# Impact of LNG Import on Bangladesh Energy Sector

By

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# Abstract

In Bangladesh gas is being used for different purposes but the entire country is now suffering from gas shortage. There is now almost 500 MMCFD gas shortage in the national grid. According to Petrobangla Report, shortfall commenced as early as 2007 for proved reserves. Gas demand in coming years will increase in such a way that during 2019-20 the demand will exceed the total summation of proved, probable and possible reserves. That is why floating LNG terminal and LNG regasification plant has been proposed. In Bangladesh the financial parameters of gas sector perspective reveal that the project is not financially viable with a very low domestic gas price. This needs a thorough financial analysis for clear understanding of the project. The effect of price and also the pipeline gas quality need to be thoroughly examined.

The main objective of the study is to analyze the effect on local gas price due to imported LNG by considering extra cost that have to be managed by the Government per unit of gas and the minimum price that the Government has to select to reduce subsidy and to study the outcome of the mixture if the gas from LNG is mixed with the existing pipe line gas.

This study covers the History of LNG, latest Developments, LNG process chain, different types of LNG receiving and regasification units and the latest energy sector scenario, discussion of world LNG pricing system. Difference between the sale and cost price of 500 MMCFD gas from LNG is calculated. Demand of Gas is estimated by using statistical tools SPSS by regression analysis. From the demand approximate yearly LNG cost is also calculated for the future. Besides this the impact on the gas pipe line and the end user’s equipment problem is discussed when the gas from the LNG is mixed with the domestic gas. Steps to improve the system are also discussed.

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# Abbreviation

APCI - Atmospheric Pressure Chemical Ionization

BAPEX - Bangladesh Petroleum Exploration and Production Co. Ltd.

BCF - Billion Cubic Feet

BDT – Bangladeshi Taka

BERC – Bangladesh Energy Regulatory Commission

BOG – Boil of Gas

BOO – Build, own and operate

BPC - Bangladesh Petroleum Corporation

BPDB - Bangladesh Power Development Board

BTU - British Thermal Unit

BGFCL - Bangladesh Gas Fields Company Ltd.

CFT - Cubic Feet

CGS - City Gate Station

CIF - Cost, Insurance and Freight

CIS - Commonwealth of Independent States

CNG - Compressed Natural Gas

DES-Desire Petroleum Share Price

DOE - Department of Energy

EMRD – Energy and Mineral Resources Division

ESD – Emergency Shutdown Device

FOB - Freight on Board

FSRU - Floating Storage and Regasification Units

FY- Fiscal Year

gal - Gallon

GDP - Gross Domestic Product

GOB - Government of Bangladesh

GTCL - Gas Transmission Company Ltd.

GWhr – Giga Watt Hour

HP - High Pressure

HHV - Higher Heating Value

IGC - International Gas Codes

IMDG - International Maritime Dangerous Goods

IMO - International Maritime Organisation

IOC - International Oil Company

Kg - Kilogram

L - Liter

lb - Pound

LFL - Lower Flammable Limit

LP - Low Pressure

MCM - Thousand Cubic Meter

MCR - Main Cryogenic Heat

MIS - Management Information System

MJ - Mega Joule

MMCM - Million Cubic Meter Per Month

MMCFD - Million Cubic Feet Per Day

MoU - Memorandum of Understanding

Mtpa - Million Ton Per Annum

MW - Mega Watt

LNG - Liquid Natural Gas

LPG - Liquid Petroleum Gas

NEB - National Energy Board

NGL - Natural Gas Liquid

PB - Petrobangla

PERC - Power Emergency Release Coupler

Psig- Pound per square inch at gauge pressure

Scf - Square Cubic Feet

SD -Supplementary Duty

SPSS- Statistical Package for the Social Sciences

TK- Taka

UFL - Upper Flammable Limit

UAE - United Arab Emirates

UK- United Kingdom

US – United States

USD - United States Dollar

VAT-Value Added Tax

# Symbol

m - meter

$m^2$ - Meter Square

$m^3$- Cubic Meter

ft- feet

$^oC$ - Degree Celsius

$^oF$ - Degree Fahrenheit

$ - Dollar

% - Percentage

> - Greater Than

< - Less Than

¢ - Cents

# CHAPTER 1

# Introduction

## 1.1 Background

In Bangladesh, natural gas is the major source of primary energy. More than 75 percent of factories and power plants are now run by locally produced gas. Presently the entire country is suffering from gas shortage. The availability of domestic primary fuel supply is getting so scarce that it is forcing severe measures like shutting down fertilizer factories, rationing gas supplies for household and transport uses and keeping installed power units idle. It is essential to minimize the difference between demand and supply situation of gas in the country. Liquid Natural Gas (LNG) import could be one of the sources of fuel for the growing energy consumption to cope with the energy crisis situation. LNG has been transported for more than 50 years and has a strong safety record. The world has enormous quantities of natural gas but much of it is in areas far from where the gas is needed. To move this cleaner burning fuel across oceans natural gas must be converted into LNG by a process called liquefaction. The gas is first extracted and transported to a processing plant where it is purified by removing any condensates such as water, oil, mud as well as other gases such as $CO_2$ and $H_2S$. An LNG process train will also typically be designed to remove trace amounts of mercury from the gas stream to prevent mercury amalgamizing with aluminium in the cryogenic heat exchanger. The gas is then cooled down in stages until it is liquefied. LNG is finally stored in storage tanks and can be loaded and shipped to the regasification point. After regasification the LNG comes to its normal state that means usual natural gas and supplied to the end user by pipeline. The natural gas being converted to its liquefied form is almost entirely methane at this point. The greenhouse gas emissions from LNG when considering the entire life cycle of production, transportation and combustion can be as high as coal along with expensive infrastructure investment. Natural gas power plants emit approximately half the carbon dioxide of an equivalent coal power plant. In its liquid state LNG is not explosive and cannot burn. For LNG to burn it must first vaporize then mix with air in the proper proportions (the flammable range is 5 percent to 15 percent)[1] and then be ignited. In the case of a leak, LNG vaporizes rapidly, turns into a gas and mixes with air. If this mixture is within the flammable range there is a risk of ignition which would create fire and thermal radiation hazards. LNG is a non-corrosive liquid that is clear and colourless like water and weighs about half as much as the same volume of water.

### Definition

Liquefied natural gas or LNG is natural gas (predominantly methane, $CH_4$) that has been converted to liquid form for ease of storage or transport. It is cooled to –260° F (–162° C) changing it from a gas into a liquid that is 1/600th of its original volume. This reduction allows it to be shipped safely and efficiently aboard specially designed LNG vessels. After arriving at its destination LNG is warmed to return it to its gaseous state and delivered to natural gas customers through local pipelines. It is odourless, colourless, non-toxic and non-corrosive. LNG achieves a higher reduction in volume than compressed natural gas (CNG). Specially designed cryogenic sea vessels (LNG carriers) or cryogenic road tankers are used for its transport. LNG is not stored under high pressure and is not explosive. Although a large amount of energy is stored in LNG, it cannot be released rapidly enough into the open environment to cause the over pressures associated with an explosion. LNG vapours (methane) mixed with air are not explosive in an unconfined environment.

## 1.2 Sources of LNG

Natural gas is a naturally occurring hydrocarbon gas mixture consisting primarily of methane with other hydrocarbons, carbon dioxide, nitrogen and hydrogen sulphide[2]. Natural gas is an important energy source to provide heat and electricity. It is also used as fuel for vehicles and as a chemical feedstock in the manufacture of plastics and other commercially important organic chemicals. Natural gas is found in deep underground natural rock formations or associated with other hydrocarbon reservoirs in coal beds and as methane clathrates. Petroleum is also another resource found in proximity to and with natural gas. Most natural gas was created over time by two mechanisms: biogenic and thermogenic. Biogenic gas is created by methanogenic organisms in marshes, bogs, landfills, and shallow sediments. Deeper in the earth, at greater temperature and pressure, thermogenic gas is created from buried organic material[3].

## 1.3 Properties of LNG

LNG is nothing but the Natural Gas, The higher heating value of LNG is 24 MJ/L. The lower heating value of LNG is 21 MJ/L. The energy density of LNG is 2.4 times greater than that of CNG. The energy density of LNG is comparable to propane and ethanol but is only 60% that of diesel and 70% that of gasoline[4]. The density of LNG is roughly 0.41 kg/L to 0.5 kg/L depending on temperature, pressure and composition, compared to water at 1.0 kg/L [5]. An LNG spill would not damage the ground or leave any residue as it evaporates. In water LNG is insoluble and would simply evaporate.

**Key properties of LNG are as follows:**

Chemical Composition

Natural gas is a fossil fuel that has been created by organic material deposited and buried in the earth millions of years ago. Crude oil and natural gas constitute types of fossil fuel known as "hydrocarbons" because these fuels contain chemical combinations of hydrogen and carbon atoms. The chemical composition of natural gas is a function of the gas source and type of processing. It is a mixture of methane, ethane, propane and butane with small amounts of heavier hydrocarbons and some impurities, notably nitrogen and complex sulphur compounds, water, carbon dioxide and hydrogen sulphide which may exist in the feed gas but are removed before liquefaction[6].Table-1.1shows different composition present in LNG.

**Table 1.1: Typical Chemical Composition of LNG**

| Chemical | Chemical Formula | Low | High |
|---|---|---|---|
| Methane | $CH_4$ | 87% | 99% |
| Ethane | $C_2H_6$ | <1% | 10% |
| Propane | $C_2H_8$ | 1% | 5% |
| Butane | $C_4H_{10}$ | 0.005% | 1% |
| Nitrogen | $N_2$ | 0.1% | 1% |

(Source: Centre for Energy economics, www.beg.utexas.edu/energyecon/lng)

## Boiling Point

Boiling point is one of the most significant properties because it defines when gas becomes a liquid. Boiling point is defined as the temperature at which a liquid boils or converts rapidly from a liquid to a vapour at atmospheric pressure. The boiling point of pure water at atmospheric pressure is 100°C (212°F). The boiling point of LNG varies with its basic composition, but typically is -162°C (-259°F). When cold LNG comes in contact with warmer air, water or the environment it begins to "boil" at that interface because the surrounding temperatures are warmer than the LNG's boiling point. The liquefaction process cools natural gas to change it to a liquid which reduces the volume occupied by the gas by approximately 600 times[6].

## Density and Specific Gravity

Density is a measurement of mass per unit of volume. LNG is not a pure substance. The density of LNG varies slightly with its actual composition. The density of LNG falls between 430 $kg/m^3$ and 470 $kg/m^3$ (3.5 to 4 lb/US gal)[6]. LNG is less than half the density of water that is why LNG will float if spilled on water.

LNG vapours at the boiling point temperature and atmospheric pressure have a relative density of about 1.8[6] which means that when initially released, the LNG vapours are heavier than air and will remain near the ground. Cold LNG vapours are negatively buoyant and more likely to accumulate in low areas until the vapours warm. Therefore, a release of LNG that occurs in an enclosed space or low spot will tend to replace the air (and oxygen) and make the area a hazard for breathing. The rate of LNG vapour ascent depends upon the quantity of LNG released, ambient weather conditions and where the LNG is released. Heat input to LNG in any form will enhance vaporisation and dispersion. LNG vaporises five times more quickly on water than on land[6], depending upon the soil condition. In fact, another strategy for managing the flammability hazard of LNG vapours is to use a water hose to warm the liquid more quickly increase vaporisation rate and make the vapours buoyant sooner, rising away from ignition sources at ground level.

## Flammability

Flammability is the property which makes natural gas desirable as an energy source and yet for the same reason flammability can be a safety hazard. LNG is not flammable because of the lack of oxygen in the liquid.

“Flammable Range” is the range of a concentration of a gas or vapour that will burn if an ignition source is introduced. The limits are commonly called the "Lower Flammable Limit" (LFL) and the "Upper Flammable Limit" (UFL). The flammability limits for methane are 5% LFL and 15% UFL by volume in air. Outside of this range the methane/air mixture is not flammable. In a closed storage tank or vessel the percentage of methane is essentially 100% (mostly liquid and some vapours). Any small leak of LNG vapour from a tank in a well-ventilated area is likely to rapidly mix and quickly dissipate to lower than 5% methane in air. Because of the rapid mixing, only a small area near the leak would have the necessary concentration to allow the fuel to ignite[6]. All LNG terminals use several types of equipment on and around the storage tanks and piping throughout the facility to detect any unlikely leakages and combustible gas mixtures. Table-1.2 shows flammability limits of hydrocarbon fuels present in LNG.

**Table 1.2: Flammability limits of hydrocarbon fuels**

| Fuel | LFL(%) | UFL(%) |
|---|---|---|
| Methane | 5.0 | 15.0 |
| Butane | 1.86 | 7.6 |
| Kerosene | 0.7 | 5.0 |
| Propane | 2.1 | 10.1 |
| Hydrogen | 4.0 | 75.0 |
| Acetylene | 2.5 | 82.0 |

(Source: NPFA Fire Protection Handbook)

## Ignition and Flame Temperatures

The ignition temperature, also known as auto-ignition temperature is the lowest temperature at which a gas or vapour in air will ignite spontaneously without a spark or flame being present. This temperature depends on factors such as air-fuel mixture and pressure. In an air-fuel mixture of about 10% methane in air the auto ignition temperature is approximately 540 °C (1,000°F). Temperatures higher than the auto ignition temperature will cause ignition after a shorter exposure time to the high temperature. The precise auto ignition temperature of natural gas varies with its composition. It has a very hot flame temperature. It burns quickly and is a better heat source than other fuels. The methane in LNG has a flame temperature of 1,330 °C (2,426°F). In comparison, gasoline has a flame temperature of 1,027°C (1,880 °F), which means LNG burns hotter. Also, LNG burns quickly at a rate of about 12.5m$^2$/minute compared to gasoline's burn rate of 4 m$^2$/minute. LNG produces more heat when burning because its heat of combustion is 50.2 MJ/kg (21,600 Btu/lb) compared to that of gasoline which has a heat of combustion of 43.4 MJ/kg (18,720 Btu/lb)[6]. The combustion of LNG produces mainly carbon dioxide and water vapour.

## 1.4 Objective of the Study

Bangladesh is a developing country. Most of the industries and power plants are running by natural gas. So total energy network actually depends on gas but recently the entire country is suffering from gas shortage. According to Petrobangla there is now almost 500 MMCFD gas shortage in natural gas national grid. Gas demand in coming years will increase in such a way that during 2019-20 the demand will exceed the total summation of proved, probable and possible reserves. Government is importing liquid fuel for its rental power generation at a high cost and has to manage a huge subsidy for that to mitigate the power crisis situation that occurred during 2009-10. Many gas based power plants cannot run properly for the shortage of gas. Fertilizers, Industries, CNG stations cannot operate properly for the same reason. So import of LNG can be one of the solutions. That is why floating LNG terminal and LNG regasification plant has been proposed. According to the economic condition of Bangladesh the project is not financially viable with a very low domestic gas price. The objective of this study is to:

- Review the energy situation of Bangladesh.
- Analyze the world of LNG trade and price.
- Financially analyze the LNG import and its impact on local gas price.
- Set gas property requirement for any imported gas to enter the national gas transmission pipeline network.

## 1.5 Procedure/ Methodology

The method of the study comprises:

- Review of relevant reports, studies and documents.
- Discussion with concerned officials.
- Data collection from Petrobangla, BPC, BPI, EMRD.

- Estimate the Approximate yearly LNG cost for different year.
- Study the gas sales contracts for gas property and energy requirement.

# CHAPTER 2

# Background of LNG Process

## 2.1 History of LNG:

Natural gas has been known in the Middle East since ancient times, particularly due to seeping gas that was on fire ("burning springs" or "eternal flames") and it was even the object of religious worship in Persia, Greece and India. In China, despite the fact that they had already drilled the first natural gas well two centuries before our era, the practical use of this resource didn't occur until the year 900.

Natural gas was discovered in Great Britain in 1659 but it had not been destined for commercial use until 1790. In the United States, William Hart drilled the first well in 1821[7] and five years later gas for lighting began to be supplied in the town of Fredonia. New York which later gave rise to one of the first gas distribution companies the "Fredonia Gas Light Company". Until 1890, natural gas was distributed and consumed locally and was used only as a light source, but gaskets improved considerably in that year and gas pipelines could reach farther with fewer losses. Even so, gas pipelines didn't exceed 150 km until the beginning of the 20th century.

The first attempt at liquefying various gases including methane was carried out in the mid 19th century by the British chemist and physicist Michael Faraday[8].

German engineer Karl Von Linde who lived in Munich facilitated advances in gas liquefaction on an industrial scale. He invented a heat exchanger and his name is linked to fundamental research on the technique of low temperatures which are necessary for liquefying air and industrially separating nitrogen, oxygen and noble gases. In 1870 he built an absorption machine, as well as the first cooling device by compression. As cooling fluid for this device he used methyl ether in 1873 and ammonia in 1876. In 1895 he liquefied air by compression and expansion combined with intermediate cooling, thereby obtaining almost pure liquid oxygen and gaseous nitrogen[8]. In 1914 in the USA Godfrey Lowell Cabot registered the first patent for transporting liquefied natural gas on a barge. The company that he founded Godfrey L. Cabot, Inc. later became the Cabot Corporation whose subsidiary Cabot LNG built the Everett regasification terminal in 1971 in Boston the first LNG import terminal in the USA[8].

The first commercial liquefaction plant for consumption peaks was built in 1941 in Cleveland, Ohio. LNG was transported by sea for the first time in 1959 aboard the Methane Pioneer, a cargo ship from World War Two that was reconverted for transporting LNG in prismatic aluminium tanks. The Methane Pioneer made the first of seven voyages loaded with LNG from Lake Charles, Louisiana to Canvey Island, United Kingdom[8].

In1964 the British Gas Council signed the first supply contract with Algeria for just under 1 million tons of LNG per year. Arzew had become the first liquefaction plant in the Mediterranean (Algeria) supplying the UK for over 15 years. The Libyan plant at Marsa El Brega had become the second liquefaction plant in the Mediterranean with its production allocated solely to Spain. In the Pacific basin, the Kenai plant (Alaska, USA) started production in 1969, exporting 1.3 mtpa to Japan. A few years later, in 1972 the first Asian LNG plant located in Lumut, Brunei started exporting not only to Japan but also to South Korea. The increase in petroleum prices favoured a strategy of replacing oil with gas in Japan and drove the construction of regasification terminals in the US between 1971 and 1981. In 1977 in the Pacific, Indonesia followed Brunei as an LNG producer and started exports to Japan which it extended to South Korea in 1986. In 1983 Malaysia also joined the group of LNG exporters. The Middle East started to diversify its exports, and in 1977 it started exporting LNG from the Das Island plant in Abu Dhabi (UAE)[8].

## 2.2 Recent evolution and latest developments

In the last decade, not only has there been a proliferation of liquefaction and regasification plants but also a rise in LNG production and transport capacity have increased. The nominal capacity of liquefaction trains has gone from an average of 3-4 mtpa to 7-8 mtpa. The protagonist of this milestone has been Qatar, where expansions with "mega-trains" at the Qatargas and RasGas plants between 2005 and 2010 have meant a scale-up in production capacity. On the other hand, to transport all this LNG the global fleet of LNG ships has grown exponentially going from 100 ships in 1998 to 200 in 2006 exceeding 300 in 2009 and reaching close to 340 by March 2010. At the end of the 90s, the average size was approximately 120,000 $m^3$ while today it's close to153,000 $m^3$. The most frequent size is 130,000 $m^3$[9]. In this new era Australia is becoming a serious competitor for Qatar in the future ranking of the largest LNG producers. If most of the more than 20 LNG planned projects are finally built Australian LNG will represent more than 50% of the Pacific basin production. Most of these projects' feed gas will come from unconventional production specifically coal bed methane. Unconventional gas has also brought a drastic change in the Atlantic Basin. Since the middle of 2008 the rise of Shale Gas in North America has over supplied the market which together with the global recession has stared a dip in US and Canadian gas prices, making LNG imports unattractive. Furthermore, it has originated a new rush for construction LNG plants only this time for exports (liquefaction). The first plans to transform regasification terminals into liquefaction plants were originated for the Kitimat LNG (British Columbia, Canada) and Sabine Pass (Luisiana) projects. These two ground breaking projects were soon followed by several others in both countries. In Canada, the National Energy Board (NEB) has already issued an export license for Kitimat's LNG and in the US the Department of Energy (DOE) has only granted an export permit to Sabine Pass. At this time, an ongoing debate has surged regarding the possible impact of LNG exports on domestic gas prices in the US, making the final number of authorised export projects uncertain. On the demand side, the Fukushima disaster has increased the LNG needs of the World's first LNG importer due to the shutdown all nuclear plants imposed by the

Japanese Government. In average, Japan now needs around 10 additional million tons per year which are keep prices high, both in the short and in the long term deals and confirming the Pacific Basin as the World's main destination of LNG. Another important development in the recent years has taken place in the innovations related to floating LNG units, either for liquefaction or for regasification. Excellerate was the first in building LNG tankers with a regasification unit on board. However, the biggest breakthrough of this innovation has been that it has represented a fast track for new importers. The LNG industry is therefore now one of the World's most international, dynamic and continuous growing sector[9].

### 2.2.1 LNG exporters

By the end of 2011, 18 countries were exporting their gas resources as LNG. In addition, five countries, namely Belgium, Brazil, Mexico, Spain and the United States, were re-exporting LNG previously imported from another source.

Qatar is by far the largest LNG exporter. In 2011, the country supplied 75.5 MT of LNG to the market nearly one third (31%) of global supply. Malaysia overtook Indonesia as the second largest LNG exporter in 2011. Together with Australia, these three Pacific Basin exporters accounted for about 27% of the world's LNG supply.

Qatar reached its planned name plate capacity of 77 MTPA, ensuring that country's dominance as the world's largest LNG exporter in 2011. Though Australia has plans to eventually build liquefaction capacity to eclipse Qatari capacity, it remained the world's fourth largest LNG producer in 2011.Table-2.1 shows the LNG exporting countries till 2011.

**Table-2.1 LNG exporters, 2011**

| Exporter | Metric Ton |
|---|---|
| Qatar | 75.5 |
| Malaysia | 25.0 |
| Indonesia | 21.4 |
| Australia | 19.2 |
| Nigeria | 18.7 |
| Trinidad | 13.9 |
| Algeria | 12.6 |
| Russia | 10.5 |
| Oman | 7.9 |
| Brunei | 6.8 |
| Yemen | 6.7 |
| Egypt | 6.4 |
| UAE | 5.9 |
| Equatorial Guinea | 4.0 |
| Peru | 3.8 |
| Norway | 2.9 |
| USA | 0.3 |
| Libya | 0.1 |
| Total Exports | 241.5 |

(Sources- Waterborne LNG reports, US DOE, PFC Energy)

### 2.2.2 LNG importers

Japan and Korea are the world's dominant LNG importers, consuming 48% of LNG supplied to the market in 2011. This figure was marginally 1% higher than 2010 volumes due to higher demand for Japan due to the Fukushima disaster that saw the country's nuclear power fleet being replaced with gas-fired power. A second important and growing feature of global LNG imports was the emergence of smaller LNG importers. Table-2.2 shows the LNG importing countries till 2011.

**Table-2.2 LNG importers, 2011**

| Importer | Metric Ton |
|---|---|
| Japan | 78.8 |
| Korea | 35.8 |
| UK | 18.6 |
| Spain | 17.1 |
| China | 12.8 |
| India | 12.7 |
| Taiwan | 12.2 |
| France | 10.7 |
| Italy | 6.4 |
| USA | 5.9 |
| Turkey | 4.6 |
| Belgium | 4.5 |
| Argentina | 3.2 |
| Mexico | 2.9 |
| Chile | 2.8 |
| Canada | 2.4 |
| Kuwait | 2.4 |
| Portugal | 2.2 |
| UAE | 1.2 |
| Greece | 1.0 |
| Dominican Republic | 0.7 |
| Thailand | 0.7 |
| Brazil | 0.6 |
| Netherlands | 0.6 |
| Puerto Rico | 0.5 |

(Sources- Waterborne LNG reports, US DOE, PFC Energy)

## 2.3 The LNG process chain

Since 1964 LNG production, export, import and distribution has followed a process sequence similar to that illustrated in Figure 2.1 below. A brief overview of the various steps along this chain is provided below.

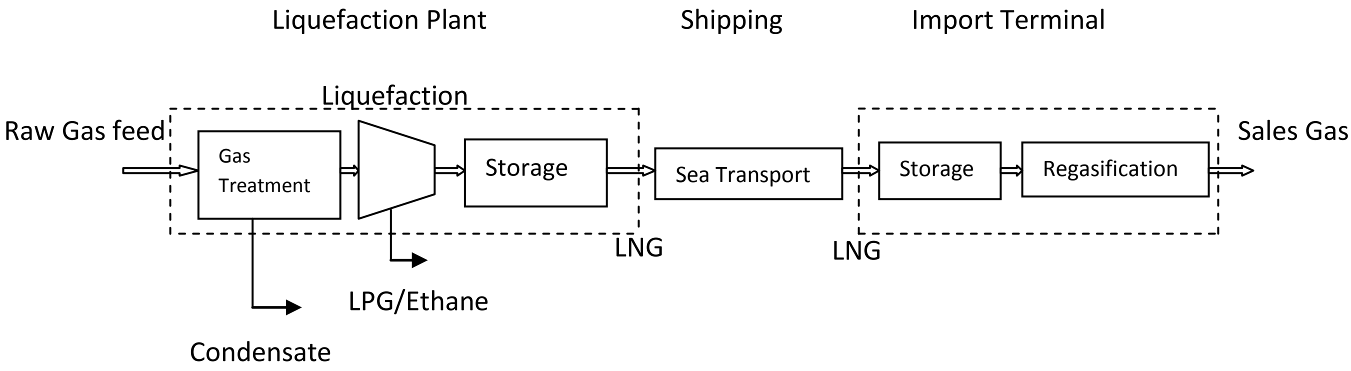



Figure 2.1: LNG process chain.

(Source: http://www.centreforenergy.com/AboutEnergy/ONG/ LiquifiedNaturalGas)

### 2.3.1 Extraction

Extraction of the natural gas from the earth's surface is the first step along the process chain. Situation in which domestic gas supply is inadequate to meet intra country demand LNG is imported. Once a potential natural gas field has been located by a team of exploration geologists and geophysicists, a team of specialists drill down to where the natural gas is thought to exist. After a well has been drilled and the presence of commercially viable quantities of gas has been verified the next step is to extract the natural gas (and/or oil) out of the ground and process it. At this point, the natural gas which is extracted from the ground is called "feed" gas. Before a commercial market for LNG existed the gas associated with oil went unused and was wasted in a flare. Now it can be used as LNG. It is important to emphasize that raw natural gas has to be purified before use it in homes and factories. The natural gas used by the consumers is almost entirely methane although natural gas is associated with a variety of other compounds and gases (e.g., ethane, propane, butane, pentanes, hydrogen sulphide [$H_2S$], carbon dioxide [$CO_2$], helium and nitrogen), as well as oil and water, which must be removed during production prior to liquefaction.

## 2.3.2 The Natural gas liquefaction plant

Step two in the process chain is cleaning the natural gas at the liquefaction plant. A series of processing steps allows the separation and removal of the various extraneous compounds from the natural gas prior to liquefaction.

Production purification

One of the primary purposes of the liquefaction plant is to provide consistent composition and combustion characteristics through the cooling and condensing of the natural gas so it may be loaded as LNG on tanker (ships or trucks) and delivered to the end user. The combustion characteristics and content consistency are critically important to obtain pipeline quality gas. Pipeline quality natural gas typically contains 85% to 99% methane[9]. It also contains the heavier hydrocarbons and other substances which are not removed during the processing. Figure 2.2 provides a summary of the stripping process that is used to remove many of the compounds present in the feed gas as it comes out of the ground prior to beginning the liquefaction process.

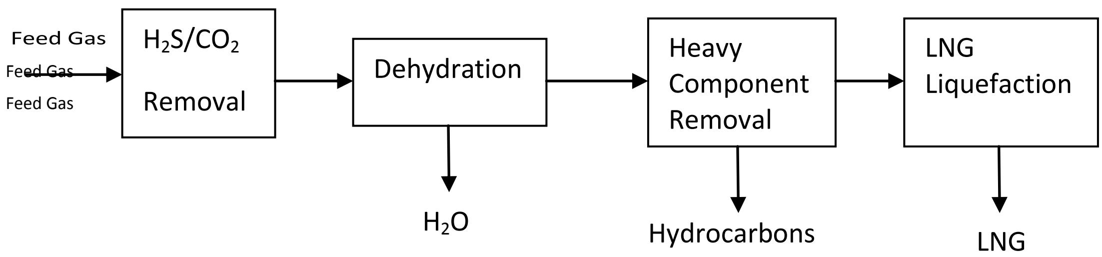



Figure 2.2: The production process flow for natural gas prior to liquefaction

(Source: Bob Shively, John Ferrare, Belinda Petty.2010. Understanding Today's Global LNG Business.)

More specifically, carbon dioxide and water are extracted upstream of liquefaction or they would cause damage to liquefaction facilities by freezing. Hydrocarbons heavier than methane are sometimes also separated and sold as raw materials to the petrochemical industry or as fuel.

## Liquefaction

Natural gas is converted from its gaseous state to a liquid state so that it can be transported via tanker. In the simplest of terms, the liquefaction process takes raw feed gas, removes impurities and other components, cools the gas until it liquefies and finally moves the liquid into storage tanks. The LNG is then loaded onto tankers for transportation to market.

The three basic steps of the liquefaction process are as follows:

1. Removal of impurities and recovery of natural gas liquids (NGLs)

2. Refrigeration of the gas until it liquefies

3. Movement of the LNG to storage and ultimately into the tanker

### *1. Removal of impurities and recovery of NGLs*

The gas supply that comes from the production field is called raw feed gas. This is typically made up of methane with other hydrocarbons such as ethane, propane, butane and pentane and substances such as water, sulphur, mercury and other impurities. The raw feed gas is delivered via pipeline to a processing plant. Here the gas is processed to remove impurities as well as valuable NGLs (Fig-2.3). The first step is pre treatment which includes the removal of acid gas such as carbon dioxide and sulphur as well as mercury and other substances. All of these must be removed either because their freezing points are well above the temperature of the final LNG product or because they are impurities that must be removed to meet pipeline specifications at the delivery point. Next water is removed. After the above steps, the NGLs such as ethane, propane, butane, and pentanes (also known as heavy hydrocarbons) are removed and collected. In many cases the gas is processed upstream of the liquefaction unit using traditional gas processing technology.

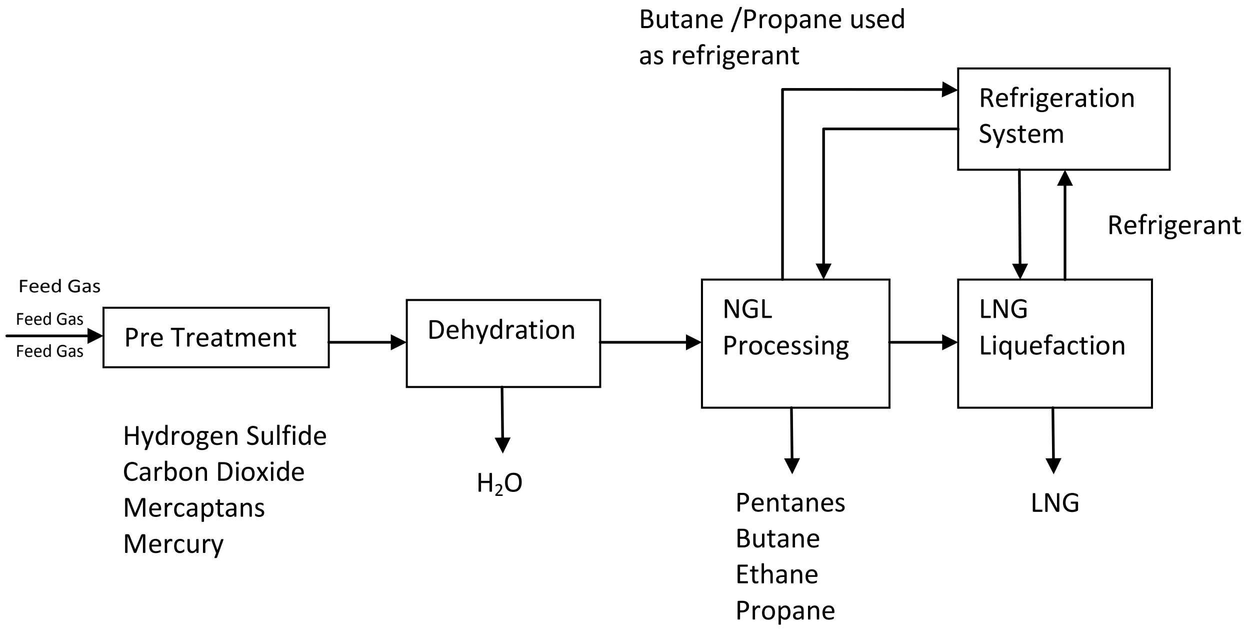



Figure 2.3: Integrated NGLS and LNG process

(Source: Benefits of integrating NGL extraction and LNG liquefaction, 5th Topical Conference on Natural Gas Utilization technology)

In other cases, the NGLs recovery may be done as an integral step in the liquefaction process. The NGLs collected are valuable products in their own right and may also be used as refrigerants for the liquefaction process or may be re-injected into the LNG stream at a later point to adjust the Btu content and flammability characteristics of the LNG. Pentanes and other heavy hydrocarbons are generally exported as a gasoline product. Butane and propane are often also exported as separate products or used as refrigerants. Ethane is often re-injected into the LNG stream and may also be used as a refrigerant.

*2. Liquefaction of the Methane*

Next the methane along with any re-injected components is further cooled to $-260^0$F using LNG liquefaction technology. In this step the methane mixture liquefies into the final cryogenic (cryogenic is the very low temperature below −150 °C/ −238 °F/ 123K) liquid state. Although slightly different processes are used in various liquefaction facilities the basic cooling and liquefaction principles of each process are the same. The key technology is heat exchange. Here, a cold liquid refrigerant is passed through cooling coils and the natural gas stream is allowed to flow over them resulting in cooling of the gas stream. As the temperature drops to about -260$^0$F (-162 $^0$C) the gas becomes liquid the pressure that maintains in this liquefaction process are 40 bars and 65 bars in case of different process  in case of the single-stage natural gas liquefier that shown in the following Figure 2.4 Design specifications have to be according to the following

Compressor discharge pressure = 24 bar

Compressor suction pressure = 3 bar

Feed (natural gas) operating pressure = 40 bar

Minimum temperature approach in the cold box heat exchangers = 3 K/-270.15$^0$ C

Minimum temperature approach in the condensers, after coolers = 5 K/-268.15$^0$ C

Pressure drop in the heat exchanger = 0 bar

LNG temperature before expansion = 113 K/-160.15$^0$C

Adiabatic efficiency of compressor = 80%[10]

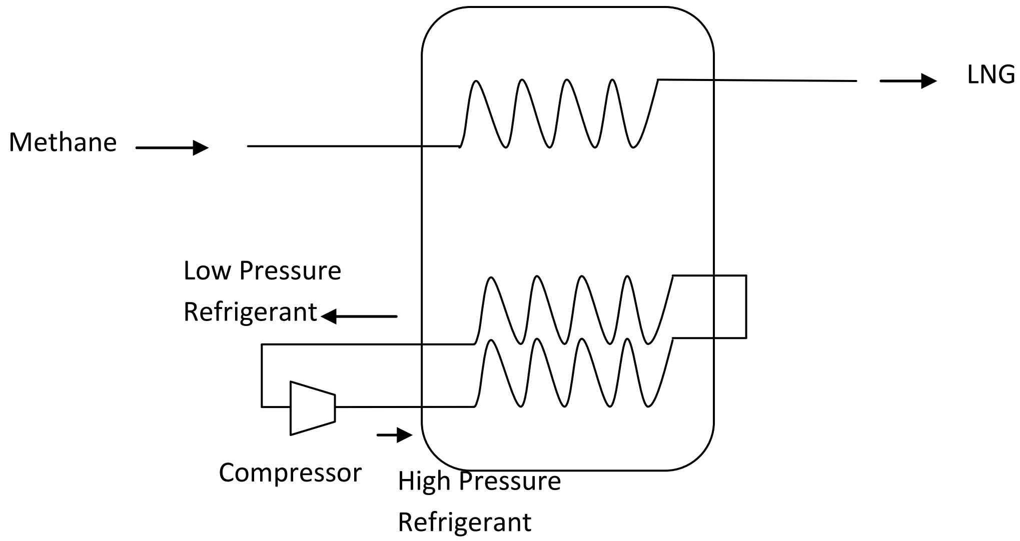



Figure 2.4: The Liquefaction Process (Source: Bob Shively, John Ferrare, Belinda Petty.2010. Understanding Today's Global LNG Business.)

Different liquefaction processes include the APCI MCR Process, the Phillips Optimized Cascade Process and the Linde/Shell Fluid Cascade Process. The process chosen is a design decision and depends on various factors including the composition of the feed gas, the availability of refrigerants, whether the NGLs are being removed upstream, the size of the facility, requirements for operational flexibility, and the cost/availability of power for compressors. Liquefaction facilities are generally constructed in modular units called trains. A train is a complete stand alone processing unit, but often multiple trains are built side-by-side. Train sizes currently range from less than 1 to 5 mtpa[11].

*3. Storage and pumping the LNG into tankers*

After the liquefaction process, the LNG is pumped into a cryogenic storage tank. These tanks are typically double walled, with an outer wall of reinforced concrete lined with carbon steel and an inner wall of nickel steel. Between the two walls insulation is given to prevent ambient air from warming the LNG. The LNG is stored in these tanks until a tanker is available to take the LNG to market. After an empty tanker docks at the berth the LNG is loaded onto the tanker by cryogenic pump through insulated pipes that are attached to the tanker by rigid loading arms. Once the tanker is filled the pipes are disconnected then the loading arms are swung away from the ship and the tanker is ready to sail.

### 2.3.3 LNG transportation

Step three in the LNG process chain is transporting the liquefied natural gas to the consumer. Primary modes are by sea and truck and in a few locations by rail (Japan).

<u>1. By Sea</u>

When LNG is to be transported any great distance, it is most often transported by sea in specialized LNG Carriers. The first voyage of the MV Methane Pioneer in 1959 was from Lake Charles, Louisiana, USA to Canvey Island, United Kingdom. Commercial voyages began in 1964 on the MV Methane Progress and MV Princess from Algeria to Canvey Island[9]. Safety systems on LNG carriers and the training of the crews that operate the vessels have evolved by a process of continuous improvement and are now robust. Recently LNG is transported on double hulled ships specifically designed to contain the cargo at or near atmospheric pressure at a cryogenic temperature of approximately -162°C (-259°F). LNG carriers (Fig-2.5) are a blend of conventional ship design with specialized materials and advanced systems for handling cryogenic cargoes. The containment tanks have layers of insulation which isolate the LNG cargo from the hull by ensuring a minimum distance from the sides and bottom of the hull per the International Gas Codes (IGC) and add layers of protection in the event of grounding or collision. Additionally, this insulation system limits the amount of LNG that boils off or evaporates during the voyages. On many LNG vessels, boil-off gas is used to supplement fuel during the voyage. There are stringent international regulations regarding the construction and operation of LNG

Figure 2.5: An LNG carrier ship

carriers at sea and in port. The International Maritime Organisation (IMO) is the agency of the United Nations responsible for adopting and updating international treaties for shipping safety and security. IMO has adopted approximately 40 conventions and protocols, including the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IMO Gas Code) and the International Maritime Dangerous Goods (IMDG) Code. At the end of 2012 Approximately 362 LNG ships are in service (more than 18000m$^3$ capacity)[12] and the majority of them can each carry 120,000 to 150,000 m$^3$(31 to 37 million gallons) of

LNG. New vessel construction has increased the LNG carrier ship cargo capacity up to 264,000 $m^3$ (71 million gallons). The cost of LNG ships is between $225-250 million for a 135,000 $m^3$ carrier up to approximately $300 million for the larger ships[9].

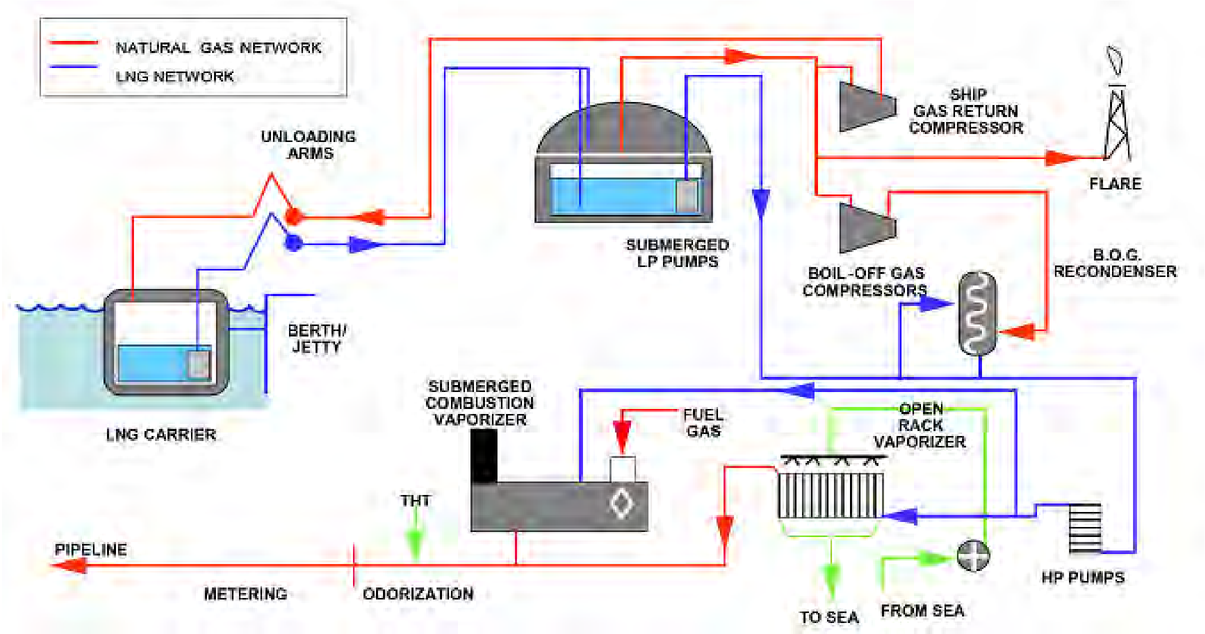
2. By truck

In areas around the world where a liquefaction plant is in the vicinity of regasification facilities, the most cost-effective transportation mechanism for LNG is by tank truck. Using specialised, double-skinned tank trucks liquefied natural gas can be transported to a regasification facility quickly and effectively. In many parts of the world trucking has been used for the transportation of LNG since 1968. LNG trucking is now a mature industry(Fig- 2.6). Using tanker trucks of 6 to 20 tonnes which meet industry requirements[9]. LNG is regularly transported by tank truck in several countries. At 2009, 284 LNG tank trucks transport approximately 1,900,000 tonnes of LNG annually; In Europe: 65,000 individual truck loads travel more than 18,000,000 km delivering close to 1,200,000 tonnes of LNG; In the Americas: Just over 21,000 individual truck loads, travel more than 3,000,000 km with almost 370,000 tonnes of LNG; In the Far East: 56,000 truck loads, travel over 8,000,000 km carrying more than 350,000 tonnes of LNG [13].


Figure 2.6: LNG truck

### 2.3.4 LNG receiving and regasification terminals

The fourth step in the LNG process chain involves the import terminals which are marine or waterfront facilities. LNG carriers deliver the LNG to a marine terminal where the LNG is stored before undergoing regasification which converts the LNG back into its gaseous form. LNG can also be delivered to offshore terminals which are LNG ships constructed to function as Floating Storage and Regasification Units (FSRU) or if no storage is needed, Floating Regasification Units (FRU). Floating facilities allow LNG terminals to be sited offshore. Regasification ships are operating in Argentina, Brazil, the UK and the US. Another type of facility which may receive LNG by ship is known as a peak-shaving facility. These plants which may be operated by utilities store LNG in tanks until it is needed at times of peak demand.




THT-Tetrahydrothiophene,

BOG- Boil Of Gas

Figure 2.7: LNG import terminal process (Source: BV 2009)

An LNG peak-shaving facility is normally connected to the gas supply system and may consist of LNG liquefaction equipment to convert the natural gas into LNG. LNG storage tank(s), pumps, vaporisers and other equipment to turn the LNG back from a liquid to natural gas. In some cases peak-shaving facilities are filled using road tankers from an import terminal. Figure 2.7 shows a typical LNG import terminal process.

# CHAPTER 3

# LNG Receiving and Regasification

## 3.1 Introduction:

It is important to understand the regasification process with respect to Bangladesh's intention of importing LNG. It is relatively simple technology although the size of the equipment and safety procedures requires high initial improvement. An LNG receiving and regasification terminal is a facility at which liquefied natural gas is regasified after shipment by sea from the area of production. The unit has four main functions:

- Receiving LNG tankers and unloading their cargo
- Storing LNG in cryogenic tanks able to withstand temperatures below -160°C
- Regasifying LNG to meet demand
- Feeding gas into the national transmission network.

## 3.2 Major equipment:

There are different designs of LNG import terminals but the overall process is often quite similar. The major equipment components of an LNG receiving and re-gasification terminal are:

- Unloading arms,
- Cryogenic pipelines,
- Storage tank(s),
- Low pressure and High pressure (HP) pumps,
- Boil-off gas (BOG) compressors and re-condensers,
- Vaporisers.

### 3.2.1 Unloading arms

The unloading arms are the place where the carrier and the terminal are connected and through which gas is passed by cryogenic transfer pumps. There are various unloading arms but their dimensions, shape and construction do not differ much. There is an important characteristic of unloading arms is operating envelope that represents a safe shift of the arm due to high tide/low tide, shift of the ship due to unloading or the horizontal shift of the ship due to the impacts of winds and currents. Consequently, these arms are equipped with emergency disconnect systems (Fig- 3.1). To protect both the ship's manifold connection and the terminal's arms a Power Emergency Release Coupler (PERC) is fitted into most arm installations.


Figure 3.1: Unloading arms

(Source: COSCO (Lianyungang) Liquid Loading & Unloading Equipment Co., Ltd.)

This system allows the rapid disconnection of the LNG carrier from the terminal while limiting the amount of LNG released. There are also position detectors to check that the ship is not moving too vigorously. These detectors can activate the emergency disconnection system. The PERC is comprised of two ball valves and an emergency release coupler. If the vessel moves outside of the normal operating range for the arms an ESD (Emergency shutdown device) will be activated automatically and cargo transfer will be stopped. Further movement of the vessel outside of the operating range will activate the emergency release system. The ball valves will close and the emergency release coupler will operate. One ball valve remains attached to the ship and the other stays attached to the arm. The PERC system may also be activated by an operator.

### 3.2.2 Vapour return

All LNG terminals must have one arm for the equalization of pressure between the ship and the terminal. On the loading terminal this equalization goes from the ship. This means that due to the increase in pressure in the ship's storage tanks during loading the ship must lower the pressure in the storage tanks by pushing the excess of gas towards the terminal. On the other hand the unloading terminals must be able to return gas on the ship so that the ship's storage tanks do not enter the vacuum. So there is no automatic termination of unloading. In order to make this possible, the unloading terminals must have two manners of filling the ship with gas. This can be achieved by means of automatically set pressure.

### 3.2.3 Cryogenic pipelines

Typical cryogenic pipeline designs consist of two coaxial pipes or Pipe-in-Pipe (PiP) concept. Some designs add a secondary containment to create the Pipe-in-Pipe-in-Pipe (PiPiP) concept. The inner pipe transports the cryogenic fluid, the annular space provides the necessary insulation properties and the outer pipe offers protection from the external environment (Fig- 3.2).

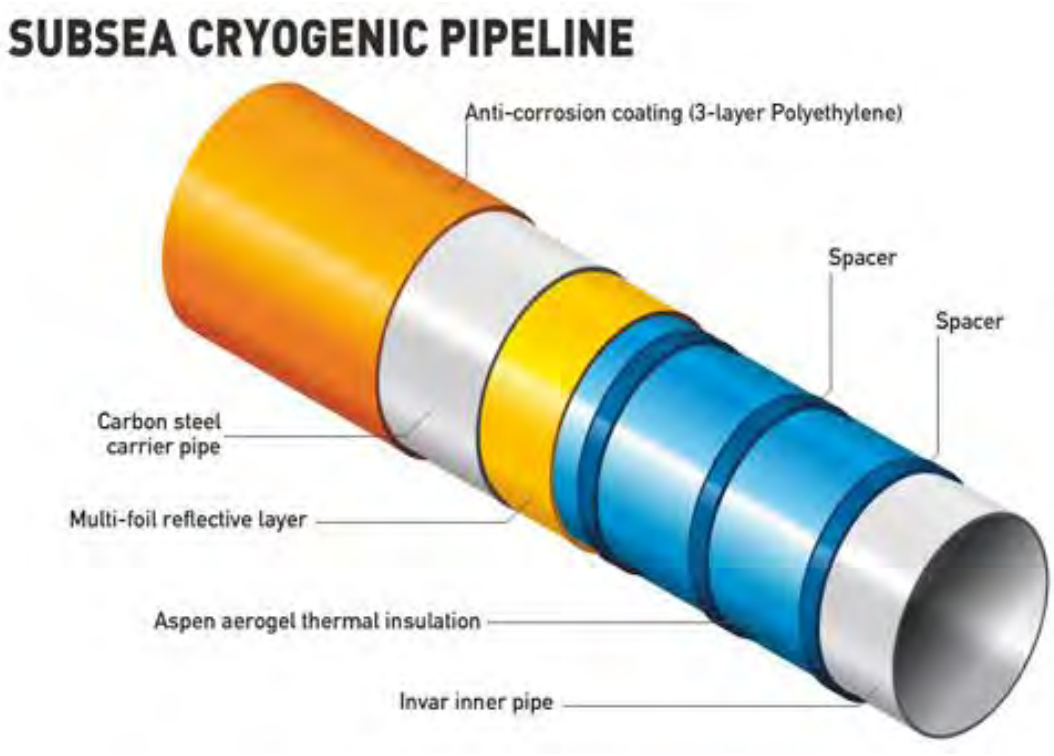



Figure 3.2: Cryogenic pipe (Source: http://total.com)

The primary function of a cryogenic subsea pipeline is to transport LNG safely and reliably during its service life.

### 3.2.4 LNG storage tank

The LNG is pumped at pipeline pressure by high pressure multistage cryogenic pumps from LNG ship to regasification terminal. A liquefied natural gas storage tank or LNG storage tank is a specialized type of storage tank used for the storage of Liquefied Natural Gas. LNG storage tanks can be found in ground, above ground or in LNG carriers. The common characteristic of LNG storage tanks is the ability to store LNG at the very low temperature of -162 °C (-260 °F). LNG storage tanks have double containers where the inner contains LNG and the outer container contains insulation materials. The most common tank type is the full containment tank. Tanks are roughly 55 m (180 ft) high and 75 m (250 ft) in diameter[14].

Figure 3.3: LNG storage tank (Source: Federal Energy Regulatory Commission)

In LNG storage tanks if LNG vapours are not released the pressure and temperature within the tank will continue to rise. LNG is a cryogen and is kept in its liquid state at very low temperature. The temperature within the tank will remain constant if the pressure is kept constant by allowing the boil-off gas to escape from the tank which is known as auto refrigeration. This gas is captured and: a) re-condensed to be sent to the vaporiser with LNG or b) re-injected into the LNG carrier to maintain positive pressure during the unloading of the ship or c) sent to the flare. Storage Tank typically consist of the following (Fig- 3.4):

· **Primary inside tank** - made of a cryogenic material such as 9% Nickel steel, aluminium alloy or reinforced pre-stressed concrete it is now common practice to use 9% Nickel steel for the inner tank in LNG service.

· **Insulation** - loose insulation material (such as perlite) surrounding the inner nickel steel tank (sides, floor and roof).

· **Vapour barrier tank** - made of carbon steel to contain the insulation system and vapour pressure of the primary tank.

· **Outer tank** - reinforced, pre-stressed concrete designed to independently store both the LNG liquid and vapour should the inner wall fail.

· **Domed roof** - reinforced pre-stressed concrete.

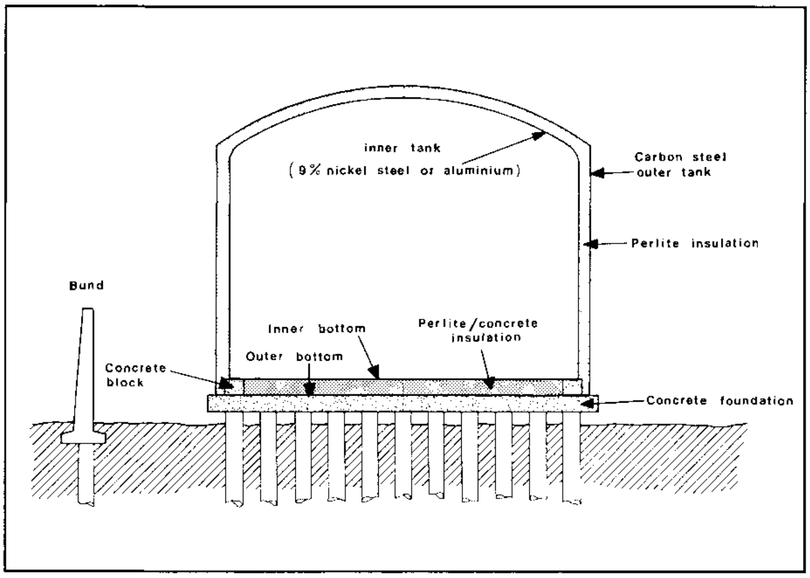



Figure 3.4: Typical LNG tank (Source- lib.znate.ru)

The LNG tanks have a top entry point for both the loading and unloading operations. Two submerged send-out pumps per tank will be suspended from the top of the tank and pump the LNG out of the tanks. All tanks will be designed to simultaneously send out (to the vaporiser units) and to receive LNG (from unloading LNG carriers). The tanks will be fitted with a low-pressure vent which will provide storage tank over pressure protection if the tank pressure exceeds the maximum operating limit of the LNG storage tank design pressure. The storage facility is designed with a venting feature as an ultimate protection against risk of overpressure due to a "roll-over" condition in the LNG tank. LNG "rollover" refers to the rapid release of LNG vapours from a storage tank resulting from stratification. The potential for rollover arises when two stratified layers of different densities exist in a tank. To prevent rollover special instruments called densitometers are used to monitor the development of the layers within the tank there by allowing the operator to mix the LNG within the tank or with that in other tanks to break up the stratification[9].

### 3.2.5 Cryogenic pumps

A type of centrifugal pump that is primarily used to pump very low temperature liquids. They are made with special materials and internal clearances selected to be able to accommodate these low temperature liquids. Other materials might readily fail in these low temperature environments.

Cryogenic pumps have one or more impellers which raise the velocity of the liquid as it passes along the impeller vanes. From there the fluid is directed through the pump volute or diffuser where the velocity is reduced and converted into pressure through a diffusion process. This process is virtually the same as it is in other centrifugal pumps. Furthermore, they are available in many of the same general configurations as other centrifugal pumps including end suction, submersible, vertical column sump and vertical turbine types.

Unlike other types of centrifugal pumps, cryogenic pumps are able to work at very low temperatures that occur in cryogenic services typically several hundred degrees below zero or lower.

Special attention must be taken by the pump manufacturer in the selection of materials for the components as ordinary pump materials would quickly fail at these low temperatures. Also, the running clearances must be adjusted carefully by the manufacturers to account for the dramatically different thermal expansion and contraction of materials at these low temperatures. Special elastomers must be used to accommodate the low temperatures. Finally, special attention must be made to protect these pumps against cavitations since many cryogenic fluids will boil if the temperature drops just a small amount.

### 3.2.6 LNG Boil off gas (BOG) compressor

In LNG storage tank boil off gas (BOG) is continuously generated from LNG liquid level due to externally applying heat and fluctuations to that level. Thus the storage tank internal pressure is increased by boil off gas continuous generation. To keep the tank pressure in designated value boil off gas has to be pumped out from the storage tank. LNG Boil off Gas (BOG) compressor (Fig-3.5) is operated to achieve the function of this purpose suctions directly at low temperature and almost atmospheric

Figure 3.5: LNG Boil off gas (BOG) compressor (Source- blog.daum.net)

pressure and pressurizes to require condition. Pressurized boil off gas discharges for re-condenser to return to the storage tank.

### 3.2.7 LNG Boil off gas (BOG) re-condenser

The most common way of recovering BOG is taking it from the LNG Storage Tanks via the BOG compressors (Fig-3.6), where it is compressed and sent to the BOG re-condenser for re-liquefaction and combined with the send out flow. The re-condenser is an apparatus where the BOG generated in the terminal is put in contact with sub-

Figure 3.6: LNG Boil off gas (BOG) condenser (Source- Boardman)

cooled LNG and is condensed, recovered and mixed with the rest of the LNG send-out flow rate. There are two main functions a re-condenser could carry out, one of them is to recondense and recover the BOG and the other is to serve as LNG buffer giving a hold up between LP pumps and HP pumps. Other important characteristic is the operating pressure in the re-condenser.

## 3.3 Vaporiser

Vaporiser is a system and method for regasification of liquefied natural gas (LNG) using with an intermittent heating during regeneration mode and/or optionally during the production mode, particularly for continuous production of natural gas in a base-load LNG regasification plant. The main types of vaporisers used in the LNG industry are Open Rack Vaporisers, Submerged Combustion Vaporisers, Intermediate Fluid Vaporisers and Ambient Air Vaporisers.

### 3.3.1 Open Rack Vaporiser (ORV)

Open Rack Vaporisers derive heat necessary to vaporise LNG from seawater (Fig-3.7). The water is first filtered to avoid the presence of small solid particles in the ORV.

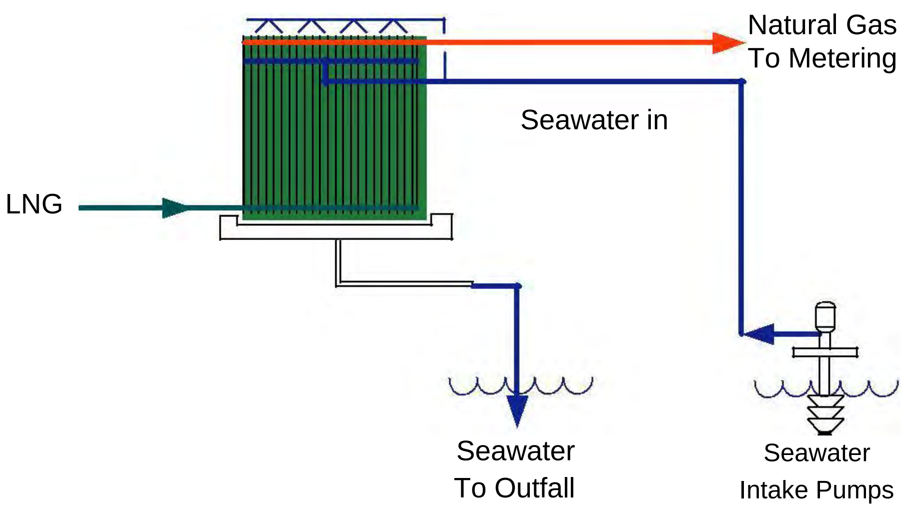



Figure 3.7: Open rack vaporiser flow scheme (Source: www.gastechnology.org)

It then falls onto panels of tubes containing LNG and then gathers in a trough underneath before being discharged back into the sea. The LNG passing through the tubes is heated and vaporises. The tubes are specifically designed to optimise heat exchange.

### 3.3.2 Submerged combustion vaporiser (SCV)

Submerged Combustion Vaporisers burn natural gas produced by the terminal and passes the hot gases into a water bath containing a tubular heat exchanger where LNG flows. The froth produced by the combustion gas increases the efficiency of heat

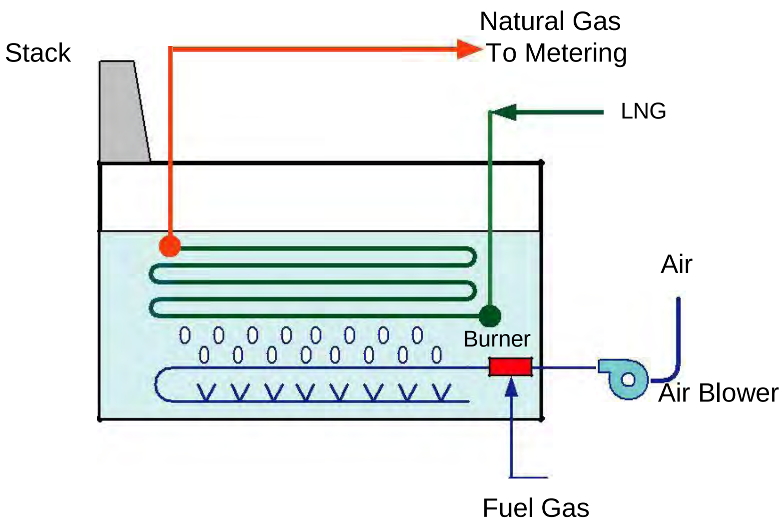


Figure 3.8: Submerged combustion vaporiser (Source: www.gastechnology.org)

transfer between the water and the LNG and prevents ice from forming on the tube bundle (Fig- 3.8). Submerged Combustion Vaporisers burn 1.2 to 1.5% of the natural gas processed.

### 3.3.3 Intermediate fluid vaporiser (IFV)

An Intermediate Fluid Vaporiser regasifier relies upon two levels of thermal exchange. The first is between LNG and an intermediate fluid such as propane and the second is between the intermediate fluid and a heat source which is usually seawater (Fig- 3.9). The surface area of the exchangers is designed to optimise the heat exchange. IFVs prevent freeze-up and reduce fouling risks.

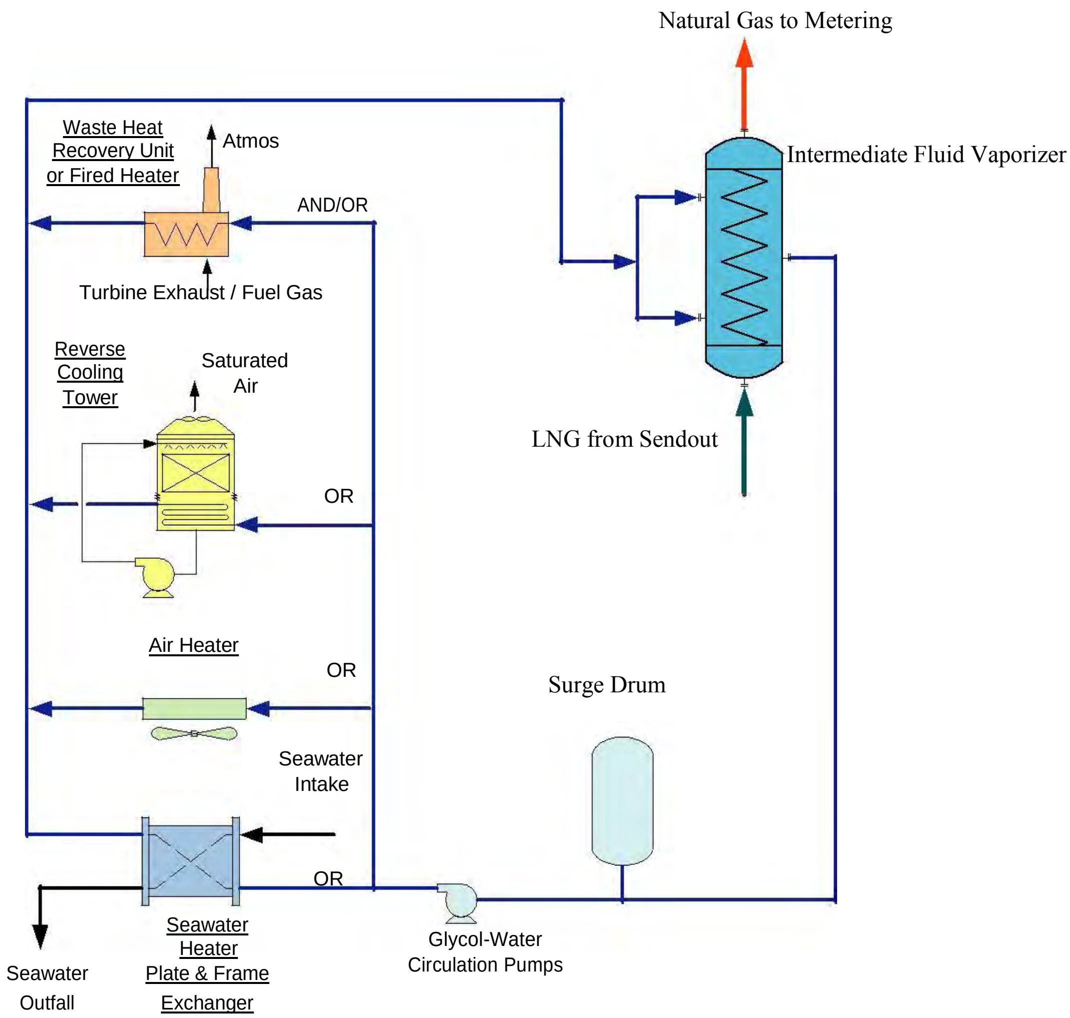



Figure 3.9: Intermediate fluid vaporiser (Source: www.gastechnology.org)

This particular operational benefit can justify the increased cost that arises from the use of an intermediate fluid.

### 3.3.4 Ambient air vaporiser (AAV)

This vaporiser uses the heat from the air. It is a proven technology and has generally been used for smaller installations such as LNG satellite terminals fed with LNG by road truck.

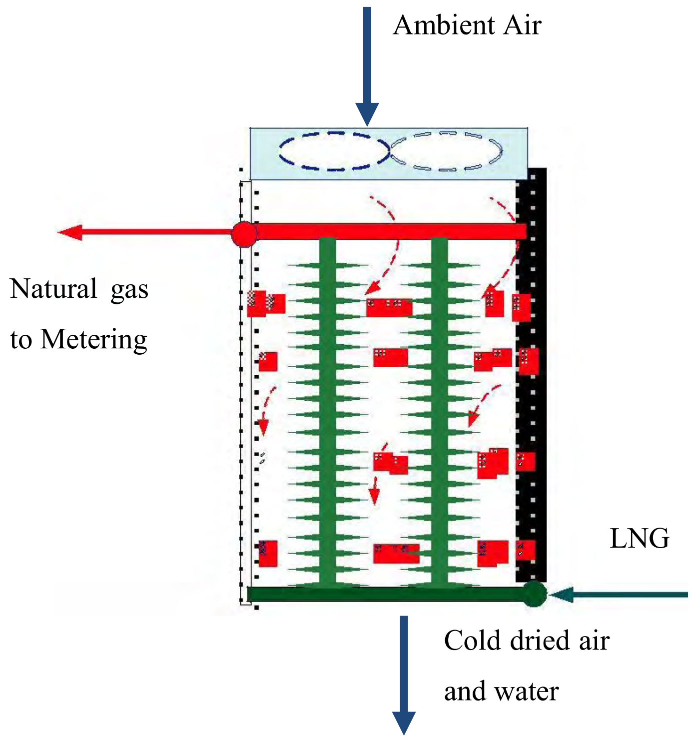



Figure 3.10: Ambient air vaporiser (Source: www.gastechnology.org)

The units may have natural convection of fan-assisted air flow. Some larger units have recently been installed at LNG import terminals where seawater systems are considered unsuitable (Fig-3.10).

These are the commonly used equipment in receiving and regasification terminal. Now a days another terminal is used by converting an existing LNG carrier in different areas which is called the FSRU (Floating Storage and Regasification Unit).

## 3.4 Floating storage and regasification unit (FSRU)

The FSRU is to be permanently moored offshore and export gas to shore through a subsea pipeline (Fig-3.11). The LNG terminal is a steel mono hull tanks arranged in the middle, regasification plant in the forward end and crew facilities, control room and utility machinery in the aft end. The terminal is permanently moored to the seabed with a turret mooring arrangement and the gas send out line is arranged through the turret down to the seabed and to shore via a seabed pipeline. The LNG tankers offloading to the floating terminal will be moored in a side-by-side configuration. Berthing, loading and unberthing will take approximately 24 hours[15]. Process and utility systems have been chosen and designed for simplicity and least retrofit as well as for ease of operation and maintenance. Active global floating LNG regasification capacity is 1,698.4bcf till 2012 and Global floating LNG Regasification Market to record planned capacity addition of 3,488.5 bcf Between 2012 and 2016[16]. Conversion typical FSRU size is 137000m$^3$ with maximum send out 0.52 bcfd, FSRU with spheres larger capacity LNG storage size is 2,70,000 m$^3$, nominal send out 0.8 bcfd and  large Capacity FSRU new build LNG storage 3,20,000 m3, nominal send-out 1.3 bcfd [17].


Figure 3.11: Floating storage and regasification unit

## Systems Description

### Turret mooring

The turret is to be connected in the forward part of the ship resulting in the need for modification of the bow area. The turret shall be configured to provide an essential non rotating platform for supporting the anchor lines flexible risers and associated control/service lines. The turret shall be equipped with a turntable which allows 360° continuous rotation of the FSRU.

### Side-by-side mooring system

The terminal shall allow safe berthing of standard LNG carriers. There is no need for modification of these LNG carriers. The side-by-side mooring system shall consist of the following:

- Primary and secondary fenders
- Nylon mooring lines. The lines shall be connected to the wire part of the LNG carrier line by special mooring shackles
- Roller fairleads, for guiding the nylon lines as required.
- Hydraulic quick release hooks with integrated capstan and adjustable release load

The terminal will be fitted with an azimuth thruster, for control of the terminal during LNG carrier berthing/unberthing. During berthing the cargo tanker will need the assistance from two tugs with minimum 50 tonnes bollard pull. After berthing a combination of transverse mooring lines and spring lines will be used to limit horizontal relative motions.

### Loading arms

The FSRU will be provided with standard loading arms to allow side-by-side transfer of LNG and vapour return. The FSRU shall be equipped with three 16 inch loading arms two for LNG and one for vapour return. Operation with two LNG arms will ensure a loading time of 16 hours. Berthing, loading and unberthing will take approximately 24 hours. The loading arms will be quite similar to the type that is used on onshore terminals however modified to account for relative motions between carrier and FSRU. The FSRU will also be fitted with equipment for guiding the arms onto the carrier's connection flanges. This pre-coupling guide operation will be necessary to compensate for relative motion during coupling when the relative motion exceeds +/- 0.5m [18].

LNG Regasification system

LNG is sent from the tanks to the regasification skid situated forward. The regasification skid essentially comprises booster pumps and steam heated vaporizers. The booster pumps will increase the pressure to about 90 bar, before the high pressure LNG is vaporised, after which the gas passes through a fiscal metering unit and is sent to the subsea pipeline via the gas swivel and flexible risers.

BOG handling

Maximum boil-off from the storage tanks is 0.25%[18]. The boil-off gas is collected and used as fuel for steam generation in the FSRU boilers. The FSRU will operate at a higher tank pressure than the offloading LNG carriers, thus avoiding the need to install unnecessary BOG handling equipment.

Land-based LNG regasification terminals can cost upwards of $700 million for a facility with a peak capacity of about 7.75 million tons per year (around 1 bcf/d). A newly built FSRU costs close to $260 million and can be ready in just 14-16 months. FSRUs have one big drawback of less capacity. Most have a peak capacity of around 4 million tons annually (about 500 million cubic feet per day), though some of the new ones are getting closer to 1 bcf/d [19]

# CHAPTER 4

# Bangladesh Energy Sector

## 4.1 Sector scenario

Bangladesh is a developing nation. The per capita energy consumption in Bangladesh is one of the lowest in the world. Bangladesh faces an acute energy crisis that has taken the form of a sectoral emergency. The frequency of power and gas outages is threatening citizen's welfare. The annual loss to production and income from power outages could well exceed 0.5% of GDP per year. Every 1% of GDP growth is estimated to lead to a growth of 1.4% in electricity demand in a typical developing country. For a 5-6% typical annual economic growth rate this would imply a need for close to 7-8% growth in electricity supply[20]. In the rural economy low power connectivity is a serious constraint to non-farm sector growth.

Due to the severity of the power crisis the Government has been forced to enter into contractual agreements for high cost temporary solutions such as rental power and small IPPs on an emergency basis much of it is diesel or liquid-fuel based. This has imposed tremendous fiscal pressure, as budgetary transfers are routinely made to the power sector in order to enable it to stay current on payments to power suppliers. The Government is aware that precious resources are being diverted to cover operating losses of the utility that arise from purchasing short term high cost power which is not sustainable for the financial health of the sector in the long run. Therefore, the longer term strategy embedded in the power sector plan is to use budgetary allocations to promote low cost, sustainable expansion of power generation, transmission, and distribution capacity.

Shortage of power is a reflection of an even bigger challenge in terms of limited supply of primary energy. Bangladesh showed early promise in terms of having adequate sources of primary energy from natural gas and coal and to a limited extent from hydro power. Lack of adequate planning and investment in primary energy for many years has caused a serious shortage of primary energy in Bangladesh. As a result, energy shortage has emerged as a binding constraint on growth in Bangladesh. Also, there has been no new capacity addition to fuel sources for power generation. With a power sector which is almost solely dependent on natural gas fired generation the country is facing a simultaneous shortage of natural gas and electricity. Nearly 400-800 MW of power could not be availed from the power plants[21] due to shortage of gas supply. Other fuels for generating low-cost, base load energy such as coal or renewable source like hydropower are not available yet.

## 4.2 Sources of energy supply

At present, Bangladesh has energy supply from both renewable and non renewable sources. However, 75 percent of commercial energy is provided from natural gas. Local companies are extracting 45 percent gas while International Oil Companies (IOCs) produce 55 percent[22]. Imported oil accounts for the major share of the rest of the energy requirement. Bangladesh's annual requirement of liquid fuel is approximately 5.4 million metric ton per year. This fuel used 20.63 % in Agriculture, 6.04% in Industry, 19.14% in Power, 44.86% in Communication and 9.33% in Domestic and Other sectors[23]. Figure- 4.1 shows the scenario of liquid fuel use in different sectors.

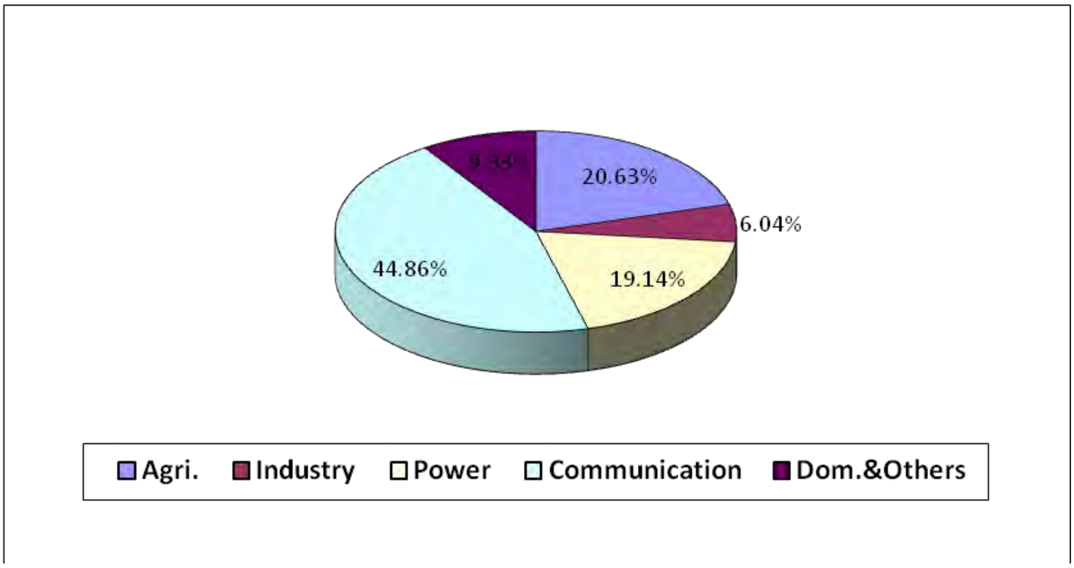



Figure 4.1: Current sector wise use of liquid fuel percent (Year-2012)

Presently, the Bangladesh Power Development Board (BPDB) is operating 42 liquid fuel fired power plants to produce 3000 MW of electricity [24]. Liquefied Petroleum Gas (LPG) is also demanded at around 0.1 million tons per annum[25] mostly for domestic use and also some industries and transportation sector. Apart from natural gas and liquid fuel, coal is mainly used as fuel in the brick-fields and at the Barapukuria Thermal Power Plant which consumes about 2,000 metric tonnes of coal per day having 250 MW installed capacity. Power is also being generated by using solar home system in off-grid areas. About 2.5 million Solar Home System (SHS) has been targeted to install by 2014. Number of SHS Installation up to October 2011 is 11,54,923 (60MW)[26]. Figure-4.2 is showing the fuel used in power Generation in 2012. In the 2011-12FY, the quick rental plants supplied 5587 GWhr of electricity to the national grid which was 15.91 per cent of the total generation.

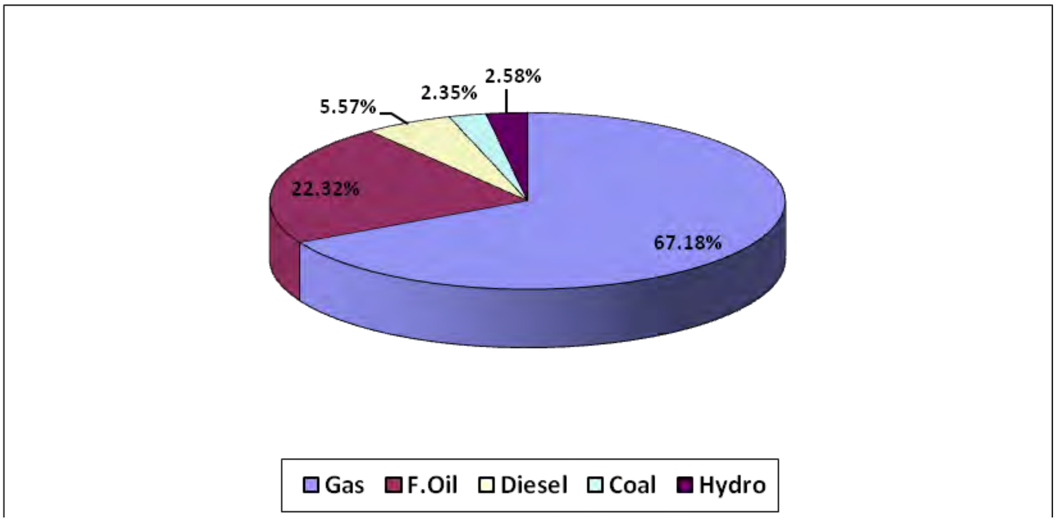



Figure 4.2: Fuel used in power generation (Dec.2012)
(Source: Power Development Board)

Solar power based irrigation pump has been used in a number of areas of the country. In addition there are some poultry and dairy farms in which Biogas plants are being set up. Biogas can be used for power generation on a small scale and also for cooking.

Steps have been taken to generate electricity by Biomass gasification. Recently, a 250 kW Biomass based power plant at Kapasia and a 400-kW rice husk gasification based power generation facility along with a precipitated silica plant at Chilarong, Thakurgaon is going to be set up [26].

About 70% of the population of Bangladesh live in rural areas. The rural economy is characterized by slow growth, high unemployment, insufficient infrastructure and widespread poverty. Due to the lack of electricity supply in rural areas, the rural population depends mainly on biomass as a source of energy. Over 70% of total primary energy consumption is covered by biomass, mainly agricultural waste and wood[27]. Table 4.1 shows different types of fuel that is used for light and cooking.

**Table-4.1 Sources of Light and cooking fuel**

| Source of Light | Percentage(%) |
|---|---|
| Grid Electricity | 53 |
| Solar Energy | 6.9 |
| Kerosene | 39.5 |
| Biogas | 0.1 |
| Others | 0.5 |
| **Source of Cooking fuel** | **Percentage(%)** |
| Wood | 34.8 |
| Kerosene | 1.0 |
| Gas/LPG | 12.6 |
| Electricity | 0.4 |
| Straw/Leaf/Dried cow dung | 51.2 |
| Bio-gas | 0.1 |

(Source- www.idcol.org)

## 4.3 Consumption of natural gas in Bangladesh

At 21-22/10/2013 gas production was 2048 MMCFD [28]. This sector caters for around 40% of the power plant feedstock, 17% of industries, 15% captive power, 11% for domestic and household, 11% for fertilizers, 5% in Compressed natural gas (CNG) activities and 1% for commercial and agricultural uses[25]. Figure- 4.3 shows the scenario of gas use in different sectors in Bangladesh.

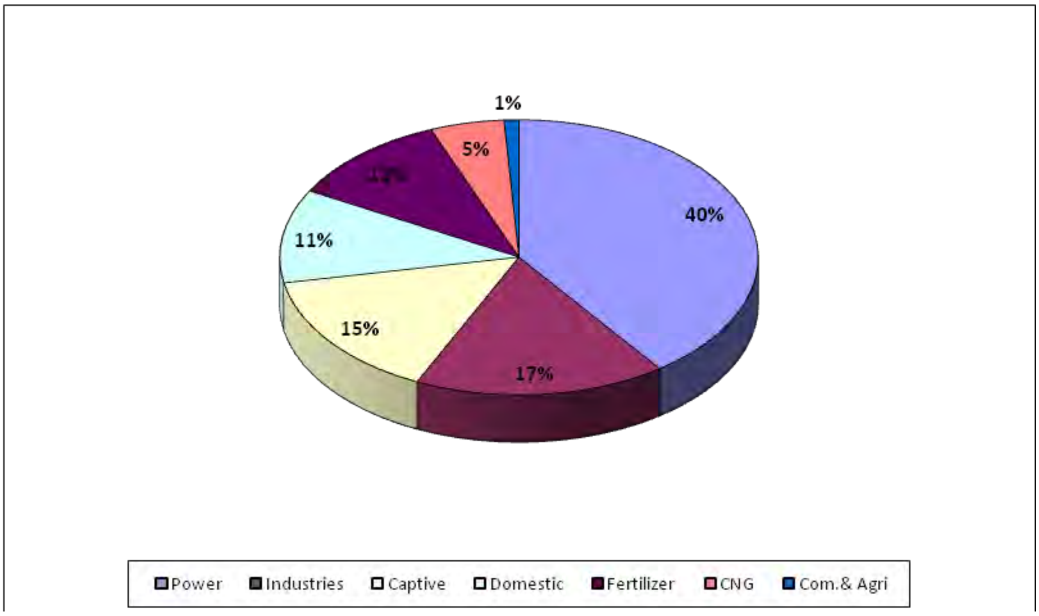



Figure 4.3: Current sectoral use of gas percent (Year-2012)
(Source: Petrobangla)

Growth rate of gas used in different sector during 1991 to 2012 is shown in Figure-4.4 where growth rate is maximum in Industries and minimum in fertilizer sector.

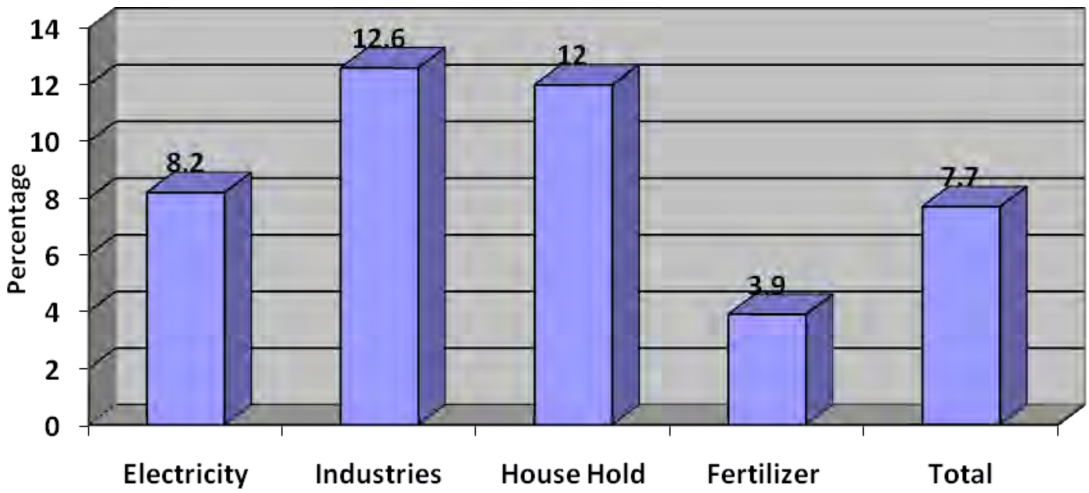



Figure 4.4: Sector wise annual growth rate of use of gas, 1991-2012
(Source-Energy and Mineral Resources Division)

## 4.4 Recent developments

Facing the shortage of gas supply the government has restricted new gas connections from July, 2010[29]. Both industries and home dwellers are facing acute gas crisis presently. Government has started to issue gas connection at household from the May, 2013. Domestic users in Rajshahi and Bhola are now under gas supply network. Gas rationing to CNG fuelling stations and holiday staggering of gas using industrial hubs continuing. In irrigation season and high summer 5 out of 7 urea fertilizer plants remain shut down[30]

Chevron, the largest IOC operating in Bangladesh which produces 1.4 billion cubic feet per day is also working on the expansion project in Bibiyana which will include expansion of the gas plant to increase natural gas production by 300 million cubic feet per day from the Bibiyana field. Expansion project is now over 50 percent completed[31].

Three Petrobangla subsidiaries i)Bangladesh Gas Fields Company Ltd, ii) Sylhet Gas Fields Ltd, and iii) Bangladesh Petroleum Exploration and Production Company Ltd (BAPEX) plan to add 150 to 175 MMCFD gas in national grid. Within that Titas Gas Field will produce 90 MMCFD of gas, Fenchuganj Gas Field will generate 35MMCFD of gas[32]. From April'2013 about 25 million cubic feet gas has been added to the national grid from the Srikail gas field. A newly drilled well at Bakhrabad Gas Field in Comilla has started providing 15 million cubic feet of gas per day to the national gridfrom 19 August'2013. Semutang gas field situated in the Manikchhari upazila under Khagrachhari district is to produce about 20 MMCFD gas[33]. Production of Shangu, Moulavibazar, Rashidpoor have been drastically reduced. One compressor is already installed at Muchai and another two is going to be installed at Ashugaonj and Elenga for increasing pipe line capacity. ConocoPhillips will explore gas in the offshore block 7. Indian state-owned Oil and Natural Gas Corporation (ONGC) will explore in the blocks 4, 9 and Bangladesh's first discovered offshore gas field, Kutubdia[34].

From the above discussion we can find out that recent production of gas is not sufficient according to the demand. According to the Petrobangla gas demand is much more than the production of gas. This difference of demand and supply will increase at the coming future. As a developing country Bangladesh has to maintain its GDP and for that per capita energy income is very important. There are some alternative sources of energy have to be found out by the Government to mitigate the energy deficit. Total infrastructure of industries and power plants are based on natural gas. So if natural gas could be imported, the existing gas network could be utilized as well as the end users' equipment that is based on natural gas could be utilized properly without any mass exchange. There is a little chance of natural gas import by pipe line. So LNG imports can one of the solutions in the current situation. So a brief impact is analysed at the following chapter if LNG is imported and supplied to the existing gas network.

# CHAPTER 5

# Impact of LNG

## 5.1 Current situation of LNG import

To reduce the dependency on imported oil import of LNG is under active consideration. Bangladesh on January 16, 2011 had signed a MoU (Memorandum of Understanding) to import 5.0 million tonnes of LNG annually from Qatar Petroleum for use in the gas industries including fertiliser factories and power plants but the country could not import LNG as necessary infrastructure or facility for this purpose is yet to be built. The MoU expired in March 2013 but Bangladesh expects its tenure to be extended until 2015 and by that time, the country would start importing LNG for domestic purposes after building necessary terminal[35]. Bangladesh Power Development Board (BPDB) is evaluating bids from the interested firms to build a 200-850 MW LNG based Combined Cycle Power Project which includes setting up of an LNG terminal, storage and re-gasification system at Chittagong on a build, own and operate (BOO) basis. Petrobangla is separately planning to float an LNG import terminal with re-gasification capacity for at least 500MMCFD and berthing and mooring facilities for LNG ships with a capacity for 138,000-260,000 cubic metres[36]. The site for building necessary infrastructure for LNG has been located at Moheshkhali Island in the Bay of Bengal. Ninety one km long pipeline from Maheshkhali to Anwara is going to be built. Petrobangla had floated a tender for the construction of the LNG import facility in November 2010 and eventually had picked a US consortium comprising Astra Oil and Excelerate Energy as the project's contractor in August, 2012 but negotiations with the consortium failed due to a misunderstanding over the terms of the bid submitted previously. Figure-5.1 and 5.2 Shows the tentative island location and pipeline route of the project.


Figure 5.1: Tentative sea island location and Pipe Line route for LNG

(Source- LNG project cell, Petobangla)


Figure 5.2: Proposed pipeline from south of Chittagong to Moheshkhali Island

(Source- LNG project cell, Petobangla)

## 5.2 LNG pricing

Natural gas is not yet a globally traded commodity so prices can vary substantially from region to region. Currently Europe, Asia and the U.S each have their own unique pricing mechanism. LNG is mainly bought and sold through long term bilateral contracts of over 10 years rather than on the basis of a traded market price although that is changing rapidly. In negotiations for these long term contracts, the transaction price is determined by the buyer and seller agreeing to a price formula indexed to crude oil prices. The price formula is negotiated in the context of market circumstances such as the balance of supply and demand and crude oil prices. So a variety of formulas are used depending on the circumstances at the time. The formula conventionally used to be a linear formula directly proportional to crude oil prices. From 1990 mainstream formulas have used S-curves with the slope determining the proportional relationship to crude oil[37].

### Asia and the Pacific:

Generally, LNG prices in the Asia-Pacific region are set with reference to crude oil prices. In Japan LNG is fit to crude oil prices by a formula consisting of Indexation to the Japan Customs Cleared Price (JCC)(Fig-5.3).The JCC consists of more than 200 types of crudes from about 30 oil producing countries. This combination makes it highly immune to manipulation and very reliable. It also captures the cost and distance required in order to ship fuel supplies to the region. The original concept tied the landed cost of LNG in Japan quite closely to the landed price of crude oil imported into Japan. This Price would be further adjusted downward if the LNG was delivered FOB to take in to account the cost of LNG shipping assumed by the buyer.

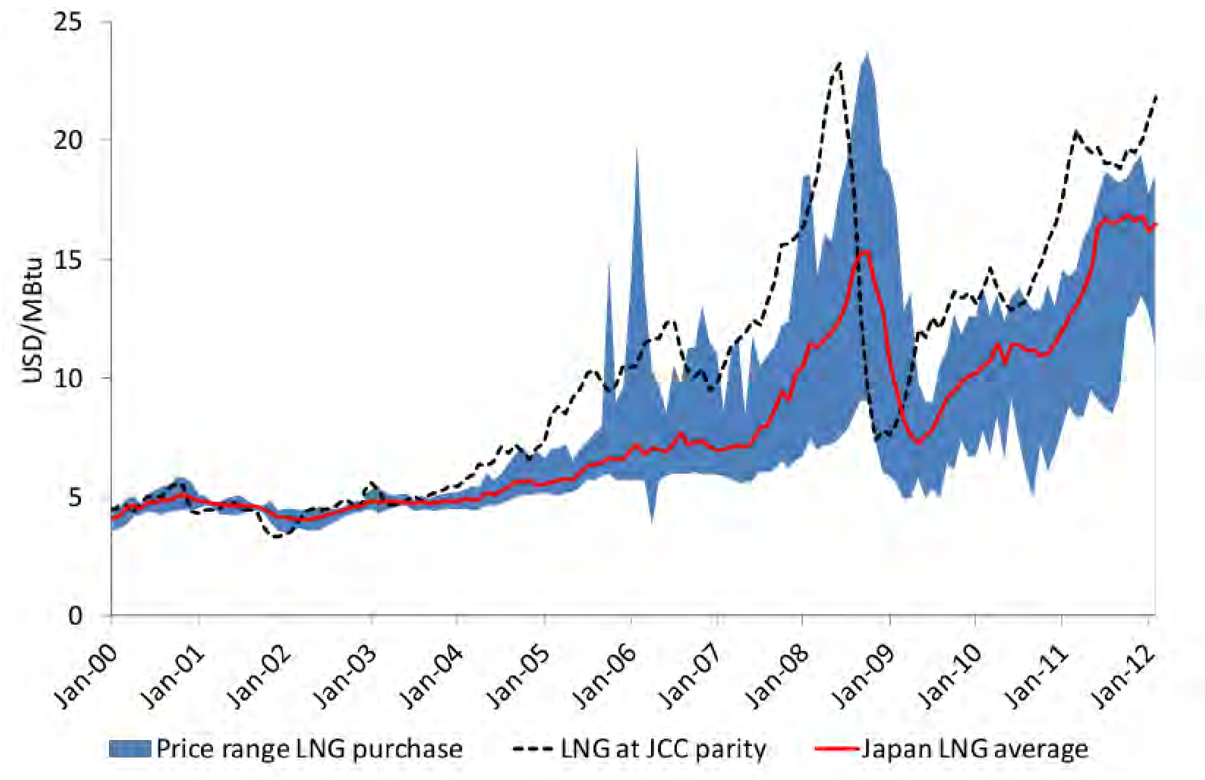



Figure 5.3: LNG Pricing in Japan (Source-Japanese customs)

The volatility of oil prices over the past decades was reduced through the adoption of dampening mechanisms known as S-curve (Fig-5.4). In this formulation the rate of increase (or decrease) in the LNG price is reduced relative to the rate of increase (or decrease) in the crude oil price above (below) a certain price level. This gives the seller downside price protection and corresponding benefit is given to the buyer on the upside.

As Figure 5.3 shows Japan's LNG prices closely followed the JCC's movements. The time lag is a result of averaging several preceding months' JCCs to calculate a single month's LNG price. This delays the immediate impact of sudden changes in the oil price on the LNG price and smoothes out the fluctuations.

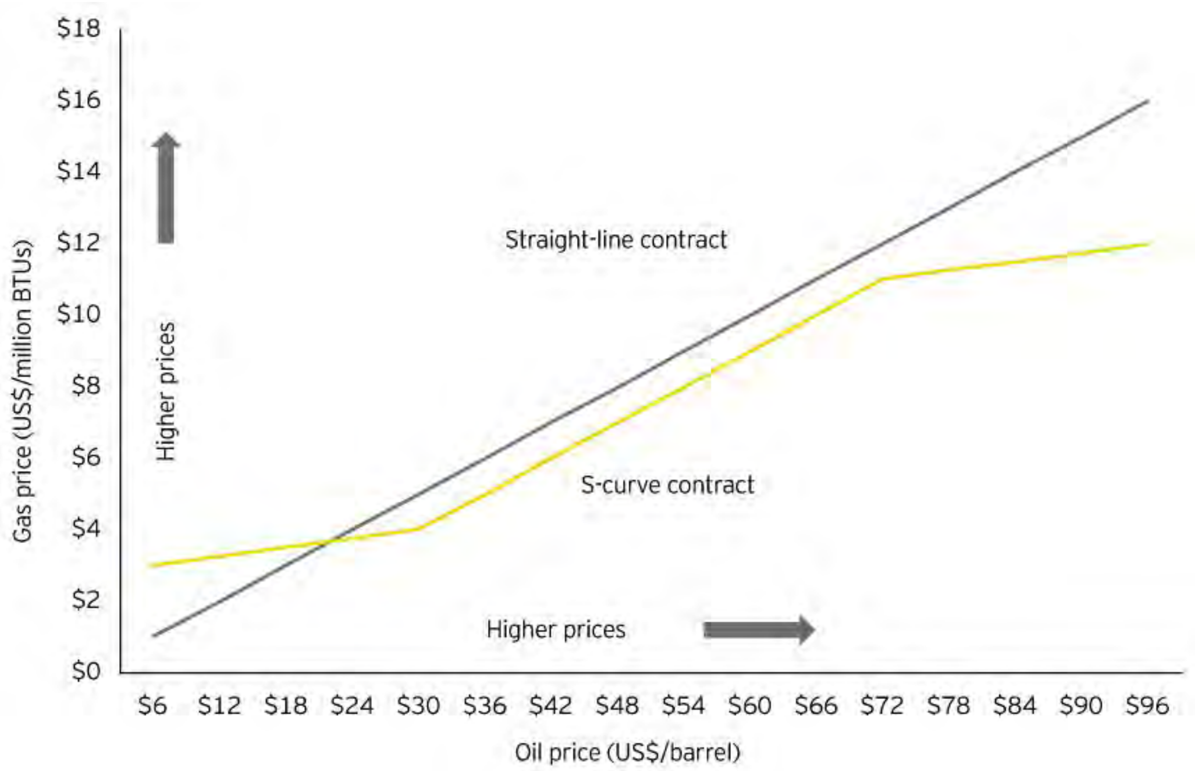



Figure 5.4: S-curve (Source- www.ey.com)

From the sellers perspective this also makes upstream project more readily financeable as the lenders can count on a more predictable flow of revenues.

More recently, this mechanism came under pressure as the rate of growth in the traditional market slowed down just as LNG supply costs were falling. New customers in China and India seeking lower LNG prices. China has held competitive bidding which has resulted in LNG prices in the Chinese market as much as 25% lower than that of Japanese prices.

## Europe:

European LNG markets outside the United Kingdom do not have significant domestic production. LNG prices are set by reference to both oil products and crude. The pricing structures tend to follow the pattern of a base FOB price indexed to a single crude oil (e.g. Brent) or a basket of crudes or a basket of products that compete with natural gas in the end use market including low-sulphur light and heavy fuel oils.

Most European oriented contracts do not have S-curves but many have floor prices. The use of a floor price in any contract raises the issue of whether the contract should also include a ceiling price or alternatively a recoupment mechanism that kicks in when the floor price payments exceed the formula price payment that would have otherwise applied. This recoupment provision would allow the buyer to reduce the contract price to cover the overpayment once the contract price moves above the floor price.

The sample following formula is typical in Europe that contains references to several fuel alternatives with different weightings that reflect a particular market's proportion of alternative fuel uses. Moreover, instead of pegging the LNG price solely to current prices, the formula compares the changes in the various alternative fuels from a base period.

$P_n=P_o \times W_1 F_1/F_{1_o}+W_2+F_2/F_{2_o}$ [36]

Where,

$P_o$= Original negotiated price (at time 0)

W= Weighted factors/percentages of alternate fuels

$F_1/F_2$=Alternate fuels' prices published by third parties. Gas oil, low/high sulphur fuel oil and coal are common alternatives.

Russia exports significant amounts of natural gas of which Seventy percent of non CIS (Commonwealth of Independent States) exported natural gas is destined for Europe with Germany, Turkey and Italy receiving the bulk of these volumes. The remainder of Russia's European gas exports are sold to the newest EU members such as Czech Republic, Poland, and Slovakia. Russia's natural gas exports to Eastern and Western Europe that are transported through pipelines traversing Ukraine and Belarus have in the past been affected by political and economic disputes between Russia and these natural gas hubs. The disputes with Ukraine and Belarus were centred on natural gas prices since 2006. Disputes between Russia and its immediate neighbours resulted in natural gas being cut off to much of Europe. Some European countries are seeking out alternate sources of natural gas like LNG and alternate pipeline routes to ensure security of natural gas supplies[37].

### Alternative pricing mechanisms:

In the Atlantic Basin market (Exporting LNG countries Algeria, Libya, Egypt, Nigeria, Oman, Qatar and Trinidad and importing LNG countries USA, Mexico, Spain, France, Italy, Turkey, Greece, Portugal, UK and Belgium) gas is increasingly expected to provide the fuel for gas fired power plants which need to complete in increasingly open and short term electricity markets. As such the electricity produced from gas must compete on a dispatchable basis with electricity generated from other fuels such as heavy oil, coal and even nuclear. To ensure a reasonable level of dispatch the pricing in power oriented gas contracts may also include factors indexed to high sulphur fuel oils, coal, inflation and even power prices. These indexation factors tend to produce a less volatile gas price and in turn permit the power generator to dispatch the plant on a reasonably high load factor. The advantage of these indexation factors from seller's perspective is that they provide a more stable cash flow.

### North America:

Given the more liquid gas markets in North America LNG pricing mechanisms are generally set with reference to price indices in those markets. LNG terminals in the Gulf of Mexico the natural gas price point is set by reference to Henry Hub or Houston Ship Channel. Pricing both of which are viewed as liquid and transparent reference price points. On the West and East coast pricing is more complex since the basis differentials between those regions and the Gulf of Mexico may be taken into account in the price formula.

There are certain provisions that are often applicable across pricing provisions regardless of the specific trade. For example many contracts allocate responsibilities for payment of taxes, fees and customs duties on LNG sales between buyers and sellers. Generally the sellers assume the obligation for these payments in the exporting countries and buyers assume them in the importing countries. Assessments on LNG tankers depend on whether the terms of trade are FOB, CIF or ex-ship[37]. The following chart at Figure-5.5 shows the gas price at US, EU and Asian market.

$/MBTU

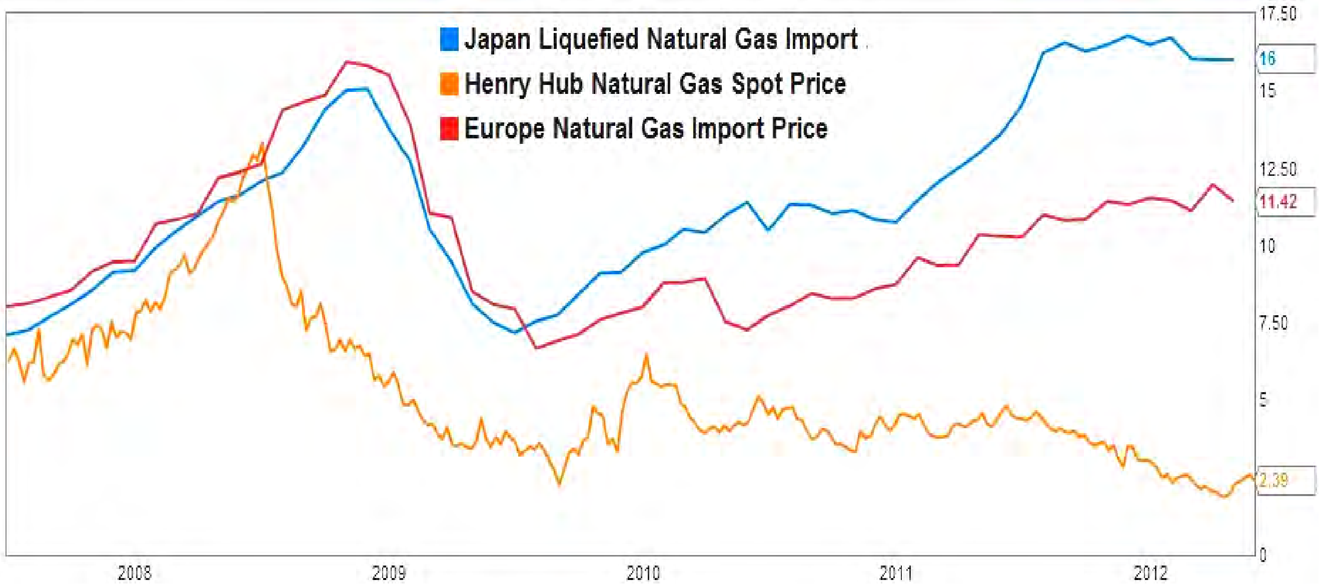



Figure 5.5: Gas prices in market

(Source- http://thomaspmbarnett.com/globlogization/2012/6/9/)

## 5.3 Gas price in Bangladesh

In Bangladesh after starting the commercial production at 1961 natural gas is priced at different sectors for providing energy at reasonable cost and protection of consumers' interest and satisfaction according to the sector demands, benefits, interests, government rules and regulations. So with the time being the natural gas price is increased at different sectors to promote equal opportunities for public and private investments and to develop competitive market. The natural gas price increment at different sectors is given at Table-5.1 which describes the detail price increment scenario from 1968 till recent year (2011) when the increment last executed. According to the Gas Development Fund Rules' 2012 a Gas Development Fund (Research and Development for the entire gas industry upstream and downstream) is created from the SD (Supplementary Duty) and VAT(Value added Tax) that has increased from the last increment of the gas price effective from July'2009. At end users' price different margins like PDF (Price Deficit Fund) Margin, BAPEX ("profit margin" of state-owned gas production) Margin, DWMB (Deficit Wellhead Margin for BAPEX), Wellhead Margin, Transmission and Distribution Margin included from the Petrobangla side and VAT and SD included as the Government's Margin. Table 5.2 shows the Detail Margin considered now at the end user's price level for different sectors.

# Table 5.1: Historical gas tariff structure of Bangladesh

Taka/CM from Dated 01.07.89
Taka/Mcf from Dated 29.07.68 to 30.06.89 Year ⟶

| Categories of Customer | 29.7.68 | 28.9.69 | 19.6.74 | 1.7.74 | 1.12.77 | 30.6.79 | 7.6.80 | 7.5.81 | 1.10.82 | 30.6.83 | 27.6.84 | 30.6.85 | 27.6.86 | 18.6.87 | 1.7.88 | 1.7.89 | 1.7.90 | 1.7.91 | 1.7.92 | 1.3.94 | 1.12.98 | 1.9.00 | 1.1.02 | 1.9.02 | 01.7.04 | 1.1.05 | 1.8.09 | 19.9.11 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Power | 1.20 | 1.60 | 3.60 | 3.72 | 5.00 | 6.25 | 7.75 | 9.30 | 10.50 | 11.50 | 13.05 | 15.66 | 19.09 | 24.82 | 28.54 | 1.16 | 1.33 | 1.38 | 1.52 | 1.68 | 1.93 | 2.22 | 2.33 | 2.47 | 2.56 | 2.61 | 2.82 | 2.82 |
| Captive Power | | | | | | | | | | | | | | | | | | | | | | | 3.68 | 3.53 | 3.53 | 3.73 | 4.18 | 4.18 |
| Fertilizer | 1.20 | 1.60 | 4.92 | 3.72 | 5.00 | 6.25 | 7.75 | 9.30 | 10.50 | 11.50 | 13.05 | 15.66 | 19.09 | 24.82 | 28.54 | 1.01 | 1.16 | 1.30 | 1.32 | 1.46 | 1.68 | 1.93 | 2.03 | 2.12 | 2.19 | 2.24 | 5.86 | 5.86 |
| Industrial | 2.52 | 2.92 | 4.92 | 7.20 | 9.00 | 16.00 | 18.00 | 27.75 | 31.00 | 36.00 | 36.00 | 43.20 | 52.14 | 52.14 | 59.96 | 2.47 | 2.84 | 3.01 | 3.31 | 3.64 | 4.20 | 4.83 | 5.07 | 4.94 | 5.13 | 5.23 | 5.86 | 5.86 |
| Seasonal(Brick Field) | - | - | - | - | - | - | - | - | - | - | 51.00 | 65.00 | 78.30 | 78.30 | 90.05 | - | - | - | 4.12 | 4.53 | 5.20 | 5.98 | 6.28 | 7.77 | 8.07 | 8.23 | 9.47 | 9.47 |
| Seasonal(Yearly) | | | | | | | | | | | | | | | | | | | | | | | 5.07 | 4.94 | | | | |
| CNG Feed Gas | | | | | | | | | | | | | | | | | | | | | | | | 1.52 | 2.47 | 2.47 | 9.97 | 23.00 |
| Commercial | 6.00 | 6.40 | 8.40 | 12.00 | 16.00 | 17.00 | 19.00 | 28.00 | 31.00 | 36.00 | 45.20 | 54.24 | 65.39 | 85.00 | 97.75 | 3.88 | 4.46 | 4.74 | 4.74 | 5.21 | 6.00 | 6.90 | 7.25 | 7.77 | 8.07 | 8.23 | 9.47 | 9.47 |
| Domestic (Metered) | 6.00 | 6.40 | 8.40 | 12.00 | 13.00 | 16.00 | 18.00 | 20.00 | 27.00 | 34.00 | 34.00 | 40.80 | 44.8 | 55.10 | 56.10 | 2.30 | 2.64 | 2.64 | 2.90 | 2.90 | 3.35 | 3.85 | 4.04 | 4.24 | 4.45 | 4.59 | 5.16 | 5.16 |
| Unmetered / Month | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Cooker-One burner | 6.00 | 6.30 | - | 15.00 | 16.00 | 20.00 | 22.00 | 25.00 | 35.00 | 45.00 | 45.00 | 60.00 | 66.00 | 80.00 | 92.00 | 100.00 | 115.00 | 115.00 | 126.00 | 160.00 | 185.00 | 210.00 | 275.00 | 325.00 | 340.00 | 350.00 | 400.00 | 400.00 |
| Cooker-Double Burner | 10.00 | 10.50 | - | 28.00 | 30.00 | 36.00 | 40.00 | 45.00 | 65.00 | 80.00 | 80.00 | 100.00 | 110.00 | 130.00 | 150.00 | 170.00 | 195.00 | 195.00 | 215.00 | 250.00 | 290.00 | 330.00 | 350.00 | 375.00 | 390.00 | 400.00 | 450.00 | 450.00 |
| Additional Burner | 3.00 | 3.15 | - | 8.00 | 9.00 | 12.00 | 14.00 | 16.00 | 27.00 | 34.00 | 34.00 | 41.00 | 45.00 | 56.00 | 64.00 | 74.00 | 85.00 | 85.00 | 93.00 | 93.00 | 93.00 | 93.00 | 98.00 | 98.00 | 98.00 | 98.00 | 98.00 | 98.00 |
| Oven(Each) | 10.00 | 10.50 | - | 28.00 | 30.00 | 30.00 | 34.00 | 38.00 | 58.00 | 74.00 | 74.00 | 89.00 | 97.00 | 121.00 | 139.00 | 169.00 | 185.00 | 185.00 | 203.00 | 203.00 | 203.00 | 203.00 | 215.00 | 215.00 | 215.00 | 215.00 | 215.00 | 215.00 |
| Additional Oven(each) | 5.00 | 5.25 | - | 14.00 | 15.00 | 15.00 | 17.00 | 19.00 | 29.00 | 37.00 | 37.00 | 45.00 | 49.00 | 61.00 | 70.00 | 81.00 | 93.00 | 93.00 | 100.00 | 100.00 | 100.00 | 100.00 | 108.00 | 108.00 | 108.00 | 108.00 | 108.00 | 108.00 |
| Grill(each) | 10.00 | 10.50 | - | 28.00 | 30.00 | 30.00 | 34.00 | 38.00 | 58.00 | 74.00 | 74.00 | 89.00 | 97.00 | 121.00 | 139.00 | 161.00 | 185.00 | 185.00 | 203.00 | 203.00 | 203.00 | 203.00 | 215.00 | 215.00 | 215.00 | 215.00 | 215.00 | 215.00 |
| Additional Grill(each) | 5.00 | 5.25 | - | 14.00 | 15.00 | 15.00 | 17.00 | 19.00 | 29.00 | 37.00 | 37.00 | 45.00 | 49.00 | 61.00 | 70.00 | 81.00 | 93.00 | 93.00 | 102.00 | 102.00 | 102.00 | 102.00 | 108.00 | 108.00 | 108.00 | 108.00 | 108.00 | 108.00 |
| Water Heater 20 Gallon | 20.00 | 21.00 | - | 56.00 | 60.00 | 60.00 | 68.00 | 76.00 | 117.00 | 147.00 | 147.00 | 177.00 | 194.00 | 242.00 | 278.00 | 322.00 | 370.00 | 370.00 | 407.00 | 407.00 | 407.00 | 407.00 | 428.00 | 428.00 | 428.00 | 428.00 | 428.00 | 428.00 |
| Water Heater above 20 gl | 25.00 | 26.25 | - | 70.00 | 75.00 | 75.00 | 84.00 | 93.00 | 146.00 | 184.00 | 184.00 | 221.00 | 242.00 | 303.00 | 348.00 | 403.00 | 463.00 | 463.00 | 509.00 | 509.00 | 509.00 | 509.00 | 535.00 | 535.00 | 535.00 | 535.00 | 535.00 | 535.00 |
| Dryer (Each) | 30.00 | 31.50 | - | 84.00 | 90.00 | 90.00 | 101.00 | 112.00 | 175.00 | 220.00 | 220.00 | 265.00 | 291.00 | 364.00 | 419.00 | 485.00 | 558.00 | 558.00 | 614.00 | 614.00 | 614.00 | 614.00 | 645.00 | 645.00 | 645.00 | 645.00 | 645.00 | 645.00 |
| Refrigerator | - | - | - | - | 75.00 | 75.00 | 84.00 | 93.00 | 117.00 | 147.00 | 147.00 | 177.00 | 194.00 | 242.00 | 278.00 | 322.00 | 370.00 | 370.00 | 407.00 | 407.00 | 407.00 | 407.00 | 428.00 | 428.00 | 428.00 | 428.00 | 428.00 | 428.00 |
| Gas Light Garden(Ext.)use | - | - | - | - | - | - | 10.00 | 20.00 | 27.00 | 34.00 | 34.00 | 41.00 | 45.00 | 56.00 | 64.00 | 74.00 | 85.00 | 85.00 | 93.00 | 93.00 | 93.00 | 93.00 | 98.00 | 98.00 | 98.00 | 98.00 | 98.00 | 98.00 |
| Gas Light inside the room | - | - | - | - | - | - | 9.00 | 10.00 | 14.00 | 17.00 | 17.00 | 21.00 | 23.00 | 28.00 | 32.00 | 37.00 | 43.00 | 43..00 | 47.00 | 47.00 | 47.00 | 47.00 | 50.00 | 50.00 | 50.00 | 50.00 | 50.00 | 50.00 |
| MINIMUM CHARGE / MONTH | | | | | | | | | | | | | | | | | | | | | | | | - | - | - | - | - |
| Domestic(Unmetered) | 5.00 | 5.00 | - | 12.00 | 13.00 | 16.00 | 18.00 | 20.00 | 27.00 | 34.00 | 34.00 | 41.00 | 63.00 | 56.00 | 64.00 | 74.00 | 85.00 | 85.00 | 85.00 | 85.00 | 85.00 | 85.00 | 85.00 | 85.00 | 85.00 | 85.00 | 85.00 | 85.002 |
| Domestic (Metered) | - | - | - | - | - | - | - | - | - | - | - | - | - | 50% of Contract Load | | | | 50% of Contract Load | | | - | - | - | - | - | - | - | - |
| Commercial | 20.00 | 25.00 | - | 60 | 85 | 85 | 95 | 140.00 | 155 | 180 | 180 | 272 | 327 | 50% of Contract Load | | | | 50% of Contract Load | | | - | - | - | - | - | - | - | - |
| Industrial | - | - | - | - | - | - | - | - | - | - | - | - | - | 50% of Contract Load | | | | 50% of Contract Load | | | - | - | - | - | - | - | - | - |

Source-Titas Gas T&D Co. Ltd.)

## Table 5.2: Gas retail price

(Taka per CM)

| Sl. No. | | End User's Price | GOB's Margin 55% | | | PB's Margin (45%) | | | | | | | End User's Price |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | VAT | SD | Total | PDF Margin | BAPEX Margin | Deficit Wellhead Margin for Bapex | Wellhead Margin | Transmission Margin | Distribution Margin | Total (7+8+9+10 +11) | 14 (6+13) |
| 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 |
| 1 | Power | 2.820 | 0.368 | 1.183 | 1.551 | 0.317 | 0.048 | 0.040 | 0.225 | 0.320 | 0.225 | 1.269 | 2.820 |
| 2 | Fertilizer | 2.580 | 0.337 | 1.082 | 1.419 | 0.268 | 0.000 | 0.040 | 0.225 | 0.320 | 0.155 | 1.161 | 2.580 |
| 3 | Captive Power | 4.180 | 0.545 | 1.754 | 2.299 | 0.456 | 0.048 | 0.040 | 0.225 | 0.320 | 0.591 | 1.881 | 4.180 |
| 4 | Industry | 5.860 | 0.764 | 2.459 | 3.223 | 0.766 | 0.048 | 0.040 | 0.225 | 0.320 | 0.955 | 2.637 | 5.860 |
| 5 | Commercial | 9.470 | 1.235 | 3.974 | 5.209 | 1.336 | 0.048 | 0.040 | 0.225 | 0.320 | 1.735 | 4.262 | 9.470 |
| 6 | Feed Gas for CNG* | 23.000 | 3.000 | 9.650 | 12.650 | 6.100 | 0.110 | 0.200 | 0.225 | 0.320 | 0.156 | 10.350 | 23.000 |
| 7 | Domestic | 5.160 | 0.673 | 2.165 | 2.838 | 0.709 | 0.048 | 0.040 | 0.225 | 0.320 | 0.725 | 2.322 | 5.160 |

(Source: Bangladesh Energy regulatory commission, 19 Sept, 2011)

Where,

PDF- Price Deficit Fund paying the IOC's for their production,

BAPEX Margin - "profit margin" of state-owned gas production,

DWMB - Deficit Wellhead Margin for BAPEX covering additional costs of local production,

Wellhead Margin - local production cost,

Transmission Margin - for transmission system operated by GTCL,

Distribution Margin - for gas distribution by the distribution franchise holders.

## 5.4 Demand and supply of gas

Petrobangla's three subsidiary gas production companies and four IOC (International Oil Company) are producing gas in the country. According to Petrobangla's MIS report (March, 2013) monthly production during one month is 1968.439MMCM of which distribution company purchase 1960.30 MMCM that costs TK 6575.27 million and the transmission margin is TK 472.60 million. So total cost of gas in one month is USD 90.35 million considering exchange rate USD1=BDT78. Monthly Gas Production (Mar'13) is given below in Table-5.3:

**Table 5.3: Monthly gas Production (Mar'13)**

| Production Petrobangla Company/IOC | Production (MMCM) | Gas sales by Petrobangla's Production Companies /Gas Sales with (IOC's cost sharing and profit recovery) (MMCM) | Tk(million) |
|---|---|---|---|
| BGFCL | 663.764 | 669.693 | 1845.80 |
| SGFL | 128.859 | 133.440 | 335.21 |
| BAPEX | 75.479 | 64.367 | 227.60 |
| Cairn (Sangu) | 9.520 | 0 | 0 |
| Chevron(Jalalabad) | 209.090 | 76.372 | 521.48 |
| Chevron(Bibiana) | 731.270 | 441.315 | 3031.19 |
| Chevron(Moulovibazar) | 76.072 | 49.944 | 331.00 |
| Naiko(Feni) | 0 | 0 | 0 |
| Tullow(Bangora) | 74.385 | 49.429 | 282.99 |
| Total | 1968.439 | | |
| Gas purchase from prod co. and IOC | 1960.30 | | 6575.27 |
| Transmission (GTCL ) Margin | | | 472.60 |
| Total Purchase Cost | | | 7047.87 |
| Equivalent to USD considering $1=BDT78 | | | $90.35million |

(Source: Petrobangla MIS Report, March-2013)

On the other side Petrobangla distribute the natural gas by its 5 subsidiary companies. With these companies gas is delivered to the end user of different sectors. Table 5.4 shows the monthly Gas Sales (Mar'13). Here we consider one month (Mar'13) gas sales from where we can find that the monthly overall sales is USD124.93 million considering exchange rate USD1=BDT78. Monthly gas sales (Mar'13) to different sectors are given below in Table-5.4:

**Table 5.4: Monthly gas sales (Mar'13)**

| Customer Type | Sale(MMCM) | TK(million) |
|---|---|---|
| Power(PDB,IPP) | 816.655 | 2351.59 |
| Fertilizer | 174.380 | 930.70 |
| Captive, SPP | 314.107 | 1274.17 |
| Industry | 314.925 | 1607.55 |
| Commercial | 19.916 | 194.44 |
| Brick | 0 | 0 |
| Tea | 0.147 | 2.91 |
| CNG | 77.042 | 1864.30 |
| Domestic | 211.577 | 1169.46 |
| Total | 1934.027 | 9744.31 |
| Total Equivalent to USD considering $1=BDT78 | | $124.93 million |

(Source: Petrobangla MIS Report, March-2013)

From Table 5.3 Weighted Average Gas cost price and From the Table 5.4 Weighted Average sale price of gas can be found out in the following way.

Weighted Average Cost Price of gas can be measured from the Table 5.3

$$\frac{\text{Total Cost Price}}{\text{Total Gas Purchase}} = \frac{7047.87 \text{ Million Taka}}{1960.30\text{MMCM}} = 3.59 \text{ TK/MCM} = \$1.31/1000\text{CFT}$$

Weighted Average Sale Price of gas can be measured from the Table 5.4

$$\frac{\text{Total Sale}}{\text{Total Gas Sales}} = \frac{9744.31 \text{ Million Taka}}{1934.027\text{MMCM}} = 5.038 \text{ TK/MCM} = \$1.82/1000\text{CFT}$$

## 5.5 World LNG price and local subsidy:

Worldwide LNG price deal is different according to the contract between supplier and the importing country and also the distance covered to supply the gas. Some recent price from the various countries and contract of Qatar with Pakistan is given in Table 5.5.

**Table 5.5: LNG Markets**

| | |
|---|---|
| DES Japan/Korea Marker (JKM) | |
| JKM (Aug) | 15.900($/MMBtu |
| DES Japan/Korea (JKM) Swaps | |
| Sep | 16.200 ($/MMBtu) |
| Oct | 16.300 ($/MMBtu) |
| Nov | 16.500 ($/MMBtu) |
| DES Southwest Europe Marker (SWE) | |
| SWE (Aug) | 12.570 ($/MMBtu) |
| DES Northwest Europe Marker (NWE) | |
| NWE (Aug) | 12.070 ($/MMBtu) |
| FOB Middle East (Aug) | 13.450 ($/MMBtu) |
| DES West India (Aug) | 14.100 ($/MMBtu) |
| FOB Australia (Aug) | 14.560 ($/MMBtu) |
| (Source: Platts Mcgraw hill Financial, Vol 10/Issue132 July11 2013) | |
| Economic Coordination Committee of Pakistan approves the LNG import from Qatar on July 18.The base cost of LNG from CP(Conoco Philips) was $16.99/mmbtu (million British thermal unit) plus additional cost of about $2.50/mmbtu to be paid to Engro, resulting in a re-gasified LNG cost of $19.49/mmbtu compared to the **open market price of $17.707/mmbtu.** | |
| (Source: Dawn.com, September 14, 2013) | |
| The international price of LNG for July delivery to Asia is $14.49 per mmBtu according to Wall Street Journal report | |
| Sources: China Raises Natural Gas Prices, Still Searching for More Supply, by: Tim Daiss, Posted date: July 09, 2013 www.energytribune.com | |

From Table 5.5 it is found that the LNG price is varying from country to country. So contact of LNG in Bangladesh can be USD15 to USD19 at the End User level as the regasification cost varies from $0.50 to $1.00/MMBtu[37]. So if we consider that the gas price in the end user remain unchanged when LNG is supplied to the national grid with the existing domestic gas the Government has to manage subsidy for the imported gas. Table-5.6 shows the difference between the sale and cost price for 500 MMCFD gas from LNG if the current end users' gas price remain unchanged.

**Table 5.6: Difference between the sale and cost price considering retail price unchanged (500MMCFD)**

| Approximate LNG price at Petrobangla receiving point | Approximate Daily payment for 500 MMCFD | Approximate Daily sale price for 500 MMCFD at current sale price of $1.82 /MCF | Difference between the sale and cost price for 500 MMCFD if the gas price remain unchanged(Daily) | Difference between the sale and cost price for 500 MMCFD if the gas price remain unchanged(Monthly) | Difference between the sale and cost price for 500 MMCFD LNG if the gas price remain unchanged (Yearly) |
|---|---|---|---|---|---|
| (US$/mmbtu) | (million US$) | (million US$) | (million US$) | (million US$) | (billion US$) |
| (A) | B=(A×500)/1000 | C=(1.82×500)/1000 | D=B-C | E=D×30 | F=E×12/1000 |
| 15 | 7.5 | .91 | 6.59 | 197.7 | 2.37 |
| 16 | 8 | .91 | 7.09 | 212.7 | 2.55 |
| 17 | 8.5 | .91 | 7.59 | 227.7 | 2.73 |
| 18 | 9 | .91 | 8.09 | 242.7 | 2.91 |
| 19 | 9.5 | .91 | 8.59 | 257.7 | 3.09 |

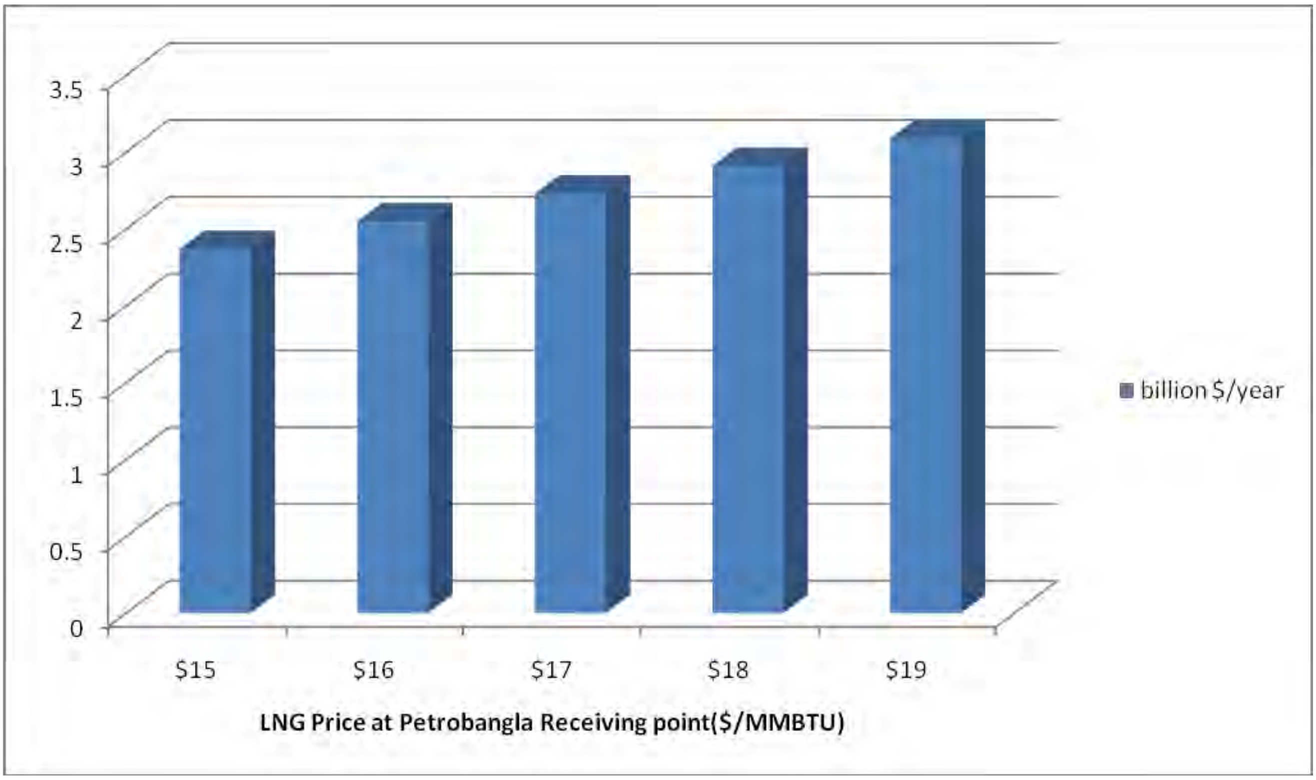



Figure 5.6: Difference between the sale and cost price for 500 MMCFD if the gas price remains unchanged at different rate of LNG

According to the Table No-5.6 and Figure 5.6 it is found that if the gas retail price is unchanged difference between the sale and cost price for 500 MMCFD LNG per year is a huge amount. For this if Government have to manage subsidy yearly at such a high rate it can affect the economy as well as the foreign reserve of the country.

In real scenario neither the Demand nor the price of gas for the end user side will remain unchanged in the coming future. So from the demand of previous years a model for future demand can be made by using statistical software. The process is shown below.

## 5.6 Demand projection

The natural gas price in Bangladesh have been among the lowest in the world partly by design and partly because they have not been able to keep up with the inflation rates during the past ten years. On average, the inflation adjusted gas price of 2012 is at about 70% of the gas prices in the year 2000. We can find the weighted average of the gas price from 1980 to 2012 from the Table-5.7. Data were collected from Petrobangla annual report 2011, Petrobangla MIS Report'June 2013 and Titas gas T&D Co. Ltd. Weighted average of the gas price is calculated by the equation $\Sigma(\text{Price}\times\text{Sale})/\text{Total Sale}$. It is found that the same weighted average price at the end user level as Table-5.4 that is 5.038 TK/MCM which can be used for further calculation to find out the increment of Gas Price the Government have to implement.

## Table 5.7: Year wise weighted average of gas price

| | Power | | Captive | | Fertilizer | | Industry | | Commercial | | CNG | | Brickfield | | Domestic | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Price (TK/MCF) | Sale(BCF) | Price (TK/MCF) | Sale(BCF) | Price (TK/MC | Sale(BCF) | Price (TK/MCF) | Sale(BCF) | Price (TK/MCF) | Sale(BCF) | Price (TK/MCF) | Sale(BCF) | Price (TK/MCF) | Sale(BCF) | Price (TK/MCF) | Sale(BCF) | Σ(Price× Sales) | Total Sale(BCF) | Weighted Avg.(TK/MCM) |
| 1980 | 7.75 | 13.3 | | | 7.75 | 17.9 | 18 | 8.1 | 19 | 1.3 | | | 18 | 0 | 18 | 3.4 | 473.5 | 44 | 0.380 |
| 1981 | 9.3 | 18 | | | 9.3 | 26.6 | 27.75 | 9.1 | 28 | 1.7 | | | 27.75 | 0 | 20 | 4.2 | 798.905 | 59.6 | 0.473 |
| 1982 | 10.5 | 22 | | | 10.5 | 25.8 | 31 | 9.8 | 31 | 1.9 | | | 31 | 0 | 27 | 5.2 | 1005 | 64.7 | 0.549 |
| 1983 | 11.5 | 22.9 | | | 11.5 | 29.4 | 36 | 10.4 | 36 | 2.1 | | | 36 | 0 | 34 | 5.8 | 1248.65 | 70.6 | 0.625 |
| 1984 | 13.05 | 38.3 | | | 13.05 | 27.2 | 36 | 12.6 | 45.2 | 2.2 | | | 51 | 0 | 34 | 6.3 | 1622.015 | 86.6 | 0.661 |
| 1985 | 15.66 | 39.8 | | | 15.06 | 33.7 | 43.2 | 16.4 | 54.24 | 2.7 | | | 65 | 0 | 40.8 | 6.8 | 2263.158 | 99.4 | 0.804 |
| 1986 | 19.09 | 51.8 | | | 19.09 | 34.9 | 52.14 | 18.7 | 85 | 3.4 | | | 78.3 | 0 | 44.68 | 6.8 | 3222.945 | 115.6 | 0.985 |
| 1987 | 24.82 | 62.1 | | | 24.82 | 51 | 52.14 | 16.7 | 65.39 | 3.6 | | | 78.3 | 0 | 56.1 | 7.6 | 4339.644 | 141 | 1.087 |
| 1988 | 28.54 | 65.5 | | | 28.54 | 53.4 | 59.96 | 15 | 97.75 | 3.2 | | | 90.05 | 0 | 56.1 | 9.3 | 5127.336 | 146.4 | 1.237 |
| | Price(TK/ MCM) | Sale(BCF) | Sale Unit has changed from TK/MCF to TK/CM | | | | | | | | | | | | | | | | |
| 1989 | 1.16 | 75.6 | | | 1.01 | 55.9 | 2.47 | 14.3 | 3.88 | 3.1 | | | | 0 | 2.3 | 10.2 | 214.964 | 159.1 | 1.351 |
| 1990 | 1.33 | 82.6 | | | 1.16 | 54.2 | 2.84 | 13.2 | 4.46 | 2.9 | 4.46 | 0.7 | | 0 | 2.64 | 10.5 | 253.994 | 164.1 | 1.548 |
| 1991 | 1.38 | 88.1 | | | 1.2 | 61.6 | 3.01 | 13.4 | 4.74 | 2.9 | 4.74 | 0.7 | 3.75 | 0.2 | 2.64 | 11.6 | 284.27 | 178.5 | 1.593 |
| 1992 | 1.52 | 93.3 | | | 1.32 | 69.2 | 3.31 | 15.2 | 4.74 | 2.4 | 4.74 | 0.7 | 4.12 | 9.2 | 2.9 | 13.5 | 375.22 | 203.5 | 1.844 |
| 1994 | 1.68 | 107.4 | | | 1.46 | 80.5 | 3.64 | 24.24 | 5.21 | 2.88 | 5.21 | 0.6 | 4.53 | 1.1 | 2.9 | 18.86 | 464.0034 | 235.58 | 1.970 |
| 1998 | 1.93 | 140.82 | 3.05 | | 1.68 | 82.71 | 4.2 | 35.79 | 6 | 4.71 | 6 | 0.71 | 5.2 | 0.35 | 3.35 | 27.02 | 685.9104 | 292.11 | 2.348 |
| 2000 | 2.22 | 175.27 | 3.5 | | 1.93 | 88.43 | 4.83 | 47.99 | 6.9 | 4.06 | 6.9 | 0.65 | 5.98 | 0.44 | 3.85 | 31.85 | 949.3137 | 348.69 | 2.723 |
| 2002 | 2.33 | 190.54 | 3.68 | | 2.03 | 95.89 | 5.07 | 63.75 | 7.25 | 4.56 | 7.25 | 0.744 | 6.28 | 0.527 | 4.04 | 44.8 | 1184.583 | 400.811 | 2.955 |
| 2003 | 2.47 | 200.01 | 3.53 | 31.43 | 2.12 | 92.8 | 4.94 | 46.48 | 7.77 | 4.84 | 1.52 | 2.75 | 7.77 | 0.12 | 4.24 | 49.22 | 1282.732 | 396.22 | 3.237 |
| 2004 | 2.56 | 206.3 | 3.53 | 43.12 | 2.19 | 93.97 | 5.13 | 52.28 | 8.07 | 4.84 | 2.47 | 4.49 | 8.07 | 0 | 4.45 | 52.6 | 1438.551 | 414.48 | 3.471 |
| 2005 | 2.61 | 216.32 | 3.73 | 56.92 | 2.24 | 89.08 | 5.23 | 63.26 | 8.23 | 5.2 | 2.47 | 17.6 | 8.23 | 0 | 4.59 | 56.74 | 1654 | 448.2 | 3.690 |
| 2009 | 2.82 | 283.56 | 4.18 | 111.43 | 2.58 | 64.71 | 5.86 | 118.8 | 9.47 | 8.11 | 9.97 | 38.91 | 9.47 | 0 | 5.16 | 80.2 | 3007.103 | 705.72 | 4.261 |
| 2012 | 2.82 | 295.48 | 4.18 | 120.8 | 2.58 | 57.74 | 5.86 | 124.4 | 9.47 | 8.45 | 23 | 41.8 | 9.47 | 0 | 5.16 | 87 | 3706.492 | 735.67 | 5.038 |

(Source: Petrobangla Annual report ’2011, Petrobangla MIS Report’June 2013, Titas gas T&D Co. Ltd.)

To find the demand forecast here a projection of the gas demand is made by SPSS projection software. Data were collected from Management Information Service (MIS) of Petrobangla. Data are analyzed using time series analysis based on regression analysis. Least square method of curve fitting was employed to develop a model $Y=a+bt+ct^2$ which is a relation between, demand(y) and time(t) to forecast future gas demand in each category of gas use. Here Data from 2000 to 2009 is used and projection is made from 2010 because from March, 2010 Government of Bangladesh stopped all type of gas connection so if we take the demand at later year then actual scenario could not be reached (Table-5.8).

Forecasting or predicting is an essential tool in any decision making process. The quality of the forecast management can make it strongly related to the information that can be extracted and used from past data. Time-series analysis is one quantitative method to determine patterns in data collected over time. Time-series analysis is used to detect patterns of change in statistical information over regular intervals of time. Projection of these patterns to arrive at an estimate for the future.

## Use of a Second-Degree Trend in a Time Series :

Time series are best described by curves, not straight lines. In these instances, the linear trend model does not adequately describe the change in the variable as time changes. To overcome this problem a parabolic curve is used, which is described mathematically by a second-degree equation. The general form for an estimated Second-degree equation is:

$Y=a+bx+cx^2$

Where,

•Y= estimate of the dependent variable

• a, b, and c = numerical constants

• x = coded values of the time variable

Finding the values for a, b, and c we use the least-squares method to determine the second-degree equation to describe the best fit.

When we find the values of a, b and c simultaneously, we substitute these values into the second-degree equation $Y=a+bx+cx^2$.

The historical gas demand is given in the Table-5.8

**Table 5.8: Demand of gas**

| Year | Demand(BCF) |
|---|---|
| 2000 | 373.42 |
| 2001 | 391.53 |
| 2002 | 421.16 |
| 2003 | 452.87 |
| 2004 | 486.74 |
| 2005 | 526.93 |
| 2006 | 562.21 |
| 2007 | 600.88 |
| 2008 | 653.71 |
| 2009 | 703.43 |

(Source: Petrobangla MIS Department)

SPSS Output and The Analysis Of The Results:

Model Employed: $Y= a+ bxt+cxt^2$

In SPSS output Time stands for t and $Time^2$ stands for $t^2$

SPSS Output For Gas Demand

**Curve Fit**

```
[DataSet1] C:\Users\Avijit\Desktop\Thesis1\Final SPSS\Demand.sav
```

**Model Description**

| | | |
|---|---|---|
| Model Name | | MOD_1 |
| Dependent Variable | 1 | Demand |
| Equation | 1 | Linear |
| | 2 | Quadratic |
| Independent Variable | | Case sequence |
| Constant | | Included |
| Variable Whose Values Label Observations in Plots | | Year |
| Tolerance for Entering Terms in Equations | | .0001 |

**Case Processing Summary**

| | N |
|---|---|
| Total Cases | 10 |
| Excluded Cases[a] | 0 |
| Forecasted Cases | 0 |
| Newly Created Cases | 0 |

a. Cases with a missing value in any variable are excluded from the analysis.

**Variable Processing Summary**

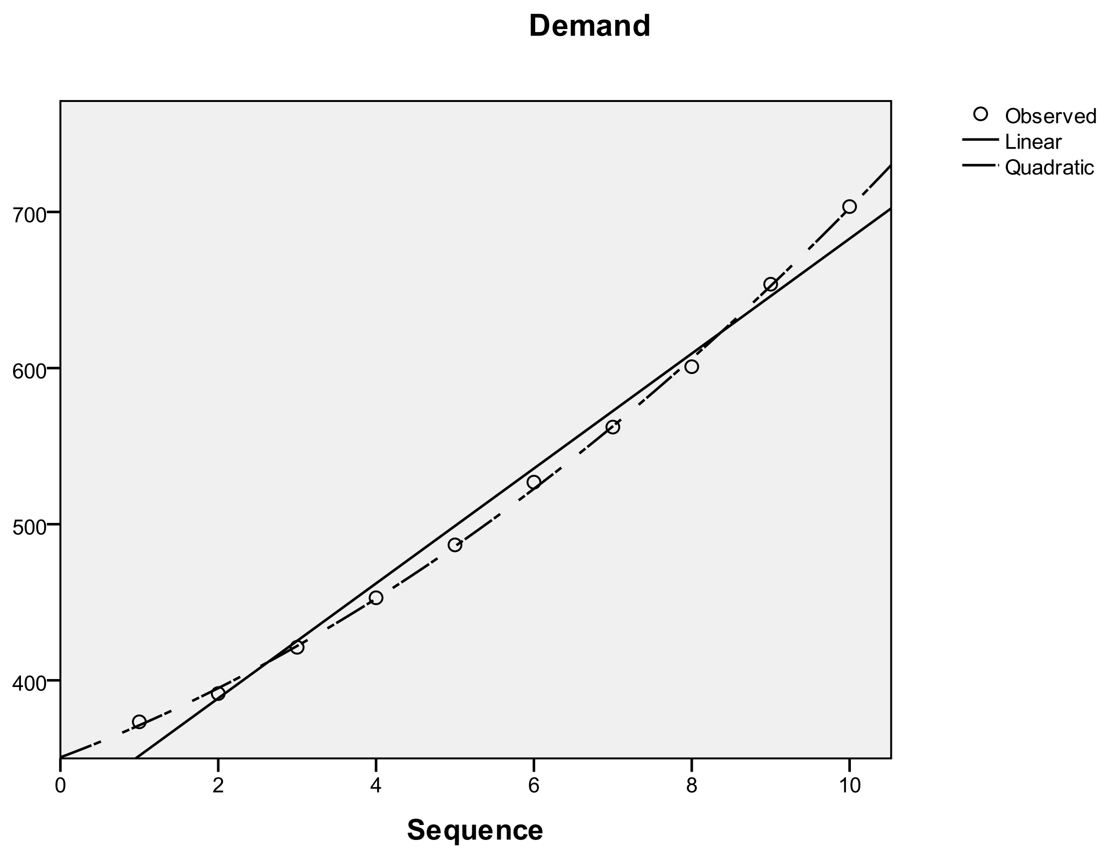
| | | Variables |
|---|---|---|
| | | Dependent |
| | | Demand |
| Number of Positive Values | | 10 |
| Number of Zeros | | 0 |
| Number of Negative Values | | 0 |
| Number of Missing Values | User-Missing | 0 |
| | System-Missing | 0 |

**Model Summary and Parameter Estimates**

Dependent Variable:Demand

| Equation | Model Summary | | | | | Parameter Estimates | | |
|---|---|---|---|---|---|---|---|---|
| | R Square | F | df1 | df2 | Sig. | Constant | b1 | b2 |
| Linear | .987 | 610.458 | 1 | 8 | .000 | 314.883 | 36.801 | |
| Quadratic | .999 | 6004.780 | 2 | 7 | .000 | 350.684 | 18.900 | 1.627 |

[N.B. $b=b_1$, $c=b_2$]




Forecasting of Gas Demand

| | |
|---|---|
| A | 350.684 |
| B | 18.9 |
| C | 1.627 |

**Table 5.9: Demand forecast**

| Year | Time(t) | Demand(BCF/YR) | Demand(MMCFD) |
|---|---|---|---|
| 2013 | 14 | 934.372 | 2560 |
| 2014 | 15 | 1000.455 | 2740 |
| 2015 | 16 | 1069.792 | 2930 |
| 2016 | 17 | 1142.383 | 3130 |
| 2017 | 18 | 1218.228 | 3340 |
| 2018 | 19 | 1297.327 | 3550 |
| 2019 | 20 | 1379.68 | 3780 |
| 2020 | 21 | 1465.287 | 4010 |
| 2021 | 22 | 1554.148 | 4260 |
| 2022 | 23 | 1646.263 | 4510 |
| 2023 | 24 | 1741.632 | 4770 |
| 2024 | 25 | 1840.255 | 5040 |
| 2025 | 26 | 1942.132 | 5320 |

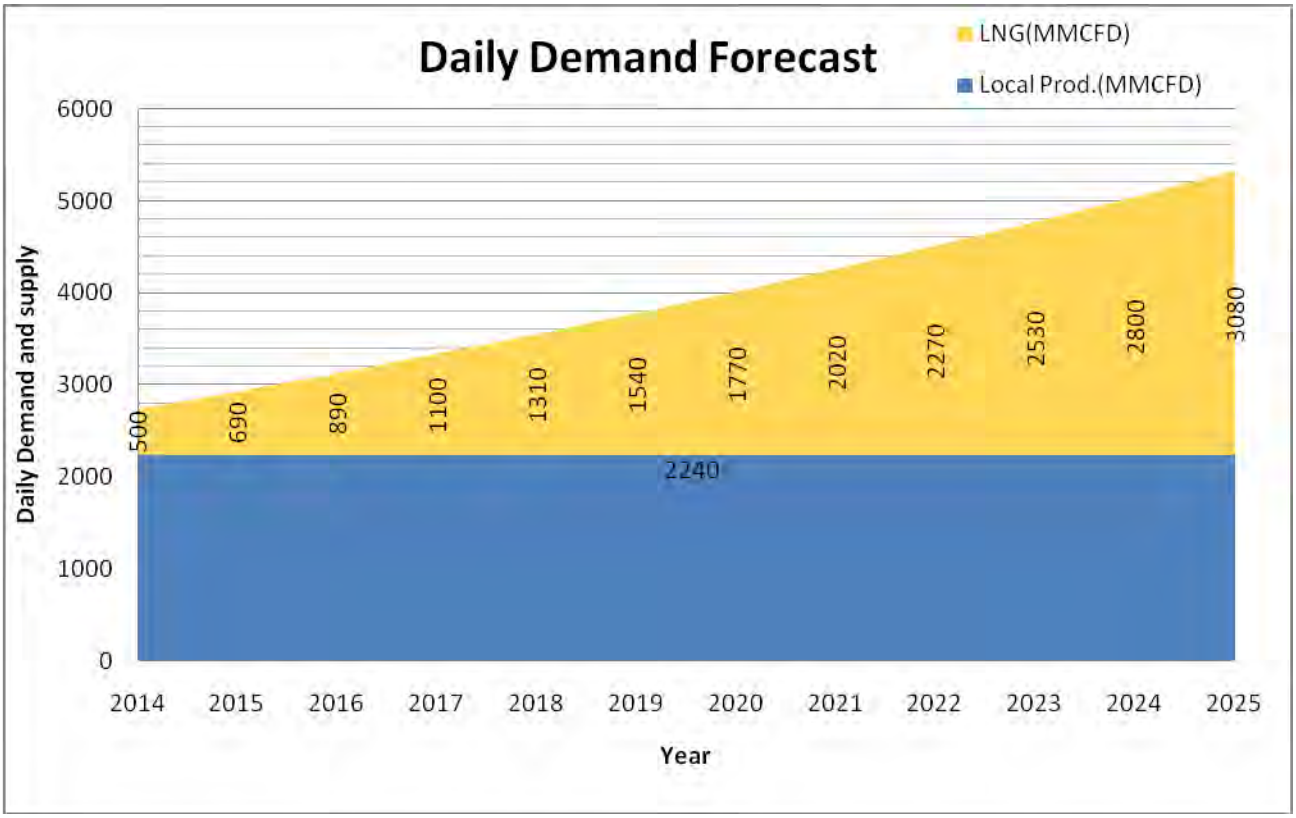



Figure 5.7: Demand forecast of the considering local production constant and fulfilling the rest amount by LNG.

From the Table-5.9 it is found that approximate demand for gas would be 2740MMCFD in 2014. We considered that LNG is added at national grid from 2014. At that time if 500 MMCFD gas is supplied from ragasification plant and rest of the amount is supplied from the locally produced gas which is approximately 2240 MMCFD. There is a little chance to increase local production at a remarkable level from the existing level. As some new gas fields could be found and some field could increase their production in future but with that some existing field production will also decrease. That is why local production assumed fixed on 2240 MMCFD. By considering the local gas production 2240 MMCFD rest of the demand will be fulfilled by imported LNG. So from the following Table-5.10 cost of LNG import considering different rate at different year till 2023 are calculated. The summary also is shown in Figure-5.8.

**Table 5.10: Price of LNG at different year**

| Approx LNG PRICE (Per MCF) | Approx. Daily LNG cost for 500 MMCFD (million USD) (2014) | Approx. yearly LNG cost for 500 MMCFD (billion USD) (2014) | Approx. Daily LNG cost for 1100 MMCFD (million USD) (2017) | Approx. yearly LNG cost for 1100 MMCFD (billion USD) (2017) | Approx. Daily LNG cost for 1770 MMCFD (Million USD) (2020) | Approx. yearly LNG cost for 1770 MMCFD (billion USD) (2020) | Approx. Daily LNG cost for 2530 MMCFD (million USD) (2023) | Approx. yearly LNG cost for 2530 MMCFD (billion USD) (2023) |
|---|---|---|---|---|---|---|---|---|
| $15 | 7.5 | 2.73 | 16.5 | 6.02 | 26.6 | 9.71 | 37.9 | 13.83 |
| $16 | 8 | 2.92 | 17.6 | 6.42 | 28.3 | 10.33 | 40.5 | 14.78 |
| $17 | 8.5 | 3.10 | 18.7 | 6.83 | 30.1 | 10.99 | 43.01 | 15.70 |
| $18 | 9 | 3.29 | 19.8 | 7.23 | 31.9 | 11.64 | 45.54 | 16.62 |
| $19 | 9.5 | 3.47 | 20.9 | 7.63 | 33.6 | 12.26 | 48.07 | 17.55 |

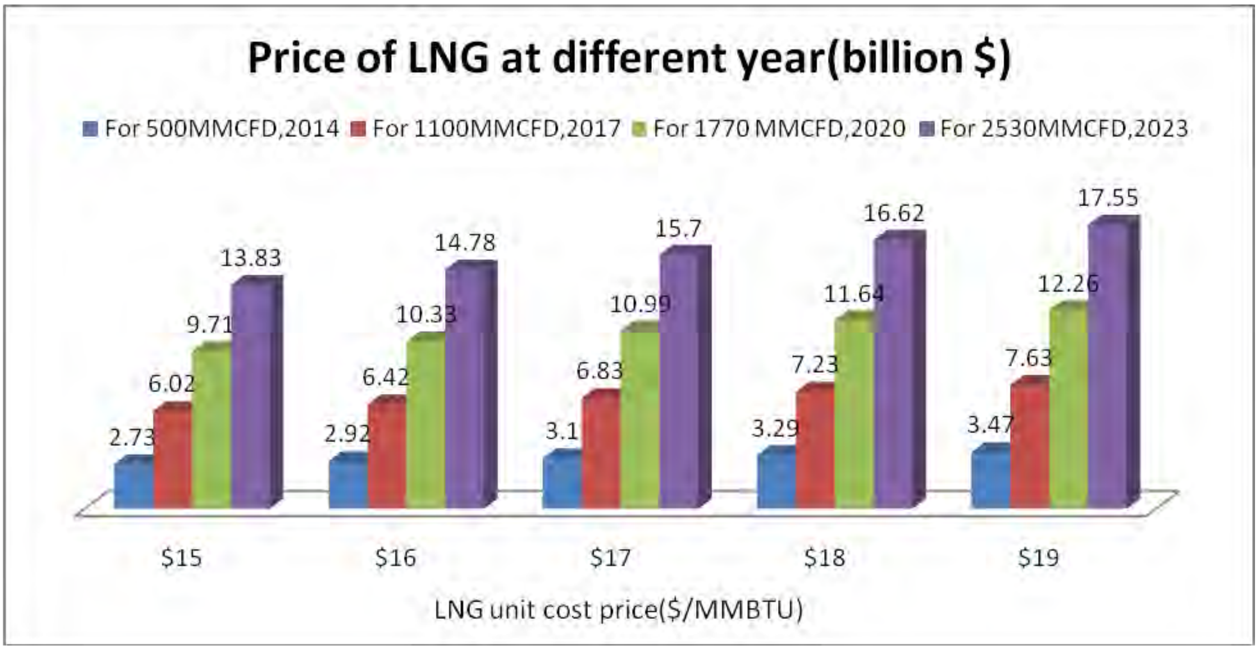



Figure 5.8: Price of LNG considering different rate at different year.

It is found that in case of $15/MCF unit price, total imported LNG cost per annum will be 2.73 billion USD for 500 MMCFD at 2014 and 13.83 billion USD for 2530MMCFD at 2023. On the other hand in case of $19/MCF unit price, total imported LNG cost per annum will be 3.47 billion USD for 500 MMCFD at 2014 and 17.55 billion USD for 2530 MMCFD at 2023. So it is found that for high LNG receiving price after regasification the overall price for the imported LNG for different year would be much higher.  So Government should increase the overall gas price or can manage some subsidy.

At the following Table-5.11 it is found out that end users price have to be at least greater than the measured price calculated at the right column of the table. Immediate action should be taken now to make a plan that the price of gas is at least more than the cost price when the LNG is supplied to the national grid with the domestic gas.

**Table 5.11: End user price level at 2014**

| Approx. LNG Price (per MCF) | Approx. Daily LNG cost for 500 MMCFD (million USD) | Domestic gas cost price should be current sale price(1.82/1000CFT) for remaining 2240 MMCFD (million USD) | Weighted average price have to be more than the value ($/1000CFT) |
|---|---|---|---|
| $15 | 7.5 | 4.08 | 4.23 |
| $16 | 8 | 4.08 | 4.41 |
| $17 | 8.5 | 4.08 | 4.59 |
| $18 | 9 | 4.08 | 4.77 |
| $19 | 9.5 | 4.08 | 4.96 |

So it is found that for high LNG receiving price the Government should increase the overall gas price for avoiding heavy subsidy. It has to be almost three times the current consumer price if the Government wants to minimize its subsidy. In India the current natural gas price is $4.2/MCF and price will be $8.4/MCF from 2014[38]. In Pakistan the natural gas price is $3.34/MCF, In Malaysia price is $3.48/MCF [39]. China already raises the natural gas price to $0.32 per cubic meter which is equivalent to $9/MCF [40].

So if Government at least double the gas price from existing price of $1.82, it is still less than the current gas price in many countries in Asia. So there is no alternative but to increase the price of gas at consumer level if LNG is imported and inject into the existing gas network. Immediate action should be taken now to make a plan to minimize the difference between cost and sale price when the LNG is supplied to the national grid with the domestic gas.

## 5.7 Impact on the network and end user

LNG is a very desirable product having virtually no water vapour or inert entrained and most of the heavier hydrocarbons removed prior to or during the liquefaction process. It contains a relatively large percentage of ethane which results in a higher heating value (HHV) product when compared to domestic gas. HHV will vary depending on country of origin producing formation and liquefaction process but will generally range between 1050 and 1200 Btu per cubic foot. While vaporized LNG poses virtually no threat in regard to hydrocarbon liquid formation and fallout in the interstate grid and distribution systems, it's HHV and other characteristics pose potential concerns to process users, gas turbine applications and end user appliance utilization. When the LNG gas mixed with the domestic gas some impact may occur at pipe line.

### Impact on internal corrosion on pipe line network

Typically, LNG when mixed with the domestic gas may not corrode pipeline interior surfaces. However, natural gas from LNG may contain small amounts of contaminants such as hydrogen sulphide, carbon dioxide and water.

- Hydrogen sulphide is a poisonous corrosive gas and forms sulphuric acid in the presence of water.
- Carbon dioxide forms carbonic acid in the presence of water.
- Water vapour present in a pipeline will condense to liquid water when cooled sufficiently. Liquid water in a pipeline will contain dissolved corrosive gases as acids and may also contain bacteria responsible for some corrosion reactions. High velocity flow conditions can remove protective oxide layers on the inside of a pipe line and accelerate the corrosion attack. Low velocity flow conditions can allow wetting of the pipe wall to occur near stagnant conditions which are ideal for biological corrosion mechanisms.

### Impact on end user equipment

There are some compositional differences between international LNG and domestic pipeline gas. These differences result from the cryogenic liquefaction process and from the unique economics of the LNG industry. LNG has very low HC and water dew points and $CO_2$ content compared to domestic gas. This is due to the need to prevent frost formation in the cryogenic liquefaction equipment. $CO_2$ in LNG is less than 50 ppm[41], compared to several thousand ppm in domestic gas. LNG has higher calorific value: 1,100 to 1,150 Btu/scf.

The Wobbe index defined as the ratio of the gross calorific value to the square root of the gas relative density.

- The thermal input is directly proportional to the Wobbe index.
- The air gas ratio is inversely proportional to the Wobbe index.

That means an increase in Wobbe index will lead to an increase of power input and a decrease of the air gas ratio.

Varying natural gas composition beyond acceptable limits can have the following effects in combustion equipment:

a. High Wobbe Index gases can cause excessive carbon monoxide formation for unflued appliances or appliances with faulty fluing systems. High Wobbe Index gas can increase the soot build-up on finned heat exchangers. Gases with higher Wobbe index will emit more $CO_2$ for the same amount of energy. Hydrogen sulphide ($H_2S$) is a corrosive, poisonous gas. Its corrosion affect on copper components in gas installations tends to be cumulative.

b. One of the major concerns of varying natural gas composition in reciprocating engines is engine knock. The anti-knock property of a natural gas fuel can be expressed as a methane number. In addition to the anti-knock quality, the operating performance of an engine on a low methane number fuel may be important. Low methane number is usually a result of the presence of high hydrocarbons in the fuel. In addition to the methane number, the Wobbe number is also an important parameter for gas engines as it determines both the power and equivalence ratio and changes that might result in poor operational and environmental performance.

c. In combustion turbines it can result in an increase in emissions reduced reliability/availability and decreased parts life.

d. In industrial boilers, furnaces and heaters it can result in degraded performance, damage to heat transfer equipment and noncompliance with emission requirements. Industrial furnaces that have been adjusted to the minimum air for combustion may also be adversely affected if “combustion quality excess air” levels (min air/gas ratio) not set properly. High Wobbe Index gases tend to have a higher combustion air requirement. If a furnace has been adjusted for low Wobbe Index gases, with insufficient excess air, there is the potential for these furnaces to have insufficient air for combustion when receiving very high Wobbe Index gas. The resulting incomplete combustion may create sufficient amounts of carbon monoxide and hydrogen that an explosion is possible if additional air is inadvertently admitted to the combustion chamber during operation.

e . High levels of hydrogen sulphide can pose a threat to the CNG (Compressed Natural Gas) cylinders of the NGV (Natural Gas for Vehicles) industry as they are exposed to pressures up to 3000 psig . The current standard for NGV cylinders specifies that they should be designed to handle hydrogen sulphide levels up to 23 mg/m3 [42] There is also the potential to form hydrates in high-pressure, natural gas vehicle (NGV) cylinders.

## 5.8 Required standard of imported LNG

From the above discussion it is found that LNG has to be imported in such condition that the problem discussed above can be minimized. The main components that can make problem in pipe line network are $H_2S$, $CO_2$ and water content. For Pipeline Sulphur content should be less than 4 Parts per million (PPM), $CO_2$ should be less than 2% by volume and water content should be less than 7 lbs per MMCF. Beside these at the end users' equipment High Wobbe Index, Gross Heating Value, Specific Gravity and $H_2S$ value need to be controlled as well. LNG is reach in heating value because it contains ethane. According to the end users requirement the Higher Heating Value (HHV) should be from 950 BTU to 1150 BTU per SCF but should not be less than 900 BTU per SCF. Specific Gravity should be from 0.57 to 0.62. On the other hand $H_2S$ content should not be exceed 2 PPM, total Sulphur content should not be exceed 5 PPM and water content should not be exceed 7 lbs per MMCF. Beside these no foreign particle/solid materials beyond 5 micron in size should be associated with the Gas to be delivered [43]. The chemical composition of the Gas by volume should be according to Table 5.11

**Table 5.12: Chemical composition range of natural gas in Bangladesh**

| Component | Minimum Volume | Maximum Volume |
|---|---|---|
| Methane | 85.00 | 100.00 |
| Ethane | 0 | 6.00 |
| Butane | 0 | 3.00 |
| Pentane & Higher | 0 | 2.00 |
| Carbon-dioxide | 0 | 2.00 |
| Nirogen | 0 | 3.00 |
| Oxygen | 0 | 1.00 |
| Inert(the total combined Nitrogen, oxygen, Carbon-dioxide and any other inert compound) | 0 | 5.00 |

(Source: Gas supply agreement between Titas Gas T&D Co. Ltd. and EGCB)

So the imported gas should not exceed the maximum allowable value of different impurities that were already discussed above.

# CHAPTER 6

# Mitigative Measures

The cost of the price of total gas and subsidy that Government has to manage if the sale price is being unchanged is already shown in Chapter 5. There are some steps that the Government can take to improve the gas utilization and minimize the price difference between cost and sale price. Beside these the price issue gas from LNG could also create some problems if the standard of gas is not maintained properly during import. This was described in the previous Chapter. The necessary measures that can be taken to mitigate this type of situation and also improve the overall energy situation are described below.

## 6.1 Steps that can be taken to improve the price adjustment

Price adjustment is very much needed if LNG is imported. The total average consumer gas price should be increased within a certain period of time or some subsidy can be managed by the Government. Gas prices should be in-line with those of other fuels in Bangladesh and in other countries. Impact of the pricing reform should be evaluated regularly and implementation plan should be reviewed regularly. The tariff elements should be aligned with the structure of the industry. These are the important issues that have to be decided by the decision makers. Beside this some steps can be taken which can directly or indirectly improve the whole energy situation in Bangladesh.

- A cost-based pricing formula should be introduced for production, transmission and distribution.

- Commercial accounting practices by state-owned enterprises should be introduced.

- Better accountability by all sub-sectors should be ensured.

- Being in-line with Bangladesh's gas and power sector master plans.

- Collaboration between the industry, BERC and Government is needed.

- Good communications with the public about the social and economic benefits.

- Develop electronic data management and communication systems.

- Residential consumers have to be metered to account for all gas consumed and the unmetered gas price have to be increase to mitigate the subsidy of the LPG that is also used for domestic cooking in different places where pipe line gas is not available.

- Investment on gas based power plants have to be reduced.

- Alternative fuels have to be introduced for vehicle.

- Imported gas has to be used at industry rather than power and domestic sectrors.

- Efficiency of end user equipment can be increased for proper utilization of high cost fuel. In case of Boilers and Generators better performance should be assured.

- Inefficient old equipment should be changed for better utilization of natural gas.

- Measures also can be taken to minimize the leak of pipe line network. Petrobangla is also taking some measures to mitigate this problem.

## 6.2 Preventive/Mitigative measures for internal corrosion of pipe

For LNG import some standards should be set by the importing country. Bangladesh as an importer of LNG has to set some standards according to the maximum values of impurities allowed in our own network. During the import of LNG the agreement with the exporting countries should be such a way that the quality of gas should not exceed the range that discussed in Section 5.8 of the previous Chapter. It is not possible all the time to achieve 100% accuracy that is why some impurities and the water content can enter in to the gas network which can be mitigated with the following measures.

### Cleaning pigs

The frequent use of cleaning pigs to scour the internal surfaces of a pipeline is a viable preventive measure. There are many types of cleaning pigs. Cleaning pigs can effectively direct both liquids and corrosive solids to pig traps for removal from the pipeline. It is noted that the build up of solids also can create internal corrosion since the solids can entrap corrosive. Routine pigging will channel any liquid pools away from low points and if performed properly out of the entire pipeline. Cleaning pigs also will displace the solids and remove them from the pipeline via the pig trap at the end of the pipeline provided that the pipeline is properly configured.

### Dehydration

Dehydration can be applied to protect against internal corrosion in gas pipelines. Dehydration removes condensation and free water that if permitted to remain would allow internal corrosion to occur at points where water droplets precipitate from the gas stream to either form liquid puddles at the bottom of the pipe or adhere to the top of the pipe

### Inhibitors

Inhibitors are chemicals that can be added to a pipeline to reduce the rate of corrosion. They can adsorb onto the metal surface or react with it to form a protective film or they may react with the corrodent to make it less corrosive. Many different chemicals are available commercially.

### Coatings

Internal coatings have been used on some gas transmission pipelines to improve product flow by reducing drag and eliminating dust. Such coatings can be somewhat effective in controlling internal corrosion but they are very difficult to apply uniformly which impacts their effectiveness. In lieu of coatings some operators have attempted to install plastic or high density polyethylene liners or inserts in their pipelines.

### Additional Preventive Measures

Drip legs or logs (also known as traps/drips) are another design mechanism to prevent internal corrosion. These devices are designed to trap liquid contaminants and prevent them from travelling downstream. The drips can be pumped so the liquids can be removed before significant internal corrosion can take place. However, if the liquids are not removed in a timely manner the drips themselves can corrode.

## 6.3 Preventive/Mitigative measures on end users

Some measures can be taken to improve the situation and also make the maximum utilization of the energy by introducing smarter operating industry and as a result reduced shortfalls of capacity.

- Power Plants are main consumer of gas in Bangladesh but most of the power plants are not running efficiently because many of them are old and running beyond their useful life. So some steps have to be taken to minimize the gas consumption of this sector. Eighty MW Installed capacity are more than 40 years and 305 MW installed capacity are 31-40 years old and 1105MW Installed capacity are 21-30 years old and nearly 25% of the power plants are 20 years of old and hence subject to temporary shutdown and high maintenance cost[44]. This has to be changed. So older power plants can be replaced by the more efficient power plants that generates more power with latest technology by consuming less fuel compared to the old one.

For all applications where the combustion products are not diluted (boiler, etc.) an oxygen sensor placed in the exhaust can be used to control the air gas ratio. However, the added price of the control systems can be a detriment for gas utilization.

For fully premixed burner if the combustion products may be diluted before sampling, or if the process may alter them, the air gas ratio can be obtained by using a "premix analyser". This will give a signal used to adjust the air gas ratio.

For all applications where no measurement representative of the air gas ratio can be made on the combustion products, the Wobbe number of the gas shall be determined, with a Wobbe meter along with air parameters (pressure, temperature, etc.) or a measurement of the mass air flow. This is used to adjust the air gas ratio. If the adjustment of the air gas ratio is not possible for a sensitive application, then the Wobbe of the gas can be adjusted by injection of air or nitrogen in the gas line up stream of the burner.

# CHAPTER 7

# Conclusion

LNG is moving rapidly from the fuel of the future to the fuel of the present with a dramatic upsurge now under way in every aspect of the industry. It was an industry largely focused on engineering and construction enabling the facilities to achieve extraordinary levels of safety, reliability and longevity. The future of the LNG industry seems assured for the next two decades. Bangladesh has not taken any initiative for importing Pipeline Gas from TAPI (Turkmenistan-Afghanistan-Pakistan-India Pipeline) or IPI(Iran-Pakistan-India Pipeline). Right at this moment surplus gas is also not available in Myanmar to consider exporting to Bangladesh. Initiative for expanding gas production has not achieved desired objectives and initiative for increasing domestic coal production. Nothing other than Barapukuria mining has been planned. Though the power generation and gas production increased significantly over the last 5 years the long term energy security remains vulnerable. BPDB is now paying Tk 20-22 for per unit power of diesel-fired plants while Tk 16-17 of furnace oil operated plants [45]. That will have tremendous adverse impacts on Bangladesh economy. So LNG import can minimize all these problems.

Government have to largely recognize that LNG import projects cannot materialize without fiscal and technical certainty. It has been see that depending on the LNG price the difference between the sale and cost price of 500MMCFD is from 2.37 to 3.09 billion dollars per annum according to the current gas price. Total imported LNG cost per annum will be 2.73 to 3.47 billion USD for 500 MMCFD. It will be 13.83 to 17.55 billion USD for 2530 MMCFD in 2023 when that much gas will be required to meet the projected deficit. On the other hand the weighted average gas price for a 500 MMCFD import has to be increased to \$4.23 to \$4.96/MCF from the current average price of \$1.82/MCF if no subsidy is planned. So Government has to increase the retail level gas price approximately three times from the present gas price otherwise a huge amount of subsidy has to be arranged by the Government.

Imported LNG should maintain some quality according to the standard that is maintained by the domestic gas network. According to the standard, Sulphur content should be less than 4 Parts per million (PPM), $H_2S$ content should not be exceed 2 PPM, $CO_2$ should be less than 2% by volume and water content should be less than 7 lbs per MMCF. Specific Gravity should range from 0.57 to 0.62; Higher Heating Value (HHV) should be from 950 BTU to 1150 BTU per SCF but should not be less than 900 BTU per SCF for the Pipeline network and end users' requirement. Beside these no foreign particle/solid materials beyond 5 micron in size should be associated with the gas to be delivered. So the above mentioned gas quality must be ensured before any LNG import. LNG can be a solution for the present gas crisis but detail financial, economical, environmental and technical aspect should be verified properly without any political influence. It also needs to be seen if this high price LNG is economically viable for any sector compared to other alternate fuel. On the other hand financing of the LNG regasification project is quite challenging issue.

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# Appendix-I

## Conversion Factor

1 Bar = 14.73 Psig

1CM= 35.3147 CFT

1 MMCFD = 1000MCFD

1 liter = 1000 Cubic Centimeter

Barrel of Oil(BOE)= 42 US Gallon=1Barrel/bbl=158.987 Litres of crude oil=$5.8\times10^{6}$ BTU

1bbl of oil = roughly $1000ft^{3}$ of Natural gas=$10^{6}$ BTU

1Kg = 2.204lb

1Day = 24Hours

1Year = 365 Days

1 ton of LNG = 2.1930 $m^{3}$ of LNG

1 ton of LNG = 1,245 $Nm^{3}$ of NG

**Appendix-II**

# GAS SUPPLY AGREEMENT

**BETWEEN**

**TITAS GAS TRANSMISSION AND DISTRIBUTION COMPANY LTD.**

**AND**

**DOREEN POWER GENERATIONS AND SYSTEMS LTD.**

**EXECUTED ON 11 OCTOBER 2007**

**RELATING TO**
**22 MW POWER GENERATION FACILITY AT NARSINGDI**

## SCHEDULE 1

## GAS SPECIFICATIONS

In order to satisfy the Gas Specifications (and, therefore, be Specification Gas) Gas delivered at the Point of Delivery shall conform to the following standards in respect of heating value, pressure, purity, chemical analysis and temperature:

a) **Heating Value**

The Gas Supplier and the Project Company agree that Gas is being sold under this Agreement on the assumption that Gas delivered will have a Higher Heating Value (HHV) of 950 BTU per standard cubic foot but shall not at any time a Higher Heating Value of less than 900 Btu per standard cubic foot.

b) **Pressure Specification**

The pressure at which the Gas will be delivered to the Project Company at the Point of Delivery shall be 105 to 150 psig.

c) **Temperature Range:**

The temperature of the delivered Gas shall not be less than 59 degrees Fahrenheit ($15^0$C) and not more than 140 degrees Fahrenheit ($60^0$C).

d) **Purity:**

Impurities present at the pressure and temperature conditions specified above shall not exceed:

| | | |
|---|---|---|
| Hydrogen Sulphide | : | 2 parts per million (by volume) |
| Total Sulphur | : | 5 parts per million (by volume) |
| Water content | : | Not excess of 7 (seven) lbs per million standard cubic foot |
| Liquefiable Hydrocarbons | : | Not more than 2 US gallons per million standard cubic foot |

e) **Odour and Solid:**

The Gas shall be commercially free from objectionable odour and dust or other solid matter, liquid matter, gum and gum forming constituents, toxic or hazardous substances in concentration which might interfere with the proper operation of the Facility or which might present a health and/or safety hazard to Project Company's employee and/or the general public. No foreign particle/solid materials beyond 5 micron in size will be associated with the Gas to be delivered.

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**Chemical Composition:**

The chemical composition of the Gas by volume shall be:

| Component | | Minimum Volume | Maximum Volume |
|---|---|---|---|
| Methane | : | 85.00 | 100.00 |
| Ethane | : | 0 | 6.00 |
| Propane | : | 0 | 5.00 |
| Butane | : | 0 | 3.00 |
| Pentane & Higher | : | 0 | 2.00 |
| Hydrogen Sulphide | : | 0 | 0 |
| Carbon dioxide | : | 0 | 2.00 |
| Nitrogen | : | 0. | 3.00 |
| Oxygen | : | 0 | 1.00 |
| Inert (the total combined Nitrogen, Oxygen, Carbon-di-oxide and any other inert compound | : | 0 | 5.00 |