CONTENTS

SECTION A. Identification of methodology

A.1. Proposed methodology title:

>> Gas powered combined cycle cogeneration replacing coal based steam generation and grid electricity

A.2. List of category(ies) of project activity to which the methodology may apply:

>>Sectoral scopes 1: Energy industries (renewable - / non-renewable sources) and Sectoral scope 4: Manufacturing industries

A.3. Conditions under which the methodology is applicable to CDM project activities:

>> The methodology is applicable to:
1. Fuel switching from imported grid (dominated by coal) electricity and coal based steam generation to combined heat and power provision to an industrial plant wherever the data exists to calculate the baseline and project activity emissions.
2. Where the cogeneration plant is owned and run by the plant it provides energy to, or by a third party operator.
3. The heat and power provided by the cogeneration plant contributes part of the energy requirements for the demand of the plant it provides utility to.
4. The leakage calculation includes a component that is applied to the production of a synthetic gas equivalent in part to natural gas.
5. This methodology is to be used in conjunction with "Monitoring methodology for gas powered combined cycle cogeneration replacing coal based steam generation and grid electricity."
6. Excess electricity is not exported to the grid.

A.4. What are the potential strengths and weaknesses of this proposed new methodology?

>> The strength is that the methodology is comprised of a number approved and approved and consolidated methodologies and employs the additionality tool in full.

Its main weakness is in the estimation of the emissions from electricity supply and upstream leakage in the production of the incremental synthetic gas. These emissions fall outside the project boundary and require data from third parties and the use of third party verifiers. These verifications require close attention in this methodology.

SECTION B. Overall summary description:

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Synthetic gas generated from natural gas with the emissions intensity per unit energy of natural gas equivalent (separately verified) is supplied by pipeline for the production of heat and power using a combined cycle gas turbine. The heat and electricity generated in the project activity is used at the industrial plant partly replacing existing sources of heat and power. The project activity heat replaces that generated by coal on site and the project activity electricity replaces that generated by coal on site and that imported from the national grid. The baseline emissions consist of existing actual emissions or historical emissions from the coal fired boilers and the emissions from the production of grid electricity taking into account transmission and distribution losses. Baseline emissions are typically calculated.

Step 1: establish the alternative to the project activity.
Step 2: assess which alternatives are plausible.
Step 3: assess the investment requirements for the project activity base-case.
Step 4: compare the investment requirements with the alternatives to the project activity.
Step 5: establish whether the return on the base case is sufficient to allow it to proceed (if so the project activity is the baseline unless there are other barriers.)
Step 6: assess the project for barriers to implementation (technical, normal practice, availability of finance etc.)
Step 7: calculate the emissions in the baseline and the project activity.

The additionality tool is used top determine whether the project activity constitutes part of the baseline. Key tests are the investment analysis and the technical barrier approach.

SECTION C. Choice of and justification as to why one of the baseline approaches listed in paragraph 48 of CDM modalities and procedures is considered to be the most appropriate:

C.1. General baseline approach:

X Existing actual or historical emissions, as applicable;

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

☐ The average emissions of similar project activities undertaken in the previous five years, in similar social, economic, environmental and technological circumstances, and whose performance is among the top 20 per cent of their category.

C.2. Justification of why the approach chosen in C.1 above is considered the most appropriate:

>> Existing actual or historical emissions are justifiable approach to the baseline methodology where few alternatives exist and the additionality of the project activity is dependent on barriers being proven.

SECTION D. Explanation and justification of the proposed new baseline methodology:

D.1. Explanation of how the methodology determines the baseline scenario (that is, indicate the scenario that reasonably represents the anthropogenic emissions by sources of greenhouse gases (GHG) that would occur in the absence of the proposed project activity):

>> The formulae and algorithms used in this baseline methodology originate from approved methodologies contained in ACM0002, AM0008, AM0014 and the "Tool for the demonstration and assessment of additionality". The formulae are therefore approved for other contexts and are adapted for this methodology.

The methodology uses the published "Tool for the demonstration and assessment of additionality" to identify the baseline and determine the additionality of the project activity. It then calculates the project activities' baseline emissions by estimating the emissions from the technologies and fuels used to produce heat and power in the absence of the project activity.

The variables are either external to the project boundary and are measured at the outset of the project (electricity grid baseline emissions), monitored according to the monitoring plan during the project or intermittently as the project is verified.

Fixed parameters are these related to the emissions intensity of fossil fuels that are either produced or graded according to calorific values. Similarly, the emissions factors of such fuels are fixed and are obtained from the IPCC or other default data sources. These default values are justifiably used. The electricity emissions are those produced by the combined margin approach (ACM0002) using relevant grid emissions. The relationship of the gas used in the project activity to natural gas is verified by external verifiers and should this relationship change, emission factors for the gas will change accordingly.

The methodology for the selection of the baseline scenarios and emissions associated with the baseline scenarios is developed in two parts.

1. The electricity baseline; and
2. The heat baseline.

The baseline emissions are those from the burning of the fuels that would have produced the exact quantities of electricity and heat as that provided by the project activity at the point of use.

Emissions intensities for the two baselines scenarios are calculated separately using the project activity's level of heat and electricity production. The electricity baseline is established using a combined margin approach whereas the heat baseline is established ex-ante from monitored data, energy balances and operational procedures for boiler sequencing in the plant being supplied and corrected ex-post operational records.

D.2. Criteria used in developing the proposed baseline methodology:

>> The general criteria used in the development of the baseline methodology are those that are relevant to the generation of heat and electricity in existing approved and/or consolidated methodologies. The specific criteria are those that relate to the specific fuels and/or technologies currently or historically used in the production of heat and power in the specific plants under consideration.

D.3. Explanation of how, through the methodology, it can be demonstrated that a project activity is additional and therefore not the baseline scenario (section B.3 of the CDM-PDD):

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The tool for the demonstration and assessment of additionality version 22 October 2004 is used for the demonstration of additionality.

The methodology determines the emissions from the existing technologies that are used for the generation of heat within the project boundary and power outside of the project boundary and determines the emissions from, and the costs of, providing the same service using candidate project activity technologies. The argument for the additionality of the project is based on the technology barrier element. Other barriers can be included in this analysis to make the case for the additionality of the project, including the return on investment of the project with and without the CDM component.

STEP 1. IDENTIFICATION OF ALTERNATIVES TO THE PROJECT ACTIVITY CONSISTENT WITH CURRENT LAWS AND REGULATIONS

Define realistic and credible alternatives[1] to the project activity(s) that can be (part of) the baseline scenario through the following sub-steps:

Sub-step 1a. Define alternatives to the project activity:

1. Identify realistic and credible alternative(s) available to the project participants or similar project developers[2] that provide outputs or services comparable with the proposed CDM project activity[3]. These alternatives are to include:

- The proposed project activity not undertaken as a CDM project activity;
- All other plausible and credible alternatives to the project activity that deliver outputs and on services (e.g. electricity, heat or cement) with comparable quality, properties and application areas;

[1] Reference to "alternatives" throughout this document denotes "alternative scenarios".

[2] For example, a coal-fired power station or hydropower may not be an alternative for an independent power producer investing in wind energy or for a sugar factory owner investing in a co-generation, but may be an alternative for a public utility. Alternatives are, therefore, related to technology and circumstances as well as to the investor.

[3] For example, the outputs of a cogeneration project could include heat for on-site use, electricity for on-site use, and excess electricity for export to the grid. In the case of a proposed landfill gas capture project, the service provided by the projects includes operation of a capped landfill.

- If applicable, continuation of the current situation (no project activity or other alternatives undertaken).

Sub-step 1b. Enforcement of applicable laws and regulations:

2. The alternative(s) shall be in compliance with all applicable legal and regulatory requirements, even if these laws and regulations have objectives other than GHG reductions, e.g. to mitigate local air pollution.[4] (This sub-step does not consider national and local policies that do not have legally-binding status.[5]).

3. If an alternative does not comply with all applicable legislation and regulations, then show that, based on an examination of current practice in the country or region in which the law or regulation applies, those applicable legal or regulatory requirements are systematically not enforced and that non-compliance with those requirements is widespread in the country. If this cannot be shown, then eliminate the alternative from further consideration;

4. If the proposed project activity is the only alternative amongst the ones considered by the project participants that is in compliance with all regulations with which there is general compliance, then the proposed CDM project activity is not additional.[6]

→ Proceed to Step 2 (Investment analysis) or Step 3 (Barrier analysis). (Project participants may also select to complete both steps 2 and 3.)

STEP 2. INVESTMENT ANALYSIS

Determine whether the proposed project activity is the economically or financially less attractive than other alternatives without the revenue from the sale of certified emission reductions (CERs). To conduct the investment analysis, use the following sub-steps:

Sub-step 2a. Determine appropriate analysis method

1. Determine whether to apply simple cost analysis, investment comparison analysis or benchmark analysis (sub-step 2b). If the CDM project activity generates no financial or economic benefits other than CDM related income, then apply the simple cost analysis (Option I). Otherwise, use the investment comparison analysis (Option II) or the benchmark analysis (Option III).

Sub-step 2b. – Option I. Apply simple cost analysis

2. Document the costs associated with the CDM project activity and demonstrate that the activity produces no economic benefits other than CDM related income.

→ If it is concluded that the proposed CDM project activity is not financially attractive then proceed to Step 4 (Common practice analysis).

Sub-step 2b. – Option II. Apply investment comparison analysis

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[4] For example, an alternative consisting of an open, uncapped landfill would be non-complying in a country where this scenario would imply violations of safety or environmental regulations pertaining to landfills.

[5] This aspect may be modified based on forthcoming guidance from the Executive Board on national and sectoral policies.

[6] This provision may be further elaborated depending on deliberation from the Board regarding requirements for the renewal of a crediting period.

3. Identify the financial indicator, such as IRR[7], NPV, cost benefit ratio, or unit cost of service (e.g., levelized cost of electricity production in $/kWh or levelized cost of delivered heat in $/GJ) most suitable for the project type and decision-making context.

Sub-step 2b – Option III. Apply benchmark analysis

4. Identify the financial indicator, such as IRR[8], NPV, cost benefit ratio, or unit cost of service (e.g., levelized cost of electricity production in $/kWh or levelized cost of delivered heat in $/GJ) most suitable for the project type and decision context. Identify the relevant benchmark value, such as the required rate of return (RRR) on equity. The benchmark is to represent standard returns in the market, considering the specific risk of the project type, but not linked to the subjective profitability expectation or risk profile of a particular project developer. Benchmarks can be derived from:

- Government bond rates, increased by a suitable risk premium to reflect private investment and/or the project type, as substantiated by an independent (financial) expert;
- Estimates of the cost of financing and required return on capital (e.g. commercial lending rates and guarantees required for the country and the type of project activity concerned), based on bankers views and private equity investors/funds' required return on comparable projects;
- A company internal benchmark (weighted average capital cost of the company) if there is only one potential project developer (e.g. when the project activity upgrades an existing process). The project developers shall demonstrate that this benchmark has been consistently used in the past, i.e. that project activities under similar conditions developed by the same company used the same benchmark.

Sub-step 2c. Calculation and comparison of financial indicators (only applicable to options II and III):

5. Calculate the suitable financial indicator for the proposed CDM project activity and, in the case of Option II above, for the other alternatives. Include all relevant costs (including, for example, the investment cost, the operations and maintenance costs), and revenues (excluding CER revenues, but including subsidies/fiscal incentives[9] where applicable), and, as appropriate, non-market cost and benefits in the case of public investors.

6. Present the investment analysis in a transparent manner and provide all the relevant assumptions in the CDM-PDD, so that a reader can reproduce the analysis and obtain the same results. Clearly present critical techno-economic parameters and assumptions (such as capital costs, fuel prices, lifetimes, and discount rate or cost of capital). Justify and/or cite assumptions in a manner that can be validated by the DOE. In calculating the financial indicator, the project's risks can be included through the cash flow pattern, subject to project-specific expectations and assumptions (e.g. insurance premiums can be used in the calculation to reflect specific risk equivalents).

7. Assumptions and input data for the investment analysis shall not differ across the project activity and its alternatives, unless differences can be well substantiated.

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[7] For the investment comparison analysis, IRRs can be calculated either as project IRRs or as equity IRRs. Project IRRs calculate a return based on project cash outflows and cash inflows only, irrespective the source of financing. Equity IRRs calculate a return to equity investors and therefore also consider amount and costs of available debt financing. The decision to proceed with an investment is based on returns to the investors, so equity IRR will be more appropriate in many cases. However, there will also be cases where a project IRR may be appropriate.

[8] For the benchmark analysis, the IRR shall be calculated as project IRR. If there is only one potential project developer (e.g. when the project activity upgrades an existing process), the IRR shall be calculated as equity IRR.

[9] This provision may be further elaborated depending on deliberations by the Board on national and sectoral policies.

8. Present in the CDM-PDD submitted for validation a clear comparison of the financial indicator for the proposed CDM activity and:

(a) The alternatives, if Option II (investment comparison analysis) is used. If one of the other alternatives has the best indicator (e.g. highest IRR), then the CDM project activity can not be considered as the most financially attractive;

(b) The financial benchmark, if Option III (benchmark analysis) is used. If the CDM project activity has a less favourable indicator (e.g. lower IRR) than the benchmark, then the CDM project activity cannot be considered as financially attractive.

Sub-step 2d. Sensitivity analysis (only applicable to options II and III):

9. Include a sensitivity analysis that shows whether the conclusion regarding the financial attractiveness is robust to reasonable variations in the critical assumptions. The investment analysis provides a valid argument in favour of additionality only if it consistently supports (for a realistic range of assumptions) the conclusion that the project activity is unlikely to be the most financially attractive (as per step 2c para 8a) or is unlikely to be financially attractive (as per step 2c para 8b).

→ If after the sensitivity analysis it is concluded that the proposed CDM project activity is unlikely to be the most financially attractive (as per step 2c para 8a) or is unlikely to be financially attractive (as per step 2c para 8b), then proceed to Step 3 (Barrier analysis) or Step 4 (Common practice analysis).

→ Otherwise, unless barrier analysis below is undertaken and indicates that the proposed project activity faces barriers that do not prevent the baseline scenario(s) from occurring, the project activity is considered not additional.

STEP 3. BARRIER ANALYSIS

If this step is used, determine whether the proposed project activity faces barriers that:

(a) Prevent the implementation of this type of proposed project activity; and

(b) Do not prevent the implementation of at least one of the alternatives.

Use the following sub-steps:

Sub-step 3a. Identify barriers that would prevent the implementation of type of the proposed project activity:

1. Establish that there are barriers that would prevent the implementation of the type of proposed project activity from being carried out if the project activity was not registered as a CDM activity. Such barriers may include, among others:

Investment barriers, other than the economic/financial barriers in Step 2 above, *inter alia*:

- Debt funding is not available for this type of innovative project activities.
- No access to international capital markets due to real or perceived risks associated with domestic or foreign direct investment in the country where the project activity is to be implemented.

Technological barriers, *inter alia*:

- Skilled and/or properly trained labour to operate and maintain the technology is not available and no education/training institution in the host country provides the needed skill, leading to equipment disrepair and malfunctioning;
- Lack of infrastructure for implementation of the technology.

Barriers due to prevailing practice, *inter alia*:

- The project activity is the "first of its kind": No project activity of this type is currently operational in the host country or region.

The identified barriers are only sufficient grounds for demonstration of additionality if they would prevent potential project proponents from carrying out the proposed project activity if it was not expected to be registered as a CDM activity.

2. Provide transparent and documented evidence, and offer conservative interpretations of this documented evidence, as to how it demonstrates the existence and significance of the identified barriers. Anecdotal evidence can be included, but alone is not sufficient proof of barriers. The type of evidence to be provided may include:

(a) Relevant legislation, regulatory information or industry norms;

(b) Relevant (sectoral) studies or surveys (e.g. market surveys, technology studies, etc) undertaken by universities, research institutions, industry associations, companies, bilateral/multilateral institutions, etc;

(c) Relevant statistical data from national or international statistics;

(d) Documentation of relevant market data (e.g. market prices, tariffs, rules);

(e) Written documentation from the company or institution developing or implementing the CDM project activity or the CDM project developer, such as minutes from Board meetings, correspondence, feasibility studies, financial or budgetary information, etc;

(f) Documents prepared by the project developer, contractors or project partners in the context of the proposed project activity or similar previous project implementations;

(g) Written documentation of independent expert judgements from industry, educational institutions (e.g. universities, technical schools, training centres), industry associations and others.

Sub-step 3 b. Show that the identified barriers would not prevent the implementation of at least one of the alternatives (except the proposed project activity):

3. If the identified barriers also affect other alternatives, explain how they are affected less strongly than they affect the proposed CDM project activity. In other words, explain how the identified barriers are not preventing the implementation of at least one of the alternatives. Any alternative that would be prevented by the barriers identified in Sub-step 3a is not a viable alternative, and shall be eliminated from consideration. At least one viable alternative shall be identified.

→ If both Sub-steps 3a – 3b are satisfied, proceed to Step 4 (Common practice analysis)

→ If one of the Sub-steps 3a – 3b is not satisfied, the project activity is not additional.

STEP 4. COMMON PRACTICE ANALYSIS

The above generic additionality tests shall be complemented with an analysis of the extent to which the proposed project type (e.g. technology or practice) has already diffused in the relevant sector and region. This test is a credibility check to complement the investment analysis (Step 2) or barrier analysis (Step 3). Identify and discuss the existing common practice through the following sub-steps:

Sub-step 4a. Analyze other activities similar to the proposed project activity:

1. Provide an analysis of any other activities implemented previously or currently underway that are similar to the proposed project activity. Projects are considered similar if they are in the same country/region and/or rely on a broadly similar technology, are of a similar scale, and take place in a comparable environment with respect to regulatory framework, investment climate, access to technology,

access to financing, etc. Other CDM project activities are not to be included in this analysis. Provide quantitative information where relevant.

Sub-step 4b. Discuss any similar options that are occurring:

2. If similar activities are widely observed and commonly carried out, it calls into question the claim that the proposed project activity is financially unattractive (as contended in Step 2) or faces barriers (as contended in Step 3). Therefore, if similar activities are identified above, then it is necessary to demonstrate why the existence of these activities does not contradict the claim that the proposed project activity is financially unattractive or subject to barriers. This can be done by comparing the proposed project activity to the other similar activities, and pointing out and explaining essential distinctions between them that explain why the similar activities enjoyed certain benefits that rendered it financially attractive (e.g., subsidies or other financial flows) or did not face the barriers to which the proposed project activity is subject.

3. Essential distinctions may include a serious change in circumstances under which the proposed CDM project activity will be implemented when compared to circumstances under which similar projects where carried out. For example, new barriers may have arisen, or promotional policies may have ended, leading to a situation in which the proposed CDM project activity would not be implemented without the incentive provided by the CDM. The change must be fundamental and verifiable.

→ If Sub-steps 4a and 4b are satisfied, i.e. similar activities cannot be observed or similar activities are observed, but essential distinctions between the project activity and similar activities can reasonably be explained, please go to step 5 (Impact of CDM registration).

→ 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 not additional.

Step 5. Impact of CDM registration

Explain how the approval and registration of the project activity as a CDM activity, and the attendant benefits and incentives derived from the project activity, will alleviate the economic and financial hurdles (Step 2) or other identified barriers (Step 3) and thus enable the project activity to be undertaken. The benefits and incentives can be of various types, such as:

- Anthropogenic greenhouse gas emission reductions;
- The financial benefit of the revenue obtained by selling CERs,
- Attracting new players who are not exposed to the same barriers, or can accept a lower IRR (for instance because they have access to cheaper capital),
- Attracting new players who bring the capacity to implement a new technology, and
- Reducing inflation /exchange rate risk affecting expected revenues and attractiveness for investors.

→ If Step 5 is satisfied, the proposed CDM project activity is not the baseline scenario.

→ If Step 5 is not satisfied, the proposed CDM project activity is not additional.

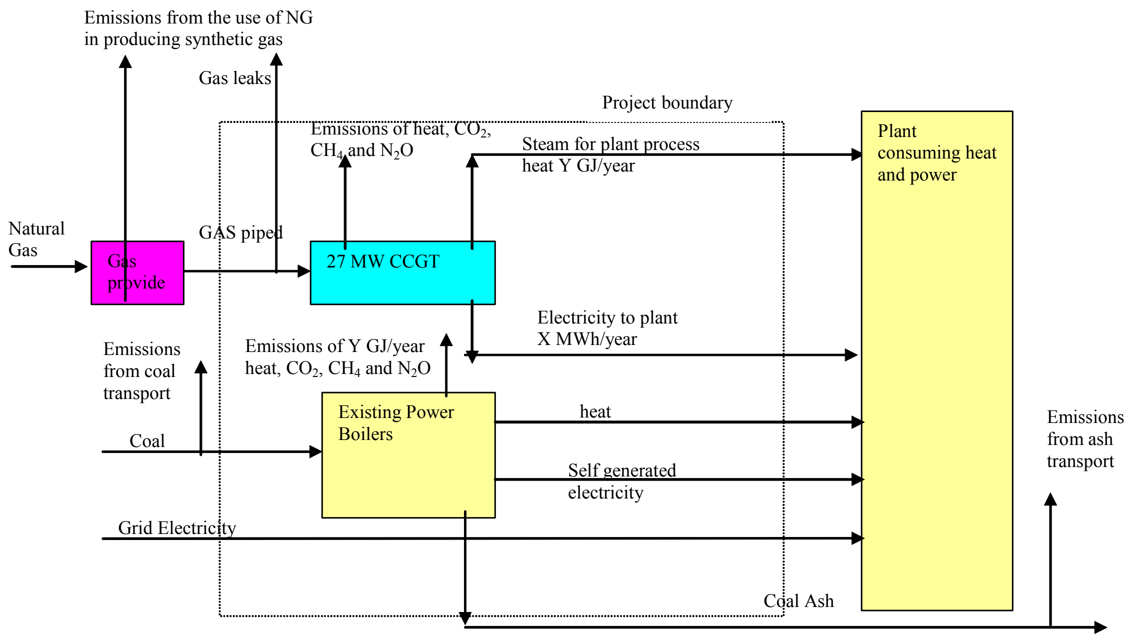
D.4. How national and/or sectoral policies and circumstances can been taken into account by the methodology:

>> The methodology takes into account the applicable sections contained within the Air Quality Bill (expected promulgation 2005), Energy Policy with respect to diversification of electricity supply options, regulation and pricing policies. Should any direct or indirect subsidies provide incentives that affect the choice of fuels/technologies these will be included in the additionality test.

D.5. Project boundary (gases and sources included, physical delineation):

>>
a) **CO_2 from combustion.** CO_2 emissions released from the combustion of coal that would have been used if the cogeneration system did not provide heat and power to the operation. CO_2 emissions released from to the combustion of gas in the project activity.
b) **CH_4 from combustion.** CH_4 emissions released from the combustion of coal that would have been used if the cogeneration system did not provide heat and power to the operation. CH_4 emissions released from the combustion of gas in the project activity.
c) **N_2O from combustion.** N_2O emissions release from the combustion of coal that would have been used if the cogeneration system did not provide heat and power to the operation. N_2O emissions released from the combustion of gas in the project activity.
d) **CH_4 leaks.** CH_4 emissions from leaks in the transport and distribution pipeline supplying the operation and leaks in the gas distribution piping within the operation, associated with the gas consumption.
e) **CO_2 from electricity generation.** CO_2 emissions associated with the production of electricity that would have to be purchased from the power grid if the cogeneration system did not provide electricity to the operation. The emissions are corrected to take account of transmission and distribution losses.
f) **CO_{2eq} from transportation.** CO_2 emissions associated with the transportation of coal and ash are included as leakage.

The diagram below describes the project boundary.



D.6. Elaborate and justify formulae/algorithms used to determine the baseline scenario. Variables, fixed parameters and values have to be reported (e.g. fuel(s) used, fuel consumption rates):

>> The formulae and algorithms have been used in the definition of approved projects ACM0002, AM0008, AM0014 and the tool for demonstration and assessment of additionality. The formulae are therefore approved for other contexts and are adapted for this methodology.

The variables are either external to the project boundary and are measured at the outset of the project (electricity grid baseline emissions), monitored according to the monitoring plan during the project or intermittently as the project is verified. These monitoring activities provide an ex-post correction to estimations of emissions.

Fixed parameters are those related to the emissions intensity of fossil fuels that are either produced or graded according to calorific values. Similarly, the emissions factors of such fuels are fixed and are

obtained from the IPCC or other default data sources. These default values are justifiably used. The electricity emissions are those produced by the combined margin approach (ACM0002) using relevant grid emissions. The relationship of the gas used in the project activity to incremental natural gas used in the Synthetic gas production process is verified by external verifiers similar to the emissions of build and operating electricity margins. Upstream emissions from the use of natural gas in the production of the incremental synthetic gas used in the project activity are considered as leakage.

The methodology uses the published "Tool for the demonstration and assessment of additionality" to identify the baseline and determine the additionality of the project activity. It then calculates the project activities' baseline emissions by estimating the emissions from the technologies and fuels used to produce heat and power in the absence of the project activity.

The methodology for the selection of the baseline scenarios and emissions is developed in two parts.

1. The electricity baseline; and
2. The heat baseline.

The baseline emissions are those from the burning of the fuels that would have produced the exact quantities of electricity and heat as that provided by the project activity at the point of use.

Both parts are included below:

D.1.1 The electricity baseline

The baseline scenario describes the emissions from grid electricity from which electricity would have been drawn in the absence of the project activity. The methodology presented below is for ACM0002 modified to consider the baseline emissions from electricity that would have been utilised in the absence of the project activity. ACM0002 is utilised in determining the emissions intensity of electricity replaced by the introduction of project activities implementing renewable energy fuelled electricity generation.

The first part entails electricity that would have otherwise been generated by the operation of grid-connected power plants and/or by the addition of new generation sources.

Choice of the grid

For accurate baseline determination and for its validation it is important to select a realistic grid representing the factual scenario associated with the project activity. An isolated grid is normally identified as a state, regional, national or sometimes trans-national grid. The following points need to be considered while selecting the grid:

1. Size of the project activity: If the size of the project activity is too small to have significant impact on the grid (=<1% of the grid to which it is connected), in terms of changes in the generation and dispatch system, then the lowest grid such as state or regional grid are to be selected. If the project size is big enough to alter the distribution pattern, then the next level of grid e.g. state/regional/national grid can be selected.

2. Connectivity of grid: If the inter-grid transmission of electricity is poor or restricted due to some reasons (e.g. policy, infrastructure) and the same can be verified then rather than choosing the larger grid (say national), an isolated grid should be selected.

It should be noted by the CDM project participants that, the bigger the size of the grid the more it is prone to errors in data assimilation and more costly for baseline determination and verification.

For project activities that modify or retrofit (but not expand the output of) an existing electricity generation facility, the guidance provided by EB08 shall be taken into account.[10]

[10] "If a proposed CDM project activity seeks to retrofit or otherwise modify an existing facility, the baseline may refer to the characteristics (i.e. emissions) of the existing facility only to the extent that the project activity does not increase the output or lifetime of the existing facility. For any increase of output or lifetime of the facility which is due to the project activity, a different baseline shall apply." (EB08, Annex 1, http://cdm.unfccc.int/EB/Meetings/).

A baseline emission factor (EF_y) is calculated as a combined margin (*CM*), consisting of the combination of operating margin (*OM*) and build margin (*BM*) factors according to the following three steps. Calculations for this combined margin must be based on data from an official source (where available)[11] and made publicly available.

STEP 1. Calculate the Operating Margin emission factor(s) ($EF_{OM,y}$) based on one of the four following methods:

(a) Simple OM, or
(b) Simple adjusted OM, or
(c) Dispatch Data Analysis OM, or
(d) Average OM.

Each method is described below.

Dispatch data analysis should be the first methodological choice. Where this option is not selected project participants shall justify why and may use the simple OM, the simple adjusted OM or the average emission rate method taking into account the provisions outlined hereafter.

The Simple OM method (a) can only be used where low-cost/must run resources[12] constitute less than 50% of total grid generation in: 1) average of the five most recent years, or 2) based on long-term normals for hydroelectricity production.

The average emission rate method (d) can only be used in cases where:

- the low-cost/must run resources constitute more than 50% of total grid generation and detailed data to apply option (b) is not available, and
- the detailed data to apply option (c) above is unavailable.

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[11] Plant emission factors used for the calculation of operating and build margin emission factors should be obtained in the following priority:

1. *acquired directly* from the dispatch center or power producers, if available; or
2. *calculated*, if data on fuel type, fuel emission factor, fuel input and power output can be obtained for each plant; if confidential data available from the relevant host Party authority are used the calculation carried out by the project participants shall be verified by the DOE and the CDM-PDD may only show the resultant carbon emission factor and the corresponding list of plants.
3. *calculated*, as above, but using estimates such as
   - default IPCC values from the *IPCC 1996 Revised Guidelines* and the *IPCC Good Practice Guidance* for net calorific values and carbon emission factors for fuels instead of plant-specific values (note that the *IPCC Good Practice Guidance* includes some updates from the *IPCC 1996 Revised Guidelines*);
   - technology provider's name plate power plant efficiency or the anticipated energy efficiency documented in official sources (instead of calculating it from fuel consumption and power output). This is likely to be a conservative estimate, because under actual operating conditions plants usually have lower efficiencies and higher emissions than name plate performance would imply;
   - conservative estimates of power plant efficiencies, based on expert judgments on the basis of the plant's technology, size and commissioning date; or
4. *calculated,* for the simple OM and the average OM, using aggregated generation and fuel consumption data, in cases where more disaggregated data is not available.

[12] Low operating cost and must run resources typically include hydro, geothermal, wind, low-cost biomass, nuclear and solar generation. If coal is obviously used as must-run, it should also be included in this list, i.e. excluded from the set of plants.

(a) *Simple OM.* The Simple OM emission factor ($EF_{OM,simple,y}$) is calculated as the generation-weighted average emissions per electricity unit (tCO_2/MWh) of all generating sources serving the system, not including low-operating cost and must-run power plants:

$$EF_{OM,simple,y} = \frac{\sum_{i,j} F_{i,j,y} \cdot COEF_{i,j}}{\sum_{j} GEN_{j,y}} \qquad \text{(Equation 4)}$$

where:

$F_{i,j,y}$ is the amount of fuel *i* (in a mass or volume unit) consumed by relevant power sources *j* in year(s) *y*,

j refers to the power sources delivering electricity to the grid, not including low-operating cost and must-run power plants, and including imports[13]to the grid,

$COEF_{i,j\,y}$ is the CO_2 emission coefficient of fuel *i* (tCO_2 / mass or volume unit of the fuel), taking into account the carbon content of the fuels used by relevant power sources j and the percent oxidation of the fuel in year(s) y, and

$GEN_{j,y}$ is the electricity (MWh) delivered to the grid by source *j*.

The CO_2 emission coefficient $COEF_i$ is obtained as

$$COEF_i = NCV_i \cdot EF_{CO2,i} \cdot OXID_i \qquad \text{(Equation 5)}$$

where:

NCV_i is the net calorific value (energy content) per mass or volume unit of a fuel *i*,

$OXID_i$ is the oxidation factor of the fuel (see page 1.29 in the 1996 Revised IPCC Guidelines for default values),

$EF_{CO2,i}$ is the CO_2 emission factor per unit of energy of the fuel *i*.

Where available, local values of NCV_i and $EF_{CO2,i}$ should be used. If no such values are available, country-specific values (see e.g. IPCC Good Practice Guidance) are preferable to IPCC world-wide default values.

The Simple OM emission factor can be calculated using either of the two following data vintages for years(s) *y*:

i) A 3-year average, based on the most recent statistics available at the time of PDD submission, or

ii) The year in which project generation occurs, if $EF_{OM,y}$ is updated based on ex post monitoring.

(b) *Simple Adjusted OM.* This emission factor ($EF_{OM,simple\ adjusted,y}$) is a variation on the previous method, where the power sources (including imports) are separated in low-cost/must-run power sources (*k*) and other power sources (*j*):

$$EF_{OM,simple\ adjusted,y} = \left(1-\lambda_y\right) \cdot \frac{\sum_{i,j} F_{i,j,y} \cdot COEF_{i,j}}{\sum_{j} GEN_{j,y}} + \lambda_y \cdot \frac{\sum_{i,k} F_{i,k,y} \cdot COEF_{i,k}}{\sum_{k} GEN_{k,y}} \qquad \text{(Equation 6)}$$

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13 As described above, an import from a connected electricity system should be considered as one power source *j*.

where $F_{i,k,y}$, $COEF_{i,k}$ and GEN_k are analogous to the variables described for the simple OM method above for plants k; the years(s) y can reflect either of the two vintages noted for simple OM above, and

$$\lambda_y(\%) = \frac{\text{Number of hours per year for which low-cost/must-run sources are on the margin}}{\text{8760 hours per year}} \quad \text{(Equation 7)}$$

where lambda (λ_y) should be calculated as follows (see figure below):

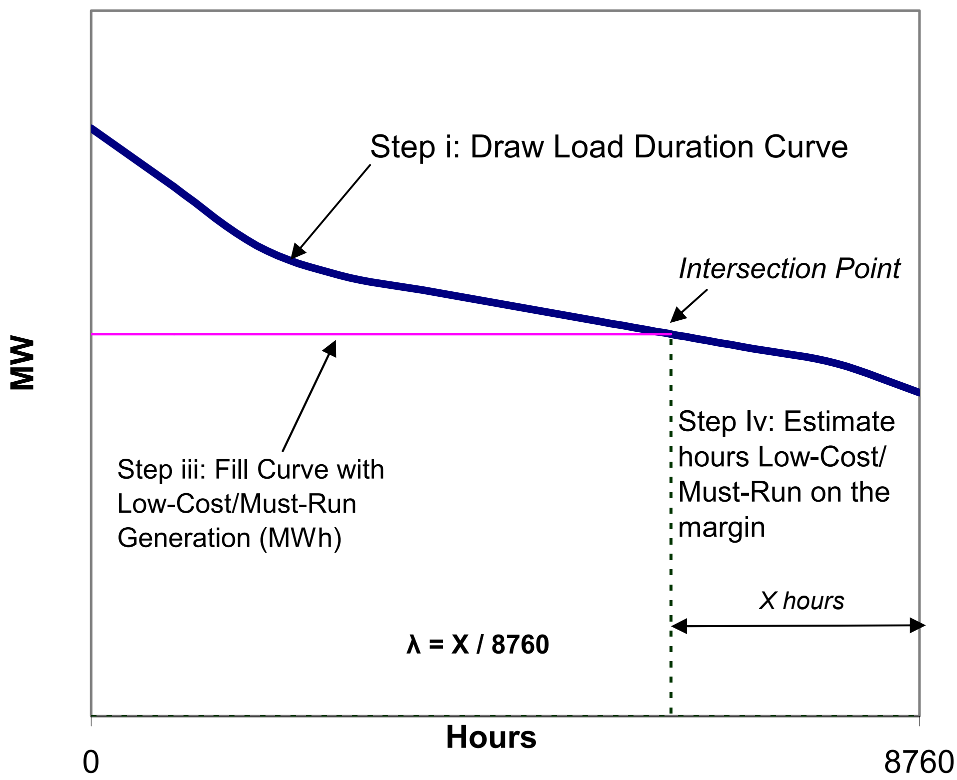
Step i) Plot a Load Duration Curve. Collect chronological load data (typically in MW) for each hour of a year, and sort load data from highest to lowest MW level. Plot the load data (MW) against 8760 hours in the year, in descending order.

Step ii) Organize Data by Generating Sources. Collect data for, and calculate total annual generation (in MWh) from low-cost/must-run resources (i.e. $\sum_k GEN_{k,y}$).

Step iii) Fill Load Duration Curve. Plot a horizontal line across load duration curve such that the area under the curve (MW times hours) equals the total generation (in MWh) from low-cost/must-run resources (i.e. $\sum_k GEN_{k,y}$).

Step iv) Determine the "Number of hours per year for which low-cost/must-run sources are on the margin". First, locate the intersection of the horizontal line plotted in step (iii) and the load duration curve plotted in step (i). The number of hours (out of the total of 8760 hours) to the right of the intersection is the number of hours for which low-cost/must-run sources are on the margin. If the lines do not intersect, then one may conclude that low-cost/must-run sources do not appear on the margin and λ_y is equal to zero. Lambda (λ_y) is the calculated number of hours divided by 8760.

Figure 1: Illustration of Lambda Calculation for Simple Adjusted OM Method



Note: Step (ii) is not shown in the figure, it deals with organizing data by source.

(c) *Dispatch Data Analysis OM.* The Dispatch Data OM emission factor ($EF_{OM,Dispatch\ Data,y}$) is summarized as follows:

$$EF_{OM,Dispatch\ Data,y} = \frac{E_{OM,y}}{EG_y}$$

(Equation 8)

where EG_y is the generation of the project (in MWh) in year y, and $E_{OM,y}$ are the emissions (tCO_2) associated with the operating margin calculated as

$$E_{OM,y} = \sum_h EG_h \cdot EF_{DD,h} \qquad \text{(Equation 9)}$$

where EG_h is the generation of the project (in MWh) in each hour h and $EF_{DD,h}$ is the hourly generation-weighted average emissions per electricity unit (tCO_2/MWh) of the set of power plants (n) in the top 10% of grid system dispatch order during hour h:

$$EF_{DD,h} = \frac{\sum_{i,n} F_{i,n,h} \cdot COEF_{i,n}}{\sum_n GEN_{n,h}} \qquad \text{(Equation 10)}$$

where F, $COEF$ and GEN are analogous to the variables described for the simple OM method above, but calculated on an hourly basis for the set of plants (n) falling within the top 10% of the system dispatch. To determine the set of plants (n), obtain from a national dispatch center: a) the grid system dispatch order of operation for each power plant of the system; and b) the amount of power (MWh) that is dispatched from all plants in the system during each hour that the project activity is operating (GEN_h). At each hour h, stack each plant's generation (GEN_h) using the merit order. The set of plants (n) consists of those plants at the top of the stack (i.e., having the least merit), whose combined generation ($\sum GEN_h$) comprises 10% of total generation from all plants during that hour (including imports to the extent they are dispatched).

(d) *Average OM.* The average Operating Margin (OM) emission factor ($EF_{OM,average,y}$) is calculated as the average emission rate of all power plants, using equation (1) above, but including low-operating cost and must-run power plants. Either of the two data vintages described for the simple OM (a) may be used.

STEP 2. Calculate the Build Margin emission factor ($EF_{BM,y}$) as the generation-weighted average emission factor (tCO_2/MWh) of a sample of power plants m, as follows:

$$EF_{BM,y} = \frac{\sum_{i,m} F_{i,m,y} \cdot COEF_{i,m}}{\sum_m GEN_{m,y}} \qquad \text{(Equation 11)}$$

where $F_{i,m,y}$, $COEF_{i,m}$ and $GEN_{m,y}$ are analogous to the variables described for the simple OM method above for plants m.

Project participants shall choose between one of the following two options:

Option 1. Calculate the Build Margin emission factor $EF_{BM,y}$ *ex ante* based on the most recent information available on plants already built for sample group m at the time of PDD submission. The sample group m consists of either

- the five power plants that have been built most recently, or
- the power plants capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently.

Project participants should use from these two options that sample group that comprises the larger annual generation.

Option 2. For the first crediting period, the Build Margin emission factor $EF_{BM,y}$ must be updated annually *ex post* for the year in which actual project generation and associated emissions reductions occur. For subsequent crediting periods, $EF_{BM,y}$ should be calculated *ex-ante*, as described in option 1 above. The sample group *m* consists of either

- the five power plants that have been built most recently, or
- the power plants capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently.

Project participants should use from these two options that sample group that comprises the larger annual generation.

Power plant capacity additions registered as CDM project activities should be excluded from the sample group *m*.

STEP 3. Calculate the baseline emission factor EF_y as the weighted average of the Operating Margin emission factor ($EF_{OM,y}$) and the Build Margin emission factor ($EF_{BM,y}$):

$$EF_y = w_{OM} \cdot EF_{OM,y} + w_{BM} \cdot EF_{BM,y} \qquad \text{(Equation 12)}$$

where the weights w_{OM} and w_{BM}, by default, are 50% (i.e., $w_{OM} = w_{BM} = 0.5$), and $EF_{OM,y}$ and $EF_{BM,y}$ are calculated as described in Steps 1 and 2 above and are expressed in tCO_2/MWh. Alternative weights can be used, as long as $w_{OM} + w_{BM} = 1$, and appropriate evidence justifying the alternative weights is presented. These justifying elements are to be assessed by the Executive Board.[14]

Distribution and transmission losses

Transmission and distribution losses may be included for electricity imported and used within the project boundary.

$$EFy_{T\&D} = \left[\frac{EFy \times 100}{100 - T\&D}\right] - EFy \qquad \text{(Equation 13)}$$

Where,

- $EFy_{T\&D}$ - Baseline emission factor of transmission and distribution losses for imported electricity to plant. The units are in tCO_2e/MWh
- T&D – Transmission & Distribution loss % (These losses include technical electrical energy losses that incur during transmission & distribution). [The value used should be supported by documentary evidence]

D.1.2 Heat baseline

The second part of the baseline includes the emissions from the fossil fuels used to produce the steam that provides process heat to the operation.

The baseline scenario for the project activity, which is eligible to use in this methodology, is that the current fuels (coal and/or petroleum fuels; denoted by *i* in the formula below) are continued to be used in

[14] More analysis on other possible weightings may be necessary and this methodology could be revised based on this analysis. There might be a need to propose different weightings for different situations.

the existing facility at least up to the end of the crediting period without any retrofit, which extends its capacity or lifetime, or improves its fuel efficiency.

The fuels that are replaced by the project activity *i* are identified using operating protocols of the plant concerned and corrected by monitoring operating records.

The baseline emissions BE_y (measured in ton of CO_2 equivalents (tCO_2e/yr)) during a year (*y*)[15] is expressed as:

$$BE_y = \sum_i Q\_F_{i,y} * (EF\_F_{i,}\_CO_{2y} + FC\_F_i\_CH_4 * GWP\_CH_4 + FC\_F_i\_N_2O * GWP\_N_2O) \text{ (Equation 14)}$$

where:

$Q\_F_{i,}$	Quantity of fuel *i* used in the baseline scenario, measured in energy units (e.g., Joule).
EF_F_i	CO_2 equivalent emission factor per unit of energy of fuel *i* (e.g., tCO_2e/Joule).
FC_F_i	CH_4 is the IPCC default CH_4 emission factor of fuel *i* associated with fuel combustion, measured in tCH_4/Joule.
FC_F_i	N_2O is the IPCC default N_2O emission factor of fuel *i* associated with fuel combustion, measured in tN_2O/Joule.
GWP_CH_4	Is the global warming potential of CH_4 set at 21 tCO_2e/tCH_4 for the 1_{st} commitment period.
GWP_N_2O	Is the global warming potential of N_2O set at 310 tCO_2e/tN_2O for the 1_{st} commitment period.

The parameters (variable) $Q\_F_{i,y}$ in the baseline emissions formula are calculated as specified in the "project scenario" section by using monitored parameters and default values.

Total baseline emissions

Total baseline emissions per year = emissions intensity of baseline electricity * quantity of electricity produced by project activity (MCEO MWh/year) + emissions intensity of baseline heat * quantity of process heat produced by the project activity (MCHO GJ/year)

Total baseline emissions = MCEO *(MWh/year)* * $EF_{y\ T\&D}$ *(tonnes CO_2e/MWh) + MCHO GJ/year * BEy/Y* (tonnes CO_2e/GJ)

D.7. Elaborate and justify formulae/algorithms used to determine the emissions from the project activity. Variables, fixed parameters and values have to be reported (e.g. fuel(s) used, fuel consumption rates):

>>The project activity is an on-site plant providing combined heat and power:

The project activity emissions are from the burning of gas used to produce steam for both:

1. The electricity generation activity; and
2. The heat generation activity.

Both parts are included below:

1. The emissions from the project activity for steam generation for heat and power are:
The project activity is to switch the fuel (from coal and/or petroleum fuels to natural gas) of some element processes of a facility. AM0008 is used to estimate the emissions reductions from this project activity.

The project emissions PE_y (measured in tonnes of CO_2 equivalents (tCO_2e/yr)) during a year (*y)* is expressed as:

[15] Throughout this document, suffix "*y*" denotes that such a variable parameter is the annual amount during a given year (*y*).

$PE_y = (\sum_i Q_i\_NG_y) * (EF\_NG + FC\_NG\_CH_4 * GWP\_CH_4 + FC\_NG\_N_2O * GWP\_N_2O)$
where:

$Q_i\_NG_y$ Quantity of natural gas used in the project scenario for replacing quantity of fuel *i* used in the baseline scenario ($Q\_F_{i,y}$) measured in energy units (e.g., Joule).

Q_NG_y The total quantity of natural gas in the project scenario for replacing all quantity of fuel *i* used in some element processes in the baseline ($\sum_i Q_i\_NG_y$) scenario

EF_NG IPCC default CO_2 emission factor per unit of natural gas associated with fuel combustion (e.g., tCO_2/Joule).

$FC\_NG\_CH_4$ IPCC default CH_4 emission factor of natural gas associated with fuel combustion, measured in tCH_4/Joule.

$FC\_F_i\_N_2O$ IPCC default N_2O emission factor of natural gas associated with fuel combustion, measured in tN_2O/Joule.

The variables in the baseline emissions ($Q_n\_F_{i,y}$) and the project emissions ($Q_n\_NG_y$) are linked with the constraint relation:

$Q_n\_F_{i,y} * \eta_n\_F_i = Q_n\_NG_y * \eta_n\_NG$

For each element process *n* which uses the fuel *i* in the baseline scenario. Here $\eta_n\_F_i$ and η_n_NG are fuel efficiency for use of fuel *i* (baseline scenario) and natural gas (project scenario) respectively, measured either in unit of output per unit of energy (e.g., ton of output/Joule) or ratio of the output energy to the input energy, or the percentage, as appropriate $\eta_n\_F_i$ and η_n_NG are regarded as functions of the load factor measured *ex-ante* before fuel switching3 (for $\eta_n\_F_i$) and at the early stage of each crediting period[16] (for η_n_NG). This relation should be kept at each operating pattern,[17] in which a single load factor can represent.

This relation is linked to the total value by summing up the processes:
$\sum_n Q_n\_F_{i,y} = Q\_F_{i,y}$ and $\sum_n Q_n\_NG_y = Q\_NG_y$.

These equations ensure that the useful heat needed is common for each element process in both project and baseline scenarios. These equations are used to obtain $Q_n\_F_{i,y}$ and $Q\_F_{i,y}$ which are baseline scenario parameters (cannot be measured directly) by using measurable project scenario parameters.

η_n_NG shall be estimated *ex ante* and used to provide an estimation of the emission reductions that can be expected from the project activity.

D.8. Description of how the baseline methodology addresses any potential leakage of the project activity:

>> Emissions from the use of the incremental natural gas at a synthetic fuel plant, fugitive CH_4 emissions from gas transmission and CO_2, CH_4, and N_2O emissions from coal and ash transportation are categorized as leakage. Emissions from fuel transportation are counted only if the fuel is transported in a non-Annex I country.

The leakage LE_y is expressed as:

$LE_y = [\text{MEC GS}_{j,y} * FE\_NG\_CH_4 - \text{MEC GS}_{k,y} * FE\_NG\_CH_4)] * GWP\_CH_4 + [\sum_j (Q\_TF_{j,y} * EF\_TF_j) - \sum_k (Q\_TF_{k,y} * EF\_TF_k)] + (\text{MEC GS - Q\_NGy} * 10^9) * \text{GWP SG}$ - (Carbon dioxide equivalent in tonnes of natural gas used to produce synthetic gas)

[16] The measurement should be repeated for each process *n* with several load factors in order to get the curve of η_n with statistical significance.

[17] The operating pattern may include normal operation, start-up, shut-down, holiday operation, etc. during which the load factor can be represented by a certain fixed value.

Where FE_NG_CH_4 and FE_F_i_CH_4 are the IPCC default CH_4 emission factor of natural gas and fuel i associated with fugitive emissions (tonnes CH_4/joules/year). In case that the effect of methane leaked from the pipeline cannot be neglected, it should be included in this term (although it is not a function of Q_NG_y in the IPCC Guidelines).

For the transportation related part, Q_$TE_{j,y}$ is the transportation energy quantity used and EF_TE_j is the $CO_{2\,e}$ emission factor associated with the transportation mode j for project scenario and for mode k for baseline scenario (such as marine, railroad or truck). In case the information or data are not available due to uncertainties and diversities in the energy market, the IPCC default value could apply. Otherwise, it could be estimated qualitatively in view of it being a relatively small part of the total emissions.

The natural gas used in the incremental synthetic gas production is considered upstream leakage. This source of leakage can be calculated using mass balances around the synthetic gas producer's plant.

$LE_y = [\ Q\_NG_y * FE\_NG\_CH_4 - \sum_i (Q\_F_{i,y} * FE\_F_i\_CH_4)\ ] * GWP\_CH_4$
$+ [\sum_j (Q\_TF_{j,y} * EF\_TF_j) - \sum_k (Q\_TF_{k,y} * EF\_TF_k)\ ]$ + (Carbon dioxide equivalent in tonnes of natural gas used to produce synthetic gas)

D.9. Elaborate and justify formulae/algorithms used to determine the emissions reductions from the project activity. Variables, fixed parameters and values have to be reported (e.g. fuel(s) used, fuel consumption rates):

>> The formulae/algorithms for the calculation of emissions are included above. The summary of the emissions reductions from the project activity are included below.

Emissions reductions from the project activity = Total baseline emissions – Total project activity emissions – Total project leakage emissions

Total baseline emissions

Total baseline emissions per year = emissions intensity of baseline electricity * quantity of electricity produced by project activity (MCEO MWh/year) + emissions intensity of baseline heat * quantity of process heat produced by the project activity (MCHO GJ/year)

Total baseline emissions = MCEO *(MWh/year)* * $EF_{y\ T\&D}$ *(tonnes CO_2e/MWh) + MCHO GJ/year * BEy/Y* (tonnes CO_2e/GJ)

Total project activity emissions

Total project emissions per year = emissions intensity of natural gas * quantity of natural gas used in the production of heat and electricity + emissions intensity of project electricity * quantity of electricity produced by project activity (MCEO MWh/year) + emissions intensity of project activity heat * quantity of process heat produced by the project activity (MCHO GJ/year)

Total project activity emissions (tonnes CO_2 per year) = MCEO (MWh/year) * 3600 (Joules/MWh) + MCHO (GJ heat) * 10 E9) * EF_NG (tonnes CO_{2e}/Joule Natural Gas)

Emissions reductions from the project activity

Emissions reductions from the project activity = MCEO *(MWh/year)* * $EF_{y\ T\&D}$ *(tonnes CO_2e/MWh) + MCHO (GJ/year) * BEy/MCHO* (tonnes CO_2e/GJ) - (MCEO (MWh/year) * 3600 (Joules/MWh) + MCHO (GJ heat) * 10^9) * EF_NG (tonnes CO_2/Joule Natural Gas) - LE_y

SECTION E. Data sources and assumptions:

E.1. Describe parameters and or assumptions (including emission factors and activity levels):

>> Key parameters include the heating value of natural gas and CO_2 emissions factor for natural gas combustion and the emissions factors for CH_4 and N_2O from natural gas and coal combustion (which would depend on technology), and CH_4 emissions factor corresponding to methane released in natural gas production and leakage from transport and distribution network.

Lower heating values are used throughout.

The heating values for natural and synthetic gas are country specific. Thus the actual value used in a given project should be obtained from the country specific source where possible.

E.2. List of data used indicating sources (e.g. official statistics, expert judgement, proprietary data, IPCC, commercial and scientific literature) and precise references and justify the appropriateness of the choice of such data:

>>

Table 1 Data required in the baseline methodology

ID no.	Data	Unit	When used	Sources
1	List of plausible scenarios		Baseline and additionality definition	To be elaborated by PP
2	Baseline IRR	%	Baseline and additionality definition	To be elaborated by PP
3	Project Activity IRR without CERs	%	Baseline and additionality definition	To be elaborated by PP
4	Discount rates	%	Baseline and additionality definition	National Statistics
4b	Escalation rates (coal, electricity, gas)	%	Baseline and additionality definition	To be elaborated by PP and suppliers
5	Threshold IRR	%	Baseline and additionality definition	To be elaborated by PP
6	Baseline power production	MWh/year	Baseline and additionality definition	To be elaborated by PP
7	Baseline heat production	GJ/year	Baseline and additionality definition	To be elaborated by PP
8	Emissions from Natural Gas	Tonnes CO_2/GJ	Project activity	IPCC, fuel type and technology specific
9	Emissions from coal	Tonnes CO_2/GJ	Baseline and additionality definition	IPCC, fuel type and technology specific
10	Emissions from Electricity Grid	Tonnes CO_2/MWh	Baseline and additionality definition	Electricity suppliers
11	Quantity of Coal used in power boilers	Tonnes/year	Baseline and additionality definition Project activity and baseline	To be elaborated by PP
12	Quantity of NG used to produce Synthetic gas	GJ/Year	Leakage	To be elaborated by gas supplier
13	Quantity of electricity used	MWh/year	Project activity and project baseline	To be elaborated by PP
14	Emissions from transportation of Ash	Tonnes CO_2/year	Leakage	To be elaborated by PP
15	Emissions from transportation of coal by rail	Tonnes CO_2/year	Leakage	To be elaborated by rail transporters and PP
16	Emissions from the transmission of Synthetic gas	Tonnes CO_2/year	Leakage	Gas supplier
17	Electricity and transmission and distribution losses	%	Project baseline	Transmission and distribution authority
18	Price of coal	Rands/tonne	Baseline and additionality definition	To be elaborated by PP
19	Price of Synthetic gas	Rands/GJ	Baseline and additionality definition	To be elaborated by PP
20	Price of electricity from grid	Rands/MWh	Baseline and additionality definition	To be elaborated by PP
21	Operations manual for power production	-	Baseline and additionality definition	To be elaborated by PP

22	Electricity outages	-	Baseline and additionality definition	To be elaborate by PP

E.3. Vintage of data (e.g. relative to starting date of the project activity):

>> Data used in the calculations of project and baseline emissions should be the most recent available prior to the construction, commissioning and subsequent commencement of the crediting period. Consolidated data over the past 3 years prior to the crediting period should be used where possible, where this is not available data that is more recent may be used but only once is has been demonstrated that such data is not available. The operational parameters required to estimate the baseline, project activity and leakage emissions will be monitored during the project crediting period.

E.4. Spatial level of data (local, regional, national):

>>

Table 2: Spatial level of data

ID no.	Data	Spatial level of Data
1	List of plausible scenarios	local
2	Baseline IRR	local
3	Project Activity IRR without CERs	local
4	Discount rate	Local/national
4a	Escalation rates (coal, electricity, gas)	Local/national
5	Threshold IRR	local
6	Baseline power production	Local
7	Baseline heat production	local
8	Emissions from Natural Gas	International
9	Emissions from coal	National/International
10	Emissions from Electricity Grid	National
11	Quantity of Coal used in power boilers	local
12	Quantity of NG used to produce Synthetic gas	local
13	Quantity of electricity used	local
14	Emissions from transportation of Ash	local
15	Emissions from transportation of coal by rail	regional
16	Emissions from the transmission of Synthetic gas	regional
17	Electricity and transmission and distribution losses	national
18	Price of coal	local
19	Price of Synthetic gas	local
20	Price of electricity from grid	local
21	Operations manual for power production	local
22	Grid electricity outages/Outages caused by poor quality in supply of electricity	Local/regional

SECTION F. Assessment of uncertainties (sensitivity to key factors and assumptions):

>> The application of the methodology described in the "Consolidated Additionality Tool- Annex 1, EB16 Meeting Report" can lead to an erroneous baseline scenario in the following situations:

- The set of plausible alternatives is incomplete. A careful analysis of possible and plausible alternatives and confirmation by a DOE of the validity of the analysis and the conclusions drawn from it is imperative in order to mitigate risks and to ensure credibility of the result.
- The financial analysis is not conservative. The DOE must carefully control and check all assumptions used in order to ensure a conservative result.

Gas provision in the project activity:

- The provision of gas needs to be demonstrated to be incremental to the current gas production operation and must be shown to have emissions equivalent to natural gas less any use of natural gas used in the production of the synthetic gas. The data for these mass balances is not in the control of the project participant and will have to be checked thoroughly to establish that the mass balances are correctly interpreted. Uncertainties could be secured by ex-post correction of shortfalls in the equivalence between Natural Gas and the incremental synthetic gas delivered for heat and power production.

Electricity provision in the baseline:

- The data used to estimate the combined margins is available and reliable.

With relation to the quantification of emission reductions, there are two sources of uncertainty:

- The first one relates to the quality of data used. In this regard, the use of quality control and management systems, such as ISO 9000 and ISO 14000, would help to ensure that data used for the quantification of emissions and emission reductions are consistent and of appropriate quality.

SECTION G. Explanation of how the baseline methodology allows for the development of baselines in a transparent and conservative manner:

>>

The methodology aims to:

- Be transparent and conservative by referring to real, verifiable data, with little use of default factors;
- Make full use of the approved Additionality Tool.
- Where default data has to be used, it should be default data from internationally recognized institutions like the Intergovernmental Panel on Climate Change and International Energy Agency;
- Mass balances around the plant are included for the baseline and incremental synthetic gas;
- Use shall be made of the approved methodology ACM0002, AM0014 or another approved methodology (as appropriate).