Approved consolidated baseline and monitoring methodology ACM0009

"Consolidated baseline and monitoring methodology for fuel switching from coal or petroleum fuel to natural gas"

I. SOURCE AND APPLICABILITY

Sources

This consolidated baseline and monitoring methodology is based on elements from the following methodologies:

- NM0131: "Baseline methodology for project activities involving fuel-switching measures at an industrial facility" prepared by MGM International and Alicorp S.A.;
- NM0132: "Industrial fuel switching from petroleum fuels to natural gas without extension of capacity and lifetime of the facility where barriers to switching exist" prepared by Nexant, Inc. and Sinai Cement Company;
- AM0008: "Industrial fuel switching from coal and petroleum fuels to natural gas without extension of capacity and lifetime of the facility", which was based on the NM0016-rev "Graneros Plant Fuel Switching Project" whose project design document was prepared by MGM International, Inc., in August 2003.

This methodology also refers to the latest approved versions of the following tool:

- Tool for the demonstration and assessment of additionality.

For more information regarding the proposed new methodologies and the tools as well as their consideration by the Executive Board (hereinafter referred to as the Board) of the clean development mechanism (CDM) please refer to <http://cdm.unfccc.int/goto/MPappmeth>.

Selected approach from paragraph 48 of the CDM modalities and procedures

"Existing actual or historical emissions, as applicable"

Applicability

This methodology is applicable to project activities that switch in one or several element processes[1] from coal or petroleum fuel to natural gas. The fuel switching is undertaken in processes for heat generation that are located at and directly linked to an industrial process with a main output other than heat or that provide heat to a district heating system by means of heat-only boilers. Furthermore, the following conditions apply:

- Prior to the implementation of the project activity, only coal or petroleum fuel (but not natural gas) have been used in the element processes;

[1] An "*element process*" is defined as fuel combustion in a single equipment at one point of an industrial facility or of a district heating system, for the purpose of providing thermal energy (the fuel is not combusted for the purpose of electricity generation or used as oxidant in chemical reactions or otherwise used as feedstock). Examples of an element process are steam generation by a boiler and hot air generation by a furnace. Each element process should generate a single output (such as steam or hot air) by using mainly a single fuel (not plural energy sources). For each element process, energy efficiency is defined as the ratio between the useful energy (the enthalpy of the steam/water/gas multiplied with the steam/water/gas quantity) and the supplied energy to the element process (the net calorific values of the fuel multiplied with the fuel quantity). This methodology covers fuel switch in several element processes, i.e. project participants may submit one CDM-PDD for fuel switch in several element processes within one industrial facility.

- Regulations/programs do not constrain the facility from using the fossil fuels being used prior to fuel switching;
- Regulations do not require the use of natural gas or any other fuel in the element processes;
- The project activity does not increase the capacity of thermal output or lifetime of the element processes during the crediting period (i.e. emission reductions are only accounted up to the end of the lifetime of the relevant element process), nor is there any thermal capacity expansion planned for the project facility during the crediting period;
- The proposed project activity does not result in integrated process change.

II. BASELINE METHODOLOGY

Project boundary

The project boundary covers CO_2 emissions associated with fuel combustion in each element process subject to the fuel switching. The project boundary is applicable to both baseline emissions and project emissions.

For the purpose of determining **project activity emissions**, project participants shall include carbon dioxide emissions from the combustion of natural gas in each element process.

For the purpose of determining **baseline emissions**, project participants shall include carbon dioxide emissions from the combustion of the quantity of coal or petroleum fuel that would be used in each element process in the absence of the project activity.

The **spatial extent** of the project boundary encompasses the physical, geographical site of the industrial facility or the district heating system.

Table 1: Emission sources included and excluded in the project boundary

	Source	Gas	Included?	Justification/Explanation
Baseline	Baseline fuel burning	CO_2	Yes	Main emission source
		CH_4	No	Minor source
		N_2O	No	Minor source
Project Activity	Natural gas burning	CO_2	Yes	Main emission source
		CH_4	No	Minor source
		N_2O	No	Minor source

Identification of the baseline scenario

Project participants shall determine the most plausible baseline scenario through the application of the following steps. Where the project activity involves fuel switching in several element processes, the steps should be applied to each element process.

Step 1: Identify all realistic and credible alternatives for the fuel use in the element process

Project participants should at least consider the following alternatives:

- Continuation of the current practice of using coal or petroleum fuel;
- Switching from coal or petroleum fuel to a different fuel than natural gas (such as biomass);

- The project activity not undertaken under the CDM (switching from coal or petroleum fuel to natural gas);
- Switching from coal or petroleum fuel to natural gas at a future point in time during the crediting period.

Step 2: Eliminate alternatives that are not complying with applicable laws and regulations

Eliminate alternatives that are not in compliance with all applicable legal and regulatory requirements. Apply Sub-step 1b of the latest version of the "Tool for the demonstration and assessment of additionality" agreed by the Board.

Step 3: Eliminate alternatives that face prohibitive barriers

Scenarios that face prohibitive barriers should be eliminated by applying Step 3 of the latest version of the "Tool for the demonstration and assessment of additionality" agreed by the Board.

Step 4: Compare economic attractiveness of remaining alternatives

Compare the economic attractiveness without revenues from CERs for all alternatives that are remaining by applying Step 2 of the latest version of the "Tool for the demonstration and assessment of additionality" agreed by the Board. The economic investment analysis shall use the net present value (NPV) analysis, and explicitly state the following parameters:

- Investment requirements (incl. break-up into major equipment cost, required construction work, installation);
- A discount rate appropriate to the country and sector (Use government bond rates, increased by a suitable risk premium to reflect private investment in fuel switching projects, as substantiated by an independent (financial) expert);
- Efficiency of each element process, taking into account any differences between fuels;
- Current price and expected future price (variable costs) of each fuel
  (Note: As a default assumption the current fuel prices may be assumed as future fuel prices. Where project participants intend to use future prices that are different from current prices, the future prices have to be substantiated by a public and official publication from a governmental body or an intergovernmental institution);
- Operating costs for each fuel (especially, handling/treatment costs for coal);
- Lifetime of the project, equal to the remaining lifetime of the existing heat generation facility;
- Other operation and maintenance costs.

The NPV calculation should take into account the residual value of the new equipment at the end of the lifetime of the project activity.[2] Provide all the assumptions in the CDM-PDD.

Compare the NPV of the different scenarios and select the most cost-effective scenario (i.e. with the highest NPV) as the baseline scenario. Include a sensitivity analysis applying Sub-step 2d of the latest version of the "Tool for the demonstration and assessment of additionality" agreed by the Board. The investment analysis provides a valid argument that the most cost-effective scenario is the baseline scenario if it consistently supports (for a realistic range of assumptions) this conclusion. In case the sensitivity analysis is not fully conclusive, select the baseline scenario alternative with least emissions among the alternatives that are the most economically attractive according to the investment analysis and the sensitivity analysis.

[2] Note that NPV values may be negative.

This methodology is only applicable if the continuation of the use of coal or petroleum fuel throughout the crediting period is the most plausible baseline scenario.

Additionality

The assessment of additionality comprises two steps:

Step 1: Investment & sensitivity analysis

Demonstrate that the project activity undertaken without the CDM is economically less attractive than the most plausible baseline scenario, by following the instructions given in Step 4 of the chapter "Identification of the baseline scenario" above. Include a sensitivity analysis applying Sub-step 2d of the latest version of the "Tool for the demonstration and assessment of additionality" agreed by the Board. The investment analysis provides a valid argument in favour of additionality only if it consistently supports (for a realistic range of assumptions) the conclusion that the project activity is unlikely to be the most financially attractive.

Step 2: Common practice analysis

Demonstrate that the project activity is not common practice in the relevant country and sector by applying Step 4 of the latest version of the "Tool for the demonstration and assessment of additionality" agreed by the Board.

If all two steps are satisfied, then the project is considered additional

Project emissions

Project emissions (PE_y) include CO_2 emissions from the combustion of natural gas in all element processes i. Project emissions are calculated based on the quantity of natural gas combusted in all element processes i and respective net calorific values and CO_2 emission factors for natural gas ($EF_{NG,CO2}$), as follows:

$$PE_y = FF_{project,y} \cdot NCV_{NG,y} \cdot EF_{NG,CO2,y} \tag{1}$$

with

$$FF_{project,y} = \sum_i FF_{project,i,y} \tag{2}$$

Where:

PE_y	=	Project emissions during the year y in tCO_2e
$FF_{project,y}$	=	Quantity of natural gas combusted in all element processes during the year y in m^3[3]
$FF_{project,i,y}$	=	Quantity of natural gas combusted in the element process i during the year y in m^3[3]
$NCV_{NG,y}$	=	Average net calorific value of the natural gas combusted during the year y in GJ/m^3[3]
$EF_{NG,CO2,y}$	=	CO_2 emission factor of the natural gas combusted in all element processes in the year y in tCO_2/GJ

For the determination of emission factors and net calorific values, guidance by the latest IPCC Good Practice Guidance should be followed where appropriate. Project participants may either conduct measurements or they may use accurate and reliable local or national data where available. Where such data is not available, IPCC default emission factors (country-specific, if available) may be used if they

[3] m^3 should be provided at norm conditions for pressure and temperature.

are deemed to reasonably represent local circumstances. All values should be chosen in a conservative manner (i.e. higher values should be chosen within a plausible range) and the choice should be justified and documented in the CDM-PDD. Where measurements are undertaken, project participants may estimate the emission factors or net calorific values ex ant*e* in the CDM-PDD and should document the measurement results after implementation of the project activity in their monitoring reports.

Baseline emissions

Baseline emissions (BE_y) include CO_2 emissions from the combustion of the quantity of coal or petroleum fuel that would in the absence of the project activity be used in all element processes *i*. Baseline emissions are calculated based on the quantity of coal or petroleum fuel that would be combusted in each element processes *i* in the absence of the project activity and respective net calorific values and CO_2 emission factors. The quantity of coal or petroleum fuel that would be used in the absence of the project activity in an element process *i* ($FF_{baseline,i,y}$) is calculated based on the actual monitored quantity of natural gas combusted in this element process ($FF_{project,i,y}$) and the relation of the energy efficiencies and the net calorific values between the project scenario (use of natural gas) and the baseline scenario (use of coal or petroleum fuel).

$$BE_y = \sum_i FF_{baseline,i,y} \cdot NCV_{FF,i} \cdot EF_{FF,CO2,i} \quad \textbf{(3)}$$

with

$$FF_{baseline,i,y} = FF_{project,i,y} \cdot \frac{NCV_{NG,y} \cdot \varepsilon_{project,i}}{NCV_{FF,i} \cdot \varepsilon_{baseline,i,y}} \quad \textbf{(4)}$$

Where:

BE_y	=	Baseline emissions during the year *y* in tCO_2e
$FF_{baseline,i,y}$	=	Quantity of coal or petroleum fuel that would be combusted in the absence of the project activity in the element process *i* during the year *y* in a volume or mass unit
$FF_{project,i,y}$	=	Quantity of natural gas combusted in the element process *i* during the year *y* in m³
$NCV_{NG,y}$	=	Average net calorific value of the natural gas combusted during the year *y* in GJ/m³
$NCV_{FF,i}$	=	Average net calorific value of the coal or petroleum fuel that would be combusted in the absence of the project activity in the element process *i* during the year *y* in GJ per volume or mass unit
$EF_{FF,CO2,i}$	=	CO_2 emission factor of the coal or petroleum fuel type that would be combusted in the absence of the project activity in the element process *i* in tCO_2/GJ
$\varepsilon_{project,i}$	=	Energy efficiency of the element process *i* if fired with natural gas
$\varepsilon_{baseline,i,y}$	=	Energy efficiency of the element process *i* if fired with coal or petroleum fuel respectively

Note that the most plausible baseline scenario may be that several fuel types would be used in the different element processes or that several fuel types would be used in one element process. Where several fuel types have been used in one element process prior to the implementation of the project activity (including cases where a start-up fuel[4] is clearly defined) and where the continuation of this practice is the most plausible baseline scenario, project participants should exclude the start-up fuel from the list of multiple fuels and, as a conservative approach, select the fuel type with the lowest CO_2

[4] If a fuel is defined as a start-up fuel, it should not represent more than 3% of the total fuel utilized in the process, on energy basis.

emission factor from the fuels used in that element process during the last three years as the baseline emission factor ($EF_{FF,CO2,i}$) and the baseline net calorific value ($NCV_{FF,i}$).

For the determination of emission factors and net calorific values, guidance by the latest IPCC Good Practice Guidance should be followed where appropriate. Project participants may either conduct measurements or they may use accurate and reliable local or national data where available. Where such data is not available, IPCC default emission factors (country-specific, if available) may be used if they are deemed to reasonably represent local circumstances. All values should be chosen in a conservative manner (i.e., lower values should be chosen within a plausible range) and the choice should be justified and documented in the CDM-PDD. Where measurements are undertaken, project participants may estimate the emission factors or net calorific values ex ante in the CDM-PDD and should document the measurement results after implementation of the project activity in their monitoring reports.

The energy efficiencies have to be determined for each element process for the project activity ($\varepsilon_{project,i}$) and the baseline scenario ($\varepsilon_{baseline,i}$). The efficiencies should be determined by undertaking measurements at the element process firing the relevant fuels. Efficiencies for the project activity ($\varepsilon_{project,i}$) should be measured monthly throughout the crediting period and annual averages should be used for emission calculations.

Baseline efficiency ($\varepsilon_{baseline,i}$) is calculated as:

Option A: Use a default conservative value equal to 1.

Option B: Use a default conservative value obtained from the manufacture’s databook, taking the highest possible efficiency under optimal operational conditions.

Option C: Measure efficiency monthly during 6 months before project implementation and the six months average should be used for emission calculations.

All measurements should be conducted at a representative load factor (or operation mode), following national or international standards. Where a representative load factor (or operation mode) cannot be determined, measurements should be conducted for different load factors (or operation modes) and be weighted by the time these load factors (or operation modes) are typically operated. The same load factor(s) (or operation mode(s)) and weight factors should be used in the determination of $\varepsilon_{project,i}$ and $\varepsilon_{baseline,i}$.

Option D: Where project participants can reasonably demonstrate that the efficiency of the element process does not change due to the fuel switch or that any changes are negligible (i.e., $\varepsilon_{project,i}$ - $\varepsilon_{baseline,i}$ < 1%) or that $\varepsilon_{project,i}$ can be expected to be smaller than $\varepsilon_{baseline,i}$, project participants may assume $\varepsilon_{project,i} = \varepsilon_{baseline,i}$ as a simplification.

Option E: Use default baseline efficiency.

Table 2: Default baseline efficiency for different boilers

Heat supply technology	**Default efficiency**
New oil fired boiler	90%
New coal fired boiler	85%
Old oil fired boiler	85%
Old coal fired boiler	80%

The values determined for $\varepsilon_{baseline,i}$ should be documented in the CDM-PDD and shall remain fixed throughout the crediting period.

Leakage

Leakage may result from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary. This includes mainly fugitive CH_4 emissions and CO_2 emissions from associated fuel combustion and flaring. In this methodology, the following leakage emission sources shall be considered:[5]

- Fugitive CH_4 emissions associated with fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of natural gas used in the project plant and fossil fuels used in the grid in the absence of the project activity;
- In the case LNG is used in the project plant: CO_2 emissions from fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system.

Thus, leakage emissions are calculated as follows:

$$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y} \tag{5}$$

Where:

LE_y	=	Leakage emissions during the year y in tCO_2e
$LE_{CH4,y}$	=	Leakage emissions due to fugitive upstream CH_4 emissions in the year y in tCO_2e
$LE_{LNG,CO2,y}$	=	Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year y in tCO_2e

Note that to the extent that upstream emissions occur in Annex I countries that have ratified the Kyoto Protocol, from 1 January 2008 onwards, these emissions should be excluded, if technically possible, in the leakage calculations.

Fugitive methane emissions

For the purpose of determining fugitive methane emissions associated with the production – and in case of natural gas, the transportation and distribution of the fuels – project participants should multiply the quantity of natural gas consumed in all element processes *i* with a methane emission factor for these upstream emissions ($EF_{NG,upstream,CH4}$), and subtract for all fuel types *k* which would be used in the absence of the project activity the fuel quantities multiplied with respective methane emission factors ($EF_{k,upstream,CH4}$), as follows:

$$LE_{CH4,y} = \left[FF_{project,y} \cdot NCV_{NG,y} \cdot EF_{NG,upstream,CH4} - \sum_k FF_{baseline,k,y} \cdot NCV_k \cdot EF_{k,upstream,CH4} \right] \cdot GWP_{CH4} \tag{6}$$

with

$$FF_{project,y} = \sum_i FF_{project,i,y} \tag{7}$$

5 The Meth Panel is undertaking further work on the estimation of leakage emission sources in case of fuel switch project activities. This approach may be revised based on outcome of this work.

and

$$FF_{baseline,k,y} = \sum_{i} FF_{baseline,i,k,y} \quad \textbf{(8)}$$

Where:

$LE_{CH4,y}$	=	Leakage emissions due to upstream fugitive CH_4 emissions in the year *y* in t CO_2e
$FF_{project,y}$	=	Quantity of natural gas combusted in all element processes during the year *y* in m^3[3]
$FF_{project,i,y}$	=	Quantity of natural gas combusted in the element process *i* during the year *y* in m^3[3]
$NCV_{NG,y}$	=	Average net calorific value of the natural gas combusted during the year *y* in GJ/m^3[3]
$EF_{NG,upstream,CH4}$	=	Emission factor for upstream fugitive methane emissions from production, transportation and distribution of natural gas in t CH_4 per GJ fuel supplied to final consumers
$FF_{baseline,k,y}$	=	Quantity of fuel type *k* (a coal or petroleum fuel type) that would be combusted in the absence of the project activity in all element processes during the year *y* in a volume or mass unit
$FF_{baseline,i,k,y}$	=	Quantity of fuel type *k* (a coal or petroleum fuel type) that would be combusted in the absence of the project activity in the element process *i* during the year *y* in a volume or mass unit
NCV_k	=	Average net calorific value of the fuel type *k* (a coal or petroleum fuel type) that would be combusted in the absence of the project activity during the year *y* in GJ per volume or mass unit
$EF_{k,upstream,CH4}$	=	Emission factor for upstream fugitive methane emissions from production of the fuel type *k* (a coal or petroleum fuel type) in t CH_4 per GJ fuel produced
GWP_{CH4}	=	Global warming potential of methane valid for the relevant commitment period

Where reliable and accurate national data on fugitive CH_4 emissions associated with the production, and in case of natural gas, the transportation and distribution of the fuels is available, project participants should use this data to determine average emission factors by dividing the total quantity of CH_4 emissions by the quantity of fuel produced or supplied respectively.[6] Where such data is not available, project participants may use the default values provided in Table 3 below. In this case, the natural gas emission factor for the location of the project should be used, except in cases where it can be shown that the relevant system element (gas production and/or processing/transmission/distribution) is predominantly of recent vintage and built and operated to international standards, in which case the US/Canada values may be used.

Note that the emission factor for fugitive upstream emissions for natural gas ($EF_{NG,upstream,CH4}$) should include fugitive emissions from production, processing, transport and distribution of natural gas, as indicated in the Table 3 below. Note further that in case of coal the emission factor is provided based on a mass unit and needs to be converted in an energy unit, taking into account the net calorific value of the coal.

6 GHG inventory data reported to the UNFCCC as part of national communications can be used where country-specific approaches (and not IPCC Tier 1 default values) have been used to estimate emissions.

Table 3: Default emission factors for fugitive CH_4 upstream emissions[7]

Activity	Unit	Default emission factor	Reference for the underlying emission factor range in Volume 3 of the *1996 Revised IPCC Guidelines*
Coal			
Underground mining	t CH4 / kt coal	13.4	Equations 1 and 4, p. 1.105 and 1.110
Surface mining	t CH4 / kt coal	0.8	Equations 2 and 4, p.1.108 and 1.110
Oil			
Production	t CH4 / PJ	2.5	Tables 1-60 to 1-64, p. 1.129 - 1.131
Transport, refining and storage	t CH4 / PJ	1.6	Tables 1-60 to 1-64, p. 1.129 - 1.131
Total	t CH4 / PJ	4.1	
Natural gas			
USA and Canada			
Production	t CH4 / PJ	72	Table 1-60, p. 1.129
Processing, transport and distribution	t CH4 / PJ	88	Table 1-60, p. 1.129
Total	t CH4 / PJ	160	
Eastern Europe and former USSR			
Production	t CH4 / PJ	393	Table 1-61, p. 1.129
Processing, transport and distribution	t CH4 / PJ	528	Table 1-61, p. 1.129
Total	t CH4 / PJ	921	
Western Europe			
Production	t CH4 / PJ	21	Table 1-62, p. 1.130
Processing, transport and distribution	t CH4 / PJ	85	Table 1-62, p. 1.130
Total	t CH4 / PJ	105	
Other oil exporting countries / Rest of world			
Production	t CH4 / PJ	68	Table 1-63 and 1-64, p. 1.130 and 1.131
Processing, transport and distribution	t CH4 / PJ	228	Table 1-63 and 1-64, p. 1.130 and 1.131
Total	t CH4 / PJ	296	

Note: The emission factors in this table have been derived from IPCC default Tier 1 emission factors provided in Volume 3 of the 1996 Revised IPCC Guidelines, by calculating the average of the provided default emission factor range.

CO_2 emissions from LNG

Where applicable, CO_2 emissions from fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($LE_{LNG,CO2,y}$) should be estimated by multiplying the quantity of natural gas combusted in the project with an appropriate emission factor, as follows:

$$LE_{LNG,CO2,y} = FF_{project,y} \cdot EF_{CO2,upstream,LNG} \tag{9}$$

Where:

$LE_{LNG,CO2,y}$	=	Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year y in tCO_2e
$FF_{project,y}$	=	Quantity of natural gas combusted in all element processes during the year y in m^3[3]
$EF_{CO2,upstream,LNG}$	=	Emission factor for upstream CO_2 emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system

7 While using values from this table in the equation 6, make the required corrections in the units.

Where reliable and accurate data on upstream CO_2 emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system is available, project participants should use this data to determine an average emission factor. Where such data is not available, project participants may assume a default value of 6 tCO_2/TJ as a rough approximation.[8]

Emission reductions

The emission reduction by the project activity during a given year y (ER_y) is the difference between the baseline emissions (BE_y) and project emissions (PE_y) and leakage emissions (L_y), as follows:

$$ER_y = BE_y - PE_y - LE_y \tag{10}$$

Where:

ER_y	=	Emissions reductions of the project activity during the year y in tCO_2e
BE_y	=	Baseline emissions during the year y in tCO_2e
PE_y	=	Project emissions during the year y in tCO_2e
LE_y	=	Leakage emissions in the year y in tCO_2e

Data and parameters not monitored

<table>
<tr><td>Parameter:</td><td>$EF_{FF,CO2,i}$</td></tr>
<tr><td>Data unit:</td><td>tCO_2/GJ</td></tr>
<tr><td>Description:</td><td>CO_2 emission factor of the coal or petroleum fuel type that would be combusted in the absence of the project activity in the element process i</td></tr>
<tr><td>Source of data:</td><td>The following data sources may be used if the relevant conditions apply:
<table>
<tr><td>Data source</td><td>Conditions for using the data source</td></tr>
<tr><td>(a) Values provided by the fuel supplier in invoices</td><td>This is the preferred source</td></tr>
<tr><td>(b) Measurements by the project participants</td><td>If (a) is not available</td></tr>
<tr><td>(c) Regional or national default values</td><td>If (a) is not available

These sources can only be used for liquid fuels and should be based on well documented, reliable sources (such as national energy balances)</td></tr>
<tr><td>(d) IPCC default values at the lower limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories</td><td>If (a) is not available</td></tr>
</table></td></tr>
</table>

[8] This value has been derived on data published for North American LNG systems. “Barclay, M. and N. Denton, 2005. Selecting offshore LNG process. <http://www.fwc.com/publications/tech_papers/files/LNJ091105p34-36.pdf> (10th April 2006)”.

Measurement procedures (if any):	For (a) and (b): Measurements should be undertaken in line with national or international fuel standards. For (a): if the fuel supplier does provide the NCV value and the CO_2 emission factor on the invoice and these two values are based on measurements for this specific fuel, this CO_2 factor should be used. If another source for the CO_2 emission factor is used or no CO_2 emission factor is provided, Options (b), (c) or (d) should be used
Any comment:	-

Parameter:	GWP_{CH4}
Data unit:	tCO_2e/tCH_4
Description	Global warming potential of methane valid for the relevant commitment period
Source of data:	IPCC
Measurement procedures (if any):	Default value for the first commitment period = 21 tCO_2e/tCH_4
Any comment:	-

<table>
<tr><td>Parameter:</td><td>$NCV_{FF,i}$</td></tr>
<tr><td>Data unit:</td><td>GJ per mass or volume unit</td></tr>
<tr><td>Description</td><td>Average net calorific value of the coal or petroleum fuel that would be combusted in the absence of the project activity in the element process i during the year y</td></tr>
<tr><td>Source of data:</td><td>The following data sources may be used if the relevant conditions apply:
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</table>
</td></tr>
<tr><td>Measurement procedures (if any):</td><td>For (a) and (b): Measurements should be undertaken in line with national or international fuel standards</td></tr>
<tr><td>Any comment:</td><td>Note that for the NCV the same basis (pressure and temperature) should be used as for the fuel consumption</td></tr>
</table>

III. MONITORING METHODOLOGY

Monitoring procedures

The monitoring procedures are explained below in the respective tables of each parameter.

Data and parameters monitored

Data / Parameter:	$FF_{project,i,y}$
Data unit:	m^3
Description:	Quantity of natural gas combusted in the element process *i* during the year *y*
Source of data:	On-site measurements
Measurement procedures (if any):	Use volume meters
Monitoring frequency:	Continuously
QA/QC procedures:	The consistency of metered fuel consumption quantities should be crosschecked by an annual energy balance that is based on purchased quantities and stock changes. Where the purchased fuel invoices can be identified specifically for the CDM project, the metered fuel consumption quantities should also be cross-checked with available purchase invoices from the financial records
Any comment:	-

Data / Parameter:	$EF_{NG,CO2,y}$
Data unit:	tCO_2/GJ
Description:	CO_2 emission factor of the natural gas combusted in all element processes in the year *y*
Source of data:	The following data sources may be used if the relevant conditions apply:

Data source	**Conditions for using the data source**
(a) Values provided by the fuel supplier in invoices	This is the preferred source
(b) Measurements by the project participants	If (a) is not available
(c) Regional or national default values	If (a) is not available These sources can only be used for liquid fuels and should be based on well documented, reliable sources (such as national energy balances)
(d) IPCC default values at the upper limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories	If (a) is not available

Measurement procedures (if any):	For (a) and (b): Measurements should be undertaken in line with national or international fuel standards. For (a): if the fuel supplier does provide the NCV value and the CO_2 emission factor on the invoice and these two values are based on measurements for this specific fuel, this CO_2 factor should be used. If another source for the CO_2 emission factor is used or no CO_2 emission factor is provided, Options (b), (c) or (d) should be used
Monitoring frequency:	Monthly
QA/QC procedures:	-
Any comment:	-

Data / Parameter:	$NCV_{NG,y}$
Data unit:	GJ/m³
Description:	Average net calorific value of the natural gas combusted during the year *y*
Source of data:	The following data sources may be used if the relevant conditions apply: <table><tr><th>Data source</th><th>Conditions for using the data source</th></tr><tr><td>(a) Values provided by the fuel supplier in invoices</td><td>This is the preferred source</td></tr><tr><td>(b) Measurements by the project participants</td><td>If (a) is not available</td></tr><tr><td>(c) Regional or national default values</td><td>If (a) is not available These sources can only be used for liquid fuels and should be based on well documented, reliable sources (such as national energy balances)</td></tr><tr><td>(d) IPCC default values at the upper or lower limit - whatever is more conservative[9] - of the uncertainty at a 95% confidence interval as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories</td><td>If (a) is not available</td></tr></table>
Measurement procedures (if any):	For (a) and (b): Measurements should be undertaken in line with national or international fuel standards

[9] The more conservative value is the value that results in the lower overall emission reductions of the project activity. This may imply using the higher or the lower value, depending on the specific configuration of the project activity.

Monitoring frequency:	For (a) and (b): the NCV should be obtained for each fuel delivery, from which weighted average annual values should be calculated.
	For (c): review appropriateness of the values annually.
	For (d): any future revision of the IPCC Guidelines should be taken into account

QA/QC procedures:	Verify if the values under (a), (b) and (c) are within the uncertainty range of the IPCC default values as provided in Table 1.2, Vol. 2 of the 2006 IPCC Guidelines. If the values fall below this range collect additional information from the testing laboratory to justify the outcome or conduct additional measurements. The laboratories in a), b) or c) should have ISO17025 accreditation or justify that they can comply with similar quality standards
Any comment:	Note that for the NCV the same basis (pressure and temperature) should be used as for the fuel consumption

Data / Parameter:	$\varepsilon_{project,i,y}$
Data unit:	-
Description:	Energy efficiency of the element process *i* if fired with natural gas
Source of data:	-
Measurement procedures (if any):	The efficiencies should be determined by undertaking measurements at the element process firing the relevant fuels. All measurements should be conducted at a representative load factor (or operation mode), based on national or international standards. Where a representative load factor (or operation mode) cannot be determined, measurements should be conducted for different load factors (or operation modes) and be weighted by the time these load factors (or operation modes) are typically operated
Monitoring frequency:	Monthly
QA/QC procedures:	-
Any comment:	-

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History of the document

Version	Date	Nature of revision(s)
04.0.0	20 July 2012	EB 68, Annex 12 The revision corrects errors with regard to the use of IPCC default values.
03.2	EB 47, Annex 8 28 May 2009	Editorial revision excluding start-up fuel from the baseline fuels and updating monitoring methodology/table.
03.1	13 October 2006	Editorial revision to the applicability conditions in the monitoring section, removing the condition on page 11: "The natural gas used in the project activity is not generated from liquified natural gas (LNG) or compressed natural gas (CNG)." to reflect the decision by the Board in paragraph 19(g) of its twenty fourth meeting.
03	EB 25, Annex 5 28 July 2006	Expansion of applicability conditions to include projects in other sectors, including fuel switches in heat-only boilers in the district heating sector.
02	EB 24, Annex 9 19 May 2006	• Inclusion of CO_2 emissions from LNG under Leakage section; • Other editorial changes.
01	EB 23, Annex 12 03 March 2006	Initial adoption.
Decision Class: Regulatory **Document Type**: Standard **Business Function**: Methodology		