Summer Internship Report

on

Emerging Natural Gas Scenario in India- Issues and Prospects

In the Partial fulfillment of the requirement for the
Master of Business Administration in Oil & Gas management

Submitted by:
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SUMMER INTERNSHIP

Emerging Natural Gas Scenario in India-Issues and Prospects

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Certificate of Declaration

This is to certify that the project title "**Emerging Natural Gas Scenario in India-Issues and Prospects**" is a project carried out by **Velancia Reginald**, a student of MBA Oil and Gas Management, **University of Petroleum and Energy Studies** and is submitted in fulfillment of their summer internship project which is essential for the award of the Master's Degree in Business Administration from the University of Petroleum and Energy Studies. This report has not been submitted earlier in the company/University or any other Company/University/Institution and is an original work of the student.

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In the last but not least, I am greatly indebted to all the people associated with the project who gave me their kind guidance for the successful completion of the project.

With Sincere thanks,

Velancia Reginald

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EXECUTIVE SUMMARY

Issues in the natural gas sector in India was studied.The major issues that concern all the stakeholders are listed briefly,followed by possible solutions.For ease,the gas sector is classified into three streams namely upstream,midstream and downstream.In each,the issues and the possible way forward is sketched.The LNG regasification process is also described in detail.The organizational structure and the SWOT Analysis on the organization is also done.

1.About the Organization

Petronet LNG Limited (PLL) was formed as a joint venture company in 1998.Petronet LNG is at the forefront of India's all-out national drive to ensure the energy security in the years to come. Formed as a Joint Venture by the Government of India to import LNG and set up LNG terminals in the country, it involves India's leading oil and natural gas industry players.

1.1Promoters

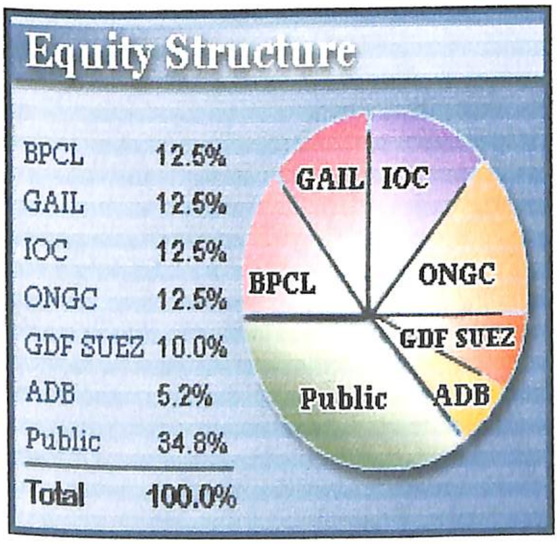
The promoters are GAIL (India) Limited (GAIL), Oil & Natural Gas Corporation Limited (ONGC), Indian Oil Corporation Limited (IOCL) and Bharat Petroleum Corporation Limited (BPCL). The authorized capital is Rs. 1,200 crore ($240 million).

1.2.Strategic Partner

GDF SUEZ, the largest importer of LNG in Europe for the last 30 years, is the strategic partner of the company and holds 10% equity in the company. GDF SUEZ, whose business covers every aspect of the gas supply chain, is recognized as a world leader. It has developed expertise in natural gas production, supply, transmission, liquefied natural gas (LNG), storage and distribution, and other applications.

1.3.Equity Structure

Four of the top public sector companies of the country's Hydrocarbon Sector viz. Oil and Natural Gas Corporation Limited (ONGC), Indian Oil Corporation Limited (IOCL), Bharat Petroleum Corporation Limited (BPCL) and GAIL (India) Limited have invested in Petronet LNG. Each has a 12.5% equity share, leading to a total of 50%. .
As per Articles of Association of the company, at any given point of time, not more than fifty percent (50%) of the company's share capital shall be held, whether directly or indirectly, by the Government, including any Government Company and Public Sector Undertaking. GDF SUEZ holds 10% and the Asian Development Bank (ADB), a member of the World Bank Group, holds 5.2% of the equity. The balance equity (34.8%) is held by the public.



1.4.Vision

To be a key energy provider to the nation by leveraging company's unique position in the LNG value chain along with an international presence.

1.5.Mission

Create and manage world class LNG infrastructure

Pursue synergetic business growth opportunities

Continue excellence in LNG business

Maximize value creation for the stakeholders

Maintain highest standards of business ethics and values

1.6 BUSINESS STRATEGY

- Create and manage world-class LNG infrastructure
- Pursue synergistic business opportunities
- Continue excellence in LNG business
    - Focus on higher capacity utilization and better operational efficiencies
    - Diversify LNG sources
- Diversify business
- Gas-based power generation
- Venture into city-gas distribution/ direct marketing to far-flung consumers
  Solid cargo port at Dahej
- Maintain highest standards of business ethics

2. LNG Terminals

2.1 DAHEJ LNG Terminal

The Company has set up South East Asia's first LNG Receiving and Regasification Terminal with an original capacity of 5 MMTPA at Dahej, Gujarat. The infrastructure was developed in the shortest possible time and at a benchmark cost. The capacity of the terminal has been expanded to 10 MMTPA and the same has been commissioned in June, 2009. The expansion involved construction of 2 additional LNG storage tanks and other vaporization facilities. The terminal is meeting around 20% of the total gas demand of the country.

2.2 Sourcing of LNG

The company has tied up 7.5 MMTPA of LNG with Ras Laffan Liquefied Natural Gas Co. Ltd(Ras Gas ,Qatar) on a long term basis. The company has also successfully signed an LNG SPA with Exxon Mobil Corporation for supply of approximately 1.5 MMTPA of LNG from the Gorgon LNG Project, Australia on a long term basis for the Kochi LNG terminal.

PLL is responsible for the arrangement of transportation of LNG from RasGas in Qatar to PLL's Regasification Terminal at Dahej. PLL signed Time Charter Agreements with the Consortium (Ship-owners) led by M/s. Mitsui OSK Lines Limited of Japan a leading company in LNG shipping business, for Time Charter of two LNG Tankers of 138,000 cu.m capacity each, and one LNG Tanker of 155,000 cu.m capacity for transportation of 7.5 MMTPA LNG from RasGas, Qatar to LNG Terminal at Dahej.

The first LNG Tanker - DISHA has been delivered on 9th January, 2004 followed by second LNG Tanker - RAAHI on 16th December 2004 and the Third LNG tanker 'Aseem' on 16th November 2009. The Tankers are regularly transporting LNG from Ras Laffan, Qatar to LNG Terminal, Dahej. These vessels are transporting contracted quantity 7.5 MMTPA of LNG. The Indian Shipping Company "The Shipping Corporation of India" (SCI) is a major equity partner in the Ship Owning companies. It is the largest shipping company of India. Both the LNG Tankers are now manned, managed / maintained and operated by SCI since December 2008. The third tanker is also managed by SCI from March 2013.

2.3 Port Operation at Dahej

PLL 's Port Operation Services are done by PSA Marine (Pt) Ltd., Singapore and Ocean Sparkle Ltd., India (Public Limited Company titled as M/s. Sealion Sparkle Port and Terminal Services (Dahej) Limited). The Port Operator owns and operates Tug Boats, Mooring Boat and Pilot Boat and undertakes safe towing, mooring & pilotage of the LNG Tankers and maintenance of jetty facilities at Dahej LNG terminal. The pilots engaged by Port Operator have thorough local knowledge and have undergone simulation training for smooth, safe and efficient berthing for larger Q Flex vessels also.

2.4 KOCHI LNG TERMINAL

The terminal shall have a capacity of 5 MMTPA. The terminal is in pre commissioning stage. The maiden commissioning cargo is expected in August,2013.The terminal at Kochi will help in meeting enormous demand of natural gas for Power, Fertilizers, Petrochemicals and various other industries in the Southern States. The Company will also supply LNG through road tankers to consumers under the brand name 'TARAL gas'.

2.5 Kochi Marine Facilities

The marine facilities of the terminal are being designed to handle LNG Tankers of size 65,000 CBM to 2, 16,000 CBM. Provisions are also kept to handle Qmax size LNG Tankers. Construction activities are progressing as per schedule.

2.6 Port Operation at Kochi

The competitive bidding process conducted by PLL for selection of port operator resulted in the selection of Ocean Sparkle Limited as the successful bidder. Ocean Sparkle Limited incorporated the Sparkle Port Services Limited (Port Operator) which shall provide the port operation services. PLL and Sparkle Port Services have executed Port Operation Services Agreement which is valid for a period of fifteen years. Services are expected to commence from 2nd quarter 2012. Port Operator shall own and operate four Tug Boats of 60 Ton bollard pull and one mooring boat cum pilot boat. Port Operator shall undertake safe towing & mooring of the LNG tankers and maintenance of jetty facilities at Kochi LNG Terminal. The pilots shall be engaged by Kochi Port Trust.

2.7 LNG Sourcing

7.5 MMTPA sourced through Long Term Contract with RasGas, Qatar with back to back sales arrangement with GAIL, IOCL & BPCL.

1.44 MMTPA LNG tied up from Exxon Mobil's Gorgon Venture in Australia.

Additional LNG being sourced through Spot /Short Term Contracts & sold to Offtakers/ Bulk Buyers.

2.8 RLNG Supply - Truck Loading

Truck Loading facility at Dahej terminal was commissioned in August 09, 2007 as a Pilot Project.

Currently about 4-5 trucks are loaded on daily basis & total of around 2000 trucks have been loaded till date.

Facility can handle 2500 loadings / Yr.

Presently LNG (by road tanker) is being sold to limited consumers in Western region.

Fast developing market with several new consumers (up to 800 KMS) are being lined up for off-take of LNG for industrial and city gas use.

2.9 Direct Marketing

Petronet plans to foray into Direct Marketing by focusing on the following areas:

Entered into direct RLNG marketing by signing HOA with bulk end consumer in Power producers, Industrial consumers , Fertilizers Producers etc

LNG/LCNG i.e. LNG through Trucks and supplies at LNG hubs, customer's premises in regions not serviced by pipelines.

LNG/RLNG trading on International and domestic platform.

The Hindustan Lifecare Ltd (HLL) and the Petronet LNG Ltd (PLL) signed an LNG Sales and Purchase Agreement (LNG SPA) in May,2013 for the supply of eight metric tonnes of LNG per day for a period of five years. The PLL would supply LNG by road tankers under the trade name 'Taral Gas' from its 5 million metric tonnes per annum (MMTPA) LNG terminal in Kochi to HLL plant in Thiruvananthapuram from January 2014.HLL is the first organisation in Kerala to avail of the benefits of LNG direct supplies and is the first direct customer of the PLL in the state.

2.10 Completed projects

LNG Terminal at Dahej

The company established South East Asia's first LNG receiving and re gasification terminal of 5 MMTPA capacity at Dahej,Gujarat,which is in operation since April 2004.The project was commissioned in a time period of thirty six months which is a record for a project of its magnitude and complexity.Petronet expanded capacity of Dahej Terminal to 10 MMTPA the year 2009-10.The Dahej expansion Project is a shining example of achieving low cost e expansion of an existing LNG terminal at a cost which is less than the phase I project cost. Dahej is the first base load LNG plant in the world that uses unique ambient air heater for re-gasification .This is a cost effective and eco friendly process compared to conventional ORV s(Open Rock Vaporizers),which use sea water as a media of vaporization. Dahej Terminal is connected to major trunk pipelines namely HBL,DUPL and GSPL.

Petronet is constructing another jetty at Dahej. The second jetty shall help attain higher operational efficiency and leverage enhanced capacity of Dahej LNG Terminal even beyond nameplate capacity of 10 MMTPA as well as serve as a risk mitigation measure, should the existing jetty may not be available for any reason. The second jetty is being handle the highest capacity LNG tankers currently available in the market i.e. Q max tankers having capacity of 260000 cubic meters.

PLL has received 1000 the Voyage at Dahej LNG terminal.

2.11 New Business Plans

Truck Loading Facility

In order to meet the requirement of consumers who do not have access to gas pipelines, a facility to supply LNG through cryogenic tankers by road has been set up at Dahej and is operating successfully for the last 5 years.Thus,India has joined an elite club of developed nations such as USA&Japan where LNG is being supplied by road tankers.Petronet LNG has plans to further increase its business of overland transportation of LNG.

Expansion of Dahej to 20 MMTPA

Petronet LNG Limited plans to expand Dahej Terminal to 20 MMTPA from existing 10 MMTPA capacity for which FEED study and other pre project activities are under progress.

Solid Cargo Port at Dahej

Petronet LNG Limited with Adani formed a (24:76) joint venture company,Adani (Petronet) Dahej Ltd. For setting up a solid cargo port in Dahej SEZ, Gujarat. The first phase of the project has been completed .The solid cargo port has the facility to import/export coal,steel,fertilizers etc.

Power Generation

Petronet LNG plans to go for integration of LNG value chain by entering into high demand Power Sector by setting up Power Plants in Dahej and Kochi.To begin with,the company plans to set up a 1200 MW power plant at Dahej,for which the feasibility study and other preliminary activities are already under progress.The company will be able to generate 8-10% higher power from its plants by harnessing the cold energy of LNG.**Third LNG terminal**

Petronet LNG Limited (PLL) signed a firm and binding term sheet for developing a land based LNG Terminal at Gangavaram Port, Andhra Pradesh with a capacity of 5.0 MMTPA with Gangavaram Port Limited (GPL), on east coast of India.

Liquid Nitrogen Production

Petronet LNG is planning to put up facilities,in collaboration with a strategic partner to produce liquid gases (Nitrogen,Oxygen) by harnessing the cold available from Dahej and Kochi LNG terminals.The company is in the process of selecting strategic partner and perform pre project activities.

3. SWOT Analysis

Strengths:

- **Developing economy:** The demand for natural gas products has traced the economic growth of the country. Petronet would also benefit from the same because of increased demand of LNG due to a growing economy.
- Strong promoters which are amongst the primary energy producers and suppliers in the country. The promoters include GAIL (India) Limited, Oil & Natural Gas Corporation Limited (ONGC), Indian Oil Corporation Limited (IOCL) and Bharat Petroleum Corporation Limited (BPCL).
- New Gas discoveries within the country
- Lower fixed costs involved and higher gestation period involved in the development

Weakness:

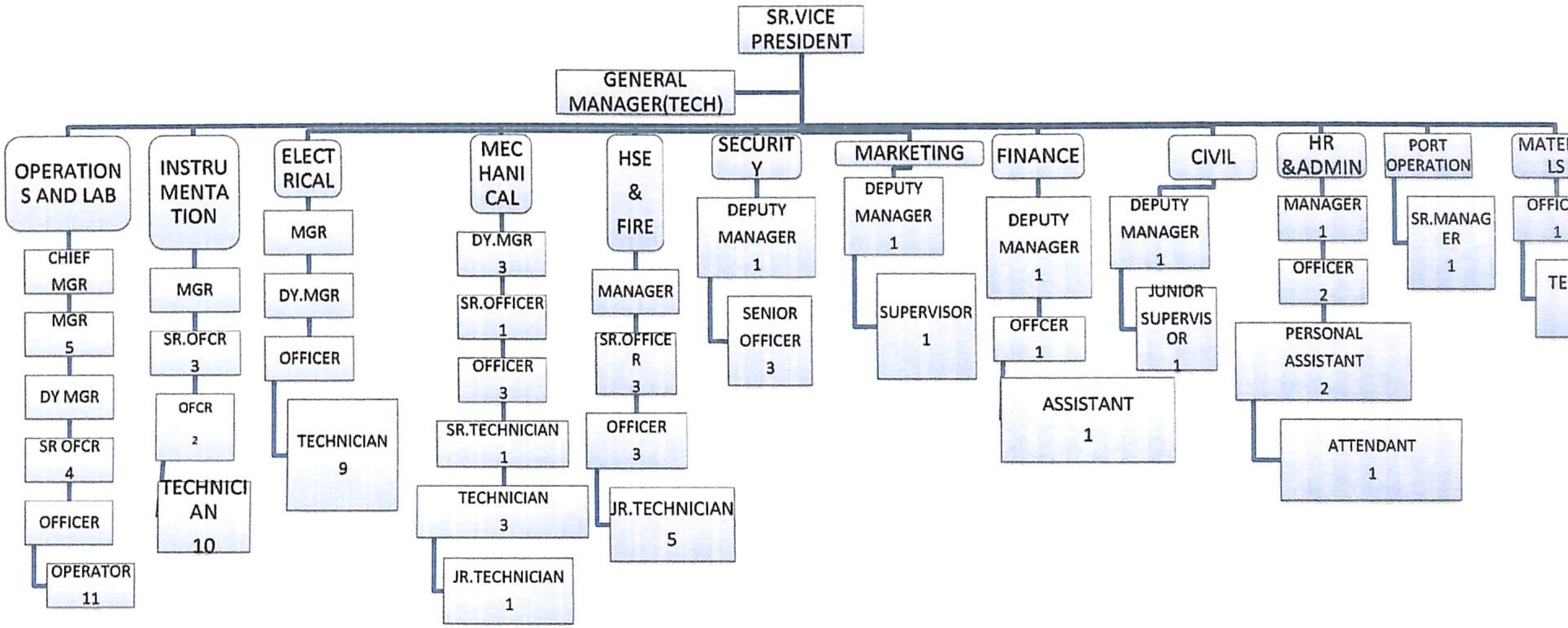
- Absence of policies and regulatory clarity on issues related to pricing and infrastructure development.
- Uncertainty in the price of gas in the domestic and global markets.
- Very high dependence on imports, over 70%.
- India don't have a national gas grid .
- Delay in the laying of phase II pipelines to Mangalore and Bangalore.

Opportunities:

- India is a country which faces huge peak energy deficit , LNG is been increasingly used as an substitute
- Emerging glut in LNG market
- Indian economic boom offers opportunities unbound in LNG industry
- Natural gas usage is increasing , due to high prices of coal and oil
- Another good opportunity for Petronet LNG is it can expand into other segments like CNG usage of CNG is also increasing. With the presence of a huge receiving and regasification terminal it would be easier for Petronet to develop in other natural gas segments .
- Also its promoter ONGC and IOCL are into upstream and production activities , Petronet can accumulate a good reserve of equity gas.

Threats:

- Increasing competition in the LNG segment like Asian Petro products and exports ltd, DCW ltd etc.
- Reluctance of power companies to pay market price
- Increasing alternative use of natural gas like city gas distribution and for other purposes makes LNG less attractive
- Regulations and government policies
- Advanced coal based technologies, Shale gas , Coal bed methane may reduce the use of LNG.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GENERAL MANAGER(TECH)
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CHIEF MGR
MGR 5
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OFFICER
OPERATOR 11
INSTRUMENTATION
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JR.TECHNICIAN 5
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SENIOR OFFICER 3
MARKETING
DEPUTY MANAGER 1
SUPERVISOR 1
FINANCE
DEPUTY MANAGER 1
OFFCER 1
ASSISTANT 1
CIVIL
DEPUTY MANAGER 1
JUNIOR SUPERVISOR 1
HR &ADMIN
MANAGER 1
OFFICER 2
PERSONAL ASSISTANT 2
ATTENDANT 1
PORT OPERATION
SR.MANAGER 1
MATERI LS
OFFICE 1
TEC

4.PROCESS DESCRIPTION

The overall process can be divided into eight main sections:

LNG tanker unloading system

LNG storage system

LNG Holding/Recirculation System

BOG/displaced vapor system

LNG send-out system

Cold recovery system

Heat recovery system

Flare system

Truck loading facility

For utility and other supporting systems, the description can be outlined as below:

Service water system

Potable water System

Glycol water draining system

Fire protection system

Condensate water system

Instrument and plant air system

Nitrogen system

Power generation and distribution system

Fuel gas system

Diesel oil system

Hot water draining system

4.1 DESCRIPTION OF PROCESS UNITS

LNG Tanker Unloading System

The facility is designed to unload only one tanker of 65,000 to 216,000 m^3 capacity at a time. The arrival pressure of the ship will be considered at minimum saturation pressure of 0.15 kg/cm^2 g. The design unloading flow rate for LNG is considered as 15,000 m^3/h (max).

The LNG will be pumped via the ship's pumps, which will transfer LNG into the on –shore LNG Storage Tanks. Space for third LNG tank and additional equipments for augmenting capacity to 5.0 MMTPA will be provided. Tie-in for hook-up of additional equipment / piping with the existing facility will be provided to avoid any shut down at the time of augmenting capacity. The delivered LNG will be unloaded from the tanker through three 20" x 16" LNG Unloading Arms. The LNG discharged from the tanker unloading arms will be directed through 38" main pipe headers from ship to the storage tanks. There will also be 4" pipe line for jetty circulation from unloading arm to BOG recondenser or LNG Storage Tank .

Prior to the ship's arrival at the terminal, the pressure of the storage tanks could be decreased as low as possible. The pressure in the ship's cargo tank is 0.15 kg/cm^2 g. This enables the boil-off gas from the ship to pass to the tanks via the Vapor Return Arm before the unloading operation begins. This will cool down the vapor return arm and vapor return header, which are close to ambient temperature before the arrival of the ship. As the unloading of LNG starts, pressure in the tank will be allowed to rise to 0.25 kg/cm^2 g and vapor dispatched by LNG will be returned to the ship via 24" vapor return line.

During ship unloading, the heat input into the system consists of heat of pumping as well as ambient heat leak. In order to effectively suppress the vapor that would ordinarily be generated due to this input, the storage tanks will be operated at a pressure higher about 0.1 kg/cm^2 than the pressure in the ship. This allows the heat input of the system to manifest itself as a sensible heat increase of the LNG. The actual operating pressure of the storage tank during ship unloading will depend, to a certain extent, upon the environmental condition at the time of unloading and by the pressure difference between tank and ship required to drive the flow of vapor needed to maintain pressure in the ship's cargo tanks.

The operating sequence during ship unloading is described as follows: At the beginning of the unloading operation, LNG from the ship is used to cool down the unloading arms and auxiliary equipment .Once the cool-down operation has been completed, the LNG pumping rate will be increased until the design flow rate is obtained. The unloading operation will continue until the LNG tanker is almost empty and the LNG pumping rates must be decreased.

LNG Storage System

Two full containment LNG Storage Tanks of 155,000 m3 (net capacity) stored capacity each are to be installed Adequate space shall be allocated for the addition of a third tank of similar capacity in future. Each storage tank shall be provided with three 60% (for 2.5 MMTPA) capacity column mounted submerged pumps (LNG In-Tank Pumps.) to deliver the product to the vaporization system Initially two pumps will be in operation for send out of 2.5 MMTPA

When the terminal capacity is increased to 5.0 MMTPA one more pump of similar capacity shall be added to each tank. During the holding mode of operation, when a ship is not unloading, a portion of the flow from these pumps is to be routed to the Jetty to maintain the unloading lines and piping to the storage tanks at cryogenic temperatures. The return flow from the Jetty is directed to recondenser. Two spare pump-wells will be provided in the storage tanks for future capacity expansion.

Each tank is to be provided with top and bottom filling options to unload product into the tanks considering the density of the product in the tank and that received from the ship. To constantly monitor the performance and the operating conditions of the tank, level / density / temperature measurement devices are to be installed in each tank.

LNG Holding/Recirculation System

Two 155,000 m3 (net capacity) full containment LNG Storage Tanks are considered. The tanks have a design pressure of 0.295 kg/cm2g and a specified heat leakage rate of 0.08 vol% per day of the tank contents based on a full tank of liquid methane Connections to the tank for filling and emptying will be made through the tank roof.

Provisions have been made in the design for top as well as bottom unloading into the storage tanks. The bottom loading will be accomplished using a standpipe inside the tank. The top loading will be carried out using separate piping connections in the top of the LNG tank.

During ship unloading operation, LNG from the ship will pass through the unloading line and the recirculation line to keep them cool. LNG cold recirculation from LNG storage tank is not required during this operation therefore XV-1803 and XV-2002 are closed for this purpose When there is no ship unloading and the terminal is in holding mode, a part of the LNG from the tank send-out pumps is required for cooling down the jetty area. The LNG will be circulated through the 38" unloading line to the jetty and back through the 4" recirculation line to maintain the lines cold .A part of the recirculated LNG also flows to the 36" tank inlet lines to maintain them cold. The remaining LNG flows to the jetty and the recirculated fluid is sent back to the recondenser. Small bypass flows of LNG are circulated through all liquid lines to maintain cold pipe temperatures when they are not in use.

BOG/Displaced Vapor System

BOG from the storage tanks is routed via 26" line then combined into the 30" boil-off gas header. The 20" pipe line connects the header to BOG Suction Knock Out Drum . The BOG flows from knock out drum through 20" header and 16" pipe line to each BOG compressor. The boil-off gas header balances the pressures between the two tanks. The header pipe line also connects the storage tank to ship vapor return line, flare stack, and BOG compressor.

During normal operation (no ship unloading), a single reciprocating BOG compressor with rated capacity at around 11,530 kg/h (include 20% overdesign margin plus additional safety margin) is used to handle the normal BOG generated in the terminal. During the unloading operation both BOG compressors are able to handle the boil-off gas.

During ship unloading, LNG is pumped out of the ship's cargo tanks at a rate of maximum 15,000 m3/h to the storage tanks. Displaced gas will be returned to the ship's cargo tanks using the vapor return arm. The rate of vapor return is reduced from the volumetric equivalent of unloading rate into the tank by the ship's boil off (0.15 vol%/day) and the pump out from the tanks.

Excess boil-off/displaced gas after allowing for ship vapor return, is compressed by the BOG compressors before being passed to the BOG Recondenser where the compressed BOG is condensed by subcooled LNG. A BOG Desuperheater located at the upstream of the BOG Compressor Suction Knockout Drum is provided for cooling down the BOG gas (possible from make-up gas) to ensure the compressor suction temperature is below (-)110 °C at high BOG temperature.

LNG Send-out System

LNG from the storage tanks is pumped by LNG In-tank Pumps at rated capacity of 385 m3/h each. Part of the pumped flow can be sent to an LNG truck loading station. The main flow is sent to the HP send-out pumps and the vaporizers. From the storage tanks, LNG is pumped via the 18" send-out header pipe line to the recondenser. The LNG flow is split into two streams. One stream is routed to a recondenser where it is put in contact with compressed boil-off gas. The rest of the flow bypasses the recondenser In the recondenser, compressed BOG is condensed into the 4 °C sub-cooled send-out LNG.

The recondenser acts as a liquid hold-up vessel for the HP pumps. It is designed to maintain three minutes of hold up time based on the maximum send out corresponding to 5.0 MMTPA. The LNG inlet control valve is controlled by the ratio of BOG and LNG quench flow into the recondenser with pressure feed back control adjustment. If the recondenser pressure starts to rise, the ratio adjustment is increased to increase LNG quench flow. Meanwhile if the recondenser pressure starts to fall, this adjustment is decreased, thus decreasing LNG quench flow. A DCS switch is provided for operator to allow feed forward ratio control to be bypassed with direct pressure feedback control .The LNG from the recondenser is directed to the LNG HP Pumps , which discharge the LNG to the vaporizers at rated capacity of 409 m3/h each. The HP pumps are provided with a kickback header to ensure a minimum flow through the pumps.

There are two type of vaporizers used. They are Shell and Tube Vaporizers (STV) and Submerged Combustion Vaporizer (SCV). For normal operation, two STVs with design capacity of 173.8 t/h each shall be provided in the terminal. LNG inlet temperature is around (-)150 °C. The LNG is vaporized to reach temperature condition not less than 5 °C at the battery limit. Heat source is provided from glycol water (GW) 36% (by WT.) flowing in the shell side. GW is circulated through the STVs by GW Pumps (P-0301A/B). GW enters the STVs at a temperature of 16 °C and the exit temperature is estimated at 2 °C. The heat exchangers shall be specially designed for LNG cryogenic services.

During maintenance or outage in the two STVs, an addition of SCV with design capacity of 173.8 t/h is provided as backup. SCV is a water bath type LNG vaporizer. Heat source is from hot water at temperature range of 20-40 °C which is heated by direct burning of fuel gas (natural gas). When any case of very low ambient temperature happened, this SCV shall also be used as backup to produce natural gas (NG) at 5 °C.

Third STV which capacity depends on the maximum heat recovery of 23,600 kW usually will be brought on line to save excessive energy (exhaust hot flue gas) from combustion of fuel gas or diesel oil in Gas Turbine Generator (GTG). Since the GTG is the main power source of the terminal, therefore at least one unit of GTG will be in operation. The main principle is utilizing the hot flue gas to heat up the glycol water by means of hot water. Flue gas can be used as the heat source in Cogeneration Heat Exchanger to heat up the hot water up to 152 °C. The heat then will be transferred to glycol water in glycol water (GW) / hot water (HW) Heat Exchanger .The hot glycol water at 90 °C from GW/HW exchanger will be used to vaporize LNG in the third STV. Applying waste heat recovery unit to vaporize LNG will save the power consumption instead of running air heater fan motor which is used in first or second STV loop.

Natural gas (NG) will be finally sent to ultrasonic metering station before being conveyed to the gas pipeline. All the parameters including pressure, temperature and flow rate of NG sendout will be detected and recorded accurately In the metering facility. A provision for meter facility is to ensure the accuracy of metering station after certain period of time. A pipeline pressure controller cascades the vaporizer inlet flow controller to reduce the flow in case of rise in pressure due to reduction in gas take-off from the pipeline. Finally through the main pipe line, NG is sent and distributed to users. NG is delivered at pressure ranging from 50 to 90 kg/cm2 g and 5 °C (min) condition in the terminal battery limit.

<u>Cold Recovery System</u>

The cold energy taken by the glycol water (GW) solution by vaporizing LNG in the STV is utilized to chill down the water required for various facilities like Heating Ventilating Air Conditioning (HVAC) system installed in composite buildings, control room and substation, GTG hall and control building, laboratory building, etc. Chilled water (CW) is also required by nitrogen plant, CW / cooling water (COW) Heat Exchanger (E-0710). The detail of CW consumer and its consumption list can be found in "Sizing calculation of equipment (utility) chilled / cooling water system".

Cold recovery system consists of GW/CW Heat Exchanger, CW Expansion Tank, CW / COW Heat Exchanger and CW Pumps . Cold GW return from the vaporizer at 2 °C is used as cooling medium to cool down CW from 12 to 5 °C in GW/CW Heat Exchanger (E-0351). Chilled water will be distributed by three chilled water pumps (two operating and one standby) with normal capacity of 268 m3/h each to users as shown as follows:

- Composite building

- Main control room

- GTG hall and control building

-Main substation

-Laboratory building

-Maintenance building

-Fire station building

-Operator room in fire water pump house

-Nitrogen Generation Package (U-0801)

-Jetty control room

-Maritime guard house

-Chilled water / Cooling water Heat Exchanger (E-0710)

Heat Recovery System

The Cogeneration Heat Exchangers shall be installed in flue gas duct of GTG . The heat recovered tn these exchangers is transferred to hot water (HW). The duty of cogeneration heat exchangers will be maximum of 11.800 kW per exchanger HW will enter the exchangers at 100 "C and exit at 152 °C.

HW will transfer its heat to GW in HW/GW Heat Exchanger at max. rate of 387.7 t/h (depends on load and numbers of GTG in operation) HW will exit at about 100 "C. GW finally will transfer the heat to LNG for vaporization in STV .

The HW recovery system shall include one HW Expansion Vessel, HW Pumps , HW/GW Heat Exchanger and the Cogeneration Heat Exchanger . The HW expansion vessel shall be pressurized to about 5 kg/cm2 g with nitrogen to maintain pressure above vapor pressure.

Flare System

A disposal system is provided to safely relieve any excess gas from the storage tank area. This piping system will be manifolded and pressure controlled such that any excess gas will be sent to the flare system before the storage tank safety valves relieve.

The flare system shall be designed to collect any relief from recondenser and compressor including any blow down from LNG tanks, vaporizers, etc. The following systems shall be connected to flare header:

- Relief from BOG Compressors

-Relief from fuel gas system

-Blow down from LNG vaporizers (SCV and STV)

-Blow down from LNG tank vapor system

-Blow down from NG send-out header

Single flare stack complete with flare tip and Flame Front Generator (FFG) will be designed based on maximum load capacity. However the relief from the following system shall be released to atmosphere to avoid unnecessary increase of flare load:

- Relief from SCV and STV

- Relief from LNG tanks

- Relief from NG send-out header

Smokeless combustion operation is up to 10% of emergency release. However, no assist media is provided for smokeless combustion purpose.

Truck Loading Facility

LNG send-out via truck to users is provided as well. A space is to be provided for truck loading service. One truck loading scale is designed to load around 15,000 kg of LNG per truck. LNG Truck Loading Arm and Truck Return Gas Arm each of 3" will be in service of truck loading facility. One 4 m x 4 m operator cabin for truck loading Is erected nearby the weighbridge This cabin is used as place for operator locally monitoring the whole truck loading activities including the preparation and end operation. Operator should be able to control the batch loading process from the cabin Another extra loading bay shall be also provided in the future.

Prior to the loading of LNG, each empty truck should be measured its weight as the basis in the weighbridge. L-0111 and L-0112 shall be ensured connecting to the truck before the loading work. During loading, the flow indicator FI-3991 is used as basis for controlling and monitoring the loading rate. The loading process is completely a batch process with supervision by operator. After the loading work, the final weight of truck shall be measured once again to determine the quantity of LNG inside the tanker.

When truck loading facility is idle, valves should be closed for safety reason and only LNG cold recirculation is allowed. LNG supplied from the intank pump will flow through recirculation line and back to the tank to keep the recirculation line in chilled condition. Skin temperature measurement is provided on 6" recirculation line for easy monitoring the LNG recirculation.

4.2 DESCRIPTION OF UTILITY AND OTHER SUPPORTING UNITS

Service Water System

Service water is required for utility hose stations. The source of service water is pumped out from the collection pit of condensate water. The pit collects any falling condensed water on outer surface of tube side air heaters. The condensate water will flow to fire water reservoir I and II and overflow from these two compartments to service water compartment. The collected service water flows to sump pit and filtered by a series of mesh filter. Service Water Pumps will transport the service water at rated capacity of 33 m3/h to treatment package before delivered to header pipe line and distributed to each user.

Potable Water System

Potable water source is rain water collected from top roof of both two LNG tanks and routed to Raw Water Storage Tank via 24" pipeline by gravity flow. Piping routine is then branched out to ditch and inlet to raw water tank. The piping inlet is reduced to 10" and in line with open funnel equipped with insect protection net. The valve in 10" piping inlet routine can be closed once the tank is full. As an alternative source, the LNG terminal have the option to receive water through barge at the location of the tug berth. Barge carrying water will be anchored at the tug berth and water will be pumped to the LNG plant by means of a pipeline using barge pumps. Water from barges will be stored in Fire Water Reservoir-I and II or Raw Water Storage Tank . The pipeline from the barge pump to the LNG terminal will be laid underground with suitable anti-corrosive protection. A layer of non-woven geotextile will also be provided below the underground piping. The capacity of water tank in the barge should be 200 m3 with rated flow capacity of 75 m3/h. It would take about 2-3 hours to deliver the water to the terminal. The raw water can also be brought from local municipal source by pipeline up to the plant battery limit.

Raw water is filtered and treated before stored in potable water storage Tank. Raw water Pumps deliver raw water through Potable Water Supply Filter and Chlorination Package to potable water storage tank. The potable water then pumped to Potable Water Overhead Tank before distributed to user by gravity such as composite buildings, guard house, jetty toilet house, etc.

Glycol Water Draining System

Demineralized water (DM water) and ethylene glycol will be unloaded from truck to Glycol Water Drain Drum one by one and this will be transferred to GW Tank by GW Drain Pump. Firstly, all the DM water will be introduced to drum.. While introducing the DM water, Pump can be started to create circulation. After establishing stable circulation, ethylene glycol will slowly be added into drum. Continuous circulation will be maintained to achieve 36 wt% glycol water (GW) solution. The concentration of GW solution will be periodically analyzed. The homogeneous GW solution will then be transferred to fill the GW loop. Glycol water drain drum also has purpose of collecting each GW drain line from LNG vaporizers. Some of the GW is also stored in GW Tank. GW tank is designed to collect the draining volume of one GW loop only, GW Drain Pump can transfer back GW both to GW tank and GW circulation loop for LNG vaporizers.

Fire Protection System

The Fire Protection system shall be designed and provided as per Tariff Advisory Committee (TAC) requirement, Oil Industry Safety Directorate (OISD) requirement, international codes and general practices.

The system consist of fire water system, foam system, dry chemical powder system, portable & wheeled extinguisher, mobile fire fighting equipments/tenders, clean agent system etc. Fire water source is from condensed water collected in Air Heater Condensate Water Collection Pit. Fire water is collected in a Fire & Service Water Reservoir with two compartments separated by concrete wall. The fire water distribution system delivers fire water to hydrants, indoor hose cabinets, water spray system, and high expansion foam system.

Condensate water will be delivered continuously to two identical compartments of fire water reservoir to ensure that fire water reservoir is always full at all time. The overflow weir from fire water reservoir is routed to service water reservoir. Condensate Water Transfer Pump will be stopped once the service water reservoir reaches high liquid level. The ditch channel from service water reservoir overflow will be provided as well. Water make up will be added in certain period of time by purchasing water from water barge.The pH value of condensate water is measured and monitored. Chemical dosing is provided to keep the pH value in the range of 6.5 to 7.

Instrument ând Plant Air System

Instrument air with dew point of (-)40 °C at atmospheric pressure is used throughout the LNG terminal as the medium for pneumatic instruments, ignition air for flare pilots and as feed air to nitrogen generation units. Plant air is also used for pneumatic tools and air driven pumps through hose stations Instrument air is compressed and dried through air dryer. The instrument air is distributed at a nominal pressure of 8.0 kg/cm2g.

Nitrogen System

Nitrogen Generation Package consists of one 100% capacity air separation unit (ASU), two liquid nitrogen storage vessels and two units of 100% natural draft nitrogen vaporizer. Instrument air is fed as the raw material for the preparation of nitrogen. ASU will separate nitrogen from the air and produce both gaseous and liquefied nitrogen with less than 100 ppm oxygen. The gaseous nitrogen can be directly supplied to the nitrogen distribution network, meanwhile the liquid phase nitrogen is stored in two nitrogen vessels. The vessels are designed to hold the nitrogen required for normal operation in the terminal including ship off loading every 4 5 days with nitrogen supply header pressure maintained at 6 5 kg/cm2 g for a total of 7 days with no incoming feed nitrogen production These two vessels have design capacity of 40 m3 each. Upon using the liquid phase nitrogen, it needs to be vaporized in nitrogen vaporizer and then sent to the nitrogen distribution network

Power Generation System

The captive power plant (CPP) is designed with the power generation system in the LNG terminal It is designed to meet the performance guarantee value. Total terminal power consumption required shall be less than or equal to 10,700 kW based on 100% nominal send out flow rate at operating pressure of 90 kg/cm2 g and operating temperature of 5 °C at the battery limit of the facilities with ship unloading at a rate of 15.000 m3/h at ambient condition: and shall be less than equal to 9,400 kW based on 100% nominal send out flow rate at the same criteria as mentioned above in the battery limit with no ship unloading at the ambient condition. The power generation system consists of three gas turbine generators and Chlorination Package to potable water storage tank. The potable water then pumped to Potable Water Overhead Tank before distributed to user by gravity such as composite buildings, guard house, jetty toilet house, etc.

Fuel Gas System

Send-out NG is used as fuel gas on the regas facility. The NG is taken at the upstream of the metering stations. The fuel gas which temperature is reduced at around (-)34.5 °C due to pressure let down from 90 to 26.5 kg/cm2 g, is heated by Fuel Gas Air Heaters and maintained the exit temperature between 5 ~ 15 °C.

The heated fuel gas at 26 kg/cm2 g will be supplied to the gas turbine generators and other fuel gas users on the regas facility such as flare pilot, SCV, and canteen. Besides the send out and fuel gas part, some portion of NG is also routed to the recondenser and the tanks for intermittent make-up as required for maintaining the pressure of recondenser and tank system.

Diesel Oil System

Diesel oil is supplied from outside by truck unloading arrangement. The connection is located at the suction line of the Diesel Oil Pumps. Diesel oil is pumped and stored in the Diesel Oil Tank .The drain shall be collected and periodically disposed off using portable hand driven pump for drum filling. The diesel oil pump will also supply diesel oil to users such as Fire Water Pumps , two units of Gas Turbine Generators and Emergency Generator.

Hot Water Draining System

Hot water draining system is used as facility for adding make up hot water to the hot water system or drain hot water back to Hot Water Drain Collection Pit. Demineralized water (DM water) will be unloaded from truck to Hot Water Drain Collection Pit and will be transferred to Hot Water Expansion Vessel and hot water loop by Hot Water Drain Pump. The net capacity of Hot Water Drain Collection Pit is 47.74 m3, which is sufficient to accommodate the total volume of hot water in the system.

5.KOCHI TERMINAL

The first contract for the construction of the LNG terminal at Kochi was awarded on 1 st June, 2008.

The main contractors are:

Storage Tank-IHI,Japan.

Regasification unit and Utilities- CTCI,Taiwan.

Marine Facilities-Afcons Infra Ltd

Admin Building Construction-MARG Lt

DEPARTMENTS

The various departments in PLL ,Kochi are

Operations

Mechanical

Civil

Electrical

Instrumentation

Hse

Retail Marketing

Hr

Finance

Laboratory

5.1 Operations

The operations department is concerned with the plant operations right from unloading,storage to regasification and transmission.The ambient air heaters,heat exchangs,nitrogen plant are all monitored.The equipments are automated and the operations are monitored in the Main Control Room using DCS.

The department has a laboratory that takes the gas samples and analyses the composition using gas chromatographs.TCD and FPD types of GC's are available.Analysis of the

Acquisition sample and Master sample are done.Water analysis is also done for the chilled water system,cooling tower and potable water system.Stack monitoring is outsourced .Regular ambient air monitoring is done.

5.2 Mechanical

The department looked after project management and construction management during the construction phase of the plant.Operation and Maintenance activities are being looked into.The department coordinates with the PMC Contractor and inspects the installations,checks for quality standards ,accepts,rejects or recommends changes.The department is now receiving stocks from the contractor , also purchasing and procuring supplies for future maintenance schedules.Maintenance schedules for the future are being planned.Service orders will be given for the complex maintenance systems like gas turbines,unloading arms.

5.3 Electrical

The department is into operation and maintenance.There are three sources of power.KSEB supplies 11 Kv power with a maximum output of 2.9 mva.There is a captive power generation system with 3 gas turbines.of these,2 are dual fuel type(gas/diesel).There is also a third emergency diesel generator.At 100% load,the plant requires 15 MW.

5.4 HSE

PLL has established Health,Safety and Environment department to ensure safe and environment friendly practices during plant operations.The department gives safety induction,refresher programs,conducts mock drills,hazard reporting,conducts awareness and motivation programs for employees,internal and external safety audits,safety inspecaittion which includes ambient air testing as well as sound testing.

The department also does work dealing with statuary bodies.Accident and Near miss investigation and reporting is done.Procuring and monitoring the stock of Personal Protective Equipment is also done.Emergency Response Plan and Monitoring is also handled by the department.

PLL has established Occupational Health Centre with basic facilities and manpower to cater for emergency and normal medical needs.

5.5 Retail Marketing

There is a retail marketing team working on the direct marketing of LNG through trucks to end customers, under the brand name TARAL GAS.

6.INTRODUCTION

With only one carbon and four hydrogen atoms per molecule, Natural Gas has the lowest carbon to hydrogen ratio, hence it burns completely, making it the cleanest of fossil fuels. Natural Gas satisfies most of the requirements for fuel in a modern day industrial society, being efficient, non-polluting and relatively economical. The periodic uncertainties and volatility in both the price and supply of oil, have also helped Natural Gas emerge as a major fuel in the energy basket across countries.

Table 1: Sector wise usage of Natural Gas.

Sector	Usage
Generation of electricity by utilities	As fuel for base load power plants In combined cycle/co-generation power plants
Fertilizer Industry	As feed stock in the production of ammonia and urea
Industrial	As an under boiler fuel for raising steam As fuel in furnaces and heating applications
Domestic and commercial	For heating of spaces and water For cooking
Automotive	As a non-polluting fuel
Petrochemicals	As the raw material from which a variety of chemical products e.g. methanol, are derived

Natural Gas comes in 4 basic forms:

Liquefied Natural Gas, LNG - Natural Gas which has been liquefied at -160 C. Natural Gas is liquefied to facilitate transportation in cryogenic tankers across sea

Re-gasified Liquefied Natural Gas -RLNG -

Compressed Natural gas, CNG - Natural Gas compressed to a pressure of 200-250 kg/cm2 used as fuel for transportation, CNG decreases vehicular pollution

Piped Natural gas, PNG - Natural Gas distributed through a pipeline network that has safety valves to maintain the pressure assuring safe, uninterrupted supply to the domestic sector.

In terms of Natural Gas, India has 1,241 billion cubic meters (bcm) of proven and indicated reserves, which is 0.6 percent of the world's total proven gas reserves. At the existing production levels of 50.9 bcm per year, the country has a Gas R/P ratio of ~ 26.9 years.

Natural gas constitutes around 10 percent of India's total primary energy basket, which is well below the world average of 23.7 percent in 2011. As per estimates from Ministry of Petroleum and Natural Gas, by 2025, the share of natural gas in India's energy basket is likely to reach 20 percent. The increased consumption of natural gas is expected to be fed both by increased domestic production and import of natural gas.

Table 2: Primary Energy Mix

Fuel Type	Percent
Coal	52.9
Oil	29
Natural Gas	9.8
Hydro	5.3
Renewables	1.6
Nuclear	1.3

Source: BP Statistical Review 2012

Over the last two decades India's primary energy mix has not changed much. The country continues to depend, for most of its energy needs, on coal and oil . However, natural gas is emerging as one of the fastest-growing fuels. Currently, it accounts for 9.8% of the total primary energy consumption. As per the World Energy Outlook 2011, IEA has projected India's energy demand in 2035 at 1,464 MMtoe. The respective shares of coal, oil and natural gas are42%, 24% and 11%, respectively. Nuclear, hydro and renewable sources put together would account for just 7%.Therefore, fossil fuels are expected to continue fuelling country's economic growth. Given the increased awareness amongst countries to reduce the carbon footprint of the energy industry, oil and gas are expected to play significant role. Natural gas, with its inherent advantages over other alternatives, is expected to emerge as the preferred fuel. Recent gas discoveries have provided encouraging results for the country and with optimum policy stimulus it is expected that India would substantially increase its domestic gas production. The country will continue to depend on biomass and waste consumed in rural and semi-urban areas, where access to energy remains a challenge. This is a significant portion of the total energy mix and indicates the potential for substitution by other primary energy fuel.

Natural gas has always been a supply-constraint market in India. The most prolific gas producing fields include Bombay High which is operated by ONGC and contributed ~34% of the total gas production in 2011-12, KG-D6 offshore which is operated by Reliance Industries Ltd and contributed ~33% of the total gas production in 2011-12. The total offshore gas production accounts for 88% of the total production in India. The share of the private sector and JVs in the country's total gas production is expected to increase, owing to recent gas discoveries expected to be monetised by the companies. The CBM production grew more than 100% over the last year and currently stands at little over 80 MMSCM (2.8BCF) per annum. CBM production is expected to increase over the years on account of the monetisation of discoveries made by Essar Oil Ltd and Reliance Industries Ltd (RIL).

In 2004, RasGas, Qatar delivered India's inaugural LNG parcel to its first LNG re-gasification terminal set up at Dahej, Gujarat by Petronet LNG Ltd. In April 2005, Shell commissioned India's second LNG re-gasification terminal at Hazira, Gujarat.

Going forward, it is expected that the gap between natural gas demand and domestic gas production will increase to88 BCM3 (3.1 TCF) by 2015, indicating the potential for LNG imports. According to supply projections for the XII and XIII Five Year Plan, the re-gasification capacity in India is expected to increase from current 18.4 BCM (0.6 TCF) to 27 BCM (1.0 TCF) by2013 and around 95 BCM (3.4 TCF) by 2017.

Table 3: LNG imports

Year	Unit	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
LNG imports	MMT	0.25	2.5	5.06	6.81	8.25	7.96	8.92	8.86	10.13
	TBTU	12.68	128.35	256.62	352.5	425.1	410.3	459.95	459.95	524.95

Source: PPAC

Over the 12th Five-Year Plan period, a major proportion of growth in demand is likely to come from the power and fertilizer sectors. Power sector consumption, which is currently at 61 mmscmd, is projected to translate into a demand of 207 mmscmd by 2016-17, while the current fertilizer consumption of 37 mmscmd is projected to translate into a demand of 106 mmscmd by 2014-15and stay at that level thereafter. These demand projections are highly prices sensitive. Other sectors, which are relatively price-insensitive and which currently consume around 68 mmscmd, will translate into a demand of 153 mmscmd by 2016-17. The total demand is likely to grow from 166 mmscmd currently to 466 mmscmd in 2016-17, with a compound annual growth rate of 18.75%.

Table 4:Sector-wise Demand of Gas during the 12th Five-Year Plan

Sector	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017
Power	135	153	171	189	207
Fertilizer	55	61	106	106	106
City gas	15	19	24	39	46
Petrochemicals/refineries	54	61	67	72	72
Sponge iron/steel	7	8	8	8	8
Total demand	286	322	398	439	466

Source: Rangarajan Committee Report

Table 5: Supply of gas from all sources during 2011-2012

Source	Qty mmscmd
APM	50.64
Non APM	7.45
NELP	42.41
Other domestic JV	14.01
RLNG	39.62
CBM	0.20
Total	154.43

Source: Rangarajan Committee Report

6.1MARKETING OF GAS

The Indian gas market is predominantly monopolistic in its operation due to a huge demand & supply gap. There are only a few producers whereas the number of consumers is large and they have a huge demand. Price is administratively determined for each source of supply. The gas market is still in a growing phase and it will be many years before the demand-supply gap is bridged. Gas produced in India by NOCs from fields which were awarded to them on nomination basis (called APM gas) is allocated to priority sectors identified by the government. These priority sectors include fertiliser, power, city gas distribution (CGD) projects and other small-scale units.. For gas produced under NELP by RIL, the government constituted an EGoM, which decided the marketing priority of gas to be produced from RIL's field, keeping in view the larger public interest.

Table 6: Natural gas demand supply trend

MMSCMD	2009-2010 E	2014-2015 P	CAGR
Demand	156.2	254.8	10.3
Domestic Supply	122	186.3	8.7
LNG imports	34.2	68.5	14.9

Source: CRISIL Research.

6.2 REGULATORY AGENCIES

Upstream

Legal Framework:
- The Oilfields Regulation and Development Act, 1948.
- The Petroleum and Natural Gas Rules, 1959

Regulator: The Directorate General of Hydrocarbons (DGH).

Policies and regulations:
- The New Exploration Licensing Policy (NELP)
- The Coal Bed Methane (CBM) Policy

Foreign direct investment (FDI) policy : 100% under automatic route.

Midstream

Governing Ministry: The Ministry of Petroleum and Natural Gas (MoPNG)

Regulator: The Petroleum and Natural Gas Regulatory Board (PNGRB)

Policies and regulations:
- Authorisation
- Tariff
- Access Code
- Affiliate Code of Conduct

Foreign direct investment (FDI) policy : 100% under automatic route.

Downstream

Governing Ministry: The Ministry of Petroleum and Natural Gas (MoPNG)

Regulator: The Petroleum and Natural Gas Regulatory Board (PNGRB)

Policies and regulations:
- Authorisation

- Tariff determination
- Exclusivity for CGD networks
- Technical standards

Foreign direct investment (FDI) policy: Refining: 49% in case of Public sector units (PSU) via FIPB route and 100% in case of private companies

Other than refining: 100% under automatic route:

The regulatory agencies are supported by some of the following key central government ministries and policy formulating bodies:

• The Empowered Group of Ministers (EGoM): It takes decisions on industry issues that have a strong impact on the country's economy and investment climate.

• The Planning Commission: It is the nodal agency responsible for building a long-term strategic vision for India and deciding its priorities. It works out sector-specific targets and provides promotional stimulus to the economy to grow in the desired direction. For the hydrocarbon sector, the Planning Commission has formulated policies such as the Integrated Energy Policy, Working Group plans for the sector, etc.

• The Ministry of Finance (MoF): It decides on tax and fiscal matters relating to the country's hydrocarbon sector.

• The Ministry of Law (MoL): It advises on legal issues related to various policies and regimes relating to the hydrocarbon sector.

• The Directorate General of Hydrocarbons (DGH): It was established in 1993 under the administrative control of the Ministry of Petroleum and Natural Gas. Its objectives are to promote sound management of the oil and natural gas resources with a balanced consideration for the environment, safety, technological and economic aspects of the petroleum activity. It has been entrusted with several responsibilities such as implementation of the New Exploration Licensing Policy (NELP), dealing with production sharing contracts (PSCs) for discovered fields and exploration blocks, promotion of investment in the E&P sector and monitoring of E&P activities including review of reservoir performance of producing fields. In addition, it also engages in opening up of new unexplored areas for future exploration and development of non-conventional hydrocarbon energy sources such as coal bed methane (CBM) and futuristic hydrocarbon energy resources such as gas hydrates and oil shale.

• The Petroleum and Natural Gas Regulatory Board (PNGRB): It regulates midstream and downstream activities, which include refining, processing, storage, transportation, distribution ,marketing and sale of petroleum, petroleum products and natural gas. It protects the interest of consumers and entities engaged in the specified activities and ensures the uninterrupted and adequate supply of petroleum, petroleum products and natural gas in all parts of the country to promote competitive markets.

7. ISSUES IN UPSTREAM

7.1 NELP

New Exploration Licensing Policy (NELP) was formulated by the Government of India, during 1997-98 to provide level playing field for all the investors and providing several concessions and incentives to both Public and Private sector companies in exploration and production of hydrocarbons with Directorate General of Hydrocarbons (DGH) acting as a nodal agency for its implementation.

India has an estimated sedimentary area of 3.14 million km^2, consisting of 26 sedimentary basins, of which, 57% (1.79 million km^2.) area is in deepwater and remaining 43% (1.35 million km^2.) area is in on land and shallow offshore.

7.1.1 Issues in NELP

The cost-recovery model of the NELP allows operators to recover all their investment in successful as well as unsuccessful wells from sale of oil and gas before sharing profits with the government. The cost recovery model incentivises firms to keep raising investment to postpone government's profits.

The pricing of JV gas is governed by the terms of PSC provisions, which are determined on the basis of arm's length prices (market prices), subject to the government's approval. Pricing under the production sharing contract (PSC) must be reviewed to clarify the extent to which producers will have the freedom to market the gas.

The issues include exploration being exempted from service tax, exemptions on overseas investment expenses, and clarification on all ambiguities arising due to

shifting from the current regime to the direct tax code (DTC).Tax holiday for natural gas production and exemption from minimum alternate tax. Natural gas producers are excluded from the 7 year tax holiday benefit. Overseas acquisition must be so incentivised so that more players are open to taking risk.

NELP is competitive bidding, but few foreign players show interest. The nine rounds of NELP have seen enthusiastic participation by the state owned companies, the participation by private players especially the foreign majors has been limited. These companies bring a lot of investment muscle required for development of capital intensive and high risk upstream projects. More importantly however, these companies bring echnological expertise and diverse project experience. The reasons for this are-The attractiveness of the resource-Countries with proven fields, recent large discoveries elicit more response. The prospective bidders are concerned about the quality of blocks on offer .Seismic data available before bidding provide only a small window to evaluate data before bidding .Fiscal terms are also a reason for low foreign participation. Exploration majors look at huge acreages .India does not offer such potential. Inconsistency and ambiguity in the policy and fiscal framework is one of the major factors due to which foreign companies either stay away or withdraw participation. Interference in terms of a signed contractual term is also counted as a factor that discourages foreign participation.

Many NELP blocks after being awarded are awaiting clearance from the Defence Ministry and Environment clearances. NELP blocks must be awarded after all the clearances are obtained.

7.1.2 Prospects

NELP X is going to be held in 2013. India may offer as many as 68 blocks or areas for exploration of oil and gas in the 10th round of New Exploration Licensing Policy (NELP).This will be the second highest offering of block since the advent of NELP 1999 .Of the blocks being considered for offering in NELP-X, 25are deep water, 20 shallow water and 23 onland blocks.

NELP-X is likely to be held on new terms wherein a bidder shall be asked to quote the amount of oil or gas output it is willing to offer to the government from the first day of production. The company offering the highest share of oil or gas produced from the field would get the block. Currently, oil companies are allowed to first recover the entire cost of exploration and production and only then share the profit with the government.

India plans to phase out the annual auctioning of oil and gas exploration blocks under the New Exploration Licensing Policy (NELP) in favour of an Open Acreage Licensing System (OALP) that will allow energy firms to bid for such blocks anytime of the year. Data for these blocks will be made available to the bidders through the National Data Repository (NDR).

7.2 GAS PRICING

At present, there are broadly two pricing regimes for gas in the country – gas priced under APM and non-APM or free market gas. The price of APM gas is fixed by the Government. As regards non-APM/free market gas, this could also be broadly sub-divided into two categories, namely, imported LNG and domestically produced gas from JV fields. While the price of LNG imported under term contracts is governed by the SPA between the LNG seller and the buyer, the spot cargoes are purchased on mutually agreeable commercial terms. As regards JV gas, its pricing is governed in terms of the PSC provisions.

The Cabinet Committee on Economic Affairs (CCEA) has decided to double the price of domestic natural gas, from $4.2 to $8.4 a million British thermal unit (mBtu), from April 2014. the government would absorb the losses the power and fertiliser sectors were going to face. However, the quantum of absorption would be determined by the ministries concerned. The Rangarajan formula uses long-term and spot liquid gas (LNG) import contracts as well as international trading benchmarks to arrive at a competitive price for India. The Rangarajan formula would be applicable for five years.

7.2.1 Positive Impact of Price Hike

- Price hike incentivise exploration while also resulting in higher revenues to the government.

- Increased participation of international oil companies

- India's producible gas reserves could rise two-founds by 55-91 trillion cubic feet at gas price of $10-12/MMBtu.

- India's gas production could rise three-fold, alleviating the largest component of India's current account deficit, which currently stands at 5.3%. Import dollars are saved thus lowering current account deficit.160 billion dollars is spent in importing oil and gas.

- Higher revenues to the government.Rs.706.7 crore will be the annual rise in government royalty.Rs.5000 crore is Addition to annual profits of public and private sector majors.

- Subsidy to users like fertilizer and power can be given from the additional revenue government gets from profit petroleum.

- An 8-9 $ /mmbtu hike would mean companies can explore 32 tcf more of reserves in deep waters. The more money you can get by sale of gas, more money you can invest in deeper seas and more oil/gas can be obtained.

- The value of rupee can be strengthened by lowered current account and the money that will come in will be FDI, which do not go away from India unlike FII.

- Increased gas usage has a positive impact on the environment as gas is a cleaner fuel.

- Price is not fixed as it changes every quarter based on Rangarajan committee report formulae, it can be 10$ in 2015, if it is 8.4 in April 2014.

7.2.2 Negative impact of price hike

- Power and fertilizer price will go high. Government will have to pay higher subsidies to the power and fertilizer sectors.

- Rs 10040 crore will be the annual loss to the power sector at 70% PLF for 28000 Mw capacity.

- Rs 3155 crore will be Annual addition to subsidy for 23 MT urea production (from 2013-14)

- Price hike can upset the CGD sector as differential between oil prices and gas becomes narrower.

- CNG and PNG to cost higher.

7.2.3 Key Recommendations of Rangarajan Committee

1. Review of existing PSCs

Recommendations :

- To scrap cost recovery model,and to shift to post royalty-payment revenue sharing.
- Revenue share to be determined by competitive bidding for future PSCs.

Committee Comments:

- Bids will be made in a bid matrix with different percentage revenue shares for different levels of production and price levels.

2. Exploring various contract models to minimise the monitoring expenditure.

Recommendations:

- MC not to be involved in budget approval.
- Extended tax hoiday from 7 to 10 years for offshore blocks >1500 m drilling depth.
- Extend exploration period for frontier/deep/ultra deep water blocks from 8 to 10 years.

Committee comments:

- Role of the MC or the Government nominees of the Management Commmittee will be largely related to monitoring and control of technical aspects.
- Contractors can be allowed to carry out further exporation through Mining Lease (ML) period in the ML area.

3. Mechanism for managing the contract implementation of PSCs

Recommendations:

- Two mechanisms for improving progress.
- For policy related issues, setting up of a Secretary level Inter ministerial committee to suggest solutions.
- For issues on delay, mandate of existing Empowered Committee of Secretaries(ECS) can be expanded.

Committee comments:

•Decisions of MC should be quick,as per relevant provisions ,and should be signed on meeting date.

•ECS to be empowered to consider extension of other timelines prescribed in the PSC.

4. Monitor and audit Government of India's share of Profit Petroleum

Recommendations:

•CAG to choose blocks for direct audit on basis of financial materiality.CAG empanelled auditors to audit other blocks.

•CAG to perform the audit within 2 years of the financial year audit. Also, for PSC s beyond a high financial threshold, concurrent audit mechanism may be considered.

Committee comments:

•CAG would continue to have right to directly audit all blocks.

•Audit of blocks without discoveries may be conducted by qualified accounting firms.

5. Determining the basis/formula for domestically produced gas

Recommendations:

To take trailing 12 month average of

a) Volume weighted net back pricing at well head for gas producers

b) Volume weighted price of US's Henry Hub, UK's NBP and Japan's JCC linked price.

Committee comments:

•PSC provides for arm's length pricing ,however since no market determined arm's length price currently obtains domestically, a policy on pricing of natural gas has been proposed.

7.3 GAS PRICING HISTORY IN INDIA

JUNE 2005-Tariff Commission set up to look into Pricing Issues. ONGC's producer price increased on ad-hoc basis Tariff Commission Recommendation. Price increased from Rs 2850 to Rs 3200 with effect from 1st July 2005.ONGC was seeking prices in line with market related pricing.

2006-Initial Report of Tariff Commission recommended price of Rs 3450/mmscm. Escalation of Rs 50/MCM for each 10 point increase in WPI Index .Both MoPNG and ONGC had reservations on this formula.

May 2007-Tariff commission revised its pricing recommendation. Revised normative producer price of Rs 3600/MCM. Escalation of Rs 50/MCM for each 10 point increase in WPI Index.

June 2007-T o avoid further delay, ONGC conveyed acceptance of revised price recommendation, despite not being in agreement. ONGC requested 20% annual increase on price of Rs 3600/MCM fixed by TC for FY06 to bring APM prices in line with market prices. ONGC also asked for market pricing for additional and new gas above current APM.CCEA decision for revision of producer pricing based on TC recommendation.

September 2007-RIL's KG-D6 gas price fixed at USD 4.2/MMBTU

September 2009-Revised pricing not yet implemented .Pending notification from Government of India.

May 2010-Government revised APM gas price to USD 4.2/MMBTU

December 2012-Rangarajan Committee submits its report on Gas Pricing.

June 2013-Government revised APM gas price to USD 8.4/MMBTU with effect from 1st April,2014..

March 2014-KG D6 gas price is slated for change in March 2014.

7.4 Shale Gas Potential &Policy

Shale gas is natural gas trapped in sedimentary rocks (shale formations) below the earth's surface. Major basins in India with potential shale reserves include Cambay, Gujarat, Assam-Arakan in the Northeast, Gondawana in central India, Krishna Godavari in Andhra Pradesh, Cauvery onshore and the Indo-Gangetic basins. According to government estimates, a few basins in India together have a potential to produce 63 TCF of shale gas, while it has a total shale potential of close to 300 TCF. Experts say shale gas and oil reserves are expected to be present in at least 11 more basins across the country. Technological collaboration will help in using sophisticated models to pick out most prolific places to start drilling.

Shale gas has been the game changer. It changed United States of America from a gas importing country to a gas exporting country in the past decade. The companies worldwide are looking to invest in the shale gas business and are considering it as a lucrative business.USA has revolutionized the shale gas and is responsible for technological and economical advantages in the shale gas production today. This shale gas revolution has turned USA from a gas importing country to a gas exporting country (to Japan). 90% of the global shale gas is currently produced by the USA.

Instead of the capex consolidated in a small area as in conventional drilling, shale gas extraction requires capex spread over wide areas – especially the extensive midstream pipeline network required to gather the gas recovered. Finally there are some new environmental challenges – a lot of water (mixed with chemicals and additives) is required for fracking, if this is not properly disposed it can pollute the ground water. India has a long way to go before it can sustainably and safely extract shale gas. A lot depends on whether the proposed regulatory framework will promote investment in the requisite resources and infrastructure. Technological knowhow, although critical, should not be the bottleneck – GAIL, OIL and RIL have already started investing in shale in USA and their local staff is onsite building technical capabilities. Where India will be challenged is in its ability to manage resources (e.g., water, for which there is a distribution problem even for human consumption) and to design regulations for sustainable development (e.g., investment incentives for developing the required supply chain and capex; preventing ground water pollution; compensating land-owners which will be critical for drilling horizontal wells in large tracts of populated land, etc.) These are complex problems and in addition to a shale gas policy (which in itself will elicit debate on production sharing/ royalty, etc.) India will need to create/ modify other policies plus tighten oversight.

The relative hardness of shale limits its exploration potential essentially to mature sedimentary formations, which are relatively brittle. It means the potential reserves in the country may not be recoverable. Extraction of shale gas is highly dependent on large-scale harnessing of another natural resource – possibly the most precious – groundwater. shale gas exploration requires drilling double or triple the number of wells, that too in quick succession. Leaving environmental concerns aside, in a country where per capita water availability is falling (Census 2011) and, close to nine-tenth (86 per cent) of available resources are used in agriculture, such high water requirements may clearly put shale gas explorers in conflict with the local population. The US is better off, because not even half its water resources are used in agriculture. And, unlike in India, American women are not expected to walk miles to collect potable water. For a country where two-third of the population is dependent on land, population-density is 10 times that of US and 2.5 times China's, and the share of arable land (to total land mass) is three times higher than either in US or China, India may offer a completely different set of challenges for shale gas exploration and production. Shale gas extraction not only requires a higher density of wells, but also needs two-three times more land (compared to a CBM well) to drill every hole on earth. The higher land requirement is attributed to its relatively complex drilling operations.

A rule of thumb estimate suggests a CBM operator needs 300 acres to drill an approximately identical number of wells. Shale gas production from the same field may require 1,200-2,700 acres of land. Shale gas will require more land acquisition, which has already proved to be a major cause of concern for Indian industry. While politics is trying to strike a solution by enhancing the compensation for land acquisition, the experience of Coal India proves that such measures alone are not sufficient.

The shale gas development policy would look into the possibility of clubbing the exploration rights of areas in which shale blocks overlap with existing oil and gas blocks. The bidding process is expected to start within the first half of this financial year. At least 100 blocks would be up for grabs. he blocks would cover the three major basins of Cambay, Krishna Godavari and Ranigunj (part of the 26 sedimentary basins in India). While the total recoverable resource in these three basins would be 12-15 trillion cubic feet (TCF), immediately recoverable resource would be in the range of two to six TCF. In the initial exploration stage, the investment is likely to stand at about \$2 billion. The policy would offer the first right of refusal to the existing oil and gas or coal bed methane contractor to match the offer of the selected bidder, in case a shale block overlaps with it, said an official. Even if the operator refuses, a co-development model would be mooted for simultaneous exploration.

7.5 Upstream skills, technology and equipment shortage

The upstream oil and gas infrastructure in India is inadequate due to underinvestment in the past. As a result, the production of oil and gas remained stagnant and has not been able to keep up with the rise in demand. The limited participation from foreign players in NELP accounts to this.

Upstream talent shortage and ageing workforce is an issue being faced the global as well as Indian upstream industry. The industry is especially pressed with shortfall of labour with specialized skills such as reservoir engineering or with experience of developing unconventional gas assets.

The rising demand for oil and gas has resulted in an increase in exploration activities, leading to the shortage of oilfield services, particularly deepwater rigs .India is facing a shortage of oilfield services, especially drilling equipment. Companies are falling short of exploration targets with cost overruns and delays in work commitments. Lack of domestic expertise in the manufacture of rigs and the time lag in the delivery of new rigs accentuates the issue. Most of the rig assets held by Indian companies are aging. These old rigs have to be retired or upgraded to remain operational. There is also a scarcity of upstream related infrastructure such as Process platforms, pipelines, collecting stations and other surface facilities to transport oil and gas from wells to delivery points.

The industry is facing a shortage of skilled manpower due to attrition, retirement and the inability to attract the young workforce .The industry is unable to attract talent from universities due to the lack of awareness of the available career opportunities within the industry and lack of awareness of the available career opportunities within the industry and difficult working conditions in the upstream segment. Domestic national oil companies are losing their employees to private sector due to significant differences in remuneration levels. Around 12% of the current workforce may retire over the next few years, resulting in significant losses of experienced personnel. The shortage of talent is likely to increase which may impact operations across the value chain. There will be a requirement of around 25000 additional professionals over the next few years due to attrition, retirement and increasing activities in the industry. The upstream sector is likely to have the highest short fall of skilled manpower of around 7600 employees. In line with the global trend, the average age of workforce in the Indian oil and gas sector is high. Around 50% of employees have more than 20 years of experience, and the majority is due to retire in the next 5–10 years. Around 11% of the current workforce is estimated to retire in the next five years. This is likely to significantly reduce experienced talent in the oil and gas sector. The sector may also face 34% of employee retirement at the middle-management level. Another cause for concern around the loss of industry talent is that skill sets in this industry are highly specialized and difficult to develop and acquire. Thus, the impact of losing industry professionals with five or more years of experience is likely to be of high magnitude.

7.6 Increased competition to procure oil and gas equities abroad.

Acquiring energy assets abroad is the most sensible thing to do to achieve energy security. As part of its energy security strategy, India has forged new ties with Russia, Iran and China and built partnerships with Burma and Venezuela. The country has also carefully entered into cooperative relationships with several oil producing countries in Africa and in the Middle East. India has also allowed public sector companies such as ONGC and OIL to secure ownership of oil and gas fields and companies overseas. ONGC has acquired equity stakes in the oil fields in Iran, Iraq, Sudan, Libya, Angola, Burma, Russia, Vietnam and Syria. India is looking at Kazakhstan as an important emerging exporter of oil and gas. Kazakhstan is among the top ten countries in the world in terms of explored oil and gas reserves. The country depends significantly on overseas funding to develop these resources, which offers investment opportunities to India.

The game of overseas energy acquisitions began with the formation of ONGC Videsh Limited (OVL) in 1989. The main objective of this 100 percent subsidiary of the flagship national oil company was to help the country achieve energy security. The primary business of OVL is to prospect for oil and gas acreages abroad including acquisition of oil and gas fields, exploration, development, production, transportation and export of oil and gas. Following the foray of OVL into acquisition of energy assets abroad, other upstream and even downstream players in the oil & gas sector had started acquiring energy assets in other nations.

Bharat PetroResources Limited (BPRL) - BPCL's Exploration & Production company .Considering the need for a focused approach for E&P activities and implementation of the investment plans of BPCL at a quicker pace, a wholly owned subsidiary company of BPCL, by the name Bharat PetroResources Limited (BPRL) was incorporated in October 2006, with the objective of carrying out Exploration and Production activities.

As of May 2013, the company has participating interests in 25 exploration blocks; in consortium with other companies. Of the blocks, 11 blocks are in India, 10 in Brazil, and 1 each in Mozambique, Indonesia. Australia and East Timor and. BPRL's total acreage holding is around 56,000 sqkm of which about 86% is offshore acreage.

<u>Competition from china</u>

A stronger yuan would also make purchases cheaper for the Chinese. India increased the amount ONGC and some other state-run firms can spend to acquire assets and set up joint ventures, allowing them greater freedom to expand and become globally competitive. The financial firepower that the Chinese companies have is a factor.

Chinese NOCs are backed by state financing from China Investment Corp, the country's sovereign wealth fund .The Chinese companies are supported by diplomatic initiatives of the Chinese Government, offer to invest in social infrastructure projects and the provision of soft loans to countries where they are seeking access to oil and gas reserves. India's overseas investments in oil and gas lag behind that of Chinese companies. Indian companies view overseas projects as a commercial activity and mostly acquire assets based on returns. The

Chinese NOC's are ready to pay for assets to strengthen energy security, overlooking project economics. Indian companies follow a strategy to purchase assets in safe countries while Chinese companies are investing in unstable regions also.

7.7 **Tax and regulatory issues**

The GOI has created a robust regulatory framework supporting the growth of the domestic oil and gas industry.Oil and Gas fields are open to domestic as well as foreign companies under the NELP framework.Upto 100% FDI is permitted in discovered small and medium sized fields through competitive bidding.DGHwas created as the upstream regulator. FDI upto 100% is permitted for natural gas/LNG pipeline with prior government approval.

The following are the tax and regulatory issues impacting the industry.

•Deduction for unsuccessful exploration expenses

Section 42 of the income tax act,1961 provides that deduction for unsuccessful exploration expenses is allowed only in respect of an area surrendered prior to the beginning of commercial production.As a result,deduction of expenses on account of abortive exploration is not available in the year when expenditure was incurred and is permitted only on surrender of area.Such requirement of surrendering the area for availing deduction for abortive expenditure induce exploration companies to surrender the area without fuly exploring the same,which is not in the interest of the industry and the country.

•No deduction for expenditure incurred on drilling and exploration activities by an dian Company with overseas production block: Section 42 of the Act provides deduction for expenditure incurred on drilling and exploration activities carried out in India.Accordingly,an Indian company with an overseas exploration block is not eligible for similar tax treatment

•No tax holiday for production of natural gas:tax holiday under section 80IB(9) of the Act is available to undertakings engaged in the commercial production of mineral oil and natural gas in blocks licensed under NELP and CBM rounds of bidding.

•No option for claiming tax holiday under section 80IB(9) of the Act:Tax holiday under section 80IB(9) is available to an undertaking ,which is engaged in the commercial production or refining of mineral oil for seven years including initial assessment year. However in the initial years there is hardly any profit to take advantage of the tax holiday since undertakings incur considerable expenditure to set off and hence actual benefit of tax holiday does not flow to them.

•No exemption of oil and gas from Minimum Alternative Tax(MAT):The benefit granted by way of tax holiday is partially offset since no exemption has been granted from levy of MAT.

8.Issues in Midstream

Pipeline Density is too low. India has 3 KM/1000 sq. km of pipeline density compared to USA, UK , China which have about 50 km/1000 sq. km .Existing connected market cannot absorb future supplies.

National Pipeline Grid requires Priority & focus for speedy implementation. This requires huge investment and levying of cess . Pass on benefit of logistics & transport cost savings to end users

Work aggressively to aim 15,000 km by 2013-14.This in itself is a huge challenge which requires huge funding.

There should be clarity and speedy authorization and tariff determination.The Gas Authority of India Ltd. (GAIL), one of India's leading Public Sector Enterprises, is the largest gas transmission and marketing company in the Country. Today GAIL owns and operates over 4000 km of pipeline and has about 95% market share in the Natural Gas business in India.

8.1 Underdeveloped natural gas infrastructure

The natural gas infrastructure in the country needs an overhaul. The infrastructure is currently underdeveloped due to limited availability of natural and inadequate transmission and distribution pipeline. India's gas density is one of the lowest in the world.

8.2 Regulated natural gas prices

India currently has numerous pricing mechanisms, which depend on the supplier, customer and region .Companies need government approval for gas price and the pricing formula, despite being given the autonomy to change market determined prices under the provisions of the NELP. The price of natural gas needs to be high enough to incentivize producers to invest in exploration and production, while at the same time be affordable for majority of gas consumers.

8.3 Difficulty in sourcing long term supplies from abroad

The import of gas in the form of LNG and the transmission of gas through international pipelines are two options available to meet the rising domestic demands for natural gas. Indian companies are constructing new LNG terminals and expanding the capacities of existing terminals. However, the country is facing difficulties in sourcing long term LNG supplies due to competition from countries such as China, Japan and South Korea.

In the past , India proposed to lay transnational pipelines and was in talks with countries such as Iran, Pakistan, Turkmenistan and Afghanistan and Myanmar. However, differences over a gas pricing and geopolitical issues have created hurdles in the construction of these pipelines. The challenge for India will be to arrange long term supplies at reasonable prices as anchor gas customers –fertilizers and power industries may not be able to pay market determined prices.

8.4 Tariff

HVJ

The transportation charges along the HVJ line are Rs 1,150 / tcm, linked to the calorific value of 8,500 kcal /scm. This transportation charge is based on:

- Discounted cash flow method
- Net asset value of HVJ, including GREP
- Return of 12% post tax on equity

Non-HVJ includes KG Basin, Cauvery Basin, North & South Gujarat, Mumbai region and Northeast region pipelines. Most of the existing contracts are taken over from ONGC Customers in these regions can be classified as:

- Consumer on common grid
- Consumer partly on grid and partly on dedicated spur line
- Consumer on dedicated pipeline

While consumers on common grid are charged proportionately, those consumers partly on grid and partly on dedicated spur line are charged proportionate common grid charges and additional dedicated spur pipeline charges. The transmission tariff for dedicated pipelines is fixed.

- Discounted cash flow method
- 12% post tax return on investment
- Three per cent escalation on tariff is taken annually for all consumer types to cover escalation in operating costs

9.Issues in Downstream

9.1.CGD NETWORKS

City gas Distribution is a business arrangement of supplying,natural Gas to various end users for their consumption. A CGD primarily markets PNG and CNG. The end users are retail customers or at best SMEs in terms of gas consumption – there are no resellers. The number of customers is very large.CGD markets CNG. The customers are located in a small geographical area. The supply of gas is required continuously, although consumption by end user may not be continuous. A great deal of vendor support is necessary to run a CGD business. Network is operated at lower pressure.CGD business is utility business.

<u>Potential customers</u>

PNG:

- Households
- Commercial establishments
- Industries

CNG:

- Public transport – autos, taxis, private buses
- State transport / city bus service
- Individual vehicle owners

<u>Competition</u>

PNG:

- Household – LPG
- Commercial – LPG
- Industrial – LPG/Propane, FO, HSD/LDO

CNG:

- Auto / cars – LPG, MS
- LCV, Bus, Cars – HSD

9.2Gas sourcing

APM gas is allocated by the Ministry of Petroleum & Natural Gas to a CGD for supply to domestic and transport sectors. RLNG is required be sourced by the CGD for supply to I&C customers. Gas supply contracts may be of 2 varieties – firm and reasonable endeavor basis.

Firm contract provides assurance of supply. The gas price is usually lower but it comes with the riders of 'Take or Pay' penalties. The operation of firm contracts requires a very meticulous planning, coordination with customers and suppliers and a sturdy nomination process. Over drawl has severe penalties.

RE contracts do not assure supplies. The gas is usually more expensive but there is no 'take or Pay' penalty. The nomination procedure has to be followed in this case too. Over drawl penalties apply in RE contracts too.

A CGD typically, contracts gas sourcing and gas sales to its customers on a back-to-back basis for Industrial category. . For others, there is no commitment from customers, but usually demand fluctuations are minimal and predictable, which can be covered by proper nominations..

9.3Challenges in developing CGD networks

Insufficient gas supplies, poorly developed pipeline infrastructure and uncertainty over regulatory policies are some of the main factors deterring the growth of CGD networks in India. Although India has a CGD network in many cities, the network is not widespread across majority of the cities. Only Delhi, Mumbai and some parts of Gujarat have a prominent gas distribution network. According to India's gas allocation policy, the power and fertilizer industries get a preferential allotment of domestic gas supplies, which leaves very little domestic gas for CGD companies .To satisfy demand, existing CGD companies may have to source increasing quantities of expensive RLNG ,which may impact the prices of CNG and PNG as well as impact margins. It is likely that new CGD networks will have to source RLNG ,which may affect the returns of proposed CGD projects.

The shortage of experienced manpower is yet another issue that needs to be overcome. With the aggressive growth plans of many companies, it is estimated that the industry will require more workforce. Some of the other challenges that may hinder the growth of the nascent CGD industry in India include the lack of safety standards and network of reliable equipment suppliers.

There is uncertainty over the bidding criteria .Eligibility criteria for CGD bidding lack provision for commitment and are very flexible. This allows inexperienced players to bid, who may find it difficult to develop or operate the network. n previous rounds, bids have been invited for areas, which are too small or underdeveloped to sustain the CGD business profitably and hence, attract only a few bids or no bids at all.

9.4 Issues in Gas Market Development

•The most critical issue in India's gas sector is to develop the end-use market. There is a growing recognition among India's gas sector players that the downstream market constitutes the weakest link in the entire gas value chain.On the whole, the most critical issue is to get right the economics of the whole gas supply chain. This requires a major reform of the gas pricing system and a redefinition of risk/return on investments along the gas chain. It also requires that the economics of alternative fuels be closely taken into account. But key to this would be identification of sectors where natural gas would have the highest market value compared to existing fuels and to ensure that the economy of these sectors does not suffer from using natural gas. The government can take a number of policy actions to facilitate the development of the downstream market:

•Reform the gas pricing policy, by adopting a net-back approach based on the market replacement value of gas compared with alternative fuels, through market-determined pricing;

•Promote switching to gas through financial incentives such as tax credits, low-interest loans and favourable depreciation rates, and by sector-specific measures;

•Reduce/exempt taxes and local add-on charges on natural gas;

•Introduce taxes and levies on competing fuels, fuel oil in particular;

•Facilitate and enable large gas off-takers such as power plants to fulfill their long-term commitments by ensuring respect for their power purchase agreements;

•Lighten the approval procedure for large gas end-use projects and improve procedural transparency;

•Lighten the approval procedure for laying down common carrier pipe-lines;

•Encourage private and foreign investment in the local gas distribution sector;

•Increase investment in end-use gas technology development and in building domestic capability for absorbing gas-use technologies.

•Define and implement a systematic and rigorous approach to gas market development, by integrating all the necessary elements such as training of downstream gas professionals, definition of natural gas quality, integration of natural gas into urban planning, putting in place as soon as possible a set of technical and safety norms and standards, etc.

•Form several regional centres of excellence for gas market development and set up all the important components along the gas chain, ensuring that none of them becomes a bottleneck.

•The last but not the least, take concrete steps to improve state and central Government coordination to improve the investment climate.

9.5 Make Environmental Protection a Real Driver for Clean Energy Development

The growing awareness of the urgency in solving serious air pollution problems provides a golden opportunity for the growth of gas and other clean energy sources. However, such development depends critically on the credibility of the country's environmental commitments expressed in real national determination translated into concrete programmes and actions. Significant work needs to be carried out to make institutions efficient in dealing with environmental issues, in defining the instruments to achieve environmental objectives, and in making the investments needed to bring money to environmental programmes. Local environmental protection authorities need to be appropriately empowered and resourced to carry out their work.

One important factor that must affect gas-coal competition is the reflection of environmental benefits and costs in economic considerations. Such a reflection can be achieved by "internalising" the environmental benefits of natural gas and applying the "polluter pays-principle" to coal specially in the power and industrial sectors. As it is difficult to impose emission fees on coal use in residential and commercial sectors, as well as in small industrial boilers, the country may need to rely initially on command and control measures to induce the replacement of coal by other fuels. It can also acknowledge the environmental benefits of natural gas by reducing taxes on gas and gas-using appliances and increasing taxes on more polluting fuels.

In power generation and large industrial boilers, the selective use of economic instruments will be necessary in addition to strengthening the enforcement of existing environmental regulations. To start with, the price/penalty per tonne of emissions (SO2' NOx, particulates) should begin to reflect the market value of emission permits taking into consideration health damage to the public.

Given the fact that natural gas is more expensive than coal, the Indian Government will have to decide how to support the environmental and energy diversification benefits of gas. Exploration and production costs can no doubt be reduced, but ultimately the incremental costs of introducing gas into the Indian economy will be borne by Indian consumers against the benefits of health and energy security improvement as well as the modernisation of industrial activities. Taxation is a powerful tool to achieve the right balance. Energy planners need to take into account the energy and environmental policy objectives of the country in designing a fiscal regime that will encourage not only substituting gas for more polluting fuels, but also investment in the gas industry.

9.6 Establish a Legal Framework on Natural Gas

Preparation of a legal framework is a priority. The Indian Government recognises this and is formulating such a framework. The enactment of Petroleum & Natural Gas Regulatory Board Act 2006 is an indication of this. A mature legal framework would provide a clear legal expression of the Governments policy and strategy for gas industry development and the ground rules for the operation of the gas industry. International practice shows that almost every country where a natural gas industry has been established, whether based on indigenous resources or imports, has adopted a gas law or laws in the early stages of market development.

9.7 Create a Central Administration for Energy

Issues, such as coal-gas competition, gas for power generation, gas pricing and investment, and the environmental driver for gas market development, need to be addressed within the context of a national energy policy. A central body is desirable to co-ordinate national energy policy issues.

India does not have a single central government entity in charge of energy policy and regulatory matters. There is, therefore, a strong case for establishing a specialist energy regulator, to manage policies on oil, gas, electricity, coal and other energy sources and markets. A number of other factors reinforce the call for the creation of such an energy regulator:

As India's oil dependency grows there is a pressing need for a co-ordinated approach towards energy security;

Competition in the electricity, oil and gas industries is just beginning, and there will be a need for specialised expertise within the government to resolve increasingly complex market related issues in the future;

Concentration of energy knowledge and expertise in a single body would facilitate the formulation of macro-economic policies and accelerate problem resolution;

There is a need for increased coherence and co-ordination in energy policy-making;

Better communication of energy policy decisions to industry stake-holders is also critical.

Without such a national energy policy regulator, it may be difficult for multiple regulators to simultaneously regulate the individual policies of separate sectors such as oil, gas and electricity, taking into account environmental, regional development and urbanization considerations. To be effective, such a regulator should be appropriately resourced in order to build strong information and analytical capabilities.

10.Key Issues - Gas for Power Generation

The utility industry is expected to be the largest gas consumer in the future. Growth in electricity demand and the diversification of fuel sources for environmental reasons are powerful incentives for setting up of gas-fired power generation. The development of large-scale power generation is also critically important for anchoring large gas infrastructure projects like pipelines or LNG. Achieving this target will not be easy since in many regions of India, gas is currently not competitive against coal in terms of base-load. While efforts to get over this situation will continue, it is possible to develop new generating capacity for peak-shaving to promote gas market development in India.

The premium market for gas-fired generation in India lies both in peak-load and in a distributed generation system that provides heating, cooling and power in populated areas via a large number of small/medium and decentralised units (50 MW or below). Those units offer basically the same economics as large ones; they can be installed close to demand centres and help reduce urban air pollution; their waste heat could be more easily used for other purposes; and their deployment can also help in building a local gas distribution system. SERCs levy a variety of charges and fees on actual delivered power costs (surcharges, cross subsidy charges, open access fee ete) that slow down reform progress and are of particular concern for IPPs and captive or CHP plants because they prove a barrier to exploiting their capacities to the best level. Its argued in the industry that such surplus power generation by Captives or CHPs, if allowed to flow into grid, would be a major source for meeting the deficits in generation capacities. The high efficiency gas based distributed power generation could thus be promoted.

Given the projected growth trajectory of the Indian economy of 8 percent per annum, electricity demand is projected to be 3,880 Billion kWh by 2031-32. Electricity requirements can be met by various alternative fuels. These include coal, nuclear, hydel, gas, oil and renewables such as bio-mass, wind energy, solar energy, etc.

Power plant developers, however, have concerns in installing power generation capacities mainly for two reasons. First, gas availability is a major constraint and even if the domestic discoveries are commercialised at market determined prices, the ability of power sector to grant an attractive power tariff is suspect. Second, the inability of transmission and distribution companies to recover the economic value of utility supplies from the consumers and the inability to arrest the transmission and distribution (T&D) or administrative, technical and commercial (AT&C) losses, mainly due to the poor political and policy support. It is estimated that arresting such losses would ensure the affordability of market determined natural gas prices for power generation by power plant developers in India. It is, therefore, necessary to evolve enabling regulations and policy reforms to reduce such huge losses in the power sector.

The global rising trend of gas prices, linkage to the rising crude oil prices and non-availability of gas on long term commitment has reduced willingness of Indian power generators to rely on gas as a fuel. The choice between coal and gas would continue to be guided by economic and commercial considerations including any policy prescriptions for pricing of certain environmental externalities.

Nevertheless, the overall prospect of the role of gas in India's power sector remains positive given its potential for sustained high economic growth, recent shortages of coal supplies, the need to integrate India's population into the commercial energy economy, large recent discoveries of indigenous gas and opening up of the country's first two LNG terminals.

Gas for power generation is an imperative from the environmental perspectives as well. Energy economists have projected that coal is here to stay. Constraints in sourcing gas and accelerated growth in energy demand by the world will force countries to retain coal in their primary energy basket. India would be no exception. But, from the other side, the environmentalists' global community would continue to pressurize the major consumers like India, China, USA, etc.,

The major element of such a new development model will be to decouple future economic prosperity from environmental pollution and even to make the economic ecological relationship a positive instead of a negative one. The key of doing this will ultimately lie in the creation of a new clean technology base. In the interim, India will be forced to tread the cleaner path of natural gas and developing gas markets and, though difficult to achieve, tying UP gas sources, is necessary. India faces several challenges to translate this potential into reality. The major constraints that need to be addressed include:

Where conditions permit, seek ways of promoting base-load gas-fired power generation to support the quick development of a gas market and anchor large-scale gas infrastructure development;

Encourage the development of decentralised gas-fired generation based distributed generation in captive or IPP mode, and where possible as heat and power c0generation, or heat, cooling and power tri-generation projects, and pursue this as a medium and long-term strategic orientation. Allow open access at no cost to generators for wheeling power into the grid.

Rationalise electricity pricing schemes to ensure that tariffs at wholesale levels better reflect costs of peaking and mid-merit generation;

Tighten environmental regulations on coal-fired power plants and strengthen their enforcement.

Develop the domestic capacity to build small and medium-sized gas turbines and Combined Cycle Gas Turbines (CCGTs) in India.

Liberalising gas pricing regime which will encourage further domestic gas exploration and gas imports;

Establishing a fully developed gas grid by expanding the gas transmission and distribution system throughout the country.

Developing regulatory framework to encourage investments.

11.Key Issues - Non-Power Natural Gas Demand

Natural gas can replace existing fuels in various sectors both for feedstock as well as for energy purposes. This substitution will, however, depend upon the competitiveness of gas vis-a-vis alternative fuels. Therefore, non-power end uses of gas will depend upon price of gas relative to that of alternatives, mainly naphtha for fertiliser and petrochemical, petrol and diesel for transport, etc.

12. Conclusion

India must look at energy planning from a long term perspective. The availability of gas is no longer an issue ,but the real issue is affordability. India must reduce dependence on liquid fuels and improve the share of natural gas in the energy basket.

Indian gas market will take off, but remain price sensitive .Partnerships between India and LNG supplying nations is vital. India has unique advantages it can leverage. India must think creatively in the context of market realities. Focus must be shifted to long term supply agreements.

There should be a speedy creation of infrastructure. End user market should be extensively developed. Reform should be made on gas pricing policy. Financial incentives must be accorded. Taxes should be reduced / exempted. Private and foreign investment in City Gas Distribution sector should be encouraged.

The approval process for large gas end use projects and laying common carrier pipelines must be simplified.

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