Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions

IPIECA

OGP

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International Petroleum Industry Environmental Conservation Association
International Association of Oil and Gas Producers
American Petroleum Institute

Prepared by Battelle

International Petroleum Industry Environmental Conservation Association

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Acknowledgements

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The Joint Industry Task Force formed a Drafting Committee to prepare the *Guidelines.* This committee consists of:

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In developing these *Guidelines*, the Drafting Committee worked under the direction of a Steering Group consisting of Bill Boyle (BP), John Campbell (OGP), Brian Flannery (ExxonMobil), Bob Greco (API), and Richard Sykes (Shell). The Steering Group provided input on policy issues related to the *Guidelines*.

Much of the material contained in these *Guidelines* comes from *the Greenhouse Gas Protocol Initiative,* a multi-stakeholder effort of the World Business Council for Sustainable Development (WBCSD) and the World Resources Institute (WRI). Material from both the first edition of *The Greenhouse Gas Protocol: a corporate accounting and reporting standard* (WRI/WBCSD, 2001) and drafts of selected chapters of the revised version—*The Greenhouse Gas Protocol: a corporate accounting and reporting standard, revised edition* (WRI/WBCSD, 2004)—were used directly or adapted for inclusion[1]. The Drafting Committee wishes to acknowledge the generosity and cooperation of WRI and WBSCD in making the original and revised versions of the *GHG Protocol* available and allowing material from them to be incorporated into these *Guidelines.*

[1] For the sake of brevity, these documents are referred to as the original or revised *Protocol* or *GHG Protocol* within these *Guidelines.*

1. Introduction

Background

As the reporting of greenhouse gas (GHG) emissions becomes more widespread, the need for guidance on how emissions should be accounted for and reported has become apparent. Current approaches vary among the few existing mandatory, governmental GHG reporting programs. Companies also differ in how they voluntarily report their emissions data. This variability in approaches has resulted in a lack of comparability of reported GHG emissions from company to company within specific industrial sectors, as well as a lack of comparability of results from reporting program to reporting program.

The petroleum industry has recognized the need for GHG accounting and reporting guidance that is focused specifically on its operations. To help meet this need, member companies—through the American Petroleum Institute—published the *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* in April 2001 (referred to below as the *Compendium*). These *Guidelines* were then developed to fulfill the need for industry guidance focused specifically on the accounting and reporting of GHG emissions at the facility through the corporate level.

The International Petroleum Industry Environmental Conservation Association (IPIECA), American Petroleum Institute (API), and International Association of Oil and Gas Producers (OGP) jointly initiated the development of these *Guidelines* to promote credible, consistent, and reliable GHG accounting and reporting practices from oil and gas operations . To maximize the acceptance and use of these *Guidelines*, they have been developed with the broad participation of petroleum operators, including those already tracking GHG emissions from their operations. To support the goal of wide acceptance, the *Guidelines* have been designed to strike a balance between flexibility and cost-effectiveness in accounting and reporting and the need for consistency and accuracy in the reported results.

The development of these *Guidelines* proceeded in recognition of the wide range of existing and evolving GHG accounting and reporting guidance. As part of an international effort to bring greater consistency to corporate GHG reporting, the original *GHG Protocol* (WRI/WBCSD, 2001) was developed as a multi-stakeholder effort of the World Business Council for Sustainable Development (WBCSD) and the World Resources Institute (WRI). The *Protocol* was carefully considered in its original and revised form in drafting these *Guidelines,* and the *Guidelines* build upon it. Indeed, much of the material in these *Guidelines*, particularly as it pertains to general accounting and reporting issues, was taken from the original or revised *GHG Protocol*—either directly or with minor modifications. Because the *GHG Protocol* does not focus specifically on the petroleum industry, best practices from it have been supplemented with petroleum industry guidance. The *Guidelines* have been developed with the aim of building upon the *GHG Protocol* and other existing guidance to serve as a model for evolving and future reporting programs that may affect the petroleum industry.

Purpose

The purpose of these *Guidelines* is to promote consistency in the accounting and reporting of petroleum industry GHG emissions. While it is hoped that greater consistency will lead to greater comparability in the emissions information reported by petroleum industry companies, these guidelines are not meant to serve as a guide to industry benchmarking. The levels of greenhouse gas emissions that result from industry operations are highly dependent on the nature of those operations—be they the crude oil processed and products produced by an oil refinery or the geology of the reservoirs from which crude oil and gas are obtained. For this reason, the results obtained by applying these *Guidelines* should not be taken as measures of the inherent GHG emissions efficiency of petroleum industry companies.

As the name implies, the purpose of the *Guidelines* is to provide guidance rather than to prescribe standards. Companies vary in the amount of experience they have in accounting for and reporting GHG emissions. Those that are newer to the process will need some time to implement the recommendations contained in this document. Nevertheless, they may use it to understand the implications of the decisions they make and to help in setting their priorities for establishing their inventories.

Scope

Inventorying of GHG emissions by companies is typically conducted as a "bottom-up" activity by summing emission from individual sources (or emissions from the total consumption of individual fuel types) at a facility to create a facility-wide inventory, aggregating emissions from individual facilities across the company's business units, and summing the business units to create a corporate inventory. These *Guidelines* focus on the accounting of emissions at the facility level and the aggregation and reporting of the results at the corporate level. They do not describe emissions estimation approaches for individual sources, which is the subject of the *Compendium*.

These *Guidelines* have been developed as a complement to the *Compendium.* While the *Compendium* focuses on GHG emissions estimation methodologies for industry sources (how to calculate emissions), the *Guidelines* primarily address GHG accounting and reporting questions faced by the industry (how to report emissions). Together, the *Guidelines* and *Compendium* provide a comprehensive set of guidance for the estimation, accounting, and reporting of petroleum industry GHG emissions. In the broader context of corporate reporting, these *Guidelines* also serve as a complement to the IPIECA and API *Compendium of Sustainability Reporting Practices and Trends for the Oil and Gas Industry* (IPIECA, 2003).

When planning the consolidation of GHG data, it is important to distinguish between GHG *accounting* and GHG *reporting.* GHG accounting concerns the recognition and consolidation of GHG emissions from operations in which a parent company holds an interest, and linking the data to specific operations, sites, geographic locations, business processes and owners. GHG reporting concerns the presentation of GHG data in formats tailored to the needs of various reporting uses.

Many companies have multiple objectives for GHG reporting, including official government reporting, emissions trading schemes, and public reporting. In developing a GHG accounting system, a fundamental consideration is therefore to ensure that the system is capable of meeting a range of reporting requirements. Ensuring that data are collected and recorded at a sufficiently disaggregated level, and capable of being consolidated in various forms, will provide companies with maximum flexibility to meet a range of reporting requirements.

As the material in these *Guidelines* should make clear, companies face a range of options on how they account for and report emissions from the facility to the corporate level. Which approach they take will depend on the intended use of the information they are reporting. Reporting emissions from an individual facility as part of a regulatory program will typically be limited to the direct emissions that occur at the site of the facility, and possibly only emissions from sources that exceed a particular size threshold. Emissions would be reported for the facility as a whole without regard to how emissions may be allocated among the owners. The rules for reporting these emissions will be determined by the specific reporting program. They may or may not correspond either with general industry practice for reporting corporate emissions or the way the company that owns the facility conducts its corporate accounting and reporting. In considering the broad scope of these *Guidelines*, it is important to bear in mind that in many cases the guidance it contains is tailored to specific reporting purposes, and does not necessarily apply for all purposes.

The material in these *Guidelines* is organized into seven chapters:

- Petroleum Industry GHG Accounting and Reporting Principles
- Setting the Boundaries for GHG Emissions Reporting
- Designing an Inventory to Monitor Performance
- Identification of Industry GHG Emissions
- Evaluation of Industry GHG Emissions
- GHG Emissions Reporting
- Inventory Assurance Processes

These chapters are followed by a list of references used in developing the *Guidelines*. A glossary and tables that link the emissions estimation guidance in Chapter 6 to the *Compendium* are provided as appendices.

Chapter 2 describes the overarching principles embodied in the *Guidelines* for accounting and reporting GHG emissions from the petroleum industry. As such, it serves as the basis for the guidance contained in the rest of this report.

Chapter 3 provides guidance on establishing boundaries for the reporting of GHG emissions by companies in the petroleum industry. Since this is an area where companies (and reporting programs) often differ, the *Guidelines* emphasize approaches to promote consistency. In addition, guidance is provided on accounting for emissions that result from operating relationships common in the petroleum industry, such as production sharing arrangements, but which are not typically addressed in general guidance on GHG emissions accounting.

Chapter 4 describes how to design an inventory to monitor performance over time. It provides guidance on selecting a base year or years for emissions. More importantly, it includes guidance on when and how to adjust the base year emissions for changes over time so that performance may be tracked on a consistent basis. It also describes various ways in which petroleum industry companies may track their performance.

Chapter 5 provides guidance on the identification of industry GHG emissions both in terms of the types of gases emitted and the sources of emissions. Chapter 6 covers the quantification of emissions. Much of the guidance in these two chapters is of a general nature, as it is not the intent of these *Guidelines* to duplicate the material in the *Compendium*, which includes detailed guidance on these issues. The guidance in Chapter 6 focuses on the quantification of emissions for selected types of petroleum industry facilities, rather than individual sources. A discussion on the assessment of the materiality of emissions sources is also included in Chapter 6.

The process for reporting GHG emissions is described in Chapter 7. Companies aggregate GHG emissions for various purposes including by business unit, by industry subsector, for individual facilities and specific geographic regions. Guidance is given on consistent approaches to promote comparability across companies, while allowing for the diversity of the different businesses within the industry. Part of Chapter 7 is devoted to the question of normalization, providing guidance to better allow comparisons of emissions across companies of different sizes operating in various sub-sectors of the industry.

Chapter 8 focuses on inventory assurance processes. It provides guidance on how companies can use internal resources and programs, as well as external parties, to provide assurance and to improve their inventory processes. Different types of assurance processes and their uses are discussed.

2. Petroleum Industry Greenhouse Gas Accounting and Reporting Principles

Companies often adopt or establish sets of principles that serve as the basis for their reporting of environmental information. The principles for GHG accounting and reporting for the petroleum industry listed below are based on the revised *GHG Protocol* (WRI/WBCSD, 2004) chapter on principles. The descriptions of the principles that follow build off of the descriptions given in the revised *Protocol*.

Generally accepted GHG accounting principles, like those for financial accounting, are intended to underpin GHG accounting and reporting to ensure that:

- The reported information represents a faithful, true and fair account of an organization's GHG emissions, and

- The reported information is credible and unbiased in its treatment and presentation of issues.

GHG accounting and reporting is evolving, and it is new to many. The principles outlined in this chapter are the outcome of a collaborative process involving a wide range of technical, environmental, and accounting disciplines.

GHG accounting and reporting should be based on the following principles:

Relevance – Define boundaries that appropriately reflect the GHG emissions of the organizations and the decision-making needs of users.

Completeness – Account for all GHG emission sources and activities within the chosen organizational and operational boundaries. Document and justify any specific exclusions. Any specific exclusions should be stated and justified.

Consistency – Use consistent methodologies and measurements to allow meaningful comparison of emissions over time. Transparently document any changes to the data, methods or any other factors in the time series.

Transparency – Address all relevant issues in a factual and coherent manner, based on a clear audit trail. Disclose assumptions and make appropriate references to the calculation methodologies and data sources used.

Accuracy – Ensure that estimates of GHG emissions are systematically neither over nor under true emission, as far as can be judged, and that uncertainties are quantified and reduced as far as practicable. Ensure that sufficient accuracy is achieved to enable users to make decisions with reasonable assurance as to the integrity of the reported GHG information.

2.1 Relevance

It is important that an organization's GHG report be relevant. This means that it contains the information that report users—both external and internal to the organization—consider significant and need for their decision-making. Timeliness is a component of relevance, for if information is reported after the time when it can influence decisions, it is no longer relevant.

The selection of reporting boundaries for GHG emissions is an important aspect of relevance. The accounting and reporting boundaries should appropriately reflect the GHG emissions of the organization. The choice of appropriate boundaries depends on the characteristics of the organization, the intended purpose of the GHG information, and the needs of the users. When choosing such boundaries, a number of different factors need to be considered such as:

- Organizational structures - operating licenses, ownership, legal agreements, joint ventures, financial and/or taxation boundaries etc.
- Operational boundaries - on-site and off site activities, processes, services and impacts
- The business context - nature of activities, geographic locations, industry sector(s), purposes of information, users of information
- Specific exclusions or inclusions, which should be transparently identified and the rationale provided

The boundaries should represent the substance and economic reality of the business, and not merely its legal form.

2.2 Completeness

All emissions within the chosen organizational and operational boundaries that are material to users should be reported to allow the reporting organization's emissions to be assessed. In practice, a lack of data or the cost of gathering data may be a limiting factor in the completeness of the inventory. For cases where emissions have not been estimated, or have been estimated at an insufficient level of quality to be included, the potential impacts and relevancy of the exclusion should be transparently documented and justified.

The principle of completeness should not be confused with or be regarded as conflicting with the provision of guidance on de minimis reporting levels. Sometimes a minimum emissions accounting threshold (often referred to as a materiality threshold) is explicitly defined, stating that a source not exceeding a certain size may be omitted from the inventory. Technically, such a threshold is simply a predefined and accepted negative bias in estimates (i.e., an under-estimate). In practice, all organizations that report GHG emissions adopt a materiality threshold, whether explicitly or implicitly, due to the extremely wide range in the magnitude of GHG emissions from their various activities. So long as the totality of emissions that go unreported are not considered material by the users of the reported information, this should not be considered to be in violation of the principle of completeness.

2.3 Consistency

Users of GHG information will want to track and compare GHG emissions information over time in order to identify trends and to assess the performance of the reporting organization. The consistent application of boundary definitions, accounting practices and calculation methodologies over time is essential to the production of comparable GHG emissions data. The GHG information for all facilities within an organization's reporting boundary must be compiled in a manner that ensures that the aggregate information is internally consistent and consistent over time. If there are changes in the scope, methods, data or any other factors affecting emission estimates, they should be transparently documented and justified.

2.4 Transparency

Transparency relates to the degree to which information on the processes, procedures, assumptions, and limitations of the GHG inventory are disclosed. Information should be reported in a clear, understandable, factual, neutral and coherent manner. Any changes to the data, methods, or other factors affecting a time series of reported emissions should be transparently documented. The process for and results of internal audits or external third party reviews should be included with the report. A "transparent" report will provide a clear understanding of the issues in the context of the reporting company, and a meaningful assessment of performance.

To promote independent review, the inventory process should be based on clear and complete documentation and archives (i.e., an audit trail). Information should be recorded, compiled and analyzed in a way that enables internal reviewers and external verifiers to attest to its credibility. Sufficient information should be provided to ensure that a third party is able to derive the same results if provided with the same source data. An independent external verification is a good way of increasing transparency and determining that an appropriate audit trail has been established and documentation provided.

2.5 Accuracy

Data should be sufficiently accurate and precise to enable intended users to make decisions with reasonable assurance as to the credibility of the reported GHG information. Because the intended uses of inventory data vary, the necessary level of accuracy will also vary. Organizations should ensure that GHG measurements, estimates or calculations are systemically neither over nor under the true emissions value, as far as can be judged, while recognizing the need to balance the cost-effectiveness of obtaining accurate emissions estimates with the intended use for the emissions information. Uncertainties in GHG calculations should be reduced as far as practicable, based on the data available to make the calculations[2]. As a means of promoting credibility in their reported emissions, organizations should report on the measures they take to ensure accuracy in their emissions estimation process.

[2] Guidance on assessing uncertainty in GHG emissions inventories has been developed by the Intergovernmental Panel on Climate Change and the U.S. EPA, focusing on national inventories. One source of information on assessing uncertainties in corporate GHG inventories is the guidance section and related spreadsheet included among the calculation tools of the *Greenhouse Gas Protocol Initiative*; see www.ghgprotocol.org/standard/tools.htm.

3. Setting the Boundaries for GHG Emissions Reporting

The petroleum industry encompasses a wide variety of operations, ranging from the discovery and production of oil and gas to the delivery of petroleum products to consumers. Oil companies typically divide these operations into different businesses, most commonly:

- Upstream Operations—the exploration, development, and production of oil and gas
- Downstream Operations—the refining, processing, distribution, and marketing of products derived from oil and gas, including service stations
- Chemicals—the manufacture, distribution, and marketing of chemical products derived from oil and gas (petrochemicals)

While large, integrated oil and gas companies participate in all of these businesses, smaller companies may have operations in only one—or part of one—of them. In addition, both large and small petroleum companies may engage in one or more activities that are not typically associated with the petroleum industry, including:

- Coal Mining
- Power Generation
- Natural Gas Transmission
- Renewable Energy Systems
- Specialty Chemical Production
- Metals Production

As discussed in Chapter 7, the way in which petroleum companies divide their activities into different businesses varies from firm to firm. Regardless of how they make these divisions, GHG emissions from all of the businesses engaged in by petroleum companies should be included in corporate reporting, provided the emissions fall within the inventory boundaries described in this chapter. Reporting should not be limited to activities associated with upstream, downstream, and petrochemical operations.

These Guidelines, while focusing on GHG accounting and reporting questions faced by traditional petroleum industry businesses, are largely applicable across the broader set of businesses in which petroleum companies may participate. Detailed guidance on estimating emissions from oil and gas industry operations is provided in the *Compendium*. API is making available (free of charge) a calculation tool that contains the emissions estimation methodologies described in the *Compendium.* The *Compendium* and the calculation tool will be made available at http://ghg.api.org. These *Guidelines* will be made available at that web site as well as at www.ipieca.org/reporting/ghg.html and www.ogp.org.uk.

Specific guidance related to estimating emissions from non-traditional petroleum industry businesses (those not included in the *Compendium*) is available from the *Greenhouse Gas*

Protocol Initiative web site. Sector-specific tools available at www.ghgprotocol.org/standard/tools.htm include procedures for estimating emissions from office-based organizations and the manufacture of:

- Aluminum
- Iron and Steel
- Ammonia
- Nitric Acid
- Adipic Acid
- HCFC-22
- Semiconductors

Tools for industrial sectors in which petroleum industry companies are less likely to have interests are also available at this web site. Where the guidance in these tools or in other sector-specific inventory guidance differs from that in these *Guidelines* or the in *Compendium*, the *Guidelines* and *Compendium* guidance should be followed.

The remainder of this chapter provides guidance on determining whether GHG emissions fall within the organizational and operational boundaries of petroleum companies, and how to account for those emissions if they do. Chapter 7 describes how to report emissions across the broad range of businesses in which petroleum companies may be involved.

3.1 Establishing Organizational Boundaries

Petroleum industry operations are commonly conducted by two or more parties working together in joint ventures[3], instead of by individual firms. These ventures take a variety of legal forms, and may or may not be established as separate legal entities. For the purposes of financial accounting, they are treated according to established rules that depend on the structure of the organization and the relationships among the parties involved. Rules for accounting for greenhouse gas emissions from ventures involving more than one party are still evolving, however. The lack of established rules inevitably leads to questions about how the parties participating in these activities should account for and report GHG emissions.

The purpose of this section is to provide guidance on accounting for GHG emissions from petroleum industry activities that involve more than one party. The guidance is based on the revised chapter on organizational boundaries in the *GHG Protocol* (WRI/WBCSD, 2004). It has been tailored to the petroleum industry and simplified to minimize the need to understand financial accounting terminology. The examples highlighted in grey come from the revised *Protocol* chapter with some minor modifications.

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[3] Unless otherwise indicated, "joint venture" is used as a generic term in these *Guidelines* for any operations or activities involving more than one party.

For corporate reporting, these *Guidelines* should be applied consistently. Existing GHG reporting schemes may have other rules that need to be applied for the entities covered by those schemes. For example, governmental trading schemes are usually based on facility emissions, and do not take into account the ownership structure of the facility. Therefore, the organizational boundary issues discussed in this section would not apply to those schemes. This implies, however, that facilities may have to report different data sets for different reporting purposes. Companies should allow for this flexibility in designing their accounting and reporting systems.

Approaches to Accounting for GHG Emissions:
Equity Share and Operational Control

The accounting for GHG emissions from joint ventures may be performed in one of two ways: on the basis of *equity share* or on the basis of *operational control*.

Equity Share Approach

Under the equity share approach, a company accounts for GHG emissions from operations according to its share of equity in the operation. The equity share reflects economic interest, which is the extent of rights a company has to the risks and benefits flowing from an operation. Typically, the share of the risks and benefits in an operation is aligned with the company's percentage ownership of that operation, and equity share will normally be the same as the ownership percentage. Where this is not the case, the economic substance of the relationship the company has with the operation will always override the legal ownership to ensure that equity share reflects the percentage of economic interest. The principle behind the equity share definition and guidance, that of economic substance taking precedence over legal form, is consistent with international financial reporting. The company should therefore consult with its accounting or legal staff to ensure that the appropriate percentage is applied for each interested operation.

Operational Control Approach

Under the operational control approach, a company reports 100 percent of the emissions from joint ventures over which it has operational control and none of the emissions from joint ventures it does not control. A variety of different criteria exist for determining operational control. For the purpose of these *Guidelines*, companies in the petroleum industry are deemed to have operational control when:

The company has authority to introduce and implement its operational and environmental, health, and safety (EHS) policies at the joint venture.

The rationale for using this definition of operational control is that if a company can implement its operational and environmental policies at a joint venture, it can ensure that the GHG emissions reporting is done in accordance with its corporate standards. Since the company has control over the data, it can ensure that it meets minimum quality standards and is consistent and reliable. The company can account for these emissions just as it does emissions from its wholly-owned operations.

The definition of operational control used in these *Guidelines* is very similar to one of the two criteria for determining control in the revised *GHG Protocol*[4] (WRI/WBCSD, 2004). This particular definition was adopted because it is consistent with the way many petroleum industry companies currently account for and report environmental information. Often, companies report on emissions from facilities that they operate (i.e., facilities for which they hold the operating license). It is expected that except in very rare instances, if a company is the operator of a joint venture facility, it will have the authority to implement its operational and environmental policies and thus has operational control.

It should be emphasized that having operational control does not mean that a company necessarily has authority to make all decisions concerning a joint venture. Making decisions on major capital investments without the approval of the other parties in the venture, for example, may be beyond its authority. Operational control does mean that a company has authority to implement its operational and EHS policies. Indeed, many companies will not agree to be the operator of a joint venture unless they have this authority.

Companies sometimes report emissions only from joint ventures in which they hold more than a 50 percent interest. This approach may lead to less complete reporting than is recommended by these *Guidelines* because the ability to implement operational and EHS policies is not limited to majority held ventures—it also applies to minority ventures where the company has operational control.

Selecting Accounting Based on Equity Share or Operational Control

Petroleum companies may choose to report their corporate GHG emissions based either on equity share or on operational control. Companies should clearly state in their reporting which method they choose. When accounting for GHG emissions, they are encouraged to employ both the equity share and operational control methods. The reason for this recommendation is that a single method has yet to be established among existing voluntary programs and emerging mandatory programs that involve reporting of GHG emissions. Accounting for GHG emissions in both ways will ensure that companies are prepared for any programs in which they may choose or be required to participate.

Companies that decide to report only on the basis of equity share or operational control should recognize the plusses and minuses of each, and choose the method that is most suitable for their businesses. They should also recognize that whichever method they choose for their corporate reporting, they may be required to utilize the other method for reporting emissions from specific facilities, businesses, or geographic areas, depending on the reporting requirements of the programs in which their individual facilities participate.

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[4] The *GHG Protocol* criterion refers to the "full" authority to introduce and implement operational and EHS policies, and uses the term "operations" rather than "joint ventures."

Reporting based on operational control is appropriate for:

- Reporting under programs that involve GHG accounting based on control[5], such as the:
    - UK Emissions Trading Scheme. When direct participants in the scheme include joint ventures, emissions are accounted for on the basis of management control. (Note, however, that the definition of management control used in the scheme differs from that used in these *Guidelines*.)
    - EU Emissions Trading Scheme. Emissions limitations under the EU Emissions Trading Scheme will be imposed at the installation level. For joint ventures, the operator (the firm that manages or controls the installation) will be responsible for ensuring compliance with the scheme and reporting emissions, in much the same way as it would be with other environmental regulations.

- Performance tracking. Having operational control suggests a greater degree of influence than merely holding a share of the equity. Since managers can only be held accountable for activities they control, the operational control approach is more appropriate for tracking their performance.

- Situations where resources for inventorying emissions are limited. Reporting on the basis of operational control can be expected to be less costly than reporting on the basis of equity share because the reporting company will, by definition, have ready access to the data needed to estimate emissions.

Accounting for GHG emissions based on equity share is appropriate for:

- Liability and risk management. For the purpose of assessing risks posed to a company, GHG emissions accounting and reporting based on equity share provides a more representative and complete picture. Therefore, it provides a realistic picture of liabilities and risks associated with GHG emissions to management, employees, shareholders, and other company stakeholders.

- Alignment with financial accounting. Increasingly, companies are required to report on environmental liabilities as part of their financial reporting. In the US, liability reporting has most commonly been for costs of cleaning up environmental contamination. In Europe, broader reporting of environmental liabilities is becoming required. In the future, GHG emissions may be treated as liabilities in financial accounting. For achieving consistency with financial accounting, emissions should be accounted for on an equity share basis.

[5] The definition of "control" employed by these programs may not correspond exactly with that used in these *Guidelines*.

- Situations where greater resources are available for conducting the inventory. Reporting on the basis of equity share requires companies to obtain information from other parties for operations they do not control[6]. If this is not possible, they may need to estimate emissions from similar operations for which they have data. In either case, costs can be expected to be greater than for calculating emissions from sources under their operational control.

Application of the Equity Share Approach within the Petroleum Industry

Accounting for GHG emissions is complicated by the wide variety of organizational relationships that are used within the petroleum industry. Some of the more common arrangements within the industry are listed in Table 3-1, along with guidelines on how to account for emissions based on equity share. These guidelines are generally consistent with financial accounting approaches. For the sake of simplicity, the descriptions of the investments and relationships among the organizations are provided using common terminology, rather than accounting terminology. For situations not covered by this table, company financial accountants should be consulted to determine how the specific investment is handled for financial accounting, and the emissions should be accounted for in an analogous manner.

Several of the types of investments listed in Table 3-1 exist in many industries. In general, application of the equity share approach of apportioning GHG emissions according to the economic interest or benefit derived from the venture would utilize the working/participating interest in the venture, or the ownership share if the venture is conducted as a separate company. This general rule would be applied unless there were specific contractual arrangements that either allocate the GHG emissions to the partners (see below), or that alter the normal practice of allocating benefits in proportion to the equity interest and hence contribution of costs.

One type of arrangement that alters the normal practice of allocating benefits in proportion to equity is the Production Sharing Agreement (PSA), which is commonly used in upstream petroleum operations. A PSA is an agreement between one or more oil companies and a government entity or state company in which the participating oil companies provide financing and bear the risk of exploration and production activities in exchange for a share of the production remaining after royalties[7] are paid to the government. The company share of this remaining production—sometimes referred to as the company share of net production or entitlement production—should be used as the basis for allocating emissions. As shown in Figure 3-1, all of the parties receiving a share of net production, whether they be a state oil company or private companies, receive a proportionate share of emissions, and all of the emissions from the operation are accounted for among the companies. No emissions are allocated to the royalties.

[6] To facilitate the reporting of emissions by partners in joint ventures, operators are encouraged to share appropriate emissions data with the other parties.

[7] Including taxes and other levies paid in kind (with oil rather than money).

The net share of production used for allocating emissions from PSAs is the production reported in financial accounts or statements prepared according to the requirements of UK GAAP, US GAAP, and the US Securities Exchange Commission (SEC). The relevant net production volumes and the company share can be obtained directly from company financial departments.

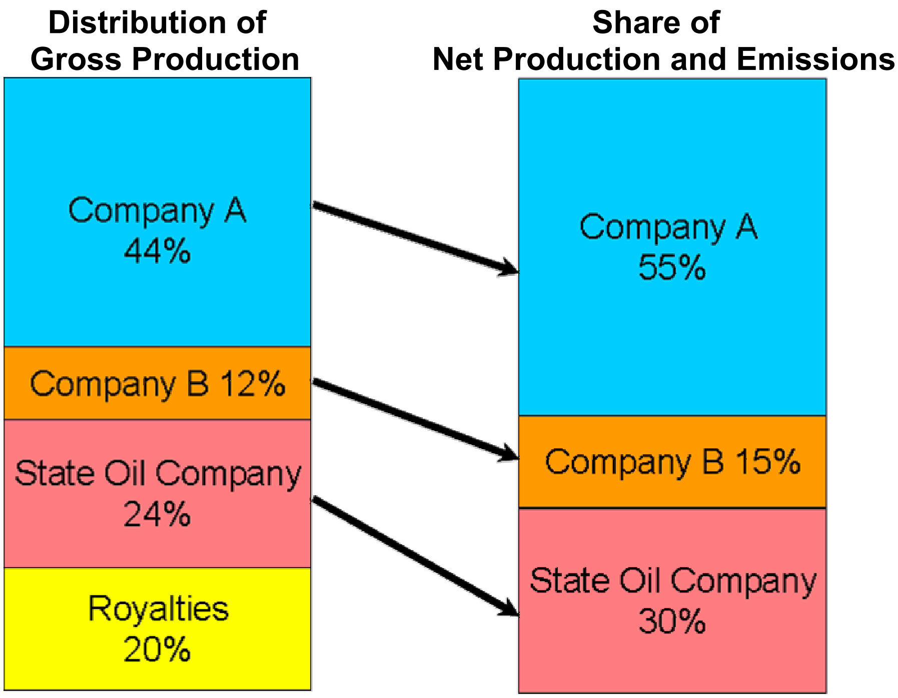
Table 3-1. Equity Share Accounting of GHG Emissions for Common Petroleum Industry Investments

Type of Investment	Description of Organizational Relationship	Accounting for GHG Emissions Based on Equity Share
Subsidiary	The petroleum company either wholly owns the subsidiary, or enough of its voting stock that it has full control of the subsidiary (e.g., through election of the board of directors).	According to the ownership share of the subsidiary (100% for wholly-owned subsidiaries).
Joint venture among two or more oil companies that operates as a separate company.	Several corporations have formed a company by combining some of their existing assets and/or capital. The several corporations are the sole shareholders.	According to the ownership share of each of the parent corporations in the new company.
Joint venture among several oil companies to develop a production facility.	Corporations work in partnership to develop the facility without forming a new company. One serves as operator.	Based on the terms of the arrangement with the other parties—typically according to the working interest.
Joint venture among a state oil company and several foreign companies to produce oil, as part of a production sharing agreement.	For example, a state oil company has 40% interest in venture, and several companies each having 15% interest or less, including the operator.	Based on company's share of net production.
Stock ownership in a publicly traded corporation—significant share of ownership.	For example, a separate company in which the petroleum company has significant influence[8].	According to the ownership share of the petroleum company in the corporation.
Stock ownership in a publicly traded corporation—small share of ownership.	For example, a separate company in which the petroleum company has made an investment, but does not have significant influence[8].	Petroleum company reports no GHG emissions from the company in which it has invested, consistent with financial accounting.

The type of investments and joint ventures listed in Table 3-1 are simplifications. In some cases, it may be necessary to account for emissions in two or more steps, for example when a parent company has a subsidiary that holds an interest in another company. In these cases, the allocations of emissions should be carried out from the

[8] Significant influence is defined by accounting standards; in general, ownership of 20 percent or more of the stock in a company results in a presumption of significant influence.

bottom up, so that the GHG data are first consolidated at the lower level organization prior to a higher parent level consolidation. (See the example at the end of this chapter.)



Note: Royalties include taxes and other levies paid in kind (with oil rather than money).

Figure 3-1. Allocation of Emissions from PSAs for Equity Share Accounting

Contractual Arrangements

Companies involved in joint ventures may have contractual arrangements that specifically address the ownership of GHG emissions. When voluntarily reporting emissions, companies should follow the arrangements described in the contracts irrespective of whether they report on an equity share or operational control basis. When reporting under particular regulatory schemes, however, companies should follow the reporting requirements of those schemes.

Production Sharing Agreements typically address the ownership of gas produced in association with oil. In situations where this gas is flared, the accounting of GHG emissions should follow the accounting rules described above without regard to the ownership of the gas. If the PSA explicitly assigns ownership of the GHG emissions, however, this assignment would take precedence over the normal GHG accounting rules. Where emissions from the flaring of associated gas are large, and the ownership of the gas and the decision to flare it rests with other parties, the reporting company may wish to report such emissions in a note or explanation to its emissions inventory.

The following example illustrates how to account for GHG emissions for a company with a more complicated set of organizational relationships:

Holland Industries is a chemicals group comprising a number of companies and joint ventures active in the production and marketing of petrochemicals. Table 3-2 outlines the organizational structure of Holland Industries and explains how GHG emissions from the different operations are accounted for under the equity share and operational control approaches.

Table 3-2. Holland Industries—Organizational Structure and GHG Emissions Accounting

Name	Legal Structure and Partners	Interest Held by Holland Industries	Operational and EHS Policies	Emissions Accounted for by Holland Industries	
				Equity Share	Operational Control
Holland America	Incorporated company	83%	Holland Industries	83%	100%
BGB	Jointly Controlled JV	50% by Holland America	Partner	41.5% (83%x50%)	0%
Lolo Industrial	Subsidiary of Holland America	75% by Holland America	Holland America	62.25% (83%x75%)	100%
Kahuna Chemicals	Non-incorporated joint venture, jointly controlled with 2 other partners: ICT and BCSF	33.3%	ICT	33.3%	0%
Nallo	Incorporated joint venture, other partner Nagua Co.	56%	Nallo	56%	0%
QuickFix	Incorporated joint venture, other partner Majox	43%	Holland Industries	43%	100%
Syntal	Incorporated company, subsidiary of Erewhon Co.	8%	Erewhon Co.	0%	0%

Note that in this example, Holland America (not Holland Industries) holds a 50% interest in BGB and a 75% interest in IRW. GHG emissions are thus apportioned first at the subsidiary level before they are consolidated at the group level.

3.2 Establishing Operational Boundaries

As part of defining the scope of their GHG inventories, companies must determine which emission sources related to their businesses should be included within the organizational boundaries they have established. This process is referred to as setting the operational boundaries of the GHG inventory.

A key distinction in setting the operational boundaries is whether GHG emission sources are categorized as: *direct emissions sources* or *indirect emissions sources*.

3.2.1 Accounting for Direct GHG Emissions

Direct GHG emissions are emissions that are from sources that are owned or controlled by the reporting company, for example, emissions from exhaust stacks in refining and upstream operations, emissions from process vents in oil and gas treatment, oil refining, and chemical production, and exhaust emissions from company-owned motor vehicles and vessels.

Companies within the petroleum industry should account for and report all of the direct GHG emissions for operations that fall within their established organizational boundaries. The types of direct emissions sources that occur within the petroleum industry are listed in Chapter 5 and described in detail in the *Compendium*. General categories of direct emissions sources that should be included in inventories are:

- Production of heat, steam, or electricity, whether for use by the company or for sale to other parties
- Combustion in flares and incinerators
- Production of work by engines and turbines, for example, to drive pumps or compressors
- Physical or chemical process emission such as from gas processing, oil refining, and petrochemical manufacture
- Transportation in company-owned motor vehicles and vessels, such as tank trucks and oil tankers
- Fugitive losses from equipment leaks such as from gas pipeline systems

The definition of direct emissions applies to sources owned or controlled by the reporting company. For sources that are leased, companies that report on the basis of operational control should account for emissions in the same way as if the sources were owned. Emissions from leased sources are accounted for if the company has authority to introduce and implement its operational and environmental, health, and safety policies at the leased source:

- The company should account for 100% of the GHG emissions produced by leased sources at which it has authority to implement its operational and EHS policies.

- If the company does not have authority to implement its operational and EHS policies at the leased source, no emissions are reported.

For companies that report on the basis of equity share, the accounting of emissions from leased sources depends on whether the source is a finance (capital) lease or an operational lease:

- A finance or capital lease is one that transfers substantially all the risks and rewards of ownership to the party leasing property from its owner. Such leases are treated as assets in financial accounting and are recorded as such on the balance sheet. The party leasing an emission source under a financial or capital lease should therefore account for GHG emissions as if it owned the source by applying the same rules described above for the equity share approach.

- A lease other than a finance or capital lease is defined as an operational lease, for which no liabilities or assets are recorded in financial accounting. The party leasing the emission source should not report GHG emissions produced by operational leases.

In general, most leased sources in petroleum industry operations will fall into the first category. The latter category may also apply, for example, when a company leases office space under rental agreements.

3.2.2 Accounting for Indirect GHG Emissions

Indirect GHG emissions are emissions that are a consequence of the activities of the reporting company, but occur from sources owned or controlled by another party, e.g., emissions from the production of purchased electricity, contract manufacturing, contracted drilling operations, and product transport by third parties.

The definition of indirect emissions is sufficiently broad that it could encompass virtually all of the life-cycle emissions of a product that are not direct emissions. Life-cycle emissions refer to emissions that occur from the point of raw material extraction through the manufacture, transportation, use, and disposal of a product. While the life-cycle assessment of emissions are sometimes conducted for specific products (usually to compare one product with another) they are not typically conducted for an entire corporation, business, or facility. Corporate GHG inventories are usually limited to emissions that occur as the result of manufacturing a product or providing a service. In industries like the petroleum industry, where companies may be involved in both the extraction of natural resources to make a product and in the process of manufacturing itself (e.g., petroleum refining), the corporate inventory may also include emissions from the raw materials extraction step.

Up through the point of product sales, companies should, at a minimum, account for and report their direct emissions. They may choose whether or not to include indirect emissions. Indirect emissions that are included should be identified as such and reported separately from direct emissions as described below and in Chapter 7. In the interest of transparency, companies should clearly state in their inventories which categories of the indirect emission sources listed in these *Guidelines* are included.

Indirect Emissions from the Consumption of Purchased Energy

Reporting programs and guidance differ in their requirements for reporting of indirect emissions. This is particularly true for the reporting of indirect emissions associated with the consumption of purchased energy. (Purchased energy is defined for the purposes of these *Guidelines* as the acquisition of electricity, steam, or hot water from a third party.) For corporate reporting, both the *GHG Protocol* and the California Climate Action Registry require the separate reporting of indirect emissions from purchased energy. The UK Emissions Trading Scheme also includes indirect emissions from energy consumption, though the EU Emissions Trading Scheme, which applies at the installation level, does not[9]. Thus, inclusion of indirect emissions is neither inherently incompatible with the conduct of regional or national inventories nor with emissions trading provided that the programs are designed properly to eliminate the possibility of double counting.

These Guidelines make no specific recommendation on the inclusion of indirect emissions from the consumption of purchased energy. Companies will need to decide whether or not to include indirect emissions from purchased energy consumption as they design their inventories for voluntary reporting. Current practice varies on this question. While some companies that voluntarily report greenhouse gas emissions as part of their annual environmental reports do include these indirect emissions, others do not. In the interest of transparency, if a company does report indirect emissions from the consumption of purchased energy, it should do so separately from direct emissions.

Companies account for and report indirect emissions from energy consumption for a variety of reasons:

- The primary reason for including indirect emissions from energy consumption is to provide a more complete picture of a firm's GHG footprint. In much the same way that reporting on energy consumption, which virtually always includes purchased energy, can be used to assess the risks of rising energy costs, including indirect GHG emissions from purchased energy allows the risks of rising GHG emission costs to be assessed.

- A second reason for encouraging companies to track these emissions is that the information may be needed for some voluntary reporting programs. API, for example, asks that indirect refinery emissions, such as those resulting from consumption of purchased electricity, be reported as part of its annual benchmarking survey.

- Another reason for accounting for indirect emissions is that it makes it easier for companies to track changes in emissions that result from outsourcing or insourcing of energy production. Firms that switch from purchasing electricity to generating it on site will be able to more accurately demonstrate the net change in their emissions from the switch if they have been tracking their indirect emissions. If they report only direct emissions, their emissions will appear to increase when they begin to generate their own electricity even if the emissions intensity of their self-generated electricity is less than that of the electricity they formerly purchased. Similarly, if companies switch from generating electricity to purchasing it, they will be less likely to face criticism for exporting emissions if they include indirect emissions from purchased energy in their reporting.

Companies that do choose to include indirect emissions from consumption of purchased energy in their inventories should remain cognizant of the methodological difficulties of doing so. Often, emissions factors for imported energy (e.g., mass of emissions per

[9] While this may make the two schemes incompatible, what is more important is that within any particular scheme the reporting be done on a consistent basis.

quantity of electricity consumed) are unavailable or have a high degree of uncertainty. This uncertainty applies to both national emission factors and those published for sub-national areas, including the state-level emission factor published by the U.S. Department of Energy and regional factors published by the U.S. EPA. Since the mix of generation sources supplying a facility vary both over time and within the regions over which the emission factors may have been averaged, indirect emissions calculated with such factors will have much greater uncertainty than estimates of direct combustion emissions.

An additional, though less significant, uncertainty in estimating indirect emissions from the consumption of purchased energy relates to transmission and distribution (T&D) losses[10]. Typically several percent of the electrical energy generated by power plants connected to the grid is lost before reaching the consumer. Often, emissions associated with T&D losses are not accounted for in corporate GHG inventories, and this approach is recommended in the revised *GHG Protocol* (WRI/WBCSD, 2004) for companies that only consume electricity and do not transmit or distribute it.

While recognizing the limitations of reporting emissions from the consumption of imported energy, companies may still wish to report them. Methods for estimating emissions from purchased energy are described in the *Compendium*.

Indirect emissions result from electricity consumed not only from the grid. In many cases, petroleum companies will consume electricity purchased directly from a third party. For companies that do report indirect emissions from imported energy, the following example illustrate how GHG emissions should be accounted for several situations in which one company provides power to another.

Power generation

A power plant is located at a refinery owned and operated by Company B, which also uses 100 percent of the power plant's output:

Situation 1 - The power plant is owned and operated by Company A: Company B (the refinery) has outsourced power generation and reports no direct GHG emissions for either the control or equity approach, but reports 100% of the plant's emissions as indirect emissions. Company A reports 100% of the plant's emissions as direct emissions.

Situation 2 – The power plant is owned by Company A but operated by Company B (the refinery): Under the operational control approach, Company B reports 100% of emissions as direct emissions and none as indirect emissions. Under the equity share approach it reports none of the power plant's emissions as direct emissions, but 100% of the emissions as indirect emissions.

Situation 3 – The power plant is operated by Company A but owned by Company B (the refinery). Under the operational control approach Company B reports none of the emissions as direct emissions but 100% of the emissions as indirect emissions. Under the equity share approach, Company B reports 100% of the emissions as direct emissions (since it owns the power plant) but none of the emissions as indirect emissions.

[10] While T&D losses apply to the transmission and distribution of electricity, losses in thermal energy occur in the transport of steam and hot water from the point of generation to the point of consumption. The discussion in this paragraph would also apply to these losses.

When accounting for indirect emissions from consumption of purchased energy, it is important for companies to understand the source of the energy and whether it comes from a combined heat and power plant (CHP). If it does, the greenhouse gas emissions will have to be apportioned between the heat (steam and/or hot water) and power unless the importing facility receives the entire output of the plant.

A variety of approaches have been used to allocate emissions between the heat and power streams of CHPs. These methods include the allocation of emissions based on the

- Energy (heat) content of the heat and power streams
- Exergy (work potential) content of the heat and power streams
- Relative efficiency of heat and power production from separate plants

Specific guidance on calculating the allocation of emission between heat and power is given in the *Compendium*. As no allocation method has yet become standard, companies that voluntarily report GHG emissions for their facilities or the corporation as a whole should clearly state in their emissions inventories which allocation method they use.

When reporting under specific GHG programs, companies should follow the CHP allocation rules established by those programs. The UK Emissions Trading Scheme, for example, uses a simplification of the relative efficiency method for allocating emissions between the heat and power streams[11], while the California Climate Action Registry requires that the allocation be based on the energy content of the two streams.

For project level reporting of GHG emission reductions, alternative methods of accounting for emissions from CHPs may be more appropriate than the method recommended for facility or corporate reporting. In project-level reporting, emission reductions are typically quantified as the difference between what emissions would have been in the absence of the project and what the actual emissions are with the project. For a CHP project in which power is exported to the grid and heat used internally, this would mean that instead of allocating emissions between the heat and power streams of the CHP, the emissions displaced from the grid could be used in calculating the emission reductions.

Other Indirect Emissions Sources

Indirect emissions associated with the consumption of purchased energy are the most commonly reported type of indirect emissions, usually because they are the largest source of indirect emissions. They may not be the only source, however. Within the petroleum industry, a range of emitting activities exist that may be performed by third parties, thus resulting in other types of indirect emissions. In order to make comparisons across companies and industry subsectors, it is important that these sources be accounted for in

[11] The UK ETS calculation is based on a default for the relative efficiency of power and heat production, rather than the actual relative efficiency for each CHP application.

comparable ways. While these *Guidelines* do not make any specific recommendations for including other indirect emission sources, companies are encouraged to be able to account for selected indirect emissions including:

- Emissions resulting from the manufacture and transport of imported hydrogen for oil refineries.

- Third party shipping of crude oil and petroleum products in vessels, by road transport, by railroad, and by pipeline up to the point of custody transfer (sale to another party).

- Contracted exploration and production operations including well drilling, well maintenance, and well workovers.

- Toll manufacture of chemicals by third parties, which is common in the chemical and petrochemical industries[12]. Companies may choose to include indirect emissions associates from toll manufacture conducted on their behalf as another form of indirect emissions.

In many cases, companies will contract out a portion of the activities listed above, and conduct some of the same activities themselves. They should be able to make rough estimates of emissions from these activities based on the emissions from their own corresponding activities and the extent to which the activities are contracted out versus performed in-house.

Production of purchased hydrogen, third party shipping, contracted exploration and production work, and tolling are activities that are related to the petroleum industry. Accurately estimating their emission may pose a challenge for many companies, however. For this reason, and because these emission sources are not expected to be large contributors to the total emissions of most companies, these *Guidelines* do not specifically recommend that they be reported in company emission inventories. However, since such information may be needed to complete industry surveys, it is suggested that companies track such emissions whenever possible.

It should be emphasized that these *Guidelines* recommend that the activities listed above be reported optionally only when they are indirect emissions sources. Transport in company owned and operated vessels, vehicles, and pipelines should be reported if they fall within a company's organizational boundaries. Similarly, a company that serves as a toll operator for another firm should include the emissions from the processing it performs. The optional inclusion of emissions from tolling applies only when the tolling operation is performed by a third party on behalf of the reporting company.

If companies do report these forms of indirect emissions, they should report them separately from their direct emission and their indirect emissions from consumption of

[12] "Toll manufacture" or "tolling" refers to an arrangement whereby one firm provides processing or manufacturing services to another firm, which supplies the raw materials.

purchased energy. They should clearly state in their reporting which of these sources of indirect emissions are included.

Minor Indirect Emissions Sources

A variety of other, minor indirect emission sources are associated with the petroleum industry. While these emission sources may be important for some industries, for larger companies within the petroleum industry, they will be insignificant. Therefore, companies within the petroleum industry need account for these indirect emissions sources only if they have some specific reasons for doing so. Such reasons include the requirements of reporting programs in which the company participates or if the company (or a particular facility) operates in a narrow sector of the petroleum industry where these emissions may be significant.

Minor sources of indirect emission in the petroleum industry include:

- Employee travel on third party vessels, chartered aircraft, and commercial airlines
- Transport of employees to remote exploration and production areas, such as offshore production platforms.
- Employee commuting to and from work
- Purchased raw materials other than hydrogen
- Waste transport and disposal by third parties

Emissions Related to Product Use

Consistent with the general practice of reporting GHG emissions from facilities and corporations, these *Guidelines* make no recommendations regarding the estimation and reporting of emissions that occur after the point of sale of petroleum industry products. Emissions that occur as the result of the use of petroleum products are under the control of the users, and are most appropriately reported by them. Indeed, reporting such emissions by the petroleum company could lead to misleading conclusions. If a petroleum company increases its natural gas sales, for example, emissions from product use would appear to increase even if the gas were used to displace coal at a power plant, thereby actually resulting in lower net GHG emissions. Reporting of emissions at the power plant where the fuel switch was made would demonstrate the reductions; reporting by the fuel suppliers would not.

Companies that choose to calculate and report emissions from the use of their products can ensure that appropriate data are used in making the calculations and can provide commentary that explains the data and its limitations. The calculation of emissions from product sales is more complicated than it might appear since oil and gas companies often market fuels produced by other companies and sell their own products for use as feedstock, rather than as fuel. Emissions calculated by others from publicly available product sales data may not make these distinctions, however, and thus may be inaccurate or misleading.

4. Designing an Inventory to Monitor Performance

Companies that report GHG emissions generally wish to maintain data consistency over time. They may also wish to track performance over time, either for internal reporting purposes or for demonstrating to external stakeholders their progress in reaching announced goals. Regardless of the purpose, performance tracking requires that some reference point for comparing emissions exist. In established voluntary reporting programs, the program rules may define what this reference point is and how it may need to be adjusted over time. The purpose of this chapter is to provide guidance on maintaining data consistency over time to petroleum industry companies that voluntarily report GHG emissions independent of specific programs. Much of the material in this chapter, particularly Section 4.2, comes from the *GHG Protocol* (WRI/WBCSD, 2001).

4.1 Establishing Base Year Emissions

The most common reference point for tracking company GHG emissions is the actual emissions for a particular year or the average annual emissions over several consecutive years. This emissions level is referred to as the *base year emissions*. The term base year emissions is used instead of *baseline emissions* because baseline emissions generally refer to what emissions would have been over time in the absence of specific actions taken to reduce them. (The term baseline is commonly used in the context of emission reduction projects.) For company reporting of GHG emissions, it is recommended that the established base year emissions remain unchanged except under certain circumstances. The process for adjusting base year emissions is described in the next section of this chapter.

These *Guidelines* make no specific recommendations as to which year or years should be chosen to establish the base year emissions. It is sometimes suggested that 1990 should be chosen, because it is consistent with the base year used in the Kyoto Protocol (1990 is the year compared to which industrialized countries will have to reduce emissions between 2008 and 2012). The Kyoto Protocol applies to nations, rather than companies, however, and those nations signing the protocol will not necessarily require companies to report their 1990 emissions. Companies that have not yet begun (or have only recently begun) to report emissions will usually find it difficult to reliably estimate their emissions as far back as 1990. For other companies, the amount of reorganization that has occurred within the petroleum industry within the past dozen years will make it difficult to quantify base year emissions that occurred more than a decade ago.

If companies have the option of selecting their base year for tracking emissions, they should:

- Ensure that the available data for estimating emissions are verifiable and allow for consistent estimation and accounting across the company

- Consider the requirements of voluntary programs in which the company may decide to participate (e.g., average annual emissions from 1998-2000 for direct participants in the UK Emissions Trading Scheme)

Whichever base year or average of years a company selects, it should state the reason for making its selection.

Under some reporting schemes, companies may not have the option of selecting a base year. If the required base year is prior to when a company began data collection for emissions estimating, then data may not be available for verifiable and consistent emissions estimating. Uncertainty may increase. In this situation, companies should make a best effort to obtain reliable data that best reflects past operations.

Companies should recognize that it may not be possible or desirable to have a single base year, or to indefinitely maintain a single base year. While particular reporting programs may specify a base year, generally these programs apply only to specific parts of the company and not the entire organization. Unless the company wishes to apply the base year for the particular program to the entire corporation—and has adequate data to do so—it will more likely choose a different base year for the corporation. In addition, as companies grow through acquisitions, the absence of reliable base year data for the acquired firm may require that the acquiring firm choose a new base year that can be applied across the entire organization.

4.2 Adjusting Base Year Emissions

Once a company has selected a base year for tracking trends in emissions, it is recommended that it make no adjustments to the base year emissions except as described below. Because the approach recommended in these *Guidelines* is to compare emissions against a fixed reference point, companies should not adjust the base year emissions to account for differences in production from year to year. Rather than adjusting their base year emissions for changes in production, companies should normalize their emissions as described in Chapter 7 to assess trends in emissions per unit of output.

Organic growth or decline is not considered a condition for base year emissions adjustment. Opening a new facility is considered a case of organic growth because it represents a new source of GHG emissions that did not exist prior to the setting of a base year. Similarly, the acquisition of companies or parts of companies that came into existence after the company's base year was set are regarded as organic growth because these changes represent new GHG emissions that occurred after the base year was set. In the following cases, there should be no adjustments to the base year emissions:

- An operating unit of a company is shut down
- A new operating unit is started
- An acquisition of a company or parts of a company that came into existence after the base year of the acquiring company was set
- 'Outsourcing' of operations that came into existence after the base year was set

- ‘Insourcing’[13] of operations that came into existence after the base year was set

There are situations when adjustments to the base year emissions are necessary to ensure that comparisons of annual emissions to the base year emissions are valid. These situations involve the transfer of emission sources that existed at the time the base year was established from one company to another. Unless adjustments to the base year emissions are made, such changes could give the appearance of increases or decreases in emissions, when in fact no changes occurred; rather, emissions would merely be transferred from one company to another. To prevent this problem, the base year emissions should be adjusted when the following situations occur:

- Significant structural changes to the organization including mergers, acquisitions, and divestitures
- Transfer in the ownership or control of emissions sources
- Outsourcing of emitting activities
- Insourcing of emitting activities

In the case of outsourcing and insourcing of emitting activities, there may be cases where adjusting the base year emissions does not affect the total emissions (direct plus indirect) reported by the company. If a company tracks both direct and indirect emissions, and continues to include outsourced activities as indirect emissions in its annual emissions inventory, or if it previously included as indirect emissions outsourced activities that have since been insourced, adjusting the base year emissions will not affect trends in the total reported emissions. For the purposes of separately reporting direct and indirect emissions, as recommended by these *Guidelines*, as well for reporting under specific programs, however, adjustments to the base year emissions should still be made.

Base year emissions should be adjusted for structural changes when there is significant impact on the reporting consistency of the organization’s total emissions. This may include accounting for the cumulative effect of a number of small acquisitions or divestitures. While adding some complexity, this approach aligns with financial accounting practices, and provides a meaningful basis for measuring performance over time.

Base year emissions should also be adjusted for the purchase or sale of significant emissions sources. This might be the case if a company purchased a major asset, for example a power plant or refinery. Similarly, if a company outsources activities to another company (e.g., transport of its crude oil and refined products), it should adjust its base year emissions to remove these sources if they are significant. Conversely, it should add emissions sources to its base year inventory if it insources activities with significant emissions. For both outsourcing and insourcing, however, base year emissions adjustments are unnecessary if the emission sources have been included in the base year and will continue to be included in the inventory as either direct or indirect emissions. In

[13] “Insourcing” refers to the assumption by the company of emitting activities that previously were performed by another company, such as the production of a raw materials, parts and supplies, and heat or electricity

this case, the total emissions will be consistent over time provided that both direct and indirect emissions are included in the total.

Companies should also adjust their base year emissions as follows:

- If significant structural changes occur during the middle of the year, the base year emissions should be adjusted for the entire year[14], and

- The base year emissions should be adjusted for changes in calculation methodologies that result in significant changes in calculated GHG emissions. Discovery of errors, or a number of cumulative errors, that significantly affect base year emissions should result in an adjustment of base year emissions.

The need for making adjustment to base year emissions depends on the significance of the changes, as well as the purpose for restating the emissions. Due to the difficulty and cost of revising data that may be more than a decade old, companies that voluntarily report emissions trends may choose to explain the limitations of their earlier reported data rather than restating the results. If the company is receiving a financial benefit from its reported reductions (such as through emissions trading) or is required to report past emissions under some regulatory scheme, it may not have this reporting flexibility, however.

These *Guidelines* make no specific recommendations as to what constitutes "significant" change and thus the need to adjust base year emissions. Companies should note that some voluntary GHG programs do specify numerical significance thresholds:

- For direct participants in the UK Emissions Trading Scheme, the "change threshold" is the lesser of 2.5 percent of the base year emissions or 25,000 metric tons of CO_2-equivalent, determined on a cumulative basis during the period 2002-2006.

- For participants in the California Climate Action Registry, the change threshold is 10 percent of the base year emissions, determined on a cumulative basis from the time the base year is established.

Companies should develop a base year emissions adjustment policy, and clearly articulate the basis for making any adjustments. The policy should state any "significance threshold" applied for considering base year emissions adjustment. ("Significance threshold" is a qualitative or quantitative criterion used to define a significant structural change.) It is the responsibility of the company to determine the significance threshold for considering base year emissions adjustment. In most cases, the significance threshold depends on the use of the information, the characteristics of the company, and the

[14] Base year emissions are adjusted for the entire year, rather than on a pro-rata basis to avoid having to make another adjustment to the base year in the succeeding year. Similarly, current year emissions would be adjusted for the entire year to be consistent with the base year adjustment.

features of structural changes. The two examples listed above illustrate this point—the threshold for the emissions trading program is stricter than for the voluntary registry.

Once a company has determined how it will adjust its base year emissions, it should apply this policy in a consistent manner. For example, it should adjust for both GHG emissions increases and decreases. The base year emissions should be retrospectively adjusted to allow for specific changes in the company that would otherwise invalidate the use of its base year emissions as a reference point, or would compromise the consistency and relevance of the reported GHG information.

4.3 Performance Monitoring

Companies within the petroleum industry demonstrate their GHG emissions performance in a variety of ways. These include:

- Demonstrating continuous improvement
- Limiting the absolute level of their emissions
- Limiting the emissions intensity of their operations
- Reducing the quantity of gas flared or vented in the production of crude oil
- Improving energy efficiency
- Purchasing renewable or less GHG-intensive electricity
- Switching to self-generated electricity with lower emissions intensity than purchased electricity

These activities are not mutually exclusive, and many companies undertake more than one of them. Each has implications on how the company reports its GHG emissions.

Companies may demonstrate continuous improvement showing that their emissions have decreased from one year to the next. Such an approach eliminates the need to continually adjust base year emissions since a company need only ensure that emissions for a given year are reported consistently with the previous year.

The demonstration of performance in reducing or limiting the absolute level of emissions relative to a fixed year requires the establishment and adjustment of base year emissions as described in the in the previous two sections of this chapter. Companies that choose to set an explicit emissions reduction target will need to consider:

- Whether to set an absolute or intensity based target
- Which geographic regions will be covered
- Which of the company businesses will be included
- Which GHGs to include
- Whether or not to include indirect emissions
- What period the target will apply to
- Whether external offsets are part of the target
- Whether to set the target relative to a fixed base year or on a year to year basis
- What the target will be

Since detailed descriptions of these considerations for target setting are provided in Chapter 11 of the revised *GHG Protocol* (WRI/WBCSD, 2004), they are not repeated here. Petroleum industry companies that may be considering establishing intensity based emission reduction targets should refer to Chapter 7 of these *Guidelines* for information on the types of parameters that may be used for normalizing emissions from various business sectors.

A number of petroleum companies have made commitments to reduce the amount of gas they flare or vent in their upstream operations. Their performance in this regard may be demonstrated by reporting trends in the amount of gas they are flaring and venting. The resulting reduction in CH_4 and CO_2 emissions may also be reported to demonstrate reductions in GHG emissions. Since flaring and venting emissions will typically be part of a company's direct emissions, reductions of flaring and venting emissions will normally be captured in their GHG inventory. These reductions may not be readily apparent, however, if the company reports only aggregated emissions results. For this reason, it may wish to report flaring and venting emissions as a separate category, report the emission reductions directly associated with actions taken to reduce flaring or venting, or report emissions from specific facilities (fields) or businesses (upstream operations) to more clearly demonstrate this aspect of its performance.

Whether actions taken to improve energy efficiency are reflected in a company's GHG emissions inventory depends on how the company conducts its inventory and the nature of the energy efficiency improvements. If the efficiency improvements apply to direct emissions sources, such as the company's own boilers, turbines, and engines, then the efficiency improvements will be reflected in the change in the company's direct GHG emissions. For efficiency improvements that affect indirect emissions, such as improvements that result in the consumption of less purchased electricity, these improvements will only be reflected in the company's GHG inventory if the company reports indirect emissions.

Companies may also reduce GHG emissions by changing the suppliers of electricity to firms that produce renewable or less GHG-intensive electricity. Since emissions associated with electricity consumption are indirect, the emissions benefit of changing suppliers will be reflected only in the inventories of companies that report indirect emissions. The ability to realize these emission reductions also requires having reliable GHG emission factors from the electricity suppliers.

A similar situation—and one that is more common within the petroleum industry—exists for companies that switch from purchasing electricity to generating it on site. If they report only their direct GHG emissions, their emissions will increase once they start to generate their own electricity. If their own generation of this electricity is less GHG-intensive than the electricity they formerly purchased, however, the actual net emissions will have decreased. By including indirect emissions in their inventory, companies will be able to demonstrate the emissions benefit of the change. For situations where the company switches to self-generation and exports excess electricity, Chapter 7 describes how to account for net reductions in emissions associated with the exported electricity.

Companies may offset their emissions by investing in external emission reduction projects. Since by definition the emission reductions from these projects are external to the company, the reductions would not be captured in the company's own inventory. How external emission reduction projects may be reported is described in Chapter 7. Similarly, companies may acquire emission reductions through trades with outside parties, which may be reported as described in Chapter 7.

5 Identification of Industry GHG Emissions

5.1 Greenhouse Gases

Gases in the atmosphere that allow solar radiation to reach the earth's surface but trap thermal radiation leaving the earth's surface are called greenhouse gases. With the exception of water vapor, these gases are present in the atmosphere in trace concentrations. Greenhouse gases enter the atmosphere both as part of natural cycles and as the result of human activities[15].

The most commonly reported greenhouse gases are those covered by the Kyoto Protocol:

- Carbon Dioxide, CO_2
- Methane, CH_4
- Nitrous Oxide, N_2O
- Hydrofluorocarbons, HFCs
- Perfluorocarbons, PFCs
- Sulfur Hexafluoride, SF_6

In addition to this list, some reporting programs, such as the national inventory reporting program of the Intergovernmental Panel on Climate Change (IPCC), include emissions of nitrogen oxides, carbon monoxide, and non-methane volatile organic compounds when accounting for GHG emissions. These compounds contribute to the formation of tropospheric ozone, which is itself a greenhouse gas.

Emissions of nitrogen oxides (NO_x) should not be confused with emissions of nitrous oxide (N_2O). While NO_x is sometimes used to collectively refer to all compounds containing nitrogen and oxygen, more commonly it is defined as the sum of NO and NO_2. In addition, analytical methods used in the measurement of NO_x emissions do not include N_2O emissions. Therefore, NO_x emissions should not be treated as equivalent to or including N_2O emissions when conducing GHG emissions inventories.

Compounds covered by the Montreal Protocol, such as chlorofluorocarbons and hydrochlorofluorocarbons, are also sometimes included in GHG emissions inventories. While these compounds are also GHGs, they currently receive relatively little attention as GHGs because they either have already been or are being phased out for most applications.

5.1.1 Petroleum Industry Greenhouse Gases

It is recommended that companies within the petroleum industry account for and report all significant emissions of each of the six GHGs listed above that fall within their established organizational and operational boundaries. Virtually all companies within the industry would be expected to have emissions of CO_2—and to a lesser extent CH_4, and

[15] For fluorinated compounds typically listed as GHGs, the atmospheric concentrations are due almost entirely to human activities.

N_2O—since these gases are produced through combustion. Both CH_4 and CO_2 are also part of the materials processed by the industry as they are produced, in varying quantities, from gas and oil wells. Because the quantities of N_2O produced through combustion are quite small compared to the amount of CO_2 produced, CO_2 and CH_4 are the predominant petroleum industry GHGs.

HFCs, PFCs, and SF_6, while not as closely associated with the petroleum industry as other GHGs, may be emitted by various subsectors and operations. HFCs are increasingly used in refrigeration systems, including virtually all motor vehicle air conditioners. Both HFCs and PFCs may be used as solvents, and PFCs are used in some fire extinguishing systems. PFCs are also emitted during the manufacture of aluminum and in some semi-conductor manufacturing processes. Sulfur hexafluoride is used in high-voltage electrical equipment and in the production and casting of magnesium. Since none of these emitting activities are core parts of the petroleum industry, total emissions of these gases would be expected to be small. For particular facilities or businesses in which petroleum industry companies have an interest, however, these kinds of emissions may be significant.

Petroleum industry companies whose organizational boundaries include industries such as metals production and processing, semiconductor manufacture, or power generation and transmission where emissions of trace greenhouse gases may be significant should consult the relevant industry guidance on how to estimate and report these trace gas emissions. This guidance includes:

- *Greenhouse Gas Emissions Monitoring and Reporting by the Aluminium Industry* (IAI, 2002; produced as an Addendum to the original *GHG Protocol*)

- *Sector-Specific Calculation Tools* developed as part of the WBCSD/WRI *Greenhouse Gas Protocol Initiative* related to the manufacture of:
    - aluminum
    - iron and steel
    - nitric acid
    - ammonia
    - adipic acid
    - HCFC-22 (HFC-23 emissions)
    - semi-conductors

These tools can be found at www.ghgprotocol.org/standard/tools.htm.

5.1.2 Greenhouse Gas Global Warming Potentials

The direct effect of GHGs in trapping thermal radiation, their indirect effects in transforming to or influencing the formation or degradation of other GHGs, and the lifetime of the gases in the atmosphere vary greatly. In order to account for these differences, the concept of Global Warming Potential (GWP) has been developed. The GWP of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing (warming effect) from the instantaneous release of 1 kg of the GHG relative to that from the release of 1 kg of CO_2. To express emissions on the basis of their global warming potential, the mass of emissions of each GHG is multiplied by its corresponding GWP. The result is referred to as the CO_2-equivalent (CO_2-eq) emissions because the GWPs are based on the warming potential relative to CO_2. Because the GWP of CO_2 is always one, the mass emissions of CO_2 and the CO_2-eq emissions are identical.

Global warming potentials are calculated over different time periods, typically ranging from 20 to 500 years. The most common time period for expressing GWPs is 100 years. It is recommended that companies use the 100-year GWP when expressing emissions on the basis of CO_2-equivalents.

Table 5-1 lists the 100-year GWPs for the six GHGs covered by the Kyoto protocol. Since two of these gases, HFCs and PFCs represent a families of compounds rather than individual chemical species, GWPs are included for selected members of these families.

The set of GWPs listed in Table 5-1 comes from *Climate Change 1995: The Science of Climate Change* (IPCC, 1996), which is commonly referred to as the Second Assessment Report. In 2001, the IPCC published *Climate Change 2001: The Scientific Basis* (IPCC, 2001), referred to as the Third Assessment Report, which contains revisions to the GWPs listed in the Second Assessment Report.

Most existing guidance uses GWP values from the Second Assessment Report, and most reporting programs require the use of these values. Where required, national reporting of emissions on a CO_2-eq is currently done on the basis of the GWPs contained in the Second Assessment report, and is expected to continue based on these values until at least 2012. Therefore, for consistency of industry reporting of GHG emissions, it is suggested that companies use the GWPs contained in the Second Assessment Report and listed in Table 5-1 (the 1996 values). They should continue to use these values until updated GWPs have been accepted by the IPCC for national reporting of GHG emissions.

The recommendation that companies use 100-year GWPs from the Second Assessment Report is consistent with the most common way of reporting CO2-eq emissions today[16]. However, scientific estimates of GWPs do change with time, and scientific and policy debate exists over the appropriateness of using the 100-year GWP, or indeed of using some other measure than GWP. Consequently companies should track their emissions of GHGs on a mass basis, as well as on a CO_2-eq basis, and transparently report which GWPs they use in reporting their emissions.

[16] Companies that report to the U.S. Department of Energy, Energy Information Agency (EIA) Voluntary Reporting of Greenhouse Gases Program (also know as the 1605b program) should note that EIA uses GWPs from the Third Assessment Report for the purpose of compiling summary program statistics.

Table 5-1. Recommended 100-Year GHG Global Warming Potentials from the Second Assessment Report

Greenhouse Gas	Global Warming Potential
Carbon Dioxide (CO_2)	1
Methane (CH_4)	21
Nitrous Oxide (N_2O)	310
HFCs	
HFC-23	11,700
HFC-32	650
HFC-41	97
HFC-125	2,800
HFC-134	1,000
HFC-134a	1,300
HFC-143	300
HFC-143a	3,800
HFC-152a	140
HFC-227ea	2,900
HFC-236fa	6,300
HFC-4310mee	1,300
PFCs	
CF_4	6,500
C_2F_6	9,200
C_3F_8	7,000
C_4F_{10}	7,000
C_5F_{12}	7,500
C_6F_{14}	7,400
Sulfur Hexafluoride (SF_6)	23,900

Source: IPCC, 1996

For the purpose of comparison, updated GWPs from *Climate Change 2001: The Scientific Basis* (IPCC, 2001), also referred to as the Third Assessment Report, are listed in Table 5-2. As the data in the table illustrate, the updated GWPs vary somewhat from the earlier values—some decreasing some increasing. Of particular interest to the petroleum industry is the increase in the GWP for methane from 21 to 23. While the use of these values is not recommended at this time, companies should remain cognizant of these values as they are revised, recognize they may need to use them in the future, and understand the implications of the changes on their emission levels.

Table 5-2. Revised 100-Year GHG Global Warming Potentials from the Third (2001) IPCC Assessment Reports (not recommended for use)

Greenhouse Gas	Global Warming Potential
Carbon Dioxide (CO_2)	1
Methane (CH_4)	23
Nitrous Oxide (N_2O)	296
HFCs	
HFC-23	12,000
HFC-32	550
HFC-41	150
HFC-125	3,400
HFC-134	1,100
HFC-134a	1,300
HFC-143	330
HFC-143a	4,300
HFC-152a	120
HFC-227ea	3,500
HFC-236fa	9,400
HFC-4310mee	1,500
PFCs	
CF_4	5,700
C_2F_6	11,900
C_3F_8	8,600
C_4F_{10}	8,600
C_5F_{12}	8,900
C_6F_{14}	9,000
Sulfur Hexafluoride (SF_6)	22,200

Source: IPCC 2001

5.2 Petroleum Industry Greenhouse Gas Emission Sources

Greenhouse gas emissions from the petroleum industry arise from a variety of different types of sources. These sources fall within three main categories:

- Combustion Emissions—including stationary and mobile combustion sources
- Process Emissions
- Fugitive Emissions

Stationary combustion emissions include the emissions resulting from the combustion of fuels in boilers, furnaces, burners, heaters, and stationary turbines and engines, as well as the combustion of wastes in incinerators and flares. These sources exist widely within the petroleum industry, and account for most of its GHG emissions.

Mobile combustion sources include combustion of fuels in ships, barges, trains, trucks, automobiles and aircraft. While these sources are also commonly used within the petroleum industry, their emissions are generally much smaller than from stationary combustion sources

Process emissions of GHGs result from the physical or chemical processing of materials—within the petroleum industry, typically gaseous or liquid hydrocarbon streams. Venting of CO_2 removed from gas steams, and the production of CO_2 in the manufacture of hydrogen are examples of process emissions from the industry. The magnitude of process emissions varies widely, and may represent significant emissions from some petroleum industry facilities.

Fugitive emissions occur from equipment leaks such as from seals, gaskets, and valves. Within the industry, fugitive emissions historically have been of primary concern due to releases of volatile organic compounds (hydrocarbons heavier than methane). In the context of GHG emissions, fugitive sources within the industry are of concern mainly due to the high concentration of CH_4 in many gaseous streams, as well as the presence of CO_2 in some streams. However, relative to combustion and process emissions, fugitive carbon dioxide and methane admissions are insignificant. (See the *Compendium.*)

The source categories listed above are consistent with those listed in the *GHG Protocol* (WRI/WBCSD, 2001). In some guidance, other categories, such as for indirect emissions and non-routine releases may be listed. The actual sources of indirect emissions, as well as non-routine emissions will generally fall into one of the three categories listed above, however. The division between direct and indirect sources is based on the operational boundaries of the inventory, and the distinction between routine and non-routine release is an issue of when emissions occur, rather than the type of source they are emitted from. Therefore, neither indirect emissions nor non-routine releases have been identified as separate source categories for the purpose of these *Guidelines*.

For listings of specific GHG emissions sources, the *Compendium* should be consulted. Chapter two of the *Compendium* lists specific types of emissions sources, their source category, and the types of GHGs they emit for a large set of petroleum industry sources.

6. Evaluation of Industry GHG Emissions

Quantification of GHG emissions from the petroleum industry is complicated by the wide variety of emission sources and the nature of the fuels consumed by the industry. A very large fraction of the industry's combustion emissions comes from burning hydrocarbon mixtures that are highly variable in composition and cannot be well characterized with published emission factors. In addition, the quality of information available to characterize emissions, including both the composition and quantities of the materials being combusted may vary substantially among and within industry subsectors.

In evaluating combustion-related GHG emissions, it is important to understand the nature of what is being burned. For the combustion of gaseous hydrocarbon mixtures in particular, estimates of CO_2 emissions based on the actual gas composition will provide the most accurate results. If the gas composition is not available, emission calculations should be made using mass-based emission factors (mass of CO_2/mass of fuel) and the actual mass of fuel burned or be made using energy-based emission factors (mass of CO_2/energy content of the fuel) and the actual amount of energy consumed. Using volume-based emission factors that have not been derived specifically for the fuel of interest and the volume of fuel consumed will produce much greater uncertainty in the calculated emissions.

The accuracy required for reporting GHG emissions depends on the uses of the data being reported. If the data are being used solely for internal purposes, the needed accuracy and completeness of the data may, in some cases, be limited. If the data are to be used for voluntary public reporting, greater rigor will be required. If the emissions data are to be used to generate some financial benefits for the company, from emissions trading, for example, the quality of the emissions estimates will be greater still.

The purpose of this chapter is to provide guidance on the evaluation of GHG emissions from the major subsectors of the petroleum industry:

- Upstream Operations,
- Downstream Operations, and
- Chemicals.

This chapter serves as a companion to the *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* (API, 2001). While the *Compendium* describes methods for estimating industry GHG emissions focusing on individual sources, these *Guidelines* recommend how the methods should be applied to achieve various reporting levels for different types of industry facilities. The *Compendium* and a calculation tool that covers the methods contained within the *Compendium* will be made available for downloading free of charge at http://ghg.api.org. These *Guidelines* will also be made available at that web site as well as at www.ipieca.org/reporting/ghg.html and www.ogp.org.uk.

Where multiple approaches exist for estimating emissions, they have been divided into three tiers, with Tier A providing the most accurate estimates, Tier B an intermediate level of accuracy, and Tier C the most general estimates. Associated with each Tier is an estimated range of uncertainty that would result from applying the Tier to an entire facility. These uncertainty ranges are based on professional judgment, rather than the results of a survey of a sample facility or facilities. The uncertainty ranges are not meant to apply to individual sources within a particular type of facility. Rather, they are given as an estimate of the uncertainty in the total emissions from a facility that would result from applying the set of listed estimation methods.

The GHGs evaluated in this chapter are limited to CO_2 and CH_4 because these are the principal GHGs emitted by the petroleum industry. Where emissions of one of these gases from a particular process are considered to be negligible, the emission estimation approach is designated as “not considered.” For example, because methane emissions from controlled combustion sources are negligible compared to CO_2 emissions, they are designated as not considered for all three Tiers. While the *Compendium* provides methods for estimating both CO_2 and CH_4 emissions from a wide variety of industry sources—and some regulatory programs may require reporting of these and other GHG emissions—this does not imply that those emissions are significant at the corporate, facility, or even the source level. Demonstrations of the insignificance of particular industry GHG emission sources are provided in exhibits and case studies included in the *Compendium*.

Emissions of nitrous oxide (N_2O) are not included in emission estimation methods described in this chapter. While N_2O is formed during combustion, stack test analyses indicate that the amounts produced are negligible when compared to emissions of CO_2—even when accounting for the high GWP of N_2O. Furthermore, relatively little data are available with which to evaluate N_2O emissions from combustion. Since N_2O emissions are not known to occur from other types of petroleum industry sources—fugitive or process emissions—N_2O emissions are not included in this chapter. Emissions of N_2O do occur through the production of adipic acid and nitric acid, and would need to be included in emissions inventories of facilities that produce them. Such facilities would not generally be classified as part of the petroleum industry, however, or even the petrochemical industry.

The definition of Tiers depends on the industry subsector under consideration because the nature of the data available to estimate emissions varies from subsector to subsector, particularly between upstream petroleum operations and other subsectors. The subsequent sections of this chapter describe how the tiered approach to quantifying emissions applies to the three major industry subsectors.

6.1 Evaluation of GHG Emissions from Upstream Petroleum Operations

Table 6-1 illustrates the three calculation Tiers for estimating emissions of GHGs from upstream petroleum operations. In Appendix B, the sections of the *Compendium* that describe the recommended calculation approaches are cross-referenced to this table. Since most emissions from the operations listed in Table 6-1 come from the combustion

Table 6-1. Exploration and Production Tiers

		Estimation Tiers		
		Tier C	Tier B	Tier A
		Uncertainty		
		+/-30-60%	+/- 20-40%	+/- 10-30%
Source Category	*GHG*	*Estimation Approach*		
Combustion Sources	CO2	Fuel consumption based on ratings, hours of operation and assumed loads for engines/turbines (energy balance for boilers/heaters); default fuel emission factors or factors based on actual measurements of fuel composition if available.	Fuel consumption based on ratings, hours of operation, and loads for engines/turbines (energy balance for boilers/heaters); fuel emission factors (mass/mass or mass/heating value) based on default factors.	Fuel consumption based on single point metering* and integrating mass flow for fuel gas, purchase records or tank measurements for commodity fuels (e.g., natural gas, diesel); fuel emission factors (mass/mass or mass/heating value) based on default factors.
	CH4	Not considered	Not considered	Not considered
Flaring	CO2	Quantity of gas flared based on available GOR measurements and quantity of oil produced. Local default CO2 emission factors applied or factor based on gas composition if available.	Quantity of gas flared based on periodic GOR measurement and quantity of oil produced. Gas composition measured at similar intervals, or local default CO2 emission factors applied.	Quantity of gas flared based measurements/metering and/or frequent GOR measurement and quantity of oil produced. Gas composition measured at similar intervals, or local default CO2 emission factors applied.
	CH4	Calculated from information above, assumed or known methane fraction in flare gas and default residual methane (flare efficiency).	Calculated from gas quantity information above, measured or assumed gas composition, and default residual methane (flare efficiency).	Calculated from gas quantity information above, measured or assumed gas composition, and default residual methane (flare efficiency).
Associated Gas Venting	CO2	Include only for CO2-rich streams. Quantity of gas vented based on available GOR measurements and quantity of oil produced; assumed duration of flare outages for inadvertent venting. Local default or actual gas composition used as available.	Quantity of gas vented estimated (e.g., by periodic GOR measurement and quantity of oil produced; duration of flare outages for inadvertent venting). Gas composition measured at similar intervals.	Quantity of gas vented estimated (e.g., by frequent GOR measurement and quantity of oil produced; duration of flare outages for inadvertent venting). Gas composition measured at similar intervals.
	CH4	Quantity of gas vented based on available GOR measurements and quantity of oil produced; assumed duration of flare outages for inadvertent venting. Local default or actual gas composition used as available.	Quantity of gas vented estimated (e.g., by periodic GOR measurement and quantity of oil produced; duration of flare outages for inadvertent venting). Gas composition measured at similar intervals.	Quantity of gas vented estimated (e.g., by frequent GOR measurement and quantity of oil produced; duration of flare outages for inadvertent venting). Gas composition measured at similar intervals.
Acid Gas Removal	CO2	Emissions based on quantity of gas produced and assumed residual CO2 content. Local default or actual inlet gas composition used as available.	Results of process simulation, such as AmineCalc	Mass balance across amine unit (e.g., based on difference between inlet gas flow and CO2 fraction and outlet gas flow and CO2 fraction--measured parameters.)
	CH4	Not considered	Application of generic emission factors or results from process simulation such as AmineCalc	Results of process simulation, such as AmineCalc
Glycol Dehydration	CO2	Not considered	Not considered	Not considered
	CH4	Not considered	Application of generic emission factors	Application of generic emission factors

continued

Table 6-1. Exploration and Production Tiers, continued

		Estimation Tiers		
		Tier C	Tier B	Tier A
		Uncertainty		
		+/-30-60%	+/- 20-40%	+/- 10-30%
Source Category	*GHG*	*Estimation Approach*		
Tank Flashing	CO_2	Not considered	Not considered	Not considered
	CH_4	Not considered	Application of generic emission factors -or- emission estimation equations	Measurement of vent gas -or- application of process simulation such as E&P Tank
Other Process Sources	CO_2	Not considered	Process mass balance as in Compendium using activity data based on best engineering estimates	Process mass balance as in Compendium using activity data based on best engineering estimates
	CH_4	Not considered	Not considered	Not considered
Non Routine Sources	CO_2	Not considered	Engineering estimates	Engineering estimates
	CH_4	Not considered	Engineering estimates	Engineering estimates
Process Fugitives	CO_2	Not considered	Include only for streams that are > 30% CO_2 based on component-level average emission factors, and typical component counts.	Include only for streams that are > 30% CO_2, based on component-level average emission factors, and actual component counts.
	CH_4	Not considered	Based on component-level average emission factors, and typical component counts.	Based on component-level average emission factors, and actual component counts.
Non-Operated Facilities	CO_2 CH_4	If the operator is unwilling or unable to provide GHG emissions data or the activity data, E&P emissions may be estimated by prorating to the nearest equivalent company-operated production facility.		

*Single point metering refers to the use of a single meter to measure the total gas flow for an entire facility or part of a facility, rather than metering flow to each emission source separately.

(in either equipment or flares) or venting of the gas that is produced, the primary differences among the Tiers relate to the level of detail in the information on the composition of the produced gas and the quantities combusted in equipment, flared, or vented.

Part of the distinction between Tiers is based on the frequency of sampling of gas streams. This applies both to vented gas streams and to gas streams that are combusted. Specific sampling intervals are not listed in Table 6-1. Increasing the frequency of sampling will reduce the uncertainty of the facility emissions estimates, particularly for large streams of variable composition and flow. Gas streams that have relatively constant compositions will require less frequent sampling; those with more variable compositions will require more frequent sampling.

6.2 Evaluation of GHG Emissions from Petroleum Refining and Petrochemicals

Petroleum refining GHG emissions result primarily from combustion and process sources, including regenerators on fluid catalytic cracking units and hydrogen plants. Fugitive emissions of GHGs will generally be much smaller than other sources.

Petrochemical production has similar emissions sources. The three tiers for quantifying GHG emissions from petroleum refining and petrochemicals are shown in Table 6-2. As for Table 6-1, the sections of the *Compendium* that describe the emission estimation methodologies for the recommended approaches in this Table are shown in Appendix B.

Table 6-2. Petroleum Refining and Petrochemical Tiers

			Estimation Tiers	
		Tier C	Tier B	Tier A
			Uncertainty	
		+/- 15-30%	<+/- 15%	+/- 5-10%
Source Category	*GHG*		*Estimation Approach*	
Combustion Sources	CO2	Thermal input (fuel burnt) estimated based on design rating of plant and hours operated, default fuel factors	Thermal input (fuel input) based on metering* or energy balances on heaters/boilers, fuel composition obtained from occasional spot sampling	Thermal input (fuel input) based on metering* or energy balances on heaters/boilers, fuel composition obtained from frequent spot sampling
	CH4	Not considered	Not considered	Not considered
FCC Coke Burn	CO2	Thermal input (fuel burnt) estimated based on design rating of plant and hours operated, default coke factor	Coke burn rate calculated based on process mass/energy balance and average coke composition based on spot samples -OR- estimated directly from measured CO and CO2 concentrations in exhaust (spot samples) and air/oxygen flow rate to regenerator	Coke burn rate calculated based on process mass/energy balance and average coke composition based on spot samples -OR- estimated directly from measured CO and CO2 concentrations in exhaust (spot samples) and air/oxygen flow rate to regenerator
	CH4	Not considered	Not considered	Not considered
Flaring	CO2	Engineering estimates of gas flared i.e., using API flame length correlation and default factor for refinery gas	Process engineering estimates of flared volume based on known purge rates, process unit flows to flare and estimates of non-routine flaring based on plant logs. Weighted average flare gas composition based on estimated composition.	Flared volume estimated from flare gas meters where available, known purge rates and best process engineering estimates, average flare gas composition based on spot samples throughout the year adjusted if significant non-routine flaring.
	CH4	Not considered	Not considered	Not considered
Hydrogen Plant (process)	CO2	Process mass balance based on estimated hydrogen production	Compendium "simple" method based on estimated hydrogen make.	Compendium "complex" method i.e. process mass balance based on known reformer feed rate and composition
	CH4	Not considered	Not considered	Not considered (spot check on methane content of CO2 vent stream)
Other Process Sources	CO2	Not considered	Process mass balance as in Compendium using activity data based on best engineering estimates	Process mass balance as in Compendium using activity data based on best engineering estimates
	CH4	Not considered	Not considered	Not considered
Non Routine Sources	CO2	Not considered	Engineering estimates	Engineering estimates
	CH4	Not considered	Engineering estimates	Engineering estimates

continued

Table 6-2. Petroleum Refining and Petrochemical Tiers, continued

		Estimation Tiers		
		Tier C	Tier B	Tier A
		Uncertainty		
		+/- 15-30%	<+/- 15%	+/- 5-10%
Source Category	*GHG*	*Estimation Approach*		
Process Fugitives	CO2	Not considered	Not considered	Not considered
	CH4	Not considered	Not considered	Not considered (possibly significant for natural gas supply pipe work)
Other Area Sources	CO2	Not considered	Not considered	Not considered
	CH4	Not considered	Not considered	Not considered
Non-Operated Refineries and Petrochemical Plants	CO2 CH4	For non-operated refineries where the operator is unwilling or unable to provide GHG emissions data or the activity data, refinery emissions may be estimated by prorating to the nearest equivalent company operated refinery with suitable adjustments for processing severity and crude properties. A similar approach may be applied for petrochemical facilities if the feedstocks, processes, and products are sufficiently similar.		

*Metering may be performed at fuel headers rather than at individual combustion sources.

Note:
Refinery loss control data (carbon mass balance) may provide lower uncertainty than the Tier B and Tier C methods, and thus may be used as a check on the CO2 emission results.

6.3 Materiality

The concept of materiality is discussed in Chapter 8 of these *Guidelines* in the context of verification of emissions inventories. As described there, a material discrepancy is one that would affect the decision making or actions of a stakeholder using the inventory information. Materiality should not be thought of as a permissible quantity of emissions that a reporting entity can leave out of its inventory. Nevertheless, companies conducting emission inventories inevitably make decisions concerning emission sources and GHGs that they deem insignificant.

These *Guidelines* make no specific recommendation concerning a de minimis level of emissions that can be left out of a GHG inventory. A specific de minimis level of emissions is not recommended because a level that is insignificant for one facility, such as an oil refinery, may be very significant for another, such as a terminal. Where companies do wish to apply some form of test on their emission levels, it is recommended that they apply it collectively to all sources within a facility or subsector. This will ensure that the total of many small sources does not become a significant (or material) omission. Companies that apply a numerical threshold for their reporting should document that information with their inventory.

Companies should recognize that some GHG programs have established thresholds either for individual sources or for total emissions that allow for minor sources to be omitted from reporting. Two such programs are the UK Emissions Trading Scheme and the California Climate Action Registry. Companies considering joining such programs will want to review their internal policies to ensure that they meet the program requirements.

7. GHG Emissions Reporting

When reporting emissions as part of an established GHG program, companies should follow the rules of those programs. For the voluntary public reporting of GHG emissions, it is recommended that companies within the petroleum industry follow the guidance provided in this chapter. The guidance below and parts of Sections 7.1 and 7.2 comes from the *GHG Protocol* (WRI/WBCSD, 2001). Sections 7.1 and 7.2 also draw upon data aggregation and normalization approaches employed by the American Petroleum Institute.

Content of a Public GHG Emissions Report

A public GHG emissions report should include the following kinds of information:

1. Description of the Reporting Organization and its Boundaries:
   - An outline of the organization and the reporting boundaries chosen
   - The reporting period covered
   - Description of the types of sources excluded and rationale for doing so

2. Information on Emissions and Performance:
   - Emissions on an operational control and/or equity share basis (specify which)
   - Direct emissions and any indirect emissions separately reported
   - Emissions for each GHG separately reported on a mass and CO_2-equivalent basis
   - Subdivided emissions, e.g., by business group, facility, country, or source type, consistent with the firm's normal reporting practices
   - Emissions performance over time, and, if appropriate, relative to a base year and a target; specification of base year
   - Normalized emissions
   - Performance against internal and external benchmarks (optional)

3. Supporting information
   - Description of methodologies used to quantify emissions
   - Any qualifications to the data (e.g., the use of preliminary data to estimate emissions pending the later availability of final data)
   - Context for any significant emission changes
   - Emissions associated with exported energy
   - Emission reductions resulting from projects that displace emissions from energy production external to the inventory boundary with less-emitting exported energy
   - Other emission reductions banked, sold to, or purchased from third parties
   - Emissions from biologically sequestered carbon (e.g., burning biomass or biofuels)
   - Emissions from geologically sequestered carbon (e.g., resulting from enhanced oil recovery operations using CO_2 injection)

- Description of any GHG management or reduction programs either within or outside of the company reporting boundaries
- Description of the results of any external assurance conducted on the reported emissions data
- Name of a person to contact for further information
- Discussion of inventory quality (optional)
- Emissions of GHGs not covered by the Kyoto Protocol (optional)

The intent of reporting information in this way is to provide the recipient of the information sufficient context to interpret it. Companies will need to exercise judgment in determining how to report in the listed information and how much to report. For example, the reporting of normalized emissions is useful only if the activity causing the emissions is well defined and readily quantified (see Section 7.2). Similarly, the types of supporting information suggested for reporting will not be appropriate for all companies, and a large amount of detail may not be possible to include in company environmental or sustainability reports. If this is the case, companies should make the more detailed information available by other means, for example, through their web site or their inventory contact person.

The remainder of this chapter provides guidance on reporting GHG emissions performance for the petroleum industry, focusing on Item 2 above, information on emissions and performance.

7.1 Data Aggregation

Greenhouse gas emissions may be aggregated across a range of dimensions including organizational and operational boundaries, geographic boundaries, industrial sectors, company divisions, facilities, and source types. As discussed in Chapter 3, companies typically set their overall organizational boundaries for reporting either on the basis of operational control or equity share. Those companies that can report on both bases are encouraged to do so.

7.1.1 Aggregating by Operational Boundaries

For their selected organizational boundaries, petroleum industry companies should report their operating emissions in three separate categories:

- Direct emissions
- Indirect emissions from energy imports (if reporting such emissions)
- Other indirect emissions specified by subcategory (if reporting such emissions)

The reason for reporting different types of emissions separately is to provide a clear picture of which GHG emissions are being reported. Emissions reporting should also be complete within each category or sub-category. Direct emissions should include any emissions associated with the production of exported energy such as steam or electricity. If a company chooses to report indirect emissions from the consumption of purchased energy, then the reported amount should be completely separate from the direct and other indirect emissions categories and should represent a complete inventory of the indirect emissions from energy imports. If a company chooses to report other indirect emissions, then they should be reported completely separately from direct emissions and indirect emissions from consumption of purchased energy. Each subcategory of other indirect emissions included in the inventory should be listed, and reporting should be complete within each sub-category. This means that if a company chooses to report a particular type of indirect emissions, it should report those emissions for all of its relevant sources, and not report them selectively.

Companies that export energy may choose to report the emissions associated with the exported energy in a note or memo to their reported emissions or as part of the supporting information that accompanies their data. In addition, if they have installed a generating facility (or cogeneration facility) that results in a net reduction in GHG emissions, they may quantify those reductions as a specific emission reduction project and list them as emission offsets in their inventory.

Figure 7-1 illustrates how corporations would report their GHG emissions for one of their companies or an individual facility, such as an oil refinery. In this example, *direct* emissions of 80 (including 15 related to exported energy) are reported separately from indirect emissions. Indirect emissions consist of emissions from consumption of purchased energy (30) and other indirect emissions (10), the indirect emissions from imported energy being reported separately from other listed indirect emissions. In addition to its direct and indirect emission sources, however, this company has implemented a project that results in emission reductions outside of its reporting boundary (20). In the case of a refinery, this might be the installation of a cogeneration facility that exports electricity thereby displacing emissions from the generation of more CO_2-intensive electricity.

Exported Energy

It is common practice today for companies within the petroleum industry to be exporters of energy (electricity, steam, or hot water). Some companies have set up subsidiaries or joint ventures for the purpose of generating electricity for sale. Refining and petrochemical operations often cogenerate steam and electricity, selling the electricity they do not need for their own production processes. When reporting their GHG emissions, companies should include emissions from exported energy in their total direct emissions, as shown in Figure 7-1. Any net reductions that result from displacing more highly emitting energy sources outside of the company's reporting boundary should be reported as project-based emission reductions, which may be used to offset the company's emissions.

Companies may choose to separately track emissions from exported energy and report this information either in a note to their emissions inventory or in the supplemental information they provide. Tracking emissions from exported energy will allow them to consistently aggregate and normalize their emissions as described in Section 7.2.

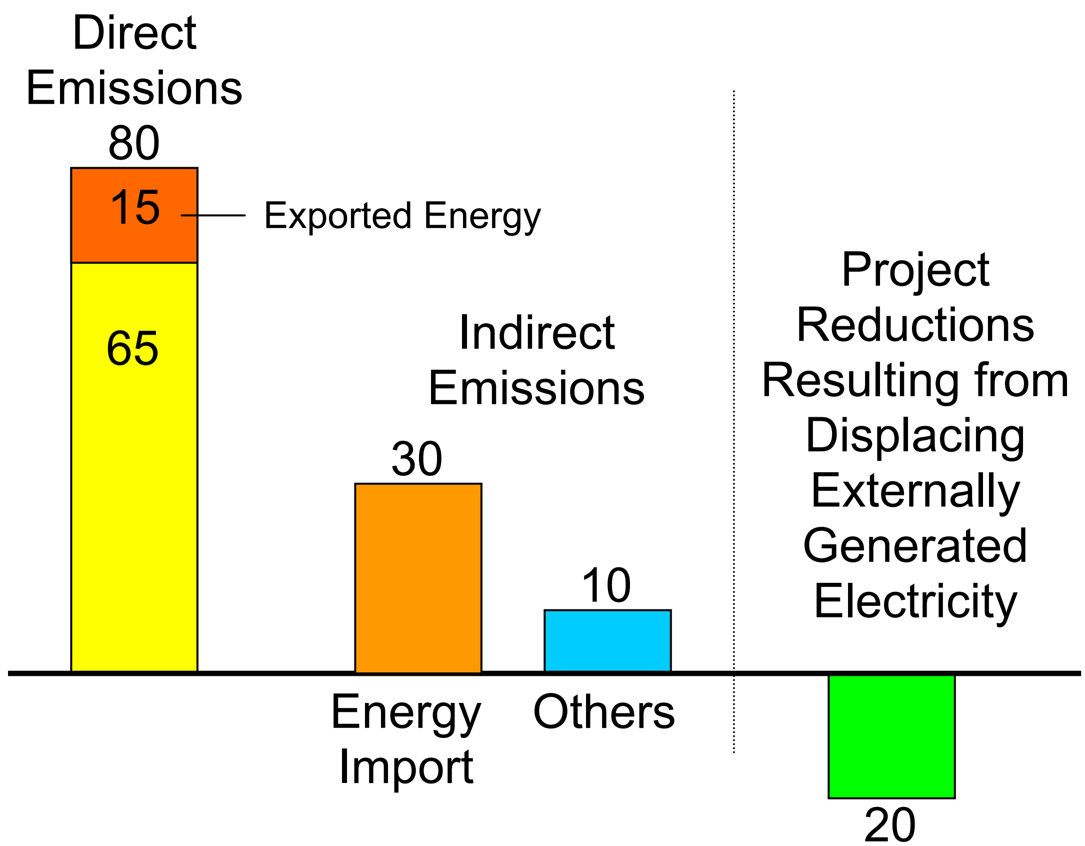


Figure 7-1. Emissions Aggregation Along Operational Boundaries

The estimation of emissions associated with the energy exported from combined heat and power plants is handled in a manner analogous to that for estimating emissions from energy imported from such plants. Companies will need to apportion the GHG emissions associated with a plant's exported energy between heat and power in the same manner as they do for imported energy, unless they export all of the heat and power from the plant. Since most refineries and petrochemical plants with cogeneration facilities typically use at least some of the produced energy internally, it is expected that apportionment of emissions will be necessary in most cases. Approaches to allocating cogeneration emissions are described in Section 3.2.2.

7.1.2 Aggregating Along other Dimensions

Companies report on their GHG emissions at varying levels of aggregation ranging from individual sources to the entire corporation. Reporting at the source level would occur, for example, by companies in the U.S. that are required to report CO_2 emissions from electric generating units regulated under the US EPA Acid Rain program. Reporting at the corporate level is most commonly done as part of the internal reporting of emissions data and as part of voluntary public reporting.

Data aggregation at one or more levels between individual sources and the entire corporation is commonly required for programs that involve GHG reporting. Program rules usually define how data should be aggregated. The EU Emissions Trading Scheme will require the reporting of emissions at the installation level, while the UK Emissions Trading Scheme is based on emissions from a company's emissions sources (or those emission sources that fall within a particular business sector of the company) located within the UK. Because rules for aggregation vary, companies should maintain their emissions data in as disaggregated form as possible. This will allow them to easily aggregate the data according to the rules of whichever scheme in which they may choose to participate.

For voluntary reporting outside of established GHG programs, companies may wish to aggregate and report emissions at multiple levels, including:

- For specific, major facilities
- By political division, e.g., country, province, or state
- By business unit

These guidelines make no specific recommendations about which of these levels of aggregation companies should report. If, however, companies aggregate and report other environmental data at these levels, it is recommended that they do the same for GHG emissions.

Companies within the petroleum industry vary widely in the breadth of their operations. Some have only exploration and production operations; others are primarily refiners or petrochemical producers. The largest companies operate across all of the major subsectors. For this reason, companies may wish to report their emissions of GHGs by industry subsector. At present, however, there are no widely accepted definitions of just what the industry subsectors are or how, exactly, they should be defined. While the terms "exploration and production," "refining," and "chemicals" are commonly used and widely understood as general categories within the industry, the activities these subsectors include vary somewhat from company to company. For example, transportation of crude oil between production operations and refineries may be included as part of production operations or as a separate subsector. Similarly, transportation of refined products may be included in a refining subsector, as part of marketing, or as a separate subsector. Also, company businesses that are used as the basis for reporting may not correspond to industry subsectors, which further complicates the process of reporting by subsector.

The American Petroleum Institute collects GHG emissions data by industry subsector as part of its annual Environmental, Health and Safety Benchmarking Survey. The survey divides petroleum industry operations into various subsectors for this purpose. As an example of how one petroleum industry trade group considered aggregating emissions, the draft API subsectors are shown in Table 7-1. The definitions of these subsectors are included in the draft instructions to the API's benchmarking survey (API, 2003).

Table 7-1. Draft API GHG Emissions Reporting Subsectors for Industry Benchmarking

Petroleum Industry Subsectors	Mass Emissions	
	CO_2	CH_4
1. Exploration and Production		
2. Refining		
3. Transportation and Terminals		
4. Pipeline		
5. Marine		
6. Chemical		
7. Mining and Minerals		

Source: API, 2003

The aggregation of emissions by industry subsector is done to better enable comparisons to be made among participating companies and to facilitate the normalization of emissions as discussed in the following section of this chapter. Companies that are not currently reporting subsector emissions for other purposes and have not already determined how they should aggregate their emissions may wish to consult with API to determine its final set of subsectors, which had not been established at the time of publication of these *Guidelines*.

Some companies may need to expand the categories listed in Table 7-1. This table does not contain separate subsectors for the production of liquefied natural gas or for facilities to convert gas to liquids. Companies with such facilities may wish to report emissions from them as separate categories.

Table 7-1 also does not contain a specific industry subsector for merchant power production or on-site cogeneration facilities. Some organizations favor the reporting of electricity generation as a separate subsector in order to more clearly demonstrate the emission reductions associated with co-generation and to eliminate one variable in benchmarking emissions from refineries.

When reporting information in a format like that shown in Table 7-1, it is important that companies explicitly state which type of emissions are being reported: direct emissions, direct plus indirect emissions, or direct emissions plus indirect emissions from energy imports minus emissions from energy exports. The use of the latter approach can eliminate one source of variability when benchmarking emissions from facilities or sectors.

7.2 Normalization of Emissions Data

There are two principal aspects of GHG performance that are of interest to management and stakeholders: the absolute quantity of GHG emissions and the quantity of emissions relative to some measure of output. The measure of output may be in physical units, such as tonnes, barrels, or kilowatt-hours, of it may be in terms of the monetary value of the output, e.g., emissions per dollar of sales. Emissions expressed in terms of output are referred to as "normalized" (or sometimes "rate-based") emissions.

The normalization of emissions facilitates comparisons between similar products and processes, while accounting for differences in production levels. Companies report normalized emissions for a number of reasons including:

- Tracking performance over time,
- Comparing performance among similar business operations within the company, and
- Facilitating comparisons with other companies.

Corporations should normalize their emissions in ways that make sense for their businesses and support their decision-making. Within the petroleum industry, the emissions profile of facilities within particular subsectors, such as oil refining or production, may vary greatly even when the operations produce similar products. For the purpose of internal improvement processes, it may be appropriate to account for the differences in these processes when normalizing emissions. For external, public reporting, a gross normalization based on output may be more appropriate. Corporations should normalize emissions for external reporting in a way that permits a better understanding and interpretation of their performance for their stakeholders than merely reporting absolute emissions. It is important for companies reporting normalized emissions results to provide perspective on issues such as the scope and limitations of the normalization in order to give greater context to the users of the information.

As noted above, emissions may be normalized on the basis of the physical quantities of output or on the basis of the value of the output. Because the values of petroleum industry outputs are closely tied to the price of crude oil, it is recommended that companies not normalize emissions in monetary terms. The wide variability in the prices of crude oil from year to year—and within the course of a year—would cause emissions normalized on the basis of monetary output to have little meaning. Instead, it is recommended that emissions be normalized on the basis of physical output.
At present, the bases for normalizing emission within the petroleum industry have not yet been firmly established. Given the wide range of activities within the industry, and the fact that many petroleum industry companies conduct only a limited set of these activities, a single basis for normalization is not possible. It is, however, possible to normalize emissions for specific subsectors. In fact, many companies currently normalize their emissions of GHGs and regulated air pollutants in their public reporting of emissions (e.g., see IPIECA, 2003).

As part of its industry benchmarking survey, API has developed draft normalization indices consistent with the draft subsectors listed in Table 7-1 (API, 2003). These draft indices are listed in Table 7-2. The types of indices used in this Table (though not necessarily the specific units) are similar to those commonly used by companies within the petroleum industry, and companies that have not already established indices and are considering reporting to API may wish to consult with API to determine the final set of normalization factors it develops.

Table 7-2. Draft API Production Indices for GHG Emissions Reporting

Petroleum Industry Subsector	Index
1. Exploration and Production	Production of Crude Oil, Condensates, Natural Gas Liquids, and Dry Gas in million BOE[17]
2. Refining	Crude oil throughput in million barrels
3. Transportation and Terminals	Terminal throughput in million barrels; trucked delivery in billion gallons
4. Pipeline	Pipeline traffic in million barrel-miles (U.S.), Throughput in barrels (outside of U.S.)[18]
5. Marine	Cargo transported in million barrels
6. Chemical	Mass production in million pounds
7. Mining and Minerals	Mass production in million pounds

Source: API, 2003

Care should be taken in interpreting and reporting emissions normalized on the basis of the indices listed in Table 7-2. These indices represent gross measures of production and do not take into account the varying nature of specific operations. Emissions from oil production, for example, will vary greatly depending on need for enhanced oil recovery techniques such as steam injection and whether the associated gas produced with the oil is flared or captured for sales. Similarly, refining emissions will depend on the type of crude oil processed and the mix of products produced, with more highly refined products resulting in greater emissions. Therefore, the emissions normalized on the bases listed in Table 7-2 should be presented as gross measures for comparison of similar operations of individual companies or for similar operations across companies, rather than as measures of inherent emissions efficiency.

[17] Barrels of oil equivalent

[18] Pipeline indices apply only to liquid pipelines; an index is not given for gas pipelines.

8. Inventory Assurance Processes

Companies within the petroleum industry report GHG emissions for a variety of reasons. Depending on the purposes of reporting, stakeholders in the reported information will have varying expectations concerning the quality of the reported data. The different reporting purposes and expectations for the reported data indicate the need for a range of assurance processes for petroleum industry GHG emissions inventories. Chapter 6 described the quality of reported emissions data in the context of emissions estimation approaches. This chapter discusses in broader terms the elements of a quality system to provide assurance on inventory results as well as the process for verifying emissions inventories.

In general, the level of assurance required for GHG emissions data will increase as a company moves from internal reporting to public reporting to reporting for a regulatory or financial purpose. The level of assurance required will also increase with the increasing Tier levels described in Chapter 6. For data that are being used only within the firm, internal assurance processes may be sufficient. For data that are being reported publicly, companies may wish to engage external assurance providers. For data reported to established emissions trading schemes and some voluntary reporting programs, external assurance will typically be required.

The material that follows in this chapter is based on two draft chapters that will be part of the revised *GHG Protocol* (WRI/WBCSD, 2004)—one on inventory quality, the other on verification. Those chapters were combined, shortened, and edited for inclusion here.

8.1 Inventory Management Systems

Companies can facilitate the assurance of their GHG inventories through the use of effective management systems. In many cases, companies within the petroleum industry will already have such systems in place for collecting and reporting other forms of environmental data. Extending the systems to greenhouse gas emissions data should be straightforward. Companies that do not have such systems in place should consider the benefits of adopting them. Having a management system in place will reduce the resources required to provide assurance on their inventory, regardless of whether the assurance is conducted internally or externally.

A practical framework is needed to help companies design their inventory program and quality management system and to help them develop a plan for its progression into the future. Such a framework should address the institutional, managerial, and especially technical attributes of inventory preparation. This simple framework has four fundamentals:

- Methods
- Data
- Inventory processes and systems
- Documentation

Each of these four fundamentals is described below.

Methods. Methods relate to the obvious technical aspects of inventory preparation. Companies should select or develop methodologies for estimating emissions that accurately represent the characteristics of their source categories. These *Guidelines* and the *Compendium* describe many calculation methods to help companies with this effort. The design of a company's inventory program and quality management system should address the ongoing needs not just for the selection, but also for the application and updating of inventory methodologies as new research becomes available, changes are made to business operations, or the importance of inventory reporting is elevated.

Data. Although it is important to use methodologies that are appropriately rigorous and detailed, given the size of a particular source category and its effect on a company's emission trends, the quality of the data that the company is collecting is probably more important. No methodology can compensate for poor quality input data. The design of a corporate inventory program should facilitate the collection of high quality inventory data and the maintenance and improvement of collection procedures.

Inventory processes and systems. Inventory processes and systems refer to all the institutional, managerial, and formal procedural aspects of preparing greenhouse gas inventories—in other words, the people and processes that get the job done. Each company should have an inventory program in place that has the inherent goal of producing high quality inventories. This program should also be integrated, where appropriate, with other corporate processes.

Documentation. Good documentation, as in any other accounting or reporting endeavor, is essential. For efforts such as estimating greenhouse gas emissions that are technical in nature (i.e., involve engineering and science), transparent documentation is even more essential to establishing credibility. If information is not credible and communicated to stakeholders then it cannot have value. Companies should develop procedures to document information intended for internal or external audiences. This documentation should include information employees need to continue preparing and improving all four fundamentals in the company's inventory. Companies should also develop document retention and record-keeping policies to ensure that sufficient information is kept to verify or adjust their emissions inventories back until their selected base year.

A quality management system is important to ensure that an inventory continues to meet the principles of these *Guidelines* into the future. However, it is recognized that companies do not have unlimited resources, and so the quality of the inventory, the extent of quality management activities, and whether uncertainty assessments are made will be a function of these resource limitations. Additionally, unlike financial accounting, corporate GHG inventories are a scientific and engineering exercise without legally sanctioned accounting standards. Given these facts, companies will have to approach the design of their own inventory program and quality management system as a cumulative effort over multiple years, in keeping with the broader evolution of policy and their own corporate vision.

Companies are not expected to rigorously implement every component of a quality management system in the first few years that they begin preparing an inventory. However, they should begin incorporating quality management procedures in the design of their inventory program from the beginning. The rigor and coverage of certain procedures may be phased in over multiple years. For example, initial efforts may focus on direct emissions, the largest source categories, categories with the most dramatic trends, mitigation efforts, or cases where significant changes are occurring in business processes. In general, the initial focus of quality management should be on collecting high quality data and building systems for its collection.

Companies should consider the integration of their inventory quality management system with their overall corporate and environmental information management systems, including any procedures in place as part of their ISO 9000 (Quality Management) or ISO 14001 (Environmental Management) certifications.

8.1.1 Implementation of Inventory Quality Management Systems

Although principles and broad program design guidelines are important, any guidance on quality management would be incomplete without a set of practical measures that can be implemented on actual data and calculations. A company should be able to implement these measures at multiple corporate levels, from the point of primary data collection to the final corporate approval process. These measures are most important to implement where data are initially collected and where calculations and data aggregations are performed. Initially, it may be the final inventory totals at the corporate level that are viewed as the most useful. However, companies may wish to consider ensuring the quality of their data at various levels of disaggregation (e.g., facility, process, operations within a state or province, according to a particular scope, etc) so that they are better prepared for possible markets or regulatory rules in the future.

While implementing their quality management measures, companies should also focus on ensuring the quality of information related to their emission trends, not only on the quality of a single year's inventory estimates. A practical approach to achieving this principle of time series consistency is to focus the company's effort on minimizing biases in the methods and data used for their base year and current year estimates.

The third component of a quality management system is generic quality checking procedures. These procedures should be applied, as appropriate, to all source categories and all levels of inventory preparation. An example list of detailed measures is given in Table 8-1.

The fourth component of a quality management system is source category-specific quality checks and investigations. The following discussion addresses the types of source-specific quality measures that can be employed for emission factors, activity data, and emission estimates.

Table 8-1. Generic Quality Management Measures

Data Gathering, Input, and Handling Activities

- Check a sample of input data for transcription errors
- Identify inventory process modifications that could provide additional controls or checks on quality
- Ensure that adequate version control procedures for any written procedures or electronic files have been implemented

Data Documentation

- Confirm that bibliographical data references are included in spreadsheets or other calculation tools for all primary data
- Check that copies of cited references have been archived
- Check that assumptions and criteria for selection of methods, activity data, emission factors, and other parameters are documented
- Check that changes in data or methodology are documented

Calculating Emissions and Checking Calculations

- Check whether emission units, parameters, and conversion factors are appropriately labeled
- Check if units are properly labeled and correctly carried through from beginning to end of calculations
- Check that conversion factors are correct
- Check the data processing steps (e.g., equations) in any calculation tools that are used
- Check that input data and calculated data are clearly differentiated
- Check a representative sample of calculations
- Check some calculations with abbreviated calculations (i.e., back of the envelope checks)
- Check the aggregation of data across source categories, business units, etc.
- When methods or data have changed, check consistency of time series inputs and calculations

Emission Factors

For a particular source category, calculated emissions will generally rely on emission factors. Published or default emission factors, or fuel, device, or site-specific emission factors may be employed. Quality investigations should assess the representativeness, applicability, and reasonableness of these emission factors. The characteristics of the company's operations should be compared to the conditions of the studies in which emission factors were derived. If company-specific emission factors have been developed, these can be compared with available default emission factors (e.g., those from the *Compendium*, *GHG Protocol* or IPCC). Within the petroleum industry, company and site-specific emission factors will often be more reliable than default factors due to the variable nature of fuels combusted in the industry. Nevertheless, differences between these factors should be documented and filed based upon the specific characteristics of a company's operations. Files containing this documentation should be maintained to allow for future retrieval of the information should it be requested by verifiers or other interested parties.

Activity Data
Possibly the most important input to a company's inventory is the activity data it collects. Therefore, establishing robust data collection procedures should be a priority in the design of any company's inventory program. Several useful measures for ensuring the quality of activity data are given below:

- Data should be collected from metered or measured sources, if possible, either from purchase records or from company measurements.
- Current year data should be compared with previous year's data and historical trends. If data do not exhibit relatively consistent changes from year to year, but rather undergo sharp increases or decreases, then the causes for this pattern should be investigated and explained.
- Activity data from multiple reference sources (e.g., government survey data or data compiled by trade associations) should be compared with corporate data when possible. Although all data may have the same origin, such checks can at least ensure that consistent data is being reported to all parties.
- Activity data will usually be generated for purposes other than preparing a corporate greenhouse gas emissions inventory. Thus, companies should check the applicability of their data to inventory purposes, including checking for completeness, consistency with the source category definition, and consistency with the emission factors used. For example, data from different operating sites should be examined for inconsistent measurement techniques, operating conditions, or technologies. In addition, quality control measures (e.g., ISO) may have already been conducted during the data's original preparation. It should be determined whether these measures are adequate compared to the company's inventory quality management plan.
- Companies should investigate whether any biases or other characteristics that could affect the quality of their data have already been identified (e.g., by communicating with experts in the company or elsewhere).
- If companies are using additional data to estimate emission intensities or other ratios, quality management measures should also extend to these additional data.

Emission Estimates
Estimated emissions for a source category in a given year can be compared with historical data or other estimates to ensure that they fall within a range that is reasonable (changes of over 10 percent from year to year may warrant further investigation). Potentially unreasonable estimates provide cause for checking emission factors or activity data, and determining whether changes in methodology, market forces, or other events are sufficient reasons for the change. In situations where actual emission monitoring

occurs (e.g., power plant CO_2 emissions), then the data from monitors can be compared with estimated emissions using other activity data and emission factors.

If any of the above emission factor, activity data, or emission estimate checks indicate a problem, more detailed investigations into the accuracy of the data or appropriateness of the methods may be required.

8.2 Verification

The previous section describes internal processes and measures that companies may adopt to ensure the reporting of high quality GHG emissions data. As a check on these measures, companies may wish to verify their emissions data. Depending on the purpose of their GHG reporting, they may be required to have their emissions verified.

Verification is an objective assessment of how complete and accurate a GHG inventory is, as well as how well it conforms to pre-established GHG accounting and reporting principles. Verification involves evaluating and testing the 'supporting' evidence (in the form of an audit trail) of the GHG inventory compilation. The practice of verifying corporate GHG inventories is still in its infancy, and the absence of generally accepted GHG accounting and reporting standards means that reporting standards against which verifications have taken place have varied from company to company. With the emergence of more widely accepted accounting and reporting standards, such as these *Guidelines*, the accompanying *Compendium*, the *GHG Protocol,* and the proposed ISO verification guidelines standard, verification practices should become more uniform, credible, and widely accepted. There will also be a growing pool of experienced GHG inventory verifiers at the entity level capable of producing consistent and comparable findings.

Emissions verification may be conducted by independent third parties or internally, through a process of self-verification. Many companies are interested in improving their GHG accounting and reporting systems and often conduct their own internal verification. If a company decides to initiate an internal verification it is preferable, for reasons of objectivity, that this activity be undertaken by a group independent of those responsible for preparing the GHG inventory and report.

This section provides background on the verification process and identifies the key aspects that companies should be aware of when compiling a GHG inventory and establishing internal reporting and documentation systems. Even if a company is not intending to conduct a verification at this time it should still develop its inventory in a manner that is amenable to verification in the future, as discussed in Section 8.1.

One of the most important considerations, in terms of verification, is to ensure transparency and auditability of inventory data. Verification of a transparent and well documented system is easier, and ultimately cheaper, than one that is not well documented. The overall goal of the verification process is to determine whether the GHG report being verified is a faithful and accurate reflection of the reporting entities position. As outlined in Chapter 2, there are a number of key principles that should be adhered to when compiling a GHG inventory. Adherence to these principles is the basis of successful data verification.

8.2.1 Objectives

Before commissioning and planning a verification, the reporting company should clearly define its objectives and decide whether an external verification is the best way to enhance those. Reasons for undertaking verification include to:

- Meet or anticipate the requirements of future emissions trading or other greenhouse policies and programs;
- Improve internal GHG accounting and reporting practices (data calculation, recording and internal reporting systems, application of GHG accounting principles, (e.g. checks for completeness, consistency, accuracy, etc.), and to facilitate learning and knowledge transfer within the organization;
- Increase management and board confidence in reported information;
- Add credibility to publicly reported information and reduction goals, and to enhance stakeholder trust in the reporting organization.

Firms deciding to have their inventories verified will need to assess whether they need an independent third party to conduct the effort, and if it is to be done internally which type of staff will conduct it. Whether the verification is conducted by an independent third party, or as an internal activity, verifiers should follow similar procedures and processes.

8.2.2 The Concept of Materiality

The concept of 'materiality' is essential to understanding the process of verification. A quantity is considered 'material' if it would influence any decision or action taken by users of the information. A *material discrepancy* is an error (for example from an oversight, omission, or miscalculation) that results in the reported quantity being sufficiently different from the true value that it influences decisions or actions. A material discrepancy cannot be ignored, as by definition it is not negligible. It is the role of the verifier to determine whether an identified discrepancy is material or not.

While the concept of materiality involves a value judgment on the part of relevant stakeholders, the point at which a discrepancy becomes material is often pre-defined. This is often referred to as the *materiality threshold* and can be expressed in terms of a percentage of the inventory (e.g., 5 percent) or a quantitative limit (e.g., > 10,000 tonnes). Materiality thresholds may be outlined in the requirements of a specific program or determined by a national or even international verification standard, depending on who is requiring the verification and for what reasons. A materiality threshold is directed at providing some guidance to verifiers on what may be a material discrepancy and to maintain consistency in the treatment of errors across different companies and verifiers. In this context, a materiality threshold is not a permissible quantity of emissions that a reporting entity can leave out of its inventory.

Verifiers also often use the technique of *inventory disaggregation* in order to separate the main emission sources that make up the total inventory into individual emission streams and then apply the relevant materiality threshold to the disaggregated inventory. While a discrepancy may seem immaterial at the aggregate company level, a verifier may well deem a discrepancy as material at the disaggregated level. In preparing an inventory it is important to be aware of what, if any, disaggregation may be adopted by a verifier. For example, a major chemical plant may have three separate operations at one facility site (urea plant, nitric acid plant and ammonia plant). These three plants are likely to be independent operations within one facility and, therefore, a verifier may apply the materiality threshold to the individual emission streams associated with each of these operations, rather than the aggregate emissions for the facility as a whole. Understanding how the verifiers may apply a materiality threshold will enable companies to more readily establish whether individual sources are insignificant and thus unlikely to raise questions of materiality if not included in the inventory.

8.2.3 Establishing the Verification Parameters

The type of verification and the level of assurance it provides will be influenced by the company goals, verification objectives and/or any specific jurisdictional requirements. It is possible to verify the entire inventory data or specific parts of it depending on the objectives of verification. Discrete parts may be specified in terms of geographic location, business units and facilities, and type of emissions. Defining the relevant inventory data and designing the processes for data collection and internal documentation are much easier when it is known in advance that the inventory must be verifiable. The verification process may also examine more general managerial issues, such as quality management procedures, managerial awareness, availability of resources, clearly defined responsibilities, segregation of duties, and internal review procedures.

The reporting company and the verifier should reach an agreement up-front on the level of assurance to be provided and the type of verification to be undertaken. This up-front specification is often referred to as the *Scope of Work*. This addresses issues such as: should the verifier simply review the data (low level of assurance) or actually undertake a detailed analysis (high level of assurance); and whether the verification should involve site visits or be limited to a desktop review of documentation. The *Scope of Work* may also indicate what type of information is necessary to complete the verification.

The *Scope of Work* should clearly specify the materiality threshold (if one is to be adopted) that is applicable and the level of disaggregation that will be used during the verification. As independent verification can be an expensive and time consuming process, it is important that the company and verifier be very clear on the type and level of verification to be performed. It is also important to determine what specific outputs the verification is intended to deliver. A verification undertaken for the purpose of identifying areas for improvement or further capacity building may differ from one directed at determining the company's compliance with a specific regime or program (for example, compliance with the rules of an emissions trading scheme). Furthermore, a clearly defined *Scope of Work* is not only important to the company and verifier but also can assist external stakeholders to understand and interpret the findings of the verification.

8.2.4 Selecting a Verifier

The selection and engagement of a verifier can occur at various points during the GHG reporting period. Some companies may establish a semi-permanent verification unit within their organization to ensure that GHG data standards are being met and improved on an on-going basis.

Verifications that occur during a reporting period can assist in correcting any reporting deficiencies or data issues before the final report is prepared. This may be particularly useful for companies preparing high profile public reports. However, some programs or jurisdictions may require, often on a random basis, an independent verification of the reported inventory following the submission of a report (e.g., the Greenhouse Challenge program in Australia). The timing and nature of the verification will depend on the purpose of the verification.

Some factors to consider when selecting a verifier include: their experience in GHG verification; their understanding of GHG issues and the company's operations; and their objectivity and independence. The knowledge and qualifications of the individual(s) conducting the verification is more important than those of the organization they come from. Effective verification of greenhouse gas inventories often requires a mix of specialized skills, particularly if the company is integrating the carbon accounts with its financial accounting system.

8.2.5 Preparing for a GHG Verification

The internal processes described in Section 8.1 are in many ways similar to those that would be followed by an independent verifier. Therefore the materials that the verifiers will need are similar. In addition, external verifiers will want such information about the company as:

- Information about the company's main activities and their GHG emissions (type of GHG produced, description of activity that causes GHG emissions)
- Company/groups/organization (list of subsidiaries and their geographic location, ownership structure, financial entities within the organization)

and other information, such as:

- Consolidation of data in paper reports or electronic files
- List of persons responsible for collecting GHG emissions data at each site and at the corporate level (name, title, e-mail and telephone numbers)
- Information on uncertainties, quantified or otherwise

Appropriate evidence needs to be available to support the information in the GHG inventory being subjected to external verification. Assertions by management for which there is no available supporting evidence cannot be verified. Where a reporting organization has not yet implemented systems for routinely measuring and recording GHG emissions data, an external verification cannot be undertaken.

Reporting entities need to guarantee the existence, quality and retention of documentation so as to create an audit trail of how the inventory was compiled. If a company has established a specific base year against which it assesses its GHG performance it must retain all relevant historical records to support the base year data. Reporting entities designing and implementing the processes and procedures for creating an inventory should, therefore, make a point of creating a clear document trail.

Information that underpins GHG inventory data should be recorded in a systematic manner, for example an electronic database. As noted in Section 8.1, some of the required information for a GHG inventory may already be in normal management/account records, or in environmental management systems such as ISO 14001 and the EU Eco-Management and Audit Scheme (EMAS).

Finally, prior to the commencement of an independent verification activity, it is often useful to undertake a dry run or internal 'dummy' verification to try and identify or highlight potential areas of concern or issues associated with accessing appropriate documentation. This can be a useful means of identifying and rectifying problems that would otherwise increase the cost and time required to complete the verification.

8.2.6 Using the Verification Findings

The process of verification should always be viewed as an essential input to the process of continual improvement. Whether a verification is undertaken for the purposes of internal review, for public reporting, or to certify compliance with a particular program or regime, it will contain useful information and guidance on how, if necessary, a company's GHG measurement and reporting system can be improved and enhanced.

For those entities that have been, or are going to be, subject to verification it is important to establish internal procedures or review mechanisms that can develop and prioritize appropriate actions to overcome any discrepancies or deficiencies identified in the verification process. As is the case with the process of selecting a verifier it is important that those responsible for assessing and implementing responses to the verification findings also have appropriate skills and understanding of GHG accounting and reporting issues. Verification reports will normally include a specific list of actions or activities that are recommended to overcome any problems identified during the verification. While recommendations for improvement are usually clear and easily understandable there may be instances when an entity is not confident of effectively dealing with the verification findings and how to implement the recommendations. In this case it can be useful to contract specialized external expertise to assist with understanding and implementing the recommendations.

9. References

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Appendix A. Glossary

Absolute target	A target defined as a reduction in absolute emissions over time, e.g., a reduction of CO_2 emissions by 25% below 1994 levels by 2010
Accounting	Recognition and consolidation of GHG emissions data
Activity	Any action or operation that causes or influences the release of GHG emissions
Aggregation	The process by which data from individual sources and/or operations are combined into a single number for a higher level entity
Base year	A historic datum (a single year or an average over multiple years) for tracking a company's emissions over time
Base year emissions	GHG emissions in the base year
Baseline	A hypothetical scenario for what GHG emissions, removals, or storage would have been in the absence of a GHG project or project activity
Benchmarking	The process of assessing relative performance against a group of peers
Boundary	The determination of which emissions are accounted for and reported by a company. GHG accounting and reporting boundaries can have several dimensions, i.e., organizational, operational, geographic, business unit, and other.
Co-generation unit/combined heat and power (CHP)	A facility producing both electricity and steam or heat using the same fuel supply
Consolidation	Combination of GHG emissions data from separate operations that form part of one company or group of companies
Control	The ability of a company to direct the operating policies of another operation. Operational control is defined as the authority to introduce and implement operational and environmental, health, and safety (EHS) policies at an operation.
CO_2 equivalent	The mass of a greenhouse gas multiplied by its global warming potential (GWP). It is used to evaluate emissions of different greenhouse gases on a common basis—the mass of CO_2 emitted that would have an equivalent warming effect.

Direct GHG emissions	Emissions from sources that are owned or controlled by the reporting company
Double counting	Two or more companies taking ownership of or reporting the same emissions or emission reductions for the same purpose
Downstream	Operations involving the refining, processing, distribution, and marketing of products derived from oil and gas, including service stations
Emission factor	A factor relating activity data (e.g., tonnes of fuel consumed, tonnes of product produced) and absolute GHG emissions
Emissions	The intentional and unintentional release of GHGs into the atmosphere
Equity share	The percentage of ownership or economic interest in an operation
Equity share approach	An approach for setting organizational boundaries. This approach requires reporting GHG emissions in proportion to the economic interest in or benefits derived by the reporting company from partially owned operations.
Fugitive emissions	Releases of GHGs from joints, seals, packings, gaskets, etc.
Greenhouse gases (GHG)	For the purposes of these *Guidelines*, GHGs are the six gases (or families of gases) listed in the Kyoto Protocol: carbon dioxide (CO_2); methane (CH_4); nitrous oxide (N_2O); hydrofluorocarbons (HFCs); perfluorocarbons (PFCs); and sulfur hexafluoride (SF_6)
GHG project	A specific project or activity designed to achieve GHG emission reductions, storage of carbon, or enhancement of GHG removals from the atmosphere. GHG projects may be stand-alone projects, or specific activities or elements within a larger non-GHG related project.
GHG Protocol Initiative ***GHG Protocol***	A multi-stakeholder collaboration convened by the World Resources Institute and World Business Council for Sustainable Development to design, develop, and promote the use of accounting and reporting standards for business. It comprises two separate but linked modules—the *GHG Protocol Corporate Accounting and Reporting Standard* and the *GHG Protocol: Project Quantification Standard.*
GHG public report	A report released to the public of a company's GHG emissions for its chosen inventory boundary
GHG registry	A public database of organizational GHG emissions and/or project reductions. For example, the US Department of Energy 1605b Voluntary GHG Reporting Program, California Climate Action

	Registry, World Economic Forum Global GHG Registry, and the Canadian Voluntary Challenge Registry.
Global Warming Potential (GWP)	A factor describing the warming potential of a given mass of a particular GHG relative to the same mass of CO_2
Heating value	The amount of energy released when a fuel is burned completely. It may be reported as higher heating value (HHV)—or gross calorific value—which includes the latent heat of vaporization of the water vapor in the combustion products, or as lower heating value (LHV)—or net calorific value—which does not include the latent heat of vaporization of the water vapor.
Indirect GHG emissions	Emissions that are a consequence of the operations of the reporting company, but occur at sources owned or controlled by another company
Intensity ratios	Ratios that express GHG emissions per unit of physical activity or unit of economic value, e.g., tonnes of CO_2 emissions per kilowatt-hour of electricity generated
Intensity target	A target defined by a reduction in the ratio of emissions and a business metric over a specified time period, e.g., reduce CO_2 emissions per tonne of crude oil produced by X% between 2000 and 2008
Intergovernmental Panel on Climate Change (IPCC)	International body of climate change scientists. The role of the IPCC is to assess the scientific, technical and socio-economic information relevant to the understanding of the risk of human-induced climate change.
Inventory	A quantified list of an organization's GHG emissions and sources
Inventory boundary	An imaginary line that encompasses the direct and indirect emissions that are included in the inventory. It results from the chosen organizational and operational boundaries.
Inventory disaggregation	The process of separating or maintaining emissions data at the source level rather than summing sources to provide aggregated or total results
Inventory quality	The extent to which an inventory provides a faithful, true and fair account of the GHG emissions it is meant to represent
Kyoto Protocol	A protocol to the United Nations Framework Convention on Climate Change (UNFCCC). Once entered into force it will require countries listed in its Annex B (developed nations) to meet reduction targets of GHG emissions relative to their 1990 levels during the period of 2008-2012.

Life-cycle emissions	Emissions that occur from the point of raw material extraction through the manufacture, transportation, use, and disposal of a product
Material discrepancy	An error (for example from an oversight, omission, or miscalculation) that results in the reported quantity being significantly different from the true value
Materiality threshold	A concept employed in the process of verification. It is used to determine whether an error or omission is a material discrepancy or not.
Mobile combustion	Burning of fuels by transportation devices such as cars, trucks, trains, airplanes, ships etc.
Normalization	The process of expressing emissions relative to some measure of output, e.g., tonnes of CO_2-eq/barrels of crude oil produced
Offset	A discrete GHG reduction used to compensate for GHGs elsewhere, for example, to meet a voluntary or mandatory GHG target or cap. To avoid double counting, the reductions giving rise to the offset must occur at sources or sinks not included in the target or cap for which it is used.
Operation	A generic term used to denote any kind of business activity
Operational boundaries	The boundaries that determine the direct and indirect emissions associated with operations owned or controlled by a reporting company
Operational control approach	An approach for setting organizational boundaries. This approach requires reporting 100 percent of GHG emissions from operations that are under the operating control of the reporting company.
Organic growth/decline	Increases or decreases in GHG emissions as a result of changes in production output, product mix, plant closures and the opening of new plants that come about through increases or decreases in business volume.
Organizational boundaries	The boundaries that determine the operations owned or controlled by the reporting company. This determination depends on the consolidation approach used (i.e., equity share or operational control approach).
Outsourcing	The contracting out of activities to other companies
Petrochemicals	The manufacture, distribution, and marketing of chemical products derived from oil and gas

Process emissions	Emissions generated from manufacturing processes, such as petroleum refining or petrochemical production
Production Sharing Agreement	An agreement between one or more oil companies and a government entity or state company in which the participating oil companies provide financing and bear the risk of exploration and production activities in exchange for a share of the production remaining after royalties (and taxes and other levies paid in oil) are paid to the government. Sometimes referred to as a **Production Sharing Contract**.
Production Sharing Contract	See **Production Sharing Agreement**
Renewable energy	Energy taken from sources that are inexhaustible, e.g., wind, water, solar, geothermal energy, and biofuels
Reporting	Presenting data to internal management and external users such as regulators, shareholders, the general public or specific stakeholder groups
Scope of work	In the context of emissions verification, an up-front specification agreed between the reporting company and the verifier that indicates the type of verification to be undertaken and the level of assurance to be provided by the verification process
Sequestration	The uptake and storage of CO_2. For example, CO_2 can be sequestered by plants and in underground or deep sea reservoirs
Significance threshold	A qualitative or quantitative criterion used to define a significant structural change
Source	Any physical unit or process that releases GHG into the atmosphere
Stationary Combustion	Burning of fuels to generate electricity, steam, heat, or power in stationary equipment such as boilers, furnaces etc.
Structural change	A change in the organizational or operational boundaries of a company that result in the transfer of ownership or control of emissions from one company to another. Structural changes include mergers, acquisitions, divestitures, and outsourcing/insourcing.
Uncertainty	The range around a reported value in which the true value can be expected to fall
Upstream	Operations involving the exploration, development, and production of oil and gas
Verification	The assessment of the how complete and accurate a GHG inventory is. Verifications may be conducted by independent third parties or internally.

Appendix B. Linkages between the *Guidelines* and the *Compendium*

Tables B-1 and B-2 in this appendix are based on Tables 6-1 and 6-2 of the *Guidelines*. They are presented here with cross-references between the estimation approaches listed in Tables 6-1 and 6-2 and the relevant sections of the *Compendium,* which contain detailed descriptions of emission estimation methodologies. Where particular emission sources are listed as "not considered" in Tables 6-1 and 6-2, Tables B-1 and B-2 refer to sections or exhibits in the *Compendium* that demonstrate the insignificance of these sources. Chapter 6 of the *Guidelines* should be consulted for additional information on these tables.

Table B-1. Linkages to Exploration and Production Tiers

Source Category	GHG	Estimation Tiers		
		Tier C	**Tier B**	**Tier A**
		Uncertainty		
		+/- 30-60%	**+/- 20-40%**	**+/- 10-30%**
		Estimation Approach		
Combustion Sources	CO_2	Fuel consumption based on ratings, hours of operation and assumed loads for engines/turbines (energy balance for boilers/heaters); [*Demonstrated in Compendium Exhibit 3-3*]	Fuel consumption based on ratings, hours of operation and loads for engines/turbines (energy balance for boilers/heaters); [*Demonstrated in Compendium Exhibit 3-3*]	Fuel consumption based on single point metering and integrating mass flow for fuel gas, purchase records or tank measurements for commodity fuels (e.g., natural gas, diesel); [*Compendium Section 4.2.*]
		Or default fuel emission factors; [*Compendium Section 4.2 Demonstrated in Exhibits 4.3 and 4.5*]	Or fuel emission factors (mass/mass or mass/heating value) based on default factors. [*Compendium Section 4.2. Demonstrated in Exhibits 4.3 and 4.5*]	Or fuel emission factors (mass/mass or mass/heating value) based on default factors. [*Compendium Section 4.2. Demonstrated in Exhibits 4.3 and 4.5*]
				Or factors based on actual measurements of fuel composition if available. [*Compendium Section 4.1. Demonstrated in Exhibit 4.1*]
	CH_4	Not considered [*CH4 emission factors are provided in Compendium Section 4.3. Calculations are demonstrated in Exhibit 4.7. Small contribution of CH4 from combustion sources is demonstrated in Compendium Section 7.1.*		
Flaring	CO_2	Quantity of gas flared based on available GOR measurements and quantity of oil produced. Local default CO2 emission factors applied [*Compendium Section 4.4, Table 4-7. Demonstrated in Exhibit 4.8*]	Quantity of gas flared based on periodic GOR measurement and quantity of oil produced. Gas composition measured at similar intervals, [*Compendium Section 4.4. Demonstrated in Exhibit 4.8*]	Quantity of gas flared based on measurements/metering and /or frequent GOR measurement and quantity of oil produced. Gas composition measured at similar intervals [*Compendium Section 4.4. Demonstrated in Exhibit 4.8*]
		Or factor based on gas composition if available available [*Compendium Section 4.4. Demonstrated in Compendium Exhibit 4.8*]	Or local default CO2 emission factors applied. [*Compendium Section 4.4, Table 4-7. Demonstrated in Exhibit 4.8*]	Or local default CO2 emission factors applied. [*Compendium Section 4.4, Table 4-7. Demonstrated in Exhibit 4.8*]
	CH_4	Calculated from information above, assumed or known methane fraction in flare gas [*Compendium Section 4.4, Table 4-6*] and default residual methane (flare efficiency) [*Demonstrated in Compendium Exhibit 4.8*]	Calculated from gas quantity information above, measured or assumed gas composition [*Compendium Section 4.4, Table 4-6*] and default residual methane (flare efficiency) [*Demonstrated in Compendium Exhibit 4.8*]	Calculated from gas quantity information above, measured or assumed gas composition [*Compendium Section 4.4, Table 4-6*] and default residual methane (flare efficiency) [*Demonstrated in Compendium Exhibit 4.8*]

Source Category	GHG	Estimation Tiers		
		Tier C	Tier B	Tier A
		Uncertainty		
		+/- 30-60%	+/- 20-40%	+/- 10-30%
		Estimation Approach		
Associated Gas Venting	CO_2	Include only for CO_2-rich streams. Quantity of gas vented based on available GOR measurements and quantity of oil produced; assumed duration of flare outages for inadvertent venting. Local default [*Compendium Table 4-6*] or actual gas composition used as available. [*Cold vent approach from Compendium Section 5.3. Demonstrated in Exhibit 5.12.*]	Quantity of gas vented estimated (e.g., by periodic GOR measurement and quantity of oil produced; duration of flare outages for inadvertent flaring). Gas composition measured at similar intervals. [*Cold vent approach from Compendium Section 5.3. Demonstrated in Exhibit 5.12.*]	Quantity of gas vented estimated (e.g., by frequent GOR measurement and quantity of oil produced; duration of flare outages for inadvertent flaring). Gas composition measured at similar intervals. [*Cold vent approach from Compendium Section 5.3. Demonstrated in Exhibit 5.12.*]
	CH_4	Quantity of gas vented based on available GOR measurements and quantity of oil produced; assumed duration of flare outages for inadvertent venting. Local default (composition) [*Compendium Table 4-6*] or actual gas composition used as available. [*Cold vent approach from Compendium Section 5.3. Demonstrated in Exhibit 5.12.*]	Quantity of gas vented estimated (e.g., by periodic GOR measurement and quantity of oil produced; duration of flare outages for inadvertent flaring). Gas composition measured at similar intervals. [*Cold vent approach from Compendium Section 5.3. Demonstrated in Exhibit 5.12.*]	Quantity of gas vented estimated (e.g., by frequent GOR measurement and quantity of oil produced; duration of flare outages for inadvertent flaring). Gas composition measured at similar intervals. [*Cold vent approach from Compendium Section 5.3. Demonstrated in Exhibit 5.12.*]
Acid Gas Removal	CO_2	Emissions based on quantity of gas produced and assumed residual CO_2 content. Local or actual inlet gas composition used as available. [*Compendium Section 5.1.4. Demonstrated in Exhibit 5.4.*]	Results of process simulation, such as AmineCalc. [*Compendium Section 5.1.4.*]	Mass balance across amine unit (e.g., based on difference between inlet gas flow and CO_2 fraction and outlet gas flow and CO_2 fraction—measured parameters.) [*Compendium Section 5.1.4. Demonstrated in Exhibit 5.4.*]
	CH_4	Not considered [*Compendium Section 5.1.3. CH4 emissions estimated in Exhibit 5.3*]	Application of generic emission factors or results from process simulation such as AmineCalc [*Compendium Section 5.1.3, Table 5-4. Demonstrated in Exhibit 5.3*]	Results of process simulation, such as AmineCalc [*Compendium Section 5.1.3*]
Glycol Dehydration	CO_2	Not considered [*Compendium Section 5.1.1. CO2 emissions from glycol dehydrators calculated in Exhibits 5.1 and 5.2*]		
	CH_4	Not considered [*Compendium Section 5.1.1. CH4 emissions from glycol dehydrators calculated in Exhibits 5.1 and 5.2.*]	Application of generic emission factors [*Compendium Section 5.1.1, Tables 5-1 to 5-3. Demonstrated in Exhibits 5.1 and 5.2.*]	Application of generic emission factors [*Compendium Section 5.1.1, Tables 5-1 to 5-3. Demonstrated in Exhibits 5.1 and 5.2.*]
Tank Flashing	CO_2	Not considered [*Tank flashing addressed in Compendium Section 5.4.1. CO2 emissions from tank flashing are estimated in Compendium Section 7.1.*]		
	CH_4	Not considered	Application of generic emission factors [*Compendium Table 5-7*] -or- emission estimation equations [*Compendium Section 5.4.1. Exhibit 5.13 provides a comparison of results from different estimation techniques.*]	Measurement of vent gas -or- application of process simulation such as E&P Tank [*Compendium Section 5.4.1*]

Source Category	GHG	Estimation Tiers		
		Tier C	Tier B	Tier A
		Uncertainty		
		+/- 30-60%	+/- 20-40%	+/- 10-30%
		Estimation Approach		
Other Process Sources	CO_2	Not considered [*CO_2 emissions from other process vents are addressed in Compendium Sections 5.3 (Cold Vents) and 5.6 (Other Venting Sources). Case studies provided in Compendium Section 7.1 show negligible CO_2 emissions from other process sources for upstream facilities*]	Process mass balance as in Compendium using activity data based on best engineering estimates [*Compendium Sections 5.3 (Cold Vents) and 5.6 (Other Venting Sources). Demonstrated in Exhibit 5.12.*]	Process mass balance as in Compendium using activity data based on best engineering estimates [*Compendium Sections 5.3 (Cold Vents) and 5.6 (Other Venting Sources). Demonstrated in Exhibit 5.12.*]
	CH_4	Not considered [*CH_4 emissions from other process vents are addressed in Compendium Sections 5.3 (Cold Vents) and 5.6 (Other Venting Sources) Demonstrated in Exhibit 5.12, and exhibits for particular emission sources.*		
Non Routine Sources	CO_2	Not considered [*CO_2 emissions from non-routine sources are addressed in Compendium Section 5.7. Case studies provided in Compendium Section 7.1 show negligible CO_2 emissions from non-routine sources for upstream facilities*]	Engineering estimates [*Compendium Section 5.7.1. Demonstrated in Exhibit 5.27.*]	Engineering estimates [*Compendium Section 5.7.1. Demonstrated in Exhibit 5.27.*]
	CH_4	Not considered [*CH_4 emissions from non-routine sources are addressed in Compendium Section 5.7. Case studies provided in Compendium Section 7.1 show negligible contribution to total CO-eq. emissions from non-routine sources for upstream facilities*]	Engineering estimates [*Compendium Section 5.7.1. Demonstrated in Exhibits 5.26 and 5.27.*]	Engineering estimates [*Compendium Section 5.7.1. Demonstrated in Exhibits 5.26 and 5.27.*]
Process Fugitives	CO_2	Not considered [*CO_2 emissions from fugitive sources are addressed in Compendium Section 6.1. Case studies provided in Compendium Section 7.1 show negligible CO_2 emissions from fugitive sources for upstream facilities*]	Include only for streams that are >30% CO_2 based on component level average emission factors and typical component counts [*Compendium Section 6.1. Demonstrated in Exhibit 6.1.*]	Include only for streams that are >30% CO_2 based on component level average emission factors and actual component counts [*Compendium Section 6.1. Demonstrated in Exhibit 6.1.*]
	CH_4	Not considered [*CH_4 emissions from fugitive sources are addressed in Compendium Section 6. Case studies provided in Compendium Section 7.1 show 0.1 to 6% contribution to total CH_4 emissions from fugitive sources for upstream facilities*]	Based on component level average emission factors and typical component counts [*Compendium Section 6.1.3. Demonstrated in Exhibit 6.3.*]	Based on component level average emission factors and actual component counts [*Compendium Section 6.1.3. Demonstrated in Exhibit 6.3.*]
Non-Operated Facilities	CO_2	If the operator is unwilling or unable to provide GHG emissions data or the activity data, E&P emissions may be estimated by prorating to the nearest equivalent company operated production facility. [*Not addressed in the Compendium*]		
	CH_4			

Table B-2. Linkages to Petroleum Refining and Petrochemical Tiers

Source Category	GHG	Estimation Tiers		
		Tier C	Tier B	Tier A
		Uncertainty		
		+/- 15-30%	< +/- 15%	+/- 5-10%
		Estimation Approach		
Combustion Sources	CO2	Thermal input (fuel burnt) estimated based on design rating of plant and hours operated, default fuel factors [*Compendium Section 4.2. Demonstrated in Exhibits 3.3, 4.3 and 4.5.*]	Thermal input (fuel input) based on metering or energy balances on heaters/boilers, fuel composition obtained from occasional spot sampling . [*Compendium Section 4.1. Demonstrated in Exhibit 4.1.*]	Thermal input (fuel input) based on metering or energy balances on heaters/boilers, fuel composition obtained from frequent spot sampling . [*Compendium Section 4.1. Demonstrated in Exhibit 4.1.*]
	CH4	Not considered [*CH4 emission factors provided in Compendium Section 4.3. Negligible contribution of CH4 emissions from combustion sources is demonstrated in Compendium Section 7.3, and Exhibit 4.6 and 4.7. Less than 1% of total CO2-eq emissions for downstream sector facility.*]		
FCC Coke Burn	CO2	Thermal input (fuel burnt) estimated based on design rating of plant and hours operated, default coke factor	Coke burn rate calculated based on process mass/energy balance and average coke composition based on spot samples . [*Compendium Section 5.2.1. Demonstrated in Exhibit 5.5.*]	Coke burn rate calculated based on process mass/energy balance and average coke composition based on spot samples [*Compendium Section 5.2.1. Demonstrated in Exhibit 5.5.*]
			OR – estimated directly from measured CO and CO2 concentrations in exhaust (spot samples) and air/oxygen flow rate to regenerator [*Compendium Section 5.2.1. Demonstrated in Exhibit 5.5.*]	OR – estimated directly from measured CO and CO2 concentrations in exhaust (spot samples) and air/oxygen flow rate to regenerator [*Compendium Section 5.2.1. Demonstrated in Exhibit 5.5.*]
	CH4	Not considered [*Compendium does not address CH4 emissions from FCC Coke Burn.*]		
Flaring	CO2	Engineering estimates of gas flared i.e., using API flame length correlation and default factor for refinery gas	Process engineering estimates of flared volume based on known purge rates, process unit flows to flare and estimates of non-routine flaring based on plant logs. Weighted average flare gas composition based on estimated composition [*Compendium Section 4.4. Flare emission calculations demonstrated in Exhibit 4.8.*]	Flared volume estimated from flare gas meters where available, known purge rates and best process engineering estimates, average flare gas composition based on spot samples throughout the year adjusted if significant non-routine flaring [*Compendium Section 4.4. Demonstrated in Exhibit 4.8.*]
	CH4	Not considered [*CH4 emission approach for refinery flares is provided in Compendium Section 4.4. Demonstrated in Exhibit 4.8. Negligible contribution of CH4 from refinery flares is demonstrated in Compendium Section 7.3*]		
Hydrogen Plant (process)	CO2	Process mass balance based on estimated hydrogen production [*Compendium Section 5.2.2. Demonstrated in Exhibit 5.6.*]	Compendium "simple" method based on estimated hydrogen make [*Compendium Section 5.2.2; Demonstrated in Exhibit 5.6.*]	Compendium "complex" method i.e. process mass balance based on known reformer feed rate and composition [*Compendium Section 5.2.2; Demonstrated in Exhibit 5.7.*]
	CH4	Not considered [*Not addressed in the Compendium; Equation 5-5 assumes complete conversion of feed gas*]	Not considered [*Not addressed in the Compendium; Equation 5-5 assumes complete conversion of feed gas*]	Not considered (spot check on methane content of CO2 vent stream) [*Not addressed in the Compendium; Equation 5-5 assumes complete conversion of feed gas*]

Source Category	GHG	Estimation Tiers		
		Tier C	Tier B	Tier A
		Uncertainty		
		+/- 15-30%	< +/- 15%	+/- 5-10%
		Estimation Approach		
Other Process Sources	CO_2	Not considered [*Negligible contribution of CO_2 emissions from other process sources is demonstrated in Compendium Section 7.3 case study for a downstream facility*]	Process mass balance as in Compendium using activity data based on best engineering estimates [*Compendium Sections 5.2 and 5.3. Demonstrated in exhibits for particular emission sources.*]	Process mass balance as in Compendium using activity data based on best engineering estimates [*Compendium Sections 5.2 and 5.3. Demonstrated in exhibits for particular emission sources.*]
	CH_4	Not considered [*Cold vent approach provided in Compendium Section 5.3. Compendium generally assumes CH_4 emissions from other refinery process vents are negligible.*]		
Non Routine Sources	CO_2	Not considered [*Compendium Section 5.7.6 assumes non-routine emissions from refineries are routed to flare.*]	Engineering estimates [*Compendium Section 5.7.1. Demonstrated in Exhibit 5.26.*]	Engineering estimates [*Compendium Section 5.7.1. Demonstrated in Exhibit 5.26.*]
	CH_4	Not considered [*Compendium Section 5.7.6 assumes non-routine emissions from refineries are routed to flare.*]	Engineering estimates [*Compendium Section 5.7.1 Demonstrated in Exhibit 5.26.*]	Engineering estimates [*Compendium Section 5.7.1. Demonstrated in Exhibit 5.26.*]
Process Fugitives	CO_2	Not considered [*CO_2 emissions from fugitive sources are addressed in Compendium Section 6. Compendium states that CO_2 emission from equipment leaks are negligible for most refineries.*]		
	CH_4	Not considered [*CH_4 emissions from fugitive sources are addressed in Compendium Section 6, though CH_4 contribution In refinery VOC emissions is assumed negligible.]*		Not considered (possibly significant for natural gas supply pipe work) [*Fugitive CH_4 emissions from refinery fuel gas system are addressed in Compendium Section 6.1*
Other Area Sources	CO_2	Not considered [*Addressed in Compendium Section 6.2. Compendium states that emissions from these sources are generally insignificant.*]		
	CH_4	Not considered [*Addressed in Compendium Section 6.2. Compendium states that emissions from these sources are generally insignificant. CH_4 emission from water treatment are demonstrated in Exhibit 6.5.*]		
Non-Operated Refineries and Petrochemical Plants	CO_2 CH_4	For non-operated refineries where the operator is unwilling or unable to provide GHG emissions data or the activity data, refinery emissions may be estimated by prorating to the nearest equivalent company operated refinery with suitable adjustments for processing severity and crude properties. A similar approach may be applied for petrochemical facilities if the feedstocks, processes, and products are sufficiently similar. [*Not addressed in the Compendium*]		