Qeshm Free Zone Organization
(QFZO)

Japan International Cooperation Agency
(JICA)

THE PROJECT FOR COMMUNITY-BASED SUSTAINABLE DEVELOPMENT MASTER PLAN OF QESHM ISLAND TOWARD “ECO-ISLAND” IN THE ISLAMIC REPUBLIC OF IRAN

FINAL REPORT

Volume 4: Review of Oil and Gas Industry

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Abbreviations

CAPEX	Capital Expenditure
CIF	Cost, Insurance and Freight
EPC	Engineering, Procurement and Construction
FOB	Free on board
FYDP	Five Year Development Plan
IFO	Intermediate Fuel Oil
IRR	Iranian Rial
IUCN	International Union for Conservation of Nature and Natural Resources
JICA	Japan International Cooperation Agency
LNG	Liquified Natural Gas
MoU	Minutes of Understanding
NIGC	National Iranian Gas Company
QFZO	Qeshm Free Zone Organization
USD	United States Dollar

Unit of Measurement

Area

m^2	square meter
km^2	square kilometer
ha	hectare (= 10,000 m^2)

Length

mm	millimeter
cm	centimeter
m	meter
km	kilometer

Weight

µg	micro gram
mg	milligram
kg	kilogram
t	ton (=1,000 kg)
tpa	ton per annual
MTPA	million ton per annual

Volume

l	liter
m^3	cubic meter (= 1,000 liter)
bbl.	barrel (=0.159 m^3)
BCM	billion cubic meter
mmscfd	million standard cubic feet per day
Nm^3	normal cubic meter

Time

sec, s	second
min	minute
h, hr	hour
d	day
y /yr	year

Energy

W	watt
kW	kilowatt
kWh	kilowatt-hour
MW	megawatt
GW	gigawatt
GWh	gigawatt-hour
cal	calorie
kcal	kilocalorie
J	joules (=4.18 cal)
kj	kilo joules

Other

%	percent
$	dollar
Avg	average
degree	degree celsius
dB	decibel
mil.	million
ppm	parts per million

Comparison of Persian Year and Gregorian Calendar

Persian Year	Gregorian Calendar
1369	21 March 1990 – 20 March 1991
1370	21 March 1991 – 20 March 1992
1371	21 March 1992 – 20 March 1993
1372	21 March 1993 – 20 March 1994
1373	21 March 1994 – 20 March 1995
1374	21 March 1995 – 19 March 1996
1375	20 March 1996 – 20 March 1997
1376	21 March 1997 – 20 March 1998
1377	21 March 1998 – 20 March 1999
1378	21 March 1999 – 19 March 2000
1379	20 March 2000 – 20 March 2001
1380	21 March 2001 – 20 March 2002
1381	21 March 2002 – 20 March 2003
1382	21 March 2003 – 19 March 2004
1383	20 March 2004 – 20 March 2005
1384	21 March 2005 – 20 March 2006
1385	21 March 2006 – 20 March 2007
1386	21 March 2007 – 19 March 2008
1387	20 March 2008 – 20 March 2009
1388	21 March 2009 – 20 March 2010
1389	21 March 2010 – 20 March 2011
1390	21 March 2011 – 19 March 2012
1391	20 March 2012 – 20 March 2013
1392	21 March 2013 – 20 March 2014

Persian Year	Gregorian Calendar
1393	21 March 2014 – 20 March 2015
1394	21 March 2015 – 19 March 2016
1395	20 March 2016 – 20 March 2017
1396	21 March 2017 – 20 March 2018
1397	21 March 2018 – 20 March 2019
1398	21 March 2019 – 19 March 2020
1399	20 March 2020 – 20 March 2021
1400	21 March 2021 – 20 March 2022
1401	21 March 2022 – 20 March 2023
1402	21 March 2023 – 19 March 2024
1403	20 March 2024 – 20 March 2025
1404	21 March 2025 – 20 March 2026
1405	21 March 2026 – 20 March 2027
1406	21 March 2027 – 19 March 2028
1407	20 March 2028 – 19 March 2029
1408	20 March 2029 – 20 March 2030
1409	21 March 2030 – 20 March 2031
1410	21 March 2031 – 19 March 2032
1411	20 March 2032 – 19 March 2033
1412	20 March 2033 – 20 March 2034
1413	21 March 2034 – 20 March 2035
1414	21 March 2035 – 19 March 2036
1415	20 March 2036 – 19 March 2037

Part 1 Review of Gas Industry and LNG Project Development

Executive Summary

Iran is the country with the largest gas reserve, with its production cost considered to be the lowest in the world.

LNG demand will grow steadily and continue to be a major clean energy source for power generation.

Economically, the LNG project on Qeshm will be one of the most competitive projects in the world. There will be hardly any difficulty in finding a market due to the deregulation movement in the global gas and power sector, with dozens of marketers looking for cargo for the spot market.

Qeshm is located at the mouth of the Persian Gulf, a geopolitically very important location, with fewer nautical miles between the island and the gas market in Asia and Europe than in the case of Qatar, the major gas exporter in the world. Qeshm is located just next to an international waterway and an ideal site for the shipment of LNG.

Qeshm is designated as an economic FZ, so no tax on material imports and no businesses tax will be applied for at least 20 years.

In view of the environmental impact, effluent from an LNG plant is considerably cleaner compared with petroleum refining and petrochemical/chemical plants and has almost no impact on sea life and air pollution, which is why LNG production is best suited for Qeshm as an eco-island.

There are several choices for liquefaction technology as follows:

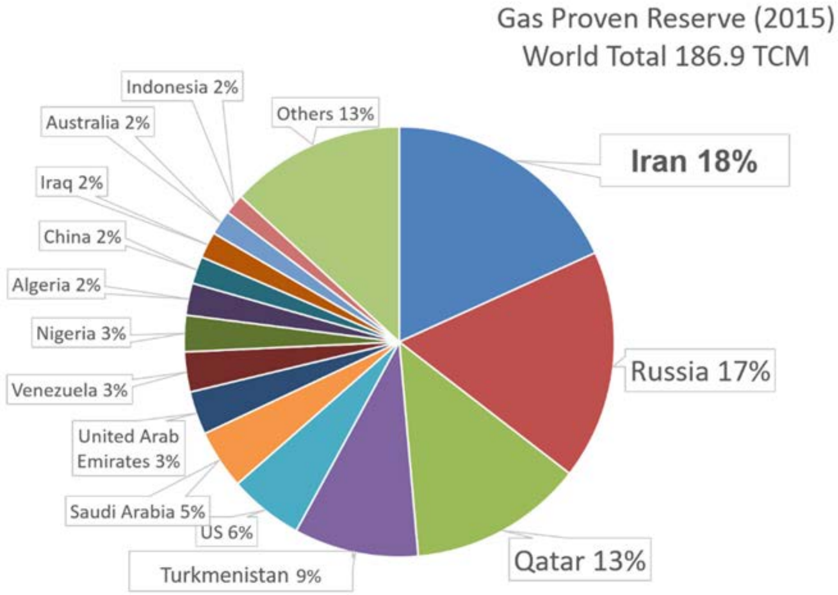
- APCI (USA): AP-C3MR, AP-X
- Shell (Holland): DMR
- Air Liquide (France): Liquefin
- Statoil/Linde (Norway/Germany): Mixed fluid cascade process (MFCP)

In view of process performance, there is no major difference between these options, all of which would work. However, it is necessary to invite an internationally experienced oil company as an **operator**, for project management and operation purposes, and employ a qualified contractor for the construction.

Another important condition is a long-term loan arrangement. The project life will be 20 years as a minimum, and some portion of the loan should cover 20 years of the plant life. This long-term loan may be arranged by the investing country in line with the framework of the **Energy Charter Treaty**.

CHAPTER 1 INTRODUCTION

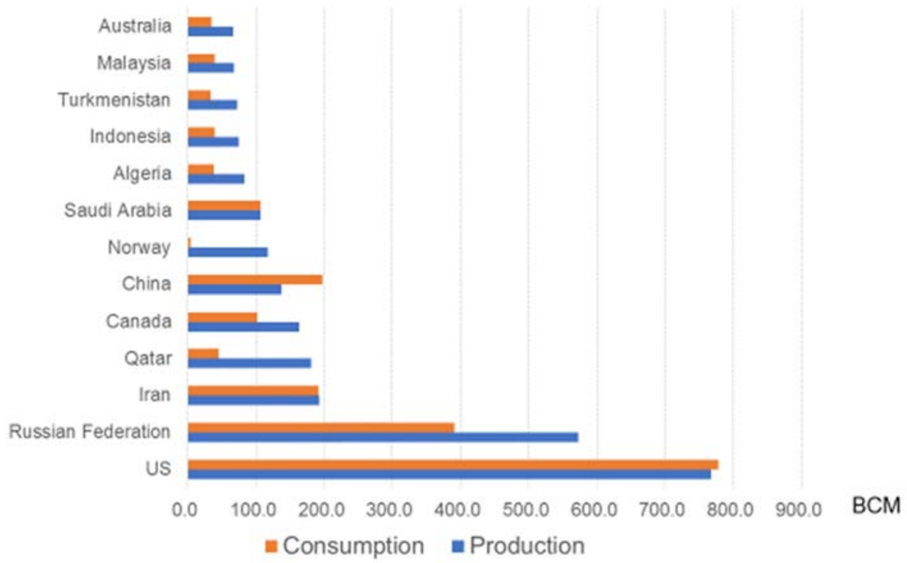
Iran is recognized as the country with the largest gas reserve, accounting for 18% of gas proven reserves in the world, followed by the Russian Federation and Qatar.



Source: BP Statistics 2016.

Figure 1.1 Gas Proven Reserve (2015)

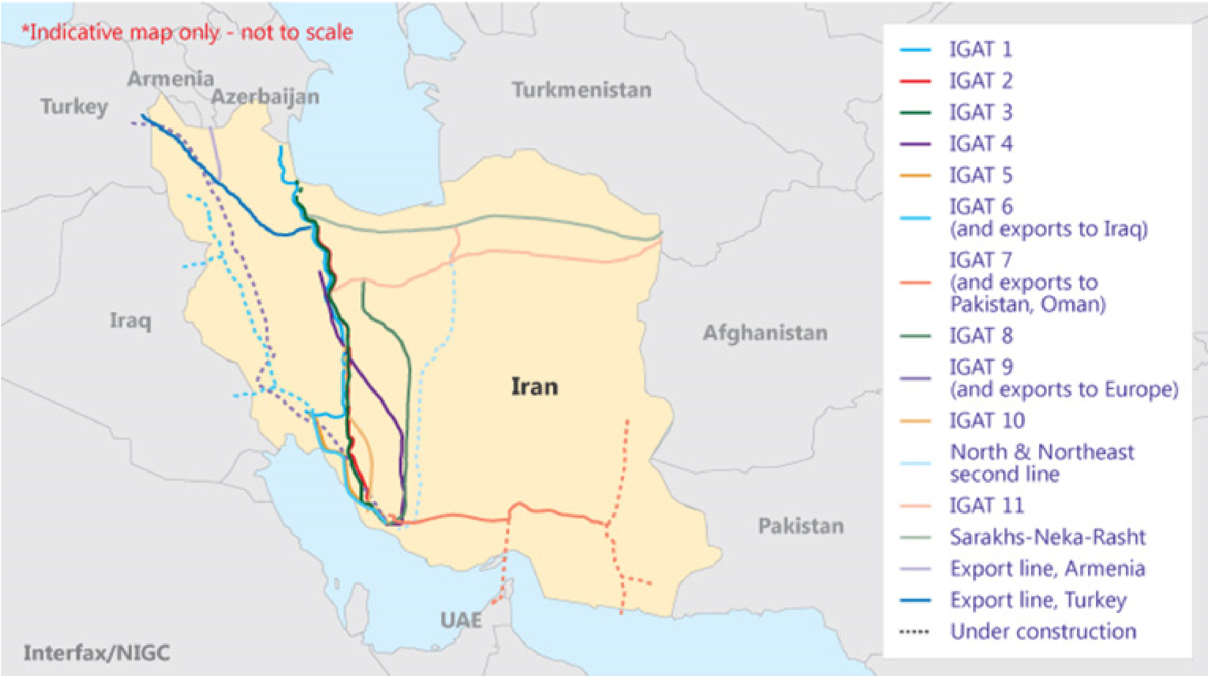
Iran is the third-largest gas producer and the four-largest gas consumer in the world. However, only a small amount of gas has been exported to neighboring countries, such as Azerbaijan, via the Iran Gas Trunk line (IGAT) 1, the first gas trunk pipeline in Iran, with Phase I commissioned in 1971 and Phase 2 in 1974.



Source: BP Statistics 2016.

Figure 1.2 Gas Production and Consumption in 2015

Since then, Iran has continued to develop its natural gas transmission system, expanding it to cover all the major provinces. The current gas transmission network is shown as follows:



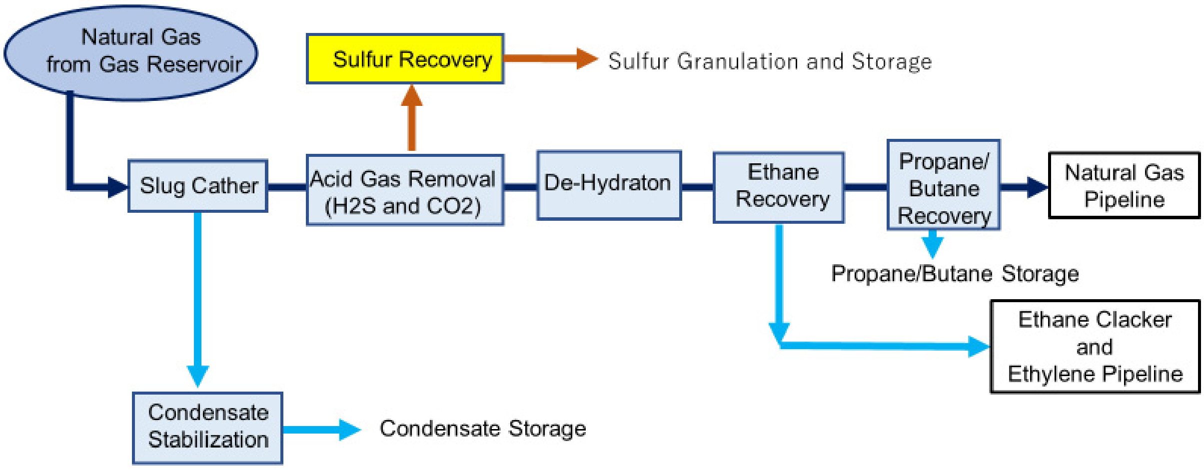
Source: Interfax, National Iranian Gas Company.

Figure 1.3 Iran Gas Transmission Pipeline Network

A list of gas transmission lines is shown as follows:

- IGAT1: 42-in (1,070-mm) line, constructed between Bid Boland Refinery in Khuzestan Province and Astara in the north.
- IGAT2: 56-in (1,420-mm) line, constructed between Kangan Refinery in Fars Province and Qazvin in the north.
- IGAT3: 56-in (1,420-mm) line, constructed between Asalouyeh and Central Province and ultimately to the north-western provinces.
- IGAT4: 56-in (1,420-mm) line, to transfer natural gas produced in South Pars, with Phases 1 to 5 from Asalouyeh to Fars and Isfahan Provinces.
- IGAT5: 56-in (1,420-mm) line, to transfer sour gas produced in Phases 6, 7 and 8 to Khuzestan Province for injecting into the oil wells.
- IGAT6: 56-in (1,420-mm) Line, to transfer natural gas produced in South Pars, with Phases 6 to 10 from Assaluyeh to Khuzestan Province for domestic and industrial use, with a possible extension to Iraq.
- IGAT7: 56-in (1,420-mm) line, to interconnect the east of Assaluyeh to Hormozgan Province and Sar-Khoon Refinery, and transfer the natural gas produced in South Pars to Hormozgan, Sistan, Baluchestan and Kermān Provinces, with a further extension to Pakistan and India.
- IGAT8: 56-in (1,420-mm) line, originates in the east of Asalouyeh and passes by Parsian Refinery in Fars Province onto Isfahan Province and then to Qom Province.
- IGAT9 (Europe Gas Export Line): 56-in (1,420 mm) line, originates in the east of Asalouyeh and passes by the western provinces (Khūzestān, Īlām, Kurdistan and Azerbaijan) before reaching the Turkish border.

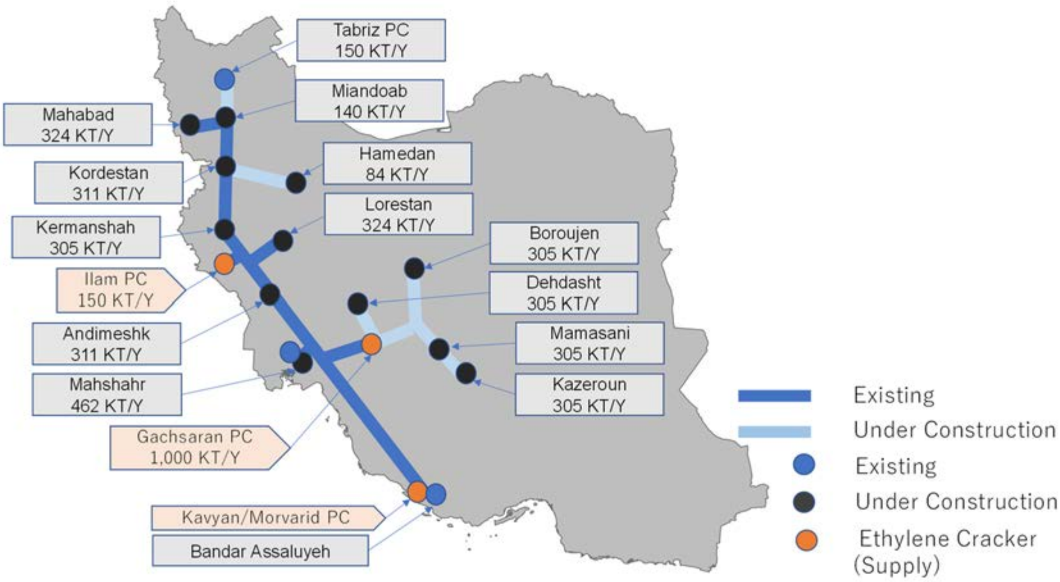
Natural gas from reservoirs contain 5-12 mol% of ethane. Gas from the reservoir is refined in the gas refinery to remove harmful impurities in the liquefaction process, such as H_2S, CO_2, water and mercuries, and to recover ethane and other heavy fractions, such as propane, butane and condensate, in order to maximize the product value. Ethane can make an excellent feedstock for ethylene production and be sent to ethane crackers for conversion into ethylene. The general configuration of the gas refinery is shown as follows:



Source: National Iranian Gas Company.

Figure 1.4 Typical Gas Refinery Configuration

Construction of the West Ethylene Pipeline started in 2004. In June 2017, the Assaluyeh to Mahabad section, running to 1,700 km in length, was completed out of the total pipeline length of 2,650 km. The pipeline is designed to supply ethylene to petrochemical plants constructed in several western regions (12 polyethylene manufacturing plants at this stage). Gas is sourced primarily from the South Pars Gas Field and the Gachsaran Gas Field. Extracted ethane is converted to ethylene in ethylene crackers in Bandar Assaluyeh and Gachsaran and injected into the West Ethylene Pipeline System.



Source: National Iranian Gas Company.

Figure 1.5 West Ethylene Pipeline System (June 2017)

Treated natural gas is transferred into the IGAT Gas Transmission Pipeline Systems and delivered to each province for domestic and industrial use.

There are also gas export plans via pipelines. IGAT 6 is intended to supply gas to Pakistan and India, while IGAT 9 is intended to supply gas to Europe.

CHAPTER 2 PETROCHEMICAL DEVELOPMENT ON QESHM

2.1 General

A program to develop the petrochemical industry in new regions was inaugurated to support sustainable development in the region and to construct infrastructure for product exports. The following six areas are collectively designated as the Petrochemical Development Zone. Methane-rich natural gas will be allocated to these areas, via the IGAT 6 and/or IGAT 7 pipeline, depending on the region:

(1) Chabahar (FZ)

- Strategic location: close to the border with Pakistan/India
- Access to international sea
- Third petrochemical hub in the country, according to the government

(2) Jask

- Suitable location for vessels entering the Persian Gulf
- Suitable for bunkering and sales
- Numerous crude oil storage facilities in the area

(3) Qeshm Island (FZ)

- Possibility of establishing at least four sizable petrochemical units
- Possibility of producing at least six million tons of petrochemical products
- Government approval for utilization of 25 million m^3/day of gas as feed

(4) Parsian Energy Industries Site

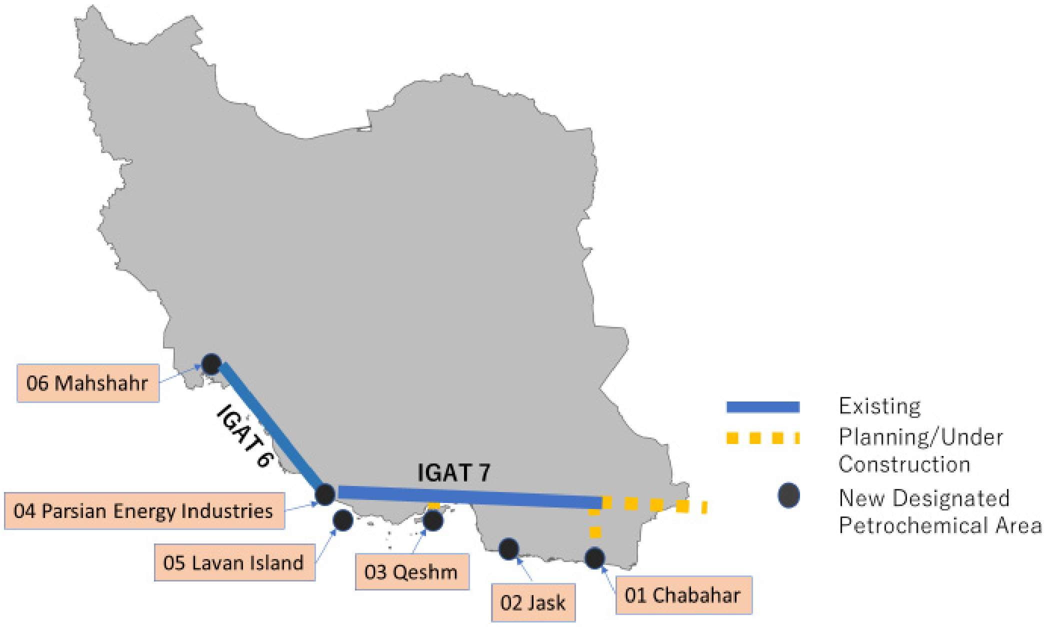
- Possibility of attracting investments from the region
- European companies' willingness to invest (four-billion-USD investment proposal by BASF Co., Germany)

(5) Lavan Island (SEZ)

- Access to 3.75 billion ft^3 of gas as feed per day
- Access to international sea and possibility of establishing infrastructure facilities
- Possible allocation of 1,250 ha of land for petrochemical units

(6) Mahshahr (SEZ)

- Existence of promising petrochemical companies in the region
- Suitable for expanding the production chain
- Good potential for increasing the number and capacity of petrochemical companies



Source: Qeshm Free Zone Organization, JICA Project Team.

Figure 2.1 Designated Petrochemical Development Areas

2.2 History of Petrochemical Development on Qeshm

Qeshm is located at the entrance of the Persian Gulf, right next to the energy corridor, a strategically important location in the region. In 1991, Qeshm was designated as a Free Zone.

Figure 2.2 Location of Qeshm

In the past, the following two studies were carried out, which have provided the basic concept for industrial development on Qeshm.

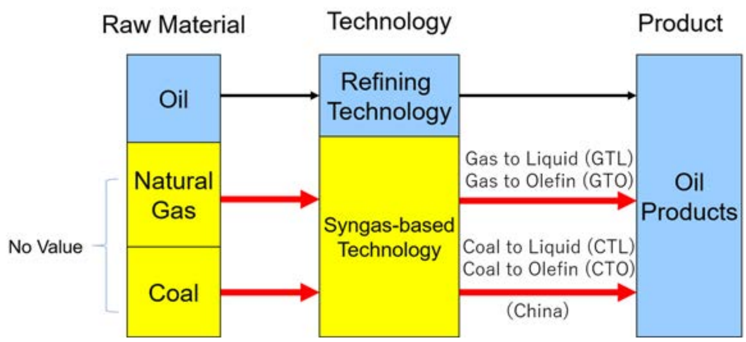
- The Qeshm Free Zone Master Plan Project was prepared by SWECO in 1994 and submitted to the QFZO
- The Oil Industries Installation Project was conducted by Foster Wheeler for the National Iranian Oil Engineering and Construction Co. in 2005

In the 1990s, the gas price was much lower than that of oil, while syngas-based technologies were developed to utilize unexploited materials, i.e., natural gas and coal. In the report by SWECO, gas-to-liquid (GTL) and gas-to-olefin (GTO) technology was emphasized, while the production of LNG was not considered as a favorable project at that time.

Nowadays, gas is traded as an oil equivalent energy resource and therefore LNG has become a favored product, while GTL is not considered economically viable under current economic circumstances.

As sulfur requirements in oil products have changed, there is more demand for gasoline, kerosene and diesel products than for fuel oil. Demand for fuel oil has declined significantly over the last decade. Refineries are required to possess higher cracking capabilities and higher sulfur-removal capacities. Oil refineries in Iran have not prepared for such changes and a considerable scale of investment will be required to modernize refining facilities. Therefore, the "Oil Industries Installation Project" by the National Iranian Oil Company (NIOC) on Qeshm from 2004 will not be materialized under the circumstances.

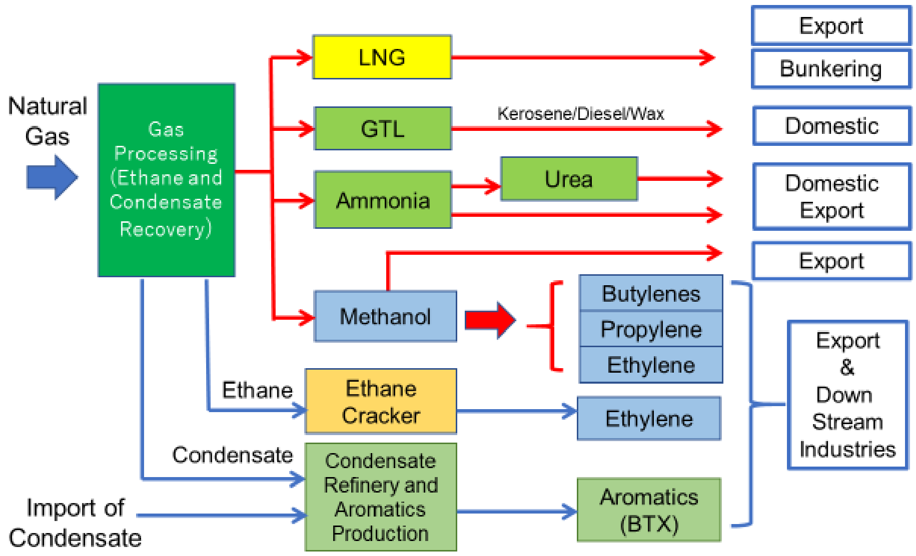
Gas use for petrochemical synthesis on a commercial scale started after the "oil crisis" in 1973. Major oil companies had started to develop new technology to produce petrochemical and oil products from unexploited hydrocarbons other than oil. Those included natural gas and coal. They also developed syngas production technologies and chemical product synthesis technologies to extend their market portfolios.



Source: DEP.

Figure 2.3 Energy Portfolio from Oil to Coal/Gas 1973-1990

All gas chemical products are manufactured from syngas (synthesis gas). Syngas is produced from natural gas, coal or oil via the auto-thermal or partial oxidation process. Nowadays, natural gas is traded at the oil equivalent value in terms of heating and not necessarily competitive feedstock for manufacturing petrochemical product. China has introduced technology to generate syngas from coal and become a price leader in petrochemical industries due to offering competitive feedstock prices and the largest amount of production. An overview of gas use in the chemical industry is illustrated in the following figure.



Source: DEP.

Figure 2.4 Gas and Gas Chemical Complex Configuration

Major chemical products from gas feedstocks will be as follows:

- GTL to primarily produce diesel oil
- Methanol and olefin (GTO or MTO)
- Ammonia/urea synthesis

2.3 Gas Chemical Development

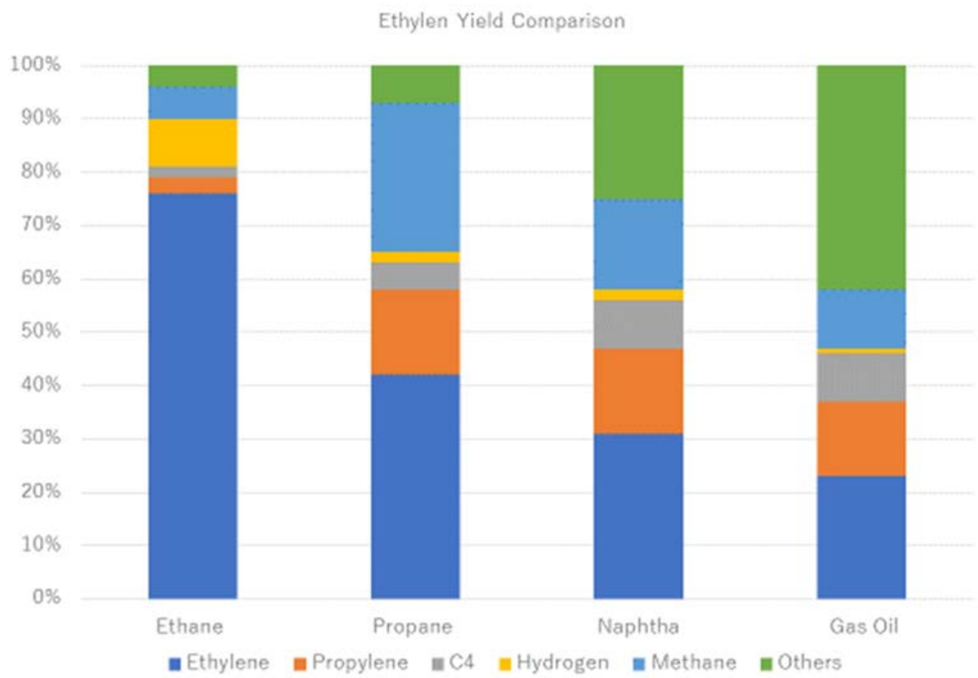
2.3.1 Aromatics (BTX)

Condensate can be used for petrochemical production. Condensate from the stabilization process is hydrotreated to remove sulfur and nitrogen compounds first, before being transferred to the catalytic reforming process unit, where the treated condensate is converted into aromatics, i.e., benzene, toluene and xylene (BTX) products. These are used as intermediate products to produce a wide range of end products, primarily for synthetic fibers, such as acrylic fibers, nylons and polyesters, and paints and plasticizers.

In the case of Qeshm, available gas is treated already in the gas refinery and no condensate will be available for chemical use, i.e., BTX production.

2.3.2 Ethylene from Ethane Extracted from Natural Gas

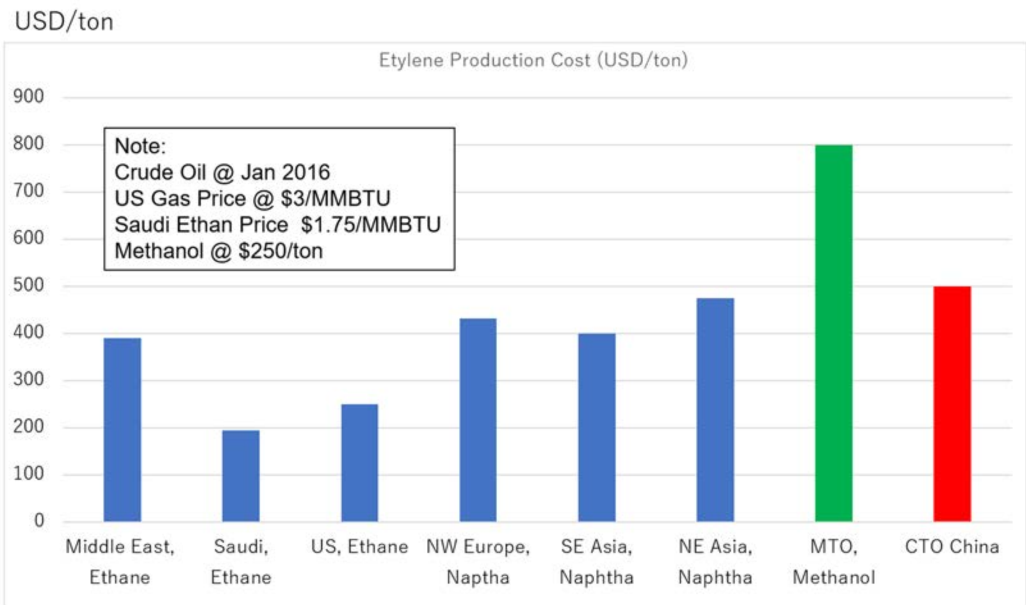
Ethane is the most efficient feedstock for producing ethylene. On a wt% basis, 76% of ethane can be converted into ethylene while the yield from propane is 42%, 31% from naphtha or condensate, and 23% from gas oil.



Source: Chenier, P. J. *Survey of Industrial Chemistry, Third Edition*. Kluwer Academic Publishers Inc. New York, New York, 2002.

Figure 2.5 Ethylene Yield Comparison with Various Feedstocks (wt%)

The following presents the indicative competitiveness of ethylene production cost, provided by Platts and reviewed by the JPT. Ethane-based Ethylene production will be the most competitive option compared with naphtha cracking, MTO and coal-to-olefin (CTO) options.



Source: Analysis by Platts and the JICA Project Team

Figure 2.6 Ethylene Production Cost

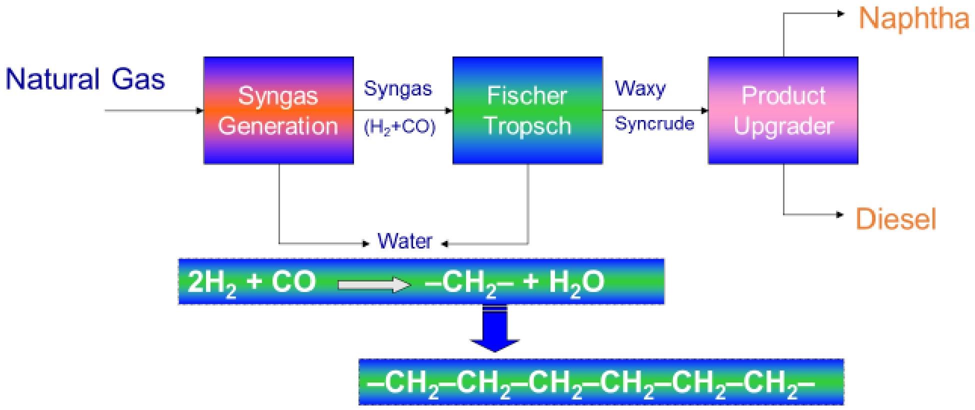
Saudi Arabia raised the ethane price from 0.75 USD to \$1.75 USD/MMBTU in 2016, but its ethylene price is still the lowest in the world. The US ethylene price is the second lowest, supported by the low US gas market price. In January 2016, the natural gas market price was just above \$3/MMBTU.

Due to a recent low oil price situation, the naphtha-based ethylene price is also down and now competitive enough to match the coal-based ethylene price from China. The coal-based ethylene production cost is considered to be 450-600 USD. The ethylene price via the MTO process is above 800 USD/metric ton and thus not considered to be competitive under the circumstances.

2.3.3 Gas to Liquid

GTL technology was developed and implemented during the Second World War in Germany. The technology was further developed after 1973 utilizing unexploited hydrocarbons, such as natural gas and coal.

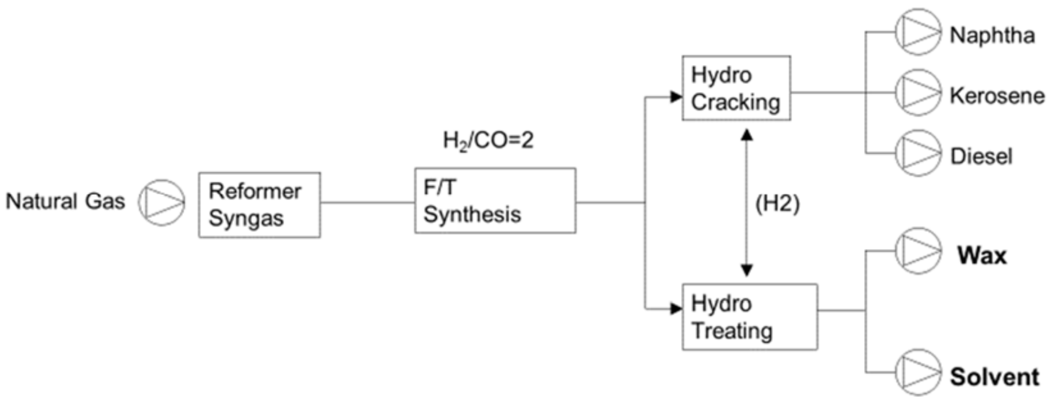
The first GTL site on a commercial scale was built in Binturu, Malaysia, by Shell in 1993 using low-cost hydrocarbons, i.e., natural gas, at that time. The GTL process is also known as the Fisher-Tropsh process and forms a hydrocarbon chain from syngas (composed of hydrogen and carbon monoxide) through a dehydration process. The produced oil is called Syncrude (a shortened form of synthetic crude oil), which is in the form of saturated paraffin. This paraffin is processed via the mild hydrocracking process to produce naphtha and diesel products.



Source: DEP.

Figure 2.7 Gas to Liquid (Fisher-Tropsh) Synthesis

Process configuration is shown in the following figure. Natural gas is converted to syngas in the reformer, after which it sent to the Fisher-Tropish reactor to produce Syncrude. Syncrude is then sent to the mild hydrocracking unit to produce an oil equivalent product, such as naphtha, kerosene and diesel. Another possible stream is to manufacture wax and solvent product via a hydrotreating unit.



Source: DEP.

Figure 2.8 Gas-to-liquid Process Configuration

GTL products are fully saturated straight hydrocarbon chains. Their quality is too "nice" for actual applications, such that the size of the market for GTL products is very limited. The following is a comparison of GTL diesel and ordinary diesel oil products.

Table 2.1 Gas-to-liquid Diesel vs. Normal Diesel

Item		GTL Diesel	JIS No. 2 Diesel
SpGr @15°C g/cm^3		0.7826	0.8330
Kinetic Viscosity mm2/s @30°C		4.145	3.496
Cetane Index (JIS)		93.2	56
Cetane Number		87.8	-
Sulfur (wt%)		<0.0001	0.0035
Aromatics (vol %)		0	26.7
BT	IBP (°C)	170.5	174.0
	50% (°C)	292.0	277.0
	90% (°C)	327.5	333.0
	EP (°C)	338.5	360.0
Pour Point (°C)		0	-7.5
Flash Point (°C)		106	73
LHV (MJ/kg)		43.52	42.95

Source: Japan Petroleum Energy Center.

GTL diesel can be a base oil for lubricant manufacturing after following the dewaxing and isomerization process. GTL naphtha and kerosene are in the same situation and should not be used for oil product blend stocks or petrochemicals. There could be a potential market as a specialty product, such as special solvent. Wax product can be used to make a food-grade wax used for food containers and fruit coatings.

GTL was developed as an alternative feedstock to crude oil, utilizing unexplored natural gas at that time; however, due to a new approach to gas use, i.e., LNG for power, as an alternative to oil product, the significance of gas has changed from being an unexploited energy resource to valuable fuel for power. Thanks to advancements in gas turbine technology, gas has been a major source of power fuel since the 1990s and demand for gas has increased dramatically.

The yield of GTL oil product is 10,000 bbl/d with the use of 100 mmscfd of natural gas as feedstock, while 100 mmscfd is equivalent to 20,000 bbl/d, with half the energy lost in the process. The processing cost of GTL is estimated to be about 5-7 USD/bbl while the refining cost (refining margin) is about 2.5 USD/bbl in general.

Under the current economic and market circumstances, GTL will not be economically viable.

2.3.4 Ammonia/Urea Synthesis

The use of natural gas for ammonia synthesis started at the beginning of 20th century, a symbol of the dawn of the modern chemical and petrochemical industries, as well as the start of a successful method ammonia synthesis known as the Haber-Bosch process.

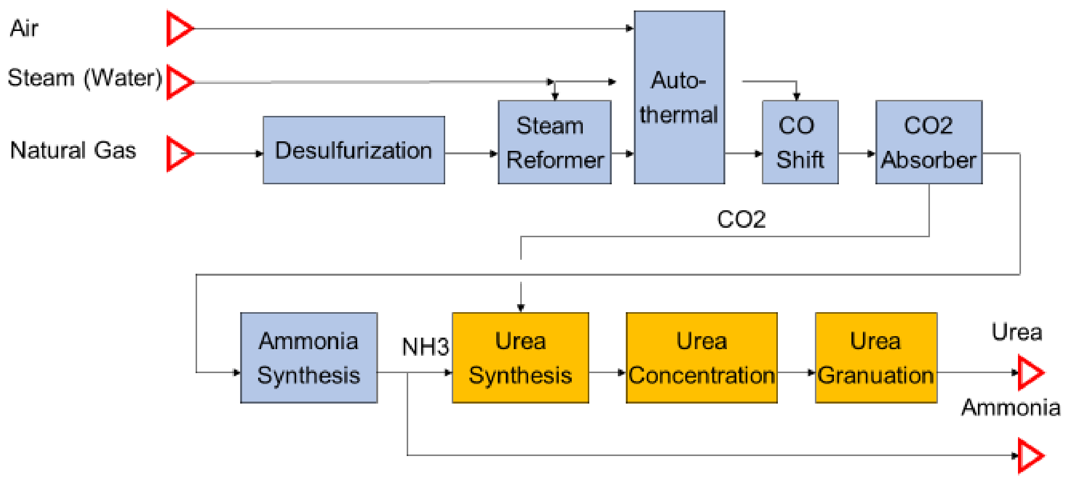
Natural gas contains rich hydrogen and is an important feedstock for ammonia manufacturing. Using natural gas, the synthesis reaction is as follows:

- CH_4 + 1/2O_2 +H2O -> 3H_2 +CO_2 (auto-thermal reformer and CO shift converter)
- N_2 +3H_2 -> 2NH_3 (ammonia synthesis reactor)
- 2NH_3 + CO_2 -> (NH_2)2CO + H_2O (urea synthesis reactor)

Hydrogen is removed from methane via the syngas production process and further hydrogen is generated in the CO shift converter, with CO_2 as the end product. The hydrogen reacts with nitrogen in the atmosphere to form ammonia, which then reacts with CO_2 to form urea.

The proposed ammonia/urea synthesis process require significant amounts of water for auto-thermal reforming and the CO shift process. A large-scale desalination plant will also be required on Qeshm.

The following is a schematic drawing of the ammonia/urea synthesis process:

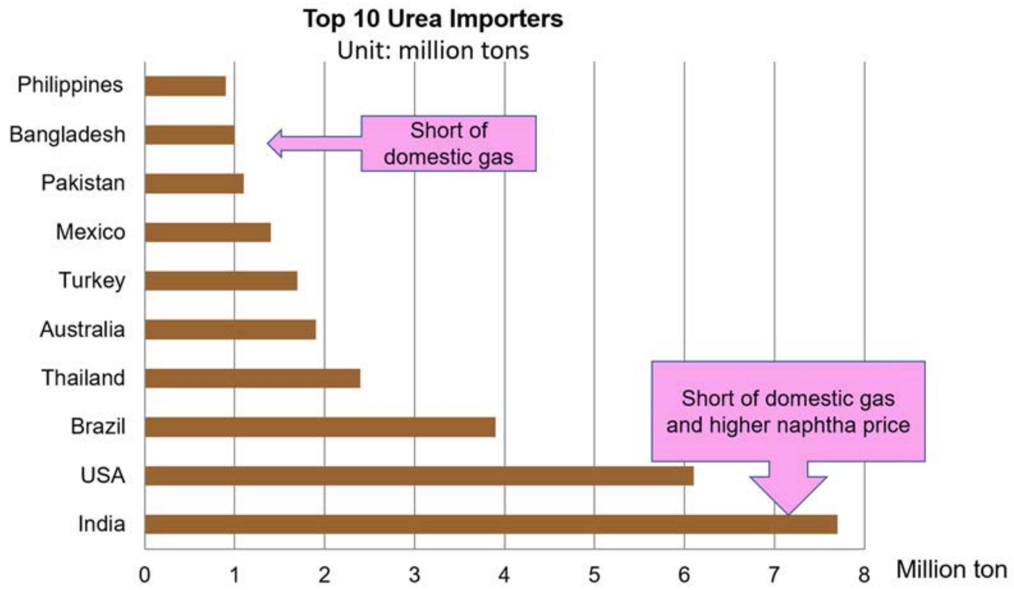


Source: DEP.

Figure 2.9 Ammonia and Urea Production Process

Urea is a very important basic chemical component used for fertilizer manufacturing. Urea is also used to manufacture resins such as urea and melamine resins.

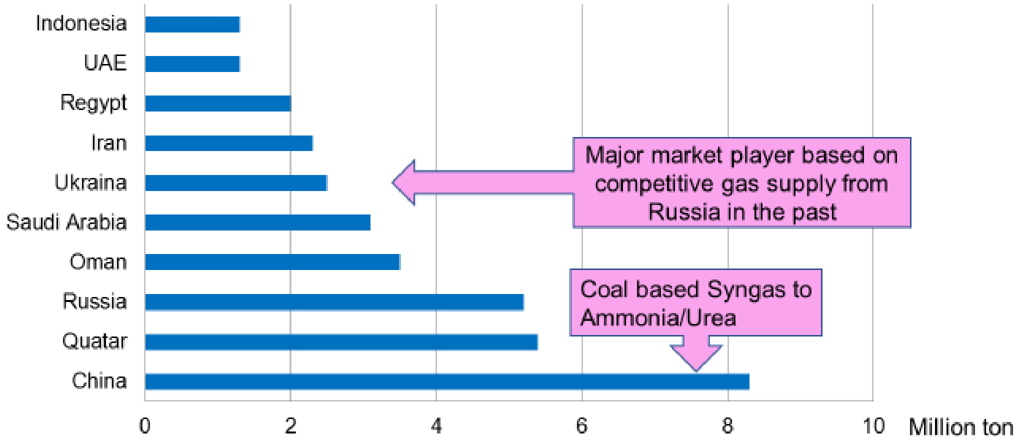
Demand for urea is considered steady and continues to grow. The annual growth rate is forecast to be 1.5-1.9%. India is a major urea importing country; however, although a number of urea manufacturing plants has been constructed in India, shortage of natural gas has limited production. Bangladesh also suffers from a shortage of gas, which has turned it in to a urea-importing country.



Source: International Fertilizer Association.

Figure 2.10 Urea-importing Countries (Global Urea Trade in 2013)

World urea exporters are mostly from gas-producing countries, including Iran. Chinese urea production relies on coal-based syngas synthesis. However, environmental issues remain a concern. Ukraine was the largest urea-exporting countries in the last decade; however, its gas deal with Russia has trimmed down urea production and affected production for export purposes.



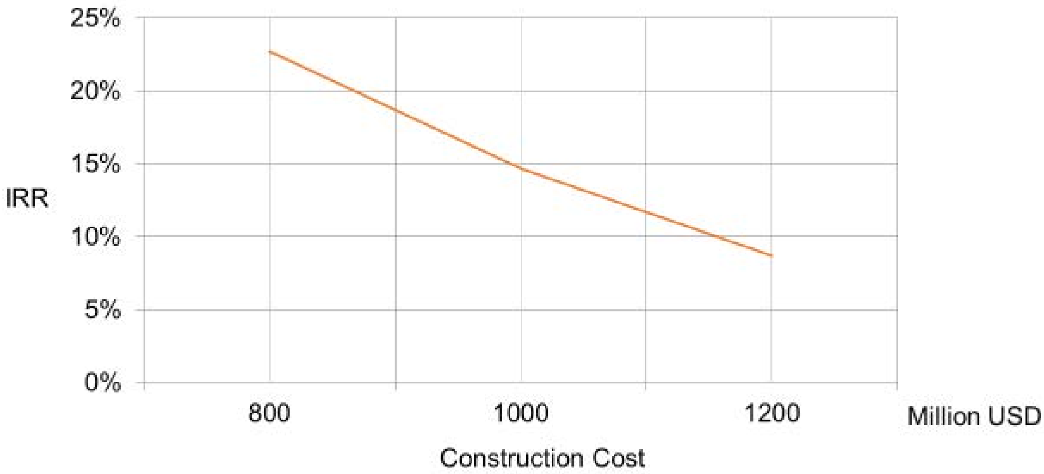
Source: International Fertilizer Association.

Figure 2.11 Urea-exporting Countries (Global Urea Trade in 2013)

A simple economic evaluation was carried out. With an assumed gas price of 2.00 USD/MMBTU, the primary economics of a urea production project will be robust and viable. The cost of construction has risen significantly over the last decade due to a construction rush supported by a hike in oil and gas (LNG) prices. The urea FOB (freight on board) price has also varied from the level of 180 to 350 USD/ton. In this report, the economics is evaluated using a simple economic model to see if the project is viable or not. Under the following economic conditions, the base economics shows an internal rate of return (IRR) of more than 15% and thus is considered viable.

Gas price:	USD 2.00/MMBTU
Urea production	1.4 million tons/year
Gas requirement:	2,650,000 Nm^3/day
Urea FOB price:	240 USD/ton
Construction cost:	1,000 million USD
Corporate tax:	0%

Sensitivity towards the construction cost is evaluated as follows:



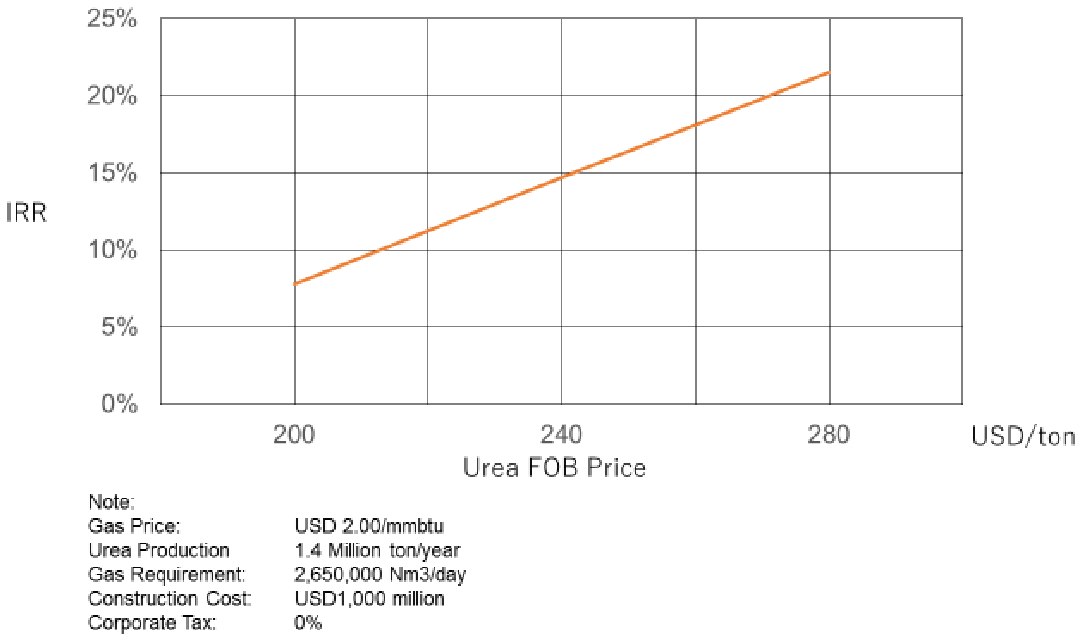
Note:

Gas Price:	USD 2.00/mmbtu
Urea FOB Price:	$240/ton
Urea Production	1.4 Million ton/year
Gas Requirement:	2,650,000 Nm3/day
Corporate Tax:	0%

Source: JICA Project Team.

Figure 2.12 Ammonia/Urea Production Plant Economics Construction Cost Sensitivity

Sensitivity towards the urea FOB price is also reviewed as follows:

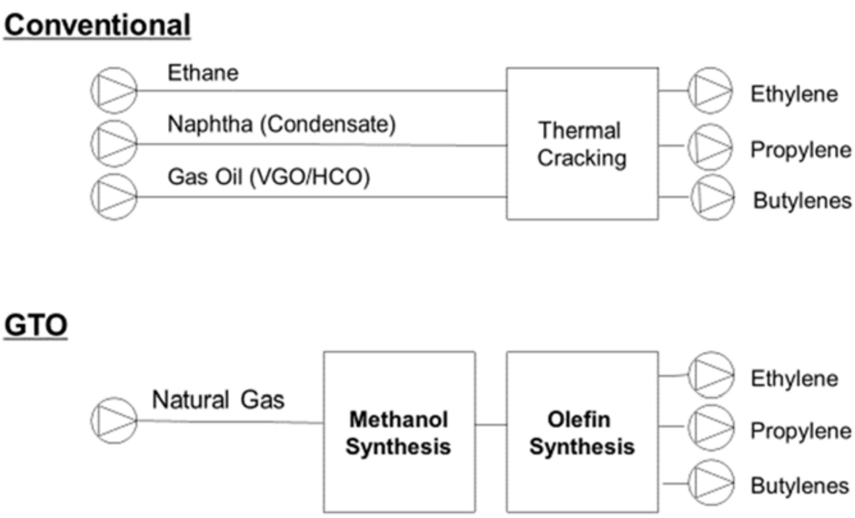


Source: JICA Project Team.

Figure 2.13 Ammonia/Urea Production Plant Economics Construction Cost Sensitivity

2.3.5 Gas to Olefin

The conventional olefin manufacturing process is called the thermal cracking process. A variety of feedstocks is used to generate olefin products. Ethane is extracted from natural gas or oil-associated gas as a byproduct, and more popularly as a feedstock for ethylene production.



Source: DEP.

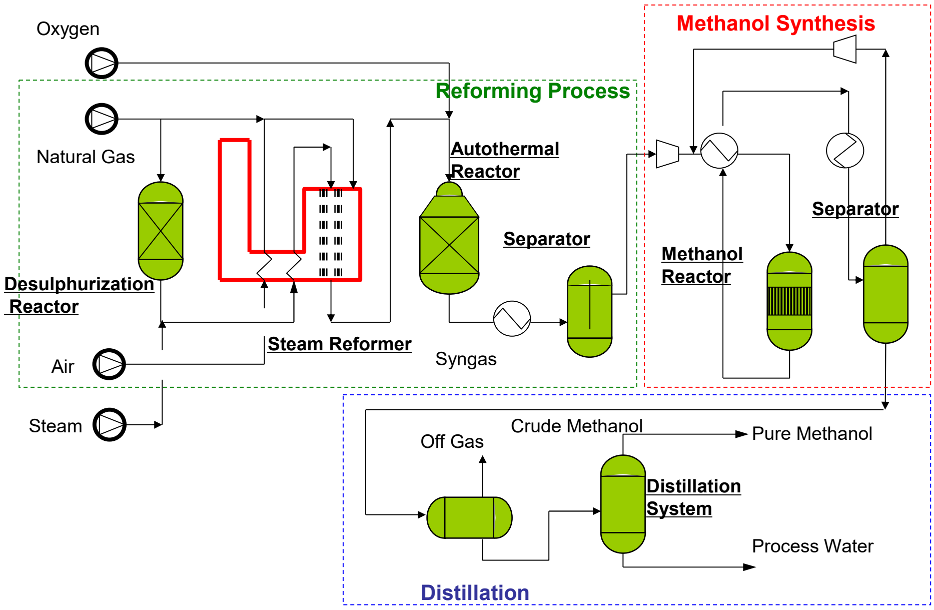
Figure 2.14 Olefin Manufacturing Process

GTO consists of methanol synthesis followed by olefin synthesis. Olefins are produced in one reactor, and the proportion of the products (ethylene, propylene and butylene) can be changed by controlling the severity of the operation.

Methanol is produced via the auto-thermal reforming process followed by the methanol synthesis process. The produced methanol is sent for olefin synthesis in order to produce ethylene/propylene as a primary product.

Olefin synthesis is a dehydration and exothermal reaction process, meaning that reaction heat will need to be removed by a cooling system. One of the major options for a cooling medium is to use sea water. Significant heat will be released into the environment as a result.

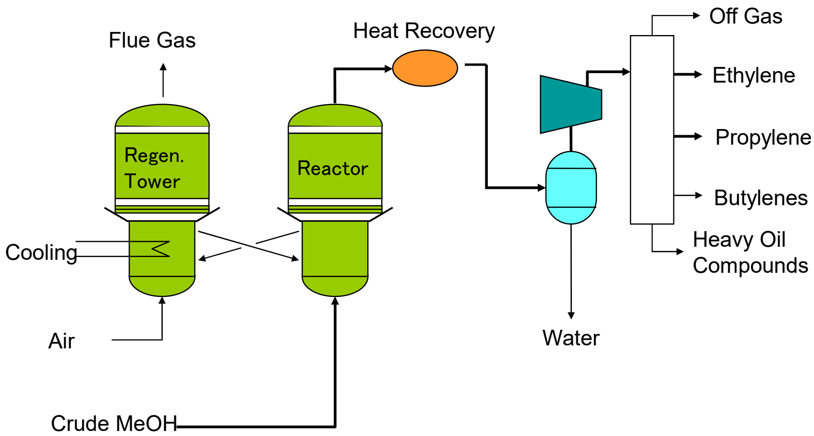
A typical process flow for methanol synthesis is shown as follows:



Source: Lurgi.

Figure 2.15 Methanol Synthesis Process

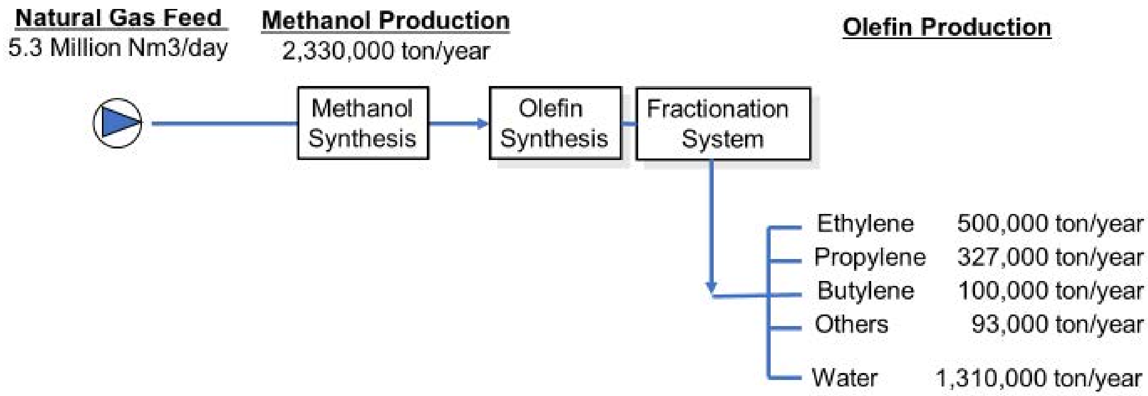
The produced methane is sent to an olefin synthesis unit (e.g., an UOP olefin synthesis unit). A process flow of olefin synthesis is shown as follows:



Source: UOP.

Figure 2.16 Methanol to Olefin Synthesis Process

The material balance in the case of 500,000-ton ethylene production is shown as follows:



Source: Vora, B. V., Marker, T. L., Barger, P. T., Nilsen, H. R., Kvisle, S., Fuglerud, T. Economic Route for Natural Gas Conversion to Ethylene and Propylene. *Stud Surf Sci Catal* 1997, 107, 87-98.

Figure 2.17 Gas to Olefin Material Balance

As discussed earlier, the ethylene production cost by MTO will not be competitive in comparison with that of ethane crackers. There are several ethylene cracker projects in Iran, which may compete in the domestic and export markets as well.

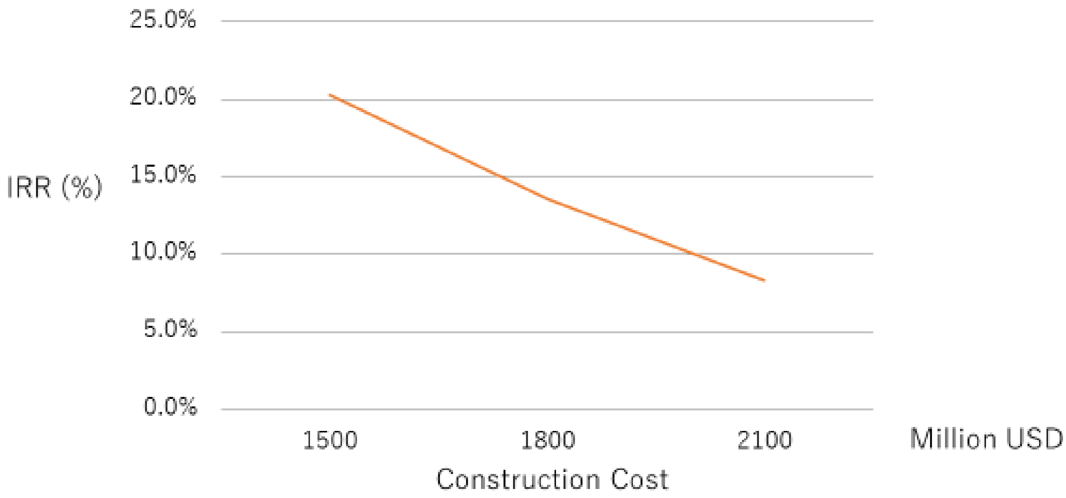
Under the circumstances, this option will not be recommended; however, methanol export could be an option.

Ethylene production competitiveness, as shown in Figure 2.6, includes MTO, based on the international methane price. The economics for gas-to-methane and MTO (or GTO) processes is examined.

The cost of constructing GTO facilities has risen significantly over the last decade due to a construction rush supported by a hike in oil and gas (LNG) prices. No recent benchmark construction cost data for GTO are available; however, by extrapolating past data, a simple set of economics can be examined under the following conditions:

● Feed gas price:	2 USD/MMBTU
● Product FOB price (average market price in 2016)	Ethylene=800 USD/ton Propylene=600 USD/ton Butylene=600 USD/ton
● Production:	Ethylene=500,000 ton/year Propylene=330,000 ton/year, Butylene=100,000 ton/year
● Gas requirement:	5,300,000 Nm^3/day
● Tax:	0%

The calculated project IRR is 13% and considered viable. Sensitivity towards the construction cost was examined, with the results as follows:

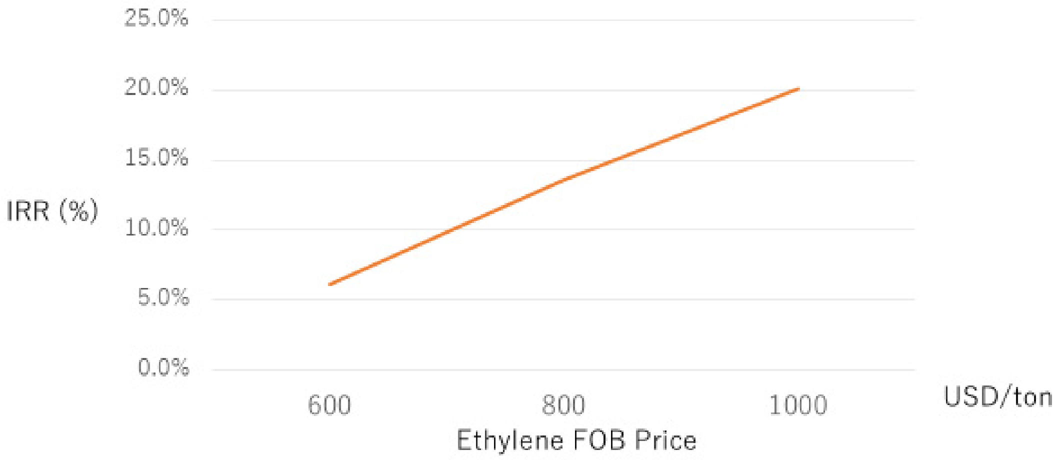


Note
Feed gas Price: $2/mmbtu
FOB Price: Ethylene=$800/ton, Propylene=$600/ton, Butylene=$600/ton
Feed Gas Price: $2.00/mmbtu
Gas requirement: 5,300,000 Nm3/day
Tax : 0%

Source: JICA Project Team.

Figure 2.18 Gas to Olefin Economics Sensitivity Towards Construction

Sensitivity towards product (ethylene) cost is also examined. The current ethylene price +/-200 USD/ton was examined. The results of the analysis are as follows:



Note
Feed gas Price: $2/mmbtu
FOB Price: Propylene=$600/ton, Butylene=$600/ton
Construction Cost: USD 1,800 million
Gas requirement: 5,300,000 Nm3/day
Tax : 0%

Source: JICA Project Team.

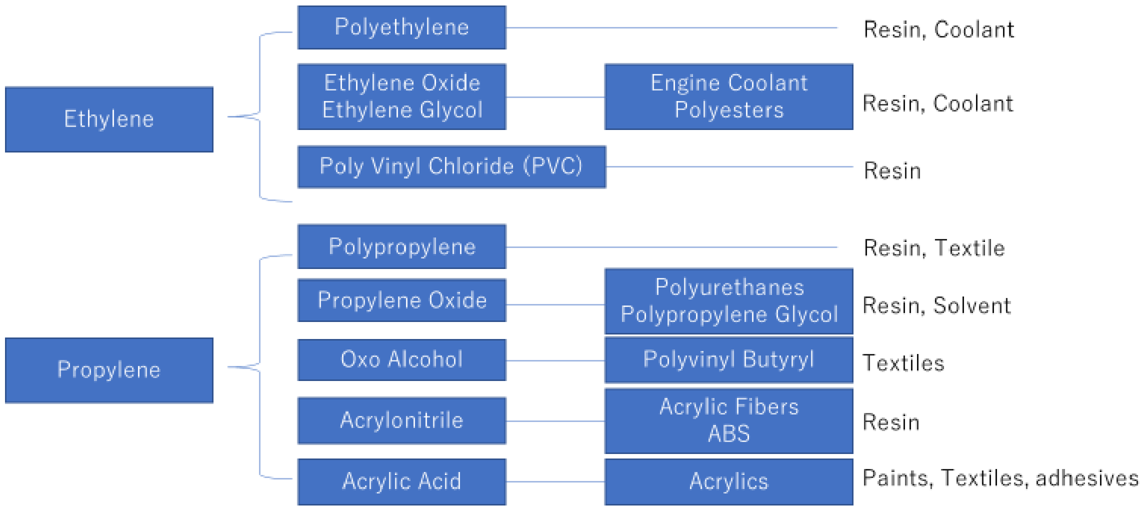
Figure 2.19 Gas to Olefin Economics Sensitivity Towards Ethylene FOB

Profit options from methanol are considered to be shifting towards olefin synthesis. Methanol production and exports will be a recommended option but not olefin production. The methanol market is not necessarily large and thus needs to be secured.

2.3.6 Petrochemical Development

The petrochemical industry is specialty industry and the market size for base or intermediate feedstocks is relatively small. There are specialty product companies in the world but the numbers of players is limited.

The following is an overview of petrochemical derivatives from ethylene and propylene. In most cases, products or intermediate products are mutually interrelated. Synergy among the companies is the key to the successful development of a petrochemical complex.

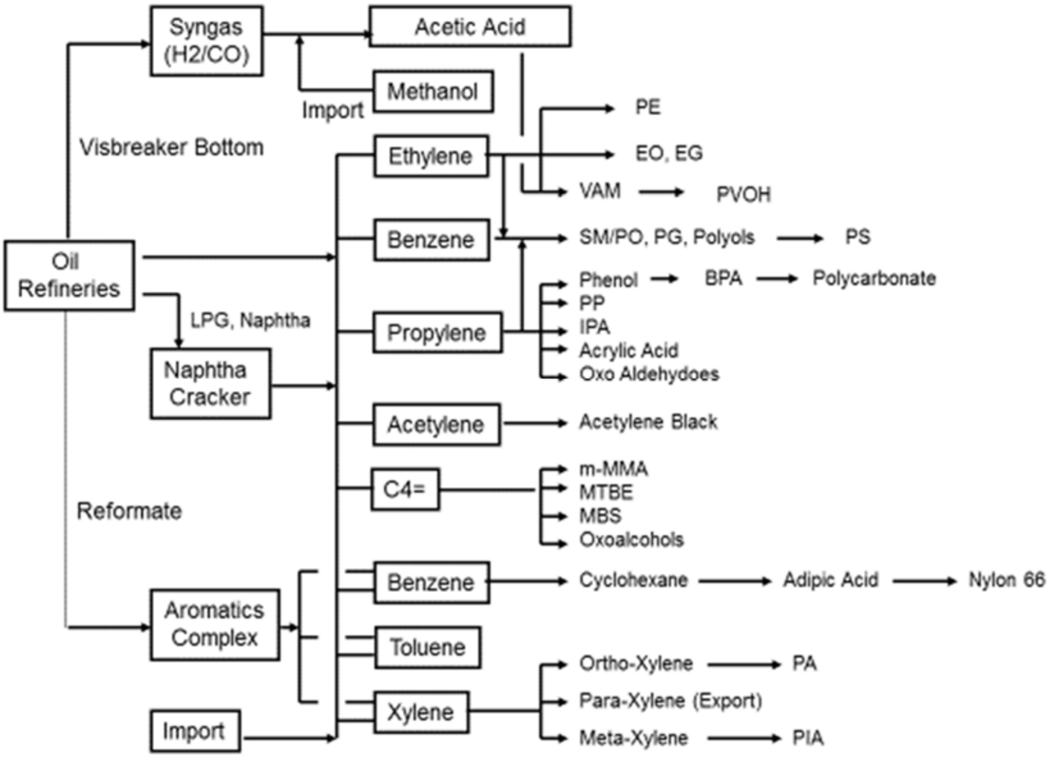


Source: DEP.

Figure 2.20 Petrochemical Derivatives (Ethylene and Propylene)

The most successful development case for a petrochemical complex in Asia is that of Singapore. In 1961, the Singapore Economic Development Board (EDB) was formed under the remit of the Ministry of Trade and Industry to attract foreign investors, as a solution to reduce the unemployment rate in the 1960s. The EDB also opened its first overseas offices in New York for investment promotion. Throughout the 1970s, the EDB was expanded globally. In the 1980s, it set up capital-intensive and high-technology industries including petrochemical industries.

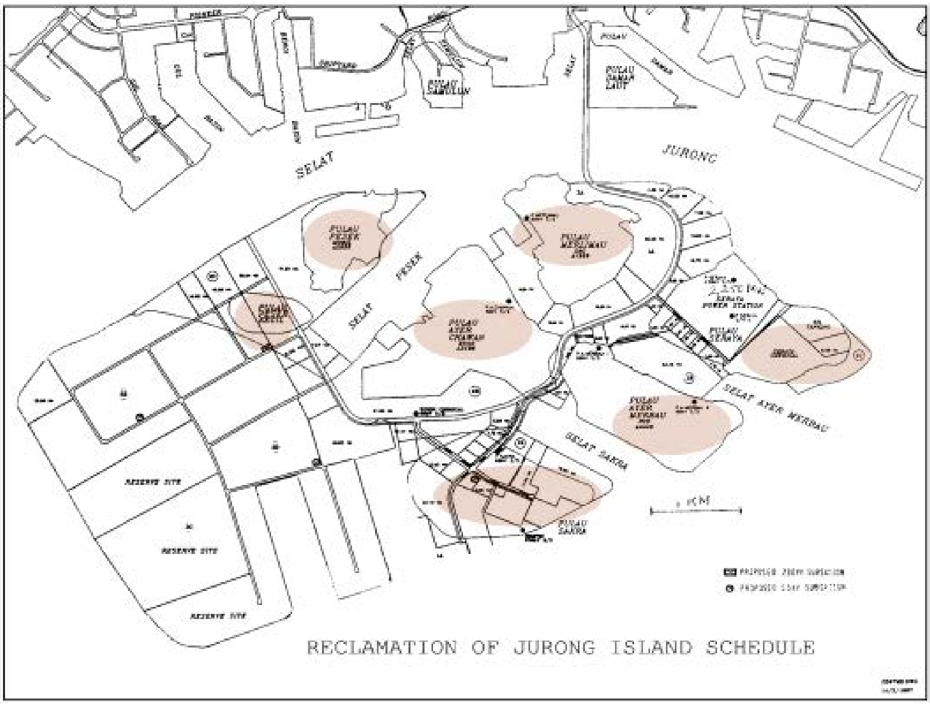
The EDB was able to invite numbers from world-class chemical companies as shown below.



Source: DEP.

Figure 2.21 Jurong Petrochemical Industry Overview

To assist in the development of a petrochemical complex, the JTC Corporation (JTC) was founded in 1968 to develop the Jurong Industrial Estate in support of Singapore's economic development. The JTC has since developed a chemical hub on Jurong Island, including over 7,000 ha of industrial land and 4 million m^2 of ready-built facilities, with land space created by reclaiming the water around seven islands.



Source: DEP.

Figure 2.22 Jurong Industrial Park developed by the JTC Corporation

Industrial water supply and sewage water treatment and recycling are critical issues for Singapore, due to a shortage of industrial water in the city state. SembCorp was founded under the Ministry of Finance to look after water issues in the industrial park. The business line for SembCorp has since been expanded to include the supply of utilities and provision of services:

- Power and steam
- Industrial and drinking water
- Effluent water treatment and recycle
- Industrial gas
- Industrial waste disposal and management
- Port operation and transportation management
- Natural gas

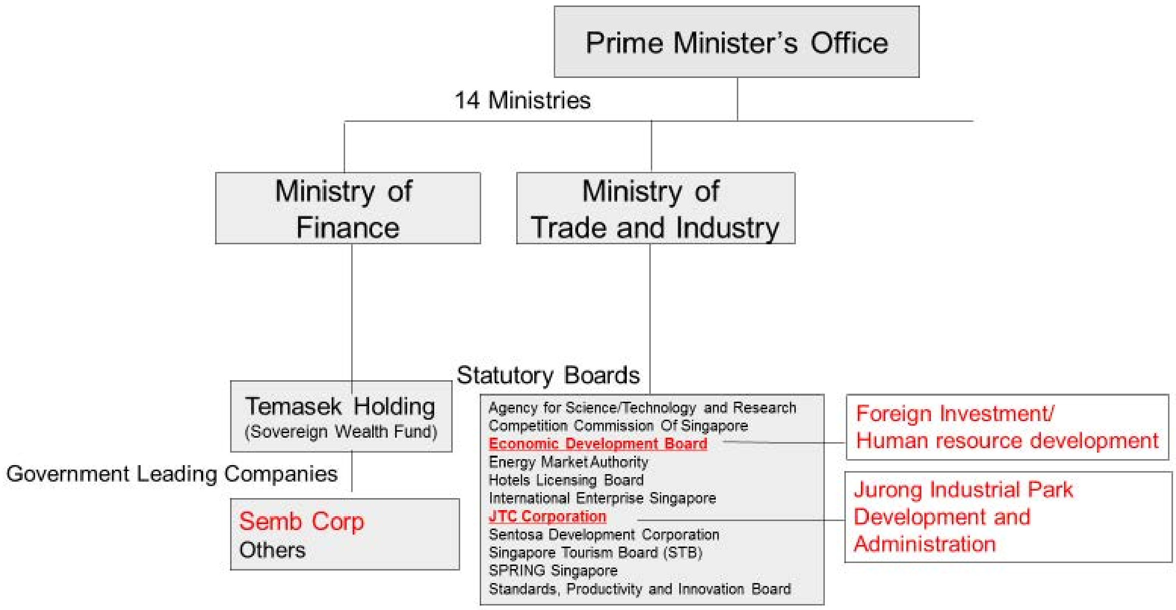
In the 1980s, the EDB co-established institutions of technology with Japan, Germany and France to train engineers for specialized jobs in the petrochemical and high-technology fields including electronics and engineering. This was made possible by setting up the Skills Development Fund to support the training costs.

In the 1990s, the emphasis was placed on technology, manufacturing and investment, with the EDB strengthening its focus on key industries, namely, chemicals, electronics and engineering. The EDB's Creative Services Strategic Business Unit was set up in 1990.

EDB Investments (EDBI) was established in 1991 as an independent equity investment arm.

In the 2000s, the focus was on innovation, knowledge, and research and development. The EDB launched the Start-up EnterprisE Development Scheme (SEEDS) in 2001 and the Business Angel Scheme (BAS) in 2005, as well as set up the Energy Innovation Program Office (EIPO), Energy Market Authority (EMA) and the Clean Energy Program Office (CEPO) in 2007.

The following depicts the organization of government in Singapore.



Source: Singapore Government Home Page.

Figure 2.23 Singapore Government Organization

2.4 Petrochemical Option on Qeshm

As shown in the case of Singapore, an internationally competitive petrochemical complex requires systematic and continuous development effort.

All the following potential petrochemical options are reviewed in this report.

- Aromatics (BTX)
- Ethylene from ethane crackers
- GTL
- Ammonia/urea
- GTO via methanol
- LNG

(1) Aromatics (BTX)

Assuming that feed gas is treated in the gas refinery near the gas field, condensate, ethane, propane and butane can be extracted from the gas. The allocated gas will be pipeline-grade methane-rich gas. No feedstock suitable for the manufacture of aromatics is included. If expansion of the petrochemical product range is necessary, aromatics would need to be imported.

(2) Ethylene from ethane crackers

Similarly, the allocated gas will not include ethane fractions. Recovered ethane from the gas refinery will be converted to ethylene and injected into the West Ethylene Pipeline to supply the gas to the regional polyethylene plant.

(3) GTL

Under the current gas pricing circumstances, GTL will not be economically viable. The market for GTL products (naphtha, kerosene, diesel) is very limited. It is also difficult to find a market when premium prices are involved.

(4) Ammonia/urea synthesis

Ammonia and urea are both potential products that can be manufactured on Qeshm. A large amount of water will be required in the ammonia and urea synthesis process. Water can be produced from sea water in the desalination plant.

(5) GTO via methanol production

One of the major products from GTO is ethylene. Ethylene is also manufactured from ethane via ethylene crackers and economically more competitive than that of ethylene from the GTO process. Under the current oil price level conditions, product from the naphtha cracking process is also competitive and shows better economics than that of GTO, although an economic evaluation shows positive results concerning the GTO option, supported by the competitive gas price assumed in this report.

It is recommended to manufacture methanol rather than olefin in order to avoid competition in the ethylene market.

Note that the MTO process is endothermic and significant heat needs to be removed via a cooling system. Sea water will be used as a cooling medium, which may impact the sea environment around Qeshm.

(6) LNG production

LNG remains a major option for Qeshm and will be discussed further in the next section.

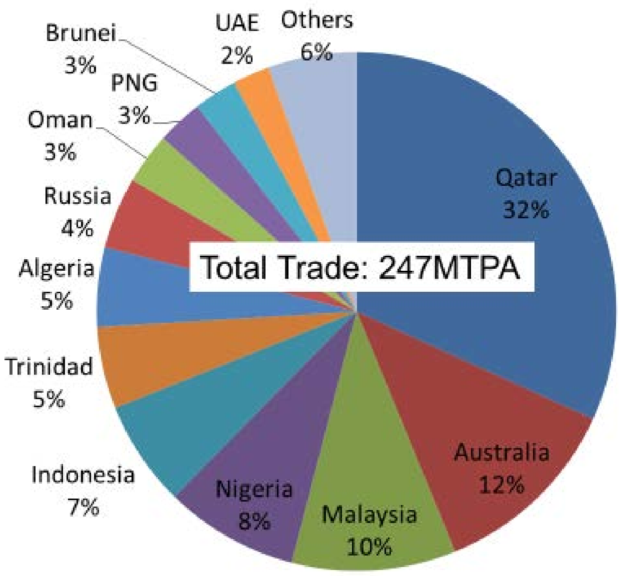
CHAPTER 3 LNG PROJECT DEVELOPMENT

3.1 LNG Market

3.1.1 LNG Supply Countries

In 2015, total LNG production was 338.3 BCM/year or 247 million tons. Qatar is the largest LNG supplier in the world, followed by Australia, Malaysia, Nigeria and Indonesia.

Malaysia and Indonesia, traditional LNG-exporting countries in Asia, started to import LNG in 2015 and are predicted to be net importing countries by the mid-2030s due to an increasing domestic demand and depleting resources.

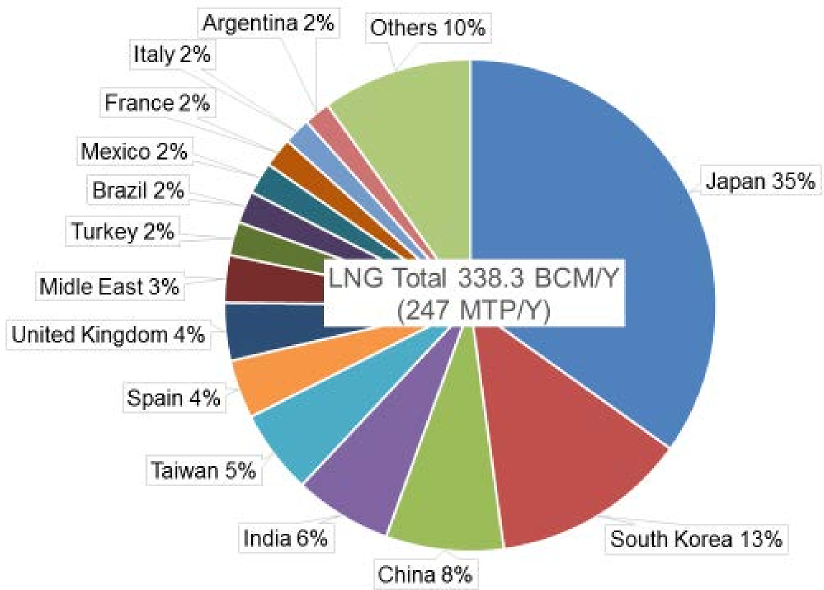


Source: HIS/International Gas Union 2017.

Figure 3.1 LNG Supply Countries (2015)

3.1.2 LNG Import Countries

Japan, Korea and Taiwan account for 50% of world imports, followed by China and India. LNG imports into Europe are influenced by the supply of Russian, Norwegian and UK gases in the market, with only the balance imported.



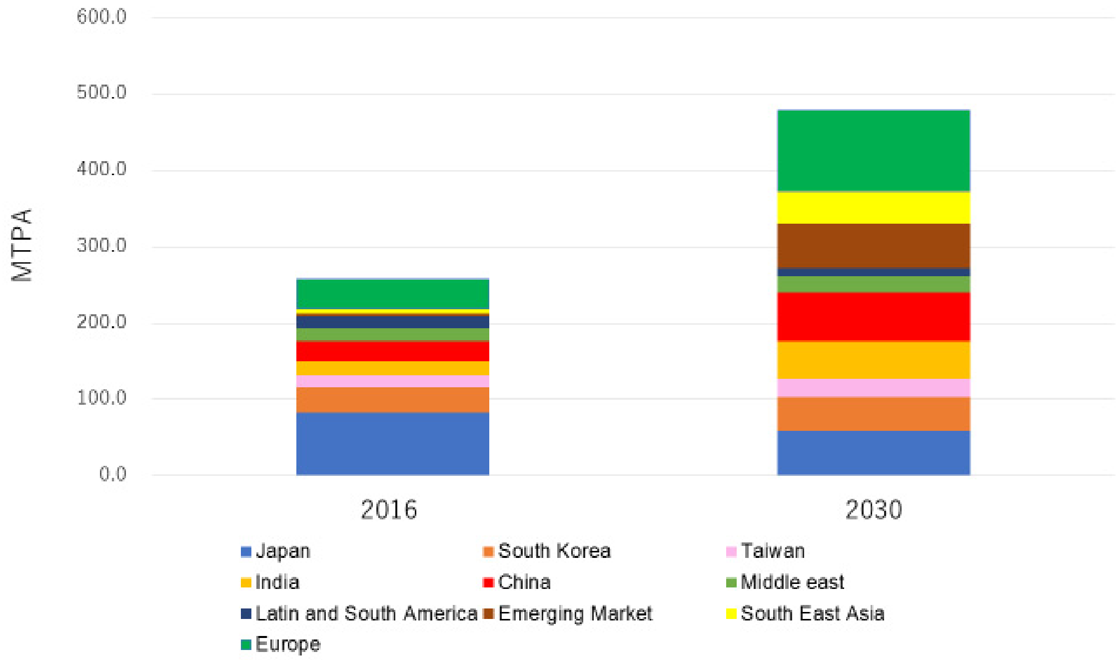
Source: BP Statistics 2016.

Figure 3.2 LNG Import Countries (2105)

3.1.3 Demand and Supply Forecast

(1) LNG demand

According to the long-term LNG demand forecast by Bloomberg and New Energy Finance, the LNG demand of 258 million tons in 2016 will be increased to 479 million tons in 2030. A significant increase is expected in Asian countries, including Thailand, Vietnam and Bangladesh, in addition to existing import countries such as China and India. Malaysia and Indonesia have become LNG import countries already and will be net importing countries in the 2030s.

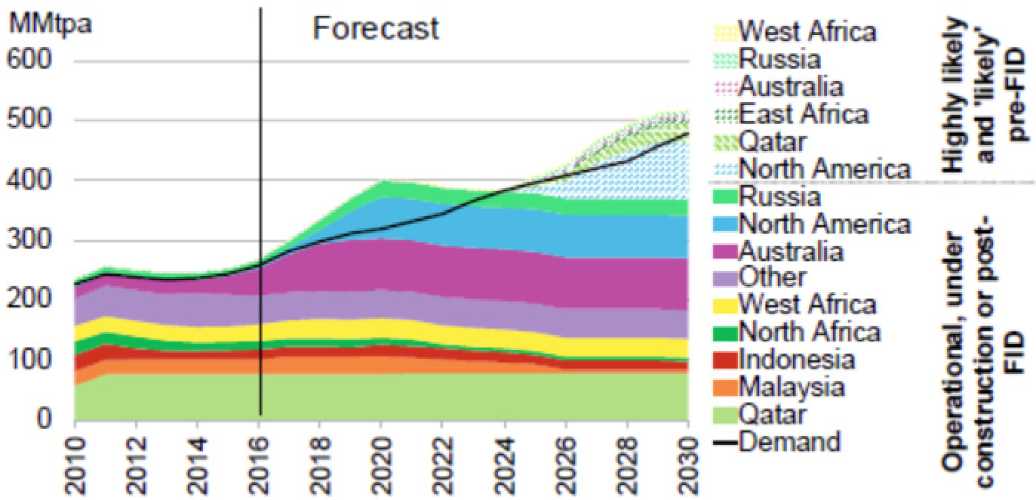


Source: Bloomberg and New Energy Finance.

Figure 3.3 Demand Forecast (2016-2030)

(2) LNG supply

According to Bloomberg and New Energy Finance, LNG supply capacity will reach 400 million tons/year in 2020. The overcapacity situation will continue until 2022-2024, with new additional capacity required after 2022. LNG production costs differ from project to project. Cost-competitiveness will also impact the LNG supply project.



Source: Bloomberg and New Energy Finance.

Figure 3.4 LNG Supply Forecast

(3) Market overview

LNG supply capacity will continue to expand until 2020. LNG demand growth will eventually catch up with the supply capacity due to the strong demand growth in Asian countries.

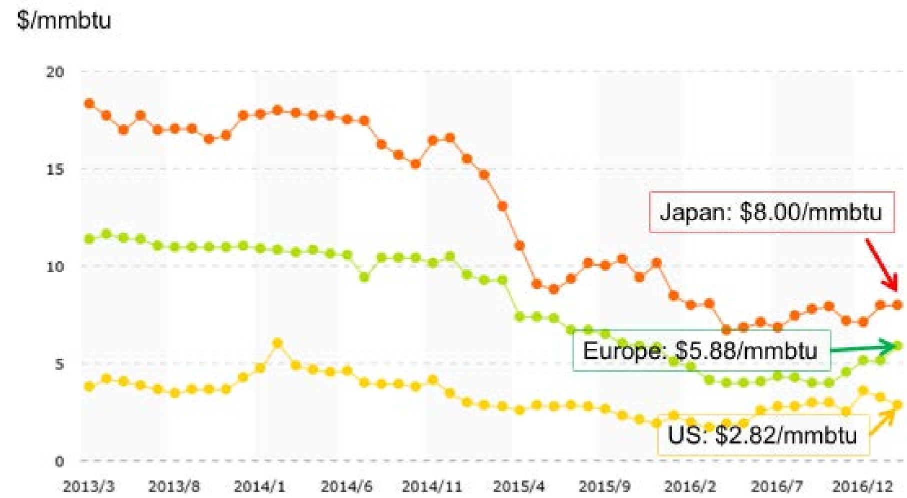
According to the Shell LNG Outlook for 2017, the global demand for gas is expected to increase by 2% per year between 2015 and 2030, while LNG demand is set to rise at twice that rate, i.e., 4 to 5%. Future LNG demand growth will be driven by a coal-to-gas policy and floating storage regasification units to replace declining domestic gas production. New investments are required to meet growing LNG demand after 2020.

The new upcoming LNG project will face a financial challenge caused by deregulation in Japan, the largest buyer in the world. Gas and power utility companies in Japan are exposed to internal competition and will not be able to commit to a long-term contract. A spot market will be created, with contract terms will be shorter and contract volumes smaller.

This will impact the future LNG development project and its financial arrangement as discussed in a later section.

3.1.4 LNG Pricing and Forecast

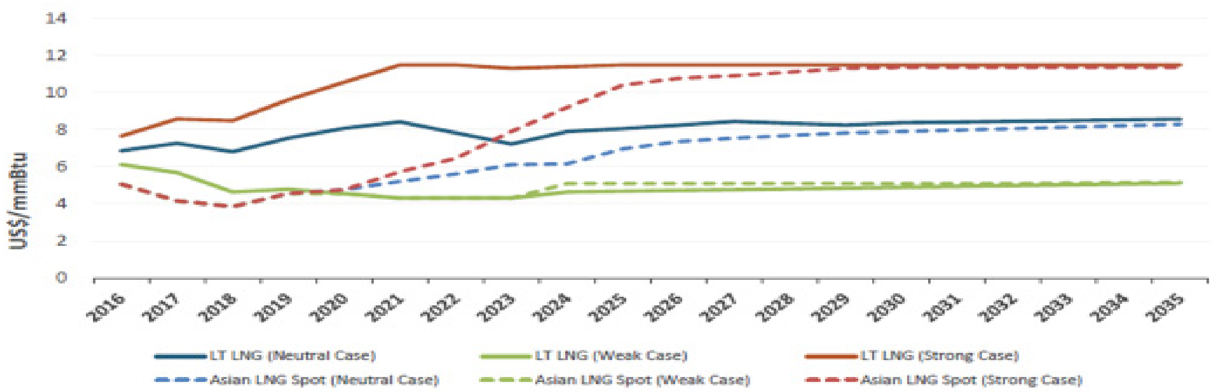
The natural gas and LNG price is expressed in USD per MMBTU. The average CIF price in Japan in December 2016 was 8.00 USD/ MMBTU, while in Europe it was 5.88 USD/MMBTU; in the US, the Henry Hub price was 2.82 USD/MMBTU. The LNG price has dropped significantly from the level of 18 USD/MMBTU in March 2013 in Japan.



Source: International Monetary Fund.

Figure 3.5 Historical LNG/Natural Gas Price (Japan, Europe and the US)

A long-term pricing forecast was provided in the Australian Energy Market Operator study from 2016. The spot price will continue to be discounted from long-term oil-linked pricing, as the market remains oversupplied. After 2023, the LNG oversupply situation will be clear and the spot price and long-term price spread will be narrowed.



Source: Study by the Australian Energy Market Operator 2016

Figure 3.6 Asian Long-term and Short-term Price Forecast

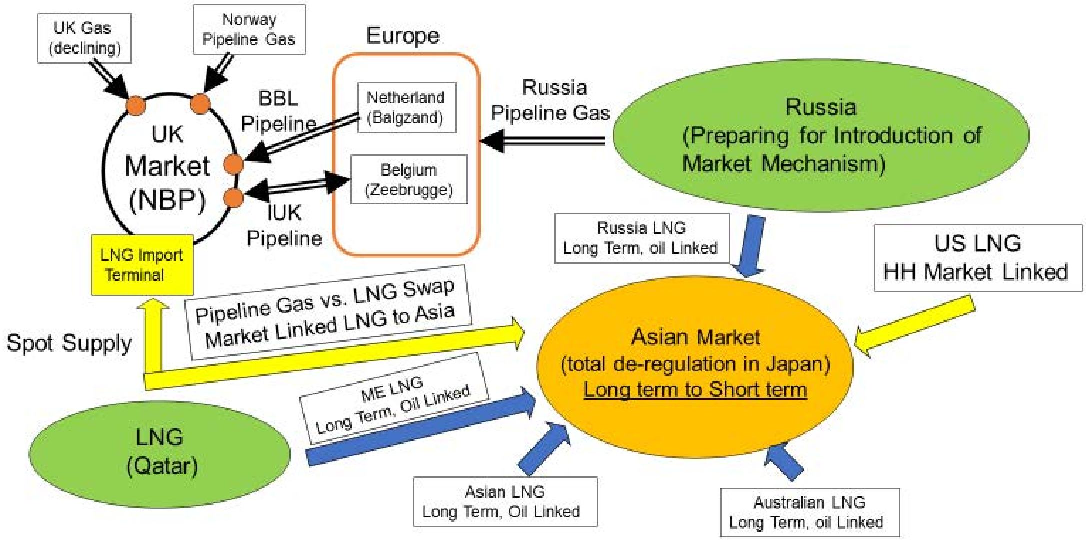
3.1.5 Deregulation in Japan

Gas sector deregulation in Japan started in April 2017, after power sector deregulation in April 2016. Opportunities are now available to newcomers and no discriminatory transmission and distribution cost can be applied to them, while gas safety/maintenance is covered by existing gas companies. A safety net is also in place to protect consumers. Gas sector deregulation is already in place in Europe: the UK and Germany deregulated in 1998, Italy in 2003, and France in 2007.

Deregulation in Japan will impact traditional take-or-pay contracts, which were the financial foundations for LNG project development. Power and gas utilities in Japan had been granted a regional monopoly under the old system, with fuel costs allowed to be transferred to the customer. Since deregulation, utilities are not able to commit to long-term contracts and must buy more from the spot market or on a short-term basis to avoid price/volume risk. Contract volume is also reduced.

3.1.6 Changes to the LNG Market

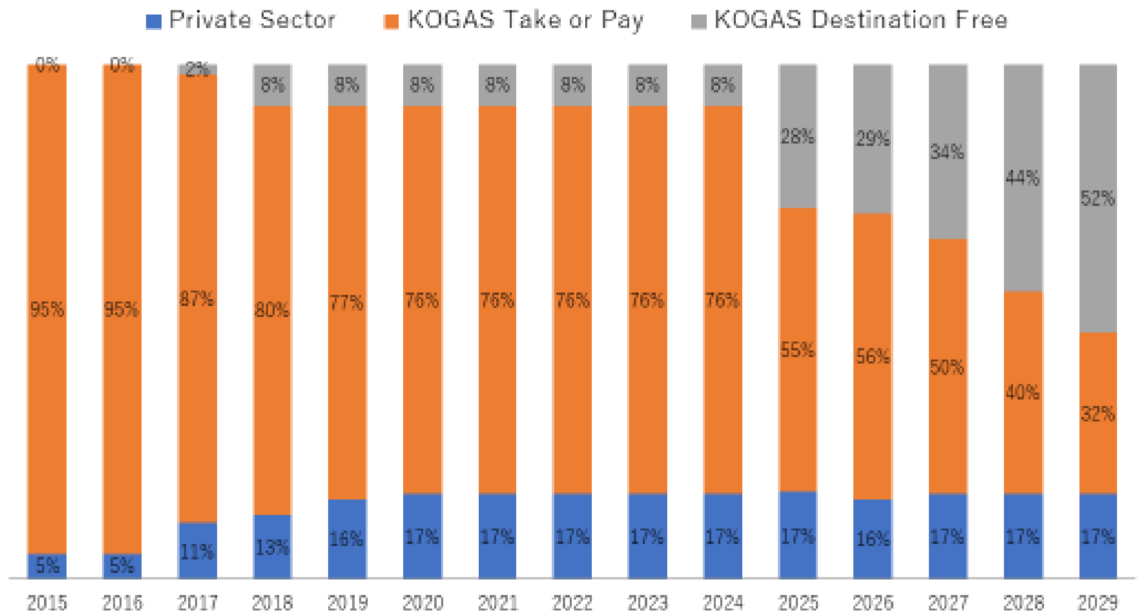
The fluidization of the LNG market has accelerated over the last few years. Portfolio traders are actively supporting the spot supply market. Due to developments in the market mechanism in the UK and the rest of Europe, any major LNG supplier to the UK needs to supply at the market price, thus balancing the market in the UK and Europe.



Source: DEP.

Figure 3.7 Fluidization of the LNG Market

The Asian market in general is still dominated by oil-linked long-term contracts. However, the South Korean monopoly, Korea Gas Corporation (KOGAS), is also preparing for change by reducing volume based on long-term take-or-pay contracts, while it will target 30% of destination-free cargo from the market after 2025.



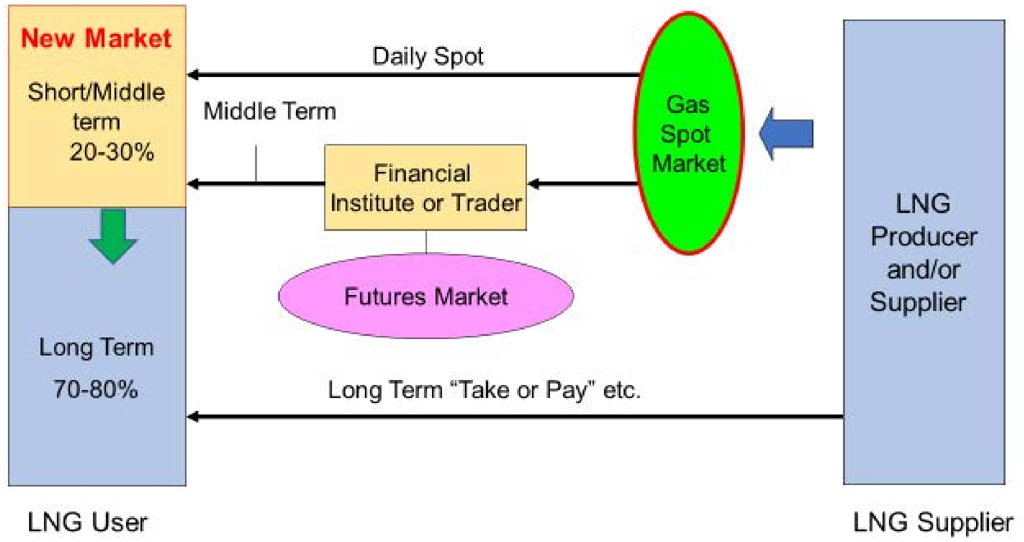
Source: Korea Gas Corporation (KOGAS).

Figure 3.8 South Korea LNG Purchase Contract

3.1.7 The Spot Market and Financial Trading

The LNG supply system will be changing from a bilateral take-or-pay model to purchasing from the market. The Japanese Government took the lead in creating a gas futures market in May 2016.

The following figure illustrates the role of the spot market and long-term contracts.



Source: DEP.

Figure 3.9 Concept of the LNG Supply Market

Spot purchases from the market will play a supplementary role in LNG procurement. The following table summarize the role of take-or-pay long-term contracts and spot procurement.

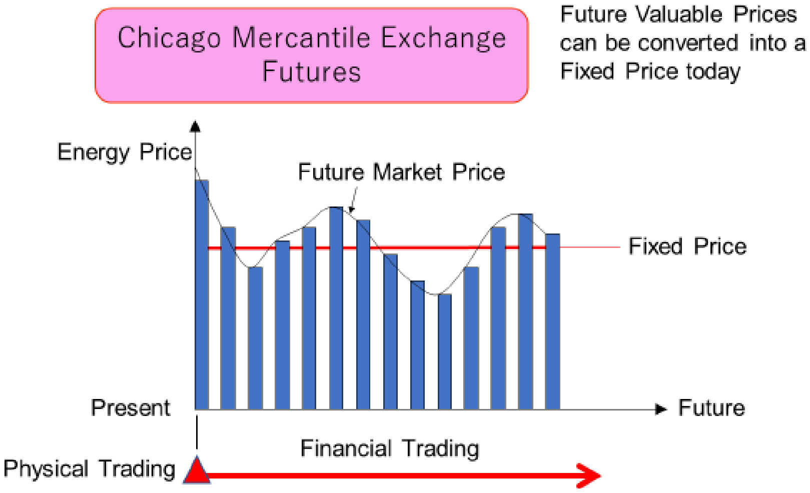
Table 3.1 Take-or-pay Contracts vs. Spot Market

	Take-or-pay Contract	New Spot Market
Supply Stability	Secured	Complementary
Contract Term	15-20 years (fixed)	Short-medium term (flexible)
Contract Volume	Large (fixed)	Small-medium (flexible)
Price	Oil-linked	Henry Hub and/or NBP-linked
Destination Constraints	Yes	No
Required Time to Complete Contract	Take some time	Immediate
Demand Fluctuation	Difficult	Easy
Regional Price Difference	Yes	Limited
LNG Supply	Dedicated to project	Portfolio

Source: DEP.

The spot market will be supported by financial trading. It is not convenient for buyers to buy gas or LNG at ever-changing market prices, meaning they may wish to buy at fixed prices for some length of time. Financial trading can provide the services needed to supply gas or LNG at a fixed price. The range of the term will differ from contract to contract, but, in general, from a few months to two years.

The mechanism to support financial trading is based on the "present value" marking on the futures market. The economic value at a certain time in the future will be translated into a present value using a discount rate based on the interest rate. The following illustrates the concept of financial trading.



Source: DEP.

Figure 3.10 Physical Trading and Financial Trading

The market will be developed and evolved further, once deregulation is started. Current take-or-pay contracts are termed as physical bilateral negotiable sales/purchase contracts.

There are two contracts types to deal with buying gas at a future price: over-the-counter (OTC) forward and futures.

An OTC forward contract is one of the ways to buy spot cargos at a future price. This is based on a bilateral contract. The following table summarizes the difference between forward procurement and futures procurement.

Table 3.2 Forwards and Futures

	Forward	Futures
Contract Conditions	Non-standardized	Standardized
Trading Location	OTC, Bilateral	Exchange
Counterparty	Identified	Anonymous
Trade Risk	Contracting Party	Clearing House (Settled by Deposit of Clearing Margin)
Contract Cancelation	Not possible	Settled by re-selling or buying back
Market Fluidity	No	Yes
Price Index	No (Price Confidential)	Yes

Note: A contract between two parties to exchange a specified asset:
1) for a price agreed today (*the futures price*);
2) with delivery occurring at a specified future date (*the delivery date*).

Source: DEP.

3.1.8 Price Competitiveness Analysis

The price of US LNG is linked with the Henry Hub price. The LNG price is calculated by the following formula:

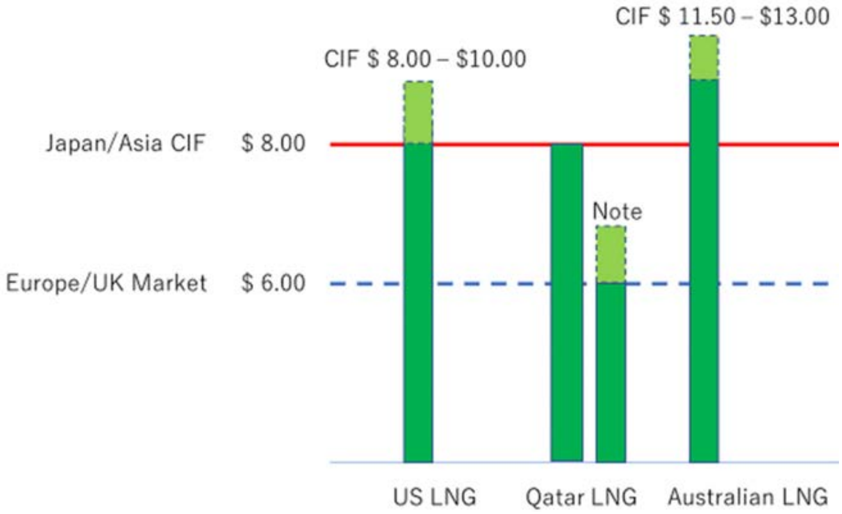
- FOB US = Henry Hub price + gas transportation tariff + liquefaction/shipping
- CIF Japan = FOB US + freight to Japan

Assuming that the Henry Hub price is 3.00 USD/MMBTU, CIF Japan will be in the range of 8.00-10.00 USD/MMBTU.

The break-even FOB price from Australian LNG is considered to be 10.00 USD/MMBTU. CIF Japan is considered to be 11.50-13.00 USD/MMBTU.

Qatari LNG exported to Asia is based on long-term take-or-pay contracts. The price formula is linked with crude oil. However, for exports to Europe, Qatar needs to supply LNG on an as-required basis due to a competing environment involving Russian pipeline gas and domestic gases including from Norway. The market gas price in the UK is created by the National Balancing Point (NBP) system.

Qatar will be able to export at the most competitive price, and the FOB price will be as low as 4.50-6.50 USD/MMBTU assuming an LNG liquefaction margin of 2.00-4.50 USD/MMBTU.



Note: Qatari LNG to Europe on an as-required basis.
Source: DEP.

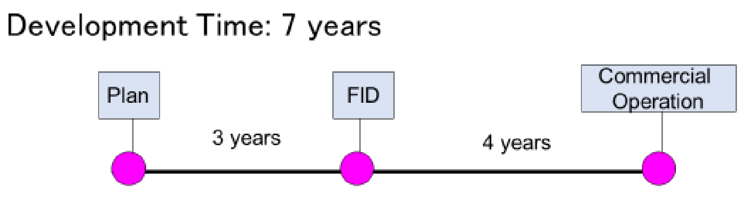
Figure 3.11 Indicative Price Competitiveness

In this study report, the 6.50 USD/MMBTU FOB price for Iran is used as a base case, assuming that the gas price to the LNG liquefaction plant will be 2.00 USD/MMBTU.

3.2 Business Arrangements and Finance

3.2.1 Project Risk Management

Development and construction of the LNG project will require considerable time, effort and funding to materialize: in general, three years of planning and financial arrangements, before a final investment decision (FID), and four more years for construction, i.e., seven years in total as a minimum.



Source: DEP.

Figure 3.12 Project Development Timescale

There could be changes in the economic environment from the time of planning to the start of commercial operations.

Conceivable risks are as follows:

- Country risk

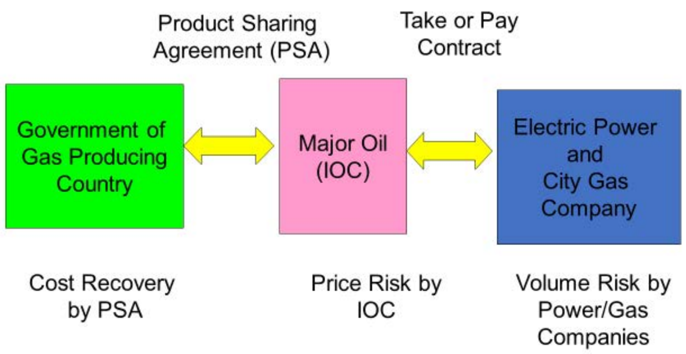
- Investment risk
- Technical risk
- Operational risk
- Market risk

Risks are mutually related. It is not the intention to individually discuss them in this report but the following must be stressed:

- The market is changing and take-or-pay contracts for long-term commitment will not be available in the near future. A new mechanism needs to be in place for the future LNG project to materialize.
- The role of an institutional support system for the project, such as the provision of long-term loan arrangements and export credit to support construction from the buyer's country, will be more important than ever.

In the past, the take-or-pay model has been one of the standard ways to develop a project in the form of a collaboration between sellers and buyers. Under the scheme, price risk could be borne by sellers and volume risk could be borne by buyers. Previously, in Japan, price risk was absorbed by the portfolio of a major oil company and volume risk was absorbed by the local monopoly.

The traditional risk share structure is illustrated as follows:

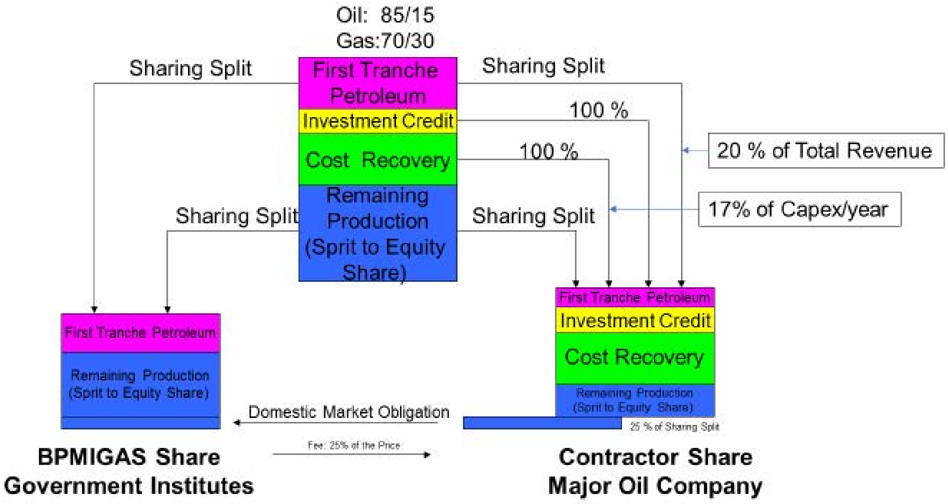


Source: DEP.

Figure 3.13 Traditional LNG Project Development Scheme

3.2.2 Product-sharing Agreement

A product sharing agreement (PSA) is a way to minimize investment risk, which was initially used in field developments in Indonesia, then extended to almost all field developments in the world. The actual contract will differ from case to case. The following figure depicts the PSA used in Indonesia.



Source: Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi (BPMIGAS).

Figure 3.14 Product Sharing Agreement in Indonesia

3.2.3 Energy Charter Treaty

The Energy Charter Treaty (ECT) provides a multilateral framework for energy cooperation, which is unique under international law. It is designed to promote energy security through the operation of more open and competitive energy markets, while respecting the principles of sustainable development and sovereignty over energy resources.

The ECT was signed in December 1994 and entered into legal force in April 1998. To date, the treaty has been signed or acceded to by 52 nations, the EU and Euratom. The total number of signatories is therefore 54.

There are 35 state-level observers to the ECT Conference, including Iran, while there are 16 international organizations with observer status. Attachment 1 contains a list of signatories and observers.

The treaty's provisions focus on four broad areas:

- The protection of foreign investments, based on the extension of national treatment, or most-favored nation treatment (whichever is more favorable), and protection against key non-commercial risks;
- non-discriminatory conditions for trade in energy materials, products and energy-related equipment, based on WTO rules, and provisions to ensure reliable cross-border energy transit flows through pipelines, grids and other means of transportation;
- the resolution of disputes between participating states and, in the case of investments, between investors and host states;
- the promotion of energy efficiency and attempts to minimize the environmental impact of energy production and use.

An agreement model exists, which consists of an intergovernment agreement (IGA) and a host government agreement (HGA):

- An IGA is a government-to-government bilateral agreement primarily to protect foreign investment and obligations to secure business environment for project operation.
- A HGA is designed to protect the contractor, i.e., the international oil company (IOC) and the consortium, from non-operational project risk and clarify the rights and privilege of the contractor, as well as the role of the host country.

The ultimate sanction in the case of a state-to-state dispute resolution is also found in the ECT.

3.2.4 Provisional Business Arrangement

In cases where there is no bilateral investment agreement between the host country and investing country, the framework of the ECT can be used in lieu of pursuing a bilateral investment agreement. Under an IGA, the following may be arranged:

- Long-term institutional loan
- Export credit for construction

To minimize the investment risk, capital recovery should be secured using the framework of a product-sharing agreement (PSA) between the national oil company (NOC) and the contractor (the IOC and the consortium).

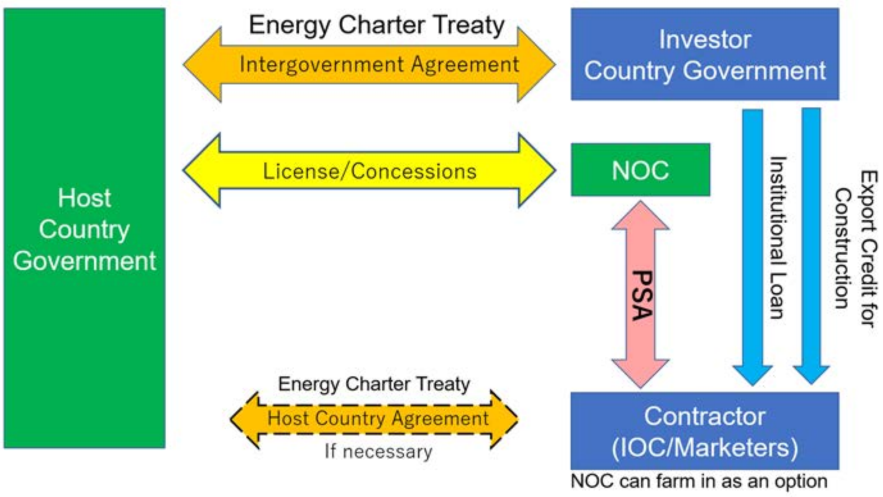
There may be two types of institutional loan arrangement: a direct loan arrangement for the project entity (Case 1) and/or an indirect loan arrangement for the project entity (Case 2), i.e., via the host country government.

(1) Direct loan arrangement

A direct loan arrangement provides a loan to the project entity of the investing country as shown in Figure 3.15.

(a) Parties involved will be as follows:
  i) Host country government: Ministry of Petroleum (MOP), Government of Iran
  ii) Investor country government: Government of Japan
  iii) NOC: NIOC or National Iranian Gas Company (NIGC)
  iv) Contractor: Consortium of IOCs and Japanese investors

(b) Agreement structure:
  i) Use of ECT framework and enter into an IGA or sign a HCA between the host country and the contractor
  ii) License or concession assigned to the NOC
  iii) PSA between the NOC and contractor is signed
  iv) Provision of loan to the contractor
  v) Provision of export credit for construction to contractor



Source: JICA Project Team.

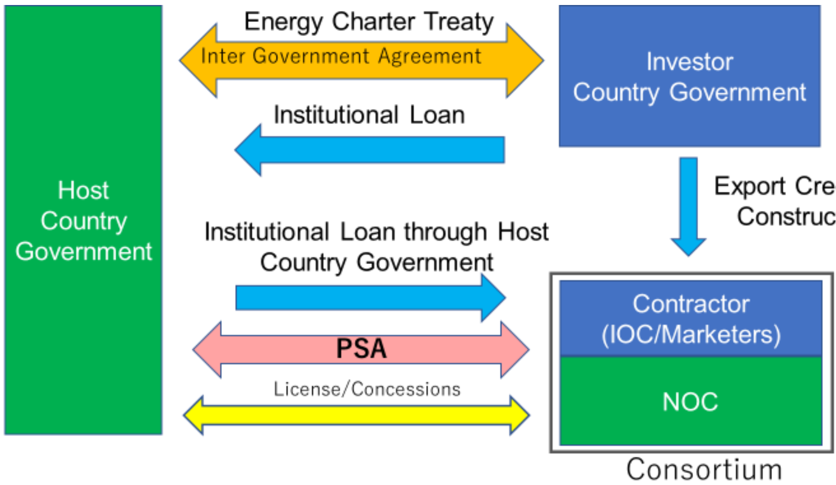
Figure 3.15 Direct Loan Arrangement (Case 1)

(2) Indirect loan arrangement

This loan is first provided to the host country government and then redirected to the project entity as illustrated in Figure 3.16.

(a) Parties involved will be as follows:
  i) Host country government: Ministry of Petroleum (MOP), Government of Iran
  ii) Investor country government: Government of Japan
  iii) Contractor/NOC consortium: Consortium of the contractor (IOC, Japanese Investors) and the NOC (NIOC or NIOG)

(b) Agreement structure:
  iv) Use ECT Framework and enter into an IGA
  v) License or concession assigned to the NOC
  vi) Sign the consortium agreement between the contractor and the NOC
  vii) PSA between the host country government and contractor
  viii) Provision of loan to host country government
  ix) Provision of loan contractor/NOC consortium
  x) Provision of export credit for construction to the contractor



Source: JICA Project Team.

Figure 3.16 Indirect Loan Arrangement (Case2)

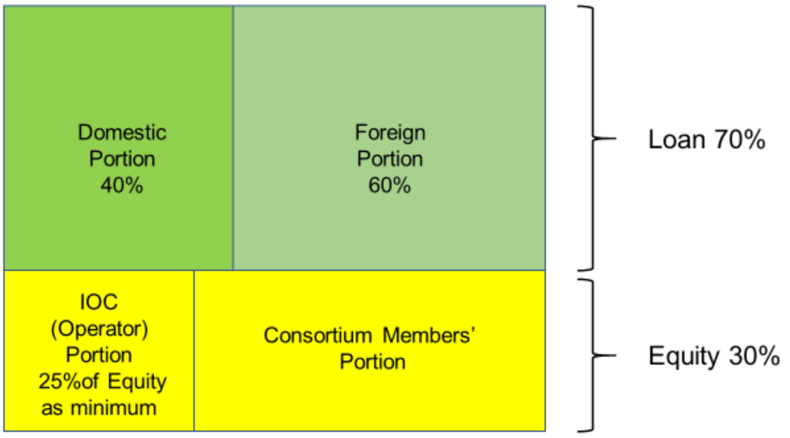
3.2.5 Provisional Business Entity Structure and Financial Arrangement

There are numerous variations in terms of forming a project entity. The main issues to be discussed and agreed upon concern the role and position of the NOC. In general, there are the following options.

(a) The NOC is not part of the contractor consortium under a PSA
(b) The NOC is not part of the contractor consortium under a PSA but it has an option to join at a later stage
(c) The NOC is part of the contractor consortium under a PSA bound by the consortium agreement with other contractor members.

The contractor consortium must include an IOC with experience of LNG development and operations. Consortium members could also include marketers and/or utility companies with responsibility for market or product offtake. The leader of the contractor consortium is known as the operator responsible for all aspects of the project, from planning to financing and finance arrangements, engineering, construction and operations, as the head of the business entity. At least 25% of the equity is required to maintain the position of operator.

An equity portion covers 30% of the entity asset, with loan portions comprising the rest. Loan portions consist of domestic portions and foreign portions. Legal requirements in Iran dictate that domestic potions must be 40% of the total loan arrangement and provided by commercial banks in the country.

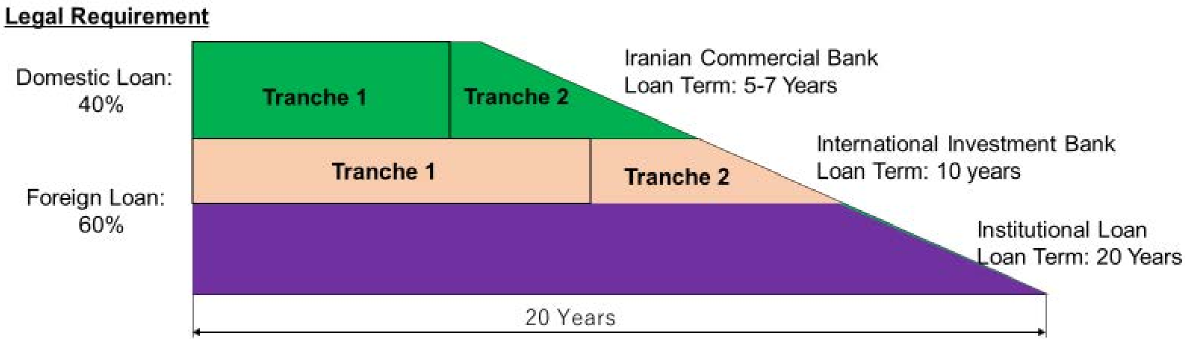


Source: JICA Project Team.

Figure 3.17 Finance: Business Entity Structure

Loan supply terms and interest will differ from loan provider to provider. In order to cover a 20-year loan term, a loan syndicate must be structured. As a syndicate organizer, an international investment bank should be invited. The term of the loan by the domestic bank may be limited to five to seven years maximum. Even an investment bank can only offer a 10-year loan in general. Since the loan term for the LNG project is expected to be 20 years overall, an institutional loan arrangement is highly expected to minimize the financial risk and lead to a lower weighted average interest rate.

The concept of the structured loan arrangement is illustrated in the following figure.



Source: JICA Project Team.

Figure 3.18 Finance Loan Arrangement

3.3 Scale of LNG Plant

3.3.1 LNG Carrier Size

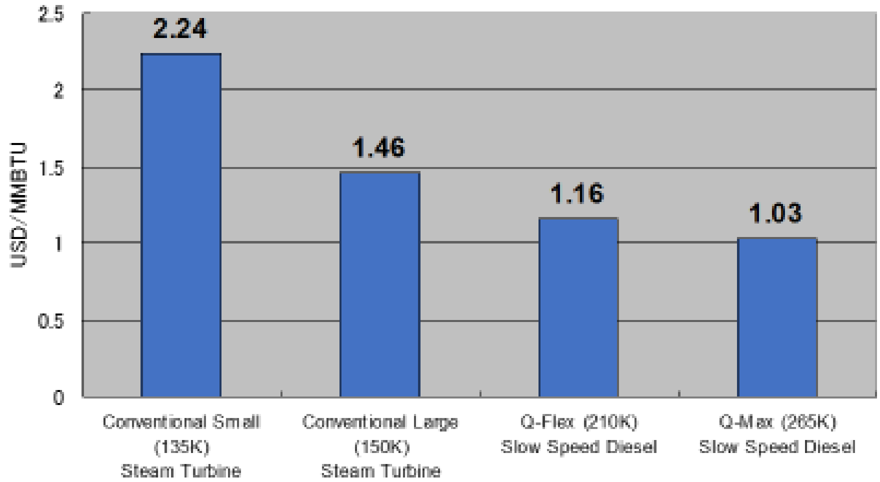
The size of LNG carriers has grown larger and larger. A modern terminal needs to be designed to accommodate the largest scale carrier, i.e., Q-Max.

Table 3.3 LNG Carrier Size

Tankar Size (M3)	Length (m)	Beam (m)	Draft (m)	Engine Type
135,000	290	45.8	11.5	Steam
145,000	290	49.0	11.4	Steam
155,000	290	49.0	11.6	DFDE
210,000 (Q-Flex)	315	50.0	12.5	SSD
260,000 (Q-Max)	345	53.8	12.0	SSD

Note: DFDE: duel-fuel diesel electric, SSD: slow-speed diesel.
Source: DEP.

Freight costs differ according to the size of the vessel and driver type. The following figure shows a freight cost comparison of relevant vessels. Large-scale carriers will be used for long-distance voyages and small-scale carriers will be used for short-distance voyages.

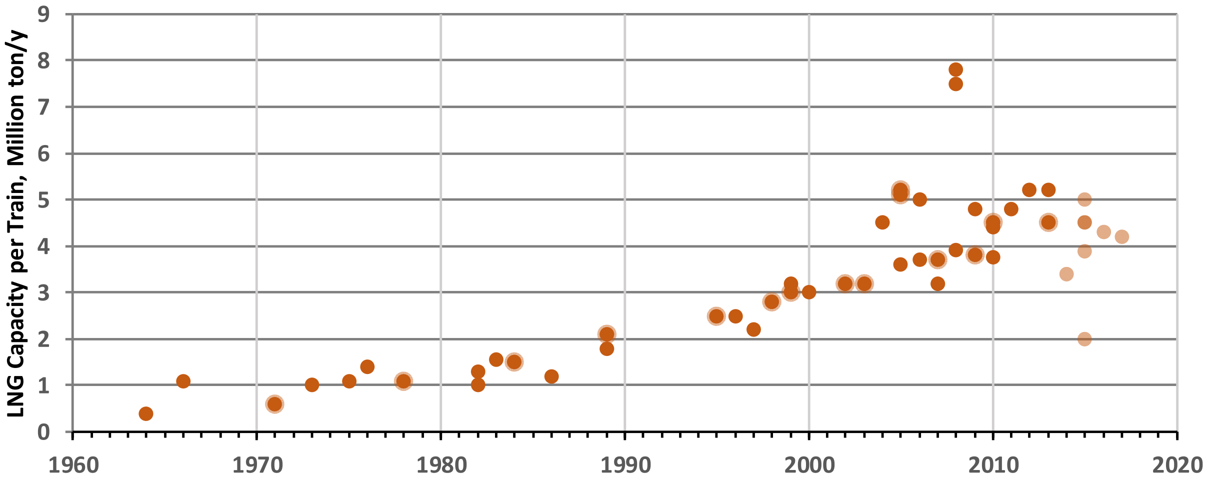


Source: DEP.

Figure 3.19 Freight from the Middle East to Japan/South Korea

3.3.2 LNG Liquefaction Plant Size

The capacity of LNG liquefaction facilities is becoming larger and larger in order to compete in the international market. As shown in Figure 3.20, the capacity of LNG trains has increased since the typical capacity of 1 MTPA (million tons per annum) in the 1970s.



Source: Reproduced from Oxford Institute for Energy Studies, LNG Plant Cost Escalation, 2014.

Figure 3.20 Trend of LNG Production Capacity per Train

The current LNG plant scale for one train is in the range of 4.5 million tons/year to 5.0 million tons/year. To stabilize the production rate, two trains are required. To produce 2 x 4.5 million tons/year of LNG, the gas requirement will be 40 million Nm^3/day. The initial gas allocation of 25 million Nm^3/day will not be enough to support the world-class LNG manufacturing facility and thus needs to be reviewed.

CHAPTER 4 ENVIRONMENTAL SENSITIVITY ANALYSIS FOR LNG SUPPLY PLANT DEVELOPMENT

4.1 Preliminary Screening of Candidate Regions for LNG Development

Candidate sites for LNG production were preliminarily screened for Kouvei, Souza and Selakh. Souza has been identified as the most suitable location for the petrochemical complex in the SWECO Master Plan. Selakh offers the best location as it is close to the international anchorage area. This strategic location is advantageous for installing bunkering facilities alongside the international waterway. However, dolphins make their habitat in the Dolphin Bay in the vicinity of Hangom Island. Coral reefs also exist in the southern area. This is the limit of the western edge of the coral reefs' habitation. The third candidate site is Kouvei, which has calm sea, with sufficient depth and soft waves; this is advantageous to the development of the seaport, while there are no environmentally sensitive animals and plants in its periphery, although the location does not offer easy access to the international waterway. Table 4.1 shows the advantages and disadvantages of each candidate site. With regard to Souza, a detailed study of the best location within this area was carried out and is shown in Attachment 1 to this report.

Table 4.1 Preliminary Screening of Candidate Regions for LNG Development

Item	Souza	Selakh	Kouvei
Advantage	・Availability of deep water depth ・Easy access to the international waterway ・Availability of broad land	・Availability of sufficient water depth to receive the large-scale vessels ・Easy access to international waterway ・Availability of sufficient land for LNG production and related activities	・Calm sea with soft waves ・Access to main seaport of Shahid Rajaee ・Relatively low threats of negative environmental impact
Disadvantage	・Risk of changes to and erosion of sandy beach ・Risk of deformation of the seabed resulting in the elimination of access to Naz Island during low tides ・Risk of deterioration to the landscape	・Risk of changes to and erosion of sandy beach ・Risk of deterioration to coral reefs and marine ecology headed by dolphins	・Low accessibility to the international waterway ・Relatively low depth of sea water

Source: JICA Project Team.

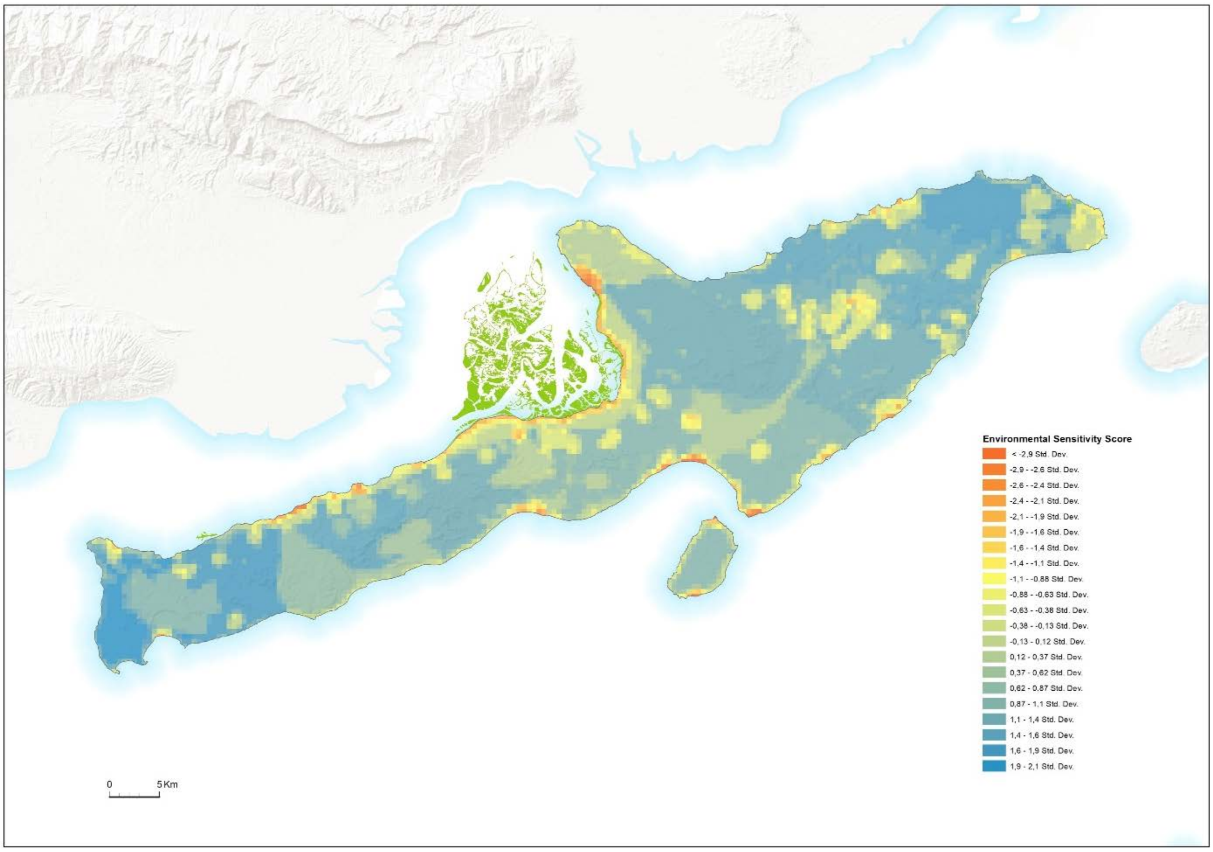
4.2 Environmental Sensitivity Analysis of Qeshm Island

Conservation and wise use of the environment are key to achieving the envisaged vision on Qeshm Island. The ES of Qeshm has been analyzed based on a 500-mr grid generated on the island as well as Hangom Island. According to the WLC aggregation method, each square of the mesh receives an ES score calculated according to natural and social environment criteria; their weighting is shown in Table 4.2, while Figure 4.1 shows the estimated ES.

Table 4.2 Criteria and Weight for Sensitivity Analysis

Criterion	Spatial influence	Weight (on a scale of 1 to 10)
Human settlements surroundings (500 m)	Overlap	10.0 (very high sensibility)
Ports surroundings (500 m)	Overlap	10.0 (very high sensibility)
Protected areas and surroundings (500 m)	Overlap	8.0 (high sensibility)
Indo-Pacific bottlenose dolphin habitat	Proximity	7.0 (high sensibility)
Sea turtle nesting sites	Proximity	7.0 (high sensibility)
Sandy beaches	Overlap	7.0 (high sensibility)
Mangrove areas	Overlap	7.0 (high sensibility)
Cultural heritage surroundings (500 m)	Overlap	6.0 (relatively high sensibility)
Geosites	Overlap	5.0 (relatively high sensibility)
Farmlands and natural local forests (acacia) areas	Overlap	5.0 (relatively high sensibility)

Source: JICA Project Team.



Source: JICA Project Team.

Figure 4.1 Environmental Sensitivity on a 500-m Grid on Qeshm Island

In addition to the ES analysis of the terrestrial and coastal areas, an ES area is identified for the marine areas focusing on marine ecology and fishery. For this purpose, the JPT carried out an interview survey among fishermen in Souza, Kouvei and Selakh to clarify the location of fishing grounds and spawning areas. The JICA Iran Office conducted a field survey to investigate a habitat of Indo-Pacific bottlenose dolphins, which are the main tourism assets of the island, from December 2017 to February 2018 (i.e., in winter) and a fishing spot in Dolphin Bay. The identified ES area includes the following:

(a) Designated environmental conservation area
- ✓ Hara Protected Area
- ✓ Natural Heritage Area
- ✓ Geosite

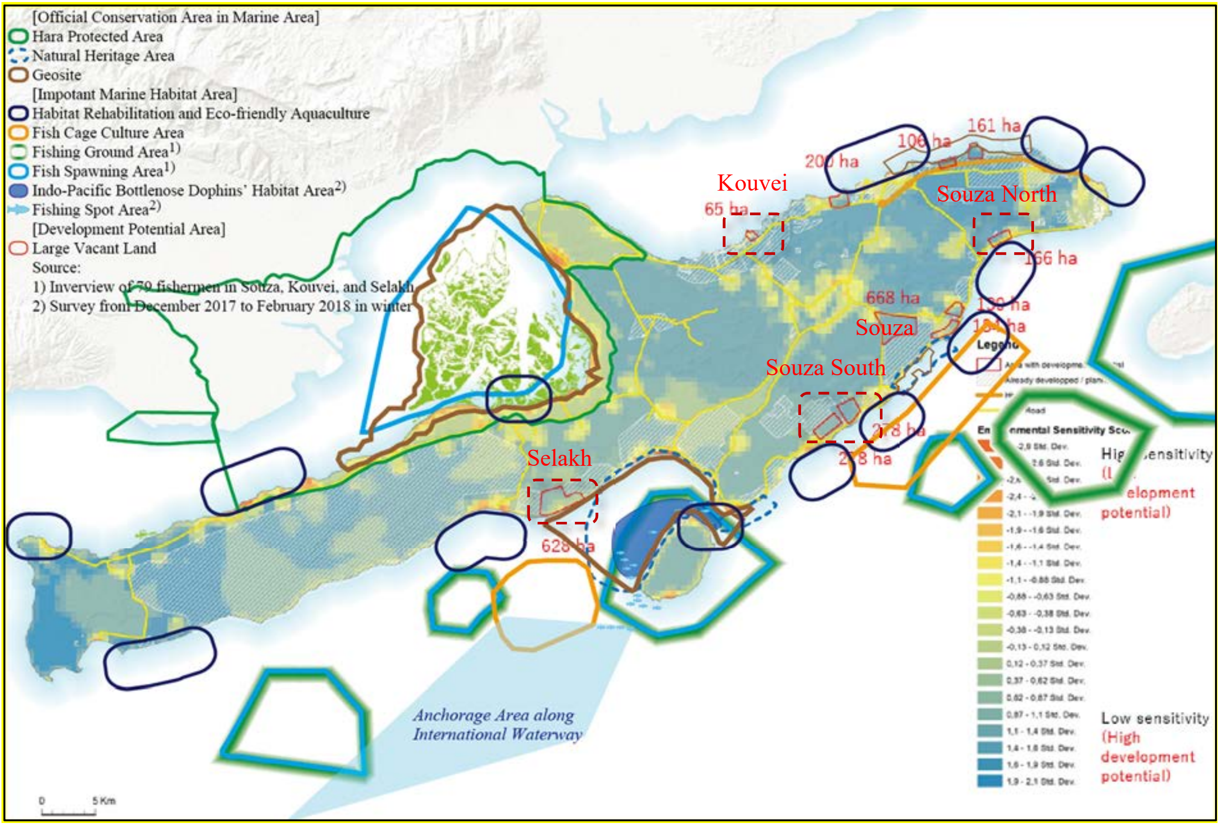
(b) Fishery and aquaculture area

- ✓ Fish cage culture area proposed by the DoE in Tehran in accordance with the sixth FYDP
- ✓ Habitat rehabilitation and ecofriendly aquaculture proposed by the JPT in line with the concept of *satoumi*[1]
- ✓ Fishing ground area and fish spawning area
- ✓ Fishing spot area using traps

(c) Habitat of Indo-Pacific bottlenose dolphin

Figure 4.2 presents an overview of the ES analysis for the terrestrial area, coastal area and marine area. The fishing ground, spawning area and fish cage culture area are located from east to west in the south of island. Areas suitable for ecofriendly aquaculture and *satoumi* are distributed along the coastal areas. Those areas need to be protected from development and environmentally negative impacts.

The figure also shows the vacant land across a relatively large area excluding the occupied areas, the ongoing project areas and the planned project areas. From the analysis, the development-potential areas are identified in four places: Kouvei, north of Souza, south of Souza and east of Selakh. Souza, which the SWECO Master Plan proposes for the petrochemical development location, is dropped from the candidate site in this analysis.



Source: JICA Project Team.

Figure 4.2 Environmental Sensitivity and Extraction of Development Potential Area

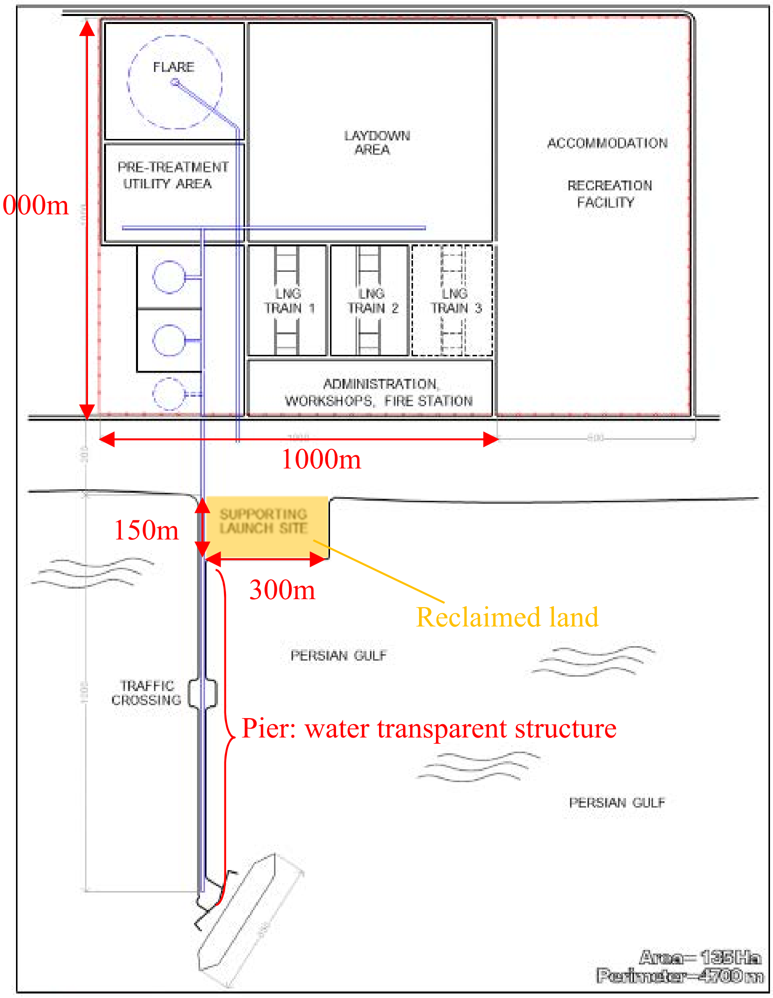
4.3 Natural Conditions Survey

4.3.1 Objective, Location and Survey Items

A brief study on the impact on marine ecosystem and coastline caused by the construction of an LNG plant in the three possible locations was conducted in order to choose the most suitable site. An LNG

[1] *Sato* means village in Japanese and *umi* means ocean. When combined, *satoumi* means a coastal area in which marine biodiversity is encouraged using the limited application of artificial tools.

manufacturing site with a nine-million-ton production capacity is assumed, as shown in Figure 4.3.



Source: JICA Project Team.

Figure 4.3 LNG Manufacturing Facility Plot Plan

Three locations on Qeshm Island (Selakh, Souza and Kouvei) were selected as the survey sites, as explained in Section 4.1. During the analysis stage after the field survey, a new candidate location for the LNG plant in Souza South was additionally proposed by the counterpart and selected using the ES analysis as discussed in Section 4.2. The detailed locations of the survey are shown in Figure 4.4 for Kouvei, Figure 4.5 for Souza, Souza North and Souza South, and Figure 4.6 for Selakh. Table 4.3 shows the coordinates of the survey locations and the survey items, respectively. Among them, Souza 1 represents Souza North, Souza 4 represents Souza South, and Selakh represents Selakh.

Source: Google Earth for imagery.

Figure 4.4 Survey Locations in Kouvei

Source: Google Earth for imagery.

Figure 4.5 Survey Locations in Souza, Souza North and Souza South

Source: Google Earth for imagery.

Figure 4.6 Survey Locations in Selakh

Table 4.3 Coordinates of the Survey Locations and Items

	Latitude	Longitude	Seagrass, Seaweed	Coral	Tidal current	Water quality	Sediment quality
Dargahan 1	26.939800˚N	55.964300˚E			x		
Dargahan 2	26.953137˚N	56.019205˚E	x	x		x	
Dargahan 3	26.950183˚N	55.985139˚E	x	x			x
Dargahan 4	26.923627˚N	55.945677˚E	x	x		x	
Dargahan 5	26.911620˚N	55.928449˚E				x	
Souza	26.904346˚N	56.165938˚E	x	x			
Souza	26.877532˚N	56.155289˚E	x	x	x	x	x
Souza	26.805472˚N	56.095367˚E				x	
Souza	26.771961˚N	56.058094˚E				x	
Souza	26.828694˚N	56.132472˚E	x	x			
Selakh	26.677800˚N	55.754300˚E	x	x	x		x
Selakh 1	26.681335˚N	55.736145˚E				x	
Selakh 2	26.684641˚N	55.724763˚E	x	x		x	
Selakh 4	26.687089˚N	55.707600˚E				x	
Selakh 5	26.681533˚N	55.718843˚E	x	x			

Source: JICA Project Team.

Table 4.4 shows the survey items and survey methodology. A field survey was carried out twice, in July 2017 and March 2018.

Table 4.4 Survey Items and Methodology

Item	Methodology	Frequency/year	Accompanying information
Seagrass, seaweed	Distribution: interviews, diving observation, echo sounding	Once (March 2018)	Including literature survey
Fishery	Confirmation of fishing ground: interview	Once (January-March 2018)	
Coral	Distribution: interviews, diving observation	Once (March 2018)	Belt transect, species list
Sea turtle nesting ground	Distribution: interviews, observation	Once (January-March 2018)	
Tidal current	Current speed and direction: measurement by equipment (ADCP*)	Once (July-August 2017)	3 locations
Coastal erosion	Comparison by Google Earth simulation	Once	Analysis of bottom sediments (3 samples, grain size composition, specific gravity)
Thermal water diffusion	Vertical distribution of water temperature and salinity: field measurement by equipment Diffusion area: simulation	Once (July-August 2017) Once	Following data were purchased: • Wave height and direction • Wind speed and direction
Water quality	Sampling and laboratory analysis	Once (July-August 2017)	
Sediment quality	Sampling and laboratory analysis	Once (July-August 2017)	

Note: Interview includes study of existing data; ADCP: acoustic doppler current profiler.
Source: JICA Project Team.

Table 4.5 shows the study schedule and Table 4.6 shows the dates and locations of the field surveys.

Table 4.5 Study Schedule

	June 2017	July	August	September	October	November	December	January 2018	February	March
Field survey										
Interview survey										
Simulation										
Reporting										

Source: JICA Project Team.

Table 4.6 Dates and Locations of Field Surveys

	Date	Survey locations
Tidal current	Kouvei: August 6-12, 2017	Dargahan 1
	Souza: August 5-12, 2017	Souza 2
	Selakh: July 29-August 3, 2017	Selakh
Vertical distribution of water temperature and salinity	Kouvei: August 6 & 12, 2017	Dargahan 1
	Souza: August 12, 2017	Souza 2
	Selakh: July 29 & August 3, 2017	Selakh
Seaweed, seagrass, coral	Kouvei: February 28 & March 20, 2018	Dargahan 2, 3, 4
	Souza: February 21, 2018	Souza 1, 2, 5
	Selakh: February 22, 2018	Selakh, Selakh 2, 5
Water quality	Kouvei: August 6, 2017	Dargahan 2, 4, 5
	Souza: August 12, 2017	Sauza 1, 2, 4
	Selakh: July, 29 2017	Selakh 2, 3, 4
Sediment quality	Kouvei: August 6, 2017	Dargahan 3
	Souza: August 12, 2017	Souza 2
	Selakh: July 29, 2017	Selakh

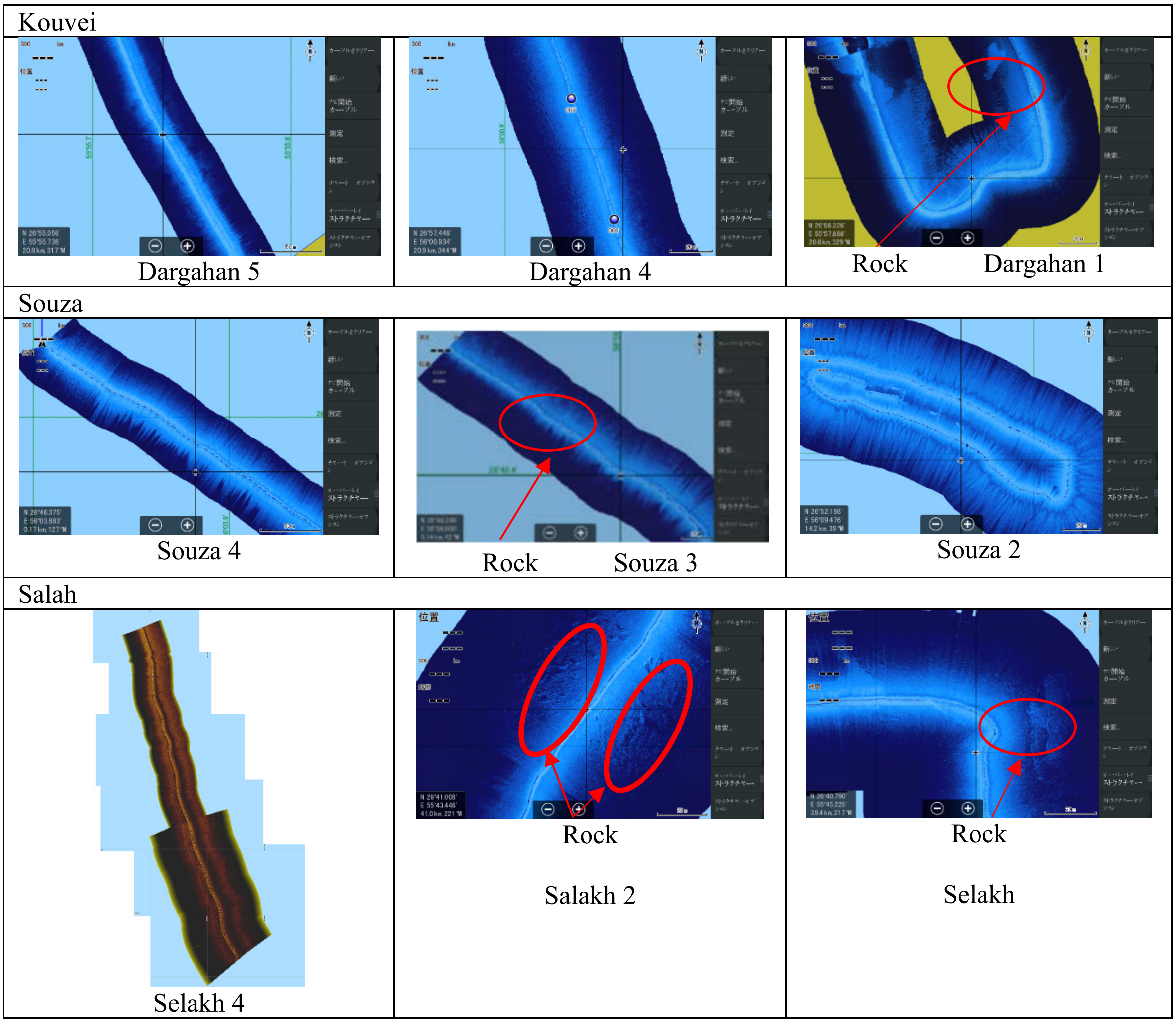
Source: JICA Project Team.

4.3.2 Survey Results

(1) Seagrass and seaweed

1) Confirmation of the attachment base

Since seaweed and seagrass species often grow by attachment to the basement, such as rock, a brief survey to confirm the basement type using a side-scan sonar was conducted in August 2017 (Figure 4.7). Based on the confirmation results, survey locations of seaweed and seagrass were determined, while another survey was conducted from February to March 2018.



Source: JICA Project Team.

Figure 4.7 Screen Images by Side-scan Sonar

2) Species

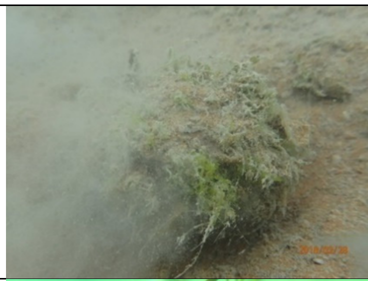
The most recent comprehensive studies of the Persian Gulf were carried out by Sohrabipour and Rabei in 1998, in which 150 algae species from the area were identified, 116 of which belonged to Qeshm, Larak and Hangom Islands (Sohrabipour and Rabiei, 1999). In 2005, during studies carried out by Rabiei et al., 46 species of algae had been introduced along the Qeshmi coast (Rabiei et al., 2005). Intensive research was carried out into algae on Hangom Island by Imani in which 51 species were identified and introduced (Imani, 2014). Two types of seagrass were reported on Hangom and Qeshmi coasts, namely, *Halophila ovalis* and *Halodula univeris*. Qaranjik also prepared an atlas of algae in the Persian Gulf and Oman Sea, which included 159 identified species.

In this survey, a total of 24 seaweed species and two seagrass species were identified. In particular, well-grown *Sargassum angustifolium* was found in the Kouvei area, which could be a potential nursery for fish species (see Table 4.7 and Figures 4.8 to 4.10).

Table 4.7 List of Seaweed and Seagrass Species

Category	Species name	IUCN Red List Status	Kouvei	Souza	Selakh
Seaweed	*Acanthophora spicifera (M.Vahl) Børgesen*			x	x
	Actinotrichia fragilis (Forssk ål) Børgesen			x	x
	Ahnfeltiopsis pygmaea (J.Agardh) P.C.Silva & DeCew				x
	Avrainvillea erecta (Berkeley) A.Gepp & E.S.Gepp			x	
	Bryopsis pennata J.V.Lamouroux				x
	Caulerpa sertularioides f. farlowii (Weber-van Bosse)				x
	Colpomenia sinuosa (Mertens ex Roth) Derbès & Solier		x	x	x
	Iyengaria stellata (Børgesen)		x		
	Gracilaria arcuata Zanardini		x		
	Gracilaria corticata (J.Agardh) J.Agardh				x
	Gracilaria spinulosa (Okamura) Chang & B.M.Xia				x
	Padina boergesenii Allender & Kraft				x
	Padina gymnospora (Kützing) Sonder		x	x	
	Padina distromatica Hauck				x
	Padina pavonica (Linnaeus) Thivy		x		
	padina tenuis Boryde Saint-Vincent			x	
	Solieria dura (Zanardini) F.Schmitz				x
	Ulva lactuca Linnaeus		x		
	Sargassum angustifolium		x		
	Ulva clathrata (Roth) C.Agardh		x		
	Ulva intestinalis Linnaeus		x		
	Hypnea charoides J.V.Lamouroux				x
	Hypnea hamulosa (Esper) J.V.Lamouroux		x		
	laurencia obtusa (Hudson) Lamouroux		x		
Seagrass	*Halophila ovalis (R.Brown) J.D.Hooker*		x		
	Halodula uninervis		x		

Source: JICA Project Team.

Dargahan 1 (depth of 2-3 m at mid tide)		
Dargahan 2 (depth of 5-6 m at high tide)		
Dargahan 4 (depth of 2 m at mid tide)		

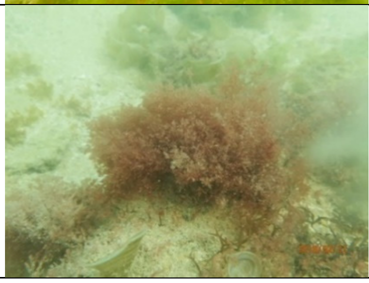
Source: JICA Project Team.

Figure 4.8 Underwater Photos at Kouvei

Souza 1 (depth of 1-3 m at mid tide)		
Souza 3 (depth of 2-3 m at mid tide)		
Souza 5 (depth of 1-2 m at mid tide)		

Source: JICA Project Team.

Figure 4.9 Underwater Photos at Souza

Selakh (depth of 1 m at low tide)		
Selakh 2 (depth of 2-3 m at mid tide)		
Selakh 5 (depth of 1-3m at mid tide)	No photo (only corals are dominated)	No photo (only corals dominate)

Source: JICA Project Team.

Figure 4.10 Underwater Photos at Selakh

(2) Fishery

The fishery status was surveyed by a questionnaire and interview approach in each survey area (Table 4.8).

Table 4.8 Number of Interviewees

Survey Area	Number	Type of Employment						
		Only fisherman	Driver	Hair stylist	Fishmonger	Worker	Self-employment	Head of Fishery Cooperative Company
Kouvei	20	15	2	0	1	1	1	0
Selakh	30	28	0	1	1	0	0	0
Souza	29	28	0	0	0	0	0	1
Total	79	71	2	1	2	1	1	1

Source: JICA Project Team.

According to the interview, the most important fishing grounds are:

- Hangom Island: 44%
- Larak Island: 35%
- Souza: 27%
- Great Tonb: 23%
- Ramchah: 19%
- Namakdan: 18%
- Selakh: 18%

Figure 4.11 shows the fishing ground, based on the interview, which is located in the offshore area on the southern coastal side of Qeshm Island.

The important fish spawning grounds from the fishermen's viewpoint are:

- Hangom Island: 19%
- The mangroves: 14%
- Larak Island: 11%
- Salakh: 11%

Source: JICA Project Team based on interviews with fishermen.

Figure 4.11 Major Fishing Grounds

- Souza: 10%
- Namakdan: 10%
- Great Tonb: 10%

Figure 4.12 shows the spawning grounds, based on the interview, which are located in the offshore area on the southern coastal side of Qeshm Island and the Hara Mangrove Area on the northern part of the island.

Source: JICA Project Team based on interviews with fishermen.

Figure 4.12 Major Spawning Grounds

The important base characteristics for fish spawning grounds from the fishermen's viewpoint are:

- Rocky grounds with natural or artificial pores: 44%
- Corals: 28%
- Muddy substrate: 11%
- Beaches: 11%
- Deeper areas: 11%
- Limited human access and traffic: 10%

Therefore, rocky and coral areas will be considered as being important from the viewpoint of fisheries as well.

According to fishermen's viewpoints, fish-catch visiting is not the reason for the presence of tourists; rather, the most important reasons include: visiting the beach (34%), QIGG sites (32%) and sea-related recreation and water sports (22%). Only 6% of tourists visit the locations with the aim of the fishing and fishery, while only 1% visit for recreational fishing. Table 4.9 shows the dependence of each area on tourism. Selakh and Souza, on the southern part of Qeshm Island, show a higher tourism dependency than Kouvei.

Table 4.9 Tourism Dependency for Each Site

Stations	Number	Percentage
Kouvei	14	20
Selakh	29	41
Souza	27	39
Total	70	100

Source: JICA Project Team.

Fishermen (42% of the respondents) believe that the current fish stock status is weak and 30% regard the status as too weak. This compares with the fact that fishing and the fish stock status were good and excellent, respectively, 20 and 30 years ago.

(3) Coral

1) Distribution of coral reefs around Qeshm Island

Due the wide sandy and muddy shores on Qeshm Island, hard corals are mainly restricted to three areas along the southern and southeastern shorelines close to Qeshm City. The southeast coast of Qeshm Island supports the only well-developed coral reef area covering approximately 45 ha and (with 14.03±0.6% live coral cover) dominated by the *Porites* species (Kavousi et al., 2011; authors' personal observations). Although there are sparsely distributed hard coral species along the southern coast, especially in Kandalou (with 8.24% ± 2.1% live coral cover) and on Naz Islands (very small satellite islands), in the main, they comprise the more tolerant species of the Faviidae family (Kavousi et al., 2011; authors' personal observations). Currently, 10 hard coral genera have been recorded on Qeshm Island (Kavousi et al., 2011) (see Figure 4.13).

One of the most unique soft coral beds in the Persian Gulf, locally known as Gesher Posht (or Gesher Springy), also occurs in the deep southern waters Qeshm Island at depths of 40-60 m (Samimi Namin and van Ofwegen, 2009; DoE of the QFZO).

Source: JICA Project Team based on interviews with fishermen; imagery from Google Earth.

Figure 4.13 Distribution of Hard Corals on Qeshm Island (Yellow Polygons)

2) Results of the field survey

Table 4.10 shows the average coverage ratio of coral at the three stations of Kouvei, Souza and Selakh, as observed during an underwater survey on this occasions.

In general, the substrate in Kouvei is a sandy-clay bed; therefore, there is no hard coral. But there is a stony substrate in front of Kouvei Village at a depth of 6 m, which is covered by up to 20% with soft corals in certain places. Selakh has an almost sandy-muddy bed too, and it is impossible for hard corals to settle and present themselves except at the Selakh 5 station, where coral exists outside the Selakh fishing harbor on the stony wall of the harbor. The most important coral area in this study is Souza 5.

Table 4.10 Average Coverage Ratio by Coral, Algae and Sponge

Unit: %

	Hard Coral	Soft Coral	Algae	Sponge	Main substrate
Dargahan 2	0	0	15	0	Sand
Dargahan 3	0	0	10	0	Sand
Dargahan 5	0	0	17	0	Sand, rock
Souza 1	0	0	53	0	Sand, rock
Souza 2	0	0	1	0	Sand, rock
Souza 5	9	0	1	0	Rock, sand
Selakh 1	0	0	5	0	Sand
Selakh 2	0	0	5	3	Rock, sand
Selakh 5	11	15	0	0	Rock

Source: JICA Project Team,

Table 4.11 lists the coral species and the status of the IUCN Red List. Three "vulnerable" species are identified in the survey.

Table 4.11 List of Coral Species Identified in the Field Survey

Coral species	Souza	Selakh	IUCN Red List
Acanthastrea echinata	X	-	LC
Acropora downingi	X	-	LC
Acropora clathrata	X	-	LC
Platygyra acuta	X	X	NT
Porites lobata	X	X	NT
Porites lutea	X	X	LC
Cyphastrea microphthalma	X	X	LC
Cyphastrea chalcidicum	X	-	LC
Dipsastraea speciosa	X	X	LC

Coral species	Souza	Selakh	IUCN Red List
Dipsastraea favus	X	X	LC
Psammocora stellata	X	X	VU
Platygyra daedalea	X	-	NT
Favites pentagona	X	X	LC
Plesiastrea versipora	X	-	LC
Pavona decussata	X	X	VU
Stylophora pistillata	X	-	NT
Turbinaria reniformis	X	-	VU

Note: LC: least concern, NT: near threatened, VU: vulnerable.
Source: JICA Project Team.

(4) Sea turtle nesting ground

The status of sea turtle nesting was studied using an interview approach as well. Table 4.12 shows the encounters with sea turtles, based on the interviews. Most fishermen have encountered sea turtles. The species may not be reliable, since it is not identified in detail. Forty-nine percent of fishermen support a reduction in sea turtles.

Table 4.12 Encounters with Sea Turtles

Unit: %

	Observed sea turtle and status	Kouvei	Selakh	Souza	Total
		95	93	90	92
Number of observed species	1 species (indistinguishable)	25	48	3	25
	2 species	0	13	10	9
	3 species and more	0	3	10	5
Different types of observed sea turtles	Hawksbill sea turtle	15	13	10	13
	Leatherback sea turtle	5	3	3	4
	Stretched sea turtle	5	0	0	1
	Green sea turtle	10	10	28	16
	Olive ridley sea turtle	10	7	14	10
Differences between past and present	Lower in size	5	0	0	1
	Lower in number	55	47	48	49
	More in number	0	13	24	14
	Unchanged	40	30	24	30

Source: JICA Project Team.

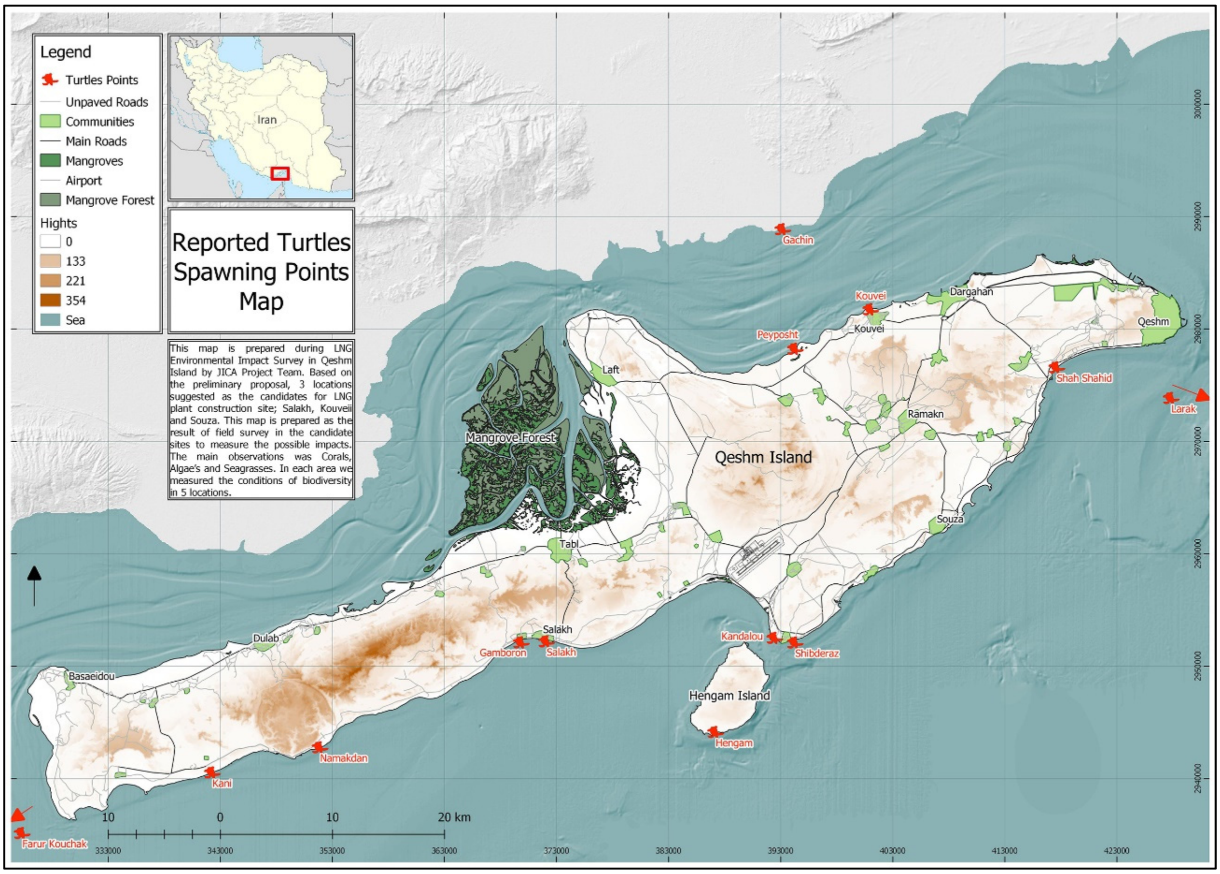
Shibderaz and Hangom Island are commonly recognized as spawning ground. However, other locations were also reported in the interviews (see Table 4.13). Figure 4.14 shows the location of spawning grounds.

Table 4.13 Spawning Status of Sea Turtles

Unit: %

	Spawning grounds	Kouvei	Selakh	Souza	Total
Spawning grounds for sea turtles	Agahi	60	83	76	75
	Peyposht	10	0	0	3
	Kouvei	10	0	0	3
	Gachin	10	0	0	3
	Larak Island	0	0	14	5
	Selakh	5	30	0	13
	Kandalou	5	0	0	1
	Sandy substrate	20	13	24	19
	Shibderaz	30	70	66	58
	Hangom Island	0	43	28	27
	Shahe Shahid (in the past)	0	0	21	8
	Kani	0	7	0	3
	Namakdan	0	27	3	11
	Small Farour	0	3	0	1
	Gomboron	0	7	0	3
Spawning season	March to April	5	20	7	11
	April to May	5	0	0	1
	November to January	15	0	17	10
	Second half of the year	5	3	0	3
	Spring	5	27	17	18
	Summer	0	23	10	13
	Winter	0	0	10	4

Source: JICA Project Team.

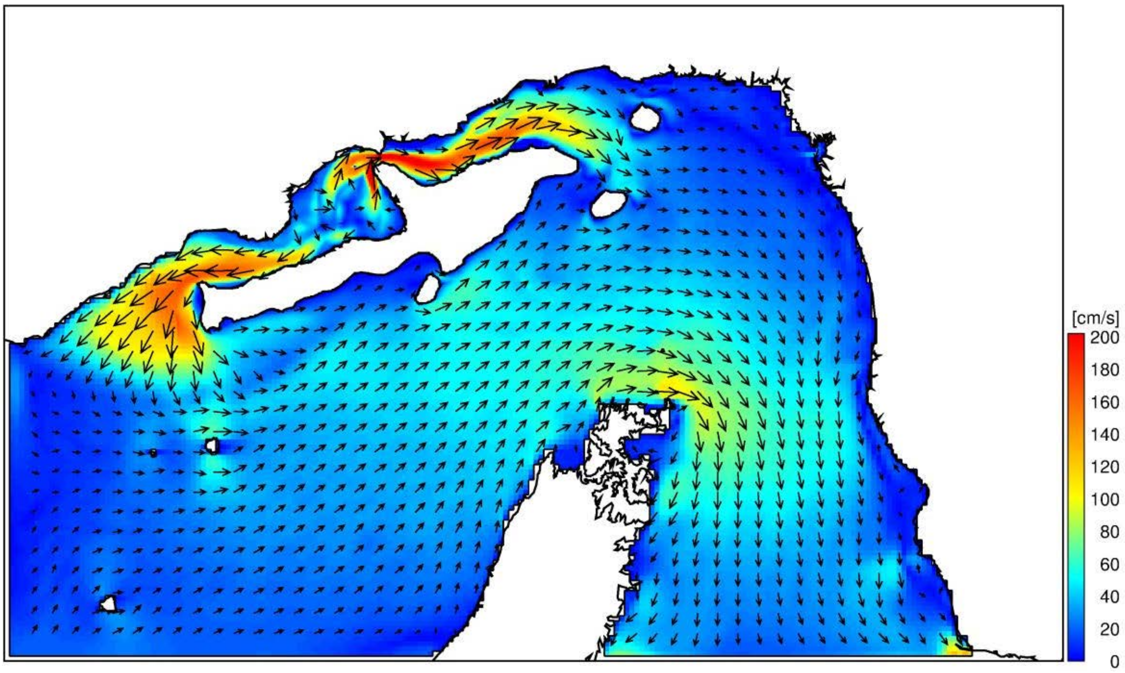


Source: JICA Project Team.

Figure 4.14 Sea Turtle Spawning Grounds

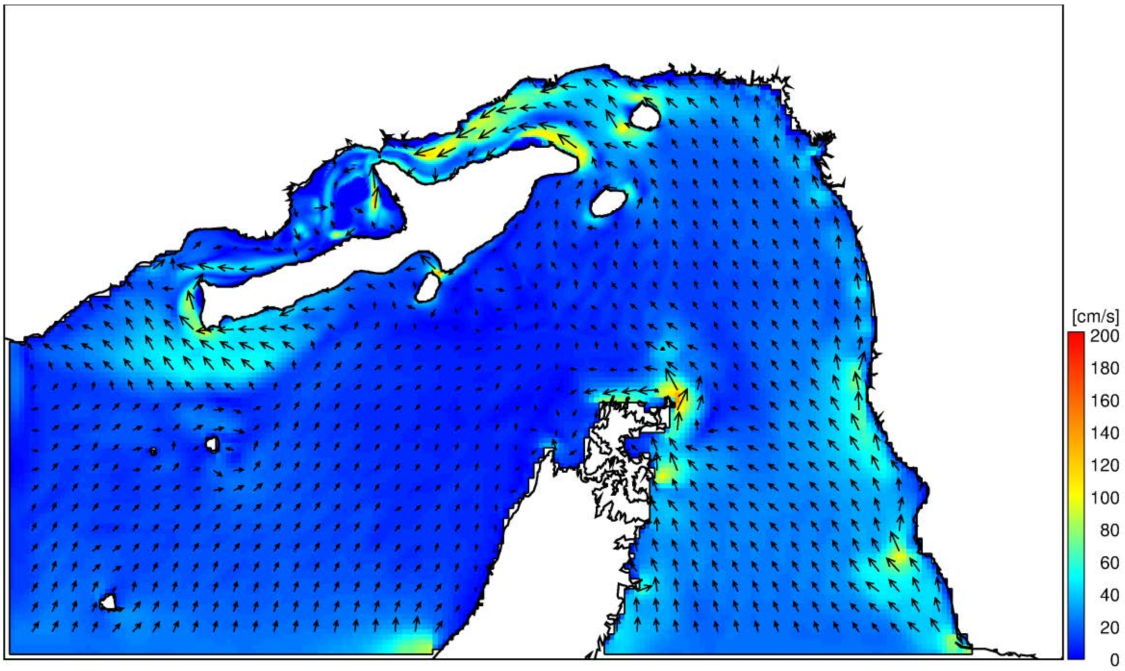
(5) Tidal current

The tidal current regimen based on the simulation is shown in Figures 4.15 to 4.18. The details of the data used for the simulation are shown in Attachments 4 and 7. In the Dargahan area, a comparatively strong reciprocating current is observed. The current speed in the Souza and Selakh areas is weaker than in Dargahan and its major direction is westward.



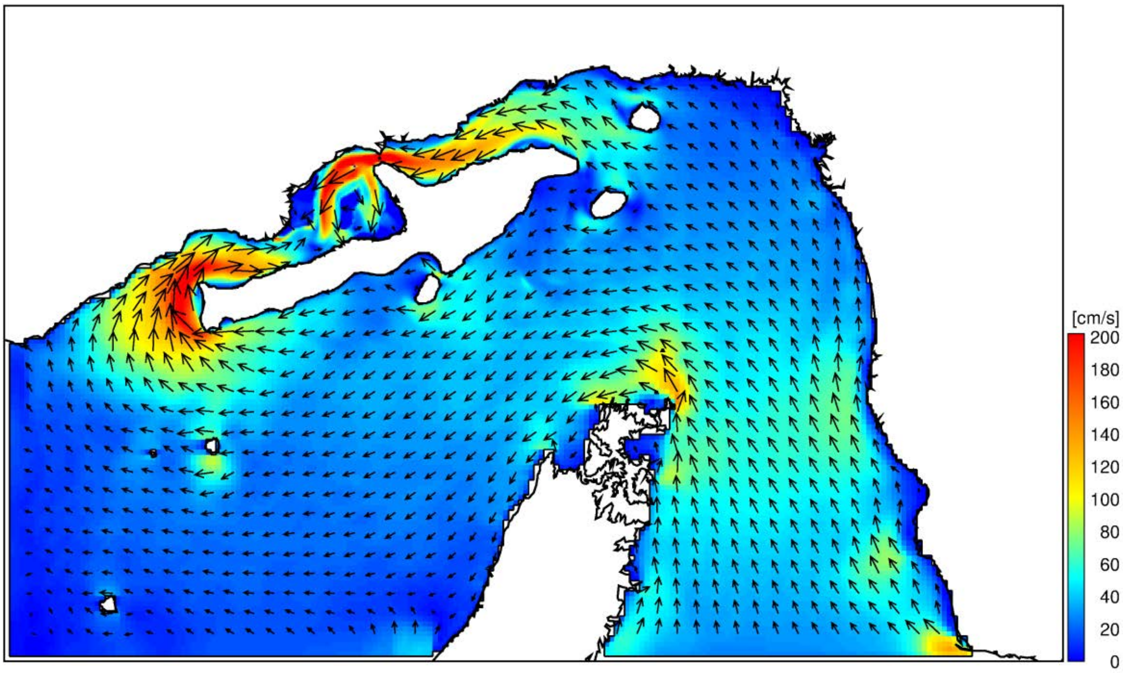
Source: JICA Project Team.

Figure 4.15 Tidal Current Pattern (Ebb Tide)



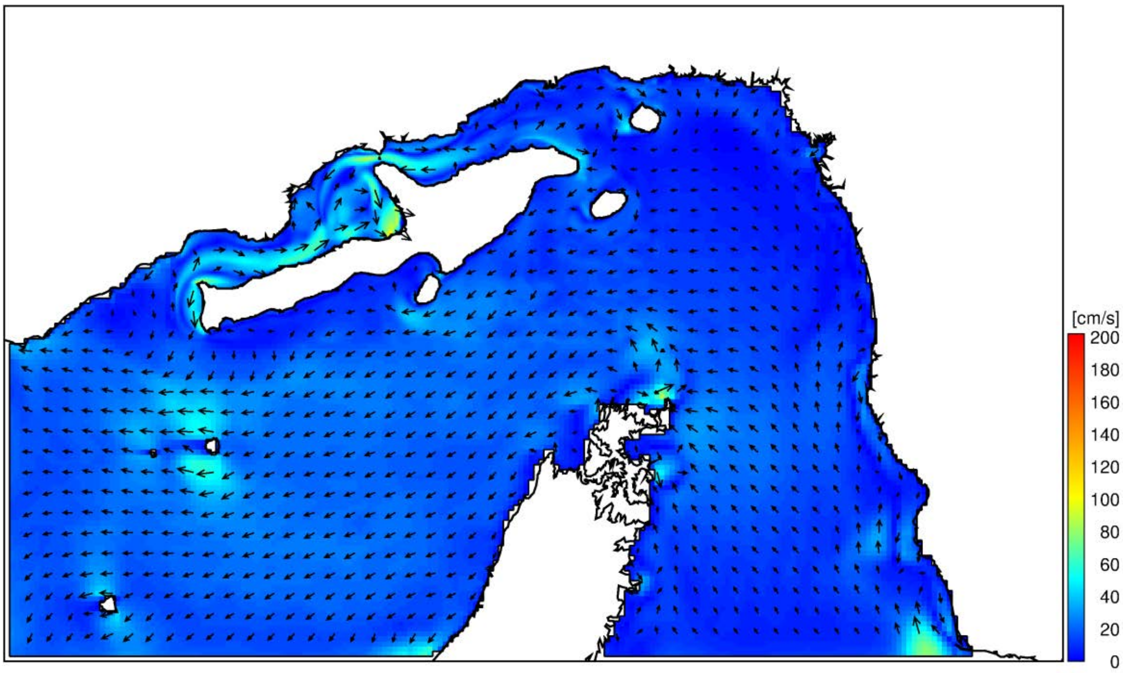
Source: JICA Project Team.

Figure 4.16 Tidal Current Pattern (Low Tide)



Source: JICA Project Team.

Figure 4.17 Tidal Current Pattern (Flood Tide)



Source: JICA Project Team.

Figure 4.18 Tidal Current Pattern (High Tide)

(6) Coastal erosion

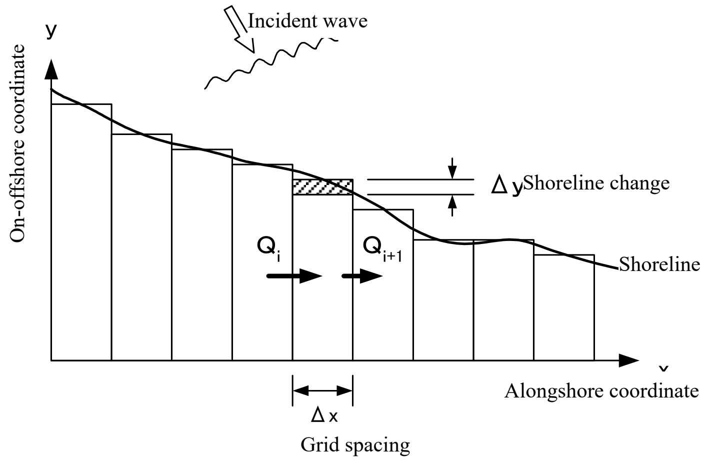
1) Methodology

An impact assessment of coastal erosion caused by the development of the LNG plant was carried out using a numerical simulation for predicting the long-term shoreline changes based on the one-line theory. The one-line theory is predicated on the concept of balancing longshore sediment transport and applied to the beach where longshore sediment transport is the dominant cause of beach profile changes. The theoretical concept behind the numerical simulation method for the prediction of shoreline change is outlined below.

The coordinate system shown in Figure 4.19 is used in the numerical simulation method for the prediction of shoreline change. Incidental wave height and wave direction at the wave breaking point are calculated by the numerical simulation of the wave field. Wave height and wave direction are used to obtain the longshore sediment transport rate Q along the shoreline.

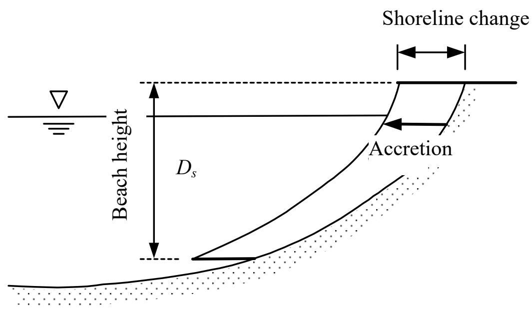
The shoreline change rate is obtained by the balance of efflux and influx of longshore sediment transport (Q_{i+1}-Q_i). The seaward movement of the shoreline (accretion), occurs when the influx surpasses the efflux and landward movement of shoreline, in other words, erosion occurs in the contrary case.

For the calculation of the rate of shoreline change, a cross-sectional beach profile is considered in order to maintain the original profile on the occasion of onshore and offshore shoreline movement, as shown in Figure 4.20.



Source: JICA Project Team.

Figure 4.19 Coordinate System for the Numerical Simulation Model of the One-line Theory



Source: JICA Project Team.

Figure 4.20 Schematic Figure of the Basic Concept of Shoreline Changes in the Numerical Simulation Model

An outline of the shoreline change prediction model is shown below.

<u>Basic equations:</u>

The one-line model, which uses a single shoreline as a representative of the entire beach process due to wave action, is employed. The basic equation is shown in (1).

$$\frac{\partial Q}{\partial x} + D_s \frac{\partial y}{\partial t} = 0 \quad (1)$$

where Q is the total longshore sediment transport rate including void, x and y are the coordinates in the alongshore and on-offshore direction (positive in the offshore direction), D_s is the beach height (representative depth of the beach process) and t is the time of the duration of wave action.

Total longshore sediment transport rate:

The total longshore sediment transport rate induced by wave action is calculated using the so-called power model shown in Equation (2), which employs the assumption that longshore sediment transport is proportional to the alongshore component of the wave energy flux at the wave breaking point.

$$Q = K\frac{(Ec_g)_B \sin\alpha_{B_s} \cos\alpha_{B_s}}{(\rho_s - \rho)g(1-\lambda_v)} \quad (2)$$

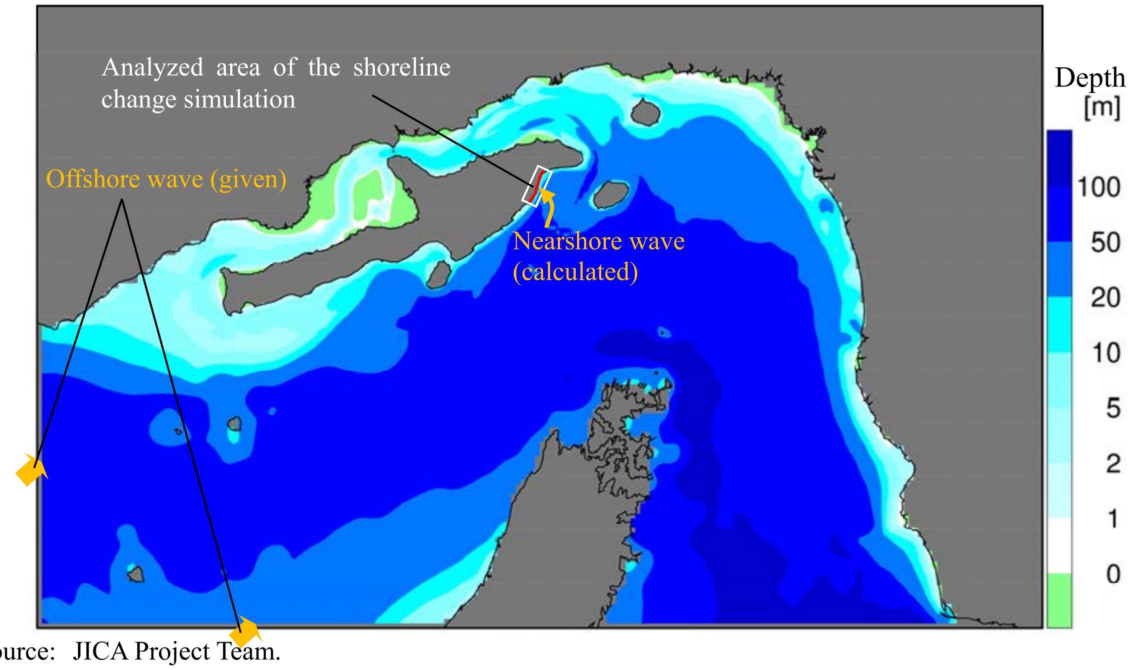
where $(Ec_g)_B$ is the wave energy flux at the wave breaking point, which is obtained by the product of wave energy density per unit area and group velocity, as shown in Equation (3); α_{Bs} is the incident wave direction, which is defined by the angle between the shoreline and wave crest line at the wave breaking point; E_B and c_{gB} are total wave energy and wave group velocity; g is the gravitational acceleration; λ_v is void ratio; K is the non-dimensional constants; ρ_s is soil density; and ρ is sea water density.

$$(Ec_g)_B = c_{gB} \cdot \frac{1}{8}\rho g H_B^{\ 2} \quad (3)$$

where H_B is the breaking wave height.

2) Area for analysis

Figure 4.21 shows the area for analysis using wave and shoreline change simulation. The area to be analyzed using the wave covers the same area being analyzed in terms of hydrologic conditions, as shown in Figure 4.21. The limit of offshore waves is determined according to the offshore open boundary. On the other hand, the area to be analyzed using the shoreline change prediction model is limited to covering the narrow areas around the candidate sites of the LNG plant.



Source: JICA Project Team.

Figure 4.21 Area to Be Analyzed for Wave and Shoreline Change Simulation

3) Input data

Data used as input for the numerical simulation of shoreline changes are shown below.

Table 4.14 Using Data and Setting Values for the Numerical Simulation of Shoreline Changes

Item	Data (Setting Value)	Source	Remarks
2D shoreline topography	Google Earth	Google Earth	Satellite image
Wave height and direction of offshore boundary	• Wave direction in ordinary: W • Wave direction in summer: ESE	Wave simulation result by the JPT	• 0.5° spatial resolution • Latitude: 26.0°N, longitude: 55.0°E • Refer to Attachment 5
Beach sediment diameter	-	JPT	Refer to Attachment 2

4) Results

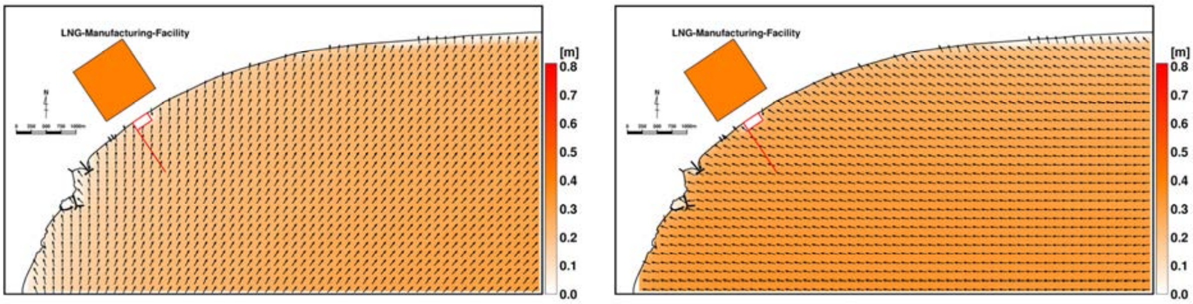
The shoreline change caused by the construction of the LNG plant with reclaimed land was simulated. Shoreline change is generally caused by a change in the waves that move coastal sediment. Figures 4.22 to 4.24 show the results of the simulation of the waves. Wave field changes will be caused by the construction of the reclaimed land (300 m x 150 m), which will be used as a supporting launch site on the coast. Figures 4.25 to 4.72 show the results of shoreline change caused by the construction of the LNG plant with reclaimed land corresponding to the wave field changes in the future.

Table 4.15 summarizes the predicted coastal erosion and the mitigation measures related to the construction of the plant.

Table 4.15 Summary of the Predicted Coastal Erosion and Mitigation Measures Related to the Construction of the Plant

Area	Costal erosion	Mitigation measure
Souza North	Approximately 5 m retreat of the shoreline in front of the hotel at the west side of the plant	Construction of a floating pier instead of using the reclaimed land for the supporting launch site
Souza South	Almost none	-
Selakh	Local erosion at a depth of more than 10 m around the existing jetty at the west side of the plant	Attaching the reclaimed land to the existing jetty

Source: JICA Project Team.

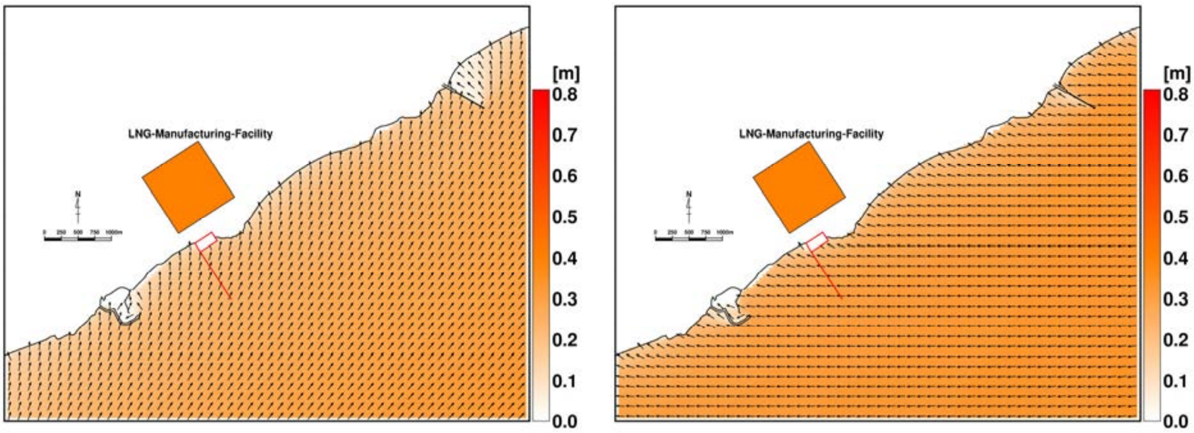


(1) Average wave under ordinary natural conditions (January to June and October to December)

(2) Average wave in summer (July to September)

Source: JICA Project Team.

Figure 4.22 Calculated Results for Wave Height and Direction (Souza North)

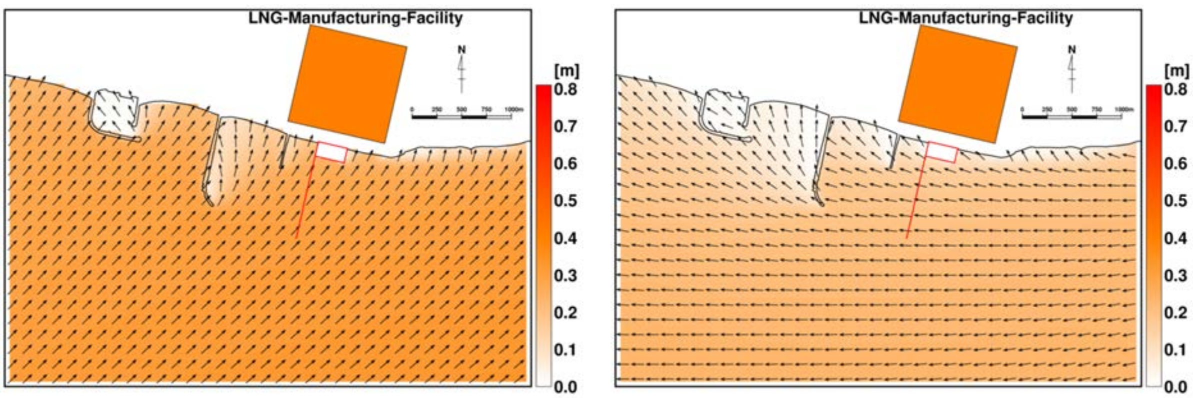


(1) Average wave under ordinary natural conditions (January to June and October to December)

(2) Average wave in summer (July to September)

Source: JICA Project Team.

Figure 4.23 Calculated Results for Wave Height and Direction (Souza South)

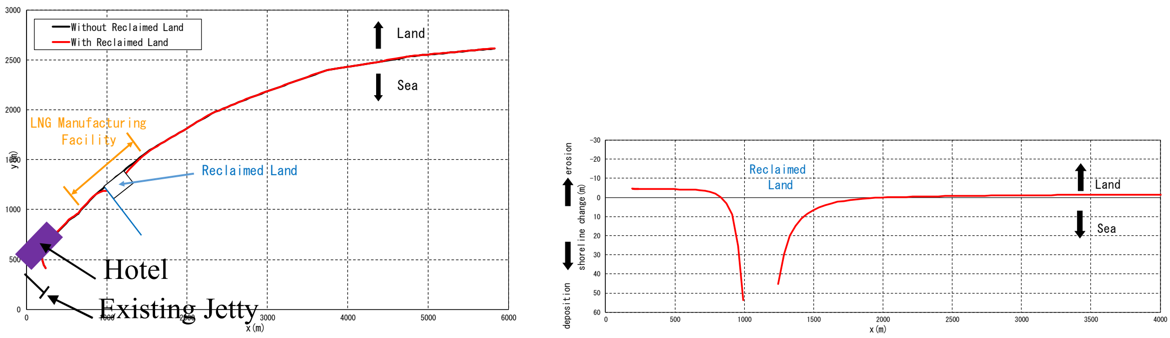


(1) Average wave under ordinary natural conditions (January to June and October to December)

(2) Average wave in summer (July to September)

Source: JICA Project Team.

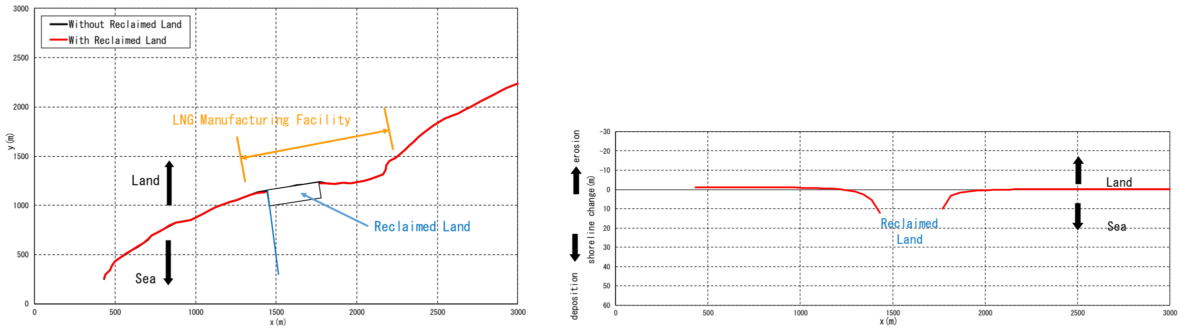
Figure 4.24 Calculated Results for Wave Height and Direction (Selakh)



(1) Calculated result of shoreline change (2) Shoreline change amount in the future

Source: JICA Project Team.

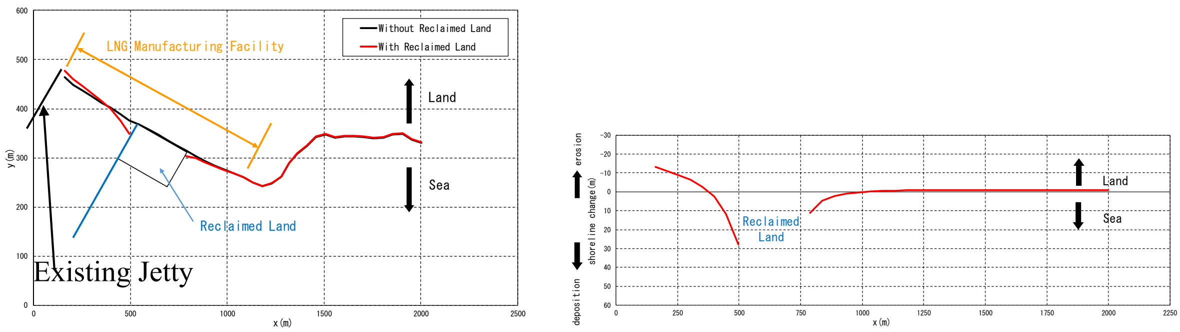
Figure 4.25 Shoreline Change Caused by the Construction of the LNG Manufacturing Facility with Reclaimed Land (Souza North)



(1) Calculated result of shoreline change (2) Shoreline change amount in the future

Source: JICA Project Team.

Figure 4.26 Shoreline Change Caused by the Construction of the LNG Manufacturing Facility with Reclaimed Land (Souza South)



(1) Calculated result of shoreline change (2) Shoreline change amount in the future

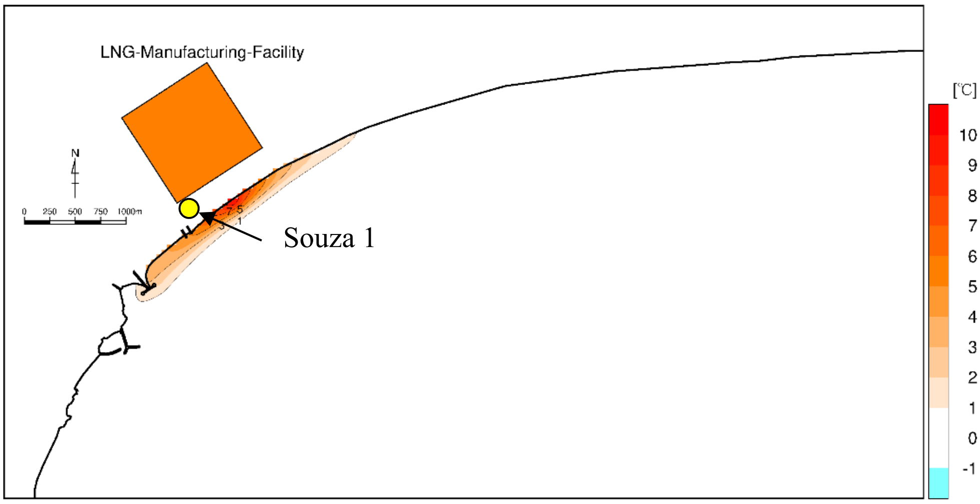
Source: JICA Project Team.

Figure 4.27 Shoreline Change Caused by the Construction of the LNG Manufacturing Facility with Reclaimed Land (Selakh)

(7) Thermal water diffusion

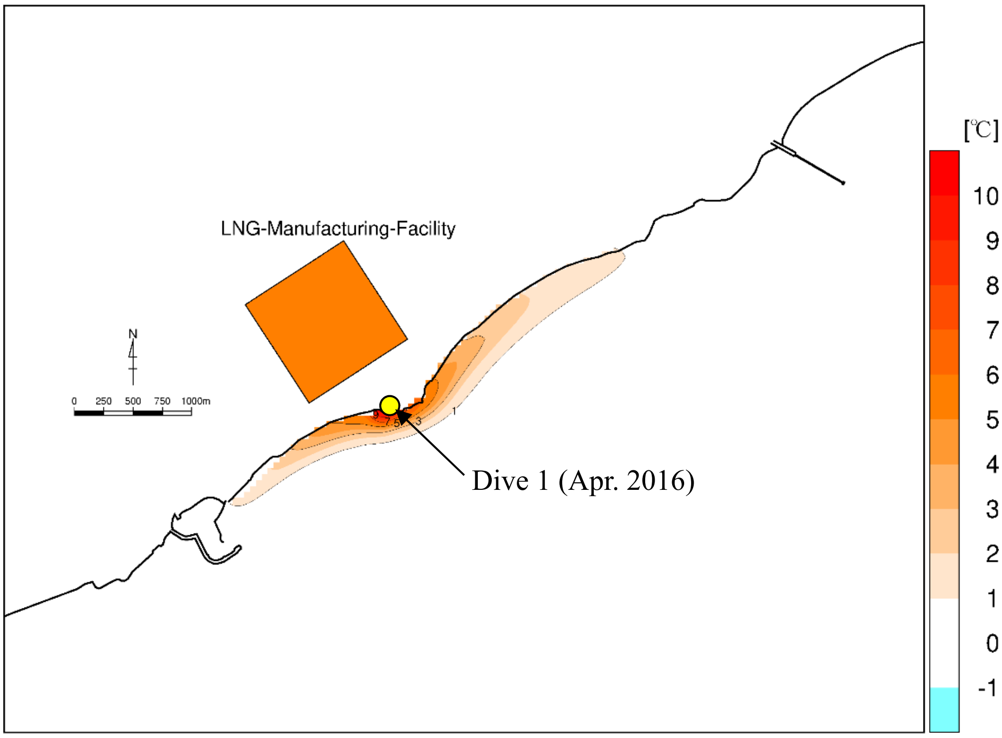
The diffusion area of thermal water from the plant was simulated. Details are described in Attachment 6. Figures 4.28 to 4.30 show the results of the simulation for each survey area. Since the Souza South area was proposed after the field survey, the underwater survey was not conducted in this area. However, snorkeling reconnaissance was carried out in April 2016 and its location is plotted.

The thermal water basically diffuses along the coast line. The distance of diffusion in an area that is 1°C higher than environmental water temperature is about 1 km for Souza North, about 2 km for Souza South and about 1.5km for Selakh from the center of the discharge point.



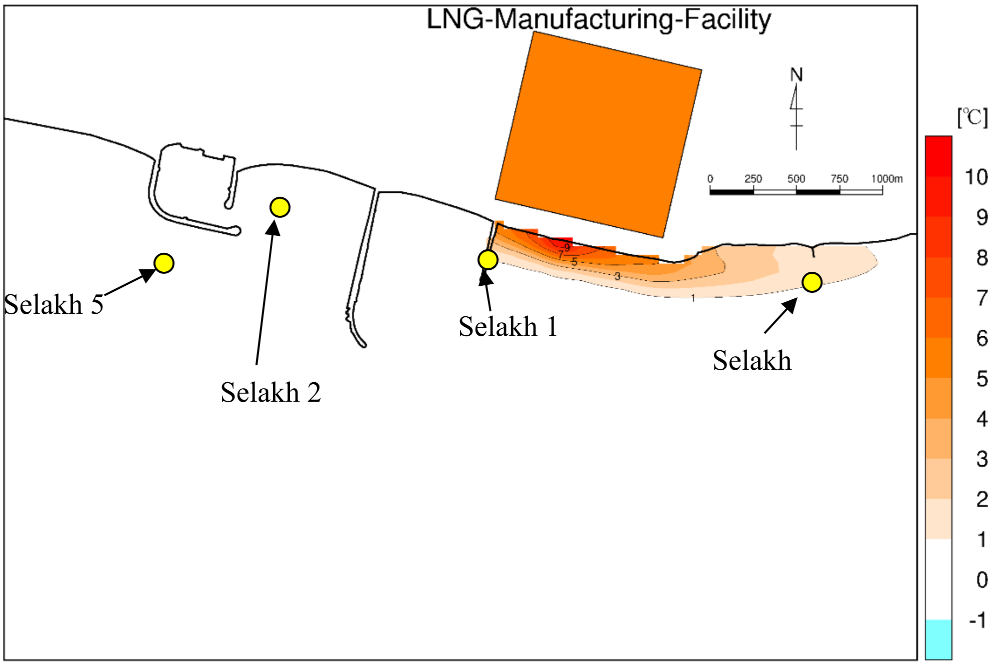
Note: Yellow dot indicates the survey point in the ecosystem.
Source: JICA Project Team.

Figure 4.28 Thermal Water Diffusion (Souza North)



Note: Yellow dot indicates the survey point in the ecosystem.
Source: JICA Project Team.

Figure 4.29 Thermal Water Diffusion (Souza South)



Note: Yellow dot indicates the survey point in the ecosystem.
Source: JICA Project Team.

Figure 4.30 Thermal Water Diffusion (Selakh)

4.3.3 Impacted Ecosystem and Conclusion

(1) Impacted ecosystem

Table 4.16 qualitatively summarizes the expected impact on the ecosystem, which was identified though the field survey, within the influence area of thermal water. Since fishing and spawning grounds are located offshore, based on the interviews with fishermen, the direct impact is not considered. However, since seaweed beds grow at Souza 1, Selakh and Selakh 1, the fishing and spawning grounds could be indirectly impacted in the future, if the seaweed bed disappears under the influence of thermal water.

In Souza South, corals were found during the field reconnaissance in April 2016, although their coverage rate is low. Therefore, some mitigation measures would be necessary if Souza South is considered as the construction site of the LNG plant.

Kouvei is located on the northern side of the island and no fishing or spawning grounds are reported. Kouvei is considered to be the least impacted among the candidate sites, although a seagrass bed was found.

Table 4.16 Summary of the Impact on the Ecosystem Caused by the Construction of the Plant

Area	Survey point	Seagrass/ Seaweed	Coral	Turtle Beach	Fishing/ spawning ground
Souza North	Souza 1	++	-	-	-
Souza South	Dive 1	-	+	-	-
Selakh	Selakh	++	-	-	-
	Selakh 1	+	-	-	-

Note: +++: large impact, ++: moderate impact, +: minor impact, -: ecosystem does not exist.
Source: JICA Project Team.

Table 4.17 compares the environmental impacts to the ecosystem caused by the LNG plant.

Table 4.17 Comparison of Environmental Impacts to the Ecosystem by the Plant

	Kouvei	Souza North	Souza South	Selakh
Seagrass/Seaweed	++	+++	-	++
Coral	-	-	+	-
Fishing/spawning ground	-	-	-	-
Turtle Beach	-	-	-	-

Note: +++: large impact, ++: moderate impact, +: minor impact, -: ecosystem does not exist.
Source: JICA Project Team.

(2) Conclusion and recommendations

Among the four candidate sites, Kouvei is considered to be the least impacted area. However, the area has the potential to see growth in the seagrass bed, which usually develops in calm and silty areas. On the southern side of Qeshm Island, Souza South could be an area of least concern although corals were found in the previous field survey.

Therefore, even though any candidate site could be chosen as the construction site, a detailed survey is necessary. A recommended survey plan is summarized in Table 4.18.

Table 4.18 Summary of the Detailed Survey

Item	Methodology	Frequency	Note
Seagrass, seaweed	Distribution: diving observation, echo sounding	4 times/year	
Fish juveniles/eggs	Net sampling, laboratory identification	4 times/year	
Coral	Distribution: diving observation	Once/year	
Sea turtle nesting ground	Distribution: interviews, observation	Every week (February-June)	In case the sand beach is closer

Source: JICA Project Team.

If the candidate area is considered to be both ecologically important and appropriate to be developed, some mitigation and compensation measures should be planned upon commencement of construction. For example:

- Long-distance discharge outlet to release thermal water outside of the seaweed/seagrass bed or coral colony areas
- Transplantation of corals to compensate for the lost area
- Installation of artificial adhesion basements for coral polyps or seaweed seeds

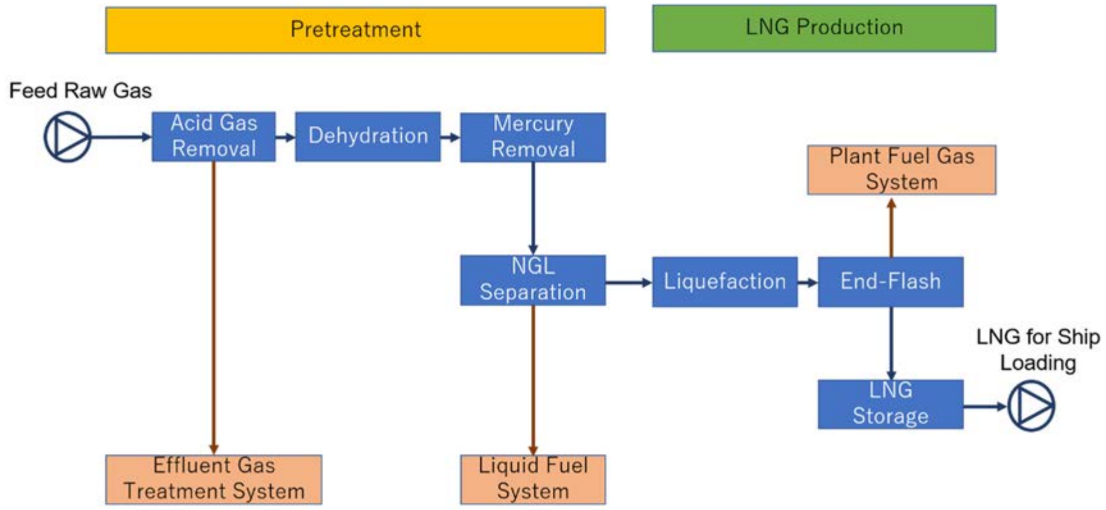
CHAPTER 5 LNG PLANT DESIGN AND CONSTRUCTION

5.1 LNG Liquefaction Plant Block Flow Diagram

Gas quality data have not been provided to the team as yet; but, it is assumed that gas will be treated at the gas refinery and that pipeline-grade methane-rich gas will be provided to the project.

The LNG manufacturing facility consist of two sections: a pretreatment section and an LNG production section.

The pretreatment section includes an acid gas removal, dehydration, mercury removal and natural gas liquid (NGL) separation unit. The LNG production section includes a liquefaction unit and LNG storage. Both sections are depicted in the block flow diagram below:



Source: JICA Project Team.

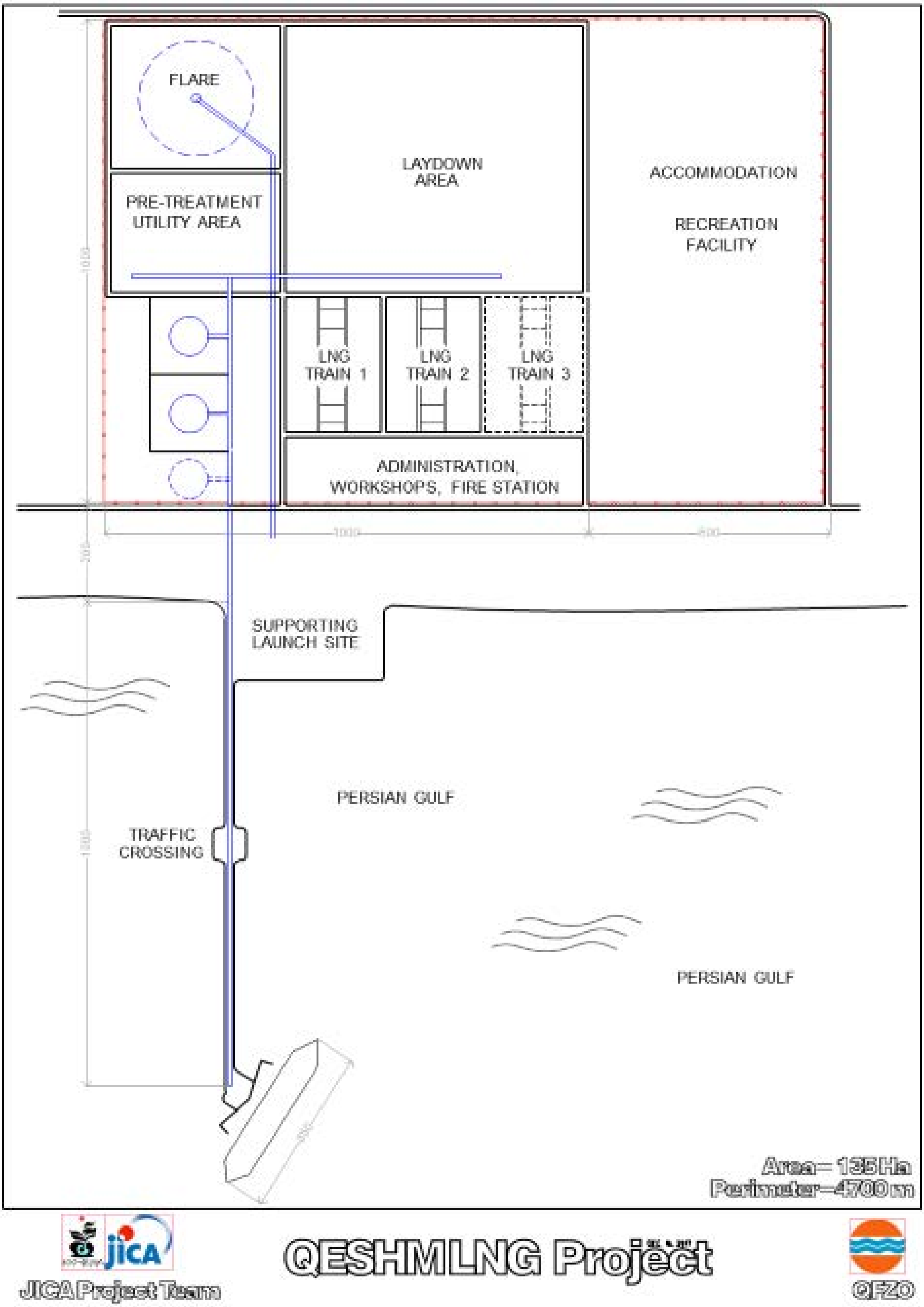
Figure 5.1 LNG Block Flow Diagram

5.2 Plot Plan (Provisional)

The LNG manufacturing site consists of the following areas:

(a) Process area (liquefaction)
(b) Gas pretreatment area
(c) Liquefaction area (three trains one for future space)
(d) Utility area
(e) Storage and offloading (two storage tanks)
(f) Flare system
(g) Office and warehouse
(h) Accommodation

The minimum required land space will be 1,000 m x 1,000 m. The general layout, including employee accommodation and a recreation facility area, is shown as follows.



Source: JICA Project Team.

Figure 5.2 LNG Manufacturing Facility Plot Plan

5.3 Liquefaction Process

5.3.1 Liquefaction Technology Overview

Overall, the liquefaction plant is the most capital-intensive in the LNG value chain, accounting for approximately 30-50% of total investment costs. As a result, significant efforts have been made to improve the efficiency of the liquefaction technology and economics. Advantage of scale is one of the directions.

One of the important technological developments that contributes to a larger-scale LNG train involves larger drivers for refrigeration compressors. Most of the early LNG plants used compressors driven by steam turbines. However, since the late 1980s, gas turbines have been developed and made available. A gas turbine does not require extensive use of steam and condensing equipment, while showing better thermodynamic efficiency than that of steam-powered systems. However, the available gas turbine is only a standard model, known as a frame model, and cannot be customized to suit the exact requirements of the project.

Capital-incentive large-scale LNG plants must be highly reliable and need to avoid long-term shutdown, which will be economically harmful. Therefore, the LNG plant operator must have experienced operation and project management teams, use highly reliable technologies and materials and recruit qualified engineering contractors.

5.3.2 LNG Liquefaction Plant

The LNG liquefaction plant consists of a gas pretreatment section and a liquefaction section, as follows:

(1) Gas pretreatment section

In this section, impurities harmful to the liquefaction process will be removed. The gas treatment section consist of:

- Acid gas removal unit (AGRU)
- Dehydration unit
- Mercury removal unit
- NGL separation unit

1) AGRU

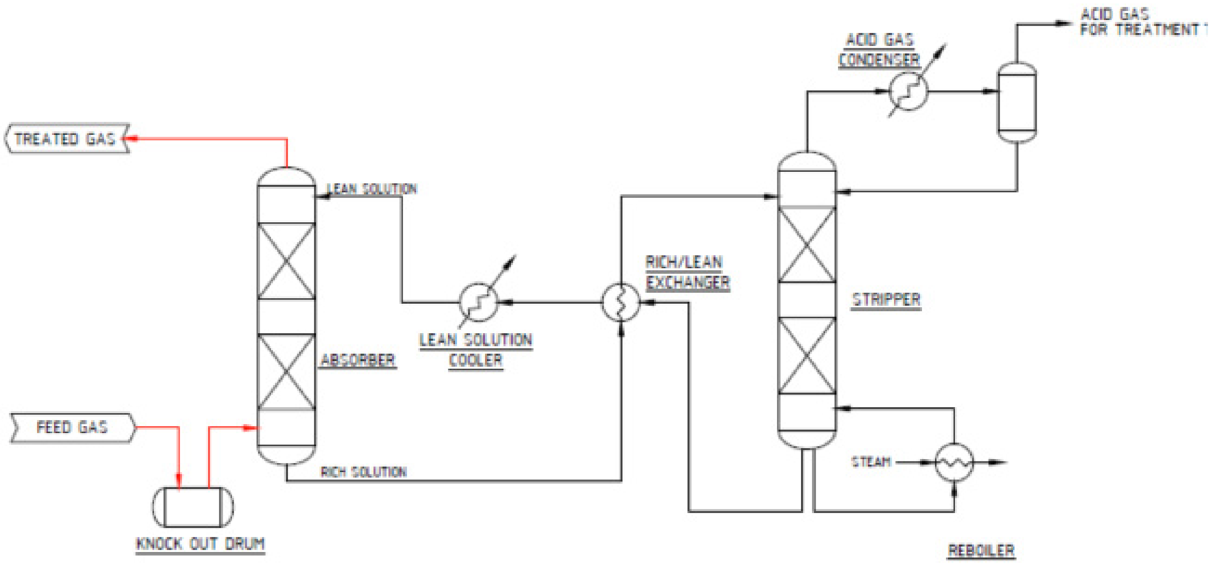
Natural gas from the reservoir contains CO_2 and H_2S, in addition to hydrocarbons. These are called acid gases and need to be removed before sending onto the liquefaction process. CO_2 will be solidified at a low temperature (-79°C) and blocking and damaging the liquefaction facilities. H_2S is toxic and will also be solidified at a low temperature (-85.5°C). CO_2 and H_2S in general will be treated at the gas processing plant to the pipeline-grade level.

However, the concentration level of CO_2 should be further lowered to less than 50-100 ppm to meet the solubility limit in LNG. H_2S concentration is also limited to less than 4 ppm in LNG. A typical AGRU configuration is shown in Figure 5.3

Acid gases are scrubbed by a regenerable solvent solution in the absorber. The absorption solvents can be either chemical solvents, which are most commonly used and react with the acid gas components, or physical solvents, which rely on the preferential solubility of the acid gas components. The most common chemical solvents are alkanol amines such as methyl diethanolamine (MDEA). Popular physical solvents are Selexol (di-methyl ethers of polyethylene glycol) and Rectisol (methanol).

The feed gas flows into the bottom of an absorber, while the lean solvent enters the top of the absorber by flowing countercurrent to the feed gas, thereby absorbing the acid gases. The treated gas leaves the top of the absorber and is routed to the dehydration unit. After exchanging heat with a recycled lean solution stream, the rich solvent solution passes to the top of the stripper (regenerator), where the acid gas-amines complexes are thermally disassociated.

The acid gas from the top of the reflux drum, containing mainly CO_2, H_2S and some water, is transferred to the next unit such as a sulfur recovery unit. The reboiled lean solution from the bottom of the stripper is cooled to around 40°C and recycled to the top of the absorber.



Source: DEP.

Figure 5.3 Process Flow of the Acid Gas Removal Unit

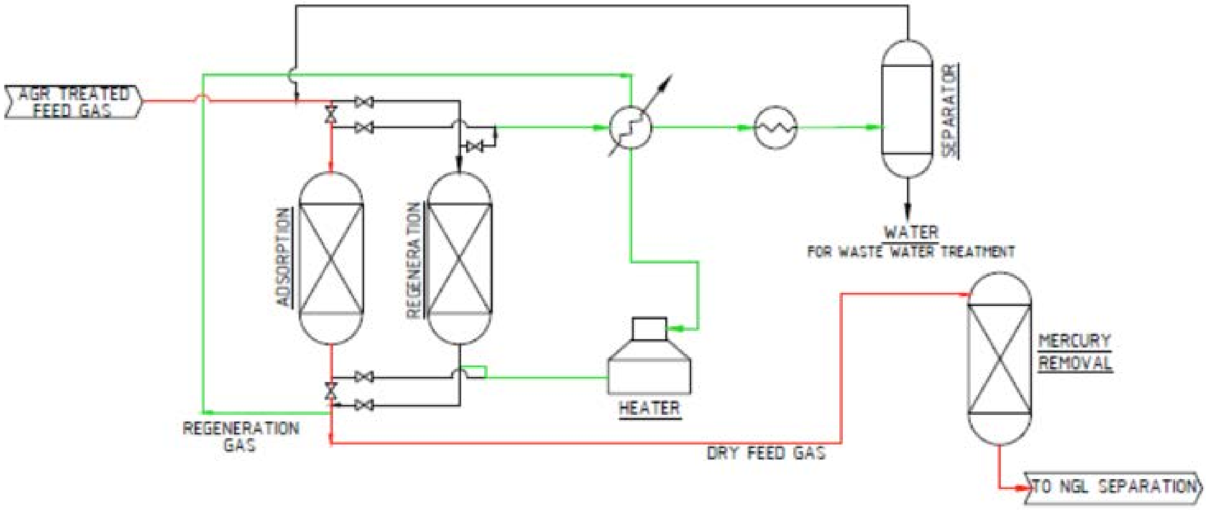
2) Dehydration unit

After the AGRU, water concentration in the feed gas must be controlled to less than 1 ppm in the dehydration unit to avoid solidification and plugging of the downstream cryogenic facilities. Molecular sieves are used for dehydration to attain the required level.

The feed gas from the AGRU is cooled by propane chiller to remove the majority of the water via condensation and water separation, before feeding into the molecular sieve vessel to lower the load in the molecular sieve system. Gas flows in and passes through the molecular sieve beds, removing the water to less than 1 ppm. The dried gas is sent to the mercury removal unit.

The molecular sieve is subject to a cyclic operation of dehydration and regeneration. Once a molecular sieve bed gets close to the full dehydration capacity, it is regenerated by use of a carry gas taken from the dried gas. The carry gas is heated in the heater and sent back to the water saturate molecular sieve bed to remove or dry the water. Water-absorbed gas is cooled and send to the water separator where water is separated out. The gas from the separate is circulated back to the inlet of the feed gas to the molecular sieve bed.

A typical system configuration of a dehydration and mercury removal unit is shown in Figure 5.4.



Source: DEP.

Figure 5.4 Dehydration and Mercury Removal Unit

3) Mercury removal unit

Mercury-induced corrosion is a concern for the LNG plant. In general, there are two types of mercury corrosion: amalgam-induced corrosion and liquid metal embrittlement (LME). LME is the diffusion of mercury into the grain boundaries and results in crack propagation along the grain boundary. This corrosion affects a broad area of materials and damages the project economics. For this reason, a mercury limit of 10 ng/Nm^3 or less should be set.

Activated carbon is used as an absorbent of mercury. Activated carbon beds cannot be regenerated and must be replaced periodically, usually at the time of major plant turnarounds.

4) NGL separation unit

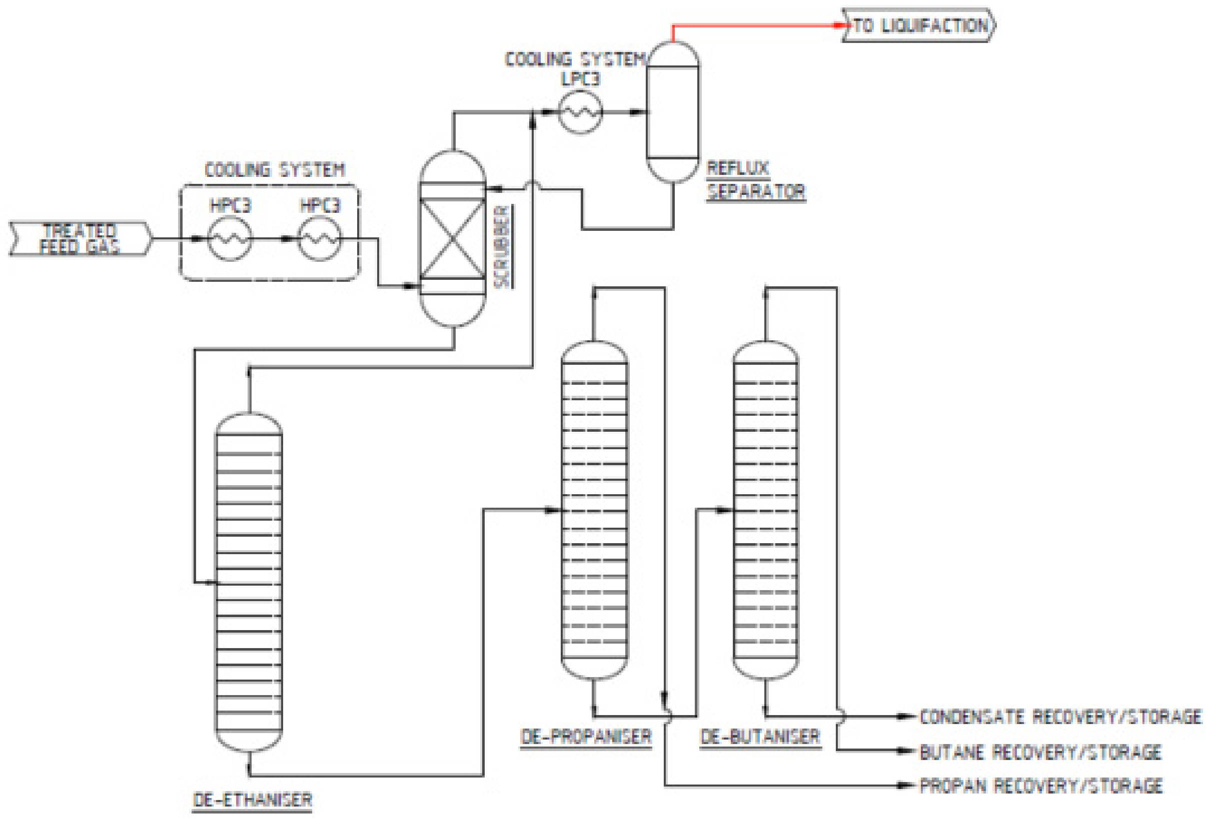
Removal of heavier hydrocarbons is required for the following reasons:

- To prevent potential solidification of C5+ in the cryogenic section
- To extract ethane and propane to make up for lost refrigerant
- To recover commercial-grade LPG depending on the feed gas composition

In view of solidification, C5+ must be less than 0.1 mol% in the LNG product.

The configuration and scale of the NGL separation unit depends on the gas composition. The minimum facility for the NGL separation unit is one scrubber drum, which works as a de-methanizer to split methane and other heavier fractions.

In case further separation of heavier hydrocarbons is required, a series of scrubber columns, such as de-ethanizers, de-propanizers and de-butanizers, will be installed to separate ethane, propane, butane and heavier fractions i.e., condensates. Ethane can be recovered or mixed with methane as part of LNG product.



Source: DEP.

Figure 5.5 Natural Gas Liquid Separation Unit

(2) LNG liquefaction section

LNG is produced by transferring heat from the feedstock natural gas to a heat sink (air or sea water) via a refrigeration cycle. All technologies for large-scale LNG production are based on the simple Carnot refrigeration cycle, which consists of four basis steps:

- Adiabatic compression
- Cooling and condensation
- Adiabatic expansion
- Evaporation of the refrigerant

In each cycle, pure components or mixtures of hydrocarbons are used as refrigerants. Efficiency of the operation depends on the selection of the refrigerant and its composition, so that the heating curve of the refrigerant closely matches the cooling curve of the gas to be liquefied.

In the expander-based process, the expander operates alongside the isentropic expansion of refrigerant gas (usually nitrogen or methane) and cools the refrigeration itself. Meanwhile, the extracted work is used to partially recompress the refrigerant, which remains in the gas phase. As this type of liquefying process typically has lower thermodynamic efficiency than methods using liquid refrigerant, it is used for small-scale or offshore applications.

LNG liquefaction can be grouped into two main categories:

- Small- to mid-scale LNG that relies on single pure refrigerants
- Large-scale LNG that relies on mixed refrigerants (MRs)

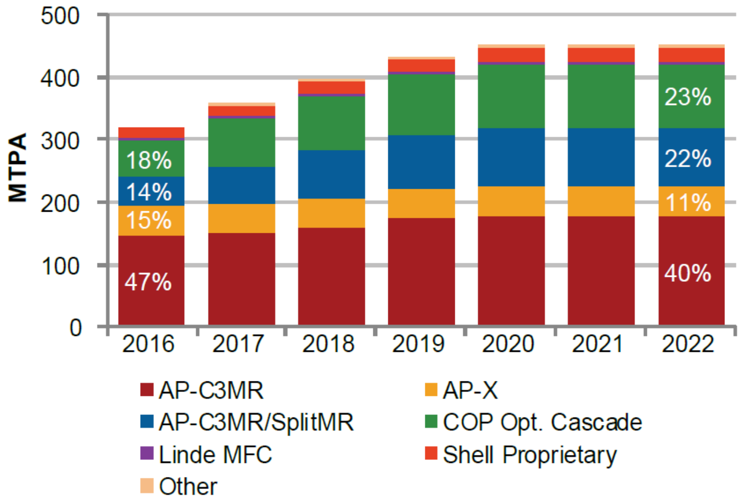
Small-scale LNG, so-called "mini-LNG", tends to fit with niche markets, such as transport fuels, energy peak shaving facilities, local gas distribution and small-scale gas field developments. Technology selection for small-scale LNG is dictated by sector demands such as intermittent service, minimum capital cost (at the expense of thermal efficiency) and variable loads. Nitrogen is mainly used for refrigerant from the viewpoint of safety and easy handling.

For large-scale LNG manufacturing processes, there are several variations of MR technologies including:

- Propane precooled MR (C3MR)
- C3 MR with a nitrogen refrigeration cycle (AP-X) process
- MFCP
- Dual MR (DMR)

The providers of MR technologies are Air Products and Chemicals Inc. (APCI), Shell, Linde and Air Liquide (Axens-IFP). Among them, technologies from APCI, Shell and Linde have been selected and used for recent LNG projects. The C3MR process was developed by APCI and is dominant in the world market, accounting for over 75% of the global share. AP-X is a modified version of C3MR.

Pure refrigerant technology for large-scale LNG projects is almost limited to the ConocoPhillips optimized cascade process.



Source: International Gas Union Annual Report 2017.

Figure 5.6 Liquefaction Capacity by Type of Process

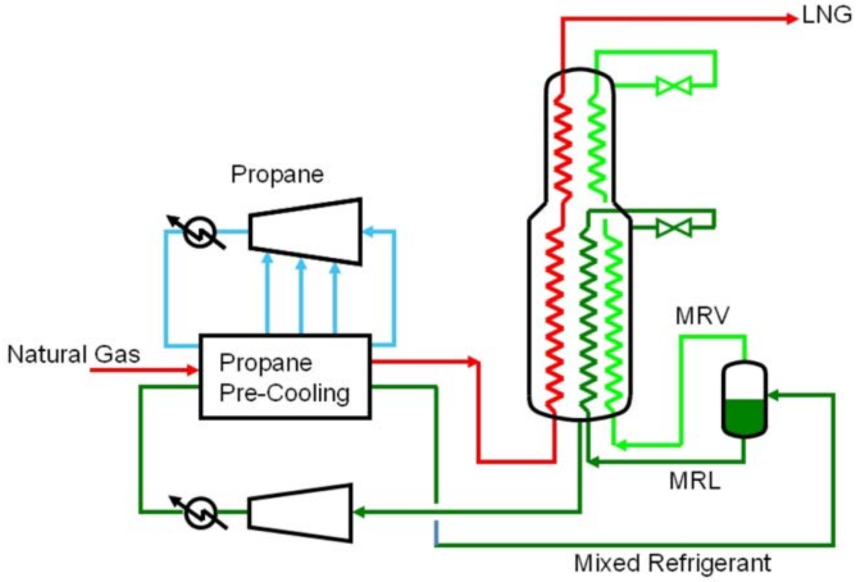
1) C3MR process

The C3MR process, developed by APCI, has been the most-used technology for baseload LNG production worldwide. The C3MR process consists of two steps: a precooling circuit using pure propane followed by a liquefaction process, which uses an MR circuit to complete the liquefaction. Propane (C3) cooling is used for cooling the feed gas and precooling and partially liquefying the MR. The treated inlet gas stream is cooled to about -30 to -35°C with a propane chiller. Propane cooling can use up to four stages of pressure (=temperature) level to achieve the desired temperature of stream with adequate thermal efficiency.

As the process gas stream cools, heavier hydrocarbons are condensed and separated, after which condensed heavy hydrocarbon is sent to the NGL separation process.

Typical MRs include nitrogen, methane, ethane, ethylene and propane. A main cryogenic heat exchanger (MCHE) is a spiral-wound heat exchanger consisting of a bundle with thousands of tubes to provide sufficient surface area necessary for close temperature access between the inlet gas and the cooling medium. These bundles are classified as warm and cold bunches, with warm bunches on the bottom and cold ones on top of the vertical shell.

The high-pressure MR is first cooled by propane and subsequently separated into a light MR stream and a heavy MR stream. The high-pressure MR and the feed gas stream flow upward through the tube side of the MCHE and the high-pressure MR dramatically reduces the temperature by a series of vacuum flashes. The MR cooled by the flashes flows countercurrent (shell side) to cool both the inlet gas and the inlet MR. The final cooling stage is accomplished via a J-T valve or a hydraulic expander to further cool the liquid and remove excess nitrogen. At this stage, the gas stream is completely liquefied to -160°C, while the liquefied gas is pumped to the storage. The warm vaporized MR flow is withdrawn from the bottom (shell side) of the exchanger and enters the first stage suction of the MR compressor. The compressed MR is first cooled with air or cooling water, then cooled with propane and returned to the MCHE, after which the process is repeated.

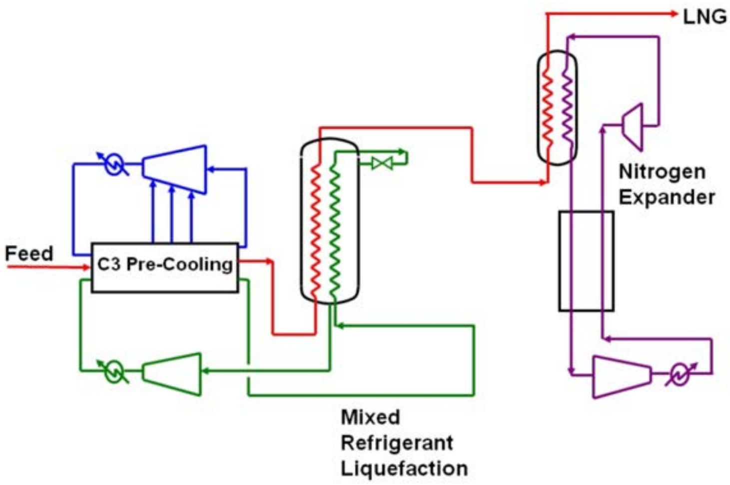


Source: APCI in International Gas Union Conference 2011.

Figure 5.7 AP-C3MR Process Flow

2) AP-X process

The AP-X process, developed by Air Products, is a modified version of C3MR technology, which can handle very large single-train LNG capacities. In addition to the propane precooling and MR cycles, the process includes a nitrogen expander loop, which provides LNG subcooling outside the MCHE. The AP-X process is used for the Qatargas II LNG project at Ras Laffan, Qatar. Two LNG trains were built, each with a capacity of 7.8 MTPA.



Source: APCI in International Gas Union Conference 2011.

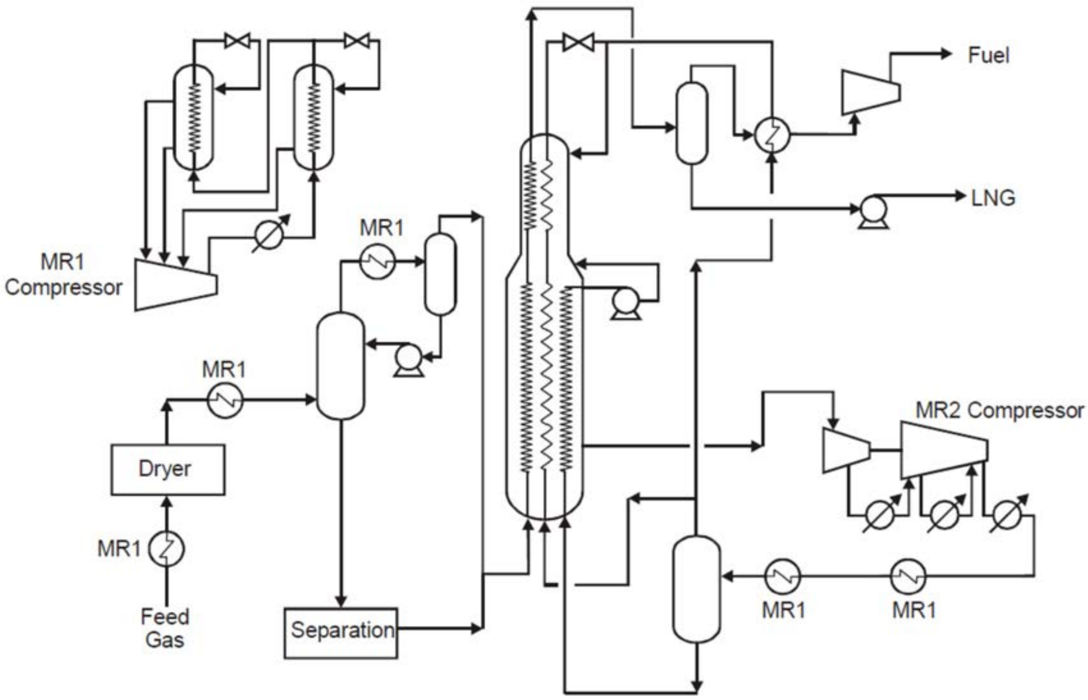
Figure 5.8 AP-X Process Flow Diagram

3) Shell DMR process

The DMR process developed by Shell is an improved version of the C3MR process. Instead of propane, separate MRs are used in the precooling cycle. Adjustment of the refrigerant composition in two cycles keeps the compressor at its best efficiency point over a wide range of ambient temperature and feed gas conditions.

Figure 5.9 shows a simplified flow scheme for the DMR process. In contrast to C3MR technology, the DMR process uses two coil-wound exchangers for the precooling circuit. The MR in this cycle mainly contains ethane and propane. After being compressed, the mixture is fully condensed against a cooling medium (air or water) and then expands to provide refrigeration. The second refrigeration cycle is similar to that used in the C3MR process. In this cycle, a mixture of nitrogen, methane, ethane and propane is used as refrigerant. Refrigerant vapor from the shell side of the spiral-wound cryogenic exchanger is compressed by an axial compressor and subsequently compressed in a two-stage centrifugal compressor. After being partially condensed in the precooling cycle, the MR vapor and liquid are separated and further cooled in the MCHE. With the above configuration, the DMR process can achieve an LNG capacity of about 5 MTPA per train.

This process has been applied to the Sakhalin Island Project in Russia. There are two LNG trains in the project, each with a capacity of 4.8 MTPA. The plant came on stream in 2008.



Source: Shell.

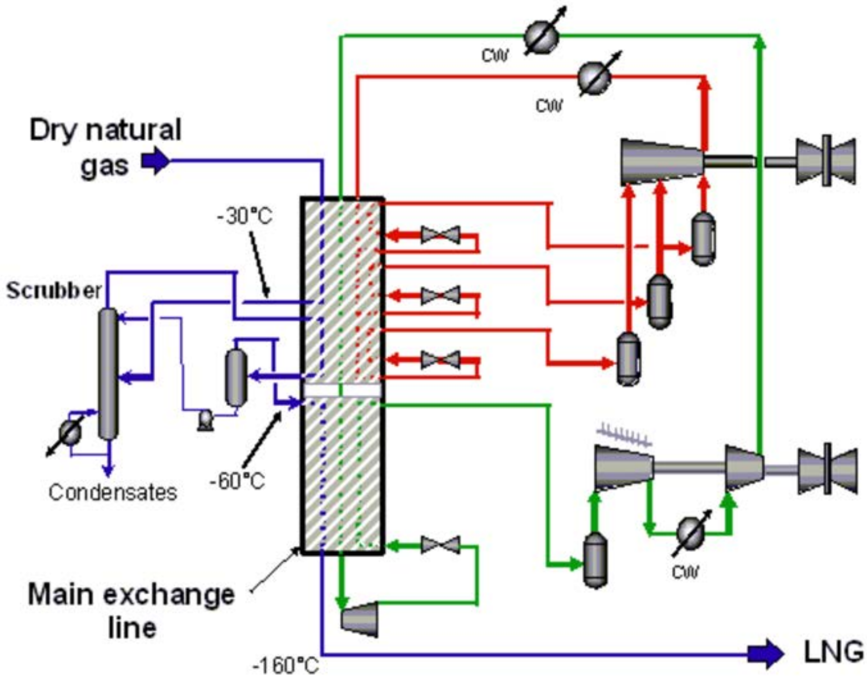
Figure 5.9 Shell DMR Process Flow Diagram

4) Air Liquide Liquefin process

The Liquefin process developed by Axens-IFP and currently owned by Air Liquide is based on a dual MR system. However, a distinguishing feature of Liquefin is the use of a single line of plate-fin heat exchangers, which cools the natural gas from ambient to cryogenic temperatures.

Figure 5.10 shows a simplified process flow scheme of the Liquefin process. Compared to the C3MR process, the Liquefin pre-refrigeration cycle is operated at much lower temperatures, in the range of -50°C to -80°C. These temperature levels ensure total condensation of the first MR, eliminating the need for phased separation of fractions. The overall required power can be decreased, as a good part of the energy necessary to condense the cryogenic MR is shifted from the cryogenic cycle to the pre-refrigeration cycle. This shifting of energy leads to a better repartition of the necessary heat exchange area: the same number of cores in parallel can be used all along between the ambient and the cryogenic temperature.

Given the economies of scale, the cost per ton of LNG decreases with the increase in capacity. Liquefin will be able to increase the capacity to the level of 8 MTPA by only changing the frame size of the gas turbine (compressor driver) rather than the process configuration.



Source: Axens.

Figure 5.10 Air Liquide Liquefin Process Flow Diagram

5) ConocoPhillips optimized cascade process

Liquefaction is achieved via three stages of cooling with pure refrigerants (propane, ethylene and methane). Air or water cooling condenses propane and condensed propane condenses ethylene, then ethylene condenses methane and a series of methane flushes completes liquefaction. Similar to the C3MR process, propane cools the inlet gas to -30 to -40°C. Within each refrigerant cycle, different operating pressures are established to maximize throughput and improve efficiency. By balancing the duty between the refrigerants, it is possible to liquefy in the case a wide range of gas compositions and conditions.

The refrigerant circuit is designed with two drivers/compressors for each refrigerant, offering a wide range of turndown capability and high availability. For the propane cycle, a core-in-drum-type exchanger is used. Brazed aluminum plate-fin exchangers (cold boxes) are mainly applied to ethylene and methane cycles. All cooling except propane cooling is done in two cold boxes.

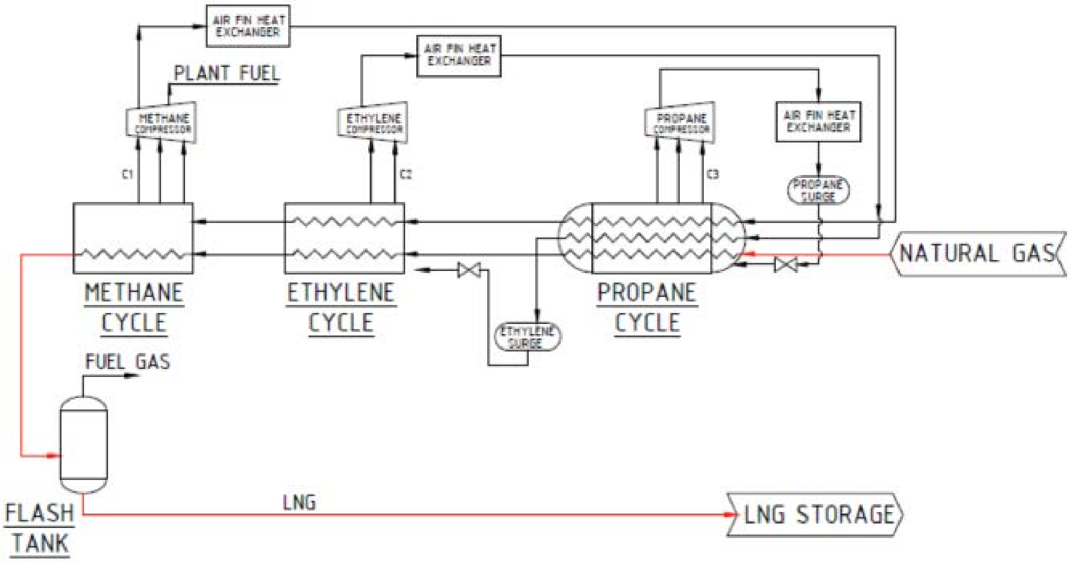


Figure 5.11 ConocoPhillips Optimized Cascade Process Flow

6) Linde LIPROM process

Linde's LIPROM (Linde Propane Mixed Refrigerant) process uses a propane precooling cycle and an MR for liquefaction and subcooling. The LIPROM process is designed to combine high efficiency and low equipment costs for liquefaction capacities of up to 3 MTPA.

7) Statoil/Linde MFCP

A combination of cascade and MR technologies was developed by Statoil and Linde for the Snøhvit LNG Project in Hammerfest, Norway. This process uses three separate mixed refrigerant systems to progressively cool the gas: precooling MR, liquefaction MR and subcooling MR. Plate-fin exchangers are used in the first two stages of cooling and final liquefaction is accomplished in spiral-wound heat exchangers (SWHEs) developed by Linde.

The 4.3 MTPA plant in Hammerfest uses five aero-derivative turbines with waste heat recovery to generate electricity for the three compressor systems. This process provides high energy efficiency since each MR can be tuned to the various cooling curves for each refrigerant system, with the use of aero-derivative turbines further reducing the energy requirements. With the generators feeding into a common power grid, this provides a greater flexibility if one of the drivers is down. Flexibility would be diminished if there were upsets without the electric drives. Upsets could create significant downtime depending on which refrigerant system is affected. Snøhvit is the first large-scale LNG plant to use variable speed electric motors to drive the refrigeration compressors.

8) Liquefaction process summary

All the options for potential LNG process licenses were reviewed. Considering the scale of production and technology reliability and experience, the following licensors are listed as candidates for the Qeshm LNG project:

- APCI (USA): AP-C3MR, AP-X
- Shell (Holland): DMR
- Air Liquide (France): Liquefin
- Statoil/Linde (Norway/Germany): MFCP

Although the APCI process enjoys 75% of world market share, liquefication technology itself is not so complex and the difference between technologies does not seem to be wide.

Licensor selection should be carried out as part of a feasibility study or during value engineering as part of a front-end engineering design (FEED) stage using qualified contractors.

(3) LNG plant utilities

The LNG plant utilities comprise various systems that store or produce input required by a plant as follows:

1) Power generation and distribution system

Electricity for site machinery such as pumps, air-fin coolers and lighting, is generated by a gas turbine using natural gas via a fuel gas system. During construction, electricity is provided by a diesel generator or purchased from the grid. There may be an option to drive refrigerant compressors with electric motors or gas turbines. This will be finalized during the value engineering stage as part of the FEED.

2) Water systems (freshwater, firefighting and service water, and demineralized water)

Water of varying quality is required for use in the LNG plant. Sea water is treated in a desalination plant to generate freshwater, which will be used and/or further treated to provide high-quality water for plant processes and human consumption.

Freshwater system

Freshwater is produced in the desalination process by reverse osmosis. The process involves solid removal, biocide, chlorine removal and membrane descaling. Salinities of sea water depend on the location but 32 g/l is assumed. The freshwater recovery rate is approximately 40%. From data on a similarly scaled LNG plant (two trains x 4 MPTA), sea water demand will be 3,000-4,000 m^3/day and the yield of freshwater will be 1,200-1,600 m^3/day.

Demineralized water system

Freshwater from a desalination plant is further treated in an ion exchanger to produce demineralized water, which will be used for:

- Washing the blades of the gas turbine
- Making up and washing water for the AGRU
- Making up water for a hot water system
- Making up water for a closed-circuit cooling system

Demineralized water used in the process is typically treated as a system loss, since there is no flow or discharge from the cleaning or makeup activities.

Service and firefighting water system

Service water is required for the washing plant and apron areas, etc.

Portable water system

Freshwater will be treated to produce portable water, which meets the required standard. Nominal capacity will be based on the number of employees who consume 300 l of water per day/person.

Wastewater system

Wastewater primarily comes from the service water system and is directed to the controlled discharge facility after use, where it is treated before been discharged into the environment.

Cooling water system (closed loop)

Process heat from the LNG plant utility units will be dissipated through air-fin coolers via closed cooling water system with cooling water sourced from the demineralized water system. A dedicated cooling water system will be provided for each of the gas turbines. A closed-loop cooling water system is also required for the instrument air system and a nitrogen system for mechanical drive purposes.

3) Fuel gas system

The fuel gas system supplies high-pressure fuels to the gas turbines, which drive the refrigerant compressors and electricity generators. Some of fuel gas is distributed to the furnace that heats up the fuel gas in order to regenerate the dehydrator.

4) Instrument and plant air system

The instrument air and plant air system supplies compressed air for instrumentation, pneumatic tools and utilities, as well as to the nitrogen system. A dryer is installed to eliminate moisture from instrument air.

5) Nitrogen system

Nitrogen is required for the following process and maintenance purposes:

- To purge equipment on startup and shutdown
- To maintain an inert atmosphere, e.g., blanket gas in hydrocarbon storage tanks
- To purge miscellaneous analytical equipment
- To purge LNG carrier loading arms after usage

The nitrogen generating package may produce around 1,000 Nm^3/h of nitrogen.

(4) Ancillary facilities

LNG plant ancillary facilities refer to equipment and facilities that support the LNG processing trains and plant utilities. The LNG ancillary facilities are:

1) LNG storage, loading and boil-off gas (BOG) system

LNG storage, loading and BOG systems provide the facilities necessary for storing and transferring LNG to LNG carriers and capturing and processing gases formed as LNG warm air in storage and handling. BOG occurs when heat is transferred to the LNG through contact with tank and pipe walls, as well as through friction during pumping.

The two low-pressure full containment or membrane LNG tanks, with a capacity of 200,000-270,000 m^3, are planned to be installed to meet the size of Q-Max class LNG carriers.

Boil-off compressors control the pressure in the storage tanks. If the BOG control range is exceeded, other process control and safety systems will be used to protect the tanks.

LNG can be pumped up to a rate of 12,000-15,000 m^3/h through the LNG loading line to the LNG carrier.

2) Flare system

Cold, hot and low-pressure flares provide for the safe disposal of hydrocarbon fluids from pressure safety valves and blowdown valves during process upsets, emergencies, maintenance activities and shutdown conditions. Flares are sized to accommodate what is expected to be the largest single event requiring gas release. For an LNG plant, this is typically the discharge from a blocked refrigerant compressor. The flares are designed to provide smokeless flaring over maximum range of operation.

3) Wastewater treatment system

The LNG plant and associated facilities generate various kinds of wastewater, including clear water (from roof and clean surface runoff, reverse osmosis plant brine and demineralization plant effluent), contaminated water (from equipment washdown and used firefighting water) and chemically contaminated water (from the slop oil tanks, wastewater sumps and other various sumps). An appropriate management system needs to be in place.

Clear water system

The clear water system will consist of liquid waste streams that do not require treatment and discharge into the environment. These will include:

- Brine water from the reverse osmosis unit
- Demineralized plant effluent
- Storm water from clean catchment areas and roof runoff

All discharges will be tested and treated to meet the water quality standard.

Controlled discharge facility

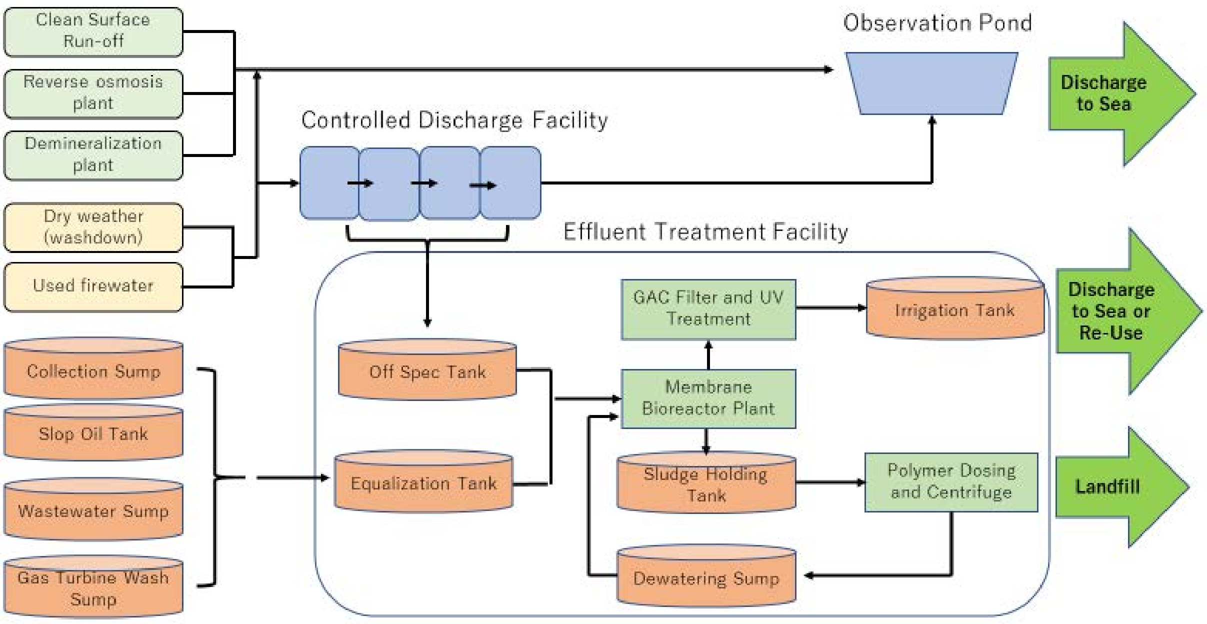
The controlled discharge facility will collect and treat all potentially contaminated water. Used firefighting water, potentially contaminated storm water and dry weather flows will be routed to the controlled discharge facility where water quality will be analyzed. If the runoff is not contaminated, it will be sent to the observation pond and mixed with clear water before being released into the environment. If runoff water is unsuitable for discharge, it will be diverted to the effluent treatment plant for treatment prior to discharge.

Effluent treatment facility

The effluent treatment facility will be designed to treat wastewater to a quality suitable for reuse in amenities or irrigation or discharge into the environment. The facility may consist of the following:

- Main equalization tank and off-spec tank
- Membrane bioreactor package
- Granular activated carbon filter package
- Chemical dosing package
- Sludge dewatering facilities

The conceptual water management system is as follows:



Source: Allow LNG.

Figure 5.12 Conceptual Water Management System

4) Fire protection system

The fire protection system should provide full firefighting capabilities, with firewater ring mains incorporated into the LNG plant and marine facilities.

5) Diesel storage and distribution system

The LNG plant includes a system for the receipt, storage and distribution of diesel fuel for use in emergency diesel generators, a diesel-driven fire protection system and an emergency instrument air compressor.

6) Refrigerant storage and makeup system

The refrigerant process uses light hydrocarbons for the liquefaction of natural gas. Light hydrocarbons are stored in tanks outside the processing area.

7) Waste management system

A number of waste materials is generated during construction and operation.

- Waste active carbon containing mercury sulfide
- Waste zeolite
- Oily waste and sludges
- Waste concrete, paint and solvent

Waste management strategies should be defined and established before the design phase.

(5) LNG jetty and berth

The berth/jetty for offloading is capable of accommodating Q-Max class (260,000 m^3) LNG carriers with a fully laden draught of 12.5 m. The shipping access channel will be 200 m wide and incorporate a swing basin in front of the berth, which will have a minimum diameter of twice the overall length of the longest LNG carrier, i.e., approximately 700 m.

5.4 Investment Costs

(1) LNG plant capacity

Assuming that feedstock gas is 40 million Nm^3/day of pipeline-grade methane-rich gas, LNG annual production will be 9 MPTA or 2 x 4.5 MTPA.

(2) Plant configuration

The LNG manufacturing facility consists of two sections: a pretreatment section and an LNG production section.

(a) The pretreatment section includes:
   i) AGRU
   ii) Dehydration unit
   iii) Mercury removal unit
   iv) NGL separation unit
(b) The LNG production section includes:
   v) Liquefaction unit
   vi) LNG storage and offloading

Since the gas feedstock is pipeline-grade methane-rich gas, a minimum-scale pretreatment facility will be required.

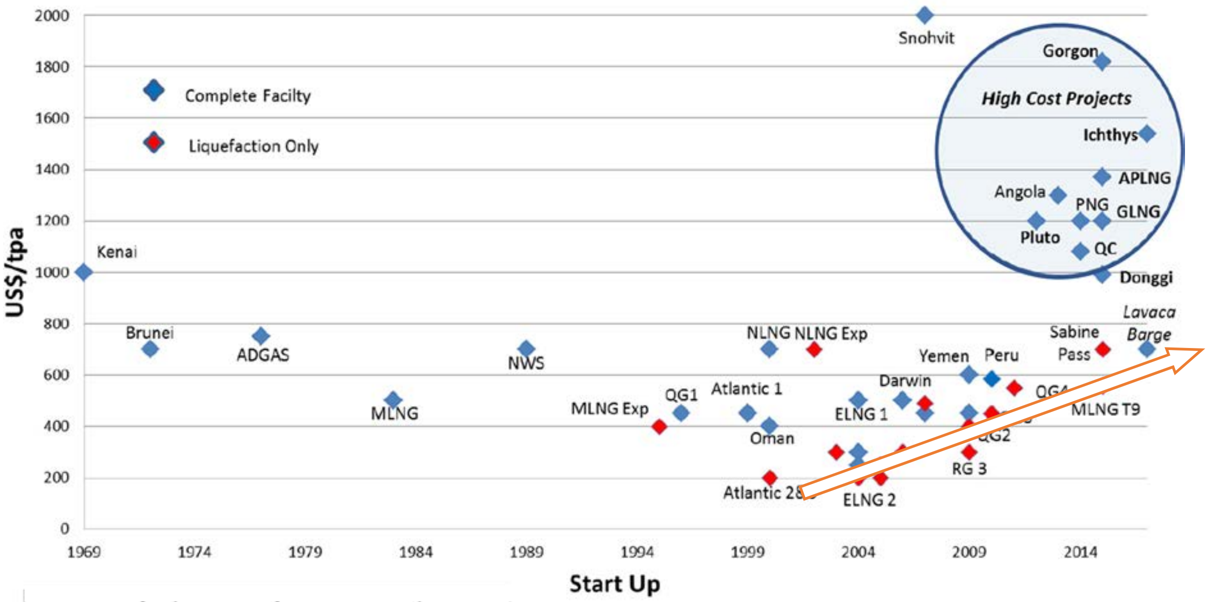
(3) Investment costs: capital expenditure (CAPEX)

Investment costs vary depending on:

- Production capacity
- Throughput (size) of the pretreatment section
- Infrastructure development cost, including pipeline, jetty and berth
- Location and local conditions including tax

- Access/transportation cost to the project site

The LNG project investment costs in terms of USD per tons per annum are as follows:

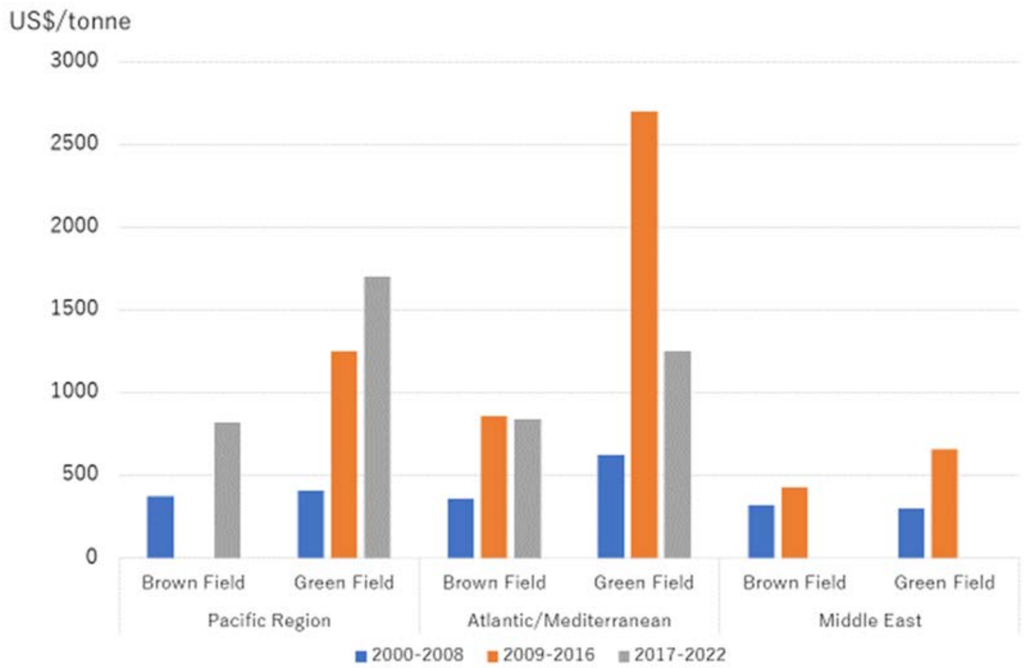


Source: Oxford Institute for Energy Studies.

Figure 5.13 LNG Plant Investment Costs

Construction costs in 2011 and after inflated significantly, due to a tight LNG supply situation caused by the Fukushima nuclear incident and the LNG market price reaching 16 USD/MMBTU FOB in Australia. A number of LNG projects was planned and some even started construction; however, given the development of shale gas LNG projects in the US, some of the projects were canceled while most of the projects were postponed.

Construction costs in terms of CAPEX by region were provided by the International Gas Union as shown below.



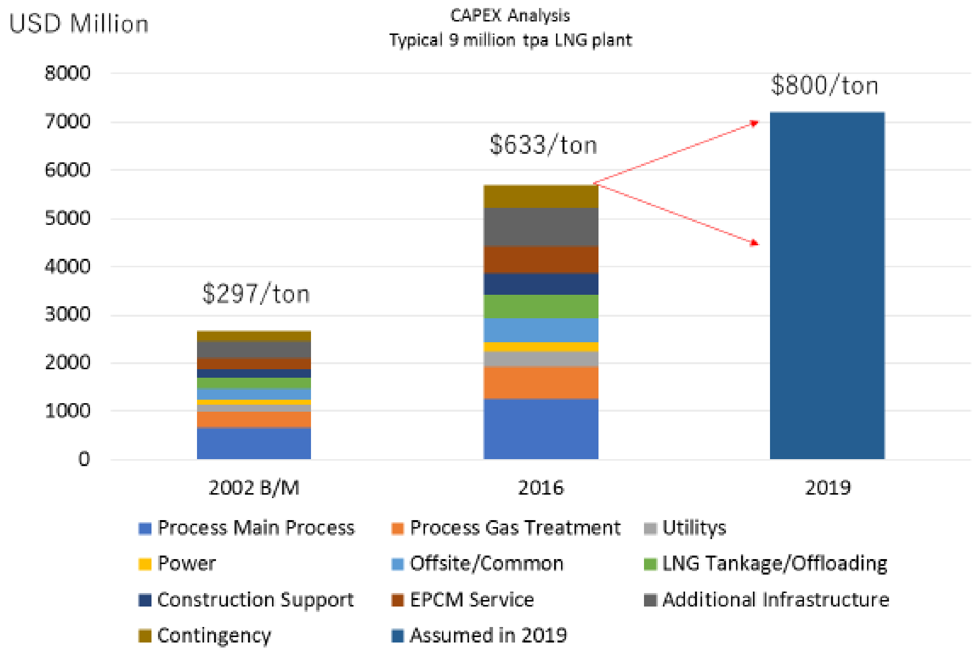
Source: International Gas Union (HIS, Company Announcements).

Figure 5.14 Average Liquefaction Unit Cost by Region

According to the data, the following figures are applicable to green field LNG liquefaction projects in the Middle East:

- 2000-2008: 300 USD/ton
- 2009-2016: 650 USA/ton

A CAPEX analysis was carried out by benchmarking one of the projects in the Pacific region in 2002.



Source: DEP.

Figure 5.15 Capital Expenditure Analysis

Construction costs of green field LNG plants with a capacity of 2 x 450 MTPA equated to about 2,700 million USD, while unit plant costs were almost identical to the data provided by the International Gas Union.

Material costs in 2016 were doubled and labor costs were three times higher than those in 2002. The benchmark data were readjusted by an inflation factor of 200% for materials and 300% for labor costs. The resulting construction costs are 5,700 million USD and 633 USD/ton.

Construction costs for 2019 cannot be predicted, considering the incomprehensible construction market situation. A unit construction cost of 600-800 USD/ton is assumed for 2019, while 800 USD/ton is used for this study. Accordingly, the CAPEX of the LNG plant will be 7.2 billion USD for a capacity of 9 MTPA.

5.5 Economics Base and Calculation

(1) Cash flow calculation base

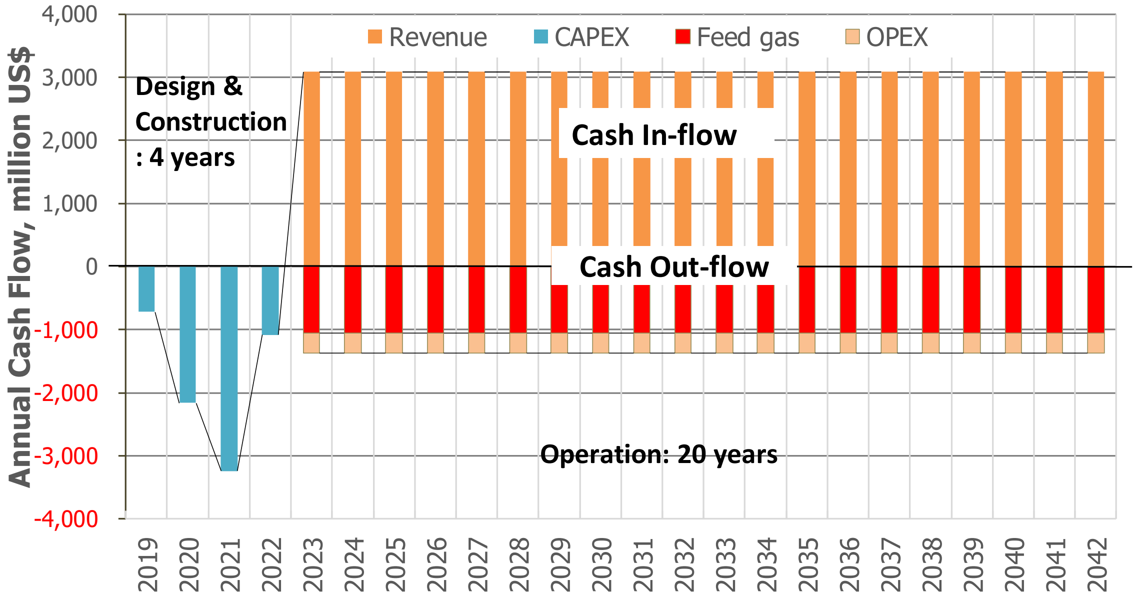
The cash flow calculation base is summarized as follows:

(a) Starting year: 2019
(b) Construction period: 4 years
(c) CAPEX 7.2 million USD
(d) Investment schedule and disbursement:
  i) Year 1: 10%
  ii) Year 2: 30%
  iii) Year 3: 45%
  iv) Year 4: 15%

(e) Depreciation: 20 years
(f) Operation expenditure: 4.4% of CAPEX
  i) Maintenance: 2.0% CAPEX
  ii) Insurance: 0.4% CAPEX
  iii) Manpower: 1.0% CAPEX
  iv) Variable costs: 1.0% CAPEX
(g) Tax rate: 0%
(h) Equity ratio: 100% Owner Fund
(i) Feed gas: 40.0 million Nm^3/day
(j) LNG production: 9.1 million tpa
(k) Internal consumption 10% of Feed Gas
(l) Feed gas price: 2.0 USD/MMBTU (HHV)
(m) LNG FOB price: 6.5 USD/MMBTU (HHV)

(2) Economic calculation

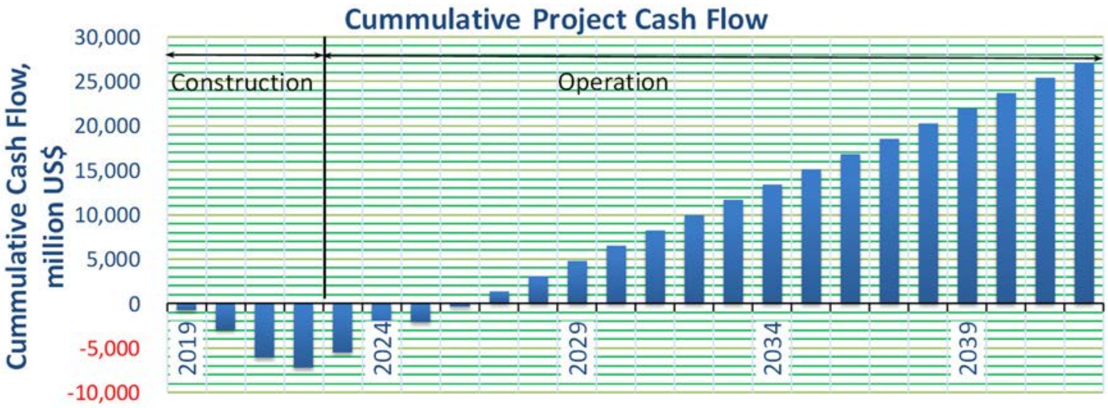
The calculated cash flow is shown as follows. The expected IRR under the prevailing economic conditions is over 18.3%.



Source: JICA Project Team.

Figure 5.16 Cash Flow for LNG Project

The cumulative cash flow trend is shown in the figure below.



Source: JICA Project Team.

Figure 5.17 Cumulative Project Cash Flow

As invested capital will be recovered after four years of operation, the "payout time" is four years.

(3) Sensitivity analysis

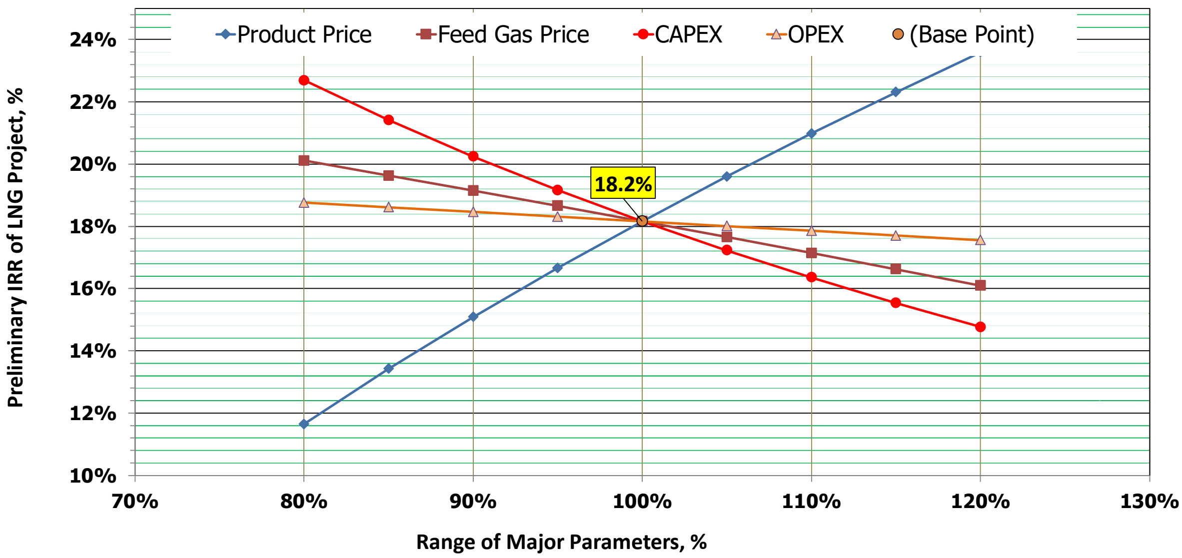
The major parameters in project economics are CAPEX and the product LNG FOB price.

1) CAPEX

Since depreciation of the LNG plant is set at 20 years, project economics is viewed in line with this timescale. The actual project life depends on the lifetime of the gas reservoir and whether the project enjoys a further revenue advantage after depreciation if the lifetime of the reservoir is longer than depreciation. As discussed earlier, CAPEX in 2019 is not easy to predict, as it is influenced by the boom/bust cycle and could fall to 75% if there is a bust trend in 2019.

2) LNG FOB price

The economics of the LNG project is mostly influenced by product price. The Middle East FOB to Europe was less than 4.5 USD/MMBTU; however, the FOB to Asia in the first quarter of 2017 was 6.5 USD/MMBTU at the lowest point but can be higher following an escalation in crude oil prices since the majority of gas pricing formulas are linked with crude oil.



Source: JICA Project Team.

Figure 5.18 Project Sensitivity

5.6 Project Schedule

The first step to enable the project to move forward is to identify or form the project entity. The project entity will be in the form of a consortium involving the NOC, an IOC as operator, and marketers and offtakes, licensed or entrusted by the government of both the host country and investing country.

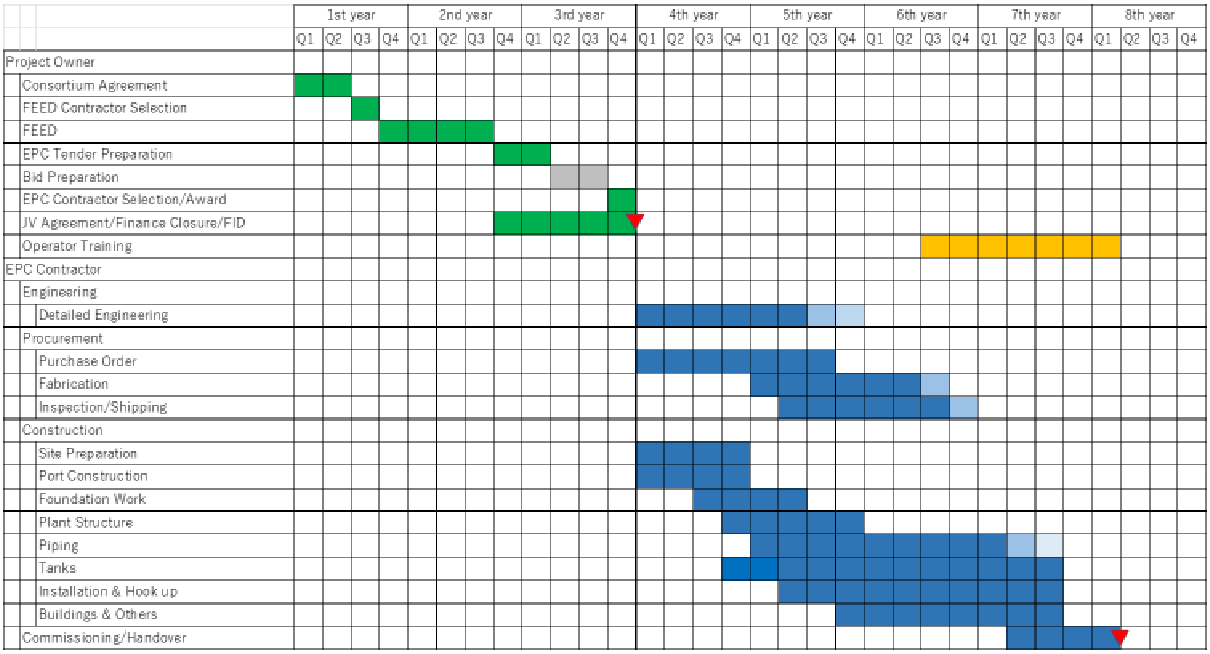
The entity will form the project management team to carry out a feasibility study and FEED. Prior to starting a FEED, value engineering will be carried out to firm up various design options in order to optimize the design issues.

The objective of a FEED is to clarify the required budget for construction and the construction schedule, as well as prepare tender documents in order to select contractors.

The project management team will prepare an engineering, procurement and construction (EPC) tender for EPC contractor selection. Invitations to tender will be issued, a prequalification procedure will be announced and qualified bidders will be confirmed. Bidders will be given a few months of time to calculate their best price and evidence the technological excellence expressed in the tender document.

The owner side needs to restructure the project entity, work on a joint venture agreement, negotiate with financers and conclude the financial arrangement before the FID is made by the joint venture entity. After confirming the financial closure, the EPC contractor award will be announced.

The construction requires almost four years to complete. There are numerous items of major equipment that need to be delivered to the LNG liquefaction facility, such as refrigerant compressors, gas turbines and coil-wound heat exchangers. The construction of LNG storage tanks also requires 36 months to complete. A typical project schedule is shown as follows:



Source: JICA Project Team.

Figure 5.19 Provisional Project Schedule

5.7 Environmental Concerns

Effluent from the LNG plant will be limited. There will be almost no impact on marine life since no sea water will be used for cooling and all the water effluent will be treated to a quality suitable for reuse or discharge into the environment.

(1) Use of closed-loop cooling water system

Process heat from the LNG plant utility units will be dissipated through air-fin coolers via a closed-loop cooling water system with cooling water sourced from the demineralized water system. A dedicated cooling water system will be provided for each of the gas turbines. A closed-loop cooling water system is also required for the instrument air system and the nitrogen system for mechanical drive purposes.

(2) Appropriate effluent water treatment facility

The effluent water treatment facility will be designed to treat wastewater to a quality suitable for reuse in amenities or irrigation or discharge into the environment.

(3) Appropriate waste management system

A number of waste materials will be generated during construction and operations, as follows. Waste management strategies should be defined and established in the design phase in line with international industrial practice.

- Waste active carbon containing mercury sulfide
- Waste zeolite
- Oily waste and sludges
- Waste concrete, paint and solvent

CHAPTER 6 ADVANTAGES OF THE LNG PROJECT IN QESHM

Iran has the largest gas reserves of any country and its production costs are considered to be the lowest in the world.

LNG demand will grow steadily and continue to be a major cleaner energy source for power generation.

The LNG project on Qeshm will be one of the most competitive LNG plants in the world and there will be no difficulty in finding a market due to the deregulation movement in the global gas and power sector.

Qeshm is located at the mouth of the Persian Gulf and the distance in nautical miles from the gas market in Asia and Europe is shorter than that between the latter and Qatar, the major gas exporting country.

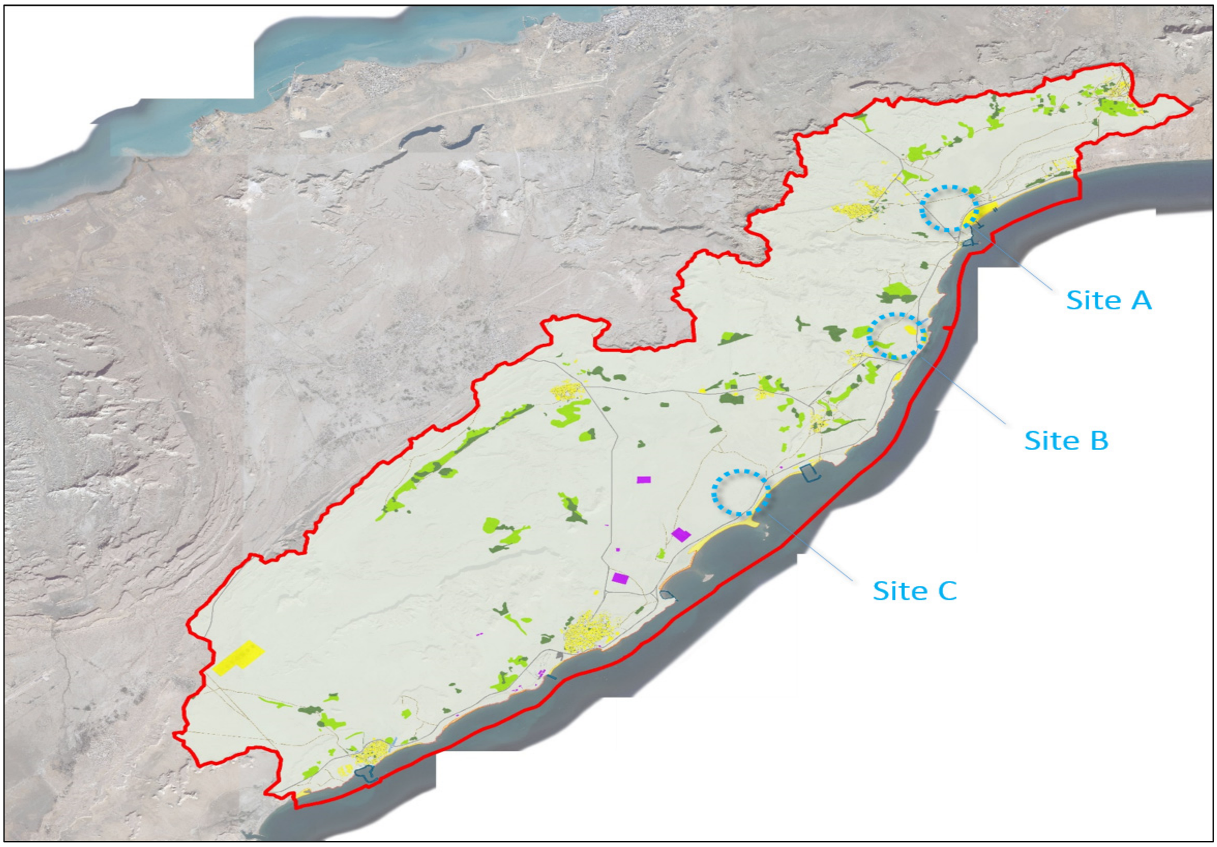
Qeshm is located just next to an international waterway and thus an ideal site for the shipment of LNG.

Qeshm is designated as a Free Zone, meaning that tax for material imports and business tax will not be initially applied for 20 years.

In view of the environmental impact, effluent from the LNG plant is considerably cleaner compared to that from petroleum refining and petrochemical/chemical plants, while there will be almost no impact on sea life and air pollution, meaning that LNG production complements the eco-island aims of Qeshm.

Attachment 1 Detailed Study of Candidate Sites on the Eastern Coast

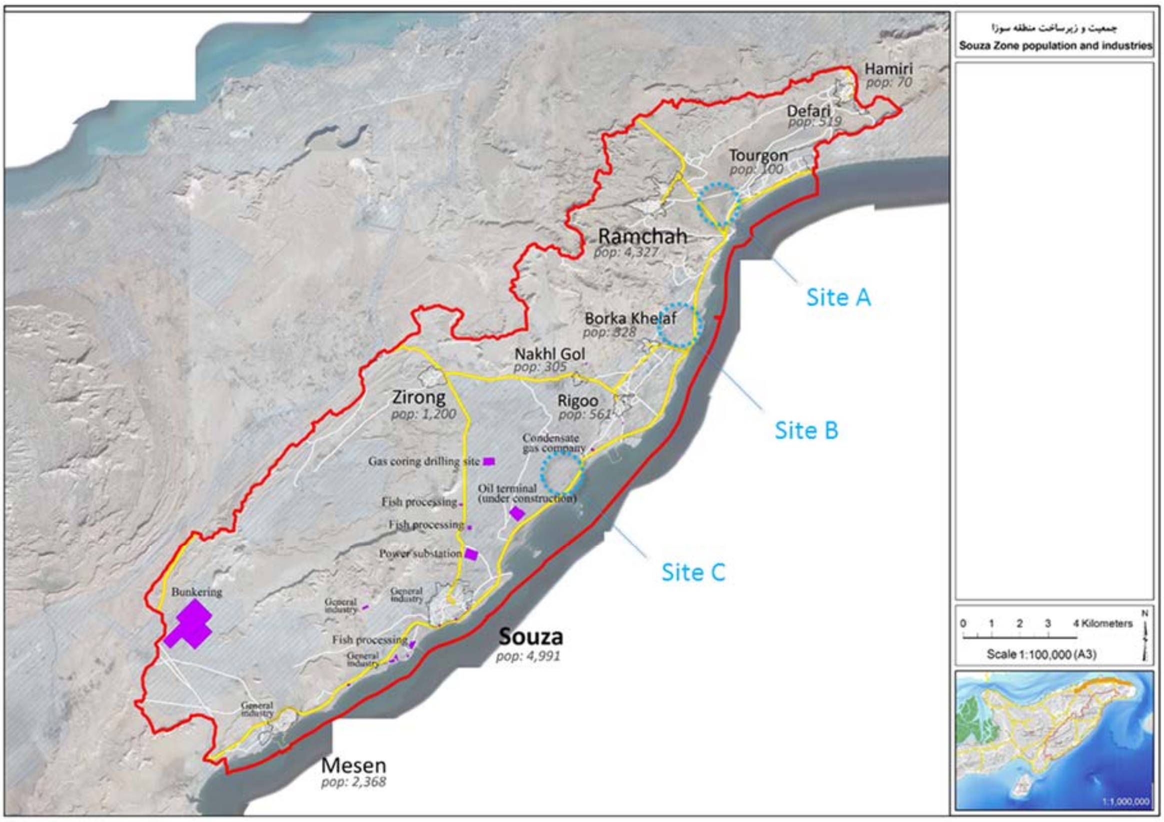
Current land use on the eastern coast, preliminarily selected as the region with the highest potential and the location of the three most-acceptable candidate sites (A, B and C), is shown in Figure A1.1 below.



Source: JICA Project Team.

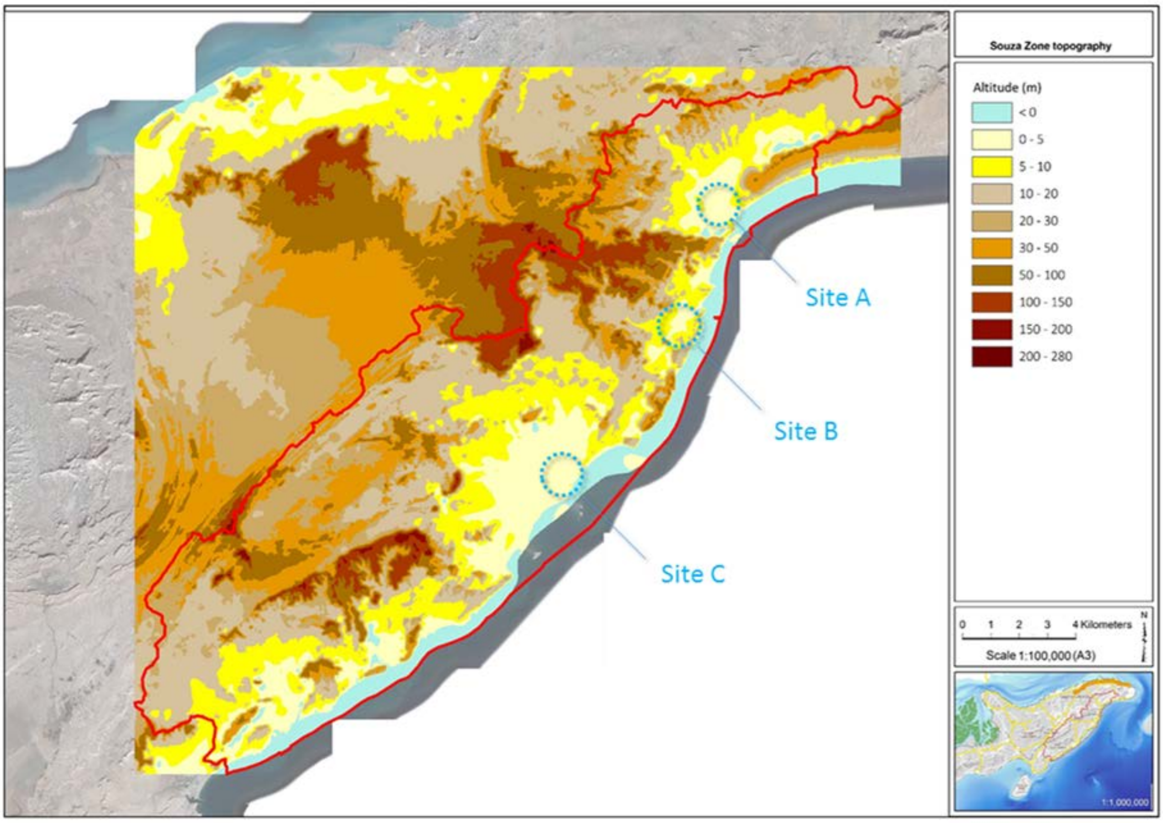
Figure A1.1 Three Candidate Sites and Existing Land Use on the Eastern Coast

The following maps illustrate the situation concerning A, B and C candidate sites in terms of the human environment (Figure A1.2), topography (Figure A1.3), slope (Figure A1.4), bathymetry (Figure A1.5), coastal environment suitability (Figure A1.6) and cultural heritage (Figure A1.7).



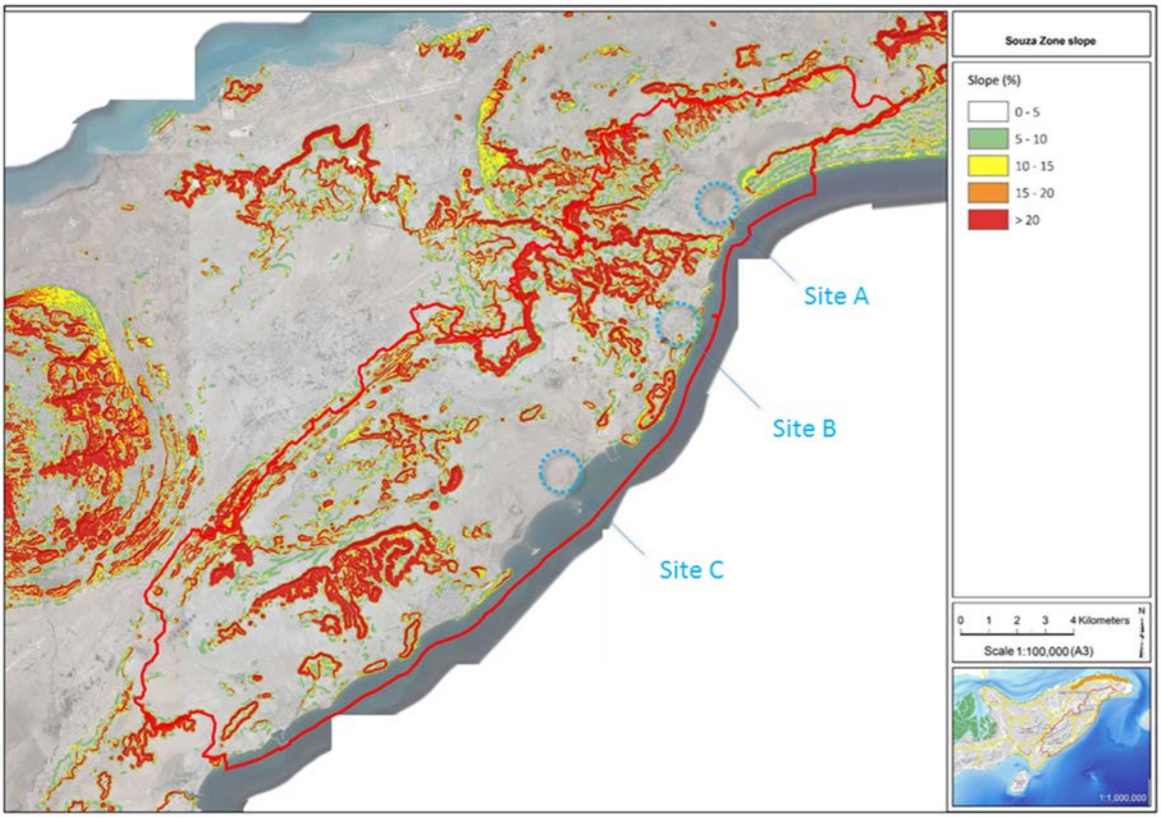
Source: JICA Project Team.

Figure A1.2 Human Environment (Settlements and Industries) on the Eastern Coast



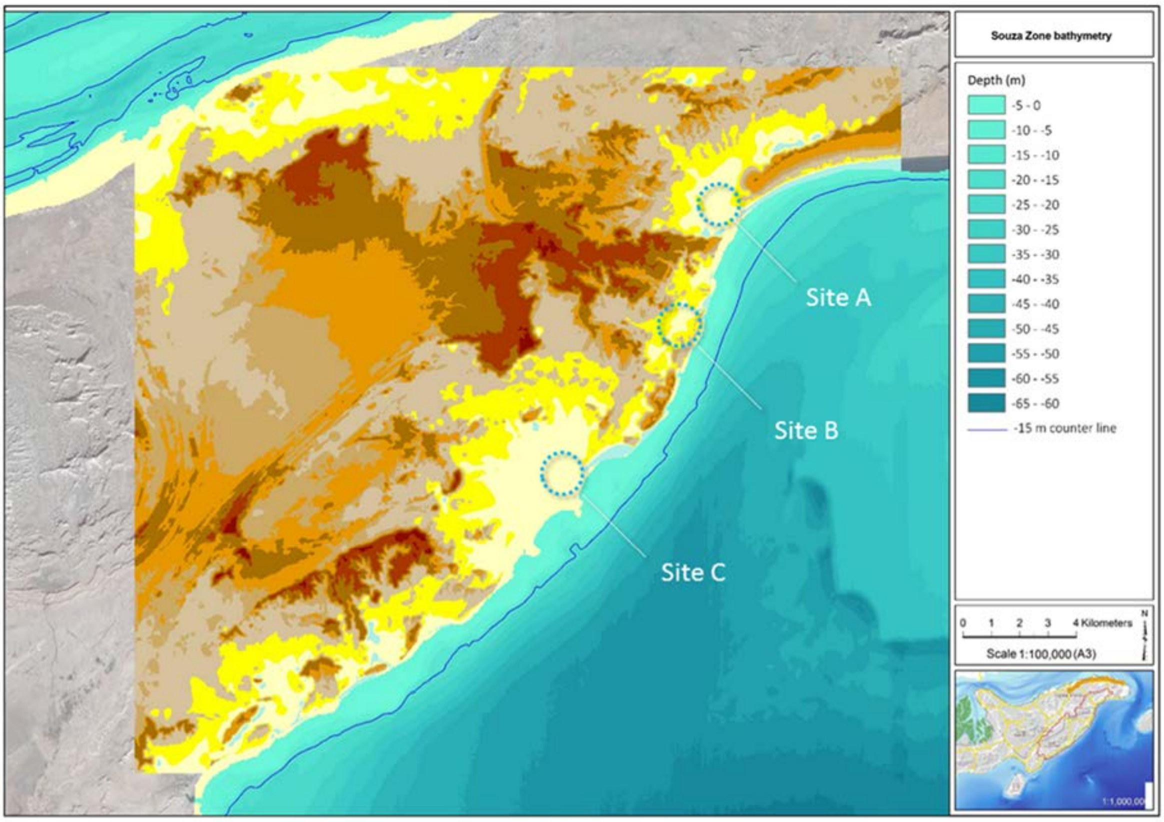
Source: JICA Project Team.

Figure A1.3 Topography on the Eastern Coast



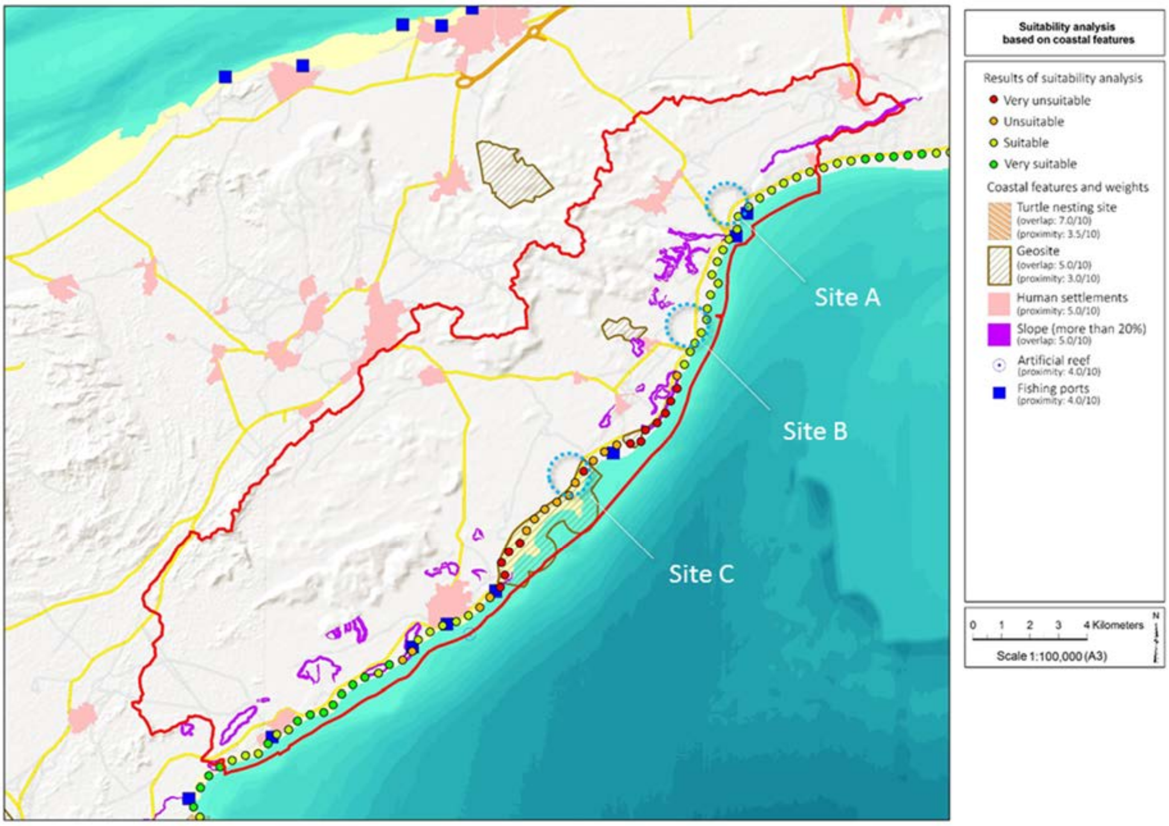
Source: JICA Project Team.

Figure A1.4 Slope on the Eastern Coast



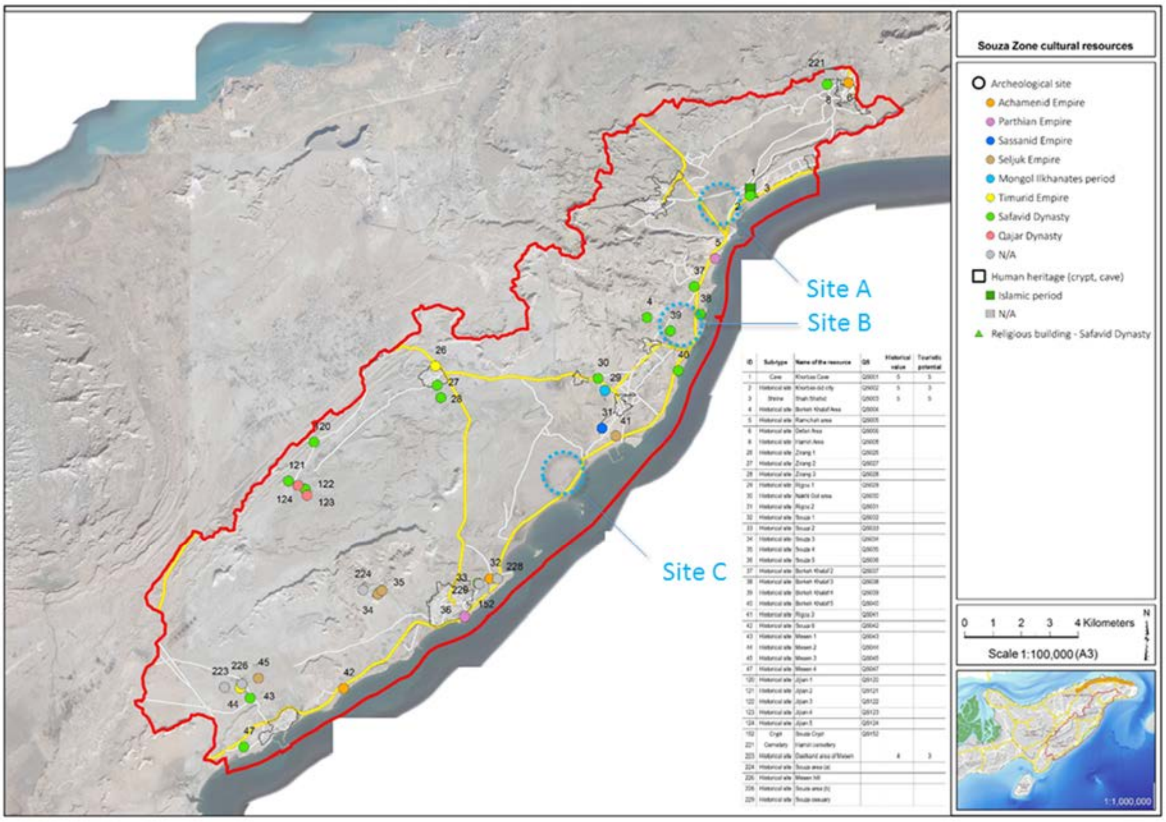
Source: JICA Project Team.

Figure A1.5 Bathymetry on the Eastern Coast



Source: JICA Project Team.

Figure A1.6 Coastal Environment Suitability on the Eastern Coast



Source: JICA Project Team based on data from the Tourism Division of the Qeshm Free Zone Organization.

Figure A1.7 Cultural Heritage on the Eastern Coast

All the physical, natural and cultural features highlighted above influence the suitability assessment of the sites candidates for LNG development. A general assessment of each criterion for the three sites on the eastern coast is shown in Table A1.1.

Table A1.1 Comparison of Candidate Sites on the Eastern Coast

Item	Site A	Site B	Site C
Human Environment	・Between the major villages of Tourgon and Ramchah but still far from housing ・Crossing the coastal road could be an issue for accessing the sea	・Close to the small village of Borka Khelaf ・Crossing the coastal road could be an issue for accessing the sea	・Far from any major human settlement ・Proximity of existing industries ・Crossing the coastal road could be an issue for accessing the sea
Topography	・Located at a low altitude (from 0 to 5 m)	・Located at a low altitude (from 0 to 5 m)	・Located at a low altitude (from 0 to 10 m)
Slope	・Flat area, relatively far from any slope	・Flat area, surrounded by a few steep slopes (especially coastal)	・Large flat area, far from any slope
Bathymetry	・Relatively good sea water depth in the vicinity (-30 m at 4 km from the shore) ・Line with a depth of -150 m relatively close to the shore	・Good sea water depth in the vicinity (-45 m at 4 km from the shore) ・Line with a depth of -15 m close to the shore (within 1 km distance)	・Best sea water depth in the vicinity (-55 m at 4 k from the shore) ・Line with a depth of -15 m relatively close to the shore
Coastal Environment Suitability	・Relatively high suitability despite the presence of two fishing ports, which will have negative impacts from LNG	・Relatively high coastal suitability	・Relatively low suitability due to the presence of a protected area (Naz Islands Geosite) on the site
Cultural Heritage	・Close to Khorbas Cave, important human heritage asset from the Islamic Period but also a famous tourist spot	・Surrounded by three relatively important archeological sites from the Safavid Period	・Far from any cultural heritage site

Source: JICA Project Team.

Attachment 2 Water Quality and Sediment Quality

(1) Water quality

The vertical distribution of water temperature, salinity, turbidity and chlorophyll was measured by an in-situ multiparameter water quality meter. The water quality was vertically uniform across all locations. This means that vertical mixing is strong due to the tidal current.

Laboratory testing of water quality was also carried out to determine the nutrient level and discharge from the land area. Table A2.1 shows the test results.

At Souza 4, the ratio of NH_3 to total nitrogen (T-N) is different to other locations. There could be some discharges, domestic waste or sewage around this area.

Table A2.1 Results of the Water Quality Analysis

	Unit	Selakh 1	Selakh 2	Selakh 4	Souza 2	Souza 3	Souza 4	Dargahan 2	Dargahan 4	Dargahan 5
T-P	ppm	N.D	N.D	N.D	N.D	N.D	N.D	N.D	N.D	N.D
T-N	ppm	17.50	12.25	14.00	14.00	14.00	7.00	8.75	12.25	14.00
TPH	ppm	0.02	0.02	0.03	0.10	0.04	0.04	0.05	0.02	0.06
TDS	ppm	25740	26641	28580	24642	25787	22256	30125	29645	29020
TSS	ppm	8450	9350	16681	4305	4450	928	15820	15340	14458
NO3	ppm	9.3	10.7	13.1	8.1	7.8	7.9	9.2	7.7	7.3
NO2	ppm	0.013	0.021	0.008	0.015	0.004	0.007	0.004	0.005	0.014
NH3	ppm	1.70	1.27	1.27	1.27	2.12	5.09	0.85	0.85	0.35

Source: JICA Project Team.

(2) Sediment quality

Laboratory testing of the physical test for sea bottom sediment and soil in the coastal area was performed to determine the composition of grain size for simulation purposes. Table A2.2 presents the test results.

The results do not show major differences in grain size composition between the survey locations, except Dargahan, which is located on the northern side of Qeshm Island and where the composition ratio of gravel is slightly higher.

Table A2.1 Results of the Water Quality Analysis

	Unit	Souza 1-2	Souza 2-1	Souza 3-1	Souza 3-2	Selakh 2	Shibderaz	Dargahan	Souza	Selakh
Specific Gravity	-	0.99655	0.99655	0.99627	0.99655	0.99655	99627	0.99655	0.99655	0.99655
Density	-	2.6717	2.6645	2.6781	2.6645	2.6574	2.6709	2.6717	2.6645	2.6574
Moisture Content	%	27.42	12.65	26.29	23.81	19.51	1.05	15.22	34.94	32.11
Gravel (75.00mm-2.00mm)	%	0.00	0.00	0.40	1.50	1.60	0.10	32.24	2.84	5.40
Sand (2.00mm-0.075.00 mm)	%	94.77	96.94	94.25	89.55	93.53	98.80	64.54	95.86	83.54
Silt (0.075mm-0.005mm)	%	5.19	2.91	5.32	8.89	4.85	1.00	2.99	1.18	10.67
Clay (<0.005mm)	%	0.04	0.15	0.03	0.06	0.02	0.01	0.23	0.12	0.39

Source: JICA Project Team.

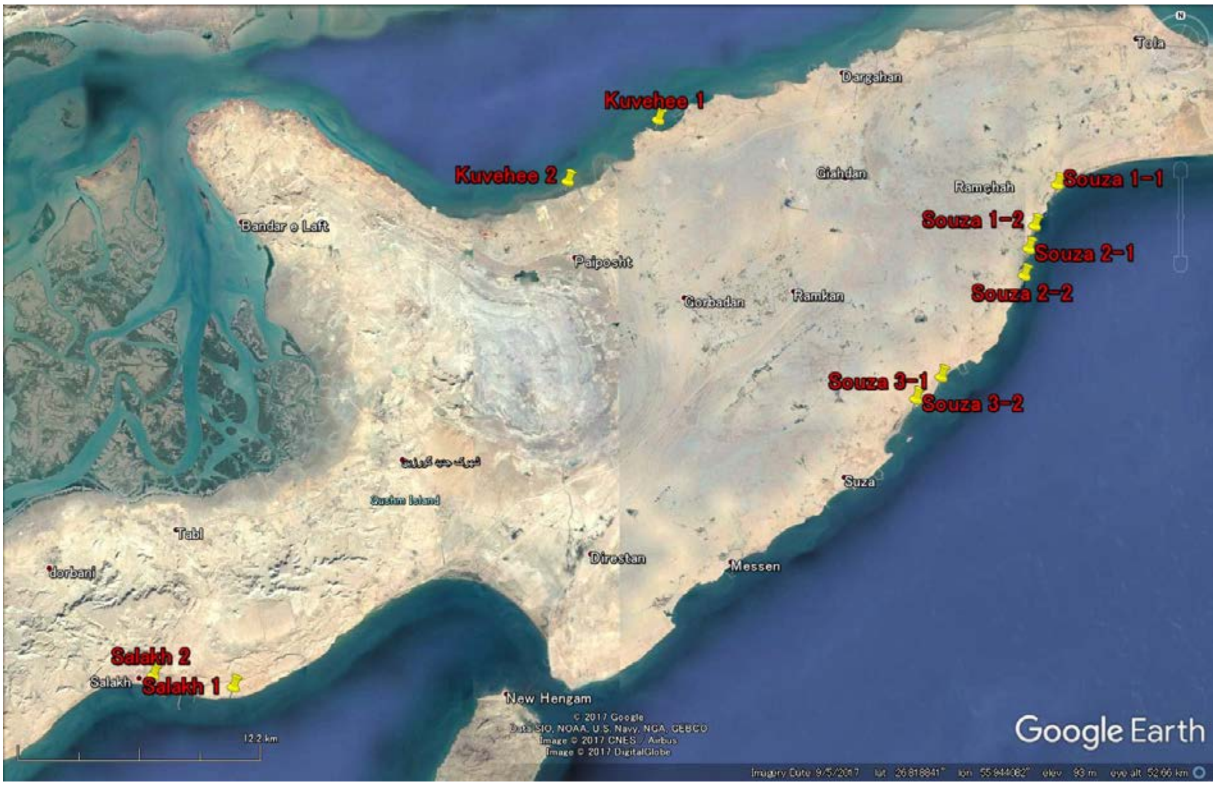
Attachment 3 Current Condition of Beaches

The JPT carried out a site visit to confirm the current conditions of the beaches around the candidate sites for LNG development on August 8 and 15, 2017. Table A3.1 below sets out the characteristics of the beaches based on the site visits. Figure A3.1 shows the location of the beaches visited by the JPT.

Table A3.1 Current Conditions of Beaches Around the Candidate Sites

Location	Beach Type	Mainly Beach Material	Beach Slope
Souza	・Sand beach or cliff	・Fine sand or rock	1/10~1/30
Selakh	・Sand beach with partial beach rock	・Fine sand with partial silt	1/10~1/30
Kouvei	・Tideland with partial sand beach	・Silt and mud (surface) ・Sand with shell fragments	Almost flat

Source: JICA Project Team.



Source: JICA Project Team (Google for imagery).

Figure A3.1 Location of Beaches Visited Around the LNG Development Candidate Sites

(1) Souza

The outcome of the site visits to Souza is presented in Table A3.2. The location of each site visit refer to the locations shown in Figure A3.1.

Table A3.2 Observation of Each Beach Based on the Site Visit to Souza

Photo	Observation
Souza 1-1: private area of the Golden Beach Resort 	・ The material of the beach is composed of fine sand and the slope is estimated to be approximately 1/15. ・ The beach has enough depth to prevent the entire area from being exposed to sea water at high tide.
Souza 1-2: Borka Khelaf  	・ A sand beach extends in front of the rock along the shoreline. ・ The material of the beach is fine sand and the slope is gentle. ・ The beach is narrow and can become entirely exposed to sea water at high tide.

Table A3.2 Observation of Each Beach Based on the Site Visit (Continued)

Souza 2-1: Rigoo 	・The material of the beach is fine sand and the slope is gentle. ・Small crabs create numerous nest holes. ・The height of the beach scarp is approximately 3 m. ・The material of the cliff is composed of sand with coral and shell fragments. The scarp is very brittle. ・The beach scarp is eroded by wave and rainfall. The eroded scarp supplies material to the beach.
	
Souza 2-2: Rigoo 	・The sand beach exists in front of the rock cliff along the shoreline. It cannot be seen except during low tide. ・The height of the cliff is about 10 m. The cliff is composed of two geological layers consisting of limestone at the upper and mudstone at the lower layer. ・The upper hard layer of limestone is corrupted due to heavy erosion of the mudstone at the soft layer, which is continuously impacted by wave effects.
 	

Table A3.2 Observation of Each Beach Based on the Site Visit (Continued)

Souza 3-1  	・ A wide sand beach exists with a slope at 1/20-1/30. ・ The material includes a small amount of black mineral. It is not supplied from the river but from sandstone or mudstone resulting from coastal erosion. ・ A few coal tar fragments are found on the beach.
Souza 3-2 	・ The sand beach extends to the areas covering Souza 3-1 and Souza 3-2. It has a length of approximately 5 km. ・ The beach is often used for recreation by residents.

Source: JICA Project Team.

(2) Selakh

The outcome of the site visits to Selakh is presented in Table A3.3.

Table A3.3 Observation of Each Beach Based on the Site Visit to Selakh

Photo	Observation
Selakh 1: East of the existing port  	・ A sand beach exists in a limited area to the east of the small jetty. Seaweed is cast ashore. ・ There is no sand beach in front of the rocks to the west of the jetty. The rock has two diagonal geological layers. The front is composed of old sandstone and the back is new limestone.
Selakh 2: In front of the village to the west of the existing fishery port 	・ The beach material is composed of fine sand with red soil. The slope is gentle. ・ The red soil can be carried from the north of the island to the west of the island at Selakh by the tidal current. ・ Numerous coal tar fragments are found on the beach.

Source: JICA Project Team.

(3) Kouvei

The outcome of the site visits to Kouvei is presented in Table A3.4.

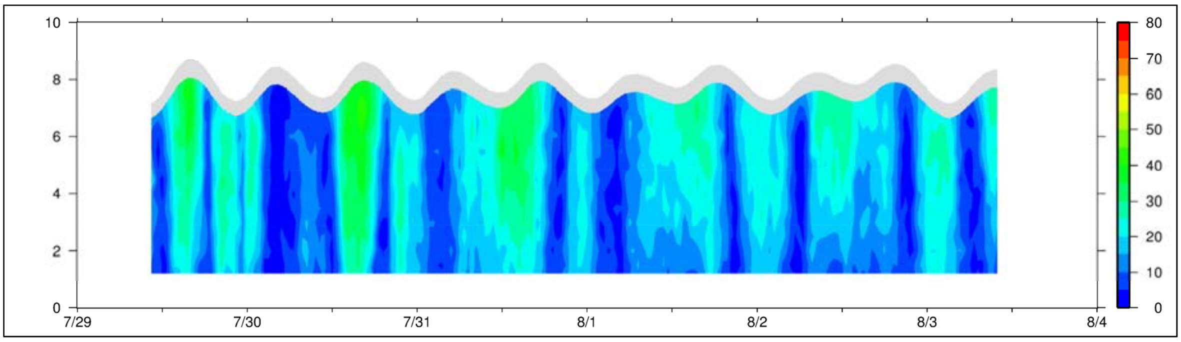
Table A3.4 Observation of Each Beach Based on the Site Visit to Kouvei

Photo	Observation
Kouvei 1: West of the port  	･ A sand beach exists in places. The beach material includes shell fragments. ･ The height of the beach scarp is about 70 cm.
Kouvei 1: West of the river mouth  	･ A tideland exists along the shoreline and is almost flat. ･ The thickness of mud on the surface of the tideland is so thin that the people can walk without difficulty. ･ Sand with shell fragments is found under the mud.

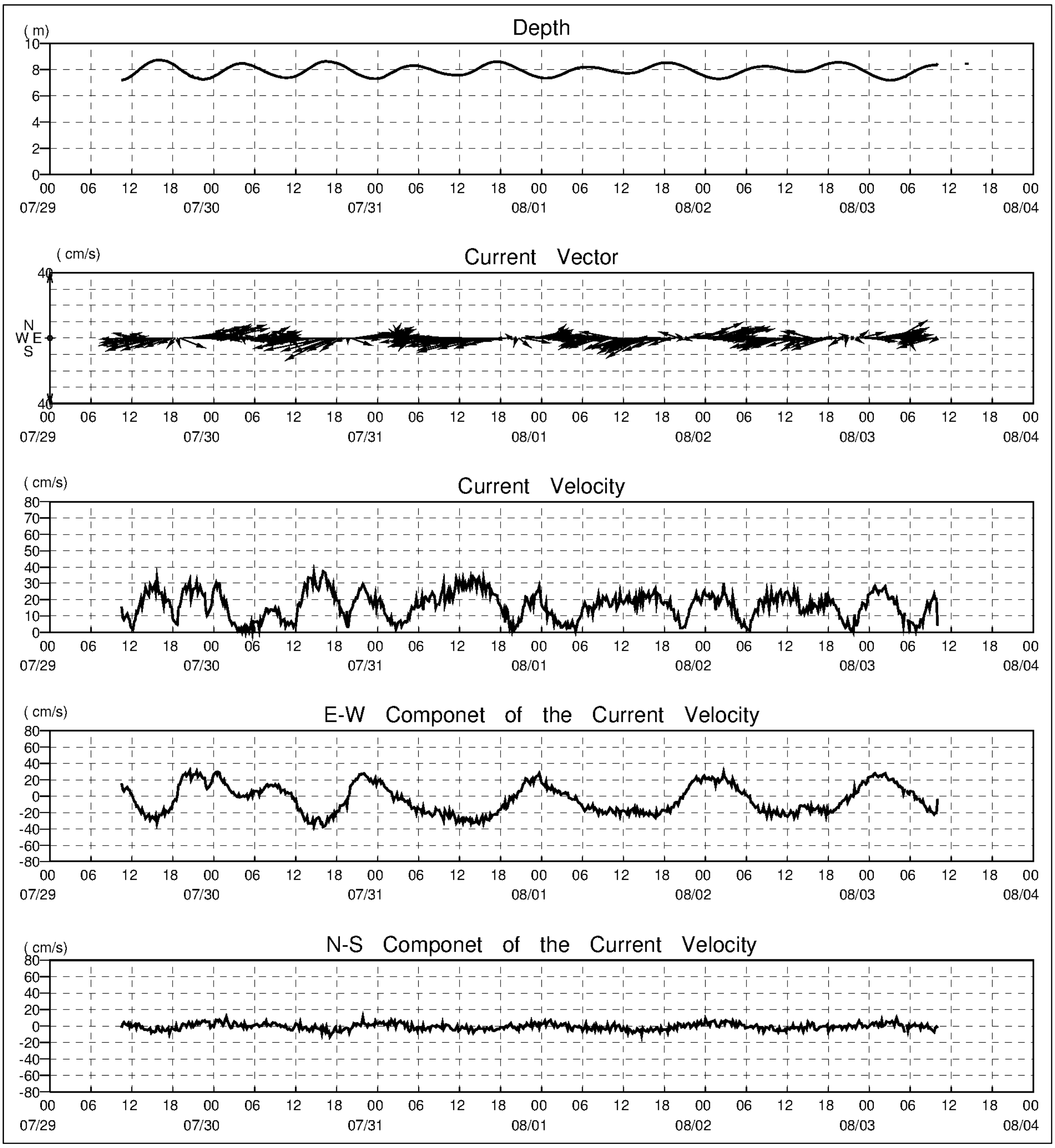
Source: JICA Project Team.

Attachment 4 Results of Tidal Current Survey

(1) Selakh

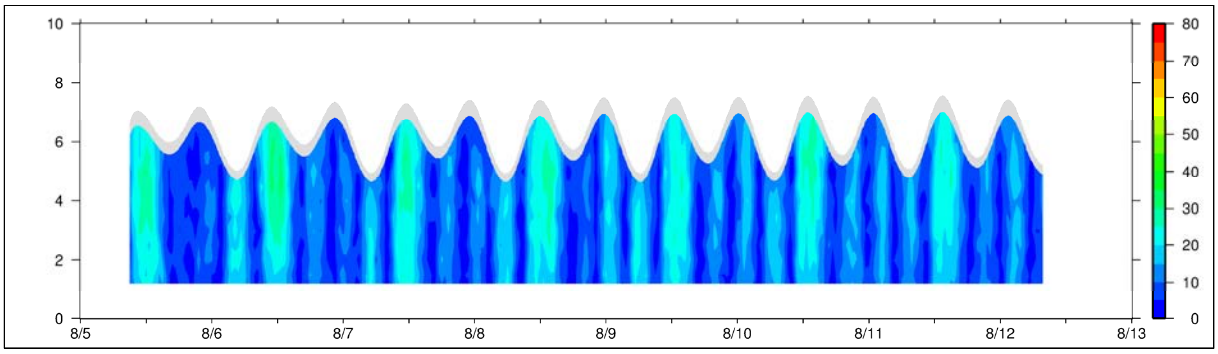


Vertical Velocity Profile

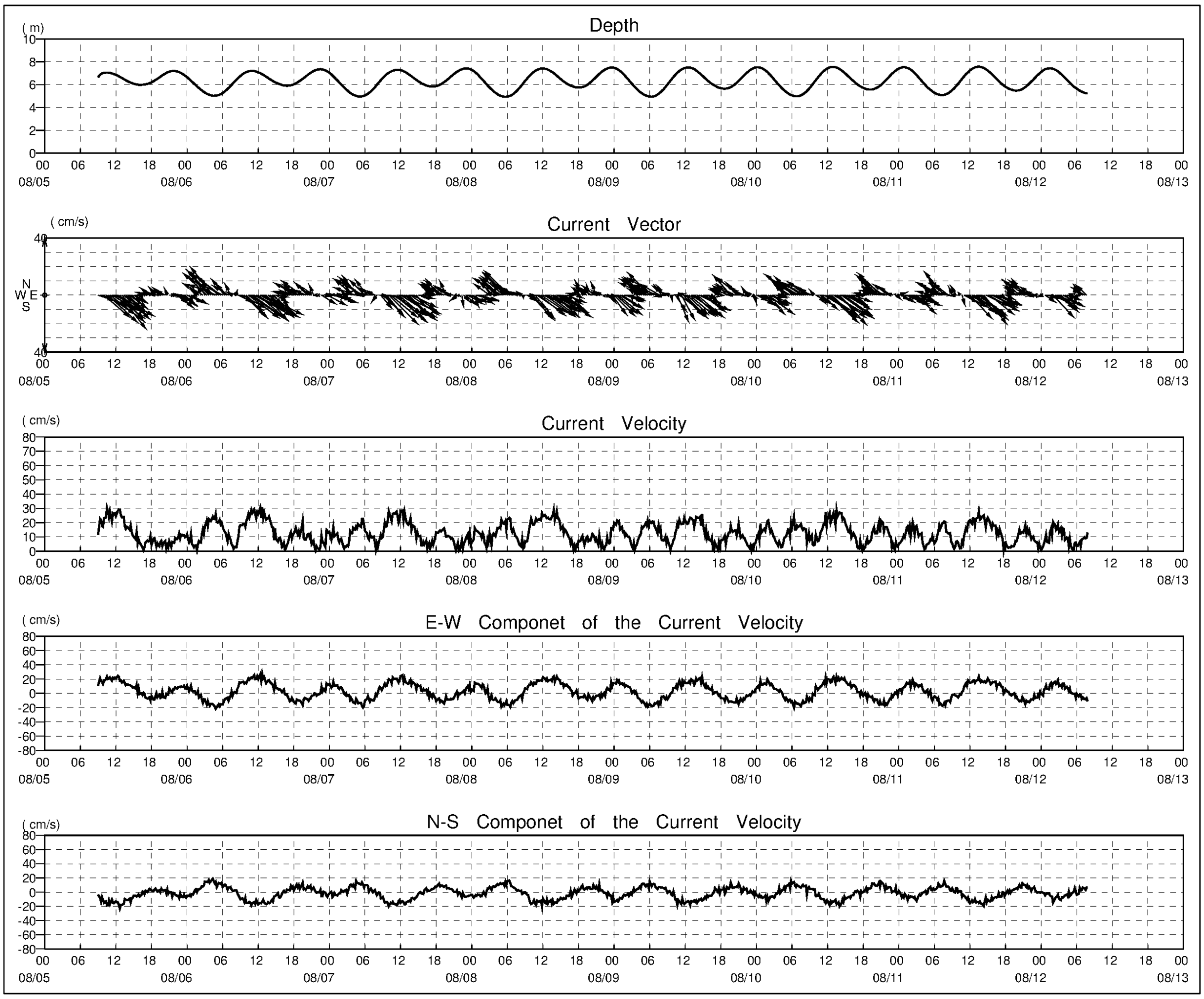


Time Series of Water Depth, Tidal Current Speed and Direction (4m above sea bottom)

(2) Souza

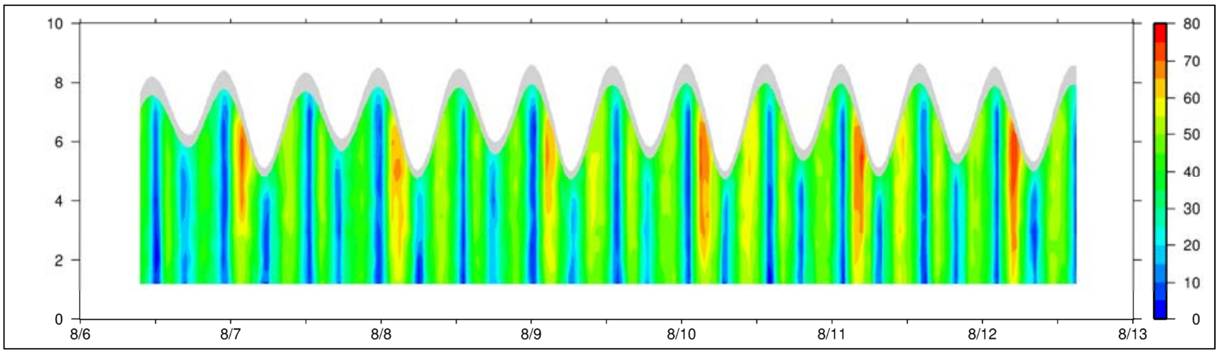


Vertical Velocity Profile

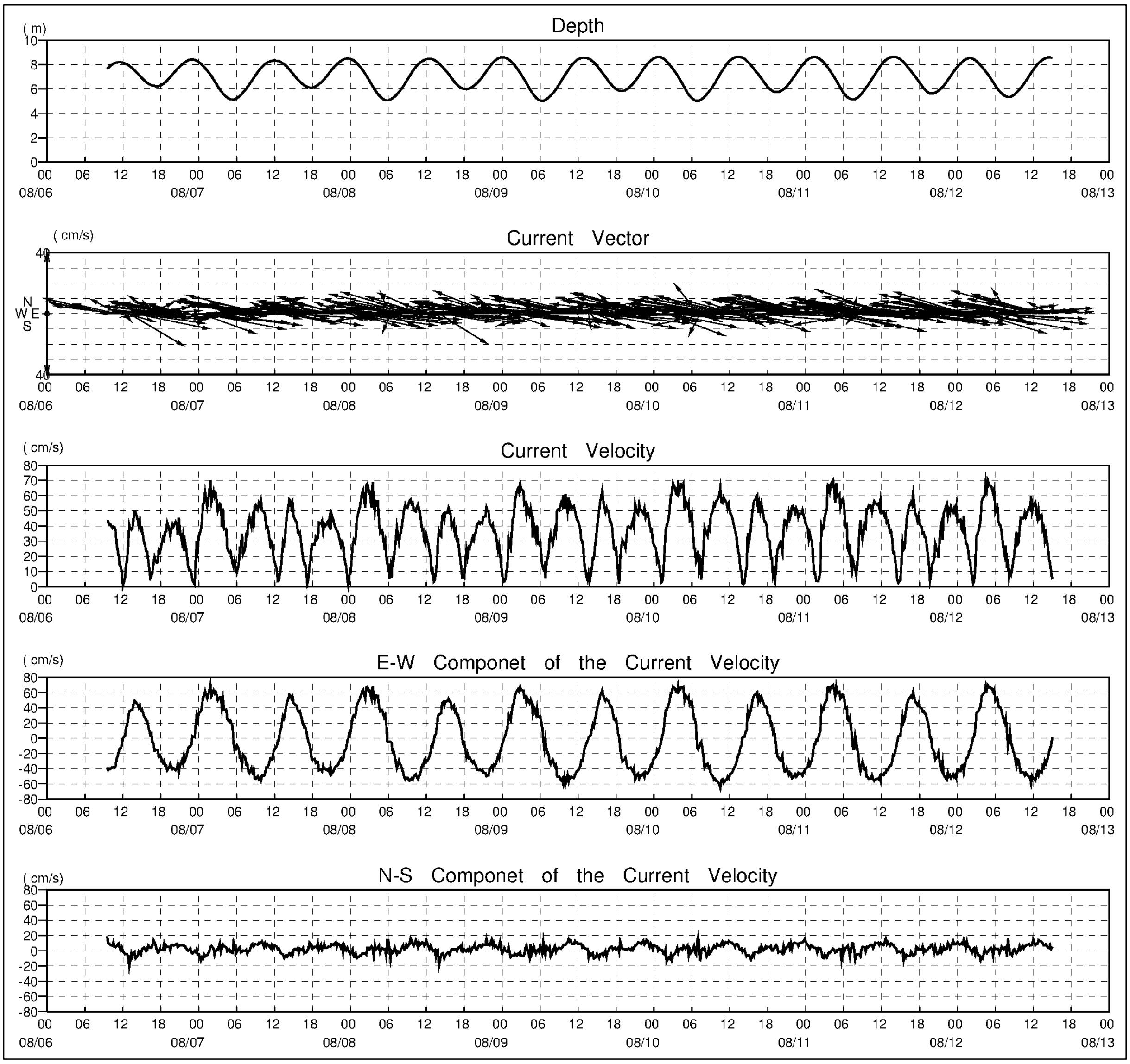


Time Series of Water Depth, Tidal Current Speed and Direction (4m above sea bottom)

(3) Souza

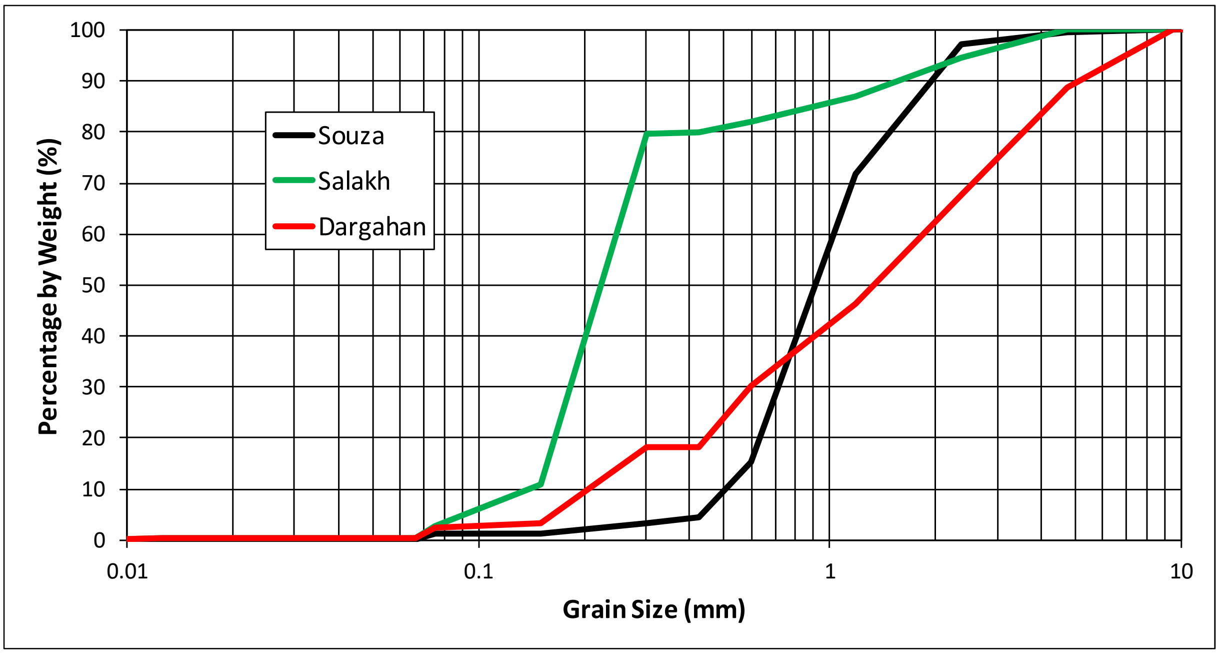


Vertical Velocity Profile

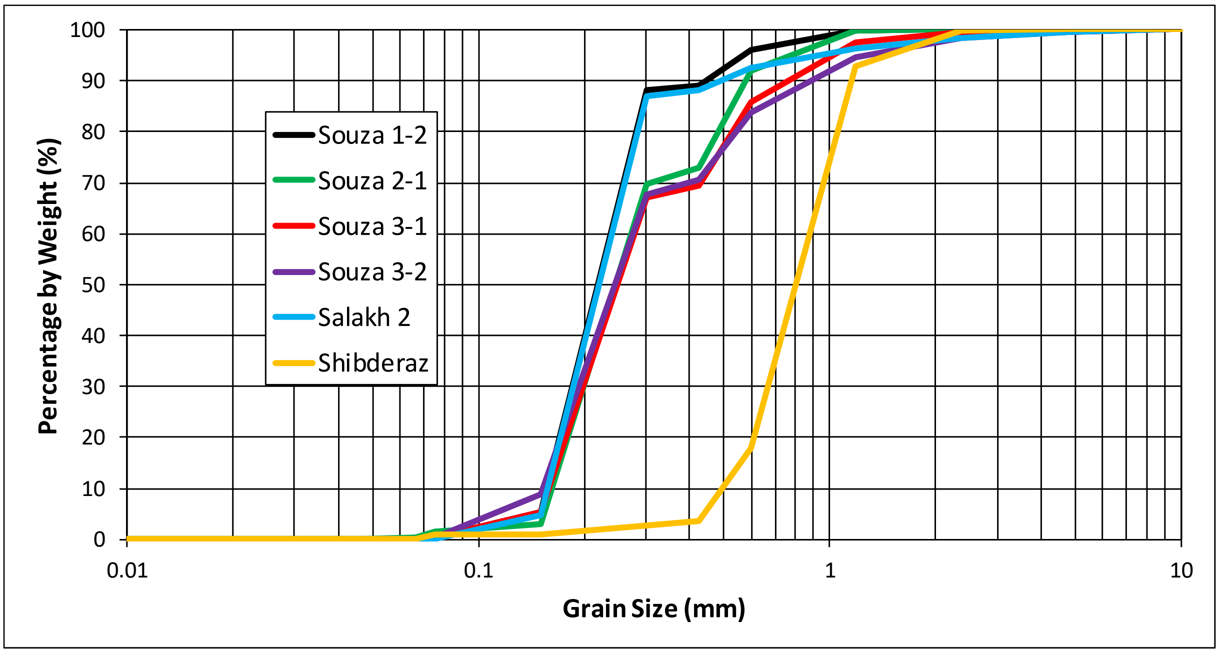


Time Series of Water Depth, Tidal Current Speed and Direction (4m above sea bottom)

Attachment 5 Analysis Results of Sediment Samples



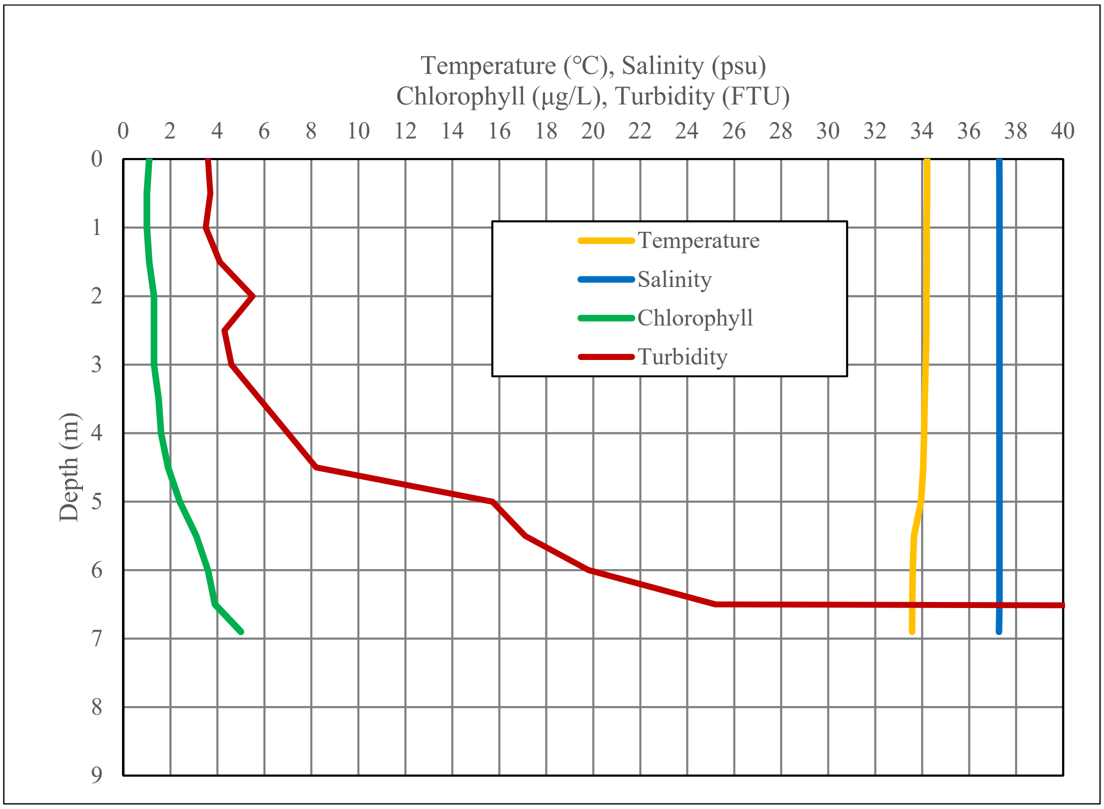
Bottom Sediment



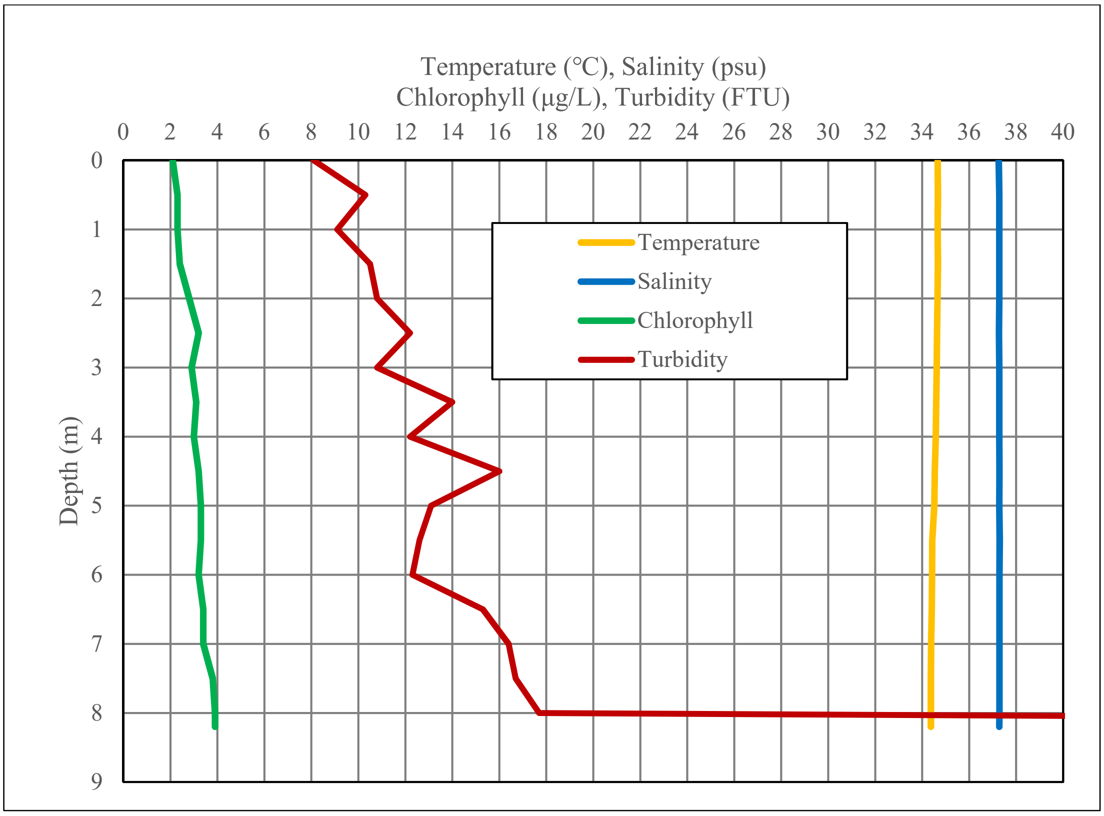
Shoreline Sediment

Attachment 6 Vertical Distribution of Seawater Temperature, Salinity, Chlorophyll and Turbidity

(1) Selakh

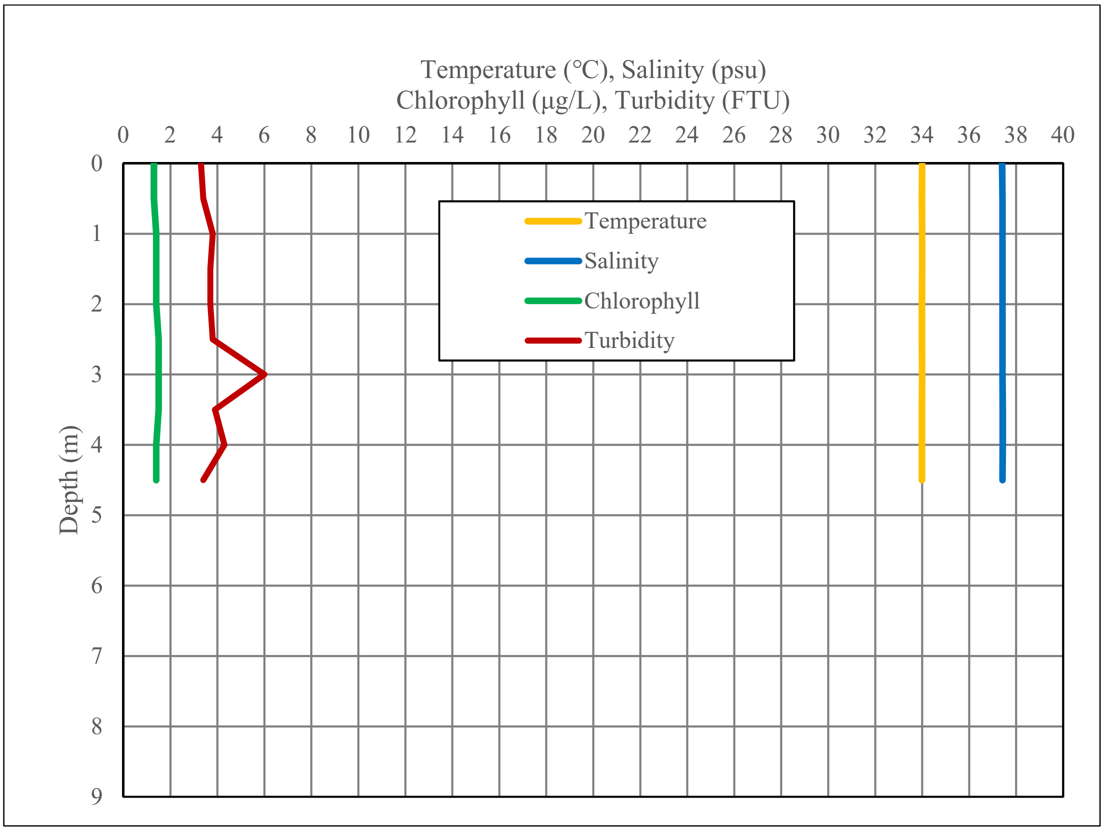


(Sep. 29 2017, 10:36)



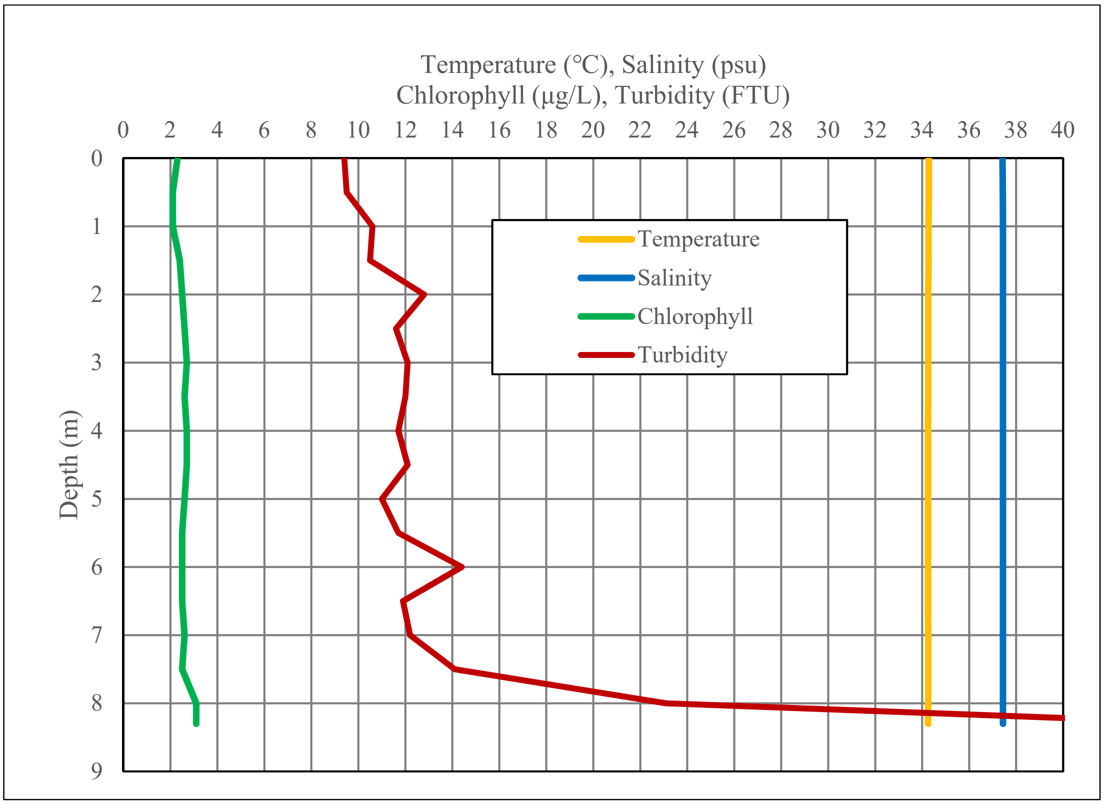
(Aug. 3 2017, 10:20)

(2) Souza



(Aug. 12 2017, 08:08)

(3) Kouvei (Dargahan)



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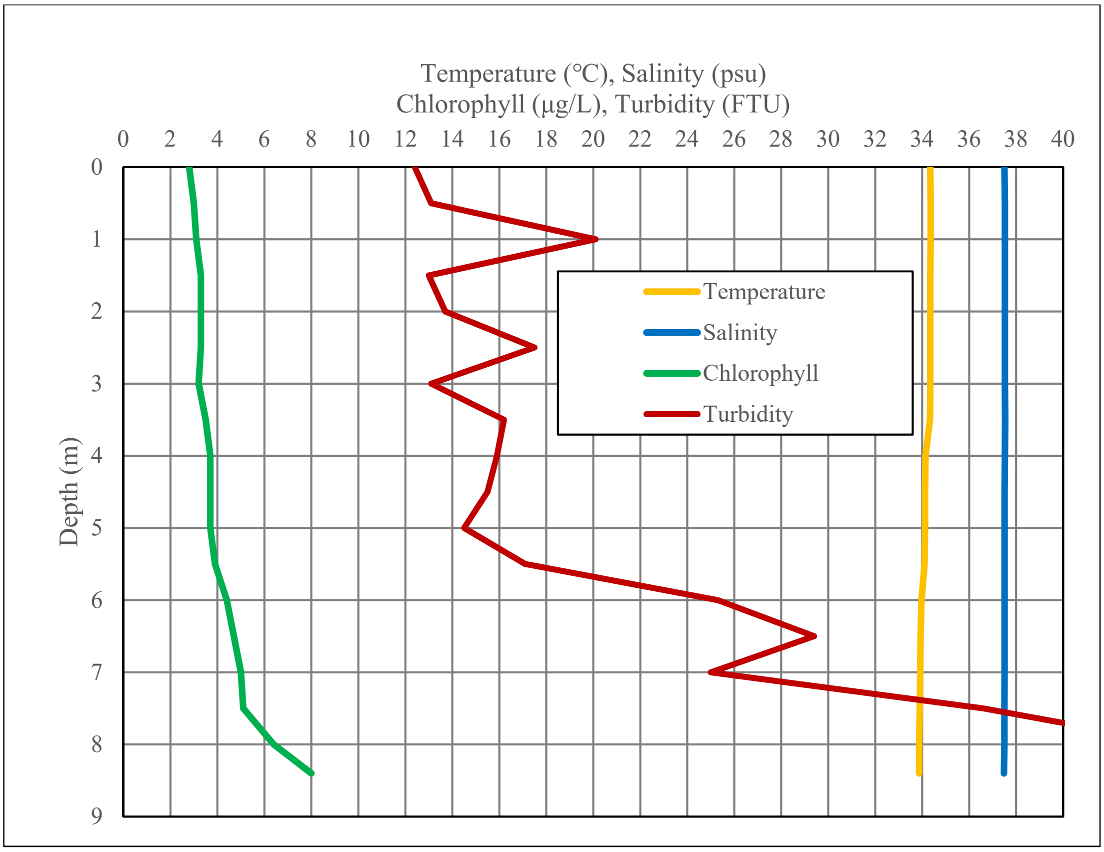
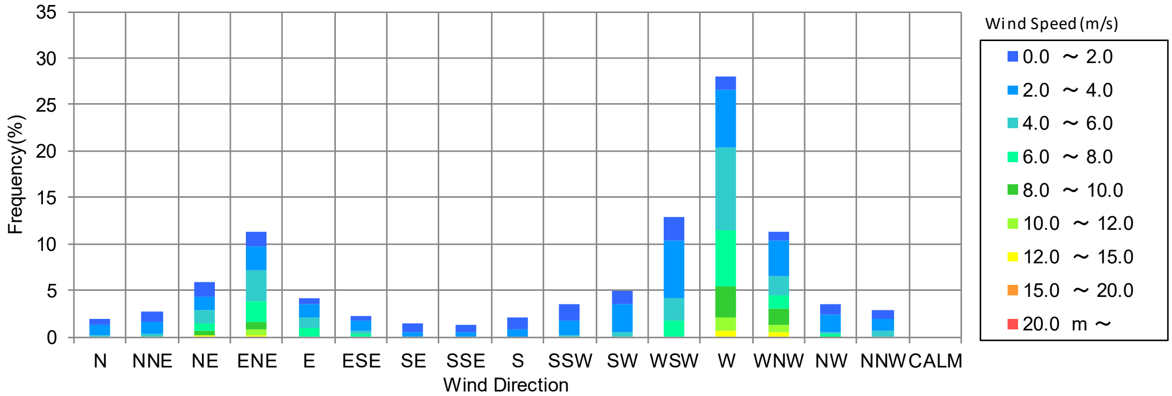
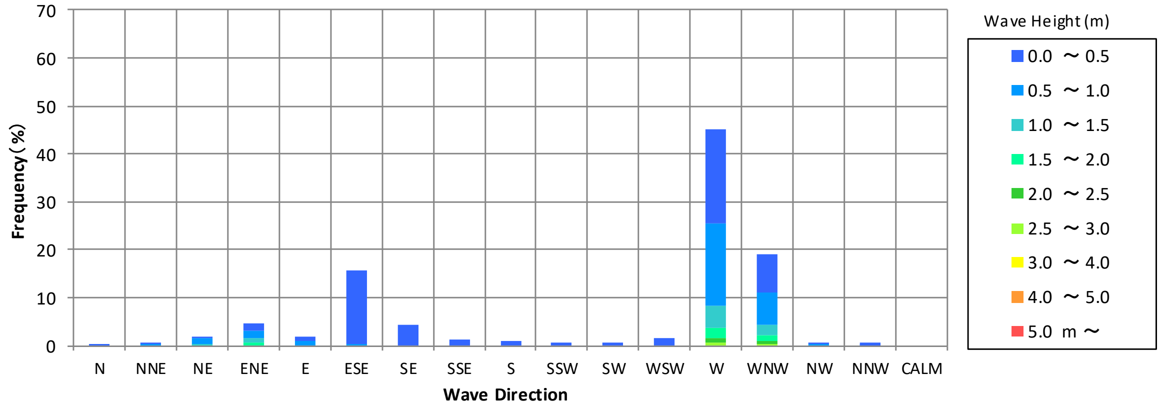


(Aug. 12 2017, 15:20)

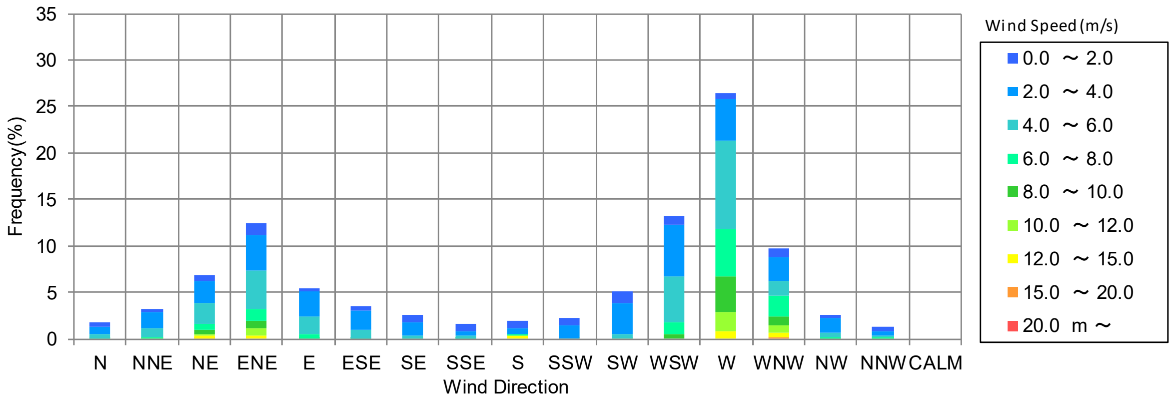
Attachment 7 Offshore Wind and Wave by Simulation for 3 years (Lat: 26.0°N, Lon: 55.0°E, 2014 to 2016)

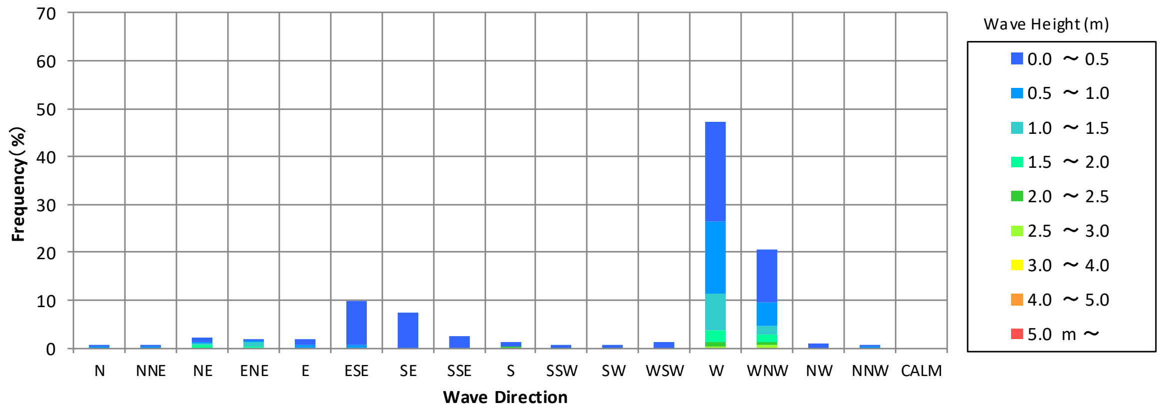
(1) January



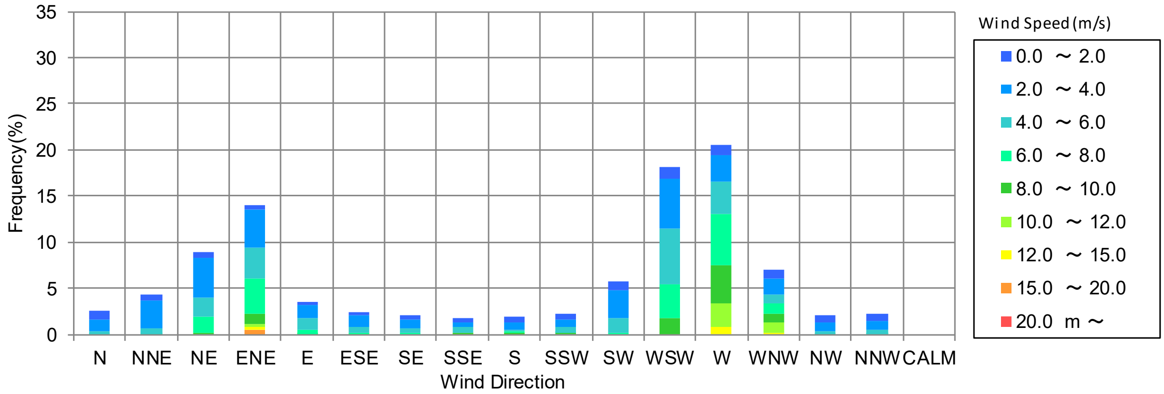


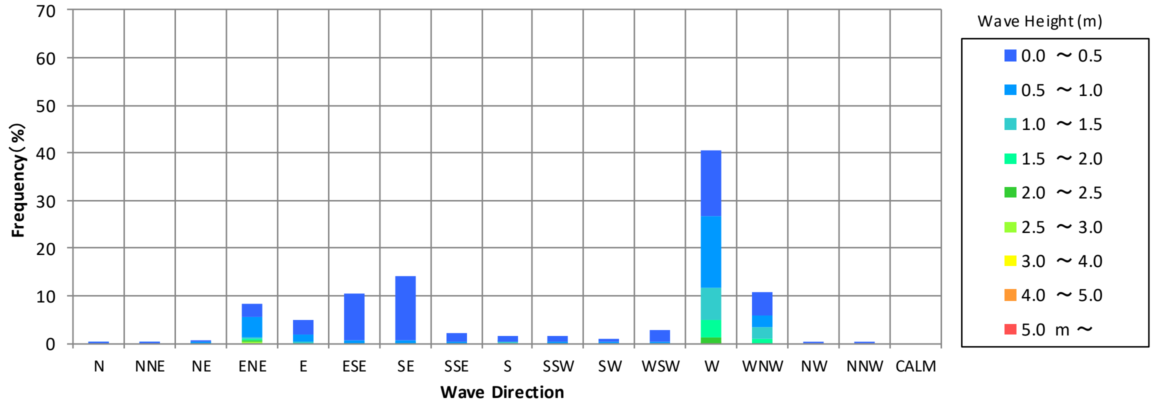
(2) February



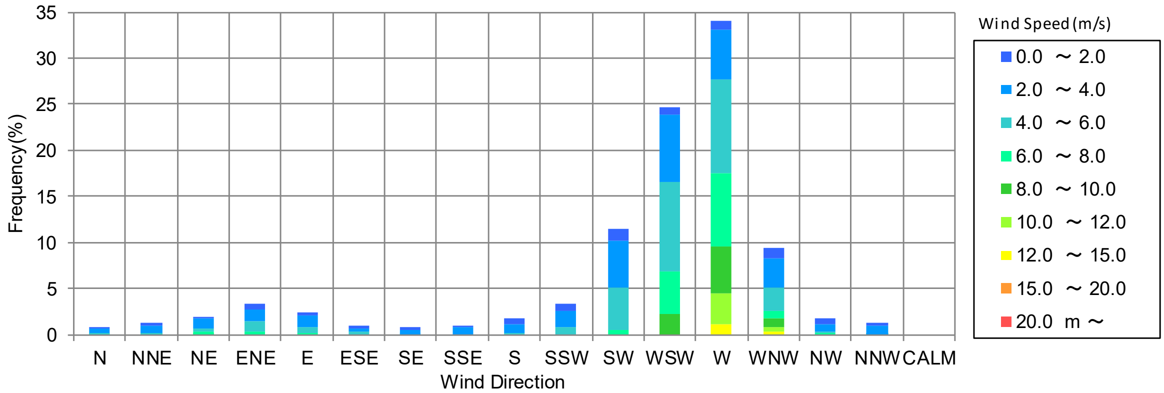


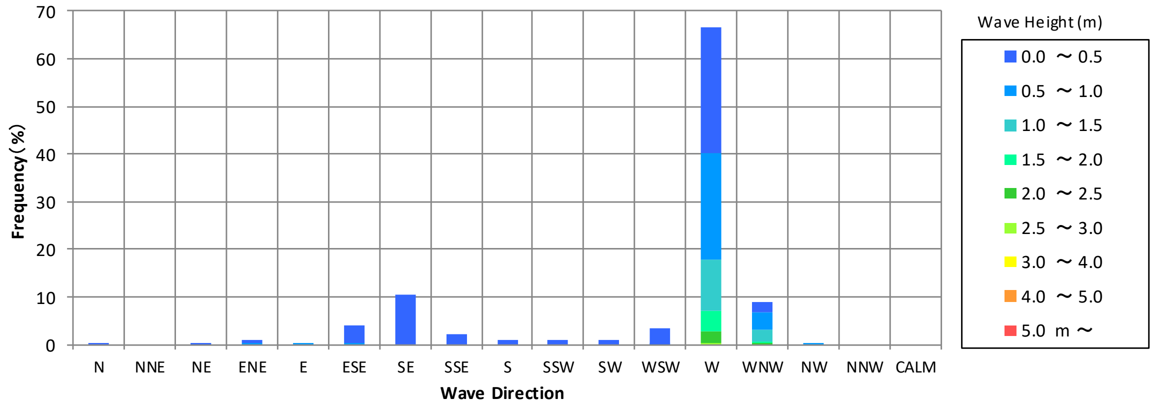
(3) March



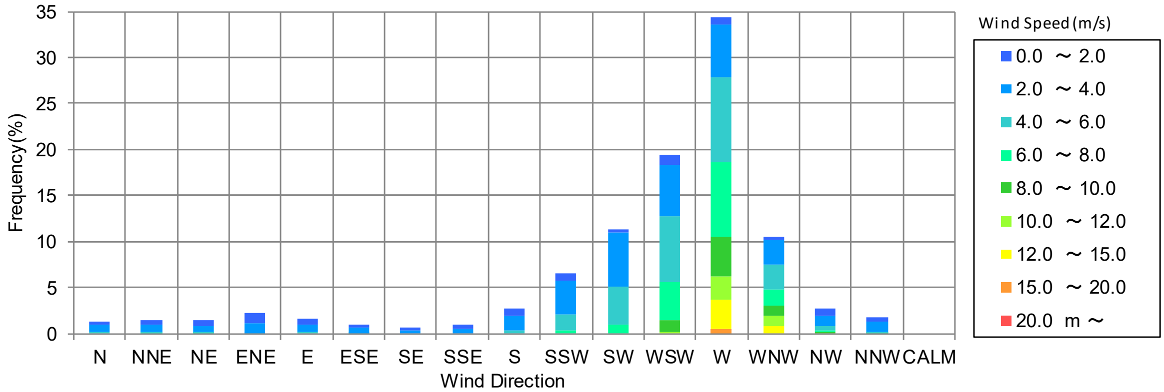


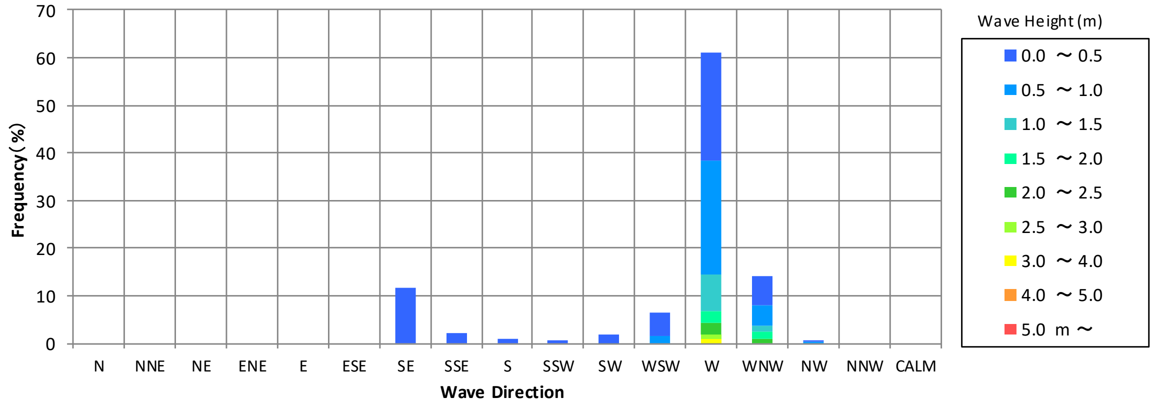
(4) April



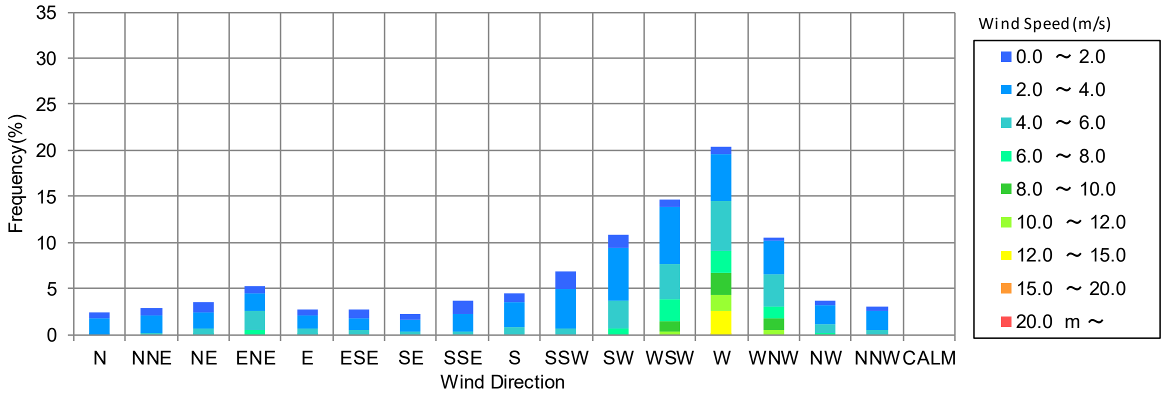


(5) May


Frequency(%)
N NNE NE ENE E ESE SE SSE S SSW SW WSW W WNW NW NNW CALM
Wind Direction
Wind Speed (m/s)
0.0 ～ 2.0
2.0 ～ 4.0
4.0 ～ 6.0
6.0 ～ 8.0
8.0 ～ 10.0
10.0 ～ 12.0
12.0 ～ 15.0
15.0 ～ 20.0
20.0 m ～


Frequency(%)
N NNE NE ENE E ESE SE SSE S SSW SW WSW W WNW NW NNW CALM
Wave Direction
Wave Height (m)
0.0 ～ 0.5
0.5 ～ 1.0
1.0 ～ 1.5
1.5 ～ 2.0
2.0 ～ 2.5
2.5 ～ 3.0
3.0 ～ 4.0
4.0 ～ 5.0
5.0 m ～

(6) June


Frequency(%)
N NNE NE ENE E ESE SE SSE S SSW SW WSW W WNW NW NNW CALM
Wind Direction
Wind Speed (m/s)
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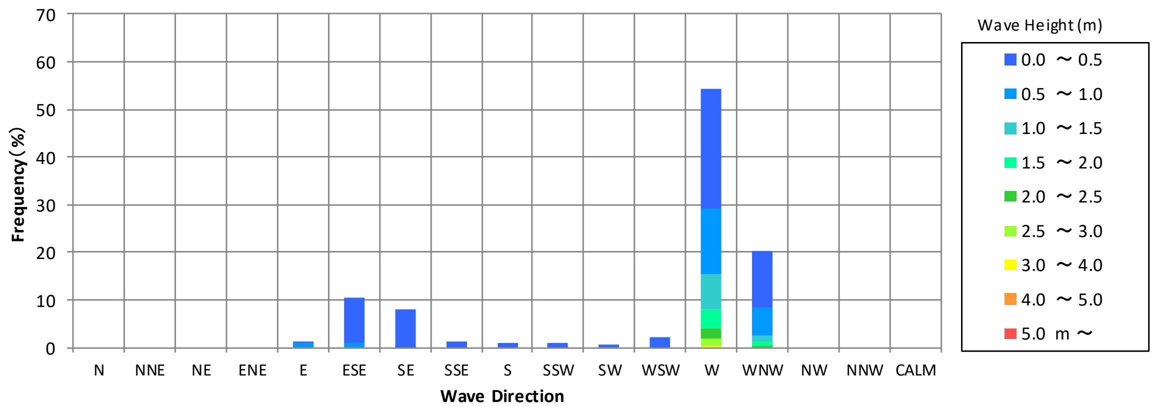
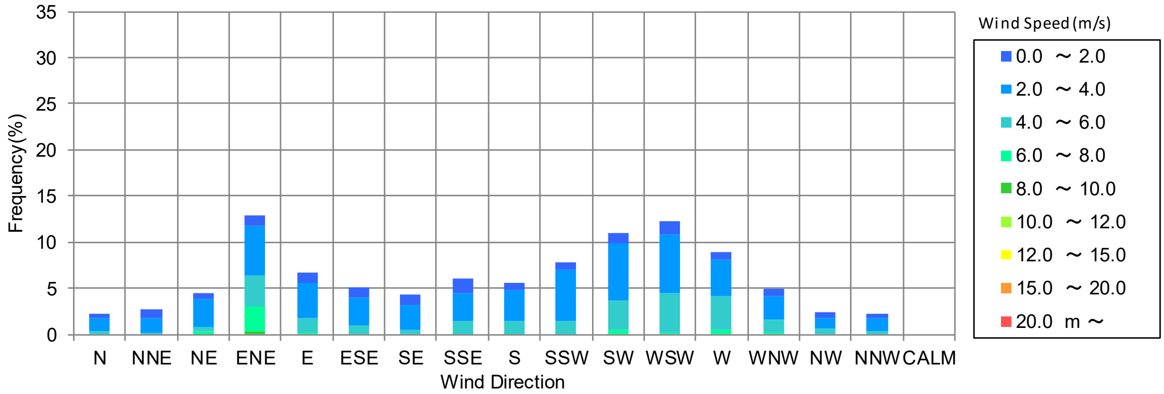
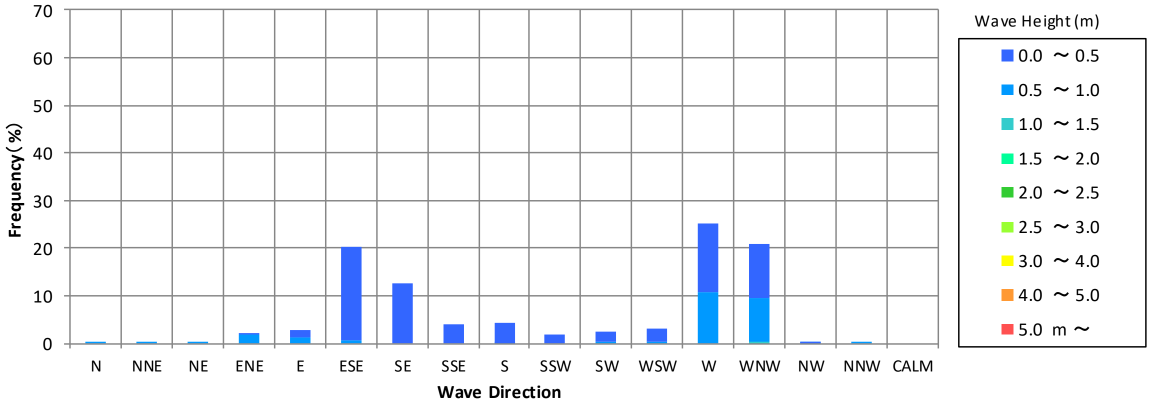
2.0 ～ 4.0
4.0 ～ 6.0
6.0 ～ 8.0
8.0 ～ 10.0
10.0 ～ 12.0
12.0 ～ 15.0
15.0 ～ 20.0
20.0 m ～

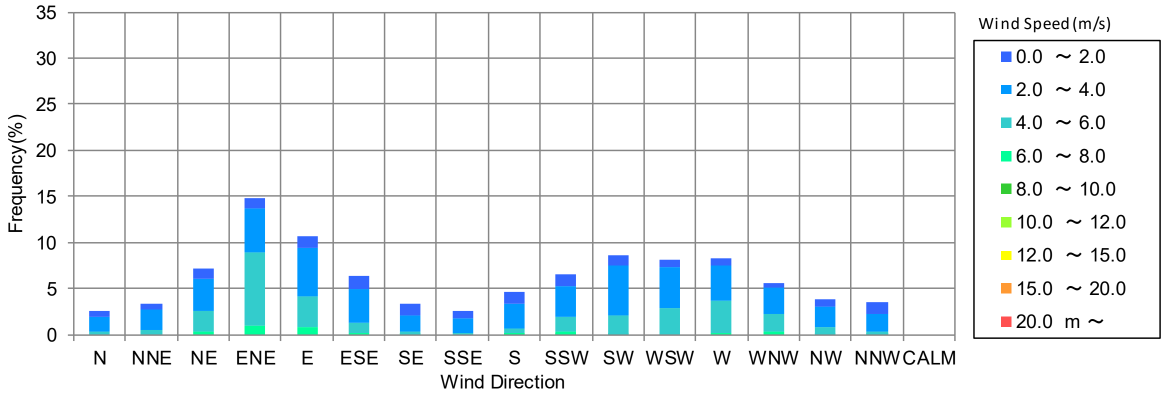

Frequency(%)
N NNE NE ENE E ESE SE SSE S SSW SW WSW W WNW NW NNW CALM
Wave Direction
Wave Height (m)
0.0 ～ 0.5
0.5 ～ 1.0
1.0 ～ 1.5
1.5 ～ 2.0
2.0 ～ 2.5
2.5 ～ 3.0
3.0 ～ 4.0
4.0 ～ 5.0
5.0 m ～

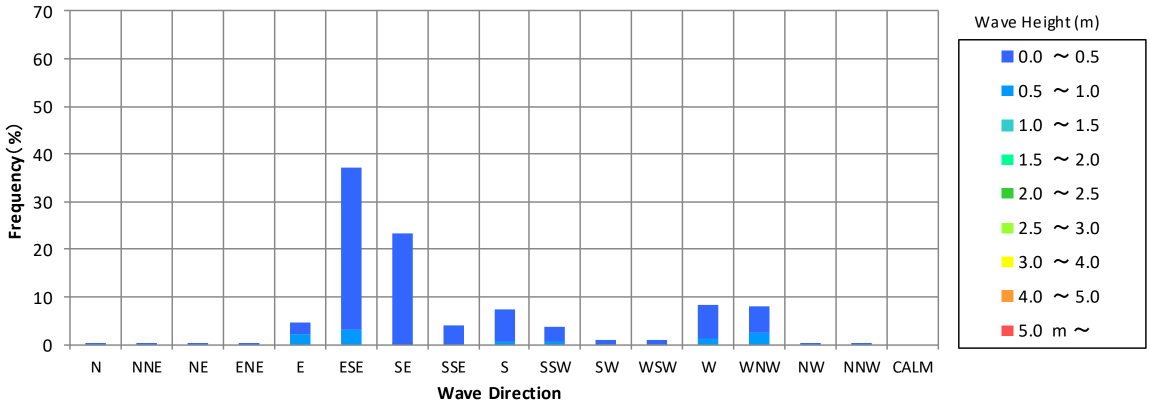
(7) July





(8) August





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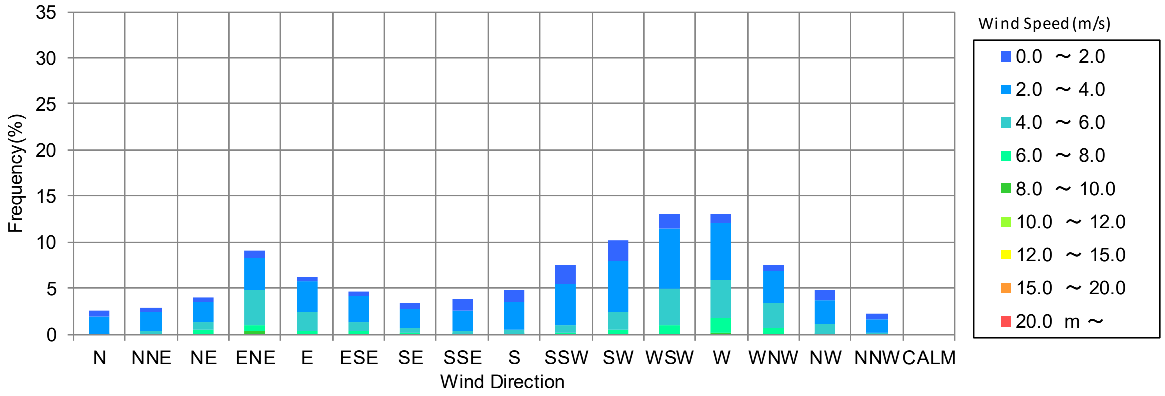
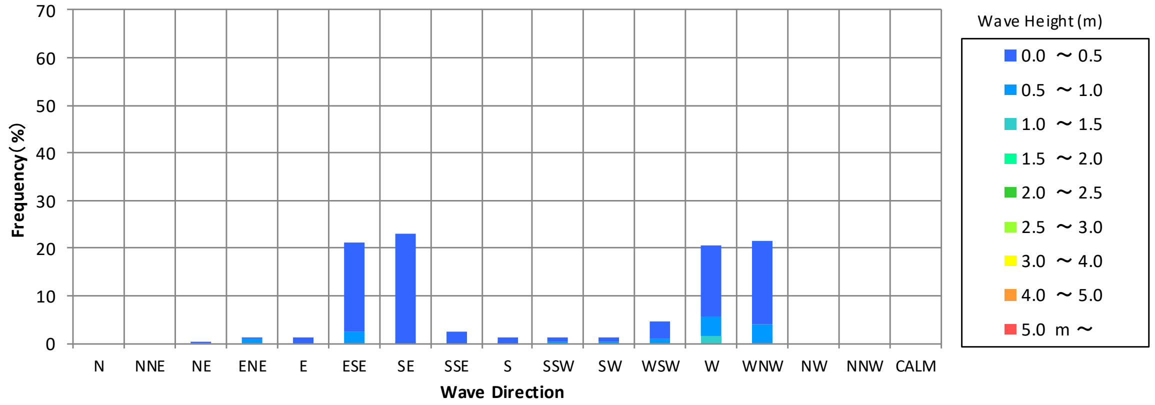
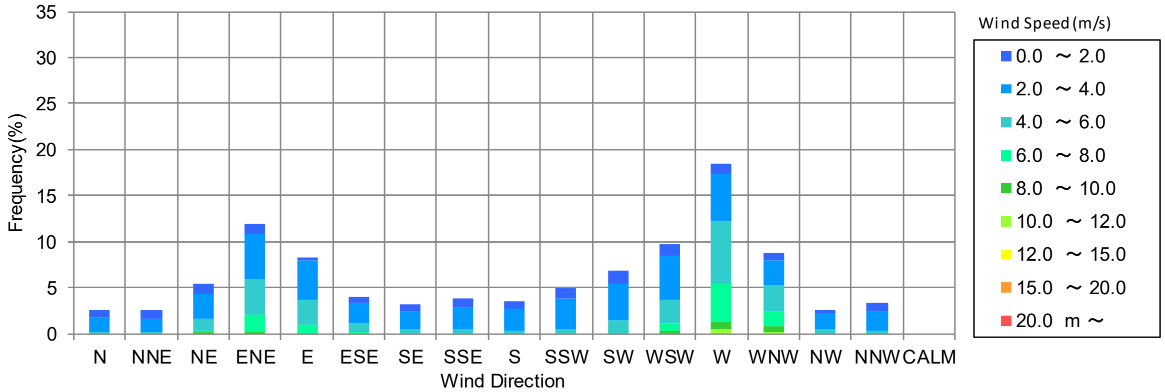
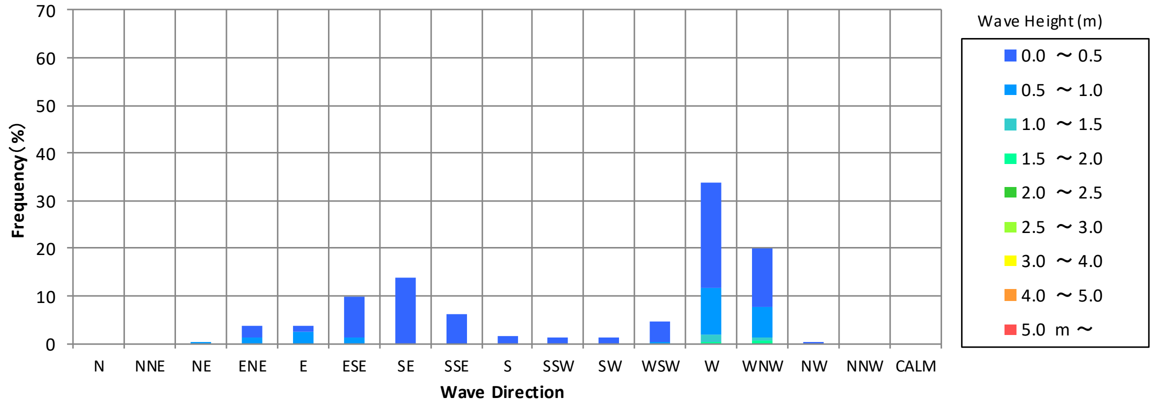


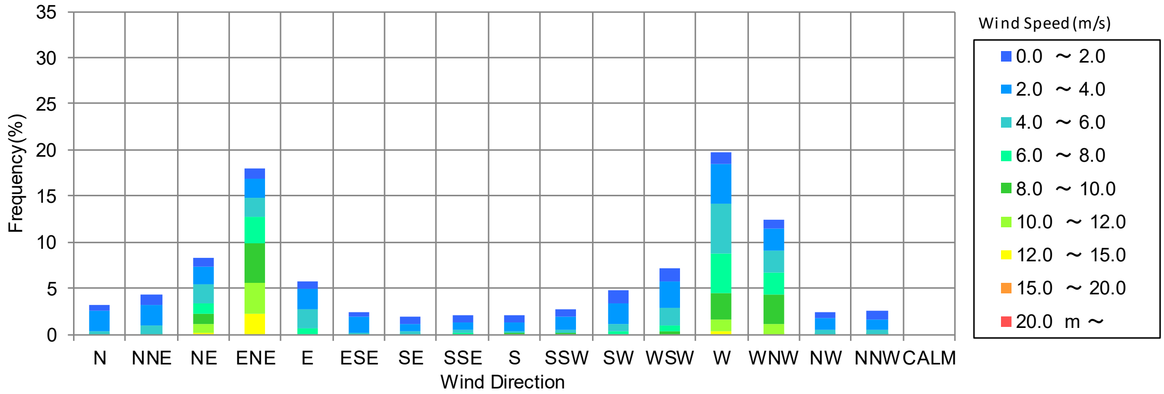


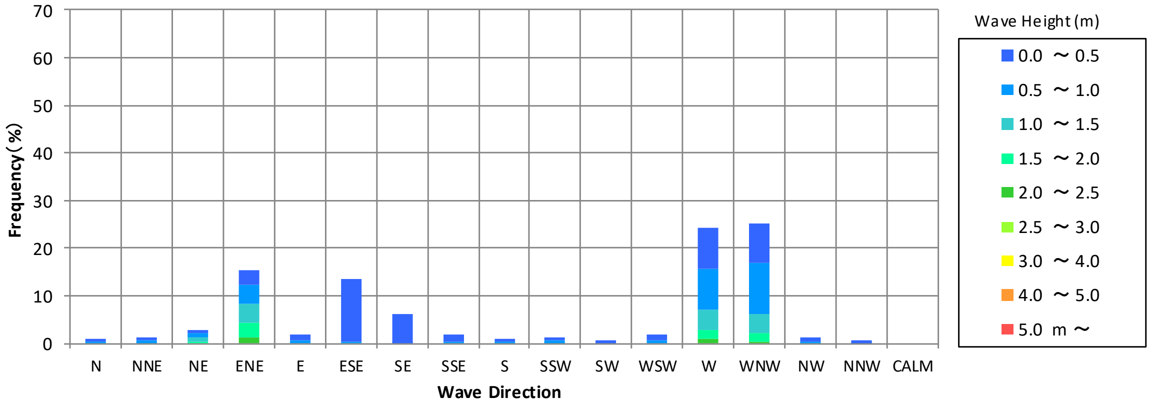
(10) October





(11) November





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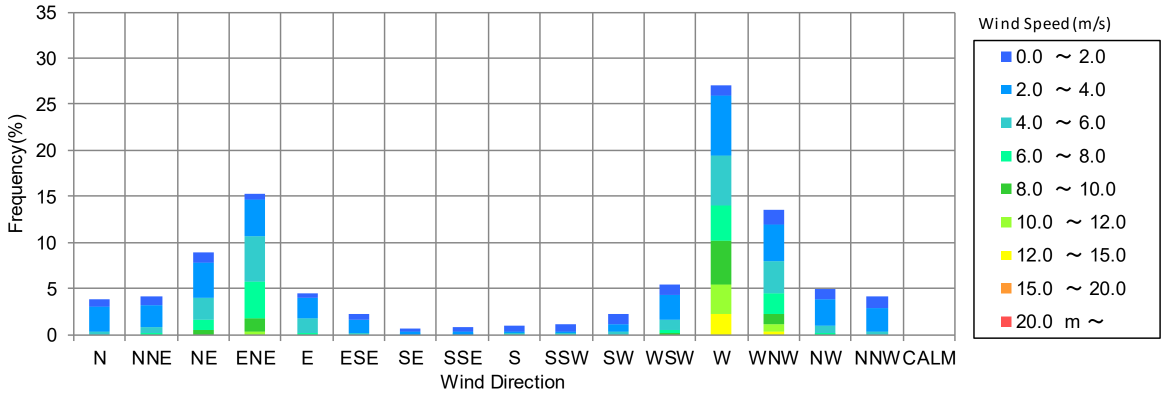
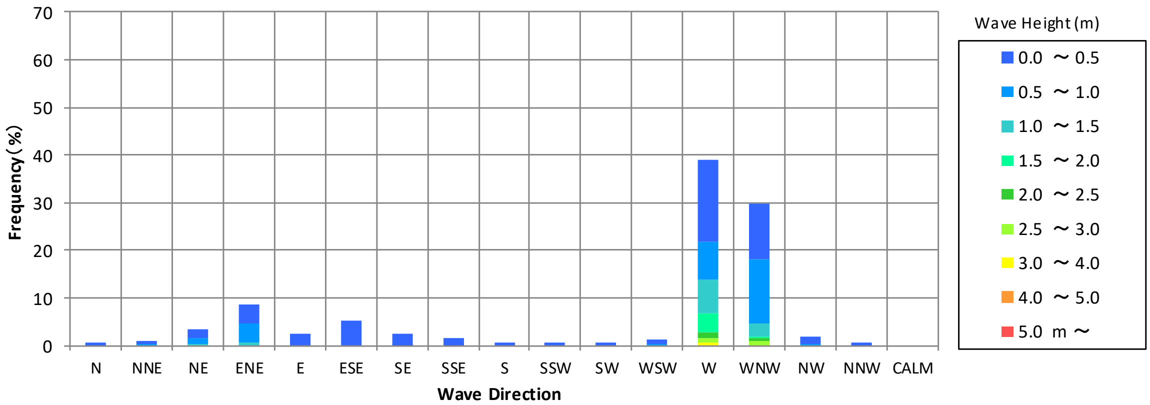




Attachment 8 Energy Charter Signatories and Observers

Energy Charter Signatories and Observers as of Nov. 2017			
Members of the Energy Charter Conference			
		All Signatories and Contracting Parties to the Energy Charter Treaty are Members of the Energy Charter Conference:	
		Country	Note
	1	Afghanistan	
	2	Albania	
	3	Armenia	
	4	Australia	Signatory but not concluded
	5	Austria	
	6	Azerbaijan	
	7	Belarus	Signatory but not concluded
	8	Belgium	
	9	Bosnia and Herzegovina	
	10	Bulgaria	
	11	Croatia	
	12	Cyprus	
	13	Czech Republic	
	14	Denmark	
	15	Estonia	
	16	European Union	International Organization
	17	Euratom	International Organization
	18	Finland	
	19	France	
	20	Georgia	
	21	Germany	
	22	Greece	
	23	Hungary	
	24	Iceland	
	25	Ireland	
	26	Japan	
	27	Kazakhstan	
	28	Kyrgyzstan	
	29	Latvia	
	30	Liechtenstein	
	31	Lithuania	
	32	Luxembourg	
	33	Malta	
	34	Moldova	
	35	Mongolia	
	36	Montenegro	
	37	The Netherlands	
	38	Norway	Signatory but not concluded
	39	Poland	
	40	Portugal	
	41	Romania	
	42	Russian Federation	Signatory but not concluded
	43	Slovakia	
	44	Slovenia	
	45	Spain	
	46	Sweden	
	47	Switzerland	
	48	Tajikistan	
	49	The former Yugoslav Republic of Macedonia	
	50	Turkey	
	51	Turkmenistan	
	52	Ukraine	
	53	United Kingdom	
	54	Uzbekistan	

Observers to the Energy Charter Conference

A. Signatories of the European Energy Charter (1991)

All Signatories of the European Energy Charter (1991) are Observers to the Energy Charter Conference. Signatories which are also Signatories of or Contracting Parties to the Energy Charter Treaty are Members of the Energy Charter Conference.

1	Burundi
2	Canada
3	Chad
4	Indonesia
5	Italy
6	Jordan
7	Mauritania
8	Morocco
9	Niger
10	Pakistan
11	Palestine
12	Serbia
13	Syria
14	United States
15	Yemen

B. Signatories of the International Energy Charter (2015)

All Signatories of the International Energy Charter (2015) - other than the ones which also signed the European Energy Charter (1991) - are Observers to the Energy Charter Conference.

1	Bangladesh
2	Benin
3	Burkina Faso
4	Cambodia
5	Chile
6	China
7	Colombia
8	Gambia
9	Guatemala
10	Iran
11	Iraq
12	Kenya
13	Mali
14	Nigeria
15	Republic of Korea
16	Rwanda
17	Senegal
18	Swaziland
19	Tanzania
20	Uganda

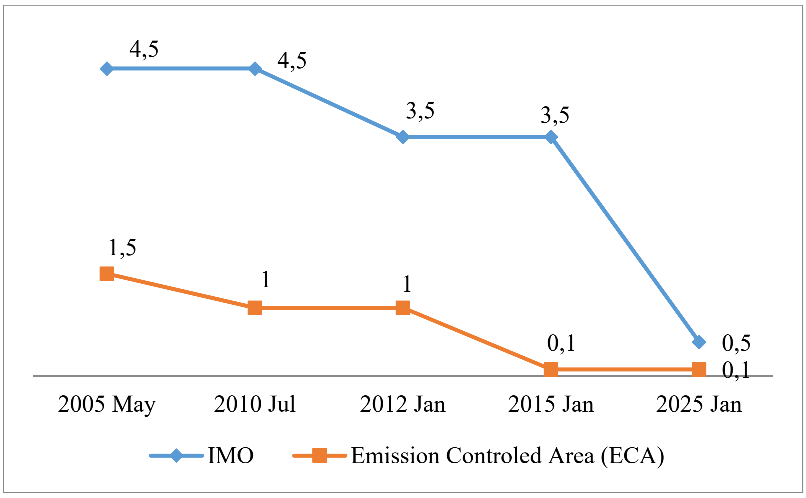
C. International Organisations with Observer Status

1	Association of Southeast Asian Nations (ASEAN)
2	Baltic Sea Region Energy Cooperation (BASREC)
3	Organisation of the Black Sea Economic Cooperation (BSEC)
4	CIS Electric Power Council
5	Economic Cooperation Organization
6	European Bank for Reconstruction and Development (EBRD)
7	International Energy Agency
8	International Renewable Energy Agency (IRENA)
9	Organisation for Economic Co-operation and Development (OECD)
10	United Nations Economic Commission for Europe (UNECE)
11	The World Bank
12	World Trade Organization
13	East African Community
14	Economic Community of Central African States
15	Economic Community of West African States
16	G5 Sahel

Part 2 Bunkering Business

CHAPTER 7 CHANGE TO MARINE FUEL SPECIFICATION IN INTERNATIONAL MARITIME TRANSPORT

Marine fuel specification is changing. Marine fuel is produced at refinery waste dumping sites and injected into the marine fuel pool for sale. Sulfur oxides and other pollutants have been spread across the ocean as a result. To prevent the further spread of pollutants into the ocean, the IMO (International Maritime Organization) has set out marine fuel standards to limit the sulfur concentration. The standard is described in the MARPOL Treaty for the signatory countries to observe. The development of sulfur concentration in marine fuel is shown in Figure 7.1.



Source: JICA Project Team.

Figure 7.1 Marine Fuel Sulfur Standard (%)

(1) Marin fuel specification and fuel demand projection

At the moment, various grades of marine fuel are used, as shown in Table 7.1 below. IFO 380 and IFO 180, which are HSFO (High Sulfur Fuel Oil), have been used as a major fuel in the majority of large ocean-going vessels.

Further to the IMO standard, tighter regulation has been in place in the area of the Baltic Sea and the international waterway between North America and Europe; these are known as Emission Controlled Area (ECA). Marine fuel requirements have been changed significantly and LNG-fueled vessels have started to be introduced. The following table includes the IMO specifications current in use:

Table 7.1 Marine Fuel Specification

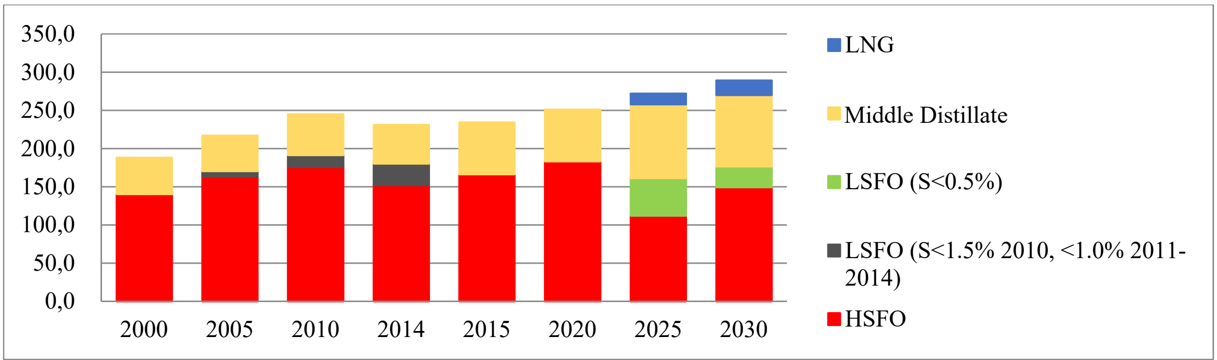
Item	Description
Product type	IFO 380: max. viscosity of 380 cSt (<3.5% sulfur) IFO 180: max. viscosity of 180 cSt (<3.5% sulfur) LS 380: low sulfur (<1.0%) with a max. viscosity of 380 cSt LS 180: low sulfur (<1.0%) with a max. viscosity of 180 cSt MDO: marine diesel oil (blend of MGO and HSFO) MGO: marine gas oil (distillate fuel oil) LSMGO: low sulfur (<0.1%) MGO used in EU ports and anchorages ULSMGO: ultra-low-sulfur MGO (sulfur 0.0015% max.) in the US
Specification	Viscosity at 50°C mm²/s (cSt) Density at 15°C kg/m³ CCAI (Calculated Carbon Aroma Index) Sulfur wt% Flash point °C Hydrogen sulfide mg/kg Acid number mg KOH/g (potassium hydrate) Total sediment wt % Carbon residue, wt% Water volume % Ash wt% Vanadium mg/kg Sodium mg/kg

Source: JICA Project Team.

Marine fuel requirements changed after sulfur concentration was limited to 3.5% in 2012. Since the availability of LSFO (Low Sulfur Fuel Oil) is very limited on the world market, the demand for middle distillate products, known as MDO and MGO, has been increasing (Figure 7.2). After 2025, sulfur regulation will be further tightened and the choice of marine fuel will be:

- Super LSFO with 0.5% sulfur
- Middle distillate
- LNG
- HSFO with scrubber

In case existing vessels need to continue to use HSFO, they must be equipped with scrubber to meet the emission standard. The cost of investing in scrubber will be reflected in the cost of HSFO, such that the price level of HSFO will be discounted to support the economics of scrubber installation.

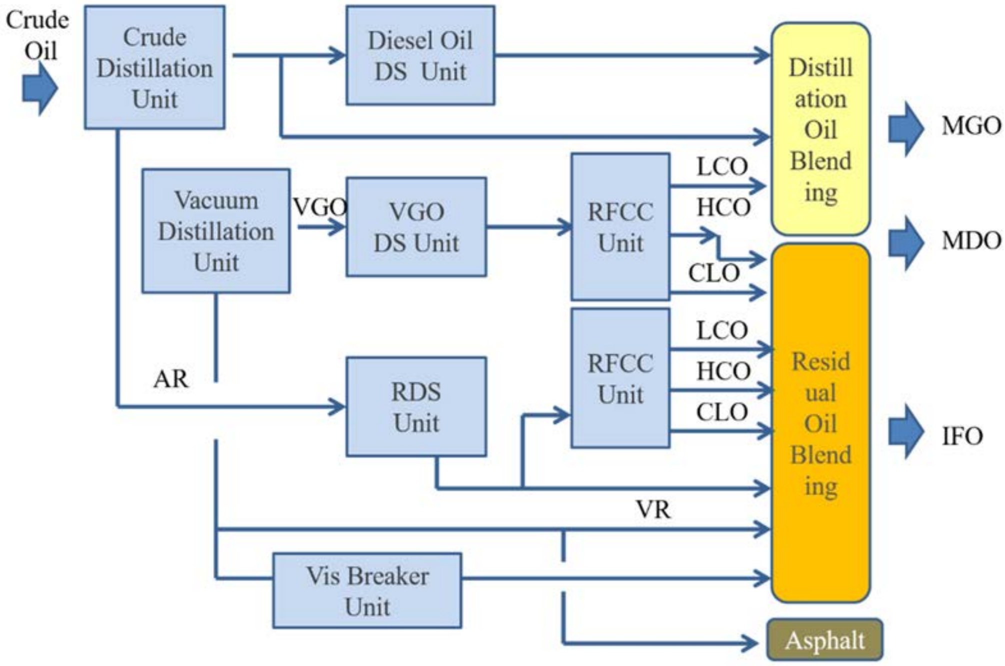


Source: JICA Project Team.

Figure 7.2 Marine Fuel Demand Forecast (Million Tons)

(2) Impact on refinery configuration

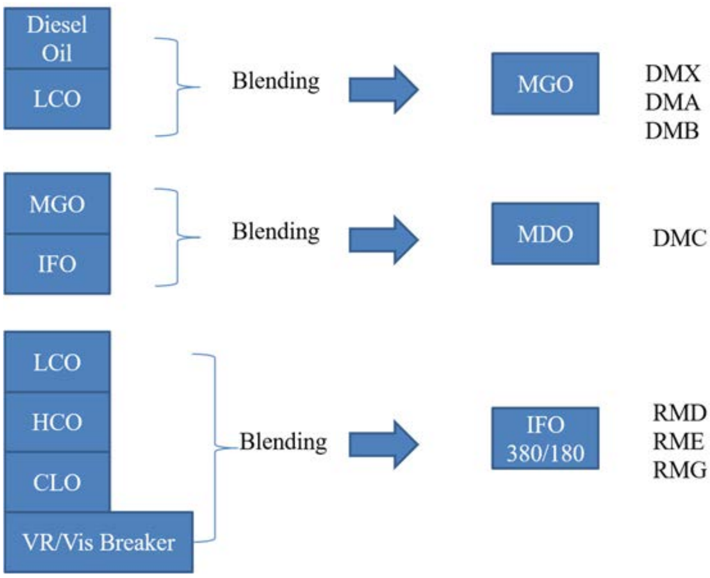
Changes in fuel specification will significantly impact refinery configurations. Refiners in Iran have relied on the marine fuel market for their high-sulfur (HS) residue disposal. However, their product will not fit with the market requirement, meaning that their residue must be processed by constructing upgrading facilities for residue fluid catalytic cracking (RFCCU), residue desulfurization (RDS) or delayed coker, for example. Investment costs for these facilities will be significant. In the case of current refining margins (i.e., 4-5 USD/bbl), investment in these facilities may not be necessarily justified.



Note: AR: atmospheric residue, CLO: clarified oil, HCO: heavy cycle oil, IFO: intermediate fuel oil, LCO: light cycle oil, MDO: marine diesel oil, MGO: marine gas oil, RDS: residue desulfurization, RFCC: residue fluid catalytic cracking, VGO: vacuum gas oil, VR: vacuum residue.
Source: JICA Project Team.

Figure 7.3 Typical Modern Refinery Configuration Including Marine Fuel Production

Figure 7.4 presents the schematics for the blending system for refinery products.

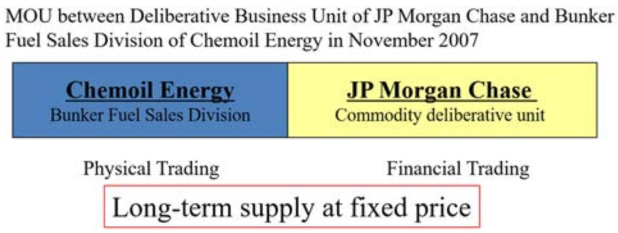


Note: CLO: clarified oil, HCO: heavy cycle oil, IFO: intermediate fuel oil, LCO: light cycle oil, MDO: marine diesel oil, MGO: marine gas oil.
Source: JICA Project Team.

Figure 7.4 Marine Fuel Blending

CHAPTER 8 CHANGE TO MARINE FUEL SALES PRACTICE

Sales mechanisms for marine fuel have changed following the development of the marine fuel physical market and the opening of the futures market. Prices of marine fuel vary hourly and daily. Buyers of marine fuel need to buy from an ever-changing market, which affects their transportation cost. Chemoil and the investment bank JP Morgan Chase entered into an agreement in November 2007 to provide long-term supply services at a flat rate using the hedging mechanism for the futures market (Figure 8.1). The agreement is configured for Chemoil, one of the largest bunker fuel sales company, to take part in physical trading and for JP Morgan Chase to take part in financial trading. Their business arrangement has been successful resulting in the world's largest marine fuel supplier.



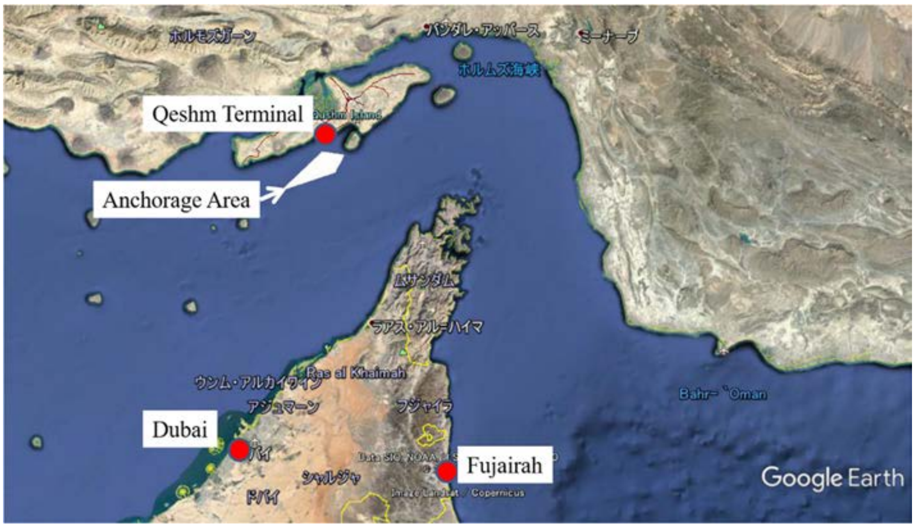
Source: JICA Project Team.

Figure 8.1 Memorandum of Understanding Between Chemoil and JP Morgan for Marine Fuel Supply

CHAPTER 9 BUNKERING BUSINESS ON QESHM ISLAND

9.1 Geographical Advantages of the Island

Qeshm is located in the middle of the Strait of Hormuz, the most important strategic area in the world, because of oil traffic. 17 million bpd (30% of world oil tanker traffic) of crude oil are exported through the strait, 22% of which is destined to Europe and the rest to Asian countries. On top of this crude oil traffic, numerous commercial vessels, such as oil product tankers and container ships, pass by the coast of Qeshm Island. An international anchorage area, in which commercial vessels can stop for bunkering and other purposes, is designated for the south of Qeshm Island (Figure 9.1).



Source: Google Earth for imagery.

Figure 9.1 Location of Qeshm Island and International Anchorage Area

9.2 Bunkering Facility on Qeshm

Qeshm Star Bunkering and Shipping Services Co. (QSBS) completed the first phase of its bunker fuel storage and supply facility in Selakh, Qeshm, in January 2017. The primary enterprise started as a bunkering company in Bandar Abbas 30 years ago.

It found Qeshm to be ideal site for a bunkering business due to the island's immediate accessibility to the international waterway. The company, which can currently provide water and food to vessels, is also considering the provision of accommodation for crew members while vessels are berthing and fueling, on the basis that Qeshm is an island with tourist attractions. The current storage capacity is 52,000 kl and will be expanded to 750,000 kl.

Project Phase 1 consist of following facilities,

- Cargo tank: 9 for heavy oil, 1 for gas oil
  - ✓ Tank capacity is 5,260 m^3 x 10 = 52,600 m^3 in total
- Feedstock: buy from Tabriz Refinery, Esfahan Refinery, Bandar Abbas Refinery
- Blending: fully automated German-made facility
  - ✓ Pump: 5 heavy oil pumps (250 m^3/h) and 3 gas oil pumps (150 m^3/h)
- Boiler: 3 boilers 500,000 kcal/h each
- Fresh water: membrane 250 m^3/day
- Fire pumps: 2 emergency 750m^3/h and 1 electric 750 m^3/h (6,000 V)

Initially, QSBS planned to construct a refinery adjacent to the terminal; however, considering the changing fuel requirement, i.e., low-sulfur fuel, its planned refinery will not be economically viable due to the envisaged heavy investment.

The company concludes that LNG will be a key bunkering fuel in the near future and is interested in securing benefits from the LNG project. Furthermore, it is willingly giving up the right to use land for the refinery in order to support the LNG project.

Source: Google Earth for imagery.

Figure 9.2 Oil Bunkering Facilities at Selakh on Qeshm Island

9.3 Competitors

Fujairah is one of the largest marine fuel suppliers in the world. It is primarily involved in dealing HSFO that originates from Iran. Several bunker fuel suppliers have constructed storage facilities and set up trading units in Fujairah. Bunker fuel trading players in Fujairah are listed below:

(a) Fujairah bunker fuel suppliers

- Aegean (Fujairah) Bunkering SA
- Akron Trade and Transport
- APSCO Petroleum Services
- BP Middle East
- Fairdeal Marine Services
- Fujairah National Bunkering Co. (LLC)
- Gulf Petrol Supplies
- International Supply
- Oil Marketing & Trading International (LLC)
- Pearl Marine Logistics UAE FZE
- Royal Bunkering &Trading Co., LLC
- VTTI Fujairah Terminals Ltd FZC
- Bominglot Fujairah LLC
- Caltex Alkhalij (Dubai)
- Dubai Fuel Supply (Dubai)
- FAL Energy Co., Ltd (Sharjah)
- Shell Markets Middle East, Ltd., (Dubai)
- Zad Fuel (Dubai)

(b) Storage tank operation and trading

- Vopak Horizon Fujairah Limited (2.13 million m^3)
- Horizon Terminal Ltd. (240,000 m^3)
- Fujairah Oil Terminal FZC (1.15 million m^3)
- Socar Aurora Fujairah Terminal FZC (815,000 m^3)
- GPS Chemoil LLC FZC (700,000 m^3)
- Gulf Petroleum
- Prime Star Energy FZC

Fujairah has not signed the MARPOL Treaty and appears to be continuing to supply HSFO to the market; however, margins may be discounted to cover the cost of investing in scrubber.

Source: Google Earth for imagery.

Figure 9.3 Marine Fuel Facilities at Fujairah Port

9.4 Benefit for Qeshm Island

The bunkering business is considered to be one of the best suited industries for Qeshm Island due to its geographic advantages. Qeshm is also known for its geological uniqueness (Geopark) and wildlife, which could attract vessel crew members off their ships. Qeshm is promoting tourism jointly with the JPT.

Once the bunkering business expands, vessel crews will be spending one or more nights on the island during fueling, which will benefit the following industry sectors and/or businesses:

(a) Tourism
(b) Food and water supply and agrobusinesses
(c) Accommodation
(d) Shopping (tax free)

Part 3 Methanol and Ammonia/Urea Development

CHAPTER 10 REVIEW OF PETROCHEMICAL OPPORTUNITY

10.1 Introduction

Petrochemical options were reviewed and discussed with the QFZO on August 18, 2018. Considering the nature of available gas, i.e., methane-rich gas, there are three options to be reviewed further, i.e., methanol, ammonia/urea and LNG. GTL is considered economically non-viable and has dropped off the list. An overview of the gas and gas chemical industry is shown as follows:

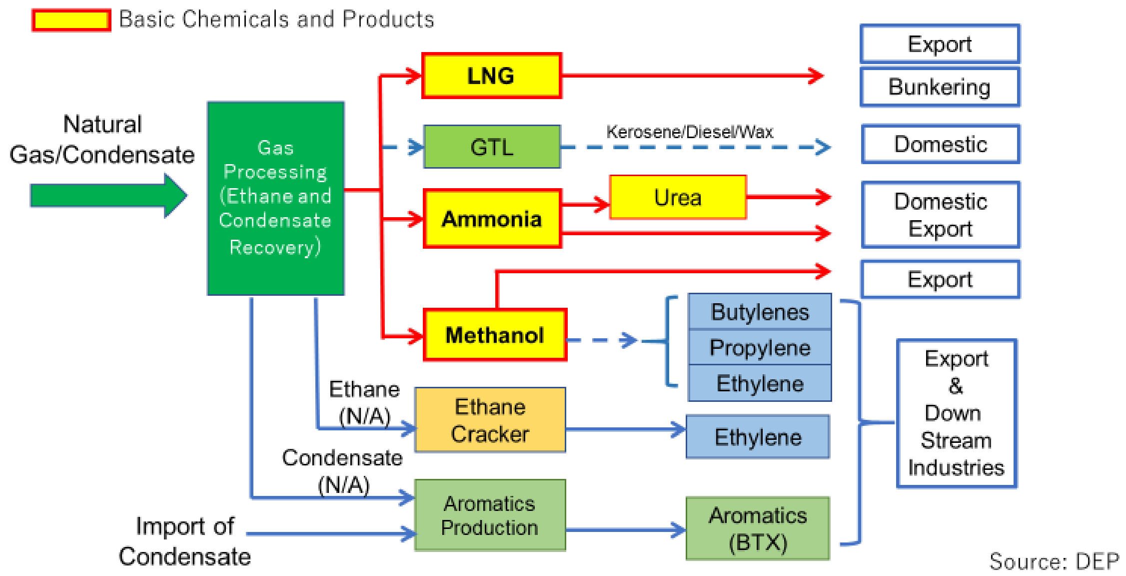


Figure 10.1 Gas and Gas Chemical Industry Overview

The selected chemical products, i.e., methanol, ammonia/urea and LNG, are known as basic chemical products and primary energy sources for power and traded worldwide.

10.2 Methanol Option

Methanol is manufactured from Syngas (hydrogen and carbon monoxide) produced from coal or methane via the partial oxidization process for coal and the steam reforming process for methane.

10.2.1 Methanol Derivatives and End Products

Methanol has been a very important basic chemical product in the petrochemical industry. In recent years, the use of methanol has been extended and started to be used as an automobile fuel alternative or a component part. It is included in the following, representing 21% of world methanol production:

- Direct use as a gasoline blend stock
- Feedstock for bio-diesel production
- DME (blend stock for diesel and LPG)

MTBE, which is used as an octane booster in a gasoline blend stock pool, accounts for 12%. Methane, which is also used as a feedstock for Olefin production and known as MTO (methane to olefin), accounts for 19% of world methanol production.

Overall, 52% of methanol has been used as an oil product alternative, mostly in China. This proportion is expected to increase further due to an increasing use of MTO and DME in China.

As for chemical use, the production of formaldehyde represents 27% of world methanol production, followed by 8% for acetic acid and 3% for chloromethane.

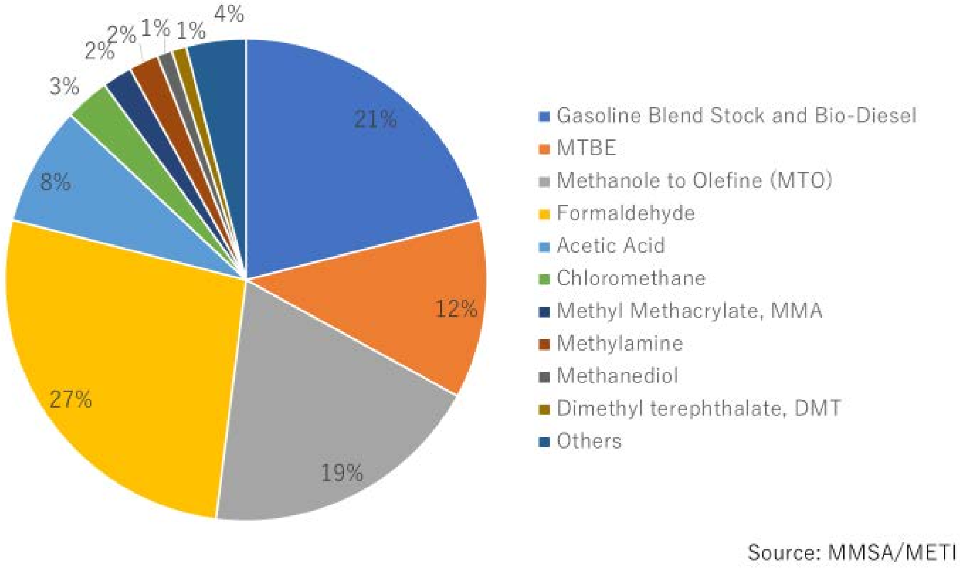


Figure 10.2 World Methanol Users in 2015

The following figure summarizes the major use of methanol, and its intermediate and end products.

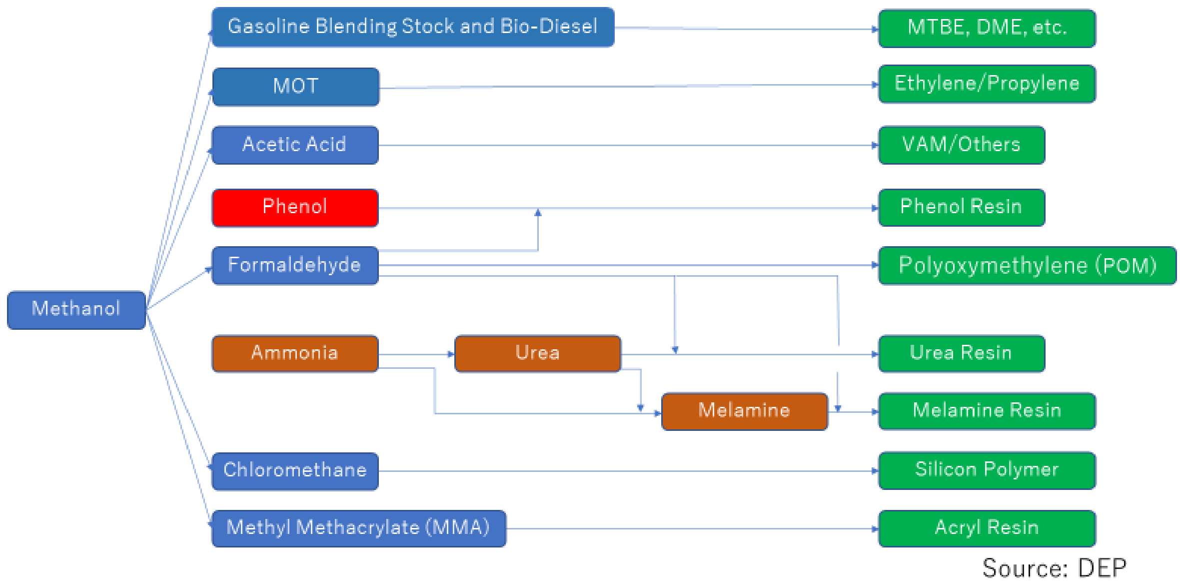


Figure 10.3 Methanol Derivatives and Final Products

10.2.2 Methanol Demand

Regarding methanol consumption in China in 2000, it accounted for 12% of world consumption. In 2015, China had a 58% share of world consumption. The majority of methanol in China has been produced from coal via the partial oxidation process.

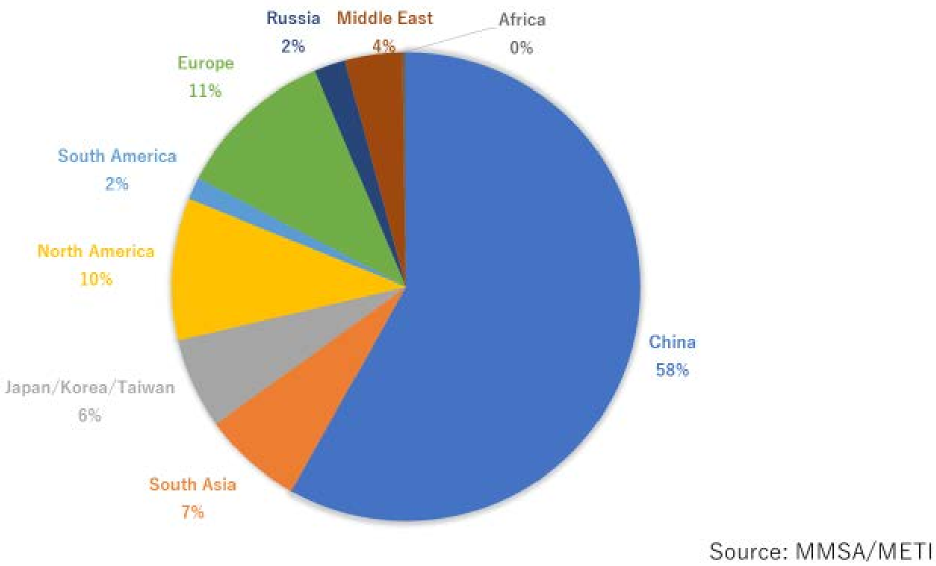


Figure 10.4 Methanol Demand by Region

Chinese demand will continue to grow until environmental capping is imposed.

10.2.3 Methanol Trade

Most of the methanol trade concerns industrial use, except in the case of China. China is the largest importer followed by the USA, the Netherlands, Japan and Germany. The largest methanol exporter is Trinidad and Tobago followed by Saudi Arabia, Oman, Iran and New Zealand.

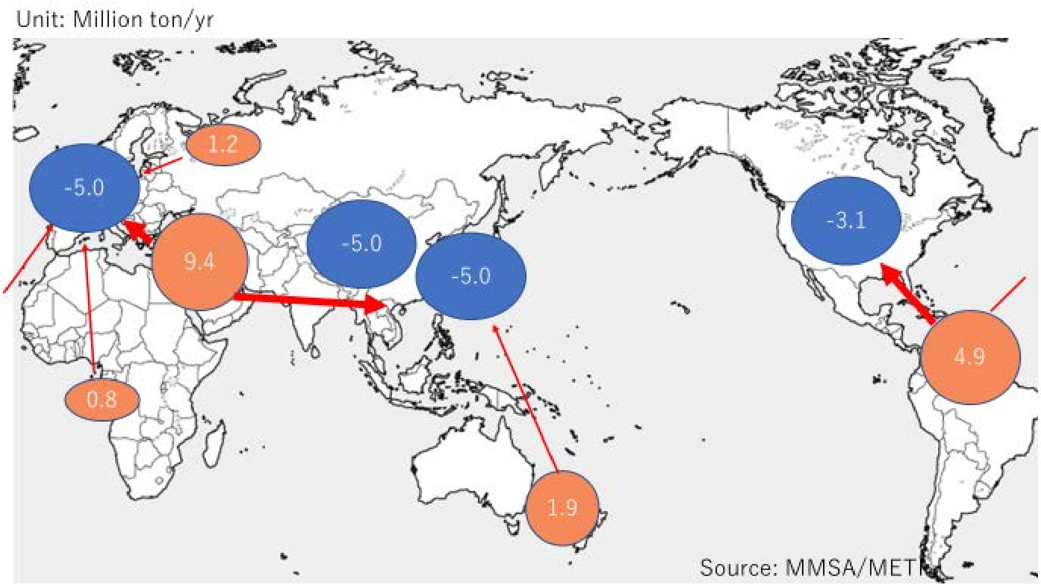
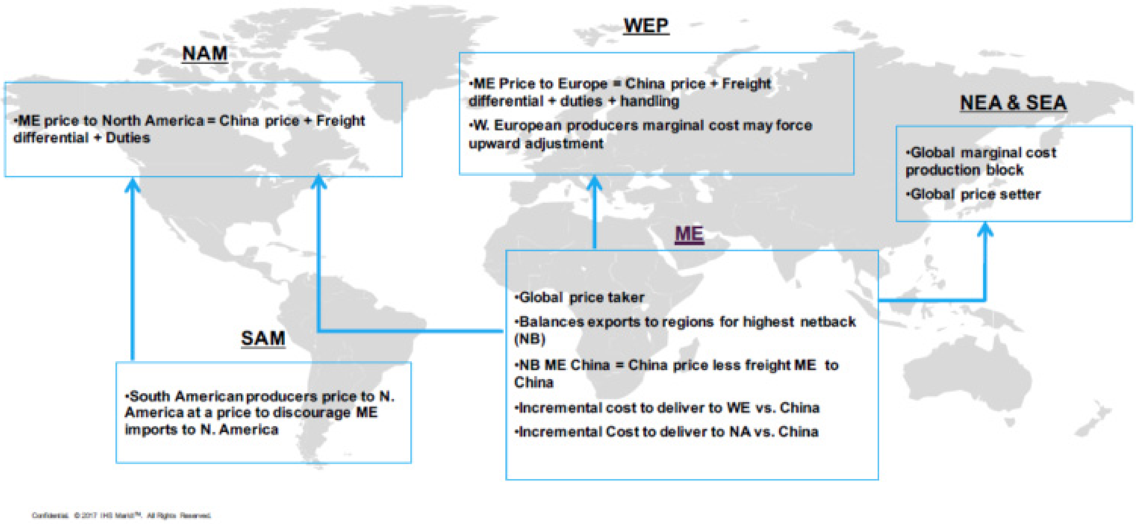


Figure 10.5 Methanol Trade in 2015

10.2.4 Methanol Pricing Structure

China is predominant in the world methanol market and works as a global price setter. International prices are influenced by the Chinese marginal coal price and capped by the affordability of MTO in China.

Under the circumstances, methanol from the Middle East works as global price taker and balances exports to regions where a higher netback is expected.



Source: HIS Market

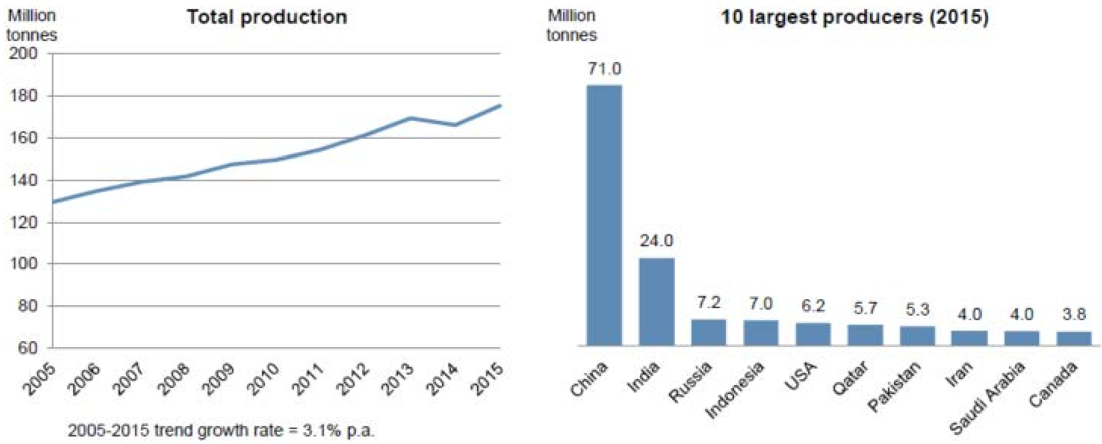
Figure 10.6 Global Methanol Price Mechanism by HIS Market

10.3 Urea/Ammonia Market Outlook

10.3.1 Global Urea Production

Urea production grew 3.1% per annum from 2005 to 2015 and is expected to grow at 1.2% between 2015 and 2025. Total production in 2015 was 178 million tons. China produced 71 million tons, representing 40% of world production. Chinese urea is produced via the coal partial oxidation process, followed by the ammonia synthesis process and the urea synthesis process.

India is the second-largest urea production country; however, Indian domestic gas production is declining and suffering from higher feedstock costs. Similarly, as gas fields in Indonesia and Pakistan are depleting, these will be listed as urea importing countries in the near future.



Source: Yara

Figure 10.7 Global Urea Production

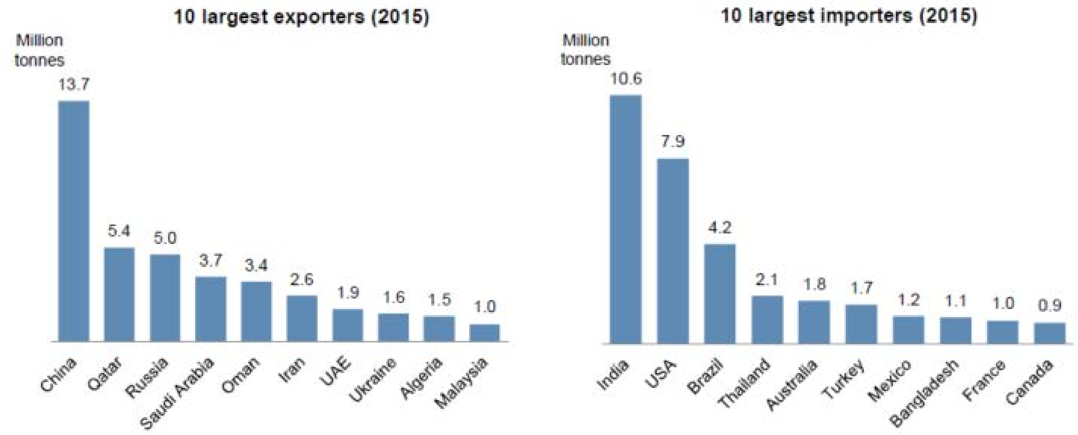
10.3.2 Global Urea Trade

(1) Urea Exports in 2015

China is the largest urea-exporting country followed by Qatar, Russia, Saudi Arabia, Oman and Iran. Russia and Ukraine were the largest urea-exporting countries and worked jointly to support the Black Sea market before 2010. In the last few years, exports from China have increased dramatically and the country is the predominant player in the world. Malaysia is exporting urea but will be listed as an importing country due to the depletion of its own gas fields.

(2) Urea Imports in 2015

Urea producing country is almost limited to gas producing countries except China. Urea is very important commodity product and exported to numbers of the countries in the world. India is the largest importer followed by USA, Brazil, and Thailand. Bangladesh has been a Urea self-sufficient county, however, they started to import Urea due to a shortage of domestic gas from existing gas field.

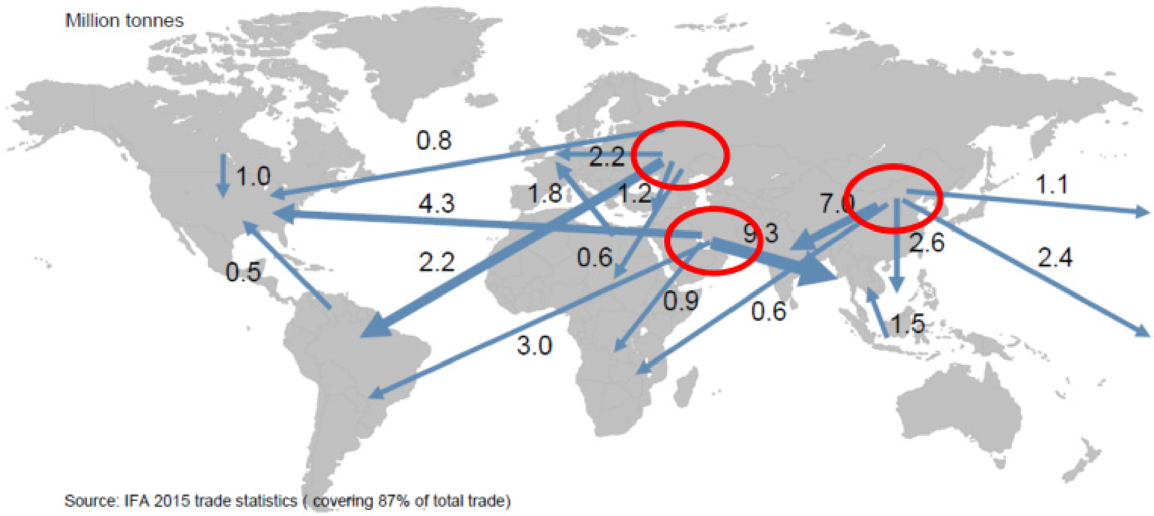


Source: Yara

Figure 10.8 Global Urea Trade

10.3.3 Urea trade flow

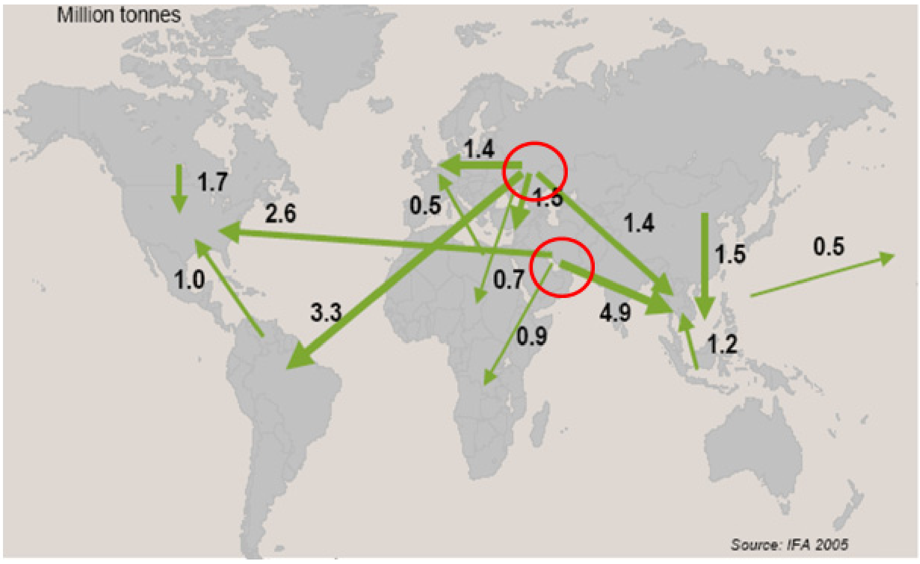
Urea is a commodity product and exported to numerous countries to support domestic food production. There are three major export centers: the Black Sea, the Middle East and China. China is the largest single exporter, but total exports from the Middle East (Qatar, Saudi Arabia, Iran and UAE) are slightly larger than those of China. The Black Sea market is declining and losing its price-setting power. The following shows the urea trade flow for 2015.



Source: Yara/IFA

Figure 10.9 Urea Trade Flow in 2015

The following shows the urea trade flow for 2005. The Black Sea market will no longer have predominant power as a price setter in the urea international market.

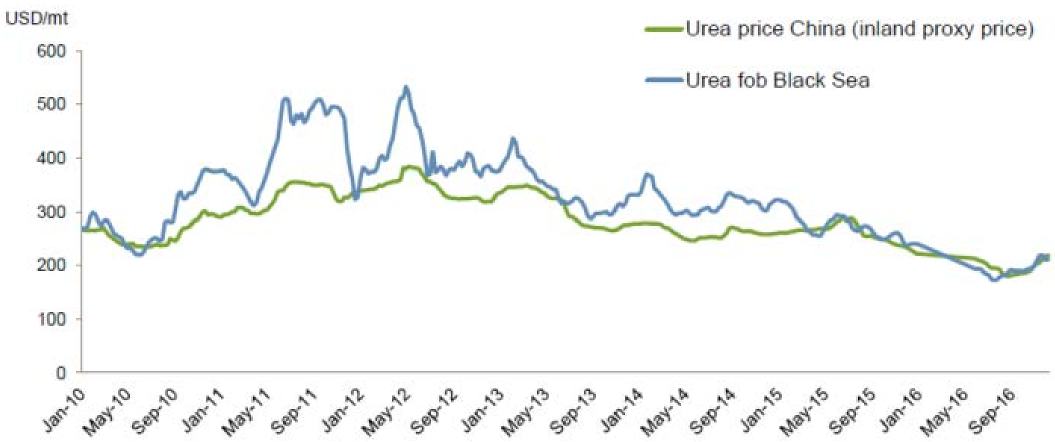


Source: Yara/IFA

Figure 10.10 Urea Trade Flow in 2005

10.3.4 Urea Market Price Mechanism

Urea international prices are influenced by the Chinese marginal coal price. The international price was reflected in gas/oil prices up to 2012. The recent increase in Chinese urea production has predominantly influenced market price-setting by disengaging international gas prices from the urea pricing mechanism and helping to minimize price fluctuations.

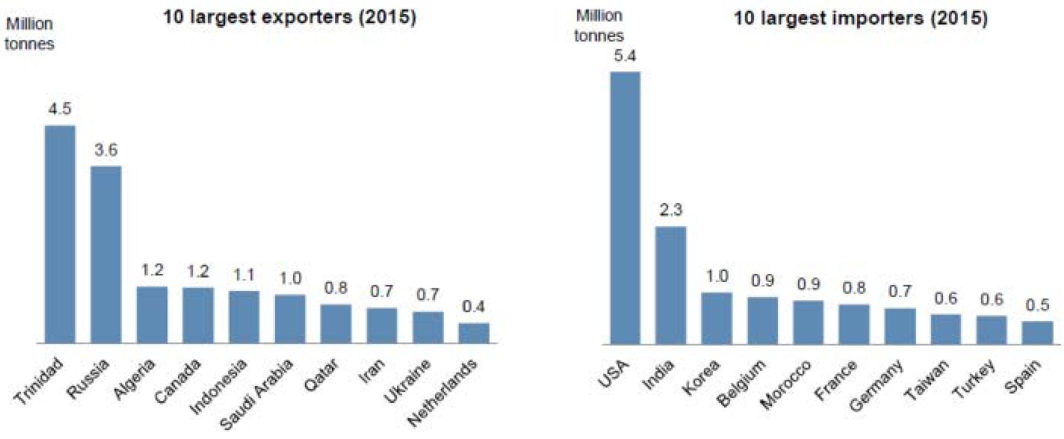


Source: China Fertilizer Market Week, International publications

Figure 10.11 Global Urea Floor Price

10.3.5 Ammonia Market

Ammonia is a basic chemical product and widely used as an intermediate industrial feedstock. Ammonia is also a swing product of urea, thus balancing the economic benefits between ammonia and urea. Total ammonia production in 2015 was 182 million tons. China is the largest producer and accounts for 37% of world production, followed by Russia at 8%. All of the ammonia produced in China has been used domestically. Most of the ammonia-importing countries are industrial countries, except for Morocco. Morocco is known as phosphate-producing country, as well as a producer of ammonium phosphate by importing ammonia to support food production in Africa. Average annual growth for ammonia production was 2.2% from 2005 to 2015 and is expected to grow.

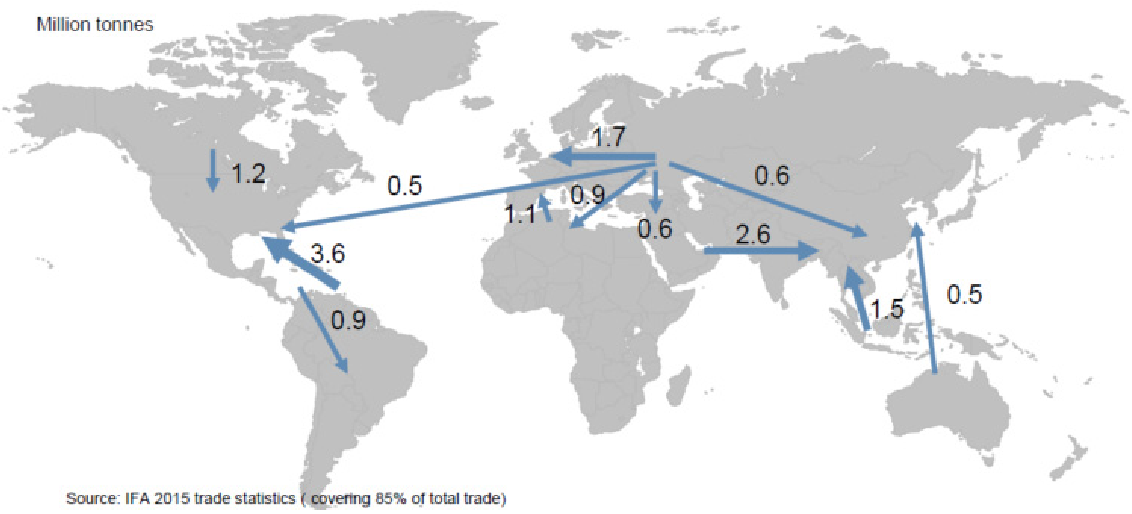


Source: Yara/IFA

Figure 10.12 Global Ammonia Trade in 2015

10.3.6 Ammonia Trade Flow

The trade flow for ammonia in 2015 shows that it is not a commodity product and its destination is mostly limited to industrial countries. Trinidad and Russia are the major suppliers of ammonia.



Source: Yara/IFA

Figure 10.13 Main Ammonia Trade Flow

10.3.7 Ammonia/Urea Industrial Development

The primary use of ammonia is to produce urea. Ammonia is also used as a basic chemical feedstock to produce nitric acid, ammonium sulphate and ammonium chloride. With the use of cyclohexane, caprolactam (an intermediate product of Nylon 6) is produced. Urea is one of the three most important elements as a fertilizer component. It can be sold directly to the market. It is also used as a feedstock to produce melamine resin and urea resin with the use of methanol. The advantage is that urea plants can operate as swing production facilities with ammonia plants to share the economic benefits and maximize profit.

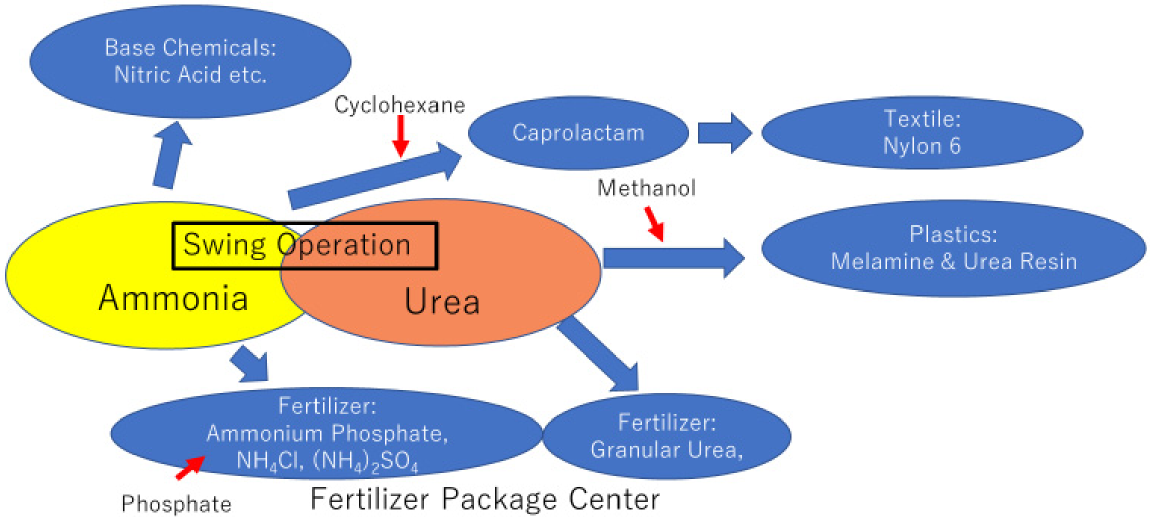


Figure 10.14　Ammonia-/Urea-based Industries

10.4 Discussion and Recommendation

10.4.1 General

The gas resource is one of the most important assets in Iran and the value should be maximized. To maximize the value, the following strategy needs to be borne in mind:

- Sell at a fair market price
- To be a market leader or price setter, not a price taker
- Avoid domestic competition

10.4.2 Methanol Option

The methanol option was reviewed and discussed with the QFZO. The current methanol price mechanism is influenced by the Chinese marginal coal price and capped by the affordability of MTO in China. In other words, the methanol price does not reflect the true market value of natural gas, while methanol suppliers from the Middle East play the role of price taker, not price setter.

52% of methanol is used as an oil alternative in China, with a significant part used as a fuel blend stock, in contrast to the way it is used in other countries. There is a risk associated with the reliance on one large buyer, namely, China.

The MTO option was also discussed. MTO is variable only in China, where low-cost coal is used as a feedstock. There are competitors in olefin production, i.e., involving ethane crackers, mixed-feed crackers, refinery fluid catalytic cracking units etc. MOT produces 3 tons of water to manufacture 1 ton of olefin, meaning that a considerable amount of heating value can be lost. There is no economic advantage under normal economic circumstances.

10.4.3 Urea/Ammonia Option

The QFZO has advised that central government has approved 11 urea projects in Iran already, thus there is no capacity for Qeshm to construct a urea plant. However, seven out of these 11 plants are in inland areas and there is no scope for exports. The other four urea projects will be constructed along the coast. Geographically, Qeshm is located close to an international waterway and offers the closest access to the Indian Ocean. In view of freight costs, Qeshm is an ideal location for exports.

Urea is a commodity product that can be sold directly to end users and marketers. Phosphate (P) and potassium (K) can be imported and mixed with nitrogen fertilizer in order to make composite NPK fertilizer as a value-added product for export. A fertilizer package center is to be considered for

Qeshm.