Revision to the approved baseline methodology AM0014 - version 02

"Natural gas-based package cogeneration"

Source

This methodology is based on the MGM natural gas-based package cogeneration project, Chile, whose baseline study, monitoring and verification plan and project design document were prepared by MGM International. For more information regarding the proposal and its consideration by the Executive Board please refer to case NM0018-rev: "MGM baseline methodology Natural Gas-Based Package cogeneration Project" on http://cdm.unfccc.int/methodologies/approved

Selected approach from paragraph 48 of the CDM modalities and procedures

"Existing actual or historical emissions as applicable."

Applicability

This methodology is applicable to natural gas-based cogeneration projects under the following conditions:

- The cogeneration system is a third party cogeneration systems, i.e. not own or operated by the consuming facility that receives the project heat and electricity or the cogeneration system is owned by the industrial user (henceforth referred to as self-owned) that consumes the project heat and electricity;
- The cogeneration system provides all or a part of the electricity and or heat demand of the consuming facility;
- No excess electricity is supplied to the power grid and no excess heat from the cogeneration system is provided to another user.

This baseline methodology shall be used in conjunction with the approved monitoring methodology AM0014 ("Natural gas-based package cogeneration").

Project activity

The project activity encompasses the installation of a package cogeneration system whose input is natural gas from the gas pipeline, and whose outputs are electricity and heat supplied to an industry with demand for heat and electricity. The project activity avoids consumption of a fossil fuel for heat generation and displaces electricity from the grid. The displaced fossil fuel for heat production, hereafter referred to as the "baseline fuel" may be natural gas or some other type of fuel with higher carbon intensity than natural gas including (but not limited to) fuel oil and coal.

Leakage

The principal sources of "leakage" in the sense of emissions of GHG emissions outside the project boundary and attributable to the CDM project are the emission of methane from natural gas production and pipeline leakage, associated with gas consumption of cogeneration system.

Baseline

Baseline emissions are those emissions that those associated with the production of heat and electricity that are offset by the output of the cogeneration system. Baseline emissions comprise five components:

a) **CO_2 from combustion.** CO_2 emissions corresponding to the combustion of a baseline fuel that would have been used if the cogeneration system did not provide **heat** to the plant.

b) **CH_4 from combustion.** CH_4 emissions corresponding to the combustion of a baseline fuel that would have been used if the cogeneration system did not provide **heat** to the plant.

c) **N_2O from combustion.** N_2O emissions corresponding to the combustion of a baseline fuel that would have been used if the cogeneration system did not provide **heat** to the plant.

d) **CH_4 leaks during production of the baseline fuel.** If the baseline fuel is natural gas, CH_4 emissions from natural gas production and leaks in the transport and distribution pipeline supplying the plant and leaks in the gas distribution piping within the plant, associated with the natural gas consumption identified in item (a) above. For other types of fuel, the baseline emissions associated with production and transportation are assumed zero for simplification and conservatism.

e) **CO_2 from electricity generation.** CO_2 emissions associated with the electricity that would have to be purchased from the power grid if the cogeneration system did not provide electricity to the plant.

The baseline emissions for the first four items are proportional to the amount of baseline fuel consumption in the plant that is offset by heat supplied by the natural gas cogeneration system. Each can be represented as the product of an emissions factor and an energy consumption, which depends on the heat output of the cogeneration system.

The consumption of the fuel avoided in the baseline for the supply of heat is determined as follows:

Annual energy consumption for heat supply at baseline plant, $ABEC_{BF}$ (GJ/year):

$$\mathrm{ABEC_{BF}} = \frac{\mathrm{CAHO}}{\mathrm{e_b}} \qquad \textbf{(3.1)}$$

Where CAHO = annual heat output from cogeneration system (GJ/year), and

e_b = industrial boiler efficiency (fraction, lower heating value basis).

The annual heat output from the cogeneration system (CAHO) is estimated on the basis of the heat output rate of the cogeneration system (*CHOR*) and an estimate of annual operating hours (*AOH*) of the cogeneration system. The formula is described below:

Annual baseline energy consumption for heat supply, *$ABEC_{BF}$* (GJ/year):

$$ABEC_{BF}\ (GJ/year) = \frac{CHOR \cdot AOH}{e_b}$$

(3.2)

Where;

CHOR = cogeneration system heat output rate (GJ/h),

AOH = Annual operating hours (h/year), and

e_b = boiler efficiency (fraction, lower heating value basis)

In order to be conservative, a high value of e_b is chosen. The methodology proposes a default value of 0.90.

The value of ***CHOR*** may be determined from the specifications of the cogeneration system. A value of ***AOH*** should be determined from an engineering study of the proposed cogeneration system.

Once the boiler energy consumption has been quantified, the four GHG emissions components (a to d, above) can be determined, as indicated below.

a) Baseline CO_2 emissions from combustion of baseline fuel for heat supply

Baseline CO2 emissions from combustion of baseline fuel for heat supply, BE_{th} **(tonnesCO2/year):**

$$BE_{th} = ABEC_{BF} \cdot EF_{BF}$$ **3.3**

Where:

$ABEC_{BF}$ = annual energy consumption for heat supply at baseline plant (GJ/year), and

EF_{BF}=CO2 emission factor of the fuel used to generate heat (t-CO2/GJ)

A value of ***EF_{BF}*** needs to be estimated from the following data sources. The numbers indicate a hierarchy in data to be used, with #1 being the best. If #1 data are not available, #2 data should be chosen. If these are not available,#3 data should be chosen.

1. National GHG inventory
2. IPCC, fuel type and technology specific
3. IPCC, near fuel type and technology

b) Baseline methane emissions from combustion of baseline fuel for heat supply to plant

Baseline methane emissions from combustion of baseline fuel for heat supply, $BE_{met\ comb}$ (tonne CH_4/year):

$$BE_{met\ comb}\ (tonne\ CH_4\ /\ year) = \frac{ABEC_{BF} \cdot MEF}{10^6} \quad \textbf{(3.4)}$$

Where

$ABEC_{BF}$ = annual baseline energy consumption for heat supply (GJ/year), and

MEF = methane emission factor for baseline fuel combustion (kg CH_4/TJ), *lower* heating value basis)

In units of carbon dioxide equivalent, $BE_{equiv\ met\ comb}$ (tonne CO_2 eq/year)

$$BE_{equiv\ met\ comb}(tonne\ CO_2 - equiv / year) = BE_{met\ comb} \cdot GWP(CH_4) \quad \textbf{(3.5)}$$

where GWP (CH_4) = global warming potential of methane = 21

The value of ***MEF*** needs to be estimated from the following data sources. The numbers indicate a hierarchy in data to be used, with #1 being the best. If #1 data are not available, #2 data should be chosen.

1. IPCC, fuel type and technology specific
2. IPCC, near fuel type and technology

c) Baseline nitrous oxide emissions from combustion of baseline fuel for heat supply to plant

Baseline nitrous oxide emissions from combustion of baseline fuel for heat supply, $BE_{N_2O\ comb}$ (tonne N_2O/year):

$$BE_{N_2O\ comb}\ (tonne\ CH_4\ /\ year) = \frac{ABEC_{BF} \cdot NEF}{10^6} \quad \textbf{(3.6)}$$

Where

$ABEC_{BF}$ = annual baseline energy consumption for heat supply (GJ/year), and

NEF = nitrous oxide emission factor for fuel combustion (kg N_2O/TJ, *lower* heating value basis)

In units of carbon dioxide equivalent, $BE_{equiv\ N_2O\ comb}$ (tonne CO_2 equiv/year)

$$BE_{equiv\ N_2O\ comb}(tonne\ CO_2 - equiv / year) = BE_{N_2O\ comb} \cdot GWP\ (N_2O) \quad \textbf{(3.7)}$$

Where

GWP (N_2O) = global warming potential of nitrous oxide = 310

The value of NEF needs to be estimated the following data sources. The numbers indicate a hierarchy in data to be used, with #1 being the best. If #1 data are not available, #2 data should be chosen.

1. IPCC, fuel type and technology specific

2. IPCC, near fuel type and technology

d) Baseline methane emissions from natural gas production and pipeline leaks in the transport and distribution

This section is applicable only for projects that displace natural gas in the baseline for heat generation. For baseline fuel other than natural gas, BE_{th_fug} is assumed zero for simplification and to be conservative.

The value of *MLR* needs to be estimated from the following data sources. The numbers indicate a hierarchy in data to be used, with #1 being the best. If #1 data are not available, #2 data should be chosen.

1. National estimates (if available)

2. IPCC estimates of fugitive emissions from oil and natural gas activities.

Baseline methane emissions from natural gas production and leakage in transport and distribution, corresponding to heat supply, $BE_{th\ fug}$ **(tonne CH_4/year)**:

$$BE_{th\ fug}\,(tonne\ CH_4 / year) = \frac{ABEC_{NG} \cdot MLR}{10^3} \qquad \textbf{(3.8)}$$

Where

MLR = methane leakage rate in natural gas production, transport and distribution leakage, including leaks at the industrial site (kg CH_4 /GJ natural gas energy consumption, lower heating value basis).

$ABEC_{NG}$ = annual baseline natural gas energy consumption for heat supply (GJ/year)

In units of carbon dioxide equivalent emissions, $BE_{th\ equiv\ fug}$ **(tonne CO_2 equiv/year):**

$$BE_{th\ equiv\ fug}\,(tonne\ CO_2 - equiv / year) = BE_{th\ fug} \cdot GWP(CH_4) \qquad \textbf{(3.9)}$$

where *GWP (CH_4)* is defined as before = 21

e) Baseline emissions of CO_2 from electricity supply to industrial plant, that is offset by electricity supplied from cogeneration system

The final item of GHG emissions in the baseline arises from *electricity,* corresponding to the emissions avoided at the power plants supplying the public grid, The relevant formula is described below:

Baseline carbon dioxide emissions for electricity supplied, BE_{elec} **(tonne CO_2/year)**:

$$BE_{elec}\,(tonne\ CO_2\ /\ year) = \frac{CEO \cdot BEF_{elec}}{10^3} \qquad \textbf{(3.10)}$$

Where

CEO = cogeneration electricity output (MWh/year), and

BEF_{elec} = baseline CO_2 emissions factor for electricity from public supply (kg CO_2/MWh)

The actual baseline emissions are determined by monitoring cogeneration electricity output (*CEO*) and calculating BE_{elec}. For an *a priori* estimation of the baseline CO_2 emissions for electricity supply to the plant, *CEO* is determined by the cogeneration electric power output (*CPO*) and annual operating hours (*AOH*), in a manner similar to Eq. (3.2) for heat output, and is described below.

Annual electricity generation from the cogeneration system, *CEO* **(MWh/year)**:

$$CEO\ (MWh\ /\ year) = CPO \cdot AOH \qquad \textbf{(3.11)}$$

where CPO = cogeneration system net power output capacity (MW_e), and

AOH = annual operating hours of cogeneration system (h/year)

To estimate BEF_{elec}, the CO_2 emission factor for electricity supply, users of this methodology shall refer to the “Consolidated Baseline Methodology for Zero-emissions Grid-Connected Electricity Generation from Renewable Sources” where different ways of determining CO_2 emission factors for electricity supply from the grid are provided, or to the “Simplified Methodology for Small-scale CDM Project activities” (in case electricity displaced is less than or equal to 15 MW equivalent).

Total baseline emissions are given by the sum of the components analyzed above:

$$BE_{total} = BE_{th} + BE_{equiv\ met\ comb} + BE_{equiv\ N_2O\ comb} + BE_{th\ equiv\ fug} + BE_{elec} \qquad \textbf{(3.15)}$$

Emission Reductions

Emission reductions are calculated as the difference between baseline and project emissions, taking into account any adjustments for leakage: Project emissions are those associated with natural gas consumption by the cogeneration system, including CO_2, CH_4 and N_2O emissions from natural gas combustion and CH_4 emissions from natural gas production and pipeline leakage, associated with the gas consumption of the cogeneration system.

Additionality

First likely alternative baseline scenarios are described:

1. Industrial plant continues to operate with equipment replacement as needed with no change in equipment efficiency (The frozen-efficiency scenario).

2. Industrial plant continues to operate with improved efficiency new equipment at the time of equipment replacement using a less carbon intensive fuel.

3. Industrial plant upgrades the thermal energy generating equipment and therefore increases the efficiency of boiler(s) immediately.

4. The heat and or electricity demand of the industrial plant is reduced through improvements in end-use efficiency.

5. Installation of a cogeneration system owned by the industrial plant.

6. Installation of a package cogeneration system owned by a company other than the industrial plant (The proposed project).

7. Installation of a cogeneration system by a third party.

The project developer can demonstrate additionality by selecting one of the following two options:

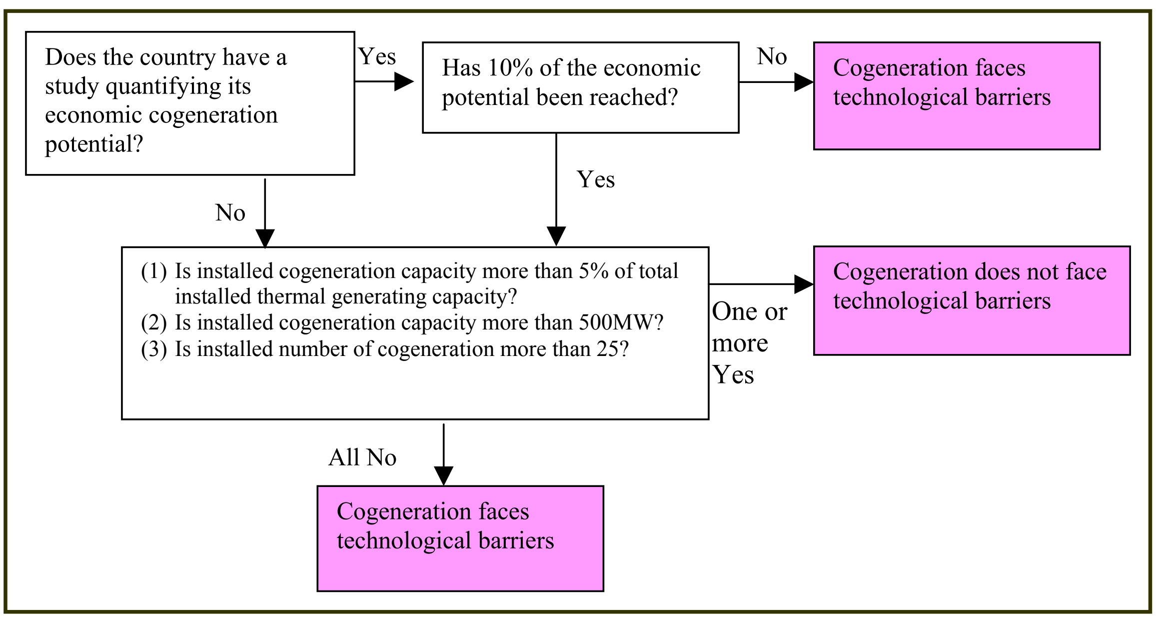
- Option 1: apply Step 2 of the latest version of the "Tool for demonstration of additionality" (Investment Analysis).

- Option 2: Methodology-specific process for determination of additionality as follows:

Four additionality tests are applied. The first two tests are applicable to *any* cogeneration ownership scenario. The third test is specific to the "package cogeneration" case where the cogeneration system is owned by a party other than the industry using the heat and electricity from the system. The fourth test is specific to the "package cogeneration" case for the self-owned cogeneration system. In the case of self owned Cogeneration project activities the project activity is additional if all the four additionality tests result in project being assessed as additional, whereas, only the first three tests need be applied in the case of third party ownership

1. Are there technological barriers to cogeneration in the country?

Additionality test 1 is applied by following the flow chart below. A low market share of cogeneration means that there is insufficient infrastructure to support installation and maintenance of such systems, acting as a technological barrier to project participants.

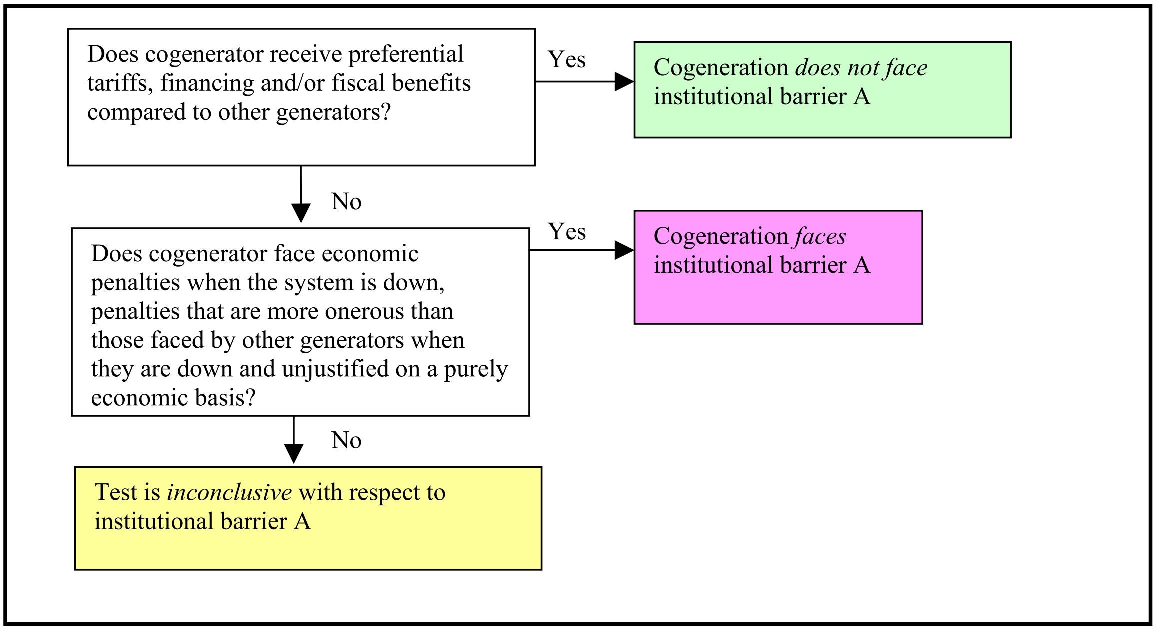


2. A Institutional barrier: Are there institutional barriers to cogeneration in general?

Additionality test 2A 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.

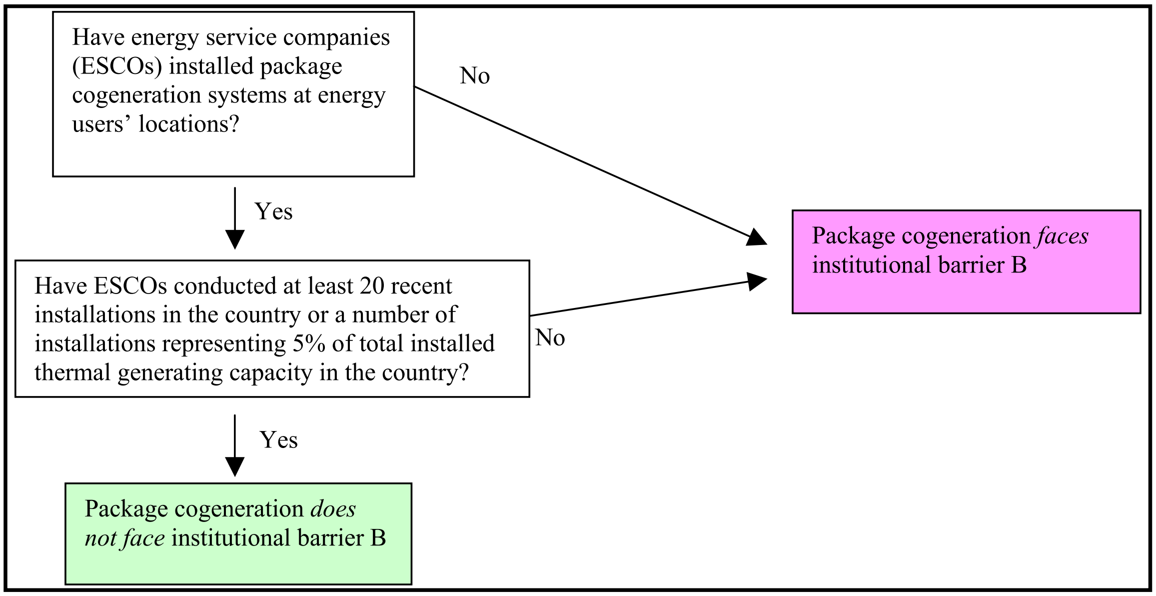
If institutional barriers are not present, but there are no specific incentives to cogeneration, then the test indicated is inconclusive with respect to institutional barrier A. Other barriers (such as technological barrier or institutional barrier B) will need to be considered to determine additionality.



2B. Institutional barrier for ESCOs: Are there institutional barriers to the “package cogeneration” operational context? In other words, is there enough experience in which one company installs a cogeneration system at the location of a separate energy user?

The traditional practice is for an industrial user to meet their electricity and natural gas demand by purchases from power and gas companies respectively. In a packaged cogeneration system, the institutional arrangement is very different. In this case, the project developer 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.

Additionality test 2B is applied by following the flow chart below.

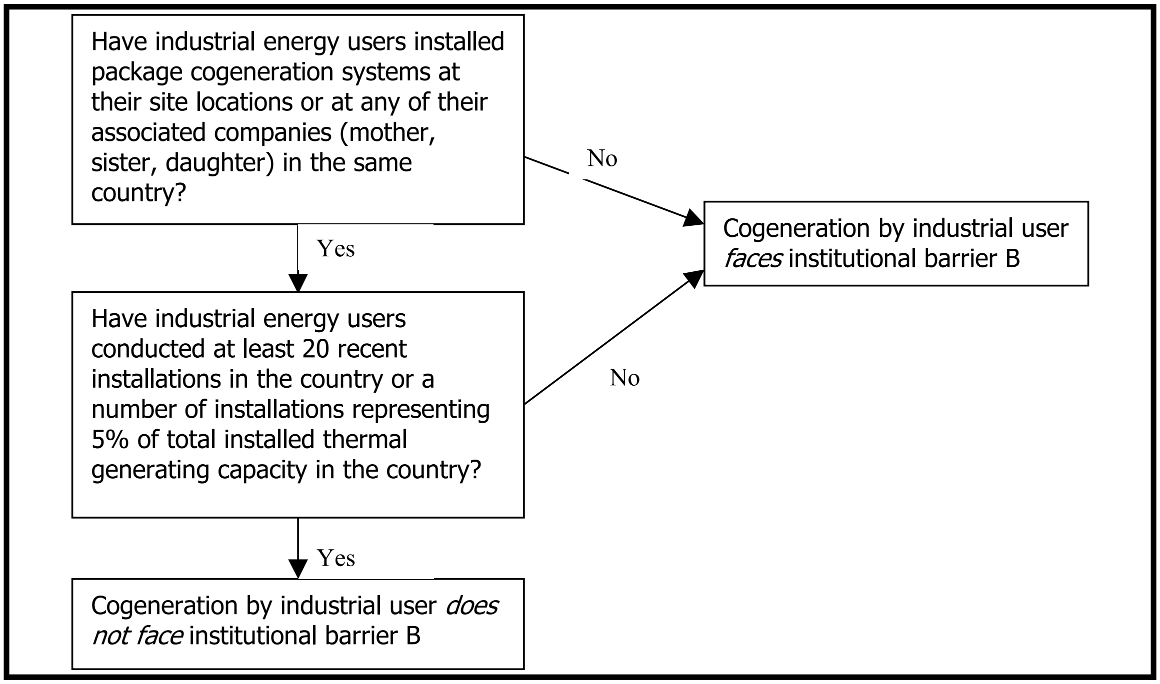


2C. Institutional barriers for Industrial Users:

Are there institutional barriers to the 'package cogeneration' operational context? In other words is there enough experience in which an industrial user can install and operate a cogeneration system at it's plant premises?

The traditional practice is for an industrial user to meet their electricity and natural gas demand by purchases from power and gas plants respectively. In this case, the industrial user, installs and operates the cogeneration system for use at its own site. This arrangement requires the industrial user to have specific expertise and knowledge of cogeneration systems. Where such experience is lacking, promoting the new arrangement involves a significant institutional barrier.

Additionality test 2C is applied by the following flow chart below:



If the above additionality tests determine that a package cogeneration system is additional with respect to scenarios where no cogeneration system, scenarios 1 to 4 remain as baseline options. The selection cannot be made without a substantial analysis. Therefore, a conservative approach is taken by assuming a high value for e_b in Eq. 3.2 to calculate the baseline emissions. This assumption implies reduced natural gas consumption in the baseline, and therefore reduced emission reductions compared to option 1-3. Option 4 is discounted for by determining the baseline ex-post on the basis of actual heat and electricity of the industrial plant.

Revision to the approved monitoring methodology AM0014

"Natural gas-based package cogeneration"

Source

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Applicability

This methodology is applicable to natural gas-based cogeneration projects under the following conditions:

- The cogeneration system is a third party cogeneration systems, i.e. not own or operated by the consuming facility that receives the project heat and electricity or the cogeneration system is owned by the industrial user (henceforth referred to as self-owned) that consumes the project heat and electricity;
- The cogeneration system provides all or a part of the electricity and or heat demand of the consuming facility;
- No excess electricity is supplied to the power grid and no excess heat from the cogeneration system is provided to another user.

This monitoring methodology shall be used in conjunction with the approved baseline methodology AM0014 ("Natural gas-based package cogeneration").

Monitoring Methodology

The monitoring methodology involves monitoring of the following:

- The natural gas consumption at the cogeneration system;
- Heat production at the cogeneration system;
- Electricity production at the cogeneration system.

Project emissions correspond to natural gas combustion by the cogeneration system, and includes the same four components as in the baseline (CO_2, CH_4 and N_2O emissions from combustion) and CH_4 emissions from natural gas production and leaks in the transport and distribution pipeline supplying the plant and leaks in the gas distribution piping within the plant, associated with the natural gas consumption. Each of these is proportional to the natural gas consumption in the cogeneration system, which is monitored. Emissions are then calculated as follows:

a) CO_2 emissions from natural gas combustion in cogeneration system

Carbon dioxide emissions from natural gas combustion in the cogeneration system, E_{CS} **(tonne CO_2/year)**:

$$E_{CS}\,(tonne\ CO_2\,/\,year) = \frac{AEC_{NG} \cdot EF_{NG}}{10^3} \qquad \textbf{(4.1)}$$

Where AEC_{NG} = annual energy consumption of natural gas in cogeneration system (GJ/year), and
EF_{NG} = CO_2 emission factor of natural gas (kg CO_2/GJ, *lower* heating value basis)

b) Methane emissions from natural gas combustion in cogeneration system

A certain amount of methane is generated in the combustion of natural gas. These are generally expressed in terms of natural gas energy consumption. Emissions are estimated using formulae described below:

Methane emissions from natural gas combustion in the cogeneration system, $E_{met\ comb}$ **(tonne CH_4/year),** are given by:

$$E_{met\ comb}\,(tonne\ CH_4\,/\,year) = \frac{AEC_{NG} \cdot MEF}{10^6} \qquad \textbf{(4.2)}$$

Where AEC_{NG} = annual energy consumption of natural gas in the cogeneration system (GJ/year), and

MEF = methane emission factor for natural gas combustion

(kg CH_4/TJ, *lower* heating value basis)

In units of carbon dioxide equivalent emissions, $E_{equiv\ met\ comb}$ **(tonne CO_2 equiv/year)**

$$E_{equiv\ met\ comb}\,(tonne\ CO_2 - equiv\,/\,year) = E_{met\ comb} \cdot GWP\,(CH_4) \qquad \textbf{(4.3)}$$

where GWP (CH_4) = global warming potential of methane = 21

c) Nitrous oxide emissions from natural gas combustion in cogeneration system

A certain amount of nitrous oxide is generated in the combustion of natural gas. These are generally expressed in terms of natural gas energy consumption. Emissions are estimated using formulae similar to those for methane emissions in combustion, and are described below:

Nitrous oxide emissions from natural gas combustion in the cogeneration system, $E_{N_2O\ comb}$ **(tonne N_2O/year),** are given by:

$$E_{N_2O\ comb}(tonne\ CH_4 / year) = \frac{AEC_{NG} \cdot NEF}{10^6} \quad \textbf{(4.4)}$$

Where AEC_{NG} = annual energy consumption of natural gas in the cogeneration system (GJ/year), and

NEF = nitrous oxide emission factor for natural gas combustion (kg N_2O/TJ, *lower* heating value basis)

In units of carbon dioxide equivalent emissions, $E_{equiv\ N_2O\ comb}$ **(tonne CO_2 equiv/year)**

$$E_{equiv\ N_2O\ comb}(tonne\ CO_2 - equiv / year) = E_{N_2O\ comb} \cdot GWP(N_2O) \quad \textbf{(4.5)}$$

Where $GWP\ (N_2O)$ = global warming potential of nitrous oxide = 310

d) Methane emissions from natural gas production and pipeline leaks in the transport and distribution of natural gas, including leakage within the industrial plant

These baseline emissions are associated with natural gas consumption in the cogeneration system. The procedure for estimating these emissions is described below:

Methane emissions from natural gas production and leakage in transport and distribution, corresponding to fuel used in cogeneration system, Efug (tonne CH4/year), are given by:

$$E_{fug}(tonne\ CH_4 / year) = \frac{AEC_{NG} \cdot MLR}{10^3} \quad \textbf{(4.6)}$$

Where AEC_{NG} is defined as before, and

MLR = methane leakage rate in natural gas production, transport and distribution leakage, including leaks at the industrial site (kg CH4/GJ natural gas energy consumption, lower heating value basis).

Convert methane emissions to carbon dioxide equivalent emissions, $E_{equiv\ fug}$ **(tonne CO_2 equiv/year)**

$$E_{equiv\ fug}(tonne\ CO_2 - equiv / year) = E_{fug} \cdot GWP(CH_4) \quad \textbf{(4.7)}$$

Where $GWP\ (CH_4)$ = is defined as before = 21

Total project emissions are given by the sum of the components analyzed above:

$$E_{total} = E_{CS} + E_{equiv\ met\ comb} + E_{equiv\ N_2O\ comb} + E_{equiv\ fug} \qquad \textbf{(4.8)}$$

The equations used to estimate project emissions are structurally very similar to those used in order to determine baseline emission. Project emissions are determined from natural gas consumption by the cogeneration. Baseline emissions depend on heat and electricity output from the cogeneration system that is supplied to the industrial plant, and are determined in a dynamic manner from monitored data using Equations leading up to Eq.3.15. By considering baseline and project emissions, emissions reductions are determined in a straightforward manner.

Parameters to be monitored

ID number	Data type	Data variable	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	For how long is archived data to be kept?	Comment
1.	Volume of natural gas consumed	MEC_{NG}	m^3	m	Monthly	100%	Paper (field record) electronic (spreadsheet)	Paper: 1 year, Electronic: 7 years	
2.	Cogeneration electricity supplied to industrial plant	*MCEO*	MWh	m	Monthly	100%	Electronic (spreadsheet)	Electronic: 7 years	
3.	Cogeneration heat supplied to industrial plant	*MCHO*	GJ	m	Monthly	100%	Electronic (spreadsheet)	Paper: 1 year Electronic: 7 years	

Quality Control (QC) and Quality Assurance (QA) Procedures

Data	Uncertainty level of data (High/Medium/Low)	Are QA/QC procedures planned for these data?	Outline explanation why QA/QC procedures are or are not being planned.
1.	Low	Yes	These data will be used as supporting information to calculate emission reductions by project activity
2.	Low	Yes	These data will be used as supporting information to calculate emission reductions by project activity
3.	Low	Yes	These data will be used as supporting information to calculate emission reductions by project activity
4.	Low	Yes	These data will be used as supporting information to calculate emission reductions by project activity