Indicative simplified baseline and monitoring methodologies
for selected small-scale CDM project activity categories

TYPE II - ENERGY EFFICIENCY IMPROVEMENT PROJECTS

Project participants shall take into account the general guidance to the methodologies, information on additionality, abbreviations and general guidance on leakage provided at http://cdm.unfccc.int/methodologies/SSCmethodologies/approved.html.

II.D. Energy efficiency and fuel switching measures for industrial facilities

Technology/measure

1. This category comprises any energy efficiency and fuel switching measure implemented at a single industrial or mining and mineral production facility. This category covers project activities aimed primarily at energy efficiency; a project activity that involves primarily fuel switching falls into category III.B.[1] Examples include energy efficiency measures (such as efficient motors), fuel switching measures (such as switching from steam or compressed air to electricity) and efficiency measures for specific industrial or mining and mineral production processes (such as steel furnaces, paper drying, tobacco curing, etc.). The measures may replace, modify or retrofit existing facilities or be installed in a new facility. The aggregate energy savings of a single project may not exceed the equivalent of 60 GWh_e per year. A total saving of 60 GWh_e per year is equivalent to a maximal saving of 180 GWh_{th} per year in fuel input.

2. This category is applicable to project activities where it is possible to directly measure and record the energy use within the project boundary (e.g. electricity and/or fossil fuel consumption).

3. This category is applicable to project activities where the impact of the measures implemented (improvements in energy efficiency) by the project activity can be clearly distinguished from changes in energy use due to other variables not influenced by the project activity (signal to noise ratio).

Boundary

4. The project boundary is the physical, geographical site of the industrial or mining and mineral production facility, processes or equipment that are affected by the project activity.

Baseline

5. In the case of replacement, modification or retrofit measures, the baseline consists of the energy baseline of the existing facility or sub-system that is replaced, modified or retrofitted. In the case of a new facility the energy baseline consists of the facility that would otherwise be built.

6. In the absence of the CDM project activity, the existing facility would continue to consume energy (ECbaseline, in GWh/year) at historical average levels (EChistorical, in GWh/year), until the time at which the industrial or mining and mineral production facility would be likely to be replaced, modified or retrofitted in the absence of the CDM project activity (DATEBaselineRetrofit). From

[1] Thus, fuel switching measures that are part of a package of energy efficiency measures at a single location may be part of a project activity included in this project category.

that point of time onwards, the baseline scenario is assumed to correspond to the project activity, and baseline energy consumption (ECbaseline) is assumed to equal project energy consumption (ECy, in GWh/year), and no emission reductions are assumed to occur.

ECbaseline = EChistorical until DATEBaselineRetrofit
ECbaseline = ECy on/after DATEBaselineRetrofit

In order to estimate the point in time when the existing equipment would need to be replaced in the absence of the project activity (DATEBaselineRetrofit), project participants may take the following approaches into account:

(a) The typical average technical lifetime of the equipment type may be determined and documented, taking into account common practices in the sector and country, e.g. based on industry surveys, statistics, technical literature, etc.

(b) The common practices of the responsible industry regarding replacement schedules may be evaluated and documented, e.g. based on historical replacement records for similar equipment.

The point in time when the existing equipment would need to be replaced in the absence of the project activity should be chosen in a conservative manner, i.e. if a range is identified, the earliest date should be chosen.

7. Each energy form in the emission baseline is multiplied by an emission coefficient (in kg CO_2e/kWh). For the electricity displaced, the emission coefficient is calculated in accordance with provisions under category I.D. For fossil fuels, the IPCC default values for emission coefficients may be used.

Leakage

8. If the energy efficiency technology is equipment transferred from another activity or if the existing equipment is transferred to another activity, leakage is to be considered.

Monitoring

9. In the case of replacement, modification and retrofit measures the monitoring shall consist of:

(a) Documenting the specifications of the equipment replaced;

(b) Metering the energy use of the industrial or mining and mineral production facility, processes or the equipment affected by the project activity;

(c) Calculating the energy savings using the metered energy obtained from sub-paragraph (b).

10. In the case of a new facility, monitoring shall consist of:

(a) Metering the energy use of the equipment installed;

(b) Calculating the energy savings due to the equipment installed.

Project activity under a programme of activities

The following conditions apply for use of this methodology in a project activity under a programme of activities:

11. In case the project activity involves fossil fuel switching measures leakage resulting from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary shall be considered. The guidance provided in the leakage section of ACM0009 as in annex 1 of this document shall be followed for this purpose.

12. In case the project activity involves the replacement of equipment, and the leakage effect of the use of the replaced equipment in another activity is neglected, because the replaced equipment is scrapped, an independent monitoring of scrapping of replaced equipment needs to be implemented. The monitoring should include a check if the number of project activity equipment distributed by the project and the number of scrapped equipment correspond with each other. For this purpose scrapped equipment should be stored until such correspondence has been checked. The scrapping of replaced equipment should be documented and independently verified.

Annex I

(GUIDANCE ON LEAKAGE BELOW CONCERNS PROJECT ACTIVITY UNDER A PROGRAMME OF ACTIVITIES)

Leakage

1. 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:[2]

- 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:

$$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y} \quad (1)$$

Where:

LE_y	Leakage emissions during the year y in t CO_2e
$LE_{CH4,y}$	Leakage emissions due to fugitive upstream CH_4 emissions in the year y in t CO_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 t CO_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

[2] 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.

used in the absence of the project activity the fuel quantities multiplied with respective methane emission factors ($EF_{k,upstream,CH4}$), as follows:

$$LE_{CH4,y} = \left[FF_{project,y} \cdot NCV_{NG,y} \cdot EF_{NG,upstream,CH4} - \sum_k FF_{baseline,k,y} \cdot NCV_k \cdot EF_{k,upstream,CH4} \right] \cdot GWP_{CH4} \quad 2$$

with

$$FF_{project,y} = \sum_i FF_{project,i,y} \quad \text{and} \quad 3$$

$$FF_{baseline,k,y} = \sum_i FF_{baseline,i,k,y} \quad 4$$

Where:

$L_{CH4,y}$	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 m³
$FF_{project,i,y}$	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 MWh/m³
$EF_{NG,upstream,CH4}$	Emission factor for upstream fugitive methane emissions from production, transportation and distribution of natural gas in t CH_4 per MWh 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 MWh 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 MWh 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.[3] Where such data is not available, project participants may use the default values provided in Table 2 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 2 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.

[3] 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 2: Default emission factors for fugitive CH_4 upstream emissions

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:

$$LE_{LNG,CO2,y} = FF_{project,y} \cdot EF_{CO2,upstream,LNG} \qquad 5$$

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 t CO_2e

$FF_{project,y}$	Quantity of natural gas combusted in all element processes during the year y in m^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

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 t CO_2/TJ as a rough approximation.[4]

[4] 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)".