Approved baseline and monitoring methodology AM0050

"Feed switch in integrated Ammonia-urea manufacturing industry"

I. SOURCE AND APPLICABILITY

Source

This methodology is based on NM0165-rev "Feed switchover from Naphtha to Natural Gas (NG) at Phulpur plant of IFFCO", whose baseline study and project design document were prepared by IFFCO - Indian Farmers Fertilizer Cooperative Ltd., India.

For more information regarding the proposal and its consideration by the Executive Board please refer to case NM0165-rev on http://cdm.unfccc.int/goto/MPappmeth

This methodology also refers to the latest version of the "Combined tool to identify the baseline scenario and demonstrate additionality".[1]

Selected approach from paragraph 48 of the CDM modalities and procedures

"Existing actual or historical emissions, as applicable".

Applicability

This methodology is applicable to feed switch project activities in existing integrated ammonia-urea manufacturing facilities. In the project activity, natural gas is used solely, or in addition to naphtha, as feed which has a lower carbon to hydrogen ratio than naphtha, which is the current practice in the plant. The emissions reductions are achieved as a result of a reduction in excess carbon, over and above that needed for the production of urea, leading to less CO_2 being released into the atmosphere.

This methodology is applicable to:

- Integrated ammonia-urea manufacturing industries that involve partial or total switching from naphtha to natural gas, as a feedstock with a lower carbon to hydrogen ratio (CHR) than that indicated in the baseline (naphtha);
- Integrated ammonia-urea manufacturing plants that are not constrained by local regulations and/or programs from using naphtha as feed, neither obliged to use natural gas (NG) and/or liquefied natural gas (LNG) as feed;
- Project activities that do not result in the increase of the production capacity;
- Natural gas is sufficiently available in the region or country, e.g. future natural gas based capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity[2];

[1] Please refer to: http://cdm.unfccc.int/goto/MPappmeth

- Integrated ammonia-urea manufacturing plants in which the carbon in the naphtha feed used prior to implementation of the project activity is in excess of that needed in the urea production process. The excess carbon in the feed is emitted as CO_2 to the atmosphere;
- The integrated ammonia-urea manufacturing plant is an existing plant with a historical operation of at least three years prior to the implementation of the project activity;
- Project activities that do not result in changes in the production process (e.g. as a result of product change) other than the feed switch;
- If the use of natural gas in project activity results in a situation where the natural gas does not have sufficient carbon to meet the requirement of urea production, then the balance CO_2 required for use in urea production is recovered with the use of a Carbon Dioxide Recovery Plant (CDR) from CO_2 in flue gases emitted from an existing source of fossil fuel combustion for energy purposes within the project boundary. The CO_2 in the flue gases would have been emitted into the atmosphere in the absence of the project activity;
- The source of thermal energy for processing the feed is the combustion of fossil fuels in boilers both in the baseline scenario as well as in the project activity;
- Prior to the implementation of the project activity, no natural gas has been used in the integrated ammonia-urea manufacturing plant;
- The quantity of steam and electricity required for the ammonia production process is not affected by the project activity, i.e. it is the same with the use of naphtha and natural gas.

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

II. BASELINE METHODOLOGY

Project boundary

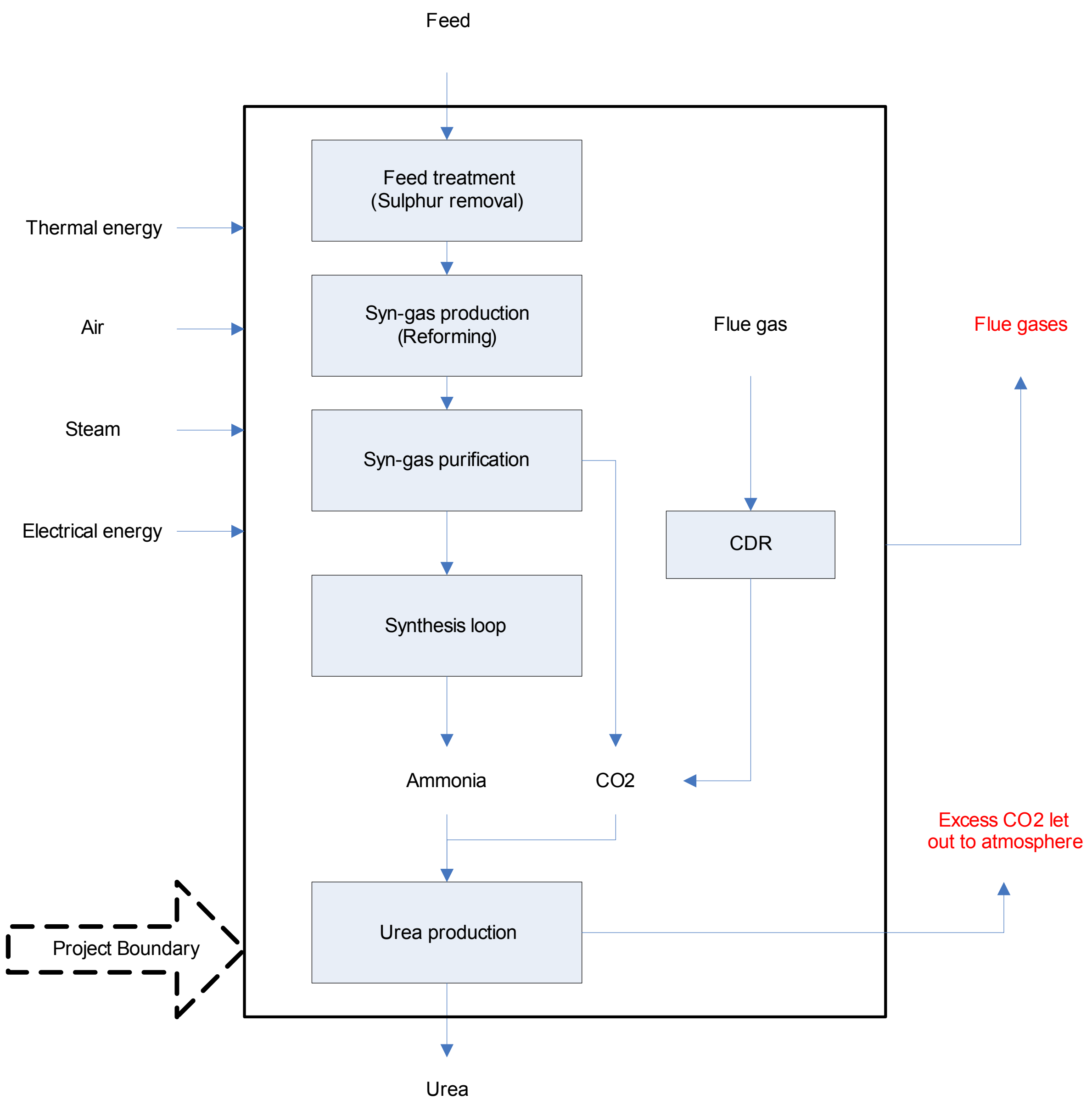

Table 1: Emissions sources included in or excluded from the project boundary

	Source	Gas	Included?	Justification / Explanation
Baseline	Processing of feed	CO_2	Yes	Main emission source. CO_2 is produced in the reforming of the feed and is partially recovered for use in the production of urea. CO_2 in excess of required amount is released to the atmosphere.
		CH_4	No	Negligible fugitive CH_4 emissions may occur during the processing of the feed. These emissions (if any) would be essentially the same as in the project activity. Therefore, they are excluded for simplification.
		N_2O	No	Not applicable.
	Fuel used in furnaces (thermal energy)	CO_2	Yes	Main emission source (flue gases) due to the combustion of fossil fuel to provide thermal energy for feed treatment (sulphur removal in hydrotreater and primary desulphurization unit) and the syn-gas production (reforming). Any CO_2 recovered from flue gases resulting from combustion of fossil fuel is deducted from this emission source.
		CH_4	No	Excluded for simplification, this is conservative.
		N_2O	No	Excluded for simplification, this is conservative.
	Fuel used in boilers (Steam generation)	CO_2	No	These emissions are expected to be the same or higher as compared to the project scenario. Excluded for simplification and because this is conservative.
		CH_4	No	These emissions are expected to be the same or higher as compared to the project scenario. Excluded for simplification and because this is conservative.
		N_2O	No	These emissions are expected to be the same or higher as compared to the project scenario. Excluded for simplification and because this is conservative.
	Electricity requirement	CO_2	No	These emissions are expected to be the same or higher as compared to the project scenario. Excluded for simplification and because this is conservative.
		CH_4	No	These emissions are expected to be the same or higher as compared to the project scenario. Excluded for simplification and because this is conservative.
		N_2O	No	These emissions are expected to be the same or higher as compared to the project scenario. Excluded for simplification and because this is conservative.

	Source	Gas	Included?	Justification / Explanation
Project Activity	Processing of feed	CO_2	Yes	Main emission source. CO_2 is produced in the reforming of the feed and is recovered for the production of urea. CO_2 in excess of that required for urea production, if any, is released into atmosphere.
		CH_4	No	Negligible fugitive CH_4 emissions may occur during the processing of the feed. These emissions (if any) would be essentially the same as in the baseline scenario. Therefore, they are excluded for simplification.
		N_2O	No	Not applicable
	Fuel used in furnaces (thermal energy)	CO_2	Yes	Main emission source due to the combustion of fossil fuels. The project activity will result in lower thermal energy required as sulphur is negligible in NG/LNG. Any CO_2 recovered from flue gases resulting from combustion of fossil fuel is deducted from this emission source.
		CH_4	No	These emissions are expected to be the same or lower as compared to the baseline scenario.
		N_2O	No	These emissions are expected to be the same or lower as compared to the baseline scenario.
	Fuel used in boilers (Steam generation)	CO_2	No	These emissions are expected to be the same or lower as compared to the baseline scenario.
		CH_4	No	These emissions are expected to be the same or lower as compared to the baseline scenario.
		N_2O	No	These emissions are expected to be the same or lower as compared to the baseline scenario.
	Electricity requirement	CO_2	No	These emissions are expected to be the same or lower as compared to the baseline scenario.
		CH_4	No	These emissions are expected to be the same or lower as compared to the baseline scenario.
		N_2O	No	These emissions are expected to be the same or lower as compared to the baseline scenario.
	Energy consumed by CDR plant	CO_2	Yes	If a CDR plant is also part of the project activity, then the emissions due to the production of energy (steam and electricity) for the operation of this equipment must also be considered.
		CH_4	No	Not applicable.
		N_2O	No	Not applicable.

Combined procedure to identify the baseline scenario and demonstrate additionality

The most plausible baseline scenario and the additionality shall be identified and determined according to the latest version of the "Combined tool to identify the baseline scenario and demonstrate additionality".

Step 1: Identification of alternative scenarios

Step 1a. Define alternative scenarios to the proposed CDM project activity

Identify all alternative scenarios that are available to the project participants and that provide outputs or services with comparable quality, properties and application areas as the proposed CDM project activity. These alternative scenarios shall include:

- The continuation of current practice, i.e. usage of naphtha alone as feed for the production of urea, resulting in CO_2 surpluses that are released to the atmosphere;
- Partial substitution of naphtha with NG/LNG so as to reduce the CO_2 surpluses released to atmosphere for similar output of urea;
- Complete switchover from Naphtha to NG/LNG resulting in the reduction of CO_2 surpluses and equivalent emissions for similar output of urea;
- Usage of naphtha as feed and production of CO_2 surpluses, but with capture of the CO_2 surpluses, which would be released to the atmosphere, for its use in other applications.

Note that the alternatives proposed are only indicative. Project proponents may identify other alternatives.

Sub-step 1b. Consistency with mandatory applicable laws and regulations:

Eliminate alternatives that are not in compliance with all applicable legal and regulatory requirements.

Step 2: Investment Analysis

Compare the economic attractiveness without considering the impacts of the CDM for all alternatives that are remaining by applying Step 3 of the "Combined tool to identify the baseline scenario and demonstrate additionality" agreed by the CDM Executive Board. National policies or regulations or other benefits that are related to the increase of the production capacity, which may have an effect on the types of feed used, should also be taken into consideration.

This methodology is only applicable if the "usage of naphtha alone as feed for the production of urea, resulting in CO_2 surpluses that are released to the atmosphere" throughout the crediting period is the most plausible baseline scenario.

NOTE: The methodology cannot be used if the most plausible baseline scenario is the use of both naphtha and NG/LNG as feed.

Step 3: Common practice analysis

Demonstrate that the project activity is not a common practice in the relevant country and sector. The common practice analysis is to be carried out as follows:

Sub-step 3a. Analyze other activities similar to the proposed project activity:

Provide an analysis of any other feed switch activity implemented previously or currently underway that is similar to the proposed project activity. Other activities are considered similar if they are in the same country/region, 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 3b. Discuss any similar options that are occurring:

If similar activities are widely observed and commonly carried out, it calls into question the claim that the proposed project activity is financially unattractive. 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. 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) to which the proposed project activity is subject.

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 activities have been carried out. For example, promotional policies may have ended, leading to a situation in which the proposed CDM project activity would not be implemented without the incentives provided by the CDM. The change must be fundamental and verifiable.

If all steps are satisfied, then the project is considered additional.

Baseline emissions

Baseline emissions are calculated as follows:

$$BE_y = BE_{Feed,y} + BE_{Heat,y} \quad \textbf{(1)}$$

Where:

$BE_{Feed,y}$ Emissions due to the use of naphtha as feed for the production of urea, in tCO_2.

$BE_{Heat,y}$ Emissions due to the production of thermal energy used in the furnaces (feed treatment and reforming), in tCO_2.

***Emissions due to the use of naphtha as feed** ($BE_{Feed,y}$)*

The emissions due to the use of naphta as feed for the production of urea are calculated as follows:

$$BE_{Feed,y} = BE_{Naphtha,y} - BS_{Urea,y} \quad \textbf{(2)}$$

Where:

$BE_{Naphta,y}$ Quantity of CO_2 that would be produced from naphtha in the baseline, in tCO_2.

$BS_{urea,y}$ Equivalent CO_2 quantity of the carbon (C) that is included the product of urea in the urea production process, in tCO_2.

The quantity of CO_2 that would be produced from naphtha in the baseline is calculated as:

$$BE_{Naphtha,y} = \frac{44}{12} \cdot P_{Urea,PJ,y} \cdot SFC_{Naphtha} \cdot CF_{Naptha,BL} \quad \textbf{(3)}$$

Where:

$P_{urea,PJ,y}$ Production of urea in each year y of the crediting period, in tonnes.

SFC_{Naphta} Specific feed consumption ratio for the production of urea in the three most recent years previous to the implementation of the project activity, tonnes of naphta/tonnes of urea.

$CF_{Naphtha,BL}$ Carbon fraction of naphta used in the baseline as feed, in tonnes of carbon/tonnes of naphtha.

44/12 Ratio between the molecular weights of CO_2 and carbon, mass units/mass units.

The specific feed consumption ratio is calculated as follows:

$$SFC_{Naphtha} = \frac{\sum_{k=1}^{3} F_{Naphtha,BL,k}}{\sum_{k=1}^{3} P_{Urea,BL,k}} \quad \textbf{(4)}$$

Where:

$P_{Urea,BL,k}$ Production of urea in each one of the three most recent years k previous to the implementation of the project activity, in tonnes.

$F_{Naphtha,BL,k}$ Quantity of naphtha used as feed in each one of the three most recent years k previous to the implementation of the project activity, in tonnes.

The CO_2 required to produce urea is calculated as follows:

$$BS_{Urea,y} = \frac{44}{60} \cdot P_{Urea,PJ,y} \quad \textbf{(5)}$$

Where:

44/60 =44/12*12/60. 44/12 represents conversion factor from carbon to carbon dioxide and 12/60 is ratio of carbon mass (each urea molecule has one molecule of carbon) to urea mass in one molecule of urea (molecular weight 60).

Emissions due to the production of thermal energy used in the furnaces ($BE_{Heat,y}$)

The CO_2 emissions from thermal energy are calculated as follows:

$$BE_{Heat,y} = P_{Urea,PJ,y} \cdot SEC_{Naphtha} \cdot EF_{CO2,BL,y} \tag{6}$$

Where:

$EF_{CO2,BL,y}$ CO_2 emission factor for the baseline fuel that would be used in the furnaces (feed treatment and reforming) in each year y of the crediting period, in tCO_2/TJ.

SEC_{Naphta} Specific thermal energy consumption ratio in the urea production process (feed treatment and reforming) in the three most recent years previous to the implementation of the project activity, TJ/tonnes of urea.

The emission factor for the fuel that would be used in the furnaces ($EF_{CO2,BL,y}$) must be chosen as the lowest of the emission factors among the fuels used in the three most recent years prior to the implementation of the project activity and the fuels used in the relevant year *y* of the crediting period.

For the determination of emission factors, guidance from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories should be followed where appropriate. Project participants may either conduct measurements or they may use accurate and reliable local or national data where available. Where such data is not available, IPCC default emission factors (country-specific, if available any) may be used if they are deemed to reasonably represent local circumstances. All values should be chosen in a conservative manner and the choice should be justified and documented in the CDM-PDD. Where measurements are undertaken, project participants may estimate the emission factors or net calorific values ex-ante in the CDM-PDD and should document the measurement results after implementation of the project activity in their monitoring reports.

The specific thermal energy consumption ratio is calculated as follows:

$$SEC_{Naphtha} = \left[\frac{\sum_k \sum_i (FC_{BL,i,k} \cdot NCV_{i,k})}{\sum_k P_{Urea,BL,k}} \right] \tag{7}$$

Where:

$FC_{BL,i,k}$ Quantity of fuel of type i consumed in the furnaces (feed treatment and reforming) in each one of the most recent three years k previous to the implementation of the project activity, in tonnes.

$NCV_{i,k}$ Net calorific value of fuel type i in each one of the most recent three years k previous to the implementation of the project activity, in TJ/tonnes.

k The most recent three years prior to the implementation of the project activity

i Fossil fuel types used in the years k

Project Emissions

Project activity emissions are calculated as follows:

$$PE_y = PE_{Feed,y} + PE_{Heat,y} + PE_{CDR,y} \qquad \textbf{(8)}$$

Where:

$PE_{Feed,y}$ Emissions due to the use of NG/LNG as feed for the production of urea in each year y of the crediting period, in tCO_2.

$PE_{Heat,y}$ Emissions due to the production of thermal energy used in the furnaces (feed treatment and reforming) after deducting the CO_2 recovered by the CDR plant (if any) in each year y of the crediting period, in tCO_2.

$PE_{CDR,y}$ Emissions due to the production of energy used by the CDR plant (if any) in each year y of the crediting period, in tCO_2.

Emissions due to the use of NG/LNG as feed ($PE_{Feed,y}$)

The emissions due to the use of NG/LNG as feed for the production of urea are calculated as follows:

$$PE_{Feed,y} = PE_{PJ,y} - PS_{Urea,y} \qquad \textbf{(9)}$$

Where:

$PE_{PJ,y}$ Quantity of CO_2 produced from NG/LNG in each year y of the crediting period, in tCO_2.

$PS_{urea,y}$ Quantity of CO_2 required for the production of urea in each year y of the crediting period, in tCO_2.

The quantity of CO_2 produced from NG/LNG is calculated as follows:

$$PE_{PJ,y} = \frac{44}{12} \cdot \left(F_{NG,PJ,y} \cdot CF_{NG} + F_{Naphtha,PJ,y} \cdot CF_{Naphtha,PJ} \right) \qquad \textbf{(10)}$$

Where:

$F_{NG,PJ,y}$ Consumption of NG/LNG as feed during the year y of the crediting period, in tonnes. If the available data are measured in volume units use the appropriate density of NG, corrected for temperature and pressure, to calculate the equivalent mass.

CF_{NG} Carbon content, expressed as weight fraction, of NG/LNG used as feed during year y of the crediting period, in tonnes of carbon/tonnes of NG/LNG.

$F_{Naphtha,PJ,y}$ Consumption of naphtha as feed during the year y of the crediting period, in tonnes.

$CF_{Naphtha,PJ}$ Carbon content, expressed as weight fraction, of naphtha used as feed during year y of the crediting period, in tonnes of carbon/tonnes of naphtha.

The quantity of CO_2 required for the production of urea is calculated as follows:

$$PS_{Urea,y} = \frac{44}{60} \cdot P_{Urea,PJ,y} \tag{11}$$

Emissions from thermal energy ($PE_{Heat,y}$)

Emissions due to the production of thermal energy used in the furnaces (feed treatment and reforming) is calculated as follows:

$$PE_{Heat,y} = (\sum_{i} FC_{i,y} \cdot NCV_{i,y}) \cdot EF_{CO2,PJ,y} \tag{12}$$

Where:

$FC_{i,y}$ Quantity of fuel type i consumed in the furnaces (feed treatment and reforming) in each year y of the crediting period, in mass or volume units.

$NCV_{i,y}$ Net calorific value of fuel type i in each year y of the crediting period, in TJ/mass or volume units.

$EF_{CO2,PJ,y}$ CO_2 emission factor of the fuel type with the lowest emission factor among all the i fossil fuels used in the furnaces (feed treatment and reforming) in each year y of the crediting period, in tCO_2/TJ.

For the determination of emission factors, guidance from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories should be followed where appropriate. Project participants may either conduct measurements or they may use accurate and reliable local or national data where available. Where such data is not available, IPCC default emission factors (country-specific, if available any) may be used if they are deemed to reasonably represent local circumstances. All values should be chosen in a conservative manner and the choice should be justified and documented in the CDM-PDD. Where measurements are undertaken, project participants may estimate the emission factors or net calorific values ex-ante in the CDM-PDD and should document the measurement results after implementation of the project activity in their monitoring reports

Emissions from CDR ($PE_{CDR,y}$)

If installation of CDR plant is also carried out in the project activity as a means to make up for reduced carbon feed, then the emissions due to the operation of the CDR plant need also to be accounted for in the project activity emissions. These emissions would arise from the production of energy (electricity and steam) required to the operation of the CDR plant. They are calculated as follows:

$$PE_{CDR,y} = PE_{CDR,elec,y} + PE_{CDR,steam,y} \tag{13}$$

Where:

$PE_{CDR,elec,y}$ Emissions due to the production of electricity used for the operation of the CDR plant in each year y of the crediting period, in tCO_2.

$PE_{CDR,steam,y}$ Emissions due to the production of steam used for the operation of the CDR plant in each year y of the crediting period, in tCO_2.

The emissions due to the production of electricity used for the operation of the CDR plant are calculated as follows:

$$PE_{CDR,elec,y} = EC_{CDR,elec,y} \cdot EF_{elec,y} \tag{14}$$

Where:

$EC_{CDR,elec,y}$ Quantity of electricity consumed by the CDR plant in each year y of the crediting period, in MWh. Measured in the project activity.

$EF_{elec,y}$ CO_2 emission factor for electricity during each year y of the crediting period, in tCO_2/MWh. Calculated as per equation below.

The electrical energy supplied to the CDR plant might be coming from either grid or captive power generation or a mix of both. Thus the CO_2 emission factor for electrical energy would be calculated as follows:

Option 1: Grid power

If the electricity used is obtained from the grid:

$EF_{elec,y}=EF_{grid,y}$

Where $EF_{grid,y}$, in tCO_2/MWh, is the emission factor of the grid that must be calculated as the generation-weighted average emissions per electricity unit of all generating sources serving the system or assumed as a default value of 1.3 tCO_2/MWh.

Option 2: Captive power

For captive power supply the emission factor would be $EF_{elec,y}=EF_{captive,y}$ calculated as follows:

$$EF_{captive,y} = \frac{44}{12} \cdot \frac{\sum_i FC_{CDR,captive,i,y} \cdot NCV_{i,y} \cdot EF_{i,y}}{TEP_{CDR,captive,y}} \quad \textbf{(15)}$$

Where:

$EF_{captive,y}$	Emission factor for captive power generation (tCO_2/MWh).
$FC_{CDR,captive,i,y}$	Amount of fossil fuel of type i used in the captive power plant in each year y of the crediting period, in mass or volume units.
$TEP_{CDR,captive,y}$	Total electricity produced by the captive power plant in year y, in MWh.
$EF_{i,y}$	Emission factor of fuel type i used for steam generation in each year y of the crediting period, tCO_2/TJ.

Option 3: Both grid and captive power

For both grid and captive power supply the emission factor $EF_{elec,y}$ would be calculated as the weighted average of grid and captive power, as follows:

$$EF_{elec,y} = \frac{EC_{grid,y}}{EC_{grid,y} + EC_{captive,y}} \cdot EF_{grid,y} + \frac{EC_{captive,y}}{EC_{grid,y} + EC_{captive,y}} \cdot EF_{captive,y} \quad \textbf{(16)}$$

Where:

$EC_{grid,y}$	Quantity of electricity obtained from the grid by the projecty activity during each year y of the crediting period, in MWh.
$EC_{captive,y}$	Quantity of electricity obtained from a captive power plant by the projecty activity during each year y of the crediting period, in MWh.

The emissions due to the production of steam used for the operation of the CDR plant are calculated as follows:

$$PE_{CDR,steam,y} = EC_{CDR,steam,y} \cdot EF_{Boiler,y} \quad \textbf{(17)}$$

Where:

$EC_{CDR,steam,y}$	Quantity of thermal energy (steam) used for the operation of the CDR plant, in TJ. The calculation of the amount of thermal energy (steam) used for the operation of the CDR plant must take into consideration the pressure and temperature in which the steam is produced (T_{steam}, P_{steam}). The specific enthalpy is a function of pressure and temperature and can be obtained from steam tables.
$EF_{Boiler,y}$	Emission factor of the steam generator, tCO_2/TJ.

The annual equivalent energy for steam consumption is calculated as follows:

$$EC_{CDR,steam,y} = SC_{CDR,y} \cdot (E_{steam} - E_{feedwater}) \qquad \textbf{(18)}$$

Where:

$SC_{CDR,y}$	Demand of steam for the operation of the CDR plant in each year y of the crediting period, in tonnes.
E_{steam}	Specific enthalpy of the steam at the steam generator outlet, in TJ/tonnes. Obtained from steam tables using the measured temperature (T_{steam}) and pressure (P_{steam}) of the steam in the steam generator outlet.
$E_{feedwater}$	Specific enthalpy of the feed water at the steam generator inlet, in TJ/tonnes. Obtained from steam tables using the measured temperature (T_{fw}) and pressure (P_{fw}) of the feedwater in the steam generator inlet.

The emission factor of the steam generator is calculated as follows:

$$EF_{Boiler,y} = \frac{\sum_i FC_{CDR,steam,i,y} \cdot NCV_{i,y} \cdot EF_{i,y}}{TSP_{CDR,steam,y} \cdot \left(E_{steam} - E_{feedwater}\right)} \qquad \textbf{(19)}$$

Where:

$FC_{CDR,steam,i,y}$	Amount of fuel type i consumed in the steam generator in each year y of the crediting period, in mass or volume units.
$TSP_{CDR,steam,y}$	Total amount of steam produced by the steam generator in each year y of the crediting period, in tonnes.

Leakage

The leakage (LE_y) in the project activity would be due to feed extraction, processing, liquefaction, transportation, re-gasification and distribution of feed outside of the project boundary. This includes mainly fugitive CH_4 emissions and CO_2 emissions from associated fuel combustion and flaring. In this methodology, the following leakage emission sources shall be considered[3]:

- Fugitive CH_4 emissions associated with feed extraction, processing, liquefaction, transportation, re-gasification and distribution of natural gas used in the project plant and fossil fuels used in the grid in the absence of the project activity.
- In the case LNG is used in the project plant: CO_2 emissions from fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system.

Thus, leakage emissions are calculated as follows:

$$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y} \tag{20}$$

Where:

$LE_{CH4,y}$	Leakage emissions due to fugitive upstream CH_4 emissions in the year y, in tCO_2.
$LE_{LNG,CO2,y}$	Leakage emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year y, in tCO_2.

Fugitive methane emissions

For the purpose of determining fugitive methane emissions associated with the production – and in case of natural gas, the transportation and distribution of the fuels – project participants should multiply the quantity of natural gas consumed as feed with a methane emission factor for these upstream emissions ($EF_{NG,upstream,CH4}$) as follows:

$$LE_{CH4,y} = F_{NG,PJ,y} \cdot NCV_{NG,y} \cdot EF_{NG,upstream,CH4} \cdot GWP_{CH4} \tag{21}$$

Where:

$F_{NG,PJ,y}$	Consumption of NG/LNG as feed during the year y of the crediting period, in m^3. If the available data are measured in mass units, use the appropriate density of NG/LNG, corrected for temperature and pressure, to calculate the equivalent volume.
$NCV_{NG,y}$	Average net calorific value of the natural gas combusted during the year y, in TJ/m^3.
$EF_{NG,upstream,CH4}$	CH_4 emission factor for upstream fugitive methane emissions from production, transportation and distribution of natural gas feed supplied to final consumers, in tCH_4/TJ.

[3] The Meth Panel is undertaking further work on the estimation of leakage emission sources in case of fuel switch project activities. This approach may be revised based on outcome of this work.

GWP_{CH4} is the global warming potential of methane = 21.

Where reliable and accurate national data on fugitive CH_4 emissions associated with the production, and in case of natural gas, the transportation and distribution of the fuels is available, project participants should use this data to determine average emission factors by dividing the total quantity of CH_4 emissions by the quantity of fuel produced or supplied respectively[4]. Where such data is not available, project participants may use the default values provided in table below. Note that the emission factor for fugitive upstream emissions for natural gas ($EF_{NG,upstream,CH4}$) should include fugitive emissions from production, processing, transport and distribution of natural gas, as indicated in the table below.

Table 2 - Default emission factors for fugitive CH_4 upstream emissions

Activity		**Unit**	**Default emission factor**	**Reference for the underlying emission factor range in Volume 2 of the 2006 Revised IPCC Guidelines**
Natural gas *Developed countries*				
Gas production		Gg per 10^6 m^3 gas production	3.8E-04 to 2.3E-03	Table 4.2.4, p. 4.48
Gas processing	Sweet gas plants	Gg per 10^6 m^3 raw gas feed	4.8E-04 to 10.3E-03	Table 4.2.4, p. 4.48
	Sour gas plant	Gg per 10^6 m^3 raw gas feed	9.7E-05	Table 4.2.4, p. 4.48
Gas transmission & Storage	Transmission	Gg per 10^6 m^3 of marketable gas	6.6E-05 to 4.8E-04	Table 4.2.4, p. 4.49
	Storage	Gg per 10^6 m^3 of marketable gas	2.5E-05	Table 4.2.4, p. 4.49
Gas distribution		Gg per 10^6 m^3 of utility sales	1.1E-03	Table 4.2.4, p. 4.50
Developing countries and countries with economies in transition				
Gas production		Gg per 10^6 m^3 gas production	3.8E-04 to 2.4E-02	Table 4.2.5, p. 4.55
Gas processing	Sweet gas plants	Gg per 10^6 m^3 raw gas feed	4.8E-04 to 1.1E-03	Table 4.2.5, p. 4.55
	Sour gas plant	Gg per 10^6 m^3 raw gas feed	9.7E-05 to 2.2E-04	Table 4.2.5, p. 4.55
Gas transmission and storage	Transmission	Gg per 10^6 m^3 of marketable gas	16.6E-05 to 1.1E-03	Table 4.2.5, p. 4.57

[4] GHG inventory data reported to the UNFCCC as part of national communications can be used where country specific approaches (and not IPCC Tier 1 default values) have been used to estimate emissions.

	Storage	Gg per 10^6 m^3 of marketable gas	2.5E-05 to 5.8E-05	Table 4.2.5, p. 4.57
Gas distribution		Gg per 10^6 m^3 of utility sales	1.1E-03 to 2.5E-03	Table 4.2.5, p. 4.57

Note: The emission factor should be selected in order to ensure conservativeness in estimation of emission reduction.

CO_2 emissions from LNG

If LNG is used as feed at the project activity, CO_2 emissions from fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($L2_{LNG,\ CO2,y}$) should be estimated by multiplying the quantity of natural gas combusted in the project with an appropriate emission factor, as follows:

$$LE_{LNG,CO_2,y} = F_{NG,PJ,y} \cdot NCV_{NG,y} \cdot EF_{CO_2,upstream,LNG,y} \tag{22}$$

Where:

$EF_{CO2,upstream,LNG,y}$	Emission factor for upstream CO_2 emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system in year y, in tCO_2/TJ.

Where reliable and accurate data on upstream CO_2 emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system is available, project participants should use this data to determine an average emission factor. Where such data is not available, project participants may assume a default value of 6 tCO_2/TJ as a rough approximation[5].

Emissions Reductions

The emissions reductions are calculated as:

$$ER_y = BE_y - PE_y - LE_y \tag{23}$$

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

At the renewal of the crediting period, project participants should evaluate whether the project activity continues not to be the baseline scenario, i.e. whether it would have been implemented in the absence of the project activity. The crediting period may only be renewed if the application of the procedure results in that the baseline as determined in the draft CDM-PDD, still apply..

Furthermore, all relevant data contained under "Data and parameters not monitored" should be updated.

[5] This value has been derived on data published for North American LNG systems. "Barclay, M. and N. Denton, 2005. Selecting offshore LNG process. http://www.fwc.com/publications/tech_papers/files/LNJ091105p34-36.pdf (10th April 2006)".

Data and parameters not monitored

Parameter:	$CF_{Naphtha,BL}$
Data unit:	tonnes of carbon/tonnes of naphtha
Description:	Carbon fraction of naphta used in the baseline as feed.
Source of data:	On-site measurements and plant laboratory records.
Measurement procedures (if any):	Laboratory analysis of the composition of the feed.
Any comment:	-
Parameter:	$F_{Naphtha,BL,I}$
Data unit:	tonnes
Description:	Quantity of naphtha used as feed in each one of the three most recent years k previous to the implementation of the project activity.
Source of data:	Obtained from data logs, measurements and plant records at the project site.
Measurement procedures (if any):	Feed consumption flow meter. Cross check with feed purchase receipts.
Any comment:	-

Parameter:	$FC_{BL,i,k}$
Data unit:	tonnes
Description:	Quantity of fuel of type i consumed in the furnaces (feed treatment and reforming) in each one of the most recent three years k previous to the implementation of the project activity.
Source of data:	Obtained from data logs, measurements and plant records at the project site.
Measurement procedures (if any):	Fuel flow meter. Cross check with fuel purchase receipts.
Any comment:	-

Parameter:	$NCV_{i,k}$
Data unit:	TJ/tonnes
Description:	Net calorific value of fuel type i consumed in the furnaces (feed treatment and reforming) in each one of the most recent three years k previous to the implementation of the project activity.
Source of data:	Project specific data obtained from fuel purchase receipts and/or laboratory tests, is preferred. In the absence of project specific data, local or national data may be used. In the absence of previous options, use data obtained in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.
Measurement procedures (if any):	-
Any comment:	-

Parameter:	$P_{urea,BL,y}$
Data unit:	tonnes
Description:	Production of urea in each one of the three most recent years k previous to the implementation of the project activity.
Source of data:	Obtained from data logs and urea stock verification records at the project site.
Measurement procedures (if any):	Daily urea production calculated based on the ammonia input to the urea plant and periodic (Quarterly) urea stock verification records.
Any comment:	-

III. MONITORING METHODOLOGY

Monitoring procedures

The data and parameters monitored are essentially related to the main activity of production of urea in the manufacturing facility.

Data and parameters monitored

Data / Parameter:	CF_{NG}
Data unit:	tonnes of carbon/tonnes of NG
Description:	Carbon content, expressed as weight fraction, of NG/LNG used as feed during year y of the crediting period, in tonnes of carbon/tonnes of NG/LNG. Obtained at the project activity.
Source of data:	Derived from the feed composition report provided by the feed supplier.
Measurement procedures (if any):	-
Monitoring frequency:	Daily
QA/QC procedures:	The feed composition report provided by the feed supplier should be from a certified laboratory
Any comment:	-

Data / Parameter:	$CF_{Naphtha,PJ}$
Data unit:	tonnes of carbon/tonnes of naphtha
Description:	Carbon content, expressed as weight fraction, of naphtha used as feed during year y of the crediting period.
Source of data:	Measured at the project activity through laboratory records.
Measurement procedures (if any):	Laboratory analysis.
Monitoring frequency:	Daily
QA/QC procedures:	The analysis should be carried out in a certified laboratory.
Any comment:	-

Data / Parameter:	$EC_{captive,y}$
Data unit:	MWh
Description:	Quantity of electricity obtained from a captive power plant by the projecty activity during each year y of the crediting period.
Source of data:	Measured in the project activity by digital control systems and/or data logs.
Measurement procedures (if any):	Electrical Energy Meter
Monitoring frequency:	Continuously
QA/QC procedures:	Electrical Energy Meter used for measurement should be calibrated regularly as per ISO procedures or according to manufacturer's guidelines
Any comment:	Applicable only if CDR plant is also being installed.

Data / Parameter:	$EC_{CDR,elec,y}$
Data unit:	MWh
Description:	Quantity of electricity consumed by the CDR plant in each year y of the crediting period.
Source of data:	Measured in the project activity by digital control systems and/or data logs.
Measurement procedures (if any):	Electrical Energy Meter
Monitoring frequency:	Continuously
QA/QC procedures:	Electrical Energy Meter used for measurement should be calibrated regularly as per ISO procedures or according to manufacturer's guidelines
Any comment:	-

Data / Parameter:	$EC_{grid,y}$
Data unit:	MWh
Description:	Quantity of electricity obtained from the grid by the projecty activity during each year y of the crediting period. Measured at the project site.
Source of data:	Measured in the project activity by digital control systems and/or data logs.
Measurement procedures (if any):	Electrical Energy Meter
Monitoring frequency:	Continuously
QA/QC procedures:	Electrical Energy Meter used for measurement should be calibrated regularly as per ISO procedures or according to manufacturer's guidelines
Any comment:	-

Data / Parameter:	$EF_{CO2,BL,y}$
Data unit:	tCO_{2e}/TJ
Description:	CO_2 emission factor for the baseline fuel that would be used in the furnaces (feed treatment and reforming) in each year y of the crediting period.
Source of data:	-
Measurement procedures (if any):	For the determination of emission factors, guidance from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories should be followed where appropriate. Project participants may either conduct measurements or they may use accurate and reliable local or national data where available. Where such data is not available, IPCC default emission factors (country-specific, if available any) may be used if they are deemed to reasonably represent local

	circumstances. All values should be chosen in a conservative manner and the choice should be justified and documented in the CDM-PDD. Laboratory analysis/Online Analysis - If carbon emission factor of fuel used is estimated by laboratory analysis, then the yearly average of fuel composition of respective fuel is to be used to calculate carbon emission factor.
Monitoring frequency:	-
QA/QC procedures:	-
Any comment:	Different fuel types might be used in the baseline scenario and project activity.

Data / Parameter:	$EF_{grid,y}$
Data unit:	tCO_2/MWh
Description:	CO_2 emission factor for grid electricity during the year *y*. This emission factor must be calculated as the generation-weighted average emissions per electricity unit of all generating sources serving the system or assumed as a default value of 1.2 tCO_2/MWh.
Source of data:	Use the latest approved version of "Tool to calculate emission factor for an electricity system" to calculate the grid emission factor.
Measurement procedures (if any):	-
Monitoring frequency:	Either once at the start of the project activity or updated annually, consistent with guidance in "Tool to calculate emission factor for an electricity system".
QA/QC procedures:	Apply procedures as in "Tool to calculate emission factor for an electricity system"
Any comment:	All data and parameters to determine the grid electricity emission factor, as required by "Tool to calculate emission factor for an electricity system", shall be included in the monitoring plan.

Data / Parameter:	$EF_{i,y}$
Data unit:	tCO_2/TJ
Description:	Emission factor of fuel type i used for steam generation in the year y.
Source of data:	-
Measurement procedures (if any):	For the determination of emission factors, guidance from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories should be followed where appropriate. Project participants may either conduct measurements or they may use accurate and reliable local or national data where available. Where such data is not available, IPCC default emission factors (country-specific, if available any) may be used if they are deemed to reasonably represent local circumstances. All values should be chosen in a conservative manner and the choice should be justified and documented in the CDM-PDD. Laboratory analysis/Online Analysis - If carbon emission factor of fuel used is estimated by laboratory analysis, then the yearly average of fuel composition of respective fuel is to be used to calculate carbon emission factor.
Monitoring frequency:	Yearly
QA/QC procedures:	Equipments and instruments used in the lab should be calibrated regularly as per ISO procedures or according to manufacturer's guidelines. If the analysis is

	carried out by outside agency ,it should be a certified /reputed lab
Any comment:	This parameter only needs to be monitored if CDR plant is also being installed

Data / Parameter:	$EF_{CO2,PJ,y}$
Data unit:	tCO_2/TJ
Description:	CO_2 emission factor of fuel type i used in the furnaces (feed treatment and reforming) in each year y of the crediting period. Chosen as the emission factor of the fuel type with the lowest emission factor among all the i fossil fuels used in the furnaces (feed treatment and reforming) in each year y of the crediting period.
Source of data:	-
Measurement procedures (if any):	For the determination of emission factors, guidance from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories should be followed where appropriate. Project participants may either conduct measurements or they may use accurate and reliable local or national data where available. Where such data is not available, IPCC default emission factors (country-specific, if available any) may be used if they are deemed to reasonably represent local circumstances. All values should be chosen in a conservative manner and the choice should be justified and documented in the CDM-PDD. Laboratory analysis/Online Analysis - If carbon emission factor of fuel used is estimated by laboratory analysis, then the yearly average of fuel composition of respective fuel is to be used to calculate carbon emission factor.
Monitoring frequency:	Yearly
QA/QC procedures:	Equipments and instruments used in the lab should be calibrated regularly as per ISO procedures or according to manufacturer's guidelines. If the analysis is carried out by outside agency ,it should be a certified /reputed lab
Any comment:	This parameter only needs to be monitored if CDR plant is also being installed

Data / Parameter:	$EF_{CO2,upstream,LNG,y}$
Data unit:	tCO_2/TJ
Description:	Emission factor for upstream CO_2 emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system in year y.
Source of data:	-
Measurement procedures (if any):	Where reliable and accurate data on upstream CO_2 emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system is available, project participants should use this data to determine an average emission factor. Where such data is not available, project participants may assume a default value of 6 tCO_2/TJ as a rough approximation[6].

[6] This value has been derived on data published for North American LNG systems. "Barclay, M. and N. Denton, 2005. Selecting offshore LNG process. http://www.fwc.com/publications/tech_papers/files/LNJ091105p34-36.pdf (10th April 2006)".

Monitoring frequency:	Yearly
QA/QC procedures:	-
Any comment:	-

Data / Parameter:	$EF_{NG,upstream,CH4}$
Data unit:	tCH_4/TJ
Description:	CH_4 emission factor for upstream fugitive methane emissions from production, transportation and distribution of natural gas feed supplied to final consumers
Source of data:	-
Measurement procedures (if any):	Where reliable and accurate national data on fugitive CH_4 emissions associated with the production, and in case of natural gas, the transportation and distribution of the fuels is available, project participants should use this data to determine average emission factors by dividing the total quantity of CH_4 emissions by the quantity of fuel produced or supplied respectively[7]. Where such data is not available, project participants may use the default values provided in table below. Note that the emission factor for fugitive upstream emissions for natural gas ($EF_{NG,upstream,CH4}$) should include fugitive emissions from production, processing, transport and distribution of natural gas, as indicated in the table provided in the baseline section.
Monitoring frequency:	Yearly
QA/QC procedures:	-
Any comment:	-

Data / Parameter:	P_{steam}
Data unit:	MPa
Description:	Pressure of the steam produced in the steam generator.
Source of data:	DCS/log sheet of steam generation plant or power plant
Measurement procedures (if any):	-
Monitoring frequency:	Daily
QA/QC procedures:	The device used for pressure measurement should be calibrated regularly as per ISO procedures or according to manufacturer's guidelines.
Any comment:	Used to calculate E_{steam}, the specific enthalpy of the steam at the steam generator outlet, in TJ/tonnes. Calculated as per guidance below.

[7] GHG inventory data reported to the UNFCCC as part of national communications can be used where country specific approaches (and not IPCC Tier 1 default values) have been used to estimate emissions.

Data / Parameter:	T_{steam}
Data unit:	^{o}C
Description:	Temperature of the steam produced in the steam generator.
Source of data:	DCS/log sheet of steam generation plant or power plant
Measurement procedures (if any):	-
Monitoring frequency:	Daily
QA/QC procedures:	The device used for temperature measurement should be calibrated as per ISO procedures or according to manufacturer's guidelines.
Any comment:	Used to calculate E_{steam}, the specific enthalpy of the steam at the steam generator outlet, in TJ/tonnes. Calculated as per guidance below.

Data / Parameter:	P_{fw}
Data unit:	MPa
Description:	Pressure of the feedwater used in the steam generator.
Source of data:	DCS/log sheet of steam generation plant or power plant.
Measurement procedures (if any):	-
Monitoring frequency:	Daily
QA/QC procedures:	The device used for pressure measurement should be calibrated regularly as per ISO procedures or according to manufacturer's guidelines.
Any comment:	Used to calculate $E_{feedwater}$, the specific enthalpy of the feed water at the steam generator inlet, in TJ/tonnes.

Data / Parameter:	T_{fw}
Data unit:	^{o}C
Description:	Temperature of the feedwater used in the steam generator.
Source of data:	DCS/log sheet of steam generation plant or power plant
Measurement procedures (if any):	-
Monitoring frequency:	Daily
QA/QC procedures:	The device used for temperature measurement should be calibrated as per ISO procedures or according to manufacturer's guidelines.
Any comment:	Used to calculate $E_{feedwater}$, the specific enthalpy of the feed water at the steam generator inlet, in TJ/tonnes.

Data / Parameter:	$F_{NG,PJ,y}$
Data unit:	Mass or volume units
Description:	Consumption of NG/LNG as feed during the year y of the crediting period. If the available data are measured in volume units use the appriopriate density of NG/LNG, corrected for temperature and pressure, to calculate the equivalent mass.
Source of data:	On-site measurements
Measurement procedures (if any):	Flow-rate meters. Cross-check with fuel purchase receipts.
Monitoring frequency:	Continuously
QA/QC procedures:	Meters should be calibrated regularly according to manufacturer's guidelines.
Any comment:	Volumetric units should be at normal pressure and temperature (NTP)

Data / Parameter:	$F_{Naphtha,PJ,y}$
Data unit:	tonnes
Description:	Consumption of naphtha as feed during the year y of the crediting period. Measured at the project activity.
Source of data:	On-site measurements
Measurement procedures (if any):	Flow-rate meters. Cross-check with fuel purchase receipts.
Monitoring frequency:	Continuously
QA/QC procedures:	Meters should be calibrated regularly according to manufacturer's guidelines.
Any comment:	-

Data / Parameter:	$FC_{CDR,captive,i,y}$
Data unit:	Mass or volume units
Description:	Amount of fossil fuel of type i used in the captive power plant in each year y of the crediting period.
Source of data:	Measured at the captive power plant.
Measurement procedures (if any):	Flow-rate meters, mass meters, cross-check with fuel purchase receipts.
Monitoring frequency:	Continuously
QA/QC procedures:	Meters should be calibrated regularly according to manufacturer's guidelines.
Any comment:	-

Data / Parameter:	$FC_{CDR,steam,i,y}$
Data unit:	Mass or volume units
Description:	Amount of fuel type i consumed in the steam generator in each year y of the crediting period.
Source of data:	Measured at the steam generator site.
Measurement procedures (if any):	Flow-rate meters, mass meters, cross-check with fuel purchase receipts.
Monitoring frequency:	Continuously
QA/QC procedures:	Meters should be calibrated regularly according to manufacturer's guidelines.
Any comment:	-

Data / Parameter:	$FC_{i,y}$
Data unit:	Mass or volume units
Description:	Quantity of fuel type i consumed in the furnaces (feed treatment and reforming) in each year y of the crediting period.
Source of data:	On-site measurements
Measurement procedures (if any):	Flow-rate meters
Monitoring frequency:	Continuously
QA/QC procedures:	Meters should be calibrated regularly according to manufacturer's guidelines.
Any comment:	Volumetric units should be at normal pressure and temperature

Parameter:	$NCV_{i,y}$ and $NCV_{NG,y}$
Data unit:	TJ/mass or volume units
Description:	Average net calorific value of fuel type i and NG/LNG respectively, in year y of the crediting period.
Source of data:	Project specific data obtained from fuel purchase receipts and/or laboratory tests, is preferred. In the absence of project specific data, local or national data may be used. In the absence of previous options, use data obtained in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.
Measurement procedures (if any):	-
Monitoring frequency	The calorific value of the respective fuel is measured daily and monthly average of calorific value is calculated by averaging daily value. Yearly average of calorific value is calculated by averaging monthly value.
QA/QC procedures	-
Any comment:	-

Data / Parameter:	$P_{urea,PJ,y}$
Data unit:	tonnes
Description:	Production of urea in each year y of the crediting period.
Source of data:	Urea stock verification records
Measurement procedures (if any):	Daily urea production calculated based on the ammonia input to the urea plant and periodic (Quarterly) urea stock verification records.
Monitoring frequency:	Quarterly
QA/QC procedures:	Flow meter(s) (Ammonia to urea plant) should be calibrated regularly according to manufacturer's guidelines. Measurement results should be cross-checked with the periodic urea stock verification carried out by external agencies.
Any comment:	-

Data / Parameter:	$SC_{CDR,y}$
Data unit:	tonnes
Description:	Demand of steam for the operation of the CDR plant in each year y of the crediting period.
Source of data:	DCS/log sheet of ammonia plant
Measurement procedures (if any):	Use steam flow meters.
Monitoring frequency:	Continuously
QA/QC procedures:	Steam Flow Meter used for measurement should be calibrated regularly as per ISO procedures or according to manufacturer's guidelines
Any comment:	-

Data / Parameter:	$TEP_{CDR,captive,y}$
Data unit:	MWh
Description:	Total electricity produced by the captive power plant in year y.
Source of data:	Measured at the captive power plant through electricity meters. Cross check with electricity purchase receipts, if any.
Measurement procedures (if any):	-
Monitoring frequency:	Continuously
QA/QC procedures:	Electricity flow meter used for measurement should be calibrated regularly as per ISO procedures or according to manufacturer's guidelines.
Any comment:	-

Data / Parameter:	$TSP_{CDR,steam,y}$
Data unit:	tonnes
Description:	Total amount of steam produced by the steam generator in each year y of the crediting period.
Source of data:	Measured at the steam generator site through steam flow meters.
Measurement procedures (if any):	-
Monitoring frequency:	Continuously
QA/QC procedures:	Steam flow meter used for measurement should be calibrated regularly as per ISO procedures or according to manufacturer's guidelines.
Any comment:	-

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History of the document

Version	Date	Nature of revision(s)
2.1	EB 39, Para 15, 14 May 2008	1. In variable description section of equation 2 change $BE_{Urea,y}$ to $BS_{Urea,y}$. 2. Delete text “after deducting the CO_2 recovered by the CDR plant (if any)”while describing emissions from thermal energy (above equation 12). 3. Note added below table-2 “The emission factor should be selected in order to ensure conservativeness in estimation of emission reduction.” 4. In section III monitoring methodology first para, the sentence mentioning that the parameters should be monitored on daily basis, is deleted. 5. In table “data and parameters monitored” the data unit of CF_{NG} is changed from “tonnes of carbon/tonnes of hydrogen” to “tonnes of carbon/tonnes of NG”.
02	EB 35, Para 24, 19 October 2007	Revision to incorporate the use of the “Tool to calculate emission factor for an electricity system”
01	EB 31, Annex 4, 4 May 2007	Initial adoption