

# BIOMASS BASED COGENERATION PLANT AT GODREJ AGROVET LTD. CHINTAMPALLI



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<b>Project Title</b>	Biomass based cogeneration plant at Godrej Agrovet Ltd. Chintampalli
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## 1 PROJECT DETAILS

### 1.1 Summary Description of the Project

Godrej Agrovet Limited (GAVL) is a diversified agribusiness company dedicated to improving the productivity of Indian farmers by innovating products and services that sustainably increase crop and livestock yields. With FY2012-13 consolidated sales of Rs. 3,100 crore, GAVL has interests in animal feed, oil palm plantations, agri-inputs and poultry.

GAVL is setting up a new Greenfield palm oil production plant at project activity location. The plant will have production capacity to process 60 TPH palm fruit. The new plant has a steam and electricity demand of 35 TPH and 2.5 MW. The project will use inhouse generated renewable biomass fibre, shell and empty fruit bunches (EFB) in the palm fruit processing facility. As the biomass is generated from agro processing industry, it is a renewable biomass as per definitions in 'Glossary of CDM Terms Ver 07.0'<sup>1</sup>.

At the time of project planning, GAVL had option to choose a coal based cogen plant for meeting the captive energy demand. However, considering the GHG emission reduction opportunity, the project proponent has chosen a renewable energy based project.

Project Location: Chintampalli village, District –West Godavari, Andhra Pradesh, India

How project reduces emissions: The project uses renewable biomass residue and replaces use of coal that would have otherwise led to equivalent CO<sub>2</sub> emissions (please refer following Sections for details).

Pre-project scenario: The project is located at a Greenfield palm oil production plant. Thus, no energy generating units or the energy demand (user plant) existed at the project location in pre-project scenario.

The project is expected to reduce average 70,314 tCO<sub>2</sub> annually over the crediting period.

### 1.2 Sectoral Scope and Project Type

As per simplified modalities and procedures for small scale CDM project activities, the project qualifies under the

Sectoral Scope            01- Energy industries (renewable-/non-renewable sources)

Type    I- Renewable Energy Projects

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<sup>1</sup> Biomass residue - Non-fossilized and biodegradable organic material originating from plants, animals and micro-organisms which is a by-product, residue or waste stream from agriculture, forestry and related industries

Category C. Thermal energy production with or without electricity

Project is neither an AFOLU project nor a grouped project.

### 1.3 Project Proponent

Godrej Agrovet Limited is the project proponent and roles/ responsibilities include

- To ensure that the project activity is in compliance with all the local laws and regulation applicable to the project activity.
- It is under the purview of their duty to ensure that parameters are monitored in accordance with the monitoring protocol and the records are maintained in a proper manner, so that it eases the validation/verification procedures.

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### 1.4 Other Entities Involved in the Project

Godrej Agrovet Limited is the sole owner of the project and emission reductions generated by it.

### 1.5 Project Start Date

18-08-2012

This is the commissioning date of turbine in the project. Even though the boiler in this project was commissioned on 30-06-2012, as the project is a cogeneration plant, only after commissioning of turbine, the project is considered to have started reducing emissions.

### 1.6 Project Crediting Period

The project chooses a renewable crediting period of 10 years. After 10 years, the crediting period will be renewed twice considering project life of 25 years.

Crediting period start date: 18-08-2012

Crediting period end date: 17-08-2022

This is the date when turbine generator was commissioned completing the project in cogeneration mode.

### 1.7 Project Scale and Estimated GHG Emission Reductions or Removals

The project falls under the category of “project” with emission reduction more than 5,000 and less than 1,000,000 tonnes of CO<sub>2</sub> equivalent emission reductions.

Project	√
Mega-project	

Years	Estimated GHG emission reductions or removals (tCO <sub>2</sub> e)
2012	23,630 <sup>2</sup>
2013	70,314
2014	70,314
2015	70,314
2016	70,314
2017	70,314
2018	70,314
2019	70,314
2020	70,314
2021	70,314
2022	46,684 <sup>3</sup>

<sup>2</sup> ER shown as per the Crediting period start date: 18-08-2012

<b>Total estimated ERs</b>	<b>703,140</b>
<b>Total number of crediting years</b>	<b>10</b>
<b>Average annual ERs</b>	<b>70,314</b>

## 1.8 Description of the Project Activity

### Description of technology/ measure employed:

The project is a cogeneration unit and had commissioned one 35 TPH biomass based boiler and a 2.5 MW turbine generator (TG). The generated steam and electricity is used to meet the captive demand of a greenfield palm oil production unit.

The detailed specifications of boiler and TG are as below

**Table 1: Specification of 35 TPH boiler**

Sr. No.	Specification	Value	Unit
1	Type – Pulsating grate bi-drum air cooled boiler	-	-
2	Design steam generation capacity at MCR	35	TPH
3	Steam pressure at MCR	35	kg/cm <sup>2</sup>
4	Steam temperature	350±10	°C
5	Make and Model - Thermax Ltd. BDPG - 350	-	-
6	Fuel requirement  Fuel 1: 75% palm fibre + 25% palm shell  Fuel 2: 70% palm fibre + 30% empty bunches	250	TPD mixed biomass
7	Efficiency of boiler (for fuel 1 and fuel 2)	73	%
8	Feed water temperature to economiser	105	°C

**Table 2: Specification of 2.5 MW turbine generator**

<sup>3</sup> ER shown as per the Crediting period end date: 17-08-2022

Sr. No.	Specification	Value	Unit
1	Type – multistage, impulse, nozzle governed back pressure	-	-
2	Design capacity	2.5	MW
3	Inlet steam pressure	33	kg/cm <sup>2</sup>
4	Inlet steam temperature	350±10	°C
5	Specific steam consumption	13.9	kg/kWh
6	Make and Model – Triveni Turbine Limited	-	-
7	Outlet steam pressure	4.5	kg/cm <sup>2</sup>
8	Electrical output at AC generator terminal  (3 phase, 4 wire system, 0.8 PF)	2500 kW (415 V, 50 Hz)	-
9	Load factor	80	%

**Steam and electricity requirement of the production plants**

Plant name	Steam requirement (TPH)	Electricity requirement (KWh/hr)
Cogen auxiliary	10	500
Crude Palm Oil (CPO)	20	1,134
Palm Kernel Oil (PKO)	5	650

The biomass required for the project boiler is generated as by-product of the production plants – CPO, PKO.

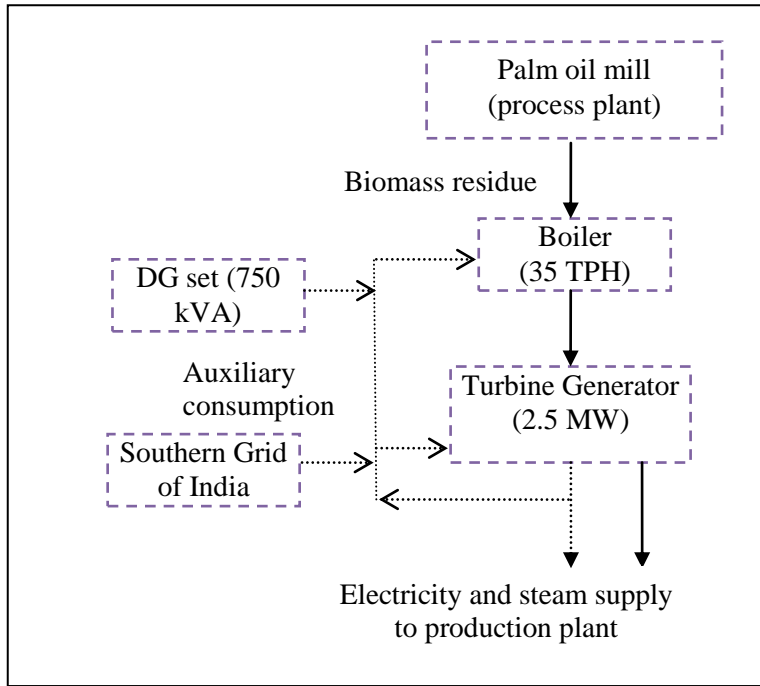


Figure 1: Line diagram of the project plant

During cold start of the cogen plant, electricity is used from the southern grid of India till TG rolling and synchronization. During the times of grid supply failure, power will be fed from DG set of 750KVA capacity.

DG set details: Rating: 750KVA,

Make: Cummins, SI no: 07/1204/00094.

**How project will achieve net GHG emission reductions or removals:**

The project activity utilizes renewable biomass for energy generation and thus displaces the use of coal. Thus, use of this renewable energy reduces equivalent amount of coal burning and in turn achieve GHG emission reduction.

The project technology uses renewable biomass as a fuel which is carbon neutral. The project also employs air pollution control technology of to control the level of the particulate matters. Therefore, the technology can be said as environmentally safe and sound technology.

**Lifetime of the project activity:**

The main project activity equipments boiler and turbine are expected to have a lifetime of 25 years<sup>4</sup>.

<sup>4</sup> Default values as per Option C of ‘Tool to determine and remaining lifetime of the equipment’ Version 01, EB 50, Annex 15.

### 1.9 Project Location

Plant location: village – Chintampalli

District –West Godavari, State – Andhra Pradesh, Country - India

Latitude -17° 12' 36" N and longitude: 80° 56' 34" E

Plant location from major town/ district headquarter – Eluru – 70 Km

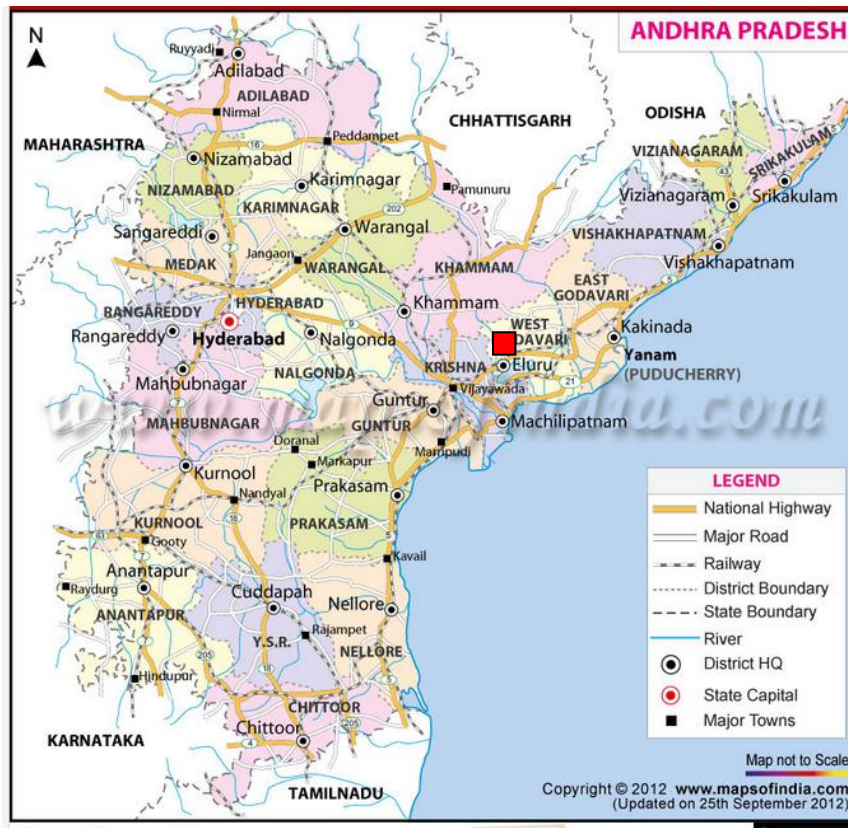


Figure 1: project location in Andhra Pradesh (■)

### 1.10 Conditions Prior to Project Initiation

This project is coming up in a Greenfield industrial plant. Thus, in pre-project scenario, no energy generation sources or the consumer of energy existed in this location.

The project proponents have implemented project for the generation of renewable energy to meet captive demand. Hence, the project was not implemented to create GHG emissions primarily for the purpose of its subsequent removal or destruction.

### 1.11 Compliance with Laws, Statutes and Other Regulatory Frameworks

The project activity is not mandated by any local or national laws. The project proponent however has obtained the necessary approvals from the applicable statutory bodies. The approvals related to the project activity and the status of its compliance is demonstrated in the Table below:

Sr. No.	Regulator	Document/ approval	Status of compliance and Date of approval
1	APPCB	Consent to Establish	Complied
2	IBR	Boiler Inspection	Complied
3	APEPDCL	Electrical connections	Complied
4	AP Electrical Inspectorates	Electrical Inspection	Complied
5	APPCB	Consent to Operate	Complied

### 1.12 Ownership and Other Programs

#### 1.12.1 Right of Use

The main project activity equipments boiler and turbine were purchased by GAVL<sup>5</sup>. POs of these equipments to the OEM/ suppliers are submitted to the DOE.

#### 1.12.2 Emissions Trading Programs and Other Binding Limits

The project proponent is not part of any emission trading program. GAVL also does not have any binding GHG emission limits. The net GHG emission reductions from the project will not be used for compliance with emission trading programs or to meet binding limits on GHG emissions. A letter of this effect from the project proponent has been submitted to the validator.

The project activity has not participated under any other GHG programs. A letter of this effect from the project proponent has been submitted to the validator.

#### 1.12.3 Other Forms of Environmental Credit

<sup>5</sup> The name of company was changed from M/s. Godrej Oil Palm Limited (at time of giving POs) to M/s. Godrej Agrovet Limited (present name) and all relevant evidences are shared with the DOE. Thus, all legal ownership and rights of earlier company are still with the same company with new name

The project activity does not result in creation of any other kind of environmental credits. A letter from the project proponent has been submitted to the validator with an undertaking that the project has not created another form of environmental credit.

**1.12.4 Participation under Other GHG Programs**

The project activity has never participated in any other GHG programs.

**1.12.5 Projects Rejected by Other GHG Programs**

The project activity has never been rejected under any other GHG programs.

**1.13 Additional Information Relevant to the Project**

**Eligibility Criteria**

The project is not part of any grouped projects.

**Leakage Management**

The project only uses renewable biomass for energy generation and does not cause leakage. The leakage applicable as per SSC methodology will be considered in the calculation of emission reductions in following sections.

**Commercially Sensitive Information**

The documents shared with DOE during this process do not include any commercially sensitive information.

**Further Information**

Not applicable

**2 APPLICATION OF METHODOLOGY**

**2.1 Title and Reference of Methodology**

Type : AMS-I.C

Title : Thermal energy production with or without electricity

Sectoral Scope : 01

Version : 19

EB : 61

Reference: <http://cdm.unfccc.int/methodologies/DB/6EL4AG49US2S1DNH55Y4S7GDQFA2JF>

In line with the applied methodology, following tools and guidelines are referred in this PD:

1. Title: Guidelines on the demonstration of additionality of small-scale project activities  
Version: 09  
Reference: EB 68, Annex 27
2. Title: Tool to calculate baseline, project and/or leakage emissions from electricity consumption  
Version: 01  
Reference: EB 39, Annex 7
3. Title: Tool to calculate project or leakage CO<sub>2</sub> emissions from fossil fuel combustion  
Version: 02  
Reference: EB 41, Annex 11
4. Title: Tool to calculate the emission factor for an electricity system  
Version: 04.0  
Reference: EB 75, Annex 15

## 2.2 Applicability of Methodology

The project activity is thermal energy production with electricity. The project activity would follow small-scale methodology and I.C project category. The justification for the applicability of the chosen methodology to the project activity is explained in the table below.

Sr. No	Applicability criteria as per AMS I.C. Version 19	Project Status
1	This methodology comprises renewable energy technologies that supply users 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 project activity comprises of renewable biomass residue based thermal energy generation for captive use. The project activity displaces the energy generation from coal. Thus the applicability condition is met.
2	Biomass-based cogeneration systems are included in this category. For the purpose of this methodology “cogeneration” shall mean the simultaneous generation of thermal energy and electrical energy in one process. Project activities that produce heat and power in separate element processes (for example, heat from a boiler and electricity from biogas engine) do not fit under the definition of cogeneration project.	The project activity involves one biomass based boiler and TG in a cogeneration mode. Thus the applicability condition is met.
3	Emission reductions from a biomass cogeneration system can accrue from one of	Emission reductions from the project activity accrue and are claimed from electricity and

	<p>the following activities:</p> <ul style="list-style-type: none"> <li>(a) Electricity supply to a grid;</li> <li>(b) Electricity and/or thermal energy (steam or heat) production for on-site consumption or for consumption by other facilities;</li> <li>(c) Combination of (a) and (b).</li> </ul>	<p>steam production for onsite consumption. Thus the applicability condition is met.</p>
4	<p>The total installed/rated thermal energy generation capacity of the project equipment is equal to or less than 45 MW thermal. (See paragraph 6 for the applicable limits for cogeneration project activities).</p>	<p>The total installed capacity of project equipment is 25.89 MWth. This is less than 45 MW thermal limit of the methodology and will remain same throughout the crediting period. Thus project activity will remain in the limits of small-scale project activity. Please refer calculations below this table for the installed capacity calculation. Thus the applicability condition is met.</p>
5	<p>For co-fired systems, the total installed thermal energy generation capacity of the project equipment, when using both fossil and renewable fuel shall not exceed 45MW thermal (see paragraph 6 for the applicable limits for cogeneration project activities).</p>	<p>The boiler of 35 TPH is a multi fuel fired boiler which is capable of firing biomass as well as coal. However, the project activity primarily intends to use biomass. In case of non-availability of biomass etc; if coal and biomass are co-fired; it will be ensured that the thermal energy generation capacity of the boiler will remain within the small scale limit of 45 MW thermal. As the thermal energy generation capacity calculation is done maximum design steam outlet 35 TPH and 35kg/cm<sup>2</sup> pressure, the thermal output will remain at 25.89 MWth and is independent of fuel (biomass/ coal / co-fired).</p>
6	<p>The following capacity limits apply for biomass cogeneration units.</p> <ul style="list-style-type: none"> <li>a. If the project activity includes emission reduction 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);</li> <li>b. If the emission reductions of the cogeneration project activity are solely on account of thermal energy production (i.e., no emission reductions accrue from electricity component), the total installed thermal energy production capacity of the project equipment of the cogeneration unit shall not exceed 45 MW thermal;</li> <li>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</li> </ul>	<p>As the project activity includes emission reduction from both the thermal and electrical energy components, the thermal energy generation capacity calculation is done maximum design steam outlet 35 TPH and 35kg/cm<sup>2</sup> pressure, the thermal output will remain at 25.89 MWth &lt; 45 MWth.</p> <p>The project activity meets the capacity limits prescribed in option (a), hence this condition is met.</p>

	energy component), the total installed electrical energy generation capacity of the project equipment of the cogeneration unit shall not exceed 15 MW.	
7	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 paragraph 4 to 6, and should be physically distinct from the existing units.	The project activity includes new facilities and meets the capacity limits specified in above paragraphs. Thus the applicability condition is met.
8	Project activities that seek to retrofit or modify an existing facility for renewable energy generation are included in this category.	The project activity includes new greenfield facilities and does not include retrofit or modification. Thus this applicability condition is not relevant.
9	New facilities (Greenfield projects) and project activities involving capacity additions compared to the baseline scenario are only eligible if they comply with the related and relevant requirements in the “General Guidelines to SSC CDM methodologies”.	The project activity includes new greenfield facilities and comply with relevant requirements in the “General Guidelines to SSC CDM methodologies”.
10	If solid biomass fuel (eg. briquette) is used, it shall be demonstrated that it has been produced using solely renewable biomass and all project or leakage emissions associated with its production shall be taken into account in the emission reduction calculation.	The project activity uses renewable biomass residues generated in the agro-industry where project is located. It does not include use of solid biomass like briquette and this applicability condition is relevant.
11	Where the project participant is not the producer of the processed solid biomass fuel, the project participant and the producer are bound by a contract that shall enable the project participant to monitor the source of the renewable biomass to account for any emissions associated with solid biomass fuel production. Such a contract shall also ensure that there is no double-counting of emission reductions.	The project activity uses renewable biomass residues generated in the agro-industry where project is located. Thus, project participant is the producer of the processed biomass residues used in the project and this applicability condition is not relevant.
12	If electricity and/or steam/heat produced by the project activity is delivered to a third party i.e. 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 that ensures there is no double-counting of emission reductions.	The electricity and steam generated in the project activity is used in-house in GAVL plant and this applicability condition is not relevant.
13	If the project activity recovers and utilizes biogas for power /heat production and applies this methodology on a standalone basis i.e. without using a Type III component of a SSC methodology, any incremental emissions occurring due to implementation of the project activity (e.g. physical leakage of the anaerobic digester, emissions due to inefficiency of the flaring), shall be taken into account either as	The project activity does not recover and utilize biogas for power/ heat production. The project activity will only use biomass residues as discussed above and this applicability condition is not relevant.

	project or leakage emissions.	
14	<p>Charcoal based biomass energy generation project activities are eligible to apply the methodology only if the charcoal is produced from renewable biomass sources provided:</p> <p>(a) Charcoal is produced in kilns equipped with methane recovery and destruction facility ; or</p> <p>(b) If charcoal is produced in kilns not equipped with a methane recovery and destruction facility, methane emissions from the production of charcoal shall be considered. These emissions shall be calculated as per the procedures defined in the approved methodology AMS - III.K. Alternatively, conservative emission factor values from peer reviewed literature or from a registered CDM project activity can be used, provided that it can be demonstrated that the parameters from these are comparable e.g. source of biomass, characteristics of biomass such as moisture, carbon content, type of kiln operating conditions such as ambient temperature.</p>	<p>The project activity will not use charcoal. The project activity will only use renewable biomass and this applicability condition is not relevant.</p>

**Installed thermal energy generation capacity of project**

Description	Unit	Details
Quantity of steam generated	TPH	35.0
Pressure of steam	kg/cm <sup>2</sup>	35.0
Temp of steam	°C	350 Superheated
Feed water temperature	°C	105
Efficiency of biomass based boiler	%	73%
Annual run hrs	hrs	6,000
Enthalpy of steam (at 35 kg/cm <sup>2</sup> )	kJ/kg	3,103
Enthalpy of feed water (at 105°C)	kJ/kg	440
Net Energy output of boiler at rated capacity	kJ/kg	2,662
Total Thermal Output of the boiler	kJ/hr	93,187
Thermal output from the boiler	MWth	<b>25.89</b>

**Compliance with “General Guidelines to SSC CDM methodologies” (Version 19.0, EB 69, Annex 27)**

For the biomass based project activities, following paragraphs apply and the compliance of applicable conditions is discussed below.

*Para 19 “In the case of project activities and PoAs using biomass, emission reductions may only be accounted for the combustion of renewable biomass. Project participants and coordinating/managing entities must refer to the “Definition of Renewable Biomass”.*

Compliance – The applicability conditions of the applied SSC methodology 1, 2, 3 and 10 have covered this requirement.

*Para 20 “For leakage in project activities and PoAs using biomass, project participants and coordinating/managing entities must refer to the “General guidance on leakage in biomass project activities.”*

Compliance – The tool is used for calculation of leakage and discussed further in the following Section 3.

Para 21 is not applicable as *project activity* does not involve biogas.

*Para 26 “For Type I methodologies, the requirement that the replaced energy-generating equipment should be scrapped and that this scrapping should be independently monitored is not needed since under most circumstances the replaced equipment would most likely replace less efficient equipment outside the project boundary”.*

Para 21 is not applicable as project activity does not involve replacement of energy generating equipments.

All the applicability conditions relevant to the project activity are met and it is used further.

### 2.3 Project Boundary

As per AMS I.C, the spatial extent of the project boundary encompasses:

- (a) All plants generating power and/or heat located at the project site, whether fired with biomass, fossil fuels or a combination of both;
- (b) All power plants connected physically to the electricity system (grid) that the project plant is connected to;
- (c) Industrial, commercial or residential facility, or facilities, consuming energy generated by the system and the processes or equipment affected by the project activity;
- (d) The processing plant of biomass residues, for project activities using solid biomass fuel (e.g. briquette), unless all associated emissions are accounted for as leakage emissions;
- (e) The transportation itineraries, if the biomass is transported over distances greater than 200 kilometres, unless all associated emissions are accounted for as leakage emissions;
- (f) The site of the anaerobic digester in the case of project activity that recovers and utilize biogas for power / heat production and applies this methodology on a standalone basis i.e. without using a Type III component of a SSC methodology.

The project boundary of this project activity includes (a), (b) and (c) as per above given components. These include (a) project boiler and turbine generator, one back up DG set (b) southern grid of India (c) palm oil production plant of PP.

Component (d) is not applicable as all associated emissions are accounted for as leakage. As biomass is used from the same industrial facility where project activity is located, transportation is within 200 km and component (e) is not applicable. The project activity does not involve anaerobic digester and hence component (f) is also not applicable.

Source	Gas	Included?	Justification/Explanation
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Baseline	Coal based cogeneration plant	CO <sub>2</sub>	Yes	Important emission source.
		CH <sub>4</sub>	No	Excluded for simplification. This is conservative.
		N <sub>2</sub> O	No	Excluded for simplification. This is conservative.
		Other	No	Excluded for simplification. This is conservative.
Project	Biomass based cogeneration plant	CO <sub>2</sub>	Yes	It is assumed that CO <sub>2</sub> emissions from surplus biomass residues do not lead to changes of carbon pools in the LULUCF sector.
		CH <sub>4</sub>	No	This emission source is assumed to be very small.
		N <sub>2</sub> O	No	This emission source is assumed to be very small.
		Other	No	This emission source is assumed to be very small.

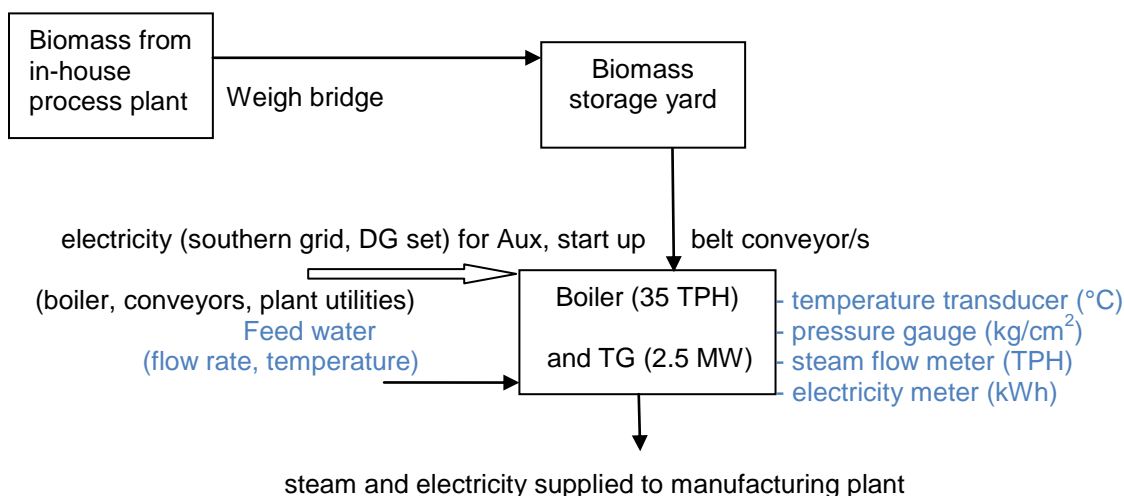


Figure: Schematic of the project boundary

## 2.4 Baseline Scenario

'Approved methodology AMS I.C. Version 19 has been applied to the project activity as it meets applicability criteria outlined in the methodology. Following paragraphs demonstrate selection of baseline scenario out of the various alternatives available to the project proponent.

### Identification of alternative baseline scenarios:

The methodology as applied to the project activity involves the identification of alternative baseline scenarios that provide or produce electricity/ steam for in-house consumption. As per the approved methodology AMS I.C. version 19, para 19, the baseline scenario applicable to the project activity is as follows:

Project activities producing both heat and electricity using biomass cogeneration shall use one of the following baseline scenarios

Baseline Alternatives as per AMS I.C	Discussion of alternative based on its realistic application	Remark
a) <i>Electricity is imported from a grid and thermal energy (steam/heat) is produced using fossil fuel;</i>	The southern grid and state face power deficit face 18-20% <sup>6</sup> . As PP requires continuous and reliable supply of electricity, the import from grid is not a realistic option.	The alternative is not realistic.
b) <i>Electricity is produced in an on-site captive power plant using fossil (with a possibility of export to the grid) and thermal energy (steam/heat) is produced using fossil fuel;</i>	The PP requires both electricity and steam and in all such cases, a cogeneration plant is preferred to save capital cost, space required for two plants etc.	The alternative is not realistic.
c) <i>A combination of (a) and (b);</i>	As alternative (a) is not realistic, this option is not possible.	The alternative is not considered.
d) <i>Electricity and thermal energy (steam/heat) are produced in a cogeneration unit using fossil fuel (with a possibility of export of electricity to a grid/other facilities and/or thermal energy to other facilities);</i>	The alternative is considered as a baseline alternative.	The alternative is realistic and considered further.
e) <i>Electricity is imported from the grid and/or produced in an on-site captive power plant using fossil fuels (with a possibility of export to a grid); steam/heat is produced from biomass;</i>	As discussed in option (a and b) above, the electricity grid is not reliable, also, a steam generation plant alone is not preferred when both steam and electricity are required.	The alternative is not realistic.
f) <i>Electricity is produced in an on-site captive power plant using biomass (with a possibility of export to a grid) and/or imported from a grid; steam/heat is produced using fossil fuel;</i>	As discussed in option (b) above, a steam generation plant alone is not preferred when both steam and electricity are required.	The alternative is not realistic.
g) <i>Electricity and thermal energy (steam/heat) are produced in a biomass fired cogeneration unit (without a possibility of export of electricity either to a grid or to other facilities and without a possibility of export of thermal energy to other facilities). This scenario applies to a project activity that installs a new grid connected biomass cogeneration system that produces surplus electricity and this surplus electricity is exported to a grid. The</i>	This situation is similar to the project activity is considered further.	The alternative is realistic and discussed further.

<sup>6</sup> <http://archive.indianexpress.com/news/power-shortage-cripples-south-indias-industrial-belts/1122437/>

[http://www.business-standard.com/article/economy-policy/dark-story-113070500956\\_1.html](http://www.business-standard.com/article/economy-policy/dark-story-113070500956_1.html)

<p><i>baseline scenario is that the electricity would otherwise have been generated by the operation of grid-connected power plants and by the addition of new generation sources to the grid;</i></p>		
<p><i>h) Electricity and/or thermal energy produced in a co-fired system.</i></p>	<p>The region of project has both coal and biomass abundantly available. However, managing two fuels and a co-fired system is difficult compared to single fuel.</p>	<p>The alternative is not realistic.</p>
<p><i>i) Electricity is imported from a grid and/or produced in a biomass fired cogeneration unit (without a possibility of export of electricity either to the grid or to other facilities); steam/heat is produced in a biomass fired cogeneration unit and/or a biomass fired boiler (without a possibility of export of thermal energy to other facilities). This scenario applies to a project activity that installs a new biomass cogeneration system that displaces electricity which otherwise would have been imported from a grid.</i></p>	<p>As discussed in alternative (a), the grid is not reliable.</p>	<p>The alternative is not realistic.</p>

Considering the case of the project, it is a stand-alone palm oil mill and requires electricity and steam for its operation. The best option for the PP would be to adopt a cogeneration plant to fulfill the electricity and steam requirements. Further, as there is no consumer of electricity and thermal energy in the vicinity of the project activity, options involving export of electricity or thermal energy are also not realistic. Thus, the options considered for further analysis are

Alternative (d)

- 1) Electricity and thermal energy (steam) are produced in a cogeneration unit using fossil fuel

Alternative (g)

- 2) Electricity and thermal energy (steam) are produced in a biomass fired cogeneration unit (without a possibility of export of electricity either to a grid or to other facilities and without a possibility of export of thermal energy to other facilities

As seen in the following section 2.5, the baseline scenario is Alternative (1) electricity and steam is produced in a cogeneration unit using coal.

## 2.5 Additionality

**National and sectoral policies and circumstances:**

As per EB-22, Annex-3, para-6(a) and para-6(b), there are two types of national and/or sectoral policies that are to be taken into account when establishing baseline scenarios. There were no such national and/or sectoral policies or regulations either under paragraph 6 (a) that have been implemented before adoption of the Kyoto Protocol by the COP (decision 1/CP.3, 11 December 1997 or under paragraph 6 (b) that have been implemented since the adoption by the COP of the CDM M&P (decision 17/CP.7, 11 November 2001) that gives comparative advantages to more emissions intensive technologies or fuels over less emissions-intensive technologies or fuels or vice-versa.

There is no regulation that stipulates fuel for boilers in industries including distilleries (PP has project activity for supplying steam to a distillery). Thus, industries use coal, lignite, biomass (bagasse, rice husk etc.) depending on availability. A list of industries using coal from Western Coalfields Limited, a Government managed coal mine owner company in the region of the project activity has been made available to the DOE. Thus, coal is abundantly available in the region and even non-core (other than power, cement, sponge iron, steel etc.) industries use coal for captive steam and power demand.

Due to low utilization of biomass, nationally there are various promotion schemes for biomass use especially for electricity generation (including cogeneration).

Biomass promotional policy of Government:

Ministry of New and Renewable Energy, Govt. of India has notified a Scheme on Biomass Energy and Co-Generation (non-bagasse)<sup>7</sup> in Industry with the following objectives:

- 1) To encourage the deployment of biomass energy systems in industry for meeting thermal and electrical energy requirements.
- 2) To promote decentralized / distributed power generation through supply of surplus power to the grid.
- 3) To conserve the use of fossil fuels for captive requirements in industry.
- 4) To bring about reduction in greenhouse gas emissions in industry
- 5) To create awareness about the potential and benefits of alternative modes of energy generation in industry.

The scheme has a provision for providing Central Financial Assistance for encouraging setting up Biomass Gasifiers and Biomass Co-generation (non-bagasse) projects in the industries for meeting their thermal and electricity requirements. This includes Central Financial Assistance in terms of capital subsidy.

This project has not received any capital subsidy/ special tax breaks and the investment analysis presented in following sections considers all applicable national and state level policies.

### **Identification of baseline alternatives**

As seen on Section 2.4, at the time of project planning, PP had following options for the energy generation to meet captive demand.

#### **1) biomass based cogeneration plant**

#### **2) Coal based cogeneration plant**

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<sup>7</sup> <http://mnre.gov.in/file-manager/offgrid-biomass-cogen-scheme-3/aa-biomass-energycogen-2011-12.pdf>  
Refer pg. 57 of [http://mnre.gov.in/file-manager/UserFiles/strategic\\_plan\\_mnre\\_2011\\_17.pdf](http://mnre.gov.in/file-manager/UserFiles/strategic_plan_mnre_2011_17.pdf)

In line with the decision making process, the PP has used investment barrier to identify the baseline and also to demonstrate the Additionality.

### **Investment barrier**

The project activity, being a small scale project, it is not mandatory to apply “Tool for the demonstration and assessment of Additionality”. However, a part of the tool (version 06) is referred here for a systematic evaluation of financial analysis for investment barrier.

#### **Step 1: Determine appropriate analysis method**

As per the tool, PP has to determine whether to apply simple cost analysis, investment comparison analysis or benchmark analysis.

Simple cost analysis is applied only in cases where there is no revenue generation apart from VCS benefits. This is not the case in the project activity as savings result from displace coal cost and electricity HT tariff) and hence, this analysis is not appropriate.

As per guidance 19 of Annex 5 of EB 62, benchmark analysis is applied where baseline does not require any investment. Since the alternatives identified here require investment to be made, this is not suitable analysis.

#### **Outcome of step 1:**

The investment comparison analysis is chosen.

#### **Step 2: Apply investment comparison analysis**

In this step, PP has identified a suitable financial indicator for the project type and in the context of decision making.

Since the alternatives defined in the step 1 provide a service i.e. generate steam and electricity, the unit cost of service i.e. levelised cost of energy generation in (INR/GJ) is found to be the most suitable indicator. Further, the same indicator was used by the PP at decision making. Hence, this indicator is correct in the context of the decision making.

As per the “Guidelines on the assessment of investment analysis” EB 62 Annex 5, para 19, it states that “If the proposed baseline scenario leaves the project participant no other choice than to make an investment to supply the same (or substitute) products or services, a benchmark analysis is not appropriate and an investment comparison analysis shall be used.” As in case of PP, there was requirement of steam and electricity, thus PP has to invest either in coal or biomass based co-generation plant. Thus, comparative analysis is appropriate and is used for demonstration of additionality.

The project activity has no direct cash revenues (as sale of steam/ energy generated in the project activity is not involved and savings from avoided coal purchase/ electricity import are only notional revenue) and there is no possibility of computation of IRR or payback period. There is no suitable indicator than the unit cost of energy generation that can be computed in first place (as cash flows cannot be computed). Also, for any production plant, keeping cost of utilities and raw materials is a main objective to increase competitiveness of the main product in the market. Thus, cost of energy generation is the selected as suitable financial indicator.

As the electricity is consumed for captive demand in the plant, there is no sale of electricity. Thus, the cost of energy generation will not account for electricity separately and total energy as boiler outlet will be used to get the financial indicator. Since for both the baseline alternatives the similar financial analysis will be used, this is conservative.

#### **Outcome of step 2:**

The unit cost of energy generation in (INR/GJ) is used as a financial indicator which is an appropriate indicator for the project type and in the context of investment decision.

### Step 3: Calculation and comparison of unit cost of energy generation

The calculation and comparison of the unit cost of energy generation for both the alternatives identified above.

The unit cost of generation for each alternative has been calculated as below:

= Total annual cost (expenditure) of energy generation (INR) / total energy generated in year (GJ)

In the absence of separate Annual Maintenance Contract for O&M for the equipments like boilers, TG and also there is only a single team involved in the O&M of the plant and there is no significant additional investment to be incurred by PP for O&M. Thus, total annual O&M cost will be same for cogen plant of similar output independent of fuel – coal or biomass. Hence O&M cost has been kept same for both the alternatives.

### Data inputs/ assumptions:

#### 1) Biomass based cogeneration plant

##### 1.1 Total project cost

Sr. No.	Equipment/ Service	Price (lakh Rs.)	Reference
1	Boiler	585.5	PO to Thermax - 10/05/2011
2	Balance of boiler plant	142.5	- do -
3	VAT, Freight and transit insurance	0	- do -
4	E&C of boiler	47	PO to Thermax - 10/05/2011
5	TG set	195	PO to Triveni - 12/05/2011
6	TG E&C	9.55	WO to Triveni - 12/05/2011
7	Fuel, material, ash handling system	79.65	PO to Global Tech. - 29/12/2011
8	Water treatment system - RO, DM plant	76.5	PO to Thermax - 19/10/2011
9	Freight and transit insurance	3.5	- do -
<b>Total</b>		<b>1139.2</b>	<b>lakh Rs</b>

##### 1.2 Plant specifications and fuel characteristics

Sr. No.	Paramater	Value and unit	Reference
1	Boiler rated capacity	35 TPH at 35 kg/cm <sup>2</sup>	Boiler PO to Thermax - 10/05/2011
2	TG rated capacity	2.5 MW	PO to Triveni - 12/05/2011
3	Plant operation days	365 / year	Based on the production plant operations estimated
4	Plant load factor	80%	APERC tariff order 06/08/2013, pg. 2
5	Inlet feed water	105°C	As per Boiler PO specifications from Thermax
6	Efficiency of Boiler	73%	As per Boiler PO specifications from Thermax
7	Fuel GCV Palm fiber - Palm shell - EFB -	in kcal/kg 2,800 4,450 2,400	Laboratory analysis of samples

8	Landed fuel cost Palm fiber - Palm shell - EFB -	In Rs./ton 2,430 (average)	As per APERC Tariff order dated 31/03/2009, pg. 5 and applying annual escalation of 5%
9	Auxiliary electricity consumption of cogen plant	10%	of generation as per APERC tariff order 06/08/2013, pg. 2
10	Depreciation on plant and machinery	5.28%	as per The Companies Act
11	Annual O&M cost	4%	of capital cost as per APERC tariff order 2004, pg. 36

Based on the excel worksheet financial model, the unit cost of biomass based cogeneration plant is 385.2 Rs./GJ.

## 2) Coal based cogeneration plant

### 1.1 Total project cost

For conservative analysis, the project cost of coal based cogeneration plant is taken same as that of biomass based plant. The boiler used in the project activity is multifuel boiler and is capable of using coal as fuel. Thus, this assumption is realistic<sup>8</sup>.

### 1.2 Plant specifications and fuel characteristics

For conservative analysis, the plant specifications of coal based cogeneration plant is taken same as that of biomass based plant. Only the coal calorific value and landed price are specific.

1	NCV of coal	4,000 kcal/kg	Price Notification of The Singareni Collieries Company Ltd. Hyderabad dt. 11/09/2013 (latest available at start of validation) – coal considered is G11 grade based on calorific value and price optimization
2	Landed cost coal	3,000 Rs./ton	Calculated from price notification referred above and public reference on railway tariff based on distance between mine and project plant

Based on the excel worksheet financial model, the unit cost of coal based cogeneration plant is 349.3 Rs./GJ.

Sr. No.	Scenario	Unit cost of process (Rs./GJ)
1	Baseline - Coal based cogen plant	349.3
2	Project Activity – biomass based cogen plant	385.2

<sup>8</sup> Also, only coal fired boilers are generally cheaper than biomass / multifuel boilers as later one require conveyor system, travelling / pulsating grate, larger furnace area etc. Thus, this assumption is conservative.

## Sensitivity analysis:

As per guidance 20 of Annex 5 of EB 62, according to the investment analysis guidance, only variables, including the initial investment cost, that constitute more than 20% of either total project costs or total project revenues should be subjected to reasonable variation in a range of +10% to -10% (all parameters varied need not necessarily be subjected to both negative and positive variations of the same magnitude), the following parameters are subjected for the sensitivity analysis:

- a) **PLF:** The PLF is taken now as per APERC Tariff Order and can change depending on change in operating days and planned/ unplanned shutdown, maintenance requirement etc. Thus parameter is subjected to a default sensitivity range +10% to -10% as per guidance.
- b) **Fuel cost:** Fuel cost is volatile parameter and it is not constant over a long period like 20 years. Hence, this parameter is considered under the sensitivity analysis. The sensitivity results show that fuel cost in case of bagasse (same is considered for biomass used in project activity) is highest compared to baseline fuel coal. PP has presented the price trend of biomass as per Office of the Economic Adviser (GOI)<sup>9</sup>. The price trend from the reference quoted for the last five years before the investment decision shows that the price of bagasse had varied by 2.55% on average. Thus, there is no predictable trend in the fuel price variations. Hence, the default sensitivity range +10% to -10% in para 20 and 21 of EB 62, Annex 5 is considered here.
- c) **NCV:** Net calorific value depends on the different types of fuel for each and every batch. It will not remain constant for every time.

As the NCV of biomass residues used in the project activity has been taken from the lab test report and calculated on dry basis, there is not much variation envisaged in the NCV. Still PP has given the provision of +10% to -10% of sensitivity.

- d) **O&M cost:** As O&M cost is taken from APERC order in absence of actual operations, it is subjected to a default sensitivity range +10% to -10% as per guidance.
- e) **Project cost:** As the project cost is used as per actual, it cannot vary. However, sensitivity analysis over default  $\pm 10\%$  is conducted on this parameter.

## Unit cost of energy generation using VCS project (Rs./GJ)

PLF		Fuel cost		NCV		O&M cost		Project cost	
-10%	+10%	-10%	+10%	-10%	+10%	-10%	+10%	-10%	+10%
386.94	383.75	348.25	422.13	426.23	351.61	384.5	385.88	383.61	386.77

<sup>9</sup> <http://www.eaindustry.nic.in/> (PP has submitted the detailed calculation in the excel sheet)

The results summarised in table above show that the unit cost of energy generation in project case is higher and economically unattractive compared to that in the baseline. In only one sensitivity case, the unit cost of energy generation using biomass is lower i.e. when cost of biomass is reduced by -10%. However, this situation is unlikely as per the national biomass price index and state regulatory order on biomass based power projects.

- 1) The data from a Government of India database shows net price increase in bagasse (a listed biomass residue) over a 10 year period. Please refer attached evidence from the website.
- 2) APERC recommends an annual 5% price escalation for biomass based power projects (APERC Tariff order dated 31/03/2009, pg. 5)

From the sensitivity analysis, it is clear that the unit cost of the project activity is still higher than the coal based alternative in all (but one) scenarios. Thus, project activity is not economically most attractive alternative and is additional.

Timeline of the project implementation

Sr. No.	Date	Milestone
1	10-05-2011	PO of boiler issued to Thermax Limited, Pune
2	12-05-2011	PO of steam turbine generator (STG) issued to Triveni Turbine Ltd.
3	16-07-2012	Commissioning of boiler
4	18-08-2012	Commissioning of STG
5	March – April 2014	Local stakeholders’ consultation
6	14-04-2014	VCS Project Pipeline listing of the project

## 2.6 Methodology Deviations

The project does not use any methodology deviation.

## 3 QUANTIFICATION OF GHG EMISSION REDUCTIONS AND REMOVALS

### 3.1 Baseline Emissions

As per para 27 of the SSC methodology

“For electricity and thermal energy (steam/heat) produced in a baseline cogeneration unit, using fossil fuel (case 19 (d)), the following equation shall be used to determine baseline emissions:

$$BE_{cogen,CO_2,y} = [(EG_{PJ,thermal,y} + EG_{PJ,electrical,y} * 3.6) / \eta_{BL,cogen}] * EF_{FF,CO_2} \quad (1)$$

Where:

$BE_{cogen,CO_2,y}$  Baseline emissions from electricity and thermal energy displaced by the project activity during the year  $y$  (tCO<sub>2</sub>)

$EG_{PJ,electrical,y}$  The amount of electricity supplied by the project activity during the year  $y$ ; GWh

3.6 Conversion factor (TJ/GWh)

$EG_{PJ,thermal,y}$  The net quantity of thermal energy supplied by the project activity during the year  $y$  (TJ)

$EF_{FF,CO_2}$  The CO<sub>2</sub> emission factor of the fossil fuel that would have been used in the baseline cogeneration plant obtained from reliable local or national data if available, alternatively, IPCC default emission factors can be used-(tCO<sub>2</sub>/TJ)

$\eta_{BL,cogen}$  The total annual average efficiency of the cogeneration plant using fossil fuel determined in accordance with paragraphs 28 and 29 below”

Energy Output Calculations	Value	Unit	Reference
Operating days	365	days	Based on the production plant operations estimated
Average Steam flow rate	35,000	kg/h	As per Boiler PO specifications from Thermax
Plant Load Factor	80%	%	APERC tariff order 06/08/2013, pg. 2
Inlet Temperature	105	deg C	As per Boiler PO specifications from Thermax
Steam pressure at the end of TG	4.5	kg/cm <sup>2</sup> (g)	As per plant design
Enthalpy of feed water @ 105 °C	440	kJ/kg	Estimated using the steam tables, refer 'Thermal Output' worksheet
thermal energy of feed water in year $y$	73.96	TJ	calculated
Enthalpy of steam @ rated 4.5 kg/cm <sup>2</sup>	2,752.30	kJ/kg	Estimated using the steam tables, refer 'Thermal Output' worksheet
thermal energy supplied by steam in year $y$	675.08	TJ	calculated
Net thermal energy supplied by steam to process plant	567.11	TJ	calculated

$$EG_{PJ,thermal,y} = 567.11 \text{ TJ}$$

Installed electrical capacity of project = 2.5 MW

Annual electricity generation = 2.5 x 365 x 24 x 80% = 17,520.00 MWh

Auxiliary consumption = 10% of generation as per APERC tariff order 06/08/2013, pg. 2

Net electricity generation by project = 17,520.00 x (1-10%)

$$= 15,768.00 \text{ MWh}$$

$$EG_{PJ,electrical,y} = 15.77 \text{ GWh}$$

$$\eta_{BL,cogen} = 85\%$$

using default efficiency of new coal fired boiler as per 'Tool to determine the baseline efficiency of thermal or electric energy generation systems', Ver. 01, EB 48, Annex 12 and

taking steam turbine efficiency of 100% as per Para 29(b) of SSC methodology

$$EF_{FF,CO_2} = 95.80 \text{ tCO}_2/\text{TJ}$$

as per Central Electricity Authority (CEA) CO<sub>2</sub> Baseline Database for the Indian Power Sector; Ver. 08, Assumption sheet, Cell D7

Keeping these values in equation (1)

$$BE_{cogen,CO_2,y} = 70,314 \text{ tCO}_2$$

### 3.2 Project Emissions

Project emissions include:

- CO<sub>2</sub> emissions from on-site consumption of fossil fuels due to the project activity  
This is not applicable as project activity will not use any fossil fuels. A provision is made to monitor fuels used in the monitoring plan.

The project emissions from fossil fuel combustion shall be calculated using the latest version of Tool to calculate project or leakage CO<sub>2</sub> emissions from fossil fuel combustion.

The project emissions will be calculated as below:

CO<sub>2</sub> emissions from fossil fuel combustion in process j are calculated based on the quantity of fuels combusted and the CO<sub>2</sub> emission coefficient of those fuels, as follows:

As per equation 1 of the “Tool to calculate project or leakage CO<sub>2</sub> emissions from fossil fuel combustion”;

$$PE_{FC,j,y} = \sum_i FC_{i,j,y} \times COEF_{i,y}$$

Where:

- PE<sub>FC,j,y</sub> = Are the CO<sub>2</sub> emissions from fossil fuel combustion in process j during the year y (tCO<sub>2</sub>/yr);
- FC<sub>i,j,y</sub> = Is the quantity of fuel type i combusted in process j during the year y (mass or volume unit/yr);
- COEF<sub>i,y</sub> = Is the CO<sub>2</sub> emission coefficient of fuel type i in year y (tCO<sub>2</sub>/mass or volume unit)
- i = Are the fuel types combusted in process j during the year y

The CO<sub>2</sub> emission coefficient COEF<sub>i,y</sub> can be calculated using one of the following two Options (A & B), depending on the availability of data on the fossil fuel type i, as follows:

PP has chosen option B

Option B: The CO<sub>2</sub> emission coefficient COEF<sub>i,y</sub> is calculated based on net calorific value and CO<sub>2</sub> emission factor of the fuel type i, as follows: Equation 4:

$$\text{COEF}_{i,y} = \text{NCV}_{i,y} \times \text{EF}_{\text{CO}_2,i,y}$$

Where:

COEF<sub>i,y</sub> = Is the CO<sub>2</sub> emission coefficient of fuel type i in year y (tCO<sub>2</sub>/mass or volume unit)

NCV<sub>i,y</sub> = Is the weighted average net calorific value of the fuel type i in year y (GJ/mass or volume unit)

EF<sub>CO<sub>2</sub>,i,y</sub> = Is the weighted average CO<sub>2</sub> emission factor of fuel type i in year y (tCO<sub>2</sub>/GJ)

i = Are the fuel types combusted in process j during the year y

- CO<sub>2</sub> emissions from electricity consumption by the project activity

The project activity will use electricity generated in the project cogen plant and net electricity after this auxiliary consumption will be monitored for emission reduction calculation. However, during cold start up of the project plant electricity from southern grid will be used.

The electricity consumption will be monitored using electricity meter during the crediting period.

As per the “Tool to calculate baseline, project and/or leakage emissions from electricity consumption Version 01, EB 39 Annex 7”, PP has chosen generic approach which is applicable in any case i.e. Case A, B or C. Since the project activity falls under the Case B (as it uses grid and an onsite DG set), this approach is used and the emissions are calculated using equation as:

$$\text{PE}_{\text{EC},y} = \sum_j \text{ECP}_{j,y} * \text{EF}_{\text{EL},j,y} *(1+\text{TDL}_{j,y})$$

Where:

PE<sub>EC,y</sub> is the project emissions from electricity consumption in year y (tCO<sub>2</sub>/yr)

ECP<sub>j,y</sub> is the quantity of electricity consumed by the project electricity consumption source j in year y (MWh/yr)

EF<sub>EL,j,y</sub> is the emission factor for electricity generation source k in year y (tCO<sub>2</sub>/MWh). This is determined using “Tool to calculate the emission factor for an electricity system”.

TD<sub>Lj,y</sub> is the average technical transmissions and distribution losses for providing electricity to source j in year y. On a conservative basis this, has assumed as zero.

ECP<sub>j,y</sub> is measured as electricity taken from grid for the cogen plant start up/ emergency operations.

The transmission and distribution losses are calculated using the recent, accurate and reliable data available within the host country.

The transmission and distribution losses in state in 2011-12 were 15.3%<sup>10</sup>.

Determination of EF<sub>EL,j,y</sub>

<sup>10</sup> <http://www.electricalmonitor.com/ArticleDetails.aspx?aid=1552&sid=2>

According to the *Tool to calculate the emission factor for an electricity system*,  $EF_{grid,CM,y}$  i.e. baseline emission factor is calculated as a combined margin (CM), consisting of the combination of operating margin (OM) and build margin (BM) factors according to the following steps.

**Step 1: Identify the relevant electricity system**

The project is located in Andhra Pradesh and drawing the electricity from the southern grid during the operation of the project activity. Therefore the project has impact on all the generation facilities in this grid. Thus all the power generation facilities connected to this grid form the boundary for the purpose of baseline estimation. The southern grid is also connected with other regional grids. However, the net exchange of energy within the regional grids is very small and negligible and hence other regional grids are not included in the boundary for estimation of baseline emissions.

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

The PP has been chosen Option I to calculate operating margin and build margin factor i.e. only grid power plants are included in the calculation.

**Step 3: Select a method to determine operating margin (OM)**

The calculation of the operating margin emission factor ( $EF_{grid,OM,y}$ ) is based on one of the following methods:

- a) Simple OM, or
- b) Simple adjusted OM, or
- c) Dispatch data analysis OM, or
- d) Average OM.

Due to non-availability of archived dispatch data in the public domain for the southern grid, 'Dispatch Data Analysis' (1c) has not been chosen, though it should be the first methodological choice.

As per the Tool, simple operating margin (Simple OM) can be used only if low-cost/must-run resources constitute less than 50% of total grid generation in (a) average of the five most recent years, or 2) based on long-term averages for hydroelectricity production.

From the available information published by Central Electricity Authority (CEA), Government of India as "CO2 baseline database for Indian Power Sector, Version 09, January 2014<sup>11</sup>", it can be seen that the average of share of the low cost/must run resources for the five most recent years constitutes less than 50%. Hence the Simple OM method has been used to calculate the operating margin emission factor applicable. The table below depicts the share of must run resources.

Share of Must-Run(Hydro/Nuclear) (% of Net Generation)					
	2008-09	2009-10	2010-11	2011-12	2012-13
<b>Southern</b>	22.8%	20.6%	21.0%	21.0%	15.2%

For simple OM, the emission factor is calculated using ex-ante option. In the ex-ante option, the emission factor is determined once at the validation stage, thus no monitoring and recalculation of the emission factor during the crediting period is required. For grid connected power plants, as in this case, a 3-year-generation-weighted average, based on the most recent years is used i.e. 2010-11, 2011-12, 2012-13.

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

<sup>11</sup> [http://www.cea.nic.in/reports/planning/cdm\\_co2/cdm\\_co2.htm](http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm)

The simple OM emission factor is calculated as the generation-weighted average CO<sub>2</sub> emissions per unit net electricity generation (tCO<sub>2</sub>/MWh) of all generating power plants serving the system, not including low cost/must-run power plants / units.

The simple OM is calculated using Option A: Based on the net electricity generation and a CO<sub>2</sub> emission factor of each power unit.

*Option A - Calculation based on average efficiency and electricity generation of each plant*

Under this option, the simple OM emission factor is calculated based on the net electricity generation of each power unit and an emission factor for each power unit, as follows:

$$EF_{grid,OM,simple,y} = (\sum m EG_{m,y} * EF_{EL,m,y}) / \sum m EG_{m,y}$$

Where,

$EF_{grid,OM,simple,y}$	Simple operating margin CO <sub>2</sub> emission factor in year <i>y</i> (tCO <sub>2</sub> /MWh)
$EG_{m,y}$	Net quantity of electricity generated and delivered to the grid by power unit <i>m</i> in year <i>y</i> (MWh)
$EF_{EL,m,y}$	CO <sub>2</sub> emission factor of power unit <i>m</i> in year <i>y</i> (tCO <sub>2</sub> /MWh)
<i>M</i>	All power units serving the grid in year <i>y</i> except low-cost/must-run power units
<i>Y</i>	The relevant year as per the data vintage chosen in Step 3

As mentioned in step 3, the emission factor for simple OM is calculated based on the weighted average of generation for years 2010-11, 2011-12, 2012-13 and is fixed ex ante.

**Step 5. Calculate the build margin (BM) emission factor**

To calculate BM, option 1 is used as follows:

The Build Margin emission factor  $EF_{grid,BM,y}$  is calculated ex-ante based on the most recent information available on plants already built . The latest BM factor information is available for year 2012-13. Therefore, this year’s Build Margin is used as  $EF_{grid,BM,y}$ . This option does not require monitoring the emission factor during the crediting period.

**Step 6. Calculate the combined margin emissions factor**

The calculation of the combined margin (CM) emission factor ( $EF_{grid,CM,y}$ ) is based on one of the following methods:

- (a) Weighted average CM; or
- (b) Simplified CM.

The weighted average CM method (option A) should be used as the preferred option.

Therefore, the combined margin emissions factor is calculated using option A as follows:

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

Where:

$EF_{grid,BM,y}$	Build margin CO <sub>2</sub> emission factor in year <i>y</i> (tCO <sub>2</sub> /MWh)
$EF_{grid,OM,y}$	Operating margin CO <sub>2</sub> emission factor in year <i>y</i> (tCO <sub>2</sub> /MWh)
$w_{OM}$	Weighting of operating margin emissions factor (%)
$w_{BM}$	Weighting of build margin emissions factor (%)

For projects other than wind and solar projects, as per [“Tool to calculate the emission factor for an electricity system”](#), the default weights are as follows:

$$w_{OM} = 0.5 \text{ and } w_{BM} = 0.5$$

$$EF_{grid,CM,y} = 0.5 * EF_{grid,OM,y} + 0.5 * EF_{grid,BM,y}$$

**Operating margin for NEWNE grid**

Simple Operating Margin (tCO <sub>2</sub> /MWh)			
	2010-11	2011-12	2012-13
Southern grid	0.9421	0.9602	0.9972

The generation weighted average (detailed calculation in the emission reduction estimation sheet) OM is 0.9677 tCO<sub>2</sub>/MWh.

**Build margin for NEWNE grid**

$$EF_{grid,BM,y} = EF_{grid,BM,(2012-13)} = 0.9509 \text{ tCO}_2/\text{MWh}$$

Now,

**Combined margin for NEWNE grid**

$$EF_{grid,CM,y} = 0.5 * 0.9677 + 0.5 * 0.9509 = 0.9032 \text{ tCO}_2/\text{MWh}$$

- As per the “Tool to calculate baseline project and or leakage emissions from electricity consumption, EB 39 Annex 7, The determination of the emission factors for electricity generation (**EF<sub>EL,j,y</sub>**) depends on which scenario (A, B or C) applies to the source of electricity consumption;

Scenario A: Electricity consumption from the grid

In this case, project participants may choose among the following options:

Option A1: Calculate the combined margin emission factor of the applicable electricity system, using the procedures in the latest approved version of the “Tool to calculate the emission factor for an electricity system”. ( $EF_{EL,j/k/l,y} = EF_{grid,CM,y}$ ).

- Any other significant emissions associated with project activity within the project boundary

There are no other significant emissions associated with project activity within the project boundary.

The biomass residue from the process plant can be used directly and do not require any preparation (drying, cutting etc.) that could require energy. Thus, there are no emissions associated with this step as well.

Thus,

$$PE_y = 0 \text{ tCO}_2$$

This calculation is only for ex-ante estimate and actual value will be calculated in the monitoring periods.

### 3.3 Leakage

The SSC methodology gives leakages to be considered in para 47 and 48 as below.

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

The energy generating equipment is purchased from OEM – Thermax, Triveni and is not transferred from outside the boundary to the project activity. Thus, this leakage need not be considered here.

48. In cases where the collection/processing/transportation of biomass residues is outside the project boundary CO<sub>2</sub> emissions from the collection/processing/transportation<sup>12</sup> of biomass residues to the project site shall be taken into account as leakage.

The biomass used in the project activity also transported within project plant as only in-house generated biomass fuel will be used in the project. Thus, leakage related to biomass collection/processing/ transport are also not involved.

As per the table 1 of Attachment C to Appendix B, the emission sources for the biomass residues are the competing use of biomass. Competing uses of biomass is the emission source which could be led due to the use of biomass elsewhere in the absence of the project activity. The assessment of this emission source is further explained in the Para 18 of Attachment C to Appendix B,

*“The project participant shall evaluate ex ante if there is a surplus of the biomass in the region of the project activity, which is not utilized. If it is demonstrated (e.g., using published literature, official reports, surveys etc.) at the beginning of each crediting period that the quantity of available biomass in the region (e.g., 50 km radius), is at least 25% larger than the quantity of biomass that is utilised including the project activity, then this source of leakage can be neglected otherwise this leakage shall be estimated and deducted from the emission reductions.”*

This project uses biomass residue generated within the project facility (by product of the palm oil mill for which the project is supplying steam and electricity dedicatedly). Thus, the PP would not have sold this biomass in market and thus there is no competing use. The palm oil mill produced more than 50% of the biomass required in last two financial years.

2012-13-Total fuel production (Mt)—25,978  
 2012-13-Fuel Consumption (Mt)-----12,684.5  
 2012-13-Surplus Fuel (Mt) -----13,293 (51%)

2013-14-Total fuel production (Mt)—69,180  
 2013-14-Fuel Consumption (Mt)-----33,779.2  
 2013-14-Surplus Fuel (Mt) -----35,401 (51%)

<sup>12</sup> If biomass residues are transported over a distance of more than 200 kilometres due to the implementation of the project activity then this leakage source attributed to transportation shall be considered, otherwise it can be neglected.

Further, the West Godavari district and 50 km area where project is located has mainly agro based industries<sup>13</sup> – sugar cane crushing, rice, cotton processing. Thus, the biomass availability is abundant.

Hence, this leakage is not applicable.

Thus,

$$LE_y = 0 \text{ tCO}_2$$

Emission reductions are calculated as follows:

$$ER_y = BE_y - PE_y - LE_y \tag{2}$$

Where:

$ER_y$  Emission reductions in year  $y$  (tCO<sub>2</sub>e)

$BE_y$  Baseline emissions in year  $y$  (tCO<sub>2</sub>e)

$PE_y$  Project emissions in year  $y$  (tCO<sub>2</sub>)

$LE_y$  Leakage emissions in year  $y$  (tCO<sub>2</sub>)

$$ER_y = 70,314 - 0 - 0$$

$$= 70,314 \text{ tCO}_2\text{e}$$

### 3.4 Net GHG Emission Reductions and Removals

Years	Estimated baseline emissions or removals (tCO <sub>2</sub> e)	Estimated project emissions or removals (tCO <sub>2</sub> e)	Estimated leakage emissions (tCO <sub>2</sub> e)	Estimated net GHG emission reductions or removals (tCO <sub>2</sub> e)
2012	23,630 <sup>14</sup>	0	0	23,630
2013	70,314	0	0	70,314
2014	70,314	0	0	70,314
2015	70,314	0	0	70,314
2016	70,314	0	0	70,314

<sup>13</sup> [www.apind.gov.in/Library/District/westgodavari.pdf](http://www.apind.gov.in/Library/District/westgodavari.pdf)  
[dcmsme.gov.in/dips/amended%20West%20Godavari.pdf](http://dcmsme.gov.in/dips/amended%20West%20Godavari.pdf)

<sup>14</sup> ER shown as per the Crediting period start date: 18-08-2012

2017	70,314	0	0	70,314
2018	70,314	0	0	70,314
2019	70,314	0	0	70,314
2020	70,314	0	0	70,314
2021	70,314	0	0	70,314
2022	46,684 <sup>15</sup>	0	0	46,684
<b>Total</b>	<b>703,140</b>	<b>0</b>	<b>0</b>	<b>703,140</b>

## 4 MONITORING

### 4.1 Data and Parameters Available at Validation

Data Unit / Parameter:	$\eta_{BL,cogen}$
Data unit:	%
Description:	The total annual average efficiency of the cogeneration plant using coal
Source of data:	Default efficiency of new coal fired boiler as per 'Tool to determine the baseline efficiency of thermal or electric energy generation systems', Ver. 01, EB 48, Annex 12 and taking steam turbine efficiency of 100% as per Para 29(b) of SSC methodology
Value applied:	85%
Justification of choice of data or description of measurement methods and procedures applied:	Default value as per SSC methodology guidance is used here Efficiency of a new coal fired boiler = 85% (as per 'Tool to determine the baseline efficiency of thermal or electric energy generation systems', Ver. 01) Efficiency of turbine = 100% (as per Para 29(b) of SSC methodology AMS I.C) Thus, efficiency of cogeneration plant = 85 x 100 = 85%
Any comment:	--

Data Unit / Parameter:	$EF_{grid,CM,y}$
Data unit:	tCO <sub>2</sub> /MWh

<sup>15</sup> ER shown as per the Crediting period end date: 17-08-2022

Description:	Combined margin emission factor of the southern grid
Source of data:	CEA "CO <sub>2</sub> baseline database for the Indian Power Sector, Version 09, January 2014"
Value applied:	0.9593
Justification of choice of data or description of measurement methods and procedures applied:	Calculated using "Tool to calculate the emission factor for an electricity system"
Any comment:	The emission factor will be fixed ex-ante and will not be monitoring throughout the crediting period

#### 4.2 Data and Parameters Monitored

Data Unit / Parameter:	<b>EF</b> <sub>CO<sub>2</sub>,i,y</sub>
Data unit:	tCO <sub>2</sub> / TJ
Description:	CO <sub>2</sub> emission factor of fossil fuels: coal and diesel
Source of data:	Central Electricity Authority (CEA) CO <sub>2</sub> Baseline Database for the Indian Power Sector
Description of measurement methods and procedures to be applied:	The database is an official publication of the Government of India for the purpose of CDM baselines. Thus, the value is taken as country specific emission factor of coal.
Frequency of monitoring/recording:	Once in a monitoring period – latest database version will be used
Value applied:	Coal = 95.80 Diesel: 76.4
Monitoring equipment:	Default value
QA/QC procedures to be applied:	The data is taken from Indian National Communication to UNFCCC and is available from authentic source, thus no additional QC is required
Calculation method:	-
Any comment:	-

Data Unit / Parameter:	<b>EG</b> <sub>PJ,thermal,y</sub>
Data unit:	TJ
Description:	Net quantity of thermal energy supplied by project

Source of data:	Calculated parameter.  Parameter $EG_{PJ,thermal,y}$ for project activity boiler is calculated from net steam output (ton) and its net enthalpy. Source for net steam output is steam production data log and corresponding enthalpy (at operating temperature) is inferred from steam table with respect to operating pressure and temperature.
Description of measurement methods and procedures to be applied:	Monitoring: This will be calculated on the monthly basis. The monthly average value of steam flow meter and pressure gauge will be used to calculate enthalpy of the steam supplied using steam table in tonnes/TJ. This value will be multiplied with the monthly average of steam generated by project activity boiler $Q_{steam}$ , to calculate enthalpy of steam supplied in a month. The enthalpy of feed water calculated using the measured values of flow meter (1 number) and its temperature (using meter: 1 number) will be subtracted to get $EG_{PJ,thermal,y}$ . The sum of $EG_{PJ,thermal}$ of all the months will provide a yearly value. Data Type: Calculated and archived Archiving Procedure: Electronic
Frequency of monitoring/recording:	Monitoring Frequency: Continuous measurement for steam flow and pressure Recording Frequency: Monthly calculation for enthalpy
Value applied:	567.11
Monitoring equipment:	Equipment accuracy class Steam flow meter: $\pm 0.5\%$ pressure gauges : $\pm 1\%$
QA/QC procedures to be applied:	The steam temperature and steam mass flow meters will be calibrated once in three years.
Calculation method:	Steam generated in a year (ton) x average enthalpy of steam (kJ/kg) / $10^6$
Any comment:	-

Data Unit / Parameter:	$EG_{PJ,electrical}$
Data unit:	MWh
Description:	Net electricity supplied by the project activity
Source of data:	Cogen plant log book
Description of measurement methods and	<u>Monitoring</u> : Electricity meter in control room will

procedures to be applied:	measure the net quantity of electricity supplied by the project activity cogen plant.  <u>Data type:</u> Measure <u>Archiving procedure:</u> Paper and Electronic <u>Responsibility:</u> Turbine operator would be responsible for monitoring and checks for regular calibration of electricity meter and Shift In-charge will be responsible for calibration of the electricity meters. <u>Calibration Frequency:</u> Once in three years
Frequency of monitoring/recording:	Continuous monitoring with monthly recording
Value applied:	15,786.00
Monitoring equipment:	Electric meter Accuracy class: 0.2s
QA/QC procedures to be applied:	electric meter/s would be calibrated once in three years at accredited third party laboratory
Calculation method:	The total generation of from the project activity – auxiliary consumption – import from grid (if any used for cogen plant during cogen plant shutdown). The trivector meter will give net generation directly by doing above calculation.
Any comment:	-

Data Unit / Parameter:	<b>Q<sub>k, biomass</sub></b>
Data unit:	ton
Description:	Net Quantity of biomass type k consumed in the boiler in year y
Source of data:	Measured using weighbridge
Description of measurement methods and procedures to be applied:	- Will be monitored ex-post
Frequency of monitoring/recording:	Monitoring: The quantity of the palm fibre consumed will be measured using weigh bridge.  Data Type: Measured and archived Archiving Procedure: Electronic Responsibility: Stores in-charge will be responsible for maintaining the records of the palm fibre consumed in project. Stock in charge will maintain a palm fibre inventory recording the opening and closing balance.  Cross-check: Cross checking the measurements using mass/energy balance.
Value applied:	- will be monitored ex-post

Monitoring equipment:	Weighbridge Accuracy class: ±1%
QA/QC procedures to be applied:	Weigh bridge used will be calibrated by an external agency once in a year.
Calculation method:	Sum of quantities of palm fibre consumption in a monitoring period
Any comment:	The parameter will monitor quantities of all biomass used palm fibre, palm shell and EFB separately

Data Unit / Parameter:	<b>NCV</b> <sub>k, biomass</sub>
Data unit:	kcal/kg
Description:	Net Calorific Value of biomass type k
Source of data:	Lab analysis report of NCV
Description of measurement methods and procedures to be applied:	Monitoring: The NCV of palm fibre will be measured once in the first year of the crediting period (3 samples in each quarter) by third party laboratory/ inhouse as per national/ international standard. Data Type: Measured and Archived Archiving Procedure: Electronic Recording frequency: once in the first year of the crediting period Responsibility: Chief Chemist will be responsible for getting the lab analysis for the NCV.
Frequency of monitoring/recording:	once in the first year of the crediting period
Value applied:	- will be monitored ex-post
Monitoring equipment:	Calorimetry – third party lab analysis
QA/QC procedures to be applied:	Average value obtained using third party analysis using three samples for each measurement every quarter in the first year of operation and will be compared with any public literature if available and IPCC default values. If the measurement results differ significantly from previous measurements or other relevant data sources, additional measurements will be conducted.
Calculation method:	Calorimetry
Any comment:	The parameter will monitor NCV of all biomass used palm fibre, palm shell and EFB separately

Data Unit / Parameter:	<b>Extracted steam Enthalpy</b>
Data unit:	kJ/kg
Description:	Enthalpy of exhaust steam at the outlet of the steam turbine
Source of data:	Plant log books
Description of measurement methods and procedures to be applied:	<p><u>Calculation Procedure:</u> Enthalpy of steam from turbine is calculated from steam tables based on the corresponding values of quantity of steam and pressure.</p> <p><u>Data type:</u> Calculate  <u>Recording Frequency:</u> Daily  <u>Archiving procedure:</u> Paper and/or Electronic  <u>Responsibility:</u> Boiler operator would be responsible for monitoring and checks for regular calibration of temperature meter and pressure gauge. The Shift In-charge will be responsible for calibration of the temperature meter and pressure gauge.</p>
Frequency of monitoring/recording:	Continuous monitoring with monthly recording
Value applied:	2,752.30
Monitoring equipment:	Pressure of steam will be measured by pressure gauge and temperature by temperature transducer
QA/QC procedures to be applied:	QA/QC procedures will be ensured as the temperature meter and pressure gauge would be calibrated at regular intervals.
Calculation method:	Enthalpy of steam at end of TG – enthalpy of feed water
Any comment:	-

Data Unit / Parameter:	<b>Pressure</b>
Data unit:	kg/cm <sup>2</sup>
Description:	Pressure of flowing exhaust steam at the outlet of steam turbine
Source of data:	Pressure gauge
Description of measurement methods and procedures to be applied:	<p><u>Monitoring:</u> Pressure gauge will measure the pressure of the steam at the turbine outlet</p> <p><u>Data type:</u> Measured and archived</p>

	<p>Recording Frequency: Hourly</p> <p>Archiving procedure: Paper and Electronic</p> <p>Responsibility: Turbine operator would be responsible for monitoring and checks for regular calibration of pressure gauge and Shift In-charge will be responsible for calibration of the pressure gauge.</p> <p>Calibration Frequency: Calibration will be carried out once in a year.</p>
Frequency of monitoring/recording:	Continuous monitoring with monthly recording
Value applied:	4.5
Monitoring equipment:	Pressure gauge Accuracy class: 1%
QA/QC procedures to be applied:	Pressure gauge will be calibrated annually
Calculation method:	Direct reading from Pressure gauge
Any comment:	-

Data Unit / Parameter:	$FC_{i,j,y}$
Data unit:	MT/year
Description:	Quantity of fossil fuel combusted in the project in year y
Source of data:	Measured using weigh bridge for coal and level guage for diesel
Description of measurement methods and procedures to be applied:	<p>Monitoring: Type and quantity of fossil fuel combusted in the project activity will be measured using electronic weigh bridge (or recorded in challans provided by the supplier and handed over to the plant people by the truck driver).</p> <p>Data Type: Continuously Measured and archived</p> <p>Archiving Procedure: Electronic</p> <p>Responsibility: plant head with Officer (stores) would be responsible for monitoring and checks for regular calibration of weigh bridge</p>
Frequency of monitoring/recording:	Continuous measurement with monthly recording/ compilation
Value applied:	0
Monitoring equipment:	weigh bridge for coal and level guage for diesel Accuracy class: $\pm 1\%$
QA/QC procedures to be applied:	<p>Weigh bridge will be calibrated by an external agency once in a year.</p> <p>The consistency of metered fuel consumption quantities will be cross-checked by an annual energy balance that is based on purchased quantities and stock changes.</p>
Calculation method:	Sum of total fuel consumed in boiler

Any comment:	-
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Data Unit / Parameter:	<b>NCV</b> <sub>fossil fuels</sub>
Data unit:	kcal/kg
Description:	Net Calorific Value of fossil fuels
Source of data:	Lab analysis report of NCV
Description of measurement methods and procedures to be applied:	<p><u>Monitoring:</u> The NCV of palm fibre will be measured once in the first year of the crediting period (3 samples in each quarter) by third party laboratory/ inhouse as per national/ international standard.</p> <p><u>Data Type:</u> Measured and Archived</p> <p><u>Archiving Procedure:</u> Electronic</p> <p><u>Recording frequency:</u> once in the first year of the crediting period</p> <p><u>Responsibility:</u> Chief Chemist will be responsible for getting the lab analysis for the NCV.</p>
Frequency of monitoring/recording:	once in the first year of the crediting period
Value applied:	-
Monitoring equipment:	Calorimetry – third party lab analysis
QA/QC procedures to be applied:	<p>Average value obtained using third party analysis using three samples for each measurement every quarter in the first year of operation and will be compared with any public literature if available and IPCC default values.</p> <p>If the measurement results differ significantly from previous measurements or other relevant data sources, additional measurements will be conducted.</p>
Calculation method:	Calorimetry
Any comment:	The parameter will monitor NCV of all fossil fuels used separately

Data Unit / Parameter:	EC <sub>PJ,j,y</sub>
Data unit:	MWh
Description:	electricity taken from grid for the cogen plant start up/ emergency operations.
Source of data:	Cogen plant log book
Description of measurement methods and procedures to be applied:	<p><u>Monitoring:</u> Electricity meter in control room</p> <p><u>Data type:</u> Measure</p> <p><u>Archiving procedure:</u> Paper and Electronic</p> <p><u>Responsibility:</u> Turbine operator would be responsible for monitoring and checks for regular</p>

	calibration of electricity meter and Shift In-charge will be responsible for calibration of the electricity meters. Calibration Frequency: Once in three years
Frequency of monitoring/recording:	Continuous monitoring with monthly recording
Value applied:	0
Monitoring equipment:	Electric meter Accuracy class: 0.2s
QA/QC procedures to be applied:	electric meter/s would be calibrated once in three years at accredited third party laboratory
Calculation method:	The trivector meter will give net generation directly by doing above calculation.
Any comment:	-

### 4.3 Monitoring Plan

The Monitoring and Verification procedures define a project-specific standard against which the project's performance and conformance with all relevant criteria will be monitored and verified. It includes

- Suitable data collection, collation and archiving methods consistent with good practices
- Data interpretation techniques for monitoring and verification of GHG emissions.

These procedures provide for a clear, credible, and accurate set of monitoring, evaluation and verification procedures. The purpose of these procedures would be to direct and support continuous monitoring of the key performance indicator for the project, i.e. Greenhouse Gas (GHG) emission reductions.

All instruments will be calibrated and marked in accordance with information in Section 4.2 so that the accuracy of measurement can be ensured all the time.

The general monitoring principles are based on:

- Frequency of monitoring
- Minimizing uncertainties and increasing reliability of performance of the project by an emergency preparedness plan
- Reporting and archiving the data used in monitoring and accounting for the emission reduction from the Project
- QA/QC

#### Frequency of monitoring

The project developer has installed all metering facilities within the plant premises. The measurements are monitored as per the frequency described in above sections, and the values of the parameters are recorded in the automatic reports generated by the PLC (only for parameters: Steam flow, Steam pressure and temperature at boiler, feed water temperature) and in log books. The monitored values will be transferred to the excel spreadsheet on monthly basis to prepare monthly reports. These monthly reports are used by the VCS Coordinator to calculate the reduction in GHG emissions and to generate monthly reports that form a necessary component of the Management Information System.

The VCS Coordinator will be responsible for

- Monitoring the project on a day to day basis,
- Co-coordinating with the Sr. Manager/Manager- projects and other internal and external agencies/authorities for the purpose of smooth operation of the project and accrual of emission reduction.

### **Emergency preparedness plan**

The amount of emission reduction units is proportional to the steam generation using the biomass residues in the Project. Measurement devices having good accuracy and procured from reputed manufacturers have been installed at site for the purpose of monitoring the various parameters of the project. Since the reliability of the monitoring system is governed by the accuracy of the measurement system and the quality of the equipment for reproducibility, all instruments will be calibrated as per the planned frequency for ensuring reliability of the system.

In the event that a particular instrument malfunctions or breaks down, all efforts will be made to restore or replace that instrument within short span of time of such eventuality. The data used in calculating the emission reduction for that particular parameter will be taken as zero from the last recorded reading.

This will ensure that the uncertainties in the parameters used for calculating the emission reductions from the project are consistent, verifiable and reliable, and any uncertainty is minimal.

### **Reporting and archiving**

General Guidelines to SSC CDM Methodologies, Ver 17 Para 17 states that: Monitoring: The monitoring requirements are maintained in line with SSC methodology AMS I.C and comply with requirements of electronic archiving for two years from end of crediting period; continuous monitoring of thermal energy generated; use of measuring equipments certified by national standards and calibration as per.

Verification is done on the basis of monthly reports that are prepared by the concerned sections covering all the monitoring parameters.

The VCS coordinator will be responsible for

- Collection and updating of all data in the project monitoring worksheet,
- Generation and distribution of monthly reports to the Management accounting for the actual emission reduction achieved during the month,
- Any specific event affecting emission reduction due to the project during the month
- Reporting data on monthly basis for the calculation and estimation of emission reductions.

This data will be checked against initial estimates. If the project is not performing as expected or if there are any negative impacts on the volume of emission reductions obtained, on the basis of the monthly data being monitored, analysis will be carried out to identify where the project is deviating in its generation of emission reductions and the immediate measures will be taken to maintain the expected generation of emission reductions from the operation of this project.

All data will be kept for a minimum of 2 years following last issuance of VCUs or the end of the crediting period, whichever is later, and the storage of this data will be the responsibility of the project proponents.

### **QA/QC procedures**

The quality assurance and quality control over the data monitored will be done by the manager as follows:

- The monitored data will be verified for the completeness and consistency.
- It will be ensured that the plant personnel receive adequate training

- It will be ensured that the equipments in the project activity undergo periodic maintenance as recommended by the manufacturer.
- It will be ensured that the monitoring instruments are calibrated as per the frequency specified in the B.7.1.
- It will be ensured that there is an adequate storage of the data monitored.

Any non-conformance will be identified and a corrective action will be taken.

## 5 ENVIRONMENTAL IMPACT

The project uses in house generated biomass and produces renewable energy. The biomass residue is carbon neutral and meets all environmental regulations. As per the Ministry of Environment & Forests, Government of India EIA notification 2006, the project activity does not fall in any of the two categories specified in the guidelines for conduction an EIA under Para 4. Moreover, as the biomass will be used for energy generation with efficient combustion, there are no significant environmental impacts of the project activity.

There are no significant environmental impacts assessed by the project participants and no trans-boundary effect is envisaged. This is in accordance with the local and country level pollution regulations as evident from the exclusion from need to conduct EIA.

## 6 STAKEHOLDER COMMENTS

The project is implemented in a Greenfield palm oil processing industrial facility. Thus it does not have any direct impact on neighbouring population. Still a survey of feedback from stakeholders was taken using feedback forms in English and local language (as per requirement of the particular stakeholder). The employees working in plant, nearby villagers were identified as important stakeholders. The survey forms were distributed in March 2014 and responses were received during March and April 2014.

All the comments by the stakeholders were given in a positive response.

The responses by the stakeholders against each question are presented in the table below. In the table, the responses are compiled under the title “positive response” or “negative response”.

Question	Response (Positive/Negative)
Is your environment negatively affected by the project?	Positive – 100%
Is there any environmental / social problem due to biomass collection and transport to project site?	Positive – 100%
Does the project have any negative impact on human health or biodiversity?	Positive – 100%
Has the employment increased due to the project?	Positive – 100%
Has your livelihood negatively affected by the project?	Positive – 100%
What are the benefits from the project?	Positive – 100%
Any other comments and suggestions	Eco-friendly, cost saving, environment friendly, employment generation

There were no comments that required any follow up actions from the PP.