text{facility}\right)}{0.788 \text{ tonne mole } CH_4 \left(\text{default}\right)} \times \frac{\text{tonne mole gas}}{0.9095 \text{ tonne mole } CH_4} \times \frac{0.0109 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2} = 0.0369 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CO_2e} = 0.0369 \text{ tonnes } CO_2/\text{yr} + \left(\frac{1.12 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right)$$

$$\underline{E_{CO_2e} = 23.6 \text{ tonne } CO_2e/\text{yr}}$$

Compressor blowdowns:

$$E_{CH_4} = (6 \text{ compressors}) \times \frac{0.07239 \text{ tonne } CH_4}{\text{compressor - yr}} \times \frac{0.9095 \text{ tonne mole } CH_4 (\text{facility})}{0.788 \text{ tonne mole } CH_4 (\text{default})}$$

$$\underline{E_{CH_4} = 0.501 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = (6 \text{ compressors}) \times \frac{0.07239 \text{ tonne } CH_4}{\text{compressor - yr}} \times \frac{\text{tonne mole } CH_4}{16.04 \text{ tonne } CH_4} \times \frac{0.9095 \text{ tonne mole } CH_4 (\text{facility})}{0.788 \text{ tonne mole } CH_4 (\text{default})} \times \frac{\text{tonne mole gas}}{0.9095 \text{ tonne mole } CH_4} \times \frac{0.0109 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2} = 0.0165 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CO_2e} = 0.0165 \text{ tonnes } CO_2/\text{yr} + \left(\frac{0.501 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4} \right)$$

$$\underline{E_{CO_2e} = 10.5 \text{ tonne } CO_2e/\text{yr}}$$

Vented Sources – Offshore ESD Systems and PRVs

Methane emissions from ESDs and PRVs are estimated using emission factors and uncertainties from Table 5-24. Methane emissions are adjusted based on the facility CH_4 content. The default CH_4 content and associated uncertainty are provided in Table E-4. Carbon dioxide emissions are calculated by using a ratio of the facility CH_4 and CO_2 contents. Emissions are calculated below, by activity.

ESD System:

$$E_{CH_4} = (1 \text{ platform}) \times \frac{4.9276 \text{ tonne } CH_4}{\text{platform - yr}} \times \frac{0.9095 \text{ tonne mole } CH_4 (\text{facility})}{0.788 \text{ tonne mole } CH_4 (\text{default})}$$

$$\underline{E_{CH_4} = 5.69 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = (1\ \text{platform}) \times \frac{4.9276\ \text{tonne CH}_4}{\text{platform-yr}} \times \frac{\text{tonne mole CH}_4}{16.04\ \text{tonne CH}_4} \times \frac{0.9095\ \text{tonne mole CH}_4\left(\text{facility}\right)}{0.788\ \text{tonne mole CH}_4\left(\text{default}\right)}$$
$$\times \frac{\text{tonne mole gas}}{0.9095\ \text{tonne mole CH}_4} \times \frac{0.0109\ \text{tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01\ \text{tonne CO}_2}{\text{tonne mole CO}_2}$$

$$\underline{E_{CO_2} = 0.187\ \text{tonnes CO}_2/\text{yr}}$$

$$E_{CO_2e} = 0.187\ \text{tonnes CO}_2/\text{yr} + \left(\frac{5.69\ \text{tonne CH}_4}{\text{yr}} \times \frac{21\ \text{tonne CO}_2\text{e}}{\text{tonne CH}_4}\right)$$

$$\underline{E_{CO_2e} = 120\ \text{tonne CO}_2\text{e/yr}}$$

PRV Releases:

$$E_{CH_4} = (175\ \text{PRVs}) \times \frac{0.00065\ \text{tonne CH}_4}{\text{PRV-yr}} \times \frac{0.9095\ \text{tonne mole CH}_4\left(\text{facility}\right)}{0.788\ \text{tonne mole CH}_4\left(\text{default}\right)}$$

$$\underline{E_{CH_4} = 0.131\ \text{tonnes CH}_4/\text{yr}}$$

$$E_{CO_2} = (175\ \text{PRVs}) \times \frac{0.00065\ \text{tonne CH}_4}{\text{PRV-yr}} \times \frac{\text{tonne mole CH}_4}{16.04\ \text{tonne CH}_4} \times \frac{0.9095\ \text{tonne mole CH}_4\left(\text{facility}\right)}{0.788\ \text{tonne mole CH}_4\left(\text{default}\right)}$$
$$\times \frac{\text{tonne mole gas}}{0.9095\ \text{tonne mole CH}_4} \times \frac{0.0109\ \text{tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01\ \text{tonne CO}_2}{\text{tonne mole CO}_2}$$

$$\underline{E_{CO_2} = 0.00432\ \text{tonnes CO}_2/\text{yr}}$$

$$E_{CO_2e} = 0.00432\ \text{tonnes CO}_2/\text{yr} + \left(\frac{0.131\ \text{tonne CH}_4}{\text{yr}} \times \frac{21\ \text{tonne CO}_2\text{e}}{\text{tonne CH}_4}\right)$$

$$\underline{E_{CO_2e} = 2.76\ \text{tonne CO}_2\text{e/yr}}$$

Fugitive Sources: Equipment Leaks

Table 8-11 provides fugitive component emission factors associated with this offshore production facility, taken from the corresponding EPA average component emission factors given in Table 6-12.

Table 8-11. Offshore Oil and Natural Gas Production Platform Fugitive Emission Factors

Component	Service	Component EF (tonnes TOC/comp./hr)	Uncertainty (±%)[a]
Valves	Light oil	2.5E-06	100
	Gas	4.5E-06	100
Connectors	Light oil	2.1E-07	100
	Gas	2.0E-07	100
OELs	Light oil	1.4E-06	100
	Gas	2.0E-06	100
Others	Light oil	7.5E-06	100
	Gas	8.8E-06	100

Footnote:

[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

Using Equation 6-9, CH_4 and CO_2 emissions are calculated for each component by multiplying the component emission factor by the component count, the annual hours of operation (8,760 hours/year, assuming the equipment remains pressurized year round), and the liquid weight fraction of either CH_4 or CO_2 presented in Table 8-10. The total fugitive emissions are the sum of each of the component emissions. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs.

An example calculation for oil valves is shown below.

$$E_{CH_4} = (1870 \text{ valves}) \times \frac{2.50\times10^{-6} \text{ tonne gas}}{\text{valve-hr}} \times \frac{8{,}760 \text{ hr}}{\text{yr}} \times \frac{0.0119 \text{ tonne CH}_4}{\text{tonne gas}}$$

$$\underline{E_{CH_4} = 0.487 \text{ tonnes CH}_4\text{/yr}}$$

$$E_{CO_2} = (1870 \text{ valves}) \times \frac{2.50\times10^{-6} \text{ tonne gas}}{\text{valve-hr}} \times \frac{8{,}760 \text{ hr}}{\text{yr}} \times \frac{0.0315 \text{ tonne } CO_2}{\text{tonne gas}}$$

$$\underline{E_{CO_2} = 0.129 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CO_2e} = \frac{0.129 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{0.487 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right)$$

$$\underline{E_{CO_2e} = 10.4 \text{ tonne } CO_2e/\text{yr}}$$

An example calculation for gas valves is shown below using the gas component count, emission factor, and gas compositions.

$$E_{CH_4} = (330 \text{ valves}) \times \frac{4.5\times10^{-6} \text{ tonne gas}}{\text{valve-hr}} \times \frac{8{,}760 \text{ hr}}{\text{yr}} \times \frac{0.8226 \text{ tonne } CH_4}{\text{tonne gas}}$$

$$\underline{E_{CH_4} = 10.7 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = (330 \text{ valves}) \times \frac{4.5\times10^{-6} \text{ tonne gas}}{\text{valve-hr}} \times \frac{8{,}760 \text{ hr}}{\text{yr}} \times \frac{0.0271 \text{ tonne } CO_2}{\text{tonne gas}}$$

$$\underline{E_{CO_2} = 0.352 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CO_2e} = \frac{0.352 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{10.7 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right)$$

$$\underline{E_{CO_2e} = 225 \text{ tonne } CO_2e/\text{yr}}$$

Completing the calculations for the rest of the components results in the emissions shown in Table 8-12.

Table 8-12. Offshore Oil and Natural Gas Production Platform Fugitive Emissions

Component	Service	Emissions (tonnes CH_4/yr)	Uncertainty [a] (±%)	Emissions (tonnes CO_2/yr	Uncertainty [a] (±%)	Emissions (tonnes CO_2e/yr)	Uncertainty [a] (±%)
Valves	Oil	0.487	125	0.129	125	10.4	124
	Gas	10.7	125	0.352	125	225	125
Connectors	Oil	0.164	125	0.0433	125	3.48	124
	Gas	1.90	125	0.0626	125	40.0	125
OELs	Oil	0.0403	125	0.0107	125	0.857	124
	Gas	0.706	125	0.0232	125	14.9	125
Others	Oil	0.0469	125	0.0124	125	0.998	124
	Gas	0.634	125	0.0209	125	13.3	125
TOTAL[b]		**14.7**	**93.1**	**0.654**	**73.5**	**309**	**92.9**

Footnotes:

[a] Uncertainty is at a 95% confidence interval.

[b] Totals may not sum due to independent rounding.

Note: the values shown above are for example only. They do not reflect actual operations.

Facility Summary

Total emissions for this facility are summarized in Table 8-13. A summary of the emissions for this facility is given in Figure 8-2.

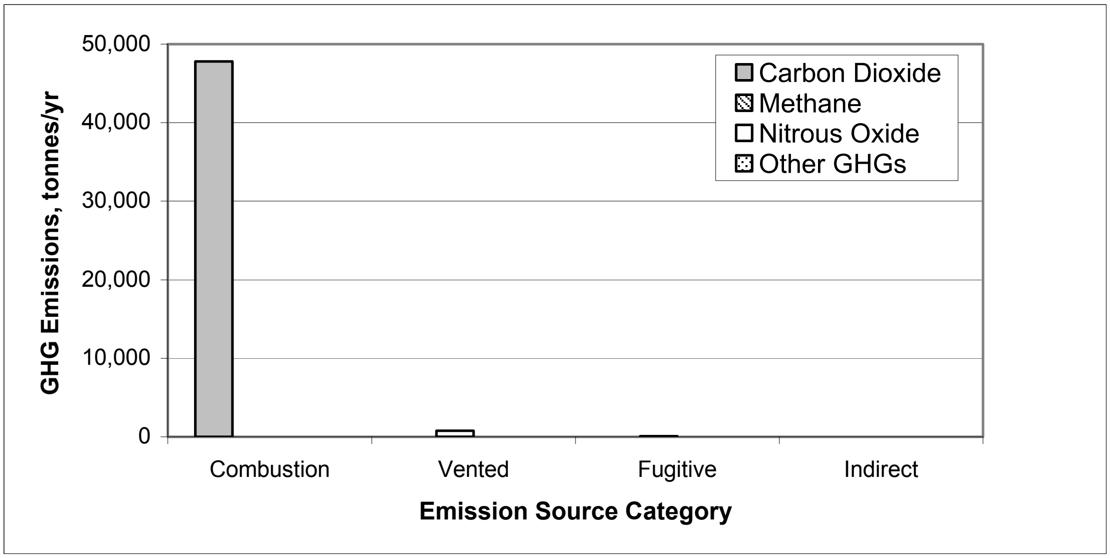


Figure 8-2. Offshore Oil and Natural Gas Production Platform Summary of Emissions

Table 8-13. Offshore Oil and Natural Gas Production Platform Emissions

	CO_2 N		CH_4		$_2$O		CO_2e	
Source	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**
Combustion Sources	**47,800**	**12.8**	**14.4**	**19.1**	**6.67**	**117**	**50,100**	**13.1**
Boilers/heaters	784	20.8	0.0147	32.0	0.00410	151	786	20.7
Gas turbines (electricity generation)	37,200	16.2	3.25	44.1	4.89	154	38,600	16.7
Gas turbines (compression)			0.806	32.3	0.281	151		
IC Engines	4,300	12.6	0.443	103	0.0185	150	4,300	12.6
Crane engine								
Crane engine								
Fire water pump IC engine								
Emergency generator, drilling			0.103	28.1	0.0168	151		
Emergency generator, production								
Forklift								
Whittaker escape capsule								
Supply boat	3,320	23.2	0.189	33.0	1.37	152	3,750	26.8
Supply boat								
Helicopters	838	24.5	0.836	33.9	0.0876	152	883	23.7
Flare - purge and pilot	1,370	25.7	8.79	26.0	0.00345	150	1,560	22.9
Flare - planned other								
Flare - planned continuous								
Flare - unplanned								

Table 8-13. Offshore Oil and Natural Gas Production Platform Emissions, continued

	CO_2 N		CH_4		$_2$O		CO_2e	
Source	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**
Vented Sources	**24.8**	**150**	**755**	**150**	**N/A**		**15,900**	**150**
Tank battery	18.4	201	560	201	N/A		11,800	201
Dehydration vents (also has Kimray pump emissions)	5.39	77.4	164	77.4	N/A		3,450	77.3
Pneumatic devices	0.642	50.0	19.5	50.0	N/A		410	49.9
CIPs	0.132	108	4.01	108	N/A		84.3	108
Vessel blowdowns (non-routine)	0.000512	326	0.0156	326	N/A		0.328	326
Compressor starts (non-routine)	0.0369	190	1.12	190	N/A		23.6	190
Compressor blowdowns (non-routine)	0.0165	179	0.501	179	N/A		10.5	179
ESDs	0.187	276	5.69	276	N/A		120	276
PRVs	0.00432	310	0.131	310	N/A		2.76	310
Fugitive Sources	**0.654**	**73.5**	**14.7**	**93.1**	**N/A**		**309**	**92.9**
Equipment leaks	0.654	73.5	14.7	93.1	N/A		309	92.9
Sumps	No GHG emissions							
Mud cuttings roll-off bins	No GHG emissions							
Indirect Sources	**No Indirect GHG Emissions**							
None								
TOTAL - Direct[b]	**47,800**	**12.8**	**784**	**145**	**6.67**	**117**	**66,300**	**37.2**
TOTAL - Indirect	**No Indirect GHG Emissions**							
TOTAL[b]	**47,800**	**12.8**	**784**	**145**	**6.67**	**117**	**66,300**	**37.2**

Footnotes:

[a] Uncertainty is at a 95% confidence interval.

[b] Totals may not sum due to independent rounding.

Note: the values shown above are for example only. They do not reflect actual operations.

8.1.3 Natural Gas Processing Plant

Facility Description: The facility consists of a natural gas processing plant.

Throughput: The plant processes 800×10^6 scf/day of gas. An uncertainty of ±10% is assumed for the throughput, based on engineering judgment.

Operations: Compositions of the produced and processed gas streams are provided in Table 8-14. The composition of the processed gas results in a heating value of 1,251 Btu/scf. An uncertainty of ±4% is assumed for both composition and heating value, based on engineering judgment.

Table 8-14. Gas Composition for Natural Gas Processing Plant

Gas Compound	**Produced Gas Mole %**	**Uncertainty[a] (±%)**	**Processed Gas Mole %**	**Uncertainty[a] (±%)**
H_2S	1.13	4	0.02	4
CO_2	3.5	4	2.0	4
N_2	2.39	4	1.2	4
CH_4	70	4	90	4
C_2H_6	12.5	4	4.7	4
C_3H_8	5.1	4	1.2	4
C_4H_{10}	3.7	4	0.5	4
C_5H_{12}	0.76	4	0.3	4
C6+	0.92	4	0.08	4

Footnotes:

[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

Note: the values shown above are for example only. They do not reflect average operations.

Tables 8-15 and 8-16 summarize the emission sources associated with this facility. Equipment at the site that does not have GHG emissions are also included in these tables.

Table 8-15. Natural Gas Processing Emission Sources

Source	Fuel Type	No. of Units	Uncertainty[a] (±%)	Unit Capacity (per unit)	Uncertainty[a] (±%)	Average Operation per unit per year	Uncertainty[a] (±%)	Activity Factor (all units combined)	Uncertainty[a] (±%)
Combustion Sources									
Auxiliary boilers	Processed Gas	2	0	130×10^6 Btu/hr	10	8400 hr/yr	5	$2,184,000\times10^6$ Btu/yr	11.2
Hot oil heaters	Processed Gas	2	0	80×10^6 Btu/hr	10	8400 hr/yr	5	$1,344,000\times10^6$ Btu/yr	11.2
Gas turbines for recompression	Processed Gas	2	0	36,300 hp	10	8665 hr/yr; 46% load	5; 20	2,337,582 $\times10^6$ Btu/yr	23.8
Gas turbines for electrical generation	Processed Gas	2	0	35,900 hp	10	8665 hr/yr; 46% load	5; 20	213,410 MW-hr/yr output	22.9
Flare - pilot	Processed Gas	1	0	0.0072×10^6 scf/day	10	365 day/yr	0	2.63×10^6 scf/yr	10
Emergency flare (acid gas, low pressure)	Acid gas (produced gas), low pressure	1	0	10×10^6 scf/day	10	156 hr/yr	15	65×10^6 scf/yr	18.0
Emergency flare	Acid gas (produced gas), high pressure	1	0	35×10^6 scf/day	10	156 hr/yr	15	227.5×10^6 scf/yr	18.0
Emergency fire water pump IC engines	Diesel	2	0	460 hp	10	24 hr/yr; 87% load	10; 20	155×10^6 Btu/yr	25.0
Emergency fire water pump IC engines	Diesel	2	0	425 hp	10	24 hr/yr; 92% load	10; 20	152×10^6 Btu/yr	25.0

Table 8-15. Natural Gas Processing Emission Sources, continued

Source	Fuel Type	No. of Units	Uncertainty[a] (±%)	Unit Capacity (per unit)	Uncertainty[a] (±%)	Average Operation (per unit per year)	Uncertainty[a] (±%)	Activity Factor (all units combined)	Uncertainty[a] (±%)
Vented Sources									
Dehydration vents (also has Kimray pump emissions)	N/A	1	0	800×10^6 scf/day	10	365 day/yr	0	$292{,}000\times10^6$ scf/yr	10
Gas processing /sour gas treating[b]									
Inlet	N/A	N/A		800×10^6 scf/day 3.5 mole% CO_2	10	365 day/yr	0	$292{,}000\times10^6$ scf/yr 3.5 mole % CO_2	10
Outlet	N/A	N/A		622×10^6 scf/day 2.0 mole % CO_2[c]	10	365 day/yr	0	$227{,}030\times10^6$ scf/yr 2.0 mole% CO_2	10
Condensate storage tanks	N/A	3 tanks	0	1,200,000 bbl/yr/tank	20	Continuous		3,600,000 bbl/yr	20
Marine loading	LPG	N/A		300,000 bbl/load	20	12 /yr	0	3,600,000 bbl/yr	20
	C_5+	N/A		300,000 bbl/load	20	12 /yr	0	3,600,000 bbl/yr	20
	Propane	N/A		175,000 bbl/load	20	12 /yr	0	2,100,000 bbl/yr	20
	Butane	N/A		125,000 bbl/load	20	12 /yr	0	1,500,000 bbl/yr	20
Compressor starts	N/A	4	0	N/A		N/A		4 compressors / turbines[d]	0
Compressor blowdowns	N/A	2	0	N/A		N/A		2 compressors[d]	0
Processing maintenance blowdowns	N/A	N/A		N/A		N/A		1 processing plant	0
Fire suppression	CO_2	10 cyl	0	30 lb/cyl	5	N/A		N/A	

Table 8-15. Natural Gas Processing Emission Sources, continued

Source	Fuel Type	No. of Units	Uncertainty[a] (±%)	Unit Capacity (per unit)	Uncertainty[a] (±%)	Average Operation (per unit per year)	Uncertainty[a] (±%)	Activity Factor (all units combined)	Uncertainty[a] (±%)
Fugitive Sources									
Equipment leaks	N/A	N/A		N/A		N/A		See Table 8-16	
Industrial refrigeration	N/A	N/A		N/A		N/A		50,000 lb/yr[e]	10
Indirect Sources									
None									

Footnotes:

[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

[b] Parameters provided are for the process, not the facility as a whole. This vent is uncontrolled and vents 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.

[c] Outlet gas flow rate calculated assuming 90% CH_4, 2% CO_2, and negligible H_2S.

[d] 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. These emissions are included under Processing maintenance blowdowns.

[e] Refrigerant loss may occur over many years; however, emissions are being reported for the year the equipment is recharged.

Note: the values shown above are for example only. They do not reflect average operations.

Table 8-16. Natural Gas Processing Fugitive Emission Sources

Component	Service	Average Component Count	Uncertainty[a] (±%)
Valves	Gas and Liquid	4,430	25
Pump seals	Liquid	90	25
Flanges	Gas and Liquid	17,600	25
Compressor seals	Gas	20	25

Footnote:
[a] Uncertainty is based on engineering judgment at a 95% confidence interval.
Note: the values shown above are for example only. They do not reflect average operations.

The remainder of this subsection presents emission calculations for the sources identified in Tables 8-15 and 8-16, and a summary of facility emissions (presented at the end of this subsection).

Stationary Combustion Devices – CO_2 Emissions

Natural Gas Combustion CO_2 Emissions

The first step in calculating CO_2 emissions is to determine the total volume of fuel combusted (V) at the facility. Power output to energy input conversion factors for a conventional combustion turbine (presented in Table 4-2) are used to convert the turbine operational data to fuel consumption, assuming an uncertainty of ±5%, based on engineering judgment. This calculation is shown below, by equipment type.

Boiler and heaters:

$$V = \left[\begin{array}{l} \left(2 \text{ boilers} \times \dfrac{130 \times 10^6 \text{ Btu}}{\text{boiler}} \times \dfrac{8{,}400 \text{ hr}}{\text{yr}} \right) + \\ \left(2 \text{ heaters} \times \dfrac{80 \times 10^6 \text{ Btu}}{\text{heater}} \times \dfrac{8{,}400 \text{ hr}}{\text{yr}} \right) \end{array} \right] \times \frac{\text{scf}}{1{,}251 \text{ Btu}} = 2{,}820 \times 10^6 \text{ scf/yr}$$

Turbines:

$$V_{ICOM} = \begin{bmatrix} \left(2\text{ turbines} \times \frac{36{,}300\text{ hp}}{\text{turbine}} \times 0.46\text{ load} \times \frac{8{,}078\text{ Btu}}{\text{hp-hr}} \times \frac{8{,}665\text{ hr}}{\text{yr}}\right) + \\ \left(2\text{ turbines} \times \frac{35{,}900\text{ hp}}{\text{turbine}} \times 0.46\text{ load} \times \frac{8{,}078\text{ Btu}}{\text{hp-hr}} \times \frac{8{,}665\text{ hr}}{\text{yr}}\right) \end{bmatrix} = 3{,}717 \times 10^6\text{ scf/yr}$$

$$\times \frac{\text{scf}}{1{,}251\text{ Btu}}$$

Carbon dioxide emissions from equipment burning natural gas are calculated using the gas composition approach provided in Section 4.3. First, the fuel analysis is converted from a molar basis to a mass basis, as shown in Exhibits 3.3 and 3.4. The molecular weight of the mixture is calculated below, using Equation 3-8:

$$MW_{\text{Mixture}} = \begin{bmatrix} (1.13\text{x}34.08) + (3.5 \times 44.01) + (2.39 \times 28.01) \\ +(70 \times 16.04) + (12.5 \times 30.07) + (5.1 \times 44.10) \\ +(3.7 \times 58.12) + (0.76 \times 72.15) + (0.92 \times 86.18) \end{bmatrix} \div 100 = 23.32\text{ lb/mole}$$

The individual weight percents are then calculated by rearranging Equation 3-7. The calculation is shown below for CH_4.

$$\text{Wt.\%}_{CH_4} = \frac{70\text{ lbmole }CH_4}{100\text{ lbmole mixture}} \times \frac{\left(\frac{16.04\text{ lb }CH_4}{\text{lbmole }CH_4}\right)}{\left(\frac{23.32\text{ lb mixture}}{\text{lbmole mixture}}\right)} = \frac{0.4814\text{ lb }CH_4}{\text{lb mixture}} = 48.14\text{ wt. \% }CH_4$$

To calculate emissions, the carbon contents of the fuel compositions provided in Table 8-14 are calculated. The first step is to calculate the carbon content of the individual components, using Equation 4-9. The carbon content calculation for an individual component is shown below for ethane (C_2H_6).

$$\text{Wt\% }C_{C_2H_6} = \frac{12.01\text{ lb C}}{\text{lbmole C}} \times \frac{2\text{ lbmoles C}}{\text{lbmole }C_2H_6} \times \frac{\text{lbmole }C_2H_6}{30.07\text{ lb }C_2H_6} \times 100\% = 79.9\%\text{ C}$$

After the calculation has been performed for all constituents, the carbon content for the mixture is calculated using Equation 4-10, shown as follows (for produced gas):

$$\mathrm{Wt\%C_{Mixture}} = \frac{1}{100} \times \sum_{i=1}^{\#\ \mathrm{components}} \left(\mathrm{Wt\%_i} \times \mathrm{Wt\%C_i}\right)$$

$$\mathrm{Wt\%\ C_{Mixture}} = \frac{1}{100} \times \begin{bmatrix} (1.65\times 0)+(6.60\times 28.3)+(2.87\times 0)+(48.14\times 74.9)+(16.12\times 79.9) \\ +(9.64\times 81.7)+(9.22\times 82.7)+(2.35\times 83.2)+(3.40\times 83.6) \end{bmatrix}$$

$$= 71.03\ \mathrm{Wt\%\ C} = 0.7103\ \mathrm{lb\ C/lb\ fuel}$$

Completing the calculations for the produced gas fuel analysis results in the fuel specific molecular weight and carbon content below:

Compound	Mole %	MW	Wt% (Calculated)	Uncertainty[a] (±%)	Compound Carbon Content (wt%C)	Mixture Carbon Content (wt%C)	Uncertainty[a] (±%)
H_2S	1.13	34.08	1.65	4.53	0	0	NA
CO_2	3.5	44.01	6.60	4.53	27.3	1.80	4.53
N_2	2.39	28.01	2.87	4.53	0	0	NA
CH_4	70	16.04	48.14	4.53	74.9	36.1	4.53
C_2H_6	12.5	30.07	16.12	4.53	79.9	12.9	4.53
C_3H_8	5.1	44.10	9.64	4.53	81.7	7.88	4.53
C_4H_{10}	3.7	58.12	9.22	4.53	82.7	7.62	4.53
C_5H_{12}	0.76	72.15	2.35	4.53	83.2	1.96	4.53
C6+	0.92	86.18	3.40	4.53	83.6	2.84	4.53
Fuel Mixture	**100**	**23.32 ±2.13%[a]**	**100.0**			**71.03**	**2.55**

Footnote:
[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

Completing the calculations for the processed gas fuel analysis results in the fuel molecular weight and carbon content below:

Compound	Mole %	MW	Wt% (Calculated)	Uncertainty[a] (±%)	Compound Carbon Content (wt%C)	Mixture Carbon Content (wt%C)	Uncertainty[a] (±%)
H_2S	0.02	34.08	0.04	5.12	0	0	NA
CO_2	2	44.01	4.84	5.12	27.3	1.32	5.12
N_2	1.2	28.01	1.85	5.12	0	0	NA
CH_4	90	16.04	79.42	5.12	74.9	59.5	5.12
C_2H_6	4.7	30.07	8.77	5.12	79.9	6.21	5.12
C_3H_8	1.2	44.10	2.91	5.12	81.7	2.38	5.12
C_4H_{10}	0.5	58.12	1.60	5.12	82.7	1.32	5.12
C_5H_{12}	0.3	72.15	1.19	5.12	83.2	0.991	5.12
C6+	0.08	86.18	0.38	5.12	83.6	0.317	5.12
Fuel Mixture	**100**	**18.18 ±3.20%[a]**	**100.0**			**72.01**	**4.26**

Footnote:
[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

Carbon dioxide emissions can then be calculated using a mass balance approach. (Note that processed gas is used for combustion.) Natural gas combustion emissions are calculated below.

$$E_{CO_2} = \frac{\left(2,820\times10^6+3,717\times10^6\right)\text{ scf fuel}}{\text{yr}}\times\frac{\text{lbmole}}{\text{379.3 scf fuel}}\times\frac{\text{18.18 lb fuel}}{\text{lbmole fuel}}\times\frac{\text{0.7201 lb C}}{\text{lb fuel}}$$

$$\times\frac{\text{lbmole C}}{\text{12.01 lb C}}\times\frac{\text{lbmole CO}_2}{\text{lbmole C}}\times\frac{\text{44.01 lb CO}_2}{\text{lbmole CO}_2}\times\frac{\text{tonne}}{\text{2204.62 lb}}$$

$$\underline{E_{CO_2} = 375,000 \text{ tonnes CO}_2\text{ / yr}}$$

Diesel Combustion

Carbon dioxide emissions from diesel combustion are calculated using the diesel emission factor provided in Table 4-3, assuming an uncertainty of ±10%, based on engineering judgment. Because the emission factor is provided on a energy input basis, the equipment ratings are converted to volume of fuel consumed on a energy input basis using the “No. 2 fuel oil IC engine” conversion factor provided in Table 4-2, assuming an uncertainty of ±5%, based on engineering judgment. Diesel combustion CO_2 emissions are calculated below.

$$V = \left(\text{2 pumps}\times\frac{\text{460 hp}}{\text{pump}}\times\text{0.87 load}\times\frac{\text{8,089 Btu}}{\text{hp-hr}}\times\frac{\text{24 h}}{\text{yr}}\right)+$$

$$+\left(\text{2 pumps}\times\frac{\text{425 hp}}{\text{pump}}\times\text{0.92 load}\times\frac{\text{8,089 Btu}}{\text{hp-hr}}\times\frac{\text{24 h}}{\text{yr}}\right)= 307\times10^6\text{ Btu /yr}$$

$$E_{CO_2} = \frac{307\times10^6\text{ Btu}}{\text{yr}}\times\frac{\text{0.0732 tonnes CO}_2}{10^6\text{ Btu}}$$

$$\underline{E_{CO_2} = 22.5 \text{ tonnes CO}_2\text{/yr}}$$

Stationary Combustion Devices – CH_4, N_2O, and CO_2e Emissions

Natural Gas Combustion

Combustion emission factors for natural gas-fired equipment are provided in Table 4-7 for controlled boilers and heaters, and Table 4-9 for uncontrolled turbines. The electricity generation turbine emission factors are taken from Table 7-1 for natural gas "Combined Cycle" units. An uncertainty of ±25% is assumed for all CH_4 emission factors and an uncertainty of ±150% is assumed for all N_2O emission factors, based on engineering judgment. The electricity generation turbine power (P) conversion from hp output to kw output is presented in Table 3-4. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Because CO_2 emissions from natural gas combustion were not calculated on an equipment basis, CO_2e emissions are also not calculated on an equipment basis.

Boilers and Heaters:

$$V = \begin{bmatrix} (2 \text{ boilers} \times \frac{130 \times 10^6 \text{ Btu}}{\text{boiler}} \times \frac{8{,}400 \text{ hr}}{\text{yr}}) \\ +(2 \text{ heaters} \times \frac{80 \times 10^6 \text{ Btu}}{\text{heater}} \times \frac{8{,}400 \text{ hr}}{\text{yr}}) \end{bmatrix} = 3{,}528{,}000 \times 10^6 \text{ Btu/yr}$$

$$E_{CH_4} = \frac{3{,}528{,}000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{1.00 \times 10^{-6} \text{ tonne } CH_4}{10^6 \text{ Btu}}$$

$$\underline{E_{CH_4} = 3.53 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{3{,}528{,}000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{2.80 \times 10^{-7} \text{ tonne } N_2O}{10^6 \text{ Btu}}$$

$$\underline{E_{N_2O} = 0.988 \text{ tonnes } N_2O/\text{yr}}$$

Turbines for Recompression:

$$V = \left(2 \text{ turbines} \times \frac{36{,}300 \text{ hp}}{\text{turbine}} \times 0.46 \text{ load} \times \frac{8{,}078 \text{ Btu}}{\text{hp-hr}} \times \frac{8{,}665 \text{ hr}}{\text{yr}} \right) = 2{,}337{,}582 \times 10^6 \text{ Btu/yr}$$

$$E_{CH_4} = \frac{2{,}337{,}582 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{3.9 \times 10^{-6} \text{ tonne } CH_4}{10^6 \text{ Btu}}$$

$$\underline{E_{CH_4} = 9.12 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{2{,}337{,}582 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{1.4 \times 10^{-6} \text{ tonne } N_2O}{10^6 \text{ Btu}}$$

$$\underline{E_{N_2O} = 3.27 \text{ tonnes } N_2O/\text{yr}}$$

Gas Combustion Turbine for Electrical Generation:

$$P = 2 \text{ units} \times \frac{35{,}900 \text{ hp}}{\text{unit}} \times \frac{0.7457 \text{ kW-hr}}{\text{hp-hr}} \times \frac{8{,}665 \text{ hr}}{\text{yr}} \times 0.46 \text{ load} \times \frac{\text{MW-hr}}{1{,}000 \text{ kW-hr}} = 213{,}410 \text{ MW-hr}$$

$$E_{CH_4} = 213{,}410 \text{ MW-hr} \times \frac{6.80 \times 10^{-6} \text{ tonne } CH_4}{\text{MW-hr}}$$

$$\underline{E_{CH_4} = 1.45 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{213{,}410 \text{ MW-hr}}{\text{yr}} \times \frac{2.86 \times 10^{-5} \text{ tonne } N_2O}{\text{MW-hr}}$$

$$\underline{E_{N_2O} = 6.10 \text{ tonnes } N_2O/\text{yr}}$$

Natural Gas Combustion CO2e Emissions:

$$E_{CO_2e} = \frac{375{,}000 \text{ tonne } CO_2}{\text{yr}} + \left[\left(\frac{3.53 \text{ tonne } CH_4}{\text{yr}} + \frac{9.12 \text{ tonne } CH_4}{\text{yr}} + \frac{1.45 \text{ tonne } CH_4}{\text{yr}}\right) \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right] +$$
$$+ \left[\left(\frac{0.988 \text{ tonne } N_2O}{\text{yr}} + \frac{3.27 \text{ tonne } N_2O}{\text{yr}} + \frac{6.10 \text{ tonne } N_2O}{\text{yr}}\right) \times \frac{310 \text{ tonne } CO_2e}{\text{tonne } N_2O}\right]$$

$$\underline{E_{CO_2e} = 378{,}100 \text{ tonne } CO_2e/\text{yr}}$$

Diesel Combustion

Diesel-operated fire water pump emissions are estimated using the "IC Engine – Diesel" emission factors from Table 4-9 (for diesel engines rated less than 600 hp). An uncertainty of ±25% is assumed for all CH_4 emission factors and an uncertainty of ±150% is assumed for all N_2O emission factors, based on engineering judgment. Table 4-9 also provides an assumed CH_4 content of 9 wt% to convert from TOC emissions if the exhaust composition is unknown. An uncertainty of ±100% is assumed for the conversion of TOC to CH_4, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Emissions are calculated below.

$$E_{CH_4} = \frac{307 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.00016 \text{ tonne TOC}}{10^6 \text{ Btu}} \times \frac{0.09 \text{ tonne CH}_4}{\text{tonne TOC}}$$

$$\underline{E_{CH_4} = 0.00451 \text{ tonnes CH}_4\text{/yr}}$$

$$E_{N_2O} = \frac{307 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{6.01 \times 10^{-7} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}}$$

$$\underline{E_{N_2O} = 0.000185 \text{ tonnes N}_2\text{O/yr}}$$

$$E_{CO_2e} = \frac{22.5 \text{ tonne CO}_2}{\text{yr}} + \left(\frac{0.00451 \text{ tonne CH}_4}{\text{yr}} \times \frac{21 \text{ tonne CO}_2\text{e}}{\text{tonne CH}_4}\right) + \left(\frac{0.000185 \text{ tonne N}_2\text{O}}{\text{yr}} \times \frac{310 \text{ tonne CO}_2\text{e}}{\text{tonne N}_2\text{O}}\right)$$

$$\underline{E_{CO_2e} = 22.6 \text{ tonne CO}_2\text{e/yr}}$$

Combustion Sources – Flares

The first step in calculating the flare emissions is to calculate the volume flared. This is shown as follows, by flared stream.

(a) Pilot gas (processed gas) flaring

$$V_{\text{Pilot}} = \frac{0.0072\times10^{6}\ \text{scf}}{\text{day}} \times \frac{365\ \text{day}}{\text{yr}} = 2{,}628{,}000\ \text{scf gas/yr}$$

(b) Sour gas flaring

$$V_{\text{Sour gas}} = \left(\frac{10\times10^{6}\ \text{scf}}{\text{day}} \times \frac{\text{day}}{24\ \text{hr}} \times \frac{156\ \text{hr}}{\text{yr}}\right) + \left(\frac{35\times10^{6}\ \text{scf}}{\text{day}} \times \frac{\text{day}}{24\ \text{hr}} \times \frac{156\ \text{hr}}{\text{yr}}\right) = 65{,}000{,}000 + 227{,}500{,}000\ \text{scf/yr}$$

Based on the guidance given in Section 4.6, CH_4 emissions from flares are calculated assuming 2% of the CH_4 remains uncombusted, and CO_2 emissions are based on 98% combustion efficiency, assuming an uncertainty of ±20% for both, based on engineering judgment. Carbon dioxide emissions are estimated as the sum of the CO_2 already present in the gas and the CO_2 that results from the product of flared gas carbon combustion. Nitrous oxide emissions are estimated using emission factors from Table 4-11, assuming an uncertainty of ±150%, based on engineering judgment. The sour gas processing flare emission factor will be used as a simplifying assumption to obtain an emissions estimate. Note that the N_2O emissions factor is based on gas feed, not gas produced. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Because N_2O emissions are calculated for the flare as a whole (not split by flared stream), CO_2e emissions are also calculated for the flare as a whole. Emissions are calculated below, by pollutant.

Carbon dioxide emissions:

(a) Flare Pilot gas (processed gas)

$$E_{CO_2} = \frac{2.628\times10^{6}\ \text{scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3\ \text{scf gas}} \times \frac{18.18\ \text{lb gas}}{\text{lbmole gas}} \times \frac{0.7201\ \text{lb C}}{\text{lb gas}} \times \frac{\text{lbmole C}}{12.01\ \text{lb C}} \times \frac{\text{lbmole } CO_2}{\text{lbmole C}} \times \frac{44.01\ \text{lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62\ \text{lb}}$$

$$\underline{E_{CO_2} = 151\ \text{tonnes } CO_2/\text{yr}}$$

(b) Sour gas flaring

$$E_{CO_2} = \frac{(65{,}000{,}000 + 227{,}500{,}000)\text{ scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3\text{ scf gas}} \times \frac{44.01\text{ lb }CO_2}{\text{lbmole }CO_2} \times \frac{\text{tonne}}{2204.62\text{ lb}}$$

$$\times \left[\begin{array}{l} \left(\begin{array}{l} \dfrac{0.70\text{ lbmole }CH_4}{\text{lbmol gas}} \times \dfrac{1\text{ lbmole C}}{\text{lbmole }CH_4} + \dfrac{0.124\text{ lbmole }C_2H_6}{\text{lbmole gas}} \times \dfrac{2\text{ lbmole C}}{\text{lbmole }C_2H_6} \\ + \dfrac{0.051\text{ lbmole }C_3H_8}{\text{lbmole gas}} \times \dfrac{3\text{ lbmole C}}{\text{lbmole }C_3H_8} + \dfrac{0.037\text{ lbmole }C_4H_{10}}{\text{lbmole gas}} \times \dfrac{4\text{ lbmole C}}{\text{lbmole }C_4H_{10}} \\ + \dfrac{0.0076\text{ lbmole }C_5H_{12}}{\text{lbmole gas}} \times \dfrac{5\text{ lbmole C}}{\text{lbmole }C_5H_{12}} + \dfrac{0.0092\text{ lbmole }C_6H_{14}}{\text{lbmole gasC}} \times \dfrac{6\text{ lbmole C}}{\text{lbmole }\ {}_6H_{14}} \end{array} \right) \\ \times \dfrac{0.98\text{ lbmole }CO_2}{\text{lbmole C combusted}} + \dfrac{0.035\text{ lbmole }CO_2}{\text{lbmole gas}} \end{array} \right]$$

$$\underline{E_{CO_2} = 20{,}800\text{ tonnes }CO_2/\text{yr}}$$

Methane emissions:

(a) Pilot gas flaring

$$E_{CH_4} = \frac{2{,}628{,}000\text{ scf gas}}{\text{yr}} \times \frac{2.3\text{ lb }CH_4}{10^6\text{ scf gas}} \times \frac{\text{tonne}}{2204.62\text{ lb}}$$

$$\underline{E_{CH_4} = 0.00274\text{ tonnes }CH_4/\text{yr}}$$

(b) Sour gas flaring

$$E_{CH_4} = \frac{(65{,}000{,}000 + 227{,}500{,}000)\text{ scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3\text{ scf gas}} \times \frac{0.7\text{ lbmole }CH_4}{\text{lbmole gas}} \times \frac{16.04\text{ lb }CH_4}{\text{lbmole }CH_4}$$
$$\times \frac{0.02\text{ lb uncombusted }CH_4}{\text{lb }CH_4} \times \frac{\text{tonne}}{2204.62\text{ lb}}$$

$$\underline{E_{CH_4} = 78.5\text{ tonnes }CH_4/\text{yr}}$$

Nitrous Oxide emissions:

(a) Pilot gas flaring

$$E_{N_2O} = \frac{2{,}628{,}000\text{ scf gas}}{\text{yr}} \times \frac{2.2\text{ lb }N_2O}{10^6\text{ scf gas}} \times \frac{\text{tonne}}{2204.62\text{ lb}}$$

$$\underline{E_{N_2O} = 0.00262\text{ tonnes }N_2O/\text{yr}}$$

(b) Sour gas flaring

$$\mathrm{V} = 800 \times 10^6 \text{ scf/day} \times \frac{365 \text{ days}}{\text{yr}} = 292{,}000 \times 10^6 \text{ scf/yr}$$

$$\mathrm{E_{N_2O}} = \frac{292{,}000 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1.50 \times 10^{-6} \text{ tonnes N}_2\text{O}}{10^6 \text{ scf gas receipts}}$$

$$\underline{\mathrm{E_{N_2O}} = 0.438 \text{ tonnes N}_2\text{O/yr}}$$

Carbon Dioxide Equivalent emissions:

$$\mathrm{E_{CO_2e}} = \frac{151 \text{ tonne CO}_2}{\text{yr}} + \frac{20{,}800 \text{ tonne CO}_2}{\text{yr}} + \left(\left(\frac{0.00274 \text{ tonne CH}_4}{\text{yr}} + \frac{78.5 \text{ tonne CH}_4}{\text{yr}}\right) \times \frac{21 \text{ tonne CO}_2\text{e}}{\text{tonne CH}_4}\right)$$
$$+ \left(\left(\frac{0.00262 \text{ tonne N}_2\text{O}}{\text{yr}} + \frac{0.438 \text{ tonne N}_2\text{O}}{\text{yr}}\right) \times \frac{310 \text{ tonne CO}_2\text{e}}{\text{tonne N}_2\text{O}}\right)$$

$$\underline{\mathrm{E_{CO_2e}} = 22{,}800 \text{ tonne CO}_2\text{e/yr}}$$

Vented Sources – Gas Dehydration

Methane emissions from the gas dehydrator vents are estimated using the gas processing segment emission factor and uncertainty given in Table 5-2. The Kimray pump emissions are estimated using the gas processing segment emission factor and uncertainty in Table 5-4. For both of these sources, emissions are based on the annual quantity of gas processed. Methane emissions are adjusted based on the facility CH_4 content. The default CH_4 content and associated uncertainty are provided in Table E-4. Carbon dioxide emissions are calculated by using a ratio of the facility CH_4 and CO_2 contents. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Emissions are calculated as follows.

$$EF_{CH_4} = \left(EF_{\text{Dehydrator vents}}\right) + \left(EF_{\text{Kimray pumps}}\right)$$

$$EF_{CH_4} = \left(\frac{0.0023315\text{ tonne CH}_4}{10^6\text{ scf}}\right) + \left(\frac{0.0034096\text{ tonne CH}_4}{10^6\text{ scf}}\right)$$

$$\underline{EF_{CH_4} = 0.0057411\text{ tonne CH}_4 / 10^6\text{ scf}}$$

$$E_{CH_4} = \frac{800\times10^6\text{ scf}}{\text{day}} \times \frac{365\text{ day}}{\text{yr}} \times \frac{0.90\text{ tonne mole CH}_4\text{ (facility)}}{0.868\text{ tonne mole CH}_4\text{ (default)}} \times \frac{0.0057411\text{ tonne CH}_4}{10^6\text{scf}}$$

$$\underline{E_{CH_4} = 1{,}740\text{ tonnes CH}_4\text{/yr}}$$

$$E_{CO_2} = \frac{800\times10^6\text{ scf}}{\text{day}} \times \frac{365\text{ day}}{\text{yr}} \times \frac{0.0057411\text{ tonne CH}_4}{10^6\text{scf}} \times \frac{\text{tonne mole CH}_4}{16.04\text{ tonne CH}_4} \times \frac{0.90\text{ tonne mole CH}_4\text{ (facility)}}{0.868\text{ tonne mole CH}_4\text{ (default)}} \times \frac{\text{tonne mole gas}}{0.90\text{ tonne mole CH}_4} \times \frac{0.035\text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01\text{ tonne CO}_2}{\text{tonne mole CO}_2}$$

$$\underline{E_{CO_2} = 186\text{ tonnes CO}_2\text{/yr}}$$

$$E_{CO_2e} = \frac{1{,}740\text{ tonne CO}_2}{\text{yr}} + \left(\frac{186\text{ tonne CH}_4}{\text{yr}} \times \frac{21\text{ tonne CO}_2\text{e}}{\text{tonne CH}_4}\right)$$

$$\underline{E_{CO_2e} = 36{,}700\text{ tonne CO}_2\text{e/yr}}$$

Vented Sources – Venting from Sour Gas Processing

Carbon dioxide emissions from sour gas processing are estimated by material balance around the process, using the known throughput and CO_2 concentrations of the inlet and outlet gas streams as described in Section 5.1.5. The volumes of gas and CO_2 contents of the inlet and outlet streams are provided in Table 8-15. Methane emissions are calculated using the default emission factor from Table 5-5 for uncontrolled acid gas removal (AGR) units. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Sour gas processing emissions are calculated as follows.

$$E_{CO_2} = (CO_2)_{inlet} - (CO_2)_{outlet} = (CO_2)_{sour} - (CO_2)_{sweet}$$

$$E_{CO_2} = \left(\frac{800\times10^6 \text{ scf}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{0.035 \text{ lbmole } CO_2}{\text{lbmole gas}} \times \frac{44.01 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonnes}}{2204.62 \text{ lb}} \right)$$
$$- \left(\frac{622\times10^6 \text{ scf}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{0.02 \text{ lbmole } CO_2}{\text{lbmole gas}} \times \frac{44.01 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonnes}}{2204.62 \text{ lb}} \right)$$

$$\underline{E_{CO_2} = 298{,}900 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CH_4} = \frac{0.0185 \text{ tonne } CH_4}{10^6 \text{ scf}} \times \frac{800\times10^6 \text{ scf}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}}$$

$$\underline{E_{CH_4} = 0.00540 \text{ tonne } CO_2e/\text{yr}}$$

$$E_{CO_2e} = \frac{298{,}900 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{0.00540 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4} \right)$$

$$\underline{E_{CO_2e} = 298{,}900 \text{ tonne } CO_2e/\text{yr}}$$

Vented Sources – Storage Tanks

Methane emissions from condensate flashing losses occur upstream of this facility, in the production segment. There is no CH_4 or CO_2 in "weathered" crude or condensate and therefore there are no CH_4 or CO_2 emissions from the storage of these products.

Similarly, tank storage of LPG, C5+, propane, and butane will not result in CH_4 or CO_2 emissions because these processed liquids do not contain CH_4 or CO_2. (As a side note, these liquids are typically stored in pressurized vessels that do not vent to the atmosphere.)

Vented Sources – Loading Operations

The marine loading of LPG, C5+, propane, and butane will not result in emissions of CH_4 or CO_2 because these processed liquids do not contain CH_4 or CO_2.

Vented Sources: Maintenance/Turnaround Emissions

Methane emissions from processing maintenance/non-routine activities are estimated using the emission factor presented in Table 5-25, assuming an uncertainty of ±100%, based on engineering judgment. Note that the emission factor is based on the total quantity of gas processed. This overall emission factor includes CH_4 emissions from compressor/turbine starts, compressor blowdowns, miscellaneous vessel blowdowns, and pressure relief valves. Methane emissions are adjusted based on the facility CH_4 content. The default CH_4 content and associated uncertainty are provided in Table E-4. Carbon dioxide emissions are calculated by using a ratio of the facility CH_4 and CO_2 contents. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs.

$$E_{CH_4} = \frac{800\times10^6\text{scf}}{\text{day}} \times \frac{365\text{ days}}{\text{yr}} \times \frac{3.524\times10^{-3}\text{ tonne CH}_4}{10^6\text{scf}} \times \frac{0.900\text{ tonne mole CH}_4\text{ (facility)}}{0.868\text{ tonne mole CH}_4\text{ (default)}}$$

$$\underline{E_{CH_4} = 1{,}070\text{ tonnes CH}_4/\text{ yr}}$$

$$E_{CO_2} = \frac{800\times10^6\text{scf}}{\text{day}} \times \frac{365\text{ days}}{\text{yr}} \times \frac{3.524\times10^{-3}\text{ tonne CH}_4}{10^6\text{scf}} \times \frac{\text{tonne mole CH}_4}{16.04\text{ tonne CH}_4} \times \frac{0.900\text{ tonne mole CH}_4\text{ (facility)}}{0.868\text{ tonne mole CH}_4\text{ (default)}}$$
$$\times \frac{\text{tonne mole gas}}{0.900\text{ tonne mole CH}_4} \times \frac{0.02\text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01\text{ tonne CO}_2}{\text{tonne mole CO}_2}$$

$$\underline{E_{CO_2} = 65.1\text{ tonnes CO}_2/\text{yr}}$$

$$E_{CO_2e} = 65.1\text{ tonnes CO}_2/\text{yr} + \left(\frac{1{,}070\text{ tonne CH}_4}{\text{yr}} \times \frac{21\text{ tonne CO}_2\text{e}}{\text{tonne CH}_4}\right)$$

$$\underline{E_{CO_2e} = 22{,}500\text{ tonne CO}_2\text{e/yr}}$$

Vented Sources: Fire Suppression Emissions

Fire suppression emissions are calculated using a mass balance approach. The quantity of CO_2 emitted can be calculated using the information provided in Table 8-15. Fire suppression emissions are calculated below. Carbon dioxide emissions are the same as the CO_2e emissions if there are no CH_4, N_2O, or other GHG emissions. $\left(E_{CO_2e} = E_{CO_2}\right)$

$$E_{CO_2} = \frac{10\text{ cylinders}}{\text{yr}} \times \frac{30\text{ lb}}{1\text{ cylinder}} \times \frac{1\text{ tonne}}{2204.62\text{ lb}}$$

$$\underline{E_{CO_2} = 0.136\text{ tonnes }CO_2/\text{yr}}$$

Fugitive Sources: Equipment Leaks

Table 8-17 provides the API average component emission factors and CH_4 content based on the average gas plant emission factors given in Table 6-16. Note that the API average emissions factors and recommended CH_4 content are not service (liquid or gas) specific.

Table 8-17. Natural Gas Processing Fugitive Emission Factors

Component	Service	Component EF (tonnes TOC/comp./hr)	Uncertainty[a] (±%)
Valves	Liquid and gas	3.86E-06	100
Pump seals	Liquid	1.15E-05	100
Flanges	Liquid and gas	4.38E-07	100
Others (compressor seals)	Gas	4.86E-06	100

Footnote:

[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

Using Equation 6-9, CH_4 emissions are calculated for each component by multiplying the component emission factor by the component count, the annual hours of operation (8,760 hours/year, assuming the equipment remains pressurized year-round), and the weight fraction of CH_4. Because factors are taken from API 4615, the weight fraction of CH_4 is taken from Table C-6, assuming an uncertainty of ±15% based on engineering judgment. Note that Table C-6 does not provide CO_2 speciation data; therefore, these emissions are not calculated. The total fugitive emissions are the sum of each of the component emissions. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs.

An example calculation for liquid pump seals is shown below.

$$E_{CH_4} = (90 \text{ seals}) \times \frac{1.15 \times 10^{-5} \text{ tonne TOC}}{\text{seal-hr}} \times \frac{8{,}760 \text{ hr}}{\text{yr}} \times \frac{0.564 \text{ tonne CH}_4}{\text{tonne TOC}}$$

$$\underline{E_{CH_4} = 5.11 \text{ tonnes CH}_4\text{/yr}}$$

$$E_{CO_2e} = \frac{5.11 \text{ tonne CH}_4}{\text{yr}} \times \frac{21 \text{ tonne CO}_2\text{e}}{\text{tonne CH}_4}$$

$$\underline{E_{CO_2e} = 107 \text{ tonne CO}_2\text{e/yr}}$$

Completing the calculations for the rest of the components results in the emissions shown in Table 8-18.

Table 8-18. Natural Gas Processing Fugitive Emissions

Component	Service	CH_4 Emissions, tonnes CH_4/yr	Uncertainty[a] (±%)	CO_2e Emissions, tonnes CO_2e/yr	Uncertainty[a] (±%)
Valves	Liquid and gas	84.5	104	1,770	104
Pump seals	Liquid	5.11	104	107	104
Flanges	Liquid and gas	39.1	104	800	104
Others	Gas	0.480	104	10.1	104
Total[b]		**128**	**75.4**	**2,690**	**75.4**

Footnotes:
[a] Uncertainty is at a 95% confidence interval.
[b] Totals may not sum due to independent rounding.
Note: the values shown above are for example only. They do not reflect average operations.

Fugitive Sources: Industrial Refrigeration

Although refrigerant loss occurs over many years, emissions are being reported during the year the equipment is recharged. The facility's industrial refrigeration emissions are calculated using a mass balance approach. The quantity of refrigerant emitted is provided in Table 8-15, assuming an uncertainty of ±10%, based on engineering judgment. The CO_2e emission is estimated using the GWP presented in Table 3-1. There are no uncertainties for any of the GWPs.

Emissions are calculated as follows.

$$E_{\text{HFC-134a}} = \frac{50{,}000 \text{ lb HFC-134a}}{\text{yr}} \times \frac{\text{tonne HFC-134a}}{2204.62 \text{ lb HFC-134a}}$$

$$\underline{E_{\text{HFC-134a}} = 22.7 \text{ tonnes HFC} - 134\text{a/yr}}$$

$$E_{CO_2e} = \frac{22.7 \text{ tonnes HFC-134a}}{\text{yr}} \times \frac{1300 \text{ tonne } CO_2e}{\text{tonne HFC-134a}}$$

$$\underline{E_{CO_2e} = 29{,}500 \text{ tonne } CO_2\text{e/yr}}$$

Facility Summary

Total emissions for this facility are summarized in Table 8-19. A summary of the emissions for this facility is given in Figure 8-3.

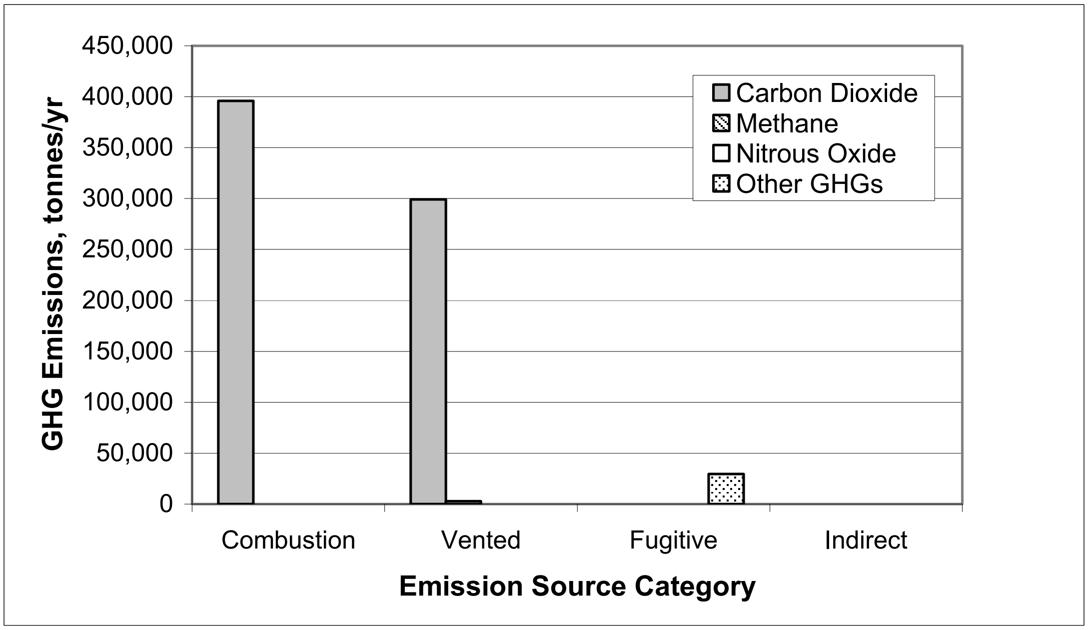


Figure 8-3. Natural Gas Processing Summary of Emissions

Table 8-19. Natural Gas Processing Emissions

	CO$_2$ N		**CH$_4$**		**$_2$O**		**CO$_2$e**	
Source	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**
Combustion Sources	**396,000**	**10.1**	**92.7**	**21.6**	**10.8**	**98.4**	**400,900**	**10.0**
Auxiliary boilers	375,000	10.6	3.53	26.3	0.988	150	378,100	10.5
Hot oil heaters								
Gas turbines for recompression			9.12	34.3	3.27	152		
Gas turbines for electrical generation			1.45	33.9	6.10	152		
Flare - pilot	151	11.3	0.00274	26.9	0.441	149	22,800	22.4
Emergency flare (acid gas, low pressure)	20,800	24.4	78.5	25.1				
Emergency flare								
Emergency fire water pump IC engines	22.5	20.3	0.00451	75.0	0.000185	151	22.6	20.2
Emergency fire water pump IC engines								

Table 8-19. Natural Gas Processing Emissions, continued

Source	CO_2 N		CH_4		$_2$O		CO_2e	
	Emissions (tonnes/yr)	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**
Vented Sources	**299,200**	**21.2**	**2,810**	**77.3**	**N/A**		**358,100**	**21.8**
Dehydration vents (also has Kimray pump emissions)	185	108	1,740	108	N/A		36,700	108
Gas processing /sour gas treating	298,900	21.2	0.00540	119	N/A		298,900	21.2
Condensate storage tanks	No GHG emissions							
LPG marine loading	No GHG emissions							
C_5+ marine loading	No GHG emissions							
Propane marine loading	No GHG emissions							
Butane marine loading	No GHG emissions							
Compressor starts	Included in maintenance blowdowns							
Compressor blowdowns	Included in maintenance blowdowns							
Processing maintenance blowdowns	65.1	101	1,070	101	N/A		22,500	101
Fire suppression	0.136	5.00	N/A		N/A		0.136	5.00

Table 8-19. Natural Gas Processing Emissions, continued

Source	**CO_2 N**		**CH_4**		**$_2$O**		**CO_2e**	
	Emissions (tonnes/yr)	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**
Fugitive Sources	**N/A**		**128**	**75.4**	**N/A**		**32,200**	**11.1**
Equipment leaks	N/A		128	75.4	N/A		2,690	75.4
Industrial refrigeration	N/A		N/A		N/A		29,500	10.0
Indirect Sources	**No Indirect GHG Emissions**							
None	No indirect GHG emissions							
TOTAL - Direct[b]	**695,100**	**10.8**	**3,030**	**71.7**	**10.8**	**98.4**	**791,100**	**11.1**
TOTAL - Indirect	**No Indirect GHG Emissions**							
TOTAL[b]	**695,100**	**10.8**	**3,030**	**71.7**	**10.8**	**98.4**	**791,100**	**11.1**

Footnotes:

[a] Uncertainty is at a 95% confidence interval.

[b] Totals may not sum due to independent rounding.

Note: the values shown above are for example only. They do not reflect average operations.

8.1.4 Production Gathering Compressor Station

Facility Description: A 3,400-hp gathering compressor station, located in Oklahoma, operates four reciprocating compressors. Eighty 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 used to operate the compressors is provided in Table 8-20. The heating value for the produced gas is 1,155 Btu/scf, assuming an uncertainty of ±4%, based on engineering judgment.

Table 8-20. Gas Composition for Production Gathering Compressor Station

Gas Compound	Produced Gas Mole %	Uncertainty[a] (±%)
CO_2	0.8	4
N_2	1.8	4
CH_4	83	4
C_2H_6	8	4
C_3H_8	5	4
C_4H_{10}	1	4
C_5H_{12}	0.3	4
C6+	0.1	4

Footnote:

[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

Note: the values shown above are for example only. They do not reflect average operations.

Details on the emission sources associated with this facility are provided in Tables 8-21 and 8-22. Equipment at the site that do not have GHG emissions are also included in these tables.

The remainder of this subsection presents emission calculations for the sources identified in Tables 8-21 and 8-22 and a summary of facility emissions (presented at the end of this subsection).

Table 8-21. Production Gathering Compressor Station Combustion and Vented Sources

Source	Fuel/Refrigerant Type	No. of Units	Uncertainty[a] (±%)	Total Capacity (all units combined)	Uncertainty[a] (±%)	Activity Factor (all units combined)	Uncertainty[a] (±%)
Combustion Sources							
4 stroke, rich burn engines	Natural Gas	3	0	2200 hp; 10,600[b] Btu/hp-hr	15; 5	612,850×10^6 Btu/yr – continuous operation	15.8
4 stroke, lean burn engine	Natural Gas	1	0	1200 hp; 10,600[b] Btu/hp-hr	15; 5	111,427×10^6 Btu/yr – continuous operation	15.8
Vehicle	Gasoline	1 car	0	N/A		975 gal/yr	10
Vented Sources							
Pneumatic devices	N/A	40	5	N/A		40 pneumatic devices	5
Compressor starts	N/A	4	0	N/A		4 compressors	0
Compressor blowdowns	N/A	4	0	N/A		4 compressors	0
PRVs	N/A	14	0	N/A		14 PRVs	0
Pipeline: Blowdowns	N/A	80 miles	10	N/A		80 miles of pipeline	10
Fugitive Sources							
Equipment Leaks	N/A	N/A		N/A		See Table 8-22	
Pipeline: Leakage Oxidation	N/A	80 miles	10	N/A		80 miles of pipeline	10
Vehicle refrigerant	R-134a	1 car	0	N/A		Unknown	
Indirect Sources							
Electricity purchased	N/A	N/A		N/A		680 MW-hr/yr	2

Footnotes:

[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

[b] Engine Btu/hp-hr based on test data or manufacturer's data.

Note: the values shown above are for example only. They do not reflect average operations.

Table 8-22. Production Gathering Compressor Station Fugitive Emission Sources

Component	Service	Average Component Count	Uncertainty[a] (±%)
Valves	Gas	675	75
Control valves	Gas	30	75
Connectors	Gas	3,000	75
Open-ended lines	Gas	60	75
Compressor seals	Gas	15	75
Pressure relief valves	Gas	15	75

Footnote:
[a] Uncertainty is based on engineering judgment at a 95% confidence interval.
Note: the values shown above are for example only. They do not reflect average operations.

Stationary Combustion Devices – CO_2 Emissions

The first step in calculating CO_2 emissions is to calculate the total volume of fuel combusted (V) at the facility. This calculation is shown below.

$$V = \begin{bmatrix} (3 \text{ rich burn} \times \frac{2{,}200 \text{ hp}}{\text{engine}} \times \frac{10{,}600 \text{ Btu}}{\text{hp-hr}} \times \frac{8{,}760 \text{ hr}}{\text{yr}}) \\ + (1 \text{ lean burn} \times \frac{1{,}200 \text{ hp}}{\text{engine}} \times \frac{10{,}600 \text{ Btu}}{\text{hp-hr}} \times \frac{8{,}760 \text{ hr}}{\text{yr}}) \end{bmatrix} \times \frac{\text{scf}}{1{,}155 \text{ Btu}} = 627 \times 10^6 \text{ scf/yr}$$

Carbon dioxide emissions from equipment burning natural gas are calculated using the gas composition approach provided in Section 4.3. First, the fuel analysis is converted from a molar basis to a mass basis, as shown in Exhibits 3.3 and 3.4. The molecular weight of the mixture is calculated below, using Equation 3-8:

$$MW_{\text{Mixture}} = \begin{bmatrix} (0.8\times44.01)+(1.8\times28.01)+(83\times16.04) \\ +(8\times30.07)+(5\times44.10)+(1\times58.12) \\ +(0.3\times72.15)+(0.1\times86.18) \end{bmatrix} \div 100 = 19.66 \text{ lb/mole}$$

The individual weight percents are then calculated by rearranging Equation 3-7. The calculation is shown as follows for CH_4.

$$\text{Wt.\%}_{CH_4} = \frac{83\text{ lbmole }CH_4}{100\text{ lbmole mixture}} \times \frac{\left(\dfrac{16.04\text{ lb }CH_4}{\text{lbmole }CH_4}\right)}{\left(\dfrac{19.66\text{ lb mixture}}{\text{lbmole mixture}}\right)} = \frac{0.6670\text{ lb }CH_4}{\text{lb mixture}} = 67.70\text{ wt. \% }CH_4$$

To calculate emissions, the carbon contents of the fuel compositions provided in Table 8-20 are calculated. The first step is to calculate the carbon content of the individual components, using Equation 4-9. The carbon content calculation for an individual component is shown below for C_2H_6.

$$\text{Wt\% }C_{C_2H_6} = \frac{12.01\text{ lb C}}{\text{lbmole C}} \times \frac{2\text{ lbmoles C}}{\text{lbmole }C_2H_6} \times \frac{\text{lbmole }C_2H_6}{30.07\text{ lb }C_2H_6} \times 100\% = 79.9\%\text{ C}$$

After the calculation has been performed for all constituents, the carbon content for the mixture is calculated using Equation 4-10, as shown below (for produced gas).

$$\text{Wt\%C}_{\text{Mixture}} = \frac{1}{100} \times \sum_{i=1}^{\#\text{ components}} \left(\text{Wt\%}_i \times \text{Wt\%C}_i\right)$$

$$\text{Wt\% C}_{\text{Mixture}} = \frac{1}{100} \times \begin{bmatrix} (1.79\times 28.3)+(2.56\times 0)+(68.70\times 74.9)+(12.23\times 79.9) \\ +(11.21\times 81.7)+(2.96\times 82.7)+(1.10\times 83.2)+(0.44\times 83.6) \end{bmatrix}$$
$$= 73.85\text{ Wt\% C} = 0.7385\text{ lb C/lb fuel}$$

Completing the calculations for the field fuel gas analysis results in the fuel mixture molecular weight and carbon content below.

Compound	Mole %	MW	Wt% (Calculated)	Uncertainty[a] (±%)	Compound Carbon Content (wt%C)	Mixture Carbon Content (wt%C)	Uncertainty[a] (±%)
CO_2	0.8	44.01	1.79	4.88	28.3	0.489	4.88
N_2	1.8	28.01	2.56	4.88	0	0	NA
CH_4	83.0	16.04	67.70	4.88	74.9	50.7	4.88
C_2H_6	8.0	30.07	12.23	4.88	79.9	9.78	4.88
C_3H_8	5.0	44.10	11.21	4.88	81.7	9.16	4.88
C_4H_{10}	1.0	58.12	2.96	4.88	82.7	2.44	4.88
C_5H_{12}	0.3	72.15	1.10	4.88	83.2	0.916	4.88
C6+	0.1	86.18	0.44	4.88	83.6	0.367	4.88
Fuel Mixture	**100**	**19.66 ±2.79%[a]**	**100.0**			**73.85**	**3.47**

Footnote:

[a] Uncertainty is at a 95% confidence interval.

Carbon dioxide emissions can then be calculated using a mass balance approach. Emissions are calculated below.

$$E_{CO_2} = \frac{627\times10^6 \text{scf}}{\text{yr}} \times \frac{\text{lbmole fuel}}{379.3 \text{ scf fuel}} \times \frac{19.66 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.7385 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}}$$

$$\times \frac{\text{lbmole } CO_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 39{,}900 \text{ tonnes } CO_2/\text{yr}}$$

Stationary Combustion Devices – CH_4, N_2O, and CO_2e Emissions

Combustion emission factors for natural gas-fired engines are provided in Table 4-9, assuming an uncertainty of ±25% for CH_4 and ±150% for N_2O, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Methane and N_2O emissions are calculated below, by equipment type. Because CO_2 emissions are calculated by fuel type, CO_2e emissions are also calculated by fuel type.

4 stroke, rich burn engines:

$$E_{CH_4} = 3 \text{ units} \times \frac{2{,}200 \text{ hp}}{\text{unit}} \times \frac{10{,}600 \text{ Btu}}{\text{hp-hr}} \times \frac{8{,}760 \text{ hr}}{\text{yr}} \times \frac{0.00010 \text{ tonne } CH_4}{10^6 \text{ Btu}}$$

$$\underline{E_{CH_4} = 61.3 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{N_2O} = 3 \text{ units} \times \frac{2{,}200 \text{ hp}}{\text{unit}} \times \frac{10{,}600 \text{ Btu}}{\text{hp-hr}} \times \frac{8{,}760 \text{ hr}}{\text{yr}} \times \frac{9.50\times10^{-8} \text{ tonne } N_2O}{10^6 \text{ Btu}}$$

$$\underline{E_{N_2O} = 0.0582 \text{ tonnes } N_2O/\text{yr}}$$

4 stroke, lean burn engine:

$$E_{CH_4} = 1\text{ unit} \times \frac{1{,}200\text{ hp}}{\text{unit}} \times \frac{10{,}600\text{ Btu}}{\text{hp-hr}} \times \frac{8{,}760\text{ hr}}{\text{yr}} \times \frac{0.00057\text{ tonne CH}_4}{10^6\text{ Btu}}$$

$$\underline{E_{CH_4} = 63.5\text{ tonnes CH}_4\text{/yr}}$$

$$E_{N_2O} = 1\text{ unit} \times \frac{1{,}200\text{ hp}}{\text{unit}} \times \frac{10{,}600\text{ Btu}}{\text{hp-hr}} \times \frac{8{,}760\text{ hr}}{\text{yr}} \times \frac{9.50 \times 10^{-8}\text{ tonne N}_2\text{O}}{10^6\text{ Btu}}$$

$$\underline{E_{N_2O} = 0.0106\text{ tonnes N}_2\text{O/yr}}$$

Natural gas-fired engines CO_2e emission:

$$E_{CO_2e} = 39{,}900\text{ tonne CO}_2\text{/yr} + \left(\frac{61.3\text{ tonne CH}_4}{\text{yr}} + \frac{63.5\text{ tonne CH}_4}{\text{yr}}\right) \times \frac{21\text{ tonne CO}_2\text{e}}{\text{tonne CH}_4}$$
$$+ \left(\frac{0.0582\text{ tonne N}_2\text{O}}{\text{yr}} + \frac{0.0106\text{ tonne N}_2\text{O}}{\text{yr}}\right) \times \frac{310\text{ tonne CO}_2\text{e}}{\text{tonne N}_2\text{O}}$$

$$\underline{E_{CO_2e} = 42{,}500\text{ tonne CO}_2\text{e/yr}}$$

Combustion Sources – Vehicles

Carbon dioxide emissions are calculated using the CO_2 emission factor for motor gasoline presented in Table 4-3, assuming an uncertainty of ±10%, based on engineering judgment. Because the emission factor for CO_2 is in terms of energy input, the volume of fuel consumed (gallons) is converted to energy input (Btu) using the heating value of gasoline provided in Table 3-8, assuming an uncertainty of ±5%, based on engineering judgment. The emission factors for CH_4 and N_2O are provided in Table 4-17. The uncertainty for both CH_4 and N_2O emission factors is assumed to be ±150%, based on engineering judgment. It is assumed that the car is a Tier 1 light duty vehicle. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Emissions are calculated below.

$$V = \frac{975\text{ gal}}{\text{yr}} \times \frac{\text{bbl}}{42\text{ gal}} \times \frac{5.25\ \times 10^6\text{ Btu}}{\text{bbl}} = 121 \times 10^6\text{ Btu/yr}$$

$$E_{CO_2} = \frac{121\times10^6 \text{ Btu}}{\text{yr}} \times \frac{0.0709 \text{ tonne } CO_2}{1\times10^6 \text{ Btu}}$$

$$\underline{E_{CO_2} = 8.64 \text{ tonne } CO_2/\text{yr}}$$

$$E_{CH_4} = \frac{975 \text{ gal}}{\text{yr}} \times \frac{4.5\times10^{-4} \text{tonne } CH_4}{\text{Mgal}} \times \frac{\text{Mgal}}{1000 \text{ gal}}$$

$$\underline{E_{CH_4} = 0.000439 \text{ tonne } CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{975 \text{ gal}}{\text{yr}} \times \frac{6.1\times10^{-4} \text{tonne } N_2O}{\text{Mgal}} \times \frac{\text{Mgal}}{1000 \text{ gal}}$$

$$\underline{E_{N_2O} = 0.000595 \text{ tonne } N_2O/\text{yr}}$$

$$E_{CO_2e} = \frac{8.64 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{0.000439 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right) + \left(\frac{0.000595 \text{ tonne } N_2O}{\text{yr}} \times \frac{310 \text{ tonne } CO_2e}{\text{tonne } N_2O}\right)$$

$$\underline{E_{CO_2e} = 8.83 \text{ tonne } CO_2e/\text{yr}}$$

Vented Sources – Pneumatic Devices

Methane emissions from pneumatic device vents are estimated using the "Production" segment average CH_4 emission factor and uncertainty presented in Table 5-15. Methane emissions are adjusted based on the facility CH_4 content. The default CH_4 content and associated uncertainty are provided in Table E-4. Carbon dioxide emissions are calculated by using a ratio of the facility CH_4 and CO_2 contents. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs.

$$E_{CH_4} = (40 \text{ pneumatic devices}) \times \frac{2.415 \text{ tonne } CH_4}{\text{device - yr}} \times \frac{0.830 \text{ tonne mole } CH_4 (\text{facility})}{0.788 \text{ tonne mole } CH_4 (\text{default})}$$

$$\underline{E_{CH_4} = 102 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = (40 \text{ pneumatic devices}) \times \frac{2.415 \text{ tonne } CH_4}{\text{device - yr}} \times \frac{\text{tonne mole } CH_4}{16.04 \text{ tonne } CH_4} \times \frac{0.830 \text{ tonne mole } CH_4 (\text{facility})}{0.788 \text{ tonne mole } CH_4 (\text{default})} \times \frac{\text{tonne mole gas}}{0.830 \text{ tonne mole } CH_4} \times \frac{0.0080 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2} = 2.69 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CO_2e} = \frac{2.69 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{102 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4} \right)$$

$$\underline{E_{CO_2e} = 2{,}140 \text{ tonne } CO_2e/\text{yr}}$$

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 and uncertainties presented in Table 5-23. Note that the emission factors are on an equipment basis, not a per-event basis. Methane emissions are adjusted based on the facility CH_4 content. The default CH_4 content and associated uncertainty are provided in Table E-4. Carbon dioxide emissions are calculated by using a ratio of the facility CH_4 and CO_2 contents. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Maintenance emissions are calculated below, by activity.

Compressor starts:

$$E_{CH_4} = (4 \text{ compressors}) \times \frac{0.1620 \text{ tonne } CH_4}{\text{compressor - yr}} \times \frac{0.830 \text{ tonne mole } CH_4 (\text{facility})}{0.788 \text{ tonne mole } CH_4 (\text{default})}$$

$$\underline{E_{CH_4} = 0.683 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = (4\text{ compressors}) \times \frac{0.1620\text{ tonne }CH_4}{\text{compressor-yr}} \times \frac{0.830\text{ tonne mole }CH_4\left(\text{facility}\right)}{0.788\text{ tonne mole }CH_4\left(\text{default}\right)}$$
$$\times \frac{\text{tonne mole gas}}{0.830\text{ tonne mole }CH_4} \times \frac{0.0080\text{ tonne mole }CO_2}{\text{tonne mole gas}} \times \frac{\text{tonne mole }CH_4}{16.04\text{ tonne }CH_4} \times \frac{44.01\text{ tonne }CO_2}{\text{tonne mole }CO_2}$$

$$\underline{E_{CO_2} = 0.00963\text{ tonnes }CO_2/\text{yr}}$$

$$E_{CO_2e} = \frac{0.00963\text{ tonne }CO_2}{\text{yr}} + \left(\frac{0.683\text{ tonne }CH_4}{\text{yr}} \times \frac{21\text{ tonne }CO_2e}{\text{tonne }CH_4}\right)$$

$$\underline{E_{CO_2e} = 14.3\text{ tonne }CO_2e/\text{yr}}$$

Compressor blowdowns:

$$E_{CH_4} = (4\text{ compressors}) \times \frac{0.07239\text{ tonne }CH_4}{\text{compressor - yr}} \times \frac{0.830\text{ tonne mole }CH_4\left(\text{facility}\right)}{0.788\text{ tonne mole }CH_4\left(\text{default}\right)}$$

$$\underline{E_{CH_4} = 0.305\text{ tonnes }CH_4/\text{yr}}$$

$$E_{CO_2} = (4\text{ compressors}) \times \frac{0.07239\text{ tonne }CH_4}{\text{compressor - yr}} \times \frac{\text{tonne mole }CH_4}{16.04\text{ tonne }CH_4} \times \frac{0.830\text{ tonne mole }CH_4\left(\text{facility}\right)}{0.788\text{ tonne mole }CH_4\left(\text{default}\right)}$$
$$\times \frac{\text{tonne mole gas}}{0.830\text{ tonne mole }CH_4} \times \frac{0.0080\text{ tonne mole }CO_2}{\text{tonne mole gas}} \times \frac{44.01\text{ tonne }CO_2}{\text{tonne mole }CO_2}$$

$$\underline{E_{CO_2} = 0.00293\text{ tonnes }CO_2/\text{yr}}$$

$$E_{CO_2e} = \frac{0.00293\text{ tonne }CO_2}{\text{yr}} + \left(\frac{0.305\text{ tonne }CH_4}{\text{yr}} \times \frac{21\text{ tonne }CO_2e}{\text{tonne }CH_4}\right)$$

$$\underline{E_{CO_2e} = 6.41\text{ tonne }CO_2e/\text{yr}}$$

Pipeline blowdown venting:

$$E_{CH_4} = (80\text{ miles}) \times \frac{0.00593\text{ tonne }CH_4}{\text{mile - yr}} \times \frac{0.830\text{ tonne mole }CH_4\left(\text{facility}\right)}{0.788\text{ tonne mole }CH_4\left(\text{default}\right)}$$

$$\underline{E_{CH_4} = 0.500\text{ tonnes }CH_4/\text{yr}}$$

$$E_{CO_2} = (80\ \text{miles}) \times \frac{0.00593\ \text{tonne}\ CH_4}{\text{mile - yr}} \times \frac{\text{tonne mole}\ CH_4}{16.04\ \text{tonne}\ CH_4} \times \frac{0.830\ \text{tonne mole}\ CH_4\,(\text{facility})}{0.788\ \text{tonne mole}\ CH_4\,(\text{default})}$$
$$\times \frac{\text{tonne mole gas}}{0.830\ \text{tonne mole}\ CH_4} \times \frac{0.0080\ \text{tonne mole}\ CO_2}{\text{tonne mole gas}} \times \frac{44.01\ \text{tonne}\ CO_2}{\text{tonne mole}\ CO_2}$$

$$\underline{E_{CO_2} = 0.00246\ \text{tonnes}\ CO_2/\text{yr}}$$

$$E_{CO_2e} = \frac{0.00246\ \text{tonne}\ CO_2}{\text{yr}} + \left(\frac{0.500\ \text{tonne}\ CH_4}{\text{yr}} \times \frac{21\ \text{tonne}\ CO_2e}{\text{tonne}\ CH_4}\right)$$

$$\underline{E_{CO_2e} = 10.5\ \text{tonne}\ CO_2e/\text{yr}}$$

Vented Sources: Other Releases

Methane emissions from PRVs are estimated using an emission factor and uncertainty presented in Table 5-24. Methane emissions are adjusted based on the facility CH_4 content. The default CH_4 content and associated uncertainty are provided in Table E-4. Carbon dioxide emissions are calculated by using a ratio of the facility CH_4 and CO_2 contents. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. PRV emissions are calculated below:

$$E_{CH_4} = (14\ \text{PRVs}) \times \frac{0.00065\ \text{tonne}\ CH_4}{\text{PRV - yr}} \times \frac{0.830\ \text{tonne mole}\ CH_4\,(\text{facility})}{0.788\ \text{tonne mole}\ CH_4\,(\text{default})}$$

$$\underline{E_{CH_4} = 0.00959\ \text{tonnes}\ CH_4/\text{yr}}$$

$$E_{CO_2} = (14\ \text{PRVs}) \times \frac{0.00065\ \text{tonne}\ CH_4}{\text{PRV-yr}} \times \frac{\text{tonne mole}\ CH_4}{16.04\ \text{tonne}\ CH_4} \times \frac{0.830\ \text{tonne mole}\ CH_4\,(\text{facility})}{0.788\ \text{tonne mole}\ CH_4\,(\text{default})}$$
$$\times \frac{\text{tonne mole gas}}{0.830\ \text{tonne mole}\ CH_4} \times \frac{0.0080\ \text{tonne mole}\ CO_2}{\text{tonne mole gas}} \times \frac{44.01\ \text{tonne}\ CO_2}{\text{tonne mole}\ CO_2}$$

$$\underline{E_{CO_2} = 0.0000700\ \text{tonnes}\ CO_2/\text{yr}}$$

$$E_{CO_2e} = \frac{0.0000700 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{0.00959 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4} \right)$$

$$\underline{E_{CO_2e} = 0.201 \text{ tonne } CO_2e/\text{yr}}$$

Fugitive Sources: Equipment Leaks

Table 8-23 provides fugitive component emission factors associated with the gathering compressor facility, taken from the corresponding average component emission factors based on the EPA average oil and natural gas production emission factors given in Table 6-12. The factor for compressor seals and pressure relief valves is taken from the "Others" component type.

Table 8-23. Production Gathering Compressor Station Fugitive Emission Factors

Component	Service	Component EF, tonnes TOC/comp./hr	Uncertainty[a] (±%)
Valves	Gas	4.5E-06	100
Control valves	Gas	4.5E-06	100
Connectors	Gas	2.0E-07	100
Open-ended lines	Gas	2.0E-06	100
Compressor seals	Gas	8.8E-06	100
PRVs	Gas	8.8E-06	100

Footnote:
[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

The TOC emission factors are converted to a CH_4 and CO_2 basis. Using Equation 6-9, CH_4 and CO_2 emissions are calculated for each component by multiplying the component emission factor by the component count, the annual hours of operation (8,760 hours/year), and the weight fraction of either CH_4 or CO_2 (calculated under "Stationary Combustion – CO_2 Emissions"). Total fugitive emissions are equal to the sum of each of the component emissions. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs.

An example calculation for connectors is shown as follows.

$$E_{CH_4} = (3,000 \text{ connectors}) \times \frac{2.00 \times 10^{-7} \text{ tonne TOC}}{\text{connectors-hr}} \times \frac{8{,}760 \text{ hr}}{\text{yr}} \times \frac{0.677 \text{ tonne CH}_4}{\text{tonne TOC}}$$

$$\underline{E_{CH_4} = 3.56 \text{ tonnes CH}_4\text{/yr}}$$

$$E_{CO_2} = (3,000 \text{ connector}) \times \frac{2.00 \times 10^{-7} \text{ tonne TOC}}{\text{connector-hr}} \times \frac{8{,}760 \text{ hr}}{\text{yr}} \times \frac{0.0179 \text{ tonne CO}_2}{\text{tonne TOC}}$$

$$\underline{E_{CO_2} = 0.0941 \text{ tonnes CO}_2\text{/yr}}$$

$$E_{CO_2e} = \frac{0.0941 \text{ tonne CO}_2}{\text{yr}} + \left(\frac{3.56 \text{ tonne CH}_4}{\text{yr}} \times \frac{21 \text{ tonne CO}_2\text{e}}{\text{tonne CH}_4}\right)$$

$$\underline{E_{CO_2e} = 74.8 \text{ tonne CO}_2\text{e/yr}}$$

Completing the calculations for the rest of the components results in the emissions shown in Table 8-24.

Table 8-24. Production Gathering Compressor Station Fugitive Emissions

Component	Service	CH_4 Emissions, tonnes CH_4/yr	Uncertainty[a] (±%)	CO_2 Emissions, tonnes CH_4/yr	Uncertainty[a] (±%)	CO_2e Emissions, tonnes CO_2/yr	Uncertainty[a] (±%)
Valves	Gas	18.8	120	0.498	120	396	120
Connectors	Gas	3.56	125	0.0941	125	74.8	125
Open-ended lines	Gas	0.712	125	0.0188	125	15.0	125
Other	Gas	1.57	88.5	0.0414	88.5	32.9	88.3
Total[b]		**24.7**	**93.5**	**0.652**	**93.5**	**518**	**93.4**

Footnotes:

[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

[b] Totals may not sum due to independent rounding.

Note: the values shown above are for example only. They do not reflect average operations.

Pipeline leaks also result in fugitive emissions. Emission factors for these sources are provided in Table 6-4. Methane emissions are adjusted based on the facility CH_4 content. Default CH_4 and CO_2 contents and their associated uncertainties are provided in Table E-4. Carbon dioxide emissions are calculated by using a ratio of the facility CH_4 and CO_2 contents. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Emissions for pipeline leaks are calculated as follows.

$$E_{CH_4} = (80 \text{ miles}) \times \frac{4.28\times10^{-5} \text{tonne } CH_4}{\text{mi - hr}} \times \frac{8{,}760 \text{ hr}}{\text{year}} \times \frac{0.830 \text{ tonne mole } CH_4 \left(\text{facility}\right)}{0.788 \text{ tonne mole } CH_4 \left(\text{default}\right)}$$

$$\underline{E_{CH_4} = 31.6 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2\text{, oxidation}} = (80 \text{ miles}) \times \frac{4.38\times10^{-6} \text{tonne } CO_2}{\text{mi-hr}} \times \frac{8{,}760 \text{ hr}}{\text{year}} \times \frac{0.00800 \text{ tonne mole } CO_2 \left(\text{facility}\right)}{0.0378 \text{ tonne mole } CO_2 \left(\text{default}\right)}$$

$$\underline{E_{CO_2\text{, oxidation}} = 0.650 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CO_2\text{, leaks}} = (80 \text{ miles}) \times \frac{5.84\times10^{-6} \text{ tonne } CO_2}{\text{mi-hr}} \times \frac{8{,}760 \text{ hr}}{\text{year}} \times \frac{0.00800 \text{ tonne mole } CO_2 \left(\text{facility}\right)}{0.0378 \text{ tonne mole } CO_2 \left(\text{default}\right)}$$

$$\underline{E_{CO_2\text{, leaks}} = 0.866 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CO_2e\text{, leaks}} = \frac{0.650 \text{ tonne } CO_2}{\text{yr}} + \frac{0.866 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{31.6 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right)$$

$$\underline{E_{CO_2e\text{, leaks}} = 665 \text{ tonne } CO_2e/\text{yr}}$$

Fugitive Sources: Vehicle Refrigerant

As the actual vehicle refrigerant capacity is unknown, the capacity is assumed to be the midpoint of the range presented in Table 6-25 for mobile air conditioning, assuming an uncertainty of ±100%, based on engineering judgment. The percentage of capacity emitted per year is also taken from Table 6-25, assuming an uncertainty of ±50%, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWP provided in Table 3-1 (for HFC-134a). There are no uncertainties for any of the GWPs. The calculations for fleet vehicle refrigeration are shown as follows.

$$E_{\text{R-134a}} = 1 \text{ vehicle} \times \frac{1.0 \text{ kg}}{\text{vehicle}} \times 20\% \times \frac{\text{tonne R-134a}}{1000 \text{ kg}}$$

$$\underline{E_{\text{R-134a}} = 0.000200 \text{ tonne R-134a/yr}}$$

$$E_{CO_2e} = \frac{0.000200 \text{ tonne R-134a}}{\text{yr}} \times \frac{1300 \text{ tonne } CO_2e}{\text{tonne R-134a}}$$

$$\underline{E_{CO_2e} = 0.260 \text{ tonne } CO_2e\text{/yr}}$$

Indirect Sources - Electricity Consumption

Emissions associated with the electricity purchased by the facility are calculated using emission factors in Table 7-2 for eGRID subregion SPP South. The uncertainties for the emission factors are assumed to be ±10% for CO_2 and ±100% for CH_4 and N_2O, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs.

$$E_{CO_2} = \frac{680 \text{ MW-hr}}{\text{yr}} \times \frac{0.752 \text{ tonne } CO_2}{\text{MW-hr}}$$

$$\underline{E_{CO_2} = 511 \text{ tonnes } CO_2\text{/yr}}$$

$$E_{CH_4} = \frac{680 \text{ MW-hr}}{\text{yr}} \times \frac{1.13 \times 10^{-5} \text{ tonne } CH_4}{\text{MW-hr}}$$

$$\underline{E_{CH_4} = 0.00768 \text{ tonnes } CH_4\text{/yr}}$$

$$E_{N_2O} = \frac{680 \text{ MW-hr}}{\text{yr}} \times \frac{1.03 \times 10^{-5} \text{ tonne } N_2O}{\text{MW-hr}}$$

$$\underline{E_{N_2O} = 0.00700 \text{ tonnes } N_2O\text{/yr}}$$

$$E_{CO_2e} = \frac{511 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{0.00768 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right) + \left(\frac{0.00700 \text{ tonne } N_2O}{\text{yr}} \times \frac{310 \text{ tonne } CO_2e}{\text{tonne } N_2O}\right)$$

$$\underline{E_{CO_2e} = 514 \text{ tonne } CO_2e/\text{yr}}$$

Facility Summary

Total emissions for this facility are summarized in Table 8-25. A summary of the emissions for this facility is given in Figure 8-4.

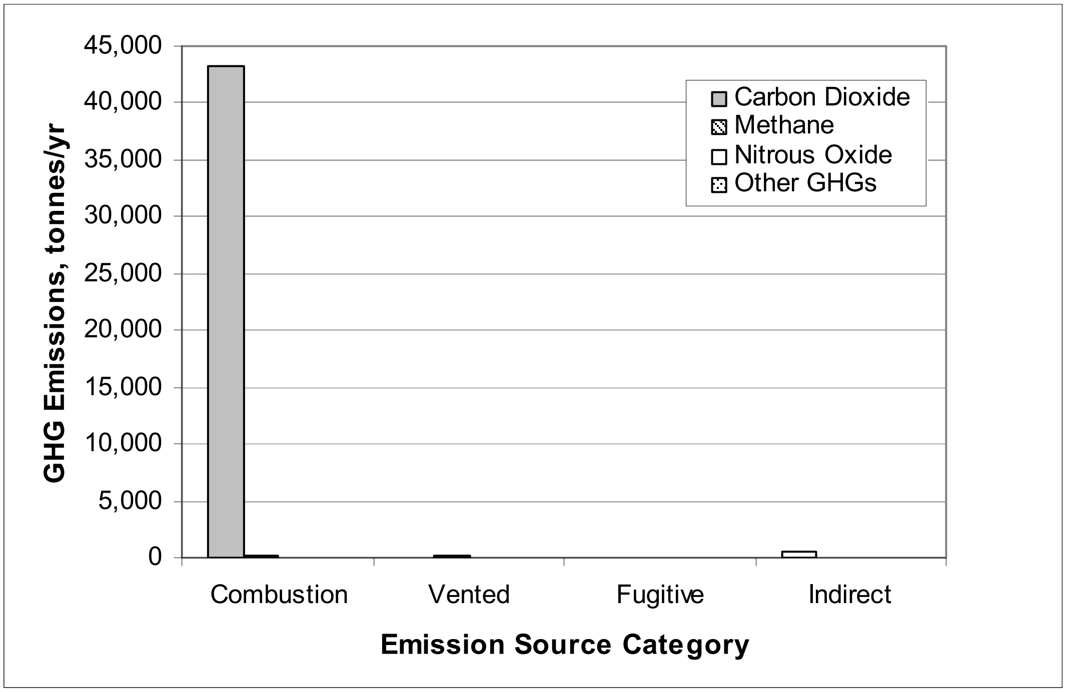


Figure 8-4. Production Gathering Compressor Station Summary of Emissions

Table 8-25. Production Gathering Compressor Station Emissions

	CO_2 N		**CH_4**		**$_2$O**		**CO_2e**	
Source	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**
Combustion Sources	**39,900**	**14.7**	**125**	**20.9**	**0.0694**	**129**	**42,500**	**13.9**
4 stroke, rich burn engines	39,900	14.7	61.3	29.6	0.0582	151	42,500	13.9
4 stroke, lean burn engine			63.5	29.6	0.0106	151		
Vehicle	8.64	15.0	0.000439	150	0.000595	150	8.83	15.0
Vented Sources	**2.71**	**49.9**	**103**	**49.5**	**N/A**		**2,170**	**49.4**
Pneumatic devices	2.69	50.2	102	50.2	N/A		2,140	50.1
Compressor starts	0.00963	190	0.683	190	N/A		14.3	190
Compressor blowdowns	0.00293	179	0.305	179	N/A		6.4	179
PRVs	0.0000700	310	0.00959	310	N/A		0.201	310
Pipeline:	0.00246	41.3	0.500	41.3	N/A		10.5	41.3
Blowdowns								
Fugitive Sources	**2.71**	**59.2**	**56.2**	**75.9**	**N/A**		**1,180**	**75.7**
Equipment leaks	0.652	93.5	24.7	93.5	N/A		518	93.4
Pipeline:								
Leakage	0.866	119	31.6	114	N/A		665	113
Oxidation	0.650	71.7						
Vehicle refrigerant	N/A		N/A		N/A		0.260	112
Indirect Sources	**511**	**10.2**	**0.00768**	**100**	**0.00700**	**100**	**514**	**10.2**
Electricity purchased	511	10.2	0.00768	100	0.00700	100	514	10.2
TOTAL - Direct[b]	**39,900**	**14.7**	**284**	**25.1**	**0.0694**	**129**	**45,900**	**13.3**
TOTAL - Indirect[b]	**511**	**10.2**	**0.00768**	**100**	**0.00700**	**100**	**514**	**10.2**
TOTAL[b]	**40,424**	**14.5**	**284**	**25.1**	**0.0764**	**117**	**46,400**	**13.1**

Footnotes:

[a] Uncertainty is at a 95% confidence interval.

[b] Totals may not sum due to independent rounding.

Note: the values shown above are for example only. They do not reflect average operations.

8.2 Transportation

8.2.1 Transmission/Distribution

Facility Description: A company operates 312 miles of natural gas transmission pipelines in Montana.

Operations: The company imports 26,108,159 kWh of electricity from the grid annually. Sulfur hexafluoride is used for pipeline leak detection. The pipeline natural gas contains 94.8 mole% CH_4 and 1.7 mole% $CO_{2,}$ assuming an uncertainty of ±4%, based on engineering judgment.

Emission sources associated with the facility operations are summarized in Table 8-26. Equipment at the site that do not have GHG emissions are also included in Table 8-26.

Table 8-26. Transmission/Distribution Emission Sources

Source	Fuel/Refrigerant Type	No. of Units	Uncertainty[a] (±%)	Total Capacity (all units combined)	Uncertainty[a] (±%)	Activity Factor (total)	Uncertainty[a] (±%)
Combustion Sources							
Electric compressors	N/A	N/A		N/A		N/A	
Venting Sources							
Pneumatic devices	N/A	N/A		N/A		N/A	
Compressor station blowdowns	N/A	1 station	0	N/A		N/A	
Miscellaneous	N/A	1 station	0	N/A		N/A	
Transmission pipeline blowdowns	N/A	1 station	0	N/A		312 miles	10
Pipeline leaks	SF_6	N/A		N/A		312 miles	10
Pipeline leak detection	SF_6	N/A		N/A		5,725 lb SF_6/yr	10
Indirect Sources							
Electricity	N/A	N/A		N/A		26,108,159 kWh	2

Footnote:

[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

Note: the values shown above are for example only. They do not reflect average operations.

The remainder of this subsection presents emission calculations for the sources identified in Table 8-26 and a summary of facility emissions (presented at the end of this subsection).

Combustion Sources – Compressors

The pipeline compressors are electric so there are no combustion emissions.

Vented Sources – Pneumatic Devices

The pneumatic devices operated on are instrument air driven so there are no vented emissions.

Vented Sources - Maintenance/Turnaround Emissions

Methane emissions from compressor blowdowns, compressor station blowdowns, miscellaneous, and gas transmission pipelines venting/blowdowns are estimated using the emission factors and uncertainties presented in Table 5-26. Miscellaneous vented emissions include M&R, odorizer, drips, sampling, pigging, and dehydrators. Methane emissions are adjusted based on the facility CH_4 content. The default CH_4 content and associated uncertainty are provided in Table E-4. Carbon dioxide emissions are calculated by using a ratio of the facility CH_4 and CO_2 contents. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Maintenance emission calculations are shown below, by activity type.

Compressor blowdowns:

$$E_{CH_4} = (1\text{ station}) \times \frac{47.14\text{ tonne CH}_4}{\text{station-yr}} \times \frac{0.948\text{ tonne mole CH}_4\text{ (facility)}}{0.934\text{ tonne mole CH}_4\text{ (default)}}$$

$$\underline{E_{CH_4} = 47.9\text{ tonnes CH}_4/\text{yr}}$$

$$E_{CO_2} = (1\text{ station}) \times \frac{47.14\text{ tonne CH}_4}{\text{station-yr}} \times \frac{\text{tonne mole CH}_4}{16.04\text{ tonne CH}_4} \times \frac{0.948\text{ tonne mole CH}_4\text{ (facility)}}{0.934\text{ tonne mole CH}_4\text{ (default)}}$$
$$\times \frac{\text{tonne mole gas}}{0.948\text{ tonne mole CH}_4} \times \frac{0.017\text{ tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01\text{ tonne CO}_2}{\text{tonne mole CO}_2}$$

$$\underline{E_{CO_2} = 2.35\text{ tonnes CO}_2/\text{yr}}$$

$$E_{CO_2e} = \frac{2.35 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{47.9 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right)$$

$$\underline{E_{CO_2e} = 1{,}010 \text{ tonne } CO_2e/\text{yr}}$$

Compressor station blowdowns:

$$E_{CH_4} = (1 \text{ station}) \times \frac{101.7 \text{ tonne } CH_4}{\text{station - yr}} \times \frac{0.948 \text{ tonne mole } CH_4 \text{ (facility)}}{0.934 \text{ tonne mole } CH_4 \text{ (default)}}$$

$$\underline{E_{CH_4} = 103 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = (1 \text{ station}) \times \frac{101.7 \text{ tonne } CH_4}{\text{station - yr}} \times \frac{\text{tonne mole } CH_4}{16.04 \text{ tonne } CH_4} \times \frac{0.948 \text{ tonne mole } CH_4 \text{ (facility)}}{0.934 \text{ tonne mole } CH_4 \text{ (default)}}$$
$$\times \frac{\text{tonne mole gas}}{0.948 \text{ tonne mole } CH_4} \times \frac{0.017 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2} = 5.08 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CO_2e} = \frac{5.08 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{103 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right)$$

$$\underline{E_{CO_2e} = 2{,}170 \text{ tonne } CO_2e/\text{yr}}$$

Miscellaneous:

$$E_{CH_4} = (1 \text{ station}) \times \frac{21.75 \text{ tonne } CH_4}{\text{station - yr}} \times \frac{0.948 \text{ tonne mole } CH_4 \text{ (facility)}}{0.934 \text{ tonne mole } CH_4 \text{ (default)}}$$

$$\underline{E_{CH_4} = 22.1 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = (1 \text{ station}) \times \frac{21.75 \text{ tonne } CH_4}{\text{station - yr}} \times \frac{\text{tonne mole } CH_4}{16.04 \text{ tonne } CH_4} \times \frac{0.948 \text{ tonne mole } CH_4 \text{ (facility)}}{0.934 \text{ tonne mole } CH_4 \text{ (default)}}$$
$$\times \frac{\text{tonne mole gas}}{0.948 \text{ tonne mole } CH_4} \times \frac{0.017 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2} = 1.09 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CO_2e} = \frac{1.09 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{22.1 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4} \right)$$

$$\underline{E_{CO_2e} = 465 \text{ tonne } CO_2e/\text{yr}}$$

Gas transmission pipelines venting/blowdowns:

$$E_{CH_4} = (312 \text{ mile}) \times \frac{0.7855 \text{ tonne } CH_4}{\text{mile-yr}} \times \frac{0.948 \text{ tonne mole } CH_4 \text{ (facility)}}{0.934 \text{ tonne mole } CH_4 \text{ (default)}}$$

$$\underline{E_{CH_4} = 249 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = (312 \text{ mile}) \times \frac{0.7855 \text{ tonne } CH_4}{\text{mile-yr}} \times \frac{\text{tonne mole } CH_4}{16.04 \text{ tonne } CH_4} \times \frac{0.948 \text{ tonne mole } CH_4 \text{ (facility)}}{0.934 \text{ tonne mole } CH_4 \text{ (default)}}$$
$$\times \frac{\text{tonne mole gas}}{0.948 \text{ tonne mole } CH_4} \times \frac{0.017 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44.01 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

$$\underline{E_{CO_2} = 12.2 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CO_2e} = \frac{12.2 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{249 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4} \right)$$

$$\underline{E_{CO_2e} = 5,240 \text{ tonne } CO_2e/\text{yr}}$$

Fugitive Sources: Compressor Station Fugitives

Methane emissions from compressor station fugitives are estimated using the emission factor and uncertainty presented in Table 6-6. Methane emissions are adjusted based on the facility CH_4 content. The default CH_4 content and associated uncertainty are provided in Table E-4. Carbon dioxide emissions are calculated by using a ratio of the facility CH_4 and CO_2 contents. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Compressor station fugitive emissions are calculated as follows.

$$E_{CH_4} = (1\ \text{station}) \times \frac{7.02\times10^{-3}\ \text{tonne CH}_4}{\text{station-hr}} \times \frac{8760\ \text{hr}}{\text{yr}} \times \frac{0.948\ \text{tonne mole CH}_4\ \text{(facility)}}{0.934\ \text{tonne mole CH}_4\ \text{(default)}}$$

$$\underline{E_{CH_4} = 62.4\ \text{tonnes CH}_4/\text{yr}}$$

$$E_{CO_2} = (1\ \text{station}) \times \frac{7.02\times10^{-3}\ \text{tonne CH}_4}{\text{station-hr}} \times \frac{8760\ \text{hr}}{\text{yr}} \times \frac{\text{tonne mole CH}_4}{16.04\ \text{tonne CH}_4} \times \frac{0.948\ \text{tonne mole CH}_4\ \text{(facility)}}{0.934\ \text{tonne mole CH}_4\ \text{(default)}}$$
$$\times \frac{\text{tonne mole gas}}{0.948\ \text{tonne mole CH}_4} \times \frac{0.017\ \text{tonne mole CO}_2}{\text{tonne mole gas}} \times \frac{44.01\ \text{tonne CO}_2}{\text{tonne mole CO}_2}$$

$$\underline{E_{CO_2} = 3.07\ \text{tonnes CO}_2/\text{yr}}$$

$$E_{CO_2e} = \frac{3.07\ \text{tonne CO}_2}{\text{yr}} + \left(\frac{62.3\ \text{tonne CH}_4}{\text{yr}} \times \frac{21\ \text{tonne CO}_2\text{e}}{\text{tonne CH}_4}\right)$$

$$\underline{E_{CO_2e} = 1{,}300\ \text{tonne CO}_2\text{e/yr}}$$

Fugitive Sources – Pipeline Leaks

Emissions from fugitive leaks of pipelines transporting natural gas include CH_4 and CO_2 (from both pipeline leaks and oxidation). Pipeline fugitive leak emissions are calculated using emission factors and uncertainties presented in Table 6-6. Methane and CO_2 emissions are adjusted based on the facility CH_4 and CO_2 content. Default CH_4 and CO_2 contents, and associated uncertainties are provided in Table E-4. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Emissions from pipeline leaks are calculated below.

$$E_{CO_2} = 312\ \text{miles} \times \left(\frac{3.93\times10^{-7}\ \text{tonne CO}_2\text{-Ox}}{\text{mi-hr}} + \frac{7.88\times10^{-8}\ \text{tonne CO}_2\text{-PL}}{\text{mi-hr}} \times \frac{8760\ \text{hr}}{\text{yr}} \times \frac{0.0170\ \text{tonne mole CO}_2\ \text{(facility)}}{0.0200\ \text{tonne mole CO}_2\ \text{(default)}}\right)$$

$$\underline{E_{CO_2} = 1.10\ \text{tonne CO}_2/\text{yr}}$$

$$E_{CH_4} = 312 \text{ miles} \times \frac{1.20\times10^{-6} \text{ tonne } CH_4}{\text{mi-hr}} \times \frac{8760 \text{ hr}}{\text{yr}} \times \frac{0.948 \text{ tonne mole } CH_4 \text{ (facility)}}{0.934 \text{ tonne mole } CH_4 \text{ (default)}}$$

$$\underline{E_{CH_4} = 3.33 \text{ tonne } CH_4/\text{yr}}$$

$$E_{CO_2e} = \frac{1.10 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{3.33 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right)$$

$$\underline{E_{CO_2e} = 71.0 \text{ tonne } CO_2e/\text{yr}}$$

Fugitive Sources: Pipeline Leak Detection

Sulfur hexafluoride is used to detect pipeline leaks for this facility. It is assumed that all of the SF_6 gas escapes during the detection process. Carbon dioxide equivalent emissions are calculated using the GWP provided in Table 3-1. There are no uncertainties for any of the GWPs. Emissions from leak detection are calculated below.

$$E_{SF_6} = \frac{5{,}725 \text{ lb } SF_6}{\text{yr}} \times \frac{\text{tonne } SF_6}{2204.62 \text{ lb } SF_6}$$

$$\underline{E_{SF_6} = 2.60 \text{ tonne } SF_6/\text{yr}}$$

$$E_{CO_2e} = \frac{2.60 \text{ tonne } SF_6}{\text{yr}} \times \frac{23{,}900 \text{ tonne } CO_2e}{\text{tonne } SF_6}$$

$$\underline{E_{CO_2e} = 62{,}100 \text{ tonne } CO_2e/\text{yr}}$$

Indirect Sources: Electricity

As shown in Figure 7-2, two eGRID subregions serve Montana: WECC Northwest and MRO West. As electricity is purchased from an unknown subregion, the higher set of emission factors (between WECC Northwest and MRO West) will be applied as a simplified assumption of the emissions estimate. According to Table 7-2, emission factors are highest for MRO West. The uncertainties for the emission factors are assumed to be ±10% for CO_2 and ±100% for CH_4 and

N_2O, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Emissions are calculated below.

$$E_{CO_2} = 26{,}108{,}159 \text{ kWh} \times \frac{\text{MWh}}{1000 \text{ kWh}} \times \frac{0.826 \text{ tonne } CO_2}{\text{MWh}}$$

$$\underline{E_{CO_2} = 21{,}600 \text{ tonne } CO_2/\text{yr}}$$

$$E_{CH_4} = 26{,}108{,}159 \text{ kWh} \times \frac{\text{MWh}}{1000 \text{ kWh}} \times \frac{1.27 \times 10^{-5} \text{ tonne } CH_4}{\text{MWh}}$$

$$\underline{E_{CH_4} = 0.332 \text{ tonne } CH_4/\text{yr}}$$

$$E_{N_2O} = 26{,}108{,}159 \text{ kWh} \times \frac{\text{MWh}}{1000 \text{ kWh}} \times \frac{1.39 \times 10^{-5} \text{ tonne } N_2O}{\text{MWh}}$$

$$\underline{E_{N_2O} = 0.363 \text{ tonne } N_2O/\text{yr}}$$

$$E_{CO_2e} = \frac{21{,}600 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{0.332 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right) + \left(\frac{0.363 \text{ tonne } N_2O}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } N_2O}\right)$$

$$\underline{E_{CO_2e} = 21{,}700 \text{ tonne } CO_2e/\text{yr}}$$

Facility Summary

Total emissions for this company are summarized in Table 8-27. A summary of the emissions for this company is shown in Figure 8-5.

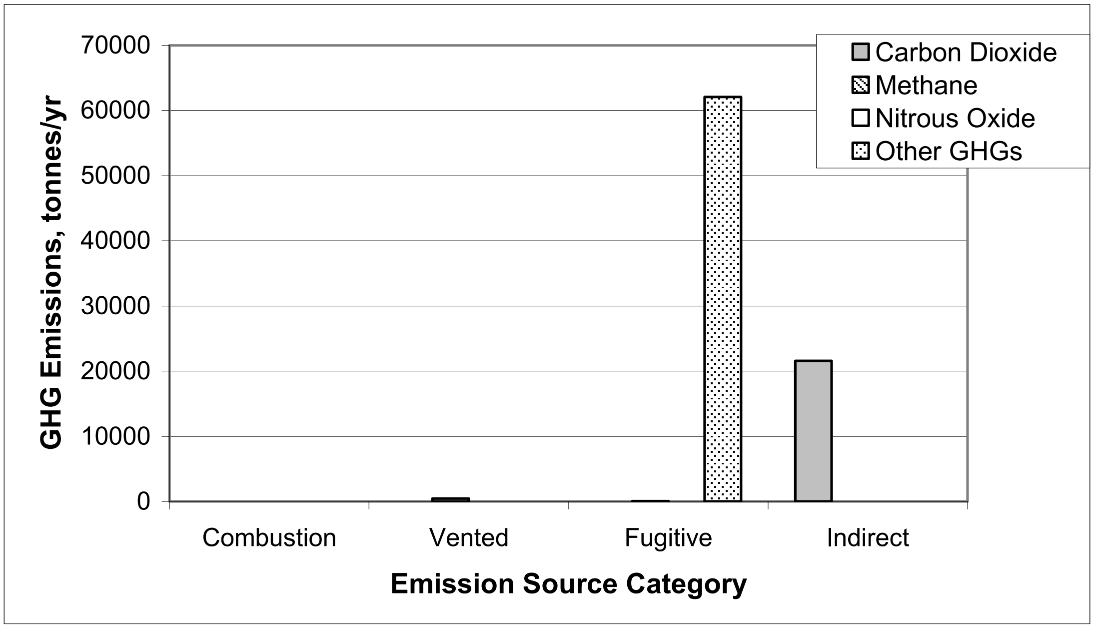


Figure 8-5. Transmission/Distribution Summary of Emissions

Table 8-27. Transmission/Distribution Emissions

Source	CO$_2$ N		CH$_4$		$_2$O		CO$_2$e	
	Emissions (tonnes/yr)	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**
Combustion Sources	**No Combustion GHG Emissions**							
Electric compressors	No GHG Emissions							
Venting Sources	**20.8**	**54.3**	**422**	**54.6**	**N/A**		**8,880**	**54.4**
Pneumatic devices	No GHG Emissions							
Compressor blowdowns	2.35	168	47.9	168	N/A		1,010	168
Compressor station blowdowns	5.08	64.4	103	64.4	N/A		2,170	64.3
Miscellaneous	1.09	43.5	22.1	43.5	N/A		465	43.4
Transmission pipeline blowdown	12.2	81.7	249	82.3	N/A		5,240	82.1
Fugitive Sources	**4.17**	**94.3**	**65.7**	**120**	**N/A**		**63,400**	**14.4**
Compressor station fugitives	3.07	126	62.4	126	N/A		1,310	126
Pipeline leaks	1.10	61.2	3.33	95.3	N/A		71.0	93.9
Pipeline leak detection	N/A		N/A		N/A		62,100	14.1
Indirect Sources	**21,600**	**10.2**	**0.332**	**100**	**0.363**	**100**	**21,700**	**10.2**
Electricity	21,600	10.2	0.332	100	0.363	100	21,700	10.2
TOTAL - Direct[b]	**24.9**	**47.9**	**488**	**49.9**	**N/A**		**72,300**	**14.0**
TOTAL - Indirect[b]	**21,600**	**10.2**	**0.332**	**100**	**0.363**	**100**	**21,700**	**10.2**
TOTAL[b]	**21,600**	**10.2**	**488**	**49.8**	**0.363**	**100**	**94,000**	**11.1**

Footnotes:

[a] Uncertainty is at a 95% confidence interval.

[b] Totals may not sum due to independent rounding.

Note: the values shown above are for example only. They do not reflect average operations.

8.2.2 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 8-28 and 8-29. Equipment at the site that do not have GHG emissions are also included in these tables.

Table 8-28. Marketing Terminal Emission Sources

Source	Fuel/Refrigerant	Unit Capacity (per unit)	Uncertainty[a] (±%)	Average Operation	Uncertainty[a] (±%)	Annual Activity Factor	Uncertainty[a] (±%)
Combustion Sources							
Heater – natural gas	Natural Gas	N/A		N/A		235,000 $\times 10^6$ Btu/yr	15
Heater – diesel	Diesel	4,500 bbl/yr	5	N/A		26,235x10^6 Btu/yr	7.07
Auxiliary fire pump	Diesel	12.5 gal/hr	5	200 hr/yr	10	2,500 gal/yr	7.07
Auxiliary generator	Diesel	22 gal/hr	5	200 hr/yr	10	4,400 gal/yr	7.07
Road tanker transport	Diesel	300,000 gal/yr	5	N/A		41,643 x10^6 Btu/yr	7.07
Vapor combustor unit (VCU)	Pilot: Propane	N/A		N/A		6000 gal/yr	5
	Gasoline Loading	N/A		N/A		200 gal/yr	15
	Diesel Loading	N/A		N/A		120 gal/yr	15
	Jet Fuel Loading	N/A		N/A		2 gal/yr	15
Facility vehicle (model year 2007)	Gasoline	N/A		N/A		11,750 mi/yr	15
Vented Sources							
Internal floating roof (IFR) storage tanks	Gasoline	N/A		N/A		700×10^6 gal/yr	15
	Diesel	N/A		N/A		450×10^6 gal/yr	15
	Jet Fuel	N/A		N/A		10×10^6 gal/yr	15
Rail car/tank car loading[b]	Gasoline	N/A		N/A		200×10^6 gal/yr	15
	Diesel	N/A		N/A		120×10^6 gal/yr	15
	Jet Fuel	N/A		N/A		2×10^6 gal/yr	15
Rail car/tank car transit	Gasoline	N/A		N/A		200×10^6 gal/yr	15
	Diesel	N/A		N/A		120×10^6 gal/yr	15
	Jet Fuel	N/A		N/A		2×10^6 gal/yr	15
Fire suppression	Purple K	N/A		N/A		N/A	
Fugitive Sources							
Equipment leaks	Refined Products	See Table 8-29		N/A		N/A	
Vehicle refrigerant	R-22	N/A		N/A		N/A	
Indirect Sources							
Electricity purchased and consumed	N/A	N/A		N/A		1100 MW-hr/yr	2
Steam purchased and consumed	N/A	N/A		N/A		$97,600\times10^9$ J/yr	5

Footnotes:

Totals may not sum due to independent rounding.

[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

[b] Loading emissions are controlled by the vapor combustor unit (VCU). Gasoline loading is submerged loading with vapor balance service; diesel and jet fuel loading are submerged loading, dedicated normal service.

Note: the values shown above are for example only. They do not reflect average operations.

Table 8-29. Marketing Terminal Fugitive Emission Sources

Component	Service	Average Component Count	Uncertainty[a] (±%)
Valves	Gas	30	75
	Light liquid	390	75
	Heavy liquid	50	75
Pump seals	Light liquid	25	75
	Heavy liquid	3	75
Connectors/flanges	Gas	190	75
	Light liquid	3,100	75
	Heavy liquid	350	75
Open-ended lines	Gas	4	75
	Light liquid	20	75
	Heavy liquid	3	75
PRVs	Gas	1	75
	Light liquid	2	75

Footnote:
[a] Uncertainty is based on engineering judgment at a 95% confidence interval.
Note: the values shown above are for example only. They do not reflect average operations.

The remainder of this subsection presents emission calculations for the sources identified in Table 8-28 and 8-29 and a summary of facility emissions (presented at the end of this subsection).

Stationary Combustion Devices – CO_2 Emissions

Carbon dioxide emissions from natural gas and diesel combustion are calculated using the fuel-based emission factors provided in Table 4-3, assuming an uncertainty of ±10% for both fuels, based on engineering judgment. Because the fuel-based emission factors are on a energy input basis, the volume of diesel fuel consumed is converted to energy input using the heating value for diesel presented in Table 3-8, assuming an uncertainty of ±4%, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Emissions are calculated below, by equipment type.

Natural gas heater:

$$E_{CO_2} = \frac{235,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.0531 \text{ tonnes } CO_2}{10^6 \text{ Btu}}$$

$$\underline{E_{CO_2} = 12,500 \text{ tonnes } CO_2 \text{ / yr}}$$

Diesel heater:

$$\text{V} = \frac{4{,}500 \text{ bbl}}{\text{yr}} \times \frac{5.83 \times 10^6 \text{ Btu}}{\text{bbl}} = 26{,}235 \times 10^6 \text{ Btu/yr}$$

$$\text{E}_{\text{CO}_2} = \frac{26{,}235 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.0732 \text{ tonnes CO}_2}{10^6 \text{ Btu}}$$

$$\underline{\text{E}_{\text{CO}_2} = 1{,}920 \text{ tonnes CO}_2 \text{ / yr}}$$

Diesel Engines:

$$\text{E}_{\text{CO}_2} = \left(\frac{12.5 + 22 \text{ gal}}{\text{hr}}\right) \times \frac{200 \text{ hr}}{\text{yr}} \times \frac{\text{bbl}}{42 \text{ gal}} \times \frac{5.83 \times 10^6 \text{ Btu}}{\text{bbl}} \times \frac{0.0732 \text{ tonne CO}_2}{10^6 \text{ Btu}}$$

$$\underline{\text{E}_{\text{CO}_2} = 70.1 \text{ tonnes CO}_2\text{/yr}}$$

Stationary Combustion Devices – CH_4, N_2O, and CO_2e Emissions

Combustion emission factors for natural gas and diesel equipment are provided in Table 4-7 for controlled boilers and heaters and Table 4-9 for engines. An uncertainty of ±25% was assumed for all CH_4 emission factors and an uncertainty of ±150% was assumed for all N_2O emission factors, based on engineering judgment. Table 4-9 provides an assumed CH_4 content of 9 wt% to convert from TOC emissions if the exhaust composition is unknown. An uncertainty of ±100% was assumed for the TOC to CH_4 conversion, based on engineering judgment. Because the engine emission factors are on a energy input basis, the volume of diesel fuel consumed is converted to energy input using the heating value for diesel presented in Table 3-8, assuming an uncertainty of ±4%, based on engineering judgment. The diesel heater and diesel engine N_2O emission factor is taken from Table 4-5 for "Gas/Diesel Oil" in the absence of an equipment-specific emission factor, assuming an uncertainty of ±150%, based on engineering judgment. The volume of diesel combusted is converted to a mass of diesel combusted using the density of diesel provided in Table 3-8, assuming an uncertainty of ±5%, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Emissions are calculated as follows, by equipment type.

Natural gas heater:

$$E_{CH_4} = \frac{235,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{1.0 \times 10^{-6} \text{ tonnes CH}_4}{10^6 \text{ Btu}}$$

$$\underline{E_{CH_4} = 0.235 \text{ tonnes CH}_4 \text{ / yr}}$$

$$E_{N_2O} = \frac{235,000 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{2.80 \times 10^{-7} \text{ tonnes N}_2\text{O}}{10^6 \text{ Btu}}$$

$$\underline{E_{N_2O} = 0.0658 \text{ tonnes N}_2\text{O / yr}}$$

$$E_{CO_2e} = \frac{12{,}500 \text{ tonne CO}_2}{\text{yr}} + \left(\frac{0.235 \text{ tonne CH}_4}{\text{yr}} \times \frac{21 \text{ tonne CO}_2\text{e}}{\text{tonne CH}_4} \right) + \left(\frac{0.0658 \text{ tonne N}_2\text{O}}{\text{yr}} \times \frac{310 \text{ tonne CO}_2\text{e}}{\text{tonne N}_2\text{O}} \right)$$

$$\underline{E_{CO_2e} = 12{,}500 \text{ tonne CO}_2\text{e/yr}}$$

Diesel heater:

$$E_{CH_4} = \frac{4,500 \text{ bbl}}{\text{yr}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{7.07 \text{ lb}}{\text{gal}} \times \frac{\text{tonne}}{2{,}204.62 \text{ lb}} \times \frac{7.8 \times 10^{-6} \text{ tonnes CH}_4}{\text{tonnes diesel}}$$

$$\underline{E_{CH_4} = 0.00473 \text{ tonnes CH}_4 \text{ / yr}}$$

$$E_{N_2O} = \frac{4,500 \text{ bbl}}{\text{yr}} \times \frac{5.83 \times 10^6 \text{ Btu}}{\text{bbl}} \times \frac{6.01 \times 10^{-7} \text{ tonnes N}_2\text{O}}{10^6 \text{ Btu}}$$

$$\underline{E_{N_2O} = 0.0158 \text{ tonnes N}_2\text{O / yr}}$$

$$E_{CO_2e} = \frac{1{,}920 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{0.00473 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right) + \left(\frac{0.0158 \text{ tonne } N_2O}{\text{yr}} \times \frac{310 \text{ tonne } CO_2e}{\text{tonne } N_2O}\right)$$

$$\underline{E_{CO_2e} = 1{,}930 \text{ tonne } CO_2e/\text{yr}}$$

Diesel engines:

$$E_{CH_4} = \left(\frac{12.5 + 22 \text{ gal}}{\text{hr}}\right) \times \frac{200 \text{ hr}}{\text{yr}} \times \frac{\text{bbl}}{42 \text{ gal}} \times \frac{5.83 \times 10^6 \text{ Btu}}{\text{bbl}} \times \frac{0.00016 \text{ tonne TOC}}{10^6 \text{ Btu}} \times \frac{0.09 \text{ tonne } CH_4}{\text{tonne TOC}}$$

$$\underline{E_{CH_4} = 0.0138 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{N_2O} = \left(\frac{12.5 + 22 \text{ gal}}{\text{hr}}\right) \times \frac{200 \text{ hr}}{\text{yr}} \times \frac{\text{bbl}}{42 \text{ gal}} \times \frac{5.83 \times 10^6 \text{ Btu}}{\text{bbl}} \times \frac{6.01 \times 10^{-7} \text{ tonne } N_2O}{10^6 \text{ Btu}}$$

$$\underline{E_{N_2O} = 0.000576 \text{ tonnes } N_2O/\text{yr}}$$

$$E_{CO_2e} = \frac{70.1 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{0.0138 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right) + \left(\frac{0.000576 \text{ tonne } N_2O}{\text{yr}} \times \frac{310 \text{ tonne } CO_2e}{\text{tonne } N_2O}\right)$$

$$\underline{E_{CO_2e} = 70.6 \text{ tonne } CO_2e/\text{yr}}$$

Combustion Sources – Vapor Combustor Unit (VCU)

The loading rack emissions are controlled by a vapor combustor, which results in CO_2 emissions from combustion of the captured hydrocarbon vapors. Because the products being loaded are refined petroleum products that do not contain CH_4, there are no CH_4 emissions from the VCU.

Emissions from the combustion of loading vapors are calculated in multiple steps. First the captured hydrocarbons from the loading operation are estimated using the simplified TOC emission factors given in Table B-10, assuming an uncertainty of ±5%, based on engineering judgment. The emission factors are for submerged loading, vapor balance service for gasoline, and submerged loading, dedicated normal service for diesel and jet fuel. The captured hydrocarbons are calculated below, by fuel type.

Gasoline:

$$E_{\text{TOC-gas}} = \frac{200\times 10^6 \text{ gal}}{\text{yr}} \times \frac{3.71 \text{ tonne TOC}}{10^6 \text{ gal loaded}} = 742 \text{ tonnes TOC/yr}$$

Diesel:

$$E_{\text{TOC-diesel}} = \frac{120\times 10^6 \text{ gal}}{\text{yr}} \times \frac{0.0064 \text{ tonne TOC}}{10^6 \text{ gal loaded}} = 0.768 \text{ tonnes TOC/yr}$$

Jet Fuel:

$$E_{\text{TOC-jet fuel}} = \frac{2\times 10^6 \text{ gal}}{\text{yr}} \times \frac{0.0072 \text{ tonne TOC}}{10^6 \text{ gal loaded}} = 0.0144 \text{ tonnes TOC/yr}$$

Carbon dioxide emissions are then estimated using the carbon content of the fuels, provided in Table 3-8 (for liquid gasoline, diesel, and jet fuel), assuming an uncertainty of ±5% for all fuels, based on engineering judgment. Note that using the carbon content of liquid fuels instead of the carbon content of the vapor phase of the fuel is a simplifying assumption, recognizing that this will overestimate emissions. In reality, the carbon content of the vapor phase will be lighter than the carbon content of the liquid, due to the fact that fuel vapors contain lighter hydrocarbons, which are more able to volatilize. However, because the carbon content for the vapor phase of the loaded fuels is not available, the liquid phase carbon content is used instead. Carbon dioxide emissions are calculated as follows, by fuel type.

Gasoline:

$$E_{CO_2\text{-gas}} = \frac{742 \text{ tonnes TOC}}{\text{yr}} \times \frac{0.866 \text{ tonne C}}{\text{tonne TOC}} \times \frac{44.01 \text{ tonne } CO_2}{12.01 \text{ tonne C}}$$

$$\underline{E_{CO_2\text{-gas}} = 2{,}360 \text{ tonnes } CO_2/\text{yr}}$$

Diesel:

$$E_{CO_2\text{-diesel}} = \frac{0.768 \text{ tonnes TOC}}{\text{yr}} \times \frac{0.8634 \text{ tonne C}}{\text{tonne TOC}} \times \frac{44.01 \text{ tonne } CO_2}{12.01 \text{ tonne C}}$$

$$\underline{E_{CO_2\text{-diesel}} = 2.43 \text{ tonnes } CO_2/\text{yr}}$$

Jet Fuel:

$$E_{CO_2\text{-jet fuel}} = \frac{0.0144 \text{ tonnes TOC}}{\text{yr}} \times \frac{0.863 \text{ tonne C}}{\text{tonne TOC}} \times \frac{44.01 \text{ tonne } CO_2}{12.01 \text{ tonne C}}$$

$$\underline{E_{CO_2\text{-jet fuel}} = 0.0455 \text{ tonnes } CO_2/\text{yr}}$$

Pilot:

Carbon dioxide emissions from burning propane for the pilot are estimated using the liquid propane heating value from Table 3-8 and the CO_2 fuel basis emission factor from Table 4-3, assuming an uncertainty of ±5% for the heating value and ±10% for the CO_2 emission factor, both based on engineering judgment.

$$E_{CO_2\text{, pilot}} = \frac{6000 \text{ gal}}{\text{yr}} \times \frac{\text{bbl}}{42 \text{ gal}} \times \frac{3.82 \times 10^6 \text{ Btu}}{\text{bbl}} \times \frac{0.0631 \text{ tonne } CO_2}{10^6 \text{ Btu}}$$

$$\underline{E_{CO_2\text{, pilot}} = 34.4 \text{ tonnes } CO_2/\text{yr}}$$

Total CO_2 emissions from the VCU are equal to the sum of the CO_2 emissions from the loading rack vapors and the pilot. Thus, the total CO_2 emissions from the vapor combustor are:

$$E_{CO_2,\ Total} = 2{,}360 \text{ tonnes } CO_2/yr + 2.43 \text{ tonnes } CO_2/yr + 0.0455 \text{ tonnes } CO_2/yr + 34.4 \text{ tonnes } CO_2/yr$$

$$\underline{E_{CO_2,\ Total} = 2{,}390 \text{ tonnes } CO_2/yr}$$

Methane and N_2O emission factors for combustion of gasoline, diesel, and jet fuel are found in Table 4-5. An uncertainty of ±25% was assumed for all CH_4 emission factors and an uncertainty of ±150% was assumed for all N_2O emission factors, based on engineering judgment. Note that the factors in Table 4-5 are for combustion of a liquid fuel. As a result, the emission factors need to be converted for the combustion of the fuel vapors. The emission factors are converted from liquid combustion to vapor combustion using the heating value and density of natural gas (processed) provided in Table 3-8, assuming an uncertainty of ±5% for both, based on engineering judgment. Note that the more accurate way to convert from liquid combustion to vapor combustion would be to use the heating value and carbon content of the vapor phase of the specific fuels; however because these were not available, the properties of natural gas were used instead. The CH_4 and N_2O emission factors are derived below, by fuel type, along with the corresponding emissions.

Gasoline:

$$EF_{CH_4\text{-gas}} = \frac{3.01\times10^{-6} \text{ tonne } CH_4}{\text{MMBtu}} \times \frac{\text{MMBtu}}{10^6 \text{ Btu}} \times \frac{1{,}020 \text{ Btu}}{\text{ft}^3} \times \frac{\text{ft}^3}{0.042 \text{ lb}} \times \frac{2204.62 \text{ lb}}{\text{tonne TOC vapor}}$$
$$= 1.61\times10^{-4} \text{ tonne } CH_4/\text{tonne TOC vapor}$$

$$EF_{N_2O\text{-gas}} = \frac{6.01\times10^{-7} \text{ tonne } N_2O}{\text{MMBtu}} \times \frac{\text{MMBtu}}{10^6 \text{ Btu}} \times \frac{1{,}020 \text{ Btu}}{\text{ft}^3} \times \frac{\text{ft}^3}{0.042 \text{ lb}} \times \frac{2204.62 \text{ lb}}{\text{tonne TOC vapor}}$$
$$= 3.22\times10^{-5} \text{ tonne } N_2O/\text{tonne TOC vapor}$$

Applying these derived emission factors results in the following estimates of CH_4 and N_2O emissions.

$$E_{CH_4\text{-gas}} = \frac{1.61\times10^{-4} \text{ tonne } CH_4}{\text{tonne TOC vapor}} \times \frac{742 \text{ tonne TOC vapor}}{\text{yr}}$$

$$\underline{E_{CH_4\text{-gas}} = 0.120 \text{ tonne } CH_4/yr}$$

$$E_{N_2O\text{-gas}} = \frac{3.22\times10^{-5}\ \text{tonne N}_2\text{O}}{\text{tonne TOC vapor}} \times \frac{742\ \text{tonne TOC vapor}}{\text{yr}}$$

$$\underline{E_{N_2O\text{-gas}} = 0.0239\ \text{tonne CH}_4/\text{yr}}$$

Diesel:

$$EF_{CH_4\text{-diesel}} = \frac{3.01\times10^{-6}\ \text{tonne CH}_4}{\text{MMBtu}} \times \frac{\text{MMBtu}}{10^6\ \text{Btu}} \times \frac{1{,}020\ \text{Btu}}{\text{ft}^3} \times \frac{\text{ft}^3}{0.042\ \text{lb}} \times \frac{2204.62\ \text{lb}}{\text{tonne TOC vapor}}$$
$$= 1.61\times10^{-4}\ \text{tonne CH}_4/\text{tonne TOC vapor}$$

$$EF_{N_2O\text{-diesel}} = \frac{6.01\times10^{-7}\ \text{tonne N}_2\text{O}}{\text{MMBtu}} \times \frac{\text{MMBtu}}{10^6\ \text{Btu}} \times \frac{1{,}020\ \text{Btu}}{\text{ft}^3} \times \frac{\text{ft}^3}{0.042\ \text{lb}} \times \frac{2204.62\ \text{lb}}{\text{tonne TOC vapor}}$$
$$= 3.22\times10^{-5}\ \text{tonne N}_2\text{O/tonne TOC vapor}$$

Applying these derived emission factors results in the following estimates of CH_4 and N_2O emissions from diesel vapor combustion.

$$E_{CH_4\text{-diesel}} = \frac{1.61\times10^{-4}\ \text{tonne CH}_4}{\text{tonne TOC vapor}} \times \frac{0.768\ \text{tonne TOC vapor}}{\text{yr}}$$

$$\underline{E_{CH_4\text{-diesel}} = 0.000124\ \text{tonne CH}_4/\text{yr}}$$

$$E_{N_2O\text{-gas}} = \frac{3.22\times10^{-5}\ \text{tonne N}_2\text{O}}{\text{tonne TOC vapor}} \times \frac{0.768\ \text{tonne TOC vapor}}{\text{yr}}$$

$$\underline{E_{N_2O\text{-gas}} = 2.47\times10^{-5}\ \text{tonne CH}_4/\text{yr}}$$

Jet Fuel:

$$EF_{CH_4\text{-jet fuel}} = \frac{3.01\times10^{-6}\ \text{tonne CH}_4}{\text{MMBtu}} \times \frac{\text{MMBtu}}{10^6\ \text{Btu}} \times \frac{1{,}020\ \text{Btu}}{\text{ft}^3} \times \frac{\text{ft}^3}{0.042\ \text{lb}} \times \frac{2204.62\ \text{lb}}{\text{tonne TOC vapor}}$$
$$= 1.61\times10^{-4}\ \text{tonne CH}_4/\text{tonne TOC vapor}$$

$$EF_{N_2O\text{-jet fuel}} = \frac{6.01\times10^{-7}\ \text{tonne N}_2\text{O}}{\text{MMBtu}} \times \frac{\text{MMBtu}}{10^6\ \text{Btu}} \times \frac{1{,}020\ \text{Btu}}{\text{ft}^3} \times \frac{\text{ft}^3}{0.042\ \text{lb}} \times \frac{2204.62\ \text{lb}}{\text{tonne TOC vapor}}$$
$$= 3.22\times10^{-5}\ \text{tonne N}_2\text{O/tonne TOC vapor}$$

Applying these derived emission factors results in the following estimates of CH_4 and N_2O emissions from jet fuel vapor combustion.

$$E_{CH_4\text{-jet fuel}} = \frac{1.61\times10^{-4}\ \text{tonne CH}_4}{\text{tonne TOC vapor}} \times \frac{0.0144\ \text{tonne TOC vapor}}{\text{yr}}$$

$$\underline{E_{CH_4\text{-jet fuel}} = 2.32\times10^{-6}\ \text{tonne CH}_4/\text{yr}}$$

$$E_{N_2O\text{-jetfuel}} = \frac{3.22\times10^{-5}\ \text{tonne N}_2\text{O}}{\text{tonne TOC vapor}} \times \frac{0.0144\ \text{tonne TOC vapor}}{\text{yr}}$$

$$\underline{E_{N_2O\text{-jetfuel}} = 4.63\times10^{-7}\ \text{tonne CH}_4/\text{yr}}$$

Methane and N_2O emissions from the propane pilot are calculated using emissions factors from Table 4-7, for "industrial/commercial boilers", assuming an uncertainty of ±25% for CH_4 emissions and ±150% for N_2O emissions, based on engineering judgment.

Pilot:

$$E_{CH_4\text{-Pilot}} = \frac{6{,}000\ \text{gal}}{\text{yr}} \times \frac{9.1\times10^{-8}\ \text{tonnes CH}_4}{\text{gal}}$$

$$\underline{E_{CH_4\text{-Pilot}} = 0.000546\ \text{tonnes CH}_4/\text{yr}}$$

$$E_{N_2O\text{-Pilot}} = \frac{6{,}000\ \text{gal}}{\text{yr}} \times \frac{4.1\times10^{-7}\ \text{tonnes N}_2\text{O}}{\text{gal}}$$

$$\underline{E_{N_2O\text{-Pilot}} = 0.00246\ \text{tonnes N}_2\text{O/yr}}$$

Methane, N_2O, and CO_2e emissions:

Total CH_4 and N_2O emissions from the VCU are equal to the sum of the CH_4 or N_2O emissions from the loading rack vapors and the pilot. Thus, the total CH_4 and N_2O emissions from the VCU are:

$$E_{CH_4,Total} = 0.120 \text{ tonnes } CH_4/yr + 0.000124 \text{ tonnes } CH_4/yr + 2.32\times10^{-6} \text{ tonnes } CH_4/yr + 0.000546 \text{ tonnes } CH_4/yr$$

$$\underline{E_{CH_4,Total} = 0.120 \text{ tonnes } CH_4/yr}$$

$$E_{N_2O,\ Total} = 0.00246 \text{ tonnes } N_2O/yr + 0.0239 \text{ tonnes } N_2O/yr + 2.47\times10^{-5} \text{ tonnes } N_2O/yr + 4.63\times10^{-7} \text{ tonnes } N_2O/yr$$

$$\underline{E_{N_2O,\ Total} = 0.0264 \text{ tonnes } N_2O/yr}$$

Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs.

$$E_{CO_2e,\ Total} = \frac{2{,}390 \text{ tonne } CO_2}{yr} + \left(\frac{0.120 \text{ tonne } CH_4}{yr} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right) + \left(\frac{0.0264 \text{ tonne } N_2O}{yr} \times \frac{310 \text{ tonne } CO_2e}{\text{tonne } N_2O}\right)$$

$$\underline{E_{CO_2e,\ Total} = 2{,}400 \text{ tonne } CO_2e/yr}$$

Combustion Sources – Road Tankers

Carbon dioxide emissions from road tankers are calculated using a fuel based factor from Table 4-3, assuming an uncertainty of ±10%, based on engineering judgment. Methane and N_2O emissions from road tankers are estimated using the emission factor for the heavy-duty diesel operated road tanker with moderate control provided in Table 4-17. An uncertainty of ±25% was assumed for all CH_4 emission factors and an uncertainty of ±150% was assumed for all N_2O emission factors, based on engineering judgment. Because the CO_2 emission factor is on a heat basis, the volume of fuel consumed is converted to energy input using the heating value for diesel provided in Table 3-8, assuming an uncertainty of ±5%, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Emissions from road tankers are calculated as follows.

$$V = \frac{300{,}000 \text{ gal}}{\text{yr}} \times \frac{\text{bbl}}{42 \text{ gal}} \times \frac{5.83 \times 10^{6} \text{ Btu}}{\text{bbl}} = 4.164 \times 10^{10} \text{ Btu/yr}$$

$$E_{CO_2} = \frac{4.164 \times 10^{10} \text{ Btu}}{\text{yr}} \times \frac{0.0732 \text{ tonne } CO_2}{10^{6} \text{ Btu}}$$

$$\underline{E_{CO_2} = 3{,}050 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CH_4} = \frac{300{,}000 \text{ gal}}{\text{yr}} \times \frac{5.3 \times 10^{-4} \text{ tonne } CH_4}{1000 \text{ gal}}$$

$$\underline{E_{CH_4} = 0.159 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{300{,}000 \text{ gal}}{\text{yr}} \times \frac{3.1 \times 10^{-4} \text{ tonne } N_2O}{1000 \text{ gal}}$$

$$\underline{E_{N_2O} = 0.093 \text{ tonnes } N_2O/\text{yr}}$$

$$E_{CO_2e} = \frac{3{,}050 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{0.159 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right) + \left(\frac{0.093 \text{ tonne } N_2O}{\text{yr}} \times \frac{310 \text{ tonne } CO_2e}{\text{tonne } N_2O}\right)$$

$$\underline{E_{CO_2e} = 3{,}080 \text{ tonne } CO_2e/\text{yr}}$$

Combustion Sources – Facility Vehicle Emissions

The facility vehicle emissions are estimated assuming the vehicle is a gasoline light truck. Carbon dioxide emissions are calculated using the fuel-based emission factor presented in Table 4-3, assuming an uncertainty of ±10%, based on engineering judgment. Because the emission factor is on a energy input basis, the distance traveled is converted to energy input using the fuel economy factor presented in Table 4-13 and the heating value of gasoline provided in Table 3-8, assuming an uncertainty of ±5% for both the fuel economy and heating value, based on engineering judgment. Because CH_4 and N_2O emission factors are not available for model year 2007 vehicles,

CH_4 and N_2O emissions are calculated using the model year 2005 emission factors presented in Table A-6. An uncertainty of ±150% was assumed for CH_4 and N_2O emission factors, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in

Table 3-1. There are no uncertainties for any of the GWPs. Emissions are calculated below.

$$V_{CO_2} = \frac{11{,}750 \text{ mi}}{\text{yr-truck}} \times \frac{\text{gal}}{14 \text{ mi}} \times \frac{\text{bbl}}{42 \text{ gal}} \times \frac{5.25 \ \times 10^6 \text{ Btu}}{\text{bbl}} = 105 \times 10^6 \text{ Btu/yr-truck}$$

$$E_{CO_2} = \frac{105 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.0709 \text{ tonne } CO_2}{1 \times 10^6 \text{ Btu}}$$

$$\underline{E_{CO_2} = 7.44 \text{ tonne } CO_2/\text{yr}}$$

$$E_{CH_4} = \frac{11{,}750 \text{ mi}}{\text{yr}} \times \frac{1.57\text{E-}08 \text{ tonne } CH_4}{\text{mi}}$$

$$\underline{E_{CH_4} = 0.000184 \text{ tonne } CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{11{,}750 \text{ mi}}{\text{yr}} \times \frac{1.01\text{E-}08 \text{ tonne } N_2O}{\text{mi}}$$

$$\underline{E_{N_2O} = 0.000119 \text{ tonne } N_2O/\text{yr}}$$

$$E_{CO_2e} = \frac{7.44 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{0.000184 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4} \right) + \left(\frac{0.000119 \text{ tonne } N_2O}{\text{yr}} \times \frac{310 \text{ tonne } CO_2e}{\text{tonne } N_2O} \right)$$

$$\underline{E_{CO_2e} = 7.48 \text{ tonne } CO_2e/\text{yr}}$$

Vented Sources – Storage Tanks

The facility storage tanks contain gasoline, diesel, and jet fuel. Because these fuels are refined petroleum products, they do not contain CH_4 or CO_2. Therefore, there are no CH_4 or CO_2 emissions from these tanks.

Vented Sources – Loading and Transit Operations

Emissions from loading operations are controlled by the VCU. Emissions resulting from the combustion from this unit are estimated under "Combustion Sources – Vapor Combustion Unit (VCU)."

The fuel types transported in association with this facility are gasoline, diesel, and jet fuel. Because these fuels are refined petroleum products, they do not contain CH_4 or CO_2. Therefore, there are no CH_4 or CO_2 emissions from transport (or other handling) of these materials.

Vented Sources – Fire Suppression

The fire suppression system uses Purple K. Purple K is a dry powder fire suppressant, which is not a GHG. Therefore, there are no GHG emissions from the use of Purple K.

Fugitive Sources – Equipment Leaks

Table 8-29 provides fugitive component counts associated with the marketing terminal equipment. The equipment at this facility handles refined petroleum products (gasoline, diesel, and jet fuel). Because these fuels are refined petroleum products, they do not contain CH_4 or CO_2. Therefore, there are no CH_4 or CO_2 emissions from equipment leaks at this facility.

Fugitive Sources – Vehicle Refrigerant

The vehicles at this facility utilize R-22 for mobile air conditioning. R-22 is not considered a GHG in accordance with UNFCCC guidelines. Therefore, there are no GHG emissions from vehicle refrigeration at this facility.

Indirect Sources – Electricity Consumption

Emissions associated with the electricity purchased by the facility are calculated using emission factors in Table 7-2 for eGRID subregion NPCC Upstate New York. The uncertainties for the emission factors are assumed to be ±10% for CO_2 and ±100% for CH_4 and N_2O, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Emissions from electricity consumption are provided below.

$$E_{CO_2} = \frac{1{,}100 \text{ MW-hr}}{\text{yr}} \times \frac{0.327 \text{ tonne } CO_2}{\text{megawatt-hr}}$$

$$\underline{E_{CO_2} = 360 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CH_4} = \frac{1{,}100 \text{ MW-hr}}{\text{yr}} \times \frac{1.13 \times 10^{-5} \text{ tonne } CH_4}{\text{megawatt-hr}}$$

$$\underline{E_{CH_4} = 0.0124 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{1{,}100 \text{ MW-hr}}{\text{yr}} \times \frac{5.08 \times 10^{-6} \text{ tonne } N_2O}{\text{megawatt-hr}}$$

$$\underline{E0_{N_2O} = \;\; .00559 \text{ tonnes } N_2O/\text{yr}}$$

$$E_{CO_2e} = \frac{360 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{0.0124 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4} \right)$$
$$+ \left(\frac{0.00559 \text{ tonne } N_2O}{\text{yr}} \times \frac{310 \text{ tonne } CO_2e}{\text{tonne } N_2O} \right)$$

$$\underline{E_{CO_2e} = 362 \text{ tonne } CO_2e/\text{yr}}$$

Indirect Sources – Steam Consumption

Emissions associated with the steam purchased by the facility are calculated using the approach described in Section 7.1.5. Because no information about the steam production is known, the assumption of a 92% efficient natural gas boiler (as noted in Section 7.1.5) is used. Emissions are calculated using the emission factors provided in Section 7.1.5. (Steam consumption is first converted to the equivalent unit using the conversion factors provided in Table 3-4.) The uncertainties for the emission factors are assumed to be ±10% for CO_2 and ±100% for CH_4 and N_2O, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Emissions from steam consumption are calculated below.

$$\text{Steam energy } = \frac{97{,}600 \times 10^9 \text{ J}}{\text{yr}} \times \frac{\text{Btu}}{1{,}055.056 \text{ J}} = 92{,}507 \times 10^6 \text{ Btu/yr}$$

$$E_{CO_2} = \frac{92{,}507 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{6.41 \times 10^{-2} \text{ tonne } CO_2}{10^6 \text{ Btu}}$$

$$\underline{E_{CO_2} = 5{,}930 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CH_4} = \frac{92{,}507 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{1.20 \times 10^{-6} \text{ tonne } CH_4}{10^6 \text{ Btu}}$$

$$\underline{E_{CH_4} = 0.111 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{92{,}507 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{3.26 \times 10^{-7} \text{ tonne } N_2O}{10^6 \text{ Btu}}$$

$$\underline{E_{N_2O} = 0.0302 \text{ tonnes } N_2O/\text{yr}}$$

$$E_{CO_2e} = \frac{5{,}930 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{0.111 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right)$$
$$+ \left(\frac{0.0302 \text{ tonne } N_2O}{\text{yr}} \times \frac{310 \text{ tonne } CO_2e}{\text{tonne } N_2O}\right)$$

$$\underline{E_{CO_2e} = 5{,}940 \text{ tonne } CO_2e/\text{yr}}$$

Facility Summary

Total emissions for this facility are summarized in Table 8-30. A summary of the emissions for this facility is given in Figure 8-6.

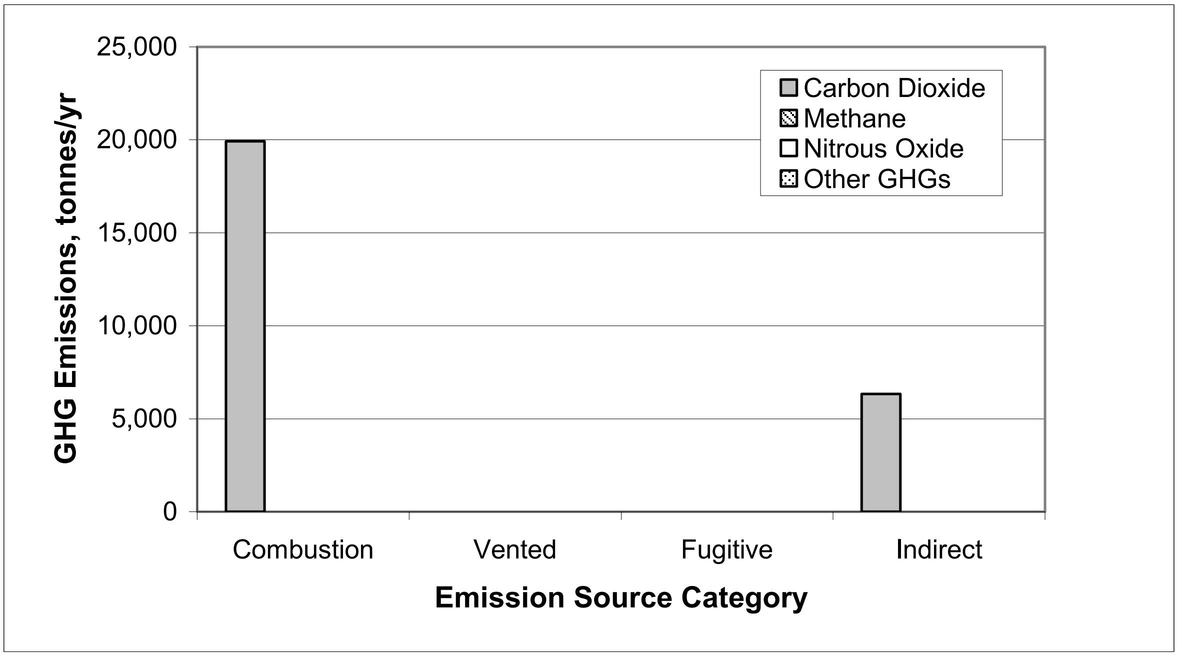


Figure 8-6. Marketing Terminal Summary of Emissions

Table 8-30. Marketing Terminal Emissions

	CO_2 N		CH_4		$_2$O		CO_2e	
Source	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**
Combustion Source	**19,900**	**11.7**	**0.533**	**16.6**	**0.202**	**87.6**	**20,000**	**11.6**
Heater – natural gas	12,500	18.0	0.235	29.2	0.0658	151	12,500	18.0
Heater – diesel	1,920	11.9	0.00473	26.0	0.0158	150	1,930	11.8
Auxiliary fire pump	70.1	15.1	0.0138	104	0.000576	150	70.6	15.1
Auxiliary generator								
Road tanker transport	3,050	11.9	0.159	25.5	0.0930	150	3,080	11.8
Vapor combustor unit (VCU)	2,390	16.3	0.120	30.1	0.0264	137	2,400	16.3
Facility vehicle	7.44	19.4	0.000184	151	0.000119	151	7.48	19.3
Vented Sources	**No Vented GHG Emissions**							
Internal floating roof (IFR) storage tanks	No GHG Emissions							
Rail car/tank car transit	No GHG Emissions							
Fire suppression	No GHG Emissions							
Fugitive Sources	**No Fugitive GHG Emissions**							
Equipment leaks	No GHG Emissions							
Vehicle refrigerant	No GHG Emissions							
Indirect Sources	**6,290**	**10.6**	**0.123**	**90.6**	**0.0357**	**85.9**	**6,300**	**10.5**
Electricity purchased and consumed	360	10.2	0.0124	100	0.00559	100	362	10.2
Steam purchased and consumed	5,930	11.2	0.111	100	0.0302	100	5,940	12.2
TOTAL - Direct[b]	**19,900**	**11.7**	**0.532**	**16.6**	**0.201**	**87.6**	**20,000**	**11.6**
TOTAL - Indirect[b]	**6,290**	**10.6**	**0.123**	**90.6**	**0.0357**	**85.9**	**6,300**	**10.5**
TOTAL[b]	**26,200**	**9.22**	**0.656**	**21.7**	**0.237**	**75.5**	**26,300**	**9.19**

Footnotes:

[a] Uncertainty is at a 95% confidence interval.

[b] Totals may not sum due to independent rounding.

Note: the values shown above are for example only. They do not reflect average operations.

8.3 Refining

8.3.1 Refinery

Facility Description: A refining 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, assuming an uncertainty of ±5%, based on engineering judgment.

Operations: The combustion sources are fired with either refinery fuel gas or natural gas. The gas compositions are presented in Table 8-31. 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, assuming an uncertainty of ±4% for both the refinery fuel and natural gas heating values, based on engineering judgment. The refinery fuel gas feed rate is 4,000 × 10^6 scf/yr; the natural gas feed rate is 6,600 × 10^6 scf/yr.

Table 8-31. Refinery Fuel Streams

	Volume %			
Gas Compound	**Natural Gas**	**Uncertainty[a] (±%)**	**Refinery Fuel Gas**	**Uncertainty[a] (±%)**
CO_2	0.6	4		
N_2	0.5	4		
H_2			30	4
CH_4	94.4	4	35	4
C_2H_6	3.4	4	31	4
C_3H_8	0.6	4	3	4
C_4H_{10}	0.5	4	1	4
C_5H_{12}				
C6+				

Footnote:

[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

Note: the values shown above are for example only. They do not reflect average operations.

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. An uncertainty of ±10% is assumed for the molecular weight and ±25% for the heating value, based on engineering judgment. The carbon content of the flared gas is assumed to be 83.24 wt % carbon, also based on the assumption that the flared gas is mostly pentane, assuming an uncertainty of ±4%, based on engineering judgment.

The facility imported 76,000 MW-hrs of electricity for the inventory year. The refinery has the emission sources listed in Table 8-32. Equipment at the site that do not have greenhouse gas emissions are also included in Table 8-32.

Table 8-32. Refinery Emissions Sources

Source	Fuel Type	No. of Units	Uncertainty[a] (±%)	Total Fuel Consumed (scf/yr)	Uncertainty[a] (±%)	Annual Activity Factor	Uncertainty[a] (±%)
Combustion Sources							
Boilers and heaters	Refinery Fuel Gas	N/A		20,018x10^{6}	5	N/A	
IC engines (2-cycle lean burn)	Natural Gas	N/A		640x10^{6}	5	N/A	
Gas turbines	Natural Gas	N/A		6,800x10^{6}	5	N/A	
Flaring	Mostly Pentane	N/A		N/A		2,400,000´10^{6} Btu/yr	10
Incinerators (sulfur recovery unit, tail gas treatment unit)	Refinery Fuel Gas; Waste Gas	4	0	10	5	344,000´10^{6} Btu/yr	11.2
Vehicle	Gasoline	10 trucks	0	N/A		14,250 gal/yr	10
Vented Sources							
Hydrogen plant	Natural Gas	N/A		N/A		6,600×10^{6} scfy	15
	Refinery Fuel Gas	N/A		N/A		4,000×10^{6} scfy	15
FCCU regenerator[b]	Coke (~91 wt% carbon)	1	0	N/A		589,778 tonne coke/yr	15
Storage tanks	Crude Oil	Not Given		N/A		91.25×10^{6} bbl/yr	15
Maintenance/turnaround activities	N/A – Vented to flare.						
Fire suppression	HFC-227ea	N/A		N/A		145 lbs	5

Table 8-32. Refinery Emissions Sources, continued

Source	Fuel Type	No. of Units	Uncertainty[a] (±%)	Total Fuel Consumed	Uncertainty[a] (±%)	Annual Activity Factor	Uncertainty[a] (±%)
Fugitive Sources							
Equipment leaks	Other	N/A		N/A		N/A	
	Refinery Fuel Gas	N/A		N/A		N/A	
	Natural Gas	N/A		N/A		N/A	
Vehicle refrigeration	R-134a	10 trucks	0	N/A		Unknown	
Indirect Sources							
Imported electricity	N/A	N/A		N/A		76,000 MW-hr/yr	2
Electricity cogeneration	N/A	N/A		N/A		245,100 MW-hr (Total) 207,150 MW-hr (Refinery)	2; 2
Steam cogeneration	N/A	N/A		N/A		1,375,000 MMBtu (Total)	10

Footnotes:

[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

[b] Annual activity factor was calculated previously by the facility.

Note: the values shown above are for example only. They do not reflect average operations.

The remainder of this subsection presents emission calculations for the sources identified in Table 8-32 and a summary of facility emissions (presented at the end of this subsection).

Stationary Combustion Devices – CO_2 Emissions

Carbon dioxide emissions from combustion are calculated using the gas composition approach provided in Section 4.3. First, the fuel analysis is converted from a molar basis to a mass basis, as shown in Exhibits 3.3 and 3.4. The molecular weight of the mixture is calculated below using Equation 3-8, for the refinery natural gas stream:

$$\mathrm{MW}_{\mathrm{Mixture}} = \begin{bmatrix} (0.6\times44.01)+(0.5\times28.01)+(0\times2.02)+(94.4\times16.04) \\ +(3.4\times30.07)+(0.6\times44.10)+(0.5\times58.12) \end{bmatrix} \div 100 = 17.12 \text{ lb/mole}$$

The individual weight percents are then calculated by rearranging Equation 3-7. The calculation is shown below for CH_4 in the refinery natural gas stream.

$$\mathrm{Wt.\%}_{\mathrm{CH_4}} = \frac{94.4 \text{ lbmole CH}_4}{100 \text{ lbmole mixture}} \times \frac{\left(\dfrac{16.04 \text{ lb CH}_4}{\text{lbmole CH}_4}\right)}{\left(\dfrac{17.12 \text{ lb mixture}}{\text{lbmole mixture}}\right)} = \frac{0.8843 \text{ lb CH}_4}{\text{lb mixture}} = 88.43 \text{ wt. \% CH}_4$$

To calculate emissions, the carbon contents of the fuel compositions provided in Table 8-31 are calculated. The first step is to calculate the carbon content of the individual components, using Equation 4-9. The carbon content calculation for an individual component is shown below for ethane (C_2H_6).

$$\mathrm{Wt\%\ C}_{\mathrm{C_2H_6}} = \frac{12.01 \text{ lb C}}{\text{lbmole C}} \times \frac{2 \text{ lbmoles C}}{\text{lbmole C}_2\text{H}_6} \times \frac{\text{lbmole C}_2\text{H}_6}{30.07 \text{ lb C}_2\text{H}_6} \times 100\% = 79.9\% \text{ C}$$

After the calculation has been performed for all constituents, the carbon content for the mixture is calculated using Equation 4-10, as shown below (for the refinery natural gas stream):

$$\begin{aligned} \mathrm{Wt\%\ C}_{\mathrm{Mixture}} &= \frac{1}{100} \times \begin{bmatrix} (1.54\times0)+(0.82\times28.3)+(0\times0)+(88.43\times74.9)+(5.97\times79.9) \\ +(1.55\times81.7)+(1.70\times82.7)+(0\times83.2)+(0\times83.6) \end{bmatrix} \\ &= 74.07 \text{ Wt\% C} = 0.7407 \text{ lb C/lb fuel} \end{aligned}$$

Completing the calculations for the natural gas analysis results in the fuel specific molecular weight and carbon content below:

Compound	Mole %	MW	Wt% (Calculated)	Uncertainty[a] (±%)	Compound Carbon Content (wt%C)	Mixture Carbon Content (wt%C)	Uncertainty[a] (±%)
CO_2	0.6	44.01	1.54	5.35			5.35
N_2	0.5	28.01	0.82	5.35	27.3	0.421	NA
H_2	0	2.02	0	NA	0	0	NA
CH_4	94.4	16.04	88.43	5.35	0	0	5.35
C_2H_6	3.4	30.07	5.97	5.35	74.9	66.2	5.35
C_3H_8	0.6	44.10	1.55	5.35	79.9	4.77	5.35
C_4H_{10}	0.5	58.12	1.70	5.35	81.7	1.26	5.35
C_5H_{12}	0	72.15	0	NA	82.7	1.40	NA
C6+	0	86.18	0	NA	83.2	0	NA
					83.6	0	
Fuel Mixture	**100**	**17.12 ±3.55%[a]**	**100.0**			**74.07**	**4.79**

Footnote:
[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

Completing the calculations for the refinery fuel gas analysis results in the fuel specific molecular weight and carbon content below:

Compound	Mole %	MW	Wt% (Calculated)	Uncertainty [a] (±%)	Compound Carbon Content (wt%C)	Mixture Carbon Content (wt%C)	Uncertainty [a] (±%)
CO_2	0	44.01	0	NA	27.3	0	NA
N_2	0	28.01	0	NA	0	0	NA
H_2	30	2.02	3.47	4.73	0	0	NA
CH_4	35	16.04	32.18	4.73	74.9	24.1	4.73
C_2H_6	31	30.07	53.43	4.73	79.9	42.7	4.73
C_3H_8	3	44.10	8.58	4.73	81.7	6.19	4.73
C_4H_{10}	1	58.12	3.33	4.73	82.7	2.75	4.73
C_5H_{12}	0	72.15	0	NA	83.2	0	2.52
C6+	0	86.18	0	NA	83.6	0	2.52
Fuel Mixture	**100**	**17.45 ±2.52%[a]**	**100.0**			**75.73**	**3.09**

Footnote:
[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

Carbon dioxide emissions can then be calculated using a mass balance approach. Emissions are calculated as follows, by equipment type.

Boilers and Heaters:

$$E_{CO_2} = \frac{40{,}895.9\times10^6 \text{scf fuel}}{\text{yr}} \times \frac{\text{lbmole fuel}}{379.3 \text{ scf fuel}} \times \frac{17.45 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.7573 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}}$$

$$\times \frac{\text{lbmole } CO_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 2{,}368{,}000 \text{ tonnes } CO_2/\text{yr}}$$

Engines and Turbines:

$$E_{CO_2} = \left(\frac{640\times10^6 \text{scf fuel}}{\text{yr}} + \frac{6{,}800\times10^6 \text{scf fuel}}{\text{yr}}\right) \times \frac{\text{lbmole fuel}}{379.3 \text{ scf fuel}} \times \frac{17.12 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.7407 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}}$$

$$\times \frac{\text{lbmole } CO_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 413{,}400 \text{ tonnes } CO_2 / \text{yr}}$$

Stationary Combustion Devices – CH_4, N_2O, and CO_2e Emissions

The “Heater – Refinery fuel gas (High H_2-content gas)” emission factors from Table 4-7 are used for the refinery fuel gas combustion equipment. Nitrous oxide emission factors for controlled natural gas heaters (also taken from Table 4-7) are used in the absence of refinery fuel gas emission factors. An uncertainty of ±25% is assumed for all CH_4 emission factors and ±150% for all N_2O emission factors, based on engineering judgment. Emission factors are provided in Table 4-9 for 2-cycle lean burn engines and controlled (SCR) turbines. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Because the CO_2 emissions from natural gas combustion were calculated on a fuel basis (not by equipment), CO_2e emissions are also calculated on a fuel basis. Emissions from steam consumption are calculated as follows, by equipment type.

Boilers and Heaters:

$$E_{CH_4} = \frac{40{,}896 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1{,}119 \text{ Btu}}{\text{scf}} \times \frac{2.27 \times 10^{-7} \text{ tonne CH}_4}{10^6 \text{ Btu}}$$

$$\underline{E_{CH_4} = 10.4 \text{ tonnes CH}_4 \text{ / yr}}$$

$$E_{N_2O} = \frac{40{,}896 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1{,}119 \text{ Btu}}{\text{scf}} \times \frac{3.69 \times 10^{-8} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}}$$

$$\underline{E_{N_2O} = 1.69 \text{ tonnes N}_2\text{O / yr}}$$

$$E_{CO_2e} = \frac{2{,}368{,}000 \text{ tonne CO}_2}{\text{yr}} + \left(\frac{10.4 \text{ tonne CH}_4}{\text{yr}} \times \frac{21 \text{ tonne CO}_2\text{e}}{\text{tonne CH}_4}\right) + \left(\frac{1.69 \text{ tonne N}_2\text{O}}{\text{yr}} \times \frac{310 \text{ tonne CO}_2\text{e}}{\text{tonne N}_2\text{O}}\right)$$

$$\underline{E_{CO_2e} = 2{,}369{,}000 \text{ tonne CO}_2\text{e/yr}}$$

Natural Gas IC Engines:

$$E_{CH_4} = \frac{640 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1{,}050 \text{ Btu}}{\text{scf}} \times \frac{0.00066 \text{ tonne CH}_4}{10^6 \text{ Btu}}$$

$$\underline{E_{CH_4} = 444 \text{ tonnes CH}_4\text{/yr}}$$

$$E_{N_2O} = \frac{640 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1{,}050 \text{ Btu}}{\text{scf}} \times \frac{9.50 \times 10^{-8} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}}$$

$$\underline{E_{N_2O} = 0.0638 \text{ tonnes N}_2\text{O/yr}}$$

Natural Gas Turbines:

$$E_{CH_4} = \frac{6{,}800 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1{,}050 \text{ Btu}}{\text{scf}} \times \frac{3.9 \times 10^{-6} \text{ tonne CH}_4}{10^6 \text{ Btu}}$$

$$\underline{E_{CH_4} = 27.8 \text{ tonnes CH}_4\text{/yr}}$$

$$E_{N_2O} = \frac{6{,}800 \times 10^6 \text{ scf}}{\text{yr}} \times \frac{1{,}050 \text{ Btu}}{\text{scf}} \times \frac{1.4 \times 10^{-6} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}}$$

$$\underline{E_{N_2O} = 10.0 \text{ tonnes N}_2\text{O/yr}}$$

Natural Gas Combustion CO₂e Emissions:

$$E_{CO_2e} = \frac{413{,}400 \text{ tonne CO}_2}{\text{yr}} + \left(\frac{444 \text{ tonne CH}_4}{\text{yr}} + \frac{27.8 \text{ tonne CH}_4}{\text{yr}}\right) \times \frac{21 \text{ tonne CO}_2\text{e}}{\text{tonne CH}_4} + \left(\frac{0.0638 \text{ tonne N}_2\text{O}}{\text{yr}} + \frac{10.0 \text{ tonne N}_2\text{O}}{\text{yr}}\right) \times \frac{310 \text{ tonne CO}_2\text{e}}{\text{tonne N}_2\text{O}}$$

$$\underline{E_{CO_2e} = 426{,}500 \text{ tonne CO}_2\text{e/yr}}$$

Combustion Sources – Flares

Flaring emissions are calculated based on the guidance in Section 4.6. Methane emissions are calculated using the emission factor provided in Table 4-11, which is based on the barrels of crude feed to the refinery, assuming an uncertainty of ±25%, based on engineering judgment. Carbon dioxide emissions are based on the quantity of gas flared, assuming 98% combustion efficiency assuming a ±20% uncertainty, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs.

$$E_{CH_4} = \frac{250{,}000 \text{ bbl}}{\text{day}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{3.63 \times 10^{-6} \text{ tonne CH}_4}{1000 \text{ bbl}}$$

$$\underline{E_{CH_4} = 0.331 \text{ tonnes CH}_4/\text{yr}}$$

$$E_{CO_2} = \frac{2{,}400{,}000 \times 10^6 \text{ Btu gas}}{\text{yr}} \times \frac{\text{scf}}{4009 \text{ Btu}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \frac{72 \text{ lb gas}}{\text{lbmole gas}} \times \frac{0.8324 \text{ lb C}}{\text{lb gas}}$$
$$\times \frac{\text{lbmole C}}{12.01 \text{ lb C}} \times \frac{0.98 \text{ lbmole CO}_2 \text{ formed}}{\text{lbmole C combusted}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 154{,}100 \text{ tonnes CO}_2/\text{yr}}$$

$$E_{CO_2e} = \frac{154{,}100 \text{ tonne CO}_2}{\text{yr}} + \left(\frac{0.330 \text{ tonne CH}_4}{\text{yr}} \times \frac{21 \text{ tonne CO}_2\text{e}}{\text{tonne CH}_4}\right)$$

$$\underline{E_{CO_2e} = 154{,}100 \text{ tonne CO}_2\text{e/yr}}$$

Combustion Sources – Incinerators

Incinerator emissions result from both combustion emissions and from the untreated (uncombusted) portion of the waste gas. The treatment efficiency of the waste gas is assumed to be 99.9%. Carbon dioxide emissions are estimated using a mass balance approach. Because the waste gas composition is unknown, only CH_4 emissions from combustion are estimated (uncombusted CH_4 emissions are not estimated). Methane emissions are estimated using the "Heater – Refinery fuel gas (High H_2 content)" emission factors given in Table 4-7, assuming an uncertainty of ±25%, based on engineering judgment. In the absence of a refinery fuel gas N_2O factor, the N_2O emission factor for the natural gas boiler/heater (provided in Table 4-7) is used for conservatism, assuming an uncertainty of ±150%, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs.

$$E_{CO_2} = \frac{307\times10^6 \text{ scf}}{\text{yr}} \times \frac{\text{lbmole}}{379.3 \text{ scf fuel}} \times \frac{17.45 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.7573 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}} \times \frac{\text{lbmole CO}_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 17{,}800 \text{ tonnes CO}_2\text{ / yr}}$$

$$E_{CH_4} = \frac{307\times10^6 \text{ scf}}{\text{yr}} \times \frac{1{,}119 \text{ Btu}}{\text{scf}} \times \frac{2.27\times10^{-7} \text{ tonne CH}_4}{10^6 \text{ Btu}}$$

$$\underline{E_{CH_4} = 0.0780 \text{ tonnes CH}_4\text{ / yr}}$$

$$E_{N_2O} = \frac{307\times10^6 \text{ scf}}{\text{yr}} \times \frac{1{,}119 \text{ Btu}}{\text{scf}} \times \frac{3.69\times10^{-8} \text{ tonne N}_2\text{O}}{10^6 \text{ Btu}}$$

$$\underline{E_{N_2O} = 0.0127 \text{ tonnes N}_2\text{O / yr}}$$

$$E_{CO_2e} = \frac{17{,}800 \text{ tonne CO}_2}{\text{yr}} + \left(\frac{0.0780 \text{ tonne CH}_4}{\text{yr}} \times \frac{21 \text{ tonne CO}_2\text{e}}{\text{tonne CH}_4}\right) + \left(\frac{0.0127 \text{ tonne N}_2\text{O}}{\text{yr}} \times \frac{310 \text{ tonne CO}_2\text{e}}{\text{tonne N}_2\text{O}}\right)$$

$$\underline{E_{CO_2e} = 17{,}800 \text{ tonne CO}_2\text{e/yr}}$$

Combustion Sources –Vehicle Emissions

The emission factor for CO_2 for motor gasoline is presented in Table 4-3, assuming an uncertainty of ±10%, based on engineering judgment. Because the CO_2 emission factor is on a heat basis, the volume of fuel consumed is converted to energy input using the heating value of gasoline provided in Table 3-8, assuming an uncertainty of ±5%, based on engineering judgment. Methane and N_2O emission factors are in Table 4-17, assuming an uncertainty of ±150%, based on engineering judgment. It is assumed the vehicles are Tier 1 vehicles. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Vehicle emissions are calculated as follows.

$$V = \frac{14{,}250\text{ gal}}{\text{yr}} \times \frac{\text{bbl}}{42\text{ gal}} \times \frac{5.25\times10^{6}\text{ Btu}}{\text{bbl}} = 1{,}781\times10^{6}\text{ Btu/yr-truck}$$

$$E_{CO_2} = \frac{1{,}781\times10^{6}\text{ Btu}}{\text{yr}} \times \frac{0.0709\text{ tonne }CO_2}{1\times10^{6}\text{ Btu}}$$

$$\underline{E_{CO_2} = 126\text{ tonne }CO_2/\text{yr}}$$

$$E_{CH_4} = \frac{14{,}250\text{ gal}}{\text{yr}} \times \frac{4.5\times10^{-4}\text{tonne }CH_4}{\text{Mgal}} \times \frac{\text{Mgal}}{1000\text{ gal}}$$

$$\underline{E_{CH_4} = 0.00641\text{ tonne }CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{14{,}250\text{ gal}}{\text{yr}} \times \frac{6.1\times10^{-4}\text{tonne }N_2O}{\text{Mgal}} \times \frac{\text{Mgal}}{1000\text{ gal}}$$

$$\underline{E_{N_2O} = 0.00869\text{ tonne }N_2O/\text{yr}}$$

$$E_{CO_2e} = \frac{126\text{ tonne }CO_2}{\text{yr}} + \left(\frac{0.00641\text{ tonne }CH_4}{\text{yr}} \times \frac{21\text{ tonne }CO_2e}{\text{tonne }CH_4}\right) + \left(\frac{0.00869\text{ tonne }N_2O}{\text{yr}} \times \frac{310\text{ tonne }CO_2e}{\text{tonne }N_2O}\right)$$

$$\underline{E_{CO_2e} = 129\text{ tonne }CO_2e/\text{yr}}$$

Vented Emissions – Hydrogen Plant

Carbon dioxide emissions from the hydrogen plant are calculated using Equation 5-8, based on the feed rate and compositions of the feed streams. The carbon contents of the streams were calculated under “Stationary Combustion Devices – CO_2 Emissions.” Carbon dioxide emissions are the same as the CO_2e emissions if there are no CH_4, N_2O, or other emissions.

$$\left(E_{CO_2e} = E_{CO_2}\right)$$

Emissions are calculated below for each of the by gas streams.

Natural gas:

$$E_{CO_2} = \frac{6{,}600 \times 10^6 \text{scf fuel}}{\text{yr}} \times \frac{\text{lbmole fuel}}{379.3 \text{ scf fuel}} \times \frac{17.12 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.7407 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}}$$
$$\times \frac{1 \text{ lbmole } CO_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 366{,}800 \text{ tonnes } CO_2/\text{yr}}$$

Refinery fuel gas:

$$E_{CO_2} = \frac{4{,}000 \times 10^6 \text{scf fuel}}{\text{yr}} \times \frac{\text{lbmole fuel}}{379.3 \text{ scf fuel}} \times \frac{17.45 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.7573 \text{ lb C}}{\text{lb fuel}} \times \frac{\text{lbmole C}}{12.01 \text{ lb C}}$$
$$\times \frac{1 \text{ lbmole } CO_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CO_2} = 231{,}600 \text{ tonnes } CO_2/\text{yr}}$$

Vented Emissions – Catalytic Cracking Regenerator Vent

Carbon dioxide emissions from the catalytic cracking regenerator vent are estimated using Equation 5-4 because of a lack of data required for the other emission calculation approaches. It is assumed CH_4 is not formed during the regeneration process. Carbon dioxide emissions are the same as the CO_2e emissions if there are no CH_4, N_2O, or other emissions.

$$E_{CO_2} = \frac{589{,}778 \text{ tonnes coke burned}}{\text{yr}} \times \frac{0.91 \text{ lb C}}{\text{lb Coke}} \times \frac{44.01 \text{ lb } CO_2}{12.01 \text{ lb C}}$$

$$\underline{E_{CO_2} = 1{,}960{,}000 \text{ tonnes } CO_2 / \text{yr}}$$

Vented Sources – Storage Tanks

Liquids stored at the facility are refined petroleum products, which contain no CH_4 or CO_2. Therefore, there are no CH_4 or CO_2 emissions from these tanks.

Vented Sources – Loading and Transit Operations

The fuel types transported in association with this facility are refined petroleum products, which contain no CH_4 or CO_2. Therefore, there are no CH_4 or CO_2 emissions from transport (or other handling) of these materials.

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 calculated under Combustion Sources – Flare.

Vented Sources – Fire Suppression

Emissions from fire suppression are calculated using a mass balance approach. Carbon dioxide equivalent emissions are calculated using the GWP for HFC-227ea provided in Table 3-1. There are no uncertainties for any of the GWPs.

$$E_{\text{HFC-227ea}} = \frac{145 \text{ lb HFC-227 ea}}{\text{yr}} \times \frac{\text{tonne HFC-227 ea}}{2{,}204.62 \text{ lb}}$$

$$\underline{E_{\text{HFC-227ea}} = 0.0658 \text{ tonne HFC-227 ea/yr}}$$

$$E_{CO_2e} = \frac{0.0658 \text{ tonne HFC-227 ea}}{\text{yr}} \times \frac{2{,}900 \text{ tonne } CO_2e}{\text{tonne HFC-227 ea}}$$

$$\underline{E_{CO_2e} = 191 \text{ tonne } CO_2e/\text{yr}}$$

Fugitive Sources – Equipment Leaks

The non-fuel gas system components handle liquids such as refined petroleum products, which do not contain CH_4 or CO_2. Therefore, there are no CH_4 or CO_2 emissions from non-fuel gas system components. Methane emission factors for leaks from refinery fuel gas and natural gas system components are presented in Table 6-2, assuming an uncertainty of ±300%, based on engineering judgment. Carbon dioxide emissions are calculated by using a ratio of the facility CH_4 and CO_2 content. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs. Emissions are calculated below for each of the gas systems.

Refinery fuel gas:

$$E_{CH_4\text{-fuel gas}} = \frac{250{,}000 \text{ bbl crude}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{1.41\times10^{-6} \text{ tonne } CH_4}{\text{bbl crude}}$$

$$\underline{E_{CH_4\text{-fuel gas}} = 129 \text{ tonne } CH_4/\text{yr}}$$

$$E_{CO_2 \text{ fuel gas}} = \frac{250{,}000 \text{ bbl crude}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{1.41\times10^{-6} \text{ tonne } CH_4}{\text{bbl crude}} \times \frac{0.00 \text{ tonne } CO_2}{0.3218 \text{ tonne } CH_4}$$

$$\underline{E_{CO_2 \text{ fuel gas}} = 0.00 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CO_2e \text{ Fuel gas}} = 0.00 \text{ tonnes } CO_2/\text{yr} + \left(\frac{129 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4} \right)$$

$$\underline{E_{CO_2e \text{ Fuel gas}} = 2{,}700 \text{ tonne } CO_2e/\text{yr}}$$

Natural gas:

$$E_{CH_4\text{-natural gas}} = \frac{250{,}000 \text{ bbl crude}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{1.01\times10^{-6} \text{ tonne } CH_4}{\text{bbl crude}}$$

$$\underline{E_{CH_4\text{-natural gas}} = 92.2 \text{ tonne } CH_4/\text{yr}}$$

$$E_{CO_2 \text{ natural gas}} = \frac{250{,}000 \text{ bbl crude}}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{1.01 \times 10^{-6} \text{ tonne CH}_4}{\text{bbl crude}} \times \frac{0.0154 \text{ tonne CO}_2}{0.8843 \text{ tonne CH}_4}$$

$$\underline{E_{CO_2 \text{ natural gas}} = 161 \text{ tonnes CO}_2\text{/yr}}$$

$$E_{CO_2e \text{ natural gas}} = 161 \text{ tonnes CO}_2\text{/yr} + \left(\frac{92.2 \text{ tonne CH}_4}{\text{yr}} \times \frac{21 \text{ tonne CO}_2\text{e}}{\text{tonne CH}_4} \right)$$

$$\underline{E_{CO_2e \text{ natural gas}} = 2{,}100 \text{ tonne CO}_2\text{e/yr}}$$

Fugitive Sources: Vehicle Refrigerant

The actual vehicle capacities are unknown and therefore the capacity is assumed to be at the midpoint of the range presented in Table 6-25 for mobile air conditioning, assuming an uncertainty of ±100%, based on engineering judgment. The percentage of capacity emitted per year is also taken from Table 6-25, assuming an uncertainty of ±50%, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWP provided in Table 3-1 (for HFC-134a). There are no uncertainties for any of the GWPs. The calculations for fleet vehicle refrigeration are shown below.

$$E_{R\text{-}134a} = 10 \text{ truck} \times \frac{1.0 \text{ kg}}{\text{truck}} \times 20\% \times \frac{\text{tonne R-134a}}{1000 \text{ kg}}$$

$$\underline{E_{R\text{-}134a} = 0.00200 \text{ tonne R-134a/yr}}$$

$$E_{CO_2e} = \frac{0.00200 \text{ tonne R-134a}}{\text{yr}} \times \frac{1300 \text{ tonne CO}_2\text{e}}{\text{tonne R-135a}}$$

$$\underline{E_{CO_2e} = 2.60 \text{ tonne CO}_2\text{e/yr}}$$

Indirect Sources – Electricity Consumption

Emissions associated with the electricity purchased by the facility are calculated using emission factors in Table 7-5 for the UK. Note that most recent CH_4 and N_2O factors are for the year 2006.

The uncertainties for the emission factors are assumed to be ±10% for CO_2 and ±100% for CH_4 and N_2O, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs.

$$E_{CO_2} = \frac{76{,}000 \text{ MW-hr}}{\text{yr}} \times \frac{0.581 \text{ tonne } CO_2}{\text{megawatt-hr}}$$

$$\underline{E_{CO_2} = 44{,}200 \text{ tonnes } CO_2/\text{yr}}$$

$$E_{CH_4} = \frac{76{,}000 \text{ MW-hr}}{\text{yr}} \times \frac{2.23\times10^{-5} \text{ tonne } CH_4}{\text{megawatt-hr}}$$

$$\underline{E_{CH_4} = 1.70 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{76{,}000 \text{ MW-hr}}{\text{yr}} \times \frac{9.14\times10^{-5} \text{ tonne } N_2O}{\text{megawatt-hr}}$$

$$\underline{E_{N_2O} = 6.95 \text{ tonnes } N_2O/\text{yr}}$$

$$E_{CO_2e} = \frac{44{,}200 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{1.70 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right) + \left(\frac{6.95 \text{ tonne } N_2O}{\text{yr}} \times \frac{310 \text{ tonne } CO_2e}{\text{tonne } N_2O}\right)$$

$$\underline{E_{CO_2e} = 46{,}300 \text{ tonne } CO_2e/\text{yr}}$$

Indirect Sources - Electricity Cogeneration

The refinery purchases electricity and steam from a cogeneration facility. The cogeneration facility consumes 2,950,500 MMBtu of natural gas, assuming an uncertainty of ±15%, based on engineering judgment, producing 1,375,000 million BTU steam and 245,100 megawatt-hr of electricity (gross) on an annual basis. The refinery purchases all of the steam (1,375,000 million Btu) and 207,150 MW-hr of electricity. The cogeneration facility itself requires 38,500 MW-hr to operate (Parasitic load), with 5,150 megawatt-hr of electricity sold to the electric grid, assuming an uncertainty of ±2% for each parameter, based on engineering judgment.

As the actual generation efficiency is unknown, defaults from Section 7.2.1 are used instead. The efficiency of steam generation is assumed to be 80% and the efficiency of the electricity generation is assumed to be 35%, assuming an uncertainty of ±30% for each, based on engineering judgment.

Refinery cogeneration is calculated using the WRI/WBCSD efficiency allocation approach using Equations 7-5 and 7-6. Emissions are calculated in steps 1-5 below.

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 Table 4-3 for CO_2 and Table 4-9 (uncontrolled turbines) for CH_4 and N_2O. The uncertainties for the emission factors are assumed to be ±100% for CO_2 and ±150% for CH_4 and N_2O, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs.

$$E_{CO_2} = 2{,}950{,}500 \times 10^6 \text{ Btu} \times \frac{0.0531 \text{ tonnes } CO_2}{10^6 \text{ Btu natural gas}}$$

$$\underline{E_{CO_2} = 156{,}700 \text{ tonnes } CO_2}$$

$$E_{CH_4} = 2{,}950{,}500 \times 10^6 \text{ Btu} \times \frac{3.9 \times 10^{-6} \text{ tonnes } CH_4}{10^6 \text{ Btu natural gas}}$$

$$\underline{E_{CH_4} = 11.5 \text{ tonnes } CH_4}$$

$$E_{N_2O} = 2{,}950{,}500 \times 10^6 \text{ Btu} \times \frac{1.4 \times 10^{-6} \text{ tonnes } N_2O}{10^6 \text{ Btu natural gas}}$$

$$\underline{E_{N_2O} = 4.13 \text{ tonnes } N_2O}$$

$$E_{CO_2e} = 156{,}700 \text{ tonnes } CO_2 + \left(11.5 \text{ tonnes } CH_4 \times \frac{21 \text{ tonnes } CO_2e}{\text{tonnes } CH_4}\right) + \left(4.13 \text{ tonnes } N_2O \times \frac{310 \text{ tonnes } CO_2e}{\text{tonnes } N_2O}\right)$$

$$\underline{E_{CO_2e} = 158{,}200 \text{ tonnes } CO_2e}$$

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

The electric power output from the cogeneration unit is converted from a megawatt-hr basis to Btu. The conversion factor for is provided in Table 3-4.

$$P = 245{,}100 \text{ megawatt-hr} \times \frac{1000 \text{ kilowatt-hr}}{\text{megawatt-hr}} \times \frac{\text{Btu}}{2.93071 \times 10^{-4} \text{ kilowatt-hr}}$$

$$\underline{P = 8.36 \times 10^{11} \text{ Btu (Electricity Output)}}$$

Step 3: Calculate the Emissions Allocated to Steam

Emissions associated with the steam generation are calculated by applying Equation 7-5.

$$E_{Heat} = 158{,}200 \text{ tonnes } CO_2e \times \frac{\dfrac{1{,}375{,}000 \times 10^6 \text{ Btu}}{0.80}}{\dfrac{1{,}375{,}000 \times 10^6 \text{ Btu}}{0.80} + \dfrac{8.36 \times 10^{11} \text{ Btu}}{0.35}}$$

$$\underline{E_{Heat} = 66{,}200 \text{ tonnes } CO_2e}$$

Step 4: Calculate the Emissions Allocated to Electricity

Applying Equation 7-6, the emissions allocated to electricity are calculated based on the difference between the total emissions and those allocated to steam.

$E_{Electricity}$ = 158,200 tonnes CO_2e (Total) – 66,200 tonnes CO_2e (Heat)

$\underline{E_{Electricity} = 92{,}000 \text{ tonnes } CO_2e}$

Step 5: Allocate Emissions for Energy Exports

The total steam and electricity emissions are estimated for exports (those energy streams consumed by the refinery) based on the ratio of the total electricity and steam generated versus the energy sold.

CO_2e Emissions for electricity sold to the refinery:

$$E_{CO_2e,\ Ref} = 92,000 \text{ tonnes } CO_2e \text{ (Total Electricity)} \times \frac{207,150 \text{ megawatt-hr (Refinery)}}{245,100 \text{ megawatt-hr (Total)}}$$

$$\underline{E_{CO_2e,\ Ref} = 77,800 \text{ tonnes } CO_2e \text{ (Refinery)}}$$

CO_2e Emissions for electricity sold to the grid:

$$E_{CO_2e,\ Grid} = 92,000 \text{ tonnes } CO_2e \text{ (Total Electricity)} \times \frac{5,150 \text{ megawatt-hr (Grid)}}{245,100 \text{ megawatt-hr (Total)}}$$

$$\underline{E_{CO_2e,\ Grid} = 1,930 \text{ tonnes } CO_2e \text{ (Grid)}}$$

CO_2e Emissions for steam sold to the refinery:

$$E_{CO_2e,Ref} = 66,200 \text{ tonnes } CO_2e \text{ (Total Heat)} \times \frac{1,375,000 \times 10^6 \text{ Btu (Refinery)}}{1,375,000 \times 10^6 \text{ Btu (Total)}}$$

$$\underline{E_{CO_2e,Ref} = 66,200 \text{ tonnes } CO_2e \text{ (Refinery)}}$$

Step 6: Calculate Net Cogeneration Facility Emissions

Net cogeneration facility emissions are calculated by subtracting emissions from steam and electricity sold to the refinery and electricity sold to the grid from the total emissions calculated in Step 1.

Net Cogeneration Facility CO_2 Emissions:

$$\text{Net } E_{CO_2e} = 158,200 \text{ tonnes } CO_2e\text{-}\left(77{,}800+1{,}930+66{,}200 \text{ tonnes } CO_2e\right)$$

$$\underline{\text{Net } E_{CO_2e} = 12{,}300 \text{ tonnes } CO_2e \text{ (Net)}}$$

The results for the allocation of emissions based on energy efficiency are shown in Table 8-33.

Table 8-33. Refinery Cogeneration Emission Summary – WRI/WBCSD Efficiency Allocation Approach

	Emissions, tonnes CO_2e	Uncertainty[a] (±%)
Cogeneration Facility (Direct, Cogen)		
Direct Emissions from Fuel Consumption	158,200	100
Emissions Associated with Electricity Sold to the Grid (Direct, Cogen, and Indirect, Grid Consumer)	1,930	189
Net Facility Emissions	12,300	1,850
Refinery Emissions (Direct, Cogen; Indirect, Refinery)		
Purchased Electricity	77,800	189
Purchased Steam	66,200	108

Footnote:

[a] Uncertainty is at a 95% confidence interval.

Note: the values shown above are for example only. They do not reflect average operations.

Facility Summary

Total emissions for this case are summarized in Table 8-34. A summary of the emissions for this facility is given in Figure 8-7.

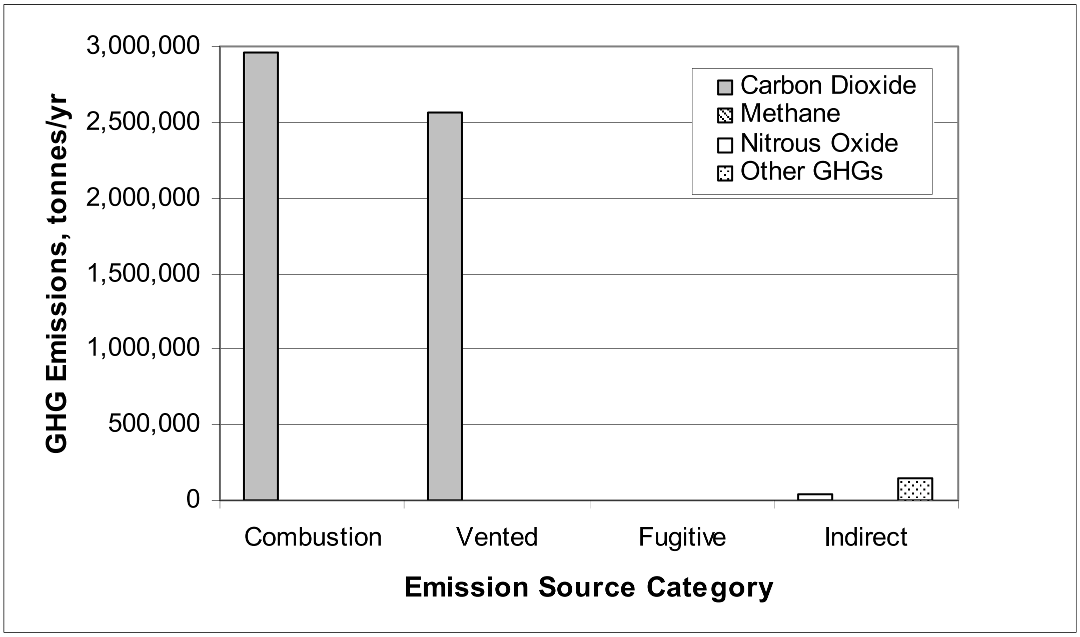


Figure 8-7. Refinery Summary of Emissions

Table 8-34. Refinery Emissions

	CO$_2$ N		CH$_4$		$_2$O		CO$_2$e	
Source	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**
Combustion Sources	**2,950,000**	**4.72**	**482**	**23.8**	**11.8**	**129**	**2,967,000**	**4.70**
Power (steam) boilers	2,368,000	5.25	10.4	25.5	1.69	150	2,369,000	5.25
Process heaters								
FCCU CO boiler								
IC engines	413,400	7.53	444	25.8	0.0638	150	426,500	7.40
Gas turbines			27.8	25.8	10.0	150		
Flaring	154,100	35.2	0.331	25.5	N/A		154,100	35.2
Incinerators (sulfur recovery unit, tail gas treatment unit)	17,800	5.65	0.0780	25.0	0.0127	150	17,800	5.65
Vehicle	12.6	15.0	0.000641	150	0.000869	150	12.9	15.0
Vented Sources	**2,558,000**	**12.3**	**N/A**		**N/A**		**2,558,000**	**12.3**
Hydrogen plant – natural gas feed	366,800	16.1	N/A		N/A		366,800	16.1
Hydrogen plant – refinery fuel gas feed	231,600	15.5	N/A		N/A		231,600	15.5
FCCU regenerator	1,960,000	15.8	N/A		N/A		1,960,000	15.8
Storage tanks	No GHG Emissions							
Maintenance/turnaround activities	Included w/ Flaring							
Fire suppression	N/A		N/A		N/A		191	5.00
Fugitive Sources	**161**	**300**	**221**	**215**	**N/A**		**4,800**	**208**
Other equipment leaks	No GHG Emissions							
Fuel gas equipment leaks	N/A		129	300	N/A		2,700	300
Natural gas equipment leaks	161	300	92.2	300	N/A		2,100	278
Vehicle refrigeration	N/A		N/A		N/A		2.60	112
Indirect Sources	**44,200**	**10.2**	**1.69**	**100**	**6.95**	**100**	**190,300**	**85.9**
Imported electricity	44,200	10.2	1.69	100	6.95	100	46,300	10.8
Electricity cogeneration	N/A		N/A		N/A		77,800	189
Steam cogeneration	N/A		N/A		N/A		66,200	108
TOTAL - Direct[b]	**5,512,00**	**6.26**	**703**	**69.5**	**11.8**	**129**	**5,531,000**	**6.24**
TOTAL - Indirect[b]	**44,200**	**10.2**	**1.69**	**100**	**6.95**	**100**	**190,300**	**85.9**
TOTAL[b]	**5,556,000**	**6.21**	**705**	**69.3**	**18.7**	**89.4**	**5,721,000**	**6.67**

Footnotes:

[a] Uncertainty is at a 95% confidence interval.

[b] Totals may not sum due to independent rounding.

Note: the values shown above are for example only. They do not reflect average operations.

8.4 Retail

8.4.1 Retail

Facility Description: A convenience store in central California has gasoline and diesel fuel storage tanks for automobile refueling.

Operations: The facility purchases 315,920 kWh/yr of electricity from the grid. Table 8-35 summarizes the emission sources associated with this facility. Equipment at the site that do not have GHG emissions are also included in Table 8-35.

Table 8-35. Retail Emissions Sources

Source	Fuel/Refrigerant	No. of Units	Uncertainty[a] (±%)	Average Firing Rate per unit (10^6 Btu/hr)	Uncertainty[a] (±%)	Average Operating Hours per Unit (hr/yr)	Uncertainty[a] (±%)	Activity Factor (total)	Uncertainty[a] (±%)
Combustion Sources									
There are no combustion sources associated with this facility.									
Vented Sources									
Underground storage tanks	Diesel	1	0	N/A		N/A		N/A	
	Gasoline	2	0	N/A		N/A		N/A	
Passenger vehicle loading	Diesel	N/A		N/A		N/A		N/A	
	Gasoline	N/A		N/A		N/A		N/A	
Fugitive Sources									
A/C unit	R-410A	1	0	N/A		N/A		N/A	
Indirect Sources									
Imported electricity	N/A	N/A		N/A		N/A		315,920 kWh/yr	2

Footnote:

[a] Uncertainty is based on engineering judgment at a 95% confidence interval.

Note: the values shown above are for example only. They do not reflect average operations.

The remainder of this subsection presents emission calculations for the sources identified in Table 8-35 and a summary of facility emissions (presented at the end of this subsection).

Combustion Sources

There are no combustion sources associated with this facility.

Vented Sources – Storage Tank Emissions

Gasoline and diesel, the two fuels stored at the facility, are refined petroleum products. Refined petroleum products do not contain CH_4 or CO_2. Therefore, no CH_4 or CO_2 emissions result from the storage tanks at this facility.

Vented Sources – Passenger Vehicle Loading

Gasoline and diesel, the two fuels loaded at the facility, are refined petroleum products. Refined petroleum products do not contain CH_4 or CO_2. Therefore, no CH_4 or CO_2 emissions result from the refueling operations at this facility.

Fugitive Sources – Air Conditioning

As the actual air conditioning (A/C) unit capacity is unknown, the capacity is assumed to be the midpoint of the range presented in Table 6-25 for commercial air conditioning, assuming an uncertainty of ±100%, based on engineering judgment. The percentage of capacity emitted per year is also taken from Table 6-25, assuming an uncertainty of ±50%, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWP provided in Table 6-26. There are no uncertainties for any of the GWPs. The calculation for A/C emissions is shown below.

$$E_{\text{R-410A}} = 1\text{ A/C Unit} \times \frac{50.25\text{ kg}}{\text{A/C Unit}} \times 10\% \times \frac{\text{tonne R-410A}}{1000\text{ kg}}$$

$$\underline{E_{\text{R-410A}} = 0.00503\text{ tonne R-410A/yr}}$$

$$E_{CO_2e} = \frac{0.00503 \text{ tonne R-410A}}{\text{yr}} \times \frac{1725 \text{ tonne } CO_2e}{\text{tonne R-410A}}$$

$$\underline{E_{CO_2e} = 8.67 \text{ tonne } CO_2e}$$

Indirect Sources - Electricity Consumption

Central California is in the eGrid subregion WECC California. Carbon dioxide, CH_4, and N_2O emissions are calculated using the emission factors provided in Table 7-2. The uncertainties for the emission factors are assumed to be ±10% for CO_2 and ±100% for CH_4 and N_2O, based on engineering judgment. Carbon dioxide equivalent emissions are calculated using the GWPs provided in Table 3-1. There are no uncertainties for any of the GWPs.

$$E_{CO_2} = 315{,}920 \text{ kWh} \times \frac{\text{MWh}}{1{,}000 \text{ kWh}} \times \frac{0.328 \text{ tonne } CO_2}{\text{MWh}}$$

$$\underline{E_{CO_2} = 104 \text{ tonne } CO_2/\text{yr}}$$

$$E_{CH_4} = 315{,}920 \text{ kWh} \times \frac{\text{MWh}}{1{,}000 \text{ kWh}} \times \frac{1.37 \times 10^{-5} \text{ tonne } CH_4}{\text{MWh}}$$

$$\underline{E_{CH_4} = 0.00433 \text{ tonne } CH_4/\text{yr}}$$

$$E_{N_2O} = 315{,}920 \text{ kWh} \times \frac{\text{MWh}}{1{,}000 \text{ kWh}} \times \frac{3.67 \times 10^{-6} \text{ tonne } N_2O}{\text{MWh}}$$

$$\underline{E_{N_2O} = 0.00116 \text{ tonne } N_2O/\text{yr}}$$

$$E_{CO_2e} = \frac{104 \text{ tonne } CO_2}{\text{yr}} + \left(\frac{0.00433 \text{ tonne } CH_4}{\text{yr}} \times \frac{21 \text{ tonne } CO_2e}{\text{tonne } CH_4}\right) + \left(\frac{0.00116 \text{ tonne } N_2O}{\text{yr}} \times \frac{310 \text{ tonne } CO_2e}{\text{tonne } N_2O}\right)$$

$$\underline{E_{CO_2e} = 104 \text{ tonne } CO_2e/\text{yr}}$$

Facility Summary

Total emissions for this facility are summarized in Table 8-36. A summary of the emissions for this facility is given in Figure 8-8.

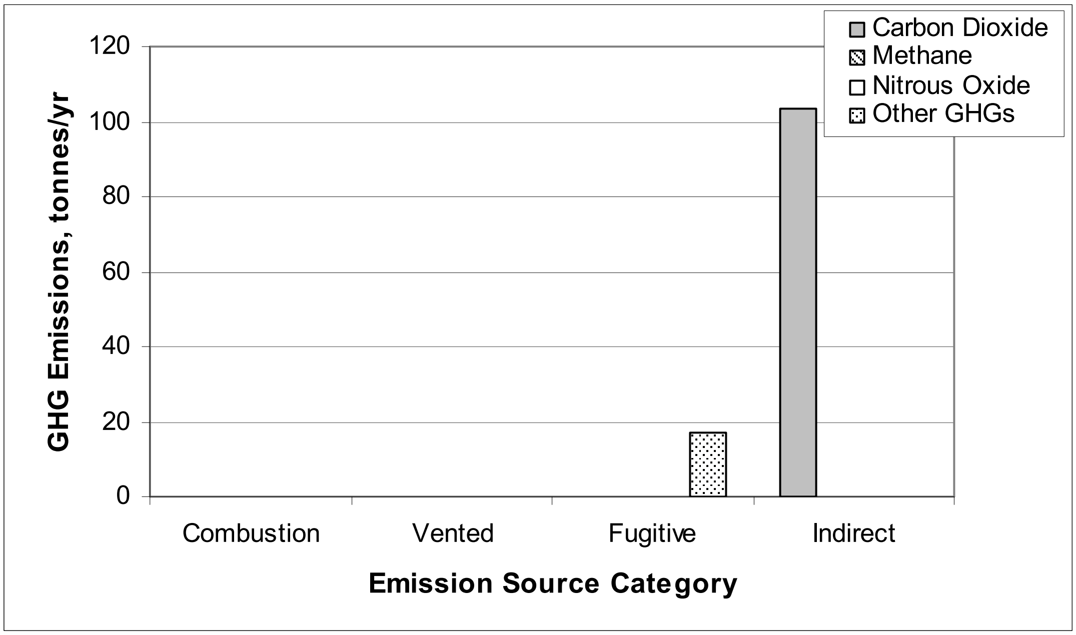


Figure 8-8. Retail Summary of Emissions

Table 8-36. Retail Emissions

	CO_2 N		CH_4		$_2O$		CO_2e	
Source	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**	**Emissions (tonnes/yr)**	**Uncertainty[a] (±%)**
Combustion Sources	**No Combustion GHG Emissions**							
There are no combustion sources associated with this facility.								
Vented Sources	**No Vented GHG Emissions**							
Underground storage tanks - diesel	No GHG emissions							
Underground storage tanks - gasoline	No GHG emissions							
Passenger vehicle loading	No GHG emissions							
Fugitive Sources	**N/A**		**N/A**		**N/A**		**8.67**	**112**
A/C unit	N/A		N/A		N/A		8.67	112
Indirect Sources	**104**	**10.2**	**0.00433**	**100**	**0.00116**	**100**	**104**	**10.2**
Imported electricity	104	10.2	0.00433	100	0.00116	100	104	10.2
TOTAL - Direct[b]	**N/A**		**N/A**		**N/A**		**8.67**	**112**
TOTAL - Indirect[b]	**104**	**10.2**	**0.00433**	**100**	**0.00116**	**100**	**104**	**10.2**
TOTAL[b]	**104**	**10.2**	**0.00433**	**100**	**0.00116**	**100**	**113**	**12.7**

Footnotes:

[a] Uncertainty is at a 95% confidence interval.

[b] Totals may not sum due to independent rounding.

Note: the values shown above are for example only. They do not reflect average operations.

energy API

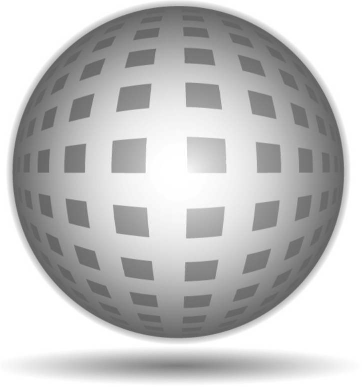
AMERICAN PETROLEUM INSTITUTE

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

AUGUST 2009

APPENDIX A

ADDITIONAL COMBUSTION CALCULATION INFORMATION



Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry

Appendix A – Additional Combustion Calculation Information

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A. ADDITIONAL COMBUSTION CALCULATION INFORMATION

This section presents supplemental information for the combustion emission calculation methodologies presented in Section 4.

A.1 Methodology for Converting Between LHV and HHV Bases

Section 4.2 provides the equations for converting emission factors between a HHV and a LHV basis for gaseous and solid/liquid fuels in Equations 4-7 and 4-8, respectively. These equations can be simplified, and are shown in their simplified form in the footnotes to certain tables in Section 4. Fuel-based emission factors may be reported in terms of energy on a HHV or LHV basis. Converting emission factors between a LHV and HHV basis is different than converting between lower and higher heating values. This subsection provides the derivation of the simplified forms of the equations.

A.1.1 Solid Fuels

Derivation of the emission factor conversion for a solid fuel is provided below.

Starting with the IPCC assumption that LHV is 5% lower than HHV for a solid-based fuel:

$$\text{LHV}\left(\frac{\text{energy}}{\text{mass}}\right) = \text{HHV}\left(\frac{\text{energy}}{\text{mass}}\right) \text{- 5\% HHV}\left(\frac{\text{energy}}{\text{mass}}\right)$$

$$\text{LHV}\left(\frac{\text{energy}}{\text{mass}}\right) = \text{HHV}\left(\frac{\text{energy}}{\text{mass}}\right)\left(1\text{-}0.05\right) = 0.95\ \text{HHV}\left(\frac{\text{energy}}{\text{mass}}\right)$$

The heating value is converted to an emission factor as shown:

$$\text{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right) = \frac{\text{X mass C}}{\text{mass fuel}} \times \frac{\text{mole C}}{\text{12 mass units C}} \times \frac{\text{mole CO}_2}{\text{mole C}} \times \frac{\text{44 mass units CO}_2}{\text{mole CO}_2} \times \frac{\text{mass fuel}}{\text{energy fuel}}$$

where

X = *carbon content of the fuel;*
12 = *molecular weight of carbon;*
mole CO_2/ mole C = *carbon to CO_2 conversion (assuming 100% carbon oxidation);*
44 = *molecular weight of CO_2; and*
mass fuel/energy fuel = *inverse heating value of the fuel.*

For an emission factor in terms of higher heating value:

$$\mathrm{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right)_{\mathrm{HHV}} = \frac{\left(\frac{44\mathrm{X}}{12}\right)\text{mass CO}_2}{\text{mass fuel}} \times \frac{1}{\mathrm{HHV}}\left(\frac{\text{mass fuel}}{\text{energy}}\right)$$

Likewise, for an emission factor in terms of lower heating value:

$$\mathrm{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right)_{\mathrm{LHV}} = \frac{\left(\frac{44\mathrm{X}}{12}\right)\text{mass CO}_2}{\text{mass fuel}} \times \frac{1}{\mathrm{LHV}}\left(\frac{\text{mass fuel}}{\text{energy}}\right)$$

To convert from a HHV-based emission factor to LHV:

$$\mathrm{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right)_{\mathrm{LHV}} = \frac{\left(\frac{44\mathrm{X}}{12}\right)\text{mass CO}_2}{\text{mass fuel}} \times \frac{1}{\mathrm{LHV}}\left(\frac{\text{mass fuel}}{\text{energy}}\right) \times \frac{\mathrm{LHV}}{0.95\ \mathrm{HHV}}$$

or expressed more simply:

$$\mathrm{EF}_{\mathrm{LHV}} = \frac{\mathrm{EF}_{\mathrm{HHV}}}{0.95}$$

A.1.2 Liquid Fuels

The approach used for solid fuels would also 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 that LHV is 5% lower than HHV for a liquid-based fuel:

$$\text{LHV}\left(\frac{\text{energy}}{\text{volume}}\right) = \text{HHV}\left(\frac{\text{energy}}{\text{volume}}\right)\text{-5\% HHV}\left(\frac{\text{energy}}{\text{volume}}\right)$$

$$\text{LHV}\left(\frac{\text{energy}}{\text{volume}}\right) = \text{HHV}\left(\frac{\text{energy}}{\text{volume}}\right)(1\text{-}0.05) = 0.95\ \text{HHV}\left(\frac{\text{energy}}{\text{volume}}\right)$$

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:

$$\text{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right) = \frac{\text{mass fuel}}{\text{volume fuel}} \times \frac{\text{X mass C}}{\text{mass fuel}} \times \frac{\text{mole C}}{\text{12 mass units C}} \times \frac{\text{mole CO}_2}{\text{mole C}} \times \frac{\text{44 mass units CO}_2}{\text{mol CO}_2} \times \frac{\text{volume fuel}}{\text{energy fuel}}$$

where

mass fuel/volume fuel = fuel density; and

volume fuel/energy fuel = inverse heating value of the fuel

For an emission factor in terms of higher heating value:

$$\text{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right)_{\text{HHV}} = \text{density}\left(\frac{\text{mass fuel}}{\text{volume fuel}}\right) \times \frac{\left(\frac{44\text{X}}{12}\right)\text{mass CO}_2}{\text{mass fuel}} \times \frac{1}{\text{HHV}}\left(\frac{\text{volume fuel}}{\text{energy}}\right)$$

Likewise, for an emission factor in terms of lower heating value:

$$\text{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right)_{\text{LHV}} = \text{density}\left(\frac{\text{mass fuel}}{\text{volume fuel}}\right) \times \frac{\left(\frac{44\text{X}}{12}\right)\text{mass CO}_2}{\text{mass fuel}} \times \frac{1}{\text{LHV}}\left(\frac{\text{volume fuel}}{\text{energy}}\right)$$

To convert from a HHV-based emission factor to LHV:

$$\text{EF}\left(\frac{\text{mass CO}_2}{\text{energy}}\right)_{\text{LHV}} = \text{density}\left(\frac{\text{mass fuel}}{\text{vol. fuel}}\right) \times \frac{\left(\frac{44\text{X}}{12}\right)\text{mass CO}_2}{\text{mass fuel}} \times \frac{1}{\text{LHV}}\left(\frac{\text{vol. fuel}}{\text{energy}}\right) \times \frac{\text{LHV}}{0.95\ \text{HHV}}$$

or expressed more simply:

$$EF_{LHV} = \frac{EF_{HHV}}{0.95}$$

A.1.3 Gases

A gas fuel would be treated like a liquid fuel, except that the LHV is 10% lower than the HHV, as shown:

$$LHV\left(\frac{energy}{volume}\right) = HHV\left(\frac{energy}{volume}\right)\text{-}10\%\ HHV\left(\frac{energy}{volume}\right)$$
$$LHV\left(\frac{energy}{volume}\right) = HHV\left(\frac{energy}{volume}\right)(1\text{-}0.10) = 0.90\ HHV\left(\frac{energy}{volume}\right)$$

Following the same approach as shown for the liquid fuel, the emission factor conversion for a gas fuel is:

$$EF_{LHV} = \frac{EF_{HHV}}{0.90}$$

A.2 Additional Stationary Combustion Emission Factors

A.2.1 Combustion Emission Factor Comparison for Industrial Equipment

The Climate Registry presents default CH_4 and N_2O emission factors by technology type for industrial combustion sources. The factors are taken from IPCC's *Guidelines for National Greenhouse Gas Inventories* (IPCC, 2006), *Volume 2, Chapter 2: Stationary Combustion*. IPCC cites U.S. EPA's Air Clearinghouse for Inventories and Emission Factors (CHIEF) (EPA, 2005) as the original source of the emission factors. Air CHIEF pulls emission factors from EPA references, including AP-42, FIRE, and EIIP. Because EPA presents emission factors on a HHV basis, IPCC converted the Air CHIEF emission factors to a LHV basis using the methodology described in Section 4.2. The emission factors were then provided by IPCC in units of kg/TJ energy input up to one decimal place. TCR then converted the IPCC factors back from LHV to HHV, converted the units from kg/TJ to g/MMBtu, and presented the results up to one decimal place.

The emission factors presented in Table 4-7, 4-8, and 4-9 are taken directly from AP-42.

Tables A-1 and A-2 provide a comparison of the API *Compendium's* emission factors to TCR's emission factors for external combustion and internal combustion sources, respectively. As shown in Table A-1, with the exception of the emission factors for N_2O for residual fuel oil boilers and gas/diesel oil boilers, the factors in the API *Compendium* match the factors in TCR. However, the emission factors for N_2O for residual fuel oil boilers and gas/diesel oil boilers do not match due to the fact that the IPCC N_2O factors for these sources were not revised with the Errata for AP-42 Section 1.3, dated 4/28/00. The differences in emission factors presented in Table A-2 can be explained due to roundoff error.

Table A–1. External Combustion Industrial Source Emission Factor Comparison

		***Compendium* Factors**						**TCR Factors**	
		Original Units				**Converted Units**		**Original Units**	
	N	**CH_4**		**$_2O$**		**N CH_4**	**$_2O$**	**N CH_4**	**$_2O$**
Fuel Type and Basic Technology	**Configuration**	**EF**	**Units**	**EF**	**Units**	**(g/MMBtu)**	**(g/MMBtu)**	**(g/MMBtu)**	**(g/MMBtu)**
Liquid Fuels[a]									
Residual fuel oil boilers[b]		1.00	lb/1000 gal	0.53	lb/1000 gal	3.0	1.6	3.0	0.3
Gas/diesel oil boilers[b]		0.052	lb/1000 gal	0.26	lb/1000 gal	0.2	0.8	0.2	0.4
Liquefied petroleum gases boilers		0.2	lb/1000 gal	0.9	lb/1000 gal	0.9	4.0	0.9	4.0
Solid Fuels[a]									
Other bituminous/sub-bit. Overfeed stoker boilers		0.06	lb/ton	0.04	lb/ton	1.0	0.7	1.0	0.7
Other bituminous/sub-bit. Underfeed stoker boilers		0.8	lb/ton	0.04	lb/ton	14	0.7	14	0.7
Other bituminous/sub-bituminous pulverized	Dry bottom, wall fired	0.04	lb/ton	0.03	lb/ton	0.7	0.5	0.7	0.5
	Dry bottom, tangentially fired	0.04	lb/ton	0.08	lb/ton	0.7	1.4	0.7	1.4
	Wet bottom	0.05	lb/ton	0.08	lb/ton	0.9	1.4	0.9	1.4
Other bituminous spreader stokers		0.06	lb/ton	0.04	lb/ton	1.0	0.7	1.0	0.7
Other bituminous/sub-bit. Fluidized bed combustor	Circulating bed	0.06	lb/ton	3.5	lb/ton	1.0	61.1	1.0	61.1
	Bubbling bed	0.06	lb/ton	3.5	lb/ton	1.0	61.1	1.0	61.1
Natural Gas[a]									
Boilers[c]		2.3	lb/10^6 scf	2.2	lb/10^6 scf	1.0	1.0	0.9	0.9

Footnotes and Sources:
API *Compendium*, Tables 4-7 and 4-8, 2009.
The Climate Registry (TCR). General Reporting Protocol, Version 1.1, Table 12.7, May 2008. Cites IPCC, *Guidelines for National Greenhouse Gas Inventories* (2006), Chapter 2: Stationary Combustion, Table 2.7. Values were converted from LHV (IPCC) to HHV (TCR).

[a] Residual fuel oil factors converted from lb/1000 gal to lb/MMBtu by dividing by 150 MMBtu/1000 gal, per AP-42, Section 1.3 (9/98). Distillate fuel oil factors converted from lb/1000 gal to lb/MMBtu by dividing by 140 MMBtu/1000 gal, per AP-42, Section 1.3 (9/98). LPG factors converted from lb/1000 gal to lb/MMBtu by dividing by 102 MMBtu/1000 gal (HHV for butane), per AP-42, Section 1.5 (7/08). Coal factors converted from lb/ton to lb/MMBtu by dividing by 26 MMBtu/ton, per AP-42, Section 1.1 (9/98). Natural gas factors converted from lb/10^6 scf to lb/MMBtu by dividing by 1020 MMBtu/10^6 scf, per AP-42, Section 1.4 (7/98).

[b] The TCR factors for N_2O for residual and gas/diesel oil boilers are citing an incorrect factor from IPCC. IPCC's factors were not revised with the Errata for AP-42 Section 1.3, dated 4/28/00.

[c] The natural gas boiler N_2O emission factor presented for the API *Compendium* is the uncontrolled factor.

Table A–2. Internal Combustion Industrial Source Emission Factor Comparison

		Compendium Factors						TCR Factors	
		Original Units				Converted Units		Original Units	
	N	CH_4		$_2O$		N CH_4	$_2O$	N CH_4	$_2O$
Fuel Type and Basic Technology	**Configuration**	**EF**	**Units**	**EF**	**Units**	**(g/MMBtu)**	**(g/MMBtu)**	**(g/MMBtu)**	**(g/MMBtu)**
Liquid Fuels									
Large stationary diesel oil engines >600 hp		0.0081	lb/10^6 Btu	NA		3.7	NA	4.0	NA
Natural Gas									
Gas-fired gas turbines >3MW [a]		0.0086	lb/10^6 Btu	0.003	lb/10^6 Btu	3.9	1.4	3.8	0.9
Natural gas-fired reciprocating engines	2-Stroke lean burn	1.45	lb/10^6 Btu	NA		657.7	NA	658.0	NA
	4-Stroke lean burn	1.25	lb/10^6 Btu	NA		567.0	NA	566.9	NA
	4-Stroke rich burn	0.23	lb/10^6 Btu	NA		104.3	NA	104.5	NA

Footnotes and Sources:

API *Compendium*, Table 4-9, 2009.

The Climate Registry (TCR). General Reporting Protocol, Version 1.1, Table 12.7, May 2008. Cites IPCC, Guidelines for National Greenhouse Gas Inventories (2006), Chapter 2: Stationary Combustion, Table 2.7. Values were converted from LHV (IPCC) to HHV (TCR).

[a] The gas-fired gas turbine >3MW factor is the same as the uncontrolled factor reported in Table 4-9.

A.2.2 Combustion Emissions Based on Equipment Manufacturer Data (Canadian)

Section 4.5.2 presents generic emission factors for internal combustion units. Tables A-3 and A-4 provide model-specific combustion emission factors for CH_4 and CO_2. These model-specific factors may be useful if a facility uses these specific types of engine drivers. Table A-3 applies to Waukesha reciprocating units and is taken from Table 1-7 of the CAPP document, *Calculating Greenhouse Gas Emissions* (CAPP, 2003). Table A-4 is appropriate for CAT reciprocating engines, and is taken from Table 1-8 of the CAPP document (CAPP, 2003).

The emission factors in Tables A-3 and A-4 are given on power output basis, but can be converted to a fuel input basis using the conversion factors for each type of engine given in Table 4.2 of this document. If available and applicable, model-specific conversion factors are more accurate than generic factors in Section 4. CAPP states that thermal efficiencies (higher heating value basis) for reciprocating engines typically are 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 A-3 and A-4. For these models, the user may want to use the fuel-based CO_2 estimation methodology or emission factors provided earlier in Sections 4.3 and 4.4. Also, model-specific N_2O emission factors are not available.

Table A–3. Waukesha Reciprocating Engines Combustion Emission Factors

Model	Carburetor Setting	Excess Air Ratio	Carbon Dioxide		Methane	
			Original Units, g/kW-hr	**Converted to tonnes/kW-hr**	**Original Units, g/kW-hr**	**Converted to tonnes/kW-hr**
AT25GL	Standard	1.74	580.8	5.808E-04	9.39	9.39E-06
AT27GL	Standard	1.74	Not Given		6.03	6.03E-06
	Ultra Lean	2.00	526.9	5.269E-04	4.16	4.16E-06
VHP G, GSI	Lowest manifold	0.97	581.29	5.8129E-04	2.61	2.61E-06
	Equal NO_x & CO	0.99	581.29	5.8129E-04	2.61	2.61E-06
	Catalytic converter	0.99	581.29	5.8129E-04	2.28	2.28E-06
	Standard	1.06	581.29	5.8129E-04	1.68	1.68E-06
VHP 3524 GSI	Equal NO_x & CO	0.99	576.13	5.7613E-04	1.14	1.14E-06
VHP 7044 GSI	Catalytic converter	0.99	573.7	5.737E-04	1.07	1.07E-06
	Standard	1.06	Not Given		0.80	8.0E-07
VHP 5794 GSI	Equal NO_x & CO	0.99	568.7	5.687E-04	3.42	3.42E-06
	Catalytic converter	0.99	Not Given		3.29	3.29E-06
	Standard	1.06	Not Given		2.75	2.75E-06
VHP GL	Standard	1.74	592.3	5.923E-04	6.03	6.03E-06
VGF Model G	Lowest manifold	0.97	575.0	5.750E-04	2.28	2.28E-06
	Equal NO_x & CO	0.98	Not Given		2.28	2.28E-06
	Catalytic converter	0.99	Not Given		2.28	2.28E-06
	Standard	1.12	Not Given		1.41	1.41E-06
VGF Model GSID	Catalytic converter	0.99	575.0	5.750E-04	1.68	1.68E-06
VGF GL, GLD 11:1 CR	Std.: high speed turbo	1.53	575.0	5.750E-04	5.7	5.7E-06
	T.A. Luft emissions	1.59	Not Given		4.09	4.09E-06
VGF GL 8.7:1 CR	Std.: high speed turbo	1.53	575.0	5.750E-04	4.09	4.09E-06
VSG G, GSI, GSID	Lowest manifold	0.97	566.8	5.668E-04	3.42	3.42E-06
	Equal NO_x & CO	0.98	Not Given		3.42	3.42E-06
	Catalytic converter	0.99	Not Given		3.08	3.08E-06
	Standard	1.10	Not Given		2.28	2.28E-06
F1197G G	Lowest manifold	0.97	Not Given		3.35	3.35E-06
	Equal NO_x & CO	1.0	Not Given		2.61	2.61E-06
	Catalytic converter	0.99	Not Given		2.61	2.61E-06
	Standard	1.06	Not Given		1.27	1.27E-06
F8176 G	Lowest manifold	0.97	Not Given		2.61	2.61E-06
	Equal NO_x & CO	1.0	Not Given		2.28	2.28E-06
	Catalytic converter	0.99	Not Given		2.28	2.28E-06
	Standard	1.06	Not Given		2.28	2.28E-06

Footnotes and Sources:

Canadian Association of Petroleum Producers (CAPP), *Calculating Greenhouse Gas Emissions*, Table 1-7, Canadian Association of Petroleum Producers, Publication Number 2003-03, April 2003.

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.

Table A–4. CAT Reciprocating Engines Combustion Emission Factors

Model	Power	Speed	% O2	Carbon Dioxide	
	kW	rpm		Original Units, g/kWh	Converted to tonnes/kW-hr
3412 SITA	447	1800	1.5	436	4.36E-04
3508 SITA	384	1200	7.7	574	5.74E-04
	470	1400	8.0	590	5.90E-04
3512 SITA	604	1200	8.2	579	5.79E-04
	705	1400	7.7	595	5.95E-04
3516 SITA	809	1200	8.3	567	5.67E-04
	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	
G398 TAHCR Catalyst	522	1200	2.0	Not Given	
	522	1200	0.5	Not Given	
G398 TAHCR 32C (low emissions)	522	1200	6.2	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 A.1 illustrates the use of the model-specific CH_4 and CO_2 combustion emission factors.

EXHIBIT A.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_4 and CO_2 emissions from this source.

CALCULATION METHODOLOGY:
The engine power output is multiplied by the model specific emission factors from Table A-3. Note that an emission factor for N_2O for this engine type is not available.

The annual power output from the unit is calculated as:

$$P = 500\ \text{kW} \times 0.90 \times \frac{1000\ \text{hr}}{\text{yr}} = 450{,}000\ \text{kW-hr/yr}$$

EXHIBIT A.1: Sample Calculation for Combustion Emissions Model-Specific Basis for Internal Combustion Device, continued

The emissions are calculated as:

$$E_{CH_4} = \frac{450{,}000 \text{ kW-hr}}{\text{yr}} \times \frac{9.39 \times 10^{-6} \text{ tonne } CH_4}{\text{kW-hr}}$$

$$\underline{E_{CH_4} = 4.2 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{CO_2} = \frac{450{,}000 \text{ kW-hr}}{\text{yr}} \times \frac{5.808 \times 10^{-4} \text{ tonne } CO_2}{\text{kW-hr}}$$

$$\underline{E_{CO_2} = 261 \text{ tonnes } CO_2/\text{yr}}$$

A.3 Mobile Source Combustion Emissions - Operational Basis

If mobile source fuel consumption is not available, or operational parameters cannot be used in such a way as to obtain fuel consumed, an alternate method for calculating emissions from mobile sources is to use non-fuel consumption data, such as distance traveled or power output.

A.3.1 Automobiles/Passenger Vehicles

Table A-5 provides simplified CO_2 emission factors for mobile sources (vehicles) in the United Kingdom based on distance traveled. These emission factors are based on Defra guidance (Defra, 2007).

Table A–5. Default Distance-Based CO_2 Mobile Source Emission Factors for the United Kingdom

Source	Original Units		Converted to	
	kg CO_2/miles	kg CO_2/km	tonne CO_2/miles	tonne CO_2/km
Small gasoline (petrol) car, up to 1.4 liter engine	0.2947	0.1831	0.0002947	0.0001831
Medium gasoline (petrol) car, 1.4 to 2.0 liter engine	0.3479	0.2162	0.0003479	0.0002162
Large gasoline (petrol) car, above 2.0 liter engine	0.4770	0.2964	0.0004770	0.0002964
Average gasoline (petrol) car	0.3372	0.2095	0.0003372	0.0002095
Small diesel car, up to 1.7 liter engine	0.2425	0.1507	0.0002425	0.0001507
Medium diesel car, 1.7 to 2.0 liter engine	0.3027	0.1881	0.0003027	0.0001881
Large diesel car, above 2.0 liter engine	0.4240	0.2635	0.0004240	0.0002635
Average diesel car	0.3197	0.1987	0.0003197	0.0001987
Medium gasoline (petrol) hybrid car	0.2031	0.1262	0.0002031	0.0001262
Large gasoline (petrol) hybrid car	0.3604	0.2240	0.0003604	0.0002240

Source:
Department for Environment, Food and Rural Affairs (Defra). *Guidelines to Defra's GHG conversion factors for company reporting, Annexes updated June 2007.* Tables 6a, 6b, and 6c.

Table A-6 provides default CH_4 and N_2O distance-based emission factors by vehicle model year.

Table A-6. CH_4 and N_2O Emission Factors for Highway Vehicles by Model Year

Vehicle Type and Year	CH_4			N_2O		
	Original Units	Converted to		Original Units	Converted to	
	(g/mile)	(tonne/mile)	(tonne/km)	(g/mile)	(tonne/mile)	(tonne/km)
Gasoline Passenger Cars						
Model Years 1984-1993	0.0704	7.04E-08	4.37E-08	0.0647	6.47E-08	4.02E-08
Model Year 1994	0.0531	5.31E-08	3.30E-08	0.0560	5.60E-08	3.48E-08
Model Year 1995	0.0358	3.58E-08	2.22E-08	0.0473	4.73E-08	2.94E-08
Model Year 1996	0.0272	2.72E-08	1.69E-08	0.0426	4.26E-08	2.65E-08
Model Year 1997	0.0268	2.68E-08	1.67E-08	0.0422	4.22E-08	2.62E-08
Model Year 1998	0.0249	2.49E-08	1.55E-08	0.0393	3.93E-08	2.44E-08
Model Year 1999	0.0216	2.16E-08	1.34E-08	0.0337	3.37E-08	2.09E-08
Model Year 2000	0.0178	1.78E-08	1.11E-08	0.0273	2.73E-08	1.70E-08
Model Year 2001	0.0110	1.10E-08	6.84E-09	0.0158	1.58E-08	9.82E-09
Model Year 2002	0.0107	1.07E-08	6.65E-09	0.0153	1.53E-08	9.51E-09
Model Year 2003	0.0114	1.14E-08	7.08E-09	0.0135	1.35E-08	8.39E-09
Model Year 2004	0.0145	1.45E-08	9.01E-09	0.0083	8.30E-09	5.16E-09
Model Year 2005	0.0147	1.47E-08	9.13E-09	0.0079	7.90E-09	4.91E-09
Gasoline Light Trucks (Vans, Pickup Trucks, SUVs)						
Model Years 1987-1993	0.0813	8.13E-08	5.05E-08	0.1035	1.04E-07	6.43E-08
Model Year 1994	0.0646	6.46E-08	4.01E-08	0.0982	9.82E-08	6.10E-08
Model Year 1995	0.0517	5.17E-08	3.21E-08	0.0908	9.08E-08	5.64E-08
Model Year 1996	0.0452	4.52E-08	2.81E-08	0.0871	8.71E-08	5.41E-08
Model Year 1997	0.0452	4.52E-08	2.81E-08	0.0871	8.71E-08	5.41E-08

Table A-6. CH_4 and N_2O Emission Factors for Highway Vehicles by Model Year, continued

	CH_4			N_2O		
	Original Units	**Converted to**		**Original Units**	**Converted to**	
Vehicle Type and Year	**(g/mile)**	**(tonne/mile)**	**(tonne/km)**	**(g/mile)**	**(tonne/mile)**	**(tonne/km)**
Gasoline Light Trucks (Vans, Pickup Trucks, SUVs), continued						
Model Year 1998	0.0391	3.91E-08	2.43E-08	0.0728	7.28E-08	4.52E-08
Model Year 1999	0.0321	3.21E-08	1.99E-08	0.0564	5.64E-08	3.50E-08
Model Year 2000	0.0346	3.46E-08	2.15E-08	0.0621	6.21E-08	3.86E-08
Model Year 2001	0.0151	1.51E-08	9.38E-09	0.0164	1.64E-08	1.02E-08
Model Year 2002	0.0178	1.78E-08	1.11E-08	0.0228	2.28E-08	1.42E-08
Model Year 2003	0.0155	1.55E-08	9.63E-09	0.0114	1.14E-08	7.08E-09
Model Year 2004	0.0152	1.52E-08	9.44E-09	0.0132	1.32E-08	8.20E-09
Model Year 2005	0.0157	1.57E-08	9.76E-09	0.0101	1.01E-08	6.28E-09
Gasoline Heavy-Duty Vehicles						
Model Years 1985-1986	0.4090	4.09E-07	2.54E-07	0.0515	5.15E-08	3.20E-08
Model Year 1987	0.3675	3.68E-07	2.28E-07	0.0849	8.49E-08	5.28E-08
Model Years 1988-1989	0.3492	3.49E-07	2.17E-07	0.0933	9.33E-08	5.80E-08
Model Years 1990-1995	0.3246	3.25E-07	2.02E-07	0.1142	1.14E-07	7.10E-08
Model Year 1996	0.1278	1.28E-07	7.94E-08	0.1680	1.68E-07	1.04E-07
Model Year 1997	0.0924	9.24E-08	5.74E-08	0.1726	1.73E-07	1.07E-07
Model Year 1998	0.0641	6.41E-08	3.98E-08	0.1693	1.69E-07	1.05E-07
Model Year 1999	0.0578	5.78E-08	3.59E-08	0.1435	1.44E-07	8.92E-08
Model Year 2000	0.0493	4.93E-08	3.06E-08	0.1092	1.09E-07	6.79E-08
Model Year 2001	0.0528	5.28E-08	3.28E-08	0.1235	1.24E-07	7.67E-08
Model Year 2002	0.0546	5.46E-08	3.39E-08	0.1307	1.31E-07	8.12E-08
Model Year 2003	0.0533	5.33E-08	3.31E-08	0.1240	1.24E-07	7.71E-08
Model Year 2004	0.0341	3.41E-08	2.12E-08	0.0285	2.85E-08	1.77E-08
Model Year 2005	0.0326	3.26E-08	2.03E-08	0.0177	1.77E-08	1.10E-08
Diesel Passenger Cars						
Model Years 1960-1982	0.0006	6.00E-10	3.73E-10	0.0012	1.20E-09	7.46E-10
Model Years 1983-2004	0.0005	5.00E-10	3.11E-10	0.0010	1.00E-09	6.21E-10
Diesel Light Trucks						
Model Years 1960-1982	0.0011	1.10E-09	6.84E-10	0.0017	1.70E-09	1.06E-09
Model Years 1983-1995	0.0009	9.00E-10	5.59E-10	0.0014	1.40E-09	8.70E-10
Model Years 1996-2004	0.0010	1.00E-09	6.21E-10	0.0015	1.50E-09	9.32E-10
Diesel Heavy-Duty Vehicles						
All Model Years	0.0051	5.10E-09	3.17E-09	0.0048	4.80E-09	2.98E-09

Source:
EPA, *Climate Leaders Greenhouse Gas Inventory Protocol Core Module Guidance: Direct Emissions from Mobile Combustion Sources*, May 2008.

Tables A-7 and A-8 provide CH_4 and N_2O emission factors for mobile sources (vehicles) in the U.S. and Europe respectively, based on distance traveled and number of cold starts. Combustion emissions can be calculated using a distance-based formula, as shown in Equation A-2:

$$E = (D \times EF_D) + (N_{CS} \times EF_{CS}) \qquad \text{(Equation A-2)}$$

where

D = vehicle distance traveled (km or miles);
EF_D = distance based emission factor (tonne/km or tonne/mi);
N_{CS} = number of cold starts (for U.S. vehicles only); and
EF_{CS} = cold start emission factor (g/start or lb/start) (for U.S. vehicles only).

Note that the portion of emissions due to cold starts is not applicable to European vehicles because cold starts are incorporated into the appropriate emission factors. However, the distance traveled by European vehicles needs to be proportioned into distances traveled in urban cold, urban hot, rural, and highway conditions. IPCC notes that a typical allocation of the annual mileage of a passenger car into the different driving conditions could be: 0.3/0.1/0.3/0.3 for urban cold, urban hot, rural and highway respectively (IPCC, 2006).

Table A–7. Default Distance Based CH_4 and N_2O Mobile Source Emission Factors for U.S. Vehicles

	N	**CH_4**					**$_2$O**				
		Running (hot)			**Cold Start**		**Running (hot)**			**Cold Start**	
Vehicle Type	**Emission Control Technology**	**mg/km**	**tonne/km**	**tonne/mi**	**mg/start**	**tonne/start**	**mg/km**	**tonne/km**	**tonne/mi**	**mg/start**	**tonne/start**
Light Duty Gasoline Vehicle (Car)	Low Emission Vehicle (LEV)	6	6.00E-09	9.66E-09	32	3.20E-08	0	0	0	90	9.00E-08
	Advanced three-way catalyst	7	7.00E-09	1.13E-08	55	5.50E-08	9	9.00E-09	1.45E-08	113	1.13E-07
	Early three-way catalyst	39	3.90E-08	6.28E-08	34	3.40E-08	26	2.60E-08	4.18E-08	92	9.20E-08
	Oxidation catalyst	82	8.20E-08	1.32E-07	9	9.00E-09	20	2.00E-08	3.22E-08	72	7.20E-08
	Non-oxidation catalyst	96	9.60E-08	1.54E-07	59	5.90E-08	8	8.00E-09	1.29E-08	28	2.80E-08
	Uncontrolled	101	1.01E-07	1.63E-07	62	6.20E-08	8	8.00E-09	1.29E-08	28	2.80E-08
Light Duty Diesel Vehicle (Car)	Advanced	1	1.00E-09	1.61E-09	-3	-3.00E-09	1	1.00E-09	1.61E-09	0	0.00E+00
	Moderate	1	1.00E-09	1.61E-09	-3	-3.00E-09	1	1.00E-09	1.61E-09	0	0.00E+00
	Uncontrolled	1	1.00E-09	1.61E-09	-3	-3.00E-09	1	1.00E-09	1.61E-09	-1	-1.00E-09
Light Duty Gasoline Truck	Low Emission Vehicle (LEV)	7	7.00E-09	1.13E-08	46	4.60E-08	1	1.00E-09	1.61E-09	59	5.90E-08
	Advanced three-way catalyst	14	1.40E-08	2.25E-08	82	8.20E-08	25	2.50E-08	4.02E-08	200	2.00E-07
	Early three-way catalyst	39	3.90E-08	6.28E-08	72	7.20E-08	43	4.30E-08	6.92E-08	153	1.53E-07
	Oxidation catalyst	81	8.10E-08	1.30E-07	99	9.90E-08	26	2.60E-08	4.18E-08	93	9.30E-08
	Non-oxidation catalyst	109	1.09E-07	1.75E-07	67	6.70E-08	9	9.00E-09	1.45E-08	32	3.20E-08
	Uncontrolled	116	1.16E-07	1.87E-07	71	7.10E-08	9	9.00E-09	1.45E-08	32	3.20E-08
Light Duty Diesel Truck	Advanced and moderate	1	1.00E-09	1.61E-09	-4	-4.00E-09	1	1.00E-09	1.61E-09	-1	-1.00E-09
	Uncontrolled	1	1.00E-09	1.61E-09	-4	-4.00E-09	1	1.00E-09	1.61E-09	-1	-1.00E-09
Heavy Duty Gasoline Vehicle	Low Emission Vehicle (LEV)	14	1.40E-08	2.25E-08	94	9.40E-08	1	1.00E-09	1.61E-09	120	1.20E-07
	Advanced three-way catalyst	15	1.50E-08	2.41E-08	163	1.63E-07	52	5.20E-08	8.37E-08	409	4.09E-07
	Early three-way catalyst	121	1.21E-07	1.95E-07	183	1.83E-07	88	8.80E-08	1.42E-07	313	3.13E-07
	Oxidation catalyst	111	1.11E-07	1.79E-07	215	2.15E-07	55	5.50E-08	8.85E-08	194	1.94E-07
	Non-oxidation catalyst	239	2.39E-07	3.85E-07	147	1.47E-07	20	2.00E-08	3.22E-08	70	7.00E-08
	Heavy Duty Gasoline Vehicle - Uncontrolled	263	2.63E-07	4.23E-07	162	1.62E-07	21	2.10E-08	3.38E-08	74	7.40E-08
Heavy Duty Diesel Vehicle	All -advanced, moderate, or uncontrolled	4	4.00E-09	6.44E-09	-11	-1.10E-08	3	3.00E-09	4.83E-09	-2	-2.00E-09
Motorcycles	Non-oxidation catalyst	40	4.00E-08	6.44E-08	24	2.40E-08	3	3.00E-09	4.83E-09	12	1.20E-08
	Uncontrolled	53	5.30E-08	8.53E-08	33	3.30E-08	4	4.00E-09	6.44E-09	15	1.50E-08

Footnotes and Sources:

IPCC, *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, *Volume 2, Chapter 3 (Mobile Combustion)*, Table 3.2.3, 2006.

Emission factors were converted from original units (mg/km; mg/start) and rounded to whole numbers. Negative emission factors indicate that a vehicle starting cold produces fewer emissions than a vehicle starting warm or running warm.

Implementation dates for vehicle control technologies vary by year. For a full description of implementation dates for U.S. vehicle control technologies, see the *Inventory of U.S. Greenhouse Gases and Sinks: 1990-2007, Annexes*, (EPA, 2009).

Table A–8. Default Distance Based CH_4 and N_2O Mobile Source Emission Factors for European Vehicles

Original Units										
			CH_4 Emission Factors (mg/km)				**N_2O Emission Factors (mg/km)**			
			Urban				**Urban**			
Vehicle Type	**Fuel**	**Vehicle Technology/Class**	**Cold**	**Hot**	**Rural**	**Highway**	**Cold**	**Hot**	**Rural**	**Highway**
Passenger Car	Gasoline	pre-Euro	201	131	86	41	10	10	6.5	6.5
		Euro 1	45	26	16	14	38	22	17	8.0
		Euro 2	94	17	13	11	24	11	4.5	2.5
		Euro 3	83	3	2	4	12	3	2.0	1.5
		Euro 4	57	2	2	0	6	2	0.8	0.7
	Diesel	pre-Euro	22	28	12	8	0	0	0	0
		Euro 1	18	11	9	3	0	2	4	4
		Euro 2	6	7	3	2	3	4	6	6
		Euro 3	7	3	0	0	15	9	4	4
		Euro 4	0	0	0	0	15	9	4	4
	LPG	pre-ECE	80		35	25	0	0	0	0
		Euro 1					38	21	13	8
		Euro 2					23	13	3	2
		Euro 3 and later					9	5	2	1
Light Duty Vehicles	Gasoline	pre-Euro	201	131	86	41	10	10	6.5	6.5
		Euro 1	45	26	16	14	122	52	52	52
		Euro 2	94	17	13	11	62	22	22	22
		Euro 3	83	3	2	4	36	5	5	5
		Euro 4	57	2	2	0	16	2	2	2
	Diesel	pre-Euro	22	28	12	8	0	0	0	0
		Euro 1	18	11	9	3	0	2	4	4
		Euro 2	6	7	3	2	3	4	6	6
		Euro 3	7	3	0	0	15	9	4	4
		Euro 4	0	0	0	0	15	9	4	4

Table A–8. Default Distance Based CH_4 and N_2O Mobile Source Emission Factors for European Vehicles, continued

Original Units

			CH_4 Emission Factors (mg/km)				N_2O Emission Factors (mg/km)			
			Urban				Urban			
Vehicle Type	**Fuel**	**Vehicle Technology/Class**	**Cold**	**Hot**	**Rural**	**Highway**	**Cold**	**Hot**	**Rural**	**Highway**
Heavy Duty Truck & Bus	Gasoline	All Technologies	140		110	70	6		6	6
	Diesel	GVW<16t	85		23	20	30		30	30
		GVW>16t	175		80	70	30		30	30
	CNG	pre-Euro 4	5400				N/A			
		Euro 4 and later (incl. EEV)	900							
Power Two Wheeler	Gasoline	<50 cm3	219		219	219	1		1	1
		>50 cm3 2-stroke	150		150	150	2		2	2
		>50 cm3 4-stroke	200		200	200	2		2	2

Units Converted to US Basis

			CH_4 Emission Factors (tonne/mi)				N_2O Emission Factors (tonne/mi)			
			Urban				Urban			
Vehicle Type	**Fuel**	**Vehicle Technology/Class**	**Cold**	**Hot**	**Rural**	**Highway**	**Cold**	**Hot**	**Rural**	**Highway**
Passenger Car	Gasoline	pre-Euro	3.23E-07	2.11E-07	1.38E-07	6.60E-08	1.61E-08	1.61E-08	1.05E-08	1.05E-08
		Euro 1	7.24E-08	4.18E-08	2.57E-08	2.25E-08	6.12E-08	3.54E-08	2.74E-08	1.29E-08
		Euro 2	1.51E-07	2.74E-08	2.09E-08	1.77E-08	3.86E-08	1.77E-08	7.24E-09	4.02E-09
		Euro 3	1.34E-07	4.83E-09	3.22E-09	6.44E-09	1.93E-08	4.83E-09	3.22E-09	2.41E-09
		Euro 4	9.17E-08	3.22E-09	3.22E-09	0	9.66E-09	3.22E-09	1.29E-09	1.13E-09
	Diesel	pre-Euro	3.54E-08	4.51E-08	1.93E-08	1.29E-08	0	0	0	0
		Euro 1	2.90E-08	1.77E-08	1.45E-08	4.83E-09	0	3.22E-09	6.44E-09	6.44E-09
		Euro 2	9.66E-09	1.13E-08	4.83E-09	3.22E-09	4.83E-09	6.44E-09	9.66E-09	9.66E-09
		Euro 3	1.13E-08	4.83E-09	0	0	2.41E-08	1.45E-08	6.44E-09	6.44E-09
		Euro 4	0	0	0	0	2.41E-08	1.45E-08	6.44E-09	6.44E-09
	LPG	pre-ECE	1.29E-07		5.63E-08	4.02E-08	0	0	0	0
		Euro 1					6.12E-08	3.38E-08	2.09E-08	1.29E-08
		Euro 2					3.70E-08	2.09E-08	4.83E-09	3.22E-09
		Euro 3 and later					1.45E-08	8.05E-09	3.22E-09	1.61E-09

Table A–8. Default Distance Based CH_4 and N_2O Mobile Source Emission Factors for European Vehicles, continued

Units Converted to US Basis

Vehicle Type	Fuel	Vehicle Technology/Class	CH_4 Emission Factors (tonne/mi)				N_2O Emission Factors (tonne/mi)			
			Urban				**Urban**			
			Cold	**Hot**	**Rural**	**Highway**	**Cold**	**Hot**	**Rural**	**Highway**
Light Duty Vehicles	Gasoline	pre-Euro	3.23E-07	2.11E-07	1.38E-07	6.60E-08	1.61E-08	1.61E-08	1.05E-08	1.05E-08
		Euro 1	7.24E-08	4.18E-08	2.57E-08	2.25E-08	1.96E-07	8.37E-08	8.37E-08	8.37E-08
		Euro 2	1.51E-07	2.74E-08	2.09E-08	1.77E-08	9.98E-08	3.54E-08	3.54E-08	3.54E-08
		Euro 3	1.34E-07	4.83E-09	3.22E-09	6.44E-09	5.79E-08	8.05E-09	8.05E-09	8.05E-09
		Euro 4	9.17E-08	3.22E-09	3.22E-09	0	2.57E-08	3.22E-09	3.22E-09	3.22E-09
	Diesel	pre-Euro	3.54E-08	4.51E-08	1.93E-08	1.29E-08	0	0	0	0
		Euro 1	2.90E-08	1.77E-08	1.45E-08	4.83E-09	0	3.22E-09	6.44E-09	6.44E-09
		Euro 2	9.66E-09	1.13E-08	4.83E-09	3.22E-09	4.83E-09	6.44E-09	9.66E-09	9.66E-09
		Euro 3	1.13E-08	4.83E-09	0	0	2.41E-08	1.45E-08	6.44E-09	6.44E-09
		Euro 4	0	0	0	0	2.41E-08	1.45E-08	6.44E-09	6.44E-09
Heavy Duty Truck & Bus	Gasoline	All Technologies	2.25E-07		1.77E-07	1.13E-07	9.66E-09		9.66E-09	9.66E-09
	Diesel	GVW<16t	1.37E-07		3.70E-08	3.22E-08	4.83E-08		4.83E-08	4.83E-08
		GVW>16t	2.82E-07		1.29E-07	1.13E-07	4.83E-08		4.83E-08	4.83E-08
	CNG	pre-Euro 4	8.69E-06				N/A			
		Euro 4 and later (incl. EEV)	1.45E-06							
Power Two Wheeler	Gasoline	<50 cm3	3.52E-07		3.52E-07	3.52E-07	1.61E-09		1.61E-09	1.61E-09
		>50 cm3 2-stroke	2.41E-07		2.41E-07	2.41E-07	3.22E-09		3.22E-09	3.22E-09
		>50 cm3 4-stroke	3.22E-07		3.22E-07	3.22E-07	3.22E-09		3.22E-09	3.22E-09

Units Converted to SI Basis

Vehicle Type	Fuel	Vehicle Technology/Class	CH_4 Emission Factors (tonne/km)				N_2O Emission Factors (tonne/km)			
			Urban				**Urban**			
			Cold	**Hot**	**Rural**	**Highway**	**Cold**	**Hot**	**Rural**	**Highway**
Passenger Car	Gasoline	pre-Euro	2.01E-07	1.31E-07	8.60E-08	4.10E-08	1.00E-08	1.00E-08	6.50E-09	6.50E-09
		Euro 1	4.50E-08	2.60E-08	1.60E-08	1.40E-08	3.80E-08	2.20E-08	1.70E-08	8.00E-09
		Euro 2	9.40E-08	1.70E-08	1.30E-08	1.10E-08	2.40E-08	1.10E-08	4.50E-09	2.50E-09
		Euro 3	8.30E-08	3.00E-09	2.00E-09	4.00E-09	1.20E-08	3.00E-09	2.00E-09	1.50E-09
		Euro 4	5.70E-08	2.00E-09	2.00E-09	0	6.00E-09	2.00E-09	8.00E-10	7.00E-10

Table A–8. Default Distance Based CH_4 and N_2O Mobile Source Emission Factors for European Vehicles, continued

Original Units										
			CH_4 Emission Factors (tonne/km)				**N_2O Emission Factors (tonne/km)**			
			Urban				**Urban**			
Vehicle Type	**Fuel**	**Vehicle Technology/Class**	**Cold**	**Hot**	**Rural**	**Highway**	**Cold**	**Hot**	**Rural**	**Highway**
Passenger Car	Diesel	pre-Euro	2.20E-08	2.80E-08	1.20E-08	8.00E-09	0	0	0	0
		Euro 1	1.80E-08	1.10E-08	9.00E-09	3.00E-09	0.00E+00	2.00E-09	4.00E-09	4.00E-09
		Euro 2	6.00E-09	7.00E-09	3.00E-09	2.00E-09	3.00E-09	4.00E-09	6.00E-09	6.00E-09
		Euro 3	7.00E-09	3.00E-09	0	0	1.50E-08	9.00E-09	4.00E-09	4.00E-09
		Euro 4	8.00E-08		3.50E-08	2.50E-08	1.50E-08	9.00E-09	4.00E-09	4.00E-09
	LPG	pre-ECE					0	0	0	0
		Euro 1					3.80E-08	2.10E-08	1.30E-08	8.00E-09
		Euro 2					2.30E-08	1.30E-08	3.00E-09	2.00E-09
		Euro 3 and later					9.00E-09	5.00E-09	2.00E-09	1.00E-09
Light Duty Vehicles	Gasoline	pre-Euro	2.01E-07	1.31E-07	8.60E-08	4.10E-08	1.00E-08	1.00E-08	6.50E-09	6.50E-09
		Euro 1	4.50E-08	2.60E-08	1.60E-08	1.40E-08	1.22E-07	5.20E-08	5.20E-08	5.20E-08
		Euro 2	9.40E-08	1.70E-08	1.30E-08	1.10E-08	6.20E-08	2.20E-08	2.20E-08	2.20E-08
		Euro 3	8.30E-08	3.00E-09	2.00E-09	4.00E-09	3.60E-08	5.00E-09	5.00E-09	5.00E-09
		Euro 4	5.70E-08	2.00E-09	2.00E-09	0.00E+00	1.60E-08	2.00E-09	2.00E-09	2.00E-09
	Diesel	pre-Euro	2.20E-08	2.80E-08	1.20E-08	8.00E-09	0	0	0	0
		Euro 1	1.80E-08	1.10E-08	9.00E-09	3.00E-09	0	2.00E-09	4.00E-09	4.00E-09
		Euro 2	6.00E-09	7.00E-09	3.00E-09	2.00E-09	3.00E-09	4.00E-09	6.00E-09	6.00E-09
		Euro 3	7.00E-09	3.00E-09	0	0	1.50E-08	9.00E-09	4.00E-09	4.00E-09
		Euro 4	0	0	0	0	1.50E-08	9.00E-09	4.00E-09	4.00E-09
Heavy Duty Truck & Bus	Gasoline	All Technologies	1.40E-07		1.10E-07	7.00E-08	6.00E-09		6.00E-09	6.00E-09
	Diesel	GVW<16t	8.50E-08		2.30E-08	2.00E-08	3.00E-08		3.00E-08	3.00E-08
		GVW>16t	1.75E-07		8.00E-08	7.00E-08	3.00E-08		3.00E-08	3.00E-08
	CNG	pre-Euro 4	5.40E-06				N/A			
		Euro 4 and later (incl. EEV)	9.00E-07							
Power Two Wheeler	Gasoline	<50 cm3	2.19E-07		2.19E-07	2.19E-07	1.00E-09		1.00E-09	1.00E-09
		>50 cm3 2-stroke	1.50E-07		1.50E-07	1.50E-07	2.00E-09		2.00E-09	2.00E-09
		>50 cm3 4-stroke	2.00E-07		2.00E-07	2.00E-07	2.00E-09		2.00E-09	2.00E-09

Footnotes and Source for Table A-8:
IPCC, *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, *Volume 2, Chapter 3 (Mobile Combustion)*, Table 3.2.5, 2006.
Emission factors were converted from original units (mg/km).
Implementation dates for vehicle control technologies vary by year and may vary by member state. For a full description of implementation dates for European vehicle control technologies, see the *EMEP/CORINAIR Emission Inventory Guidebook*, *Group 7: Road transport* (UNECE/EMEP, 2007).
The urban emission factor is divided into cold and hot for passenger cars and light duty trucks. The cold emission factor is relevant for trips which start with the engine at ambient temperature. A typical allocation of the annual mileage of a passenger car into the different driving conditions could be: 0.3/0.1/0.3/0.3 for urban cold, urban hot, rural and highway respectively.

Table A-9 provides CH_4 and N_2O emission factors for alternative fuel vehicles, based on distance traveled.

Table A-9. Default Distance Based CH_4 and N_2O Emission Factors for Alternative Fuel Vehicles

	CH_4			N_2O		
	Original Units	**Converted to**		**Original Units**	**Converted to**	
Vehicle Type and Year	**(g/mile)**	**(tonne/mile)**	**(tonne/km)**	**(g/mile)**	**(tonne/mile)**	**(tonne/km)**
Light Duty Alternative Fuel						
Methanol	0.018	1.80E-08	1.12E-08	0.067	6.70E-08	4.16E-08
CNG	0.737	7.37E-07	4.58E-07	0.050	5.00E-08	3.11E-08
LPG	0.037	3.70E-08	2.30E-08	0.067	6.70E-08	4.16E-08
Ethanol	0.055	5.50E-08	3.42E-08	0.067	6.70E-08	4.16E-08
Biodiesel (B20)	0.0005	5.00E-10	3.11E-10	0.001	1.00E-09	6.21E-10
Medium and Heavy-Duty Trucks						
Methanol	0.066	6.60E-08	4.10E-08	0.175	1.75E-07	1.09E-07
CNG	1.966	1.97E-06	1.22E-06	0.175	1.75E-07	1.09E-07
LNG	1.966	1.97E-06	1.22E-06	0.175	1.75E-07	1.09E-07
LPG	0.066	6.60E-08	4.10E-08	0.175	1.75E-07	1.09E-07
Ethanol	0.197	1.97E-07	1.22E-07	0.175	1.75E-07	1.09E-07
Biodiesel (B20)	0.005	5.00E-09	3.11E-09	0.005	5.00E-09	3.11E-09

Source:
EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, *Annexes*, Table A-91, April 15, 2009.

Exhibit A.2 provides an illustration of how to calculate emissions from vehicles using an operational basis.

EXHIBIT A.2: Sample Operational Basis Calculation for Combustion Emissions from Vehicles

INPUT DATA:
A fleet of heavy-duty (HD) diesel freight trucks travels 1,000,000 miles during the year. The trucks are equipped with advance control systems. There were approximately 1,500 cold starts during the year. Calculate the CH_4 and N_2O emissions using a distance-based approach and a fuel consumption approach.

EXHIBIT A.2: Sample Operational Basis Calculation for Combustion Emissions from Vehicles, continued

CALCULATION METHODOLOGY:

1. *Calculate emissions using a distance-based approach.* CH_4 and N_2O emissions are estimated using the default distance-based approach. CH_4 and N_2O emissions are calculated using emission factors obtained from Table A-7, for "Heavy Duty Diesel Vehicles".

$$E_{CH_4} = \left(\frac{1{,}000{,}000 \text{ miles}}{\text{year}} \times \frac{6.44\times10^{-9} \text{ tonne}}{\text{mile}}\right) + \left(\frac{1{,}500 \text{ cold starts}}{\text{year}} \times \frac{-1.10\times10^{-8} \text{ tonne}}{\text{start}}\right)$$

$$\underline{E_{CH_4} = 0.00642 \text{ tonne } CH_4/\text{yr}}$$

$$E_{N_2O} = \left(\frac{1{,}000{,}000 \text{ miles}}{\text{year}} \times \frac{4.83\times10^{-9} \text{ tonne}}{\text{mile}}\right) + \left(\frac{1{,}500 \text{ cold starts}}{\text{year}} \times \frac{-2.00\times10^{-9} \text{ tonne}}{\text{start}}\right)$$

$$\underline{E_{N_2O} = 0.00483 \text{ tonne } N_2O/\text{yr}}$$

2. *Calculate emissions using a fuel consumption approach.* Emissions were calculated using a fuel consumed basis in Exhibit 4.12. The CH_4 and N_2O emissions were calculated to be:

$$E_{CH_4} = \frac{142{,}857 \text{ gal}}{\text{yr}} \times \frac{4.5\times10^{-4} \text{ tonne } CH_4}{1000 \text{ gal}}$$

$$\underline{E_{CH_4} = 0.064 \text{ tonnes } CH_4/\text{yr}}$$

$$E_{N_2O} = \frac{142{,}857 \text{ gal}}{\text{yr}} \times \frac{3.1\times10^{-4} \text{ tonne } N_2O}{1000 \text{ gal}}$$

$$\underline{E_{N_2O} = 0.044 \text{ tonnes } CO_2/\text{yr}}$$

A.3.2 Marine Vessels

An alternate method for calculating emissions from marine vessels is to use operational data instead of fuel consumed. Emissions can be calculated using the following equation:

$$E = AH \times kW \times LF \times EF \times CF$$

(Equation A-3)

where

E = vessel emissions (tonnes/yr) ;
AH = annual hours per mode of operation (at sea, maneuvering) (hours);
kW = average total vessel kW (kW);
LF = engine load factor, for specified mode of operation (fraction);
EF = emission factor (g/kWh); and
CF = conversion Factor (tonne/10^6 g).

Table A-10 provides default engine load factors and emission factors for marine vessels, based on operational mode.

Table A–10. Default Operational Based Emission Factors for Marine Vessels

Vessel Type	Mode	Engine type[a]	Load Factor	Emission Factors, Original Units (g/kWh)			Emission Factors, Converted Units (tonne/kWh)		
				CO_2	NCH_4	$_2$O	CO_2	NCH_4	$_2$O
Vessel Lightening									
Oil tankers	Maneuvering	SSD	0.10	647	0.012	0.031	6.47E-04	1.20E-08	3.10E-08
Escort vessels	Maneuvering	MSD	0.10	717	0.008	0.031	7.17E-04	8.00E-09	3.10E-08
	At sea	MSD	0.80	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08
Louisiana Offshore Oil Port (LOOP)									
Tankers	At sea	SSD	0.55	588	0.006	0.031	5.88E-04	6.00E-09	3.10E-08
	Maneuvering	SSD	0.10	647	0.012	0.031	6.47E-04	1.20E-08	3.10E-08
Support vessels	Maneuvering	HSD	0.25	717	0.008	0.031	7.17E-04	8.00E-09	3.10E-08
LOOP generator	At sea	HSD	0.50	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08
LOOP pumps	At sea	HSD	1.00	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08
Pipelaying Operations									
Pipelaying	Maneuvering	MSD	0.75	717	0.008	0.031	7.17E-04	8.00E-09	3.10E-08
Drilling Rigs									
Drill ship equipment	At sea	HSD	0.75	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08
Jack-up equipment	At sea	HSD	0.75	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08
Semisubmersible equipment	At sea	HSD	0.75	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08
Submersible equipment	At sea	HSD	0.75	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08
Drilling propulsion	At sea	HSD	0.15	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08
Semisubmersible propulsion	At sea	HSD	0.15	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08
Survey Vessels									
Survey vessels	At sea	MSD	0.90	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08
Anchor handling	At sea	HSD	0.85	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08
	Maneuvering	HSD	0.10	9.6	0.008	0.031	9.60E-06	8.00E-09	3.10E-08
Support Vessels									
Supply/crew boats	At sea	HSD	0.85	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08
	Maneuvering	HSD	0.10	9.6	0.008	0.031	9.60E-06	8.00E-09	3.10E-08
Lift boats	At sea	HSD	0.85	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08
	Maneuvering	HSD	0.10	9.6	0.008	0.031	9.60E-06	8.00E-09	3.10E-08

Table A–10. Default Operational Based Emission Factors for Marine Vessels, continued

Vessel Type	Mode	Engine type[a]	Load Factor	Emission Factors, Original Units (g/kWh)			Emission Factors, Converted Units (tonne/kWh)		
				CO_2	NCH_4	$_2$O	CO_2	NCH_4	$_2$O
Support Vessels, continued									
Tugs/towing boats	At sea	HSD	0.85	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08
	Maneuvering	HSD	0.10	9.6	0.008	0.031	9.60E-06	8.00E-09	3.10E-08
Commercial Marine Vessels									
Average/Unknown	At sea	SSD	0.80	588	0.006	0.031	5.88E-04	6.00E-09	3.10E-08
Bulk materials	At sea	SSD	0.80	588	0.006	0.031	5.88E-04	6.00E-09	3.10E-08
Container ships	At sea	SSD	0.80	588	0.006	0.031	5.88E-04	6.00E-09	3.10E-08
Ferries	At sea	MSD	0.80	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08
General cargo	At sea	SSD	0.80	588	0.006	0.031	5.88E-04	6.00E-09	3.10E-08
Miscellaneous	At sea	SSD	0.80	588	0.006	0.031	5.88E-04	6.00E-09	3.10E-08
Offshore	At sea	MSD	0.80	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08
Refrigerated	At sea	SSD	0.80	588	0.006	0.031	5.88E-04	6.00E-09	3.10E-08
Roll On/Roll Off	At sea	MSD	0.80	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08
Tankers	At sea	SSD	0.80	588	0.006	0.031	5.88E-04	6.00E-09	3.10E-08
Tug boats	At sea	MSD	0.80	652	0.004	0.031	6.52E-04	4.00E-09	3.10E-08

Footnotes and Source:

Wilson, Darcy, Richard Billings, Regi Oommen, and Roger Chang, Eastern Research Group, Inc. *Year 2005 Gulfwide Emission Inventory Study*, OCS Study MMS 2007-067, U.S. Department of the Interior, Minerals Management Service (MMS), Gulf of Mexico OCS Region, New Orleans, December 2007.

[a] SSD = Slow Speed Diesel Engine; MSD = Medium Speed Diesel Engine; HSD = High Speed Diesel Engine.

Exhibit A.3 provides an illustration of how to calculate emissions from marine vessels using an operational basis.

EXHIBIT A.3: Sample Operational Basis Calculation for Combustion Emissions from Marine Vessels

INPUT DATA:
A fleet of 17 diesel-powered tankers operated 90 percent of the year at sea. The fuel consumption and Gross Registered Tonnage for each ship is unknown. The vessels have an average engine rating of 9,400 kW with an average of 2,000 kW auxiliary power. Calculate the CO_2, CH_4, and N_2O emissions from the fleet using an operational basis. Compare the results to the emissions calculated in Exhibit 4.12 (using a fuel consumption basis).

CALCULATION METHODOLOGY:
1. *Calculate fleet emissions using an operational basis*. Emissions are estimated using the operational-based approach load and emission factors provided in Table A-10 (for "*Commercial Marine Vessels*: Tankers "). Emissions are calculated using Equation A-3.

$$E_{CO_2} = 17\text{ ships} \times 0.9 \times \frac{365\text{ days}}{\text{year}} \times \frac{24\text{ h}}{\text{day}} \times \frac{11{,}400\text{ kW}}{\text{ship}} \times 0.80 \times \frac{588\text{ g}}{\text{kWh}} \times \frac{\text{kg}}{1{,}000\text{ g}} \times \frac{\text{tonne}}{1{,}000\text{ kg}}$$

$$\underline{E_{CO_2} = 718{,}733\text{ tonne } CO_2/\text{yr}}$$

$$E_{CH_4} = 17\text{ ships} \times 0.9 \times \frac{365\text{ days}}{\text{year}} \times \frac{24\text{ h}}{\text{day}} \times \frac{11{,}400\text{ kW}}{\text{ship}} \times 0.80 \times \frac{0.006\text{ g}}{\text{kWh}} \times \frac{\text{kg}}{1{,}000\text{ g}} \times \frac{\text{tonne}}{1{,}000\text{ kg}}$$

$$\underline{E_{CH_4} = 7.33\text{ tonne } CH_4/\text{yr}}$$

$$E_{N_2O} = 17\text{ ships} \times 0.9 \times \frac{365\text{ days}}{\text{year}} \times \frac{24\text{ h}}{\text{day}} \times \frac{11{,}400\text{ kW}}{\text{ship}} \times 0.80 \times \frac{0.031\text{ g}}{\text{kWh}} \times \frac{\text{kg}}{1{,}000\text{ g}} \times \frac{\text{tonne}}{1{,}000\text{ kg}}$$

$$\underline{E_{N_2O} = 37.89\text{ tonne } N_2O/\text{yr}}$$

2. Compare the operational basis emissions to the fuel consumption basis emissions. For comparison purposes, emissions calculated using the fuel consumed basis were calculated (in Exhibit 4.13) to be:

EXHIBIT A.3: Sample Operational Basis Calculation for Combustion Emissions from Marine Vessels, continued

$$E_{CO_2} = \frac{1.07 \times 10^{16}\ J}{yr} \times \frac{69.3\ tonne\ CO_2}{10^{12}\ J}$$

$$\underline{E_{CO_2} = 738{,}861\ tonnes\ CO_2/yr}$$

$$E_{CH_4} = \frac{275{,}498\ m^3}{yr} \times \frac{1.5 \times 10^{-4}\ tonne\ CH_4}{m^3}$$

$$\underline{E_{CH_4} = 41.32\ tonnes\ CH_4/yr}$$

$$E_{N_2O} = \frac{275{,}498\ m^3}{yr} \times \frac{1.1 \times 10^{-3}\ tonne\ N_2O}{m^3}$$

$$\underline{E_{N_2O} = 303.05\ tonnes\ N_2O/yr}$$

A.4 References

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AMERICAN PETROLEUM INSTITUTE

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

AUGUST 2009

APPENDIX B

ADDITIONAL VENTING CALCULATION INFORMATION

Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry

Appendix B – Additional Venting Calculation Information

August 2009

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B. ADDITIONAL VENTING CALCULATION INFORMATION

This section presents supplemental information for the vented emission calculation methodologies presented in Section 5.

B.1 Derivation of Asphalt Blowing Emission Factors

The asphalt blowing CH_4 emission factors provided in Section 5.2.5 were derived from asphalt blowing exhaust composition data presented in an *Oil & Gas Journal* article (Dimpfl, 1980). Because the asphalt blowing emission factor presented in AP-42 is assumed to be on an air-free basis, the composition is also converted to an air-free basis. Both the original and adjusted samples are presented in Table B-1, along with the molecular weight of each compound:

Table B–1. Default Asphalt Blowing Exhaust Composition

Substance	Industrial Air Blowing Flux, Mole % [a]	Adjusted Industrial Air Blowing Flux, Mole% [b]	Molecular Weight	Air Free Basis, Mol % [c]
H_2	1.20%	1.20%	2.02	52.2%
H_2S	0.10%	0.10%	34.08	4.3%
N and Ar	81.2%	81.25%	28.01	--
O_2	16.4%	16.45%	32.00	--
CO	0.10%	0.10%	28.01	4.3%
CO_2	0.20%	0.20%	44.01	8.7%
CH_4	0.30%	0.30%	16.04	13.0%
C_2	0.10%	0.10%	30.07	4.3%
C_3	0.10%	0.10%	44.10	4.3%
C_4	0.10%	0.10%	58.12	4.3%
C_5+	0.10%	0.10%	72.15	4.3%
Total	99.9%	100%	--	100%

Footnotes and Sources:

[a] Dimpfl, “Study Gives Insight Into Asphalt Tank Explosions”, *Oil and Gas Journal*, December 1980.

[b] The Dimpfl results accounted for only 99.9% of the speciation; this column presents the speciation data, adjusted to 100%. speciation.

[c] Derived from Dimpfl. Also reported in ARPEL, *Atmospheric Emissions Inventories Methodologies in the Petroleum Industry*, Table 6.24, 1998.

The exhaust emission rate is typically on a mass basis. Since the exhaust analysis is on a molar basis, the exhaust concentration must be converted to a mass basis. First, the exhaust gas molecular weight of the mixture ($MW_{Mixture}$) must be estimated. Equation 3-8 is used to estimate the gas molecular weight of the air-free mixture.

$$MW_{Mixture} = \frac{1}{100} \times \sum_{i=1}^{\#\,compounds} \left(Mole\%_i \times MW_i\right) \qquad \text{(Equation 3-8)}$$

$$MW_{Mixture} = \frac{1}{100} \times \begin{bmatrix} (52.2 \times 2.02) + (4.3 \times 34.08) + (4.3 \times 28.01) + \\ (8.7 \times 44.01) + (13.0 \times 16.04) + (4.3 \times 30.07) \\ + (4.3 \times 44.10) + (4.3 \times 58.12) + (4.3 \times 72.15) \end{bmatrix}$$

$$\underline{MW_{Mixture} = 18.56}$$

Next, the weight percent of CH_4 is estimated using Equation 3-7 and rearranged in terms of the weight percent ($Wt\%_i$).

$$Mole\%_i = Wt\%_i \times \frac{MW_{Mixture}}{MW_i} \Rightarrow Wt\%_i = Mole\%_i \times \frac{MW_i}{MW_{Mixture}}$$

$$Wt\%_{CH_4} = \frac{13.0}{100} \times \frac{16.04}{18.56}$$

$$\underline{Wt\%_{CH_4} = 11.27\%}$$

$$Wt\%_{CO_2} = \frac{8.7}{100} \times \frac{44.01}{18.56}$$

$$\underline{Wt\%_{CO_2} = 20.62\%}$$

Finally CO_2 and CH_4 emission factors are calculated, using the density of asphalt (taken from Table 3-8), the AP-42 emission factor for blown asphalt (provided in Section 5.2.6), and the weight percent CH_4 (calculated above). The derivation is shown as follows, for common U.S. units:

$$EF_{CO_2} = \text{bbl asphalt blown} \times \frac{42\text{ gal}}{\text{bbl}} \times \frac{8.61\text{ lb asphalt}}{\text{gal asphalt}} \times \frac{\text{tonne}}{2204.62\text{ lb}} \times \frac{0.03\text{ tonne exhaust}}{\text{tonne asphalt blown}} \times \frac{20.62\text{ tonne }CO_2}{100\text{ tonne exhaust}}$$

$$EF_{CO_2} = \frac{1.01\text{E-03 tonne }CO_2}{\text{bbl asphalt blown}}$$

$$EF_{CO_2} = \text{ton asphalt blown} \times \frac{2000\text{ lb}}{\text{ton}} \times \frac{\text{tonne}}{2204.62\text{ lb}} \times \frac{0.03\text{ tonne exhaust}}{\text{tonne asphalt blown}} \times \frac{20.62\text{ tonne }CO_2}{100\text{ tonne exhaust}}$$

$$EF_{CO_2} = \frac{5.61\text{E-03 tonne }CO_2}{\text{ton asphalt blown}}$$

$$EF_{CH_4} = \text{bbl asphalt blown} \times \frac{42\text{ gal}}{\text{bbl}} \times \frac{8.61\text{ lb asphalt}}{\text{gal asphalt}} \times \frac{\text{tonne}}{2204.62\text{ lb}} \times \frac{0.03\text{ tonne exhaust}}{\text{tonne asphalt blown}} \times \frac{11.27\text{ tonne }CH_4}{100\text{ tonne exhaust}}$$

$$EF_{CH_4} = \frac{5.55\text{E-04 tonne }CH_4}{\text{bbl asphalt blown}}$$

$$EF_{CH_4} = \text{ton asphalt blown} \times \frac{2000\text{ lb}}{\text{ton}} \times \frac{\text{tonne}}{2204.62\text{ lb}} \times \frac{0.03\text{ tonne exhaust}}{\text{tonne asphalt blown}} \times \frac{11.27\text{ tonne }CH_4}{100\text{ tonne exhaust}}$$

$$EF_{CH_4} = \frac{3.07\text{E-03 tonne }CH_4}{\text{ton asphalt blown}}$$

B.2 Catalytic Cracking Regenerator “K_1, K_2, K_3” Approach

Section 5.2.1 presents two approaches to estimate CO_2 emissions from catalytic cracking regeneration. The first approach, shown in Equation 5-4, is based on the coke burn rate and the coke carbon fraction. The second approach, shown in Equation 5-5, is based on the air blower rate and flue gas CO and CO_2 concentrations.

EPA rule 40 CFR 63, Subpart UUU (April 2002) and EPA rule 40 CFR 60, Subpart Ja (July 2008) provide an approach to estimate the coke burn rate using the “K_1, K_2, K_3” approach. This coke burn rate equation is:

$$CC = \left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO}\right)\right] + \left(K_2 \times Q_a\right) - \left[K_3 \times Q_r \times \left(\frac{P_{CO}}{2} + P_{CO_2} + P_{O_2}\right)\right] + \left(K_3 \times Q_{oxy} \times P_{O_{xy}}\right) \qquad \text{(Equation B-1)}$$

where

CC = coke burn rate in units of mass per year (lb/hr or kg/hr);
K_1, K_2, K_3 = material balance and conversion factors (see units provided in table below);
Q_r = volumetric flow rate of exhaust gas before entering the emission control system, calculated using Equation B-2 (dscf/min or dscm/min);
Q_a = volumetric flow rate of air to regenerator as determined from control room instrumentation (dscf/min or dscm/min);
Q_{Oxy} = volumetric flow rate of O_2-enriched air to regenerator as determined from control room instrumentation (dscf/min or dscm/min);
P_{CO_2} = percent CO_2 concentration in regenerator exhaust, percent by volume (dry basis);
P_{CO} = percent CO concentration in regenerator exhaust, percent by volume (dry basis); when no auxiliary fuel is burned and a continuous CO monitor is not required, assume P_{CO} to be zero;
P_{O2} = percent O_2 concentration in regenerator exhaust, percent by volume (dry basis); and
P_{Oxy} = O_2 concentration in O_2-enriched air stream inlet to regenerator, percent by volume (dry basis).

The coke burn rate material balance conversion factors from 40 CFR 63.1564 (July 2008) are shown below:

Table B–2. Coke Burn Rate Material Balance Conversion Factors

Variable	Variable Purpose	Value	Unit
K_1	Carbon burn term	0.2982 0.0186	(kg min)/(hr dscm %) (lb min)/(hr dscf %)
K_2	Hydrogen burn term from O_2 in Air	2.0880 0.1303	(kg min)/(hr dscm %) (lb min)/(hr dscf %)
K_3	Hydrogen burn equivalent in excess O_2 and carbon oxides	0.0994 0.0062	(kg min)/(hr dscm) (lb min)/(hr dscf)

The volumetric flow rate of exhaust gas before entering the emission control system is calculated using Equation B-2:

$$Q_r = \frac{79 \times Q_a + \left(100 - P_{O_{xy}}\right) \times Q_{oxy}}{100 - P_{CO_2} - P_{CO} - P_{O_2}} \qquad \text{(Equation B-2)}$$

The coke burned is assumed to proceed completely to CO_2. Based on this assumption and accounting for the conversion of units, the CO_2 emission rate is then calculated from Equation B-3.

$$E_{CO_2} = CC_{Avg} \times CF \times \frac{44 \text{ mass units } CO_2}{12 \text{ mass units C}} \qquad \text{(Equation B-3)}$$

where

E_{CO_2} = emissions of CO_2 in units of mass (pounds, kg, tonnes) per year;
CC = daily average coke burn rate in units of mass per year;
CF = fraction of carbon in the coke burned;
44 = molecular weight of CO_2; and
12 = molecular weight of carbon (coke is assumed to be carbon).

Although the EPA rules include the use of all three "K" terms, CO_2 emissions can be estimated directly from the K_1 term. The first term in Equation B-1 ($[K_1 \text{ x } Q_r \text{ x } (P_{CO2} + P_{CO})]$) is the total carbon content in the coke. With this knowledge, the carbon fraction (CF) can be determined by dividing the total carbon content in the coke by the total coke burned, as shown in Equation B-4.

$$CF = \frac{\left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO}\right)\right]}{\left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO}\right)\right] + \left(K_2 \times Q_a\right) - \left[K_3 \times Q_r \times \left(\frac{P_{CO}}{2} + P_{CO_2} + P_{O_2}\right)\right] + \left(K_3 \times Q_{oxy} \times P_{O_{xy}}\right)} \qquad \text{(Equation B-4)}$$

Substituting the CC and CF terms into Equation B-3 results in Equation B-5.

$$\begin{aligned} E_{CO_2} = {} & \left\{\left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO}\right)\right] + \left(K_2 \times Q_a\right) - \left[K_3 \times Q_r \times \left(\frac{P_{CO}}{2} + P_{CO_2} + P_{O_2}\right)\right] + \left(K_3 \times Q_{oxy} \times P_{O_{xy}}\right)\right\} \\ & \times \frac{\left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO}\right)\right]}{\left\{\left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO}\right)\right] + \left(K_2 \times Q_a\right) - \left[K_3 \times Q_r \times \left(\frac{P_{CO}}{2} + P_{CO_2} + P_{O_2}\right)\right] + \left(K_3 \times Q_{oxy} \times P_{O_{xy}}\right)\right\}} \times \frac{44}{12} \end{aligned} \qquad \text{(Equation B-5)}$$

Which reduces to the equation shown below:

$$E_{CO_2} = \left[K_1 \times Q_r \times \left(P_{CO_2} + P_{CO}\right)\right] \times \frac{44}{12} \qquad \text{(Equation B-6)}$$

Therefore, by inspection, the CO_2 emissions can be estimated directly from the K_1 term without introducing the error associated with K_2 and K_3 terms and the coke carbon fraction. Equation B-6 is also shown in Section 5.2.1 (Equation 5-5).

B.3 Derivation of Simplified Tank Flashing Emission Factors

B.3.1 *Crude Oil Flashing Losses*

A simplified CH_4 emission factor was derived from combining crude oil 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_4 contents. In order to combine the measurements, each was converted to a common production segment CH_4 concentration of 78.8% (Shires and Harrison, 1996). The measurement data and conversion calculations are summarized in Table B-3.

Table B–3. Crude Oil Tank Flashing Loss Emission Factor Development

Measurement	Oil Fill Rate, bbl/day	CH_4 Emissions, scf/hr [a]	Separator Mol % CH_4	CH_4 EF, scf/bbl	Normalized CH_4 EF, scf/bbl/sep-% CH_4
Canadian Measurements [b]					
1	34.6	4.98	75.91	3.45	0.045
2	69.2	128	81.78	44.5	0.544
3	2,717	5.32	69.99	0.05	0.001
4	34.6	9.32	75.91	6.46	0.085
5	1,413	376	88.16	6.38	0.072
Canadian Average			*78.35*	*12.16*	*0.15*
API Measurements [c]					
1	188	179	57.91	22.8	0.394
2	1,600	573	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	56.9	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
API Average			*54.19*	*47.6*	*0.90*
Combined Average [d,e]				**32.84±106%**	**0.586±109%**
Corrected Emission Factor, scf CH_4/bbl [d,e]				**46.20**	**±110%**
Corrected Emission Factor, lb CH_4/bbl [d,e]				**1.954**	**±110%**
Corrected Emission Factor, tonnes CH_4/bbl [d,e]				**8.86E-04**	**±110%**
Corrected Emission Factor, tonnes CH_4/m^3 oil [d,e]				**5.57E-03**	**±110%**

Footnotes and Sources:

[a] Corrected to 60°F and 1 atm.

[b] Source: Picard, D. J., B. D. Ross, and D. W. H. Koon. *A Detailed Inventory of CH_4 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.

[c] 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_4 concentration).

[d] Uncertainty based on a 95% confidence interval.

[e] Corrected to average CH_4 concentration for natural gas industry production operations of 78.8%. Source for 78.8% CH_4 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 U.S. Environmental Protection Agency, June 1996.

B.3.2 Condensate Flashing Losses

A simplified CH_4 emission factor was derived for condensate flashing losses using a measurement program conducted in east Texas for the Houston Advanced Research Center (Hendler et al., 2006). Condensate tanks were distinguished from crude oil tanks in the measurements program based on how the well sites were classified in the Texas Railroad Commission online database. The measurement program presented flashing loss emission rates, compositions, and liquid production rates. From these data, an average condensate flashing loss emission factor was developed based on averaging the data as summarized in Table B-4.

Table B–4. Condensate Tank Flashing Loss Emission Factor Development [a]

HARC Study Tank Battery Number	Data Point Number	Condensate Production Rate, bbl/day	Tank Vent Rate, scf/day	Tank Vent MWT, lb/lbmole	Total Gas Vent Mass Rate, lb/day [b]	Vent Gas CH_4 Content, Wt. %	CH_4 Emission Rate, lb/day	CH_4 Emission Factor, lb/bbl
2	1	105	11,406	27.3	821	39.71	325.8	3.103
3	2	87	12,642	33.4	1,113	26.30	292.7	3.364
4	3	120	1,807	34.3	163	22.07	36.0	0.300
5	4	100	863	42.2	96.1	12.06	11.6	0.116
6	5	130	6,200	36.4	594	19.27	114.5	0.881
13	6	2	793	46.4	96.9	8.53	8.3	4.133
14	7	4	2,744	30.5	221	31.52	69.5	17.373
15	8	5	584	47.6	73.3	6.52	4.8	0.956
16	9	2	1,084	50.0	143	5.83	8.3	4.167
17	10	2	4,594	36.6	443	23.26	103.0	51.501
18	11	10	1,015	38.9	104	20.24	21.1	2.108
19	12	2	291	44.3	34.0	13.81	4.7	2.345
20	13	10	3,113	46.4	380	7.91	30.1	3.010
23	14	27	1,358	51.9	186	10.28	19.1	0.707
24	15	1	53	43.0	6.01	12.35	0.7	0.742
25	16	1	926	89.0	217	0.09	0.2	0.200
27	17	2	235	54.0	33.5	6.53	2.2	1.093
28	18	30	2,846	30.2	227	31.93	72.4	2.413
29	19	61	21,601	43.5	2,474	10.04	248.4	4.072
30	20	15	1,639	34.2	148	23.10	34.1	2.277
32	21	142	77,319	50.6	10,304	2.15	221.9	1.562
26	22	1	9,210	56.2	1,365	3.93	53.6	Excluded [c]
Average, lb CH_4/bbl [d]:							**5.068**	**±101%**
Average converted to tonnes CH_4/bbl [d]:							**0.00230**	**±101%**
Average converted to tonnes CH_4/m^3 condensate [d]:							**0.0145**	**±101%**

Footnotes and Sources:

[a] Hendler, Albert, Jim Nunn, Joe Lundeen, Ray McKaskle. *VOC Emissions from Oil and Condensate Storage Tanks*, Final Report, prepared for Houston Advanced Research Center (HARC), October 31, 2006 (Cited Tables 3-3 and 3-5).

[b] Corrected to 60°F and 1 atm.

[c] Data point excluded from analysis since the report indicates that the value is an anomaly due to fracking at an adjacent well.

[d] Uncertainty based on a 95% confidence interval.

B.4 Additional Loading, Ballasting, and Transit Loss Methodology

Calculating evaporative emissions associated with loading, ballasting, and transit operations is suggested only for "live" crude oil or if measured CH_4 or CO_2 content data are available for "weathered" crude or other petroleum vapors.[1] Section 5.5 presents the simple calculation approaches for loading, ballasting, and transit loss emissions for crude oil. This section provides more detailed calculation approaches. However, due to the fact that there is typically no CH_4 or CO_2 in most petroleum products nor in "weathered" crude. These methods are useful for estimating CO_2 emissions that result when the evaporative emissions associated with loading, ballasting, and transit operations are sent to a combustion control device, such as a thermal oxidizer or VCU. More information on the CH_4 and CO_2 content of "weathered" crude and other petroleum products is provided in Appendix E.

B.4.1 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. When loading losses are routed to a combustion device, the mass of vapors sent to the combustion device can be estimated using the methodology described in this section. Emissions from the combustion device should be calculated using the methodology described in Section 4.

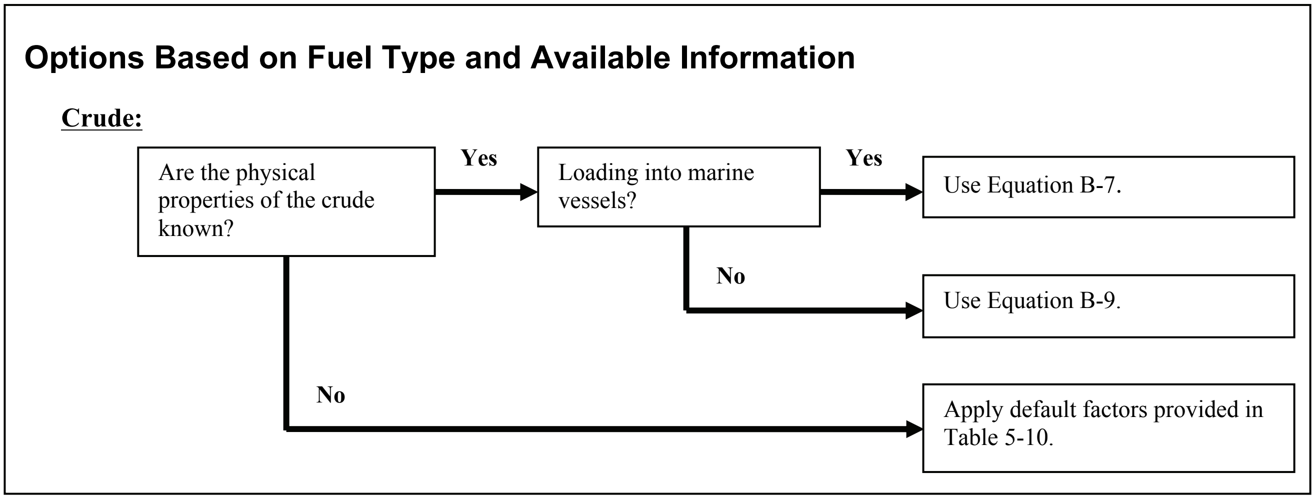

Figure B–1. Decision Tree for Crude Loading Losses

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[1] This is consistent with AP-42, which notes that the non-VOC (i.e., CH_4 and C_2H_6) portion of TOC emissions from other petroleum liquids is generally considered negligible (EPA, AP-42 Section 5.2, 2008).

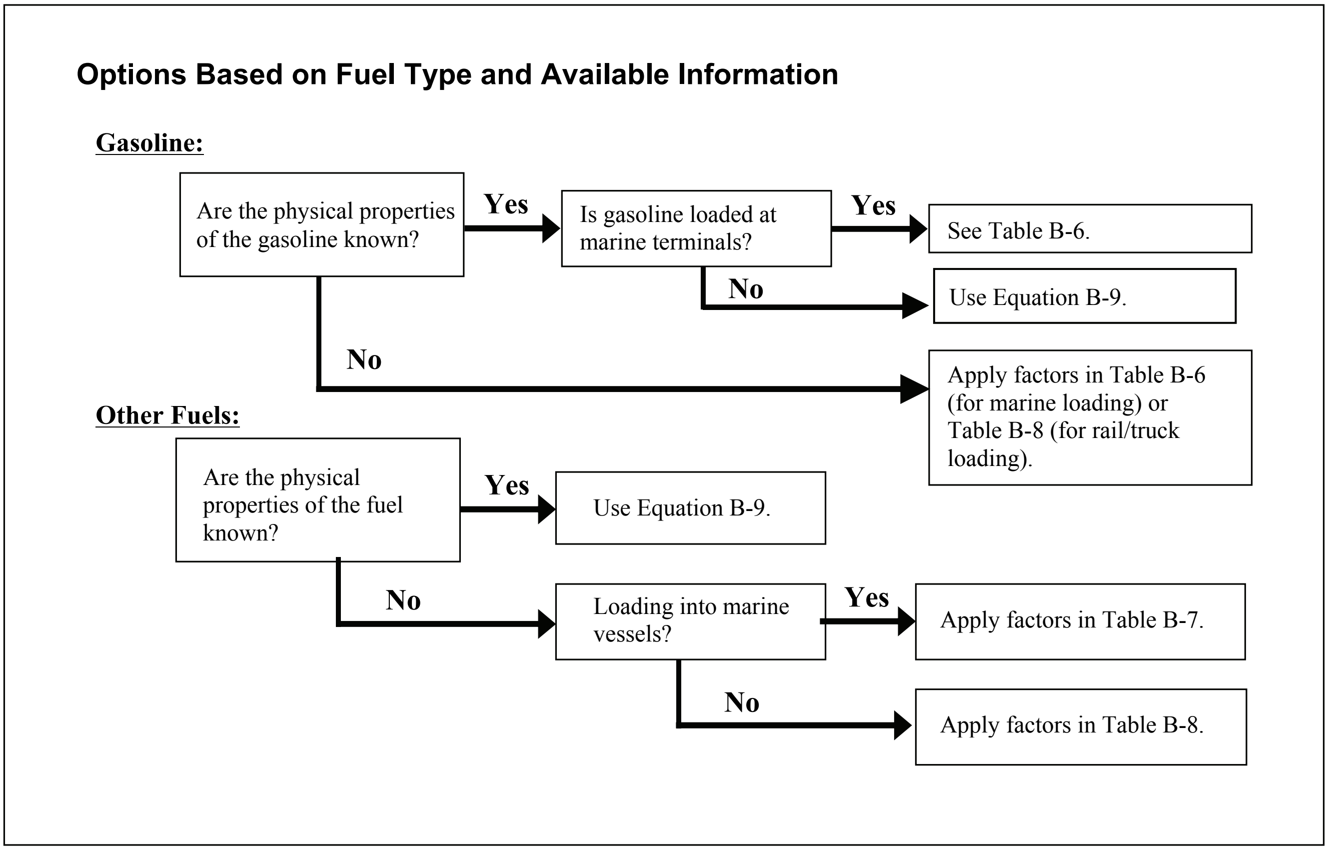

Figure B–2. Decision Tree for Gasoline and Other Liquid Fuel Loading Losses

For crude oil loaded into ships and ocean barges, Equation B-7, below, is applicable (EPA, AP-42, Section 5.2, 2008).

$$C_L = C_A + C_G \qquad \text{(Equation B-7)}$$

where

C_L = total loading loss TOC emission factor, lb/10^3 gallon of crude oil loaded;
C_A = arrival emission factor, from vapors in the empty tank vessel before loading, lb/10^3 gallon loaded (shown in Table B-5); and
C_G = emission factor for emissions generated during loading, lb/10^3 gallon (calculated using Equation B-8).

Equation B-8 provides the calculation for the factor C_G (EPA, AP-42 Section 5.2, Equation 3, 2008).

$$C_G = 1.84 \times (0.44\ P - 0.42) \times \left(\frac{M \times G}{T}\right) \qquad \text{(Equation B-8)}$$

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; and
T = temperature of the vapors, °R (°R = °F + 459.7)

The arrival factor, C_A, in the expression above is presented in Table B-5 below.

Table B–5. Average Arrival TOC Emission Factor, C_A, for the Crude Oil Marine Vessel Loading Emission Factor Equation

Ship/Ocean Barge Tank Condition	Previous Cargo [b]	Arrival Emission Factor, C_A		
		Original Units [a,c]	Converted Units	
		lb TOC/10^3 gallon	tonnes TOC/ 10^6 gal	tonnes TOC/ 10^6 m^3
Uncleaned	Volatile	0.86	0.39	103
Ballasted	Volatile	0.46	0.21	55
Cleaned or gas-freed	Volatile	0.33	0.15	40
Any condition	Non-volatile	0.33	0.15	40

Footnotes and Sources:
[a] EPA, AP-42, Section 5.2, June 2008.
[b] The factors shown are for TOCs. AP-42 reports that the VOC comprises 55-100% of the TOC, with a typical value of 85%. Thus, a simplifying assumption for the CH_4 content of the TOC is 15% in the absence of site-specific data, recognizing that this likely overestimates the CH_4 emissions.
[c] "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 references provide this information, including *Perry's Chemical Engineering Handbook* (Perry, 1984) and the *CRC Handbook of Chemistry and Physics* (CRC Press, 1984). Table B-6 provides these properties for some select petroleum liquids based on the average ambient temperature of the facility (EPA, AP-42, Section 7.1, 2006).

Average temperature information for a specific location can be found at a number of Internet sites, such as[2]:

http://www.worldclimate.com/
http://www.weatherbase.com/
http://www.ncdc.noaa.gov/oa/ncdc.html

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[2] Accessed January 9, 2009.

Table B–6. Properties of Select Petroleum Liquids [a]

Petroleum Liquid [b]	Vapor Molecular Weight at 60°F, (lb/lbmole)	Liquid Density 60°F, (lb/gal)	True Vapor Pressure (psi)						
			40°F	50°F	60°F	70°F	80°F	90°F	100°F
Crude oil RVP 5	50	7.1	1.8	2.3	2.8	3.4	4.0	4.8	5.7
Distillate fuel oil No. 2	130	7.1	0.0031	0.0045	0.0065	0.009	0.012	0.016	0.022
Gasoline RVP 7	68	5.6	2.3	2.9	3.5	4.3	5.2	6.2	7.4
Gasoline RVP 10	66	5.6	3.4	4.2	5.2	6.2	7.4	8.8	10.5
Gasoline RVP 13	62	5.6	4.7	5.7	6.9	8.3	9.9	11.7	13.8
Jet kerosene	130	7	0.0041	0.006	0.0085	0.011	0.015	0.021	0.029
Jet naphtha (JP-4)	80	6.4	0.8	1	1.3	1.6	1.9	2.4	2.7
Residual oil No. 6	190	7.9	0.00002	0.00003	0.00004	0.00006	0.00009	0.000013	0.000019
Petroleum Liquid [b]	**Vapor Molecular Weight at 60°F, (lb/lbmole)**	**Liquid Density 60°F, (kg/m^3)**	**True Vapor Pressure (psi)**						
			4.4°C	10.0°C	15.6°C	21.1°C	26.7°C	32.2°C	37.8°C
Crude oil RVP 5	50	851	12.4	15.9	19.3	23.4	27.6	33.1	39.3
Distillate fuel oil No. 2	130	851	0.021	0.031	0.045	0.062	0.083	0.11	0.15
Gasoline RVP 7	68	671	15.9	20.0	24.1	29.6	35.9	42.7	51.0
Gasoline RVP 10	66	671	23.4	29.0	35.9	42.7	51.0	60.7	72.4
Gasoline RVP 13	62	671	32.4	39.3	47.6	57.2	68.3	80.7	95.1
Jet kerosene	130	839	0.028	0.041	0.059	0.076	0.10	0.14	0.20
Jet naphtha (JP-4)	80	767	5.5	6.9	9.0	11.0	13.1	16.5	18.6
Residual oil No. 6	190	947	0.000138	0.000207	0.000276	0.000414	0.000621	0.000896	0.000131

Footnotes and Sources:

[a] EPA, AP-42, Table 7.1-2, November 2006.

[b] Properties of additional petroleum liquids and petrochemicals are available in AP-42, Section 7.1, November 2006.

When estimating evaporative CH_4 (or CO_2, if present) emissions from loading operations, the fuel CH_4 (or CO_2) content is required to convert from the TOC emission factors provided in this section. For crude oil, AP-42 reports that the VOC comprises 55-100 wt% of the TOC, with a typical value of 85%. Thus, a simplifying assumption for the CH_4 content of the "live" crude TOC is 15 wt% in the absence of site-specific data. This assumption overestimates emissions because the non-VOC portion of the TOC includes both CH_4 and ethane (C_2H_6). Based on composition data presented in Appendix E, this wt% CH_4 would not be applicable to "weathered" crude or refined petroleum products. However, evaporative emissions from loading operations may be combusted in the control device, which would convert the hydrocarbons to CO_2.

Exhibit B.6 illustrates the use of Equation B-7 for estimating evaporative CH_4 emissions from marine vessel loading of "live" crude oil.

EXHIBIT B.6: Sample Calculation for Estimating Crude Oil Marine Loading Loss CH_4 Emissions Using Equations B-7 and B-8

INPUT DATA:
50,000 bbl/yr of "live" 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). The average ambient temperature at the facility is 70°F (529.7°R) based on average annual meteorological data. Calculate the CH_4 emissions.

CALCULATION METHODOLOGY:
The crude oil molecular weight and vapor pressure are estimated using data provided in Table B-6 for crude oil with an RVP of 5 psi. Using Equation B-8, the "generated emission factor" or C_G is calculated as:

$$C_G = 1.84 \times [(0.44 \times 3.4) - 0.42] \times \left(\frac{50 \times 1.02}{529.7}\right)$$

$$C_G = 0.19 \text{ lb TOC/}10^3\text{gal crude}$$

Next, the "arrival" emission factor, C_A, is read from Table B-5. 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-5 gives a C_A factor of 0.86 lb TOC/10^3 gallons of crude loaded. With the factors C_A and C_G now defined, the total loading loss factor, C_L, is estimated using Equation B-7:

$$C_L = (0.86 \text{ lb TOC/}10^3 \text{ gal}) + (0.19 \text{ lb TOC/}10^3 \text{ gal})$$

$$C_L = 1.05 \text{ lb TOC/}10^3 \text{ gal crude loaded}$$

EXHIBIT B.6: Sample Calculation for Estimating Crude Oil Marine Loading Loss CH_4 Emissions Using Equations B-7 and B-8, continued

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_4 content of the vapors to obtain the CH_4 emissions. Because a specific CH_4 content is not available, 15% by weight is assumed, per Table B-5. Thus, the CH_4 emissions from the "live" crude oil ship loading are:

$$E_{CH_4} = \frac{1.05 \text{ lb TOC}}{10^3 \text{gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{50{,}000 \text{ bbl}}{\text{yr}} \times \frac{15 \text{ lb } CH_4}{100 \text{ lb TOC}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{E_{CH_4} = 0.15 \text{ tonnes } CH_4/\text{yr}}$$

A general equation is provided for estimating loading losses for all other petroleum liquids, including crude and gasoline, into tank trucks and rail cars (EPA, AP-42 Section 5.2, 2008). This equation also applies to marine vessel loading for petroleum liquids other than crude and gasoline. AP-42 provides an accuracy estimate of ±30% associated with this approach.

$$L_L = 12.46 \; \frac{S \times P \times M}{T} \qquad \text{(Equation B-9)}$$

where

L_L = loading loss emission factor, lb/10^3 gallon of liquid loaded; this factor is for TOC;
S = saturation factor (shown in Table B-7);
P = liquid true vapor pressure, psia;
M = molecular weight of the vapors, lb/lb-mole; and
T = temperature of bulk liquid loaded, °R (°R = °F + 459.7).

The calculated TOC emissions are then used to estimate CO_2 emissions resulting from routing the loading loss vapors to a combustion control device, as shown in Equation B-10.

$$\begin{aligned} &CO_2 \text{ Emissions (tonnes)} \\ &= \text{Volume loaded (gal)} \times \frac{\text{lb TOC}}{10^3 \text{ gal}} \times \frac{\text{lb C}}{\text{lb TOC}} \times \text{EFF} \times \frac{44 \text{ lb } CO_2 / \text{lbmole } CO_2}{12 \text{ lb C / lbmole C}} \times \frac{\text{tonne } CO_2}{2204.62 \text{ lb}} \end{aligned} \qquad \text{(Equation B-10)}$$

or

$$\begin{aligned} &CO_2 \text{ Emissions (tonnes)} \\ &= \frac{\text{tonnes TOC}}{\text{yr}} \times \frac{\text{tonne C}}{\text{tonne TOC}} \times \text{EFF} \times \frac{44 \text{ lb } CO_2 \text{ / lbmole } CO_2}{12 \text{ lb C / lbmole C}} \times \frac{\text{tonne } CO_2}{2204.62 \text{ lb}} \end{aligned} \qquad \text{(Equation B-11)}$$

where

EFF = efficiency of the control device in converting hydrocarbon to CO_2. If site data are not available, a 98% combustion efficiency can be assumed.

Physical properties for select petroleum fuels are provided above in Table B-6. Table B-7 presents saturation factors used in Equation B-9, according to cargo carrier type and mode of operation.

Table B–7. Saturation, S, Factors for Estimating Loading Losses

Cargo Carrier Type	Mode of Operation	S Factor [a]
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 [b]	Submerged loading: ships	0.2
	Submerged loading: barges	0.5

Footnotes and Sources:

[a] EPA AP-42, Section 5.2, June 2008.

[a] Marine vessel saturation factor shown above is not applicable for gasoline and crude oil loading. For marine loading of crude oil, use Equations B-7 and B-8, and Table B-3. For marine loading of gasoline, refer to Table B-5.

As mentioned earlier, "weathered" crude and other petroleum liquids typically contain no CH_4 (or CO_2); for this reason, no evaporative CH_4 (and CO_2) emissions result from the loading of these liquids.

A sample calculation illustrating the use of Equation B-9 for estimating controlled emissions from "weathered" crude oil tank truck loading follows in Exhibit B.7.

EXHIBIT B.7: Sample Calculation for Estimating Loading Loss CH_4 Emissions Using General Equation Approach

INPUT DATA:

100 bbl/day of "weathered" 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. Vapors from the loading operation are sent to a thermal oxidizer, rated at 99.95% destruction efficiency. The average ambient temperature at this facility is 70 °F. Calculate the CO_2 emissions. (Note that because "weathered" crude oil does not contain CH_4, there are no residual CH_4 emissions from combustion of the loading vapors.)

EXHIBIT B.7: Sample Calculation for Estimating Loading Loss CH_4 Emissions Using General Equation Approach, continued

CALCULATION METHODOLOGY:
To use Equation B-9, physical properties of the crude oil and the saturation factor, S, must be determined. Table B-6 is used to determine the physical properties of the crude oil based on the average ambient temperature. The saturation factor, S, is taken from Table B-7 for submerged loading, dedicated normal service of the tank truck.

Using Equation B-9, the TOC loading loss emission factor is calculated as:

$$L_L = 12.46 \; \frac{(0.6)\times(3.4)\times(50)}{529.7}$$

$$L_L = 2.40 \text{ lb TOC}/10^3\text{gal}$$

The loading loss emissions are calculated by multiplying the loading loss emission factor by the throughput.

$$E_{TOC} = \frac{2.40 \text{ lb TOC}}{10^3\text{gal}}\times\frac{42 \text{ gal}}{\text{bbl}}\times\frac{100 \text{ bbl}}{\text{day}}\times\frac{365 \text{ day}}{\text{yr}}\times\frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$E_{TOC} = 1.67 \text{ tonnes TOC/yr}$$

Carbon dioxide emissions are then calculated by converting the mass of TOC to a mass of carbon, as shown in Equation B-11. Because the carbon content of the “weathered” crude oil vapors is not available, the carbon content of crude oil given in Table 3-8 (for liquid crude oil) is used instead. Note that using the carbon content of the liquid fuel instead of the carbon content of the vapor phase is a simplifying assumption. In reality, the carbon content of vapor phase crude oil will be less than the carbon content of liquid crude oil, due to the fact that vapors contain lighter hydrocarbons, which are more able to volatilize. Carbon dioxide emissions are calculated below.

$$E_{CO_2} = \frac{1.67 \text{ tonnes TOC}}{\text{yr}}\times\frac{0.848 \text{ tonne C}}{\text{tonne TOC}}\times\frac{0.9995 \text{ tonne } CO_2 \text{ formed}}{\text{tonne } CO_2 \text{ combusted}}\times\frac{44.01 \text{ tonne } CO_2}{12.01 \text{ tonne C}}$$

$$\underline{E_{CO_2} = 5.19 \text{ tonnes } CO_2/\text{yr}}$$

In addition to the detailed methods presented above for loading loss emissions, simplified TOC emission factors for loading loss emissions can be found in Table 5-12 (Section 5.2.2) for crude oil loading and in Tables B-8 through B-10 for other petroleum product loading. These simplified loading loss emission factors should be used when specific input data for Equations B-7 through B-9 above are not available.

Table B-8 presents TOC emission factors for gasoline loading into ships and barges (EPA, AP-42 Table 5.2-2, 2008).

Table B-8. TOC Emission Factors for Gasoline Loading at Marine Terminals [a]

Vessel Tank Condition	Previous Cargo [b]	Units		Ships/Ocean Barges [c]	Barges [d]
Uncleaned	Volatile	Original Units	lb TOC/10^3 gal loaded	2.6	3.9
			mg TOC/L loaded	315	465
		Converted Units [e]	tonne TOC/106 gal loaded	1.19	1.76
			tonne TOC/1000m3 loaded	0.315	0.465
Ballasted	Volatile	Original Units	lb TOC/103 gal loaded	1.7	Barges are typically not ballasted
			mg TOC/L loaded	205	
		Converted Units [e]	tonne TOC/10^6 gal loaded	0.776	
			tonne TOC/1000m^3 loaded	0.205	
Cleaned	Volatile	Original Units	lb TOC/10^3 gal loaded	1.5	No data
			mg TOC/L loaded	180	
		Converted Units [e]	tonne TOC/10^6 gal loaded	0.681	No data
			tonne TOC/1000m^3 loaded	0.180	
Gas-freed	Volatile	Original Units	lb TOC/10^3 gal loaded	0.7	No data
			mg TOC/L loaded	85	
		Converted Units [e]	tonne TOC/10^6 gal loaded	0.322	No data
			tonne TOC/1000m^3 loaded	0.085	
Any condition	Non-volatile	Original Units	lb TOC/10^3 gal loaded	0.7	No data
			mg TOC/L loaded	85	
		Converted Units [e]	tonne TOC/10^6 gal loaded	0.322	No data
			tonne TOC/1000m^3 loaded	0.085	
Gas-freed	Any cargo	Original Units	lb TOC/10^3 gal loaded	No data	2.0
			mg TOC/L loaded		245
		Converted Units [e]	tonne TOC/10^6 gal loaded	No data	0.93
			tonne TOC/1000m^3 loaded		0.245
Typical overall situation	Any cargo	Original Units	lb TOC/10^3 gal loaded	1.8	3.4
			mg TOC/L loaded	215	410
		Converted Units [e]	tonne TOC/10^6 gal loaded	0.814	1.55
			tonne TOC/1000m^3 loaded	0.215	0.410

Footnotes and Sources:

[a] EPA, AP-42, Section 5, Table 5.2-2, 2008. 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.

[b] "Volatile" cargo refers to those liquids with a vapor pressure greater than 1.5 psia.

[c] AP-42 reports that ocean barges (tank compartment depth of ~40 feet) exhibit emission levels similar to tank ships.

[d] Shallow draft barges (tank compartment depth of 10-12 feet) yield higher emissions than ocean barges.

[e] 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/10^3 gallons.

Table B-9 presents TOC emission factors for marine loading of other petroleum products (EPA, AP-42 Table 5.2-6, 2008).

Table B-9. TOC Emission Factors for Marine Loading of Additional Petroleum Products [a]

Loading Type	Units		Jet Naphtha (JP-4)	Jet Kerosene	Distillate Oil No. 2	Residual Oil No. 6
Ships/ocean barge loading	Original Units	lb TOC/10^3 gal loaded	0.50	0.005	0.005	0.00004
		mg TOC/L loaded	60	0.63	0.55	0.004
	Converted Units [b]	tonne TOC/10^6 gal loaded	0.23	0.0024	0.0021	1.51E-05
		tonne TOC/10^3 m^3 loaded	0.060	0.00063	0.00055	4.00E-06
Barge loading	Original Units	lb TOC/10^3 gal loaded	1.2	0.013	0.012	0.00009
		mg TOC/L loaded	150	1.6	1.4	0.011
	Converted Units [b]	tonne TOC/10^6 gal loaded	0.57	0.0061	0.0053	4.16E-05
		tonne TOC/10^3 m^3 loaded	0.150	0.0016	0.0014	1.10E-05

Footnotes and Sources:

[a] EPA, AP-42, Section 5, Table 5.2-6, 2008. 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.

[b] 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/10^3 gallons.

Table B-10 presents simplified TOC emission factors for emissions resulting from rail and tank car loading (EPA, AP-42 Table 5.2-2, 2008).

Table B-10. TOC Emission Factors for Rail/Truck Loading Losses [a]

Loading Type	Units		Gasoline[b]	Jet Naphtha (JP-4)	Jet Kerosene	Distillate Oil No. 2	Residual Oil No. 6
Rail / Truck Loading Submerged Loading - Dedicated normal service	Original Units	lb TOC/10^3 gal loaded	5	1.5	0.016	0.014	0.0001
		mg TOC/L loaded	590	180	1.9	1.7	0.01
	Converted Units [c]	tonne TOC/10^6 gal loaded	2.23	0.68	0.0072	0.0064	3.79E-05
		tonne TOC/10^3 m^3 loaded	0.590	0.180	0.0019	0.0017	1.00E-05
Rail / Truck Loading Submerged Loading - Vapor balance service	Original Units	lb TOC/10^3 gal loaded	8	2.5	--[d]	--[d]	--[d]
		mg TOC/L loaded	980	300	--[d]	--[d]	--[d]
	Converted Units [c]	tonne TOC/10^6 gal loaded	3.71	1.14	--[d]	--[d]	--[d]
		tonne TOC/10^3 m^3 loaded	0.980	0.300	--[d]	--[d]	--[d]
Rail / Truck Loading Splash Loading - Dedicated normal service	Original Units	lb TOC/10^3 gal loaded	12	4	0.04	0.03	0.0003
		mg TOC/L loaded	1,430	430	5	4	0.03
	Converted Units [c]	tonne TOC/10^6 gal loaded	5.41	1.63	0.019	0.015	1.14E-04
		tonne TOC/10^3 m^3 loaded	1.430	0.430	0.0050	0.0040	3.00E-05
Rail / Truck Loading Splash Loading - Vapor balance service	Original Units	lb TOC/10^3 gal loaded	8	2.5	--[d]	--[d]	--[d]
		mg TOC/L loaded	980	300	--[d]	--[d]	--[d]
	Converted Units [c]	tonne TOC/10^6 gal loaded	3.71	1.14	--[d]	--[d]	--[d]
		tonne TOC/10^3 m^3 loaded	0.980	0.300	--[d]	--[d]	--[d]

Footnotes and Sources:

[a] EPA, AP-42, Section 5, Table 5.2-5, June 2008. 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. The rail/truck loading emission factors were derived using Equation B-5 assuming a liquid temperature of 60°F.

[b] The example gasoline has an RVP of 10 psia.

[c] 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/10^3 gallons.

[d] Not normally used.

A sample calculation illustrating the use of the marine gasoline loading emission factors is presented in Exhibit B.8.

EXHIBIT B.8: Sample Calculation for Estimating Gasoline Marine Loading Loss Vapor Combustion Unit 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 vapors from loading operations are captured and sent to a vapor combustion unit (VCU). The vapor combustion unit does not require a pilot to operate. Calculate the CO_2 emissions.

CALCULATION METHODOLOGY:
To calculate the VCU CO_2 emissions, the mass of the vapors sent to the VCU from the loading operation must be calculated. Loading losses are calculated using an emission factor from Table B-8, for clean ships and ocean barges previously storing volatile gasoline. Based on an average ambient temperature, the gasoline (RVP 7) vapor pressure is 4.3 psia, per Table B-6. Because the vapor pressure is greater than 1.5 psia, the previous cargo is classified as "volatile." Loading loss emissions are calculated below.

$$E_{TOC} = \frac{0.681 \text{ tonne TOC}}{10^6 \text{ gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{50{,}000 \text{ bbl}}{\text{yr}}$$

$$E_{TOC} = 1.43 \text{ tonnes TOC/yr}$$

Carbon dioxide emissions are then calculated by converting the mass of TOC to a mass of carbon, and applying the API *Compendium* default assumption of 100% conversion of carbon to CO_2. Because the carbon content of gasoline vapors is not available for this example, the carbon content of motor gasoline given in Table 3-8 (for liquid gasoline) is used instead.

Note that using the carbon content of liquid fuels instead of the carbon content of vapor phase gasoline is a simplifying assumption. In reality, the carbon content of vapor phase gasoline will be less than the carbon content of liquid gasoline, due to the fact that gasoline vapors contain lighter hydrocarbons, which are more able to volatilize. Carbon dioxide emissions are calculated below.

$$E_{CO_2} = \frac{1.43 \text{ tonnes TOC}}{\text{yr}} \times \frac{0.866 \text{ tonne C}}{\text{tonne TOC}} \times \frac{44.01 \text{ tonne } CO_2}{12.01 \text{ tonne C}}$$

$$\underline{E_{CO_2} = 4.54 \text{ tonnes } CO_2\text{/yr}}$$

B.4.2 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. Figure B-3 illustrates the calculation options available for ballasting emissions based on the petroleum liquid type and other available information.

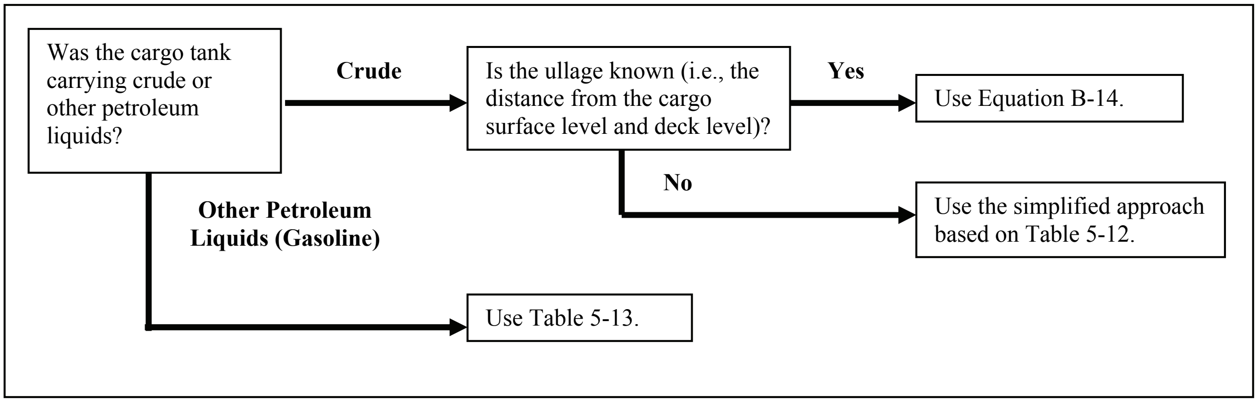

Figure B–3. Decision Tree for Petroleum Liquid Ballasting Emissions

Ballasting emissions from crude oil ships and ocean barges can be estimated using Equation B-12 (EPA, AP-42 Section 5.2, Equation 4, 2008), developed from test data. This equation results in a TOC emission rate that should be converted to CH_4 (or CO_2, if present) emissions based on the CH_4 (or CO_2) content of the vapors. As noted earlier, "weathered" crude and other petroleum products typically do not contain CH_4 (or CO_2).

$$L_B = 0.31 + 0.20\ P + 0.01\ P\ U_A \qquad \text{(Equation B-12)}$$

where

L_B = ballasting TOC emission factor, lb/10^3 gallon of ballast water;
P = true vapor pressure of crude oil unloaded, psia; and
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-6 using the average ambient temperature of the facility.

A sample calculation for estimating crude oil ballasting emissions is shown in Exhibit B.9.

EXHIBIT B.9: Sample Calculation for Crude Oil Ballasting Emissions Based on Known Ullage

INPUT DATA:
"Weathered" 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). Vapors are sent to a VCU with a destruction efficiency of 99.9%. The average ambient temperature at the facility is 70°F (529.7°R) based on average annual meteorological data. Calculate the CO_2 emissions. (Note that because 'weathered' crude oil does not contain CH_4, there are no residual CH_4 emissions from combustion of the ballasting vapors.)

CALCULATION METHODOLOGY:
Using the average ambient temperature and Table B-6, the crude oil vapor pressure is 3.4 psia at 70°F. The ballasting TOC emission factor is calculated using Equation B-12:

$$L_B = 0.31 + (0.20 \times 3.4 \text{ psia}) + (0.01 \times 3.4 \text{ psia} \times 5 \text{ ft})$$

$$L_B = 1.16 \text{ lb TOC}/10^3 \text{ gal ballast water}$$

The ballasting emissions are obtained by multiplying the ballasting emission factor, L_B, by the annual ballast water throughput loaded into the ships.

$$E_{TOC} = \frac{1.16 \text{ lb TOC}}{10^3 \text{ gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{1 \times 10^6 \text{ bbl}}{\text{yr}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$E_{TOC} = 22.10 \text{ tonnes TOC/yr}$$

Carbon dioxide emissions are then calculated by converting the mass of TOC to a mass of carbon. Because the carbon content of the "weathered" crude oil vapors is not available for this example, the carbon content of crude oil given in Table 3-8 (for liquid crude oil) is used instead. Note that using the carbon content of the liquid fuel instead of the carbon content of the vapor phase is a simplifying assumption. In reality, the carbon content of vapor phase crude oil will be less than the carbon content of liquid crude oil, due to the fact that vapors contain lighter hydrocarbons, which are more able to volatilize. Carbon dioxide emissions are calculated below.

$$E_{CO_2} = \frac{22.10 \text{ tonnes TOC}}{\text{yr}} \times \frac{0.848 \text{ tonne C}}{\text{tonne TOC}} \times \frac{0.999 \text{ tonne } CO_2 \text{ formed}}{\text{tonne } CO_2 \text{ combusted}} \times \frac{44.01 \text{ tonne } CO_2}{12.01 \text{ tonne C}}$$

$$\underline{E_{CO_2} = 68.61 \text{ tonnes } CO_2/\text{yr}}$$

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, 2008). These emission factors are provided in Table 5-13 in Section 5.5.2 (refer to Section 5.5.2 for a sample calculation as well).

As mentioned earlier, "weathered" crude and other petroleum liquids typically contain no CH_4 (or CO_2). For this reason, evaporative CH_4 (and CO_2) emissions do not occur. However, TOC evaporative emissions may be routed to a combustion control device, resulting in CO_2 emissions. Table B-11 provides simple emission factors for gasoline ballasting (EPA, AP-42 Table 5.2-6, 2008). Ballasting emissions factors are not available for petroleum products other than gasoline due to limited data.

Table B-11. Simplified TOC Emission Factors for Gasoline Ballasting Losses [a]

Operation	Units		Gasoline [b]
Tanker Ballasting	Original Units	lb TOC/10^3 gal ballast water	0.8
		mg/L ballast water	100
	Converted Units [c]	tonne TOC/ 106 gal water	0.379
		tonne TOC/ 103 m3 water	0.100

Footnotes and Sources:
[a] EPA, AP-42, Section 5, Table 5.2-6, 2008. The factors shown are for total organic compounds.
[b] The example gasoline has an RVP of 10 psia.
[c] 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/10^3 gallons.

B.4.3 Transit Loss Emissions

In addition to emissions resulting from petroleum loading operations and marine ballasting operations, TOC emissions also occur during petroleum transit. The mechanism resulting in transit losses is similar to breathing losses that occur for storage tanks.[3] For marine transit, the estimation methods are based on the availability of the fuel CH_4 (or CO_2, if present) content and other physical properties. For other transit modes, the choice of methods is based solely on the availability of the fuel CH_4 (or CO_2, if present) content.

For transit by marine vessel (i.e., ships and barges), Equation B-13 provides an emission estimate based on experimental tests on ships and barges (EPA, AP-42 Section 5.2, 2008).

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[3] Note that, as discussed in Section 5.4.2, CH_4 and CO_2 emissions from the working and breathing losses of storage tanks containing "live" crude are assumed to be negligible. In addition, it is assumed that there are no CH_4 or CO_2 emissions from the working and breathing losses of tanks containing weathered crude or other refined petroleum products.

$L_T = 0.1\ P\ W$ (Equation B-13)

where

L_T = ship and barge transit loss TOC emission factor, lb/week-10^3 gallon transported;
P = true vapor pressure of the liquid transported, psia; and
W = density of the condensed vapors, lb/gal.

The equation above provides a TOC emission factor, which is converted to CH_4 (or CO_2, if present) based on the concentration of CH_4 (or CO_2) in the fuel vapors. The vapor pressure (P) and vapor density (W) factors in Equation B-13 can be estimated from Table B-4 based on the average ambient temperature of the facility. If the CH_4 concentration for "live" crude is unknown, a typical value of 15 wt% can be assumed. As discussed earlier, for "weathered" crude and other petroleum products, there is no CH_4 (or CO_2). However, CO_2 emissions would result if the TOC evaporative emissions are routed to a combustion control device.

An exhibit calculation demonstrating the use of Equation B-13 in estimating transit loss emissions is shown in Exhibit B.10.

EXHIBIT B.10: Sample Calculation for Estimating Marine Transit Loss Emissions Associated with Crude Oil Transportation

INPUT DATA:
500,000 barrels of "weathered" 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 crude TOC vapors are 75% carbon by weight. Evaporative emissions are routed to a combustion control device. The average ambient temperature at the facility is 70°F (529.7°R) based on average annual meteorological data. Calculate the CO_2 emissions resulting from transit.

CALCULATION METHODOLOGY:
The vapor pressure and condensed vapor density of RVP 5 crude oil are taken from Table B-5. Using Equation B-13, the ship transit loss TOC emission factor is calculated as shown below:

$$L_T = (0.1) \times (3.4 \text{ psi}) \times (4.5 \text{ lb/gal})$$

$$L_T = 1.53 \text{ lb TOC/week-}10^3 \text{ gal transported}$$

EXHIBIT B.10: Sample Calculation for Estimating Marine Transit Loss Emissions Associated with Crude Oil Transportation, continued

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.

$$E_{TOC} = \frac{1.53 \text{ lb TOC}}{\text{week-}10^3\text{gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times 500,000 \text{ bbl} \times \frac{10 \text{ days}}{\text{trip}} \times \frac{25 \text{ trips}}{\text{year}} \times \frac{\text{week}}{7 \text{ days}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$E_{TOC} = 520.5 \text{ tonnes TOC/yr}$$

The CO_2 emissions are then calculated by applying Equation B-11:

$$E_{CO_2} = \frac{520.5 \text{ tonnes TOC}}{\text{yr}} \times \frac{0.75 \text{ tonne C}}{\text{tonne TOC}} \times 0.99 \times \frac{44 \text{ lb } CO_2 \text{ / lbmole } CO_2}{12 \text{ lb C / lbmole C}}$$

$$\underline{E_{CO_2} = 1,417 \text{ tonnes } CO_2\text{/yr}}$$

Table 5-14 in Section 5.5.3 provides simple transit TOC emission factors for marine transit of crude oil (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-12 (EPA, AP-42 Section 5.2.2.1.3, 2008). Emission factors for marine transit of gasoline are provided in Table B-13 (EPA, AP-42 Section 5.2.2.1.3, 2008). Carbon dioxide emissions would result when the TOC evaporative emissions are routed to a combustion control device.

Table B–12. Simplified TOC Emission Factors for Rail/Truck Gasoline Transit Losses [a]

Transit Type	Units		Gasoline [b]
Loaded with Product			
Typical Operation	Original Units	lb TOC/10^3 gal transported	0 - 0.01
		mg TOC/L transported	0 - 1.0
	Converted Units [c]	tonne TOC/10^6 gal transported	0 - 0.0038
		tonne TOC/10^3 m^3 transported	0 - 0.0010
Extreme Operation	Original Units	lb TOC/10^3 gal transported	0 - 0.08
		mg TOC/L transported	0 - 9.0
	Converted Units [c]	tonne TOC/10^6 gal transported	0 - 0.034
		tonne TOC/10^3 m^3 transported	0 - 0.0090

Table B–12. Simplified TOC Emission Factors for Rail/Truck Gasoline Transit Losses [a], continued

Transit Type	Units		Gasoline [b]
Return with Vapor			
Typical Operation	Original Units	lb TOC/10^3 gal transported	0 - 0.11
		mg TOC/L transported	0 - 13.0
	Converted Units [c]	tonne TOC/10^6 gal transported	0 - 0.049
		tonne TOC/10^3 m^3 transported	0 - 0.0130
Extreme Operation	Original Units	lb TOC/10^3 gal transported	0 - 0.37
		mg TOC/L transported	0 - 44.0
	Converted Units [c]	tonne TOC/10^6 gal transported	0 - 0.167
		tonne TOC/10^3 m^3 transported	0 - 0.0440

Footnotes and Sources:

[a] EPA, AP-42, Section 5, Table 5.2-5, 2008. The emission factors for the other products listed above are for both TOC and VOC because AP-42 reports that the CH_4 and C_2H_6 content of the loading emissions is negligible for gasoline.

[b] The example gasoline has an RVP of 10 psia.

[c] 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/10^3 gallons.

Table B-13. Simplified TOC Emission Factors for Marine Transit Losses [a]

Operation	Units		Gasoline [b]
Marine Transit	Original Units	lb TOC/week-10^3 gal transported	2.7
		mg TOC/week-L transported	320
	Converted Units [c]	tonne TOC/week-10^6 gal transported	1.21
		tonne TOC/week-10^3 m^3 transported	0.320

Footnotes and Sources: .

[a] EPA, AP-42, Section 5, Table 5.2-6, 2008 The factors shown are for TOCs.

[b] The example gasoline has an RVP of 10 psia.

[c] 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/10^3 gallons.

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 PRV 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.

Exhibit B.11 illustrates the use of the simple gasoline transit emission factors.

EXHIBIT B.11: Sample Calculation for Estimating CH_4 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 gasoline vapors are 85 wt% carbon and are routed to a VCU with 99.5% combustion efficiency. Calculate the CO_2 emissions associated with the transit operations.

CALCULATION METHODOLOGY:
The transit loss emission factor given in Table B-12 for the truck when loaded with product for typical operation is 0-0.01 lb TOC/1000 gallons transported (0-0.0038 tonne TOC/10^6 gallon transported). For conservatism, the upper bound factor is used. Thus, the transit emissions when loaded with product are:

$$E_{TOC} = \frac{0.0038 \text{ tonne TOC}}{10^6 \text{ gal transported}} \times \frac{8000 \text{ gal}}{\text{trip}} \times \frac{100 \text{ trips}}{\text{yr}}$$

$$E_{TOC} = 0.00304 \text{ tonnes TOC/yr}$$

Similarly, the transit emissions of the truck when returning with vapor are estimated. The transit loss emission factor given in Table B-12 for the truck with vapor for typical operation is 0-0.11 lb TOC/1000 gallons transported (0-0.049 tonne TOC/10^6 gallon transported). For conservatism, the upper bound factor is used. Thus, the transit emissions when loaded with product are:

$$E_{TOC} = \frac{0.049 \text{ tonne TOC}}{10^6 \text{ gal transported}} \times \frac{8000 \text{ gal}}{\text{trip}} \times \frac{100 \text{ trips}}{\text{yr}}$$

$$E_{TOC} = 0.0392 \text{ tonnes TOC/yr}$$

The CO_2 emissions are then calculated by applying Equation B-11:

$$E_{CO_2} = (0.0392 + 0.00304) \frac{\text{tonnes TOC}}{\text{yr}} \times \frac{0.85 \text{ tonne C}}{\text{tonne TOC}} \times 0.995 \times \frac{44 \text{ lb } CO_2 / \text{lbmole } CO_2}{12 \text{ lb C / lbmole C}}$$

$$\underline{E_{CO_2} = 0.131 \text{ tonnes } CO_2\text{/yr}}$$

B.5 Production Sector High-/Low-Bleed Pneumatic Devices Emission Factor Development

Section 5.6.1 of the API *Compendium* presents simplified gas-driven pneumatic device emission factors by industry segment, including an emission factor for continuous bleed pneumatic devices in the production sector. This continuous bleed device emission factor was further split out according to whether the device is high-bleed or low-bleed. The EPA Gas STAR program defines a pneumatic device that bleeds more than 6 scfh as a "high-bleed" device, with "low-bleed" devices venting less than 6 scf/hr (EPA Gas STAR, Lessons Learned, July 2003). Therefore, the same data set that was used to develop the production sector continuous bleed device emission factor in Volume 12 of the 1996 GRI/EPA natural gas CH_4 emissions study (Shires and Harrison, 1996) was also used to develop the high- and low-bleed device emission factors by stratifying the data according to whether the leak rate is greater than or less than 6 scfh. The development of these emission factors is provided below in Table B-14.

Table B–14. Production Sector Pneumatic Device High/Low-Bleed Emission Factor Development [a]

Number	Device Type	Bleed Rate (scf/day)	Stratification [b]	
			Low-Bleed, ≤ 6 scf/hr (scf/day)	High-Bleed, ≥ 6 scf/hr (scf/day)
1	Norriseal 1001A	2334.1		2334.1
2	Fisher 2513	2170		2170
3	Fisher 4100	1065		1065
4	Norriseal 1001A	428		428
5	CE Invalco	1107		1107
6	Fisher 2500	596		596
7	Fisher 2502	962		962
8	Fisher 2900	954		954
9	Fisher 4150	634		634
10	Fisher 4160	560		560
11	Fisher 4160	380		380
12	Fisher 2900	1548		1548
13	CE Natco AE 155	1056		1056
14	Fisher 4160	609		609
15	Fisher 2900	508		508
16	Fisher 4150	145		145
17	Fisher 4160	108	108	
18	Fisher 4160	534		534
19	CPA Data	1.53	1.53	
20	CPA Data	59.92	59.92	
21	CPA Data	11.27	11.27	
22	CPA Data	34.50	34.50	
23	CPA Data	7.80	7.80	

Table B–14. Production Sector Pneumatic Device High/Low-Bleed Emission Factor Development [a], continued

Number	Device Type	Bleed Rate (scf/day)	Stratification [b]	
			Low-Bleed, ≤ 6 scf/hr (scf/day)	High-Bleed, ≥ 6 scf/hr (scf/day)
24	CPA Data	529.04		529.04
25	CPA Data	10.68	10.68	
Average (scf total gas/day):		654.1	33.4	895.5
Uncertainty [c], ±:		40%	107%	33%
Average (scf CH_4/day) [d]:		515.4	26.3	705.7
Average (tonnes CH_4/device-yr) [e]:		3.609	0.184	4.941

Footnotes and Sources:

[a] Developed from data used for Volume 12 of the GRI/EPA natural gas industry CH_4 emissions study (Shires and Harrison, 1996).

[b] High-bleed devices refer to devices with leak rates greater than 6 scf/hr while low-bleed devices are 6 scf/hr or less based on definitions provided by EPA's Gas STAR program (EPA Gas STAR, Lessons Learned, July 2003).

[c] Uncertainty based on 95% confidence interval from the data used to develop the original emission factor.

[d] Converted from a total gas basis to a methane basis assuming 78.8 mole % CH_4 (Shires and Harrison, 1996).

[e] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia.

An example calculation illustrating the use of the high- and low-bleed classification for pneumatic device emissions follows.

EXHIBIT B.12: Sample Calculation for Gas-Driven Pneumatic Device Emissions

INPUT DATA:
A gas production site has 80 natural gas-driven pneumatic devices; 60 of the devices are low-bleed and the remaining 20 are high-bleed devices. The average CH_4 content of the gas is 70 mole %. There is also 9 mole % CO_2 in the gas. Calculate the CH_4 and CO_2 emissions.

CALCULATION METHODOLOGY:
The counts of high-bleed and low-bleed devices are multiplied by their respective emission factors from Table B-14.

$$E_{CH_4} = \left[(60 \text{ pneumatic devices}) \times \frac{0.184 \text{ tonne CH}_4}{\text{device - yr}} + (20 \text{ pneumatic devices}) \times \frac{4.941 \text{ tonne CH}_4}{\text{device - yr}} \right] \times \frac{70 \text{ mole \% CH}_4}{78.8 \text{ mole \% CH}_4}$$

$$\underline{E_{CH_4} = 97.59 \text{ tonnes CH}_4/\text{yr}}$$

EXHIBIT B.12: Sample Calculation for Gas-Driven Pneumatic Device Emissions, continued

$$E_{CO_2} = \left[(60 \text{ pneumatic devices}) \times \frac{0.184 \text{ tonne } CH_4}{\text{device - yr}} + (20 \text{ pneumatic devices}) \times \frac{4.941 \text{ tonne } CH_4}{\text{device - yr}} \right]$$

$$\times \left[\frac{70 \text{ mole \% } CH_4}{78.8 \text{ mole \% } CH_4} \times \frac{\text{tonne mole } CH_4}{16 \text{ tonne } CH_4} \times \frac{\text{tonne mole gas}}{0.70 \text{ tonne mole } CH_4} \times \frac{0.09 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne } CO_2}{\text{tonne mole } CO_2} \right]$$

$$\underline{E_{CO_2} = 34.51 \text{ tonnes } CO_2/\text{yr}}$$

B.6 Additional Coal Mining Data

The emission factors in Table 5-20 were developed from data provided in the Annexes of the EPA report, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007* (EPA, 2009). The emission factors were derived by dividing the U.S. coal mining CH_4 emissions by the U.S. coal production rates. Factors were derived for 2005 through 2007. The derivation is shown below.

Coal production rates for the years 2005 through 2007 are provided in Table B-15.

Table B–15. U.S. Total Coal Production, 2005 - 2007

Coal Source	Coal Production by Year [a], 1000 tons/yr		
	2005	2006	2007
Underground	368,611	359,020	351,791
Surface	762,191	802,975	793,689

Footnote and Source:
[a] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, Table A-104, April 15, 2009.

Table B-16 provides CH_4 emissions from coal mining activities, for the years 2005 through 2007.

Table B–16. U.S. CH_4 Emissions from Coal Mining Activities, 2005 - 2007

Coal Mining Activity	CH_4 Emissions [a], Bscf/yr 2005	2006	2007
Total Underground Mining Emitted	89	89	85
Underground Post-Mining	16	15	15
Surface Mining	33	35	34
Surface Post-Mining	5	6	6

Footnote and Source:
[a] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, Tables A-106 and A-107, April 15, 2009.

The emission factors presented in Table B-17 were calculated by dividing the emissions presented in Table B-16 by the coal production rates presented in Table B-154.

Table B–17. CH_4 Emission Factors for Coal Mining

Activity	CH_4 Emissions [a], scf/ton coal 2005	2006	2007
Total Underground Mining Emitted	241	248	242
Underground Post-Mining (coal handling)	43.4	41.8	42.6
Surface Mining	43.3	43.6	42.8
Surface Post-Mining (coal handling)	6.56	7.47	7.56

Footnote and Source:
[a] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*, April 15, 2009.

Coal mining emission factors for the U.S. are provided in Section 5.6.7 on a national average basis. If the coal supply region and coal type are known, the emission factors provided in Table B-18 can be used to calculate coal mining emissions (EIA, 2008).

Table B–18. Coal Mining Emission Factors by Coal Supply Region

Coal Supply Region	Coal Rank And Sulfur Level	Mine Type	Heat Content [a] (MMBtu/ton)	CO_2 [a] (lb/MMBtu)	CO_2 (tonne/MMBtu)
Northern Appalachia	Metallurgical	Underground	26.27	207.5	0.0941
	Mid-Sulfur Bituminous	All	25.24	207.5	0.0941
	High-Sulfur Bituminous	All	24.84	205.7	0.0933
	Waste Coal (Gob and Culm)	Surface	12.70	205.7	0.0933
Central Appalachia	Metallurgical	Underground	26.27	205.9	0.0934
	Low-Sulfur Bituminous	All	24.84	205.9	0.0934
	Mid-Sulfur Bituminous	All	24.74	205.9	0.0934
Southern Appalachia	Metallurgical	Underground	26.27	205.4	0.0932
	Low-Sulfur Bituminous	All	24.84	205.4	0.0932
	Mid-Sulfur Bituminous	All	24.85	205.4	0.0932
East Interior	Mid-Sulfur Bituminous	All	22.26	204.9	0.0929
	High-Sulfur Bituminous	All	22.85	204.7	0.0929
	Mid-Sulfur Lignite	Surface	10.23	213.5	0.0968
West Interior	High-Sulfur Bituminous	Surface	22.66	204.4	0.0927
Gulf Lignite	Mid-Sulfur Lignite	Surface	13.38	213.5	0.0968
	High-Sulfur Lignite	Surface	12.57	213.5	0.0968
Dakota Lignite	Mid-Sulfur Lignite	Surface	13.26	218.8	0.0992
Western Montana	Low-Sulfur Subbituminous	Underground	20.03	209.6	0.0951
		Surface	18.72	213.5	0.0968
	Mid-Sulfur Subbituminous	Surface	17.19	213.5	0.0968
Northern Wyoming	Low-Sulfur Subbituminous	Surface	16.88	212.7	0.0965
	Mid-Sulfur Subbituminous	Surface	16.27	212.7	0.0965
Southern Wyoming	Low-Sulfur Subbituminous	Surface	17.66	212.7	0.0965
Western Wyoming	Low-Sulfur Subbituminous	Underground	18.53	206.5	0.0937
		Surface	18.88	212.7	0.0965
	Mid-Sulfur Subbituminous	Surface	19.00	212.7	0.0965
Rocky Mountain	Low-Sulfur Bituminous	Underground	22.95	205.1	0.0930
	Low-Sulfur Subbituminous	Surface	20.70	212.7	0.0965
Southwest	Low-Sulfur Bituminous	Surface	20.89	207.5	0.0941
	Mid-Sulfur Subbituminous	Surface	18.09	208.8	0.0947
	Mid-Sulfur Bituminous	Underground	19.52	208.8	0.0947
Northwest	Mid-Sulfur Subbituminous	Surface	15.61	210.0	0.0953

Footnote and Source:

[a] Energy Information Administration (EIA), *Assumptions to the Annual Energy Outlook 2008, With Projections for 2030*, Report Number DOE/EIA-0554 (2008), June 2008.

B.7 Additional Vented Volume Calculation Methodologies

This subsection presents additional calculation methodologies for estimating the volume of gas released in non-routine activities. After calculating the volume of gas released, CH_4 and CO_2 emissions from such releases would be calculated using an engineering approach, such as described in Section 5.7.1

B.7.1 Calculating Pressure Vessel Volume

The volume of gas released from an equipment blowdown is typically based on equipment design specifications for the vessel/pipeline/equipment of interest. In the absence of 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, which are presented in Table B-19.

Use of the gas law is most appropriate for situations where the entire volume of the vessel is blown down and the gas blowdown volume is finite. More rigorous engineering approaches are needed for a blowdown situation where only a portion of the vessel contents are released.

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 (Cp/Cv). 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.

Table B–19. Volume Per Meter of Pipeline Length

NPS Size	Volume Released (m^3/m) [a]							Volume Released (scf/ft) [a,b]						
	Sch 40	**Sch 60**	**Sch 80**	**Sch 100**	**Sch 120**	**Sch 140**	**Sch 160**	**Sch 40**	**Sch 60**	**Sch 80**	**Sch 100**	**Sch 120**	**Sch 140**	**Sch 160**
1	5.57E-04		4.64E-04				3.37E-04	6.00E-03		4.99E-03				3.62E-03
2	2.17E-03		1.91E-03				1.45E-03	2.33E-02		2.05E-02				1.56E-02
3	4.77E-03		4.26E-03				3.49E-03	5.13E-02		4.59E-02				3.76E-02
4	8.21E-03		7.42E-03		6.65E-03		5.99E-03	8.84E-02		7.99E-02		7.16E-02		6.44E-02
6	1.86E-02		1.68E-02		1.53E-02		1.37E-02	2.01E-01		1.81E-01		1.65E-01		1.47E-01
8	3.23E-02	3.09E-02	2.95E-02	2.80E-02	2.62E-02	2.48E-02	2.35E-02	3.47E-01	3.33E-01	3.17E-01	3.02E-01	2.82E-01	2.67E-01	2.53E-01
10	5.09E-02	4.82E-02	4.64E-02	4.40E-02	4.16E-02	3.88E-02	3.66E-02	5.48E-01	5.18E-01	4.99E-01	4.73E-01	4.48E-01	4.18E-01	3.94E-01
12	7.22E-02	6.85E-02	6.56E-02	6.20E-02	5.86E-02	5.59E-02	5.20E-02	7.77E-01	7.37E-01	7.06E-01	6.68E-01	6.30E-01	6.01E-01	5.59E-01
14	8.73E-02	8.32E-02	7.92E-02	7.45E-02	7.07E-02	6.70E-02	6.34E-02	9.39E-01	8.96E-01	8.52E-01	8.02E-01	7.61E-01	7.21E-01	6.83E-01
16	1.14E-01	1.09E-01	1.04E-01	9.84E-02	9.32E-02	8.73E-02	8.32E-02	1.23E+00	1.18E+00	1.12E+00	1.06E+00	1.00E+00	9.39E-01	8.96E-01
18	1.44E-01	1.38E-01	1.32E-01	1.25E-01	1.18E-01	1.12E-01	1.06E-01	1.55E+00	1.49E+00	1.42E+00	1.34E+00	1.27E+00	1.21E+00	1.14E+00
20	1.79E-01	1.71E-01	1.63E-01	1.54E-01	1.46E-01	1.38E-01	1.31E-01	1.93E+00	1.84E+00	1.75E+00	1.66E+00	1.58E+00	1.48E+00	1.41E+00

Footnotes and Sources:

[a] Canadian Association of Petroleum Producers (CAPP), *Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, Guide, Canadian Association of Petroleum Producers, Publication Number 2002-0009, May 2002, Table 3-8.

[b] Volumes were converted from m^3/m to scf/ft.

B.7.2 Calculating Well Unloading Emissions

CAPP (CAPP, 2002, Section 3.2.1) provides information on calculating the volume of gas released during well unloading. The total volume released is dependent on many properties, including the duration of the event, size of the vent line, quantity of water released, and properties of the gas. CAPP models the vent process as an isentropic flow of an ideal gas through a nozzle[4], as shown in Equation B-14.

$$\dot{m}_T = A^* \times \frac{P_0}{\sqrt{T_0}} \times \sqrt{\frac{k}{R}} \times \frac{1}{\left(\frac{k+1}{2}\right)^{(k+1) \div (2 \times k-2)}} \times 1000 \qquad \text{(Equation B-14)}$$

where

$\dot{m}_T$ = the total mass flow rate of gas and water vapor from the unloading (kg/s);
A^* = the cross sectional area of the unloading valve or vent pipe (m^2);
P_0 = wellhead pressure (kPa);
T_0 = wellhead temperature (K);
k = specific heat ratio, Cp/Cv (1.32 for natural gas); and
R = gas constant (kJ/kg K), (8314.5 / gas molecular weight).

The quantity of water produced during the unloading must be subtracted from the quantity of gas vented. Equation B-15 can be used to calculate the quantity of water vented:

$$\dot{m}_W = \frac{V \times \rho_w}{t} \qquad \text{(Equation B-15)}$$

where

$\dot{m}_W$ = mass flow rate of water produced by the unloading event (kg/s);
V = volume of liquid water produced by the unloading event (m^3);
ρ_w = density of liquid water (1000 kg/m^3); and
t = duration of the blow down event (s).

The mass flow rate of gas released is calculated using Equation B-16.

$$\dot{m}_V = \dot{m}_T - \dot{m}_W \qquad \text{(Equation B-16)}$$

where

$\dot{m}_v$ = mass flow rate of gas released.

The total volume of gas released is then calculated using Equation B-17.

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[4] CAPP notes that "modeling the system as an ideal gas yields good results up to wellhead pressures of about 50 atmospheres," but at higher pressures a more rigorous equation of state must be used (CAPP, 2002, Section 3.2.1).

$$V = \frac{\dot{m}_V \times t}{W_V} \times 23.6449 \qquad \text{(Equation B-17)}$$

where

V = volume of gas released (m^3);
W_V = molecular weight of the vapor released (kg/kmole); and
23.6449 = the volume (m3) occupied by one kmole of and ideal gas at 15ºC and 101.325 kPa.

B.7.3 Calculating Pressure Relief Valve Release Volumes

Emission factors for PRV releases are provided in Section 5.7.2. Alternatively, CAPP (CAPP, 2002, Section 3.2.3) provides information on calculating the volume of gas released during a PRV event. The total volume released is dependent on many properties, including the duration of the event, size of the relief valve, and properties of the gas. As for well unloading, CAPP models the vent process as an isentropic flow of an ideal gas through a nozzle,[5] as shown in Equation B-18.

$$\dot{m}_V = A^* \times \frac{P_0}{\sqrt{T_0}} \times \sqrt{\frac{k}{R}} \times \frac{1}{\left(\frac{k+1}{2}\right)^{(k+1) \div (2\times k\text{-}2)}} \times 1000 \qquad \text{(Equation B-18)}$$

where

$\dot{m}_V$ = the total mass flow rate of gas through the PRV (kg/s);
A^* = the cross sectional area of the throat (or orifice) of the valve (m^2);
P_0 = PRV set point (kPa);
T_0 = vessel temperature (K);
k = specific heat ratio, Cp/Cv (1.32 for natural gas); and
R = gas constant (kJ/kg K), (8314.5 / gas molecular weight).

The total volume of gas released can then be calculated using Equation B-17.

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[5] CAPP notes that “modeling the system as an ideal gas yields good results up to wellhead pressures of about 50 atmospheres,” but at higher pressures a more rigorous equation of state must be used (CAPP, 2002, Section 3.2.1).

B.8 Derivation of Vented Emission Factors

B.8.1 Derivation of Transmission Pipeline and Compressor Station Blowdown Emission Factor

The emission factors for pipeline and compressor station blowdowns are based on combined data from the GRI/EPA methane emissions study (Shires and Harrison, Volume 7, 1996) and the 1995 Canadian emissions study (Radian, 1997). Site data used in the development of these two studies were combined to establish the pipeline and compressor station blowdown emission factors.

Table B-20 presents the development of the transmission compressor station blowdown emission factor based on the combined U.S. and Canadian data.

Table B–20. Transmission Compressor Station Blowdown Emission Factor Development

Company Number	Annual Station Blowdown Emissions (Mscf/yr)	Number of Stations	Annual Station Blowdown Emissions (MMscm CH_4/station)	Blowdown/Station [a] (Mscf CH_4/station-yr)
U.S.Data [b]				
1	120,757	11		10,253.37
2	272,589	15		16,973.21
3	33,731	27		1,166.84
4	Not Available	19		-
5	325,418	47		6,466.82
6	Unknown	48		-
7	60,956	69		825.11
8	194,541	47		3,865.98
Canadian Data [c]				
1			0.00485	171.28
2			0.2995654	10,579.06
3			0.03056	1,079.22
4			No Data	-
5			0.248	8,758.05
6			0.0021015	74.21
7			0.096	3,390.21
Average Emission Factor, Mscf CH_4/station-yr [d]				**5,300.28±64.3%**

Footnotes and Sources:

[a] U.S. blowdown/station estimated by dividing the annual blowdown emissions by the number of stations and then multiplying by the default CH_4 content for the transmission sector, provided in Table E-4 (93.4 mole %).

[b] GRI/EPA methane emissions study (Shires and Harrison, 1996), Volume 7, page B-15.

[c] Company information developed as part of 1995 Canadian natural gas industry emissions study (Radian, 1997).

[d] Uncertainty based on 95% confidence interval.

Table B-21 presents the development of the transmission pipeline blowdown emission factor.

Table B–21. Transmission Pipeline Blowdown Vented Emission Factor Development

Company Number	Annual Pipeline Blowdown Emissions (Mscf/yr)	Pipeline Length (Miles)	Annual Pipeline Blowdown Emissions (MMscm CH_4/km)	Blowdown/ Mile [a] (Mscf CH_4/mile-yr)
U.S. Data [b]				
1	189,044	3,857		45.78
2	11,358	4,000		2.65
3	138,988	5,886		22.05
4	Not Available	5,450		-
5	Unknown	4,725		-
6	161,628	7,896		19.12
7	750,000	14,666		47.76
8	315,058	9,915		29.68
Canadian Data [c]				
1			0.001026	58.31
2			0.003199	181.83
3			0.000211	11.97
4			0.0000272	1.54
5			0.000355	20.15
6			0.00000828	0.47
7			0.001602	91.03
Average Emission Factor, Mscf CH_4/mile-yr [d]				**40.95 ± 73.3%**

Footnotes and Sources:

[a] U.S. blowdown/mile estimated by dividing the annual blowdown emissions by the number of miles and then multiplying by the default CH_4 content for the transmission sector, provided in Table E-4 (93.4 mole %).

[b]: GRI/EPA methane emissions study (Shires and Harrison, 1996), Volume 7, page B-15.

[c]: Company information developed as part of 1995 Canadian natural gas industry emissions study (Radian, 1997).

[d] Uncertainty based on 95% confidence interval.

B.8.2 Derivation of Pipeline Blowdowns Emission Factor

The emission factors for distribution pipeline blowdowns are based on combined data from the GRI/EPA (Shires and Harrison, 1996) and 1995 Canadian emissions studies (Radian, 1997; URS, 2001). Site data used in the development of these two studies were combined to establish the distribution pipeline vented blowdown emission factor as shown in Table B-21.

Table B–22. Distribution Pipeline Blowdown Vented Emission Factor Development

Company Number	Annual Pipeline Blowdown Emissions (Mscf/yr)	Pipeline Length (Miles)	Annual Pipeline Blowdown Emissions (MMscm CH_4/km)	Blowdown/Mile [a] (Mscf CH_4/mile-yr)
U.S. Data [b]				
1	8,972	58,024		0.1546
2	5,688	82,337		0.0691
3	2,360	24,916		0.0947
4	1,695	18,713		0.0906
Canadian Data [c]				
1			0.000136	7.73
2			0.00000271	0.15
3			0.0000907	5.15
4			0.00000130	0.07
5			0.000055	3.13
6			0.00000248	0.14
Average Emission Factor, Mscf CH_4/mile-yr [d]				**1.68 ± 117%**

Footnotes and Sources:

[a] U.S. blowdown/mile estimated by dividing the annual blowdown emissions by the number of miles, and then multiplying by the default CH_4 content for the distribution sector, provided in Table E-4 (93.4 mole %).

[b] Source: GRI/EPA methane emissions study (Shires and Harrison, 1996), Volume 7, page B-20.

[c] Source: Company information developed as part of 1995 Canadian natural gas industry emissions study (Radian, 1997).

[d] Uncertainty based on 95% confidence interval.

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AMERICAN PETROLEUM INSTITUTE

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

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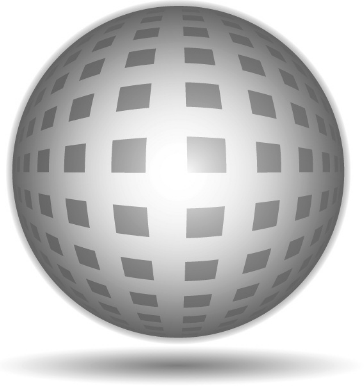
APPENDIX C

ADDITIONAL FUGITIVE CALCULATION INFORMATION



Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry

Appendix C – Additional Fugitive Calculation Information

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C. ADDITIONAL FUGITIVE CALCULATION INFORMATION

This section presents supplemental information for the fugitive emission calculation methodologies presented in Section 6.

C.1 Additional Equipment Leak Emission Calculation Methodologies

The following provides estimation methods for CH_4 and CO_2 fugitive emissions from equipment leaks that are more rigorous than the methods presented in Section 6.1. The additional approaches available for estimating fugitive equipment leak emissions, in order of increasing data requirements and increasing accuracy are:

1. Screening ranges approach;
2. Correlation approach; and
3. Unit-Specific correlation approach.

Applicable to all of these approaches, the CH_4 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_4 emissions from fugitive sources, when site specific speciation data are not available. "Generic" component counts are also provided for different equipment and process types.

Note that leaks from equipment used in association with "weathered" crude or other refined petroleum products will not emit CH_4 or CO_2, as "weathered" crude and refined petroleum products do not contain CH_4 or CO_2.[1]

C.1.1 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 U.S. 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

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[1] For more information, see Appendix E.

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:

$$E_{TOC} = (F_G \times N_G) + (F_L \times N_L) \qquad \text{(Equation C-1)}$$

where

E_{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; and
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 6-9.

Tables C-1 and C-2 present screening emission factors for different industry segments. Note that Table C-1 provides service specific emission factors, while Table C-2 is facility specific. Service categories include gas, light liquid or heavy liquid service. Liquid services are defined differently by EPA (EPA, 1995) and API (API, 1995). EPA defines light liquid service 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, which generally includes naphtha and more volatile petroleum liquids. EPA defines 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. Unlike EPA, 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°.

Table C–1. EPA Oil and Natural Gas Production Screening Factors

Component – Service[c]	Emission Factor, kg TOC/hr/comp.[a,b]		Emission Factor, tonne TOC/component-hr[b]	
	<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	8.4E-09	NA
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	2.4E-08	NA
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	3.2E-08	NA
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	7.5E-09	NA
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	3.9E-10	NA
Flanges – Water/Oil	2.9E-06	NA	2.9E-09	NA
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

Footnotes and Sources:

[a] U.S. 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.

[b] NA means that there were not sufficient examples of that emission category found to develop an emission factor.

[c] EPA defines light liquids as liquids for which the sum of the concentration of individual constituents with a vapor pressure over 0.3 kPa at 20 °C is greather than or equal to 20 weight percent. EPA defines heavy liquids as liquids not in gas/vapor or light liquid service.

Table C–2. API Oil and Natural Gas Production and Processing Screening Factors

Component – Facility Type [c]	Emission Factor, lb TOC/day/comp. [a,b]		Emission Factor, tonne TOC/component-hr [b]	
	<10,000 ppmv	**≥10,000 ppmv**	**<10,000 ppmv**	**≥10,000 ppmv**
Valves – All Facility Types	NA	3.381	NA	6.390E-05
Valves – Gas Production	1.63E-03	3.381	3.08E-08	6.390E-05
Valves – Light Crude Production	1.11E-03	3.381	2.10E-08	6.390E-05
Valves – Heavy Crude Production	6.95E-04	3.381	1.31E-08	6.390E-05
Valves – Offshore Production	8.50E-04	3.381	1.61E-08	6.390E-05
Valves – Gas Processing	1.81E-03	3.381	3.42E-08	6.390E-05
Connectors – All Facility Types	NA	1.497	NA	2.829E-05
Connectors – Gas Production	6.33E-04	1.497	1.20E-08	2.829E-05
Connectors – Light Crude Prod.	5.25E-04	1.497	9.92E-09	2.829E-05
Connectors – Heavy Crude Prod.	4.41E-04	1.497	8.33E-09	2.829E-05
Connectors – Offshore Production	5.11E-04	1.497	9.66E-09	2.829E-05
Connectors – Gas Processing	5.76E-04	1.497	1.09E-08	2.829E-05
Flanges – All Facility Types	NA	4.490	NA	8.486E-05
Flanges – Gas Production	1.30E-03	4.490	2.46E-08	8.486E-05
Flanges – Light Crude Production	1.24E-03	4.490	2.34E-08	8.486E-05
Flanges – Heavy Crude Production	1.19E-03	4.490	2.25E-08	8.486E-05
Flanges – Offshore Production	1.33E-03	4.490	2.51E-08	8.486E-05
Flanges – Gas Processing	1.44E-03	4.490	2.72E-08	8.486E-05
Open-ended Lines – All Facilities	NA	1.600	NA	3.024E-05
Open-ended Lines – Gas Production	1.26E-03	1.600	2.38E-08	3.024E-05
Open-ended Lines – Light Crude Production[2]	1.50E-03	1.600	2.83E-08	3.024E-05
Open-ended Lines – Heavy Crude Production[3]	8.86E-04	1.600	1.67E-08	3.024E-05
Open-ended Lines – Offshore Production	9.40E-04	1.600	1.78E-08	3.024E-05
Open-ended Lines – Gas Processing	1.62E-03	1.600	3.06E-08	3.024E-05
Pump Seals – All Facilities	NA	3.905	NA	7.380E-05
Pump Seals – Gas Production	1.03E-02	3.905	1.95E-07	7.380E-05
Pump Seals – Heavy Crude Prod.	No data	3.905	No data	7.380E-05
Pump Seals – Light Crude Prod.	1.68E-02	3.905	3.18E-07	7.380E-05
Pump Seals – Offshore Production	1.03E-02	3.905	1.95E-07	7.380E-05
Pump Seals – Gas Processing	4.3E-02	3.905	8.13E-07	7.380E-05
Others – All Facilities	NA	3.846	NA	7.269E-05
Others – Gas Production	7.92E-03	3.846	1.50E-07	7.269E-05
Others – Heavy Crude Production	3.67E-03	3.846	6.94E-08	7.269E-05
Others – Light Crude Production	9.01E-03	3.846	1.70E-07	7.269E-05
Others – Offshore Production	3.76E-03	3.846	7.11E-08	7.269E-05
Others – Gas Processing	9.09E-03	3.846	1.72E-07	7.269E-05

Footnotes and Sources:

[a] 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.

[b] 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.

[c] These emission factors are facility specific, not service specific. For example, a facility producing light crude would apply the light crude production emission factors regardless of the service type. API Publication 4615 defines light crude as oil with an API gravity of 20 or more, and heavy crude as oil with an API gravity of less than 20.

EXHIBIT C.1: 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. Calculate the CH_4 emissions using the "Valves–Gas" screening factor provided in Table C-1 and for comparison using the production emission factors provided in Table C-2.

CALCULATION METHODOLOGY:
Because no plant-specific stream composition data is available, the composition data will be taken from Table C-7 (presented in Section C.1.4) when applied to the service specific emission factors. Where emission factors from Table C-2 are applied, the CH_4 composition from Table C-6 is used since these are based on an aggregated stream composition for the facility.

1. *Calculate CH_4 emissions using the "Valves-Gas" screening factor.* The emission factors in Table C-1 are in terms of TOC. TOC emissions are calculated using Equation C-1. Emissions are calculated below, by screening value:

For components screening >=10,000 ppmv:

$$E_{TOC>10000} = 9.8 \times 10^{-5} \frac{\text{tonne}}{\text{hr} \times \text{valve}} \times 5 \text{ valves}$$

$$\underline{E_{TOC>10000} = 4.9 \times 10^{-4} \text{ tonne TOC/hr}}$$

For components screening <10,000 ppmv:

$$E_{TOC<10000} = 2.5 \times 10^{-8} \frac{\text{tonne}}{\text{hr} \times \text{valve}} \times 95 \text{ valves}$$

$$\underline{E_{TOC<10000} = 2.4 \times 10^{-6} \text{ tonne TOC/hr}}$$

The combined valve emissions are:

$$E_{TOC\ Total} = 4.9 \times 10^{-4} + 2.4 \times 10^{-6}$$

$$\underline{E_{TOC\ Total} = 4.92 \times 10^{-4} \text{ tonne TOC/hr}}$$

EXHIBIT C.1: Sample Calculation for Screening Factor Approach, continued

Methane emissions are then calculated by applying the CH_4 composition from Table C-7, expressed as weight fraction. The CH_4 composition for a sweet gas facility, with components in gas service is 91.8796 mole %, or 84.1609 weight %.

$$E_{CH_4} = 4.92 \times 10^{-4} \frac{\text{tonne TOC}}{\text{hr}} \times 0.841609 \frac{\text{tonne CH}_4}{\text{tonne TOC}} \times \frac{8760 \text{ hr}}{\text{yr}}$$

$$\underline{E_{CH_4} = 3.6 \text{ tonnes CH}_4 / \text{yr}}$$

2. *Calculate CH_4 emissions using the "Valves-Gas" screening factor.* Alternatively, CH_4 emissions can be calculated using the production emission factors from Table C-2 and gas composition data from Table C-6 (presented in Section C.1.4). Emissions are calculated below, by screening value:

For components screening >=10,000 ppmv:

$$E_{TOC>10000} = 6.4 \times 10^{-5} \frac{\text{tonne}}{\text{hr} \times \text{valve}} \times 5 \text{ valves}$$

$$\underline{E_{TOC>10000} = 3.2 \times 10^{-4} \text{ tonne TOC/hr}}$$

For components screening <10,000 ppmv:

$$E_{TOC<10000} = 3.1 \times 10^{-8} \frac{\text{tonne}}{\text{hr} \times \text{valve}} \times 95 \text{ valves}$$

$$\underline{E_{TOC<10000} = 2.94 \times 10^{-6} \text{ tonne TOC/hr}}$$

The combined valve emissions are:

$$E_{TOC\ Total} = 3.2 \times 10^{-4} + 2.94 \times 10^{-6}$$

$$\underline{E_{TOC\ Total} = 3.23 \times 10^{-4} \text{ tonne TOC/hr}}$$

Methane emissions are then calculated by applying the CH_4 composition from Table C-6, for gas production facilities (0.92 weight fraction).

$$E_{CH_4} = 3.23 \times 10^{-4} \frac{\text{tonne TOC}}{\text{hr}} \times 0.92 \frac{\text{tonne CH}_4}{\text{tonne TOC}} \times \frac{8760 \text{ hr}}{\text{yr}}$$

$$\underline{E_{CH_4} = 2.6 \text{ tonnes CH}_4 / \text{yr}}$$

C.1.2 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, and oil and natural 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 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 natural gas industry facilities. While refineries have the database to support emission estimating by correlations, the CH_4 composition of refinery fugitive equipment leak emissions is generally negligible (with the exception of the natural gas system, which is not commonly covered by the LDAR database). If monitoring data and the means to make the correlation calculations on an individual component basis are available, the correlation approach can provide accurate estimates of equipment leak emissions.

The correlation equations apply to the entire range of the analyzer used for monitoring. The form of the correlation is:

$$E_{TOC} = A \times SV^{B} \qquad \text{(Equation C-2)}$$

where

E_{TOC} = emission rate expressed as kg of TOC/hour;
A and B = constants developed in the correlation fitting; and
SV = screening value in ppmv estimated according to U.S. 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:

$$E_{TOC} = F_A \times N \qquad \text{(Equation C-3)}$$

where

F_A = the applicable default zero or pegged emission factor and
N = the number of components found to be default zeros or pegged components.

Tables C-3 through C-5 presents the correlation equations, the default zero emission factors, and the pegged emission factors.

Table C–3. Petroleum Industry Leak Rate/Screening Value (SV) Correlations

Equipment Type	Leak Rate Correlation Equation [a,b]	
	kg TOC/hr/component	tonne TOC/hr/component
Valves	$2.29E\text{-}06 \times (SV)^{0.746}$	$2.29E\text{-}09 \times (SV)^{0.746}$
Pump Seals	$5.03E\text{-}05 \times (SV)^{0.610}$	$5.03E\text{-}08 \times (SV)^{0.610}$
Connectors	$1.53E\text{-}06 \times (SV)^{0.735}$	$1.53E\text{-}09 \times (SV)^{0.735}$
Flanges	$4.61E\text{-}06 \times (SV)^{0.703}$	$4.61E\text{-}09 \times (SV)^{0.703}$
Open-Ended Lines	$2.20E\text{-}06 \times (SV)^{0.704}$	$2.20E\text{-}09 \times (SV)^{0.704}$
Others [c]	$1.36E\text{-}05 \times (SV)^{0.589}$	$1.36E\text{-}08 \times (SV)^{0.589}$

Footnotes and Sources:
[a] U.S. 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.
[b] SV stands for Screening Value, entered in units of ppmv.
[c] 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 C–4. Default-Zero Values for the Petroleum Industry

	Default-zero Emission Factors [a]	
Equipment Type	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 [b]	4.0E-06	4.0E-09

Footnotes and Sources:
[a] U.S. 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.
[b] 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 C–5. Pegged Emission Rates for the Petroleum Industry

Equipment Type	10,000 ppm Pegged Emission Factor [a]		100,000 ppm Pegged Emission Factor [a]	
	kg TOC/hr / component	tonne TOC/hr / component	kg TOC/hr / component	tonne TOC/hr/ component
Valves	0.064	6.4E-05	0.140	1.40E-04
Pump Seals	0.074	7.4E-05	0.160	1.60E-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 [b]	0.073	7.3E-05	0.110	1.10E-04

Footnotes and Sources:

[a] U.S. 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 2-14.

[b] The other equipment type was developed for instruments, loading arms, pressure relief valves, stuffing boxes, vents, compressors, dump lever arms, diaphrams, drains, hatches, meters and polished rods. This type should be applied to any equipment other than valves, pump seals, connectors, flanges, 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 C.2: 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). Calculate the CH_4 emissions.

CALCULATION METHODOLOGY:
Because plant-specific composition data is not available, the composition data will be taken from Table C-6 (presented in Section C.1.4) since the components are not classified by service type. The default CH_4 concentration is 56.4%, or a weight fraction of 0.564.

EXHIBIT C.2: Sample Calculation for the Correlation Approach, continued

TOC emissions are calculated using Equations C-2 and C-3:

From Table C-4, emissions from default zeros are:

$$E_{\text{TOC, Default Zeros}} = 3.1 \times 10^{-7} \frac{\text{kg}}{\text{hr} \times \text{flange}} \times 95 \text{ flanges}$$

$$\underline{E_{\text{TOC, Default Zeros}} = 2.95 \times 10^{-5} \text{ kg TOC/hr}}$$

From Table C-5, emissions within the correlation range are:

$$E_{\text{TOC, Correlation}} = 4.61 \times 10^{-6} \times (7950)^{0.703} \frac{\text{kg TOC}}{\text{hr} \times \text{flange}} \times 4 \text{ flanges}$$

$$\underline{E_{\text{TOC, Correlation}} = 1.02 \times 10^{-2} \text{ kg TOC/hr}}$$

From Table C-7, emissions from pegged components are:

$$E_{\text{TOC, Pegged}} = 0.085 \frac{\text{kg}}{\text{hr} \times \text{flange}} \times 1 \text{ flange}$$

$$\underline{E_{\text{TOC, Pegged}} = 8.5 \times 10^{-2} \text{ kg TOC/hr}}$$

Summing these results, the total TOC emissions are:

$$E_{\text{TOC, Total}} = \left(2.95 \times 10^{-5} + 1.02 \times 10^{-2} + 8.5 \times 10^{-2}\right)$$

$$\underline{E_{\text{TOC, Total}} = 9.5 \times 10^{-2} \text{ kg TOC/hr}}$$

The CH_4 emissions are calculated using Equation 6-9:

$$E_{CH_4} = 9.5 \times 10^{-2} \frac{\text{kg TOC}}{\text{hr}} \times \frac{0.564 \text{ kg } CH_4}{\text{kg TOC}} \times \frac{\text{tonne } CH_4}{1000 \text{ kg } CH_4} \times \frac{8760 \text{ hr}}{\text{yr}}$$

$$\underline{E_{CH_4} = 0.47 \text{ tonne } CH_4/\text{yr}}$$

C.1.3 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.

C.1.4 Methane-Specific Data for Emission Rate Calculations

Most fugitive emission factors are for THC, TOC, or 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_4 emissions from these types of emission factors. Calculating CH_4 fugitive emissions from THC or TOC emission factors is done using Equations 6-9 and C-4, 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 C-6 provides “generic” speciation factors that can be applied to THC fugitive emissions to obtain compound specific emissions data. The table includes data on average CH_4 fractions of the THC fugitive emissions for various oil and natural gas industry operations. The composition data in Table C-6 are taken from API Publication 4615 (API, 1995).

Note that the CH_4 speciation factors in Table C-6 are not specified by the type of service (gas, light liquid or heavy liquid), but are instead provided as speciation factors (expressed as weight fractions) of the average CH_4 fraction that can be applied to the THC fugitive emissions from operations such as light crude production, heavy crude production, gas production, natural gas processing plants, and offshore oil and natural gas production. These fractions are not to be confused with actual weight fractions of the different species in the produced fluids. They are provided as a convenient average factor that can be used to speciate fugitive emissions when using the component specific emission factors provided in API 4615 given in Tables 6-13, 6-14, and 6-16.

Table C–6. "Generic" Speciation Factors for Component Specific THC Emissions Factors for Oil and Natural Gas Operations

Best Applied To API 4615 Emission Factors

Compound	Onshore Operations				Offshore Oil and Natural Gas
	Light Crude	**Heavy Crude**	**Gas Production**	**Gas Plant**	
Methane	0.613	0.942	0.920	0.564	0.791
NMHC [a]	0.387	0.058	0.080	0.436	0.210
VOC [b]	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

Footnotes and Sources:
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.
[a] NMHC = Non-methane hydrocarbon.
[b] VOC = Propane and heavier hydrocarbon.

Additionally, Table C-7 provides generic fugitive stream composition data based on a Canadian study of upstream oil and natural gas operations in Alberta (Picard, Vol. II, 1992). Unlike the data in Table C-6, the composition data in Table C-7 are specified by gas or liquid service. As noted in the table title, these compositions are best applied to service specific emission factors, such as from EPA Protocol factors shown in Table 6-21. 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 C-7 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; and
- 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 C–7. "Generic" Production (Canadian) Composition by Service [a]

Best Applied To Service-Specific Emission Factors

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 % [b]	Weight % [c]	Mole % [b]	Weight % [c]	Mole % [b]	Weight % [c]	Mole % [b]	Weight % [c]	Mole % [b]	Weight % [c]	Mole % [b]	Weight % [c]
N_2	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_2	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_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	3.5460	6.6772	0.0000	0.0000	0.0000	0.0000
C1	97.4524	95.1997	91.8796	84.1609	0.0000	0.0000	88.6210	78.5410	0.0000	0.0000	91.8796	84.1609
C2	1.1439	2.0949	5.4263	9.3180	6.2600	3.8133	5.2339	8.6959	6.2600	3.8133	5.4263	9.3180
C3	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-C4	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-C4	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-C5	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-C5	0.0005	0.0022	0.0296	0.1220	1.4300	2.0901	0.0286	0.1140	1.4300	2.0901	0.0296	0.1220
C6	0.0000	0.0000	0.0060	0.0295	1.2000	2.0950	0.0058	0.0276	1.2000	2.0950	0.0060	0.0295
C7+	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

Table C–7. “Generic” Production (Canadian) Composition by Service [a], continued

Best Applied To Service-Specific Emission Factors

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 % [b]	Weight % [c]	Mole % [b]	Weight % [c]	Mole % [b]	Weight % [c]	Mole % [b]	Weight % [c]	Mole % [b]	Weight % [c]	Mole % [b]	Weight % [c]	Mole % [b]	Weight % [c]
N_2	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_2	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_2S	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
C1	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
C2	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
C3	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-C4	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-C4	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-C5	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-C5	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
C6	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
C7+	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

Footnotes and Sources:

[a] Picard, D. J., B. D. Ross, and D. W. H. Koon. *A Detailed Inventory of CH_4 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.

[b] Original composition provided in mole percent on a moisture-free (dry) basis.

[c] Compositions were converted from mole percents to weight percents using the approach described in Section 3.6.4 of this API *Compendium*.

C.1.5 Generic Component Counts

When using the component-level average emission factors, site-specific data should be used for the component counts. 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 C-8 provides generic component counts for onshore oil production facilities, and Table C-9 provides generic counts for onshore gas production, onshore gas processing, and offshore oil and natural 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. CAPP also provides more detailed component counts by equipment type for the upstream oil and natural gas industry (CAPP, 2004).

Note that the UKOOA provides adjustment factors that can be applied to the fugitive component 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. $E_{CH4} = FA \times WF_{CH4} \times N \times$ (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.

A summary of the number of vessels, compressors, and pumps associated with various natural gas processes is presented in Table C-10.

Table C–8. "Generic" Fugitive Counts for Onshore Oil Production Facilities (per Equipment/Process Type)

Equipment/ Process	Light Onshore Oil Production [a,b,c]					Heavy Onshore Oil Production [a,b,c]				
	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							

Footnotes and Sources:

[a] 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.

[b] American Petroleum Institute (API*). Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations*, API Publication No. 4589, Health and Environmental Sciences Department, December 1993.

[c] 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 C–9. "Generic" Fugitive Counts for Gas Production, Gas Processing, and Offshore Facilities (per Equipment/Process Type)

Equipment/ Process	**Gas Production [a,b]**					**Gas Processing Plants [a,b]**					**Offshore Oil and Natural Gas Production Platforms [a,b]**				
	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

Footnotes and Sources:

[a] 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:

[b] American Petroleum Institute (API). *Fugitive Hydrocarbon Emissions from Oil and Gas Production Operations*, API Publication No. 4589, Health and Environmental Sciences Department, December 1993.

Table C-10. Summary of the Number of Vessels, Compressors, and Pumps Associated with Various Natural Gas Processes

Process	Vessels	Compressors	Pumps
Absorption	13	0	1
Adsorption	5	1	0
Chemsweet	5	1	0
Cold Bed Absorption	6	0	0
Compression	4	1	0
Cycling	12	1	2
DEA-Diethanolamine	13	0	1
DGA-Diglycolamine	13	0	1
Deepcut	14	1	2
Deethanizing	10	1	2
Dehydration	5	1	0
Demethanizing	10	1	2
Desiccant	5	1	0
Dewpoint	6	2	2
Fractionation	12	1	2
Iron Sponge	6	0	0
LoCat	5	1	0
MCRC - Sub-dewpoint sulphur recovery	6	0	0
MDEA - Monodiethanolamine	13	0	1
MEA - Monoethanolamine	13	0	1
Molecular Sieve	5	1	0
NGL - Natural gas liquid	14	1	2
Physical Solvent	12	1	1
Proprietary Sweetening	13	0	1
Refrigeration	6	2	2
Selexol	12	1	1
Separation	3	0	1
Sluri-sweet	13	0	1
Stabilization	8	0	1
Sulfacheck	12	1	1
Sulfinol	12	1	1
Sulfreen	6	0	0
Sweetening	13	0	1
Turbo Expander	1	1	0

Sources:
Clearstone Engineering Ltd. *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H_2S) Emissions by the Upstream Oil and Gas Industry*, Volume 5, September 2004.

C.2 Refinery Fugitive Emissions

As noted in Section 6 and Appendix F, refinery fugitive emissions will generally have an insignificant contribution to the total GHG inventory because most refinery streams do not contain CH_4 (as demonstrated in Appendix E). Note that leaks from equipment used in association with "weathered" crude or other refined petroleum products will not emit CH_4 or CO_2, as "weathered" crude and refined petroleum products do not contain CH_4 or CO_2.[2]

The estimation method for refinery fugitive emissions provided in Section 6 is consistent with the materiality of fugitive emissions relative to total GHG emissions from refinery operations. Alternatively, this subsection presents more detailed emission estimation methodologies for refineries.

Refinery component-level average emission factors are presented in Table C-11. The component-level average factors should be used in accordance with the methodology discussed in Section 6.1.3. The refinery component-level average emission factors are expressed as VOC, where VOC = TOC – CH_4. To correct these factors to a CH_4 basis, 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_4 (VOC) organic compounds. The equation below illustrates the emission factor adjustment that corrects the VOC emission factor to a CH_4 basis:

$$E_{CH_4} = F_{A\ VOC} \times \frac{WF_{CH_4}}{WF_{TOC} - WF_{CH_4}} \times N \qquad \text{(Equation C-4)}$$

where

E_{CH_4} = emission rate of CH_4 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_4 in the TOC; and
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_4 and organic compounds. The maximum CH_4 concentration correction should not

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[2] For more information, see Appendix E.

exceed 10 weight percent, even if a stream contains more than 10 weight percent CH_4. This limitation generally is not an issue for refinery streams because they contain very little CH_4. The exceptions are for the refinery natural gas system and potentially the fuel gas system, in which case the gas service emission factors from Table 6-11 may be more representative and applicable to the higher CH_4 concentrations.

EPA average emission factors for refineries are provided in Table C-11 (EPA, 1995). As noted in Section 6, 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 Table C-11 are service specific.

Table C-11. EPA Average Refinery Emission Factors [a]

Component – Service [b]	Emission Factor	
	kg VOC/hr/comp.	**tonne VOC/hr/comp.**
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

Footnotes and Sources:

[a] U.S. 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. 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_4 basis using Equation 6-8.

[b] EPA defines light liquids as liquids for which the sum of the concentration of individual constituents with a vapor pressure over 0.3 kPa at 20 °C is greather than or equal to 20 weight percent. EPA defines heavy liquids as liquids not in gas/vapor or light liquid service.

Screening range factors for refineries are presented in Table C-12. These emission factors should be used in accordance with the methodology described in Section C.1.1. The refinery screening range factors are given in VOC rather than TOC. Equation C-4 presents the correction for refinery emission factors from a VOC to a CH_4 basis.

Table C–12. Refinery Screening Factors

Component – Service [b]	Emission Factor [a] (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 – Light Liquid	1.70E-03	8.52E-02	1.70E-06	8.52E-05
Valves – Heavy Liquid	2.30E-04	2.30E-04	2.30E-07	2.30E-07
Pump Seals – Light Liquid	1.20E-02	4.37E-01	1.20E-05	4.37E-04
Pump Seals – Heavy Liquid	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	6.00E-05	3.75E-02	6.00E-08	3.75E-05
Open-Ended Lines – All	1.50E-03	1.20E-02	1.50E-06	1.20E-05

Footnotes and Sources:

[a] U.S. 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.

[b] EPA defines light liquids as liquids for which the sum of the concentration of individual constituents with a vapor pressure over 0.3 kPa at 20 °C is greather than or equal to 20 weight percent. EPA defines heavy liquids as liquids not in gas/vapor or light liquid service.

Note: These emission factors do not apply to streams containing >10% CH_4.

If a specific downstream operation has potentially significant CH_4 fugitive emissions, then the CH_4 weight fraction should be characterized using plant-specific data. In the absence of plant-specific composition data, Table E-3 provides “generic” vapor phase speciation data for “weathered” crude oil and refined petroleum products based on data taken from the EPA’s SPECIATE computer database program, Version 4.0 (EPA, 2006). 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 C-12.

C.3 Derivation of Fugitive Emission Factors

This section provides the derivation of fugitive emission factors provided in Section 6. Factor derivations are presented in this section by industry segment.

C.3.1 Onshore Oil Production Fugitive Emission Factor

The onshore oil production fugitive emission factor presented in Table 6-2 was developed using data presented in the EPA petroleum industry CH_4 emissions study (Harrison, et al., 1998). All identified onshore fugitive emission sources are combined into this single emission factor. The precision data was calculated using data presented in Volume 8 of the GRI/EPA study (Hummel, et al., 1996). Emissions were calculated by dividing the total CH_4 emissions for onshore oil production by the total volume of oil produced (DOE, 1993). The factor derivation is presented in Table C-13.

Table C–13. Derivation of Facility-Level Average Fugitive Emission Factor for Onshore Oil Production

Source	U.S. Methane Emissions [a,b], Bscf CH_4/yr	Uncertainty [c], (± %)
Oil Wellheads (heavy crude)	0.012	128
Oil Wellheads (light crude)	3.879	128
Separators (heavy crude)	0.003	110
Separators (light crude)	2.118	102
Heater/Treaters (light crude)	1.687	166
Headers (heavy crude)	0.003	139
Headers (light crude)	3.500	141
Tanks (light crude)	0.681	141
Small Compressor (light crude)	0.011	192
Large Compressor (light crude)	11.585	192
Sales Areas	0.066	66.4
Pipelines [d]	1.441	154
Total Emissions	24.986	95.0
Activity Data		
National Onshore Crude Oil Production [e]	2,042,625,000 bbl/yr	10
CH_4 Emission Factor		
Emission Factor Development	EF = (24.986 x 10^9 scf CH_4/yr) ÷ (2,042,625,000 bbl oil/yr) =12.232 scf CH_4/bbl	**95.5**
Onshore Oil Production Fugitive Emission Factor, Converted to lb CH_4/bbl oil	**0.5173 lb CH_4/bbl oil**	

Footnotes and Sources:

[a] Harrison, M.R., T.M. Shires, R.A. Baker, and C.J. Loughran. *Methane Emissions from the U.S. Petroleum Industry*, Final Report, EPA-600/R-99-010. U.S. Environmental Protection Agency, February 1999.

[b] Hummel, K.E., L.M. Campbell, and M.R. Harrison. *Methane Emissions from the Natural Gas Industry*, *Volume 8: Equipment Leaks*, Final Report, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[d] Because the data used to calculate the reference emission factor were unavailable, the precision at a 95% confidence interval was calculated based on the precision at a 90% confidence interval presented in the source assuming a data set size of ten.

[e] DOE, Petroleum Supply Annual, 1993. An uncertainty factor of 10% was assigned based on engineering judgment.

C.3.2 Onshore Gas Production Fugitive Emission Factors

The onshore gas production facility-level average fugitive emission factor presented in Table 6-2 was developed using data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). All identified onshore fugitive emission sources are combined into this single emission factor. The precision data were calculated using data presented in Volume 8 of the

GRI/EPA study (Hummel, et al., 1996). Emissions were calculated by dividing the total CH_4 emissions for onshore gas production by the total volume of gas produced (DOE, 1993). The factor derivation is presented in Table C-14.

Table C–14. Derivation of Facility-Level Average Fugitive Emission Factor for Onshore Gas Production

Source	**U.S. Methane Emissions [a,b], Bscf CH_4/yr**	**Uncertainty [c], (± %)**
Gas Wells (Eastern onshore)	0.3352	32.8
Gas Wells (Rest of U.S. onshore)	1.8991	29.3
Heaters (Eastern onshore)	0.0013	260
Heaters (Rest of U.S. onshore)	1.0689	131
Separators (Eastern onshore)	0.0301	43.0
Separators (Rest of U.S. onshore)	3.3257	81.8
Small Reciprocating Compressors (Eastern onshore)	0.0006	87.7
Small Reciprocating Compressors (Rest of U.S. onshore)	1.6531	111
Large Reciprocating Compressors	0.5328	162
Large Reciprocating Compressor Stations	0.0361	210
Meters/Piping (Eastern onshore)	0.2508	130
Meters/Piping (Rest of U.S. onshore)	5.8158	130
Dehydrators (Eastern onshore)	0.0083	49.0
Dehydrators (Rest of U.S. onshore)	1.2233	38.8
Pipeline Leaks	6.6060	129
Total Emissions	22.7871	52.7
Activity Data		
Gross Onshore National Gas Production [d]	16,808 Bscf/yr	5
CH_4 Emission Factor		
Emission Factor Development	EF = (22.7871 × 10^9 scf CH_4/yr) ÷ (16,808 × 10^9 scf gas/yr) × (10^6/MM) = 1,356 scf CH_4/MMscf	**52.9%**
Onshore Gas Production Fugitive Emission Factor, Converted to lb CH_4/MMscf gas	**57.33 lb CH_4/MMscf**	

Footnotes and Sources:

[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[b] Hummel, K.E., L.M. Campbell, and M.R. Harrison. *Methane Emissions from the Natural Gas Industry*, *Volume 8: Equipment Leaks*, Final Report, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. Environmental Protection Agency, June 1996. Component emission factors for onshore production in the Eastern U.S. were based on a measurement program of 192 well sites at 12 eastern gas production facilities. Site visits and phone surveys of 7 additional sites provided data used for determining the number of heaters and dehydrators. Component emissions factors for onshore production in the Western U.S. were based on a comprehensive fugitive emissions measurement program at 12 sites. An additional 13 sites were visited as part of the GRI/EPA study to develop average component counts for each piece of major process equipment

[c] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[d] DOE, *Natural Gas Annual*, 1993. An uncertainty factor of 5% was assigned based on engineering judgment.

The onshore gas production equipment level CH_4 fugitive emission factors presented in Table 6-4 were developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). All identified onshore fugitive emissions are combined into this single emission factor except pipeline related fugitives. The precision data were calculated using data presented in Volume 9 of the GRI/EPA study (Campbell, et al., 1996). Source type emissions were calculated by dividing the sum of the CH_4 emissions for "Eastern Onshore" and "Rest of U.S." by the total national equipment counts.

Component emission factors for onshore production in the "Eastern U.S." were based on a measurement program of 192 well sites at 12 eastern gas production facilities. Site visits and phone surveys of 7 additional sites provided data used for determining the number of heaters and dehydrators. Component emission factors for onshore production in the "Rest of U.S." were based on a comprehensive fugitive emissions measurement program at 12 sites. An additional 13 sites were visited as part of the GRI/EPA study to develop average component counts for each piece of major process equipment (Campbell, et al., 1996). Table C-15 presents the factor derivations by equipment type.

Table C–15. Derivation of Equipment-Level Fugitive Emission Factors for Gas Production [a]

	Emissions [b,c], Bscf CH_4/yr			**National Equipment Counts [b,c]**			**Emission Factor, scf CH_4/ equip.**
Source	**Eastern Onshore [d]**	**Rest of U.S. [e]**	**Total**	**Eastern Onshore**	**Rest of U.S.**	**Total**	
Gas Wellheads	0.3352 ±32.8%	1.8991 ± 29.3%	2.2343 ± 25.4%	129,157 ± 5.97%	142,771 ± 5.97%	271,928± 4.22%	8,217 ± 25.7%
Gas Separators	0.0301 ± 43.0%	3.3257 ± 81.8%	3.3557 ± 81.0%	91,670 ± 27.5%	74,674 ± 68.0%	166,344 ± 34.1%	20,174 ± 87.9%
Gas Heaters	0.0013 ± 260%	1.0689 ±131%	1.0702 ±131%	260 ± 234%	50,740 ± 114%	51,000 ± 113%	20,985 ± 173%
Gas Small Gathering Compressor	0.0006 ± 87.7%	1.6531 ± 111%	1.6537 ± 111%	129 ± 66.4%	16,915 ± 62.3%	17,044 ± 61.8%	97,023 ± 127%
Gas Large Gathering Compressor	0	0.5328 ± 162%	0.5328 ± 162%	0	96.0 ± 120%	96.0 ± 120%	5,550,000 ± 202%
Gas Meters/Piping	0.2508 ± 130%	5.8158 ± 130%	6.0666 ± 125%	76,262 ± 120%	301,180 ± 120%	377,442 ± 98.5%	16,073 ± 159%
Gas Dehydrators	0.0083 ± 49.0%	1.2233 ± 38.8%	1.2316 ± 38.6%	1,047 ± 24.0%	36,777 ± 24.0%	37,824 ± 23.3%	32,561 ± 45.1%

Footnotes and Sources:

[a] Uncertainty values are based on 95% confidence intervals, converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[d] Component emission factors for onshore production in the Eastern U.S. were based on a measurement program of 192 well sites at 12 eastern gas production facilities. Site visits and phone surveys of 7 additional sites provided data used for determining the number of heaters and dehydrators (Campbell, et al., 1996).

[e] Component emissions factors for onshore production in the Western U.S. were based on a comprehensive fugitive emissions measurement program at 12 sites. An additional 13 sites were visited as part of the GRI/EPA study to develop average component counts for each piece of major process equipment (Campbell, et al., 1996).

The gathering pipeline fugitive emission factors presented in Table 6-4 were developed using emissions data presented in Volume 9 of the GRI/EPA study (Campbell, et al., 1996). The original emissions data in the GRI/EPA report were given in terms of CH_4 emissions on an equivalent leak basis; the emission factors were converted to a pipeline mile basis using pipeline miles presented in Volume 9 of the GRI/EPA study (Campbell, et al., 1996).

Methane emission factors were first calculated by pipe material, as shown in Table C-16. A gathering pipeline average CH_4 emission factor was then derived as shown in Table C-17. Emission factors for CO_2 from pipeline oxidation and pipeline leaks were calculated using Equations 6-4 and 6-5, respectively. Similar to the derivation of the pipeline CH_4 emission factors, CO_2 emission factors were first derived by pipe material, as shown in Table C-18. Average CO_2 emission factors for oxidation and pipeline leaks were then derived from the factors by pipe material, as shown in Table C-19.

Table C–16. Derivation of Fugitive CH_4 Emission Factors for Natural Gas Gathering Pipelines, by Pipe Material [a]

Pipe Material	CH_4 Emission Factor [b,c] (scf/leak-yr)	Activity Factor [b,c] (e.q. leaks)	Annual CH_4 Emissions [d] (Bscf CH_4/yr)	Pipeline Miles [b,c,e]	Emission Factor [f]	
					(scf CH_4/mi-yr)	(lb CH_4/mi-yr)
Cast Iron [g]			0.172 ± 77.7%	856 ± 10%	201,418 ± 77.0%	8,518 ± 77.0%
Plastic	84,237 ± 212 %	6,467 ± 97.0%	0.545 ± 233%	29,862 ± 10%	18,243 ± 233%	771.5 ± 233%
Protected Steel	17,102 ± 103%	53,657 ± 92.3%	0.918 ± 138%	268,082 ± 10%	3,423 ± 139%	144.8 ± 139%
Unprotected Steel	43,705 ± 113%	114,655 ± 92.1%	5.01 ± 146%	41,400 ± 10%	121,039 ± 146%	5,119 ± 146%

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996. The cast iron leak rate was derived from 21 sample measurements, the plastic leak was derived from 6 measurements, the protected steel leak rate was derived from 17 measurements, and the unprotected steal leak rate was derived from 20 measurements. Note that the CH_4 emission factor shown has already been adjusted for soil oxidation.

[d] Annual CH_4 emissions are estimated by multiplying the leak based emission factor by the number of equivalent leaks.

[e] A confidence interval of ± 10% was assumed based on engineering judgment (Campbell, et al., 1996).

[f] The pipeline based CH_4 emission factor is calculated by dividing the annual CH_4 emissions by the miles of pipeline.

[g] For cast iron pipe, the original emission factor and activity factor are presented on a mile basis.

Table C–17. Derivation of Combined Fugitive CH_4 Emission Factor for Natural Gas Gathering Pipelines [a]

Pipe Material	Annual CH_4 Emissions [b] (Bscf CH_4/yr)	Pipeline Miles [c,d,e] (miles)
Cast Iron	0.172 ± 77.7%	856 ± 10%
Plastic	0.545 ± 233%	29,862 ± 10%
Protected Steel	0.918 ± 138%	268,082 ± 10%
Unprotected Steel	5.01 ± 146%	41,400 ± 10%
Total	6.646 ± 113 %	340,200 ± 8.02%
CH_4 Emission Factor		
Emission Factor Development	EF = (6.646 Bscf CH_4/yr) ÷ 340,200 miles = 19,535 scf CH_4/mile	
Gas Gathering Pipeline Fugitive Emission Factor, Converted to lb CH_4/mile	**826 ± 113% lb CH_4/mile**	

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-16.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[e] A confidence interval of ± 10% was assumed based on engineering judgment (Campbell, et al., 1996).

Table C–18. Derivation of Fugitive CO_2 Emission Factors for Natural Gas Gathering Pipelines, by Pipe Material [a]

Pipe Material	CH_4 Emission Factor [b] (lb CH_4/leak-yr)	% Soil Oxidation [c,d,e]	Pre-oxidized CH_4 Emission Factor (lb CH_4/leak-yr)	CO_2 Oxidation Emission Factor (lb CO_2/mi-yr)	CO_2 Leak Emission Factor [f] (lb CO_2/mi-yr)
Cast Iron	8,518 ± 77.0%	40.3% ± 25%	14,267 ± 81.0%	15,808 ± 81.0%	1,878 ± 81.3%
Plastic	771.5 ± 233%	2.0% ± 25%	787.2 ± 234%	43.29 ± 234%	103.6 ± 235%
Protected Steel	144.8 ± 139%	3.0% ± 25%	149.2 ± 141%	12.31 ± 141%	19.64 ± 141%
Unprotected Steel	5,119 ± 146%	1.8% ± 25%	5,212 ± 148%	258.0 ± 148%	686.0 ± 148%

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Converted from scf CH_4/leak-yr to lb CH_4/leak-yr from Table C-16 based on 60ºF and 14.7 psia.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[e] Uncertainty of the soil oxidation values is assumed to be ± 25% based on engineering judgment (Campbell, et al., 1996).

[f] The default contents for CH_4 and CO_2 in the production segment are 78.8 mole % and 3.78 mole %, respectively, as shown in Table E-4.

Table C–19. Derivation of Combined Fugitive CO_2 Emission Factors for Gas Gathering Pipelines [a]

Pipe Material	CO_2 Oxidation Emission Factor [b] (lb CO_2/mi-yr)	CO_2 Leak Emission Factor [b] (lb CO_2/mi-yr)	Pipeline Miles [c,d,e]	CO_2 Oxidation Emissions (lb CO_2/yr)	CO_2 Leak Emissions (lb CO_2/yr)
Cast Iron	15,808 ± 81.0%	1,878 ± 81.3%	856 ± 10%	13,531,891 ± 81.6%	1,607,429 ± 81.9%
Plastic	43.29 ± 234%	103.6 ± 235%	29,862 ± 10%	1,292,604 ± 233%	3,093,954 ± 235%
Protected Steel	12.31 ± 141%	19.64 ± 141%	268,082 ± 10%	3,299,731 ± 141%	5,265,452 ± 142%
Unprotected Steel	258.0 ± 148%	686.0 ± 148%	41,400 ± 10%	10,679,253 ± 148%	28,401,857 ± 148%
TOTAL			340,200 ± 8.02%	28,803,480 ± 69.8%	38,368,692 ± 113%
CO_2 Emission Factors					
CO_2 Oxidation Fugitive Emission Factor Development	**EF = 28,803,480 lb CO_2/yr ÷ 340,200 miles = 84.7 ± 70.2% lb CO_2/mile-yr**				
CO_2 Leak Fugitive Emission Factor Development	**EF = 38,368,692 lb CO_2/yr ÷ 340,200 miles = 112.8 ± 114% lb CO_2/mile-yr**				

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Dervied in Table C-18.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[e] A confidence interval of ± 10% was assumed based on engineering judgment (Campbell, et al., 1996).

C.3.3 Gas Processing Fugitive Emission Factors

The gas processing fugitive emission factor in Table 6-2 was developed using data from in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). The gas processing factor is based on the total volume of gas processed, and includes emissions from compressors and other fugitives associated with the processing plant. The precision data were calculated using data presented in Volume 8 of the GRI/EPA study (Hummel, et al., 1996). The emission factor was calculated by dividing the sum of the gas processing CH_4 emissions by the total volume of gas processed (DOE, 1993). The factor derivation is presented in Table C-20.

Table C–20. Derivation of Facility and Equipment-Level Fugitive Emission Factors for Gas Processing

Source	**U.S. Methane Emissions [a,b], Bscf CH_4/yr**	**Uncertainty [c], (± %)**
Gas Processing Plants	2.095	57.3
Reciprocating Compressors	16.73	113
Centrifugal Compressors	5.626	109
Total	24.45	81.6
Activity Data		
Total Gas Processed [d]	16,045.86 Bscf/yr	10
CH_4 Emission Factors		
Facility-Level Gas Processing Fugitive Emission Factor Development	EF = $(24.45 \times 10^9$ scf CH_4/yr$)$ ÷ $(16,045.86 \times 10^9$ scf gas/yr$) \times (10^6$/MM$)$ = 1,523.5 scf CH_4/MMscf	**82.2**
Facility-Level Gas Processing Fugitive Emission Factor, Converted to lb CH_4/MMscf gas	**64.43 lb CH_4/MMscf** cited in Table 6-2	
Equipment-Level Gas Processing Fugitive Emission Factor Development	EF = $(2.095 \times 10^9$ scf CH_4/yr$)$ ÷ $(16,045.86 \times 10^9$ scf gas/yr$) \times (10^6$/MM$)$ = 130.563 scf CH_4/MMscf cited in Table 6-5	**58.1**
Equipment-Level Gas Processing Fugitive Emission Factor, Converted to lb CH_4/MMscf gas	**5.52 lb CH_4/MMscf**	

Footnotes and Sources:

[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[b] Hummel, K.E., L.M. Campbell, and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*, Final Report, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[d] DOE, *Natural Gas Annual*, 1993. An uncertainty factor of 10% was assigned based on engineering judgment.

The gas processing plant fugitive emission factor in Table 6-5, which includes fugitive emissions from sources other than compressors, was developed using data from Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). The precision data were calculated using data presented in Volume 8 of the GRI/EPA study (Hummel, et al., 1996). The factor derivation is presented below and shown in Table C-20.

Known: Estimated processing plant fugitive methane emissions = 2.095 ± 57.3% Bscf/year (Harrison, et al., Volume 2, 1996), precision at a 95% confidence interval was calculated using data from Hummel, et al., Volume 8, 1996.

Estimated annual gas processed = 16,045.855 Bscf/yr (DOE, 1993). A 10.0% uncertainty value is assumed for the gas processing rate, based on engineering judgment.

The conversion of the gas processing plant emission factor to tonnes CH_4 per volume of gas processed follows:

$$EF = \frac{2.095 \text{ Bscf } CH_4}{16{,}045.855 \text{ Bscf gas processed}} \times \frac{\text{lbmole } CH_4}{379.3 \text{ scf } CH_4} \times \frac{16 \text{ lb } CH_4}{\text{lbmole } CH_4} \times \frac{10^6 \text{ scf}}{\text{MMscf}} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$\underline{EF = 2.50E\text{-}03 \pm 58.1\% \text{ tonne } CH_4/\text{MMscf gas processed}}$$

C.3.4 Natural Gas Storage Station Fugitive Emission Factor

The natural gas storage station fugitive emission factor presented in Table 6-2 was developed using data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). The storage emission factor is presented on a station basis, and includes fugitive emissions associated with the station itself, as well as storage wells and compressors. The emission factor was calculated by dividing the sum of the gas storage station CH_4 emissions by the total number of storage stations. The precision data were calculated using data presented in Volume 8 of the GRI/EPA study (Hummel, et al., 1996). The factor derivation is presented in Table C-21.

Table C–21. Derivation of Facility-Level Average Natural Gas Storage Station Fugitive Emission Factor

Source	**U.S. Methane Emissions [a,b], Bscf CH_4/yr**	**Uncertainty [c], ± (%)**
Storage Stations	3.7288	132
Storage Reciprocating Compressors	10.7594	104
Storage Centrifugal Compressors	1.5176	164
Storage Wells	0.7522	76.3
Total	16.7580	74.5
Activity Data		
Total Storage Stations (Count) [d]	475	5
CH_4 Emission Factor		
Emission Factor Development	EF = (16.7580 × 10^9 scf CH_4/yr) ÷ (475 stations) = 35.28 × 10^6 scf CH_4/station-yr	**74.7%**
Gas Storage Station Fugitive Emission Factor, Converted to lb CH_4/station-yr	**1,491,936 lb CH_4/station-yr**	

Footnotes and Sources:

[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[b] Hummel, K.E., L.M. Campbell, and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*, Final Report, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[d] An uncertainty factor of 5% was assigned based on engineering judgment.

C.3.5 Gas Transmission Fugitive Emission Factors

The facility-level average gas transmission pipeline CH_4 fugitive emission factor presented in Table 6-2 was developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). The transmission facility-level average emission factor is based on CH_4 emissions from all identified fugitive sources present in the segment. The CH_4 emission factor was calculated by dividing the total transmission segment CH_4 emissions by the number of transmission pipeline miles. Pipeline miles were taken from Volume 9 of the GRI/EPA report (Campbell, et al, 1996). The precision data were calculated using data presented in Volume 8 of the GRI/EPA study (Hummel, et al., 1996) and Volume 10 of the GRI/EPA study (Campbell, et al., 1996). The factor derivation is presented in Table C-22.

Table C–22. Derivation of Facility-Level Average Fugitive CH_4 Emission Factor for Gas Transmission Pipelines

Source	U.S. Methane Emissions [a,b,c,d], Bscf CH_4/yr	Uncertainty [e], (± %)
Pipeline Leaks [f]	0.1614	94.2
Transmission Compressor Stations [g]	5.4467	127
Trans. Reciprocating Compressors	37.6787	88.7
Trans. Centrifugal Compressors	7.5302	58.0
Farm Taps and Direct Sales	0.8271	1,390
Transmission Interconnects	3.6834	1,380
Total	55.3274	113
Activity Data		
Total Transmission Pipeline Miles [f]	295,105	9.73
Methane Emission Factor		
Emission Factor Development	EF = (55.3274 × 10^9 scf CH_4/yr) ÷ (295,105 miles) = 187,484 scf CH_4/station-yr	**113**
Transmission Fugitive Emission Factor, Converted to lb CH_4/station-yr	**7,928 lb CH_4/mile-yr**	

Footnotes and Sources:

[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[b] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Hummel, K.E., L.M. Campbell, and M.R. Harrison. *Methane Emissions from the Natural Gas Industry*, *Volume 8: Equipment Leaks*, Final Report, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[d] U.S. Department of Transportation (DOT). *Research and Special Programs Administration*, 1991.

[e] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[f] Total shown in Table C-24.

[g] Because the data used to calculate the reference emission was unavailable, the precision at a 95% confidence interval was calculated based on the precision at a 90% confidence interval presented in the source assuming a data set size of ten.

The facility-level average natural gas transmission pipeline CO_2 emission factors were derived in conjunction with the equipment-level gas transmission pipeline CO_2 emission factor; the gas transmission pipeline CO_2 facility-level factor derivation is discussed later in this subsection.

The equipment-level average gas transmission pipeline CH_4 fugitive emission factor presented in Table 6-6 was developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). Emission factors were calculated in the same manner as for gas gathering pipelines. Methane emissions (and corresponding emission factors) were first calculated by pipe material, as shown in Table C-23. A transmission pipeline average CH_4 emission factor was then derived, as shown in Table C-24. Similar to the derivation of the pipeline CH_4 emission factors, CO_2 emission factors were first derived by pipe material, as shown in Table C-25. Average CO_2 emission factors for oxidation and pipeline leaks were then derived from the factors by pipe material, as shown in Table C-26. Methane and CO_2 emission factors by transmission pipe type are also shown in Table 6-8. The precision data was calculated using data presented in Volume 9 of the GRI/EPA study (Campbell, et al., 1996).

Table C–23. Derivation of Detailed Equipment-Level Fugitive CH_4 Emission Factors for Gas Transmission Pipelines, by Pipe Material [a]

Pipe Material	CH_4 Emission Factor [b,c] (scf/leak-yr)	Activity Factor [b,c] (e.q. leaks)	Annual CH_4 Emissions [d] (Bscf CH_4/yr)	Pipeline Miles [c,e,f] (miles)	CH_4 Emission Factor [g] (scf CH_4/mi-yr)	CH_4 Emission Factor (lb CH_4/mi-yr)
Cast Iron [h]			0.0229 ± 77.7%	96 ± 10%	238,736 ± 77.0%	10,096 ± 77.0%
Plastic	99,845 ± 212%	14 ± 97.0%	0.00140 ± 233%	2,621 ± 10%	533.3 ± 233%	22.55 ± 233%
Protected Steel	20,270 ± 103%	5,077 ± 92.3%	0.103 ± 138%	287,155 ± 10%	358.4 ± 139%	15.16 ± 139%
Unprotected Steel	51,802 ± 113%	659 ± 92.1%	0.0341 ± 146%	5,233 ± 10%	6524 ± 146%	275.9 ± 146%

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996. The cast iron leak rate was derived from 21 sample measurements, the plastic leak was derived from 6 measurements, the protected steel leak rate was derived from 17 measurements, and the unprotected steal leak rate was derived from 19 measurements. Note that the CH_4 emission factor shown has already been adjusted for soil oxidation.

[d] Annual CH_4 emissions are estimated by multiplying the leak based emission factor by the number of equivalent leaks.

[e] U.S. Department of Transportation (DOT). Research and Special Programs Administration, 1991.

[f] A confidence interval of ±10% was assumed based on engineering judgment in the 1991 DOT RSPA database (Campbell, et al., 1996).

[g] The pipeline based methane emission factor is calculated by dividing the annual methane emissions by the miles of pipeline.

[h] For cast iron pipe, the original emission factor and activity factor are presented on a mile basis.

Table C–24. Derivation of Equipment-Level Gas Transmission Pipeline Fugitive CH_4 Emission Factor [a]

Pipe Material	Annual CH_4 Emissions [b] (Bscf CH_4/yr)	Pipeline Miles [c,d] (miles)
Cast Iron [e]	0.0229 ± 77.7%	96 ± 10%
Plastic	0.0014 ± 233%	2,621 ± 10%
Protected Steel	0.103 ± 138%	287,155 ± 10%
Unprotected Steel	0.0341 ± 146%	5,233 ± 10%
Total	0.1614 ± 94.2%	295,105 ± 9.73%
Emission Factor Development	EF = (0.1614 Bscf CH_4/yr) / 295,105 miles = 546.8 scf CH_4/mile	
Gas Transmission Pipeline Fugitive Emission Factor, Converted to lb CH_4/mile	**23.12 ± 94.7% lb CH_4/mile**	

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-23.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines,* Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[d] U.S. Department of Transportation (DOT). Research and Special Programs Administration, 1991. A confidence interval of ±10% was assumed based on engineering judgment in the 1991 DOT RSPA database (Campbell, et al., 1996).

[e] For cast iron pipe, the original emission factor and activity factor are presented on a mile basis.

Equipment-level average emission factors for CO_2 from pipeline oxidation and pipeline leaks were calculated using Equations 6-4 and 6-5, respectively.

Table C–25. Derivation of Fugitive CO_2 Emission Factors for Gas Transmission Pipelines, by Pipe Material [a]

Pipe Material	CH_4 Emission Factor [b] (lb CH_4/leak-yr)	% Soil Oxidation [c,d,e]	Pre-oxidized CH_4 Emission Factor (lb CH4/leak-yr)	CO_2 Oxidation Emission Factor (lb CO_2/mi-yr)	CO_2 Leak Emission Factor [f] (lb CO_2/mi-yr)
Cast Iron	10,096 ± 77.0%	40.3% ± 25%	16,911 ± 81.0%	18,699 ± 81.0%	993.6 ± 81.1%
Plastic	22.55 ± 233%	2.0% ± 25%	23.01 ± 234%	1.263 ± 234%	1.352 ± 234%
Protected Steel	15.16 ± 139%	3.0% ± 25%	15.62 ± 141%	1.286 ± 141%	0.9180 ± 141%
Unprotected Steel	275.9 ± 146%	1.8% ± 25%	280.9 ± 148%	13.87 ± 148%	16.51 ± 148%

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-23.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[e] The precision of the soil oxidation values is assumed to be ± 25% based on engineering judgment (Campbell, et al., 1996).

[f] The default contents for CH_4 and CO_2 in the transmission segment are 93.4 mole % and 2.0 mole %, respectively, as shown in Table E-4.

Table C–26. Derivation of Equipment-Level Average Fugitive CO_2 Emission Factors for Gas Transmission Pipelines [a]

Pipe Material	Annual CO_2 Oxidation Emission [b] (lb CO_2/mi-yr)	Annual CO_2 Leak Emissions [b] (lb CO2/mi-yr)	Pipeline Miles [c,d] (miles)	Annual CO_2 Oxidation Emissions (lb CO_2/yr)	Annual CO_2 Leak Emission (lb CO_2/yr)
Cast Iron	18,699 ± 81.0%	993.6 ± 81.1%	96 ± 10%	1,795,099 ± 81.6%	95,382 ± 81.7%
Plastic	1.263 ± 234%	1.352 ± 234%	2,621 ± 10%	3,310 ± 235%	3,543 ± 235%
Protected Steel	1.286 ± 141%	0.9180 ± 141%	287,155 ± 10%	369,300 ± 141%	263,597 ± 141%
Unprotected Steel	13.87 ± 148%	16.51 ± 148%	5,233 ± 10%	72,604 ± 148%	86,372 ± 148%
Total			295,105 ± 9.73%	2,240,313 ± 69.6%	448,895 ± 89.6%
CO_2 Oxidation Fugitive Emission Factor Development	**2,240,313 lb CO_2/yr ÷ 295,105 miles = 7.59 ± 70.3% lb CO_2/mile-yr**				
CO_2 Leak Fugitive Emission Factor Development	**448,895 lb CO_2/yr ÷ 295,105 miles = 1.52 ± 90.1% lb CO_2/mile-yr**				

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-25.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[d] U.S. Department of Transportation (DOT). Research and Special Programs Administration, 1991. A confidence interval of ±10% was assumed based on engineering judgment in the 1991 DOT RSPA database (Campbell, et al., 1996).

The derivation of the facility-level average gas transmission pipeline CO_2 emission factor for CO_2 from pipeline leaks (as shown in Table 6-2) is shown in Table C-27. The factor was developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). The factor is calculated in three steps: first, by first subtracting the pipeline leak emissions from the total transmission emissions (calculated in Table C-22); second, by dividing the result by the transmission pipeline miles (calculated in Table C-26); and third, by adding the equipment-level average CO_2 leak emission factor derived in Table C-26. Note that the reason that the pipeline leak emissions have to be considered separately is that the pipeline leak emissions shown in Table C-22 take into account soil oxidation effects associated with buried pipelines. Therefore, the pipeline leak emissions cannot be converted directly from the CH_4 leak emission factor as shown for the rest of the transmission segment emissions.

Table C–27. Derivation of Facility-Level Average Gas Transmission Pipeline Fugitive CO_2 Leak Emission Factor

Source	U.S. Methane Emissions, Bscf CH_4/yr	Uncertainty [a], ± (%)
Total Transmission Emissions [b]	55.3274	113
Pipeline Leaks [c]	0.1614	94.2
Adjusted Transmission Emissions	55.166	113
Activity Data		
Total Transmission Pipeline Miles [d]	295,105	9.73
CO_2 Emission Factor		
CH_4 Emission Factor Development	EF = (55.2×10^9 scf CH_4/yr) / (295,105 miles) = 186,937 scf CH_4/station-yr	113
Transmission Fugitive Emission Factor, converted to lb CH_4/mile-yr	7,905 lb CH_4/mile-yr	
Equipment-Level CO_2 Leak Fugitive Emission Factor Development	1.52 lb CO_2/mile-yr (Derived in Table C-26)	93.2
CO_2 Leak Emission Factor Development	EF = (7,905 lb CH_4/mile-yr) × (lbmole CH_4/16 lb CH_4) × (lbmol gas/0.934 lbmole CH_4) × (0.02 lbmol CO_2/lbmol gas) × (44 lb CO_2/lbmol CO_2) = 464.46 lb CO_2/mile-yr + 1.52 lb CO_2/mile-yr	
Transmission Fugitive CO_2 Leak Emission Factor, lb CO_2/mile-yr	**466.0 lb CO_2/mile-yr**	**113**

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-22.

[c] Derived in Table C-24.

[d] Total shown in Table C-26.

The gas transmission meter/regulator (M&R) station fugitive CH_4 emission factor presented in Table 6-6 was developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). This emission factor combines the transmission interconnect and farm tap/direct sales M&R emission and activity data. The precision data were calculated using data presented in Volume 10 of the GRI/EPA study (Campbell, et al., 1996). The factor development is presented in Table C-28.

Table C–28. Derivation of M&R Stations Fugitive CH_4 Emission Factor

Source	U.S. Methane Emissions [a,b], Bscf CH_4/yr	Uncertainty [c], (± %)
Farm Taps and Direct Sales	0.8271	1390 [d]
Transmission Interconnects	3.6834	1380 [e]
Total	4.5105	1150 [f]
Activity Data		
Farm Tap and Direct Sale Stations (Count)	72,629	991
Transmission Interconnect Stations (Count)	2533	990
Total M&R Stations Count	75,162	958
CH_4 Emission Factor		
Emission Factor Development	EF = (4.5105 × 10^9 scf CH_4/yr) ÷ (75,162 stations)	**1,500 [g]**
M&R Station Fugitive Emission Factor, scf CH_4/station-yr	**60,011 scf CH_4/station-yr**	

Footnotes and Sources:

[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[b] Campbell, L.M. and B.E. Stapper. *Methane Emissions from the Natural Gas Industry*, *Volume 10: Metering and Pressure Regulating, Stations in Natural Gas, and Transmission and Distribution,* Final Report, GRI-94/0257.27 and EPA-600/R-96-080j. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[d] Uncertainty range (0 – 11.5 Bscf CH_4/yr)

[e] Uncertainty range (0 – 50.8 Bscf CH_4/yr)

[f] Uncertainty range (0 – 52.3 Bscf CH_4/yr)

[g] Uncertainty range (0 – 900,158 scf CH_4/station-yr)

C.3.6 Gas Distribution Fugitive Emission Factors

The facility-level average gas distribution pipeline CH_4 fugitive emission factor presented in Table 6-2 was developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). The CH_4 emission factor is based on CH_4 emissions from all identified fugitive emission sources in the segment. The factor was calculated by dividing the total distribution segment CH_4 emissions by the number of transmission pipeline miles. Pipeline miles were taken from Volume 9 of the GRI/EPA report (Campbell, et al, 1996). The uncertainty data were calculated using data presented in Volume 8 of the GRI/EPA study (Hummel, et al.,

1996) and Volume 9 of the GRI/EPA study (Campbell, et al., 1996). The factor derivation is presented in Table C-29.

Table C–29. Derivation of Facility-Level Average Fugitive CH_4 Emission Factor for Gas Distribution Pipelines

Source	**U.S. Methane Emissions [a,b,c], Bscf CH_4/yr**	**Uncertainty [d], ± (%)**
Pipeline Mains - Cast Iron	13.1992	77.5
Pipeline Mains - Unprotected Steel	9.0476	159
Pipeline Mains - Protected Steel	1.3846	154
Pipeline Mains - Plastic	4.9150	411
Services - Unprotected Steel	9.2630	259
Services - Protected Steel	3.5922	225
Services - Plastic	0.1644	332
Services - Copper	0.0593	215
M&R Station [e]	27.3202	105
Residential Meters	5.5468	23.7
Commercial/Industrial Meters	0.2207	47.5
Total	74.7131	62.6
Activity Data		
Total Main Pipeline Miles [f]	888,284	3.10
CH_4 Emission Factor		
Emission Factor Development	EF = (74.7130 × 10^9 scf CH_4/yr) ÷ (888,284 miles) = 84,110 scf CH_4/mile-yr	**62.7**
Gas Distribution Pipeline Fugitive Emission Factor, Converted to lb CH_4/ mile-yr	**3,557 lb CH_4/mile-yr**	

Footnotes and Sources:

[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[b] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Hummel, K.E., L.M. Campbell, and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*, Final Report, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[d] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[e] M&R station total emissions are based on the sum of emissions from the 10 M&R station categories presented in Table C-41.

[f] Total distribution main miles are taken from Table C-31.

The facility-level average gas transmission pipeline CO_2 emission factor derivations were derived in conjunction with the equipment-level gas distribution pipeline and gas distribution service CO_2 emission factors. The CO_2 facility-level factor derivation is discussed later in this subsection.

The equipment-level average gas distribution pipeline CH_4 fugitive emission factor presented in Table 6-7 was developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). Emission factors were calculated in the same manner as for gas transmission pipelines. Methane emissions (and corresponding emission factors) were first calculated by pipe material, as shown in Table C-30. A distribution pipeline average CH_4 emission factor was then derived, as shown in Table C-31. Equipment-level average emission factors for CO_2 from pipeline oxidation and pipeline leaks were calculated using Equations 6-4 and 6-5, respectively.

Table C–30. Derivation of Equipment-Level Fugitive CH_4 Emission Factors for Gas Distribution Mains, by Pipe Material [a]

Pipe Material	CH_4 Emission Factor [b,c] (scf/leak-yr)	Activity Factor [b,c] (e.q. leaks)	Annual CH_4 Emissions [d] (Bscf CH_4/yr)	Pipeline Miles [b,c,e] (miles)	CH_4 Emission Factor [f] (scf CH_4/mi-yr)	CH_4 Emission Factor (lb CH_4/mi-yr)
Cast Iron [g]			13.199 ± 77.2%	55,288 ± 5%	238,736 ± 77.0%	10,096 ± 77.0%
Plastic	99,845 ± 212%	49,226 ± 151%	4.915 ± 260%	299,421 ± 5%	16,415 ± 260%	694.2 ± 260%
Protected Steel	20,270 ± 103%	68,308 ± 75.3%	1.385 ± 128%	451,466 ± 5%	3,067 ± 128%	129.7 ± 128%
Unprotected Steel	51,802 ± 113%	174,657 ± 70.3%	9.048 ± 133%	82,109 ± 5%	110,190 ± 133%	4,660 ± 133%

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996. The cast iron leak rate was derived from 21 sample measurements, the plastic leak was derived from 6 measurements, the protected steel leak rate was derived from 17 measurements, and the unprotected steal leak rate was derived from 20 measurements. Note that the CH_4 emission factor shown has already been adjusted for soil oxidation.

[d] Annual CH_4 emissions are estimated by multiplying the leak based emission factor by the number of equivalent leaks.

[e] A confidence interval of ± 5% was assumed based on engineering judgment (Campbell,et al., 1996).

[f] The pipeline based methane emission factor is calculated by dividing the annual methane emissions by the miles of pipeline.

[g] For cast iron pipe, the original emission factor and activity factor are presented on a mile basis.

Table C–31. Derivation of Equipment-Level Average Fugitive CH_4 Emission Factor for Gas Distribution Mains [a]

Pipe Material	Annual CH_4 Emissions (Bscf CH_4/yr) [b,c]	Pipeline Miles (miles) [d,e,f]
Cast Iron	13.199 ± 77.2%	55,288[e] ± 5%
Plastic	4.915 ± 260%	299,421 ± 5%
Protected Steel	1.385 ± 128%	451,466 ± 5%
Unprotected Steel	9.048 ± 133%	82,109 ± 5%
Total	28.546 ± 71.3 %	888,284 ± 3.10%
Emission Factor Development	EF = (28.546×10^9 scf CH_4/yr) ÷ 888,284 miles = 32,137 scf CH_4/mile	
Gas Pipeline Emission Factor, Converted to lb CH_4/mile	**1,359 ± 71.4% lb CH_4/mile**	

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-30.

[c] Annual CH_4 emissions are estimated by multiplying the leak based emission factor by the number of equivalent leaks.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[e] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines,* Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[f] A confidence interval of ± 5% was assumed based on engineering judgment (Campbell, et al., 1996).

Similar to the derivation of the pipeline CH_4 emission factors, CO_2 emission factors were first derived by pipe material, as shown in Table C-32. Average CO_2 emission factors for oxidation and pipeline leaks were then derived from the factors by pipe material, as shown in Table C-33. Methane and CO_2 emission factors by distribution pipe type are also shown in Table 6-7. The precision data were calculated using data presented in Volume 9 of the GRI/EPA study (Campbell, et al., 1996).

Table C–32. Derivation of Fugitive CO_2 Emission Factors for Gas Distribution Mains, by Pipe Material [a]

Pipe Material	CH_4 Emission Factor [b] (lb CH_4/leak-yr)	% Soil Oxidation [c,d,e]	Pre-oxidized CH_4 Emission Factor (lb CH_4/leak-yr)	CO_2 Oxidation Emission Factor (lb CO_2/mi-yr)	CO_2 Leak Emission Factor [f] (lb CO_2/mi-yr)
Cast Iron	10,096 ± 77.0%	40.3% ± 25%	16,911 ± 81.0%	18,699 ± 81.0%	993.6 ± 81.1%
Plastic	694.2 ± 260%	2.0% ± 25%	708.3 ± 261%	38.87 ± 261%	41.62 ± 261%
Protected Steel	129.7 ± 128%	3.0% ± 25%	133.7 ± 130%	11.01 ± 130%	7.856 ± 130%
Unprotected Steel	4,660 ± 133%	1.8% ± 25%	4,745 ± 135%	234.4 ± 135%	278.8 ± 135%

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-30.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[e] The uncertainty of the soil oxidation values is assumed to be ± 25% based on engineering judgment (Campbell, et al., 1996).

[f] The default contents for CH_4 and CO_2 in the distribution segment are 93.4 mole % and 2.0 mole %, respectively, as shown in Table E-4.

Table C–33. Derivation of Equipment-Level Average Fugitive CO_2 Emission Factor for Gas Distribution Mains [a]

Pipe Material	Annual CO_2 Oxidation Emission Factor [b] (lb CO_2/mi-yr)	Annual CO_2 Leak Emission Factor [b] (lb CO_2/mi-yr)	Pipeline Miles [c,d,e] (miles)	Annual CO_2 Oxidation Emissions (lb CO_2/yr)	Annual CO_2 Leak Emissions (lb CO_2/yr)
Cast Iron	18,699 ± 81.0%	994 ± 81.1%	55,288 ± 5%	1,033,827,389 ± 81.1%	54,932,088 ± 81.3%
Plastic	38.9 ± 261%	41.6 ± 261%	299,421 ± 5%	11,638,401 ± 261%	12,460,815 ± 261%
Protected Steel	11.0 ± 130%	7.86 ± 130%	451,466 ± 5%	4,968,707 ± 130%	3,546,543 ± 130%
Unprotected Steel	234.4 ± 135%	278.8 ± 135%	82,109 ± 5%	19,242,525 ± 135%	22,891,417 ± 135%
Total			888,284 ± 3.10%	1,069,677,022 ± 78.5%	93,830,863 ± 67.7%
CO_2 Oxidation Fugitive Emission Factor Development	**1,069,677,022 lb CO_2/yr ÷ 888,284 miles =1,204 ± 78.6% lb CO_2/mile-yr**				
CO_2 Leak Fugitive Emission Factor Development	**93,830,863 lb CO_2/yr ÷ 888,284 miles =105.6 ± 67.7% lb CO_2/mile-yr**				

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-32.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[e] A confidence interval of ± 5% was assumed based on engineering judgment (Campbell, et al., 1996).

The equipment-level average gas distribution service CH_4 fugitive emission factor presented in Table 6-7 was developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). Emission factors were calculated in the same manner as for gas distribution pipelines, except emission factors are estimated by dividing the emissions by pipeline services instead of pipeline miles.

Methane emissions (and corresponding emission factors) were first calculated by pipe material, as shown in Table C-34. A distribution service average CH_4 emission factor was then derived, as shown in Table C-35. The average factor was converted from a service basis to a mileage basis by scaling the EPA/GRI study service count to miles using 1992 pipeline statistics from the U.S. Department of Transportation, Research and Special Programs Administration website (Volume 9, Campbell, et al., 1996).

Table C–34. Derivation of Detailed Fugitive CH_4 Emission Factors for Gas Distribution Services, by Pipe Material [a]

Pipe Material	CH_4 Emission Factor [b,c] (scf/leak-yr)	Activity Factor [b,c] (e.q. leaks)	Annual CH_4 Emissions [d] (Bscf CH_4/yr)	Services [b,c,e] (Count)	CH_4 Emission Factor [f] (scf CH_4/ service-yr)	CH_4 Emission Factor (lb CH_4/ service-yr)
Copper	7,684 ± 94.2%	7,720 ± 144%	0.0593 ± 172%	233,246 ± 5%	254.3 ± 172%	10.76 ± 172%
Plastic	2,386 ± 193%	68,903 ± 131%	0.1644 ± 234%	17,681,238 ± 5%	9.298 ± 234%	0.3932 ± 234%
Protected Steel	9,196 ± 73.3%	390,628 ± 163%	3.592 ± 178%	20,352,983 ± 5%	176.5 ± 178%	7.464 ± 178%
Unprotected Steel	20,204 ± 128%	458,476 ± 133%	9.263 ± 185%	5,446,393 ± 5%	1,701 ± 185%	71.92 ± 185%

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996. The copper leak rate was derived from 5 sample measurements, the plastic leak was derived from 4 measurements, the protected steel leak rate was derived from 24 measurements, and the unprotected steal leak rate was derived from 13 measurements. Note that the CH_4 emission factor shown has already been adjusted for soil oxidation.

[d] Annual CH_4 emissions are estimated by multiplying the leak based emission factor by the number of equivalent leaks.

[e] A confidence interval of ± 5% was assumed based on engineering judgment (Campbell, et al., 1996).

[f] The pipeline service based methane emission factor is calculated by dividing the annual CH_4 emissions by the number of services.

Table C–35. Derivation of Equipment-Level Average Fugitive CH_4 Emission Factor for Gas Distribution Services [a]

Pipe Material	Annual CH_4 Emissions [b] (Bscf CH_4/yr)	Pipeline Services [c,d,e]
Copper	0.0593 ± 172%	233,246 ± 5%
Plastic	0.1644 ± 234%	17,681,238 ± 5%
Protected Steel	3.592 ± 178%	20,352,983 ± 5%
Unprotected Steel	9.263 ± 185%	5,446,393 ± 5%
TOTAL	**13.08 ± 140%**	**43,713,860 ± 3.15%**
Gas Distribution Service Fugitive CH_4 Emission Factor Development (service basis)	EF = (13.08 Bscf CH4/yr) ÷ 43,713,860 services = 299.2 scf CH_4/service-yr	
Gas Distribution Service Fugitive CH_4 Emission Factor (service basis), Converted to lb CH_4/service-yr	**12.65 ± 140% lb CH_4/service-yr**	
Gas Distribution Service Fugitive CH_4 Emission Factor Development (mileage basis)	Activity Factor	
	518,335 ± 5.00%	miles [f]
	EF = (13.08 Bscf CH_4/yr) ÷ 518,335 miles = 25,233 scf CH_4/mile-yr	
Gas Distribution Service Fugitive CH_4 Emission Factor (mileage basis), Converted to lb CH_4/services-yr	**1,067 ± 140% lb CH_4/mile-yr**	

Footnotes and Sources for Table C-35:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-34.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[e] A confidence interval of ± 5% was assumed based on engineering judgment (Campbell, et al., 1996).

[f] 1992 pipeline statistics from U.S. Department of Transportation (DOT) Research and Special Programs Administration (RSPA).

Equipment-level average emission factors for CO_2 from pipeline oxidation and pipeline leaks were calculated using Equations 6-4 and 6-5, respectively. Similar to the derivation of the pipeline CH_4 emission factors, CO_2 emission factors were first derived by pipe material, as shown in Table C-36. Average CO_2 emission factors for oxidation and pipeline leaks were then derived from the factors by pipe material, as shown in Table C-37. Methane and CO_2 emission factors by distribution pipe type are also shown in Table 6-9. The precision data were calculated using data presented in Volume 9 of the GRI/EPA study (Campbell, et al., 1996).

Table C–36. Derivation of Fugitive CO_2 Emission Factors for Gas Distribution Services, by Pipe Material [a]

Pipe Material	CH_4 Emission Factor [b] (lb CH_4/leak-yr)	% Soil Oxidation [c,d,e]	Pre-oxidized CH_4 Emission Factor (lb CH4/leak-yr)	CO_2 Oxidation Emission Factor (lb CO_2/service-yr)	CO_2 Leak Emission Factor [f] (lb CO_2/service-yr)
Copper	10.76 ± 172%	0%	10.76 ± 174%	0	0.6319 ± 174%
Plastic	0.3932 ± 234%	21.2% ± 25%	0.4990 ± 235%	0.2903 ± 235%	0.02932 ± 235%
Protected Steel	7.464 ± 178%	2.6% ± 25%	7.663 ± 180%	0.5467 ± 180%	0.4502 ± 180%
Unprotected Steel	71.92 ± 185%	1.1% ± 25%	72.72 ± 186%	2.195 ± 186%	4.273 ± 186%

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-34.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines,* Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[e] The precision of soil oxidation is assumed to be ±25% based on engineering judgment (Campbell, et al., 1996).

[f] The default contents for CH_4 and CO_2 in the distribution segment are 93.4 mole% and 2.0 mole%, respectively, as shown in Table E-4.

Table C–37. Derivation of Equipment-Level Average Fugitive CO_2 Emission Factor for Gas Distribution Services [a]

Pipe Material	**CO_2 Oxidation Emission Factor [b] (lb CO_2/service-yr)**	**CO_2 Leak Emission Factor [b] (lb CO_2/service-yr)**	**Pipeline Services [c,d,e] (Count)**	**CO_2 Oxidation Emissions (lb CO_2/yr)**	**CO_2 Leak Emissions (lb CO_2/yr)**
Copper	0	0.6319 ± 174%	233,246 ± 5%	0	147,386 ± 174%
Plastic	0.2903 ± 235%	0.02932 ± 235%	17,681,238 ± 5%	5,132,001 ± 235%	518,363 ± 235%
Protected Steel	0.5467 ± 180%	0.4502 ± 180%	20,352,983 ± 5%	11,126,159 ± 180%	9,163,366 ± 180%
Unprotected Steel	2.195 ± 186%	4.273 ± 186%	5,446,393 ± 5%	11,954,155 ± 187%	23,270,693 ± 187%
Total			43,713,860 ± 3.15%	28,212,315 ± 115%	33,099,808 ± 140%
CO_2 Emission Factors (Service Basis)					
CO_2 Oxidation Fugitive Emission Factor Development	**28,212,315 lb CO_2/yr ÷ 43,713,860 services = 0.65 ± 115% lb CO_2/mile-yr**				
CO_2 Leak Fugitive Emission Factor Development	**33,099,808 lb CO_2/yr ÷ 43,713,860 services = 0.76 ± 140% lb CO_2/mile-yr**				
CO_2 Emission Factors (Mileage Basis)					
Activity Data					
Service Miles [d]	518,335 ±5% miles				
CO_2 Oxidation Fugitive Emission Factor Development	**28,212,315 lb CO_2/yr ÷ 518,335 miles of services = 54.4 ± 115% lb CO_2/mile-yr**				
CO_2 Leak Fugitive Emission Factor Development	**33,099,808 lb CO_2/yr ÷ 518,335 miles of services = 63.9 ± 140% lb CO_2/mile-yr**				

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Derived in Table C-36.

[c] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[d] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines,* Final Report, GRI-94/0257.26 and EPA-600/R-96-080i. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[e] A confidence interval of ± 5% was assumed based on engineering judgment (Campbell, 1996).

The facility-level average CO_2 emission factors for gas distribution pipelines are derived in Table C-38. The facility-level average CO_2 emission factor for distribution pipeline leak oxidation is calculated by combining the emission contributions from distribution main pipelines and services and dividing by the total distribution pipeline miles. Carbon dioxide emissions from distribution pipeline leaks originate from pipeline leaks and other process equipment leaks. The CO_2 emission factor for pipeline leaks is calculated in three steps: first, by subtracting the emissions from pipeline mains and services from the total distribution emissions (calculated in Table C-29); second, by dividing by the total main pipeline miles and converting to a mass basis; and third, by adding the pre-oxidized distribution pipeline leak emissions, which are calculated by dividing the sum of the total main pipeline leak emissions (derived in Table C-33) and total distribution service leak emissions (derived in Table C-37) by the total miles of distribution pipeline. Emissions data were taken from Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). Pipeline miles were taken from Volume 9 of the GRI/EPA report (Campbell, et al, 1996). The precision data was calculated using data presented in Volume 9 of the GRI/EPA study (Campbell, et al., 1996). The factor derivations are shown in Table C-38.

Table C–38. Derivation of Facility-Level Average Fugitive CO_2 Emission Factors for Gas Distribution Pipelines

CO_2 From Oxidation		
Source	**U.S. CO_2 Emissions, lb CO_2/yr**	**Uncertainty [a], (± %)**
Total Distribution Mains Emissions [b]	1,069,677,022	78.5
Total Distribution Services Emissions [c]	28,212,315	115
Total	1,097,889,337	76.6
Activity Data		
Total Distribution Pipeline Miles[b]	888,284	3.10
CO_2 From Oxidation Emission Factor		
Emission Factor Development	EF = (1,097,889,337 lb CO_2/yr) ÷ (888,284 miles) =	**76.6**
CO_2 Oxidation Fugitive Emission Factor	**1,236 lb CO_2/mile-yr**	
CO_2 from Leaks		
Source	**U.S. CH_4 Emissions, Bscf CH_4/yr**	**Uncertainty [a], (± %)**
Total Distribution Emissions [d]	74.71	62.7
Total Distribution Mains Emissions [d]	28.55	78.6
Total Distribution Services Emissions [d]	13.08	115
Total	33.0878	163
Activity Data		
Total Distribution Pipeline Miles [b]	888,284	3.10
CO_2 From Leaks Emission Factor		
Emission Factor Development	EF = (33.0878 × 10^9 scf CH_4/yr) ÷ (888,284 miles) = 37,249 scf CH_4/mile-yr = 1,575 lb CH_4/mile-yr	163

Table C–38. Derivation of Facility-Level Average Fugitive CO_2 Emission Factors for Gas Distribution Pipelines, continued

Source	U.S. CH_4 Emissions, Bscf CH_4/yr	Uncertainty [a], (± %)
CO_2 From Leaks Emission Factor, continued		
Emission Factor Development, continued	EF = (1,575 lb CH_4/mile-yr) × (lbmole CH_4/16 lb CH_4) × (lbmol gas/0.934 lbmole CH_4) × (0.02 lbmol CO_2/lbmol gas) × (44 lb CO_2/lbmol CO_2) = 92.55 lb CO_2/mile-yr	163
	EF = (93,830,863 lb CO_2/yr[b] + 33,099,808 lb CO_2/yr[c]) ÷ (888,284 miles) = 142.9 lb CO_2/mile-yr	62.1
	EF = (92.55 lb CO_2/mile-yr) + (142.9 lb CO_2/mile-yr)	
CO_2 Leak Fugitive Emission Factor	**235.4 lb CO_2/mile-yr**	**74.4**

Footnotes and Sources:

[a] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[b] Total shown in Table C-33.

[c] Derived in Table C-37.

[d] Total shown in Table C-29.

The customer meter CH_4 fugitive emission factor presented in Table 6-7 was developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). This emission factor represents a combination of the commercial/industrial and residential meter emission factors. The precision data were calculated using data presented in Volume 8 of the GRI/EPA study (Hummel, et al., 1996). The factor derivation is presented in Table C-39.

Table C–39. Derivation of Equipment-Level Fugitive CH_4 Emission Factor for Customer Meters

Source	U.S. Methane Emissions [a,b], Bscf CH_4/yr	Uncertainty [c], ± (%)
Residential Meters	5.5468	23.7
Commercial/Industrial Meters	0.2207	47.5
Total	5.7676	22.9
Activity Data		
Residential Meters (Count) [d]	40,049,306	10
Commercial/Industrial Meters (Count) [e]	4,608,000	5
Total Customer Meters Count	44,657,306	8.98
Methane Emission Factor		
Emission Factor Development	EF = (5.7676×10^9 scf CH_4/yr) ÷ (44,657,306 meters) =	**24.6%**
Customer Meter Fugitive CH4 Emission Factor	**129.15 scf CH_4/meters-yr**	

Footnotes and Sources for Table C-39:

[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.

[b] Hummel, K.E., L.M. Campbell, and M.R. Harrison. *Methane Emissions from the Natural Gas Industry*, *Volume 8: Equipment Leaks*, Final Report, GRI-94/0257.25 and EPA-600/R-96-080h. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[c] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

[d] An uncertainty factor of 10% was assigned based on engineering judgment.

[e] An uncertainty factor of 5% was assigned based on engineering judgment.

The distribution meter/regulating stations fugitive CH_4 emission factor presented in Table 6-7 was developed using emissions data presented in Appendix A of Volume 2 of the GRI/EPA study (Harrison, et al., 1996). The precision data were calculated using data presented in Volume 10 of the GRI/EPA study (Campbell, et al., 1996). The factor derivation is presented in Table C-40.

Table C–40. Derivation of Equipment-Level Fugitive CH_4 Emission Factor for Distribution/Meter Reg. Stations

Source	**U.S. Methane Emissions [a,b], Bscf CH_4/yr**	**Uncertainty [c] (± %)**
M & R > 300 psig	5.451	105
M & R 100-300 psig	11.1731	239
M & R < 100 psig	0.2693	455
Regulating > 300 psig	5.6655	119
R-Vault > 300 psig	0.0266	282
Regulating 100-300 psig	4.352	121
R-Vault 100-300 psig	0.0087	155
Regulating 40-100 psig	0.3317	134
R-Vault 40-100 psig	0.0244	121
Regulating <40 psig	0.0179	213
Total	27.3202	105
Activity Data		
M & R > 300 psig, stations	3,460	87.0
M & R 100-300 psig, stations	13,335	130
M & R < 100 psig, stations	7,127	145
Regulating > 300 psig, stations	3,995	83.3
R-Vault > 300 psig, stations	2,346	83.3
Regulating 100-300 psig, stations	12,273	74.8
R-Vault 100-300 psig, stations	5,514	74.8
Regulating 40-100 psig, stations	36,328	78.4
R-Vault 40-100 psig, stations	32,215	78.4
Regulating <40 psig, stations	15,377	79.7
Total Stations	131,970	35.0
Methane Emission Factor		
Emission Factor Development	EF = (27.3202 × 10^9 scf CH_4/yr) ÷ (131,970 stations) =	**111**
Distribution M&R Station Fugitive Emission Factor	**207,018 scf CH_4/station-yr**	

Footnotes and Sources for Table C-40:
[a] Campbell, L.M., M.V. Campbell, and D.L. Epperson. *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 U.S. Environmental Protection Agency, June 1996.
[b] Campbell, L.M. and B.E. Stapper. *Methane Emissions from the Natural Gas Industry*, *Volume 10: Metering and Pressure Regulating, Stations in Natural Gas, and Transmission and Distribution*, Final Report, GRI-94/0257.27 and EPA-600/R-96-080j. Gas Research Institute and U.S. Environmental Protection Agency, June 1996. Emissions are based on data collected from 95 measurements at 12 locations using downwind tracer gas measurements. The number of stations in each inlet pressure/station category were provided by 12 distribution companies.
[c] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original emission factor.

C.3.7 Plastic Pipeline Fugitive Emission Leak Factors

The leak basis plastic pipeline emission factors presented in Table 6-11 were developed using data (six data points) presented in Table A-2 of Volume 9 of the GRI/EPA study (Campbell, et al., 1996) and from seven data points from a SoCal gas "unaccounted for" study (SoCal, 1993), as shown below in Table C-41.

Table C–41. Derivation of Fugitive Emission Leak Factor from Plastic Pipelines by Construction Year

Data Source	Test ID Number	Pre-1982 Gas Leak Rate (scf/leak-hr)	Post-1982 (ASTM D2837) Gas Leak Rate (scf/leak-hr)
1996 GRI/EPA, Volume 9, Table A-2 [a]	2014	0.008	0.008
	3020	0.700	0.700
	3019	1.130	1.130
	3039	1.620	1.620
	11002	10.266	
	2002	61.000	
SoCal Unaccounted Study [b, c]	NA	1.2	1.2
	NA	1.2	1.2
	NA	1.2	1.2
	NA	1.2	1.2
	NA	1.2	1.2
	NA	1.2	1.2
	NA	1.2	1.2
Average Total Gas Leak Rate (scf/leak-hr):		**6.394**	**1.078**

Footnotes and Sources:
[a] Campbell, L. M., M. V. Campbell, and D. L. Epperson. *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA 600/R-96-080i. Gas Research Institute and U. S. Environmental Protection Agency, June 1996.
[b] Southern California Gas Company (SoCal). *A Study of the 1991 Unacconted-for Gas Volume at the Southern Gas Company*, April 1993.
[c] The SoCal data were taken from: California Energy Commission (CEC). *Evaluation of Oil and Gas Sector Greenhouse Gas Emissions Estimation and Reporting*, California Energy Commission, Consultant Report, Final Draft, April 14, 2006.

All six leak data points from Table A-2 of Volume 9 of the GRI/EPA study and all seven data points from the SoCal data were averaged to develop the pre-1982 plastic pipeline emission factor (i.e., average of the 13 total data points). As shown in Table C-41, data points "11002" and "2002" appear high, and were assumed to reflect the amount of inferior pre-1982 plastic pipelines that may be used. Therefore, these two data points were not included in the dataset used to develop the post-1982 (ASTM 2837) pipeline emission factors (but the other 11 out of 13 data points from the GRI/EPA and SoCal studies were included and assumed to reflect post-1982 plastic pipeline materials of construction).

The leak based emission factors provided in Table C-41 were further converted to a plastic pipeline mileage basis based on the U.S. national equivalent leak/miles ratio taken from data presented in Volume 9 of the 1996 GRI/EPA study. Equivalent leaks and plastic pipeline miles were not provided by year of construction, so this conversion was based on the total U.S. equivalent leaks and miles of plastic pipeline. The converted factors are presented in Table 6-11.

C.3.8 CO_2 Pipeline Fugitive Emissions

Section 6.1.4 cites an IPCC equation to estimate fugitive emissions from the pipeline transport of CO_2, such as for EOR operations, similar to fugitive emissions from the pipeline transport of natural gas. IPCC starts the derivation by characterizing the pressure drop in the pipe using the following formula for any geometry:

$$\Delta P = \frac{f}{2} \rho \, v^2 \frac{l}{D} \qquad \text{(Equation C-5)}$$

where

v = linear velocity of the gas through the leak;
ρ = gas density;
f = the dimensionless friction number;
l = length of the system; and
D = diameter of the system.

IPCC assumes that that the friction number, f, is one due its independence from the nature of the gas. IPCC assumes that the internal pressure and physical dimensions of the pipeline are the same for CH_4 and CO_2. These assumptions result in the velocity being proportional to the square root of the density, and therefore proportional to the square root of the molecular weights when assuming an ideal gas, as shown in the equation below.

$$v \sim \frac{1}{\sqrt{\rho}} \quad \text{or} \quad v \sim \frac{1}{\sqrt{\text{Molecular Weight}}}$$ (Equation C-6)

The mass emission rate is equal to the product of the velocity, area, and gas density:

$$\text{Mass emission rate} = v \times (\text{area}) \times \rho$$ (Equation C-7)

Substituting Equation C-7 into the proportionality represented by Equation C-6 and expressing the densities as being proportional to the molecular weights (16 for CH_4 and 44 for CO_2) yields Equation 6-9, repeated here.

$$EF_{CO_2} = EF_{CH_4} \times \sqrt{\frac{44}{16}}$$ (Equation 6-9)

C.4 References

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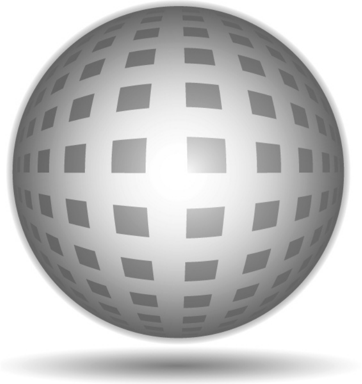
AMERICAN PETROLEUM INSTITUTE

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

AUGUST 2009

APPENDIX D

ADDITIONAL INDIRECT CALCULATION INFORMATION



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Appendix D – Additional Indirect Calculation Information

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D. ADDITIONAL INDIRECT CALCULATION INFORMATION

This section presents supplemental information for the indirect emission calculation methodologies presented in Section 7.

D.1 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. This approach can also be applied to account for green power purchases as part of a designated electric block.

The IEA provides annual electric generation data (data for OECD countries as summarized in Table D-1) (IEA, 2007). This information can be combined with the emission factors from Table 7-1 using a weighted average basis to derive country-based emission factors for electricity generation. This weighted average approach is represented by Equation D-1:

$$\text{National Electric EF} = \sum \left[\frac{10^{12}\,\text{W-hr for Fuel Type}_i}{10^{12}\,\text{W-hr Total}} \times \text{Base EF for Fuel/Generation Type}_i \left(\frac{\text{tonnes}}{10^{6}\,\text{W-hr}} \right) \right]$$

(Equation D-1)

Table 7-1 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_2 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_2 emissions are applied for these sources. However, the CH_4 and N_2O emission factors from Table 7-1 are included in the calculations.

Table D–1. Summary of Year 2006 Electricity Generation Information for OECD Countries

Country	Coal	Oil	Gas	Geothermal	Wind, hydro, solar nuclear & chemical	Solid biomass & biogas	Industrial waste	Municipal waste	Peat	Other fuels and waste	Total Generation (10^{12} W-hr)
	Generation Contribution (%)										
Australia	78.86	0.80	12.42	0.00	7.05	0.88	0.00	0.00	0.00	0.00	254.99
Austria	11.09	2.56	22.07	0.00	59.26	4.17	0.33	0.50	0.00	0.00	63.57
Belgium	9.50	2.02	29.13	0.00	56.77	1.46	0.16	0.99	0.00	0.00	86.21
Canada	15.88	3.04	6.12	0.00	73.49	1.47	0.00	0.00	0.00	0.00	616.57
Czech Republic	58.48	0.39	5.22	0.00	34.83	1.08	0.00	0.02	0.00	0.00	84.29
Denmark	53.43	3.29	20.84	0.00	13.45	4.80	0.00	4.21	0.00	0.00	45.59
Finland	17.65	0.61	16.29	0.00	42.33	14.09	0.07	0.44	8.52	0.00	82.16
France	3.99	1.23	4.44	0.00	89.47	0.34	0.00	0.53	0.00	0.00	574.47
Germany	45.49	1.66	13.20	0.00	35.96	2.55	0.00	1.14	0.00	0.00	633.16
Greece	57.69	14.95	13.26	0.00	13.72	0.20	0.17	0.00	0.00	0.00	59.35
Hungary	19.94	1.20	36.73	0.00	38.18	3.46	0.03	0.47	0.00	0.00	35.86
Iceland	0.00	0.10	0.00	26.49	73.41	0.00	0.00	0.00	0.00	0.00	9.93
Ireland	21.08	9.75	50.05	0.00	11.08	0.47	0.00	0.00	7.57	0.00	27.89
Italy	14.16	14.97	52.14	1.76	14.99	1.08	0.05	0.85	0.00	0.00	315.05
Japan	24.35	9.96	26.35	0.29	37.64	0.76	0.01	0.65	0.00	0.00	1073.21
Korea	36.40	5.77	19.89	0.00	37.87	0.05	0.00	0.03	0.00	0.00	407.38
Luxembourg	0.00	0.00	75.06	0.00	23.09	0.69	0.00	1.39	0.00	0.00	4.33
Mexico	12.44	27.33	40.23	2.64	16.35	1.01	0.00	0.00	0.00	0.00	253.29
Netherlands	23.22	2.21	61.22	0.00	6.61	3.92	0.00	2.83	0.00	0.00	98.27
New Zealand	11.26	0.05	23.29	7.75	56.09	1.53	0.00	0.00	0.00	0.00	43.07
Norway	0.04	0.01	0.44	0.00	99.15	0.28	0.01	0.08	0.00	0.00	121.66
Poland	91.87	1.58	3.13	0.00	2.03	1.16	0.24	0.00	0.00	0.00	161.69
Portugal	30.56	10.38	25.46	0.16	29.34	2.87	0.02	1.20	0.00	0.00	49.05
Slovak Republic	17.25	2.33	8.29	0.00	72.00	0.03	0.00	0.16	0.00	0.00	31.36

Table D–1. Summary of Year 2006 Electricity Generation Information for OECD Countries, continued

Country	Coal	Oil	Gas	Geothermal	Wind, hydro, solar nuclear & chemical	Solid biomass & biogas	Industrial waste	Municipal waste	Peat	Other fuels and waste	Total Generation (10^{12} W-hr)
	Generation Contribution (%)										
Spain	21.99	7.87	30.20	0.00	37.15	1.98	0.00	0.82	0.00	0.00	302.86
Sweden	0.68	1.41	1.50	0.00	90.58	4.83	0.03	0.63	0.34	0.34	143.14
Switzerland	0.00	0.33	1.50	0.00	94.58	0.39	0.48	2.74	0.00	0.00	64.21
Turkey	25.85	4.38	44.48	0.05	25.18	0.02	0.05	0.00	0.00	0.00	175.89
United Kingdom	37.68	1.51	35.95	0.00	22.02	1.64	0.82	0.39	0.00	0.00	398.72
United States	49.57	1.85	19.59	0.39	26.93	1.15	0.12	0.40	0.00	0.00	4277.10
OECD Total	36.46	4.12	20.56	0.36	36.48	1.34	0.10	0.49	0.09	0.09	10494.32
OECD Europe	26.94	3.72	21.72	0.23	44.31	1.93	0.13	0.75	0.27	0.27	3568.72
OECD Pacific	34.61	7.45	22.80	0.36	33.75	0.63	0.01	0.40	0.00	0.00	1778.64
OECD North America	43.71	3.25	18.99	0.45	31.98	1.18	0.10	0.34	0.00	0.00	5146.96

Source:
International Energy Agency, Electricity Information 2007 Edition: *Documentation for Beyond 2020 Files*, Table 2.2. Gross Electricity Production, By Country, By Fuel, 2006e (TWh) and Table 2.3. Gross Electricity Production From Combustible Fuels, By Country, 2006e (TWh).

Additional IEA information provides the electrical capacity of each country within the OECD (IEA, 2007). For the purpose of developing international grid emission factors for the API *Compendium*, this information was used to assign appropriate emission factors from Table 7-1 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_2 are not included, but the CH_4 and N_2O emission factors are applied to electricity generation by combustible renewables. Similarly, the CO_2 emissions from municipal solid waste are zero, while the DOE CH_4 and N_2O 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 D.1 Electricity Emission Factor Development for Italy – Generation Based Approach

INPUT DATA:
Calculate the weighted average emission factors for Italy for 2006. Provide the complete derivation for the CO_2 emission factor.

CALCULATION METHODOLOGY:
Table D-1 provides the year 2006 fuel mix for electricity production in Italy. Table 7-1 provides the emission factors for different electricity generation types. Applying Equation D-1, the weighted emission factors are calculated by multiplying the ratio of the electricity generation of each fuel to the overall generation (from Table D-1) by the base emission factor (from Table 7-1), then summing for all of the fuel types.

Exhibit D.1 Electricity Emission Factor Development for Italy – Generation Based Approach, continued

$$
\begin{aligned}
\mathrm{EF}_{\mathrm{CO_2}} = {} & \left(\frac{0.1416\times10^{12}\,\text{W-hr}_{\text{coal}}}{10^{12}\,\text{W-hr}_{\text{Total}}}\times\frac{0.828\text{ tonnes CO}_2}{10^{6}\,\text{W-hr}}\right) \\
& +\left(\frac{0.1497\times10^{12}\,\text{W-hr}_{\text{oil}}}{10^{12}\,\text{W-hr}_{\text{Total}}}\times\frac{0.682\text{ tonnes CO}_2}{10^{6}\,\text{W-hr}}\right)+\left(\frac{0.5214\times10^{12}\,\text{Whr}_{\text{gas}}}{10^{12}\,\text{W-hr}_{\text{Total}}}\times\frac{0.483\text{ tonnes CO}_2}{10^{6}\,\text{W-hr}}\right) \\
& +\left(\frac{0.0176\times10^{12}\,\text{W-hr}_{\text{geothermal}}}{10^{12}\,\text{W-hr}_{\text{Total}}}\times\frac{0.0764\text{ tonnes CO}_2}{10^{6}\,\text{W-hr}}\right)+\left(\frac{0.1499\times10^{12}\,\text{W-hr}_{\substack{\text{wind, hydro,}\\\text{solar, nuclear,}\\\text{chemical}}}}{10^{12}\,\text{W-hr}_{\text{Total}}}\times\frac{0\text{ tonnes CO}_2}{10^{6}\,\text{W-hr}}\right) \\
& +\left(\frac{0.0108\ \times10^{12}\,\text{W-hr}_{\substack{\text{solid biomass}\\\text{\& biogas}}}}{10^{12}\,\text{W-hr}_{\text{Total}}}\times\frac{1.700\text{ tonnes CO}_2}{10^{6}\,\text{W-hr}}\right)+\left(\frac{0.0005\ \times10^{12}\,\text{W-hr}_{\substack{\text{industrial}\\\text{waste}}}}{10^{12}\,\text{W-hr}_{\text{Total}}}\times\frac{1.700\text{ tonnes CO}_2}{10^{6}\,\text{W-hr}}\right) \\
& +\left(\frac{0.0085\times10^{12}\,\text{W-hr}_{\substack{\text{municipal}\\\text{waste}}}}{10^{12}\,\text{W-hr}_{\text{Total}}}\times\frac{0\text{ tonnes CO}_2}{10^{6}\,\text{W-hr}}\right)+\left(\frac{0\times10^{12}\,\text{W-hr}_{\text{peat}}}{10^{12}\,\text{W-hr}_{\text{Total}}}\times\frac{1.7\text{ tonnes CO}_2}{10^{6}\,\text{W-hr}}\right) \\
& +\left(\frac{0\ \times10^{12}\,\text{Whr}_{\text{other}}}{10^{12}\,\text{Whr}_{\text{Total}}}\times\frac{0.40\text{ tonnes CO}_2}{10^{6}\,\text{Whr}}\right)
\end{aligned}
$$

$$
\mathrm{EF}_{\mathrm{CO_2}} = \left[
\begin{array}{l}
\left(0.117\ \dfrac{\text{tonnes CO}_2}{10^{6}\,\text{W-hr}}\right)_{\text{coal}}+\left(0.102\ \dfrac{\text{tonnes CO}_2}{10^{6}\,\text{W-hr}}\right)_{\text{oil}}+\left(0.252\ \dfrac{\text{tonnes CO}_2}{10^{6}\,\text{W-hr}}\right)_{\text{gas}} \\
+\left(0.001\ \dfrac{\text{tonnes CO}_2}{10^{6}\,\text{W-hr}}\right)_{\text{geothermal}}+\left(0\ \dfrac{\text{tonnes CO}_2}{10^{6}\,\text{W-hr}}\right)_{\substack{\text{wind, hydro,}\\\text{solar, nuclear,}\\\text{chemical}}}+\left(0\ \dfrac{\text{tonnes CO}_2}{10^{6}\,\text{W-hr}}\right)_{\substack{\text{solid biomass}\\\text{\& biogas}}} \\
+\left(0.001\ \dfrac{\text{tonnes CO}_2}{10^{6}\,\text{W-hr}}\right)_{\substack{\text{industrial}\\\text{waste}}}+\left(0\ \dfrac{\text{tonnes CO}_2}{10^{6}\,\text{W-hr}}\right)_{\substack{\text{municipal}\\\text{waste}}}+\left(0\ \dfrac{\text{tonnes CO}_2}{10^{6}\,\text{W-hr}}\right)_{\text{peat}} \\
+\left(0\ \dfrac{\text{tonnes CO}_2}{10^{6}\,\text{W-hr}}\right)_{\text{other}}
\end{array}
\right]
$$

Exhibit D.1 Electricity Emission Factor Development for Italy – Generation Based Approach, continued

EF_{CO_2} = 0.473 tonnes $CO_2/10^6$ W-hr

Fuel/ Generation Type	% Contribution to Electricity Generation	Tonnes/ 10^6 W-hr					
		Base CO_2 EF	**Weighted CO_2 EF**	**Base CH_4 EF**	**Weighted CH_4 EF**	**Base N_2O EF**	**Weighted N_2O EF**
Coal	14.16	0.828	0.117	1.81E-05	2.57E-06	1.542E-04	2.18E-05
Oil	14.97	0.682	0.102	6.35E-06	9.51E-07	9.870E-05	1.48E-05
Gas	52.14	0.483	0.252	3.97E-05	2.07E-05	6.872E-05	3.58E-05
Geothermal	1.76	0.0764	0.001	7.53E-07	1.32E-08	0	0
Wind, hydro, solar, nuclear, chemical	14.99	0	0	0	0.00E+00	0	0
Solid biomass (wood) & biogas	1.08	0	0	6.35E-05	6.87E-07	2.495E-04	2.70E-06
Industrial waste	0.05	1.700	0.001	9.07E-06	4.32E-09	2.495E-04	1.19E-07
Municipal waste	0.85	0	0	9.07E-06	7.75E-08	2.495E-04	2.13E-06
Peat	0.00	1.700	0	9.07E-06	0	2.495E-04	0
Other	0.00	0.40	0	0	0	0	0
Total	**100.00**	**--**	**0.473**	--	**2.50E-05**	--	**7.74E-05**

The resulting 2006 weighted average emission factors for Italy are:
EF_{CO2} = 0.473 tonnes/10^6 W-hr
EF_{CH4} = 2.50E-05 tonnes/10^6 W-hr
EF_{N2O} = 7.74E-05 tonnes/10^6 W-hr

The same approach was used to estimate "grid" emission factors for the years 2003 through 2005. The results shown in Table 7-5 are an average of the four years for OECD countries. Table D-2 summarizes the electricity generation information for non-OECD countries for 2005. Table 7-6 presents 2005 data for non-OECD countries (2003, 2004 and 2006 data are not currently available for the non-OECD countries).

Table D–2. Summary of Year 2005 Electricity Generation Information for Non-OECD Countries

Country	Coal	Oil	Gas	Geothermal	Wind, hydro, solar, nuclear, chemical & Other	Solid biomass & biogas	Industrial waste	Municipal waste	Peat	Total Generation (10^{12} W-hr)
	Generation Contribution (%)									
Africa										
Algeria	0.00	2.15	96.20	0.00	1.65	0.00	0.00	0.00	0.00	33.92
Angola	0.00	34.34	0.00	0.00	66.04	0.00	0.00	0.00	0.00	2.65
Benin	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11
Botswana	100.00	1.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.97
Cameroon	0.00	5.54	0.00	0.00	94.22	0.00	0.00	0.00	0.00	4.15
Congo	0.00	0.00	0.00	0.00	100.00	0.00	0.00	0.00	0.00	0.36
Democratic Republic of Congo	0.00	0.27	0.00	0.00	99.73	0.00	0.00	0.00	0.00	7.42
Côte d'Ivoire	0.00	0.18	74.15	0.00	25.85	0.00	0.00	0.00	0.00	5.57
Egypt	0.00	13.55	74.31	0.00	12.14	0.00	0.00	0.00	0.00	108.69
Eritrea	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.29
Ethiopia	0.00	0.70	0.00	0.00	99.30	0.00	0.00	0.00	0.00	2.87
Gabon	0.00	31.85	15.92	0.00	51.59	0.64	0.00	0.00	0.00	1.57
Ghana	0.00	21.50	0.00	0.00	78.50	0.00	0.00	0.00	0.00	6.79
Kenya	0.00	29.50	0.00	14.83	50.50	5.33	0.00	0.00	0.00	6.00
Libya	0.00	71.82	28.18	0.00	0.00	0.00	0.00	0.00	0.00	22.50
Morocco	69.21	23.59	0.00	0.00	7.24	0.00	0.00	0.00	0.00	22.64
Mozambique	0.00	0.08	0.08	0.00	99.77	0.00	0.00	0.00	0.00	13.29
Namibia	0.58	2.92	0.00	0.00	97.08	0.00	0.00	0.00	0.00	1.71
Nigeria	0.00	12.66	53.57	0.00	33.77	0.00	0.00	0.00	0.00	23.54
Senegal	0.00	79.53	2.36	0.00	16.54	1.97	0.00	0.00	0.00	2.54
South Africa	93.34	0.00	0.00	0.00	6.55	0.11	0.00	0.00	0.00	244.92
Sudan	0.00	70.15	0.00	0.00	30.10	0.00	0.00	0.00	0.00	4.12
United Republic of Tanzania	3.29	38.16	0.00	0.00	58.55	0.00	0.00	0.00	0.00	3.04
Togo	0.00	57.89	0.00	0.00	36.84	0.00	0.00	0.00	0.00	0.19
Tunisia	0.00	8.20	90.41	0.00	1.39	0.00	0.00	0.00	0.00	13.66

Table D–2. Summary of Year 2005 Electricity Generation Information for Non-OECD Countries, continued

Country	Coal	Oil	Gas	Geothermal	Wind, hydro, solar, nuclear, chemical & Other	Solid biomass & biogas	Industrial waste	Municipal waste	Peat	Total Generation (10^{12} W-hr)
	Generation Contribution (%)									
Africa (cont)										
Zambia	0.22	0.45	0.00	0.00	99.33	0.00	0.00	0.00	0.00	8.94
Zimbabwe	42.94	0.19	0.00	0.00	56.77	0.00	0.00	0.00	0.00	10.27
Other Africa	8.78	46.03	0.00	0.00	45.27	0.00	0.00	0.00	0.00	13.21
Latin America										
Argentina	1.49	5.44	52.88	0.00	38.96	1.23	0.00	0.00	0.00	105.77
Bolivia	0.00	16.63	32.31	0.00	47.80	3.25	0.00	0.00	0.00	5.23
Brazil	1.58	2.91	5.57	0.00	86.39	3.56	0.00	0.00	0.00	403.03
Chile	16.72	3.40	29.94	0.00	48.14	1.80	0.00	0.00	0.00	49.94
Colombia	7.87	0.21	13.65	0.00	77.18	1.09	0.00	0.00	0.00	51.57
Costa Rica	0.00	3.27	0.00	13.94	82.06	0.73	0.00	0.00	0.00	8.25
Cuba	0.00	97.52	0.00	0.00	0.59	1.96	0.00	0.00	0.00	15.34
Dominican Republic	10.00	74.57	0.31	0.00	14.73	0.47	0.00	0.00	0.00	12.90
Ecuador	0.00	40.97	7.69	0.00	51.34	0.00	0.00	0.00	0.00	13.40
El Salvador	0.00	42.56	0.00	22.01	35.01	0.42	0.00	0.00	0.00	4.77
Guatemala	13.89	31.48	0.00	0.00	42.72	11.90	0.00	0.00	0.00	7.56
Haiti	0.00	51.79	0.00	0.00	48.21	0.00	0.00	0.00	0.00	0.56
Honduras	0.00	66.49	0.00	0.00	32.26	1.25	0.00	0.00	0.00	5.58
Jamaica	0.00	96.63	0.00	0.00	2.02	1.35	0.00	0.00	0.00	7.42
Netherlands Antilles	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.25
Nicaragua	0.00	69.69	0.00	9.41	14.98	5.57	0.00	0.00	0.00	2.87
Panama	0.00	35.68	0.00	0.00	63.81	0.34	0.00	0.00	0.00	5.83
Paraguay	0.00	0.00	0.00	0.00	100.00	0.00	0.00	0.00	0.00	51.17
Peru	3.14	8.24	9.69	0.00	78.27	0.63	0.00	0.00	0.00	25.50
Trinidad and Tobago	0.00	0.14	99.43	0.00	0.00	0.28	0.00	0.00	0.00	7.06

Table D–2. Summary of Year 2005 Electricity Generation Information for Non-OECD Countries, continued

Country	Coal	Oil	Gas	Geothermal	Wind, hydro, solar, nuclear, chemical & Other	Solid biomass & biogas	Industrial waste	Municipal waste	Peat	Total Generation (10^{12} W-hr)
	Generation Contribution (%)									
Latin America (cont)										
Uruguay	0.00	12.50	0.00	0.00	87.11	0.52	0.00	0.00	0.00	7.68
Venezuela	0.00	10.48	15.64	0.00	73.89	0.00	0.00	0.00	0.00	101.54
Other Latin America	0.00	85.60	0.09	0.00	13.45	0.86	0.00	0.00	0.00	11.60
Asia										
Bangladesh	0.00	6.76	87.54	0.00	5.70	0.00	0.00	0.00	0.00	22.64
Brunei Darussalam	0.00	1.03	98.97	0.00	0.00	0.00	0.00	0.00	0.00	2.91
Cambodia	0.00	95.45	0.00	0.00	4.55	0.00	0.00	0.00	0.00	0.88
India	68.66	4.47	8.94	0.00	17.66	0.27	0.00	0.00	0.00	699.04
Indonesia	40.65	31.94	13.78	5.18	8.45	0.00	0.00	0.00	0.00	127.36
Democratic People's Republic of Korea	39.02	3.67	0.00	0.00	57.31	0.00	0.00	0.00	0.00	22.91
Malaysia	26.49	2.85	64.02	0.00	6.62	0.00	0.00	0.00	0.00	87.31
Mongolia	97.15	2.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.51
Myanmar	0.00	10.30	39.87	0.00	49.83	0.00	0.00	0.00	0.00	6.02
Nepal	0.00	0.00	0.00	0.00	99.59	0.00	0.00	0.00	0.00	2.42
Pakistan	0.14	20.32	44.01	0.00	35.53	0.00	0.00	0.00	0.00	93.83
Philippines	26.98	10.86	29.81	17.51	14.84	0.00	0.00	0.00	0.00	56.55
Singapore	0.00	25.60	74.40	0.00	0.00	0.00	0.00	0.00	0.00	38.21
Sri Lanka	0.00	60.55	0.00	0.00	39.34	0.00	0.00	0.00	0.00	8.77
Chinese Taipei	52.81	6.58	18.25	0.00	21.06	0.13	0.00	1.16	0.00	227.36
Thailand	15.11	6.60	71.42	0.00	4.39	2.49	0.00	0.00	0.00	132.20
Vietnam	16.72	4.64	38.51	0.00	40.12	0.00	0.00	0.00	0.00	53.46
Other Asia	0.00	59.64	0.00	0.00	40.36	0.00	0.00	0.00	0.00	14.27
Hong Kong (China)	62.65	0.57	36.78	0.00	0.00	0.00	0.00	0.00	0.00	38.45

Table D–2. Summary of Year 2005 Electricity Generation Information for Non-OECD Countries, continued

Country	Coal	Oil	Gas	Geothermal	Wind, hydro, solar, nuclear, chemical & Other	Solid biomass & biogas	Industrial waste	Municipal waste	Peat	Total Generation (10^{12} W-hr)
	Generation Contribution (%)									
Asia (cont)										
People's Republic of China	78.37	2.43	1.08	0.00	18.02	0.10	0.00	0.00	0.00	2497.44
Non-OECD Europe										
Albania	0.00	1.29	0.00	0.00	98.71	0.00	0.00	0.00	0.00	5.44
Bulgaria	41.61	1.38	4.28	0.00	52.71	0.00	0.05	0.00	0.00	44.36
Cyprus	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.38
Gibraltar	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15
Malta	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.24
Romania	36.88	3.18	16.55	0.00	43.38	0.02	0.00	0.00	0.00	59.41
Bosnia and Herzegovina	55.97	1.10	0.00	0.00	42.92	0.00	0.00	0.00	0.00	12.72
Croatia	18.70	14.93	14.53	0.00	51.77	0.08	0.00	0.00	0.00	12.46
Former Yugoslav Republic of Macedonia	78.39	0.29	0.00	0.00	21.47	0.00	0.00	0.00	0.00	6.94
Serbia and Montenegro	64.11	1.73	1.21	0.00	32.99	0.00	0.00	0.00	0.00	36.47
Slovenia	34.85	0.26	2.25	0.00	61.77	0.73	0.07	0.00	0.00	15.12
Armenia	0.00	0.00	28.96	0.00	71.04	0.00	0.00	0.00	0.00	6.32
Azerbaijan	0.00	27.66	58.15	0.00	14.18	0.00	0.00	0.00	0.00	21.22
Belarus	0.00	8.40	91.38	0.00	0.13	0.00	0.10	0.00	0.00	30.96
Estonia	90.99	0.29	7.44	0.00	0.69	0.29	0.00	0.00	0.10	10.21
Georgia	0.00	0.96	13.34	0.00	85.83	0.00	0.00	0.00	0.00	7.27
Kazakhstan	70.33	7.41	10.67	0.00	11.57	0.00	0.00	0.00	0.00	67.92
Kyrgyzstan	3.59	0.00	9.50	0.00	86.85	0.00	0.00	0.00	0.00	16.42
Latvia	0.00	0.20	30.35	0.00	68.84	1.02	0.00	0.00	0.00	4.91
Lithuania	0.00	2.71	20.43	0.00	76.86	0.00	0.00	0.00	0.00	14.78

Table D–2. Summary of Year 2005 Electricity Generation Information for Non-OECD Countries, continued

Country	Coal	Oil	Gas	Geothermal	Wind, hydro, solar, nuclear, chemical & Other	Solid biomass & biogas	Industrial waste	Municipal waste	Peat	Total Generation (10^{12} W-hr)
	Generation Contribution (%)									
Non-OECD Europe (cont)										
Republic of Moldova	0.00	0.26	97.93	0.00	1.55	0.00	0.00	0.00	0.00	3.87
Russia	16.62	2.23	46.74	0.04	34.00	0.00	0.27	0.00	0.10	953.09
Tajikistan	0.00	0.00	2.34	0.00	97.66	0.00	0.00	0.00	0.00	17.09
Turkmenistan	0.00	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	12.82
Ukraine	26.63	0.28	18.64	0.00	54.45	0.00	0.00	0.00	0.00	186.06
Uzbekistan	4.70	13.62	68.83	0.00	12.85	0.00	0.00	0.00	0.00	47.71
Middle East										
Bahrain	0.00	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	8.70
Islamic Republic of Iran	0.00	18.03	73.04	0.00	8.93	0.00	0.00	0.00	0.00	180.39
Iraq	0.00	98.47	0.00	0.00	1.53	0.00	0.00	0.00	0.00	34.00
Israel	71.07	17.50	11.36	0.00	0.08	0.00	0.00	0.00	0.00	49.84
Jordan	0.00	42.07	57.31	0.00	0.62	0.00	0.00	0.00	0.00	9.65
Kuwait	0.00	82.14	17.88	0.00	0.00	0.00	0.00	0.00	0.00	43.73
Lebanon	0.00	89.72	0.00	0.00	10.38	0.00	0.00	0.00	0.00	10.12
Oman	0.00	18.02	81.98	0.00	0.00	0.00	0.00	0.00	0.00	12.65
Qatar	0.00	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	14.40
Saudi Arabia	0.00	50.90	49.11	0.00	0.00	0.00	0.00	0.00	0.00	176.12
Syria	0.00	53.03	37.09	0.00	9.87	0.00	0.00	0.00	0.00	34.94
United Arab Emirates	0.00	2.14	97.86	0.00	0.00	0.00	0.00	0.00	0.00	60.70
Yemen	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.74

Source:
International Energy Agency, Electricity Information 2007 Edition: *Documentation for Beyond 2020 Files*, Table 2.2. Gross Electricity Production, By Country, By Fuel, 2006e (TWh) and Table 2.3. Gross Electricity Production From Combustible Fuels, By Country, 2006e (TWh).

Calculation worksheets associated with the WRI and the WBCSD GHG Protocol (WRI/WBCSD, January and December 2007) provide CO_2 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. (See footnote to calculation worksheet "EFs Electricity Intl All Fuels"). For these emission factors, the total CO_2 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, as presented here, is recommended over the WRI/WBCSD published emission factors.

D.2 Historical Electric Grid Emission Factors

Section 7 provides 2006 electric grid emission factors, the most current data available at the time of this API *Compendium* revision. Table D-3 provides international electric grid emission factors for OECD member countries for 2000-2002 that were provided in the previous API *Compendium* (API, 2004). Similarly, Table D-4 provides international electric grid emission factors for Non-OECD member countries for 2000-2001 that were provided in the previous API *Compendium* (API, 2004). Table D-5 provides Canadian electricity emission factors for 1999-2001 that were also provided in the previous API *Compendium*. Emission factors for OECD and Non-OECD countries were derived as described in Section D, using an average of 2000 through 2002 data for OECD countries, and an average of 2000 and 2001 data for non-OECD countries. At the time of derivation, 2002 data was not available for the non-OECD countries. The Canadian 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, and are the average of data for years 2003 through 2005.

Table D–3. OECD Member Country International Electric Grid Emission Factors, Average of 2000 – 2002 Data (Generation Basis) [a]

tonnes/10^6 W-hr			
Country	**CO_2**	**CH_4**	**N_2O**
Australia	0.754	1.54E-05	1.25E-04
Austria	0.193	4.92E-06	2.95E-05
Belgium	0.242	4.44E-06	3.23E-05
Canada [b]	0.222	7.82E-06	4.14E-06
Czech Republic	0.647	1.33E-05	1.10E-04
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 [c]	0.43	9.26E-06	6.50E-05
US [d]	0.606	5.03E-06	8.71E-06

Footnotes and Sources:

[a] International Energy Agency (IEA). *Electricity Information 2002*. IEA Energy Statistics Division, 2002. All factors developed from IEA (IEA, 2002), with the exception of factors for countries identified in footnotes b – d. Section D.1.1 provides the approach used to estimate emission factors.

[b] 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. Emission factors derived from electric generation and emissions data provided by Environment Canada; discussed further in Table D-5.

[c] 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. CO_2 emission factor taken from Defra (Defra, 2003). CH_4 and N_2O factors derived from IEA data (IEA, 2002), using methodology described in Section D.

[d] 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, March 2002.

Table D–4. Non-OECD Member Country International Electric Grid Emission Factors, Average of 2000 – 2001 Data (Generation Basis)

tonnes/10^6 W-hr

Country	CO_2	CH_4	N_2O	Country	CO_2	CH_4	N_2O
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				

Table D–4. Non-OECD Member Country International Electric Grid Emission Factors, Average of 2000 – 2001 Data (Generation Basis), continued

tonnes/10^6 W-hr

Country	CO_2	CH_4	N_2O	Country	CO_2	CH_4	N_2O
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				

Source:
International Energy Agency (IEA). *Electricity Information 2002*. IEA Energy Statistics Division, 2002. Electricity Emissions Database purchased from http://www.iea.org.

Table D–5. Average Canadian Electricity Usage Emission Factors by Province (1999-2001 data) [a,b]

Location	tonnes/10^6 W-hr		
	CO_2	CH_4	N_2O
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
Canada Average	**0.222**	**7.82E-06**	**4.14E-06**

Footnotes and Sources:
[a] Electricity generation data: Ha, Chia. Environment Canada, data provided to URS Corporation on September 16, 2003.
[b] Emissions data: Olsen, K., et al. *Canada's Greenhouse Gas Inventory 1990-2001*, Greenhouse Gas Division, Environment Canada, August 2003.

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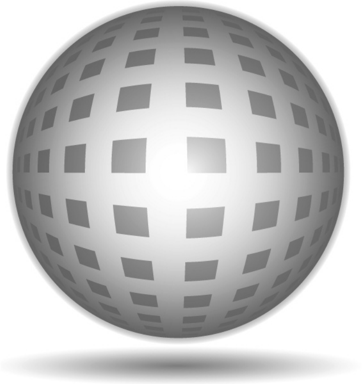
AMERICAN PETROLEUM INSTITUTE

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

AUGUST 2009

APPENDIX E

ADDITIONAL INFORMATION



Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry

Appendix E – Additional Information

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E. ADDITIONAL INFORMATION

This section provides additional information to supplement general methodologies and calculation approaches presented throughout the API *Compendium*.

E.1 “Weathered” Crude and Other Petroleum Product Vented CH_4 and CO_2 Emissions

Total hydrocarbon emissions and/or VOC emissions are commonly estimated from liquid loading, ballasting, and transit operations associated with refined petroleum liquids. As described in this section, CH_4 and CO_2 emissions are not expected from these operations. Unless site specific data indicate otherwise, CH_4 and CO_2 emissions should only be calculated for vented emissions from “live” crude.

Live crude is the term used for crude oil that has not been exposed to the atmosphere. Live crude may contain CH_4 and/or CO_2. Once “live” crude reaches atmospheric pressure and the volatile CH_4/CO_2 has flashed off (as described in Section 5.4.1), the crude is considered “weathered” and the crude oil vapors contain very little, if any, CH_4 or CO_2.

Analyses for “weathered” crude oil are provided in Table E-1, for crude produced in three locations: Alaska North Slope, Utah Altamont, and San Joaquin Valley (API, 2000). As shown in Table E-1, there is no C1 (i.e. CH_4) in the “weathered” crude.

Table E–1. Liquid “Weathered” Crude Speciation Data

Constituent	Alaska North Slope (ANS) Crude	Utah Altamont (ALT) Crude	San Joaquin Valley (SJV) Crude
	Weight %		
C1	0.0000	0.0000	0.0000
C2	0.0020	0.0000	0.0000
C3	0.0550	0.0000	0.0000
C4	0.6370	0.0130	0.0000
C5	1.1910	0.1560	0.0040
C6	2.2560	0.8230	0.0170
C7	2.8820	1.9940	0.0520
C8	3.1590	2.6860	0.1160

Table E–1. Liquid "Weathered" Crude Speciation Data, continued

Constituent	Alaska North Slope (ANS) Crude	Utah Altamont (ALT) Crude	San Joaquin Valley (SJV) Crude
	Weight %		
C9	2.5680	2.6090	0.2420
C10	2.5270	2.5170	0.4190
C11	1.5800	2.0370	0.3420
C12	0.9930	1.8420	0.2560
C13	0.3720	0.0000	0.0850

Source:
API, *Comprehensive Report of API Crude Oil Characterization Measurements*, August 2000. Analyses shown are the for the whole crude, and are sums of individual weight percents identified for parafins, iso-parafins, aromatics, and naphthalenes. Additional speciation data is provided in Table 14; methane is not listed in Table 14 other than as presented here.

Because "weathered" crude contains no CH_4, refined petroleum products also contain no CH_4. (The refining process does not add CH_4 to the liquids being refined.) Thus, for petroleum liquids other than "live" crude, the liquid phase CH_4 content is assumed to be zero. Examples of "weathered" crude oil and refined petroleum product liquid phase compositions are presented in Table E-2. Note that CH_4 is not present in the liquid composition data, as expected.

Table E–2. Average Liquid Compositions by Fuel Type

Constituent	Gasoline [a]	No. 1 Diesel Fuel [b]	Ultra Low Sulfur Diesel [c]	No. 4 Fuel Oil [d]	No. 5 Fuel Oil [e]	No. 6 Fuel Oil [f]	Crude Oil [g]
	Weight %						
C_2 Compounds							
Ethanol	11						
C_4 Compounds							
Butane	4						
C_5 Compounds							
Isopentane	9						
Methyl-Tert-Butyl Ether	15						
Pentane	4						
C_6 Compounds							
2,3-Dimethylbutane	2						
2-Methylpentane	4						
3-Methylpentane	2						
Benzene	2		Trace				0-2
n-Hexane	2						
C_7 Compounds							
2-Methylhexane	1						
3-Methylhexane	2						
Methylcyclohexane	1						
Toluene	5						0-20
C_8 Compounds							
Ethyl Benzene	2	0 - 1					0-4

Table E–2. Average Liquid Compositions by Fuel Type, continued

Constituent	Gasoline [a]	No. 1 Diesel Fuel [b]	Ultra Low Sulfur Diesel [c]	No. 4 Fuel Oil [d]	No. 5 Fuel Oil [e]	No. 6 Fuel Oil [f]	Crude Oil [g]
	Weight %						
C_{9+} Compounds							
Ethylmethylbenzenes (Ethyltoluenes)		1 - 3					
1, 2, 4 Trimethylbenzene		0 - 1					
5-methylchrysene						0.01-2	
Benzo(a)phenanthrene						0.01-0.1	
Cumene		0 - 1					
Naphthalene		0 - 3	Trace	0.01-0.2	0.01-0.15	0.01-0.15	
Nonane, all isomers		20 - 30					
Trimethyl Benzene	8	0 - 2					0-2
Xylene	10	0 - 1					0-20
Other Compounds							
Catalytic Cracked Clarified Oil				0-60	0-100	0-90	
Diesel Oil				10-40		0-30	
Fuel Oil No. 6				30-60	0-70		
Hydrogen Sulfide				0-0.01	0-0.01	0-0.01	0-1
Middle Distillate Fuel					10-30		
Petroleum Residua				0-24	0-28	0-100	
Polycyclic aromatic hydrocarbons (PAHs)			Up to 10				1-10
Sulfur Compounds			<0.0015	1-3	1-3	0.5-4	

Footnotes and Sources:

[a] Taken from Kinder Morgan *MSDS for Unleaded Gasoline*, revised 18 Feb 2003. The *MSDS* notes that "because of volatility considerations, gasoline vapor may have concentrations of components very different from those of liquid gasoline. The major components of gasoline vapor are: butane, isobutane, pentane, and isopentane."

[b] Taken from Citgo *MSDS for No. 1 Diesel Fuel, All Grades*, revised 12/31/07.

[c] Taken from Irving *MSDS for Ultra Low Sulphur Diesel*, revised December 23, 2006.

[d] Taken from Marathon *MSDS for Marathon No. 4 Fuel Oil*, revised 07/25/2006.

[e] Taken from Marathon *MSDS for Marathon No. 5 Fuel Oil*, revised 07/25/2006.

[f] Taken from Marathon *MSDS for Marathon No. 6 Fuel Oil*, revised 07/25/2006.

[g] Taken from El Paso Corporation *MSDS for Crude Oil*, revised 06/26/2007.

For the most part, the vapor phase of a fuel will consist of the lighter hydrocarbons present in the liquid phase of the fuel. This is due to the fact that lighter hydrocarbons, having a higher vapor pressure, will more readily volatilize than heavier hydrocarbons. Since CH_4 is an extremely light hydrocarbon, it volatilizes readily, and would therefore be expected in the vapor phase of the fuel. Conversely, if there is no CH_4 in the liquid phase of the fuel, it can be assumed that there is no CH_4 in the vapor phase of the fuel.

As demonstrated in Tables E-1 and E-2, there is no CH_4 in the liquid phase of "weathered" crude or refined petroleum products. For this reason, it can be expected that there is no CH_4 in the vapor phase of the fuels. To validate this assumption, typical "weathered" crude oil and refined petroleum product vapor compositions are presented in Table E-3 (EPA, SPECIATE Version 4.0, 2006). As expected, it is observed from the vapor composition data that there is no CH_4 in any of the vapor streams.

Table E–3. Vapor Phase Speciation Data[a]

Constituent	Crude [b,c]	Gasoline [b,d]	Distillate [b,e]	Jet Fuel (Jet A) [f,g]
	Weight %			
C_2 Compounds				
Ethane	4.17	0.07	2.13	
C_3 Compounds				
Propane	16.9	1.06	12.7	
Propylene	0.39			
C_4 Compounds				
Cis-2-butene		0.83		
Isobutane	4.42	8.34	7.34	
N-butane	24.5	28.53	28.08	
Trans-2-butene		1.02		
C_5 Compounds				
1-pentene		0.86		
Cis-2-pentene		0.67		
Cyclopentane		0.61		
N-pentane	12.77	7.25	7.97	
Trans-2-pentene		1.37		
C_6 Compounds				
2,2-dimethylbutane		1.04		
3-methylpentane		1.99		
Benzene	1.04	1.41	2.57	
Cyclohexane	0.66	0.43	1.23	
Methylcyclopentane		1.41		
N-hexane	6.3	3.75	5.61	
C_7 Compounds				
2,4-dimethylpentane		0.43		
3-methylhexane		0.42		
Methylcyclohexane		0.12		
N-heptane	6.37	0.4	1.7	0.1
Toluene	0.79	1.25	2.06	

Table E–3. Vapor Phase Speciation Data [a], continued

Constituent	Crude [b,c]	Gasoline [b,d]	Distillate [b,e]	Jet Fuel (Jet A) [f,g]
	Weight %			
C_8 Compounds				
2,2,4-trimethylpentane		0.42		
2,3,4-trimethylpentane		0.07		
3-methylheptane		0.06		
Ethylbenzene	0.07	0.06	0.32	
N-octane	4.2	0.03	0.01	0.5
C_{9+} Compounds				
1,2,4-trimethylbenzene (1,3,4-trimethylbenzene)	0.01	0.05	0.37	
1,3,5-trimethylbenzene		0.02		
Isopropylbenzene (cumene)	0.04	0.01	0.05	
N-decane				19.6
N-dodecane				18.2
N-nonane			0.04	4.7
N-tridecane				17.7
N-undecane				20.3
O-xylene	0.03	0.04	0.13	
Pentadecane				7.2
Tetradecane				11.7
Other Compounds				
Unidentified [h]	17.34	35.98	27.69	
Data Quality Rating [i]	N/A	N/A	N/A	3
EPA SPECIATE Program Profile Number	2487	2490	2488	0100

Footnotes and Sources:

[a] EPA Speciate Version 4.0, December 2006.

[b] Profiles normalized to equal 100% for the sum of the 55 PAMS (Photochemical Assessment Monitoring Stations) pollutants + MTBE, UNIDENTIFIED and OTHER.

[c] Composite of 7 Emission Profiles from Crude Oil Storage Tanks – 1993.

[d] Composite of 14 Emission Profiles from Gasoline Storage Tanks – 1993.

[e] Composite of 9 Emission Profiles from Distillate Oil Storage Tanks. – 1993.

[f] Fixed Roof Tank - Commercial Jet Fuel (Jet A).

[g] Engineering evaluation of literature data.

[h] The "Unidentified" fraction is typically the high molecular weight tail of liquids that are very hard to separate, identify and quantify by most typical gas chromatography speciation methods.

[i] Quality rating pertains to the quality of the data; "5" has the highest quality while "1" has the lowest quality.

In accordance with the liquid and vapor phase compositions shown in Tables E-1 through E-3, the CH_4 content (and therefore, vented and fugitive CH_4 emissions) of all petroleum liquids other than "live" crude oil is assumed to be zero if measured data demonstrating otherwise are not available. However, where site data indicates that CH_4 is contained in the vapor stream, CH_4 emissions should be estimated from vented activities. For example, some cracking or coking operations might produce CH_4 as a part of the process of breaking up larger molecules into smaller molecular fragments.

The vapor phase CH_4 content of "live" crude oil is assumed to be 15 percent by weight (wt%), if site-specific data are not available. This assumption is derived from AP-42, which reports that the VOC comprises 55-100 wt% of the TOC, with a typical value of 85 wt% (EPA, AP-42 Section 5.2, 2008). Assuming that the CH_4 comprises 15 wt. % of the TOC is a simplifying assumption because the non-VOC portion of the TOC includes both CH_4 and ethane; the ethane content has been discounted in the assumed 15 weight % CH_4 in the vapor phase.

Note that although CO_2 was not analyzed in the speciation data presented in Tables E-1 through E-3, CO_2 is not expected to be present in "weathered" crude or other refined petroleum products, in either the liquid or vapor phases. Carbon dioxide that is entrained in the oil from the producing formation is usually separated into the produced gas at the oil/gas separators during the production phase. Carbon dioxide is therefore not expected in any appreciable amount in the liquid after separation of the gases in the field. However, where site data shows that CO_2 is contained in the vapor stream, CO_2 emissions should be estimated from vented activities.

These assumptions are consistent with AP-42, which notes that the non-VOC (i.e., CH_4 and C_2H_6) portion of TOC emissions from other petroleum liquids is generally considered negligible (EPA, AP-42 Section 5.2, 2008).

E.2 Default GRI/EPA Methane and Carbon Dioxide Compositions

The default CH_4 and CO_2 compositions used to develop emission factors presented in Sections 5 and 6 are presented in Table E-4.

Table E–4. Default GRI/EPA Methane and Carbon Dioxide Compositions

Industry Segment	Average Methane Composition [a]	Uncertainty [a,b] (±%)	Average Carbon Dioxde Composition	Uncertainty [d] (±%)
Production	78.8%	5.53%	3.78 [c]	4%
Gas Processing [e]	86.8%	6.54%	2.0 [f]	4%
Transmission	93.4%	1.80%	2.0 [f]	4%
Distribution	93.4%	1.80%	2.0 [f]	4%

Footnotes and Sources for Table E-4:

[a] Shires, T.M., M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 6: Vented and Combustion Source Summary,* GRI-94/0257.23 and EPA-600/R-96-080f. Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[b] Uncertainty based on 95% confidence interval converted from the 90% confidence intervals for the data used to develop the original methane compositions.

[c] Dalrymple, D.A., F.D. Skinner, and N.P. Meserole. *Investigation of U.S. Natural Gas Reserve Demographics and Gas Treatment Processes*, Topical Report, GRI-91/0019. Gas Research Institute, January 23, 1991.

[d] Uncertainty is based on engineering judgment at a 95% confidence interval.

[e] Composition based on "after the processing plant", i.e., leaving the processing sector.

[f] The CO_2 compositions for gas processing, transmission, and distribution are assumed values based on pipeline quality gas.

E.3 Atmospheric Oxidation of Emissions

A conversion factor of 0.6 wt% CH_4 in TOC has been cited by some GHG regulations (CARB, draft WCI). As demonstrated in Section E.1, the 0.6 factor is not consistent with measured CH_4 concentrations for "weathered" crude or refined petroleum products and is significantly higher than the default 15 wt% suggested by EPA for "live" crude. This section provides the origin of the 0.6 factor as cited by CARB.

Most, if not all, organic carbon compounds are subject to a myriad of atmospheric chain reactions, including photo oxidation that would eventually form atmospheric CO_2. IPCC provided a methodology to account for estimating CO_2 emissions from emissions of CH_4, CO, and Non-Methane Volatile Organic Compounds (NMVOC), as shown in Equations E-1, E-2, and E-3 (IPCC, Draft Volume 1, Chapter 7, 2006).

$$\text{Emissions}_{CO_2} = \text{Emissions}_{CH_4} \times \frac{44}{16} \qquad \text{(Equation E-1)}$$

where

Emissions of CO_2 = emissions of CO_2 formed through atmospheric oxidation;
Emissions CH_4 = emissions of CH_4 from inventory;
44 = molecular weight of CO_2; and
16 = molecular weight of CH_4.

$$\text{Emissions}_{CO_2} = \text{Emissions}_{CO} \times \frac{44}{28} \qquad \text{(Equation E-2)}$$

where

Emissions of CO_2 = emissions of CO_2 formed through atmospheric oxidation;
Emissions CO = emissions of CO from inventory;
44 = molecular weight of CO_2; and
28 = molecular weight of CO.

$$\text{Emissions}_{CO_2} = \text{Emissions}_{NMVOC} \times C \times \frac{44}{12} \qquad \text{(Equation E-3)}$$

where

Emissions of CO_2 = emissions of CO_2 formed through atmospheric oxidation;
Emissions CH_4 = emissions of $CH_4$from inventory;
C = mass fraction of carbon in NMVOC;
44 = molecular weight of CO_2; and
12 = molecular weight of C.

The factor "C" in Equation E-3 is the mass fraction of carbon in the NMVOC, which should be calculated based on the speciation of the NMVOC compounds. Alternatively, IPCC provides a *default carbon fraction of 0.6*. The 0.6 default factor provided by IPCC should only be used as the weight fraction of carbon in non-methane VOC emissions for the purpose of determining atmospheric CO_2, after all atmospheric oxidation reactions have taken place. It is in no way related to the CH_4 content of non-methane hydrocarbon emissions or of the petroleum streams, and therefore is not appropriate for directly calculating emissions of CO_2 or CH_4.

E.4 Non-GHG Emission Sources

Many emission sources at oil and natural gas facilities are sources of VOCs but are not sources of GHG emissions. As such, a methodology is not provided in this API *Compendium* for calculating GHG emissions from these sources.

Non-GHG sources at production facilities include the following:

- Chemical Storage Tanks;
- Glycol Storage Tanks;
- Mud Cuttings Roll-Off Bins;
- Naphtha Storage Tanks;
- Slop Oil Tanks;
- Sumps; and
- Water Blowdown Tanks.

Additional non-GHG sources which may be present at refineries include the following:

- Cooling Towers;
- Equipment Leaks from liquid process streams[1];
- Product Tanks (e.g. gasoline tanks)[1];
- Oil/Water Separators; and
- Process Drains.

Marketing terminals may also be sources of VOC emissions (such as from equipment leaks and storage tanks), but are not sources of GHG emissions.

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[1] Note that if site specific data indicates CH_4 or CO_2 are present in the vapors, methodology is provided for emission calculations in Appendix B.

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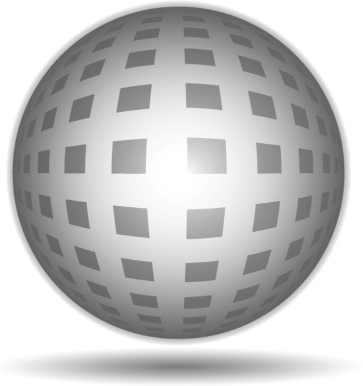
COMPENDIUM OF GREENHOUSE GAS EMISSIONS METHODOLOGIES FOR THE OIL AND NATURAL GAS INDUSTRY

AUGUST 2009

APPENDIX F

REFINERY METHANE FUGITIVE EMISSION STUDY



Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry

Appendix F – Refinery Methane Fugitive Emissions Study

August 2009

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F. REFINERY METHANE FUGITIVE EMISSIONS STUDY

F.1 Overview

This appendix describes the results of a study to test the hypothesis that CH_4 fugitive emissions are negligible compared to overall refinery GHG emissions. The study has estimated CH_4 fugitive emissions for two refineries: a small relatively simple refinery and a larger more complex refinery. Information on the refineries is provided in Table F-1.

Table F-1. Refinery Background Data

	Refinery A	**Refinery B**
Refinery Type	Fuels refinery	Integrated fuels & chemicals
Capacity (BPD)	50,000 to 99,000	100,000 to 199,000
Process Type	Single train (multiple HDS)	Old multi-train refinery

F.2 Study Summary

The study approach is to gather data on the numbers of components in natural gas and refinery fuel gas service. Potential emissions are estimated using the average emission factor for gas service for the oil and natural gas industry rather than applying refinery emission factors since the refinery emission factors specifically exclude streams exceeding 10% CH_4. Control effectiveness estimates are taken from the Protocol for Equipment Leak Emission Estimates, Table 5-3, published by EPA in 1995. The control effectiveness factors are applied only for components subject to formal LDAR, which normally applies to refinery fuel gas service components, but not to natural gas service components.

Data are also gathered from the refinery on their overall GHG inventory. This allows a comparison of the estimated CH_4 fugitive emissions as a percent of the overall GHG inventory in

CO_2-equivalents. One of the refineries provided CO_2 emissions both with and without imported electricity. Imported electricity emissions were not included in the base GHG emissions to which the contribution of fugitive CH_4 emissions was compared.

Tables F-2 and F-4 present GHG emission inventory data (not including fugitive CH_4) for Refineries A and B, respectively. Tables F-3 and F-5 present fugitive CH_4 emissions summary data for Refineries A and B, respectively. Unit level component counts and emission calculation tables are also available, but they have not been included because the unit names and configurations might allow identification of the refineries.

Table F-2. Refinery A Greenhouse Gas Emissions Inventory

Compound	Emissions	Units	Factor	CO_2e	Units
CH_4 [a]	19.48	ton/year	21	371	tonnes/year
N_2O	16.98	ton/year	310	4,775	tonnes/year
CO_2	732,675	ton/year	1	664,672	tonnes/year
Total Greenhouse Gas Emissions:				**669,819**	**tonnes/year CO_2e**

Footnote:
[a] Not including fugitive CH_4.

Table F-3. Refinery A Fugitive CH_4 Emissions Summary

Service	# Components	CH_4 Emissions (tonnes/year)	CO_2e (tonnes/year)	% of GHG CO_2e Emission Inventory
Natural Gas	2,780	26	544	0.08%
Fuel Gas	5,432	10	216	0.03%
Make Gas	159	0.2	5	0.001%
Totals	8,371	36	765	0.11%

Table F-4. Refinery B Greenhouse Gas Emissions Inventory

Compound	Emissions	Units	Factor	CO_2e	Units
CH_4 [a]	53	ton/yr	21	1,004	tonnes/yr
N_2O	19	ton/yr	310	5,364	tonnes/yr
CO_2 [b]	1,912,392	ton/yr	1	1,734,895	tonnes/yr
CO_2 [c]	1,618,748	ton/yr	1	1,468,505	tonnes/yr
Total Greenhouse Gas Emissions:				**1,741,263**	**tonnes/yr CO_2e[b]**
				1,474,873	**tonnes/yr CO_2e[c]**

Footnotes:
[a] Not including fugitive methane.
[b] Includes imported electricity.
[c] Excludes imported electricity.

Table F-5. Refinery B Fugitive CH_4 Emissions Summary

Service	# Components	CH_4 Emissions (tonnes/year)	CO_2e (tonnes/year)	% of GHG CO_2e Emission Inventory
Natural Gas	5,744	55	1,149	0.08%
Fuel Gas	21,002	77	1,609	0.11%
Make Gas [a]	--	--	--	--
Totals [b]	26,746	131	2,759	0.19%

Footnotes:
[a] No separate data for make gas were gathered at Refinery B.
[b] Excludes imported electricity.

F.3 Conclusions

The study has completed data gathering and analyses for two refineries: a small simple refinery and a larger, more complex refinery. The estimated CH_4 fugitive emissions represent about 0.11% of the total GHG inventory for the small/simple refinery and about 0.19% of the GHG inventory for the large/complex refinery. Since other large GHG emitting sources have uncertainties in the range of 1% to 5% of the overall GHG inventory, a CH_4 fugitive emission contribution in the range of 0.1% to 0.2% does appear to be negligible.

F.4 References

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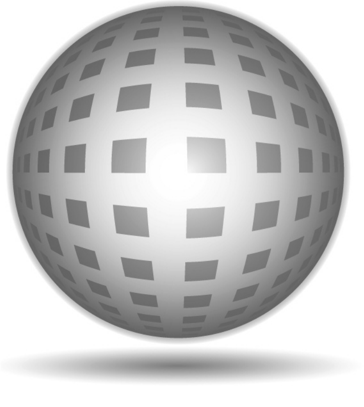
GLOSSARY



GLOSSARY

Acid Gas

The hydrogen sulfide and/or carbon dioxide contained in or extracted from gas or other streams (GPSA, 1987). *See also sour gas.*

Acid Gas Removal Unit (AGR)

Systems used to remove acid gases (hydrogen sulfide and carbon dioxide) by contracting the stream with a solvent (usually amines) and then driving the absorbed components from the solvent. The amines can also absorb methane and, therefore, methane can be released to the atmosphere through the reboiler vent (Shires and Harrison, 1996).

Accuracy

A measure of the total error associated with a data value, accounting for both random and bias errors (Williamson, Hall, and Harrison, 1996).

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.

Actual Conditions

Temperature, pressure, and volume at measurement conditions.

Aerobic

Referring to a condition or a situation or a living creature, such as a bacteria, in which oxygen is required to sustain life (Schlumberger).

Anaerobic

Pertaining to systems, reactions or life processes of species, such as bacteria, in which atmospheric oxygen is not present or not required for survival (Schlumberger).

Anaerobic Digester

The equipment designed and operated for waste stabilization by the microbial reduction (using acid forming and CH_4 forming bacteria, in the absence of oxygen) of complex organic compounds to CO_2 and CH_4. The produced CH_4 may be captured for use as a fuel or flared (CIWMB, 2008).

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 [(141.5/SG) - 131.5], where SG is the specific gravity of the fluid at 60°F (Schlumberger).

Associated Gas

Natural gas which is found in association with crude oil either dissolved in the oil or as a cap of free gas above the oil (EIA, 2008).

Auto-refrigeration

The process in which LNG is kept at its boiling point, so that any added heat is countered by energy lost from boil off.

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 (EPA, AP-42, 1995-2000).

Barrel of Oil Equivalent (BOE)

The quantity of any fuel necessary to equate on a British Thermal Unit (Btu) basis with a barrel of crude oil. This quantity will vary depending on the heating value of crude. For example, according to the US Internal Revenue Service (IRS), a BOE is any amount of fuel which has a Btu content of 5.8 million; according to the California Energy Commission (CEC), one barrel of oil has an energy content of 6 million Btu.

Bitumen

A thick, black, high-sulfur, heavy oil extracted from tar sand and then upgraded to synthetic fuel oil. Bitumen includes hydrocarbons such as asphalt and mineral wax (Schlumberger).

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 (EIA, 2008).

Biomass

Non-fossilized and biodegradable organic material originating from plants, animals and microorganisms, including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material (TCR, 2008).

Blanket Gas

A gas phase maintained above a liquid in a vessel to protect the liquid against air contamination, to reduce the hazard of detonation or to pressurize the liquid (Schlumberger).

Blowdown

The act of emptying or depressuring a vessel. This may also refer to the discarded material such as blowdown water from a boiler or cooling tower (GPSA, 1987).

Blowout

An uncontrolled flow of well fluids and/or formation fluids from the wellbore or into lower pressured subsurface zones (underground blowout) (API, 1988).

British Thermal Unit (Btu)

A measure of heat energy required to raise the temperature of one pound of water by one degree Fahrenheit. British thermal unit is abbreviated as Btu (Schlumberger).

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_2 emission factors listed in Table 4-3 can be used for marine and aviation bunker fuels (EIA, 2008).

Ci+

Refers to a natural gas fraction consisting of hydrocarbon molecules "*i*" and heavier. For example, C6+ is the natural gas fraction of hydrocarbon molecules hexane and heavier.

Carbon Capture and Storage

A process consisting of separation of CO_2 from industrial and energy-related sources, transport to a storage location, and long-term isolation from the atmosphere (IPCC).

Carbon Dioxide (CO_2)

A colorless, odorless, non-toxic gas that is a normal component of ambient air. Carbon dioxide is a product of fossil fuel combustion (API, 1988). Although CO_2 does not directly impair human health, it is a GHG that traps terrestrial (i.e. infrared) radiation and contributes to the potential for global warming.

Carbon Dioxide Equivalent (CO_2e)

The mass of a GHG species multiplied by the global warming potential (GWP) for that species. It is used to evaluate emissions of different GHGs on a common basis—the mass of CO_2 emitted that would have an equivalent warming effect (IPIECA, 2003).

Carbon Equivalent

Determined by first multiplying the total mass of a GHG gas species by the global warming potential for that species, which converts the units to a mass of CO_2 basis. Then the CO_2 mass units are converted to carbon based on the molecular weight ratio of carbon to CO_2. Exhibit 3.1 provides an example of this calculation.

Casinghead Gas

Natural gas produced along with crude oil from oil wells. It contains either dissolved or associated gas or both (EIA).

Catalyst Coke

In many catalytic operations (e.g., catalytic cracking), carbon is deposited on the catalyst, thus deactivating the catalyst. The catalyst is reactivated by burning off the carbon, which is used as a fuel in the refining process. This carbon or coke is not recoverable in a concentrated form (EIA).

Catalytic Cracking Unit

A refinery process unit in which petroleum derivatives are continuously charged and hydrocarbon molecules in the presence of a catalyst are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. Catalytic cracking units include both fluidized bed systems, which are referred to as fluid catalytic cracking units (FCCU), and moving bed systems, which are also referred to as thermal catalytic cracking units. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery (EIA).

Centrifugal Compressor

Any equipment that increases the pressure of a gas stream by centrifugal action, employing rotating movement of the driven shaft (Hyne, 1991).

Centrifugal Compressor Dry Seals

A series of rings that are located around the compressor shaft where it exits the compressor case and that operate mechanically under the opposing forces to prevent natural gas from escaping to the atmosphere (Methane to Markets, 2009).

Centrifugal Compressor Wet Seals

A series of rings around the compressor shaft where it exits the compressor case that use oil circulated under high pressure between the rings to prevent natural gas from escaping to the atmosphere (Methane to Markets, 2009).

Chemical Injection

A general term for injection processes that use special chemical solutions to improve oil and gas operations. Injection can be administered continuously, in batches, in injection wells, or at times in production wells. Some of the chemical solutions used include but are not limited to corrosion inhibitor, scale inhibitor, biocide, demulsifier, clarifier, and hydrate inhibitor. Natural gas powered chemical injection pumps use gas pressure acting on a piston to pump a chemical on the opposite side of the piston. The gas is then vented directly to the atmosphere. Electric powered pumps would be a source of indirect GHG emissions (Schlumberger; Shires, 1996).

Chemical Oxygen Demand (COD)

The amount of oxygen needed to oxidize reactive chemicals in a water system, typically determined by a standardized test procedure. COD is used to estimate the amount of a pollutant in an effluent (Schlumberger).

Coal

A readily combustible black or brownish-black rock whose composition, including inherent moisture, consists of more than 50 percent by weight and more than 70 percent by volume of carbonaceous material. It is formed from plant remains that have been compacted, hardened, chemically altered, and metamorphosed by heat and pressure over geologic time (EIA).

Co-generation unit/Combined Heat and Power (CHP)

Cogeneration, also known as combined heat and power (CHP), is the simultaneous production of energy and process heat from the same fuel.

Coke (Petroleum)

A residue high in carbon content and low in hydrogen that is the final product of thermal decomposition in the condensation process in cracking. This product is reported as marketable coke or catalyst coke (EIA, 2008).

Coke Burn-off

In the regenerator, coke deposited on the catalyst as a result of the cracking reactions is burned off in a controlled combustion process with preheated air. The catalyst is then recycled to be mixed with fresh hydrocarbon feed [EPA, 1998(b)].

Combined Cycle

An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit (EIA).

Commercial Combustor

Refers to commercial boilers/furnaces with Source Classification Codes (SCCs) 1-03-004-01/02/03/04 and 1-03-005-01/02/03/04. According to 40 CFR 63.7575 (December 6, 2006), a *commercial/institutional boiler* means a boiler used in commercial establishments or institutional establishments such as medical centers, research centers, institutions of higher education, hotels, and laundries to provide electricity, steam, and/or hot water. A previous edition (4th edition) of AP-42 defined a natural gas or liquefied petroleum gas fired commercial boiler as a boiler with a heat input capacity between 0.3 and 10 MMBtu/hr (EPA, 1985 to 1993).

Component

Sealed surfaces of above-ground process equipment, including valves, flanges, and other connectors, pump seals, compressor seals, pressure relief valves, open-ended lines, and sampling connections. These components represent mechanical joints, seals, and rotating surfaces, which in time tend to wear and develop unintentional leaks (Hummel, Campbell, and Harrison, 1996).

Compressor

A device that raises the pressure of air or natural gas. A compressor normally uses positive displacement to compress the gas to higher pressures so that the gas can flow into pipelines and other facilities (Schlumberger).

Condensate

Liquid formed by the condensation of a liquid or gas; specifically, the hydrocarbon liquid separated from natural gas because of changes in temperature and pressure when the gas from the reservoir was delivered to the surface separators. Such condensate remains liquid at atmospheric temperature and pressure.

Connector

Any threaded or non-threaded union or joint associated with pipeline segments, tubing, piece of attached equipment or an instrument. These include but are not limited to flanges, elbows, reducers, "T's", or valves. These are potential sources for fugitive emissions (Schlumberger; Hummel, Campbell, and Harrison, 1996).

Cracking

The process of splitting a large heavy hydrocarbon molecule into smaller, lighter components. The process involves very high temperature and pressure and can involve a chemical catalyst to improve the process efficiency (Schlumberger).

Crude Oil

A mixture of hydrocarbons that exists in the liquid phase in the underground reservoir and remains liquid at atmospheric pressure after passing through surface separating facilities (API, 1988).

Cryogenic Liquid or Cryogens

Cryogenic liquids (cryogens) are liquefied gases that are kept in their liquid state at very low temperatures and have a normal boiling point below -238 °F(-150 °C). All cryogenic liquids are gases at normal temperatures and pressures. Examples of cryogens include methane, oxygen, nitrogen, helium and hydrogen. Additional information on cryogens is available from the Canadian Centre for Occupational Health and Safety (CCOHS).

Dehydrator

A device used to remove water and water vapors from gas, including but not limited to desiccant, ethylene glycol, diethylene glycol, or triethylene glycol (Schlumberger).

Delayed Coking Unit

One or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked under elevated temperatures and pressure to produce petroleum coke in a series of closed, batch system reactors (EIA).

Destruction efficiency

The extent to which a target substance present in the input combustibles has been fully oxidized or converted to environmentally safer chemicals (e.g., CH_4 to CO_2, H_2S to SO_2, ammonia/NH_3 to N_2) released into the atmosphere (Methane to Markets, 2009).

Diaphragm Chemical Injection Pump (CIP)

A small positive displacement, reciprocating unit designed to inject precise amounts of chemicals into process streams using a flexible diaphragm to move the plunger.

Diesel Fuel

A fuel composed of distillates obtained in petroleum refining operation or blends of such distillates with residual oil used in motor vehicles. The boiling point and specific gravity are higher for diesel fuels than for gasoline (EIA).

Dig-in

Ruptures of pipelines caused by unintentional (often third-party) damage (Shires and Harrison, 1996).

Direct Emissions

Emissions from sources within the reporting entity’s organizational boundaries that are owned or controlled by the reporting entity, including stationary combustion emissions, mobile combustion emissions, process emissions, and fugitive emissions (TCR, 2008).

Distillate Oil

A general classification for one of the petroleum fractions produced in conventional distillation operations. It includes diesel fuels and fuel oils. Products known as no. 1, no. 2, and no. 4 diesel fuel are used in on-highway diesel engines, such as those in trucks and automobiles, as well as off-highway engines, such as those in railroad locomotives and agricultural machinery. Products known as no. 1, no. 2, and no. 4 fuel oils are used primarily for space heating and electric power generation (EIA).

Downstream

Operations involving the refining, processing, distribution and marketing of products derived from oil and gas, including service stations (IPIECA, 2003).

Dry Gas

(1) Gas whose water content has been reduced by a dehydration process. (2) Gas containing little or no hydrocarbons commercially recoverable as liquid product. Gas in this second definition preferably should be called "lean gas" (GPSA).

Emergency generator

A stationary internal combustion engine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued (EIA; Hynes, 1991).

Emergency Shutdown (ESD)

The emergency procedure of depressuring equipment. The gas may be vented to the atmosphere or routed to a flare.

Emission Factor

The rate of emission per unit of activity, output or input (IPCC).

Emissions

The intentional or unintentional release of greenhouse gases into the atmosphere (IPIECA, 2003).

Engineering Estimate

An estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters. Engineering estimate can also refer to estimated fuel use based on engine run time, load, heat rate curve, and fuel characteristics.

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, stream-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_2 concentrations associated with

EOR operations, CO_2 emissions from vented and fugitive sources should be considered in a greenhouse gas inventory.

External Combustion Device

Steam/electric generating plants, industrial boilers, process heating and space heating, and other commercial and domestic combustion units [EPA, 1998(b)].

Feedstock

A chemical refined and manufactured from hydrocarbons and used to produce petrochemicals. Methane, ethylene, propylene, butylene, and napthenes are common feedstocks (Hyne, 1991).

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 into shuttle tankers. They may also include gas processing (Offshore Technology, 2009).

Fluid Catalytic Cracking Unit (FCCU)

The refining process of breaking down the larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules. Catalytic cracking is accomplished by the use of a catalytic agent and is an effective process for increasing the yield of gasoline from crude oil (EIA).

Fluid Coking Unit (FCU)

A thermal cracking process utilizing the fluidized-solids technique to remove carbon (coke) for continuous conversion of heavy, low-grade oils into lighter products (EIA).

Fluorinated Greenhouse Gas

Sulfur hexafluoride (SF_6), nitrogen trifluoride (NF_3), and any fluorocarbon except for controlled substances as defined at 40 CFR Part 82 Subpart A. In addition to SF_6 and NF_3, "fluorinated GHG" includes but is not limited to any hydrofluorocarbon, any perfluorocarbon, any fully fluorinated linear, branched or cyclic alkane, ether, tertiary amine or aminoether, any perfluoropolyether, and any hydrofluoropolyether (EPA, 2006).

Fossil Fuel

Coal, oil, and other natural gas derived from decomposed organic material.

Fuel Gas (Still Gas)

Gas generated at a petroleum refinery, petrochemical plant, or similar industrial process unit, and that is combusted separately or in any combination with any type of gas. This definition does not include natural gas used as a fuel.

Fugitive Emissions

Unintentional releases from piping components and equipment leaks at sealed surfaces, as well as from underground pipeline leaks. Fugitive emissions also include non-point evaporative sources such as from wastewater treatment, pits, and impoundments. (*Compendium*, Section 3.2.3)

Gas/Diesel Oil

Gas oils are obtained from the lowest fraction from atmospheric distillation of crude oil, while heavy gas oils are obtained by vacuum redistillation of the residual from atmospheric distillation. Gas/diesel oil distils between 180ºC and 380ºC. Several grades are available depending on uses: diesel oil for diesel compression ignition (cars, trucks, marine, etc.), light heating oil for industrial and commercial uses, and other gas oil including heavy gas oils which distil between 380ºC and 540ºC and which are used as petrochemical feedstocks (IEA).

Gaseous Fuel

A material that is in the gaseous state at standard atmospheric temperature and pressure conditions and that is combusted to produce heat and/or energy.

Gas Processing Plant

An installation that processes natural gas to recover natural gas liquids (condensate, natural gasoline and liquefied petroleum gas) and sometimes other substances such as sulfur. A gas processing plant is also known as a natural gas processing plant (Schlumberger).

Gas/Oil Ratio (GOR)

The ratio of produced gas to produced oil (Schlumberger).

Gathering Lines

The pipes used to transport oil and gas from a field to the main pipeline in the area (Schlumberger).

Gathering System

The flowline network and process facilities that transport and control the flow of oil or gas from the wells to a main storage facility, processing plant or shipping point. A gathering system includes pumps, headers, separators, emulsion treaters, tanks, regulators, compressors, dehydrators, valves and associated equipment. There are two types of gathering systems, radial and trunk line. The radial type brings all the flowlines to a central header, while the trunk-line type uses several remote headers to collect fluid. The latter is mainly used in large fields. The gathering system is also called the collecting system or gathering facility (Schlumberger).

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_2, for a specified time period. As the reference gas, CO_2 has a GWP value of 1. GWPs for common GHGs can be found in Table 3-1 (EIA, 2008).

Greenhouse Gas (GHG)

Gaseous constituents of the atmosphere, both natural and anthropogenic, that absorb and emit radiation at specific wavelengths within the spectrum of infrared radiation emitted by the Earth's surface, the atmosphere and clouds. This property causes the greenhouse effect. Water vapor (H_2O), carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4) and ozone (O_3) are the primary GHGs in the earth's atmosphere. Moreover, there are a number of entirely human-made greenhouse gases in the atmosphere, such as the halocarbons and other chlorine and bromine-containing substances, dealt with under the Montreal Protocol. Besides CO_2, N_2O and CH_4, the Kyoto Protocol deals with the GHGs sulfur hexafluoride, hydrofluorocarbons, and perfluorocarbons (IPCC).

Heating Value

The amount of energy released when a fuel is burned completely. See also HHV and LHV (IPIECA, 2003).

Heavy Crude Oil

A category of crude oil characterized by relatively high viscosity, a higher carbon-to-hydrogen ratio, and a relatively higher density. API Report 4638, *Calculation Workbook For Oil and Gas Production Equipment Fugitive Emissions*, designates heavy crude as having an API gravity of less than 20° (API, 1996).

Higher Heating Value (HHV)

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. Also referred to as Gross Calorific Value (*Compendium*, Section 3.6.3).

Hydrocarbon

A naturally occurring organic compound comprising hydrogen and carbon. Hydrocarbons can be as simple as methane (CH_4), but many are highly complex molecules, and can occur as gases, liquids or solids. The molecules can have the shape of chains, branching chains, rings or other structures. The most common hydrocarbons are natural gas, oil and coal (Schlumberger).

Hydrofluorocarbon (HFC)

Halocarbons containing only hydrogen, fluorine and carbon atoms. Because HFCs contain no chlorine, bromine, or iodine, they do not deplete the ozone layer. Like other halocarbons, they are potent greenhouse gases (IPCC, 2006).

Indirect Emissions

The release of GHG 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 or steam) (IPIECA, 2003).

Industrial Boiler

Source Classification Codes (SCCs) most applicable to the Oil and Natural Gas Industry include: 1-02-004-01/02/03/04/05 (distillate fuel fired units), 1-02-005-01/02/03/04/05 (residual fuel fired units), 1-02-006-01/02/03/04 (natural gas fired units), 1-02-010-01/02/03 (liquefied petroleum gas fired units), and 1-02-007-01/04/07/10/99 (process gas fired units). According to 40 CFR 63.7575 (December 6, 2006), an *Industrial boiler* means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity. A previous edition (4th edition) of AP-42 defined a natural gas fired large industrial boiler as a boiler with a heat input capacity of greater than 100 MMBtu/hr (EPA, 1985 to 1993). The same edition of AP-42 also defined a natural gas fired small industrial boiler and a liquefied petroleum gas fired industrial boiler as a boiler with a heat input capacity between 10 to 100 MMBtu/hr (EPA, 1985 to 1993).

Injection Gas

Gas injected into a formation to maintain or restore reservoir pressure. Other reasons for gas injection are gas-lift operations, cycling in gas-condensate reservoirs or storing gas (Schlumberger).

Internal Combustion Engines

An engine that 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 (EIA; Hyne, 1991).

Kimray Pump

A specific type of gas-powered glycol circulation pumps. These pumps use the high pressure of the rich glycol from the absorber to power pistons that pump the low pressure, lean glycol from the regenerator. The pump configuration pulls additional gas from the absorber along with the rich glycol. This gas is emitted through the dehydrator vent stack along with the methane absorbed in the rich glycol stream (Shires and Harrison, 1996).

Lower Heating Value (LHV)

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). Also referred to as Net Calorific Value (*Compendium*, Section 3.6.3).

Light Crude Oil

A category of crude oil characterized by relatively low viscosity, a lower carbon-to-hydrogen ratio, and a relatively lower density. API Report 4638, *Calculation Workbook For Oil and Gas Production Equipment Fugitive Emissions*, designates light crude as having an API gravity of greater than 20° (API, 1996). EPA's *Protocol for Equipment Leak Emission Estimates* defines light crude as material in a liquid state in which the sum of the concentration of individual constituents with a vapor pressure over 0.3 kilopascals (kPa) at 20 ^{o}C is greater than or equal to 20 weight percent. (EPA, 1995).

Liquefied Natural Gas (LNG)

Natural gas, mainly methane and ethane, which has been liquefied at cryogenic temperatures. This process occurs at an extremely low temperature and a pressure near the atmospheric pressure (Schlumberger).

Liquefied Petroleum Gas (LPG)

A group of hydrocarbon-based gases derived from crude oil refining or natural gas fractionation. They include ethane, ethylene, propane, propylene, normal butane, butylene, isobutane, and isobutylene. For convenience of transportation, these gases are liquefied through pressurization (EIA, 2008).

Live Crude Oil

Crude oil containing dissolved gas in solution that may be released from solution at surface conditions. Also referred to as unstabilized crude oil (Schlumberger).

Loading Emissions

The hydrocarbon vapors residing in “empty” cargo tanks that are displaced to the atmosphere by liquids being loaded into the tanks.

Lubricants

Substances used to reduce friction between bearing surfaces, or incorporated into other materials used as processing aids in the manufacture of other products, or used as carriers of other materials. Petroleum lubricants may be produced either from distillates or residues. Lubricants include all grades of lubricating oils, from spindle oil to cylinder oil to those used in greases (EIA, 2008).

Material Balance

An expression for conservation of mass governed by the observation that the amount of mass leaving a control volume is equal to the amount of mass entering the volume minus the amount of mass accumulated in the volume (Schlumberger).

Meter and Regulation Station (M&R Station)

A facility whose purpose is to measure the volume of gas passing through a pipeline. A regulation station is a facility whose purpose is to regulate the pressure of gas passing through a pipeline to a set level (CAPP, 2004).

Methane (CH_4)

The lightest and most abundant of the hydrocarbon gases and the principal component of natural gas (Schlumberger). 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 (IPCC, 2006).

Miscellaneous Petroleum Products

Includes all refined petroleum products not classified elsewhere. This definition includes petrolatum lube refining by-products (aromatic extracts and tars) absorption oils, ram-jet fuel, petroleum rocket fuels, synthetic natural gas feedstocks, and specialty oils.

Mobile Combustion Sources

Engines providing the motive power for vehicles or marine vessels used in the transport of feedstock or product, construction or maintenance equipment, or in the work-related transport of company personnel.

Natural Gas

A naturally occurring mixture of hydrocarbons and varying quantities of non-hydrocarbons that exists either in the gaseous phase or in solution with crude oil in natural underground reservoirs (API, 1988).

Natural Gas Liquids

Components of natural gas that are liquid at surface in field facilities or in gas-processing plants. Natural gas liquids can be classified according to their vapor pressures as low (condensate), intermediate (natural gasoline) and high (liquefied petroleum gas) vapor pressure. Natural gas liquids include propane, butane, pentane, hexane and heptane, but not methane and ethane, since these hydrocarbons need refrigeration to be liquefied. The term is commonly abbreviated as NGL (Schlumberger).

Natural Gasoline

A term used in the gas processing industry to refer to a mixture of liquid hydrocarbons (mostly pentanes and heavier hydrocarbons) extracted from natural gas with a vapor pressure intermediate between condensate and liquefied petroleum gas. It includes isopentane (Schlumberger).

Natural Gas Processing Facilities

A facility designed (1) to achieve the recovery of natural gas liquids from the stream of natural gas which may not have been processed through lease separators and field facilities, and (2) to control the quality of the natural gas to be marketed (API, 1988).

Natural Gas Products

Products produced for consumers from natural gas processing facilities including, but not limited to, ethane, propane, butane, iso-butane, and pentanes-plus (Hyne, 1992; Schlumberger).

Non-Associated Gas

Natural gas that is not in contact with oil in a subsurface reservoir. Non-associated gas is usually dry gas and is in contrast to associated or dissolved gas (e.g., gas well or unassociated gas) (Hyne, 1991).

Non-Point Sources

A type of emission that includes evaporative sources, such as from wastewater treatment, pits, impoundments, and mine tailing pond surface emissions (*Compendium*, Section 6.0).

Oil/Water Separator

Equipment installed usually at the entrance to a drain, which removes oil and grease from water flows entering the drain. Equipment includes but not limited to gravity separators or ponds and air flotation systems. This definition specifically excludes sumps and storm water ponds (API, 1988).

Open-ended Valve or Lines (OELs)

Any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid and one side open to atmosphere, either directly or through open piping.

Operator

The person, firm, corporation, proprietor or lessee, or any other organization or entity employed by the owners to conduct operations (API, 1988; MMS 2006).

Owner

A word used to designate the company, person, or entity that specifies the type of inspection or testing to be conducted and has the authority to order it performed (API, 1988).

Petrochemicals

The manufacture, distribution, and marketing of chemical products derived from oil and gas (IPIECA, 2003).

Petroleum

A complex mixture of naturally occurring hydrocarbon compounds found in rock. Petroleum can range from solid to gas, but the term is generally used to refer to liquid crude oil. Impurities such as sulfur, oxygen and nitrogen are common in petroleum. There is considerable variation in color, gravity, odor, sulfur content and viscosity in petroleum from different areas (Schlumberger).

Petroleum Coke

A solid residue high in carbon content and low in hydrogen that is the final product of thermal decomposition in the condensation process in cracking. This product is reported as marketable coke or catalyst coke. The conversion is 5 barrels (of U.S. 42 gallons each) per short ton. Coke from petroleum has a heating value of 6.024 million Btu per barrel (EIA).

Pigging

A procedure of forcing a solid object through a pipeline for the purposes of displacing or separating fluids, and cleaning or inspecting the line (Schlumberger).

Piston Chemical Injection Pump (CIP)

There are two different types of piston CIPs. Both are a small positive displacement, reciprocating unit designed to inject precise amounts of chemicals into process streams. There are two different types. The barrel-type piston pump consists of a cylindrical piston-plunger assembly where the movement of the larger-diameter piston provides the force needed to move the plunger. Another type of piston pump observed at sites in California use a horizontal plunger to operate a gear mechanism that drives the plunger (Shires, 1996).

Pneumatic Device

A mechanical device operated by some type of compressed gas. In the oil and natural gas industry, many devices, especially for instruments and valves, are powered by natural gas (Shires and Harrison, 1996). They may also be powered by air pressure (EIA).

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 (Williamson, Hall, and Harrison, 1996).

Pressure Relief Device (or Pressure Relief Valve or Pressure Safety Valve)

A valve that opens at a preset pressure to relieve excessive pressures within a vessel or line; also called a relief valve, safety valve, or pop valve (API, 1988).

Process Gas

Any gas generated by an industrial process (e.g. petroleum refining).

Process Vents

A subcategory of point sources that produce emissions as a result of some form of chemical transformation or processing step.

Pump Seals

Any seal on a pump drive shaft used to keep methane and/ or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Purge

The process of clearing air from equipment by displacing it with natural gas; in the process, some purge gas is emitted as the air is evacuated from the equipment (Shires, 1996).

Reciprocating Compressor

A piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the drive shaft (CAPP, 2004).

Reciprocating Compressor Rod Packing

A series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere (Hyne, 1991).

Reciprocating Engine

An engine that uses the up and down motion of pistons in a cylinder to drive a crankshaft (Hyne, 1991).

Refinery Fuel Gas (still gas)

Any form or mixture of gases produced in refineries by distillation, cracking, reforming, and other processes. The principal constituents are methane, ethane, ethylene, normal butane, butylene, propane, propylene, etc. Still gas is used as a refinery fuel and a petrochemical feedstock (EIA, 2008).

Regasification

The process by which LNG is heated, converting it into its gaseous state (LNG, 2006).

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 (Hyne, 2006).

Renewable Energy

Energy taken from sources that are inexhaustible (e.g., wind, water, solar, geothermal, and biofuels) (IPIECA, 2003).

Residual Fuel Oils

A general classification for the heavier oils, known as No. 5 and No. 6 fuel oils, that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations. No. 5, a residual fuel oil of medium viscosity, is also known as Navy Special and is used in steam-powered vessels in government service and inshore power plants. No. 6 fuel oil includes Bunker C fuel oil and is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes (EIA).

Source

Any physical unit or process that releases greenhouse gases into the atmosphere (IPIECA, 2003).

Sour Gas

A general term for those gases that are acidic either alone or when associated with water. See also acid gas (Schlumberger).

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 external combustion devices such as boilers and heaters, and internal combustion devices such as turbines and engines.

Steam Reforming

A catalytic process that produces hydrogen by splitting water. This involves a reaction between natural gas or other light hydrocarbons and steam. The result is a mixture of hydrogen, carbon monoxide, carbon dioxide, and water (Hydrocarbons-Technology, 2009).

Sulfur Recovery Unit

A process unit that recovers elemental sulfur from gases that contain reduced sulfur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

Ton

A short ton is equivalent to 2,000 US pounds.

Tonne

A metric tonne is equivalent to 1,000 kg and 2,204.62 US pounds. Metric tonnes are the standard convention for reporting greenhouse gas equivalent emissions used by IPCC and other international climate change organizations (Hyne, 1991; LNG, 2006).

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).

Total Organic Compound (TOC)

Includes VOCs, semi-volatile organic compounds, and condensable organic compounds. Emissions of VOCs are primarily characterized by the criteria pollutant class of unburned vapor phase hydrocarbons. Unburned hydrocarbon emissions can include essentially all vapor phase organic compounds emitted from a combustion source. These are primarily emissions of aliphatic, oxygenated, and low molecular weight aromatic compounds which exist in the vapor phase at flue gas temperatures. These emissions include all alkanes, alkenes, aldehydes, carboxylic acids, and substituted benzenes (e.g., benzene, toluene, xylene, and ethyl benzene). 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 [EPA, 1998(a)].

Turbine

A motor consisting of a rotating shaft with propellers or blades that are driven by a fluid (Hyne, 1991).

Uncertainty

The range around a reported value in which the true value can be expected to fall (IPIECA, 2003).

Unfinished Oils

All oils requiring further processing, except those requiring only mechanical blending. Unfinished oils are produced by partial refining of crude oil and include naphthas and lighter oils, kerosene and light gas oils, heavy gas oils, and residuum (EIA).

Upstream

Operations involving the exploration, development, and production of oil and gas. May also include gas processing (IPIECA, 2003).

Utility Boiler

Refers to the following Source Classification Codes (SCC) for Electric Generation units: 1-01-004-01/04/05/06 (distillate fuel fired units), 1-01-005-01/04/05 (residual fuel fired units), 1-01-006-01/02/04 (natural gas fired units), 1-01-010-01/02/03 (liquefied petroleum gas fired units), and 1-01-007-01/02/03/04/07/12 (process gas fired units). A previous edition (4th edition) of AP-42 defined a natural gas utility boiler as a boiler with a heat input capacity of greater than 100 MMBtu/hr (EPA, 1985 to 1993).

Vapor Recovery Unit

A system used to recover vapors formed inside completely sealed crude oil or condensate tanks (Schlumberger).

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 photochemical reactions (40 CFR 51.100, June 23, 2009). 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 acetone, methane, ethane, methylene chloride, methyl chloroform, perchloroethylene, methylated siloxanes, many chlorofluorocarbons, certain classes of perfluorocarbons and hydrofluorethers, and some fluorinated alkenes, ethers and amines.

Weathered Crude Oil

Crude oil which has reached atmospheric pressure and has had the volatile CH_4 flashed off.

Well Completion

A term used to describe the assembly of down hole tubulars and equipment required to enable safe and efficient production from an oil or gas well (Schlumberger).

Wet Natural Gas or Wet Gas

(1) A gas containing water, or a gas which has not been dehydrated. (2) A term synonymous with rich gas, i.e., a gas from which products have not been extracted (GPSA, 1987).

Workover

Operations on a producing well to restore or increase production. A workover may be done to wash out sand, acidize, hydraulically fracture, mechanically repair, or for other reasons (API, 1988).

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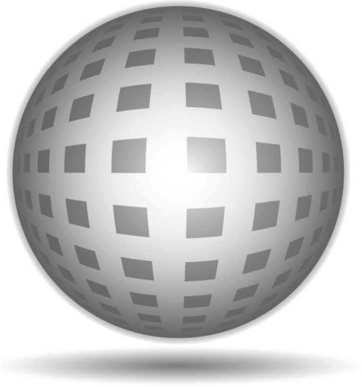
ACRONYMS



ACRONYMS AND ABBREVIATIONS

AF	activity factor
AGA	American Gas Association
AGR	acid gas removal
API	American Petroleum Institute
AR4	Fourth Assessment Report
ARPEL	Regional Association of Oil and Natural Gas Companies in Latin America and the Caribbean
ASTM	American Society of Testing and Materials
bbl	barrels
BOD	Biological Oxygen Demand
BOE	barrels of oil equivalent
BTU	British Thermal Units
ºC	Celsius
C	carbon
C_2H_6	ethane
CAC	Criteria Air Contaminant
CAPP	Canadian Association of Petroleum Producers
CARB	California Air Resource Board
CBM	coal bed methane
CCS	carbon capture and geological storage

CCU	catalytic cracking unit
CEC	California Energy Commission
CF	fraction of carbon in the feedstock
CH_4	methane
CHIEF	Clearinghouse for Inventories and Emission Factors
CHP	Combined Heat and Power
CIPs	chemical injection pumps
cm^3	cubic centimeter
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
COD	Chemical Oxygen Demand
CONCAWE	Conservation of Clean Air and Water in Europe
COP	Conference of Parties
Cp/Cv	gas specific heat ratio
CRR	catalyst regeneration rate
CRUs	catalytic reformer units
DEA	diethanol amine
Defra	Department for Environment, Food and Rural Affairs
DI&M	directed inspection and maintenance
DOE	U.S. Department of Energy
E&P	exploration and production

EF	emission factor
EEA	European Environment Agency
EIA	Energy Information Administration
EIIP	Emission Inventory Improvement Program
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
ESB	emergency blowdowns
ESD	emergency shutdowns
ETS	Emissions Trading Scheme
EU	European Union
EUB	Alberta Energy Utility Board
ºF	Fahrenheit
FCC	fluid catalytic cracking
FCCUs	fluid catalytic cracking units
FPSO	floating production storage and offloading
ft^3	cubic feet
gal	gallon
GOR	gas-to-oil ratio
GPR	gas production rate
GPSA	Gas Processors Suppliers Association
GHG	greenhouse gas
GRI	Gas Research Institute
GTI	Gas Technology Institute

GWP	global warming potential
H_2	hydrogen
H_2O	water
H_2S	hydrogen sulfide
HD	heavy duty
HFCs	hydrofluorocarbons
HHV	higher heating value
HNO_3	nitric acid
IC	internal combustion
IEA	International Energy Agency
IELE	Institute for Energy Law and Enterprise
IFC	International Flare Consortium
INGAA	Interstate Natural Gas Association of America
IPCC	Intergovernmental Panel on Climate Change
IPIECA	International Petroleum Industry Environmental Conservation Association
ISO	International Organization for Standardization
K	Kelvin
kg	kilogram
kPaa	Kilo-Pascals absolute
L	liter
lb	pound
LDAR	leak detection and repair
LHV	lower heating value

LNG	liquefied natural gas
m^3	cubic meters
M&R	meter and pressure regulating
MMS	Minerals Management Services
MMT	million metric tones
MMTCE	million metric tones of carbon equivalent
MOVES	Motor Vehicle Emission Simulator
MPMS	Manual of Petroleum Measurement Standards
MW	molecular weight
N_2O	nitrous oxide
NCASI	National Council for Air and Stream Improvement
NERC	North American Electric Reliability Council
NMVOC	non-methane volatile organic compounds
ODSs	ozone-depleting substances
OECD	Organization for Economic Co-operation and Development
OGP	Association of Oil and Gas Producers
PFCs	perfluorocarbons
PRV	pressure relief valves
PSI	Pipeline Systems Incorporated
psia	pounds per square inch
ºR	Rankine
RVP	Reid Vapor Pressure
SAR	Second Assessment Report

scf	standard cubic feet
scm	standard cubic meters
SF_6	sulfur hexafluoride
SI	International System of Units
SRUs	Sulfur Recovery Units
TAR	Third Assessment Report
TCR	The Climate Registry
THC	total hydrocarbon
TOC	total organic compound
UKOOA	Offshore Operators Association Limited
UNFCCC	United Nations Framework Convention on Climate
USC	U.S. customary units
V	volume
VBE	The Vasquez-Beggs Equation
VCU	vapor combustion units
VOC	volatile organic compounds
VR	vent rate
WRI/WBCSD	World Resources Institute/World Business Council for Sustainable Development

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