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

CONTENTS

Annexes

SECTION A. General description of project activity

A.1 Title of the project activity:

GHG Emission Reductions through grid connected high efficiency power generation

Version 03, January 04 2010

A.2. Description of the project activity:

Coastal Gujarat Power Limited (CGPL) has proposed to undertake the new grid connected fossil fuel fired power plant in Mundra using a less GHG intensive technology (*i.e.* coal fired supercritical boiler), which would result in reduced consumption of fossil fuel compared to conventional sub critical technology for thermal power generation.

CGPL is a wholly owned subsidiary of The Tata Power Company Limited. The Tata Power Company Limited (TPCL) is recognized as India's largest private sector power utility, with a reputation for trust, built up over nearly nine decades. Led by a powerful vision, TPCL pioneered the generation of electricity in India. Today, it is the country's largest private player in the power generation sector. It has power generation stations located in Mumbai, Jojobera (Jharkhand) and Karnataka. TPCL has an installed power generation capacity of over 2300 MW. Its diversified power generation portfolio facilitates the company in producing reliable and quality energy. Significant amongst its many achievements are the installation and commissioning of India's first 500 MW unit (at its Thermal Power Generating Station, Trombay), the 150 MW Pumped Storage Unit at its Hydro Generating Station, Bhira, and implementation of various environmental control systems like the First Flue Gas Desulphurization plant in India *etc*.

Purpose of the project activity

The proposed project activity (installed capacity of around 4000 MW) will be a super-critical coal fired power plant which will have higher generation efficiency (about 43.8%[1]) as compared to sub-critical coal fired power plants having average generation efficiency of around 30.06%[2] (please refer Table A0 in Annex 3) presently operating in India. The electricity generated will be evacuated through the local/regional/national grid.

The project activity involves steam generation at super-critical condition (output condition at main steam header: steam temperature of 568.5^{0}C and pressure of 255 kg/cm^2 g and subsequent generation of power

[1] Estimated as per the gross station heat rate (1965 kCal/kWh) for the power plant to be installed under the project activity

through condensing type steam turbine. Due to the super-critical conditions, the efficiency of steam generation through super-critical technology is significantly higher than that of the conventional sub critical technology (which typically operates in Indian condition at 169.27 kg/cm^2 main steam pressure and 538 ^{0}C[3]). Higher steam generation efficiency and hence higher overall cycle efficiency will lead to lower specific coal (*i.e.* fossil fuel) consumption.

Therefore, the project activity fulfils the following objectives:

-Reduction in GHG emissions due to reduced consumption of fossil fuel

-Conservation of depleting non renewable natural resources like coal

-Bridging the demand-supply gap of electricity in India by enhancing installed capacity base of the regional/national grid and hence contributing to mitigation of energy security and energy-GDP concerns.

-Promotion of sustainable economic growth through environment-friendly and higher energy efficient technology

Salient features of the proposed project activity

The proposed project activity will have a nominal installed generation capacity of around 4000MW (5 x 800 MW units). Under the project activity a once-through type coal fired Benson Boiler will be used. The boiler will generate steam (hereafter referred to as 'main steam') at super-critical conditions of 256.05 kg/cm^2 (abs) pressure and 568.5^{0}C temperature and reheat steam[4] at a temperature of 595.6^{0}C. At super-critical condition, the fluid conditions eliminate the requirement of re-circulating boiler. Maintaining the steam parameters at super-critical conditions will increase the efficiency of overall power generation cycle of the super-critical power plant over that of a sub-critical power plant. In India the generation efficiency of a typical sub-critical power plant is around 30.06% (please refer to Table A0 of Annex-3, however for the purpose of baseline emission calculation a more conservative efficiency value of 35.1%[5] has been considered) whereas the super-critical technology offers generation efficiency of around 43.8[6]%. Higher generation efficiency would result in lower fossil fuel consumption and thus less GHG emissions.

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[2] Source: http://www.cea.nic.in/god/opm/Thermal_Performance_Review/0607/SECTION-13.pdf

[3]Source: Mott MacDonald & British High Commission Report: "India's Ultra Mega Power Projects-Exploring the use of carbon financing", October 2006, page S-3

[4] The steam after passing through the HP turbine is reheated in the reheater before passing through the IP/LP turbine. This is referred to as the reheat steam. Refer to Figure 2 (part marked 3).

[5] http://www.cercind.gov.in/Final_Tariff.htm

[6]Source: Detailed Project Report of UMPP Mundra prepared by TCE Consulting Engineers Ltd

Thus the proposed project activity will reduce fossil fuel combustion for the generation of same amount of electricity and thus contribute to mitigation of global warming.

Project's contribution to sustainable development

The contribution of the proposed project to the sustainable development of India is elaborated under the following four pillars of sustainable development:

Economic sustainability

The proposed project activity of 4000 MW ultra mega power project will help in mobilizing significant amount of investment in the region of project activity which will spur economic growth through multiplier benefits.

India's non-coking coal imports for 2006-07 are 41.52 Million Tons of coal[7]. Approximately 57% of coal imports are used for power generation purpose. The higher efficiency power generation will contribute to increased availability of coal – a depleting non renewable resource and hence make it usable for other applications. Savings of coal resources will result in reduced import of non-coking coal and hence savings on account of foreign exchange outflow. The proposed project activity will reduce the peak demand deficit and energy deficits in India and thereby contribute to the infrastructural and economic growth. The most striking sustainability aspect of the project will be the immense contribution of the project to enhance energy security of the country and contribute to GDP growth. Industrial growth will be accelerated due to increased availability of power in the region. The proposed project activity will also generate significant amount of local employment in construction, commissioning, operation and maintenance of this ultra-mega power project and also create opportunities for self employment. The equipment suppliers and other service providers to the project would be benefited economically because of the proposed project activity.

Furthermore, it is worthwhile to mention that in the surrounding areas of the project activity CGPL will facilitate in developing basic infrastructure like communications, schools, medical facilities *etc* which will benefit both its employees as well as the local population.

Environmental sustainability

The proposed project is a part of the government's initiative to promote environmentally efficient technologies for sustainable growth. This ultra mega power project based on super-critical technology is a novel initiative which will result in lower GHG emissions as compared to prevailing, less efficient coal

[7] Source: Provisional Coal Statistics, Ministry of Coal, 2007-08, Page 43 : http://www.coal.nic.in/provcoalstat0708.pdf

based subcritical power generation technology. Due to higher efficiency of power generation the proposed project activity would reduce amount of coal combusted and thus avoid emissions of CO_2 and other air pollutants (SPM, SO_2, NOx) in the atmosphere.

Social sustainability

The proposed project activity will benefit the local rural community by high employment generation (both direct and indirect) and strengthening of social infrastructure in the region. It will also contribute to improvement of the power deficit situation thereby improving the quality of life in several parts of rural and urban India. It would facilitate accelerated implementation of rural electrification initiatives in India due to higher availability of electricity.

Well known multilateral financial institutions Asian Development Bank (ADB) and International Finance Corporation (IFC) as part of the requirement of their lending process have carried out environmental-social sustainability assessment of this proposed Ultra Mega Power Project. The project activity is being developed in compliance with IFC's Performance Standards on Social and Environmental Sustainability[8]. Similar assessments conducted by Asian Development Bank also indicated the strong social sustainability aspect of the project activity[9] (The document is attached in Appendix 4).

Technological sustainability

The super-critical technology to be adopted by the project activity has wide replication potential in various upcoming mega and ultra-mega thermal power projects of India. Furthermore, the technology employed being the first-of-its-kind in the scale of 4000 MW in the thermal power generation sector of India the project activity will result in capacity building and development of new skills and knowledge base for development, commissioning and operational aspects of this technology in India by virtue of exposure to various aspects of this technology. At the time of project conceptualization/bid submission for the project activity, there was no other supercritical power plant in India and this is the first-of-its-kind power plant in India in terms of technology and size.

Innovative technologies are key to successful development of industries; in view of that proposed project activity will demonstrate an excellent example of cross border transfer of expertise in thermal power

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[8] http://www.ifc.org/ifcext/southasia.nsf/Content/SelectedProject?OpenDocument&UNID=1584EA74DA3979AB852573A0006847BB

[9] 'Initial Poverty and Social Assessment' and 'Resettlement Planning Document;: Project No: 41946, Asian Development Bank

generation sector of India which will result in further investment and efforts in technology development and deployment. Such technology will reduce overall environmental impact of the power generation sector of India.

A.3. Project participants:

Name of Party involved	Private and/or public entity (ies) project participants	Kindly indicate if the Party involved wishes to be considered as project participant (Yes/ No)
Government of India (Host Country)	Coastal Gujarat Power Limited	No

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

A.4.1.1. Host Party(ies):

India

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

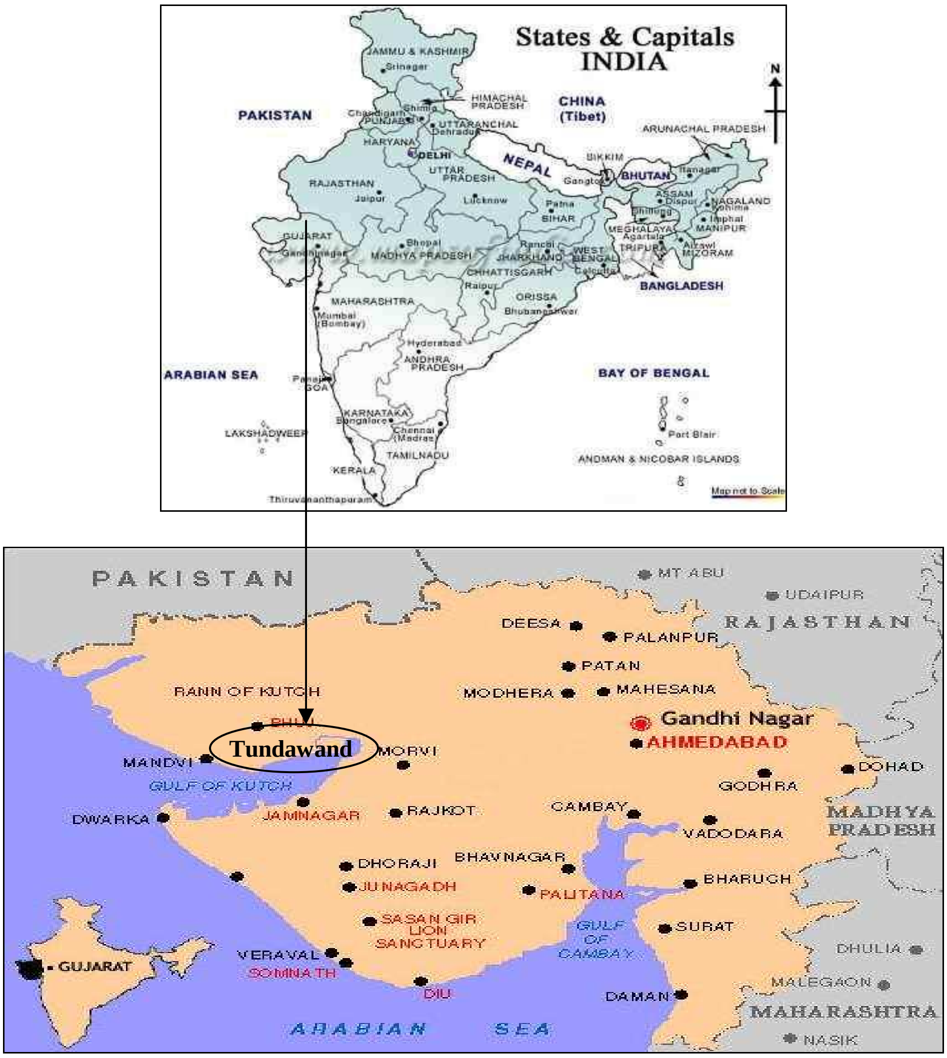
Gujarat

A.4.1.3. City/Town/Community etc:

Mundra Taluk of Kutch District

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 in a site near Tundawand village in Mundra Taluk, Kutch District of Gujarat. The site is about 75 km from Bhuj airport, 85 km from Adipur railway station and 25 km from Mundra port. The latitude and longitude of north-west corner of plant site are 22^{O} 49’ 48” N and 69^{O} 30’ 58”E respectively.



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

The project activity is a large scale potential CDM project, which fits into the Category 1: Energy industries (renewable-/ non renewable sources) as per 'List of Sectoral Scopes'[10].

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

The project activity will adopt power generation technology using steam at supercritical condition. The "critical point" refers to a thermodynamic expression where all three states of a substance coexist. The

[10] Reference: http://cdm.unfccc.int/DOE/scopes.html

critical pressure of water being 225.35 kg/cm^2, the steam above this pressure will be at super-critical pressure and below the critical pressure the steam will be sub-critical.

The technology of the super-critical boiler differs from that of the sub-critical boiler. The super-critical boiler is a once through type of boiler unlike sub-critical boiler where water and steam remains in saturated condition in the boiler drum and water is re-circulated for generation of steam. The once through boiler does not require any circulating pump or drum except for boiler feed water (BFW) pump. Energy required for circulation is provided by the feed pump.

Supercritical cycle is described in the following diagram, (Figure 1), point 1 indicates the super-critical steam conditions. After expansion through the High Pressure (HP) Turbine, at point 2, steam enters the re-heater and then into the Low Pressure (LP) Turbine. From points 4 to 5, the steam condenses to form saturated liquid. It is then mixed with make up water, if required and pumped to a deaerator. The Boiler Feed Pump pumps the water from the deaerator to the boiler.

Figure 1: T-S diagram for super-critical Rankine Cycle

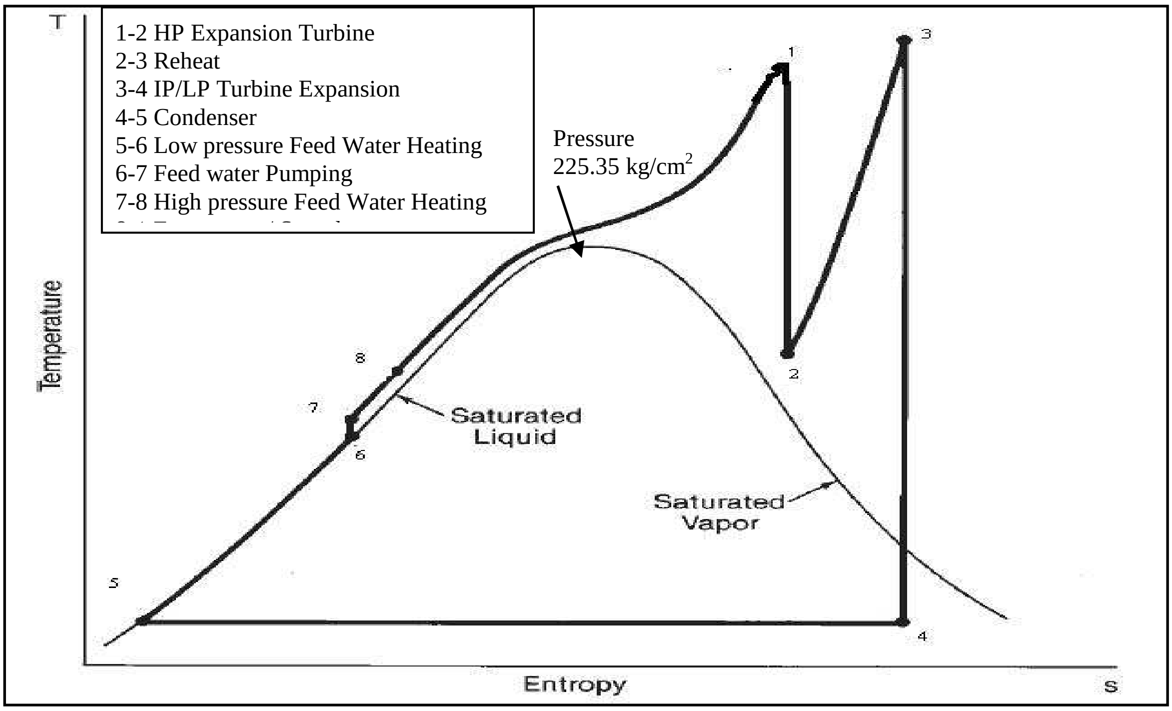
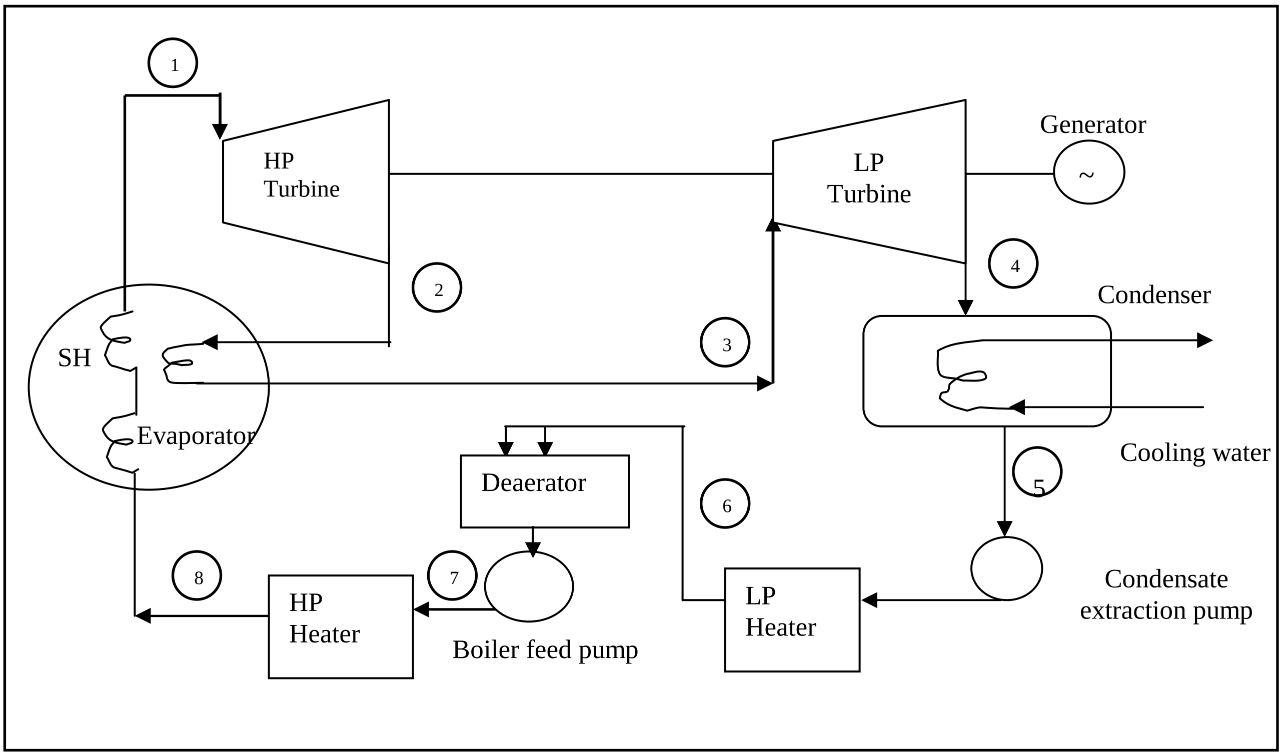


Figure 2: Super-critical Rankine Cycle



The proposed project activity will involve setting up of 5 Nos super-critical coal fired power generation units, each of which has 800 MW (Nominal) capacity, providing a total installed capacity of 4000 MW (Nominal). The steam generator (SG) would be once through type of Benson boiler and would be designed for firing with specified coal as mentioned in Annex 3. The SG would be radiant, two pass design, single reheat, balanced draft and semi outdoor type. The parameters for the SG are as below.

Table 1: Parameters for Steam Generators (Boiler)

Parameter	**Value**
Super heater outlet pressure	256.05 kg/cm^2 (a)
Super heater outlet temperature	$568.5^{O}C$
Super heater outlet flow	701.6 kg/s
Re-heater outlet pressure	61.59 kg/cm^2 (a)
Re-heater outlet temperature	596.1 ^{0}C
Re-heater outlet flow	559.7 kg/s
Feed water inlet temperature to economizer	295 ^{0}C

The water wall would be spiral wound plain tubes with vertical tubes over the spiral water walls.

The steam parameters at the condensing steam turbine generator (STG) inlet will be as below.

Table 2: Parameters for Steam Turbo-Generator

Parameter	**Value**
Pressure	246.97 kg/cm^2 (a)

Main Steam temperature	565 ^{0}C
Reheat Steam temperature	593 ^{0}C

The STG and SG would be designed for sliding pressure operation, which would increase turbine cycle efficiency and reduce boiler feed pump power consumption.

As mentioned in the previous section super-critical power plants can achieve generation efficiency of around 43.8%. Higher generation efficiency leads to the environment friendliness of super-critical technology in terms of its potential to emit lower GHG emissions compared to the sub-critical power plants of same generation capacity.

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

Operating Years	**CO_2 Emission Reductions (tonnes of CO_2)**
January 2011-December 2011	1136466
January 2012-December 2012	2651754
January 2013-December 2013	2841165
January 2014-December 2014	2841165
January 2015-December 2015	2841165
January 2016-December 2016	2841165
January 2017-December 2017	2841165
January 2018-December 2018	2841165
January 2019-December 2019	2841165
January 2020-December 2020	2841165
Total estimated reductions (tonnes of CO_2 e)	**26517539**
Total number of crediting years	10
Annual average over the crediting period of estimated reductions (tonnes of CO_2 e)	**2651753**

A.4.5. Public funding of the project activity:

There is no public funding available for the proposed 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:

Title: Consolidated baseline and monitoring methodology for new grid connected fossil fuel fired power plants using a less GHG intensive technology

Reference: ACM0013, Version 02,

http://cdm.unfccc.int/UserManagement/FileStorage/CDMWF_AM_JD73SPVZEDDN6IY8M6WFC7WIOBMNRN

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

The methodology ACM0013, Version 02 is applicable to "*new electricity generation plants*" and thus can be considered for the proposed project activity under consideration since the proposed project activity of CGPL involves development of a greenfield, coal based power generation plant using super-critical technology which will supply power to the Western Regional Grid of India.

Further, the project activity meets the applicability criteria of ACM0013, Version 02 as under.

"The project activity is the construction and operation of a new fossil fuel fired grid-connected electricity generation plant that uses a more efficient power generation technology than what would otherwise be used with the given fossil fuel"- The proposed project activity of CGPL involves construction of a new super-critical coal fired power plant at Mundra. The project activity uses super-critical technology which is more efficient than the conventional coal fired sub-critical power generation technology which is the established and prevailing practice in similar social, economic, environmental and technological circumstances. Out of the total 132329 MW of installed power generation capacity in India, 71121 MW are thermal[11] and all of them are based on coal fired subcritical technology (as on 31.03.2007). As mentioned above the average generation efficiency of a super-critical coal fired power plant would be around 43.8% while that of a sub-critical coal fired power plant is around 30.06% in Indian context and therefore it can be reasonably argued that the project activity '*uses a more efficient power generation technology than what would otherwise be used with the given fossil fuel', i.e.* coal.

[11] http://www.cea.nic.in/power_sec_reports/Executive_Summary/2007_03/6.pdf

"The project activity is not a co-generation power plant"- The proposed project activity generates only power and is not a cogeneration power plant. A condensing type turbine will be used in the proposed project activity. The turbine will operate at a pressure of about 246.97 kg/cm^2 (a), main steam temperature of about 565 ^{0}C and reheat steam temperature of about 593 ^{0}C.

"Data on fuel consumption and electricity generation of recently constructed power plants is available."- The relevant data/ information on electricity generation and fuel consumption are available with Central Electricity Authority (CEA), Govt. of India and the same have been used by CEA for calculation of baseline emission factor which has been published by CEA[12]. The same factor is used by the project proponent to arrive at the baseline emissions for the project activity[13].

"The identified baseline fuel is used in more than 50% of total generation by utilities in the geographical area within the country, as defined later in the methodology, or in the country[2]. To demonstrate this applicability condition data for latest three years shall be used. Maximum value of same fossil fuel generation estimated for three years should be greater than 50%"

-The identified baseline fuel is coal which is used in more than 50% of total generation by utilities within India. Data for latest three years have been given below.

Table 3: All India Electricity Generation Data in GWh

[2] For the purpose of demonstrating compliance with the applicability condition the geographical area has to be limited by the physical borders of the host country and cannot be extended to neighboring non-Annex I countries, even if such an extended geographical area is used for the calculation of a benchmark emission factor.

[12] As per CEA website (http://www.cea.nic.in/planning/cdm.pdf), *"The CO_2 Baseline Emission factor for coal based power units as applicable to new coal fired power generating units with supercritical steam parameters has been worked out as 0.941 tCO2/MWh (based on net generation) for the year 2007-08. The calculations are based on CDM Executive Board approved methodology ACM0013 Ver 01 " New Grid connected fossil fuel fired power plants using a less GHG intensive technology*". The calculation procedure followed in ACM0013 version 01 and ACM0013, version 02 are exactly same. As the project activity follows the methodology ACM0013, version 02, hence the same baseline emission factor has been used here.

[13] http://www.cea.nic.in/planning/cdm.pdf

All India Energy Generation Data			
	Generation (GWh)		
Type of Generation	2006-07[1]	2005-06	2004-05[3]
Coal	452168.41	425775.28	424244.06
Gas+Diesel	66207.38	62117.66	64084.28
Total Thermal	527499.14	497214	486075.48
Hydro	113358.77	101293.13	84610.38
Nuclear	18606.75	17238.89	17011
Total	**659464.66**	**615746.02**	**587696.86**
% of coal in Total Generation	**68.57**	**69.15**	**72.19**
% of gas+diesel in Total Generation	**10.04**	**10.09**	**10.90**
[1]http://www.cea.nic.in/god/opm/Monthly_Generation_Report/18col_07_03.pdf			
[3] *Source: http://www.cea.nic.in/power_sec_reports/general_review/0405/ch3.pdf*			

It can be concluded from table 3 that coal is used as a fuel in more than 50% of the generation utilities in India. Thus coal has been identified as the baseline fuel for the proposed project activity.

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

The spatial extent of the project boundary includes the power plant at the project site and all power plants considered for the calculation of the baseline CO_2 emission factor ($EF_{BL,CO2,y}$). In the calculation of project emissions, only CO_2 emissions from fossil fuel combustion in the project plant are considered. In the calculation of baseline emissions, only CO_2 emissions from fossil fuel combustion in power plant(s) in the baseline are considered.

The project boundary is described as below.

Table 4: Overview on emissions sources included in or excluded from the project boundary

	Source	Gas	Included?	Justification / Explanation
Baseline	Power generation in baseline	CO_2	Yes	Main emission source.
		CH_4	No	Excluded for simplification. This is conservative.
		N_2O	No	Excluded for simplification. This is conservative.
Project Activity	On-site fuel combustion in the project plant	CO_2	Yes	Main emission source.
		CH_4	No	Excluded for simplification.
		N_2O	No	Excluded for simplification.

According to the methodology, the project boundary includes the top 15% coal fired power plants constructed in the last 5 years, operating in India with a capacity of 500 MW at base load. Besides these power plants, the proposed project activity at Mundra is also included in the project boundary.

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

In the context of identification and establishment of baseline scenario it is worth mentioning that according to the approved methodology (ACM0013, Version 02) followed in this PDD, "A power plant is a facility for the generation of electric power from thermal energy from combustion of a fuel. In case where several power generation units have been installed at one site in a single location, each unit should be considered as a power plant." Therefore, each of the 800 MW super-critical technology based unit (project activity case) or 500 MW sub-critical units (baseline case) have been considered as separate power plant for subsequent discussion on emission reduction and baseline computation.

Step 1: Identify plausible baseline scenarios

As stipulated in the methodology the identification of alternative baseline scenarios includes all possible realistic and credible alternatives that provide outputs or services (e.g. peak vs. base load services) comparable with the proposed CDM project activity (including the proposed project activity without CDM benefits), *i.e.*, all type of power plants that could be constructed as alternative to the project activity within the project boundary, as defined in the section "Project boundary" and in Step 2 of the section "Baseline emissions" below. As mentioned earlier for discussion on baseline each of the 5x 800 MW super-critical coal fired unit located in a single location have been considered as 'single power plant'. Also, the identified alternative scenarios, as mentioned below, involve all relevant power plant technologies that have recently been constructed or are under construction or are being planned (as documented in Report of the Working Group on Power for 11th Plan (2007-12), Volume II, Ministry of Power, Govt. of India[14]).

To arrive at plausible baseline options, the following definition of fossil fuel type has been used as per the methodology (page 6 & 7, ACM0013, Version 02). Fossil fuel types in relation to the project activity and baseline scenario are defined in the following categories:

[14] http://planningcommission.nic.in/aboutus/committee/wrkgrp11/wg11_power.pdf

- Coal
- Oils (e.g. diesel, kerosene, residual oil)
- Natural gas;

The following Alternatives have been identified and analyzed as below.

Alternative 1. The project activity not implemented as a CDM project

This alternative involves implementation of the proposed project activity but not as a CDM project activity. The generation efficiency of the supercritical technology based coal fired power plant is around 43.8% and according to Central Electricity Regulatory Commission (CERC)[15] depreciation guidelines the technical lifetime for coal based generation project assets is 25 years. This alternative is in compliance with all applicable local and national laws and regulations and hence is considered further for arriving at the baseline scenario.

Alternative 2. Power generation using coal-fired sub-critical power generation technologies

In absence of the project activity coal fired sub-critical power generation technology could have been adopted for providing similar services. In this case, the power plant will continue to emit higher quantity of GHGs due to lower generation efficiency of sub-critical technology. The average heat rate of a subcritical coal fired power plant in India is 2861 kCal/kWh (Ref: Table A0 in Annex 3) which gives an efficiency of 30.06% (Table A0 in Annex 3and as per CERC[16] guidelines, depreciation for coal based generation assets is 25 years. Coal based subcritical power plants are typically used as base load stations (used for more than 3000 hours equivalent and 34.25% load factor) as is evident from the table below.

Table 5: Plant Load Factor for Coal based Power Plants in India[17]

	Unit	2006-07	2005-06	2004-05
Generation	GWh	452168.41	425775.3	424244.06
Installed capacity	MW	71121.38	68518.88	67790.87
Load Factor	%	72.58%	70.94%	71.44%

This alternative is in compliance with all applicable laws and regulations of the country. This alternative has been considered further for arriving at the baseline scenario.

15 http://www.cercind.gov.in/070104/appendix_2.doc
16 http://www.cercind.gov.in/070104/appendix_2.doc
17 http://www.cea.nic.in/power_sec_reports/general_review/0405/ch2.pdf, http://www.cea.nic.in/power_sec_reports/executive_summary/2006_03/6.pdf, http://www.cea.nic.in/power_sec_reports/Executive_Summary/2007_03/6.pdf, http://www.cea.nic.in/god/opm/Monthly_Generation_Report/18col_07_03.pdf, http://www.cea.nic.in/power_sec_reports/general_review/0405/ch3.pdf

Alternative 3. Power generation using energy sources (natural gas) other than coal

As an alternative to the project activity, natural gas based power generation could have been opted for providing similar services. Gas based power generation is used as base load stations (used for more than 3000 hours equivalent and 34.25% load factor) as is evident from the table below.

Table 6: Plant Load Factor for Natural Gas based Power Plants in India[18]

	Unit	2006-07	2005-06	2004-05
Generation	GWh	63718.61	60127.98	61524.66
Installed capacity	MW	13691.71	12689.91	11909.82
Load Factor	%	53.13%	54.09%	58.97%

In this case, the power plants will emit GHGs associated with combustion of natural gas. This alternative is in compliance with all applicable laws and regulations of the country. However, this alternative is associated with some barriers which will prevent the implementation of this option. Given the deficit situation of natural gas supply and the available projection of long-term natural gas price it is unlikely that any new thermal power generation capacity to the tune of 4000 MW will come up with natural gas as fuel[19]. Furthermore, there is no gas supply infrastructure available in the existing project site at Mundra.

According to Planning Commission, Ministry of Power, Govt of India, “Although gas is relatively a clean fuel, at present there is uncertainty about the availability, period of availability and price of gas. Only 2,114 MW gas based capacity has been planned for 11th 5 Year Plan of India where gas supply has

[18] http://www.cea.nic.in/power_sec_reports/general_review/0405/ch2.pdf,
http://www.cea.nic.in/power_sec_reports/executive_summary/2006_03/6.pdf,
http://www.cea.nic.in/power_sec_reports/Executive_Summary/2007_03/6.pdf,
http://www.cea.nic.in/god/opm/Monthly_Generation_Report/18col_07_03.pdf,
http://www.cea.nic.in/power_sec_reports/general_review/0405/ch3.pdf

[19] According to the report of Working Group on Petroleum and Natural Gas for XIth Plan (2007-12), [Ref: Planning Commission, Govt. of India] there is a natural gas demand–supply gap (shortfall in supply) to the extent of 67.98 MMSCMD in 2007-08 which may fall to 42.81 MMSCMD in 2008 – 09. According to the same projections, from this level, the gap would increase steadily to 91.13 MMSCMD by 2011-12. At present in India, only the industries in Power and fertilizer sector and small-scale users deserve the supply of Government regulated natural gas under Administered Price Mechanism (APM). According to a policy document (L-12015/5/04-GP (i) of Ministry of Petroleum and Natural Gas the power and fertilizer sector and some other specific units will receive NG supply against their existing allocation. Also, in case of reduction in availability of this gas in future, the supplies to APM consumer would be reduced on a pro-rate basis. The project proponent – CGPL does not have any existing allocation of NG. Tata Power Company Limited has an existing allocation of 1 MMSCMD which is not even sufficient to run their existing 128 MW gas based capacity. Furthermore, considering the declining volume of APM gas supply in future (Ref: Crisil Research Natural Gas Update – November 2007) it is highly unlikely that the 4000 MW or nearing power generation capacity would come up based on APM gas supply.

Even if it is assumed that the project proponent will implement 4000 MW gas based power generation the gas supply required can be partially met through RIL KG D6 field (located in the eastern coast of India) which is expected to start production from 2008 onward. In Gujarat, the cost of generation of electricity from this gas is estimated to be Rs.1.76/kWh which is higher than the cost of generation from domestic coal. (Ref: CRISIL document: Impact of RIL’s KG gas price on end-user segment). The power tariff being low in the merit order for Gujarat it will not be a viable option for the project proponent to generate power from KG basin gas supply.

already been tied up."(Ref: Report of Working Group on Power for 11th Plan, Demand for Power and Generation Planning, Ministry of Power, Govt. of India[20])

Two important policy guidelines for natural gas utilization are the Integrated Energy Policy (2005)[21] and Natural Gas Utilization Policy (2008-draft released and is under finalization)[22]. The Integrated Energy Policy (2005) of India projects the gas supply deficit in India and highlights the fact that no new gas based power generation capacity can be installed under such gas deficit situation.

According to the draft natural gas utilization policy released by Ministry of Petroleum & Natural Gas[23], the following would be the order of priority for allocation of future natural gas produced:

-Fertilizer

-Petrochemical,

-Existing gas-based power projects with public sector undertakings,

-City gas distribution projects,

-Other industrial users like steel

-New gas-based power units etc

If this draft policy is implemented as per the indicated sectoral priority, it would impede the implementation of any new gas based power generation project in the country till the gas supply deficit is met. Therefore, the feasibility of natural gas utilization as fuel for power generation (to the tune of 4000MW) seems to be rather weak and the feasibility would depend upon the priority sector categorization, gas availability and affordability and associated infrastructure[24].

Natural gas may be utilized in power plants based on the technologies *viz.* Advanced Class Combined Cycle Turbine technology and E-Class Combined Cycle Turbine technology. The average efficiency of the Advanced class turbines is 46.5%[25] and that of the E-class turbines is 44.10%[26]. As per CERC[27] guidelines regarding the depreciation of the project assets, technical lifetime of the gas based generation stations is 15 years.

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[20] http://planningcommission.nic.in/aboutus/committee/wrkgrp11/wg11_power.pdf, Page 20 of Chapter 1

[21] http://planningcommission.nic.in/reports/genrep/intengpol.pdf

[22] http://www.infraline.com/ong/NaturalGas/Utilisation/DraftPolPaperUtilisNatGas-Mar08.htm

[23] Source: http://www.financialexpress.com/printer/news/266083/

[24] Source: http://powermin.nic.in/indian_electricity_scenario/national_electricity_policy.htm

[25] Source: Page - 12, Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2004 - http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

[26] Source: Page - 12, Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2004 - http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

[27] Source: Appendix- 2, Depriciation Schedule, Page - 1, http://www.cercind.gov.in/070104/appendix_2.doc

Use of Liquefied Natural Gas (LNG) may be considered as another alternative to the project activity. However, LNG has more serious disadvantages as natural gas in terms of availability and cost of power generation. The cost of generation using LNG would be INR 2.16/kWh[28] which is much higher than the cost of generation using domestic coal. This cost of generation may even go up considering the costly import option of LNG from outside.

Due to the above-mentioned barriers like fuel supply constraint, higher cost of generation, lack of infrastructure *etc* this alternative can not be regarded as a possible realistic and credible baseline alternative for the project activity. Hence this alternative is not considered further for arriving at the baseline scenario.

Alternative 4. Power generation using energy sources (hydro) other than coal

A 4000 MW hydro power project could have been implemented as an alternative to the project activity. In this case there would have been lower GHG emissions. This alternative is in compliance with all applicable laws and regulations of the country. However, a large-scale(> 25 MW) hydro power project is highly capital intensive (around INR 80 million per MW) [29] and has huge risks of geological and hydrological uncertainties, delays in land acquisition, rehabilitation and resettlement issues and potential risks of natural calamities *etc*.[30]. A 4000MW hydro power project could possibly cause dislocation of significant population besides possibly causing ecological issues. Given the current un-availability of suitable sites in India compounded by potential social and environmental issues related to a hydro power project, a plant of such capacity will be difficult to manage from a regulatory and social management point of view. On such consideration severe obstacles would have been faced in obtaining regulatory approvals for the project and this would act as a prohibitive barrier to select this alternative.

Moreover, being dependent on the seasonal flow of water, the nature of operation of hydro power plants in India is mainly as peaking stations rather than base load stations. As seen from the table below, hydro projects have been typically used as peak load stations as their plant load factor on an average is around 34.25% (around 3000 hours equivalent).

Table 7: Plant Load Factor for Hydro Power Plants in India[31]

[28] CRISIL Research Report: "Impact of RIL's KG gas price on end user segments" page 7

[29] CERC Petition No.107/2006 for Dhauliganga Hydroelectric Project Stage-I of National Hydroelectric Power Corporation Limited

[30] Ref: National Policy for Hydro Power Development in India

[31] http://www.cea.nic.in/power_sec_reports/general_review/0405/ch2.pdf,
http://www.cea.nic.in/power_sec_reports/executive_summary/2006_03/6.pdf,
http://www.cea.nic.in/power_sec_reports/Executive_Summary/2007_03/6.pdf,
http://www.cea.nic.in/god/opm/Monthly_Generation_Report/18col_07_03.pdf,
http://www.cea.nic.in/power_sec_reports/general_review/0405/ch3.pdf

	Unit	2006-07	2005-06	2004-05
Generation	GWh	113358.77	101293.13	84610.38
Installed capacity	MW	34653.77	32325.77	30942.24
Load Factor	%	37.34%	35.77%	31.22%

Therefore, the nature of the project activity and this baseline option on delivering similar services vary significantly[32]. As per CERC[33] guidelines regarding the depreciation of the project assets, technical lifetime of the hydro based generation stations is 35 years.

Moreover, several smaller hydro power projects amounting to the capacity equal to that of the project activity can not be compared with the project activity since the operational characteristics (size vs. delivered output, base load vs. peak load) of these two options can not the same.

Hence this alternative is not considered further for arriving at the baseline scenario.

Alternative 5. Power generation using energy sources (diesel/ fuel oil/naphtha) other than coal

Diesel/ fuel oil/naphtha based power generation could have been an alternative to the proposed project activity. This alternative would be in compliance with all applicable laws and regulations of the country. However, in this alternative high operational cost barrier would have been faced on account of spiraling diesel/ fuel oil/ naphtha prices for consumers. Under merit order purchasing or compared to low cost of generation through other fuel alternatives, selling of power would be extremely difficult from such power stations. In fact, the highest capacity power plant running on diesel in India is of 106.5 MW (Brahmapuram DG) only. Also, diesel based power generation is typically used as a peak load station as is evident from the table below.

Table 8: Plant Load Factor for Diesel based Power Plants in India[34]

	Unit	2006-07	2005-06	2004-05
Generation	GWh	2488.77	1989.68	2559.62
Installed capacity	MW	1201.75	1201.75	1201.75
Load Factor	%	23.64%	18.90%	24.31%

[32] As per Ministry of Power Guidelines for development of Hydro Electric projects sites by private developers, GoI, several potential risks of natural calamities such as inter-state water sharing disputes, ecological imbalance, displacement and land submergence. For e.g. seven tribunals were set-up by Ministry of Water Resources for resolving various disputes including the inter-state. As a result of these disputes, large hydro generation projects are withheld for execution among various Indian states.

[33] Source: Appendix- 2, Depreciation Schedule, Page - 1, http://www.cercind.gov.in/070104/appendix_2.doc

[34] http://www.cea.nic.in/power_sec_reports/general_review/0405/ch2.pdf,
http://www.cea.nic.in/power_sec_reports/executive_summary/2006_03/6.pdf,
http://www.cea.nic.in/power_sec_reports/Executive_Summary/2007_03/6.pdf,
http://www.cea.nic.in/god/opm/Monthly_Generation_Report/18col_07_03.pdf,
http://www.cea.nic.in/power_sec_reports/general_review/0405/ch3.pdf

The efficiency of Naphtha based generation stations is 43%[35]. As per CERC guidelines for depreciation of the project assets, lifetime of Diesel based generation stations is 15 years[36]. The tariff of naphtha based generation stations is fixed on the basis of 15 years Power Purchase Agreement and hence 15 years has been considered as the lifetime of Naphtha based generation stations.

Moreover,

-Total installed capacity of Naphtha based generation capacity installed in India is 1,822 MW[37]. No Naphtha based generation capacity is added in India since 2000-01 due to very high operational costs as mentioned above.

-Majority of naphtha based generation capacity commissioned in India is of older generation, designed to use on dual fuel mode (both naphtha and natural gas). State utilities had either renegotiated with PPA's benchmarked to natural gas based generation projects and as a consequence IPPs who had already commissioned their plant switched over to Natural Gas.

Further to that there is increased policy thrust for switching over to gaseous fuel from liquid fuel as evident from the National Electricity Policy under section 5.2.16 which suggests existing liquid fuels plants be converted into natural gas / LNG at the earliest[38]. This emphasizes that implementation of 4000 MW power generation capacity using naphtha/diesel as fuel can not be considered as a credible baseline alternative.

Hence this alternative is not considered further for arriving at the baseline scenario.

Alternative 6. Power generation using energy sources (renewable energy sources excluding hydro) other than coal

In this alternative scenario, generation of power using renewable energy sources other than hydro which includes wind power, biomass energy *etc* could have been considered. In this option there would be no GHG emissions and this alternative is in compliance with all applicable laws and regulations of the country. However, generation of power to the tune of 4000MW (which would be running on a base load) using renewable resources like wind, biomass *etc.* is not a technically and economically feasible proposition on account of inconsistent availability of renewable resources, resulting in high risks, and high cost associated with renewable technologies.

[35] Source: Government of India notification dated 30/03/1992, Point 9, http://www.cercind.gov.in/pet22002407.html
[36] Source: Appendix- 2, Depriciation Schedule, Page - 1, http://www.cercind.gov.in/070104/appendix_2.doc
[37] Source: Baseline Carbon Dioxide Emission Database Version 3.0 – LATEST
http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm
[38] Source: National Electricity Plan - www.powermin.nic.in/indian_electricity_scenario/national_electricity_policy.htm, Page 6 states "Imported LNG based power plants are also a potential source of electricity and the pace of their development would

Wind energy is known to have low load factors due to seasonal and intermittent wind flows during the seasons. These low load factors result in high fixed cost of generation of electricity. Highest load factor achieved by the wind based generation projects in the western regional grid is at a maximum of 33%, which is much lower as compared to the proposed project activity[39]. Hence the alternative is not credible in terms of load factor. The designed life expectancy of the wind turbines is 20 years (Maharashtra Electricity Regulatory Commission)[40].

Thus, Solar power cannot be an alternative to the project activity keeping in view the high initial capital cost of solar power plants and the high cost of power generation (Rs 15/kWh) [41]. It is also evident from the fact that in case of solar energy, India has a capacity addition target of only 50 MW during the XIth 5 year Plan of the Government of India which is very low as compared to the total capacity addition target.

India has 1,140.63 MW of biomass based generation capacity installed[42]. The target capacity addition for the 11th Plan is 2100 MW which is about half the capacity of the proposed project activity. This is primarily due to lack of reliable and sufficient feedstock for biomass based power projects. Thus, biomass power generation is not a feasible alternative to the proposed project activity.

High investment, technological and other barriers would have been faced in order to implement the above alternatives. Furthermore, renewable resource based power generating stations typically used for peak load services. Hence this alternative is not considered further for arriving at the baseline scenario.

Alternative 7. Power generation using energy sources (nuclear) other than coal

As an alternative to the project activity, nuclear power generation could have been opted for. In this option there would be very less GHG emissions and this alternative will be in compliance with all applicable laws and regulations of the country. The efficiency of nuclear power plants is 29%[43]. Nuclear power plants are used as base load stations.

Table 9: Plant Load Factor for Nuclear Power Plants in India[44]

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depend on their commercial viability. The existing power plants using liquid fuels should shift to use of Natural Gas/LNG at the earliest to reduce the cost of generation.”

[39] Source: Page 30 of Maharashtra Electricity Regulatory Commission Order Case No. 17(3), 3, 4 & 5 Of 2002 - http://mercindia.org.in/pdf/Detail_Wind_Energy_Order.pdf

[40] Source: Page 51 of Maharashtra Electricity Regulatory Commission Order Case No. 17(3), 3, 4 & 5 Of 2002 - http://mercindia.org.in/pdf/Detail_Wind_Energy_Order.pdf

[41] http://www.thehindubusinessline.com/2008/01/07/stories/2008010751560300.htm

[42] Source: Page 64, Report Of The Working Group On New And Renewable Energy For XIth Five Year Plan (2007-12) - http://planningcommission.nic.in/aboutus/committee/wrkgrp11/wg11_renewable.pdf

[43] Source: Atoms for War? U.S.-Indian Civilian Nuclear Cooperation and India’s Nuclear Arsenal , Page 20, Paragraph 2 - www.carnegieendowment.org/files/atomsforwarfinal4.pdf

[44] http://www.cea.nic.in/power_sec_reports/general_review/0405/ch2.pdf,
http://www.cea.nic.in/power_sec_reports/executive_summary/2006_03/6.pdf,
http://www.cea.nic.in/power_sec_reports/Executive_Summary/2007_03/6.pdf,

	Unit	2006-07	2005-06	2004-05
Generation	GWh	18606.75	17238.89	17011
Installed capacity	MW	3900.00	3360.00	2770.00
Load Factor	%	54.46%	58.57%	70.10%

Although electricity generation is de-licensed in India, nuclear based electricity generation is realistically not available for any of the private sector entities. As per the Atomic Energy Act of India (Indian Atomic Energy Act - 1962[45] is not under purview of The Electricity Act – 2003) prevailing during the time of decision making for the project activity, nuclear power generation is restricted to Government or Government owned companies only and not so far open to any private sector participation[46]. Stiff regulatory barriers exist thus preventing implementation of this option.

Total nuclear based generation capacity installed in India is 3,900 MW, *i.e.*, 3.15% of installed capacity in India. Currently 2,660 MW of nuclear capacity is under implementation by NPCIL[47]. Almost 2,000 MW of commissioned nuclear capacity is non-operational because of the lack of fuels for the project. Moreover, the capacity addition planned for the 11th Plan is a meager 3160 MW, keeping in view the availability of fuel[48].

Hence this alternative is not considered further for arriving at the baseline scenario.

Alternative 8: Import of electricity from connected grids, including the possibility of new interconnections

Table 10: Import of Electricity in India

http://www.cea.nic.in/god/opm/Monthly_Generation_Report/18col_07_03.pdf,
http://www.cea.nic.in/power_sec_reports/general_review/0405/ch3.pdf

45 Source: http://www.dae.gov.in/rules/aeact.pdf

46 National Report to the Convention on Nuclear Safety, Fourth Review Meeting of the Contracting Parties, April 2008, Govt. of India-Under Special Provisions Section 22-(a) of the Indian Atomic Energy Act - 1962, ‘Government of India has complete and comprehensive control to implement schemes for generation of electricity and to operate electricity generation stations either by itself or through any authority or corporation established by it or a government company, atomic power stations in the manner determined by GoI in consultation with Boards or Corporations concerned established for the purpose’.

47 Source: http://www.npcil.nic.in/ProjectConstStatus.asp

48 Report of the Working Group on Power for 11th Plan, Volume II, Main report, Page 8

All India Energy Generation Data		
Type of Generation	Generation (GWh)	
	2006-07	2005-06
Thermal	527547.36	497206.93
Nuclear	18606.75	17238.89
Hydro	113358.77	101293.13
Bhtuan Import	3010.08	1764.12
Total	**662522.96**	**617503.07**
% of import in Total Generation	**0.45**	**0.29**
http://www.cea.nic.in/god/opm/Monthly_ Generation_Report/18col_ 07_03.pdf		

As an alternative to the project activity the same amount of power from connected grid could have been imported. This alternative is in compliance with all applicable laws and regulations of the country. However, the import of power by India has been 0.45% in 2006-07 and 0.29% in 2005-06. Considering this historical trend of import of power and also considering the fact that large scale power import in India is constrained by inadequate power transmission infrastructure and lack of grid integration among neighbouring countries, it can be concluded that the import of electricity from connected grids is not a realistic and credible alternative. Hence this alternative is not considered further for baseline scenario establishment.

The following baseline alternatives have been analyzed:

- Alternative 1. The project activity not implemented as a CDM project
- Alternative 2. Power generation using coal-fired sub-critical power generation technologies
- Alternative 3. Power generation using energy sources (natural gas) other than coal
- Alternative 4. Power generation using energy sources (hydro) other than coal
- Alternative 5. Power generation using energy sources (diesel/ fuel oil/naphtha) other than coal
- Alternative 6. Power generation using energy sources (renewable energy sources excluding hydro) other than coal
- Alternative 7. Power generation using energy sources (nuclear) other than coal
- Alternative 8: Import of electricity from connected grids, including the possibility of new interconnections.

In view of the analysis of the above alternatives, Alternative 1 and Alternative 2 are the options which are considered in the next section for further analysis of their economies in terms of their levelized costs of power generation.

Step 2: Identify the economically most attractive baseline scenario alternative

According to the methodological guidance, the economically most attractive baseline scenario is identified using investment analysis. As per the guidance of the methodology, the levelized cost of electricity generation in INR/kWh has been used as financial indicator for comparison of economic attractiveness of baseline alternatives and select that option as baseline scenario which will yield the lowest levelized cost of generation. It is worthwhile to mention that the economic analysis has been carried out for four sub-alternatives considering the two alternative technologies (*i.e.* subcritical and supercritical) and two alternative sources of fuel (*i.e.* domestic and imported coal) to add further credibility and robustness to the analysis.

1. (a) Domestic coal based supercritical power generation technology
1. (b) Imported coal based supercritical power generation technology
2. (a) Domestic coal based subcritical power generation technology
2. (b) Imported coal based subcritical power generation technology

Table 11: Economic analysis of all the realistic and credible alternatives available with CGPL in absence of the proposed project activity

Parameters	1(a) Domestic coal based supercritical power generation technology	1 (b) Imported coal based supercritical power generation technology	2 (a) Domestic coal based subcritical power generation technology	2 (b) Imported coal based subcritical power generation technology
Levelized Cost of electricity production (INR/kWh)	1.71	1.86	1.61	1.80
Note: The detail computation of the levelized cost calculation and assumptions for the same are below and the excel sheet is appended as Appendix 1.				

Inputs					
Assumptions	**Units**	**Subcritical**	**Supportives**	**Supercritical**	**Supportives**
Project Size	MW	500	Standard subcritical unit size	800	Project unit size
Project Cost	INR Million	13960	Calculated	34000	Calculated
Cost Per MW	INR Million/MW	27.92	CERC order dated 22.5.2007	42.50	Calculated from total project cost and capacity. Total project cost taken from lender's document (term sheet of BNP Paribas)
Debt	%	75.00%	Same as of Supercritical	75.00%	Term Sheet of BNP Paribas & Board Presentation
Equity	%	25.00%	Same as of Supercritical	25.00%	Term Sheet of BNP Paribas & Board Presentation
Rate of Interest on loan Capital	%	10.00%	Same as of Supercritical	10.00%	Budgetory quotes from lenders
Rate of Interest on Working Capital	%	8.50%	Same as of Supercritical	8.50%	Assumed (Bloomberg)
Return on Equity	%	0.00%	Bid route project hence not applicable	0.00%	Bid route project hence not applicable
Loan Repayment Period	Years	20	Same as of Supercritical	20	Budgetory quotes from lenders
Depreciation	%	15.00%	As per IT Act	15.00%	As per IT Act
O&M Cost (Fixed)	Mill INR/MW	0.6175	Same as of Supercritical	0.6175	Budgetory quotes, refer assumption below
O&M Cost (Variable)	INR/MWh	0.00		0.00	
Escalation	%	5.37%	CERC notification dated 22.11.2006	5.37%	CERC notification dated 22.11.2006
Insurance	% of Capital Cost	1.00%		1.00%	
Maintainence Spares	% of Capital Cost	1.00%	CERC order dated 22.5.2007	1.00%	Same as subcritical
Plant Life	Years	25	CERC Regulations Appendix II	25	Same as subcritical
	Subcritical	**Supportives**	**Supercritical**	**Supportives**	
PLF	85%	Estimated PLF	85%	Estimated PLF	
Auxiliary Consumption	7.50%	CERC order dated 22.5.2007	7.50%	Estimated	

Coal Assumptions for Imported Coal		
Percentage fixed	55%	
Percentage Variable	45%	As per PPA

	Subcritical (domestic coal)		Subcritical (imported coal)		Supercritical (domestic coal)		Supercritical (imported coal)	
GCV kCal/Kg	3562.33	CERC order dated 22.5.2007	5750	Same as supercritical (imported coal)	3562.33	Same as subcritical (domestic coal)	5750	GCV of imported coal taken from proximate analysis of coal
SHR (kCal/kWh)	2450	CERC order dated 22.5.2007	2450	Same as subcritical (domestic coal)	1965	Same as supercritical (imported coal)	1965	Estimated from DPR using turbine heat rate (of 1895kCal/kWh) & boiler efficiency (of 88%)
Price Per Tonne (INR)	1150.24	CERC order dated 22.5.2007	2248	Same as supercritical (imported coal)	1150.24	Same as subcritical (domestic coal)	2248	Estimated
Fuel Price Escalation %	3.46%	CERC notification dated 22.11.2006	3.46%	Same as subcritical (domestic coal)	3.46%	Same as subcritical (domestic coal)	3.46%	Same as subcritical (domestic coal)

Other Assumptions	Comparison Between 500 MW Sub Critical Plant and 800 MW Super Critical Plant
	Cost of debt is always lower than cost of equity. So debt:equity ratio taken here is 75:25 to improve the profitability of the project
	Domestic coal is domestic Singrauli Coal and Imported coal is Indonesian Coal.
	The O & M Costs for Supercritical Plant have been assumed based on budgetory information given by prospective equipment supplier. These costs are not comparable with local Sub Critical Plants, given the higher capital cost, different maintainance schedule, issues of availablity of suitable O & M facilities & vendor for the Super Critical equipments. However for comparisons for baseline selection purpose the O & M costs for Sub Critical plants have been assumed to be same for as of Super Critical Plant

1 (a) Domestic coal based supercritical power generation technology- Levelized Cost Calculations

Years		I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	XIII
A	**Working Capital Calculations**													
	O&M Expenses for one month (INR Million)	69.50	71.71	74.04	76.49	79.08	81.81	84.68	87.70	90.89	94.25	97.79	101.52	105.45
	Maintenance Spares (INR Million)	340.00	360.40	382.02	404.95	429.24	455.00	482.30	511.23	541.91	574.42	608.89	645.42	684.15
	Landed Cost of Coal for 1.5 Months (INR Million)	437.00	443.80	450.84	458.13	465.66	473.46	481.52	489.87	498.50	507.43	516.67	526.24	536.13
	Receivables for 2 months (INR Million)	1490.17	1489.37	1353.44	1233.13	1125.97	1029.82	942.87	863.57	790.59	722.77	659.13	620.06	583.57

	Years	XIV	XV	XVI	XVII	XVIII	XIX	XX	XXI	XXII	XXIII	XXIV	XXV
A	Working Capital Calculations												
	O&M Expenses for one month (INR Million)	109.59	113.95	118.55	123.40	128.50	133.88	139.55	145.52	151.81	158.45	165.43	172.80
	Maintenance Spares (INR Million)	725.20	768.71	814.83	863.72	915.54	970.48	1028.70	1090.43	1155.85	1225.20	1298.71	1376.64
	Landed Cost of Coal for 1.5 Months (INR Million)	546.36	556.95	567.90	579.24	590.96	603.09	615.64	628.63	642.06	655.96	670.34	685.22
	Receivables for 2 months (INR Million)	549.01	515.82	483.48	451.56	419.65	387.38	354.41	320.45	285.19	248.36	209.69	168.92

	Years	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	XIII
B	Fixed Cost Calculations													
	Interest on Loan Capital (INR Million)	2550.00	2422.50	2295.00	2167.50	2040.00	1912.50	1785.00	1657.50	1530.00	1402.50	1275.00	1275.00	1275.00
	Depreciation (INR Million)	5100.00	4335.00	3684.75	3132.04	2662.23	2262.90	1923.46	1634.94	1389.70	1181.25	1004.06	853.45	725.43
	Advance Against Depreciation (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Return on Equity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Loan outstanding (INR Million)	24225.00	22950.00	21675.00	20400.00	19125.00	17850.00	16575.00	15300.00	14025.00	12750.00	12750.00	12750.00	12750.00
	O&M Expenses (Fixed) (INR Million)	494.00	520.53	548.48	577.93	608.97	641.67	676.13	712.44	750.69	791.01	833.48	878.24	925.40
	O &M Expenses (Variable) (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Insurance (INR Million)	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00
	Total O & M Expenses (INR Million)	834.00	860.53	888.48	917.93	948.97	981.67	1016.13	1052.44	1090.69	1131.01	1173.48	1218.24	1265.40
	Interest on Working Capital (INR Million)	198.62	201.05	192.13	184.68	178.50	173.41	169.27	165.95	163.36	161.40	160.01	160.92	162.29
	Tax (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Annual Fixed Cost (INR Million)	8682.62	7819.08	7060.36	6402.15	5829.70	5330.47	4893.86	4510.83	4173.76	3876.16	3612.55	3507.62	3428.13
	Fixed Cost/Unit (INR/kWh)	1.58	1.42	1.28	1.16	1.06	0.97	0.89	0.82	0.76	0.70	0.66	0.64	0.62

	Years	XIV	XV	XVI	XVII	XVIII	XIX	XX	XXI	XXII	XXIII	XXIV	XXV
B	Fixed Cost Calculations												
	Interest on Loan Capital (INR Million)	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00
	Depreciation (INR Million)	616.62	524.13	445.51	378.68	321.88	273.60	232.56	197.67	168.02	142.82	121.40	103.19
	Advance Against Depreciation (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Return on Equity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Loan outstanding (INR Million)	12750.00	12750.00	12750.00	12750.00	12750.00	12750.00	12750.00	12750.00	12750.00	12750.00	12750.00	12750.00
	O&M Expenses (Fixed) (INR Million)	975.10	1027.46	1082.63	1140.77	1202.03	1266.58	1334.60	1406.26	1481.78	1561.35	1645.20	1733.54
	O &M Expenses (Variable) (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Insurance (INR Million)	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00
	Total O & M Expenses (INR Million)	1315.10	1367.46	1422.63	1480.77	1542.03	1606.58	1674.60	1746.26	1821.78	1901.35	1985.20	2073.54
	Interest on Working Capital (INR Million)	164.06	166.21	168.71	171.52	174.65	178.06	181.76	185.73	189.97	194.48	199.26	204.30
	Tax (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Annual Fixed Cost (INR Million)	3370.78	3332.80	3311.85	3305.97	3313.55	3333.24	3363.91	3404.66	3454.77	3513.65	3580.85	3656.03
	Fixed Cost/Unit (INR/kWh)	0.61	0.60	0.60	0.60	0.60	0.60	0.61	0.62	0.63	0.64	0.65	0.66

	Years	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	XIII
C	Working for Fuel Cost													
	GCV kCal/kg	3562.33												
	Gross SHR (kCal/kWh)	1965												
	Annual Coal Consumption (Tonnes)	3039367.10	3039367.10	3039367.10	3039367.10	3039367.10	3039367.10	3039367.10	3039367.10	3039367.10	3039367.10	3039367.10	3039367.10	3039367.10
	Price Per Tonne (INR)	1150.24	1168.15	1186.68	1205.85	1225.68	1246.20	1267.43	1289.39	1312.12	1335.63	1359.95	1385.12	1411.15
	Escalation %	3.46%	1.035											
	Annual Fuel Cost (INR Million)	3496.00	3550.43	3606.75	3665.02	3725.30	3787.66	3852.19	3918.94	3988.01	4059.47	4133.39	4209.88	4289.01
	Fuel Cost/Unit (INR/kWh)	0.63	0.64	0.65	0.67	0.68	0.69	0.70	0.71	0.72	0.74	0.75	0.76	0.78
	Units Generated in the year (MUs)	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8
	Auxiliary Consumption (MUs)	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76
	Transformation Losses (MUs)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net Exportable Units (MUs)	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04
	Unit Cost (INR /kWh)	2.21	2.06	1.94	1.83	1.73	1.65	1.59	1.53	1.48	1.44	1.41	1.40	1.40
		1.00	0.90	0.81	0.73	0.66	0.59	0.53	0.48	0.43	0.39	0.35	0.31	0.28
	11.1%	2.21	1.86	1.57	1.33	1.14	0.98	0.84	0.73	0.64	0.56	0.49	0.44	0.40
	Levelized Cost (25 Years)	1.71 INR/kWh												
CERC notification dated 24.9.2007														

	Years	XIV	XV	XVI	XVII	XVIII	XIX	XX	XXI	XXII	XXIII	XXIV	XXV
C	**Working for Fuel Cost**												
	GCV kCal/kg												
	Gross SHR (kCal/kWh)												
	Annual Coal Consumption (Tonnes)	3039367.10	3039367.10	3039367.10	3039367.10	3039367.10	3039367.10	3039367.10	3039367.10	3039367.10	3039367.10	3039367.10	3039367.10
	Price Per Tonne (INR)	1438.09	1465.96	1494.79	1524.62	1555.49	1587.42	1620.45	1654.63	1689.99	1726.58	1764.43	1803.59
	Escalation %												
	Annual Fuel Cost (INR Million)	4370.88	4455.59	4543.22	4633.89	4727.69	4824.74	4925.15	5029.03	5136.51	5247.70	5362.74	5481.76
	Fuel Cost/Unit (INR/kWh)	0.79	0.81	0.82	0.84	0.86	0.88	0.89	0.91	0.93	0.95	0.97	0.99
	Units Generated in the year (MUs)	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8
	Auxiliary Consumption (MUs)	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76
	Transformation Losses (MUs)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net Exportable Units (MUs)	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04
	Unit Cost (INR /kWh)	1.41	1.41	1.43	1.44	1.46	1.48	1.50	1.53	1.56	1.59	1.62	1.66
		0.25	0.23	0.21	0.19	0.17	0.15	0.14	0.12	0.11	0.10	0.09	0.08
	11.1%	0.36	0.32	0.29	0.27	0.24	0.22	0.20	0.19	0.17	0.16	0.14	0.13
	Levelized Cost (25 Years)												
CERC notification dated 24.9.2007													

1 (b) Imported coal based supercritical power generation technology- Levelized Cost Calculations

	Years	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	XIII
A	**Working Capital Calculations**													
	O&M Expenses for one month (INR Million)	69.50	71.71	74.04	76.49	79.08	81.81	84.68	87.70	90.89	94.25	97.79	101.52	105.45
	Maintenance Spares (INR Million)	340.00	360.40	382.02	404.95	429.24	455.00	482.30	511.23	541.91	574.42	608.89	645.42	684.15
	Landed Cost of Coal for 1.5 Months (INR Million)	257.41	261.42	265.57	269.86	274.29	278.89	283.64	288.55	293.64	298.90	304.34	309.97	315.80
	Receivables for 2 months (INR Million)	1430.30	1246.19	1106.40	982.10	870.81	770.39	679.02	595.15	517.43	444.72	376.02	331.71	289.80

	Years	XIV	XV	XVI	XVII	XVIII	XIX	XX	XXI	XXII	XXIII	XXIV	XXV
A	**Working Capital Calculations**												
	O&M Expenses for one month (INR Million)	109.59	113.95	118.55	123.40	128.50	133.88	139.55	145.52	151.81	158.45	165.43	172.80
	Maintenance Spares (INR Million)	725.20	768.71	814.83	863.72	915.54	970.48	1028.70	1090.43	1155.85	1225.20	1298.71	1376.64
	Landed Cost of Coal for 1.5 Months (INR Million)	321.83	328.07	334.52	341.19	348.10	355.25	362.64	370.29	378.20	386.39	394.86	403.62
	Receivables for 2 months (INR Million)	249.64	210.64	172.30	134.17	95.83	56.91	17.07	-24.00	-66.62	-111.07	-157.62	-206.54

	Years	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	XIII
B	**Fixed Cost Calculations**													
	Interest on Loan Capital (INR Million)	2550.00	2422.50	2295.00	2167.50	2040.00	1912.50	1785.00	1657.50	1530.00	1402.50	1275.00	1275.00	1275.00
	Depreciation (INR Million)	5100.00	4335.00	3684.75	3132.04	2662.23	2262.90	1923.46	1634.94	1389.70	1181.25	1004.06	853.45	725.43
	Advance Against Depreciation (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Return on Equity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Loan outstanding	24225.00	22950.00	21675.00	20400.00	19125.00	17850.00	16575.00	15300.00	14025.00	12750.00	12750.00	12750.00	12750.00
	O&M Expenses (Fixed) (INR Million)	494.00	520.53	548.48	577.93	608.97	641.67	676.13	712.44	750.69	791.01	833.48	878.24	925.40
	O &M Expenses (Variable) (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Insurance (INR Million)	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00
	Total O & M Expenses (INR Million)	834.00	860.53	888.48	917.93	948.97	981.67	1016.13	1052.44	1090.69	1131.01	1173.48	1218.24	1265.40
	Interest on Working Capital (INR Million)	178.26	164.88	155.38	147.34	140.54	134.82	130.02	126.02	122.73	120.04	117.90	118.03	118.59
	Tax (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Annual Fixed Cost (INR Million)	8662.26	7782.90	7023.61	6364.81	5791.74	5291.88	4854.61	4470.90	4133.12	3834.80	3570.44	3464.72	3384.43
	Fixed Cost/Unit (INR/kWh)	1.57	1.41	1.27	1.16	1.05	0.96	0.88	0.81	0.75	0.70	0.65	0.63	0.61

	Years	XIV	XV	XVI	XVII	XVIII	XIX	XX	XXI	XXII	XXIII	XXIV	XXV
B	**Fixed Cost Calculations**												
	Interest on Loan Capital (INR Million)	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00	1275.00
	Depreciation (INR Million)	616.62	524.13	445.51	378.68	321.88	273.60	232.56	197.67	168.02	142.82	121.40	103.19
	Advance Against Depreciation (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Return on Equity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Loan outstanding	12750.00	12750.00	12750.00	12750.00	12750.00	12750.00	12750.00	12750.00	12750.00	12750.00	12750.00	12750.00
	O&M Expenses (Fixed) (INR Million)	975.10	1027.46	1082.63	1140.77	1202.03	1266.58	1334.60	1406.26	1481.78	1561.35	1645.20	1733.54
	O &M Expenses (Variable) (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Insurance (INR Million)	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00	340.00
	Total O & M Expenses (INR Million)	1315.10	1367.46	1422.63	1480.77	1542.03	1606.58	1674.60	1746.26	1821.78	1901.35	1985.20	2073.54
	Interest on Working Capital (INR Million)	119.53	120.82	122.42	124.31	126.48	128.90	131.58	134.49	137.64	141.01	144.62	148.45
	Tax (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Annual Fixed Cost (INR Million)	3326.25	3287.40	3265.56	3258.76	3265.39	3284.08	3313.73	3353.43	3402.44	3460.18	3526.21	3600.18
	Fixed Cost/Unit (INR/kWh)	0.60	0.60	0.59	0.59	0.59	0.60	0.60	0.61	0.62	0.63	0.64	0.65

	Years	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	XIII
C	Working for Fuel Cost													
	GCV kCal/kg	5750.00												
	SHR (kCal/kWh)	1965												
	Annual Coal Consumption (Tonnes)	2035671.65	2035671.65	2035671.65	2035671.65	2035671.65	2035671.65	2035671.65	2035671.65	2035671.65	2035671.65	2035671.65	2035671.65	2035671.65
	Price Per Tonne (INR)	2248.00	2283.00	2319.21	2356.68	2395.44	2435.54	2477.03	2519.96	2564.37	2610.32	2657.86	2707.04	2757.92
	Escalation %	3.46%	1.035											
	Annual Fuel Cost (INR Million) - Variable 45%	2059.29	2091.35	2124.52	2158.84	2194.35	2231.09	2269.09	2308.41	2349.10	2391.19	2434.74	2479.79	2526.40
	Annual Fuel Cost (INR Million) - Fixed 55%	2516.90	2516.90	2516.90	2516.90	2516.90	2516.90	2516.90	2516.90	2516.90	2516.90	2516.90	2516.90	2516.90
	Total Fuel Cost (INR Million)	4576.19	4608.25	4641.43	4675.75	4711.25	4747.99	4786.00	4825.32	4866.00	4908.09	4951.64	4996.69	5043.31
	Fuel Cost/Unit (INR/kWh)	0.83	0.84	0.84	0.85	0.86	0.86	0.87	0.88	0.88	0.89	0.90	0.91	0.92
	Units Generated in the year (MUs)	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8
	Auxiliary Consumption (MUs)	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76
	Transformation Losses (MUs)	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
	Net Exportable Units (MUs)	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04
	Unit Cost (INR/kWh)	2.40	2.25	2.12	2.00	1.91	1.82	1.75	1.69	1.63	1.59	1.55	1.54	1.53
		1.00	0.90	0.81	0.73	0.66	0.59	0.53	0.48	0.43	0.39	0.35	0.31	0.28
	11.1%	2.40	2.02	1.72	1.46	1.25	1.08	0.93	0.81	0.70	0.62	0.54	0.48	0.43
	Levelized Cost (25 Years)	**1.86 INR/kWh**												
CERC notification dated 24.9.2007														

	Years	XIV	XV	XVI	XVII	XVIII	XIX	XX	XXI	XXII	XXIII	XXIV	XXV
C	Working for Fuel Cost												
	GCV kCal/kg												
	SHR (kCal/kWh)												
	Annual Coal Consumption (Tonnes)	2035671.65	2035671.65	2035671.65	2035671.65	2035671.65	2035671.65	2035671.65	2035671.65	2035671.65	2035671.65	2035671.65	2035671.65
	Price Per Tonne (INR)	2810.57	2865.03	2921.38	2979.69	3040.00	3102.41	3166.97	3233.77	3302.88	3374.38	3448.35	3524.89
	Escalation %												
	Annual Fuel Cost (INR Million) - Variable 45%	2574.63	2624.52	2676.14	2729.55	2784.80	2841.97	2901.11	2962.30	3025.61	3091.11	3158.87	3228.98
	Annual Fuel Cost (INR Million) - Fixed 55%	2516.90	2516.90	2516.90	2516.90	2516.90	2516.90	2516.90	2516.90	2516.90	2516.90	2516.90	2516.90
	Total Fuel Cost (INR Million)	5091.53	5141.43	5193.05	5246.45	5301.71	5358.87	5418.02	5479.21	5542.51	5608.01	5675.78	5745.88
	Fuel Cost/Unit (INR/kWh)	0.92	0.93	0.94	0.95	0.96	0.97	0.98	0.99	1.01	1.02	1.03	1.04
	Units Generated in the year (MUs)	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8	5956.8
	Auxiliary Consumption (MUs)	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76	446.76
	Transformation Losses (MUs)	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
	Net Exportable Units (MUs)	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04	5510.04
	Unit Cost (INR/kWh)	1.53	1.53	1.54	1.54	1.55	1.57	1.58	1.60	1.62	1.65	1.67	1.70
		0.25	0.23	0.21	0.19	0.17	0.15	0.14	0.12	0.11	0.10	0.09	0.08
	11.1%	0.39	0.35	0.32	0.29	0.26	0.24	0.21	0.20	0.18	0.16	0.15	0.14
	Levelized Cost (25 Years)												
CERC notification dated 24.9.2007													

2 (a) Domestic coal based subcritical power generation technology –Levelized Cost Calculations

No.	Description	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	XIII
A	Working Capital Calculations													
	O&M Expenses for one month (INR Million)	37.36	38.74	40.20	41.73	43.35	45.05	46.85	48.74	50.73	52.83	55.04	57.38	59.83
	Maintenance Spares (INR Million)	139.60	147.98	156.85	166.27	176.24	186.82	198.03	209.91	222.50	235.85	250.00	265.00	280.90
	Landed Cost of Coal for 1.5 Months (INR Million)	340.54	345.84	351.33	357.00	362.87	368.95	375.23	381.74	388.46	395.42	402.62	410.08	417.78
	Receivables for 2 months (INR Million)	674.38	838.98	787.12	741.84	702.09	667.03	635.91	608.10	583.06	560.33	539.50	528.96	519.68

No.	Description	XIV	XV	XVI	XVII	XVIII	XIX	XX	XXI	XXII	XXIII	XXIV	XXV
A	Working Capital Calculations												
	O&M Expenses for one month (INR Million)	62.42	65.15	68.02	71.05	74.24	77.60	81.14	84.88	88.81	92.95	97.32	101.92
	Maintenance Spares (INR Million)	297.76	315.62	334.56	354.63	375.91	398.47	422.37	447.72	474.58	503.05	533.24	565.23
	Landed Cost of Coal for 1.5 Months (INR Million)	425.76	434.01	442.55	451.38	460.51	469.97	479.75	489.87	500.34	511.17	522.37	533.97
	Receivables for 2 months (INR Million)	511.41	503.92	497.02	490.52	484.28	478.14	471.99	465.71	459.19	452.32	445.01	437.16

No.	Description	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	XIII
B	**Fixed Cost Calculations**													
	Interest on Loan Capital (INR Million)	1047.00	994.65	942.30	889.95	837.60	785.25	732.90	680.55	628.20	575.85	523.50	523.50	523.50
	Depreciation (INR Million)	2094.00	1779.90	1512.92	1285.98	1093.08	929.12	789.75	671.29	570.60	485.01	412.26	350.42	297.85
	Advance Against Depreciation (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Return on Equity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Loan outstanding (INR Million)	9946.50	9423.00	8899.50	8376.00	7852.50	7329.00	6805.50	6282.00	5758.50	5235.00	5235.00	5235.00	5235.00
	O&M Expenses (Fixed) (INR Million)	308.75	325.33	342.80	361.21	380.61	401.04	422.58	445.27	469.18	494.38	520.93	548.90	578.38
	O &M Expenses (Variable) (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Insurance (INR Million)	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60
	Total O & M Expenses (INR Million)	448.35	464.93	482.40	500.81	520.21	540.64	562.18	584.87	608.78	633.98	660.53	688.50	717.98
	Interest on Working Capital (INR Million)	101.31	116.58	113.52	111.08	109.19	107.77	106.76	106.12	105.80	105.78	106.01	107.22	108.65
	Tax (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Annual Fixed Cost (INR Million)	3690.66	3356.06	3051.13	2787.82	2560.07	2362.78	2191.59	2042.83	1913.38	1800.61	1702.29	1669.64	1647.98
	Fixed Cost/Unit (INR/kWh)	1.07	0.97	0.89	0.81	0.74	0.69	0.64	0.59	0.56	0.52	0.49	0.48	0.48

No.	Description	XIV	XV	XVI	XVII	XVIII	XIX	XX	XXI	XXII	XXIII	XXIV	XXV
B	**Fixed Cost Calculations**												
	Interest on Loan Capital (INR Million)	523.50	523.50	523.50	523.50	523.50	523.50	523.50	523.50	523.50	523.50	523.50	523.50
	Depreciation (INR Million)	253.18	215.20	182.92	155.48	132.16	112.34	95.49	81.16	68.99	58.64	49.84	42.37
	Advance Against Depreciation (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Return on Equity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Loan outstanding (INR Million)	5235.00	5235.00	5235.00	5235.00	5235.00	5235.00	5235.00	5235.00	5235.00	5235.00	5235.00	5235.00
	O&M Expenses (Fixed) (INR Million)	609.44	642.16	676.65	712.98	751.27	791.61	834.12	878.91	926.11	975.84	1028.25	1083.46
	O &M Expenses (Variable) (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Insurance (INR Million)	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60
	Total O & M Expenses (INR Million)	749.04	781.76	816.25	852.58	890.87	931.21	973.72	1018.51	1065.71	1115.44	1167.85	1223.06
	Interest on Working Capital (INR Million)	110.27	112.09	114.08	116.24	118.57	121.05	123.70	126.49	129.45	132.56	135.82	139.25
	Tax (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Annual Fixed Cost (INR Million)	1635.99	1632.55	1636.75	1647.81	1665.10	1688.10	1716.40	1749.67	1787.65	1830.14	1877.02	1928.19
	Fixed Cost/Unit (INR/kWh)	0.48	0.47	0.48	0.48	0.48	0.49	0.50	0.51	0.52	0.53	0.55	0.56

No.	Description	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	XIII
C	Working for Fuel Cost													
	GCV kCal/Kg	3562.33												
	Gross SHR (kCal/kWh)	2450												
	Coal Consumption/year (Ton)	2368463.55	2368463.55	2368463.55	2368463.55	2368463.55	2368463.55	2368463.55	2368463.55	2368463.55	2368463.55	2368463.55	2368463.55	2368463.55
	Price Per Tonne (INR)	1150.24	1168.15	1186.68	1205.85	1225.68	1246.20	1267.43	1289.39	1312.12	1335.63	1359.95	1385.12	1411.15
	Escalation %	3.46%	1.03											
	Annual Fuel Cost (INR Million)	2724.30	2766.72	2810.60	2856.01	2902.98	2951.58	3001.86	3053.88	3107.70	3163.39	3221.00	3280.60	3342.27
	Fuel Cost/Unit (INR/kWh)	0.79	0.80	0.82	0.83	0.84	0.86	0.87	0.89	0.90	0.92	0.94	0.95	0.97
	Units Generated in year (MU)	3723	3723	3723	3723	3723	3723	3723	3723	3723	3723	3723	3723	3723
	Auxiliary Consumption (MUs)	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23
	Transformation Losses (MUs)	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
	Net Exportable Units (MUs)	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78
	Unit Cost (INR /kWh) as per Norms	1.86	1.78	1.70	1.64	1.59	1.54	1.51	1.48	1.46	1.44	1.43	1.44	1.45
		1.00	0.90	0.81	0.73	0.66	0.59	0.53	0.48	0.43	0.39	0.35	0.31	0.28
	11.1%	1.86	1.60	1.38	1.20	1.04	0.91	0.80	0.71	0.63	0.56	0.50	0.45	0.41
Levelized Cost (25 Years) for domestic coal		**1.61**	**INR/kWh**											
CERC notification dated 24.9.2007														

No.	Description	XIV	XV	XVI	XVII	XVIII	XIX	XX	XXI	XXII	XXIII	XXIV	XXV
C	**Working for Fuel Cost**												
	GCV kCal/Kg												
	Gross SHR (kCal/kWh)												
	Coal Consumption/year (Ton)	2368463.55	2368463.55	2368463.55	2368463.55	2368463.55	2368463.55	2368463.55	2368463.55	2368463.55	2368463.55	2368463.55	2368463.55
	Price Per Tonne (INR)	1438.09	1465.96	1494.79	1524.62	1555.49	1587.42	1620.45	1654.63	1689.99	1726.58	1764.43	1803.59
	Escalation %												
	Annual Fuel Cost (INR Million)	3406.06	3472.07	3540.36	3611.01	3684.11	3759.74	3837.98	3918.93	4002.68	4089.33	4178.98	4271.73
	Fuel Cost/Unit (INR/kWh)	0.99	1.01	1.03	1.05	1.07	1.09	1.11	1.14	1.16	1.19	1.21	1.24
	Units Generated in year (MU)	3723	3723	3723	3723	3723	3723	3723	3723	3723	3723	3723	3723
	Auxiliary Consumption (MUs)	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23
	Transformation Losses (MUs)	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
	Net Exportable Units (MUs)	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78
	Unit Cost (INR /kWh) as per Norms	1.46	1.48	1.50	1.53	1.55	1.58	1.61	1.65	1.68	1.72	1.76	1.80
		0.25	0.23	0.21	0.19	0.17	0.15	0.14	0.12	0.11	0.10	0.09	0.08
	11.1%	0.37	0.34	0.31	0.28	0.26	0.24	0.22	0.20	0.18	0.17	0.16	0.14
Levelized Cost (25 Years) for domestic coal													
CERC notification dated 24.9.2007													

2 (b) Imported coal based subcritical power generation technology –Levelized Cost Calculations

No.	Description	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	XIII
A	**Working Capital Calculations**													
	O&M Expenses for one month (INR Million)	37.36	38.74	40.20	41.73	43.35	45.05	46.85	48.74	50.73	52.83	55.04	57.38	59.83
	Maintenance Spares (INR Million)	139.60	147.98	156.85	166.27	176.24	186.82	198.03	209.91	222.50	235.85	250.00	265.00	280.90
	Landed Cost of Coal for 1.5 Months (INR Million)	200.59	203.71	206.94	210.29	213.75	217.33	221.03	224.86	228.82	232.92	237.16	241.55	246.09
	Receivables for 2 months (INR Million)	627.73	649.47	594.62	546.22	503.26	464.87	430.31	398.93	370.21	343.66	318.88	304.26	290.76

No.	Description	XIV	XV	XVI	XVII	XVIII	XIX	XX	XXI	XXII	XXIII	XXIV	XXV
A	**Working Capital Calculations**												
	O&M Expenses for one month (INR Million)	62.42	65.15	68.02	71.05	74.24	77.60	81.14	84.88	88.81	92.95	97.32	101.92
	Maintenance Spares (INR Million)	297.76	315.62	334.56	354.63	375.91	398.47	422.37	447.72	474.58	503.05	533.24	565.23
	Landed Cost of Coal for 1.5 Months (INR Million)	250.79	255.65	260.68	265.88	271.26	276.83	282.59	288.55	294.72	301.10	307.70	314.53
	Receivables for 2 months (INR Million)	278.12	266.11	254.53	243.19	231.94	220.63	209.12	197.29	185.03	172.23	158.78	144.58

No.	Description	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	XIII
B	**Fixed Cost Calculations**													
	Interest on Loan Capital (INR Million)	1047.00	994.65	942.30	889.95	837.60	785.25	732.90	680.55	628.20	575.85	523.50	523.50	523.50
	Depreciation (INR Million)	2094.00	1779.90	1512.92	1285.98	1093.08	929.12	789.75	671.29	570.60	485.01	412.26	350.42	297.85
	Advance Against Depreciation (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Return on Equity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Loan outstanding (INR Million)	9946.50	9423.00	8899.50	8376.00	7852.50	7329.00	6805.50	6282.00	5758.50	5235.00	5235.00	5235.00	5235.00
	O&M Expenses (Fixed) (INR Million)	308.75	325.33	342.80	361.21	380.61	401.04	422.58	445.27	469.18	494.38	520.93	548.90	578.38
	O &M Expenses (Variable) (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Insurance (INR Million)	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60
	Total O & M Expenses (INR Million)	448.35	464.93	482.40	500.81	520.21	540.64	562.18	584.87	608.78	633.98	660.53	688.50	717.98
	Interest on Working Capital (INR Million)	85.45	88.39	84.88	81.98	79.61	77.70	76.18	75.01	74.14	73.55	73.19	73.80	74.59
	Tax	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Annual Fixed Cost (INR Million)	3674.80	3327.87	3022.50	2758.72	2530.50	2332.71	2161.01	2011.72	1881.72	1768.38	1669.47	1636.21	1613.93
	Fixed Cost/Unit (INR/kWh)	1.07	0.97	0.88	0.80	0.73	0.68	0.63	0.58	0.55	0.51	0.48	0.48	0.47

No.	Description	XIV	XV	XVI	XVII	XVIII	XIX	XX	XXI	XXII	XXIII	XXIV	XXV
B	**Fixed Cost Calculations**												
	Interest on Loan Capital (INR Million)	523.50	523.50	523.50	523.50	523.50	523.50	523.50	523.50	523.50	523.50	523.50	523.50
	Depreciation (INR Million)	253.18	215.20	182.92	155.48	132.16	112.34	95.49	81.16	68.99	58.64	49.84	42.37
	Advance Against Depreciation (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Return on Equity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Loan outstanding (INR Million)	5235.00	5235.00	5235.00	5235.00	5235.00	5235.00	5235.00	5235.00	5235.00	5235.00	5235.00	5235.00
	O&M Expenses (Fixed) (INR Million)	609.44	642.16	676.65	712.98	751.27	791.61	834.12	878.91	926.11	975.84	1028.25	1083.46
	O &M Expenses (Variable) (INR Million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Insurance (INR Million)	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60	139.60
	Total O & M Expenses (INR Million)	749.04	781.76	816.25	852.58	890.87	931.21	973.72	1018.51	1065.71	1115.44	1167.85	1223.06
	Interest on Working Capital (INR Million)	75.57	76.71	78.01	79.45	81.03	82.75	84.59	86.57	88.67	90.89	93.25	95.73
	Tax	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Annual Fixed Cost (INR Million)	1601.28	1597.18	1600.68	1611.02	1627.56	1649.80	1677.30	1709.74	1746.87	1788.48	1834.44	1884.66
	Fixed Cost/Unit (INR/kWh)	0.46	0.46	0.46	0.47	0.47	0.48	0.49	0.50	0.51	0.52	0.53	0.55

No.	Description	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII	XIII
C	**Working for Fuel Cost**													
	GCV kCal/Kg	5750.00												
	Gross SHR (kCal/kWh)	2450												
	Coal Consumption/year (Ton)	1586321.74	1586321.74	1586321.74	1586321.74	1586321.74	1586321.74	1586321.74	1586321.74	1586321.74	1586321.74	1586321.74	1586321.74	1586321.74
	Price Per Tonne (INR)	2248.00	2283.00	2319.21	2356.68	2395.44	2435.54	2477.03	2519.96	2564.37	2610.32	2657.86	2707.04	2757.92
	Escalation %	3.46%	1.03											
	Annual Fuel Cost (INR Million) -Variable 45%	1604.72	1629.71	1655.56	1682.30	1709.97	1738.60	1768.22	1798.86	1830.56	1863.36	1897.30	1932.41	1968.73
	Annual Fuel Cost (INR Million) - Fixed 55%	1961.33	1961.33	1961.33	1961.33	1961.33	1961.33	1961.33	1961.33	1961.33	1961.33	1961.33	1961.33	1961.33
	Total Fuel Cost (INR Million)	3566.05	3591.04	3616.89	3643.63	3671.30	3699.93	3729.55	3760.19	3791.89	3824.69	3858.63	3893.73	3930.06
	Fuel Cost/Unit (INR/kWh)	1.04	1.04	1.05	1.06	1.07	1.07	1.08	1.09	1.10	1.11	1.12	1.13	1.14
	Units Generated in year (MU)	3723	3723	3723	3723	3723	3723	3723	3723	3723	3723	3723	3723	3723
	Auxiliary Consumption (MUs)	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23
	Transformation Losses (MUs)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net Exportable Units (MUs)	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78
	Unit Cost (INR / kWh) as per Norms	2.10	2.01	1.93	1.86	1.80	1.75	1.71	1.68	1.65	1.62	1.61	1.61	1.61
		1.00	0.90	0.81	0.73	0.66	0.59	0.53	0.48	0.43	0.39	0.35	0.31	0.28
	11.1%	2.10	1.81	1.56	1.36	1.18	1.03	0.91	0.80	0.71	0.63	0.56	0.50	0.46
Levelized Cost (25 Years) for domestic coal		1.80	INR/kWh											
CERC notification dated 24.9.2007														

No.	Description	XIV	XV	XVI	XVII	XVIII	XIX	XX	XXI	XXII	XXIII	XXIV	XXV
C	**Working for Fuel Cost**												
	GCV kCal/Kg												
	Gross SHR (kCal/kWh)												
	Coal Consumption/year (Ton)	1586321.74	1586321.74	1586321.74	1586321.74	1586321.74	1586321.74	1586321.74	1586321.74	1586321.74	1586321.74	1586321.74	1586321.74
	Price Per Tonne (INR)	2810.57	2865.03	2921.38	2979.69	3040.00	3102.41	3166.97	3233.77	3302.88	3374.38	3448.35	3524.89
	Escalation %												
	Annual Fuel Cost (INR Million) -Variable 45%	2006.31	2045.19	2085.42	2127.03	2170.09	2214.64	2260.73	2308.41	2357.74	2408.78	2461.59	2516.22
	Annual Fuel Cost (INR Million) - Fixed 55%	1961.33	1961.33	1961.33	1961.33	1961.33	1961.33	1961.33	1961.33	1961.33	1961.33	1961.33	1961.33
	Total Fuel Cost (INR Million)	3967.64	4006.52	4046.74	4088.36	4131.42	4175.97	4222.05	4269.74	4319.07	4370.11	4422.92	4477.55
	Fuel Cost/Unit (INR/kWh)	1.15	1.16	1.18	1.19	1.20	1.21	1.23	1.24	1.25	1.27	1.28	1.30
	Units Generated in year (MU)	3723	3723	3723	3723	3723	3723	3723	3723	3723	3723	3723	3723
	Auxiliary Consumption (MUs)	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23	279.23
	Transformation Losses (MUs)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net Exportable Units (MUs)	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78	3443.78
	Unit Cost (INR / kWh) as per Norms	1.62	1.63	1.64	1.65	1.67	1.69	1.71	1.74	1.76	1.79	1.82	1.85
		0.25	0.23	0.21	0.19	0.17	0.15	0.14	0.12	0.11	0.10	0.09	0.08
	11.1%	0.41	0.37	0.34	0.31	0.28	0.25	0.23	0.21	0.19	0.18	0.16	0.15
Levelized Cost (25 Years) for domestic coal													
CERC notification dated 24.9.2007													

Sensitivity Analysis for Levelized Cost

% change in fuel (coal) price	Subcritical (domestic coal)		Subcritical (imported coal)		Supercritical (domestic coal)		Supercritical (imported coal)	
	INR/ton	INR/unit	INR/ton	INR/unit	INR/ton	INR/unit	INR/ton	INR/unit
10%	1265.26	1.70	2472.80	1.91	1265.26	1.78	2472.80	1.95
20%	1380.29	1.79	2697.60	2.02	1380.29	1.86	2697.60	2.04
-10%	1035.22	1.51	2023.20	1.69	1035.22	1.64	2023.20	1.77
-20%	920.19	1.42	1798.40	1.58	920.19	1.56	1798.40	1.69

% change in PLF	Subcritical	Domestic coal	Imported coal	Supercritical	Domestic coal	Imported coal
	PLF	INR/unit	INR/unit	PLF	INR/unit	INR/unit
5%	89%	1.57	1.77	89%	1.66	1.82
10%	94%	1.54	1.74	94%	1.62	1.78
-5%	81%	1.64	1.83	81%	1.76	1.92
-10%	77%	1.68	1.87	77%	1.82	1.97

% change in Project Cost	Subcritical	Domestic coal	Imported coal	Supercritical	Domestic coal	Imported coal
	Project Cost	INR/unit	INR/unit	Project Cost	INR/unit	INR/unit
5%	14658	1.63	1.83	35700	1.75	1.91
10%	15356	1.66	1.85	37400	1.79	1.95
-5%	13262	1.58	1.77	32300	1.67	1.82
-10%	12564	1.55	1.74	30600	1.63	1.78

The sensitivity analysis further establishes that the sub-alternatives "2(a): Domestic coal based subcritical power generation technology" is the economically most attractive alternative.

The sensitivity analysis has been done with a variation in domestic coal price upto the extent of 20% as an increase in domestic coal price greater than 20% is improbable. The grade of domestic coal (GCV 3562.33kCal/kg) to be used will be G grade coal (as per Ministry of Coal, Government of India[49]). Coal price of G grade coal was deregulated in January 2000. Coal India Ltd has increased prices of coal by INR 20/ton in August 2002[50], 2.4% per year after 2002-03 (i.e. around 9.6% till 2007-08)[51] and 10% in December 2007[52]. The Prime Minister's Office, Govt. of India is always against any hike in domestic coal price as any increase in input costs would have forced generation companies and other consumers of coal to pass on the price increase[53] to the end consumers. Considering the above fact it is highly unlikely that the price of domestic coal will increase by more than 20% in the next 10-12 years.

For the case of imported coal, the project proponent had assumed the least cost option for its coal price assumptions i.e., low calorific value Indonesian coal. Further the least cost option of ownership of mines was assumed to reduce overall coal cost. This is reflected in the bid documents submitted by CGPL wherein 55% of coal cost was assumed as fixed. During the time of the investment decision, the long term price difference between lead global coal indices and Indonesian Coal was 25% to 30 % (Indonesian coals being cheaper). Hence, 25% discount for Indonesian coal was assumed on the prevailing API4 & GCCNC indices. Thus having considered steep 25% reduction on spot prices a further reduction of coal price would not have been a possible scenario given the demand supply scenario of coal which continues even today. Given the growing acceptance and demand for Indonesian coal this differential has actually been seen reducing considerably past the investment decision. Thus a decrease in imported coal price of more than 20% over the price assumed here is highly improbable.

The sensitivity analysis has been done with a variation in capital cost upto the extent of 10% as a decrease in the capital cost of the proposed project activity by more than 10% is highly improbable. The average inflation rate in India was around 7.3% in October 2006[54] and 8.5-9%[55] (as of 2008-09) and going by these past trends, India is expected to experience an increase in price trends. Given the trends in inflation, prices of goods and equipment purchased will increase and it is extremely unlikely that the project cost will be reduced. Further, due to limited supply of equipments and a dearth of EPC contractors for supercritical power technology, there are chances of increase in cost.

[49] http://coal.nic.in/welcome.html
[50] http://www.thehindubusinessline.com/2002/08/24/stories/2002082402240400.htm
[51] http://www.livemint.com/2008/09/14223106/Chaturvedi-suggests-increase-i.html
[52] http://www.thehindubusinessline.com/2007/12/15/stories/2007121550750200.htm
[53] http://www.financialexpress.com/news/No-coal-price-hike-this-year-Bagrodia/312666/
http://www.livemint.com/2007/09/12001247/PMO-turns-down-price-hike-requ.html

[54] http://labour.nic.in/annrep/annrep0607/english/Table17.pdf
[55] CRISIL Ecoview, January 2009, Page 6, https://www.crisilresearch.com/ResearchProWeb/control/welcome

The high levelized cost of generation of sub-alternatives “1(a): Domestic coal based supercritical power generation technology”, “1 (b): Imported coal based supercritical power generation technology” and “2 (b): Imported coal based subcritical power generation technology” prohibits implementation of the same. Apart from higher levelized cost of electricity generation the occurrence of sub-alternative -1 (b) (*i.e.* the project activity not implemented as CDM project) will be prohibited by other investment, technological and common practice barriers elaborated in the section B.5. Also sub-alternative 2 (b) will face barriers related to import of coal as elaborated in the ‘additionality’ section. These barriers have been elaborated under section B.5. Hence, these alternatives can not be considered as baseline options.

In view of the above discussion, “sub-alternative 2 (a): Domestic coal based subcritical power generation technology” is found to be economically the most attractive option available to the project proponent (or any stakeholder within the project boundary) in absence of the proposed project activity and therefore, following methodological guidance, this alternative represents the baseline scenario.

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): >>

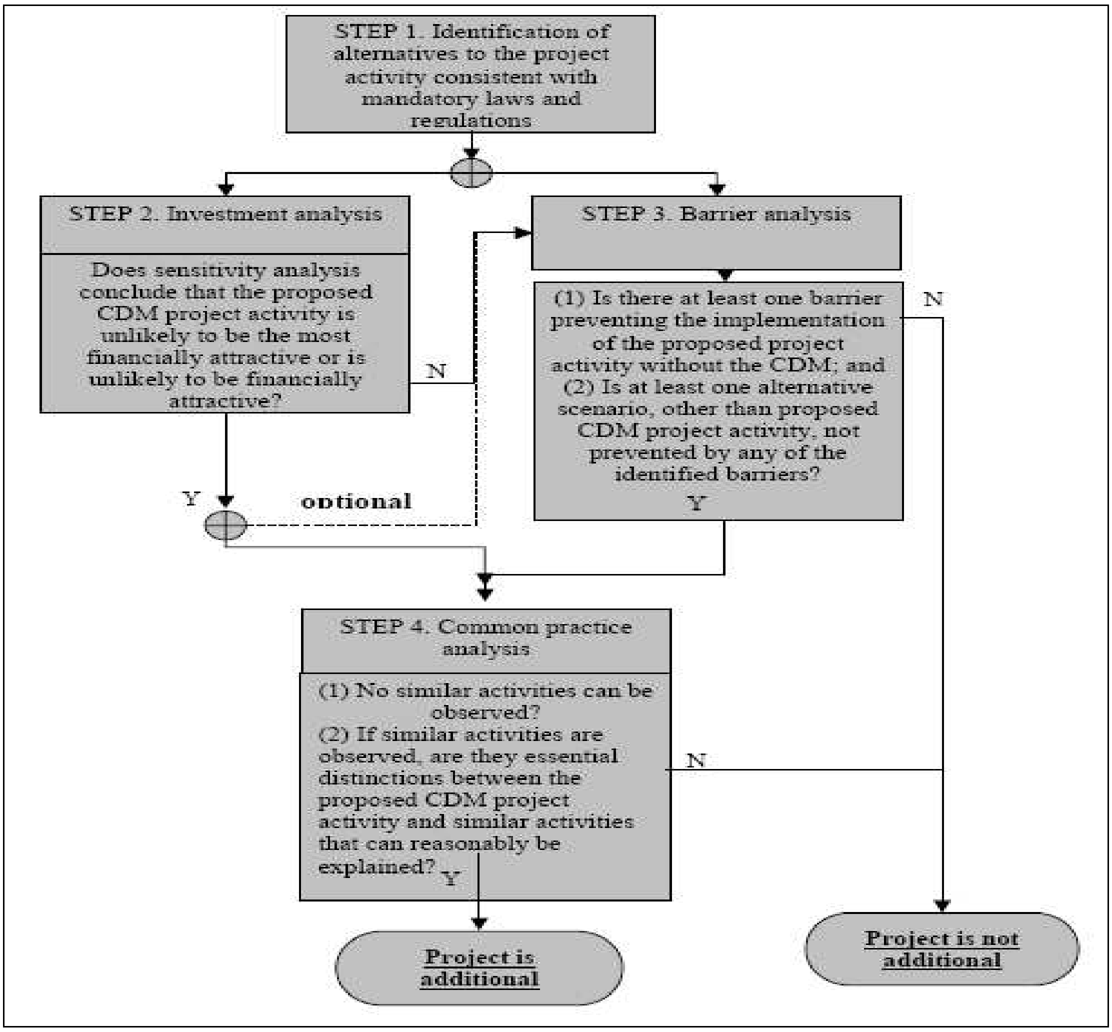
The proposed project activity involves power generation using super-critical technology. Even though this technology is already in practice in other developed nations like USA, UK, Germany, Japan *etc.*, no super-critical power plant is yet operational in India, where the total installed thermal power generation capacity is even more than many of these developed countries. According to Central Electricity Authority, Govt. of India, out of total installed power generation capacity of 132329.21 MW the installed capacity of coal based thermal power constitutes 71121.38 MW as on 31.03.2007, as is evident from the table below.

Table 12: All India Installed Generating Capacity in MW

All India Generating Installed Capacity (MW)									
		Thermal							
Year	Hydro	Coal	Gas	Diesel	Total	Nuclear	R.E.S	Total	% of coal in Total Generating Installed Capacity
As on 31-03-2005[1]	30942.24	67790.87	11909.82	1201.75	80902.44	2770.00	3811.01	118425.69	57.24
As on 31-03-2006[2]	32325.77	68518.88	12689.91	1201.75	82410.54	3360.00	6190.86	124287.17	55.13
As on 31-03-2007[3]	34653.77	71121.38	13691.71	1201.75	86014.84	3900.00	7760.60	132329.21	53.75
1Source:http://www.cea.nic.in/power_sec_reports/general_review/0405/ch2.pdf									
2Source: http://www.cea.nic.in/power_sec_reports/executive_summary/2006_03/6.pdf									
3Source: http://www.cea.nic.in/power_sec_reports/Executive_Summary/2007_03/6.pdf									
R.E.S-Renewable Energy Sources includes Small Hydro Project(SHP), Biomass Gas(BG), Biomass Power(BP), Urban & Industrial waste Power(U&I), and Wind Energy									

However, till date not a single thermal power plant in India has come up with super-critical technology. This demonstrates the uniqueness of the project which involves setting up of a single location 4000 MW generation capacity using coal fired super-critical technology. As on date the technology has achieved **no** penetration in India due to the investment, technology and other barriers as elaborated below.

The "Tool for the demonstration and assessment of additionality" version 05.2 has been followed to demonstrate the additionality of this proposed project activity.



Step 1: Identification of alternatives to the project activity consistent with current laws and regulations

Sub-step 1a: Define alternatives to the project activity

Plausible alternatives to the proposed project activity which can be part of the baseline scenario have been identified in Section B.4. These alternatives include:

- Alternative 1. The project activity not implemented as a CDM project
- Alternative 2. Power generation using coal-fired sub-critical power generation technologies
- Alternative 3. Power generation using energy sources (natural gas) other than coal
- Alternative 4. Power generation using energy sources (hydro) other than coal
- Alternative 5. Power generation using energy sources (diesel/ fuel oil/naphtha) other than coal
- Alternative 6. Power generation using energy sources (renewable energy sources excluding hydro) other than coal

- Alternative 7. Power generation using energy sources (nuclear) other than coal
- Alternative 8: Import of electricity from connected grids, including the possibility of new interconnections.

In view of the analysis of the above alternatives in Section B.4, Alternative 1 and Alternative 2 are the options which are the realistic and credible alternatives to the project activity.

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

Both Alternatives 1 and 2 are in compliance with all mandatory applicable legal and regulatory requirements.

Step 2: Investment Analysis

Sub-step 2a: Determine appropriate analysis method

As the proposed project activity and the alternative identified in Step 1 (Alternative 2) generate financial/economic benefits other than CDM related income, hence the simple cost analysis (Option I) cannot be applied. According to the 'Tool for demonstration and assessment of additionality'-Version 05.2, the project proponent has adopted 'Sub-step 2b – Option III: Benchmark analysis' to establish the project as financially additional.

Sub-step 2b: Option III. Apply benchmark analysis

In this context the Return on Equity (ROE) has been considered as the suitable financial indicator whose value for the project scenario (*i.e.* super-critical power generation) has been compared with that of the benchmark (*i.e.* the normal ROE guaranteed for a similar baseline power plant by CERC, Govt of India).

Sub-step 2c: Calculation and comparison of financial indicators

The levelized cost of power generation for the proposed project activity as on today's date is INR 1.81/kWh and the levelized tariff stands at INR 2.26/kWh[56]. The ROE during bid submission was calculated to be 10.20% (without consideration of CDM revenue).

Input parameters for ROE calculation

Parameter	**Unit**	**Value**

[56] http://www.pib.nic.in/release/release.asp?relid=27057&kwd

Project Size	MW	4000
Total Project Cost	INR million	170130
Project Cost per MW	INR million/MW	42.5
Debt: Equity Ratio		75:25
Loan Repayment Period Average (from end of moratorium period	years	20
Maintenance Spares	% of project cost	1%
Escalation in cost of spares		6%
Rate of Interest on loan Capital (Average)		10.00%
Rate of Interest on Working Capital		8.5%
Depreciation (as per IT Act)		15%
Plant Life	years	25
PLF		85%
Auxiliary Consumption		7.5%
GCV	kCal/kg	5750
SHR	kCal/kWh	1965
Price of coal	INR/ton	2248
Escalation on fuel charges		3.46%
O&M Cost	INR million/MW	0.6175

The ROE calculated during the decision making time stood at 10.20% which is much lower than what would be otherwise available to the developer, in the event the developer chose to go for sub-critical domestic coal based power plant. (The details of the ROE calculation with all relevant assumptions have been attached in Appendix 2). It is worthwhile to note here that the project activity was awarded to the project proponent through a competitive bidding mechanism and the levelized tariff quoted by the project proponent was significantly lower than the second lowest bid amongst those quoted by other prospective bidders, indicating a higher risk perception among the prospective bidders for the proposed project activity. The equivalent levelized tariff proposals submitted by the six qualifying bidders are given below[57].

[57] http://www.cercind.gov.in/03022007/No_18-2007.pdf

Sl. No	Bidder	Equivalent Levelised Tariff (Rs./kWh)
1.	Tata Power Company Limited	2.26367
2.	Reliance Energy Generation Limited	2.66119
3.	Adani Enterprises Ltd.	2.69601
4.	Essar Power Ltd	2.80054
5.	Larsen & Toubro Power Limited	3.22049
6.	Sterlite Industries (India) Limited	3.74625

The project proponent has considered a benchmark of 14%[58] which is the CERC, Govt of India approved ROE for coal based subcritical power projects in India. As per "Tool for the demonstration and assessment of additionality" Version 05.2, page 6, point 6e "*Discount rates and benchmarks shall be derived from Government/official approved benchmark where such benchmarks are used for investment decisions*." The 14% ROE (post tax) is the benchmark rate of return which is approved by CERC and is the assured return which the project proponent would have got had the project proponent gone for a subcritical coal based power plant. Thus, the project proponent has taken a benchmark ROE as 14%.

Sub-step 2d. Sensitivity analysis

A sensitivity analysis was carried out which further substantiates the robustness of the financial analysis carried out.

Parameter	**Variation**	**ROE**
Project Cost	5% decrease	11.61%
	10% decrease	13.74%
	10.79% decrease	14%
Coal Cost	5% decrease	12.18%
	9.43% decrease	14%
PLF	2.5% decrease	10.24%
	5% decrease	10.29%

[58] http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf, Page 20

	2.5% increase	10.15%
	5% increase	9.84%
	Infinite decrease	14%
O&M Costs	5% decrease	10.48%
	10% decrease	10.57%
	60.00% decrease	14%

The sensitivity analysis shows that the ROE (during bid submission) is always lower than the benchmark ROE under any predictable variation of the sensitivity parameters. The availability of CDM revenue would make the investment in the higher capital intensive technology more attractive. In fact this will also provide a cushion to the project proponent when ROE decreases substantially due to increase in the critical parameters like fuel cost, project cost *etc*. as shown in the sensitivity analysis. For the fuel price (coal price), a 9.43% decrease in price is not a feasible scenario.[59] This is because the company had assumed the least cost option for its coal price assumptions i.e., low calorific value Indonesian coal. Further the least cost option of ownership of mines was assumed to reduce overall coal cost. This is reflected in the bid documents submitted by CGPL wherein 55% of coal cost was assumed as fixed. During the time of the investment decision, the long term price difference between lead global coal indices and Indonesian Coal was 25% to 30% (Indonesian coals being cheaper). Hence, 25% discount for Indonesian coal was assumed on the prevailing API4 & GCCNC indices. Thus having considered steep 25% reduction on sport prices a further reduction of coal price would not have been a possible scenario given the demand supply scenario of coal which continues even today. Given the growing acceptance and demand for Indonesian coal this differential has actually been seen reducing considerably past the investment decision.

The sensitivity analysis has been done with a variation in capital cost upto the extent of 10% as a decrease in the capital cost of the proposed project activity by more than 10% is highly improbable.

[59] http://www.businessstandard.com/india/storypage.php?autono=155593
Also it is worthwhile to note that even though imported coal prices have been spiralling year after year (between 2002 and 2004, imported coal prices have increased by 100%), domestic coal prices have hardly increased in the last 8-9 years (since price of domestic coal was deregulated in January 2000 by Govt of India). http://www.hindu.com/2008/11/14/stories/2008111456741600.htm

The average inflation rate in India stands at around 8.5-9% (as of 2008) and going by the past trends, India is expected to experience an increase in price trends. Given the trends in inflation, prices of goods and equipment purchased will increase and it is extremely unlikely that the project cost will be reduced. Further, due to limited supply of equipments and a dearth of EPC contractors for supercritical power technology, there are chances of increase in cost.

In addition prior to the bidding date, budgetary quotes were taken from key equipment suppliers (supportive provided to Validator) which constitute of about 50 – 60 % of the total hard cost of the project. These quotes were invited on a fixed price basis, thus there is no possibility of any reduction of the price post accepting the offer. Final contracts signed with these parties also prove that the final negotiated price is very close to the quoted price prior to bidding. The remaining cost entails to the Civil works for the plant, the Balance of Plant equipments, cost of consultants, Financial Charges, Interest During Construction and Preoperative expanses. Given that the Inflation in India has historically been always in the positive territory there is no reason to believe that these costs can come down from the then existing prices.

An infinite decrease in PLF or 60.00% decrease in O&M costs is not realistic. Considering CDM revenue, the ROE stood at 15.59% at the time of taking the decision to bid for the proposed project activity, which is greater than the benchmark ROE of 14%.

Step 3: Barrier Analysis

Sub-step 3a: Identify barriers that would prevent the implementation of the proposed CDM project activity

The project proponent has performed barrier analysis to establish the additionality of the proposed project activity. The project proponent is facing certain barriers which may hinder the project proponent in successful implementation of the project activity.

These barriers are elaborated below.

Barrier due to prevailing practice

Lack of Trained Manpower in India for the Project Operation: The proposed project activity *i.e.* generation of thermal power through super-critical technology is a very recent addition in Indian power generation sector. The project proponent or any other power generation utility in India does not have sufficient familiarity with operating the technology. There exists significant risk, as elaborated above, for being the first to implement a new technology in a country where there is a lack of local knowledge of the new technology, dearth of adequate man power with relevant technical expertise for operation of the technology and maintenance of the equipments.

Coal fired power generation is dominant in India. As on 31.03.2007, out of an installed generation capacity of 132329.21 MW, coal based power generation accounts for 71121.38 MW and out of a total generation of 659419.4 GWh, coal based generation accounts for 452168.4 GWh. Even though almost 68% of the total generation is coal based in India, none of the coal based power generation utilities in India is so far operational with a generation capacity to the tune of 4000 MW using super-critical technology. These facts emphasise so far no penetration of super-critical power generation technology in India and further substantiate the uniqueness of the proposed project activity in Indian power generation sector. The project activity will be the first single location thermal power plant in India of 4000 MW scale which will utilize higher efficiency super-critical technology and contribute to GHG emission mitigation.

Table 13: Percentage of Coal based Generation in All India Electricity Generation

All India Energy Generation Data			
	Generation (GWh)		
Type of Generation	**2006-07[1]**	**2005-06**	**2004-05**
Coal	452168.4	426138	415484
Gas+Diesel	75330.73	71076	70591.48
Total Thermal	527499.1	497214	486075.5
Hydro	113314.9	101293.1	84495.3
Nuclear	18605.36	17238.89	16845.29
Total	**659419.4**	**615746**	**587416.1**
% of coal in Total Generation	**68.57**	**69.21**	**70.73**
[1]http://www.cea.nic.in/god/opm/Monthly_Generation_Report/18col_07_03.pdf			
Source: Thermal Performance Review http://www.cea.nic.in/			

Technological barrier

The project proponent envisaged the following technological / operational risk factors associated with super-critical technology.

In the recirculation boiler (which is typically used in sub-critical power plant), the quantity of water re-circulated is in the range of five times the quantity of feed water flow. In a once through boiler (which is used in supercritical technology), the flow quantity is limited only to feed water flow *i.e.* the ratio of steam generation to feed water flow is close to 1. For a thermal power plant connected to the grid, any extreme load fluctuation in the grid will result in corresponding variation in boiler steam generation and feed water flow. For this reason the thermal response on account of extreme load fluctuation will be much severe in once through boiler system, compared to a subcritical boiler,

leading to thermal shock. In addition, unlike the re-circulation boiler where the tubes always contain some water and therefore, operate at close to saturation temperature, in a once through boiler there will be differential fluid temperatures between tubes due to differential heat absorption rates between tubes. At super-critical pressures temperature differentials are likely to be higher as there is no part of the heating process in which a constant temperature exists for change in enthalpy. Differential heat pick-up between tubes will increase the potential for temperature differentials between tubes resulting in thermal stresses[60]. The high thermal shock/ stresses on the boiler tubes can lead to failure of the boiler tubes and jeopardise the power plant operation. Such phenomena are even more serious when the boiler operates at part load although presently high strength materials are used in boiler tubes to counter the stresses.

The super-critical power plants under UMPP are supposed to run on base load. However, looking at India's proposed 12485MW[61] capacity addition of nuclear power (which have to run on base load) by end of 11th Plan it is highly probable that during grid fluctuation the UMPPs may be forced to operate on partial load giving priority to the grid connected nuclear power plants to continue to run on base load.

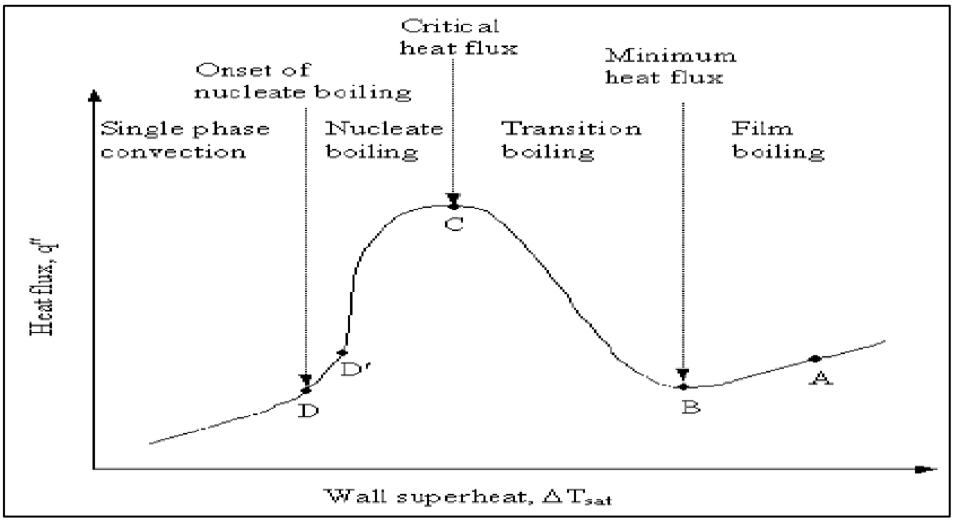
The boiler design of the proposed project activity involves a high mass flux through the tubes to avoid departure from nucleate boiling (DNB)[62] and subsequent overheating of the tube metal. A high mass flux design has the negative flow characteristic[63] which causes tubes to experience higher than average heating and draws lower than average fluid flow. The negative flow characteristic can lead to non uniform temperature profile, resulting in possible overheating of tubes in the upper furnace, DNB at high heat flux areas and differential thermal expansion of the water walls which ultimately leads to tube failure.

Figure 3: Boiling Curve

[60] SWIS Power Procurement – Comparative Supercritical Study, Western Power Corporation

[61] http://www.npcil.nic.in/nupower_vol13_1/nugenn.htm

[62] The point at which the heat transfer from a body rapidly decreases due to the insulating effect of a steam blanket that forms on the rod surface when the temperature continues to increase.
Nucleate boiling- Steam bubbles form at the heat transfer surface and then break away and are carried into the main stream of the fluid. Such movement enhances heat transfer because the heat generated at the surface is carried directly into the fluid stream. This heat transfer process is sometimes desirable because the energy created at the heat transfer surface is quickly and efficiently "carried" away.



Significant risks exist as there is dearth of local knowledge of the new technology and lack of skilled personnel to understand the technology and operate the equipments. The project proponent has to heavily rely on foreign expertise at every stage of project construction, commissioning and subsequent operation which in-turn will escalate the project cost. There is also the need to procure critical equipments from developed countries which adds to the possibility of .increase in the overall project cost on account of foreign exchange dynamics and uncertainties inherent to the economies of the seller countries. Extra spares are required as there are no local manufacturers of this technology.

The above-mentioned technological problems and lack of competent manpower and knowledge base, unavailability of local technology supplier or supplier of BTG (Boiler-Turbine-Generator) package are some of the major barriers anticipated by the project proponent which would hinder the project proponent to implement the project activity without considering CDM benefit.

Investment barrier

The project activity *i.e.* implementation of 4000 MW super-critical technology based coal fired power generation is highly capital intensive and entails capital investment to the tune of INR 170000 million. As evident from the previous capital expenditure plan of the TPCL (the parent company of CGPL – the project proponent) this is the first time TPCL is venturing into a project which not only involves high capital investment but also involves implementation of a technology which is completely new in Indian context. The project will be financed through Coastal Gujarat Power

[63]Sub-critical boilers with natural circulation have positive flow characteristic whereby tubes experience higher than average heating and tend to draw higher than average fluid flow.

Limited (the project proponent) which is 100% subsidiary of TPCL. It is worthwhile to mention that as per the 2006-07 Annual Report of Tata Power Company Limited, the net free cash flow generation was INR 11505.6 million for FY 2006-07. This free cash flow generation is insufficient to meet TPCL's capital expenditure requirement which stands at INR 32140 million for FY 2007-08 (a significant part of this CAPEX involves equity of TPCL in the super-critical power project of CGPL). Moreover, capital in the form of Equity (From Tata Power) blockage to the tune of Rs 42500 million for 4 years (this is the period along which the entire capital investment is phased out) will impact the liquidity of the company and hence its future debt servicing capability. It may be noted that other alternative investment options for the company would have been relatively of a lower risk. The reason being these projects are either local coal based / have a lower capital cost, for example projects like the 1050 MW Maithon project at West Bengal, 2400 MW Dehrand project at Maharashtra *etc*. (Ref: 12 year CAPEX plan of TPCL). If a 4000MW subcritical power project would have been implemented (*i.e.* the baseline alternative), financing can be arranged with relative ease as the baseline is a low risk and established technology and there would be no penalty in case of late implementation. For the proposed project activity, a delay in implementation and supply of power would lead to high penalty[64].

Till date entire investment in thermal power sector by all types of investors (both Indian and oversees investors) has been in the subcritical units. The certainty of achieving the desired efficiency level and hence the desired return on investment for super-critical technology is not tested in Indian context where the power plant will be subjected to various factors like ambient environmental conditions affecting power generation efficiency, as coal quality and supercritical are independent of each other operational bottlenecks considering non familiarity of technology by the workforce..

There is a heightened risk perception among the project proponents and project lenders due to non-availability of established local support base for supply of suitable expertise spares and services required for the project. In addition, this being the first 800 MW supercritical power plant in India there is an enhanced risk perception among the lenders.

Furthermore, the Indian EPC contractors are familiar with the engineering, procurement and construction services primarily for the sub-critical units in the scale of 300MW, 400MW, 500MW

[64] As per the PPA, there is a penalty of INR 10000 per day per MW for late implementation and supply of power.

etc. but not with 800 MW units[65]. The project proponent found out during the initial planning or the project that no EPC contractor was ready to do the project within the timeframe promised in the Power Purchase Agreement and the required cost parameters due to which the project proponent decided to go for the package route. The project proponent decided to go on a package route. The entire project has been divided into about 100 packages with each package being ordered separately to individual contractors. This exposes the project activity to a risk on the integration issues of various packages and also delay made by one party can lead to a potential risk of delaying the entire project. Contrasted to a typical single party EPC contract, in package philosophy the liability of the contractor (in the form of liquidated damage paid to the project developer) on account of delay is low but the project developer is exposed to high risks of non-completion even if a single contractor, who is supposed to deliver one of the critical job, defaults. Alternatively in baseline cases, availability of various experienced EPC contractors for sub-critical units provides the comfort of integration issues, cost effectiveness and on-time completion of the project.

Since, as per the bid condition of Ultra Mega Power Project (UMPP) the project activity has to operate on imported coal there will be the associated risks of volatility in coal prices in the international market and there will be consequent impact on the cost of generation. The price risk associated with imported coal is expected to be partially mitigated through an escalation mechanism (as escalation is available only for a portion of the total imported coal requirement and not the entire quantity) linked with a basket of internationally accepted spot coal indices. However, these indices represent averages and project activity would continue to face risk of buying coal at a price different from the level suggested by the index[66]. Volatility in fuel prices could mean that when coal prices are high the project may rank low resulting in uncertainty over dispatch recovery of capacity charges, incentive income *etc.* The inherent risk for the project which has decided to follow the long term supply based model lies in the following major issues:

-As per the bid conditions the cost of only the escalable portion of coal will be escalating on a per annum basis as opposed to a fixed (*i.e.* non escalable) component which represents 55% of coal cost. In the event of coal price increase over and above the one assumed during bidding, the tariff to be paid to the project proponent will only take care of the escalable component of the coal cost but will

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[65] Source: CRISIL Research: "Power generation: Equipment availability- A critical focus area", Page 13

[66] Consultant's Report: 'Escalation rates for escalable components of imported coal and captive mine coal for thermal power projects' - Central Electricity regulatory Commission of Govt. of India

not compensate for the increase in the non-escalable component. This creates a potential risk where the revenue only for the '**Quoted Fuel Energy Charges'** (as in the PPA) can be inadequate to meet the entire cost of coal.

-Change in bilateral diplomatic relations between India and coal exporting countries can severely jeopardize the coal availability and increase the coal price which in turn can impact cost of generation. In order to maintain sustained supply of fuel to the power plant, the project proponent may have to acquire coal mines abroad; high cost of such acquisition of mining assets in the foreign country further strains the company's financials and thereby increases the expected rate of return from the project[67].

In case of baseline option *i.e.* subcritical coal fired power plant, there is no restriction on usage of domestic coal and therefore the project proponent could have secured coal from domestic sources also. The above mentioned risk lies with the particular bid condition which stipulated compulsory usage of imported coal.

The above-mentioned barriers also remain significant areas of concern for the prospective financiers of the project.

Sub-step 3 b: Show that the identified barriers would not prevent the implementation of at least one of the alternatives (except the proposed project activity)

The above mentioned barriers are not applicable to the identified baseline scenario *i.e.* "Power generation using coal-fired sub-critical power generation technologies" as already discussed in Sub-step 3 b).

During the conceptualization of the proposed CDM project activity the potential CDM revenue that would flow to the proposed project activity had been seriously considered. Following impacts of CDM fund are identified from the point of view of mitigation of risks and barriers discussed above.

- ✓ CDM revenues will provide additional coverage to the risks associated with the proposed project activity and partially offset the impact of other technical risk factors as mentioned above.
- ✓ The revenues from CDM will further stimulate efforts in CGPL to find methods of mitigating risks and enhance replication of such advanced power generation technologies to achieve GHG abatement.

[67] *Source: CRISIL, April 2007, OPINION*

Step 4. Common practice analysis

Sub-step 4a. Analyze other activities similar to the proposed project activity

The super-critical technology is a recent addition in India. At present there is no operating super-critical power plant in India. (installed capacity of 4000 MW) which is running on imported coal and supplying electricity to the grid. In fact this is the first Greenfield project to add 4000MW of generation capacity at a single location in India.

Sub-step 4b: Discuss any similar Options that are occurring

Since similar activities are not observed as discussed in Sub-step 4a, hence it may be concluded that similar activities are not commonly carried out.

Therefore, Step 4 is satisfied.

Thus, it may be concluded that the proposed project activity is additional as it satisfies all the criteria of the "**Tool for the demonstration and assessment of additionality", Version 05.2.**

Chronology of the proposed project activity

Milestone	Date	Supportive Document
Initiative for Ultra Mega Power projects by Power Finance Corporation Ltd (A Govt. of India undertaking)	January 2006	http://pfc.gov.in/Tariff_Policy.pdf http://pfc.gov.in/selection_process.pdf
Detailed Project Report (technical) by TCE Consulting Engineers Ltd	July 2006	Submitted to DOE
Study on India's Ultra Mega Power Projects by Mott MacDonald (engaged by British High Commission)	October 2006	Final Report of Mott MacDonald on "Exploring the Use of Carbon Financing" submitted to DOE The report was used as initial concept document for the bidders
Communications with CDM consultants and internal communications of TPCL regarding the CDM potential of the Mundra UMPP	September-November 2006	The trail of email communications have been forwarded to the DOE.
Board Meeting of Tata Power Company Ltd and decision regarding	2nd December 2006	Certified true extracts of the Minutes of Meeting of Tata Power submitted to DOE

bidding for Ultra Mega Power Project using super-critical technology		
Bid Submission for Coastal Gujarat Power Ltd by TPCL	7th December 2006	Cover letter of bid submission submitted to DOE
Communications with CDM consultants regarding the Mundra UMPP	December 2006	Email Communications forwarded to DOE
Mundra UMPP awarded to TPCL	December 2006	http://timesofindia.indiatimes.com/articleshow/843633.cms
Power Purchase Agreement was signed for the project	22nd April 2007	Copy of PPA submitted to DOE
Submission to Ministry of Environment & Forests for Host Country Approval	20th November 2007	Letter to MoEF submitted to DOE
Webhosting of PDD on UNFCCC website	13th January to 11th February 2008	http://cdm.unfccc.int/Projects/Validation/index.html
Financial due diligence by the lenders taking into consideration future CDM benefits	February 2008	Email from ADB dated 14.02.2008 Letter from IFC dated 26.02.2008
Financial closure for the CGPL project	24th April 2008	http://economictimes.indiatimes.com/Power/TPC_announces_financial_closure_of_Mundra_project/articleshow/2980723.cms

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

The relevant methodological steps are described below.

Baseline Emissions

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

$$BE_y = EG_{PJ,y} x EF_{BL,CO2,y}$$

Where:

BE_y	Baseline emissions in year y (tCO_2)

$EG_{PJ,y}$	Net quantity of electricity generated in the project plant in year *y* (MWh)
$EF_{BL,CO2}$	Baseline emission factor in year *y* (tCO_2/MWh)

$EF_{BL,CO2}$ is determined using the lower value between the emission factor of the technology and fuel type that has been identified as the most likely baseline scenario and a benchmark emission factor determined based on the performance of the top 15% power plants that use the same fuel as the project plant and any technology available in the geographical area as defined in Step 2 below.
To calculate $EF_{BL,CO2,y}$ the lowest value among the following two options will be used.

Option 1: The emission factor of the technology and fuel identified as the most likely baseline scenario under "Identification of the baseline scenario" section above, and calculated as follows:

$$EF_{BL,CO2,y} = \frac{MIN(EF_{FF,BL,CO2,y}; EF_{FF,PJ,COP2,y})}{\eta_{BL}} x3.6GJ/MWh$$

Where:

$EF_{BL,CO2,y}$	Baseline emission factor in year *y* (tCO_2/MWh)
$EF_{FF,CO2,y}$	CO_2 baseline emission factor of the baseline fossil fuel type that has been identified as the most likely baseline scenario (tCO_2 / Mass or volume unit)
$EF_{FF,PJ,CO2,y}$	Average CO_2 emission factor of the fossil fuel type used in the project plant in year *y* (tCO_2 / Mass or volume unit)
η_{BL}	Energy efficiency of the power generation technology that has been identified as the most likely baseline scenario

For the proposed project activity, the baseline fossil fuel type that has been identified as the most likely baseline scenario is coal and the fossil fuel to be used in the proposed project activity is also coal.

Option 2: The average emissions intensity of all power plants *j*, corresponding to the power plants whose performance is among the top 15 % of their category, as follows:

$$EF_{BL,CO2,y} = \frac{\sum_j FC_{j,x} * NCV_{j,x} * EF_{CO2,j,x}}{\sum_j EG_{j,x}}$$

Where:

$EF_{BL,CO2,y}$	Baseline emission factor in year *y* (tCO_2/MWh)

$FC_{j,x}$	Amount of fuel consumed by power plant *j* in year *x* (Mass or volume unit)
NCVj,x	Net calorific value of the fossil fuel type consumed by power plant j in year *x* (GJ / Mass or volume unit)
$EF_{CO2,j,x}$	CO_2 emission factor of the fossil fuel type consumed by power plant *j* in year *x* (tCO_2 / Mass or volume unit)
$EG_{j,x}$	Net electricity generated and delivered to the grid by power plant *j* in year *x*
X	Most recent year prior to the start of the project activity for which data is available
j	Top 15% performing power plants (excluding cogeneration plants and including power plants registered as CDM project activities), as identified below, among all power plants in a defined geographical area (India) that have a similar size, are operated at similar load (*i.e.* at base load) and use the same fuel type (coal) as the project activity

For determination of the top 15% performer power plants *j*, the following step-wise approach is used:

Step 1: Definition of similar plants to the project activity

The sample group of similar power plants should consist of all power plants (except for cogeneration power plants):

• Those use the same fossil fuel type as the project activity, where fuel types are defined in the following categories:

-Coal

-Oils (e.g. diesel, kerosene, residual oil)

-Natural gas

• Those have been constructed in the previous five years;

• Those have a comparable size to the project activity, defined as the range from 50% to 150% of the rated capacity of the project plant;

• Those are operated in the same load category, *i.e.* at peak load (defined as a load factor of less than 3,000 hours per year) or base load (defined as a load factor of more than 3,000 hours per year) as the project activity; and

• Those have operated (supplied electricity to the grid) in the year prior to the start of the project activity.

The sample group of plants identified consists of coal based sub-critical power plants that have a capacity between 400MW to 1200MW, have been constructed in last 5 years, operate at base load and have supplied electricity to the grid before start of the proposed project activity.

Step 2: Definition of the geographical area

As per the methodology ACM0013, Version 02, the geographical area to identify similar power plants is chosen in a manner that the total number of power plants "N" in the sample group comprises at least 10 plants. As a default, the grid to which the project plant will be connected should be used. As the number of similar plants, as defined in Step 1, within the Western regional grid boundary is less than 10, the geographical area is extended to India. The number of similar plants is now greater than 10.

Step 3: Identification of the sample group

Identify all power plants *n* that are to be included in the sample group. Determine the total number "N" of all identified power plants that use the same fuel as the project plant and any technology available within the geographical area, as defined in Step 2 above.

The sample group should also include all power plants within the geographical area registered as CDM project activities, which meet the criteria defined in Step 1 above.

Step 4: Determination of the plant efficiencies

Calculate the operational efficiency of each power plant *n* identified in the previous step. The most recent one-year data available is used. The operational efficiency of each power plant *n* in the sample group is calculated as follows:

$$\eta_{n,x} = \frac{EG_{n,x}}{FC_{n,x} * NCV_{n,x} * 277.8}$$

Where:

$EG_{n,x}$	Net electricity generated and delivered to the grid by the power plant *n* in the year *x* *(MWh)*
$FC_{n,x}$	Quantity of fuel consumed in the power plant *n* in year *x* (Mass or volume unit)
$NCV_{n,x}$	Net calorific value of the fuel type fired in power plant *n* in year *y* (GJ / mass or volume unit)n are all power plants in the defined geographical area that have a similar size, are operated at similar load and use the same fuel types as the project activity
277.8	Conversion factor from TJ to MWh
x	Most recent year prior to the start of the project activity for which data are available

Step 5: Identification of the top 15% performer plants j

Sort the sample group of *N* plants from the power plants with the highest to the lowest operational efficiency. Identify the top 15% performer plants *j* as the plants with the 1st to Jth highest operational efficiency, where the *J* (the total number of plants *j*) is calculated as the product of N (the total number of plants *n* identified in step 3) and 15%, rounded down if it is decimal.4 If the generation of all identified plants *j* (the top 15% performers) is less than 15% of the total generation of all plants n (the whole sample group), then the number of plants *j* included in the top 15% performer group should be enlarged until the group represents at least 15% of total generation of all plants *n*. All Steps should be documented transparently, including a list of the plants identified in Steps 3 and 5, as well as relevant data on the fuel consumption and electricity generation of all identified power plants.

The emission factor has been calculated by Central Electricity Authority, Govt of India and published on their website (http://www.cea.nic.in/planning/cdm.pdf).

Project emissions

The CO_2 emissions from electricity generation in the proposed project activity (PE_y) is calculated using the latest approved version of the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion" (Version 02, EB 41), where the process *j* in the tool corresponds to the combustion of fossil fuels in the project plant. Here the process *j* corresponds to combustion of coal for power generation using super-critical technology in the proposed project activity. As per this tool,

CO_2 emissions from fossil fuel combustion in process *j* are calculated based on the quantity of fuels combusted and the CO_2 emission coefficient of those fuels, as follows:

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

Where:

$PE_{FC,j,y}$	CO_2 emissions from fossil fuel combustion in process *j* during the year *y* (tCO_2 / yr)
$FC_{i,j,y}$	Quantity of fuel type *i* combusted in process *j* during the year *y* (mass or volume unit / yr);
$COEF_{i,y}$	CO_2 emission coefficient of fuel type *i* in year *y* (tCO_2 / mass or volume unit);
I	Fuel types combusted in process *j* during the year *y*

The CO_2 emission coefficient $COEF_{i,y}$ can be calculated following two procedures, depending on the available data on the fossil fuel type *i*, as follows:

Option A: The CO_2 emission coefficient $COEF_{i,y}$ is calculated based on the chemical composition of the fossil fuel type *i*, or

Option B: The CO_2 emission coefficient $COEF_{i,y}$ is calculated based on net calorific value and CO_2 emission factor of the fuel type *i*.

Option A is followed here.

$$COEF_{i,y} = w_{c,i,y} x 44/12$$

Where:

$COEF_{i,y}$	CO_2 emission coefficient of fuel type *i* in year *y* (tCO_2 / mass or volume unit);
$w_{c,i,y}$	Weighted average mass fraction of carbon in fuel type i in year y (tC / mass unit of the fuel)
i	Fuel types combusted in process *j* during the year *y*

Leakage

The methodology does not require the consideration of any leakage emissions.

$LE_y=0$

LE_y are the leakage emissions during the year y (tCO_2e).

Emission reductions

Emission reductions (ER_y) by the project activity during year y are the difference between the baseline emissions (BE_y), project emissions (PE_y) and emissions due to leakage (LE_y), and are expressed as follows:

$ER_y = BE_y - PE_y - LE_y$……………………………………….. **(15)**

where:

ER_y	Emission reductions due to the project activity during the year y (tCO_2e)
BE_y	Baseline emissions during the year y (tCO_2e)
PE_y	Project emissions during the year y (tCO_2e)
LE_y	Leakage emissions during the year y (tCO_2e)

The detailed emission reduction calculations have been attached as Appendix 3.

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

(Copy this table for each data and parameter)

Data / Parameter:	$EF_{FF,BL,CO2,y}$
Data unit:	tCO_2/GJ
Description:	CO_2 baseline emission factor of the baseline fossil fuel type that has been identified as the most likely baseline scenario
Source of data used:	2006 IPCC Guidelines for National Greenhouse Gas Inventories, Table 2.2, Default Emission Factor for Sub bituminous Coal
Value applied:	0.0961
Justification of the choice of data or description of measurement methods and procedures actually applied :	IPCC default value is internationally accepted and hence used.
Any comment:	-

Data / Parameter:	η_{BL}
Data unit:	-
Description:	Energy efficiency of the power generation technology that has been identified as the most likely baseline scenario
Source of data used:	This parameter is calculated as part of the baseline scenario selection procedure.
Value applied:	0.351
Justification of the choice of data or description of measurement methods and procedures actually applied :	The efficiency has been taken as the higher efficiency between: a) Efficiency (35.1%) calculated as per the station heat rate (of 2450 kCal/kWh) as given in the CERC order dated 22.5.07 b) Efficiency (30.06%) calculated as per the weighted average station heat rate (of 2861 kCal/kWh as given in Annex 3, Table A0) of thermal power plants in India in 2006-07 published by CEA, Govt of India.
Any comment:	

Data / Parameter:	$EF_{FF, PJ,CO2,y}$
Data unit:	tCO_2e/GJ
Description:	CO_2 emission factor of the fossil fuel type consumed by the proposed project activity
Source of data used:	2006 IPCC Guidelines for National Greenhouse Gas Inventories-Table 2.2 for sub bituminous coal
Value applied:	0.0946
Justification of the choice of data or description of measurement methods and procedures	The proposed project activity will use other bituminous coal. Hence IPCC default value of emission factor for other bituminous coal is used as it is internationally accepted.

actually applied :	
Any comment:	

Data / Parameter:	$EF_{BL,CO2,y}$
Data unit:	tCO_2e/MWh
Description:	Baseline emission factor in the year
Source of data used:	2006 IPCC Guidelines for National Greenhouse Gas Inventories and CEA Website (www.cea.nic.in)
Value applied:	0.941
Justification of the choice of data or description of measurement methods and procedures actually applied :	The baseline emission factor as per the two options namely Option 1 and Option 2 have been calculated and the lower value of the two options (in this case Option 2) have been used for calculation of baseline emissions. **Option 1:** Calculated from the three parameters η_{BL}, $EF_{FF,BL,CO2,y}$ and $EF_{FF,PJ,CO2,y}$. The value is calculated as 0.970 tCO_2/MWh **Option 2:** This factor is published on the CEA website (http://www.cea.nic.in/planning/cdm.pdf) and the value stands at 0.941 tCO_2/MWh
Any comment:	Since Option 2 is the lower between Options 1 and 2, hence the Option 2 emission factor has been used for emission reduction calculation. Also as per the methodology ACM0013, version 02, in case of option 2, $EF_{BL,CO2,y}$ is not monitored annually but only calculated once at the start of the crediting period and updated at the renewal of a crediting period.

B.6.3 Ex-ante calculation of emission reductions:

The list of thermal power plants commissioned during last 5 years is as below.

Table 14: List of Thermal Power Plants Commissioned in Last 5 Years

Thermal Power Projects/Units Commissioned During 10th Plan			
Name of the Project/Unit No.		**Capacity**	**Commissioning Date**
Unchahar TPS-III	U-5	210	28.9.06
Vindhyachal TPS-III	U-9	500	27.7.06
	U-10	500	08.03.07
Kahalgaon STPS-II (Ph-I)	U-5	500	31.03.07
Mejia TPS	U-5	250	31.03.07
Giral TPP	U-1	125	28.02.07
Dholpur CCPP (Ph-I)	GT-1	110	29.03.07
Parichha TPS Extn	U-4	210	28.12.06
Korba East TPP St-V	U-1	250	30.03.07
New Parli TPS	U-1	250	16.02.07
Rayalaseema TPS-II	U-3	210	25.01.07
Ratnagiri CCPP (Dabhol)	Block-II	740	4/06 to 5/06
Vemagiri CCPP	ST	137	08.06.06
Valantharvi GTPP	ST	14.8	15.04.06
Total capacity addition in 2006-07		**4006.8**	
Rihand STPS-II	U-4	500	24.09.05
Akrimota Lignite based TPP	U-2	125	19.12.05
Dhuvaran CCPP Extn	GT	72	17.03.06
Rokhia GT Extn	GT-8	21	31.03.06
Parichha TPS Extn	U-3	210	29.03.06
Valantharvi GTPP	GT	38	29.10.05
Karuppur CCPP	ST	49.8	15.07.05
Jegrupadu CCPP Extn	GT	140	8.10.05
	ST	80	11.11.05
Vemagiri CCPP	GT	233	13.01.06
Jojobera TPP	U-1	120	23.09.05
Total capacity addition in 2005-06		**1588.8**	
Ramagundam STPS St-III	U-7	500	31.08.04
Talcher STPP St-II	U-5	500	13.05.04
	U-6	500	06.02.05
Mejia TPS Extn	U-4	210	12.10.04
TDL (Panipat) TPS	U-7	250	28.09.04
	U-8	250	28.01.05
Bairabi DGPP	DG 1-4	22.92	07.05.04
Akrimota TPP	U-1	125	31.03.05
Rangat Bay DGPP	DG 1-2	2.4	05.02.05
	DG 3-5	3.6	22.02.05
Karuppur CCPP	GT	70	19.02.05
Rihand STPS-II	U-3	500	31.01.05
Total capacity addition in 2004-05		**2933.92**	
Talcher STPP ST II	U-4	500	25.10.03
Neyveli FST Extn	U-2	210	22.07.03
Suratgarh TPP St III	U-5	250	30.06.03
Kota TPP St IV	U-6	195	30.07.03
Dhuvaran CCPP	GT	67.85	04.06.03
	ST	38.767	22.09.03
Kuttalam CCPP	GT	63	26.11.03
	ST	37	24.03.04
Total capacity addition in 2003-04		**1361.6**	

Thermal Power Projects/Units Commissioned During 10th Plan			
Simhadri TPS	U-2	500	24.08.02
Neyveli FST Extn	U-1	210	21.10.02
Pragati CCGT	GT-2	104.6	09.11.02
	ST	121.2	31.01.03
Ramgarh CCGT St II	GT-2	37.5	07.08.02
	ST	37.8	31.03.03
Raichur TPP	U-7	210	11.12.02
Valuthur CCGT	GT	60	24.12.02
	ST	34	13.03.03
Leimakhong DGPP	DG-4	6	10.04.02
	DG-5	6	16.04.02
	DG-6	6	12.04.02
Rokhia GT Extn Ph II	GT-7	21	11.07.02
Baramura GT Extn	GT	21	27.11.02
Peddapuram	ST	78	12.09.02
Neyveli TPS	Zero Unit	250	11.10.02
Bambooflat DG	DG-1	5	02/03
	DG-2	5	06/02
	DG-3	5	02/03
	DG-4	5	06/02
Talcher STPP St II	U-3	500	04.01.03
Total capacity addition in 2002-03		**2223.1**	
Source: http://www.cea.nic.in/thermal/project_monitoring/summary.pdf			

These power plants were commissioned in the last five years in India. Out of these power plants- only those plants have been considered that satisfy the following criteria:

• use the same fossil fuel type as the project activity (coal)

• have a comparable size to the project activity, defined as the range from 50% to 150% of the rated capacity of the project plant (i.e. 400MW to 1200MW)

• are operated in the base load category, *i.e.* defined as a load factor of more than 3,000 hours per year and

• have operated (supplied electricity to the grid) in the year prior to the start of the project activity.

The top 15% power plants satisfying the above criteria have been selected by CEA. These top power plants have been used by CEA to calculate the baseline emission factor as per Option 2 given in the methodology ACM0013, version 02.

Table 15: Baseline Emissions

Baseline Emissions									
							Option 1	Option 2	
Year	PLF		$EG_{PJ,y}$	$EF_{FF,BL,CO2,y}$	$EF_{FF,PJ,CO2,y}$	η_{BL}	$EF_{BL,CO2,y}$	$EF_{BL,CO2,y}$	BE_y
	%		MWh	tCO_2/GJ	tCO_2/GJ		tCO_2/MWh	tCO_2/MWh	tCO_2
		Auxiliary Consumption %		IPCC value for sub-bituminous coal	IPCC value for other bituminous coal				
January 2011-December 2011	85	7.50%	11020080	0.0961	0.0946	0.351	0.970	0.941	10369895
January 2012-December 2012	85	7.50%	25713520	0.0961	0.0946	0.351	0.970	0.941	24196422
January 2013-December 2013	85	7.50%	27550200	0.0961	0.0946	0.351	0.970	0.941	25924738
January 2014-December 2014	85	7.50%	27550200	0.0961	0.0946	0.351	0.970	0.941	25924738
January 2015-December 2015	85	7.50%	27550200	0.0961	0.0946	0.351	0.970	0.941	25924738
January 2016-December 2016	85	7.50%	27550200	0.0961	0.0946	0.351	0.970	0.941	25924738
January 2017-December 2017	85	7.50%	27550200	0.0961	0.0946	0.351	0.970	0.941	25924738
January 2018-December 2018	85	7.50%	27550200	0.0961	0.0946	0.351	0.970	0.941	25924738
January 2019-December 2019	85	7.50%	27550200	0.0961	0.0946	0.351	0.970	0.941	25924738
January 2020-December 2020	85	7.50%	27550200	0.0961	0.0946	0.351	0.970	0.941	25924738
Total									**241964223**

Table 16: Project Emissions

Project Emissions				
Year	Other bituminous Coal required per kWh	$FC_{i,j,y}$	$w_{c,i,y}$	PEy
	ton/MWh	ton	%C	tCO_2
January 2011-December 2011	0.3431	4088000	61.6	9233429
January 2012-December 2012	0.3431	9538667	61.6	21544668
January 2013-December 2013	0.3431	10220000	61.6	23083573
January 2014-December 2014	0.3431	10220000	61.6	23083573
January 2015-December 2015	0.3431	10220000	61.6	23083573
January 2016-December 2016	0.3431	10220000	61.6	23083573
January 2017-December 2017	0.3431	10220000	61.6	23083573
January 2018-December 2018	0.3431	10220000	61.6	23083573
January 2019-December 2019	0.3431	10220000	61.6	23083573
January 2020-December 2020	0.3431	10220000	61.6	23083573
Total		**95386667**		**215446684**

Table 17: Emission Reductions

Emission Reductions			
Year	Baseline emission	Project emission	Emission reduction
	tCO_2	tCO_2	tCO_2
January 2011-December 2011	10369895	9233429	1136466
January 2012-December 2012	24196422	21544668	2651754
January 2013-December 2013	25924738	23083573	2841165
January 2014-December 2014	25924738	23083573	2841165
January 2015-December 2015	25924738	23083573	2841165
January 2016-December 2016	25924738	23083573	2841165
January 2017-December 2017	25924738	23083573	2841165
January 2018-December 2018	25924738	23083573	2841165
January 2019-December 2019	25924738	23083573	2841165
January 2020-December 2020	25924738	23083573	2841165
Total	**241964223**	**215446684**	**26517539**

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

Year	Estimation of proposed project activity emission (tonnes of CO_2 e)	Estimation of baseline emissions (tonnes of CO_2 e)	Estimation of leakage (tonnes of CO_2 e)	Estimation of emission reductions (tonnes of CO_2 e)
Jan 2011-Dec 2011	9233429	10369895	0	1136466
Jan 2012-Dec 2012	21544668	24196422	0	2651754
Jan 2013-Dec 2013	23083573	25924738	0	2841165
Jan 2014-Dec 2014	23083573	25924738	0	2841165
Jan 2015-Dec 2015	23083573	25924738	0	2841165
Jan 2016-Dec 2016	23083573	25924738	0	2841165
Jan 2017-Dec 2017	23083573	25924738	0	2841165
Jan 2018-Dec 2018	23083573	25924738	0	2841165
Jan 2019-Dec 2019	23083573	25924738	0	2841165
Jan 2020-Dec2020	23083573	25924738	0	2841165
Total (tonnes of CO_2 e)	**215446684**	**241964223**	**0**	**26517539**

Note: The emission reductions are different in the first two years as the commissioning of the units would take place as below.

Table 18: Commissioning Schedule of proposed project activity

Unit No. (each of 800 MW)	Commercial Operation Date (COD)
Unit # 1	January 2011
Unit # 2	May 2011
Unit # 3	September 2011
Unit # 4	January 2012
Unit # 5	May 2012

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

B.7.1 Data and parameters monitored:

(Copy this table for each data and parameter)

Data / Parameter:	$EG_{PJ,y}$
Data unit:	MWh
Description:	Net quantity of electricity generated in the project plant in year *y*
Source of data to be	Power plant records

used:		
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Jan 2011-Dec 2011	11020080
	Jan 2012-Dec 2012	25713520
	Jan 2013-Dec 2013	27550200
	Jan 2014-Dec 2014	27550200
	Jan 2015-Dec 2015	27550200
	Jan 2016-Dec 2016	27550200
	Jan 2017-Dec 2017	27550200
	Jan 2018-Dec 2018	27550200
	Jan 2019-Dec 2019	27550200
	Jan 2020-Dec2020	27550200
Description of measurement methods and procedures to be applied:	-This data will be monitored on a daily basis by cumulative type kWh meter installed at the generator terminal of each power generation unit. The kWh meter will be calibrated on a regular interval by an accredited agency. The Plant In-charge will be responsible for the regular calibration of the meter. -Data will be recorded in paper/electronic format and archived for Crediting Period + 2 years.	
QA/QC procedures to be applied:	The data of the internal generation meter can be cross verified from the monthly electricity bills for supplying power to the grid.	
Any comment:		

Parameters to be monitored to calculate Project Emissions as per Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion/Version 02

Data / Parameter:	$FC_{i,j,y}$	
Data unit:	Ton/year	
Description:	Quantity of fuel type *i* combusted in process *j* during the year *y*	
Source of data to be used:	Power plant records	
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Jan 2011-Dec 2011[68]	4088000
	Jan 2012-Dec 2012	9538667
	Jan 2013-Dec 2013	10220000
	Jan 2014-Dec 2014	10220000
	Jan 2015-Dec 2015	10220000
	Jan 2016-Dec 2016	10220000
	Jan 2017-Dec 2017	10220000
	Jan 2018-Dec 2018	10220000
	Jan 2019-Dec 2019	10220000
	Jan 2020-Dec2020	10220000
Description of measurement methods	-This data will be monitored on a daily basis with the help of a weighing machine installed at each power generation unit. The weighing machine	

[68] Please refer to Table 18 for Commissioning Schedule of proposed project activity

and procedures to be applied:	will be calibrated on a regular interval by an accredited agency. The Plant In-charge will be responsible for the regular calibration of the instrument. -Data will be recorded in paper/electronic format and archived for Crediting Period + 2 years.
QA/QC procedures to be applied:	Metering and cross-checking with fuel suppliers' data
Any comment:	Total coal consumption will be monitored both at supplier and project end for cross verification.

Data / Parameter:	$w_{c,i,y}$
Data unit:	%
Description:	Weighted average mass fraction of carbon in fuel type i in year y (tC / mass unit of the fuel)
Source of data to be used:	Analysis reports of coal from a national/international accredited laboratory
Value of data applied for the purpose of calculating expected emission reductions in section B.5	i=1 for coal whose $w_{c,i,y}$= 61.6%
Description of measurement methods and procedures to be applied:	-Data will be recorded in paper/electronic format and archived for Crediting Period + 2 years. -Data will be monitored on a monthly basis
QA/QC procedures to be applied:	The reliability of the parameter is ensured since it is from a national/international accredited laboratory.
Any comment:	

B.7.2 Description of the monitoring plan:

Please refer to Annex 4 for the monitoring plan.

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)

18th February 2009

Name of person/entity determining the baseline: Consultants and Experts of Coastal Gujarat Power Limited. Please refer to Annex 1 for contact details.

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:

1st September 2007 (Notice to proceed issued to Toshiba Corporation and Doosan Heavy Industries & Construction Company Ltd. (they are the major equipment suppliers for the project activity.))

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

25 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:

01/01/11 or on registration at UNFCCC (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:

Article 12 of the Kyoto Protocol requires that a CDM project activity contribute to the sustainable development of the host country. Assessing the project's positive and negative impacts on the local environment and on society is thus a key element for each CDM project. CGPL proposes to implement the proposed project activity because of its commitment to ensure maximum global and local benefits in relation to certain environmental and social issues and is a major step towards sustainable development.

Assessment of Environmental Impact

The impact of the project on the environment occurs during two stages:

1. Construction phase
2. Operational phase

Impacts during construction phase

The impacts due to the construction of the project activity are very negligible as it would be only for a period of four years as compared to the lifetime of the power plant (25 years). This would involve construction of the power plant. Associated activities would cause negligible air pollution.

Impacts during operational phase

The operational phase of the proposed project activity involves generation of power under super-critical steam conditions. The environmental impacts would occur as a result of coal consumption which would release gaseous emissions into the atmosphere. However if a sub-critical power plant of the same capacity had been set up, then the coal consumption would have been higher resulting in more GHG emissions.

The nature of the impacts that are evident during the operational and maintenance phases are discussed in the tables given below. All possible environmental aspects for the proposed project activity have been identified and discussed for their impacts on the baseline environment (that prevails before the proposed project activity is executed). The following table summarizes the environmental scenario before the proposed project activity is executed, proposed project activity's local and environmental, social and other impacts, benefits and the mitigation measures taken by CGPL to reduce/ minimize negative impacts if any and enhance the positive impacts.

Sl. No.	ENVIRONMENTAL IMPACTS & BENEFITS	MITIGATION MEASURES/ REMARKS
A	**CATEGORY: ENVIRONMENTAL – NATURAL RESOURCE CONSERVATION**	
1.	Conservation of coal – A non-renewable natural resource: By adopting the super-critical technology, the generation efficiency of the power plant will be greater than that of a sub-critical power plant. The super-critical power plant will require less coal consumption as compared to a sub-critical plant for the same amount of power generated.	The proposed project activity is a step towards Coal Conservation.
B	**CATEGORY: ENVIRONMETAL – AIR EMISSIONS (AMBIENT AIR QUALITY)**	
1.	CGPL has in-house monitoring capability and will conduct ambient air quality monitoring at a regular basis. The ambient air quality in and around the CGPL Power plant will be well within the statutory limits (National Ambient Air Quality Standards-NAAQS).	
C	**CATEGORY: ENVIRONMENTAL – AIR EMISSIONS (DIRECT)**	
1.	All necessary pollution control measures to maintain the emission levels of dust particles, sulphur dioxide and nitrogen oxides within the permissible limits would be taken and necessary treatment of effluents would be carried out, to minimize the impact on air and water quality in the vicinity of the power plant.	
D	**CATEGORY: ENVIRONMENTAL – AIR EMISSIONS (INDIRECT)**	
1.	The proposed project activity will reduce emissions related to additional coal which would have been consumed in a sub-critical thermal power plant. This includes carbon dioxide, sulphur dioxides and particulates. The proposed project activity will also reduce the adverse impacts on air quality related to transportation of coal and coal mining that would have been required to meet the additional	

	capacity requirement of sub-critical thermal power plants.	
E	**CATEGORY: ENVIRONMENTAL – WASTE WATER GENERATION**	
1.	The water pollutants for a thermal power plant are: · Boiler blow down water · Water treatment plant effluent · Effluent from Bottom ash handling system · Coal pile area run off · Air pre-heater wash water effluent · Plant wash down water Floor and Equipment drainage effluent · Rain water drainage · Concentrated brine from desalination plant · Sewage from various buildings in the plant.	**Boiler Blow Down Water:** There would be no blow down system provided for the once through steam generators. All other waste water would be treated to conform to Applicable Standards limiting water pollution. Sewage from various buildings in the power plant. would be conveyed through separate drains to septic tanks. The effluent would be disposed off in the soil by providing dispersion trenches. There would be no ground pollution because of leaching. Sludge shall be removed and disposed off as land fill.
F	**CATEGORY: ENVIRONMENTAL – SOIL**	
1.	The impacts on soil due to the proposed project activity will be	

	negligible and restricted to the construction phase.	
G	**CATEGORY: ENVIRONMENTAL – SOLID WASTE GENERATION**	
1.	The bulk of the solid wastes will be generated from dusts of the ESP plant containing fly ash and coal fines. There will be no additional solid waste generation from the proposed project activity. There will be negligible environmental issues/ impacts related to the collection, handling and transport of solid wastes. Also there will be minimal further pollution risk of air, water or soil at the place of disposal of solid wastes.	The fly ash will be used for manufacturing bricks, cement industry, road making *etc*.
H	**CATEGORY: ENVIRONMENTAL – NOISE GENERATION**	
1.	The equipment used in the proposed project activity are designed taking into consideration the noise abatement measures so as to keep the noise level below 85- 90db (A) at a distance of 1.5 m from the equipments.	The plant and equipment used are designed and specified with a view to keep the noise level within the statutory norms. Major noise producing equipment such as steam turbine generators will be provided with acoustic enclosures. Statutory warnings will be displayed in high noise producing areas and appropriate protective equipment will be provided for operating personal within the power plant. Provision of

		extensive green belt would also reduce the noise levels.

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:

As per Ministry of Environment and Forests Notification, New Delhi, 13th June, 2002, an Environment Impact Assessment (EIA) study need not be done for a project activity if the investment is less than INR1000 million for new project and less than INR 500 million for expansion / modernization project[69]. For the proposed project activity under consideration, the total investment is about INR 170000 million. Therefore, EIA is required for this proposed project activity. Accordingly, a separate Environment Management Plan or EIA study had been developed for the proposed project activity.

The assessment of Environmental Impact for the proposed project activity has also been carried out as required under Environmental (Protection) Act 1986, Government of India, mandatory for expansion or modernization of any activity or for setting up new projects listed in Schedule I of the notification.

SECTION E. Stakeholders' comments

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

Identification of Stakeholders

The stakeholders identified for the project are as under.

- Employees of CGPL
- Ministry of Environment & Forests, India
- Gujarat State Pollution Control Board

[69] Source: EIA Notification Amendment dated June 13, 2002

- Gujarat State Electricity Board
- Ministry of Power, India
- Gujarat Maritime Board
- Consultants
- Equipment Suppliers

Stakeholders list also includes the government and non-government parties, which are involved in the project at various stages. The stakeholders were invited for a meeting. A presentation was given by CGPL discussing the various aspects of the project.

E.2. Summary of the comments received:

Stakeholders Involvement

CGPL has communicated to the relevant stakeholders about the project.

The proposed project activity is an environmentally friendly project which enables improvement of the local area by setting up a power plant. It does not require any displacement of local population. The proposed project activity has therefore not caused any adverse social impacts on local population but has rather helped in improving their quality of life.

Several industries are stakeholders to the project. Project consultants were involved in the project to take care of various pre-contract and post contract project activities like preparation of reports, preparation of engineering documents, selection of vendors / suppliers and supervision of project implementation.

Equipment suppliers will supply the equipments as per the specifications finalized for the project activity and equipment supplier/CGPL are responsible for successful erection and commissioning of the same at the site.

Stakeholders' Comments

CGPL has invited and consulted local stakeholders in an open and transparent manner. No adverse comments are being received from any of the stakeholders. A summary of the stakeholder comments received is presented below.

Sl No	Stake Holder Name	Nature of relationship with CGPL	Comments
1	Employees of CGPL	Employed at CGPL	The employees of CGPL have appreciated this initiative of CGPL.
2	Non Governmental Organization (NGO)	Local NGO associated with the welfare of society	The NGOs have appreciated the initiative taken by CGPL which will help in employment generation and electrification of parts of India.
3	Consultants	Provided engineering consulting service to CGPL for the proposed project activity	The consultants have encouraged CGPL to implement such an advanced technology which will result in GHG reduction and mitigation of global warming.
4	Equipment Suppliers	Contracted for supply of equipments to CGPL for the proposed project activity	The equipment suppliers have appreciated the initiative of CGPL to implement this less GHG intensive technology.

CGPL has obtained all necessary clearances from Government/statutory bodies for implementation of the proposed project activity.

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

As per UNFCCC requirement the PDD will be published at the validator's/UNFCCC web site for public comments for a period of 30 days.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	Coastal Gujarat Power Limited
Street/P.O.Box:	Tata Power Backbay Receiving Station, 148, Lt General J. Bhonsle Marg, Nariman Point
Building:	
City:	Mumbai
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E-Mail:	rameshsubramanyam@tatapower.com
URL:	www.tatapower.com
Represented by:	
Title:	
Salutation:	Mr.
Last Name:	Subramanyam
Middle Name:	
First Name:	Ramesh
Department:	CFO & Company Secretary
Mobile:	+91 9223341063
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Direct tel:	+91 22-6717 1535
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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

No public funding available for this project.

Annex 3

BASELINE INFORMATION

Table A0: Average station heat rate in Indian power plant as published by Central Electricity Authority, Government of India

(a) ALL INDIA STATION HEAT RATE

Year	No. of Stations analyzed	Capacity (MW)	Weighted Average Design SHR (kcal/kWh)	Weighted average Operating SHR (kcal/kWh)	% Operating SHR Deviation with respect to Design SHR	% improvement (+) / deterioration (-) in Operating Station Heat Rate over preceding year
2005-06	57	35480	2398	2747	14.57	(-) 1.47 (wrt 2004-05)
2006-07	56	38611	2398	2861	19.31	(-) 3.35

Source: http://www.cea.nic.in/god/opm/Thermal_Performance_Review/0607/SECTION-13.pdf

Table A1: Baseline Emissions

Baseline Emissions										
							Option 1	Option 2	
Year	PLF	Auxiliary Consumption %	$EG_{PJ,y}$	$EF_{FF,BL,CO2,y}$	$EF_{FF,PJ,CO2,y}$	η_{BL}	$EF_{BL,CO2,y}$	$EF_{BL,CO2,y}$	BE_y
	%		MWh	tCO_2/GJ	tCO_2/GJ		tCO_2/MWh	tCO_2/MWh	tCO_2
				IPCC value for sub-bituminous coal	IPCC value for other bituminous coal				
June 2011-May 2012	85	7.50%	8265060	0.0961	0.0946	0.351	0.970	0.941	7777421
June 2012-May 2013	85	7.50%	22040160	0.0961	0.0946	0.351	0.970	0.941	20739791
June 2013-May 2014	85	7.50%	27550200	0.0961	0.0946	0.351	0.970	0.941	25924738
June 2014-May 2015	85	7.50%	27550200	0.0961	0.0946	0.351	0.970	0.941	25924738
June 2015-May 2016	85	7.50%	27550200	0.0961	0.0946	0.351	0.970	0.941	25924738
June 2016-May 2017	85	7.50%	27550200	0.0961	0.0946	0.351	0.970	0.941	25924738
June 2017-May 2018	85	7.50%	27550200	0.0961	0.0946	0.351	0.970	0.941	25924738
June 2018-May 2019	85	7.50%	27550200	0.0961	0.0946	0.351	0.970	0.941	25924738
June 2019-May 2020	85	7.50%	27550200	0.0961	0.0946	0.351	0.970	0.941	25924738
June 2020-May 2021	85	7.50%	27550200	0.0961	0.0946	0.351	0.970	0.941	25924738
Total									235915118

Table A2: Coal Analysis

Description	Unit	Range
Total moisture	% by weight	7 to 10
Inherent moisture	% by weight	2 to 5
Ash content	% by weight	8 to 15
Fixed carbon	% by weight	45 to 50
Volatile matter	% by weight	25 to 35
Sulphur	% by weight	0.3 to 1.0
Gross calorific value	k Cal / kg	5,400 to 7,000
Elemental Carbon	% by weight	61.65

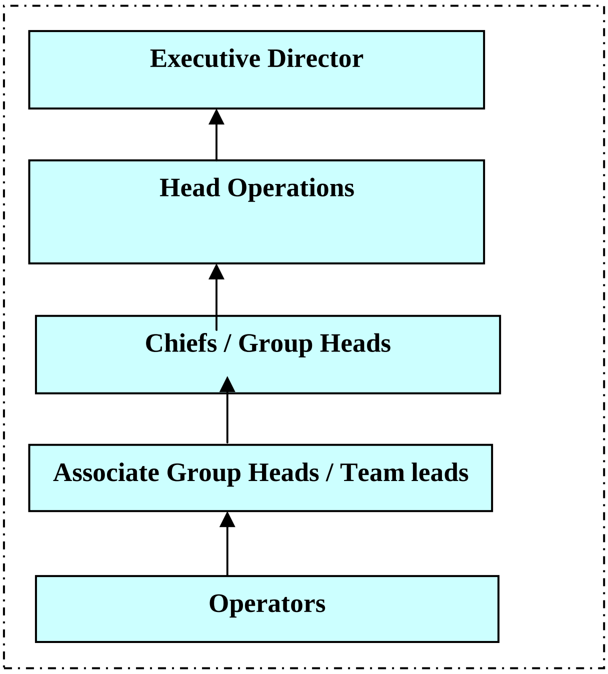
Table A3: Power Plants included in the sample group

S. No.	Name	Unit No.	Capacity	Location	Date of Commissioning
1.	TALCHER STPS	3	500	Orissa	4-Jan-03
2.	TALCHER STPS	4	500	Orissa	25-Oct-03
3.	TALCHER STPS	5	500	Orissa	13-May-04
4.	TALCHER STPS	6	500	Orissa	6-Feb-05
5.	R_GUNDEM STPS	7	500	Andhra Pradesh	26-Sep-04
6.	VINDH_CHAL STPS	9	500	Madhya Pradesh	27-Jul-06
7.	VINDH_CHAL STPS	10	500	Madhya Pradesh	8-Mar-07
8.	RIHAND	3	500	Uttar Pradesh	31-Jan-05
9.	RIHAND	4	500	Uttar Pradesh	24-Sep-05
10.	KAHALGAON	6	500	Bihar	16-Mar-2008
11.	BELLARY TPS	1	500	Karnataka	3-Dec-07
12.	SANJAY GANDHI	5	500	Madhya Pradesh	18-Jun-07
13.	SIPAT STPS	1	500	Chattisgarh	27-May-07

Annex 4

MONITORING INFORMATION

The operational and management structure that will monitor the proposed CDM project activity is described below.



Roles and responsibility specific to monitoring of the proposed CDM project activity:

1. Head Operations of the CGPL Power Plant will have the following responsibilities

- Ensuring implementation of monitoring procedures
- Internal audit and project conformance reviews

2. Chiefs / Group Heads will have the following responsibilities

- Organizing and conduct training programs on CDM
- Implementing all monitoring control procedures
- Associating with the Manager (Technical Services) towards maintenance and calibration of equipments
- Has the overall responsibility for record handling and maintenance.
- Reviewing of records and dealing with monitored data
- Organizing internal audit for checking the data recorded

• Has the overall responsibility for closing project non-conformances and implementing corrective actions before the verification

3. Associate Group Heads / Team Leads will have the following responsibilities:

• Supervising and training the operators and maintaining training records.

• Has the overall responsibility of monitoring measurements and reporting

• Will assist the Manager (Operations) in record handling, records checks and review and during internal audit and check the data recorded by the Operators in the individual sections as described in Section B7.1.

4. The Operator would collect and record appropriate data of the project activity represented in the monitoring tables of Section B 7.1 based on the monitoring frequency and as per the instructions of his seniors.

The Monitoring and Verification (M&V) procedures define a project-specific standard (baseline of historical emissions) 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. It also allows scope for review, scrutinize and benchmark all this information against reports pertaining to M & V protocols.

The M&V protocol provides a range of data measurement, estimation and collection options/techniques in each case indicating preferred options consistent with good practices to allow project managers and operational staff, auditors, and verifiers to apply the most practical and cost-effective measurement approaches to the project. The aim is to enable this project have a clear, credible, and accurate set of monitoring, evaluation and verification procedures. The purpose of these procedures would be to direct and support continuous monitoring of project performance/key project indicators to determine project outcomes, GHG emission reductions.

The instrumentation system installed for the project is equipped with shift-wise recording and feedback facility with desired level of accuracy.

All instruments will be calibrated and marked at regular intervals so that the accuracy of measurement can be ensured all the time.

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