CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-SSC-PDD)
Version 03 - in effect as of: 22 December 2006

CONTENTS

Revision history of this document

Version Number	Date	Description and reason of revision
01	21 January 2003	Initial adoption
02	8 July 2005	• The Board agreed to revise the CDM SSC PDD to reflect guidance and clarifications provided by the Board since version 01 of this document. • As a consequence, the guidelines for completing CDM SSC PDD have been revised accordingly to version 2. The latest version can be found at <http://cdm.unfccc.int/Reference/Documents>.
03	22 December 2006	• The Board agreed to revise the CDM project design document for small-scale activities (CDM-SSC-PDD), taking into account CDM-PDD and CDM-NM.

SECTION A. General description of small-scale project activity

A.1 Title of the small-scale project activity:

Title Blue Fire Bio wastewater treatment and biogas utilization project
Version 02.6
Date 18/11/2010

A.2. Description of the small-scale project activity:

Project Description

The proposed project entails the installation of two sets of upflow anaerobic sludge blanket technology (UASB) biogas reactors and 3.128MW_{el} gas engines[1] at an existing starch factory in Thailand for:

a) the extraction of methane (biogas) from the wastewater stream through the biogas reactors;
b) the reuse of biogas as fuel in existing thermal boiler within the plant for starch drying; and
c) the reuse of biogas as fuel for power generation.

The proposed project is implemented by Blue Fire Bio Co.,Ltd at the Chaodee Starch (2004) facility in the northeast of Thailand with a total wastewater flow-rate of 5,780m^3/day and an average COD concentration of 12,000 mg/l.
Prior to the implementation of the project, the wastewater was treated by an open lagoon system, consisting of six anaerobic ponds all with a depth of over 4 metres. After the lagoons, the wastewater was re-used for starch cleaning. There was no discharge. Heavy fuel oil was used in boiler for heating purposes and electricity was provided by the grid.

In phase I, the project introduces successively two new sets of biogas reactors with methane capture and utilisation for energy purposes. The first reactor will be introduced into the existing open anaerobic lagoon based wastewater treatment system. As the starch factory plans to expand its starch production with the construction of a second line similar to the existing one, another biogas reactor will be then introduced; and the lagoon system will be extended to 15 lagoons (Phase II). As a consequence of the new anaerobic reactors, the organic load entering the lagoon system is drastically reduced because most of the organic matter is converted to biogas in the reactor. The project activity avoids the release of methane into the atmosphere, which would occur due to the anaerobic digestion of the organic content in the open lagoon based wastewater treatment system (anaerobic conditions, leading to methane generation within the lagoon are the result of a lagoon depth greater than 2- 4m and an average atmospheric temperature of about 28°C)[2].

In addition, the biogas reactors produce sufficient quantities of biogas to fuel thermal oil boilers for starch drying, replacing partly the use of heavy fuel oil, and to fuel a gas engine for the production of power for both in-house use and/or sale to the electricity grid. For phase I, existing boiler will be used and a new boiler will be installed for Phase II.

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[1] The exact total capacity of the gas engines is not yet decided.

[2] As per published source Pollution control Department, Thailand. http://www.pcd.go.th/info_serv/water_wt.html

Up to 1,994 tons/year of heavy fuel oil are replaced for heating purposes, and up to 5,794MWh are generated annually with the biogas generators. A first 1.128MW_{el} biogas gensets will be installed in 2009, and the second one with a capacity up to 2 MW_{el} is planned to be installed one year later. The partial replacement of heavy fuel oil in the thermal oil boilers, and displacement of electricity from the national grid, which is generated by fossil fuel fired power plants from the Thai national grid to a large extent, will lead to further reductions of greenhouse gases.

In accordance with the project owner plans, the electricity generated will be sold to PEA[3] under a firm power purchase agreement under the Very Small Power Producer[4] (VSPP) program.

The average estimated emission reduction is 51,817 tonnes per year of CO_2 equivalent.

Sustainable Development Benefits of the Project
According to the definition of sustainable development criteria for CDM projects by Thai DNA[5], the project will directly contribute to sustainable development in Thailand in several ways as shown below:

Natural Resources and Environment benefits

- Reduction of greenhouse gas emissions through the avoided electricity generation by other grid connected power plants;
- Reduction of offensive odour;
- Reduction in usage of non-renewable energy, i.e. fossil fuel for grid electricity generation;
- Improvement of the quality of water discharged into the environment;

Social benefits

- Involvement of local communities through a public participation meeting, in which people accepted the project;
- Increased employment by employing 17 full time staff to operate the system;

Technology transfer benefits

- Promoting technological excellence in Thailand, which could be replicated across Thailand and the region;
- Necessary training on the management of the power plant will be provided to staff;

Economic benefits

- Reduction in dependency on fossil fuel for electricity generation while at the same time enhancing energy security by increasing diversity of supply;

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[3] The Provincial Electricity Authority is a government enterprise under the Ministry of Interior. The authority's responsibility is primarily concerned with the generation, distribution, sales and provision of electric energy services to the business and industrial sectors as well as to the general public in provincial areas, with the exception of Bangkok, Nonthaburi and Samut Prakran provinces.
[4] A Very Small Power Producer (VSPP) can be any private entity, government or state-owned enterprise that generates electricity either (a) from non-conventional sources such as wind, solar and mini-hydro energy or fuels such as waste, residues or biomass, or (b) from conventional sources provided they also produce steam through cogeneration. As per the VSPP program, the VSPP is limited to sell no more than 10MW of its electrical power output to the designated distribution utility, such as Metropolitan Electricity Authority (MEA) and/or Provincial Electricity Authority (PEA).

[5] http://www.tgo.or.th/english/index.php?option=com_content&task=view&id=15&Itemid=1

- Generating incomes to the local community through additional local employment;
- Demonstrating the use of CDM as an incentive for bringing about an renewable energy project;
- Besides, due to rapidly, continuously rising and unstable of oil prices, the Thai government has set an ambitious target for the share of renewable energy in electricity production. In year 2003, the government has published the "Energy Strategies for Competitiveness" which targets to increase the share of renewable energy in Thailand from 0.5% in year 2002 to 8% in year 2011 (source: http://www.eppo.go.th/doc/strategy2546/strategy.html). This national plan will benefit from initiatives in industries such as this project. The project, by producing energy from biogas, will directly complement the Thai government's efforts to reduce the country's dependency of imported fossil fuels. Besides, National's electricity generation, which is dominated by natural gas, lignite and imported fuel oil, will also benefit from this kind of project where the electricity fed to the grid come from renewable energy sources.

The Project is, also, implemented on a pure voluntary basis. There is no regulation that requires implementing such a project.

A.3. Project participants:

Name of Party involved (*) (host) indicate a host party	Private and/or public entity(ies) project participants (*) (as applicable)	Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)
Thailand (host)	Blue Fire Bio Co.,Ltd	No
Switzerland	South Pole Carbon Asset Management Ltd.	No
(*) In accordance with the CDM modalities and procedures, at the time of making the CDM-PDD public at the stage of validation, a Party involved may or may not have provided its approval. At the time of requesting registration, the approval by the Party(ies) involved is required.		

A.4. Technical description of the small-scale project activity:

A.4.1. Location of the small-scale project activity:

A.4.1.1. Host Party(ies):

Thailand

A.4.1.2. Region/State/Province etc.:

Nakhorn Ratchasima (Korat)

A.4.1.3. City/Town/Community etc:

61 Moo 14, Hindad, Dan Khun Tot District

A.4.1.4. Details of physical location, including information allowing the unique identification of this small-scale project activity :

The proposed project is located in Chaodee Starch factory, in Dan Khun Tot district, Nakhorn Ratchasima, Korat, Thailand. It is situated at about 250 km north of Bangkok, in the Northeast of Thailand. Most of the starch plants in Thailand are located in this province.

The exact location of the plant is 15.1303N 101.5586E.
A map indicating the location of the project is provided in Figure 1.

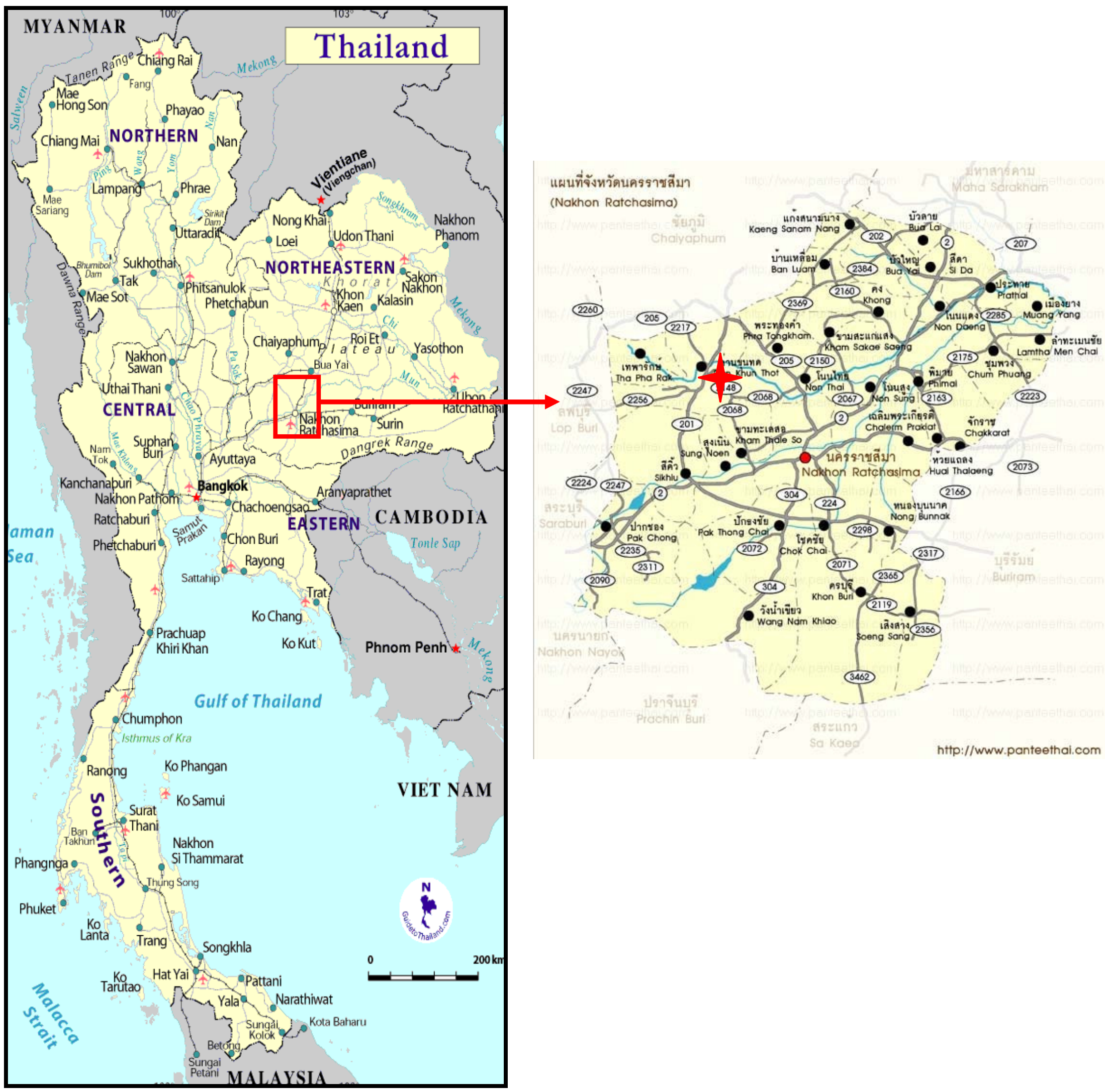


Figure 1. Location of the project activity

A.4.2. Type and category(ies) and technology/measure of the small-scale project activity:

According to Appendix B to the "Simplified Modalities and Procedures for Small-Scale CDM Project Activities", the project type and categories are defined as follows:

Methane avoidance component

Type III: Other project activities
Category III.H: Methane Recovery in Wastewater Treatment
Sectoral Scope 13: Waste handling and disposal

Thermal energy generation component

Type I: Renewable energy projects
Category I.C: Thermal energy production with or without electricity
Sectoral Scope 1: Energy industries (renewable/non-renewable source)

Electricity generation component:

Type I: Renewable energy projects
Category I.D: Grid connected renewable electricity generation
Sectoral Scope 1: Energy industries (renewable /non-renewable sources)

Technology

Situation prior project implementation:
Before the implementation of the project, the wastewater is treated by an open lagoon system, consisting of six anaerobic ponds all with a depth of over 4 metres. After the lagoons, the wastewater is re-used in the starch factory for cleaning purpose. This mode of treatment is the prevalent practice in this kind of industry, particularly where there is a relative abundance of land.
For heating purposes (starch drying), Heavy Fuel Oil is used in boiler. The boiler is an oil circulating boiler, type Circotherm, with a continuous output of 3,500,000 kCal/h.
There is no generator on site. The electricity is provided by the grid.

Situation after project implementation:
Under the project, the effluent from the starch factory is instead diverted to an anaerobic digester with biogas recovery. The proposed project uses local know-how so called "Biofuel reactor" in order to extract methane gas from wastewater treatment system.

The project will be done in two stages.

- Stage I of the project includes the installation of a new set of UASB biogas reactors and of two generators with a capacity of 0.5MW each. It will treat the wastewater coming currently from the factory. The existing boiler, with a burner suitable for oil-biogas combination, is used. Part of the biogas is used for partial replacement of HFO.
- Stage II of the project will follow the extension of the factory. As it plans to expand its starch production by two, the wastewater flows will be doubled. A new biodigester – boiler – generators will be introduced. The new boiler will have the same type and capacity (3,500,000 kCal/h) than the existing one for phase one. Two generators of 1MW capacity are planned to be installed. The lagoon system will be expanded to 15 anaerobic ponds to be used as a backup system.

The two systems are very similar and are described below:

Pre-treatment
There are two main sources of wastewater from factory. One is separator unit in the process line, the other is washing activity. Wastewater from separation unit which is consisted of high organic substances is firstly treated in primary sedimentation tank in order to extract suspended solid from the wastewater. Clear wastewater from primary sedimentation is treated further in equalizing and acid pond. This pond is also used for storage of the generated biogas. The sludge removed from the sedimentation tank is then directly sent to the anaerobic lagoons (secondary treatment). The sedimentary tank has a very low retention time (0.03 days); therefore no methane emissions occur in the sedimentation tank.

Anaerobic treatment
The effluent from equalization lagoon flows then into a pump sump and is pumped into the methane reactors through an influent distribution system at the bottom of the reactor. In BFR tank, organic compounds in wastewater are transformed mainly into biogas by anaerobic bacteria in the system. There are three tanks, two for the first line and one for the second line. The tanks have a total volume of 14,000m^3 and are designed to handle about 3,400 m^3/day for each phase. The removal efficiency is 80%. The production of biogas is estimated to be 7,575,000 Nm^3/year (with 55% of methane).

Biogas handling
Part of the biogas (60%) is used as fuel in an existing thermal oil boiler and in a new boiler used for starch drying. A duel fuel burner able to fire oil and gas is employed to burn biogas instead of heavy fuel oil. This is only partial replacement of the HFO. After project implementation, HFO is still used in the boilers.
The rest of the biogas (40%) is used as fuel in power generators (gensets) consisting of a biogas fired engine and an alternator each, with a planned total installed capacity of 3 MW_{el}.[6] A rented small gas engine with a capacity of 0.128 MW_{el} is first used during a phase test; this engine might be used as backup system during the project activity.
Electricity will be used on site or sent to the grid.
If some biogas remains, it is flared off in a monitoring open flaring system. The flaring system will be used only in case of emergency.

Secondary treatment
Effluent from the BFR system is treated in the secondary treatment, consisting of a series of six existing lagoons. The lagoons receive around 20% of the COD loading directed into the digester. The lagoons system is extended to 15 anaerobic ponds after implementation of the second line.
Wastewater from root washing is primarily treated in screening unit and grit chamber in order to remove debris and gravel; both effluent from grit chamber and floor cleaning wastewater, containing low amount of COD, are treated in the secondary treatment unit.

Final sludge and wastewater treatment
After the treatments, the wastewater shall have a low COD concentration and will be re-used at the factory or used by farmers for land application.
Some excess sludge may accumulate over the years in the bio-digesters and can be removed from the bottom of the reactors.
The sludge will be handled as follows:

[6] The final total capacity of the generators is not decided yet. There might be some changes in the future.

- **First period**: Sludge will be kept in the BFR 1&2 for the starting up of BFR 3 for one year, since it is activated sludge.
- **Second period**: Sludge will be kept in the BFR tanks in order to increase the performance of the system for about six months.
- **Third period**: Once the suitable quantity of sludge will be reached in the 3 BFRs, excess sludge will be managed by one of the methods below:
  1. To use for starting up other systems or for any other purposes.
  2. To fill the land and level the soil inside the boundary of the project.
  3. To use as fertilizer inside the project boundary.

Figure 2. The BFR tanks

Figure 3. The lagoons

A.4.3 Estimated amount of emission reductions over the chosen crediting period:

The estimated amount of emission reductions from the small-scale project activity over first seven-year crediting period is shown in the following table below.

Years	Annual estimation of emission reductions in tonnes of CO2e
2011	51,817
2012	51,817
2013	51,817
2014	51,817
2015	51,817
2016	51,817
2017	51,817

Total emission reductions (tonnes of CO2e)	**362,717**
Total number of crediting years	**7**
Annual average over the crediting period of estimated reductions (tonnes of CO2e)	51,817

Table 1. Estimated amount of emissions reductions

A.4.4. Public funding of the small-scale project activity:

No public funding from Annex I countries has been sought for this project.

A.4.5. Confirmation that the small-scale project activity is not a debundled component of a large scale project activity:

According to the ***"Appendix C of the Simplified Modalities and Procedures for Small-Scale CDM project activities"***, this project is not a debundled component of a larger project activity since there is not a registered small-scale activity or an application to register another small-scale CDM activity:

- ✓ Within the same project participant;
- ✓ In the same project category and technology/measure;
- ✓ Registered within the previous 2 years;
- ✓ Whose boundary is within 1km of the project boundary of the proposed small scale activity at the closest point.

Hence, the project activity is eligible as a small-scale CDM project and can use the simplified modalities and procedures for small-scale CDM project activities.

SECTION B. Application of a baseline and monitoring methodology

B.1. Title and reference of the approved baseline and monitoring methodology applied to the small-scale project activity:

The following Small-Scale methodologies are applied:

- AMS III.H "Methane recovery in wastewater treatment" version 13, for the methane avoidance and recovery aspect of the project;
- AMS I.C "Thermal energy production with or without electricity" version 16, for the heat and electricity generation;
- AMS I.D "Grid connected renewable electricity generation" version 15, for the electricity generation component.

These methodologies refer to the following tools:

- Version 02 of the tool to calculate the emission factor for an electricity system;

- Version 01 of the tool to determine project emissions from flaring gases containing methane;
- Version 02 of the Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion.

More information about the methodologies and tools can be found on the following website:
http://cdm.unfccc.int/methodologies/PAmethodologies/approved.html

B.2 Justification of the choice of the project category:

The project meets all the applicability conditions of the methodologies, as described below:

Applicability conditions for AMS III.H

	Applicability conditions	Project case
1	This project category comprises measures that recover methane from biogenic organic matter in wastewaters by means of one of the following options: … (vi) Introduction of a sequential stage of wastewater treatment with methane recovery and combustion, with or without sludge treatment, to an existing wastewater treatment system without methane recovery (e.g. introduction of treatment in an anaerobic reactor with methane recovery as a sequential treatment step for the wastewater that is presently being treated in an anaerobic lagoon without methane recovery).	In absence of the project activity, the wastewater would be treated in open lagoons and then reused in the factory. The project activity involves the installation of new system: the wastewater from the separator is treated sequentially in a primary sediment tank, an acid pond, the biofuel reactor with methane recovery and finally to a succession of six anaerobic ponds (15 anaerobic ponds after implementation of phase II) before being reused in the factory. Therefore, the project activity satisfies the applicability criterion (vi).
2	The recovered biogas from the above measures may also be utilised for the following applications instead of combustion/flaring: (a) **Thermal or electrical energy generation directly; or** (b) Thermal or electrical energy generation after bottling of upgraded biogas; or (c) Thermal or electrical energy generation after upgrading and distribution: (i) Upgrading and injection of biogas into a natural gas distribution grid with no significant transmission constraints; or (ii) Upgrading and transportation of biogas via a dedicated piped network to a group of end users; or Hydrogen production.	The biogas from the system is utilized for thermal and electricity energy generation directly. Hence, the project activity satisfies the criterion (a).
3	If the recovered methane is used for project activity covered under paragraph 2 (a), that component of the project activity can use a corresponding category under type I.	The approved baseline and monitoring methodologies AMS-I.C. and AMS-I.D. are used for the thermal and electricity generation components of the project

		activity.
4	If the recovered biogas is utilized for production of hydrogen (project activities covered under paragraph 2 (d)), that component of project activity shall use corresponding category AMS-III.O.	The recovered biogas is not utilized for production of hydrogen, thus this applicability condition is of no relevance.
5	In case of project activities covered under paragraph 2 (b) if bottles with upgraded biogas are sold outside the project boundary the end-use of the biogas shall be ensured via a contract between the bottled biogas vendor and the end-user. No emission reductions may be claimed from the displacement of fuels from the end use of bottled biogas in such situations. If however the end use of the bottled biogas is included in the project boundary and is monitored during the crediting period CO2 emissions avoided by the displacement of the fuels is eligible under a corresponding Type I methodology, e.g., AMS-I.C.	The project activity does not involve an application of recovered biogas as per paragraph 2(b), thus this applicability criterion is of no relevance.
6	In case of project activities covered under paragraph 2 (c i) emission reductions from the displacement of the use of natural gas is eligible under this methodology, provided the geographical extent of the natural gas distribution grid is within the host country boundaries.	The project activity does not involve an application of recovered biogas as per paragraph 2(c i), thus this applicability criterion is of no relevance.
7	In case of project activities covered under paragraph 2 (c ii) emission reductions for the displacement of the use of fuels can be claimed following the provision in the corresponding Type I methodology, e.g., AMS-I.C.	The project activity does not involve an application of recovered biogas as per paragraph 2(c ii), thus this applicability criterion is of no relevance.
8	In case of project activities covered under paragraph 2 (b) and (c), this methodology is applicable if upgrade is done by one of the following technologies7 such that the methane content of the upgraded biogas is in accordance with relevant national regulations (where these exist) or, in the absence of national regulations, a minimum of 96% (by volume). These conditions are necessary to ensure that the recovered biogas is completely destroyed through combustion in an end use: • Pressure Swing Adsorption; • Absorption with/without water circulation; Absorption with water, with or without water recirculation (with or without recovery of methane emissions from discharge).	The project activity does not involve an application of recovered biogas as per paragraph 2 (b) and (c), thus this applicability criterion is of no relevance.
9	New facilities (Greenfield projects) and project	The project involves a capacity increase of

[7] Please refer to annex 1 of approved methodology AM0053 / Version 01.1 regarding the description of these technologies.

	activities involving a change of equipment resulting in a capacity addition of the wastewater or sludge treatment system compared to the designed capacity of the baseline treatment system are only eligible to apply this methodology if they comply with the requirements in the General Guidance for SSC methodologies3 concerning these topics. In addition the requirements for demonstration of the remaining lifetime of the equipment replaced as described in the general guidance shall be followed.	the factory, but it doesn't involve a change in equipment resulting in a capacity addition. The second phase of the project is a new installation and it is therefore considered as a Greenfield project It will be demonstrated that the most plausible baseline scenario for the Greenfield part is the baseline provided in the methodology.
10	For project activities covered under paragraph 2 (b) and (c) additional guidance provided in annex 1 shall be followed for the calculations in addition to the procedures in the relevant sections below.	The project doesn't involve an application of recovered biogas as per paragraph 2 (b), thus applicability is of no relevance.
11	The location of the wastewater treatment plant shall be uniquely defined as well as source generating the wastewater and described in the PDD.	The WWT plant and the source generating the WW are situated at the Chaodee plant, as described in the paragraph A4.1.4.
12	Measures are limited to those that result in emission reductions of less than or equal to 60 kt CO2 equivalent annually from all type III components of the project activity.	The emission reductions to be achieved by the project activity are estimated 43,939 tCO_2 per year from all type III component, which is lower than 60 $ktCO_2e$ per year over the crediting period. Hence, the project activity satisfies this applicability criterion as well.

Applicability conditions for AMS.I.C

	Reference to AMS I.C	Relevance of the project activity
1	This category comprises renewable energy technologies that supply users[8] 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.	The boilers used in the project activity will use biogas as fuel to produce heat for starch drying. Therefore, the project activity fulfils this applicability criterion.
2	Biomass-based co-generating systems that produce heat and electricity are included in this category. For the purpose of this methodology "Cogeneration" shall mean the simultaneous generation of thermal energy and electrical and/or mechanical energy in one process. Cogeneration system may supply one of the following: (a) Electricity to a grid; (b) Electricity and/or thermal energy	The project activity is not a biomass-based cogeneration system. Not applicable to the project activity.

[8] E.g., residential, industrial or commercial facilities.

	(steam or heat) for on-site consumption or for consumption by other facilities; (c) Combination of (a) and (b).	
3	The total installed/rated thermal energy generation capacity of the project equipment is equal to or less than 45 MW thermal[9] (see paragraph 5 for the applicable limits for cogeneration project activities).	The thermal power capacity installed is less than 45 MW_{th},. The two boilers have a capacity of 9MW_{th}. The boiler are oil circulating boiler, type Circotherm, with a continuous output of 3,500,000 kCal/h (4.5 MW_{th}).
4	For co-fired[10] 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 5 for the applicable limits for cogeneration project activities)	This is a co-fired system, using both HFO and biogas. The total installed thermal capacity is equal to 9 $MW_{thermal}$, It is less than 45 $MW_{thermal}$ thresholds. Hence, the project activity satisfies this applicability criterion.
5	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 (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	The project activity is not a biomass-based cogeneration system. Not applicable to the project activity.

[9] 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.

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

	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.	
6	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.	The project activity doesn't deliver electricity or heat to other facilities.
7	Project activities that seek to retrofit or modify an existing facility for renewable energy generation are included in this category.	The thermal displacement is only partial. The boiler uses HFO and biogas. The burner of the boiler was changed with the project implementation to allow co-firing (HFO and biogas).
8	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 3 to 5 and should be physically distinct[11] from the existing units.	The total capacity complies with the limit specified in paragraphs 3 to 5.
9	Charcoal based biomass energy generation project activities eligible to apply the methodology only if the charcoal is produced from renewable biomass sources.	Not applicable.

<u>Applicability conditions for AMS.I.D</u>

[11] 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".

	Reference to AMS I.D	Relevance of the project activity
1	This category comprises renewable energy generation units, such as photovoltaics, hydro,tidal/wave, wind, geothermal and renewable biomass, that supply electricity to and/or displace electricity from an electricity distribution system that is or would have been supplied by at least one fossil fuel fired generating unit.	The project involves the installation of generators that will use biogas as fuel to produce electricity. The total capacity of the generators for producing electricity is planned to be 3.128 MW. First line consists of 2 generators of 0.5MW and one generator used a back-up system of 0,128MW. Second line consists of 2 generators of 1 MW. However, the generators for second line are not yet bought. Hence, the project activity satisfies this applicability criterion.
2	Hydro power plants with reservoirs that satisfy at least one of the following conditions are eligible to this methodology: • The project activity is implemented in an existing reservoir with no change in the volume of reservoir; • The project activity is implemented in an existing reservoir, where the volume of reservoir is increased and the power density of the project activity, as per definitions given in the Project Emissions section, is greater than 4 W/m2; • The project activity results in new reservoirs and the power density of the power plant, as per definitions given in the Project Emissions section, is greater than 4 W/m^2.	Not applicable
3	If the unit added has both renewable and non-renewable components (e.g.. a wind/diesel unit), the eligibility limit of 15MW for a small-scale CDM project activity applies only to the renewable component. If the unit added co-fires fossil fuel, the capacity of the entire unit shall not exceed the limit of 15MW.	The total capacity of the generators for producing electricity is 3.128MW. Hence, the project activity satisfies this applicability criterion. The project does not consist of co-firing system. Only biogas is used in generator.
4	Combined heat and power (co-generation) systems are not eligible under this category.	Not applicable
5	In the case of project activities that involve the addition of renewable energy generation units at an existing renewable power generation facility, the added capacity of the units added by the project should be lower than 15 MW and should be physically distinct from the existing units.	Not applicable
6	Project activities that seek to retrofit or modify an existing facility for renewable energy generation are included in this category. To qualify as a small-scale project, the total output of the modified or retrofitted unit shall not exceed the limit of 15 MW.	Not applicable

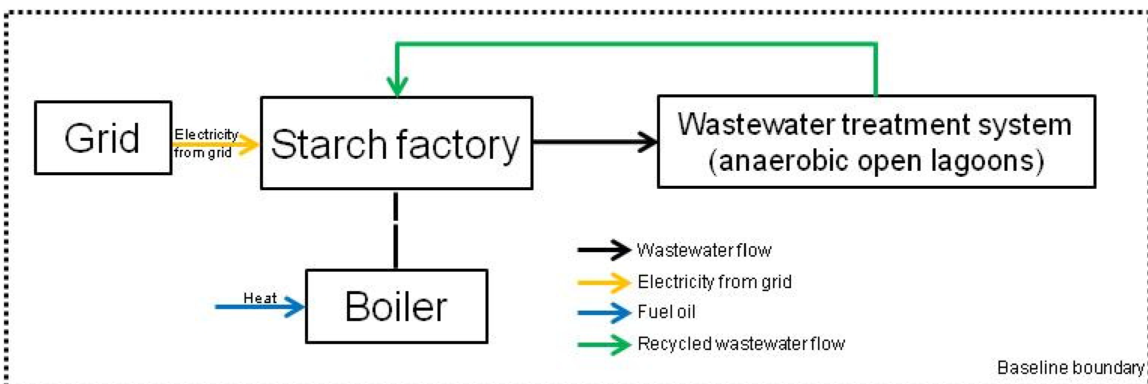
B.3. Description of the project boundary:

- With reference to AMS.III.H, the project boundary is the physical, geographical site where the wastewater and sludge treatment takes place in baseline and project situation. It covers all facilities affected by the project activity including sites where the processing, transportation and application or disposal of waste products as well as biogas takes place It includes the biogas tanks, the biogas storage vessel, the methane flaring system, the aeration ponds (aerobic treatment where emissions of methane still occur), and the usage of solid sludge for soil application.

- With reference to AMS.I.C, 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. In the case of this project, the boundary is therefore limited to the biogas boiler and the starch plant where the heat is consumed for starch drying.

- With reference to AMS.I.D, the project boundary encompasses the physical, geographical site of the renewable generation. In the case of this project, the boundary is therefore limited to the biogas engines and the grid.

The baseline and the project boundaries are as follows:



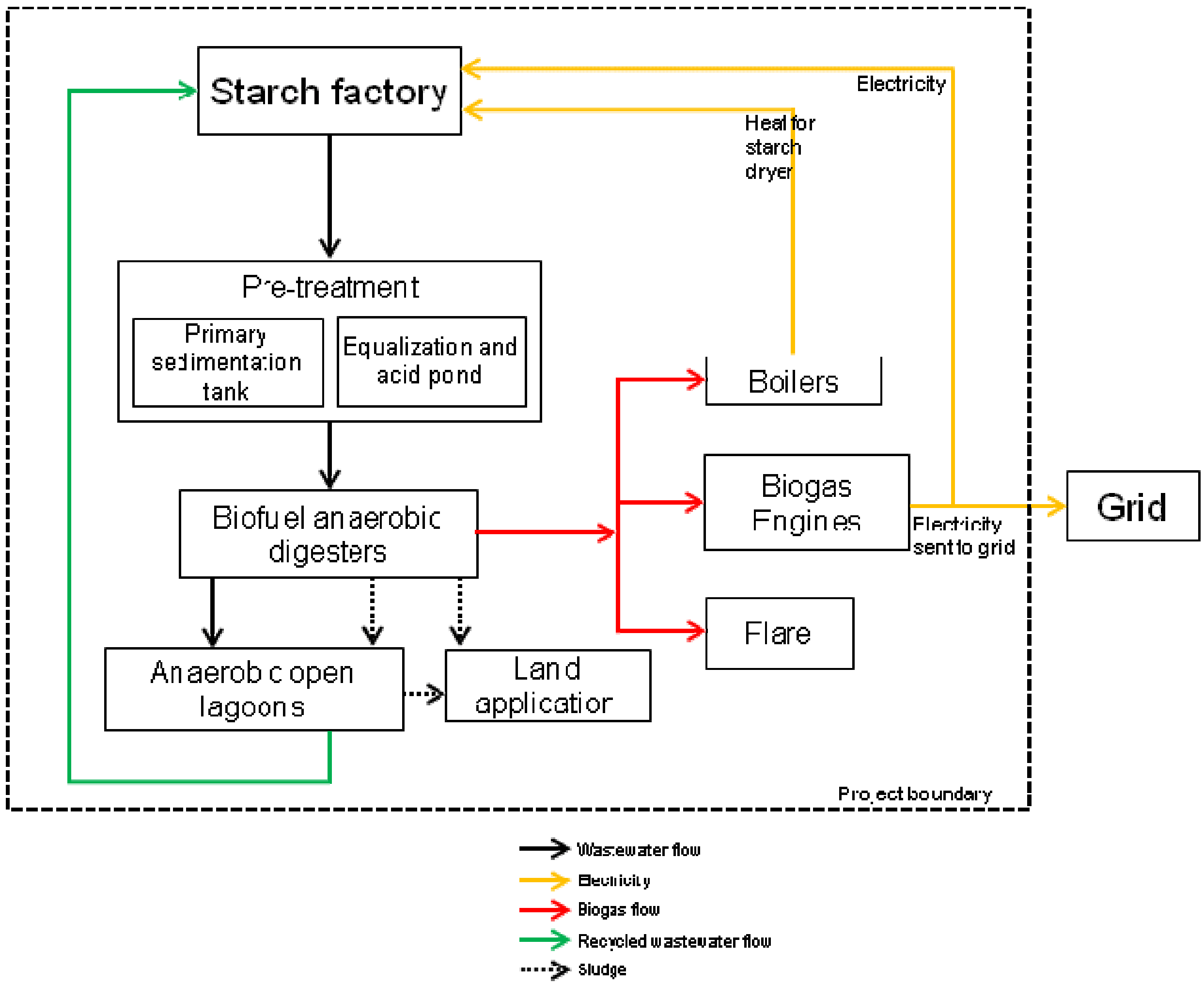


Figure 4. Baseline situation and project boundary

Following emission sources and gases are considered in the emission reduction calculations.

	Source	Gas	Explanation
Baseline	Anaerobic lagoon	CH_4	Emission from decay of organic matter in anaerobic conditions.
	Thermal energy generation	CO_2	CO_2 emission from fuel oil consumption in the boiler in the absence of the project.
	Electricity generation	CO_2	Emission from electricity generation in the grid displaced by the project activity.
Project activity	Anaerobic reactor	CH_4	Fugitive emissions on account of inefficiencies in capture systems.
	Open-flare	CH_4	Emission due to incomplete flaring.
	Anaerobic lagoon	CH_4	Emissions from decay of organic matter in the WWT system not equipped with biogas recovery.

	Facilities	CO_2	Emissions on account of power and fuel used by the project activity facilities.
	Boiler	CO_2	Emissions on account of fossil fuel consumption in the boiler.

Table 2. Sources and gas

B.4. Description of baseline and its development:

Since the project will be developed in two stages, one corresponding to the current situation and the other one following the extension of the factory, the baseline is determined for each stage with two different approaches.

Baseline for the first line

The baseline for the first line of the project activity has been developed by using two categories listed in the simplified modalities and procedure for small-scale CDM project activity:

1. Type III – Other project activities, Category III.H – Methane recovery in wastewater treatment Version 13 (AMS III.H)

   The baseline scenario is described by paragraph 1 (vi) of AMS III.H version 13 as being the existing anaerobic wastewater treatment system without methane recovery. In the project's case, the system is a series of six deep open anaerobic lagoons.

   As per paragraphs17 and 18 of the methodology, historical records of at least one year prior to the project implementation shall be used. In case one year of historical data is not available, the parameters shall be determined by a measurement campaign in the baseline wastewater systems for at least 10 days. In the case of the project, one year historical records for the COD removal efficiency of the lagoons system are not available. However, measurements in the lagoons system have been conducted during a 10 day campaign prior the project start date. Therefore, the chemical oxygen demand removal efficiency of the baseline wastewater treatment system (the 6 anaerobic lagoons) is calculated based on these values of the COD of the wastewater discharge from the starch factory before treatment and at the last lagoon of baseline treatment, multiplied by 0.89 to account for the uncertainty range associated with this approach compared to one-year historical data. Actual reduction across the system is approximately 99% as per the 10 day measurement campaign. Therefore, a value of 89% for the COD removal efficiency is used for the baseline.

2. Type I – Renewable energy projects, Category I.C – Thermal energy for user with or without electricity Version 16 (AMS I.C) and Category I.D – Grid connected renewable electricity generation Version 15 (AMS I.D).

   The baseline scenario is (a) where electricity is imported from the grid and steam/heat is produced using fossil fuel. For the project, electricity is drawn from Thai grid system while the heat is produced by Heavy Fuel Oil (HFO) boiler.

Baseline for the second line
According to the Indicative simplified baseline and monitoring methodologies for selected small-scale CDM project activity categories, version 14.1, Annex 35 EB55, new facilities (Greenfield projects) may use a Type-III small-scale methodology provided that they can demonstrate that the most plausible baseline scenario for this project activity is the baseline provided in the respective type III small-scale methodology. The demonstration should include the assessment of the alternatives of the project activity using the following steps:

Step 1: Identify the various alternatives available to the project proponent that deliver comparable level of service including the proposed project activity undertaken without being registered as a CDM project activity.

The main output or service of the project activity is the treatment of effluent water. The by-products of the project activity arising from the utilisation of biogas captured are the production of heat and electricity.
Therefore, the 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 small-scale CDM project activity are:

Alternative 1: Methane recovery and utilization for heat and electricity generation (proposed project without CDM assistance)
Alternative 2: Open anaerobic lagoon based wastewater treatment system (common practice)
Alternative 3: Aerobic wastewater treatment
Alternative 4: Direct discharge
Alternative 5: Methane recovery and flaring
Alternative 6: Covered lagoons

Step 2: List the alternatives identified per step 1 in compliance with the local regulations (if any of the identified baseline is not in compliance with the local regulations, then exclude the same for further consideration).

Alternatives 1, 2, 3, 5 and *6* are in compliance with current laws and regulations in Thailand, which allow the use of open lagoon systems and other wastewater treatment technologies that meet effluent standards for the discharge of treated wastewater into the environment. The release of wastewater into watercourses in Thailand is regulated by the "Notification of the Ministry of Science, Technology and Environment, No. 3, B.E.2539 (1996)"[12] published in the Royal Government Gazette, Vol. 113 Part 13 D, dated February 13, B.E.2539 (1996). According to this regulation the COD of wastewater is not allowed to exceed 120 mg/litre and 5-day BOD (BOD_5) shall not exceed 20 mg/litre. However there is an exception for starch plants which stipulates that BOD_5 should not exceed 60 mg/litre[13]. Considering the high COD-load of a starch plant, it is prohibited by legal regulations to release wastewater directly into water bodies. There is no other regulatory requirement for the implementation of a specific wastewater treatment technology such as anaerobic digester or aerobic treatment system to tapioca starch processing plants for effluent treatment.

[12] Ministry of Science, Technology and Environment. Thailand (1996). Notification the Ministry of Science, Technology and Environment, No. 3, B.E.2539 (1996). Cited at: http://infofile.pcd.go.th/law/3_4_water.pdf (Document in Thai)
[13] Pollution Control Department. Thailand (2004). Industrial effluents standards. Cited at http://www.pcd.go.th/info_serv/en_reg_std_water04.html (Document in English)

Alternative 4 is in violation with the effluent discharge standards set by the laws and regulations of Thailand. Therefore, alternative 4 cannot be considered as the baseline and is excluded from further assessment.

Step 3. Eliminate and rank the alternatives identified in step 2 taking into account barrier tests specified in attachment A to Appendix B of the simplified modalities and procedures of SSC CDM.

Technical barrier

Alternative 1 is seen as a high risk alternative with limited performance guarantee.
The performance of this alternative depends on the quantity and quality of biogas generated, starting up and maintaining the anaerobic digestor at optimal conditions. Anaerobic digestion systems are unstable systems and require several control loops to keep the digester parameters within appropriate levels. There are different parameters, such as the COD load of the wastewater, the pH-value, TSS (total suspended solids) and the temperature which have an impact on the performance of the digester[14]. An anaerobic digestion system is a biological system which has to be balanced constantly to provide best conditions for the anaerobic bacteria. Therefore the proper operating of the control system is essential for the output of biogas.
Improper operation of the digester or the wrong use of chemical substances harm the bacteria and lead very often to the collapse of the reactor system[15]. Poor performance of the digester affects adversely the quantity and the methane content of the biogas. However, for the gen-set the methane content of the biogas is crucial for the electricity generation. In Thailand, there is little experience with anaerobic technology in the starch sector. The lack of technical knowledge is often related to the fact that technologies have been developed abroad without proper technology or know-how transfer[16],[17]. There is also a lack of skilled and trained operators for biogas plants in Thailand, which is often related to the remote location of biogas plants and the lack of qualified professionals in rural areas. This is another reason why operators of starch factories hesitate to use this technology. Staff has to be trained to ensure an uninterrupted handling of the wastewater treatment system and continuous generation of heat and electricity.
The operators of Chaodee's factory have no prior experience in operating and maintaining an anaerobic digestion process with a methane recovery system. Since biogas plants require sophisticated operation procedures to manage the complicated biological, gas and electrical components of the project, specific and detailed training of BFB's employees is required, which is a significant challenge for the company.
Until now, no company in the starch sector in Thailand operates advanced anaerobic digestions systems, such as UASB reactors, without the support of CDM (see Step 4 below for more information).

[14] Effect of temperature on the anaerobic digestion of palm oil mill effluent, Electronic Journal of Biotechnology.

[15] The microbiology of anaerobic digester (2003). M. H. Gerardi. Wastewater microbiology series.

[16] Biogas from wastewater in palm oil mill project'. ASEAN renewable energy project competition 2007. Cited at: http://www.aseanenergy.org/download/aea/renewable_energy/2007/awardees/on%20grid_biogas%20from%20wastewater%20in%20palm%20oil%20mill_th.pdf

[17] IP-Institut für Projektplanung GmbH on behalf of GTZ (1997). Environmental Management Guideline for the Palm Oil Industry, Thailand. – Chapter 6 review of suitable wastewater treatment technologies. Cited at: http://www.elaw.org/assets/pdf/th.palm.oil.industry.guidelines.pdf

Alternative 2 has been a common practice of handling wastewater from tapioca starch production in Thailand for the last thirty years. Most of the tapioca starch production facilities in the project region (Korat Region) utilize open lagoon based systems for treating wastewater[18]. The related requirements in terms of technology, skills and labour required for such lagoon systems are far below the requirements of anaerobic reactor systems and are readily available in Thailand. There risk level associated with such lagoon systems are considered as very low because of their extremely simple and robust operation principles, as well as their history and the expertise available in the agricultural sector in Thailand.
For the implementation of a lagoon system large areas of land are necessary on which several ponds are dredged. Through gravity, the effluent flows directly from one lagoon to the next. Due to a long residence time of wastewater in the lagoons, the biological process is less efficient but more robust, delivering ultimately the required effluent quality levels as per Thai environmental regulations. Open anaerobic lagoons require extremely limited operation and maintenance due to the self-regulatory nature of the systems. Hence, lagoons are a very cost-effective solution, do not require advanced technology and are easy to operate and maintain[19]. Therefore, almost all starch plants in Thailand use or have used (prior to implementation of biogas reactors as CDM projects) open lagoon systems for the treatment of wastewater. This scenario is therefore in line with the business as usual scenario[20], which is further elaborated under Step 4 below.

It should be noted that BFB has been utilizing an open lagoon based system since the beginning of its operation.

It can be concluded that Alternative 2 does not face technical barriers.

Alternative 3 is well established and commonly used for both domestic and industrial wastewater treatment in many parts of the world. However, aerobic treatment is commonly used for wastewater with low COD content. There is no reference to or experience with this type of technology in the tapioca starch industry in Thailand and no starch factory operator is considering the use of this technology at this point in time. Furthermore aerobic treatment requires also skilled operators and sophisticated systems for control and is considered costly due to the high energy demand and the large volume of sludge that will be produced. Oxygen is supplied to the system through air compression which requires a lot of electricity, The necessary requirements, both in terms costs and skills to operate and maintain such systems is much higher than the use of an anaerobic lagoon. Furthermore, a significant amount of sludge generated by aerobic systems must be disposed of, which adds to operational complexity and costs.
Considering lack of interest in this technology, technical barriers are deemed less important than investment barriers, which are discussed in more detail below.

Alternative 4 is already excluded.

Alternative 5 is not considered by project operators due to commercial reasons as it creates no income streams in form of biogas utilisation and is not required by law. Technical reasons are deemed irrelevant.

[18] Rajbhandari, B.K., Annachhatre, A.P. 2004, Anaerobic ponds treatment of starch wastewater: case study in Thailand. Bioresource Technology 95 (2004) 135–143.

[19] Cinara, 2004 “Waste stabilization ponds for wastewater treatment, International Water and Sanitation Centre” http://www.irc.nl/page/8237

[20] Rajbhandari, B.K., Annachhatre, A.P. 2004, Anaerobic ponds treatment of starch wastewater: case study in Thailand. Bioresource Technology 95 (2004) 135–143.

Alternative 6 faces similar technological barriers than Alternative 1 and can be regarded as a comparable alternative to the project activity. The operational and maintenance requirements include possessing the means to maintain pond circulation (once they are covered), maintaining biochemical equilibrium within the digesters and a detailed monitoring (including equipment and material maintenance) program to maintain system performance levels. With such requirements, there is a need for significant investments as well as skilled and experienced operators; the availability of such personnel is limited as such biogas systems are still relatively rare in the Thai tapioca starch production industry21.

Investment barriers

Alternative 1 entails high investment and O&M costs and uncertain commercial returns (from the production and use of biogas).
According to the *Energy Conservation and Renewable Energy Division* and *Energy Policy and Planning Division* of the Ministry of Environment, Government of Thailand *"Most of the tapioca starch plants choose to retain wastewater in their open lagoons because of insufficient knowledge /confidence in the technology, high investment cost compared to cheap land price, the resulting operating cost throughout the treatment life*"[22]. Therefore penetration of other advanced wastewater treatment technologies is very low in Thailand and biogas projects are considered highly risky by the financiers. Hence, financing of biogas project in starch industry is regarded as a constraint[23]. Due to high risks associated with such kind of projects even, without subsidies, it is very difficult to obtain a loan approval[24].
In recent years (2003- 2005), Ministry of Environment started a pilot demonstration of biogas system in starch industry in four different wastewater treatment technology. Nine factories have been selected and received financial support from the Energy Conservation Promotion Fund (ENCON)[25]. In addition to these factories, the other tapioca starch mills have also implemented biogas plants considering CDM revenue to overcome the risk and financial barriers faced by these projects[26].

Prior to implementation of the project activity at BFB, the project owner assessed the costs, potential returns and the risks of the proposed activity and came to the conclusion that, given the high investment costs and insecure returns due to technological risks, the company would not be able to implement the the project activity without the long term financial returns linked to CERs .
Alternative 2 creates acceptable operational costs to achieve compliance with domestic effluent regulation. The anaerobic open lagoon technology is well established at the project site and easy to

[21] S. Prasertsan, B. Sajjakulnukit, 2005, Biomass and biogas energy in Thailand: Potential, opportunity and barriers http://www.energy-based.nrct.go.th/Article/Ts-3%20biomass%20and%20biogas%20energy%20in%20thailand%20potential,%20opportunity%20and%20barriers.pdf.

[22] The Promotion of Biogas from Wastewater as An Alternative Energy and for Environmental Improvement, published by the Energy Conservation and Renewable Energy Division and Energy Policy and Planning Office (EPPO), 2007 Page no. 47.

[23] Renewable Energy in Asia: The Thailand Report. An overview of the energy systems, renewable energy options, initiatives, actors and opportunities in Thailand, 2005. Australian Business Council for Sustainable Energy, Page No. 5.

[24] Prasertsan, S. B. Sajjakulnukit (2006). Biomass and biogas energy in Thailand: Potential, opportunity and barriers. Renewable Energy 31:599–610.

[25] Energy Policy and Planning Office, Ministry of Energy, Seminar on the Promotion of Production of Biogas from Wastewater as an Alternative Energy and for Environmental Improvement, At Ballroom, Sirikit Convention Centre 29 August 2007, pp.46-47,

[26] The pilot project of CDM development program in "bundle" pattern among medium size starch manufacturers and small size starch manufacturers http://www.thaitapiocastarch.org/cooperation_detail.asp?id=5

operate. Open anaerobic lagoons require less investment and have lower operation and maintenance costs[27,28], as compared to alternative systems such as anaerobic reactors, covered lagoons and aerobic systems. Therefore, it can be concluded that Alternative 2 does not face any financial barriers.

Alternative 3 entails high investment and very high O&M costs. The major reason for high O&M costs for treating wastewater with high organic content in aerobic systems is the very high electricity demand for forced aeration and high costs associated to sludge disposal as compared to anaerobic treatment systems. Due to high investment and O&M costs and the lack of commercial returns from energy production or energy saving (as no biogas is produced), the financial barrier for this type of technology is not surmountable and the alternative is excluded from further analysis.

Alternative 4 is already excluded.

Alternative 5, anaerobic digester with methane recovery and flaring, also entails high investment and O&M costs and no commercial return as the produced biogas is destroyed without use. There will be no expected revenue generation from the project activity. The financial barriers are not surmountable and the alternative is excluded from further analysis.

Alternative 6: The identified barriers for the alternative scenario 1 are also applicable to covered lagoon systems. Investment and O&M costs are also very high and similar to UASB systems. Depending on the design, investment costs for covered lagoon systems might be lower as compared to UASB systems, but they lead to high O&M costs because of the shorter life time of lining material and lagoon covers, as compared to concrete and/or steel reactor tanks of UASB reactors. Covered lagoons projects are also implemented with the help of additional revenues in order to overcome investment barriers, since they require substantial investment[29]. As mentioned in the common practice analysis, there are currently 6 projects using anaerobic covered lagoon technology, which are seeking carbon revenues. This is a clear indication that these projects face serious investment barriers.
Besides, compared to the technology used in the project activity, covered lagoon technology has a lower COD removal efficiency (60% compared to 87% for UASB system)[30], depending very much on the retention time. With similar investment costs, the project owner preferred to go for a more efficient technology. Given explanations above, it can be concluded that Alternative 6 would be rather an alternative CDM project and not a plausible baseline scenario. Therefore, this alternative is excluded from further analysis.

Alternatives scenarios 3 to 6 are prevented by at least one barrier as shown above. Therefore, these scenarios are eliminated from further consideration. No barriers have been identified for Alternative 2 (Open anaerobic lagoon based wastewater treatment system). According to explanations above, Alternative 1 (proposed project without CDM assistance) faces technological and investment barriers. However, this alternative is not excluded at this stage and is further analysed on the basis of an investment analysis.

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[27] Cinara, 2004 “Waste stabilization ponds for wastewater treatment, International Water and Sanitation Centre”

[28] Pena,M.R, Mara, D., 2003, High-rate anaerobic pond concept for domestic wastewater treatment: results from pilot scale experience.

[29] Chol Charoen Group Wastewater Treatment with Biogas System Projects.

[30] Conversion of Biomass to Electricity and Thermal Energy Biogas. www.efe.or.th/download/Chapter7.pdf

To prove that the project is only feasible with CDM revenues a benchmark analysis is used followed by a sensitivity analysis as described in Section B.5.

Step 4: Only one alternative remains (Alternative 2), which is not the proposed project activity undertaken without being registered as a CDM project activity. Therefore, since Alternative 2, open anaerobic lagoon based wastewater treatment system, corresponds to the baseline scenario (vi) of AMS.III.H, the project activity is eligible under the methodology.

Conclusion:
Following these different steps, it has been demonstrated that the wastewater of the second line would have been treated in an open anaerobic lagoon in the absence of the Project. Therefore, for both lines, the project activity refers thus to case (vi) described in AMS.III.H and fulfils the applicability conditions of the respective project category:

> (vi) Introduction of a sequential stage of wastewater treatment with methane recovery and combustion, with or without sludge treatment, to an existing wastewater treatment system without methane recovery (e.g. introduction of treatment in an anaerobic reactor with methane recovery as a sequential treatment step for the wastewater that is presently being treated in an anaerobic lagoon without methane recovery).

As per § 18(b) of the methodology AMS IIIH, '*In the case of Greenfield projects, one of the following procedures shall be used to determine the baseline emissions:*

(i) Value obtained from a measurement campaign in a comparable existing wastewater treatment plant i.e., having similar environmental and technological circumstances for example treating similar flow and same type of wastewater (domestic, industrial, etc.), located in the same host country and region. Average values from the measurement campaign shall be used and the result shall be multiplied by 0.89 to account for the uncertainty range (30% to 50%) associated with this approach;'

(ii) Value provided by the manufacturer/designer of a Greenfield wastewater treatment plant using the same technology, demonstrated to be conservative (less emitting) for example by choosing parameters from the top 20 per cent of the plants installed in the last five years designed for the same country/region to treat the same type and similar flow of wastewater as in the project activity.

Option (i) has been chosen. The project proponent uses data from the first phase of this project activity for which a measurement campaign has been carried out before the implementation of the biodigester. The reference plant has comparable starch production capacity, climatic conditions and COD loading value per tonne of starch generated.

All the other data parameters used in the estimation of baseline emissions are explained in detail in section B.6.2 and B.7.1. The choice of methodological formulae and calculation is explained in section B.6.3 and B.6.4.

The baseline for the type I components for the second line is similar to the baseline for the first line: Type I – Renewable energy projects, Category I.C – Thermal energy for user with or without electricity Version 16 (AMS I.C) and Category I.D – Grid connected renewable electricity generation Version 15 (AMS I.D).

> The baseline scenario is (a) where electricity is imported from the grid and steam/heat is produced using fossil fuel. For the project, electricity is drawn from Thai grid system while the heat is produced by Heavy Fuel Oil (HFO) boiler.

B.5. Description of how the anthropogenic emissions of GHG by sources are reduced below those that would have occurred in the absence of the registered small-scale CDM project activity:

The project activity, as explained above, reduces GHG emissions by capturing the methane that would have escaped into the environment from anaerobic reduction of COD in lagoons and also by using the captured methane to replace the use of fossil fuel in heat boiler and to generate power replacing grid electricity. The carbon credit incomes were well taken into account before the project initiation and played a key role in the decision making process.

- **Time schedule of the project activity**

The following table gives an overview of the timeline of the key milestones in the project implementation so far.

Date	**Event**	**Verified information and evidence submitted by PP**
2004	Operation start of the starch factory	Production data
25 January 2005	Consideration of the CDM to develop WWT treatment system = **proof of early consideration**	Board minutes
May 2005	First technical proposal on biogas project	Proposal
4 and 6 May 2005	Communication with the Energy for Environment Foundation (E for E), an independent not-for-profit organization about CDM	Fax from E for E and letter from Chaodee to E for E
June 2005	E for E proposal for a biofuel reactor	Proposal
8 August 2005	Decision by Chaodee Starch factory to invest in a new wastewater treatment system **= investment decision date**	Board minutes
20 August 2005	Biofuel Co. Ltd (BFR) proposal (requested as alternative to E for E proposal)	Proposal
15 October 2005	Contract between Blue Fire Bio Co., Ltd (BFB) and carbon consultants for CDM services	Contract
26 October 2005	Acceptance of BFR proposal by BFB for the construction of an anaerobic biofuel reactor = **Project Start date**	Contract

11 November 2005	First invoice to BFR for the biodigester design work	Invoice
May 2006	Physical construction start of the first line of the anaerobic digester	Purchase orders
30 January 2007	Thai cabinet approves first batch of seven projects, ending an interminable period of waiting	GTZ newsletter – January 2007
10 May 2007	Communication from consultant stating the difficulties to implement CDM project in Thailand	Letter from consultant to BFB
25 May 2007	CDM cooperation agreement between South Pole and the carbon consultant, whereas South Pole was supposed to support CDM project implementation and purchase CERs.	Cooperation agreement
06 July 2007	Thailand Greenhouse Gas Management Organization (TGO) was established with a view to take over approval process from cabinet	
July 2007	Operation start of the 1st line	Monitoring report
18 December 2007	ERPA signed between BFB and South Pole	ERPA
August 2008	Investment for the second line	Contract between BFB – Bio Forerunner (BioFuel has established a new company)
25 September 2008	South Pole requested TUV Rheinland proposal for validation	Email
10 November 2008	Initial CDM Gold Standard stakeholder consultation at Chaodee factory	Stakeholder consultation documents
20 November 2008	Finishing Initial Environmental Evaluation and draft PDD	IEE and draft PDD
28 November 2008	Submission of the Letter of Approval (LoA) request to Thai DNA (Host)	LoA request
7 February 2009	PDD webhosted on UNFCCC	UNFCCC website
27 February 2009	DOE site visit	
20 August 2009	Letter of Approval issued by Thai DNA	Thai LoA. Nr. B.E. 2552 (2009)
28 September 2009	Letter of Approval issued by Switzerland	LoA Swiss G 514-3487
May 2010	Expected start operation date of the second line (postponed to end of 2010)	BFB schedule

Table 3. Time schedule of the project

The above chronology of events clearly demonstrates that the incentive from the CDM was seriously considered in the decision to proceed with the project activity and that continuing and real actions were taken to secure CDM status for the project activity in parallel with its implementation.

Indeed, there is ample evidence to show that Blue Fire Bio Co., Ltd seriously considered the CDM from the early stages of the project development. The project was considered as it became known that the Korat wastewater project, the first wastewater-related project in Thailand, had started developing its project as a CDM. Various consultants emphasized the attractiveness of such a project due to the CERs

revenues, and there was much talk in the industry from all biogas digester suppliers. Chaodee Starch (2004) Co., Ltd received various proposals (e.g. from E for E), and decided to invest in the new wastewater treatment system in August 2005. After receipt of the proposal from BFR, the project owner decided to contract with them, due to the reliable references of the company. At the same time, the contract with the first consultant for CDM services was signed.
Afterwards, they established the company Blue Fire Bio Co.,Ltd to implement the project.
In November 2005, the first payment to BFR for the design work was released.
The construction of the project activity started in May 2006 and the operation in July 2007.

It is pertinent to note that despite pioneering efforts by Thai developers, who were among the first in the world to attempt to develop CDM projects from as early as 2001, the first batch of Letter of Approval (LoAs) for host country approval were not handed out until 2007. Because of this delay, mainly due to the political situation in Thailand, which had to cope with the political turmoil surrounding the military coup, many early Thai developers adopted an active approach to lobby the Thai government. However, BFB was unable to obtain the LoA earlier, due to a new DNA rule introduced immediately after the first batch of retroactive projects were approved, which required all projects applying for the CDM to first submit an Initial Environmental Evaluation Report. The first CDM Thai project was finally registered in June 2007[31].

In addition to these complications, the CDM consultant had to face changes of CDM methodologies and procedures. At the time of the decision, no methodology applied to greenfield projects or projects involving capacity increase under category III of small-scale CDM projects. Hence, no small-scale methodology was applicable to the project activity. The CDM consultant first planned to use the large-scale AM0013 methodology, which did not allow a greenfield project component either. The same situation applied also to AM0022, which was valid at that time. The first version of AMS.III.H methodology was available as of March 2006[32] and the provisions for greenfield/capacity expansion projects under category III were issued by the EB only in October 2007 (EB 35, Annex 35[33]). Therefore, in addition to other internal difficulties, the CDM consultant initially contracted was unable to develop the project, and BFB had to contact another CDM consultant to follow up with the project. South Pole Carbon Asset Management was contacted in May 2007, and took over the project. The contract between South Pole and BFB was signed in November 2007, followed by continuous actions within the CDM project cycle. The complexity of the project delayed the process of PDD development and validation.

The documents and information mentioned above are in line with paragraphs 5 (a) and (b) of the "Guidance on the demonstration and assessment of prior consideration of the CDM (version 01)" from EB41, Annex 46. The verified documents mentioned in the table above are applicable evidences to prove that (a) the project participants were aware of the CDM prior to the project activity start date, and that the benefits of the CDM were a decisive factor in the decision to proceed with the project; and (b) that continuing and real actions were taken to secure CDM status for the project in parallel with its implementation. There is no gap bigger than two years between relevant actions to secure CDM status.

[31] Korat waste to Energy : http://cdm.unfccc.int/Projects/DB/KPMG1175141470.89

[32] http://cdm.unfccc.int/methodologies/DB/38KXC1GFF824VHL2VB6K3FLNXJ8J5D/view.html

[33] Indicative simplified baseline and monitoring methodologies for selected small-scale CDM project activity categories (Version 11), Paragraph 14: http://cdm.unfccc.int/EB/035/eb35_repan35.pdf

As per attachment A of Appendix B of the *Simplified Modalities and Procedures for Small-Scale CDM Project Activities*, additionality of the project shall be demonstrated by providing an explanation to show that the project activity would not have occurred anyway due to at least one of the following barriers: (a) investment barrier, (b) technological barrier, (c) barrier due to prevailing practice, and (d) other barriers.

- **Investment Barrier:**

At the date of the investment decision, in August 2005, at the project location, the existing lagoons were sufficient to meet wastewater treatment needs of the facility and of the extended part as well and complied with national environmental regulations. There was no incentive to change to a more costly technology nor did the facility need to comply with stricter discharge limits. As explained in section B.4, compared to the project activity, the existing anaerobic lagoon system requires no additional investment and its operation and maintenance costs are much lower than for the anaerobic reactor system. Nevertheless, options have been searched for a profitable investment in the wastewater treatment process aiming to avoid methane emissions.

The project activity entails high investment and O&M costs and uncertain commercial returns (from the production and use of biogas). CDM revenues play a key role in overcoming financial barriers to the project, making it financially less risky. CDM revenues have been considered since the beginning of the project and were a major driver for implementing the project.

Besides the implementation of the CDM project activity it would also be possible to implement the project without CDM revenues. Since the baseline does not require investment and is outside the direct control of the project developer, as per the paragraph 16 of Guidelines on the Assessment of Investment Analysis, Annex 58, EB 51, the benchmark approach is appropriate. In line with the investment decision, the investment analysis is carried out for the two phases of the project as described in Section A.4.2 of the PDD.

a) Determination of the benchmark

As instructed further in paragraph 11of the Guidelines on the Assessment of Investment Analysis, Annex 58, EB 51, "*Local commercial lending rates or weighted average costs of capital (WACC) are appropriate benchmarks for a project IRR*". The project activity involves both equity and debt component. Hence, the cost of financing has been derived based upon weighted average of the cost of debt and equity component as determined for the project activity.
The project participant applies the following WACC equation to estimate the *required return on capital* as a benchmark for this project IRR:

$$WACC = \frac{E}{V} * \mathrm{R_e} + \frac{D}{V} * \mathrm{R}_d * (1 - T_c)$$

Where:

R_e : cost of equity

R_d : cost of debt

E : Amount of equity in the project

D : Amount of debt in the project

V : Total investment cost (=E + D)

T_c : average enterprise tax rate

Determine the cost of equity

To determine the cost of equity for electricity generation project type, which is not a company-specific, the project participant opts for "*equity indices*" data as guided in para. 12, Guidelines on the Assessment of Investment Analysis, Annex 58, EB 51.

The cost of equity has been determined based upon two different approaches.
The first one is based on the Capital Asset Pricing Model (CAPM)[34]. The Capital Asset Pricing Model (CAPM) is used to determine a theoretically appropriate required rate of return of an asset. The model takes into account the asset's sensitivity to non-diversifiable risk (also known as market risk), often represented by the quantity beta (β) in the financial industry, as well as the expected return of the market and the expected return of a theoretical risk-free asset.

The underlying algorithm of CAPM is as follows :

$R_e = R_f + \beta_L * R_{m,premium}$ Where:

$R_{e,}$: cost of equity for electricity generation project type

R_f : Risk free rate

β_L : Beta of the security for electricity generation project type

$R_{m,premium}$: Market risk premium (Expected market return – Rate of a risk free investment)

It is apparent from the above equation that the expected return from a security is the return of a risk- free investment plus Beta times the difference between the expected market return and the return from the risk-free investment (termed as market risk premium). Hence CAPM justifies that the expected return of an investor should be commensurate with the higher expected risk of the investment.

Thus, in order to apply CAPM, the following estimates are required

- Risk Free rate
- Market Risk Premium
- Beta

Risk Free Rate

R_f *(Risk Free Return):* The risk free return on a security that is free from default risk and is uncorrelated with returns from anything else in the economy. The rate on Thai government bond[35] has been used.

R_m *(Market Return):* The Market Return has been calculated on the basis of return of SET50.

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[34] Ref.: page No. 312, The CAPM Aprroch, equation (9-3) of Financial Management and practice (Theory and Practice, 11th addition) by Eugene F. Brigham and Michael C. Ehrahardt, published by Thomson South-Western.

[35] http://www.thaibma.or.th/yieldcurve/YieldTTM.aspx

Suitability of SET50: SET50 index is calculated from the prices of 50 selected SET stocks by the Stock Exchange of Thailand. The changing pattern of the economy and that of the market were kept in mind while constructing this index.[36]

Beta: **β** (Beta): Risk is an important consideration in holding any portfolio. The risk in holding securities is generally associated with the possibility that realised returns will be less than the returns expected. Risks can be classified as Systematic risks and Unsystematic risks.

➢ Unsystematic risks: These are risks that are unique to a firm or industry. Factors such as management capability, consumer preferences, labour, etc. contribute to unsystematic risks. Unsystematic risks are controllable by nature and can be considerably reduced by sufficiently diversifying one's portfolio.

➢ Systematic risks: These are risks associated with the economic, political, sociological and other macro-level changes. They affect the entire market as a whole and cannot be controlled or eliminated merely by diversifying one's portfolio.

The degree, to which different portfolios are affected by these systematic risks as compared to the effect on the market as a whole, is different and is measured by Beta. To put it differently, the systematic risks of various securities differ due to their relationships with the market. The Beta factor describes the movement in a stock's or a portfolio's returns in relation to that of the market return. For all practical purposes, the market returns are measured by the returns on the index, since the index is a good reflector of the market.

The beta is calculated by appling following formula over returns of SET50 index and Resources/Energy sector index.

Beta = COVAR(return of SET50,return of Energy index)/VAR(return of SET50).

Based on the above method, the Cost of Equity has been calculated as:

$R_e = R_f + \beta_L * R_{m,premium} = 5.27\% + (33.5\% - 5.27\%) * 1.03.$

$\boldsymbol{R_e = 34.38\%}$

In the second approach, the cost of equity derived from the Return on Equity (ROE) of listed companies in the country published by the Stock Exchange of Thailand[37]. The ROE is calculated using the operational results of listed companies in Energy & Utility Industry, since the project's major activity is electricity and heat generation.

The following formula has been used:

ROE = Profit / Stockholders' Equity

= 118,283 / 471,127

= 25.11%

[36] http://www.set.or.th/set/fetchfile.do?filename=roi/industry.xls

[37] http://www.set.or.th/en/market/market_statistics.html

The values of the third quarter of 2005 have been chosen for the calculation.

The most conservative approach has been chosen and a value of **25.11%** has been applied for the cost of equity.

Determine the cost of debt

The cost of debt is the interest rate for a long-term loan prevailed at the time of making the investment decision.

Cost of debt is taken as the Minimum Lending Rate for that time period. This information is easily available in the public domain, as it is published rate by the public bank of host country. Cost of debt for this case is taken as 6.16%[38].

Determine the WACC

The Weighted Average Cost of Capital is thus calculated based on the following data:

Parameters	**Value**
Percentage of total investment Equity financed	42%
Percentage of total investment Senior Debt financed	58%
Cost of equity	25.11%
Cost of debt	6.16
WACC	**14.14%**

The benchmark is thus equal to 14.14%, which is lower than average return expected from similar project in Thailand. As per a study published by the National Energy Policy Office's study Biomass-based Power generation and cogeneration within small scale rural industries in Thailand, hurdle rate in Thailand is approx. 23%. Even though this figure is for biomass based projects but the projects are very similar in nature and correspond to the similar sector because this study corresponds to energy generation in context of rural industries.

For a conservative estimation, the benchmark of 14.14% is conservative.
For Net Present Value (NPV) estimations, this benchmark is chosen as discount rate to arrive at NPV for project activity, i.e. with and without CER benefits.

b) Calculation of the financial indicators

The economic key indicators of the project activity (IRR, NPV) are based on information available at the date of investment decision on August 8th, 2005. The basic financial parameters of the project for the two phases are listed in the table below. All reference documents will be provided to the DOE during site visit.

Total Investment (Euro)	1,756,098	BFR proposal
Operating and maintenance costs (Euro/year)	139,908	BFR proposal

[38] http://www.bot.or.th/English/Statistics/FinancialMarkets/Interestrate/_layouts/application/interest_rate/IN_Rate.aspx on August 8th, 2005

Annual Biogas generated (Nm3/yr)	7,575,000	As per ER calculation sheet
Annual Power supplied to the Grid (MWh/yr)	5,794	As per ER calculation sheet
Price of electricity sold (THB/kWh)	2.19	Historical average before investment decision
Fossil fuel replaced	Heavy oil	
Amount of fossil fuel replaced (liter/year)	2,095,636	As per IRR calculation sheet
Price of fossil fuel (THB/liter)	9.70	Historical average before investment decision
Expected emission reduction (tCO_2 e/yr)	51,817	CERs calculation
Operation lifetime	15	Expected lifetime of the WWT system

Table 4. The basic financial parameters of the project (both lines)

Based on the financial parameters listed above, the project IRR is not competitive with other investment possibilities when not considering CDM revenues. Through the additional income through CDM the project reaches at the end of the lifetime of the equipment attractive financial indicators.

Project IRR (%)	without CDM revenues	8.43%
	with CDM revenues	18.74%

Table 5. Comparative financial indicators with without CDM revenues

The figures in the table above show that developing the project without CDM revenue will end up with significant lower financial indicators then usually demanded for this project type in Thailand. These figures show the criticality of CER revenue for the project activity.

c) Sensitivity analysis

Purpose of sensitivity analysis is to show whether the conclusion regarding the financial attractiveness is robust to reasonable variations in the critical assumptions.

EB 51, Annex 58, paragraph 17 guides that “Only variables, including the initial investment cost, that constitute more than 20% of either total project costs or total project revenue should be subjected to reasonable variation”. Therefore, the following parameters that constitute more than 20% of the total investment cost are taken into account in the sensitivity analysis of the project activity:

- Initial investment,
- Price of electricity,
- Price of fossil fuel,
- Operating and management costs.

As recommended by the Guidance on investment analysis, EB51 Annex 58, variations in the sensitivity analysis cover a range of +10% and -10%.

No	Parameter	Variation	Project IRR	Likelihoods to happen
1	HFO market price	10%	10.02%	Lower than the benchmark
		37.12%	14.14%	Fuel oil prices are dependent on crude oil prices and the crude oil market is very volatile. According to historical trends prior investment decision date, an increase of 37% of HFO market price is unlikely to happen. The decision making process is a long process. When the project owner decided to invest in the biogas system, he had in mind the prices of the previous years, which show a variation of around 10%.
		-10%	6.78%	Lower than the benchmark
2	Non labour O&M costs	10%	7.68%	Lower than the benchmark
		-83.46%	14.14%	The probability of a -83.46% decrease in non labour O&M costs annually is very unlikely since the inflation rate in 2005[39] shows an annual increase of around 4.5%..
		-10%	9.16%	Lower than the benchmark
3	Electricity price	10%	9.24%	Lower than the benchmark
		78.39%	14.14%	The probability of a 78.39% increase in electricity price is very low. The electricity tariff applied has been derived from the figure set by the Provincial Electricity Authority of Thailand, a purchaser of the electricity generated from the project. The tariff fluctuates monthly linking with the wholesale electricity sales price set by Energy Policy and Planning Office in Thailand. The historical trends of the electricity price at the time of investment decision fluctuate at an average below 2%.
		-10%	7.59%	Lower than the benchmark
4	Initial investment	10%	6.96%	Lower than the benchmark
		-28.03%	14.14%	The probability of a 28.03% decrease in the total investment cost is not likely to happen. The cost of investment applied for the project

[39] http://www.tradingeconomics.com/Economics/Inflation-CPI.aspx?Symbol=THB

				IRR calculation has been derived from the proposal received from BFB contractor. The price offered compared to similar project is reasonable. In addition, often proposals from technology suppliers are skewed in towards higher returns to get acceptance on projects. The positive variation is more appropriate as compared to negative variation.
		-10%	10.14%	Lower than the benchmark

Table 6. IRR sensitivity analysis

For further analysis, it is demonstrated that the electricity tariff increase until October 2010 (the month of the project starting date, when tariff is at 2.25 THB/kWh compared to 2.19 THB/kWh) does not affect the results of the investment analysis. With the tariff of October 2005, the IRR calculated is then equal to 8.59%, which is still much lower than the benchmark of 14.14%.

The only rationale for the investment in a costly BFR technology is thus the availability of additional incentives from carbon credits and revenues from electricity sales. CDM revenues play a key role in overcoming investment barriers to the project, making it financially more attractive and less risky for potential investors. CDM revenues have been considered since the beginning of the project and were a major driver for the project owner, BFB Co. Ltd. CDM revenues allow the project owner to have an attractive return on investment and a lower exposure to risks, such as variations of the effluent quality and quantity resulting in unexpected dying of the micro organisms and changes in electricity tariff.

Conclusion:
It is clear that the carbon credits revenues play a significant role in the financial viability of the project and that the project owner would not have invested in such a project without the consideration of carbon credits revenues. In absence of the project activity, the existing lagoons would lead to higher green house emissions due to methane release from the lagoon to the atmosphere and CO2 emissions related to fossil fuel fired power plants connected to the grid.

Hence, according to Attachment A of Appendix B of the *Simplified Modalities and Procedures for Small-Scale CDM Project Activities*, Paragraph 1 (a), a financially more viable alternative to the project activity would have led to higher emissions, which confirms the existence of the investment barrier.
Therefore, the project is additional.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

The amount of methane that would be emitted to the atmosphere in the absence of the project activity is estimated according to AMS III.H, Version 13.
For the emission reduction on account of fuel and power savings the applicable methodologies are AMS

I.C, Version 16 and AMS I.D, Version 15.

This section details the applicable formulas from the methodologies applied to the project activity.

Baseline emissions

Baseline emissions are the sum of emissions from the degradable organic matter in the treated wastewater (calculated according to AMS III.H- Version 13), the emissions due to the displacement of electricity from the grid (calculated according to AMS I.D- Version 15) and the emissions due to fossil fuel replacement for heating calculated according to AMS I.C- Version 16):

$$BE_{y} = BE_{elec,y} + BE_{thermal,CO2,y} + BE_{power,y} + BE_{ww,\ treatment,\ y} + BE_{s,\ treatment,\ y} + BE_{ww,\ discharge,\ y} + BE_{s,\ final,\ y} \qquad (1)$$

Where:

BE_y	Baseline emissions in the year y (tCO_2e).
$BE_{power,y}$	Baseline emissions from electricity or fuel consumption in year y (tCO_2e).
$BE_{thermal,CO2,y}$	Baseline emissions from steam/heat displaced by the project activity during the year y in tCO2e.
$BE_{elec,y}$	Baseline emissions from electricity displaced by the project activity during the year y in tCO_2e.
$BE_{ww,treatment,y}$	Baseline emissions of the wastewater treatment systems affected by the project activity in year y (tCO_2e).
$BE_{s,treatment,y}$	Baseline emissions of the sludge treatment systems affected by the project activity in year y (tCO_2e).
$BE_{ww,discharge,y}$	Baseline methane emissions from degradable organic carbon in treated wastewater discharge into sea/river/lake in year y (tCO_2e). The value of this term is zero for the case 1 (ii).
$BE_{s,final,y}$	Baseline methane emissions from anaerobic decay of the final sludge produced in year y (tCO_2e). If the sludge is controlled combusted, disposed in a landfill with biogas recovery, or used for soil application in the baseline scenario, this term shall be neglected.

AMS III H

Methane emissions from the baseline wastewater treatment systems affected by the project ($BE_{ww,treatment,y}$) are determined using the methane generation potential of the wastewater treatment systems as per paragraph 20 of AMS III.H version 13:

$$BE_{ww,\ treatment,y} = \sum Q_{ww,i,y} * COD_{removed,i,y} * MCF_{ww,\ treatment,BL,i} * B_{o,\ ww} * UF_{BL} * GWP_{CH4} \qquad (2)$$

Where:

$Q_{ww,i,y}$	Volume of wastewater treated in baseline wastewater treatment system i in year y (m^3).
$COD_{removed,i,y}$	Chemical oxygen demand removed by baseline treatment system i in year y (tonnes/m3), measured as the difference between inflow COD and the outflow COD in system i.
$MCF_{ww,treatment,BL,i}$	Methane correction factor for baseline wastewater treatment system i (MCF value as per table III.H.l).
i	Index for baseline wastewater treatment system.

$B_{o,ww}$	Methane producing capacity of the wastewater (IPCC lower value for domestic wastewater of 0.21 kg CH_4/kg COD)[40]
UF_{BL}	Model correction factor to account for model uncertainties (0.94)[41]
GWP_{CH4}	Global Warming Potential for methane (value of 21).

In the baseline, there is no sludge treatment and the treated wastewater is not discharged into sea/lake/river.
Therefore:
$BE_{s,treatment,y} = 0$
$BE_{ww,discharge,y} = 0$
$BE_{s,final,y} = 0$

Baseline emissions from electricity consumption ($BE_{power,y}$) are neglected. This is conservative.

As per AMS III.H, paragraph 3, since the recovered biogas is used for thermal and electricity generation, type I methodologies are used. As per AMS III.H, paragraph19 and AMS I.C, paragraph 14, baseline emissions for supply of electricity to and/or displacement electricity from a grid shall be calculated as per the procedures described in AMS-I.D. For emissions from fossil fuel consumption, the emission factor for the fossil fuel shall be used (tCO_2/tonne).

AMS-I.C
As per paragraph 15 of AMS I.C, for steam/heat produced using fossil fuels the baseline emissions are calculated as follows:

$$\mathbf{BE_{thermal,CO2,y} = (EG_{thermal,y} / \eta_{BL,thermal})^{*} EF_{FF,CO2}} \qquad \mathbf{(4)}$$

Where:

$BE_{thermal,CO2,y}$	the baseline emissions from steam/heat displaced by the project activity during the year y in tCO2e.
$EG_{thermal,y}$	the net quantity of steam/heat supplied by the project activity during the year y in TJ.
$EF_{FF,CO2}$	the CO2 emission factor per unit of energy of the fuel that would have been used in the baseline plant in (tCO2 / 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.

The net quantity of steam/heat supplied by the project activity is calculated as follows:

$$\mathbf{EG_{thermal,y} = \sum_{h}[Q_{oil,h} X(T_{out,h} - T_{in,h})]XC_{oil}}$$

[40] The IPCC default value of 0.25 kg CH_4/kg COD was corrected to take into account the uncertainties. For domestic waste water, a COD based value of $B_{o,ww}$ can be converted to BOD_5 based value by dividing it by 2.4 i.e. a default value of 0.504 kg CH_4/kg COD can be used.

[41] Reference: FCCC/SBSTA/2003/10/Add.2, page 25.

$T_{out,h}$	Temperature of heating medium (thermal oil) coming out of boiler during hour h
$T_{in,h}$	Temperature of heating medium (thermal oil) going into the boiler during hour h
$Q_{oil,h}$	Thermal oil flow rate during hou r (kg/h)
C_{oil}	Specific heat of oil - Standard

AMS-I.D

As per paragraph 10 of AMS I.D, for the electricity displaced by the project activity, the baseline emissions are calculated as follows:

$$\mathbf{BE_{elec,y} = EG_y * EF_{CO2}} \quad \mathbf{(5)}$$

$BE_{elec,y}$	the baseline emissions from electricity displaced by the project activity during the year y in tCO_2e.
EG_y	the net quantity of electricity generated by the project activity during the year y in TJ.
EF_{CO2}	Grid emission factor of Thailand, calculated with the tool to calculate the emission factor of an electricity system, in tCO_2/MWh

Detailed calculation of grid emission factor is given in Annex 3.

Project emissions

AMS III H

Project emissions are the sum of emissions from the wastewater treatment systems affected by the project and not equipped with biogas recovery, methane fugitive emissions on account of inefficiencies in capture systems, methane emissions due to incomplete flaring, CO_2 emissions on account of power and and fuel used by the project activity facilities (calculated according to AMS III.H- Version 13, paragraph 26).
The project activity emissions are calculated as follows:

$$\mathbf{PE_y = PE_{power,y} + PE_{ww,\,treatment,\,y} + PE_{s,\,treatment,\,y} + PE_{ww,\,discharge,\,y} + PE_{s,\,final,\,y} + PE_{fugitive,\,y} + PE_{biomass,\,y} + PE_{flaring,\,y}} \quad \mathbf{(6)}$$

Where:

PE_y	Project activity emissions in the year y (tCO_2e)
$PE_{power,y}$	Emissions from electricity or fossil fuel consumption in the year y
$PE_{ww,\,treatment,\,y}$	Methane emissions from wastewater treatment systems not equipped with biogas recovery in year y
$PE_{s,\,treatment,\,y}$	Emissions from sludge treatment systems not equipped with biogas recovery in year y
$PE_{ww,\,discharge,\,y}$	Emissions from degradable organic carbon in treated wastewater in year y
$PE_{s,\,final,\,y}$	Emissions from anaerobic decay of the final sludge produced in the year y
$PE_{fugitive,\,y}$	Emissions from biogas release in capture systems in year y
$PE_{biomass,\,y}$	Emissions from biomass stored under anaerobic condition
$PE_{flaring,\,y}$	Emissions from incomplete flaring in year y

- **$PE_{power,y}$:** These emissions are calculated as per paragraphs 19 and 26 of AMS III.H. All the equipments that are involved in operation of biogas generation and consumption are to be included in estimation of power consumption.

$$\mathbf{PE_{power,y} = EC_y * EF_{CO2}} \qquad \textbf{(7)}$$

Where,

$PE_{power,y}$	project emissions from electricity consumption by the project activity during the year y in tCO_2e.
EC_y	net quantity of electricity imported by the project activity during the year y in TJ.
EF_{CO2}	Grid emission factor of Thailand, calculated with the tool to calculate the emission factor of an electricity system, in tCO_2/MWh

- **$PE_{ww,\ treatment,\ y}$:** These accounts for project emissions in wastewater not equipped with biogas recovery system and are calculated as per paragraph 20, using an uncertainty factor of 1.06, as follows:

$$\mathbf{PE_{ww,\ treatment,\ y} = \sum Q_{ww,k,y} * COD_{removed,PJ,ky} * MCF_{ww,\ treatment,PJ,k} * B_{o,\ ww} * UF_{PJ} * GWP_{CH4}} \qquad \textbf{(8)}$$

Where;

$Q_{ww,k,y}$	Volume of wastewater treated in project wastewater treatment system k without biogas recovery in the year "y" (m3/yr)
GWP_{CH4}	Global Warming Potential for methane (value of 21 is used)
$B_{o,\ ww}$	Methane producing capacity of the wastewater (IPCC default value of 0.21 kg CH4/kg COD)[42]
$COD_{removed,PJ,k,y}$	Chemical oxygen demand removed by project wastewater treatment system k without biogas recovery in the year "y" (tonnes/m3); measured as the difference between inflow COD and the outflow COD in system k.
$MCF_{ww,treatment,PJ,k}$	Methane correction factor for project wastewater treatment system k without biogas recovery.
UF_{PJ}	Model correction for uncertainties (1.06)

- **$PE_{s,\ treatment,y}$** : These emissions account for methane emissions from sludge treatment system affected by the project activity, and not equipped with biogas recovery in the project situation. However, the project activity does not include sludge treatment system, therefore the emission from sludge treatment system is null:

$$PE_{s,treatment,\ y} \mathbf{= 0}$$

- **$PE_{ww,\ discharge,\ y}$**: These emissions account of inefficiency of the project activity wastewater treatment systems and presence of degradable organic carbon in treated wastewater. Not applicable to the project activity, since the treated wastewater is not discharged in river, sea or lake.

[42] As per AMS.III.H, the IPCC default value of 0.25 kg CH4/kg COD was corrected to take into account the uncertainties.

- **PE $_{s,\ final,\ y}$** : These emissions account for methane emissions from anaerobic decay of the final sludge produced in year *y* and are calculated as follows:

$$PE_{s,\ final,\ y} = S_{final,PJ,y} * DOC_{s} * UF_{PJ} * MCF_{s,\ PJ,final} * DOC_{F} * F * 16/12 * GWP_{CH4} \quad (9)$$

Where;

$S_{final,PJ,y}$	Amount of dry matter in final sludge generated by the project wastewater treatment systems in year *y* (tonnes)
DOC_S	Degradable organic content of the untreated sludge generated in the year "y" (fraction, dry basis). Default value of 0.5 for domestic sludge and 0.257 for industrial sludge (wet basis, assuming dry matter content of 35 percent) will be used
UF_{PJ}	Model correction for factor to account for model uncertainties (1.06)
$MCF_{s,PJ,final}$	Methane correction factor of the disposal site that receives the final sludge in the project situation, estimated as per the procedures described in AMS-III.G
DOC_F	Degradable organic content of the final sludge generated by the wastewater treatment in the year "y" (fraction). IPCC default value of 0.09 for industrial sludge (wet basis, assuming dry matter content of 35 percent) will be used
F	Fraction of CH_4 in biogas (IPCC default of 0.5)
GWP_{CH4}	Global Warming Potential for methane (value of 21 is used)

However, a relatively small amount of final sludge will be removed from the digester during the crediting period. The project proponent will use the excess sludge for starting up other systems, to fill the land or as fertilizer inside the project boundary. The final disposal of the sludge shall be monitored during the crediting period. Therefore as suggested by the AMS III.H, paragraph 26, the emission from anaerobic decay from the final sludge produced can be omitted.

In case sludge is given outside the project boundary and its application cannot be monitored, for conservativeness, it will be assumed that the sludge will decay anaerobically. Equation (9) of the PDD will then be used.

- **PE $_{fugitive,y}$:** These emissions account methane release in capture system. They are determined as per paragraph 27 of AMS III.H:

$$PE_{fugitive,y} = PE_{fugitive,\ ww,\ y} + PE_{fugitive,\ s,y} \quad (10)$$

Where;

$PE_{fugitive,\ ww,\ y}$	Fugitive emissions through capture inefficiencies in the anaerobic wastewater treatment systems equipped with biogas recovery in year "y" (tCO2e);
$PE_{fugitive,\ s,y}$	Fugitive emissions through capture inefficiencies in the anaerobic sludge treatment in the year "y" (tCO2e)

$$PE_{fugitive,\ ww,y} = (1 - CFE_{ww}) * MEP_{ww,\ treatment,y} * GWP_{CH4} \quad (11)$$

Where;

CFE_{ww}	Capture efficiency of the biogas recovery equipment in the wastewater treatment (a default value of 0.9 shall be used, given no other appropriate value)

$MEP_{ww,\ treatment,y}$ Methane emission potential of wastewater treatment system equipped with biogas recovery in the year "y" (tonnes)

$$\mathbf{MEP_{ww,\ treatment,y} = Q_{ww,y} * B_{o,\ ww} * UF_{PJ} * \sum COD_{removed,PJ,k,y} * MCF_{ww,\ treatment,PJ,k}} \quad \textbf{(12)}$$

Where;

$COD_{removed,PJ,k,y}$	The chemical oxygen demand removed by the treatment system k of the project activity equipped with biogas recovery in the year "y" (tonnes/m^3)
$MCF_{ww,\ treatment,PJ,k}$	Methane correction factor for the wastewater treatment system k equipped with methane biogas equipment
$B_{o,\ ww}$	Methane producing capacity of the wastewater (IPCC default value for domestic wastewater of 0.21 kg CH4/kg COD)
UF_{PJ}	Model correction factor to account for model uncertainties (1.06)

$$\mathbf{PE_{fugitive,\ s,y} = (1 - CFE_s) * MEP_{s,\ treatment,y} * GWP_{CH4}} \quad \textbf{(13)}$$

Where;

CFE_s	Capture efficiency of the biogas recovery equipment in the sludge treatment (a default value of 0.9 shall be used, given no other appropriate value)
$MEP_{s,\ treatment,y}$	Methane emission potential of sludge treatment system equipped with biogas recovery in the year "y" (tonnes)

$$\mathbf{MEP_{s,\ treatment,y} = \sum(S_{l,PJ,y} * MCF_{s,\ treatment,PJl}) * DOC_s * UF_{PJ} * DOC_F * F * 16/12} \quad \textbf{(14)}$$

Where;

$S_{l,PJ,y}$	Amount of sludge treated in the project sludge treatment system l, equipped with biogas recovery system (on dry basis) in year y (tonnes)
DOC_F	Degradable organic content of the final sludge generated by the wastewater treatment in the year "y" (fraction). IPCC default value of 0.09 for industrial sludge (wet basis, assuming dry matter content of 35 percent) will be used
$MCF_{s,\ treatment,PJ,l}$	Methane correction factor for the sludge treatment system that will be equipped with methane recovery and combustion/utilization/flare equipment (MCF Higher value of 1.0 as per table III.H.1)
UF_{PJ}	Model correction for factor to account for model uncertainties (1.06)

In the project activity, sludge is kept in suspension by the upward flow of wastewater. Eventually excess of sludge will be withdrawn and used to start-up new reactors elsewhere or used as fertilizer inside the project boundary. However, the quantity of excess sludge is expected to be negligible for ex-ante calculation. Therefore, emissions from sludge treatment are not considered.

- **$PE_{biomass,\ y}$** : Methane emissions from biomass stored under anaerobic conditions which does not take place in the baseline situation. Not applicable to the project activity, since no biomass storage is envisaged in the project activity.

- **$PE_{flaring,y}$:** Methane emission due to incomplete flaring in year y as per "Tool to determine project emissions from flaring gases containing methane" (tCO_2e).

The calculation steps for project emissions are as follows:

STEP 1. Determination of the mass flow rate of the residual gas that is flared
This step calculates the residual gas mass flow rate in each hour h, based on the volumetric flow rate and the density of the residual gas. The density of the residual gas is determined based on the volumetric fraction of all components in the gas.
As per the guidance of the tool, a simplified approach will be used and only the volumetric fraction of methane will be measured, the difference is considered to be 100% Nitrogen.

STEP 2 though STEP 4 are not applicable for this project.

STEP 5: Determination of methane mass flow rate in the residual gas on a dry basis
The quantity of methane in the residual gas flowing into the flare is the product of the volumetric flow rate of the residual gas ($FV_{RG,h}$), the volumetric fraction of methane in the residual gas ($fv_{CH4,RG,h}$) and the density of methane ($\rho_{CH\ 4,n,h}$) in the same reference conditions (normal conditions and dry or wet basis). Considering that the gas is cooler than 60 degrees Celsius, the reported density is expressed on dry basis already.

$$\mathbf{TM_{RG,h} = FV_{RG,h} * fv_{CH4,RG,h} * \rho_{CH\ 4,n}} \quad \mathbf{(15)}$$

Where:

$FV_{RG,h}$	Volumetric flow rate of the residual gas in dry basis at normal conditions in hour h (Nm^3/h)
$fv_{CH4,RG,h}$	Volumetric fraction of methane in the residual gas on dry basis in hour h
$\rho_{CH4,n}$	Density of methane at normal condition (kg/m3)

STEP 6: Determination of the hourly flare efficiency
The determination of the hourly flare efficiency depends on the operation of the flare (e.g. temperature), the type of flare used (open or enclosed) and, in case of enclosed flares, the approach selected by project participants to determine the flare efficiency (default value or continuous monitoring).

In case of open flares, the default value for flare efficiency ($\boldsymbol{\eta_{flare,h}}$) in the hour h is:

- 0%, if the flame is not detected for more than 20 minutes during the hour h;
- 50%, if the flame is detected for more than 20 minutes during the hour h.

The 50% default is applied.

STEP 7: Calculation of annual project emissions from flaring
Project emissions from flaring are calculated as the sum of emissions from each hour h, based on the methane flow rate in the residual gas ($TM_{RG,h}$) and the flare efficiency during each hour h ($\eta_{flare,h}$), as follows:

$$\mathbf{PE_{flare,y} = \Sigma\ TM_{RG,h} * (1- \eta_{flare,h}) * GWP_{CH4}/1000} \quad \mathbf{(16)}$$

Where:

$TM_{RG,h}$	Mass flow rate of methane in the residual gas in hour h
$\eta_{flare,h}$	Flare efficiency in hour h
GWP_{CH4}	Global Warming Potential of methane valid for the commitment period

The open-flare system will be used only in case in emergency. Therefore, for ex-ante calculation, the amount of biogas flared is zero. However, this data will be monitored during the crediting period.

AMS.I.C

According to paragraph 26 of AMS-I.C, CO_2 emissions from on-site consumption of fossil fuels due to the project activity shall be calculated using the latest version of "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion".

$$\mathbf{PE_{FC} = FC_{HFO,\,y} * NCV_{HFO} * EF_{HFO,CO2}} \qquad \mathbf{(17)}$$

Where :

$FC_{HFO,\,y}$	Amount of fossil used in the boiler in ton/yr
NCV_{HFO}	NCV of fossil fuel used in the process i.e. Fuel oil – 40.4 GJ/tonne
$EF_{HFO,CO2}$	Emission factor of Heavy fuel oil as per IPCC – 77.4 tCO2/TJ

<u>Leakage emissions</u>

The used technology is not equipment transferred from another activity, therefore according to the AMS.III.H, there is no leakage to be considered.
All the equipment used in the project activity for power and heat generation is either brought for purpose of project activity and no shifting of old equipment takes place. No energy equipment currently being utilised is transferred from outside the boundary to the project activity. Therefore, there is no leakage as per AMS.I.C and AMS.I.D.

<u>Emissions reductions</u>

As per the Paragraph 29 of AMS III.H, emission reduction are estimated ex-ante in the PDD using formulas mentioned in baseline, project and leakage emissions sections above. Emission reductions are estimated ex-ante as follows;

$$\mathbf{ER_{y,ex\text{-}ante} = BE_{y,exante} - (PE_{y,exante} + LE_{y,exante})} \qquad \mathbf{(18)}$$

Where:

$ER_{y,ex\text{-}ante}$	*Ex ante* emission reduction in year *y* (tCO_2e)
$BR_{y,ex\text{-}ante}$	*Ex ante* emission reduction in year *y* (tCO_2e)
$PE_{y,ex\text{-}ante}$	*Ex ante* emission reduction in year *y* (tCO_2e)
$LE_{y,ex\text{-}ante}$	*Ex ante* emission reduction in year *y* (tCO_2e)

According to the paragraph 31 AMS III.H, emission reduction achieved by the project activity is limited to the ex-post calculated baseline emissions minus project emissions using the actual monitored data for the project activity. Emission reductions achieved on any year are the lowest value of the following:

(i) The amount of biogas captured and destroyed or gainfully used by the project activity, that is monitored ex post;

(ii) Ex post calculated baseline, project and leakage emissions base on actual monitored data for the project activity.

$$\mathbf{ER_{y,expost} = min(BE_{y,expost} - PE_{y,\ expost} - LE_{,y\ expost}),(MD_y - PE_{power,y} - PE_{biomass,y} - LE_{y,\ expost}\ )} \qquad \mathbf{(19)}$$

Where:

$ER_{y,ex\text{-}post}$	*Ex post* emission reduction in year *y* (tCO_2e)
$BR_{y,ex\text{-}\ post}$	*Ex post* emission reduction in year *y* (tCO_2e)
$PE_{y,ex\text{-}\ post}$	*Ex post* emission reduction in year *y* (tCO_2e)
$LE_{y,ex\text{-}\ post}$	*Ex post* emission reduction in year *y* (tCO_2e)
MD_y	Methane captured and destroyed/gainfully used by the project activity in the year y

As per paragraph 32 in AMS III.H., *in case of flaring/combustion MD_y will be measured using the conditions of the flaring process*:

$$\mathbf{MD_y = BG_{burnt,y} * w_{CH4,y} * D_{CH4} * FE * GWP_{CH4}} \qquad \mathbf{(20)}$$

Where:

$BG_{burnt,\ y}$	Biogas flared/combusted in year *y* (m^3)
W_{CH4}	Methane content in the biogas in the year *y* (mass fraction)
D_{CH4}	Density of methane at the temperature and pressure of the biogas in the year *y* (tonnes/m^3)
FE	Flare efficiency in year *y* (fraction)

B.6.2. Data and parameters that are available at validation:

All data and parameters used for the emission reductions calculations but not monitored during the crediting period are provided in the following tables.

Data and parameters from the AMS.III.H

Data / Parameter:	GWP_{CH4}
Data unit:	-
Description:	Global warning potential of methane gas
Source of data used:	Intergovernmental Panel on Climate Change, Climate Change 1995: The Science of Climate Change (Cambridge, UK: Cambridge University Press, 1996)
Value applied:	21
Justification of the choice of data or description of measurement methods and procedures actually applied :	IPCC default value.
Any comment:	

Data / Parameter:	$B_{o, ww}$
Data unit:	kg CH_4/kg COD
Description:	Methane generation capacity of COD in waste water.
Source of data used:	IPCC default value, corrected as per methodology AMS III-H page 5, is used for estimation
Value applied:	0.21 kg CH_4/kg COD
Justification of the choice of data or description of measurement methods and procedures actually applied :	IPCC default value
Any comment:	As per AMS.III.H Version 13, the IPCC default value of 0.25 kg CH4/kg COD was corrected to 0.21 kg CH4/kg COD to take into account the uncertainties.

Data / Parameter:	UF_{BL}
Data unit:	-
Description:	Model correction factor to account of model uncertainties
Source of data used:	AMS.III.H
Value applied:	0.94
Justification of the choice of data or description of measurement methods and procedures actually applied :	Value for the baseline emissions calculation.
Any comment:	The original source of data is: FCCC/SBSTA/2003/Add.2, page 25

Data / Parameter:	UF_{PJ}
Data unit:	-
Description:	Model correction factor to account of model uncertainties
Source of data used:	AMS.III.H
Value applied:	1.06
Justification of the choice of data or description of measurement methods and procedures actually applied :	Value for the project emissions calculation.
Any comment:	The original source of data is: FCCC/SBSTA/2003/Add.2, page 25

Data / Parameter:	$MCF_{ww, treatment,BL,i}$
Data unit:	Fraction
Description:	Methane correction factor for the baseline anaerobic wastewater treatment systems
Source of data used:	Table III.H.1 from AMS-III.H, Version 13 methodology
Value applied:	0.8
Justification of the	All MCF values have been chosen in a conservative manner according to table

choice of data or description of measurement methods and procedures actually applied :	III.H.1 from methodology AMS-III.H, Version 13. The baseline wastewater treatment system consists in a succession of deep lagoons, with depth more than 2 metres, so the value of 0.8 has been chosen.
Any comment:	The original source of data can be checked for IPCC default value, Volume 5 Chapter 6, page 6.21. The lower value is used for conservative estimation of baseline emissions

Data / Parameter:	$MCF_{ww, treatment,PJ,BFR}$
Data unit:	Fraction
Description:	Methane correction factor for project wastewater treatment system equipped with biogas recovery
Source of data used:	Table III.H.1 from AMS-III.H, Version 13 methodology
Value applied:	0.8
Justification of the choice of data or description of measurement methods and procedures actually applied :	All MCF values have been chosen in a conservative manner according to table III.H.1 from methodology AMS-III.H, Version 13. The project wastewater treatment system with biogas recovery consists in a biodigester.
Any comment:	The original source of data can be checked for IPCC default value, Volume 5 Chapter 6, page 6.21. The lower value is used for conservative estimation of baseline emissions

Data / Parameter:	$MCF_{ww, treatment,PJ,lagoon}$
Data unit:	Fraction
Description:	Methane correction factor for project wastewater treatment system not equipped with biogas recovery
Source of data used:	Table III.H.1 from AMS-III.H, Version 13 methodology
Value applied:	0.8
Justification of the choice of data or description of measurement methods and procedures actually applied :	All MCF values have been chosen in a conservative manner according to table III.H.1 from methodology AMS-III.H, Version 13. The project wastewater treatment system without biogas recovery (secondary treatment) consists in a succession of deep lagoons, with depth more than 2 metres, so the value of 0.8 has been chosen.
Any comment:	The original source of data can be checked for IPCC default value, Volume 5 Chapter 6, page 6.21. The lower value is used for conservative estimation of baseline emissions

Data / Parameter:	CFE_{ww}
Data unit:	Fraction
Description:	Capture efficiency of the biogas recovery equipment in the wastewater treatment
Source of data used:	IPCC
Value applied:	0.9
Justification of the	In absence of an appropriate value the methodology describes to use adefault

choice of data or description of measurement methods and procedures actually applied :	value of 0.9
Any comment:	

Data / Parameter:	DOC_s
Data unit:	Fraction
Description:	Degradable organic content of the untreated sludge generated in the year "y"
Source of data used:	IPCC default values for industrial waste
Value applied:	0.09
Justification of the choice of data or description of measurement methods and procedures actually applied :	IPCC default value of 0.09 for industrial sludge (wet basis, assuming dry matter content of 35 percent) will be used
Any comment:	

Data / Parameter:	DOC_F
Data unit:	Fraction
Description:	Fraction of DOC dissimilated to biogas
Source of data used:	IPCC default value
Value applied:	0.5
Justification of the choice of data or description of measurement methods and procedures actually applied :	IPCC default value will be used
Any comment:	

Data / Parameter:	F
Data unit:	Fraction
Description:	Fraction of CH_4 in biogas
Source of data used:	IPCC default value
Value applied:	0.5
Justification of the choice of data or description of measurement methods and procedures actually applied :	IPCC default value will be used
Any comment:	

Data / Parameter:	$MCF_{s, final}$

Data unit:	Fraction
Description:	Methane correction factor of the landfill that receives the final sludge.
Source of data used:	AMS III.G default values
Value applied:	Default conservative value of 1.0 is used.
Justification of the choice of data or description of measurement methods and procedures actually applied :	The maximum possible value of MCF is assumed for estimation of project emissions.
Any comment:	Default values from chapter 6 of volume 5. Waste in 2006 IPCC Guidelines for National Greenhouse Gas Inventories

Data / Parameter:	$MCF_{s, treatment}$
Data unit:	Fraction
Description:	Methane correction factor for the sludge treatment system
Source of data used:	IPCC
Value applied:	0.8
Justification of the choice of data or description of measurement methods and procedures actually applied :	Anaerobic lagoons
Any comment:	Default values from chapter 6 of volume 5. Waste in 2006 IPCC Guidelines for National Greenhouse Gas Inventories

Data / Parameter:	$\eta_{removed,baseline}$
Data unit:	%
Description:	COD removal efficiency of the baseline system
Source of data used:	Measured historical values
Value applied:	89%
Justification of the choice of data or description of measurement methods and procedures actually applied :	As per paragraphs17 and 18 of the methodology, historical records of at least one year prior to the project implementation shall be used. In case one year of historical data is not available, the parameters shall be determined by a measurement campaign in the baseline wastewater systems for at least 10 days. In the case of the project, one year historical records for the COD removal efficiency of the lagoons system are not available. However, measurements in the lagoons system have been conducted during a 10 day campaign prior the project start date. Therefore, the chemical oxygen demand removal efficiency of the baseline wastewater treatment system (the 6 anaerobic lagoons) is calculated based on the average 10 day campaign values of the COD of the wastewater discharge from the starch factory before treatment and at the last lagoon of baseline treatment, multiplied by 0.89 to account for the uncertainty range

	associated with this approach compared to one-year historical data. Actual reduction across the system is approximately 99% as per the 10 day measurement campaign. Therefore, a value of 89% for the COD removal efficiency is used for the baseline.
Any comment:	

Data / Parameter:	D_{CH4}
Data unit:	kg/m^3
Description:	Density of methane at normal conditions
Source of data used:	"Tool to determine project emissions from flaring gases containing methane", page 9
Value applied:	0.716
Justification of the choice of data or description of measurement methods and procedures actually applied :	CDM EB as per EB28 Meeting report (Annex 13) http://cdm.unfccc.int/methodologies/Tools/eb28_repan13.pdf
Any comment:	

Data / Parameter:	NCV_{CH4}
Data unit:	MJ/ton
Description:	NCV of methane
Source of data used:	http://www.engineeringtoolbox.com/gross-net-heating-values-d_420.html
Value applied:	50,016
Justification of the choice of data or description of measurement methods and procedures actually applied :	
Any comment:	-

Data / Parameter:	EC_y
Data unit:	MWh
Description:	Auxiliary electricity consumed by biogas system and gas engine
Source of data used:	Rated power capacity equipment list
Value applied:	2691
Justification of the choice of data or description of measurement methods and procedures actually applied :	According to the methodology AMS.III.H, the auxiliary electricity consumed can be determined ex-ante. All relevant electrical equipments operate at full rated capacity*1.1 (10%account for distribution losses)*8760 hours per annum.
Any comment:	

Data / Parameter:	FE
Data unit:	%
Description:	Flare efficiency
Source of data used:	Tool to determine project emissions from flaring gases containing methane.
Value applied:	50%
Justification of the choice of data or description of measurement methods and procedures actually applied :	Default value for open flare as per Tool to determine project emissions from flaring gases containing methane has been applied.
Any comment:	-

Data and parameters from the AMS.I.C

Data / Parameter:	$EF_{HFO,CO2}$
Data unit:	tCO_2/TJ
Description:	Emission factor of fossil fuel replaced – Residual Fuel oil
Source of data used:	IPCC 2006 default value for residual fuel oil, Volume 2, Chapter 1, 1.23
Value applied:	77.4 tCO2/TJ
Justification of the choice of data or description of measurement methods and procedures actually applied :	IPCC default values used for unavailability of national data. In pre project scenario the residual fuel oil has been main source of thermal energy for the processes.
Any comment:	

Data / Parameter:	C_{oil}
Data unit:	KJ/kg. K
Description:	Specific heat of oil
Source of data used:	http://www.nirmalenergy.com/therminol_55.pdf
Value applied:	2.87 KJ/kg.K at 293°C
Justification of the choice of data or description of measurement methods and procedures actually applied :	Standard value available on public source is used for calculation purpose. The specific heat of oil will be adjusted depending on the outlet temperature of the oil. The 95% confidence interval of temperature will be calculated and the lower bond will be used to determine the specific heat of oil for conservativeness.
Any comment:	As per the boiler specification, the supply temperature is 300°C

Data / Parameter:	$\eta_{BL,thermal}$
Data unit:	-
Description:	Efficiency of thermal oil boiler.
Source of data used:	Technological specification
Value applied:	86%
Justification of the	

choice of data or description of measurement methods and procedures actually applied :	
Any comment:	

Data / Parameter:	NCV $_{HFO,CO2}$
Data unit:	GJ/tonne
Description:	Net calorific value of heavy fuel oil
Source of data used:	2006 IPCC Guidelines
Value applied:	40.4
Justification of the choice of data or description of measurement methods and procedures actually applied :	
Any comment:	

Data / Parameter:	ρ_{HFO}
Data unit:	kg/litre
Description:	Density of fossil fuel
Source of data used:	Thai local value (PTT)
Value applied:	0.95
Justification of the choice of data or description of measurement methods and procedures actually applied :	http://www.pttplc.com/Files/Document/Pdf/energy/nc_en_ee-01_01.pdf Thai local value is used
Any comment:	

Data / Parameter:	Density of thermic oil
Data unit:	Kg/m^3
Description:	Density of fluid used for heating purposes
Source of data used:	http://www.nirmalenergy.com/therminol_55.pdf
Value applied:	677 kg/m^3
Justification of the choice of data or description of measurement methods and procedures actually applied :	Published source for a standard fluid. The specific density of oil will be adjusted depending on the outlet temperature of the oil. The 95% confidence interval of temperature will be calculated and the lower bond will be used to determine the density of oil for conservativeness.
Any comment:	This value is used to convert the flow rate of thermic fluid $Q_{oil,\ h}$.

Data and parameters from the AMS.I.D

Data / Parameter:	EF_{CO2}
Data unit:	tCO_2/MWh
Description:	Grid emission factor of Thailand
Source of data used:	Refer to Annex 3
Value applied:	0.530
Justification of the choice of data or description of measurement methods and procedures actually applied :	Based on AMS.I.D and the "Tool to calculate the Emission Factor for an electricity system."
Any comment:	

B.6.3 Ex-ante calculation of emission reductions:

The following section gives details of ex – ante estimation of CERs for the project activity, calculated as defined in section B.6.1.

The data sheet of calculations will be provided to the DOE.

The main calculation parameters and results are provided below:

Baseline emissions:

Methodology: AMS III H (Methane avoidance component)		
Formula: $BE_{ww,treatment,y} = Q_{y, ww} * \sum(COD_{y, removed} * B_{o, ww} * MCF_{ww, treatment, i} * GWP_{CH4}*UF_{BL})$		
$Q_{y, ww}$	1,849,600Nm3	Based on wastewater flow rate of 3400 m^3/day for one phase,85% of starch plant load factor and operation of 320 days.
$COD_{y, removed}$	10,680mg/l	89% of inlet value: $COD_{in, treatment}$ =12,000 mg/l (BFR proposal)
$B_{o, ww}$	0.21kg CH_4/kg COD	Default value
$MCF_{ww, treatment, i}$	0.8	Default value for anaerobic deep lagoons
GWP_{CH4}	21	Default value
UF_{BL}	0.94	Default value
Calculation: 1849600 X (12000 X 0.89 / 1000000) X 0.21 X 0.8 X 21 X0.94= **65,308tCO_2e**		
Methodology: AMS I C (Fuel replacement component)		
Formula: $BE_{thermal,CO2,y} = (EG_{thermal,y} / \eta_{BL,thermal})* EF_{FF,CO2}$		
$EG_{thermal,y}$	153 TJ	Based on historical consumption of HFO per tonne of starch produced (0.034 l_{HFO}/$tonne_{starch}$ and on expected starch production.
$EF_{FF,CO2}$	77.4 tCO2/TJ	Emission factor of fossil fuel replaced (IPCC 2006 default value for residual fuel oil, Volume 2, Chapter 1, 1.23)
$\eta_{BL,thermal}$	0.86	Boiler specification

Calculation: 153X 77.4 = **13,745 tCO_2e**		
Methodology: AMS I D (Power generation component)		
Formula: $BE_{elec,y} = EG_y * EF_{CO2}$		
EG_y =	5,794 MWh	Based on info available for gas engine and biogas used for generation process (40% of total biogas generated). Efficiency of gas engine (10300 kJ/kWh) and NCV of methane
EF_{CO2} =	0.530 tCO2/MWh	Grid emission factor – Refer to Annex 3
Calculation: ▪ 5,794 X 0.530 = **3,071 tCO_2e**		

Project emissions:

Methodology: AMS III H (Methane avoidance component)		
Emissions in wastewater treatment system without biogas recovery		
Formula: $PE_{ww,treatment,y} = Q_{y,ww} * \sum(COD_{y,removed} * B_{o,ww} * MCF_{ww,treatment,i} * GWP_{CH4} * UF_{PJ})$		
$Q_{y,ww}$ =	1,849,600 Nm^3	Based on wastewater flow rate of 3400 m^3/day for one phase, 85% of starch plant load factor and operation of 320 days.
$COD_{y,removed}$ =	2,129 mg/l	Assuming 89% of lagoons efficiency
$B_{o,ww}$ =	0.21kg CH_4/kg COD	Default value
$MCF_{ww,treatment,i}$ =	0.8	Default value for anaerobic deep lagoons
GWP_{CH4} =	21	Default value
UF_{PJ}	1.06	Default value
Calculation: 1,849,600 X (0.89 X 12000 X 0.20 / 1000000) X 0.21 X 0.8 X 21 X 1.06= **14,729tCO_2 e**		
Fugitive emissions in wastewater treatment system with biogas recovery		
Formula: $PE_{fugitive,ww,y} = (1 - CFE_{ww}) * MEP_{ww,treatment,y} * GWP_{CH4}$		
CFE_{ww}	0.9	Default value
$MEP_{ww,treatment,y}$	66,402 t	Methane emission potential of wastewater treatment systems equipped with biogas recovery : $MEP_{ww,treatment,y} = Q_{y,ww} * B_{o,ww} * UF_{PJ} * \sum COD_{y,removed} * MCF_{ww,treatment,PJ,BFR}$, with $COD_{y,removed} = COD_{y,in} * \eta_{BFR} = COD_{y,in} * 0.80$.
Calculation: 66,402 X (1-0.9) = **6,640 tCO_2 e**		
Methane emissions due to incomplete flaring		
Formula: $PE_{flare,y} = \Sigma TM_{RG,h} * (1 - \eta_{flare,h}) * GWP_{CH4}/1000$		
$\eta_{flare,h}$	0.5	Efficiency of the open flare
$\Sigma TM_{RG,h}$	0 t	No biogas flared (only emergency)
Calculation: 0 X (1-0.5) X 21 =**0 tCO_2e**		
Methodology: AMS I C (Heat generation component)		

Formula: $PE_{FC} = FC_{HFO,y} * NCV_{HFO} * EF_{HFO,CO2}$		
$FC_{HFO,y}$	2,403 t	Based on expected consumption of fossil fuel minus expected fossil fuel replacement
NCV_{HFO}	40.4 GJ/t	IPCC value
$EF_{HFO,CO2}$	77.4 tCO_2 e/TJ	Emission factor of fossil fuel replaced (IPCC 2006 default value for residual fuel oil, Volume 2, Chapter 1, 1.23)
Calculation: 2,028 X 40.4 X 77.4 **= 7,511 tCO_2e**		
Methodology: AMS I D (Power generation component)		
Formula: $PE_{power} = EC_y * EF_{CO2}$		
EC_y	2,691MWh	Based on power capacity installed (279.22kW for both line), and assuming that all relevant electrical equipments operate at full capacity, plus 10% to account for distribution losses, for 8760 hours per annum.
EF_{CO2}	0.530 tCO2/MWh	Grid emission factor of Thailand (Annex 3)
Calculation: 2,691*0.530=**1,426 tCO_2e**		

Emission reductions due to type III component (methane avoidance):

ER_{III} = $BE_{ww,treatment,y} - PE_{ww,treatment,y} - PE_{fugitive,ww,y} - PE_{flare,y}$
= 65,308 – 14,729 – 6,640 – 0
= **43,939 tCO_2e**

Summary

Year	1	2	3	4	5	6	7
Baseline Emissions	82123	82123	82123	82123	82123	82123	82123
from WWT system	65308	65308	65308	65308	65308	65308	65308
from sludge treatment system	0	0	0	0	0	0	0
from WW discharge	0	0	0	0	0	0	0
from final sludge	0	0	0	0	0	0	0
from fossil replacement - AMS IC	13745	13745	13745	13745	13745	13745	13745
from disp of grid power - AMS ID	3071	3071	3071	3071	3071	3071	3071
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Project Emissions	30307	30307	30307	30307	30307	30307	30307
Emissions due to power	1426	1426	1426	1426	1426	1426	1426
Emissions in WWT system without biogas recovery	14729	14729	14729	14729	14729	14729	14729
Emissions from sludge treatment	0	0	0	0	0	0	0
Fugitive emissions from use of waste water	6640	6640	6640	6640	6640	6640	6640
Fugitive emissions from use of sludge	0	0	0	0	0	0	0
Project Emissions due to discharged treated waste water	0	0	0	0	0	0	0
Emissions from flaring	0	0	0	0	0	0	0
Emissions from fossil fuel	7511	7511	7511	7511	7511	7511	7511
Leakage	0	0	0	0	0	0	0
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**
Emission Reductions	51,817	51,817	51,817	51,817	51,817	51,817	51,817

B.6.4 Summary of the ex-ante estimation of emission reductions:

	Emission of project activity emissions (tCO2e)	Estimation of baseline emissions (tCO2e)	Estimation of leakage (tCO2e)	Estimation of overall emission reductions (tCO2e)
1	30,307	82,123	0	51,817
2	30,307	82,123	0	51,817
3	30,307	82,123	0	51,817
4	30,307	82,123	0	51,817
5	30,307	82,123	0	51,817
6	30,307	82,123	0	51,817
7	30,307	82,123	0	51,817
Total (tonnes CO2e)	212,147	574,864	0	362,717

	Emission of project activity emissions (tCO_2e)	Estimation of baseline emissions (tCO_2e)	Estimation of leakage (tCO_2e)	Estimation of overall emission reductions (tCO_2e)
1	30,307	82,123	0	51,817
2	30,307	82,123	0	51,817
3	30,307	82,123	0	51,817
4	30,307	82,123	0	51,817
5	30,307	82,123	0	51,817
6	30,307	82,123	0	51,817
7	30,307	82,123	0	51,817
Total (tonnes CO_2e)	212,147	574,864	0	362,717

B.7 Application of a monitoring methodology and description of the monitoring plan:

B.7.1 Data and parameters monitored:

The following data and parameters will be monitored after the implementation of the project activity. The values provided in this section are the ones used for the ER estimations provided in this PDD. The data refer to the process flow chart in section A.4.2 of the PDD.

Data / Parameter:	$Q_{ww,y}$
Data unit:	m^3
Description:	Flow of wastewater treated in the year y
Source of data to be used:	Measured - Volumetric flow meters
Value of data applied for the purpose of calculating expected emission reductions in section B.5	1,849,600 after the implementation of the second line. Based on 320 operating days, 3,400m3/d wastewater generation and a 0.85 factor of workload that comes from an average of three years historical workload of the factory.
Description of measurement methods and procedures to be applied:	The volumetric flow meters are installed and integrated with PLC system at the plant. Frequency of monitoring is once a day on minimum basis.
QA/QC procedures to be applied:	Calibrations of flow meter are ensured as per manufacturer specification or at least once in three years. This calibration is usually undertaken in off season to ensure data accuracy and sufficiency in operation days.
Any comment:	

Data / Parameter:	$COD_{ww,\ untreated,y} = COD_{y,\ in,\ BFR}$
Data unit:	mg/l
Description:	Chemical oxygen demand of the wastewater entering the wastewater treatment system in the year y

Source of data to be used:	Measured
Value of data applied for the purpose of calculating expected emission reductions in section B.5	12,000
Description of measurement methods and procedures to be applied:	The COD content will be analyzed using a Close Reflux Titrimetric method in the on-site laboratory of the treatment plant. The results will be logged in the plant operation report on a daily basis.
QA/QC procedures to be applied:	The Close Reflux Titrimetric method is well documented and well accepted either by national or international standards[43].
Any comment:	

Data / Parameter:	$COD_{ww,treated,y} = COD_{y, out, BFR}$
Data unit:	mg/l
Description:	COD of water exiting the BFR treatment process.
Source of data to be used:	Measured – Close Reflux Titrimetric analysis.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	2,400 Calculated as $COD_{y, in, BFR}$*(1-80%) This would be monitored during the monitoring period. However for estimation of project emissions for the anaerobic collection of methane, maximum possible value is assumed from 80% efficiency.
Description of measurement methods and procedures to be applied:	The COD content will be analyzed using a Close Reflux Titrimetric method in the on-site laboratory of the treatment plant. The results will be logged in the plant operation report on a daily basis.
QA/QC procedures to be applied:	The Close Reflux Titrimetric method is well documented and well accepted either by national or international standards.
Any comment:	

Data / Parameter:	$COD_{out,lagoon,PJ,y}$
Data unit:	mg/l
Description:	COD of water after the secondary treatment process, before being reused.
Source of data to be used:	Measured – Close Reflux Titrimetric analysis.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	271
Description of measurement methods and procedures to be applied:	The COD content will be analyzed using a Close Reflux Titrimetric method in the on-site laboratory of the treatment plant. The results will be logged in the plant operation report on a daily basis.
QA/QC procedures to be applied:	The Close Reflux Titrimetric method is well documented and well accepted either by national or international standards.
Any comment:	

[43] The Close Reflux Titrimetric method is approved by Standard Methods Committee: the method 5220D is described in "*Standard Methods for the Examination of Water and Wastewater*, 17th edition, American Public Health Association, American Water Works Association et Water Pollution Control Federation, 1989, Washington, DC.

Data / Parameter:	$COD_{ww,removed,PJ,BFR,y}$
Data unit:	tones/m^3
Description:	Chemical Oxygen Demand removed by the treatment system of the project activity equipped with biogas recovery (BFR) in the year y
Source of data to be used:	Calculated
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.002129
Description of measurement methods and procedures to be applied:	The COD content will be analyzed using a Close Reflux Titrimetric method in the on-site laboratory of the treatment plant. The results will be logged in the plant operation report on a daily basis. The COD removed will be calculated as the difference between the $COD_{ww,untreated,y}$ and $COD_{ww,treated,y}$.
QA/QC procedures to be applied:	The Close Reflux Titrimetric method is well documented and well accepted either by national or international standards.
Any comment:	

Data / Parameter:	$S_{y, final}$
Data unit:	Tonnes
Description:	Amount of final sludge as dry matter generated by the wastewater treatment in the year y
Source of data to be used:	Measured – all the sludge quantity produced during a monitoring period is measured before final disposal / treatment
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0
Description of measurement methods and procedures to be applied:	The project proponent doesn't envisage the generation of any sludge on regular basis, requiring regular treatment. If any, the sludge will be weighted and used as soil fertilizer or other applications.
QA/QC procedures to be applied:	The measurement equipment shall be calibrated on regular basis.
Any comment:	The end use of sludge generated is monitored in log records in form of soil application site for quantity of sludge generated.

Data / Parameter:	$BG_{combusted,y}$
Data unit:	Nm^3
Description:	Quantity of biogas combusted for gainful use
Source of data to be used:	Measured – Gas flow meter
Value of data applied for the purpose of calculating expected emission reductions in section B.5	7,575,000 Based on assumption that biogas contains about 55% of methane.
Description of measurement	Measurements of volume of biogas are done continuously using gas flow

methods and procedures to be applied:	meters. In recording these parameters, plant's operators shall first manually archieve the monitored data onto log sheets then transfer to the computer for electronic storage. Continuously measurements will be done and cumulative reading will be recorded daily.
QA/QC procedures to be applied:	The gas flow meter is calibrated on regular basis, at least once every three years, from a certified testing agency or institution.
Any comment:	

Data / Parameter:	$BG_{ToFlare, y}$
Data unit:	Nm^3
Description:	Total quantity of biogas flared
Source of data to be used:	Measured - Gas Flow meter provided at the inlet of flare system.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0 Used only in case of emergency
Description of measurement methods and procedures to be applied:	Measurements of volume of biogas sent to flare are done continuously using gas flow meters. In recording these parameters, plant's operators shall first manually archieve the monitored data onto log sheets then transfer to the computer for electronic storage. Continuously measurements will be done and cumulative reading will be recorded daily.
QA/QC procedures to be applied:	The gas flow meter is calibrated on regular basis, at least once every three years, from a certified testing agency or institution.
Any comment:	

Data / Parameter:	EG_{y}
Data unit:	kWh (converted into MWh for calculation purpose)
Description:	Net electricity generated from the biogas collected in the anaerobic treatment facility and sent to the grid
Source of data to be used:	Measured by electricity meters maintained by PEA.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	5,794 MWh after the operation of the gas engines for the second line. Based on same assumptions as the total biogas production parameter
Description of measurement methods and procedures to be applied:	Meter readings, continuous measurement using calibrated meter. This parameter will be recorded monthly.
QA/QC procedures to be applied:	Electricity meters will undergo maintenance / calibration subject to appropriate industry standards or at least every three years. The quantity of electricity sent to the grid will be cross-checked with invoices raised by PEA.
Any comment:	

Data / Parameter:	$BG_{recovered, y}$
Data unit:	Nm^3
Description:	Amount of biogas recovered
Source of data to be used:	Measured - Flow meters

Value of data applied for the purpose of calculating expected emission reductions in section B.5	7,575,000
Description of measurement methods and procedures to be applied:	Measurements of volume of biogas recovered are done continuously using gas flow meters. In recording these parameters, plant's operators shall first manually archive the monitored data onto log sheets then transfer to the computer for electronic storage. Continuously measurements will be done and cumulative reading will be recorded daily.
QA/QC procedures to be applied:	The gas flow meter is calibrated on regular basis, at least once every three years, from a certified testing agency or institution.
Any comment:	

Data / Parameter:	$BG_{boiler, y}$
Data unit:	Nm^3
Description:	Amount of biogas fired in boiler
Source of data to be used:	Measured - Flow meters provided at the inlet of boiler system.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	4,545,000 Based on same assumptions as the total biogas production parameter, and 60% used for heating.
Description of measurement methods and procedures to be applied:	Measurements of volume of biogas sent to boiler are done continuously using gas flow meters. In recording these parameters, plant's operators shall first manually archive the monitored data onto log sheets then transfer to the computer for electronic storage. Continuously measurements will be done and cumulative reading will be recorded daily.
QA/QC procedures to be applied:	The gas flow meter is calibrated on regular basis, at least once every three years, from a certified testing agency or institution.
Any comment:	

Data / Parameter:	$BG_{gas\ engine, y}$
Data unit:	Nm^3
Description:	Amount of biogas used for power generation in gas engine
Source of data to be used:	Measured - Flow meters provided at the inlet of gas engine to monitor the biogas supplied to gas engine
Value of data applied for the purpose of calculating expected emission reductions in section B.5	3,030,000 Based on same assumptions as the total biogas production parameter, and 40% used for power generation.
Description of measurement methods and procedures to be applied:	Measurements of volume of biogas sent to the gas engines are done continuously using gas flow meters. In recording these parameters, plant's operators shall first manually archive the monitored data onto log sheets then transfer to the computer for electronic storage. Continuously measurements will be done and cumulative reading will be recorded daily.

QA/QC procedures to be applied:	The gas flow meter is calibrated on regular basis, at least once every three years, from a certified testing agency or institution. There are separate biogas meters for the different gas engines.
Any comment:	

Data / Parameter:	W_{CH4}
Data unit:	%
Description:	Methane content in biogas
Source of data to be used:	Measured by project developer
Value of data applied for the purpose of calculating expected emission reductions in section B.5	55%
Description of measurement methods and procedures to be applied:	Measurement shall be done using an online system. The volumetric fraction of methane will be measured with a continuous gas analyzer or alternatively with periodical measurements at a 95% confidence level.
QA/QC procedures to be applied:	Gas analyzers shall be periodically calibrated according to the manufacturer's recommendation.
Any comment:	In the case of the online system breakdown, portable gas analyzer is used to measure the methane content in biogas.

Parameter:	T_{flare}
Unit:	°C
Description:	Flame temperature of the flare
Source of data:	Measurements
Value of data applied for the purpose of calculating expected emission reductions in section B.5	>500°C
Brief description of measurement methods and procedures to be applied:	The flame temperature will be continuously measured with a thermocouple sensor. Data will be recorded and stored electronically on a continuous basis.
QA/QC procedures to be applied (if any):	The temperature meter shall be subject to periodic calibration according to the equipment's specifications and applicable industrial standards.
Any comment:	It is sufficient to reach the given minimum temperature from the manufacturer to demonstrate that the flare is operating.

Data / Parameter:	$FV_{RG,h}$
Data unit:	Nm^{3}/hr
Description:	Biogas sent to flare (volumetric flow rate of the residual gas in dry basis at normal conditions in the hour h)
Source of data to be used:	Measured - Flow meters provided at the inlet of the flare to monitor the biogas supplied to flare
Value of data applied for the purpose of calculating expected emission reductions	0

in section B.5	
Description of measurement methods and procedures to be applied:	Measurements of volume of biogas sent to flare are done continuously using gas flow meters.
QA/QC procedures to be applied:	The gas flow meter is calibrated on regular basis, at least once every three years, from a certified testing agency or institution..
Any comment:	

Data / Parameter:	$\eta_{flare\text{-}h}$
Data unit:	%
Description:	Flare efficiency of the open flare
Source of data to be used:	"Tool to determine project emissions from flaring gases containing methane"
Value of data applied for the purpose of calculating expected emission reductions in section B.5	50% default factor for an open flare
Description of measurement methods and procedures to be applied:	Default value. The project has an open flare. Therefore, the efficiency of the flaring process is defined as 50% based on the default factor for open flares if the flame temperature is recorded for more than 20 minutes during the hour.
QA/QC procedures to be applied:	
Any comment:	-

Data / Parameter:	$T_{out.h}$
Data unit:	Deg C
Description:	Temperature of thermic fluid leaving the boiler for starch drying.
Source of data to be used:	Measured
Value of data applied for the purpose of calculating expected emission reductions in section B.5	300 deg C Based on technical specification. Not used for ex-ante calculation.
Description of measurement methods and procedures to be applied:	Temperature gauge shall be used on hourly basis
QA/QC procedures to be applied:	The temperature gauge shall be calibrated as per manufacturer's specification or once every three years.
Any comment:	

Data / Parameter:	$T_{in,h}$
Data unit:	Deg C
Description:	Temperature of thermic fluid entering the boiler for starch drying.
Source of data to be used:	Measured
Value of data applied for the purpose of calculating	For ex ante estimation room temperature value shall be used.

expected emission reductions in section B.5	
Description of measurement methods and procedures to be applied:	Temperature gauge shall be used to monitor the temperature of fluid going back into boiler on hourly basis.
QA/QC procedures to be applied:	Temperature gauges will be calibrated regularly.
Any comment:	

Data / Parameter:	$Q_{oil,h}$
Data unit:	m^3/hr
Description:	Flow of the thermic fluid in the boiler.
Source of data to be used:	Measured
Value of data applied for the purpose of calculating expected emission reductions in section B.5	To be monitored. Not used for ex-ante calculation.
Description of measurement methods and procedures to be applied:	The flow rate of thermic fluid shall be monitored on hourly basis. This shall be done only during the operation hours of the thermic fluid boiler. In case the hourly data of flow rate readings is not available, a conservative approach shall be applied to estimate baseline emissions
QA/QC procedures to be applied:	
Any comment:	The specific value of density of oil shall be used to convert the monitored value in kg/hr.

Data / Parameter:	$Q_{HFO, y}$
Data unit:	Tonnes
Description:	Fuel oil burnt in the hot oil boiler along with biogas.
Source of data to be used:	Meter records for fuel oil usage
Value of data applied for the purpose of calculating expected emission reductions in section B.5	For ex-ante estimation 2,403 tons of fuel oil is assumed to be used in project activity.
Description of measurement methods and procedures to be applied:	The amount of HFO burnt in the hot oil boiler is monitored by flow meter. Actual fuel usage records are used along with fuel purchase record to cross check. Default value of density of HFO, fixed ex-ante, is used to convert the monitored value in tons.
QA/QC procedures to be applied:	The meter used for fossil fuel measurement shall undergo regular maintenance.
Any comment:	

B.7.2 Description of the monitoring plan:

1. Monitoring Management

The project will hire people to operate the new plant. The required monitoring equipment is installed in consultation with the equipment supplier under supervision of operation manager and QC manager.

Data acquisition for the gas and wastewater flow meters is executed through the process control unit of the biogas plant and the plant operations software. Lab data is fed into the operations software through a manual data entry user interface.
The plant is operated by trained operators who also collect data under the supervision of qualified managers.

Please refer to Annex 4 for further information.

2. Quality Assurance and Quality Control
The Plant Manager monitors overall performance of the plant, ensures proper and timely calibration, data acquisition and storage.

3. On-site Procedures
The operations software creates daily logs of plant performance which are printed out and recorded electronically for periodic download onsite or remote transfer for further processing.
Procedures for Calibration of Equipment are included in GHG performance protocol.
The operation manager and QC manager are responsible to execute timely calibration as per the specification from equipment supplier or at least once in three years.

4. Data Storage and Filing – Electric Workbook
All relevant data is stored electronically with the process control computer unit, external storage media and transferred. A daily log is printed.
All parameters monitored under the monitoring plan will be kept for a period of two years following the end of the crediting period or the last issuance of CERs for the project activity, whichever occurs later.

5. Emergency preparedness
The project activity does not result in any unidentified activity that can result in substantial emissions from the project activity.

However, the leakages, if any, in the piping or digester shall come under notice of plant operator either instantly on the control screens else at the time of data logging, due to mismatch between expected biogas generation from wastewater quantities processed or other way around.

B.8 Date of completion of the application of the baseline and monitoring methodology and the name of the responsible person(s)/entity(ies)

Completion date: 07/01/2009

Patrick Bürgi
South Pole Carbon Asset Management Ltd.

Technoparkstrasse 1
CH-8005 Zurich
Switzerland

SECTION C. Duration of the project activity / crediting period

C.1 Duration of the project activity:

C.1.1. Starting date of the project activity:

26/10/2005
The starting date is the earliest date at which either the implementation or construction or real action of the project activity begins. In line with this definition, the start date considered for this project activity is the date on which the contract between BFB and BFR has been signed for the construction of the biofuel reactor.
Since the starting date is earlier than the date of publication of the PDD, the description of how the benefits of the CDM were considered prior to the starting date is included in Section B.5.

C.1.2. Expected operational lifetime of the project activity:

15 years

C.2 Choice of the crediting period and related information:

C.2.1. Renewable crediting period

C.2.1.1. Starting date of the first crediting period:

01/01/2011

C.2.1.2. Length of the first crediting period:

7 years

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

Not Applicable

C.2.2.2. Length:

Not Applicable

SECTION D. Environmental impacts

D.1. If required by the host Party, documentation on the analysis of the environmental impacts of the project activity:

The project does not lead to any additional emissions. The proposed project is not required to undertake an Environmental Impact Assessment according to the Thailand regulations (http://www.onep.go.th/eia/).

D.2. If environmental impacts are considered significant by the project participants or the host Party, please provide conclusions and all references to support documentation of an environmental impact assessment undertaken in accordance with the procedures as required by the host Party:

No negative environmental effects are expected from the implementation of the project as a result of Initial Environmental Evaluation required by Thai DNA.

SECTION E. Stakeholders' comments

E.1. Brief description how comments by local stakeholders have been invited and compiled:

Procedure followed to invite stakeholder comments

Public hearing for local stakeholders:

Invitation procedure
The Initial Stakeholder Consultation has been conducted by the project owner Blue Fire Bio Co Ldt. with assistance from South Pole Carbon Asset Management Limited (Switzerland based company responsible for CDM project development) and BFR Co Ldt. (Thai engineering company response for implementation of the wastewater treatment plant).

Stakeholder groups have been identified and informed through oral and written means about the meeting. The invitation letter was sent by fax to participants located a long distance from the project, by regular mail to participants without access to a fax and there was an announcement of this meeting posted at the community hall for people who had not received an invitation letter. This invitation process was done 2 weeks before the meeting date. An example of the invitation letter can be seen in annex 5.

The persons or organizations invited are:

Government Sector, State Agency, Independent Entity and Private Organization
- National Science and Technology Development Agency (NSTDA)
- Thailand Environment Institute (TEI)
- Energy and Climate Change Part of World Wildlife Fund Thailand
- Office of Natural Resources and Environmental Policy and Planning
- Ministry of Agriculture and Cooperatives
- Green Leaf Foundation
- International Institute for Energy Conservation (IIEC)

- Thailand Development Research Institute (TDRI)
- Appropriate Technology Association (ATA)
- The Environmental Engineering Association of Thailand (EEAT)
- Thailand Greenhouse Gas Management Organization (TGO)
- Department of Environmental Engineering of Chulalongkorn University
- Department of Environmental Engineering of King Mongkut's University of Technology Thonburi (KMUTT)
- Faculty of Environment and Resource Studies of Mahidol University

Local Participants

- Assistant district officer of Dankuntod district
- Mayor of Dankuntod
- Superintendent of Dankuntod Police Station
- Provincial Electricity Authority of Dankuntod
- Headman in surrounding area of the project
- Village headman in surrounding area of the project
- Villager of Hindad Subdistrict

Place and date of the meeting

The initial stakeholder consultation was held at a meeting room within Chaodee Starch factory which is located 400m away from the wastewater treatment plant, on November 10, 2008.

Meeting Participants

The mentioned meeting was attended by local residents and representatives from the following stakeholder categories:

1. Local residents
2. Local government representatives
3. Local entrepreneurs
4. Employees
5. Local farmers

There are 41 participants who have followed the invitation, attended the meeting and returned the questionnaire.

Language

Documentation and meeting was held in Thai which is the local language.

Meetings procedure

- Opening (15 min)
- Purpose of the consultation (5 min)
- Description of the project and environmental impacts (20 min)
- Questions and Answers session (10 min)
- Completing checklists (10 min)

- General feedback (15 min)

Meeting documents and protocols
On completion of the various meetings, the following documents were collected and attested by the signatures of the stakeholders that were present at the venue:

1. Presence list with name, address and occupation.(Annex 5)
2. Non-technical description of the project (Annex 5)
3. Documentation on environmental impacts of the project (Annex 5)
4. Notes for additional comments on the project activity

These documents are available as hardcopies and will be handed over to the designated operational entity (DOE).

E.2. Summary of the comments received:

The overall response to the project, from all invited stakeholders, was encouraging and positive. Most of the questions from the participant are more concern on the environmental impact regarding the bad odour from the current open lagoon which was clarified during the meeting. The greatest asset achieved by the project appears to be the positive effect on the environment. Stakeholders acknowledge that the improvement of wastewater treatment technology will reduce odors released to the surrounding area, which previously was a major concern for the surrounding community like other cases of tapioca starch factory. This project is viewed as a positive environmental plan that is important for local water resources and the community's quality of life. This project is considered a financially risky plan due to the required investment and rate of return.

To sum up the sustainability of the project, the various benefits (as reported by local stakeholders) are listed below.

1. The installed technology contributes to clean soil, water and reduced odors.
2. Use of biogas represents a sustainable way for generating energy.
3. While the system operates within strict environmental standards there will be no negative impacts to the environment due to the plant.
4. The project is well designed, returning clean water to the environment and not producing additional pollution.
5. The plant will create new jobs at the plant.

In all, no adverse reaction/comments/clarifications have been sought/received during the Initial Stakeholder Consultation process. The participants of the meetings have not raised any significant concerns related to potential impacts of the Project.

Summary of comments received during forum:

A Q&A session was conducted at the event, where questions were invited from the related parties. The questions were answered by the BFB with additional explanation on technical details by the technology supplier, BFR. The questions and answers are listed in the following sections:

- *Does the carbon dioxide gas affect the environment?*

Yes, the carbon dioxide gas is one of the GHG. However, it has lower impact on the environment than methane. Furthermore, the plant can use carbon dioxide gas.

- *Where does the wastewater come from?*

It comes from the starch production of Chaodee Starch(2004) Co.,Ltd. and the project will use it in the new system. The biofuel reactor is a closed system and the biogas produced is utilized for electricity and heat generation, so there is no biogas released to the environmental.

- *How can we have confidence in the performance of the biogas system? Are there any site references for this technology?*

Biogas systems have been developed and implemented since 10 years in many sectors. For biogas in starch plants: out of the 83 starch plants in Thailand, 3 plants have installed this technology with a positive track record.

E.3. Report on how due account was taken of any comments received:

As no major environmental concerns were raised during the entire initial stakeholder consultation process, it was neither necessary to make any changes to the Project design nor to incorporate any additional measures to limit or avoid negative environmental impacts. The same applies to socio-economic concerns, which have not been raised at all.

It is evident from the stakeholder consultation process, that the project is perceived as a positive example for the Tapioca starch factory in Thailand and that it contributes to sustainable development of the region.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	Blue Fire Bio Co., Ltd.
Street/P.O.Box:	61 MOO 14
Building:	
City:	Dan Khun Thot district
State/Region:	Nakhon Ratchasima
Postfix/ZIP:	
Country:	Thailand
Telephone:	+6644331234
FAX:	
E-Mail:	
URL:	
Represented by:	Chanchai Chaodee
Title:	Managing director
Salutation:	Mr.
Last Name:	Chaodee
Middle Name:	
First Name:	Chanchai
Department:	
Mobile:	
Direct FAX:	
Direct tel:	+6644331234
Personal E-Mail:	bugtee@hotmail.com

Organization:	South Pole Carbon Asset Management Ltd.
Street/P.O.Box:	Technoparkstrasse 1
Building:	
City:	Zurich
State/Region:	
Postfix/ZIP:	8005
Country:	Switzerland
Telephone:	
FAX:	
E-Mail:	i.puhl@southpolecarbon.com
URL:	
Represented by:	Ingo Puhl
Title:	Managing Partner
Salutation:	Mr.
Last Name:	Puhl
Middle Name:	
First Name:	Ingo
Department:	-

Mobile:	+ 66 86 778 2869
Direct FAX:	
Direct tel:	+ 41 44 633 78 70
Personal E-Mail:	

<u>Annex 2</u>

INFORMATION REGARDING PUBLIC FUNDING

No public information is involved in the project activity.

Annex 3

BASELINE INFORMATION

Calculation of the grid emission factor of Thailand

The study of the estimation of grid emission baseline is carried out in accordance with the tool **"Tool to calculate the emission factor for an electricity system**", version 02, approved by the CDM Executive Board (CDM EB) at EB50.

The data employed in this study was based on the latest data available from DEDE annual report "Electricity Power in Thailand 2008"[44].

The value applied is **0.530 tCO_2e/MWh**.
The details of the grid emission factor calculation are shown below.

The "***Tool to calculate the emission factor for an electricity system"*** states procedures to determine the following parameters to estimate baseline grid emission factor:

Parameter	SI Unit	Description
$EF_{grid,CM,y}$	tCO_2/MWh	Combined margin CO_2 emission factor for the project electricity system in year *y*
$EF_{grid,BM,y}$	tCO_2/MWh	Build margin CO_2 emission factor for the project electricity system in year *y*
$EF_{grid,OM,y}$	tCO_2/MWh	Operating margin CO_2 emission factor for the project electricity system in year *y*

As per the "***Tool to calculate the emission factor for an electricity system"*** project participants shall apply the following seven steps:

STEP 1. Identify the relevant electric power system.
STEP 2.Choose whether to include off-grid power plants in the project electricity system (optional)
STEP 3. Select a method to determine the operating margin (OM).
STEP 4. Calculate the operating margin emission factor according to the selected method.
STEP 5. Identify the group of power units to be included in the build margin (BM).
STEP 6. Calculate the build margin emission factor.
STEP 7. Calculate the combined margin (CM) emissions factor.

[44] "Electric Power in Thailand 2008" Department of Alternative Energy Development and Efficiency (DEDE), Ministry of Energy http://www.dede.go.th/dede/fileadmin/usr/wpd/static/2008/EleThai2008.pdf

Step 1: Identifying the relevant electric power system

The tool defines the *project electricity system* as the spatial extent of the power plants that are physically connected through transmission and distribution lines to the project activity and that can be dispatched without significant transmission constraints.

The national grid is identified as the project electricity system. Electric power transmitted by the national grid includes electricity generated annually by the Electricity Generating Authority of Thailand (EGAT), Independent Power Producers (IPPs), Small Power Producers (SPPs), Very Small Power Producers (VSPPs) and imported electricity from neighboring countries.

Electricity transfers from connected electricity systems to the project electricity system are defined as electricity imports and electricity transfers to connected electricity system are defined as electricity exports.

For all electricity imports, the CO_2 emission factor is taken as 0 tons CO_2 per MWh.

Step 2: Choose whether to include off-grid power plants in the project electricity system (optional)

Project participants chose "**Option I** : Only grid power plants are included in the calculation", to calculate the operating margin and build margin emission factor.
This option corresponds to the procedure contained in earlier versions of the tool.

Step 3: Selecting a method to determine the operating margin (OM)

The calculation of the Operating Margin, $EF_{grid,OM,y}$, is based on one of the following methods according to the 'Tool to calculate the emission factor for an electricity system':

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

For this proposed project activity, (a) the Simple OM is applied.

According to the 'Tool to calculate the emission factor for an electricity system', version 02, the simple OM method can only be used if the low –cost/ must-run resources constitute less than 50% of total grid generation in 1) average of the 5 most recent years, or 2) based on long-term averages for hydroelectricity production.
Low –cost/ must-run resources are defined as power plants with low marginal generation costs or power plants that are dispatched independently of the daily or seasonal load of the grid. They typically include hydro, geothermal, wind, low-cost biomass, nuclear and solar generation.

EGAT is in charge of the national electricity grid for sufficient supply in Thailand. In addition to the power plants owned by EGAT, there are three types of private power companies: Independent Power Producers (IPPs), Small Power Producers (SPPs), Very Small Power Producers (VSPPs). Some of SPP and VSPP power plants use both of renewable and conventional energy. Therefore, the calculation of

Low –cost/ must-run in this study includes also electricity generated from SPP and VSPP power plants to be conservative.

Based on the data from "Electricity Power in Thailand 2008", the average Low –cost/ must-run of the five most recent years is determined to be 15.32% as shown in Table 1.

Consequently, the *Simple OM* is deployed for calculation of the OM emission factor in this study.

Table 7. National grid generation in Thailand, 2004-2008

Year	Total	Hydro	Other	SPP&VSPP	Total LCMR	
	GWh	GWh	GWh	GWh	GWh	%
2004	125,726	6,040	2	13,513	19,555	15.55%
2005	132,195	5,798	2	13,700	19,500	14.75%
2006	138,732	8,125	3	13,721	21,849	15.75%
2007	143,364	8,114	3	14,545	22,662	15.81%
2008	147,388	7,113	5	14,607	21,725	14.74%
Average over last five years						**15.32%**

Source: "Electric Power in Thailand 2008" Department of Alternative Energy Development and Efficiency (DEDE), Ministry of Energy

Besides, for the simple OM, the simple adjusted OM and the average OM, the emission factor can be calculated using one of the two data vintages mentioned in the tool. The *ex ante* option is chosen:
Ex-ante option: The emission factor is determined once at validation stage, thus no monitoring and recalculation of emission factor during the crediting period is required. For grid power plants, a 3-year generation-weighted average, based on the most recent data available at the time of submission of the CDM-PDD to the DOE for validation.

The data vintage shall not be changed during the crediting period.

Step 4: Calculate the operating margin emission factor according to the selected method

The simple OM emission factor is calculated as the generation-weighted average CO_2 emissions per unit net electricity generation (tCO_2/MWh) of all generating power plants serving the system, not including low-cost / must-run power plants / units.

Since the data of fuel consumption and electricity generation for each power unit is not available, **option B** of the tool is used. Moreover, only nuclear and renewable power generation are considered as low-cost/must-run power sources and the quantity of electricity supplied to the grid by these sources is known and off-grid power plants are not included in the calculation.
Therefore, the simple OM emission factor can be calculated based on the total net electricity generation of all power plants serving the system and the fuel types and total fuel consumption of the project electricity system, as follows:

$$EF_{grid,OM,simple,y} = \frac{\sum_i \left(FC_{i,y} \times NCV_{i,y} \times EF_{CO2,i,y}\right)}{EG_y}$$

Where:

$EF_{grid,OM,simple,y}$ =Simple operating margin CO_2 emission factor in year y (t CO_2/MWh)

$FC_{i,y}$ = Amount of fossil fuel type *i* consumed in the project electricity system in year *y*, (mass or volume unit)

$NCV_{i,y}$ = Net calorific value (energy content) of fossil fuel type *i* in year *y* (GJ/mass or volume unit)

$EF_{CO2,i,y}$ = CO_2 emission factor of fossil fuel type *i* in year *y* (tCO_2/GJ)

EG_y = Net electricity generated and delivered to the grid by all power sources serving the system, not including low-cost/must-run power plants/units in year *y* (MWh)

y = The relevant year as per the data vintage chosen in step 3

Option B can be used since the necessary data for Option A is not available; nuclear and renewable power generation are considered as low-cost/must-run power sources and the quantity of electricity supplied to the grid by these sources is known; and off-grid power plants are not included in the calculation.

For this approach to calculate the operating margin, electricity imports to the grid are included.

Data used and calculations

Table 8. Electricity generation (including imports), EG_y

Year	Electricity generation (GWh)						
	Fuel Oil*	Diesel Oil*	Coal & Lignite*	Natural Gas*	SPP & VSPP**	Import***	Total
2006	8,350	143	22,051	86,339	13,721	5,159	135,763
2007	3,646	174	28,716	88,166	14,545	4,491	139,738
2008	1,454	180	29,480	94,549	14,607	2,785	143,055

* Table 17, Page 21

**Table 16, Page 20

***Table 22, Page 25

#Including geothermal, solar cell and wind turbine, etc.

Ref: "Electric Power in Thailand 2008" Department of Alternative Energy Development and Efficiency (DEDE), Ministry of Energy

http://www.dede.go.th/dede/fileadmin/usr/wpd/static/2008/EleThai2008.pdf

Table 3: Fuel consumption (2006-2008) (fossil fuel based power plant) $FC_{i,y}$

Year	Fuel Oil	Diesel Oil	Coal & Lignite	Natural Gas
	Million litres	Million litres	Thousand tonnes	(MMscf)
2006	2,022	40	16,250	764,215
2007	936	23	19,650	783,137
2008	350	44	20,465	812,620

Ref : Table 19 Fuel Consumption for Electric generation to National Grid
"Electric Power in Thailand 2008" Department of Alternative Energy Development and Efficiency (DEDE), Ministry of Energy

Table 4: Fuel consumption (2006-2008) (SPP and VSPP) $FC_{i,y}$

Year	Fuel Oil	Diesel Oil	Coal & Lignite	Natural Gas
	Million litres	Million litres	Thousand tonnes	(MMscf)
2006*	8.1745	0.44	915.93	92,888
2007**	6.9750	1.25	898.83	94,725
2008***	7.5479	1.45	969.82	94,707

Ref:

* Table 20 Fuel Consumption for Co-genration selling to National Grid
http://www.dede.go.th/dede/fileadmin/usr/wpd/static/thail_ele_2006/34T20.pdf

** Table 20 Fuel Consumption for Co-genration selling to National Grid
http://www.dede.go.th/dede/fileadmin/upload/cc/EleThai110951.pdf

***Table 20 Fuel Consumption for Co-genration selling to National Grid
http://www.dede.go.th/dede/fileadmin/usr/wpd/static/2008/EleThai2008.pdf

Table 5: Total Fuel consumption (2006-2008) $FC_{i,y}$ (sum of Table 3 + Table 4)

Year	Fuel Oil	Diesel Oil	Coal & Lignite	Natural Gas
	litres	litres	tonnes	(MMscf)
2006	2,030,174,530	40,436,418	17,165,933	857,103
2007	942,975,007	24,248,725	20,548,833	877,862
2008	357,547,882	45,449,715	21,434,819	907,327

Table 6: Parameters

Parameters	Fuel Oil	Diesel Oil	Coal & Lignite	Natural Gas	Units
NCV*	39.77	36.42	10.47	1.02	
Units (NCV)	MJ/litre	MJ/litre	MJ/kg	MJ/scf	
$EF_{CO2,i}$ (kg/TJ)**	75,500	72,600	89,500	54,300	tCO2/TJ

http://www.dede.go.th/dede/fileadmin/usr/wpd/static/2008/OilandThailand2008.pdf

* page 42 (conservative values of the NVC of coal and natural gas are used)

http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_1_Ch1_Introduction.pdf

** Lower value in 95% confidential interval of Table 1.4 (Default CO2 emission factors for combustion), Volume 2, Chapter 1, IPCC Guidelines 2006

Conservative value of EF for coal is used (sub-bituminous coal)

Table 7: CO2 Emission (tCO_2)

Year	Fci,y*NCVi,y*EFCo2,i,y			
	Fuel Oil*	Diesel Oil*	Coal & Lignite*	Natural Gas*
2006	6,095,873	106,918	16,085,595	47,471,507
2007	2,831,410	64,116	19,255,592	48,621,265
2008	1,073,586	120,173	20,085,819	50,253,213

Table 8: Simple OM emission factor ($EF_{grid,OM,simple,y}$)

Year	EG,y	FCi,y*NCVi,y*EFCo2,i,y	$EF_{grid,OMsimple,y}$
	GWh	(tCO2)	
2006	135,763	69,759,892	0.514
2007	139,738	70,772,383	0.506
2008	143,055	71,532,791	0.500
			0.507

From the table, $EF_{grid,OM,,,y}$ = **0.507 tCO_2/MWh**

Step 5: Identifying the group of power units to be included in the build margin

According to the 'Tool to calculate the emission factor for an electricity system', version 02, the sample group of power units *m* used to calculate the build margin consists of either:

(a) The set of five power units that have been built most recently, or
(b) The set of power capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently.

The following table shows the list of most recently built larger annual generation five power plants which also comprise more than 20% (at 21.9 %) of the system generation (in KWh). Besides, all these five power plants are not registered as CDM project activity and not built more than 10 years ago from the date that the proposed project started to supply electricity to the grid.

Table 9. Group of power units to be included in the Build Margin

Plant name		Plant Capacity	Generation (2008)	Efficiency	Type of Fuel	Commercial Operation Date
(Sample group m)	Full name	(MW)	(GWh)	(Btu/kWh)		COD
EPEC (IPP)	2. Eastern Power & Electric Co., Ltd.	350.0	2,670	6,811	Natural Gas	March 2003
BLCP (IPP)	3. BLCP Power Limited	1,346.6	10,801	9,100	Coal	Unit 1 : August 2006 Unit 2: November 2006
GPG (IPP)	4. Gulf Power Generation Co., Ltd.	1,468.0	9,195	6,950	Natural Gas	Unit 1 : May 2007 Unit 2: March 2008
RGCO POWER (IPP)	1. Ratchburi Power	1,400.0	5,812	7,051	Natural Gas	Unit 1 : May 2008 Unit 2: June 2008
Chana	Chana	710.0	3,754	7,082	Natural Gas	July 2008

Source: Electric Power in Thailand 2008 Report, DEDE, Table 8, page 10 and Table 18 page 22 and EPPO website

In term of vintage data, **Option 1**: the build margin emission factor *ex ante* based on the most recent information available on unites already built at the time of CDM-PDD submission to the DOE for validation is chosen, hence, monitoring the emission factor is not required during the crediting period. For the second crediting period, the build margin emission factor should be updated based on the most recent information available on units already built at the time of submission of the request for renewal of the crediting period to the DOE. For the third crediting period, the build margin emission factor calculated for the second crediting period should be used. This option does not require monitoring the emission factor during the crediting period.

Step 6: Calculating the build margin emission factor

The Build Margin emission factor is calculated as the generation-weighted average emission factor of all power units m during the most recent year y for which power generation, as follows:

$$EF_{grid,BM,y} = \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

Where:
$EF_{grid,BM,y}$ = Build margin CO_2 emission factor in year *y* (tCO_2/MWh)
$EG_{m,y}$ = Net quantity of electricity generated and delivered to the grid by power unit *m* in year *y*
$EF_{EL,m,y}$ = CO_2 emission factor of power unit *m* in year *y* (tCO_2/MWh)
m = Power unit included in the build margin
y = Most recent historical year for which power generation data is available

The CO_2 emission factor of each power plant unit m ($EF_{EL,m,y}$) should be determined as per the simple OM.

Option A2 is used to calculate it, as there is data on electricity generation, fuel types and the efficiency of the group of power unit to be included in the build margin:

$$EF_{EL,m,y} = \frac{EF_{CO2,m,i,y} \cdot 3.6}{\eta_{m,y}}$$

Where:
$EF_{EL,m,y}$ = CO2 emission factor of power unit *m* in year *y* (tCO_2/MWh)
$EF_{CO2,,m,i,y}$ = Average CO2 emission factor of fossil fuel type *i* in power unit *m* in year *y* (tCO_2/GJ)
$\eta_{m,y}$ = Average net energy conversion efficiency of power unit *m* in year *y* (ration)
m = All power units serving the grid in year *y* except low-cost/must-run power units
y = The relevant year as per the data vintage chosen in Step 3

Table 10: Build Margin emission factor ($EF_{grid,BM,y}$)

Plant name	Plant Capacity	Generation (2008)	Efficiency	Efficiency	$EF_{EL,m}$	Emissions
(Sample group m)	(MW)	(GWh)	(Btu/kWh)	%	(tCO2/MWh)	(tCO2)
EPEC	350.0	2670.00	6,811	50.10%	0.39	1,041,716
BLCP	1,346.6	10801.00	9,100	37.50%	0.86	9,280,170
GPG	1,468.0	9195.00	6,950	49.10%	0.40	3,660,698
RGCO POWER	1,400.0	5812.00	7,051	48.40%	0.40	2,347,490
Chana	710.0	3754.00	7,082	48.19%	0.41	1,522,922
Generation of group m is part of total grid generation						

(GWh)	32,232
Total grid generation (GWh)	147,388
Total CO2 emission (tCO2)	17,852,997
Build margin emission factor (EFgrid, BM,y)	**0.554**

Ref: "Electric Power in Thailand 2008" Department of Alternative Energy Development and Efficiency (DEDE), Ministry of Energy
http://www.dede.go.th/dede/fileadmin/usr/wpd/static/2008/EleThai2008.pdf

From the table, $EF_{grid,BM,,,y}$ = **0.554 tCO_2/MWh**

Step 7: Calculating the combined margin emission factor

The combined margin emissions factor is calculated as follows:

$$EF_{grid,CM,y} = EF_{gird,OM,Y} * w_{OM} + EF_{grid,BM,Y} * w_{BM}$$

Where:
$EF_{BM,Y}$ = Build margin CO_2 emission factor in year *y* (tCO2/MWh)
$EF_{OM,Y}$ = operation margin CO_2 emission factor in year *y* (tCO2/MWh)
w_{OM} = Weight of operating margin emission factor (%)
w_{BM} = Weight of build margin emission factor (%)

The following default value should be used for w_{OM} and w_{BM}:

- Wind and solar power generation project activities: w_{OM} = 0.75 and w_{BM} = 0.25 (owing to their intermittent and non-dispatchable nature) for the first crediting period and for subsequent crediting periods.
- All other project: w_{OM} = 0.5 and w_{BM} = 0.5 for the first crediting period, and w_{OM} = 0.25 and w_{BM} = 0.75 for the second and third crediting period, unless otherwise specified in the approved methodology which refer to this tool.

For this project activity, which is not a wind or solar power generation project activity, the following weights are chosen: w_{OM} = 0.5 and w_{BM} = 0.5.

Table 11. Calculation of the Combined Margin factor

		$EF_{grid,CM,y}$
Operating Margin EF	tCO2/MWh	0.507
Build Margin EF	tCO2/MWh	0.554
Weight age for OM (W_{OM})	%	0.500
Weight age for BM (W_{BM})	%	0.500
Combined Margin EF ($EF_{CM,y}$)	tCO2/MWh	**0.530**

Therefore, the baseline emission factor **EF_{CO2} = $EF_{grid,CM,y}$ = 0.530 tCO_2/MWh.**

Annex 4

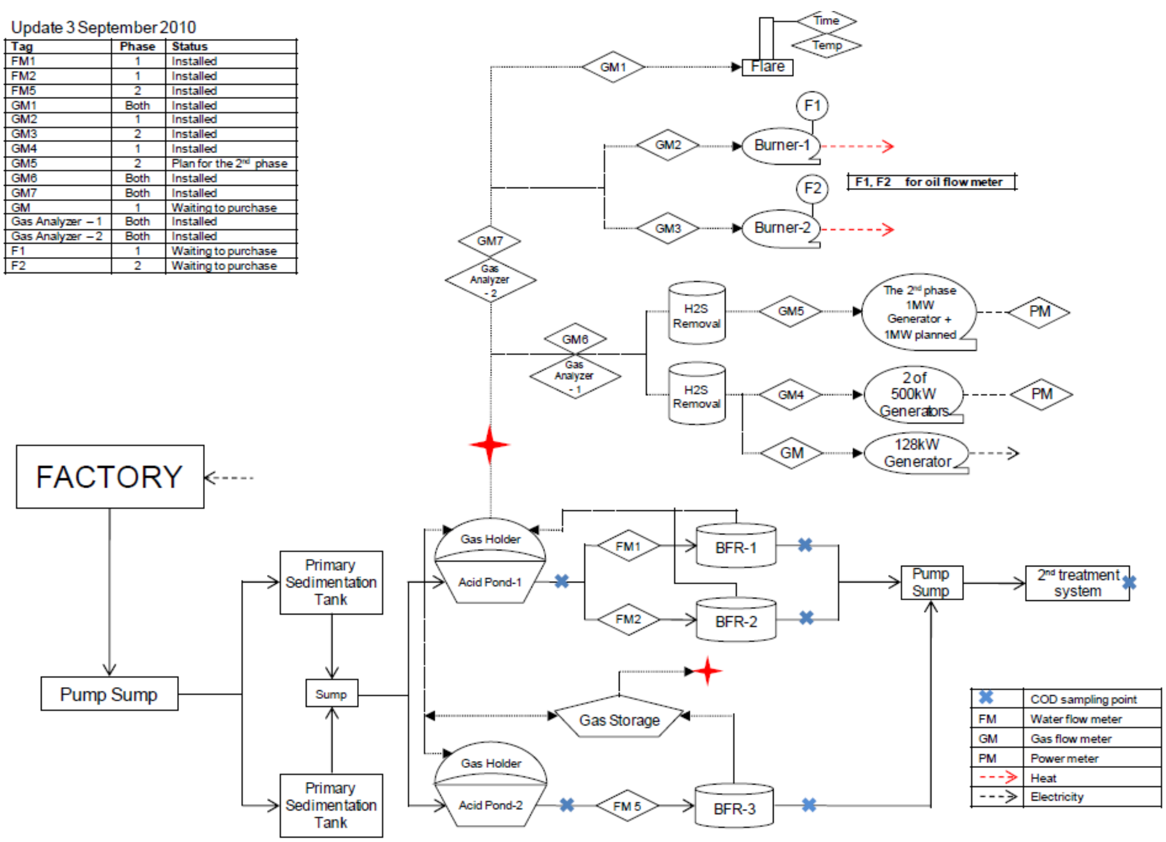
MONITORING INFORMATION

Monitoring will be conducted in accordance with the monitoring plan outlined in section B.7 of the PDD.

The following flow chart represents the monitoring of both phases. It is updated in September 2010.

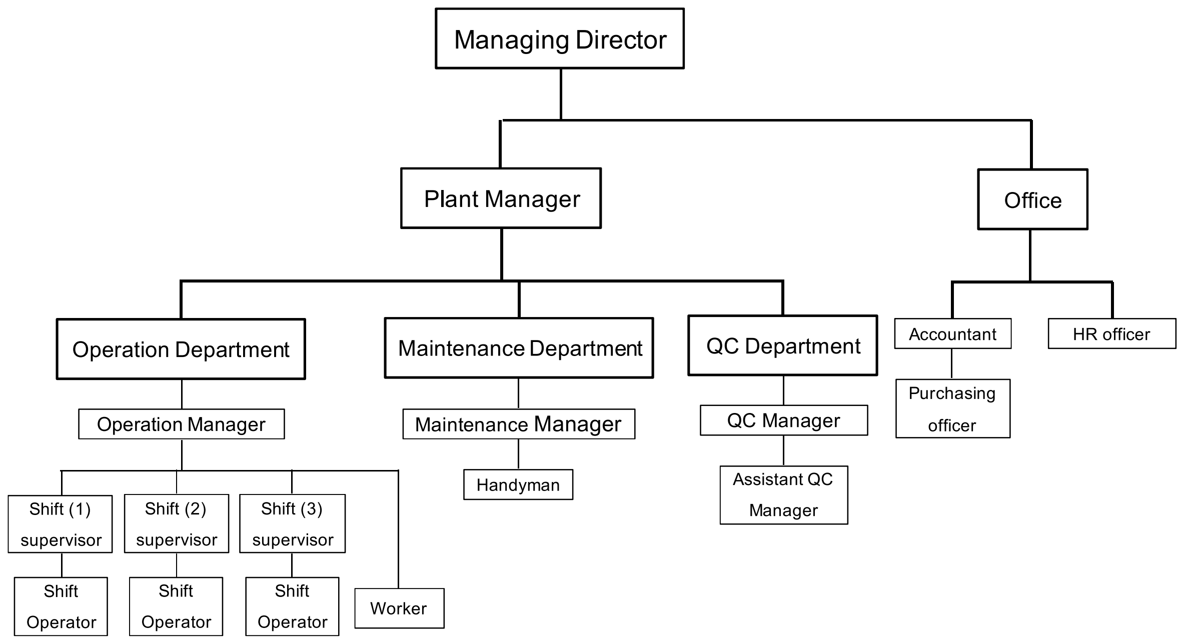
Update 3 September 2010

Tag	Phase	Status
FM1	1	Installed
FM2	1	Installed
FM5	2	Installed
GM1	Both	Installed
GM2	1	Installed
GM3	2	Installed
GM4	1	Installed
GM5	2	Plan for the 2nd phase
GM6	Both	Installed
GM7	Both	Installed
GM	1	Waiting to purchase
Gas Analyzer – 1	Both	Installed
Gas Analyzer – 2	Both	Installed
F1	1	Waiting to purchase
F2	2	Waiting to purchase



Note: If the small gas engine (0.128MW) is used as a back up system, a separate biogas meter will monitor the amount of biogas sent to this engine. The electricity generated, which will be used on site, will not be monitored (the PO cannot afford to buy an additional meter). Therefore, no ERs will be claimed for the electricity generated by this small engine. This is conservative.

The responsibilities are defined in the following diagram.



Responsibilities

Managing Director	- Review the performance report
	- Approve for hiring new staff
Office	- Employment
	- Input the data from all of log books into electronic sheets
	- Collect all electronic sheets
Plant Manager	- Plan for biogas production
	- Approve for purchasing new equipment
	- Review performance report and submit to MD
Operation Manager / QC Manager	- Conduct calibration of equipment (QC Manager)
	- Quality check for log books
	- Quality check for electronic sheets
	- Request for installation new equipment
	- Report performance to plant manager
Shift supervisor/ Shift operator	- Record the data into log books
	- Support QC team for wastewater analysis
Assistant QC Manager	- Wastewater analysis
	- Analysis report to QC manager
Maintenance Manager	- Provide maintenance plan
	- Approve for delivering equipment to in-house fixing
Handyman	- Take responsibilities for the electricity and control system
	- Check capability of all equipment and machine