Voluntary Carbon Standard
Project Description

[Date of the VCS PD] 31/03/2011

Contents

1 Description of Project:

1.1 Project title

Combined cycle natural gas based grid connected power plant at Jegurupadu, India

Version Number: 04
Date of document: 31/03/2011

1.2 Type/Category of the project

- *Project category which is part of a GHG program that has been approved by the VCS Board.*

Clean Development Mechanism (CDM) under United Nation Framework on Climate Change (UNFCCC) is one of the GHG programs which have been approved by the VCS board. The project activity is categorized according to the most recent version of categorization under GHG program –CDM (http://cdm.unfccc.int/methodologies/PAmethodologies/approved)
The categorization is as follows:

Type	: I- Renewable energy projects
Category	: AM0029 ("Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas")
Version No	: 03, EB 39
Sectoral Scope	: 01 Energy Industries (renewable/non-renewable)

- *Specify here if the project is a Grouped project.*

As per the definitions and requirements set out in VCS program guidelines 2007.1 (Clause 4.1.2 and Clause 5.2), ***"Any combination of GHG projects or project categories that meet the requirements of VCS 2007.1"*** is treated as a grouped project, and can be registered as a grouped project.

The project activity is a single GHG project activity that aims at reducing or removing GHG emissions. **The project activity is not a grouped project.**

Project activity is a non-AFOLU project and non -Agricultural Land Management (ALM) project is focusing on emissions reductions of CO_2 and CH_4..

1.3 Estimated amount of emission reductions over the crediting period including project size:

- *Micro project: Less than 5,000 tonnes CO2 equivalent emissions reductions per year.*
- *Mega Project: More than 1,000,000 tonnes CO2 equivalent emissions reductions per year*

The estimated GHG emission reductions for the project activity are 630,005 tonnes of CO_2 per annum. The project activity has chosen the crediting period of 10 years with option of renewal of one time[1].

The project falls under the category of "project" with emission reduction more than 5,000 and less than 1,000,000 tonnes of CO_2 equivalent emission reductions.

[1] As project life is estimated as 20 years

1.4 A brief description of the project:

The project activity is construction and operation of a 228 MW natural gas based power plant. GVK Industries Limited (GVKIL), the project proponent for this proposed activity has been promoted by GVK Group[2].

Purpose of the project activity:

The purpose of the project activity is construction and operation of a new 228 MW natural gas based power plant. The electricity generated will be exported to the southern grid. The project activity once operational will help in reducing the carbon intensity and power deficit on the southern grid.

The proposed project activity comprises of one combustion turbine, one Heat recovery Steam Generators (HRSG) and one Steam Turbine Generator (STG). This configuration has been adopted due to (a) higher efficiency of Combustion Turbines of larger size and (b) shorter implementation period (compare to coal based power plant) of the power project[3]. The Combustion Turbine and Steam turbine are designed as indoor equipments.

At the site ambient temperature of 29ºC and a frequency of 50 Hz, the combustion turbine generator with NG as fuel would have an output of 148 MW while the output from the steam turbine generator would be 80 MW. The heat content of the exhaust gas from the combustion turbine would be recovered in a triple pressure heat recovery steam generator. The steam generated would then be expanded in a condensing type non reheat steam turbine driving an electric generator.

The proposed project activity is installed by GVKIL at Jegurupadu site near Rajahmundry town in East Godavari District (in Andhra Pradesh). To achieve the project commissioning within the normal period stipulated under the typical PPA, the proposed project activity has been executed under the Engineering, Procurement and Construction (EPC) contracts basis. The EPC contract is entered into with Alstom (Switzerland) and Alstom Projects India Limited. The Operation and Maintenance of the project is carried out by GVK Power and Infrastructure Limited (GVKPIL).

The Combustion Turbine is a single shaft machine with the compressor and turbine installed in a single casting. Annular combustor of dry low NOx (DLN) type is being adopted. The combustion turbine drives the generator directly. The combustion turbine would be started by operating the generator as a variable speed motor. The variable frequency power required for this purpose will be supplied by the static frequency converter system.

The Heat Recovery Steam Generator (HRSG) is triple pressure natural circulation heat recovery steam generators for outdoor installation that would generate the steam for the steam turbine set, utilising the waste heat from the gas turbine (GT) exhaust. The Steam Turbine is of the triple-pressure single-casing design with an axial exhaust. The live steam supplied by the HRSG is admitted to the high pressure (HP)-turbine through the main stop valve and the main control valve. Intermediate pressure

[2] *www.**gvk**.com*

[3] Evidence provided to the DOE

(IP) and light pressure (LP)- steam is admitted via one stop valve and one control valve for each pressure level. From the LP-turbine exhaust the expanded steam flows into the condenser.

Project participant:
The project is owned by GVKIL and operated by GVKPIL, Hyderabad. GVK Group is involved in development of various infrastructure projects in the areas of Power, Roads, Airports, Urban Infrastructure, Coal and Special Economic Zones. GVK Group is also involved in the hospitality industry, manufacturing industry and also in bio-sciences.

Baseline scenario:
PP has applied AM0029 Version 03 to the project activity and the baseline has been identified in accordance with the applied methodology. The identified baseline scenario is:
'In the absence of the project activity, the equivalent amount of electricity would have been generated in the coal based power plants (existing and future additions) connected to the southern grid of India.'

A detail discussion of the identification of the baseline scenario is provided in the section 2.4 of the PD.

Reduction of greenhouse gas emissions:
The project activity replaces anthropogenic emissions of greenhouse gases (GHGs) in to the atmosphere, which is estimated to be approximately 630,005 tCO_2e per year, by displacing the equivalent amount of electricity generation through the operation of existing fuel mix grid comprising mainly fossil fuel based power plants and future capacity expansions connected to the southern grid of India.

Pre-project scenario:

The project activity is a new, independent natural gas based power plant.

The PP has 235.4 MW NG based combined cycle power plant commissioned phase wise in 1996-98 in the project activity in adjoining site. That project has a different tariff structure (which includes 16% return on equity and the fuel pass through PPA) and is discussed in detail in the Section 2.4.

The project activity plant is independent from existing unit and thus, the pre-project scenario is continuation of existing fuel mix in the grid to generate power at huge total deficit in the grid.

The present project is called expansion project in some of the official documents like PPA, statutory clearances as PP had a TEC approved from CEA in 1996 for 235 MW naphtha based combined cycle power plant. For procedural simplicity, this same approval was used for the changed configuration to the project activity i.e. 228 NG CCPP in 2003.

1.5 Project location including geographic and physical information allowing the unique identification and delineation of the specific extent of the project:

The proposed project activity is near Jegurupadu village south east of Rajahmundry in East Godavari district of Andhra Pradesh, India. The location is close to Krishna-Godavari pipeline of Gas Authority of India Limited.

Geographic location and accessibility:

Nearest village: Kondaguntur (1.5 km); Nearest town: Rajahmundry (15 km)
Nearest highway: NH-5 (5 km); Nearest railway station: Kadiyam (4 km)
Nearest airport: Rajahmundry (15 km); Nearest seaport: Kakinada (50 km)
The geographical coordinates of the project activity are 16º59'42" N and 81º53'12" E.
The location of the project activity is also depicted in the following map:

(Source: www.mapsofindia.com)

Figure 1: Map of (A) India and (B) East Godavari district showing the site of project activity

1.6 Duration of the project activity/crediting period:

- *Project start date: Date on which a financial commitment was made to the project and the project reached financial closure.*
- *Crediting period start date: the date the first monitoring period commenced*
  - *VCS project crediting period:* A maximum of ten years which may be renewed at most two times

As per the policy announcement made by VCS Association on 10 September 2007, start date of the project activity is considered as the date on which the project began reducing GHG emissions. The commissioning date for the project activity is 14/04/2009.

Crediting period start date: 14/04/2009

VCS project crediting period: 10 years with a renewal of one time. As project life is envisaged 15 years, in the second crediting period monitoring will be continued for the actual plant operation.

Years	Estimation of annual emission reductions in tonnes of CO_2e
2009	446,253
2010	630,005
2011	630,005
2012	630,005
2013	630,005
2014	630,005
2015	630,005
2016	630,005
2017	630,005
2018	630,005
2019	183,751
Total estimated reductions (tonnes of CO_2e)	6,300,050
Total number of crediting years	10
Annual average of the estimated reductions over the crediting period (tCO_2e)	630,005

1.7 Conditions prior to project initiation:
The project activity is a new, independent natural gas based power plant.

The PP has 235.4 MW NG based combined cycle power plant commissioned phase wise in 1996-98 in the project activity in adjoining site. That project has a different tariff structure (which includes 16% return on equity and the fuel pass through PPA) and is discussed in detail in the Section 2.4.

The project activity plant is independent from existing unit and thus, the pre-project scenario is continuation of existing fuel mix in the grid to generate power at huge total deficit in the grid.

1.8 A description of how the project will achieve GHG emission reductions and/or removal enhancements:
In the absence of the project activity the project proponent would have opted for a coal based power plant as described in the section 2.4 of the PD. However, here the PD uses baseline as per applicable methodology AM0029. The project activity thus reduces anthropogenic GHG emissions into the atmosphere due to the use of relatively lower GHG intensive fuel (Natural Gas) and much higher efficient power generation due to combined cycle operation in comparison to coal.

1.9 Project technologies, products, services and the expected level of activity:
The pre-project scenario is continuation of existing fuel mix in the grid to generate power at huge total deficit in the grid.

The project activity is commissioning and operation of a new natural gas based 228 MW power plant. It includes one ALSTOM 13E2 dual fuel Gas Turbine, one ALSTOM make triple pressure unfired HRSG and one ALSTOM make Steam Turbine.

The nameplate capacities of the turbine generators are – 210,000 kVA and 0.8 power factor (i.e. 210 x 0.8 = 168 MW) for GT and 110,000 kVA and power factor = 0.8 (i.e. 110 x 0.8 = 88 MW) for ST (total 256 MW under ISO conditions). However, this value is under standard test conditions and can undergo change at instantaneous production by factors including power factor. The PPA capacity is 220 MW and EPC design is 228 MW. During the commissioning test approved by Andhra Pradesh Power Coordination Committee (dt. 14/04/2009), the gross generation capacity in the test corrected for site conditions was demonstrated as 228.85 MW.

Sr.No.	Document	Plant capacity
1	PPA (2003)	220 MW
2	EPC (2003)	228 MW
3a	Capacity test witnessed by Andhra Pradesh Power Coordination Committee (APPCC) (09/01/2009)	231.98 MW
3b	Capacity test correction for site conditions letter from APPCC (14/07/2009)	228.85 MW
4	Nameplate Capacity under ISO condition	256 MW

The PP has a PPA for sale of 220 MW. To be able to supply net 220 MW, after accounting for auxiliary consumption (3%) and station heat degradation in the later life of plant, a higher configuration 228 MW was chosen for EPC contract. The name plate capacity by the supplier converted from rating in kVA and using power factor is 256MW (at ISO condition). This is never likely to be achieved as Indian climatic conditions are not in range of ISO conditions. Please refer to schedule F; Test Procedure of the PPA wherein standard site reference conditions for capacity test are prescribed. Notably, the section reads '*the gross generation capacity is related to the following conditions* and includes ambient temperature, atmospheric pressure, humidity, frequency and base load condition'. Thus, based on these conditions, the gross generation can vary on a given time. Further, as can be seen from the communication from APPCC, the gross generation capacity observed during the capacity test was also corrected via letter dt. 14/07/2009.

However, the annual performance guaranty by EPC is for 228 MW based on one year operation. Also, gross generation with 228 MW after accounting for auxiliaries (3%) will be about 220 MW which is also the PPA capacity. Thus, using 228 MW capacity will be conservative for the financial analysis and emission reduction calculation. Thus, further analysis is done based on 228 MW installed plant capacity.

The Gas turbine is a single shaft machine with the compressor and turbine sections assembled in a single casing. Annular type combustor using EV (Environmental) Burners are provided to limit the NOx emissions to below 40 ppm. The compressed air exits the unit compressor and is passed to the Combustion Chamber where Natural Gas is fired. The hot gases generated in the Combustion Chamber would be passed into the turbine, at about 1100ºC where the Heat Energy of the hot gases is converted into Mechanical Energy, thus rotating the Turbine / Generator. The output of the Electrical Energy is controlled by regulating the flow rate of the fuel sent to the combustor. The gas turbine is designed for option of dual firing, the other possible fuel being HSD. However, the project activity will run only using natural gas for the crediting period as per the management decision and as per the proposed amendments to the PPA that deletes alternative fuel clause.

The exhaust gas from the turbine is sent to HRSG (Heat Recovery Steam Generator) depending on the mode of operation. The exhaust gas after giving away its heat in the HRSG is dispersed through stack at about 100ºC. The HRSG is unfired type and there will not be any supplementary firing.

The following are the technical specifications of the main equipments:

Gas Turbine:
The gas turbine block consists of the turbine and the compressor. The annular combustor is installed between these units. The main parts are:

- rotor, with the turbine blades and the compressor blades, supported and guided in two journal bearings and one thrust bearing
- compressor casing and the turbine casing which also surrounds the annular combustor
- variable compressor inlet guide vanes
- compressor inlet
- compressor vanes, installed in the compressor casing and the compressor vane carrier
- compressor diffuser
- turbine vane carrier and turbine vanes
- exhaust casing
- blow-off system, with the blow-off valves of the first two stages installed under the blow-off hood (the valve for the third stage is mounted at the side and blows off into the exhaust duct)
- supports on the turbine end and the compressor end.

The exhaust gas from GT comes out[4] at 522ºC and this energy is recovered in the HRSG for steam generation. Without this heat recovery, the open cycle electrical efficiency is about 36.4%. With the combined cycle operation, the efficiency increases to 51.1%[5]. Thus, due to combined cycle operations, the net electrical efficiency increases by ~ 40%.

From the heat balance diagram for plant -
Temperature of combustion gases from exhaust of GT to inlet of HRSG = 582.7kJ/kg

[4] http://www.netl.doe.gov/technologies/coalpower/turbines/refshelf/handbook/1.1.pdf (pg. 38)

[5] Refer VER calculations 'Assumptions' sheet

Mass of exhaust gases = 504.96 kg/s
Temperature of exhaust gases after heat exchange in HRSG = 103.6 kJ/kg

Thus, energy recovered in HRSG = 241.93 MJ/s

Heat Recovery steam Generator (HRSG): The main features of the HRSG are as follows

- Triple pressure natural circulation heat recovery steam generator
- Horizontal type
- Outdoor installation
- Internal insulated (Cold casing design)
- Maximum extent of shop assembly allowing short erection time
- High degree of standardisation enabling the use of the same basic elements for different HRSG sizes
- Serrated finned tube design
- Special welding process assures high heat transfer rate
- Large HP, IP and LP steam drums

Sr. no.	HRSG Section	Design Pressures (bar)a
1	HP (High Pressure)	97.30
2	IP (Intermediate Pressure)	24.70
3	LP (Low Pressure)	4.90

Steam Turbine Generator (STG):
The single casing steam turbine consists of a standardised inlet- and exhaust-casing. Depending on the steam parameters different inlet and exhaust casings can be combined. The concept features of the steam turbine are as follows:

- modular product structure
- base mounted turbine with axial exhaust
- pre-assembled turbine packages
- compact turbine arrangement

The modular product structure enables the connection of different modular turbine parts for special requirements and therefore an optimised concept of the proposed steam turbine. Base mounted turbine with axial exhaust and pre-assembled turbine packages economise foundation- and erection- expenses.

The main components of the steam turbine are:

- HP-casing with flanged valve casing
- HP inner casing
- blade carriers in the low pressure section
- reaction blading
- welded (built-up) rotor
- integral friction coupling

The axial fix-point of the turbine casing is the support of the LP-part on the foundation. To compensate thermal expansion, the turbine casing and the front bearing pedestal are free to move into the direction of the front end. The thrust bearing is located within the front bearing pedestal and represents the fix-point of the

shaft. The advantage of this design is the minimised differential expansion between static and rotating elements.

Under the EPC contract, all the major units were imported from Alstom Europe for the project activity. As per EPC contract (volume IV, Appendix D) a total 670 days period was envisaged for commissioning of the project. The initial training of the employees for the operation and maintenance has taken place as part of the EPC. The training was on the project activity site as well as the EPC contractor's European offices.

The age of the equipments installed under the project activity is 0 years (new) and the lifetime is 15 years. The installed capacity is 228 MW and will not alter in the crediting period or project life. The plant load factor is estimated to be 85%. The heat rate of the plant would be 1850 kcal/kWh on GCV (or 1682 kcal/kWh on NCV)[6]. The power plant will deliver annual 1647 GWh exportable electricity and consume 1.07 million standard cubic meter (SCM) natural gas per day. The gas supply[7] agreement with the Gas Authority of India Ltd. (GAIL) is signed for supply of 1.10 million SCM gas/day. Later in 2009, PP has signed gas supply agreement with Reliance Industries Limited. This RIL gas will also be supplied using existing gas transmission infrastructure of GAIL. The monitoring for the project activity constitutes the net electricity exported, quantity of natural gas consumed and its NCV. The net electricity exported is measured at the dispatch sub-station by two separate meters (main and check). The quantity of gas is monitored at the gas supplier's terminal at the project site and also checked before the usage at GT. The supplier terminal also measures continuous NCV of the gas being fed.

The technology for the power generation is best available in the category. The choice of the technology will further reduce the GHG emission associated with the most probable alternative choice – coal fired thermal power plant and open cycle option. In addition, the emissions of CO, particulates (fly ash) will also be reduced compared to the identified alternate. The project activity will abide by all the regulatory norms of the pollution control board and will maintain environmentally clean and sound process.

The project technology was the best available at the time of EPC. It includes advanced features like dry low NOx EV burners for reducing the emissions of NOx (http://www.power.alstom.com/home/equipment___systems/turbines/gas_turbines/gt 13e2). The project proponents will not replace the units in the project activity more efficient technology within the project period.

There is no technology transfer involved in the project activity.

In absence of the project activity, the project proponent could have chosen a coal fired power plant of similar power output resulting in substantially higher GHG

[6] As per guaranteed performance by EPC contractor the heat rate is 6779 kJ/kWh. This translate into 1619 kJ/kWh.

[7] The gas sources as per 05/10/1999 contract with GAIL (refer pg. 1 and also further amendments in 2001, 2003, 2004) were 'from the ONGC fields at Tatipaka, Parsarlapudi, Kesnappali, Mori and other firlds of ONGC and as well from Ravva offshore fields'.

emissions. However, here the PD uses baseline as per applicable methodology AM0029. The main equipments in the baseline include boilers and turbine generators equivalent to the same electricity export as that of the project activity.

Environmental safe technology
Natural gas is often described as the cleanest fossil fuel, producing less carbon dioxide per joule delivered than either coal or oil.[8] Natural gas burns more cleanly than other fossil fuels, such as oil and coal, and produces less carbon dioxide per unit of energy released. For an equivalent amount of heat, burning natural gas produces about 30% less carbon dioxide than burning petroleum and about 45% less than burning coal.[9]

The technology used in the project, which has been used worldwide, is environmentally safe and the usage of this technology for power generation has no negative impacts on the ecosystem.

Technology Transfer
There is no transfer of technology from Annex I countries.

1.10 Compliance with relevant local laws and regulations related to the project:

The VCS PD shall include identification of relevant local laws and regulations related to the project and demonstration of compliance with them.

The project activity is not mandated by any local or national laws.[10] The project proponent has also obtained the necessary approvals from respective authorities as summarised below.

Sr.No.	Statutory clearance/ document required	Status for the project activity
1	Certificate of Incorporation from Registrar of Companies	Available – 18/06/1992
2	Permission for water use - Govt. of AP	Available – 16/10/1992
3	Allocation of Natural gas from Ministry of Petroleum & Natural Gas – GoI	Available – 08/07/1999
4	Permit to establish, operate and maintain power plant by Energy Department, Govt. of AP	Available – 17/04/2001
5	Chimney height clearance form Airports Authority of India	Available – 16/01/2001
6	Environmental Clearance from Ministry of Environment & Forests	Available – 02/11/2000
7	Consent order for establishment from APPCB	Available – 20/04/2000

[8] http://www.naturalgas.org/environment/naturalgas.asp#greenhouse/

[9] http://www.naturalgas.org/environment/naturalgas.asp#greenhouse/

[10] http://www.powermin.nic.in/acts_notification/electricity_act2003/pdf/Setting%20up%20of%20generating%20station.pdf

8	Completion of Project COD from APPCD	Available – 13/05/2009
9	Consent to Operate – APPCB (latest applicable)	Available – 07/01/2010

1.11 Identification of risks that may substantially affect the project's GHG emission reductions or removal enhancements:

The purpose of the project activity is construction and operation of a new 228 MW natural gas based power plant which is one of the cleanest source of energy

In the absence of the project activity the project proponent would have opted for a coal based power plant as described in the section. The project activity thus reduces anthropogenic GHG emissions into the atmosphere due to the use of relatively lower GHG intensive fuel (Natural Gas) and much higher efficient power generation due to combined cycle operation in comparison to coal.

1.12 Demonstration to confirm that the project was not implemented to create GHG emissions primarily for the purpose of its subsequent removal or destruction.

The project is a voluntary initiative implemented to reduce GHG emissions by way of construction and operation of a new 228 MW natural gas based power plant. Thus, project activity reduces emissions by use of a lower carbon intensive fuel (natural gas) than the grid carbon intensity. SO, project does not create emissions for subsequent removal/ destruction.

1.13 Demonstration that the project has not created another form of environmental credit (for example renewable energy certificates).

> If the project has created another form of environmental credit, the proponent must provide a letter from the program operator that the credit has not been used and has been cancelled from the relevant program.

The project proponent (GVKIL) has taken initiatives to register the same project activity under the Clean Development Mechanism of UNFCCC. Presently, the project is under CDM validation process.

The project proponent has provided a commitment letter stating that the benefits from VCS would be availed till the date the project activity gets registered under UNFCCC-CDM.

In the event of project activity getting registered under CDM, PP will retire their account from VCS registry for the period starting from the date of registration under UNFCCC-CDM.

In addition, PP is not availing benefits from any other schemes/programmes introduced by the Govt. of India.

1.14 Project rejected under other GHG programs (if applicable):

> *Projects rejected by other GHG programs, due to procedural or eligibility requirements where the GHG program applied have been approved by the VCS Board; can be considered for VCU but project proponents for such a project shall:*

- *clearly state in its VCS PD all GHG programs for which the project has applied for credits and why the project was rejected, such information shall not be deemed commercially sensitive information; and*
- *provide the VCS verifier and Registry with the actual rejection document(s) including explanation; and*
- *have the project validated against VCS program requirements.*

Not applicable.
The project has not been rejected by other GHG programs.

The project is under validation for CDM and the link to webhosted PDD is

http://cdm.unfccc.int/Projects/Validation/DB/82ORS4DFFAE3F7JI64VMOSYQEYXGCB/view.html

1.15 Project proponent's roles and responsibilities, including contact information of the project proponent, other project participants:
GVKIL the project proponent for this proposed activity has been promoted by GVK Group.[11]

The following table gives the contact information of the project proponent.

Organization:	GVK Industries Limited
Street/P.O.Box:	156-159, Sardar Patel Road
Building:	Paigah House
City:	Secunderabad
State/Region:	Andhra Pradesh
Postfix/ZIP:	500003
Country:	India
Telephone:	040-27902663
FAX:	040-27902665
E-Mail:	issac@gvk.com
URL:	www.gvk.com
Represented by:	
Title:	Director
Salutation:	Mr.
Last Name:	George
Middle Name:	Issac
First Name:	A.
Department:	Finance
Mobile:	-
Direct FAX:	040-27902665
Direct tel:	040-66262103
Personal E-mail	-

1.16 Any information relevant for the eligibility of the project and quantification of emission reductions or removal enhancements, including legislative, technical,

[11] www.gvk.com

economic, Sectoral, social, environmental, geographic, site-specific and temporal information.):

Contribution of the project activity to sustainable development:
Ministry of Environment and Forests, Govt. of India has stipulated the social well being, economic well being, environmental well being and technological well being as the four indicators for sustainable development in the host country approval eligibility criteria for Clean Development Mechanism (CDM) projects.

Socio-economic well-being:
The plant management has been involved in several social activities like and would continue need based developments

- Building bus shelters in Jegurupadu and Kadiyam village for the benefit of the travellers using the bus shelters
- Building the school building in Jegurupadu village, to provide high school facilities benefiting to a population of the 12,000 villagers
- Undertaking the responsibility of repairing the state highway from Dowleshwaram and Kesawaram villages, which has benefited more than one lakh of people living in the vicinity

Environmental well being:

- The electricity generated by project activity will be supplied to Southern grid, which otherwise would have been generated by more carbon intensive fossil fuels. Hence the project activity will help in reduction of the greenhouse gases emission and air pollutants (especially NOx and SO2).

Economic well being:

- Employment – the project activity has provided direct employment to 39 people during operations

Technological well being:

- The project activity demonstrates application of a cleaner technology, the use of natural gas for efficient combined cycle power generation.

1.17 List of commercially sensitive information (if applicable):

NOT APPLICABLE

Any commercially sensitive information that has been excluded from the public version of the VCS PD that will be displayed on the VCS Project Database shall be listed by the project proponent.

2 VCS Methodology:

2.1 Title and reference of the VCS methodology applied to the project activity and explanation of methodology choices:

Projects shall use one of the VCS program approved project methodologies and provide information relevant to methodology deviations or methodology revisions.

Clean Development Mechanism (CDM) of United Nation Framework on Climate Change (UNFCCC) is one of the GHG programs which are approved by the VCS

board. The project activity uses methodology approved by UNFCCC-CDM GHG program
http://cdm.unfccc.int/methodologies/PAmethodologies/approved.

Title: AM0029, Ver.03 "Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas"

Reference:http://cdm.unfccc.int/methodologies/PAmethodologies/approved

2.2 Justification of the choice of the methodology and why it is applicable to the project activity:

The chosen project category of the project activity is:

Project Category: AM0029, Ver.03 "Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas"
The choice of the project category AM0029 is justified below:

Table 2.2.1: Justification of the applicability of AM0029 Version 03 to the project activity

Requirements as per the Baseline Methodology, AM0029, Ver. 03	**Applicability to this Project Activity**
The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant	The project activity involves the construction and operation of a new natural gas fired combined cycle power plant (CCPP), of 228 MW capacity for electricity generation. The project activity is connected to the Southern regional grid of India. Natural Gas is the only fuel to be used in the project activity. There is no other fuel used either during the start up or co-fired.
The geographical/ physical boundaries of the baseline grid can be clearly identified and information pertaining to the grid and estimating baseline emissions is publicly available.	In this case the baseline grid is Southern regional grid of India and the information pertaining to the grid and estimating baseline emission is publicly made available by the Central Electricity Authority (CEA) of India[12].
Natural gas is sufficiently available in the region or country, e.g. future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of Natural Gas in the project activity.	Attachment 1 discusses further on the gas availability and it is concluded that there is potential for another 8,000 MW capacity addition using available and future upcoming natural gas supplies. Thus natural gas is sufficiently available in the region and country and future

[7] http://cea.nic.in/planning/c%20and%20e/CO2%20Database.zip

	capacity addition of comparable size is not constrained due to the project activity plant.

Gas supply agreement to support the availability

Considering the total project activity size 228 MW and 100% PLF, the maximum gas requirement is 1.07 million SCM/day. The project proponent has a long term fuel supply agreement with GAIL to supply 1.1 million SCM/day till the entire crediting period.[13] Later in 2009, PP has signed gas supply agreement with Reliance Industries Limited who is supplying gas now. The RIL gas will also be supplied using existing gas transmission infrastructure of GAIL.

The maximum gas requirement is calculated as below

Maximum gas requirement = electricity generated at 100% PLF (kWh) x heat rate (kcal/kWh) / calorific value (kcal/SCM)

= (228 x 1 x 24 x 365 x (1682/ 8750) / (365 x 103))

= 1.07 million SCM / day

< 1.1 million SCM / day (fuel supply agreement)

Thus, the maximum gas requirement even at the 100% PLF is less than that project activity has access to as per the fuel supply agreement.

Since the project activity meets all the applicability criteria as required by the project category the choice of the project category AM0029, version 03, the selection of methodology is justified.

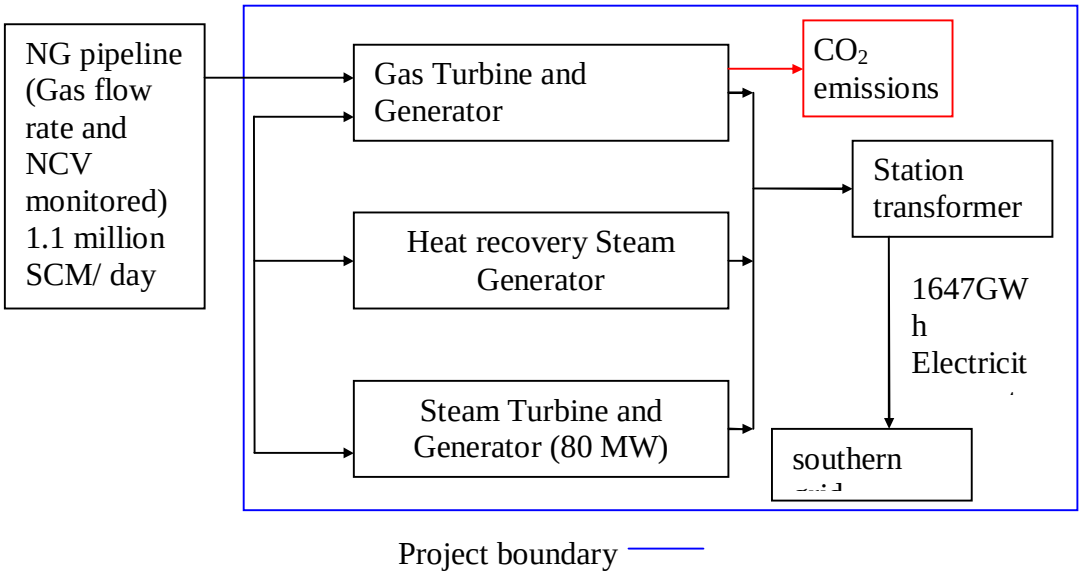
2.3 Identifying GHG sources, sinks and reservoirs for the baseline scenario and for the project:

According to AM0029, the spatial extent of the project boundary includes the project site and all power plants connected physically to the baseline grid as defined in "Tool to calculate the emission factor for an electricity system." According to the Tool to calculate the emission factor for an electricity system, for the baseline emission factor, the spatial extent of the project boundary includes the project site and all power plants connected physically to the electricity system that the CDM project power plant is connected to.

Since the VCS project is connected to the regional grid it is also preferred to take the Southern regional grid as project boundary than the state boundary. It also minimizes the effect of interstate power transactions, which are dynamic and vary widely. Thus the project boundary comprises the project site and all power plants connected physically to the southern grid. The specific components and facilities included in the project boundary are (1) Gas Turbine -one (2) Heat recovery steam generator – one (3) steam turbine generator – one (4) Station transformers (5) Auxiliary equipments

[13] Fuel Supply Agreement with GAIL, was signed before the start date of the project activity

of Gas Turbine and Generator, Heat Recovery Steam Generator and Steam Turbine and Generator; meters (gas, electricity) and gas supply pipelines.



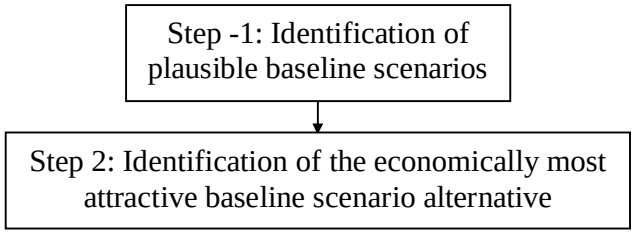
2.3.1: Project boundary

	Source	Gas	Included/ Excluded	Justification/Explanation
Baseline	Power Generation in baseline	CO_2	Included	Main emission source
		CH_4	Excluded	Excluded for simplification. This is conservative
		N_2O	Excluded	Excluded for simplification. This is conservative
Project Activity	On-site fuel combustion due to the project activity	CO_2	Included	Main emission source
		CH_4	included	Included for fugitive and upstream emissions.
		N_2O	Excluded	Excluded for simplification. This is a minor emission source.

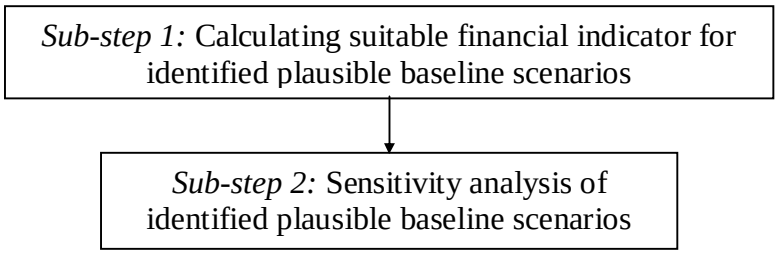
2.4 Description of how the baseline scenario is identified and description of the identified baseline scenario:

The project proponent shall select the most reasonable baseline scenario for the project. This shall reflect what most likely would have occurred in the absence of the project.

The following is a flow chart indicating the flow of various steps involved in identifying and describing baseline scenario in accordance with AM0029.



Further, for the purpose of identifying the economically most attractive baseline scenario alternative the following *sub-steps* are involved.



Baseline scenario identification as per the requirements of AM0029 leads us to the following assessment at the start of the project activity.

1. Identify plausible baseline scenarios

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

The purpose of the project activity is to generate electricity and deliver it to the Southern Grid to cater to the base load power requirement of the grid. As per CEA report in Jan 2010 the power demand in southern grid in 2009 was between 27094 to 29216 MW. This also translated in a deficit of 2771 to 1183 MW[14].

The latest available (at validation start) CEA CO_2 database for Indian Power Sector (Ver. 05) is studied analyse all relevant power plant technologies that have been recently constructed and are included in the identification of plausible alternative scenarios.

The various possible alternatives available with the project proponent at the time of notice to proceed to the EPC Contractor, include the following:

a) **The project activity i.e. 228 MW NG based Combined Cycle power plant with an efficiency of 50%[15] and with a lifetime of 15 years not taken as a VCS project activity.**

The purpose of the project activity is to generate electricity from the Natural Gas and deliver it to the Southern Grid to meet the base load power requirement of the grid. This alternative is in compliance with all the applicable legal and regulatory guidelines. Hence this option can be a part of the baseline scenario.
This alternative can meet the base load demand of southern grid.

b) **Power generation using Natural Gas as the fuel but with different alternative technologies.**

[14] CEA, Planning Wing , Power Scenario at a Glance, Jan 2010. pg 10.

[15] http://www.energymanagertraining.com/CHPMaterial/07-II-Gas_Combined_Cycle.doc.

The different possible technologies that are available with the project proponent to generate power using natural gas as the fuel include

b.1) Power generation using Combustion Turbine with an installed capacity of 228 MW (ISO Conditions) with an efficiency of 39%[16] using Open cycle mode of operation with a lifetime of 15 years[17].

This alternative generates electricity using Natural Gas as the fuel and can cater to the base load demand of the southern grid but has lower system efficiency compared to the project activity. A report of the CEA's 'Performance Review of Thermal Power Stations 2006-07 Section-10' shows that not a single NG based power plant is commissioned using open cycle after 2000. Further, the CEA's 'Performance Review of Thermal Power Stations in 2007-08 says 'Use of combined cycle operation in the field of Gas Turbines is being promoted for energy conservation.' Having lower efficiency will result in higher fuel consumption making operations unviable even compared to the project activity (i.e. higher levelized cost). Thus it can not be a financially attractive scenario and a realistic baseline. This alternative can meet the base load demand of southern grid.

Thus, open cycle based power plant is not a credible alternative. Therefore this alternative cannot be a part of the baseline scenario.

This alternative is in compliance with all the applicable legal and regulatory guidelines.

b.2) 228 MW Power generation using Gas Turbine in Cogeneration mode of operation.

The lifetime of such plant is 15 years[17]. This alternative generates both steam and electricity from Natural Gas, though the thermal efficiency is very high in this mode of operation (63%) [18] the electrical efficiency is low in comparison with the Combined Cycle Mode of Operation (50%).[11] The Cogeneration mode of operation is mainly used to provide electricity and steam for industrial facility and the project activity's purpose is to deliver the power to the grid. Hence this option does not deliver the similar output/ services comparable to the project activity. This alternative can meet the base load demand of southern grid.

Hence, this is also not a credible and realistic alternative for the Project Proponent and therefore this alternative cannot be a part of the baseline scenarios.
This alternative is in compliance with all the applicable legal and regulatory guidelines.

c) Power generation using energy sources other than Natural Gas

The various alternative energy sources that can generate power other than natural gas include:

[16] Plant Engineer's Reference Book, pg. 22/7

[17] http://powermin.nic.in/acts_notification/generating_companies.htm

[18] http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/2B1.pdf (p. 3)

c.1) Power generation with 250 MW thermal power plants using coal as the energy source with an efficiency of 34%-36%[19] with a life of 25-30 years[20]
This is a realistic and credible alternative to the project proponent which delivers base load power to the grid. This alternative can meet the base load demand of southern grid. Hence this is a plausible baseline scenario.
This alternative is in compliance with all the applicable legal and regulatory guidelines.

Parameter	**Gas**	**Coal**
Plant capacity (MW)	228	250
PLF	85%	85%
Auxiliary consumption	3%	9%
electricity generated	1,646,757.36	1,693,965.00
Difference in electricity generation		2.87%

c.2) Power generation with thermal power plants using lignite as the energy source
The option is not a plausible scenario given its low calorific value and property of spontaneous combustion[21], lignite is likely to remain a captive energy resource for pit head power plants. In India, lignite is produced mainly in Tamil Nadu by Neyveli Lignite Corporation and Gujarat Mineral Development Corporation Ltd. in Gujarat[22]. Thus, the option is limited to those sites as there can be problems in the transport and storage of lignite due to its property of spontaneous combustion. This alternative can meet the base load demand of southern grid.

This alternative is in compliance with all the applicable legal and regulatory guidelines.

c.3) Power generation using wind as the energy source with an average PLF of 20%[23].
Power generation from wind does not meet the base load requirement for the grid on a continuous basis as wind is seasonal in nature and the capacity utilization factor is very low. Due to the high uncertainty of wind it is not a credible and realistic option for the project proponent for such high capacity comparable to the project activity.
This alternative is in compliance with all the applicable legal and regulatory guidelines.

c.4) Power generation using Hydro as the energy source
The different types of hydro power projects available with the project proponent include:

[19] http://www.iea.org/textbase/work/2004/zets/apec/presentations/sharma.pdf (p. 15)

[20] cercind.gov.in/160502/comp_bidding.pdf (p. 12)

[21] www.benetechusa.com/pdf/article/SpontaneousCombOfPRBCoal.pdf

[22] http://www.indiaenergyportal.org/subthemes_link.php?themeid=10&text=coal#

[23] Refers to data from Ministry of Non-conventional Energy Sources, Govt. of India. www.energymanagertraining.com/kaupp/Article28.pdf

c.4.1) Reservoir storage based hydro power plants:
This is not a plausible baseline scenario as it delivers peak-load power to the grid and not the base load power[24]. Thus it does not deliver same level of services as the project activity.
This alternative is in compliance with all the applicable legal and regulatory guidelines.

c.4.2) Run-of-river based hydro power projects
Power generation from hydro is not a feasible alternative to the project activity as it involves high gestation periods and also cannot meet the base load power requirement for the grid on a continuous basis due to the uncertainty of monsoons. Moreover, the hydro power projects are not credible and realistic alternative to the project proponent due to the following reasons.

- Hydro power projects generally entail a long gestation period. In addition to this, these projects are comparatively capital intensive[25]. In the context of resource shortages and continuing power shortages, thermal projects (coal, liquid fuel and gas), which need a relatively short gestation period, have been getting priority in fund allotments[26].
- The existing tariff formulation norms for hydro projects (based on a cost plus approach) with no premium for peaking services and the provision for 12% free power to distressed states from the initial years are also proving to be deterrents[27].

Hence, the above alternative cannot be an option for baseline scenario.
This alternative is in compliance with all the applicable legal and regulatory guidelines.

c.5) Power generation using cluster of Diesel Engine based power plants with an efficiency of 50%[28] and a lifetime of 15 years[29].
The following table gives the list of various Diesel Engine based power plants connected to the Southern grid[30].

Power Plant	**Owner**	**City**	**State**	**Capacity (MW)**	**Year**
Chennai	CMS India	Chennai	Tamil	4 × 50	1998-99

[24] The Base Load Fallacy, Author: Mark Diesendorf; http://www.cana.net.au/documents/Diesendorf_TheBaseLoadFallacy_FS16.pdf

[25] http://www.adb.org/Documents/Reports/Hydropower-Devt-India/Hydropower-Devt-India.pdf (pg. 9)

[26] http://www.adb.org/Documents/Reports/Hydropower-Devt-India/Hydropower-Devt-India.pdf (pg. 9)

[27] http://www.adb.org/Documents/Reports/Hydropower-Devt-India/Hydropower-Devt-India.pdf (pg. 11)

[28] Power generation technologies, P. Breeze. Elsevier Publications. Pg. 66. http://books.google.com/books?id=D9qSDgTbRZoC&pg=PA66&dq=diesel+power+plant+efficiency&ei=4l7TSbfIJYGUkAS70KCmCQ#PPA66,M1

[29] http://mnes.nic.in/baselinepdfs/annexure2c.pdf

[30] www.cea.nic.in/thermal/List of Thermal Power Stations in the Country.pdf

Vasavi	Ltd.		Nadu		
VVNL Yelahanka	Karnataka SEB	Bangalore	Karnataka	127.92	1993-94
Kozhikode	Kerala SEB	Kozhikode	Kerala	128	1999
Samayanallur	Balaji Power Corp. Ltd.	Samayanallur	Tamil Nadu	106	2001
Samalpatti	Samalpatti Power Corp.	Samilpatti	Tamil Nadu	105.65	2001
Bellary DG	Shrirayalaseeme Ltd.	Bellary	Karnataka	25.2	2000
Belgaum	TATA	Belgaum	Karnataka	3 × 27.3	2001
Kasargode	RPG		Kerala	21.84	1999

The above table show that all the plants were installed before 2001 and lately the IPPs are not going for the liquid fuel based generation due to the increase in the fuel costs. The State Electricity Boards are also discouraging the IPPs to go for Liquid fuel based power plants for the same reason[31]. The prices of petroleum products have long since been controlled by the Government of India (GoI) under the Administered Pricing Mechanism (APM) to reduce the burden on the consumers. However, in April 2002 the GoI dismantled the APM on the oil derived fuels (petrol, diesel etc.) after which there has been sharp increase in their prices to match international parity prices. Hence the option is not an economically viable alternative to any individual IPP with such a large capacity as it was mandated by the Central Government that sanction of IPPs should be through the competitive bidding mechanism[32]. Moreover, the fully rupee denominated tariffs not being financeable also owes itself to the failures that have been observed in the Indian power sector particularly relating to the short gestation liquid fuel projects[33]. In the Merit Order Dispatch regime, the dispatch from the individual power producing stations will be taken by the DISCOM based on the merit order. In the power surplus scenario, the generating station which produces high cost power will be first asked to back down. This system is to bring the cost competitiveness in the market and would not allow the high priced generating stations to operate. The cost of electricity generation at central generating stations was Rs. 5.36/ kWh[34] in 2004-05 and Rs. 7.00/ kWh in 2005-06.

Therefore this alternative cannot be a part of the baseline scenario.

Diesel based power plants operate to cater to peak load demand[35]. This alternative is in compliance with all the applicable legal and regulatory guidelines.

c.5) Power generation using Nuclear Fuel

[31] http://www.capitalmarket.com/Magazine/cm1409/indrep.htm

[32] www.cercind.gov.in/160502/comp_bidding.pdf

[33] www.cercind.gov.in/160502/comp_bidding.pdf

[34] Reference submitted to DOE

[35] http://en.wikipedia.org/wiki/List_of_power_stations_in_India#Diesel_Based; http://www.manipurpower.nic.in/generation/dieselgen.htm

This scenario is available only to Nuclear Power Corporation of India Limited, a 100% Government of India owned Company[36], whose capacity additions are driven by the Government of India initiatives based on its long term strategic programmes and not by the project activity. Hence, this option is not available for any of the stakeholders including the project proponent. This alternative can meet the base load demand of southern grid.

Therefore this alternative cannot be a part of the baseline scenario.

c.6) Electricity generation using Naphtha as fuel

The Naphtha based power plant comprises naphtha turbine and heat recovery system in the combined cycle mode. The overall efficiency in combined cycle is 39%[37]. In 2000, APTransco stopped all future liquid fuel (including naphtha) projects and thus can not be considered a realistic alternative.

This alternative is in compliance with all the applicable legal and regulatory guidelines.

c.7) Coal fired supercritical power plant

The coal fired supercritical power plant is new advanced technology. However, the technology was not available in India in 2003 (at the time of project activity decision was made). The first supercritical power plant in India was being built in 2006.[38,39] This alternative can meet the base load demand of southern grid.

This alternative is in compliance with all the applicable legal and regulatory guidelines.

c.8) Electricity generation using Biomass as fuel

Biomass based power projects are generally operate in co-generation mode and mostly the industries such as sugar plants who produce biomass and need steam for their process have biomass based projects. Further there is high seasonal availability and price fluctuation. Due to such situation preferential tariff is given by state governments[40]. Further, the same reference (footnote no. 40) by Ministry of New and Renewable Energy shows that Andhra Pradesh has less than 100 MW installed capacity based on biomass in last 5 years. Thus this option is not discussed further.

d) Electricity imports from other grids:

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[36] Atomic Energy Act, 1962 & news letter issued by Business Line- http://www.blonnet.com/2006/05/22/stories/2006052202930300.hmt

[37] Plant Engineer's Reference Book, Second Edt. Dennis Snow, Butterworth-Heinemann, 2002

ISBN 0750644524, pg. 22/7; NG and Naphtha based plants are same – duel fired capacity, soefficiency taken same as that of NG power plant.

http://books.google.co.in/books?id=KJOoQm3fbEoC&pg=PT433&lpg=PT433&dq=efficiency+of+open+cycle+power+plant&source=web&ots=HRYT81RY0h&sig=yRBE5betwGqHsZ6RQVpjrYZoQWQ&hl=en&sa=X&oi=book_result&resnum=6&ct=result#PPT433,M1

[38] Suresh et al., 2006. Advances in Energy Research. http://www.ese.iitb.ac.in/aer2006_files/papers/031.pdf

[39] http://goliath.ecnext.com/coms2/summary_0198-211733_ITM

[40] http://www.mnre.gov.in/prog-biomasspower.htm

This is not a realistic alternative as all the other grids are themselves facing shortages in meeting the energy demands and especially at the peak demand. The monthly average peak deficit for the year 2004-05 being: Northern Region – 9.1% deficit; Eastern Region – 2.5% deficit; North-Eastern Region –13.6% deficit; Southern Region – 2.5% deficit and Western Region – 20.3 % deficit[41]. This alternative also does not deliver the same output comparable to the project activity due to the high transmission losses. Hence this alternative cannot be a part of the baseline scenario. This alternative can not meet the base load demand of southern grid.

This alternative is in compliance with all the applicable legal and regulatory guidelines.

From the above discussion it is evident that the plausible baseline scenarios identified by the Project Proponent include:

a) The project activity i.e. 228 MW NG based Combined Cycle power plant with an efficiency of 50%-55% in combined cycle mode of operation and with a lifetime of 15 years not taken as a VCS project activity.
b) Power generation using coal as the energy source with an efficiency of 35%-38% with a life of 25-30 years

2.5 Description of how the emissions of GHG by source in baseline scenario are reduced below those that would have occurred in the absence of the project activity (assessment and demonstration of additionality):

The project proponent shall in the VCS PD, in addition to describing how the project meets the VCS methodology, demonstrate that the project is additional based on one of the tests, the project test, the performance test, and technology test.

The demonstration of additionality is continued further using Step 2 of the Tool for the demonstration assessment and of additionality

2. Identify the economically most attractive baseline scenario alternative.

Sub Step -1: Benchmark Investment Analysis

As per Additionality tool Version 5.2, Sub-step 2b, option III "Identify the financial/economic indicator, such as IRR, most suitable for the project type and decision context".

Hence, the benchmark used for proving the additionality can be any financial indicator, such as IRR which is most suitable for the decision making context.

The tariff structure for the concerned project activity is the two part tariff system, which consists of two components Viz.

1. Capacity Charge: Capacity charge includes Foreign Debt Service Charge ("FDSC") and other fixed charge ("OFC"). The FDSC of US$0.006 per unit of Cumulative Available Energy is converted into Rupees at the prevailing exchange

[41] http://www.cea.nic.in/about_us/Annual%20Report/2004-05/Contents.htm (Chapter 4)

rate. Under the PPA, the FDSC shall be payable to us only for a period of 11 years to cover our foreign debt repayment obligations. The OFC of Rs. 0.669 per unit of the Cumulative Available Energy is fixed for the term of the PPA, (i.e. 15 years from COD).

2. Energy Charge. The Energy Charge, which includes the cost of fuel as delivered at the fuel metering point at the site. The formula for computing the Energy Charge under the tariff is as given below:

Energy Charge = EU x {(hC) /G x (1-A/100)}, where:

EU = The total number of energy units (kWh) delivered at the interconnection point;

h = Station Heat Rate of 1,850 Kilo Cal/kWh;

G = GCV of gas in Kilo Cal/unit of fuel;

C = cost of gas in Rupees per unit of fuel as delivered at the fuel metering point at the site; and

A = Auxilliary consumption which is 3% of generation.

Based on these two parameters a levelised tariff is fixed by the APPCC and it is paid for the concerned power generating stations throughout the PPA term.

Hence in the power policy regime, the project proponent is deemed to get a fixed ROE based on the equity investment. However, the dispatch from the individual power producing stations will be taken by the DISCOM based on the Merit order dispatch. In the power surplus scenario, the generating station which produces high cost power will be first asked to back down. This system is to bring the cost competitiveness in the market and would not allow the high priced generating stations to operate at the design efficiency. In the event of back down, the plant will operate at lower PLF and lower efficiency consuming more fuel than that at the design heat rate. Thus, the actual operating efficiency and the IRR would be lower than that covered by the tariff structure and additional fuel cost is not 'pass through', but would be borne by the PP. The actual I|RR will be dependent on the actual dispatch possible in the case of demand supply scenario in the future and availability of power to grid from other power plants, which can not be predicted by PP during project conceptualization stage.

In the case of ABT and merit order dispatch, the project proponent is prone to fall in power off take preference list to the central sector coal based power plants. Hence for the project activity in such a power policy regime, taking the levelised cost of power generation as the financial indicator is justified.

The equity IRR is again irrelevant in the project activity as it is 100% debt financed. The project proponent has chosen to compare the levelized cost of electricity production in "Rs. /kWh" for identified plausible baseline scenarios.

The levelized cost for the alternative (a) i.e. implementing the project activity without the consideration of CDM revenue is calculated by the following assumptions:

The following table details the assumptions used for the financial calculations. All the assumptions used in the financial model are based on the inputs that were used in the financial closure obtained by the project activity.

Techno Economic parameters 228 MW NG based power plant			References
Installed Capacity	228	MW	EPC (GT = 148 MW and HRSG = 80 MW)
Total Investment	7189.09	Million INR	Common loan agreement – Pg. 134 (site development cost 7 Mn removed and land cost as per sale deeds) pg. 121
Debt: Equity	100:0	-	
Rupee Debt	4843.84	Million INR	
US Dollar Debt	2345.25	Million INR	
Exchange rate	1 USD = 47 INR		
O&M Costs	3.88% of the capital Cost	-	Common Loan Agreement
O&M US $ Portion	65% with an escalation of 2% every annum	-	
O&M Rupee Portion	35% with an escalation of 5% per annum	-	
Plant Load Factor	85	Percentage	Financial appraisal
Auxiliary Consumption	3	Percentage	CERC (Terms & Conditions of Tariff) Regulations, 2001, pg. 8
Total Units Sold	24,719	GWh for 15 years	Estimated for project capacity at 85% PLF
Net Calorific Value	8570	kcal/SCM	Invoices from fuel supplier (GAIL)
Station Heat Rate	1850	kcal/ kWh	PPA June 2003, pg. 13
Fuel Charges	8,644.20 INR/ 1000 SCM	-	Latest Invoice for gas bill from GAIL
Book Depreciation Rate (Straight Line Method basis)			
Plant and Machinery	8.24	Percentage	As per the rates applicable to Power Generating Units
Book Depreciation up to (% of asset value)	90	Percentage	
Income Tax			
Income Tax rate	35	Percentage	IT Rules

Minimum Alternate Tax	7.5	Percentage	
Surcharge	2.5	Percentage	
Dividend Distribution Tax	12	Percentage	
Working capital			
Receivables (No. of days)	35	-	Common Loan Agreement
Spares	1% of Capital Cost	-	
Working capital interest rate	13	Percentage	
Working Capital Margin	25% of the working capital	-	
Working Capital Loan	75% of working capital	-	

The levelized cost of electricity generation using Natural gas as the energy source calculated using the above values comes out to be 2.25 Rs./kWh.

The assumptions considered for calculating the levelized cost of generation for the alternative (b) i.e. power generation using coal as the energy source are described in the table below. For coal based power plant, the nearest capacity in the standard available[42] TG Set i.e. 250 MW which is used for comparison. This 250 MW plant at 85% PLF and 9% auxiliary consumption will generate 1,693,965 MWh electricity. Whereas, a 228 MW gas based unit at 85% PLF and 3% auxiliary consumption will generate 1,646,757 MWh electricity. The difference is only 2.87% (higher for the coal based unit) between the baseline and project plant.

Techno Economic parameters for power generation using coal as the energy source		
Installed Capacity	250 MW	CERC (Terms & Conditions of tariff) Regulations, 2001
Total Investment	9,977 Million INR	Estimate by PP based on TEC available for other plant
Debt : Equity	70:30	CERC (Terms & Conditions of tariff) Regulations, 2001
O&M Costs + Insurance Charges	2.5% of the capital Cost	CERC (Terms & Conditions of tariff) Regulations, 2001, pg. 11
Plant Load Factor	85 %	
Auxiliary Consumption	9.5%	CERC (Terms & Conditions of tariff) Regulations, 2001, pg. 8
Total Units Sold	33,716 Million	

[42] CERC - Terms & Conditions of Tariff applicable from 1.4.2004. pg. 53

	kWh for 20 years	
Return on Equity	16 %	CERC (Terms & Conditions of tariff) Regulations, 2001
Gross Calorific Value	4,706.50 kcal/kg	Price Notification No. 7/2001-2002 dated 9th April, 2001 from The Singereni Collories Co. Ltd
Station Heat Rate-Stabilization	2,600 kcal/ kWh	CERC (Terms & Conditions of tariff) Regulations, 2001
Station Heat Rate- Post Stabilization	2,500 kcal/ kWh	
Fuel Charges	1,356.72 INR / 1,000 kg	Price Notification No. 7/2001-2002 dated 9th April, 2001 from The Singereni Collories Co. Ltd
Depreciation rate for revenue calculation (Straight Line Method basis)		
Civil Works	7.84%	Electricity Supply Act
Plant and Machinery	7.84%	Electricity Supply Act
Book Depreciation up to (% of asset value)	90%	Electricity Supply Act
Book Depreciation Rate (Straight Line Method basis)		
Civil Works	3.34%	Company's Act
Plant and Machinery	5.28%	Company's Act
Book Depreciation up to (% of asset value)	95%	Company's Act
Surcharge	2.5%	
Dividend Distribution Tax	12%	

The levelized cost of electricity generation using Coal as the energy source calculated using the above values comes out to be 1.49 INR/ kWh.

The table below summarizes the levelized cost of electricity generation for various alternatives.

Sr. No.	**Baseline Scenario**	**Levelized Cost of generation (INR/ kWh) at 85% PLF**
(a)	Power generation using Natural Gas as the energy source	2.25
(b)	Power generation using coal as the energy source	1.49

Thus, the economically attractive baseline scenario as identified by the investment analysis using the levelized cost of electricity generation (in INR/ kWh) as the financial indicator is the alternative (b) which is power generation using coal as the energy source.

Sub Step -2: A sensitivity analysis is performed for all alternatives; to confirm that the conclusion regarding the financial attractiveness is robust to reasonable variations in the critical assumptions i.e. fuel price, plant heat rate and the plant load factor.

Sensitivity analysis considering variation in fuel price		
Price of fuel	-10%	+10%
Levelized cost of electricity generation for power generation using natural gas	2.09	2.41
Levelized cost of electricity generation for power generation using coal	1.42	1.56

Sensitivity analysis considering variation in heat rate		
Heat rate change	-10%	+10%
Levelized cost of electricity generation for power generation using natural gas as energy source	2.15	2.36
Levelized cost of electricity generation for power generation using coal	1.42	1.56

Sensitivity analysis considering variation in Plant Load Factor (PLF)		
PLF	-10%	+10%
Levelized cost of electricity generation for power generation using natural gas as energy source	2.33	2.20
Levelized cost of electricity generation for power generation using coal	1.57	1.42

The sensitivity analysis confirms that the economically most attractive baseline scenario identified in the sub-step 1 is robust to reasonable variations in the critical assumptions (i.e. fuel prices, heat rate and the PLF).

Benchmark investment analysis

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

For determining the benchmark, project proponent has taken into consideration all the financial parameters relevant to the project activity and has also conducted sensitivity analysis to gauge the impact of probable realistic fluctuation of key parameters. According to the additionality tool, levelized cost of electricity generation can be used as financial indicator for the Benchmark Investment Analysis. This parameter is appropriate for this project activity, as all thermal electricity generation projects in the baseline grid are allowed return of 16% on equity investment in determining their cost for tariff purposes.

Also the CERC had implemented Availability Based Tariff (ABT) in all the five regions of the country at the inter-state level. The ABT facilities merit order dispatch of various generating stations having different variable costs. Hence in such a

competitive bidding scenario it is very important for the IPP to have a low cost of power generation. Thus the levelized cost of generation is the most appropriate benchmark indicator.

The levelized cost of electricity generation for the project activity and the levelized cost of electricity generation of the baseline scenario (i.e. power generation using Coal as the energy source) are compared with the average cost of generation in central sector coal stations in 2004[43] . The following table summarizes the results of the comparison.

Sr. No.	Alternatives	Levelized Tariff (INR/kWh) at 85% PLF
(a)	Power Generation using natural gas as the energy source	2.25
(b)	Power Generation using coal as the energy source (Baseline Scenario)	1.49
(c)	Power Generation using naphtha as the energy source	3.76
(d)	Benchmark : Average cost of generation in central sector coal stations in 2004	1.42

From the above table it can be seen that Coal based power generation is the most financially attractive alternative. Also, it can be seen that project activity without CDM revenue is not the most financially attractive option making it uncompetitive. It is important to note that due to the higher cost of generation the project activity will be subjected to lower Plant capacity utilization i.e. lower PLF and hence further increasing the cost of electricity generation.

Common Practice Analysis

According to the "Tool for the demonstration assessment and of additionality", version 5.2; analysis of any other activities implemented previously or currently underway that are similar to the proposed project activity needs to be performed to describe whether and to which extent similar activities have already diffused in the relevant region.
Similar project activities include Grid Connected Power Plant

- of similar scale
- that take place in a comparable environment with respect to regulatory framework, investment climate, access to technology etc: in the state of Andhra Pradesh with the tariff determined through the International Competitive Bidding Process (ICB).
- those activities that are implemented previously or currently underway

The following table represents the total installed capacity in India and the share of the coal based power plants and natural gas based power plants[44].

[43] Cost of generation of central sector station (pdf file provided to DOE)

[44] Infralines' paper on "Natural gas for power sector: issues and challenges". Infraline Energy Research & Information Services. New Delhi. (Copy of paper provided to DOE)

Region	Total Thermal Power Generation, (MW)	Generation using Coal as fuel (MW)	% generation using coal as fuel of the thermal power generation	Generation using gas as fuel (MW)	% generation using gas as fuel of the total installed capacity
Northern	19,143	15,915	83	3,213	10
Western	25,845	20,792	80	5,035	16
Southern	16,982	13,393	79	2,650	9
Eastern	15,235	15,027	97	190	1
North Eastern	1,223	330	27	751	32
Island	64	0	0	0	0
All India	78,491	65,456	83	11,840	11

As it can be seen from the above table, the percentage of the gas based power plants in the entire India is 11% of the total installed capacity and that of coal based power plants is 83% of the thermal capacity and 60% of the total installed capacity in India. The total percentage of the gas based power plants in Southern Region is only 9% of the total installed capacity. This collaborates the fact that Natural Gas based power generation is not commonly carried out practice in India.

Step 4: Common practice analysis

Sub-step 4a: Analyze other activities similar to the proposed project activity
In this step, an analysis of any other activities that are operational and that are similar to the proposed project activity in done. As per the latest CEA database, the following NG based plants are operational in the south grid.

SN	Unit name	Capacity	Commiss-ioning	Fuel	Sector	ICB/ two part tariff
1	VIJESWARAN GT	272.3	1990- 97	Gas/ Napt	State	No
2	JEGURUPADU GT	235.4	1996-98	- do -	Pvt. (GVK Ind)	No
3	GODAVARI GT	208	1997-98	- do -	Pvt. (SPECT Ind)	No
4	KONDAPALLI GT	350	2000	- do -	Pvt.	Yes
5	PEDDAPURAM CCGT	220	2002	- do -	Pvt. (REL)	Yes
6			2001	- do -	Pvt. (GMR)	No
7	KAYAM KULAM GT	350	1998-99	- do -	Center	No
8	VALUTHUR GT	95	2002-03	Gas	State	No
9	KUTTALAM GT	101	2003-04	Gas	State	No
10	KOVILKALAPPAL	107	2001	Gas	State	No
11	P.NALLUR CCGT	330.5	2001	Gas/	Pvt.	No

				Napt		
12	KARUPPUR GT	119.8	2005	Gas	Pvt. (ABAN)	-
13	KARAIKAL	32.5	1999	Gas	State	No
14	VALANTHARVI GT	67.6	2005-06	Gas	State	No
15	VEMAGIRI CCCP	388.5	2006	Gas	Pvt.	Yes

The Table above shows that only four power plants are from private sector that have the same investment environment as the project activity. The Power Purchase Agreement for the project activity was signed with APTRANSCO with the tariff that was fixed for the short gestation projects (Natural Gas Based Power Generation Projects) selected under the International Competitive Bid Process (ICB). The other fixed charges was fixed at ` 0.669 per unit of cumulative available energy and the Foreign Debt Service Charge was fixed at US $ 0.006 per unit of cumulative available energy payable at the current exchange rate. The Foreign Debt Service Charges are payable only in respect of period ending on 11th annual anniversary of the COD of the project activity.

The tariff fixed for the project activity was to match the tariff fixed for the Natural Gas based Power Projects which have participated in the International Competitive Bid Process. The Natural Gas based power plants that have participated in the process and won the bid for the similar tariff[45] include:

1. 370 MW Vemagiri Power Project promoted by GMR Group.
2. 445 MW Konasema Power Project promoted by Konasema Gas Power Limited.
3. 469 MW Gautami Power Project being promoted by Gautami Power Limited.

All three of these projects are in CDM process and were web hosted for the global stakeholder comments.

The plants that existed from earlier days in the vicinity namely Spectrum Power Generation and another project from the same project promoters (GVKIL Jegurupadu CCGT power plant) is based on a different tariff structure to include a guaranteed 16% return on equity.

Thus, all the projects with similar tariff structures as the project activity are in different stages of CDM registration Process.

3 Monitoring:

3.1 Title and reference of the VCS methodology (which includes the monitoring requirements) applied to the project activity and explanation of methodology choices:

The project activity uses AM0029 monitoring methodology approved by CDM-EB under UNFCCC. UNFCCC Clean Development Mechanism is one of the approved

[45] http://www.ercap.org/OtherOrders/

GHG programs by the VCS board. The monitoring methodology applied to the project activity is as follows:

Type : AM0029
Category : "Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas")
Version No : 03, EB 39
Sectoral Scope : 01 Energy Industries (renewable/non-renewable)

3.2 Monitoring, including estimation, modelling, measurement or calculation approaches:

- *Purpose of monitoring*
- *Types of data and information to be reported, including units of measurement*
- *Origin of the data)*
- *Monitoring, including estimation, modelling, measurement or calculation approaches*
- *Monitoring times and periods, considering the needs of intended users*
- *Monitoring roles and responsibilities*
- *Managing data quality*

The purpose of monitoring is to calculate real, measurable, permanent GHG emission reductions. A complete set of procedures and monitoring plan (see section 3.4) has been developed to ensure that accurate and relevant measurements and observations are made to document gross electricity generation and net electricity generation. Roles and responsibilities have been assigned to each person as shown in the monitoring plan.

Data and parameter to be monitored includes Net electricity displaced by the project activity.
Data and parameters to be monitored for relevant GHG sources & source/origin of data have been explained in more detail in the section 3.3.

The project proponent has applied GHG monitoring criteria and procedures on a regular basis during project implementation. Where measurement and monitoring equipment is used, the project proponent has ensured the equipment is calibrated according to current good practice.

3.3 Data and parameters monitored / Selecting relevant GHG sources, sinks and reservoirs for monitoring or estimating GHG emissions and removals:

Describe each data and parameter using this table.

Data / Parameter:	**$EG_{PJ,y,}$**
Data unit:	kWh
Description:	Electricity exported by the project plant
Source of data to be used:	The readings taken from the export meter present in the Tariff metering room present in the switch yard. The readings are stored in power plant log book.
Value of data applied for the purpose of calculating expected emission reductions	1,646,800,000
Description of measurement methods and procedures to be applied:	The data represents the electricity measured by the Energy Meter. The meter is a 3 phase 4 wire meter of standard make and of an accuracy of 0.2S class. The daily readings are stored in the power plant log book.

	The readings are taken by the shift engineers and are cross checked by the Electrical Engineer and are recorded in the log book.
QA/QC procedures to be applied:	The calibration of the equipments will be done by approved agencies and the instruments would be recalibrated annually. When a set of energy meter is taken for calibration, another calibrated set would be installed in their place. There is another check meter for the confirmation of the reading, in case of discrepancy, the lower value of the two will be used and faulty meter will be sent for the calibration.
Any comment:	--

Data / Parameter:	**$FCf_{,y}$**
Data unit:	SCM
Description:	Quantity of NG consumed in the project activity
Source of data to be used:	The daily readings are recorded manually and are stored in the power plant log book.
Value of data applied for the purpose of calculating expected emission reductions	304,252,146
Description of measurement methods and procedures to be applied:	The quantity of Natural Gas is measured by the gas flow meter which would be installed by GAIL at their terminal
QA/QC procedures to be applied:	The quantity of natural gas is cross checked with the invoices that are obtained from the GAIL (gas supplier) and it is also tallied with the quantity of Natural Gas measured by the natural gas flow meter (Check meter) that is installed by the project proponent for internal purposes. The meter installed by GAIL will be calibrated according to their standard procedures. The readings can be cross checked by their invoices for the gas bills. Calibration - Annual
Any comment:	In case of main and check meters showing different values, the emergency procedure as discussed in Section 3.4 will be used to calculate conservative (highest) gas consumption

Data / Parameter:	**NCVf,y**
Data unit:	kcal/SCM
Description:	Net Calorific Value of Natural Gas
Source of data to be used:	Invoice from the supplier
Value of data applied for the purpose of calculating expected emission reductions	9384.33
Description of measurement methods and procedures to be applied:	The Supplier provides the value of the NCV in the invoice that is being given to the project proponent. The NCV is measured by the Gas chromatograph that would be installed by GAIL at their terminal. If the GCV alone is reported in the invoice, the NCV will be calculated using this GCV and delta factor of 10% (CEA CO_2 baseline database for Indian Power Sector, Database Excel Sheet, Assumptions worksheet, Cell F8).
QA/QC procedures to be applied:	The PP has installed check meter (for NCV of gas) and this will be used as check meter. The NCV of natural gas is cross checked with the invoices that are obtained from the GAIL. The meter installed by GAIL will be calibrated annually.
Any comment:	GAIL gas purchase bills for project activity plant on

	commissioning date is used presently. In case of main and check meters showing different values, the emergency procedure as discussed in Section 3.4 will be used to calculate conservative (lowest) NCV value.

Data / Parameter:	**$FCf_{LNG, y}$**
Data unit:	SCM
Description:	Quantity of LNG consumed in the project activity
Source of data to be used:	The daily readings are recorded manually and are stored in the power plant log book.
Value of data applied for the purpose of calculating expected emission reductions	0
Description of measurement methods and procedures to be applied:	The quantity of Liquefied Natural Gas is measured by the gas flow meter which would be installed by GAIL at their terminal
QA/QC procedures to be applied:	The quantity of natural gas is cross checked with the invoices that are obtained from the supplier.
Any comment:	There is no plan for the usage of LNG. However, provision is kept for the monitoring purpose.

Data / Parameter:	$EF_{BM, y}$
Data unit:	tCO_2/MWh
Description:	The Build Margin emission factor of Southern grid
Source of data to be used:	CEA CO_2 Baseline Database, version 05; November 2009
Value of data applied for the purpose of calculating expected emission reductions	0.8179
Description of measurement methods and procedures to be applied:	The value is taken from the database developed by Central Electricity Authority (CO_2 Baseline database for the Indian power sector, Version 5.0). The database is Government of India's official publication based on the 'Tool to calculate the emission factor for an electricity system'.
QA/QC procedures to be applied:	Latest available value for 2008-09 is used.
Any comment:	This is used for ex-ante estimation and as per methodology requirement, this will be monitored ex-post for ER calculation in the monitoring period (latest available database, most recent year BM will be used)

Data / Parameter:	**$FCf_{FF, y}$**
Data unit:	ton
Description:	Quantity of any other fossil fuel consumed in the project activity as start up or cofired
Source of data to be used:	The daily readings are recorded manually and are stored in the power plant log book.
Value of data applied for the purpose of calculating expected emission reductions	0
Description of measurement methods and procedures to be applied:	The quantity of any other fossil fuel will be measured from appropriate – volumetric/ mass flow meter
QA/QC procedures to be applied:	The quantity of fossil fuel will be cross checked with the invoices that are obtained from the supplier.
Any comment:	There is no plan for the usage of any other fossil fuel. However, provision is kept for the monitoring purpose.

Data / Parameter:	EF_{NG}

Data unit:	$kgCO_2e/TJ$
Description:	Emission Factor of Natural Gas
Source of data to be used:	Table 1.4, Chapter 1, Volume 2, 2006 IPCC Guidelines for National Greenhouse Gas Inventories
Value of data applied for the purpose of calculating expected emission reductions	56,100
Description of measurement methods and procedures to be applied:	In absence of country specific data; IPCC default value used as recommended in methodology.
QA/QC procedures to be applied:	nil
Any comment:	As IPCC emission factors are updated, conservative value will be chosen

Data / Parameter:	$Oxid_{NG}$
Data unit:	Unit less factor
Description:	Oxidation Factor of NG
Source of data to be used:	Table 1.4, Chapter 1, Volume 2, 2006 IPCC Guidelines for National Greenhouse Gas Inventories
Value of data applied for the purpose of calculating expected emission reductions	1
Description of measurement methods and procedures to be applied:	In absence of country specific data; IPCC default value used as recommended in methodology.
QA/QC procedures to be applied:	nil
Any comment:	As IPCC emission factors are updated, conservative value will be chosen

3.4 Description of the monitoring plan

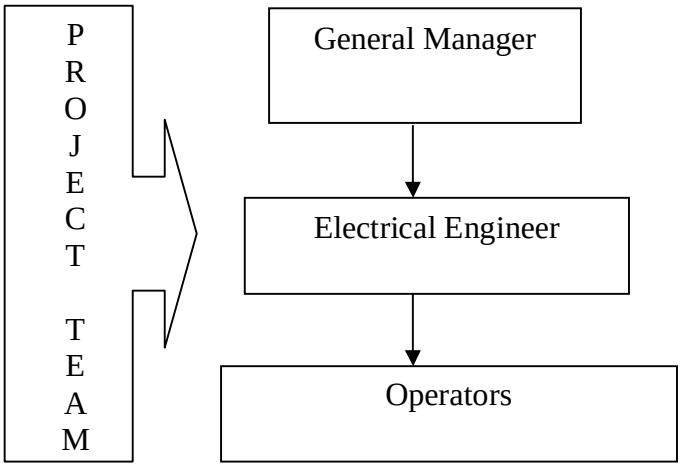
The project activity is operated and managed by the project proponent. The individual plants record data related to their respective project activity. The natural gas based power project abides and will abide by all regulatory and statutory requirements as prescribed under the state and central laws and regulations.

A CDM project team has been placed at the plant site. The project team has been entrusted with the responsibility of storing, recording the data related to the project activity. The project team is also responsible for calculation of actual creditable emission reduction in the most transparent and relevant manner. Installed meters are calibrated according to the maintenance schedule programmed at the start of the operation and recalibrated according the plants performance requirement.

All the monitoring data is /will be stored, recorded and kept under safe custody of the Project Executor and Head (Power Plant and Utilities) at the plant site for a period of crediting period + 2 years. The data will be achieved in both hard copies and electronic format (excel sheets). Also, any change within the project boundary, such as change in spare and or equipments will be recorded and any change in the emission reduction due to such alteration will also be studied and recorded.

The electricity meters (both the main meter and the check meter) are calibrated annually. Also, there are quarterly checks for error and if any meter is found to give error more than permissible in the class of the meter, it will be taken for the calibration. For the electricity measurement, the meter (from the main and check) that does not show the error will be used for the data recording. In case, both the meters have shown error more than the limit prescribed in the class, both the meters will be taken for the calibration and correction will be applied to the electricity generation recorded by the main meter.

Designation	Responsibilities
General Manager	• Registration • Project Execution
Electrical Engineer	• Operation • Verification of data Inspection of data whenever necessary to independently check the authenticity of data and take corrective actions wherever required. • Storage/ Achieving of data • Internal audit of monitored data and GHG reduction calculation
Operators	• Operation, Monitoring and Verification of Data • Data Recording • Storage of data
Operation and Maintenance Contractor	• Operation and Maintenance • Storage of data • Data Recording • Data Collection



Entity responsible for application of the baseline and monitoring methodology:

DATA BACK UP

In case if the main meter fails to record the reading or is under maintenance, then for that period the monthly invoice/generation statement (whichever is applicable in the particular case) signed by the APTransco from the conservatively applied value as per the PPA terms and practices followed in the region will be applied to compute emission reductions. This is conservative as APTransco being an electricity buyer, will estimate (un-monitored data due to meter failure) conservatively.

QA & QC PROCEDURES

The main meter will be calibrated once in a year by a Government Approved third party laboratory.

1) The electricity meter will be calibrated against Traceable National Standards at ETDC (Electronic Test and Development Centre).
2) GAIL Gas flow meters are calibrated as per the standards of AGA-9/10.

EMERGENCY PLAN

An emergency plan is prepared to account for monitoring equipments failure and accidental release of GHGs in the project activity plant.

1) Both electricity meters (main and check) failure: As per PPA dt. June 2003, Article 4: Metering, clause 4.4 and 4.5, following provision are available and will be followed for the monitoring plan.
   (A) Errors in main meters – If main meter check indicates error beyond prescribed limit, but no such error is noticed in the check meter, billing for the month will be done on the basis of check meter. Also, the main meter will be calibrated or replaced immediately.
   (B) Errors in main meter and check meters: If both the main and check meter show error during quarterly check, both meters will be sent for calibration and replaced immediately with new meters for further monitoring. The error found in the main meter calibration will be applied to the electricity measurement values for the period from last check.
2) Failure of gas flow meter: In case gas flow meter of the supplier (GAIL) which is main meter is found to have error more than ±2% or if the meter is out of service, the gas quantity will be computed using (a) using check meter of the PP if installed and accurately registering (b) applying main meter error factor to readings from last calibration (c) estimating the volume of gas delivered by comparison with deliveries during the period under similar conditions when seller's meter was registering accurately (In same order of preference among a,b and c. Refer clause 8.04 of the gas supply agreement with GAIL).
3) Gas leakage detection: Emergency gas alarm system is installed at GAIL supply terminal near the project plant to detect gas in case of leakage.
4) Complete power failure scenario: In case of complete power failure, the GAIL terminal will get indication on the gas flow control panel and the gas flow valve will be shut when the power plant will have to be shut down. Thus, the accidental release of gas is avoided in any case.

The calculation of combine fugitive emission factor in the absence of project activity ($EF_{BL,upstream,CH4}$):

The latest available CEA CO_2 baseline database for the Indian Power Sector will be used and the plants commissioned in southern grid in the last five years from publication of database will be short listed. Fuel consumption as per category i.e. coal and lignite, natural gas, liquid fuels will be summarized. The electricity generation in those particular categories will also be summarized for the years and then default methane fugitive emission factors for each fuel type is applied to get combine fugitive emission factor in the absence of project activity.

INTERNAL AUDIT AND PERFORMANCE REVIEWS

Monitoring team will be responsible for the annual performance reviews. The monthly invoices from APTransco will be cross checked with the monthly export data in the VCS monitoring report. Any non-conformity if observed will be corrected.

The energy meter calibration due dates will be informed to the O&M team. In the review meeting, if the calibrations are found to be not done on due date, the meters will calibrated immediately and the correction factor will be applied to the monitored values.

4 GHG Emission Reductions:

4.1 Explanation of methodological choice:

EMISSION REDUCTION CALCULATION FOR THE PROJECT ACTIVITY COMPONENT:

According to the approved methodology AM0029, Version 3

Project emissions

The project activity is on-site combustion of natural gas to generate electricity. The CO_2 emissions from electricity generation (PEy) are calculated as follows:

$$PE_y = \sum_f FC_{f,y} * COEF_{f,y}$$

$FC_{f,y}$: is the total volume of natural gas or other fuel 'f' combusted in the project plant or other startup fuel (m^3 or similar) in year(s) 'y'

$COEF_{f,y}$: is the CO_2 emission coefficient (tCO_2/m^3 or similar) in year(s) for each fuel and is obtained as:

$COEF_{f,y}$ = ΣNCVy x $EFCO_{2f,f,y}$ x OXIDf

Where:

NCVf,y : is the net calorific value (energy content) per volume unit of natural gas in year 'y' (GJ/m^3) as determined from the fuel supplier, wherever possible, otherwise from local or national data;

The supplier of NG gives NCV in the invoice and this will be used for the ER calculation.

$EFCO_2$,f,y : is the CO_2 emission factor per unit of energy of natural gas in year 'y' (tCO_2/GJ) as determined from the fuel supplier, wherever possible, otherwise from local or national data;

As supplier of gas does not specify emission factor, also NATCOM report is checked and it has also referred IPCC for this value. Thus, IPCC default is used as per the preference order in the methodology.

OXIDf : is the oxidation factor of natural gas

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:

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

According to the approved methodology AM0029 version 3, project participants shall use for $EF_{BL,CO2,y}$ the lowest emission factor among the following three options:
For the first crediting period:
Option 1. The build margin, calculated according to "Tool to calculate emission factor for an electricity system"; and
Option 2 The combined margin, calculated according to "Tool to calculate emission factor for an electricity system", using a 50/50 OM/BM weight.
Option 3 The emission factor of the technology (and fuel) identified as the most likely baseline scenario under "Identification of the baseline scenario" above, and calculated as follows:

$$EF_{BL,CO2}(tco2/Mwh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6GJ/MWh$$

where,
$COEF_{BL}$ = the fuel emission coefficient (tCO_2e/GJ), based on national average fuel data, if available, otherwise IPCC defaults can be used

This is taken from national level data (CEA CO_2 baseline database for Indian Power Sector, Database Excel Sheet, Assumptions worksheet, Cell D7).

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

For the option 1, the build margin is calculated by the Central Electricity Authority (CEA) India according to the procedures prescribed in the "Tool to calculate emission factor for an electricity system". We have referred the same value for the baseline calculation.

For option 2, the combined margin is calculated with a 50/50 OM/BM weights. The Operating Margin (OM) and the Build Margin (BM) has been calculated by the Central Electricity Authority (CEA) India according to the procedures prescribed in the "Tool to calculate emission factor for an electricity system". We have referred the same value for the baseline calculation.

For option 3, coal fired power plant using conventional i.e. sub-critical technology has been identified in section 2.4 of the PD. as the economically most attractive baseline scenario alternative due to its lowest levelized electricity generation cost, whose emission factor are calculated in accordance with and as per equation No. 4 of AM0029. *The determination of baseline emissions will be made once at the validation stage based on an ex ante assessment, once again at the start of each subsequent crediting period (if applicable). If either option 1 (BM) or option 2 (CM) are selected, they will be estimated ex post, as described in "Tool to calculate emission factor for an electricity system".*

As per this requirement, as the Option 1 has lowest emission factor, this will be used as the emission factor for emission reduction calculations and will be monitored ex-post.

Leakages

As per the approved methodology AM0029, Version 3, leakage emissions are calculated as follows:

$$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y}$$

where:

LE_y Leakage emissions during the year y in tCO_2e

$LE_{CH4,y}$ Leakage emissions due to fugitive upstream CH_4 emissions in the year y in tCO_2e

$LE_{LNG,CO2,y}$ Leakage emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year y in tCO_2e.

Fugitive methane emissions

According to the approved methodology AM0029, Version 3, the fugitive methane emissions are calculated as follows:

$$LE_{CH4,y} = \left[FC_y \cdot NCV_y \cdot EF_{NG,upstream,CH4} - EG_{PJ,y} \cdot EF_{BL,upstream,CH4}\right] \cdot GWP_{CH4}$$

where:

$LE_{CH4,y:}$ Leakage emissions due to fugitive upstream CH_4 emissions in the year y in t CO_2e

FCy: Quantity of natural gas combusted in the project plant during the year *y* in m^3

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

$EF_{NG,upstream,CH4}$: Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, distribution, and, in the case of LNG, liquefaction, transportation, re-gasification and compression into a transmission or distribution system, in t CH_4 per GJ fuel supplied to final consumers

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

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

GWP_{CH4} : Global warming potential of methane valid for the relevant commitment period

$EF_{NG,upstream,CH4}$: is used from the default specified in Table 2 of the baseline methodology AM0029, and value is 296 tCH_4/ PJ. This is applicable for Rest of World..

As the baseline emissions are calculated based on option 1 i.e. the build margin calculated by CEA in accordance with the procedures in "Tool to calculate emission factor for an electricity system", the emission factor for upstream fugitive CH_4 emissions occurring in the absence of the project activity is derived using the flowing equation:

Option 1: Build Margin:

$$EF_{BL,upstream,CH4} = \frac{\sum_j FF_{j,k} \cdot EF_{k,upstream,CH4}}{\sum_j EG_j}$$

Thus, the emission factor for upstream fugitive CH_4 emissions is consistent with the baseline emission factor calculation as per option-1.

During the crediting period for fugitive CH_4 emissions associated with NG, default values provided in Table 2 of the approved methodology AM0029 version 3 will be used, as reliable and accurate national data are not available. The default values to be used in relation to NG production, processing, transport and distribution from Table 2 of AM0029 is that corresponding to Rest of World (296 tCH_4/PJ) as this is highest value and hence conservative.

In the current context LNG is not being used in the project activity hence,
$LE_{LNG,CO2,y} = 0$.
In future, if the LNG is being used the leakage is calculated as described below:
Calculated as per the methodology, AM0029
Quantity of natural gas combusted in the project plant ($FC_{LNG\,y}$) (For CO_2 emissions from LNG):
Emission factor for upstream CO_2 emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($EF_{CO2, upstream,LNG}$)
Based on the above, the estimated Leakage emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($LE_{LNG,CO2,y}$) will be:
$= FC_{LNGy}$ **x** $EF_{CO2, upstream, LNG}$ t CO_2 e

Upstream fugitive emissions occurring in the absence of the project activity electricity generation has been calculated using the Build Margin power plants. Therefore in line with the AM0029 requirement of ex-post determination of the Build Margin, the Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity electricity generation (tCH_4/MWh) will also be determined ex-post.

Emission Reductions

ERy = BEy – PEy – LEy
Where:
ERy : emissions reductions in year y (t CO_2e)
BEy : emissions in the baseline scenario in year y (t CO_2e)
PEy : emissions in the project scenario in year y (t CO_2e)
LEy : leakage in year y (t CO_2e)

No credits are claimed for activities during the project construction activity.

4.2 Quantifying GHG emissions and/or removals for the baseline scenario:

1. Calculation of baseline emissions
To calculate the baseline emissions the lowest of the three values amongst the build margin, combined margin and the emission factor for the most likely baseline scenario is taken as the baseline CO_2 emission factor.

In case of the build margin and operating margin, the grid emission factors available at the time of PDD web hosting for the global stakeholder comments and the validators site visit is used.

A.) Build margin
The build margin is calculated by the Central Electricity Authority (CEA) India (CO_2 Baseline database for the Indian power sector, Version 5.0). according to the procedures prescribed in the "Tool to calculate emission factor for an electricity system". The value taken is 817.9 tCO_2e/GWh for the most recent available year in the data base 2008-09.

This will be monitored ex-post in the monitoring period and latest available recent one year data will be used from the latest CO_2 baseline database for the Indian Power Sector.

B.) Combined margin
The combined margin is calculated with a 50/50 OM/BM weights. The Operating Margin (OM) and the Build Margin (BM) has been calculated by the Central Electricity Authority (CEA,) India according to the procedures prescribed in the "Tool to calculate emission factor for an electricity system". The Operating margin is fixed ex-ante and is taken as the average of the recent three years of data given by the CEA at the time of PDD submission for validation (i.e. for the years 2006-2007, 2007-2008, 2008-2009). The value applied for Operating Margin is 987.5 tCO_2/GWh. The value applied for the build margin is 817.9 tCO_2e/ GWh. The value applied for the combined margin is **902.72** tCO_2e/GWh.

C) Emission factor of the most likely baseline scenario.
Calculated as per equation number- 3 of AM 0029 where the most likely baseline scenario is identified as the Coal based power plant Values of sub-variables:
Fuel CO_2 emission co-efficient (COEF BL): 0.0958 tCO_2e/GJ

This is taken from national level data (CEA CO_2 baseline database for Indian Power Sector, Database Excel Sheet, Assumptions worksheet, Cell D7).

Energy Efficiency of technology (h BL): 33.3%
= 0.0958 t CO_2e/GJ x 3.6 GJ/MWh x1000/0.333 = **1036** t CO_2/GWh

Therefore, according to AM 0029, **817.9** t CO_2/GWh (i.e. Build Margin) is chosen as baseline emissions factor EF BL,CO_2,y.

As per the requirement of baseline methodology (pg. 6, line No. 2 and 3) as the Option 1 has lowest emission factor, this will be monitored ex-post.

Project electricity generation (i.e. net evacuation to the grid) EGy is estimated as 1,646.8 GWh per year.
= Project plant capacity x Hours x No. of days x Plant load factor x (1- Auxiliary consumption) / 1000
[228 x 24 x 365 x 85% x (100-3)% / 1,000 = 1,646.8 GWh]

Therefore, the estimated annual baseline emissions (BE_y) will be (as per equation 2 of AM0029)

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

= 1646.8 GWh x 817.9 tCO_2/GWh

= **1,346,883** tCO_2/ yr.

4.3 Quantifying GHG emissions and/or removals for the project:

A) Calculation of Project Emissions (PE_y)

Calculated as per equation number-2 of AM 0029 as contained in part A (Procedure followed for estimating emissions in the project scenario) of section B.6.1 "Explanation of Methodological Choices".

The value of project emissions is **670,500 tCO_2e**

Values of sub-variables:

Volume of fuel combusted in project plant ($FC_{f,y}$) : 304,252,146 SCM/ year

CO_2 emission coefficient of fuel ($COEF_{f,y}$) : 0.002204 t CO_2/ m^3 of natural gas

Based on the above, the estimated annual project emissions (PE_y) will be

$$PE_y = \sum_f FC_{f,y} * COEF_{f,y}$$

= 0.00228 tCO_2/SCM x 304,252,146 SCM/ year

= 670,500 tCO_2/year

The Sub-variables are calculated as follows

Calculation of CO_2 Emission Co-efficient of natural gas ($COEF_{f,y}$)

CO_2 Emission Co-efficient of natural gas is calculated as per equation number-2a of AM0029 Values of sub-variables:

1) Net Calorific Value of gas (NCV_y): 9,384.33 kcal/SCM

2) CO_2 emission factor ($EF_{CO2,f,y}$): 0.0561 t CO_2/GJ

3) Oxidation factor of gas ($OXID_f$): 1

$COEF_{f,y}$ = ΣNCVy x $EFCO_{2f,f,y}$ x OXIDf

= 9,384.33 (kcal/SCM) x 4.186 x 10^{-9} x 56.1 (t CO_2 / TJ) x 1

= **0.002204 t CO_2/ m^3**

B) Calculation of Leakages (LE_y)

Leakages are calculated as per equation number-5 of AM 0029 is

46, 378 t CO_2e

1) Leakage emission due to fugitive upstream CH_4 emissions ($LE_{CH4,y}$): 46,378tCO_2e.

2) Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($LE_{LNG,CO2,y}$) : 0 t CO_2 in the present case

Based on the above, the estimated annual leakages (LE_y) will be

$$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y}$$

= 46,378 + 0 t CO_2 e = **46,378** t CO_2 e

CEA database version 05. is taken and plants commissioned in southern grid in the last five years from publication of database i.e. November 2005 are short listed. Fuel consumption as per category i.e. coal and lignite, natural gas, liquid fuels is summarized for 2008-09. The electricity generation in this particular categories is also summarized for the year then default methane fugitive emission factors for each fuel type is applied to get combine fugitive emission factor in the absence of project activity.

Table: Emission factor calculation for upstream fugitive methane emissions occurring in the absence of the project activity

Estimated Quantity of coal and Lignite combusted in plants included in build margin	6,651,782	tonnes/year
Fugitive methane emission factor for coal production (surface mining)	0.8	t CH_4/ kt coal
Total fugitive emission from coal production	111,750	tonne CO_2/year
Estimated Quantity of gas combusted in plants included in build margin	464,005,905	m^3/year
Average calorific value of gas used	9,384.33	Kcal/SCM
Total energy content of the gas used	18.23	PJ
Fugitive methane emission factor for NG consumption	296.00	t CH_4/ PJ
Total fugitive emission from gas	113,302	tonne CO_2/year
Estimated Quantity of oil combusted in plants included in build margin	0	tonne/year
Average calorific value of oil	0	Kcal/kg
Total energy content of the oil	0.00	PJ
Fugitive methane emission factor for oil consumption	4.1	tCH4/PJ
Total fugitive emission from oil	0	tonne CO_2/year
Net power generation in the BM	13,687	MU
Combined fugitive emission factor	**16.44**	**tonne CO_2/MU**

Table: Leakage Emission Calculation

1	**Fugitive Methane Emission**		
1 a)	Fugitive Methane Emission from NG consumption		
	Quantity of natural gas combusted in the project plant per year	304,252,146	SCM/year
	Average Net Calorific Value of the natural gas combusted	9384.33	Kcal/ SCM

	Total energy content of the gas used	12	PJ
	Emission factor for fugitive emission for NG	296	t CH_4/PJ
	Fugitive Methane Emission from NG consumption	74,293	t CO_2e
1 b)	Fugitive emission from fossil fuel in absence of the project		
	Electricity generation from project during a year	1698	MU
	Combined fugitive emission factor (coal & gas & Oil)	**16.44**	t CO_2e/MU
	Total fugitive emission from fossil fuels in absence of the project	27,915	t CO_2e
	Net leakage attributable to the project activity	46,378	t CO_2/year
2	**CO2 emissions from LNG**		
	Emission factor for upstream CO2 emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system	6.0	tCO_2/TJ
	Quantity of natural gas combusted in the project plant per year	0	SCM/year
	Average Net Calorific Value of the natural gas combusted	9384.33	Kcal/ SCM
	Leakage	0	tCO_2/year
	Effective leakage	**46,378**	**t CO_2/year**

A) Calculation of leakage emissions due to fugitive upstream CH_4 emissions ($LE_{CH4,y}$)

Leakage emissions due to fugitive upstream CH_4 emissions are calculated as per equation number-6 of AM0029:

Quantity of natural gas combusted in the project plant (FC_y): 304,252,146 SCM/ year

Average net calorific value of natural gas ($NCV_{NG,y}$): 9384.33 kcal/SCM

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

($EF_{NG, upstream,CH4}$) : 296 t CH_4/ PJ

Electricity generated in the project plant ($EG_{PJ,y}$) : 1,697,700 MWh

Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in t CH_4 per MWh electricity generation in the project plant ($EF_{BL, upstream, CH4}$): 16.16 t CO_2e/ GWh.

$$LE_{CH4,y} = \left[FC_y \cdot NCV_y \cdot EF_{NG,upstream,CH4} - EG_{PJ,y} \cdot EF_{BL,upstream,CH4}\right] \cdot GWP_{CH4}$$

= 304,252,146 x 9384.33 x 4.186 x 10^{-12} x 296 x 21 – 1,697.7 x 16.44
= 46,378 tCO_2e.

B) Leakage emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re -gasification and compression of LNG into a natural gas transmission or distribution system (LE $_{LNG,CO2,y}$)
In the current context LNG is not being used in the project activity hence, LE $_{LNG,CO2,y}$ = 0.
In future if the LNG is being used the leakage is calculated as described below:
Calculated as per the methodology, AM0029
Quantity of natural gas combusted in the project plant (FC $_{LNG\ y}$) (For CO_2 emissions from LNG): Q SCM
Calorific Value of Natural Gas: 9384.33 kcal/ SCM
Emission factor for upstream CO_2 emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system (EF $_{CO2,\ upstream,LNG}$) : 6 t CO_2/ TJ

Based on the above, the estimated Leakage emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system (LE $_{LNG,CO2,y}$) will be:
= Q SCM x 9384.33 kcal/ SCM x 4.186 x 10^ (-9) x 6 t CO_2/ TJ = LE $_{LNG,CO2,y}$ t CO_2

4.4 Quantifying GHG emission reductions and removal enhancements for the GHG project:

Emissions Reduction (ER $_y$)
According to the approved Methodology AM0029 Version 3:

$$\mathbf{ERy = BEy - PEy - LEy}$$

Where:
ERy : emissions reductions in year y (t CO_2e)
BEy : emissions in the baseline scenario in year y (t CO_2e)
PEy : emissions in the project scenario in year y (t CO_2e)
LEy : leakage in year y (t CO_2e)

ERy = 1,346,883– 670,500 – 46,378= 630,005 tCO_2e

Year	Estimation of Project Activity Emissions (tCO_2e)	Estimation of baseline emissions (tCO_2e)	Estimation of leakage (tCO_2e)	Estimation of overall emission reductions (tCO_2e)
2009	481,291	966,804	33,290	452,222
2010	670,500	1,346,883	46,378	630,005
2011	670,500	1,346,883	46,378	630,005

2012	670,500	1,346,883	46,378	630,005
2013	670,500	1,346,883	46,378	630,005
2014	670,500	1,346,883	46,378	630,005
2015	670,500	1,346,883	46,378	630,005
2016	670,500	1,346,883	46,378	630,005
2017	670,500	1,346,883	46,378	630,005
2018	670,500	1,346,883	46,378	630,005
2019	189,210	380,079	13,087	177,782
Total (tonnes of CO_2e)	**6,705,000**	**13,468,830**	**463,780**	**6,300,050**

5 Environmental Impact:

The project activity has obtained all the consents from the state pollution control board (Consent to Establish and Consent to Operate) and the clearance form the Ministry of Environment an Forests has also been obtained. The specific conditions from the 'Consent to Operate' are as summarized in the following table[46]

Table: Conditions from the APPCB 'Consent to Operate'

Sr. No.	Parameter	Limiting value	Unit	Point of discharge
Discharge of Effluents				
1	Cooling tower blow down, boiler blow down – after treatment	3541	KLPD	On land plantation and excess in irrigation drain
2	DM plant rejects after treatment	28	KLPD	
3	Domestic Effluents	61	KLPD	Septic Tank followed by Soak Pit
4	Tolerance Limits			
a	Temperature	Not more than 5°C than the intake		
b	pH	6.5 to 8.5		
c	Free available chlorine	0.50 mg/l		
d	Suspended solids	100 mg/l		
e	Oil and grease	10 mg/l		
f	Copper (Total)	1.0 mg/l		
g	Iron (Total)	1.0 mg/l		
h	Zinc	1.00 mg/l		
i	Chromium (Total)	0.20 mg/l		
j	Phosphate	5.00 mg/l		
k	BOD	30.0 mg/l		
Emissions from Chimneys				
5	Chimneys attached to 93 TPH	381600	Nm^3/hr	-

[46] Consent to Operate from APPCB, Hyderabad; Order No. APPCB/VSP/RJY/289/HO/2008 2565 dt. 23/02/2008

	Waste Heat Recovery Boiler 1,2 and 3			
6	Chimneys attached to 93 TPH Waste Heat Recovery Boiler	748800	Nm^3/hr	-
7	Prescribed limits			
a	SPM	115 mg/Nm^3		
b	NOx	75 ppm		
8	Ambient Air quality standards			
a	TSPM	200 $\mu g/m^3$		
b	RSPM	100 $\mu g/m^3$		
c	SO_2	80 $\mu g/m^3$		
d	NOx	80 $\mu g/m^3$		
9	Noise Levels			
	75 dB (A)	Day time (6 am to 10 pm)		
	70 dB (A)	Night time (10 pm to 6 am)		

All these conditions are met by various environmental control equipments/ units for the treatment exhaust gas and the effluent water before the discharge.

The mitigation measures that have been adopted are summarised below

A. Management during construction phase

The impact during the construction phase on the environment would be basically of transient nature and are expected to reduce gradually on completion of the construction activities. In order to mitigate them following measures are proposed:

1. Designation and demarcation of sites for construction camps and ensuring due provision of necessary infrastructural services.

a. During excavation and transportation over unmetalled roads near the proposed plant site, there is a scope of local dust emissions. Frequent water sprinkling in the vicinity of the construction activity should be done and it should be continued even after the completion of the plant construction, as there is scope for heavy truck mobility. The industry should make provision for water sprinklers.
b. Since there is likelihood of fugitive dust from the construction activity, material handling and from the truck movement in the premises of the proposed plant, the industry should go for green belt plantation programme along the boundaries of the proposed plant site.
c. The construction site should be provided with sufficient and suitable toilet facilities for workers to allow proper standards of hygiene. These facilities would be connected to septic tank and maintained to ensure minimum environmental impact.
d. Though the noise effect on the nearest inhabitants due to construction activity will be negligible it is advisable that onsite workers using high noise equipment adopt noise protection devices. Noise prone activities should be restricted to the extent possible during night particularly during the period 10:00 PM to 6:00 AM in order to have minimum environmental impact.

e. It should be ensured that both gasoline and diesel powered construction vehicles are properly maintained to minimize smoke in the exhaust emissions. The vehicle maintenance area should be located in such a manner to prevent contamination of surface and ground water sources by accidental spillages of oil. Unauthorized dumping of waste oil should be prohibited
f. As soon as construction is over, the surplus earth should be utilized to fill up low lying areas, the rubbish should be cleared and all unbuilt surfaces reinstated. Appropriate vegetation should be planned and all such areas should be landscaped. Hazardous materials (e.g. acids, paints, explosives) should be stored in proper and designated areas.

2. To prevent unauthorized felling of trees by construction workers for their fuel needs, it should be ensured that the contractor provides fuel to the construction workers

B. Management during the operational phase

a. Air pollution control system: The air pollution control measures proposed for the project are described below:
   i. 70 m tall stack should be provided to ensure wider dispersion of pollutants
   ii. Appropriate system to control NOx emissions to 75 ppm should be provided
   iii. Green belt development in and around the plant premises should be undertaken
   iv. The proposed air pollution control equipment should be installed prior to commissioning of the plant
   v. Monitoring of stack emissions for NOx and SO_2 should be carried out regularly to meet all statutory requirements
   vi. All the internal roads should be asphalted to reduce the fugitive dust due to vehicle movement
b. Water pollution control system: The waste water will be originating from cooling system, plant service water system, filter backwash and sanitary effluents from plant. All these waste will be treated and discharged on the land to be utilized for green belt through a central monitoring basin.

Following effluent treatment and disposal systems are proposed to be installed:
i. Minimize quantity of effluents through reuse to the extent possible;
ii. Treatment of the DM plant waste through neutralization;
iii. Provision of oil separators; and
iv. Biological treatment for domestic waste from plant.

Effluent monitoring instruments namely pH meter, flow meter, etc., should be provided in the effluent discharge line. Flow integrators should be provided both at the plant intake and discharge point at central effluent holding pond

Apart from the proposed treatment schemes, some additional measures are given here under:
i. Minimize quality of effluents through reuse to the maximum extent feasible;
ii. The treatment scheme proposed should be constructed before the commissioning of the plant

iii. Sedimentation tanks should be cleaned regularly in order to avoid clogging. Sludge should be removed regularly and sufficient time should be given for proper settling of solids
iv. The treatment units viz., STP should be operated regularly
v. Monthly effluent samples should be collected and analysed at the inlet and outlet of the treatment plants to ascertain the efficiency of the treatment plants and to meet the statutory requirements.

c. Solid waste management plan: Solid wastes generated from the plant are basically from sedimentation tanks and sewage treatment plants. The solid waste does not contain any toxic matter and safe to dispose off on land.

The suitable landfill area should be identified taking in to consideration permeability of soil, distance from population area, etc. the collection, transport and disposal of solid wastes from different parts of the plant to the disposal area should be through sanitation contract package. The contractors deployed by the proponents are required to allow certain norms with respect to tools and safety equipments.

The waste brought to the landfill site would be unloaded immediately over the working face of the landfill and would be evenly separated and compacted by bulldozers/loaders. The top surface and the slopes of the refuse dumped would be covered progressively with a layer of soil or civil debris or any other sealing material. A daily inspection will be made for rodent burrows or insect infestations and appropriate control measures shall be taken.

The generating of leachate from the landfill area should not be a common phenomenon under Indian conditions. The compaction and provision of proper slope would prevent stagnation of water inside the landfill area, thereby minimizing leachates. In addition, a drainage system should be constructed around the landfill area. However two wells should be monitored near the landfill area.

d. Noise level management: The predominant noise levels will be confined to the work zones in the plant. The noise levels at the entire sources will not exceed 85 dB(A). Community noise levels are not likely to be affected because of proposed vegetation and attenuation due to the physical barriers.
   i. The use of damping materials such as thin rubber/lead sheet for wrapping the work places like turbine halls, compressor rooms, DG sets, etc.;
   ii. Shock absorbing techniques should be adopted to reduce impact;
   iii. Efficient low techniques for noise associated with high fluid velocities and turbulence should be used;
   iv. All the openings like covers, partitions should be acoustically sealed;
   v. Inlet and outlet mufflers should be provided which are easy to design and construct;
   vi. Reflected noise should be reduced by the use of absorbing material on roofs walls and floors;
   vii. Ear plugs should be provided to the workers, and it should be enforced to be used by the workers;
   viii. Increase the distance between source and receiver and by altering the relative orientation of the source and receiver;
   ix. Provision of the separate cabins for workers and operators

x. The industrial compound should be thickly vegetated with species of rich canopy

e. Measures for improvement of ecology

i. Clearing of existing vegetation should be kept to minimum and should be done only when absolutely necessary. Even then clear felling of big trees should be kept to bare minimum.
ii. Plantation programme should be undertaken in all areas. This should include plantation in the proposed plant premises, along the internal and external roads
iii. Use of biogas, solar energy, etc. should be encouraged both at individual and at society levels
iv. People should be educated and trained in social forestry activities by local governmental and non governmental organizations

f. Socio-economic development activities: GVK has created economic and social benefits to the people of areas surrounding the Jegurupadu power project. Some of the socio economic projects undertaken and developed by GVK are:

i. Supply of drinking water to the villages of Kadiyarn mandal
ii. Built bus shelters in Jegurupadu and Kadiyapu village for the benefit of the travellers using the bus shelters
iii. The school building was built in Jegurupadu village by GVK to provide a high school facilities to benefit the 12000 population of the village
iv. Undertook the responsibility to repair the state highway from Dowleshwaram and Kesawaram villages which has benefited over a lakh of people living in the vicinity
v. GVK has sponsored the construction of about 25 school buildings in the district of Nellore around the Krishnapatnam project site
vi. GVK has developed a green landscape along some of the Hyderabad city roads, which have been appreciated by number of visitors to Hyderabad as well.

6 Stakeholders comments:

Relevant outcomes from stakeholder consultations and mechanisms for on-going communication.

A stakeholders consultation meeting was organized on 01/12/2007 at GVKPIL Plant Jegurupadu. GVKPIL identified local villagers, local NGO, employees of GVK Power Plant, government officials as the most important stakeholders, with an interest in the CDM activities. Accordingly the stakeholders were duly informed of the consultation meeting through written invitations. A record of these invitations is available with the project proponents. For the stakeholders that could not come for the meeting, another 15 days time was given to contact the Director Technical to inform about their concerns and opinions.

Comments of stakeholders were recorded during the stakeholder meeting.

The stakeholders meeting process was followed in the following sequence

- Welcome Address

- Election of the Chair of the meeting and approval of the proposed Agenda
- Presentation of the CDM-Kyoto Protocol and role of local stake holder
- Presentation of the Projects undertaken by GVK Group.
- Discussion and Articulation of concerns
- Chair summarizing the local stake holder concerns
- Vote of Thanks followed by Tea

Mr. G Satyanarayana, Advisor – Tech, GVKPIL welcomed all the stakeholders to the consultation meeting. Mr. John Fernandes, Vice President, GVKPIL proposed Dr. Ramana Murthy to chair the meeting and Mr. Zakir Hussain supported him. Mr. Ramesh Babu, Manager (E&C) gave a brief presentation on the plant, configuration and power generation and gas supply, water supply and power evacuation system in the vernacular language (Telugu). Mr. Sandeep Kota from CantorCO2e gave a presentation in the vernacular language (Telugu) on global warming, Kyoto protocol and proposed CDM Project activity. He provided a brief on the CDM project process and the role of the local stakeholders in the CDM project. He also explained that the purpose of the meeting is to internalise the local stakeholders concern for the project activity.

The summary of the meeting was recorded - copy of which will be made available to Designated Operating Entity during validation process. The list of participants with their signature is kept for record and photographs of the event were also taken. After the presentation, chairman invited the stakeholders to raise their queries.

For any further queries, another 15 days time was given to stakeholders for contacting GVKPIL. Mr. Ramalingeswara Rao thanked all the stakeholders for attending the local stakeholders' consultation meeting.Table 5.1 Summary of the stakeholder's comments

The specific concerns expressed by the participants are summarized below along with clarifications provided on such concerns:

Stakeholder concerns / question / comment	**Answer / clarifications**
Dr. P. Syam Prasah What are the possible leakages expected and how they will be controlled?	The possible gas leakages are Natural gas and chlorine. In case of natural gas leakage the control vales automatically shutoff and thereby the gas supply to terminal station will be stopped. In case of chlorine gas leakages the control valves will close automatically. In case of chlorine spillages occur it will be absorbed by sodium hydroxide tower and neutralized. This has been included in emergency plan and mock drills are conducted.
Dr. DV Ramana Murthy What is the basis of emission reduction	In the absence of this project activity the project proponent or any other players would have constructed more

calculations?	carbon emissive power plant like the coal based power plant[47]. That power plant would have produced equivalent power similar to GVK power plant and would have emitted more amount of CO_2 in to the atmosphere per unit of electricity generation. The project activity will emit less amount of CO_2 per unit of electricity generation. This is called emission reduction per unit of electricity generation. This will be multiplied with the total amount of electricity generation and the total figure will give total amount of CO_2 emission reduction per annum.
The stakeholders appreciated the social activities like Construction of School buildings, conducting health camps and providing water supplies to neighbouring villages undertaken by GVK Group. They further suggested the following: 1. To create environmental awareness in the near by villages especially in the school going children / college going students to neighbouring towns. 2. To adopt some villages and support panchayats in improvement of sanitation. 3. Create health observatory, to observe new diseases coming in the surrounding areas. 4. To provide tree guards being planned in the local gram panchayat of Jegurupadu village.	As GVK is committed to the society towards sustainable development, it has taken many social initiatives in the area of education, health care and poverty eradication. As a part of corporate policy on continuous basis GVK is involved in various social activities and will be involved in the local areas and similar kind of activities. Neighbouring engineering colleges are being given training (as part of the curriculum). Also plant visits from neighbouring colleges are encouraged. The suggestion is under consideration and once the plant is operational, the implementation will be considered. It was explained that all the pollution norms are met and rapid EIA confirms that there are no major health impacts due to the project activity. However, a health observatory to study the impact specifically due to project activity is out of the scope of project

[47] This was actual answer given for the understanding of stakeholder. However the PD uses baseline as per applicable methodology AM0029.

	proponents. However, the workers in the plant and their families staying in the adjacent residential colony (who are likely to be affected in the first place) are continuous monitored by medical officer. The suggestion is under consideration and once the plant is operational, the implementation will be considered.

In summarizing the discussion, Dr. Ramana Murthy (chairman of the meeting) appreciated the greenery development in the plant area and the social activities of GVK Group. He also commended GVK group for the natural gas based power project activity as it is a cleaner source of energy

7 Schedule:

Chronological plan for the date of initiating project activities, date of terminating the project, frequency of monitoring and reporting and the project period, including relevant project activities in each step of the GHG project cycle.

The following table represents chronological order of the efforts/decisions (milestones of the project activity) undertaken by the project developer for the project activity development:

Table 6.1.Chronology of the VCS project activity

S.N	**Time**	**Project Execution Step**	**CDM registration efforts**	**Evidence**
1	14/06/2003	EPC contract signed with Alstom	-	Agreement for Supplies (Ex-Works)
2	18/06/2003	PPA signed with AP Transco	-	-
3	14/01/2004	Construction start date	-	NTP letter to Alstom Project India Ltd.
4	01/12/2007	-	Local stakeholders' meeting at the project site	Minutes of the meeting
5	08/05/2008 31/05/2008	-	Submission of PDD for validation PDD web hosted for global stakeholder comments	- CDM website validation link
6	03/09/2008	-	Host Country	HCA letter from

			Approval award	NCDMA, India
7	14/04/2009	Project activity plant commissioning	-	Letter of Acceptance of project COD by Andhra Pradesh Power Coordination Committee

8 Ownership:

8.1 Proof of Title:

Provide evidence of proof of title through one of the following:

- *a legislative right;*
- *a right under local common law;*
- *Ownership of the plant, equipment and/or process generating the reductions/removals;*
- *A contractual arrangement with the owner of the plant, equipment or process that grants all reductions/removals to the proponent*

Proof of title is the EPC contract signed, Certificate of Incorporation of company and PPA with APTransco.

8.2 Projects that reduce GHG emissions from activities that participate in an emissions trading program (if applicable):

The project activity takes place in India (STATE: Andhra Pradesh, DISTRICT: East Godavari). India has no binding limit for GHG emission reductions. Also the project activity doesn't participate in any emission trading program approved by VCS Board.

Project proponents of projects that reduce GHG emissions from activities that:

- are included in an emissions trading Program; or
- take place in a jurisdiction or sector in which binding limits are established on GHG emissions;

shall provide evidence that the reductions or removals generated by the project have or will not be used in the Program or jurisdiction for the purpose of demonstrating compliance. The evidence could include:

- a letter from the Program operator or designated national authority that emissions allowances (or other GHG credits used in the Program) equivalent to the reductions/removals generated by the project have been cancelled from the Program; or national cap as applicable or;
- purchase and cancellation of GHG allowances equivalent to the reductions/removals generated by the project related to the Program or national cap.

Appendix –1

Natural gas availability in the project activity location/ region

The spirit of emphasizing "sufficient availability" of NG in the methodology as an applicability criterion is:

(a) to ensure that NG from other users are not diverted and
(b) to ensure future power generation facilities of comparable size are not deprived due to NG being taken up by the project activity [Ref: footnote No. 2 of the AM0029, Version 3]

The points (a) and (b) above are borne out by the clarification [Ref: F-CDM-AM-Clar_Resp_ver 01.1 - AM_CLA_0091] issued by EB in response to a DOE query. In the response, EB also clearly mentions how the applicability condition pertaining to availability is to be implemented. In EB's view, a project activity to demonstrate that it meets the applicability condition will need to do so by resorting to appropriate monitoring. The relevant excerpt from EB's clarification– "*the monitoring should show that satisfying the project activity's demand for natural gas will not lead to shortages in supplies of the gas to other projects within the country*".

In other similar examples, recently registered projects from China in the applicable methodology AM0029, have shown 'LNG import agreements from other countries like Malaysia' (Project reference No.s 1381, 1343, 1344) in support of the NG availability. Thus, NG availability in the project activity region alone is not the applicability of methodology here. The same spirit of applicability allows new power plant even with imported NG to qualify for AM0029.

In this project we demonstrate that:
1) NG was sufficiently available in the source of supply so that other NG based projects do not get deprived and leakage does not occur.
2) Also future natural gas based power capacity addition also not constrained

The applicability condition in the methodology aims to avoid the diversion of natural gas from other future and existing users. It is evident from the AM0029 applicability condition on sufficient availability 'future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity'.

The PP chooses to demonstrate gas availability in the region of project activity i.e. state – Andhra Pradesh. Considering the source of gas for the project activity in KG basin and also the power purchaser in the state, the choice of region is appropriate.

India has about 0.4% of world's natural gas reserves[48]. However, India continued to be one of the least explored regions with 30% of its estimated gas reserves explored so far. Almost 70% of India's natural gas reserves are found in the Bombay High

[48] http://www.nedcap.org/index_files/Page2514.htm

basin and the state of Gujarat[49]. Off shore reserves are also located in Andhra Pradesh coast (Krishna Godavari Basin) and Tamil Nadu coast (Cauvery Basin)[50]. Onshore reserves are located in Gujarat and the North Eastern states. Smaller reserves are also found in Rajasthan[51].

At the time of initiation of the project activity i.e. award of the EPC Contract, Natural gas was available for procurement and there have been no evident restrictions caused by the project activity's choice of natural gas as the fuel, on significant future capacity additions to the baseline grid comparable in size to the project activity, in choosing natural gas as fuel.

The abundant 'availability' of NG in the KG basin from where the gas is proposed (and secured by a fuel supply agreement with the Gas Authority of India Ltd. -GAIL) is established[8]. The agreement for the supply of 1.1 million SCM/ day gas (more than that required for the operation) is signed before the financial closure (the project start date). Later in 2009, PP has signed gas supply agreement with Reliance Industries Limited. This RIL gas is also being supplied using existing gas transmission infrastructure of GAIL.

The project activity is slated to draw NG coming out from a new source (not a source which was earlier supplying NG elsewhere). The project activity has contracted NG supply for more than that required at the design PLF not from an existing gas source[57] but from a new gas source i.e. KG Basin. The NG to be used in this project is therefore not a result of diversion of NG destined for other projects in any region. For the purpose of gas supply a priority list for allocation has been created by Gas allocation committee of MoP&NG. The fact that this project activity figures in the allocation list of NG supply, proves that the planned gas consumption of this project activity, will be met by the NG available from the new sources. The source of NG is a bonafide gas find as has been borne out by publicly available information - The Sankar Committee on Utilization of Natural Gas in Andhra Pradesh, constituted by the Government of Andhra Pradesh in May 2003 observed that the established reserves in KG basin as on April 1, 2002 was about 45.59 BCM[52].

Reliance Industries Limited (RIL) in October, 2002 found 9 Trillion cubic Feed (tcft) of gas reserves, the biggest gas find in India in three decades, in the exploration block called KGBDW-6 (renamed asKG-DWN-98/3) in deep waters, 150 km off the Andhra Pradesh Coast near Kakinada. Cairn Energy also announced discovery of about 1 tcft of gas in Krishna Godavari Basin. The present estimates indicate that RIL can supply 40 MMSCMD of gas per day after all the facilities are built and gas transported to landfall point near Kakinada. ONGC, Gujarat State Petroleum Corpn. Ltd and Reliance Industries Limited are further intensifying exploration for gas, both onshore and offshore in Krishna Godavari Basin and this is expected to result in

[49] http://iea.org/textbase/papers/2000/oilgas.pdf

[50] http://www.sourcewatch.org/index.php?title=India's_oil_industry

[51] http://petroleum.nic.in/ng.htm

[52]http://www.infraline.com/ong/default.asp?URL1=/ong/naturalgas/utilisation/SankarCommRepUtilisNatGasMay03.asp&idCategory=4798#infra

considerable additions to gas availability[53]. Further planned projects and national NG grid and trans-national pipelines will make gas availability possible[54].

Further, the announcement of consideration of Lanco's Kondapalli[55] and ongoing 768 MW expansion[56] at Vemagiri power as well as 800 MW GVK Gautami Power Ltd., prove that the project in question is not depriving any other future users. The fact that the two projects mentioned above are of comparable capacity to the concerned power project, proves that future power projects of same scale have not been negatively affected by the NG to be used in VPGL.

Evidence / Analysis / Justification supporting surplus availability of NG at the point of time

- **Management took decision:**

Indian Natural gas production had been increasing steeply in past 20 years before the investment decision. From production of 8 bcm (billion cubic meter) in 1985-86, it had increased to 26.4 bcm in 1997-98 (> 400% in 12 years) which became 31.9 bcm by 2003-04.

The project activity power plant had signed a gas supply agreement for sufficient gas to operate at more than 85% PLF on 09/10/2000, before the investment decision (25/08/2003). The gas was to come from a new find in KG basin[57].

The Sankar Committee on Utilization of Natural Gas in Andhra Pradesh, constituted by the Government of Andhra Pradesh in May 2003 observed that the established reserves in KG basin as on April 1, 2002 was about 45.59 BCM[58]. In the state of Andhra Pradesh, the demand from consumers having firm commitments for supply in the year 2001-2002 was 6.12 MCMD. Against this demand, the availability from GAIL for the year 2001-2002 was 7.50 MCMD.

In October 2002, Reliance Industries Ltd. made India's largest gas discovery in three decades in KG basin off Andhra Pradesh coast. This gas reserve was estimated to have capacity of 9 trillion cubic feet (TCF). That gas would enable supply of 40 MMSCD against the demand in project activity of 1.64 MMSCD. Cairn Energy also had announced discovery of about 1 TCF of gas reserves in KG basin. The demand supply data of India available from[59] Ministry

[53] Department of Industries, Govt. of AP; http://www.apind.gov.in/indussectors.html

[54]http://www.pwc.com/extweb/pwcpublications.nsf/docid/5EBE732379E5428ECA257184005E7A2B/$file/oil_gas.pdf

[55] http://petroleum.nic.in/clip4151206.pdf

[56] http://asian-power.com/regulation/more-news/ge-supply-parts-and-services-vemagiri-plant; http://www.gmrgroup.in/corporate/pdf/GIL_Q3-FY_11_-_Press_Release_Ver3_0_Final.pdf

[57] Gas supply contract with GAIL dt. 09/10/2000 (and all later amendments) specified gas obtained from the fields of ONGCL at Tatipaka, Parsarlapudi, Kesnapalli, Mori and Ravva offshore. These fields are all in KG-basin of Andhra Pradesh and some with latest discoveries in the duration

[58]http://www.infraline.com/ong/default.asp?URL1=/ong/naturalgas/utilisation/SankarCommRepUtilisNatGasMay03.asp&idCategory=4798#infra

[59] A report on OIL & GAS by PricewaterhouseCoopers.

of Petroleum and Natural gas shows that the country's natural gas consumption has been less than the gross production as presented below:

Table 1: Natural Gas Consumption & Production (Billion Cubic Meters - BCM)

	99-00	00-01	01-02	02-03	03-04	04-05	CAGR
Consumption	26.88	27.68	28.03	29.96	30.90	30.77	2.74%
Gross Production	28.45	29.48	29.71	31.40	31.96	31.80	2.25%

Source: MoPNG

On 17th June 2005, GSPC discovered India's largest gas reserve in its KG # 8 well. Estimated at 20 TCF, it was expected to double the country's gas production.

At investment decision (2003), it was estimated[60] that the total domestic production of natural gas would go up from the current 70 mscmd to 142 mscmd in 2006–7, with the Krishna–Godavari basin contributing a major part. Compared to this the domestic gas demand in 2006–7 could be around 135–150 mscmd. This would imply that the domestic production of natural gas would be able to meet much of the domestic demand.

The demand supply scenario the XI Five Year Plan where project activity started operations is presented below[61].

S.N.	Year	2007-08	2008-09	2009*-10	2010-11	2011-12
1	Total supply –Optimistic (BCM)	40.51	56.06	88.50	97.49	104.18
2	Total demand (BCM)	65.40	71.77	82.31	95.66	101.99
3	Demand supply gap (optimistic)	24.89	15.72	-6.19	-1.83	-2.19

As can be seen from the table above, from 2009-10 (where project activity plant was commissioned), the gas supply was expected to be surplus. This is further evident from a press release by RIL on 22/01/2010. Here, RIL informed that they have capacity to produce 80 MCMD and have agreements for supply of 61 MCMD i.e. surplus gas availability.

- **Commissioning date:**

A new fuel supply term sheet was signed with Reliance Industries Ltd. (RIL) on 09 June 2007 for supply of NG from new discovery in KG basin[62] (KG—DWN-98/3)

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http://www.pwc.com/extweb/pwcpublications.nsf/docid/5EBE732379E5428ECA257184005E7A2B/$file/oil_gas.pdf

[60] The Infrastructure Sector in India, 2002–3, pg. 31 (10 of file)
http://www.iitk.ac.in/3inetwork/html/reports/IIR-2004/Chap%202%202003.pdf

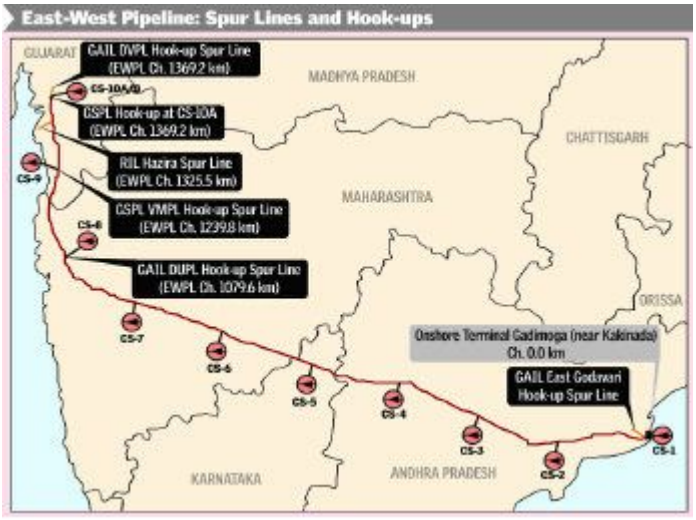
[61] http://www.infraline.com/ong/naturalgas/gasdemsup/DemandSupplyIntro1 (Note - this report has given values in MMSCMD, here converted in BCM by multiplying with 365 (No. of days/ year) and dividing with 1000 (conversion factor million to billion)

The project activity power plant started commercial operations in 14/04/2009[63]. The gas from RIL will also be supplied using the existing infrastructure of GAIL. The contracted capacity from the RIL under Agreement is also 1.1 million SCM/ day. The project activity power plant is currently receiving natural gas from this new source.

- **As on date:**

ONGC, Gujarat State Petroleum Corporation Ltd. and Reliance Industries Limited are further intensifying exploration for gas, both onshore and offshore in KG basin and this is expected to result in considerable additions to gas availability[64]. Further planned projects and national NG grid and trans-national pipelines will make gas availability possible[65].

A recent media release by RIL on 22 January 2010, has declared a 61 MMSCD demand and capacity of 80 MMSCD for the KG basin operations[66]. **Reliance Gas Transportation Infrastructure Ltd (RGTIL) has started commercial operations of east-west gas pipeline in April 2009. This is 1,385 km pipeline traverses the four States of Andhra Pradesh, Karnataka, Maharashtra, and Gujarat.**



The project activity plant has operated for more than 85% PLF in last about one year since COD and gas supply has never been disrupted.

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[62] Gas sale term sheet between PP and RIL, pg. 3

[63] Andhra Pradesh Power Coordination Committee Consent for COD letter after performance acceptance tests as per PPA

[64] Department of Industries, Govt. of AP; http://www.apind.gov.in/indussectors.html

[65] http://www.pwc.com/extweb/pwcpublications.nsf/docid/5EBE732379E5428ECA257184005E7A2B/$file/oil_gas.pdf

[66] http://www.ril.com/rportal/jsp/eportal/media/MediaHome.jsp

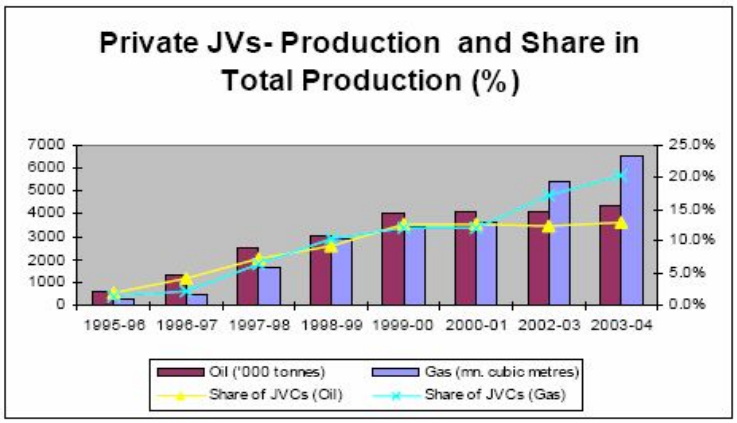
- **Future projection:**

Natural gas supply to Indian market is managed through following approaches:

1. Increase production through private participation and encouragement of the existing gas producers
2. Make attractive exploration and licensing policy
3. Import gas through pipelines
4. LNG import

1. Production trend:

As described in earlier sections, Indian Natural gas production had been increasing steeply in past 20 years. From production of 8 bcm (billion cubic meter) in 1985-86, it increased to 26.4 bcm in 1997-98 (> 400% in 12 years) which became 31.9 bcm[Error! Bookmark not defined.] by 2003-04. Private participation in the form of Joint ventures had given a boost to this trend and it has been continuously increasing as presented below:



Source: Ministry of Petroleum & Natural Gas

Gas Exploration and licensing policy:

Government has introduced attractive fiscal terms and conditions in the oil and gas exploration policy. This has facilitated the major gas discovery by Reliance.

It has implemented a New Exploration and Licensing Policy (NELP) in 1997. Under this policy it awarded 90 blocks in a period of 5 years compare to 10 blocks awarded in 10 years prior to NELP. The result of the new policy was reflected in the series of gas reserve discovery between 2006 and 2008 (as presented in the section on 'gas reserve' earlier)

It is also encouraging sourcing the Coal Bed Methane (CBM) at its existing coal reserves. In the 200 Billion tones of present coal reserve it is believed to contain 800 billion cubic meters of methane. Till date 5 blocks have been awarded to 5 parties and 9 other blocks are in process of awardance.

Gas imports through pipeline:

Government is actively planning to import gas through following pipelines:

- Iran-Pakistan-India (IPI) pipeline – this plan to import 5.4 Bcf/d gas from Iran through a 1700 mile pipeline through Pakistan.
- Turkmenistan – Afganistan – Pakistan- India (TAPI) pipeline – this would source gas from Turkmenistan and import 3.2 Bcf/d gas through a 1050 mile long pipeline.
- Myanmar – Bangladesh- India pipeline – This would be sourcing gas from Swe field (of estimated reserve 7 Tcf) for India.

LNG Import[Error! Bookmark not defined.]*:*

Since 2004, India have been importing LNG and had set up two terminals in Gujarat (Hazira and Dahej).

Realising the ease of transporting natural gas as LNG and the growing demand for fuel in India, the GoI had set up a new company Petronet LNG, with GAIL, ONGC, IOC and Bharat Petroleum Corporation Limited (BPCL) as the main promoters. Petronet LNG has been entrusted with the task of developing terminals in the country for importing LNG. Petronet LNG has signed a gas purchase contract with Ras Gas, Qatar, for the import of 5 mmtpa of LNG at Dahej (Gujarat) and 2.5 mmtpa at Kochi (Kerala).

Free market availability: Petronet[67] is formed as a Joint Venture by the Government of India to import LNG and set up LNG terminals in the country and it involves India's leading oil and natural gas industry players. The promoters of company are GAIL (India) Limited (GAIL), Oil & Natural Gas Corporation Limited (ONGC), Indian Oil Corporation Limited (IOCL) and Bharat Petroleum Corporation Limited (BPCL).

Petronet's Dahej terminal has a nominal capacity of 10 million metric tones per annum (MMTPA) [equivalent to 40 million standard cubic meters per day (MMSCMD) of natural gas], the Kochi terminal will have a capacity of 2.5 MMTPA (equivalent to 10 MMSCMD of natural gas)[67]. It also plans to increase the Dahej terminal capacity to 15 MMTPA by 2012[68].

GAIL has 6196 km natural gas pipeline[69] and further planning Vijaywada-Vijaipur pipeline[70].
MOP&NG[71] statics also shows that free market availability of gas ("*Around 8.5 MMSCMD of gas is being directly supplied by the JVs/private companies at market prices to various consumers. This gas is outside the purview of the Government allocations.*") and also acknowledges that the further LNG imports will increase

[67] http://www.petronetlng.com/

http://petroleum.nic.in/ng.htm

[68] http://www.reuters.com/article/idUSDEB00091720090824

[69] http://www.gailonline.com/gailnewsite/businesses/gastransmission.html

[70] http://www.hinduonnet.com/2009/04/25/stories/2009042551751600.htm

[71] Para 9 on natural gas page of MOP&NG website (http://petroleum.nic.in/ng.htm)

market availability. GAIL also estimated that the LNG imports could be 22-15 MMTPA in coming 5-6 years[72].

The gas transmission pipelines existing and proposed will interconnect all sources including LNG terminals and major user points. Following snapshot from GAIL presentation[73] gives existing and planned gas pipelines.

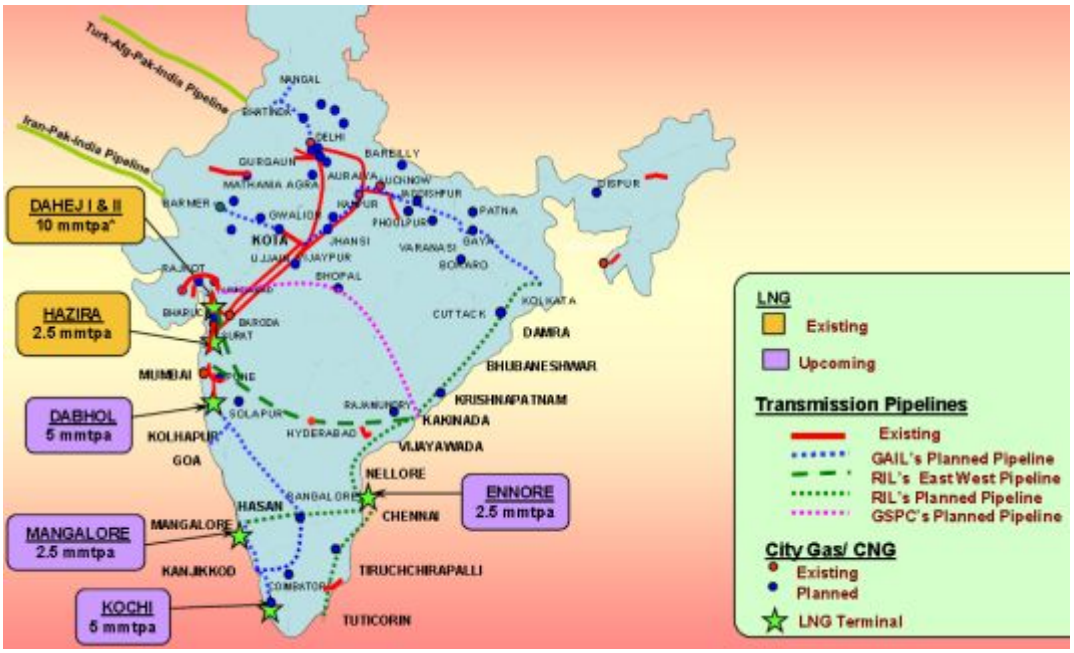


Figure: Natural gas distribution pipelines- existing and planned in India

Justification /Evidence that Allocation for gas did not result in diversion of NG reserves (or) Monitoring plan to monitor leakage:

The project activity power plant had a fuel supply agreement, approved by a Central Government Committee before the start date. When the plant is commissioned, it has started receiving gas from a new gas find by Reliance Industries Ltd. (discussed above). The same supplier has recently declared surplus capacity more than the present demand. Thus, the natural gas being used in the power plant is not diverted either from the present users and excess capacity from the gas supplier than demand shows that future capacity additions are also not constrained.

Hence, the required NG is adequately available at source and applicability condition is satisfied.

[72] http://www.gailonline.com/gailnewsite/businesses/lngandrlng.html

[73] http://petrofed.winwinhosting.net/upload/IAI/NGP/I_Mathur_GAIL.pdf