Prepared by **URS Corporation**

Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects

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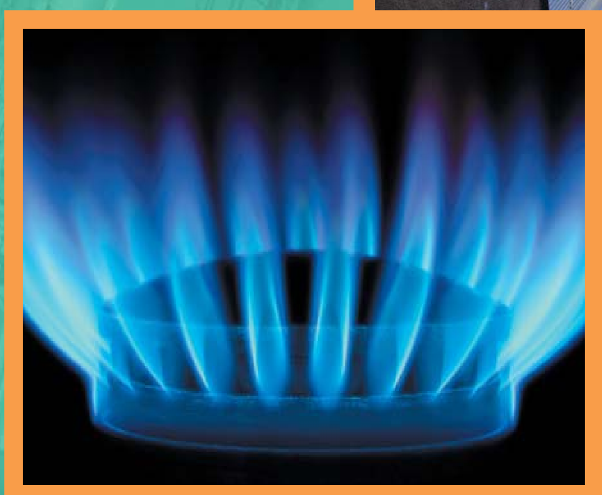

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International Petroleum Industry Environmental Conservation Association

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IPIECA is the single global association representing both the upstream and downstream oil and gas industry on key global environmental and social issues. IPIECA's programme takes full account of international developments in these issues, serving as a forum for discussion and cooperation involving industry and international organizations.

IPIECA's aims are to develop and promote scientifically-sound, cost-effective, practical, socially and economically acceptable solutions to global environmental and social issues pertaining to the oil and gas industry. IPIECA is not a lobbying organization, but provides a forum for encouraging continuous improvement of industry performance.

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American Petroleum Institute

The American Petroleum Institute is the primary trade association in the United States representing the oil and natural gas industry, and the only one representing all segments of the industry. Representing one of the most technologically advanced industries in the world, API's membership includes more than 400 corporations involved in all aspects of the oil and gas industry, including exploration and production, refining and marketing, marine and pipeline transportation and service and supply companies to the oil and natural gas industry.

API is headquartered in Washington, D.C. and has offices in 27 state capitals and provides its members with representation on state issues in 33 states. API provides a forum for all segments of the oil and natural gas industry to pursue public policy objectives and advance the interests of the industry. API undertakes in-depth scientific, technical and economic research to assist in the development of its positions, and develops standards and quality certification programs used throughout the world. As a major research institute, API supports these public policy positions with scientific, technical and economic research. For more information, please visit www.api.org.

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Acknowledgements

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Executive Summary

Oil and natural gas companies are evaluating options for reducing greenhouse gas (GHG) emissions, developing project plans, and implementing emission reduction projects either voluntarily or to comply with regulatory requirements. At the same time, various domestic and international organizations are developing guidance and procedures for quantifying, reporting, and registering project-level GHG emission reductions. This presents a challenge for oil and natural gas companies, where multi-national operations must be managed within a variety of GHG programs. Guidance is needed that is suitable for a broad range of climate change regimes or GHG registries and will serve the industry's global operations. This document aims to provide this guidance by focusing on the technical aspects of reducing GHG emissions separate from the policy considerations.

Although the requirements for creditable emission reductions continue to evolve, the technical concepts associated with quantifying GHG emission reductions are grounded in the basic principles of completeness, consistency, accuracy, transparency, relevance, and conservatism. Key messages related to the technical focus of this document include recognition of the following:

- Determination of emission reductions should be based on generally accepted principles and sound technical considerations.
- Reported information should provide a faithful, true, and fair account of the reductions achieved.
- For existing operations, historical conditions, which are distinctly different from historical emissions, often provide the most realistic baseline scenario.
- For new operations, common practice is generally an objective and credible prediction of what would have happened in the absence of the project.
- Companies may wish to quantify GHG emission reductions for many reasons, thus methodologies for estimating and monitoring project reductions should be fit for their purpose.
- Care must be taken in selecting the baseline scenario, particularly in the oil and natural gas industry, where differences in oil field characteristics, age and other factors must be considered.
- Methods used to select, reject, or rank baseline scenarios based on financial analyses are not always objective.
- Excessive monitoring requirements may discourage participation without improving measurement accuracy or reporting consistency.

While individual and public policy decisions can have a very significant effect on the eligibility of GHG reductions for credits, actions that result in the reduction of GHG emissions or the removal of GHGs from the atmosphere can be undertaken for a variety of reasons. This guidance document provides a framework for quantifying GHG emission reductions with sufficient transparency that the information can be used with reasonable confidence.

Section 1. Introduction

The oil and natural gas industry is addressing the challenge of meeting the world's growing energy demands in a responsible manner, including with respect to climate change. Real and sustainable actions to reduce greenhouse gas (GHG) emissions can be one component of that response. These *Oil and Natural Gas Guidelines for Greenhouse Gas Emission Reduction Projects* (referred to as Project Guidelines) aim to support transparent and credible calculation and reporting of GHG emission reductions from such activities in a comprehensive and consistent manner.

With the Kyoto Protocol officially entering into force February 16, 2005, the incentives for implementing GHG emission reduction projects and opportunities for gaining credits associated with these projects are expected to grow, particularly in those countries which have adopted the protocol. Even beyond the realm of commitments for Kyoto or other regulatory programs, many companies are taking action to reduce GHG emissions for a variety of reasons. Motives for implementing a GHG emission reduction project and reasons for reporting emission reductions vary and may include any or all of the following examples:

- Financial benefits of the project with or without revenues from the sale of emission reduction credits;
- Voluntary actions to reduce GHG emissions;
- Compliance with any applicable regulatory regime;
- Stakeholder reporting;
- Meeting internal company emission reduction targets; and/or
- Generating credits or offsets for an external reporting program.

At the same time, the policies associated with what is deemed an acceptable or creditable emission reduction continue to evolve. Mandatory and voluntary GHG programs exist with specific criteria for recognizing credits or with tools and guidance for quantifying GHG reductions. These include decisions taken by the Clean Development Mechanism (CDM) Executive Board, methodologies appropriate for the EU Emissions Trading Scheme (ETS), General and Technical Guidelines for Voluntary Greenhouse Gas Reporting recently revised by the US Department of Energy 1605(b), guidance published by the International Standards Organization (ISO) 14064 Part 2, and the World Business Council for Sustainable Development and World Resources Institute (WBCSD/WRI) *GHG Protocol for Project Accounting* (referred to as the Project Protocol).

The purpose of this document is to provide oil and natural gas companies with voluntary guidelines for documenting and reporting GHG emission reductions, i.e., decreases in GHG emissions or increases in removals and/or storage of GHGs[1]. The focus is on the technical basis and considerations of emission reduction projects, recognizing that individual or public policy decisions may have a significant impact on the application of these technical principles. Regardless of the policy considerations, an emission reduction project is any activity that reduces GHG emissions to the atmosphere. This is different from an eligible emission reduction credit. Examining GHG emission reduction projects on a strictly technical basis requires understanding the difference between the broad classification of credible GHG emission reductions and the smaller sub-set of GHG reduction credits which meet specific requirements of a climate change regime or GHG registry.

1.1 Overarching Objectives of Program

The purpose of this document is to:

1. Develop a voluntary framework for assessing GHG emission reductions associated with specific types of oil and natural gas projects, including references to relevant methodologies or guidance, and
2. Assist the oil and natural gas industry by providing guidelines on identifying, assessing, and developing candidate projects that would lead to credible (distinguished from creditable) emission reductions.

1.2 Approach

These guidelines address the technical aspects of GHG emission reduction activities. The document is written from the perspective of the oil and natural gas industry, with examples and considerations specific to oil and natural gas industry operations.

The document is currently organized into five sections:

- Introduction;
- Project Emission Reductions Principles and Quantification;
- Policy Considerations;
- Project Family Overview; and
- Cogeneration Project Family.

Section 2 outlines some overarching principles associated with quantifying and reporting GHG emission reductions. Key concepts relating projects, baseline scenarios, and emission reductions are defined in this section and a general methodology for quantifying emission

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[1] This guidance document is not intended to create any requirement or industry standards for GHG reduction projects. Rather it is intended solely for the convenience and voluntary use of oil and natural gas companies that may find it helpful. Nor is this document intended to imply a direct connection between GHG emissions from the oil and natural gas industry and the phenomenon commonly referred to as climate change. To the contrary, this guidance document recognizes that companies may undertake GHG reduction projects for a variety of reasons.

reductions is provided. The information in this section is potentially applicable to any project type and can help establish the foundation for assessing any GHG reduction project activity.

Section 3 presents policy considerations in order to acknowledge the impact of non-technical aspects and to characterize the distinction between emission reductions and credits. A summary of several climate change regimes and GHG registries is provided in Appendix A to assist the reader in determining if a particular emission reduction project may qualify as a "credit".[2]

Section 4 presents an overview of key considerations for each of five broadly applicable emissions reduction "project families":

- Cogeneration;
- Carbon Capture and Geological Storage;
- Flare Reduction;
- Fuel Switching; and
- Energy Efficiency Improvements.

Section 5 delves into further detail for one of the project families – Cogeneration – and illustrates the application of the general principles from Section 2. Examples are provided based on industry experience for addressing the unique project considerations regarding assessment boundary determination, baseline scenario selection, and policy considerations. Additional chapters for each of the remaining project families will be added over time, starting with Carbon Capture and Geological Storage.

This document is an initial attempt to provide guidelines specific to oil and natural gas industry operations for common GHG emission reduction projects. The American Petroleum Institute (API) and the International Petroleum Industry Environmental Conservation Association (IPIECA) intend to update and revise the document as GHG emission reduction programs and climate change regimes mature.

[2] The American Petroleum Institute (API) and the International Petroleum Industry Environmental Conservation Association (IPIECA) make no representation that use of this guidance document would satisfy any legal or technical requirements of standards for creditable GHG reduction projects, or ensure compliance with any other requirements, under any applicable regulatory regime. Any company that uses these Project Guidelines should consult its own legal counsel as to any legal requirements that may apply to a project.

Section 2. GHG Reduction Project Concepts and Principles

These Project Guidelines explain key concepts for GHG reduction project accounting and provide some consistent principles and criteria for credible GHG emission reduction quantification. Additional requirements may apply for reporting these reductions through specific climate change regimes or GHG registries, or for trading emission credits. This section presents general guidelines that could be applied to any reduction project for quantifying GHG emission reductions based on generally accepted principles and sound technical considerations.

Throughout these Project Guidelines, the term GHG reduction refers to either a reduction in GHG emissions or an increase in removals or storage of GHG from the atmosphere, relative to baseline emissions.

2.1 GHG Reduction Project Principles

Similar to GHG inventory accounting and reporting, GHG reductions, removals, or storage should be based on generally accepted quantification and reporting principles to ensure that:

- The reported information represents a faithful, true, and fair account of the GHG emission reductions achieved by implementing the reduction project; and
- The reported information is credible and unbiased in its treatment and presentation of issues.

The procedures required to account and quantify the GHG reductions resulting from a GHG reduction project are still evolving and new to many; however, the principles outlined below are intended to:

a) Provide the first-order principles for defining GHG project accounting concepts, such as identifying the baseline scenario and GHG assessment boundary, which have no ready parallels in financial accounting; and
b) Guide project proponents, verifiers, and others when dealing with uncertainty while accounting, quantifying, monitoring, reporting, and verifying GHG reduction project emissions, removals, and storage.

In both cases, the principles outlined below become especially important if a climate change regime or GHG registry is not available or has not clearly defined the terms, processes, and methodologies required for GHG project accounting and quantification. Following these principles should provide assurance to all parties involved that the processes by which the GHG project's reduction is accounted and quantified are verifiable, replicable, and credible.

Relevance – Select GHG sources, GHG sinks, GHG reservoirs, data and methodologies appropriate to the scope of the project and needs of the intended user.

Completeness - Include all relevant GHG emissions, removals, and storage.

Consistency - Enable meaningful comparisons in GHG-related information.

Accuracy - Reduce bias and uncertainties as far as practical.

Transparency - Disclose sufficient and appropriate GHG-related information to allow intended users to make decisions with reasonable confidence.

Conservatism – Where questions arise regarding uncertain parameters or data sources, or where further analysis is not cost-effective, choose a conservative approach that is likely to underestimate rather than overestimate the GHG reductions.

2.2 Quantifying Emission Reductions

Table 2-1 presents the primary steps for quantifying emission reductions. Each of these steps will be discussed in more detail in the following sections.

Table 2-1. Steps for Quantifying Emission Reductions

Primary Steps	Activities	Document Reference
Step 1: Define Project	• Describe the activity or set of activities that reduce GHG emissions	Section 2.3
Step 2: Determine Baseline Scenario	• Identify baseline candidates for each project activity • Determine the baseline scenario based on sound, technical considerations and guided by common practice • Examine the geographic area and time frame for which the baseline is applicable	Section 2.4
Step 3: Determine Assessment Boundary	• Identify potential sources, sinks, or reservoirs controlled by, related to, affected by, and relevant to the baseline scenario	Section 2.5
Step 4: Quantify Emission Reductions	• Quantify GHG emissions for the project activity • Estimate GHG emissions associated with the baseline scenario • Quantify the emission reductions: Emission Reductions = Baseline emissions – Project emissions	Section 2.6

Where formal credit is sought for the reduction, additional or different steps may be dictated by the crediting climate change regime or GHG registry (see Section 3).

2.3 Project Definition

A GHG reduction project is a recognizable and distinct activity or set of activities that reduce global GHG emissions, increase the storage of carbon, or enhance GHG removals from the atmosphere. A project activity is a specific action or intervention that changes GHG emissions, removals, or storage

This document defines three fundamental principles for the quantification of emission reductions:

1. A GHG reduction is the difference between the actual emissions resulting from the implementation of a GHG project and the estimated baseline emissions.
2. The GHG project and baseline emissions must be evaluated on a comparable basis.
3. Reasonable account or consideration should be taken of emissions outside the direct control of the GHG project, as appropriate. That is, sources related to or affected by the GHG project may need to be assessed for their relevance to the project.

Project definition refers to the description of the project activity or set of activities that result in the reduction, removal, or storage of GHG emissions. The information included in the definition is intended to provide the context for the GHG project. Climate change regimes or GHG registries may identify specific information to be included in the project definition or description.

2.4 Baseline Scenario Determination

GHG reductions must be quantified relative to a reference level of GHG emissions, referred to as the baseline scenario. Potential candidates for the baseline scenario represent situations or conditions that plausibly would have occurred in the absence of the reduction project. Determining the baselines scenario from among these candidates is a complex task, which may involve subjective and objective elements, as the baseline scenario is always a hypothetical estimation of what would have happened without the project. In general, identifying baseline candidates should consider existing and alternative project types, activities, and technologies that result in a product or service identical (or nearly identical) to that of the project activity, and should be credible over a range of assumptions for the duration of the baseline application. For some climate change regimes, baseline scenario determination may be directed by the policy requirements of that regime. (See Section 3.)

> The WBCSD/WRI Project Protocol presents two procedures for estimating baselines emissions: the project-specific and performance standard procedures. For the project family types that the oil and natural gas industry is currently focusing on – cogeneration and carbon capture and storage – the project-specific approach is most applicable.
>
> Details on the performance standard approach are available in the WBCSD/WRI Project Protocol. Application of this method will be examined further when the energy efficiency and fuel switching project families are developed.

Because the baseline scenario is a hypothetical situation, there may be multiple candidate scenarios for what might have happened in the absence of the project. Determination of the baseline scenario from two or more candidates should first be based on a sound, technical basis, guided by commonly accepted practice. Common practice provides the most objective means of identifying what would have happened in the absence of the project. Based on the specific details of the project, baseline candidates developed from common practice would include consideration of:

- Similar operations in the local region;
- Comparable operating conditions and age;
- Identical or similar product, output, or service; and
- Similar social, environmental, financial, and technological circumstances.

This is particularly important for oil and natural gas industry operations, where determining "common" practice is not always straightforward. For example, exploration and production operations in the same geographic region may vary significantly due to the age of the reservoir, oil to gas ratio, and recompression requirements. Similarly, refining operations can vary significantly due to characteristics of the crude processed and the mix of products generated.

Baseline scenario determination is demonstrated for the cogeneration reduction project example in Section 5. As the example shows, the determination of the baseline scenario is highly project-specific and dependent upon project type, industry sector, location, etc.

2.4.1 Time frame

Two elements of the time frame should be considered in determining the baseline scenario:

1. The time period from which to select relevant baseline candidates (defined as the temporal range in the WBCSD/WRI Project Protocol); and
2. The period of time that the baseline scenario is applicable and justifiable.

The time frame applicable for determining baseline candidates considers installation, implementation, or establishment times of various technologies, equipment or practices. This is usually based on: recent plants, technologies, equipment, or recently established practices; plants under construction; equipment, technologies, or practices being implemented; or planned plants, technologies, equipment or proposed practices. The circumstances surrounding the project activity influence the span of the temporal range, as well as the principles of relevance and transparency.

Emission reductions will continue to occur for as long as the baseline scenario is applicable and justifiable. The time frame for which the baseline scenario applies should therefore be considered, such that anticipated changes can be factored in from the start, to the extent possible. Establishing a finite period of time for which the baseline is valid can also increase confidence in the certainty of the project. The length of this period may vary, depending on technical and policy considerations, and on whether baseline emission estimates are static or dynamic.

As common practice evolves or as a benchmark improves over time, the baseline scenario and project activity may eventually converge. In addition, factors or conditions affecting the project may change over time, such that the baseline scenario is no longer valid for the purpose of quantifying GHG reductions. For example, factors that may influence the selection of the baseline scenario, or may require future revision to the baseline scenario, include:

- The remaining life of equipment;
- An anticipated change in activity level relative to the baseline, where the effect of the change is significant enough to warrant a change to the baseline scenario;
- Legislative or regulatory changes; and
- A change in available resources (e.g., a gas pipeline to the area).

The impact and timing of such changes will be specific to the conditions of the project activity, and should be examined relative to the baseline scenario. For these situations, it may be necessary to establish a new baseline scenario at the time that such a change occurs. Emission reductions from this point forward would be evaluated against the new baseline scenario. If such a change is anticipated, it may be beneficial to include review of these conditions as part of the monitoring plan (discussed further in Section 2.6.1).

2.4.2 Geographic Application

The geographic area establishes the location of operations, equipment, or practices that are included in the assessment of baseline candidates. Depending on the circumstances of the project, the geographic area may be narrow (e.g., an area within a nation or an electric grid), or broad (e.g., an international region or global area).

2.4.3 Existing Versus New Operations

Determination of the baseline scenario may also vary depending on whether the emission reduction project is associated with existing operations (retrofit) or new operations.

Existing Operations

For existing operations, historical conditions[3] often provide the most realistic baseline scenario, as it is generally reasonable to assume the continuation of current activities in the absence of the project. This assumption is most credible for the time period immediately following the initiation of the project activity, but requires reevaluation in subsequent years. The bulleted factors listed above should also be considered to determine their potential impact on the baseline scenario.

The terms "best practices" and "best practice standards" are used here to differentiate from the "performance standards" baselines approach presented in the WBCSD/WRI Project Protocol. In the context of these guidelines, best practice is used as a reference for considering baseline candidates where common practice is difficult to define. It is not intended to imply the need for rigorous statistical analysis or comparison against a stringency level. For some climate change regimes, best practices or a level of stringency associated with a performance standard may be directed by the policy requirements of that regime (see Section 3).

[3] Historical conditions refer to the pre-project operating conditions as status quo (such as, burning coal), not the pre-project emissions (i.e., estimated tonnes of emissions pre-project).

New Operations

For new operations, where GHG emissions associated with the project activity did not previously exist, the baseline is established by evaluating what would have occurred in the absence of the project. Common practice is the preferred approach for determining a credible baseline scenario because it is generally the most objective prediction of what would have happened in the absence of the project. Common practice refers to the predominant technology(ies) or practice(s) in place in a specific region or sector.

Where common practice is difficult to determine or justify, the minimum requirements under any applicable best practice standards could be adopted as the baseline scenario. These may include best practice standards negotiated by a particular sector with a regulatory body, as well as purely voluntary best practices that a single company or sector may have adopted. In some situations, best practice standards for other industry sectors may provide a justifiable scenario for oil and natural gas industry operations.

A disadvantage to this approach is that one or two operators or facilities in a region may bias what is perceived as common practice or best practice, even if they are in the minority. Another disadvantage is where an imposed Best Available Control Technology is used to define the baseline, although this is likely to be a policy decision (see Section 3).

2.5 Assessment Boundary

After defining the project and determining the baseline scenario, the next step is to establish the assessment boundary. The assessment boundary encompasses GHG emission sources, sinks, and reservoirs:

1. Controlled by the project proponent - This includes sources under the direct control or influence of the project proponent through financial, management, or other means.
2. Related to the GHG reduction project - These are emission sources associated with significant energy or material flows into or out of the project, such as imported electricity or heat, or the transportation of materials, products, or wastes. These sources can be either on or off the project site, and may include activities related to design, construction and decommissioning of a project.
3. Affected by the GHG reduction project - These sources encompass an increase or decrease in emissions resulting from changes in market demand or supply for associated products or services, or through physical displacement of products or services. For example, where natural gas is captured for sale as part of a flare reduction project, the availability of that natural gas may impact the energy market

for other energy consumers. Other climate change regimes may refer to these as "leakage"[4] or "secondary effects".

4. Relevant to the baseline scenario and reduction project – Relevant relates to the three assessment boundary considerations above and considers the needs of the intended user. An emission source may be determined to be irrelevant if the resulting emissions are not materially different for the project and the baseline scenario. For example, where a CO_2 stream captured from an industrial process replaces an underground-sourced CO_2 stream for enhanced oil recovery, emissions from the capture and transport of the industrial stream may not be materially different from the emissions associated with the extraction and transport of the underground-sourced CO_2.

This assessment may result in a number of potential emission sources. The practical application of identifying and assessing the relevant GHG emission sources, sinks, and reservoirs should consider:

- The ability to quantify/monitor the emissions;
- The significance of the source; and
- The ability to clearly attribute the emission sources, sinks or reservoirs to the project activity or baseline scenario.

Narrowing down the potential GHG emission sources through these considerations results in the assessment boundary. Documentation of those sources included in the assessment boundary and those determined to not include (with a explanation) support transparent project reporting.

The approach to determining the assessment boundary is applied for the cogeneration project family examples provided in Section 5, as the technicalities associated with the specific reduction projects are addressed. In addition, some reporting regimes have specific requirements for defining the reduction project assessment boundary. These policy considerations are addressed in Section 3.

2.6 Quantifying Emission Reductions

Greenhouse gas emission reductions are quantified as the difference between the baseline emissions and the reduction project emissions, where baseline emissions are determined for the same quantity of output as the project. Figure 2-1 illustrates the relation between the project emissions and the baseline emissions for the baseline scenario determined through an assessment of baseline candidates.

[4] It should be noted here that the term "leakage" in this context refers to "secondary" emissions that are accounted as part of a climate change regime or GHG registry requirements, as opposed to physical leakage (escape) of GHG emissions to the atmosphere.

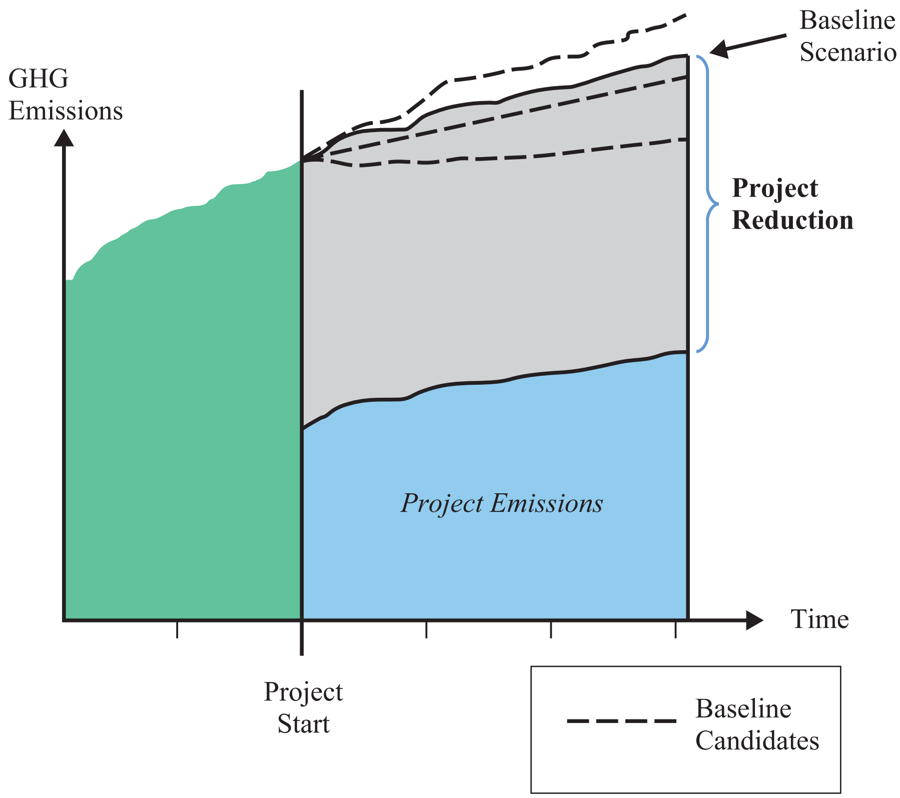


Figure 2-1. Illustration of Emission Reductions Relative to Baseline Scenarios

Where the GHG reduction project consists of more than one project activity, the overall net reduction is the sum of the GHG reductions from each individual activity. For example, the reduction project may consist of energy efficiency improvements to several engines at a facility. An emission reduction is determined for each engine based on the equipment-specific baseline emissions and project emissions. These are then summed to result in an aggregate emission reduction for the facility-level reduction project.

Quantifying Project Emissions

Greenhouse gas emissions associated with emission reduction projects can be estimated based on expected or forecast activity data (ex-ante) or calculated based on actual operating conditions (ex-post). These approaches are useful for specific purposes. For example, predictive emission estimates are often used for planning purposes, while ex-post emissions are more technically sound for quantifying emission reductions.

In quantifying the project emissions, the following recommendations are provided:

- Concentrate on the largest and/or most variable emission sources, sinks, and reservoirs;

- Use measured or metered activity data, where available, and actual operating conditions; and
- Apply calculation methodologies such as those provided in the API Compendium where appropriate/applicable.

The selection of a specific methodology to quantify the project emissions depends on the type of project, the availability of activity data, and considerations of costs versus accuracy. Some of these considerations are demonstrated in Section 5. The methodology may also be dictated by a particular climate change regime or GHG registry, if applicable (refer to Section 3).

Estimating Baseline Emissions

The baseline emissions are the estimated tonnes[5] of GHG emissions for relevant emission sources, sinks, and reservoirs corresponding to the baseline scenario. Because the baseline emissions are representative of a hypothetical scenario, baseline emissions are only estimates. Guidelines for estimating the baseline emissions are:

- First, identify the most suitable characteristic output for the project. For example, m^3 of natural gas produced, bbl of crude intake to a refinery, or MW-hr of electricity generated.
- Then, estimate emissions for the relevant emission sources, sinks, and reservoirs associated with the baseline scenario at the same characteristic output as the GHG reduction project. This removes the effects of operational growth or decline and enables the baseline and reduction project emissions to be assessed on a comparable activity basis.
- Apply calculation methodologies such as those provided in the API Compendium where appropriate/applicable. Selecting a methodology will depend on specific conditions related to the baseline scenario and the project activity.

2.7 Monitoring, Reporting and Verification

As a general rule, the cost of monitoring, reporting, and verification should not exceed the value of the GHG emission reductions.

2.7.1 Monitoring

Monitoring provides the means for quantifying, reporting, and validating GHG emissions and/or removals relevant to the project and baseline scenario and may include a combination of measurements, modeling, and estimation techniques. Monitoring should be cost-effective, with emphasis placed on those parameters that are highly variable and/or related to the most significant emission sources. Monitoring is based on:

- Selecting appropriate parameters from which to gauge emissions controlled by, related to and affected by the project activity, as well as relevant to the baseline scenario;

[5] Metric tonnes = 1000 kg = 2204.62 lb

- Determining the monitoring means (e.g., measurement or metering), frequency and duration consistent with the variability of the parameter; and
- Examining changes in conditions that might impact the baseline scenario, such as new regulations.

There are two types of parameters that may be monitored:

- Parameters that indicate the continued validity of certain assumptions. This includes analyzing information to determine if the project is performing as expected and if information used to estimate the baseline is still valid. If monitoring these parameters indicates that a key assumption is no longer valid, then the project emissions may need to be re-evaluated or the baseline scenario (or associated baseline emission estimate) may need to be reconsidered.
- Parameters that help determine baseline emission estimates, such as emission factors or other variables that directly determine baseline emissions over time.

Applying the points above and general GHG accounting principles, monitoring should consider the following for each emission source, sink or reservoir that comprises the project or baseline emissions:

- Measurements, modeling, calculation methodologies, or estimation approaches that apply to data or parameters, and the associated level of estimation uncertainty; and
- Frequency of monitoring relative to the variability in the data or parameters.

Ideally, the plan for monitoring would be developed prior to the project being implemented. This enables baseline data collection.

Specific monitoring requirements may be dictated by a particular climate change regime, if applicable.

2.7.2 Project Reporting

Emission reductions are generally reported on an annual basis. The objective of reporting is to provide sufficient transparency to enable the intended audience to make an informed decision on the credibility of the emission reduction. A GHG emission reduction report should provide a plausible and transparent account of the project, decisions, and assumptions. A GHG emission reduction report should be supported by documentation maintained by the project proponent.

A transparent emission reduction report supports validation or verification against a monitoring plan if one existed, or against guidelines or standards such as this document, ISO 14064, WBCSD/WRI Project Protocol, API Compendium, etc. Specific reporting requirements may be dictated by the particular climate change regime, if applicable. Information that is generally reported include the following:

- Description of the project;
- Geographic location;

- Start date of the project, and if different, the date when GHG emission reductions were first generated;
- The identified baseline candidates, the process for assessing the baseline candidates, and justification for the baseline scenario;
- Assessment boundary determination, and the project and baseline emission sources within the assessment boundary;
- Estimated baseline emissions, quantified project emissions, and the resulting reductions;
- Calculation methods, monitored parameters, assumptions, and uncertainties.

2.7.3 Project Verification

Verification should focus on quality assurance with the objective of improving the overall reliability of the reported emission reductions. Verification should provide the stakeholder or user of the information assurance that the reported emission reduction is credible.

Specific verification requirements may be dictated by the particular climate change regime or GHG registry, if applicable.

Section 3. Policy Considerations

The purpose of this section is to highlight considerations regarding specific GHG policy requirements. In some cases, this may require distinguishing between a quantified, "credible" GHG emission reduction and a GHG reduction that meets any applicable criteria for recognition as a tradable credit (a "creditable" reduction).

A GHG reduction project is a recognizable and distinct activity or set of activities that reduce global GHG emissions. Section 2 outlines the general guidelines for assessing, quantifying, and monitoring project-based emissions reductions, focused on the technical aspects of quantifying emission reductions. In addition to tracking emission reductions, however, many oil and natural gas companies seek to register or certify project-based activities that qualify as creditable under specific climate change regimes or GHG registries (e.g., Clean Development Mechanism or Joint Implementation under the Kyoto Protocol framework). To qualify as creditable under a regime, there are specific policy-related considerations that may be required in addition to those presented in Section 2.

In practice, an emission reduction is only considered "creditable" if it meets the requirements of the particular climate change regime, GHG registry, or inventory program under which it is being implemented. Typically, these requirements fall into two main categories: first, the project activity must be eligible; and second, the screening process for determining the baseline scenario should ensure that the reductions resulting from the GHG reduction project would not have occurred anyway. Assessment boundary issues are also considered in this section since they may be defined differently by the policies of different climate change regimes, thus impacting the quantity of emission reduction credits.

Table 3-1 summarizes the eligibility and baseline scenario or additionality requirements (as of August 2006) for several climate change regimes and GHG registries (listed in Appendix A).[6] These policy-related requirements are characterized as criteria that influence:

a) The eligibility of the GHG reduction project in terms of meeting specific requirements for a particular climate change regime – These requirements influence whether the GHG reduction project qualifies as creditable under the climate change regime, and may not have any impact on the accounting of the GHG reductions. The most prevalent of these eligibility criteria are presented in Section 3.1;
b) The determination of the baseline scenario that represents what would have otherwise occurred – The policy criteria that influence baseline determination have

[6] As indicated in Footnote 2, this guidance document is not intended as an exhaustive or authoritative summary of all applicable policy requirements. Any company that wishes to register or otherwise obtain credit for a GHG reduction project should consult its own legal counsel as to any legal requirements that might apply to the project.

a direct impact on GHG reduction project accounting, as the magnitude of baseline emissions sets the overall creditable emission reductions from the project activity. Screening tests under various regimes for determining the baseline scenario are discussed in Section 3.2; and

c) The determination of the assessment boundaries for monitoring the GHG reduction project and corresponding baseline emissions – As with baseline scenario determination, policy driven requirements may dictate the assessment boundary. A discussion of the considerations for establishing the assessment boundaries under common climate change regimes is included in Section 3.3.

Policy criteria often differ among programs, and not all project activities will qualify for creditable reductions. Many of the climate change regimes and GHG registries are in early stages of implementation and the requirements/guidelines for GHG reduction project eligibility may evolve over time. With the 2005 entry into force of the Kyoto Protocol, some of the non-Kyoto oriented regimes [e.g., Clean Air Canada, Inc. (CACI)] are being phased out. Due to this evolving framework, it is prudent for the project participant to understand the specific requirements of the climate change regime under consideration (see footnote 6, above).

Table 3-1. Summary of Policy Requirements for Common Climate Change Regimes

Category	Potential Criteria for Creditable Emission Reductions
a) Criteria that may impact GHG reduction project eligibility	Geographical location of project activity
	Stakeholder engagement, environmental impact assessment (EIA) completed & host country approval
	Contribution to sustainable development
	Financial additionality
	Impact on, or diversion of, Government Official Development Assistance
	Timing of GHG reduction project implementation
	Project activity type / technology
	Proof of ownership of emission reduction credits
	Emission reductions in excess of voluntary standards and policy guidelines
b) Criteria that may impact baseline scenario determination	Prevailing practices in the region
	Sector-specific benchmarks
	Regulatory surplus (GHG reductions that exceed regulatory requirements or GHG reductions that result from meeting regulatory requirements for other emissions)
	"Barriers" to GHG reduction project implementation
	Investment ranking to prioritize economic attractiveness of alternatives

Table 3-1. Summary of Policy Requirements for Common Climate Change Regimes, continued

Category	Potential Criteria for Creditable Emission Reductions
c) Criteria that may impact assessment boundary definition	Assessment boundary changes outside control of the project proponent
	Inclusion of related emission sources (e.g., purchased electricity)
	Life cycle impacts – how far up the value chain that GHG emissions must be examined
	Activity shifting – displacement of GHG generating activities to other locations
	Market leakage – changes in commercial markets as a result of project activities that cause changes in GHG emissions
	Permanence
	Sources, sinks and reservoirs under operational control of project proponent
	Significance / materiality of emissions outside assessment boundary
	Difficulty obtaining data

3.1 Criteria that May Impact GHG Reduction Project Eligibility

The criteria described here could impact whether or not a GHG reduction project is eligible to register credits under various programs. Generally, these criteria are political in nature and have little or no impact on GHG reduction project accounting.

Criteria required by some of the climate change regimes and GHG registries include:

- Geographical project activity location (e.g., Joint Implementation [JI] projects can only be undertaken in Annex I countries);
- Host country approval (e.g., Clean Development Mechanism [CDM] requires approval by the host country through the Designated National Authority);
- Environmental impact assessment of the project activity;
- Engagement of stakeholders (e.g., engagement or approval by different stakeholders may be required for the issuance of credits);
- Contribution to sustainable development (e.g., CDM requires that all GHG reduction projects must contribute to sustainable development. It is the prerogative of the host country to determine the types of project activities that constitute sustainable development within its jurisdiction);
- Separation of the project activity from official development assistance (ODA) funding (referred to as "financial additionality" in CDM context);
- Timing of GHG reduction project implementation (e.g., emission reductions from JI project activities are creditable starting in 2008);

- Project activity type/technology – certain regimes have restrictions on eligible project activity types (e.g., many regimes exclude nuclear power generation projects); and
- Proof of ownership of the emission reduction credits.

In addition, the climate change regime may require a financial analysis to demonstrate the following:

a. The GHG reduction project is not financially attractive without factoring the value of potential credits. (Also referred to as investment or economic additionality. The rationale is to demonstrate that without credits, the GHG reduction project would not be undertaken because it would not be economically attractive.);
b. There are no financial barriers to the implementation of the identified baseline scenario (for example, a financial barrier might be the high cost associated with a technology that is not currently proven for the specific application).
c. The baseline scenario is the most financially attractive option (investment ranking).

The first criterion deals with economic additionality of the GHG reduction project. The latter two criteria relate to baseline scenario determination and are discussed in Section 3.2. However, all three financial analysis criteria have complexities in their application, both in general and for the oil and natural gas industry.

In determining what is financially attractive (or not), financial return is important, but other factors may be equally relevant in making capital allocation decisions. Companies and investors operate under capital constraints and the estimated financial returns of such GHG reduction projects may not justify diverting capital from other higher return or more strategic initiatives.

For the oil and natural gas industry, joint ventures are frequent. In many concession areas, only the joint venture can make investment decisions, because outside parties are not able to invest. In those situations, the only potential GHG reduction project proponents are the existing partners whose return from the GHG reduction project might differ substantially among each other (this is particularly true when the state is a partner or where gas pipelines are owned by outside interests). Further, there exist cases in oil concessions where ownership of the associated gas is different than that of the oil, and thus any GHG reduction project economics could be different among partners. This is exemplified in the most extreme case where the associated gas belongs exclusively to the state and the private partners would derive no benefit from its sale; yet the legal requirement could well be that the partners must share equally in all investments.

Due to these issues, financial analysis can be quite subjective.

3.2 Policy Considerations that Impact GHG Reduction Project Accounting and Baseline Scenario Determination

As mentioned above, a GHG reduction project is any activity (or activities) that reduces the net GHG emissions to the atmosphere. A creditable GHG reduction project is one that meets the applicable technical and policy requirements of the particular climate change regime. Under specific regimes, there may be additional policy considerations that go beyond those aspects addressed in Section 2 that must be taken into account for a GHG reduction project to qualify as creditable. Some typical policy considerations that apply specifically to determining a baseline scenario are addressed in this section.

For most GHG reduction projects, common practice in the sector and/or geographical region provides a credible baseline candidate, as discussed in Section 2. However, under some climate change regimes, other policy-related considerations may be required. One of the key requirements of many climate change regimes is that project-based reductions are additional to what would have occurred otherwise in the absence of the project activity. Some climate change regimes will only recognize the reductions as additional if certain procedures are used to determine the baseline scenario. For example, CDM requires that baseline methodologies approved by the CDM Methodology Panel be used. Other climate change regimes have identified assessments or screening procedures to assist in baseline determination.

The first step in baseline scenario determination is to identify all potential baseline candidates, including the alternatives of continuing current activities and doing the project activity itself. Then, one or more of the comparative assessments outlined below can be used to determine the most appropriate baseline candidate among the alternatives. The most common comparative assessments used to determine the baseline scenario include:

- Common practice test: Demonstrate that the baseline scenario is consistent with the prevailing practices in the region.
- Benchmark assessment: Also referred to as a performance standard (see WBCSD/WRI Project Protocol for additional information on applying this baseline procedure). This procedure defines a rate of GHG emissions per unit of an output produced by all of the baseline candidates, such as tCO2e/MWh.
- Policy and regulatory assessment: Demonstrate that the baseline scenario is consistent with applicable laws or regulations;
- Barriers assessment: Demonstrate that other barriers (aside from regulatory) do not exist that make the baseline scenario infeasible, and that the GHG reduction project faces greater barriers to implementation than the baseline scenario.
- Investment ranking: Without considering the revenue from potential credits, demonstrate that the baseline scenario is the most economically attractive alternative.
- Net benefits assessment: Identify the baseline scenario as the alternative that would provide the greatest incentives (identified as benefits) to the decision-makers relative to any disincentives (identified as barriers).

The choice of comparative assessments used to determine the baseline scenario will depend on the specific climate change regime. For example, where prescribed by an approved methodology, the CDM requires some of these tests, in a specific order, in its "tool for the demonstration and assessment of additionality"[7]. Through this process of baseline determination, if the baseline scenario has a higher GHG emission profile than the project activity, then the GHG reduction project is considered additional (i.e., resulting in the reduction, removal, or storage of CO_2 emissions over what would have occurred in the baseline scenario).

Each of the screening assessments is discussed further in the following subsections. Through this filtering process, potential baseline candidates are ruled out, resulting in either:

1. Determining the most appropriate baseline scenario and demonstrating additionality; or
2. Determining that the project activity is the baseline scenario and, therefore, is not additional (with no creditable emission reductions resulting from the GHG reduction project under the applicable climate change regime).

To illustrate how these assessments can be applied in practice, a flare elimination project is presented as an example in the following subsections. The example is introduced below, with subsequent illustrations of how each of the respective baseline screening tests might be applied for this illustrative example. Further application of the process for baseline scenario determination is provided in Section 5 for the cogeneration project family.

[7] http://cdm.unfccc.int/methodologies/PAmethodologies/AdditionalityTools/Additionality_tool.pdf, November2005.

Flare Elimination Project Example – Identifying Potential Baseline Candidates

In this example, an oil production operation has historically utilized associated gas as fuel in on-site production operations, but has flared the excess associated gas. With changing market conditions in the regional area, facilities are installed at the existing production site to recover the previously flared associated gas and export the gas to an independently owned power station. Therefore, the emission reduction project entails installation of gas compression, dehydration, metering and pipeline facilities to recover and sell the previously flared gas from the existing operations.

The first step in the baseline screening process is to identify all potential baseline candidates, including continuing current activities and the project activity itself.

Baseline candidates for this example project include:

1. Continuation of current activities: Associated gas continues to be flared, and gas market demand is supplied through other means;
2. Flare elimination is a regulatory requirement;
3. Project activity: Gas is recovered and transported for sale to local markets;
4. Gas is reinjected or utilized for gas lift;
5. Gas is recovered for LNG export to global markets; and
6. Gas liquids (e.g., GTL) are recovered for export to regional markets.

3.2.1 Common Practice Assessment

The common practice assessment provides a realistic and practical means to evaluate the baseline candidates. The common practice assessment is applied to compare the existing common practice in the region to the baseline candidates, including the project activity. An analysis of any other activities implemented previously or that are currently underway that are considered similar to the project activity (in the same region and/or rely on a similar technology, comparable scale, comparable regulatory framework, etc.) are included in the common practice assessment. Similarly, the evaluation includes geographic areas that exhibit circumstances similar to those surrounding the project activity (e.g., technological, resource, socioeconomic, or political circumstances).

The following sources of information may be useful for assessing common practice:

- Vendor surveys of technology penetration or use;
- Review of permit revisions for plants in construction or equipment installations;
- Review of permit applications for planned or proposed plants, technologies, equipment or practices; and
- Expert opinion.

The common practice test is used either to: a) determine the baseline scenario based on common practice; or b) assess the GHG reduction project's financial attractiveness and/or applicable barriers to implementation (i.e., the most economically attractive alternative and/or least barriers to implementation would nominally be expected to be consistent with common practice), depending on any applicable climate change regime requirements.

What is considered a typical practice in the region? Are there industry best-practice standards in place that clearly set out a baseline scenario?

If there is an industry best-practice standard or technology in practice in the region, then the minimum requirements under the best-practice standard could arguably be adopted as the most likely baseline scenario. Within a region, operations with similar gas to oil ratio (GOR) and built at the same time would be expected to exhibit similarities that make common practice a suitable baseline scenario. However, in practice, it may be difficult to apply common practice due to operational variations even within the same geographical region. In these cases, sectoral practices across similar technologies may be more appropriate than geographical practices. This is particularly important for the oil and natural gas industry, since oil and natural gas fields in the same geographical area may have widely different

Flare Elimination Project Example – Applying the Common Practice Test

For this flare elimination example, the common practice test would include an analysis of other activities in the region considered similar to the project activity. This analysis would need to consider aspects such as:

- Oil and natural gas production activities in the same geographic area with similar reservoir characteristics, such as gas to oil ratio (GOR) and maturity of field; and
- Similar access to natural gas pipeline infrastructure and/or end use.

A list of similar activities would then be developed and analyzed to determine common practice. Relevant information to make such a common practice determination ideally might include the following gas utilization characteristics related to similar oil and natural gas operations:

- Percentage of associated gas flared (or vented);
- Percentage of associated gas exported for sale;
- Percentage of associated gas reinjected or utilized for gas lift; and
- Percentage of associated gas used as on-site fuel gas.

Alternatively, data to determine total gas flared per barrel of oil equivalent (BOE) production may be reported to the government and available for analysis. The average percentage of gas flared across similar operations could arguably be determined to be common practice, hence an appropriate baseline. In actuality, the lack of publicly available data (in terms of the proportion of gas utilized versus gas flared) may impede application of this detailed theoretical approach.

A more practical approach to determine the appropriate baseline may be to broadly assess whether flaring occurs routinely from other existing operations. Qualitative or semi-quantitative information may be necessary to support this assessment, such as qualitative knowledge of operational differences between fields/reservoirs. For example, a common practice test could show that in a particular region, it is common for operators of existing facilities to flare excess un-utilized associated gas, but that new projects are typically designed for zero routine flaring.

characteristics.

Is the baseline scenario consistent with customary practices in the region or sector?

Through this assessment, a likely baseline scenario would be one that demonstrates the average GHG emissions or establishes a benchmark from similar project activities. For some

GHG reduction projects, it may be possible to consider similar activities within other industry sectors as part of the benchmark (for example, comparing cogeneration from a refinery to electricity generated by an electric utility company). As noted above, developing a benchmark is particularly difficult for exploration and production operations, since oil and natural gas fields have different characteristics, which change during the production cycle.

A key disadvantage to benchmarking is the cost associated with gathering the necessary data for recent project activities in order to develop the baseline candidates. These costs are likely greatest for the first assessment of a particular project activity type. However, once the data for GHG emissions from most recent project activities are collected, project proponents undertaking subsequent project activities can benefit from this information. These costs can be reduced if the program administrator develops the benchmark or performance standard. This would lead to cost reductions and an increase in certainty for project proponents.

3.2.2 Regulatory Assessment

Are there regulations in place that require the reduction activity? Is the GHG reduction project operational prior to the deadline for compliance with applicable regulations? Are there government policies or goals that apply to the reduction activity?

Regulations and government policies may directly affect the GHG emissions of the project activity or a baseline candidate, or may affect GHG emissions indirectly as a consequence of their implementation (e.g., NOx controls may result in increased N_2O emissions). Both regulations and policies should be considered when assessing a project activity or baseline candidates.

If the project activity reduces emissions beyond minimum regulatory requirements, then the project activity may be eligible as creditable reductions for the increment beyond the baseline scenario. (Under some regimes, this is referred to as regulatory surplus.) If the GHG reduction project is operational prior to the regulatory compliance deadline, then the baseline scenario for the period prior to regulatory compliance may be less stringent (i.e., result in higher baseline emissions) and provide greater opportunity for emission reduction credits.

Under the CDM "tool for the demonstration and assessment of additionality"[8], the project activity and baseline candidates must comply with all applicable legal and regulatory requirements, even if these laws and regulations have objectives other than GHG reductions, e.g., to mitigate local air pollution. The CDM screening, however, does not consider national and local policies that are not legally binding, or that are systematically not enforced.

[8] http://cdm.unfccc.int/methodologies/PAmethodologies/AdditionalityTools/Additionality_tool.pdf, November2005.

Flare Elimination Project Example – Regulatory Assessment

For the example flare elimination project, a well enforced government regulation on gas venting and/or flaring in the region or country would affect the baseline scenario assessment. Any baseline candidates that do not meet the minimum regulatory requirements would be eliminated from the analysis as nonviable. All potential baseline candidates must meet existing regulatory requirements, i.e. if flare elimination is required by an enforced law, then this effectively becomes the baseline scenario.

In some cases, identifying legal requirements relative to potential baseline candidates is complicated. The enforcement of laws and regulations may be uneven or weak because of financial and/or administrative constraints on enforcement or regulatory agencies. For example, a regulation may have been promulgated at the national level, but implementation at the regional level may be weak. The following sources of information may be useful for understanding enforcement levels:

- Regulatory permits to see what companies undertaking similar activities are required to do;
- Fines administered for not complying with a given law; and
- Surveys of technology penetration or use, compliance actions, etc.

3.2.3 Barrier Assessment

What barriers exist that could prevent implementation of the proposed baseline scenario?

In this assessment, all baseline candidates are examined relative to each potential barrier that would prevent or reduce the likelihood of implementation. Potential barriers are shown in Table 3-2.

Table 3-2. Potential Barriers for Baseline Candidate Assessment

Barrier Category	**Barrier Description/Examples**
Legal	• Unclear credit ownership rights • Poor or inadequate enforcement of law • Immature legal framework • Negative environmental impact assessment
Financial/budgetary	• Poor risk/reward profile • Limited access to capital • Insufficient or unavailable debt funding • Immature capital market
Technology	• Higher perceived risks associated with implementing new technology • Lack of trained personnel or expertise • Lack of educational resources to train labor force • Inadequate supply or transport infrastructure for raw materials or products

Table 3-2. Potential Barriers for Baseline Screening, continued

Barrier Category	Barrier Description/Examples
Market structure	• Market distortions that favor other technology (e.g., the fiscal regime may be designed for oil and thus provide de facto disincentives for gas recovery or even assign the ownership of the gas to a different entity than the operators of the field.) • High transaction costs • Slow rate of technology penetration
Institutional/social	• Unstable social and/or political environment • Social or cultural traditions slow adoption of technology or practices • Institutional, social, or political opposition to the implementation of the technology or practice
Resource availability	• Insufficient or irregular supply of resources

Adapted from WBCSD/WRI, The GHG Protocol for Project Accounting, Table 8.1.

The importance of the barriers is assessed relative to each other and for each baseline candidate. The degree to which an identified barrier affects each baseline candidate may be characterized qualitatively using descriptive explanations and relative rankings (e.g., high, medium, or low). Rankings can be presented in a matrix to enable side-by-side comparison.

Baseline candidates are eliminated if it is determined that the barriers would prevent or significantly reduce their likelihood of implementation. The baseline candidate that faces fewer barriers to implementation than the other possible candidates can arguably be identified as the most likely to occur.

Flare Elimination Project Example – Barrier Assessment

In the barrier assessment process for the flare elimination example, barriers are identified that would prevent or reduce the likelihood of implementation of baseline candidates. Some potential barriers related to the flare elimination project include:

- Complex commercial situation for marketing associated gas, due to multiple stakeholders involved in joint venture partnerships, third party operators, government policies, infrastructure owners, etc.;
- Lack of infrastructure integration between consumers and producers (i.e., stranded gas with limited to no access to gas pipeline infrastructure);
- Production Sharing Agreements (PSAs) that do not allow the costs associated with gas infrastructure development to be recovered;
- Variability in production rates of associated gas, leading to uncertainties in supply;
- Ownership rights to associated gas (e.g., in many countries, the government has full ownership rights to the associated gas);
- Market pricing influences, such as competing non-associated, produced gas and subsidies for alternative fuels; and
- Financial risks associated with lack of payment guarantees from consumers, especially in impoverished regions.

Flare Elimination Project Example – Barrier Assessment, continued

These barriers are assessed qualitatively relative to the baseline candidates in the following matrix.

	Barriers						
	Commercial Complexities	Lack of Infrastructure	Production Sharing contracts	Variable gas volume	Ownership rights	Market pricing influences	Financial risks
Overall Barrier Assessment	**M**	**H**	**M**	**M**	**H**	**M**	**M**
Continuation of current activities	NP	NP	NP	NP	NP	NP	NP
Flare elimination project	P	P	P	P	P	P	P
Re-injection or Gas lift	NP	NP	NP	NP	NP	NP	NP
Gas recovered for LNG	P	P	P	P	P	P	P
Gas-to-liquids	P	P	P	P	P	P	P

P = barrier is present; NP = barrier is not present

H = significant barrier; M = moderately significant barrier; L = less significant barrier

3.2.4 Investment Ranking

Are there financial or economic incentives that make a particular baseline scenario a more attractive investment option than other scenarios?

For screening baseline candidates, one assessment is to rank the candidates in accordance with the investment requirements and attractiveness to investors. The investment ranking analysis seeks to assess expected financial returns that may arise from implementing the GHG reduction project or a baseline candidate without considering non-revenue benefits and without accounting for identified barriers other than cost. Investment analysis excludes any potential revenues associated with the sale of GHG reduction credits.

In establishing the investment ranking of baseline candidates, the following relevant costs should be included:

- Investment costs;
- Operating and maintenance costs;
- Revenues; and
- Subsidies/fiscal incentives, where applicable.

Flare Elimination Project Example – Investment Ranking

Investment ranking looks at the relative investment of the baseline candidates and ranks them according to investment requirements and/or attractiveness to project investors. For the flare elimination project example, some potential considerations are presented below.

For concessions in many regions, only joint ventures partners can make investment decisions and outside parties may not be able invest. Thus, flare elimination projects may or may not be funded depending on the investment priorities of the joint venture partners.

For evaluating baseline candidates (i.e., gas recovery and export to local market), investment ranking considerations may include:

- Fuel pricing may be influenced by competing, lower cost fuel supply to market, hence impacting project return; and/or
- Project investment – the return on investment for taking gas to market may be marginal, at best, due to high capital investment.
- For LNG or gas liquids recovery, the project return may be relatively high even though capital investment is high, due to favorable product pricing in global or regional markets.

By ranking the results of the investment analysis for the project activity and baseline candidates, it may be possible to show that the least cost option is to continue flaring, or that the flare elimination project ranks lower than typical capital investments made by the operator.

Assumptions used for capital costs, fuel pricing, equipment lifetimes, discount rates or cost of capital should be appropriate for the region or sector and transparently reported. The baseline scenarios are ranked according to an appropriate financial indicator [e.g., internal rate of return (IRR)], and the one that represents the most financially attractive option is considered the most likely to occur and determined to be the baseline scenario. In practice, this investment ranking can be difficult because financial return is only one of the relevant factors in making financial decisions.

Annex C of the WBCSD/WRI Project Protocol provides further details on assessing net benefits using investment analysis.

3.3 Assessment Boundary

The assessment boundary should capture all relevant effects of the project activity as discussed in Section 2. The general guidance for determining the assessment boundary is to expand the range as far as possible taking into consideration the relevant GHG emission sources, sinks and reservoirs controlled by the project proponent, related to and/or affected by the GHG reduction project. In practice, the ability to quantify and monitor emissions, significance of the sources, or the ability to attribute the effects to the project activity are considerations for inclusion within the assessment boundary.

Although the assessment boundary should capture all relevant effects of the project activity, particular regimes may have specific requirements for defining the assessment boundary. For example, CDM defines the GHG reduction project boundary as encompassing “all anthropogenic emissions by sources of greenhouse gases (GHG) under the control of the project participants that are significant and reasonably attributable to the CDM project activity." Any emissions outside the control of the project proponent are termed leakage, also referred to as secondary effects[9] in other programs (e.g., WBCSD/WRI Project Protocol). The extent and detail to which secondary effects are included in the assessment boundary are policy decisions of GHG registries and climate change regimes. Based on the policy requirements, secondary effects may include:

- Life cycle impacts – GHG emissions upstream or downstream of the intended change caused by the project activity. These are referred to as secondary effects in the WBCSD/WRI Project Protocol;
- Activity shifting – the physical displacement of GHG generating activities that would have occurred in the baseline scenario to other locations;
- Market leakage – GHG emissions resulting from changes in supply or demand in commercial markets as a result of the project's activities; and
- One-time effects – GHG emissions resulting from one-time occurrences associated with the project activity, generally construction, installation, commissioning, and/or decommissioning phase activities.

Another assessment boundary consideration is permanence, or the ability of a GHG sink or reservoir to store GHG emissions indefinitely, such as for a carbon capture and geological storage (CCS) project. For CCS projects, the potential exists for stored carbon to be re-emitted to the atmosphere at a later date. Different regimes have proposed methods to account for the potential reversibility of stored sequestered emissions for CCS projects. Considerations regarding permanence are addressed further in the CCS Project Family example presented in Section 6 (released as a separate document).

[9] A secondary effect refers to an unintended change in GHG emissions, removals, or storage caused by a project activity, while a primary effect refers to the intended change in GHG emissions, removals, or storage caused by the project activity (WBCSD/WRI, Project Protocol, 2005).

Flare Elimination Project Example – Assessment Boundary

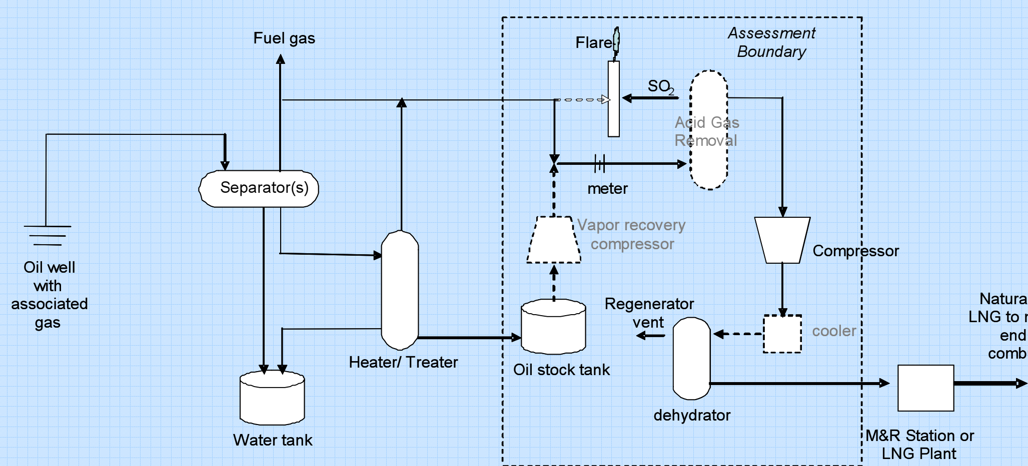
Sources within the assessment boundary should be identified consistent with Section 2.5. However, some regimes require a specific assessment boundary. For the flare elimination project example, the assessment boundary definition under some regimes, such as the CDM, would include all process operations relevant to the project and baseline that are under the control of the project proponent. In this instance, the assessment boundary would include:

- Emission sources from on-site operations associated with gas flaring, recovery, processing, compression, and metering; and
- Emission sources from off-site operations associated with pipeline transport, under the control of the project proponent.

(These emission sources would be associated with the primary effects under the WBCSD/WRI Project Protocol.)

The secondary effects associated with the flare elimination project example might include:

- Life-cycle impacts: Downstream utilization of the associated gas;
- Market leakage: Increase in gas demand as a result of the project; and
- One-time effects: Emissions associated with construction and/or start-up of the new process equipment.



Section 4. Overview of GHG Reduction Project Families

This section provides a brief overview of key considerations for several GHG reduction project families applicable to oil and natural gas industry operations. The project families considered – cogeneration, carbon capture and geological storage, flare reduction, fuel switching, and energy efficiency improvements – are of particular interest to the oil and natural gas industry due to their potential for substantive reductions in GHG emissions from industry operations.

4.1 Cogeneration

Cogeneration, also known as combined heat and power (CHP), is the simultaneous production of electricity and process heat from the same fuel. Cogeneration projects have the potential to reduce GHG emissions in two ways:

1. The cogeneration system represents an improvement in overall energy efficiency compared to the separate generation of electricity and steam; and
2. The cogeneration fuel source may replace or displace other more carbon intensive fuel sources, in relation to steam generation, electricity generation, or both. This impact is essentially a "fuel switch" project activity, which is addressed separately in Section 4.4.

For the oil and natural gas industry, cogeneration projects provide an efficient means of generating steam and electricity needed for refinery operations or for steam-flood in enhanced oil recovery operations. However, specific issues and challenges related to quantifying GHG emission reductions associated with a cogeneration project include the following:

- <u>Calculation of GHG reductions</u> – Where the cogeneration project replaces previously imported electricity and/or steam, an increase in direct emissions due to onsite fuel combustion results. However, quantifying the emission reductions must consider the net change in GHG emissions from the imported energy streams in the baseline scenario relative to the cogeneration emission sources created from the GHG reduction project. There are numerous methodologies to do so, some requiring more data and complexity than others. The choice will depend on the data availability, as well as the goal for demonstrating emission reductions, whether for credits, internal reporting, etc. Specific regimes or registries may require a particular approach. For example, to determine baseline emissions associated with grid-supplied electricity, different baseline scenario methodologies have been used or are considered acceptable.
- <u>Variability in Grid Mix</u> – Due to frequent changes in the generation mix for grid-supplied electricity, the baseline emission factor will likely change over time. Ex-post assessment of the baseline emissions should utilize information on the actual generation mix for the

relevant time period. The frequency of adjusting the baseline emission factor may also be dictated by the climate change regime or GHG registry.

- Policy Considerations – Cogeneration facilities enable refineries to be power suppliers. This is often overlooked where policy considerations focus on the electric generation industry. Organizations such as the American Petroleum Institute (API) and the International Petroleum Industry Environmental Conservation Association (IPIECA) advocate for representation of the petroleum industry's position in policy decisions. However, a project proponent may need to work with the climate change regime or GHG registry to adapt program components for petroleum industry cogeneration applications.
- Additionality – A complication for the steam generation portion of the cogeneration project is the difficulty in justifying why cogeneration is not common practice for new facilities with large steam loads, even if excess electricity is exported to satisfy the internal steam load. From a technical perspective, cogeneration is likely to reduce emissions from current or previous forms of steam generation, and therefore result in a credible emission reduction. Whether or not this activity is determined to be common practice, and therefore becomes the baseline scenario, is a policy matter established by the climate change regime or GHG registry.
- Ownership and Potential Double Counting of Emission Reductions – Ownership of the emission reductions normally reside with the entity responsible for the investment in the project. For a cogeneration unit, this would generally be the entity that owns or controls the unit. However, there is a potential for multiple parties to claim credit for emission reductions associated with utilizing the energy streams in place of less efficient sources of electricity or heat/steam.

4.2 Carbon Capture and Geological Storage

Carbon dioxide (CO_2) capture and geological storage (CCS) refers to the chain of processes to collect or capture a CO_2 gas stream, transport the CO_2 to a storage location, and inject the CO_2 into a geological formation[10] for long-term isolation from the atmosphere. Compared with other emission reduction projects, CCS involves the generation of CO_2 gas, but emissions to the atmosphere are avoided because the CO_2 is injected and ultimately stored in a geological formation on a permanent basis. Examples of geological formations suitable for storage include depleted oil and natural gas reservoirs, unmineable coal seams, deep saline formations, etc. Candidates for CO_2 capture are separation from natural gas if the CO_2 content is larger than the sales gas specifications or for the natural gas to be used for LNG, large stationary sources, such as from electric power plants and other large industrial facilities.

Application of CCS for climate change mitigation builds on existing operations, in particular large-scale CO_2 injection and storage in depleted oil fields is already taking place as a result

[10] For the purpose of this project family, geologic storage reservoirs explicitly exclude ocean sequestration.

of enhanced oil recovery (EOR) operations. Geologic structural and stratigraphic traps have demonstrated the ability of reservoirs to seal and store hydrocarbons for millions of years. The mechanisms that initially trapped these hydrocarbons remain intact as fluids are extracted from or injected into these reservoirs. The proven ability for hydrocarbon reservoirs to successfully trap and store fluids for several million years demonstrates the viability of these formations for long-term CO_2 storage. This is further enhanced by other mechanisms that more readily retain CO_2 in the subsurface than hydrocarbons (i.e., capillary trapping, dissolution in water, and mineralization).

In order to create a GHG emission reduction, CCS projects must result in the long-term confinement of CO_2 away from the atmosphere. The project family for CCS addresses risk management in terms of site selection, as well as monitoring to provide assurance that the CCS project is performing as expected. Technical and policy issues associated with quantifying GHG emission reductions from CCS include the following:

- Permanence/Reversibility – Although CCS projects will be selected and operated to avoid physical leakage, there exists a small probability that physical leakage may occur and remediation methods will be needed, either to stop the leak or to prevent/minimize impacts. Should physical leakage occur, net emission reductions should be adjusted accordingly.
- Eligibility – In some regimes, geological sequestration projects may not be eligible as a candidate GHG reduction project.
- Additionality – Also in some regimes, the eligibility of a GHG reduction project as a candidate for emissions reduction credits may be dependent on the financial viability of the project activity without the revenues from the sale of CERs. The project proponent may need to demonstrate that the project activity is not a financially attractive investment even with the increased oil production (or methane production from enhanced coal bed methane [ECBM] or enhanced gas recovery [EGR] operations).
- Calculation of GHG reductions – The assessment boundary should consider emissions associated with CO_2 co-produced with oil and/or gas, and its disposition. Policy decisions from some climate change regimes may require accounting for emissions that result from the combustion of oil or natural gas produced from EOR, ECBM, and/or EGR operations.
- Ownership – Multiple parties may be involved in the operation or control of the different elements of the CCS chain, or multiple parties may use the same geological structure for storing CO_2 or for producing hydrocarbons. These arrangements complicate the allocation of benefits or the assignment of liability.

4.3 Flare Reduction

Reduced flaring of gas associated with the extraction of crude oil minimizes the waste of resources and contributes to reducing GHG emissions. Potential options for utilizing otherwise flared natural gas are shown in Table 4-1.

Table 4-1. Potential Flaring Reduction Scenarios

GHG Reduction Project type	Baseline Candidate Conditions	Project Activity
Existing Operation	No gas export route - all excess gas flared	Associated gas is reinjected for disposal or field pressure maintenance
		Associated gas is exported to market
Existing Operation	No gas export route	Entrained liquids are recovered rather than flared and added to crude export line - remaining gas flared
Existing Operation	Gas export route - high operational flaring	Operational improvements (e.g. minimize compressor downtime or flame-out) reduce the volume of gas flared
New Operation		Associated gas reinjected
		Associated gas exported to market
		Entrained liquids are recovered rather than flared and added to crude export line - remaining gas flared

Specific issues and challenges related to quantifying GHG emission reductions associated with flaring reductions include the following:

- Variability - In production fields, more energy is required to produce a barrel of crude as the field is depleted. In such cases, an emission reduction project activity may reduce emissions relative to the baseline scenario, yet still increase over time. This is illustrated in Figures 4-1a and 4-1b. This issue will be addressed through the Flare Reduction Project Family (planned for development in 2007).
- Additionality – For flare reduction projects in countries or regions that have targets, guidelines, or other non-enforceable policies associated with flaring activities, specific climate change regimes may require the project proponent to demonstrate that the flare reduction project is not business as usual. In addition, for a GHG reduction project where the flared gas is captured and reinjected into the production field, policy requirements for particular climate change regimes may require the project proponent to demonstrate that the reinjection was not implemented to maintain oil production.
- Permanence – For reinjection in particular, the permanence of the emission reductions may need to be addressed based on the specific characteristics of the GHG reduction project and the reservoir. A consideration of the suitability of the reservoir for long-term gas storage may be required under specific climate change regimes.
- Affected Sources, Sinks, and Reservoirs – A potential issue for flaring reduction projects is the impact on oil production and energy demand in downstream markets. This applies to re-injection, which can be used to enhance oil production, as well as the capture of previously flared gas streams for transport and consumption in local markets.

The Global Gas Flaring Reduction program provides guidance on addressing these types of specific concerns related to flare reduction project activities (GGFR, 2004).

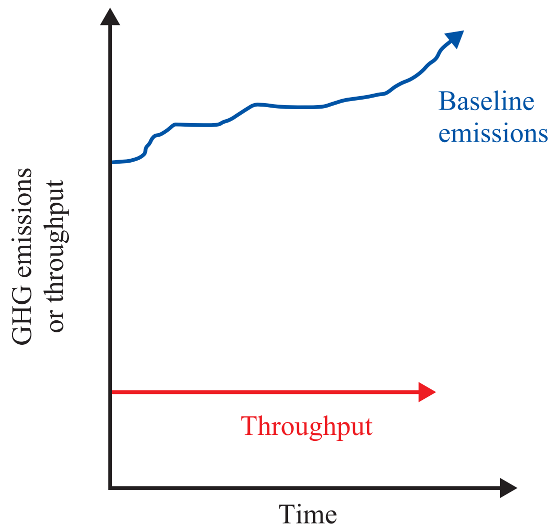


Figure 4-1a. Illustration of Baseline Emission Rate Independent of Throughput

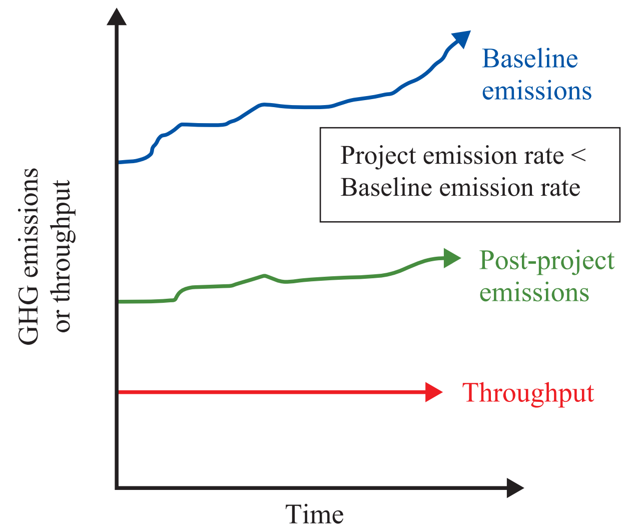


Figure 4-1b. Illustration of Increasing Project Emission Rate, Though at a Rate Reduced from the Baseline Scenario

4.4 Fuel Switching

For the purposes of this document, the distinction between a fuel switching project and an energy efficiency improvement project is that fuel switching entails the use of a different fuel. Fuel switching projects may also include retrofit of burners, changes in the fuel supply system at the facility, changes in the combustion air delivery system, etc.

Combustion efficiency may change with different fuels, requiring more or less fuel to generate the same energy. As such, a fuel switching retrofit may result in changes in system efficiency, and potentially an overall change in system capacity and/or output due to the retrofit project activity. Fuel switching retrofit installations may also result in an overall extension of the life of the equipment.

Specific issues and challenges related to quantifying GHG emission reductions associated with fuel switching reductions include the following:

- Ownership – Ownership of the emission reductions attributable to a fuel switching project will normally reside with the entity responsible for the investment in the project, which is generally the owner/operator of the combustion equipment where the fuel replacement is being made.

However, potential scenarios may arise in the oil and natural gas industry related to the supply of natural gas, rather than the consumption of the gas. An example is where a company makes natural gas available and shoulders the financial risk, including infrastructure investment and demand/price risks, of supplying the gas to a downstream consumer. The gas supplier has no equity interest or operational control over the downstream combustion of the gas, but may invest in the equipment upgrades or retrofit of existing third party combustion equipment to maximize the availability of gas. In these scenarios, the ownership of the emission reduction credits may not be straightforward in the absence of legally binding contractual ownership rights.

- Baseline Scenario Assessment – As discussed in Section 3, comparative assessments used to determine the baseline scenario may include an assessment of barriers to the project or economic incentives/disincentives. For example, in some regimes, such as CDM, the eligibility of a fuel switching project as a candidate GHG reduction project may be dependent on the financial viability of the project activity without the revenues from the sale of Certified Emission Reductions (CERs). In this case, the project proponent would need to demonstrate that the GHG reduction project is not a financially attractive investment without the CER revenues, and therefore is not considered business as usual. The argument is that if the fuel switching project is financially viable on its own merit, then it would have happened anyway.

  For most fuel switching projects, the financial integrity of the GHG reduction project is dependent on somewhat uncertain and subjective fuel price projections for the replacement and historic fuels, respectively. For fuel switching project methodologies approved by the CDM Executive Board (UNFCCC, CDM EB), the monitoring methodology integrates a requirement to monitor the fuel pricing of both the replacement fuel and the historic fuel in the local region of the project activity. As long as the replacement fuel is more expensive than the historic fuel, the baseline scenario of the historic fuel is considered appropriate. If the price of the replacement fuel becomes lower than the historic fuel, then the GHG reduction project itself would be considered the baseline scenario.

  Another baseline scenario consideration is how the economic assessment may be altered by other project activities of its type. If the project activity is considered new technology in the region, representing the first of its kind, it may ultimately have an influence over the use of that technology in the future by the availability of the replacement fuel. An example is a GHG reduction project that uses new technology to switch fuel use from coal to natural gas, where coal represents the most widely used technology and gas infrastructure is not adequate to deliver the required amount of fuel to the project activity site. This condition of an insufficient gas supply network is a resource barrier that must be overcome. At this point in time, the GHG reduction project is an early adopter, and would be considered additional under the CDM. As more plants switch to gas, more pipelines are built, access to the fuel is easier, and the effect of the barrier decreases.

After a certain point, the lack of gas infrastructure may no longer be a resource barrier as a critical number of plants have switched to gas and additional pipelines have been built to supply these plants. For the newer plants, the financial analysis will be different than for earlier plants and the baseline scenario assessment will need to reflect current conditions.

- Additionality – In some regimes, fuel switching may be necessary to meet certain NOx or particulate emission regulatory requirements. The eligibility of the resulting GHG emissions reductions must be considered in the context of additionality requirements associated with the specific climate change regime.

4.5 Energy Efficiency Improvements

Overall efficiency can be improved in two ways: by improving the efficiency of an individual piece of equipment or group of equipment, or by improving process efficiency.

Specific issues and challenges related to quantifying GHG emission reductions associated with energy efficiency improvements include the following:

- Variability in Operations – Due to the dynamic nature of oil and natural gas industry operations, the energy requirements are also variable over time. This is especially true in heat transfer equipment where fouling requires more energy to produce the required heat duty. In such cases, a GHG reduction project may reduce emissions relative to the baseline scenario, yet still increase over time (refer to Figure 4-1). In some cases, the project activity may decrease the rate at which emissions increase with time. For example an energy efficiency project may reduce fouling in a heat exchanger. The exchanger still fouls, but at a much lower rate, thus decreasing energy used and, consequently, GHG emissions. These are examples of dynamic baselines.

  For these situations where operations vary over time, the baseline and project emissions may be best expressed on a normalized basis, such as emissions per unit of energy output. In addition, the valid time length for the baseline scenario should reflect this variability.

- Efficiency Degradation – Just as efficiency can deteriorate over time for the project activity conditions, in the absence of the GHG reduction project, the efficiency of the existing equipment would also have deteriorated over time. This is another example of a dynamic baseline. Baseline scenario efficiency information may be available through the equipment manufacturer. Where the equipment is properly maintained, the impact of the efficiency deterioration is likely immaterial. Where this impact is material, the change in baseline emissions should be accounted for.

- Equipment Capacity – Variable energy demands may impact what would have happened in the absence of the GHG reduction project. A potential scenario involves delaying the need for additional capacity by implementing energy efficiency improvements. When the energy efficiency improvements are no longer sufficient to meet the capacity requirements, a new baseline scenario is required. This baseline scenario should consider what would have happened in the absence of the project activity at the higher capacity. Several potential options include:

- The addition of a small package plant or equipment;
- Importing the additional energy from another location; or
- Replacing the old equipment with new equipment.

The GHG reductions going forward are then evaluated against this new baseline scenario.

- Ownership – Ownership of the emission reductions attributable to an energy efficiency project will normally reside with the entity responsible for the investment in the project activity. Complications can occur where energy efficiency improvements reduce electricity consumption, an indirect emission source. Generally efficiency improvements in the generation of electricity are considered to be owned by the entity generating the electricity, while efficiency improvements in the use of electricity are considered owned by the specific user that implemented the improvement.
- Baseline Scenario Assessment – Regulations may exist that require equipment tuning to maintain efficiency and minimize other air emissions. In this situation, the eligibility of the resulting GHG emissions reductions must be considered in the context of additionality requirements associated with the climate change regime of interest.

Section 5. Cogeneration Project Family

5.1 Overview

This section presents the first of five greenhouse gas (GHG) reduction "project families". Guidelines are provided for evaluating emission reductions associated with replacing the separate generation of electricity and steam with a cogeneration unit. This section follows the framework for quantifying emission reductions, as presented in Section 2, Table 2-1. In addition, issues and challenges are addressed through case studies demonstrating the technical analysis for three potential applications (provided in Appendix B-1).

5.2 Introduction

Cogeneration, also known as combined heat and power (CHP), is the simultaneous production of electricity and process heat from the same fuel, generally natural gas. In these units, the heat produced from the electricity generating process (e.g., from the exhaust systems of gas turbines or from conventional boilers with steam turbines) is captured and used for process steam, furnace applications, hot water heating, space heating, and/or other thermal needs.

The most common application of cogeneration for the oil and natural gas industry is where a new cogeneration unit is installed to replace a dedicated steam boiler(s) within an existing refinery or crude production operation. For this type of application, the cogeneration unit generally replaces imported electricity from the grid and may produce excess electricity and/or steam for export. Other applications include installing a new cogeneration unit as part of a new refinery operation or retrofitting an existing fully integrated cogeneration unit with newer, more efficient technology.

5.3 Project Definition

As indicated in Section 4.1, cogeneration projects have the potential to reduce GHG emissions in two ways:

1. The cogeneration system represents an improvement in overall energy efficiency compared to the separate generation of electricity and steam; and
2. The cogeneration fuel source may replace or displace other more carbon intensive fuel sources, in relation to steam generation, electricity generation, or both. This impact is essentially a "fuel switching" project activity, which is planned as a separate Project Family.

There are two common configurations for CHP systems. The first, shown in Figure 5-1(a), utilizes a boiler to make high-pressure steam that is fed to a turbine to produce electricity. The turbine is designed so that a stream of low-pressure steam is available to feed an industrial process. Thus, one fuel input to the boiler supplies electric and thermal energy by extracting uncondensed steam from the turbine driving the electric generator. This boiler/turbine CHP approach has been the most widely used CHP system to date (WRI/WBCSD, 2006). The second CHP approach, illustrated in Figure 5-1(b), utilizes a combustion turbine or reciprocating engine to drive an electric generator, and thermal energy is recovered from the exhaust stream to make steam or supply thermal energy.

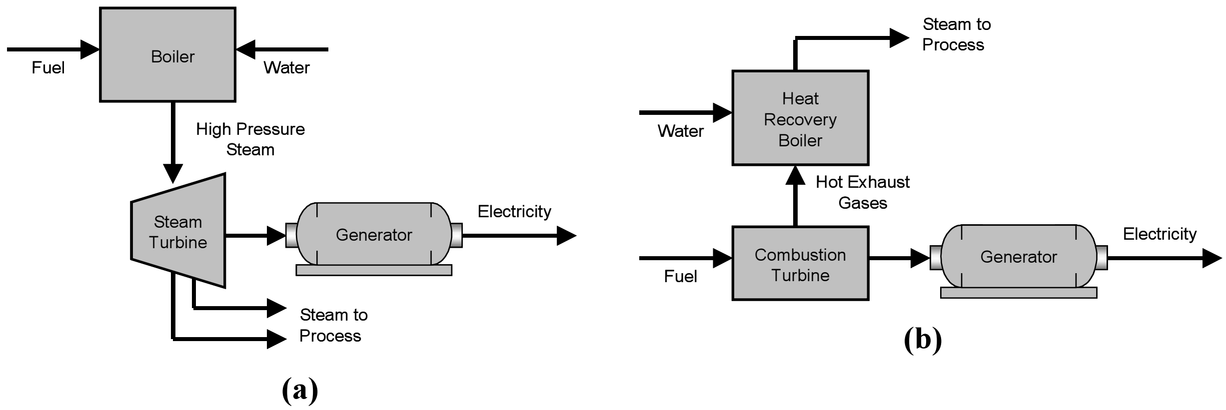


Figure 5-1. Typical CHP Configurations

Direct emissions, thermal energy and electricity demands, and indirect energy imports and energy exports are all key considerations for determining cogeneration project GHG emission reductions.

5.4 Baseline Scenarios

As described in Section 2.3, potential baseline candidates represent situations or conditions that plausibly would have occurred in the absence of the GHG reduction project. For a cogeneration project, this requires separate consideration of the steam and electricity generation aspects, resulting in a separate baseline scenario for each of the two energy streams.

5.4.1 Baseline Candidates for Electricity Generation

A common baseline candidate for the electricity generation component of the cogeneration project is grid-connected electricity import. However, the grid-connected electricity sector is complex. Electricity can be generated from many different sources and fuels, and GHG emissions can vary from zero (renewable sources) to high emitters. Because demand for electricity varies minute by minute, grids operate with a mix of generating plants including baseload plants that operate continuously because there is always some demand, and load-following or peak load plants whose output varies as demand changes.

Baseload plants operate during both peak and off-peak periods either because of the nature of the generation technology (run-of-river hydro) or the low cost energy source (coal-fired plant located near the mine). Baseload plants are the last to be shutdown in response to decreases in power demand. Load-following plants are generally smaller plants, often gas-fired, oil or small hydro (except run-of-river hydro) stations. Power generation plants may also be referred to as firm or non-firm. Generating plants whose output can be controlled supply firm power, while sources that fluctuate depending on natural conditions, such as wind, supply non-firm power.

Defining the grid may also be complicated. The grid may encompass an entire nation or it may reflect electricity generation for a region, where a region can range from a small, well-defined area to an area that crosses national borders.

The inherent complexity of the grid can make it difficult to determine exactly what source(s) will be displaced by a new grid-connected electricity project. Appendix B-2 summarizes different baseline scenario methodologies available for examining grid-displacement reduction projects. The appendix table also indicates programs where the different approaches have been applied or accepted. The baseline scenario methodology will depend on the specific GHG reduction project situation, including, the goal of demonstrating reductions (i.e., internal reporting, credits, etc.), the availability of data, costs, and the acceptability of the chosen approach by the GHG registry or climate change regime. For example, it may be a policy decision by the specific GHG program or climate change regime whether the cogeneration project will be evaluated in the context of average emission factors that are applicable to the electric generation mix currently serving the region, or relative to marginal emission factors that are representative of newer generation technologies in the local market.

In addition, due to frequent changes in the generation mix for grid-supplied electricity, the baseline scenario will change with time and should be reevaluated periodically as appropriate for the particular location or GHG reduction project situation. The frequency of evaluating the baseline scenario may also be dictated by the climate change regime.

5.4.2 Steam Generation Baseline Candidate Considerations

Common baseline candidates for steam generation include on- or off-site steam production in less efficient steam boilers. In addition to the efficiency improvement for steam generation in a cogeneration unit, the steam generation portion of the GHG reduction project may also represent a fuel switch over the baseline scenario to a less carbon intensive fuel.

A complexity for the steam component of the baseline scenario occurs where the steam output from the cogeneration unit exceeds the capacity of the old steam generation equipment being replaced. For the incremental capacity beyond that for the replaced boilers, the baseline candidate corresponds to what would have happened in the absence of the GHG reduction project at the higher capacity. Several potential options include (but are not limited to):

- The addition of a small package boiler;
- Importing the additional steam from another location;
- Replacing the old boiler or turbine with new equipment; or

- Replacing the old boiler or turbine with a cogeneration unit.

For the incremental energy that exceeds the capacity of the baseline equipment, the baseline scenario would be identical to that for a new project activity.

Similarly, where excess steam is produced by the cogeneration project and exported to a third party, the baseline conditions for the incremental steam that is exported should be considered relative to other methods of generating this steam. The options listed above would apply here also.

5.5 Emission Sources and Assessment Boundary

As discussed in Section 2.2.1, the consideration of potential emission sources within the assessment boundary should include those that are controlled by the project proponent, related to the cogeneration project, or affected by the cogeneration project. The assessment boundary includes both project activity and baseline sources that are considered for determining an emission reduction. In addition, the assessment boundary also includes changes in emissions from displaced electricity generation in the electric grid.

A checklist of potential sources is provided in Table 5-1. GHG emissions occur from the combustion of fossil fuels in the CHP plant to generate multiple energy streams. The GHG emissions of interest include carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O).

Table 5-1. Potential Emission Sources within the Assessment Boundary

	Potential Emission Sources	Relation to the Project Proponent	Considerations
Baseline Scenario	✓ CO_2, CH_4 and N_2O emissions from offsite cogeneration fuel combustion allocated to onsite electricity or steam usage	Related	✓ Baseline emissions allocated to imported and exported electricity will be dependent on the chosen methodology (see Appendix B-2)
	✓ CO_2, and to a lesser extent, CH_4 and N_2O emissions from onsite fuel combustion associated with on-site steam generation	Controlled	✓ CH_4 and N_2O emissions are likely de minimis.
	✓ Vented and fugitive CH_4 emissions, as well as CO_2, CH_4 and N_2O combustion emissions, associated with extraction, processing, and transport of natural gas to the electricity and/or steam generation facility	Controlled, Related or Affected	✓ CH_4 emissions from extraction, processing, and transport sources may be considered irrelevant if they are the same in the GHG reduction project and baseline, or if the difference is not material.
Project Activity	✓ CO_2, and to a lesser extent, CH_4 and N_2O emissions from onsite fuel combustion associated with electricity and/or steam generation	Controlled or Related	✓ CH_4 and N_2O emissions are likely de minimis.
	✓ CH_4 emissions from vented or fugitive sources within the facility associated with natural gas fuel used to generate electricity and/or steam	Controlled or Related	✓ Data to estimate CH_4 emissions may not be available. These emissions are likely de minimis.

	Potential Emission Sources	Relation to the Project Proponent	Considerations
Project Activity	✓ CO_2, CH_4 and N_2O emissions displaced by the GHG reduction project through the exported electricity and/or steam	Affected	
	✓ CO_2, CH_4 and N_2O emissions allocated to imported electricity and/or steam	Related	
	✓ Vented and fugitive CH_4 emissions, as well as CO_2, CH_4 and N_2O combustion emissions, associated with extraction, processing, and transport of natural gas to the cogeneration facility.	Controlled, Related or Affected	✓ CH_4 emissions from extraction, processing, and transport sources may be considered irrelevant if they are the same in the GHG reduction project and baseline, or if the difference is not material.
	✓ Cogeneration construction phase emissions	Controlled or Related	✓ Construction phase emissions are likely de minimis.
	✓ Changes in product output for neighboring energy users and associated emissions caused by increased supply or demand of steam and electricity.	Affected	✓ The effects of exported or imported energy streams from a single GHG reduction project on the existing market place are usually difficult to assess

The cogeneration facility might exist within the fence of a refinery or production field or outside the physical boundaries of the oil and natural gas company's facility. In addition, the cogeneration facility might be wholly owned and operated by the oil and natural gas company, or might be constructed/operated through a joint venture arrangement or by a third party. Each of these arrangements impacts the evaluation of emission sources controlled by, related to, and affected by the GHG reduction project. The checklist provided in Table 5-1 should be evaluated relative to the specific GHG reduction project conditions.

5.6 Emission Reductions

Emission reductions result from the difference between baseline emissions and GHG reduction project emissions for a given time period, typically on an annual basis. This section provides a general discussion on the quantification of GHG reduction project and baseline emissions for a cogeneration project. This is illustrated further in the examples provided in Appendix B-1.

5.6.1 Quantifying GHG Reduction Project Emissions

Emissions for a cogeneration project are primarily CO_2 emissions resulting from associated fuel combustion. The API Compendium recommends estimating these combustion emissions based on the quantity of fuel consumed and the fuel carbon content. Ex-post GHG reduction project emissions should be based on metered fuel consumption rates and fuel-specific carbon contents from onsite measurements or from the fuel supplier. Produced energy, exported energy streams, and on-site energy usage should be metered.

To a lesser extent, fuel combustion also produces CH_4 and N_2O emissions. Section 4.3 of the API Compendium provides CH_4 and N_2O emission factors for stationary combustion sources. These emissions may not be material.

Non-combustion CH_4 emissions may also result from vented and fugitive emission sources associated with the natural gas supply to the cogeneration equipment. Emissions from these sources are generally small compared to CO_2 emissions from combustion. Where specific approaches for estimating these emissions are not provided by the particular climate change regime or GHG registry, general emission factors for distribution sector vented and fugitive emission sources can be applied to the natural gas equipment within the assessment boundary for the cogeneration unit. Alternatively, these emission sources may be excluded from the assessment due to their small impact relative to combustion emissions. The examples shown in Appendix B-1 demonstrate the insignificance of CH_4 and N_2O emissions relative to CO_2 for sources common to cogeneration projects.

5.6.2 Quantifying Baseline Emissions

Baseline emissions are the quantified tonnes of GHG emissions (in CO_2 equivalents) for the relevant emission sources, sinks, and reservoirs corresponding to the baseline scenario.

For on-site energy generation displaced by the cogeneration project, information should be available to quantify the baseline scenario emission rates for steam (tonnes CO_2e/ MMBtu) and electricity (tonnes CO_2e/MW-hr) production. Generally this would include historical fuel composition information, metered fuel consumption rates, metered electricity, and measured steam properties and quantity.

Imported electricity and steam rates should be metered and/or tracked through energy purchase records. For imported electricity or steam, the baseline emissions should be quantified using fuel consumption rates and carbon content for the fuels used to produce the imported energy streams, if known. Otherwise, emission factors corresponding to the specific fuel and energy generation methods can be applied (refer to Section 4 of the API Compendium). Where a grid average emissions methodology is appropriate, grid-based emission factors should be used. The methodologies provided in Appendix B-2 apply to quantifying baseline emissions for electricity grid displacement.

As in quantifying GHG reduction project emissions, the baseline emissions for a cogeneration project are primarily CO_2. Methane and N_2O emissions also result from fuel combustion used to generate electricity and steam, though these emissions are generally small compared to CO_2. Non-combustion CH_4 emissions may also result from vented and fugitive emission sources associated with natural gas usage in the baseline scenario. These emissions are also generally small compared to CO_2 emissions, and may be offset by similar emissions associated with the GHG reduction project.

5.7 Monitoring

As discussed in Section 2.7, monitoring should encompass appropriate parameters from which to gauge emissions controlled by, related to and affected by the project activity, as well as relevant to the baseline scenario. Monitoring may consist of measurements, modeling, calculation methodologies, or estimation approaches.

For a CHP reduction project, monitoring would generally involve the following parameters:

- Data to determine the quantity of electricity generated and the quantity and characteristics of steam generated;
- Data to determine emissions from fossil fuel combustion due to the project activity;
- Data to determine the electric grid emission factor; and
- Data to determine baseline emissions due to the displacement of thermal energy at the project site.

Actual monitoring requirements are dependent on the specific project characteristics. In addition, specific monitoring requirements may be dictated by a particular climate change regime, if applicable.

5.8 Project Examples

Appendix B-1 provides three examples to demonstrate the application of procedures for quantifying GHG reductions from hypothetical cogeneration projects for a one-year period. The approach, emission factors, and assumptions used in these examples reflect the methodology selected by the fictional project proponent based on the defined GHG reduction project site-specific conditions and do not universally apply in all situations. For example, in Exhibit 5.1 baseline emissions associated with imported and exported electricity are evaluated using the combined margin approach (discussed further in Appendix B-2) based on the availability of data and the project proponent's assessment that it best reflects the grid characteristics in the absence of the GHG reduction project. If adequate data are unavailable or the same GHG reduction project is developed in another location, other approaches may be appropriately used (e.g., a grid-averaged emission factor approach).

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Glossary

Activity Factor

The numeric value representing any action or operation that causes or influences the release of GHG emissions (e.g., amount of fuel consumed or counts of emission sources); absolute GHG emissions result when related to the rate of emissions from the action.

Additionality

A criterion often applied to GHG reduction projects, stipulating that project-based GHG reductions should only be quantified if the project activity would not have otherwise happened (i.e., that the project activity is distinctly different from the baseline scenario and/or that project activity emissions are lower than the baseline emissions). (Adapted from WBCSD/WRI Project Guidelines)

Affected Sources, Sinks, and Reservoirs

A GHG source, sink or reservoir materially influenced by a project activity, through changes in market demand or supply for associated products or services, or through physical displacement. (Taken from ISO 14064 Part 2)

Assessment Boundary

Encompasses all primary effects and significant secondary effects associated with the GHG reduction project. Where the GHG reduction project involves more than one project activity, the primary and significant secondary effects from all project activities are included in the assessment boundary. (Taken from WBCSD/WRI Project Guidelines)

Baseline Candidates

Alternative technologies or practices within a specific geographic area and temporal range that could provide the same product or service as the project activity. (Taken from WBCSD/WRI Project Guidelines)

Baseline Emissions

An estimate of GHG emissions, removals, or storage associated with a baseline scenario or derived using a performance standard (see baseline procedures). (Taken from WBCSD/WRI Project Guidelines)

Baseline Procedures

Methods used to estimate baseline emissions. These Project Guidelines generally apply a project-specific approach. Additional information on this method and on an alternative method, the performance standard procedure, is provided in the WBCSD/WRI Project Guidelines.

Baseline Scenario

A hypothetical description of what would have most likely occurred in the absence of any considerations about climate change mitigation. (Taken from WBCSD/WRI Project Guidelines)

Benchmark

A reference level of emissions from an activity based on an assessment of a similar activities. (Benchmarking – The process of assessing relative performance against a group of peers)

Carbon Dioxide Equivalent (CO_2 Eq.)

The mass of a GHG species multiplied by the global warming potential (GWP) for that species. It is used to evaluate the impacts of releasing (or avoiding the release of) different GHGs on a common basis—the mass of CO_2 emitted that would have an equivalent warming effect. (Adapted from the API Compendium)

Climate Change Regime

A generic term for (1) any mandatory, government or non-government initiative, system or program that registers, reports, or certifies GHG emissions or reductions; or (2) any parties responsible for developing or administering such initiatives, systems or programs. (Adapted from WBCSD/WRI Project Guidelines definition of registry)

Co-generation unit/Combined Heat and Power (CHP)

A facility producing both electricity and steam/heat using the same fuel supply. (Taken from the API Compendium)

Common Practice

The predominant technology(ies) implemented or practice(s) undertaken in a particular geographical region or industrial sector. (Adapted from WBCSD/WRI Project Guidelines)

Controlled Sources, Sinks, and Reservoirs

A GHG source, sink or reservoir whose operation is under the direction and influence of the project proponent through financial, policy, management, or other instruments. (Taken from ISO 14064 Part 2)

Direct Emissions

Greenhouse gas emissions (or removals) from sources (or sinks) that are owned or controlled by the reporting entity. (Adapted from the API Compendium)

Dynamic Baseline Emissions

Baseline emission estimates that change over the valid time length of the baseline scenario. (Taken from WBCSD/WRI Project Guidelines)

Eligibility Criteria

Conditions that a GHG reduction project must meet irrespective of how its baseline scenario is determined, how emission reductions are quantified, or how additionality is determined.

Emission Factor

The emission rate for a particular emission source per unit of the source, when related to the activity data (e.g., amount of fuel consumed or counts of emission sources) results in absolute GHG emissions. (Taken from the API Compendium)

Emissions

The intentional or unintentional release of greenhouse gases into the atmosphere. (Taken from the API Compendium)

Enhanced Oil Recovery (EOR)

Artificial methods used to recover more oil after primary production by the natural reservoir drive and, possibly, water-flooding. Common EOR methods include thermal (cyclic steam stimulation, steam-flooding, and in-situ combustion), chemical (polymer, micellarpolymer, and alkaline flooding), and gas miscible (cyclic, carbon dioxide stimulation, carbon dioxide flooding, and nitrogen flooding). (Taken from the API Compendium)

Ex Ante Emissions

A predicted estimate of a project activity's performance (and possibly how baseline emissions may change). (Adapted from WBCSD/WRI Project Guidelines)

Ex Post Emissions

Quantification of a project activity's performance based on actual data or information collected over a period of time following the project's implementation. (Adapted from WBCSD/WRI Project Guidelines)

Fuel Switching

Using an alternative fuel (usually of lower carbon intensity) to produce required energy. (Taken from WBCSD/WRI Project Guidelines)

Fugitive Emissions

Releases of GHGs from pressurized equipment, such as joints, seals, packings, and gaskets. Fugitive emissions also include evaporative or non-point sources, such as wastewater treatment. (Taken from the API Compendium)

GHG Reduction

A decrease in GHG emissions (or an increase in removal or storage of GHGs) from the atmosphere relative to the baseline emissions. Where the GHG reduction project consists of more than one activity, the overall net reduction is the sum of the GHG reductions from each individual activity. (Adapted from WBCSD/WRI Project Guidelines)

GHG Reduction Project

A specific activity or set of activities intended to reduce GHG emissions, increase the storage of GHG emissions, or enhance GHG removals from the atmosphere. (Adapted from WBCSD/WRI Project Guidelines)

GHG Registry

A generic term for: (1) any voluntary, government or non-government initiative, system or program that registers, reports, or certifies GHG emissions or reductions; or (2) any parties responsible for developing or administering such initiatives, systems or programs. (Adapted from WBCSD/WRI Project Guidelines)

Global Warming Potential (GWP)

An index used to relate the level of emissions of various GHGs to a common measure. The GWP is defined as the ratio of the amount of global warming or radiative forcing produced by a given gas relative to the global warming produced by the reference gas CO_2, for a specified time period. As the reference gas, CO_2 has a GWP value of 1. The current GWP for methane is 21, based on a 100-year time period, as recommended by the Intergovernmental Panel for Climate Change (EPA, 1998). Therefore, one mass unit of methane has the same impact on global warming as 21 mass units of carbon dioxide over a 100-year time period. (Taken from the API Compendium)

Greenhouse Gas (GHG)

Any gas that absorbs infrared radiation in the atmosphere. Greenhouse gases include water vapor, carbon dioxide, methane, nitrous oxide (N_2O), hydrochlorofluorocarbons (HCFCs), ozone (O_3), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). (Taken from the API Compendium)

Indirect Emissions

The release of GHG emissions as a consequence of operations of the reporting company, but physically occurring at sources owned or operated by another organization (e.g., purchased electricity). (Taken from the API Compendium)

Intended User

An individual or organization identified by those reporting GHG-related information as being the one who relies on that information to make decisions. (Taken from ISO 14064 Part 2)

Leakage

Emissions outside of the assessment boundary that are measurable and attributable to the project. (Adapted from GGFR)

Materiality

A threshold for determining whether an error or omission in the estimated emissions (or reduced emissions) results in the reported quantity being different from the true value to the extent that it will influence decisions (Adapted from WBCSD/WRI Project Guidelines and EPA's Climate Leaders).

Methane (CH_4)

A hydrocarbon that is a greenhouse gas. Methane is released to the atmosphere through anaerobic (without air) decomposition of waste, animal digestion, production and distribution of oil and natural gas, coal production, and incomplete fossil fuel combustion. (Taken from the API Compendium)

Monitoring

The assessment of GHG emissions and removals or other GHG-related data. (Adapted from ISO 14064 Part 2)

Performance Standard

A GHG emission rate used to determine baseline emissions for a particular type of project activity. A performance standard may be used to estimate baseline emissions for any number of similar project activities in the same geographic area. (Taken from WBCSD/WRI Project Guidelines)

Permanence

The state or condition at which removed or stored carbon would not be returned to the atmosphere during the crediting period of the project. (Adapted from reversibility from EPA Climate Leaders)

Policy Criteria

Requirements that must be met to qualify for creditable GHG reductions.

Primary Effect

The intended change caused by a project activity. Each project activity will generally have only one primary effect. (Adapted from WBCSD/WRI Project Guidelines)

Project Activity

A specific action or intervention targeted at changing GHG emissions, removals, or storage. It may include modifications or alterations to existing systems/processes, as well as the introduction of new systems/processes. (Adapted from WBCSD/WRI Project Guidelines)

Project Proponent

A person, company, or organization developing a GHG reduction project (Adapted from WBCSD/WRI Project Guidelines)

Related Sources, Sinks, and Reservoirs

GHG source, sink or reservoir that has material or energy flows into, out of, or within the project. (Taken from ISO 14064 Part 2)

Reservoir

Any physical unit or component of the biosphere, geosphere, or hydrosphere with the capability to store or accumulate a GHG removed from the atmosphere by a GHG sink or a GHG captured from a GHG source. (Taken from ISO 14064 Part 2)

Secondary Effect

An unintended change in GHG emissions, removals or storage caused by a project activity. Secondary effects may be "positive" (i.e., resulting in GHG reductions) or "negative" (i.e., resulting in GHG emissions). (Adapted from WBCSD/WRI Project Guidelines).

Sink

Any physical unit or process that removes GHG emissions from the atmosphere and stores them. (Combination of ISO 14064 Part 2 and WBCSD/WRI Project Guidelines)

Source

Any physical unit or process that releases GHGS into the atmosphere. (Combination of ISO 14064 Part 2 and WBCSD/WRI Project Guidelines)

Static Baseline Emissions

Baseline emission estimates that do not change over the valid time length of the baseline scenario. (Taken from WBCSD/WRI Project Guidelines)

Temporal Boundary

A contiguous time period that helps define the baseline candidates. The temporal range may be defined by a number of factors, such as the dominance of a single technology for an extended period of time, the diversity of options in a sector or region, and/or a discrete change in an location's policy, technology, practice, or resource. (Adapted from WBCSD/WRI Project Guidelines)

Ton

A short ton is equivalent to 2,000 US pounds. (Taken from the API Compendium)

Tonnes

A metric tonne is equivalent to 1,000 kg and 2,205 US pounds. Metric tonnes are the standard convention for reporting greenhouse gas equivalent emissions used by IPCC and other international climate change organizations. (Taken from the API Compendium)

Uncertainty

The range around a reported value in which the true value can be expected to fall. (Taken from the API Compendium)

Appendix A
Summary of Climate Change Regimes

Appendix A-1. Summary of Climate Change Regimes[11]

Climate Change Regimes	Summary	Eligibility Requirements	Resource for Additional Information
Kyoto Protocol	Parties to the United Nations Framework Convention on Climate Change that have also become Parties to the Protocol (i.e. by ratifying, accepting, approving, or acceding to it) are bound by the Kyoto Protocol's commitments Any Annex I Party that has ratified the Protocol may use the mechanisms (described below) to help meet its emissions target, provided that it is complying with its methodological and reporting obligations under the Protocol.	• Parties must provide evidence that their use of the mechanisms is "supplemental to domestic action", which must constitute "a significant element" of their efforts in meeting their commitments.	cdm.unfccc.int
Kyoto Protocol: Clean Development Mechanism (CDM)	The clean development mechanism (CDM) defined in Article 12 provides for Annex I Parties to implement project activities that reduce emissions in non-Annex I Parties, in return for certified emission reductions (CERs). The CERs generated by such project activities can be used by Annex I Parties to help meet their emissions targets under the Kyoto Protocol.	• Project must demonstrate additionality • Specifies allowable project types (e.g., nuclear projects not allowed) • Host country is non-Annex I and ratified under Kyoto Protocol • Project approval by host country Designated National Authority • Meets sustainable development goals • Acceptable environmental impacts	cdm.unfccc.int
Kyoto Protocol: Joint Implementation (JI)	Joint implementation (JI) under Article 6 of the Kyoto Protocol provides for Annex I Parties to implement projects that reduce emissions, or remove carbon from the atmosphere, in other Annex I Parties, in return for emission reduction units (ERUs). The ERUs generated by JI projects can be used by Annex I Parties to help meet their emissions targets under the Protocol.	• Host country is Annex I and ratified under Kyoto Protocol	www.unfccc.int

[11] As stated in footnote 2 of the Project Guidelines, this Appendix is not intended as an exhaustive or authoritative summary of all currently applicable GHG emission reduction registries or requirements for participating in such registries. Any entity that wishes to register or otherwise obtain credit for greenhouse gas emission reductions should contact the registry and consult with counsel as appropriate to determine all requirements that may apply to registering emission reductions.

Appendix A-1. Summary of Climate Change Regimes, continued

Climate Change Regimes	Summary	Eligibility Requirements	Resource for Additional Information
EU Emissions Trading Scheme (EU ETS)	The EU ETS was established under Directive 2003/87/EC. The scheme started January 1, 2005, and applies to the 25 EU member states. The program will be implemented in phases, with the first phase (2005-2007) focusing only on CO_2 emissions from large emitters in the power and heat generation industry and in selected energy-intensive industrial sectors (e.g., combustion plants and oil refineries).	• Companies can use credits from Kyoto's project-based mechanisms JI and the CDM to meet emission's cap. • Specifies allowable project types (e.g., nuclear projects, land use/land change, and forestry activities are not allowed).	www.europa.eu.int/comm/environment/climat/emission.htm
UK Emissions Trading Scheme	The world's first economy-wide GHG emissions trading scheme. The voluntary UK ETS was established as a 5 year pilot scheme initiated in March 2002, and is set to end for Direct Participants in December 2006. Installations temporarily excluded from the EU ETS due to UK ETS participation will then move into the EU ETS. Direct Participants in the scheme have voluntarily taken on emission reduction targets to reduce their emissions against 1998-2000 levels. The UK ETS provides incentive money to participants, focuses on a subset of sectors covered by the IPPC Directive (and some smaller combustion installations), and covers all 6 greenhouse gases.	• A project must be additional to emission reductions that would have been delivered under business as usual. • Sources not eligible include: direct emissions from electricity or heat generation except where both are generated and used on-site; emissions from facilities within a target unit covered by an Agreement; emissions from land and water transport; methane emissions from landfill sites covered by the Landfill Directive; and emissions from households	www.defra.gov.uk
Oregon Carbon Dioxide Emissions Standards	In 1997, the Oregon legislature gave the Energy Facility Siting Council authority to set CO_2 emissions standards for new energy facilities (HB 3283). There are specific standards for base load gas plants, non-base load (peaking) power plants and non-generating energy facilities that emit carbon dioxide.	• At their discretion, applicants can propose CO_2 offset projects they or a third party will manage, or they can provide funds via the "monetary path" to The Climate Trust (see Table A.2).	www.oregon.gov/ENERGY/SITING/standards.shtml#Carbon_Dioxide_Emissions

Appendix A-1. Summary of Climate Change Regimes, continued

Climate Change Regimes	Summary	Eligibility Requirements	Resource for Additional Information
Massachusetts Regulations	A CO_2 cap was established for six power plants in Massachusetts under 310 CMR 7.29 “Emissions Standards for Power Plants” (5/11/2001). The Department of Environmental Protection (DEP) will also allow the use of off-site reductions and carbon sequestration to comply with the CO_2 emission cap and emission rate. A proposed amendment to 310 CMR 7.00, “Emission Banking, Trading, and Averaging” would add CO_2 and establish a process to verify GHGs reduced, avoided or sequestered.	• Requirement that “off-site reductions or sequestration” be “real, surplus, verifiable, permanent, and enforceable, as defined at 310 CMR 7.00 Appendix B”. • Facilities subject to 310 CMR 7.29 (“affected facilities”) would be the only entities allowed to apply to create GHG Credits under 310 CMR 7.00: Appendix B(7). • GHG Credits may only be used for compliance with 310 CMR 7.29. This will be revised when Massachusetts signs the RGGI MOU • The following areas are NOT eligible for certification or verification as GHG Credits: nuclear power generation, under-water and under-ground sequestration, and over-compliance with the cap and rate limitations in 310 CMR 7.29 by affected facilities.	www.mass.gov/dep/air/laws/ghgregdd.doc
California Global Warming Solutions Act of 2006 (AB32)	Establishes annual mandatory reporting of GHG emissions for significant sources and sets limits to cut statewide emissions to 1990 levels by 2020, about 25 percent below today's levels. Industries would be required to begin making reductions in 2012. California’s 11-member Air Resources Board, which is appointed by the governor, will be charged with developing targets for each industry and for seeing that those targets are met. The board now will embark on a years-long process to fully develop regulations. The broad requirements of agreement stipulate that, by January 2008, the air board start requiring the state's major GHG producers to report their GHG output. By January 2009, the air board is to develop a plan outlining how to achieve the emissions cuts. By January 2011, the air board is to adopt actual rules to take effect a year later.	To be determined	www.climateregistry.org

Appendix A-1. Summary of Climate Change Regimes, continued

Climate Change Regimes	Summary	Eligibility Requirements	Resource for Additional Information
Regional Greenhouse Gas Initiative (RGGI)	The RGGI participating states are developing a regional strategy for controlling emissions. Central to this initiative is the implementation of a multi-state cap-and-trade program with a market-based emissions trading system. The proposed program will require electric power generators in participating states to reduce carbon dioxide emissions. On December 20, 2005, seven states announced an agreement to implement the Regional Greenhouse Gas Initiative, as outlined in a Memorandum of Understanding (MOU) signed by the Governors of the participating states.	At a minimum, eligible offsets shall consist of actions that are real, surplus, verifiable, permanent and enforceable. The initial offset project types that may be approved by a Signatory State are: landfill gas (methane) capture and combustion; sulfur hexafluoride (SF_6) capture and recycling; afforestation (transition of land from non-forested to forested state); end-use efficiency for natural gas, propane and heating oil; methane capture from farming operations; and projects to reduce fugitive methane emissions from natural gas transmission and distribution.	http://www.rggi.org/index.htm

Appendix A-2. Summary of GHG Registries[12]

GHG Registries	Summary	Eligibility Requirements	Resource for Additional Information
Australian Greenhouse Challenge Plus	The Greenhouse Challenge was launched in 1995 and is a joint initiative between the national Government and industry to abate GHG emissions. Participants in the voluntary program sign agreements with the Government that provide a framework for undertaking and reporting emissions abatement actions. In return, participants gain access to technical expertise and get recognition for being part of the program.	To become a member, an organization must: • Sign a Letter of Intent; • Develop a Cooperative Agreement with Commonwealth Govt. to reduce emissions; • Work towards milestones and provide ongoing reporting of emissions reduction progress; • Participate in independent verification of annual progress reports.	www.greenhouse.gov.au/challenge/
California Climate Action Registry	Established by California statute as a non-profit voluntary registry for greenhouse gas (GHG) emissions. The purpose of the inventory-based registry is to help companies and organizations with operations in CA establish GHG emissions baselines against which any future GHG emission reduction requirements may be applied. The State of CA will offer its best efforts to ensure that participants receive appropriate consideration for early actions in the event that any future state, federal, or international GHG scheme becomes effective.	• Reporting of CO_2 emissions for the first 3 years of participation; all 6 GHG pollutants must be reported after 3 years of participation; • Includes direct and indirect GHG emissions (indirect from electricity use); • Base year is any year from 1990 or later.	www.climateregistry.org

[12] As stated in footnote 2 of the Project Guidance, this Appendix is not intended as an exhaustive or authoritative summary of all currently applicable GHG emission reduction registries or requirements for participating in such registries. Any entity that wishes to register or otherwise obtain credit for greenhouse gas emission reductions should contact the registry and consult with counsel as appropriate to determine all requirements that may apply to registering emission reductions.

Appendix A-2. Summary of GHG Registries

GHG Registries	Summary	Eligibility Requirements	Resource for Additional Information
Canadian Pilot Emission Removals, Reductions, and Learnings Initiative (PERRL)	Environment Canada is responsible for delivery of the PERRL Initiative with support provided by Natural Resources Canada and other federal agencies. Through PERRL, the Government of Canada enters into agreements to purchase verified GHG emission reductions from eligible projects in four strategically important sectors, on a fixed price per tonne basis.	The four strategic sectors eligible to participate in PERRL include: • Landfill gas capture and combustion • CO_2 capture and geological storage • Renewable energy • Agricultural and forest carbon sinks	www.ec.gc.ca/PERRL/home_e.html
Canadian GHG Reductions Registry – formerly the Canadian GHG Credit Registry and the Clean Air Canada Initiative	This registry provides a service for organizations that wish to have GHG reduction projects validated and their annual emission reductions registered. This registry tracks the annual emission reductions and subsequent transactions (i.e. sale or retirement). Assigns "Registered Emission Reductions" as the result of project activities. Includes a 30-day public review period for a project.	• Must meet Canadian Standard Association validation review process for relevance, completeness, consistency, transparency, accuracy, and the reductions must be real, measurable, and verifiable; • Must meet requirements of scheme set by organization, national govt. or international body; • Subject to public review of the project.	www.ghgregistries.ca/reductions/index_e.cfm
Canadian GHG Challenge Registry (formerly the Canadian Voluntary Challenge Registry)	The VCR was established in Oct. 1997 as a government program but has since transitioned to a private-public partnership. The GHG Challenge Registry is Canada's only publicly accessible national registry of voluntary GHG baselines, targets, and reductions based on individual entities and/or facilities.	An Offset exists if money was spent to create the emission reduction or removal and the reduction is quantifiable. An action plan is required for registration. An action plan includes inventory development, business-as-usual projections, setting targets (based on the registrant's best judgment), identifying measures to achieve targets, and recording the results achieved.	www.ghgregistries.ca/challenge/index_e.cfm

Appendix A-2. Summary of GHG Registries, continued

GHG Registries	Summary	Eligibility Requirements	Resource for Additional Information
Chicago Climate Exchange (CCX)	CCX® is a voluntary self-regulatory, rules-based exchange designed and governed by CCX® Members for emission sources and offset projects in the United States, Canada, and Mexico. Members have made a voluntary, legally binding commitment to reduce their GHG emissions by four percent below the average of their 1998-2001 baseline by 2006, the last year of the pilot program. Exchange Allowances are issued to members in accordance to Member's Emission Baseline and Emission Reduction Schedule. Allowances are also issued on the basis of forest carbon sequestration and reductions in electricity use. Exchange Offsets are generated by qualifying mitigation projects and registered with CCX by Exchange Participant Members.	Emissions include CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6 Emission sources and offset projects in the United States, Canada, Mexico, Brazil and worldwide. Categories of eligible offset projects are: • Landfill and livestock methane destruction; • Agricultural practices that reduce GHG emissions; • Carbon sequestration in forestry projects and agricultural soils; • Fuel switching and renewable energy projects in Brazil; • Renewable energy; and • Clean Development Mechanism eligible projects.	www.chicagoclimatex.com
Climate Neutral Network	Non-profit organization dedicated to helping companies and communities achieve a net zero impact on the Earth's climate. Provides "Climate Cool" certification to companies. Can benefit companies by establishing them as "environmental leaders".	Companies seeking certification to use the Climate Neutral trademark prepare a Climate Neutral Certification Application, outlining how they plan to zero-out the emissions from their product or enterprise. Certification requires creating a portfolio of internal, on-site reductions of GHG emissions and external offset projects.	climateneutralnetwork.org/

Appendix A-2. Summary of GHG Registries, continued

GHG Registries	Summary	Eligibility Requirements	Resource for Additional Information
Climate Trust	Established in 1997, the Climate Trust is a leading non-profit organization dedicated to providing solutions to stabilize climate change. The Climate Trust provides offsets to: power plants, regulators, businesses and entities, and individuals. The current offset portfolio includes reductions from energy efficiency improvements, renewable energy, forestry sequestration, cogeneration, material substitution, and transportation efficiency improvements.	Each project must meet stringent additionality quantification requirements, and undergoes extensive due diligence to evaluate the offset provider's capacity to deliver the proposed project. The Climate Trust is active in domestic and international policy arenas on offset project standards to ensure that our projects are consistent with or exceed the requirements of the developing carbon market. Primary criteria used to solicit, select, and contract offset projects are: Cost-Effectiveness, Additionality, Leakage, Measurability, Types of Projects, Permanence, Guarantees, Replicability, Location, Timing, Monitoring, and Verification	www.climatetrust.org
GEMCo – Greenhouse Gas Emissions Management Consortium	Not-for profit Canadian corporation established by companies in 1996 to demonstrate leadership in developing voluntary and market-based opportunities to GHG management. Participating companies have included in their corporate environmental management strategy consideration of investment in GHG offsets.	Website identifies four projects where GHG emission reduction credits have been purchased by GEMCo: • Sept 2004 – Landfill integrated gas recovery system • Nov 2000 – CO_2 capture for EOR operations in Texas and Wyoming (brokered through CO_2e.com) • Mar 2000 – landfill gas used for combustion • Oct 1999 - Agricultural reductions in Iowa	www.gemco.org/index.htm
Environmental Resources Trust (ERT) - GHG Registry℠	The registry records validated GHG emission profiles to help create a market that will enable efficient emission reductions. Provides a system for ensuring that GHG reductions and sequestration are technically credible and of sufficient quality.	Annual emissions tracking and transaction tracking for participants are provided for 1990-2005. Eligibility requirements for reductions and offsets are not provided on the website.	www.ecoregistry.org http://www.ert.net

Appendix A-2. Summary of GHG Registries, continued

GHG Registries	Summary	Eligibility Requirements	Resource for Additional Information
EPA Climate Leaders	Climate Leaders is a voluntary industry- government partnership that encourages companies to develop long-term comprehensive climate change strategies and set GHG emissions reduction goals. In return for joining, Partners receive technical assistance and recognition. Climate Leaders is an inventory-based registry.	Partners agree to: • Develop corporate-wide GHG inventory of 6 major GHG compounds using Climate Leaders GHG Protocol; • Set aggressive corporate-wide GHG emissions reduction goal to be achieved over the next 5-10 years; • Annually report inventory data and document progress towards reduction goal (via a performance indicator)	www.epa.gov/climateleaders/
Eastern Climate Registry – formerly Regional Greenhouse Gas Registry (RGGR)	Since 2003, ten Northeast and Mid-Atlantic states--including Connecticut, Delaware Maine, Massachusetts, New York, New Hampshire, New Jersey, Pennsylvania, Rhode Island, and Vermont--have worked in partnership to establish the infrastructure for a multi-state GHG Registry and to develop a voluntary GHG emissions reporting program. The goal of the Eastern Climate Registry is to provide a GHG emissions platform to support state voluntary and mandatory GHG reporting programs and to provide the technical platform for state and regional climate change initiatives. Companies voluntarily report their national GHG emissions data into the system to demonstrate environmental leadership, manage carbon-related risks, increase operational efficiency, and document early action. States that have mandatory GHG reporting programs, such as Connecticut and Maine, will also have the option to import mandatory GHG emissions data from stationary sources into the Registry database.	Accounting and reporting principles build on the WRI/WBCSD GHG Protocol Standard. • Reporting on all 6 GHGs • Includes direct and indirect emissions (indirect from electricity, heat, or steam)	www.easternclimateregistry.org www.rggr.us www.nescaum.org

Appendix A-2. Summary of GHG Registries, continued

GHG Registries	Summary	Eligibility Requirements	Resource for Additional Information
New Hampshire Greenhouse Gas Reduction Registry	This registry is intended to quantify and submit GHG emissions reduction actions to a state database for safekeeping against some future federal requirements.	• A business, municipality, or individual within New Hampshire may choose to register a specific project that resulted in reduction of GHG emissions • Businesses within New Hampshire can register GHG emission reductions at three different levels: company, facility or project level.	www.des.state.nh.us/ard/climatechange/ghgr.htm
Wisconsin Voluntary Emissions Reduction Registry	Went into effect on June 1, 2000 under section 285.78 of the Wisconsin Statutes. The law directs the Department to "establish and operate a system under which the department registers reductions in emissions of GHGs if the reductions are made before the reductions are required by law."	Reductions occurring within Wisconsin and greater than 25 tons/yr CO_2 equivalent may be registered for the following activities: (a) Change in type of fuel used. (b) Installation and operation or modification of emission control equipment. (c) Implementation of energy efficiency measures by the energy producer or user. (d) Production, use, or purchase of renewable energy. (e) Changes to, replacement of, or retirement of a manufacturing or combustion process. (f) Product reformulation or replacement. (g) Beneficial reuse or recycling activities. (h) Increases in vehicle fleet fuel efficiency. (i) Changes that reduce vehicle miles traveled. (j) Carbon sequestration projects.	http://www.dnr.state.wi.us/org/aw/air/registry/about.html
US DOE 1605(b)	The Voluntary Reporting of Greenhouse Gases Program, established by Section 1605(b) of the Energy Policy Act of 1992, provides a means for organizations and individuals who have reduced their emissions to record their accomplishments and share their ideas for action.	• Must submit entity-wide emission inventories that meet or exceed minimum quality requirements • Reductions must be calculated using a base period no later than 2002 (or 2000 if participating in Climate Leaders or Climate VISION) • Registered reductions must meet entity statement and certification requirements.	www.eia.doe.gov http://www.eia.doe.gov/oiaf/1605/frntvrgg.html

Appendix B-1
Cogeneration Project Case Studies

Cogeneration Project Case Study #1:

New Cogeneration Unit To Replace Steam Generation From An Offsite Steam Boiler

Project Definition

Refinery AXA constructs a cogeneration facility in the Electric Reliability Council of Texas (ERCOT), a sub-group of the North American Electricity Reliability Council (NERC). Table 1 summarizes information available from EPA's E-GRID database for ERCOT.

Table 1. ERCOT Emission Factor Information

Year	Emission Rate for Fossil Fuel Generation		Fossil Fuel Generation,		Net Generation,		Total CO_2 Emissions,
	lb CO_2/ MW-hr	kg CO_2/ 10^6 J	MW-hr	10^{16} J	MW-hr	10^{16} J	tonnes
2003	1607.199	0.2025	274,748,781	98.91	313,658,556	112.9	200,359,541
2002	1619.2	0.204	259,515,579	93.43	297,548,850	107.1	190,512,295
2001	1637.469	0.206	255,989,521	92.16	296,042,502	106.6	190,243,112
2000	1896.136	0.2389	188,302,822	67.79	280,592,586	101.0	189,324,882
		Total	**978,556,703**	**352.3**	**1,187,842,493**	**427.6**	**770,439,831**

The cogeneration facility consists of three natural gas fired combustion turbines and three heat recovery steam generators with supplemental duct firing capability and three steam turbines. A simplified schematic of the project activity is shown in Figure 1.

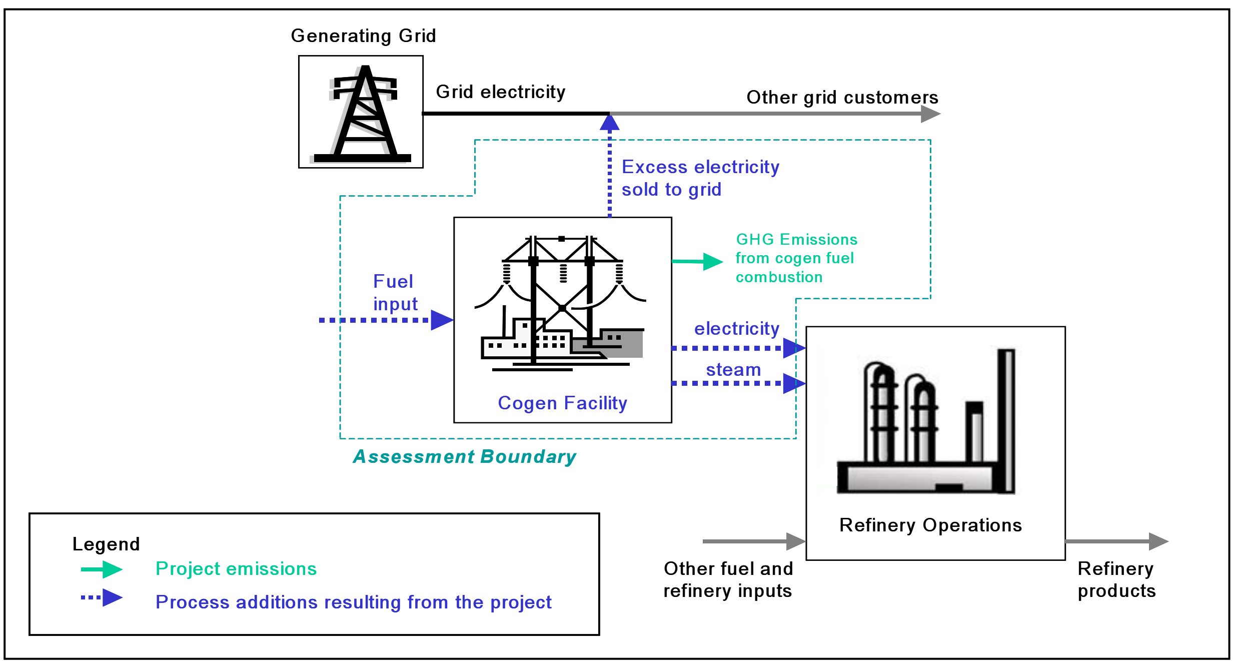

Figure 1. Project Illustration of Cogeneration Operations

Once operating, the cogeneration facility consumes 15.57×10^{15} J (14,760,000 million BTU) of natural gas, producing 5.483×10^{15} J (1,523,000 megawatt-hr) of electricity (gross) with a parasitic load of 138.6×10^{12} J (38,500 MW-hr) on an annual basis. The facility uses 900×10^{12} J (250,000 MW-hr) of electricity and the remainder is sold to the grid (4444.2×10^{12} J). 1.32×10^{15} J/yr (1,250,000 MMBtu/yr) of steam [equivalent to approximately 488,973 tonnes at 360 °C (680 °F), 3.999×10^{6} Pa (580 psig)] is generated by the cogeneration unit and used by the refinery, resulting in the decommissioning of the industrial facility's coal-fired spreader stoker boilers. The cogeneration operation is illustrated in Figure 2.

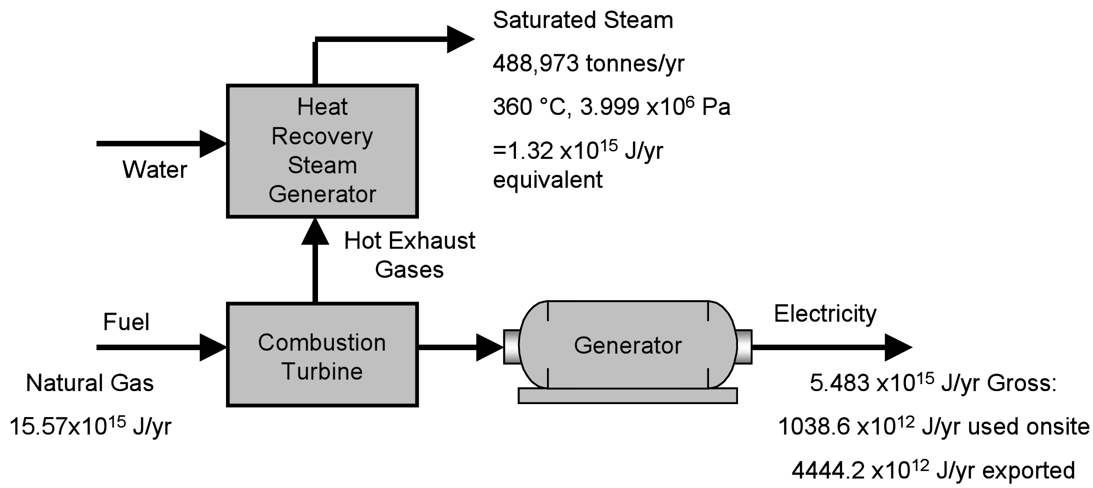

Figure 2. Case Study #1 Cogeneration Operations

The project proponent would like to report the emission reductions associated with this GHG reduction project as part of a corporate initiative. The project proponent decides to use the Combined Margin Method (described in Appendix B-2). The Combined Margin method uses the average of the operating margin and build margin for the power grid. The Operating Margin is determined based on a generation-weighted average emission rate, excluding nuclear, hydro, geothermal, wind, low cost biomass, and solar generation. The Build Margin is determined from a weighted average emission rate for new capacity.

Assumptions for this example include the following:

- Prior to the installation of the cogeneration unit, the refinery imported electricity from the grid and purchased steam from a nearby industrial facility, which generated the steam using coal-fired spreader stoker boilers.
- CO_2 emissions associated with the coal used by the industrial facility are calculated based on the average carbon content and heating value of the coal, which is assumed to = 0.098 tonnes CO_2/MMBtu (LHV) = 9.289×10^{-11} tonnes CO_2/J. The coal heating value is assumed to be = 11,800 Btu (LHV)/lb = 2.745×10^{10} J/tonne.

Baseline Scenario Selection

The baseline scenario represents the situation or conditions that plausibly would have occurred in the absence of the project. For this example, there are two aspects to the baseline scenario: the generation of the electricity and the generation of the steam. Plausible candidates for the baseline scenario are identified in Table 2.

Table 2. Baseline Candidates

Potential Baseline Candidates for Electricity Generation	Potential Baseline Candidates for Steam Generation
Candidate 1: Continuation of current activities – electricity purchased/imported from the grid. **Candidate 2:** The refinery adds a small dedicated generator. **Candidate 3:** Electricity purchased from a dedicated generator. **Candidate 4:** *The project activity*, where a cogeneration unit is installed to generate electricity and steam.	**Candidate A:** Continuation of current activities – steam is purchased/imported from another location. **Candidate B:** The refinery adds a small package boiler. **Candidate C:** The industrial facility replaces the coal-fired stoker boilers with a new, more efficient natural gas boiler **Candidate D:** *The project activity*, where a cogeneration unit is installed to generate electricity and steam.

Table 3 applies some common tests or screening procedures to assist in evaluating the baseline candidates.

Table 3. Baseline Scenario Assessment

<table>
<tr><th></th><th>Baseline Scenario Alternatives</th><th>Investment Ranking</th><th>Technology</th><th>Policy/ Regulatory</th><th>Benchmarking</th></tr>
<tr><td rowspan="4">Electricity Generation</td><td>Candidate 1: Continuation of current activities</td><td>No additional costs</td><td>No additional technology requirements</td><td rowspan="4">Consistent with current, applicable laws or regulations</td><td>Common practice</td></tr>
<tr><td>Candidate 2: Refinery adds an electric generator</td><td>High</td><td rowspan="3">Existing technologies</td><td rowspan="3">Commercial in some applications</td></tr>
<tr><td>Candidate 3: Electricity purchased from a dedicated electric generator</td><td>No direct costs for the refinery. Requires commitment from an electricity provider</td></tr>
<tr><td>Candidate 4: The project activity – Cogeneration unit</td><td>High</td></tr>
</table>

Table 3. Baseline Scenario Assessment, continued

	Baseline Scenario Alternatives	Investment Ranking	Technology	Policy/ Regulatory	Benchmarking
Steam Generation	**Candidate A:** Continuation of current activities	No additional costs	No additional technology requirements	Consistent with current, applicable laws or regulations	Common practice in region
	Candidate B: Addition of a small package boiler	Moderate to high costs	Existing technologies		Commercial applications
	Candidate C: Replacement of the coal-fired stoker boilers	No direct costs for the refinery. Moderate costs for the industrial provider.	Existing technologies		Commercial applications
	Candidate D: *The project activity* - Cogeneration unit	High			Commercial applications

Based on comparing the baseline candidates presented above:

- Candidates 2 and B require additional capital expenditures by the refinery. Since the refinery uses both electricity and steam, it is unlikely that separate generation units would be constructed.
- Candidate 3 would require a third party to install an electric generation facility and distribution to the refinery. Under certain circumstances, this option could occur. However, for this example, it is assumed that this is not viable.
- Candidate C would require the industrial facility to replace the existing boilers. Under certain circumstances, this option could occur. For example, the industrial facility may implement such a project in an effort to improve energy efficiency. However, for this example, it is assumed that this is not viable.
- Candidates 4 and D (*the project activity*) require significant investment for the refinery.

As a result of this analysis, Candidates 1 and A, which represent the continuation of current activities are the most probable baseline scenarios. Figure 3 provides a simple schematic of the baseline scenario.

Project Assessment Boundary

After defining the project and determining the baseline scenario, the next step is to determine the assessment boundary. The assessment boundary encompasses GHG emission sources, sinks, and reservoirs, controlled by the project proponent, related to the GHG reduction project, affected by the GHG reduction projects, and relevant to the baseline scenario. Figures 1 and 3 illustrate the energy streams within the assessment boundary for both the project activity and the baseline scenario, respectively. Table 4 examines potential emission sources within the assessment boundary and compares the baseline scenario to the project activity.

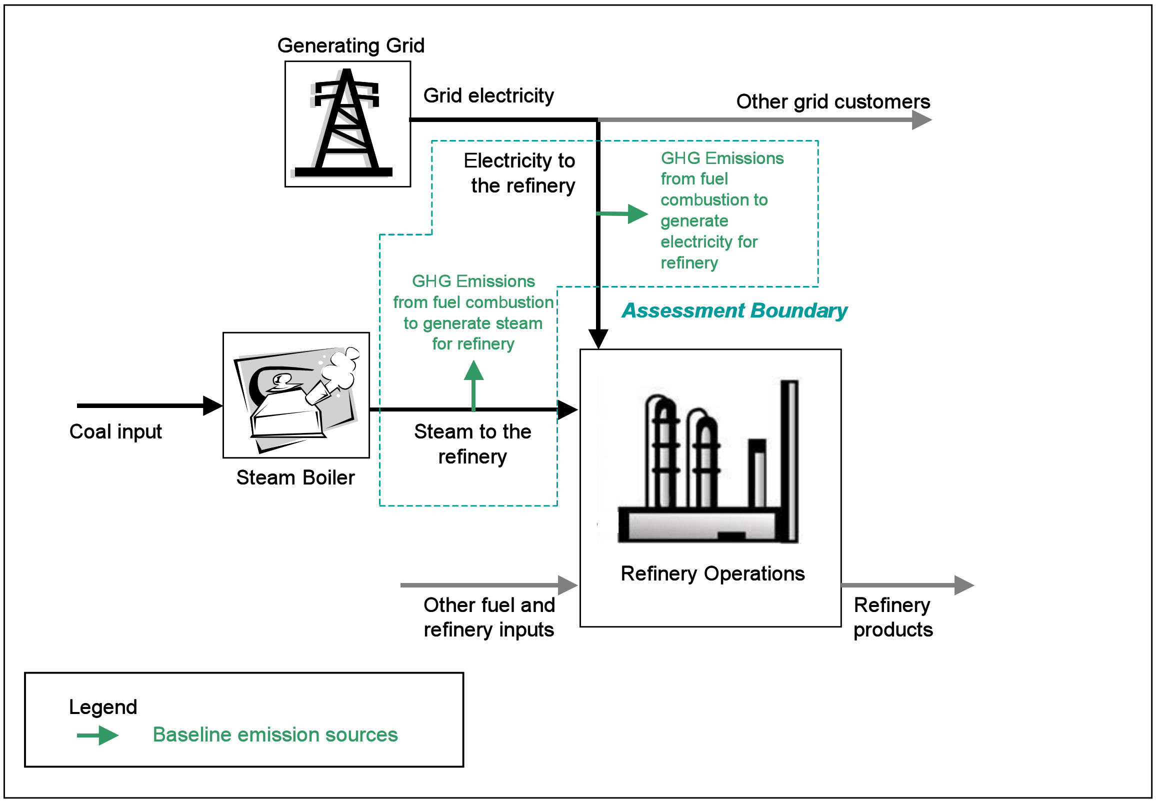

Figure 3. Baseline Illustration

Table 4. Assessment Boundary Determination

	Potential Emission Sources	Relation to the Project Proponent	Considerations
Baseline Scenario	✓ CO_2, CH_4 and N_2O combustion emissions from boilers and prime movers at the industrial facility used to produce and transport the steam ✓ CO_2, CH_4 and N_2O emissions associated with electricity generation capacity on the grid ✓ Vented and fugitive CH_4 emissions, as well as CO_2, CH_4 and N_2O combustion emissions, associated with extraction, processing, and transport of coal to the industrial facility	Related Related Affected	✓ These emissions are assumed to be offset by the life-cycle emissions of the natural gas used by the cogeneration unit

Table 4. Assessment Boundary Determination, continued

	Potential Emission Sources	Relation to the Project Proponent	Considerations
Project Activity	✓ CO_2, and to a lesser extent, CH_4 and N_2O emissions from combustion turbines and duct burners associated with the cogeneration unit	✓ Controlled	
	✓ CH_4 emissions from vented or fugitive sources within the refinery associated with natural gas fuel used to generate electricity and steam	✓ Controlled	✓ These emissions are assumed to be negligible due to the minimal number of sources
	✓ CO_2, CH_4 and N_2O emissions displaced by the GHG reduction project through the exported electricity	✓ Affected	
	✓ Vented and fugitive CH_4 emissions, as well as CO_2, CH_4 and N_2O combustion emissions, associated with extraction, processing, and transport of natural gas to the cogeneration facility.	✓ Affected	✓ These emissions are assumed to be offset by the life-cycle emissions of the coal used by the industrial facility
	✓ Cogeneration construction phase emissions	✓ Controlled or Related	✓ Construction phase emissions are likely de minimis.
	✓ Changes in product output for neighboring energy users and associated emissions caused by increased supply or demand of steam and electricity.	✓ Affected	✓ It is rarely possible to quantify the market impact of a single cogeneration project on the demand for associated energy supply through market affects such as the impact of additional supply on product output or price.

Quantifying Emission Reductions

The following Exhibit demonstrates the emission estimation methods for the baseline scenario and project activity. Emission reductions are quantified as the difference between the baseline and project emissions.

EXHIBIT 5.1: Refinery builds a new cogeneration unit to replace steam generation from an offsite steam boiler.

Known information (based on hypothetical data)

- The cogeneration facility consumes 15.57×10^{15} J (14,760,000 million BTU) of natural gas, producing 5.48×10^{15} J (1,523,000 megawatt-hr) of electricity (gross) with a parasitic load of 138.6×10^{12} J (38,500 MW-hr) on an annual basis
- The facility uses 900×10^{12} J (250,000 MW-hr) of electricity and the remainder is sold to the grid
- 1.32×10^{15} J (1,250,000 MMBtu) of steam [equivalent to 488,973 tonnes (539,000 tons) at 360°C (680 °F), 3.999×10^{6} Pa (580 psig)] is generated by the cogeneration unit and used by the refinery
- The gas composition results in 72.27 wt% carbon and heating value of 37.72×10^{6} J/m^3 (1012.36 Btu (HHV)/scf), and the molecular weight of the gas is 16.84 kg/kgmol (16.84 lb/lbmol)

Project Emissions

The project emissions are equivalent to the combustion emissions from the cogeneration unit. Based on the gas composition information, a CO_2 emission factor can be calculated:

$$\frac{\text{m}^3\text{ gas}}{37.72\times10^{6}\text{ J}}\times\frac{\text{kgmole gas}}{23.685\text{ m}^3}\times\frac{16.84\text{ kg gas}}{\text{kgmole gas}}\times\frac{0.7227\text{ kg C}}{\text{kg gas}}\times\frac{44\text{ kg CO}_2\text{/lbmole CO}_2}{12\text{ kg C/lbmole C}}$$
$$\times\frac{\text{tonne}}{1000\text{ kg}}=4.99\times10^{-11}\text{ tonnes CO}_2\text{ / J}$$

Project CO_2 emissions =

$$15.57\times10^{15}\text{ J gas}\times\frac{4.99\times10^{-11}\text{ tonnes CO}_2}{\text{J gas}}=776{,}943\text{ tonnes CO}_2$$

CH_4 and N_2O emissions are determined based on industry accepted emission factors for natural gas combustion in turbines (API Compendium Table 4-5).

CH_4 EF = 0.0037 tonnes/10^{12} J(HHV)

Project CH_4 emissions =

$$15.57\times10^{15}\text{ J gas}\times\frac{0.0037\text{ tonnes CH}_4}{10^{12}\text{ J gas}}=57.6\text{ tonnes CH}_4$$

N_2O EF (SCR controlled) = 0.013 tonnes/10^{12} J(HHV)

Project N_2O emissions =

$$15.57\times10^{15}\text{ J gas}\times\frac{0.013\text{ tonnes N}_2\text{O}}{10^{12}\text{ J gas}}=202\text{ tonnes N}_2\text{O}$$

The total CO_2 equivalent emissions for the Project are:

776,943 tonnes CO_2 +(21×57.6 tonnes CH_4) + (310×202 tonnes N_2O)

= 840,773 tonnes CO_2 Eq./yr

EXHIBIT 5.1: Refinery builds a new cogeneration unit to replace steam generation from an offsite steam boiler, continued

Baseline Emissions

The baseline emissions consist of those emissions that would have occurred to separately generate the electricity and steam used by the refinery.

Electricity Baseline Emissions

For this example, the project proponent decides to use the Combined Margin method to develop the grid-based emission factor, which will be used to represent the emissions that would have occurred had the refinery purchased electricity from the grid. The Combined Margin method uses the average of the Operating Margin and the Build Margin for the power grid.

Using the ERCOT information presented in Table 1, the Operating Margin is:

$$= \frac{\sum_{i=1}^{\#years}\left(\text{Fossil Fuel Generation Emission Rate}_{\text{i}} \times \text{Fossil Fuel Generation}_{\text{i}}\right)}{\text{Total Fossil Fuel Generation}}$$

$$= \frac{\sum_{i=1}^{\#years}\left(\left(\frac{\text{kg CO}_2}{\text{J}}\right)_{\text{i}} \times \text{J}_{\text{i}}\right)}{\text{Total J}} \times \frac{\text{tonne}}{1000\text{ kg}} = 0.00021\text{ tonnes CO}_2/10^6\text{ J (0.7593 tonnes CO}_2\text{/MWhr)}$$

The Build Margin is based on the weighted average emissions of the 5 most recent plants. Using information available in the E-GRID database, the Build Margin
= 1.392×10^{-4} tonne/10^6 J (0.5012 tonnes CO_2/MW-hr)

The Combined Margin CO_2 Baseline Emission Rate for Electricity
= 1.7506×10^{-4} tonne/10^6 J (0.63025 tonnes CO_2/MW-hr)

The CO_2 emissions for the electricity baseline are therefore:

$$\text{CO}_2 : 900 \times 10^{12}\text{ J} \times \frac{1.7506 \times 10^{-4}\text{ tonnes CO}_2}{10^6\text{ J}} = 157{,}554\text{ tonnes CO}_2$$

EPA's E-GRID system does not track CH_4 and N_2O emission factors. However, EPA's Climate Leaders provides CH_4 and N_2O emission factors for each eGRID subregion. Although EPA does not report information to the level of detail necessary to determine the CH_4, and N_2O emission factors on a Combined Margin basis, this difference is believed to be insignificant, particularly given the small contribution of CH_4 and N_2O emission relative to CO_2, as demonstrated below.

EXHIBIT 5.1: Refinery builds a new cogeneration unit to replace steam generation from an offsite steam boiler, continued

From EPA's Climate Leaders Purchases/Sales of Electricity and Steam Guidance for ERCOT, CH_4 EF = 0.0207 lbs/MW-hr = 2.61×10^{-15} tonnes CH_4/J

The CH_4 emissions for the electricity baseline are:

$$CH_4 : 900\times10^{12}\ J \times \frac{2.61\times10^{-15}\ \text{tonnes}\ CH_4}{J} = 2.35\ \text{tonnes}\ CH_4$$

N_2O EF = 0.134 lb N_2O/MW-hr= 1.688×10^{-14} tonnes N_2O/J

The N_2O emissions for the electricity baseline are:

$$N_2O : 900\times10^{12}\ J \times \frac{1.688\times10^{-14}\ \text{tonnes}\ N_2O}{J} = 15.2\ \text{tonnes}\ N_2O$$

The total CO_2 equivalent emissions for the Electricity Baseline
= 157,554 tonnes CO_2 + +(21×2.35 tonnes CH_4) + (310×15.2 tonnes N_2O)
= 162,315 tonnes CO_2 Eq./yr

<u>Steam Baseline Emissions</u>
The baseline scenario for exported steam must consider the previous generation methods or a plausible replacement scenario for steam that is being supplied by the cogeneration plant. For this example, the previous generation method for the exported steam was via coal-fired stoker boilers at the adjacent industrial facility (which were subsequently retired with the cogeneration project's operation).

The coal consumption to generate the 1.32×10^{15} J of exported steam is determined based on the 80% thermal efficiency of the coal-fired stoker boilers at the industrial facility.

Estimated Coal Usage:

$$\frac{1\ J\ (LHV)\ \text{heat input}}{0.80\ J\ \text{steam generated}} \times 1.32\times10^{15}\ J\ \text{Steam Exported}$$

$$= 1.65\times10^{15}\ J\ (LHV)\ \text{coal fired}$$

EXHIBIT 5.1: Refinery builds a new cogeneration unit to replace steam generation from an offsite steam boiler, continued

CO_2 emissions resulting from the combustion of this coal are calculated based on the average carbon content and heating value of the coal previously used in the industrial facility
= 9.289×10^{-11} tonnes CO_2/J (LHV)

$$CO_2 : 1.65\times10^{15} \text{ J coal} \times \frac{9.289\times10^{-11} \text{ tonnes } CO_2}{\text{J (LHV) coal}} = 153{,}268 \text{ tonnes } CO_2$$

CH_4 and N_2O emission are determined based on measured emissions data, if available, or industry-accepted emission factors for coal-fired boilers (API Compendium Table 4-4b). In applying emission factors, the coal heating value is needed to convert energy units to a mass basis = 2.745×10^{10} J/tonne.

CH_4 EF = 3.0×10^{-5} tonnes/tonne
CH_4 Baseline Emissions for Steam =

$$CH_4 = 1.65\times10^{15} \text{ J coal} \times \frac{\text{tonne coal}}{2.745\times10^{10} \text{ J}} \times \frac{3.0\times10^{-5} \text{ tonnes } CH_4}{\text{tonne coal}}$$
$$= 1.8 \text{ tonnes } CH_4$$

N_2O EF = 2.0×10^{-5} tonnes/tonne
N_2O Baseline Emissions for Steam =

$$N_2O = 1.65\times10^{15} \text{ J coal} \times \frac{\text{tonne coal}}{2.745\times10^{10} \text{ J}} \times \frac{2.0\times10^{-5} \text{ tonnes } N_2O}{\text{tonne coal}}$$
$$= 1.2 \text{ tonnes } N_2O$$

The total CO_2 equivalent emissions for the Baseline Steam
= 153,268 tonnes CO_2 + +(21×1.8 tonnes CH_4) + (310×1.2 tonnes N_2O)
= 153,678 tonnes CO_2 Eq./yr

The final aspect of this example is the reduction in emissions associated with exporting the electricity not used by the refinery to the grid, which displaces electricity that would have been generated by other means. This is equivalent to (5482.8-138.6-900)$\times10^{12}$ J of electricity = 4444.2 $\times10^{12}$ J

As shown above, the CO_2 emission factor for the grid is represented by the Combined Margin emission factor. So, the CO_2 grid emissions displaced by the exported electricity are:

$$CO_2 : 4444.2\times10^{12} \text{ J} \times \frac{1.7506\times10^{-4} \text{ tonnes } CO_2}{10^6 \text{ J}} = 778{,}002 \text{ tonnes } CO_2$$

EXHIBIT 5.1: Refinery builds a new cogeneration unit to replace steam generation from an offsite steam boiler, continued

The CH_4 grid emissions displaced by the exported electricity =

$$CH_4 : 4444.2 \times 10^{12}\ J \times \frac{2.61 \times 10^{-15}\ \text{tonnes}\ CH_4}{J} = 11.6\ \text{tonnes}\ CH_4$$

The N_2O grid emissions displaced by the exported electricity =

$$N_2O : 4444.2 \times 10^{12}\ J \times \frac{1.688 \times 10^{-14}\ \text{tonnes}\ N_2O}{J} = 75\ \text{tonnes}\ N_2O$$

The total CO_2 equivalent emissions displaced by the exported electricity
= 778,002 tonnes CO_2 + +(21×11.6 tonnes CH_4) + (310×75 tonnes N_2O)
= 801,496 tonnes CO_2 Eq./yr

Emission Reduction Calculation:

Overall emission reductions are determined by the difference between the GHG reduction project emissions and the baseline emissions, as shown in Table 5.

Table 5. Summary of Annual Emissions for EXHIBIT 5.1: Refinery builds a new cogeneration unit to replace steam generation from an offsite steam boiler.

		Tonnes CO_2 Eq.
Baseline Scenario	Electricity Equivalent Emissions	162,315
	Electricity Grid Displacement	801,496
	Steam Equivalent Emissions	153,678
	Total Baseline Emissions	**1,117,489**
GHG Reduction Project	**Total Direct Emissions**	**840,773**
Annual Net GHG Reductions		**276,716**

Cogeneration Project Case Study #2:

Cogeneration with Increased On-Site Energy Consumption

This case study examines a facility that has installed a cogeneration unit to improve an existing facility's overall efficiency. For this example, previously imported energy is replaced with on-site generation. Excess electricity is exported to grid. Post-project energy use is higher than the baseline scenario due to organic growth. However, for this example, the increased steam capacity occurring post-project is within the physical capabilities of the baseline boiler.

Project Definition

Prior to installation of the GHG reduction project, a refinery located in Thailand purchases 7.12×10^{14} J (198,000 MW-hr) of electricity from the national grid and generates 2.86×10^{15} J (LHV) (2,710,000 million Btu) of steam on-site. The on-site steam is produced by a diesel-fired boiler using 190,785 m^3 (1.2×10^6 barrels) of fuel (3.82×10^{10} J/m^3 HHV, 3.62×10^{10} J/m^3 LHV).

To improve the existing facility's overall energy efficiency, the refinery installs a cogeneration facility consisting of three natural gas fired combustion turbines and three heat recovery steam generators with supplemental duct firing capability and steam turbines.

After installation of the cogeneration facility, electricity is no longer purchased from the grid. The cogeneration facility consumes 8.58×10^{15} J (8,131,500 million Btu) of natural gas, producing 3.81×10^{15} J (3,614,000 million Btu) steam and 3.96×10^{15} J (1,100,600 megawatt-hr) of electricity (gross) on an annual basis. After installation of the cogeneration plant, the refinery uses all of the generated steam and 9.9×10^{14} J (275,000 MW-hr) of electricity. The facility parasitic load is 138.6×10^{12} J (38,500 MW-hr), with the net electricity sold to the grid (2.83×10^{15} J). The cogeneration operation is illustrated in Figure 4.

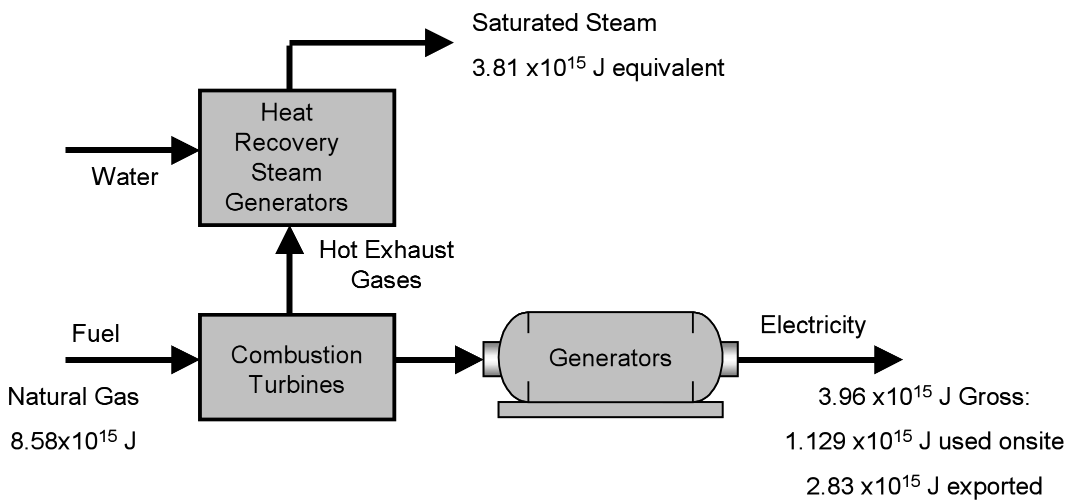

Figure 4. Case Study #2 Cogeneration Operations

The project proponent would like to report the GHG reductions associated with these project activities to meet internal emission reduction targets.

Baseline Scenario Selection

Plausible candidates for the baseline scenario are identified in Table 6.

Table 6. Baseline Candidates

Potential Baseline Candidates for Electricity Generation	Potential Baseline Candidates for Steam Generation
Candidate 1: Continuation of current activities – electricity purchased/imported from the grid. **Candidate 2:** The refinery adds a small dedicated generator. **Candidate 3:** Electricity purchased from a dedicated generator. **Candidate 4:** *The project activity*, where a cogeneration unit is installed to generate electricity and steam.	**Candidate A:** Continuation of current activities – steam is generated onsite using a diesel-fired boiler. **Candidate B:** The refinery replaces the diesel boiler with a more efficient unit **Candidate C:** The refinery purchases steam **Candidate D:** *The project activity*, where a cogeneration unit is installed to generate electricity and steam.

Table 7 applies some common tests or screening procedures to assist in evaluating the baseline candidates.

Table 7. Baseline Scenario Assessment

<table>
<tr><th></th><th>Baseline Scenario Alternatives</th><th>Investment Ranking</th><th>Technology</th><th>Policy/ Regulatory</th><th>Benchmarking</th></tr>
<tr><td rowspan="4">Electricity Generation</td><td>Candidate 1: Continuation of current activities</td><td>No additional costs</td><td>No additional technology requirements</td><td rowspan="4">Consistent with current, applicable laws or regulations</td><td>Common practice</td></tr>
<tr><td>Candidate 2: Refinery adds an electric generator</td><td>High</td><td rowspan="3">Existing technologies</td><td rowspan="3">Commercial in some applications</td></tr>
<tr><td>Candidate 3: Electricity purchased from a dedicated electric generator</td><td>No direct costs for the refinery. Requires commitment from an electricity provider</td></tr>
<tr><td>Candidate 4: The project activity – Cogeneration unit</td><td>High</td></tr>
<tr><td rowspan="4">Steam Generation</td><td>Candidate A: Continuation of current activities</td><td>No additional costs</td><td>No additional technology requirements</td><td rowspan="4">Consistent with current, applicable laws or regulations</td><td>Common practice in region</td></tr>
<tr><td>Candidate B: Replacement of the diesel boiler</td><td>Moderate costs</td><td>Existing technologies</td><td>Commercial applications</td></tr>
<tr><td>Candidate C: Refinery purchases steam</td><td>No direct costs for the refinery. Requires an outside supplier for steam</td><td rowspan="2">Existing technologies</td><td>Commercial in some applications</td></tr>
<tr><td>Candidate D: The project activity - Cogeneration unit</td><td>High</td><td>Commercial in some applications</td></tr>
</table>

Based on comparing the baseline candidates presented above:

- Candidates 2 and B require additional capital expenditures by the refinery. For energy efficiency improvements, the refinery may upgrade or replace the diesel boilers. However, for this example, it is assumed that this is not viable.
- Candidates 3 and C would require third party suppliers to install the electricity or steam generation facility and distribution to the refinery. Under certain circumstances, this option could occur. However, for this example, it is assumed that this is not viable.
- Candidates 4 and D (*the project activity*) require significant investment for the refinery.

As a result of this analysis, Candidates 1 and A, which represent the continuation of current activities are the most probable baseline scenarios.

Project Assessment Boundary

After defining the project and determining the baseline scenario, the next step is to determine the assessment boundary. The assessment boundary encompasses GHG emission sources, sinks, and reservoirs, controlled by the project proponent, related to the GHG reduction project, affected by the GHG reduction projects, and relevant to the baseline scenario. Figures 1 and 3 illustrate the energy streams within the assessment boundary for both the project activity and the baseline scenario, respectively. Table 8 examines potential emission sources within the assessment boundary and compares the baseline scenario to the project activity.

Table 8. Assessment Boundary Determination

	Potential Emission Sources	**Relation to the Project Proponent**	**Considerations**
Baseline Scenario	✓ CO_2, CH_4 and N_2O combustion emissions from the diesel boiler used to produce the steam	Controlled	
	✓ CO_2, CH_4 and N_2O emissions associated with electricity generation capacity on the grid	Related	
	✓ Vented and fugitive CH_4 emissions, as well as CO_2, CH_4 and N_2O combustion emissions, associated with processing the diesel	Controlled	✓ These emissions are assumed to be offset by the life-cycle emissions of the natural gas used by the cogeneration unit

Table 8. Assessment Boundary Determination, continued

	Potential Emission Sources	Relation to the Project Proponent	Considerations
Project Activity	✓ CO_2, and to a lesser extent, CH_4 and N_2O emissions from combustion turbines and duct burners associated with the cogeneration unit	✓ Controlled	
	✓ CH_4 emissions from vented or fugitive sources within the refinery associated with natural gas fuel used to generate electricity and steam	✓ Controlled	✓ These emissions are assumed to be negligible due to the minimal number of sources
	✓ CO_2, CH_4 and N_2O emissions displaced by the GHG reduction project through the exported electricity	✓ Affected	
	✓ Vented and fugitive CH_4 emissions, as well as CO_2, CH_4 and N_2O combustion emissions, associated with extraction, processing, and transport of natural gas to the cogeneration facility.	✓ Affected	✓ These emissions are assumed to be offset by the emissions associated with the production of diesel in the baseline
	✓ Cogeneration construction phase emissions	✓ Controlled or Related	✓ Construction phase emissions are likely de minimis.
	✓ Changes in product output for neighboring energy users and associated emissions caused by increased supply or demand of steam and electricity.	✓ Affected	✓ It is rarely possible to quantify the market impact of a single cogeneration project on the demand for associated energy supply through market affects such as the impact of additional supply on product output or price.

Quantifying Emission Reductions

The following Exhibit demonstrates the emission estimation methods for the baseline scenario and project activity. Emission reductions are quantified as the difference between the baseline and project emissions.

EXHIBIT 5.2: Cogeneration With Increased On-Site Energy Consumption

Known information (based on hypothetical data)

- The cogeneration facility consumes 8.587×10^{15} J (8,131,500 million BTU) of natural gas, producing 3.96×10^{15} J (1,100,600 megawatt-hr) of electricity (gross) with a parasitic load of 138.6×10^{12} J (38,500 MW-hr) on an annual basis
- The facility uses 9.9×10^{14} J (275,000 MW-hr) of electricity and the remainder, 2.83×10^{15} J (786,100 MW-hr) is sold to the grid
- 3.81×10^{15} J (3,614,000 MMBtu) of steam is generated by the cogeneration unit and used by the refinery

EXHIBIT 5.2 Cogeneration With Increased On-Site Energy Consumption, Continued

- The gas composition results in 72.27 wt% carbon and heating value of 37.72×10^6 J/m^3 (1012.36 Btu (HHV)/scf), and the molecular weight of the gas is 16.84 kg/kgmol (16.84 lb/lbmol)
- The project proponent decides to use national grid emission factors to calculate emission rates associated with imported and exported electricity.

Project Emissions

For the cogeneration unit, the project emissions are determined based on the metered gas usage and measured composition. From Exhibit 5.1, the CO_2 EF associated with the natural gas = 4.99×10^{11} tonnes CO_2/J (0.0527 tonnes CO_2/MMBtu).
Project CO_2 Emissions =

$$CO_2 :\ 8.58\times10^{15}\ J \times \frac{4.99\times10^{-11}\ \text{tonnes}\ CO_2}{\text{J natural gas}} = 428{,}142\ \text{tonnes}\ CO_2$$

CH_4 and N_2O emissions are determined based on industry accepted emission factors for natural gas combustion in turbines (API Compendium Table 4-5).
CH_4 EF = 0.0037 tonnes/10^{12} J(HHV)
Project CH_4 emissions =

$$8.58\times10^{15}\ \text{J gas} \times \frac{0.0037\ \text{tonnes}\ CH_4}{10^{12}\ \text{J gas}} = 31.7\ \text{tonnes}\ CH_4$$

N_2O EF (SCR controlled) = 0.013 tonnes/10^{12} J(HHV)
Project N_2O emissions =

$$8.58\times10^{15}\ \text{J gas} \times \frac{0.013\ \text{tonnes}\ N_2O}{10^{12}\ \text{J gas}} = 111.5\ \text{tonnes}\ N_2O$$

The total CO_2 equivalent emissions for the Project are:
428,142 tonnes CO_2 +(21×31.7 tonnes CH_4) + (310×111.5 tonnes N_2O)
= 463,373 tonnes CO_2 Eq./yr

Baseline Emissions
Baseline emissions consist of those emissions that would have occurred to separately generate the electricity and steam used by the refinery.

Steam Baseline Emissions
The baseline emission rate for steam generated from a diesel boiler is based on the fuel properties and efficiency of the equipment. For this example, the diesel fuel properties result in the following CO_2 emission factor.

CO_2 Baseline Emission Rate for Steam = 7.402×10^{-11} tonnes CO_2/J (LHV)

EXHIBIT 5.2 Cogeneration With Increased On-Site Energy Consumption, Continued

CO_2 emissions associated with generating the baseline scenario steam are calculated for the diesel-fired boiler using the 80% thermal efficiency of the boiler:

CO_2 Baseline Emissions for Steam:

$$CO_2 : 3.81 \times 10^{15} \text{ J steam out} \times \frac{\text{J in (LHV)}}{0.80 \text{ J out}} \times \frac{7.402 \times 10^{-11} \text{ tonnes } CO_2}{\text{J (LHV)}}$$
$$= 352{,}520 \text{ tonnes } CO_2$$

CH_4 and N_2O emissions are determined based on industry accepted emission factors for diesel (distillate) industrial boilers (API Compendium Table 4-4a). Emission factors for CH_4 and N_2O are per unit volume of diesel combusted. The heating value of the diesel is needed to estimate the volume of diesel required to generate the project-level quantity of steam.

CH_4 EF = 6.2×10^{-6} tonnes/m^3
CH_4 Baseline Emissions for Steam =

$$CH_4 : 3.81 \times 10^{15} \text{ J steam out} \times \frac{\text{J in (LHV)}}{0.8 \text{ J out}} \times \frac{\text{m}^3 \text{ diesel}}{3.62 \times 10^{10} \text{ J (LHV)}}$$
$$\times \frac{6.2 \times 10^{-6} \text{ tonnes } CH_4}{\text{m}^3 \text{ diesel}} = 0.816 \text{ tonnes } CH_4$$

N_2O EF = 3.1×10^{-5} tonnes/m^3
N_2O Baseline Emissions for Steam =

$$N_2O : 3.81 \times 10^{15} \text{ J steam out} \times \frac{\text{J in (LHV)}}{0.8 \text{ J out}} \times \frac{\text{m}^3 \text{ diesel}}{3.62 \times 10^{10} \text{ J (LHV)}}$$
$$\times \frac{3.1 \times 10^{-5} \text{ tonnes } N_2O}{\text{m}^3 \text{ diesel}} = 4.08 \text{ tonnes } N_2O$$

The total CO_2 equivalent emissions for the Steam Baseline are:
352,520 tonnes CO_2 +(21×0.816 tonnes CH_4) + (310×4.08 tonnes N_2O)
= 353,802 tonnes CO_2 Eq./yr

EXHIBIT 5.2 Cogeneration With Increased On-Site Energy Consumption, Continued

Electricity Baseline Emissions

Baseline electricity emission rates are required for the electricity that was imported prior to the GHG reduction project. The CO_2 emission factor for the Thailand national grid is,

CO_2 EF = 1.39×10^{-10} tonnes CO_2/J

The CO_2 Baseline Emissions for Onsite Electricity Consumption =

$$CO_2 : (9.9 + 1.386)\times 10^{14}\ \text{J} \times \frac{1.39\times10^{-10}\ \text{tonnes}\,CO_2}{\text{J}} = 156{,}875\ \text{tonnes}\,CO_2$$

Thailand national grid CH_4 EF = 2.48×10^{-15} tonnes/J

CH_4 Baseline Emissions for Onsite Electricity Consumption =

$$CH_4 : (9.9 + 1.386)\times 10^{14}\ \text{J} \times \frac{2.48\times10^{-15}\ \text{tonnes}\,CH_4}{\text{J}} = 2.80\ \text{tonnes}\,CH_4$$

N_2O EF = 1.436×10^{-14} tonnes/J

N_2O Baseline Emissions for Onsite Electricity Consumption =

$$N_2O : (9.9 + 1.386)\times 10^{14}\ \text{J} \times \frac{1.436\times10^{-14}\ \text{tonnes}\,CH_4}{\text{J}} = 16.21\ \text{tonnes}\,N_2O$$

The CO2 equivalent emissions for Electricity Baseline are:

156,875 tonnes CO_2 +(21×2.80 tonnes CH_4) + (310×16.21 tonnes N_2O)

= 161,959 tonnes CO_2 Eq./yr

The final aspect of this example is the reduction in emissions associated with exporting the electricity not used by the refinery to the grid, which displaces electricity that would have been generated by other means. This is equivalent to 2.83×10^{15} J of electricity

As shown above, the CO_2 emission factor for the Thailand national grid is

CO_2 EF = 1.39×10^{-10} tonnes CO_2/J

So, the CO_2 grid emissions displaced by the exported electricity are:

$$CO_2 : 2.83\times 10^{15}\ \text{J} \times \frac{1.39\times10^{-10}\ \text{tonnes}\,CO_2}{\text{J}} = 393{,}370\ \text{tonnes}\,CO_2$$

The CH_4 grid emissions displaced by the exported electricity =

$$CH_4 : 2.83\times 10^{15}\ \text{J} \times \frac{2.48\times10^{-15}\ \text{tonnes}\,CH_4}{\text{J}} = 7.02\ \text{tonnes}\,CH_4$$

EXHIBIT 5.2 Cogeneration With Increased On-Site Energy Consumption, Continued

The N_2O grid emissions displaced by the exported electricity =

$$N_2O : 2.83 \times 10^{15}\ J \times \frac{1.436 \times 10^{-14}\ \text{tonnes}\ N_2O}{J} = 40.6\ \text{tonnes}\ N_2O$$

The total CO_2 equivalent emissions displaced by the exported electricity
= 393,370 tonnes CO_2 +(21×7.02 tonnes CH_4) + (310×40.6 tonnes N_2O)

= 406,103 tonnes CO_2 Eq./yr

Table 9 summarizes the results of the cogeneration case study where the GHG reduction project on-site energy consumption increases over the baseline scenario.

Table 9. Summary of Annual Emissions for EXHIBIT 5.2: Cogeneration with Increased On-Site Energy Consumption

		Tonnes CO_2 Eq.
Baseline Scenario	Electricity Equivalent Emissions	161,959
	Electricity Grid Displacement	406,103
	Steam Equivalent Emissions	353,802
	Total Baseline Emissions	**921,864**
GHG Reduction Project	**Total Direct Emissions**	**463,373**
Annual Net GHG Reductions		**458,491**

Cogeneration Project Case Study #3:

Cogeneration with Increased On-Site Energy Consumption – Exceeding Baseline Scenario Capacity

This example is a continuation of Case Study #2. Here, the steam boiler has reached its maximum capacity at the baseline scenario conditions. As a result, an additional baseline emission rate is needed to compare to the additional steam capacity at the GHG reduction project conditions.

Project Definition

Prior to installation of the cogeneration facility, a refinery in Thailand purchases 7.416×10^{14} J (206,000 megawatt-hr) of electricity from the grid and generates 2.86×10^{15} J (2,710,000 million Btu) of steam on-site. The on-site steam is produced by a diesel-fired boiler using 190,785 m^3 (1.2×10^6 barrels) of fuel (3.82×10^{10} J/m^3 HHV, 3.62×10^{10} J/m^3 LHV). *The diesel boiler is operating at its maximum capacity.*

To meet expanding energy needs and to improve the existing facility's overall energy efficiency, the refinery installs a cogeneration facility consisting of three natural gas fired combustion turbines and three heat recovery steam generators with supplemental duct firing capability and steam turbines.

After installation of the cogeneration facility, electricity is no longer purchased from the grid. The cogeneration facility consumes 8.58×10^{15} J (HHV) (8,131,500 million Btu) of natural gas, producing 3.81×10^{15} J (3,614,000 million Btu) steam and 3.96×10^{15} J (1,100,600 megawatt-hr) of electricity (gross) on an annual basis. After installation of the cogeneration plant, the refinery uses all of the generated steam and 9.9×10^{14} J (275,000 MW-hr) of electricity. The facility parasitic load is 1.386×10^{14} J (38,500 MW-hr), with the net electricity sold to the grid (2.83×10^{15} J).

Baseline Scenario Selection

Plausible candidates for the baseline scenario are identified in Table 10. Note that a third baseline component is included for the incremental steam requirement at the project activity level.

The baseline scenario assessment for the steam and electricity generation are the same as were presented in Table 7. Table 11 applies the screening procedures to assist in evaluating the incremental steam component of this case study.

Table 10. Baseline Candidates

Potential Baseline Candidates for Electricity Generation	Potential Baseline Candidates for Steam Generation to Maximum Capacity	Potential Baseline Candidates for Incremental Steam Generation
Candidate 1: Continuation of current activities – electricity purchased/imported from the grid. **Candidate 2:** The refinery adds a small dedicated generator. **Candidate 3:** Electricity purchased from a dedicated generator. **Candidate 4:** *The project activity*, where a cogeneration unit is installed to generate electricity and steam.	**Candidate A:** Continuation of current activities – steam is generated onsite using a diesel-fired boiler. **Candidate B:** The refinery replaces the diesel boiler with a more efficient unit **Candidate C:** The refinery purchases steam **Candidate D:** *The project activity*, where a cogeneration unit is installed to generate electricity and steam.	**Candidate I:** The refinery adds a small package boiler to produce the extra steam **Candidate II:** The refinery imports the extra steam **Candidate III:** The refinery replaces the diesel boiler with new equipment that can produce the extra steam **Candidate IV**: *The project activity*, where a cogeneration unit is installed to generate electricity and steam.

Table 11. Baseline Scenario Assessment

	Baseline Scenario Alternatives	Investment Ranking	Technology	Policy/ Regulatory	Benchmarking
Incremental Steam Generation	**Candidate I:** Small package boiler	Moderate costs	Existing technologies	Consistent with current, applicable laws or regulations	Commercial applications
	Candidate II: Imports the extra steam	No direct costs for the refinery. Requires an outside supplier for steam			Commercial in some applications
	Candidate III: Replace the diesel boiler	Moderate to high costs			Commercial applications
	Candidate IV: *The project activity* - Cogeneration unit	High			Commercial in some applications

Based on comparing the baseline candidates presented above:

- Candidates I and III require additional capital expenditures by the refinery.
- Candidate III may be justified if there is significant additional demand for steam.
- Candidate II requires a third party supplier to generate the additional steam at the required flow rate and conditions. Under certain circumstances, this option could occur. However, for this example, it is assumed that this is not viable.
- Candidate IV (*the project activity*) requires significant investment for the refinery.

For this example, Candidate 1, meeting the incremental steam demand through the addition of a small package boiler, is determined to be the most probable scenario.

Project Assessment Boundary

Table 12 examines potential baseline scenario emission sources for the incremental steam demand. Emission sources listed in Table 8 would also apply to the baseline scenario and project activity.

Table 12. Assessment Boundary Determination

	Potential Emission Sources	Relation to the Project Proponent	Considerations
Baseline Scenario	✓ CO_2, CH_4 and N_2O combustion emissions from the small package boiler that would have been used to generate the incremental steam	Controlled	
	✓ Vented and fugitive CH_4 emissions, as well as CO_2, CH_4 and N_2O combustion emissions, associated with producing the fuel needed for the small boiler	Controlled or Related	✓ These emissions are assumed to be offset by the life-cycle emissions of the natural gas used by the cogeneration unit

Quantifying Emission Reductions

The following Exhibit builds on Case Study #2 by demonstrating the emission estimation methods for the baseline scenario and project activity associated with the incremental steam demand.

EXHIBIT 5.3: Cogeneration With Increased On-Site Energy Consumption – Exceeding Baseline Scenario Capacity

Known information (based on hypothetical data)

- The baseline scenario for the added steam capacity is based on a natural gas-fired package boiler.
- The natural gas composition results in 72.27 wt.% carbon, 33.95×10^6 J/m^3 LHV (911 BTU/scf) and the molecular weight of the gas is 16.84 kg/kgmol. The calculated natural gas CO_2 emission factor was shown in Exhibit 5.1.
- Diesel fuel properties result in the following CO_2 emission factor: 7.402×10^{-11} tonnes CO_2/J (LHV)

Project Emissions

The project emissions are the same as shown for Exhibit 5.2.

The total CO_2 equivalent emissions for the Project are:

428,142 tonnes CO_2 +(21×31.7 tonnes CH_4) + (310×111.5 tonnes N_2O)

= 463,373 tonnes CO_2 Eq./yr

EXHIBIT 5.3 Cogeneration With Increased On-Site Energy Consumption – Exceeding Baseline Scenario Capacity, Continued

Baseline Emissions

Steam Baseline Emissions

Two baseline emission estimates are needed for the steam in this example. The first corresponds to the steam generation at the baseline scenario capacity limits. The second corresponds to the additional steam generated at the GHG reduction project conditions.

CO_2 emissions associated with generating the baseline scenario steam are calculated for the diesel-fired boiler using the 80% thermal efficiency of the boiler and the diesel fuel emission factor:

CO_2 Baseline Emissions for Steam:

$$\mathrm{CO_2}:\ 2.86\times10^{15}\ \text{J steam out}\times\frac{\text{J in (LHV)}}{0.80\ \text{J out}}\times\frac{7.402\times10^{-11}\ \text{tonnes}\ \mathrm{CO_2}}{\text{J (LHV)}}$$
$$=264{,}622\ \text{tonnes}\ \mathrm{CO_2}$$

CH_4 and N_2O baseline emissions associated with the steam are calculated similar to Exhibit 5.2.

CH_4 EF = 6.2×10^{-6} tonnes/m^3
CH_4 Baseline Emissions for Steam =

$$\mathrm{CH_4}:\ 2.86\times10^{15}\ \text{J steam out}\times\frac{\text{J in (LHV)}}{0.8\ \text{J out}}\times\frac{\text{m}^3\ \text{diesel}}{3.62\times10^{10}\ \text{J (LHV)}}$$
$$\times\frac{6.2\times10^{-6}\ \text{tonnes}\ \mathrm{CH_4}}{\text{m}^3\ \text{diesel}}=0.612\ \text{tonnes}\ \mathrm{CH_4}$$

N_2O EF = 3.1×10^{-5} tonnes/m^3
N_2O Baseline Emissions for Steam =

$$\mathrm{N_2O}:\ 2.86\times10^{15}\ \text{J steam out}\times\frac{\text{J in (LHV)}}{0.8\ \text{J out}}\times\frac{\text{m}^3\ \text{diesel}}{3.62\times10^{10}\ \text{J (LHV)}}$$
$$\times\frac{3.1\times10^{-5}\ \text{tonnes}\ \mathrm{N_2O}}{\text{m}^3\ \text{diesel}}=3.06\ \text{tonnes}\ \mathrm{N_2O}$$

The total CO_2 equivalent emissions for the Steam Baseline are:
264,622 tonnes CO_2 +(21×0.612 tonnes CH_4) + (310×3.06 tonnes N_2O)
= 265,583 tonnes CO_2 Eq./yr

EXHIBIT 5.3 Cogeneration With Increased On-Site Energy Consumption – Exceeding Baseline Scenario Capacity, Continued

The baseline scenario for the added steam capacity is based on a natural gas-fired package boiler. Baseline emissions are determined from the natural gas fuel properties and the efficiency of the boiler. Here the calculated natural gas CO_2 emission factor is based on the lower heating value of the fuel.

$$\frac{\text{m}^3\text{ gas}}{33.95\times10^6\text{ J(LHV)}}\times\frac{\text{kgmole gas}}{23.685\text{ m}^3}\times\frac{16.84\text{ kg gas}}{\text{kgmole gas}}\times\frac{0.7227\text{ kg C}}{\text{kg gas}}\times\frac{44\text{ kg CO}_2\text{/lbmole CO}_2}{12\text{ kg C/lbmole C}}$$
$$\times\frac{\text{tonne}}{1000\text{ kg}}=5.55\times10^{-11}\text{ tonnes CO}_2\text{ / J (LHV)}$$

The thermal efficiency of the natural gas-fired boiler is 85%. CO_2 emissions associated with generating the additional steam for a natural gas-fired boiler are:

$$\text{CO}_2:\ (3.81-2.86)\times10^{15}\text{ J steam out}\times\frac{\text{Btu in (LHV)}}{0.85\text{ Btu out}}\times\frac{5.55\times10^{-11}\text{ tonnes CO}_2}{\text{J (LHV)}}$$
$$=62{,}029\text{ tonnes CO}_2$$

CH_4 and N_2O emissions are determined based on industry accepted emission factors for natural gas combustion in a steam boiler (API Compendium Table 4-4a).

CH_4 EF = 1.1×10^{-3} tonnes/10^{12} J (LHV)
CH_4 Baseline Emissions for Additional Steam =

$$\text{CH}_4:\ (3.81-2.86)\times10^{15}\text{ J steam out}\times\frac{\text{Btu in (LHV)}}{0.85\text{ Btu out}}\times\frac{1.1\times10^{-3}\text{ tonnes CH}_4}{10^{12}\text{ J natural gas (LHV)}}$$
$$=1.23\text{ tonnes CH}_4$$

N_2O EF (controlled) = 2.8×10^{-4} tonnes/10^{12} J (LHV)
N_2O Baseline Emissions for Additional Steam =

$$\text{N}_2\text{O}:\ (3.81-2.86)\times10^{15}\text{ J steam out}\times\frac{\text{Btu in (LHV)}}{0.85\text{ Btu out}}\times\frac{2.8\times10^{-4}\text{ tonnes N}_2\text{O}}{10^{12}\text{ J natural gas (LHV)}}$$
$$=0.31\text{ tonnes N}_2\text{O}$$

The total CO_2 equivalent emissions for the Additional Steam are:
62,029 tonnes CO_2 +(21×1.23 tonnes CH_4) + (310×0.31 tonnes N_2O)
= 62,151 tonnes CO_2 Eq./yr

EXHIBIT 5.3 Cogeneration With Increased On-Site Energy Consumption – Exceeding Baseline Scenario Capacity, Continued

Electricity Baseline Emissions

As for Exhibit 5.2, baseline electricity emissions are calculated for the electricity that was imported prior to the GHG reduction project. The emissions associated with the electricity baseline are the same as shown in Exhibit 5.2.

The CO2 equivalent emissions for Electricity Baseline are:

156,875 tonnes CO_2 +(21×2.80 tonnes CH_4) + (310×16.21 tonnes N_2O)

= 161,959 tonnes CO_2 Eq./yr

Displaced Electricity

Likewise, the emissions associated with exporting the electricity not used by the refinery to the grid are the same as shown in Exhibit 5.2.

The total CO_2 equivalent emissions displaced by the exported electricity

= 393,370 tonnes CO_2 +(21×7.02 tonnes CH_4) + (310×40.6 tonnes N_2O)

= 406,103 tonnes CO_2 Eq./yr

Table 13 summarizes the results of the cogeneration case study where the on-site energy consumption increased for the GHG reduction project and exceeded the baseline scenario steam boiler capacity.

Table 13. Summary of Annual Emissions for EXHIBIT 5.3: Cogeneration with Increased On-Site Energy Consumption – Exceeding Baseline Scenario Capacity

		Tonnes CO_2 Eq.
Baseline Scenario	Refinery steam for baseline scenario capacity	265,583
	Refinery steam for incremental capacity	62,151
	Electricity Equivalent Emissions	161,959
	Electricity Grid Displacement	406,103
	Total Baseline Emissions	**895,796**
GHG Reduction Project	**Total Direct Emissions**	**463,373**
Annual Net GHG Reductions		**432,423**

Appendix B-2
Baseline Methodologies for Grid-Displacement GHG Reduction Projects

Appendix B-2. Baseline Methodologies for Grid-Displacement GHG Reduction Projects

Baseline Performance Standard Approach	Description	Advantages	Disadvantages	Applications[13]
Operating Margin Methods (i.e., based on operating existing facilities)				
Average of all plants and facilities	Applies weighted average emission rate across all plants in the defined region. Assumes that any new plant will offset emissions from all plants in the system. Either current year data or an average of a number of years can be used to account for annual variations.	Simple and transparent. Emissions or fuel use data per MW-hr generation is available from EIA (in the US), CAPP (in Canada), or IEA.	Depending on the fuel mix, this may bias the average toward baseload plants or low running cost plants such as hydro or nuclear. Assumes the average is applicable for the "what would have happened in the absence of the GHG reduction project".	Used in the US DOE 1605(b) Program prior to April 2006 updates
Average of all plants and facilities excluding known baseload plants.	Variation on the above approach. Excludes baseload plants because the project is assumed to have no impact on the baseload. Baseload plants have low operating costs and are designed to run at high capacity factors (>70%). These include nuclear, hydro, geothermal, wind, solar, and low cost biomass. For 1605(b) the benchmark emission factors associated with the grid average using this approach is capped.	Simple and transparent. Eliminates bias toward baseload or low operating cost plants. For 1605b) the Energy Information Administration (EIA) will specify the benchmark emission factor.	Requires knowing enough about other plants to determine if they are used for baseload or load-following. Assumes the load-following average is applicable for the "what would have happened in the absence of the project" scenario. Information may not be as readily available as for the average of all plants. May be viewed as bias toward higher emission reduction.	CERUPT US DOE 1605(b)

[13] Refers to programs where the particular approach has been used or is accepted.

Appendix B-2. Baseline Methodologies for Grid-Displacement GHG Reduction Projects, continued

Baseline Performance Standard Approach	Description	Advantages	Disadvantages	Applications[14]
Dispatch decrement or time-of-use marginal analysis	Uses actual dispatch data (or some proxy) to determine the amount of electricity generated each hour (or other time period) of the year.	Makes use of actual generation mix being used in response to increases or decreases in demand and enables developers to calculate marginal emissions rate.	Data is usually kept by the grid operator, is rarely published, and is often considered confidential.	World Back/AIJ/GEF ILUMEX lighting DSM project in Mexico PCF Liepaja landfill gas utilization project in Latvia.
Dispatch or "production cost" modeling	Uses production-costing models to simulate the dispatch system with and without the cogen reduction project.	Provides technical portrayal of the project's impacts. Accuracy is based on model configuration but can be tested through historic data.	Modeling tools may not be readily applicable to oil and natural gas industry facilities. Modeling is labor intensive and costly to use, may be less transparent, and requires specialized expertise. Results are sensitive to fuel price and other assumptions.	

[14] Refers to programs where the particular approach has been used or is accepted.

Appendix B-2. Baseline Methodologies for Grid-Displacement GHG Reduction Projects, continued

Baseline Performance Standard Approach	Description	Advantages	Disadvantages	Applications[15]
Build Margin Methods (i.e., new electricity generating plants)				
Average of recent capacity additions (i.e., built or under construction)	Collects data from all recently built and under-construction plants and calculates an average emission rate based on all or some sub-set of these plants	Information is generally available through regulatory permits or publicly reported fuel/generation information.	Defining "recent" is somewhat arbitrary. The analysis should consider conditions within a grid that may change in the future, such as planned construction of a natural gas pipeline in a region where gas was not previously available. Information specific to new capacity additions may not be publicly available.	IEA, Tellus Institute, Lawrence Berkley National Laboratory, US EPA, US DOE.
Judgment/proxy plant	One type of plant is chosen based on technical judgment as the type of plant that would have been built in the absence of the project.	Useful for grids that are dominated by one type of plant or fuel.	Difficult to justify one choice for a region where there is a mixture of plants or fuels being built.	
Other Methods				
Combined margin method	For the first crediting period both operating and build margin methods are used. Where possible, the average of all plants and facilities, excluding known baseload plants, is used for the operating margin calculations. The average recent capacity addition is used for the build margin. For subsequent crediting periods, only the build margin is used	Recognizes that all projects impact the operating margin, then as investors react to the presence of the project, the build margin is affected.	Difficulties associated with obtaining the necessary information for the operating margin and build margin approaches apply here.	CDM Approved baseline methodology AM0015 and Approved consolidated baseline methodology ACM0002, Oregon Climate Trust, OEAC, and PCF.

[15] Refers to programs where the particular approach has been used or is accepted.

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International Petroleum Industry Environmental Conservation Association