CLEAN DEVELOPMENT MECHANISM
PROPOSED NEW METHODOLOGY: BASELINE (CDM-NMB)
Version 01 - in effect as of: 1 July 2004

CONTENTS

SECTION A. Identification of methodology

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A.1. Proposed methodology title:

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Cogeneration at an industrial facility.
Version no. 1.
31 May 2005.

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

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The methodology may be applicable to the following categories of project activities: (1) Energy industries (renewable / non-renewable sources), (4) Manufacturing industries and (5) Chemical industry.

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

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Cogeneration involves the simultaneous production of heat and electricity from a single fuel source. The activities covered by this methodology could involve the installation of new cogeneration capacity or increase in existing cogeneration capacity. The project activity may involve fuel switching since cogeneration equipment normally require higher quality fuels (e.g. natural gas and petroleum distillate) so that there is likely to be increased consumption of such fuels and decreased consumption of other fuels such as coal, fuel oil, etc.

The methodology would apply to cases where cogenerated electricity meets some or all of the power demand at the industrial facility. The industry may purchase electricity from the grid in order to meet on-site demand or sell electricity to the grid when electricity generation exceeds on-site demand.

While fuel switching may be involved in the cogeneration project implementation, this methodology is not applicable to projects that are limited to fuel switching only for equipment generating thermal energy.

The methodology is not applicable to situations where the industry purchases from, or sells thermal energy to, other users, either in the baseline scenario or in the project scenario.

The methodology is also *not* applicable to project activities involving improvements in end-use efficiency, i.e. where thermal energy and/or electricity is used more efficiently. The methodology proposed here can be applied to projects where end-use efficiency improvements also take place in addition to the activities covered by this methodology. However, emission reductions resulting from efficiency improvement would not lead to creditable emission reductions in this methodology because the baseline is adjusted in accordance with actual thermal energy delivered to the industry's thermal load during the project. Consequently, efficiency improvements tend to decrease both project emissions and baseline emissions.

The methodology is applicable to industries with existing cogeneration equipment. However, if this is the case, and the new cogeneration equipment would replace some of the existing equipment, the crediting period would be limited by the remaining lifetime of any existing cogeneration equipment.

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

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One potential strength of the proposed new methodology is that it is fairly straightforward to apply. The methodology allows for baseline emissions to be determined in a dynamic manner, thus allowing for changes in industrial demand.

On potential weakness of the proposed methodology is that it requires three years of reliable historical data to determine relationship between industrial parameters.

SECTION B. Overall summary description:

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The methodology considers emissions from fuel consumption by all equipment producing heat and/or electricity at the industrial site where heat and electricity are produced to meet demand elsewhere at the industrial site. Baseline emissions would depend on the *net* electricity purchased through the grid in the baseline scenario. Moreover, net electricity sold through the grid in the *project* scenario would reduce emissions elsewhere in the power grid. In the absence of the project activity, these emissions would have taken place. Thus these emissions that are *avoided* by the project activity also need to be counted as *baseline* emissions. The magnitude of these emissions may be expressed as the product of the amount of electricity purchased or sold and an emissions factor that characterises power generation in the rest of the grid.

This new methodology incorporates the following procedures and methodologies:

- Tool for demonstration and assessment of additionality (Oct. 2004, published as Annex 1 to EB 16 Report).
- Approved consolidated baseline methodology ACM0002 "Consolidated baseline methodology for grid-connected electricity generation from renewable sources".
- For projects where power exported from the industrial facility through the power grid is below 15 MW, an alternative methodology is the Small-scale methodology AMS I. D "Renewable electricity generation for a grid."

The additionality tool is adapted for application within this new methodology for the specific types of projects involved here.

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:

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C.1. General baseline approach:

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☒ 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:

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The approach chosen is applicable since the project activity may involve one or more cogeneration technologies using a variety of fuels, so that no single technology can be used as a reference, as required in the second option. For the same reason, each project within the proposed set of applicable project activities is likely to be unique and cannot be readily identified with "similar" project activities elsewhere. The first option "existing actual or historical emissions" involves data that are uniquely determined, so that emissions and emissions reductions can be determined from actual measured data.

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

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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):

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The first step in determining the baseline scenario is to analyse all options available to project participants. These include the business-as-usual case, the project scenario, and all other scenarios that might be applicable. Since the project involves cogeneration, the available scenarios are given below:

- Continue with the fuel or fuels currently being used at the facility and maintain all equipment currently in use.
- Add or modify cogeneration equipment capacity at industrial site using any fuel or combination of fuels, and modify the type and quantity of fuels used to produce heat at the industrial facility, as needed.

The choice of the baseline scenario will need to be determined by the additionality tests described in section D.3. This methodology proposes an analysis of legal requirements and, principally, the use of barrier analysis in order to determine if the proposed project activity is additional. If application of the methodology can demonstrate that the proposed project activity is additional, the baseline scenario would be a continuation of the historical pattern of fuel use and electricity generation and purchase as necessary. The baseline scenario is determined in a dynamic manner, from monitored data following project implementation. If additionality cannot be demonstrated, the project scenario is not different from the baseline scenario, and no CDM project can be based on the proposed project activity.

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

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The proposed methodology is based on approved consolidated methodologies: ACM0002 "Consolidated baseline methodology for grid-connected electricity generation from renewable sources" and AMS I.D "Renewable electricity generation for a grid".It also incorporates the approved Tool for demonstration and assessment of additionality, and applies this for the types of project activities covered in the proposed new methodology.

The proposed methodology covers electricity cogeneration at an industrial facility. The impact of such generation on an interconnected power system is similar to that from CDM projects involving renewable electricity generation connected to the grid. The Approved Consolidated Methodology ACM0002 or AMS I.D would thus be applicable even though the project does not involve renewable energy. (Note that in the approved methodology AM0014, which involves cogeneration of electricity at an industrial facility using a non-renewable fuel, the Methodology Panel recommended, and the CDM Executive Board approved, the use of ACM0002 or AMS I.D in order to determine emissions reductions in the grid corresponding to cogenerated electricity at the industrial facility.)

Electricity generation or cogeneration using a fossil fuel would result in CO_2 emissions, and such emissions are accounted for in the proposed methodology.

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 methodology proposed here uses the Tool for demonstration and assessment of additionality (Oct. 2004, published as Annex 1 to EB 16 Report). However, in order to adapt the Tool for the specific type of project activities covered by the proposed methodology, we incorporate the Tool within this methodology. In the discussion that follows, we first present "within quotes" the original text of the additionality tool, followed by comments in order to apply the tool for the specific project activity, if necessary.

"Step 0. Preliminary screening based on the starting date of the project activity

"The Marrakesh Accords and decision 18/CP.9 provide guidance on the eligibility of a proposed CDM project activity which started before registration.

"1. If project participants wish to have the crediting period starting prior to the registration of their project activity, they shall:

(a) Provide evidence that the starting date of the CDM project activity falls between 1 January 2000 and the date of the registration of a first CDM project activity, bearing in mind that only CDM project activities submitted for registration before 31 December 2005 may claim for a crediting period starting before the date of registration; and

(b) Provide evidence that the incentive from the CDM was seriously considered in the decision to proceed with the project activity. This evidence shall be based on (preferably official, legal and/or other corporate) documentation that was available to third parties at, or prior to, the start of the project activity."

We find no need to modify Step 0 of the tool for the project activities considered here. In order to proceed with the additionality test, the project proponent must show that the project is not retroactive or provide independently verifiable evidence that CDM was seriously considered prior to the decision to proceed with the project activity.

"Step 1. Identification of alternatives to the project activity consistent with current laws and regulations

(Note: In accordance with guidance by the Executive Board, consistency is to be ensured between "baseline scenario" and "baseline emissions")

"Define realistic and credible alternatives 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 that provide outputs or services comparable with the proposed CDM project activity[1]. 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;
- If applicable, continuation of the current situation (no project activity or other alternatives undertaken)."

It is our view that there are an infinite number of possible project activities that may be undertaken at a given project site. For instance, at an industrial site, one could add cogeneration equipment with any power output within a wide range of magnitudes, from very small where only a small part of the on-site power demand is met by the power plant being considered, to very large capacities, far exceeding the on-site power demand. Moreover, the power generation may be based on a number of technologies applicable to fossil fuels (gas turbine, internal combustion engine, steam turbine, combined cycle, etc.). Such technologies could be based on the use of any one or a combination of fossil fuels, although of course not all fossil fuels can be used with all technological alternatives.

However, we believe that the infinite number of possible project activities may all be considered as a single *type*: cogeneration at an industrial facility, and the methodology would determine if this type of project activity can be additional, and if so, what the appropriate baseline would be.

The sub-step 1a of the tool requires us to *"identify realistic and credible alternative(s) available to the project participants or similar project developers that provide outputs or services comparable with the proposed CDM project activity."*

A footnote in the tool adds this explanation:
"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."

If we consider other project developers that could provide the same heat output for on-site use and electricity for on-site use and for export, the viable alternative is "package cogeneration", whereby a third party invests in a cogeneration plant at the industrial facility and sells electricity and heat to that facility. One methodology applicable to package cogeneration has already been approved (see AM0014). However, package cogeneration could be an alternative to the project scenario and needs to be considered as a possible baseline scenario.

In principle it is possible to exchange thermal energy between an industry and other sites. However, this is not common, and is not contemplated in this methodology. The proposed methodology is thus not applicable to projects involving thermal energy transfer in or out of the industrial plant site.

Thus the alternatives that need to be considered as possible baselines are the following:

[1] 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.

- The industry continues to generate thermal energy and power using existing equipment using the same combination of fuels as in the recent past.
- The project proponent installs or increases the cogeneration capacity using steam turbines, gas turbines, internal combustion engines or other technologies, using the waste heat to meet on-site thermal energy demand. Any combination of fuels would be admissible as variants on this alternative. Electricity generated would be used at the industrial site and excess electricity would be exported through the grid. This is indeed the project activity, so that this alternative implies undertaking the activity without CDM registration.
- A third party installs cogeneration capacity at the industrial facility, of any magnitude, with any technology and fuel, selling thermal energy and electricity to the industry and selling any excess electricity through the grid.

The alternatives to the current situation may be implemented immediately or at any time in the future. In the most extreme case, cogeneration equipment is already present at the industry, this equipment is close to the end of its useful life, and a proposed project activity comprises replacing this equipment with new cogeneration equipment of the same power output. This is clearly not additional.

This methodology applies to a specific project *type*: add or install cogeneration using any technology and any fuel. Thus even if the replacement cogeneration equipment were of a more efficient technology or used a different fuel, this methodology would not consider any of those alternatives as additional.

The situation is more complex when the new cogeneration equipment to be installed provides higher power output than the cogeneration system it replaces. However, in order to be conservative, this methodology would not consider such an expansion to be additional, when the existing cogeneration equipment is close to the end of its useful life.

Indeed, we place a highly conservative restriction on the applicability of this methodology: *the crediting period cannot be more than the life of any existing cogeneration equipment at the industrial facility*. Specifically, this condition applies to any equipment that provides both electricity and heat, such as diesel engines, steam turbines, gas turbines used for cogeneration.

The additionality tool continues with:
"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. (This sub-step does not consider national and local policies that do not have legally-binding status).

"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 noncompliance 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."

Note here that applicability of laws and regulations described above is in line with the CDM Modalities and Procedures, paragraph 45(e), which states:

"45. A baseline shall be established:

…
"(e) Taking into account relevant national and/or sectoral policies and circumstances, such as sectoral reform initiatives, local fuel availability, power sector expansion plans, and the economic situation in the project sector."

Articles 2, 3, and 4 of the Additionality Tool, cited above, are consistent with 45(e).

However, it was felt that this requirement may lead to the perverse situation, whereby countries or regions decide not to implement environmental legislation in order not to lose project additionality. To prevent such a perverse incentive, the CDM Executive Board has issued "*Clarifications on the treatment of national and/or sectoral policies and regulations in determining a baseline scenario*." (CDM Executive Board, 16th Meeting report, Annex 3.)

This document identifies four types of national and/or sectoral policies in determining a baseline scenario, including:

> "Type E+: Existing national and/or sectoral policies or regulations that create policy-driven market distortions which give comparative advantages to more emissions-intensive technologies or fuels over less emissions-intensive technologies or fuels.
>
> "Type E-: National and/or sectoral policies or regulations that give positive comparative advantages to less emissions-intensive technologies over more emissions-intensive technologies (e.g. public subsidies to promote the diffusion of renewable energy or to finance energy efficiency programs)."

In order to prevent perverse incentives and to encourage such legislation, these Clarifications state that:

> "2. Only "Type E+" national and/or sectoral policies or regulations that have been implemented before adoption of the Kyoto Protocol by the COP (decision 1/CP.3, 11 December 1997) shall be taken into account when developing a baseline scenario. If "Type E+" national and/or sectoral policies were implemented since the adoption of the Kyoto Protocol, the baseline scenario should refer to a hypothetical situation without the national and/or sectoral policies or regulations being in place.
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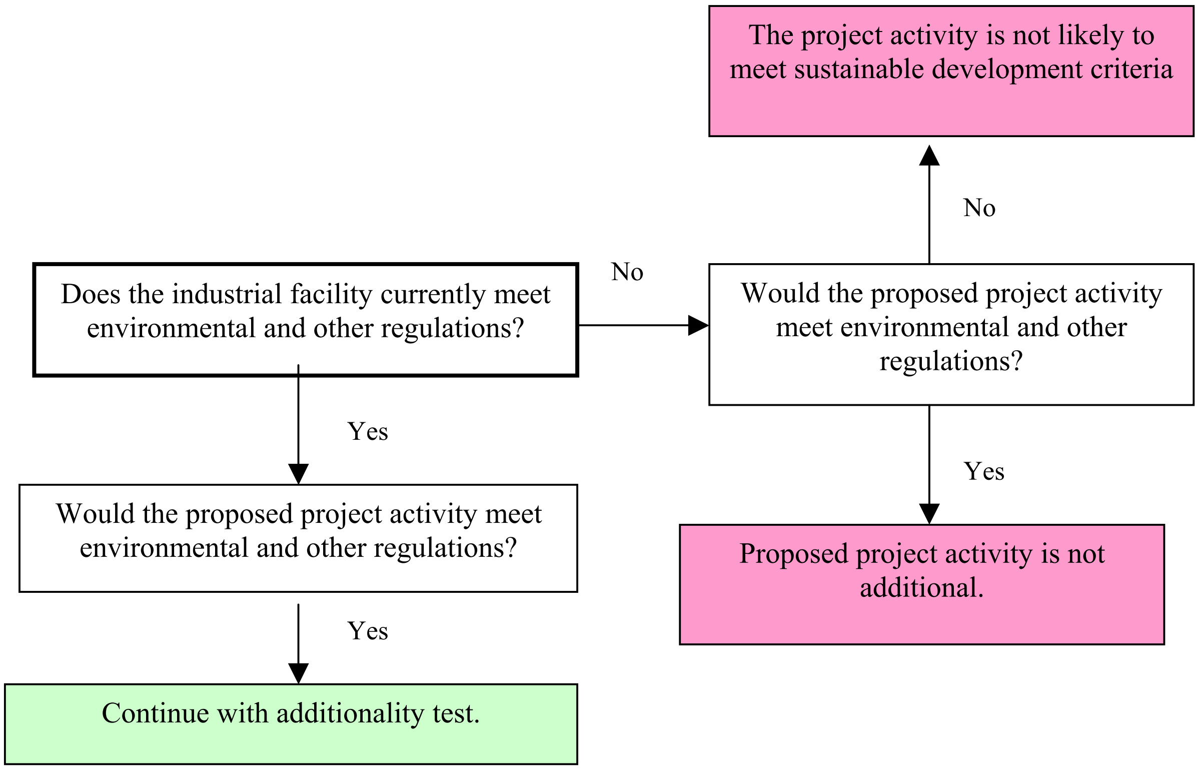
> "3. "Type E-" national and/or sectoral policies or regulations that have been implemented since the adoption by the COP of the CDM M&P (decision 17/CP.7, 11 November 2001) *may not be taken into account in developing a baseline scenario (i.e. the baseline scenario should refer to a hypothetical situation without the national and/or sectoral policies or regulations being in place)*." (Emphasis added.)

Clearly the requirements of CDM M&P 45(e) as interpreted by Articles 2, 3 and 4 of the additionality tool are inconsistent with Article 3 of the "Clarifications." We believe the Clarifications do not represent a definitive document, insofar as it leaves pending appropriate guidelines for two of the four types (L+ and L-) of national and sectoral policies defined in the document. Moreover, the original position expressed in CDM M&P 45(e) is more conservative. Furthermore, this methodology relies heavily on barriers analysis in order to determine additionality. We therefore adopt the more conservative position that if the proposed project activity is a consequence of meeting national and/or sectoral policies, then it is not additional.

Whether the project activity is being implemented in order to comply with existing regulations, can be determined using the following flowchart.

For cogeneration projects at an industrial facility, that may involve some fuel shifting in order to operate the cogeneration equipment, in order to demonstrate whether regulations are met, the project sponsor

needs to consider any requirements not to use certain fuels, such as coal and/or fuel oil, as well as any regulations that require theimplementation of cogeneration in certain classes of industrial facilities.



Note that minor infractions of environmental and other regulations that occur from time to time even in the best run industries need not be included.

If the proposed project activity passes Sub-step 1(b), above, the additionality tool then states:
"Proceed to Step 2 (Investment analysis) or Step 3 (Barrier analysis). (Project participants may also select to complete both steps 2 and 3.)"

The tool introduces Step 2 thus:
"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)."

While the project activity comprises a single *type* of activity: adding or increasing the capacity of a cogeneration system, there are an infinite number of possible alternatives within the type, differing in technology, power output, fuel input, etc., and each of these possibilities would need to be considered as a possible baseline, e.g. without CER revenues, as well as continuing the current situation where none of the alternatives are undertaken. We believe that a complete economic analysis considering all possible alternatives is clearly unrealistic.

The methodology proposed here will be based entirely on Step 3: Barrier analysis. The project proponent needs to show that ***all*** possible alternatives, other than continuing the current situation, face barriers so that the only viable baseline comprises continuing the current situation.

Thus we skip Step 2 of the additionality tool and proceed directly to Step 3.

The tool states:

"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."

To this list provided in the additionality tool, we may add another type: Institutional barriers. This category of barriers was included in the additionality tests for AM0014, which also refers to cogeneration projects.

"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;

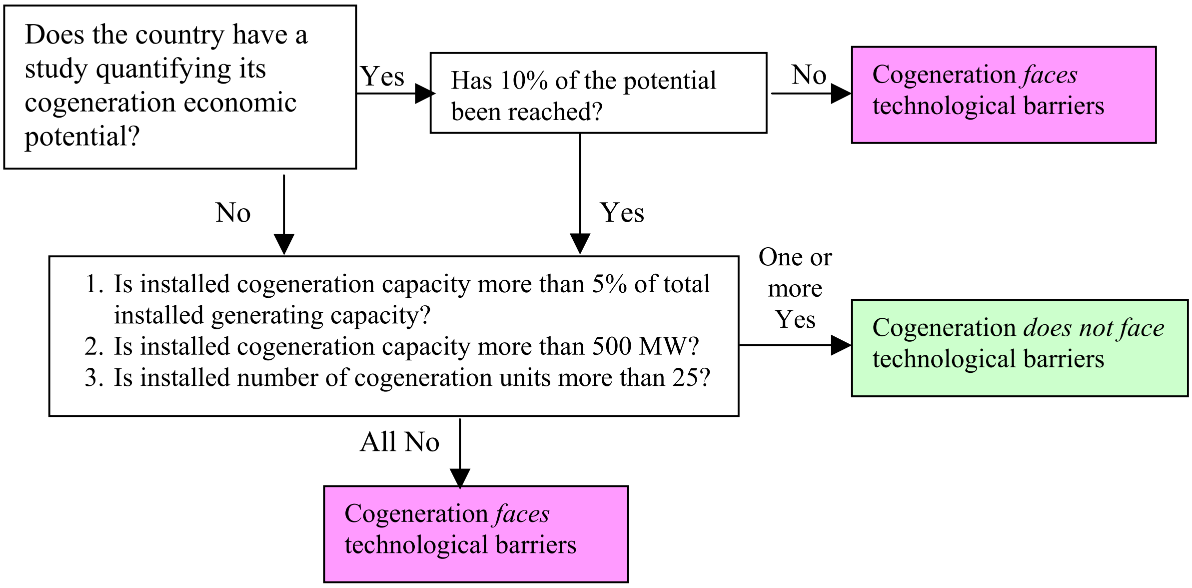
(g) Written documentation of independent expert judgements from industry, educational institutions (e.g. universities, technical schools, training centres), industry associations and others.

Note that Sub-step 3(a) of the tool refers to the "*type* of project activity," and we need to show that this type faces barriers.

We may expect the barriers to be Investment barriers, Technological barriers, or Barriers due to prevailing practice.

The presence of investment barriers can be evaluated as stated in the additionality tool, and cited above.

We consider "barriers due to prevailing practice" within the class of technological barriers, and evaluate the presence of both through the following flowchart.

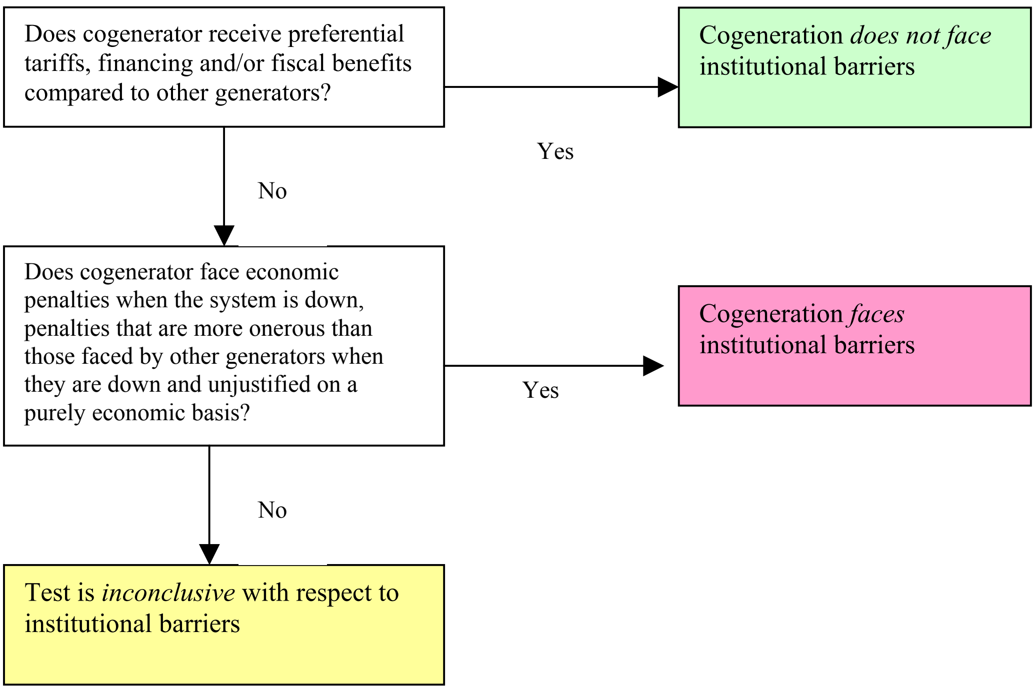


The values in this flowchart are not arbitrary. These are the values accepted by the Meth Panel in AM0014.

Next we consider *Institutional barriers:* Are there institutional barriers to cogeneration in general?

This additionality test is applied by following the flow chart below. It should be noted that even if preferential tariffs or other incentives do exist, they may not be sufficient to promote cogeneration.

A serious barrier may be present, especially in deregulated power systems. All electricity users may have to pay the maximum demand charge for the whole year. Thus, when the cogeneration system is not operating (due to routine maintenance or forced outage), the user of electricity would have to purchase the electricity from the power grid. While this period may be small, the purchase may involve paying for the power demand (kW) for the whole year. This is a significant penalty for users of cogeneration systems.



If the proposed project activity is shown to face barriers, the tool states:
"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."

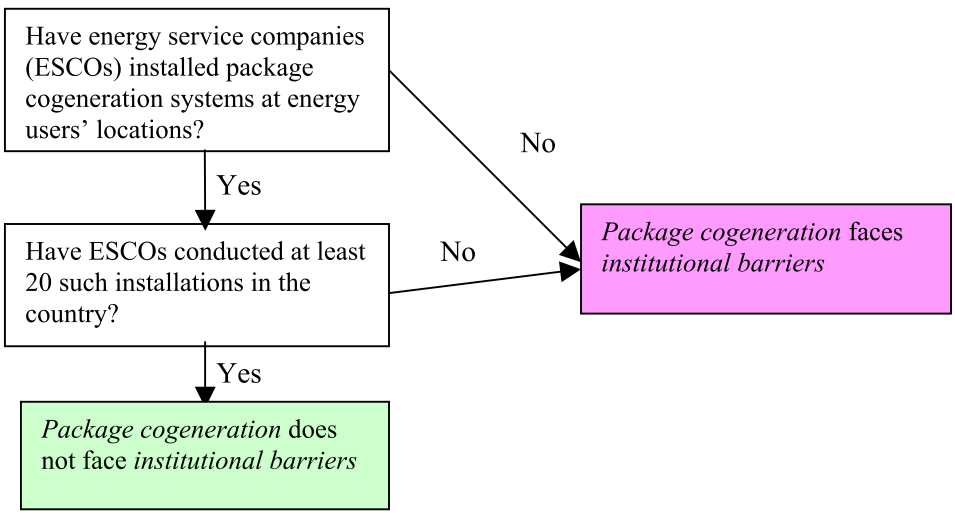
There are two alternatives to the proposed project activity: continuing with the current situation or that a third party (e.g. an Energy Services Company, ESCO) undertakes the cogeneration project at the industrial plant, i.e. package cogeneration.

Clearly, continuing with the current situation does not face either the investment barrier or the technological barrier. We therefore need to consider barriers facing package cogeneration. In general, the package cogeneration alternative would also face the technological barriers faced by the project proponent installing their own cogeneration system. In that case, this alternative faces these barriers as well as any others faced by third party investment in industrial cogeneration.

In this case, the ESCO invests in and installs the cogeneration system at the industrial user site, and provides electricity and *heat* to that user. This institutional arrangement requires project developer to have special management resources and organizational capacity, and for the industrial energy user to accept this arrangement. Where such experience is lacking, promoting the new arrangement involves a significant institutional barrier.

The test to determine whether package cogeneration faces institutional barriers basically constitutes an evaluation of prevailing practice. In other words, is there enough experience in which one company installs a cogeneration system at the location of a separate energy user?

The test is described in the following flowchart.



As we have stated above, package cogeneration is likely to face both technological and institutional barriers. If project proponent can demonstrate that this alternative faces more barriers than the project alternative, then clearly continuing current practice (which faces no barriers) is the baseline. In that case, Sub-step 3(b) is satisfied.

The additionality tool states:
"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.

This methodology incorporates an evaluation of common practice within its determination of technological barriers to industrial cogeneration. If the project proponent incorporates an analysis of technological barriers, *including barriers due to prevailing practice*, in Sub-step 3(a), then the proposed project activity also meets the conditions of Sub-step 4.

However, if barriers due to prevailing practice was not invoked in Sub-step 3(a), then Sub-steps 4(a) and 4(b) need also to be undertaken.

Finally, the additionality tool indicates:
“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.”

For the type of project activity considered in this methodology, the first two items of this list are likely to be most relevant. The project activity reduces GHG emissions with respect to the baseline and generates revenues. However, other benefits may be relevant as well. CDM may provide incentives to obtain financing or involve players with more experience in cogeneration, etc.

To the list of potential benefits of CDM registration presented in the additionality tool, one could add another: the environmental image of the project proponent. The project activity could involve the installation of cogeneration at a large national or multinational company. Large companies are often more questioned on their environmental performance. Implementing a project that reduces GHG emissions, with the project getting international recognition through CDM registration, can be an additional motivation for the project proponent to undertake the activity within the CDM.

The proposed project activity needs to be analysed in this context in order to demonstrate that Step 5 can be satisfied. This would confirm the demonstration of project additionality, as stated in the additionality tool:

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:

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The type of activity involves equipment changes at an industrial facility. Such changes generally must meet legal requirements, often including environmental impact assessment. If the proposed project is required by the laws or regulations, the project scenario would not be additional. Similarly if there are special incentives to promote project activities similar to those proposed, again the activity would not be additional. All these issues are taken into consideration in the Tool for demonstration and assessment of additionality mentioned in section D.3. As a part of that determination, the project proponent is required to:

- Analyse legal requirements and obligations with respect to the project activities.

- Analyse national incentives to promote similar project activities.
- Analyse sectoral policies to promote similar project activities.

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

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The project boundary could encompass the physical, geographical site of the industrial plant. If there is an energy facility at the industrial plant, where fuels are consumed to produce heat and/or electricity then it might be convenient to limit the project boundary to this energy facility. Schematically, Figure D.5.1 shows the project boundary, indicating energy flows into the boundary and GHG emissions associated with fuel combustion within the project boundary. We consider all fuels used both in the baseline scenario and in the project case. This indicates that the project boundary is applicable both for the baseline analysis as well as for monitoring of emissions following project implementation, and emissions reductions.

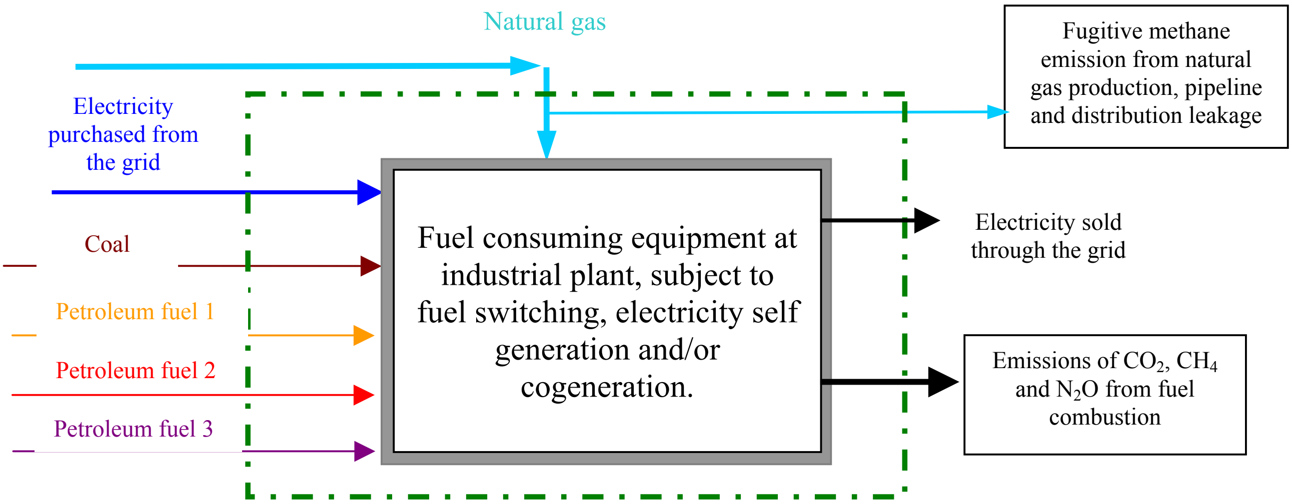

Fig. D.5.1. Project boundary

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):

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The baseline scenario for the project, which is eligible to use 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 the existing facility to produce heat and electricity without any substantial investments in equipment to increase the electric power output of the facility. Existing cogeneration equipment should have a lifetime exceeding that of the crediting period for this methodology to be applicable.

Baseline and project emissions depend mainly on fuel consumption within the project boundary, which may include the entire industrial facility or an energy facility located within the industrial facility.

Emissions also depend on electricity purchases from the interconnected grid and electricity sales to the grid. Electricity purchased through the connected power grid to meet a part or all of the demand at the facility in the baseline would cause emissions elsewhere in the power grid. These emissions need to be included in baseline emissions. If, following project implementation, electricity is sold from the industrial facility through the power grid, then emissions would be offset elsewhere in the grid. In the absence of such electricity supply in the baseline scenario, there would be additional emissions in electricity generation, *which are also included in baseline emissions*.

Baseline emissions depends on fuel consumption in the baseline scenario, net power purchase from the grid in the baseline scenario and net power sales in the project scenario.

Baseline emissions *BE* (expressed in tonne CO_2equivalent per year, tonne CO_2e/yr) are given by:

$$BE = \sum_i BFC_i (EF_i + MEF_i \cdot GWP(CH_4) + NEF_i \cdot GWP(N_2O)) + (NBEP + NPES) \cdot EF_{elec\ gen} \tag{Eq. 6.1}$$

where:

BFC_i	consumption of fuel *i* used in the baseline scenario, measured in energy units (e.g. gigajoule, GJ)
EF_i	carbon dioxide emission factor per unit energy of fuel *i* (e.g. tCO_2/GJ) (combustion)
MEF_i	methane emission factor per unit energy of fuel *i* (e.g. tCH_4/ GJ) (combustion)
$GWP(CH_4)$	global warming potential of CH_4 set as 21 tCO_2e/tCH_4 for the 1st commitment period
NEF_i	nitrous oxide emission factor per unit of energy of fuel *i* (e.g. tN_2O/ GJ) (combustion)
$GWP(N_2O)$	global warming potential of N_2O set as 310 tCO_2e/tN_2O for the 1st commitment period
$NBEP$	net electricity purchased (electricity purchased less electricity sold) through the grid in the baseline (e.g. MWh)
$NPES$	net electricity sold (electricity sold less electricity purchased) through the grid in the project scenario (e.g. MWh)
$EF_{elec\ gen}$	baseline emission factor for grid electricity generation (e.g. tCO_2e/MWh)

Note that we consider *net* electricity purchase from the grid in the baseline scenario and *net* electricity sold through the grid in the project scenario, as explained in the definitions of *NBEP* and *NPES*.

Let us clarify this point. Let us suppose that prior to project implementation, the industry generally purchases electricity to meet some or all of its power demand. A part of the power demand could be met by existing self-generation or cogeneration equipment[2]. In this case, net electricity purchases are positive and imply emissions at power plants elsewhere in the interconnected grid. Thus, electricity purchases in the baseline scenario imply additional emissions that need to be added (as long as electricity purchases are positive).

Now let us assume that in the project scenario, after the new cogeneration system has been installed, the industry is a net exporter of electricity, i.e. total electricity generation exceeds on-site demand and the excess is exported. This part of the project scenario is similar to that of any power plant whereby electricity generated at the power plant and exported to the grid *reduces* emissions from power generation elsewhere in the grid.

This is similar to electricity generation through renewable energy sources, whereby reduction in emissions in the project scenario (i.e. with renewable power generation) is considered to be emissions in the baseline scenario rather than "negative emissions" in the project scenario. This is the approach taken in ACM0002 and other approved methodologies.

Thus, we consider *net* electricity sales to the grid in the *project* scenario as contributing to *baseline* emissions.

[2] The emissions on-site are already included as emissions from fuel combustion at the site.

Of course, in a specific project, the *net* purchases in the baseline scenario could be negative, if the industry is already generating more electricity than on-site demand prior to project implementation. Alternatively, *net* electricity sales in the project scenario could be negative if, even after the project implementation of cogeneration, the power output is less than on-site demand. These possibilities do not change the concept, if we allow for the "net purchases" or "net sales" to be algebraic, i.e. with either positive or negative values.

Note that *net* electricity purchases in the baseline scenario and *net* electricity sales in the project scenario are determined from monitored data of electricity transfers with the power grid. In other words, if the interconnected grid cannot supply electricity or cannot receive electricity from the project site at any time for shortages or excess capacity or other reasons, these limitations to electricity transfers would not cause errors in emissions reductions estimates. Therefore, it is not necessary to assess the capacity of the grid or whether the power demand of the grid is growing or declining.

In the typical project, both terms, $NBEP$ and $NPES$, are expected to be positive. However, equation (6.1) remains equally valid if one or other of these quantities were to be negative.

The emissions associated with electric power generation depend on the sum $NBEP + NPES$ and multiplied by $EF_{elec\ gen}$, the emissions factor for electricity generation in the connected power grid.

Note that the emissions factor of the connected power grid do not depend on how electricity is generated in the proposed project activity. Thus 1 kWh generated and exported from an industrial cogeneration facility would reduce emissions elsewhere in the power grid by exactly the same amount as if that kWh were generated using renewable energy sources. While the kWh generated by a cogeneration plant would have emissions, these are already accounted for as emissions from all fuels burnt at the industrial facility.

Thus the emissions factor for electricity generation, $EF_{elec\ gen}$, is no different from the emissions factor for power generation on a grid on which a CDM renewable power project is to be added. The CDM Methodology Panel and Executive Board have already proposed a consolidated methodology for determining $EF_{elec\ gen}$ from renewable sources. We recommend the use of this Approved Consolidated Baseline Methodology (ACM0002) or the Small-scale Methodology (AMS I.D) as a component of the proposed new methodology, for the purpose of determining $EF_{elec\ gen}$. Note that another new methodology submission, "Natural gas-based package cogeneration", was accepted as AM0014 under the condition that the consolidated methodology for grid-connected electricity generation from renewable sources be used.

ACM0002 offers some alternative pathways for determining $EF_{elec\ gen}$, and each specific PDD should adopt a specific procedure, according to its circumstances.

If power output from the cogeneration plant exported to the grid is less than 15 MW, then another methodology may be used for estimating $EF_{elec\ gen}$, namely the "Simplified Methodology for Small-scale CDM Project activities." AM0014 offers an alternative procedure.

Thus, this proposed new methodology recommends the use of either ACM0002 or AMS I.D, as appropriate, in order to determine the emissions factor for power generation at the interconnected grid.

This methodology recommends the use of *ex-ante* estimates of both baseline and project emissions for use in the PDD formulation. However, baseline and project emissions used for calculating and crediting emissions reductions would be based on monitored data. These are called *ex-post* emissions. In order to

compensate for variations in emissions due to changes in industrial output, *ex-post* baseline emissions would be determined in a dynamic manner from monitored data.

Procedure for determining *ex-ante* baseline and project emissions

A cogeneration project involves taking advantage of heat flows at different temperatures and pressures in order to generate electricity or use as heat. This necessarily involves a thermodynamic analysis of equipment configuration expected after project implementation. Thus in order to make ex-ante estimations of project emissions we recommend a thermodynamic analysis supported by performance specifications from the equipment supplier for more accurate estimations.

Ex-ante baseline emissions could be determined either by thermodynamic analysis or from actual historical data on fuel consumption and electricity generation. However, in order to be compatible with assumptions made for thermodynamic analysis of project performance, we recommend the use of thermodynamic analysis in order to determine ex-ante baseline emissions, using the same values for industry heat and electricity demand as in the project thermodynamic analysis. The input data for baseline thermodynamic analysis may be based on equipment specifications and/or measured performance data.

We recognize that thermodynamic analysis cannot be easily and completely verified by the validator. However, we should keep in mind that this analysis is only the basis for estimating *ex-ante* emissions reductions to be reported in the PDD. Thermodynamic analysis is ***not*** the basis for monitored emissions reductions. This approach is similar to that used for landfill gas recovery, where the emissions reductions are estimated by a theoretical model in the PDD. The model parameters are impossible to check prior to project implementation. However, emissions reductions are determined by measurements and are not based on the model predictions. In the proposed methodology, as well as in approved landfill gas recovery methodologies, the measurements lead to a rigorous determination of emissions reductions.

Procedure for determining *ex-post* baseline and project emissions

Ex-post project emissions are determined from measurements of fuel consumption at the industrial facility to generate electricity and to provide thermal energy.

Baseline emissions depend not only on fuel consumption at the project site in the baseline scenario but also on both *net* electricity purchases in the baseline scenario and *net* electricity sales in the project scenario.

This methodology recommends that baseline fuel consumption be determined in a dynamic manner from project monitoring data. In general, baseline emissions would change depending on the activity level of the industry in question. Thus, we propose that an appropriate indicator of activity level be chosen in such a way that this indicator can be monitored following project implementation, and the baseline emissions may be adjusted by this indicator.. However there could be a problem in identifying the right indicator.

Consider for example a factory producing a single chemical, e.g. ammonia. Then the total output (weight) of the chemical in a given period of time (e.g. day) would be the ideal indicator of activity level. From actual, historical data, we would know the statistical relationship between baseline fuel consumption (and emissions) and activity level. Thus, following project implementation, we would only need to keep track of the activity level (e.g. total ammonia production in a day) in order to determine baseline emissions corresponding to the level of activity actually observed.

However, if an improvement were to occur in end-use efficiency, so that less heat and/or electricity were needed to produce a tonne of ammonia (considering the same example), then this reduced energy demand would be reflected as reduced fuel consumption at the cogeneration facility, thereby reducing project

emissions. Baseline emissions, scaled by activity level (e.g. ammonia production) would remain unchanged, so that emissions reductions would be artificially increased.

This methodology is applicable to industrial cogeneration without increase in end-use energy efficiency. It is not the purpose of the methodology to inhibit energy efficiency improvements, but rather to exclude any emissions reductions from efficiency improvements from being counted.

While the cogeneration system produces both heat and electricity, the project activity increases electricity generation, thus leading to reduced electricity purchase from the interconnected grid, or even electricity sales through the grid. Thus the electric power output of the cogeneration system is *not* a measure of industrial activity level. This methodology thus recommends the use of steam output from the cogeneration system as a measure of industrial activity level.

Note that if cogeneration steam demand decreases, either through reduced activity level (less ammonia production) or through end-use energy efficiency improvements, this would affect *both* project and baseline emissions, so that there will be no undue increase in emissions reductions.

Note also that steam output as the indicator of industrial activity level causes no problems when the industry output comprises many different products, which is the more general case.

Cogeneration steam output may take place at different temperatures and pressures, with different thermodynamic values. The different qualities of steam could be added in terms of their enthalpies (i.e. heat content) or in terms of their ability to do work (i.e. available energy or exergy). However, the work output of the cogeneration system has already been accounted for as electric power output, so that the heat output of cogeneration can be counted in terms of its enthalpy content, without committing any thermodynamic error.

When the cogeneration system produces steam at different temperatures and pressures, this methodology recommends that the total heat output be determined by summing the enthalpies of all steam output streams.

Ex-post baseline emissions will be determined in a dynamic manner from project monitoring data through the following steps:

1. From historical data, determine the relationship between fuel input and total steam enthalpy output and total electric power output (if any).
2. If more than one fuel type is used prior to project implementation, determine average ratio of fuel input of different fuels, again from historical data.
3. Following project implementation, determine total enthalpy value of steam produced by the cogeneration system from monitored data.
4. Using the historic relationship (step 1 above), determine baseline fuel consumption and electric power output corresponding to the measured data on steam output following project implementation. When more than one fuel is used prior to project implementation, determine consumption of each fuel using historical ratios of the different components (step 2 above). These are the values of BFC_i.
5. From the step 4 estimate of electric power output and monitored power demand of industry, determine net purchase of electricity from the grid in baseline, *NBEP*.
6. From monitored data of electricity sold through the interconnected grid following project implementation, determine electricity sale through the grid, NPES.
7. Use Eq. (6.1) to calculate baseline emissions using BFC_i from Step 4, *NBEP* from Step 5, and *NPES* from Step 6.

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):

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The project activity involves installing or increasing cogeneration capacity for providing heat and electricity at an industrial facility. The increased electricity generation at the facility could lead to a situation where generation exceeds on-site electricity demand, so that the excess electricity would be exported through the interconnected power grid. Note that electricity exported through the grid would reduce emissions elsewhere in the power grid. Looking at it another way, if the project activity did not export this amount of electricity, the same amount would need to be generated elsewhere in the grid. Thus emissions corresponding to net electricity exports in the *project* scenario correspond to emissions in the *baseline* scenario, as explained in the description of the baseline emissions.

The project emissions *E* (expressed in tonnes of CO_2 equivalent, tCO_2e/yr) are determined by fuel consumption at the project site and are given by :

$$E = \sum_i FC_i \cdot (EF_i + MEF_i \cdot GWP(CH_4) + NEF_i \cdot GWP(N_2O)) \qquad \text{(Eq. 7.1)}$$

FC_i	consumption of fuel *i* used in the project scenario, measured in energy units (e.g. gigajoule, GJ)
EF_i	carbon dioxide emission factor per unit energy of fuel *i* (e.g. tCO_2e/GJ) (combustion)
MEF_i	methane emission factor per unit energy of fuel *i* (e.g. tCH_4/GJ) (combustion)
$GWP(CH_4)$	global warming potential of CH_4 set as 21 tCO_2e/tCH_4 for the 1st commitment period
NEF_i	nitrous oxide emission factor per unit energy of fuel *i* (e.g. tN_2O/GJ) (combustion)
$GWP(N_2O)$	global warming potential of N_2O set as 310 tCO_2e/tN_2O for the 1st commitment period

Additional details on emissions associated with electricity generation in the power grid outside the project facility, including the methodology to be used in order to estimate such emissions, were also presented in D.6.

Prior to project implementation, an *ex-ante* estimate of project emissions can only be obtained through a thermodynamic analysis, based on design configuration and operation of equipment involved in the project activity. Thermodynamic analysis would determine the expected fuel consumption and changes in electricity generation following project implementation, to provide a certain level of steam output in order to meet industry demand. Once fuel consumption is estimated through thermodynamic analysis, corresponding emissions can be determined using Eq. (7.1) In order to be consistent, this methodology recommends the use of thermodynamic analysis for ex-ante estimates of baseline emissions as well. In the two thermodynamic analyses, steam output of the system in the baseline and project scenario is maintained constant at a value typical of operating conditions prior to project implementation. The thermodynamic analysis should be based on equipment performance parameters provided by equipment supplier (and/or determined from independent measurements). Thermodynamic analysis should provide temperature, pressure and mass flow rates at all conditions, so that the validator can readily check the results of the analysis.

Recall that thermodynamic analysis is the basis for *ex-ante* project (and baseline) emissions. This analysis is not the basis for estimating emissions reductions that would eventually be certified. The actual emissions reductions would be determined from *ex-post* estimates of project and baseline emissions.

For *ex-post* baseline emissions would be determined in a dynamic manner from monitored data following project implementation, as explained in section D.6.

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

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Fugitive CH_4 emissions from fuel production and CO_2 emissions from fuel transportation are categorized as leakage. Emissions from fuel production/transportation are counted only if the fuel is produced/transported in a non-Annex I country.

The leakage LE_y is expressed as

$$\begin{aligned} LE = & \left(FC_i - BFC_i\right) \bullet FE_i\left(CH_4\right) \bullet GWP\left(CH_4\right) \\ & + \sum_i TF_i \bullet EF_i - \sum_i BTF_i \bullet EF_i \end{aligned} \qquad \text{(Eq. 8.1)}$$

where FC and BFC are consumption estimates for fuel *i* as before, and
$FE_i\left(CH_4\right)$ is the IPCC default methane emission factor of fuel *i* associated with fugitive emissions.

Typical fuels might be natural gas and coal, the former more likely in the project scenario and the latter more likely in the baseline. Fugitive methane emissions are associated with natural gas production and pipeline leakage. Fugitive methane emissions are also associated with coal mining. In case that the effect of these methane emissions cannot be neglected, they should be included here.

The second line in the above formula refers to emissions from fuel transportation, shown as a product of the transportation fuels used (TF_i in the project scenario and BTF_i in the baseline scenario) and the corresponding CO_2 emissions factor for the fuel *i* (EF_i). The first sum applies to transport fuels used in the project scenario while the second corresponds to the baseline scenario (such as marine, railroad or truck). In case the information and data are not available due to uncertainties and diversities in energy market, the IPCC default value could apply. Note that the magnitude of CO_2 emissions from fuel transportation in typical industrial fuels is relatively small, so the expression in the second line is not important.

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 emissions reduction by the project activity, ER, expressed in tonnes of CO_2 equivalent (tCO_2e/yr), are given by:

$$ER = BE - E - LE \qquad \text{(Eq. 9.1)}$$

where

ER	annual emission reductions, in tonnes of CO_2 equivalent (tCO_2e/yr).
BE	annual baseline emissions, in tonnes of CO_2 equivalent (tCO_2e/yr).
E	annual project emissions, in tonnes of CO_2 equivalent (tCO_2e/yr).
LE	annual leakage emissions, in tonnes of CO_2 equivalent (tCO_2e/yr).

Total emission reductions are calculated *ex ant*e, using estimated values for BE and E obtained by thermodynamic analysis, and the application of Eq (6.1) for baseline emissions and Eq. (7.1) for project emissions. The *ex-ante* estimate of total emission reductions shall be reported in the PDD submitted for validation.

Ex post project emissions (E) are determined from monitored values of fuel consumption. Ex-post baseline emissions (BE) are determined in a dynamic manner as explained in Sec. D.6. The *ex-post* estimate of emissions reductions will form a part of the monitoring procedure and will be the basis for verification and certification of emissions reductions.

SECTION E. Data sources and assumptions:

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

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The parameters are listed together with data sources in the section below.

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:

>>

The determination of baseline emissions depends on measurements of the consumption of each fuel used in the baseline scenario as well as electricity purchases and sales in the baseline and project scenarios.

Fuel consumption is measured prior to and following project implementation.

Moreover, the calculation depends on the values of the following parameters, whose sources are given below:

Symbol	Definition	Data source (in order or preference) and justification
EF_i	carbon dioxide emission factor per unit energy of fuel *i* (e.g. tCO_2/GJ) (combustion)	1. National inventory of GHG emissions, prepared as part of National Communications to the UNFCCC or other official documents. This is the most important emissions factor and thus needs to be based on the most reliable and specific data source as possible. 2. On-site measurements of carbon content and calorific value of fuels. This would be recommended for fuels where there is significant variation in properties and/or when the fuel is not widely commercialised. 3. IPCC default emissions factors. This is the last choice, and should be used only where data from other sources are not available.
MEF_i	methane emission factor per unit energy of fuel *i* (e.g. tCH_4/GJ) (combustion)	IPCC default values. Methane emissions from fuel combustion are likely to be insignificant so that standard values should suffice to provide an adequate estimate.
NEF_i	nitrous oxide emission factor per unit of energy of fuel *i* (e.g. tN_2O/GJ) (combustion)	IPCC default values. Nitrous oxide emissions from fuel combustion are likely to be insignificant so that standard values should suffice to provide an adequate estimate.
$EF_{elec\ gen}$	baseline emission factor for grid electricity generation (e.g. kg CO_2e/MWh)	Determined using either: ▪ ACM0002: Approved consolidated methodology for grid-connected renewable electricity generation from renewable sources. ▪ AMS I.D, where power export from the industry to the grid is less than 15 MW: Simplified methodology for small-scale CDM project activities

Ex-ante baseline emissions estimate depends on a thermodynamic analysis of the process involved. The results depend on mass flow rates as well as efficiency of heat and electricity producing equipment. All values should be based on historically measured values. A preferred source of thermal efficiency data would be based on direct measurements of heat output and fuel input. When this is not possible, efficiency measurements may be based on stack gas analysis (measurements of temperature and oxygen or CO_2 concentration).

Similarly, *ex-ante* project emissions based on thermodynamic analysis should be based on the same assumptions on mass flows, overall heat and electricity output. For equipment introduced as part of the project activity, catalogue or design values of equipment performance should be used.

All parameters used for thermodynamic analysis should be clearly expressed in the PDD, so the procedure can be adequately checked during validation.

Emissions from grid-connected electricity generation require data as specified in ACM0002 or AMS I.D, and depend on the specific methodological option chosen among various alternatives proposed therein.

Leakage calculations require estimates of fugitive methane emissions from fuel production. Since these are likely to be small compared to other components of baseline and project emissions, default values from IPCC may be chosen to make these estimates.

Leakage calculations also require estimates of fuel consumption for fuel transport, where applicable. These need to be estimated on the basis of fuel intensity of the transport mode and distances involved, and fuel-specific CO_2 emissions factors, all based on IPCC default values. Again, this is justified since these emissions are likely to be small.

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

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Historical data on fuel consumption, and any on-site electric power generation prior to project implementation should be available for at least three years prior to project implementation. These data are used to determine average heat and electric power demand of the industrial plant, as well as relationships between fuel input, and heat and electricity output. The historical data are also the basis for determining performance parameters used for thermodynamic analysis of baseline scenario, used in estimating *ex-ante* baseline emissions.

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

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Fuel consumption and equipment efficiency data correspond to the industrial facility or to a boiler room / power plant providing heat and/or electricity to the industrial facility.

Parameters needed to determine the emissions factor for grid-connected electricity generation depend on the power plants connected to the grid in question.

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

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The most important components of emissions depend on fuel consumption at the industrial facility prior to and following project implementation, and the CO_2 emissions factor of the fuels involved. These variables and parameters are very well known. Equipment efficiency values are needed for thermodynamic analysis and *ex-ante* estimates of baseline and project emissions. While thermodynamic analysis should be conducted rigorously, it should be kept in mind that the results are only the basis for ex-ante estimates, since actual, *ex-post* emissions reductions are estimated from monitored data. Methane

and nitrous oxide emissions from fuel combustion as well as leakage emissions are small, and the procedures and data sources indicated permit an adequate determination of the emissions involved.

One potentially large source of emissions and emissions reductions is associated with grid-connected power generation. The methodology proposed here is the approved consolidated methodology ACM0002 in general, and the small-scale methodology (AMS I.D) when power sold to the power grid is less than 15 MW. While the latter procedure is relatively simple, ACM0002 and AMS I.D include multiple options for determining the emissions factor for grid-connected electricity. The resulting emissions factor is likely to be sensitive to the option chosen.

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

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All equations that make up the determination of baseline emissions are straightforward and transparent. Wherever data limitations might exist, this methodology proposes alternative procedures and, in case of doubt, how to make conservative assumptions.

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