Indicative simplified baseline and monitoring methodologies
for selected small-scale CDM project activity categories

TYPE I - RENEWABLE ENERGY PROJECTS

Project participants shall apply the general guidlines to the SSC CDM methodologies, information on additionality (attachment A to Appendix B) and general guidance on leakage in biomass project activities (attachment C to Appendix B) provided at <http://cdm.unfccc.int/methodologies/SSCmethodologies/approved.html> *mutatis mutandis*.

I.C. Thermal energy production with or without electricity

Technology/measure

1. This category comprises renewable energy technologies that supply users[1] with thermal energy that displaces fossil fuel use. These units include technologies such as solar thermal water heaters and dryers, solar cookers, energy derived from renewable biomass and other technologies that provide thermal energy that displaces fossil fuel.

2. Biomass-based cogeneration systems consisting of steam generator(s) and steam turbine(s) are included in this category. For the purpose of this methodology "cogeneration" shall mean the simultaneous generation of thermal energy and electrical energy in one process. Project activities that produce heat and power in separate element processes (for example, heat from a boiler and electricity from biogas engine) do not fit under the definition of cogeneration project.

3. Emission reductions from a biomass cogeneration system can accrue from one of the following activities:

   (a) Electricity supply to a grid;

   (b) Electricity and/or thermal energy (steam or heat) production for on-site consumption or for consumption by other facilities;

   (c) Combination of (a) and (b).

4. The total installed/rated thermal energy generation capacity of the project equipment is equal to or less than 45 MW thermal[2] (see paragraph 6 for the applicable limits for cogeneration project activities).

5. For co-fired[3] systems, the total installed thermal energy generation capacity of the project equipment, when using both fossil and renewable fuel shall not exceed 45 MW thermal (see paragraph 6 for the applicable limits for cogeneration project activities).

6. The following capacity limits apply for biomass cogeneration units:

   (a) If the project activity includes emission reductions from both the thermal and electrical energy components, the total installed energy generation capacity

[1] That is residential, industrial or commercial facilities.

[2] Thermal energy generation capacity shall be manufacturer's rated thermal energy output, or if that rating is not available the capacity shall be determined by taking the difference between enthalpy of total output (for example steam or hot air in kcal/kg or kcal/m^3) leaving the project equipment and the total enthalpy of input (for example feed water or air in kcal/kg or kcal/m^3) entering the project equipment. For boilers, condensate return (if any) must be incorporated into enthalpy of the feed.

[3] Co-fired system uses both fossil and renewable fuels.

(thermal and electrical) of the project equipment shall not exceed 45 MW thermal. For the purpose of calculating this capacity limit the conversion factor of 1:3 shall be used for converting electrical energy to thermal energy (i.e. for renewable project activities, the maximal limit of 15 MW(e) is equivalent to 45 MW thermal output of the equipment or the plant);

(b) If the emission reductions of the cogeneration project activity are solely on account of thermal energy production (i.e. no emission reductions accrue from electricity component), the total installed thermal energy production capacity of the project equipment of the cogeneration unit shall not exceed 45 MW thermal;

(c) If the emission reductions of the cogeneration project activity are solely on account of electrical energy production (i.e. no emission reductions accrue from thermal energy component), the total installed electrical energy generation capacity of the project equipment of the cogeneration unit shall not exceed 15 MW.

7. In case electricity and/or steam/heat produced by the project activity is delivered to another facility or facilities within the project boundary, a contract between the supplier and consumer(s) of the energy will have to be entered into specifying that only the facility generating the energy can claim emission reductions from the energy displaced.

8. Project activities that seek to retrofit or modify an existing facility for renewable energy generation are included in this category.

9. The capacity limits specified in the above paragraphs apply to both new facilities and retrofit projects. In the case of project activities that involve the addition of renewable energy units at an existing renewable energy facility, the total capacity of the units added by the project should comply with capacity limits in paragraphs 4 to 6 and should be physically distinct[4] from the existing units.

10. Charcoal based biomass energy generation project activities are eligible to apply the methodology only if the charcoal is produced from renewable biomass sources[5] provided:

(a) Charcoal is produced in kilns equipped with methane recovery and destruction facility; or

(b) If charcoal is produced in kilns not equipped with a methane recovery and destruction facility, methane emissions from the production of charcoal shall be considered. These emissions shall be calculated as per the procedures defined in the approved methodology AMS-III.K. Alternatively, conservative emission factor values from peer reviewed literature or from a registered CDM project activity can be used, provided that it can be demonstrated that the parameters from these are comparable e.g. source of biomass, characteristics of biomass such as

[4] Physically distinct units are those that are capable of producing thermal/electrical energy without the operation of existing units, and that do not directly affect the mechanical, thermal, or electrical characteristics of the existing facility. For example, the addition of a steam turbine to an existing combustion turbine to create a combined cycle unit would not be considered “physically distinct”.

[5] Refer to EB 23, Annex 18 for the definition of renewable biomass.

moisture, carbon content, type of kiln, operating conditions such as ambient temperature.

11. If solid biomass fuel (e.g. briquette) is used, it shall be demonstrated that it has been produced using solely renewable biomass and all project or leakage emissions associated with its production shall be taken into account in emissions reduction calculation.

Project Boundary

12. The physical, geographical site of the project equipment producing the renewable energy delineates the project boundary. The boundary also extends to the industrial, commercial or residential facility, or facilities, consuming energy generated by the system and the processes or equipment that is affected by the project activity.

Baseline Emissions

13. For renewable energy technologies that displace technologies using fossil fuels, the simplified baseline is the fuel consumption of the technologies that would have been used in the absence of the project activity times an emission factor for the fossil fuel displaced. For calculating the emission factor, reliable local or national data shall be used. IPCC default values shall be used only when country or project specific data are not available or demonstrably difficult to obtain.

14. For fuel switching from fossil fuel to renewable biomass in existing facilities, historical information (detailed records) on the use of energy sources (e.g. electricity, fossil fuel) and the plant output (e.g. steam/electricity) in the baseline plant from at least three years prior to project implementation shall be used in the baseline calculations. For facilities that are less than three years old, all historical data shall be available (a minimum of one year data would be required). In case of project activity exporting to other facilities included in the project boundary, the above historical information from the recipient plants are required.

15. Project activities producing both heat and electricity using biomass cogeneration shall use one of the following baseline scenarios:[6]

(a) Electricity is imported from the grid and thermal energy (steam/heat) is produced using fossil fuel;

(b) Electricity is produced in an on-site captive power plant using fossil (with a possibility of export to the grid) and thermal energy (steam/heat) is produced using fossil fuel;

(c) A combination of (a) and (b);

(d) Electricity and thermal energy (steam/heat) are produced in a cogeneration unit using fossil fuel (with a possibility of export of electricity to the grid/other facilities and/or thermal energy to other facilities);

[6] Cases where no historical information is available, the most plausible energy supply sources shall be established in accordance with the guidance on Greenfield projects in the general guidelines to SSC CDM methodologies.

(e) Electricity is imported from the grid and/or produced in an on-site captive power plant using fossil fuels (with a possibility of export to the grid); steam/heat is produced from biomass;

(f) Electricity is produced in an on-site captive power plant using biomass (with a possibility of export to the grid) and/or imported from the grid; steam/heat is produced using fossil fuel;

(g) Electricity and thermal energy (steam/heat) are produced in a biomass fired cogeneration unit (without a possibility of export of electricity either to the grid or to other facilities and without a possibility of export of thermal energy to other facilities):[7]

(h) Electricity and/or thermal energy produced in a co-fired system.

(i) Electricity is imported from the grid[8] and/ or produced in a biomass fired cogeneration unit (without a possibility of export of electricity either to the grid or to other facilities); steam/heat is produced from biomass fired cogeneration unit or biomass fired boiler (without a possibility of export of thermal energy to other facilities).

16. Baseline emissions for electricity produced in captive plants shall be calculated as follows:

$$BE_{captelec,y} = (EG_{captelec,PJ,y} / \eta_{BL,captive\ plant}) * EF_{BL,FF,CO_2} \quad \textbf{(1)}$$

Where:

$BE_{captelec,y}$	The baseline emissions from electricity displaced by the project activity during the year *y* (tCO_2)
$EG_{captelec,PJ,y}$	The amount of electricity produced by the project activity during the year *y* (MWh)
EF_{BL,FF,CO_2}	The CO_2 emission factor of the fossil fuel that would have been used in the baseline plant obtained from reliable local or national data if available; otherwise, IPCC default emission factors are used; (tCO_2/MWh)
$\eta_{BL,captive\ plant}$	The efficiency of the plant using fossil fuel that would have been used in the absence of the project activity

17. Baseline emissions for supply of electricity to and/or displacement electricity from a grid shall be calculated as per the procedures detailed in AMS-I.D.

18. For steam/heat produced using fossil fuels the baseline emissions are calculated as follows:

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[7] This scenario applies to the situation where new grid connected biomass cogeneration system/s installed by the project activity produces surplus electricity compared to the pre-project situation and all the services provided in baseline i.e. energy supply are maintained at the same level or improved during the crediting period (see paragraph 32).

[8] Grid import is more than captive electricity generation using biomass.

$$BE_{thermal,CO_2,y} = (EG_{thermal,y} / \eta_{BL,thermal}) * EF_{FF,CO_2} \quad \textbf{(2)}$$

Where:

$BE_{thermal,CO_2,y}$	The baseline emissions from steam/heat displaced by the project activity during the year *y* (tCO_2)
$EG_{thermal,y}$	The net quantity of steam/heat supplied by the project activity during the year *y* (TJ)
EF_{FF,CO_2}	The CO_2 emission factor of the fossil fuel that would have been used in the baseline plant; tCO_2/TJ, obtained from reliable local or national data if available, otherwise, IPCC default emission factors are used
$\eta_{BL,thermal}$	The efficiency of the plant using fossil fuel that would have been used in the absence of the project activity

19. For cases 15 (a), (b) and (c), baseline emissions shall be calculated as the sum of emissions from the production of electricity and steam/heat considering most recent historical records (average of the data from a minimum of three most recent years excluding abnormal years is required).

20. For project activities that displace on-site captive electricity and/or displace grid electricity import and/or supply electricity to grid, the emission factor for the electricity should reflect the emissions intensity of the captive power plant and the grid of the baseline scenario. If annual electricity produced in the project activity is less than or equal to the sum of on-site captive generation and net grid import[9] (average of most recent three years data) in the baseline scenario, the emission factor shall be calculated as the weighted average of on-site captive electricity generation and the net grid electricity import in the baseline.[10] If annual electricity produced in the project activity is greater than the sum of on-site captive generation and net grid import (average of most recent three years data) in the baseline, lower of the two i.e. emission factor of the grid or the emission factor of the baseline captive plant shall be used for the incremental generation (i.e. the difference between the electricity generation in the project activity and the sum of captive generation and net grid import).

21. For project activities that do not displace captive electricity generated by existing plant but displace grid electricity import and/or supply electricity to grid, the emission factor of the grid shall be calculated as per the procedures detailed in AMS-I.D.

22. For new facilities, the most conservative (lowest) emission factor of the two power sources should be used.

23. For electricity and thermal energy (steam/heat) produced in a baseline cogeneration unit, using fossil fuel (case 15 (d)), the following equation shall be used to determine baseline emissions:

$$BE_{cogen,CO_2,y} = [(EG_{PJ,thermal,y} + EG_{PJ,electrical,y} * 3.6) / \eta_{BL,cogen}] * EF_{FF,CO_2} \quad \textbf{(3)}$$

[9] Difference of total electricity imported from the grid and total electricity exported to the grid.

[10] For example in the baseline if 80% of annual electricity requirement was met by grid import and rest by captive generation, the weighted average emission factor (EF) would be 0.8 EF_{grid}+ 0.2 $EF_{captive}$.

Where:

$BE_{cogen,CO_2,y}$	Baseline emissions from electricity and thermal energy displaced by the project activity during the year *y* (tCO_2)
$EG_{PJ,electrical,y}$	The amount of electricity supplied by the project activity during the year *y*; GWh
3.6	Conversion factor (TJ/GWh)
$EG_{PJ,thermal,y}$	The net quantity of thermal energy supplied by the project activity during the year *y* (TJ)
EF_{FF,CO_2}	The CO_2 emission factor of the fossil fuel that would have been used in the baseline cogeneration plant; tCO_2/TJ obtained from reliable local or national data if available, otherwise IPCC default emission factors are used
$\eta_{BL,cogen}$	The total annual average efficiency of the cogeneration plant using fossil fuel determined in accordance with paragraphs 24 and 25 below

24. In the case of an existing baseline cogeneration plant, the efficiency shall be calculated as the total annual energy produced over the last three years using the historical data as prescribed in paragraph 14 (total electricity generated and total steam/heat extracted divided by the thermal energy value of the fuel use).

25. In the case of a Greenfield project cogeneration plant where the baseline is a cogeneration plant (using a steam turbine and steam generator that would have been built in the absence of the project activity), the total annual average efficiency of the cogeneration plant using fossil fuel shall be defined as the ratio of thermal energy (steam/heat) and electricity produced to total thermal energy value of the fuel use. This ratio shall be determined using one of the two following options (in preferential order):

(a) Calculated as a single value with consideration of the following:

Step 1:

The total annual average efficiency of the cogeneration plant using fossil fuel is determined using documented efficiency specification for new steam turbines and steam generators provided by two or more manufacturers for each type of such equipment within in the region:[11]

- Efficiency values for the steam turbine(s) and steam generator(s) shall be based on turbines and steam generators with specifications nearly equivalent to baseline units that would have been utilized in the absence of the project activity;
- The efficiency values utilized shall be the highest individual efficiency values (over the full range of expected operating conditions of the baseline cogeneration system) that can be achieved by the steam turbine(s) and steam generator(s).

Step 2:

[11] In case equipment is not available within the region the project proponent shall consider adjoining regions.

The total annual average efficiency of the cogeneration plant using fossil fuel is then calculated as the product of the highest efficiency value for the steam turbine(s) and the highest efficiency value of the steam generator(s), assuming both efficiencies are in the form of a percentage of output per input.

(b) Calculated as a single value with consideration of the following:

Step 1:

- A default steam turbine efficiency of 100%;
- A default steam generator efficiency determined using the "Tool to determine the baseline efficiency of thermal or electric energy generation systems".

Step 2:

- The total annual average efficiency of the cogeneration plant using fossil fuel is then calculated as the product of the efficiency value for the steam turbine(s) and the efficiency value of the steam generator(s), assuming both efficiencies are in the form of a percentage of output per input.

26. Efficiency of the baseline units (excluding cogeneration plants) shall be determined by adopting one of the following criteria (in a preferential order):

(a) Highest measured operational efficiency over the full range of operating conditions of a unit with similar specifications, using baseline fuel. The efficiency tests shall be conducted following the guidance provided in relevant national/international standards;

(b) Highest of the efficiency values provided by two or more manufacturers for units with similar specifications, using the baseline fuel;

(c) Default efficiency of 100%.

27. For household or commercial applications/systems, whose maximum output capacity is less than 45 kW thermal and where it can be demonstrated that the metering of thermal energy output is not plausible, as in the case of cooking stoves, gasifiers, driers, water heaters etc., efficiency of the baseline units shall be determined by adopting one of the following criteria:

(a) Highest measured operational efficiency over the full range of operating conditions of a representative sample of units with similar specifications, using baseline fuel. The efficiency tests shall be conducted following the guidance provided in relevant national/international standards;

(b) Highest of the efficiency values provided by two or more manufacturers for units with similar specifications using the baseline fuel;

(c) Highest efficiency from referenced literature values or default efficiency of 100%.

28. For case 15 (e), baseline emissions from the production of electricity shall be calculated as per paragraph 19 to 22. Emission reductions from heat generation are not eligible.

29. For case 15 (f), baseline emissions from the production of steam/heat using fossil fuel shall be calculated as per paragraph 18. Emission reductions from displacing on-site electricity generation are not eligible.

30. For case 15 (g), baseline emissions from the production of electricity that displaces grid electricity import and/or supply electricity to the grid, shall be calculated as per paragraph 17. Emission reductions from both the generation of electricity and thermal energy (steam/heat) for on-site consumption are not eligible.

31. For 15 (h), baseline emissions shall be determined based on three years average historical data on the relative share of fossil fuel and biomass in the baseline fuel mix. The relative share is determined based on the energy content of each fuel.

$$BE_{cofire,CO_2,y} = (EG_{cofire,PJ,y} / \eta_{BL,cofire}) * EF_{cofire,CO_2} \qquad \textbf{(4)}$$

Where:

$BE_{cofire,CO_2,y}$	The baseline emissions from thermal and/or electrical energy displaced by the project activity during the year *y* (tCO_2e)
$EG_{cofire,PJ,y}$	The net quantity of energy (electricity/thermal) supplied by the project activity during the year *y* (TJ)
EF_{cofire,CO_2}	CO_2 emission factor of the baseline co-fired plant established using three years average historical data (tCO_2/TJ). In the case where more than one fossil fuel is used by the co-fired plant, the weighted average emission factor (in energy basis) among the identified fossil fuels shall be used
$\eta_{BL,cofire}$	The efficiency of the co-fired plant that would have been used in the absence of the project activity

32. For case 15 (i), baseline emissions from the production of electricity shall be calculated as per paragraph 21. Emission reductions from heat generation are not eligible.

33. In the case of project activities that involve the addition of renewable energy units at an existing renewable energy production facility, where the existing and new units share the use of common and limited renewable resources (e.g. biomass residues), the potential for the project activity to reduce the amount of renewable resource available to, and thus thermal energy production by, existing units must be considered in the determination of baseline emissions, project emissions, and/or leakage, as relevant.

34. For project activities that involve the addition of new energy production units (e.g. turbines) at an existing facility, net increase in thermal energy generation should be calculated as follows:

$$EG_{thermal,add,y} = EG_{thermal,PJ,y} - EG_{thermal,old,y} \qquad \textbf{(5)}$$

Where:

$EG_{thermal,add,y}$	Net increase in thermal energy generation at existing plant in year *y* that should be considered as energy baseline (EG_{BL}) (TJ)
$EG_{thermal,PJ,y}$	Total actual thermal energy produced in year *y* by all units, existing and new

project units (TJ)

$EG_{thermal,old,y}$ Estimated thermal energy that would have been produced by existing units (installed before the project activity) in year *y* in the absence of the project activity; TJ

The value $EG_{thermal,old,y}$ is given by:

$$EG_{thermal,old,y} = MAX\left(EG_{thermal,actual,y}, EG_{thermal,estimated,y}\right) \quad \textbf{(6)}$$

Where:

$EG_{thermal,actual,y}$ The actual, measured thermal energy production of the existing units in year *y* (TJ)

$EG_{thermal,estimated,y}$ The estimated thermal energy that would have been produced by the existing units under the observed availability of the renewable resource for year *y (*TJ)

If the existing units shut down, are derated, or otherwise become limited in production, the project activity should not get credit for generating thermal energy from the same renewable resources that would have otherwise been used by the existing units (or their replacements). Therefore, the equation for $EG_{thermal,old,y}$ still holds, and the value for $EG_{thermal,estimated,y}$ should continue to be estimated assuming the capacity and operating parameters are the same as that at the time of the start of the project activity.

If the existing units are subject to modifications or retrofits that increase production, then $EG_{thermal,old,y}$ can be estimated using the procedures described for $EG_{BL,thermal,retrofit,y}$ below.

35. For project activities that seek to retrofit or modify an existing facility for renewable energy generation the baseline scenario is the following:

In the absence of the CDM project activity, the existing facility would continue to provide thermal energy $EG_{BL,thermal,retrofit,y}$ at historical average levels $EG_{HY,thermal,retrofit,y}$, until the time at which the thermal energy facility would be likely to be replaced or retrofitted in the absence of the CDM project activity ($DATE_{BaselineRetrofit}$). From that point of time onwards, the baseline scenario is assumed to correspond to the project activity, and baseline thermal energy production is assumed to equal project thermal energy production and no emission reductions are assumed to occur.

$$EG_{BL,thermal,retrofit,y} = MAX\left(EG_{historical,thermal,y}, EG_{estimated,thermal,y}\right) \quad until \quad DATE_{BaselineRretrofit} \quad \textbf{(7)}$$

Where:

$EG_{BL,thermal,retrofit,y}$	Thermal energy production by an existing facility in the absence of the project activity (TJ)
$EG_{historical,thermal,y}$	Average of historical thermal energy levels delivered by the existing facility, spanning all data from the most recent available year (or month, week or other time period) to the time at which the facility was constructed, retrofit, or modified in a manner that significantly affected output (i.e. by 5% or more). A minimum of three years (excluding abnormal years) of historical production data is required. In the case that three years of historical data are not available - e.g. due to recent retrofits or exceptional circumstances, a new methodology or methodology revision must be proposed (TJ)
$EG_{estimated,thermal,y}$	Estimated thermal energy that would have been produced by the existing units under the observed availability of renewable resource in year *y* (TJ)
$DATE_{BaselineRretrofit}$	Date at which the existing generation facility is likely to be replaced or retrofitted in the absence of the CDM project activity

36. For project activities that seek to retrofit or modify an existing facility to enhance the energy conversion efficiency, the baseline emissions $BE_{retrofit,CO_2,y}$ then correspond to the difference of the thermal energy supplied by the project activity and the baseline thermal energy supplied in the case of modified or retrofit facilities multiplied by the emission factor of the fuel that would have been used to generate the incremental energy:

$$BE_{retrofit,CO2,y} = \left(EG_{thermal,retrofit,y} - EG_{BL,thermal,retrofit,y}\right) * EF_{FF,CO2} \quad \textbf{(8)}$$

Where:

$BE_{retrofit,CO2,y}$	Baseline emissions from the incremental thermal energy supplied due to retrofit (tCO_2)
$EG_{thermal,retrofit,y}$	Thermal energy supplied by the project activity (after retrofit) in year *y* (TJ)
$EG_{BL,thermal,retrofit,y}$	Thermal energy production by an existing facility in the absence of the project activity (before retrofit) in year *y* (TJ)
$EF_{FF,CO2}$	The CO_2 emission factor of the fossil fuel that would have been used in the baseline plant to generate the incremental energy; tCO_2/TJ obtained from reliable local or national data if available, otherwise IPCC default emission factors are used

37. The requirements concerning demonstration of the remaining lifetime of the replaced equipment shall be met as described in the "General Guidelines to SSC CDM methodologies". If the remaining lifetime of the affected systems increases due to the project activity, the crediting period shall be limited to the estimated remaining lifetime, i.e. the time when the affected systems would have been replaced in the absence of the project activity.

38. In order to estimate the point in time when the existing equipment would need to be replaced in the absence of the project activity ($DATE_{BaselineRretrofit}$), project participants may follow the procedures described in the general guidelines.

39. For project activities that seek to retrofit or modify an existing facility for the purpose of fuel switch from fossil fuels to biomass residues in heat generation equipment, the baseline emissions shall be calculated as per equation 2.

40. For household or commercial applications/systems, whose maximum output capacity is less than 45 kW thermal and where it can be demonstrated that the metering of thermal energy output is not plausible, as in the case of biomass stoves, gasifiers, driers, water heaters etc, the project output energy shall be estimated based on consumption of the biomass (in terms of energy quantity) times the efficiency of the project equipment. The equation below shall be used:

$$BE_y = [HG_{PJ,y} / \eta_{BL}] * EF_{FF,CO2}$$
$$= \{[B_{biomass,PJ,y} * NCV_{biomass} * \eta_{PJ}] / \eta_{BL}\} * EF_{FF,CO2} \quad \textbf{(9)}$$

Where:

BE_y	The baseline emissions from thermal energy displaced by the project activity using renewable biomass during the year *y* (tCO_2)
$HG_{PJ,y}$	The net quantity of thermal energy supplied by the project activity using renewable biomass during the year *y* (TJ)
η_{BL}	Efficiency of the baseline equipment being replaced (determined as per paragraph 26 or 27)
η_{PJ}	Efficiency of the project equipment measured using representative sampling methods or based on referenced literature values. The efficiency tests shall be conducted following the guidance provided in the relevant national/international standards
$EF_{FF,CO2}$	The CO_2 emission factor of the fossil fuel that would have been used in the baseline (tCO_2/TJ)
$B_{biomass,PJ,y}$	The net quantity of the biomass consumed in year *y* (tons)
$NCV_{biomass}$	The net calorific value of the biomass (TJ/tons)

41. In the case of project activity consuming biomass and fossil fuel to produce thermal and or electrical energy, specific energy consumption[12] of each type of fuel (biomass or fossil) to be used shall be specified *ex ante*. The consumption of each type of fuel shall be monitored.

Specific energy consumption can be derived as follows:

[12] Specific energy consumption is the fuel consumption (in energy basis) per unit of thermal energy or electricity generated (e.g. TJ of bagasse energy per MWh output).

$$SEC_{j,PJ,y,measured} = \frac{\sum_{j}(FC_{j,PJ,y} * NCV_{j,y})}{EG_{PJ,y}} \quad \textbf{(10)}$$

Where:

$SEC_{j,PJ,y,measured}$	Specific energy consumption of fuel type *j* of the project activity in year *y* (TJ/MWh)
$EG_{PJ,y}$	Energy generation in year *y* (MWh)
$FC_{j,PJ,y}$	Quantity of fuel type *j* combusted in the project activity during the year *y* (volume or mass unit)
$NCV_{j,y}$	Average net calorific value of fuel type *j* combusted during the year *y* (TJ per unit volume or mass unit)

42. For the specific case of co-fired plants, the baseline emissions for the amount of thermal energy or electricity produced corresponding to biomass fuels use shall be calculated as follows:

$$BE_{cofire,y} = \frac{\sum_{k}(FC_{biomass,k,y} \times NCV_{biomass,k,y})}{SEC_{PJ,j,y,measured} \times \eta_{BL}} * EF_{BL} \quad \textbf{(11)}$$

Where:

$BE_{cofire,y}$	Baseline emissions during the year *y* (tCO_2)
$FC_{biomass,k,y}$	Quantity of biomass type *k* combusted during the year *y* (volume or mass unit)
$NCV_{biomass,k,y}$	Average net calorific value of biomass type *k* combusted during the year *y* (TJ per unit volume or mass unit)
EF_{BL}	CO_2 emission factor of the fossil fuel that would have been used in the baseline co-fired plant established using three years average historical data (tCO_2/MWh)
η_{BL}	Energy efficiency of the equipment that would have been used in the baseline

43. For the co-fired systems, baseline emissions calculated as per paragraph 31 shall be compared with the baseline emissions calculated as per paragraph 41. The lower of the two values shall be used to calculate emission reductions.

Project Emissions

44. Project emissions include:

- CO_2 emissions from on-site consumption of fossil fuels due to the project activity shall be calculated using the latest version of the “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion”;

- CO_2 emissions from electricity consumption by the project activity using the latest version of the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption";
- Any other significant emissions associated with project activity within the project boundary;
- For geothermal project activities, project participants shall account for the following emission sources, where applicable: fugitive emissions of carbon dioxide and methane due to release of non-condensable gases from produced steam; and carbon dioxide emissions resulting from combustion of fossil fuels related to the operation of the geothermal power plant.[13]

45. Project emissions in the case of geothermal project activities are calculated as follows:

$$PE_{Geo,y} = PE_{s,y} + PE_{FF,y} \quad \textbf{(12)}$$

Where:

$PE_{Geo,y}$	Project emissions in year *y* (tCO_2/y)
$PE_{s,y}$	Project emissions of carbon dioxide and methane due to the release of non-condensable gases from the steam produced in the geothermal power plant in year *y* (tCO_2)
$PE_{FF,y}$	Project emissions from combustion of fossil fuels related to the operation of the geothermal power plant in year *y* (tCO_2)

Project emissions of carbon dioxide and methane due to the release of non-condensable gases from the steam produced in the geothermal power plant is calculated as:

$$PE_{s,y} = \left(w_{Main,CO2} + w_{Main,CH4} * GWP_{CH4}\right) * M_{S,y} \quad \textbf{(13)}$$

Where:

$w_{Main,CO2}$	Average mass fraction of carbon dioxide in the produced steam (non-dimensional)
$w_{Main,CH4}$	Average mass fraction of methane in the produced steam (non-dimensional)
GWP_{CH4}	Global warming potential of methane valid for the relevant commitment period (tCO_2e/tCH_4)
$M_{S,y}$	Quantity of steam produced during the year *y* (tonnes)

Project emissions from combustion of fossil fuels related to the operation of the geothermal power plant is calculated as:

$$PE_{FF,y} = PE_{FC,j,y} \quad \textbf{(14)}$$

[13] Fugitive carbon dioxide and methane emissions due to well testing and well bleeding are not considered, as they are negligible.

Where:

$PE_{FC,j,y}$	CO_2 emissions from fossil fuel combustion in process *j* during the year *y* (tCO_2). This parameter shall be calculated as per the latest version of the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion" where *j* stands for the processes required for the operation of the geothermal power plant

Leakage

46. If the energy generating equipment currently being utilised is transferred from outside the boundary to the project activity, leakage is to be considered.

47. In case collection/processing/transportation of biomass residues is outside the project boundary CO_2 emissions from collection/processing/transportation[14] of biomass residues to the project site.

Emission reductions

48. Emission reductions are calculated as follows:

$$ER_y = BE_y - PE_y - LE_y \quad \textbf{(15)}$$

Where:

ER_y	Emission reductions in year *y* (tCO_2e)
BE_y	Baseline emissions in year *y* (tCO_2e)
PE_y	Project emissions in year *y* (tCO_2)
LE_y	Leakage emissions in year *y* (tCO_2)

[14] If biomass residues are transported over a distance of more than 200 kilometres due to the implementation of the project activity then this leakage source attributed to transportation shall be considered, otherwise it can be neglected.

Monitoring

49. Relevant parameters shall be monitored as indicated in the table below:

Table 1: Parameters for monitoring during the crediting period

No.	Parameter	Description	Unit	Monitoring/recording Frequency	Measurement Methods and Procedures
1		Continuous operation of the equipment/ system		Annual check of all appliances or a representative sample thereof to ensure that they are still operating or are replaced by an equivalent in service appliance	If the emissions reduction per system is less than five tonnes of CO_2e a year; or In the case of household or commercial applications/systems, whose maximum output capacity is less than 45 kW thermal and where it can be demonstrated that the metering of thermal energy output is not plausible: (i) Recording annually the number of systems operating (evidence of continuing operation, such as on-going rental/lease payments could be a substitute), if necessary using survey methods; (ii) Estimating the annual hours of operation of an average system, if necessary using survey methods. Annual hours of operation can be estimated from total output (e.g. tonnes of grain dried) and output per hour if an accurate value of output per hour is available. Where necessary refer to the "General guidelines for sampling and surveys for SSC project activities"
	EF_{CO2}	CO_2 emission factor for the grid electricity in year *y*	tCO_2e/kWh		As described in AMS-I.D

No.	Parameter	Description	Unit	Monitoring/recording Frequency	Measurement Methods and Procedures
2	$EF_{CO2,i}$	CO_2 emission factor of fossil fuel type *i*	tCO_2e/GJ	As per the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion"	As per the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion"
3		Quantity of electricity generated/ supplied	MWh	Continuous monitoring, integrated hourly and at least monthly recording	Measured using calibrated meters. Calibration shall be as per the relevant paragraphs of "General guidelines to SSC CDM methodologies". In case the project activity is exporting electricity to other facilities, the metering shall be carried out at the recipient's end and measurement results shall be cross checked with records for sold/purchased electricity (e.g. invoices/receipts). Metering the energy produced by a sample of the systems where the simplified baseline is based on the energy produced multiplied by an emission coefficient
4		Quantity of hot air	Nm^3/hr	Continuous monitoring, integrated hourly and at least monthly recording	Measured using calibrated meters. Calibration shall be as per the relevant paragraphs of "General guidelines to SSC CDM methodologies". If applicable, measurement results shall be cross checked with records for sold/purchased electricity (e.g. invoices/receipts). Where it is not feasible (e.g. because of too high temperature), spot measurements can be used through sampling with a 90% confidence level and a 10% precision
		Quantity of steam	Nm^3/hr	Continuous monitoring, integrated hourly and at least monthly recording	Measured using calibrated meters. Calibration shall be as per the relevant paragraphs of the "General guidelines to SSC CDM methodologies". If applicable, measurement results shall be cross checked with records for sold/purchased electricity (e.g. invoices/receipts)

No.	Parameter	Description	Unit	Monitoring/recording Frequency	Measurement Methods and Procedures
5		Net quantity of thermal energy supplied by the project activity during the year *y*	TJ	Continuous monitoring, aggregated annually	Heat generation is determined as the difference of the enthalpy of the steam or hot fluid and/or gases generated by the heat generation equipment and the sum of the enthalpies of the feed-fluid and/or gases blow-down and any condensate returns. The respective enthalpies should be determined based on the mass (or volume) flows, the temperatures and, in case of superheated steam, the pressure. Steam tables or appropriate thermodynamic equations may be used to calculate the enthalpy as a function of temperature and pressure. In case of equipment that produces hot water/oil this is expressed as difference in the enthalpy between the hot water/oil supplied to and returned by the plant. In case of equipment that produces hot gases or combustion gases, this is expressed as difference in the enthalpy between the hot gas produced and all streams supplied to the plant. The enthalpy of all relevant streams shall be determined based on the monitored mass flow, temperature, pressure, density and specific heat of the gas. In case the project activity is exporting heat to other facilities, the metering shall be carried out at the recipient's end and measurement results shall be cross checked with records for sold/purchased thermal energy (e.g. invoices/receipts). Metering the energy produced by a sample of the systems where the simplified baseline is based on the energy produced multiplied by an emission coefficient
6		Quantity of fossil fuel type *j* combusted in year *y*	Mass or volume unit	As per the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion"	As per the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion"

No.	Parameter	Description	Unit	Monitoring/recording Frequency	Measurement Methods and Procedures
7	$B_{Biomass,y}$	Net quantity of biomass consumed in year *y*	Ton	Continuously or estimate using annual mass/ energy balance	Use mass or volume based measurements. Adjust for the moisture content in order to determine the quantity of dry biomass. And/or perform an annual energy/mass balance that is based on purchased quantities and stock. If more than one type of biomass fuel is consumed, each shall be monitored separately
8		Moisture content of the biomass residues	% water	The moisture content of biomass of homogeneous quality shall be monitored at least on a monthly basis. The weighted average should be calculated for each monitoring period and used in the calculations	On-site measurements. In case of dry biomass, monitoring of this parameter is not necessary
9	*T*	Temperature	°C	Continuous monitoring, integrated hourly and at least monthly recording	Measured using calibrated meters. Calibration shall be as per the relevant paragraphs of the “General guidelines to SSC CDM methodologies”
10	*P*	Pressure	kg/cm^2	Continuous monitoring, integrated hourly and at least monthly recording	Measured using calibrated meters. Calibration shall be as per the relevant paragraphs of the “General guidelines to SSC CDM methodologies”
11	$NCV_{i,y}$	Net calorific value of fossil fuel type *i*	GJ/mass or volume unit	As per the “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion”	As per the “Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion”

No.	Parameter	Description	Unit	Monitoring/recording Frequency	Measurement Methods and Procedures
12	NCV_k	Net calorific value of biomass residue type *k*	GJ/mass or volume unit	Annually	Measurement in laboratories according to relevant national/international standards. Measure the NCV based on dry biomass. Check the consistency of the measurements by comparing the measurement results with measurements from previous years, relevant data sources (e.g. values in the literature, values used in the national GHG inventory) and default values by the IPCC. If the measurement results differ significantly from previous measurements or other relevant data sources, conduct additional measurements
Parameters related to Geothermal project activity					
13	$w_{Main,CO2}$	Average mass fraction of carbon dioxide in the produced steam	tCO_2/t steam	At least every three months and more frequently, if necessary	Non-condensable gases sampling should be carried out in production wells and at the steam field-power plant interface using ASTM Standard Practice E1675 for Sampling 2-Phase Geothermal Fluid for Purposes of Chemical Analysis (as applicable to sampling single phase steam only). The CO_2 and CH_4 sampling and analysis procedure consists of collecting non-condensable gases samples from the main steam line with glass flasks, filled with sodium hydroxide solution and additional chemicals to prevent oxidation. Hydrogen sulphide (H2S) and carbon dioxide (CO_2) dissolve in the solvent while the residual compounds remain in their gaseous phase. The gas portion is then analyzed using gas chromatography to determine the content of the residuals including CH_4. All alkanes concentrations are reported in terms of methane

No.	Parameter	Description	Unit	Monitoring/recording Frequency	Measurement Methods and Procedures
14	$w_{Main,CH4}$	Average mass fraction of methane in the produced steam	tCH_4/t steam	At least every three months and more frequently, if necessary	As per the procedures outlined for $wMain,CO_2$
	$M_{S,y}$	Quantity of steam produced during the year *y*	Nm^3/hr	Daily	The steam quantity discharged from the geothermal wells should be measured with a venture flow meter (or other equipment with at least the same accuracy). Measurement of temperature and pressure upstream of the venture meter is required to define the steam properties. The calculation of steam quantities should be conducted on a continuous basis and should be based on international standards. The measurement results should be summarized transparently in regular production reports

Project activity under a programme of activities

50. The following conditions apply for use of this methodology in a project activity under a programme of activities:

(a) In the specific case of biomass project activities the applicability of the methodology is limited to either project activities that use biomass residues only or biomass from dedicated plantations complying with the applicability conditions of AM0042;

(b) In the specific case of biomass project activities the determination of leakage shall be done following the general guidance for leakage in small-scale biomass project activities (attachment C of Appendix B[15] of simplified modalities and procedures for small-scale clean development mechanism project activities; decision 4/CMP.1) or following the procedures included in the leakage section of AM0042;

(c) In case the project activity involves the replacement of equipment, and the leakage from the use of the replaced equipment in another activity is neglected, because the replaced equipment is scrapped, an independent monitoring of scrapping of replaced equipment needs to be implemented. The monitoring should include a check if the number of project activity equipment distributed by the project and the number of scrapped equipment correspond with each other. For this purpose scrapped equipment should be stored until such correspondence has been checked. The scrapping of replaced equipment should be documented and independently verified.

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History of the document*

Version	Date	Nature of revision(s)
18	EB 56, Annex 18 17 September 2010	To include a procedure for determining baseline efficiency for a new cogeneration system.
17	EB 54, Annex 9 28 May 2010	To include additional guidelines on determining baseline emissions for project activities involving fuel switch from fossil fuel to biomass in thermal generating equipment. An applicability criterion on the use of biomass briquette has also been provided.
16	EB 51, Annex 19 04 December 2009	To expand the applicability of the methodology to biomass based cogeneration project activities supplying surplus electricity to a grid.
15	EB 48, Annex 24 17 July 2009	To: (a) Include simplified procedures for determining efficiency of small thermal appliances used in household or commercial applications (<45kW thermal capacity); and (b) Include procedures for the estimation of baseline emission factors for co-fired systems.

[15] Available at <http://cdm.unfccc.int/methodologies/SSCmethodologies/approved.html>.

14	EB 46, Annex 21 25 March 2009	To include additional baseline scenarios; expanded applicability of the methodology for renewable fuel based heat and/or power generation project activities (including cogeneration) that supply: (a) Electricity to a grid and/or displace grid electricity; (b) Electricity and/or thermal energy for on-site consumption or for consumption by other facilities and combination of (a) and (b); guidance on use of charcoal from renewable biomass sources; procedures for project emission calculations when applying to geothermal projects; more guidance on metering of thermal energy output.
13	EB 38, Annex 9 14 March 2008	To expand its applicability to include additional baseline scenarios (e.g. steam/heat produced from renewable biomass and electricity imported from the grid and/or generated in a captive plant in the baseline, while in the project case heat and electricity are produced by a renewable biomass based co-generation unit).
12	EB 33, Annex 22 27 July 2007	To allow for their application under a programme of activities (PoA), where the limit of the entire PoA exceeds the limit for small-scale CDM project activities.
11	EB 32, Annex 27 22 June 2007	To clarify the monitoring of biomass in project activities that apply these methodologies which is consistent with monitoring of biomass in the approved methodology AMS-I.D.
10	EB 31, Annex 20 04 May 2007	To provide options for baseline calculations when cogeneration from fossil fuels is the baseline activity thereby broadening the applicability of AMS-I.C.
09	EB 28, Annex 23 23 December 2006	To align the guidance on capacity addition and retrofit activities to be consistent with the revisions of AMS-I.D.
08	EB 23, Annex 31 24 February 2006	To: (i) Include provisions for retrofit and renewable energy capacity additions as eligible activities; (ii) Provide clarification for baseline calculations under category I.D; and (iii) Provide clarification on the applicability of Category I.A as against Category I.D.
Decision Class: Regulatory **Document Type**: Standard **Business Function**: Methodology		

* This document, together with the 'General Guidance' and all other approved SSC methodologies, was part of a single document entitled: Appendix B of the Simplified Modalities and Procedures for Small-Scale CDM project activities until version 07.

Appendix B of the Simplified Modalities and Procedures for Small-Scale CDM project activities contained both the General Guidance and Approved Methodologies until version 07. After version 07 the document was divided into separate documents: 'General Guidance' and separate approved small-scale methodologies (AMS).		
Version	**Date**	**Nature of revision**
07	EB 22, Para. 59 25 November 2005	References to "non-renewable biomass" in Appendix B deleted.
06	EB 21, Annex 22 20 September 2005	Guidance on consideration of non-renewable biomass in Type I methodologies, thermal equivalence of Type II GWhe limits included.
05	EB 18, Annex 6 25 February 2005	Guidance on 'capacity addition' and 'cofiring' in Type I methodologies and monitoring of methane in AMS-III.D included.
04	EB 16, Annex 2 22 October 2004	AMS-II.F was adopted, leakage due to equipment transfer was included in all Type I and Type II methodologies.
03	EB 14, Annex 2 30 June 2004	New methodology AMS-III.E was adopted.
02	EB 12, Annex 2 28 November 2003	Definition of build margin included in AMS-I.D, minor revisions to AMS-I.A, AMS-III.D, AMS-II.E.

01	EB 7, Annex 6 21 January 2003	Initial adoption. The Board at its seventh meeting noted the adoption by the Conference of the Parties (COP), by its decision 21/CP.8, of simplified modalities and procedures for small-scale CDM project activities (SSC M&P).
Decision Class: Regulatory **Document Type**: Standard **Business Function**: Methodology		