Department of Energy
Republic of South Africa

Republic of South Africa
Study on Natural Gas Utilisation

Final Report

(Disclosure Version)

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Japan International Cooperation Agency
The Institute of Energy Economics, Japan

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Abbreviations

Acronym	Definition
BAU	Business as Usual
Bbl	Barrels
Bcf	Billion cubic feet
BD	Barrels per day
BOG	Boil Off Gas
Btu	British Thermal Units
C/P	Counterpart
CAPEX	Capital Expenditure
CBM	Coal Bed Methane
CFC	Cash Flow Chart
CIS	Commonwealth of Independent States
CNG	Compressed Natural Gas, used for vehicles or transport of natural gas
CNPC	China National Petroleum Corporation
CTL	Coal to Liquid
CTMS	Custody Transfer Measuring System
DME	Di-Methyl Ether
DMR	Department of Mineral Resources
DOE	Department of Energy
DPF	Diesel Particulate Filter
EPC	Engineering, Procurement and Construction
FDI	Foreign Direct Investment
FEED	Front End Engineering and Design
FID	Final Investment Decision
FIRR	Financial Internal Rate of Return
FLNG	Floating LNG
FSRU	Floating Storage and Re-gasification Unit
FT	Fischer-Tropsh
GDP	Gross Domestic Product
GHG	Green House Gas
GIIGNL	The International Group of Liquefied Natural Gas Importers
GIIP	Gas Initially in Place
GTL	Gas to Liquid
GUMP	Gas Utilisation Master Plan

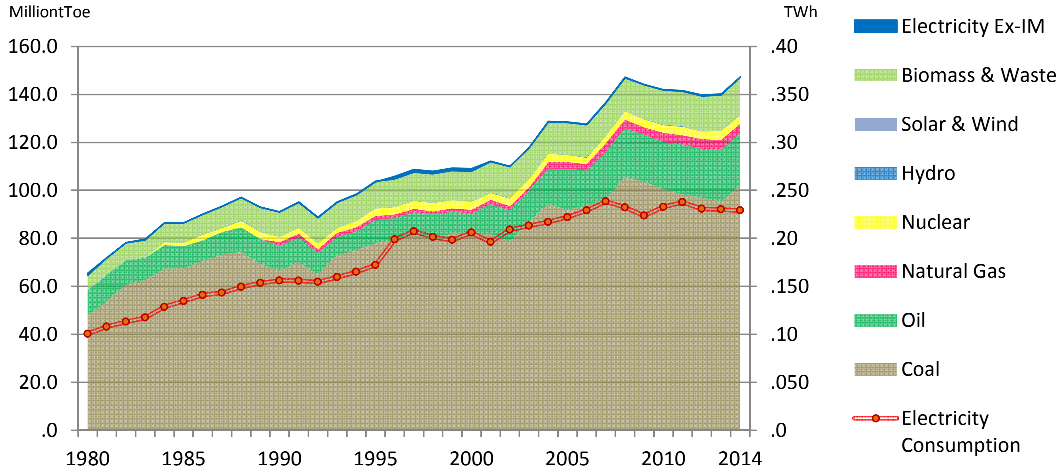
GWh	Giga Watt hours
IDZ	Industrial Development Zone
IEA	International Energy Agency
IEEJ	The Institute of Energy Economics, Japan
IEP	Integrated Energy Plan
IGCC	Integrated Coal Gasification Combined Cycle
IGU	The International Gas Union
IMF	International Monetary Fund
IOC	International Oil Company
IPP	Independent Power Producer
IRP	Integrated Resources Plan
IRR	Internal Rate of Return
ISO	International Organization for Standardization
JAPEX	Japan Petroleum Exploration Co., Ltd.
JICA	Japan International Cooperation Agency
JKM	Japan Korea Marker
ktoe	thousand tonnes oil equivalent
LIBOR	London Inter-Bank Offered Rate
LNG	Liquefied Natural Gas
LNGRV	LNG Regasification Vessel
LPG	Liquefied Petroleum Gas
MJ	Mega Joule
MM	Million
MMBtu	Million British Thermal Units
MMSCF	Million Standard Cubic Feet
MMSCFD	Million Standard Cubic Feet per Day
MPa	Mega Pascal
MTG	Methanol to Gasoline
MTO	Methanol to Olefin
MTO	Methanol to Olefins
MTPA	Million tonnes per Annum
MW	Mega Watt
NGV	Natural Gas Vehicles
NPV	Net Present Value
OCGT	Open Cycle Gas Turbine
OECD	Organisation for Economic Co-operation and Development
OPEX	Operational Expenditure

ORV	Open Rack Vaporizer
PM	Particulate Matter
PRA	Price Reporting Agency
PVs	Photovoltaics
RFI	Request for Information
ROMPCO	the Republic of Mozambique Pipeline Company
SEZ	Special Economic Zone
SG	Specific Gravity
SMV	Submerged Combustion Vaporizer
Tcf	Trillion cubic feet
UCG	Underground Coal Gasification
US EIA	United States Energy Information Administration
UUOA	Unitization and Unit Operating Agreement
VAT	Value Added Tax

Chapter 1 Outline of the Study

1.1 Background of the Study

The Republic of South Africa (RSA) is endowed with abundant coal resources which put the country at the world's ninth place in terms of the amount of reserves and at the seventh for its production. For this reason the country has traditionally relied on coal for its source of energy. According to the IEA (see Fig. 1.1), RSA's primary energy consumption in 2014 was made up of 69.4% coal, 14.9% oil, 2.6% gas, 2.4% nuclear, and 10.7% renewables and others. With respect to the power generation mix, its dependency on coal is even higher at 94%, with the balance taken up by 5% nuclear and 1% hydro and others, making the country heavily dependent on its ample coal production in both the total energy supply as well as electricity generation.



(Source) IEA, "Energy Statistics of Non-OECD 2016"

Figure 1.1-1 Primary Energy Consumption in RSA

Against the above backdrop the government of South Africa is endeavoring to diversify the country's energy sources with an aim of lowering its coal dependency from the viewpoints of achieving an energy best mix and improving its energy security. The Integrated Resource Plan (IRP2010), a national program released in 2010, advocates an aggressive introduction of renewable energy and natural gas in an attempt to promote the use of clean energy through the system of procuring energy produced by independent power producers (IPPs).

Based on the renewable energy IPP procurement program described above, first three bidding rounds have completed as of 2015 and currently the fourth round is in progress. Meanwhile, under the IPP program for gas-fired power generation it is planned to invite a tender for procuring 3,126 MW of new capacity within the fiscal 2015 for finalization in the second quarter of fiscal 2016. However, since it remains unclear as to how the necessary gas as the source of energy should be acquired the program appears to be under investigation within the RSA government.

In South Africa, in addition to natural gas fields found in Mossel Bay in the south, which have been utilized as the feed for a gas-to-liquid (GTL) plant since 1992, discoveries of modest-sized gas fields have been made in the offshore Atlantic coast. In addition, importation of piped natural gas from Mozambique began in 2004. Furthermore, in activities of exploring coal bed methane (CBM) in the Karoo Basins situated in the southeast of Johannesburg, conventional gas reserves have been discovered. Elsewhere, while Karoo Basin is considered to be a prospective area for world-class shale gas reserves in South Africa, specific undertaking of exploration work has yet to begin. As discussed in the above, although indigenous gas production may well head for an increase in the future, additional exploration work and subsequent study on the development potential are needed, and the prospect of large-scale natural gas production is not in sight at the moment. To promote widespread use of natural gas in South Africa, therefore, importation of natural gas in the form of piped supply and LNG from abroad is considered to be a realistic option available in the short term.

So far natural gas imports into South Africa have been limited to those made via pipeline from Mozambique, and the country has no experience of full-fledged gas import in the form of liquefied natural gas (LNG). For this reason, the RSA government has requested Japan, the world's largest LNG importer, for advice based on its experience and knowledge relating to the development of LNG import facilities, industrial gas use as well as creation of gas demand. In this Study, it is intended to review the current situation concerning gas introduction plans and related discussions as well as the future prospect in South Africa to identify issues and challenges so that a set of recommendations can be developed in the end. In addition to the above, throughout the course of this Study, discussions will be held with appropriate counterparts in the RSA government on possible technical collaboration so that cooperation between the two countries could be promoted with respect to the efforts concerning global energy policy issues such as strengthening energy security and global warming measures.

1.2 Objectives of the Study

This Study intends to review the current situation concerning the national plans and related discussions as well as the future prospect on the development of full-fledged gas utilisation in South Africa, evaluate their appropriateness and identify issues and challenges so that a set of recommendations can be developed for further collaborative work.

Since a part of the Gas Utilisation Master Plan (GUMP) currently being formulated by the RSA government was released in May 2014. Together with other data and information provided by the RSA government, starting with a review on the content therein, the Study has undertaken activities as listed below:

a) Gather information related to the present status of natural gas reserves and their exploratory as well as development work in South Africa, and examine possibility of indigenous natural gas production in the future;

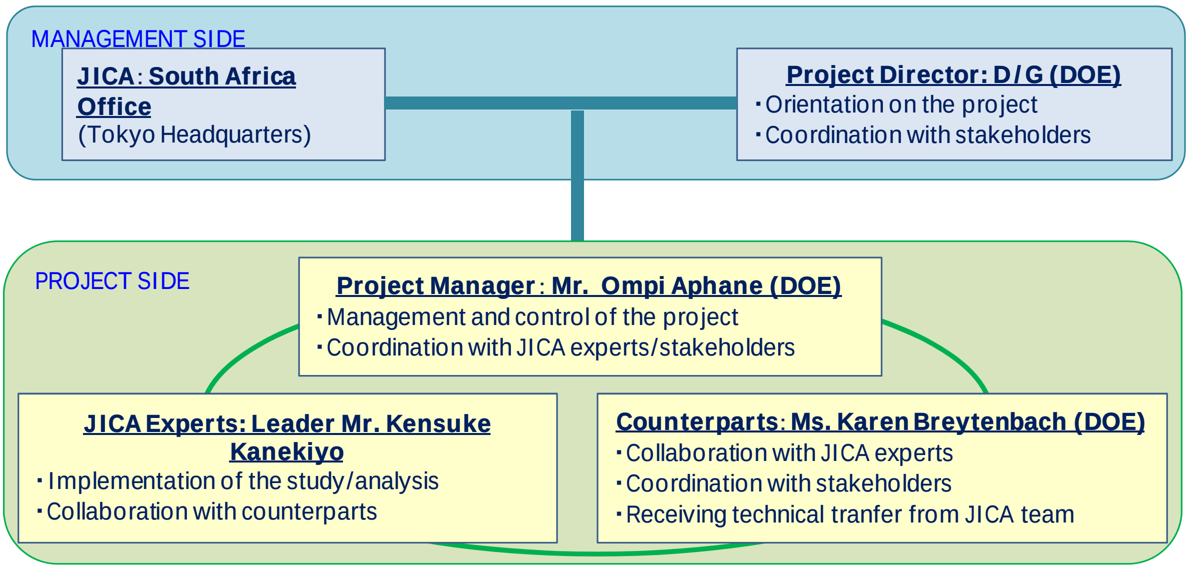
b) Examine and analyze the trends in natural gas demand in the area of thermal power generation and in respective sectors of industry, commercial, transportation, and residential, as well as industries using gas as a feed stock such as fertilizer production, and develop future gas utilisation outlook along with several alternative scenarios;

c) On the basis of the foregoing survey, examine appropriateness of the gas importing methods and site locations as well as responsible entities for gas receiving facilities that are currently envisioned by the RSA government to identify challenges involved and issues to be addressed;

d) In addition to the above, investigate the potentiality of further gas utilisation in the industrial sector and the benefits of expanded introduction of gas to come up with a set of recommendations for the RSA government.

1.3 Study Organisation, team and function

(1) This Study has been carried out by the organisation as shown below:



G/G: Director General

Figure 1.3-1 Study Organisation, Team and their Function

(2) The JICA team participating in this Study comprises 6 experts as tabled below:

Table 1.3-1 Study Team Members

Category	Name	Designation
Team Leader/Overall Plan	Kensuke Kanekiyo	Councillor Asia-Pacific Energy Research Centre
Secretary/Overall Plan/Gas Utilization Industries	Shinji Omoteyama	Director Planning & Administration Unit
International Gas Market Analysis/LNG Outlook	Yoshikazu Kobayashi	Manager, Gas Group Fossil Fuels & Electric Power Industry Unit
Economic and Financial Analysis/Gas Utilization Industries	Tsukasa Taneichi	Senior Researcher, Global Energy Group 2 Strategy Research Unit
Demand Forecast/Energy Market Analysis	Chew Chong Siang	Senior Researcher, New and Renewable Energy Group New and Renewable Energy & International Cooperation Unit
Gas Supply/Distribution Infrastructure	Shinya Tanaka	Researcher, Gas Group Fossil Fuels & Electric Power Industry Unit

1.4 Basic Framework of the Study

This Study has been conducted with the basic framework and objectives as listed below. While some of them were not fully covered due to time constraints and lack of information, most of the original intentions have been achieved in principle.

(1) Time frame of study

The RSA government, in its short-term policy measure to deal with the power supply problems, is planning to launch a tender for procuring gas-fired power generation capacity from IPPs. On the matter of arrangements for the required fuel, development of gas (i.e. LNG) import facility is currently being studied among the parties concerned mainly on the basis of short-term considerations. On the other hand, since the original purposes of natural gas introduction were diversification of energy sources and mitigation of greenhouse gas (GHG) emissions, the construction of import facility needs to be planned keeping in mind its utilisation with a long-term perspective. In consideration of the foregoing, for the demand forecasting and economic evaluations in this Study, along with the studies targeting at short to medium term of period up to 2025, studies for medium- to long-term period of up to 2040 will also be carried out with an eye on a longer perspective.

(2) Information on subjects under the RSA government deliberation

In the RSA government, headed mainly by the IPP Office of the Department of Energy (DoE), careful examinations and discussions are under way concerning subjects such as importation methods of natural gas (LNG), arrangements for preparing gas import facilities, administration of the tender process for procuring gas-fired power generation capacity from IPPs and so on. Since the details of such examinations and discussions are crucially important to each of business enterprises that are considering submitting bids for the tenders, and also from obvious needs for ensuring fair competition, it is considered difficult to obtain the relevant information on such matters firsthand from the RSA government. For the above reasons, this Study will use publically available information as the base to first come up with conceivable options for subjects to be examined, and then make evaluations on costs, benefits, and other elements on each of the options so proposed.

It is understood that the following information has so far been made publically available in this area:

1) Gas Utilisation Master Plan (GUMP):

The RSA government has been in the process of formulating the GUMP with an eye on 30 years into the future, and a part of its content under discussion was publicized in a presentation made in May 2014. The information released therein contained, among others, current state of the natural gas industry in South Africa and the policy environment that led to the ambitious gas utilisation initiative, along with updates on related infrastructure development such as construction of pipelines from neighboring countries, candidate sites for the gas receiving facilities including a floating LNG receiving terminal (Floating Storage and Regasification Unit: FSRU), as well as other factors involved in the expanded gas utilisation such as legal/social/environmental impacts of the program.

2) Current status of gas-fired power generation facilities:

South Africa currently has two main peaking-power plants, i.e. Ankerlig and Gourikwa Power Stations in Western Cape, having generation capacity of 1,338MW and 746MW, respectively. They are of an Open Cycle Gas Turbine (OCGT) design that can be powered by either natural gas or liquid fuel like kerosene or diesel. As South Africa presently does not procure natural gas as power generation fuel, these plants are operating on diesel fuel to cope with the increasing power demands. Upon completion of the proposed natural gas import facilities, these plants will be converted to gas in accordance with the original plans.

3) Request for Information (RFI) on Gas-to-Power Program:

In May 2015, the DoE released an RFI document concerning the IPP procurement program for new generation capacity based on gas-fired power generation. The gist of what transpired from this RFI was as follows:

a) The RFI is written with recognition that it will become necessary to import gas in the form of LNG or CNG, where Eskom Holdings SOC Limited will be the sole power buyer;
b) For the proposed gas to power plants such as open cycle gas turbine (OCGT) and combined cycle gas turbine (CCGT), in addition to natural gas which occurs naturally underground including shale gas and coal bed methane ("CBM"), the gas source may include synthesis gas ("syngas") generated by coal gasification technology such as underground coal gasification ("UCG") or integrated coal gasification combined cycle ("IGCC") technology, as well as liquefied petroleum gas ("LPG");
c) The bidder (i.e. the respondent to the RFI) may elect to propose a project as an integrated

Bundled Project complete with all plant, machinery, equipment and the necessary infrastructure from gas supply to power generation, or as an Unbundled Project, covering any one of the above-mentioned elements in accordance with the definition of the RFI.

d) The bidder/respondent is requested to provide the DoE with information concerning his proposed project as it relates to the project entity and its make-up and form of incorporation, mode and scope of participation, type of fuel (LNG or others), details of its source/s of gas supply to be used for the project and the supply assurance, details of the overall capacity of the power generation facility, details of the proposed gas receiving facility, description of the project location, information on the water use and supply for the project, and other information including the financing of each element of the project and others as set out in the RFI.

4) Business entity relating to various forms of gas importation:

As can be understood from the above RFI, the RSA government at this stage has not made it clear as to the business entity for importation of natural gas required in the program, and proposes the following two options:

a) An arrangement in which domestic gas supply enterprises are to own the gas (LNG) import facilities, procure the gas in the international market, and supply the imported gas to power producers;

b) An arrangement in which the power producers are responsible for preparing the gas receiving facilities, whereas a separate organ is to be established for domestic gas supply and demand adjustment.

(3) Estimation on domestic gas demand in South Africa

While the RSA government has a short-term plan to import natural gas for use in gas-fired power generation, it is also anticipating gas usage in the industrial sector in the future and studying its potential. Since the projection on future gas demand will have a large impact on the design and installation of the gas import facilities, this Study estimated the domestic gas demand in addition to the power generation use, after studying and analyzing potential consumption in the general industry, the industry using gas as the feedstock, or the transportation sector in the form of LNG or CNG, as well as by the possible introduction of town gas for commercial and household use. In particular, with respect to the gas use in the industrial sector, existence of potential demand is known in the areas such as a welding application of compressed gas by the Japanese automobile factories operating in South Africa. The potential gas use was examined with a focus on these applications as well.

(4) Investigation relating to indigenous gas production within South Africa

In South Africa in addition to the confirmed discoveries of subsea gas fields in the southern and Atlantic coasts of the country and Namibia, exploration work is in progress for CBM reserves, while a prospect of shale gas is also suggested. However, in order to increase the production of indigenous natural gas, additional exploration work and subsequent study on the development potential are needed on both technical as well as economic grounds, calling for a fairly long period of effort. For this reason, as far as the fuel supply for the gas-fired IPP in the immediate future is concerned, importation of natural gas in the form of LNG is considered realistic. On the other hand, since the prospect of increased production of indigenous gas is considered to play an important role in natural gas supply and demand in the longer term, the Study attempted to gather information on its potential and costs involved to prepare a long-term natural gas development program based on a reference as well as an enhanced production scenarios.

Furthermore, the RSA government is currently implementing the "Operation Phakisa[1]" initiative to activate marine transport and maritime industries, offshore oil and gas exploration, aquaculture, and marine protection services and governance. Accordingly, this Study will look into the progress being made in the area of its oil and gas development program.

(5) Assessment of natural gas development plans

In the course of this Study, concerning the natural gas import mainly comprising LNG, the method of importation and site locations as well as entities responsible for preparing gas receiving facilities were examined with respect to the state of investigation to date, whereby the economics and appropriateness will be assessed in reference to cases and examples in other countries to identify issues and challenges. On the matter of development of natural gas utilisation, in addition to own investigation by the DoE chiefly led by the IPP Office, independent studies are also carried out by interested private enterprises and, as a result of which, the study on fundamental issues is considered to have progressed to a considerable degree by now. In this Study, in addition to natural gas utilisation in the power generation sector and the same in the industrial sector as well as the possibility of demand creation by way of introducing town gas, along with its benefits including the effect on the GHG emission reduction policy, were looked into to come up with a set of recommendations after a comprehensive assessment.

(6) Environmental and social considerations

Upon investigating the options available for promoting natural gas utilisation in this Study, relevant information was gathered concerning environmental and social considerations program associated with the gas field development, construction of gas receiving facilities and others.

1.5 Others

(1) Visit Japan Program by invitation

[1] Meaning "hurry up" in Southern Sotho, it is a government-led initiative to fast-track the delivery of priorities outlined in the country's National Development Plan, launched in July 2014 in association with the “Big Fast Results” approach successfully applied by Malaysia.

As the C/P has expressed a strong desire to acquire the knowledge on natural gas utilisation, seven C/P officials from Department of Energy (DOE) and eleven C/P officials from Development Bank of Southern Africa (DBSA) were invited to visit Japan for discussion on natural gas utilisation in South Africa as well as site observation visits to natural gas related facilities for a targeted timing of April 2016 and February 2017. As the Study Plan was discussed with the C/P from DOE taking this opportunity ahead of the visit of the Study Team, joint study in South Africa was conducted very smoothly. The salient points of the invitation program are:

- DOE Participants: Mr. Ompi Aphane, Deputy-Director General, Energy & Policy Planning, Department of Energy, Ms. Karen Breytenbach, Head of IPP Office, and five officials from the Department.
- Duration : April 23 through May 1, 2016
- DBSA Participants: Mr. Mohan Vivekanandan, General Executive: Strategy, Development Bank of Southern Africa, Mr. Ernest Dietrich, General Executive: SA Financing, and nine officials from the Bank.
- Duration : February 18 through February 25, 2017
- Major Events: Seminar on Energy Trends and IPP Program – The Republic of South Africa
  Visits to government offices and relevant organizations
  Site visit to LNG power station, USC coal station, District Heating/Cooling system
  Discussions with engineering companies and potential investors

(2) Site visit in South Africa

The Study team visited candidate LNG terminal sites in Richards Bay and Saldanha Bay as well as Durban City and obtained information and comments on the current status and future outlook from IDZs and business corporations there.

Chapter 2 Trend in the World Gas Market

2.1 LNG - An Ever-evolving Industry

In the history of LNG, its global market has doubled in size every ten years - from 50 million tonnes in 1990 to 100 million tonnes in 2000, and to 220 million tonnes in 2010. Further it is expanding to 400 million tonnes per year by 2020.

The LNG industry is relatively young, just celebrated its 50 year anniversary in October 2014. It will continue changing its shape and ever evolving. The latest expansion phase of the LNG industry is featured with unprecedented transformation. Supply capacity increased dramatically between 2009 and 2011. Then the Fukushima Daiichi nuclear plant accident occurred in March 2011. It prompted shut down of all nuclear power plants in Japan. Power companies rushed to secure every available LNG cargo to compensate the loss. The traditional LNG transaction formula assuming long term contract could not fully accommodate the new situation with significant expansion of demand and supply and their wide discrepancies in location. New trading patterns such as spot trading, short-term contract, arbitrage, equity lifting and commoditization are spreading widely in the global LNG trade.

Presently, further evolution of trading patterns is ongoing with significant increase in the global LNG supply capacity. During the current expansion phase, two production centres are increasing their presence: Australia and the United States. This will also bring about another layer of flexibility and liquidity into the market.

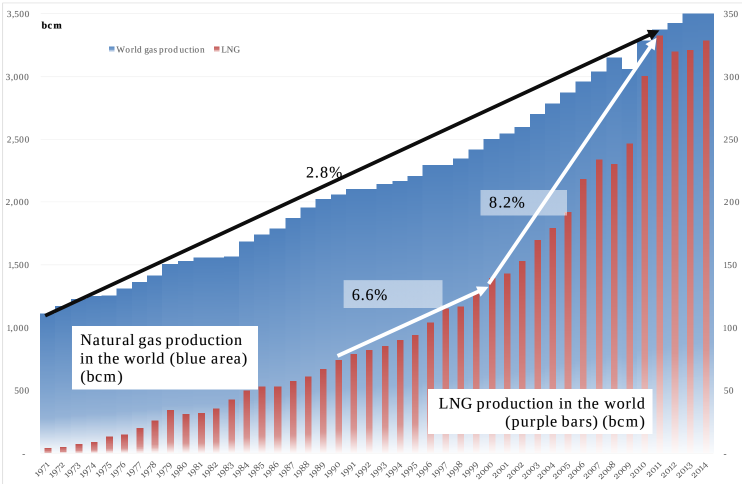
On the supply side, however, LNG production projects have been capital intensive and newer projects will be even more capital intensive. At the recent steep decline in energy prices, investors’ minds are cooling down rapidly resulting in significant delays or even withdrawals of new projects. Under the circumstance, market transformation will continue with vulnerable LNG price for several years to come until the cyclical wave of the market hits a new balance.

2.1.1 LNG grows faster than gas as a whole

In 1964, the first commercial LNG plant started operation in Algeria. Then the Alaskan LNG opened up an era of LNG in 1969 bringing natural gas to Japan. Recording high economic growth, Japan needed clean energies to fuel its heavy industrialization without adding environmental burden on its land and people. Low sulfur crude oil was scarce and desulfurization of fuel oil was expensive. For municipal gas supply, replacing toxic coal gas with natural gas was one of important enablers of modern home life. Thus, LNG penetrated into the Japanese energy market rapidly during the 1970s and 1980s.

Because of its capital intensive nature and to realise competitive price, LNG projects in the early time needed assurance of stable revenue under a long term contract to enable lower but extended annual capital recovery. Thus, very long contract periods on average for 20 years became dominant. On the other hand, this peculiar contract structure made LNG to be a secured energy supply source for resource poor Japan.

Following Japan, Korea started importing LNG in 1989 and Taiwan in 1990. After the turn of the century, India began LNG import in 2004 and China in 2006. Southeast Asian countries such as Thailand, Malaysia and Indonesia and Latin American countries such as Mexico, Brazil, Chile, and Argentine also commenced domestic use of LNG. Among them, Northeast Asia is the largest LNG market centre in the world.



(Source) Compiled by IEEJ based on data from Natural Gas Information 2015, IEA, and Natural Gas In The World 2015 Edition, Cedigaz

Figure 2.1-1 Global LNG and gas production since 1970s (to be updated when IEA's NGI 2016 becomes available)

Figure 2.1-1 describes growth of global LNG and total natural gas production since 1970. The blue area indicates total gas measured by the left axis. The purple bars indicate LNG measured by the right axis, which is one-tenth of the left one. In recent years the purple and blue have come closer to each other, which means about 10% of the total natural gas is now traded as LNG.

LNG has grown from almost nothing in 1970 to the current 10%, meaning that the growth rate for LNG has been much higher than that of natural gas as a whole, which in turn has been much higher than total primary energy demand growth.

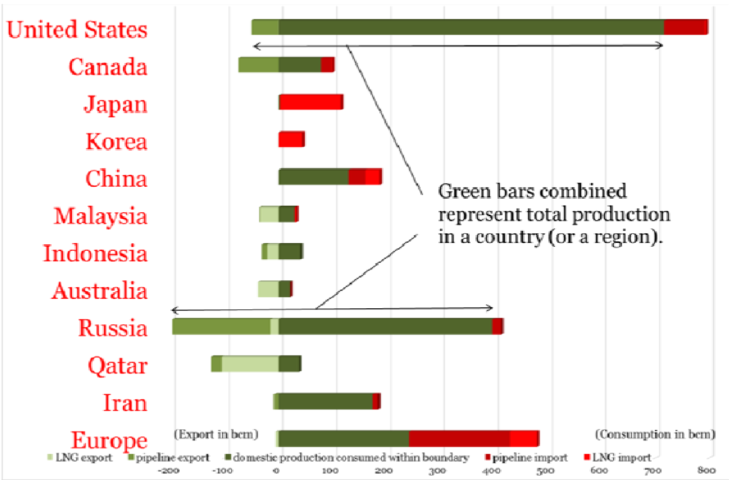
2.1.2 The Global LNG and Gas World are dominated by Several Players

Then who are the largest in production, consumption, exports, and imports of natural gas and

LNG? The countries indicated in the chart are the current largest countries in such categories.

The length of the line to the right from the zero line indicates individual market size. The green sections are covered by domestic production. The red sections include imports either via pipeline or in the form of LNG. The length of the line to the left from the zero line indicates exports. The total length of the green sections indicates production.

Thus the current two biggest gas producers are the United States and Russia, each producing about one-fifth of the global total natural gas. But their profiles are very different - the United States consumes most of gas domestically while Russia exports a significant portion of its production.



(Source) Compiled by IEEJ based on data from Natural Gas In The World 2015 Edition, Cedigaz

Figure 2.1-2 Global LNG and gas powerhouses in 2014

2.1.3 Existing and Expected changes in the LNG World

Anticipated changes in the LNG market, featured by specific aspects as below, are summarized in the Table 2.1-1:

a. LNG grows faster than natural gas as a whole and energy in general;
b. The Asia Pacific region evolves into more diversified combination of producers and consumers, supplemented by supply sources from outside;

More emerging markets are expected from Southeast Asia, Middle East and South America, while the role LNG in the energy market is changing from a premium energy source in the last century to an essential way of developing gas markets around the world, as well as a more globalized market.

Table 2.1-1 Existing and expected changes in the LNG world

	Past	Present	Future
Expansion of the LNG market	Growth rates: LNG > gas as a whole > total primary energy	LNG continues growing faster than gas as a whole, although representing less than 10% of the total gas	Is LNG expected to expand its share in the total gas trade?
The hybrid structure of the Asia Pacific market	Simple trade flows from Southeast Asia and Australia to North Asia's traditional buyers	Emerging markets joins traditional markets as core buyers to underpin new supply project development	New emerging markets (Southeast Asia) develop into a production and consumption center
Emerging LNG markets in Southeast Asia, Middle East, and South America	Standalone and small-scale pipeline gas markets, with some LNG exports	Fast-track LNG import projects with LNGRVs and FSRUs to meet rapidly growing local gas demand	Gas market sizes catch up with and surpass those of some OECD members
Evolving roles of LNG	LNG provides long-term security of supply and demand. LNG represents a premium energy source.	LNG is a clean and affordable essential energy source. LNG transmits price signals between regional gas markets.	LNG promotes increasing use of natural gas (in different regions and applications). LNG acts as a balancer between markets.

In this industry it has always been difficult to predict the future. Some specific perspectives often have led to unintended consequences.

Just ten years ago many people thought that the United States would become short of natural gas supply and import a huge amount of LNG. Expectation of higher gas prices in the country encouraged domestic gas production while a number of LNG production projects around the world was planned to target the market of the United States. However, the Shale revolution that was occurring coincidently totally nullified the previous views.

Then at this moment we are seeing steep decline in oil prices since the latter half of 2014, partly caused by expansion of oil production in the United States, which in turn would cause substantial changes in price gaps between dry gas and oil. This recent development would totally change the global LNG market, trading patterns and price formulation mechanism.

While some people may expect an LNG market with ample supply for some years to come, others may be worried about slowing investment and project withdrawals leading to supply shortage in several years later. The steeper and longer the price decline, the greater the budget cutting. Because of the gigantic size of the required capital investment and highly sophisticated technology, it is not easy for new players to participate in the LNG game.

Table 2.1-2 Actions are sometimes based on uncertain assumptions in the industry

Generally-held perspective	Reactions by players	Consequences
Higher gas prices in the United States (held until 2007)	Investment in LNG production in the world Accelerated shale gas development in the United States	Major expansion in LNG supplying capacity Major increases in gas production in the United States
Widening gap between gas and oil prices (held until 2013)	Investment shifting from dry shale gas to liquid LNG export plans in the United States	Declining crude oil prices Leading to lower LNG prices linked to crude prices
Illusion of tight LNG market (held until early 2014)	Shifting away from LNG	Declining LNG prices
Buoyant outlook of Chinese and Asian gas demand	Accelerated LNG production investment	Chinese demand looking uncertain
Expected increase of LNG supplying capacity from 2014	Buyers reluctant to commit Review and delays of LNG investment	Concern over slower investment and possible shortage of capacity in the future

2.1.4 Important LNG Events in 2016

Eleven important events in the global LNG industry in 2016, which are also expected to have significant implications on the future of the industry, are summarized below:

a. Major LNG production capacity expansion continues in the Pacific region;

b. LNG export are starting in the United States;

c. Projects are slow in Canada and East Africa, but potential is huge;

d. The pipeline deal between Russia and China may have impacts on pricing but also may be slowing;

e. Russia’s Yamal LNG project makes progress but may have difficulties;

f. Southeast Asia grows as an LNG consuming region;

g. More new LNG procurement deals are signed and buyers mull alliances;

h. Oil prices and spot LNG prices are lower for longer;

i. LNG demand is relatively flat in 2014 and 2015;

j. Japanese project finance still dominates the LNG world; and

k. Greater flexibility in LNG trade is requested and gradually realised.

2.2 New LNG projects

2.2.1 Additional 60 million tonnes expected in Australia and Indonesia by 2020

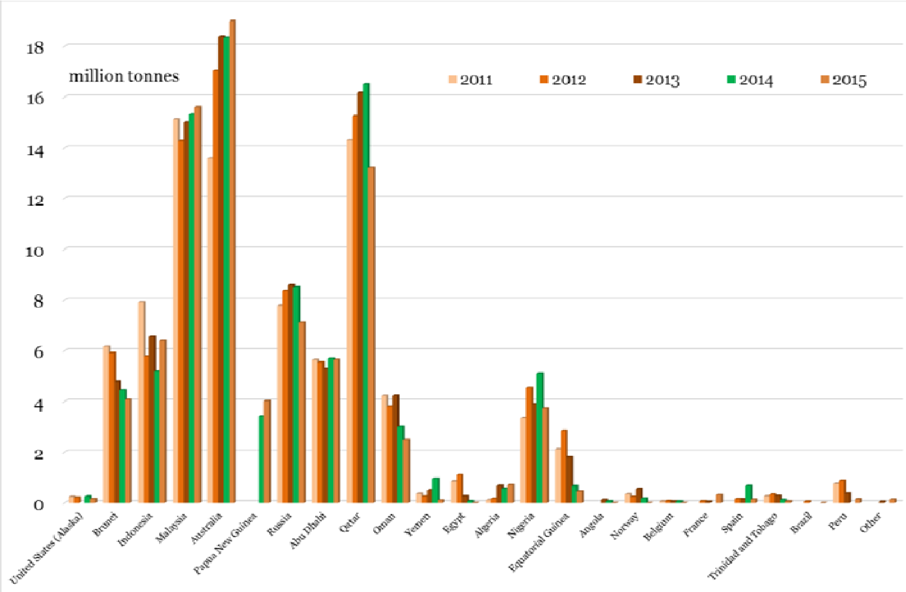
The first item is the major expansion of capacity mainly from Australia. The country has already been a major supplier of LNG for more than 25 years from the western states. Now in addition to other new projects in the west, large-scale LNG production projects are also under development in the eastern state of Queensland. Another notable feature of these projects is increasing buyers' equity participation.

Table 2.2-1 Additional 60 million tonnes is expected in Australia and Indonesia by 2020

Projects	Sponsors		mt	Offtakers (Bold with equity; Thinner letters indicate portfolio purchase)
QCLNG	BG	2015	8.5	**CNOOC, Tokyo Gas,** Chubu Electric, Singapore, Chile
GLNG	Santos, Total	2015	7.8	**Petronas, Kogas**
APLNG	ConocoPhillips, Origin	2016	9	**Sinopec,** Kansai Electric
Gorgon	Chevron, Shell, ExxonMobil	2016	15.6	**Osaka Gas, Chubu Electric, Tokyo Gas,** Kyushu Electric, JX, PetroChina, Petronet LNG
Wheatstone	Chevron, Woodside	2017	8.9	**Tepco, Kyushu Electric,** Chubu Electric, Tohoku Electric
Ichthys	Inpex, Total	2017	8.4	**Tokyo Gas, Osaka Gas, Chubu Electric, Toho Gas, Kansai Electric,** Tepco, Kyushu Electric, **CPC,** Kogas
Prelude	Shell, Inpex	2017	3.6	Tepco, Shizuoka Gas, Osaka Gas, Chubu Electric, JX, **Kogas,** CPC
Donggi Senoro	Mitsubishi Corporation	2015	2	Chubu Electric, Kyushu Electric, **Kogas**

In recent years, Japan has seen major shifts in its LNG supply sources in parallel with shifts in global LNG production. This is being enhanced by the changes in the gas markets of traditional LNG suppliers such as Indonesia and Malaysia, where domestic use of LNG has started in the 2010s.

Currently Australia is the largest supplier of LNG for Japan and it will continue to be so in the foreseeable future, while Australia will overtake Qatar as the world largest LNG producer before 2020. In recent years Japan has increased LNG imports from West Africa, while East Africa may become a promising candidate for Japan and Asia as a future source of supply. Likewise, Australia and African countries are expected to be promising suppliers for South Africa in view of their proximity and the ample resource potential.



(Source) Custom statistics

Figure 2.2-1 Japan's LNG supply sources in fiscal years 2011 – 2015

2.2.2 Another 60 million tonnes expected from the United States

There are several LNG export projects in the United States that are already under construction or in the advanced stage of planning. Three projects targeting the Japanese market started construction in 2014. Among them, Sabine Pass LNG started its export in February 2016. Japan and Asian countries are playing the pivotal role in realizing LNG projects in the United States as investor as well as customer. There are over 20 LNG projects proposed to date in the United States amounting to over 200 million tons of LNG supply capacity. Among them, only a single digit number of projects may be completed before 2020. Nevertheless, this will easily push up the United States to the third largest LNG producer in the world after Australia and Qatar. Once it has become a dominant power in the market, the US LNG based on the liquid domestic gas market may impact the global LNG trade pattern significantly.

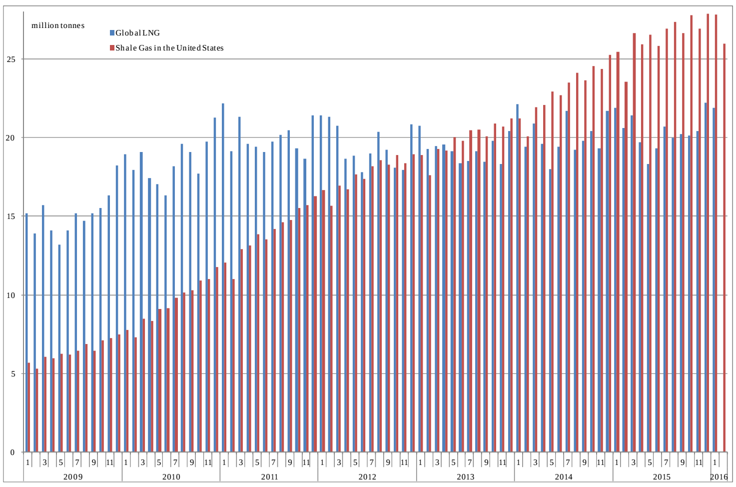
As South Africa is geographically located much closer from the Gulf of Mexico than Asian markets, the United States will be another promising LNG supply source. South Africa will be able to benefit from ample LNG supply sources in the east and west.

Table 2.2-2 Another 60 million tonnes is expected from the United States

Projects	Sponsors		mt	Offtakers (**Bold with equity;** *Italic* letters indicate portfolio purchase)
Nearing completion				
Sabine Pass	Cheniere	2016	18	BG, Gas Natural Fenosa, Kogas, Gail
Primarily to Japan				
Cameron	Sempra, Mitsui & Company, Mitsubishi Corporation/NYK, GDF Suez	2018	13.5	Tepco, Tohoku Electric, Kansai Electric, Toho Gas, Tokyo Gas, CPC, Singapore
Freeport	Freeport LNG	2018	13.2	**Osaka Gas, Chubu Electric**, Toshiba, *Tepco, Kansai Electric*
Cove Point	Dominion, Sumitomo Corporation	2018	5	Tokyo Gas, Kansai Electric, Gail
Planned				
Corpus Christi	Cheniere	2019	13.5	Pertamina, Endesa, Iberdrola, Gas Natural Fenosa, Woodside, EDF, EDP

(Source) IEEJ based on Corporate Press Releases

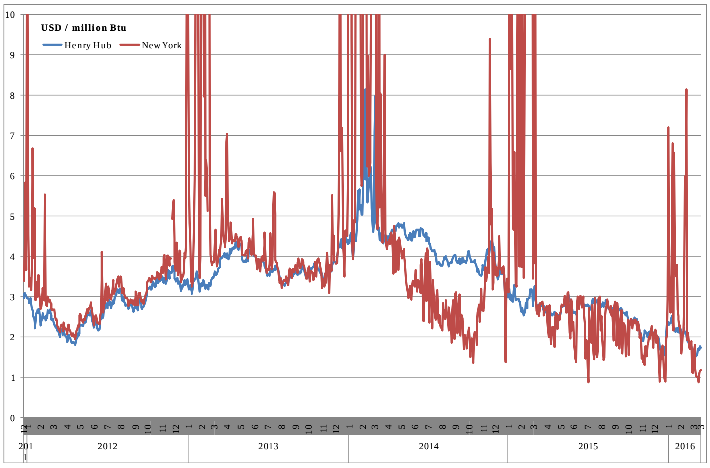
Expanding shale gas production is the driving force of the LNG projects in the United States. The shale gas revolution is pretty much still ongoing. Figure 2.2-2 shows monthly production of shale gas in the United States and global LNG in blue. In 2013 shale gas production became larger than the global LNG production.



(Source) Compiled by IEEJ based on data from Energy Information Administration, the United States and trade information and Customs statistics

Figure 2.2-2 Shale plays in the United States produce more than the global LNG industry (to be updated before Final Report submission)

Another example of ongoing features of the shale revolution is changing regional prices in the country (See the chart below). Spot gas prices in the United States have different movements depending on local market factors. Prices in New York (in red) in general fluctuate more wildly than those at Henry Hub. New York has been traditionally a large consumption centre while Henry Hub is close to traditional gas production centres. But in 2014 they took notably different courses - New York saw lower spot prices for an extended period due to increasing shale gas production from nearby Marcellus Shale.



(Source) Compiled by IEEJ based on data from data from the Energy Information Administration, the United States

Figure 2.2-3 Natural gas prices are still shifting in the United States (to be updated before FR submission)

So Japan and Asia expect LNG import from the United States. Another question is how long it will take to transport, as LNG transport is significantly more expensive than oil. Panama Canal was expanded to be able to accommodate LNG tankers in June 2016. As the projects are being constructed in the eastern side of the United States, potential saving by using the expanded canal from 45 days to 25 days will be significant. Recently the canal authority released the draft tariffs for 2016 including those for LNG tankers. The release of will give the industry a clearer picture for its future of the canal.

Table 2.2-3 Draft tariffs for LNG tankers in 2016 proposed by the Panama Canal Authority

Bands in m³	Laden	Ballast	Ballast (Roundtrip)
- 60,000	USD 2.50	USD 2.23	USD 2.00
- 90,000	USD 2.15	USD 1.88	USD 1.75
- 120,000	USD 2.07	USD 1.80	USD 1.60
Rest	USD 1.96	USD 1.71	USD 1.50

2.2.3 East Africa and Canada expected to provide the next wave

As Japan continues pursuing diversification of supply sources, expectations have been high for development in resource rich areas including East Africa and Canada. Although it is difficult to predict when, but most likely Japan and Asia will need both as future sources of LNG.

Table 2.2-4 LNG development summary in East Africa

	Partners	mt	Developments in 2014-2015
Tanzania	Shell (formely BG) /Ophir, Statoil/ExxonMobil	10	Pavilion joins
Mozambique Area 1	Anadarko, Mitsui & Company, ENH, PTT, OVL/OIL		Non-binding offtake agreements for 2/3 of the Train 1 outputs
Mozambique Area 4	Eni, CNPC, Kogas, Galp, ENH		FLNG FEED

Table 2.2-5 Selected LNG projects in Canada

Projects	Partners	mt	Developments in 2014-2015
Pacific Northwest	Petronas, Sinopec, Japex, Indian Oil, Petroleum Brunei	12	No FID Parallel FEEDs by JGC, etc. BC environmental permit
LNG Canada	Shell, PetroChina, Mitsubishi Corporation, Kogas	12	Project company is formed Chiyoda conducts FEED
Kitimat LNG	Chevron, Woodside	10	Apache is replaced by Woodside JGC consortium is awarded EPC

2.2.4 Russia advances gas sales strategy toward the East

Russia has two major deals with China. One is pipeline supply from Siberia and the other is LNG from Yamal. Agreed volumes of supply are significant; and the pricing arrangement is also expected to have some impacts on LNG pricing in the Asia Pacific region. Yamal LNG is expected to supply LNG from the Arctic region to China. The rate of expansion of Chinese gas market has somewhat slowed down, registering 3% growth in 2015 compared to 10% in 2014, due to the recent economic slump. Yet, given its market size, China is undoubtedly the most prospective market for the future natural gas supply. .

Table 2.2-6 Gas market developments between Russia and China

	Developments in 2014-2015
Planned pipeline gas sales to China	Gazprom and CNPC agreed on pipeline gas supply of 38 bcm per year (equivalent of 28 million tonnes per year) for 30 years beginning in 2018. The deal is said to be worth USD 400 billion, translated into USD 10 per million Btu. This may have implications on LNG prices in Northeast Asia The two sides also principally agreed on additional 30 bcm via the Western Route in November.
Yamal LNG	With the FID in December 2013, the project is under construction and has already secured sales to CNPC and Gazprom M&T. 9 ice-class LNG carriers have already been on firm orders Chinese and Russian banks provide financing
Chinese gas market	3% growth in 2015 China produced 132.9 bcm in 2014, of which 1.3 bcm came from shale

2.2.5 Southeast Asia produces and consumes LNG

Japan continues relying on Southeast Asia as a major supply source. At the same time some countries are increasing LNG use. Indonesia and Malaysia continue supplying LNG to other countries, at the same time they began receiving LNG in their main gas consuming areas.

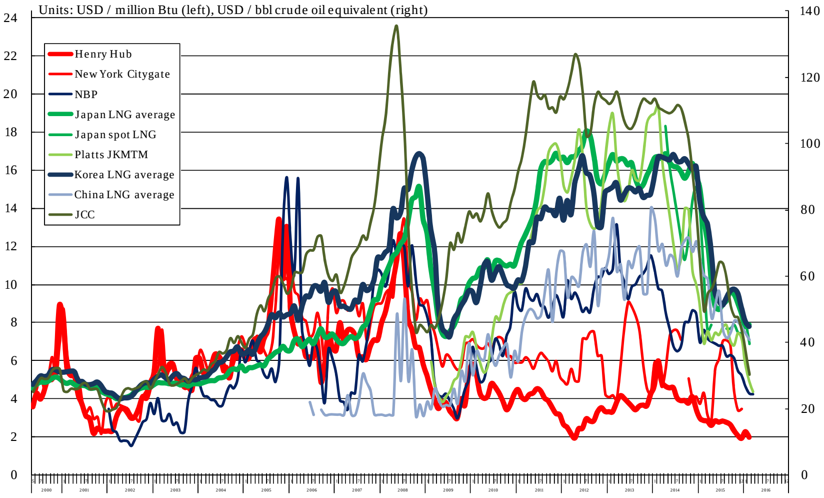
Table 2.2-7 LNG market developments in Southeast Asia

	LNG demand	LNG production
Indonesia	West Java opened an LNG terminal in 2012 Lampung opened another in August 2014 Arun's converted into an LNG receiving terminal in 2015 LNG purchase from Corpus Christi	Existing supply to the Bontang plant is expected to decline Some delays are anticipated for development of new feedgas sources to supply Bontang Donggi Senoro LNG started operation in 2015 Tangguh expansion in 2019
Malaysia	Melaka started in 2013 Pengerang due in 2017 Procurement from PNW LNG	Petronas FLNG1-2 and Malaysia LNG 9 are under construction
Thailand	Map Ta Phut started in 2011 Term deliveries from Qatar started in 2015	
Singapore	Jurong started in 2013	

2.3 Trends in LNG Price and Trade

2.3.1 Regional prices walk in different paths

The chart shows representing gas prices around the world from 2000 to 2014. Since 2008 the gap between regional prices have been widening and persisting up until 2014.

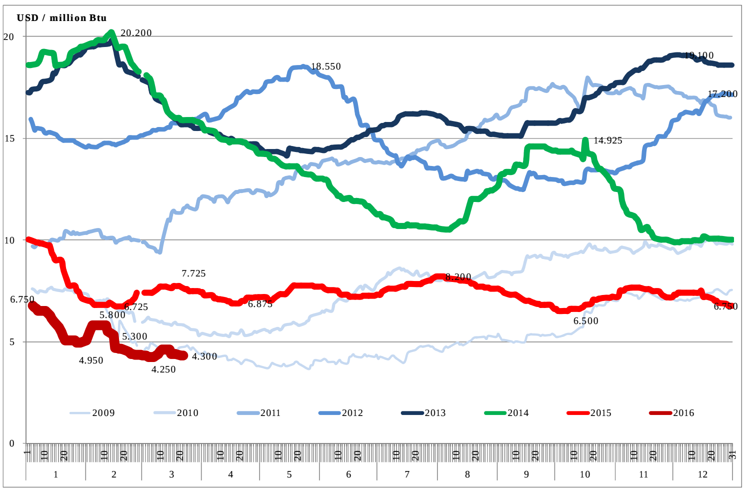


(Source) Compiled by IEEJ based on data from custom statistics of countries, the US EIA, Energy Intelligence and Platts

Figure 2.3-1 Regional gas prices (updated before FR submission)

While majority of LNG is traded under long-term contracts, spot and short-term cargoes are playing a more important role in recent years.

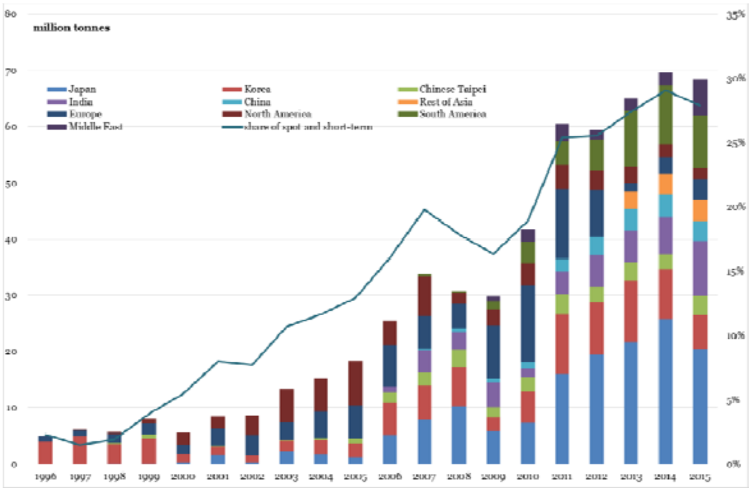
Some price reporting agencies (PRAs) have provided spot price assessments. Those have not established as reliable price benchmarks yet, as the market is not liquid enough. As actual transactions are still scarce, the assessments are mostly based on notified offers and bids. Despite such limits, they can be viewed as some indications of market sentiments. In 2014 the assessed price was very high, hitting 20 dollars per million btu in February. In 2015 at one point was less than 7 dollars per million btu, much lower than previous years.



(Source) Compiled by IEEJ based on data from Platts LNG Daily

Figure 2.3-2 Spot LNG assessment prices (to be updated before FR submission)

Growth of short-term trades is accompanied with the growth of the overall market, as well as diversification of sources and markets. More than 60 million tonnes or 1/4 of the total LNG is traded under short-term arrangements.

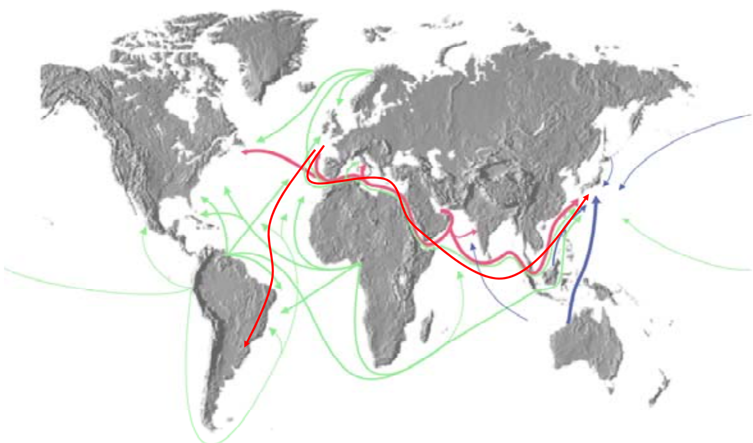


(Source) Compiled by IEEJ based on data from GIIGNL

Figure 2.3-3 Spot and short-term LNG volumes

Also supply routes are diversifying. In 1998, the markets were relatively simply divided.

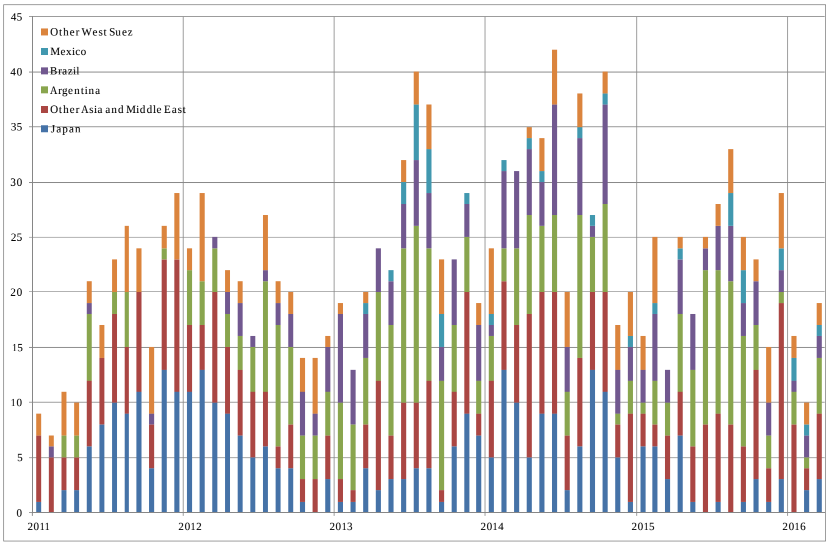
LNG flows in 2015 were rather complicated. Traditional supply sources in the Asia Pacific and Middle East regions continued supplying to the markets in the East, while the suppliers in the Atlantic region also supplied some LNG to the East. Additionally some European importers re-exported LNG after imports.



(Source) BP Statistical Review of the World Energy

Figure 2.3-4 LNG trade flows in 2015

If we look at the cargo movements by month, they also change quite significantly depending on seasonable weather patterns and other factors. Japan increased spot purchases immediately after the nuclear crisis in 2011 (shown in blue) but decreased gradually in 2012 as it shifted some incremental purchase into contract arrangements. Since 2013, Latin American importers increased their presence in the spot LNG market.



(Source) Compiled by IEEJ based on data from ICIS Heren Global LNG Markets and Platts LNG Daily

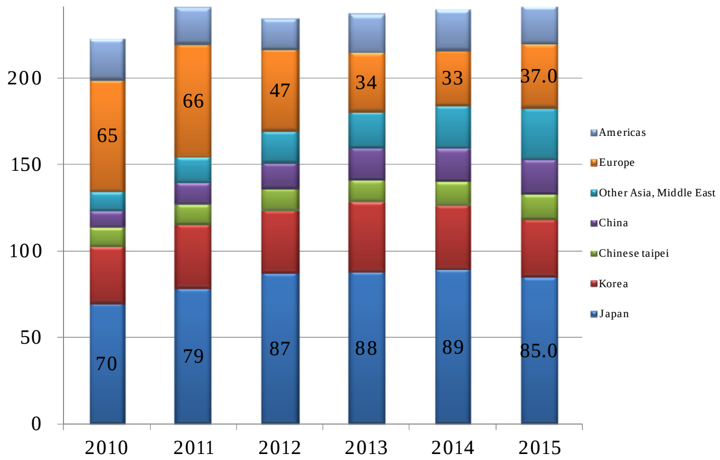
Figure 2.3-5 Number of spot LNG cargoes by destination (to be updated before FR submission)

Many observers in the industry used to say, especially until early 2014, that the LNG market would be tight until 2015. They often fail to distinguish between the global LNG market as a whole and the short-term LNG market. The perception of tightness itself may have had effects to raise negotiated prices. Because of this, the perception itself is part of the structural problem of expensive LNG prices. Such arguments of tightness of short-term LNG markets, often found in commercial media and sellers' comments, could give undue supports to LNG sellers leading to unrealistically high offering prices.

The overall balance in the LNG market did not show any signs of tightness, even though some supply disruptions are observed from the Atlantic region producers. Lost LNG volumes in European markets in recent years have been more than offset by Russian pipeline gas supply, as well as reduction of overall gas demand. Some decreasing liquidity of short-term LNG cargoes is sometimes observed leading to seasonal imbalances.

2.3.2 LNG market has not seen significant growth since 2012

Even though major expansion is expected to begin, the past few years have been quite an unusual time of lower growth for the LNG industry caused by combination of factors of supply disruptions in some Atlantic region sources and more importantly disappeared LNG demand in Europe. Part of this demand destruction in Europe has been also caused by the illusive perception of LNG market tightness and higher prices.



(Source) Compiled by IEEJ based on data from custom statistics of countries and data from GIIGNL

Figure 2.3-6 Global LNG import in 2010 - 2015

2.4 Conclusion

A larger and more flexible LNG market is expected with capacity expanding to 400 million tonnes globally by 2020. Demand for the fuel is expected to grow but with significant uncertainties. Therefore greater flexibility is not only expected but is necessary.

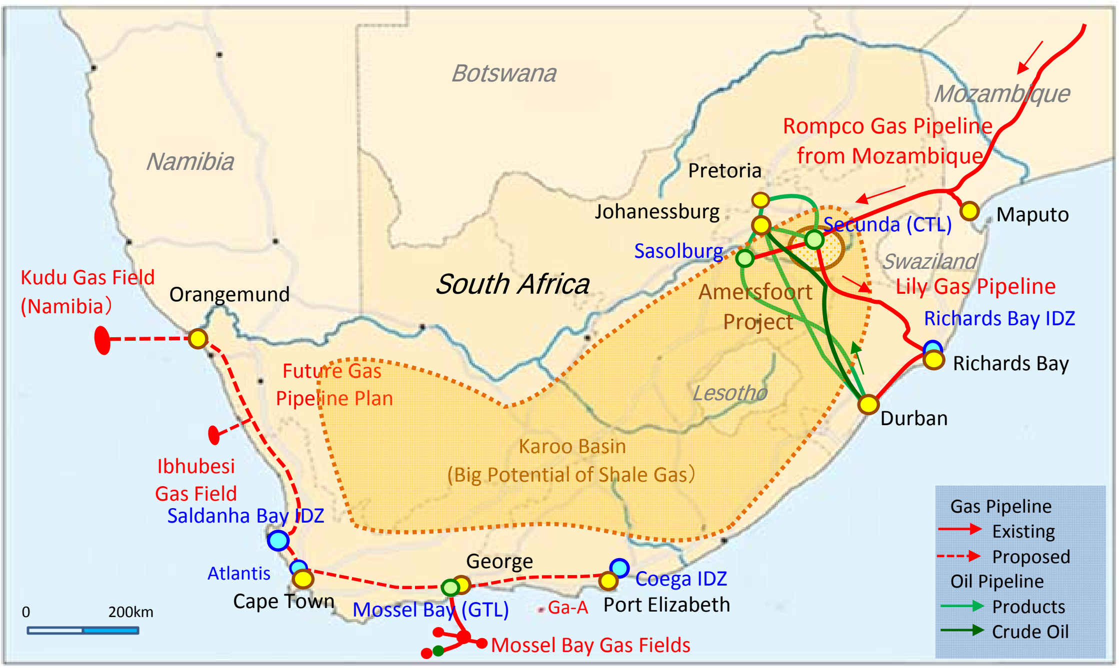
Although the market is accompanied with more uncertainties and is anticipated to be more difficult to manage, the greater market is expected to provide more rewards. New reality of lower crude prices and market calls for more competitive LNG prices pose challenges - but they can be overcome through cooperation between suppliers and consumers.

Despite the uncertain market outlook, it is certain that South Africa is geographically located in a very advantageous location to choose its LNG supply among the United States, Middle East and Asia-Oceania. To enjoy this favourable position, it is essential to carefully investigate the ongoing market transformation and set forth LNG procurement policy strategically.

Chapter 3 Natural Gas Supply Potential for South Africa

3.1 Overview of Gas Supply in South Africa

While South Africa is endowed with more than 30 trillion tons of rich coal reserves[2], only a limited amount of natural gas has been discovered to date. All of the indigenous gas production is presently used at the Gas to Liquid (GTL) plant of PetroSA located at Mossel Bay. Presently producing gas fields are depleting, however, there are no reliable domestic resources to immediately supplement the reducing production. Several smaller gas fields have been discovered in isolated locations but they are considered to be sub-commercial under the present market conditions. On the other hand, unconventional natural gas resources such as coal bed methane (CBM) and shale gas are said to have big potential; but they are yet to be explored and proved. Thus, it is widely thought that natural gas production in South Africa is not likely to increase substantially in the next 10 years.



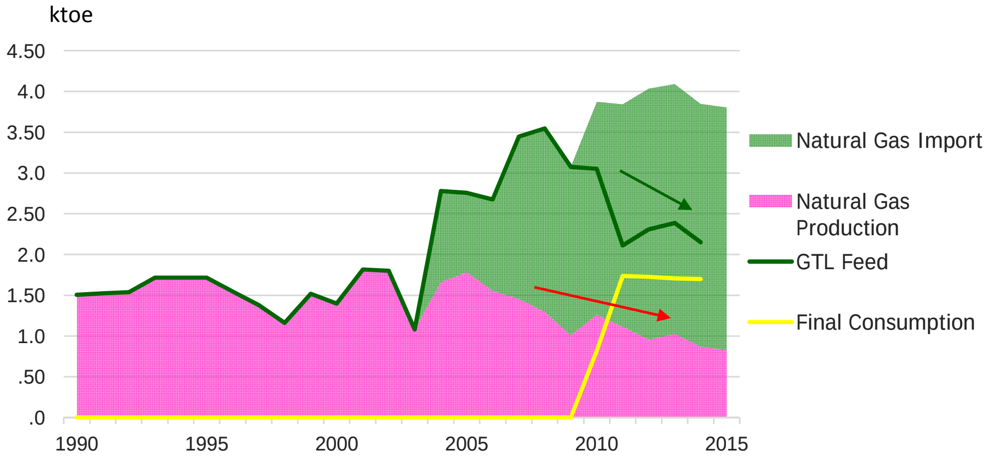
(Source) Petroleum Agency SA and IEEJ

Figure 3.1-1 Natural Gas fields and Pipelines

Since 2004, South Africa is importing natural gas from neighboring Mozambique via ROMPCO (the Republic of Mozambique Pipeline Company) pipeline that connects Pande and Temane gas fields in Mozambique and the Secunda CTL/GTL plant near Johannesburg. At first the imported gas was used solely for GTL process feed. Since 2010, a part of imported gas has been delivered to adjacent industrial and other users. According to the present arrangement, natural gas import remains at about 3.0 million toe or 120 Bcf a year, of which 1.7 million toe is

[2] BP Statistical Review of World Energy 2016.

delivered for local gas users while 1.2 million toe was used at the GTL plant in 2014. While SASOL has a plan to expand the import of piped natural gas, it may take some time before green light is given to it. Reflecting the production decline in Mossel Bay gas fields, natural gas supply at GTL plants in South Africa is decreasing fast. To maintain production at these plants, it is the most pressing issue to prepare alternative sources of natural gas as feedstock.



(Source) IEA World Energy Balances (2016 edition)

Figure 3.1-2 Natural Gas supply in South Africa

In addition to the gas fields presently producing, huge natural gas reserves have been discovered in northeastern part of Mozambique. They will offer a possibility of increasing piped gas import in the future. However, these reserves are located in the offshore deepwater blocks more than 1,500m below sea surface and 2,600km away from the demand center in South Africa. Developing these gas fields and a long distance pipeline system will be expensive and time-consuming requiring careful consideration.

In coal rich South Africa, history of gas distribution dates back to 1892 when a 30m gas pipeline was installed in President Street, Johannesburg, for street lighting purposes. Since then, Johannesburg has remained the only city in South Africa with piped gas infrastructure. The city relied on the supply of highly toxic coal based hydrogen rich gas produced at the Cottesloe Gas Works until 1991. Metro Gas, the department for city gas supply, decided to cease production at the Gas Works and purchase its entire gas requirement from SASOL. The Egoli Gas Consortium[3] bought the Metro Gas in 2000, and the entire system including supply to 35,000 individuals were converted from toxic coal gas to methane rich gas[4] supplied by SASOL in 2004-2005.[5] Presently, the synthetic gas produced at the Secunda plant of SASOL is supplied to Gauteng Province and also to Richards Bay and Durban areas in KwaZulu-Natal Province via

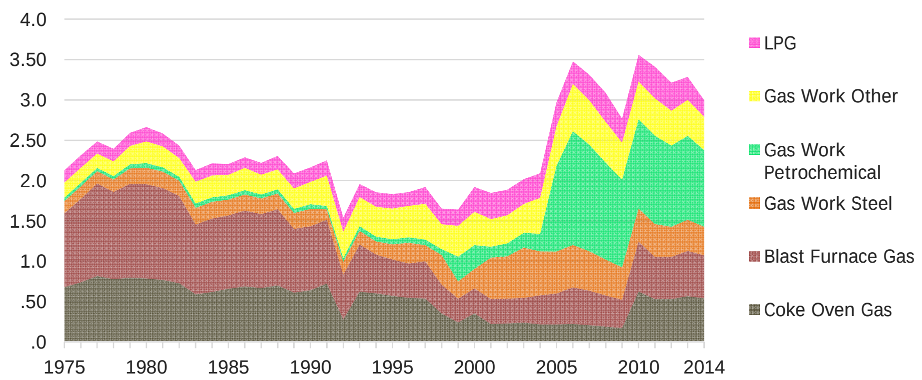
[3] A joint venture between US-based Cinergy Global Power and Egoli Empowerment Holdings.

[4] Toxic coal gas comprising CO and H_2 is upgraded to methane rich hydrocarbon gas via F/T synthesis process; characteristics of the latter are very similar to natural gas.

[5] http://egsite.co.za/about-us.html

Lily pipeline.[6]

Among the gaseous fuel supply other than natural gas, a part of synthetic gas and whole of the coke oven gas and blast furnace gas are used at steel mills. Except that synthetic gas use at petrochemical production increased in 2005, its supply for industrial and residential use remains at an almost same level. There is no immediate plan to expand synthetic gas production. LPG supply mainly comes from domestic refineries (89.6% in 2014). It recorded 375 ktoe in 2011 but has decreased to 57% of the peak production. LPG consumption has shrunk to almost half of its peak recorded in 2011, while there is a tendency that LPG supply is gradually shifting to import.



(Source) IEA World Energy Balances (2016 edition)

Figure 3.1-3 Gas Supply in South Africa other than Natural Gas

Under the circumstance, LNG will provide an earlier measure of increasing natural gas supply for South Africa. As shown in Figure 3.1-1, three candidate sites are under study for construction of LNG import terminals; namely, Saldanha Bay, Coega and Richards Bay. As discussed in the previous chapter, the global LNG market is developing fast and will provide reliable access to stable and sustainable supply of natural gas.

3.2 Natural Gas Production Outlook

3.2.1 Conventional Gas Resources

In South Africa, oil and gas exploration drilling started in the late 1960s. Exploration activities were mainly conducted during the 1980s and 1990s off South Africa's southern coast resulting in several discoveries of oil and gas fields. All of the present oil and gas production comes from the Block-9 in the Bredasdorp Sub-basin of the Outeniqua Basin. According to the

6 The first coal synthesis plant started operation at Sasolburg located 80km south of Johannesburg in 1956 with 17 fixed bed gasifiers, producing LPG, gasoline, diesel and feedstocks for production of synthetic rubber and fertilizers. The second plant at Secunda located 120 km south-east of Johannesburg started operation in 1993. Its production capacity is 160,000bpd and is presently producing 155,000bpd of petroleum and chemical products.

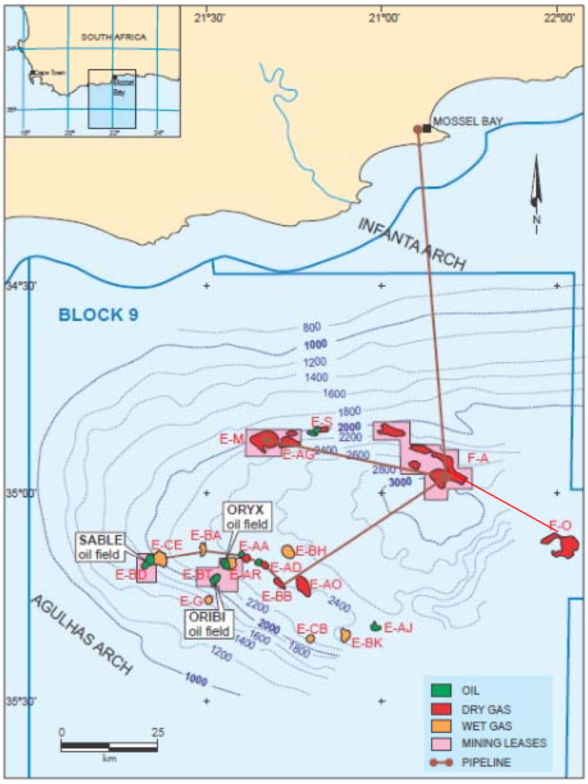
IEA statistics[7], however, oil and natural gas production in South Africa is quite limited. In 2014, natural gas production was 869 ktoe (thousand tonnes oil equivalent) or 34 Bcf and crude oil production was 232 ktoe or 5.7 kbpd. These were smaller than the productions in resource poor Japan as shown in Table 3.2-1.

Table 3.2-1 Oil and Gas Production in South Africa (2014)

	Natural Gas		Oil/Condensate	
	ktoe	Bcf	ktoe	kbpd
South Africa	869	34.1	232	5.7
Japan	2,586	101.4	515	12.7

(Source) IEA World Energy Balances (2016 edition)

In South Africa, domestic natural gas production started in 1992 from the gas fields F-A and E-M and satellite gas fields located 90km south offshore Mossel Bay. These fields produced approximately 160 MMcfd (54 Bcf/year) of natural gas and 3,900 bpd of oil in 2006. All the produced gas is piped to the PetroSA GTL plant located at Mossel Bay and used as GTL feedstock. In 1997, crude oil production started at the Oribi oil field located in the same block at an initial rate of 25,000 bpd. A floating production facility is used and produced oil is transported by a shuttle tanker to the refinery located in Cape Town. In 2000, the Oryx oil field was put on stream and in 2003 the third oil field Sable. Associated natural gas from these fields is piped to the Mossel Bay GTL plant via F-A platform. The Oribi/Oryx are now almost depleted with only minor production.[8] In December 2014, the F-O gas field started production to supplement depleting gas production in other fields.



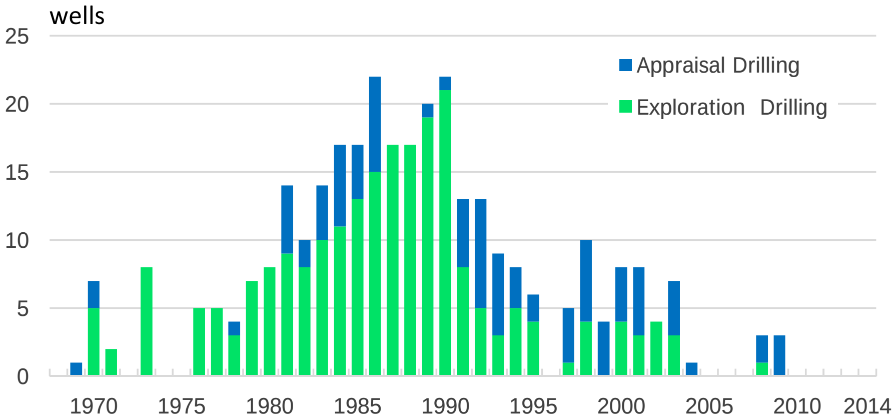
(Source) Petroleum Agency SA

Figure 3.2-1 Producing Gas Fields in South Africa

After recording 22 exploratory and appraisal wells drilled in 1986 and 1990, drilling activities

[7] IEA World Energy Balances (2016 edition).
[8] Petroleum Agency SA, "Petroleum Exploration in South Africa", http://www.petroleumagencysa.com/images/pdfs/Pet_expl_opp_broch_2013h6_final_web.pdf

has almost ceased in South Africa after 2000. To date, 36 hydrocarbon discoveries were made in South Africa, of which 15 are producing, three have ceased production and 17 were considered too small to develop.[9] Only one, Ibhubesi, located in the Orange Basin of Atlantic Ocean is deemed to be in the pre-production stage. However, it is isolated from the existing gas production system. With its relatively small reserves of 540 Bcf, standalone development of a new gas system is unlikely. In particular, it is necessary to secure supplemental supply of natural gas for the post-peak period when the field starts declining in order to assure stable supply to its potential users. Development of the field may be considered as a part of an integrated sustainable gas supply system such as LNG import.



(Source) Wood Mackenzie "South Africa's Oil & Gas Licensing and Fiscal System," October 2014

Figure 3.2-2 Exploratory and Appraisal Drilling in South Africa

In South Africa, the remaining gas reserves at the producing gas fields were only 339 Bcf at January 2014 as shown in Table 3.2-2, which is depleting fast. PetroSA has further revised downward its estimate of the proved gas reserves at the end of 2015 only to 98Bcf.[10] For the PetroSA GTL plant at Mossel Bay, it is a pressing issue to find alternative gas supply sources.

Table 3.2-2 Oil and Gas Reserves of South Africa(As at 2014/1/1)

Location		Initial Reserves			Remaining Reserves		
		Oil	Gas	Total	Oil	Gas	Total
		MMbbl	Bcf	Mmboe	MMbbl	Bcf	Mmboe
Block 2A	Ibhubesi	4	540	99	4	540	99
Block 9	E-M and F-A	52	1,487	313	2	283	51
	Oribi and Oryx	47	-	47	0	-	0
	Sable	24	-	24	0	-	0
	South Coast Gas Development	5	174	36	1	56	11
Total		132	2,201	519	7	879	161

(Note) South Coast Gas Development includes E-AA, E-AD, E=BA, E-BB, E-CA and E-CE gas fields connected to the F-A platform via 90 km pipeline.
(Source) Wood Mackenzie "Review of South Africa's Oil & Gas Licensing and Fiscal System," October 2014

As shown in Figure 3.2-2, exploration drilling has been almost nil in the past ten years.

9 Wood Mackenzie, "Analysis of South Africa's Upstream Sector," 2014
10 PetroSA Integrated Annual Report 2015

However, with recent sizable discoveries in deepwater exploration in Mozambique and Tanzania, offshore deepwater blocks in South Africa have attracted interest of international oil companies. Since 2011 several exploration right permits have been awarded to IOCs including TOTAL, ExxonMobil and Anadarko. To back up their exploration, the government of South Africa launched “Operation Phakisa” in July 2014, which lists offshore oil and gas development among nine priority development sectors.[11] The government is looking at enhancing the enabling environment for exploration of oil and gas wells, resulting in an increased number of exploration wells drilled, while simultaneously maximizing the value captured for South Africa to increase the sector GDP from ZAR 4 billion in 2010 to ZAR 11-17 billion in 2033.

Despite these efforts, deepwater blocks are yet to be tested while IOCs are presently suffering from severe budget constraints after the oil and gas price plunge that started in the fall of 2014. In addition, the upstream legislation issue relating to the Mineral and Petroleum Resources Development Act Amendment Bill (MPRDA Amendment Bill)[12], which was published in 2012 and referred back to Parliament by the President in January 2015, adds up uncertainties on upstream exploration activities. It may take some time before expensive deepwater drilling starts. Then, if successful, any deepwater discoveries are likely to need a decade before they are put in production.

3.2.2 Unconventional Gas Resources

The Karoo Basin, which extends for half the area of mainland South Africa (see Figure 3.1-1), is expected to have huge potential for unconventional gas plays, namely CBM and shale gas. The north-eastern part of the Great Karoo Basin, where most of the country’s coal deposits are located, is deemed as the target for CBM play. On the other hand, the south-western part of the Karoo Basin where rich organic shales are developed is deemed as the target for tight shale gas play.

In the north-eastern part of the Karoo Basin, the Waterberg/Ellisras Basin is reported to be the most promising target for the CBM play being speculated to have up to 1 Tcf gas resources.[13] Anglo American Plc and several foreign companies in joint venture with indigenous companies are operating CBM licenses in the rich coal region. The Anglo Operations mining group is investigating the basin's methane potential by drilling more than 70 wells and conducting production tests.

Recent promising news is that conventional gas was discovered in CBM exploration.

[11] http://www.operationphakisa.gov.za/pages/home.aspx President Jacob Zuma launched the Operation Phakisa in July 2014. In August 2013, President Jacob Zuma undertook a State Visit to Malaysia. He was introduced to the Big Fast Results Methodology through which the Malaysian government achieved significant government and economic transformation within a very short time. Using this approach, they addressed national key priority areas such as poverty, crime and unemployment. Phakisa” means “hurry up” in Sesotho. https://www.environment.gov.za/projectsprogrammes/operationphakisa/oceanseconomy

[12] The bill proposes additional state participation with development cost carry, which is very unusual in the upstream legislation and brings about significant uncertainty on field development economics.

[13] Petroleum Agency SA, “Petroleum Exploration in South Africa”

Australian based Kinetiko Energy Limited has successfully tested the KA-03PT well drilled in the Amersfoort coal mine region. Kinetiko has been conducting exploration of CBM in this region since 2010 and found natural gas in a sandstone layer lying at a depth of 220-440m and above the CBM layer. Kinetiko is evaluating the discovery dubbed as Amersfoort Project[14] with a size of contingent resources estimated to be as much as 1.5 Trillion Cubic Feet (Tcf), comprising 1.0 Tcf of CBM and 0.5 Tcf of conventional natural gas. As these gas fields are moderately large and located at a shallow depth, they are likely to become a promising gas supply source in the Gauteng Province.

In 2013 the U.S. EIA reported that the Karoo Basin is considered to be a prospective area for world-class shale gas reserves.[15] EIA estimated that the Karoo Basin may contain 390Tcf of technically recoverable shale gas resources, putting the country among the top 10 countries in the world. However, available data is limited on the shale gas potential in the Karoo Basin, though gas shows were discovered in the southern Karoo several decades ago. Before extensive exploration activities bring sufficient affirmative information, the EIA's estimate remains hypothetical.

Following protests on the impact of hydraulic fracturing (fracking) operations, a shale gas exploration moratorium was imposed in April 2011 by the South African government. After the moratorium was lifted, Department of Mineral Resources (DMR) published in June 2015 Regulations for Petroleum Exploration and Production (the Regulations) which introduced guidelines covering onshore hydraulic fracturing. So far Shell and several other companies have applied for exploration licenses for shale gas and presently waiting for approval. One of the concerns is water availability in this dry region, while significant amount of water is necessary to conduct hydraulic fracturing. Since no exploration work targeting at shale gas has been undertaken as yet, it is still unclear as to how the future development will unfold in this area overcoming various technical, economic and environmental barriers. At present, shale gas potential in the Karoo Basin should be deemed only as a long term possibility.

3.2.3 Gas Reserve Estimates

According to the report prepared by Wood Mackenzie for the Department of Energy in 2014, potential recoverable gas reserves are estimated as shown in Table 3.2-3.[16] Discovery of conventional gas is expected mainly in the deepwater blocks pending future exploration efforts. The

Table 3.2-3 Gas Reserve Estimates by Resource Type

	Recoverable Reserve
	Tcf
Conventional (offshore)	9.0
Karoo Shale	9.0
Karoo CBM	1.5
Total	19.5

14 http://www.kinetiko.com.au/projects/amersfoort-project/
15 U.S. Energy Information Administration, "Technically Re coverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States", June 2013
16 Wood Mackenzie, "Analysis of South Africa's Upstream Sector

entire Karoo Basin may hold up to 120 Tcf of shale gas, of which 9.0 Tcf may be recoverable; and 8.0 Tcf of coal bed methane, of which 1.5 Tcf could be recoverable. The estimate for shale gas looks conservative compared with the estimation by the US EIA. At any rate these estimates are only a guide and remain hypothetical until significant drilling and evaluation activity takes place. Most of the entire 19.5Tcf gases are yet to be found, while possibility is slim for them to be put on stream in the near future.

3.3 Regional Gas Supply

In addition to the existing piped gas from the Pande and Temane gas fields in Mozambique, natural gas resources discovered in neighboring countries may be considered as future supply sources via pipeline. They may include significant gas discoveries in the eastern coast of Mozambique, Kudu gas field discovered in the Atlantic Ocean of Namibian water and coal bed methane from Botswana.

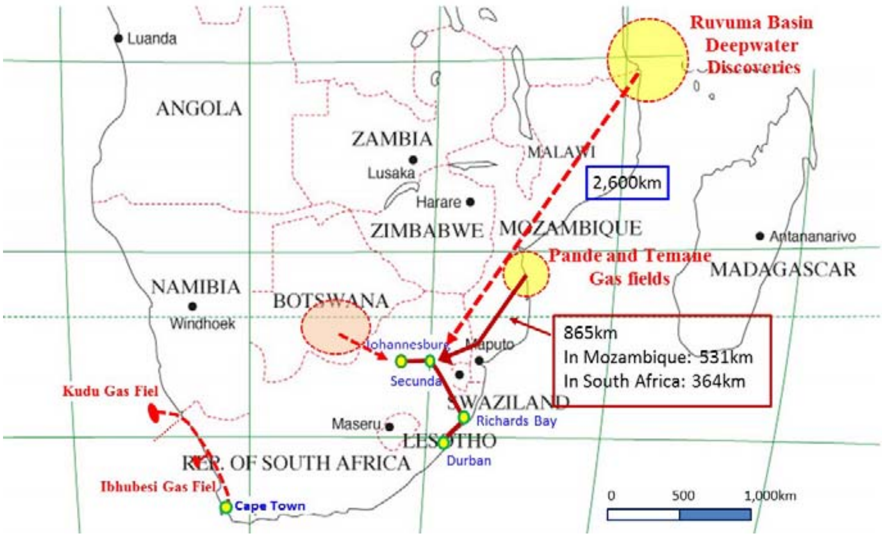


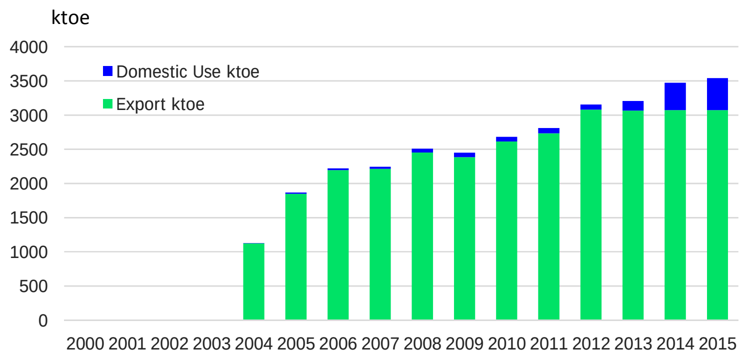
Figure 3.3-1 Potential Natural Gas Supply from Neighboring Countries

3.3.1 Mozambique

Since 2004, Mozambique started natural gas production at the Pande and Temane gas fields located near the eastern coast about 500km northeast of Maputo. These gas fields were discovered in the 1960s (Pande: 1961, Temane: 1967). However, due to civil unrest in the 1970s, upstream activities were ceased. In 2003, SASOL carried out an extensive drilling campaign in the onshore blocks and discovered new gas fields; the reserve increased to 5.5Tcf.[17] SASOL started natural gas production in 2004 and exported almost all of the production to Secunda, South Africa, via the ROMPCO pipeline. The export amount reached 120 Bcf in 2012 and has been kept at the same level while domestic consumption is emerging mainly for power

[17] David Ledsema, “East Africa Gas – Potential for Export”, The Oxford Institute for Energy Studies, March 2013

generation.



(Source) IEA World Energy Balances (2016 edition)

Figure 3.3-2 Natural Gas Production in Mozambique

SASOL is conducting exploration activities in the four blocks in the area, and expects that the natural gas resources in this area will far exceed the 3.3 Tcf, which is the proved reserve registered at the US SEC. In general, the so-called probable reserves estimated with a 50% probability of recovery are much greater in numerical term than the more tightly defined proved reserves, estimated at a 90% probability for reporting to the SEC. SASOL is considering a plan to triple the gas import to 1 Bcf/day (365 Bcf a year), of which 0.6 Bcf/day will be allocated for GTL feedstock and 0.4 Bcf/day for power generation. SASOL further considers to increase the import to 2 Bcf/day by 2030, of which 0.6 Bcf/day will be allocated for GTL feedstock and 0.4 Bcf/day for steel production. However, economics of a new GTL project remain speculative under the present low oil price. SASOL considers that harmonious development of gas demand is most important in materializing the plan.[18]

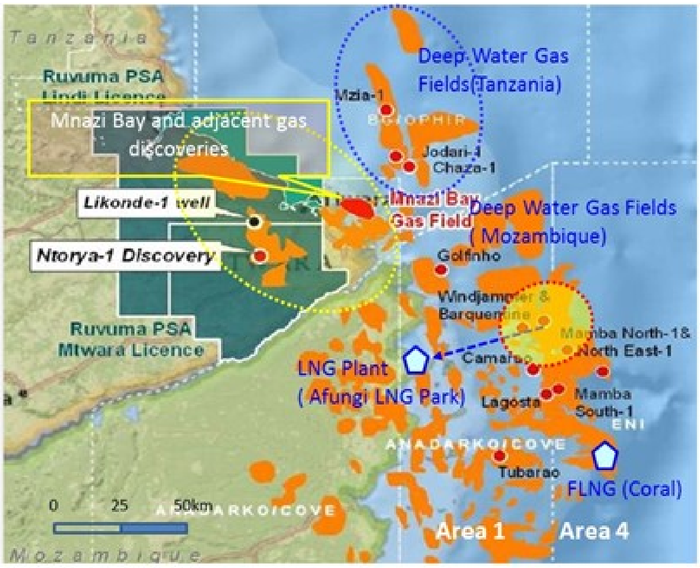
In addition, huge natural gas reserves are found in the Ruvuma Basin further north. In 2009, Anadarko discovered natural gas in Area 1 and in 2011 ENI found natural gas in Area 4. After a series of successful gas discoveries, it is estimated presently that Area 1 contains 75 Tcf recoverable reserve[19] and Area 4 contains 2.5 Tcm (88Tcf) GIIP.[20] With this huge gas discovery, IOCs are aiming to construct four (4) trains of onshore LNG plant (typically 5-6 MTPA each) and eventually up to 10 trains. In addition, as an early solution, a floating LNG (FLNG) project is being implemented.

To start with, Anadarko and ENI including their co-venturers signed in December 2015 a Unitization and Unit Operating Agreement (UUOA) for the development of the massive natural gas resources.[21] Under the UUOA, the Prosperidade and Mamba straddling natural gas reservoirs, which comprise the Unit, will be developed in a separate but coordinated manner by

18 Hearing from SASOL on 17 May 2016.
19 Anadarko Mozambique Fact Sheet 2016 https://www.anadarko.com/content/documents/apc/news/Fact_Sheets/Mozambique_Fact_Sheet.pdf
20 Eni's activities in Mozambique, https://www.eni.com/enipedia/en_IT/international-presence/africa/enis-activities-in-mozambique.page
21 http://www.mzlng.com/

the two operators until 24 trillion cubic feet (Tcf) of natural gas reserves (12 Tcf from each Area) have been developed. The jointly produced gas will be piped to the onshore LNG plant at Afungi LNG Park at the Palma Bay.

Developing these deepwater fields, the consortium has to conquer the technical challenges to build subsea production system and lay down pipelines to the shore. The gas reserves are located in 1,500m deep water within 50km from the shore. The seabed topography is characterized by a very narrow continental shelf and is followed by a steep slope to the ocean floor, of which water depth is more than 2,000 meters. Slope gradients are typically up to 10 degree although these are over 15 degree in places. There is a potential risk of mass slide of soft soils on the steep slope. There are also a series of active canyons running out perpendicular to the shorelines. The consortium is yet to reach final investment decision for construction of the gas fields and onshore LNG plant.



Source: IEEJ, Tanzania Petroleum Development Corporation, USEIA,

Figure 3.3-3 Deepwater Gas Discoveries Offshore Mozambique and Tanzania

Apart from the on shore project, ENI announced in February 2016 that an approval was obtained for developing FLNG on its Coral discovery.[22] The approval relates to the first phase of development of 5 trillion cubic feet of gas in the Coral discovery located in the Area 4 permit. The discovery is located in water more than 2000 meters deep and approximately 80 kilometers offshore of the Palma bay in the northern province of Cabo Delgado. According to the development plan, 6 subsea wells will be drilled and connected to the floating LNG system with production capacity of 3.4 MTPA. ENI has been conducting FEED on FLNG plant since 2014, which will be a turret moored double-hull floating vessel. Once final investment decision is made in an early time, the project may become onstream even before 2020.

Combined with the above natural gas development, there is a potential of piped natural gas supply to South Africa, which would become available from the Domestic Market Obligation (25%) of the production. The national oil company of Mozambique (Mozambique Empresa Nacional de Hidrocarbonetos: ENH) has invited bids for construction of a pipeline that would

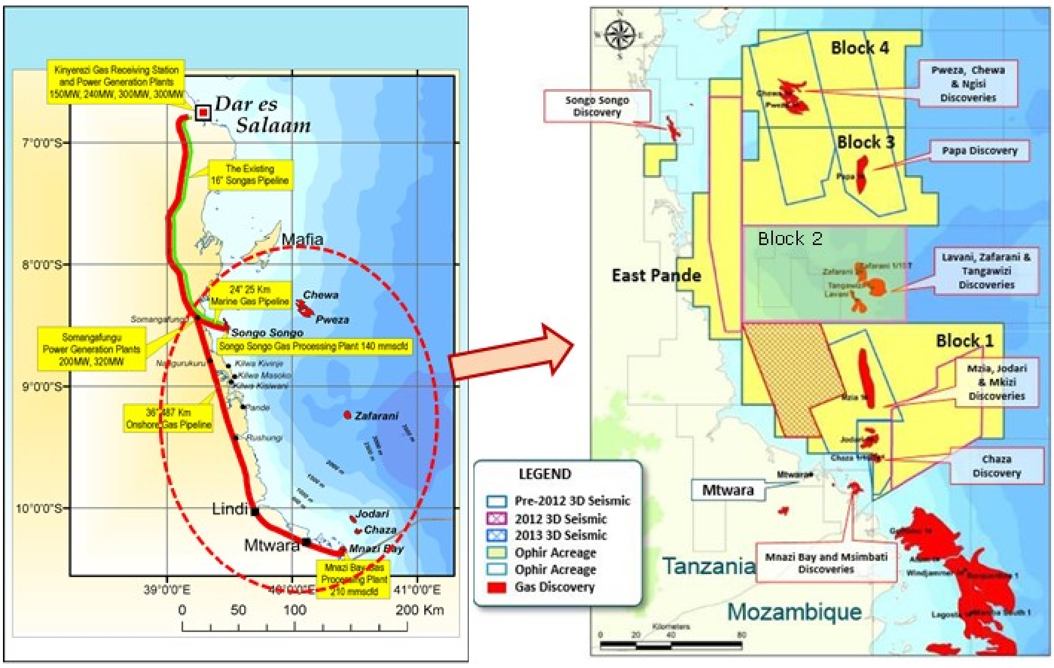
[22] Eni: Approval of the development plan for Eni's Coral discovery offshore Mozambique, 24 February 2016

cross Mozambique and deliver gas to South Africa. However, to justify huge investment for construction of an extra-long pipeline, it is necessary to secure a significant amount of demand. Hence, this project may be considered as one of the long term potential gas sources.

3.3.2 Tanzania

In Tanzania, a small quantity of natural gas is produced since 2004 from near shore gas fields such as Songo Songo and Mnazi Bay, which were discovered in the 1970s. They are piped to Dar es Salaam and used mainly for power generation. In addition, to significantly increase the gas supply for domestic requirement, a 534 Km 36” pipeline with the capacity of 784 Bcf per year was constructed connecting the Mnazi Bay gas field located in a shallow water block further south to Dar as Salaam in the summer of 2015, upon completion of which a newly constructed Kinyerezi I Thermal Power Station (150MW) commenced operation.

Upon successful gas discoveries results in the Mozambique deepwater, extensive exploration activities have been carried out also in the Tanzanian blocks since 2010 by consortiums led by BG (now acquired by Shell) and Statoil. At the end of 2015, the estimated GIIP reached 57Tcf, of which 10 Tcf is found in the onshore/near shore blocks and 47 Tcf was found in the offshore deepwater blocks.[23] Gas recovery ratio from these sandstone reservoirs is estimated to be about 70%.



(Source) Tanzania Petroleum Development Corporation

Figure 3.3-4 Natural Gas Discoveries Offshore Tanzania

[23] Justin W. Ntalikwa (Permanent Secretary, Ministry of Energy and Minerals), “Tanzania’s Economy and Energy Sector”, presentation at the Tanzania Natural Gas Forum held in Tokyo on 4 August 2016.

In Tanzania, onshore/shallow water natural gas will be developed at first for domestic use such as power generation and fertilizer. For development of deepwater gas which is expensive and needs substantial anchor demand to justify economics, construction of an onshore LNG plant is under study with target start-up by 2025. Under the circumstance, Tanzania may be deemed as a potential LNG supplier in the medium/long term. Because of the short distance, LNG from Mozambique and Tanzania will offer beneficial supply sources for South Africa.

3.3.3 Botswana

According to the preliminary exploration study by the Department of Geological Survey of Botswana conducted in the early 2000s, the coal-bearing sequences of the Kalahari Karoo Basin is estimated to contain 60 Tcf of CBM as GIIP. The highest development potential is expected along the eastern margin of the basin.[24] At present, however, only limited study has been conducted including a small gas to power project (10MW) proposed by Tlou Energy, an Australian based independent player.[25] CBM export from Botswana may be considered only after certain gas reserves are confirmed by extensive exploration activities.

3.3.4 Namibia

The Kudu gas field is located in the Namibian water of the Atlantic Ocean (see Figure 3.1-1) 170km northwest of Oranjemund city. It was found by Chevron in 1974. The present proven natural gas reserve is 1.4 Tcf. Tullow Oil farmed in the block in 2004 and is continuing exploration aiming for oil.[26] There is a plan to use the natural gas for a gas to power project at Oranjemund. Once the gas supply system along the Atlantic coast including the Saldanha Bay/Cape Town demand centre is built, Kudu could be connected to the system.

3.4 Summary

The above observations on domestic and regional gas supply potential may be summarized as follows:

1) At present there is no immediately available natural gas from indigenous and regional gas sources. Small discoveries in the Atlantic Ocean may be developed only when an integrated gas supply system is established in the Saldanha Bay/Cape Town region. Deepwater potential is yet to be explored.

2) Import of natural gas from Mozambique via pipeline is one of viable options for South

[24] The Department of Geological Survey, “Coal Bed Methane Study,” http://www.gov.bw/Global/MMWER/dgscbmstudy.pdf

[25] The company says “Tlou’s 100% owned Lesedi CBM project has an independently certified contingent resource of up to 3.3 trillion cubic feet (TCF) (3C) with a further prospective resource totaling 8.6 TCF (High Estimate). Tlou is aiming to have certified gas reserves in the near future,” .http://tlouenergy.com/overview

[26] http://www.reuters.com/article/africa-oil-namibia-idUSL8N12T3D620151029

Africa. To materialize it, a comprehensive gas supply plan needs to be established including harmonious gas demand development that could provide sufficient anchor demand. In view of the present project progress, Mozambique and Tanzania may be deemed as short distance LNG options in the medium term.

3) Unconventional natural gas such as shale gas and CBM expected from the Karoo Basin remains long term possibilities before certain proved reserves are established through extensive and successful exploration activities.

Chapter 4 Energy/Natural Gas Demand Outlook of South Africa

In this chapter, an econometric model is developed based on the available data such as World Bank and the International Energy Agency (IEA), and data collected from Statistics South Africa, Department of Energy and state owned power company ESKOM to analyze the long term energy outlook or South Africa. We have visited energy related departments and authorities at national level and local government, candidate LNG import sites, State-owned enterprises, and private energy companies to interview and collect data for the energy demand model construction. The data and information obtained through the field survey are reflected in the long-term energy demand outlook for South Africa extending to 2045.

4.1 Concept of Energy and Natural Gas Demand Outlook

After the first democratic election in South Africa introduced in 1994, the country's economy has been expanding at an annual average growth rate of 2.96 % between 1994 and 2015. The country has driven economic growth of the entire African Region. Although the country was hit by runaway inflation and economic turmoil in the 1990s, the country's economy in the 2000s mostly stabilized at an average 5% annual inflation. However, since 2014 the economic growth rate has reduced reflecting the decline in international prices of energy and mineral resources; the GDP growth rate declined to 1.5 % in 2014 and 1.3 % in 2015.[27]

In this study, we conduct forecast of energy and natural gas demand for South Africa using an econometric model based on the historical data. The background setting for the projection is as follows;

a) Since 1994, the economic activity of the country is relatively stable and the inflation rate since 2000 has stabilized at 5 %. Therefore, we can expect that relatively stable analysis outcome may be obtained if we apply an econometric model.

b) Enough numerical samples required for statistical data are obtained after 1994, and the data is in a level applicable for econometric analysis.

c) Usually, the correlation of macro-economic activities and energy demand is closely in accordance with development of market mechanism. It means that the environment under which we can apply an econometric model is prepared. The country's economy has continued high growth as a member of BRICS, and the country has reached the "Medium Development Stage"[28]. The environment under which we can apply an econometric analysis is judged to be well-prepared based on the accelerated development of a variety of economic/energy statistics.

In addition, we consider the draft long term power development plan and the natural gas industry plan in this study, and prepare projections of energy demand outlook for a long term up

[27] IMF, "World Economic Outlook", April, 2016
[28] UNIDO 「Industrial Development Report 2016」

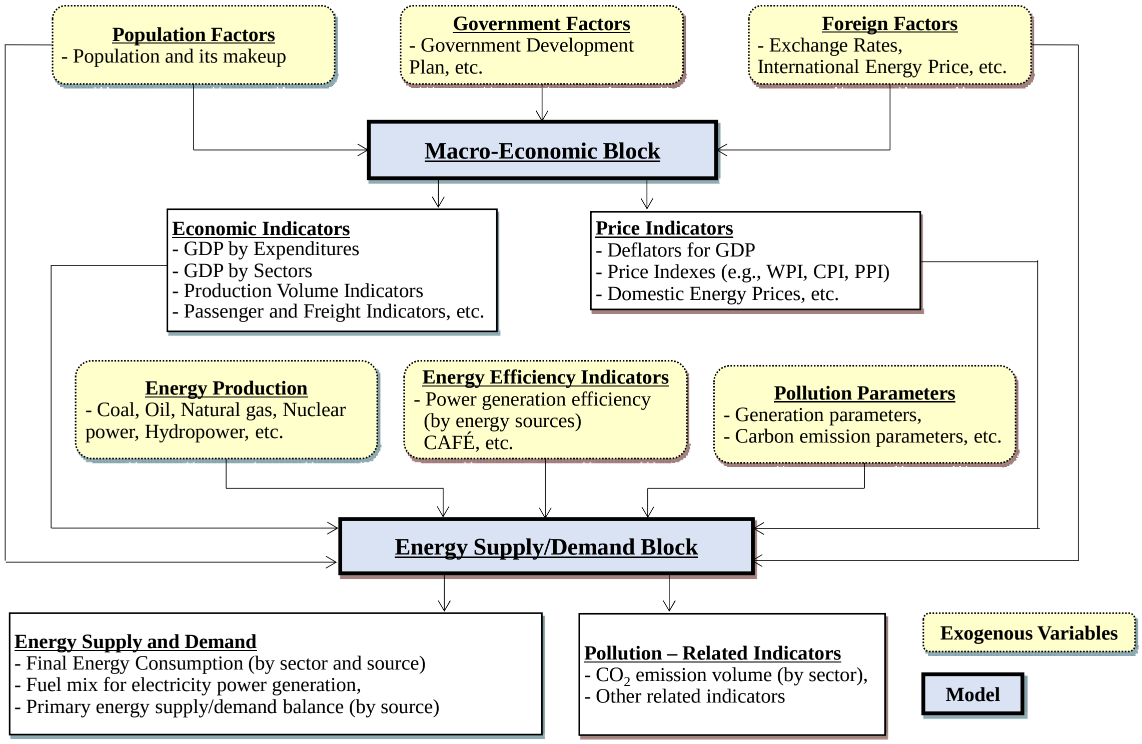
to 2045 and analyze the position and prospects of natural gas in South Africa.

4.1.1 Outline of Model

(1) Concept and Structure

The structure of the model comprises two sub-models called "Macro Economic Block" and "Energy Supply/Demand Block" in order to examine the long term energy demand from 2013 up to 2045. In this report, the energy demand of South Africa up to 2045 will be simulated through the two sub-models and the final energy demand by sector will be projected considering the country's energy structure in the future.

The whole constitution of the model is shown in Figure 4.1-1. Applying this type of integrated econometric model method, it is relatively easy to examine correlations between macro-economic indicators and energy demand, and changes in future energy demand based on trends in economic activities.



(Source) JICA Team

Figure 4.1-1 Structure of Model

In addition, in order to estimate a primary energy supply outlook, it is necessary to consider how to deal with the transformation sector such as the power sector, coal sector, and natural gas liquefaction sector. It is also necessary to reflect collected information by field survey to the model. For this reason, the information collection and exchange of ideas were implemented in the first and second field surveys and used to modify the model, along with attempts to improve the accuracy of projection for estimating primary energy supply outlook.

Macro-Economy Block

In this modeling study, the growth rate of Gross Domestic Product (GDP) is given as an external assumption adopting the IMF World Economic Outlook and South Africa's GDP projection. The sectoral GDP is simulated by share functions based on the historical trends and changes in the industry structure. Here, important points are how to set changes in the industrial structure that will occur in future, how to maintain the mineral resource industries, and how to introduce the middle-tech and high-tech industries. The model reflects the numerical targets from the State Development Planning announced in 2012[29] and industry policy given as an external variable to simulate the long-term sectoral structure change.

Final Energy Demand Block

"Energy Demand Block" will become the core part of the entire model structure. Indicators of explanatory variables obtained from the "Macro-economic Block" such as the GDP by sector, electricity tariff, population, income, industry production index, and price index are used to determine the energy demand by sector in the final energy consumption.

(2) Projection Period and Model Scale

Model estimation period extends over 30 years from 2015 to 2045. The model has total 232 equations composed of 57 function equations and 175 definitional equations. All equations in the model are calculated as simultaneous equations. Historical data of the model start from 1990 up to 2014.

(3) Data

Sources of historical macroeconomic data are the International Monetary Fund (IMF), United Nations statistics Division (UNSTAT) and Statistic South Africa, while the energy sector data are collected from the International Energy Agency (IEA) and Department of Energy. The electricity tariff records obtained from the state owned power company (ESKOM), and the crude oil and coal prices were obtained the trade statistics of South Africa.

4.1.2 Assumptions

(1) Population Factor

According to the United Nation's Population Division database, the total population of South Africa in 2014 was 53.97 million. The annual average growth rate of population was 2.0 % from 1990 to 2000, and 1.4 % from 2000 to 2010, where the growth rate continued to slow down. In 2014, the population growth rate decreased compared to previous year to 1.03 %.

For the future projection, the growth rate for population projection from 2015 to 2045 is obtained from the United Nations Statistic Division and is introduced into the model as an

[29] National Development Commission, "National Development Plan 2030", August 2012.

external variable. According to the population projection results, the increase rate of population in South Africa will gradually decelerate from 0.97 % in 2015 to 0.40 % in 2045. The population will become 64.35 million by 2045.

Table 4.1-1 Population Projection of South Africa (2015~2045)

Year	Population (Million)	Annual Growth Rate (%)	Year	Population (Million)	Annual Growth Rate (%)
2013	53.42(Acutual)	1.10			
2014	53.97(Actual)	1.03			
2015	54.49	0.97			
2016	54.98	0.90	2031	60.34	0.51
2017	55.44	0.83	2032	60.65	0.51
2018	55.87	0.78	2033	60.95	0.50
2019	56.28	0.73	2034	61.25	0.49
2020	56.67	0.70	2035	61.55	0.49
2021	57.05	0.67	2036	61.85	0.48
2022	57.41	0.64	2037	62.14	0.47
2023	57.76	0.61	2038	62.43	0.47
2024	58.10	0.59	2039	62.72	0.46
2025	58.44	0.58	2040	63.00	0.45
2026	58.76	0.56	2036	63.28	0.44
2027	59.09	0.55	2037	63.55	0.43
2028	59.41	0.54	2038	63.82	0.42
2029	59.72	0.53	2039	64.09	0.41
2030	60.03	0.52	2040	64.35	0.40

(Source) United Nations, Department of Economic and Social Affairs, Population Division (2015). "World Population Prospects: The 2015 Revision", July 2015

(2) Government Factor

The government economic policy is the most important key factor in a model analysis. Generally, government expenditures and investments as an effective policy are drivers of the economic development. In this model, GDP growth rate is set as an external variable in the macro-economic block. In addition, in reference to the long term economic development potential based on the standard perspective for the Total Factor Productivity, as mentioned before, assumptions about the future key growth areas are necessary to be taken into account.

In this model, the energy demand outlook is projected based on the numeric targets developed in the macro-economic and energy development policies announced by the South African government. However, for the short-term from 2016 to 2022 estimation of economic growth rates by the IMF are adopted and for the longer-term from 2023 to 2045 economic growth rates projected by the South African Government at 4.2 % as a target for a Moderate Growth case[30].

[30] Department of Energy, "Integrated Energy Plan Final Report", page 62

Table 4.1-2 shows economic growth rate projected for each year.

In addition, it is assumed that the energy development target promoted by the South African Government will be successfully implemented, being reflected in the model. The specific policy objectives are described as below.

- Nuclear power : 9,600 MW by 2030
- Natural gas : 30% in the generation fuel mix by 2050

Table 4.1-2 GDP Growth Rate of South Africa (2014~2045)

Year	GDP Growth Rate (Previous year, %)	Remarks
2014	1.549	Actual
2015	1.283	
2016	0.612	IMF Projection
2017	1.206	
2018	2.063	
2019	2.4	
2020	2.4	
2021	2.4	
2022	3.7	
2023~2045	4.2	IEP Projection

(Source) IMF projection result on June 2016. IEP projection, “IEP Final Report”

(3) Overseas Factor

Overseas factors are mainly economic trends of trading partners, foreign currency exchange rates and international energy prices. In particular, trends in the coal price and crude oil price will give strong impacts to the South African economy. Exchange rate and international energy prices are important elements in evaluation of the domestic energy costs. Coal and mineral resources are important export goods to earn foreign currencies. (Please refer to Chapter 2 Trend in the World Gas Market)

4.2 Simulation Results

4.2.1 Macro Economy

Table 4.2-1 below shows the macro-economic indices of South Africa. As described above, the economic growth rates from 2016 to 2022 are the one projected by IMF and 2023 to 2045 are the one projected by the South African government at 4.2%. As a result, the compound annual growth rate of GDP for the whole projection period from 2014 to 2045 is calculated to be 3.63%. The manufacturing sector will be expanding at 5.9% of average annual growth rate reflecting the fiscal expansion policies and restructuring of the sectoral composition of the manufacturing sector. The share of manufacturing sector will expand by 11.7% points from 13.3% in 2014 to 25.0% in 2045.

On the other hand, the share of other industries (informal industry or industry of unknown classification) will reduce 28.7% points from 43.2 % in 2014 to 14.5% in 2045. Although it is difficult to identify by statistics what kinds of industries are included in this category, its share is remarkably high in the statistics presently available. Economic activities which are generally classified as "other industries" are said to represent activities by the informal sector. It is common among African economies that this sector dominates as the majority in their economic statistics. We assume that South Africa will continue to reform its industrial structure in the future course of economic development, where the transformation of informal sector to industrial and commercial activities will define the standard scenario, and hence manufacturing, financial, and services sectors will expand rapidly in the decades to come.

The above assumptions suggest a shift from an energy intensive and highly resource export-dependent economy to a highly energy efficient industrialized economy; how to achieve this will be the key factor when we consider the future energy and environmental policy.

Table 4.2-1 Macro Economy Index and Assumption (2014 ~ 2045)

Items	Unit	Actual	Projection			Compound Annual		
		2014	2025	2035	2045	2025 /2014	2035 /2014	2045 /2014
Real GDP	Million Rand	3,009,292	3,990,314	6,021,216	9,085,763	2.60	3.36	3.63
GDP Annual Growth Rate	%	1.55	4.20	4.20	4.20			
Population	Million	53,969.05	58,436.20	61,551.46	64,347.87	0.73	0.63	0.57
Population Annual Growth Rate	%	1.03	0.58	0.49	0.40			
Real GDP by Sector (2010＝100)								
Agricultural	Million Rand	75,416	87,787	120,424	172,629	1.4	2.3	2.7
Mining and Utilities	Million Rand	295,645	347,157	385,358	427,031	1.5	1.3	1.2
Manufacturing	Million Rand	379,089	822,005	1,354,774	2,271,441	7.3	6.3	5.9
Construction	Million Rand	103,358	171,583	270,955	436,117	4.7	4.7	4.8
Commercial*	Million Rand	411,083	754,169	1,408,965	2,643,957	5.7	6.0	6.2
Service**	Million Rand	252,648	558,644	1,023,607	1,817,153	7.5	6.9	6.6
Other Activities	Million Rand	1,216,341	1,248,968	1,457,134	1,317,436	0.2	0.9	0.3
Share of GDP by Component		100	100	100	100			
Agricultural	%	2.5	2.2	2.0	1.9			
Mining and Utilities	%	12.1	8.7	6.4	4.7			
Manufacturing	%	13.3	20.6	22.5	25.0			
Construction	%	4.1	4.3	4.5	4.8			
Commercial*	%	14.8	18.9	23.4	29.1			
Service**	%	10.0	14.0	17.0	20.0			
Other Activities	%	43.2	31.3	24.2	14.5			

Note: * Commercial: Wholesale, retail trade, restaurants and hotels, ** Service: Transport, storage and communication
(Source) JICA Team

4.2.2 Projection Results of Final Energy Consumption

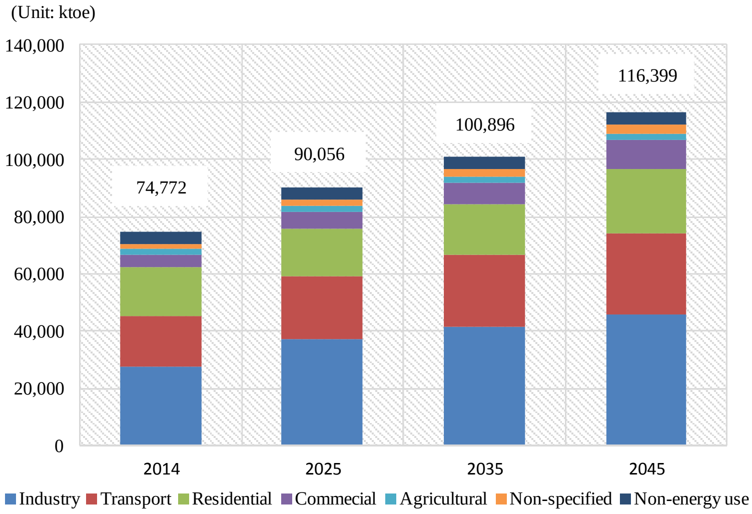
(1) Final Energy Demand by Sector

According to our projection, the final energy demand of South Africa will increase from 74,772 ktoe in 2014 (oil equivalent, thousand tons) to 116,399 ktoe in 2045 at an annual 1.4 % growth rate. Energy - GDP elasticity of the same period is 0.4. Among them, the industrial sector will become the largest energy consuming sector in 2045 and its share in the final energy demand reaches 39.5% (45,997 ktoe). Annual average growth rate of the energy demand in the industrial sector from 2014 to 2045 is 1.7%, and the sector will lead the increase of the overall energy demand. In the industrial sector, growth is now put on track after a long period of adjustment since 1994; the effect of the industry reform has gradually appeared. If same policy is continually performed, the power demand in the industrial sector is likely to continue increasing in the future. As a result of estimation by the model, the energy demand of the transport sector and household sector will become second and third largest energy consuming sectors after the industrial sector, and account for 24.2% and 19.1% of the total energy demand in 2045, respectively.

Table 4.2-2 Final Energy Demand by Sector and Average Growth Rate (2014~2045)

Items	Actual	Projection			Compound Annual		
	2014	2025	2035	2045	2025 /2014	2035 /2014	2045 /2014
Final Consumption (ktoe)	74,772	90,056	100,896	116,399	1.7	1.4	1.4
Industry	27,413	37,004	41,451	45,997	2.8	2.0	1.7
Transport	17,883	21,888	25,081	28,199	1.9	1.6	1.5
Residential	16,834	16,862	18,024	22,288	0.0	0.3	0.9
Commecial	4,401	5,728	7,242	10,269	2.4	2.4	2.8
Agricultural	2,196	2,132	2,144	2,167	-0.3	-0.1	-0.0
Non-specified	1,770	2,167	2,678	3,204	1.9	2.0	1.9
Non-energy use	4,275	4,275	4,275	4,275	0.0	0.0	0.0
Share (%)	100.0	100.0	100.0	100.0			
Industry	36.7	41.1	41.1	39.5			
Transport	23.9	24.3	24.9	24.2			
Residential	22.5	18.7	17.9	19.1			
Commecial	5.9	6.4	7.2	8.8			
Agricultural	2.9	2.4	2.1	1.9			
Non-specified	2.4	2.4	2.7	2.8			
Non-energy use	5.7	4.7	4.2	3.7			

(Source) JICA Team



(Source) JICA Team

Figure 4.2-1 Final Energy Demand by Sector and Share (2014~2045)

(2) Final Energy Demand by Energy Source

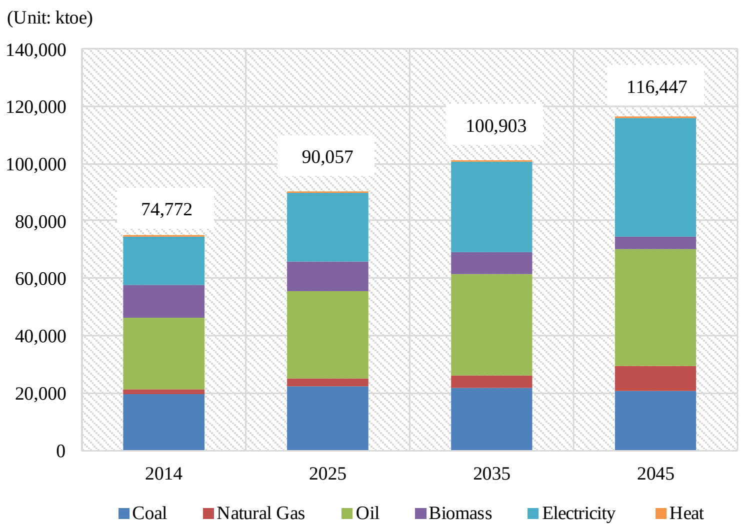
According to the estimation result of the model, the final energy demand by energy source is expected to show major structural changes during the projection period from 2014 to 2045. The energy mix in 2045 is projected as 35.0% for oil, 35.5% for electric power, 17.9% for coal, 7.5% for natural gas, 3.6% for biomass, and 0.4 % for heat. The major features of the outlook are summarized as follows.

- Coal demand will gradually increase at an annual 0.2% growth rate and the share of coal in the total final energy demand will reduce 8.2% points from 26.1% in 2014 to 17.9% in 2045.

- Consumption of biomass as the present major energy source for the residential sector will decrease at 3.2% annually and will account for 3.6% in the total final energy demand in 2045. Compared with 15.2% in 2014, biomass will have reduced its share by 11.6% points. Energy demand in the rural area will increase following population increase. Within the next decade or two, energy use in rural households will shift from biomass to modern energies such as electricity or LPG reflecting policies promoting rural electrification and forest protection.

- Use of clean energy such as natural gas and solar heat will spread rapidly during the projection period increasing at 5.4% and 5.0% annually, respectively.

- Among changes in the final energy demand structure, electricity will continue to be the most important energy source. Electricity demand will increase at annual 2.9% during the projection period between 2014 and 2045 and will reach 41,359 ktoe in 2045.



(Source) JICA Team

Figure 4.2-2 Final Energy Demand by Energy Source and Share (2014~2045)

Table 4.2-3 Final Energy Demand by Source and Average Growth Rate (2014~2045)

Items		Actual	Projection			Compound Annual		
		2014	2025	2035	2045	2025 /2014	2035 /2014	2045 /2014
Final Demand by Energy (ktoe)		74,772	90,057	100,903	116,447	1.7	1.4	1.4
	Coal	19,491	22,401	21,890	20,854	1.3	0.6	0.2
	Natural Gas	1,699	2,867	4,420	8,771	4.9	4.7	5.4
	Oil	25,090	30,405	35,196	40,809	1.8	1.6	1.6
	Biomass	11,355	10,313	7,871	4,193	-0.9	-1.7	-3.2
	Electricity	17,035	23,898	31,244	41,359	3.1	2.9	2.9
	Heat	101	173	283	461	5.0	5.0	5.0
Share (%)		100.0	100.0	100.0	100.0			
	Coal	26.1	24.9	21.7	17.9			
	Natural Gas	2.3	3.2	4.4	7.5			
	Oil	33.6	33.8	34.9	35.0			
	Biomass	15.2	11.5	7.8	3.6			
	Electricity	22.8	26.5	31.0	35.5			
	Heat	0.1	0.2	0.3	0.4			

(Source) JICA Team

4.2.3 Power Sector

Table 4.2-4 shows the estimation of the generation mix by energy source until 2045 in South Africa. The total required amount of electricity generation is calculated considering electricity demand, own use at power plants, losses incurred in transmission and distribution. As a result, power generation will increase 2.3 times from 249 TWh in 2014 to 579 TWh in 2045 at 2.8% annually.

The generation mix by energy source will diversify by 2045: the composition will change to 50.3% of coal, 25.1% of natural gas, 12.5% of nuclear, 12.0% of renewable energy, and 0.1 % of oil. In 2014, electricity generation relied on coal at 93.0%. In 2045, the share of coal will decrease to 50.3%. Among others expansion of electricity generation by natural gas is expected to increase significantly and its share is projected to account for 25.1% of the total power generation in 2045.

Table 4.2-5 shows the composition of the required fuel for the above power generation except nuclear power, hydro and renewable energy. In 2014, 99.8% of the fuel for power generation was supplied with coal. However, amount of the gas fired power generation will increase rapidly by promotion of gasification policy. While no natural gas demand was recorded for power generation in 2014, gas demand for power generation is projected to increase from 4,081 ktoe (equivalent to 3.14 million LNG)[31] in 2025, to 8,292 ktoe (6.38 million tones LNG) in 2035, and 21,928 ktoe (16.87 million tones LNG) in 2045.

Table 4.2-4 Power Generation by Source (2014~2045)

Items	Actual	Projection			Compound Annual Growth Rate (%)		
	2014	2025	2035	2045	2025 /2014	2035 /2014	2045 /2014
1.1 Total Generation (GWh)	249,471	338,175	439,760	579,156	2.8	2.7	2.8
Coal	232,020	269,525	277,489	291,315	1.4	0.9	0.7
Natural gas	0	27,054	54,970	145,368	0.0	0.0	0.0
Oil	189	338	440	579	5.4	4.1	3.7
Nuclear	13,794	13,527	54,530	72,394	-0.2	6.8	5.5
Hydro	975	2,029	3,518	4,633	6.9	6.3	5.2
Biomass	303	4,058	8,795	11,583	26.6	17.4	12.5
Solar PV	1,120	9,807	18,030	24,325	21.8	14.1	10.4
Wind	1,070	11,836	21,988	28,958	24.4	15.5	11.2
1.2 Own use	27,784	36,887	45,867	57,747	2.6	2.4	2.4
1.3 Loss	20,944	23,335	30,507	40,384	1.0	1.8	2.1
Generation Mix (%)	100.0	100.0	100.0	100.0			
Coal	93.0	79.7	63.1	50.3			
Natural gas	0.0	8.0	12.5	25.1			
Oil	0.1	0.1	0.1	0.1			
Nuclear	5.5	4.0	12.4	12.5			
Renewable Energy	1.4	8.2	11.9	12.0			
Hydro	0.4	0.6	0.8	0.8			
Biomass	0.1	1.2	2.0	2.0			
Solar PV	0.4	2.9	4.1	4.2			
Wind	0.4	3.5	5.0	5.0			

(Source) JICA Team

31 1 ktoe equivalent to 768.26 tones LNG.

Table 4.2-5 Fuel Consumption in Power Sector of South Africa (2014~2045)

Items	Actual (ktoe)	Projection (ktoe)			Compound Annual Growth Rate (%)		
	2014	2025	2035	2045	2025 /2014	2035 /2014	2045 /2014
Coal	63,537	68,975	66,773	65,914	0.7	0.2	0.1
Oil	46	83	107	141	5.4	4.1	3.7
Biomass	104	1,395	3,024	3,983	26.6	17.4	12.5
Natural gas	0	4,081	8,292	21,928	0.0	0.0	0.0
Total	63,687	74,533	78,196	91,966			
Share (%)							
Coal	99.8	92.5	85.4	71.7			
Oil	0.1	0.1	0.1	0.2			
Biomass	0.2	1.9	3.9	4.3			
Natural gas	0.0	5.5	10.6	23.8			
Total	100.0	100.0	100.0	100.0			

(Source) JICA Team

According to the ESKOM's "Integrated Report 2016"[32], the total installed generation capacity of South Africa in 2015/2016 fiscal year[33] reached 46,202 MW. Among the total installed capacity, 42,810 MW (92.7 %) was owned by ESKOM and the rest of 3,392 MW (7.3%) was owned by the IPP operators. Composition of the installed capacity by energy source was 79.9 % of coal, 6.5 % of gas, 4.4 % of hydro (included pumped storage), 4.0 % of nuclear, 2.5 % of solar PV, and 2.3 % of wind. On the other hand, based on the projection results of the total power generation amount and power development plan promoted by the South Africa, composition of the installed capacity will be 34.9% of coal, followed by gas 18.7%, solar PV 14.6%, wind 13.0%, nuclear 9.1%, and hydro 8.3% in 2045. Compared to 2015/2016, the dependence on coal has greatly reduced its ratio being replaced by natural gas fired plants.

Table 4.2-6 Installed Capacity of South Africa (2015/2016 and 2045)

Source	2015/2016* (Actual)		2045	
	Installed Capacity (MW)	Share (%)	Installed Capacity (MW)	Share (%)
Coal	36,901	79.9	44,340	34.9
Gas	2,997	6.5	23,706	18.7
Nuclear	1,860	4.0	11,510	9.1
Hydro**	2,010	4.4	10,578	8.3
Solar PV	1,165	2.5	18,512	14.6
Wind	1,070	2.3	16,528	13.0
Others	199	0.4	1,928	1.5
Total	46,202	100.0	127,103	100.0

Note: * 2015/2016, fiscal year from April. ** Included Pumped Storage. Not included isolated small hydro 61 MW.
(Source) ESKOM, "Integrated Report 2016"

32 Eskom, "Integrated Report 31 March 2016"
33 Fiscal year from April.

4.2.4 Total Primary Energy Supply

Table 4.2-7 shows the total primary energy supply of South Africa from 2014 to 2045. The total primary energy supply will increase from 142,230 ktoe in 2014 to 207,058 ktoe in 2045 at an annual 1.2%. Compared with an annual 1.4% growth for the earlier period between 2014 and 2025, the long-term growth rate (1.2%) for the whole projection period of 2013-2045 will be slightly lower. The direct cause of the slowing growth rate is improving efficiency in energy use. The total primary energy supply per GDP reduces from 47 toe per million Rand in 2014 to 23 toe per million Rand in 2045; the efficiency of energy use will be improved by 51%. Other key features are described as follow.

- Coal-dependence of the total primary energy supply decreases from 67.8% in 2014 to 49.2% in 2045. Compared with year 2014, diversification of the total primary energy supply will progress toward 2045. Then, South Africa’s energy mix will be 49.2% of coal, followed by oil at 17.4%, natural gas 16.5%, nuclear 9.5%, renewable energy 7.4%.

- The share of natural gas in the total primary energy supply will expand from 2.7% in 2014 to 16.5% in 2045; natural gas will become an important energy source after coal.

- The share of renewable energy will decrease from 12.1% in 2014 to 7.4% in 2045 because of the reduction in the use of traditional biomass. Among renewable energy sources, solar power, wind power, and solar heat will show high increase rates at annual 9.6%, 11.8%, and 5.0%, respectively, during the projection period.

Table 4.2-7 Total Primary Energy Supply of South Africa (2014 - 2045)

Items	Actual (ktoe)	Projection (ktoe)			Compound Annual Growth Rate (%)		
	2014	2025	2035	2045	2025 /2014	2035 /2014	2045 /2014
Total Primary Energy Supply (ktoe)	142,230	165,413	186,320	207,058	1.4	1.3	1.2
Coal	96,473	106,362	103,739	101,851	0.9	0.3	0.2
Natural gas	3,848	10,515	16,279	34,267	9.6	7.1	7.3
Oil	21,432	26,808	31,042	36,008	2.1	1.8	1.7
Nuclear	3,270	3,270	16,967	19,706	0.0	8.2	6.0
Renewable energy	17,207	18,457	18,293	15,226	0.6	0.3	-0.4
Biomass	16,833	16,577	14,582	10,082	-0.1	-0.7	-1.6
Hydro	84	102	119	136	1.8	1.7	1.6
Solar PV	96	650	1,337	1,630	19.0	13.3	9.6
Wind	92	954	1,972	2,917	23.7	15.7	11.8
Solar Heat	101	173	283	461	5.0	5.0	5.0
Share (%)	100.0	100.0	100.0	100.0			
Coal	67.8	64.3	55.7	49.2			
Natural gas	2.7	6.4	8.7	16.5			
Oil	15.1	16.2	16.7	17.4			
Nuclear	2.3	2.0	9.1	9.5			
Renewable energy	12.1	11.2	9.8	7.4			

(Source) JICA Team

4.2.5 GHG Emissions

Table 4.2-8 shows the emissions of greenhouse gases (GHG, equivalent to tones of carbon dioxide) from fossil fuels in South Africa based on the projection result. The GHG emissions incurred by fossil fuel use will increase from 436 million tons in 2014 to 566 million tons in 2045 at an annual 0.8% growth rate. In 2014, 83.0% of the total GHG emissions by fossil fuel burning was brought by coal reflecting the country's high dependency on coal. Introduction of natural gas will replace some of coal consumption. As a result, the share of coal in the total GHG emissions in 2045 will decrease to 67.5%.

Despite the aggressive introduction of natural gas, GHG emissions per total primary energy supply improve only slightly from 3.06 tons CO_2 per toe (tons of oil equivalent) in 2014 to 2.73 tons CO_2 per toe in 2045. Although coal dependency decreases with energy shift to cleaner sources such as natural gas, nuclear, and renewable energy, the total demand of energy will continue to grow reflecting expanding economic activities. This will keep increase of GHG emissions while the coal dependency is maintained still at a high ratio. On the other hand, this BAU projection assumes a case without any replacement of old equipment and energy saving technologies. In other words, high potential can be expected for improving energy efficiency in South Africa compared with the present projection.

Table 4.2-8 GHG Emission of South Africa (2014 - 2045)

Items	Actual	Projection			Compound Annual Growth Rate (%)		
	2014	2025	2035	2045	2025 /2014	2035 /2014	2045 /2014
Total emmision (Million ton CO_2)	435.5	502.4	518.6	565.5	1.3	0.8	0.8
Natural gas	8.1	22.1	34.2	72.1	9.6	7.1	7.3
Coal	361.6	398.7	388.8	381.8	0.9	0.3	0.2
Oil	65.8	81.6	95.6	111.7	2.0	1.8	1.7
Motor gasoline	24.4	29.5	31.5	33.8	1.8	1.2	1.1
Diesel	33.1	41.1	49.3	57.4	2.0	1.9	1.8
Fuel oil	1.8	2.9	3.5	4.1	4.4	3.2	2.7
LPG	0.7	1.5	3.2	6.7	7.3	7.4	7.5
Kerosene	1.2	1.5	2.2	3.1	2.0	2.6	3.0
Jet Fuel	2.9	3.0	3.4	3.8	0.1	0.8	0.8
Refinary gas	1.7	2.1	2.4	2.8	2.1	1.8	1.7
Share (%)	100.0	100.0	100.0	100.0			
Natural gas	1.9	4.4	6.6	12.7			
Coal	83.0	79.4	75.0	67.5			
Oil	15.1	16.2	18.4	19.8			
Total emmision from power sector (Million ton CO_2)	238	267	268	294	1.0	0.5	0.7
Natural gas	0.0	8.6	17.4	46.1	0.0	0.0	0.0
Coal	238.1	258.5	250.3	247.1	0.7	0.2	0.1
Oil	0.1	0.2	0.3	0.4	5.0	3.9	3.6

(Source) JICA Team

4.3 Natural Gas Demand Outlook

First natural gas consumption as the final energy demand in South Africa appeared on the energy statistics in 2010. SASOL completed the natural gas pipeline from Mozambique and started to provide it to its gas to liquefied (GTL) plant, while a small amount of natural gas was supplied to nearby manufacturing plants. It is difficult to estimate natural gas demand trend by econometric methods without historical data for certain period. In this study, therefore, we project the future natural gas demand based on the future total energy demand trend in South Africa and assuming effect of proactive introduction of natural gas that should reflect national aspiration to develop cleaner energy supply.

Natural gas consumption reached 3,848 ktoe in 2014 mainly for industrial use (1,698 ktoe, 44.1%) and GTL plant feed (2,149 ktoe, 55.9%). In the industrial sector, natural gas (including coal gas) was consumed by iron and steel industry (236 ktoe, 13.9 %), chemical industry (933 ktoe, 54.9 %), non-metallic industrial (314 ktoe, 18.5 %), non-ferrous metal industry (14 ktoe, 0.8 %) and other general industries (201 ktoe, 11.8%).

Through the above model analysis, feature of natural gas demand outlook of South Africa are summarized as follows:

- Natural gas as primary energy supply will increase at an annual growth rate of 7.7% or will expand to 9-fold the current level from 3,848 ktoe in 2014 to 34,267 ktoe in 2045.
- Natural gas will be mainly consumed in the power sector. Natural gas demand in power sector will account for 64.0% of the total natural gas requirement (21,928 ktoe) in 2045. Thus the natural gas promotion policy should at first concentrate on the power sector development considering the benefits of natural gas such as economic scale, energy efficiency and environmental friendliness To further expand use of natural gas, a comprehensive long-term development plan should be established since development of gas supply infrastructure and demand build-up will take long time.
- Industrial sector has a certain potential of natural gas demand. In this sector, the natural gas demand will increase at an annual rate of 3.6 % and reach 5,035 ktoe in 2045, which accounts for 14.7% of the total natural gas demand.
- Demand for natural gas in the transport sector will remain small unless strong policy promotion. As analyzed in later chapters, CNG supply for motor vehicles will be a prospective business and replacement of electricity with natural gas at commercial and residential sectors will contribute to stabilize the electricity system while these are all environmentally friendly. Proactive policy to support such engagement will be highly appreciated.

Table 4.3-1 Natural Gas Demand Outlook (2014 - 2045)

Items	Actual (ktoe)	Projection (ktoe)			Compound Annual Growth Rate (%)		
	2014	2025	2035	2045	2025 /2013	2035/ 2013	2045/ 2013
Final Consumption Sector	1,699	2,867	4,420	8,771	4.9	4.7	5.4
Industry	1,698	2,719	3,681	5,035	4.4	3.8	3.6
Transportation	0	1	8	48	20.0	20.0	20.0
Residential	0	42	211	1,070	0.0	0.0	0.0
Commercial	2	104	520	2,618	46.2	31.7	27.0
Agricultural	0	0	0	0	0.0	0.0	0.0
Other Industry	0	0	0	0	0.0	0.0	0.0
Transformation Sector	2,149	7,649	11,860	25,496	11.2	8.1	8.0
Power	0	4,081	8,292	21,928	0.0	0.0	0.0
GTL	2,149	3,568	3,568	3,568	4.3	2.3	1.6
Total Primary Energy Supply	3,848	10,515	16,279	34,267	8.7	6.8	7.1
Share by Sector (%)	100.0	100.0	100.0	100.0			
Final Consumption Sector	44.2	27.3	27.1	25.6			
Transformation Sector	55.8	72.7	72.9	74.4			

(Source) JICA Team

Chapter 5 Options for Natural Gas Utilisation

5.1 Natural Gas Utilisation Industry

In this section, we overview outlines of industries to use natural gas as feedstock. They are classified into two groups, namely, gas chemical industries to produce conventional chemical products such as ammonia and methanol, and gas to fuel industries to convert natural gas to easier-to-use fuels. The latter comprises gas to liquid (GTL), dimethyl-ether (DME) and methanol to gasoline (MTG) technologies.

5.1.1 Ammonia and Fertilizer

Ammonia is a very popular chemical product mainly used as interim product to produce fertilizer and other chemical products. Here we consider an ammonia to urea plant.

Plants take up water and inorganic substances through their roots, and take carbon dioxide from the air through their leaves as nutrients. Fertilizers are substances that supply plant nutrients which are not always enough available in the soil. Nitrogen (N), phosphorus (P) and potassium (K) are the most important elements in plant nutrition, called three fertilizer elements. Besides them, plants cannot grow well without other fertilizers that supply calcium (Ca), magnesium (Mg) and micronutrients that are also not always enough in the soil.

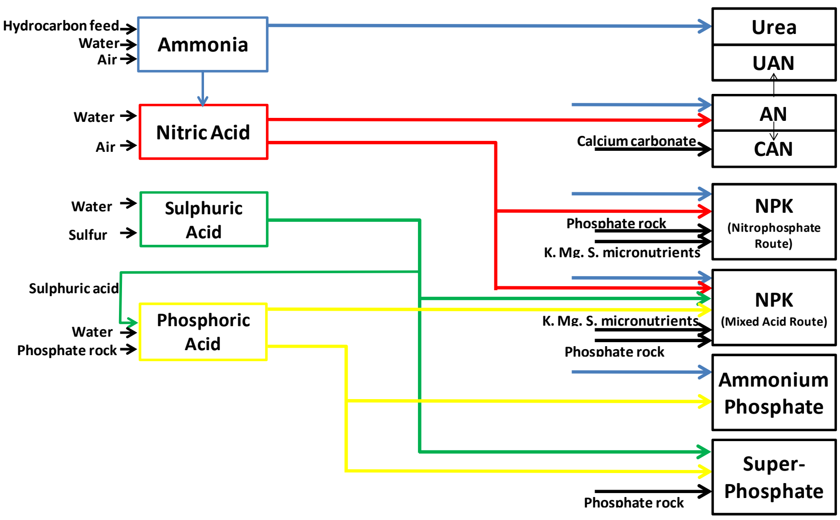


Figure 5.1-1 Fertilizer Value Chain

Urea is a typical nitrogen-based chemical fertilizer, and accounts for about 40% of chemical fertilizers comprising nitrogen-, phosphorus-, and potassium-based products combined. Ammonia, which is a starting material for urea, is produced by reacting hydrogen (H_2) included in natural gas with nitrogen (N_2) in air. Urea is produced from ammonia (NH_3) using carbon dioxide (CO_2) produced as a by-product in the above process.

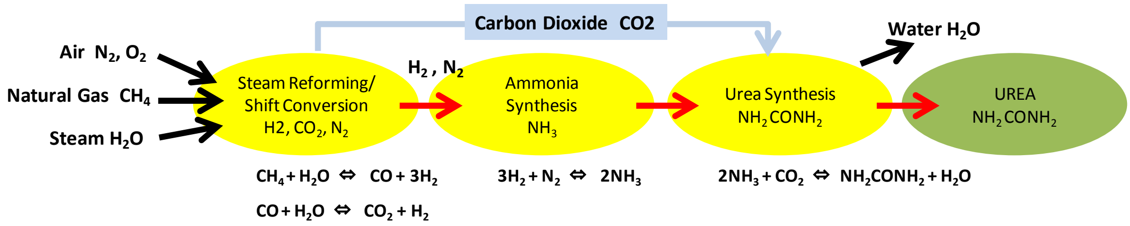


Figure 5.1-2 Process for Ammonia and Urea Production

Ammonia is also used as a raw material for other nitrogen-based fertilizers including ammonium nitrate and ammonium sulfate as well as chemicals such as synthetic fibers, whereas urea is also used as a raw material for plywood adhesives and melamine. Therefore, a chemical industry group can be formed by combining these products. In recent years, ammonia and urea plants have grown in scale with reduced unit energy consumption, where their capacity has reached a level of 3,000 to 4,000 tonnes/day. The typical natural gas consumption is about 80 MMSCFD or 0.5 to 0.6 Tcf over 20 years, on the basis of a combination of a 2,300 tonnes/day ammonia plant and a 4,000 tonnes/day urea plant. The natural gas consumption in a typical combination plant is about 1/10th of that of LNG plants.

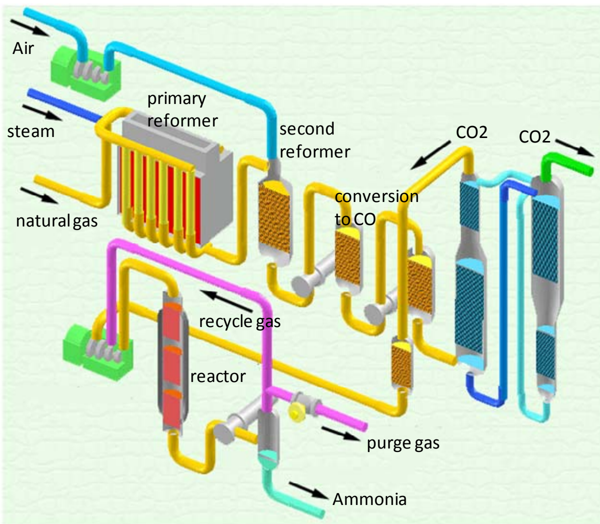


Figure 5.1-3 Process Flow Diagram of Ammonia Production Process

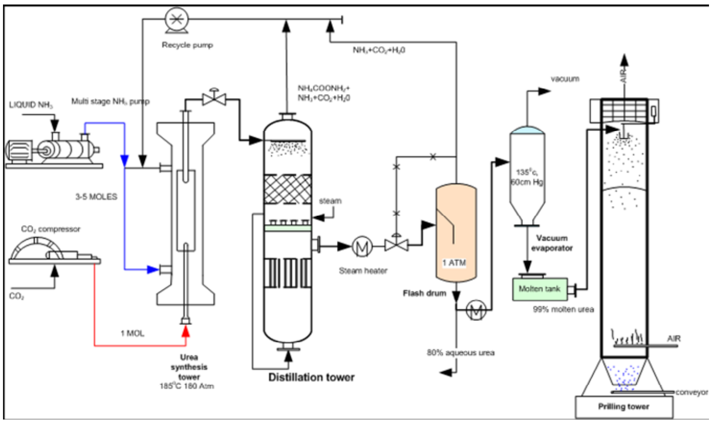


Figure 5.1-4 Process Flow Diagram of Urea Production Process

5.1.2 Methanol

Methanol plants produce highly-purified methanol from hydrocarbon sources such as natural gas as a raw material via syngas and methanol synthesis through catalysis and distillation. A typical syngas preparation process is a steam reforming process in which the feedstock hydrocarbon reacts with steam as reforming agent in the presence of catalyst at high temperature.

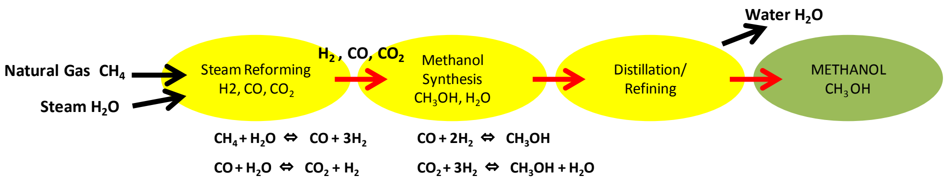


Figure 5.1-5 Methanol Production Process

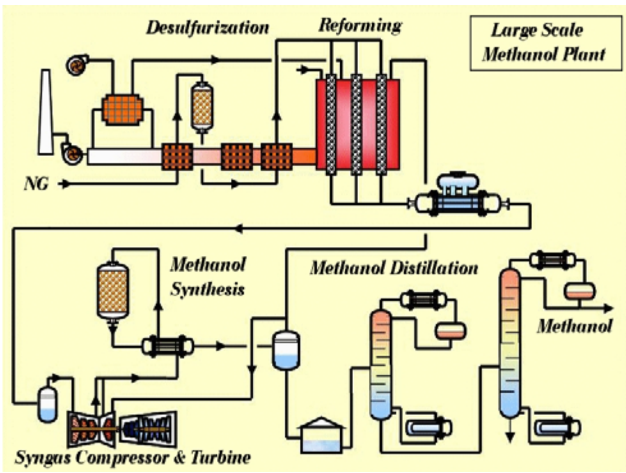


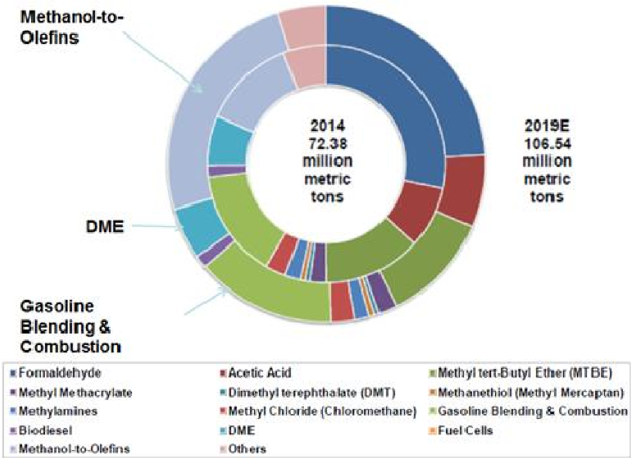
Figure 5.1-6 Process Flow Diagram of Methanol Production

The scale of methanol plants has been increasing significantly, and their capacity has reached 3,000 to 5,000 tonnes/day (1.0 to 1.7 million tonnes/year) per single train. The consumption of natural gas in producing 3,000 tonnes/day of methanol is approximately 100 MMSCFD (about 0.7 Tcf over 20 years), which is comparable to that of ammonia - urea plants.

(Source) Mitsubishi Heavy Industries, Ltd.

Figure 5.1-7 Methanol Plant in Saudi Arabia

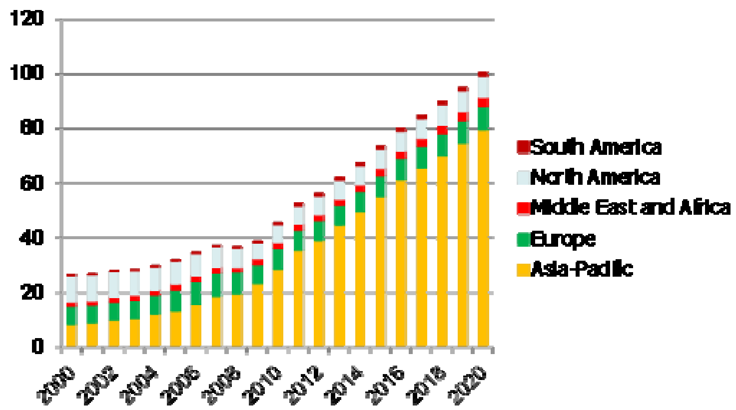
Methanol is mainly consumed in advanced countries and China. It is distributed from gas producing regions such as The Middle East, CIS, South America, and Southeast Asia to consuming regions such as Europe, North America, Far East, and China. The global methanol market was about 72 million tonnes in 2014, of which approximately half being traded internationally, and is predicted to reach approximately 107 million tonnes in 2019.



(Source) Courtesy of MMSA Pte Ltd. Feb 2015

Figure 5.1-8 Global Methanol Use by Derivative

About 70 to 80% of methanol is used for chemical applications as a basic raw material, whereas 20 to 30% is for fuel. As an economy develops, demand for methanol will increase steadily to supply conventional chemicals. Methanol is used as interim feedstock to produce formalin, acetic acid, synthetic fibers, agrichemicals, adhesives, etc. In recent years, methanol is further attracting attention as a feedstock to produce olefins such as ethylene and propylene for an alternative production method called MTO (Methanol to Olefin) instead of using conventional feedstocks such as naphtha and ethane. In fuel applications, methanol is used either for direct blending with gasoline, or to produce gasoline via MTG (Methanol to Gasoline) technology, DME (described in 5.1.4), etc.



(Source) Global Data (19 Jan. 2015)

Figure 5.1-9 World Methanol Demand

As one of the natural gas utilisation industries, methanol produced in South Africa will be mainly supplied for the domestic market, while any surplus can be exported as the global market is well established. It could be the platform to develop conventional chemical industries starting from methanol as well as new industries such as production of basic chemicals (MTO), gasoline (MTG) and DME, etc.

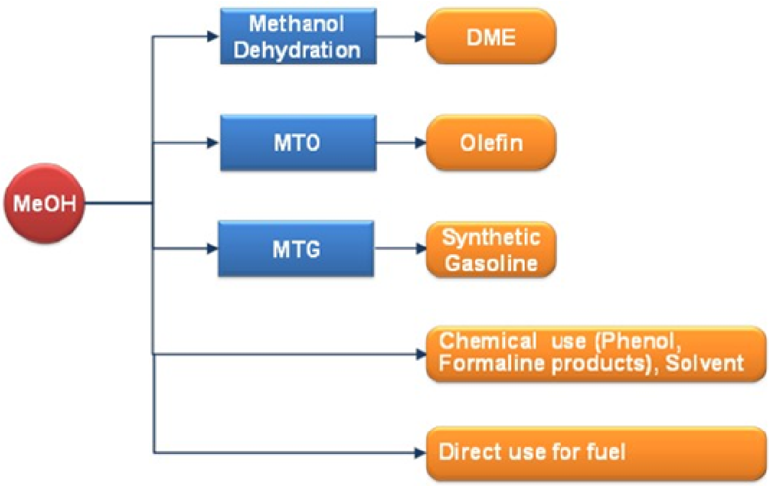


Figure 5.1-10 Methanol Value Chain

MTO is a process which converts methanol to olefins. In case that olefins are produced at a low cost from methanol, downstream chemical industries such as polymer plants could be developed as well. In general, 3,000 tonnes/day of methanol can be converted into 300,000 tonnes /year of olefins.

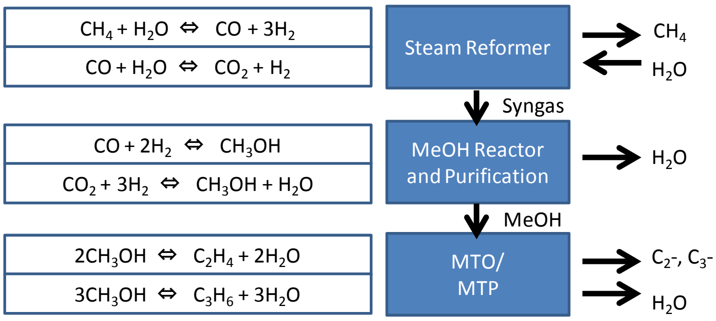
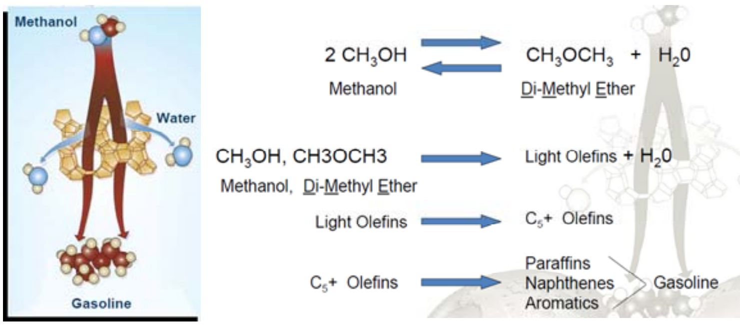


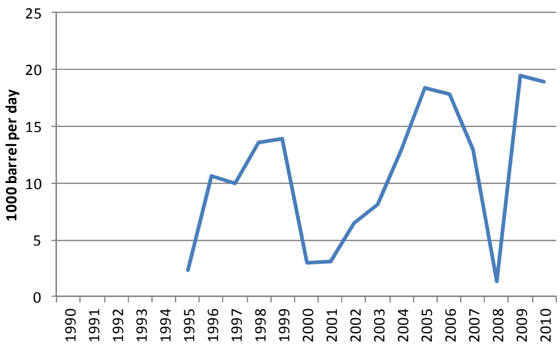
Figure 5.1-11 MTO Production Process

MTG refers to processes which converts methanol into gasoline. As shown in Figure 5.1-13, imports of gasoline have been increasing in South Africa, reaching 20,000 bpd in 2010. Considering that motorization trend will be rising, demand for gasoline is expected to further grow in the future. In this context, gasoline production via MTG process from methanol in South Africa could reduce the import of gasoline, and subsequently achieve self-sufficiency in gasoline. In general, 3,000 tonnes/day of methanol can be converted into 10,000 bpd of gasoline.



(Source) Courtesy of ExxonMobil Research & Engineering

Figure 5.1-12 MTG Production Process



(Source) Index Mundi

Figure 5.1-13 Imports of Gasoline in South Africa

5.1.3 GTL

In South Africa, Sasol has been producing petroleum products via the GTL (Gas to Liquid) technology using natural gas produced from the Mossel Bay gas fields and imported from Mozambique. Due to lack of domestic oil production, GTL has been one of the important options for South Africa to secure supply of petroleum products. It produces liquid petroleum products such as naphtha, kerosene and diesel oil and petroleum products produced by GTL mainly contain paraffinic components.

Figure 5.1-14 General Image of GTL Plant

GTL process consists of three sections; Syngas production, FT synthesis, and Upgrading sections as shown in Figure 5.1-15.

Natural gas is first fed to the Syngas production section. The feedstock is mainly methane accompanied with steam, O_2, or CO_2, and the output from this section is the mixture of H_2 and CO, which is called syngas. The syngas is then fed to the Fischer Tropsch (FT) synthesis section and transformed into FT oil, liquid hydrocarbon. FT oil is then fed to the Upgrading section and treated to be the final GTL oil.

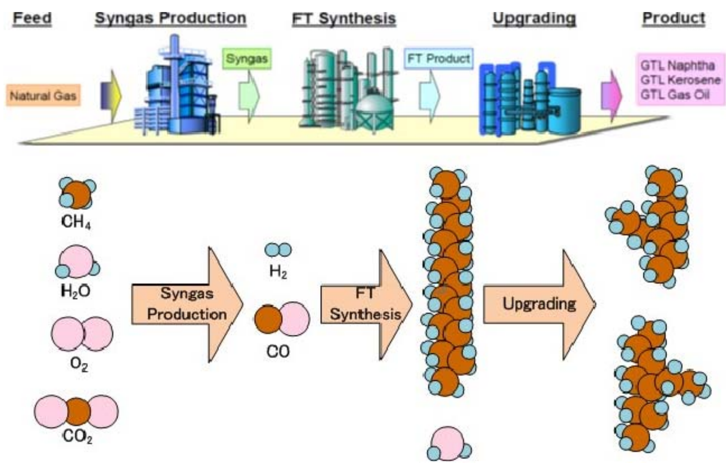


Figure 5.1-15 Constitution of GTL Process

FT oil produced in the FT synthesis is not the final product because it still contains some undesirable components for fuel such as olefins and alcohols, and therefore the FT oil is fed to the last section for upgrading. There, the FT oil is treated by hydro-treating, isomerization, and hydrocracking to improve its properties as fuel, and finally the GTL oil of naphtha, kerosene, and diesel oil will be obtained.

Major GTL processes which are commercially available are shown below. Sasol, Shell, and Japan GTL consist of different combinations of syngas production, FT synthesis, and upgrading. Currently in the world, there are several operating GTL plants such as Mossel Bay in South Africa, Bintulu in Malaysia, Oryx and Pearl in Qatar. In addition, there are numerous plans of GTL project in various areas.

Table 5.1-1 Major GTL Technologies

	Syngas Profuction	FT Synthesis	Upgrading
Sasol	Topsoe (Autothermal Reforming)	Sasol (SBCR)	Chevron (Isomerization/ Hydrocracking)
Shell	Shell (Partial Oxydation)	Shell (Fixed Bed)	Shell (Hydrocracking)
Japan-GTL	Chiyoda (CO_2/Steam Reforming)	NSENGI (SBCR)	JX-NOE (Isomerization/ Hydrocracking)

Note: SBCR: Slurry Bubble Colum Reactor
Chiyoda: Chiyoda Corporation
NSENGI: Nippon Steel & Sumikin Engineering Co.,
JX-NOE: JX Nippon Oil & Energy Corporation Ltd.

Among them, Japan-GTL Process has rather newly attained to the phase of commercialization, which is a unique cutting-edge technology made-in-Japan. As shown in Figure 5.1-16, Japan-GTL Process can utilize CO_2 directly 40% or less in feedstock gas and can eliminate the O_2 generation plant which is necessary for other conventional GTL processes.

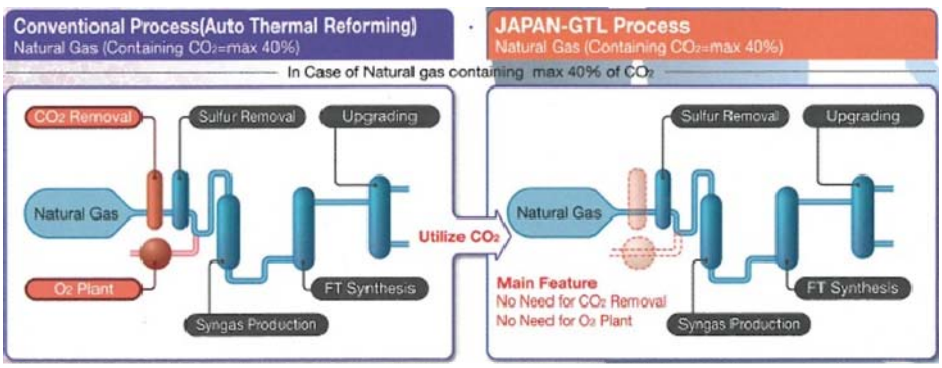


Figure 5.1-16 Feature of Japan-GTL Process

As GTL oil products, kerosene and diesel oil are superior fuel. GTL diesel oil, compared with conventional oil product, has superior characteristics for fuel because it has higher cetane number, no poly-aromatic, and no sulfur. This shows that GTL oil has higher cleanness and environmental friendliness than the conventional petroleum products. On the other hand, GTL naphtha is paraffinic and can be used as a superior petrochemical feedstock, but is not suitable for the direct use as gasoline.

The product of GTL plants is delivered to the various markets, such as fuel, mainly fuel for transportation, base oil for lubricant oil, and feedstock for petrochemical industries. In any case, the feasibility of GTL project depends on the value of products, the initial investment, and the cost of natural gas.

5.1.4 DME

DME (dimethyl ether) is produced either through dehydration of methanol or direct synthesis from syngas, and therefore produced from multi-source materials via synthesis gas at all events. DME have been commercially produced as a propellant for spray cans because of its non-toxicity and suitable solubility and vapor pressure at ambient temperatures. However, DME is now attracting great attention as a clean energy for the 21st century as a hydrogen carrier and a feedstock for petrochemicals because of its excellent physical and chemical properties.

Table 5.1-2 Properties of DME (Compared with other fuels)

	DME	Methane	Propane	Methanol	Diesel
Boiling Point (℃)	-25.1	-161.5	-42	64.6	180～360
Liquid Density (g/cm^3@20℃)	0.67	-	0.49	0.79	0.84
Ignition Temp. (℃)	350	650	470	450	250
Cetane Number	55～60	-	5	5	40～55
Lower Heating Value (kcal/kg)	6,900	12,000	11,100	4,800	12,200

It can be said that physical properties of DME are relatively similar to LPG. When DME and LPG are compared, the vapor pressure of DME is approximately the average of those of propane and butane. Besides, the gas density and the molecular weight are slightly higher than those of propane, but approximately equivalent. The boiling point of DME is -25degC, and DME is gaseous at ambient temperatures and pressures. DME can, however, be liquefied even at 20 degree C with about 5 atmospheric pressure, and it can be transported in a normal temperature pressurized container. LPG technology can be basically used for the storage and handling of DME. However, there are some discrepancies in the physical properties that originate in the chemical structure differences between DME and LPG. While LPG consists of hydrocarbon that contains only carbon and hydrogen, DME includes oxygen. It is therefore necessary to take into account the different physical properties of DME and LPG in the system design when LPG facilities are applied to DME. Table 5.1-2 summarizes properties of DME and other fuels.

DME burns cleanly without exhausting any black smoke during combustion. It doesn't emit SOx and any particulate matters such as PM2.5. In addition, it helps to significantly reduce CO_2 emissions and minimize NOx emissions. Based on these characteristics, when it is used as fuel for diesel engine, DPF (Diesel Particulate Filter) will not be needed, drastically reducing the burden of aftertreatment for exhausts. As a result, the cost and man-hour of the maintenance will be saved significantly.

Figure 5.1-17 Comparison of Exhaust Gas (Diesel Car vs. DME Car)

DME is produced via an indirect (dehydration) method that uses methanol as a raw material, or a direct method that uses synthesis gas as a raw material; the reaction formulas are as follows:

Indirect method: $2CH_3OH \rightarrow CH_3OCH_3+H2O$ (1)

Direct method: $3H_2+3CO \rightarrow CH_3OCH_3+CO_2$ (2)

So far, only the indirect method has been used on a commercial scale, while the direct method remains only the bench scale verification.

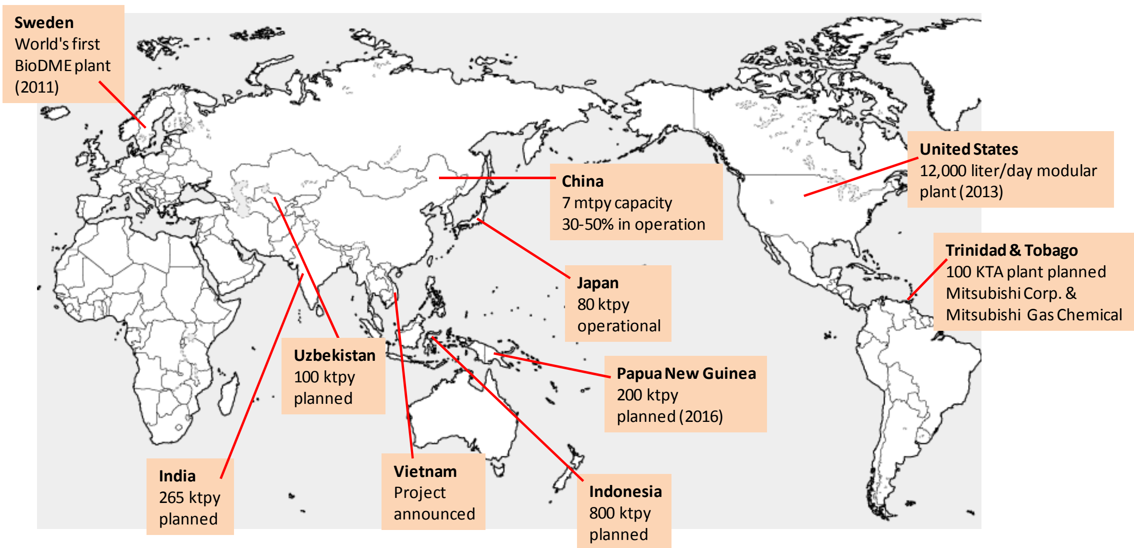


Figure 5.1-18 Capacity of the world's DME plants (including facilities in planning stage)

At present, the global demand of DME for fuel applications is 2 to 3 million tonnes/year, and the global demand for DME in applications other than fuel is about 150,000 tonnes/year. It is expected that the global demand for DME as fuel for consumer and transportation applications will expand and DME produced in South Africa can be consumed domestically as a new clean fuel, and also be exported to neighboring countries. Figure 5.1-18 shows capacity of the world's DME plants including planning stage.

It is possible to use DME in various fields and DME has been experimentally confirmed practical for various utilisation equipment.

(1)Household use fuel

DME can be used for cooking stove and home heating similar to the city gas and LPG. It is confirmed that equipment for LPG can be used with a mixture of DME and LPG of which the concentration of DME is maximum 20%. A cogeneration system using the diesel engine fueled with DME has been developed.

(2) Transportation fuel

As Cetane number of DME is as high as 55 to 60, DME can be used as a fuel for diesel engines. DME engine development and DME vehicle development have been completed, and the durability of DME vehicle has been confirmed by road running test for 100,000km or longer. Moreover, a technical development of DME filling equipment to DME vehicles has been completed, too.

(3) Power generation and industrial fuel

DME can be used as boiler fuel as well as gas turbine fuel.

(4) Chemical feedstock

A technology producing ethylene and propylene from DME has been developed. It is expected that the production cost will be reduced compared with producing them from petroleum naphtha, which is more expensive.

5.1.5 Methanol to Gasoline (MTG)

Gasoline is one of the major fuels used in South Africa with a share of a quarter among the petroleum products consumption. Since good quality motor gasoline could not be produced by a GTL plant, we consider a Methanol to Gasoline (MTG) process to produce gasoline from natural gas via methanol as an option to produce liquid fuel from natural gas.

As explained earlier, there are two methods to produce liquid fuel from natural gas, namely, GTL (Gas to Liquid) process to mainly produce kerosene and gas oil, and MTG (Methanol to Gasoline) to produce gasoline. Naphtha produced via the GTL process has low octane number and hence not suitable to use as motor gasoline. As South Africa relies its gasoline supply heavily on imported oil, we have added MTG process to produce gasoline domestically in the study. Production schemes of these synthetic liquid fuels are shown in Figure 5.1-19. Both of them are three-step processes using natural gas as feedstock. MTG plant is a synthetic fuel plant positioned in the downstream of a methanol plant.

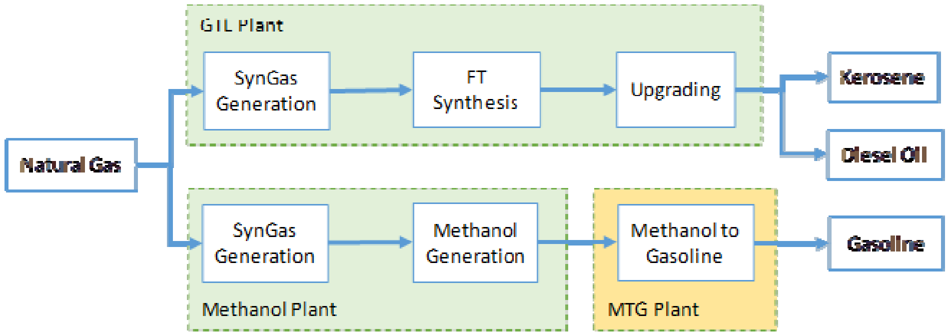


Figure 5.1-19 Production Scheme of Synthetic Transportation Fuel

Commercial MTG process was developed by Exxon/Mobil. The company constructed a commercial plant in 1986 in New Zealand which produces gasoline from natural gas via methanol, with an annual production capacity of 570,000 tonnes. In recent years, China has imported this process from Exxon/Mobil and trying to apply it to gasoline production from methanol originated from coal. A demonstration plant with a capacity of 100,000t/y is presently in operation and many plans to adopt this technology have been announced.

5.2 Natural Gas Utilisation for Transport

Use of natural gas for transport is developing fast elsewhere in the world. Compressed natural gas (CNG) is popular as fuel for light duty vehicles and buses while liquefied natural gas (LNG) is being developed as fuel for long haul trucks and locomotives.

Since the density of the natural gas is very low, we can transport and keep only relatively small amount per cubic volume of the gas in its normal gaseous state. Therefore, in addition to pipeline transport, natural gas is often converted to CNG by compressing it at a high pressure or to LNG by liquefying it at a temperature below -162°C, in particular for long haul transport.

In recent years, natural gas is widely used in many countries as clean fuel for vehicles. Compared to other fossil fuels, it produces lesser amount of CO_2 which is responsible for global warming, lesser amount of NOx and SOx which cause photochemical smog and acid rain, and no black smoke and PM (Particulate Matter) which damage health.

5.2.1 Type of Natural Gas Vehicles

There are mainly two types of natural gas vehicles (NGVs); CNG vehicles and LNG vehicles. Presently, most of NGVs used worldwide are CNG vehicles as shown in Figure 5.2-1. Fuels for CNG vehicles can be handled easily at ambient temperatures, and engine of common vehicle can be converted easily for CNG use. On the other hand, LNG are introduced quite recently in the United States for long haul heavy freighters and locomotive engines, while LNG needs more sophisticated supply system but is powerful for heavy duty engines.

CNG vehicles are classified into four kinds according to their engine type.

(1) Dedicated type

As dedicated type CNG vehicles can combust only CNG as a fuel, this type of vehicle carries CNG cylinder, instead of fuel tank. This type of vehicle has higher combustion efficiency than other types because the engine is optimized sorely for CNG. However, this type of vehicle cannot be used in the region without CNG stations.

It is generally thought that this type of vehicle is suitable for use in urban areas. They are used for regular routine services in certain regions such as fixed-route buses, garbage trucks, delivery trucks, etc. Vehicle owners often operate their own CNG stations supplied by municipal gas system.

(2) Bi-fuel type

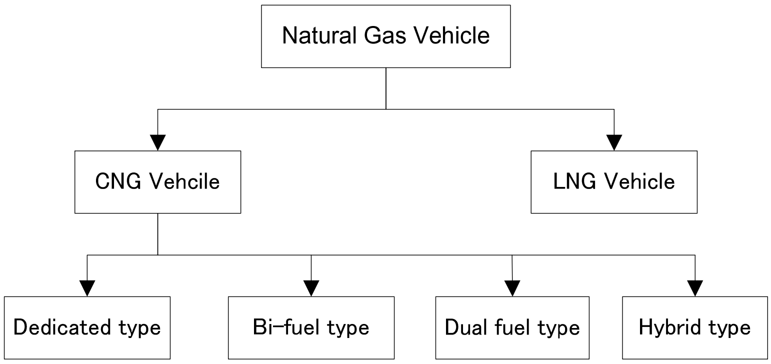
Bi-fuel type vehicles can run on either CNG or gasoline. Thus, it is possible to use them even in the region where CNG stations do not exist. This type of vehicle normally uses CNG as fuel and switches to gasoline once it runs out of CNG.

(3) Dual-fuel type

Dual-fuel type vehicle is a vehicle which uses natural gas as a part of inhalated air and diesel oil as an ignition source, using the structure of diesel engine. This type of engine has a high energy efficiency similar to regular diesel engines, and can reduce the amount of CO_2 emissions about 10–20% when natural gas makes up 60–85% of the used fuel compared with the case using only diesel oil as fuel. Moreover, it is possible to run a dual-fuel type vehicles only on diesel oil, and thus they can be used even in a region without CNG stations.

(4) Hybrid type

Hybrid type vehicles are equipped with both natural gas engines and electric motors. Hybrid vehicle generates electricity utilizing the additional power that are produced when engine is running effectively and also the energy produced during deceleration, and then this electricity can be used for the electric motor during the startup. Thus, a hybrid type vehicle realizes a better mileage, while its price tends to be higher than that for a dedicated type CNG vehicle.



(Source) The Japan Gas Association

Figure 5.2-1 NGV Types

CNG vehicles were initially used mainly for public transportation such as buses and taxies because of shortage of CNG stations and shorter travel distances of these vehicles. In recent years, however, with technology improvement and expanding gas supply network, CNG vehicles have become an option of choice for environmentally friendly alternative-fuel vehicles worldwide in view of their practical as well as environmental performance.

5.2.2 Natural Gas Vehicle in the World

Use of CNG vehicles has increased in Iran, China, Pakistan, Argentina, India, Brazil, and other countries where domestic natural gas resources are available, and the number of NGV in the world reached almost 22 million units in 2015 as shown in Table 5.2.1. On the other hand, the number of CNG filling station in the world reached almost 26,600 stations and one CNG filling station is supplying CNG to 800 NGV in average.

Table 5.2-1 NGV and Filling Station in the World

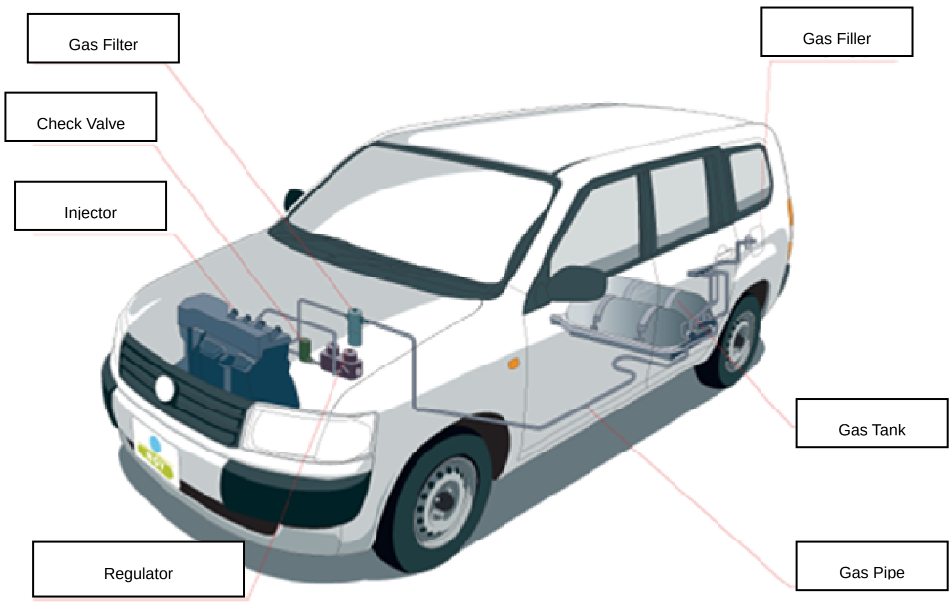
	Country	No.of NGV	No. of CNG Station		Country	No.of NGV	No. of CNG Station
1	Iran	4,000,000	2,220	14	Bangladesh	220,000	585
2	China	3,994,350	6,502	15	Egypt	207,617	181
3	Pakistan	3,700,000	2,997	16	Peru	183,786	237
4	Argentine	2,487,349	1,939	17	Ukraine	170,000	325
5	India	1,800,000	936	18	Germany	98,172	921
6	Brazil	1,781,102	1,805	19	Russia	90,050	253
7	Italia	885,300	1,060	20	Venezuela	90,000	166
8	Colombia	500,000	800	21	Georgia	80,600	100
9	Thailand	462,454	497	22	Bulgaria	61,320	110
10	Uzbekistan	450,000	213	23	Malaysia	55,999	184
11	Bolivia	300,000	178	24	Sweden	46,715	213
12	USA	250,000	1,615	25	Japan	44,676	290
13	Armenia	244,000	345	26	Others	132,283	1,957
					Total	22,335,773	26,629

(Source) Japan Gas Association

5.2.3 CNG Vehicle

(1) Structure of CNG Vehicle

Structure of CNG Vehicle is almost same as gasoline and diesel vehicles except fuel supply device. CNG of 20MPa is filled in the gas cylinder through gas filler. Natural gas that is reduced pressure by the regulator is supplied to the engine through fuel pipe.



(Source) Japan Gas Association

Figure 5.2-2 Structure of CNG Vehicle

CNG vehicle is environmental friendly because amount of CO_2 and NOx emission from CNG vehicle is 70% of that of gasoline vehicle. Also CNG vehicle does not exhaust particulate matter and exhaust little SOx.

(2) Mileage of CNG Vehicle

Based on general information, mileages of CNG vehicle and gasoline vehicle are compared. CNG vehicle is able to run 300km by 30m3 of CNG. Average price of CNG in April and May 2016 in Japan was 87Jp¥/m3. Therefore, cost for 1km of CNG vehicle is 5.8Jp¥ (20m3×87Jp¥/m3÷300km = 5.8Jp¥/km).

It is assumed that the mileage of gasoline vehicle is 15km/littler. Average price of gasoline in April and May 2016 in Japan was 117Jp¥/litter. Therefore, cost for 1km of gasoline vehicle is 7.8Jp¥ (117Jp¥/litter÷15km/litter = 7.8Jp¥/km). The cost of mileage of CNG vehicle is 75% of that of gasoline vehicle.

But this is just example in Japan. The result is depending on gasoline and CNG price and fuel consumption per km.

Table 5.2-2 Comparison of mileage between CNG and Gasoline Vehicle

	Mileage	Fuel Price	Cost per 1km
CNG Vehicle	15km/m3	87Jp¥/m3	5.8Jp¥
Gasoline Vehicle	15km/litter	117Jp¥/litter	7.8Jp¥

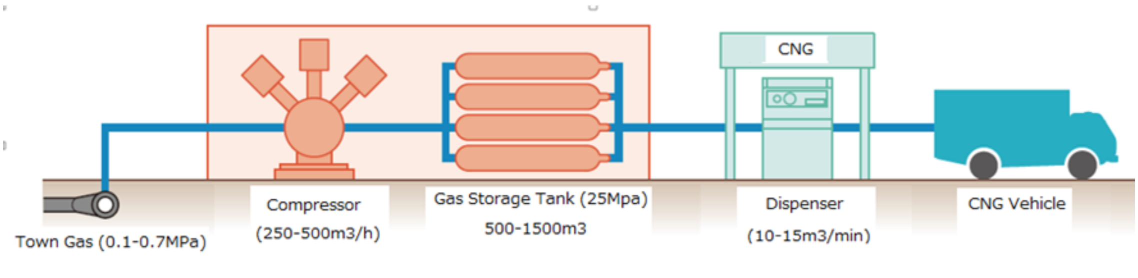
(Source) JICA Team

However, in Japan, the price of CNG vehicle is more expensive than that of gasoline vehicle. To promote CNG vehicle, government and gas related organization and company give some incentives. Government gives subsidy to CNG vehicle purchaser. Amount of subsidy is 50% of price gap between CNG vehicle and diesel vehicle or 25% of CNG vehicle price. As for taxation system for vehicle, there are some incentive. Also gas company and truck association have unique incentive.

5.2.4 CNG Filling Facilities

(1) CNG Station

Town gas with 0.1-0.7MPa is supplied to CNG station through middle pressure gas pipeline as shown in Figure 5.2-3. Town gas in CNG station is compressed by the compressor and is stored in gas storage tank as CNG. Then CNG is filled in CNG vehicle through the dispenser.



(Source) Japan Gas Association

Figure 5.2-3 CNG Station

(2) Package Type Filling Equipment

Package type filling equipment is simplified and unified CNG station. This equipment is used by factory that has small trucks and forklift as private system. Advantage of this equipment are as follows.

1) It is easy to install because of package.

2) It is possible to reduce construction period and cost.

3) It is possible to install small space.

(Source) Japan Gas Association

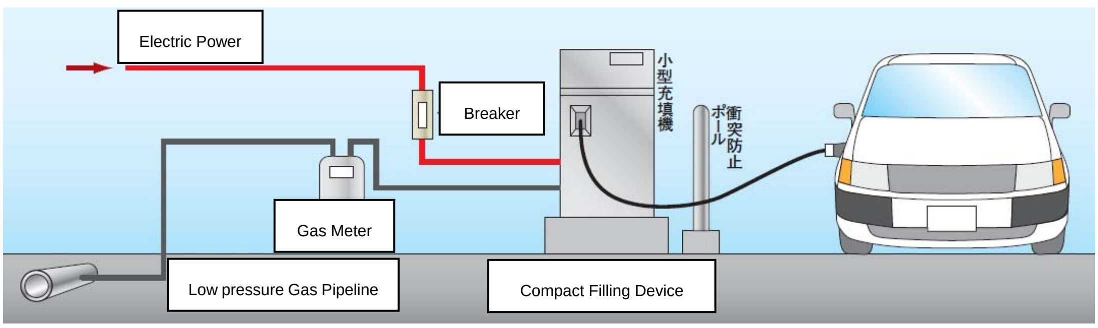
Figure 5.2-4 Package Type Filling Equipment (250m3/h)

(3) Compact Filling Device

Compact filling device fills CNG in CNG vehicle for 4-5 hours using low pressure town gas for household. It is convenient in case of no CNG station at the nearby site.

(Source) Japan Gas Association

Figure 5.2-5 Compact Filling Device (10m3/h)



(Source) Japan Gas Association

Figure 5.2-6 Illustration of Compact Filling Device

Chapter 6 LNG Supply Systems

6.1 Global LNG Supply and Demand

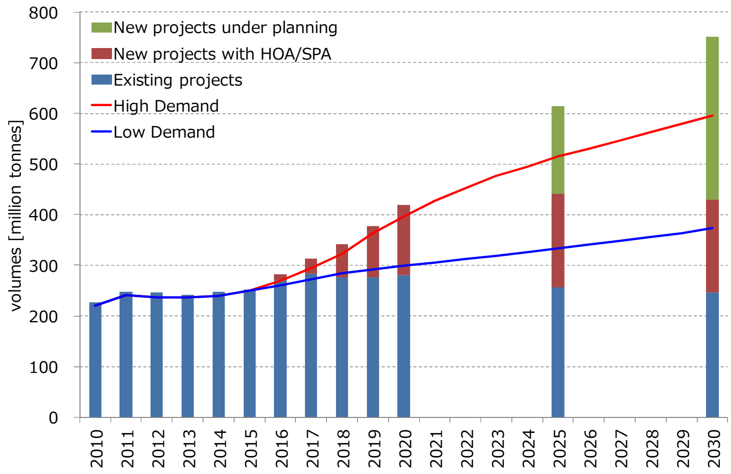
In October 2014, the LNG market celebrated its 50th anniversary since the first commercial LNG plant started its operation in Algeria in 1964. The global demand for natural gas has been growing by virtue of its unparalleled environmental characteristics amongst fossil fuels and more ubiquitous availability of resources in comparison with oil. Against such backdrops, LNG trading as a means of natural gas supply is growing in the world and especially in countries where pipeline systems are difficult to develop due to geographical constraints.

According to Cedigaz, the volume of global LNG trading in 1990 was 72.1 Billion cubic meters (Bcm) or approximately 53 million tons (MT), accounting for 23.5% of the total natural gas trading. Ten years later in 2000, the volume grew to 137.2Bcm or about 100MT, and further to 295.5Bcm or about 220MT in 2010, thus doubling the market size every ten years during those two decades. Further, the volume of global natural gas trading in 2014 was 1,005.2Bcm or approximately 740MT in LNG equivalent, of which LNG trade was 313.7Bcm (about 230MT) accounting for 31.2% of the total. While the total natural gas trade expanded at an average annual rate of 5.1% during the 24 years from 1990 to 2014, the rate of growth for LNG trade has surpassed that of natural gas demand and averaged at 6.3% for the same period.

In the meantime, the number of countries engaged in LNG trade has been steadily increasing; LNG was imported by nine countries and exported by eight countries in 1990, their numbers grew to 31 importing countries and 27 exporting countries in 2014. In 2015, Egypt, Pakistan, Jordan, and Poland joined the ranks of LNG importing countries, with the Philippines, Vietnam, Myanmar as well as Bangladesh and so on contemplating the introduction of LNG. Meanwhile, in the area of new exporters, an LNG plant was brought online in Papua New Guinea in 2014, and LNG exports from the mainland United States started in 2016. It is envisaged that Canada, Cameroon, Tanzania, Mozambique and others will participate the market as new LNG exporters in the future.

According to the Institute of Energy Economics, Japan (IEEJ), the global LNG demand is expected to grow to 270 MT in 2016, to 300 - 390 MT by 2020, and to 410 - 570 MT by 2030. Concerning the future LNG demand, there are downside factors related to the status of nuclear power plant restarts and domestic electricity and gas market reforms in Japan, as well as China's economic slowdown and its domestic gas policy, and so on. Conversely, in addition to a recovery in natural gas imports into the European countries due to decreased natural gas production within the Region, LNG imports are expected to increase in emerging countries such as Vietnam and the Philippines which so far have baulked at introduction of LNG for economic reasons but are now encouraged by the prospect of reduced LNG prices due to the influx of LNG from the United States.

Against the demand pictures discussed above, existing LNG production capacity in the world is about 320 million tons per annum (MTPA) at the end of 2015. Excluding Libya, Egypt, and Angola, where production is suspended at the moment, about 300 MTPA of capacity is still available, which is sufficient to meet the demand even after considering for their net operating rates. Further, taking into account the projects currently under construction, the total capacity is expected to reach about 400 MTPA by 2020. Looking at regions other than North America and Australia, large LNG projects are also launched in East African countries such as Mozambique and Tanzania and, together with those on the drawing board, these plans and proposals will bring the total capacity to about 610 MT by 2025 and 750 MT by 2030, which will far exceed the projected LNG demand.



(Source) IEEJ

Figure 6.1-1 Global LNG Supply and Demand up to 2030

6.2 LNG Receiving Terminals

6.2.1 Overview

An LNG receiving terminal is a facility designed to receive LNG cargoes that have been transported by LNG tankers from across the seas and store them in cryogenic storage tanks. The LNG is then re-gasified and fed to consuming destinations via pipelines or alternatively shipped out to secondary (satellite) terminals in liquid state, depending on the requirement.

The world's first LNG receiving terminal was constructed in Canvey Island, U.K., and started commercial operation in 1964[34]. Since then, reflecting the construction of LNG production plants in various parts of the world triggered by a wave of global natural gas demand expansion, LNG receiving terminals have been constructed and put into operation mainly in East Asia and Europe. In recent years, however, construction of LNG receiving terminals is also planned in countries situated in Central and South America, Middle East, Southeast Asia and others,

34 BG, http://www.bg-group.com/~/tiles/?tiletype=blog&id=31

exhibiting a global trend of propagation. In 2015, seven LNG receiving terminals were completed. Among the foregoing, four terminals constructed in the new LNG importing countries of Egypt, Pakistan, and Jordan were of floating design called an FSRU (=Floating Storage and Regasification Unit). In June 2016, Poland joined the ranks of LNG importers when the first commercial LNG cargo arrived at its first LNG receiving terminal commissioned earlier. Meanwhile, as a unique case observed in Indonesia, its Arun liquefaction plant has been converted to a receiving terminal due to the surge in its domestic natural gas demand that devoured the nation's export availability. Taking advantage of a low cost LNG market in recent years together with the benefit of FSRU design that allows a short construction lead time, emerging economies are able to secure desired regasification capacity in relatively short order. Elsewhere, in the existing LNG receiving terminals, projects are also under way to increase their receiving capacities by augmenting the number of storage tanks, along with plans to add facilities for LNG re-export (reloading) or those for bunkering service for LNG-fueled ships. According to IEEJ, as of April 2016, the number of LNG receiving terminals (including secondary terminals) operating worldwide is 144 with a total combined receiving capacity of about 590 MTPA. Tables 6.2-1 and 6.2-2 respectively show a summary of LNG receiving terminals currently operating as well as those under construction or planning in the world.

Table 6.2-1 LNG Receiving Terminals in Operation

	Americas	Europe	Northeast Asia	Southeast Asia	South Asia	Middle east	Africas	World
-1980	3	4	7	0	0	0	0	14
1980-2000	1	5	18	0	0	0	0	24
2000-201	25	22	40	7	6	5	1	106
Number Total	29	31	65	7	6	5	1	144
Onshore Terminal	160.84	139.47	182.095	14	25	N.A.	0	521.4
Offshore Terminal	28.36	13.3	2.2	9.3	5.24	9.84	N.A.	68.24
Capacity Total	189.2	152.77	184.295	23.3	30.24	9.84	0	589.6

(Source) IEEJ

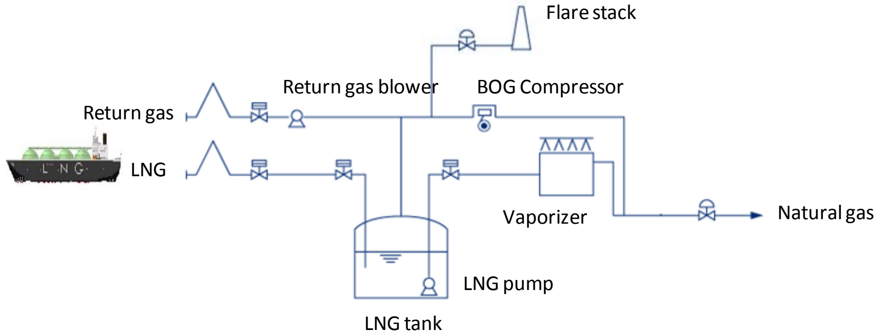
Table 6.2-2 LNG Receiving Terminals under Construction/Planning

	Americas	Europe	Northeast Asia	Southeast Asia	South Asia	Middle east	Africas	World
Onshore Terminal	14	35	39	11	12	2	3	116
Offshore Terminal	11	8	1	5	11	2	7	45
Number Total	25	43	40	16	23	4	10	161
Onshore Terminal	40.54	117.51	57.5	26.3	60.36	20.39	6.21	328.8
Offshore Terminal	38.18	17.77	N.A.	12.4	45.41	7.38	1.8	122.9
Capacity Total	78.72	135.28	57.5	38.7	105.77	27.77	8.01	451.8

(Source) IEEJ

6.2.2 Configuration

A schematic diagram of a conventional LNG receiving terminal is shown in Figure 6.2-1 below. Key components of a typical LNG receiving terminal include marine jetty facilities for unloading LNG, special tanks for LNG storage, process equipment for regasification of LNG, send-out pipelines, utilities and other infrastructure.



(Source) Tokyo Gas Engineering Solutions Corporation

（http://www.tge.co.jp/service/lng/1st/）

Figure 6.2-1 Schematic Diagram of an LNG Receiving Terminal

(a) Cargo offloading unit

Following berthing of an LNG tanker, the LNG is pumped ashore via the carrier's pumps through unloading arms to a cryogenic pipeline to the storage tanks. During the offloading process, the boil-off gas (BOG) produced in the tank due to external heat is compressed and forced into the vessel cargo tank with a return gas blower to maintain adequate pressures in the vessel tank and the shore tank.

(Source) Oita LNG（http://www.oitalng.co.jp/business/acceptance.shtml）

Figure 6.2-2 LNG Cargo Offloading

(b) Storage facilities

An LNG receiving terminal usually functions as a storage installation as well. Based on the relationship between the main body and the ground, LNG tanks can be classified into three structure types, i.e. above-ground, underground, and in-ground. Naturally the above-ground design is popular owing to its low cost of construction. However, in countries like Japan or Korea, a number of LNG storage tanks are built with underground or in-ground structures. Since the underground/in-ground tanks will cause a reduced degree of impact on the surrounding environment in the unlikely event of a breakage, relaxed regulations for tank separation distances are applied to allow more effective use of land in comparison with above-ground ones. The underground/in-ground designs have additional advantages of offering a better landscape as well as superior protection against earthquakes. On the other hand, there are handicaps of high labor and cost associated with soil excavation and a need to lay an antifreeze heater around the tank to prevent freezing of the soil. In configuring the tank capacity for an LNG receiving terminal, a designed size may not be sufficient if it merely corresponds to regular shipments meeting the demand. The required storage capacity should be determined after considering seasonal demand fluctuations, the size of the LNG vessels, operating margins taking into account such factors as delays in ship arrival due to bad weather, possible liquefaction plant troubles, heating value variations by LNG production area, and a stockpiling requirement for emergency. As Japan imports LNG at a constant rate irrespective of the season, LNG receiving terminal utilisation rate is about 50% on average. In South Korea, however, since its winter heating requirement is high in proportion, the capacity utilisation tends to be lower and was 34% in 2015[35]. The boil-off gas (BOG) produced during storage is either sent out through compressors or used as fuel for the gas-fired generator installed nearby, or sometimes processed as LNG by re-liquefaction.

(Sources) Hokkaido Gas, Tokyo Gas, Hiroshima Gas

Figure 6.2-3 Types of LNG Storage Tanks

(c) Regasification unit

The technology for regasification is determined in consideration of user's gas consumption patterns, usage of the vaporization equipment (e.g. for base load, for peak shaving, or for emergency reserve), the required capacity, locational conditions of the terminal, and so on. Generally, for the base load operation, an Open Rack Vaporizer (ORV) that uses seawater as the external heat source is employed for its low cost of operation. An ORV incorporates panels comprising heat transfer tubes made of aluminum

35 IGU, World LNG Report 2016

alloy. The LNG flows inside the heat transfer tubes while seawater flows over the outer surface of the panels, where the heat exchange with much warmer seawater allows the LNG to vaporize. For peak shaving or emergency applications, a Submerged Combustion Vaporizer (SCV) is used for its superior capability to deal with sudden load fluctuations or quick start up/shut downs. An SCV uses a waterbath heated by flue gases coming from a submerged combustion burner that burns a portion of regasified natural gas. The LNG is warmed and vaporized by flowing through tube bundles that are submerged in the waterbath. Apart from the foregoing types, a Shell and Tube Vaporizer (STV) uses an intermediate fluid to transfer the seawater heat in a shell-and-tube type heat exchanger, whereas other designs use ambient air for the external heat source. In addition, in order to recover and utilize the cold energy released in the regasification process, liquefaction of industrial gases such as carbon dioxide, oxygen, or nitrogen is being practiced, as well as cryogenic power generation that directly uses the expansion at the time of vaporizing LNG.

(Source) Tokyo Gas（http://www.tokyo-gas.co.jp/techno/menu1/15_index_detail.html）

Figure 6.2-4 LNG Vaporizer (ORV)

(d) Send-out facility

After regasification, the raw natural gas is conditioned to an adequate calorific value and combustion characteristics and transferred to a reginal distribution center in the consumption area through high-pressure trunk pipelines. In certain countries in Europe or North America where the gas value chain is unbundled, a metering system may be installed in the send-out pipe. Furthermore, some of the LNG receiving terminals also have equipment for loading LNG tank trucks to transport LNG to satellite (secondary) terminals in demand centers located in remote areas.

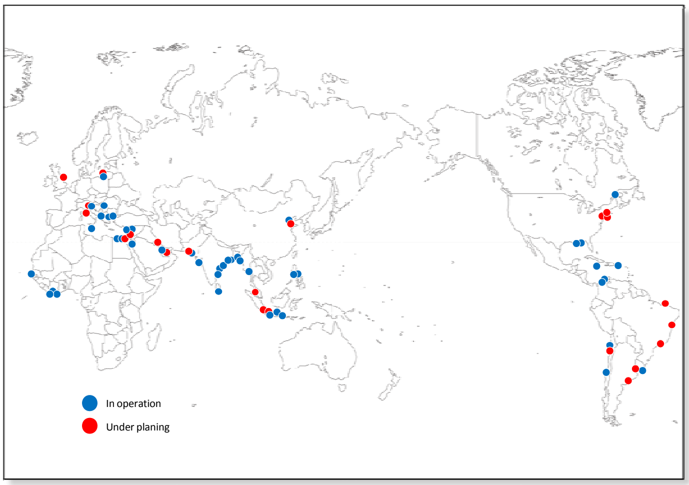
6.2.3 Floating Storage and Regasification Unit (FSRU)

While an LNG receiving terminal desirably should be situated near the major gas consumption area, it can be a difficult challenge to secure an adequate site with a sufficient space to contain the required facilities including the marine jetty and those for unloading, storing, regasifying and shipping LNG as well as other utilities. For this reason, designs based on the concept of a floating structure, called a Floating Storage and Regasification Unit (FSRU), were developed around 2000 for advantages in the cost and lead-time for construction over their land-based counterparts.

(Source) Höegh LNG（http://www.hoeghlng.com/Pages/OurBusiness.aspx#FloatingLNGImportTerminals-0）

Figure 6.2-5 Floating Storage and Regasification Unit

The world's first FSRU was an offshore LNG receiving terminal "*Gulf Gateway Deepwater Port*", built by Excelerate Energy116 miles offshore Louisiana in the US Gulf of Mexico. The facility was commissioned in 2005 but discontinued in 2012 due to an adverse market environment[36]. As of 2016, twenty-two (22) units of FSRU are operating in the world and 40 projects or more of FSRU including plan are considered in addition. Furthermore, advanced technologies are available for converting an LNG carrier into a floating terminal, which are often utilized to reuse aging LNG vessels considered for retirement. Figure 6.2-6 gives a worldwide picture of floating LNG receiving terminals currently in operation as well as those in the planning stage.



(Sources) Websites of enterprises concerned

Figure 6.2-6 World's Floating LNG Receiving Terminals (In operation/planning)

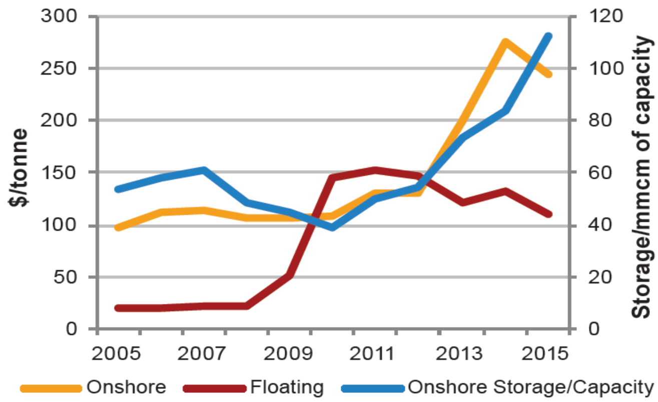
36 Excelerate Energy, http://excelerateenergy.com/project/gulf-gateway-deepwater-port-2/

Advantages and disadvantages of floating LNG receiving terminals in comparison with the on-shore options are discussed below:

<Advantages>

(a) Cost of construction

While the construction cost of a conventional land-based LNG receiving terminal varies depending on the number and capacity of tanks, site area, and the scale of ancillary facilities such as the vaporizer unit or dockage, etc., the average unit cost of onshore regasification capacity that came online in recent years is reported to be $245/ton. On the other hand, since FRSUs are built with designs and structures similar to those of conventional LNG tankers, an average construction cost is lower and said to be around $109/ton for units completed in recent years[37]. Further cost reductions may be attained in the case where an existing LNG vessel is converted. Although FSRUs require additional costs in furnishing pier facilities for berthing and mooring, it is still possible to significantly reduce the expenditure compared to onshore LNG receiving terminals.



(Source) IGU, World LNG Report 2016

Figure 6.2-7 LNG Receiving Terminal Cost Trend

(b) Construction lead-time

It takes approximately six years or so to construct an onshore LNG receiving terminal, including the time needed for design work and permits such as the Environmental Impact Assessment (EIA). By comparison, an FSRU could be newly built in about three years which is roughly equal to a conventional LNG carrier. The above could be further shortened to around one year in the case of remodeling and converting an existing LNG carrier[38]. While additional pier facilities for berthing and mooring may sometimes be required, it is possible that the time

37 IGU, World LNG Report 2016, http://www.igu.org/publications/2016-world-lng-report

38 Excelerate Energy, http://excelerateenergy.com/fsru-technology/

required for the EIA could be shortened since FSRUs do not involve onshore land use.

(c) Operational flexibility

Since FSRUs in many cases are provided with navigational capability comparable to conventional LNG carriers, it is relatively easy to pull a unit out of service and divert it to elsewhere in the event that the capacity becomes unnecessary in the future. Additionally, the short lead-time required to bring an FSRU online enables the use for temporary purposes such as a bridging use during the period waiting for the commissioning of a full-scale onshore terminal, or for limited operations only during the winter period when gas demand surges.

<Disadvantages>
(d) Weathering performance

Because an FSRU is moored at sea, its operation can be seriously affected by weather and/or sea conditions, potentially presenting a problem in operational stability compared to the land-based options. In particular, the wave height reportedly becomes a safety problem when it exceeds 1.5 m, and in general, it is desirable to install one in a small bay where the influence of waves is weaker. Moreover, when a typhoon or a hurricane approaches, it could become necessary for the FSRU to leave the shore and evacuate for safety.

(e) Scalability

The storage capacity of an FSRU is dictated by its hull dimensions for housing the LNG tanks. Further, the size of an FSRU determines the range of acceptable LNG tankers. Accordingly, when a capacity enhancement is needed in response to a growing demand, the only way available is to increase the number of FSRUs, which by necessity calls for a requisite expansion of mooring facilities. The largest FSRU to date is the one being deployed in the LNG terminal project in Montevideo, Uruguay for completion in 2016, with a storage capacity of 263,000 cubic meters which is roughly equal to the world's largest Q-Max class LNG carriers[39].

6.2.4 Topics and recent trends on LNG tankers

The commercial sea transport of LNG began in February 1959, when a converted naval freighter, the *Methane Pioneer*, successfully made a pioneering voyage transporting world's first ocean cargo of 2,000 tons of LNG from Lake Charles, Louisiana, USA to the world’s first LNG terminal at Canvey Island, England. The success of the experiment paved the way for the world’s first LNG export scheme and the construction of two purpose-built LNG carriers, Methane Princess and Methane Progress, with a capacity of 27,400 cubic meters each. The

[39] IHI, http://www.mol.co.jp/en/pr/2013/13073.html

vessels delivered the world's first commercial LNG cargoes from the Port of Arzew in Algeria to the Canvey Island starting from October 1964. Subsequent expansion of LNG trade has brought about a large expansion of the fleet and, in recent years, the size and capacity of LNG carriers have greatly increased along with the trade volume and the need for cost reduction. The most popular size during 1990s was 125,000 cubic meters, while it was in the 138,000 - 145,000 cubic meter range in early 2000s. Since 2005, Qatargas, the world's largest LNG exporter, has pioneered the development of two new classes of LNG carriers, referred to as Q-Flex and Q-Max. Each ship has a cargo capacity of 210,000/up or 260,000/up in cubic meters, respectively, and is equipped with a re-liquefaction plant.

Since LNG is lighter than crude oil in specific gravity, LNG carriers require a shallower draft compared to crude carriers. A 137,000 cubic meter class LNG carrier, for example, needs a draft of only 11 to 12 meters which is equivalent to that of a 50,000-ton oil tanker. Giant LNG carriers such as Q-Flex or Q-Max classes are also designed with a similar draft depth as above to enable accommodation at the receiving terminals. However, operation of such mammoth vessels can pose a number of challenges to be met in areas such as maneuvering in port, strength of berthing and mooring facilities, as well as canal transit, for which reasons 170,000 cubic meter class carriers are today becoming the mainstream of the world. As of the end of 2015 the active fleet of LNG carriers stood at 424 ships worldwide, of which 29 were newly delivered during the year. The average cargo capacity of these 29 newbuilds was 163,813 cubic meters[40]. Although construction cost of LNG tankers has declined substantially in recent years, still a 140,000 cubic meter class vessel will cost around $1.7 billion, which is nearly three times the crude oil tanker of an equivalent size.

A typical LNG carrier has four to ten tanks located along the center-line of the vessel. Because of its cryogenic temperature of -162°C, it is necessary to provide the tanks with adequate insulation to keep the LNG cold and minimize evaporation during the voyage. Today there are basically two types of cargo containment systems in use for LNG vessels. One is the self-supporting type as represented by the Moss Rosenberg design well known for its independent spherical tanks that often have the top half exposed on LNG carriers. The other is the membrane type using thin, flexible membranes supported only by the insulated hull structure, most commonly designed by Gaztransport and Technigaz (GTT). By the end of 2015, 76% of the active fleet had a membrane-type containment system mainly due to its advantage in allowing more efficient utilisation of the hull shape.

For the propulsion systems, unlike common cargo carriers powered by diesel engines running on liquid fuels, LNG tankers have traditionally been powered by steam turbines with boilers. Due to heat entering the cryogenic tank during storage and transportation, a part of the LNG in the tank continuously evaporates creating a gas called boil-off gas (BOG). The BOG is used to fire the boilers and produce steam which in turn drives the turbines and propels the ship.

[40] IGU, World LNG Report 2016

However, since this system has poor fuel efficiency, in order to improve economics and to reduce the environmental footprint, alternatives to steam turbine have been proposed by the industry including, for instance, direct drive slow speed diesel engine propulsion with a re-liquefaction plant as the means for dispose of the BOG, or dual-fuel diesel-electric propulsion (DFDE) systems which are able to burn both diesel oil and BOG and to improve vessel efficiency by around 25-30% over the traditional steam-turbines. While the existing fleet is still dominated by the legacy steam propulsion system, a growing percentage of active LNG fleet employs these advanced propulsion systems and even more so on those on the orderbook.

Table 6.2-3 World's LNG Fleet (Active/Orderbook)

	-100,000m3	100,000-20,000m3	20,000m3-	Total
-1980	2	14	0	16
1980-2000	5	62	0	67
2000-2015	3	280	44	327
Total Active LNG Fleet	10	356	44	410
LNG Vessel Orderbook	1	141	1	143

(Source) IGU, World LNG Report 2016

6.2.5 LNG Transactions

An LNG project requires a huge investment in each component of value chain starting from the development of natural gas fields to construction of a liquefaction plant, acquisition of a LNG tanker fleet, and to construction of a receiving terminal. This made the initial investment for LNG much more expensive than oil for which the requisite infrastructures are already in place. For this reason, project developments traditionally have been carried out after securing a long-term sales and purchase contract between the seller and the buyer over a period of 20 years or more. In operating a long-term contract it is common to prepare a delivery program well in advance with regard to the deployment of LNG tanker fleet, loading/unloading particulars as well as voyage schedules. In the case of a major LNG importing entity in Japan, while LNG tankers are arriving almost on a daily basis, their voyage schedule is prepared three months or so in advance. However, depending on weather or sea conditions, vessel arrivals may delay or vessels may be prevented from berthing. In addition, due to an emergency stop or sudden changes in the demand of a power plant, for instance, situations could also occur in which the supply quantity according to voyage and delivery plans turns out to be either deficit or surplus, in each such case it becomes necessary to adjust the shipping schedule with the seller and other LNG customers. It is not a simple task to adjust the delivery schedule such as a change in arrival time, as it necessitates clearing a variety of conditions including assessment of the impact of such actions on the next voyage schedule of the affected vessel or confirming the availability of alternative vessels. Moreover, in the event that the vessel is prevented from discharging cargo within the stipulated laytime (i.e. the time allowed within which an operation is allowed to be made) the LNG buyer could be required to pay demurrage to the shipowner according to the relevant agreement.

In the crude oil transactions, as a general rule, quantity determination for the settlement or customs clearance purposes is carried out by measurements with the shore-side stationary equipment. In the LNG transactions, however, measurements are taken normally at ship's side. This is because of the circumstances unique to the cargo handling in the LNG trade, where, for example, about 0.1% to 0.15% of the LNG cargo continuously evaporates as BOG every day during the laden (loaded) voyage. After discharging, in order for the ship to have fuel until the next loading and to be able to keep the storage tanks cold, a certain amount of cargo called “heel” is always left. This heel is used as a cooling medium as well as propulsion fuel during the ballast voyage. Further, unloading is done in a closed circle, in that the unloaded LNG cargo in the ship storage tanks is replaced by the natural gas vapor from the terminal called return gas to maintain the positive vessel tank pressure. Safety of the system is kept without in-take of air into the tank while the ship is used consecutively; such gas must be purged before dry docking

Moreover, LNG cargoes are transacted on the basis of heating value (Btu) of the quantity transferred, and in order to determine this quantity of transaction it is necessary to measure the volume of LNG transferred and also to measure the unit heating value by sampling and analysis (for density and composition) of the cargo in question. For measuring the quantities transferred during loading and unloading, LNG carriers are usually fitted with an automatic system for the continuous monitoring, calculation, and display of LNG and gas volumes in each tank. Such equipment, commonly referred to as the Custody Transfer Measurement System (CTMS), processes data from tank level-, temperature-, and pressure-sensors in real time, taking into account the required corrections based on certified gauge table, to produce a calculation of volumes before, during and after the transfer. For this purpose an LNG tanker must always carry appropriate tank gauge tables that are officially certified and calibrated.

Meanwhile, for the determination of the density and the heating value of the LNG transferred, samples are taken from a sampling system fitted in the transfer line between the ship’s unloading arm and the terminal and then analyzed by gas chromatography. The gross calorific value (GCV) of the LNG transferred is then determined by a calculation based on the average composition of the LNG and characteristics of elementary components (GCV, molar volume, molar weight), its average temperature, and the coefficients for the density as given by the relevant authorities. The process of determining the GCV for LNG transaction is illustrated in Figure 6.2-8.

In the case of crude oil or refined petroleum products transaction, since the quantity of custody transfer (including the customs clearance quantity) is determined by the measurements taken in the shore side, transfer of the cargo from the receiving tank is not possible during the period from the start until the end of the unloading operation and usually for about two days. However, in the case of LNG since the quantity of custody transfer is determined by measurements on the ship's side, it is possible to use the receiving tank even during the loading and unloading operations. Thus, a fewer number of tanks are required to operate an LNG receiving terminal, making it possible to operate a terminal even when it is furnished with just one tank.

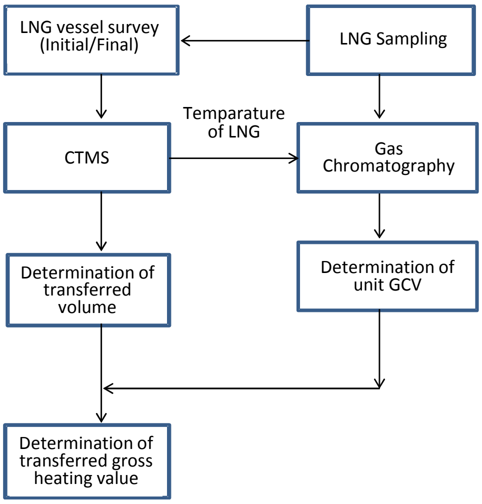
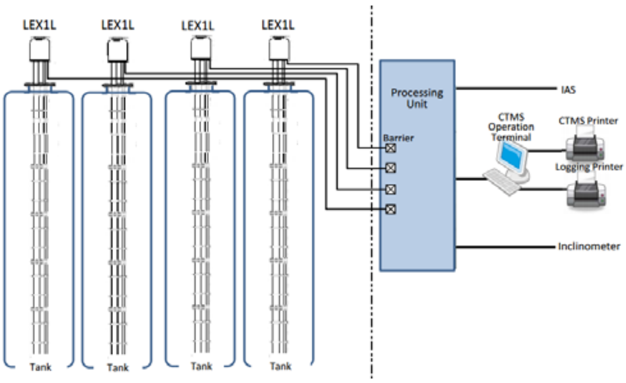
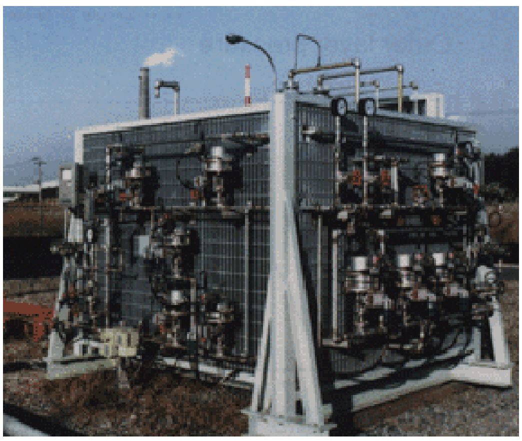


Figure 6.2-8 Process of determining GCV for LNG transaction



(Source) Musasino Co., Ltd.（http://www.musasino.biz/jp/product/ctms/）

Figure 6.2-9 Example of CTMS



(Source) Tokyo Gas（http://www.tokyo-gas.co.jp/techno/menu1/6_index_detail.html）

Figure 6.2-10 LNG Sampling System

Although the trading volume of LNG transactions may vary from terminal to terminal, with large-scale transactions such as those on the order of 10 MTPA, even a small error or discrepancy in measurement can amount to a large financial difference.

For this reason, quantity measurements with CTMS as well as the sampling and composition analysis are carried out in accordance with the prescribed procedure and timing and in the presence of representatives of the seller, buyer, the customs, and an independent surveyor. The volume and the relevant data witnessed and verified by the surveyor shall become the official records for finalizing the transaction and the customs declaration.

6.3 Gas pipelines

6.3.1 History of gas pipelines

The Industrial Revolution that began in the United Kingdom progressed based on coal as an energy source. On the other hand, the discovery and utilisation of oil and natural gas served as a driving force for the development of the United States. In Europe and the United States, use of town gas started in the early 19th century, and an aqueous gas produced using coal as a raw material was supplied mainly for lighting. In 1859, E.L. Drake succeeded in mechanical oil drilling in Titusville, Pennsylvania, USA. In 1872, the United States' first natural gas pipeline was constructed from Titusville to a village about 10 km away. However, coal gas was exclusively used as town gas for a long time, and it was only in the 20th century that construction of long-distance pipelines from gas fields and utilisation of natural gas started in the United States. As mentioned above, utilisation of natural gas started with a considerable handicap compared with oil as a liquid fuel. At present, however, natural gas is used as the major energy source that provides for about a quarter of the global energy demand.

Beginning from the early 1950s, transportation of natural gas to large consumer regions through long-distance pipelines advanced along with the development of pipeline technology and a reduction in cost. In the natural gas pipelines connecting the Southern States such as Texas or Louisiana and Canada to industrial regions in the northern part of the nation served as energy transportation arteries. In Europe, the Groningen gas field was discovered in the Netherlands in 1959, and the development of pipelines started. Thereafter, oil fields and gas fields were discovered in succession in North Africa as well as in the North Sea, leading to an extensive development of pipeline networks in Europe.

Pipeline transportation outside of the United States also became popular in oil-producing regions in Canada, the Middle and Near East, Latin America, and Russia along with the advancement of US and British oil companies into these regions. Further, natural gas development projects were carried out in the Netherlands, the North Sea, and North Africa in the 1960s, and a network of long-distance, high-pressure gas pipelines was developed all over Europe to distribute natural gas produced in the above-mentioned production areas and also to transport gas being exported from Urals and Western Siberia (Russia) cutting through East European countries to West European countries.

During the 1960s and 1970s, international pipelines were developed in Europe for transporting the gas produced in North Africa and Russia to European markets. In the 21st century, in addition to pipelines extending from Central Asia to Europe, pipelines connecting Central Asia and Russia with the rapidly expanding Chinese markets are under construction.

6.3.2 Pipelines and LNG

In spite of the development of pipeline networks with the times, natural gas discovered in a remote region far away from consumer regions had to be abandoned as stranded gas. Meanwhile, it was impossible for countries such as Japan that are located away from natural gas resources to utilize a large quantity of natural gas. In view of such a situation, LNG technology was developed that cools natural gas to a temperature as low as -161.5oC to produce LNG having a volume about 1/600th that of natural gas, and enables long-distance transportation of natural gas using tankers. The world's first commercial LNG plant was constructed in Algeria in 1964 after overcoming the challenges in technology and economic efficiency related to materials and cooling systems to be used at cryogenic temperatures. In 1969, the export of LNG from Alaska to Japan started. In the early 1980s, however, the export of LNG from North Africa started to decline due to severe competition with natural gas transported from the North Sea through pipelines and political as well as other reasons. Under such circumstances, Japan was the consumer that contributed to the widespread utilisation of LNG.

In the 1970s during which the use of LNG was commercialized, Japan needed to diversify energy sources and introduce the use of cleaner energy in response to the bitter experience from the two oil shocks and environmental pollution problems that occurred through high economic growth of the time. Thus, Japan employed LNG as a powerful solution to reduce its dependence on oil as well as to promote the use of cleaner energy. In Japan, coal gas was mainly used as town gas until LNG was introduced. As a result of the shift to natural gas, the number of gas poisoning accidents decreased dramatically, and the heating value of town gas increased from 5,000 kcal/m3 (20.3 MJ/m3) to 11,000 kcal/m3 (46 MJ/m3), so that the pipeline transportation capacity in overpopulated cities was significantly improved on a heating value basis.

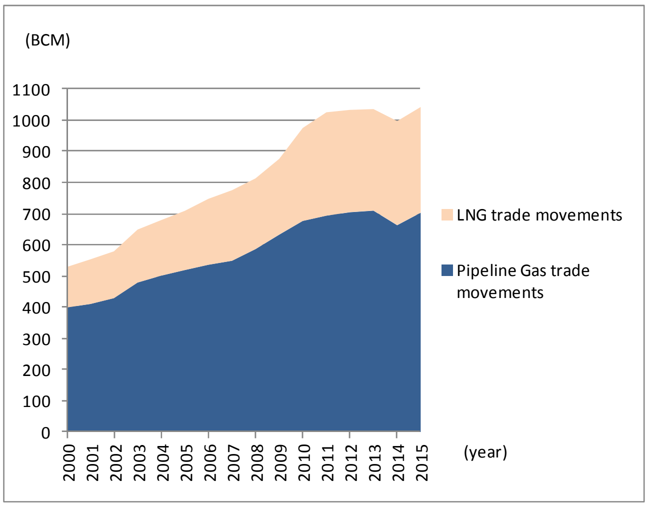
In order to cope with an increasing LNG demand, Japan extensively promoted LNG projects in Southeast Asia, the Middle East, Australia, as well as in other places. South Korea and Taiwan started to import LNG in 1986 and 1990, respectively. In the 21st century, the use of LNG became extensive in Asia, with India and China starting to import LNG in 2004 and 2006, respectively.

The 1990s saw a significant reduction in LNG cost and great expansions in the capacity of LNG plants as well as LNG carriers, leading to the advent of a mammoth LNG plant having an annual supply capacity of 77 million tons (i.e. equivalent to about 2 million BD of crude oil) was constructed in Qatar that owns the world's largest gas field. Early in the 2000s when the natural gas price in Europe and the United States rose from the traditional level of $2/MMBTU to $4 or $5/MMBTU levels, long-distance LNG transportation from the Middle East, Australia, Africa, and the like suddenly began to attract attention. As a result, an unprecedented LNG boom occurred also aided by a large increase in shale gas production in North America, which incidentally led to somewhat ominous sign of plant cost inflation starting again from around 2010.

A considerable portion of natural gas resources discovered in the past in areas far away from the markets or those located in deep sea fields had been abandoned as stranded gas. However, the development of unused resources began to advance in many parts of the world owing to a significant improvement in the economic efficiency of LNG. In addition to a sizable expansion of LNG production capacity in Qatar, new LNG projects also started in Australia, countries on the west coast of Africa, Latin America, the Arctic Ocean, and others. Iran also has a high potential in natural gas supply capacity, even though there are political issues to be resolved. Various new projects have now been proposed and in progress including a floating LNG (FLNG) project that produces gas from an offshore gas field of medium scale, liquefy, store and transfer the LNG to carriers at sea; another is an LNG project that utilizes coalbed methane (CBM: see related section) as a feedstock.

As all of the nuclear power plants in Japan stopped or suspended operations following the Great East Japan Earthquake of March 11, 2011, it suddenly became necessary to enlist the full capacity operation of available gas-fired power stations as a relief. Japanese power companies scrambled for LNG from all parts of the world through spot trading since it was difficult to satisfy the demand based on the existing long-term gas purchase contracts. A sizable quantity of LNG produced in Africa such as Nigeria, aided also by a slackening demand in Europe, was exported to Japan causing an expansion in spot trading. At the same time, the global natural gas trade also grew from 530 Bcm in 2000 to 1,042 Bcm in 2015 or about twice that in 2000. Natural gas is transported through pipelines or transported in the form of LNG. In 2000, about 75% of natural gas was transported through pipelines and about 25% in the form of LNG. In 2015, however, natural transported as LNG increased to 32% along with the increase in spot trading of LNG.

Figure 6.3-1 below is a graph showing the natural gas trading volume through pipelines and the LNG trading volume since 2000.



(Source) BP Statistics

Figure 6.3-1 Global Natural Gas Trading Volume

6.3.3 Pipeline cost

The cost of pipeline transportation is significantly affected by the construction cost. The transportation cost is calculated based on the sum of the amortization cost, the operating cost, and the operator's profit. In general, the profitability of natural gas supply business varies depending on the annual supply volume and the transportation distance. Long-distance pipelines can have a cost advantage over other methods if a large volume of natural gas can be sold using large-diameter pipelines.

The transportation cost using pipelines is often studied in comparison with one using LNG carriers when the method of natural gas supply is at issue. With regard to the cost comparison between ocean-going LNG carriers and international gas pipelines, the cost of transportation using undersea pipelines becomes relatively higher as the transportation distance increases. On the other hand, ocean-going LNG carriers require a high initial investment such as the construction cost of the ships, and thereafter the running cost accounts for the majority of cost of operation. It is generally understood that the economic edge shifts from transportation using undersea pipelines to ocean-going LNG carriers when the transportation distance exceeds about 1,000 km. Likewise, in the case of transportation using overland pipelines the shift to ocean-going LNG carriers occurs when the transportation distance exceeds about 3,000 km.

6.4 LNG Distribution Systems – Options and Economics

As shown in Figure 6.4-1, the means of transporting the LNG imported from the international market to the main consumption region can be divided mainly into a pipeline supply of regasified gas and a direct supply to satellite facilities for local distribution. While piped supplies are common in general, the large initial investment on the pipeline facilities makes it uneconomical to transport small quantities to remote consumers. In an arrangement to overcome the above difficulty, the LNG received at the main marine terminal is directly transported via tank trucks, rail container cars, or coasting vessels to the satellite facility (secondary terminal) constructed near the consumption area for subsequent re-gasification and local distribution through the pipeline networks. Furthermore, LNG is supplied by a like manner in the case where factories or other end users with requirements of sufficient size are disconnected from the main pipeline system. If the adoption of such a system can lead to an increase in the natural gas utilisation in that region, a switch of the mode of gas supply to pipeline will become possible in the future. In this section, with regard to the mode of supply from the main LNG receiving terminal to the secondary terminals, the economics of a piped supply system and a satellite supply system will be comparatively discussed. Additionally, the economics is also compared for each of the tank trucks (road transport), ISO containers (railway), and coastal tankers (water transport) as a means of transportation from the main terminal to the satellite facility.

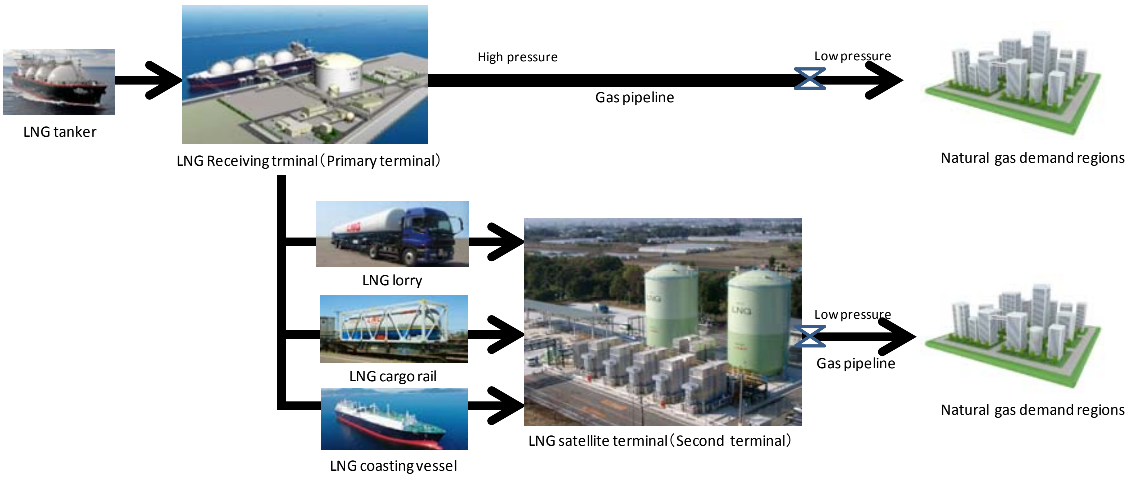
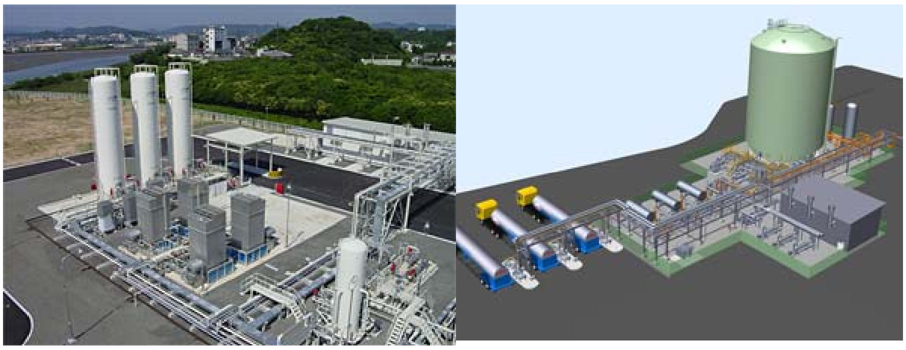


Figure 6.4-1 Piped supply system and satellite supply system

6.4.1 LNG Satellite Facilities (Secondary Terminals): Examples in Japan

(1) Overview

Figure 6.4-2 shows a general layout of an LNG satellite facility. Such a facility has been developed to enable use of LNG in remote locations where pipelines are not accessible. An LNG satellite facility is a secondary LNG receiving terminal, and a number of such terminals can be laid out around a main terminal like the celestial bodies that orbit around a planet, hence the appellation. An LNG satellite facility consists of LNG tank(s) and vaporizer(s), with a land requirement of about 400m^2 which is much smaller than the main LNG terminal. While a secondary terminal for receiving coastal tankers has similar equipment and functions, it tends to be larger in scale and requires a pier facility to berth the coasters.



(Source) Tokyo Gas Engineering （http://www.tge.co.jp/service/lng/satellite/）

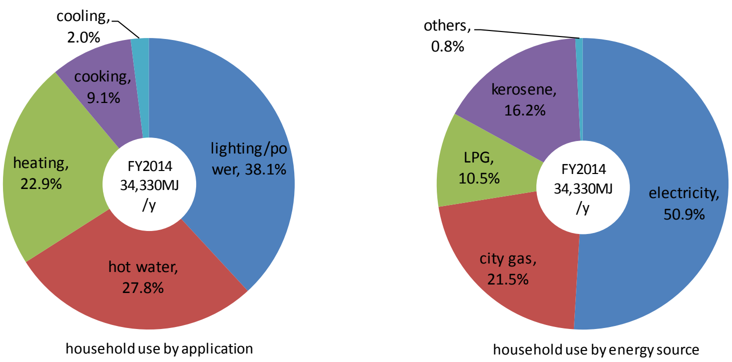
Figure 6.4-2 LNG Satellite Terminal Layout

Table 6.4-1 shows specifications of LNG satellite facility. These facilities are designed for supply of 1,000 - 8,000 tonnes of LNG demand per annum, where 1,000 tonnes of LNG can serve 7,600 households in Japan for one year.

Table 6.4-1 Specification of LNG Satellite Facilities

			Case 1	Case 2	Case 3	Case 4	Case 5
LNG supply capacity		ton/year	8,000	6,000	4,000	2,000	1,000
LNG tank	Capacity	kl/unit	125	100	70	70	40
	Number	Unit	4	3	2	1	1
LNG vaporizer	Capacity	ton/hour	1.2	1.0	0.5	0.3	0.2
	Number	Unit	2	2	2	2	2
Gas pressure		Mpa	0.2-0.15				
Stock amount		day	5.0	5.4	3.8	3.8	4.3
Required land space		m x m	24x17	24x17	18x22	16x16	15x15

(Source) http://www.awi.co.jp/business/energy/equipment/lngsatellite.html



(Source) Whitepaper 2016, METI

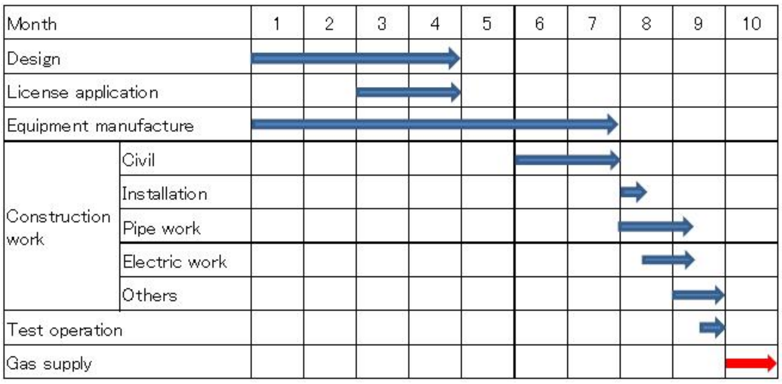
（http://www.enecho.meti.go.jp/about/whitepaper/2016pdf/whitepaper2016pdf_2_1.pdf）

Figure 6.4-3 Energy Consumption in Household in Japan

(2) Construction period

Table 6.4-2 shows a typical construction schedule for an LNG satellite facility. In Japan, it is now possible to construct an LNG satellite facility from designing to handover in just 9 months.

Table 6.4-2 Construction Schedule for LNG Satellite Facility



(Source) http://www.jfe-eng.co.jp/products/energy/energy_plant/ene03.html

(3) Construction cost

Construction cost of an LNG satellite facility depends on capacity and the site condition. Table 6.4-3 shows examples of particulars and cost of two facilities constructed in the past by Japanese engineering companies. Table 6.4-4 shows specification and construction cost of secondary terminal for domestic vessel.

Table 6.4-3 Specification and Construction Cost of LNG Satellite Facilities

			A company	B company
Year of the completion			2002	2015
LNG tank	Capacity	kl/unit	150	100
	Number	Unit	2	2
LNG vaporizer	Capacity	ton/hour	1.0	6.0
	Number	Unit	5	3
Construction cost		1,000US$	4,240	10,833

(Source) JICA Team Research

Table 6.4-4 Specification and Construction Cost of Secondary Terminal for Domestic Vessel

			A company	B company
Year of the completion			2005	2015
LNG tank	Capacity	kl/unit	5,000	12,000
	Number	Unit	1	1
LNG vaporizer	Capacity	ton/hour	2.0	2.85
	Number	Unit	3	6
Construction cost		Million US$	91	50

(Source) JICA Team Research

6.4.2 Transport System to Secondary Terminal

(1) LNG Tank Truck

Figure 6.4-4 shows an LNG tank truck with a 15.1 tonne payload. The LNG tank truck loads LNG at a special loading facility and transports its cargo to remote areas. In Japan, such a tank truck is designed, manufactured, inspected, and maintained under the provisions of the High Pressure Gas Safety Act. The LNG tank trucks are operated by qualified organizations and individuals in accordance with stringent safety rules and regulations. Table 6.4-5 and 6.4-6 show specifications and price of LNG tank trucks. An LNG tank truck costs about US$500,000 and its diesel consumption is around 2.5km/litter. The transportation cost of LNG tank trucks will be estimated by referring to these data including labor cost for the truck driver.

(Source) http://www.tng-gas.co.jp/lng.html

Figure 6.4-4 LNG Tank Truck (15.1 tonne)

Table 6.4-5 Specifications of LNG Tank Truck

Capacity (tonne)	Length (m)	Width (m)	Height (m)	Required Road Width (m)
8.0	11.95	2.49	3.28	6.4
10.5	15.48	2.49	3.44	7.0
14.8	16.48	2.49	3.38	7.5
15.1	16.98	2.49	3.38	7.7
15.7	16.98	2.49	3.39	7.8

(Source) http://www.tng-gas.co.jp/lng.html

Table 6.4-6 Price and Diesel Consumption of LNG Tank Truck

Capacity	tonne	12.3	13.5	13.6
Price	1,000US$	500	650	450
Fuel consumption	km/l	3	2-3	2.35
Year purchased		2006	2012	-
Fuel		Diesel	Diesel	Diesel

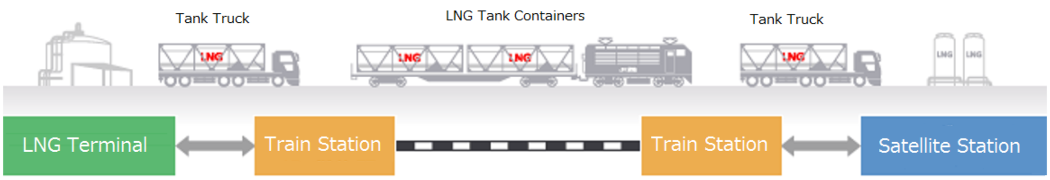
(Source) JICA Team Research

(2) Freight containers (Railway)

In addition to tank trucks, railway containers are an option to transport LNG on land. In this mode of transport, special tank containers as shown in Figure 6.4-5 are used. The LNG containers are first transported by trailers from the base LNG terminal to the originating railway station, and then transferred by rail to the destination station, and again by trailers to the satellite facility near the demand sites (see Figure 6.4-6). If service lines are available both at the base LNG terminal and the satellite facility, LNG can be transported only by rail throughout the route. However, due to high cost of constructing the service line, in the case of Japan, LNG containers are transported by a combination of trailers and railway. For lifting and lowering of LNG containers on and off flat cars at the freight stations, a heavy lift machine called a Trip Lifter as shown in Figure 6.4-7 is used.

(Source) JAPEX

Figure 6.4-5 LNG Tank Containers



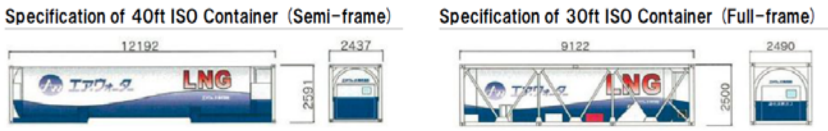
(Source) JAPEX (http://www.japex.co.jp/english/business/japan/lng.html)

Figure 6.4-6 Rail Transportation of LNG

(Source) JAPEX

Figure 6.4-7 Container handling with a Trip Lifter

In Japan, railway transport of LNG using a 30-ft standard freight container[41] was developed and commercialized in 2000 by Japan Petroleum Exploration Company (JAPEX). In this system, two 30-ft containers can be loaded on a flat car. Subsequently in 2002, a system using 40-ft containers with LNG loading capacity of 13.5 tons was developed. Based on a 20-car freight train, this system can haul up to 540 tons of LNG per trip.



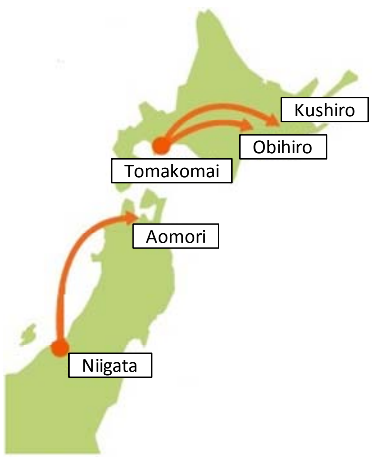
Size	Pressure (bar)	Gross Capacity (lt)	Max. Load (kg)	Max. Gross Weight (kg)
40 ft	6	32,000	13,500	23,500
30 ft	7.5	25,880	10,900	20,000
20 ft	9.3	13,380	5,660	12,630

(Source) Air Water Inc.（http://www.meti.go.jp/meti_lib/report/2015fy/000136.pdf）

http://www.awi.co.jp/english/business/energy/equipment/

Figure 6.4-8 ISO Standards for Rail Containers

Figure 6.4-9 shows case examples of LNG transport by freight containers in Japan, where the distance of rail LNG transportation routes currently in operation in Japan are all exceeding 200km, such as from Niigata to Kanazawa (340km) / Akita (270km) / Aomori (450km), or from Tomakomai to Obihiro (200km) / Kushiro (320km).



(Source) Japan Freight Railway（http://www.jrfreight.co.jp/transport/service/lng.html）

Figure 6.4-9 LNG transport by freight containers in Japan

41 ISO establishes and publishes the standards for external dimensions of the 20-, 30-, and 40-ft type freight containers to be used in intermodal traffic.

Japan Freight Railway Company states that rail LNG transportation is more economical than tank trucks if the distance is greater than 200km, albeit without defining conditions such as quantities or frequencies[42]. Likewise, Ocean Policy Research Foundation (OPRF) reports that rail transport can be competitive in LNG transportation if the distance exceeds 200km. It should be noted here that, although the service range of Japan Freight Railway far exceeds 1,000km, rail LNG transportation extending that far is not practiced due to various constraints such as tight scheduling and the work space availability at freight stations[43].

(3) Coastal vessels

For a consuming region which has a demand size insufficient to justify a direct LNG import from abroad, and yet being handicapped for a transportation arrangement with LNG tank trucks or rail containers due to geographical or other constraints, another option is available in which the imported LNG is transported from the main receiving terminal to a secondary terminal by means of coastal tankers.

While international LNG transportation is conducted by large tankers with capacities ranging 130,000 - 260,000 cubic meters (maximum loadable LNG: 59.000 - 122,000 tons), small coastal tankers with 1,000 - 30,000 cubic meters (5,000 - 14,000 tons) of capacity are available for the domestic seaborne LNG transportation practiced in some consuming countries. In Japan, specially built coastal tankers have been in use to domestically transfer LNG since 2003, and currently six of them with capacity in the range of 2,500 - 3,500 cubic meters (1,100-1,600 tons) are operated for that purpose. Other than Japan, LNG transport by coastal tankers is also practiced in countries such as China or those neighboring Baltic Sea. Particulars of a relatively new coastal LNG tanker, *MS Kakuyu Maru*, are given in Figure 6.4-10.

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42 Japan Freight Railway Company, http://www.jrfreight.co.jp/transport/service/lng.html
43 Ocean Policy Research Foundation, "Study report on developing short distance natural gas transportation system, 2009, https://www.sof.or.jp/jp/report/pdf/201003_ISBN978_4_88404_240_0.pdf

Items	Description
Flag (Home Port)	Japan (Tokyo)
Principal Dimensions	LBP:82.56m×Breadth:15.30m×Depth:7.20m (LOA: 88.80m, Full Draft: 4.30m)
Gross Tonnage	3,031 tons
Deadweight	1,865 tons
LNG Tank Capacity	2,538 m^3
Main Engine	Hanshin LH38L, Low-speed marine diesel, 4-stroke single acting trunk piston type, non-reversible M.C.R: 2,059kW x 240RPM
Sea Speed	13.0Kt
Crew	14
Delivered	October 2013

(Source) K.H.I. (https://www.khi.co.jp/news/detail/20131031_1.html)

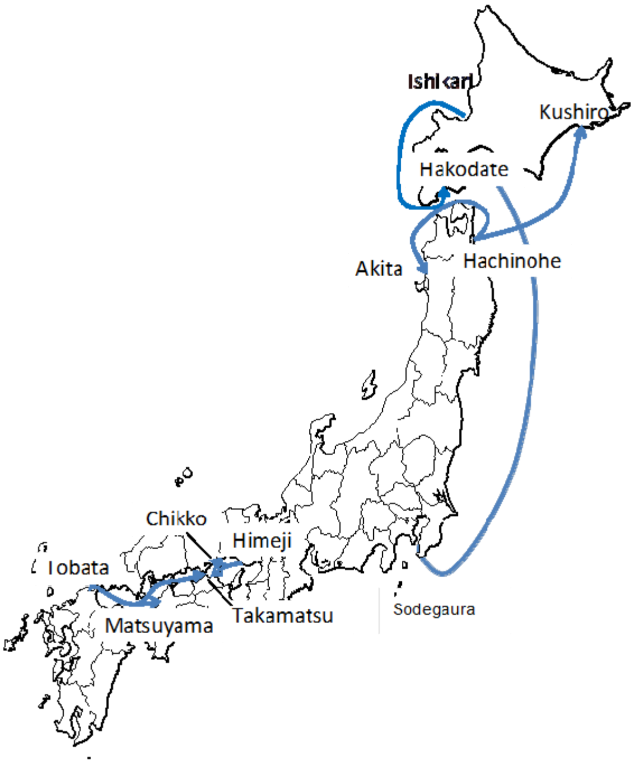
Figure 6.4-10 Ship Particulars "*MS Kakuyu Maru*"

Figure 6.4-11 shows the coastal LNG shipping routes currently in service in Japan. LNG is shipped from primary import terminals in ports such as Ishikari, Hachinohe, Himeji, and Tobata to secondary terminals located in Chikko, Takamatsu, Matsuyama, Kushiro, and Akita. The transportation distance varies significantly from 50 km (Himeji to Chikko) to 850 km (Sodegaura to Hakodate)[44]. Although it is generally understood that the seaborne transport, as with the case of rail container transport, becomes economically feasible for the distance of 200 km or more[45], there is a case where a short trip such as from Himeji to Chikko above could justify the economics.

Note that operation of LNG supply using coastal vessels requires, in addition to the ships themselves, a loading arm for loading coastal tankers at the primary terminal, a secondary terminal (equipped with a berth, an unloading arm, LNG tanks, a regasification unit, etc.), and the further transportation means for LNG or natural gas to be shipped from the secondary base (via tank trucks or pipelines).

44 However, LNG no longer is transported from Sodegaura to Hakodate.

45 Ocean Policy Research Foundation, "Study report on developing short distance natural gas transportation system, 2009, https://www.sof.or.jp/jp/report/pdf/201003_ISBN978_4_88404_240_0.pdf



(Source) Company Websites

Figure 6.4-11 Coastal LNG transportation in Japan

(Source) Tobu Gas（http://www.meti.go.jp/committee/sougouenergy/kihonseisaku/gas_system/pdf/004_05_00.pdf）

Figure 6.4-12 Secondary LNG Terminal in Akita

Table 6.4-7 shows the historical construction cost of large-sized LNG tankers for ocean-going trade with a cargo capacity of 125,000 to 155,000 cubic meters. In some countries LNG is being shipped to local cities using coastal tankers of 2,000 - 3,000 cubic meter size. The cost of such coastal vessels is said to be about 1/10 of large ocean-going vessels shown in the table and, as a means of LNG transport to regions with modest demand, the mode of transport could often be more efficient than pipelines or tank trucks.

Table 6.4-7 Construction Cost of Large LNG Tankers (Oceangoing)

Year	Price ($m)	Year	Price ($m)	Year	Price ($m)
1975	125	1988	175	2001	165
1976	105	1989	220	2002	160
1977	115	1990	260	2003	153
1978	115	1991	280	2004	173
1979	125	1992	270	2005	202
1980	145	1993	250	2006	218
1981	175	1994	240	2007	225
1982	150	1995	250	2008	233
1983	150	1996	220	2009	227
1984	130	1997	230	2010	208
1985	130	1998	190	2011	202
1986	120	1999	165	2012	201
1987	145	2000	150	2013	205

(Source) Drewry, LNG Shipping Market Review and Forecast – 2013/14

Chapter 7 Gas Industry Models and Economics

This chapter summarizes economic assessment of options for natural gas utilisation. Section 7.1 explains the structure of the evaluation model and key assumptions such as the natural gas price as feedstock and business conditions such as taxation in South Africa. Unless ample indigenous gas is available, natural gas needs to be imported. Thus, Section 7.2 explains economics of natural gas import infrastructure such as LNG import terminal and natural gas import pipeline. For the areas remote from the importing point, natural gas must be delivered further by transmission pipeline before delivered to users.

Based on the studies as above, Section 7.3 examines conventional chemical industries to produce ammonia/fertilizer and methanol. Their products may be sold in the domestic market as well as exported, while economics are significantly different between the cases when they are considered for import-substitution and when they are exported. Section 7.4 examines industries to produce liquid fuels such as Gas to Liquid (GTL), DME and methanol to Gasoline (MTG). While GTL plants are being commercially operated in South Africa, economics look severe should they be based upon expensive imported gas. Section 7.5 examines natural gas use as cleaner substitute of other fuels such as coal, oil and biomass, or as more efficient substitute of electricity, in the form of Natural Gas Vehicles (NGV), LNG delivery by truck, and city gas service development.

Imported natural gas would not be cheap. Unless ample indigenous gas are found that could be developed at reasonable cost, natural gas is not a cheap option. Our study shows that the above projects could be pushed forward only when backed by serious political decision under national aspiration.

7.1 Method of Approach and Assumptions

7.1.1 Economic Model for Feasibility Analysis

In this study, business models are built to run feasibility studies on natural gas projects, which are designed to output key indicators relating to project economics under certain conditions and scenarios. These models are constructed by formulating the project parameters into a mathematical system based on the data and information that are publicly available, locally obtained by surveys and interviews, and/or prepared by the JICA study team. Major elements incorporated in the model may be classified into two categories. Those in the first category are general assumptions equally applied to all analyses; which are oil and gas price scenarios and business conditions in South Africa such as tax, duty, fees and other modes of government take, subsidies, loan and interest payments, profit, and so on. Those in the second category are project specific elements such as facility/plant scale, construction time schedule, capital expenditure (CAPEX), operation expenditure (OPEX), production amount, feedgas requirement based on the technical feature of the process, product price, etc.

Given these inputs, the model returns indicators of project economics such as net present value (NPV) and internal rate of return (IRR). To understand the realistic financial arrangement, a loan system to finance investment requirement together with calculation of FIRR (financial internal rate of return) is prepared in the model. Sensitivity analysis is conducted to evaluate the effects of changes in key assumptions and policy selections. The models are also able to examine the impact of various policy options such as changes in taxes, subsidies and price control.

The standard model is constructed on a cash flow chart, based on technical specifications of the project and monetary relationships of elements constituting the project, covering the entire project life from the inauguration through the end of the evaluation period. In this study, project economics are calculated for a 25 year production period, which can be changed with minor modification of the model.

Technical and general economic relationships of the key elements are internally formulated, while scenarios on price outlook and project specifications should be selectively prepared, in particular setting out assumptions on facility/plant size, construction cost and other key factors as explained below.

For easy understanding, operation and modification, this model is developed on a Microsoft Excel spreadsheet. Sensitivity analysis is run using SimpleE modeling software developed by the IEEJ which is compatible with Excel. Case studies are also run changing assumptions for scenario setting.

Major model outputs are as follows:

1) Total amount of revenue, feedstock, tax, profit, etc. (elements incorporated in the CFC) and Net Cash Flow
2) Internal Rate of Return (IRR)
3) Net Present Value (NPV for Project Owner and Government) at a given discount rate
4) Financial Internal Rate of Return (FIRR)
5) Loan repayment schedule and interest payable
6) Debt service ratio
7) Debt/Equity Ratio
8) NPV for Loan Case

The general configuration of the model is as shown in Figure 7.1-1. For operational simplicity to treat different issues separately, the model is developed on four separate worksheets. The worksheet 2 “Cash Flow Chart” is the main engine of the model, where technical and economic relationships of the key elements are formulated and outputs are calculated.

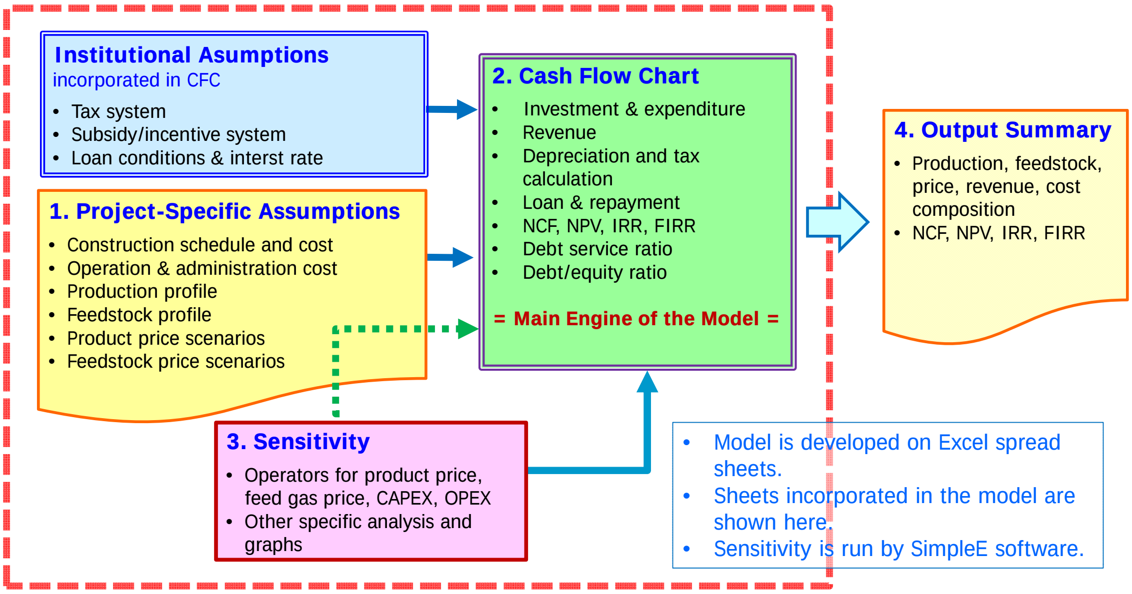


Figure 7.1-1 Model Structure

Assumptions relating to the project specific scenario are developed and worked out on the worksheet “1 Assumption”, such as;

1) Construction and start-up schedule
2) Budget for construction and operation
3) Production profile based on marketing scenario
4) Feedgas profile based on technical relations
5) Price scenarios for products and feedgas

Other assumptions relating to institutional conditions such as taxation and subsidy are given on the worksheet 2 “Cash Flow Chart”:

1) Tax rates: Income Tax, VAT, Excise Tax, Withholding Tax and Tax Holiday
2) Applicable depreciation rate;
   (Straight line method: four (4) years for plants and ten (10) years for pipeline)
3) Discount rate for calculation of NPV is set at 10%
4) Loan ratio and interest rate for FIRR analysis

The model returns all calculation results on the same sheet, and their summary is listed in the “4 Summary” sheet. The worksheet 3 “Sensitivity” includes the system to run sensitivity analysis using modeling software SimpleE altering product price, feedgas price, CAPEX (Capital Expenditure) and OPEX (Operational Expenditure). Other different analyses are mainly controlled by the worksheet 3 “Summary.” To run multiple case studies, the model should be run for multiple times for each case, and outputs should be recorded at each run.

To consider fund requirement and more realistic economics in project investment, FIRR (Financial Internal Rate of Return) calculation incorporating loan arrangement is formulated.

1) Loan

Equity/Loan Ratio is given in the worksheet 2 “Cash Flow” sheet. As the first approach, loan ratio is set at 60% in order to maintain the debt/equity ratio below 2.

2) Interest Rate

As the first approach, interest rate is set at 10%, considering some premium on the prime rate prevailing in South Africa. In case institutional finance were available from international financial institutions such as the World Bank, an interest rate at around 5% with a slight premium on the LIBOR (London Inter-Bank Offered Rate) may be applicable. A realistic interest rate should be considered with in-depth study on the financial conditions available for each project.

It should be noted that healthy project economics is required to qualify for a huge amount of loan.

Policy options can be examined by altering following parameters.

a) Taxation - set on the worksheet 2 “Cash Flow Chart”
   → Income tax, withholding tax, excise tax, and import duty
b) Depreciation rates for calculation of Income Tax
c) Tax holiday years, which also enables calculation of pre-tax economics.

It should be noted that changes in taxation work to improve economics only when project economics is at a healthy level, otherwise tax would not be paid much.

3) Subsidy

Subsidy is not specifically considered in the present model. Subsidy can be considered in two ways:

a) Giving negative numbers for tax rates
b) Changing price profiles giving higher product prices or lower feedstock prices in the worksheet 1 “Assumptions” sheet.

7.1.2 Price Scenarios

In conducting economic evaluation, while it is obvious that the model should accurately formulate relevant factors such as technical characteristics of the individual projects, the tax system and other socio-economic institutions applicable in the host country, the decisive factor above all is how to anticipate the prices of products and the cost of feedstock gas. In this sense, price scenario setting is an important factor that determines the life or death of a project.

a. Natural Gas Price Outlook

Since the summer of 2014, crude oil and natural gas prices have plunged from the historical high triggered by the Shale Revolution in the United States; this progressed at a faster and severer pace than that had been anticipated. As of late June 2016, the Henry Hub based natural gas spot price in the United States was around $2.50/MMBtu, which is substantially lower compared with $8.86/MMBtu for 2008 or $4.37/MMBtu for 2014. It is also noted that in the world LNG market, spot cargoes have showed up with very low prices. Even the Japanese LNG import price dropped from the prolonged high level of $16/MMBtu for 2011-2014 to as low as $7.74/MMBtu in March 2016. Since this import price is an average figure including both long-term as well as spot contracts, this indicates a significant fall in the spot cargo prices that is hovering around $5/MMBtu, much lower than the long-term contact prices.

In the United States, LNG shipment started in February 2016 from the first LNG export plant in Sabine Pass, Texas. This may have worked to relief supply pressure in the US gas market and the Henry Hub price, which recorded as low as $1.50/MMBtu in the middle of March, rebounded to $2.50/MMBtu by June. However, shipment from the Sabine Pass plant reportedly remains low due to slow demand in the global LNG market. While LNG export was expected to provide the world market for the US gas suppliers, US domestic natural gas prices may still remain weak. Elsewhere in the world, large-scale LNG projects are going online in succession particularly in the US and Australia, and the state of LNG oversupply is anticipated to last for years to come.

Meanwhile, Chinese economy is substantially slowing down since 2014 and Brazilian economy to a more serious extent, which had led the economic growth of the world during the past decade. The surprise decision that the UK will leave the European Union or “Brexit” made in June 2016 will add significant uncertainty to the world economy. Together with factors such as the prospect of nuclear power plants in Japan gradually returning to the lineup, the demand trend in natural gas importing countries is anticipated to remain weak.

On the supply side, in the upcoming competition with the U.S.-produced LNG in the European market, which is already slow, Russia will strengthen its natural gas export drive aiming at Asia, likely causing an additional supply pressure in the Asian market. Under these circumstances, slackened supply and demand situation in the world LNG market will last over a considerable period of time, and it appears that the prices will not recover to the level previously anticipated.

In the global gas market, Asia is expected to remain as the main source of new demands. While European market will be able to maintain its advantageous market conditions where it could secure import supplies from an extensive range of sources such as Russia or the U.S., the price gap between the European and the Asian markets will gradually diminish assisted by a number of new LNG projects that are being launched around the world, in particular the Pacific rim region.

Table 7.1-1 Natural Gas Price Scenarios

	Reference Case			Low Case			Domestic Gas	
	Asia	Europe	US	Asia	Europe	US	Starting Price	
	LNG DES	NBP	Henry Hub	LNG DES	NBP	Henry Hub	$4/MMBtu	$3/MMBtu
	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
2016	5.4	4.4	2.0	5.4	4.4	2.0	4.0	3.0
2020	7.5	6.0	3.5	7.0	5.5	3.0	4.3	3.2
2025	8.3	6.8	4.0	7.3	6.0	3.5	4.8	3.6
2030	9.0	7.5	4.5	7.5	6.5	4.0	5.3	4.0
2035	9.5	8.3	5.3	7.8	7.0	4.3	5.8	4.4
2040	10.0	9.0	6.0	8.0	7.5	4.5	6.4	4.8
2045	10.5	9.5	6.5	8.0	7.8	4.8	7.1	5.3
2050	11.0	10.0	7.0	8.0	8.0	5.0	7.8	5.9

(Source) IEEJ Analysis

Based on the above analysis, we set out natural gas price scenarios as follows.

A. Reference Case

1) From the present low level, natural gas prices will rebound to certain level, though not the previously experienced high level, by 2020:

US Henry Hub .... $2.0/MMBtu to $3.5/MMBtu
British National Balancing Point.............................. $4.4/MMBtu to $6.0/MMBtu
Asian JKM LNG Delivered Ex-ship......................... $5.4/MMBtu to $7.5/MMBtu

2) After 2020, gas prices will keep increasing but at a slower speed as ample gas supply will come into the market under the increased prices.

3) Price differences among markets will prevail, but at a much smaller level compared with the Asian Premiums experienced in early years of this decade, being regulated by much easier arbitrage balance among markets after expansion of the Panama Canal in 2016.

B. Low Price Case

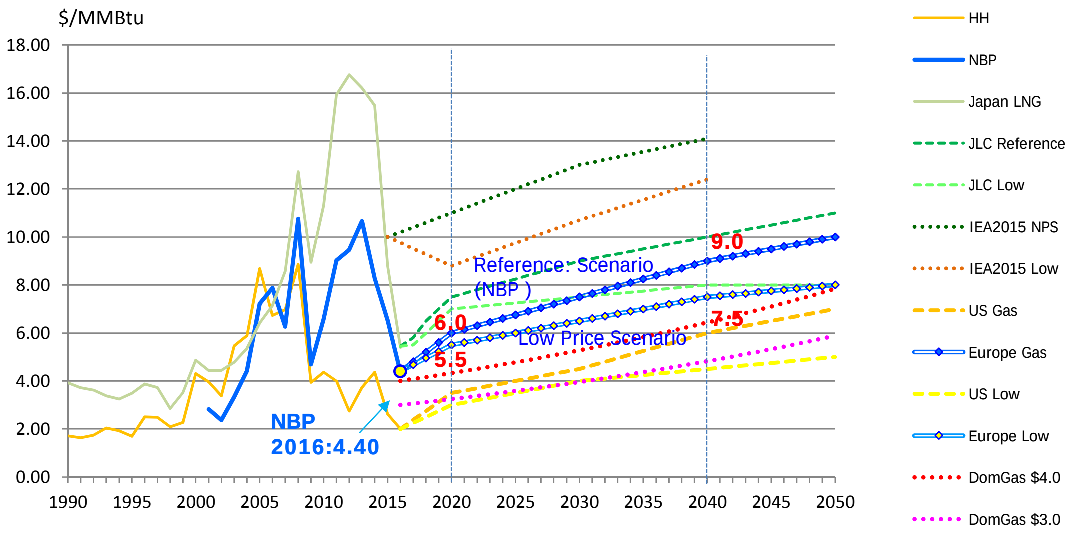
Compared with the Reference Case, much slower increase in the natural gas prices are projected assuming that:

a. Demand for natural gas will grow at a slower pace with slower world economic growth and improving energy efficiency,

b. Supply potential for natural gas will continue to increase with technology progress in conventional, frontier and unconventional gas productions, and

c. Asian Premium will cease to exist reflecting slackened demand /supply balance.

In addition to these scenarios for the global gas market, two price scenarios are set out to consider emergence of domestic gas production. They start from the initial price of $3/MMBtu and $4/MMBtu in 2016 and escalated at an annual rate of 2%. These price scenarios look being on the lower side in view that outlook of domestic gas production is not very bright in South Africa. However, compared with the price projections for the world gas markets as summarized in Table 7.1-1, they are not extremely cheap. Thus, these scenarios may be applicable for examining bonanza cases for South Africa.

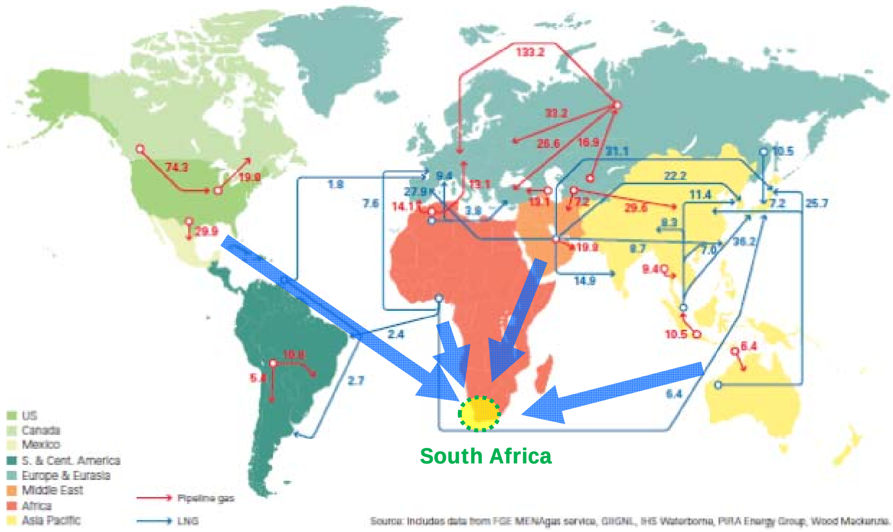


(Source) IEEJ Analysis

Figure 7.1-2 World Natural Gas Price Outlook

For procurement of LNG, South Africa is located in a beneficial position similar to Europe, relatively closer from major LNG suppliers such as the Middle East and the United States. Russia, the biggest gas supplier for Europe, is remote and not a choice for South Africa. Instead, a big LNG player Australia is closer and African suppliers such as Nigeria and Angola are much closer. In future, once LNG projects in the East African countries such as Mozambique and Tanzania come on stream, they are also very close. In view of this beneficial location, we assume that South Africa will be able to procure LNG in the global market at a price, on Delivered Ex-ship basis, similar in the European market, but not at a premium price projected for the Asian market.

Considering the gas cost for domestic use, it is necessary to consider handling charges at the LNG import terminal in addition to the natural gas price to be procured from the international market. For the industries to use natural gas as feedstock, the handling toll at LNG import terminal is assumed at $1.50/MMBtu for 2016 and escalated at annual 2%, as analyzed in Section7.2. It is further assumed that such plant will be built very close to an LNG import terminal and therefore there would be no additional cost for transporting natural gas from the import terminal to the plant.



(Source) BP Statistical Review of World Energy 2016

Figure 7.1-3 World LNG Trade and South Africa

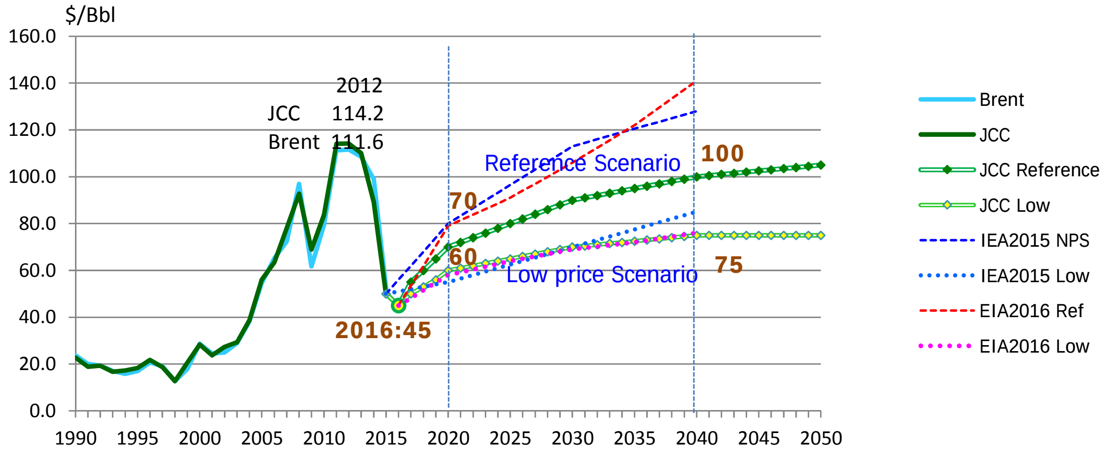
However, in case of gas supply for the general market or CNG for natural gas vehicles, natural gas must be transported to the market via pipeline. If the interior regions such as Gauteng Province are considered as market, gas transportation cost is not cheap. Such costs are also analyzed and discussed in Section7.2.

b. Crude Oil Price Outlook

Crude oil prices have been substantially affected by the Shale Revolution in the United States and, especially after Saudi Arabia declared in autumn 2014 that it would not take measures against the weak market with production cuts, they have fallen sharply from the previous \$100/Bbl levels to as low as \$35/Bbl. Although the prices have bounced back to \$40-50/Bbl in June 2016, the pace of the recovery looks still weak. The number of drilling rigs operating in the United States has dropped to nearly one-third of the peak time and tight oil production trend has turned negative since 2015. The supply pressure caused by the Shale Revolution may be mitigated gradually. However, if crude oil price exceeds certain threshold price, tight oil production may again turn to increase. In addition, the advanced hydrofracking technologies are being applied to conventional oil fields as well, which may lead to increased recovery.

On the demand side, oil consumption generally is sluggish as can be identified by events such as a sign of shadow over China's economy that has so far played a leading role in oil imports, as well as decline in the new car sales in Southeast Asia.

In view of the above described situation, for the purpose of the present evaluation, the Study will adopt a Reference Case, where the crude oil prices are assumed to recover from the current slump to about \$70/Bbl by 2020 and thereafter go up to reach \$100/Bbl in 2040 reflecting steady demand increase in developing countries. In addition, a Low Case is considered, where the crude oil prices will recover to $60/Bbl by 2020 but thereafter will increase very slowly to $75/Bbl in 2040 reflecting slow demand caused by improved energy efficiency and conversion to other fuels such as natural gas, electricity and renewables.



(Source) IEEJ Analysis

Figure 7.1-4 Oil Price Scenarios

While this Study has adopted the forecast as shown in Table 7.1-2 as the Reference Case, where the crude oil prices are assumed to recover to a $100/Bbl level by around 2040, the USEIA 2016 International Energy Outlook assumes much higher price for the Reference Case which may reflect high cost for oil and gas exploration and production, which have kept on soaring under the high oil prices in the past 10 years or so. However, since a fair amount of factors that may dampen the overdriven cost situation can be observed including a sharp decrease in operating rigs in the U.S., or the slowing down of deep-water development in Brazil, it would also be important to carefully watch the trends in the costing situation from now on.

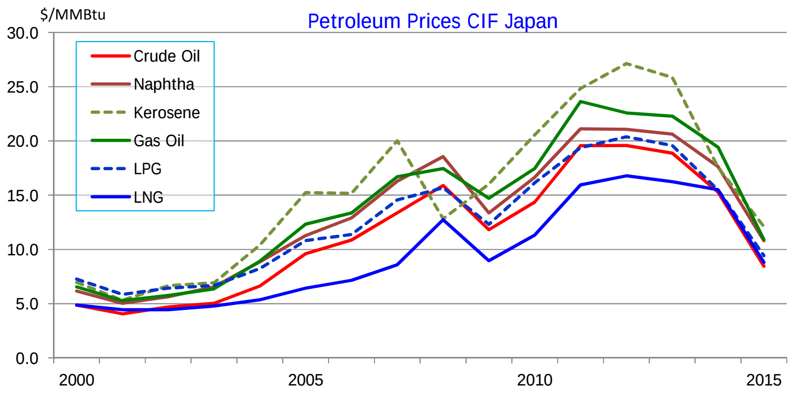
Table 7.1-2 Crude Oil Price Scenarios

	IEEJ 2016		IEA 2015		USEIA 2016	
Case	Ref	Low	NPS	Low Price	Ref	Low
	$/Bbl	$/Bbl	$/Bbl	$/Bbl	$/Bbl	$/Bbl
2012	111				113	113
2014	99		97	97		
2016	45	45				
2020	70	60	80	55	79	58
2030	90	70	113	70	106	69
2040	100	75	128	85	141	76
2050	110	75				

c. Petroleum Products Price Outlook

For economic evaluation of GTL, DME and MTG projects, prices of petroleum product as output are necessary. They are projected in relation to the crude oil price as follows.

For assessing grade differentials among petroleum products in the international market, Japan customs clearance data on prices of imported petroleum products for the past 15 years since 2000 are used as a large and reliable statistics, results of which are given in Figure 7.1-5.



(Source) IEEJ analysis, original data from Japanese Ministry of Finance

Figure 7.1-5 Grade Differentials in Petroleum Products Prices

From the average figures summarized in Table 7.1-3, the value ratios of petroleum products over the crude oil mix are calculated. However, since motor gasoline is scarcely imported into Japan, gasoline price is derived based on market trends (i.e. the gasoline/diesel price ratio) in South Africa, and thus assumed at 150% of crude oil in heat value equivalent. Kerosene may be used as jet fuel after some specification adjustments

Table 7.1-3 Value Ratio of Petroleum Products

	Crude Oil	Gasoline	Naphtha	Kerosene	Gas Oil	LPG	LNG
Japan Import	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
Historical	11.4	N.A.	13.3	15.2	14.0	12.5	9.5
(2000-2015)	100.0%	N.A.	116.2%	133.2%	122.3%	109.1%	83.3%
Import Price	100%	150%	115%	130%	120%	110%	N.A.
Wholesale price (+20%)	(Pivot)	180%	138%	156%	144%	132%	N.A.

(Source) IEEJ analysis

On top of the above calculated import prices linked to the changes in crude oil price, a mark-up of 20% is added as the “handling charge and fair profit” for product importers/marketers. Prices so calculated are applied in this study as the ex-refinery wholesale prices of petroleum products. As these numbers adopted here could be somewhat modest, the pricing structure of petroleum products should be looked into more carefully.

7.1.3 Taxation System

In South Africa, while tax systems such as the following are implemented[46], in the economic evaluation of gas projects under this Study, only the income tax and the withholding tax for dividend remittance are considered:

a) Income tax: 28%;
b) Value Added Tax (VAT): 14%, not considered in the Study;
c) Withholding tax on dividend (=after tax profit) remittance: 15%;
d) Import duty: not considered in the Study;
e) Levies on petroleum products: not considered in the Study;

In South Africa, General Fuel Levy and Road Accident Levy are imposed on petroleum products; General Fuel Levy on petrol at C285/*l*, kerosene and diesel at C270/*l*, and Road Accident fund Levy on petrol or diesel at C154/*l* as of 6 April 2016. However, these levies are not considered in calculation of project economics, as they are neutral on project economics being imposed on top of the wholesale prices irrespective of whether they are produced domestically or imported.

In the current tax systems, depreciation of invested assets is regulated as follows:

a) Manufacturing assets.
   40% of the cost for the first year, and
   20% of the cost for the following three years
b) Pipelines
   10% (10- year straight-line basis) of the cost for 10 years

In South Africa, various incentives for investment are being considered under the concept of Special Economic Zone (SEZ) to promote economic growth and exports through the stimulation of FDI and domestic direct investment in targeted manufacturing and tradeable service industries. The SEZs grew out of South Africa's Industrial Development Zones (IDZs) Programme established in the early 2000s which intended to stimulate foreign direct investment (FDI). These IDZs generated 42 operational investments worth R4 billion. However, in view of its several weaknesses, it was reviewed and the Special Economic Zones Act was promulgated in 2014. Currently, the IDZs under the old IDZ policy are being converted into SEZs. Currently, the IDZs under the old IDZ policy are being converted into SEZs. This process is expected to be completed by 2019. The incentives under the new SEZ Act have not yet been granted to any company.

Under the circumstance, no specific tax incentive is considered in the Reference Case evaluation in this Study. However, the model is prepared with functions to examine effect of tax incentives or subsidy by altering tax rates and effect of tax holidays by altering tax holiday years. This provides the function to calculate pre-tax and post-tax economics of projects. Since

[46] South African Revenue Service (SARS) "Taxation in South Africa 2015/16"

economics of gas projects would not be very optimistic when they are based upon imported natural gas, comparison of pre-tax and post-tax economics will be important to consider if such project could be pushed forward with specific incentives under national aspiration.

7.1.4 Specification of Natural Gas

Specifications of natural gas are necessary to incorporate the technical feature of gas projects into the economic model, which are diverse among LNG sources. As shown in Table 7.1-4, some are methane rich and light, while others contain more of heavier components such as ethane and propane.

Table 7.1-4 Component and Specification of LNG

	N_2	Methane	Ethane	Propane	C4+	Total	LNG Density	Gas Density	Expanshion Ratio	Gas GCV	Wobbe Index
	%	%	%	%	%	%	kg/m^3	kg/m^3	m^3/m^3liq	MJ/m^3	MJ/m^3
Australia NWS	0.04	87.33	8.33	3.33	0.97	100	467.35	0.83	562.46	45.32	56.53
Brunei	0.04	90.12	5.34	3.02	1.48	100	461.63	0.82	564.48	44.68	56.18
Indonesia Badak	0.01	90.14	5.46	2.98	1.40	100	461.07	0.82	564.89	44.63	56.17
Indoneasi Tangguh	0.13	96.91	2.37	0.44	0.15	100	431.22	0.74	581.47	41.00	54.14
Malaysia	0.14	91.69	4.64	2.60	0.93	100	454.19	0.80	569.15	43.67	55.59
Nigeria	0.03	91.70	5.52	2.17	0.58	100	451.66	0.79	571.14	43.41	55.50
Oman	0.20	90.68	5.75	2.12	1.24	100	457.27	0.81	567.76	43.99	55.73
Peru	0.57	89.07	10.26	0.10	0.01	100	451.80	0.79	574.30	42.90	55.00
Qatar	0.27	90.91	6.43	1.66	0.74	100	453.46	0.79	570.68	43.43	55.40
Russia Sakhalin	0.07	92.53	4.47	1.97	0.95	100	450.67	0.79	571.05	43.30	55.43
Trinidad	0.01	96.78	2.78	0.37	0.06	100	431.03	0.74	581.77	41.05	54.23
USA Alaska	0.17	99.71	0.09	0.03	0.01	100	421.39	0.72	585.75	39.91	53.51
Average	0.14	92.30	5.12	1.73	0.71	100	449.40	0.79	572.08	43.11	55.28

(Source) GIIGNL, "The LNG Industry" GIIGNL Annual Report 2016 Edition

Natural gas produced from underground gas fields generally contains some impurities such as N_2 and CO_2 and heavier hydrocarbons such as C4+ and condensate. Contents of them are diverse among gas fields from almost nil to as high as 30% or even higher. However, these impurities are removed and heavier hydrocarbons are separated in the liquefaction process to produce LNG. Thus, the internationally traded LNG contains very little amount of them. The difference of LNG specification is generally defined by the component of methane, ethane and propane.

The average gross calorific value of typical LNGs is about 43 MJ/m^3 or 1150 Btu/cf as summarized in Table 7.1-4. Coal bed methane based LNG like GLNG from Australia is very methane rich. On the other hand, Cheniere Energy recently started LNG production at Sabine Pass, Texas, USA, stipulates in its model LNG Sale Purchase Agreement that the specification of LNG should be with gross calorific value of 1,000 -1150 Btu/cf. From these observations, we assume in this study the gross calorific value of LNG to be imported in South Africa at 43.0 MJ/m^3 and the net gross calorific value at 38.8 MJ/m^3.

The domestic natural gas to be considered for future use is yet to be discovered. Therefore, in this study, we assume the same calorific value for them, which should be corrected if more certain information becomes available. In general, naturally produced gas contains higher impurities and its calorific value will be lower than LNG. However, as far as the natural gas is priced against its calorific value, namely at \$/MMBtu, rather than on volume, namely \$/kcf, differences in gas characteristics would not affect the project economics seriously.

7.2 Natural Gas Import Facilities

For import of natural gas, we need gas transport and handling infrastructure such as pipelines and LNG import terminal. Although it is not the purpose of to this study to peer review options for natural gas import methods, this section will examine such cost as we need to recognize the gas cost for domestic utilisation, which comprises imported natural gas price comprises natural price and handling/transportation cost until the point of gas consumption.

7.2.1 LNG Import Terminal

Traditionally, LNG receiving terminals have been built on shore along the coast. Key components of an LNG terminal are deepwater port (14m+) to receive ocean going LNG carriers, LNG storage tanks and regasification facilities. LNG is unloaded through cryogenic pipeline to storage tanks. Boil-off gas arising from unloading operation is partly returned to the LNG vessel to maintain the pressure balance of both vessel and shore sides. LNG is regasified at the terminal and sent out for consumption.

At present, tanks up to 190,000m^3 are in operation, those up to 230,000m^3 are under construction and those up to 260,000m^3 are under development. Maximum vessel size is 260,000m3 (Q-Max), but the general sizes of vessels widely used for international trade is 120,000 – 180,000m3 with a drought approximately 12m.

Recently, Floating, Storage Regasification Units (FSRU) have been introduced. Many old LNG tankers in the sizes of 120,000-140,000m^3 have been converted to FSRU, while newly built FSRUs are in the size of 170,000m^3. FSRU is moored to a jetty or a buoy in calm water, having storage capacity in the hull and regasification unit on board. Regasified natural gas is supplied via pipeline to users on land. As explained in Chapter 6, an FSRU may be built in three (3) years much faster than an onshore LNG terminal which may need six (6) years to complete. Once its role is over at a location, FSRU can be moved to other location. Its operation will be constrained by sea conditions, and capacity ramp-up is difficult.

a. Onshore LNG Terminal

For the purpose of this study, we assume the outline of an onshore LNG terminal as follows:

a. Total handling capacity: 2.5 million tonnes a year
b. Storage Tank: 180,000m3 x2
c. Construction cost: EPC cost at \$1.0 billion plus project management cost
d. Annual operation cost: Initial CAPEX x 3%

e. Construction Period: four (4) years to commercial operation and two (2) more years to complete.

f. Operation build-up: Year-1 starts at 30%, Year-3 rises to 60% and Year-5 reach 100%

We further assume that FID for construction of the LNG terminal will be made in 2016 and construction starts in 2017. Suppose that three units of gas thermal plant start up with a two year interval, operation of the terminal builds up starting from 30% of the capacity, rising to 60% in the third year and reaching 100% in the fifth year. Natural gas for outlets other than power generation will increase, though a small quantity, in the later part of the operation build-up period. The schedule of investment operation is as assumed as shown in Table 7.2-1.

Table 7.2-1 Construction Schedule and Investment Amount of Onshore LNG Terminal

	Year 1-5	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Project Owner	$ million	$ million	$ million	$ million	$ million	$ million	$ million	$ million	$ million	$ million	$ million
Project Management Cost	80	0	20	20	20	20	0	20			
Construction Cost (=Total EPC Cost)	1,000	0	100	250	250	200	0	200			
Operating Cost	0	0	0	0	0	0	24	24	30	30	30
Administration Cost	4	0	1	1	1	1	2	2	2	2	2
Total	1,104	0	121	271	271	221	0	220	32	32	32
Operation Profile (Build-up)							30%	30%	60%	70%	100%
							kt	kt	kt	kt	kt
Annual Throughput							750	750	1,500	1,750	2,500

In view that natural gas handling facilities such as pipelines and LNG terminals do not accompany high business risks such as those incurred in oil and gas exploration activities and that they serve as a part of social infrastructure, we apply in this Study a 10% IRR as target feasibility criteria. Altering the initial handling toll with annual 2% escalation, the initial toll to give a 10% IRR under the existing tax resume was searched. The answer was $1.24/MMBtu, or $1.68/MMBtu as an average for the whole project life of 25 years. This being the base case, several case studies are run altering tax holiday years and the interest rates for the loan as shown in Table 7.2-2.

Table 7.2-2 Case Studies on Onshore LNG Terminal

		Base Case		10 yrs Tax Holiday		5% interest		Pre-tax @2%		Pre-tax no esc.	
Initial Toll		**1.24**	**$/MMBtu**	**1.19**	**$/MMBtu**	**1.19**	**$/MMBtu**	**1.00**	**$/MMBtu**	**1.21**	**$/MMBtu**
Average Toll		1.68	$/MMBtu	1.61	$/MMBtu	1.61	$/MMBtu	1.35	$/MMBtu	1.21	$/MMBtu
Tax holiday		0	yrs	10	yrs	10	yrs	25	yrs	25	yrs
Annual Escalation		2%		2%		2%		2%		0%	
Interesr Rate		10%		10%		5%		5%		5%	
Production											
Annual Production Capacit	MTPA	2.5		2.5		2.5		2.5		2.5	
Total Production (25 years	Million tonr	57.3		57.3		57.3		57.3		57.3	
Economics of LNG Terminal											
Revenue (25 years)	$ million	5,965	100%	5,715	100%	5,715	100%	4,816	100%	4,442	100%
CAPEX	$ million	1,104	19%	1,104	19%	1,104	19%	1,104	23%	1,104	25%
OPEX	$ million	650	11%	650	11%	650	11%	650	13%	650	15%
Direct Tax	$ million	1,634	27%	1,413	25%	1,413	25%	0	0%	0	0%
Profit after tax	$ million	2,577	43%	2,548	45%	2,548	45%	3,062	64%	2,688	61%
Net Cash Flow	$ million	**2,577**		**2,548**		**2,548**		**3,062**		**2,688**	
Net Present Value	$ million	**0**		**1**		**1**		**0**		**1**	
IRR		**10.0%**		**10.0%**		**10.0%**		**10.0%**		**10.0%**	
FIRR		**10.4%**		**10.4%**		**13.2%**		**12.8%**		**13.1%**	
Revenue/CAPEX Ratio		5.4		5.2		5.2		4.4		4.0	
NPV/Investment Ratio		0.0%		0.0%		0.0%		0.0%		0.1%	
Government Revenue											
Total Government Reve	$ million	**1,634**		**1,413**		**1,413**		**0**		**0**	
NPV	$ million	**211**		**165**		**165**		**0**		**0**	
Government's Profit Share (Gross)		38.8%		35.7%		35.7%		0.0%		0.0%	

Relaxing taxation with a 10 year tax holiday, economics will be significantly improved and the toll to bring a 10% IRR decreases to $1.19/MMBtu. In this case, if a loan for the construction fund is obtained at a lower interest rate, the FIRR of the project player goes up from 10.5% to 13.3%. Then, pre-tax economics is examined assuming a tax holiday for the whole project life of 25 years. In this case, the 10% IRR toll is $1.00/MMBtu with an annual 2% escalation or $1.21/MMBtu without escalation. This means that there are wide range of political options to support materialization of LNG import terminal.

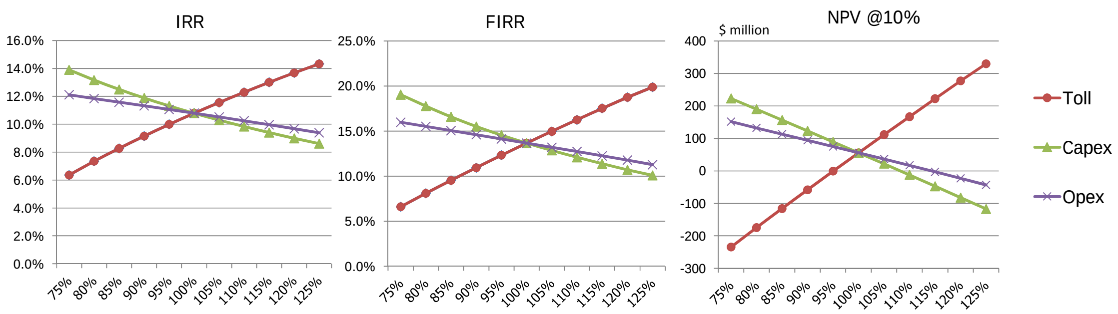


Figure 7.2-1 Sensitivity Analysis on Onshore LNG Terminal

Outcome of the sensitivity study on changes in CAPEX, OPEX and Toll is as shown in Figure 7.2-1. Changes in CAPEX and toll show almost similar trends while in opposite directions. If the CAPEX is decreased by 10%, the target toll decreases by 8.8%.

With the above observation, we apply in this study a LNG terminal toll of $1.40 as a first approach. However, setting out the applicable toll, we should carefully look into effects of changes in CAPEX and policy considerations such as tax exemption.

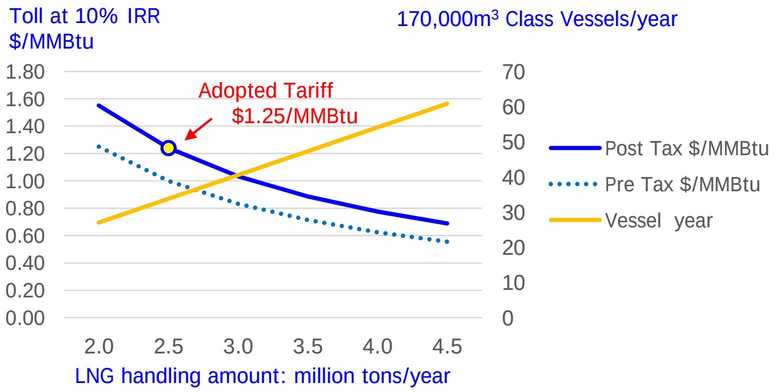


Figure 7.2-2 LNG Terminal Toll Changes with Handling Quantity

It should also be noted that the required toll changes according to handling amount of LNG as shown in Figure 7.2-2. Here we assume 2.5 million tons as the annual handling amount in consideration of demand in adjacent area of the candidate LNG terminal. When the handling amount increases in future, the toll may be reduced, accordingly.

b. FSRU

In this Study, we assume new building of a Floating Storage Regasification Unit (FSRU) rather than conversion of a secondhand LNG tanker. It will be a 170,000m3 FSRU, a regular size among recent new FSRUs.[47] Outline of the project is as follows:

a. Total handling capacity: 1.5 million tonnes a year
b. Storage Tank Capacity: 170,000m^3
c. Construction cost: $300 million for FSRU and $100 million for jetty, plus project management cost
d. Annual operation cost: Initial CAPEX x 5%
e. Construction Period: four (3) years to commercial operation.
f. Operation build-up: Year-1 starts at 30%, Year-3 rises to 60% and Year-5 reach 100%

The relationship of the storage capacity and annual maximum handling amount is calculated as follows:

a. Storage capacity: 170,000m^3 (73,950tonnes, SG=0.435)
b. Cargo size (storage capacity x 80%): 136,000m3 (59,160 tonnes)
c. Number of cargoes per annum: 25
d. Annual handling amount: 3,400,000m3 (1,479,000 tonnes)
e. Average daily amount: 9,315m3 (4,052 tonnes)

[47] Seven FSRUs delivered worldwide in 2014 and 2015 were all in this size, according to IGU World Gas LNG Report - 2016 edition.

f. Maximum stock at the time of receiving: 3.7 days

The above assumes that the FSRU receives two cargoes a month with storage at hand for 3.7 days. As unloading operation generally takes one day (24 hours), operating margin is very tight. If smaller vessels are used with greater frequency, this margin may be relaxed. However, most of LNG tankers being built in recent years are in the sizes of 140,000 – 170,000m^3, it is increasingly difficult to find just-size vessels for the FSRU as assumed above. Then, larger vessels may be used with 75-80% laden.

We further assume that FID for construction of the LNG terminal will be made in 2017 and construction starts in 2018. Suppose that three units of 500MW class gas thermal plant start up with a two year interval, operation of the terminal builds up starting from 30% of the capacity, rising to 60% in the third year and reaching 100% in the fifth year. Natural gas for outlets other than power generation will increase, though a small quantity, in the later part of the operation build-up period. However, FSRU may have a limited capacity to accommodate such additional requirements. The schedule of investment operation is as assumed as shown in Table 7.2-3:

Table 7.2-3 Construction Schedule and Investment Amount of FSRU

	Year 1-5	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Project Owner	$ million	$ million	$ million	$ million	$ million	$ million	$ million	$ million	$ million	$ million	$ million
Project Management Cost	30	0	0	10	10	10	0	0			
Construction Cost (=Total EPC Cost)	400	0	0	150	150	100	0	0			
Operating Cost	0	0	0	0	0	0	20	20	20	20	20
Administration Cost	3	0	0	1	1	1	2	2	2	2	2
Total	433	0	0	161	161	111	22	22	22	22	22
Operation Profile (Build-up)							30%	30%	60%	70%	100%
							kt	kt	kt	kt	kt
Annual Throughput							450	450	900	1,050	1,500

Under the above assumptions, the toll to give a 10% IRR under the existing tax resume is calculated to be initial \$0.97/MMBtu with 2% annual escalation, or \$1.31/MMBtu as an average for the whole project life of 25 years. This being the base case, several case studies are run altering tax holiday years and the interest rate for the loan as shown in Table 7.2-4. With a 10 year tax holiday, the initial toll will be lowered to \$0.93/MMBtu and the Pre-tax toll is at \$.80/MMBtu. The total revenue for 25 years for the Base case is \$3,172 million, which translates to be approximately \$350,000 per day. This may be compared to the current market rate for the same size LNG vessels, which is in the range of \$150,000 - 200,000. FSRU may be leased at such rate as well for certain period as a solution for early operation before a solid onshore facility will be completed.

Table 7.2-4 Case Studies on FSRU

		Base Case		10 yrs Tax Holiday		5% interest		Pre-tax @2%		Pre-tax no esc.	
Initial Toll		0.97	$/MMBtu	0.93	$/MMBtu	0.93	$/MMBtu	0.80	$/MMBtu	0.96	$/MMBtu
Average Toll		1.31	$/MMBtu	1.26	$/MMBtu	1.26	$/MMBtu	1.08	$/MMBtu	0.96	$/MMBtu
Tax holiday		0	yrs	10	yrs	10	yrs	25	yrs	25	yrs
Annual Escalation		2%		2%		2%		2%		0%	
Interesr Rate		10%		10%		5%		5%		5%	
Production											
Annual Production Capacit	MTPA	1.5		1.5		1.5		1.5		1.5	
Total Production (25 years	Million tonr	34.4		34.4		34.4		34.4		34.4	
Economics of LNG Terminal											
Revenue (25 years)	$ million	2,803	100%	2,691	100%	2,691	100%	2,307	100%	2,126	100%
CAPEX	$ million	433	15%	433	16%	433	16%	433	19%	433	20%
OPEX	$ million	550	20%	550	20%	550	20%	550	24%	550	26%
Direct Tax	$ million	706	25%	608	23%	608	23%	0	0%	0	0%
Profit after tax	$ million	1,114	40%	1,099	41%	1,099	41%	1,324	57%	1,143	54%
Net Cash Flow	$ million	**1,114**		**1,099**		**1,099**		**1,324**		**1,143**	
Net Present Value	$ million	**0**		**0**		**0**		**0**		**0**	
IRR		**10.0%**		**10.0%**		**10.0%**		**10.0%**		**10.0%**	
FIRR		**9.2%**		**9.2%**		**11.8%**		**11.6%**		**11.8%**	
Revenue/CAPEX Ratio		6.5		6.2		6.2		5.3		4.9	
NPV/Investment Ratio		0.1%		0.0%		0.0%		0.1%		0.1%	
Government Revenue											
Total Government Reve	$ million	**706**		**608**		**608**		**0**		**0**	
NPV	$ million	**91**		**71**		**71**		**0**		**0**	
Government's Profit Share (Gross)		38.8%		35.6%		35.6%		0.0%		0.0%	

The sensitivity study as illustrated in Figure 7.2-3 shows fairly similar trends with an onshore LNG terminal.

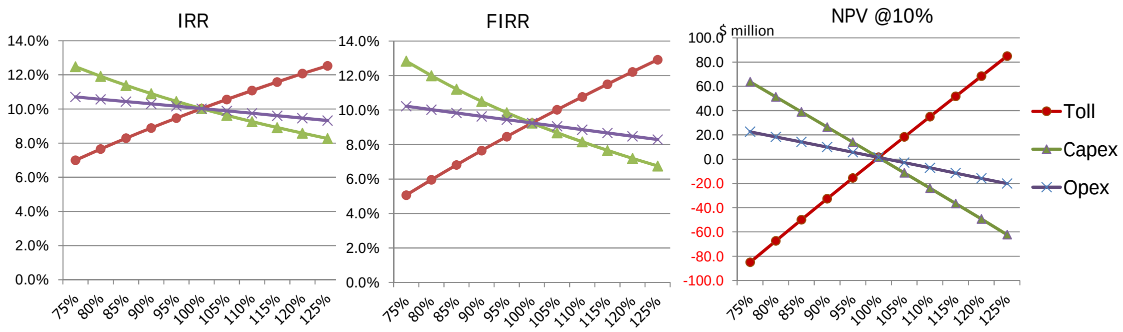


Figure 7.2-3 Sensitivity Analysis on FSRU

c. FSRU + Onshore Storage Tank

As calculated above, the LNG handling cost is much cheaper for the FSRU case compared with the Onshore LNG Terminal case reflecting the shorter construction period and smaller capital expenditure. However, if a FSRU alone were considered, operation becomes increasingly tighter as LNG import expands while flexibility is limited for tanker selection and future capacity expansion. In view that LNG must be received stably to assure gas supply for the downstream users, it should be carefully looked into if the FSRU case assumed above is a preferable permanent option for South Africa.

In this regard, this section examines a case where one 170,000m^3 onshore storage tank is added to the FSRU case before the FSRU operation reaches 100% utilization. This will substantially ease the terminal operation as well as tanker chartering while cargo size can be increased from 138,000m^3 to more popular 170,000m^3. Outline of the project will change to:

a. Total handling capacity: 1.5 million tonnes ++
b. Storage Tank Capacity: 170,000m^3 x 2 (FSRU + one onshore tank)
c. Construction cost: $600 million comprising $300 million for FSRU, $100 million for jetty and $200 million for onshore tank and related facilities.
d. Annual operation cost: Initial CAPEX x 5%
e. Construction Period: three (3) years before operation plus two (2) years for onshore facility
f. Operation build-up: in Year-1 operation starts at 30%, in Year-3 rises to 60% and in Year-5 reaches 100% as power plants are built stepwise.

Construction schedule and investment amount are assumed for this case as shown in Table 7.2-5, where the onshore tank is constructed during the year-6 and year-7 of the project and the demand builds up to 100% in year-10.

Table 7.2-5 Schedule for Investment: FSRU + One Onshore Tank

	Year 1-5	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Project Owner	$ million	$ million	$ million	$ million	$ million	$ million	$ million	$ million	$ million	$ million	$ million
Project Management Cost	30	0	0	10	10	10	0	0			
Construction Cost (=Total EPC Cost)	600	0	0	150	150	100	100	100			
Operating Cost	0	0	0	0	0	0	20	25	30	30	30
Administration Cost	3	0	0	1	1	1	2	2	2	2	2
Total	633	0	0	161	161	111	100	100	0	0	0
Operation Profile (Build-up)							30%	30%	60%	70%	100%
							kt	kt	kt	kt	kt
Annual Throughput							525	525	1,050	1,225	1,750

In this case, the toll to give a 10% IRR when handling 1.5 million tonnes per year of LNG will be $1.22/MMBtu with 2% annual escalation, or $1.65/MMBtu as an average for the whole project life as shown below. The outcome is similar to that for the onshore terminal case shown in Table 7.2-2. Sensitivity analysis on this case is as shown in Figure 7.2-4.

Table 7.2-6 Case Studies on FSRU + One Onshore Tank Case

		Base Case		10 yrs Tax Holiday		5% interest		Pre-tax @2%		Pre-tax no esc.	
Initial Toll		**1.22**	**$/MMBtu**	**1.18**	**$/MMBtu**	**1.18**	**$/MMBtu**	**1.00**	**$/MMBtu**	**1.21**	**$/MMBtu**
Average Toll		1.65	$/MMBtu	1.60	$/MMBtu	1.60	$/MMBtu	1.36	$/MMBtu	1.21	$/MMBtu
Tax holiday		0	yrs	10	yrs	10	yrs	25	yrs	25	yrs
Annual Escalation		2%		2%		2%		2%		0%	
Interesr Rate		10%		10%		5%		5%		5%	
Production											
Annual Production Capacity	MTPA	1.5		1.5		1.5		1.5		1.5	
Total Production (25 years)	Million tonne	34.4		34.4		34.4		34.4		34.4	
Economics of LNG Terminal											
Revenue (25 years)	$ million	3,518	100%	3,403	100%	3,403	100%	2,892	100%	2,667	100%
CAPEX	$ million	633	18%	633	19%	633	19%	633	22%	633	24%
OPEX	$ million	550	16%	550	16%	550	16%	550	19%	550	21%
Direct Tax	$ million	906	26%	803	24%	803	24%	0	0%	0	0%
Profit after tax	$ million	1,429	41%	1,416	42%	1,416	42%	1,709	59%	1,484	56%
Net Cash Flow	$ million	**1,429**		**1,416**		**1,416**		**1,709**		**1,484**	
Net Present Value	$ million	**0**		**1**		**1**		**0**		**0**	
IRR		**10.0%**		**10.0%**		**10.0%**		**10.0%**		**10.0%**	
FIRR		**11.5%**		**11.5%**		**14.1%**		**13.5%**		**13.9%**	
Revenue/CAPEX Ratio		5.6		5.4		5.4		4.6		4.2	
NPV/Investment Ratio		0.1%		0.1%		0.1%		0.1%		0.1%	
Government Revenue											
Total Government Revenue	$ million	**906**		**803**		**803**		**0**		**0**	
NPV	$ million	**115**		**94**		**94**		**0**		**0**	
Government's Profit Share (Gross)		38.8%		36.2%		36.2%		0.0%		0.0%	

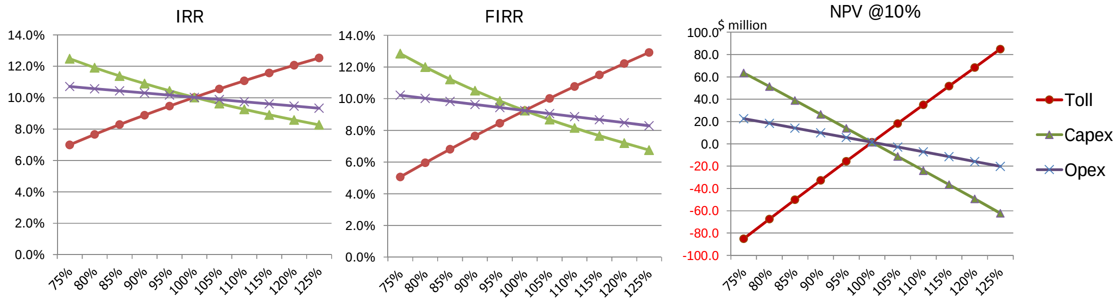


Figure 7.2-4 Sensitivity Analysis on “FSRU + One” Case

d. Summary

The above three cases are compared in Table 7.2-7, where the post-tax LNG terminal toll at IRR-10%, maximum stock days just before receiving a new cargo, and the number of vessels received monthly and annually are shown in accordance with changes in annual handling amount of LNG. Cargo sizes are assumed at 136,000m^3 for the FSRU case and 170,000m^3 for other cases.

Table 7.2-7 Comparison of Three Cases

Annual Amount	Post Tax Toll				Stock Days		Vessels (Monthly)		Vessels (Annually)	
	FSRU	FSRU+One	Onshore x2	CAPEX 70%	FSRU	FSRU +One	FSRU	FSRU+One	FSRU	FSRU +One
MTPA	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	Days	Days	Vessels	Vessels	Vessels	Vessels
0.50	2.91				10.8		0.7		8.5	
0.75	1.95				7.2		1.1		12.7	
1.00	1.46	1.83	3.10	2.30	5.4	27.0	1.4	1.1	16.9	13.5
1.25	1.17	1.46	2.48	1.84	4.3	21.6	1.8	1.4	21.1	16.9
1.50	0.97	1.22	2.07	1.53	3.6	18.0	2.1	1.7	25.4	20.3
1.75	0.83	1.05	1.77	1.31	3.1	15.4	2.5	2.0	29.6	23.7
2.00	0.73	0.92	1.55	1.15	2.7	13.5	2.8	2.3	33.8	27.1
2.25		0.81	1.38	1.02		12.0		2.5		30.4
2.50		0.73	1.24	0.92		10.8		2.8		33.8
2.75		0.67	1.13	0.84		9.8		3.1		37.2
3.00		0.61	1.03	0.77		9.0		3.4		40.6

(Note) Stock days and number of received vessels are same for the "FSRU+One onshore storage tank" case and the "Onshore with 2 strorage tanks" case as their total storage capacities are same.

At a glance, the FSRU option looks cheapest. However, the calculated maximum stock at hand just before receiving a new cargo is less than seven (7) days when the annual handling amount exceeds 750,000 tonnes. Receiving 1.5 million tonnes, it goes down to as low as 3.6 days. In general oil and gas import operation, a comfortable running stock may be around two weeks and the minimum running stock may be one week. From this experimental rule, it is extremely difficult to stably handle more than 750,000 tonnes of LNG a year with a FSRU alone. In addition, tanker chartering for the FSRU alone case may encounter many difficulties as 136,000m^3 class vessels are old type and phasing out of the market, while a part cargo transport by larger vessels for a long distance is technically not recommendable due to sloshing problem. Because of the small stock at hand, demurrage would be incurred regularly.

In other cases, more than 2.5 million tonnes of LNG a year may be stably handled. However, unit handling costs are higher when the handling amount is small. In addition, the post-tax tolls calculated for these cases are significantly different, which reflects differences in assumed CAPEX for these cases; $1,156 million for the “Onshore Terminal Case” with two storage tanks and $633 million for the “FSRU + One Onshore Tank” case. While the LNG receiving terminal cost study was not in the initial scope of this study, these numbers are prepared information from market and hearing. As a reference, revised tolls are calculated in the same table where CAPEX for the Onshore Terminal case is reduced to 70% of the original projection. Then, differences among cases become much smaller. To narrow down these gaps in cost estimation further, more precise study is necessary.

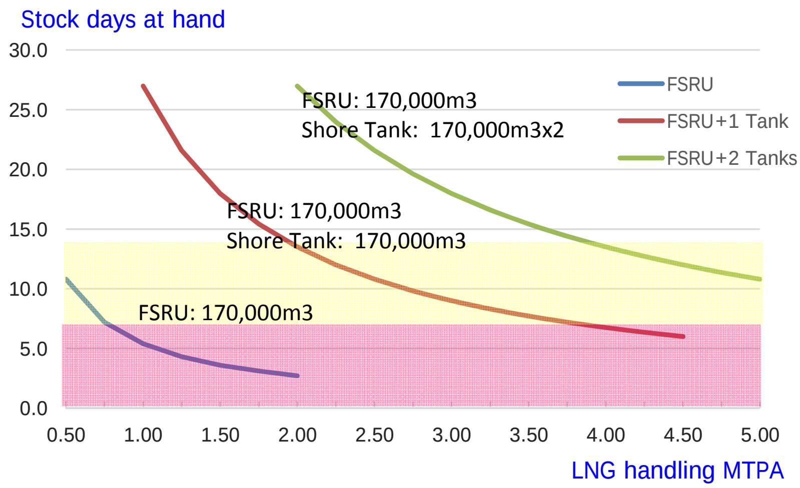


Figure 7.2-5 Maximum Stock Days at hand when a New Cargo Arrives

To consider the supply security issue, Figure 7.2-5 shows calculation of the stock days at hand before arrival of a new cargo. The stock at hand goes down less than one week for the FSRU alone case when the handling amount of LNG exceeds 750,000 tonnes a year. If one onshore tank is added, the threshold goes up to 3.75 MTPA. If two onshore tanks are added, the stock days at hand remain higher than 10 days even handling 5 MTPA of LNG. In general international shipping operation, delays of one week or so in vessel operation are often experienced due to disturbance in the previous voyage, rough weather, etc. As South Africa is isolated from other LNG markets, international LNG shipping routes or most of LNG supply points, it would be difficult to find help in case vessel operation encounters any problem. In this regard, a proper amount of stock at hand must be considered to assure stable supply of natural gas with LNG import.

7.2.2 Long Distance Pipeline from the Ruvuma Basin of Mozambique

South Africa is presently importing natural gas from Mozambique via international pipeline. The pipeline extends for 865km from Pande and Temane gas fields located in onshore blocks about 500km northeast of Maputo to Secunda, an industrial city east of Johannesburg, in South Africa. Natural gas is mainly used at the Gas to Liquid (GTL) plant of SASOL, while a limited amount is sold to adjacent industrial factories and other facilities. Certain amount of gas is used within Mozambique as well. Proactive exploration activities are under way around the existing gas fields. Once additional reserves are confirmed, as well as effective demand, more natural gas may be imported to South Africa, while expansion of the existing facility or construction of additional pipeline may be required then. Economics of such expansion may be reasonably established as an extension of the existing business.

In addition, a huge amount of natural gas has been discovered in the Ruvuma basin offshore Mozambique and Tanzania. They are located in very deep water ranging for 1,000 – 2,000m, while relatively near from the shore in 50 - 100km distances. Presently recognized natural gas resources in this area are reported to be approximately 100Tcf in Mozambique and 50 Tcf in Tanzania.[48] They are considered for export as LNG or supply for local gas industries to be developed in the future. The first batch of LNG projects is already underway in Mozambique.

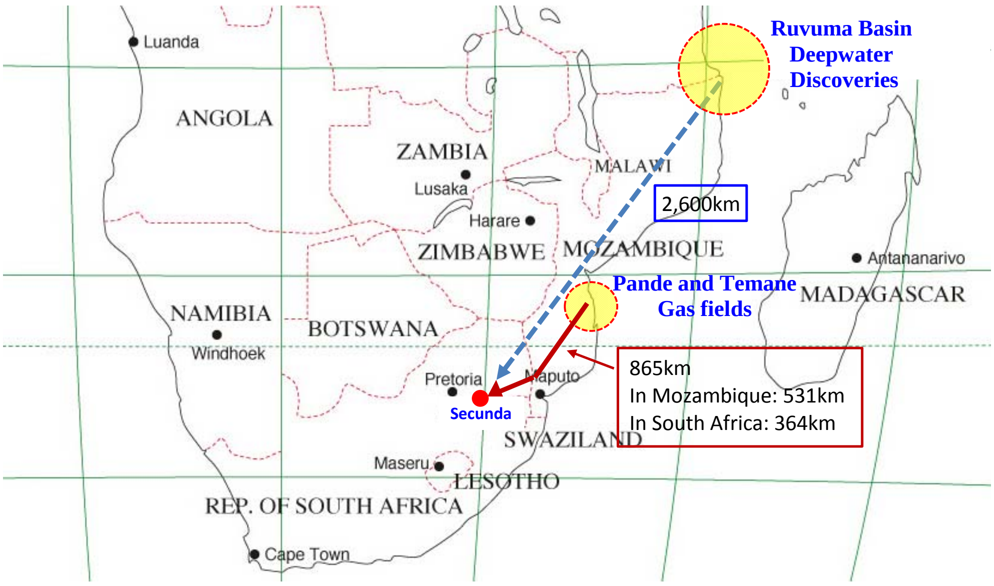


Figure 7.2-6 International Gas Pipeline from Mozambique

Natural gas import from the Ruvuma basin is being considered in South Africa. In view of the huge resource base, it looks a natural consequence while it is located very far from the demand centre in South Africa. The present conceptual plan is to construct an international pipeline extending for 2,600km at a cost of $6.0 billion.[49] In order to justify a huge amount of investment, the pipeline must carry a huge amount of natural gas to secure sufficient revenue. In

[48] IEEJ "The Study for Review of Natural Gas Utilization Master Plan", being drafted in June 2016 under a JICA project, The Oxford Institute for energy Studies, "East Africa Gas – Potential for Export", March 2013, and other various sources.

[49] Hearing from SASOL in May 2016, and other sources such as Visiongain, "Onshore Oil & Gas Pipelines Market Report 2015-2025.

this Study, outline of the pipeline is assumed as below.

a. Pipeline Capacity: 36” pipeline with a maximum capacity to transport 700 MMcfd, which is 255Bcf a year or 5.4 million tons LNG equivalent a year. If demand increases later, this could be expanded installing booster stations along the pipeline.
b. Average load on pipeline: 80%
Annual throughput: 204 Bcf per year (4.2 million tonnes LNG equivalent)
c. Construction cost: EPC cost at $6.0 billion plus project management cost
d. Construction Period: four (4) years to commercial operation
e. Annual operation cost: Initial CAPEX x 2%
f. Operation build-up: Year-1 starts at 50%, Year-3 rises to 70% and Year-7 reaches 100%

Because of the long distance between the gas fields and the demand centre, a big size pipeline is assumed for construction so that it can accommodate future demand growth. For example, a same size pipeline extending for 534km was constructed in Tanzania, completed in August 2015, which can accommodate 750 MMcfd of natural gas although initial demand may be less than 200 MMcfd.

The pipeline capacity may be shared between Mozambique and South Africa to supply respective demands.

Table 7.2-8 Construction Schedule and Investment Amount of Mozambique to South Africa Pipeline

		Year 1-4	Year 1 2021	Year 2 2022	Year 3 2023	Year 4 2024	Year 5 2025	Year 6 2026	Year 7 2027	Year 8 2028	Year 9 2029	Year 10 2030	Year 11 2031
Project Owner	$ million												
Project Management Cost		80	20	20	20	20							
Construction Cost (=Total EPC)		6,000	1,500	1,500	1,500	1,500							
Operating Cost		0					120	120	120	120	120	120	120
Administration Cost		4	1.0	1.0	1.0	1.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Total		6,084	1,521	1,521	1,521	1,521	122	122	122	122	122	122	122
Pipeline Capacity at 80% load													
Daily	MMcfd						560	560	560	560	560	560	560
Annual	Bcf						204	204	204	204	204	204	204
Operation Profile	%						50%	50%	70%	70%	80%	90%	100%
Annual Throughput	Bcf						102	102	143	143	164	184	204
(LNG equivalent)	kt						2,116	2,116	2,963	2,963	3,386	3,809	4,233

Likewise the LNG terminal, target pipeline tariffs are calculated for the IRR of 10% and 8%. For the Base case where the general tax scheme in South Africa is applied, the initial tariff with annual 2% escalation to give 10% IRR is calculated to be $5.07/MMBtu. Because of the long distance and the required huge investment, it is significantly expensive and would be close to the cost of LNG import.

However, if a 10 year tax holiday is introduced, this will be reduced to $4.81/MMBtu. Further, in view that the pipeline is supposed to serve as infrastructure to promote gas utilisation, if the target IRR is lowered to 8%, the initial tariff will be lowered to $4.00/MMBtu. In this case, if supportive low interest loan is available, FIRR for the project promoter will be improved from

6.2% to 9.2%. The pre-tax initial tariff will be $4.06/MMBtu for a 10% IRR and as low as $3.33/MMBtu for an 8% IRR.

Table 7.2-9 Economics of Long Distance Pipeline from Mozambique

		Base Case		10 year Tax holiday		IRR=8%		Interest @5%		Pre-Tax @10%		Pre-Tax @8%	
Initial Toll		5.07	$/MMBtu	4.81	$/MMBtu	4.03	$/MMBtu	4.03	$/MMBtu	4.06	$/MMBtu	3.33	$/MMBtu
Average Toll		6.57	$/MMBtu	6.22	$/MMBtu	5.21	$/MMBtu	5.21	$/MMBtu	5.25	$/MMBtu	4.31	$/MMBtu
Tax holiday		0	yrs	10	yrs	10	yrs	10	yrs	25	yrs	25	yrs
Annual Escalation		2%		2%		2%		2%		2%		2%	
Interesr Rate		10%		10%		10%		5%		5%		5%	
Production													
Annual Throughput	Bcf	204	Bcf	204	Bcf	204	Bcf	204	Bcf	204	Bcf	204	Bcf
Total Production (25 years)	Bcf	4,722	Bcf	4,722	Bcf	4,722	Bcf	4,722	Bcf	4,722	Bcf	4,722	Bcf
Economics of LNG Terminal													
Revenue (25 years)	$ million	33,808	100%	32,022	100%	26,819	100%	26,819	100%	27,032	100%	22,188	100%
CAPEX	$ million	6,084	18%	6,084	19%	6,084	23%	6,084	23%	6,084	23%	6,084	27%
OPEX	$ million	3,050	9%	3,050	10%	3,050	11%	3,050	11%	3,050	11%	3,050	14%
Direct Tax	$ million	9,574	28%	8,002	25%	6,587	25%	6,587	25%	0	0%	0	0%
Profit after tax	$ million	15,101	45%	14,886	46%	11,098	41%	11,098	41%	17,898	66%	13,054	59%
Net Cash Flow	$ million	**15,101**		**14,886**		**11,098**		**11,098**		**17,898**		**13,054**	
Net Present Value	$ million	**0**		**1**		**-890**		**-890**		**0**		**-999**	
IRR		**10.0%**		**10.0%**		**8.0%**		**8.0%**		**10.0%**		**8.0%**	
FIRR		**9.1%**		**9.1%**		**6.2%**		**9.2%**		**11.8%**		**8.9%**	
Revenue/CAPEX Ratio		5.6		5.3		4.4		4.4		4.4		3.6	
NPV/Investment Ratio		0.0%		0.0%		-14.6%		-14.6%		0.0%		-16.4%	
Government Revenue													
Total Government Revenue	$ million	**9,574**		**8,002**		**6,587**		**6,587**		**0**		**0**	
NPV	$ million	**1,398**		**1,029**		**847**		**847**		**0**		**0**	
Government's Profit Share (Gross)		38.8%		35.0%		37.2%		37.2%		0.0%		0.0%	

The outcome of sensitivity study is shown in Figure 7.2-7. Effect of changes in the capital expenditure shows the same trend observed for LNG terminal.

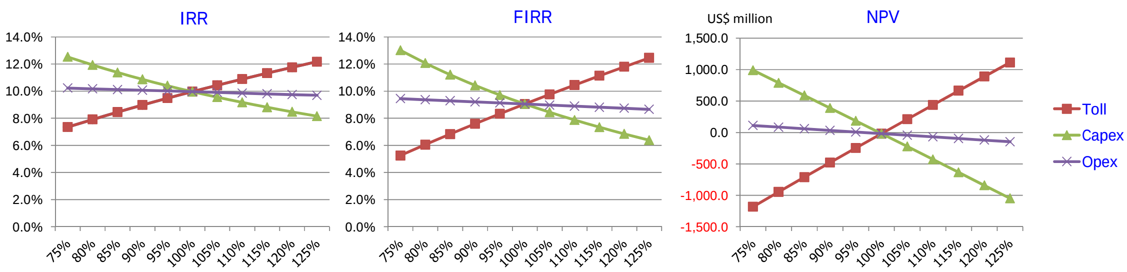


Figure 7.2-7 Sensitivity Analysis on Long Distance Pipeline from Mozambique

From the above observation, natural gas import from the huge Ruvuma gas fields may be possible, but its economics is not optimistic. In order to justify such project, uncertainties relating to demand and required capital expenditure must be investigated carefully together with political consideration on applicable economic regime.

7.2.3 Gas Transmission Pipelines

Imported natural gas, either via LNG or international pipeline, must be delivered to users. Such transportation cost must be considered for introduction of natural gas. For example, Gauteng Province is located about 500km from Richards Bay, one of optional LNG import terminal, and Cape Town is 120km from Saldanha Bay. Thus, domestic transportation cost of natural gas is assessed in this section as follows:

a. For 100km: pipelines with diameters of 12, 16, 20 and 24 inches
b. For 300km: pipelines with diameters of 20, 24, 30 and 34 inches
c. For 500km: pipelines with diameters of 20, 24, 30 and 34 inches

Major assumptions for construction and operation costs are made by pipeline distance as summarized in Table 7.2-10 and Table 7.2-11.

Pipeline construction costs are provided in the draft GUMP sourced from the USEIA website.

Table 7.2-10 Example of Pipeline Construction Cost

Pipeline Diameter	Transport Capacity		Construction Cost
Inches	MMcfd	LNG mtpa	$million/km
12	78	0.6	1.0
16	138	1.1	1.3
20	216	1.7	1.5
24	310	2.4	1.9
30	485	3.7	2.2
36	700	5.4	2.6

Since the above construction costs are compiled from the actual records and thus include substantial variance due to diverse conditions, we use the standardized number as follows.

1) A 24" pipeline for 100km transporting 310MMcfd is deemed as the standard case and may be constructed at a cost of $200 million.
2) Such cost comprises
   a. Fixed cost for send-out and receiving facilities at both end of the pipeline $100 million ($50 million each), and
   b. Variable cost per distance at $100 million ($1 million/km).
3) Fixed cost varies according to the flow volume, that is, a square of the diameter. But, $50 million will be required every 500km to put a branching/booster station.
4) Variable cost varies according to the pipe diameter and pipeline distance.
5) Operation cost may be annual 2% of the initial CAPEX for a large sized pipeline, which will increase up to 3% for smaller ones.

Table 7.2-11 shows the standardized cost assumption for pipelines.

Table 7.2-11 Assumptions for Pipeline Economics by Distance

Pipeline Diameter	Transport Capacity		Construction Cost					OPEX
			Fixed Cost	Distance km	100	300	500	CAPEX x
Inches	MMcfd	LNG mtpa	$million	$million/km	$million	$million	$million	%
12	78	0.6	25.0	0.50	75	175	275	3.0
16	138	1.1	44.4	0.67	111	244	378	2.8
20	216	1.7	69.4	0.83	153	319	486	2.6
24	310	2.4	100.0	1.00	200	400	600	2.4
30	485	3.7	156.3	1.25	281	531	781	2.2
36	700	5.4	225.0	1.50	375	675	975	2.0

In addition, these pipelines would not be utilized at 100%. While a pipeline to serve for a plant operating 24 hours a day such as GTL refinery may be utilized 100%, a pipeline to serve a power station can be used at only 40% on average. A typical gas power plant operates at 100% during the peak hours but operates very low or even shut down during the off-peak hours. They are generally used as mid-merit plant working 30-50% on average. Commercial and public sector buildings may operate mostly in day time through early evening, 12 to 18 hours a day. Residential gas consumption generally concentrates in late afternoon to early evening peak hours, which limits usage of pipeline grid serving for residential sector to 10 to 30%. To see these variances, the pipeline costs are calculated for different diameter, distance and load factors as shown in the table and figures below, which produce 10% IRR for 25 year operation.

As observed here, pipeline costs are severely affected by its diameter, distance and utilisation rate. In particular, it goes up significantly when the load factor falls below 40%. In actuality, pipeline itself has some flexibility to store natural gas with pressure changes plus/minus 10% or so, which means 20% flexibility. If demand fluctuation is big, gas holders (tanks) are prepared. Thus, it may be more realistic to consider that delivery pipelines may be operated at loads of 30% to 50%.

Table 7.2-12 Pipeline Tariff by Diameter and Distance at IRR 10%

Load		20%	30%	40%	50%	60%	70%	80%	90%	100%
Distance	Diameter	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
100km	12Inch	2.36	1.57	1.18	0.94	0.79	0.67	0.59	0.52	0.47
	16Inch	1.83	1.22	0.91	0.73	0.61	0.52	0.46	0.41	0.37
	20Inch	1.59	1.06	0.79	0.63	0.53	0.45	0.40	0.35	0.32
	24Inch	1.43	0.95	0.72	0.57	0.48	0.41	0.36	0.32	0.29
300km	20Inch	3.22	2.15	1.61	1.29	1.07	0.92	0.81	0.72	0.64
	24Inch	2.82	1.88	1.41	1.13	0.94	0.80	0.70	0.63	0.56
	30Inch	2.39	1.59	1.19	0.95	0.80	0.68	0.60	0.53	0.48
	36Inch	2.05	1.37	1.03	0.82	0.68	0.59	0.51	0.46	0.41
500km	20Inch	4.86	3.24	2.43	1.94	1.62	1.39	1.22	1.08	0.97
	24Inch	4.20	2.80	2.10	1.68	1.40	1.20	1.05	0.93	0.84
	30Inch	3.50	2.33	1.75	1.40	1.17	1.00	0.88	0.78	0.70
	36Inch	2.95	1.97	1.48	1.18	0.98	0.84	0.74	0.66	0.59

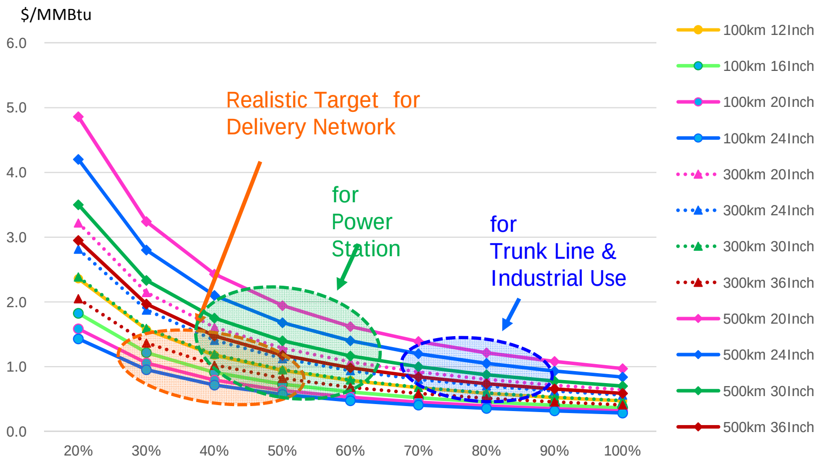


Figure 7.2-8 Pipeline Tariff by Diameter and Distance at IRR 10%

In view of the nature of these pipelines as social infrastructure and their very long demand build-up time, pipeline tariffs may be considered at a lower profitability such as 8% IRR. From the above observation, assuming an average load factor at 70%, pipeline tariffs are calculated for various cases as shown in Table 7.2-13. Pipeline tariff can be lowered with political consideration such as government back-up to assure sustainable business under lower profitability, provision of low interest loans, tax exemption, etc.

Table 7.2-13 Policy Consideration for Loweing Pipeline Tariff

20" for 100km @ 50% load		IRR=10%		IRR=8%		10 year Tax Holiday		Interest @5%		Pre-Tax @8%	
Initial Toll		**0.63**	$/MMBtu	**0.53**	$/MMBtu	**0.51**	$/MMBtu	**0.51**	$/MMBtu	**0.44**	$/MMBtu
Average Toll		**0.82**	$/MMBtu	**0.68**	$/MMBtu	**0.67**	$/MMBtu	**0.67**	$/MMBtu	**0.57**	$/MMBtu
Tax holiday		0	yrs	0	yrs	10	yrs	10	yrs	25	yrs
Annual Escalation		2%		2%		2%		2%		2%	
Interesr Rate		10%		10%		10%		5%		5%	
Throughput											
Capacity		211	MMcfd	211	MMcfd	211	MMcfd	211	MMcfd	211	MMcfd
Utilization		50%		50%		50%		50%		50%	
Annual Throughput	Bcf	38.6	Bcf	38.6	Bcf	38.6	Bcf	38.6	Bcf	38.6	Bcf
LNG equivalent	MTPA	0.9	MYPA	0.9	MYPA	0.9	MYPA	0.9	MYPA	0.9	MYPA
Economics of Pipeline											
Revenue (25 years)	$ million	875	100%	725	100%	709	100%	709	100%	607	100%
CAPEX	$ million	164	19%	164	23%	164	23%	164	23%	164	27%
OPEX	$ million	124	14%	124	17%	124	18%	124	18%	124	20%
Direct Tax	$ million	228	26%	169	23%	158	22%	158	22%	0	0%
Profit after tax	$ million	359	41%	267	37%	263	37%	263	37%	319	53%
Net Cash Flow	$ million	**359**		**267**		**263**		**263**		**319**	
Net Present Value	$ million	**0**		**-21**		**-22**		**-22**		**-24**	
IRR		**10.0%**		**8.0%**		**8.0%**		**8.0%**		**8.0%**	
FIRR		**9.1%**		**6.2%**		**6.1%**		**9.0%**		**8.9%**	
Revenue/CAPEX Ratio		5.3		4.4		4.3		4.3		3.7	
NPV/Investment Ratio		0.1%		-12.9%		-13.4%		-13.4%		-14.4%	
Government Revenue											
Total Government Revenue	$ million	**228**		**169**		**158**		**158**		**0**	
NPV	$ million	**34**		**23**		**20**		**20**		**0**	
Government's Profit Share (Gross)		38.8%		38.8%		37.5%		37.5%		0.0%	

30" for 500km @ 70% load		IRR=10%		IRR=8%		10 year Tax Holiday		Interest @5%		Pre-Tax @8%	
Initial Toll		**1.00**	$/MMBtu	**0.82**	$/MMBtu	**0.81**	$/MMBtu	**0.81**	$/MMBtu	**0.68**	$/MMBtu
Average Toll		**1.30**	$/MMBtu	**1.06**	$/MMBtu	**1.04**	$/MMBtu	**1.04**	$/MMBtu	**0.88**	$/MMBtu
Tax holiday		0	yrs	0	yrs	10	yrs	10	yrs	25	yrs
Annual Escalation		2%		2%		2%		2%		2%	
Interesr Rate		10%		10%		10%		5%		5%	
Throughput											
Capacity		460	MMcfd	460	MMcfd	460	MMcfd	460	MMcfd	460	MMcfd
Utilization		70%		70%		70%		70%		70%	
Annual Throughput	Bcf	117.5	Bcf	117.5	Bcf	117.5	Bcf	117.5	Bcf	117.5	Bcf
LNG equivalent	MTPA	2.6	MYPA	2.6	MYPA	2.6	MYPA	2.6	MYPA	2.6	MYPA
Economics of Pipeline											
Revenue (25 years)	$ million	4,206	100%	3,449	100%	3,385	100%	3,385	100%	2,860	100%
CAPEX	$ million	823	20%	823	24%	823	24%	823	24%	823	29%
OPEX	$ million	455	11%	455	13%	455	13%	455	13%	455	16%
Direct Tax	$ million	1,136	27%	842	24%	787	23%	787	23%	0	0%
Profit after tax	$ million	1,792	43%	1,329	39%	1,321	39%	1,321	39%	1,582	55%
Net Cash Flow	$ million	**1,792**		**1,329**		**1,321**		**1,321**		**1,582**	
Net Present Value	$ million	**2**		**-105**		**-106**		**-106**		**-118**	
IRR		**10.0%**		**8.0%**		**8.0%**		**8.0%**		**8.0%**	
FIRR		**9.1%**		**6.2%**		**6.1%**		**9.1%**		**8.9%**	
Revenue/CAPEX Ratio		5.1		4.2		4.1		4.1		3.5	
NPV/Investment Ratio		0.2%		-12.8%		-12.9%		-12.9%		-14.3%	
Government Revenue											
Total Government Revenue	$ million	**1,136**		**842**		**787**		**787**		**0**	
NPV	$ million	**169**		**113**		**101**		**101**		**0**	
Government's Profit Share (Gross)		38.8%		38.8%		37.3%		37.3%		0.0%	

7.3 Chemical Products Based on Natural Gas

This section is withheld as it contains confidential information, while the summary of the outcome is shown in Table8.1-3.

7.4 Liquid Fuel Production Based on Natural Gas

This section is withheld as it contains confidential information, while the summary of the outcome is shown in Table8.1-3.

7.5 CNG for Natural Gas Vehicles (NGV)

Today, use of natural gas as automotive fuel is getting popular as cheaper fuel in natural gas rich countries and as cleaner fuel in countries where deteriorating air quality is of serious concern. Natural gas is used in a form of compressed natural gas (CNG) for light vehicles and buses, and in a form of LNG for heavy duty trucks, buses, trains and ships.

In this section, we examine economics of a CNG supply station for light vehicles applying an average case operated in Japan as follows:

a. A standard CNG station with sale of 10,000m^3 a day, or annual 3.3 million m^3 (117 million cf).
b. Such CNG station may be constructed within a year at $2.5 million.
c. Annual operation and maintenance cost: CAPEX x 30% a year
d. Build-up of sale: 50% of the capacity in Year 1, increases 10% a year to reach 100% in Year 6

Table 7.5-1 Investment and Demand Build-up Schedule for CNG Station

		Year 1	year 2	Year 3	Year 4	Year 5	Year 6
	2024	2025	2026	2027	2028	2029	2030
	$ million	$ million	$ million	$ million	$ million	$ million	$ million
Construction Cost	2.50						
Operating Cost (CAPEX x 30%)		0.75	0.75	0.75	0.75	0.75	0.75
Total	2.50	0.75	0.75	0.75	0.75	0.75	0.75
Operation Build-up		50%	60%	70%	80%	90%	100%
Annual Sales	Kcm	1,650	1,980	2,310	2,640	2,970	3,300
	million cf	58.3	69.9	81.6	93.2	104.9	116.5

The above sales amount is calculated assuming that on average 125 customers a day fill 80m^3 natural gas as CNG which can run a car for 300km. Where no existing business is in operation, such station may be started only when certain number of regular customers are identified. We assume that operation starts at 50% of the capacity and goes up 10% a year, and finally reach 100% in year six. To kick off such business from the scratch, preparation of certain base demand is critically important.

For assessment of economics, the price of CNG sold at a station in Gauteng Province is assumed as follows:

1) Selling price of CNG is assumed at a level equivalent to a 50:50 mix of gasoline and diesel in heat value equivalent and discounted by 15% for sales promotion and inferior

fuel mileage.[50] Here, gasoline price is 150% and diesel gas oil price is 125% of crude oil price, respectively, as discussed in Section 7.1.

2) Costs for LNG receiving and gas transport/delivery
   a. Receiving and regasification cost at LNG Terminal at Richards Bay: $1.25/MMBtu
   b. Trunk line from Richards Bay to Gauteng Province: $1.0/MMBtu
   c. Local delivery in Gauteng Province: $4.0/MMBtu (as discussed below)

3) As marketing cost for a CNG station operator, a 30% shall be added on top of the above LNG import cost plus transportation cost.

Thus, the hypothetical delivered gas wholesale price for a CNG station operator in Gauteng Province in 2016 will be a sum of LNG CIF and $6.25/MMBtu, which will be escalated 2% per annum thereafter. On top of this, 30% marketing cost will be incurred.

The above relationship is illustrated in Figure 7.5-1.

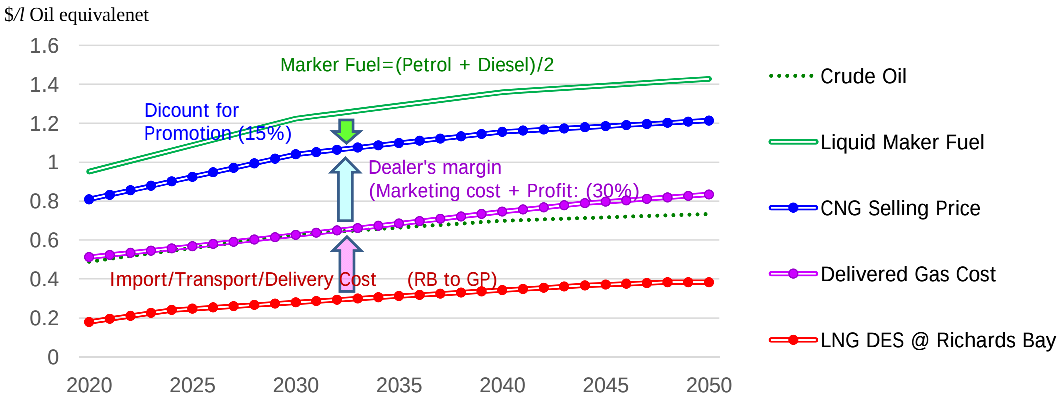


Figure 7.5-1 Price Assumption for Natural Gas for CNG Station

Based on the above assumptions, economics of CNG business to supply motor fuel can expect stable and reasonable profit, because LNG is much cheaper than oil products. This can be identified by the calculation results shown Table 7.5-2. IRR will be 10.9% for the Reference Case, and it goes up to 15.2% if LNG is procured according to the low price scenario. Should indigenous gas become available at much cheaper price, economics will be further improved. For a country such as South Africa where oil is not produced but totally need to be imported, CNG is a favorable option for transport fuel.

[50] Fuel mileage for a 2-ton class truck is 5.4km/m^3 for CNG versus 6.0km/l for diesel according to a survey by IEEJ.

Table 7.5-2 Economics of CNG Station

Oil price		Oil Price= Reference Scenario, Post-tax case										Pre-tax Case			
Feed Gas		LNG Reference				LNG Low		Indig-Gas $4.0		Indig-Gas $3.0		LNG Reference		Indig-Gas $3.0	
City Gas System Toll	$/MMBtu	4.0		4.0		4.0		4.0		4.0		4.0		4.0	
Tax Holidays		0	years	10	years	10	years	10	years	10	years	25	years	25	years
Interest Rate		10%		10%		10%		10%		10%		10%		10%	
Sale															
Annual Sale	Million cf	116.5		116.5		116.5		116.5		116.5		116.5		116.5	
LNG equivalent	t	2,570		2,570		2,570		2,570		2,570		2,570		2,570	
Total Sale (25 years)	Million cf	2,739		2,739		2,739		2,739		2,739		2,739		2,739	
Price															
Crude Oil: 2015	$/Bbl	45.0		45.0		45.0		45.0		45.0		45.0		45.0	
Average	$/Bbl	96		96		96		96		96		96		96	
CNG Price	$/l	0.43		0.43		0.43		0.43		0.43		0.43		0.43	
per MMBtu	$/MMBtu	12.75		12.75		12.75		12.75		12.75		12.75		12.75	
Average	$/MMBtu	27		27.06		27		27.06		27.06		27		27	
Feed Gas: 2015	$/MMBtu	5.65		5.65		5.65		4.00		3.00		5.65		3.00	
Average	$/MMBtu	9.64		9.64		8.32		6.12		4.59		9.64		4.59	
Economics of ABC GTL Company															
Revenue (25 years)	$ million	86	100%	86	100%	86	100%	86	100%	86	100%	86	100%	86	100%
CAPEX	$ million	3	3%	3	3%	3	3%	3	3%	3	3%	3	3%	3	3%
Feed Gas	$ million	55	64%	55	64%	51	59%	44	51%	39	45%	55	64%	39	45%
OPEX	$ million	19	22%	19	22%	19	22%	19	22%	19	22%	19	22%	19	22%
Direct Tax	$ million	4	4%	3	4%	5	5%	6	7%	7	9%	0	0%	0	0%
Profit after tax	$ million	6	7%	6	7%	10	11%	15	17%	18	21%	10	11%	26	30%
Net Cash Flow	$ million	6		6		10		15		18		10		26	
Net Present Value	$ million	0		0		1		2		3		1		4	
IRR		10.9%		11.6%		15.2%		22.7%		26.6%		13.5%		27.9%	
FIRR		10.4%		11.3%		16.3%		28.1%		34.7%		14.0%		36.0%	
Revenue/CAPEX Ratio		34.5		34.5		34.5		34.5		34.5		34.5		34.5	
Government Revenue															
Total Government Revenue	$ million	4		3		5		6		7		0		0	
NPV	$ million	1		0		1		1		1		0		0	
Government's Profit Share (Gross)		38.8%		33.8%		32.2%		29.2%		28.7%		0.0%		0.0%	

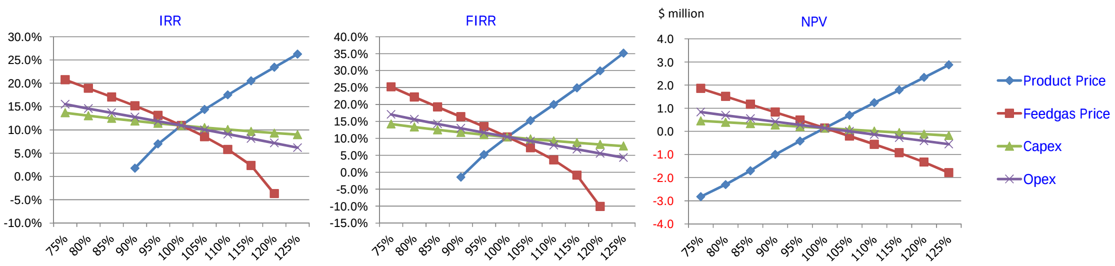


Figure 7.5-2 Sensitivity Analysis of CNG Station

As shown in Table7.5-2, economics of operating a CNG station heavily depends on product price. This means that the sales quantity also give similar impact on economics. Impact of feedgas cost is second largest.

Here, it should be noted that the delivered cost of natural gas is influenced by toll at LNG terminal, trunk pipeline and regional gas delivery services. Among them, the regional gas delivery cost is the biggest element comprising two thirds of the transportation/delivery cost, while it varies significantly according to the size and utilization rate of the city gas supply system as discussed later in Section 7.6.3. Assuming that a CNG system may be considered in an advanced stage of gasification and treated as larger user, such charge for a CNG business is assumed at $4/MMBtu here. However, we should note that changes in the city gas charge affect the economics of a CNG business seriously. As shown in Figure 7.4-7, if the city gas charge exceeds $5/MMBtu, economics of CNG deteriorates seriously. If its lower, on the other hand, economics of CNG business improves modestly.

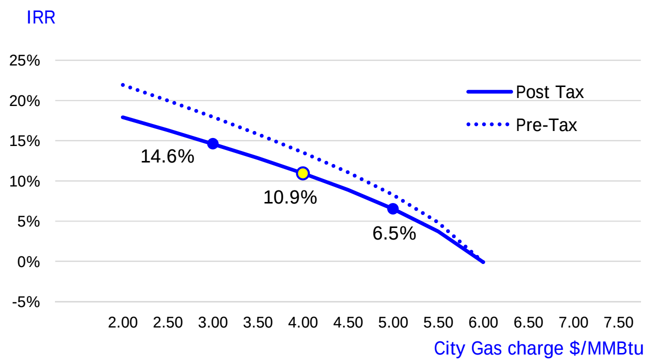


Figure 7.5-3 Economics of CNG Depends on City Gas Charge

As discussed above, economics of CNG supply for motor fuel looks generally good. However, we should note that individual CNG station businesses are tiny and cannot independently support large scale infrastructure projects. On the demand side, a significant amount of CNG vehicles must be introduced to absorb CNG supply. Because of the immense size of LNG business, gas supply system must be justified by other gas consumers providing anchor demand for the infrastructure before introduction of CNG station can be considered. Lessons at many countries including Japan show that diffusion of CNG vehicles has been slow and limited due to short driving distance despite the fact that CNG is economic and environment friendly motor fuel. To introduce CNG driven vehicles, it is necessary to establish a consistent and sustainable transportation policy.

7.6 Case Studies on Piped Gas Supply

In this section, we look into several specific cases in South Africa to supply LNG-based natural gas via pipeline. They are 1) feedgas supply to the PetroSA GTL refinery at Mossel Bay, 2) LNG transport by tank truck to small size users located not close to gas pipelines, and 3) competitiveness of city gas system compared with LPG.

7.6.1 LNG for Mossel Bay GTL Refinery

PetroSA's Mossel Bay Refinery has been using natural gas from the offshore gas fields as feedstock for the GTL process. Today these gas fields are depleting after decades of production and feedgas supply is in short as discussed in Chapter 3. To cope with the situation, PetroSA is considering increase of condensate import as feedstock for the liquid processing section. At the same time, the company is considering imported LNG as an alternative gas source.

Explanation on the assumption is withheld as it contains confidential information.

Table 7.6-1 Construction Schedule and Investment Amount for GTL Pipeline

GTL by LNG

Pipeline Construction Cost

FS/FEED ↓ Design | Construction start ↓ | Production Start

via Saldanha Bay	Year 1 2020	Year 2 2021	Year 3 2022	Year 4 2023	Year 5 2024	Year 6 2025	Total
Project Owner	$ million	$ million	$ million	$ million	$ million	$ million	$ million
Project Management Cost			10	20	20		50
Construction Cost (=Total EPC Cost)			70	315	315		700
Operating Cost (Pipeline + Plant)						284	0
Administration Cost			5	10	10	5	25
Total	0	0	85	345	345		**775**
EPC							
CAPEX 700 $ million			10%	45%	45%		
Annual			70	315	315		

via Coega	Year 1 2020	Year 2 2021	Year 3 2022	Year 4 2023	Year 5 2024	Year 6 2025	Total
Project Owner	$ million	$ million	$ million	$ million	$ million	$ million	$ million
Project Management Cost			5	10	10		25
Construction Cost (=Total EPC Cost)			60	270	270		600
Operating Cost (Pipeline + Plant)						282	0
Administration Cost			5	10	10	5	25
Total	0	0	70	290	290		**650**
EPC							
CAPEX 600 $ million			10%	45%	45%		
Annual			60	270	270		

The above assumes the pipeline cost on a higher side. We also examine a case where pipeline construction cost would be less expensive as shown in Table 7.6-2. The pipeline construction cost has certain impact on the project economics. It should be noted that the pipeline size is assumed to sufficiently accommodate the maximum quantity of feedgas required at the 45,000 bpd plant.

Table 7.6-2 Variance in Pipeline Construction Cost

Case		Pipeline construction cost			
Construction Zone	Inches	Fixed Cost ($ million)	Variable Cost ($ million/km)	Distance (km)	Investment ($ million)
Coega⇔Mossel bay	30inch	150	1.25	400	650
Low cost		100	1.00	400	500
Saldanha bay ⇔ Mossel bay	30inch	150	1.25	500	775
Low Cost		100	1.00	500	600

Table 7.6-3 Case Studies on Pipeline for GTL from Saldanha Bay

Oil Price		**Reference**		**Low**							
Light Product		**Naphtha**				**Gasoline**					
Feed Gas		Reference		Low							
LNG Terminal Toll		1.25	$/MMBtu	1.25	$/MMBtu	1.25	$/MMBtu	1.0	$/MMBtu	1.0	$/MMBtu
CAPEX		Reference ($775 million)						Low ($600 million)			
Production										**(Pre-Tax)**	
Annual Production Capacity	kbpd	45.0		45.0		45.0		45.0		45.0	
Total Production (25 years)	Million Bbls	371.3		371.3		371.3		371.3		371.3	
Feed Gas											
Daily Consumption (Peak)	MMcfd	402		402		402		402		402	
Total Consumption (25 years)	Tcf	3.3		3.3		3.3		3.3		3.3	
Price											
Crude Oil: 2015	$/Bbl	**45.0**		**45.0**		**45.0**		**45.0**		**45.0**	
Average	$/Bbl	96		72		72		72		72	
GTL Products	$/Bbl	**66.7**		**66.7**		**71.4**		**71.4**		**71.4**	
Average	$/Bbl	142		107		115		115		115	
Feed Gas: 2015 including LNG terminal toll	$/MMBtu	**5.65**		**5.65**		**5.65**		**5.40**		**5.40**	
Average	$/MMBtu	10.45		9.07		9.07		8.69		8.69	
Economics of ABC GTL Company											
Revenue (25 years)	$ million	52,543	100%	39,779	100%	42,597	100%	42,597	100%	42,597	100%
CAPEX	**$ million**	**775**	**1%**	**775**	**2%**	**775**	**2%**	**775**	**2%**	**775**	**2%**
Feed Gas	$ million	34,867	66%	30,720	77%	30,720	72%	29,445	69%	29,445	69%
OPEX	$ million	7,225	14%	7,225	18%	7,225	17%	7,225	17%	7,225	17%
Direct Tax	$ million	3,755	7%	511	1%	1,504	4%	1,999	5%	0	0%
Profit after tax	$ million	5,922	11%	806	2%	2,373	6%	3,153	7%	5,152	12%
Net Cash Flow	$ million	**5,922**		**548**		**2,373**		**3,153**		**5,152**	
Net Present Value	$ million	**1,145**		**20**		**417**		**580**		**1,019**	
IRR		**34.0%**		**10.8%**		**21.6%**		**24.9%**		**31.0%**	
FIRR		**57.6%**		**8.8%**		**33.0%**		**40.0%**		**49.4%**	
Revenue/CAPEX Ratio		67.8		51.3		55.0		55.0		55.0	
Government Revenue											
Total Government Revenue	$ million	**3,755**		**511**		**1,504**		**1,999**		**0**	
NPV	$ million	**795**		**120**		**340**		**440**		**0**	
Government's Profit Share (Gross)		38.8%		48.3%		38.8%		38.8%		0.0%	
IRR for Coega (30"x400km)		**38.8%**		**14.1%**		**25.5%**		**29.0%**		**36.3%**	

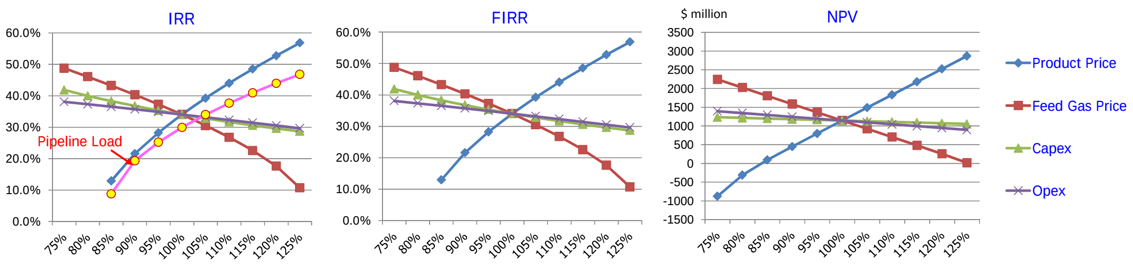


Figure 7.6-1 Sensitivity Analysis on Pipeline for GTL

Economics of utilizing LNG as feedstock for the Mossel Bay GTL plant is summarized in Table 7.6-3, and sensitivity analysis is shown in Figure 7.6-1. If the proposed Coega LNG terminal could be justified, economics may be better than the above case because of the shorter distance. However, it should be carefully studied if sufficient demand would be available in the early days to support an LNG terminal in Coega.

The Reference Case under which the standard price scenario is assumed produces very good economics with an IRR at 34.0%. However, we should be cautious about the fact that the project is highly sensitive to the price scenario. As shown Figure 7.6-1, if the crude oil price which defines the prices of GTL products goes below 85% of the Reference Case, the project incurs deficit. Under the low price scenario, the total revenue through the whole project period of 25 years decreases 24.3% compared with the Reference Case. Then the economics deteriorates significantly though still acceptable as shown in Table 7.6-2. As analyzed here, the project economics is highly vulnerable to changes in oil and gas prices which define the revenue and feedgas cost. In particular, the feedgas cost amounts to 70-80% of the revenue, while CAPEX amounts to only 2% of the whole revenue obtained through the 25 year project period. The economics is also sensitive to the load factor which directly affects the amount of revenue.

With these observations, we have examined additional cases such as:

a. Naphtha is used not as petrochemical feedstock but is used as gasoline which returns much higher price[51],
b. LNG terminal toll is lowered from $1.25/MMBtu to $1.00/MMBtu as the GTL project will provide stable anchor throughput.

These changes improve the project economics significantly as shown in Table 7.6-2. Pre-tax project economics reaches 31%. In addition, there are other elements such as:

a. As the pipeline is assumed at the sufficiently large size to fully supply the feedgas needed at the plant but it could be downsized considering continued supply of indigenous gas,
b. The pipeline may be co-used for gas supply to the Atlantis/Cape Town area, and thus the unit cost may be reduced,
c. Pipeline cost assumed here may be higher than what is being studied by PetroSA.

These factors may further improve the project economics. On the other hand, the variance of project scenarios examined here should be narrowed down with more in-depth information. All in all, use of LNG as alternative feedstock at the Mossel Bay GTL Refinery looks good, while plausible project scenarios should be developed with more precise data and realistic/acceptable assumptions for careful investigation before the final project decision.

7.6.2 LNG Transport by Tank Truck for Smaller Users

Pipeline is an effective and safe measure to transport a large quantity of natural gas from one point to the other. A significant amount of natural gas can be transported even with a pipeline of smaller diameter. However, it is expensive and certain demand has to be secured alongside and/or near the demand end terminal to justify its construction.

[51] According to the analysis in Section 7.1, price of naphtha as petrochemical feedstock is assumed at 115% of the crude oil price, while that of gasoline at 150%. This change pushes up the total revenue for the whole project period by 7.1%.

Table 7.6-4 Transportation Capacity of Pipeline and its Cost

Pipeline Diameter	Transport Capacity		Construction Cost					OPEX
			Fixed Cost	Distance km	100	300	500	CAPEX x
Inches	MMcfd	LNG mtpa	$million	$million/km	$million	$million	$million	%
12	78	0.6	25.0	0.50	75	175	275	3.0
16	138	1.1	44.4	0.67	111	244	378	2.8
20	216	1.7	69.4	0.83	153	319	486	2.6
24	310	2.4	100.0	1.00	200	400	600	2.4
30	485	3.7	156.3	1.25	281	531	781	2.2
36	700	5.4	225.0	1.50	375	675	975	2.0

In case demand is relatively small, pipeline would not be economical. For example, a 12 inch pipeline can transport 78 MMcfd of natural gas, or 600 thousand tons a year in LNG equivalent, which compares to city gas consumption of two million households in Japan. This means that a substantial number of customers is necessary to assure high usage of the city gas system.[52]

Table 7.6-5 City Gas Consumption per Customer in Japan

	Residential	Commercial	Industrial	Others	Average
City Gas	m^3/year	m^3/year	m^3/year	m^3/year	m^3/year
2010	424	5,053	383,387	14,574	1,452
2011	422	4,837	410,318	13,801	1,474
2012	420	4,890	421,266	13,809	1,479
2013	406	4,896	439,973	13,889	1,484
2014	404	4,756	460,766	13,388	1,489
LNG Equivalent	t/year	t/year	t/year	t/year	t/year
2010	0.309	3.684	279.554	10.627	1.059
2011	0.308	3.527	299.191	10.063	1.075
2012	0.306	3.566	307.174	10.069	1.078
2013	0.296	3.570	320.814	10.127	1.082
2014	0.294	3.468	335.976	9.762	1.086

(Source) IEEJ

Based on the analysis implemented in Section 7.2, pipeline tariff to achieve 10% IRR is calculated per utilisation rate and distance for a hypothetical 12” pipeline. Given that the total cost is same, if the utilisation rate of the pipeline is 10%, the pipeline tariff must be 10-fold to obtain the same amount of revenue. At 50% use, pipeline tariff must be double. To assure 50% use of a 12” pipeline, however, natural gas demand of 300,000 tons in LNG equivalent is necessary. This number compares to a fully gasified city with population of 300,000 -500,000. Only limited number of cities in South Africa are clears this size. Then, how can other cities obtain natural gas supply?

[52] To cope with demand hourly and seasonal flexibility, most of the trunk transmission lines in the Japanese city gas systems are 20” or lager.

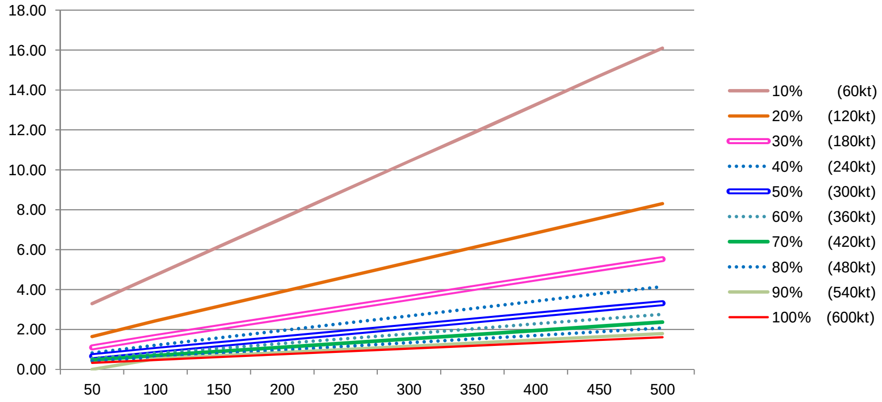


Figure 7.6-2 Pipeline Tariff to Achieve 10% IRR

The solution may be a system to transport LNG in smaller unit by tank track as discussed in Chapter 6. LNG may be transported to a min-LNG terminal for further delivery or directly to industrial/commercial users.

We examine such case with following assumptions:

LNG Tank Truck

a. Capacity: 30 m^3 (KL) or 13.5 tons of LNG
b. Price: $500,000 per unit
c. Durable Life: ten years or one million km, whichever is earlier.
d. Operation: Within 100km radiance, two rounds of delivery a day
   100km to 250km, one round delivery a day
   250km to 500km, two days per delivery
e. Operation: 220 days a year
f. Fuel Consumption: 2.5km/*l*
   Price (Diesel): US$1.0/*l*
   Lube and maintenance: annually 1% of CAPEX
g. Drivers wage including welfare: $100 a day

Fixed Facility

a. Shipping facility: $10 million
b. Satellite facility: $20 million
c. Operation and maintenance cost: annually 10% of CAPEX

Mark-up

20% of the sum of the above cost per year to be allocated for fair profit and corporate tax.

Table 7.6-6 LNG Transportation Cost by Tank Truck: 200,000tons/year case

Delivery distance	km	50	100	150	200	250	300	350	400	450	500
Tank Truck											
Number of Delivery		14,815	14,815	14,815	14,815	14,815	14,815	14,815	14,815	14,815	14,815
Required number of tank truck		34	34	68	68	68	135	135	135	135	135
Annual Driving distance	1000km	1,481	2,963	4,444	5,926	7,407	8,889	10,370	11,852	13,333	14,815
Per unit	1000km	43.6	87.1	65.4	87.1	108.9	65.8	76.8	87.8	98.8	109.7
Total number of Truck (for 25 years)		85	85	170	170	186	338	338	338	338	371
CAPEX for whole porject peirod	$ million	42.5	42.5	85.0	85.0	93.0	169.0	169.0	169.0	169.0	185.5
Fuel Consumption	kl/year	592.6	1,185.2	1,777.8	2,370.4	2,963.0	3,555.6	4,148.1	4,740.7	5,333.3	5,925.9
Fuel Expenditure	$ million	0.59	1.19	1.78	2.37	2.96	3.56	4.15	4.74	5.33	5.93
Lube and maintenance		0.17	0.17	0.34	0.34	0.34	0.68	0.68	0.68	0.68	0.68
Number of Drivers (2.5 person per truck)		85	85	170	170	170	338	338	338	338	338
Wage for Drivers		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Annual expenditure for tank truck		0.76	1.36	2.12	2.71	3.30	4.23	4.82	5.42	6.01	6.60
Facility Operation and Maintenance											
Shipping	$ million	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Satellite	$ million	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Sub-total	$ million	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Annual Expenditure		3.76	4.36	5.12	5.71	6.30	7.23	7.82	8.42	9.01	9.60
Unit Cost											
Tank Truck CAPEX	$/ton	8.5	8.5	17.0	17.0	18.6	33.8	33.8	33.8	33.8	37.1
OPEX	$/ton	3.8	6.8	10.6	13.6	16.5	21.2	24.1	27.1	30.0	33.0
Sub total		12.3	15.3	27.6	30.6	35.1	55.0	57.9	60.9	63.8	70.1
Tank Truck Operation Cost/Total Toll		10%	16%	18%	22%	25%	23%	25%	28%	30%	30%
Fixed Facility CAPEX	$/ton	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
OPEX	$/ton	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Sub total		21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Total	$/ton	33.3	36.3	48.6	51.6	56.1	76.0	78.9	81.9	84.8	91.1
Mark up	$/ton	6.7	7.3	9.7	10.3	11.2	15.2	15.8	16.4	17.0	18.2
Total Toll	$/ton	40.0	43.5	58.3	61.9	67.3	91.1	94.7	98.3	101.8	109.3
	$/MMBtu	0.77	0.84	1.13	1.20	1.30	1.76	1.83	1.90	1.97	2.12

Economics of transporting 200,000 tons of LNG a year by tank truck for various distances are calculated as shown in Table 7.6-6. For simplicity of calculation, cash flow chart is not applied. Instead, a mark-up of 20% on top of the calculated unit cost is applied, which is allocated for fair profit for the operator and corporate income tax and produce around 10% IRR. This result shows that LNG transport cost for a medium size city within a radius of 250km, the distance conceivable for one day return trip, will be less than $1.50/MMBtu. Another finding is that the direct cost relating to operation of tank truck is less than 25% of the toll. Capital expenditure for purchase of tank trucks and construction of fixed facilities for loading, receiving and regasification will be about 40% of the toll. Cost for operating fixed facilities will be 20% -40% of the toll, which is linked to the CAPEX for these facilities. These observations mean that even for the case of tank truck transport, the share of fixed cost is high and hence quantity effect on the toll is big.

In Figure7.6-3, natural gas transportation costs by pipeline and tank trucks are compared for various demand size by distance. In case of pipeline, LNG is regasified at the LNG receiving terminal and sent out by a pipeline. Instead, in case of pipeline, LNG is transported loaded to tank trucks at the LNG receiving terminal, transported by tank truck, and unloaded and regasified at the satellite terminal. To consider small quantity supplies, construction of 12” pipeline is assumed. It will be used at 50% load for 300,000 tons a year LNG equivalent case, and at much lower load for smaller quantity supply. From the graph, pipeline and tank truck are competitive in the range of 300,000 tons supply. However, in the smaller supply quantity ranges, tank truck is apparently more efficient. In addition, within the 250km radius range, the toll for tank truck transport remains within a reasonable range, that is, less than $5.00/MMBtu.

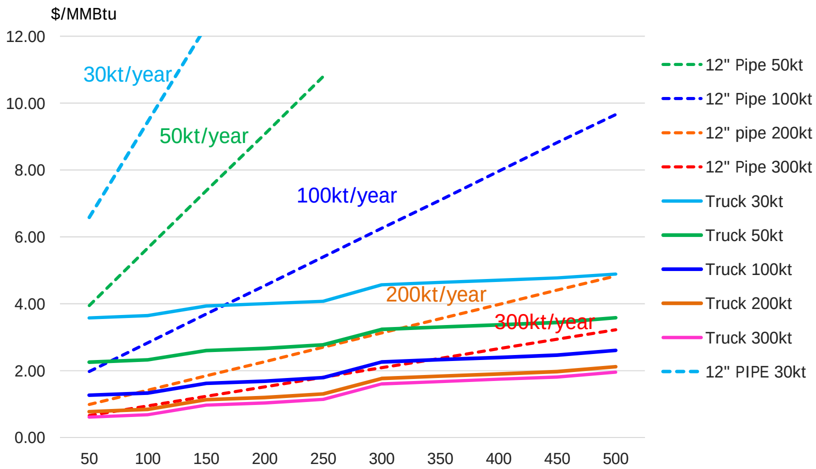


Figure 7.6-3 Comparison of Tank Truck and Pipeline

For supply of natural gas beyond 250km, surprisingly, the gap between the two methods widens. This is because a slim pipeline of 12” is assumed here, which is usually supposed for short distance, small quantity supply. Economics of pipeline is a function of quantity and distance, and for a long distance, much greater quantity should be supplied with much larger pipelines. On the other hand, long haul track transportation of a huge quantity would incur problems on road traffic and environment.

Another benefit of tank truck supply is that the system can consider demands scattered within a certain radius as tank truck can deliver LNG to every direction while pipeline can transport natural gas only to one point. Of course an LNG receiving and regasification facility is necessary at each consumption point, economics may work as discussed in the next section.

The above analysis is made on a hypothetical case. For actual application, possible local gas demand and realistic conditions for the candidate site should be looked into and plausible development scenarios should be developed for further investigation.

7.6.3 Natural Gas Supply for Industrial, Commercial and Residential Users

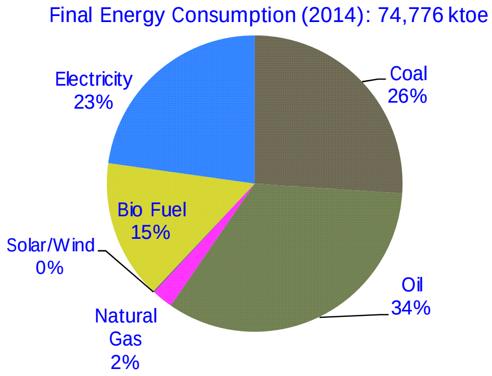
In Gauteng Province and KwaZulu-Natal Province, imported natural gas and domestic synthetic gas are supplied by pipeline to industrial and residential users. However, because of supply constraints, gas supply to these users has remained at the same level for years. In addition to consumption by energy intensive steel mills and SASOL’s own GTL and petrochemical use, other users in Gauteng Province and those along the Lily pipeline in KwaZulu-Natal Province used 2,110 ktoe of these gases in 2014. However, consumption of coal and biomass is still substantial, while natural gas is used only 2%.

Table 7.6-7 Gas Consumption in South Africa

Consumption of Natural Gas and Synthetic Gas (2014): 5.563 ktoe

	Natural Gas		Synthetic Gas	Total
	Indigenous	Imported		
	ktoe	ktoe	ktoe	ktoe
GTL	869	1,280		2,149
Petrochemicals			950	950
Steel			353	353
Others		1,699	411	2,110
Total	869	2,979	1,715	5,563

Source: IEA



Energy shift to cleaner natural gas is a pressing issue for South Africa to combat environmental issues and reduce GHG emissions. Unlike power plants and energy intensive industries such as steel mills and cement factories, other users are not sufficiently big to individually endorse gas supply plan, industrial, commercial and residential users may be collectively considered for shift to natural gas. To this end, it is essential for the country to proactively vitalize the city gas supply system for smaller users. With this backdrop, we will examine a scenario that LNG is imported at Richards Bay and transported to Gauteng Province utilizing the existing Lily pipeline. The existing gas supply system in the Johannesburg area will be extensively expanded to promote gasification. We will examine the economics of developing city gas supply by LNG compared with LPG, which may be deemed as the immediate competitor.

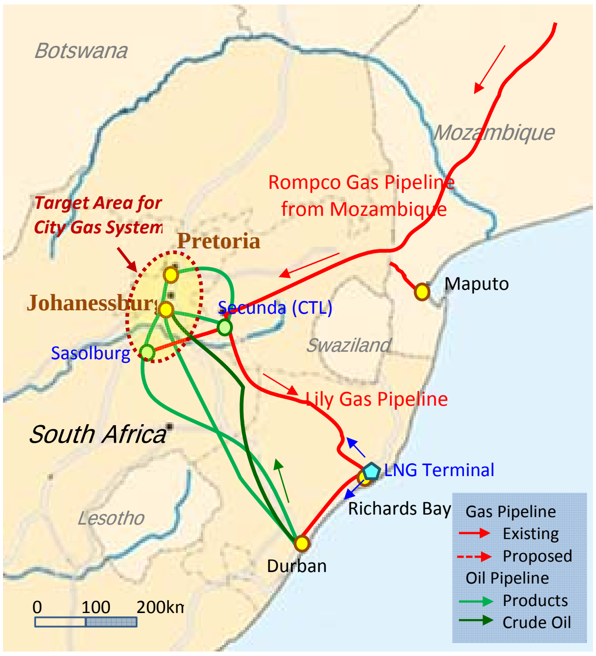


Figure 7.6-4 Gas Pipelines in South Africa

For this analysis, we assume a relatively modest size of demand as shown in Table 7.6-8, which includes 300,000 household, 10,000 small shops and restaurants, 2,000 medium shops, restaurants and buildings, 100 medium size factories, shopping malls and public facilities and 10relatively large factories. Gas consumption per unit is given in terms of electricity consumption, which is converted into gas requirement. For example, then, gas consumption per household is calculated to be 0.4 tons in LNG equivalent (2kW used for 2 hours for cooking and 12 hours for heating during winter), which is same with that observed in Japan.

Table 7.6-8 City Gas Customers and Demand

			Household	Small shops & Restaurants	Medium Shops, Restaurants and Buildings	Medium Factories, Shopping Malls & Public Facilities	Large Factories	Total
Energy Consumption in Electrivcity Equivalnet	Capacity	kW	2	10	100	1000	5000	
Daily use (to consider demand size in terms of electricity consumption)	Cooking	hours	2	yes	yes	a bit	a bit	
	Heating	hours	6	12	12	yes[2]	yes[2]	
	Power	hours	No	No	yes	15	18	
	Overall	hours	8	12	12	15	18	
	Annual	hours	2,920	4,380	4,380	5,475	6,570	
Utilization Efficiency	Electricity		35%	35%	35%	35%	35%	
(to calculate electricity equivalent demand)	Heat					33%	33%	
	Total		35%	35%	35%	68%	68%	
Fuel Consumption	E equiv	kWh/yr	5,840	43,800	438,000	5,475,000	32,850,000	
	Oil Equiv	toe	0.6	4.4	43.8	547.5	3,285.0	
	LNG equiv	ton	0.4	3.4	33.7	421.2	2,526.9	
Number of Customers as Target			300,000	10,000	2,000	100	10	312,110
Total Fuel Consumption: LNG equivalent		kt LNG	135	34	67	42	25	303
City Gas @43MJ		Bcm	0.17	0.04	0.09	0.05	0.03	0.39
		Bcf	6.11	1.53	3.06	1.91	1.15	13.75

Table 7.6-9 Assumptions for City Gas System

1.Budget

Trunk Line 20"Circle Line	300	km
Fixed Cost	200	$50x4
Distance Variable Cost	1.25	$ MM/km
Total Cost	575	
Branch Line 12" & 8"	10	km Total 1,000km
10km brach line 12"	20	Branches
8"	80	Branches
Fixed Cost for branching	0.1	$ MM/branch
Distance Variable Cost: 12"	0.5	$ MM/km
8"	0.3	$ MM/km
Total Cost	350	
Total Cost	925	$ MM

2.Throughput Profile

Maximum Capacity (LNG equiv.)	0.6	MTPA ++
(Natural Gas)	74.6	MMcfd
Utilization Rate	50%	
Daily Throughput	37.3	MMcfd
Operating Days	365	year
Annual Throughput	13.6	Bcf
LNG Equivalent	300	kt/year

The total gas demand at plateau will be 300kt in LNG equivalent, or, 13.75 Bcf a year. We assume that the demand will start at 50% of the final level in the start-up year and build up slowly to reach 100% in the 7th year. The city gas system may comprise 20" x 300km trunk circle line and 100 branch lines with diameter of 12" or 8" extending for 10km each. Detail cost assumptions are as shown in Table 7.6-9, which are derived from the analysis in Section 7.2. As the system capacity is shown to be 0.6 MTPA in LNG equivalent in the table, this is just for model operation purpose. The system may be able to handle more than 2.0 MTPA.

Schedule for construction, budget, and demand build-up are given in Table7.6-10. Construction of one trunk line for 150km may take two years and two lines will be completed in four years. Branch lines will be constructed simultaneously, and 60% will be completed in four years. While construction is ongoing, city gas supply will start in the fourth year.

Table 7.6-10 Schedule for Construction and Demand Build-up

	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Trunk Line	$ million	$ million	$ million	$ million	$ million	$ million	$ million	$ million	$ million	$ million	
Project Management Cost	28.8	7.2	7.2	7.2	7.2						
Construction Cost	575.0	143.8	143.8	143.8	143.8						
Branch Line	0										
Project Management Cost	17.5	2.6	2.6	2.6	2.6	1.4	1.4	1.4	1.4	1.4	
Construction Cost	350	52.5	52.5	52.5	52.5	28	28	28	28	28	
	100%	15%	15%	15%	15%	8%	8%	8%	8%	8%	
Total CAPEX	971	206	206	206	206	29	29	29	29	29	
Operating Cost	153.9				23.6	24.4	25.2	26.1	26.9	27.8	
Operating Cost Ratio	3.0%										
Administration Cost	45.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	
Demand											
Final Demad (LNG equiv.)					150.0	180.0	210.0	240.0	270.0	285.0	300.0
Build up ratio					50%	60%	70%	80%	90%	95%	100%

Outcome of the analysis is as shown in Table 7.6-11. In the Reference Case where IRR=10% is targeted, $10.35/MMBtu as the initial toll (with 2% annual escalation) is necessary for the city gas system. Economic is very sensitive to changes in the toll and CAPEX. In view of the nature of the system as a social infrastructure, if we apply IRR=8% as economic criteria, the required toll reduced to $8.67/MMBtu. If 10 year tax holiday is applied, it goes down to $8.55/MMBtu, while the pre-tax required toll is $7.35/MMBtu.

Table 7.6-11 Economic Analysis on City Gas System

		IRR=10%		IRR=8%		10 year Tax Holiday		Interest @5%		**Pre-Tax @8%**	
Initial Toll	$/MMBtu	**10.35**	$/MMBtu	**8.67**	$/MMBtu	**8.55**	$/MMBtu	**8.55**	$/MMBtu	**7.35**	$/MMBtu
Average Toll	$/MMBtu	**13.40**	$/MMBtu	**11.23**	$/MMBtu	**11.07**	$/MMBtu	**11.07**	$/MMBtu	**9.52**	$/MMBtu
Tax holiday		0	yrs	0	yrs	10	yrs	10	yrs	25	yrs
Annual Escalation		2%		2%		2%		2%		2%	
Interesr Rate		10%		10%		10%		5%		5%	
Throughput											
Capacity	MMcfd	75	MMcfd	75	MMcfd	75	MMcfd	75	MMcfd	75	MMcfd
Utilization	%	50%		50%		50%		50%		50%	
Annual Throughput	Bcf	13.6	Bcf	13.6	Bcf	13.6	Bcf	13.6	Bcf	13.6	Bcf
LNG equivalent	MTPA	0.3	MYPA	0.3	MYPA	0.3	MYPA	0.3	MYPA	0.3	MYPA
Economics of Pipeline											
Revenue (25 years)	$ million	4,948	100%	4,145	100%	4,088	100%	4,088	100%	3,514	100%
CAPEX	$ million	971	20%	971	23%	971	24%	971	24%	971	28%
OPEX	$ million	806	16%	806	19%	806	20%	806	20%	806	23%
Direct Tax	$ million	1,230	25%	919	22%	877	21%	877	21%	0	0%
Profit after tax	$ million	1,941	39%	1,449	35%	1,433	35%	1,433	35%	1,737	49%
Net Cash Flow	$ million	1,941		1,449		1,433		1,433		1,737	
Net Present Value	$ million	**2**		**-109**		**-112**		**-112**		**-123**	
IRR	%	**10.0%**		**8.0%**		**8.0%**		**8.0%**		**8.0%**	
FIRR	%	**11.6%**		**8.6%**		**8.5%**		**11.1%**		**10.6%**	
Revenue/CAPEX Ratio		5.1		4.3		4.2		4.2		3.6	
NPV/Investment Ratio		0.2%		-11.2%		-11.6%		-11.6%		-12.6%	
Government Revenue											
Total Government Revenue	$ million	1,230		919		877		877		0	
NPV	$ million	**176**		**119**		**110**		**110**		**0**	
Government's Profit Share (Gross)		38.8%		38.8%		38.0%		38.0%		0.0%	

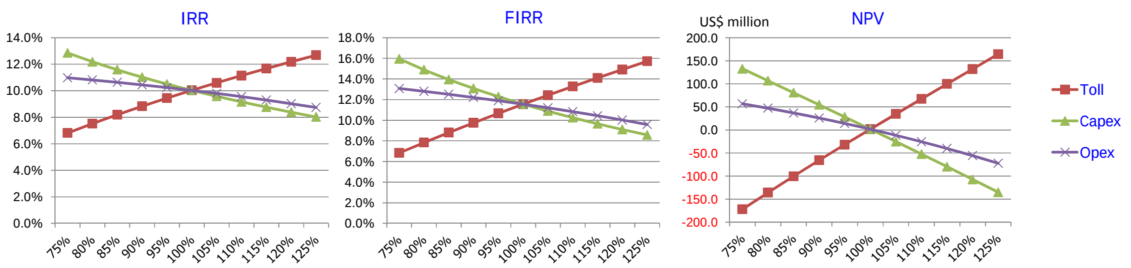


Figure 7.6-5 Sensitivity Analysis on City Gas System

The capital intensive system takes very long time for construction and demand build-up. Revenue is low in the early stage and cost recovery is hence very slow. Because of this nature, if we apply general commercial criteria for assessment, tax and profit that will come up only in later project stage amount to a huge portion of the total revenue for the whole project period, which is not very desirable for social infrastructure. At the same time, a 10 year tax holiday system does not work since taxable income is almost nil during the early project period. On the other hand, if we look to the operator's realistic profitability by FIRR, low interest loan is very effective.

In view of its utility nature of the business, the city gas operator's toll to achieve 10% FIRR is calculated in Table 7.6-12 for different interest rate and loan ratio. In particular, impact of interest rate is enormous. If it is cut from 10% to 5%, the initial toll at 60% loan ratio can be lowered from \$9.48/MMBtu to \$8.10/MMBtu, by 15%. On the other hand, impact of the loan ratio is not high. It is only 5% if the loan ratio is raised from 60% to 90%, while it is slightly more effective when interest rate is lower.

Table 7.6-12 City Gas Toll for FIRR 10%

	No Tax Holiday					10 year Tax Holiday				
Interest Rate	10.0%	7.5%	5.0%	2.5%	0.0%	10.0%	7.5%	5.0%	2.5%	0.0%
Loan Ratio	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
50%	9.60	9.00	8.45	8.00	7.60	9.35	8.82	8.40	8.00	7.60
60%	9.48	8.70	8.10	7.55	7.10	9.20	8.61	8.10	7.55	7.10
70%	9.33	8.45	7.75	7.10	6.60	9.12	8.42	7.72	7.10	6.60
80%	9.17	8.20	7.37	6.70	6.12	9.00	8.22	7.40	6.70	6.13
90%	9.05	7.95	7.05	6.27	5.65	8.88	7.96	7.05	6.27	5.65
	%	%	%	%	%	%	%	%	%	%
50%	101.3	94.9	89.1	84.4	80.2	98.6	93.0	88.6	84.4	80.2
60%	100.0	91.8	85.4	79.6	74.9	97.0	90.8	85.4	79.6	74.9
70%	98.4	89.1	81.8	74.9	69.6	96.2	88.8	81.4	74.9	69.6
80%	96.7	86.5	77.7	70.7	64.6	94.9	86.7	78.1	70.7	64.7
90%	95.5	83.9	74.4	66.1	59.6	93.7	84.0	74.4	66.1	59.6

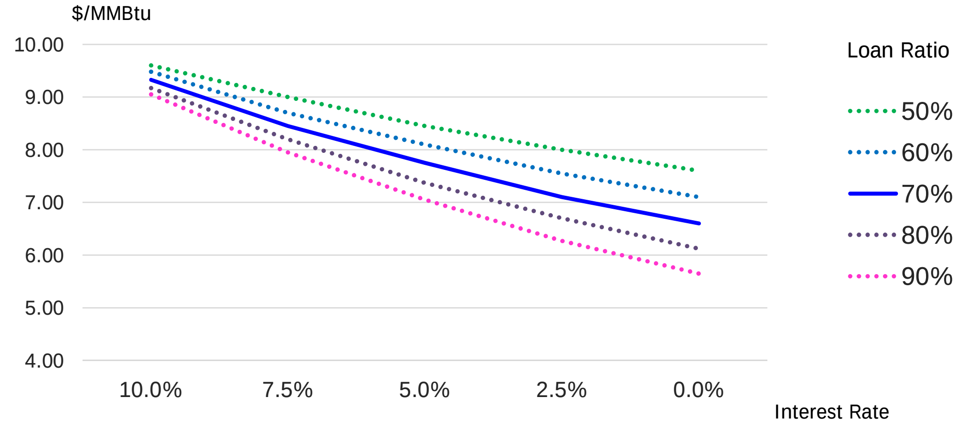


Figure 7.6-6 City Gas Toll for FIRR 10

Based on the above study, let us sum up the delivered cost of natural gas for end users which comprises:

a. LNG CIF price at the Richard Bay LNG terminal
b. LNG handling toll at the LNG terminal
c. Regasified natural gas transportation cost from Richard Bay to Johannesburg
d. City gas toll for the city gas company
e. Connecting fee for individual user

As the present LNG market is quite depressed, for the purpose of the present study, we may apply the LNG CIF price at $6.0/MMBtu, which is adopted as the price in the European market for 2020. LNG terminal handling toll will be $1.00-1.25/MMBtu as analyzed in Section 7.2. The present pipeline tariff set out by NERSA for Secunda to Richards Bay is ZAR 13.34/GJ or $0.93/MMBtu. Our analysis on a new pipeline for 500km shows an almost same level that $1.00/MMBtu is necessary to justify 30" pipeline at 70% operation. On top of these receiving and transportation cost, city gas toll will be $9.48/MMBtu at 10% FIRR and handling amount of 300kt/year in LNG equivalent. This is an average toll to bring the FIRR of 10%, while the city gas toll may be applied differently to users of different sizes, generally higher for smaller users and lower for larger users. If we assume volume differentials, for example, at 150% of the average rate for the smaller users such as household and small restaurants and 75% for the larger users such as medium factories and shopping malls, applicable tolls will be $14.0/MMBtu and $7.5/MMBtu, respectively.

In addition, connecting fee from the street gas line to the user's facility needs to be considered. We assume $1,000 for residential users which is a half of the rate generally applied in Japan. A standard annual consumption per household will be 0.4t or 23MMBtu a year as explained in Table 7.6-8. If we assume the consumer's conscious horizon at three years, payment of $1,000 may be recognized as a cost of $14.4/MMBtu ($1,000/23MMBtu*3years =$14.5/MMBtu). These calculations for residential users may be summarized as below:

LNG CIF Price... 6.00 $/MMBtu
LNG Terminal Toll....................................... 1.25
Trunk line Gas Transportation Cost 1.00
City Gas Toll 14.00
Connecting Fee 14.50
Total .... 36.75 $/MMBtu

Presently, LPG retail price is set by DOE. An actual LPG price delivered to a user in Pretoria in June 2016 was ZAR 23.6/kg before VAT, which comprises ZAR 22.0/kg for LPG price and ZAR 1.6/kg for delivery cost for use of 9kg cylinder, or $36.3/MMBtu. This means that imported LNG will be competitive even for residential users. In addition, the connecting fee of $14.40 as calculated above will no more be aware of in consumers' mind after city gas supply system has been installed. Once supply starts, consumers may feel that city gas is much cheaper than LNG. It is also noted that the above calculation is made on a higher cost side. And that, if additional anchor demand is found to raise the system load, gas supply unit cost will be significantly cut down.

For the larger industrial and commercial users, the connecting cost per unit of gas supply will be much cheaper, which may be calculated with longer economic horizon and greater consumption quantity. In addition, they can clear environmental requirement by shifting fuel to natural gas. At relatively smaller energy users, convenience of natural gas like electricity that does not need supply/inventory management will significantly ease administration cost.

In the above calculation, a relatively modest development of city gas system is assumed to supply 300kt of city gas in LNG equivalent. However, the system assumed here may be able to accommodate much more gas requirement if a sufficient amount of demand is developed. Figure 7.6-7 shows the changes in the city gas toll in accordance with demand expansion.

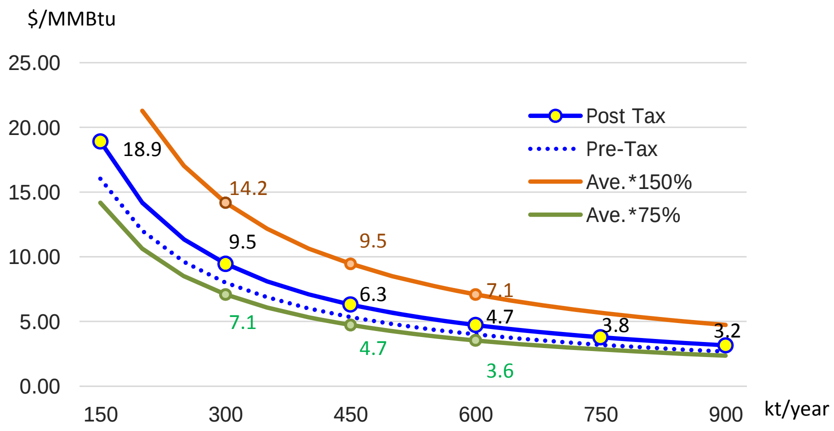


Figure 7.6-7 City Gas Toll Subject to Handling Amount

According to the calculation, the required average toll of city gas is $9.5/MMBtu for the case of handling 300kt LNG equivalent natural gas annually, which decreases to $6.3/MMBtu for the case handling 450kt a year and $4.7/MMBtu for the case handling 600kt a year. Applying a volume factor of 150% for the smaller users, the toll goes down remarkably from $14.2/MMBtu to $9.5/MMBtu for the 450kt case and further less to $7.1/MMBtu for the 600kt case. For the larger users with the volume factor at 75%, it goes down from $7.1/MMBtu to $4.7/MMBtu and further less to $3.6/MMBtu, respectively.

Development of city gas system by LNG looks beneficial wherever certain size of collective demand is expected, while the relationship between the market size and invest amount gives a significant impact on the delivery cost of city gas as analyzed above. As this study is carried out on a hypothetical case with bold assumptions, it will be valuable to examine the possibility of developing city gas system in the Gauteng Province with more deliberate study on the feature of the regional energy demand.

Chapter 8 Pathways to Introduce Natural Gas

In this chapter, we develop possible pathways to introduce natural gas to South Africa based on the foregoing study. From the experience of the preceding countries where resources are scarce, natural gas would not be introduced automatically despite the fact that it is thought as fuel of choice for the modern society. Strong political motivation and persevering efforts are always needed to materialize epoch making socio-economic objectives.

8.1 Summary of Findings

8.1.1 Natural Gas Supply Options for South Africa

Natural gas resources discovered to date in South Africa are quite limited. Total 2.2 Tcf of natural gas reserves have been discovered offshore southern and western coasts of the country mostly in the 20th century, of which 0.9 Tcf is the present remaining reserve and only 0.3 Tcf is producible with the existing system as summarized in Table 3.2-2. All the indigenous production is used at the GTL plant of PetroSA located at Mossel Bay. The existing gas fields are depleting fast after production for decades. However, exploration activities have been quite slow in the past decade without any remarkable success.

In addition to the conventional gas resources, it is expected that a huge amount of unconventional gas resources such as coal bed methane (CBM) and shale gas would exist in the Great Karoo Basin. However, exploration for CBM is being implemented only by a limited number of independent oil companies and exploration for shale gas is yet to be approved by the government despite applications for license have been filed by international oil companies (IOCs) several years ago. Considering the totally stagnant international atmosphere for hydrocarbon exploration at present doubled with slow response by the government, unconventional gas resources are anticipated to remain just as a dream for years to come.

All in all, domestic natural gas production is not likely to increase in the next 10 years. Rather, its shortage is a pressing problem for PetroSA who is using indigenous natural gas as feedstock for its refinery.

In South Africa, synthetic gas produced from coal has been supplied for decades by SASOL. This is a legacy technology inherited from the Apartheid age applying highly energy wasteful process. Presently, high quality gas is being supplied from the SASOL’s Secunda plant in the Gauteng Province and via Lily pipeline to the KwaZulu-Natal Province. However, SASOL has no further plan to expand the plant.

In addition to the domestic gas supply, South Africa has been importing natural gas from Pande and Temane gas fields in Mozambique. However, to increase import, it is necessary to expand the gas field production and pipeline capacity, which is proposed by SASOL but yet to be put on the negotiation table. In the Ruvuma Basin located in the northeastern part of

Mozambique, huge natural gas resources have been discovered. However, as analyzed in Section7.2, these resources are located in very deep water. In view of the long distance to the demand centre in South Africa and the huge demand size required to justify such pipeline, they should be considered as one of potential sources of LNG supply rather than a pipeline option. In addition, the piped gas import from Mozambique must be examined together with the ambitious domestic gas utilisation program proposed in the country, which complicates the issues relating to materialization of the development plan. Under the circumstance, piped gas import from Mozambique may be considered not an immediate but a long term secondary option.

In Botswana, CBM exploration is being implemented by small independent oil companies and its supply is offered to South Africa. However, the CBM reserves recognized to date is quite limited and it will take significant time before certain resources for development could be established. This should be another long term option.

On the other hand, LNG supply is developing fast in the world since the turn of the century. It is being accelerated by the shale gas revolution in the United States. Global LNG supply is forecast to be ample for at least another decade. In addition, South Africa is located at a quite beneficial point to obtain LNG supply from most of major LNG suppliers in the world. It is about 10 days voyage from both of the Middle East and North West shelf of Australia.[53] Though it is necessary to construct LNG receiving facility, it can be the most reliable and sustainable natural gas supply source.

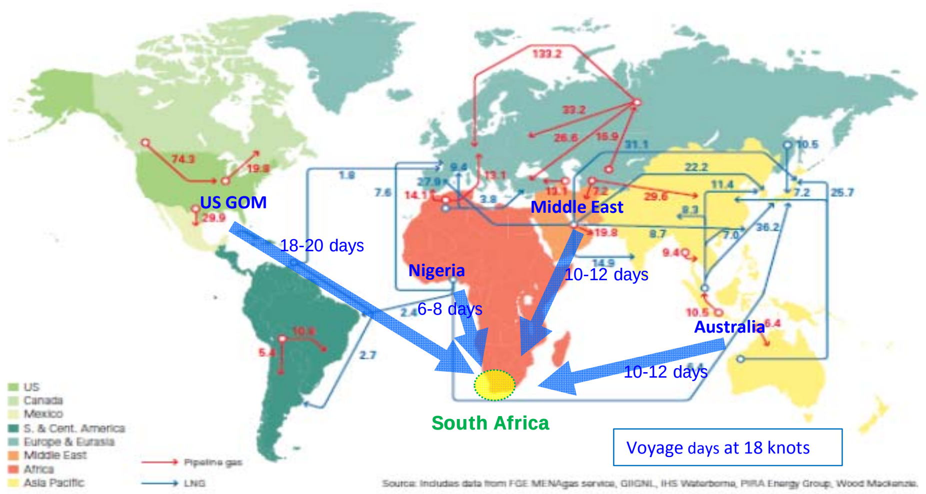


Figure 8.1-1 LNG sources for South Africa

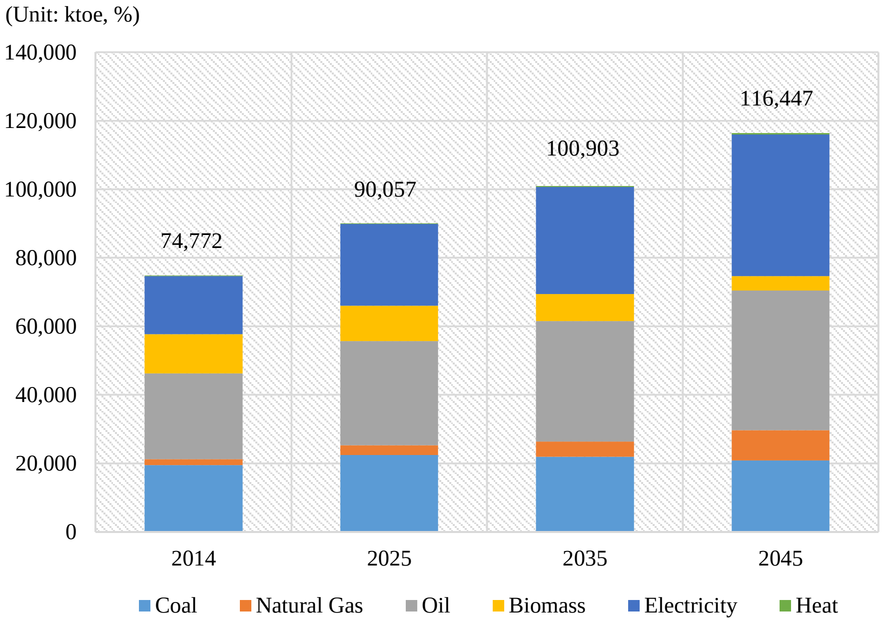
From the above observation, LNG should be deemed as the only realistic and immediate option for South Africa to provide stable natural gas supply at least for the next 10 years.

[53] At 18 knot tanker speed it takes approximately 10days voyage to Richards Bay from Doha, Qatar, and Karratha, northwest shelf of Australia, while 20 days from Gulf of Mexico, 7 days from Nigeria, and only 3 days from the Ruvuma Basin of Mozambique.

8.1.2 Energy and Natural Gas Demand

(1) Final Energy Consumption by Energy Source

The final energy demand of South Africa will increase from 74,722 ktoe in 2014 (in oil equivalent, thousand tons) to 116,447 ktoe in 2045 at 1.4 % of average annual growth rate. Energy – GDP elasticity of the same period is 0.4. Figure 8.1-2 shows the final energy demand by energy source and shares. The energy mix in 2045 is projected at 35.0 % for oil, 35.5 % for electric power, 17.9 % for coal, 7.5 % for natural gas, 3.6 % for biomass, and 0.4 % for heat. The share of oil remains at the same level between 2013 and 2045. A part of coal and biomass consumption will be shifted to electricity and natural gas reflecting promotion of modern fuel use and environmental protection.



(Source) JICA Study Team

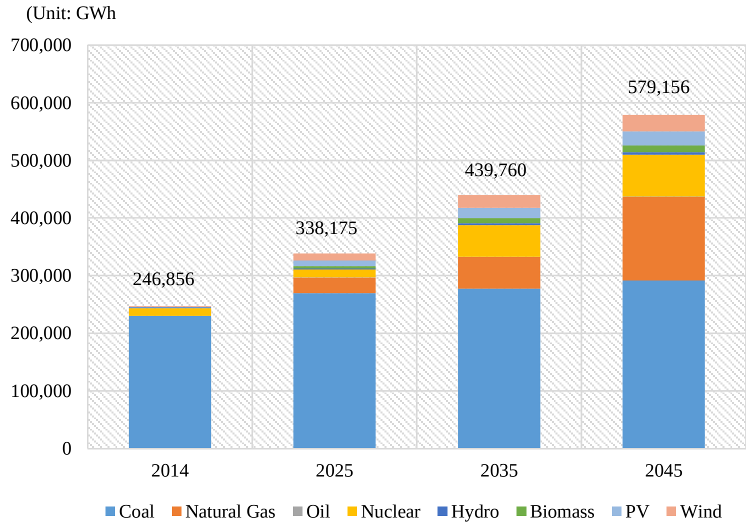
Figure 8.1-2 Final Energy Demand by Energy Source and Share (2013~2045)

(2) Power Supply

As shown in Figure 8.1-3, electric generation will increase 2.3 times from 247 TWh in 2014 compare to 579 TWh in 2045 at annual average growth rate 2.8 %.

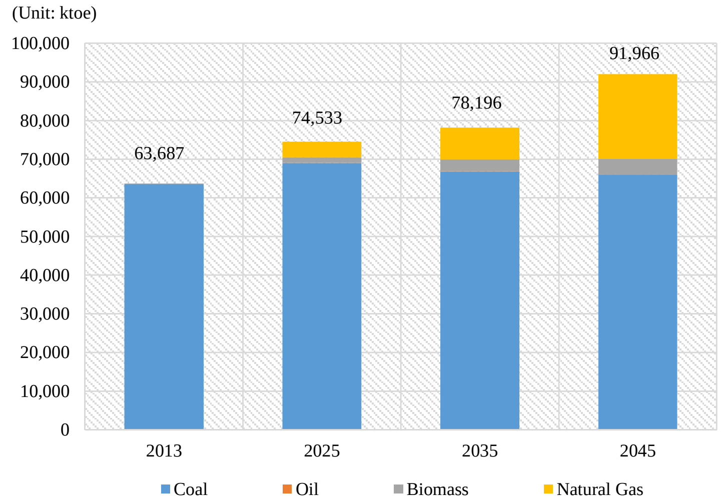
The generation mix by energy sources will diversify toward 2045 resulting in 50.3% for coal, 25.1% for natural gas, 12.5% for nuclear, 11.2% for renewable energy, and 0.1 % for oil. In year 2014, 93.1% of the electricity generation relied on coal. Coal ratio is however decreasing to 50.3 % in 2045. Among others, expansion of electricity generation by natural gas will significantly increase, and the share of natural gas generation is estimated to account for 25.1 % of the total power generation in 2045.

Figure 8.1-4 shows the composition of the required fuel for thermal power generation excluding nuclear, hydro and renewable energy. In 2014, 99.8 % of fuel for power generation in South Africa was supplied with coal. However, the amount of gas fired power generation will rapidly increase by promotion of the natural gas policy. In 2014, there was no natural gas consumption for power generation, but gas demand is projected to increase to 4,081 ktoe (equivalent to 3.1 million LNG)[54] in 2025, 8,292 ktoe (6.04 million tones LNG) in 2035, and 21,928 ktoe (16.9 million tones LNG) in 2045.



(Source) JICA Study Team

Figure 8.1-3 Power Generation by Source (2013~2045)



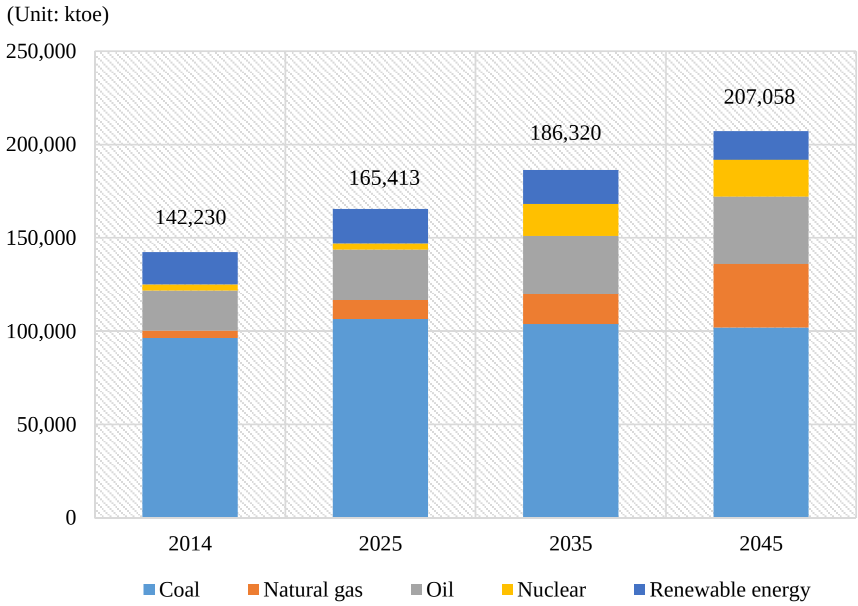
(Source) JICA Study Team

Figure 8.1-4 Fuel Consumption in Power Sector of South Africa (2013~2045)

54 1 ktoe equivalent to 768.26 tones LNG.

(3) Total Primary Energy Supply

Figure 8.1-5 shows evolution of the total primary energy supply in South Africa from 2014 to 2045. The total primary energy supply will increase from 142,230 ktoe in 2014 to 207,058 ktoe in 2045 at an annual 1.2 % growth rate. Compared with an annual 1.4 % growth rate for the earlier period for 2014-2025, the long-term growth rate (1.2 %) for the whole projection period for 2014-2045 will be slightly lower. The share of natural gas in the total primary energy supply will expand from 2.7 % in 2013 to 16.5 % in 2045. Natural gas will become an important energy source after coal.



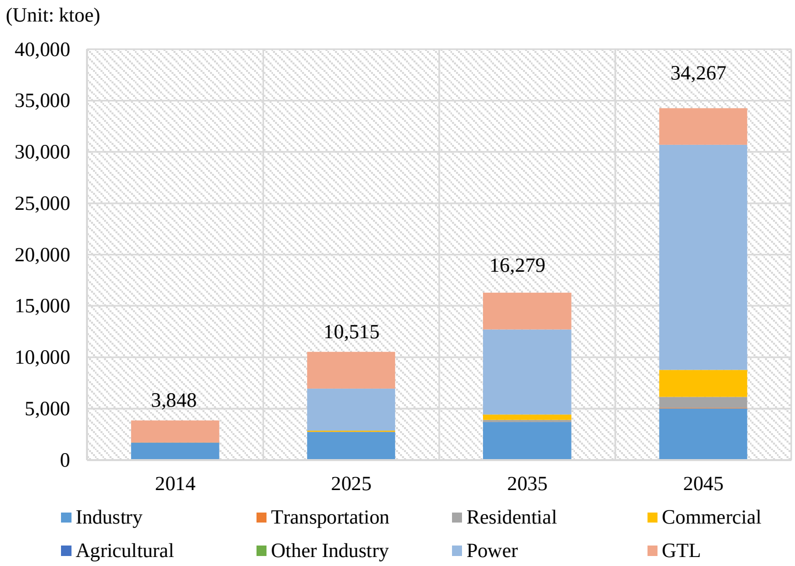
(Source) JICA Study Team

Figure 8.1-5 Total Primary Energy Supply of South Africa (2013 - 2045)

(4) Natural Gas Demand Outlook

Figure 8.1-6 shows natural gas demand outlook in South Africa. Natural gas demand was to 3,848 ktoe in 2014 where it was mainly consumed by the industry sector (1,698 ktoe, 44.1 %) and GTL plants (2,149 ktoe, 55.8 %). In the industrial sector, natural gas was consumed by iron and steel industry (236 ktoe, 13.9 %), chemical industry (933 ktoe, 54.9 %), non-metallic industrial (314 ktoe, 18.5 %), non-ferrous metal industry (14 ktoe, 0.8 %) and other general industry (201 ktoe, 11.8%).

According to the model analysis conducted in this study, natural gas as primary energy supply will increase at annual 7.3% and expand 9 times from the current level of 3,848 ktoe in 2014 to 44,487 ktoe in 2045. Natural gas will be mainly consumed in the power sector and the residential sector. Among others, gas consumption in the power sector will account for 64.0% (21,928 ktoe) of the total natural gas demand in 2045. Industrial sector has a certain potential of increasing natural gas consumption. In this sector, the natural gas demand will increase at annual 3.6 % and reach 5,035 ktoe in 2045, amounting to 14.7 % of the total natural gas demand. In the transport and commercial sectors natural gas consumption will be still small with limited potential in the BAU projection. To promote penetration of natural gas use in these sectors, it is essential to provide strong policy support.



(Source) JICA Study Team

Figure 8.1-6 Natural Gas Demand Outlook (2013 - 2045)

8.1.3 Natural Gas Import via LNG and Pipeline

Natural gas may be imported in the form of LNG or via international pipeline. Outcome of the analysis conducted in Section 7.2 is summarized in Table 8.1-1, where the necessary tolls to achieve IRR=10% are calculated. LNG terminal cost may be in the range of $1.0-1.3/MMBtu. Considering the LNG liquefaction cost at approximately $4.0/MMBtu and ocean freight at $1-2/MMBtu, the long distance pipeline from the Ruvuma basin of Mozambique may be competitive with LNG. However, to justify such a huge project, an immense amount of demand exceeding 5 million tons a year in LNG equivalent should be secured. This is not an easy task to achieve. Thus the Ruvuma gas pipeline may be considered not as an immediate option but as one of the future options.

Table 8.1-1 Economics of LNG Terminal and Long Distance Pipeline

	Quantity	Toll at 10% IRR	
		Post Tax	Pre-Tax
	MTPA	$/MMBtu	$/MMBtu
LNG Onshore Terminal	2.50	1.24	1.00
FSRU	1.50	0.98	0.80
Ruvuma Pipeline	5.40	5.05	4.05

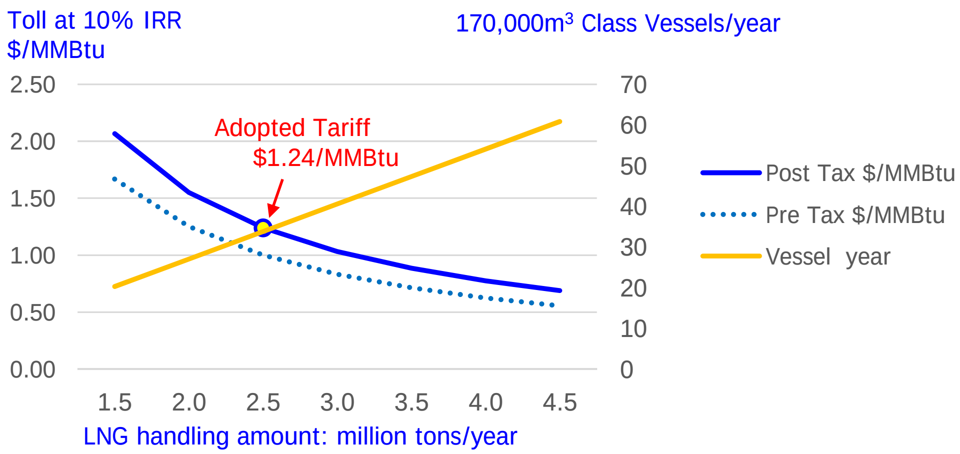


Figure 8.1-7 LNG Terminal Toll

It should be noted that an LNG terminal is a highly capital intensive facility, and the required toll changes according to the amount of LNG handled at the terminal. In this Study, we have assumed 2.5 million tons as an annual throughput in view of the presently anticipated gas demand size in South Africa and consideration on supply security as stipulated below, and adopted $1.25/MMBtu as a toll for other analyses. However, if the annual throughput increases in future as the country's gasification progresses, the toll may be lowered as shown in Figure 8.1-7.

Compared with that for an onshore terminal, the toll for FSRU is cheaper as shown in Table 8.1-1. However, its operation is anticipated to be terribly tight as calculated in Table 8.1-2.

Table 8.1-2 Assumptions for Operation of LNG Terminals

	Quantity	Tank Space	Cargo Size	Stock	
	MTPA	m^3	m^3	m^3	days
Onshore LNG Terminal	2.50	360,000	170,000	190,000	12.1
FSRU	1.50	170,000	136,000	34,000	3.6
Ratio	60%	47%	80%	18%	30%

(Note) LNG with heat value of 43 MJ/m3 and SG of 0.435

Here, the onshore LNG terminal is equipped with 180,000m^3 x 2 storage tanks. Assuming a general cargo size at 170,000m^3 representing the recent trends of new builds, just before receiving a new cargo, the terminal may have a 12-day stock at hand (at maximum) for a 2.5 MTPA throughput. In the case of a FSRU with storage capacity of 170,000m^3, however, considering a smaller cargo lot of 136,000m^3, a size of aging tankers, only a 3.5-day stock will be at hand at maximum at the time of unloading for a 1.5 MTPA throughput.

To consider the supply security aspect, stock days at hand just before arrival of a new cargo are compared among cases of 1) FSRU, alone. 2) FSRU+ one onshore tank or onshore terminal with two tanks, and 3) FSRU + tow onshore tanks or onshore terminal with three tanks as below.

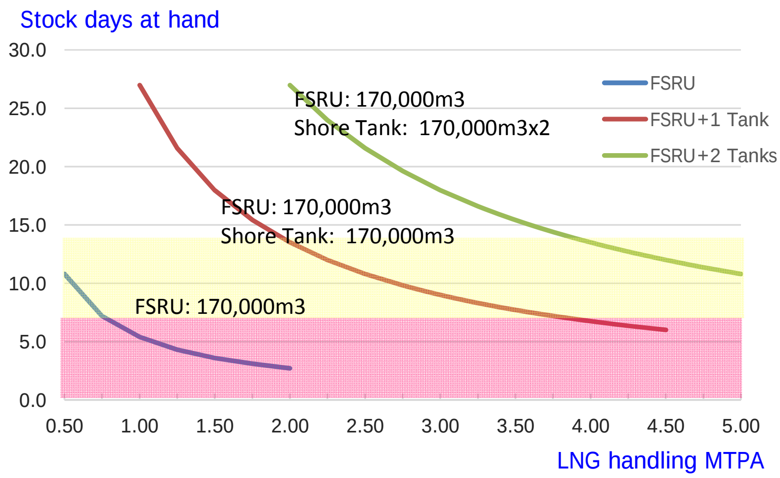


Figure 8.1-8 Maximum Stock Days at hand when a New Cargo Arrives

In international shipping operation, oil and gas companies generally keep two week running stock since delays of one week or so in vessel operation are often experienced due to disturbance in the previous voyage, rough weather, etc. As South Africa is isolated from other LNG markets, international LNG shipping routes or most of LNG supply points, it would be difficult to find quick help in case vessel operation encounters any problem. In this regard, implementing natural gas supply with LNG import, a proper amount of stock must be kept at hand to assure stable operation. From the national security view point, it is desirable to consider some strategic stockpiling in addition to a safe running stock.

8.1.4 Economics of Gas Projects

Feasibility of various gas based projects is examined in Chapter 7 as summarized in Table 8.1-3. Objective projects include chemical industries to produce fertilizer and methanol, liquid fuel industries such as GTL, DME and MTG, and CNG station business to supply natural gas to motor vehicles. In addition, feasibility of LNG supply as feedstock for the Mossel Bay GTL Refinery of PetroSA is examined, where the present feedgas supply from the offshore gas fields is depleting fast. The outcome are summarized as follows:

a. Using LNG as feedstock, chemical industries such as fertilizer and methanol are marginally commercial if their products are directed solely for the domestic market. If the CAPEX were reduced by 20%, these projects would come into the commercial range. However, sufficient domestic demand must exist to support this, which is not the case for South Africa. When the project operators are forced to sell their products in the international market at discount prices, project economics deteriorates seriously. Only when ample indigenous gas were available at cheaper price, these projects may be safely developed even for the export market.

b. Using LNG as feedstock, liquid fuel industries such as GTL, DME and MTG are totally sub-commercial. Even if capital cost were reduced by 20%, this result does not change. This is because substantial heat value is lost in the F/T synthesis process, which is the core technology for liquefaction. Only when ample indigenous gas were available at cheaper price, these projects may become commercial.

c. In contrast to the above industries, CNG supply for motor vehicles using LNG will produce good economics. However, as individual business size is quite tiny, collective development under a comprehensive transportation policy will be needed to materialize this bushiness. In addition, LNG import and city gas supply system must be established by other gas consumers providing anchor demand to support the immense size of LNG business.

d. Supply of LNG as feedgas for the Mossel Bay GTL Refinery shows favorable economics. However, as discussed in Chapter 7, the economics heavily depends upon the balance of prices between petroleum products and LNG. The project scenario must be carefully examined before the final investment decision.

Table 8.1-3 Economics of Gas Projects

Base Case (LNG Terminal Toll: $1.25/MMBtu)

			Fertilizer	Methanol	GTL	DME	MTG	CNG	PetroSA GTL
Plant Size			1.3 MTPA	1.0 MTPA	30,000 bpd	0.25 MTPA	0.23 MTPA	10,000m^3/d	45,000bpd
Gas Consumption	Daily	MMcfd	80	100	268	35	60	0.35	402
	Annual	LNG kt	582	728	1,950	255	437	2.6	2,925
	25 years	Bcf	647	809	2,211	289	396	2.7	3,317
Project Economics									
IRR: LNG	Post-tax	%	8.3	8.8	3.3	-0.6	NA	10.9	34.0
Reference Case	Pre-tax	%	10.4	10.7	4.5	-0.6	NA	13.5	42.5
IRR: Indineous Gas	Post-tax	%	14.1	20.6	12.0	12.0	7.0	22.9	NA
$3.00/MMBtu	Ppre-tax	%	17.2	24.5	14.9	14.9	8.9	27.9	NA

For CNG, city gas charge is assumed at $4.0/MMBtu

Alternative Case (LNG Terminal Toll: $1.00/MMBtu, CAPEX:80%)

			Fertilizer	Methanol	GTL	DME	MTG	CNG	PetroSA GTL
Plant Size			1.3 MTPA	1.0 MTPA	30,000 bpd	0.25 MTPA	0.23 MTPA	10,000m3/d	45,000bpd
Gas Consumption	Daily	MMcfd	80	100	268	35	60	0.35	402
	Annual	LNG kt	582	728	1,950	255	437	2.6	2,925
	25 years	Bcf	647	809	2,211	289	396	2.7	3,317
Project Economics									
IRR: CAPEX=80%	Post-tax	%	10.6	10.8	5.8	1.9	NA	13.8	40.0
Reference Case	Pre-tax	%	13.1	13.0	7.6	2.7	NA	16.9	50.4
IRR: Indineous Gas	Post-tax	%	16.5	24.4	14.6	14.5	8.9	26.7	NA
$3.00/MMBtu	Ppre-tax	%	20.1	28.8	18.0	17.8	11.2	32.4	NA

(Note) All products are sold solely in the domestic market.

In summary, use of LNG as feedstock for specific gas industry would not be feasible under the current hydrocarbon market conditions. These industries may be considered only when ample indigenous natural gas become available at a cheaper price, or if oil price goes up significantly while LNG price remain stagnant.

However, in view of the good economics found for the CNG business, it is valuable to look into feasibility of developing city gas supply system to enable such smaller gas businesses. This will be discussed in the next session.

8.1.5 Natural Gas for Smaller Users

In addition to the natural gas use for gas based industries, possibilities of natural gas delivery to smaller users are examined by way of a) LNG delivery by tank truck and b) developing city gas supply system.

Figure 8.1-8 shows the comparison of the required toll for pipeline and tank truck transport to achieve IRR 10%. The pipeline cost does not include regasification cost as LNG is regasified at the LNG terminal, while tank truck cost includes regasification cost at a satellite terminal. For transporting small volume of natural gas, tank truck plus LNG satellite station system is significantly beneficial.

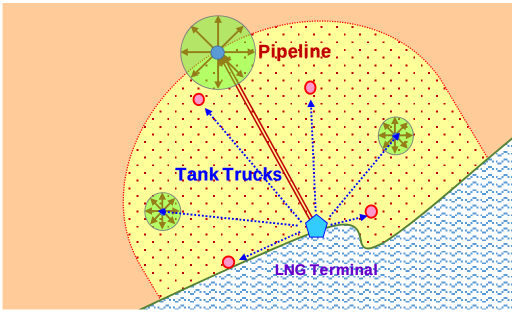


Figure 8.1-9 Delivery Area of Pipeline and Tank Truck

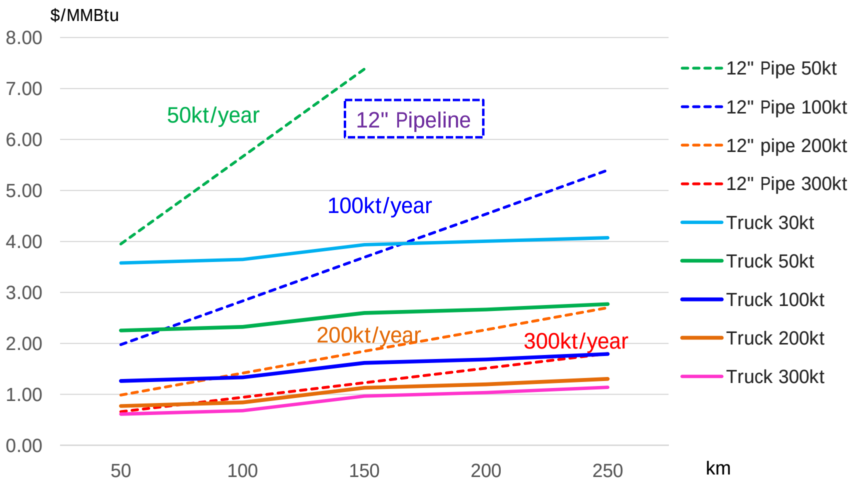


Figure 8.1-10 Pipeline versus Tank Truck

In addition, as a pipeline can transport natural gas in relatively large volume from one point to another, tank truck can deliver LNG in a smaller lot to users scattered within an area of certain radius. Thus, it is possible to pick up scattered smaller demand collectively. Though it is necessary to prepare regasification unit at each end users, it would not be too expensive to deteriorate the economics seriously. Then, one day after local demand has sufficiently grown up, gas pipeline can be constructed to replace tank truck transport.

In addition, expansion of the existing city gas system in the Johannesburg area is examined in Section 7.6.3 assuming a target gas supply of 300,000 tons a year in LNG equivalent. The bottom-up calculation shows the city gas delivered price for residential users including one time connecting fee of $1,000 will be around $37/MMBtu assuming that LNG CIF price at $6.00/MMBtu. This is very similar to the LPG retail price at $37.3/MMBtu set out by NERSA. Since the connecting fee is one-time payment, after city gas supply has started, consumers may feel that city gas is much cheaper than LPG.

Thus, it is valuable to examine a city gas development plan. However, consumers are usually conservative. To implement this, it is necessary to establish a good and publicly acceptable plan and proactively promote it.

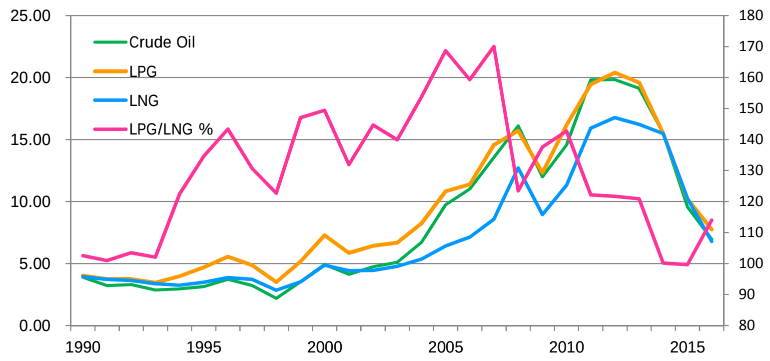


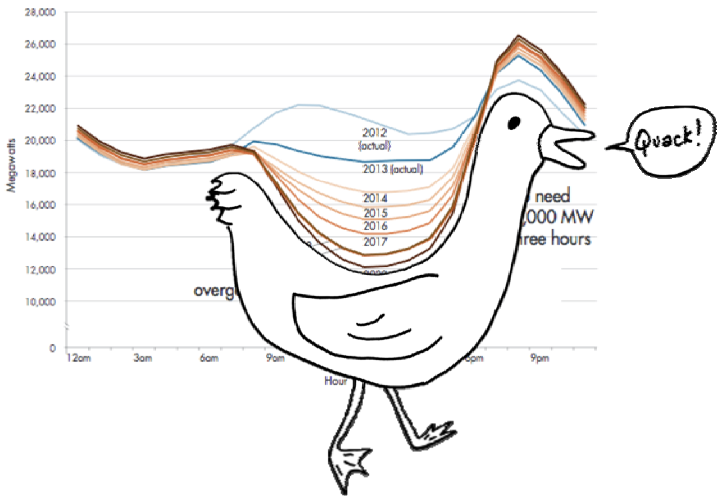
Figure 8.1-11 LPG and LNG: CIF Prices at Japan

In view of the recent development in the world energy market, LPG may be an effective option to accommodate gas requirement of small-medium sized users. Historically LPG used to be expensive compared with LNG. It is popular being easy to handle with less expensive facility and in smaller lots, while its supply was unstable. LPG is a subjective product produced associated with crude oil, natural gas and refinery processing and often fails to meet demand change. In recent years, however, a significant amount of LPG supply has come up in the United States associated with the emerging shale gas and tight oil production. In 2016 LPG price has come down to a level almost equal to that of LNG in the global market. Present ample supply situation is expected to last for some time.

LPG import and delivery can be implemented at smaller cost without requiring a large anchor demand like LNG. Under the circumstance, LPG may be an easy and quick solution to promote gasification in the commercial and residential sectors.

8.2 City Gas to Save Power Crisis

With penetration of photovoltaics (PVs) into the power grid, so called "Duck Curve" is increasingly threatening the hourly electricity supply balance. During the day time, PVs supply more electricity depressing operation of other plants. However, after the sunset, PVs no more produce electricity; peak requirement for other power sources shifts to the evening. This phenomenon is typically observed in California. [55] As PVs are being strongly promoted in South Africa, peak shaving in the morning and evening will become increasingly an issue as well.

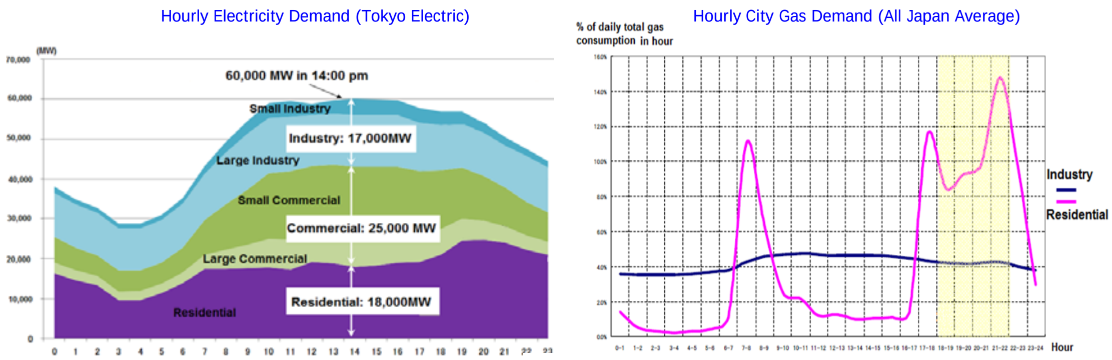


(Source) California ISO (Independent System Operator) / Jordan Wirfs-Brock

Figure 8.2-1 Duck Curve Representing Shift of Peak Demand

Introduction of city gas system may ease the problem. Electricity is widely used for cooking and space heating in South Africa. As shown in Figure 8.2-2, in case of Japan, evening peak of residential electricity demand is absorbed by decreasing demand in the commercial sector, and the total balance does not show the "Duck Curve" phenomenon yet. In contrast, city gas demand in the residential sector for cooking, hot water and space heating concentrates in the morning and evening. This suggests that, introducing city gas system, early evening electricity demand may be significantly trimmed. In particular, in Gauteng Province where winter energy consumption for space heating is high, city gas may become a relief for the power supply system. Unlike electricity, city gas does not need exact simultaneous supply. Pipeline can allow pressure changes of ±10%. If further flexibility is necessary, gas holders (tanks) may be installed to supplement the capacity.

[55] California ISO, which operates a large part of California's electric grid and is focused on future grid security, published a graph of what the net load looks like today, and what it could look like in the future as California switches to a mandated renewable- and solar-reliant electricity system. The blue lines at the top are what the net load looked like in 2012 and 2013, based on real data from the grid. The brown lines are future projections of what the grid load might look like, culminating with 2020.



(Source) Tokyo Electric Power Company and Japan Gas Association

Figure 8.2-2 Hourly Electricity and City Gas Demand

As shown in Figure 8.2-3, the share of residential city gas consumption is about 30% in Japan. Therefore, residential demand has significant impact on the total gas and electricity demand.

Compared with construction of peak shaving power stations, development of city gas system will be significantly cheaper. It is also energy effective as power generation and transmission losses will be avoided.

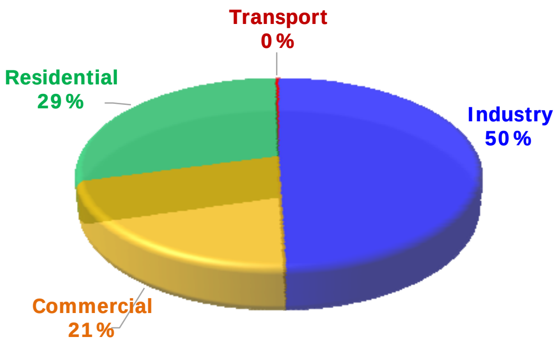


Figure 8.2-3 City Gas Demand in Japan

As discussed above, our preliminary assessment shows that city gas system is economically viable. Thus, we would recommend that development of city gas system based on LNG should be sought from overall energy planning view point.

8.3 Way forward

According to the draft Integrated Energy Plan (IEP) presently under review, aggressive introduction of natural gas is planned to change the energy structure of South Africa to improve energy security and reduce GHG emissions. As discussed in Chapter 4, this will incur significant increase in requirement for natural gas supply. The resultant gas requirement is calculated for two cases as shown in Table 8.3-2 as follows:

Case-A: Domestic gas production will deplete without new additional discoveries. Natural gas import from Pande and Temane gas fields in Mozambique shall remain at the present level.

Case-B: Domestic production of conventional gas will increase with new discoveries in the deepwater blocks, while unconventional gas in the Great Karoo Basin will also be developed. Piped natural gas import from the Pande and Temane gas fields and adjacent blocks will increase significantly.

Table 8.3-1 Natural Gas Supply Balance for South Africa

		2014	2025	2035	2045
Gas Demand		ktoe	ktoe	ktoe	ktoe
	GTL	2,149	3,568	3,568	3,568
	Power	0	4,081	8,292	21,928
	Industry	1,698	2,719	3,681	5,035
	ResCom	2	146	731	3,688
	Total	3,848	10,514	16,272	34,219
Gas Supply					
Case-A		ktoe	ktoe	ktoe	ktoe
	Production: Conventional	869	500	0	0
	Import: Pande $ Temane	2,979	3,000	3,000	3,000
	Sub-Total	3,848	3,500	3,000	3,000
	Additional Import	0	7,014	13,272	31,219
	LNG Equivalent (kt)	0	5,396	10,209	24,015
Case-B	Production: Conventional	869	500	1,000	1,000
	Unconventional	0	500	5,000	10,000
	Import: Pande $ Temane	2,979	5,000	10,000	10,000
	Sub-Total	3,848	6,000	16,000	21,000
	Additional Import	0	4,514	272	13,219
	LNG Equivalent (kt)	0	3,472	209	10,169

As shown in the table, Case-A requires higher amount of natural gas import which will exceed 5 million tons per annum (MTPA) in LNG equivalent by 2025 and grow rapidly thereafter. Case-B gives a smaller requirement, but it still exceeds 3.0 MTPA in LNG equivalent by 2025 and continues to increase at a modest speed. These calculations suggest that the country will be importing 3 - 5 million tons of LNG by 2025 and 10 - 25 MTPA around 2040.

From this calculation, it is apparent that construction of multiple LNG terminals will be necessary in the near future to accommodate the natural gas introduction plan. And that such plans can be justified by confirmation of gas power plant construction plans that will provide anchor demand. Once this procedure has been successfully completed, LNG supply for smaller users will become possible. LNG supply as feedstock for the GTL Refinery at the Mossel Bay should be considered as a pressing issue to effectively utilize the existing plant.

Another important issue is that South Africa must prepare appropriate legal regime to promote exploration in deepwater blocks for conventional oil and gas and also to support exploration and development of unconventional gas expected in the Great Karoo Basin. In particular, successful development of unconventional gas may open the door to develop gas based industries in the country.

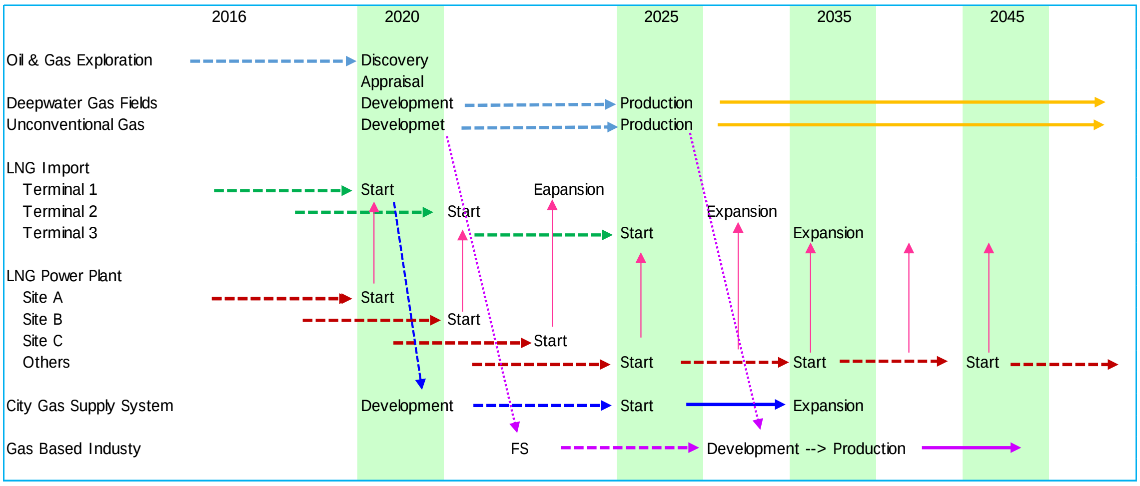


Figure 8.3-1 Timeline for Development of Natural Gas Supply by LNG

The above prospects may be summarized as a roadmap to develop natural gas utilisation in South Africa as illustrated in Figure 8.3-1.To kick-off these activities, it is critical to identify construction of power plants and LNG terminals at first, as well as to prepare conditions for proactive oil and gas exploration. It should be noted that multiple plans need to be developed simultaneously to accommodate the rapidly increasing gas demand. Then, city gas supply system may be deemed as another important flagship project to promote awareness of citizens that natural gas is an indispensable option to improve the energy structure of the country and to reduce GHG emissions.

From the above analysis, the Study team wishes to recommend the following actions to be taken for promoting gasification in South Africa:

1) Immediate Action:

a. Firm-up energy and natural gas demand outlook for the next decade or two. Based on the outlook, multiple LNG import projects should be developed to accommodate gas demand expansion.

b. To this end, firm-up the LNG import plans for power generation and the Mossel Bay GTL refinery.

c. Set out consistent legal framework for oil and gas exploration targeting deepwater and unconventional resources.

2) Medium-term Action:

a. Develop a proactive expansion plan of the city gas supply system in the Johannesburg and peripheral area for general industries and commercial and residential sectors.

b. Examine small lot LNG transport to enhance penetration of natural gas as cleaner and healthy energy source to replace biomass.

c. Consider institution to invite FDI for these projects.

It is also recommended that the DOE should look into benefits of proactively introducing

LPG as a quick measure to enhance gasification of the country, the aspect of which was not in the scope of this study.

All in all, the Study team looks forward to proactive implementation of a natural gas utilisation program in South Africa.