Approved consolidated baseline and monitoring methodology ACM0007

"Conversion from single cycle to combined cycle power generation"

I. SOURCE AND APPLICABILITY

Sources

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

- NM0070: Conversion of existing open cycle gas turbine to combined cycle operation at Guaracachi power station, Santa Cruz, Bolivia whose Baseline study, Monitoring and Verification Plan and Project Design Document were prepared by KPMG, London;
- NM0078-rev: Conversion of single cycle to combined cycle power generation, Ghana whose Baseline study, Monitoring and Verification Plan and Project Design Document were prepared by Quality Tonnes and The Energy Foundation.

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

- "Tool to calculate the emission factor for an electricity system";
- "Combined tool to identify the baseline scenario and demonstrate additionality";
- "Tool to determine the remaining lifetime of equipment"; and
- "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion".

To access these tools and for more information regarding the proposed new methodologies that are listed above please refer to <http://cdm.unfccc.int/goto/MPappmeth>.

Definitions

Combined cycle mode. The operation of a power unit with recovery of exhaust heat for the purpose of power generation. The recovered exhaust heat is used to generate steam to operate a steam turbine. The mechanical energy generated by the steam turbine is used to generate electric power. The exhaust heat could be recovered from a gas turbine (combined cycle gas turbine) or an internal combustion engine (combined cycle engine system)**.**

Exhaust heat. Exhaust heat from a power plant/unit operated in single cycle mode, which is used for power generation under the project activity.

Major retrofit. A non-routine maintenance activity which either changes a power unit's basic design parameters or for which the fixed capital cost of the replaced component, plus the costs of any repair and maintenance activities that are part of the replacement activity (such as labor, contract services, major equipment rental, etc.) exceeds 20 percent of the cost to construct a new unit.[1] This cost should be based on

[1] This threshold was selected based on a United States Environmental Protection Agency (USEPA) technical discussion document analyzing a 20% cost threshold of replacement value as an indicator for routine maintenance. This indicator (amongst others) is included in the Equipment Replacement Provision ("ERP") rule for the US New Source Review permitting program that prospectively defined what types of equipment replacements are excluded from major NSR.

the invested cost (eg. as recorded in company books), adjusted for inflation and value of currency (either USD or EUR).

Net electricity generation. The difference between the total quantity of electricity generated by the power plant/unit and the auxiliary electricity consumption (also known as parasitic load) of the power plant/unit (e.g. for pumps, fans, controlling, etc).

Operational history. A period of time immediately prior to the implementation of the project activity or prior to the submission of the Project Design Document (CDM-PDD) for validation, whatever is earlier, for which there are records available on the operation of the power unit. The operational history typically defined in this methodology is one or three years.

Power plant/unit. A facility that generates electric power. Several power units at one site comprise a power plant, whereby a power unit is characterized by its ability to operate independently of other power units at the same site.

Project power unit. A power unit that was operated in single cycle mode prior to the implementation of the project activity and is upgraded to operate in combined cycle mode under the project activity.

Single cycle mode. The operation of a power unit with no provision for exhaust heat recovery for the purpose of power generation. The power unit could be driven by a gas turbine (single cycle gas turbine) or an internal combustion engine (single cycle engine system).

In addition, the definitions in the tools referred to above apply, as long as the terms are not defined in this methodology differently.

Selected approach from paragraph 48 of the CDM modalities and procedures

"Existing actual or historical emissions, as applicable".

Applicability

This methodology applies to project activities that convert one or several grid connected[2] power units at one site from single-cycle to combined-cycle mode.

This methodology applies if the project power unit(s) fulfil the following conditions:

- The unit(s) have an operational history of at least one year with no major retrofit, and at least one unit has an operational history of more than three years with no major retrofit. There is no major retrofit in these time periods.

- In the case that a unit has less than three years operational history: all project power unit(s) were designed and commissioned for operation in single cycle mode only. This shall be demonstrated by the project participants by providing relevant documents, such as original process diagrams and

"Office of Air Quality Planning and Standards, 2005. Technical Support Document for the Equipment Replacement Provision of the Routine Maintenance, Repair and Replacement Exclusion: Reconsideration < http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2002-0068-2819> (8 March 2011)"

[2] No provisions are provided to apply this methodology to captive power units in order to keep the methodology simple. If required, project participant may submit a request for revision to this methodology to apply it to captive power units.

schemes from the construction of the plant, licenses and/or by an on-site check by the DOE prior to the implementation of the project activity.

- During the most recent three years prior to the implementation of the project activity and during the crediting period the project power unit(s) use(d) only the following fuel types:
  - (a) Fossil fuels; and/or
  - (b) Blends of fossil fuels and biofuels, where the biofuel is blended to the fossil fuel in a situation that is outside the control of the project participants (such as regulatory requirements to blend biodiesel with diesel or biogas with natural gas).

  Note that this methodology does not allow crediting for an increase in the share of biofuels.

- The type(s) of fossil fuels used by the project power unit(s) during the crediting period were also used during the most recent three years prior to the implementation of the project activity, except, where applicable, any auxiliary fuel consumption (e.g. for start-ups) which shall not exceed 3% of the total fuel consumption in the unit(s) (measured on an energy basis).

Moreover, this methodology is applicable under the condition that the project activity does not increase the lifetime of the existing gas turbine or engine during the crediting period, as determined using the "Tool to determine the remaining lifetime of equipment" (i.e. this methodology is applicable up to the end of the lifetime of existing gas turbine or engine, if shorter than crediting period).

In addition, the applicability conditions included in the tools referred to above apply.

II. BASELINE METHODOLOGY PROCEDURE

Project boundary

The spatial extent of the project boundary includes the project power unit(s) and all other power plants connected to the same grid electricity system. The spatial extent of the project electricity system, including issues related to the calculation of the build margin and operating margin, is defined in "Tool to calculate the emission factor for an electricity system".

When determining project emissions, project participants shall include the following emissions sources:

- CO_2 emissions from on-site consumption of fossil fuels to operate the project power unit(s); and
- CO_2 emissions from on-site consumption of fossil fuels, to supplement the exhaust heat used to operate the steam turbine.

When determining baseline emissions, project participants shall include the following emission sources:

- CO_2 emissions from fossil fuel fired power plants connected to the same electricity system as the project power unit(s); and
- CO_2 emissions from operation of the project power unit(s) in single cycle mode.

The emission sources included in or excluded from the project boundary are shown in Table 1. Upstream emissions related to fossil fuels consumed by the project power unit(s) and emissions associated with the a

change in the amount of exhaust heat recovery due to the project activity are outside the project boundary and included as leakage emissions.

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

	Source	Gas	Included?	Justification / Explanation
Baseline Scenario	Grid electricity generation	CO_2	Yes	Main emission source
		CH_4	No	Excluded for simplification. This is conservative
		N_2O	No	Excluded for simplification. This is conservative
	On-site fossil fuel consumption to operate the project power unit(s) in single cycle mode	CO_2	Yes	An important emission source
		CH_4	No	Excluded for simplification. This emission source is assumed to be very small
		N_2O	No	Excluded for simplification. This emission source is assumed to be very small
Project Activity	On-site fossil fuel consumption to operate the project power unit(s) in combined cycle mode	CO_2	Yes	An important emission source
		CH_4	No	Excluded for simplification. This emission source is assumed to be very small
		N_2O	No	Excluded for simplification. This emission source is assumed to be very small
	On-site fossil fuel consumption to supplement the exhaust heat in operating the steam turbine	CO_2	Yes	May be an important emission source
		CH_4	No	Excluded for simplification. This emission source is assumed to be very small
		N_2O	No	Excluded for simplification. This emission source is assumed to be very small

Procedure for the selection of the baseline scenario and the demonstration of additionality

Project participants shall use the latest approved version of the "Combined tool to identify the baseline scenario and demonstrate additionality" to demonstrate additionality and identify the most plausible baseline scenario.

In applying step 1 of the tool, the following three alternatives should be considered:

(a) Proposed project activity undertaken without being registered as a CDM project activity;

(b) Continuation of the current practice (to not implementing the project activity);

(c) If applicable the "proposed project activity undertaken without being registered as a CDM project activity" undertaken at a later point in time (e.g. due to existing regulations, end-of-life of existing equipment, financing aspects).

Moreover, in applying the tool, the following is required:

- When the current practice condition (to continue the operation in open cycle) is assessed, the future estimated load factor should reflect the changes due to new conditions in the grid.
- If undertaking investment analysis, then this shall include the revenue generated from the possible increase in electricity produced from the open cycle component in the project situation.

- When undertaking the common practice analysis for the operation of the project power unit(s) in combined cycle mode:
    - *Similar activities to the project activity* shall mean all single cycle and combined cycle power plants that have an installed capacity within a range of ±50% of the project power plant and that are using one the fossil fuel types used by the project power unit(s) (except start-up and auxiliary fuels)
    - *Relevant geographical area* shall in principle be the host country of the proposed CDM project activity. A region within the country could be the relevant geographical area if the framework conditions vary significantly within the country. However, the relevant geographical area should include preferably ten or more such power plants. If less than ten power plants are found in the region the geographical area may be expanded to an area that covers, if possible, ten such power plants within the national grid boundary. In cases where this definition of geographical area is not suitable, the project participants should provide an alternative definition of geographical area.
    - The project activity is regarded common practice if more than 50% of the assessed power plants operate in combined cycle mode. A power plant is considered to operate in combined cycle mode if any of its units operate in combined cycle mode.

This methodology is only applicable where it can be demonstrated that the baseline scenario is the continuation of the current practice, i.e. that in the absence of the proposed project activity the electricity, to meet the demand in the grid system, will be generated:

(1) By the operation of the project power unit(s) in single cycle mode;

(2) By the operation of existing grid-connected power plants; and

(3) By the addition of new generation sources to the grid.

Emission reductions

Emission reductions are determined as follows:

$$ER_y = BE_y - PE_y - LE_y \quad \textbf{(1)}$$

Where:

ER_y	=	Emissions reductions in year *y* (tCO_2)
BE_y	=	Baseline emissions in year *y* (tCO_2)
PE_y	=	Project emissions in year *y* (tCO_2)
LE_y	=	Leakage emissions in year *y* (tCO_2)

Project emissions

Project emissions (PE_y) should be determined using the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion" PE_y is referred to in this tool as $PE_{FC,j,y}$, where *j* corresponds to the combustion of fossil fuels to operate the project power unit(s) and to supplement the exhaust heat in operating the steam turbine.

When applying the tool, fuels blended with biofuel should be considered to consist 100% of the fossil fuel used in the blend.

Baseline emissions

The baseline scenario is the generation of electricity by the operation of the project power unit(s) in single cycle mode as well as by grid-connected power plants. The project will partially displace electricity generated by the project power unit(s) in the baseline scenario. In addition, it may also displace electricity in the grid, if the quantity of electricity generation by the plant increases as a result of the project activity. However, it is unknown to what extent such an increase is due to the project activity or would have occurred anyway (e.g. due to a change in the electricity demand or availability of other power plants). The calculation of baseline emissions is therefore based on the three cases shown in Figure 1.

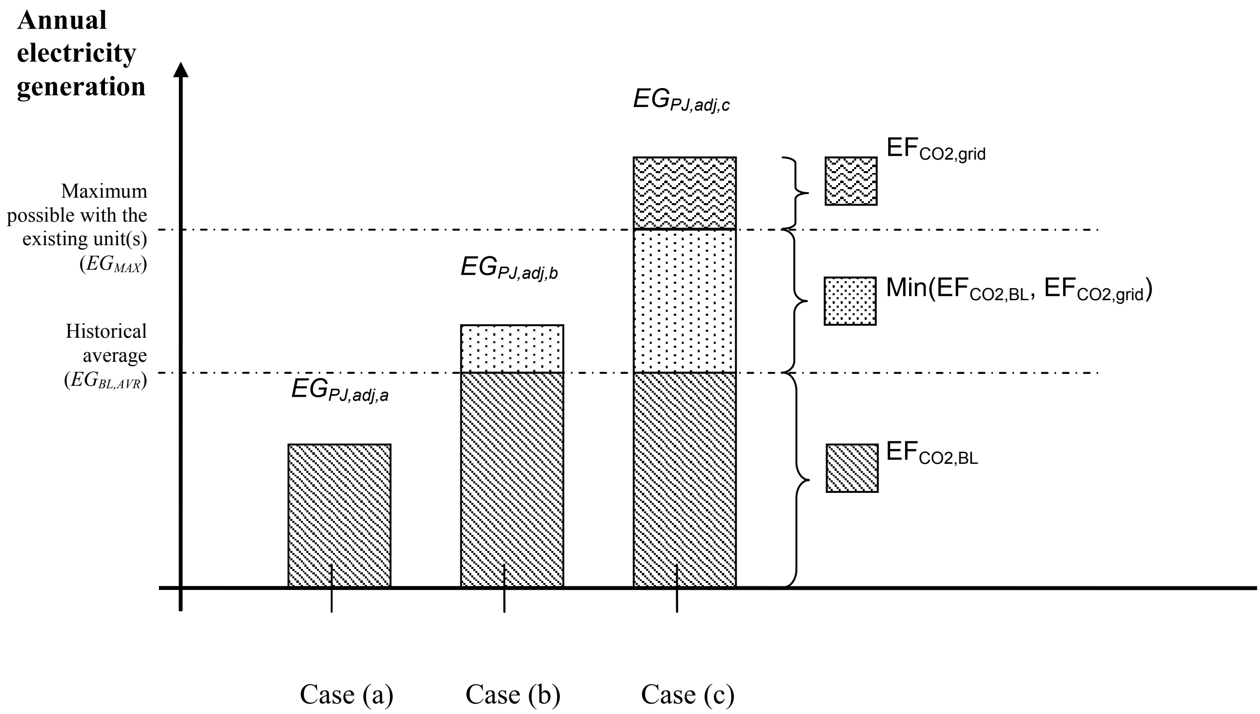

Figure 1: Baseline emissions calculation for three cases of different quantities of electricity generated.

The baseline emissions for year *y* (BE_y) are calculated as follows:

Step 1: Determination of the baseline emissions for different scenarios of project electricity generation

Case (a) The quantity of electricity generated in the project power unit(s), adjusted for changes to efficiency, ($EG_{PJ,adj,y}$) is lower than or equal to the historic average annual generation level ($EG_{BL,AVR}$). Baseline emissions are calculated as:

$$BE_y = EG_{PJ,adj,y} \cdot EF_{CO2,BL} \tag{2}$$

Case (b) The quantity of electricity generated in the project power unit(s), adjusted for changes to efficiency, ($EG_{PJ,adj,y}$) exceeds the historic average annual generation level ($EG_{BL,AVR}$) but is lower than or equal to the maximum annual quantity of electricity that the project power unit(s) could have produced prior to the implementation of the project activity (EG_{MAX}). Baseline emissions are calculated as:

$$BE_y = EG_{BL,AVR} \cdot EF_{CO2,BL,y} + \left(EG_{PJ,adj,y} - EG_{BL,AVR}\right) \cdot \min\left(EF_{CO2,BL}; EF_{grid,y}\right) \quad \textbf{(3)}$$

Case (c) The quantity of electricity generated in the project power unit(s), adjusted for changes to efficiency, ($EG_{PJ,adj,y}$) exceeds the maximum annual quantity of electricity that the project power unit(s) could have produced prior to the implementation of the project activity (EG_{MAX}). Baseline emissions are calculated as:

$$BE_y = EG_{BL,AVR} \cdot EF_{CO2,BL,y} + \left(EG_{MAX} - EG_{BL,AVR}\right) \cdot \min\left(EF_{CO2,BL,}; EF_{grid,y}\right) + \left(EG_{PJ,adj,y} - EG_{MAX}\right) \cdot EF_{grid,y} \quad \textbf{(4)}$$

Where:

BE_y	=	Baseline emissions in year *y* (tCO_2/yr)
$EG_{PJ,adj,y}$	=	Quantity of electricity supplied by all project power units to the electricity grid in year *y*, adjusted for changes to efficiency (MWh/yr)
$EG_{BL,AVR}$	=	Average annual quantity of electricity supplied by all project power units to the electricity grid during the defined operational history (MWh/yr)
EG_{MAX}	=	Maximum annual quantity of electricity that could be generated by all project power units in the baseline scenario (MWh/yr)
$EF_{CO2,BL}$	=	Baseline emission factor of all project power units operated in single cycle mode (tCO_2/MWh)
$EF_{grid,y}$	=	Emission factor of the electricity grid to which the project power unit is connected (tCO_2/MWh)

The maximum annual quantity of electricity that could be generated by the project power unit(s) in the baseline scenario (EG_{MAX}) is calculated as:

$$EG_{MAX} = CAP_{max} \cdot T_{max} \quad \textbf{(5)}$$

Where:

EG_{MAX}	=	Maximum annual quantity of electricity that could be generated by all project power units in the baseline scenario (MWh/yr)
CAP_{max}	=	Maximum gross power generation capacity of the project power unit(s) prior to the implementation of the project activity (MW)
T_{MAX}	=	Maximum amount of time during a year in which the project power unit(s) could have operated at full power generation capacity prior to the implementation of the project activity (hours/yr)

If all project power units have three years operational history, and if there was no major retrofit during this period in any of the units, then the maximum annual amount of time that the project power unit(s) could have operated at full load prior to the validation of the project activity is calculated according to equation 6. Otherwise as a simplification, T_{MAX} equals 8,760 hours/yr.

$$T_{MAX} = 8,760 - \frac{\sum_{x=1}^{3} HMR_x}{3} \quad \textbf{(6)}$$

Where:

T_{MAX}	=	Maximum amount of time during a year in which the project power unit(s) could have operated at full power generation capacity prior to the implementation of the project activity (hours/yr)
HMR_x	=	Average number of hours during which the plant did not operate due to maintenance or repair in year *x* (hours/yr)
x	=	Each year during the three years operational history

The average annual amount of electricity supplied to the electricity grid by the project power unit(s) in the three years historical period is calculated according to equation 7. This calculation should be based on data from only those units that have at least a three years operational history and no major retrofit during this period.

$$EG_{BL,AVR} = \frac{\sum_{x=1}^{3} EG_x}{3} \qquad (7)$$

Where:

$EG_{BL,AVR}$	=	Average annual quantity of electricity supplied by all project power units to the electricity grid during the three year operational history (MWh/yr)
EG_x	=	Quantity of electricity supplied by the project power unit(s) with three years operational history and no retrofit in this period, to the electricity grid in year *x* (MWh/yr)
x	=	Each year of the three years operational history

The total amount of electricity supplied to the electricity grid by all project power units in year *y* of the crediting period has to be adjusted for the calculation of baseline emissions so that future energy efficiency improvement measures (e.g. measures that may be implemented after the project activity) shall not result in emissions reductions. Therefore, the total amount of electricity supplied to the grid ($EG_{PJ,y}$) shall be conservatively adjusted by applying a discount factor based on the minimum of the monitored efficiencies after the implementation of the project activity, as described in the equations below:

$$EG_{PJ,adj,y} = EG_{PJ,y} \cdot \frac{\eta_{PJ,\min,y}}{\eta_{PJ,y}} \qquad (8)$$

with

$$\eta_{PJ,\min,y} = \min(\eta_{PJ,1},...,\eta_{PJ,y}) \qquad (9)$$

Where:

$EG_{PJ,adj,y}$	=	Quantity of electricity supplied by all project power units to the electricity grid in year *y*, adjusted for changes to project power plant efficiency (MWh/yr)
$EG_{PJ,y}$	=	Total amount of electricity supplied to the electricity grid by the project power units in year *y* (MWh/yr)
$\eta_{PJ,min,y}$	=	Minimum of the yearly average energy efficiency of the project power unit(s) monitored during the previous years (1 to y) after the implementation of the project activity for year *y*

$\eta_{PJ,i}\ldots\eta_{PJ,y}$	=	Average energy efficiency of the project power unit(s) in years 1 to y of the crediting period (refer to $\eta_{PJ,y}$ in the monitoring tables)

Step 2: Estimating the emissions factor for electricity generated in single cycle mode in the baseline ($EF_{CO2,BL}$)

If all project power units have a three years operational history and if there was no major retrofit in these unit during this period, then the baseline CO_2 emissions factor for the project power unit(s) operated in single cycle mode ($EF_{CO2,BL}$) is determined based on the historical performance of the units and calculated according to equation 10. Otherwise, $EF_{CO2,BL}$ is calculated according to equation 11.

$$EF_{CO2,BL} = \frac{\sum_{x=1}^{3}\sum_{i} FC_{i,x} \times NCV_{i,x}}{\sum_{x=1}^{3} EG_x} \times EF_{CO2,min} \tag{10}$$

Where:

$EF_{CO2,BL}$	=	CO_2 emission factor for electricity generated in single cycle mode in the baseline (tCO_2/MWh)
$FC_{i,x}$	=	Quantity of fuel type *i* used by the project power unit(s) in year *x* (mass or volume unit/yr)
$NCV_{i,x}$	=	Net calorific value of the fuel type *i* used by the project power unit(s) in year *x* (GJ/mass or volume unit)
$EF_{CO2,min}$	=	CO_2 emission factor of the least carbon intensive fuel type used by the project power unit(s) during the three years operational history (tCO_2/GJ)
EG_x	=	Quantity of electricity supplied by the project power unit(s) with three years operational history and no retrofit in this period, to the electricity grid in year x (MWh/yr)
x	=	Each year of the three years operational history

If three years operational history is not available for all the units or if there was a major retrofit during this period in any of the units, then the CO_2 emission factor for electricity generated in single cycle mode in the baseline ($EF_{CO2,BL}$) is determined using the default values for the efficiency of the power units from Annex 1 of the "Tool to calculate the emission factor for an electricity system", according to the following equation:

$$EF_{CO2,BL} = \frac{3.6}{\eta} \times EF_{CO2,min} \tag{11}$$

Where:

$EF_{CO2,BL}$	=	CO_2 emission factor for electricity generated in single cycle mode in the baseline (tCO_2/MWh)
$EF_{CO2,min}$	=	CO_2 emission factor of the least carbon intensive fuel type used by the project power unit(s) during the three years operational history (tCO_2/GJ)
η	=	Default efficiency of the project power unit(s) operated in single cycle mode

Step 3: Determine the emissions factor for the grid electricity system ($EF_{grid,y}$)

The baseline emission factor for the grid ($EF_{grid,y}$) should be calculated as a combined margin emission factor, using the "Tool to calculate the emission factor for an electricity system".

If project participants use the dispatch data analysis method, as described in the "Tool to calculate the emission factor for an electricity system", the following modification applies:

The group *n* of power plants in the dispatch margin is set of power plants in the top x% of total electricity dispatched by the grid system during hour *h*, where x% is equal to the greater of either:

- 10%; or
- The project generation during hour *h* expressed as a percentage of the total grid generation for that hour.

Leakage

The main emissions potentially giving rise to leakage in the context of the proposed projects are:

(i) Emissions associated with the situation that exhaust heat was already recovered prior to the implementation of the project activity, in which case the diversion of this heat to the project power unit(s) may increase emissions elsewhere; and

(ii) Emissions associated with extraction, production, transportation, distribution and processing of an increased quantity of fossil fuels consumed by the project activity ($LE_{upstream,y}$).

Leakage emissions are calculated as follows:

$$LE_y = LE_{upstream,y} + LE_{HR,y} \quad \textbf{(12)}$$

Where:

LE_y	=	Leakage emissions in year *y* (tCO_2e/yr)
$LE_{upstream,y}$	=	Leakage emissions associated with the upstream emissions of an increase in fossil fuel use in the project activity in year *y* (tCO_2e/yr)
$LE_{HR,y}$	=	Leakage emissions due to a decrease in the amount of heat recovered from exhaust heat for purposes other than power generation in the project, compared to the most recent year prior to the implementation of the project activity, in year *y* (tCO_2e/yr)

Determination of $LE_{HR,y}$

If the quantity of heat recovered from the exhaust heat during the most recent year prior to the implementation of the project activity ($Q_{HR,x}$) is either less than 3% of the fossil fuels consumed by the project power units in an energy basis or is smaller or equal to the amount of heat recovered from exhaust heat in year *y* for purposes other than power generation ($Q_{HR,y}$), then emissions from this leakage source are equal to zero.

Otherwise, $LE_{HR,y}$ is calculated as the amount of reduction in heat recovery multiplied by the emission factor for the most carbon intensive fuel used during the operational history of the project power unit(s) according to equation 14. If a fuel blended with biofuels was used in the operational history, then the emission factor for this fuel should be considered to be the emission factor for the fossil fuel used in the blend.

$$LE_{HR,y} = \left(Q_{HR,x} - Q_{HR,y}\right) \cdot EF_{CO2,max} \quad \textbf{(13)}$$

Where:

$LE_{HR,y}$	=	Leakage emissions due to a decrease in the amount of heat recovered from exhaust heat for purposes other than power generation in the project, compared to the most recent year prior to the implementation of the project activity, in year y (tCO_2e/yr)
$Q_{HR,x}$	=	Quantity of heat recovered from the exhaust heat of the project power unit(s) during the most recent year prior to the implementation of the project activity (GJ/yr)
$Q_{HR,y}$	=	Quantity of heat recovered from the exhaust heat of the project power unit(s) for purposes other than power generation in year *y* (GJ/yr)
$EF_{CO2,max}$	=	CO_2 emission factor of the of the most carbon intensive fuel type used by the project power unit(s) in the operational history (tCO_2/GJ)

Determination of $LE_{upstream,y}$

In cases where $EG_{PJ,,adj,y}$ is smaller than $EG_{BL,AVR}$ (as illustrated by case (a) in Figure 1), then leakage emissions from this source are equal to zero. Otherwise, leakage emissions associated with the upstream emissions of an increase in fossil fuel use in the project activity are calculated as follows:

$$LE_{upstream,y} = \left(\left(\sum_i FC_{i,y} \cdot NCV_{i,y} \cdot EF_{i,upstream,CH4}\right) \cdot GWP_{CH4} + LE_{LNG,upstream,y}\right) \times \left(\frac{\sum_i FC_{i,y} \cdot NCV_{i,y}}{\frac{1}{3} \cdot \sum_{x=1}^{3} \sum_i FC_{i,x} \cdot NCV_{i,x}} - 1\right) \quad \textbf{(14)}$$

Where:

$LE_{upstream,y}$	=	Leakage emissions associated with the upstream emissions of an increase in fossil fuel use in the project activity in the year y (tCO_2e/yr)
$FC_{i,y}$	=	Quantity of fuel type *i* used by the project power unit(s) in year *y* (mass or volume unit/yr)
$NCV_{i,y}$	=	Average net calorific value of the fuel type *i* used by the project power unit(s) in year *y* (GJ/mass or volume unit)
$EF_{i,upstream,CH4}$	=	Emission factor for upstream fugitive methane emissions from production, transportation, distribution of fossil fuel i used by the project power unit(s) in year y (tCH_4/GJ)
GWP_{CH4}	=	Global warming potential of methane valid for the relevant commitment period (tCO_2e/tCH_4)
$LE_{LNG,CO2,y}$:	=	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 in year *y* (tCO_2e/yr)
$FC_{i,x}$	=	Quantity of fuel type *i* used by the project power unit(s) in year *x* (mass or volume unit/yr)
$NCV_{i,x}$	=	Net calorific value of fuel type i used by the project power unit(s) in year x (GJ/mass or volume unit)
x	=	Each year of the three years operational history

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 ($LE_{LNG,CO2,y}$) are calculated, where applicable, as follows:

$$LE_{LNG,CO2,y} = FC_{LNG,y} \cdot NCV_{LNG,y} \cdot EF_{CO2,upstream,LNG} \quad \textbf{(15)}$$

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 in year *y* (tCO_2e/yr)
$FC_{LNG,y}$:	=	Quantity of natural gas produced from LNG used by the project power unit(s) in year *y* (mass or volume unit/yr)
$NCV_{LNG,y}$	=	Net calorific value of natural gas produced from LNG used by the project power unit(s) in year *y* (GJ/mass or volume unit)
$EF_{CO2,upstream,LNG}$:	=	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 ($t\ CO_2e/GJ$)

Data and parameters not monitored

In addition to the parameters listed in the tables below, the provisions on data and parameters not monitored in the tools referred to in this methodology apply.

Data / Parameter:	EG_x
Data unit:	MWh/yr
Description:	Quantity of electricity supplied by the project power unit(s) with three years operational history and no retrofit in this period, to the electricity grid in year *x*
Source of data:	Generation records. Historical data of electricity supplied by the project to the grid in the defined operational history (see Definitions)
Measurement procedures:	
Any comment:	The consistency of metered net electricity generation should be cross-checked with receipts from sales (if available). Meters should be subject to regular maintenance and calibration. Year *x* refers to each year of the unit's three years operational history. This parameter is only required if any of the project power unit(s) does not have three years operational history with no major retrofit in this period

Data / Parameter:	$FC_{i,x}$
Data unit:	Mass or volume unit/yr
Description:	Quantity of fuel type *i* used by the project power unit(s) in year *x*
Source of data:	Historical data of annual fuel consumption by the project operating in single cycle mode
Measurement procedures:	
Any comment:	The data for any direct measurements with mass or volume meters at the plant site should be cross-checked with an annual energy balance that is based on purchased quantities and stock changes. Meters should be subject to regular maintenance and calibration Year *x* refers to each year of the unit's operational history

<table>
<tr><td>Data / Parameter:</td><td>$NCV_{i,x}$</td></tr>
<tr><td>Data unit:</td><td>GJ/mass or volume unit</td></tr>
<tr><td>Description:</td><td>Net calorific value of fuel type i used by the project power unit(s) in year x</td></tr>
<tr><td>Source of data:</td><td>The following data sources may be used if the relevant conditions apply:
<table>
<tr><th>Data source</th><th>Conditions for using the data source</th></tr>
<tr><td>(a) Values provided by the fuel supplier in invoices</td><td>This is the preferred source</td></tr>
<tr><td>(b) Measurements by the project participants</td><td>If (a) is not available</td></tr>
<tr><td>(c) Regional or national default values</td><td>If (a) is not available

These sources can only be used for liquid fuels and should be based on well documented, reliable sources (such as national energy balances)</td></tr>
<tr><td>(d) IPCC default values at the lower limit of the uncertainty at a 95% confidence interval as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories</td><td>If (a) is not available</td></tr>
</table></td></tr>
<tr><td>Measurement procedures:</td><td>For (a) and (b): measurements should be undertaken in line with national or international fuel standards. The NCV should be obtained for each fuel delivery, from which weighted average annual values should be calculated
For (c): review appropriateness of the values annually
For (d): any future revision of the IPCC Guidelines should be taken into account</td></tr>
<tr><td>Any comment:</td><td>If more than one fuel is used in the gas turbine or engine, the NCV of the least carbon intensive fuel that has been used before or after project implementation, should be determined.
Verify if the values under (a), (b) and (c) are within the uncertainty range of the IPCC default values as provided in Table 1.2, Vol. 2 of the 2006 IPCC Guidelines. If the values fall below this range collect additional information from the testing laboratory to justify the outcome or conduct additional measurements. The laboratories in (a), (b) or (c) should have ISO17025 accreditation or justify that they can comply with similar quality standards.
Year x refers to each year of the unit's operational history</td></tr>
</table>

<table>
<tr><td>Data / Parameter:</td><td>$EF_{CO2,min}$</td></tr>
<tr><td>Data unit:</td><td>tCO_2/GJ</td></tr>
<tr><td>Description:</td><td>CO_2 emission factor of the least carbon intensive fuel type used by the project power unit(s) during the three years operational history</td></tr>
<tr><td>Source of data:</td><td>The following data sources may be used if the relevant conditions apply:
<table>
<tr><th>Data source</th><th>Conditions for using the data source</th></tr>
<tr><td>(a) Values provided by the fuel supplier in invoices</td><td>This is the preferred source</td></tr>
<tr><td>(b) Measurements by the project participants</td><td>If (a) is not available</td></tr>
<tr><td>(c) Regional or national default values</td><td>If (a) is not available

These sources can only be used for liquid fuels and should be based on well-documented, reliable sources (such as national energy balances)</td></tr>
<tr><td>(d) IPCC default values at the lower limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories</td><td>If (a) is not available</td></tr>
</table></td></tr>
<tr><td>Measurement procedures:</td><td>For (a) and (b): measurements should be undertaken in line with national or international fuel standards. The NCV should be obtained for each fuel delivery, from which weighted average annual values should be calculated
For (c): review appropriateness of the values annually
For (d): any future revision of the IPCC Guidelines should be taken into account</td></tr>
<tr><td>Any comment:</td><td>If more than one fuel is used in the gas turbine or engine, the emission factor of the least carbon intensive fuel that has been used before or after project implementation, should be determined.
Verify if the values under a), b) and c) are within the uncertainty range of the IPCC default values as provided in Table 1.3, Vol. 2 of the 2006 IPCC Guidelines. If the values fall below this range collect additional information from the testing laboratory to justify the outcome or conduct additional measurements. The laboratories in (a), (b) or (c) should have ISO17025 accreditation or justify that they can comply with similar quality standards</td></tr>
</table>

<table>
<tr><td>Data / Parameter:</td><td>$EF_{CO2,max}$</td></tr>
<tr><td>Data unit:</td><td>tCO_2/GJ</td></tr>
<tr><td>Description:</td><td>CO_2 emission factor of the most carbon intensive fuel type used by the project power unit(s) during three years operational history</td></tr>
<tr><td>Source of data:</td><td>The following data sources may be used if the relevant conditions apply:
<table>
<tr><td>Data source</td><td>Conditions for using the data source</td></tr>
<tr><td>(a) Values provided by the fuel supplier in invoices</td><td>This is the preferred source</td></tr>
<tr><td>(b) Measurements by the project participants</td><td>If (a) is not available</td></tr>
<tr><td>(c) Regional or national default values</td><td>If (a) is not available

These sources can only be used for liquid fuels and should be based on well-documented, reliable sources (such as national energy balances)</td></tr>
<tr><td>(d) IPCC default values at the upper limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories</td><td>If (a) is not available</td></tr>
</table></td></tr>
<tr><td>Measurement procedures (if any):</td><td>For (a) and (b): measurements should be undertaken in line with national or international fuel standards. The NCV should be obtained for each fuel delivery, from which weighted average annual values should be calculated
For (c): review appropriateness of the values annually
For (d): any future revision of the IPCC Guidelines should be taken into account</td></tr>
<tr><td>Any comment:</td><td>If more than one fuel is used in the gas turbine or engine, the emission factor of the least carbon intensive fuel that has been used before or after project implementation, should be determined
Verify if the values under a), b) and c) are within the uncertainty range of the IPCC default values as provided in Table 1.3, Vol. 2 of the 2006 IPCC Guidelines. If the values fall below this range collect additional information from the testing laboratory to justify the outcome or conduct additional measurements. The laboratories in (a), (b) or (c) should have ISO17025 accreditation or justify that they can comply with similar quality standards
In the case that the fuel is blended with biofuels, only the emission factor for the fossil fuel used in the blend should be considered</td></tr>
</table>

Data / Parameter:	CAP_{max}
Data unit:	MW
Description:	Maximum gross power generation capacity of the project power unit(s) prior to the implementation of the project activity
Source of data:	Maximum generation capacity determined by performance tests under optimal operation conditions (optimal load, after maintenance, etc)

Measurement procedures (if any):	1. Generation licenses or manufacturer's specification. 2. Using recognized standards for the measurement of the turbine efficiency, such as the ASME PTC 6 (1996) or IEC 60953-3 (2001)
Any comment:	All results of tests have to be documented in the CDM-PDD (including outliers)

Data / Parameter:	T_{max}
Data unit:	Hours/yr
Description	Maximum amount of time during a year in which the project power unit(s) could have operated at full power generation capacity prior to the implementation of the project activity
Source of data:	
Value to be applied:	8760 or calculated as per equation 6
Any comment:	If the parameter is calculated, then the DOE shall also validate the information on T_{max} based on expert view on maximum permissible operation hours for similar type of power plants

Data / Parameter:	HMR_x
Data unit:	Hours/yr
Description:	Average number of hours during which the plant did not operate due to maintenance or repair in year *x* (hours)
Source of data:	Project activity site
Measurement procedures (if any):	Use historical records for such maintenance and repair intervals
Any comment:	This parameter is not required if there is less than three years operational history for all project power unit(s), or if a major retrofit occurred in this period. As a simplification, project proponents may also assume this parameter as zero Year *x* refers to each year of the unit's three years operational history

Data / Parameter:	η
Data unit:	-
Description	Default efficiency of the project power unit(s) operated in single cycle mode
Source of data:	"Tool to calculate the emission factor for an electricity system", Annex 1
Value to be applied:	
Any comment:	This parameter is only required if there is less than three years operational data for all project power unit(s), or if a major retrofit occurred in this period

Data / Parameter:	$Q_{HR,x}$
Data unit:	GJ/yr
Description:	Quantity of heat recovered from the exhaust heat during the most recent year prior to the implementation of the project activity
Source of data:	Site of the recovery process (eg. heat exchanger, etc.)
Measurement procedures (if any):	Calculation from historical records from appropriate metering devices (e.g. temperature, pressure and flow meters for air or feed water)
Any comment:	

Data / Parameter:	GWP_{CH4}
Data unit:	tCO2e/tCH4
Description:	Global warming potential of methane valid for the relevant commitment period
Source of data:	IPCC
Value to be applied	For the first commitment period: 21

III. MONITORING METHODOLOGY

All data collected as part of monitoring should be archived electronically and be kept at least for two years after the end of the last crediting period. One hundred per cent of the data should be monitored if not indicated otherwise in the tables below. All measurements should be conducted with calibrated measurement equipment according to relevant industry standards.

In addition, the monitoring provisions in the tools referred to in this methodology apply.

Data and parameters monitored

Data / Parameter:	$EG_{PJ,y}$
Data unit:	MWh/yr
Description:	Total amount of electricity supplied to the electricity grid by the project power units in year *y*
Source of data:	Generation records
Measurement procedures (if any):	
Monitoring frequency:	Continuously
QA/QC procedures:	The consistency of metered net electricity generation should be cross-checked with receipts from sales (if available)
Any comment:	

Data / parameter:	$FC_{i,y}$
Data unit:	Mass or volume unit/yr
Description:	Quantity of fuel type *i* used by the project power unit(s) in year *y*
Source of data:	Onsite measurements
Measurement procedures (if any):	• Use either mass or volume meters. In cases where fuel is supplied from small daily tanks, rulers can be used to determine mass or volume of the fuel consumed, with the following conditions: The ruler gauge must be part of the daily tank and calibrated at least once a year and have a book of control for recording the measurements (on a daily basis or per shift); • Accessories such as transducers, sonar and piezoelectronic devices are accepted if they are properly calibrated with the ruler gauge and receiving a reasonable maintenance; • In case of daily tanks with pre-heaters for heavy oil, the calibration will be made with the system at typical operational conditions

Monitoring frequency:	Continuously
QA/QC procedures:	The consistency of metered fuel consumption quantities should be cross-checked by an annual energy balance that is based on purchased quantities and stock changes. Where the purchased fuel invoices can be identified specifically for the CDM project, the metered fuel consumption quantities should also be cross-checked with available purchase invoices from the financial records
Any comment:	

Data / Parameter:	$\eta_{PJ,y}$
Data unit:	-
Description:	Average energy efficiency of the project power unit(s) in year *y* of the crediting period
Source of data:	Project activity site
Measurement procedures (if any):	To calculate the efficiencies: • Use the direct method (dividing the net electricity 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); • Use recognized standards for the measurement of the power plant efficiency; The efficiency has to be referred in terms of the net calorific values of the fuels used and the net electricity produced, i.e. total electricity produced minus internal consumption of electricity
Monitoring frequency:	Once during each year y of the crediting period. The first calculation shall be made during the first year after implementing the project activity
QA/QC procedures:	
Any comment:	

Data / Parameter:	$Q_{HR,y}$
Data unit:	GJ/yr
Description:	Quantity of heat recovered from the exhaust heat of the project power unit(s) for purposes other than power generation in year *y*
Source of data:	Site of the recovery process (eg. heat exchanger, etc.)
Measurement procedures (if any):	Calculation from direct measurements by project participants through appropriate metering devices (e.g. temperature, pressure and flow meters for air or feed water)
Monitoring frequency:	Continuously
Any comment:	Monitoring of this parameter is only required if heat is recovered from the exhaust heat in the most recent year prior to the implementation of the project activity and the amount recovered is more than 3% of energy of the fuel consumed by the project power plant(s) in the same year

Data / Parameter:	$NCV_{i,y}$
Data unit:	GJ/mass or volume unit
Description:	Average net calorific value of the fuel type *i* used by the project power unit(s) in year *y*
Source of data:	The following data sources may be used if the relevant conditions apply: <table><tr><th>Data source</th><th>Conditions for using the data source</th></tr><tr><td>(a) Values provided by the fuel supplier in invoices</td><td>This is the preferred source</td></tr><tr><td>(b) Measurements by the project participants</td><td>If (a) is not available</td></tr><tr><td>(c) Regional or national default values</td><td>If (a) is not available These sources can only be used for liquid fuels and should be based on well documented, reliable sources (such as national energy balances).</td></tr><tr><td>(d) IPCC default values at the upper limit of the uncertainty at a 95% confidence interval as provided in Table 1.2 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories.</td><td>If (a) is not available</td></tr></table>

Measurement procedures (if any):	For (a) and (b): measurements should be undertaken in line with national or international fuel standards. The NCV should be obtained for each fuel delivery, from which weighted average annual values should be calculated
	For (c): review appropriateness of the values annually
	For (d): any future revision of the IPCC Guidelines should be taken into account

Any comment:	If more than one fuel is used in the gas turbine or engine, the NCV of the least carbon intensive fuel that has been used before or after project implementation, should be determined Verify if the values under (a), (b) and (c) are within the uncertainty range of the IPCC default values as provided in Table 1.2, Vol. 2 of the 2006 IPCC Guidelines. If the values fall below this range collect additional information from the testing laboratory to justify the outcome or conduct additional measurements. The laboratories in (a), (b) or (c) should have ISO17025 accreditation or justify that they can comply with similar quality standards This parameter is only required to calculate upstream leakage emissions, if applicable

Data / Parameter:	$EF_{i,upstream,CH4}$
Data unit:	tCH_4/GJ
Description:	Emission factor for upstream fugitive methane emissions from production, transportation, distribution of fossil fuel *i* used by the project power unit(s) in year *y*

<table>
<tr>
<td>Source of data:</td>
<td>
The following data sources may be used if the relevant conditions apply:
<table>
<tr><th>Data source</th><th>Conditions for using the data source</th></tr>
<tr><td>(a) Reliable and accurate national data on fugitive CH_4 emissions associated with the production, transportation and distribution of the fuels. 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</td><td>This is the preferred source</td></tr>
<tr><td>(b) Default emission factors
<table>
<tr><th>Activity</th><th>Unit</th><th>Default emission factor</th></tr>
<tr><td>Coal</td><td></td><td></td></tr>
<tr><td>Underground mining</td><td>t CH4 / kt coal</td><td>13.4</td></tr>
<tr><td>Surface mining</td><td>t CH4 / kt coal</td><td>0.8</td></tr>
<tr><td>Oil</td><td></td><td></td></tr>
<tr><td>Production</td><td>t CH4 / PJ</td><td>2.5</td></tr>
<tr><td>Transport, refining and storage</td><td>t CH4 / PJ</td><td>1.6</td></tr>
<tr><td>Total</td><td>t CH4 / PJ</td><td>4.1</td></tr>
<tr><td>Natural gas</td><td></td><td></td></tr>
<tr><td>USA and Canada</td><td></td><td></td></tr>
<tr><td>Production</td><td>t CH4 / PJ</td><td>72</td></tr>
<tr><td>Processing, transport and distribution</td><td>t CH4 / PJ</td><td>88</td></tr>
<tr><td>Total</td><td>t CH4 / PJ</td><td>160</td></tr>
<tr><td>Eastern Europe and former USSR</td><td></td><td></td></tr>
<tr><td>Production</td><td>t CH4 / PJ</td><td>393</td></tr>
<tr><td>Processing, transport and distribution</td><td>t CH4 / PJ</td><td>528</td></tr>
<tr><td>Total</td><td>t CH4 / PJ</td><td>921</td></tr>
<tr><td>Western Europe</td><td></td><td></td></tr>
<tr><td>Production</td><td>t CH4 / PJ</td><td>21</td></tr>
<tr><td>Processing, transport and distribution</td><td>t CH4 / PJ</td><td>85</td></tr>
<tr><td>Total</td><td>t CH4 / PJ</td><td>105</td></tr>
<tr><td>Other oil exporting countries / Rest of world</td><td></td><td></td></tr>
<tr><td>Production</td><td>t CH4 / PJ</td><td>68</td></tr>
<tr><td>Processing, transport and distribution</td><td>t CH4 / PJ</td><td>228</td></tr>
<tr><td>Total</td><td>t CH4 / PJ</td><td>296</td></tr>
</table>
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</td>
<td>If (a) is not available.

Natural gas emission factors for the location of the project activity should be used. The US/Canada values may be used 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.

Since the fugitive upstream emissions for coal depends on the source (underground or surface mines), project participants should use the emission factor that corresponds to the predominant source (underground or surface) currently used by coal-based power plants in the region. The emission factor for coal 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</td></tr>
</table>
</td>
</tr>
</table>

Measurement procedures:	
Any comment:	The emission factor for fugitive upstream emissions for natural gas should include fugitive emissions from production, processing, transport and distribution of natural gas, as indicated in the table of default values above. To the extent that upstream emissions occur in Annex I countries that have ratified the Kyoto Protocol, from 1 January 2008 onwards, these emissions should be excluded, if technically possible, in the leakage calculations. This parameter is only required to calculate the upstream leakage emissions, if applicable

Data / Parameter:	$EF_{CO2,upstream,LNG}$
Data unit:	tCO_2/GJ
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 during year y of the project activity
Source of data:	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 If reliable and accurate data is not available, then a default value of 0.006 t CO_2/GJ may be used as a rough approximation.
Any comment:	Default 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)"

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History of the document

Version	Date	Nature of Revision
05.0.0	EB 60, Annex 4 15 April 2011	• Applicability was expanded: o Required operational history between one and three years (not three and five years); o Use of a limited amount of an alternative fuel type for auxiliary requirements allowed; o Fuels blended biofuel allowed to be used in situations where this is beyond the control of the project proponents; o Recovery of heat from exhaust heat allowed in the operational history (other than for electricity generation). • Baseline emissions calculation procedure was made consistent with other power generation methodologies to address the situation that if electricity generation increases then it is unknown if this is due to the project activity or not. The procedure also accounts for energy efficiency improvements implemented during the project activity; • Additional guidance on how to calculate leakage emissions included; • Baseline scenario determination simplified by requiring analysis of only three alternatives; • Additional guidance on how to undertake the common practice analysis included; • Definitions section was included, including a definition for what constitutes a major retrofit; • Several editorial improvements.
04	EB 55, Annex 11 30 July 2010	• Annual average fuel consumption of the open cycle gas turbine or engine may be estimated using data from five years previous to start of the project at the time of validation. If five years data is not available, then data for the highest number of complete years available, but not less than three, should be used; • References to "Tool to determine the remaining lifetime of equipment" and "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion" were added; • The format of the methodology was updated.
03	EB 35, Paragraph 24 02 November 2007	The reference to ACM0002 was replaced by a reference to “Tool to calculate the emission factor for an electricity system”.
02	EB 31, Annex 9 02 May 2007	The applicability of the approved methodology was expanded to single cycle engine systems.
01	EB 22, Annex 9 28 November 2005	Initial adoption.
Decision Class: Regulatory **Document Type**: Standard **Business Function**: Methodology		