Prepared by URS Corporation

Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects

Part III: Flare Reduction Project Family

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IPIECA

energy API

International Petroleum Industry Environmental Conservation Association

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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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[1] International Petroleum Industry Environmental Conservation Association (IPIECA) and American Petroleum Institute (API). *Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects*, March 2007.

[2] IPIECA and API. *Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects*, Part II: Carbon Capture and Geological Storage Emission Reduction Project Family, June 2007.

Attachments

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SECTION 7. FLARE REDUCTION PROJECT FAMILY

7.1 Overview

This section is a continuation of the *Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects* (IPIECA and API, 2007), referred to as the General Project Guidelines. It is the third greenhouse gas (GHG) reduction "project family" in an ongoing process of developing guidelines for project activities of interest to the oil and natural gas industry.

This project family addresses GHG emission reductions associated with reduced flaring activities from oil and natural gas operations. Guidelines are provided following the framework presented in Section 2 of the General Project Guidelines (IPIECA and API, 2007). The focus is on specific technical considerations and aspects rather than policy considerations. Case studies of three potential applications are provided in Attachment 1.

7.2 Introduction

Flares are important safety and emission control devices in the oil and natural gas industry. Flaring, which combusts hydrocarbon gas streams, is necessary to prevent uncontrolled releases to the atmosphere and to relieve dangerous equipment overpressure conditions. Flaring is generally preferable, in terms of both safety and GHG emission considerations, to venting, i.e., the release of uncombusted gas to the atmosphere.

The most recent data reported by the Energy Information Administration (EIA) indicate that approximately 97×10^9 cubic meters (m^3) [3.4×10^{12} cubic feet (ft^3)] of natural gas are flared annually, or about 2.7 percent of all natural gas production worldwide.[3] This flared gas is equivalent to almost 15 percent of the annual natural gas consumption in the U.S. The EIA also estimates that the U.S. flares or vents only about 0.55 percent of its gross natural gas production and about 3.8 percent of the total amount of natural gas flared and vented worldwide. As shown in Table 7-1, the top 20 countries accounted for the flaring of 86.1 billion cubic meters, which is over 88 percent of the total flaring in the world in 2006.[3]

Flared gas is not tracked separately from vented gas within the U.S. oil and natural gas production sector. The states voluntarily report monthly combined volumes of natural gas vented and flared using Form EIA-895A. EIA then reports all of this as flared gas in compiling its annual GHG inventories. Venting volumes are not included in the data for other countries listed in Table 7-1.

[3] Energy Information Administration, August 22, 2008. http://www.eia.doe.gov/international/RecentNaturalGasProductionAllTypes.xls

Table 7-1. EIA Top Twenty Gas Flaring Countries for 2006

Rank	Country	2006 Gross Natural Gas Production 10^9 cubic meters	2006 Flared Volume, 10^9 cubic meters	Approximate CO_2 Emissions from Flaring (10^6 tonnes /year)*
1	Nigeria	61.80	22.3	53.2
2	Iran	168.50	12.5	29.8
3	Iraq	11.90	7.7	18.4
4	Angola	9.40	6.5	15.5
5	Indonesia	83.67	4.4	10.5
6	United States**	665.64	3.7	8.8
7	Algeria	193.60	3.3	7.9
8	Venezuela	53.00	3.2	7.6
9	Qatar	62.00	3.1	7.4
10	Mexico	51.81	2.5	6.0
11	Congo (Brazzaville)	7.50	2.2	5.2
12	Canada	220.43	2.1	5.0
13	Cameroon	1.96	1.9	4.6
14	Malaysia	82.60	1.9	4.5
15	Brazil	17.71	1.9	4.4
16	United Kingdom	86.36	1.5	3.7
17	Oman	29.78	1.4	3.4
18	Germany	21.00	1.4	3.3
19	Trinidad and Tobago	40.13	1.4	3.2
20	Equatorial Guinea	3.80	1.2	2.9
Total for the Top 20 Countries		**1,873**	**86.1**	**205.4**
Global Total		**3,618**	**97.1**	**231.4**

* For comparison purposes, CO_2 emissions have been estimated using the API *Compendium* default natural gas higher heating value of 1235 Btu/ft^3 (raw, unprocessed gas) (*Compendium* Table 3-8) and the emission factor of 0.0547 tonnes CO_2/MMBtu for flared natural gas (*Compendium* Table 4-3).
** Data for the United States includes an undifferentiated volume of vented gas. Many countries other than the U.S. (e.g., Indonesia and Venezuela) are known to vent significant volumes of gas, but these vented gas volumes are not included in the above table.
Source: Energy Information Administration, "World Natural Gas Production, Most Recent Estimates, 2006," August 22, 2008.

The annual 2006 GHG inventory report compiled by EIA for the U.S. attributes 7.8 million tonnes[4] of CO_2 emissions to "natural gas flaring," which is defined as gas disposed of by burning in flares, usually at the production sites or at gas processing plants (EIA, 2008). This accounts for approximately 87% of the total flaring (and venting) emissions listed for the U.S. in Table 7 - 1, providing a strong indication that flaring and venting at oil and gas production sites is the dominant type of flaring in the U.S.

As a comparison to the EIA data, Table 7-2 presents data on the top 20 flaring countries as reported by the World Bank based on satellite data.

[4] tonnes = 1000 kg

Table 7-2. World Bank Estimated Top Twenty Gas Flaring Countries

Rank*	Country	Flared Volume, 10^9 cubic meters			Approximate CO_2 Emissions from Flaring (10^6 tonnes/year) for 2006**
		2005	2006	2007	
1	Russia	55.2	48.8	50.0	116.4
2	Nigeria	21.3	19.3	16.8	46.0
3	Iran	1.3	12.1	10.6	28.9
4	Iraq	7.1	7.4	7.0	17.7
5	Kazakhstan	5.8	6.0	5.3	14.3
6	Algeria	5.2	6.2	5.2	14.8
7	Libya	4.4	4.3	3.7	10.3
8	Angola	4.6	4.0	3.5	9.5
9	Saudi Arabia	3.0	3.3	3.4	7.9
10	Qatar	2.7	2.8	2.9	6.7
11	China	2.8	2.8	2.5	6.7
12	Indonesia	2.7	3.0	2.4	7.2
13	Kuwait	2.5	2.5	2.1	6.0
14	Venezuela	2.1	2.0	2.1	4.8
15	Uzbekistan	2.5	2.8	2.0	6.7
16	United States	2.0	1.9	1.9	4.5
17	Oman	2.5	2.2	1.9	5.2
18	Mexico	0.9	1.2	1.7	2.9
19	Malaysia	1.7	1.8	1.7	4.3
20	Gabon	2.2	1.9	1.6	4.5
Total for the Top 20 Countries		**142**	**136**	**128**	**325.2**
Global Flaring Level		**162**	**157**	**147**	**374.5**

* Rankings shown are based on 2007 data.
** CO_2 emissions have been estimated using the API *Compendium* default natural gas higher heating value of 1235 Btu/ft^3 (raw, unprocessed gas) (*Compendium* Table 3-8) and the emission factor of 0.0547 tonnes CO_2/MMBtu for flared natural gas (*Compendium* Table 4-3).
Source: http://go.worldbank.org/G2OAW2DKZ0

The World Bank's worldwide flared gas estimate for 2006 is 60×10^9 m^3 (2.1×10^{12} ft^3) higher than that provided by EIA, resulting in an additional 143×10^6 tonnes of CO_2 emissions. The World Bank's flare estimate for the U.S. based on satellite data is only about one-half of the corresponding EIA estimate. The likely explanation for this discrepancy is that the EIA data for the U.S. are known to include vented volumes, which would not be detected by the satellite measurements. The countries included in the top 20 also differ between the two lists, indicating some important data gaps in the EIA information.

7.3 Project Definition

Flare reduction projects impact the natural gas and oil value chain. As illustrated in Figure 7-1, this chain consists of production and processing; refining; transport, storage, and distribution.

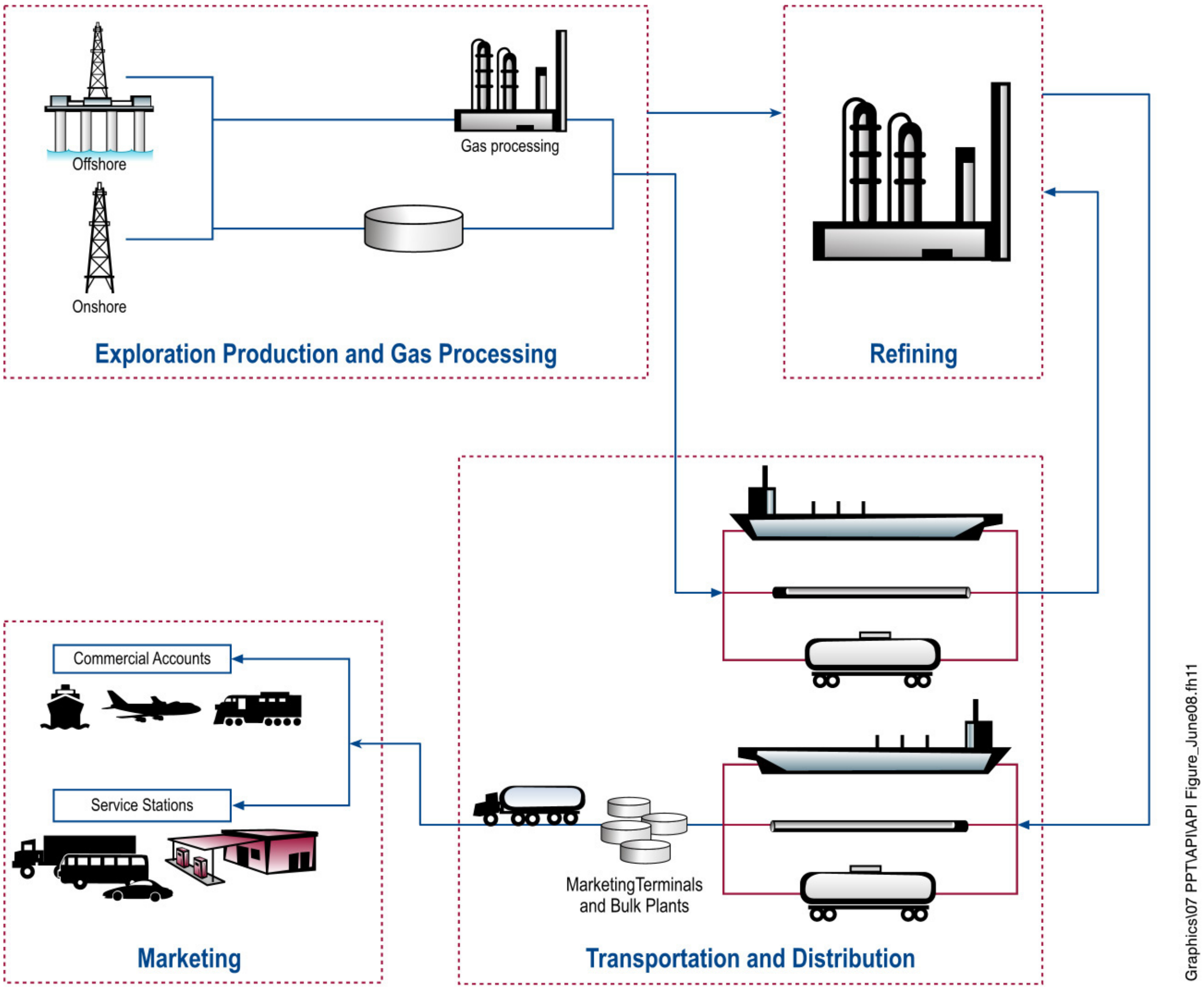

Figure 7-1. Natural Gas and Oil Industry Value Chain

The best opportunities for flare reduction projects are in the oil production and refining sectors of the industry. However, flaring at refineries is generally limited and, in developed countries, closely regulated. Thus, this guidance document focuses on upstream operations. Opportunities to eliminate continuous flaring of associated gas at oil production sites in some parts of the world have enabled several projects to be implemented that have achieved very large GHG emission reductions. For example, eight flare reduction projects at oil production operations have been registered to date for carbon credit generation under the Clean Development Mechanism (CDM) provisions of the Kyoto Protocol.[5]

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[5] http://cdm.unfccc.int/Projects/projsearch.html. Six projects have been registered under methodology AM0009; two have been registered under methodology AM0037.

Notwithstanding the fact that larger flare reduction projects are probably of greatest interest from the perspective of generating carbon credits, companies may also wish to consider smaller projects for other reasons, such as utilization of an otherwise wasted energy source or to comply with an internal policy to decrease the carbon footprint of a company or business unit. Two flare reduction projects of this type have been registered for CDM carbon credit generation at petroleum refineries.[6] In certain cases, utilization of waste gas rather than flaring can represent an economically attractive option, even without consideration of potential carbon credits. Accordingly, these types of projects are also addressed in this section.

Venting also occurs primarily in the production sector, because this activity is regulated to low levels or eliminated at most U.S. refineries. Although, as noted above, separate flaring and venting statistics are not maintained by the U.S. federal government, flaring probably is used much more commonly in this country than venting. Flaring of gas is preferable to venting from the standpoint of the GHG emissions perspective given that the global warming potential of methane (CH_4) is 21 times that for CO_2.

7.3.1 Extraction and Production

The production of crude oil may also produce natural gas, referred to as associated gas.[7] If the crude is produced in an area that lacks either a natural gas infrastructure or a market for the natural gas, the associated gas may be vented or flared.

Potential types of flare reduction projects in the upstream sector include measures to avoid routine flaring of associated gas, reduction in venting of associated gas, or reduction in non-routine gas flaring. Greenhouse gas emission reductions result when associated gas is captured for energy use, reducing CH_4 emissions where the gas was previously vented or reducing CO_2 emissions where other fuel streams are replaced with the previously flared gas. A flare reduction project may also decrease GHG emissions through the capture and underground injection of the associated gas for long-term isolation from the atmosphere or for enhanced oil recovery. A number of projects involving re-injection and recovery of previously flared or vented associated gas streams have been implemented in the last several years. Some of these projects have included subsequent use of the recovered gas as feedstock for gas processing plants or as fuel for power plants. Several such projects have resulted in the award of carbon credits under the CDM program.

7.3.2 Processing

Flares are used at natural gas processing facilities to handle emergency releases of gas and to ensure safe plant shut-downs and start-ups. Gas processing flares are also used as emission control devices to eliminate venting of waste gas streams from sweetening and dehydration equipment. In this context, flares are an integral part of a gas plant's operation and are designed

[6] http://cdm.unfccc.int/Projects/projsearch.html. Methodology AMS-III.P.

[7] Associated gas is defined as natural gas that is found in association with crude oil, either dissolved in the oil or as a cap of free gas above the oil.

to be used routinely. Introduction of a flare to combust a gas stream that would otherwise be vented to the atmosphere could be a candidate project for reducing GHG emissions by virtue of the lower global warming potential of CO_2 versus that of CH_4.

7.3.3 Refining

Flares are necessary for the safe disposal of gas streams generated within oil refineries. The refinery blowdown system gathers relief gas from various refinery process units; separates liquid from vapors; recovers any condensable oil and water; and recovers gases for use in the refinery fuel gas system. When the heating value of a recovered gas stream is insufficient to use as refinery fuel or when, as sometimes occurs during upsets, the volume of gas exceeds the refinery's capacity for its recovery and use as a fuel, the blowdown system routes the vapors to the flare (BAAQMD, 2005). The units most likely to contribute to flaring are the crude unit, the fluid catalytic cracking unit (FCCU), and the coker (RTI International, 2007).

Opportunities for reduced flaring at refineries include:

- Using flare gas recovery systems for routine venting and planned shutdowns;
- Improving operator training and better documentation procedures, highlighting environmental impacts, and allowing additional time for process unit start-ups and shut-downs; and
- Reducing flaring among ethylene producers by recycling off-spec streams to furnace feed, augmenting the plant's steam capacity, or using a ground flare to handle off-spec and start-up loads (Industry Professionals for Clean Air, 2005).

As mentioned previously, two projects have been registered by the CDM Executive Board for flare reduction projects at refineries. In addition, an approved methodology for quantifying the baseline and project emissions from such projects also exists (AM0055).

7.3.4 Transport, Storage, and Distribution

For natural gas transport, storage, and distribution facilities, flares may be used for emergency releases of natural gas and to handle blowdown volumes associated with maintenance of large compressor stations, storage facilities, or metering and pressure regulating stations. Since such flares are used primarily for temporary service under certain conditions, the corresponding amounts of potential emission reductions are generally smaller than for an industry sector like Extraction and Production that uses flares continuously.

7.4 Baseline Scenarios

Candidate baseline scenarios for flare reduction projects represent operations or conditions that would have occurred in the absence of such projects. A list of potential baseline scenarios for the most probable flare reduction projects (i.e., at oil production operations) is provided in Table 7-3.

Table 7-3. Candidate Baseline Conditions for Probable Flare Reduction Projects at Oil Production Facilities

(Bold italic text indicates the project activity)

Probable Project Elements	Candidate Baseline Scenarios
Gas recovery options for flare gas reduction: • Natural gas supply for on-site energy use • Gas recovery and transport to supply local energy markets • Gas recovery for LNG export markets or international pipelining to targeted domestic or international markets • Gas separation and liquefied petroleum gas (LPG) recovery for markets, possibly in conjunction with re-injection of the stripped (dry) gas into the petroleum reservoir.	• Gas is vented to the atmosphere • Gas is flared • ***Gas is recovered for use as a fuel***
Gas compression and re-injection into an oil or gas reservoir[8]	• Gas is vented to the atmosphere • Gas is flared • ***Gas is re-injected for storage*** *(differentiated from gas recovery and use)*
Gas lift for improved oil recovery[8]	• Gas is vented to the atmosphere • Gas is flared • ***Gas is re-injected into the reservoir for improved oil recovery***

7.5 Emission Sources and Assessment Boundary

As discussed in Section 2.5 of the General Project Guidelines (IPIECA and API, 2006), the assessment boundary encompasses all project and baseline emission sources that are controlled by the project proponent, that are related to the project, or that are affected by the flare reduction project. The assessment boundary can vary even among projects with similar emission reduction approaches, depending on which sources are controlled or have been invested in by the project proponent. Different emission sources that may be associated with a flare reduction project are summarized in Table 7-4.

[8] Note that no baseline methodology has yet been approved for gas lift projects under the CDM program.

Table 7-4. Summary of Potential GHG Emission Sources

Stage in Gas Chain	Emission Source	Emission Type*	Controlled, Related or Affected	GHG Species
Extraction and Production	Emissions from stationary combustion sources associated with the extraction of crude oil	Combustion	Controlled	Primarily CO_2; CH_4 and N_2O to lesser degree
	Flaring of associated gas	Combustion	Controlled	
	Consumption of other fuels in place of the associated gas	Combustion	Controlled	Primarily CO_2; CH_4 and N_2O to lesser degree
	Venting of associated gas	Vented	Controlled	CH_4; potentially some CO_2
	Fugitive emissions from equipment associated with the extraction of crude oil	Fugitive	Controlled	CH_4; potentially some CO_2
	Process emissions from gas handling operations, maintenance or emergency releases of gas associated with the extraction of crude oil	Vented	Controlled	CH_4; potentially some CO_2
	Mobile source energy consumption	Combustion	Controlled	Primarily CO_2; CH_4 and N_2O to lesser degree
	Purchased electricity	Indirect	Related	Primarily CO_2; CH_4 and N_2O to lesser degree
Gas Recovery	Emissions from stationary combustion sources associated with the separation of associated gas from crude oil	Combustion	Controlled	Primarily CO_2; CH_4 and N_2O to lesser degree
	Fugitive emissions from gas handling equipment associated with the separation of associated gas from crude oil	Fugitive	Controlled	CH_4; potentially some CO_2
	Process emissions from gas handling operations, maintenance or emergency releases of gas	Vented	Controlled	CH_4; potentially some CO_2
	Mobile source energy consumption	Combustion	Controlled	Primarily CO_2; CH_4 and N_2O to lesser degree
	Purchased electricity	Indirect	Related	Primarily CO_2; CH_4 and N_2O to lesser degree
Gas Processing, Storage, Transport, and Distribution	Emissions from stationary combustion sources associated with gas processing and transport	Combustion	Controlled	Primarily CO_2; CH_4 and N_2O to lesser degree

Table 7-4. Summary of Potential GHG Emission Sources, continued

Stage in Gas Chain	Emission Source	Emission Type*	Controlled, Related or Affected	GHG Species
Gas Processing, Storage, Transport, and Distribution, continued	Fugitive emissions from gas handling equipment associated with gas processing, intermediate storage, and transport	Fugitive	Controlled	CH_4; potentially some CO_2
	Process emissions from gas handling operations, intermediate storage, maintenance or emergency releases of gas associated with gas processing and transport	Vented	Controlled	CH_4; potentially CO_2
	Fugitive emissions Loading/unloading of LNG or LPG	Fugitive	Controlled	CH_4
	Mobile source energy consumption	Combustion	Controlled	Primarily CO_2; CH_4 and N_2O to lesser degree
	Purchased electricity	Indirect	Related	Primarily CO_2; CH_4 and N_2O to lesser degree
End-Use	Combustion emissions associated with re-injection of the gas for disposal or for enhanced oil recovery	Combustion	Controlled	Primarily CO_2; CH_4 and N_2O to lesser degree
	Combustion emissions associated with end-use of associated gas	Combustion	Potentially Related or Affected	Primarily CO_2; CH_4 and N_2O to lesser degree
	Fugitive emissions from gas handling equipment associated with end use operations	Fugitive	Potentially Related or Affected	CH_4; potentially some CO_2
	Process emissions from gas handling equipment associated with end use operations	Vented	Potentially Related or Affected	CH_4; potentially CO_2

* Indirect emissions are "Related" emission sources. All others may be "Controlled" or "Related" depending on which sources the project proponent controls.

The assessment boundary may include combustion, venting, and fugitive emissions associated with oil and gas extraction, as well as capture and processing of the previously flared or vented gas. Emissions from transport and distribution infrastructure facilities that are part of the project investment would also be included in the assessment boundary, e.g., compression of recovered gas transported via pipeline to receiving facilities or points of sale, fugitive emissions from pipeline components, and venting of pipelines during maintenance activities.

A few projects that use previously flared gas as a feedstock for production of chemicals have been successfully registered under the CDM program. However, emissions related to the combustion of recovered natural gas at off-site locations generally have not been included within the project boundary for crediting purposes (for example, see CDM Approved Methodology 0009). Although conceptually it should be possible to include emissions associated with combustion of recovered gas from a flare reduction project for electric power generation, no methodology for doing so has yet been approved by the CDM Executive Board. Thus, obtaining CDM credits for use of previously-flared gas to replace a more carbon-intensive fuel at a power plant would require development and approval of a new methodology.[9]

7.6 Project Emission Reductions

Emissions reductions are the net difference between the baseline emissions and project emissions. Emissions reductions are typically reported in terms of carbon dioxide equivalents (CO_2e), in which all of the GHG species are converted to an equivalent basis by weighting the mass emission contribution of each species by its global warming potential (GWP) relative to that of CO_2. For example, the GWP for CH_4 is 21 times higher than that for CO_2. The calculation of potential emission reductions for different categories of flare reduction projects is demonstrated by means of three examples presented in Attachment 1.

In quantifying project emission reductions, baseline emissions should reflect emission sources associated with each step of the gas chain that would have occurred in the absence of the project. This can be expressed by the following general equation:

$$\text{Baseline Emissions} = CMB_1 + VENT_1 + FUG_1 + IND_1 \qquad \text{(Equation 1)}$$

where:

CMB_1 = Direct combustion emissions that would have occurred in the baseline scenario;
$VENT_1$ = Vented GHG emissions from baseline operations or equipment that would have occurred in the baseline scenario;
FUG_1 = Fugitive GHG emissions from baseline equipment that would have occurred in the baseline scenario; and
IND_1 = Indirect emissions that would have occurred due to electricity purchased from outside sources in the baseline scenario.

Similarly, project emissions can be expressed as:

$$\text{Project Emissions} = CMB_2 + VENT_2 + FUG_2 + IND_2 \qquad \text{(Equation 2)}$$

where CMB_2, $VENT_2$, FUG_2, and IND_2 refer to combustion, vented, fugitive, and indirect emissions, respectively, associated with the project being considered.

7.7 Monitoring

Monitoring for a flare reduction project is necessary to establish and document the resulting GHG emissions reduction. Monitoring refers to the continuous or periodic measurement and/or

[9] One possible approach would be to propose a combination of two previously approved methodologies, such as AM0009 for flare reduction projects and ACM0011 for fuel switching projects. Detailed information on all approved methodologies, as well as successful and unsuccessful attempts to modify them can be found on the main CDM website at http://cdm.unfccc.int/index.html.

recording of parameter values needed to quantify actual emissions and emission reductions from the project relative to the baseline scenario.

Monitoring for a flare reduction project may include the following:

- Measurement of the composition and quantity of associated gas recovered;
- Estimation of emissions associated with operations or processes along the gas value chain;
- Measurement of the composition and quantity of other fuels replaced by associated gas as part of a project activity; and
- Measurement of the quantity of associated gas or gas products consumed or transferred to other parties.

7.8 Reporting and Documentation

Section 2 of the General Project Guidelines provides the following high-level objectives for emission reduction reporting and documentation:

- Provide sufficient transparency to enable the intended audience to make an informed decision on the validity of the emission reductions;
- Provide a plausible and transparent accounting of the project decisions and assumptions; and
- Maintain supporting documentation.

These general principles also apply to reporting in support of emission reductions from flare reduction projects.

7.9 Verification/Assurance

Verification involves an assessment to provide confirmation that the project and its associated emission reductions have not been materially misstated. This largely entails evaluating the implementation of the approved monitoring methodology against reported project and baseline emissions. On the basis of the verification activities, a conclusion is reached as to whether the data within the emissions report contain any omissions, misrepresentation, or errors that would lead to a material misstatement of the reported information. As stated in Section 2 of the General Project Guidelines (IPIECA and API, 2006), verification should focus on quality assurance with the objective of improving the overall reliability of the reported emission reductions. Verification should provide the user with assurance that the reported emission reductions are credible.

7.10 Technical Considerations

Some technical issues and challenges associated with implementing a flare reduction project may warrant consideration. These include, but are not limited to, the following elements:

- Gas re-injection technical considerations:
  - Reservoir suitability for gas re-injection and long-term storage;
  - Possible detrimental impacts on oil production due to gas re-injection;

  - Use of re-injection for gas lift purposes;
  - Fuel usage requirements and GHG emissions (combustion, vented and fugitive) from equipment used to re-inject and recover CO_2 from produced oil and comparison of these emissions relative to those associated with the flaring option;
- Limitations to on-site energy needs, limitations in gas-liquid fraction, etc.; and
- Estimated remaining life of the producing reservoir.

7.11 Policy Considerations

The following policy issues should be noted and may impact the ability to receive credit for a flare reduction project:

- Government regulations and policies to prohibit routine gas venting and/or flaring appear to be gaining increased support in certain countries and may affect whether continued flaring can be considered a viable baseline scenario in the future;
- Potential barriers that would prevent or reduce the likelihood of the project or other baseline scenarios could include situations such as:
  - Complex commercial situation for marketing associated gas due to multiple stakeholder involvement in joint venture partnerships, third party operators, government, infrastructure owners, etc.;
  - Undeveloped domestic market for gas and gas products;
  - Lack of infrastructure integration between producers and consumers of gas and/or electricity;
  - Issues of ownership rights to associated gas; and
  - Limitations in access to capital.

7.12 Project Examples

Attachment 1 provides three examples of flare reduction projects to illustrate the steps of project definition; baseline scenario determination; project assessment boundary and emission source determination; emission reduction calculation; and assessment of monitoring methods. Two of these hypothetical examples are developed from the types of activities that petroleum companies are conducting to achieve large-scale GHG reductions, and are similar in nature and scope to actual projects that have applied for CDM certification. The third example is a smaller project that could be implemented to stop flaring of associated gas in favor of on-site utilization as a fuel for electricity generation and recovery of an otherwise wasted energy source. The approaches, emission factors, and assumptions used in these examples reflect a fictional project proponent decision process based on the defined conditions, and do not apply universally to all situations.

Attachment 2 provides a brief summary of the baseline methodologies that have been proposed and approved for flare reduction projects that have sought certification and award of carbon credits under the CDM program.

7.12.1 Associated Gas Recovery for Processing and Sales

In this example, an oil production operation has historically flared associated gas due to lack of infrastructure and a market for the natural gas. With changing market conditions in the region, the operator plans to install facilities at the existing production site to recover the previously flared associated gas and to construct a new processing plant to treat the recovered gas and marketable liquids for sale to local and international markets. The remaining dry gas will be sent by pipeline to the local gas distribution system.

7.12.2 Associated Gas Recovery for Re-injection and Utilization

The project activity in this example involves recovery, processing, and utilization of associated gas that would otherwise be flared, and re-injection of a fraction of the produced gas in an oil production field. Currently, oil from five regional oil fields is sent to an oil and gas processing plant (OGPP), where the associated gas is separated and processed. Two relatively small fractions of the processed gas are used to provide energy for operation of the OGPP and exported by pipeline to an LNG plant to provide supplemental fuel. However, a large majority of the gas currently is flared. The proposed project would not affect the first two gas streams, but would involve recovery of the previously flared gas stream for use as the primary fuel for a new combined cycle gas turbine power plant. In addition, a portion of the recovered gas would be sent to the oil production fields and re-injected for long-term storage.

7.12.3 Utilizing a Small Flare Gas Stream for On-Site Power Generation

A relatively small associated gas stream at an onshore oil production field is recovered and used to fuel new internal combustion engine drivers for generators to provide electric power for on-site use. The new engines replace older, less-efficient engines that used produced crude oil as fuel, and are specifically designed to accommodate the variability in composition and energy content that is typical of some associated gas. Such a project may be implemented less for the generation of carbon credits than as part of the operating company's efforts to reduce the carbon footprint of its facilities, and to exploit an otherwise wasted energy source for production of energy needed to support local operations.

7.13 Conclusions

Flare reduction projects at oil production sites can provide significant opportunities for generation of carbon credits, and several such projects have been certified by United Nations Framework Convention on Climate Change (UNFCCC) under the CDM provisions of the Kyoto Protocol. In addition, a smaller number of projects to capture and blend previously flared gas streams in refineries and gas processing facilities have been undertaken. However, available infrastructure and stringent air quality regulations in the U.S. and other developed countries minimize the amount of gas being flared and vented at gas plants and refineries. As a result, projects to reduce GHG emissions at these facilities are less promising in terms of credit generation potential.

It is worth noting that there is a growing movement in many of the largest flaring countries to ban routine flaring and venting at oil production sites. To the extent that such prohibitions are adopted and enforced, they would lessen the probability that continued flaring could be demonstrated to be "business as usual", i.e., a viable baseline scenario against which carbon reductions can be measured for credit generation.

7.14 References

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ATTACHMENTS TO SECTION 7: FLARE REDUCTION PROJECT FAMILY[10]

[10] All of the project case studies in this attachment are hypothetical examples developed from the types of flare reduction activities that petroleum companies are conducting to demonstrate the application of guidelines for quantifying GHG reductions. The approaches, emission factors, and assumptions used in these examples reflect the decision process by a fictional project proponent based on the defined conditions, and do not universally apply in all situations.

ATTACHMENT 1
FLARE REDUCTION PROJECT CASE STUDY #1: GAS RECOVERY FOR LOCAL AND INTERNATIONAL SALE

Project Definition

Description of the Project Activity[11]

In this example, an oil production operation has historically flared associated gas due to lack of infrastructure and a market for the natural gas. With changing market conditions in the region, the operator plans to install facilities at the existing production site to recover the previously flared associated gas and to construct a new processing plant to treat the recovered gas and separate out marketable liquids for sale to local and international markets. The project will include a pipeline to allow the remaining dry gas to be sent to a newly constructed local gas distribution system.

A schematic diagram of the project activity is shown in Figure 7-2.

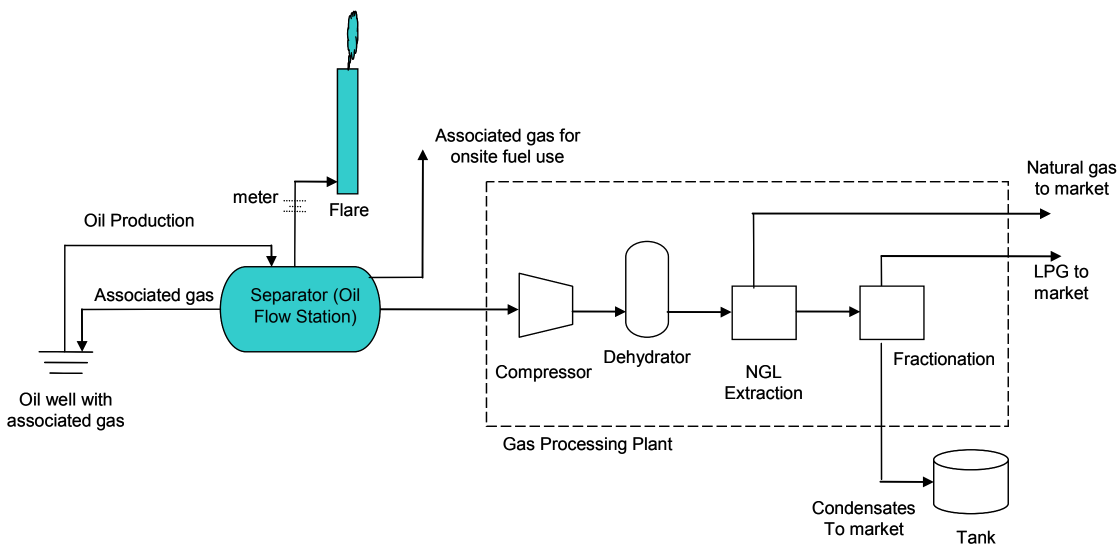

Figure 7-2. Project Illustration for Case Study #1 - Flare Gas Recovery in a Gas Processing Plant

This project involves the following operational information.

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[11] This case study is a variation of the Clean Development Mechanism (CDM) Project Design Document (PDD) and baseline methodology associated with the Ovade Ogharefe Gas Capture Processing Project in Nigeria. In this project example, the schematic diagram of the project, the equations to quantify the baseline and project emissions, the gas volumes, and emission factors are modified from the CDM-PDD to conform to the approaches in Section 2 of the General Project Guidelines (IPIECA and API, 2007).

Before the project:

The oil and associated gas are produced at wells in the oil field, and transported by gathering pipelines to an existing oil flow station. At the flow station, the associated gas is separated from the oil and most of the gas is flared. A fraction of the produced gas, amounting to 20 million standard cubic feet per day (20×10^6 scfd; 5.67×10^5 scm/day), is used to meet the on-site fuel requirements of the oil production facilities. The oil is shipped by pipeline to market. A total of 130×10^6 scfd (3.68×10^6 scm/day) of gas is flared at the oil flow station. The flared gas is untreated (wet) and contains NGLs and condensates, as well as CH_4.

What the project will change:

The project activity encompasses the recovery of the associated gas consisting of the connection of the gas from the oil flow station; the construction of a gas processing plant for the production of dry gas, LPG and condensates; and the construction of a pipeline to deliver natural gas to a gas distribution system. Processing of the gas will consist of gas conditioning, compression, liquid extraction, fractionation, storage, and distribution to sales points. On-site usage of associated gas at the oil production facilities is unchanged from the 20×10^6 scfd (5.67×10^5 scm/day) used before the project.

Recovered LPG and condensates from the gas stream will be sold. A third party will construct transport, storage, and loading facilities to move these liquids from the gas processing plant to the market.

Energy required for processing and transport of the recovered associated gas will be generated by using 10% (13×10^6 scfd or 3.68×10^5 scm/day) of the treated recovered gas.

Newly constructed pipelines with lengths of 1 km (0.62 miles) and 2.5 km (1.55 miles), respectively, will transport the untreated gas from the oil flow station to the gas processing facility, and the condensates extracted from the gas stream to an oil storage area. A third new pipeline (2 km or 1.24 miles in length) will be constructed to transport the processed natural gas to the natural gas distribution system. The project proponent will operate these pipelines.

The carbon content of the flared (wet) gas is 0.63 kg carbon/m^3 (0.0393 lb C/scf, 2.31 kg CO_2e/cubic meter, or 0.144 lb CO_2e /scf). The carbon content of the treated (dry) gas is 0.61 kg carbon/m^3 (0.00381 lb C/scf, 2.22 kg CO_2e /cubic meter, or 0.139 lb CO_2e /scf of dry gas).

Other project information:

The products (dry gas, LPG, and condensate) are likely to substitute in the market for the same type of fuels or fuels with higher carbon content per unit of energy. The substitution of fuels due to the project activity is unlikely to lead to an increase in fuel consumption in the respective market.

Common industry practice in the project area is to flare associated gas not used on-site.

The project will reduce flaring by more than 98%, with a small amount of continued flaring to provide relief during process upsets.

Baseline Scenario Determination

Baseline Candidates Considered

Candidate baseline scenarios represent plausible conditions that may have occurred in the absence of the project. Candidates for this example project include:

1. Continuation of current practices, i.e., associated gas continues to be flared and gas market demand is supplied through other means;
2. Associated gas is vented to the atmosphere;
3. Gas is re-injected for disposal or utilized for gas lift;
4. Gas is recovered for fuel use on-site;
5. Gas is recovered and transported for sale to local markets (included in the project activity);
6. Gas liquids are recovered for export to regional markets (included in the project activity); and
7. Gas is recovered for LNG export to global markets.

Baseline Scenario

Table 7-5 applies some common tests or screening criteria to assist in a relative assessment of candidate baseline scenarios.

Table 7-5. Case Study #1 Baseline Scenarios Assessment

Baseline Scenario Alternatives	Investment Ranking	Technology	Policy/ Regulatory	Benchmarking
Candidate 1: Continuation of current activities: Associated gas is flared	No additional costs	No additional technology requirements	May be prohibited by local regulations at some future time	Common practice in project region[12]
Candidate 2: Gas is vented to the atmosphere	No additional costs	Existing technologies	May be prohibited by local regulations	Generally avoided due to safety risk
Candidate 3: Gas is re-injected for disposal or utilized for gas lift	Moderate costs for recovering and re-injecting gas	Existing technologies	May be impractical in some locations	Commercially viable in some regions
Candidate 4: Gas is recovered for fuel use on-site	Moderate cost for recovering and processing the gas	Existing technologies	Consistent with current applicable laws and regulations	Commercial in some regions However, supply of associated gas far exceeds on-site demand

[12] Depending on the circumstances of the project, the region or geographic area may be narrow (e.g., a specific area within a nation or state), or broad (e.g., an international region or global area).

Table 7-5. Case Study #1 Baseline Scenarios Assessment, continued

Baseline Scenario Alternatives	Investment Ranking	Technology	Policy/ Regulatory	Benchmarking
Candidate 5 *(Project activity)*: Gas is recovered and transported for sale to local markets	Moderate to high costs for recovering, processing, and transporting gas	Existing technologies	Consistent with current applicable laws and regulations	Commercially viable in some regions
Candidate 6 *(Project activity)*: Gas liquids are recovered for export to international markets (could occur together with Candidates 5 and/or 7)	Moderate to high costs for recovering and transporting liquids	Existing technologies	Consistent with current applicable laws and regulations	Commercially viable in some regions
Candidate 7: Condensates are recovered and sent back to oil storage facilities (could occur together with Candidates 5 or 6)	Moderate to high costs for recovering, processing, and transporting condensates	Existing technologies	Consistent with current applicable laws and regulations	Commercial in some regions

A comparison of the baseline candidates presented above shows the following:

- Candidate 1 has been utilized since the field began production. The low monetary value of the gas in the domestic market and the costs associated with processing and transporting the gas, LPGs, and condensates to market have historically caused those options to be economically infeasible from the field operator's perspective.
- Candidate 2 can pose a significant safety risk if the volume of gas vented is large, and may be prohibited by host country policies and/or regulations. This candidate is assumed not to be feasible for this example.
- Candidate 3 requires oil production reservoir characteristics that are compatible with storage of the gas or enhanced oil recovery. This candidate is assumed not to be feasible for this example.
- Candidate 4 may have limited application if the local fuel requirements for the production operations are less than the amount of associated gas available, as is the case in this example.
- Candidates 5 and 6 *(the Project activity)*, and 7 are fairly comparable in terms of additional costs for gas recovery, processing, and transport. These candidate scenarios utilize existing technologies and are commercially viable in some regions.

As a result of this analysis, Candidate 1, representing the continuation of current activities, is selected as the most probable baseline scenario.[13] The basic components of the baseline operations are illustrated in Figure 7-3.

[13] Baseline candidates and the analysis presented here are for illustrative purposes only. Actual project activities will require an assessment of the candidates and characteristics specific to the project application. Specific climate change regimes may require additional details and justification for baseline scenario determination.

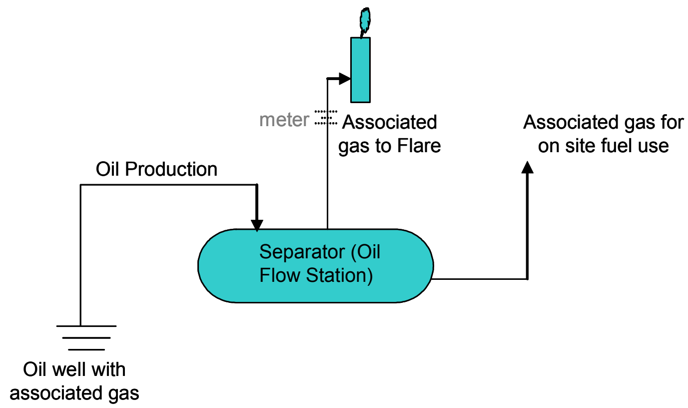

Figure 7-3. Baseline Illustration for Case Study #1

Project Assessment Boundary

After defining the project and identifying the baseline scenario, the next step is to determine the assessment boundary. The assessment boundary encompasses GHG emission sources, sinks, and reservoirs under the control of the project proponent that are affected by the GHG reduction project and sources contained in the baseline scenario. Figure 7-4 illustrates the processes and operations within the assessment boundary for both the project activity and the baseline scenario.

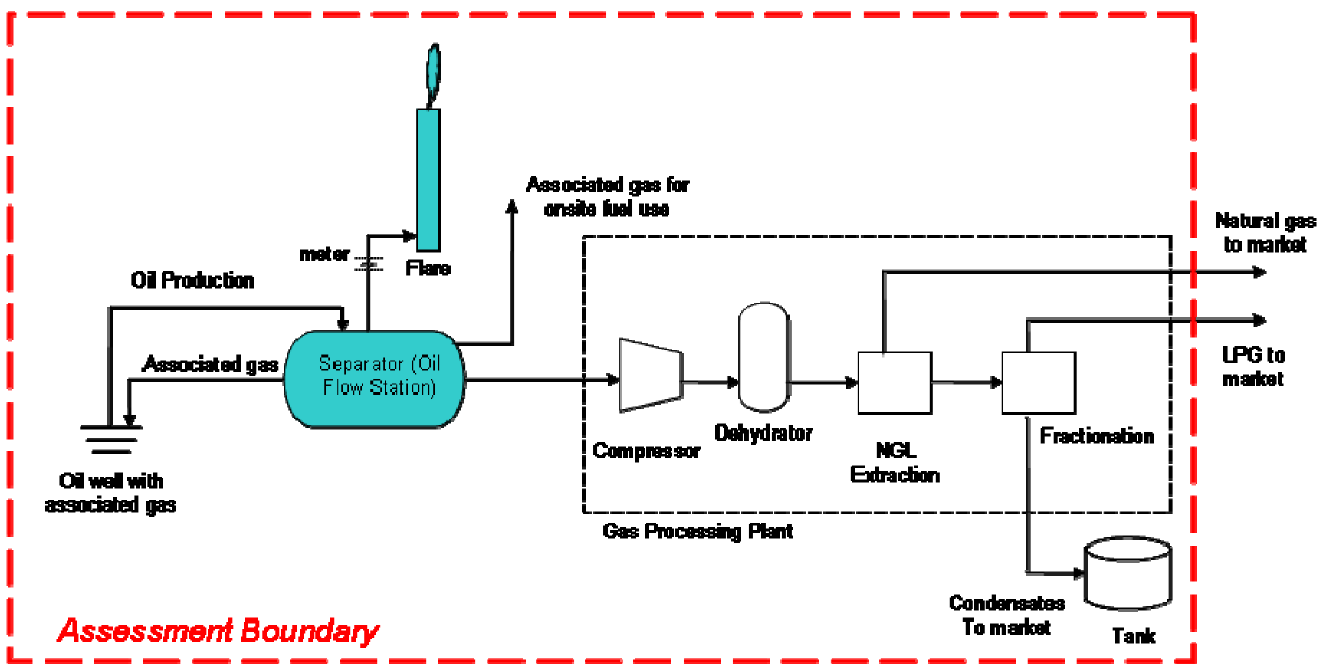

Figure 7-4. Project Assessment Boundary for Case Study #1

The project activity encompasses the recovery of gas that was originally flared at the oil flow station, the transportation of the recovered gas to a gas processing plant, the production of the dry gas, LPG, and condensate, and the transport of the dry gas and condensates to their respective points of sale. In this instance, the assessment boundary would include:

- Emission sources at the oil flow station and the new gas processing plant that are associated with gas flaring, recovery, processing, compression, and metering; and
- Emission sources from new operations and equipment associated with transport of the recovered dry gas, LPG and condensate from the gas plant to their points of sale.

Other potential effects associated with the flare elimination project that warrant consideration include:

- Life-cycle impacts: Downstream utilization of the associated gas; and
- Market leakage: Increase in gas demand as a result of the project.

Table 7-6 examines potential emission sources within the assessment boundary and compares the baseline scenario to the project activity.

Table 7-6. Case Study #1 Assessment Boundary Determination

Potential Emission Sources		**Relation to the Project Proponent**	**Considerations**
Baseline Scenario			
Oil/Gas Extraction and/or Separation	✓ CO_2, CH_4 and N_2O emissions from fuel combustion associated with the separation of the associated gas from produced oil ✓ Vented and fugitive CH_4 emissions, associated with the separation of the associated gas.	Controlled	Activity unchanged by project
	✓ CO_2 and to a lesser extent, CH_4 and N_2O emissions from flaring the associated gas at the oil flow station	Controlled	Reduced in project scenario by 98%
Gas Recovery	✓ Currently, only sufficient gas to provide energy for oilfield operations is recovered; remainder is flared	Controlled	Activity unchanged by project
Gas Transportation and Distribution	✓ Currently only sufficient gas to provide fuel for oilfield operations is transported	Controlled	Activity unchanged by project
End-Use of Gas	✓ Currently, only sufficient gas to provide fuel for oilfield operations is used, remainder is flared	Controlled	Activity unchanged by project

Table 7-6. Case Study #1 Assessment Boundary Determination, continued

Potential Emission Sources		Relation to the Project Proponent	Considerations
Project Activity			
Gas from Extraction and/or Separation	✓ CO_2, CH_4 and N_2O emissions from fuel combustion associated with the separation of the associated gas from produced oil ✓ Vented and fugitive CH_4 emissions, associated with the separation of the associated gas	Controlled	The emissions associated with the separation of the associated gas from produced oil are unchanged by the project activity; therefore, they can be ignored in the calculation of project emission reductions
	✓ CO_2 and to a lesser extent, CH_4 and N_2O emissions from flaring the associated gas at the oil flow station	Controlled	Project will reduce flared volumes by 98%
Gas Recovery	✓ CO_2, CH_4 and N_2O combustion emissions from gas processing, including separation of LPGs and condensates from untreated gas	Controlled	New emission source -- 10 percent of associated gas is used for gas processing, as well as separation of NGLs and condensates
	✓ Vented and fugitive CH_4 emissions, associated with the processing of associated gas and separation of liquids	Controlled	
Gas Transportation and Distribution	✓ CO_2, CH_4 and N_2O combustion emissions due to local transport of associated gas to meet oilfield energy needs ✓ Fugitive and vented emissions due to local transport of associated gas to meet oilfield energy needs	Controlled	Emissions from this activity are unchanged by the project and can therefore be ignored in the calculation of project emission reductions
	✓ CO_2, CH_4 and N_2O emissions from fuel combustion associated with transport of treated gas, LPGs and condensates to their respective points of sale ✓ Vented and fugitive CH_4 emissions, associated with transport pipeline operations and equipment	Controlled	New sources of combustion, vented and fugitive emissions
End-Use of Gas	✓ CO_2, CH_4 and N_2O emissions from end-use combustion of the recovered associated gas, LPGs, and condensates ✓ Vented and fugitive CH_4 emissions, associated with transport operations and equipment from the point of custody transfer to the point of end use combustion	Affected	Need to consider the potential impact of the recovered gas on the local market

Quantifying Emission Reductions

Exhibit 7.1 demonstrates the emission estimation process for the baseline scenario and project activity. Emission reductions are quantified as the difference between the baseline and project emissions.

EXHIBIT 7.1: Flare Gas Recovery for Local Sale and LNG Export

Project Information (based on hypothetical, measured data):

- 130×10^6 scf/day (3.68×10^6 m^3) of gas is flared before the project.
- Flared gas composition is 0.63 kg carbon/m^3 (0.0393 lb C/scf) or 2.31 kg CO_2e/cubic meter (0.144 lb CO_2e/scf).
- Recovered and processed gas composition is 0.61 kg carbon/m^3 (0.0381 lb C/scf) or 2.22 kg CO_2e/cubic meter (0.139 lb CO_2e /scf), assuming all of the carbon is converted to CO_2 in combustion.
- A 2-km (1.24 mile) pipeline will be constructed to transport the processed natural gas to the existing gas grid; a 1-km (0.62 mile) pipeline will be constructed to transport untreated gas to the gas processing facility; and 2.5-km (1.55 miles) of liquid pipeline will be constructed to transport condensates extracted from the gas stream to the oil storage area.
- Energy Requirements consist of 10% of the recovered gas (132×10^6 m^3/year or 4.66×10^9 scf/yr) to provide energy for recovery, processing and transport of the recovered gas to the local gas distribution system, and to recover and transport LPGs and condensates to their respective destinations.

Baseline Emissions

Baseline emissions = CMB_1+ $VENT_1$ + FUG_1 + IND_1

where,

CMB_1 = The flared associated gas emissions prior to the project activity. Combustion emissions associated with the equipment handling the associated gas prior to the flare are unchanged in the project activity and therefore cancel out in the calculation of project emission reductions.

$VENT_1$ = Vented gas from process units, maintenance, or upset conditions for equipment handling the associated gas prior to the flare. The vented emissions also occur unchanged in the project activity and therefore cancel out in the calculation of project emission reductions

FUG_1 = Fugitive emissions from process units handling the associated gas prior to the flare. These fugitive emissions also occur in the project activity and therefore cancel out in the calculation of baseline emission reductions

IND_1 = Indirect emissions would result from usage of electricity obtained from outside sources. No such purchased power is used for either the baseline or project scenarios.

EXHIBIT 7.1: Flare Gas Recovery for Local Sale and LNG Export (Continued)

Baseline Emissions Estimate

Combustion Emissions (CMB_1):
Combustion emissions associated with the equipment handling the associated gas prior to the flare also occur in the project activity and therefore cancel out in the calculation of project emission reductions. The flare emissions, included as part of CMB_1, are estimated based on the flare gas composition. It is assumed that the flared gas carbon is all converted to CO_2.

CMB_1= (Meter volume) × (Flare gas composition)

$$= \frac{3.68 \times 10^6 \text{ m}^3}{\text{day}} \times \frac{365 \text{ days}}{\text{yr}} \times \frac{2.31 \text{ kg CO}_2}{\text{m}^3} \times \frac{\text{tonne CO}_2}{1000 \text{ kg}}$$

= 3,102,792 tonnes CO_2e.

Vented Emissions ($VENT_1$):
Vented emissions associated with handling the gas prior to the flare occur in both the baseline and project scenarios, and therefore cancel out in the calculation of project emission reductions.

Fugitive Emissions (FUG_1):
Fugitive emissions associated with handling the gas prior to the flare occur in both the baseline and project scenario, and therefore cancel out in the calculation of project emission reductions.

Indirect Emissions (IND_1):
There are no indirect emissions associated with the baseline scenario.

BASELINE EMISSIONS = 3,102,792 + 0+ 0 + 0
= 3,102,792 tonnes CO_2e.

Project Emissions Categories
Project emissions = $CMB_2 + VENT_2 + FUG_2 + IND_2$

where,

CMB_2 = Combustion emissions associated with the equipment handling the associated gas prior to the flare also occur in the baseline scenario, and therefore cancel out this component of the project emissions. New emissions will result from the combustion of recovered gas to provide process energy in the gas processing plant and compression to transport dry gas to the local gas distribution system. This also includes any flared gas emissions that occur after project implementation.

EXHIBIT 7.1: Flare Gas Recovery for Local Sale and LNG Export (Continued)

$VENT_2$ = Process venting and maintenance/upset emissions from gas processing and transporting the processed natural gas to the gas distribution system. This also includes CH_4 emissions from gas dehydration.

FUG_2 = The fugitive emissions from process units handling the associated gas prior to the flare also occur in the baseline activity and therefore cancel out here. New emissions will result from gas leakage at the gas processing plant and during transport of the recovered gas by pipeline

IND_2 = There are no indirect emissions associated with project operations.

Project Emissions Estimates

Combustion emissions (CMB_2):

Project combustion emissions are calculated based on measured fuel consumption rates and fuel analysis data. Energy required for processing and transport of the recovered gas is generated by using 10% (132 million cubic meters) of the treated gas per year. The emission calculation below conservatively assumes that all the carbon in the fuel is converted to CO_2 during the combustion process and is discharged to the atmosphere, consistent with the API *Compendium*. Also under the project scenario, the quantity of associated gas flared will be reduced to 2% of the baseline amount.

The annual CO_2 emissions are calculated as follows:

CMB_2= (combustion volume) × (gas composition)
+ (flared volume) × (flare gas composition)

$$= \left(\frac{132 \times 10^6 \, m^3}{yr} \times \frac{2.22 \text{ kg } CO_2}{m^3} + \frac{0.02 \times 3.68 \times 10^6 \, m^3}{day} \times \frac{365 \text{ days}}{yr} \times \frac{2.31 \text{ kg } CO_2}{m^3} \right) \times \frac{\text{tonne } CO_2}{1000 \text{ kg}}$$

= 355,095 tonnes CO_2e.

Vented Emissions ($VENT_2$):

Vented emissions are based on the volume of gas processed and the length of newly constructed gas pipelines. The volume of gas processed is equivalent to the amount of gas previously flared. API *Compendium* Tables 5-2 and 5-4 provide emission factors for gas dehydration (0.082338 tonnes $CH_4/10^6$ m^3 from dehydration and 0.12041 tonnes $CH_4/10^6$ m^3 associated with the glycol pump). API *Compendium* Table 5-25 provides an emission factor for non-routine venting activities associated with gas processing (0.1244 tonnes $CH_4/10^6$ m^3).

For the 3 km of newly constructed gas pipeline, API *Compendium* Table 5-24 provides an emission factor for gathering gas pipeline blowdowns (0.00368 tonnes CH_4/km-yr) and Table 5-24 provides an emission factor for gathering gas pipeline dig-ins (0.00797 tonnes CH_4/km-yr).

EXHIBIT 7.1: Flare Gas Recovery for Local Sale and LNG Export (Continued)

$$\text{VENT}_2 = \text{Volume of gas processed} \times \left(\text{EF}_{Dehydrator} + \text{EF}_{Glycol\ pump} + \text{EF}_{Non-routine}\right)$$
$$+ \text{ Pipeline length } \times \left(\text{EF}_{Blowdowns} + \text{EF}_{Dig-ins}\right)$$

$$\text{VENT}_2 = \left[\begin{array}{l} \dfrac{3.68\times10^6\,\text{m}^3}{\text{day}} \times \dfrac{365\text{ days}}{\text{yr}} \times \left(0.082338 + 0.12041 + 0.1244\right) \dfrac{\text{tonnes CH}_4}{10^6\text{ m}^3} \\ +3\text{ km} \times \left(0.00368 + 0.00797\right) \dfrac{\text{tonnes CH}_4}{\text{km-yr}} \end{array}\right]$$
$$\times \frac{21\text{ tonne CO}_2\text{e}}{\text{tonne CH}_4}$$
$$= 9{,}227 \text{ tonnes CO}_2\text{e.}$$

Fugitive Emissions (FUG_2):
Fugitive emissions are estimated based on leakage from the gas processing operations and the transport of the recovered gas. API *Compendium* Table 6-2 provides a fugitive emission factor for gas processing (1.032 tonnes CH4/10^6 m^3) operations and Table 6-4 provides a fugitive pipeline emission factor for production pipelines (2.66×10^{-5} tonnes CH_4/km-yr).

$$\text{FUG}_2 = \text{Volume of gas processed} \times \left(\text{EF}_{Processing}\right) + \text{ Pipeline length } \times \left(\text{EF}_{Gathering\ Pipeline}\right)$$

$$\text{FUG}_2 = \left[\begin{array}{l} \dfrac{3.68\times10^6\,\text{m}^3}{\text{day}} \times \dfrac{365\text{ days}}{\text{yr}} \times \dfrac{1.032\text{ tonnes CH}_4}{10^6\text{ m}^3} \\ +3\text{ km} \times \dfrac{2.66\times10^{-5}\text{ tonnes CH}_4}{\text{km-yr}} \end{array}\right]$$
$$\times \frac{21\text{ tonne CO}_2\text{e}}{\text{tonne CH}_4}$$
$$= 29{,}110 \text{ tonnes CO}_2\text{e.}$$

Indirect emissions (IND_2)

For this project, all energy is supplied on-site. There is no import or purchase of electricity so there are no emissions associated with off-site electricity generation.

PROJECT EMISSIONS = CMB_2+$VENT_2$ + +FUG_2 + IND_2
= 355,095+9,227+29,110 = 393,432 tonnes CO_2e per year

EMISSION REDUCTIONS= Baseline Emissions – Project Emissions
=3,069,066-393,432
= 2,675,634 tonnes CO_2e.

Monitoring

Monitoring for this project example would include the following:

- The composition and quantity of recovered gas, as well as the composition and quantity of products (dry gas, LPG, and condensate);
- Metering of the quantity of gas provided to the local gas grid;
- Monitoring of natural gas liquids and condensates produced;
- The types and quantity of any additional fuels consumed in the processing and transport of the recovered gas and products, if applicable; and
- The CH_4 content and operating times for equipment and processes subject to venting and fugitive emissions and associated with the processing and transport of the recovered gas and liquid products.

ATTACHMENT 1
FLARE REDUCTION PROJECT CASE STUDY #2: GAS RECOVERY FOR RE-INJECTION AND UTILIZATION FOR POWER GENERATION

Project Definition

Description of the Project Activity[21]

This project example recovers associated gas that would otherwise be flared, re-injects a portion of the gas, and uses the majority of the gas to provide fuel for a new power plant. In this example, an existing oil and gas processing plant (OGPP) receives oil from local oil fields and separates associated gas from the oil. A small portion of gas produced at the OGPP is exported to a LNG plant to provide supplemental fuel. Another small fraction of the produced gas is used for on-site power and processing needs at the OGPP (oil/gas separation, oil heaters, glycol dehydration and glycol regeneration, pumping, compression etc.). The remaining large portion of the gas produced at the OGPP currently is flared.

Flaring a large portion of the gas results in the release of CO_2 emissions and uncombusted CH_4 to the atmosphere. After evaluating alternative approaches, the project proponent decided to re-inject a portion of the associated gas for storage in the oil production fields, and also to build an independent power plant (IPP) that will use the major portion of the currently flared gas as fuel, as well as a new pipeline to deliver this gas to the power plant. Significant GHG emissions will thus be eliminated by recovering and utilizing the volumes of gas that are currently flared.

This example project is described in more detail below.

<u>Before the project:</u>

The oil from production wells in five local oil fields is transported to the OGPP for separation of the oil and wet gas. The annual volume of wet gas produced from the oil-gas separation system is about 2.7×10^9 standard cubic meters (scm; 9.53×10^{10} scf/yr). Only a small fraction of the associated gas produced at the OGPP, 1.2×10^8 scm/year (4.24×10^9 scf/year), is used for on-site power and processing needs. In addition, an existing pipeline exports 2.07×10^8 scm/year (7.31×10^9 scf/year) of high-pressure associated gas to an off-site LNG plant to provide supplemental fuel. The remaining gas production, 2.3×10^9 scm/year (8.12×10^{10} scf/yr) from the OGPP, is sent to the flare system.

[21] This case study is derived from the Clean Development Mechanism (CDM) Project Design Document (PDD) and baseline methodology associated with the "Recovery of associated gas that would otherwise be flared at Kwale oil-gas processing plant" project in Nigeria. In this project example, the schematic diagram of the project, the equations to quantify the baseline and project emissions, the gas volume, and emission factors are modified from the CDM-PDD to conform to the approaches in Section 2 of the General Project Guidelines (IPIECA and API, 2007).

What the project will change,

The project activity will encompass the utilization and re-injection of the processed associated gas produced from the OGPP. The volumes of processed associated gas exported from the low- and medium-pressure trains for re-injection at the oil fields and for utilization at IPP will be 3.5×10^{8} scm/year (1.24×10^{10} scf/yr) and 1.4×10^{9} scm/year (4.94×10^{10} scf/yr), respectively.

The re-injected gas will be stored at reservoirs within the five local oil fields for potential future use. It is not used to enhance oil recovery or for gas lift.

The carbon content of the gas stream, 0.648 kg carbon/m^3 (0.0404 lb C/scf), can be applied to the wet gas produced from the OGPP separators and the high-pressure associated gas stream transported from the OGPP to the LNG plant, as well as the medium- and low-pressure streams from the OGPP to the oil field re-injection sites and to the IPP.

In the project scenario, the volume of oil delivered from the oil fields and the volume of high pressure associated gas exported to the LNG plant will be unchanged from their respective baseline levels. No gas will be sent to the flare system under the project scenario, except for process upset or emergency situations, which is assumed to represent a negligible annual volume for the purposes of this example project. However, the on-site energy needs of the OGPP will increase to 2.0×10^{8} scm/year (7.06×10^{9} scf/yr) due to the addition of a new compressor to transport the processed gas by new pipelines to the oil field for re-injection and to the IPP.

A new gas pipeline with a length of 14 km (8.7 miles) will deliver the processed associated gas from the OGPP to the IPP. The second new gas pipeline 10 km in length (6.21 miles) will transport processed gas from the OGPP to the oil fields for re-injection. The project proponent will operate both pipelines.

The products sent to the IPP for generation of electric power, i.e., medium- and low-pressure AG, are assumed to be a substitute in the market for fuels of equal or higher carbon content per unit of fuel energy. The substitution of fuels due to the project activity is unlikely to lead to an increase in fuel consumption in the local or regional market.

Common practice in the area is to flare associated gas due to a lack of natural gas infrastructure and market demand for gas in the host country.

Baseline Scenario Determination

Baseline Candidates Considered

The baseline scenario represents the situation or conditions that plausibly would have occurred in the absence of the project. Baseline candidates for this example project include:

1. Continuation of current activities, i.e., associated gas continues to be flared;
2. Associated gas is vented to the atmosphere;
3. Associated gas is transported and re-injected for storage (included in the project activity);

4. Associated gas is used to meet the on-site energy requirements of the OGPP (included in the project activity); and
5. Associated gas is transported to the IPP to generate power for sale on the local electricity grid (included in the project activity).

Baseline Scenario

Table 7-7 applies some common tests or screening criteria to assist in assessing the baseline candidates.

Table 7-7. Case Study #2 Baseline Scenario Assessment

Baseline Scenario Alternatives	Investment Ranking	Technology	Policy/ Regulatory	Benchmarking
Candidate 1: Continuation of current activities: Associated gas continues to be flared	No additional costs	No additional technology requirements	May be prohibited by local regulations	Common practice in region[15]
Candidate 2: Associated gas is vented to the atmosphere	No additional costs	Existing technologies	May be prohibited by local regulations	Generally avoided due to safety risk
Candidate 3 *(Project activity):* Associated gas is transported and re-injected for storage	Moderate costs for re-injection gas	Existing technologies	May be restricted in some locations	Commercially viable in some regions
Candidate 4 *(Project activity):* Associated gas is used for on-site fuel	No additional costs	Existing technologies	Consistent with current applicable laws or regulations	Commercial in some regions However, supply of associated gas far exceeds on-site demand
Candidate 5 *(Project activity):* Associated gas is transported to IPP to generate power to export to the grid	Moderate to high costs for transporting gas	Existing technologies	Consistent with current applicable laws or regulations	Commercially viable in some regions

Based on comparing the baseline candidates presented above:

- Candidates 1 and 2 are restricted by local policies and/or regulations. However, flaring of associated gas (Candidate 1) occurs routinely in the project area because assessed penalties for doing so are too low to be an effective deterrent to the practice. Enforcement of the prohibition against routine venting is more substantive because of potential serious safety

[15] Depending on the circumstances of the project, the region or geographic area may be narrow (e.g., an area within a nation or state), or broad (e.g., an international region or global area).

risks associated with venting of large gas volumes. Accordingly, Candidate 2 is assumed not to be feasible for this example.

- Candidates 3 and 5 (*which are included in the project activity*) would both incur substantial gas transport costs. Both candidates utilize existing technologies. Costs for implementing Candidate 5 also include a large incremental component for development of the IPP, which cannot be assumed to be the baseline scenario.
- Candidate 4 would have limited application for this example project, because the on-site fuel requirements for the existing operations are far less than the amount of associated gas currently flared. For this reason, this candidate is rejected as the baseline scenario

As a result of this analysis, Candidate 1, which represents the continuation of current activities, is determined to be the most probable baseline scenario.[16] The baseline operations are illustrated in Figure 7-5.

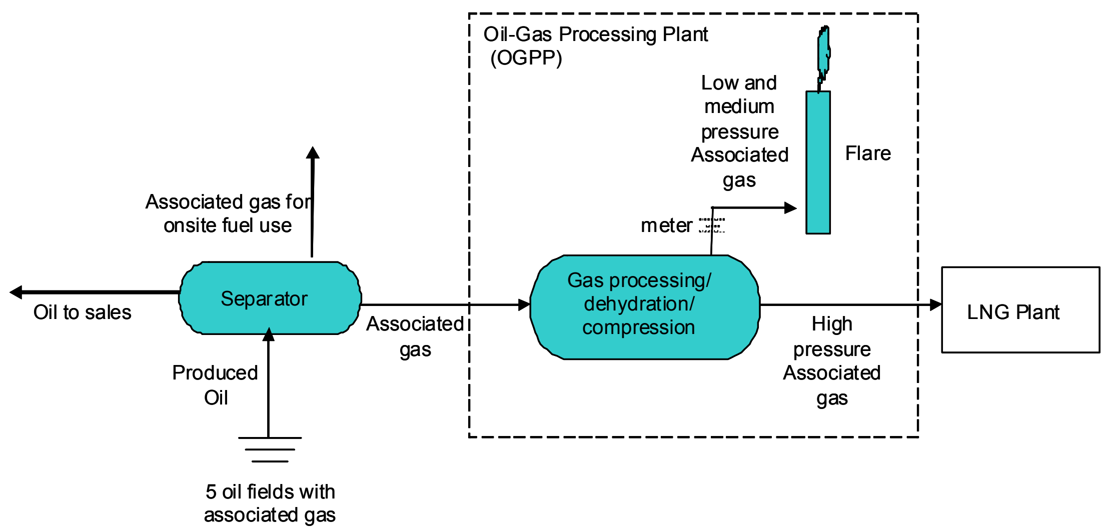

Figure 7-5. Baseline Illustration for Case Study #2

Project Assessment Boundary

After defining the project and identifying the baseline scenario, the next step is to determine the assessment boundary. The assessment boundary encompasses GHG emission sources, sinks, and reservoirs that are controlled by the project proponent, would be affected by the GHG reduction project, and are relevant to the baseline scenario. Figure 7-6 illustrates the processes and operations within the assessment boundary for both the project activity and the baseline scenario.

[16] Baseline candidates and the analysis presented here are for illustrative purposes only. Actual project activities will require an assessment of the candidates and characteristics specific to the project application. Specific climate change regimes may require additional details and justification for baseline scenario determination.

The project activity encompasses the utilization and re-injection of the processed associated gas from the OGPP. In this instance, the assessment boundary would include:

- All existing emission sources within the OGPP, including fuel combustion for pumping oil from the production facilities to the OGPP and from the OGPP to the point of sale;
- Fuel combustion and fugitive emissions related to oil-gas separation and gas processing at the OGPP;
- Fuel combustion and fugitive emissions associated with delivery of high pressure gas to the external LNG plant;
- Emission sources associated with increased OGPP energy needs to compress processed gas for shipment via the new pipelines to the IPP and to the oil field re-injection area; and
- Fugitive and maintenance venting emissions from these new pipelines.

Additional effects associated with the flare elimination project that warrant consideration include:

- Life-cycle impacts: Downstream utilization of the associated gas; e.g., in the IPP; and
- Market leakage: Potential for an increase in gas demand as a result of the project.

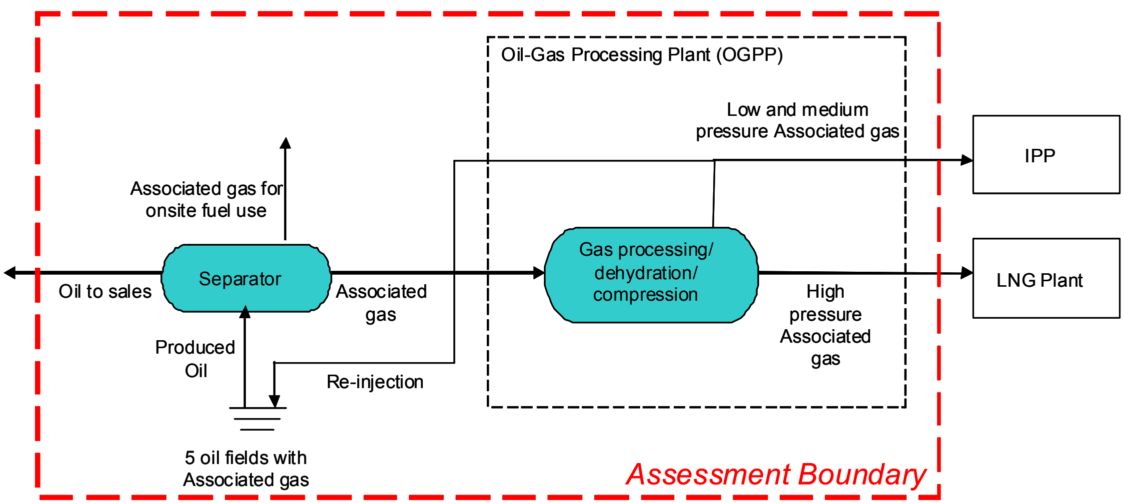

Figure 7-6. Project Assessment Boundary for Case Study #2

Table 7-8 lists the potential emission sources within the assessment boundary and affords a comparison between the types of emissions sources included in the baseline scenario and in the project activity.[17]

[17] Note that although CDM methodology AMS III-P allows for emission reductions associated with recovery of flared waste gas streams for process heat or replacing fossil fuel combustion, this methodology is limited to refineries. The currently approved CDM methodologies for flare reduction projects at oil and natural gas production and processing operations (e.g., AM0009) do not include combustion of recovered gas at end user facilities, whether or not they are under the control of the project proponent. Thus, obtaining CDM credits for use of previously-flared

Table 7-8. Case Study #2 Assessment Boundary Determination

Potential Emission Sources		Relation to the Project Proponent	Considerations
Baseline Scenario			
Gas from Extraction and/or Separation	✓ CO_2, CH_4 and N_2O combustion emissions from the separation of associated gas from produced oil ✓ Vented and fugitive CH_4 emissions, associated with the separation of the associated gas	Controlled	Emissions are unchanged by the project activity, and thus cancel out in the calculation of project emission reductions
Gas Processing	✓ CO_2 and to a lesser extent, CH_4 and N_2O emissions from flaring the associated gas at the OGPP	Controlled	Flaring is effectively eliminated by the project activity
	✓ CO_2, CH_4 and N_2O combustion emissions from gas processing	Controlled	Gas processing emissions are unchanged by the project activity, and thus cancel out in the calculation of emission reductions
	✓ Vented and fugitive CH_4 emissions, associated with the processing of associated gas	Controlled	Emissions are unchanged by the project activity, and thus cancel out in the emission calculation
Gas Transportation and Distribution	✓ CO_2, CH_4 and N_2O combustion emissions associated with transport pipelines from the oil field to the OGPP and from the OGPP to the LNG plant	Controlled	CO_2, CH_4 and N_2O combustion emissions at the OGPP will be increased by the project activity as additional energy will be required for transport of produced gas streams to the IPP and to the oilfield re-injection sites, but emissions from gas transport to the LNG plant are unchanged by the project
Gas Transportation and Distribution, continued	✓ Vented and fugitive CH_4 emissions associated with transport pipelines from the oil field to the OGPP and from the OGPP to the LNG plant	Controlled	New vented and fugitive CH_4 emissions will result from the new pipelines to be constructed for the project activity
End-Use of Gas	✓ No emissions associated with the end uses of the gas pertain to the baseline scenario	Not Applicable	

gas at non-refinery facilities to replace a more carbon-intensive fuel at a power plant would require development and approval of a new methodology, which could be a combination of already-approved methodologies for flare reduction and fuel switching projects.

Table 7-8. Case Study #2 Assessment Boundary Determination, continued

Potential Emission Sources		Relation to the Project Proponent	Considerations
Project Activity			
Gas from Extraction and/or Separation	✓ CO_2, CH_4 and N_2O emissions from fuel combustion associated with the separation of the associated gas from produced oil. ✓ Vented and fugitive CH_4 emissions, associated with the separation of the associated gas	Controlled	These emissions are unchanged by the project activity, and thus cancel out in the calculation of project emission reductions
Gas Processing	✓ CO_2, CH_4 and N_2O combustion emissions from gas processing	Controlled	Gas processing emissions unchanged by the project activity, and thus cancel out in the calculation of emission reductions
	✓ Vented and fugitive CH_4 emissions, associated with the processing of associated gas	Controlled	Emissions unchanged by the project activity, and thus cancel out in the emission calculation.
Gas Transportation and Distribution	✓ CO_2, CH_4 and N_2O combustion emissions associated with transport pipelines from the oil field to the OGPP and from the OGPP to the LNG plant ✓ Vented and fugitive CH_4 emissions, associated with transport pipelines from the oil field to the OGPP and from the OGPP to the LNG plant	Controlled	Emissions unchanged by the project activity, and therefore cancel out in the calculation of emission reductions
	✓ CO_2, CH_4 and N_2O combustion emissions associated with gas transport via new pipelines from the OGPP to the IPP and from the OGPP to the re-injection wells within the oil fields ✓ Vented and fugitive CH_4 emissions, associated with gas transport via new pipelines from the OGPP to the IPP and from the OGPP to the re-injection wells within the oil fields	Controlled	New emissions due to the project activity

Table 7-8. Case Study #2 Assessment Boundary Determination, continued

Potential Emission Sources		Relation to the Project Proponent	Considerations
Project Activity			
End-Use of Gas	✓ CO_2, CH_4 and N_2O emissions from end use combustion of the recovered associated gas at the IPP and potential future combustion of associated gas re-injected by the project activity ✓ Vented and fugitive CH_4 emissions, associated with future recovery and transport of associated gas re-injected by the project activity	Affected	Not included in project definition or in calculation of project emission reductions unless the project proponent is also the operator or is invested in the end-use facility

Quantifying Emission Reductions

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

EXHIBIT 7.2: Flare Gas Recovery for Re-injection and Utilization

Project Information (based on hypothetical, measured data):

- Volume of wet gas produced from the oil-gas separation system is 2.7×10^9 m^3/year (9.53×10^{10} scf/yr).
- 2.3×10^9 m^3 (8.12×10^{10} scf/yr) of gas is flared annually in the baseline scenario.
- The volumes of processed associated gas exported in the project scenario from the low- and medium-pressure trains of the oil-gas processing plant (OGPP) for re-injection at the oil fields and for utilization at the independent power plant (IPP) will be 3.5×10^8 scm per year (1.24×10^{10}) and 1.4×10^9 scm per year (4.94×10^{10} scf/yr), respectively.
- Untreated associated gas carbon content: 0.648 kg carbon/m^3 (0.0404 lb C/scf).
- CH_4 content of treated associated gas is 85% by volume. The content of CO_2 in this gas is negligible.
- Processed low- and medium-pressure associated gas carbon content: 0.648 kg carbon/m^3 (0.0404 lb C/scf).
- The total length of the new constructed gas transmission pipelines is 24 km (14.9 miles), based on a 14-km (8.7 miles) pipeline that will transport the processed gas from the OGPP to the IPP and a 10-km (6.2 miles) pipeline that will transport the processed gas from the OGPP for oil field re-injection.

EXHIBIT 7.2: Flare Gas Recovery for Re-injection and Utilization, continued

- Energy Requirements consist of 1.2×10^8 m^3/year (4.24×10^9 scf/yr) of the untreated gas is used to meet on-site energy requirements at the OGPP in the baseline scenario, increasing to 2.0×10^8 m^3/year (7.06×10^9 scf/yr) after project implementation.

Baseline Emissions

Baseline emissions = $CMB_1 + VENT_1 + FUG_1 + IND_1$
where,

CMB_1 = Combustion emissions due to equipment usage for separation and processing of associated gas at the OGPP and compression of the gas stream delivered to the LNG plant. CMB_1 also includes emissions from flared processed gas prior to the project activity.

$VENT_1$ = Vented gas from separation of associated gas and gas processing plant maintenance, or upset conditions for equipment handling the associated gas. These emissions are unchanged by the project activity and therefore cancel out in the calculation of project emission reductions.

FUG_1 = Fugitive emissions from process units involved in the separation and processing of associated gas at the OGPP and transport of associated gas to the LNG plant. These emissions are unchanged by the project activity, and therefore cancel out in the calculation of project emission reductions activity.

IND_1 = Indirect emissions would result from usage of electricity obtained from outside sources. No such purchased power is used for the either the baseline or project scenarios.

Baseline Emissions Estimate

Combustion Emissions (CMB_1):
Existing combustion emissions are calculated based on measured fuel consumption rates and fuel analysis data. The annual quantity of treated associated gas used for on-site energy production at the OGPP is 1.2×10^8 m^3 in the baseline scenario. The volume of gas flared in the baseline scenario is 2.3×10^9 m^3. The associated emissions were conservatively estimated by assuming that all the carbon in the fuel is converted to CO_2 during the combustion process and discharged to the atmosphere, consistent with the API *Compendium*.

Based on the above data, the annual CO_2 emissions due to baseline fuel consumption are calculated as follows:

CMB_1= (Metered gas volume + flared gas volume) × (gas composition)

$$= \left(\frac{1.2\times10^8\,\text{m}^3}{\text{yr}} + \frac{2.3\times10^9\,\text{m}^3}{\text{yr}}\right)\times\frac{0.648\text{ kg C}}{\text{m}^3}\times\frac{44\text{ kg CO}_2}{12\text{ kg C}}\times\frac{\text{tonne CO}_2}{1000\text{ kg}}$$

= 5,749,920 tonnes CO_2e.

EXHIBIT 7.2: Flare Gas Recovery for Re-injection and Utilization, continued

Vented Emissions ($VENT_1$)
Vented emissions associated with operation of the existing equipment are unchanged by the project activity and therefore cancel out in the estimation of project emission reductions.

Fugitive Emissions (FUG_1):
Fugitive emissions associated with the operation of existing equipment will be unchanged by the project activity, and therefore cancel out in the calculation of project emission reductions.

Indirect Emissions (IND_1):
There are no indirect emissions associated with either the baseline or the project scenario.

Baseline emissions $= CMB_1 + VENT_1 + FUG_1 + IND_1$
$= 5{,}749{,}920 + 0 + 0 + 0$
$= 5{,}749{,}920$ tonnes CO_2e.

Project Emissions Estimate
Project emissions = $CMB_2 + VENT_2 + FUG_2 + IND_2$

where,

CMB_2 = Combustion emissions associated with increased use of existing equipment at the OGPP to provide compression for associated gas transport from the OGPP by means of the new gas pipelines to the IPP and the oilfield reinjection area. No gas will be flared after implementation of the project activity.

$VENT_2$ = Vented gas associated with transport in new pipelines of the processed low- and medium-pressure associated gas streams to the IPP and to the oilfield re-injection area.

FUG_2 = Pipeline fugitive emissions associated with transport of processed low- and medium-pressure associated gas from OGPP to the IPP and the oilfield re-injection area. Note that fugitive emissions from process units handling the associated gas at the OGPP are unchanged by the project scenarios, and therefore cancel out in the calculation of project emission reductions.

IND_2 = There are no indirect emissions associated with either the baseline or the project scenario.

Combustion emissions (CMB_2):

Fuel combustion emissions are calculated based on projected fuel consumption rates and fuel analysis data. Based on the data presented above, 2.0 ×108 m3/year of associated gas will be consumed to meet the on-site energy needs of the OGPP after implementation of the project. The emission calculation conservatively assumes that all the carbon in the fuel will be converted to CO2 during the combustion process and discharged to the atmosphere, consistent with the API Compendium.

EXHIBIT 7.2: Flare Gas Recovery for Re-injection and Utilization, continued

Using this data, the annual CO_2 emissions for fuel combustion are calculated as follows:

CMB_2= (Metered gas volume) × (combustion gas composition)

$$= \frac{2.0 \times 10^8 \, m^3}{yr} \times \frac{0.648 \text{ kg C}}{m^3} \times \frac{44 \text{ kg } CO_2}{12 \text{ kg C}} \times \frac{\text{tonne } CO_2}{1000 \text{ kg}}$$

= 475,200 tonnes CO_2e.

Vented Emissions ($VENT_2$):

The 24 km of new gas pipelines that will transport the processed natural gas to the IPP (14 km) and oilfield re-injection area (10 km) will be the only new source of venting/blowdown CH_4 emissions that will result from the project activity. API *Compendium* Table 5-26 provides an emission factor for transmission gas pipeline venting and blowdowns of 0.4881 tonnes CH_4/km-yr. The API *Compendium* emission factor is based on 93.4 mole% CH_4 composition, compared to 85% for the project activity.

$$\text{VENT}_2 = \text{Pipeline length } \times \text{EF}_{Blowdowns/Venting}$$

$$\text{VENT}_2 = 24 \text{ km} \times \frac{0.4881 \text{ tonnes } CH_4}{\text{km-yr}} \times \frac{0.85 \text{ tonne mole } CH_4 (\textit{project})}{0.934 \text{ tonne mole } CH_4 (\textit{default})}$$

$$\times \frac{21 \text{ tonne } CO_2\text{e}}{\text{tonne } CH_4}$$

= 224 tonnes CO_2e.

Fugitive Emissions (FUG_2):

This emissions category includes fugitive CH_4 leakage from the new pipelines that will connect the OGPP to the IPP and oilfield re-injection area. API *Compendium* Table 6-2 provides a transmission fugitive pipeline CH_4 emission factor which is 2.237 tonne CH_4 per year per kilometer of transmission pipeline based on a 93.4% mole fraction of CH_4.

$$\text{FUG}_2 = \text{Pipeline length } \times \text{EF}_{Fugitive}$$

$$\text{FUG}_2 = 24 \text{ km} \times \frac{2.235 \text{ tonnes } CH_4}{\text{km-yr}} \times \frac{0.85 \text{ tonne mole } CH_4 (\textit{project})}{0.934 \text{ tonne mole } CH_4 (\textit{default})}$$

$$\times \frac{21 \text{ tonne } CO_2\text{e}}{\text{tonne } CH_4}$$

= 1,025 tonnes CO_2e.

EXHIBIT 7.2: Flare Gas Recovery for Re-injection and Utilization, continued

Indirect emissions (IND_2):

There are no indirect emissions associated with either the baseline or the project scenario.

PROJECT EMISSIONS = $CMB_2 + VENT_2 + FUG_2 + IND_2$
= 475,200+224+ 1,025 +0
= 476,449 tonnes CO_2e per year

EMISSION REDUCTIONS= Baseline Emissions – Project Emissions
= (5,749,920 – 476,449) tonnes CO_2e per year
= 5,273,471 tonnes CO_2e per year

Monitoring

Monitoring for this project example would include the following:

- The composition and quantity of unprocessed associated gas delivered to the OGPP and of the processed high-, medium-, and low-pressure gas streams produced by the OGPP.
- Quantities of processed gas sent to the IPP and the oilfield re-injection area.
- The types and quantities of any additional fuels consumed in the processing and transport of the recovered gas, if any.
- The CH_4 content and operating time of equipment and processes subject to venting and fugitive emissions, and associated with the processing and transport of the recovered gas.

ATTACHMENT 1
FLARE REDUCTION PROJECT CASE STUDY #3: RECOVERY OF FLARE GAS AND UTILIZATION FOR ON-SITE POWER GENERATION

Project Definition

Description of the Project Activity[18]

This example project recovers associated gas that has historically been flared at a moderately sized onshore oil production field, and uses this otherwise wasted energy source to produce energy to meet on-site needs. Specifically, the recovered associated gas is used to fuel a bank of internal combustion engine drivers for the production of electric power to support oilfield operations, including electrical pumps to transport the produced crude oil to an off-site destination. These engines previously operated on crude oil fuel produced at the site. In this case, the recovered gas is sufficient to support increased on-site power generation and its use in this manner eliminates all routine flaring. Most of the pre-project combustion of crude oil on the site is also eliminated.

Before project implementation, flaring of the associated gas stream releases emissions of CO_2 and uncombusted CH_4 to the atmosphere, and wastes a valuable energy source. Additional pre-project emissions result from crude oil combustion to generate on-site power. After evaluating the costs and benefits of alternative approaches, the project proponent decided to capture the flare gas stream and use it for on-site power generation in place of crude oil to the maximum extent possible. The project also includes replacing the older, less efficient engines previously used to drive on-site electric power generators with larger new units that are specifically designed to accommodate the variable energy content and composition of AG. Thus, the project will also increase power generation to meet the facility's growing demand. Another benefit of the project is that most of the crude oil previously used on-site can now be marketed with the rest of the oil field's production. It is expected that the supply of associated gas will be sufficient to fuel 90% of the on-site power generation, with crude oil still supplying 10% of the fuel for this purpose.

The principal differences between this example project and the others presented with this guidance are this project's much smaller scale and the fact that implementation of this project under certain circumstances could result in comparable or better cost effectiveness for the project proponent than continued flaring. This case study demonstrates a type of project that may be worthwhile, even though not necessarily one that would qualify to generate carbon emission reduction credits on a large scale.

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18 This case study is hypothetical and is not based on any specific real-world project. However, it has been constructed using information on relatively new internal combustion engine designs that can accommodate associated gas fuel. One example of such a project was described in a recent paper presented by Dr. Jacob Klimstra of Wartsilla Power Plants titled *Operational Experience with a Gas-Diesel Engine Running on Flare Gas* at the Global Forum on Flaring and Venting Reduction and Natural Gas Utilisation, Amsterdam, December 3-5, 2008.

<u>Before the project:</u>

The oil from production wells in the field is treated on-site by an oil-gas separator and subsequently an oil-water separator. Except for the fraction of the oil used for on-site power generation, this production is transported by pipeline to external markets by electrically powered pumps located adjacent to the oilfield. The wet gas produced from the oil-gas separator is treated by a dehydration unit and compressed before its delivery to the flare.

Before implementation of the flare reduction project, several internal combustion engines are operating solely on crude oil fuel to drive generators for on-site electric power production. Electric pumps to transport crude oil to off-site markets are the primary use of the power generated by means of these engines.

<u>What the project will change:</u>

The project activity will encompass the recovery and on-site utilization of the processed associated gas stream previously sent to the flare, and replacement of the current IC engines with larger and more efficient units capable of burning either associated gas or crude oil. The same dehydration and compression equipment that was used to prepare the gas for flaring is adequate to deliver this stream to the new IC engines, and the volume of recovered gas used for power generation is expected to match the gas flaring amounts before the project's implementation.

New IC engines capable of burning either associated gas or crude oil or both will be installed in place of the existing engines. The rated output of the new engines is 42% higher than for the original engines. However, the thermal efficiency of the new engines is higher for either fuel type than that of the existing units. Since the associated gas production at this site is variable and will sometimes be insufficient to provide all the fuel needed for power generation, about 10% of the fuel energy input requirement of the new engines will continue to be met using crude oil after the project is implemented.

Baseline Scenario Determination

Baseline Candidates Considered

The baseline scenario represents the situation or conditions that plausibly would have occurred in the absence of the project. Candidate baseline scenarios for this example project include:

1. Continuation of current activities, i.e., associated gas continues to be flared;
2. Associated gas is vented to the atmosphere;
3. Associated gas is used to meet the on-site energy requirements of the OGPP (included in the project activity); and
4. Associated gas is transported off-site to be sold as a fuel to an outside party.

Baseline Scenario Selection

Table 7-9 applies some common tests or screening criteria to assist in assessing the baseline candidates.

Table 7-9. Case Study #3 Baseline Scenario Assessment

Baseline Scenario Alternatives	Investment Ranking	Technology	Policy/ Regulatory	Benchmarking
Candidate 1: Continuation of current activities: Associated gas continues to be flared	No additional costs	No additional technology requirements	May be prohibited by local regulations	Common practice in project region[19]
Candidate 2: Associated gas is vented to the atmosphere	No additional costs	Existing technologies	May be prohibited by local regulations	Generally avoided due to safety risk
Candidate 3: *(Project activity)*: Associated gas is used for fuel to generate power on-site	Replacement of existing IC engines with new units that can accommodate associated gas fuel	Existing technologies	Consistent with current applicable laws and regulations	Associated gas quantity nearly matches facility's power generation requirements
Candidate 4: Associated gas is transported off-site to be sold as fuel to an outside party	Moderate to high costs for new compression equipment and a new pipeline to transport gas	Existing technologies	Consistent with current applicable laws and regulations	Gas infrastructure not developed in project region

Based on comparing the baseline candidates presented above:

- Candidates 1 and 2 are restricted by local policies and/or regulations. However, flaring of associated gas (Candidate 1) occurs routinely in the project region because assessed penalties for flaring are too low to effectively discourage the practice. Enforcement of the prohibition against routine venting is more substantive because of potential serious safety risks associated with gas venting. Accordingly, Candidate 2 is assumed not to be feasible for this example.
- Candidate 3 (Project activity) would incur substantial costs to change out the engine drivers for power generation in a manner that will enable their use on associated gas fuel. Offsetting this cost over the long term will be the savings in crude oil that can be marketed, rather than used on-site for fuel, because of its replacement with the previously flared associated gas. This candidate scenario would utilize the emerging technology of engines that are being designed to better accommodate variable fuel quality and composition. Depending on the scale of the production and local pricing factors, this scenario could conceivably be considered a viable baseline scenario.
- Costs for implementing Candidate 4 are also considerable in that new compression capacity and a new gas pipeline would need to be developed to support delivery of produced gas to

[19] Depending on the circumstances of the project, the region or geographic area may be narrow (e.g., an area within a nation or state), or broad (e.g., an international region or global area).

markets. However, there is no natural gas infrastructure in the project region, with the result that the gas has little value, and these expenses are not justified. Thus, this Candidate cannot be assumed to be the baseline scenario.

In the above analysis, Candidate 1, which represents the continuation of current activities, could be considered the most probable baseline scenario.[20] However, depending on local pricing factors and the scale and remaining lifetime of oil production at the field in question, it is possible that Candidate 3, which represents the project activity, could also be a viable baseline scenario and could even be more economically attractive in the long run than continued flaring. While this type of project would almost certainly result in an overall reduction in facility emissions of GHGs (replacement of a higher carbon intensity fuel with a lower intensity one for on-site consumption), it might well be undertaken based simply on improving operational economics, rather than to obtain emission reduction credits.

Most of the following discussion pertains to a scenario in which continued flaring can be demonstrated to be the most likely baseline scenario, i.e., where the circumstances of the project's implementation would cause it to be substantially more costly than a continuation of associated gas flaring and where acquisition of emission credits may be at least a partial motivation for the flare reduction project. Figure 7-7 provides a schematic illustration of this baseline scenario.

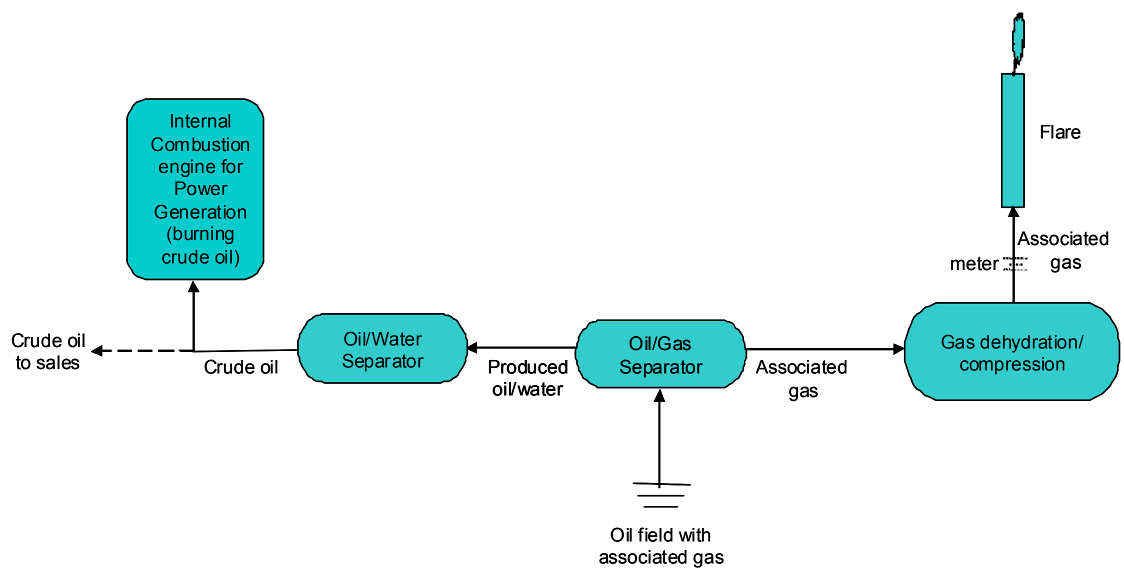

Figure 7-7. Baseline Illustration for Case Study #3

[20] Baseline candidates and the analysis presented here are for illustrative purposes only. Actual project activities will require an assessment of the candidates and characteristics specific to the project application. Specific climate change regimes may require additional details and justification for baseline scenario determination.

Project Assessment Boundary

After defining the project and identifying the baseline scenario, the next step is to determine the assessment boundary. The assessment boundary encompasses GHG emission sources, sinks, and reservoirs that are controlled by the project proponent, that would be affected by the GHG reduction project, and that are relevant to the baseline scenario. Figure 7-8 illustrates the processes and operations within the assessment boundary for the project activity and the baseline scenario. For purposes of this discussion, the baseline condition is assumed to be continued flaring of all produced AG, although as discussed above, this may not necessarily be the case under some site-specific circumstances.

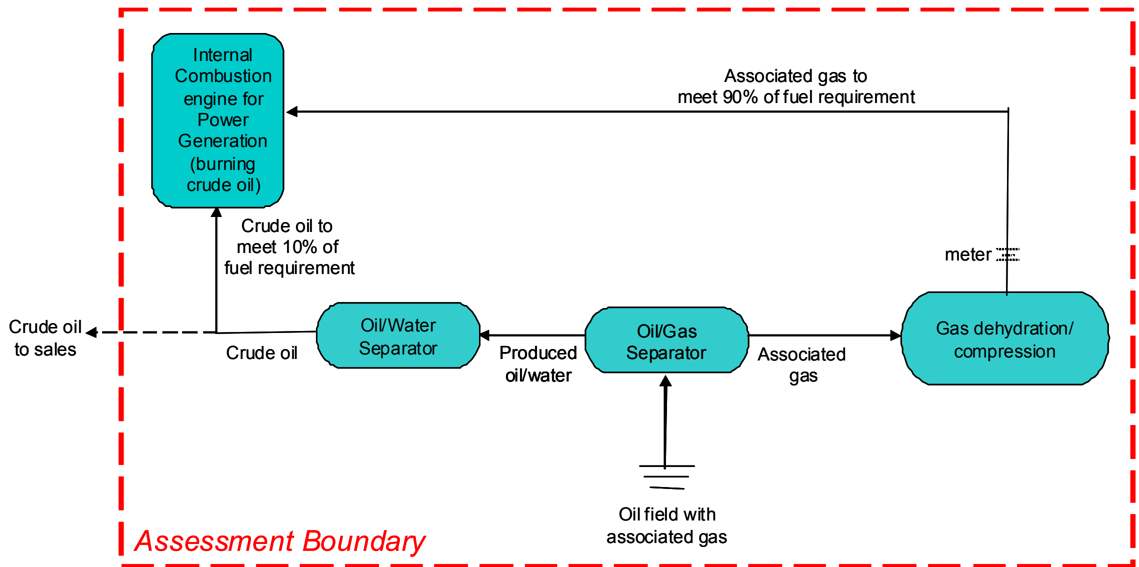

Figure 7-8. Project Assessment Boundary for Case Study #3

The project activity includes the utilization of the processed associated gas produced from the oil-gas separator for electric power generation to meet on-site energy needs. This gas replaces crude oil as the fuel for this on-site generation. In this instance, the assessment boundary would include:

- All existing emission sources within the oil field, including fuel combustion for pumping oil from the production facilities to the oil-gas separator and oil-water separator;
- Fuel combustion and fugitive emissions from equipment for dehydration of the associated gas and compression equipment prior to delivery of the recovered associated gas to the flare

in the baseline scenario or to the new internal combustion engine drivers for power generation in the project scenario;[21]

- Fuel combustion and fugitive emissions from operation of the engine drivers for power generation on crude oil fuel in the baseline scenario and primarily on associated gas in the project scenario;
- Electric pumps powered by the on-site engine drivers will continue to be used for transporting crude oil by pipeline to an off-site point of sale, as is the case in the baseline scenario; and
- No substantive life cycle or leakage issues are caused by the project activity.

Table 7-10 lists the potential emission sources within the assessment boundary and affords a comparison between the types of emissions present in the baseline scenario and project activity.

Table 7-10. Case Study #3 Assessment Boundary Determination

Potential Emission Sources		Relation to the Project Proponent	Considerations
Baseline Scenario			
Extraction and Separation of Produced Oil and Associated Gas	✓ CO_2, CH_4 and N_2O combustion emissions from the extraction and separation of associated gas from produced oil ✓ Vented and fugitive CH_4 emissions, associated with the separation of the associated gas from produced oil	Controlled	Emissions are unchanged by the project activity, and thus cancel out in the calculation of project emission reductions
Gas Treatment	✓ CO_2, CH_4 and N_2O combustion emissions from dehydration and compression of associated gas ✓ Vented and fugitive CH_4 emissions from dehydration and compression of associated gas	Controlled	Emissions are unchanged by the project activity, and thus cancel out in the calculation of project emission reductions

[21] Compression and removal of water from the gas stream sent to the flare is assumed in this hypothetical case for the baseline scenario. Depending on site-specific factors, including the pressure and moisture content of the associated gas, this equipment may not be necessary for the gas stream to the flare.

Table 7-10. Case Study #3 Assessment Boundary Determination, continued

Potential Emission Sources		Relation to the Project Proponent	Considerations
Baseline Scenario			
Associated Gas Flaring	✓ CO_2, CH_4 and N_2O combustion emissions from gas flaring ✓ Fugitive CH_4 emissions associated with flaring of associated gas at the site	Controlled	All produced associated gas is flared, but project activity effectively eliminates flaring at the site
Power Generation	✓ CO_2, CH_4 and N_2O combustion emissions from crude oil combustion in engine drivers for power generation ✓ Vented and fugitive CH_4 emissions associated with the operation of engine drivers	Controlled	Crude oil fuel for power generation will be mostly replaced in the project scenario by combustion of associated gas
Off-site Transportation of Crude Oil	✓ No direct emissions	Controlled	Electric pumps transport produced oil by pipeline to an off-site point of sale
Project Activity			
Extraction and Separation of Produced Oil and Associated Gas	✓ CO_2, CH_4 and N_2O combustion emissions from dehydration and compression of associated gas ✓ Vented and fugitive CH_4 emissions from dehydration and compression of associated gas	Controlled	Emissions are unchanged by the project activity, and thus cancel out in the calculation of project emission reductions
Gas Treatment	✓ CO_2, CH_4 and N_2O combustion emissions from dehydration and compression of associated gas ✓ Vented and fugitive CH_4 emissions from dehydration and compression of associated gas	Controlled	The same gas compression capability to prepare gas for flaring is also adequate for treating and sending the gas to the generator driver engines. Thus, this component cancels out in the calculation of emission changes
Associated Gas Flaring	✓ No emissions due to discontinuance of flaring	Controlled	Project activity effectively eliminates flaring at the site

Table 7-10. Case Study #3 Assessment Boundary Determination, continued

Potential Emission Sources		Relation to the Project Proponent	Considerations
Project Activity			
Power Generation	✓ CO_2, CH_4 and N_2O combustion emissions from associated gas and crude oil combustion in engine drivers for power (expected fuel mix for engines is 90% AG/10% crude oil) ✓ Vented and fugitive CH_4 emissions, associated with the operation of engine drivers	Controlled	Decrease in emissions due to transfer to a less carbon-intensive fuel Differences in vented and fugitive emissions compared with the baseline are negligibly small
Off-site Transportation of Crude Oil	✓ No direct emissions	Controlled	No change due to project activity. Electric pumps transport produced oil by pipeline using electric-driven pumps

Calculating Project Emission Reductions

The following exhibit demonstrates the estimation of emissions for the baseline scenario and project activity. Emission reductions are quantified as the difference between the baseline and project emissions. This example demonstrates that recovery and utilization of even a modest quantity of previously flared associated gas at an oil production site could result in a substantial increase in fuel for generating on-site power, while reducing the GHG emissions at the site by almost half and preserving for sales a crude oil stream that was previously used to meet on-site energy needs.

The project involves the following information.

<u>Before the project:</u>

- In the baseline scenario, crude oil fuel consumption for operation of the internal combustion engine drivers used to generate electricity for on-site combustion is 13,963 barrels per year. Average carbon content of the produced crude after gas and water separation is 85% by weight, and the higher heating value of this crude oil is 570 MMBtu/barrel.
- The volume of processed associated gas sent to the flare in the baseline scenario is 2.62×10^6 m^3/year (92.56×10^6 scf/yr), with a carbon content of 0.65 kg carbon/m^3 (0.0404 lb C/scf).
- The combustion and fugitive emissions associated with dehydration and compression of the associated gas for flaring in the baseline scenario are the same as dehydration and

compression to prepare this gas for use as fuel in the generator engine drivers in the project scenario.[22] Similarly, the minor combustion and fugitive emissions associated with oil-gas separation in the baseline scenario are unchanged by implementation of the project.
- All of the gas flared in the baseline scenario is used as fuel in the project scenario. However the quantity of gas is sufficient to meet only 90% of the required annual fuel stream to the replacement engines, with the remaining 10% of the fuel still supplied in the form of crude oil.
- Electric power generating capacity in the baseline scenario using the existing engines is 950 kW. The thermal efficiency of these engines burning only crude oil is 28%. Most of the produced electrical energy is used to drive electric pumps for shipment of the remaining produced crude oil to an off-site destination.

What the project will change:

- The quantity of crude oil used for power generation in the project scenario is 2,362 barrels per year. This scenario thus enables 11,601 additional barrels of crude to be shipped to markets compared with the baseline scenario. The increase in fugitive emissions associated with this increment of crude oil shipping is negligibly small.
- Electric power generating capacity in the project scenario uses new, more efficient engines rated at 1350 kW, and these engines are configured to operate on both associated gas and crude oil fuel. The thermal efficiency of the replacement engines is 33% on associated gas fuel and 30% on crude oil.

EXHIBIT 7.3: Flare Gas Recovery for On-Site Power Generation

Project Information (based on hypothetical, measured data):
- 2.62×10^6 m^3/year (92.56×10^6 scf/yr) of processed associated gas is sent to the flare in the baseline scenario.
- The carbon content of the processed associated gas is 0.65 kg carbon/m^3 (0.0404 lb C/scf).
- In the baseline scenario, crude oil fuel consumption for operation of the internal combustion engine drivers used to generate electricity for on-site combustion is 13,963 barrels per year.
- Average carbon content of the produced crude after gas and water separation is 85% by weight, and the higher heating value of this crude oil is 570 MMBtu/barrel.

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[22] As noted previously, if gas dehydration and compression equipment were not present in the baseline scenario, their addition in the project scenario would create new emissions.

EXHIBIT 7.3: Flare Gas Recovery for On-Site Power Generation, continued

- The combustion and fugitive emissions associated with dehydration and compression of the associated gas for flaring in the baseline scenario are the same as dehydration and compression to prepare this gas for use as fuel in the generator engine drivers in the project scenario. Similarly, the minor combustion and fugitive emissions associated with oil-gas separation in the baseline scenario are unchanged by implementation of the project.
- All of the gas flared in the baseline scenario is used as fuel in the project scenario. However the quantity of gas is sufficient to meet only 90% of the required annual fuel stream to the replacement engines, with the remaining 10% of the fuel still supplied in the form of crude oil.
- Electric power generating capacity is 950 kW in the baseline scenario using the existing engines. The thermal efficiency of these engines burning only crude oil is 28%. Most of the produced electrical energy is used to drive electric pumps for shipment of the remaining produced crude oil to an off-site destination.
- Electric power generating capacity in the project scenario uses new, more efficient engines rated at 1350 kW, and these engines are configured to operate on both associated gas and crude oil fuel. Thermal efficiency of the replacement engines is 33% on associated gas fuel and 30% on crude oil.
- The quantity of crude oil used for power generation in the project scenario is 2,362 barrels per year. This scenario thus enables 11,601 additional barrels of crude to be shipped to markets compared with the baseline scenario. The increase in fugitive emissions associated with this increment of crude oil shipping is negligibly small.

Baseline Emissions

Baseline emissions = CMB_1+ $VENT_1$ + FUG_1 + IND_1
where,

CMB_1 = Combustion emissions from the flared stream prior to the project and from the combustion of crude oil to operate the pump engines.
$VENT_1$ = Vented gas from maintenance or upset conditions associated with gas separation, dehydration, and compression. The vented emissions also occur unchanged in the project activity and therefore cancel out in the calculation of project emission reductions.
FUG_1 = Fugitive emissions from process units associated with gas separation, dehydration, and compression. These fugitive emissions also occur in the project activity and therefore cancel out in the calculation of baseline emission reductions.
IND_1 = Indirect emissions would result from usage of electricity obtained from outside sources. No such purchased power is used for either the baseline or project scenarios.

EXHIBIT 7.3: Flare Gas Recovery for On-Site Power Generation, continued

Baseline Emissions Estimate

Combustion Emissions (CMB_1):
Existing combustion emissions from the flare are calculated based on the metered gas volume downstream of dehydration and compression equipment, and other parameter values presented above. The annual quantity of treated associated gas that is produced and flared is 2.62×10^6 m^3 in the baseline scenario. The associated emissions were conservatively estimated by assuming that all the carbon in the fuel is converted to CO_2 during the combustion process and discharged to the atmosphere, consistent with the API *Compendium*.

Combustion emission from the existing power generation engine drivers are calculated based on the estimated volume of crude oil used to generate 950 kW of electric power (13,963 barrels per year) and the assumption that all carbon contained in the fuel is converted to CO_2 and emitted to the atmosphere.

Based on the above data, the annual CO_2 emissions due to baseline fuel consumption are calculated as follows:

CMB_1= (Metered gas volume to the flare) × (gas composition) + (Measured crude oil volume to engines) × (crude oil composition)

Flare gas portion:

$$CMB_{Flare} = \frac{2.62 \times 10^6\ m^3}{year} \times \frac{0.65\ kg\ C}{m^3} \times \frac{44\ kg\ CO_2}{12\ kg\ C} \times \frac{tonne}{1000\ kg}$$
$$= 6{,}247\ tonnes\ CO_2e$$

Crude oil portion:

$$CMB_{Crude} = \frac{17{,}807\ bbl}{year} \times \frac{42\ gal}{bbl} \times \frac{7.3\ lb}{gal} \times \frac{kg}{2.205\ lb}$$
$$\times \frac{0.85\ kg\ C}{kg\ oil} \times \frac{44\ kg\ CO_2}{12\ kg\ C} \times \frac{tonne}{1000\ kg}$$
$$= 7{,}717\ tonnes\ CO_2e$$

CMB_1 = 6,247 tonnes CO_2e + 7717 tonnes CO_2e = **13,964 tonnes CO_2e**

Vented Emissions ($VENT_1$)
Vented emissions associated with operation of the existing equipment are unchanged by the project activity and therefore cancel out in the estimation of project emission reductions.

Fugitive Emissions (FUG_1):
Fugitive emissions associated with the operation of existing equipment will be unchanged by the project activity, and therefore cancel out in the calculation of project emission reductions.

EXHIBIT 7.3: Flare Gas Recovery for On-Site Power Generation, continued

Indirect Emissions (IND_1):
There are no indirect emissions associated with either the baseline or the project scenario.

Baseline Emissions: $= CMB_1 + VENT_1 + FUG_1 + IND_1$
$= 13{,}964 + 0 + 0 + 0$
$= 13{,}964$ tonnes CO_2e.

Project Emissions Estimate:
Project emissions = $CMB_2 + VENT_2 + FUG_2 + IND_2$
where,

CMB_2 = Combustion emissions associated with use of the entire previously-flared quantity of associated gas along with some crude oil in the new internal combustion engines for on-site power generation that replace the engines in the baseline scenario. The new engines and generator have a combined capacity of 1,350 kW, 90% of which will be supplied by recovered AG, with 10% contributed by crude oil.

$VENT_2$ = Vented gas from separation of the associated gas from crude oil and subsequent dehydration and compression of the gas for use in the new generator engine drivers. For purposes of this example, it is assumed that these emissions are comparable to those in preparing the gas for flaring in the baseline scenario, and therefore cancel out in the calculation of project emission reductions

FUG_2 = Fugitive emissions resulting from separation and processing of associated gas prior to its use as a fuel for on-site power generation. These emissions are very minor and are assumed to be the same as those in the baseline scenario and therefore cancel out in the calculation of project emission reductions activity.

IND_2 = Indirect emissions would result from usage of electricity obtained from outside sources. No such purchased power is used for either the baseline or project scenarios.

Combustion Emissions (CMB_2):

Combustion of two fuels in the internal combustion engines used for on-site power generation are calculated based on the metered gas volume downstream of dehydration and compression equipment, and other parameter values presented in the first section of this exhibit. The annual quantity of treated associated gas that is produced and flared is 2.62×10^6 m^3 and in the project scenario this will all be sent to the engine drivers.

EXHIBIT 7.3: Flare Gas Recovery for On-Site Power Generation, continued

The associated emissions were conservatively estimated by assuming that all the carbon in the fuel is converted to CO_2 during the combustion process and discharged to the atmosphere, consistent with the API *Compendium*. Thus this component of the project combustion emissions is identical to the flaring emissions in the baseline scenario. This gas stream will provide 90% of the fuel energy necessary to achieve the maximum on-site power generation capacity in the project scenario of 1,350 kW. The remaining 10% will be supplied by use of crude oil fuel.

Combustion emission from crude oil used for the replacement power generation engine drivers are calculated based on the estimated volume of crude oil used to generate 135 kW of electric power (10% of the total generation) and the conservative assumption that all carbon contained in the fuel is converted to CO_2 and emitted to the atmosphere.

Based on the above data, the annual CO_2 emissions due to project activity fuel consumption are calculated as follows:

CMB_2= (Metered gas volume to power generation engine drivers) × (gas composition) + (Metered crude oil volume to the power generation engine drivers) × (crude oil composition)

Associated gas portion:

$$CMB_{Associated\ Gas} = \frac{2.62 \times 10^6\ m^3}{year} \times \frac{0.65\ kg\ C}{m^3} \times \frac{44\ kg\ CO_2}{12\ kg\ C} \times \frac{tonne}{1000\ kg}$$
$$= 6{,}247\ tonnes\ CO_2e$$

Crude oil portion:

$$CMB_{Crude} = \frac{2{,}362\ bbl}{year} \times \frac{42\ gal}{bbl} \times \frac{7.3\ lb}{gal} \times \frac{kg}{2.205\ lb}$$
$$\times \frac{0.85\ kg\ C}{kg\ oil} \times \frac{44\ kg\ CO_2}{12\ kg\ C} \times \frac{tonne}{1000\ kg}$$
$$= 1{,}024\ tonnes\ CO_2e$$

CMB_2 = CMB $_{Associated\ Gas}$ + CMB $_{Crude}$
CMB_2 = 6,247 tonnes CO_2e + 7,717 tonnes CO_2e = **7,271 tonnes CO_2e**

Vented Emissions ($VENT_2$):
Vented emissions associated with operation of the existing equipment are unchanged by the project activity and therefore cancel out in the estimation of project emission reductions.

Fugitive Emissions (FUG_2):
Fugitive emissions associated with the operation of existing equipment are unchanged by the project activity, and therefore cancel out in the calculation of project emission reductions.

EXHIBIT 7.3: Flare Gas Recovery for On-Site Power Generation, continued

Indirect emissions (IND_2)

There are no indirect emissions associated with either the baseline or the project scenario.

PROJECT EMISSIONS = $CMB_2 + VENT_2 + FUG_2 + IND_2$
= 7,271+0+0+0
= 7,271 tonnes CO_2e per year

EMISSION REDUCTIONS = Baseline Emissions – Project Emissions
= (13,964 – 7,271) tonnes CO_2e per year
= 6,693 tonnes CO_2e per year

Monitoring

Monitoring to verify the project emissions reductions resulting from this project would include the following:

- The composition, energy content and volume of associated gas delivered to the new internal combustion engines (same gas stream sent to the flare in the baseline scenario); and
- The composition, energy content and volume of crude oil delivered to the existing and new internal combustion engines in the baseline and project scenarios, respectively.

ATTACHMENT 2
CDM PROJECT METHODOLOGIES INVOLVING FLARING REDUCTION

As of the date of this document, a total of eight projects to reduce gas flaring have been successfully registered to earn carbon credits under the UNFCCC Clean Development Mechanism program. All of these projects have used one of the following approved methodologies pertaining to flare reduction projects: AM0009, AM0037, and AMS-III.P. Another methodology NM0277, Use of Recovered Gas from Oil Fields for Gas-Lift to Replace Non-Associated Gas-Lift Gas, was proposed, but not approved by the CDM Executive Board (EB). The baseline methodology used in support of a Project Design Document (PDD) submitted to the CDM Executive Board is the blueprint that defines, among other things, what baseline scenario is appropriate to the circumstances of a proposed project and what must be included and excluded in the emissions used to represent the baseline conditions and the project activity.

This Attachment summarizes the history and evolution of AM0009, AM0037, and AMS-III.P, including the rather extensive revisions to these methodologies that have occurred in just a few years. These revisions reflect changes to correct errors in previous versions, to incorporate specific features of new projects that differ in some way from those previously approved under the methodologies, or to reflect decisions by the Executive Board regarding general changes that should be incorporated by CDM methodologies of all types. These histories clearly demonstrate the level of effort that is often involved in applying or adapting the existing methodologies. However, as demonstrated by the fact that so few methodologies have been approved for flare reduction projects, adaptation or revision of an existing methodology has been generally found to be preferable to obtaining approval for a new methodology.

Most of the data presented in Table 7-11 below have been taken directly or paraphrased from a series of excellent information sheets prepared by the firm carbon Limits and distributed at a CDM Methodology Workshop on Gas Flaring on December 3, 2008 in Amsterdam, the Netherlands.

Table 7-11. Applicability and History of Approved CDM Baseline Methodologies for Flare Reduction Projects

Methodology	Version	Date Approved	History of Methodology Development and Revisions	Notes
AM0009	01	26 March 2004	**Methodology originally approved:** Applicable to gas from oil wells that was primarily flared and partly used for on-site energy needs. In the project scenario, this gas would be piped, processed, and distributed for various end uses, displacing other energy sources that had been used while the gas was flared to result in a reduction in GHG emissions.	The first methodology approved by the CDM Methodology Panel for flare reduction projects
	02	13 May 2005	**Revised methodology:** Changed applicability requirement regarding end use of gas products to those previously using "the same types of fuels or fuels with higher carbon content per unit of energy." Changed section on fugitive emissions from pipelines transporting gas. Added new section on CH_4 emissions from pipelines resulting from accidental events.	Additional revisions were proposed by project proponents to enable use of AM0009 for gas flaring reduction projects at gas processing plants and to further extend applicability to situations in which energy required for recovered gas transportation and processing is not provided by the recovered flare gas. Also proposed was a change to allow use of AM0009 when recovered gas is directly transported to end users without processing. The CDM Methodology Panel denied these proposals pending resolution of the following issues in a revised proposal for amendments: • For projects that would be implemented at gas plants, how to ensure that the amount of waste gas in the project scenario is not affected by a change in process parameters; and • For projects involving recovery and transportation of gas to end users, how to identify end users and monitor the fossil fuels replaced by recovered gas.
	02.1	22 June 2007	**Revised methodology:** Amendments to require project validators to confirm that associated gas flare reduction indicated in the PDD did not result from intentional manipulation of oil production to maximize certified emission reductions (CERs).	

Table 7-11. Applicability and History of Approved CDM Baseline Methodologies for Flare Reduction Projects, continued

Methodology	Version	Date Approved	History of Methodology Development and Revisions	Notes
AM0009 (continued)	03	30 November 2007	**Revised methodology:** Amendments expanded applicability to include project activities where associated gas is vented in the baseline. Other changes included the following: • The term "gas recovered at oil wells" used in previous versions of the methodology was changed to "associated gas." • A restriction prohibiting the use of the methodology for recovered gas streams used for gas lift was added, as was a direction to evaluate project additionality using a new "Additionality Tool" developed by UNFCCC. • Changes were made in the algorithms for calculation of project emissions to rely more heavily on measurements. • A new limitation was added to limit changes in the production of high pressure gas extracted at the production site.	The explicit prohibition against the use of AM0009 for projects involved with gas lift could exclude a fairly high fraction of oil wells from CDM consideration. A clarification was requested (AM_CLA_0073) as to whether projects that replace non-associated gas with previously flared gas would qualify under Version 03. This was denied by the Methodology Panel on the grounds that associated gas and its products can only be used for energy purposes. A revision was proposed to: (1) expand AM0009 activities to include projects where captured associated gas is compressed and transported by trucks to end-users (i.e., CNG); and (2) allow for mixing of associated and non-associated gas while ensuring that only emissions from flaring of associated gas are counted in the baseline emissions. The request for revision was not approved for the following reasons: • The baseline selection should include a procedure to identify baseline scenarios for end-user facilities (What fuel would be used in the absence of the project?) • At its 36th meeting, the CDM EB clarified that project activities that result in emission reductions due to the use of a product produced in the project activity are only eligible as a CDM project activity if: (1) the users of the product are included in the project boundary; and (2) monitoring takes place of the actual use and location of the product used by consumers. This means end-user facilities must be included in the project boundary. In response to this guidance from the EB, the Methodology Panel determined that procedures for monitoring the final use of CNG at end-user facilities needed to be developed.

Table 7-11. Applicability and History of Approved CDM Baseline Methodologies for Flare Reduction Projects, continued

Methodology	Version	Date Approved	History of Methodology Development and Revisions	Notes
AM0009 (continued)	3.2	26 September 2008	A request for clarification pointed out an error in an equation in Version 3.1 and this was corrected.	Per this correction, any imbalance between input and output during the processing of gas or its products is assumed to leak out as CH_4, regardless of the actual composition. This very conservative assumption can be a significant factor in the calculation of GHG emission reductions resulting from projects involving large gas processing facilities.
	3.3	28 November 2008	**Revised methodology:** Editorial revisions were made to delete the term 'transportation' from the section "CH_4 project emissions from venting, leak or flaring of the associated gas."	Requests for clarification regarding Version 3.2 were submitted to the Methodology Panel. Clarification was sought on: (1) the approach for calculating project emissions of CH_4 from venting, leaking or flaring of the associated gas; (2) accounting of potential emission reductions due to fuel switching at on-site units; (3) the approach to address the uncertainty associated with monitoring data; and (4) the limitation of recovery to "associated gas from oil wells" and introduction of applicability conditions limiting changes in oil and non-associated gas production. The Methodology Panel responded to these requests as follows: • AM0009 has no provisions concerning the selection of baseline scenarios for the gas source used for gas-lift or the calculation of upstream emissions from possible external gas sources; • Calculation of CH_4 project emissions was changed from default factors because that approach does not account for emissions from flaring and venting within the project activity; and • Encouraged requests for revisions to include the opportunity for fuel switching within the project boundary (e.g., from wet to dry gas) and expand the assessment of uncertainty. Subsequently, a new revision to AM0009 was proposed in order to address the following: • Extend the scope to allow gas originating from a gas-lift operation; • Extend the scope to include situations where the recovered gas is mixed with gas from other oil wells prior to delivery to gas processing facilities and transmission pipelines; and • Include CH_4 emissions from gas venting in the baseline scenario (apply a factor of 21 to CH_4 vented in the baseline). The Methodology Panel determined that further analysis is needed to address the proposed expansion to include gas from gas-lift systems.

Table 7-11. Applicability and History of Approved CDM Baseline Methodologies for Flare Reduction Projects, continued

Methodology	Version	Date Approved	History of Methodology Development and Revisions	Notes
AM0037	01	29 September 2006	**Initial Adoption:** This methodology was developed for projects that recover previously-flared associated gas from oil wells and utilize the gas in an existing or new end-use facility, both as a feedstock and, if applicable, partly as an energy source to produce a useful chemical product. Such chemical products could include methanol, ethylene or ammonia. The specific applicability criteria stated in Version 01 included: • The surplus tail gas substitutes the same type of fuels/feedstock with a higher CO_2 equivalent emissions impact. • The use of tail gas in production of a useful product does not lead to displacement of production in a new plant that would be built in the absence of the project activity in an Annex 1 country. • The use of tail gas by the project activity will not lead to an increase in fuel consumption outside the project boundary. • Energy requirements of the project activity are met primarily using the previously flared tail gas.	When this methodology was developed, the original version of AM0009 was already approved. It was meant to build upon AM0009 to include projects where flaring occurred after processing instead of at the point of extraction. The original proposed methodology (NM0145) defined the boundary that included the end-user facility that utilizes the recovered gas as a feedstock or fuel. It was envisioned as being applicable only to new facilities constructed to use otherwise-flared gas as a feedstock and not existing facilities. The Methodology Panel found that the proposal did not address the issue of potential changes in emissions due to substitution of fuels or additional fuel use by end-users and suggested that the corresponding section of AM0009 be brought into the methodology. The Panel also felt that unlike the facilities addressed in AM0009, those using the proposed methodology may construct new end-product facilities to produce methanol, ethylene or ammonia, thus having a possible effect on the international supply of these chemicals, and hence on activities outside the project boundary. The Panel concluded that this topic should be addressed in the leakage analysis and that the project boundary should explicitly include the production facilities for the end product. The methodology proposal was approved after revisions were made in response to the above concerns. Of particular note was that the treatment of baseline, project, and leakage emissions was based on the criterion that the project generated from CDM activities would otherwise have used a fuel and/or feedstock with equal or higher CO_2 equivalent emissions.

Table 7-11. Applicability and History of Approved CDM Baseline Methodologies for Flare Reduction Projects, continued

Methodology	Version	Date Approved	History of Methodology Development and Revisions	Notes
AM0037	02	14 March 2008	**Revised Methodology:** The methodology was revised to incorporate a number of specific changes in its applicability, baseline scenario, identification process and determination of emission reductions, as summarized below: • The applicable source of gas was changed from oil and gas processing facility tail gas to associated gas from oil wells. • The applicability was limited to exclude project activities that use associated gas for energy purposes alone (such projects should use AM0009). • Both the end-use facility using the associated gas in the project activity and the facilities where the useful product would be produced without the project were included in the project boundary. • The baseline scenario is determined based on an assessment of both what would happen to the associated gas in the absence of the project and how the chemical product resulting from the project activity would have been produced in the absence of the project activity. • Baseline emissions were changed to reflect emissions from gas flaring and from production of useful products with an alternative production method, while project emissions include those from consumption of all fossil fuels (including recovered gas), and fugitive emissions from transportation and leaks form accidental events. • The emission reduction calculation reflects the avoided emissions from not producing the same products using the preferred alternative minus any additional emissions from production based on recovered gas (not including emissions from flared gas).	

Table 7-11. Applicability and History of Approved CDM Baseline Methodologies for flare reduction projects, continued

Methodology	Version	Date Approved	History of Methodology Development and Revisions	Notes
AMS-III.P	01	19 October 2007	**Initial Adoption.** Applicable to project activities at existing refineries that develop an alternate use for the energy content of waste gas that is being flared in order to generate process heat, replacing fossil fuel combustion. The following conditions apply to this methodology: • Recovered waste gases are used in the same refinery facility; • The project activity does not lead to an increase in the production capacity of the refinery; • Waste gas flow and composition are measureable; • There should not be any addition of fuel gas or refinery gas in the waste gas pipeline between the point of recovery and the point where it is mixed in the fuel gas system or used directly in an elemental process; and • The recovery device is placed just before the flare header and after all the waste gas generation devices.	The methodology is limited to applications that result in emission reductions of less than or equal to 60 ktonnes CO_2 equivalent annually.

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