

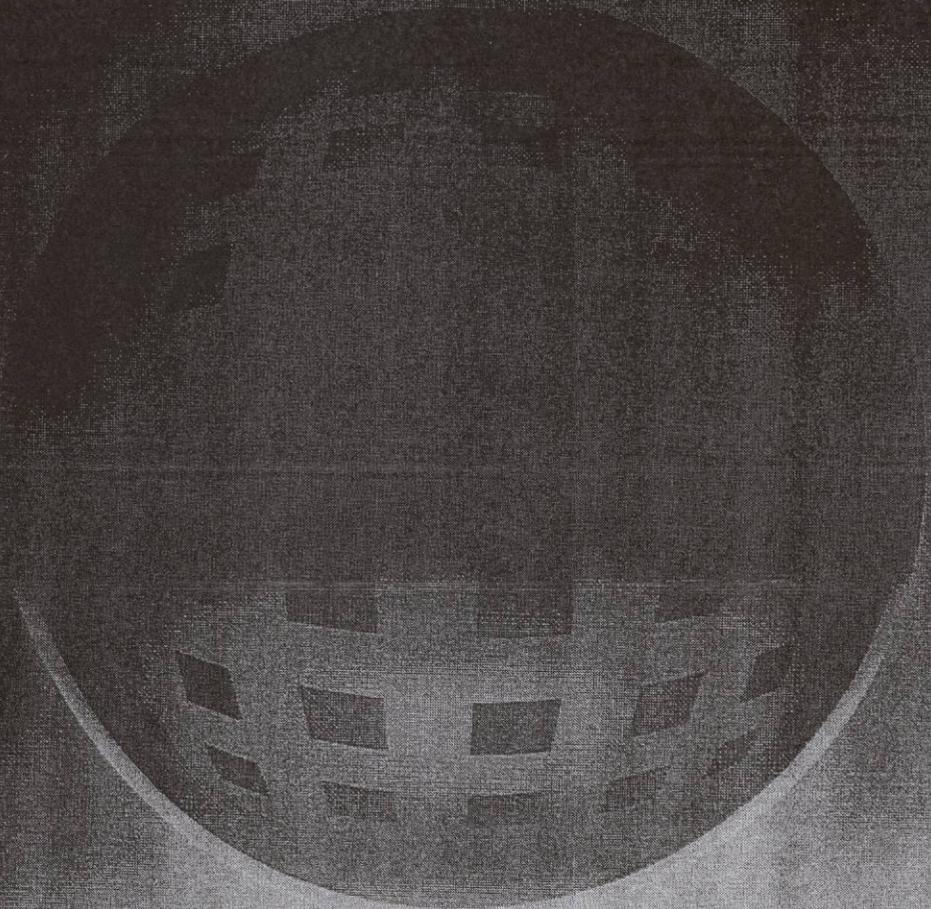
EXHIBIT 13



AMERICAN PETROLEUM INSTITUTE

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

AUGUST 2009



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.

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 operations¹. 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 (CO₂), methane (CH₄), nitrous oxide (N₂O), hydrofluorocarbons (HFCs), perfluorocarbons

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 (SF₆) 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 (CO₂, CH₄, N₂O, HFCs, PFCs, and SF₆) 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 CO₂, CH₄, and N₂O 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:
<i>Direct Emissions</i>	
Combustion Sources	
<i>Stationary Devices</i>	Boilers, heaters, furnaces, reciprocating internal combustion engines and turbines, flares, incinerators, and thermal/catalytic oxidizers
<i>Mobile Sources</i>	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}	
<i>Process Emissions</i>	Hydrogen plants, amine units, glycol dehydrators, fluid catalytic cracking unit and reformer regeneration, and flexi-coker coke burn
<i>Other Venting</i>	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
<i>Maintenance/Turnaround</i>	Decoking of furnace tubes, well unloading, vessel and gas compressor depressurizing, compressor starts, gas sampling, and pipeline blowdowns
<i>Non-Routine Activities</i>	Pressure relief valves, PCVs, fuel supply unloading valves, and emergency shut-down devices
Fugitive Sources^d	
<i>Fugitive Emissions</i>	Valves, flanges, connectors, pumps, compressor seal leaks, and catadyne heaters
<i>Other Non-Point Sources</i>	Wastewater treatment and surface impoundments
Indirect Emissions	
<i>Electricity</i>	Off-site generation of electricity for on-site power
<i>Steam/Heat</i>	Off-site generation of hot water and steam for on-site heat
<i>District Cooling</i>	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 eGrid² 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.

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 CH₄ 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]

American Petroleum Institute (API). *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry*, April 2004.

http://www.api.org/ehs/climate/new/upload/2004_COMPENDIUM.pdf, accessed May 1, 2009.

American Petroleum Institute (API). *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry*, Errata, February 2005.

<http://ghg.api.org/documents/CompendiumErrata205.pdf>, accessed May 1, 2009.

American Petroleum Institute (API), and International Petroleum Industry Environmental Conservation Association (IPIECA). *Greenhouse Gas Emissions Estimation and Inventories Addressing Uncertainty and Accuracy*, Summary Report, An IPIECA / API Workshop, Brussels, Belgium, January 16, 2007.

http://www.ipieca.org/activities/climate_change/downloads/publications/Uncertainty.pdf, accessed May 1, 2009.

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International Petroleum Industry Environmental Conservation Association (IPIECA), International Association of Oil and Gas Producers (OGP), and American Petroleum Institute (API). *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions*, December 2003.

http://www.ipieca.org/activities/climate_change/downloads/publications/ghg_guidelines.pdf, accessed May 1, 2009.

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.

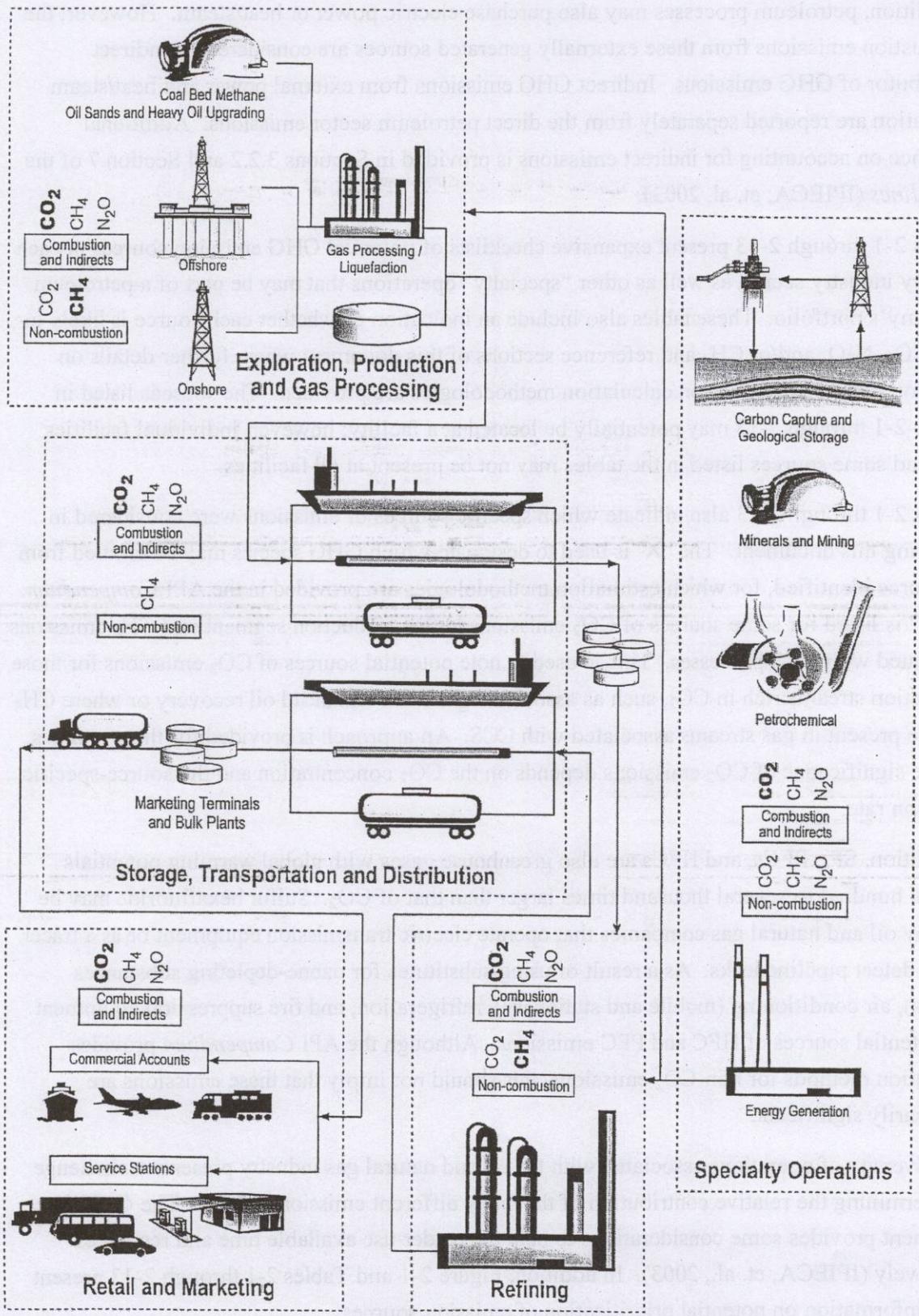


Figure 2-1. Oil and Natural Gas Industry Schematic of GHG Emissions

Graphics09 PPT/AP/PI/PI Figure 2_09.1h11

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 CO₂, N₂O, and/or CH₄ 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 CO₂ emissions in the production segment and CH₄ emissions associated with CCS processes. This is used to note potential sources of CO₂ emissions for those production streams rich in CO₂, such as associated gas from enhanced oil recovery or where CH₄ may be present in gas streams associated with CCS. An approach is provided for these sources, but the significance of CO₂ emissions depends on the CO₂ concentration and the source-specific emission rate.

In addition, SF₆, PFCs, and HFCs are also greenhouse gases with global warming potentials several hundred to several thousand times larger than that of CO₂. 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-CO₂ 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.

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

COAL BED METHANE PRODUCTION	CO ₂	N ₂ O	CH ₄	Section
<i>VENTED SOURCES – Maintenance/Turnarounds</i>				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
<i>VENTED SOURCES – Non-routine Activities</i>				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
<i>FUGITIVE SOURCES</i>				6.0
Equipment component leaks			X	6.1
Wastewater treatment	X		X	6.2
Air conditioning/refrigeration				6.3

Footnotes:

X Indicates if CO₂, CH₄, or N₂O 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 CH₄. 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, CO₂) 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 ₂ O	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 CO₂, CH₄, or N₂O emissions may result from the source.

*Emission estimation approach is provided, but only applicable to CO₂-rich streams. Significance of these sources depends on the CO₂ 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 CH₄ emissions. Fugitive equipment leaks are also a source of CH₄ emissions. Combustion sources, such as boilers, heaters, engines, and flares result in CO₂ emissions, as well as smaller quantities of N₂O and CH₄ 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 CO₂ gas stream, transport the CO₂ to a storage location, and inject the CO₂ into a geological formation¹ for long-term isolation from the atmosphere.

In the capture step, CO₂ is separated from other gaseous products, compressed to facilitate efficient transportation, and when necessary, conditioned for transport (e.g., by dehydration). Captured CO₂ is then transported from the point of capture to the storage site. Pipelines are the most common method for transporting CO₂; however, bulk transport of CO₂ by ship, truck, and rail occurs on a much smaller scale. Once at the storage site, the CO₂ 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) CO₂ and CH₄. 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 CO₂ 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 CO₂ co-produced with oil and/or gas, and enhanced hydrocarbon recovery operations.

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

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

NATURAL GAS TRANSMISSION AND DISTRIBUTION	CO ₂	N ₂ O	CH ₄	Section
<i>COMBUSTION SOURCES – Stationary Devices</i>				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
<i>COMBUSTION SOURCES – Mobile Sources</i>				4.8
Other company vehicles	X	X	X	4.8
Planes/helicopters	X	X	X	4.8
<i>INDIRECT SOURCES</i>				7.0
Electricity imports	X	X	X	7.1
Process heat/steam imports	X	X	X	7.1
<i>VENTED SOURCES – Process Vents</i>				5.0
Dehydration processes			X	5.1
Dehydrator Kimray pumps			X	5.1
Gas treatment processes	X		X	5.1
<i>VENTED SOURCES – Other Venting</i>				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
<i>VENTED SOURCES – Maintenance/Turnarounds</i>				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
<i>VENTED SOURCES – Non-routine Activities</i>				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	CO₂	N₂O	CH₄	Section
<i>FUGITIVE SOURCES</i>				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 CO₂, CH₄, or N₂O 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 CO₂. When these combustion sources are fired with natural gas or refinery fuel gas, there may also be trace quantities of unburned CH₄ emissions.

The natural gas system, and potentially the refinery fuel gas system, are the only process streams within the refinery with potentially significant CH₄ concentrations. Fugitive CH₄ 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.

² Methane emissions data gathering and analyses were conducted for two refineries: a small simple refinery and a larger, more complex refinery. The estimated CH₄ 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.

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:

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

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 (cm³)/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 tonnes¹ per unit of activity, where the unit of activity is expressed in both the International System of Units (SI units) and

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 CO₂.

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 CO₂ 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 N₂O 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 (CH₄ and potentially CO₂) 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 CO₂, CH₄, and N₂O 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 (CO₂, CH₄, N₂O, SF₆, 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 CO₂-rich field gas. For these non-combustion sources, the potential for emitting CO₂ will depend on the CO₂ concentration associated with the emission source, as well as design and operating practices at facilities. The concentration of CO₂ 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 CO₂ emissions from CCS operations may be more significant than those from natural gas systems, but still small compared to CO₂ 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 N₂O may be formed from reactions between nitrogen and oxygen that occur during stationary or mobile source combustion. The quantity of N₂O 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 N₂O 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, N₂O emissions can be more than 2% of the total facility GHG emissions inventory, on a CO₂e basis. As indicated in Section 8, N₂O emissions contribute less than 1% of a refinery's overall GHG inventory (on a CO₂e 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 (CO₂e), 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 CO₂ 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 CH₄ and N₂O, the time interval chosen can have a significant impact because there is a large difference between the lifetime of CH₄ and N₂O (approximately 12.2 years and 120 years, respectively) and the effective lifetime of CO₂ (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 CO₂. 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.

² For example, using the recommended GWP and selecting a time period of 50 years, the CH₄ 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 ₂ O	310	298
<i>Hydrofluorocarbons (HFCs)</i>		
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
<i>Perfluorinated compounds</i>		
CF ₄	6,500	7,390
C ₂ F ₆	9,200	12,200
C ₃ F ₈	7,000	8,830
c-C ₄ F ₈	8,700	10,300
C ₄ F ₁₀	7,000	8,860
C ₅ F ₁₂	7,500	9,160
C ₆ F ₁₄	7,400	9,300
C ₁₀ F ₁₈		>7,500
NF ₃		17,200
SF ₆	23,900	22,800
SF ₅ CF 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
<i>Fluorinated ethers</i>		
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-569s12 (HFE-7200)		59
HFE-43-10pccc124 (H-Galden 1040x)		1,870
HFE-236ca12 (HG-10)		2,800
HFE-338pcc13 (HG-01)		1,500
<i>Perfluoropolyethers</i>		
PFPME		10,300
<i>Hydrocarbons and other compounds – Direct Effects</i>		
Dimethylether		1
Methylene chloride		8.7
Methyl chloride		13

Footnotes and Sources:

^a The GWP of CH₄ 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 CO₂ 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 CO₂, CH₄, N₂O, HFCs, PFCs, and SF₆ 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 CO₂e. 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 CO₂e or Carbon Equivalents for final summation. Although any units of mass may be used to convert GHG

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 $\pm 10\%$ 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 $\pm 4\%$ 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 ₂ S	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 ₂ H ₆	12.5	4	4.7	4
C ₃ H ₈	5.1	4	1.2	4
C ₄ H ₁₀	3.7	4	0.5	4
C ₅ H 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	2,184,000×10 ⁶ Btu/yr	11.2
Hot oil heaters	Processed Gas	2	0	80×10 ⁶ Btu/hr	10	8400 hr/yr	5	1,344,000×10 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 ×10 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	292,000×10 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	292,000×10 ⁶ scf/yr 3.5 mole% CO ₂	10
Outlet	N/A		N/A	622×10 ⁶ scf/day 2.0 mole% CO ₂	10	365 day/yr	0	227,030×10 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	N/A		4 compressors / turbines ^d	0
Compressor blowdowns	N/A	2	0	N/A	N/A	N/A		2 compressors ^d	0
Processing maintenance blowdowns	N/A		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	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 (±%)
<i>Fugitive Sources</i>									
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
<i>Indirect Sources</i>									
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% CH₄, 2% CO₂, and negligible H₂S.
- ^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 – CO₂ Emissions

Natural Gas Combustion CO₂ Emissions

The first step in calculating CO₂ 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:

$$V = \left[\left(2 \text{ boilers} \times \frac{130 \times 10^6 \text{ Btu}}{\text{boiler}} \times \frac{8,400 \text{ hr}}{\text{yr}} \right) + \left(2 \text{ heaters} \times \frac{80 \times 10^6 \text{ Btu}}{\text{heater}} \times \frac{8,400 \text{ hr}}{\text{yr}} \right) \right] \times \frac{\text{scf}}{1,251 \text{ Btu}} = 2,820 \times 10^6 \text{ scf/yr}$$

Turbines:

$$V_{\text{ICOM}} = \left[\left(2 \text{ turbines} \times \frac{36,300 \text{ hp}}{\text{turbine}} \times 0.46 \text{ load} \times \frac{8,078 \text{ Btu}}{\text{hp-hr}} \times \frac{8,665 \text{ hr}}{\text{yr}} \right) + \left(2 \text{ turbines} \times \frac{35,900 \text{ hp}}{\text{turbine}} \times 0.46 \text{ load} \times \frac{8,078 \text{ Btu}}{\text{hp-hr}} \times \frac{8,665 \text{ hr}}{\text{yr}} \right) \right] \times \frac{\text{scf}}{1,251 \text{ Btu}} = 3,717 \times 10^6 \text{ scf/yr}$$

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:

$$\text{MW}_{\text{Mixture}} = \left[\begin{array}{l} (1.13 \times 34.08) + (3.5 \times 44.01) + (2.39 \times 28.01) \\ + (70 \times 16.04) + (12.5 \times 30.07) + (5.1 \times 44.10) \\ + (3.7 \times 58.12) + (0.76 \times 72.15) + (0.92 \times 86.18) \end{array} \right] \div 100 = 23.32 \text{ lb/mole}$$

The individual weight percents are then calculated by rearranging Equation 3-7. The calculation is shown below for CH_4 .

$$\text{Wt. \%}_{\text{CH}_4} = \frac{70 \text{ lbmole CH}_4}{100 \text{ lbmole mixture}} \times \frac{\left(\frac{16.04 \text{ lb CH}_4}{\text{lbmole CH}_4} \right)}{\left(\frac{23.32 \text{ lb mixture}}{\text{lbmole mixture}} \right)} = \frac{0.4814 \text{ lb CH}_4}{\text{lb mixture}} = 48.14 \text{ wt. \% CH}_4$$

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).

$$\text{Wt \% C}_{\text{C}_2\text{H}_6} = \frac{12.01 \text{ lb C}}{\text{lbmole C}} \times \frac{2 \text{ lbmoles C}}{\text{lbmole C}_2\text{H}_6} \times \frac{\text{lbmole C}_2\text{H}_6}{30.07 \text{ lb C}_2\text{H}_6} \times 100\% = 79.9\% \text{ C}$$

After the calculation has been performed for all constituents, the carbon content for the mixture is calculated using Equation 4-10, shown as follows (for produced gas):

$$\text{Wt\%C}_{\text{Mixture}} = \frac{1}{100} \times \sum_{i=1}^{\text{\# components}} (\text{Wt\%}_i \times \text{Wt\%C}_i)$$

$$\begin{aligned} \text{Wt\% C}_{\text{Mixture}} &= \frac{1}{100} \times \left[(1.65 \times 0) + (6.60 \times 28.3) + (2.87 \times 0) + (48.14 \times 74.9) + (16.12 \times 79.9) \right. \\ &\quad \left. + (9.64 \times 81.7) + (9.22 \times 82.7) + (2.35 \times 83.2) + (3.40 \times 83.6) \right] \\ &= 71.03 \text{ Wt\% C} = 0.7103 \text{ lb C/lb fuel} \end{aligned}$$

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 ₂ S	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 ₂ H ₆	12.5	30.07	16.12	4.53	79.9	12.9	4.53
C ₃ H ₈	5.1	44.10	9.64	4.53	81.7	7.88	4.53
C ₄ H ₁₀	3.7	58.12	9.22	4.53	82.7	7.62	4.53
C ₅ H 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	100.0			71.03	2.55
		±2.13%^a					

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 ₂ S	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 ₂ H ₆	4.7	30.07	8.77	5.12	79.9	6.21	5.12
C ₃ H ₈	1.2	44.10	2.91	5.12	81.7	2.38	5.12
C ₄ H ₁₀	0.5	58.12	1.60	5.12	82.7	1.32	5.12
C ₅ H 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	100.0			72.01	4.26
		±3.20%^a					

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.

$$E_{\text{CO}_2} = \frac{(2,820 \times 10^6 + 3,717 \times 10^6) \text{ scf fuel}}{\text{yr}} \times \frac{\text{lbmole}}{379.3 \text{ scf fuel}} \times \frac{18.18 \text{ lb fuel}}{\text{lbmole fuel}} \times \frac{0.7201 \text{ lb C}}{\text{lb fuel}} \\ \times \frac{\text{lbmole C}}{12.01 \text{ lb C}} \times \frac{\text{lbmole CO}_2}{\text{lbmole C}} \times \frac{44.01 \text{ lb CO}_2}{\text{lbmole CO}_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

$$E_{\text{CO}_2} = 375,000 \text{ tonnes CO}_2 / \text{yr}$$

Diesel Combustion

Carbon dioxide emissions from diesel combustion are calculated using the diesel emission factor provided in Table 4-3, assuming an uncertainty of $\pm 10\%$, 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 $\pm 5\%$, based on engineering judgment.

Diesel combustion CO_2 emissions are calculated below.

$$V = \left(2 \text{ pumps} \times \frac{460 \text{ hp}}{\text{pump}} \times 0.87 \text{ load} \times \frac{8,089 \text{ Btu}}{\text{hp-hr}} \times \frac{24 \text{ h}}{\text{yr}} \right) + \\ + \left(2 \text{ pumps} \times \frac{425 \text{ hp}}{\text{pump}} \times 0.92 \text{ load} \times \frac{8,089 \text{ Btu}}{\text{hp-hr}} \times \frac{24 \text{ h}}{\text{yr}} \right) = 307 \times 10^6 \text{ Btu / yr}$$

$$E_{\text{CO}_2} = \frac{307 \times 10^6 \text{ Btu}}{\text{yr}} \times \frac{0.0732 \text{ tonnes CO}_2}{10^6 \text{ Btu}}$$

$$E_{\text{CO}_2} = 22.5 \text{ tonnes CO}_2 / \text{yr}$$

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