



**CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-PDD)
Version 03 - in effect as of: 28 July 2006**

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**SECTION A. General description of project activity.****A.1 Title of the project activity:**

>> “Grid connected electricity generation using natural gas by Lanco Kondapalli Power Private Limited.”

Version 04

Dated: 02/01/2012

A.2. Description of the project activity:**Purpose of the project activity**

The scope of the project activity involves implementation and operation of a new natural gas fired grid-connected Combined Cycle Power Plant (CCPP) of 366 MW capacity at Kondapalli near Vijayawada, Andhra Pradesh by Lanco Kondapalli Power Private Limited (LKPPL).

The proposed CCPP will operate on Brayton Cycle (Compressor & Gas Turbine) at top and Rankine Cycle (Heat Recovery Steam Generator & Steam Turbine) at bottom. The power generated from the project activity will be sold on merchant basis to the state utilities in Southern, Western & Northern India. The project employs state of the art technology with estimated project life of 20 years.

The project will comprise of the following major equipments:

- One advanced class, heavy duty, Gas turbine generator with a nominal output of about 234 MW at site condition and with Gas turbine Inlet air-cooling system under operation.
- One Heat Recovery, natural circulation, three pressure vertical type Steam Generator.
- One Steam Turbine Generator of around 132 MW (@ 30 deg C, 60% RH), multistage, intermediate injection, condensing, type.

The project activity is designed to use natural gas as main fuel for power generation. Natural gas will be sourced from the Krishna Godavari basin of Reliance Industries Limited (RIL). Gas Supply & Transportation Agreements have been executed with Reliance Industries Limited and Reliance Gas Transportation Infrastructure Limited, respectively, in this regard.

The power generated would be stepped up to 400 kV level by using 15/420 kV generator transformers. To enable the process a 400 kV Gas Insulated Switchgear (GIS) type substation will be provided. A double circuit 400 kV transmission line has been proposed to export power to 400 kV receiving end substation of the Power Grid Corporation of India Limited (PGCIL) located at Nunna.

The pre project scenario

The project activity is a new grid connected power plant. Hence the pre-project scenario will include generation of power from existing or proposed new power plants connected to the Southern regional grid. Alternatives to the project activity include power generation based on domestic coal, imported coal; lignite; natural gas, naphtha, nuclear energy; renewable sources of energy (like wind, hydro). The other alternatives included capacity additions to existing power plants in the region or establishing new inter-connections with the other regional grid. All these alternatives have been discussed in detail in section B.4 of the PDD.

Baseline Scenario

In accordance with the approved baseline methodology AM0029, version – 03 (based on approach 48b of the CDM modalities and procedures) baseline has been established considering “emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment”. In line with this approach a detailed investment comparison analysis has been carried out in



section B.4 of this document considering the levelised cost of generation as the most suitable financial indicator.

In the present context it has been established that coal based power station using subcritical technology would be the economically most attractive alternative to the project activity and hence the most plausible baseline scenario. The details on technology, efficiency, operating lifetime for various fuel/ technology options have been discussed in detail in Section B.4.

Reduction of greenhouse gas emissions

The project activity involves power generation from the grid connected (Southern Regional Grid) gas based Combined Cycle Power Plant (CCPP). The technology employed in the project activity has been discussed in section A.4.3 of this document

The carbon intensity of the present project activity would be lower than the southern regional grid (as per Build Margin & Combined Margin) or the coal based power station using sub-critical technology identified as the most plausible baseline option. Hence the project activity reduces CO₂ emission by way of avoiding power generation from relatively higher carbon intensive sources.

The approved baseline methodology AM0029, version – 03 recommends the lowest emission factor amongst the following three options to be considered for ascertaining the emission reductions due to the project activity:

Option 1 The build margin, calculated according to “Tool to calculate emission factor for an electricity system”; and

Option 2 The combined margin, calculated according to “Tool to calculate emission factor for an electricity system”, using a 50/50 OM/BM weight;

Option 3 The emission factor of the technology (and fuel) identified as the most likely baseline scenario under “Identification of the baseline scenario”

In the context of the present project activity the option 1 has been found to be the most conservative. Hence the build margin emission factor has been considered towards determining the emission reduction due to the present project activity. It has been discussed in detail in section B.6.1 of this document.

The description of the sources of greenhouse gases included in or excluded from the project boundary has been discussed in section B.3 of this document.

Views of the project participant on contribution of the project activity to sustainable development

The contribution of this project activity towards sustainable development as per the four indicators prescribed by The National CDM Authority (“NCDMA”) in India i.e., Ministry of Environment and Forests (“MoEF”) is presented below.

Social well being:

- The project activity has generated employment for the local population during the construction as well as operational phases of the project activity, both direct and indirect.
- It has also provided an opportunity for secondary small scale entrepreneurs’ development near the project site, such as small shops, etc. Overall, there has been employment creation as a result of the project activity.

Economic well being:

- By creating employment in the area, as described above, the project activity has brought in economic improvement for the local population.
- If the project activity is registered as a CDM project, then by way of generating Certified Emission Reductions (“CERs”) and through transaction of such CERs with Annex I Parties, the project activity would bring in additional revenue to India.

**Environmental well being:**

- The project activity avoids use of any other fossil fuels such as coal, lignite, naphtha, diesel, etc., and thus reduces emissions of GHGs, oxides of sulphur and nitrogen, particulate matters and unburned carbon, fly ash (in case of coal and lignite), etc.

Technological well being:

- The project activity is a natural gas based combined cycle power plant and would result in improved power generation efficiency as compared to an open cycle CCGT or coal or lignite based thermal power plant of similar capacity.

The project proponent will contribute 2% of the revenue realized from sale of certified emission reduction arising from the candidate CDM project towards sustainable development including initiatives towards society / community development.

LKPPL is aware about the DNA guideline and a formal undertaking is being submitted separately.

A.3. Project participants:

Name of Party involved ((host) indicates a host Party)	Private and/or public entity(ies) project participants (as applicable)	Kind indicate if the Party involved wishes to be considered as project participant (Yes/No)
India (host)	Private Entity: Lanco Kondapalli Power Private Limited.	No

A.4. Technical description of the project activity:**A.4.1. Location of the project activity:**

>> Village – Kondapalli, District – Krishna, Andhra Pradesh, India

A.4.1.1. Host Party (ies):

>> India

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

>> Andhra Pradesh

A.4.1.3. City/Town/Community etc:

>> Village – Kondapalli, District – Krishna

A.4.1.4. Detail of physical location, including information allowing the unique identification of this project activity (maximum one page):

>>The proposed project activity will be located at Kondapalli Industrial Development Area in Andhra Pradesh. The project activity will be located in a plot of area 132 acres. Kondapalli railway station is approximately 1km from the site and the nearest Airport is at Gannavaram at about 35 kms from the plant. The proposed project site is at a latitude of 16°38'30.10" N and at a longitude of 80°33'05.33" E.

The location details are presented in **Appendix 1** of this document.

A.4.2. Category (ies) of project activity:

>> As per the scope of the project activity listed in the "List of Sectoral scopes" (Document CDM-ACCR-06 version 04)', the project activity will principally fall in Scope Number 1, Sectoral scope –



energy industries (renewable/ non-renewable sources) being a Grid-connected electricity generating project using non-renewable fuel in energy industries.

A.4.3. Technology to be employed by the project activity:

>> The project activity construction and operation of a new natural gas fired grid-connected electricity generation plant.

Pre-project scenario:

Since the project activity is a new grid connected (Southern Region) power plant, the pre-project scenario includes generation of power from existing or proposed new power plants connected to the Southern regional grid or import of electricity from connected grids, including the possibility of new interconnections.

Project activity:

The scope of the project activity involves implementation and operation of a new natural gas fired grid-connected Combined Cycle Power Plant (CCPP). The project proposes to employ state of the art technology with estimated project life of 20 years . There is no technology transfer in this project activity. The table below provides the details of main equipment of the power plant:

S.No	Equipment	Specifications	Special Features
1.	GTG	Make : GE, USA GTG is of advanced class industrial heavy-duty type (Model 9FA) with dry low NO _x technology capable of operating in combined cycle mode, Nominal output capacity: 234 MW at site conditions (Dry Bulb Temperature - 32 deg. C; Design Wet Bulb Temperature - 25 deg. C; Relative Humidity (RH) = 70%)	Low NO _x technology along with state of the art cooling. Thermal efficiency close to 53 - 58% (LHV)
2.	STG	Make: Harbin, China One steam turbine generator of output capacity 132 MW at site condition (Dry Bulb Temperature - 32 deg. C; Design Wet Bulb Temperature - 25 deg. C; Relative Humidity (RH) = 70%)	• Multistage, intermediate injection, condensing type steam turbine. • State of the art DCS control system
3.	HRSG	Make: : Thermax , India Capacity: : HP/IP/LP Flow 282.79/ 42/34.26 TPH; temperature 567.3/567/286.6 DegC ; pressure 98.47/22.4/3.1 Bar	• Horizontal flue gas flow and natural circulation. • HRSGs are designed with three pressure stages to improve thermal efficiency, against conventional two pressure stages for similar application. • State of the art DCS control system.

In addition to the main plant equipment, auxiliary cooling water system, condenser cooling water system, electrical systems, evacuation of power, etc., are also parts of the power project. Also included are features for addressing environmental aspects and safety in operation and maintenance of the power project.

The power generated would be stepped up to 400 kV level by using 15/420 kV generator transformers. As to enable the process a 400 kV Gas Insulated Switchgear (GIS) type substation will



be provided. A double circuit 400 kV transmission line has been proposed to export power to 400 kV receiving end substation of the Power Grid Corporation of India Limited (PGCIL) located at Nunna.

The necessary transmission lines for this purpose will be installed by LKPPL. The GTG is connected to the bus in the switchyard through a generator transformer that steps up voltage from 15 kV to 400 kV, provided with off load tap changers on the high voltage side. The STG is connected to the switchyard through a generator transformer that steps up voltage of 13.8 kV to 420 kV.

The project activity is designed to use natural gas as fuel for power generation. NG used as fuel for the project in future may be a combination of NG and Regasified- Liquid Natural Gas (“**R-LNG**”). Natural gas will be sourced from the Krishna Godavari basin of Reliance Industries Limited (RIL) through pipe line up to the project site. Gas Supply Agreement (GSA) & Gas Transportation Agreement (GTA) have been executed with RIL¹ & Reliance Gas Transportation Infrastructure Limited (RGTEL)² respectively in this regard.

The duration of the GSA as entered with RIL is spanned over a period of almost five years (i.e. 29th August, 2009 to 31st March, 2014) with a provision to renew the same for further periods. The thermal quantity of gas contracted is 46929 MMBTU per day (Firm basis) and 5071 MMBTU per day (Fall back basis). The GTA with RGTEL has been made effective from 23rd September, 2009 and is valid for a period of 15 years. A minimum gas pressure of 98 bar (a) at RIL terminal point will have to be maintained and the gas conditioned to meet the requirement of gas turbine fuel specification. The total gas requirement of the project activity has been estimated to be around 1.52 MMSCMD³. The above requirement is based on 8553⁴ kcal/SCM as net calorific value of gas and heat rate of 1850⁵ kCal / kWh rate at generator terminal.

The green house gases emitted from project activity would include CO₂ emissions due to on-site fuel combustion; CO₂ and CH₄ emissions due to Transportation of fuel to project site (inside the project boundary). The CO₂ emissions due to Processing and transportation of fuel outside the project boundary are being accounted for as leakage emissions.

Baseline scenario:

Since the project activity is a new grid connected (Southern Region) power plant, the baseline scenario will include generation of power from existing or proposed new power plants connected to the southern regional grid or import of electricity from connected grids, including the possibility of new interconnections.

The applied baseline methodology AM0029 version 03 is based on the approach 48 (b) of CDM modalities and procedures “*Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment*” for determining the baseline scenario. Based on this, all the plausible baseline scenarios (as enlisted above) were evaluated based on investment comparison analysis using levelized cost of generation as a parameter for identifying the “economically most attractive baseline scenario alternative”. In case of the subject project activity, a power plant (s) based on coal using sub-critical technology has been established as the economically the most attractive option

¹ All the required evidences have been submitted to the DOE during validation.

² All the required evidences have been submitted to the DOE during validation.

³ This is equivalent to 51585 MMBTU per day considering net calorific value of natural gas as 8553.6 kCal / SCM and 1MMMBTU = 252000 kCal

⁴ Reference: Detailed Project Report

⁵ Reference: Detailed Project Report



The details on technology, efficiency, operating lifetime for various fuel/ technology options have been discussed in detail in Section B.4.

The green house gases in the baseline scenario (coal based power plant using sub-critical technology) would emit higher CO₂.

A.4.4 Estimated amount of emission reductions over the chosen crediting period:

>> The estimated emission reductions over the 10 year fixed crediting period (2010-2020) would be 8,301,330 tCO_{2e} as per details on annual emission reductions provided below.

Years	Annual estimation of emission reduction (tCO_{2e})
2010 –2011	830,133
2011 –2012	830,133
2012 –2013	830,133
2013 –2014	830,133
2014 –2015	830,133
2015 –2016	830,133
2016 –2017	830,133
2017 –2018	830,133
2018 –2019	830,133
2019 –2020	830,133
Total estimated reductions (tCO_{2e})	8,301,330
Total number of crediting years	10
Annual average over the crediting period of estimated reductions (tCO_{2e})	830,133

A.4.5. Public funding of the project activity:

>> There is no ODA involved in development of the proposed CDM project activity.

SECTION B. Application of a baseline and monitoring methodology

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

>> Approved baseline methodology AM0029 (version 03.0 EB39) has been used to determine the baseline emissions and emission reduction due to the project activity. The title of this baseline methodology is “**Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas**”⁶.

The project activity also refers to the “Tools to calculate the emission factor for an electricity system” (Version 02.2.1, EB 63 ; Annex-19)⁷.

The project activity also refers to the “Tool for the demonstration and assessment of additionality” (Version 6 , EB 65, Annex 21)⁸.

⁶

http://cdm.unfccc.int/filestorage/C/D/M/CDMWF_AM_15YH7UTNQ40J8MGMVX62CGNE0K49Y0/EB39_repan03_AM0029_ver03.pdf?t=S0V8bHQ1c3dlfDBKDOHnvoncpW_arK9G_FB9

⁷ <http://cdm.unfccc.int/methodologies/PAMethodologies/tools/am-tool-07-v2.2.1.pdf>

⁸ http://cdm.unfccc.int/methodologies/PAMethodologies/tools/am-tool-01-v6.0.0.pdf/history_view

**B.2 Justification of the choice of the methodology and why it is applicable to the project activity:**

>> The selected methodology AM0029 version 3.0 is applicable to the proposed CDM project activity. The justification for the various applicability conditions of AM0029 has been presented below.

The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant.⁹

The project activity involves construction and operation of a new natural gas fired grid-connected electricity generation plant, of 366 MW capacity. The only fuel used is natural gas and no auxiliary fuels are used.

The geographical/ physical boundaries of the baseline grid can be clearly identified and information pertaining to the grid and estimating baseline emissions is publicly available.

The baseline grid is southern¹⁰ regional electricity grid, whose geographical/ physical boundaries can be clearly identified and information pertaining to the grid and estimating baseline emissions is available in public domain on the website of the Central Electric Authority of India <http://cea.nic.in>.

Natural gas is sufficiently available in the region or country, e.g. future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity. In some situations, there could be price-inelastic supply constraints (e.g. limited resources without possibility of expansion during the crediting period) that could mean that a project activity displaces natural gas that would otherwise be used elsewhere in an economy, thus leading to possible leakage. Hence, it is important for the project proponent to document that supply limitations will not result in significant leakage as indicated here.

Production of natural gas in India is at present at the level of around 87 million standard cubic meters per day¹¹ (“MMSCMD”). The main producers of natural gas are Oil & Natural Gas Corporation Ltd. (“ONGC”), Oil India Limited (“OIL”) and JVs of Tapti, Panna-Mukta and Ravva¹². Out of the total production of around 87 MMSCMD, after internal consumption, extraction of Liquefied Petroleum Gas (“LPG”) and unavoidable flaring, around 74 MMSCMD¹³ is available for sale to various consumers.

Under the Production Sharing Contracts, private parties from some of the fields are also producing gas. Government have also offered blocks under New Exploration Licensing Policy (“NELP”) to private and public sector companies with the right to market gas at market determined prices¹⁴.

Most of the production of gas comes from the Western offshore area. The on-shore fields in Assam, Andhra Pradesh and Gujarat States are other major producers of gas. Smaller quantities of gas are also produced in Tripura, Tamil Nadu and Rajasthan States. OIL is operating in Assam and Rajasthan States, whereas ONGC is operating in the Western offshore fields and in other states. The gas produced by ONGC and a part of gas produced by the JV consortiums is marketed by the Gas Authority of India Ltd (“GAIL”). The gas produced by OIL is marketed by OIL itself except in Rajasthan where GAIL is marketing its gas. Gas produced by Cairn Energy from Lakshmi fields and

⁹ Natural gas should be the primary fuel. Small amounts of other startup or auxiliary fuels can be used, but can comprise no more than 1% of total fuel use, on energy basis

¹⁰ Southern regional grid is used as the default grid in pursuance with the CDM EB recommendations on grid selection.

¹¹ <http://petroleum.nic.in/ng.htm>

¹² <http://petroleum.nic.in/ng.htm>

¹³ <http://petroleum.nic.in/ng.htm>

¹⁴ <http://petroleum.nic.in/ng.htm>



Gujarat State Petroleum Corporation Ltd. (“GSPCL”) from Hazira fields is being sold directly by them at market determined prices.

There have been discoveries in Krishna-Godavari (KG) basin¹⁵ by – Reliance Industries Limited (“RIL”) way back in 2002. RIL expected to produce @ 80 MMSCMD¹⁶ (i.e. 29.2 Billion Cubic Meter per year) with effect from 2009. RIL has also been constructing a cross country natural gas pipeline connecting eastern coast of India in Andhra Pradesh and Bharuch in Gujarat on western coast of India. State-owned Gujarat State Petroleum Corporation Limited (“GSPCL”) has also struck gas in the Krishna Godavari basin, off Andhra Pradesh coast in the Bay of Bengal. This additional indigenous gas can be brought to Gujarat through the pipeline.

LNG Re-gasification terminals:

The installed terminals include– Dahej (5 Million Metric Tonnes Per Annum (“MMTPA”) equivalent to 7142.85 Million Standard Cubic Meter (MSCM) / Year), Hazira (2.5 MMTPA equivalent to 3571.4 MSCM/Year) on west coast.

Under implementation: Dabhol (RGPPL) (2.5 MMTPA equivalent to 3571.4 MSCM/Year), Dahej Expansion (5 Million Metric Tonnes Per Annum (“MMTPA”) equivalent to 7142.85 Million Standard Cubic Meter (MSCM) / Year), Kochi (2.5 MMTPA equivalent to 3571.4 MSCM/Year).

Proposed LNG Regas – Dahej Expansion (5 MMTPA), Mangalore (5 MMTPA equivalent to 3571.4 MSCM/Year), Ennore (2.5 MMTPA equivalent to 3571.4 MSCM/Year).

Amongst all the NG/RLNG supply sources discussed above the likely future supply sources in the Southern region are as follows:

Supply Source (Southern Region)	Units (MMTPA/Year)	Units (MSCM/Year)
Reliance Industries Limited (RIL) – domestic natural gas. (East – West gas distribution network)	-	29200
Dahej Expansion – imported re-gasified LNG ¹⁷ . (East – West gas distribution network)	5	7142.85
Dhabol – imported re-gasified LNG ¹⁸ (East – West gas distribution network)	2.5	3571.429
Total	-	39914.29

For understanding the natural gas requirement of the future gas based power station in the Southern region, the table below gives a list of gas based power stations included in the 11th five year plan (2007 - 2012)¹⁹ in the Southern Region and associated natural gas requirement therein. This estimation is based on a normative station heat rate of 1950 kCal /kWh²⁰ and at PLF of 80%²¹.

¹⁵ <http://www.financialexpress.com/news/reliance-ippes-under-bses-may-use-krishnagodavari-gas/68427/>

¹⁶ <http://www.business-standard.com/india/news/more-d-6-gas-may-dryspot-lng-in-months/361130/>

¹⁷ <http://www.petronetlng.com/> ; <http://www.petronetlng.com/news1/detailedratingrationalefinal.pdf> (company profile page 3 of 11)

¹⁸ <http://www.rgppl.com/project.html>

¹⁹ <http://www.cea.nic.in/>

²⁰ CERC tariff order dated 26th March, 2004

²¹ Detailed Project Report of the project activity



Sl.No	Station	Capacity (MW)	Power generation (Million units/Year)	Gas requirement (Million SCM/Year)
1.	Gautami - CCPP ; Andhra Pradesh ²²	Gas Turbine – 290 Steam Turbine – 174	3251.71	667.18
2.	Koenseema CCPP ; Andhra Pradesh ²³	Gas Turbine 1 – 140 Gas Turbine 2 – 140 Steam Turbine – 165	3119	640
3.	Lanco Kondapalli - CCPP - Stage - II ; (Project Activity) Andhra Pradesh	Gas Turbine – 233 Steam Turbine – 133	2565	554.79 (assumed SHR 1850 kCal / kWh)
4.	Valuthur - GTPP; Phase II; Tamil Nadu ²⁴	Gas Turbine – 59.8 Steam Turbine – 32.4	646	133
Total			9581	1994

Natural gas requirement by gas based power station in the Southern region including the project activity is 1994 million SCM per year against an availability of 39914.29 million SCM per year. It is apparent from the statistics presented above that the future gas supply in the Southern region would be adequate for meeting the fuel requirement of the gas based power stations as included in the 11th five year plan of Government of India. This data further substantiates that natural gas is sufficiently available in the region and future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity.

From the above discussion, it is apparent that the project activity satisfies all the applicability conditions of AM0029, version - 03.

B.3. Description of the sources and gases included in the project boundary.

>> The spatial extent of the project boundary includes the equipment that constitute the 366 MW CCPP at Kondapalli site of LKPPL as listed below and all power plants connected physically to the baseline grid as defined in “Tool to calculate the emission factor for an electricity system”.

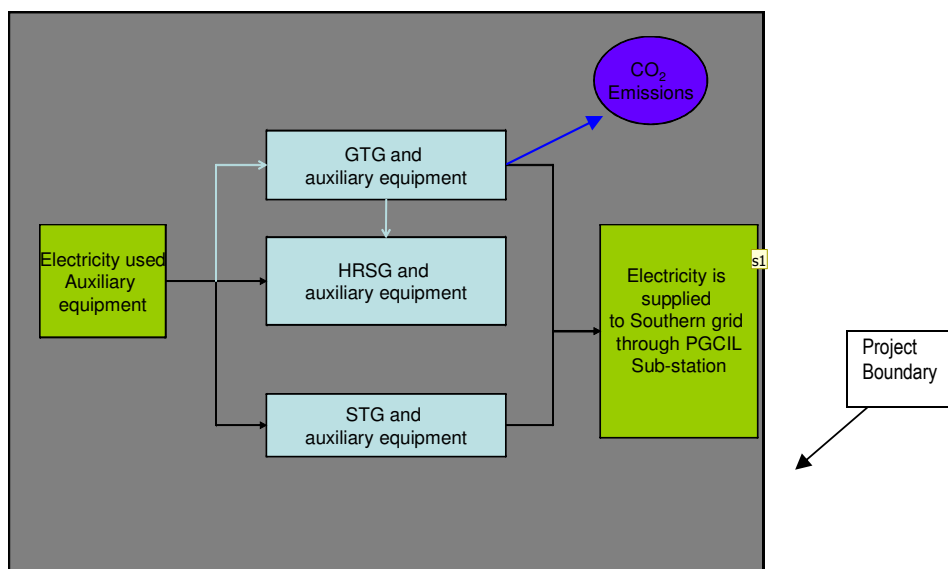
The equipments that form part of the project boundary are:

1. Gas Turbine Generator – 234 MW capacity
2. Steam Turbine Generator – 132 MW
3. GT/ST Generator & Unit aux. transformers – 290 MVA/190 MVA, 20 MVA.
4. Auxiliary equipments of Gas Turbine & Generator – Lube oil system, Air intake system, Evaporative cooling system, Exhaust system, Heat Recovery Steam Generator - Circulation Pumps, valves, HP/LP Bypass system, Piping etc.
5. Auxiliary equipments of Steam Turbine & Generator – Hydraulic and lube oil system, condenser, Feed Pumps, Condensate extraction pumps,

²²http://www.cea.nic.in/thermal/project_monitoring/BS%20AP.pdf

²³ http://www.cea.nic.in/thermal/project_monitoring/BS%20AP.pdf

²⁴ http://www.cea.nic.in/thermal/project_monitoring/BS%20TN.pdf



In the calculation of project emissions, only CO₂ emissions from fossil fuel combustion at the project plant are considered. In the calculation of baseline emissions, only CO₂ emissions from fossil fuel combustion in power plant(s) in the baseline are considered.

The greenhouse gases included in or excluded from the project boundary are shown in the table below:

Table 1: Overview of emissions sources included in or excluded from the project boundary

	Source	Gas	Included?	Justification / Explanation
Baseline	Power generation using coal/lignite/naphtha as fuel	CO ₂	Yes	Main emission source.
		CH ₄	No	Excluded (conservative approach).
		N ₂ O	No	Excluded (conservative approach).
	Grid electricity generation in baseline	CO ₂	Yes	Main emission source.
		CH ₄	No	Excluded (conservative approach).
		N ₂ O	No	Excluded (conservative approach).
Project Activity	On-site fuel combustion due to the project activity	CO ₂	Yes	Main emission source.
		CH ₄	No	Excluded for simplification.
		N ₂ O	No	Excluded for simplification.

B.4. Description of how the baseline scenario is identified and description of the identified baseline scenario:

>> As required under AM0029, version - 03 the approach 48 (b) of CDM modalities and procedures “Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment” is being used to determine the baseline scenario.

The plausible baseline scenarios, as required using Step 1 of “Identification of baseline scenarios” of the applied baseline methodology AM0029, are described below. In the absence of the project activity, one or more of the following could happen:

1. Establishing similar new generation capacity following the recent fuel and technology choice trend in power generation in India, including addition of plants running on coal – sub critical technology; coal – super critical technology (domestic & imported fuel); lignite; naphtha;



2. Establishing similar new generation capacity power plant based on natural gas but with alternative technologies;
3. Establishing similar new generation capacity power plant based on nuclear energy;
4. Establishing similar new generation capacity with renewable energy sources e.g., wind, hydro based power generation in India;
5. Capacity additions to a number of existing power plants aggregating to the capacity of the project activity; and
6. Import of electricity from connected grids, including the possibility of new interconnections.

An important fact to note here is that the project activity power plant will be built as a Merchant Power Plant (MPP). It is connected to the Southern regional electricity grid. On analysing the installed capacities connected to the southern grid as on 30th September, 2007, the pattern for fuel distribution²⁵ emerges as follows:

Power Generating Source	Hydro	Coal	Gas	Diesel	Total thermal	Nuclear	RES	Total
Total Installed Capacity (MW)	10646.18	15972.5	3586.3	939.32	20498.12	1100	5899.33	38143.63
Contribution to the total installed capacity (%)	27.91	41.87	9.40	2.46	53.74	2.88	15.47	100.00

It is apparent from the table above that the thermal generating sources are quite predominant in the Southern regional grid as against the other sources of power generation. The thermal generating sources are mainly based on coal followed by gas and diesel.

In line with the statistics discussed above the potential baseline alternatives available to the present project activity is summarised in the table below

Scenario	Potential alternative conditions	Permitted by regulations
1.	Project activity implemented as a project without the CDM revenue	Yes
2.	Power generation using Natural Gas as fuel and open cycle technology.	Yes
3.	New power plant (s) based on coal – sub-critical technology	Yes
4.	New power plant (s) based on coal (Imported fuel)– super-critical technology	Yes
5.	New power plant (s) based on coal (Domestic fuel)– super-critical technology	Yes
6.	New power plant (s) based on lignite	Yes
7.	New power plant (s) based on naphtha	Yes
8.	New power plant (s) based on hydro power (run-of-river ²⁶)	Yes
9.	New power plant (s) based on wind energy	Yes
10.	Import of electricity from connected grids, including the possibility of new interconnections	Yes

All the above options are permitted by regulations. Analysis of all these options for their suitability as a most probable baseline scenario is presented in the sections below. For all the plausible options,

²⁵ http://www.cea.nic.in/archives/exec_summary/sep07.pdf

²⁶ Storage, reservoir type hydro has been excluded since it deliver peak in power rather than base load power



levelized cost of electricity generation has been calculated in INR/kWh. The detailed levelized tariff calculations of all fuel/ technology options will be made available to the DOE during validation.

In this regard please note that new power plant based upon nuclear power has not been listed in the table above. The most recent capacity additions of nuclear power plants in the country are as follows:

S.No	Power Station Name	Promoter	Capacity (MW)	Date of Commissioning
1.	Kaiga Generating station –III	Nuclear Power Corp. Ltd.	220	6 May 2007
2.	Tarapur Atomic Power Station 3	Nuclear Power Corp. Ltd.	540.00	18 August 2006
3.	Tarapur Atomic Power Station 3	Nuclear Power Corp. Ltd.	540.00	12 September 2005

In this regard please refer to The Atomic Energy Act, 1962. The relevant section (Clause 3a)²⁷ of the Act specifies that Central Government shall have the power to produce, develop, use and dispose of atomic energy either by itself or through any authority or Corporation established by it or a Government company and carry out research into any matters connected therewith. In pursuance to Atomic Energy Act, 1962, Nuclear Power Corporation of India Limited (NPCIL) was established for implementation and operation of nuclear power station in India²⁸. NPCIL is a public sector enterprise under the administrative control of the Department of Atomic Energy (DAE), Government of India²⁹. Hence it is evident that nuclear power plant in India does not fall under the purview of CERC/ SERCs and the tariff is unilaterally decided by Nuclear Power Corp. Ltd. This option is not available to a private investor and hence has been excluded as a baseline option.

Scenario 1: Power generation using natural gas as fuel and combined cycle technology without CDM revenues

Technology: Gas turbine plants operate on the Brayton cycle. They use a compressor to compress the inlet air upstream of a combustion chamber. Then the fuel normally Natural Gas / Liquefied Natural Gas is introduced and ignited to produce a high temperature, high-pressure gas that enters and expands through the turbine section. The turbine section powers both the generator and compressor. Gas turbines are also able to burn a wide range of liquid and gaseous fuels. The turbine's energy conversion efficiency typically remains low (@ 25-35 %) when utilised as an Open (simple) cycle. The simple cycle efficiency can be increased by installing a waste heat recovery boiler onto the turbine's exhaust. A waste heat boiler generates steam by capturing heat from the turbine exhaust. These boilers are known as heat recovery steam generators (HRSG). They can provide steam at high pressure and temperature which can be used to generate power with steam turbines (Rankine Cycle), which is called a combined cycle (Gas and steam turbine operation). Thus HRSG and STG increase the overall energy cycle efficiency to around 50 %³⁰).

Scenario 2: Power generation using Natural Gas as fuel and open cycle technology.

Technology: Gas turbine plants operate on the Brayton cycle. They use a compressor to compress the inlet air upstream of a combustion chamber. Then the fuel normally Natural Gas / Liquefied Natural

²⁷ <http://www.dae.gov.in/rules/aeact.htm>

²⁸ <http://www.npcil.nic.in/index.aspx>

²⁹ <http://www.npcil.nic.in/index.aspx>

³⁰

http://books.google.co.in/books?id=KJOoQm3fbEoC&pg=PT433&lpg=PT433&dq=efficiency+of+open+cycle+power+plant&source=web&ots=HRYT81RY0h&sig=yRBE5betwGqHsZ6RQVpirYZoQWQ&hl=en&sa=X&oi=book_result&resnum=6&ct=result



Gas is introduced and ignited to produce a high temperature, high-pressure gas that enters and expands through the turbine section. The turbine section powers both the generator and compressor. Gas turbines are also able to burn a wide range of liquid and gaseous fuels. The turbine's energy conversion efficiency typically remains low (@ 25-35³¹ %) when utilized as an Open (simple) cycle. This very low efficiency makes open cycle gas turbine based power generation as a non-plausible baseline option and thus this option has not been discussed any further in the PDD.

Scenario 3: Power generation using coal as fuel – sub critical technology

Technology: Fossil fuel-fired (coal) power plants use steam to provide the mechanical power to electrical generators. Pressurized high temperature steam or gas expands through various stages of a turbine, transferring energy to the rotating turbine blades. The turbine is mechanically coupled to a generator, which produces electricity. Steam turbine power plants operate on a Rankine cycle. The steam is generated by a boiler, where pure water passes through a series of tubes to capture heat from the furnace and then boils under high pressure to become superheated steam. The heat in the furnace is normally provided by burning fossil fuel (e.g. coal, fuel oil etc). The coal is fed to boiler after pulverization in the coal mills. The pulverized coal is transported to burners through primary air which is heated in Air Pre-heaters. The secondary air (preheated) is fed to boilers for complete combustion. The fuel firing normally takes place in the range of 1200-1300°C. The combustion chamber is enclosed by tubes termed as water wall tubes and these tubes form the gas tight chamber and water cooled furnace. The bottom ash is collected in the furnace bottom and fly ash carried along with the flue gases is collected in ESP hoppers and discharged to Ash areas. The superheated steam leaving the boiler then enters the steam turbine throttle, where it powers the turbine and connected generator to make electricity. After the steam expands through the turbine, it exits at the back end of the turbine, where it is cooled and condensed back to water in the surface condenser. This condensate is then returned to the boiler through high-pressure feed pumps for reuse. Heat from the condensing steam is normally rejected from the condenser to a body of water or cooling tower. The power plant efficiency is typically remains around 33 to 38%.

Scenario 4: Power generation using coal (imported & domestic) as fuel with super-critical technology

Technology: Super critical technology is almost similar to the sub critical technology explained in the Scenario 2 except that the super critical steam generators operate at "supercritical pressure". In contrast to a "sub-critical boiler", a supercritical steam generator operates at such a high pressure (over 3200 PSI, 22 MPa, 220 bar) that actual boiling ceases to occur, and the boiler has no water - steam separation. There is no generation of steam bubbles within the water, because the pressure is above the "critical pressure" at which steam bubbles can form. It passes below the critical point as it does work in the high pressure turbine and enters the generator's condenser. This is more efficient, resulting in slightly less fuel use and therefore less greenhouse gas production. The term "boiler" should not be used for a supercritical pressure steam generator, as no "boiling" actually occurs in this device. Differences between sub critical and super critical power plants are limited to a relatively small number of components; primarily the feed water pumps and the high-pressure feed water train equipment. All the remaining components are common to sub critical and super critical coal-fired power plants. Super critical technology also follows the same Rankine cycle. Steam generated from the generator will be allowed to expand in the Steam turbine and thus producing the work. The power plant cycle efficiency is in the range of 36 % to 43%. Since the efficiency of the super critical technology is better, the coal consumption and ash / pollution generated are also less compared with the sub critical technology. However the capital cost for the super critical technology is much higher.

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http://books.google.co.in/books?id=KJOoQm3fbEoC&pg=PT433&lpg=PT433&dq=efficiency+of+open+cycle+power+plant&source=web&ots=HRYT81RY0h&sig=yRBE5betwGqHsZ6ROVpjYZoOWQ&hl=en&sa=X&oi=book_result&resnum=6&ct=res ult

**Scenario 5: Power generation using lignite as fuel**

Technology: Fuel combustion in Circulating Fluid Bed system takes place in a vertical chamber referred to as the Combustor, in which the fluidisation of the fuel and the fuel combustion takes place. The fuel is preheated before entry and burnt at 850°C. The particle size of fuel used at bed is typically in the range of 50-300 microns. The bed material is fluidized by preheated primary air introduced through a grate at the bottom of the bed and by the combustion gases generated which flow upwards at a relatively high fluidizing velocity. The entire combustor contains a high concentration of suspended solids, which decrease continuously towards the top of combustor. The combustion gas entrains a considerable portion of the solids inventory from combustor. The bulk of these entrained solids is separated from the gas in the cyclone and is continuously returned to be bed by recycle loop. The very high internal and external circulating rates of solids, characteristics of the Circulating Fluid Bed, result in consistently uniform temperatures throughout the combustor and the solids recycle system. The long residence and contact times, coupled with the small particle sizes and efficient heat and mass transfer rates, produce high combustion efficiency. The relatively high ratio of solids circulation to fuel feed means that the Combustor is largely full of recycled solids and actual carbon content is surprising low. Further the large thermal inertia of the recycled solids allows the CFB system to handle high ash or high moisture fuels better than conventional combustion systems. Combustion of low volatile fuels like coke breeze in a CFB system is therefore more stable and of high efficiency. Combustion air is introduced into the combustor at multiple levels. About forty percent of the combustion air is passed as primary fluidizing air through the grate at the bottom and the balance is admitted as preheated secondary air through multiple ports in the side walls of the combustor. Combustion therefore occurs in two zones: a primary reducing zone in the lower section of the combustor, and complete combustion using excess air via the secondary air ports in the upper section. This staged combustion at controlled low temperatures of around 850°C, effectively suppresses NO_x formation. The entire combustor as well as the grate is enclosed by water walls and the lower water wall section is refractory lined to prevent corrosion and attack of the metal surfaces. The upper water wall section is not refractory lined and provides the majority of the evaporative duty of the boiler. The bottom ash discharged from the combustor is at 850°C and so it needs to be cooled in an ash cooler to approx. 200-250°C. The fly ash separated in the back pass and air pre heater and the fly ash from the ESPs are collected in the hoppers. The steam from the steam generator is fed to turbine for power generation and turbine and other systems are similar to that of conventional Thermal Power plant.

Scenario 6: Power generation using naphtha as fuel

Technology: The power generation technology using Naphtha as fuel is same as that of the project activity. Thus for comparison with project activity a naphtha based power plant of 366 MW has been considered. Naphtha fired gas turbine power plants operate on the Brayton cycle. They use a compressor to compress the inlet air upstream of a combustion chamber. Then the fuel, naphtha is introduced and ignited to produce a high temperature, high-pressure gas that enters and expands through the turbine section. The turbine section powers both the generator and compressor. The turbine's energy conversion efficiency typically remains low (@25-35 %³² when utilised as an Open (simple) cycle. The simple cycle efficiency can be increased by installing a waste heat recovery boiler onto the turbine's exhaust. A waste heat boiler generates steam by capturing heat form the turbine exhaust. These boilers are known as heat recovery steam generators ("HRSG"). They can provide steam at high pressure and temperature which can be used to generate power with steam turbines, which is called a combined cycle (steam and Gas turbine operation). Thus HRSG and STG increase the overall energy cycle efficiency to around 50%³³

³² <http://books.google.co.in/books?id=9YkqH5HgSgwC&dq=efficiency+of+open+cycle+power+plant&q=25-35%25#v=snippet&q=25-35%25&f=false> ; (Page no 105))

³³ <http://books.google.co.in/books?id=9YkqH5HgSgwC&dq=efficiency+of+open+cycle+power+plant&q=25-35%25#v=snippet&q=EFFICIENCY%2050%25&f=false> ; (Page no 105)

**Scenario 7: Power generation using hydro power**

Technology: In the last five years the following hydel energy based power plants have been added to the southern grid³⁴:

S.No.	Power Plant Name	Unit	State	Date of Addition	Capacity (MW)
1.	Srisaillam LBPH	3	Andhra Pradesh	29-Mar-02	150
2.	Srisaillam LBPH	4	Andhra Pradesh	30-Nov-02	150
3.	Srisaillam LBPH	5	Andhra Pradesh	28-Mar-02	150
4.	Srisaillam LBPH	6	Andhra Pradesh	04-Sep-03	150
Total – Andhra Pradesh					600
1.	Sharavathy Tail Race	4	Karnataka	30-Mar-02	60
2.	Jog	8	Karnataka	30-Oct-02	21.6
3.	Madhavamantri	1	Karnataka	31-Mar-03	1.5
4.	Madhavamantri	2	Karnataka	31-Mar-03	1.5
5.	Madhavamantri	3	Karnataka	31-Mar-03	1.5
6.	Almatti Dam	1	Karnataka	26-Mar-04	15
7.	Almatti Dam	2	Karnataka	4-Nov-04	55
8.	Almatti Dam	3	Karnataka	13-Jan-05	55
9.	Almatti Dam	4	Karnataka	26-Mar-05	55
10.	Almatti Dam	5	Karnataka	6-Jul-05	55
11.	Almatti Dam	6	Karnataka	10-Aug-05	55
Total – Karnataka					376.1
1.	Chembukadavu-II	1	Kerala	25-Jan-04	1.25
2.	Chembukadavu-II	2	Kerala	25-Jan-04	1.25
3.	Chembukadavu-II	3	Kerala	25-Jan-04	1.25
4.	Urumi	1	Kerala	25-Jan-04	1.25
5.	Urumi	2	Kerala	25-Jan-04	1.25
6.	Urumi	3	Kerala	25-Jan-04	1.25
Total – Kerala					7.5
1.	Pykara Alimate	1	Tamil Nadu	11-Aug-05	50
2.	Pykara Alimate	2	Tamil Nadu	11-Aug-05	50
3.	Pykara Alimate	3	Tamil Nadu	5-Sep-05	50
4.	Bhawani Kattalai Barrage	1	Tamil Nadu	1-Aug-06	15
5.	Bhawani Kattalai Barrage	2	Tamil Nadu	22-Sep-06	15
Total Tamil Nadu					180
Total Southern Region					1163.6

This data indicates that out of the entire capacity of 1163.6 MW of hydro power plant, 88% (1025 MW) has been with 50 MW plus size with storage hydro thereby catering to the peak-in load rather than base load of the grid.

On the contrary the project activity is a gas based MPP. Depending upon the requirement, the project activity power plant would provide steady supplies to the grid and also could be used to meet the grid demand during peak loads. This makes run-of-the-river hydro energy based power generation as a non-plausible baseline option.

Scenario 8: Power generation using wind energy

³⁴ <http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm>; baseline CO2 emission database, version - 04

The proposed project activity is a gas based MPP without any PPA being executed for power off-take. In absence of PPA as with traditional independent power projects, the project activity would compete for customers and absorb full market risks. Depending upon the requirement, the project activity power plant would provide steady supplies to the grid and also could be used to meet the grid demand during peak loads.

Wind power generation will not qualify as a source of "base-load firm power" because wind power projects are not subject to the dispatch rules as the coal or gas or hydro. This is also due to the fact that there is no scheduling and dispatching of wind power - the grid accepts wind power generation as and when the wind generators generate electricity. Moreover unlike present project activity wind power projects are always governed by long term PPA.

Thus, wind energy based power generation cannot be strictly compared with the proposed project activity in terms of the services that it delivers and hence has been excluded as a baseline option.

Scenario 9: Import of electricity from connected grids, including the possibility of new interconnections

The actual power supply position during the period April – September, 2007³⁵ is as follows

Regional Grid	Northern Region	Western Region	Southern Region	Eastern Region	North – Eastern Region
Power Requirement (Million Units)	112,411	111,517	91,242	37,868	4,421
Power Availability (Million Units)	104,707	97,960	89,252	36,645	3,911
Surplus / Deficit (-)	(-)7,704	(-)13,557	(-)1,990	(-)1,223	(-)510

It remains implied from the statistics furnished above that all the regional grids in the country are power deficit.

Import of electricity from the inter-regional grid is not a plausible option due to intermittent power availability and power deficit nature of the regional grid. Further, the import of power from grid is subjected to other transmission issues like availability of transmission corridor for long term etc. Hence this scenario is excluded from further consideration to determine the baseline alternative of the project activity

Given the grid data of last 3 years, all the regional grids are power deficit. It makes import of electricity from the interconnected grids not a plausible baseline option.

The above analysis of the 10 alternatives available to a company investing in power generation for supply of base load power to Southern regional grid in India leads to following alternatives:

Scenario 1: Power plant based on natural gas using CCPP technology without CDM revenue.

Scenario 2: Power plant based on coal using sub-critical technology

Scenario 3: Power plant based on coal (Imported fuel) with super-critical technology

Scenario 4: Power plant based on coal (Domestic fuel) with super-critical technology

Scenario 5: Power plant (s) based on lignite

Scenario 6: Power plant (s) based on naphtha

For these six alternatives, the economically most attractive option has been evaluated in Step-2 in the following section.

³⁵ http://www.cea.nic.in/power_sec_reports/Executive_Summary/2007_09/20.pdf



Step 2 “**Identify the economically most attractive baseline scenario alternative**” of AM0029, version - 03 requires:

“The economically most attractive baseline scenario alternative is identified using investment analysis. Calculate a suitable financial indicator for all alternatives remaining after Step 1. Include all relevant costs (including, for example, the investment cost, fuel costs and operation and maintenance costs), and revenues (including subsidies/fiscal incentives, ODA, etc. where applicable), and, as appropriate, non-market costs and benefits in the case of public investors.”

LKPPL has chosen levelized tariff i.e., levelized cost of generation as the financial indicator for identifying the economically most attractive baseline scenarios of the 5 plausible scenarios identified under step 1 above. Levelized tariff accounts for all relevant costs, revenues and benefits that are available to investors in power sector in the country.

Further, for all power generation projects in India, levelized cost of electricity generation is one way to perform comparisons among different technologies (alternatives) since it allows to quantify, the unitary cost of the electricity (the kWh) generated during the lifetime of all the alternatives being compared. The levelized cost of electricity being a mean value, allows the immediate comparison with the cost of other alternatives. It considers the total electrical energy that the power plant will produce in its lifetime and it is divided between the total cost generated by construction investment along with the interest rate and the cash flow during construction plus the operation and maintenance cost, etc (considering everything in present money worth). The consideration of all the affecting components in present money worth in calculation of levelized cost of generation provides a level ground for comparison and justifies its use as a suitable indicator. It is also important to note that for all power generation projects in India which are evaluated by Ministry of Power, Government of India, levelized cost of generation³⁶ is the evaluation criteria.

Levelized Tariff Analysis

For the scenarios 1,3,4,5 and 6 discussed earlier in this section, the levelized tariff has been calculated based on two major components namely fixed cost and variable cost. The fixed cost includes the following factors³⁷ as per the guidelines prescribed by Central Electricity Regulatory Commission (CERC)³⁸:

1. Return on Equity (ROE) at 14% as per CERC regulation
2. Debt: Equity ratio of 75:25.
3. Operation & Maintenance expenses: 2.8% of the capital cost (This is inclusive of employee cost, repairs and maintenance charges and administrative and general charges).
4. O&M escalation at 4%.
5. Depreciation inclusive opening gross fixed assets and average additions during the year at 3.6%
6. Interest on loan at 13 % as per the average of prevailing interest rate at the time of investment decision making³⁹.
7. Interest on working capital (WC): 11.50% as per the DPR

³⁶ http://powermin.nic.in/whats_new/competitive_guidelines.htm

³⁷ Reference: Tariff Order no L-7/25(5)/2003-CERC of Central Electricity Regulatory Commission dated 26 March 2004

³⁸ Central Electricity Regulatory Commission (Terms & Conditions of Tariff) Regulations, 2001 available on <http://cercind.gov.in>

³⁹ <http://www.rbi.org.in/scripts/WSSView.aspx?Id=11614>



8. Normative Plant Load Factor (PLF) at 80%
9. Discount factor of 10 % as per CERC order
10. Tax on income at 33.99% as per Income Tax Act
11. MAT rate for the first 10 years considering 80IA benefit at 11.33% as per Income Tax Act

The variable cost has been calculated based on the cost of the fuel.

Levelized tariff for gas: The levelized tariff comes out as **INR 2.6819 / kWh**. This has been calculated based on the following factors:

Capacity in MW	366	Aux. Consumption	3%
Rate of Depreciation	3.60%	GSHR (kcal/kWh)	1850
Per MW Cost (INR million)	32.46	Price of Fuel (INR/SCM)	7.86
Total Debt (INR million)	8910	NCV (kCal / SCM)	8,553
Total Equity (INR million)	2970	O&M Expenses (% of capital cost)	2.8%

Levelized tariff for coal with sub-critical technology:

The levelized tariff for power generation with coal comes out as **INR 2.1182/ kWh**. This has been calculated based on the following factors:

Capacity in MW	500	Aux. Consumption	7.5%
Rate of Depreciation	3.60%	GSHR (kcal/kWh)	2450
Per MW Cost (INR million)	40	Price of Fuel (Rs / kg)	1.2849
Total Debt (INR million)	15000	NCV (Kcal/kg) –	3946
Total Equity (INR million)	5000	O&M Expenses (lacs per MW/yr)	11.84

Levelized tariff for with super-critical technology using domestic coal:

The levelized tariff for power generation with coal on Super critical technology comes out as **INR 2.2707/ kWh**. This has been calculated based on the following factors:

Capacity in MW	660	Aux. Consumption	9.00%
Rate of Depreciation	3.60%	GSHR (kcal/kWh)	2186
Per MW Cost (INR million)	49.36	Price of Fuel (Rs / kg)	1.2849
Total Debt (INR million)	21780	NCV (Kcal/kg)	3946
Total Equity (INR million)	7260	O&M Expenses (lacs per MW/yr)	11.84

Levelized tariff for super-critical technology using imported coal:

The levelized tariff for power generation with coal on Super critical technology comes out as **INR 2.3283 / kWh**. This has been calculated based on the following factors:

Capacity in MW	660	Aux. Consumption	9.00%
Rate of Depreciation	3.60%	GSHR (kcal/kWh)	2167
Per MW Cost (INR million)	47.47	Price of Fuel (Rs / kg)	1.925
Total Debt (INR million)	21780	NCV (Kcal/kg)	5206
Total Equity (INR million)	7260	O&M Expenses (lacs per MW/yr)	11.84

Levelized tariff for lignite:

The levelized tariff for power generation with lignite comes out as **INR 2.2439 /kWh**. This has been calculated based on the following factors:

Capacity in MW	500	Aux. Consumption	9.50%
Rate of Depreciation (up to 90%)	3.60%	SHR (kcal/kWh)	2695
Per MW Cost (INR million)	40.60	Price of Fuel (Rs/ kg))	0.80
Total Debt (INR million)	15225	NCV (Kcal/kg)	2699



Total Equity (INR million)	5075	O&M Expenses (per MW/yr)	13.16
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Levelized tariff for naphtha:

The levelized tariff for power generation with naphtha comes out as **INR 4.2872 / kWh**. This has been calculated based on the following factors:

Capacity in MW	366	Aux. Consumption	3.00%
Rate of Depreciation (up to 90%)	3.60%	GSHR (kcal/kWh)	1850
Per MW Cost (INR million)	32.46	Price of Fuel (Rs/kg)	17.40
Total Debt (INR million)	8910	NCV (Kcal/kg)	9975
Total Equity (INR million)	2970	O&M Expenses (% of capital cost)	2.50

Summary of levelized tariff for all plausible baseline options is as follows:

S.No.	Baseline Scenario	Levelized Tariff (INR/kWh)
1.	New power plant (s) based on natural gas	2.6819
2.	New power plant (s) based on coal with sub-critical technology	2.1182
3.	New power plant (s) based on coal with super-critical technology using imported coal	2.3283
4.	New power plant (s) based on coal with super-critical technology using domestic coal	2.2707
5.	New power plant (s) based on lignite	2.2439
6.	New power plant (s) based on naphtha	4.2872

Option 2 i.e. power generation plant based on coal with subcritical technology is clearly the most attractive option. Levelized tariff under option 1 i.e. the project activity implemented without considering the CDM revenue is amongst the more costly generation sources.

A sensitivity analysis was performed on the data above for the following factors to corroborate the conclusions drawn from the analysis above.

1. Total project cost: Increase and decrease by 10%.
2. Station Heat Rate (SHR): Increase and decrease by 10%.
3. Fuel price: Increase and decrease by 10%.
4. Plant Load Factor (PLF): increase and decrease by 10%.

The results of sensitivity analysis on levelized tariff of generation for various fuels are presented in the table below:

Fuel Type	Project Cost	
	Project Cost -10%	Project Cost +10%
Gas	2.6057	2.7701
Coal – Sub-critical	2.0275	2.2089
Lignite	2.1497	2.3380
Super Critical Coal (Domestic fuel)	2.1569	2.3845
Super Critical Coal (Imported fuel)	2.2189	2.4378
Naphtha	4.2127	4.3736

Fuel Type	Station Heat Rate (SHR)	
	SHR - 10%	SHR +10%
Gas	2.5019	2.8620



Coal– Sub-critical	2.0286	2.2078
Lignite	2.1522	2.3355
Super Critical Coal (Domestic fuel)	2.1895	2.3519
Super Critical Coal (Imported fuel)	2.2369	2.4198
Naphtha	3.7943	4.4447

Fuel Type	Fuel Price	
	Fuel Price -10%	Fuel Price +10%
Gas	2.5019	2.8620
Coal– Sub-critical	2.0293	2.2071
Lignite	2.1532	2.3345
Super Critical Coal (Domestic fuel)	2.1902	2.3512
Super Critical Coal (Imported fuel)	2.2377	2.4190
Naphtha	3.9449	4.6294

Fuel Type	Plant Load Factor	
	PLF -10%	PLF +10%
Gas	2.7799	2.6018
Coal– Sub-critical	2.2466	2.0132
Lignite	2.3798	2.1326
Super Critical Coal (Domestic fuel)	2.4252	2.1443
Super Critical Coal (Imported fuel)	2.4780	2.2059
Naphtha	4.3832	4.2086

From the data presented above, it can be observed that with variations in total project cost, SHR, fuel price and PLF coal based power generation alternative using subcritical technology continue to remain the economically most attractive options and natural gas as fuel remains amongst the more expensive options. Hence it substantiates that the project activity is not the economically most attractive route for power generation.

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 CDM project activity (assessment and demonstration of additionality):

>> The proposed power plant will use natural gas, a comparatively less GHG intensive fuel compared to other fossil fuels like coal, lignite, etc., resulting in reduction of anthropogenic emission of GHGs. There is no legal requirement in India to choose natural gas in preference to higher GHG intensive fuels like coal.

The national and sectoral policies that may guide the implementation of above options can be understood from discussions provided under the previous section. As per existing national legislation / regulation applicable to similar projects there is no restrictions on utilization of any fuel for Grid Connected Generating stations. Therefore, the alternative to the project activity that could have been installed include either of the following fuels, viz. Coal, Lignite, Naphtha, etc. with conventional technologies.

The project activity leads to additional GHG emission reductions than would have occurred in its absence. In order to demonstrate that the project activity is not a baseline scenario, the following steps are followed for additionality demonstration as recommended in the applied baseline methodology.

Steps for Additionality Check



The Project start date is prior to the date of validation of the PDD. The justification as to demonstrate the serious consideration of CDM in line with the “Guidance on the demonstration and assessment of prior consideration of CDM” (EB41, Annex- 46)⁴⁰ is as follows.

The paragraph 6 (a) of the “Guidance on the demonstration and assessment of prior consideration of CDM” (EB 49, Annex 22) entails project proponent to indicate awareness 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. The extract of the Board Resolution dated 15th October, 2007 evidently justifies that LKPPL was aware of CDM and had considered CDM revenue while according approval to the project investment. The extract of the Board Resolution had been submitted to DOE during validation.

The paragraph 6 (b) of the “Guidance on the demonstration and assessment of prior consideration of CDM” entails project proponent to indicate the continuing and real actions towards CDM implementation in parallel with project implementation have been undertaken by LKPPL. In order to justify the same an implementation timeline of the proposed CDM project activity along with the chronology of events is presented in the table below:

Sl. No.	Milestone	Date	Reference ⁴¹
01.	News paper advertisement on Request for Quotation (RFQ) & Request for Proposal (RFP) towards awarding EPC contract.	24 th September, 2007	The news paper advertisement
02.	Service order for preparation of feasibility –cum-detailed project report.	27 th September, 2007	The feasibility –cum-detailed project report.
03.	Extract of the Board Resolution evidencing CDM revenue has been seriously considered in the decision to go ahead with the project activity.	15 th October, 2007	The extract of the Board Resolution.
04.	Execution of the EPC agreement.	30 th January, 2008	The EPC agreement.
05.	Notice to proceed to the EPC contractor	1 st February, 2008	Notice to Proceed (NTP) to the EPC contractor.
06.	Appointment of CDM consultant.	5 th June, 2008	The CDM advisory agreement.
07.	Achieving financial closure	14 th November, 2008	The relevant section of the loan sanction letter as received from the FI.
08.	Invitation letter for stakeholders’ consultation meeting.	22 nd December, 2008	The invitation letter.
09.	The stakeholders’ consultation meeting.	6 th January, 2009	The minutes of the stakeholders’ consultation meeting.
10.	Submission of the project to MoEF as to obtain HGA.	3 rd March, 2009	The application letter to MoEF.
11.	Execution of the operation & maintenance agreement.	15 th July, 2009	The EPC agreement.
12.	Communication sent to DOEs	14 th August, 2009	Copy of the e-mail

⁴⁰ http://cdm.unfccc.int/EB/041/eb41_repan46.pdf

⁴¹ All the required evidences will be submitted to the DOE during validation



Sl. No.	Milestone	Date	Reference ⁴¹
	requesting offers to carry out CDM validation.		communication between LKPPL and the DOE.
13.	Communication with another CDM consultant.	August, 2009	E-mail communications
14	Gas supply agreement with RIL	29 th August, 2009	The gas supply agreement
15.	Appointment of new CDM consultant	26 th October, 2009	Contract document
16	Appointment of DOE	29 th January, 2010	Engagement agreement with DOE
17	Obtained the Host Country Approval (HCA)	18 th June, 2010	HCA Certificate
18	Project actual commissioning date	1 st August, 2010	Commissioning Certificate

It remains apparent from the above discussion that in tandem with the actual project implementation activities LKPPL has taken initiative on continuous basis to secure CDM status of the project activity. Hence it substantiates that CDM has been seriously considered by LKPPL in their decision to go ahead with the project activity.

Step 1: Benchmark Investment analysis

Demonstrate that the proposed CDM project activity is unlikely to be financially attractive by applying sub-steps 2b (Option III: Apply benchmark analysis), Sub-step 2c (Calculation and comparison of financial indicators), and 2d (Sensitivity Analysis) of the version 05.2.1 of the “Tool for demonstration assessment and of additionality” agreed by the CDM Executive Board.

To determine whether the proposed project activity is economically or financially less attractive than the other alternatives without the CDM revenues, the sub-steps 2b, 2c and 2d have been followed as required under AM0029, version 03.

Sub-step 2(b): Benchmark Analysis (Option III)

Benchmark analysis using levelised tariff as the financial indicator:

The paragraph 4 under sub-step (2b), option III of the additionality tool version - 6 recommends the following guideline

“Identify the financial/economic indicator, such as IRR, most suitable for the project type and decision context.”

Considering the context of decision making levelised cost for power generation (INR / kWh) has been regarded as the most suitable indicator for the project type.

In this regard please refer to the paragraph-19 of the “Guidelines on the Assessment of Investment Analysis” version – 05.

“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. If the alternative to the project activity is the supply of electricity from a grid this is not to be considered an investment and a benchmark approach is considered appropriate.”

The present project activity is a green field natural gas based grid connected Combined Cycle Power Plant (CCPP) of 366 MW capacity. LKPPL is an Independent Power Producer (IPP) and in the past has ventured into both conventional and non-conventional sources of energy including gas, coal, biomass, hydro and wind. LKPPL has operational and under execution projects amounting to over



11000MW⁴². It is apparent that in absence of the project activity the project proponent would have invested in developing power plant based on any of the alternatives mentioned in section B.4. above.

Hence in line with AM0029, version -03 and also following the investment analysis guideline, version -05 the levelised cost of power generation has been considered as the suitable financial indicator.

To further substantiate the choice of the financial indicator as considered in the benchmark analysis please refer to the relevant section of the hand book on “India’s Electricity Sector Widening Scope for Private Participation”, 6th edition⁴³. The particular section of the book elaborates the gradual invention of levelised tariff to evaluate private sector power projects in India.

It is quite explicit from the above discussion that levelised tariff is the key indicator to evaluate the financial proposal of any private sector power producer.

Similar approach (i.e. levelised cost of generation of different alternatives) has been followed by LKPPL in order to carry out financial evaluation of the candidate project activity while deciding upon the project investment.

Determination of the investment benchmark:

The lowest value of levelised cost of generation of all the baseline alternatives discussed in section B.4. of this document has been considered to determine the benchmark of the investment analysis. Explanation to justify the suitability of the benchmark is as follows.

For benchmark, the Sub-step 2 b, option III of tool , version 6 states "Discount rates and benchmarks shall be derived from:..."

The approaches suggested to determine the benchmark in paragraph a to c under the *Sub-step 2 b, option III of additionality tool* are appropriate when Internal Rate of Return (IRR) is identified as the financial indicator. Hence the same has not been considered appropriate to determine the benchmark.

Paragraph d under sub-step (2b), option III of the additionality tool refers to a Government/official approved benchmark where such benchmarks are used for investment decisions. There is no such Government/official⁴⁴ approved benchmark available for private sector power generation in the country.

Paragraph e under sub-step (2b), option III of the additionality tool suggests the option of using any other indicators, if the project participants can demonstrate that the above Options are not applicable and their indicator is appropriately justified.

Given the above discussion, in the context of the project activity, the lowest levelised cost of power generation amongst all the plausible baseline options, has been considered as the suitable benchmark.

Benchmark analysis using project IRR as the financial indicator:

In addition to the above, project IRR has also been estimated for the project activity. In this regard please refer to paragraph 12 of the guidelines on the assessment of investment analysis, version -05 (EB62; Annex-05.2.1). The guideline recommends the following to determine the benchmark

“In cases where a benchmark approach is used the applied benchmark shall be appropriate to the type of IRR calculated. Local commercial lending rates or weighted average costs of capital (WACC) are

⁴² <http://www.lancogroup.com/power/Power.html>

⁴³ The relevant document has been submitted to the DOE during validation.

⁴⁴ Central Electricity Authority (CEA) /or Central Electricity Regulatory Commission (CERC) do not specify any benchmark return in order to evaluate investment in power project in India



appropriate benchmarks for a project IRR. Required/expected returns on equity are appropriate benchmarks for equity IRR.”

In the present context in line with the financial indicator (project IRR) Weighted Average Cost of Capital (WACC) of the project activity has been considered as the investment benchmark. Further, the financial indicator i.e. project IRR will be computed post tax hence the same approach (post tax) will be followed while estimating the WACC i.e. investment benchmark of the project activity. In this regard it is worthwhile to note that that project activity can be implemented by any other entity apart from the project participant. Hence following the guideline provided in the sub-step 2b, option III of the tool version 6 the benchmark has been derived based upon the parameters that are standard in the market and not linked to the subjective profitability expectation or risk profile of the project developer.

WACC has been calculated as per the following illustration:

$$\text{WACC} = [D/(D+E)] * [\text{Cost of Debt}] + [E/(D+E)] * [\text{Cost of Equity}]$$

Cost of Equity:

Paragraph 15 of the investment analysis guideline, version -05 provides the following guideline to determine the cost of equity

“If the benchmark is based on parameters that are standard in the market, the cost of equity should be determined either by: (a) selecting the values provided in Appendix A; or by (b) calculating the cost of equity using best financial practices, based on data sources which can be clearly validated by the DOE, while properly justifying all underlying factors.”

In case of the present project activity the cost of equity has been determined following the option (b) as mentioned in the guideline above. The Capital Asset Pricing Model (CAPM) has been followed considering Beta values of selected power generating companies in India that were listed at the time of investment decision making process. Detailed calculations of cost of equity and WACC along with an elaboration of the approach are provided in Appendix – 03 of this document. The cost of equity has been estimated at 19.55%.

Cost of Debt:

In order to reflect the standard rate in the market the prime lending rate prevailing at the time of investment decision making has been considered as the cost of debt. The Prime Lending Rate (PLR) at the time of investment was in the range of 12.75 – 13.25⁴⁵. Hence the average value of 13.00% (pre-tax) has been considered as the applicable cost of debt.

Debt - Equity Ratio:

Paragraph 18 of the guideline on the assessment of investment analysis, version -05 provides the following in order to determine the debt/equity finance structure.

“If the benchmark is based on parameters that are standard in the market, then the typical debt/equity finance structure observed in the sector of the country should be used.”

⁴⁵ <http://www.rbi.org.in/scripts/WSSView.aspx?Id=11982>



In this regard please refer to the Central Electricity Regulatory Commission (CERC) tariff order dated 26th March, 2004⁴⁶ that specifies that debt and equity to be considered at 70:30 for tariff determination. The same has been applied in the present context.

WACC:

Referring to the explanation above the WACC of the project activity has been estimated at 13.53%.

Sub-step 2c (Calculation and comparison of financial indicators)

Comparison using levelised tariff as the financial indicator:

The levelized tariff for all the plausible options to the proposed project activity has been calculated and presented in Section B.4 above. A summary of these levelized tariff⁴⁷ calculations is presented in the table below:

S.No.	Baseline Scenario	Levelized Tariff (INR/kWh)
1.	New power plant (s) based on natural gas	2.6819
2.	New power plant (s) based on coal – sub-critical	2.1182
3.	New power plant (s) based on coal (Domestic fuel) with super-critical technology	2.2707
4.	New power plant (s) based on coal (Imported fuel) with super-critical technology	2.3283
5.	New power plant (s) based on lignite	2.2439
6.	New power plant (s) based on naphtha	4.2872

On analysing this data it can be clearly seen that the project activity is not the most economical for power production. Using coal as fuel with sub-critical technology is economically the most feasible investment option for power generation. Amongst all the above options, the GHG emissions will be more than the project option.

The Cost of Power Generation using coal as fuel with subcritical technology is considered as the benchmark, as this is the economically most viable option to the project proponent.

Comparison using project IRR as the financial indicator:

Project IRR has been considered as the financial indicator for the project activity. In this regard please refer to the discussion in section B.4 above on assumption considered to estimate levelised tariff. The same set of assumptions has been considered to determine the IRR of the project activity. In order to compute the IRR of the project activity the annual cost of generation as computed to determine the levelised tariff over 20 year period has been used.

The computation of levelised cost includes 14% return on equity (ROE) in addition to other variable and fixed cost elements as per CERC guideline dated 26th March, 2004. Hence the same has been used as tariff for IRR computation.

Prior to the investment approval PP has developed the Detailed project Report (DPR) that has formed the basis of according investment approval to the present project activity. The approach that has been followed to estimate the levelised cost of generation in DPR conforms to the guideline on tariff computation (please refer to the CERC regulation dated 26th March, 2004⁴⁸) for the utility scale

⁴⁶ http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

⁴⁷ The detailed excel sheets of these calculations are available with the project proponent for verification by DOE.

⁴⁸ http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf



power projects in the country. As per the guideline the levelised cost of generation for power projects will be derived based upon total fixed (including return on equity @ 14%) and variable cost as incurred by the project activity. In order to determine the levelised cost of generation the following cost elements have been estimated

- Variable cost
 - Cost of fuel
- Fixed cost
 - Interest on debt
 - Interest on working capital
 - Operation and Maintenance expenses
 - Depreciation
 - Advance against depreciation
 - Return on equity
 - Tax

At the time of investment decision making process the project proponent was owning and operating the following power projects

- Lanco Kondapalli Stage-I (368.144 MW)
- Aban Power 120 MW

The applicable tariff of all the power stations had been decided following the CERC regulation dated 26th March, 2004⁴⁹.

Drawing reference from the above the project proponent has estimated tariff following the levelised cost approach which is also in accordance with the guideline recommended by CEA.

The project IRR has been estimated at 11.80% which is lower than the applicable investment benchmark value of 13.53%.

Sub-step 2d (Sensitivity Analysis)

Sensitivity analysis: Levelised tariff for power generation

The findings of sensitivity analysis on levelized tariff for power generation using natural gas, coal, sub-critical, coal super-critical(Domestic & international fuel), lignite & naphtha were presented in section B.4 above. It further substantiates that even with reasonable variations in the key variable e.g. project cost, fuel price, SHR and PLF, power generation using natural gas as fuel continues to remain amongst the more expensive alternatives and the same using coal as fuel with sub-critical technology is economically the most attractive option.

Sensitivity analysis: Project IRR

Sensitivity analysis of the candidate project activity has been conducted following the paragraph 20 and 21 of the “guidelines on the assessment of investment analysis”, version - 05 (EB 62, Annex - 5). The following parameters have been considered to have material impact upon the project IRR and have been subjected to sensitivity analysis.

- Plant load factor (PLF)

⁴⁹ http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf



- Station heat rate
- Project capital cost
- Fuel cost
- O&M cost

The table below represents the result of the sensitivity analysis

Sr. No.	Parameter	Project IRR (%)	Project IRR (%)	Project IRR (%)	Benchmark (%)
		(+10%)	(Base case)	(-10%)	
1.	Plant load factor	11.80	11.80	11.80	13.53
2.	Station heat rate	11.80	11.80	11.80	13.53
3.	Project capital cost	11.80	11.80	12.09	13.53
4.	Fuel cost	11.80	11.80	11.80	13.53
5.	O&M cost	11.80	11.80	11.80	13.53

It is quite evident from the table above that project IRR remains below the benchmark value (13.53%) in all the sensitivity scenarios.

Also, it can be observed that there is marginal variation in the project IRR corresponding to various sensitivity scenarios and base case. This is mostly attributable to the following reasons

- Tariff for IRR computation has been derived from the annual levelised cost of generation.
- Cost elements as considered for computing the project IRR have been estimated following the fixed and variable cost as determined to compute levelised cost of generation.

Hence any variation in the input parameters (apart from the project cost) will have similar impact upon applicable tariff and related cost elements resulting into marginal change in the IRR value.

Step 2: Common practice analysis

The common practice analysis have been carried out following the UNFCCC guidelines on common practice (version 01.0 ; EB 63 Annex-12)50.

Step 1: Calculate applicable output range as +/-50% of the design output or capacity of the proposed project activity.

The project activity is of capacity 366 MW; in accordance to step 1, “applicable output range” would be from 183 MW (project capacity-50%) to 549 MW (project capacity + 50%).

Also, following the default choice as recommended in the guidelines on common practice (version 01.0; EB 63 Annex-12) the applicable geographical area has been considered as the entire host country i.e. India.

All gas based power plants in India with capacity in the range 183 MW to 549 MW are being considered further.



Step 2: In the applicable geographical area, identify all plants that deliver the same output or capacity, within the applicable output range calculated in Step 1, as the proposed project activity and have started commercial operation before the start date of the project. Note their number N_{all} . registered CDM project activities shall not be included in this step

The start date of the project activity is 1st February, 2008. The following table enlists all projects⁵¹ that commenced operations before start date of the project activity and fall within capacity range of +/- 50% (i.e. between 183 MW & 549 MW) of the candidate project activity.

S.No	Name of the Plant	Capacity (as on start date of the project) (MW)	Primary Fuel	Secondary Fuel (if any)	Owned by	CDM Registration Status
1	Kathalguri GT	291	Gas	N.a	Center	No
2	I.P.G.C	270	Gas	Diesel	State	No
3	Pragati CCGT	330.4	Gas	N.a	State	No
4	F_Bad CCGT	431.59	Gas	Naphtha	Center	No
5	Anta GT	419.33	Gas	Naphtha	Center	No
6	Dholpur	330	Gas	N.a	State	No
7	Dhuvran CCPP	218.62	Gas	N.a	State	Yes
8	Essar GT IMP	515	Gas	Naphtha	Private	No
9	GIPCL GT	305	Gas	Naphtha	Private	No
10	Vijeswaran GT	272.3	Gas	Naphtha	State	No
11	Jegurupadu GT	235.4	Gas	Naphtha	Private	No
12	Godavari GT	208	Gas	Naphtha	Private	No
13	Kondapalli GT	350	Gas	Naphtha	Private	No
14	Peddapuram CCGT	220	Gas	Naphtha	Private	No
15	Tanir Bavi	220	Gas	Naphtha	Private	No
16	Kayam Kulam GT	350	Gas	Naphtha	Central	No
17	P.Nallur CCGT	330.5	Gas	Naphtha	Private	No
18	Vemagiri CCCP	388.5	Gas	N.a	Private	Yes

It is quite evident that t Dhuvran CCPP and Vemagiri CCCP have completed CDM registration. In line with the guidelines on common practice these power plants are excluded in order to determine the gas based CCPP units similar to the project activity. Hence within the given geographical area

⁵¹ http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm ; version -06



number of power plants within the applicable output range to the project activity (Nall) has been estimated at 16.

Step 3: Within plants identified in Step 2, identify those that apply technologies different that the technology applied in the proposed project activity. Note their number N diff.

Different Technologies (Investment climate)

Amongst all the 16 plants that are grouped as Nall it can be observed that 8 plants are owned by state or central government enterprises. All these projects would involve public/ or sovereign financing since these have been commissioned by public sector entities. Risk associated with public/ or sovereign financing would be much lower when compared to financing a private enterprise. Hence public sector projects would have easier access to avail finance than the candidate project activity. Hence, these are deemed to be different from the candidate project in terms of investment climate and considered to be categorised as Ndiff.

Different Technologies (Energy source / fuel)

Essar GT IMP, GIPCL GT, Jegurupadu, Godavari GT, Kondapalli GT (350 MW), Peddapuram CCGT, Tanir Bavi and P.Nallur CCGT to are the private owned power plants in the above list (i.e there are 8 private owned non-CDM gas based power plants within the applicable range in the country).

It can be observed that all these 8 plants have multi fuel firing option.. Multi-fuel fired CCGTs are not only technologically different (burner design, storage tanks, pipelines, etc.) but also have greater flexibility to choose within a range of fuels, depending on economics and availability and are thus better able to diversify fuel risks and dispatch risks, as compared to single fuel (natural gas) fired plants. Hence these four projects are considered as applying technologies different from the candidate project activity and are categorised as Ndiff..

The above discussion concludes that all the 16 power plants (Ndiff) have applied technology different from the candidate project activity.

Step 4: Calculate factor $F=1-Ndiff/Nall$ representing the share of plants using technology similar to the technology used in the proposed project activity in all plants that deliver the same output or capacity as the proposed project activity.

The discussion presented from step 1 to step 3 above have estimated the value of both Nall and Ndiff at 16. Hence the calculation of factor F is as follows

$$\begin{aligned}\text{Factor } F &= 1 - 16/16 \\ &= 1 - 1 \\ &= 0\end{aligned}$$

Step 5: The proposed project activity is a common practice within a sector in the applicable geographical area if the factor F is greater than 0.2 and Nall - Ndiff is greater than 3.

Please refer to the step 4 where-in the value of factor F has been estimated as zero. Hence the above discussion demonstrates that the project activity is not a common practice within the given geographical area.

Step 3: Impact of CDM registration



Describe the impact of the registration of the project activity by applying Step 5 (Impact of CDM registration) of the latest version of the “Tool for demonstration assessment and of additionality” agreed by the CDM Executive Board.

The latest version of “Tool for demonstration assessment and of additionality” version 6 EB65 has done away with Step 5 and therefore this has not been analysed.

Based on the findings from above steps it is established that project activity itself is not the baseline scenario and hence is additional.mm

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

>> According to the approved baseline methodology AM0029, the emission reductions ER_y by the project activity is calculated using the equation number 6 of version 03 (EB 39)

$$ER_y = BE_y - PE_y - LE_y$$

Where:

ER_y : emissions reductions in year y (tCO₂e)

BE_y : emissions in the baseline scenario in year y (t CO₂e)

PE_y : emissions in the project scenario in year y (tCO₂e)

LE_y : leakage in year y (tCO₂e)

Baseline emissions

Baseline emissions are calculated, using equation number 2 of AM0029 ver 03, by multiplying the electricity generated in the project plant ($EG_{PJ,y}$) with a baseline CO₂ emission factor ($EF_{BL,CO_2,y}$), as follows:

$$BE_y = EG_{PJ,y} * EF_{BL,CO_2,y}$$

For construction of large new power capacity additions under the CDM, there is a considerable uncertainty relating to which type of other power generation is substituted by the power generation of the project plant. However, for the proposed CDM project activity as mentioned in the Section B.4 above, power generation using coal as fuel applying sub-critical technology is the economically most attractive baseline alternative.

AM0029 advises to address the baseline uncertainties in a conservative manner by choosing the $EF_{BL,CO_2,y}$ as the lowest emission factor among the following three options:

Option 1. The build margin, calculated according to “Tool to calculate the emission factor for an electricity system”; and

Option 2 The combined margin, calculated according to “Tool to calculate the emission factor for an electricity system”, using a 50/50 OM/BM weight.

Option 3 The emission factor of the technology (and fuel) identified as the most likely baseline scenario under “Identification of the baseline scenario” above, and calculated as follows:

$$EF_{BL,CO_2}(tCO_2/MWh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6GJ/MWh \text{ (using equation number 3 of AM0029 ver 03)}$$

where,

$COEF_{BL}$ = the fuel emission coefficient (tCO₂e/GJ), based on Table 2.2 of 2006 IPCC Guidelines for National Greenhouse Gas Inventories

η_{BL} = the energy efficiency of the technology, as estimated in the baseline scenario analysis above.

As per AM0029, the baseline emission factor determination is required to be made once at the validation stage based on an *ex ante* assessment and once again at the start of each subsequent crediting period (if applicable). If either option 1 (BM) or option 2 (CM) are selected, then they will be estimated *ex post*, as described in “Tool to calculate the emission factor for an electricity system”.

Option 1: Build Margin, calculated according to “Tool to calculate the emission factor for an electricity system”

The Build Margin emission factor $EF_{grid,BM,y}$ (tCO₂/MWh) is given as the generation-weighted average emission factor of the selected representative set of recent power plants represented by the 5 most recent plants or the most recent 20% of the generating units built:

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

(using equation number 12 of Tool to calculate the emission factor for an electricity system)

Where

$EF_{grid,m,y}$ is Build Margin CO₂ emission factor in year y (tCO₂/MWh)

$EG_{m,y}$ is net quantity of electricity generated and delivered to the grid by power unit m in year y (MWh)

$EF_{BL,m,y}$ is CO₂ emission factor of power unit m in year y (tCO₂/MWh)

m is power units included in the build margin

y is most recent historical year for which power generation data is available

The Central Electricity Authority, Ministry of Power, Government of India has published a database⁵² of Carbon Dioxide Emission from the power sector in India based on detailed authenticated information obtained from all operating power stations in the country. This database i.e. The CO₂ Baseline Database provides information about the Operating Margin and Build Margin Emission Factors of all the regional electricity grids in India. The Operating Margin in the CEA database is calculated *ex ante* using the Simple OM approach and the Build Margin is calculated *ex ante* based on 20% most recent capacity additions in the grid based on net generation as described in “Tool to calculate the emission factor for an electricity system”. We have, therefore, used the Operating Margin and Build Margin data published in the CEA database, version – 5.0 for calculating the baseline emission factor.

The Build Margin for the southern regional grid for year 2008-09 as per CEA database, version – 5.0 is **0.818 tCO₂e/MWh**.

Option 2 The combined margin, calculated according to “Tool to calculate the emission factor for an electricity system”, using a 50/50 OM/BM weight.

The combined margin emission factor as per “Tool to calculate the emission factor for an electricity system”, is calculated as a combination of the Operating Margin (OM) and the Build Margin (BM). Considering the emission factors for these two margins as $EF_{grid,OM,y}$ and $EF_{grid,BM,y}$, then the $EF_{grid,CM,y}$ is given by:

⁵²<http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm>



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

with respective weight factors w_{OM} and w_{BM} (where $w_{OM} + w_{BM} = 1$).

As instructed in AM0029, we have used a 50/50 weight for OM and BM while calculating the combined margin emission factor.

Operating Margin emission factor

As per “Tool to calculate the emission factor for an electricity system”, dispatch data analysis should be the first methodological choice. However, this option is not selected because the information required for calculating OM based on dispatch data is not available in the public domain for the Southern electricity regional grid.

The Simple Operating Margin approach is appropriate to calculate the Operating Margin emission factor applicable in this case. As per “Tool to calculate the emission factor for an electricity system” the Simple OM method can only be used where low cost must run resources constitute less than 50% of grid generation based on average of the five most recent years. The generation profile of the Southern grid in the last five years is as follows:



Generation in GWh	2004-05	2003-04	2002-03	2001-02	2000-01
Low cost/must run sources					
Hydro	24,951	16,943	18,288	26,260	29,902
Wind & Renewables	3,256	1,865	1,607	1,456	1,262
Nuclear	4,408	4,700	4,390	5,244	4,331
Other sources					
Coal	99,010	98,435	92,053	84,032	83,292
Diesel	2,434	3,295	4,379	4,155	2,868
Gas	12,428	14,214	13,950	10,331	7,132
Total Generation	146,487	139,451	134,667	131,478	128,787
Low cost/must run sources	32,615	23,508	24,285	32,960	35,496
Low cost/must run sources	22%	17%	18%	25%	28%

Source: Table 3.4 of CEA General Review 2004-05, 2003-04, 2002-03, 2001-02, 2000-01

From the available information it is clear that low cost/must run sources account for less than 50% of the total generation in the Southern grid in the last five years. Hence the Simple OM method is appropriate to calculate the Operating Margin Emission factor applicable.

As mentioned earlier, Operating Margin in the CEA database has been calculated using the Simple OM method. We have therefore considered the OM numbers provided in the CEA database.

Operating margin data for the Southern region electricity grid for the latest three years available in the CEA database are given below:

Year	Operating Margin (tCO ₂ e/MWh)
2006 – 07	0.999
2007 – 08	0.991
2008 – 09	0.973
Average of 3 years	0.988

The Operating Margin applicable for the project activity is taken as average of the latest three years operating margins. Accordingly the Operating Margin is determined as 0.988 tCO₂e/MWh. As mentioned earlier, the applicable Build Margin value is 0.818 tCO₂e/MWh.

Applying a 50/50 weightage to the values for operating margin (Average of last three years) and build margin emission factors provided in the CEA database, the Combined Margin emission factor is calculated as **0.902tCO₂e/MWh**.

Option 3 The emission factor of the technology (and fuel) identified as the most likely baseline scenario under “Identification of the baseline scenario”

As demonstrated under section B.4 earlier, coal based power generation using sub-critical technology represents economically the most attractive course of action, taking into account barriers to investment. Therefore, coal based power generation using sub-critical technology has been identified as the baseline scenario.

The emission factor of coal based power generation calculated using the equation below:

$$EF_{BL, CO_2} (tCO_2 / MWh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6 GJ / MWh$$

$COEF_{BL}$ = Carbon Emission Factor of coal x Oxidation Factor of coal x 44/12

$COEF_{BL}$ has been estimated at 95.81 tCO₂/TJ (i.e. 0.09581 tCO₂/GJ)



$\eta_{BL} = 34.60\%$ (refer Annex 3 for calculations) for 1 coal based power plants using sub-critical technology

$$EF_{BL,CO_2}(tCO_2/MWh) = 0.09581 (tCO_2e/GJ) \times 3.6 (GJ/MWh) / 34.60\% \\ = 0.997 tCO_2e/MWh$$

Baseline Emission Factor

Emission factors determined using the three options are summarised in the table below

Option	Emission Factor (tCO ₂ e/MWh)
Option 1: Build Margin	0.818
Option 2: Combined Margin	0.902
Option 3: Emission factor of coal based power plant using sub-critical technology	0.997

Option 1: Build Margin value is the lowest of all the three options and hence the appropriate Baseline Emission Factor. Accordingly, Baseline Emission Factor value applicable to the project activity is 0.818 tCO₂e/MWh.

As per AM0029, in case the Build Margin or the Combined Margin is selected as the baseline emission factor, the baseline emission factor (Build Margin) will be determined *ex-post*, as described in “Tool to calculate the emission factor for an electricity system”. As per “Tool to calculate the emission factor for an electricity system”, in case of *ex-post* determination, the Build Margin must be updated annually *ex-post* for the year in which the actual generation and associated emission reduction occur. The latest version of CEA CO₂ baseline database that is used to determine the BM factor was published in November 2009 and contains information up to 2008-09. CEA has acknowledged that because of the dynamic nature of data, the database will have to be updated every year. Therefore we expect the CEA database to be updated every year. If the CEA database is not updated, the Build Margin number will be calculated by the project proponent using the available CEA data.

Project emissions

The project activity is on-site combustion of natural gas to generate electricity. The CO₂ emissions from electricity generation (PE_y) are calculated as follows:

$$PE_y = \sum_f FC_{f,y} * COEF_{f,y} \quad (\text{using equation 1 of AM0029 ver 03})$$

Where:

FC_{f,y}: is the total volume of natural gas or other fuel ‘f’ combusted in the project plant or other startup fuel (m³ or similar) in year(s) ‘y’

COEF_{f,y}: is the CO₂ emission coefficient (tCO₂/m³ or similar) in year(s) for each fuel and is obtained as:

$$COEF_{f,y} = \sum NCV_y * EF_{CO_2,f,y} * OXID_f \quad (\text{using equation 1a of AM0029 ver 03})$$

Where:

NCV_{f,y}: is the net calorific value (energy content) per volume unit of natural gas in year ‘y’ (GJ/m³) as determined from the fuel supplier, wherever possible, otherwise from local or national data;

EF_{CO₂,f,y}: is the CO₂ emission factor per unit of energy of natural gas in year ‘y’ (tCO₂/GJ) taken from IPCC;

OXID_f: is the oxidation factor of natural gas



For start-up fuels, IPCC default calorific values and CO₂ emission factors are acceptable, if local or national estimates are unavailable.

Applicable values for the above parameters are provided below:

NCV_y: Net Calorific Value of Natural Gas consumed by the Project activity is: 8553 kCal/SCM or 35809.70 KJ/SCM

EF_{CO₂,f,y}: CO₂ emission factor per unit of energy of Natural gas is determined as follows:

IPCC default value for Carbon Emission Factor of Natural Gas is 56.10 tCO₂e/tJ

EF_{CO₂,f,y} = 56.10 tCO₂e/tJ

OXID_f: Oxidation factor of Natural Gas as per IPCC Guidelines is 1.0

COEF_{f,y}: CO₂ emission coefficient for Natural Gas is determined as:

COEF_{f,y} = 35809.70 7/10⁹ (tJ/SCM) x 56.10 (tCO₂e/tJ) x 1

COEF_{f,y} = 2008.92 tCO₂e/Mcum

Leakage emissions

Leakage may result from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary. This includes mainly fugitive CH₄ emissions and CO₂ emissions from associated fuel combustion and flaring. In this methodology, the following leakage emission sources shall be considered:⁵³

Fugitive CH₄ emissions associated with fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of natural gas used in the project plant and fossil fuels used in the grid in the absence of the project activity.

In the case LNG is used in the project plant: CO₂ emissions from fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system.

Thus, leakage emissions are calculated as follows:

$$LE_y = LE_{CH_4, y} + LE_{LNG, CO_2, y} \quad (5)$$

where:

LE_y Leakage emissions during the year y in tCO₂e

LE_{CH₄,y} Leakage emissions due to fugitive upstream CH₄ emissions in the year y in t CO₂e

LE_{LNG,CO₂,y} Leakage emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year y in t CO₂e

Fugitive methane emissions

For the purpose of estimating fugitive CH₄ emissions, project participants should multiply the quantity of natural gas consumed by the project in year y with an emission factor for fugitive CH₄ emissions (EF_{NG,upstream,CH₄}) from natural gas consumption and subtract the emissions occurring from fossil fuels used in the absence of the project activity, as follows:

$$LE_{CH_4, y} = [FC_y \cdot NCV_y \cdot EF_{NG, upstream, CH_4} - EG_{PJ, y} \cdot EF_{BL, upstream, CH_4}] \cdot GWP_{CH_4} \quad (6)$$

⁵³ The EB is undertaking further work on the estimation of leakage emission sources in case of fuel switch project activities. This approach may be revised based on outcome of this work.



where:

$LE_{CH_4,y}$ Leakage emissions due to fugitive upstream CH_4 emissions in the year y in t CO_2e

FC_y Quantity of natural gas combusted in the project plant during the year y in m^3

$NCV_{NG,y}$ Average net calorific value of the natural gas combusted during the year y in GJ/m^3

$EF_{NG,upstream,CH_4}$ Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, distribution, and, in the case of LNG, liquefaction, transportation, re-gasification and compression into a transmission or distribution system, in t CH_4 per GJ fuel supplied to final consumers

$EG_{PJ,y}$ Electricity generation in the project plant during the year in MWh

$EF_{BL,upstream,CH_4}$ Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in t CH_4 per MWh electricity generation in the project plant, as defined below

GWP_{CH_4} Global warming potential of methane valid for the relevant commitment period

The emission factor for upstream fugitive CH_4 emissions occurring in the absence of the project activity ($EF_{BL,upstream,CH_4}$) should be calculated consistent with the baseline emission factor (EF_{BL,CO_2}) used in equation (4) above. As presented in Annex 3, the emission factor was found to be the lowest with Build Margin method for the Southern grid, so the same calculation procedure has been adopted to calculate $EF_{BL,upstream,CH_4}$, as presented below:

$$EF_{BL,upstream,CH_4} = \frac{\sum_j FF_{j,k} \cdot EF_{k,upstream,CH_4}}{\sum_j EG_j}$$

where:

$EF_{BL,upstream,CH_4}$ Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in t CH_4 per MWh electricity generation in the project plant

j Plants included in the build margin

$FF_{j,k}$ Quantity of fuel type k (a coal or oil type) combusted in power plant j included in the build margin

$EF_{k,upstream,CH_4}$ Emission factor for upstream fugitive methane emissions from production of the fuel type k (a coal or oil type) in t CH_4 per MJ fuel produced

EG_j Electricity generation in the plant j included in the build margin in MWh/a

Default values used for calculating leakage emissions due to the project activity are as follows:

Sl. No	Parameter	Default Value	Remarks
1	Emission factor for fugitive CH_4 upstream emissions for coal	0.8 t CH_4 /kt coal	Most of the coal production in India comes from open pit mines contributing over 81% of the total production. A number of large open pit mines of over 10 million tonnes per annum capacity are in operation. Underground mining currently accounts for around 19% of national output. (http://www.coal.nic.in/welcome.html). Further, Singareni Collieries Company Limited (SCCL) is the main source for supply of coal to the southern region (http://www.coal.nic.in/cpddoc.htm) and more than 80% of coal at SCCL is mined from open cast mines (http://www.coal.nic.in/cpdanx.htm#Annexure-II).



Sl. No	Parameter	Default Value	Remarks
			Hence 0.8 tCH ₄ /kt coal value is used for surface mining
2	Emission factor for fugitive CH ₄ upstream emissions for Oil	4.1 tCH ₄ /PJ	As per the Table 2 of the methodology. This value includes for oil production, transport, refining and storage.
3	Emission factor for fugitive CH ₄ upstream emissions for Natural Gas	296 tCH ₄ /PJ	As per the Table 2 of the approved methodology.
4	Oxidation factor of natural gas	1.0	IPCC value as per 2006 IPCC guidelines for National Green House Gas inventories

Leakage calculations are provided in Appendix 2.

Upstream fugitive emissions occurring in the absence of the project activity electricity generation has been calculated using the Build Margin power plants. Therefore in line with the AM0029 requirement of *ex-post* determination of the Build Margin, the Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity electricity generation (tCH₄/MWh) will also be determined *ex-post*.

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

>> The data/ parameters that are available at validation include the following:

1.Data / Parameter:	$EF_{BM,y}$
Data unit:	tCO ₂ e/MWh
Description:	Build Margin Emission Factor of Southern Regional Electricity Grid
Source of data used:	“CO ₂ Baseline Database for Indian Power Sector” Version 5.0 dated 1 st November 2009 published by the Central Electricity Authority, Ministry of Power, Government of India. The “CO ₂ Baseline Database for Indian Power Sector” is available at www.cea.nic.in
Value applied:	0.818
Justification of the choice of data or description of measurement methods and procedures actually applied :	Build Margin Emission Factor has been calculated by the Central Electricity Authority in accordance with “Tool to calculate the emission factor for an electricity system”.
Any comment:	-

2. Data / Parameter:	$EF_{OM,y}$						
Data unit:	tCO ₂ e/MWh						
Description:	Operating Margin Emission Factor of Southern Regional Electricity Grid						
Source of data used:	“CO ₂ Baseline Database for Indian Power Sector” Version 5.0 dated 1 st November, 2009 published by the Central Electricity Authority, Ministry of Power, Government of India. The “CO ₂ Baseline Database for Indian Power Sector” is available at www.cea.nic.in						
Value applied:	<table border="1"> <tr> <td>2006 – 07</td><td>0.999</td></tr> <tr> <td>2007 – 08</td><td>0.991</td></tr> <tr> <td>2008 – 09</td><td>0.973</td></tr> </table>	2006 – 07	0.999	2007 – 08	0.991	2008 – 09	0.973
2006 – 07	0.999						
2007 – 08	0.991						
2008 – 09	0.973						
Justification of the choice of data or	Operating Margin Emission Factor has been calculated by the Central Electricity Authority using the simple OM approach in accordance with “Tool						



description of measurement methods and procedures actually applied :	to calculate the emission factor for an electricity system”.
Any comment:	-

3. Data / Parameter:	Carbon Emission Factor of Natural Gas (EF_{CO2,f,y})
Data unit:	tCO ₂ /GJ
Description:	The CO ₂ emission factor per unit of energy of natural gas in year ‘y’
Source of data used:	IPCC default value has been applied (Source: Chapter-2 IPCC 2006 Guidelines for National Greenhouse Gas Inventories)
Value applied:	56.1 tCO ₂ /TJ (= 0.0561 tCO ₂ /GJ)
Justification of the choice of data or description of measurement methods and procedures actually applied :	As there are no national data available for the emission factor of the fuel used, default value based on Table 2.2 of 2006 IPCC Guidelines for National Greenhouse Gas Inventories has been applied.
Any comment:	-

4. Data / Parameter:	Oxidation Factor of Natural Gas (OXID_f)
Data unit:	-
Description:	Oxidation factor of natural gas
Source of data used:	IPCC default value has been applied (Source: Chapter-2 IPCC 2006 Guidelines for National Greenhouse Gas Inventories)
Value applied:	1.0
Justification of the choice of data or description of measurement methods and procedures actually applied :	As there are no national data available, IPCC default value based on is considered
Any comment:	-

5. Data / Parameter:	Station Heat Rate of the Project activity
Data unit:	kCal/kWh
Description:	Station Heat Rate has been used to calculate the quantity of Natural Gas consumption associated with the expected electricity generations from the project activity. This data is used as an input for calculating Project Emissions.
Source of data used:	Detailed project report (DPR) The CERC tariff order dated 26 th March, 2004 has also specified the SHR of combined cycle gas based power plant with advanced class machines 1850 kCal/ kWh. (Reference : http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf)
Value applied:	1850
Justification of the choice of data or description of measurement methods and procedures actually applied :	-



applied :	
Any comment:	-

6. Data / Parameter:	Carbon Emission Factor of Coal, Lignite, Diesel, Oil, Natural Gas
Data unit:	tCO ₂ /TJ
Description:	Emission factor of Coal, Lignite, Diesel, Oil, Natural Gas. This data will be used as an input for calculating the fugitive CH ₄ emissions occurring in the absence of the project activity
Source of data used:	Carbon Emission Factor for Coal, Lignite & Oil: Table 2.3 - India specific CO ₂ emission coefficients, India's first National Communication to the United Nations Carbon Emission Factor for Diesel & Natural Gas: Table 1.4, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 1, Volume 2, Energy
Value applied:	Refer Appendix 2
Justification of the choice of data or description of measurement methods and procedures actually applied :	As per AM0029, the fuel emission coefficient is to be determined based on national average fuel data if available. Accordingly we have used the data available in India's first national communication to the United Nations for our calculations where available, otherwise IPCC default values have been used.
Any comment:	-

7. Data / Parameter:	Oxidation Factor of Coal, Lignite, Diesel, Oil, Natural Gas
Data unit:	-
Description:	Oxidation factor of coal which has been identified as the baseline scenario fuel This data is used as an input for calculating the fugitive CH ₄ emissions occurring in the absence of the project activity
Source of data used:	Table 1.4, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 1, Volume 2, Energy
Value applied:	Refer Appendix 2
Justification of the choice of data or description of measurement methods and procedures actually applied :	Only IPCC default values are available.
Any comment:	-

8. Data / Parameter:	Calorific values of Coal, Lignite, Diesel, Oil and Natural Gas Naphtha
Data unit:	kCal/Kg or kCal/SCM
Description:	This data is used as an input for calculating the Energy efficiency of coal fired power plants and the fugitive CH ₄ emissions occurring in the absence of the project activity
Source of data used:	NCV of Coal – Table 6.3, CEA General Review 2006 NCV of Natural Gas, Diesel : CEA Data on Petroleum fuels used by various Gas Turbines and Diesel Engine Power Plants in India in 2003-04
Value applied:	Refer Appendix 2
Justification of the choice of data or description of	Central Electricity Authority, Government of India mandated to publish information on performance of power sector in India by the Electricity Act 2003.



measurement methods and procedures actually applied :	
Any comment:	-

9. Data / Parameter:	η_{BL} – Efficiency of coal fired power generating stations using sub-critical technology
Data unit:	-
Description:	Energy efficiency of coal fired power plant using sub-critical technology which has been identified as the baseline scenario
Source of data used:	Calculated value based on fuel consumption, NCV of coal and electricity generation data of coal fired power stations published in the CEA carbon-dioxide emission database, version - 05
Value applied:	34.60%
Justification of the choice of data or description of measurement methods and procedures actually applied :	Central Electricity Authority, Government of India mandated to publish information on performance of power sector in India by the Electricity Act 2003.
Any comment:	-

10. Data / Parameter:	Fuel consumption in coal fired power plants using sub-critical technology in the southern region																		
Data unit:	Million tonnes (MT)																		
Description:	This data is used as an input for calculating the Energy efficiency of coal fired power plants																		
Source of data used:	CEA CO ₂ Baseline database, version - 05																		
Value applied:	<table border="1"> <thead> <tr> <th>Coal Based Power Station using sub-critical technology</th><th>Fuel Consumption</th></tr> <tr> <th></th><th>Million Tonnes</th></tr> </thead> <tbody> <tr> <td>RAYAL SEEMA</td><td>1045.8</td></tr> <tr> <td>RAYAL SEEMA</td><td>1012.6</td></tr> <tr> <td>R_GUNDEM STPS</td><td>2574.4</td></tr> <tr> <td>SIMHADRI</td><td>2544.5</td></tr> <tr> <td>SIMHADRI</td><td>2774.7</td></tr> <tr> <td>RAICHUR</td><td>1115.0</td></tr> <tr> <td>BELLARY TPS</td><td>1016.3</td></tr> </tbody> </table>	Coal Based Power Station using sub-critical technology	Fuel Consumption		Million Tonnes	RAYAL SEEMA	1045.8	RAYAL SEEMA	1012.6	R_GUNDEM STPS	2574.4	SIMHADRI	2544.5	SIMHADRI	2774.7	RAICHUR	1115.0	BELLARY TPS	1016.3
Coal Based Power Station using sub-critical technology	Fuel Consumption																		
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SIMHADRI	2774.7																		
RAICHUR	1115.0																		
BELLARY TPS	1016.3																		
Justification of the choice of data or description of measurement methods and procedures actually applied :	CEA CO ₂ Baseline database, version - 05																		
Any comment:	-																		



11. Data / Parameter:	Electricity Generation from coal fired power plants using sub-critical technology in the Southern Region																		
Data unit:	GWh																		
Description:	This data is used as an input for calculating the Energy efficiency of coal fired power plants																		
Source of data used:	CEA CO ₂ baseline database, version -05																		
Value applied:	<table border="1"> <thead> <tr> <th>Coal Based Power Station using sub-critical technology</th><th>Generation</th></tr> <tr> <th></th><th>GWh</th></tr> </thead> <tbody> <tr> <td>RAYAL SEEMA</td><td>1,577</td></tr> <tr> <td>RAYAL SEEMA</td><td>1,527</td></tr> <tr> <td>R_GUNDEM STPS</td><td>3,919</td></tr> <tr> <td>SIMHADRI</td><td>3,865</td></tr> <tr> <td>SIMHADRI</td><td>4,215</td></tr> <tr> <td>RAICHUR</td><td>1,540</td></tr> <tr> <td>BELLARY TPS</td><td>1,106</td></tr> </tbody> </table>	Coal Based Power Station using sub-critical technology	Generation		GWh	RAYAL SEEMA	1,577	RAYAL SEEMA	1,527	R_GUNDEM STPS	3,919	SIMHADRI	3,865	SIMHADRI	4,215	RAICHUR	1,540	BELLARY TPS	1,106
Coal Based Power Station using sub-critical technology	Generation																		
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RAYAL SEEMA	1,577																		
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SIMHADRI	4,215																		
RAICHUR	1,540																		
BELLARY TPS	1,106																		
Justification of the choice of data or description of measurement methods and procedures actually applied :	Central Electricity Authority, Government of India mandated to publish information on performance of power sector in India by the Electricity Act 2003. In order to facilitate baseline emissions relating to electricity generation activities, CEA has published a database of CO ₂ emission factors, version -05 for all the regional grids in India. This database also contains information on electricity generation from all major thermal power stations in the country.																		
Any comment:	-																		

12. Data / Parameter:	CO2 emissions from Build Margin Power plants in the southern region
Data unit:	tCO ₂ e
Description:	This data is used as an input for calculating the fugitive CH ₄ emissions occurring in the absence of the project activity
Source of data used:	CEA CO ₂ Baseline database, version 5,0
Value applied:	Refer Appendix 2
Justification of the choice of data or description of measurement methods and procedures actually applied :	Central Electricity Authority, Government of India mandated to publish information on performance of power sector in India by the Electricity Act 2003. In order to facilitate baseline emissions relating to electricity generation activities, CEA has published a database of CO ₂ emission factors for all the regional grids in India. This database also contains information on CO ₂ emissions of all major thermal power stations in the country.
Any comment:	-

**B.6.3 Ex-ante calculation of emission reductions:**

>> The emission reductions ER_y by the project activity during a given year y is:

$$ER_y = BE_y - PE_y - LE_y$$

Where:

ER_y : emissions reductions in year y (t CO₂e)

BE_y : emissions in the baseline scenario in year y (t CO₂e)

PE_y : emissions in the project scenario in year y (t CO₂e)

LE_y : leakage in year y (t CO₂e)

Baseline Emissions:

$$\text{Baseline Emissions: } BE_y = EG_{PJ, y} * EF_{BL, CO_2, y}$$

EG_y = Annual expected net electricity generation from the project activity

= Gross electricity generation – Auxiliary Power Consumption @ 3% of gross generation

= (366 MW x 80% (PLF) x 8,760 (hours))*0.97

= 2,487,980 MWh

$EF_{BL, CO_2, y} = 0.818 \text{ tCO}_2\text{e} / \text{MWh}$. (refer section B.6.1)

$$\text{Baseline Emissions} = 2,487,980 \text{ MWh} \times 0.818 \text{ tCO}_2\text{e/MWh} = 2,035,168 \text{ tCO}_2\text{e}$$

Project Emissions (PE_y):

$$\text{Project Emissions: } PE_y = \sum_f FC_{f, y} * COEF_{f, y}$$

$FC_{f, y}$ = Annual fuel consumption by the project activity

= Annual Electricity Generation x Gross Station Heat Rate / Calorific Value of Natural Gas

= 2,564,928 (MWh) x 1850 (MCal/MWh) / 8553(MCal/1000SCM)

= 554.79(Mcum)

$COEF_{f, y} = 2008.92 \text{ tCO}_2\text{e/Mcum}$ (refer section B.6.1)

$$\text{Project Emissions} = 554.79(\text{Mcum}) \times 2008.92 \text{ (tCO}_2\text{e/Mcum)} = 1,114,531 \text{ tCO}_2\text{e}$$

Leakage Emissions (LE_y)

Leakage: $LE_y = 90,504 \text{ tCO}_2\text{e}$ (Please refer Appendix 2 for details of Leakage calculations)

$$\text{Emission Reductions} = 2,035,168 \text{ tCO}_2\text{e} - 1,114,531 \text{ tCO}_2\text{e} - 90,504 \text{ tCO}_2\text{e}$$

$$= 830,133 \text{ tCO}_2\text{e}$$

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

>> A summary of the ex-ante estimation of emission reductions for all years of the crediting period has been presented in the table below:

Year	Estimation of project activity emissions (tCO ₂ e)	Estimation of baseline emissions (tCO ₂ e)	Estimation of leakage (tCO ₂ e)	Estimation of overall emission reductions (tCO ₂ e)
2010 –2011	1,114 ,531	2,035,168	90,504	830,133
2011 –2012	1,114 ,531	2,035,168	90,504	830,133



Year	Estimation of project activity emissions (tCO ₂ e)	Estimation of baseline emissions (tCO ₂ e)	Estimation of leakage (tCO ₂ e)	Estimation of overall emission reductions (tCO ₂ e)
2012 –2013	1,114 ,531	2,035,168	90,504	830,133
2013 –2014	1,114 ,531	2,035,168	90,504	830,133
2014 –2015	1,114 ,531	2,035,168	90,504	830,133
2015 –2016	1,114 ,531	2,035,168	90,504	830,133
2016 –2017	1,114 ,531	2,035,168	90,504	830,133
2017 –2018	1,114 ,531	2,035,168	90,504	830,133
2018 –2019	1,114 ,531	2,035,168	90,504	830,133
2019 –2020	1,114 ,531	2,035,168	90,504	830,133
Total	11,145,310	20,351,680	905,040	8,301,330

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

>> **Approved monitoring methodology AM0029 “Grid Connected Electricity Generation Plants using Non-Renewable and Less GHG Intensive Fuel”.**

Reference: Available on <http://cdm.unfccc.int>, Version 03.0 EB 39.

The applicability of this methodology to the proposed CDM project activity has been discussed in Section B.2 above.

All the data monitored for the estimation of project, baseline and leakage emissions for verification and issuance will be kept for two years after the end of the crediting period or the last issuance of CERs for this project activity, whichever occurs later.

B.7.1 Data and parameters monitored:

1. Data / Parameter:	FC_{fy}
Data unit:	sm ³ (million scum)
Description:	Total volume of natural gas combusted in the project plant in year y
Source of data to be used:	Fuel supplier data
Value of data applied for the purpose of calculating expected emission reductions in section B.5	554.79
Description of measurement methods and procedures to be applied:	The value will be taken from gas tickets received from RGTIL. Fuel flow meter shall be installed at plant site (RGTIL) and readings shall be recorded daily. The values will be correlated with fortnight joint ticket received from RGTIL fortnightly. The mode of archiving data will be electronic and paper.
QA/QC procedures to be applied:	The meters will be calibrated on annual basis and the accuracy will be maintained at 0.1%. Please refer to Annex 4 for more details.
Any comment:	100% of data will be monitored.

2. Data / Parameter:	NCV_{fy}
Data unit:	kCal/scum
Description:	The net calorific value (energy content) per volume unit of natural gas in year ‘y’
Source of data to be used:	Fuel supplier data
Value of data applied for	8553



the purpose of calculating expected emission reductions in section B.5	
Description of measurement methods and procedures to be applied:	The average net calorific value of natural gas consumed would be provided by gas supplier and recorded by LKPPL for verification
QA/QC procedures to be applied:	
Any comment:	The data will be archived electronically

3. Data / Parameter:	EF_{co2,f,v}
Data unit:	tCO ₂ eq/GJ
Description:	CO ₂ Emission Factor of Natural Gas
Source of data to be used:	IPCC 2006 default values for Carbon Emission Factor
Value of data applied for the purpose of calculating expected emission reductions in section B.6	0.0561
Description of measurement methods and procedures to be applied:	Default values for Carbon Emission Factor of Natural Gas as per Table 1.3 2006 IPCC Guidelines for National Greenhouse Gas Inventories, (Chapter 1, Volume 2, Energy) has been considered. This is also in conformity with the recommendations of the GhG inventory information report submitted by India's Initial National Communication (Chapter 2) where in it is mentioned that in the case of petroleum products and natural gas, the use of default emissions would be fairly accurate due to relatively low variation in quality of these fuels across the globe, as compared to coal. This data will be recorded annually based on latest IPCC information available and will be archived in electronic/paper form. Archived data will be kept up to two years from the end of crediting period or the last issuance, which ever occurs later.
QA/QC procedures to be applied:	No additional QA/QC procedures are planned.
Any comment:	Carbon Emission factor of natural gas will be updated as per the latest guidelines available from IPCC on national greenhouse gas inventory on year to year basis.

4. Data / Parameter:	OXID_f
Data unit:	
Description:	Oxidation Factor of Natural Gas
Source of data to be used:	IPCC
Value of data applied for the purpose of calculating expected emission reductions in section B.6	1.0
Description of measurement methods and procedures to be	Default values as per Table 1.4 Revised 2006 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual has been considered This is also in conformity with the recommendations of the GhG inventory information



applied:	report submitted by India's Initial National Communication (Chapter 2) where in it is mentioned that in the case of petroleum products and natural gas, the use of default emissions would be fairly accurate due to relatively low variation in quality of these fuels across the globe, as compared to coal. This data will be recorded annually based on latest IPCC information available and will be archived in electronic/paper form. Archived data will be kept up to two years from the end of crediting period or the last issuance, which ever occurs later.
QA/QC procedures to be applied:	No additional QA/QC procedures are planned.
Any comment:	Oxidation factor of natural gas will be updated as per the latest guidelines available from IPCC on national greenhouse gas inventory on year to year basis.

5. Data / Parameter:	EG_{PJ,y}
Data unit:	MWh/ year
Description:	Net electricity generation in the project plant during the year y
Source of data to be used:	From the electronic meters installed at the grid inter-connection point at 400 kV PGCIL Nunna sub-station.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	2,487,980 MWh (Based on a normative PLF of 80 % and auxiliary power consumption of 3%)
Description of measurement methods and procedures to be applied:	As per actual meter readings taken jointly by LKPPL and PGCIL. The daily reading will be archived electronically. Monthly joint meter reading will be archived in paper form.
QA/QC procedures to be applied:	The meters will be calibrated as per the standard procedures and documents for the same will be maintained throughout. The accuracy of energy meter is 0.2 class. Refer Annex 4 for more details.
Any comment:	

6. Data / Parameter:	EF_{BM,y}
Data unit:	tCO ₂ /MWh
Description:	Build Margin Emission factor for Southern grid
Source of data used:	"CO ₂ Baseline Database for Indian Power Sector" published by the Central Electricity Authority, Ministry of Power, Government of India. The "CO ₂ Baseline Database for Indian Power Sector" version 5.0 dated 01 November 2009 available on website of Central Electricity Authority (http://cea.nic.in)
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.818
Description of measurement methods and procedures to be applied:	Build Margin Emission Factor will be taken from the CO ₂ baseline database published by CEA. In case the CEA database is not updated, the project proponent will calculate the Build Margin number using the available CEA data. This data will be computed annually based on latest available information and will be archived in electronic/paper form. Archived data will be kept up to two years from the end of crediting period or the last issuance, which ever occurs later.
QA/QC procedures to	No additional QA/QC procedures are planned.



be applied:	
Any comment:	-

7. Data / Parameter:	$EF_{BL,upstream,CH_4}$
Data unit:	tCO ₂ e/MWh
Description:	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity electricity generation
Source of data to be used:	CEA CO ₂ baseline database or calculated value based on available CEA data in case the database is not updated
Value of data applied for the purpose of calculating expected emission reductions in section B.6	13.26 tCO ₂ e /MWh (Refer Appendix 2 of this document for calculations)
Description of measurement methods and procedures to be applied:	$EF_{BL,upstream,CH_4}$ is calculated for power plants included in the Build Margin, inline with the baseline emission factor selection. Therefore in line with the AM0029 requirement of ex-post determination of the Build Margin, the Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity electricity generation (tCH ₄ or tCO ₂ e/MWh) will also be determined <i>ex-post</i> . This data will be computed annually based on latest available information and will be archived in electronic/paper form. Archived data will be kept up to two years from the end of crediting period or the last issuance, which ever occurs later.
QA/QC procedures to be applied:	No additional QA/QC procedures are planned.
Any comment:	-

8.Data / Parameter:	COEF_{f,y}
Data unit:	tCO ₂ / Mcum
Description:	CO2 emission factor of Natural Gas - Quantity (COEF _{f,y})
Source of data to be used:	Calculated
Value of data applied for the purpose of calculating expected emission reductions in section B.6	2008.92
Description of measurement methods and procedures to be applied:	CO2 emission factor of Natural Gas - Quantity (COEF _{f,y}) is calculated using (i) calorific value of natural gas (ii) CO2 Emission coefficient for natural gas in energy units as follows: COEF_{f,y} : CO2 emission factor of Natural Gas – energy (tCO ₂ e/TJ) * Calorific value of Natural Gas (KJ/SCM)
QA/QC procedures to be applied:	No additional QA/QC procedures are planned.
Any comment:	-

8.Data / Parameter:	PE_y
Data unit:	tCO ₂
Description:	Project emission due to combustion of fuel



Source of data to be used:	Calculated
Value of data applied for the purpose of calculating expected emission reductions in section B.6	1,114,531
Description of measurement methods and procedures to be applied:	Project emission due to combustion of fuel is calculated using (i) Total volume of natural gas combusted in the project plant and (ii) CO₂ Emission coefficient for natural gas as follows: $PE_y = \sum_f FC_{f,y} \times COEF_{f,y}$
QA/QC procedures to be applied:	No additional QA/QC procedures are planned.
Any comment:	-

**B.7.2 Description of the monitoring plan:**

>> The Monitoring and Verification (M&V) procedures define a project-specific standard against which the project's performance (i.e. GHG reductions) and conformance with all relevant criteria will be monitored and verified. It includes developing suitable data collection methods and data interpretation techniques for monitoring and verification of GHG emissions with specific focus on technical performance parameters. It also allows scope for review, scrutiny and benchmarking of all this information against reports pertaining to M & V protocols. The monitoring plan is prepared considering in following areas of Project Activity:

1. Establishing and maintaining the appropriate monitoring systems for consumption of NG and electricity generated by the proposed project.
2. Quality control at Project Activity and measurements.
3. Assigning monitoring responsibilities to personnel.
4. Data storage and filing system.

The detailed monitoring plan for the proposed CDM project activity has been presented in Annex-4.

Action Plan for Monitoring of 2% CER Revenue Committed Towards Sustainable Development

LKPPL is committed to contribute a minimum of 2% of the CDM revenue realized from the sale of CERs towards sustainable development. The expected CER revenue generation from the project and the annual revenue committed towards sustainable development are summarized in the table below:

Year	Estimation of overall emission reductions (tCO₂e)	CER Revenue (Million INR)⁵⁴	Contribution to Sustainable Development (2% of CER revenue) (Million INR)
2010 –2011	830,133	647.504	12.950
2011 –2012	830,133	647.504	12.950
2012 –2013	830,133	647.504	12.950
2013 –2014	830,133	647.504	12.950
2014 –2015	830,133	647.504	12.950
2015 –2016	830,133	647.504	12.950
2016 –2017	830,133	647.504	12.950
2017 –2018	830,133	647.504	12.950
2018 –2019	830,133	647.504	12.950
2019 –2020	830,133	647.504	12.950
Total	8,301,330	6475.04	129.50

LKPPL will undertake an annual review process of the actual CERs accrued and the price transacted. On the basis of the actual price and exchange rate, LKPPL will commit 2% of the revenue for sustainable development activities in the local areas.

As part of the annual review, LKPPL will undertake informal discussions with the locals at the project site and commit the revenue towards society / community developmental activities in areas that are of

⁵⁴ CER revenue at 12 euro and euro @ 65 INR

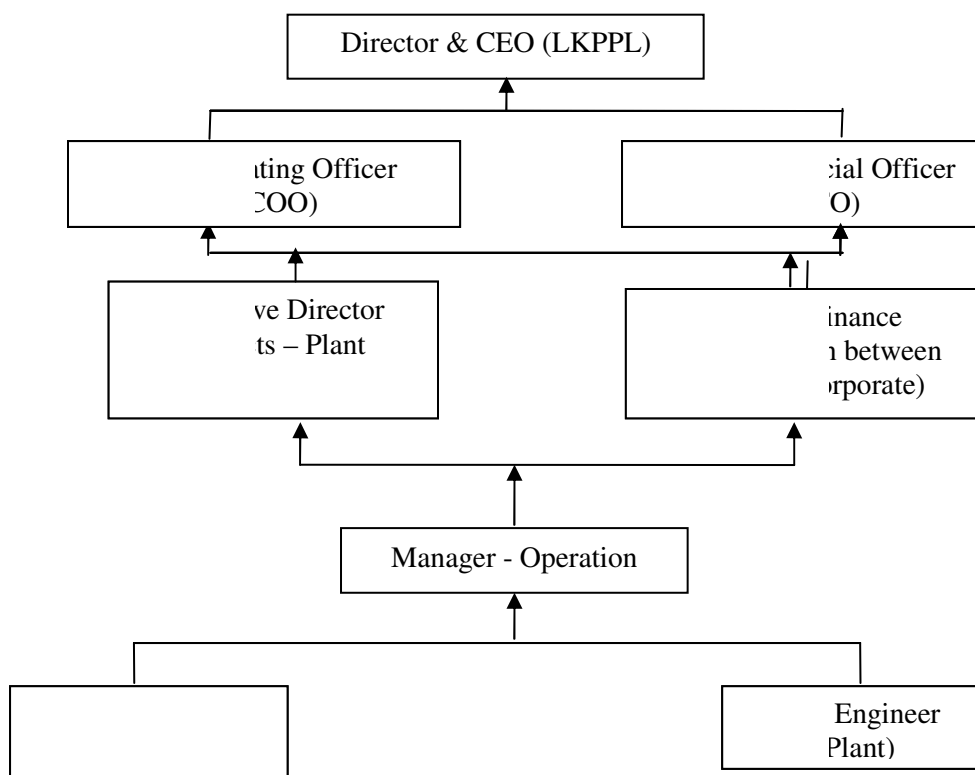


most concern to the local population. These areas could include health, education, sanitation, skill development, infrastructure development, etc. The annual review process will detail the exact activities that would be undertaken using the 2% revenue and the detailed mode of implementation of the proposed activity.

LKPPL commits that a CSR team will be appointed to oversee the activities towards sustainable development and also that the activities are undertaken and concluded in a timely manner each year.

Project Management Structure

The schematic organogram of the project management team as maintained in LKPPL is as follows





At the power plant level the project management team is basically engaged performing day to day activities related to operation and maintenance of the project. The team at the power plant level will primarily be collecting the CDM data and maintaining all records related to CDM activities of the project. The shift engineers would be primarily responsible for primary data collection at the respective verticals & calibration. Shift engineer will report to Manager (Operation). The Manager (Operation) would be responsible for reviewing the data and will report to the Executive Director – Project (Plant). If the data reported by the shift engineers are found satisfactory the same will be recorded in the Management Information System (MIS). In the event of any discrepancy, Manager (Operation) will propose the corrective action in discussion with ED – Project (Plant). ED (Plant) will report to COO

The project management at the corporate level is basically engaged in overall project monitoring. The team at corporate level will review power plant operations and also the data related to CDM activity of the project. AGM – Finance (Corporate) would be responsible for overall project coordination between the plant level and corporate office. Information pertaining to plant operation including CDM related data will be reviewed by AGM Finance. AGM – Finance will report to CFO. In the event of any disconnect, AGM – Finance will suggest the corrective action to the plant officials in discussion with the COO & CFO. Director & CEO would be responsible for overall plant operation. COO & CFO will report to the Director.

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

>> The baseline study and application of baseline methodology was completed on 02/01/2012.

Lanco Kondapalli Power Pvt. Ltd. (The project proponent) has completed the application of the baseline study and monitoring methodology. The contact details appear in Annex 1 of this document.

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:**

>> Date of start: 01/02/2008

The Notice to Proceed for the project activity was issued on 1st February, 2008.

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

>> 20 years 0 months.

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:**

>> Not applicable.

C.2.1.2. Length of the first crediting period:

>> Not applicable.

**C.2.2. Fixed crediting period:****C.2.2.1. Starting date:**

>> Date of request for registration or 31/03/2012 whichever is later.

C.2.2.2. Length:

>> 10 years 0 months

SECTION D. Environmental impacts**D.1. Documentation on the analysis of the environmental impacts, including transboundary impacts:**

>> The proposed project is 366 MW natural gas based power plant. The Environmental Impact Assessment study for the proposed project activity was carried out by M/s Pioneer Consultants Pvt. Ltd., Hyderabad to assess the likely environmental impact and suggest mitigation measures.

The project has received the Environmental Clearance from MoEF and Consent for Establishment from Andhra Pradesh Pollution Control Board (APPCB).

Environmental Impact Statement: The impact statement focuses on the study area of 10km radius around the project site. The environmental components discussed are air, noise, water, land and socio – economic environment. For each of these components, the impacts were identified, predicted and evaluated through Battelle Environmental Evaluation System. The summary of findings of this EIA study as related to the construction of CCPP is presented below:

Air:

The meteorological data such as wind direction, wind speed, maximum temperature, minimum temperature and relative humidity are collected and confirmed that it is consistent with the regional meteorology. Vegetation and human settlement in the vicinity is not likely to be affected. The existing greenbelt will further attenuate air, water or noise emissions that arise due to the power project.

Water:

The entire water requirement for the project will be met from Krishna River. A dedicated pipeline has already been laid from Old Ibrahimpatnam to the project site to meet the water requirement for the project. Waste water will be treated in the Effluent Treatment Plant (ETP). Most quantity of the treated effluent will be used for green belt within the plant premises to the extent possible and the remaining will be discharged into the Budameru drain after ensuring compliance with APPCB standards.

Noise:

The impact of noise generated by the project on the community will be insignificant. It is observed that the general noise level in the plant premises would be within the limits. However, average noise level may increase due to operation of gas turbines, steam turbines and compressors. The increase in the noise levels due to this activity will be limited to the plant premises only.

Land:

There is absolutely no adverse impact on land environment due to the project. There are no important plant species that are rare and endangered or threatened either at plant site or in adjoining areas. The water requirement for green belt development will be met from treated effluents. The soil chemistry will not be affected much.

Socio-economic environment:



The impact of the project will be more on the positive side than on the negative side. These positive impacts can be attributed to development of area with increase in job opportunities, health status, educational status, economic output and other social benefits.

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:

>> The project activity uses natural gas in preference over other fossil fuels such as coal and hence results in lower GHG emissions. Other air and liquid pollutants are minimal. There are no significant solid wastes such as fly ash. The EIA study revealed that there are no significant environmental impacts.

SECTION E. Stakeholders' comments

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

>> The local stakeholders of the project activity were invited through an invitation letter dated 22nd December, 2008. The date and venue of the local stakeholders' consultation meeting was explicitly stated in the invitation letter. The stakeholders identified for the project activity are

- Representative from the Local Pollution Control Board
- Representative from the adjacent village
- Representative from Gas Authority of India Limited
- Contractor
- Government official
- Employees of LKPPL

The local stakeholders' consultation meeting to discuss stakeholder concerns was held on 6th January, 2009. Representative from LKPPL delivered the welcome speech wherein the basic purpose of convening such meeting was explained. It was also elaborated how the project activity leads to reduction in carbon-di-oxide emission in the atmosphere. Subsequently a questionnaire was circulated amongst the stakeholders who were present during the discussion. All the related documents have been shared with DOE during the validation process.

E.2. Summary of the comments received:

>> The summary of the comments received during the meeting is as follows:

The stakeholders opined that the project activity is beneficial to the local people in many ways. The project activity provides employment opportunities to the local population. Since the project uses efficient equipment powered by latest technology, there would be reduction in specific consumption of Natural Gas, which would lead to reduction in emission of greenhouse gases. Also, they pointed out that electricity generation through usage of less carbon intensive fuels is environmentally friendly.

The local population mentioned that the setup of the project improved drinking water and street lighting facilities in the village. They hoped that setup of the project would encourage development of other small scale industries in the village. Most of the stakeholders mentioned that the project has a positive impact on the environment as it emits less greenhouse gases. They also encouraged the green belt developed around the project activity by the project proponent. The minutes of the meeting has been shared with DOE during the validation process.

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



>> The stakeholders held a positive opinion about the project, and no negative comments were received. Therefore, there was no requirement of addressing the negative comments during the meeting.

**Annex 1****CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY**

Organization:	Lanco Kondapalli Power Private Limited
Street/P.O.Box:	Lanco House, Plot No. 4, Software Units Layout,
Building:	HITEC City, Madhapur
City:	Hyderabad
State/Region:	Andhra Pradesh
Postcode/ZIP:	500 081
Country:	India
Telephone:	+91 40 4009 0400
FAX:	+91 40 2311 6127
E-Mail:	lkpl@lancogroup.com
URL:	www.lancogroup.com
Represented by:	
Title:	Director & CEO
Salutation:	Mr.
Last name:	Rao
Middle name:	Panduranga
First name:	P
Department:	Lanco Kondapalli Power Private Limited
Mobile:	+91-986-662-9520
Direct FAX:	+91 40 2311 8444
Direct tel:	+91 40 4009 0400
Personal e-mail:	ppr@lancogroup.com



Annex 2

INFORMATION REGARDING PUBLIC FUNDING

No public funding has been used for the proposed CDM project activity.

**Annex 3****BASELINE INFORMATION****Grid Emission Factors⁵⁵:**

The Operating Margin data for the most recent three years and the Build Margin data for the Southern Region Electricity Grid as published in the CEA database are as follows:

Simple Operating Margin

	Southern Grid (tCO₂e/GWh)
Simple Operating Margin - 2006-07	999.12
Simple Operating Margin - 2007-08	990.62
Simple Operating Margin - 2008-09	972.92
Average Operating Margin of last three years	987.56

Build Margin

	Southern Grid (tCO₂e/GWh)
Build Margin	817.92

Combined Margin Calculations

	Southern Grid (tCO₂e/GWh)
Combined Margin	902.74

⁵⁵ <http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm>

**CALCULATION OF ENERGY EFFICIENCY OF BASELINE ALTERNATIVE⁵⁶**

Coal Based Power Station using sub-critical technology	Fuel Consumption	NCV	Input Energy	Generation	Output Energy	Efficiency
	Million Tonnes	kCal/kg	GJ	GWh	GJ	
RAYAL SEEMA	1045.8	3,567	15,616,188	1,577	5,677,200	36.35%
RAYAL SEEMA	1012.6	3,567	15,121,065	1,527	5,497,200	36.35%
R_GUNDEM STPS	2574.4	3,567	38,442,293	3,919	14,108,400	36.70%
SIMHADRI	2544.5	3,567	37,995,047	3,865	13,914,971	36.62%
SIMHADRI	2774.7	3,567	41,433,141	4,215	15,174,109	36.62%
RAICHUR	1115.0	3,567	16,649,269	1,540	5,543,690	33.30%
BELLARY TPS	1016.3	3,567	15,175,560	1,106	3,982,943	26.25%
Average						34.60%

Carbon - di -oxide emission coefficient	95.81	tCO ₂ /TJ
	0.09581	tCO ₂ /GJ
Emission factor for baseline option	0.997	tCO ₂ /MWh

⁵⁶ Reference : <http://cea.nic.in>



Annex 4

MONITORING INFORMATION

Monitoring Plan for CDM activity:

The general conditions set out in this monitoring plan for metering, recording, meter inspections, test & checking; and communication shall be applicable for both electrical energy and natural gas, where relevant and applicable.

Data for Calculation of CER:

The Emission Reductions (ER_y) will be calculated based on calculations for Project Emissions (PE_y); Baseline Emissions (BE_y) and Leakage (LE_y)

$$ER_y = BE_y - PE_y - LE_y$$

The parameters that would be monitored for PE_y are:

1. **Natural Gas Consumption ($FC_{f,y}$):** Based on daily meter readings for the total natural gas consumption archived electronically
2. **Net Calorific Value of Natural Gas ($NCV_{f,y}$):** Based on daily arithmetic average value of net calorific value, archived electronically

The parameters that would be monitored for BE_y are:

3. **Net Electricity Generation (EG_y):** Based on the energy meter readings at the grid interconnection point at 400kV PGCIL substation.
4. **Emission Factor based on Build Margin ($EF_{BM,y}$) for the Southern regional grid of India:** This value would be taken from the database published annually by Central Electric Authority (CEA) on their website <http://cea.nic.in>. In case for any particular year CEA does not publish the value then $EF_{BM,y}$ will be calculated based on the electricity generation and other relevant data published by CEA.

I. Monitoring for Net Electricity Generation (EG_y):

Metering Plan The Energy (kwh) delivered to the grid is measured by energy meters (0.2 class accuracy) at the grid interconnection point at the 400 kV PGCIL Nunna substation. The meter reading will be recorded by PGCIL.

Meter Test / Checking for Energy Meter Reading (Gross Energy Generated):

All the related energy meters used to record energy delivered to the grid by the project activity will undergo periodical calibration (i.e. once in every five year) as per Central Electricity Authority (CEA) regulation, 2006⁵⁷ on installation and operation of energy meters.

II. Monitoring for Natural Gas Consumption ($FC_{f,y}$):

⁵⁷ http://www.cea.nic.in/e&c/regulations/notified_regulations/Metering_Regulations.pdf



Metering Plan

The natural gas consumed is metered by the Project Proponent at the following locations

1. Main meter - Measurement are recorded at the M&R (receiving and measurement) station of ~~RHL~~ RGTIL located within the plant boundary. ~~RHL~~ RGTIL would subsequently issue a daily (06 to 06 hrs) gas ticket to LKPPL clearly specifying total flow. The meter reading is archived by LKPPL on daily basis.
2. Check meter - The similar measurement facility is available at LKPPL gas conditioning skid.

RGTIL will issue a joint ticket to LKPPL every fortnight. The fortnight joint ticket will also be considered for the purpose of cross verification.

Metering Equipment for Natural Gas Consumption:

Metering equipments for natural gas consumption consists of ultrasonic meters along with , pressure transmitters and temperature transmitters. The Natural Gas Consumption metering is done using a main meter. The main meter is located at the supplier gas conditioning/metering skid. The main meter is installed and owned by the Gas Supplier. The metering equipment shall be maintained in accordance with OEM guidelines as per relevant standards. The accuracy of the ultrasonic meters will be maintained at less than 0.1%.

The measurement shall include all corrections in installations practices recommended for accurate metering of gas by the AGA as applicable and shall be binding to Gas supplier as well as project proponent.

Metering Equipment for Natural Gas Gross/Net Calorific Value: Gross/Net calorific value of the natural gas is measured by using an online chromatograph installed by Gas supplier . The metering equipment shall be maintained in accordance with OEM guidelines as per relevant standards. The measurements are obtained daily by Gas Supplier and are transmitted to Project Proponent on dialy and every fortnight basis.

Meter Test Checking for Natural Gas Meter Reading (Natural Gas Consumed): The natural gas meter shall be tested at site for accuracy periodically against an accepted laboratory standard meter in accordance with prescribed standards. The consumption registered by the meter will hold well as long as the error in the meters is within the permissible limits. The calibration frequency of natural gas flow meter will be maintained at once in a year.

If on calibration, the Gas Supplier's meter registers a variation of more than + 2 (two) percent or if the Gas Supplier's meter is out of service, the procedure for the quantity of Gas during the period between the last calibration and the present shall be followed as per the provisions of GSA:

- I. By using recording by the meter of the Project Proponent and accurately registering; or
- II. By correcting the error if the percentage of error is ascertainable by calibration, test or mathematical calculation; or
- III. By estimating the volume of Gas delivered by comparison with deliveries during the period under similar conditions when the Gas supplier's meter was registering accurately.

Calculation of ratio of RLNG and NG in the gas supplied:

LKPPL will receive co-mingled gas (mixture of natural gas and regasified LNG) from its gas supplier. The ratio of NG and RLNG in the received gas is calculated using the following procedure.



$$\% \text{ of NG in the gas received} = \frac{(NCV_{RLNG} - NCV_f)}{(NCV_{RLNG} - NCV_{NG})}$$

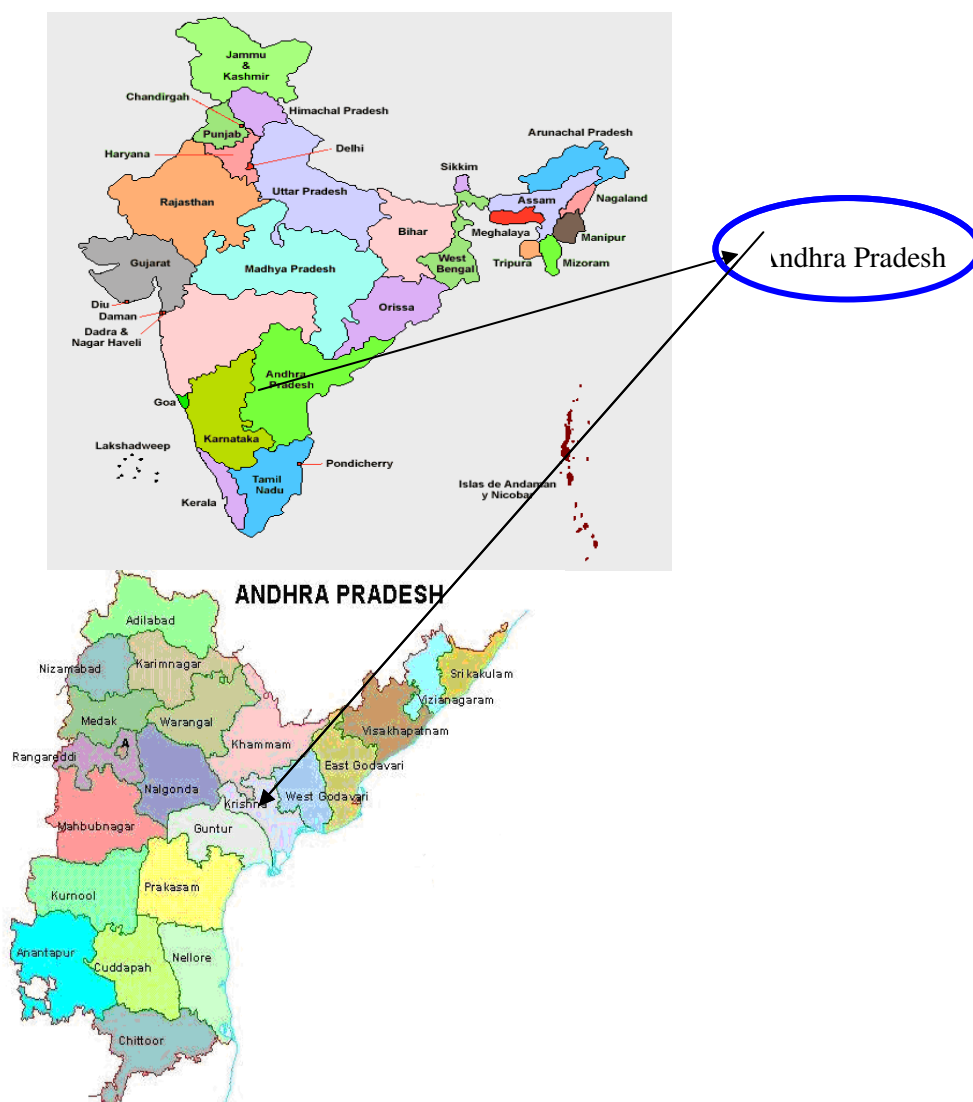
$$\% \text{ of RLNG in the gas received} = \frac{(NCV_f - NCV_{NG})}{(NCV_{RLNG} - NCV_{NG})}$$

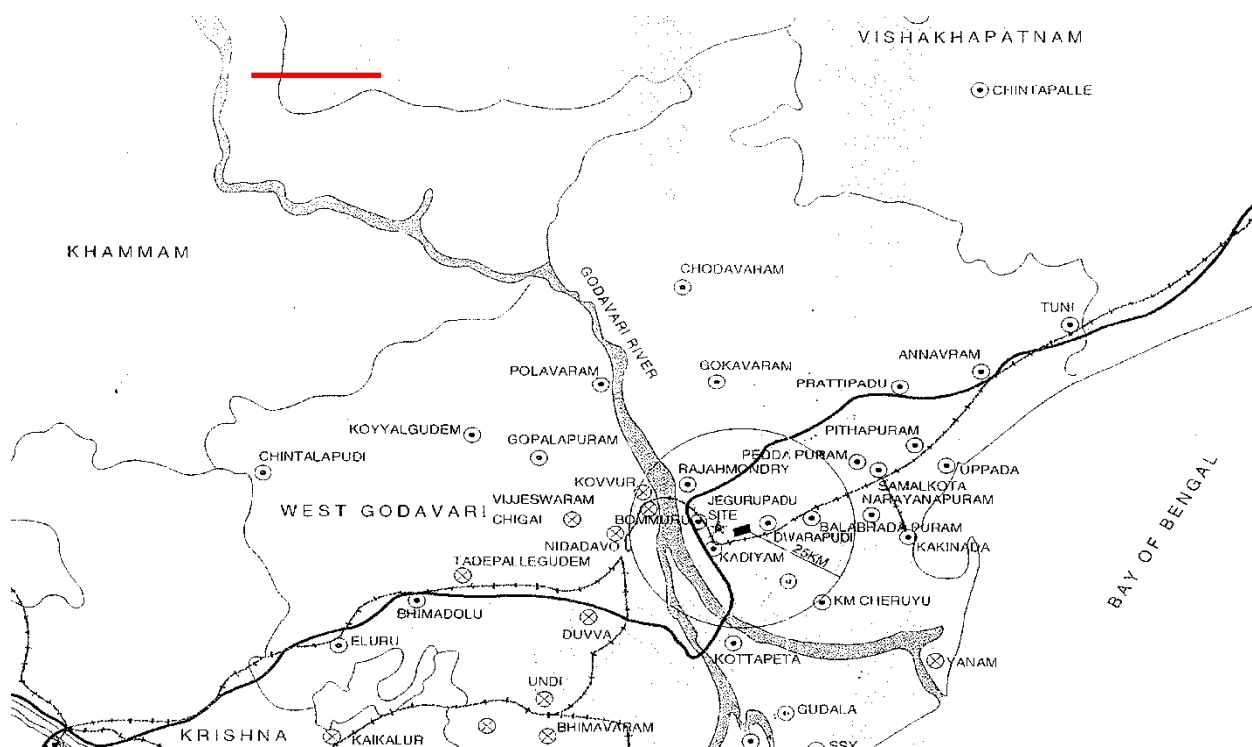
% NG and RLNG will be calculated on a monthly basis using the above formulae while NCV_f is the monthly arithmetic average value of NCV for the month calculated as described earlier in the monitoring plan.



Appendix 1

Project Location Map





**Appendix 2****LEAKAGE CALCULATIONS**

Leakage emissions: $LE_y = LE_{CH_4, y} + LE_{LNG, CO_2, y}$

where:

LE_y Leakage emissions during the year y in tCO₂e

$LE_{CH_4, y}$ Leakage emissions due to fugitive upstream CH₄ emissions in the year y in t CO₂e

$LE_{LNG, CO_2, y}$ Leakage emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year y in t CO₂e

$$LE_{CH_4, y} = [FC_y \cdot NCV_y \cdot EF_{NG, upstream, CH_4} - EG_{PJ, y} \cdot EF_{BL, upstream, CH_4}] \cdot GWP_{CH_4}$$

where:

$LE_{CH_4, y}$ Leakage emissions due to fugitive upstream CH₄ emissions in the year y in t CO₂e

FC_y Quantity of natural gas combusted in the project plant during the year y in m³

$NCV_{NG, y}$ Average net calorific value of the natural gas combusted during the year y in GJ/m³

$EF_{NG, upstream, CH_4}$ Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, distribution, and, in the case of LNG, liquefaction, transportation, re-gasification and compression into a transmission or distribution system, in tCH₄ per GJ fuel supplied to final consumers

$EG_{PJ, y}$ Electricity generation in the project plant during the year in MWh

$EF_{BL, upstream, CH_4}$ Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in t CH₄ per MWh electricity generation in the project plant, as defined below

GWP_{CH_4} Global warming potential of methane valid for the relevant commitment period

$$EF_{BL, upstream, CH_4} = \frac{\sum_j FF_{j, k} \cdot EF_{k, upstream, CH_4}}{\sum_j EG_j}$$

where:

$EF_{BL, upstream, CH_4}$ Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in t CH₄ per MWh electricity generation in the project plant

j Plants included in the build margin

$FF_{j, k}$ Quantity of fuel type k (a coal or oil type) combusted in power plant j included in the build margin

$EF_{k, upstream, CH_4}$ Emission factor for upstream fugitive methane emissions from production of the fuel type k (a coal or oil type) in t CH₄ per MJ fuel produced

EG_j Electricity generation in the plant j included in the build margin in MWh/a



In the present context only NG will be used as fuel. Hence leakage due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system is ignored.

Upstream fugitive emissions on account of use of natural gas by the project activity

Sr. No	Fugitive Emissions due to gas usage	Unit of measurement	Formula for calculation	Value
1	Fugitive CH ₄ emission factor	tCH ₄ /PJ		296.00
2	Annual Gas consumption	Mcum		554.79
3	Calorific Value	kCal/SCM		8,553
4	Calorific Value	TJ/Mcum	= (3) x 4.1868/10 ³	35.80
5	Energy content in Gas consumed	PJ	= (2) x (4)/10 ³	19.87
6	Fugitive CH ₄ emissions	tCH ₄	= (1) x (5)	5,880.59
7	Equivalent CO ₂ emissions	tCO ₂ e	= (6) x 21	123,492

Upstream fugitive emissions on account of use of LNG by the project activity

There is no LNG consumption in the proposed CDM project activity at present. In the event of LNG consumption in future the percentage combination of NG and RLNG could be readjusted to arrive at the fugitive emission.

Upstream fugitive emission occurring in the absence of the project activity

Upstream fugitive emission occurring in the absence of the project activity = $EG_{PJ,y} \times EF_{BL,upstream,CH_4}$

Fugitive emission factor	tCO ₂ e/GWh	13.26
Electricity generations from the Project activity	GWh	2,487.98
Fugitive Emissions in the absence of project activity	tCO ₂ e	32,988

Leakage = 123,492 tCO₂e – 32,988 tCO₂e = 90,504 tCO₂e

Calculation of $EF_{BL,upstream,CH_4}$ is shown in the table below:

	Emissions tCO ₂ e	Emission factor tCO ₂ e/1000 t or Mcum	Fuel consumption 1000 t PJ	Fugitive emission factor tCH ₄ /1000t tCH ₄ /PJ	Fugitive emissions tCO ₂ e
Coal	17,290,548	1,431	12,083	0.8	202,998
Lignite	5,632,280	1,150	4,897	0.8	82,274
Diesel	428,111	3,093	6	4.1	498
Natural gas	2,220,410	1,860	40	160	132,987
Oil	279,988	3,108	4	4.1	312
Total					419,068

Net electricity generation (Million kWh) corresponding to build margin from CEA Database	31,606
--	--------

Fugitive emission factor (tCO₂e/Million kWh)

13.26

Selection of Thermal Plants in Southern grid that are included in the build margin								
NAME	UNIT_NO	DT_COMM	CAPACITY MW AS ON 31/03/2009	STATE	FUEL 1	FUEL 2	2008-09 Absolute Emissions t CO ₂	2008-09 Net Generation GWh
RAYAL SEEMA	3	25-Jan-07	210	ANDHRA PRADESH	COAL	OIL	1,496,473	1,577
RAYAL SEEMA	4	20-Nov-07	210	ANDHRA PRADESH	COAL	OIL	1,449,026	1,527
R_GUNDE M STPS	7	26-Sep-04	500	ANDHRA PRADESH	COAL	OIL	3,683,860	3,919
SIMHADR I	1	22-Feb-02	500	ANDHRA PRADESH	COAL	OIL	3,641,001	3,865
SIMHADR I	2	24-Aug-02	500	ANDHRA PRADESH	COAL	OIL	3,970,468	4,215
RAICHUR	7	11-Dec-02	210	KARNATAKA	COAL	OIL	1,595,471	1,540
BELLARY TPS	1	3-Dec-07	500	KARNATAKA	COAL	OIL	1,454,248	1,106
Total Coal							17,290,548	17,750
LVS POWER DG	1	18-Oct-01	18.4	ANDHRA PRADESH	DISL	n/a	0	0
LVS POWER DG	2	18-Oct-01	18.4	ANDHRA PRADESH	DISL	n/a	0	0
SAMAYA NALLUR DG	1	22-Sep-01	106	TAMIL NADU	DISL	OIL	428,111	663
Total DG							428,111	663
PEDDAPU RAM CCGT	1	8-Nov-02	220	ANDHRA PRADESH	GAS	NAPT	465,963	979
TANIR BAVI	1	8-Jun-01	42.5	KARNATAKA	GAS	NAPT	82,409	150
TANIR BAVI	2	8-Jun-01	42.5	KARNATAKA	GAS	NAPT	82,409	150
TANIR BAVI	3	8-Jun-01	42.5	KARNATAKA	GAS	NAPT	82,409	150
TANIR BAVI	4	8-Jun-01	42.5	KARNATAKA	GAS	NAPT	82,409	150
TANIR BAVI	5	21-Nov-01	50	KARNATAKA	GAS	NAPT	96,951	177
VALUTHU R GT	1	24-Feb-02	58.9	TAMIL NADU	GAS	n/a	108,174	262
VALUTHU R GT	2	13-Mar-03	35.1	TAMIL NADU	GAS	n/a	64,464	156
VALUTHU R GT	3	1-Sep-08	58.5	TAMIL NADU	GAS	n/a	62,109	150



VALUTHUR GT	4	1-Sep-08	33.7	TAMIL NADU	GAS	n/a	35,779	87
VALUTHUR GT	5	6-May-08	59.8	TAMIL NADU	GAS	n/a	98,995	240
KUTTALAM GT	1	27-Nov-03	64	TAMIL NADU	GAS	n/a	170,074	432
KUTTALAM GT	2	24-Mar-04	37	TAMIL NADU	GAS	n/a	98,324	250
KOVILKALAPPAL	1	14-Jul-01	107	TAMIL NADU	GAS	n/a	275,812	666
VALANTHARVI GT	1	29-Oct-05	52.8	TAMIL NADU	GAS	n/a	125,766	263
VALANTHARVI GT	2	15-Apr-06	14.8	TAMIL NADU	GAS	n/a	35,253	74
VEMAGIRI CCCP	1	13-Jan-06	251.5	ANDHRA PRADESH	GAS	n/a	163,855	424
VEMAGIRI CCCP	2	8-Jun-06	137	ANDHRA PRADESH	GAS	n/a	89,257	231
Total Gas							2,220,410	4,991
NEYVELI FST EXT	1	21-Oct-02	210	TAMIL NADU	LIGN	OIL	1,800,140	1,431
NEYVELI FST EXT	2	22-Jul-03	210	TAMIL NADU	LIGN	OIL	1,796,493	1,428
NEYVELI TPS(Z)	1	11-Oct-02	250	TAMIL NADU	LIGN	OIL	2,035,646	1,642
Total Lignite							5,632,280	4,500
BELGAUM DG	1	31-Mar-01	27.1	KARNATAKA	OIL	n/a	93,329	141
BELGAUM DG	2	31-Mar-01	27.1	KARNATAKA	OIL	n/a	93,329	141
BELGAUM DG	3	31-Mar-01	27.1	KARNATAKA	OIL	n/a	93,329	141
Total oil							279,988	424
Source: CEA Database Version 5.0								

Type of FUEL	Net Calorific Value (TJ/103 tonnes or TJ/Mcum) (Note)	Carbon Emission Factor (tC/ TJ)	Fraction of Carbon Oxidised Oxidation Factor	Emission Factor (tCO ₂ / 103 tonnes or tCO ₂ /Mcum)
Coal	14.94	26.13	1.00	1,431
Diesel	41.76	20.20	1.00	3,093
Lignite	10.83	28.95	1.00	1,150
Natural Gas	33.16	15.30	1.00	1,860
Oil	40.17	21.10	1.00	3,108

Note: The NCV has been calculated by multiplying the GCV with the ratio of NCV to GCV.



APPENDIX 3

Weighted Average Cost of Capital:

$$WACC = [D / (D+E)] * [\text{Cost of Debt}] + [E / (D+E)] * [\text{Cost of Equity}]$$

Cost of Debt:

In order to reflect the standard rate in the market the prime lending rate prevailing at the time of investment decision making has been considered as the cost of debt. The Prime Lending Rate (PLR) at the time of investment was in the range of 12.75 – 13.25⁵⁸. Hence the average value of 13.00% (pre-tax) has been considered as the applicable cost of debt.

Interest costs are tax deductible, therefore in order to arrive at the post tax cost of debt, the cost of debt is multiplied with marginal tax rate. The loan tenure of the project is 12 years. It may be noted that for the first 10 years, all power projects in India are exempted from regular corporate tax (as per section 80 IA of Income Tax Act) and will pay Minimum Alternate Tax (MAT). It clarifies during the loan servicing period the project proponent will be paying MAT for first 10 years. Accordingly applicable tax rate has been considered as 11.33%. The post tax cost of debt is as follows

$$: 13.0\% * (1-11.33\%) = 11.53\%$$

PLR rate of 10.50% - 12.00% corresponds to the week ending on 12th January, 2007, which is almost a year before the project activity start date. Hence the same has not been considered to ascertain cost of debt. The PLR values that correspond to the time period (December, 2007 to 2nd week of January, 2008) which is immediately prior to the project activity start date have been considered to arrive at the cost of debt.

Calculation of Cost of Equity:

The expected return on equity has been determined using the Capital Asset Pricing Model (CAPM)⁵⁹. The CAPM economic model is used worldwide to determine the required/expected return on equity based on potential risk of an investment. The CAPM framework is the Nobel award winning work of financial economist Dr. William Sharpe.

$$K_e = R_f + B \times (R_m - R_f)$$

where:

K_e = Rate of return on equity capital;

R_f = Risk-free rate of return;

B = Beta;

$R_m - R_f$ = Market risk premium;

⁵⁸ <http://www.rbi.org.in/scripts/WSSView.aspx?Id=11982>

⁵⁹ The Capital Asset Pricing Model (CAPM) was published in 1964 by William Sharpe, for his work on CAPM Sharpe received the Nobel Prize in 1990. <http://www.investopedia.com/articles/06/CAPM.asp>

**Risk free rate:**

The risk free rate is understood as the rate of return on an asset that is theoretically free of any risks, therefore the rate of interest on government bonds are considered as risk free rates. Page 191 of text book on “Corporate Finance Theory and Practice” by Dr. Aswath Damodaran⁶⁰ of Stern School of Business, New York University describes that the long term government bond rates are suitable indicators of risk free rates since the time horizon for this investment is long term.

Accordingly the risk free rate has been taken from long dated Indian government bond rates prior to the project investment decision. The data on government bond rates is published by Reserve Bank of India⁶¹.

The applicable risk free rate is 7.89 %.

Risk Premium:

The most common approach for estimating the risk premium is to base it on historical data, in the CAPM, the premium is estimated by looking at the difference between average return on stocks and applicable risk free rate as explained above. The average return on stocks has been determined by estimating the compounded annual return of the BSE – SENSEX.

The risk premium has been estimated at 11.76%.

Beta:

Beta (B) indicates the sensitivity of the company to market risk factors. For companies that are not publicly listed, the beta is determined by referring beta values of publicly listed companies that are engaged in similar types of business. Therefore, we have considered beta values of selected electricity generating companies in India. Beta values of individual companies have been sourced from Bloomberg and screenshots are available in appendix - 5. The table below summarises the beta values:

Company	Bloomberg Symbol	Beta (5 year, weekly)
BF Utilities LTd.	BFUT IN Equity	1.436
CESC Ltd.	CESC IN Equity	1.349
Neyveli Lignite Corpn.	NLC IN Equity	1.238
Tata Power Co. Ltd.	TPWR IN Equity	1.162
Gujarat Industries Power Co. Ltd.	GIP IS Equity	0.974
GVK Power	GVKP IN Equity	1.187
Reliance Infrastructure Ltd.	RELI IN Equity	1.202
Torrent Power	TPW IN Equity	0.843
JPVL	JPVL:IN Equity	1.038

⁶⁰ Dr. Damodaran is one of the foremost authorities in the world in the field of Investment Analysis

⁶¹ (Web-link: <http://rbidocs.rbi.org.in/rdocs/Publications/PDFs/80303.pdf>)



Average	1.159
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Approach to estimate Beta has been further revised. In order to draw comparison of applicable “Beta” over different time duration the same has been considered from 1 year to 5 year. The Beta is along with screenshots are provided in Appendix - 4 of document. The table below represents the “Beta” estimated over different time period

Company	Bloomberg Symbol	1 Year (31st January, 07 - 31st Dec , 07),	2 Years (29th January, 06 - 27th January , 08)	3 Years (30th January, 05 - 27th January , 08)	4 Years (30th January, 04 - 27th January , 08)	5 Years (2nd Feb, 03 - 27th January , 08)
BF Utilities LTd.	BFUT IN Equity	0.842	1.499	1.518	1.492	1.436
CESC Ltd.	CESC IN Equity	0.964	1.116	1.124	1.222	1.349
Neyveli Lignite Corpn.	NLC IN Equity	1.016	1.060	1.000	1.196	1.238
Tata Power Co. Ltd.	TPWR IN Equity	1.057	0.977	1.031	1.151	1.162
Gujarat Industries Power Co. Ltd.	GIP IS Equity	0.543	0.732	0.780	0.939	0.974
GVK Power	GVKP IN Equity	0.956	1.187	1.187	1.187	1.187
Reliance Infrastructure Ltd.	RELI IN Equity	1.622	1.361	1.311	1.260	1.202
Torrent Power	TPW IN Equity	0.815	0.843	0.843	0.843	0.843
JPVL	JPVL:IN Equity	1.107	1.121	1.038	1.038	1.038
Average		0.9913	1.0996	1.0924	1.1476	1.159
Minimum				0.9913		

It is quite evident that value of “Beta” is the lowest that corresponds to one year average. The WACC of the project activity using 1 year average “Beta” has been estimated at 13.53% which is higher than the IRR of the project activity. It justifies additionality of the project activity even after following a conservative approach to compute WACC.

Debt - Equity Ratio:

Paragraph 18 of the guideline on the assessment of investment analysis, version -05 provides the following in order to determine the debt/equity finance structure.

“If the benchmark is based on parameters that are standard in the market, then the typical debt/equity finance structure observed in the sector of the country should be used.”



In this regard please refer to the Central Electricity Regulatory Commission (CERC) tariff order dated 26th March, 2004⁶² that specifies that debt and equity to be considered at 70:30 for tariff determination. The same has been applied in the present context.

Weighted Average Cost of Capital (WACC):

WACC has been estimated as per the following illustration

$$\text{WACC} = [D / (D+E)] * [\text{Cost of Debt}] + [E / (D+E)] * [\text{Cost of Equity}]$$

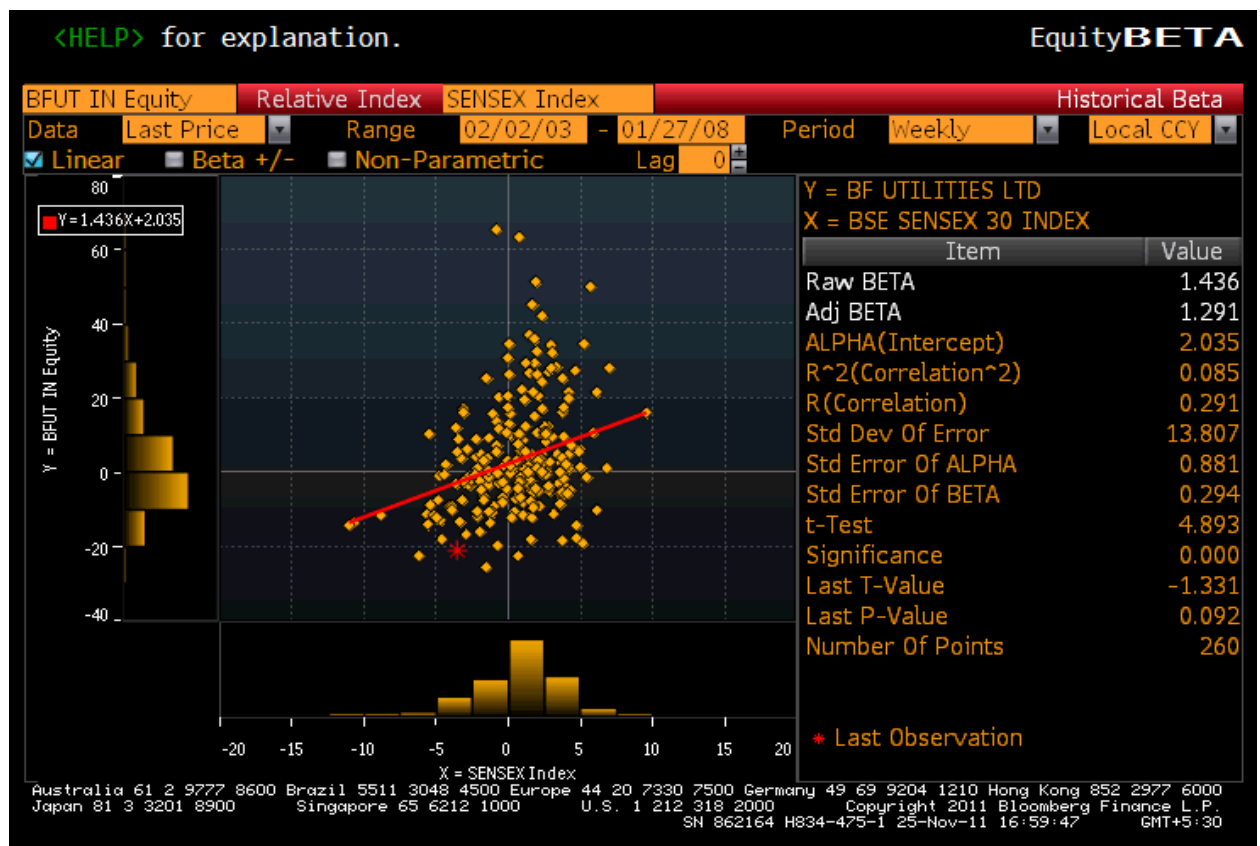
$$\text{WACC} = 75\% * 13\% * (1 - 11.33\%) + 25\% * (7.89\% + 0.991 * 11.76\%)$$

$$\text{Therefore, WACC} = 75\% * 11.53\% + 25\% * 19.55\% = 13.53\%$$

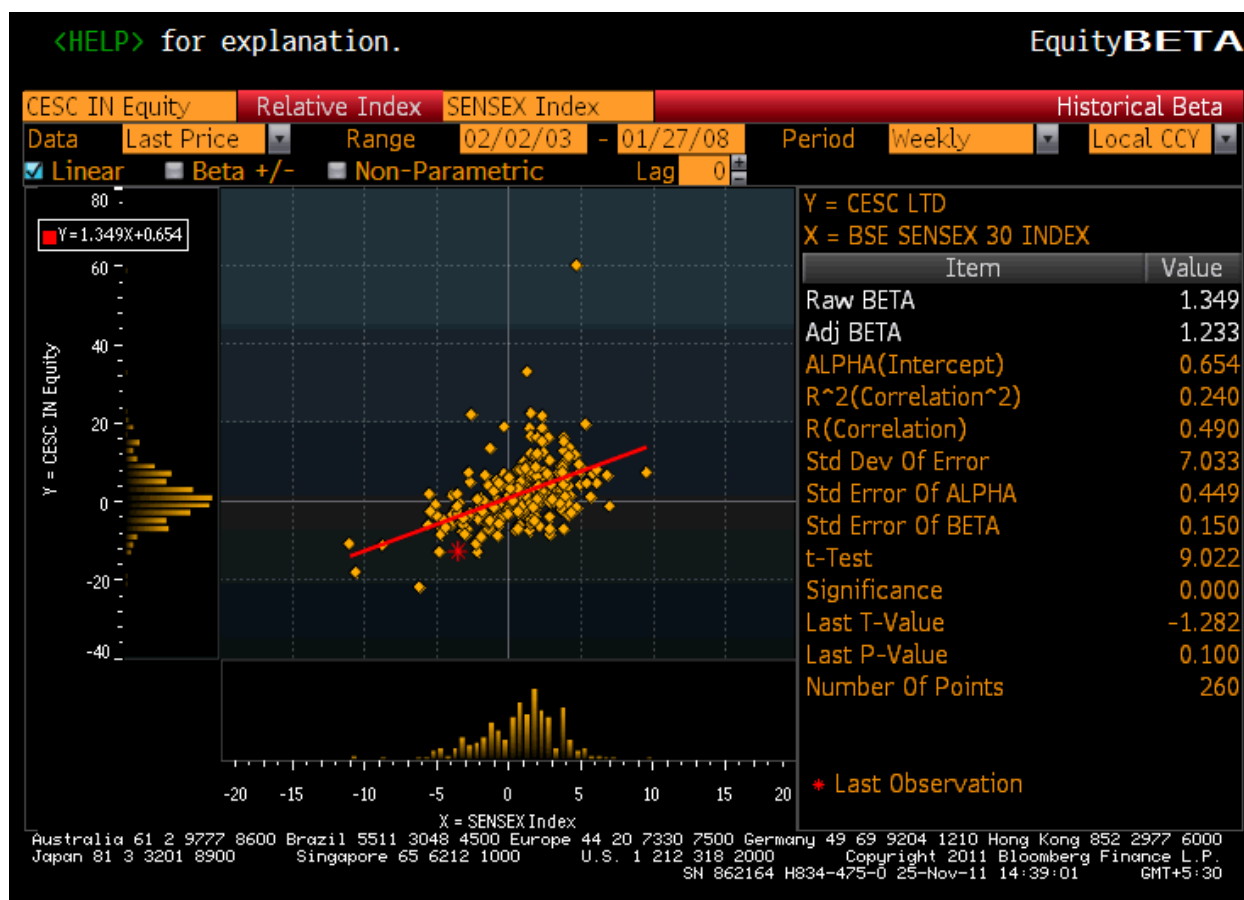
⁶² http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf



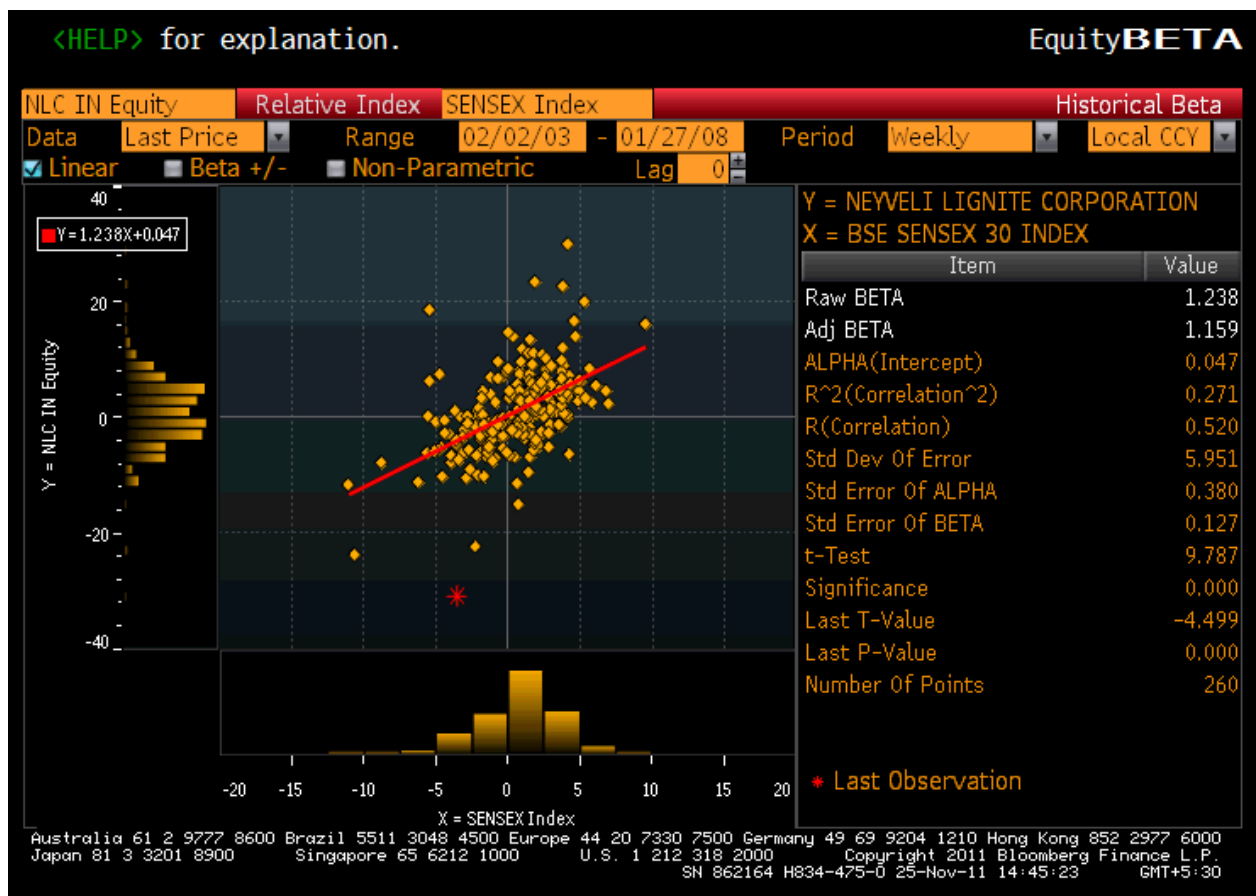
APPENDIX 4



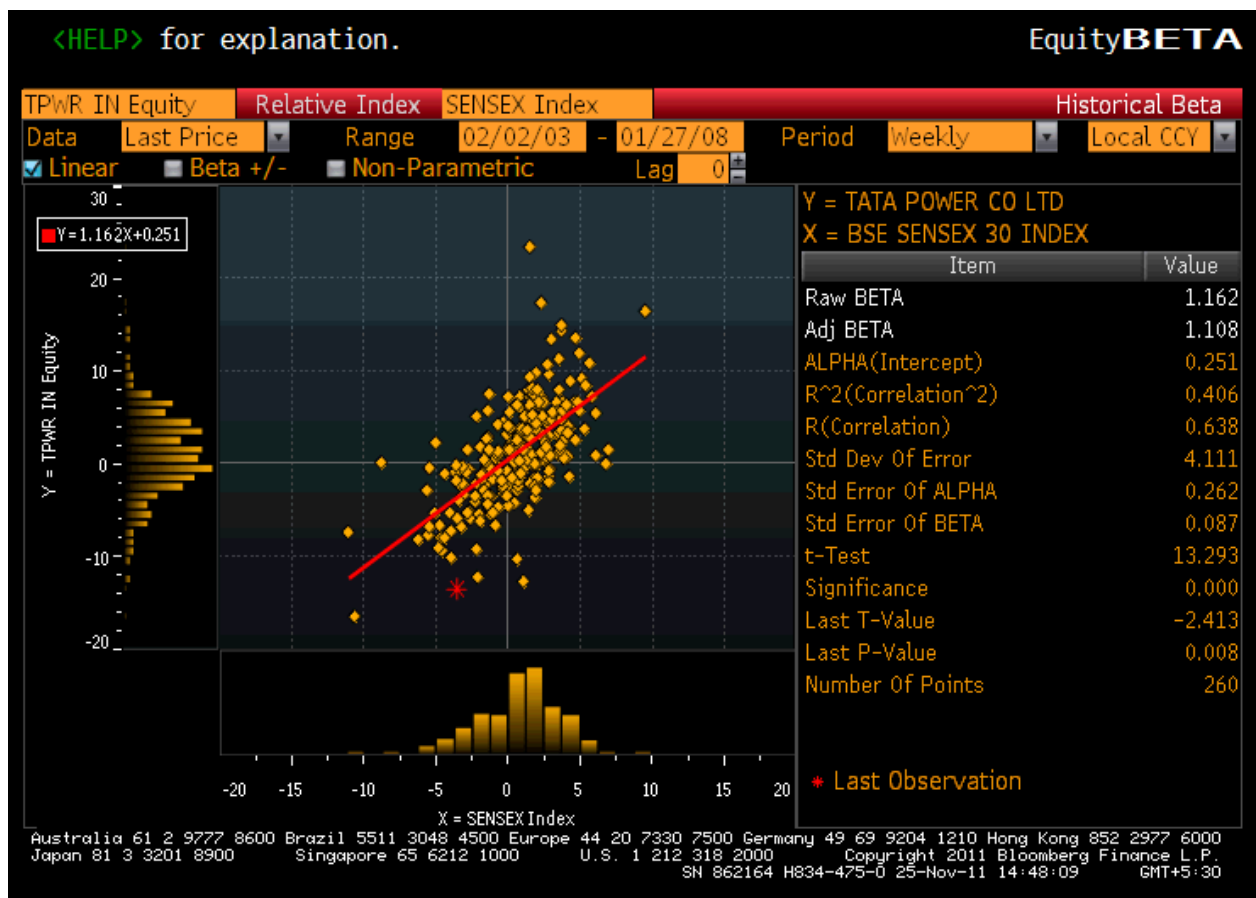
BF Utilities Ltd



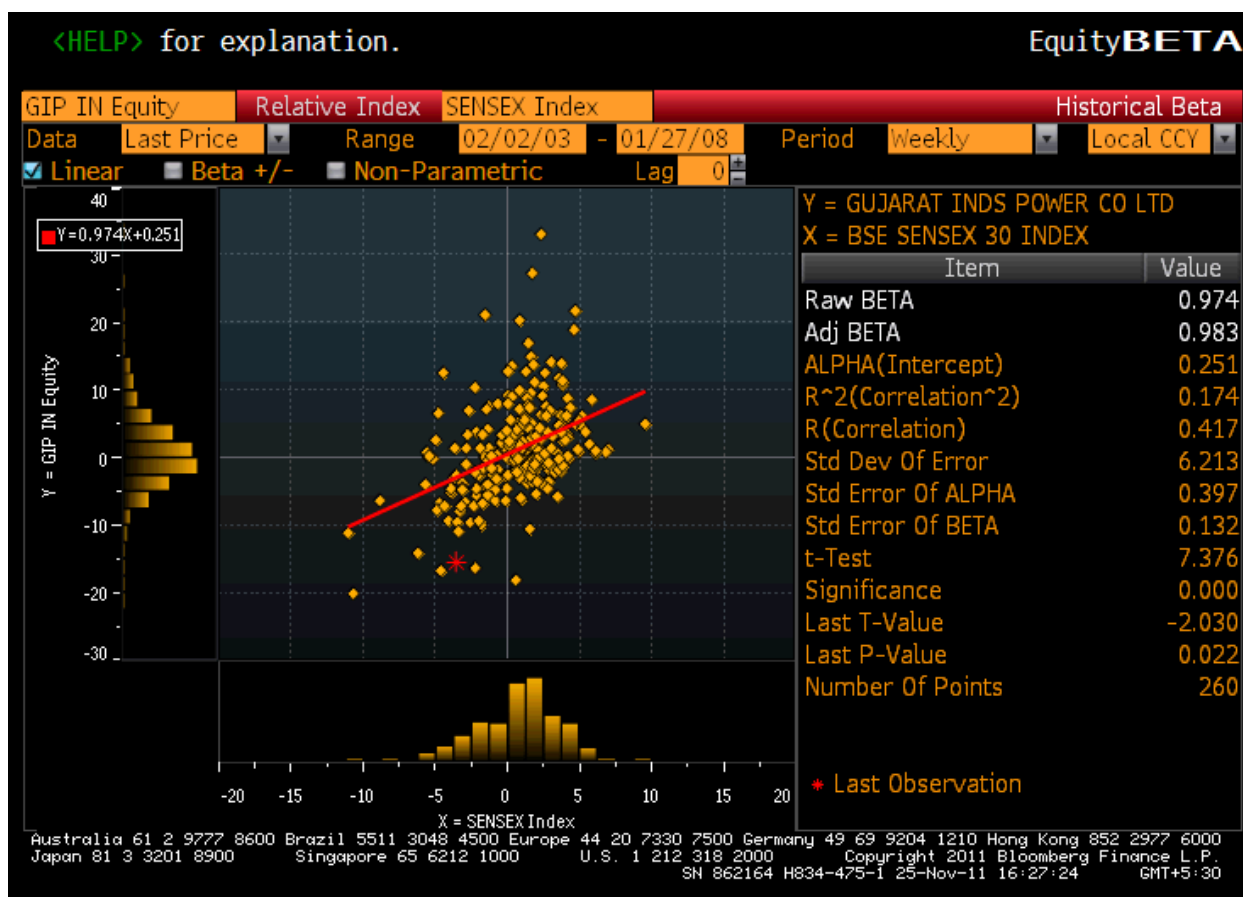
CESC Limited

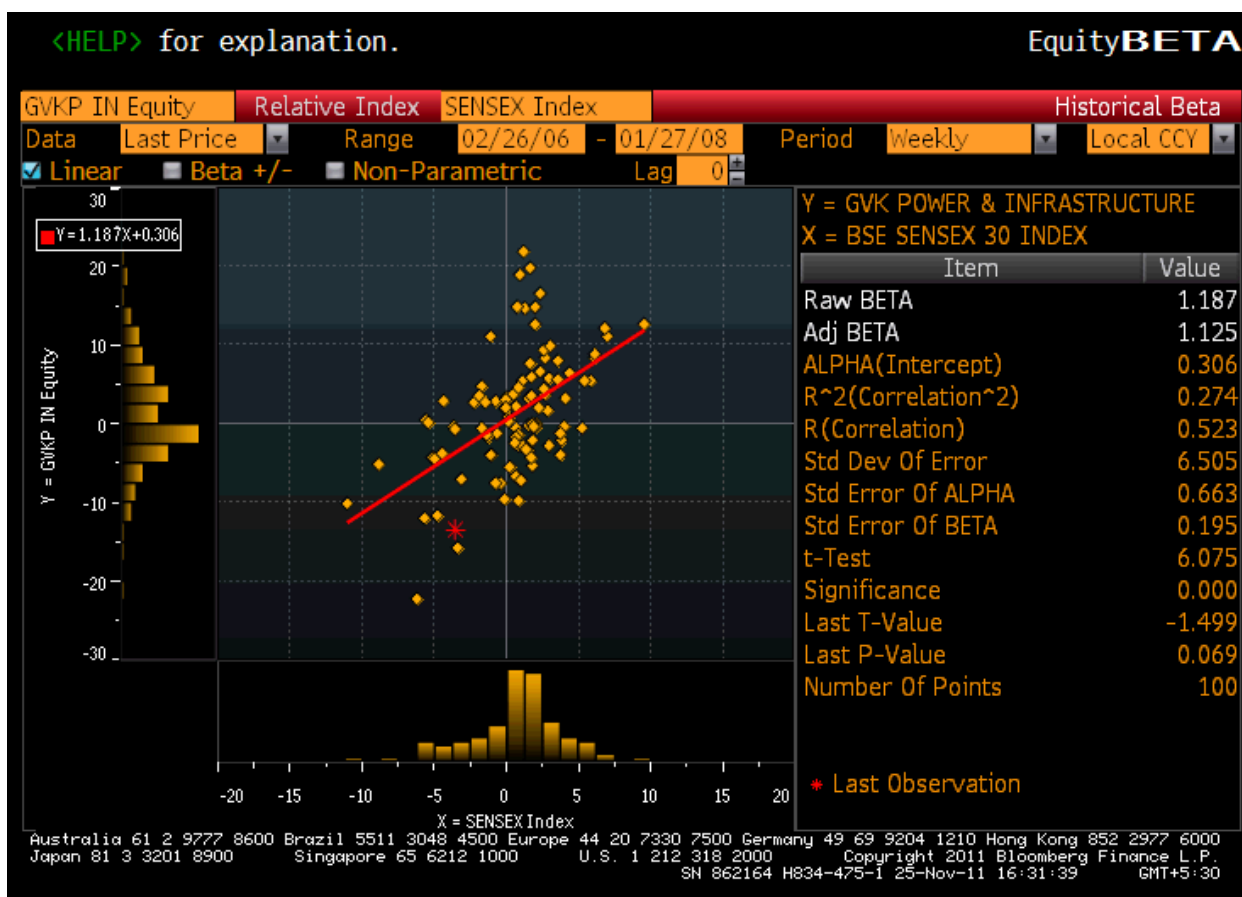


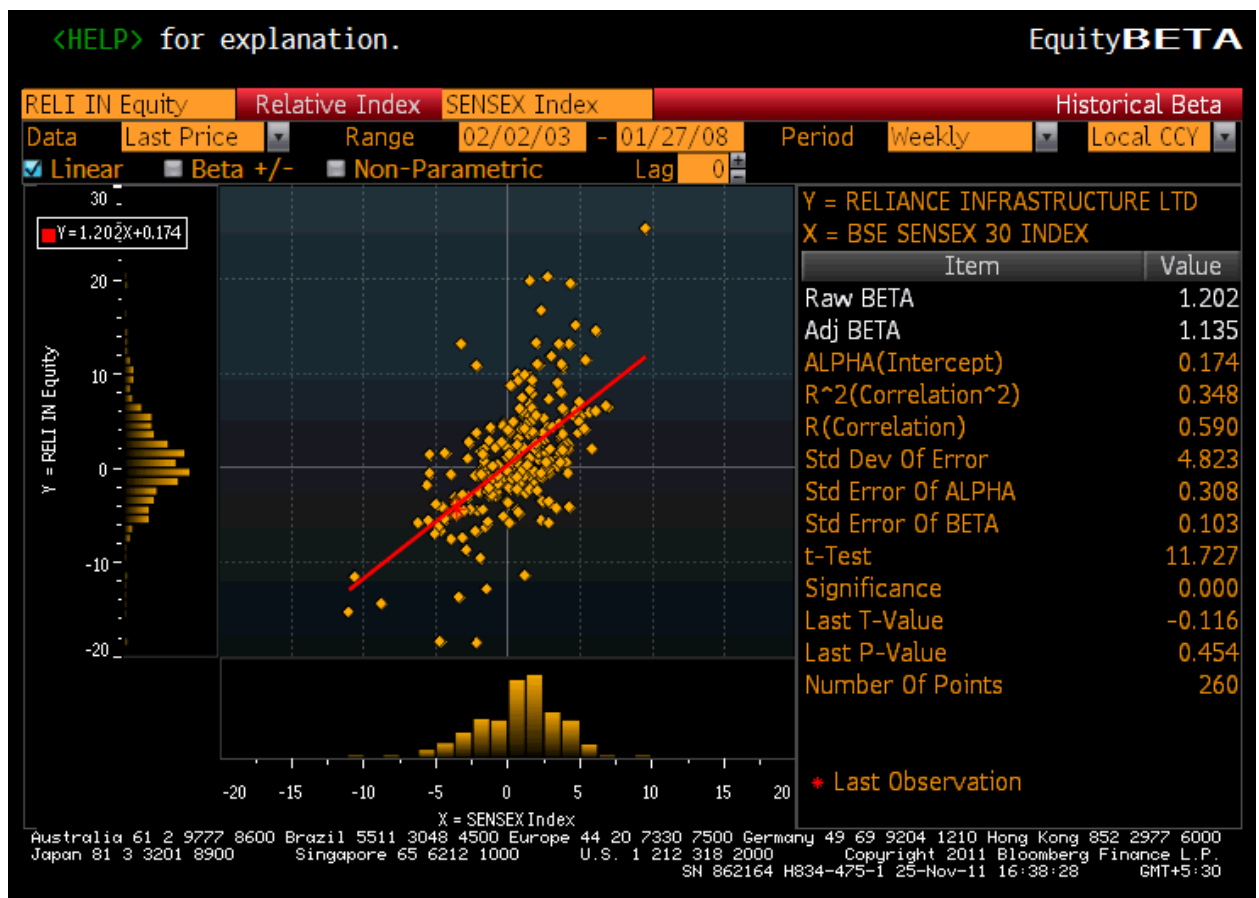
NEYVELI LIGNITE CORPN.



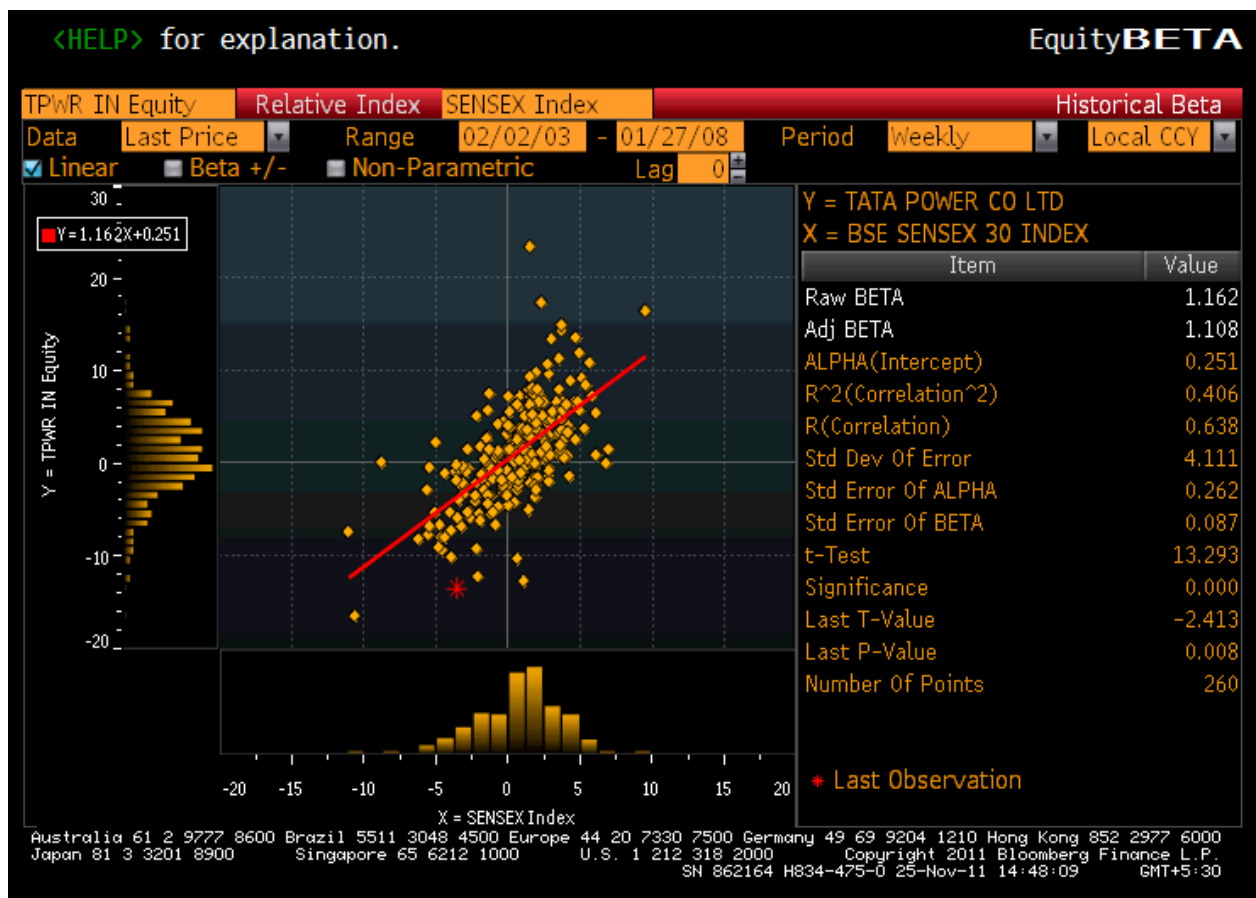
TATA POWER CO. LTD.

**GUJARAT INDUSTRIES POWER CO. LTD.**

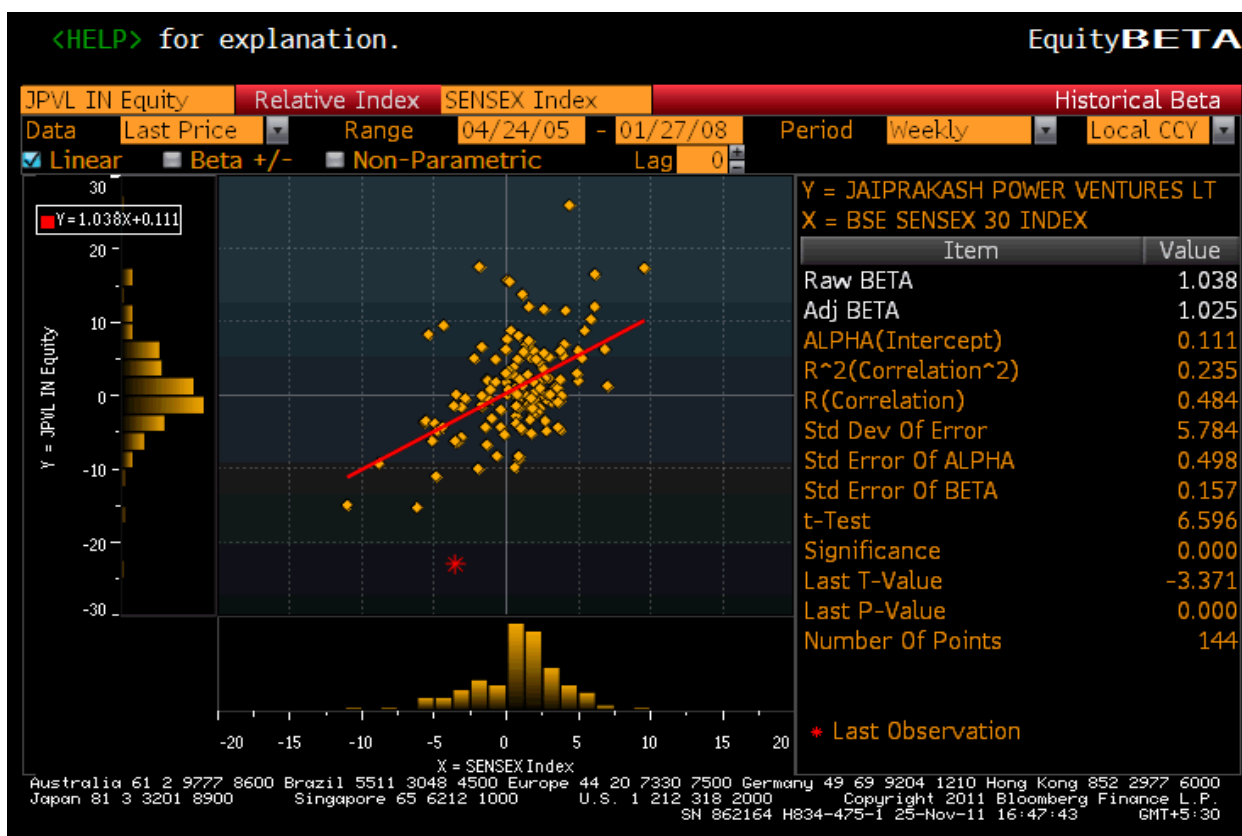
**GVK POWER**



Reliance Infrastructure Ltd.



Torrent Power



Jaiprakash Power Ventures Limited



APPENDIX 5

Assumptions - Levelized Cost of Generation

I. Levelized Cost of Generation for Natural Gas based CCPP:

Parameter	Unit	Value	References
Project Cost			
Plant EPC	Rs. Crores	974.95	As per Detailed Project Report (DPR)
Other cost	Rs. Crores	105.33	
Margin Money - Working Capital	Rs. Crores	-	As per Detailed Project Report (DPR)
Interest During Construction	Rs. Crores	101.01	As per Detailed Project Report (DPR)
Financing Charges	Rs. Crores	6.71	As per Detailed Project Report (DPR)
Project cost including IDC	Rs. Crores	1,188.0	Calculated
Project Specifications			
Project capacity	MW	366	As per Detailed Project Report (DPR)
Project life	Years	20	As per Detailed Project Report (DPR)
Project cost per MW	Rs. Crores	3.246	Calculated
CoD - Open cycle		Oct-09	As per Detailed Project Report (DPR)
CoD - Combined cycle		Apr-10	As per Detailed Project Report (DPR)
Project Financing			
Project Equity	%	25%	As per Detailed Project Report (DPR)
Project Debt	%	75%	As per Detailed Project Report (DPR)
Project Equity	Rs. Crores	297.0	Calculated
ROE	%	14%	
Project Debt	Rs. Crores	891.00	Calculated
Term of Debt	Years	12.0	As per Detailed Project Report (DPR)
Interest on Debt	%	13%	Average of prevailing interest rate at the time of investment decision making. Reference: : http://www.rbi.org.in/scripts/WSSView.aspx?Id=11614
Moratorium Period	Months	6.0	As per Detailed Project Report (DPR)



Operating Norms			
Heat Rate			
Open cycle	Kcal/Kwh	2,685	As per Detailed Project report (DPR)
Combined Cycle	Kcal/Kwh	1,850	As per Detailed Project report (DPR)
Auxiliary Consumption			
Open cycle	%	1.00%	As per Detailed Project report (DPR)
Combined Cycle		3.00%	As per Detailed Project report (DPR)
PLF			
		80%	As per Detailed Project report (DPR)
Fuel Specifications			
Primary Fuel - Natural Gas			
NCV of Natural Gas	kCal/SCM	8,553	As per Detailed Project Report (DPR) the GCV of gas is 12672 kCal/kg. The density has been considered at 0.75 kg/m ³ . The NCV has been considered as 90% of GCV
Specific Gas consumption - Open cycle	SCM/kWh	0.31	Calculated
Specific Gas consumption - Combined cycle	SCM/kWh	0.22	Calculated
Landed Cost of NG	Rs. / scm	7.86	Calculated
Annual Gas Price Escalation		0%	-
Secondary Fuel -Oil			
NCV of Oil	kCal / lt	9,595	CEA CO2 Emission Database version 2: http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm
Specific Oil consumption - Open cycle	ml / kWh	0.0	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Specific Oil consumption - Combined cycle	ml / kWh	0.0	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Cost of Oil	Rs. / kl	33,000	To check
Escalation for oil	%	0%	
Depreciation			
Recovery of Depreciation	%	90%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Rate of Depreciation - Book Depreciation	%	3.60%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Advance Against Depreciation	of loan amount	10%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf



O&M			
O&M Expenses	% of total capital cost	2.50%	As per Detailed Project Report (DPR)
Escalation Factor	%	4%	As per Detailed Project Report (DPR)
Tax			
Tax Rate	%	33.99%	Income Tax Act
MAT Rate	%	11.33%	Income Tax Act
80IA Exemption	Years	10.00	Income Tax Act
Working Capital norms			
Receivables	Days	60	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Spares	% of Project Cost	1%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Escalation factor for spares	%	6%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Primary Fuel Stock	Days	30	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Secondary Fuel Stock	days	15	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
O&M Expenses	Days	30	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Interest on Working Capital	%	11.50%	As per Detailed Project Report (DPR)

**II. Levelized Cost of Generation for Lignite Based Alternative:**

Parameter	Unit	Value	Reference
Project Cost			
Plant EPC	Rs. Crores		
Other cost	Rs. Crores		
Margin Money - Working Capital	Rs. Crores		
Interest During Construction	Rs. Crores		
Financing Charges	Rs. Crores		
Project cost including IDC	Rs. Crores	2,030.0	
Project Specifications			
Project capacity	MW	500	
Project life	Years	20	
Project cost per MW	Rs. Crores	4.06	http://cea.nic.in/reports/proj_mon/bs_nlc.pdf
CoD - Open cycle		Apr-10	
CoD - Combined cycle		Apr-10	
Project Financing			
Project Equity	%	25%	Detailed Project Report (DPR)
Project Debt	%	75%	Detailed Project Report (DPR)
Project Equity	Rs. Crores	507.5	
ROE	%	14%	
Project Debt	Rs. Crores	1,522.5	
Term of Debt	Years	12.0	As per Detailed Project Report (DPR)
Interest on Debt	%	13.00%	Average of prevailing interest rate at the time of investment decision making. Reference : http://www.rbi.org.in/scripts/WSSView.aspx?Id=11614
Moratorium Period	Months	6.0	As per Detailed Project Report (DPR)
Operating Norms			
Heat Rate			
1st year	Kcal/Kwh	2,695	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
2nd year onwards	Kcal/Kwh	2,695	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Auxiliary Consumption			



1st year	%	9.50%	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
2nd year onwards		9.50%	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
PLF		80%	
Fuel Specifications			
Primary Fuel - Lignite			
NCV of Lignite	kCal/kg	2699	CEA expert committee report on fuel for power generation; page 4 of 17 Reference : http://www.cea.nic.in/reports/articles/thermal/expert_committee_report_fuel.pdf The difference between GCV and NCV has been considered at 3.6%. (Reference: CEA CO2 database; version 02 dated 21st June, 2007) Source : http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm
Specific Lignite consumption - 1st year	kg/kWh	0.96	
Specific Lignite consumption - 2nd yr onwards	kg/kWh	0.96	
Landed Cost of Lignite	Rs. / kg	0.80	<u>CEA expert committee report on fuel for power generation; page 4 of 17</u>
Annual Lignite Price Escalation		0%	
Secondary Fuel -Oil			
NCV of Oil	kCal / lt	9,595	CEA CO2 Emission Database version 2: http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm
Specific Oil consumption - Open cycle	ml / kWh	3.0	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Specific Oil consumption - Combined cycle	ml / kWh	3.0	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Cost of Oil	Rs. / kl	33,000	To check
Escalation for oil	%	0%	
Depreciation			
Recovery of Depreciation	%	90%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Rate of Depreciation - Book Depreciation	%	3.60%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf



			<u>d conditions of tariff.pdf</u>
Advance Against Depreciation	of loan amount	10%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
O&M			
O&M expenses	Rs. Lakhs/MW	13.16	http://www.cercind.gov.in/08022007/Final-Order-Terms.pdf
Escalation Factor	%	4%	
Tax			
Tax Rate	%	33.99%	Income Tax Act
MAT Rate	%	11.33%	Income Tax Act
80IA Exemption	Years	10.00	Income Tax Act
Working Capital norms			
Receivables	Days	60	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Spares	% of Project Cost	1%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Escalation factor for spares	%	6%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Primary Fuel Stock	Days	60	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Secondary Fuel Stock	days	60	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
O&M Expenses	Days	30	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Interest on Working Capital	%	11.50%	As per Detailed Project Report (DPR)

**III. Levelized Cost of Generation for Coal - Super-critical Alternative using imported fuel:**

Parameter	Units	Value	Reference
Project Cost			
Plant EPC	Rs. Crores		
Other cost	Rs. Crores		
Margin Money - Working Capital	Rs. Crores		
Interest During Construction	Rs. Crores		
Financing Charges	Rs. Crores		
Project cost including IDC	Rs. Crores	3133.1	Calculated
Project Specifications			
Project capacity	MW	660	
Project life	Years	20	
Project cost per MW	Rs. Crores	4.747	British High Commission Report on UMPP Risk Analysis, April 2007 ; Page no 12 of 151(USD 1227 per kW ; exchange rate USD @ 40.23 INR).The specific cost as considered corresponds to low supercritical category using international coal (Mount Arthur coal). Please refer to page no 10 of the same report that specifies the unit size of low super critical category as 660 MW. The exchange rate has also been referred from the British High Commission Report on UMPP Risk Analysis, April 2007 ; Page no 14 of 151.
CoD - Open cycle		Apr-10	
CoD - Combined cycle		Apr-10	
Project Financing			
Project Equity	%	25%	Detailed Project Report (DPR)
Project Debt	%	75%	Detailed Project Report (DPR)
Project Equity	Rs. Crores	783.3	
ROE	%	14%	
Project Debt	Rs. Crores	2349.8	
Term of Debt	Years	12.0	As per Detailed Project Report (DPR)
Interest on Debt	%	13%	Average of prevailing interest rate at the time of investment decision making. Reference : http://www.rbi.org.in/scripts/WSView.aspx?Id=11614



Moratorium Period	Months	6.0	As per Detailed Project Report (DPR)
Operating Norms			
Heat Rate			
1st year	Kcal/Kwh	2167	Calculated from efficiency of 39.35%. The efficiency value has been referred from British High Commission Report on UMPP Risk Analysis, April 2007 ; Page no 10 of 151 (Corresponding to International coal under Indian condition, LHV, for low super critical technology).
2nd year onwards	Kcal/Kwh	2167	Same as above
Auxiliary Consumption			
1st year	%	9.00%	http://www.cercind.gov.in/13042007/Terms and conditions of tariff.pdf
2nd year onwards		9.00%	http://www.cercind.gov.in/13042007/Terms and conditions of tariff.pdf
PLF		80%	As per Detailed Project report (DPR)
Fuel Specifications			
Primary Fuel - Coal			
NCV of Coal	kCal/kg	5206	CEA expert committee report on fuel pricing (Page 4 of 17) The difference between GCV and NCV has been considered at 3.6%. (Reference: CEA CO2 database; version 02 dated 21st June, 2007 Weblink: http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm
Specific coal consumption - 1st year	kg/kWh	0.42	
Specific coal consumption - 2nd yr onwards	kg/kWh	0.42	
Landed Cost of Coal	Rs. / kg	1.925	CEA expert committee report on fuel pricing (Page 4 of 17); The cost of coal if higher than the same considered in the sub-critical model. The difference is



			attributable to the fact that a super-critical power plant would require superior quality fuel as against the same for a sub-critical power plant
Annual Coal Price Escalation		0%	
Secondary Fuel -Oil			
NCV of Oil	kCal / lt	9,595	CEA CO2 Emission Database version 2: http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm
Specific Oil consumption - Open cycle	ml / kWh	2.0	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Specific Oil consumption - Combined cycle	ml / kWh	2.0	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Cost of Oil	Rs. / kl	33,000	To check
Escalation for oil	%	0%	
Depreciation			
Recovery of Depreciation	%	90%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Rate of Depreciation - Book Depreciation	%	3.60%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Advance Against Depreciation	of loan amount	10%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
O&M			
O&M Expenses	Rs. Lakhs/MW	11.84	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Escalation Factor	%	4%	As per Detailed Project Report (DPR)
Tax			
Tax Rate	%	33.99%	Income Tax Act
MAT Rate	%	11.33%	Income Tax Act
80IA Exemption	Years	10.00	Income Tax Act



Working Capital norms			
Receivables	Days	60	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Spares	% of Project Cost	1%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Escalation factor for spares	%	6%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Primary Fuel Stock	Days	60	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Secondary Fuel Stock	days	60	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
O&M Expenses	Days	30	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Interest on Working Capital	%	11.50%	As per Detailed Project Report (DPR)

**IV. Levelized Cost of Generation for Coal - Super-critical Alternative using domestic fuel:**

Parameter	Unit	Value	References
Project Cost			
Plant EPC	Rs. Crores		
Other cost	Rs. Crores		
Margin Money - Working Capital	Rs. Crores		
Interest During Construction	Rs. Crores		
Financing Charges	Rs. Crores		
Project cost including IDC	Rs. Crores	3,257.9	Calculated
Project Specifications			
Project capacity	MW	660	
Project life	Years	20	
Project cost per MW	Rs. Crores	4.936	British High Commission Report on UMPP Risk Analysis, April 2007; Page no 12 of 151(USD 1180 per kW; exchange rate USD @ 40.23 INR).The specific cost as considered corresponds to low supercritical category. Please refer to page no 10 of the same report that specifies the unit size of low super critical category as 660 MW. The exchange rate has also been referred from the British High Commission Report on UMPP Risk Analysis, April 2007 ; Page no 14 of 151.
CoD - Open cycle		Apr-10	
CoD - Combined cycle		Apr-10	
Project Financing			
Project Equity	%	25%	Detailed Project Report (DPR)
Project Debt	%	75%	Detailed Project Report (DPR)
Project Equity	Rs. Crores	814.5	
ROE	%	14%	
Project Debt	Rs. Crores	2,443.4	
Term of Debt	Years	12.0	As per Detailed Project Report (DPR)
Interest on Debt	%	13.00%	Average of prevailing interest rate at the time of investment decision making. Reference : http://www.rbi.org.in/scripts/WSSView.aspx?Id=11614
Moratorium Period	Months	6.0	As per Detailed Project Report (DPR)



Operating Norms			
Heat Rate			
1st year	Kcal/Kwh	2,186	Calculated from efficiency of 39.35%. The efficiency value has been referred from British High Commission Report on UMPP Risk Analysis, April 2007 ; Page no 10 of 151(Corresponding to Indian coal under Indian condition, LHV, for low super critical technology)
2nd year onwards	Kcal/Kwh	2,186	http://www.cea.nic.in/more_upload/efficiency_super_critical_units.pdf
Auxiliary Consumption			
1st year	%	9.00%	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
2nd year onwards		9.00%	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
PLF			
		80%	As per Detailed Project report (DPR)
Fuel Specifications			
Primary Fuel - Coal			
NCV of Coal	kCal/kg	3,946	CERC Tariff petition (140/2005 ; page no 25 of 34) in respect of Ramagundam Super Thermal Power Station Stage (III) for the period 25.03.2009 to 31.03.2009. The value corresponding to the month of February, 2005 (the latest month) has been considered. Weblink: http://cercind.gov.in/03022007/No-140-05-doh-22-5-07.pdf The difference between GCV and NCV has been considered at 3.6%.(Reference: CEA CO2 database; version 02 dated 21st June, 2007 Weblink: http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm
Specific coal consumption - 1st year	kg/kWh	0.55	
Specific coal consumption - 2nd yr onwards	kg/kWh	0.55	
Landed Cost of Coal	Rs. / kg	1.2849	CERC Tariff petition (140/2005 ; page no 25 of 34) in respect of Ramagundam Super Thermal Power Station Stage (III) for the period 25.03.2009 to 31.03.2009. The value corresponding to the month of February, 2005 (the latest month) has been considered. Weblink: http://cercind.gov.in/03022007/No-140-05-doh-22-5-07.pdf
Annual Coal Price Escalation		0%	
Secondary Fuel -Oil			



NCV of Oil	kCal / lt	9,595	CEA CO2 Emission Database version 2: http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm
Specific Oil consumption - Open cycle	ml / kWh	2.0	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Specific Oil consumption - Combined cycle	ml / kWh	2.0	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Cost of Oil	Rs. / kl	33,000	To check
Escalation for oil	%	0%	
Depreciation			
Recovery of Depreciation	%	90%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Rate of Depreciation - Book Depreciation	%	3.60%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Advance Against Depreciation	of loan amount	10%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
O&M			
O&M Expenses	Rs. Lakhs/MW	11.84	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Escalation Factor	%	4%	As per Detailed Project Report (DPR)
Tax			
Tax Rate	%	33.99%	Income Tax Act
MAT Rate	%	11.33%	Income Tax Act
80IA Exemption	Years	10.00	Income Tax Act
Working Capital norms			
Receivables	Days	60	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Spares	% of Project Cost	1%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Escalation factor for spares	%	6%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf



			nditions_of_tariff.pdf
Primary Fuel Stock	Days	60	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Secondary Fuel Stock	days	60	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
O&M Expenses	Days	30	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Interest on Working Capital	%	11.50%	As per Detailed Project Report (DPR)

**V. Levelized Cost of Generation for Coal (Sub-critical)Based Alternative:**

Parameter	Unit	Value	Reference
Project Cost			
Plant EPC	Rs. Crores		
Other cost	Rs. Crores		
Margin Money - Working Capital	Rs. Crores		
Interest During Construction	Rs. Crores		
Financing Charges	Rs. Crores		
Project cost including IDC	Rs. Crores	2,000.0	
Project Specifications			
Project capacity	MW	500	
Project life	Years	20	
Project cost per MW	Rs. Crores	4.00	http://cea.nic.in/reports/articles/thermal/expert_committee_report_fuel.pdf
CoD - Open cycle		Apr-10	
CoD - Combined cycle		Apr-10	
Project Financing			
Project Equity	%	25%	Detailed Project Report (DPR)
Project Debt	%	75%	Detailed Project Report (DPR)
Project Equity	Rs. Crores	500.0	
ROE	%	14%	
Project Debt	Rs. Crores	1,500.0	
Term of Debt	Years	12.0	As per Detailed Project Report (DPR)
Interest on Debt	%	13.00%	Average of prevailing interest rate at the time of investment decision making. Reference : http://www.rbi.org.in/scripts/WSSView.aspx?Id=11614
Moratorium Period	Months	6.0	As per Detailed Project Report (DPR)
Operating Norms			
Heat Rate			



1st year	Kcal/Kwh	2,450	http://www.cercind.gov.in/13042007/Terms and conditions of tariff.pdf
2nd year onwards	Kcal/Kwh	2,450	http://www.cercind.gov.in/13042007/Terms and conditions of tariff.pdf
Auxiliary Consumption			
1st year	%	7.50%	http://www.cercind.gov.in/13042007/Terms and conditions of tariff.pdf
2nd year onwards		7.50%	http://www.cercind.gov.in/13042007/Terms and conditions of tariff.pdf
PLF		80%	
Fuel Specifications			
Primary Fuel - Coal			
NCV of Coal	kCal/kg	3,946	http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm
Specific Coal consumption - 1st year	kg/kWh	0.62	
Specific Coal consumption - 2nd yr onwards	kg/kWh	0.62	
Landed Cost of Coal	Rs. / kg	1.2849	CERC Tariff petition (140/2005 ; page no 25 of 34) in respect of Ramagundam Super Thermal Power Station Stage (III) for the period 25.03.2009 to 31.03.2009. The value corresponding to the month of February, 2005 (the latest month) has been considered. Weblink: http://cercind.gov.in/03022007/No-140-05-doh-22-5-07.pdf
Annual Coal Price Escalation		0%	
Secondary Fuel -Oil			
NCV of Oil	kCal / lt	9,595	http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm
Specific Oil consumption - Open cycle	ml / kWh	2.0	http://www.cercind.gov.in/13042007/Terms and conditions of tariff.pdf
Specific Oil consumption - Combined cycle	ml / kWh	2.0	http://www.cercind.gov.in/13042007/Terms and conditions of tariff.pdf
Cost of Oil	Rs. / kl	33,000	To check
Escalation for oil	%	0%	
Depreciation			



Recovery of Depreciation	%	90%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Rate of Depreciation - Book Depreciation	%	3.60%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Advance Against Depreciation	of loan amount	10%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
O&M			
O&M Expenses	Rs. Lakhs/MW	11.84	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Escalation Factor	%	4%	
Tax			
Tax Rate	%	33.99%	Income Tax Act
MAT Rate	%	11.33%	Income Tax Act
80IA Exemption	Years	10.00	Income Tax Act
Working Capital norms			
Receivables	Days	60	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Spares	% of Project Cost	1%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Escalation factor for spares	%	6%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Primary Fuel Stock	Days	60	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Secondary Fuel Stock	days	60	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
O&M Expenses	Days	30	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Interest on Working Capital	%	11.50%	

**VI. Levelized Cost of Generation for Naphtha Based Alternative:**

Parameter	Unit	Value	Reference
Project Cost			
Plant EPC	Rs. Crores		
Other cost	Rs. Crores		
Margin Money - Working Capital	Rs. Crores		
Interest During Construction	Rs. Crores		
Financing Charges	Rs. Crores		
Project cost including IDC	Rs. Crores	1188.0	
Project Specifications			
Project capacity	MW	366	
Project life	Years	20	
Project cost per MW	Rs. Crores	3.26	Assumed to be same as the project cost
CoD - Open cycle		Apr-10	
CoD - Combined cycle		Apr-10	
Project Financing			
Project Equity	%	25%	Detailed Project Report (DPR)
Project Debt	%	75%	Detailed Project Report (DPR)
Project Equity	Rs. Crores	298.2	
ROE	%	14%	
Project Debt	Rs. Crores	894.6	
Term of Debt	Years	12.0	As per Detailed Project Report (DPR)
Interest on Debt	%	13.00%	Average of prevailing interest rate at the time of investment decision making. Reference : http://www.rbi.org.in/scripts/WSSView.aspx?Id=11614
Moratorium Period	Months	6.0	As per Detailed Project Report (DPR)
Operating Norms			
Heat Rate			
1st year	Kcal/Kwh	1,850	Assumed to be same as the project
2nd year onwards	Kcal/Kwh	1,850	Assumed to be same as the project



Auxiliary Consumption			
1st year	%	3.00%	http://www.cercind.gov.in/oper7.htm
2nd year onwards		3.00%	http://www.cercind.gov.in/oper7.htm
PLF		80%	
Fuel Specifications			
Primary Fuel - Naphtha			
NCV of Naphtha	kCal/kg	9975	CEA expert committee report on fuel for power generation; page 5 of 17 Reference : http://www.cea.nic.in/reports/articles/thermal/expert_committee_report_fuel.pdf The difference between GCV and NCV has been considered at 5%. (Reference: CEA CO2 database; version 02 dated 21st June, 2007 http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm)
Specific Naphtha consumption - 1st year	kg/kWh	0.18	
Specific Naphtha consumption - 2nd yr onwards	kg/kWh	0.18	
Landed Cost of Naphtha	Rs. / kg	17.40	http://cea.nic.in/reports/articles/thermal/expert_committee_report_fuel.pdf
Annual Naphtha Price Escalation		0%	
Secondary Fuel -Oil			
NCV of Oil	kCal / lt	9,595	CEA CO2 Emission Database version 2: http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm
Specific Oil consumption - Open cycle	ml / kWh	0.0	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Specific Oil consumption - Combined cycle	ml / kWh	0.0	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Cost of Oil	Rs. / kl	33,000	To check
Escalation for oil	%	0%	



Depreciation			
Recovery of Depreciation	%	90%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Rate of Depreciation - Book Depreciation	%	3.60%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Advance Against Depreciation	of loan amount	10%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
O&M			
O&M Expenses	% of total capital cost	2.50%	http://www.thegef.org/gef/sites/thegef.org/files/repository/09.PAD.Annex_9.pdf
Escalation Factor	%	4%	
Tax			
Tax Rate	%	33.66%	Income Tax Act
MAT Rate	%	11.33%	Income Tax Act
80IA Exemption	Years	10.00	Income Tax Act
Working Capital norms			
Receivables	Days	60	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Spares	% of Project Cost	1%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Escalation factor for spares	%	6%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Primary Fuel Stock	Days	30	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Secondary Fuel Stock	days	15	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
O&M Expenses	Days	30	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Interest on Working Capital	%	11.50%	As per Detailed Project Report (DPR)