Approved baseline and monitoring methodology AM0049

"Methodology for gas based energy generation in an industrial facility"

I. SOURCE AND APPLICABILITY

Source

This baseline and monitoring methodology is based on the following proposed new methodology:

- NM0161-rev "Mondi Gas Turbine Co-generation in Richards Bay, South Africa", whose baseline and monitoring methodology and project design document were prepared by Mondi Business Paper, Richard Bay, South Africa and SouthSouthNorth.

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

- "Tool for the demonstration and assessment of additionality";
- "Tool to calculate the emission factor for electricity system".

The formulae and algorithms used in this baseline methodology originate from the "Tool to calculate the emission factor for electricity system".

For more information regarding the proposed new methodology and the tool as well as their consideration by the Executive Board please refer to <http://cdm.unfccc.int/goto/MPappmeth>.

Selected approach from paragraph 48 of the CDM modalities and procedures

"Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment"

Applicability

The methodology is applicable to project activities that install gas[1] based energy generation (electricity and/or steam/heat) system at an existing industrial facility to meet its own energy demand. The methodology is applicable to the following types of project activities:

(1) Project activities that generate on-site electricity and/or steam in:

(a) Separate generation systems on-site in an industrial facility; or
(b) Co-generate[2] electricity and steam on-site in an industrial facility;

[1] Gas should be the primary fuel. Small amounts of other startup or auxiliary fuels can be used, but can comprise no more than 1% of total fuel use.

[2] Cogeneration (could be either in combined heat and power system or sequentially produced from a single fuel source).

(2) Project activities that generate non-steam thermal energy in one or several element processes.[3]
(3) Project activities that switch from the use of coal or oil to gaseous fuel for generating energy.[4]
(4) Project activities that use one of the following four technologies available for cogeneration of electrical and thermal energy:

(a) Topping cycle - Fuel is burned to generate electrical energy, and the remaining heat or steam is used in an industrial process; or
(b) Bottoming cycle - Fuel is burned to produce industrial process heat, and the remaining heat used to generate electrical energy; or
(c) Topping cycle with steam turbine - Fuel is burned in a boiler to produce high temperature and pressure steam, which powers a turbine that drives an electrical generator. A portion of the energy in the steam is converted to electrical energy, and the remaining thermal energy is available for use in an industrial process; or
(d) Topping cycle with gas turbine/engine applications - Fuel is burned in a version of a jet engine, and the mechanical shaft power is used to drive an electrical generator. Waste heat from the gas turbine is captured and used directly or is sent to a waste heat boiler where it produces steam for an industrial process.

The methodology is applicable under the following conditions:

- The fuel used in the project activity may include natural gas or methane rich gas (MRG) ~~synthetic gas~~ produced by a coal and/or natural gas-to-liquid-products plant (henceforth referred to as 'project fuel');
- Prior to the project activity, the existing industrial facility, where the project activity is implemented, meets its thermal energy demand through self generation and may produce electricity, but the electricity produced is not sufficient to meet the demand of the industrial facility;
- Prior to the implementation of the project activity, only coal or oil (but not natural gas) were used in the steam generation facilities and/or element processes;
- 'Project fuel' is sufficiently available in the region or country, e.g. future 'project fuel' based energy generation additions, comparable in size to the project activity, are not constrained by the use of project fuel in the project activity;[5]

[3] An "*element process*" is defined as a single facility at one point of an industrial facility where fuel is combusted (in the project and baseline cases), for the purpose of providing non-steam thermal energy. The fuel is not combusted in the *element process* for steam or electricity generation or is not used as oxidant in chemical reactions or otherwise used as feedstock. An example of an element process is hot air generation by a furnace. Each element process should generate a single output (such as 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 from the element process 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.

[4] The methodology allows for fuel-switching in existing technologies and/or new technologies implemented to replace coal or oil fired technologies.

[5] In some situations, there could be price-inelastic supply constraints (e.g. limited resources without possibility of expansion during the crediting period) that could mean that a project activity displaces natural gas that would otherwise be used elsewhere in an economy, thus leading to possible leakage. Hence, it is important for the project proponent to document that supply limitations will not result in significant leakage as indicated here.

- Regulations/ programs do not constrain the facility from continuing to use the fossil fuels used prior to the implementation of the project activity;[6]
- Regulations do not require the use of a specific fuel, including the 'project fuel', in steam and/or power generating facilities and/or element processes;
- Regulations do not stipulate a change or upgrade in technologies at the time of the project activity;
- There is no increase in the output capacity or lifetime of the steam or element processes during the crediting period (i.e. emission reductions are only accounted for to the end of the lifetime of the relevant equipment). There is no planned expansion in capacity of energy generation on-site during the crediting period;[7]
- The project activity does not result in a change in the quality of steam/heat required by the processes of the industrial facility where the project is implemented;
- The geographical/physical boundaries of the baseline grid can be clearly identified and information pertaining to the grid and estimating baseline emissions is publicly available;
- Electricity from the co-generation unit may be exported to the grid on ad-hoc basis (e.g. during shut-downs or periods of maintenance on sections of the industrial process). In this case the total amount of the annual electricity exported must be less than 10% of the total electricity produced by the cogeneration plant, and potential emission reductions from displacing grid electricity can not be claimed by project participants;
- In cases where the project ~~uses synthetic gas~~ fuel is MRG[8] produced by a coal and/or natural gas-to-liquid-fuels plant,

  (a) There is no capacity expansion of the synthetic fuel production plant based on fuels other than natural gas;
  (b) Data on fuel inputs and product outputs from the synthetic fuel plant are available to calculate energy and/or carbon balance for the synthetic fuel production plant.

Note: The project participants should check whether the procedures to calculate emission reductions work appropriately for the project specific context. If the equations do not fully fit with the context of the project, **a revision or deviation to this methodology should be requested.**

II. BASELINE METHODOLOGY

Project boundary

The project boundary covers CO_2 emissions associated with fuel combustion in each (1) *element process i,* (2) steam and/or (3) power generating facility where the fuel switching is implemented under the project activity. The project boundary is applicable to both baseline emissions and project emissions.

For the purpose of determining **project activity emissions,** project participants shall include CO_2 emissions from the combustion of 'project fuel' in each (1) *element process* and (2) on-site power and/or (3) co-generation facility.

[6] Changes in regulations that may affect the use of fuels or technologies should be monitored and their effect on the baseline assessed and applied to calculations of emissions reductions at renewal of each crediting period.
[7] If any expansion is planned, it shall be considered as a separate project.
[8] Methane rich gas (MRG) ~~Synthetic gas~~ produced as off-gas by the coal and natural gas-to-liquid-fuel process.

For the purpose of determining **baseline emissions** for heat, project participants shall include CO_2 emissions from the combustion of the quantity of coal or oil that would have been used in the absence of the project activity to generate steam and/or non-steam thermal energy. For determining electricity **baseline emissions**, project participants shall include CO_2 emissions from the generation of electricity from sources in the absence of the project activity as per approved "Tool to calculate the emission factor for electricity system".

The **spatial extent** of the project boundary encompasses the physical, geographical site of the industrial facility where the project is implemented, and the electricity grid from which the electricity would have been sourced in the absence of the project activity.

Table 1: Emissions sources included in or excluded from the project boundary

	Source	Gas	Included?	Justification/ Explanation
Baseline	Heat (steam and non-steam) generation in baseline	CO_2	Yes	Main emissions source
		CH_4	No	Minor source
		N_2O	No	Minor source
	Power generation in baseline (grid based)	CO_2	Yes	Main emissions source
		CH_4	No	Minor source
		N_2O	No	Minor source
Project Activity	On-site fuel combustion due to project activity	CO_2	Yes	Main emissions source
		CH_4	No	Minor source
		N_2O	No	Minor source

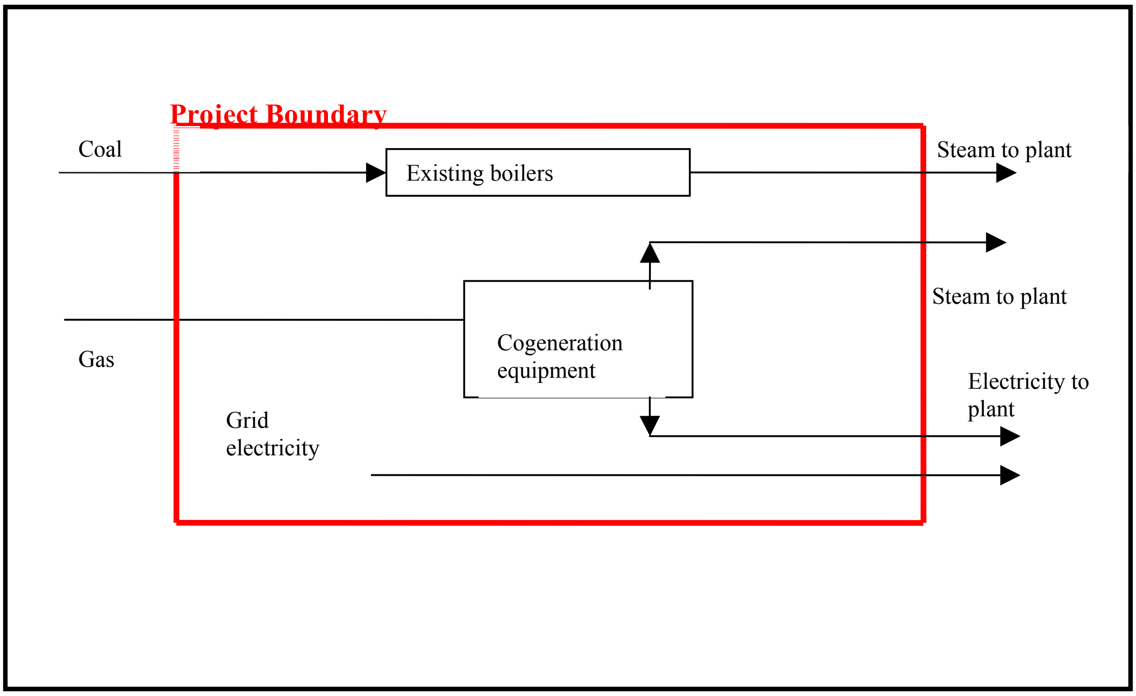


Figure 1: Diagram of the project boundary.

Procedure for estimating lifetime of the existing equipment(s), used to generate heat and electricity

The following approaches shall be taken into account to estimate the remaining lifetime of the existing equipment, i.e., the time when the existing equipment(s), that are replaced by the project activity, would need to be replaced in the absence of the project activity:

(a) The typical average technical lifetime of the type of equipment may be determined taking into account common practices in the sector and country (e.g. based on industry surveys, statistics, technical literature, etc.);
(b) The practices of the responsible company regarding replacement schedules may be evaluated and documented (e.g. based on historical replacement records for similar equipment).

The time to replacement of the existing equipment in the absence of the project activity should be selected in a conservative manner, i.e. the earliest point in time should be selected in cases where only a time frame can be estimated. This information should be documented in CDM-PDD.

Procedure for the selection of the most plausible baseline scenario

Project participants shall determine the most plausible baseline scenario through the application of the following steps. If the project activity involves fuel and/or fuel and technology switching in several cogeneration systems within the project boundary, the steps should be applied to each cogeneration system.

Step 1: Identify all realistic and credible alternatives to cogeneration systems

Project participants should at least consider the following alternatives:
For power generation, the realistic and credible alternative(s) may include, *inter alia:*

P1: Proposed project activity not undertaken as a CDM project activity;
P2: On-site or off-site coal/oil fired cogeneration plant;
P3: On-site or off-site coal/oil fired captive power plant;
P4: On-site or off-site renewable energy based cogeneration plant or a captive power plant;
P5: On-site or off-site renewable energy based captive power plant;
P6: Off-site fossil fuel based existing plant;
P7: Electricity imported from grid.

For heat generation, realistic and credible alternative(s) may include, *inter alia*:

H1: Proposed project activity not undertaken as a CDM project activity;
H2: On-site or off-site coal/oil fired cogeneration plant;
H3: On-site or off-site coal/oil fired element process;
H4: On-site or off-site renewable energy based cogeneration plant;
H5: On-site or off-site renewable energy based element process;
H6: On-site coal/oil fired element process/s;
H7: Any other source such as district heat;
H8: Other heat generation technologies (e.g. heat pumps or solar energy).

If one or more scenarios are excluded, appropriate explanations and documentation to support the exclusion of such scenario shall be provided.

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

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

Step 4: Compare economic attractiveness of remaining alternatives

Apply Step 2 of the latest version of the "Tool for demonstration and assessment of additionality" agreed by the CDM Executive Board" to compare the economic attractiveness for all alternatives that are remaining after Step 3. The economic investment analysis shall use the one of the following investment indicators for the analysis of NPV/IRR/ROI/payback periods for comparative purposes, 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; and
- Other operation and maintenance costs.

The investment indicator calculation should take into account the residual value of the new equipment at the end of the lifetime (or crediting period whichever is shorter) of the project activity.[9] Provide all the assumptions in the CDM-PDD.

Compare the investment indicators of the different scenarios and select the most cost-effective scenario (i.e. with the most attractive investment indicator) as the baseline scenario. Check the result with a sensitivity analysis applying Sub-step 2d of the latest version of the "Tool for demonstration and assessment of additionality" agreed by the CDM Executive 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.

[9] Note that NPV values may be negative.

In case the sensitivity analysis is not fully conclusive, select the baseline scenario alternative with the least emissions among the alternatives that are the economically most attractive according to the investment analysis and the sensitivity analysis.

Note: This methodology is only applicable if the baseline scenario is on-site generation of heat using coal/oil (H6) and import of electricity from grid (P7) throughout the crediting period.

Additionality

The assessment of additionality shall be through the following two Steps:

Step 1: Investment comparison analysis

Demonstrate that the project activity undertaken without the CDM is economically less attractive than the identified baseline scenario, by undertaking a benchmark analysis following the instructions given in Step 4 of the section "Identification of the baseline scenario". Undertake a sensitivity analysis using Sub-step 2d of the latest version of the "Tool for demonstration assessment and of additionality" agreed by the CDM Executive Board to check the conclusions of the investment analysis.

Following aspects shall be adhered to while undertaking investment analysis:

(1) For project activity, as a minimum, (including all power generation/co-generation/element process), the financial indicator for comparison with benchmark shall be calculated using the following data. The financial indicator may include the IRR (Equity IRR or Project IRR), NPV, Levelised cost of service provided (e.g. Cost/TJ).

- Initial investment - project activity related costs only;
- O & M costs including, but not limited to, the cost of fuel, labour etc. (value/year);
- Amount of savings in cost of power/steam/heat as compared to baseline cost (value/yr);
- Project lifetime to be used for calculation of return on investment or IRR;
- Residual value of equipment at the end of life time.

(2) In case Equity IRR is used as the financial indicator, the data for the amount and cost of debt financing should also be used.

(3) The benchmark should be estimated based on either of following:

- The average rate of return (or IRR) of similar projects implemented by project proponent in past (based on last three year balance sheet of the company);
- The Weighted Average Cost of Capital (WACC) of the company based on company's balance sheet in past, taking into account project specific well-justified risk factors, if any;
- Optimum levelised cost of service (Value/TJ) based on market survey of technologies similar to that of project activity;
- Levelised cost of service for the baseline scenario.

(4) The assumptions made for estimation of financial indicator and benchmark should be realistic and readily verifiable by DOE during validation of project activity.

In case the financial indicator indicates that the CDM project activity is more attractive than the benchmark, the project activity is non-additional, otherwise perform the sensitivity analysis to conclude that the non-attractiveness of project activity (as compared to benchmark) is robust enough to reasonable variations in assumptions those have impact on financial indicator of the project activity. If the sensitivity analysis is conclusive, proceed to Step 2.

Step 2: Common practice analysis

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

"***If Sub-steps 4a and 4b are satisfied of the*** "Tool for demonstration assessment and of additionality"***, i.e.(i) similar activities cannot be observed or (ii) similar activities are observed, but essential distinctions between the project activity and similar activities can reasonably be explained, then the proposed project activity is additional".***

"If Sub-steps 4a and 4b are not satisfied, i.e. similar activities can be observed and essential distinctions between the project activity and similar activities cannot reasonably be explained, the proposed CDM project activity is <u>not additional</u>."

Baseline emissions

Baseline emissions are the sum of the emissions from the generation of electricity and generation of heat for each element process. These emissions are calculated as follows:

$$BE_y = BE_{elect,y} + BE_{heat,y} \tag{1}$$

Where:

BE_y	=	Baseline emissions during the year *y* (tCO2e/yr)
$BE_{elect,y}$	=	Baseline emissions due to electricity generation during the year *y* in t CO2e
$BE_{heat,y}$	=	Baseline emissions due to heat generation during the year *y* in t CO2e

Baseline electricity emissions

Baseline emissions are calculated by multiplying the electricity generated by all electricity generation units in the project boundary, excluding the electricity exported to the grid on ad-hoc basis, and CO_2 emission factor ($EF_{BL,CO2,y}$) for electricity, as follows:

$$\cancel{BE_{elect,y} = \frac{\sum_i EG_{PJ,i,y} \times EF_{BL,CO2,y}}{1 - TDL}} \qquad \cancel{(2)}$$

$$BE_{elect,y} = \frac{\sum_i \left(EG_{PJ,i,y} - EG_{PJ,export,y}\right) \times EF_{BL,CO2,y}}{1 - TDL} \tag{2}$$

Where:

$BE_{elect\ y}$	=	Baseline emissions from electricity generation during the year *y* (tCO2e/yr)
$EG_{PJ,i\ ,y}$	=	Electricity generated by electricity generation unit *i* included in the project boundary in year *y* (MWh/yr). If electricity is generated on-site prior to implementation of the project activity, this shall be deducted from the total electricity generated by the project activity
$EG_{PJ,export,y}$	=	Electricity produced on-site and exported on ad-hoc basis to the grid in year *y* (MWh/yr)
$EF_{BL,\ CO2,\ y}$	=	Emissions factor of electricity generated in the baseline year *y* (tCO_2e/MWh)
TDL	=	Transmission and distribution losses for electricity imported from the grid in the baseline, expressed as a fraction (0<TDL<1). The value used should be supported by documentary evidence. If documentation cannot support the percentage of losses accurately, on the basis of conservatism, the lowest losses in a range of estimates should be used, or losses ignored in the baseline scenario (i.e. T&D =0%)

In the case that electricity is exported to the grid on ad-hoc basis, the industrial facility has to meet the following requirement:

$$100 \times \frac{EG_{PJ,export,y}}{\sum_i EG_{PJ,i,y}} \leq 10 \quad \textbf{(2a)}$$

If the amount of electricity exported to the grid is more than 10% than the electricity produced by the project activity, this methodology is not applicable.

The baseline scenario is import of electricity from the grid. Emission factor $EF_{BL,\ CO2,\ y}$ is for grid and will be calculated *ex-post* using the combined margin approach according to "Tool to calculate the emission factor for electricity system", using a 50:50 weight ratio of Operating Margin (OM) and Built Margin (BM).

Baseline heat emissions

There are two plausible project case scenarios for steam/heat generation. These are:

(i) Scenario 1: Fuel switch in element process/s that generates the same amount of heat/steam as in the baseline using the project fuel; or
(ii) Scenario 2: Heat is generated in a cogeneration unit that displaces the element process in the baseline.

Scenario 1: Fuel switch from baseline fuel to 'project fuel' in element process

Baseline heat emissions ($BE_{heat,y}$) are CO_2 emissions from the combustion of the quantity of coal or oil that would have been used in all the element processes, in the absence of the project activity. The quantity of coal or oil ($FF_{baseline,i,y}$) that would have been used in an element process *i* in year *y,* in the absence of the project activity, is calculated based on the actual monitored quantity of project fuel combusted in the element process ($FF_{project,i,y}$) *i* in year *y*, as presented below:

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

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

Where:

$BE_{heat,y}$	=	Baseline emissions during the year *y* in t CO_2e
$FF_{baseline,i,y}$	=	Quantity of coal or oil that would have been 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 'project fuel' combusted in the *element process* i during the year *y* in m^3
$NCV_{PF,y}$	=	Average net calorific value of the 'project Fuel'[10] combusted during the year *y* in TJ/m^3
$NCV_{FF,i}$	=	Average net calorific value of coal or oil that would have been combusted in the absence of the project activity in the element process *i* during the year *y* in TJ per volume or mass unit
$EF_{FF,CO2,i}$	=	CO_2 emission factor of coal or oil type that would be combusted in the absence of the project activity in the element process *i* in t CO_2/TJ
$\varepsilon_{project,i,y}$	=	Energy efficiency of the element process *i* in year *y*
$\varepsilon_{baseline,i,y}$	=	Energy efficiency of the element process *i* when fired with coal/oil corresponding to the load factor of the elemental process *I* in year *y*

Scenario 2: Steam/ heat is generated by waste heat of cogeneration unit

Where heat ($HR_{project,\,i,\,y}$), which in the absence of the project activity was generated by element process 'i', is generated from cogeneration (cogeneration could be either combined heat and power or use of waste heat from electricity generator(e.g. from exhaust gases of gas turbine or diesel generator or diesel engine)) the baseline fuel consumption is estimated as follows:

$$FF_{baseline,y} = \sum_i \frac{HR_{project,i,y}}{NCV_{FF,i} \times \varepsilon_{baseline,i,y}} \quad \textbf{(5)}$$

$$HR_{project,i,y} = FR_{heat,i,y} \times (h_{heatout,i,y} - h_{heatin,i,y}) \times hrs_{i,y} \quad \textbf{(6)}$$

[10] Separate emission factors and calorific values should be used for Natural Gas and MRG ~~Synthetic gas~~, though represented by common abbreviation PF.

Where:

$FF_{baseline,y}$	=	Quantity of coal or oil that would have been combusted in the baseline in absence of the project activity in year *y* in mass units
$*HR_{project,i,y}$	=	Project heat that in the absence of the project activity would have been generated in element process '*i*' during year *y* in TJ
$FR_{heat,i,y}$	=	Flow rate of heat carrier (e.g., air or steam or thermic fluid) generated in the Waste Heat Recovery Source (element process *i)* in kg/hrs
$h_{heatout,i,y}$	=	Enthalpy of heat carrier at outlet of the waste heat recovery source (element process *i*), in TJ/kg
$h_{heatin,i,y}$	=	Enthalpy of heat carrier at inlet of waste heat generating source (element process *i*), in TJ/kg
$NCV_{FF,i}$	=	Average net calorific value of the fuel type (coal or oil) that would be combusted in the absence of the project activity in the element process i during the year *y* in TJ per volume or mass unit
$*\varepsilon_{baseline,i,y}$	=	Energy efficiency of the element process *i,* which would have been used in absence of the project activity using coal or oil respectively and corresponding to the load factor of elemental process in year *y*
$hrs_{i,y}$	=	Hours of operation of the waste heat generating source (element process *i*) where heat is generated (which would have been generated by coal or oil in absence of the project activity) in year *y*

* In project activities where more than one element process equipment supplying steam/heat are replaced by direct supply of steam/heat to the process from a cogeneration unit and where it is not possible to separate the steam/heat from cogeneration into fractions that would have been supplied by the baseline element process, assume 100% efficiency for the baseline element process ($\varepsilon_{baseline,i,y}$). $HR_{project,i,y}$ is taken as output steam/heat supplied by cogeneration unit to the process.

Emission Factors and Calorific Values

Note that the most plausible baseline scenario may be that several fuel types and/or heat sources would be used in the different element processes or that several fuel types and/or heat sources would be used in one element process. Where several fuel types and/or heat sources have been used in element processes prior to the implementation of the project, project participants shall as a conservative approach select the fuel type or heat source with the lowest CO_2 emission factor from the fuels or heat sources 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 IPCC 2006 guidelines should be followed where appropriate. For MRG ~~synthetic gas~~, a separate emission factor and net calorific value shall be used than that used for the natural gas. 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 (2006) default emission factors (country-specific, if available) may be used if they are deemed to reasonably represent the local circumstances. All values should be chosen in a conservative manner (i.e. lower values for baseline emissions 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.

Energy Efficiency of Element Processes in the baseline and the project scenario

The efficiency of element process depends significantly on the load and operational conditions. Consequently, also the residual fuel oil consumption in the baseline depends on the load and operational conditions of the element process. This methodology allows for two options to determine the baseline efficiency of boiler ($\varepsilon_{baseline,i,y}$), used in equations 5 and 6:

Option A: Assume a constant efficiency of the element process and determine the efficiency, as a conservative approach, for optimal operation conditions (i.e. optimal load, optimal oxygen content in flue gases, adequate fuel viscosity, representative or favourable ambient conditions for the efficiency of the element process, including temperature and humidity, etc). Substitute the value of efficiency in equation 5 and 6.

Option B: Establish an efficiency-load-function of the element process. The fuel consumption is then determined separately for discrete time intervals *t*, based on the actual monitored heat generation during each time interval *t* and the baseline efficiency corresponding to that heat generation, determined with the efficiency-load-function:

$$\varepsilon_{baseline,t} = \mathrm{f}\left(HR_{project,t}\right) + 1.96 \cdot \mathrm{SE}(\mathrm{f}(HR_{project,t})) \qquad \textbf{(7)}$$

and

$$\mathrm{N_t} = \frac{8760}{\mathrm{T}} \qquad \textbf{(8)}$$

Where:

$FF_{baseline,y}$	=	Quantity of coal or oil that would be burned in the baseline in absence of the project activity in year *y* in a mass unit
$HR_{project,t}$	=	Heat generated by the element process during the time interval *t* where *t* is a discrete time interval during the year *y* (GJ)
$\varepsilon_{baseline,t}$	=	Baseline energy efficiency of the element process during time interval *t* where *t* is a discrete time interval during the year *y*
$f(HR_{PJ,t})$	=	Efficiency load function of the element process, determined through the regression analysis
$SE(f(HR_{project,t}))$	=	Standard error of the result of the efficiency-load-function f($HR_{project,t}$) for time interval *t* where *t* is a discrete time interval during the year *y*
t	=	Discrete time interval of duration *T* during the year *y*
N_t	=	Number of time intervals *t* during year *y*
T	=	Duration of the discrete time intervals *t* (h)

Each time interval *t* should have the same duration *T*. In choosing the duration *T*, the typical load variation of the element process should be taken into account. The maximum value for *T* is 1 hour, resulting in 8760 discrete time intervals *t* per year *y* (N_t = 8760). If the load of the element process may vary considerably within an hour, a shorter time interval *T* should be chosen by project participants (e.g. 15 minutes).

The efficiency-load-function should be derived by applying a regression analysis to at least 10 measurements *x* within the load range where the element process can be operated. It is recommended that project participants apply standard software to apply the regression analysis. More details on the procedure to measure the efficiency at different loads are provided in the monitoring methodology. Each measurement *x* delivers a data pair of heat generation (HR_x) and efficiency of the element process (η_x). Project participants should choose an appropriate regression equation to apply to the measurement results. For example, in case of a polynomial function, the following regression equation would be applied:

$$\varepsilon_x = f(\mathrm{HR}_x) = a + b_1 \mathrm{HR}_x + b_2 (\mathrm{HR}_x)^2 + ... + b_n (\mathrm{HR}_x)^n \qquad \textbf{(9)}$$

Where:

(ε_x , HR_x)	=	The pair of data recorded from measurement x at a defined load level
ε_x	=	Efficiency of the element process at measurement *x*
HR_x	=	Quantity of heat generated by the element process during the time length *T* at the measurement *x* (GJ)[11]
x	=	Measurements undertaken at defined load levels
a, b_1, b_2,…, b_n	=	Parameters of the regression equation estimated using the regression analysis

In order to ensure that the results of the regression analysis are conservative, the baseline efficiency is adjusted for the upper bound of uncertainty of the result of efficiency-load-function at a 95% confidence level by introducing the standard error $SE(f(HR_{project,t}))$ in equation (4) above. The standard error $SE(f(HR_{project,t}))$ has to be determined for each time interval *t*. It is recommended that project participants use the standard software to determine the standard error $SE(f(HR_{Project,t}))$.

In case of a linear regression equation, i.e. if n=1 in equation (8) above, the standard error can be determined as follows:

$$\mathrm{SE}\left(\mathrm{f}\left(\mathrm{HR}_{\mathrm{project,t}}\right)\right) = \sigma * \sqrt{\left(1 + \frac{1}{\mathrm{N_x}} + \frac{(\mathrm{HR}_{\mathrm{project,t}} - \mathrm{HR})^2}{\sum_{x=1}^{\mathrm{N_x}} (\mathrm{HR_x} - \mathrm{HR})^2}\right)} \qquad \textbf{(10)}$$

with

$$\sigma = \frac{1}{\mathrm{N_x} - 2} * \sqrt{(1 - \mathrm{R}^2) * \left[\sum_{x=1}^{\mathrm{N_x}} (\eta_x - \eta)^2\right]} \quad \text{and} \qquad \textbf{(11)}$$

[11] The value of HG_x should correspond to the quantity of heat that would be generated in the time length T at the defined load level. If the measurement has a different duration than T, the measured quantity of heat generation should be extrapolated to the quantity that would be generated during the time length T.

$$\eta = \frac{\sum_{x=1}^{N_x} \eta_x}{N_x} \quad \text{and} \tag{12}$$

$$HR = \frac{\sum_{x=1}^{N_x} HR_x}{N_x} \quad \text{and} \tag{13}$$

$$R = \frac{b_1^2 * \sum_{x=1}^{N_x} (HR_x - HR)}{\sum_{x=1}^{N_x} (\eta_x - \eta)} \tag{14}$$

Where:

$SE(f(HR_{Project,t}))$	=	Standard error of the result of the efficiency-load-function $f(HR_{project,t})$ for time interval *t*
$f(HR_{project,t})$	=	Efficiency load function of the element process, determined through the regression analysis
σ	=	Standard error of the regression equation
$HR_{project,t}$	=	Heat generated by the element process during the time interval *t* (GJ)
HR_x	=	Quantity of heat generated by the element process during the time length *T* at the measurement *x* (GJ)
HR	=	Mean heat generation by the element process during the time length *T* of all measurements *x* (GJ)
η_x	=	Efficiency of the element process at measurement *x*
η	=	Mean efficiency of the element process of all measurements *x*
R	=	Adjusted R square.
x	=	Measurements undertaken at defined load levels
N_x	=	Number of measurements *x* undertaken to establish the efficiency-load-function (at least 10)
t	=	Discrete time interval of duration *T* during the year *y*
T	=	Duration of the discrete time intervals *t* (h)

For calculation of project efficiency $\varepsilon_{project,i,y}$ of element process (in case of Scenario 1 described above) should also be calculated by using Option-A of efficiency determination methods described above. The efficiency should be tested at normal operating conditions, representative of annual conditions and not at best operating condition as in case of baseline efficiency.

Where project participants can reasonably demonstrate consistently for one year that the efficiency of the element process does not change due to the fuel switch or that any changes are negligible (i.e. $\varepsilon_{project,i} - \varepsilon_{baseline,i} < 1\%$ of $\varepsilon_{baseline,i}$) 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.

Project Emissions

Project emissions (*PEy*) are CO_2 emissions from the combustion of project fuel in all element processes, stand alone electricity generation units or cogeneration unit. Project emissions are calculated as product of the quantity of project fuel combusted, net calorific value, and CO_2 emission factors for project fuel[12] ($EFPF,CO_2$), as follows:

$$PE_y = FF_{project,y} \times NCV_{PF,y} \times EF_{PF,CO2,y} \tag{15}$$

$$FF_{project,y} = \sum_i FF_{project,i,y} + \sum_j FF_{project,j,y} \tag{16}$$

Where:

PEy	=	Project emissions during the year *y* in t CO2e
FFproject,y	=	Quantity of project fuel combusted in all element processes and electricity generation units during the year *y* in m^3 [13]
FFproject,i,y	=	Quantity of project fuel combusted in the element process *i* during the year *y* in m^3
FFproject,j,y	=	Quantity of project fuel combusted in the electricity/co- generator *j* during the year *y* in m^3
NCVPF,y	=	Average net calorific value of the project fuel combusted during the year *y* in TJ/m^3
$EFPF,CO_2,y$	=	CO_2 emission factor of the project fuel combusted in all element processes in the year *y* in t CO_2/TJ

If natural gas is used as the project fuel, for the determination of emission factors and net calorific values, the IPCC guidelines 2006 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. higher values should be chosen, for project emissions, 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.

For ~~synthetic fuel~~ MRG, the project proponent should make measurements to determine the calorific values and emission factor.

[12] Separate emission factors and calorific values should be used for Natural Gas and ~~Synthetic gas~~ MRG, though represented by common abbreviation PF.
[13] M^3 should be provided at norm conditions for pressure and temperature.

Leakage

Positive leakage associated with the reduction of coal and ash transportation to and from the project, is not accounted for, as this is conservative.

Two major sources of leakage shall be considered.

(i) Leakage due to fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of project fuel. This includes mainly fugitive CH_4 emissions and CO_2 emissions from associated fuel combustion and flaring.

(ii) Leakage from upstream emissions related to the production of project fuel, if the project fuel is ~~synthetic gas~~ MRG produced in a coal to liquid fuels plant.

$$LE_y = LE_{US,y} + LE_{p,y} \tag{17}$$

Where:

LE_y	=	Total leakage emissions during the year *y* in tonnes CO_2e
$LE_{US,y}$	=	Leakage emissions due to upstream emissions from fuel extraction, processing, liquefaction, transportation (of both natural gas and MRG ~~synthetic gas~~) and re-gasification of natural gas in the year *y* in tonnes CO_2e
$LE_{p,y}$	=	Leakage due to the production of MRG ~~synthetic gas~~[14] in the year *y* in tonnes CO_2e.

1. Upstream emissions from fuel extraction, processing, liquefaction, transportation and re-gasification of Natural Gas (to be considered only when the project fuel is Natural Gas)

In this methodology, the following leakage emission sources shall be considered:[15]

- 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:

$$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y} \tag{18}$$

[14] The production of synfuel ~~thetic gas~~ involves the gasification of coal and can involve the introduction of natural gas as resource in producing synfuel. ~~mixing with natural gas introduced to the synthetic fuel plant~~. The methane rich gas is a 'waste product' and a small portion may be used for purging to reduce inerts from the system.~~The syngas is either the final product or an intermediary stage in a process where the majority of the synthetic gas is used for further products (e.g. liquid fuels etc.) and/or part that is purged to reduce inerts from the system. Either the synthetic gas or the inert purge stream can be considered here as the syngas.~~

[15] 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.

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

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:

$$LE_{CH4,y} = \left[FF_{project,y} \cdot NCV_{NG,y} \cdot EF_{NG,upstream,CH4} - \sum_k FF_{baseline,k,y} \cdot NCV_k \cdot EF_{k,upstream,CH4} \right] \cdot GWP_{CH4} \quad \textbf{(19)}$$

with

$$FF_{project,y} = \sum_i FF_{project,i,y} \quad \text{and} \quad \textbf{(20)}$$

$$FF_{baseline,k,y} = \sum_i FF_{baseline,i,k,y} \quad \textbf{(21)}$$

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 m³[16]
$FF_{project,i,y}$	=	Quantity of natural gas combusted in the element process *i* during the year y in m³ [17]
$NCV_{NG,y}$	=	Average net calorific value of the natural gas combusted during the year y in /m³ [18]
$EF_{NG,upstream,CH4}$	=	Emission factor for upstream fugitive methane emissions from production, transportation and distribution of natural gas in t CH_4 per TJ fuel supplied to final consumers
$FF_{baseline,k,y}$	=	Quantity of fuel type *k* (a coal or oil) 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 oil) that would be combusted in the absence of the project activity in the element process *i* estimated for 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 TJ per volume or mass unit

[16] M3 should be provided at normal conditions for pressure and temperature.
[17] M3 should be provided at normal conditions for pressure and temperature.
[18] M3 should be provided at normal conditions for pressure and temperature.

$EF_{k,upstream,CH4}$	=	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 TJ 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.[19] 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.

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.

[19] 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.

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:

$$LE_{LNG,CO2,y} = FF_{project,y} \cdot EF_{CO2,upstream,LNG} \tag{22}$$

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.[20]

2. Upstream emissions from ~~synthetic gas~~ MRG production (if appropriate e.g. if gas is waste gas or syngas from a fuel plant)

$$\cancel{LE_{PJ,y} = FF_{sg,pr,y} \times \left(EF_{sg,y}\right)} \qquad \cancel{(23)}$$

$$LE_{PJ,y} = FF_{MRG,pr,y} \times \left(EF_{MRG,y}\right) \tag{23}$$

Where:

$FF_{\cancel{sg}MRG,pr,y}$	=	Quantity of ~~synthetic gas~~ MRG consumed by project activity during the project in year y in TJ
$EF_{\cancel{sg}MRG,y}$	=	Emissions factor for the production of the ~~synthetic gas~~ MRG used in the project activity in the year y in tonnes CO_2/TJ
$LE_{PJ,y}$	=	Leakage emissions associated with the production of ~~synthetic gas~~ MRG for year y in t CO2e

[20] 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)".

The marginal approach

To ensure that the project activity demand only creates marginal demand for an additional natural gas exclusively, it is necessary to measure and cumulatively record a number of operational parameters at the ~~synthetic~~ fuel plant before the project commences, and every year thereafter for the duration of the project activity. The measurements prior to the commencement of the project are used to estimate the amount of fossil fuel inputs that are used for energy in the ~~synthetic~~ fuel process, which is necessary for comparison with the scenario at the synfuel plant during the project activity.

Once the project commences, the fuel inputs and outputs from the ~~synthetic~~ fuel production plant should be monitored, aggregated and reported annually. The following conditions must be satisfied *ex-post* for the ~~synthetic~~ fuel production plant for the duration of the project activity to prove that the ~~synthetic gas~~ MRG used on the margin is attributable to natural gas alone:

For i=coal $Q_{SPin,PJ,i,y} \times CF_{SPin,PJ,i,y} < Q_{SPin,BL,i,y} \times CF_{SPin,BL,i,y}$ [21]

For i=NG $Q_{SPin,PJ,i,y} \times CF_{SPin,PJ,i,y} > Q_{SPin,BL,i,y} \times CF_{SPin,BL,i,y}$

For i=LF + products $Q_{SPout,PJ,i,y} \times CF_{SPout,PJ,i,y} > Q_{SPout,BL,i,y} \times CF_{SPout,BL,i,y}$

For i=~~Synthetic Gas~~ MRG $Q_{SPout,PJ,i,y} \times CF_{SPout,PJ,i,y} > Q_{SPout,BL,i,y} \times CF_{SPout,BL,i,y}$

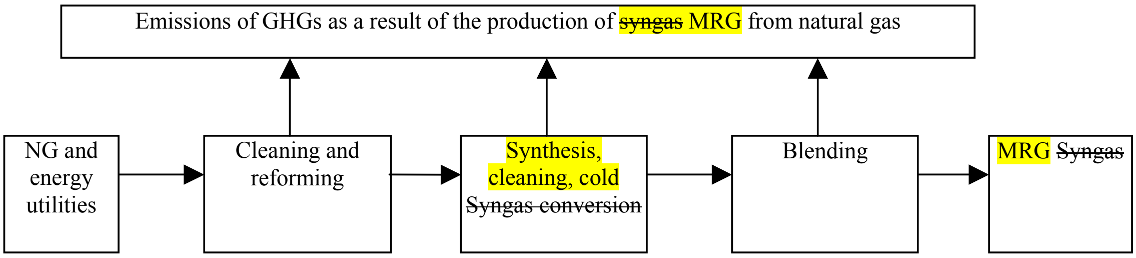
Where:

$Q_{SPin,PJ,i,y}$	=	Quantity of fossil fuel and fossil fuel derived utilities (*i*) consumed by synfuel plant for the duration of the project in year *y* in TJ
$Q_{SPout,PJ,i.y}$	=	Quantity of liquid fuels, products and fossil fuel derived utilities (*i*) produced by the synfuel plant for the duration of the project in year *y* in TJ
$Q_{SPin,BL,i,y}$	=	Quantity of fossil fuel and fossil fuel derived utilities (*i*) consumed by synfuel plant in the baseline year *y* in TJ
$Q_{SPout,BL,i.y}$	=	Quantity of liquid fuels, products and fossil fuel derived utilities (*i*) produced by the synfuel plant in the base year *y* in TJ
CF_i	=	It represents the corresponding emission factor for the fossil fuel 'i' and is expressed as tCO_2/TJ

If all four of these conditions are met, then the upstream emissions are attributable to the production of ~~syngas~~ MRG from natural gas on the margin. The emissions from the production of ~~syngas~~ MRG from natural gas exclusively can be used as $EF_{sMRG\cancel{g},y}$.

Typically there are general processes in producing the ~~syngas~~ MRG, which include cleaning, reforming, ~~syngas~~ conversion and blending. The emissions from the production of ~~syngas~~ MRG are calculated from a mass and energy balance around the ~~syngas~~ synfuel production processes. The estimation shall be undertaken before the project and every six months during the project activity.

[21] In cases where the coal gasification technology capacity remains the same but there is an small increase (< 2%) in the use of coal that is exclusively associated with efficiencies in coal gasification and associated down stream processes, this condition can be met.



This emission factor is estimated ex-post as follows:

$$EF_{MRG,prd,y} = \frac{((Q_{NGin,PJ,y} * EF_{NG} - \sum FF_{MRGout,PJ,i,y} * EF_{MRG,i}) - (Q_{NGin,Bly} * EF_{NG} - \sum FF_{MRGout,BL,i,y} * EF_{MRG,i}))}{(\sum FF_{MRGout,PJ,i,y} - \sum FF_{MRGout,BL,i,y})} \quad \textbf{(24)}$$

Where:

$EF_{\cancel{sg}MRG,prd,y}$ = Emission factor for production of ~~syngas~~ MRG used by the project in year *y*.

$Q_{NGin,PJ,y}$ = The sum of all natural gas (and any energy utilities) used in the synful~~gas~~ production processes during the project in year *y* in TJ in year *y*

EF_{NG} = The emissions factor of natural gas (and energy utilities) in tCO2/TJ in year *y*

$\sum FF_{sMRGout,PJ,i,y}$ = The total quantity of ~~synthetic gas~~MRG produced from natural gas during the project in year *y* in TJ in year *y*

$EF_{SG,i}$ = The emissions factor for synthetic gases in tCO2/TJ

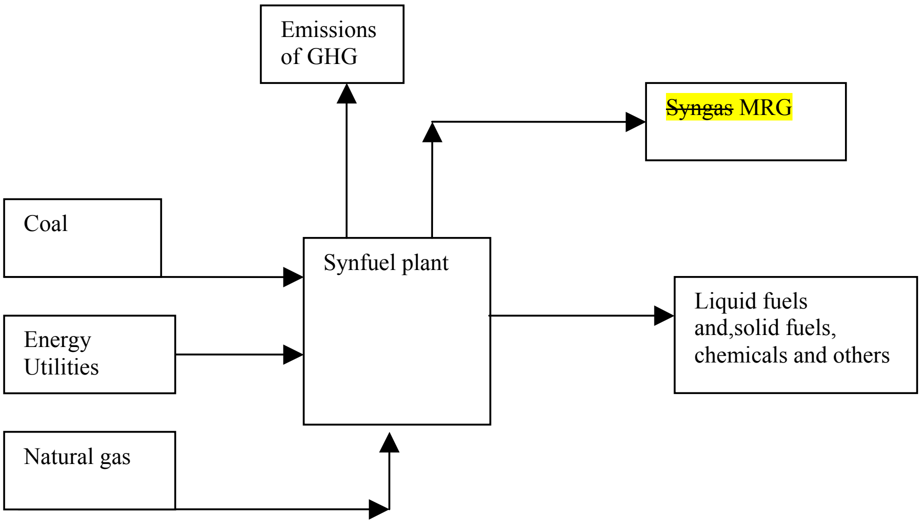
$Q_{NGin,BL,i,y}$ = Quantity of natural gas (and energy utilities) consumed by synfuel plant prior to project implementation in TJ in year *y*

$\sum FF_{\cancel{s}MRGout,BL,i,y}$ = The total quantity of ~~synthetic gas~~ MRG produced from natural gas prior to project implementation in TJ in year *y*

Data for the material and energy balances can be monitored failing that computer process simulation can be carried out to establish such the emissions associated with the production of the ~~syngas~~ MRG used in the project activity.

The default approach

If it cannot be proven that the ~~syngas~~ MRG is produced exclusively by marginal increases in natural gas consumption at the synthetic fuel plant then the emission factor for MRG ~~syngas~~ is estimated using energy and material balances of the entire plant before and after the project is implemented. The net increase in carbon from such an analysis (in ton CO2e) divided by the volume of MRG ~~syngas~~ used in the project activity in a particular year is the emission factor for MRG ~~syngas~~ production.



This is represented mathematically and calculated ex-post as follows:[22]

$$EF_{MRG\ prd,y} = \frac{((Q_{SPin,PJ,y} * CF_{SPin,PJ,i,y} - \sum Q_{SPout,PJ,i,y} * CF_{SPout,PJ,i,y}) - (Q_{SPin,Bl,i,y} * CF_{SPin,BL,i,y} - \sum Q_{SPout,BL,i,y} * CF_{SPout,BL,i,y}))}{(\sum FF_{MRGout,PJ,i,y} - \sum FF_{MRGout,BL,i,y})} \quad \textbf{(25)}$$

Where:

$EF_{sMRG\cancel{g}\ prd,y}$	=	Emission factor for ~~syngas~~ MRG production in tCO2/TJ
$Q_{SPin,PJ,i,y}$	=	Quantity of fossil fuel and fossil fuel derived utilities (*i*) consumed by synfuel plant for the duration of the project in year *y* in TJ
$Q_{SPout,PJ,i,y}$	=	Quantity of liquid fuels, products and fossil fuel derived utilities (*i*) produced by the synfuel plant for the duration of the project in year *y* in TJ
$Q_{SPin,BL,i,y}$	=	Quantity of fossil fuel and fossil fuel derived utilities (*i*) consumed by synfuel plant prior to the implementation of project activity, in TJ
$Q_{SPout,BL,i,y}$	=	Quantity of liquid fuels, products and fossil fuel derived utilities (*i*) produced by the synfuel plant prior to the implementation of the project activity, in TJ
CF_i	=	It represents the corresponding emission factor for the fossil fuel 'i' and is expressed as tCO_2/TJ
$\sum FF_{\cancel{s}\ MRGout,PJ,i,y}$	=	The total quantity of ~~synthetic gas~~MRG produced from natural gas during the project in year *y* in TJ
$\sum FF_{MR\cancel{S}Gout,BL,i,y}$	=	The total quantity of MRG ~~synthetic gas~~ produced from natural gas prior to project implementation in TJ

Data for the material and energy balances can be monitored failing that computer process simulation can be carried out to establish such emissions associated with the production of the MRG ~~syngas~~ used in the project activity.

[22] The MRG ~~syngas~~ for the project is accompanied by other changes to the range of outputs, for example changes in the liquid fuel slate or other MRG ~~syngas~~ users the emissions factor should be changed to reflect this by making changes to the denominator of the equation 22.

Emission reductions

The emission reduction by the project activity during a given year *y* (*ERy*) is the difference between the baseline emissions (*BEy*) and project emissions (*PEy*) and leakage emissions (*Ly*), as follows:

$$ER_y = BE_y - PE_y - LE_y \quad \textbf{(26)}$$

Where:

ER_y	=	Emission reductions during the year *y* (tCO_2/yr)
BE_y	=	Baseline emissions during the year *y* (tCO_2/yr)
PE_y	=	Project emissions during the year *y* (tCO_2/yr)
LE_y	=	Leakage emissions during the year *y* (tCO_2/yr)

Changes required for methodology implementation in 2nd and 3rd crediting periods

Step 1: Check that the project activity is still additional and not all or part of the baseline.
Step 2: Check for changes in the Global Warming Potential of the Greenhouse Gases.
Step 3: If project is still additional leave the baseline as is and resubmit project for validation.
Step 4: If project is part of the baseline, correct baseline and resubmit project for validation.
Step 5: If the project has become the baseline the project is no longer additional and should be abandoned as a CDM project activity.

Data and parameters not monitored

ID Number:	1
Parameter:	$EF_{CO2, coal}$; $EF_{CO2, oil,}$ $EF_{CO2, NG,}$ $EF_{CO2,LF}$, $EF_{CO2,\cancel{syngas}MRG}$
Data unit:	Tonnes CO_2/TJ
Description:	The default emissions factor for a fuel used in the baseline or the project activity and in synfuel~~gas~~ plant. International data most recently published.
Source of data:	IPCC, fuel type and technology specific
Measurement procedures (if any):	Published data
Any comment:	The parameter will not be monitored if a default value is used. Used in the assessment of additionality

ID Number:	2
Parameter:	$EF_{BL,CO2,y}$
Data unit:	tCO2/MWh
Description:	Emissions factor of electricity generated in the baseline year *y* (tCO_2e/MWh)
Source of data:	National grid data for Grid emission factor and from supplier of technology which is most likely baseline scenario
Measurement procedures (if any):	Estimated based on OM/BM for the national grid and based on fuel and efficiency of technology which is most likely baseline scenario
Any comment:	The lowest value of emission factor should be selected as defined in baseline emissions section

ID Number:	3
Parameter:	$EF_{k,upstream,CH4}$
Data unit:	tonnes CH_4/TJ
Description	Fugitive CH_4 emissions associated with fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of gas used in the project plant and fossil fuels used in the grid in the absence of the project activity. International data, regionally specific. Most recently published
Source of data:	Table 2 above
Measurement procedures (if any):	Default
Any comment:	Used in the calculation of leakage

ID Number:	4
Parameter:	$EF_{NG,upstream,CH4}$
Data unit:	tonnes CH_4/TJ
Description	Emission factor for upstream fugitive methane emissions from production, transportation and distribution of natural gas fuel supplied to final consumers
Source of data:	Table 2 above
Measurement procedures (if any):	Default
Any comment:	Used in the calculation of leakage

ID Number:	5
Parameter:	$EF_{CO2,upstream,LNG}$
Data unit:	tonnes CH_4/TJ
Description:	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
Source of data:	Measured or default values used
Measurement procedures (if any):	
Any comment:	Used in the calculation of leakage

III. MONITORING METHODOLOGY

Monitoring procedures

As per monitoring methodology, the primary parameters to be monitored during the crediting period of the project activity are listed below. Other parameters will be calculated using the primary parameters. Primary parameters for project emissions:

(1) Annual fuel(s) (gas) consumption in project activity;
(2) Net Calorific Value(s) of the fuel(s) (gas) used in the project activity;
(3) Fuel emission factors for fuel(s) (gas) used in the project activity.

Baseline Electricity emissions will be monitored per "Tool to calculate the emission factor for an electricity system" if and as applicable.

Parameters to be monitored for baseline emissions include:

(1) Electricity generated by the project activity;
(2) Efficiencies of co-generation equipment units;
(3) Heat generated by the element process.

Parameters to be monitored for leakage emissions (if ~~syngas~~ MRG from natural gas/coal-to-liquid fuel plant is used in project) include:

(1) Marginal increase of natural Gas and coal as feed to natural gas/coal-to-liquid fuel plant;
(2) Energy consumed in the production of synthetic fuels in the baseline including Natural Gas and Coal consumption.

Data and parameters monitored

Data / Parameter:	T&D Technical electricity transmission and distribution losses (TDL)
Data unit:	%
Description:	Transfer and distribution losses associated with electricity import. Losses include technical electrical energy losses that are incurred during transmission & distribution
Source of data:	Information to be supplied by the grid electricity provider or sources such as the national energy regulator or national or local data published
Measurement procedures (if any):	
Monitoring frequency:	Yearly
QA/QC procedures:	The information should be recorded, compiled and reported for the duration of the project. If an environmental management system or a quality management system exits, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis. All responsibilities in terms compilation of data, record keeping and corrective action should be defined clearly
Any comment:	The value used should be supported by documentary evidence. If documentation cannot support the percentage of losses accurately, on the basis of conservatism, the lowest losses in a range of estimates should be used, or losses should be ignored in the baseline scenario (i.e. T&D =0%)

Data / Parameter:	$FF_{project,i,y}$
Data unit:	tonne or m^3
Description:	Annual quantity of project fuel (natural gas or synthesis gas) consumed in element process *i* in the project activity in any year *y*
Source of data:	Fuel flow meter reading at project boundary
Measurement procedures (if any):	Annual gas consumption for each element process *i* should be monitored on a continuous basis
Monitoring frequency:	Continuously
QA/QC procedures:	Natural gas supply metering to the project will be subject to regular (in accordance with stipulation of the meter supplier) maintenance, calibration and testing to ensure acceptable monitoring accuracy. The readings should be verified by comparing gas bills received from the gas supply company. Records of calibration should be kept for at least 2 years following verification. All responsibilities in terms of calibration, compilation of data and corrective action should be defined clearly. The information should be recorded, compiled and reported for the duration of the project. If an environmental management system or a quality management system exits, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis
Any comment:	The total fuel consumption should be monitored both at the supplier and the project end for cross-verification

Data / Parameter:	$EF_{FF,CO2,I,y}$
Data unit:	tCO_2/m^3 or tCO_2/t
Description:	GHG Emission factor of coal or oil used in element process *i* in absence of project activity.
Source of data:	Local, Regional, Global (IPCC)
Measurement procedures (if any):	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, default emission factors IPCC-2006 guidelines 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, for baseline emissions, within a plausible range) and the choice should be justified and document in the CDM-PDD
Monitoring frequency:	Once or through regular sampling (at least one sample for each consignment).
QA/QC procedures:	The information should be recorded, compiled and reported for the duration of the project. All responsibilities in terms of calibration, compilation of data and corrective action should be defined clearly. If an environmental management system or a quality management system exits, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis.
Any comment:	Alternatively, use default values as stated above

Data / Parameter:	$EF_{PF,CO2,i}$
Data unit:	tCO_2/m^3 or tCO_2/t
Description:	GHG Emission factor for project fuel (either natural gas or ~~synthetic gas~~ MRG) used in element process *i* in absence of project activity.
Source of data:	Local, Regional, Global (IPCC), Project Proponent, ~~Synthetic Gas Manufacturer~~ MRG producer
Measurement procedures (if any):	In case of Natural Gas: Project proponents may either conduct measurements or they may use accurate and reliable local or national data where available. Where such data is not available, default emission factors IPCC-2006 guidelines 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, for baseline emissions, within a plausible range) and the choice should be justified and document in the CDM-PDD. In case of ~~Synthetic Gas~~ MRG: Project Proponent should conduct measurement. Alternatively, they can get this data from the manufacturer of syntheric gas
Monitoring frequency:	Once or through regular sampling (at least one sample for each consignment).
QA/QC procedures:	The information should be recorded, compiled and reported for the duration of the project. All responsibilities in terms of calibration, compilation of data and corrective action should be defined clearly. If an environmental management system or a quality management system exits, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis.
Any comment:	Alternatively, use default values as stated above

Data / Parameter:	$\varepsilon_{project,i,y}$
Data unit:	-
Description:	Energy efficiency of the element process with project fuel (natural gas or ~~synthetic gas~~ MRG)
Source of data:	Use one of the following options: (a) Undertake on-site measurements, or use documented manufacturer's specification of the energy efficiency for normal operation conditions (normal representative load, between two maintenance activities, etc) if no retrofit or other change has been undertaken to the element process
Measurement procedures (if any):	Use recognized standards for the measurement of the element process efficiency, such as the "British Standard Methods for Assessing the thermal performance of boilers for steam, hot water and high temperature heat transfer fluids" (BS845) or similar other standards. Use the direct method (dividing the net heat generation by the energy content of the fuels fired during a representative time period) and not the indirect method (determination of fuel supply or heat generation and estimation of the losses). Measure the efficiency at steady-state operation under normal operation conditions (normal representative load, average oxygen content in the flue gases, representative or favorable ambient conditions for the efficiency of the element process, etc). The measurement should be supervised by a competent independent third party (e.g. the DOE). The measurement should be conducted during between two maintenance activities to represent normal condition of element process. Document the measurement procedures and results transparently in the CDM-PDD or, if undertaken during the crediting period, in the monitoring report
Monitoring frequency:	Measurements should be undertaken: • Between two maintenance activities; • If the characteristics of the 'project fuel' change substantially during the project activity; • If major retrofits or changes to the element process are undertaken that may affect the efficiency of element process; • At the renewal of a crediting period.
QA/QC procedures:	
Any comment:	Only Option A for establishing efficiency, as defined in the baseline emissions sections, is applicable for project efficiency

Data / Parameter:	$\varepsilon_{baseline,i,y}$
Data unit:	-
Description:	Energy efficiency of the element process with baseline fuel (oil and coal)
Source of data:	Use one of the following options: (b) Undertake on-site measurements, or (c) Use documented manufacturer's specification of the energy efficiency for optimal operation conditions (optimal load, after maintenance, etc) if no retrofit or other change has been undertaken to the element process and if the fuel type used corresponds to the specification of efficiency by the manufacturer
Measurement procedures (if any):	Use recognized standards for the measurement of the element process efficiency, such as the "British Standard Methods for Assessing the thermal performance of boilers for steam, hot water and high temperature heat transfer fluids" (BS845). Use the direct method (dividing the net heat generation by the energy content of the fuels fired during a representative time period) and not the indirect method (determination of fuel supply or heat generation and estimation of the losses). Measure the efficiency at steady-state operation under optimal operation conditions (optimal load, optimal oxygen content in the flue gases, adequate fuel viscosity, representative or favorable ambient conditions for the efficiency of the element process, etc. Best practices for operation of element processs should be followed. The measurement should be supervised by a competent independent third party (e.g. the DOE). The measurement should be conducted immediately after scheduled preventive maintenance has been undertaken. Document the measurement procedures and results transparently in the CDM-PDD or, if undertaken during the crediting period, in the monitoring report
Monitoring frequency:	Measurements should be undertaken: • At the start of the project activity; • If major retrofits or changes to the element process are undertaken that may affect the efficiency of element process; • At the renewal of a crediting period
QA/QC procedures:	
Any comment:	If Option A is chosen

Data / Parameter:	$\varepsilon_{baseline,t}$
Data unit:	-
Description:	Baseline efficiency of the element process during time interval *t* where *t* is a discrete time interval during the year *y*
Source of data:	Measurements by project participants
Measurement procedures (if any):	Establish an efficiency-load-function for the element process ($\eta_{BL,t} = f(HR_{project,t})$) with baseline fuels (coal or oil). Use recognized standards for the measurement of the element process efficiency, such as the "British Standard Methods for Assessing the thermal performance of boilers for steam, hot water and high temperature heat transfer fluids" (BS845). Use the direct method (dividing the net heat generation by the energy content of the fuels fired during a representative time period) and not the indirect method (determination of fuel supply or heat generation and estimation of the losses). Best practices for operation of element processs should be followed. The measurement should be supervised by a competent independent third party (e.g. the DOE). The measurement should be conducted immediately after scheduled preventive maintenance has been undertaken and under good operation conditions (optimal load, optimal oxygen content in the flue gases, adequate fuel viscosity, representative or favorable ambient conditions for the efficiency of the element process, etc). During the measurement campaign, the load is varied over the whole operation range and the efficiency of the element process is measured for different steady-state load levels. The efficiency should be measured for at least 10 different load levels covering the operation range. Apply a regression analysis to the measured efficiency for different load levels. Calculate the standard deviation of the regression, using the guidance in the Annex to this methodology. Document the measurement procedures and results (i.e. efficiency at different load levels, application of the regression analysis) transparently in the CDM-PDD or, if undertaken during the crediting period, in the monitoring report
Monitoring frequency:	Measurements should be undertaken: • At the start of the project activity; • If major retrofits or changes to the element process are undertaken that may affect the efficiency; • At the renewal of a crediting period
QA/QC procedures:	
Any comment:	If Option B is chosen

Data / Parameter:	$NCV_{FF,i}$
Data unit:	TJ/t or TJ/m^3
Description:	Net Calorific Value of fuel coal or oil used in element process *I*
Source of data:	Fuel supplier, Local Authority, Country-specific, IPCC
Measurement procedures (if any):	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, default values from IPCC-2006 guidelines 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 for baseline emissions within a plausible range) and the choice should be justified and document in the CDM-PDD
Monitoring frequency:	Monthly or as and when new consignment of fuel is received
QA/QC procedures:	No additional QA/QC procedures may need to be planned
Any comment:	Standardised to the lower heating value

Data / Parameter:	$NCV_{PF,y}$
Data unit:	TJ/t or TJ/m^3
Description:	Net Calorific Value of Project Fuel (Natural Gas or synthesis gas) used in element process in project scenario
Source of data:	Local, Regional, Global (IPCC), Project Proponent, ~~Synthetic Gas Manufacturer~~ MRG producer
Measurement procedures (if any):	In case of Natural Gas: Project proponents may either conduct measurements or they may use accurate and reliable local or national data where available. Where such data is not available, default emission factors IPCC-2006 guidelines 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, for baseline emissions, within a plausible range) and the choice should be justified and document in the CDM-PDD. In case of MRG ~~Synthetic Gas~~: Project Proponent should conduct measurement. Alternatively, they can get this data from the manufacturer of syntheric gas.
Monitoring frequency:	Monthly or as and when fuel is received
QA/QC procedures:	No additional QA/QC procedures may need to be planned
Any comment:	Standardised to the lower heating value

Data / Parameter:	$h_{heatout,i,y}$
Data unit:	TJ/kg
Description:	Enthalpy of heat carrier at outlet of the waste heat generating source (element process *i*) that would have been generated in the element process by coal or oil in absence of the project activity, in TJ/kg
Source of data:	Enthalpy calculated by the project proponent using Standard Steam tables
Measurement procedures (if any):	In case heat carrier is steam, the steam temperature and pressure at the output of the element process (boiler) *i* should be monitored to determine the steam enthalpy. The temperature and pressure monitoring equipment should be calibrated and maintained as per supplier requirements or best practice
Monitoring frequency:	At least monthly. In case of fluctuating element process load, the frequency should be daily
QA/QC procedures:	The information should be recorded, compiled and reported for the duration of the project. If an environmental management system or a quality management system exists, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis. Records of calibration should be kept for at least 2 years following verification. All responsibilities in terms of calibration, compilation of data, record keeping and corrective action should be defined clearly
Any comment:	An average enthalpy can be calculated monthly if the enthalpy of the steam produced does not vary significantly

Data / Parameter:	$h_{heatin\ ,i,y}$
Data unit:	TJ/kg
Description:	Enthalpy of heat carrier at inlet of waste heat generating source (element process *i*)in TJ/kg
Source of data:	Enthalpy calculated by the project proponent using Standard Steam tables
Measurement procedures (if any):	The temperature and flow of heat carrier should be measured at the entry point of element process where heat is generated. In case heat carrier is steam, thewater temperature at the inlet of boiler drum of element process (boiler) *i* should be monitored to determine the steam enthalpy. The temperature and pressure monitoring equipment should be calibrated and maintained as per supplier requirements or best practice
Monitoring frequency:	At least monthly. In case of fluctuating boiler load, the frequency should be daily
QA/QC procedures:	The information should be recorded, compiled and reported for the duration of the project. If an environmental management system or a quality management system exists, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis. Records of calibration should be kept for at least 2 years following verification. All responsibilities in terms of calibration, compilation of data, record keeping and corrective action should be defined clearly
Any comment:	An average enthalpy can be calculated monthly if the enthalpy of the steam produced by boiler does not vary significantly

Data / Parameter:	$FR_{heat,i,y}$
Data unit:	kg/hrs
Description:	Flow rate of heat carrier (e.g. air or steam or thermic fluid) generated in the Waste Heat Generating Source (element process *i*).
Source of data:	Monitoring equipment (steam flow meter) at the element process *i*
Measurement procedures (if any):	It should be measured at the outlet of element process where heat is generated
Monitoring frequency:	Continuous basis
QA/QC procedures:	Pressure and temperature calibration of steam meter should be carried out at regular intervals and calibration records should be maintained. The information should be recorded, compiled and reported for the duration of the project. If an environmental management system or a quality management system exits, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis. Records of calibration should be kept for at least 2 years following verification. All responsibilities in terms of calibration, compilation of data, record keeping and corrective action should be defined clearly
Any comment:	

Data / Parameter:	$hrs_{i,y}$
Data unit:	Hours
Description:	Hours of operation of Waste Heat Generating Source (element process *i*).
Source of data:	
Measurement procedures (if any):	
Monitoring frequency:	Continuous basis
QA/QC procedures:	
Any comment:	

Data / Parameter:	$FF_{project,j,y}$
Data unit:	tonne or m^3
Description:	Annual quantity of project fuel (natural gas or synthesis gas) consumed in electricity generator/ cogenerator *j* in the project activity in year *y*
Source of data:	Fuel flow meter reading at project boundary
Measurement procedures (if any):	Annual gas consumption for each electricity generator/ cogenerator *j* should be monitored on a continuous basis
Monitoring frequency:	Continuously
QA/QC procedures:	Natural gas supply metering to the project will be subject to regular (in accordance with stipulation of the meter supplier) maintenance, calibration and testing to ensure acceptable monitoring accuracy. The readings should be verified by comparing gas bills received from the gas supply company. Records of calibration should be kept for at least 2 years following verification. All responsibilities in terms of calibration, compilation of data and corrective action should be defined clearly. The information should be recorded, compiled and reported for the duration of the project. If an environmental management system or a quality management system exits, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis
Any comment:	The total fuel consumption should be monitored both at the supplier and the project end for cross-verification

Data / Parameter:	$EG_{PJ,y}$
Data unit:	MWh
Description:	Cogeneration electricity supplied to the industrial plant
Source of data:	Measurements of electricity generated from
Measurement procedures (if any):	
Monitoring frequency:	Continuous
QA/QC procedures:	The information should be recorded, compiled and reported for the duration of the project. If an environmental management system or a quality management system exits, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis. Records of calibration should be kept for at least 2 years following verification. All responsibilities in terms of calibration, compilation of data, record keeping and corrective action should be defined clearly
Any comment:	

Data / Parameter:	$FF_{\cancel{s}MRG\cancel{g},pr,y}$
Data unit:	TJ
Description:	Quantity of ~~synthetic gas~~ MRG consumed by project activity during the project in year *y*
Source of data:	The project proponent or the gas supplier should provide the information.
Measurement procedures (if any):	Fuel flow meter reading at project boundary
Monitoring frequency:	Cumulative annual
QA/QC procedures:	The information should be recorded, compiled and reported for the duration of the project. If an environmental management system or a quality management system exits, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis. Records of calibration should be kept for at least 2 years following verification. All responsibilities in terms of calibration, compilation of data, record keeping and corrective action should be defined clearly. If the project proponent provides the information, it can be cross checked against purchase invoices from the gas supplier
Any comment:	Not applicable when in cases where (1) the gas used is natural gas[23] or (2) it is shown that project activity does not impact on upstream emissions at a synfuel[24] plant. Otherwise it is used to calculate leakage emissions associated with the production of ~~synthetic gas~~MRG

Data / Parameter:	$EF_{\cancel{s}MRG\cancel{g},prd,y}$
Data unit:	t CO_2/TJ
Description:	Emissions factor for the production of the ~~synthetic gas~~MRG used in the project activity in the year *y*
Source of data:	Estimated
Measurement procedures (if any):	
Monitoring frequency:	Yearly
QA/QC procedures:	No additional QA/QC procedures may need to be planned
Any comment:	These emission factors are used when it cannot be proven that the gas used in the project activity is attributable to natural gas on an equivalent energy basis. Then the information is used to calculate leakage associated with the production of ~~synthetic gas~~MRG at the synfuel plant in equation 16

[23] The gas is pumped directly from the natural gas source to the facility where it is used.
[24] Synfuel plant refers to the plant where the liquid fuels are produced, i.e. the synthetic fuel production plant.

Data / Parameter:	$Q_{SPin,PJ,i,y}$
Data unit:	TJ
Description:	Quantity of fossil fuel and fossil fuel derived utilities (*i*) consumed by synfuel plant for the duration of the project in year *y*.
Source of data:	Information to be supplied by the gas supplier or synfuel plant.
Measurement procedures (if any):	The total fuel consumption should be monitored by the ~~synthetic gas~~MRG supplier and should be cross-verified with purchase information
Monitoring frequency:	Cumulative annual
QA/QC procedures:	The information should be recorded, compiled and reported for the duration of the project. If an environmental management system or a quality management system exits, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis. All responsibilities in terms compilation of data, record keeping and corrective action should be defined clearly
Any comment:	Information used to determine whether there is additional leakage from the synthetic fuel production plant

Data / Parameter:	$Q_{SPin,BL,i,y}$
Data unit:	TJ
Description:	Quantity of fossil fuel and fossil fuel derived utilities (*i*) consumed by synfuel plant in the baseline year *y*
Source of data:	Information to be supplied by the gas supplier or synfuel plant.
Measurement procedures (if any):	The total fuel consumption should be monitored by the ~~synthetic gas~~MRG supplier and should be cross-verified with purchase information
Monitoring frequency:	Cumulative annual
QA/QC procedures:	The information should be recorded, compiled and reported for the duration of the project. If an environmental management system or a quality management system exits, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis. All responsibilities in terms compilation of data, record keeping and corrective action should be defined clearly
Any comment:	Information used to determine whether there is additional leakage from the synthetic fuel production plant

Data / Parameter:	$Q_{SPout,PJ,i,y}$
Data unit:	TJ
Description:	Quantity of liquid fuels, products and fossil fuel derived utilities (*i*) produced by the synfuel plant in the base year *y*
Source of data:	Information to be supplied by the gas supplier or synfuel plant.
Measurement procedures (if any):	The total fuel products produced should be monitored by the ~~synthetic gas~~MRG supplier and should be cross-verified with sale information
Monitoring frequency:	Cumulative annual
QA/QC procedures:	The information should be recorded, compiled and reported for the duration of the project. If an environmental management system or a quality management system exits, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis. All responsibilities in terms compilation of data, record keeping and corrective action should be defined clearly
Any comment:	Information used to determine whether there is additional leakage from the synthetic fuel production plant

Data / Parameter:	$Q_{SPout,BL,i,y}$
Data unit:	TJ
Description:	Quantity of fossil fuel and fossil fuel derived utilities (*i*) consumed by synfuel plant in the baseline year *y* in TJ
Source of data:	Information to be supplied by the gas supplier or synfuel plant
Measurement procedures (if any):	The total production should be monitored by the ~~synthetic gas~~MRG supplier
Monitoring frequency:	Cumulative annual
QA/QC procedures:	The information should be recorded, compiled and reported for the duration of the project. If an environmental management system or a quality management system exits, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis. All responsibilities in terms compilation of data, record keeping and corrective action should be defined clearly
Any comment:	Information used to determine whether there is additional leakage from the synthetic fuel production plant

Data / Parameter:	CF_i
Data unit:	tC/TJ
Description:	It represents the corresponding emission factor for the fossil fuel 'i' and is expressed as tC/TJ
Source of data:	Local, Regional, Global (IPCC), Project Proponent, ~~Synthetic Gas Manufacturer~~ MRG producer.
Measurement procedures (if any):	Project proponent and/or Synthesis fuel manufacturer may either conduct measurements or they may use accurate and reliable local or national data where available. Where such data is not available, default emission factors IPCC-2006 guidelines 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, for baseline emissions, within a plausible range) and the choice should be justified and document in the CDM-PDD
Monitoring frequency:	Once or through regular sampling (at least one sample for each consignment)
QA/QC procedures:	The information should be recorded, compiled and reported for the duration of the project. All responsibilities in terms of calibration, compilation of data and corrective action should be defined clearly. If an environmental management system or a quality management system exits, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis
Any comment:	Alternatively, use default values as stated above

Data / Parameter:	$Q_{NGin,PJ,y}$
Data unit:	TJ
Description:	The sum of all natural gas (and any energy utilities) in to the ~~syngas~~ MRG processes during the project in year *y* in TJ
Source of data:	Information to be supplied by the gas supplier or synfuel plant.
Measurement procedures (if any):	The total fuel consumption should be monitored by the ~~synthetic gas~~MRG supplier and should be cross-verified with purchase information
Monitoring frequency:	Cumulative annual
QA/QC procedures:	The information should be recorded, compiled and reported for the duration of the project. If an environmental management system or a quality management system exits, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis. All responsibilities in terms compilation of data, record keeping and corrective action should be defined clearly
Any comment:	Information used to determine whether there is additional leakage from the synthetic fuel production plant

Data / Parameter:	EF_{NG}
Data unit:	t CO_2/TJ
Description:	The emissions factor of natural gas (and energy utilities) in tCO2/TJ
Source of data:	Guidance from IPCC 2006 Guidelines should be followed where appropriate. The liquid fuel manufacturer may either conduct measurements or 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. The choice of values should be justified and document in the CDM-PDD
Measurement procedures (if any):	Measurements can be done by the ~~synthetic gas~~MRG supplier/producer. Standardised measurement protocols and procedures should be used, internationally acceptable where applicable
Monitoring frequency:	Yearly
QA/QC procedures:	No additional QA/QC procedures may need to be planned
Any comment:	Information used to determine whether there is additional leakage from the synthetic fuel production plant

Data / Parameter:	$Q_{NGin,BL,y}$
Data unit:	TJ
Description:	The sum of all natural gas (and any energy utilities) in to the ~~syngas~~ MRG processes during the baseline in year *y* in TJ
Source of data:	Information to be supplied by the gas supplier or synfuel plant
Measurement procedures (if any):	The total fuel consumption should be monitored by the ~~synthetic gas~~MRG supplier and should be cross-verified with purchase information
Monitoring frequency:	Cumulative annual
QA/QC procedures:	The information should be recorded, compiled and reported for the duration of the project. If an environmental management system or a quality management system exits, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis. All responsibilities in terms compilation of data, record keeping and corrective action should be defined clearly
Any comment:	Information used to determine whether there is additional leakage from the synthetic fuel production plant

Data / Parameter:	$FF_{\cancel{S}MRGout,PJ,i,y}$
Data unit:	TJ
Description:	Quantity of ~~synthetic gas~~MRG 'i' produced from natural gas out of ~~synthetic gas~~MRG processes during the project in year *y* in TJ
Source of data:	Information to be supplied by the gas supplier or synfuel plant.
Measurement procedures (if any):	The total fuel consumption should be monitored by the ~~synthetic gas~~MRG supplier and should be cross-verified with purchase information
Monitoring frequency:	Cumulative annual
QA/QC procedures:	The information should be recorded, compiled and reported for the duration of the project. If an environmental management system or a quality management system exits, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis. All responsibilities in terms compilation of data, record keeping and corrective action should be defined clearly
Any comment:	Data for all ~~synthetic gas~~MRG 'i' will be recorded and stored. Information used to determine whether there is additional leakage from the synthetic fuel production plant

Data / Parameter:	$FF_{\cancel{S}MRGout,BL,i,y}$
Data unit:	TJ
Description:	Quantity of ~~synthetic gas~~MRG 'i' produced from natural gas out of ~~synthetic gas~~MRG processes during the baseline in year *y* in TJ
Source of data:	Information to be supplied by the gas supplier or synfuel plant
Measurement procedures (if any):	The total fuel consumption should be monitored by the ~~synthetic gas~~MRG supplier and should be cross-verified with purchase information
Monitoring frequency:	Cumulative annual
QA/QC procedures:	The information should be recorded, compiled and reported for the duration of the project. If an environmental management system or a quality management system exits, the parameter should be incorporated into the system, ensuring that auditing is done on a regular basis. All responsibilities in terms compilation of data, record keeping and corrective action should be defined clearly
Any comment:	Data for all ~~synthetic gas~~MRG 'i' will be recorded and stored. Information used to determine whether there is additional leakage from the synthetic fuel production plant

Data / Parameter:	$EF_{SMRG,I}$
Data unit:	TJ
Description:	Project Proponent, ~~Synthetic Gas Manufacturer~~ MRG producer
Source of data:	Project Proponent should conduct measurement. Alternatively, they can get this data from the manufacturer of synthetic gas
Measurement procedures (if any):	Measurements can be done by the ~~synthetic gas~~MRG supplier/producer. Standardised measurement protocols and procedures should be used, internationally acceptable where applicable
Monitoring frequency:	Yearly
QA/QC procedures:	No additional QA/QC procedures may need to be planned
Any comment:	Information used to determine whether there is additional leakage from the synthetic fuel production plant

Data / Parameter:	$EG_{PJ,export,y}$
Data unit:	MWh
Description:	Electricity produced at the industrial facility and intermittently exported to the grid
Source of data:	Actual measurements, plant operational records
Measurement procedures (if any):	Measured constantly using an electricity meter, which is calibrated regularly
Monitoring frequency:	Continuously, aggregated monthly/yearly
QA/QC procedures:	Double checked with information from the grid operator
Any comment:	

IV. REFERENCES AND ANY OTHER INFORMATION

References are in the body of the text and in the footnotes.

2000 IPCC Good Practice Guidance
GHG inventory data reported to the UNFCCC as part of national communications can be used where country-specific approaches (and not Tier 1 default values) have been used to estimate emissions.
Volume 3 of the 1996 Revised IPCC Guidelines
Barclay, M. and N. Denton, 2005. Selecting offshore LNG process.
<http://www.fwc.com/publications/tech_papers/files/LNJ091105p34-36.pdf> (10th April 2006)"
"Tool to calculate the emission factor for an electricity system",
AM0014 "Natural gas-based package cogeneration" for barrier analysis/common practice",
AM0029 "Baseline methodology for grid connected electricity generation plants using natural gas",
ACM0009 "Consolidated baseline methodology for industrial fuel switching from coal or petroleum fuel to natural gas" (heat generation from natural gas) and
"Tool for the demonstration and assessment of additionality".

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History of the document

Version	Date	Nature of revision(s)
03	EB 45, Annex 8 13 February 2009	Revision to: • Expand the applicability of this methodology to project activities exporting electricity to the grid on ad-hoc basis. In this case, annual exported electricity is capped at 10% of the total power produced by the project activity, and project participants cannot claim emission reductions due to displacing grid electricity; and • Replace the term “syngas” or “synthetic gas” by the term “Methane Rich Gas (MRG)” in the text of this methodology.
02	EB 35, Para 24 19 October 2007	Revision to incorporate the use of the “Tool to calculate the emission factor for an electricity system”.
01	EB 31, Annex 3 4 May 2007	Initial adoption.