



# **Mini / Micro LNG for commercialization of small volumes of associated gas**

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## EXECUTIVE SUMMARY

The Global Gas Flaring Reduction Partnership (GGFR) provides its members with overviews of the potential solutions to recover and monetize the flared and/or associated gas.

This study analyses the LNG chain concept which can be used for the monetization of small volumes (1 -15 MMscf/d) of associated gas.

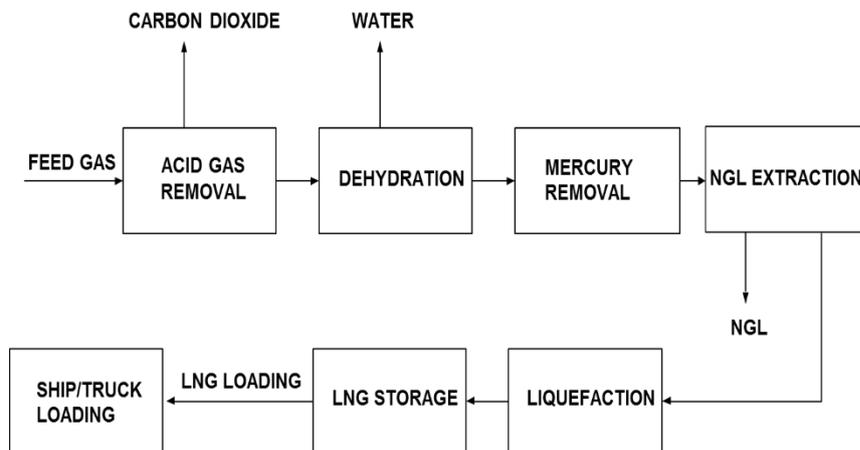
### The LNG business background

While the LNG industry has traditionally focussed primarily on development of ever increasing plant capacities, the maturity of the technology has allowed development of technologies applicable for small volumes to be competitive and potentially economically attractive. The main challenge for small scale LNG applications is therefore not technical but economic.

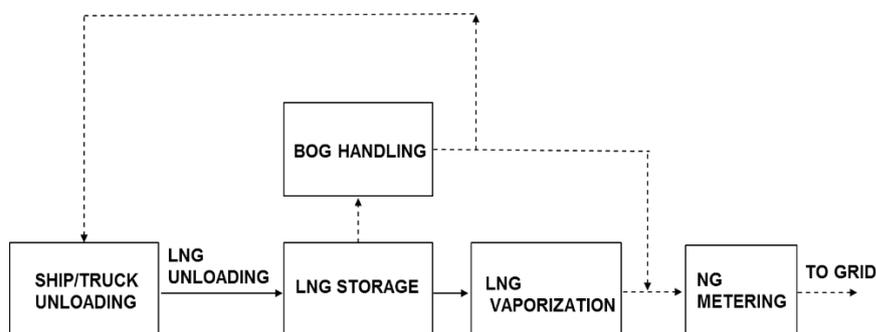
### The LNG chain

Traditionally the LNG chain was composed of three elements: liquefaction plants, transportation by ship and receiving terminals. However, attention is now being given to the diversification of LNG to increase gas distribution flexibility and to reach new consumers through small scale facilities, LNG distribution by trucks, LNG refuelling stations, etc.

Natural gas liquefaction is a process which typically involves several steps: the various feed gas pre-treatments followed by liquefaction as shown in the block flow diagram below.



At the receiving end, facilities are required to store the received LNG and reconvert it back to gas for use by consumers.



Alternatively, where the LNG will be used as a fuel directly e.g. in trucks, only storage and a loading facility is required.

## Mini/micro LNG liquefaction Technologies

Mini/micro LNG facilities currently mainly consist of LNG liquefaction plants supplying LNG satellite stations with annual LNG volumes up to 0.2 mtpa. As an indication, these LNG quantities correspond to the yearly LNG demand for a power plant up to approximately 100 MW.

The mini-LNG chain is virtually identical to the conventional LNG chain, differing only in scale. One difference is that for small gas volumes, LNG transport is feasible using trucks (onshore) or barges (offshore) rather than large marine carriers.

While the purpose of this study is not provide a tool to estimate the cost of the chain but to provide an overview of the main elements that should be taken into consideration when evaluating the potential for specific projects, it is important to give some indication of potential cost (capital and operating) of an LNG chain.

The sizing and cost of the different elements of the chain depend on the specific characteristics of each project such as: gas volume and composition, distance to consumers, storage and infrastructure requirements, geographical location etc..

The unit cost (capital and operating) for four scenarios have been evaluated: Gas volumes of 3 and 10 MMscf/d, and short and long distances to customers. It must be noted that these cost estimates are only indicative as specific circumstances (e.g. a challenging physical environment, high labour costs in an overheated business environment such as the Bakken in N. Dakota, high import duties), can affect the costs and hence economics significantly.

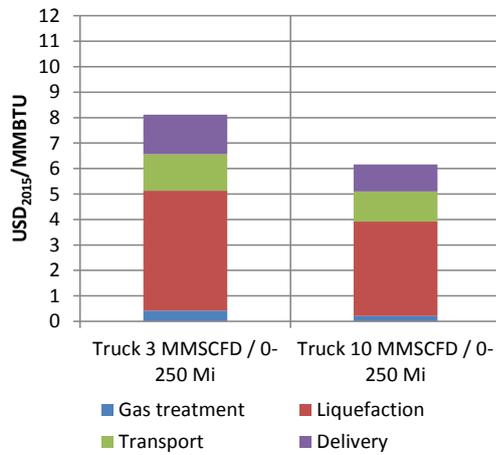
Transport method	<b>Short distance</b>		
Offshore	<b>Capital &amp; Operating cost, USD<sub>2015</sub>/MMBTU</b>		
	Item	Marine 3 MMSCFD / 55-150 MN	Marine 10 MMSCFD / 55-150 MN
	<i>Gas treatment</i>	0.42	0.21
	<i>Liquefaction</i>	4.71	3.71
	<i>Transport</i>	2.36	1.86
	<i>Delivery</i>	1.56	1.06
<b>Total</b>	<b>9.05</b>	<b>6.84</b>	

Onshore	<b>Capital &amp; Operating cost, USD<sub>2015</sub>/MMBTU</b>		
	Item	Truck 3 MMSCFD / 0-250 Mi	Truck 10 MMSCFD / 0-250 Mi
	<i>Gas treatment</i>	0.42	0.21
	<i>Liquefaction</i>	4.71	3.71
	<i>Transport</i>	1.43	1.18
	<i>Delivery</i>	1.56	1.06
<b>Total</b>	<b>8.12</b>	<b>6.16</b>	

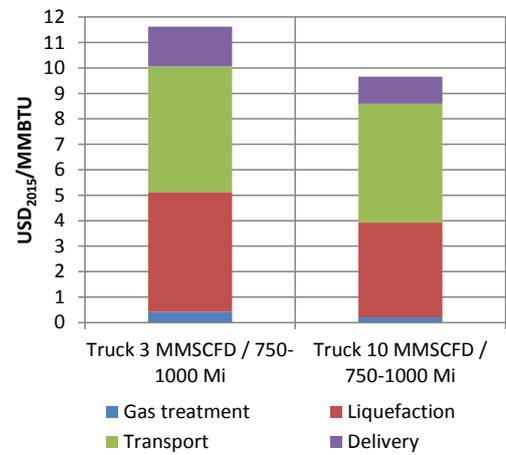
Transport method	<b>Long distance</b>		
Offshore	<b>Capital &amp; Operating cost, USD<sub>2015</sub>/MMBTU</b>		
	Item	Marine 3 MMSCFD / 550-800 MN	Marine 10 MMSCFD / 550-800 MN
	<i>Gas treatment</i>	0.42	0.21
	<i>Liquefaction</i>	4.71	3.71
	<i>Transport</i>	3.36	2.86
	<i>Delivery</i>	1.56	1.06
<b>Total</b>	<b>10.05</b>	<b>7.84</b>	

Onshore	<b>Capital &amp; Operating cost, USD<sub>2015</sub>/MMBTU</b>		
	Item	Truck 3 MMSCFD / 750-1000 Mi	Truck 10 MMSCFD / 750-1000 Mi
	<i>Gas treatment</i>	0.42	0.21
	<i>Liquefaction</i>	4.71	3.71
	<i>Transport</i>	4.93	4.68
	<i>Delivery</i>	1.56	1.06
<b>Total</b>	<b>11.62</b>	<b>9.66</b>	

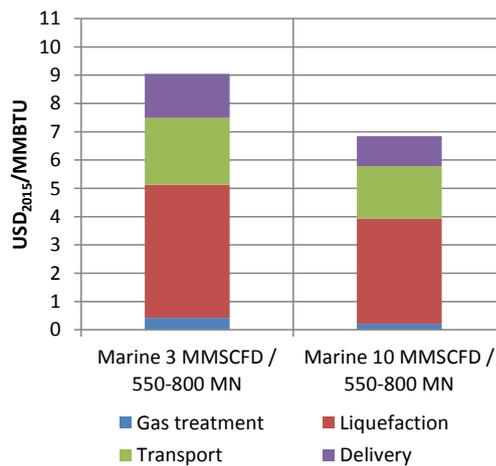
### Short distance, Onshore



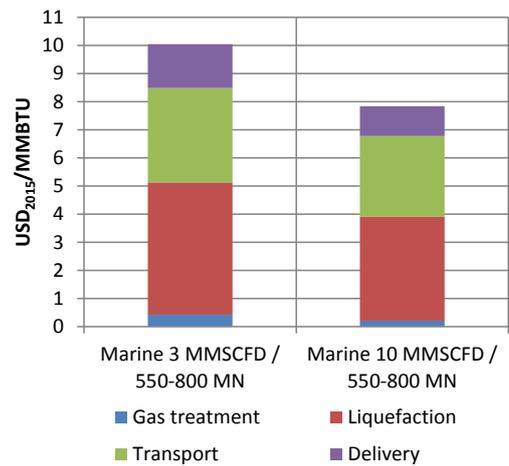
### Long distance, Onshore



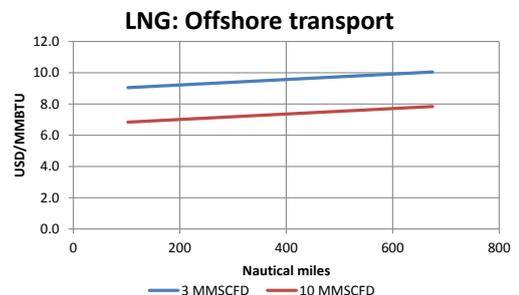
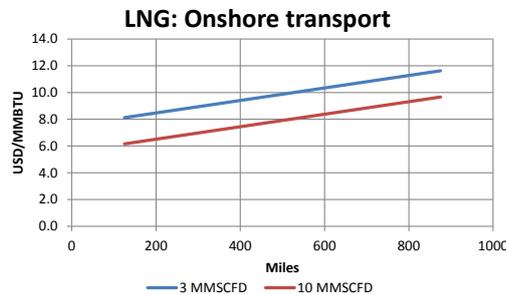
### Short distance, Offshore



### Long distance, Offshore



The above examples can be summarized as follows:



In summary, where specific circumstances do not adversely affect cost, for gas volumes between 3 and 10 MMscf/d and distances up to 800 MN/1000 miles, total unit costs (capital plus operating) for mini/micro LNG projects range from 12 to 6 US\$/MMBTU.

## Mini/micro LNG market overview

An analysis of the market for mini LNG facilities in the US and China has been performed in order to explore potential opportunities to commercialize small LNG volumes from associated gas in low and middle-income economies in economically beneficial ways.

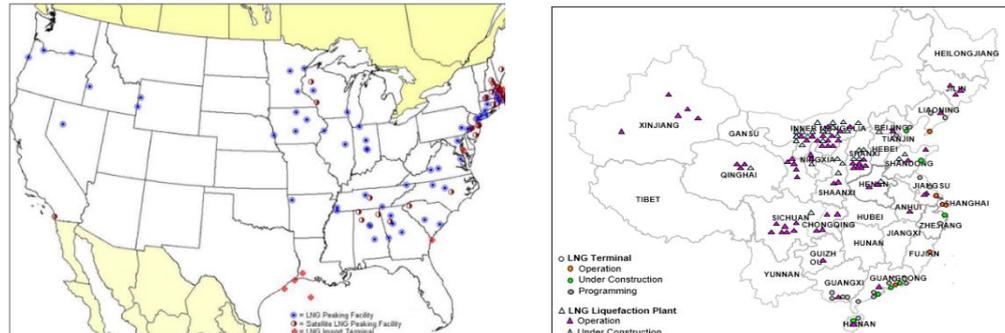


Figure 1: LNG Plants in USA and China

Small-scale LNG solutions have been implemented in the following situations:

- Restrictions of infrastructure:
  - In USA, peak shaving was used to solve pipeline network restrictions or deficient storage capacity.
  - In China, domestic gas demand had a boom which could not be matched by the required infrastructure development (gas transportation and transmission). LNG virtual chain provided a transitional solution to solve the gap.
  - Demand does not reach the minimum volume required to invest in traditional gas infrastructure transportation.
- Emission reduction policies (already implemented in China and expected in USA in the near future).
- More competitive prices of natural gas in the transportation sector against petroleum derivatives.

Similar small scale LNG models could be implemented in countries such as Nigeria, Iraq and Indonesia among others, which have high flaring levels.

Nigeria and Iraq present some similarities to the aspects which made China and the USA consider small scale LNG: restrictions on power supply & transmission and security issues hindering the development of the most economically suitable infrastructure for large scale flaring solutions. Also, Indonesia offers further opportunity for economic use: LNG as fuel for ships.

## Conclusion

LNG technologies are readily available making it possible for “fast-track” implementation of mini LNG facilities with relatively low investment (compared to pipelines or large scale facilities).

Small-scale LNG can enable rapid establishment of power plants or industries (fertilizers, food industry, ceramic, etc.) in areas limited by lack of infrastructure.

Use of small-scale LNG as a fuel for the transportation sector - trucks, buses, ships - is increasing, stimulated by the increasing cost of conventional fuels and environmental concerns.

# 1. INTRODUCTION

The purpose of this report is to analyse the LNG chain concept, using different technologies available in the market for small volumes (1-15MMscf/d), in order to monetise small volumes of associated gas and avoid or reduce the current gas flaring.

The LNG technology is mature, in use for over 50 years. This maturity allows applications for small volumes to be competitive and economically attractive.

As part of the chain analysis, an overview of the existing micro/mini LNG liquefaction technologies will be provided with their main characteristics. A recommendation will be done for the most suitable processes for the volumes and characteristics of this study.

## 1.1. Abbreviations

The following abbreviations are used in this report:

AAV	Ambient Air Vaporizer
AAV	Ambient Air Vaporizer
ACHX	Air Cooled Heat Exchanger
ADR	European Agreement International Carriage of Dangerous Goods by Road
APCI	Air Products Chemicals Incorporation
BAHX	Brazed Aluminum Heat Exchanger
BOG	Boil-off gas
C3MR	Propane Pre-cooled Mixed Refrigerant Process
CAMEL	Compagnie Algérienne du Méthane Liquide
CAPEX	CAPital EXpenditures
CNG	Compressed Natural Gas
CO2	Carbon Dioxide
COS	Carbonyl Sulphur
CWHE	Coil Wound Heat Exchanger

DES	Delivered ex Ship
DMR	Double Mixed Refrigerant
DOT	Department of Transportation (US)
EIA	Energy Information Administration
EPF	Engineering Procurement Fabrication
FOB	Free on Board
GE	General Electric
GGFR	Global Gas Flaring Reduction Partnership
GHG	Greenhouse Gas
GHG	Greenhouse Gas
GPD	Gallon per Day
H <sub>2</sub> S	Hydrogen Sulphide
HP	High Pressure
IA	Instrument Air
IPSMR	Integrated Pre-cooled Single Mixed Refrigerant
ISO	International Standardization Organization
JGA	Japanese Gas Association
JT	Joules-Thompson
kWh	Kilo Watt Hour
LNG	Liquefied Natural Gas
LP	Low Pressure
LPG	Liquid Petroleum Gas
MAWP	Maximum Allowable Working Pressure
MFC	Mixed Fluid Cascade
MMscf/d	Million standard cubic feet per day
MMUSD	Millions of US Dollars

MR	Mixed Refrigerant
mtpa	Million Tonnes per Annum
MW	Mega Watt
N2	Nitrogen
NDLNG	North Dakota LNG
NDRC	National Development and Reform Commission
NGL	Natural Gas Liquids
OPEX	OPERating EXpense
ORV	Open Rack Vaporizer
PCMR	Pre-Cooled Mixed Refrigeration
PFHE	Plate Fin Heat Exchangers
ppmv	Parts per million by volume
SCMR	Single Cycle Mixed Refrigeration
SCV	Submerged Combustion Vaporizer
SMR	Single mixed refrigerant
STV	Shell and Tube Vaporizer
t	Tons
TADOPTR	Thermoacoustic Driver Orifice Pulse Tube Refrigerator
tpd	Tons per day

## 2. BACKGROUND

The Global Gas Flaring Reduction Partnership (GGFR) is a public-private partnership, hosted by the World Bank, which brings together a wide range of countries and companies to work together to reduce gas flaring and utilize the gas, currently flared, in economically beneficial ways.

The GGFR Partnership was initiated in 2002 and has been active since in providing advice and guidance to GGFR Partners on a wide variety of flaring related issues including regulation, measurement, reporting, and utilization technologies.

The World Bank intends through this study to provide all GGFR partners an overview of the potential solutions to monetise the associated gas in order to decrease the global associated gas flaring.

## 3. LIQUEFIED NATURAL GAS (LNG)

### 3.1. LNG business evolution in a nutshell

The idea to liquefy the natural gas appeared after some centuries of gas experiments as a solution to bring large volumes of gas from the source to the consumers in an economical way. The LNG reduces the volume of natural gas approximately 600 times.

The LNG provides:

- gas transport across long distances where pipelines are not feasible or too expensive
- flexibility of gas importation
- secure supply from different suppliers

The first LNG commercial plant started operations in 1940 in Cleveland, Ohio, USA. It was a peak shaving plant to cover the high gas demand during the winter period. The terminal was in operations for almost four years until a fatal accident occurred in 1944. This accident postponed the implementation of new LNG project for several years.

In 1959, Great Britain received the first LNG carrier, the Methane Pioneer, from the US.

LNG international trade started in 1964 between Algeria and France and the UK. The first liquefaction facilities in Algeria, the CAMEL (Compagnie Algérienne du Méthane Liquide) project had a capacity of 1.2 mtpa and the process was developed by Air Liquid and Technip and used three separate cooling cycles (propane, ethylene and methane).

Since then, 26 LNG exporting facilities have been built all over the world (17 countries) with a total capacity of 280 mtpa, with capacity range from 1 to almost 8mtpa per train. As mentioned, the LNG technology is mature and the excellent safety record demonstrates the strong standards and regulations, and industry commitment to risk management.

The LNG industry has historically developed import/export projects of ever increasing capacity to capture economies of scale as illustrated on Figure 1. The maturity of the technology, however, now allows development of other LNG applications, often of smaller scale, that increase gas distribution flexibility and to reach new consumers as illustrated on Figure 2.



Figure 2: Typical LNG Chain

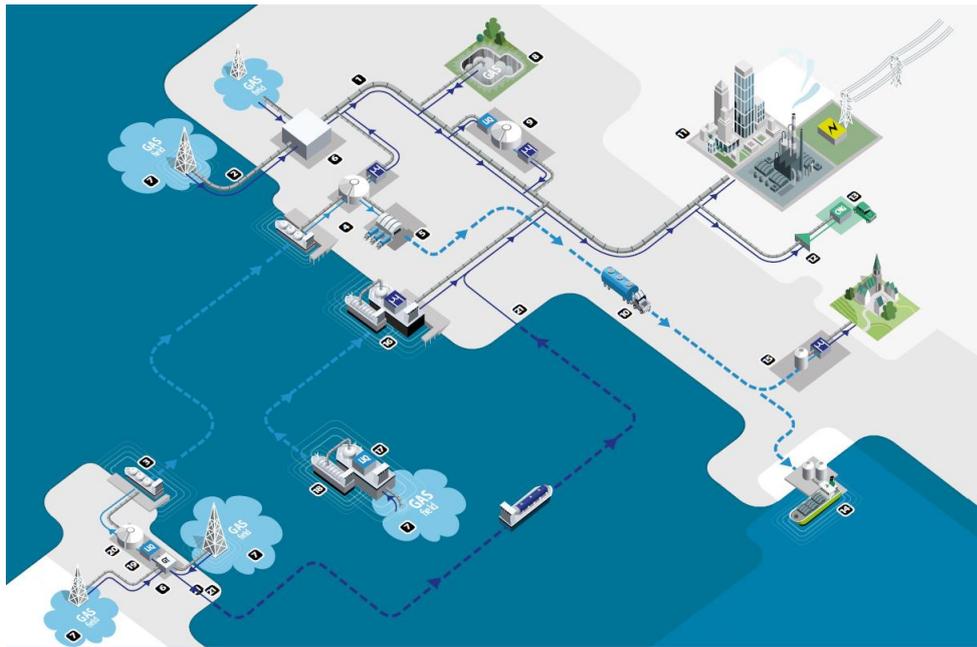


Figure 3: Small Scale New Horizons for LNG Chain

In this new market approach, the demand for small scale LNG is growing both to monetise small gas fields or associated gas and to deliver gas to a new and different type of customer.

## 3.2. LNG terminals main codes and standards

LNG industry has a remarkable safety record mainly due to the strict application of standards and best practices from the design to the operation of the facilities. The most stringent code categories are applied.

As a general rule, the following order of priority is applied to the design and operation of LNG facilities:

- Local/ national laws and regulations,
- Requirements of design and construction specifications,
- Referred codes and standards.

There are two widely used standards for the design of LNG facilities:

- EN 1473: European Standard for Installation and equipment for LNG – Design onshore installations
- NFPA 59A: American Standard for the Production, Storage and handling of LNG.

There are other national standards, like Recommended Practice for LNG Facilities (JGA-102) from Japanese Gas Association, which are only applicable in Japan.

In addition to the general LNG facilities standards, additional standards are followed specifically for LNG tanks, civil works, piping, equipment, insulation, electricity, instrumentation, safety, communications, etc. Some of them are International Standards developed by International Standardization Organization (ISO) and some others are local or European or American. The appliance of each one it will depend on the area where the project is developed.

Regarding the mini/micro LNG facilities, the dedicated standards are applicable either for vehicular use or for a specific range of capacities, for instance:

- EN 13645: Installations and equipment for liquefied natural gas - Design of onshore installations with a storage capacity between 5 t and 200 t
- NFPA 57: LNG Vehicular Fuel Systems Code
- ISO 16924: Natural gas fuelling stations — LNG stations for fuelling vehicles (still under development)

If those codes are not applicable, the LNG facilities shall follow the general LNG standards previously mentioned.

## 4. LNG EXPORTING FACILITIES

Natural gas liquefaction is a process which typically involves several steps: a number of feed gas pre-treatments and liquefaction as shown in figure 3: block flow diagram.

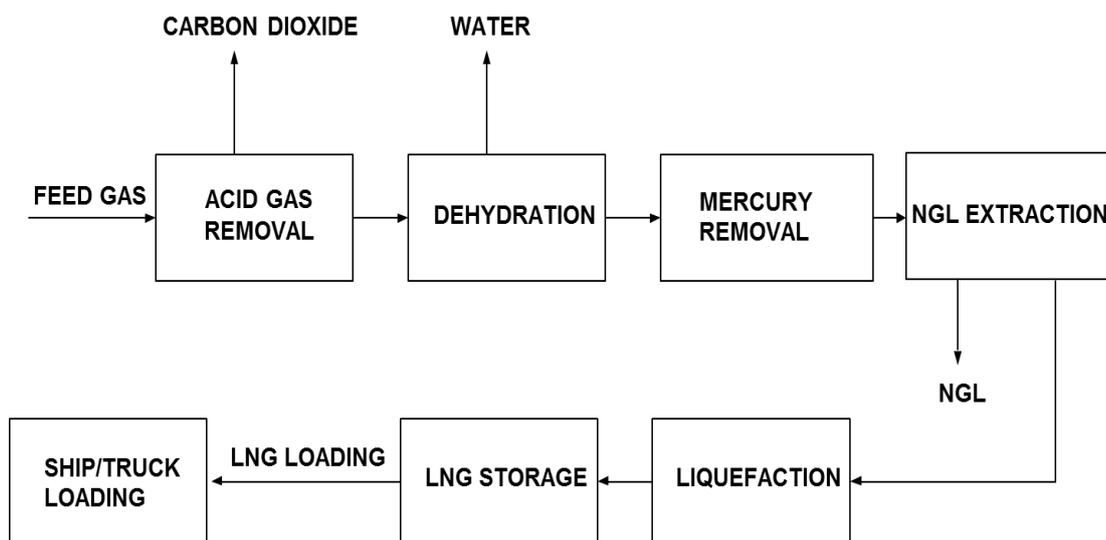


Figure 4: Liquefaction Block Flow Diagram

The gas pre-treatment will depend on the feed gas composition and on the requirements of the liquefaction process, but basically it consist of:

- Acid gas removal unit: to remove acid gases ( $\text{CO}_2$  and  $\text{H}_2\text{S}$ ) to prevent freezing out and blockage in the downstream liquefaction unit.
- Dehydration: to remove water to prevent ice and hydrate formation in the liquefaction unit.
- Mercury removal: to reduce mercury level in the feed gas to prevent corrosion in heat exchanger (aluminium).
- Natural Gas Liquids (NGL) (condensate) extraction: to remove heavy hydrocarbons to prevent freezing in the cryogenic sections and/or to meet the required LNG specification (i.e. High Heating Value (HHV) or Wobbe Index).

Once the feed gas has been treated and conditioned, it is liquefied in the liquefaction unit and stored as LNG in the storage tank(s) and then distributed to the consumers by ship or truck (or train). Liquefaction is achieved by cooling, liquefying and subcooling the hydrocarbons to a temperature ranging from  $-145^\circ\text{C}$  to  $-160^\circ\text{C}$ , depending on the operating pressure. The subcooled hydrocarbons are then flashed at atmospheric pressure. In these conditions the LNG is at about  $-160^\circ\text{C}$ . There are several processes to liquefy natural gas developed by different companies under licences.

The LNG specification will be fixed according to the consumers' needs; however as general rule a typical LNG specification is as follows:

<b>Composition (mol %)</b>	
C4+	2.0 max %
C5+	0.1 max %
N2	1 % max
CO2	50 ppm max
Benzene (mg/Nm <sup>3</sup> )	4 ppm max
HHV (BTU/SCF)	37–43 MJ/Sm <sup>3</sup>
Wobbe Index	48-53 MJ/Sm <sup>3</sup>

Table 1: Typical LNG Composition

## 4.1. LNG liquefaction process for standard size terminals

There are four main large-scale liquefaction process:

- Propane Pre-cooled Mixed Refrigerant Process (C3MR) designed by Air Products & Chemicals, Incorporation (APCI)
- Optimized Cascade Process (Cascade) designed by Conoco Phillips.
- Double mixed refrigerant process (DMR) designed by Shell
- Mixed Fluid Cascade designed by Linde

The APCI C3MR is the most installed process for LNG exporting terminals with around 86% of the market, followed by the Conoco Phillips Cascade with 10%, DMR by Shell with 3% and Linde process with 1%.

The different process block flow diagrams are shown here below.

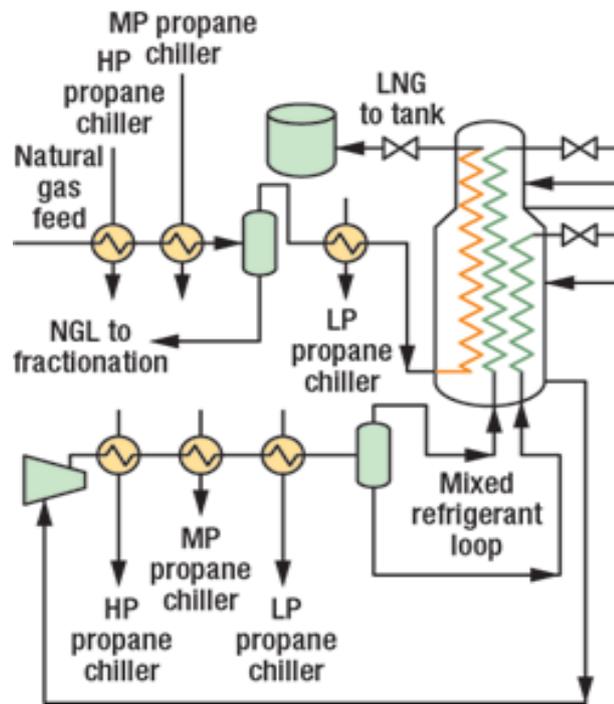


Figure 5: C3MR Process APCI

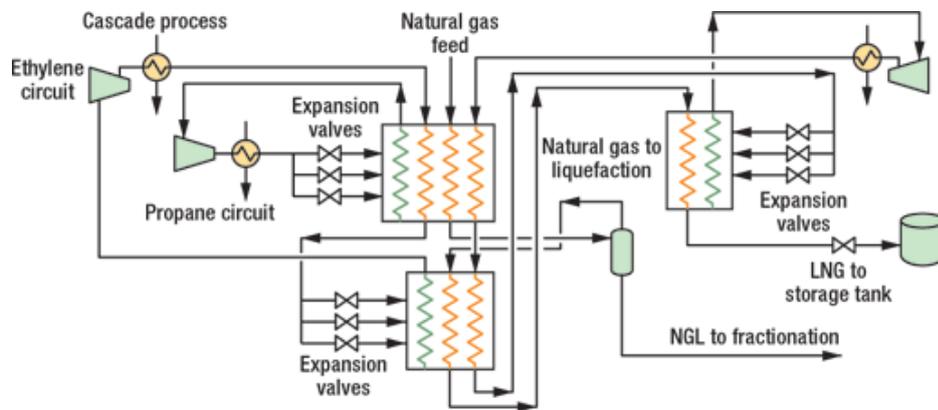


Figure 6: Cascade Process Conoco Phillips

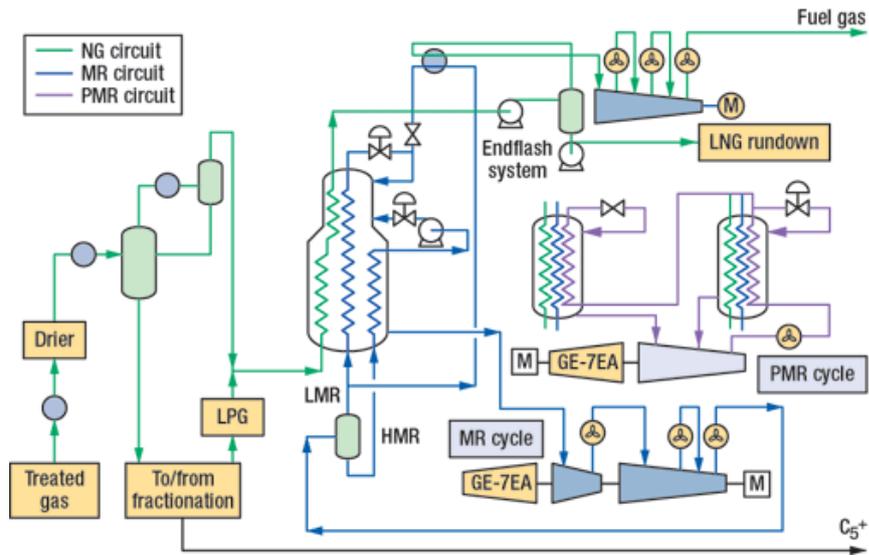


Figure 7: DMR Shell

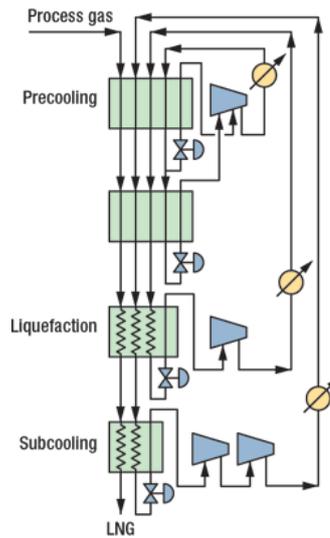


Figure 8: Mixed Fluid Cascade- Linde

These processes are complex and require a very significant investment; therefore they are mostly installed in plants of more than 1 mtpa capacity.

In order to develop small/mini LNG liquefaction projects, the processes have been simplified using a different design approach to make them economically viable for small volumes.

## 5. MINI/MICRO LNG LIQUEFACTION TECHNOLOGIES

Small scale LNG facilities typically refer to facilities with a capacity between 0.2 to 1 mtpa.

Mini/micro LNG facilities are the LNG liquefaction plants and LNG satellite stations with capacities below 0.2 mtpa. These mini/micro LNG quantities correspond to the yearly LNG demand of a power plant up to 100 MW (as indicative value).

### 5.1. General

Many liquefaction technologies use a refrigeration cycle and can be classified based on the characteristics of this cycle. A limited number of technologies do not use refrigerant, and are described by specific features.

When classifying the liquefaction technologies according to the refrigerant cycles they employ, one usually finds the following wording:

- Closed or open cycles
- Single or multiple cycles
- Single or mixed refrigerants (one single component or a mixture of several different components)

Additional functions like pre-cooling, which improve the efficiency of the refrigeration cycle, are also options in many of the liquefaction technologies.

The following list covers a wide range of liquefaction techniques:

- Pre-cooled Joule-Thomson Cycle
- Nitrogen Expansion Cycle (also called closed Brayton or Claude cycle)
- Cascade Cycle
- Mixed refrigerant cycle
- Open cycle (includes Open Claude cycle)
- Gas expansion
- Stirling cycle
- Liquid nitrogen open cycle evaporation
- Thermoacoustic driver orifice pulse tube refrigerator (TADOPTR)

Out of these technologies three are of particular interest for the 1-15 MMscf/d range:

- Nitrogen and gas expansion
- Mixed refrigerant, and
- Single Mixed Refrigerant

## 5.2. Peak Shaving

When looking at small capacities it is to be mentioned that peak shaving has been implemented since several decades. Therefore it is deemed of interest to briefly review the technologies typically used for this type of application. These liquefaction technologies were/are:

- Gas Expansion
- Nitrogen Expansion
- Mixed Refrigerant
- Cascade

### 5.2.1. Gas Expansion

The gas expansion process is attractive when a facility is located where a large volume of natural gas can be let down from a high pressure to a low pressure gas distribution system. The process is often applied with no compression or minimal compression, which helps reduce power requirements. The process liquefies about 15% of the feed gas and the balance is discharged to a low pressure system (pipeline). The ratio of high to low system pressures drives the process. A ratio of approximately 16:1 to 20:1 (in absolute pressure) is needed for the process to be applied efficiently with little or no compression. Lower pressure ratios drive the process to liquefy less of the feed gas.

A typical gas expansion process is shown here-below. All of the feed gas is dehydrated before it enters the process. Two expander/compressors are then used to boost the pressure of the gas. After compression and cooling, the gas is split into parts. The major portion is expanded and used as refrigerant, and then dumped to the low pressure system. The minor portion to be liquefied is sent to a carbon dioxide removal unit and then to the cold box. The major portion of the feed gas is cooled and expanded in two steps to provide cold streams for liquefying the gas.

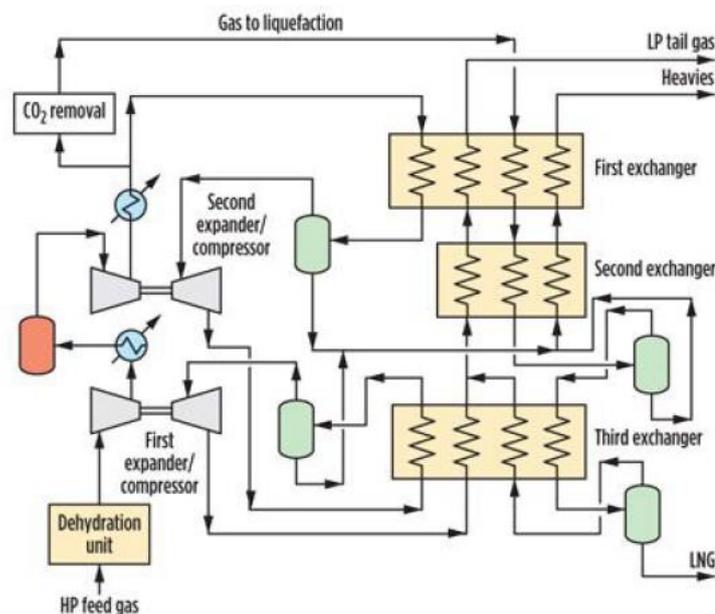


Figure 9: Gas expansion process (Courtesy of Black & Veatch)

The major benefit of this technology is the reduction in power consumption. For many situations, no compression is required; however, the process is capital intensive due to the complexity of the cycle with multiple expander/compressor systems, multiple exchangers and the need to process a much larger gas stream, due to the fact that this type of gas expansion process requires that some of the feed gas being used at low pressure without being liquefied. Another issue with expansion plants is the sensitivity to feed gas pressure and composition. Pressure is related mostly to capacity, but the composition is critical (it determines the CO<sub>2</sub> allowance in the gas to be liquefied) in the cold separators and in the carbon dioxide solidification area.

## 5.2.2. Nitrogen Expansion

The nitrogen refrigeration process utilizes nitrogen to accomplish liquefaction.

The process works by compressing the nitrogen (either produced on-site or purchased) and then cooling and expanding it in two steps to produce temperatures low enough to liquefy the feed gas. This process has been used for many years, but it has had limited application recently because of the large amount of power required to circulate the nitrogen. In the recent years the nitrogen refrigeration process has been mostly applied on small-scale projects where refrigerant power consumption is not a primary consideration. Indeed this arrangement is rather simple but its efficiency is poor as the feed gas is cooled, condensed and subcooled again a single component, single phase refrigerant. It is to be noted that the refrigerant is entirely in its vapour form. Efficiency improvement can be obtained by implementing additional levels of expansion. However this efficiency increase will have to be weighed against cost and complexity increase.

It is to be noted that nitrogen is an efficient refrigerant in cryogenic applications but shows poor efficiency at higher temperature levels of the liquefaction process. As a consequence many nitrogen cycles include a precooling unit that provides refrigeration duty at higher temperature levels. Again this efficiency increase has to be weighed against cost and complexity increase.

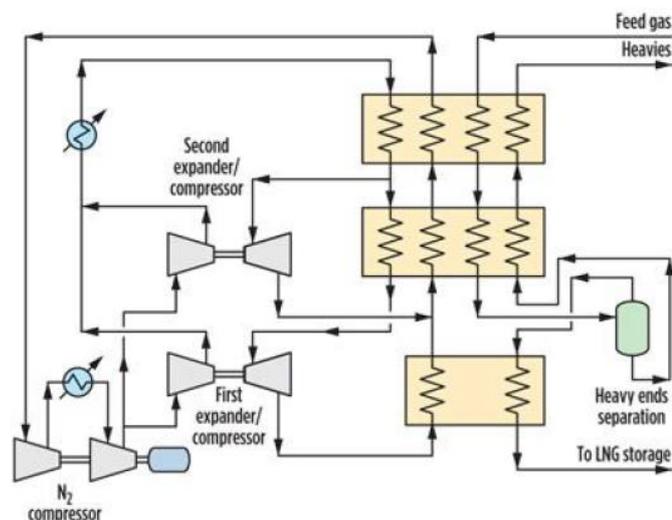


Figure 10: Nitrogen expansion process (Courtesy of Black & Veatch)

### 5.2.3. Single Mixed Refrigerant (SMR) process

A SMR is a single cycle using a mixture of different components (nitrogen plus hydrocarbons from methane to isopentane) as a refrigerant. A SMR can tightly follow the feed gas cooling curve, and thus has a better thermodynamic efficiency.

The SMR process is widely used in the LNG industry. This process is based on a single mixed-refrigerant (SMR) system to perform the liquefaction. The system includes a refrigerant separator, upstream the main heat exchanger, which produces vapour and liquid streams. The coolant liquid flow rate (and, therefore, the vessel holdup) can be changed in the distributed control system. This liquid flow rate combined with a constant high pressure (HP) vapour stream determines the molecular weight of the refrigerant in the main exchanger. Therefore, the refrigerant can easily be adjusted for changes in feed conditions while the plant is in operation, which allows to ensure a level of efficiency by adjusting the process to the modified cooling curve. Gas or nitrogen cooled liquefaction processes cannot alter the composition of the circulating refrigerant; the only adjustment available is flow rate (of refrigerant). This ability to adjust to changes in feed gas conditions and composition is the primary reason that mixed-refrigerant systems are more flexible.

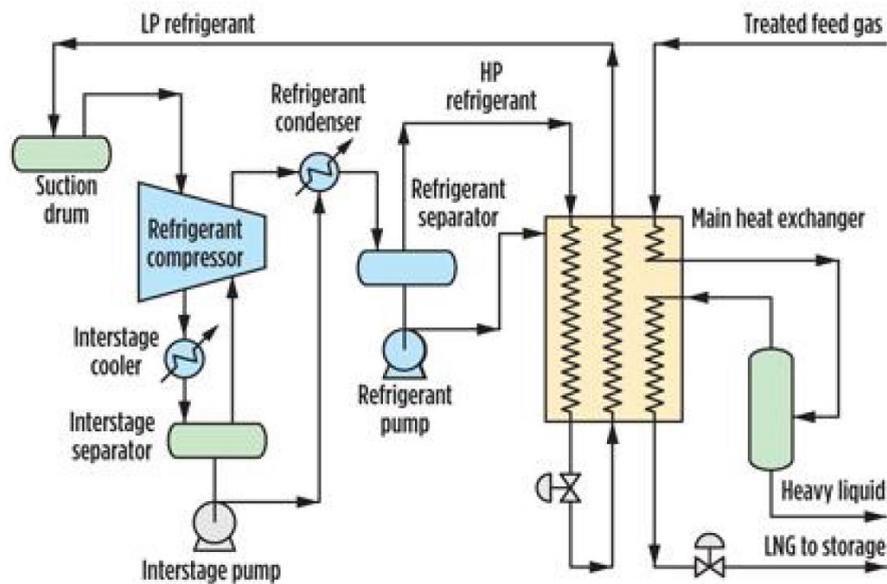


Figure 11: Single Mixed Refrigerant process (Courtesy of Black & Veatch)

#### 5.2.4. Cascade

Higher efficiency can be achieved by using several single components in separate, sequential refrigeration loops to better match the cooling curve of the natural gas. The architecture of cascade processes follows this principle. As each loop contains a single component refrigerant it supplies refrigeration at a given temperature level. The various refrigerant loops are cascaded in series in order to reach the temperature needed to liquefy the natural gas. The loops typically contain propane, ethylene and methane. The efficiency of the cascade cycle is higher than the nitrogen expander. However there is still a loss of efficiency in trying to match the discrete refrigerant temperature levels (propane, ethylene...) with the condensation of the natural gas. The efficiency can be improved by increasing the number of stages of refrigeration or by utilising a greater number of refrigerants. In turn cost and complexity increase.

This process is no longer used in the peak shaving/small scale applications.

### 5.3. Associated Gas

When producing crude oil from a reservoir and treating it for transport or storage vapour hydrocarbons are released. These vapours are called the associated gas. Such vapours result from the multiple flashes imposed to the crude oil during its treatment. These vapours also can come from the reservoir itself, should a gas cap be present or should the reservoir pressure be lower than the crude oil bubble point. In such case the reservoir fluid (the crude oil) is two-phase in the reservoir itself which means that gas and liquid are produced at the same time. As gas moves more easily in the reservoir than oil the gas to oil ratio tends to increase over time.

In many cases, pressure in a crude oil reservoir decreases over time as the oil is produced. In these cases, the crude oil production rate generally is kept constant during a given duration (plateau) and then gradually decreases as the reservoir pressure does so. In surface the wellhead pressure decreases too, leading to the requirement to adjust the oil treatment pressure accordingly. As a consequence the associated gas will be produced at a flow rate, pressure and quality varying with time over the life of the oil reservoir.

The mini/micro LNG plant should be designed based on the most probable associated gas production profile while maximising profitability. The gas pre-treatment over design or space reservation for additional treatment could be envisaged if there are some uncertainties on the gas composition/contaminants evolution over time. A modular approach could also be considered in order to adapt the liquefaction capacity to the associated gas flow. For this reason, reservoir studies are needed as the gas production, pressure and composition profiles will be estimated from these studies.

As reservoirs are mostly made of water saturated rocks it is to be noted that the hydrocarbons produced from a well are generally water saturated.

Crude oil reservoirs can contain impurities such as CO<sub>2</sub>, H<sub>2</sub>S, Mercury, Nitrogen and their nature is such that heavy hydrocarbon components are typically at higher concentrations than in gas reservoirs.

Many liquefaction facilities in the range 1-15 MMscf/d exist across the world. However the vast majority of these facilities are fed with pipeline gas. Pipeline gas is a hydrocarbon stream already treated to meet pipeline transportation specifications. These specifications are not as rigorous as is required for liquefaction, but result in gas with much more favourable characteristics than associated gas, which is a raw untreated product.

In addition, pipelines typically operate at pressures above 40 barg, which is high enough to feed a liquefaction unit. Pipelines also deliver a continuous supply so operation of the liquefaction unit is not interrupted by feed gas supply issues. In contrast, associated gas supply, by its nature as an oil production bi-product, is variable and can be interrupted, and is often at low pressure (which implies additional compression for some processes to reach their normal operating pressure)

## 5.4. Current status overview (technology screening)

There are different liquefaction technologies that could be applied for small volumes as considered in the present study, i.e. 1-15MMscf/d (equivalent to approximately 20-300 tpd or 0.0073-0.1095 mtpa).

The products from several companies have been selected for the purpose of this project for deeper analysis – these companies are:

- Linde / Cryostar
- Black & Veatch
- Chart
- Wartsila / Hamworthy
- GE Oil & Gas
- Galileo
- Dresser-Rand

This list is not exhaustive and some other players also have available technologies for this type of application (e.g. APCI or Cryonorm).

### Notes:

- Wood Group Mustang is also active on the LNG liquefaction market; however its current technologies (LNG Smart, OCX and NDX) are not deemed applicable to the 1-15 MMscf/d mini/micro LNG range;
- The CAPEX, OPEX/specific consumption and GHG emissions associated to the mini/micro LNG liquefaction technologies in the range 1-15 MMscf/d are discussed collectively in chapter 5.6.

### 5.4.1. Linde / Cryostar

The liquefaction technologies proposed by Linde can be classified as follows:

- The Mixed-fluid cascade (MFC) technology

- The StarLNG™ and StartLiteLNG™ products, covering Nitrogen Expansion and SMR technologies

#### 5.4.1.1. MIXED FLUID CASCADE

The MFC is adapted to the 3 to 12 mtpa LNG capacity.

This process uses three mixed refrigerant cycles. The process is comprised of plate-fin heat exchangers for feed gas precooling, Coil Wound Heat Exchangers (CWHE) for liquefaction and LNG subcooling. The process also includes three separate mixed refrigerant cycles, each with different compositions, which result in minimum compressor shaft power requirement. There are three cold suction centrifugal compressors in the cycle.

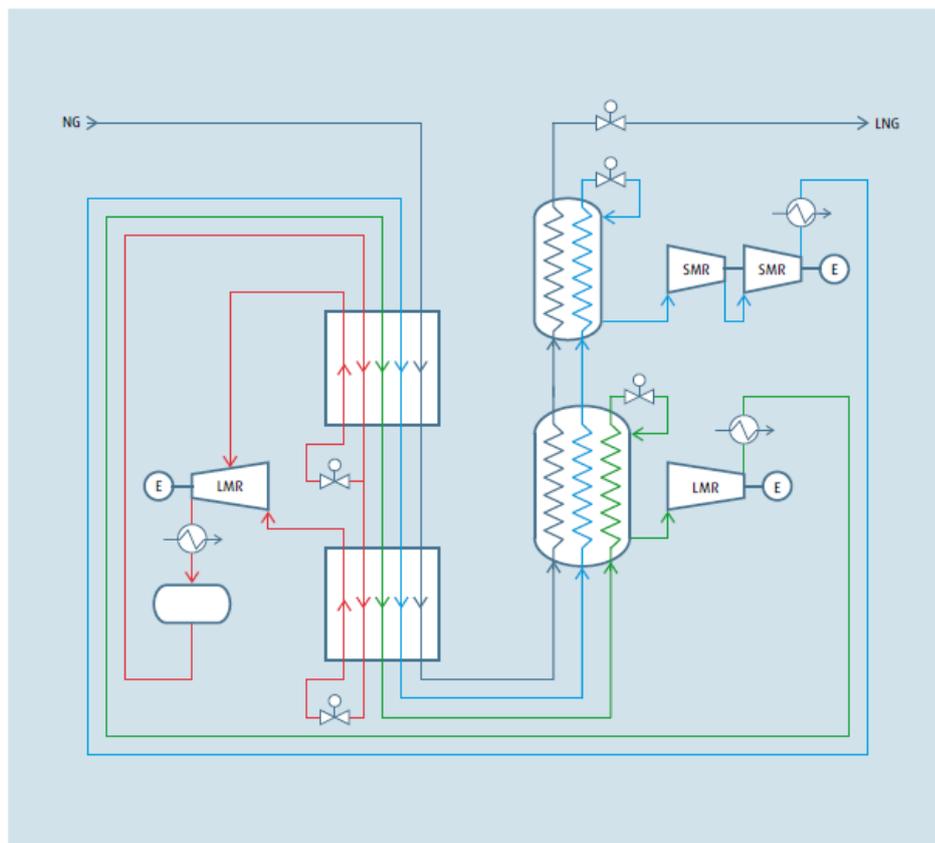


Figure 12: MFC process (Courtesy of Linde)

There is one reference for this technology – it is the Snohvit liquefaction facility located in Hammerfest, Norway. This plant has a capacity of 4.3 mtpa.

As indicated the capacity range for this technology is far above the 1 to 15 MMscf/d (0.01 to 0.12 mtpa). As a result it won't be further discussed.

#### 5.4.1.2. STARLNG™

As mentioned earlier the StarLNG™ product family covers liquefaction technologies based on Nitrogen Expansion as well as liquefaction technologies based on SMR cycles.

## NITROGEN EXPANSION

The StarLiteLNG™ plant, part of the StarLNG™ product family, is a standardized product covering the liquefaction capacity range of 1 to 10 MMscf/d (20-200 tpd). The process is designed and manufactured by Linde's fully owned subsidiary CRYOSTAR.

The StarLiteLNG™ unit is based on Linde's proprietary EcoRel system, used for on-board re-liquefaction of boil-off gas (BOG) on LNG carriers such as the Q-Max carrier (transporting world-scale LNG cargoes from Qatar to the Far East).

At the heart of the StarLiteLNG™ refrigeration unit is the compander, a combination of compressors and an expander in a single machine, with an integrally geared design, that is installed in the nitrogen refrigeration cycle.

The following figure shows the main principles of these units.

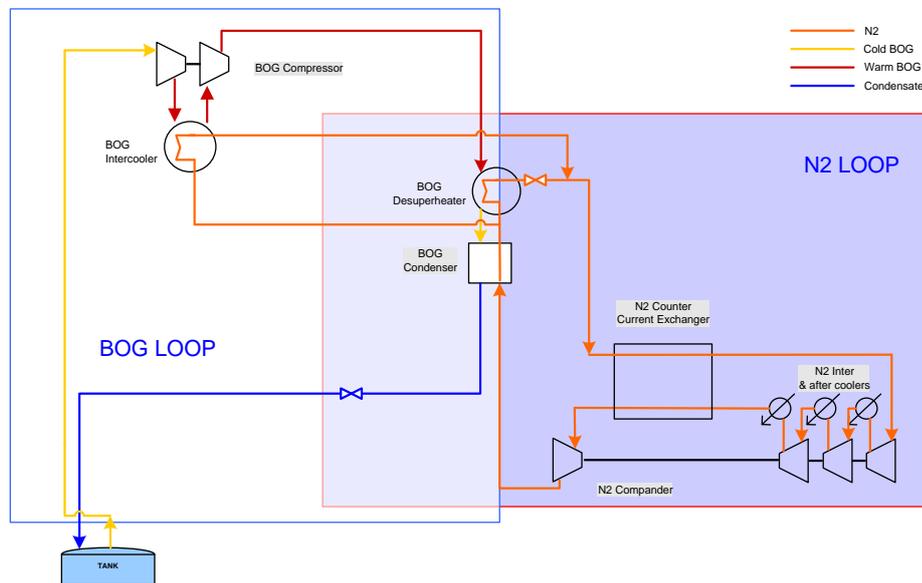


Figure 13: StarLiteLNG™ refrigeration and liquefaction units (Courtesy of Linde)

This technology is in industrial use with about 18 references. Most of these references are for LNG carriers' on-board re-liquefaction units. Currently there is one 28 tpd unit (~1.4 MMscf/d) being delivered for a Biogas liquefaction plant located in Indonesia.

The standard capacities and associated characteristics for this product are as follows:

Product Code	Typical capacity [tpd]	Liquefier footprint w/o air coolers [m]	Rated power of compander [MW]
XS	28	30 x 15	1.5
S	50	20 x 15	2.2
M	88	20 x 15	3.5
L	125	20 x 15	4.5
XL	200	20 x 15	6



Figure 14: EcoRel compander unit consisting of 3 stages of compressors with water intercoolers and one expander manufactured and tested at Cryostar workshop in Hesingue/France (Courtesy of Linde)

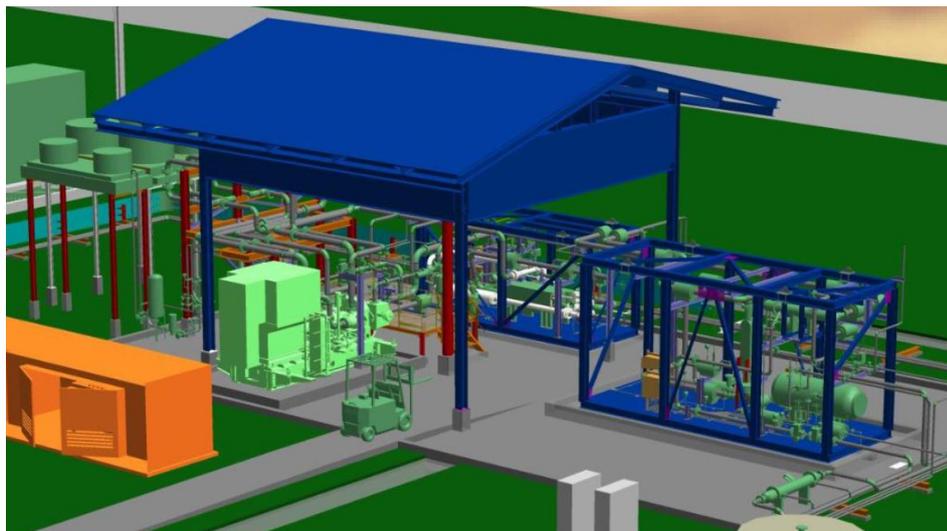


Figure 15: 3D CAD model of StarLiteLNG™ XS modules with 20 tpd liquefaction capacity (Courtesy of Linde)

The Nitrogen closed loop is a gas-gas cycle designed to be flexible in term of turndown and gas composition, and able to cover a large range of feed gas composition change in particular with nitrogen content, subject to be considered during design stage.

The Nitrogen single expansion stage closed loop can operate with a pressure from 7 to 10 barg. Pressure above this value is possible but brings no added advantage in term of power consumption due to the process in a single expansion stage.

The StarLiteLNG™ requires medium voltage electrical power, instrument air and cryogenic quality nitrogen for seal gas.

Linde also offers StarLNG™ Nitrogen Expansion based units for capacities up to 5 MMscf/d (100 tpd) using its own expanders. This range of product is in commercial use and there are approximately 10 referenced plants with Nitrogen expansion technology designed and/or build by Linde in this range. It is to be noted that 8 out of the 10 references were built between 1970 and 1990. The latest project is the Gazmetro project in Montreal, Canada, which is currently being developed, with ~6 MMscf/d (120 tpd) liquefaction capacity. This project is based on a dual expander cycle.

#### SINGLE MIXED REFRIGERANT

The StarLNG™ SMR cycles were developed for capacities from about 5 MMscf/d (100 tpd) up to 80 MMscf/d (1,600 tpd) with Plate Fin Heat Exchangers (PFHE) or up to 150 MMscf/d (3,000 tpd) with CWHE.

These cycles are based on the LIMUM® products.

LIMUM® 1 is suitable for capacities below 80 MMscf/d (1,600 tpd); down to 5 MMscf/d (100 tpd).

In this cycle the low pressure (LP) mixed refrigerant is compressed in a two stage centrifugal compressor and partially condensed against cooling water or air. Both phases of the compressed mixed refrigerant are jointly fed to a brazed aluminium PFHE, are fully liquefied and subcooled. After expansion through a Joules-Thompson valve the mixed refrigerant is fully vaporized, and the cooling provides the refrigeration for natural gas liquefaction and, if required, fractionation to remove LPGs.

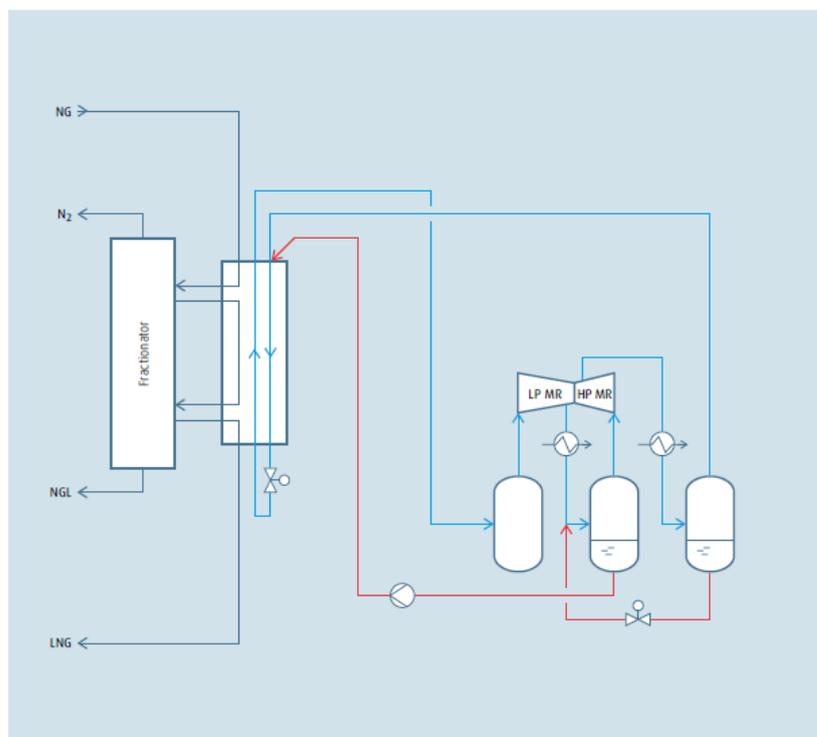


Figure 16: LIMUM® 1 process (Courtesy of Linde)

LIMUM® 3 is adapted to capacities ranging between 30 to 150 MMscf/d (6,00 to 3,000 tpd)

In this arrangement the LP mixed refrigerant is compressed in a two stage centrifugal compressor and partially condensed against cooling water or air. The heavy, liquid mixed refrigerant fraction is used in a CWHE to pre-cool natural gas and to condense the light, gaseous mixed refrigerant fraction partially. The resulting, intermediately boiling mixed refrigerant fraction serves as liquefaction refrigerant, while the remaining light ends mixed refrigerant fraction sub-cools the liquefied natural gas.

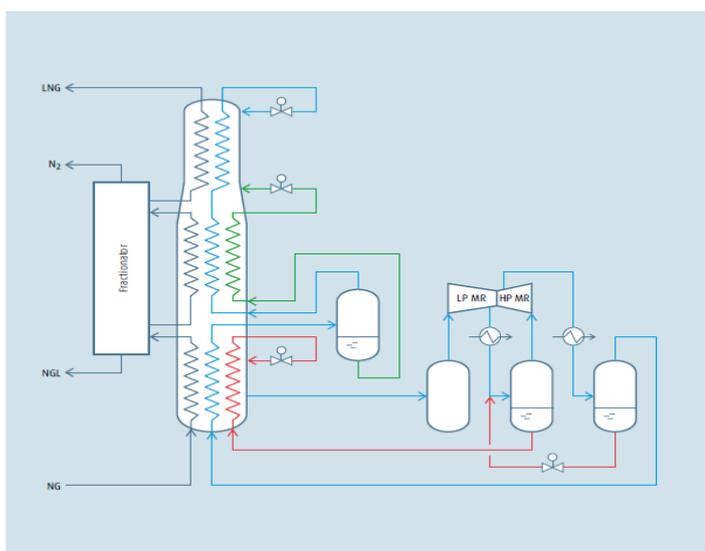


Figure 17: LIMUM® 3 process (Courtesy of Linde)

The LIMUM® 1 and LIMUM® 3 technologies are in commercial use and have several references. The smallest referenced capacity is about 6 MMscf/d (120 tpd) and there are 4-5 references in the range 6 to 15 MMscf/d (120-300 tpd).

#### GAS QUALITY REQUIREMENT

The gas quality requirement is independent of the size and technology of the liquefaction unit. As a consequence the quality requirement is similar to all plants.

#### GAS QUALITY VARIATION

Composition variations can be handled within a certain range. However this depends significantly on the gas composition, degree of variation and possible measures within process design which can already be considered during the design phase.

#### PRESSURE EVOLUTION

Below approx. 50 barg feed pressure, there is a strong impact on the energetic efficiency. As a rule of thumb, a 10 bar pressure drop results in approx. +/- 10% efficiency reduction. Above 50 barg feed pressure, the efficiency increase per increase in feed pressure still increases but less pronouncedly.

#### UTILITY REQUIREMENT

Electric Power (alternatively for MR cycle: steam in case of a steam turbine driver or fuel gas in case of a gas turbine driver).

Nitrogen for purging and seal gas, Instrument Air (IA) for pneumatic control valves.

MR Make Up: Nitrogen (available as plant utility), Methane (from dry feed gas), Ethane/ethylene, Butane (commercial grade, to be purchased).

#### CARBON FOOTPRINT

Depending on the design and operating philosophy, e.g. no flaring philosophy except for emergency, carbon footprint of such a plant can be minimized and the major CO<sub>2</sub> generation will be related to the power consumption of the MR compressors.

No environmental issues are known that have stopped LNG projects awarded to Linde. Some of Linde's reference plants have been built with close proximity (few kilometers) of residential areas or next to environmental sensitive areas (sea, nature reserves).

## APPLICATION IN LESSER DEVELOPED COUNTRIES

Make up refrigerant required for the SMR process only requires supply of commercial butane and ethane/ethylene which is normally available globally; especially if an NGL plant is nearby. Methane is taken from dry feed gas and N<sub>2</sub> is available as plant utility at Site.

Both process technologies require well trained, reliable and educated operational personnel. Even though SMR process operability is more demanding than a nitrogen cycle, the required skills of operators are similar and can be ensured through extensive training.

## APPLICATIONS IN SPECIFIC ENVIRONMENTS

No such limitations are present. References exist for plants in operation under harsh climatic conditions (e.g. Northwest China, Norway).

## LINDE'S GENERAL REFERENCES

Linde has a number of plants in operation:

- In remote areas
- With oil production associated gas application; however typically with upstream NGL extraction.
- With low pressure feed gas pressure application
- With significantly changing flow over time. In several of Linde's plants, feed gas unavailability has led to plant operation at flow levels as low as 20% of the design capacity. Such turndown is only achievable with Linde's proprietary CWHE design and the LIMUM® SMR process, which is typically applied from capacities of 300 tpd. The STARLNG™ process technology with PFHE is able to handle feed gas flow variation within a certain range (up to 50%).

### 5.4.2. Black & Veatch

Black & Veatch has developed a proprietary mixed refrigerant process, PRICO®, which has been used in base load and peak shaving applications. It is a SMR loop and a single refrigeration compression system. The MRt is made up of nitrogen, methane, ethane, propane and iso-pentane. The component ratio is chosen to closely match its boiling curve with the cooling curve of the specific feed gas composition. The closer the curves match, the more efficient the process becomes. The MR is compressed and partially condensed prior to entering the insulated enclosure known as the "cold box".

The cold box contains a number of PFHE cores that allow multiple streams to be heated / cooled to extremely close temperature differentials. The MR is fully condensed and then flashed from high pressure across an expansion valve, causing a dramatic reduction in temperature. This very cold vapour is used to condense the MR stream, as well as the natural gas feed stream. The warmed LP MR vapour is then sent to the compressor for recompression. The natural gas feed stream enters the cold box and is initially cooled to about -35°C. The gas is then sent to a separator to remove heavier components, which are sent to the fractionation plant. The expanded MR then cools the remaining light components, primarily methane, to liquefaction temperature.

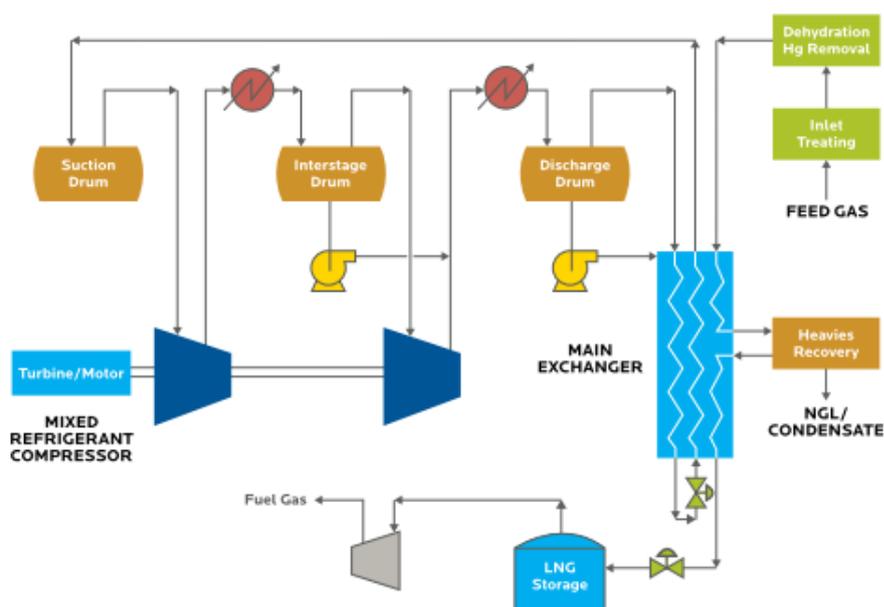


Figure 18 - PRICO® Process Flow (Courtesy of Black & Veatch)

The PRICO® process is in commercial use.

There are 14 references in the range 3 to 18 MMscf/d. Capacities from 1 MMscf/d should be possible, as the technology is feasible at virtually any size.

The mixed refrigerant process has a low equipment count which helps in the ease of operation and minimization of maintenance costs. Having only one compression system, the mixed refrigerant process should have the highest reliability.

Black & Veatch's standard unit includes gas treating (sulphur, mercury removal and dehydration) capable of handling a wide range of feed gas compositions and pressures and to prepare the gas for liquefaction. If other feed components like benzene, n-hexane, and mercaptans are present that may cause issues in the cold box additional gas treating may be required.

The PRICO® process can handle a wide variety of feed gas compositions, ambient temperature conditions, and other operating parameters. By adjusting the refrigerant composition, plant production is optimized for the feed conditions at the time of start-up. While a precise refrigerant composition is not necessary to operate the unit, the composition can be modified “on the fly” to maintain optimal performance of the unit. High purity refrigerant makeup components are not required and readily available commercial grade components, purchasable from the market even in lesser developed countries and/or remote areas, can be used.

Black & Veatch has developed a modularized LNG plant, including all associated gas treating, storage and off-loading, and it is available in the following approximate sizes: 8 MMscf/d, 16 MMscf/d, 24 MMscf/d, and 32 MMscf/d. All these designs are in modular units which can be mixed and matched as desired,

Black & Veatch provides EPC services for the full turnkey design and build of LNG facilities, including the PRICO® LNG one-time non-transferrable technology license and its associated guarantees. Black & Veatch do not currently have a leasing or rental scheme but this could be considered on a project by project basis.

### 5.4.3. Chart

Chart offers several technologies:

- Nitrogen cycle
- Integrated Pre-cooled Single Mixed Refrigerant (IPSMR) – see figure below
- IPMSR+ which includes an additional pre-cooling with Chart’s core-in-kettle exchangers) – see figure below

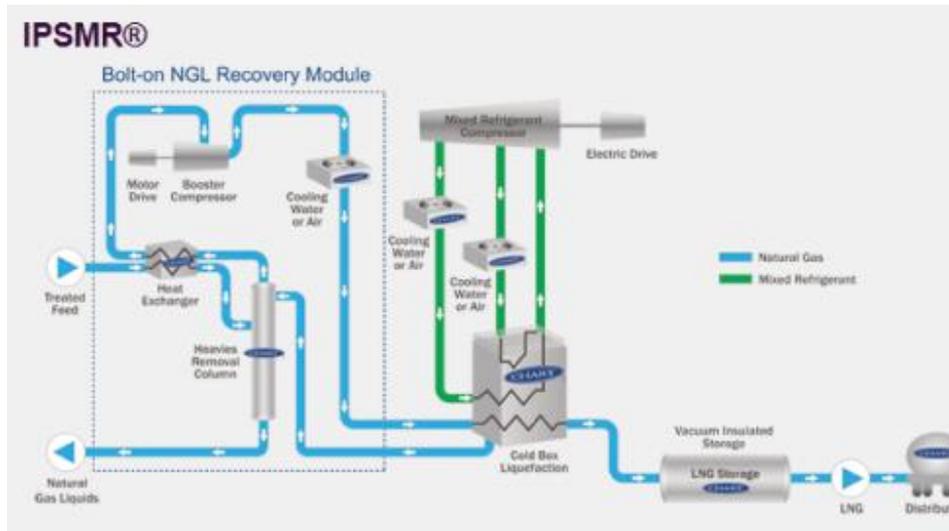


Figure 19: IPSMR process (Courtesy of Chart)



### 5.4.3.1. CHART REFERENCES

Only one reference is known so far, in Pakistan, using MR (further information is not available from the vendor).

## 5.4.4. Wartsila / Hamworthy

Wartsila / Hamworthy offers technologies based on:

- Brayton Nitrogen Expansion
- MR cycles (Mini LNG)

### 5.4.4.1. BRAYTON NITROGEN CYCLE

The Nitrogen Expansion based technology is proposed for the ~1.5 to 25 MMscf/d (30 to 500 tpd) capacity range.

The following figures show the principles of the cycle.

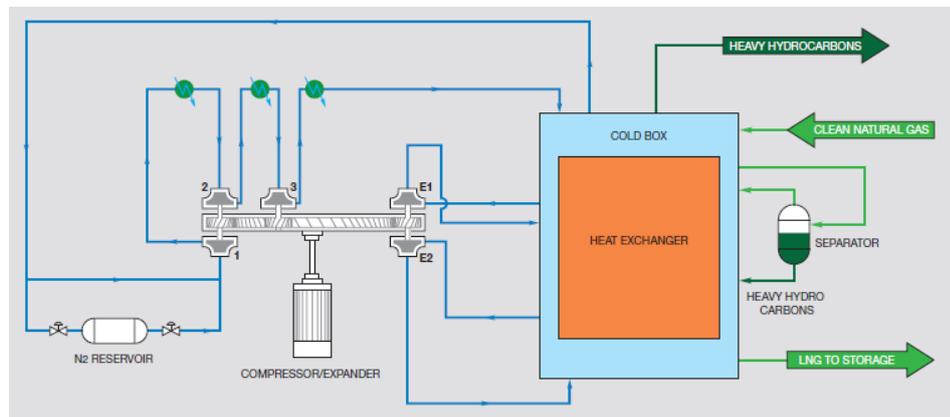


Figure 21: Nitrogen expansion cycle (Courtesy of Wartsila / Hamworthy)

This technology is used for onshore applications and is also used as LNG carrier on-board re-liquefaction units.

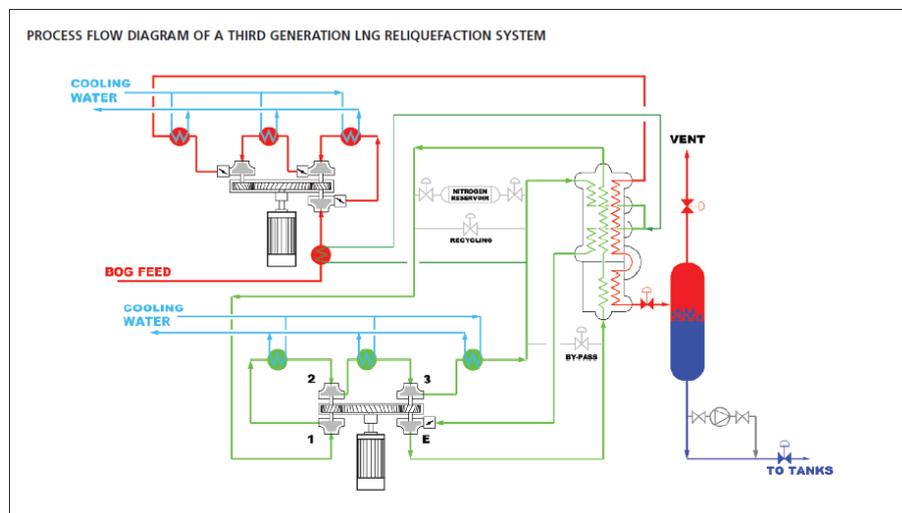


Figure 22: Third generation on-board BOG re-liquefaction process (Courtesy of Wartsila / Hamworthy)

This process is in industrial use and there are some references (additional information out of reach) in the range 1 to 15 MMscf/d for onshore applications.

#### 5.4.4.2. MINILNG / NEWMR

The MiniLNG / NewMR is based on a mixed refrigerant cycle. It seems that this technology has one reference in the 1-15 MMscf/d range (further information not available).

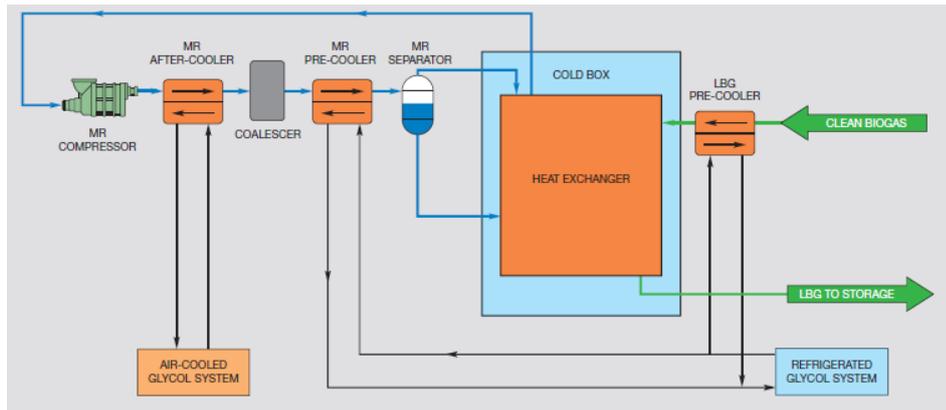


Figure 23: MiniLNG / NewMR liquefaction process (Courtesy of Wartsila / Hamworthy)

Please note that the Wartsila / Hamworthy branding seems to be evolving from MiniLNG to NewMR (very limited information available in these regards)

#### 5.4.5. GE Oil & Gas

GE Oil & Gas offers liquefaction technologies from its ‘Small Scale LNG’ product line. Please note that GE Oil & Gas product line is evolving and now includes the Salof technologies.

The ‘Small Scale LNG’ portfolio includes various technologies:

- Expansion with BOG or nitrogen refrigeration
- Pre-Cooled Mixed Refrigeration (PCMR)
- Single Cycle Mixed Refrigeration (SCMR)

GE's 'Small Scale LNG' portfolio covers the range 2 to 300-400 MMscf/d (40 to 6,000-8,000 tpd).

The working principle of the nitrogen expansion cycle (LH side of figure) and boil off gas expansion cycle (RH side of figure) are shown below:

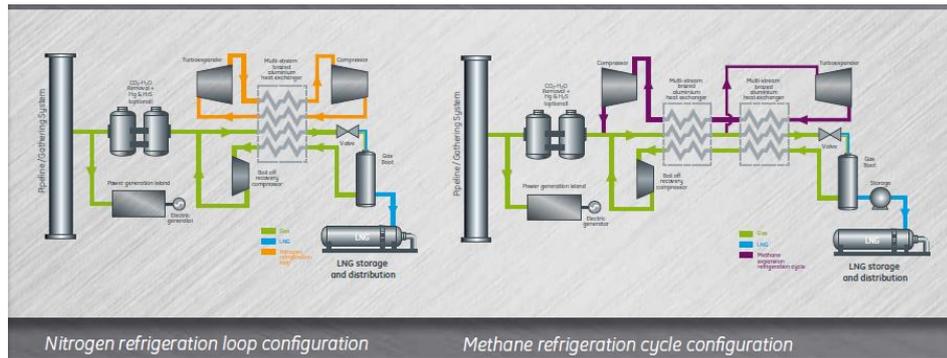


Figure 24: Small Scale LNG liquefaction process (Courtesy of GE Oil & Gas)

GE Oil & Gas has about 10 references in the 1-15 MMscf/d range. GE Oil & Gas (Salof) has references for each type of liquefaction technology (GE do not provide additional information)

GE Oil & Gas offers fully integrated plants. For these plants, the smaller the size the higher the modularity, they can be:

- Stick built
- Modular
- Fully Modular Plug-n-Play



Figure 25: Small Scale LNG liquefaction skid (Courtesy of GE Oil & Gas)

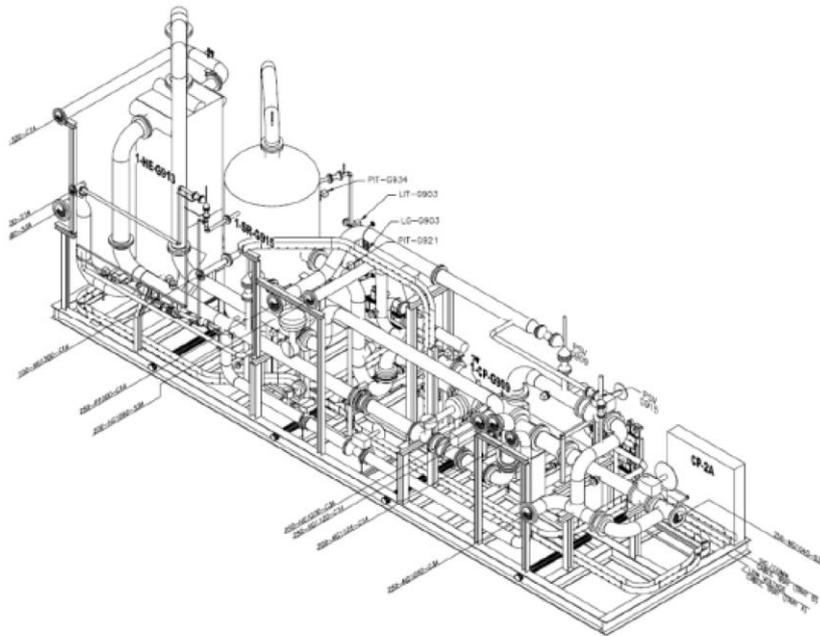


Figure 26: Small Scale LNG liquefaction skid (Courtesy of GE Oil & Gas)

#### 5.4.6. Galileo

Galileo proposes a liquefaction technology from its Cryobox® product line. Galileo's Cryobox® system is a compact natural gas liquefaction plant in trailer-size modules capable of producing 12 to 16 tpd of LNG per module (equivalent to about 0.6 to 0.8 MMscf/d).

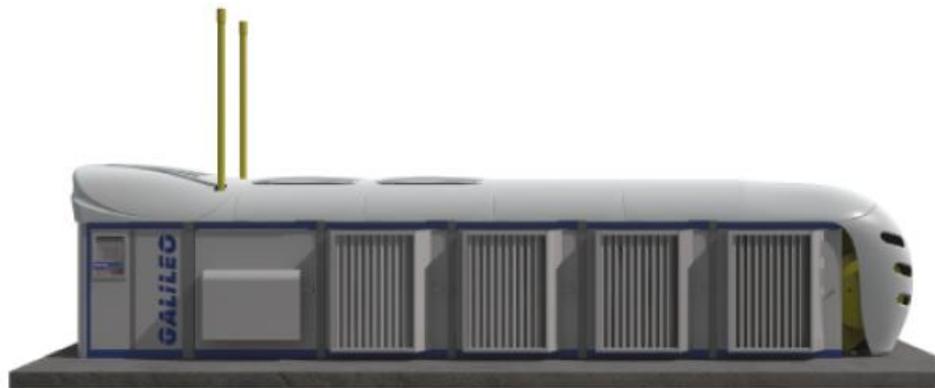


Figure 27: Cryobox® (Courtesy of Galileo)

Cryobox® Liquefaction technology is based on a compression and expansion process; no more detailed information on the liquefaction process is available.

The pre-treatment technology is made up of zeolite adsorption modules (= molecular sieves). More modules are added according to the gas composition if needed.

Cryobox® can easily be deployed with no need of major infrastructure. The only requirements are ground levelling and inlet/outlet connections. If there is no electrical power available, the best options are natural gas fired generator(s) or a (higher cost) natural gas motor.

Although Galileo’s technology is new in the market, there are already seven in operation in Argentina and one is scheduled to start production in March 2015 in North Dakota (USA), for flaring mitigation applications.

Sale and rental options are available. Rental schemes are adapted to each operation, where full on-site service support is provided, with production volume supply and quality guaranteed by contract, and technological updates at no cost during contract duration. Companies which prefer not to take on the technological risk find this approach extremely beneficial.

#### 5.4.7. Dresser-Rand

Dresser-Rand offers liquefaction technology from its LNGo™ product line. Dresser-Rand’s LNGo™ system is a modularized, portable natural gas liquefaction plant capable of producing 10 to 14 tpd (equivalent to about 0.5 to 0.7 MMscf/d). The production plant is a standardized product made up of four packaged skids: a power module, compressor module, process module and a conditioning module. The unit is powered by natural gas which is also used as the process refrigerant to eliminate complexity and maintenance.

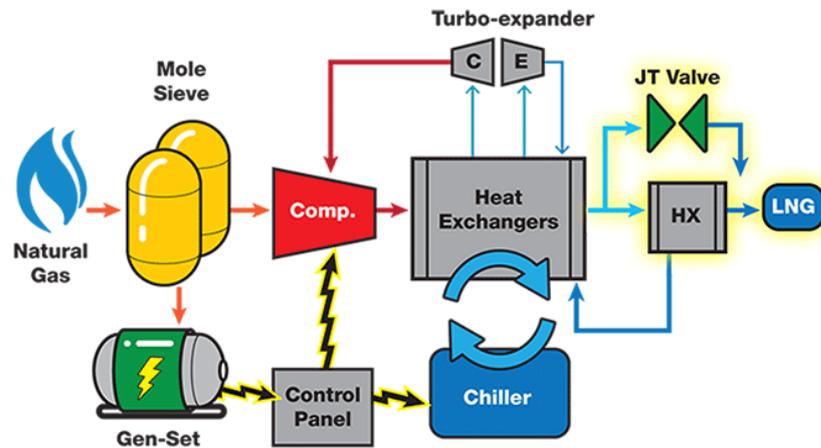


Figure 28: LNGo™ Process (Courtesy of Dresser-Rand)

- Pipeline gas enters the system, directed to the mole sieve and the compressor for CO<sub>2</sub> and H<sub>2</sub>O removal.
- Mole sieve waste gas is blended with pipeline gas to fuel the engine/generator.
- Gas compressed by the reciprocating unit is cooled by the chiller system. Dresser-Rand Engineuity® control panel provides automatic control.
- Turbo-expander cools the compressed natural gas (CNG), while the patented heat exchanger arrangement maximizes cooling.
- Joules-Thompson (JT) valve combines with a final heat exchanger providing LNG output.



Figure 29: LNGo™ Conditioning, Power, Compressor & Process Modules (Courtesy of Dresser-Rand)

The Dresser-Rand LNGo™ system is not yet in commercial use; there is only one demonstration unit (for which only limited information is available).

## 5.5. Liquefaction Process Gas Pre-Treatment Requirements

No differentiators were identified between the various liquefaction technologies in terms of gas pre-treatment requirements.

Before entering the liquefaction unit the gas must be treated in order to remove the impurities that otherwise would be detrimental to the process. These impurities typically are water, carbon dioxide, hydrogen sulphide, oxygen and mercury as well as COS (Carbonyl Sulphur) and other sulphur compounds. In addition, heavy hydrocarbons (C5+) must be removed as they cause freezing problems in the cryogenic heat exchangers.

The typical gas specifications at the liquefaction section inlet are:

- Water: 0.1 ppmv max
- Carbon dioxide: 50 ppmv max
- Hydrogen Sulphide: 4 ppmv max

A number of technologies are available to achieve these specifications. Typically, the following are used:

- Molecular sieves for water removal
- Molecular sieves, Amine unit & Membranes for acid gas removal
- Chilling for heavy hydrocarbons removal

Pre-treatment of associated gas can be significantly more complex than pipeline gas as the impurities may be present in higher quantities, particularly heavy hydrocarbons. This will require greater equipment capacity, higher energy consumption, and increased impurities disposal and by-products management. It also can contain large amount of ethane, propane, butane that may have to be removed/reduced depending on the LNG specification requirements. Unless they can be spiked into the oil stream, these hydrocarbons will need to be stored and exported, increasing CAPEX and requiring additional space and logistics. It is to be noted that, should ethane have to be removed, there is no guarantee that there would be a (local) market for this product..

Depending on the associated gas supply pressure, compression may have be required, if deemed globally beneficial( as it is usually more economical to add a feed gas compression rather than operating on a low pressure liquefaction basis). This will increase the CAPEX and space requirement, and potentially reduce availability/reliability.

## 5.6. Summary of the mini/micro LNG liquefaction technologies

### 5.6.1. Capacity range by supplier

According to information provided by some of the potential suppliers and / or gathered from the literature, there are numerous mini/micro LNG liquefaction systems in the range 1-15 MMscf/d (20-300 tpd):

Supplier	Name	Technology	Capacity range (1)
Black & Veatch	PRICO®	Mixed refrigerant	1-15+ MMscf/d
Chart	C100N	Nitrogen cycle	8 MMscf/d
Dresser-Rand	LNGo™	Gas compression / expansion	0.5-0.7 MMscf/d
Galileo	Cryobox®	Gas compression / expansion	0.6-0.8 MMscf/d
GE	LNG in a box™	Salof technologies (2)	0.8-4 MMscf/d
GE	Micro LNG	Salof technologies (2)	4-15+ MMscf/d
Linde / Cryostar	StarLiteLNG™	Nitrogen cycle	1-10 MMscf/d
Linde	StarLNG™	Nitrogen cycle or Mixed refrigerant	5-15+ MMscf/d
Linde	LIMUM™	Mixed refrigerant	5-15+ MMscf/d
Wartsila / Hamworthy	MiniLNG	Nitrogen cycle	1.5-15+ MMscf/d(3)
Wartsila	NewMR	Mixed refrigerant	< 2.5 MMscf/d (3)

- (1) For a single unit/plant;
- (2) EXP (compression / expansion boil-off gas refrigeration) or N2 (compression / expansion nitrogen refrigeration) or PCMR or SCMR
- (3) To be confirmed.

For lower capacities around 1 MMscf/d, the new “micro LNG” solutions proposed by Dresser-Rand (LNGo™), Galileo (Cryobox®), GE (LNG in a box™) and Linde / Cryostar (StarLiteLNG™) seem promising; however these solutions are just beginning to be commercialized.

For higher capacities, a more proven single “mini LNG” plant (as proposed by Black & Veatch, Chart, GE, Linde or Wartsila) can be used, as a conventional plant, or in a modular approach. As an alternative “micro LNG” units could also be used (e.g. the BUQUEBUS LNG station; see next figure), depending on the overall costs and planning of a specific project.



Figure 30: BUQUEBUS LNG station (Argentina) equipped with 7 Cryobox (Courtesy of Galileo)

## 5.6.2. CAPEX

According to information provided by some of the potential suppliers and / or gathered from the literature, the CAPEX of the equipment required for a mini/micro LNG liquefaction plant (including some “standard” gas pre-treatment but no LNG storage) in the range 1-15 MMscf/d should be in the range 4-27 MMUSD (2014), as shown by the following graph (N2 = nitrogen cycle; Gas = gas expansion process):

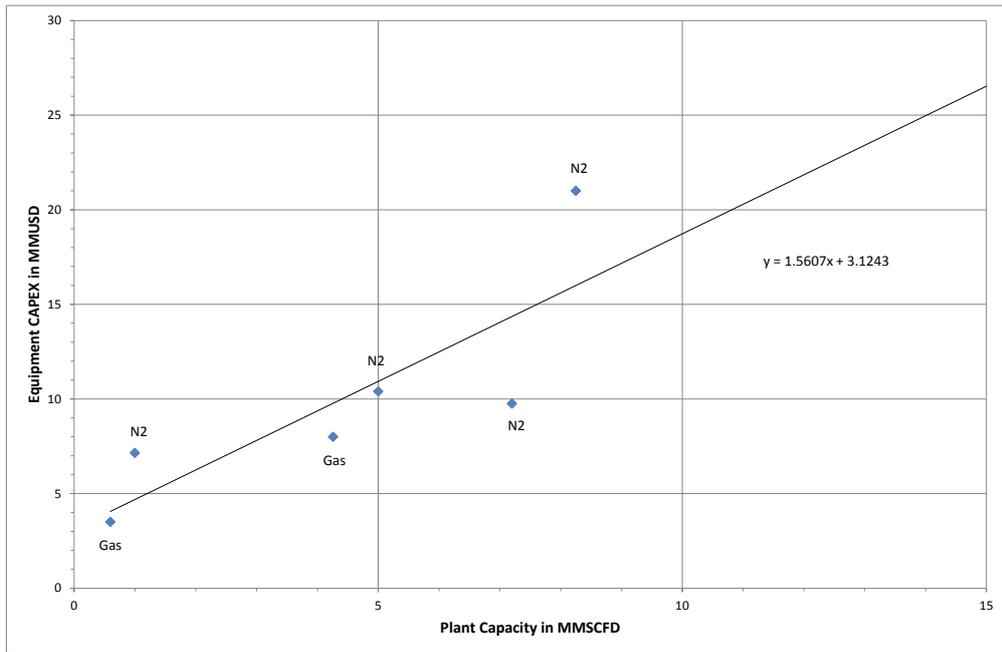


Figure 31 – Equipment CAPEX vs Plant Capacity

It was not possible to make a clear distinction between the equipment CAPEX of the different technologies (nitrogen cycles or gas expansion cycles; no specific equipment CAPEX was available in the 1-15 MMscf/d range for mixed refrigerant cycles). This is in accordance with some information that can be found in the literature.

In order to obtain the total installed cost (in MMUSD 2014), the above values should be approximately be doubled:

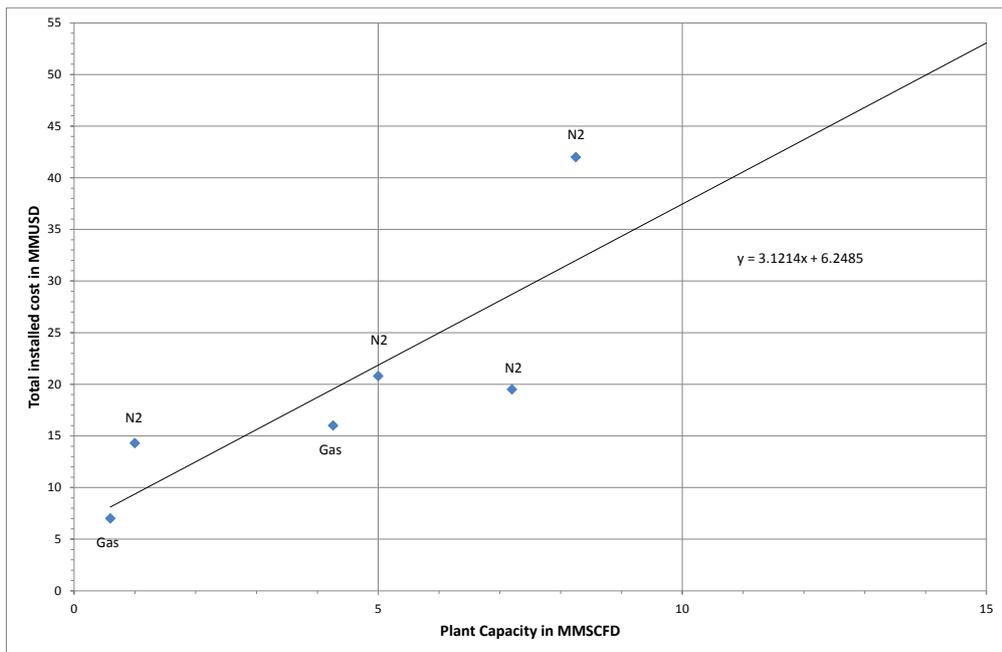


Figure 32 – Total installed cost vs Plant Capacity

The above cost data include gas treatment equipment for a "typical" pipeline gas composition (i.e. low carbon dioxide, nitrogen, heavy hydrocarbons, water content, and minimal sulphur compounds or mercury); however the information provided by the suppliers did not include details as to the gas pre-treatment. Therefore there would likely be additional CAPEX for gas pre-treatment unit for associated gas as feed gas, the amount depending on the specific gas composition. There could also be additional CAPEX depending on the gas composition and / or LNG quality specification; for example if a lean LNG is required from a rich associated gas, a LPG extraction unit would be required, or if the associated gas nitrogen content is too high, a Nitrogen Rejection Unit could be required.

The above cost data are considered reasonable as indicative values for an associated gas recovery project economic evaluation. Each project, however, has its own specific constraints that could lead to increased cost.

#### 5.6.2.1. GAS PRE-TREATMENT UNIT

Mini/micro LNG liquefaction plants typically include a "standard" gas pre-treatment train consisting of:

- Mercury removal unit;
- Acid gas removal unit (amines);
- Dehydration unit (molecular sieves).

The CAPEX for this level of processing is included in the liquefaction cost vs capacity plot above. If the feed gas quality is such that additional treatment is required, this will entail additional CAPEX.

The CAPEX for such additional gas pre-treatment is estimated to be ~19 MMUSD for a 15 MMscf/d plant. According to the previous chapter this could represent an increase of about 35% of the CAPEX of a "mini LNG" liquefaction plant (of about 15 MMscf/d), and even more in case of a "micro LNG" plant (of about 1 MMscf/d).

Gas quality is therefore a key factor that could impact the economics of an eventual associated gas recovery project, especially at the lower end of the foreseen 1-15 MMscf/d capacity range.

#### 5.6.3. Operating cost and specific consumption

Apart from the maintenance cost and of the eventual operator(s) cost (depending on the plant size and level of automation), the OPEX of a mini/micro LNG liquefaction plant mainly comes from the power consumption.

According to information provided by different potential suppliers and / or gathered from the literature, the specific power consumption of a mini/micro LNG liquefaction plant in the range 1-15 M MMscf/d should be in the range 0.7-1.1 kWh per kg of LNG produced, as shown by the following graph:

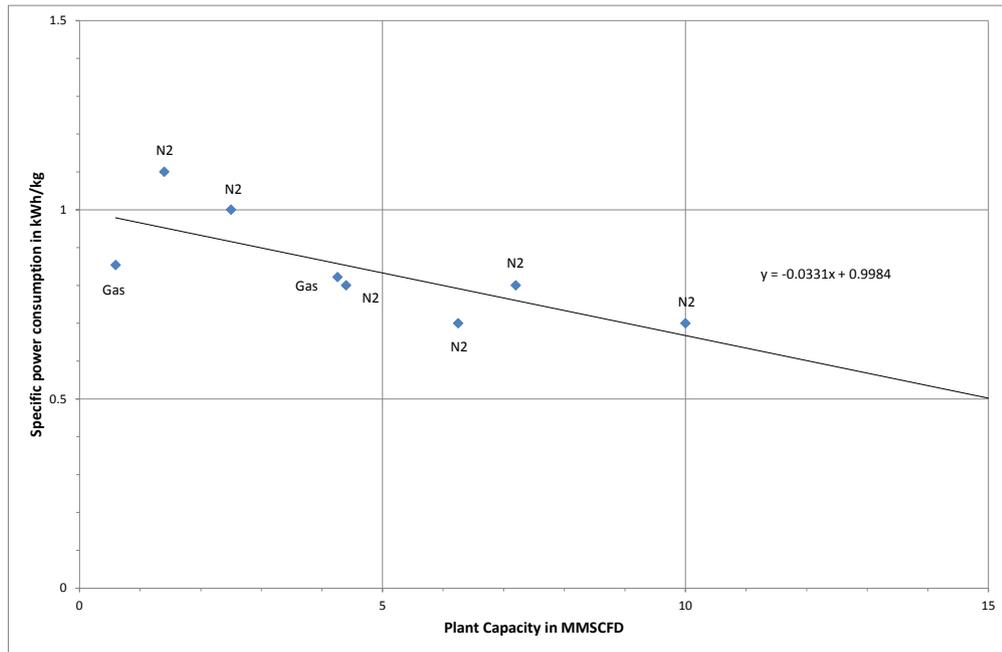


Figure 33 – Equipment CAPEX vs Plant Capacity

All the above data comes from nitrogen or gas expansion cycles; no specific consumption figure was available in the 1-15 MMscf/d range for MR cycles.

According to the literature, nitrogen cycles should have higher specific consumption of 15 to 35 % compared to MR cycles, depending on the liquefaction plant data (feed gas quality and supply pressure, ambient temperature...).

One supplier claims that he can reach a specific consumption as low as 0.6 kWh/kg for a plant capacity of ~1 MMscf/d with a non-mixed refrigerant cycle, but this is still to be confirmed on an actual real associated gas project.

Unless a specific project and location is defined, it is therefore not really possible to compare the specific consumption of the possible LNG liquefaction solutions proposed by the different suppliers.

#### 5.6.4. Greenhouse gas (GHG) emissions

The following processes lead to GHG emissions in a mini/micro LNG liquefaction plant:

- Power generation;
- Heat generation;
- Acid gas removal unit vent;
- Dehydration unit regeneration gas vent;
- Emergency or maintenance venting.

The main GHG emissions from a mini/micro LNG liquefaction plant are due to fuel gas combustion for power generation from gas engine(s). However if the mini/micro LNG liquefaction plant uses electrically driven compressors without on-site electrical power generation, there will be no on-site GHG emission for power generation.

The requirement for heat generation for gas pre-treatment depends on the type of gas pre-treatment required; heat is generally required for the amine regeneration reboiler and for the dehydration molecular sieve regeneration. If the mini/micro LNG liquefaction plant uses gas on-site gas engine(s), heat can usually be recovered from the flue gas. The level of GHG emissions associated with heat generation thus depends on the gas pre-treatment configuration, on the type of power generation, and on the degree of heat integration of the plant.

The acid gas vent is a small flow, mainly consisting of carbon dioxide and the hydrogen sulphide initially present in the feed gas, plus some water and a small amount of methane. The GHG emissions associated with this stream thus depend on the feed gas composition.

The dehydration unit regeneration gas is a flow mainly consisting of natural gas and water. It can be burnt as fuel gas for power generation (in case a gas motor is used), or recycled internally, or even vented if the regeneration flow is very small, as this is an unnecessary loss of feed gas. The GHG emissions associated with this stream thus depend on the gas pre-treatment configuration, the type of power generation, and on the degree of heat integration of the plant.

Emergency or maintenance venting needs to be evaluated on a case by case analysis. It has to be noted that gas expansion or mixed refrigerant processes will lead to hydrocarbons release to the atmosphere in case of venting of the liquefaction cycle loop, while it won't be the case for nitrogen cycles.

#### 5.6.4.1. POWER GENERATION BY GAS ENGINE

If the mini/micro LNG liquefaction plant is equipped with on-site electrical power generation based on gas engine(s), the estimated GHG emissions due to the power generation are about 0.4 to 0.9 t CO<sub>2</sub>eq per t LNG produced; the exact value depends on the associated gas composition, gas engine efficiency and liquefaction plant specific consumption.

#### 5.6.5. Pros and cons of the main liquefaction processes

The following table provides a basic qualitative comparison between the different types of liquefaction processes discussed in the previous chapters of this report (“+” is more favourable, “-” is less favourable):

	<b>Nitrogen cycles</b>	<b>Mixed Refrigerant cycles</b>	<b>Gas expansion cycles (3)</b>
Efficiency	-	+	-
Safety	+ (2)	-	-
Complexity	+	-	+
Flexibility	-	+	-
CAPEX	=	=	=
References (1)	+	+	- (4)

- (1) In the 1-15 MMscf/d range.
- (2) No hydrocarbons in the liquefaction cycle.
- (3) Gas expansion cycles as proposed by GE Oil & Gas, Galileo or Dresser-Rand, without a dedicated low pressure gas utilisation (other than the fuel gas for internal power generation).
- (4) This type of liquefaction process has actually no real commercial reference.

It can be concluded from the above table that no liquefaction process has all the advantages and no disadvantages. The nitrogen or mixed refrigerant cycles are credible and proven alternatives for the 1-15 MMscf/d range, while the gas expansion cycles are promising solutions for the lower side of this capacity range. Some project specific constraint (like safety or flexibility) might be in favour of the nitrogen cycles, while the increased flexibility of the mixed refrigerant cycles might be required to match a specific associated gas production profile (with changing composition).

### 5.6.6. Applicability to offshore projects

Some of the above mentioned “main” LNG liquefaction plants suppliers, such as Black & Veatch and Linde, have some experience and / or have made some developments in offshore applications. Therefore it should be possible to implement an offshore LNG liquefaction plant in the range 1-15 MMscf/d with this kind of supplier; however it would be on a case by case basis (to be confirmed).

## 6. LNG STORAGE

There are two main types of LNG storage tanks: vertical cylindrical flat bottom tanks (or self-supporting) and vacuum insulated pressurized tanks (bullets).

As a general rule, the main selection criterion to choose one or the other is the volume of LNG to be stored. For larger LNG volumes, vertical cylindrical tanks are the optimum solution, due mainly to their lower cost per m<sup>3</sup> of LNG and lower space requirement (mainly for full containment type<sup>1</sup>).

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<sup>1</sup> Single and double containment type are not considered for this study due to the space required for the secondary containment

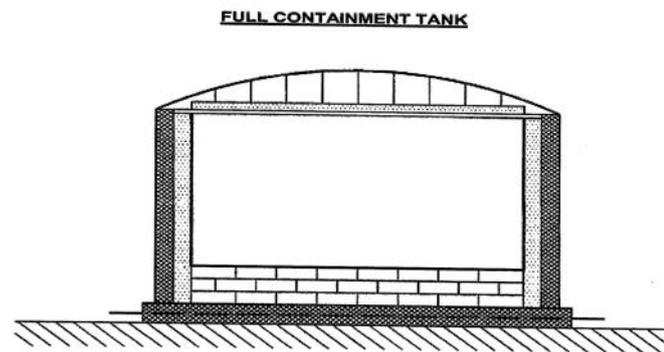


Figure 34 Vertical cylindrical flat bottom tank

For small volumes the vacuum insulated tanks are the best option for several reasons: short delivery time, can be built in the workshop (maximum volume of per unit of 1,000m<sup>3</sup>), simpler and less expensive foundation system, allows modular and sequential construction, better behaviour in seismicly active areas and lower boil-off gas generation from heat ingress.



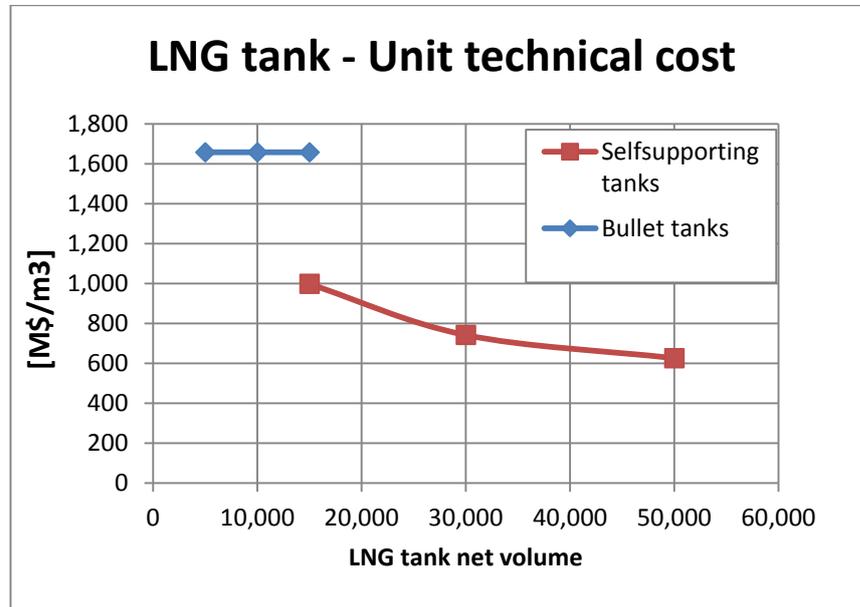
Figure 35 Vacuum insulated pressurized tanks

The breakeven point between one technology and the other is between 10,000m<sup>3</sup> to 15,000m<sup>3</sup>; below 10,000m<sup>3</sup> vacuum insulated tanks are recommended, while above 15,000m<sup>3</sup> flat bottom tanks are preferred. For intermediate volumes (from 10,000 to 15,000m<sup>3</sup>) the storage type should be analysed case by case.

Analysis the cost per m<sup>3</sup> for both technologies, we obtain:

- Cost of LNG storage for bullets is roughly 2,000 USD /m<sup>3</sup> (for a storage volume of 1,000 to 15,000m<sup>3</sup>)

- Cost for LNG self-supporting tank is roughly 1,000 to 1,300 USD/m<sup>3</sup> (for tanks from 15,000 to 30,000m<sup>3</sup>)



## 7. LNG TRANSPORTATION

LNG distribution from the liquefaction facilities to consumers could be either by land using LNG trucks/trailers or by water using LNG ships/barges. Railway transportation is not considered in the scope of this study.

The selection of one or the other will depend on several factors:

- Location: sea side, waterway,
- Required investment: infrastructure, number of units, etc.
- LNG production (volume to transport)
- Existing infrastructure: roads, traffic
- Distance to consumers

All these factors will determine the most suitable transportation system although marine transport obviously requires easy access to the sea or suitable waterways.

### 7.1. LNG transportation by truck/trailer

#### 7.1.1. LNG trailers characteristics

The LNG trucks or trailers are designed for cryogenic temperature.

They are double walled, with internal containment in stainless steel or aluminium and external in carbon or stainless steel and vacuum isolation in between with super insulation (multilayer) or perlite. This system reduces the production losses due to heat transfer; moreover some studies confirm that the LNG can be stored in a trailer for more than 45 days without any venting due to the pressure increase from the boil-off gasses.

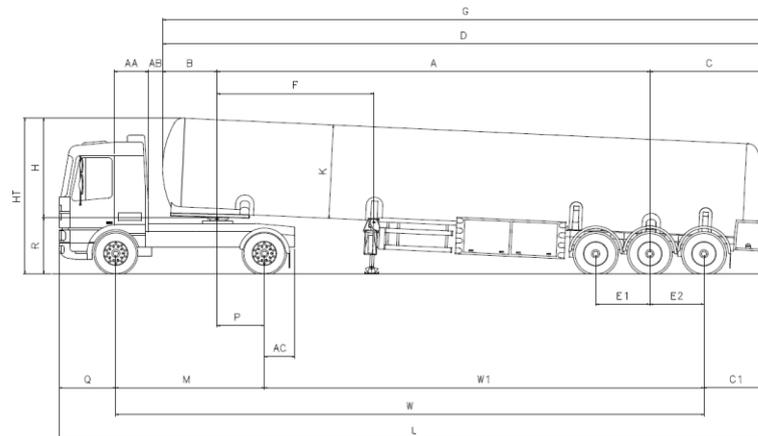


Figure 36: LNG Trailer

### 7.1.2. Safety

The LNG trailer is equipped with safety equipment to protect it against over pressure; a pressure relief device should safely release the gas to the atmosphere if the tank pressure exceeds the maximum allowable working pressure (MAWP).

A safety assessment is recommended in order to identify the potential risks during the truck transit on public roads and highways as well as their consequences and probability of occurrence.

### 7.1.3. Codes and standards

The codes and standards applied for the LNG road transport on trailers are different in each country. However the USA standards on LNG are considered a benchmark and are also followed by other countries such as Australia and Canada.

In the USA, the LNG trucks shall follow the Department of Transportation's design standards DOT CFR49 specifications– 49 CFR parts 173.318 and 178.338 (MC-338) and also the specifications of NFPA 52 'Vehicular Gaseous Fuel Systems Code'.

In Europe the LNG road transport is regulated by the European Agreement International Carriage of Dangerous Goods by Road (ADR).

#### 7.1.4. LNG trailer costs

The cost of LNG trailers varies from one country to other, therefore is very difficult to provide an order of magnitude that could be applicable worldwide.

As reference, an average cost in the US of an LNG trailer of 40m<sup>3</sup> (capacity for maximum allowed weight in the US) is in the range of 300k USD including the tractor.

#### 7.1.5. Methodology for truck number calculation

For estimating the required number of trucks for a specific project the following elements have to be considered:

- Maximum allowed weight in the country
- Maximum allowed speed of the truck
- Distance from the source to the consumer
- Truck traffic regulation (for instance night driven allowed?)
- Loading & unloading time
- LNG demand at the consumer

For instance, for a project in the USA where the consumer is located at 150km from the source, average truck speed of 50km/h and an equivalent LNG consumption of 60m<sup>3</sup>/hour, the optimum number of trucks would be 14. Two spare trucks are included to cover the unavailability of the trucks due to maintenance activities. This means that the terminal would receive around 35 LNG trucks per day.

### 7.2. LNG transportation by ship/barge

If the liquefaction facilities are located at sea or waterway side, LNG transportation by ship or barge could be more interesting than trucks due to the possibility of transporting bigger volumes and longer distances.

The small LNG vessels are a range in size from 1,000 m<sup>3</sup> to 18,000 m<sup>3</sup> and are basically mini versions of conventional LNG carriers. The smallest current LNG carrier is the Knutsen Pioneer with a capacity of 1,100m<sup>3</sup>.

The high cost of small LNG carriers (between 25,000 to 40,000 USD/day), together with a maximum recommended occupancy of 80%<sup>2</sup>, make their use very difficult its use for mini/micro LNG facilities.

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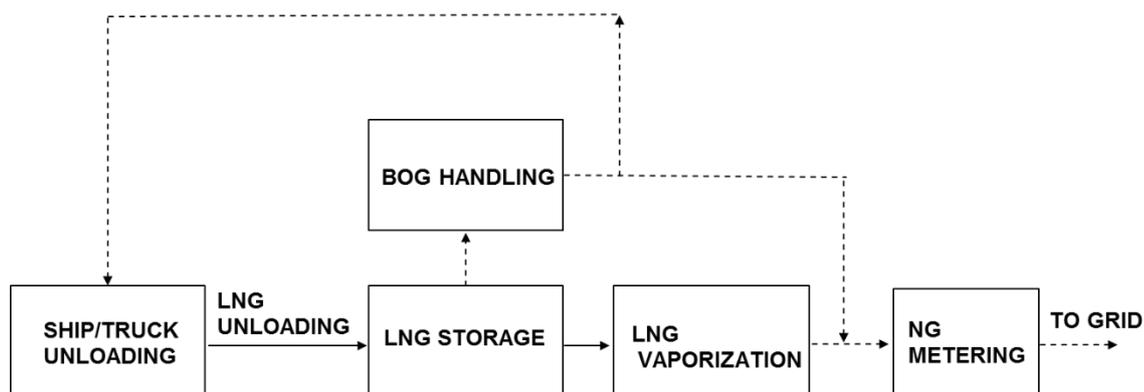
<sup>2</sup> The ship maximum occupancy is calculated to have some allowance for maintenance, inspections and bad weather conditions in order to minimize the impact in the LNG facilities operation.

## 8. RECEIVING FACILITIES

LNG receiving facilities have three main functions:

- Unloading
- Storage
- Send-out and measurement

The LNG is unloaded, sent to the LNG storage and, from there pressurized and vaporized before feeding the gas grid or dedicated consumer.



### 8.1. Unloading facilities

The unloading facilities are significantly different if the LNG transportation is by truck or by ship. In the case of supply by ship, the terminal requires: jetty platform, unloading arms or hoses, gangway, fences and hooks, dolphins, unloading lines, recirculation, etc.

If the LNG is supplied by truck, the facilities are much simpler and therefore less expensive. The main components of LNG truck unloading facilities are:

- weigh-bridge
- unloading bay composed of the following elements
  - unloading pump
  - LNG unloading arm or flexible hose
- safety equipment
- associate utilities

The number of unloading bays is calculated according to the LNG volumes and consequently the number of LNG trucks per day.

## 8.2. Storage

Options for storage at the receiving facility are the same as at the liquefaction plant. See Section §6.

## 8.3. Re-Gasification and Send-out

LNG will be pressurized from the storage tank(s) by LNG pumps up to the consumer pressure level and sent to the vaporizers.

There are four main types of vaporizers:

- Open rack vaporizer (ORV): which uses sea/river water as the heat source, is composed of panel-shaped heat transfer tubes. LNG flows upward inside the finned heat transfer tubes, while water flows down along the outer surface of the tubes.
- Submerged combustion vaporizer (SCV): a fired heat source LNG vaporizer using low pressure fuel gas coming from the boil-off gas system. The SCV uses a heat transfer coil installed in a water bath, with the liquid LNG flowing inside the coil. The conventional vaporizer is equipped with submerged combustion burners firing into the water bath.
- Shell and Tube vaporizer (STV): uses a liquid as heating media to evaporate the LNG. The LNG flows through multiple tubes and the heating fluid enters in the shell surrounding the tubes. If an open loop is used, sea/river water is used as the heating fluid. If a closed loop is used, a variety of fluids can be used: glycol, water, propane, etc.
- Ambient Air vaporizer (AAV): uses air as the heating medium, either with natural or forced draft.

Type of vaporizer	Advantages	Disadvantages
ORV	<ul style="list-style-type: none"> <li>• Low vaporization cost, OPEX for sea water pumps</li> <li>• Use worldwide and proven technology for base load LNG terminal</li> </ul>	<ul style="list-style-type: none"> <li>• Sea water system CAPEX</li> <li>• ORV coating (every 5 years as average)</li> <li>• Water release impact (cold water release) in flora and fauna</li> <li>• Sea water shall be chlorinated to avoid bio-fouling and de-chlorinated before releasing to the sea</li> <li>• Sea water quality as per vendor recommendation (solids, heavy metals, etc.)</li> <li>• Regular maintenance of sea water pumps</li> </ul>

Type of vaporizer	Advantages	Disadvantages
SCV	<ul style="list-style-type: none"> <li>• Lower investment cost than ORV</li> <li>• More flexibility under any conditions</li> <li>• Possible to combine with cogeneration system, reduction in energy consumption and less emissions.</li> </ul>	<ul style="list-style-type: none"> <li>• High operating cost due to the gas consumption (1.3% of total send-out)</li> <li>• High amount of emissions due to combustion of natural gas (NO<sub>x</sub>, CO<sub>2</sub>)</li> <li>• Require a dedicated fuel gas system</li> </ul>
STV/IFV	<ul style="list-style-type: none"> <li>• Lower investment cost than ORV if open loop</li> <li>• Lower maintenance than ORV, if close loop</li> </ul>	<ul style="list-style-type: none"> <li>• Open loop: <ul style="list-style-type: none"> <li>• Sea water release as in ORV: temperature and chlorine content,</li> </ul> </li> <li>• Close loop <ul style="list-style-type: none"> <li>• Water glycol, risk of spillage and contamination</li> <li>• Higher OPEX for air heaters and water pumps than ORV</li> <li>• Require a stable LNG and water flow to avoid icing</li> </ul> </li> </ul>
AAV	<ul style="list-style-type: none"> <li>•OPEX mainly null</li> <li>•Maintenance null, no corrosion no erosion</li> <li>•Not external coating is required</li> <li>•Zero emissions, zero releases</li> </ul>	<ul style="list-style-type: none"> <li>• Higher CAPEX</li> <li>• Large footprint</li> <li>• Distance between banks of minimum 4.5meters to avoid cold air recirculation</li> <li>• If big amount of units, the middle tubes efficiency could be affected</li> </ul>

Vaporizer type ranking regarding CAPEX and OPEX is:

Vaporizer	CAPEX (higher to lower)	OPEX (higher to lower)
ORV	2	2 or 3 <sup>3</sup>
SCV	1	1
STV/IFV	3	2 or 3
AAV	4	4

For low volume facilities, ambient air vaporizers are in most of the cases the most suitable choice for the LNG re-gasification mainly due to the negligible OPEX and environmental impact even if CAPEX is the highest. This type of vaporizers have been proven in small scale LNG Terminals since many years ago with a very good performance even in adverse weather conditions like Norway.

Once re-gasified, the natural gas is sent to the consumers/grid through the metering station.

## 8.4. Utilities and buildings

In addition to the main systems, the importing facilities will require the following utilities and buildings:

- Electricity
- Instrument air
- Nitrogen system
- Water system
- Fire protection
- Flare/vent
- Buildings<sup>4</sup>: Control room/ warehouse/ workshop/ administration building

## 8.5. Capital cost

The capital cost of a receiving facility varies as a function of a number of parameters: storage capacity, send-out capacity, send-out pressure, unloading facilities, local conditions (supply of equipment and raw material, manpower cost), etc.

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<sup>3</sup>ORV OPEX is lower than STV if close loop due to the water and air heaters

<sup>4</sup> The number/design of the buildings will depend on the size of the facilities. It should be analysed case by case.

An order of magnitude capital cost estimate for a typical (non-marine) receiving facility with the following characteristics:

- Storage capacity of 4,000m<sup>3</sup> (3 days)
- Send-out gas at medium pressure (~45barg)
- Ambient air vaporizers
- 3 truck unloading bays
- Utilities and buildings

would be around 35 MMUSD.

## **8.6. Operating cost**

The operating cost (OPEX) of LNG Terminal is mainly composed of:

- Personnel (salaries, training, consultant, etc.-)
- Consumables (water, nitrogen, oil, dry powder, emulsifier, electricity, etc.)
- Maintenance (outsourcing, spare parts, etc.)
- Other costs (insurances, customs and taxes, etc.)

being the consumables (mainly electricity) and personnel the most important components. Both strongly depend on the local conditions.

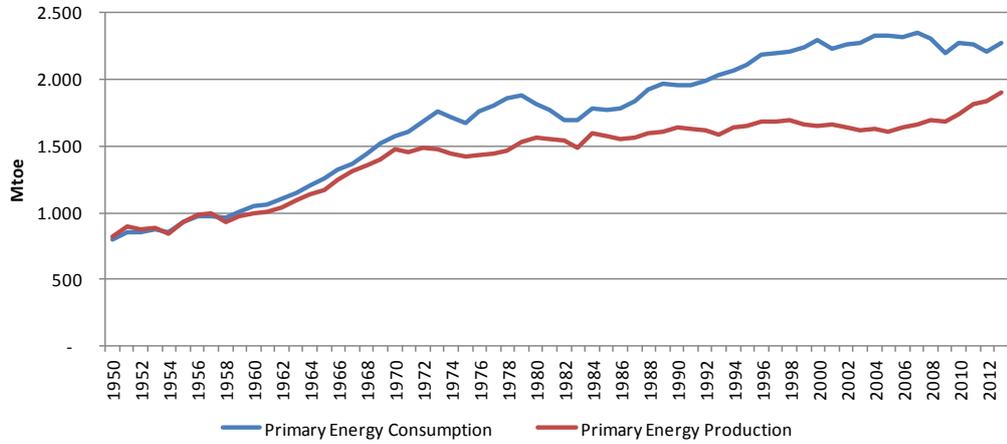
In general, the OPEX of LNG importing facilities is estimated between 3 to 5% of the CAPEX.

# **9. LNG MARKET IN THE UNITED STATES OF AMERICA**

## **9.1. Overview of the natural gas market in the USA**

Since the mid-1950s, domestic consumption of energy - used by industry, transportation, commercial and residential users - has exceeded the domestic production in USA. The gap has increased over time, reaching a maximum in 2005. Since then, technological development has provided new methods to take advantage of unexploited energy resources and improvements in the efficiency of traditional energy production, reducing the gap. The USA has experienced a rapid increase in natural gas and oil production from shale and other tight resources in recent years. Nowadays, the USA is the largest producer of petroleum and natural gas in the world.

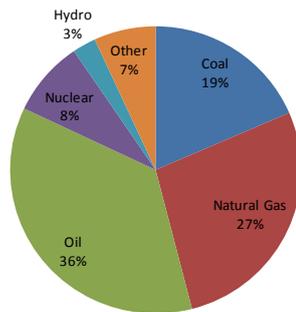
## US Primary Energy Consumption and Production



Source: U.S. Energy Information Administration

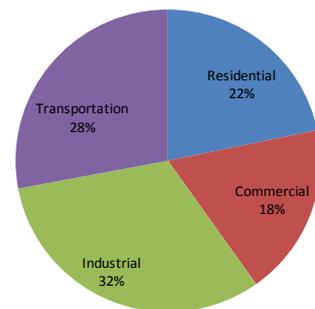
Primary energy consumed in the United States is mainly in the form of fossil fuels: coal, oil and natural gas. Together, they represent more than 80% of total consumption. Particularly, Coal was the main energy source until the middle of the 20th century, when it was surpassed by crude oil and natural gas.

### Primary Energy Consumption by Source (2013)



Source: U.S. Energy Information Administration

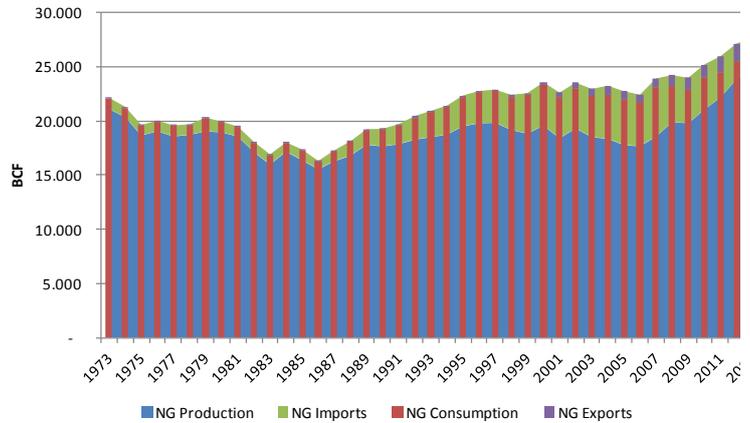
### Power Consumption by Sector (2013)



Source: U.S. Energy Information Administration

Natural gas production and consumption were close to balance until 1986, when consumption began to outpace production. As a result, gas imports rose in order to meet domestic requirements. Nowadays, the increase of unconventional gas production (tight and shale gas), especially since 2005, is helping to reduce imports.

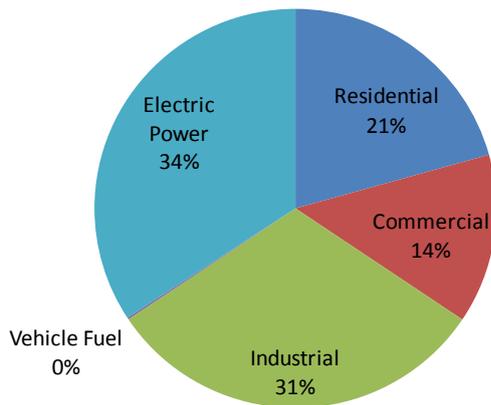
### NG production and consumption evolution



Source: U.S. Energy Information Administration

The electricity sector in particular has increased natural gas usage in recent years, displacing fueled coal fired generation, while variability in industrial activity has resulted in the significant demand volatility in that sector.

### NG consumption by sector (2013)

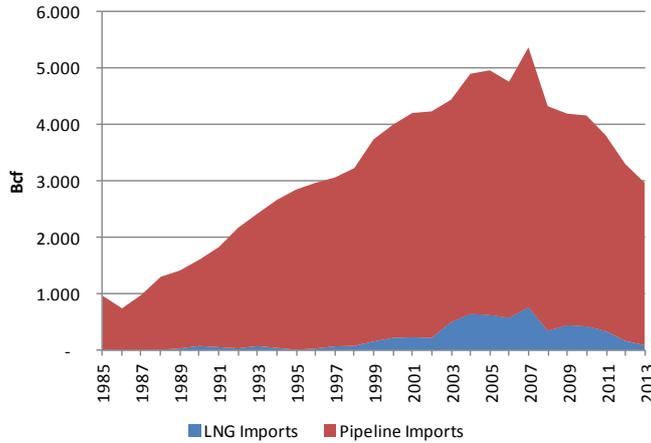


Source: U.S. Energy Information Administration

Finally, natural gas demand by residential and commercial users has seasonal variation, with consumption patterns highly driven by weather. Maximum gas consumption is observed during winter, when cold weather increases gas demand for heating<sup>5</sup>. In this regard, it is important to note that during the cold season peaking facilities provide additional sources of supply (to meet gas requirements) such as line pack, propane-air plants, underground storage facilities, and LNG plants.

<sup>5</sup> Residential and commercial demand for heating accounts for more than 50% of gas delivered to end-users during the winter.

## NG Imports Breakdown



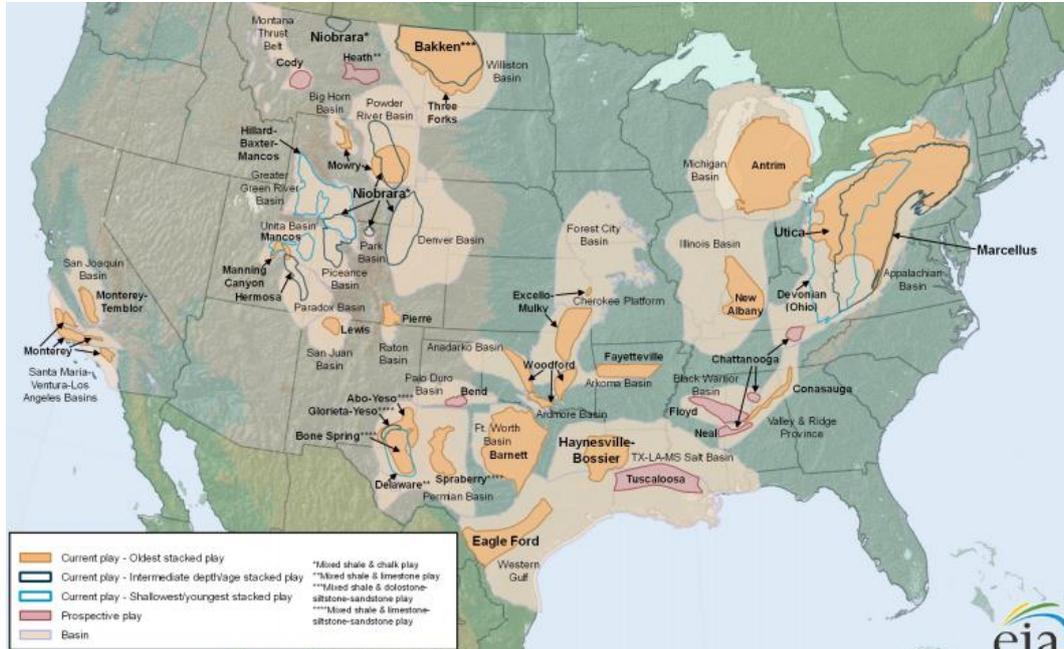
Source: U.S. Energy Information Administration

Historically, natural gas imports to the US were mainly through pipelines, from Canada and Mexico. More recently, they have also included LNG deliveries to regasification terminals (12 plants with a total regasification capacity over 6,000 Bcf/y).

However, after the record level in 2007's, both pipeline gas and LNG imports have gradually decreased due to the increase of domestic gas production, primarily from tight/shale gas formations.

Since 2005, the country's unconventional gas production grew at a rate of 35% a year. In 2007, shale/tight gas production was around 8% of total natural gas produced in the USA<sup>6</sup>. Today, unconventional gas share has reached 40% of total gross gas production. Furthermore, unconventional gas production's share by state has significantly changed in the US, with major producers currently located in Pennsylvania, Louisiana and Arkansas.

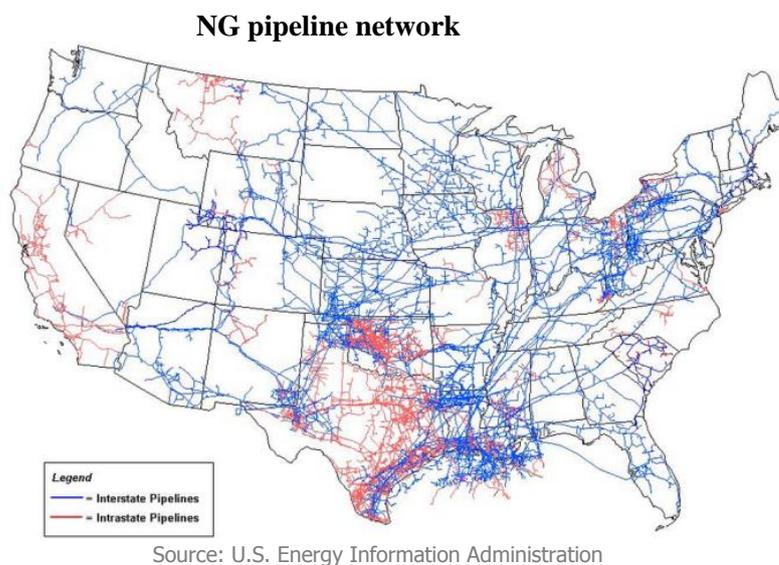
## USA Shale Plays



Source: U.S. Energy Information Administration

<sup>6</sup> In 2007, 63% of shale-gas production was located in Texas.

Thanks to the continuous increase in shale-gas production, it is expected that, rather than being an LNG importer, the USA will become an important player in the LNG export market. Its first liquefaction plant will start operations late 2015/early 2016. Furthermore, liquefaction capacity under construction or study would reach around 12,000 Bcf/y (approximately double of current regasification capacity).



## 9.2. Overview of Small-scale LNG in the USA

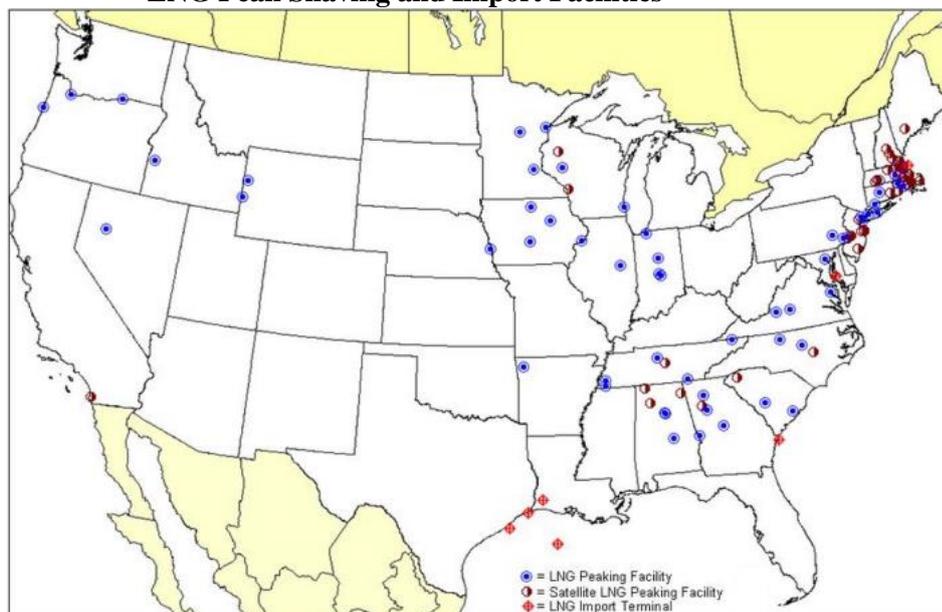
This section presents an outline of the uses and main drivers of mini/micro LNG liquefaction technologies in USA, with particular focus on those applicable for use with small volumes (1-15 MMscf/d) of associated gas.

### 9.2.1. Peak shaving plants

Within the USA, LNG was initially applied to “peak shave” natural gas use. Peak shaving by LNG consists of liquefying and storing natural gas during the off-season (summer) and then vaporizing and releasing it back into the pipeline network during high demand periods (winter).

Extremely low temperatures affect gas demand mainly in northern states, resulting in daily peak loads often 1 to 2 times larger than during regular winter days. Distribution companies must take this peak demand into account when contracting their transport capacity to assure adequate supply. This is a very inefficient way to secure peaking services, since the additional capacity is paid for on a 365 day basis, while it is used for just a few days (or even, a few hours) a year, depending on the weather.

### LNG Peak Shaving and Import Facilities

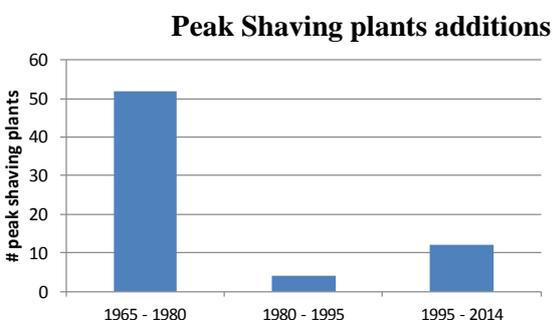


Source: U.S. Energy Information Administration

Currently, the USA has 68 peak shaving plants where LNG is produced and stored. Their total liquefaction capacity is around 7.75Mt/d, with a range from 20 tpd to 470 t/d per plant. Considering these plants liquefy during 200 days, in average, the total liquefaction capacity is 1,550 Mt/y. The total regasification capacity is 4,817 MMscf/d, providing around 5 to 15 days of storage at the maximum send out rate.

The graph shows the historical additions of LNG peak shaving plants.

The bulk of the peak shaving capacity was installed between 1965 and 1975, driven by a rapidly expanding natural gas demand and capacity limitations on major US pipelines.



Source: INGAA Foundations<sup>7</sup>

The significant reduction in peak shaving plant additions after 1980 was due to gas supply curtailments, the development of more economically attractive peaking supply options (underground storage and LNG import terminals) and, recently, the boom in gas availability.

<sup>7</sup> Use of Liquefied Natural Gas for Peaking Service - INGAA Foundation – 1996.

In recent years, peak shaving liquefaction facilities are also being used to supply heavy vehicle fleets. This supply source would appear to be an ideal (but limited) LNG vehicle fuel because the investment in plants has already been made. The following table shows the 14 peak shaving plants which currently also supply LNG to heavy vehicles.

Plant	Capacity (Mcf/d)
AGL Chattanooga, TN	8.7
AGL, Trussville, AL	4.8
Centerpoint Energy, Burnsville, MN	5.3
Citizens Energy Group, Beech Grove, IN	4.9
Citizens Energy Group, Indianapolis, IN	7.5
Memphis LG&W, Capleville, TN	5.5
NiSource, Kokomo, IN	1.3
NiSource, La Porte, IN	10.6
NiSource, Ludlow, MA	8.5
Northeast Utilities, Waterbury, CT	6.4
NW Natural, Portland, OR	1.6
Philadelphia Gas Works, Philadelphia, PA	16.5
UGI Corporation, Reading, PA	4.8
Williams, Carlstadt, NJ	9.2
Total	95.5

Source: Zeus Intelligence

There are, however, a number of challenges associated with dual-usage of the facilities: Some peak shaving facility owners are reluctant to drawdown their LNG reserves for other than their primary purpose of peak shaving. Utility regulatory agencies are cautious about approving such plans due to the potential requirement of partial reimbursement to ratepayers, who originally paid for the capital investment through tariff in the gas price. Finally, peak shaving plants are not necessarily located near areas of LNG vehicle fuel demand.

### 9.2.2. LNG as a fuel

The most prevalent purpose for 'new' small-scale LNG facilities in the USA is the production and dispensing of LNG as a vehicle grade fuel. The following table shows the 14 liquefaction plants exclusively dedicated to vehicle fuel supply.

Plant	Capacity (Mcf/d)	Startup Year
Applied LNG Topock, AZ	13.8	2014
Bowerman Liquefied Landfill Gas	0.4	2007
Clean Energy Fuels Boron, California Plant	19.3	2008
Clean Energy Fuel, Pickens Plant	8.7	1994
Exxon Shute Creek NRU	2.4	1994
Fairbanks Natural Gas LNG Plant 1	3.2	1997
Kiefer Road Liquefied Landfill Gas	1.0	2010
Madera County, California	0.8	2008
North Dakota LNG	6.1	2014
Painter Complex NRU	0.8	1994
PG&E Prototype Ranch Plant	0.4	1999
Prometheus Energy, Cuervo New Mexico Plant	0.8	2010
Spectrum Ehrenberg Plant	4.4	2010
WMI-Linde Altamont Landfill LNG Project	1.0	2009
Total	63.1	

Source: Zeus Intelligence

The Production-to-Dispensing model mainly employs a centralized liquefaction plant from which the LNG is distributed in special trailers to local storage and dispensing sites. There, the LNG is dispensed to heavy-duty vehicles directly as LNG or, after regasification, to light-duty vehicles as CNG.

There are 38 additional private stations serving only own vehicles, customer fleets or government fleets. According to the US Department of Energy, another 70 stations – public and private - are under construction or in planning stages.

### Public LNG Fueling Stations

The 63 public LNG dispensing facilities that serve the market are shown in the map to the right.

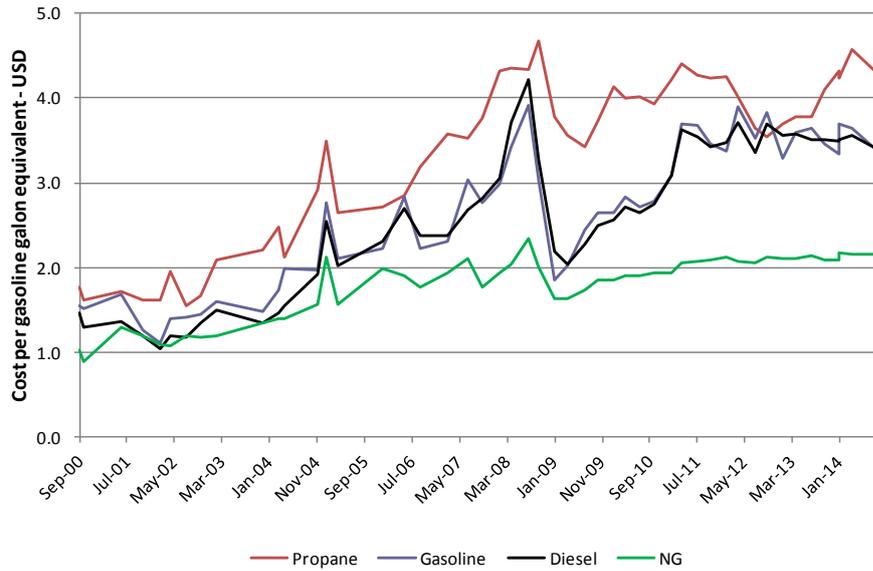


Source: U.S. Energy Information Administration

The LNG infrastructure dedicated to supplying LNG as fuel has developed to date in discrete location where deployment of LNG vehicles has been accompanied by development of infrastructure (e.g., Los Angeles and Phoenix). LNG vehicles currently in operation are therefore limited in range by the distribution of stations and, unlike diesel vehicles, are not yet able to traverse the entire country. However, as the infrastructure continues to develop, broader opportunities for LNG vehicle markets will emerge. Development of corridors to connect various hubs is in progress, including the joint UPS-Clean Energy effort to connect Southern California to Las Vegas.

The USA consumes 37 billion gallons of diesel per year and 10 billion gallons of diesel per year, which suggests a huge potential market for cheaper alternative fuels such as LNG.

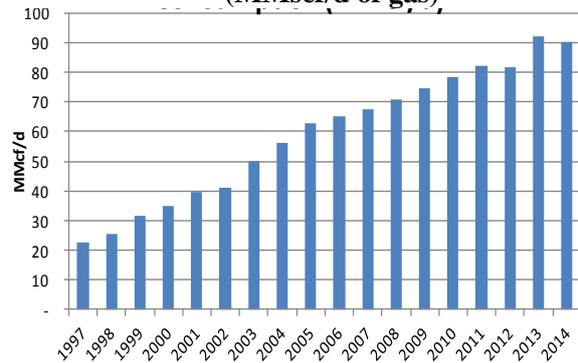
### USA Average Retail Fuel Prices



Source: Alternative Fuels Data Center

As shown in the chart to the right, vehicle use of natural gas (especially heavy trucking industry) has grown steadily over the last fifteen years, reaching 90 MMscf/d in 2013. But this volume represents only 0.14% of USA's natural gas consumption. LNG is most appropriate for heavy-duty vehicles, which can accommodate the large volume of LNG storage needed as LNG has a far lower energy density than conventional vehicle fuels.

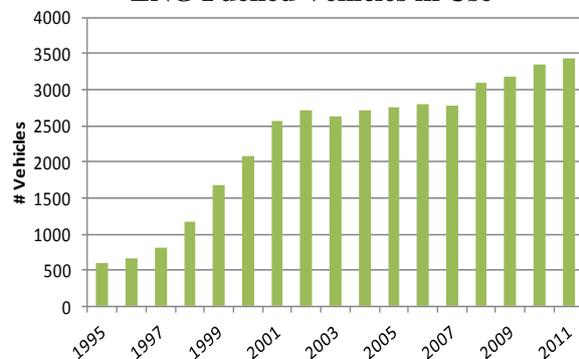
### Natural Gas Vehicle Fuel Consumption (MMscf/d of gas)



Source: U.S. Energy Information Administration

As of 2011 there were 3436 LNG fuelled vehicles in the USA (according to the Department of Energy). Since then, there have been several large commitments to deploy LNG trucks as the refueling infrastructure becomes available, the largest by UPS with 700 LNG tractors as of the end of 2014.

### LNG Fuelled Vehicles in Use

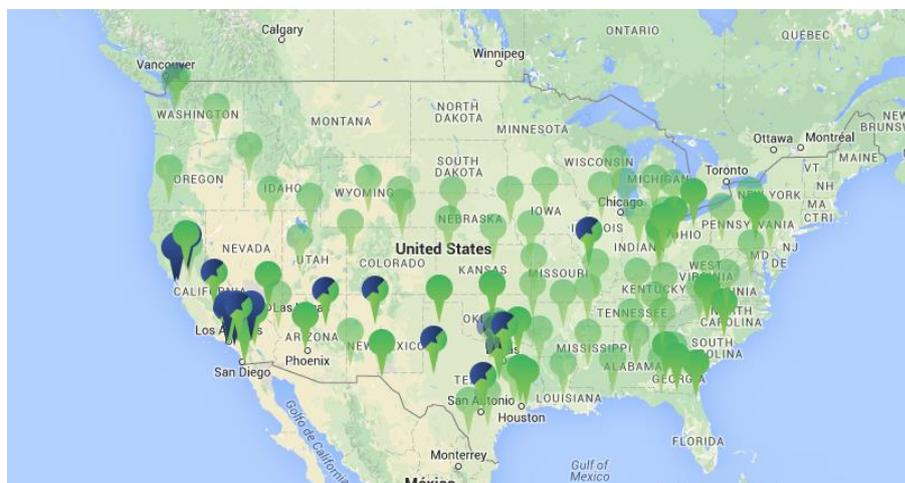


Source: Alternative Fuels Data Center

Developing infrastructure to support these new LNG trucks is the major hurdle. The current 63 LNG public stations compare with 157,000 gasoline stations. The LNG fuel industry needs to reach critical mass of infrastructure to persuade operators to switch over. In trucking, major investors are partnering with filling (conventional gas/diesel) station operators to orchestrate nationwide LNG filling networks.

Clean Energy Fuels has been one of the first companies to provide a network of LNG fueling stations, with 27 stations completed and 60 more planned in the near future. Additionally, with two liquefaction plants, Clean Energy Fuels will take part in both stages of the supply chain: production and marketing.

### **Clean Energy Fuels operational and planned LNG fuel stations**



Source: Clean Energy Fuels

Another company with large investments in US LNG fueling infrastructure is Chinese-owned ENN. They have plans to build up to 500 LNG stations, and have partnered with a small Utah company, CH4 Energy, to create Blu LNG, a joint venture trading company. ENN also expects to build LNG liquefaction plants in the future.

Shell is also investing in both LNG liquefaction and refueling infrastructure. The two liquefaction facilities planned will support two new LNG refueling networks located in the Gulf Coast Corridor (Texas and Louisiana) and the Great Lakes Corridor. Shell has partnered with Travel Centers of America in long-term plans to develop a commercial LNG fuelling network spanning the USA as shown in the map below.

## Shell and Travel Centers of America proposed LNG network



Source: Shell

Finally, UPS is working with the US Department of Energy to advance the LNG technology deployment in the marketplace. Launched in 2009, the program's objective is to encourage the reduction of petroleum usage and reduce greenhouse emissions. Part of that mandate is to increase investment in infrastructure, assist in the purchase of LNG equipment, and construct fuelling stations. The targeted LNG corridor stretches from Los Angeles, in California, to Nevada and Utah. UPS has already purchased 700 LNG tractors and built 4 new fueling stations.

In conclusion, the LNG market as a vehicle fuel has grown, but is still a small portion of the fuel market in the USA. Some barriers individually or in combination could limit the deployment of LNG facilities, such as:

- **Capital Cost of LNG Plants:** When attempting to match the size and capital cost of LNG production facilities with the customer base, there is a tension between economic production volumes and product demand. That is, larger facilities with capacities of 50,000 gallons/d and more achieve reasonable economies of scale. However, they require a larger customer base than exists, especially before the LNG plant is built. The development of LNG infrastructure and its success as a transportation fuel requires a different strategy from that adopted historically for other fuels to break the “coordination problem” between supply (infrastructure) and demand (fuelled vehicles). LNG needs significant infrastructure investment along the supply chain including liquefaction facilities, LNG distribution trucks and LNG stations before significant vehicle adoption will occur. On the other hand, small facilities (less than 4 MMscf/d of production) cannot be built cost-effectively with the technologies that have been deployed to date.
- **Cost and range of LNG Vehicles:** LNG buses and heavy-duty trucks currently cost up to USD 50,000 more than those conventionally fuelled, which is difficult to justify for vehicles that do not travel a large number of miles each day/week. Moreover, LNG trucks have a reduced resale value.

### Estimated Retail Price

Vehicle	Diesel (kUSD)	CNG/LNG (kUSD)	Premium (kUSD)	Premium (%)
Transit bus (CNG)	300	325	25	8%
Garbage truck (CNG)	220	260	40	18%
Tractor trailer (LNG)	125	175	50	40%

Source: Massachusetts Institute of Technology MIT<sup>8</sup>

The range of single-tank LNG trucks today is around 300 miles, half that of diesel trucks, requiring up to twice as many refuelling stations for the same coverage. A solution is dual-tank LNG trucks, but this implies a significant additional cost per vehicle, and may not be viable except on trucks with the longest distance duty cycles.

- **Engine Options:** LNG is more suitable as a fuel for heavy-duty trucks or buses than CNG, since the latter is not a viable option for the provision of long distance services due to the weight of its tanks and/or the lack of travel range. The natural-gas-fired engine industry has been slow to respond to the need for high-horsepower engines, which are necessary for the heaviest long-haul trucks. Nevertheless, several engine producers are now offering heavy-duty gas-fired engines.
- **Fuel Prices:** The gap between diesel fuel and LNG prices, with the equivalent energy content, needs to be high enough to encourage public and private fleets to substitute LNG for diesel. This gap has increased with the boom in shale gas production and the related fall in natural gas prices in the US. The gap is however reducing again with the drop in oil price.

Alternative fuel station deployment suffers a “coordination problem” - the uncertainty in timing of station building and vehicle purchases - which dissuade either party from committing to the vehicles or station that depend on each another<sup>9</sup>. In this regard, Federal and State governments have been asked to provide incentives, tax credits, and subsidies to encourage development of the infrastructure.

### 9.2.3. Liquefaction projects at oil production sites

From 2008 to 2012, North Dakota accounted for 0.5% of total gross natural gas production in the United States but flared 22% of the total natural gas that was either flared or vented in the USA (EIA).

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<sup>8</sup> Modeling the Global Prospects and Impacts of Heavy Duty Liquefied Natural Gas Vehicles in Computable General Equilibrium - Arthur Hong Chun Yip – Massachusetts Institute of Technology (MIT).

<sup>9</sup> The “coordination problem” is common in social science, representing situations where all parties can realize mutual gains, but they are no individual incentives to take decisions in a cooperative way. This problem is usually analyzed in game theory by means of “coordination games”, which are a class of games with multiple pure strategy Nash equilibriums. A common application is the choice of technological standards. Not by chance, a common application of this theoretical tool is the analysis of technological alternative standards.

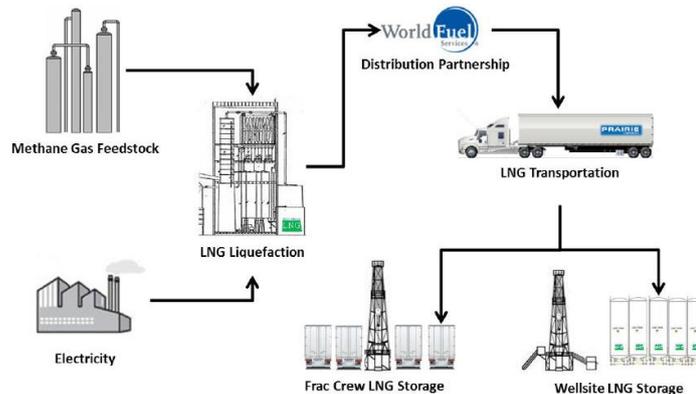
Natural gas production in North Dakota's portion of the Bakken formation has grown significantly, alongside the rapid rise in oil production in the State. Natural gas production has outpaced additions to the State's gas pipeline and processing facilities capacity. As a result, the amount of non-marketed natural gas output continued to grow, rising to an average of 0.31 Bcf/d by the end of 2013, almost twice the level of 2011 (0.16 Bcf/d), according to the North Dakota Department of Mineral Resource.

Several projects have come online in the past years to improve North Dakota's ability to bring new gas production to market including expansion of gas treatment plants and pipelines and the application of General Electric's CNG in a box system (GNG).

North Dakota LNG LLC (NDLNG), part of the oil and gas services company Prairie Co. LLC, brought the first LNG liquefaction facility online in North Dakota during 2014. The facility is located adjacent to Hess Corp's recently commissioned natural gas processing facility near Tioga, N.D. Using Hess supplied feedstock gas, the ND-LNG facility initially produced 0.8 MMscf/d. The capacity of the facility is expected to increase to 6 MMscf/d.

Although the NDLNG facility will provide LNG to more than just the oil and gas industry, the first use will be for drilling rigs operated by Slawson Exploration Co. The volume of diesel used for drilling operations varies, but can be as high as 0.2 MMscf/d.

The trucking and transport arm, Prairie Field Services, will supply each rig site with storage for the LNG along with staff to help implement the use of the LNG to power the rigs. It is also expected to use LNG in its vehicles.



Source: North Dakota LNG LLC

In the zone of Bakken formation (shale oil/gas fields in Montana, North Dakota, Saskatchewan and Manitoba) will provide dual-fuel (gas and diesel) basis equipment (trucks and construction machinery, among others) allowing them to switch fuel sources in case of lack of gas supply.

In 2010, Prometheus Energy Group Inc., Encana Oil, Gas (USA) Inc. and Ensign United States Drilling, Inc. worked together to repower two diesel fuelled drilling rigs with natural gas fuelled engines. Prometheus Energy designed, built and commissioned LNG mobile storage and vaporization equipment, and provided the LNG fuel for the project. The dedicated LNG fuelled rigs, the first of their kind, provided Encana significant cost savings, while also reducing NOx and particulate emissions by as much as 25%.

Prometheus Energy's mobile LNG solution has now been used for drilling operations in Louisiana, Utah, Texas, Wyoming, Colorado and California. The use of natural gas in these drilling operations replaces approximately 1,500 gallons daily per rig of diesel, or over 500,000 gallons per rig annually.

In 2006, Prometheus installed the world's first commercial LNG liquefaction plant using landfill gas in Orange County, California. The entire output of the plant, with capacity of 0.4 MMscf/d, has been used to fuel public transport vehicles.

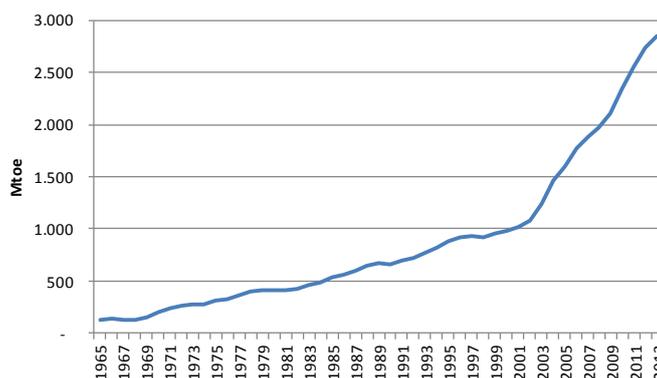
## 10. LNG MARKET IN CHINA

### 10.1. Overview of the natural gas market in China

China is the world's most populous country, with a fast-growing economy, which has led it to be the largest energy consumer and producer in the world. Additionally, rapidly increasing energy demand, especially for liquid fuels, has made China extremely influential in worldwide energy markets.

According to the International Monetary Fund, China's annual real gross domestic product (GDP) growth slowed to 7.7% in both 2012 and 2013, after registering an average growth rate of 10% per year between 2000 and 2011. In the same period, primary energy consumption also increased at an annual rate of 9.1%.

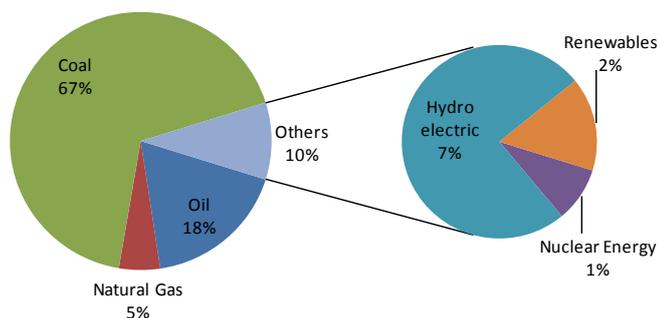
**Primary Energy Consumption**



Source: U.S. Energy Information Administration

Coal supplied the largest share (67%) of China's total energy consumption in 2013. China is the world's top coal producer, consumer, and importer and accounted for about half of global coal consumption<sup>10</sup>.

### Primary Energy Consumption by Source (2013)



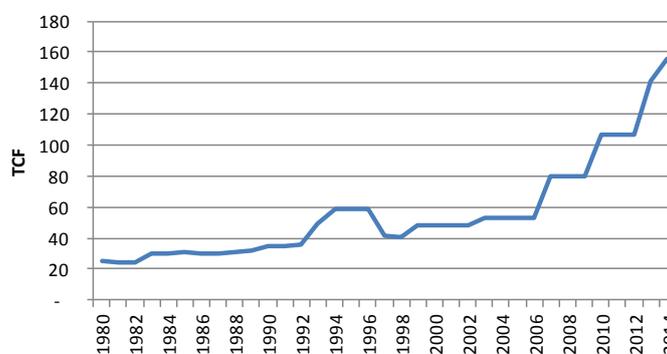
Source: BP Statistical Review of World Energy

Oil was the second-largest source, accounting for 18% of the country's total energy consumption. While China has made an effort to diversify its energy matrix, hydroelectric (7%), natural gas (5%), nuclear power (nearly 1%), and other renewable energy sources (2%) accounted for relatively small shares of China's energy consumption. The Chinese government plans to cap coal use to below 65% of total primary energy consumption by 2017 in an effort to reduce heavy air pollution that has afflicted certain areas of the country in recent years.

Although natural gas production and use is rapidly increasing in China, gas comprised only 5% of the country's total primary energy consumption in 2013. Major investment in upstream gas development and increased imports, including LNG, are likely to support significant growth in China's natural gas sector.

### Proven NG Reserves

In 2014, China's proven natural gas reserves were 155 Tcf, 14 Tcf higher than in 2013 and the largest in the Asia-Pacific region.

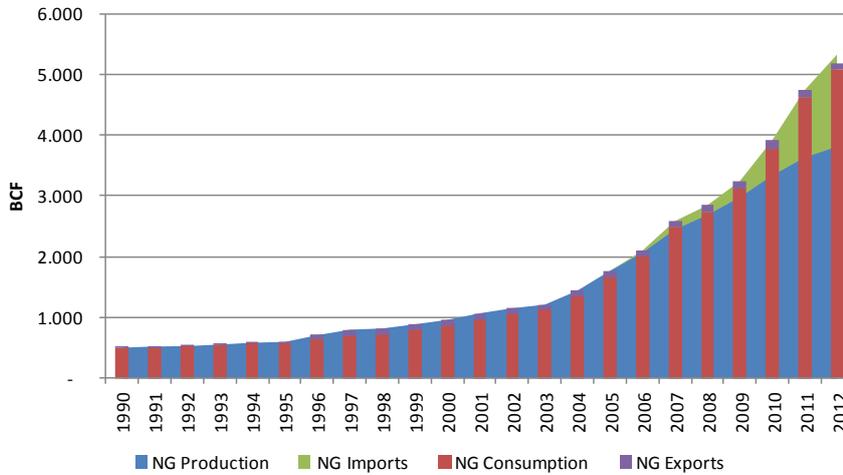


Source: U.S. Energy Information Administration

The Chinese government anticipates boosting the share of natural gas in total energy consumption to around 8% by the end of 2015 and 10% by 2020.

<sup>10</sup> Coal consumption is an important factor in world's energy-related carbon dioxide emissions.

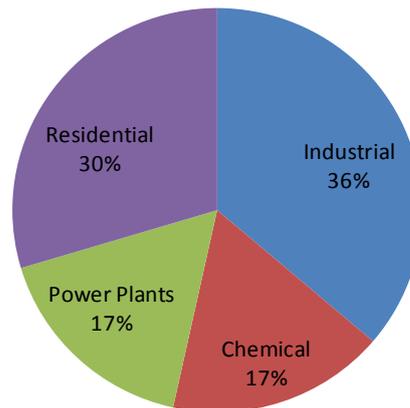
### NG Balance Evolution



Source: U.S. Energy Information Administration

### NG Consumption Breakdown (2012)

Natural gas consumption has increased more than five times since the year 2000. According to the China Energy Fund Committee, in 2012 industrial and chemical users accounted for 53% of gas consumption, the residential sector 30%, and power generation the remaining 17%.



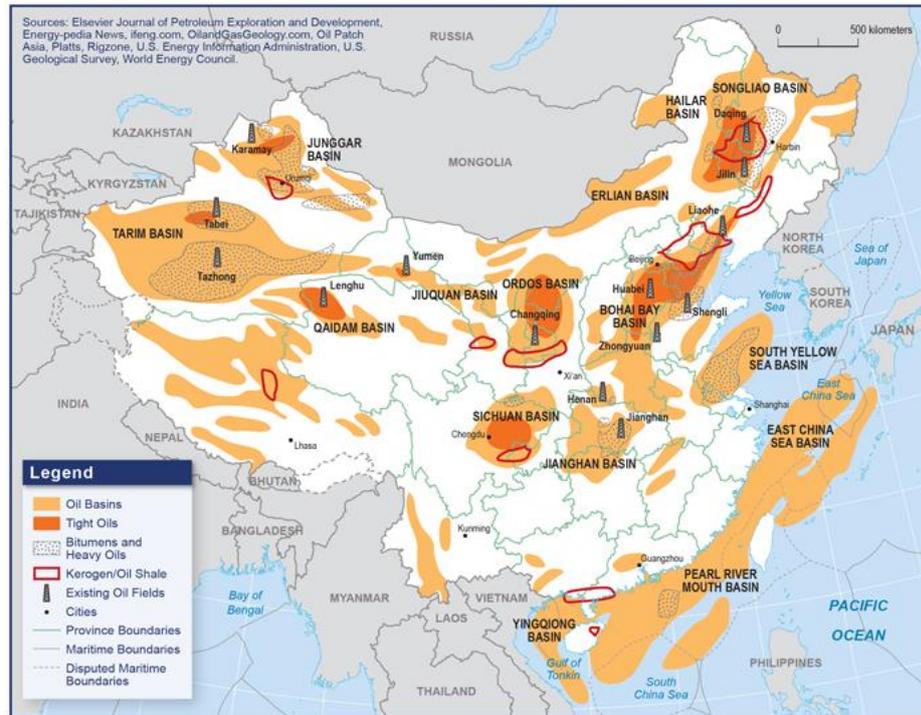
Source: China Energy Fund Committee

China has a number of natural gas producing regions, in the western and central areas of the country and offshore. While continuing to develop natural gas fields, China's oil companies are also exploring other gas sources such as shale gas and coal-bed methane.

China's primary onshore gas producing regions are Sichuan Province in the Southwest (Sichuan Basin); the Xinjiang and Qinghai Provinces in the Northwest (Tarim, Junggar, and Qaidam Basins); and Shanxi Province in the North (Ordos Basin). China efforts have been focused on several offshore natural gas fields located in the Bohai Basin and the Panyu complex of the Pearl River Mouth Basin (South China Sea).

Historically, natural gas exploration has been closely linked to the development of oil fields, with the exception of the Sichuan gas field, which was, until recently, the largest non-associated gas field. Nowadays, more than two-thirds of proven reserves in the country are currently classified as non-associated gas. The three majors NG basins are Tarim, Ordos and Sichuan.

## Oil Basins Map

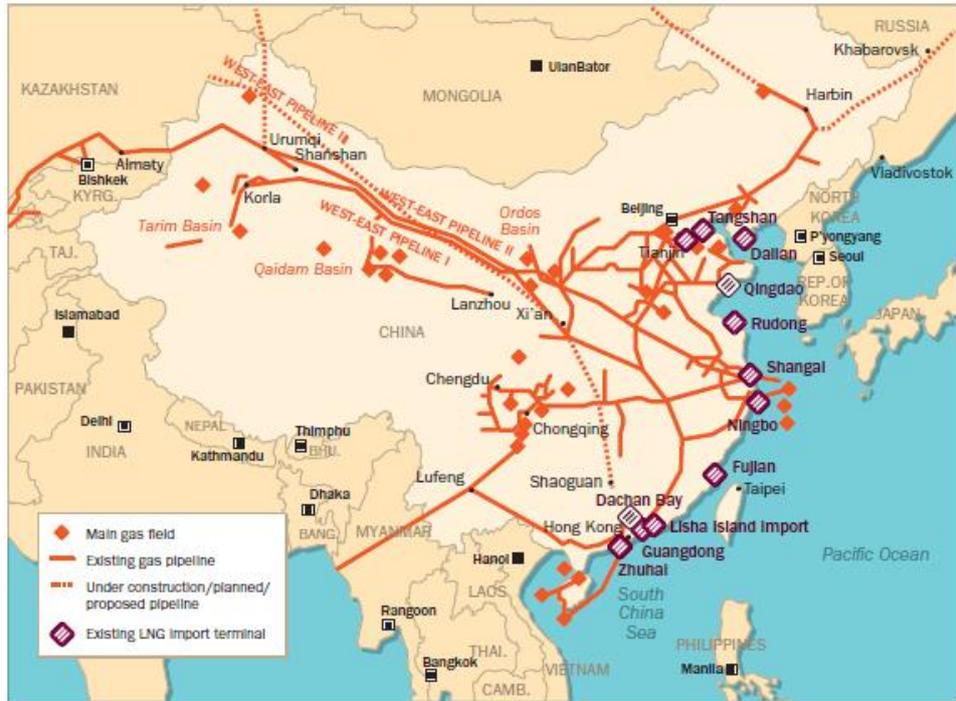


Source: Carnegie Endowment for International Peace

From 2000 to 2012, China's natural gas production increased more than three fold. However, this was not enough to meet demand, leading to a significant increase in gas imports.

Investments in natural gas pipeline infrastructure aim to link production areas in the western and northern regions of the country with demand hubs along the coast and to allow greater imports from Central Asia and Southeast Asia. Over the past years, China has ramped up imports of natural gas via pipelines as production from Central Asia and Myanmar increased and as gas infrastructure in the region improved. The Central Asian Gas Pipeline (CAGP) transports natural gas through twin parallel pipelines from Turkmenistan, Uzbekistan, and Kazakhstan to the border in western China. The China-Myanmar gas pipeline has boosted China's gas imports and diversified its sources of supply. In 2013, CNPC officials signed a framework agreement with Gazprom to purchase 1.3 Tcf/y of gas from the proposed East Siberian pipeline, which is expected to connect Russia's Far East and Sakhalin Island to northeastern China.

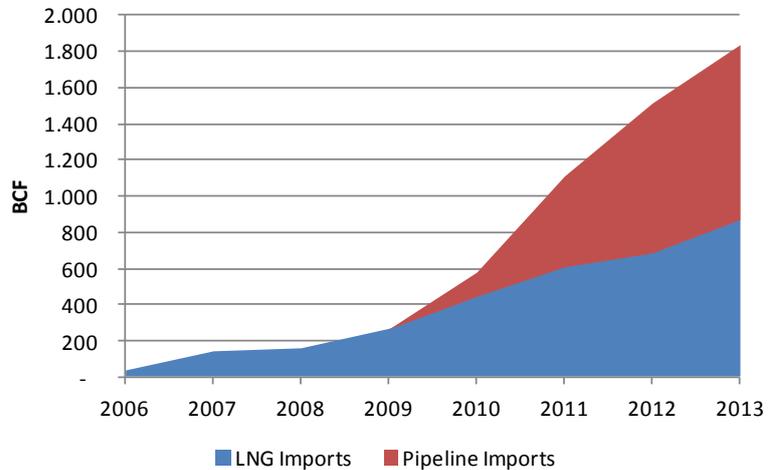
## NG Supply Infrastructure



Source: Platts

The strong growth observed in natural gas demand in the urban coastal areas has led China to become the third largest LNG importer and has accelerated the development of its own LNG infrastructure.

### NG Imports Breakdown



Source: EIA, BP & GIIGNL

At the end of 2014, the 12 operating LNG import terminals had a total capacity of 35 mtpa. By 2018, when the planned 17 terminal come on line, regasification capacity would grow to 75 mtpa.

So far, NOCs (National Oil Companies) have led natural gas development in China. International players partnered with them when developing projects requiring more technical expertise. Additionally, the changing landscape of China's gas supply sources (toward greater imports) and the need to boost gas investments recently led the government to implement price reforms and align domestic natural gas prices more closely to market-based rates.

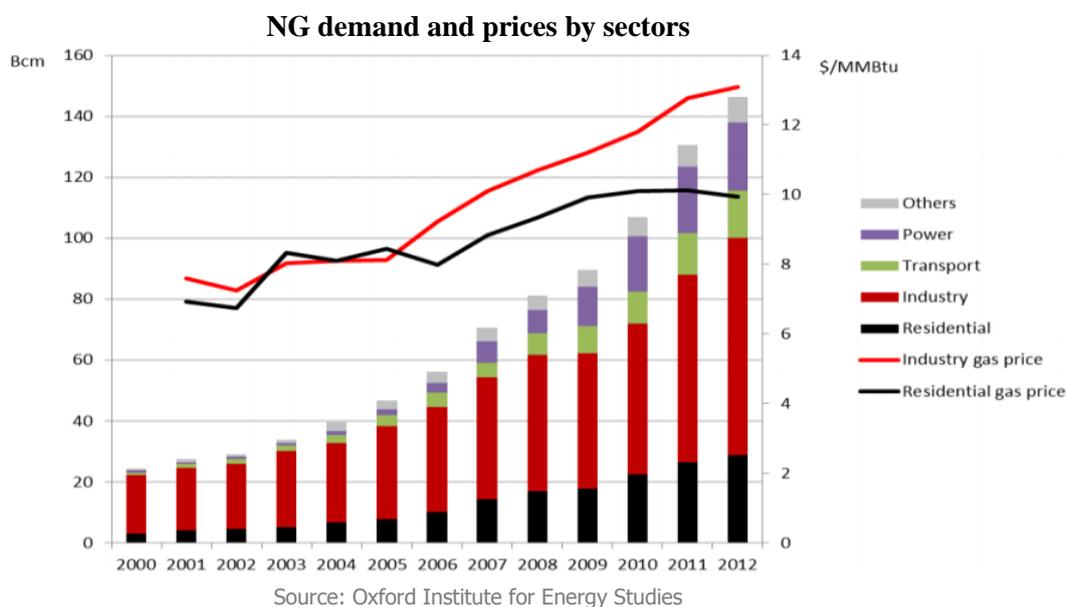
## 10.2. Overview of Small-scale LNG in China

This section reviews the uses and main drivers of mini/micro LNG liquefaction technologies in China.

A series of factors sustain the growth of the small LNG industry.

First of all, the demand-supply gas balance in China is very tight, while the pipeline grid is limited. Since China's natural gas pipeline infrastructure density is significantly lower than developed countries such as the US, most communities lie outside the reach of pipelines, requiring LNG/CNG storage and trailers to transport gas to those regions. In eastern and southern China, many industrial and urban users<sup>11</sup> still have limited supply of natural gas, especially for peak-shaving purposes during winter. However, gas use in those areas would increase boosted by the expansion of urban gas distribution networks, and tightening even more daily and seasonal peaks supply in the coming years. Therefore, development of LNG storage capacity is very important.

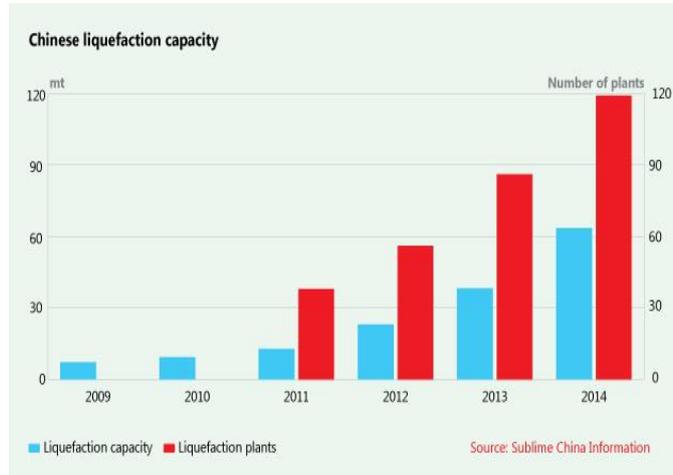
Secondly, in regions far from the main transmission pipeline, where it is not economically viable to build pipeline connections, mini-LNG could be a viable alternative solution for gas supply. In addition, natural gas serves as an alternative fuel in the transport sector. Finally, from the gas producer's perspective, LNG is also a solution to unlock the potential of stranded gas fields.



<sup>11</sup> Urban users are: residential, commercial and transportation.

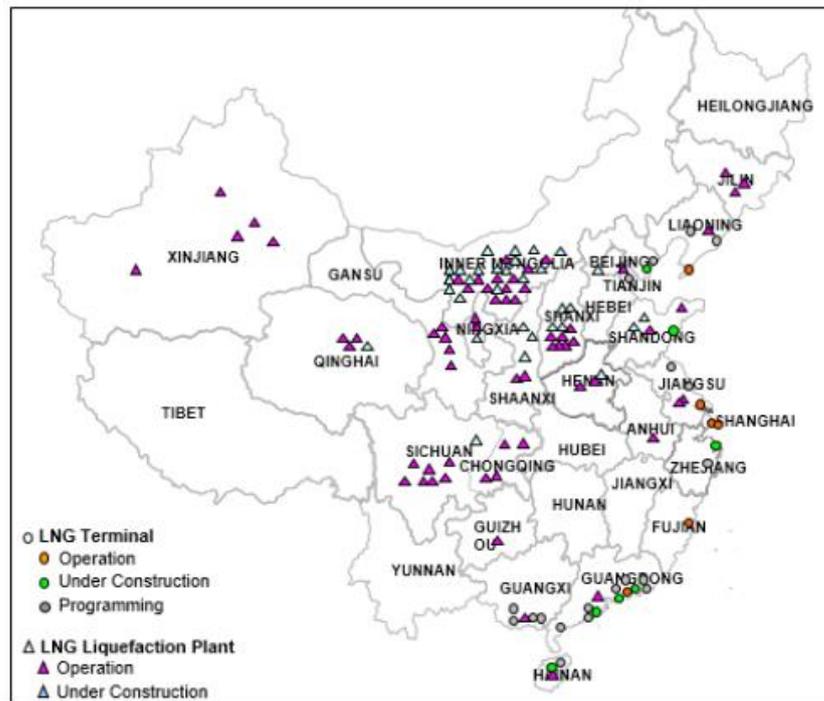
### Chinese liquefaction capacity

Regarding liquefaction infrastructure, the first liquefaction plant was installed in 2000. Currently, China has a retail liquefaction capacity of 2,100 MMscf/d (16 mtpa of LNG), spread across 120 small-scale plants<sup>12</sup>. Plants under construction or in planning stage would add another 2,400 MMscf/d to this capacity.



Source: Sublime China Information

### Distribution of LNG import terminals and liquefaction plants in China



Source: China Natural Gas Industry Magazine - 2013

LNG production is produced in the north-western (50% of total liquefaction capacity) and central-north provinces (40% of total capacity). The figure below shows the distribution of LNG infrastructure across China.

<sup>12</sup> A few mid scale plants.

As LNG transport, traditionally, trucks travel across the country from the western and central gas producing regions, often with routes of more than 3,500 km long, to supply LNG satellite stations at major cities along the North-east and South coast.

Nonetheless, as more LNG import terminals come on stream along the East coast, the routes for LNG trucks will become shorter.

**Example of traditional LNG tanker route: from Shan Shan LNG plant in Xinjian to satellite stations along the coast**



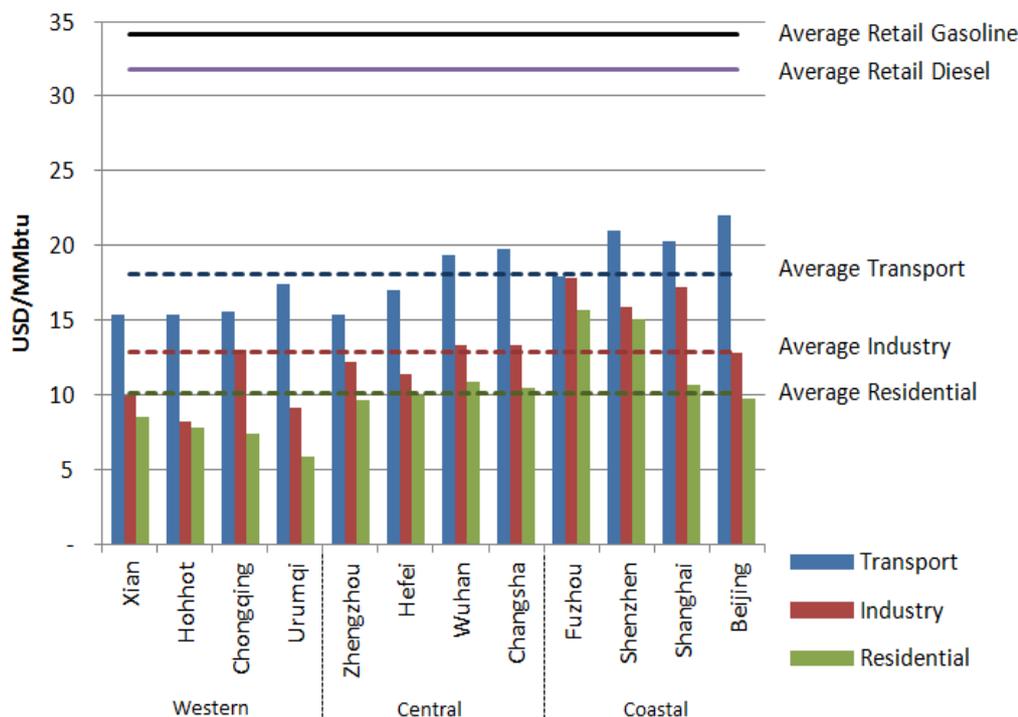
Source: Linde

Ex-plant prices, which include wellhead prices and processing fees, have been traditionally set by the National Development and Reform Commission (NDRC) for each well (onshore conventional gas) and each region. They are based on the type of end-user – for example, industrial, residential, fertilizer and power sectors – which are supplied.

Consumer affordability has been the key driver of ex-plant price regulation but the determining factor is the production cost, which depends on the source of local gas. Well-head prices are calculated from a base price (which takes into account project cost, taxes and loan repayments), processing fees and an appropriate margin for producers. Processing fees are determined by the quality of the gas and subject to negotiations between the NDRC and producers. The ex-plant price serves as a reference for producers and buyers to negotiate final prices within a +/- 10% band. It applies only to conventional gas since the price of unconventional gas price is based on market rates.

In China there is an important spot market where the LNG is traded. Operations are performed by electronic trading (West Center of Shanghai Petroleum Exchange) or conventional trading. Regarding electronic way, LNG can be traded on DES (Delivered ex Ship) or FOB (Free on Board) mode. There is also a freight market. The local LNG competes now with the imported LNG, moved from the large regasification terminals.

### End users Natural Gas & fuel prices, 2013



Source: Oxford Institute for Energy Studies & Reuters

#### 10.2.1. LNG as fuel for vehicles

The national government has strongly encouraged the deployment of natural gas fueling infrastructure, especially for LNG stations. In 2013, there were 3,350 CNG stations, and more notably, 1,844 LNG stations. The 12<sup>th</sup> Five Year Plan (2011-2015) includes a target of 5,000 LNG stations. The CNG deployment - as well as LNG - is led by the three major Chinese oil and gas state-owned enterprises: China National Petroleum Corporation (CNPC, which do business as PetroChina and via its subsidiary Kunlun Energy), China Petroleum and Chemical Corporation (Sinopec), and China National Offshore Oil Corporation (CNOOC). Some private energy companies, such as ENN Energy Holdings, Xinjiang Guanghui Industry Investment Group, and Hanas New Energy Group based in Ningxia and Shandong, are also doing business in the area.

#### LNG fueling stations in China



Source: China Energy News 2014, Bars (left axis) represent number of LNG stations (2014 estimated). Line (right axis) represents annual growth rate of LNG sections

Gas use in transportation sector accounts for around 13% (or 20.6 Bcf) of total gas consumption. Its significant share is supported by the government's gas-use policy (especially its subsidy for LNG trucks), zero VAT on transport gas, favorable oil and gas price differentials and the rapid growth of natural gas refueling stations.

An increasingly important vehicle segment for potential natural gas penetration is the heavy-duty long-haul freight trucks and semi-tractors. Natural gas use in this segment will be possible thanks to the use of LNG instead of CNG. An estimated 63,000 vehicles in China were LNG-fuelled in 2013.

#### LNG fleet

Type of LNGV	Number (unit)		
	Year 2011	Year 2012	Year 2013
LNG passenger bus	6,000	12,000	18,000
LNG heavy-duty Vehicle	25,000	30,000	45,000

Source: Trends of LNG/CNG Application in the Transportation Industry in China Australia-China Natural Gas Technology Partnership Fund - 2013

In 2014, China LNG Group Ltd (a financial-investment company) has issued a statement declaring the Company and Sinopec Fuel Oil Sales Corporation Limited (Shanghai) have entered into a sales framework agreement. This would enhance the cooperation for the development of a LNG market, including the development of LNG refueling stations and the application of LNG heavy-duty trucks in China.

As a pilot program, the contracting parties intend to select two highways - Ningbo Expressway (G60, connecting Shanghai and Hangzhou, 151 km) and Pu-Hangzhou Expressway (G15, connecting Pudong and Hangzhou, 112 km) -, adding LNG infrastructure to existing filling facilities<sup>13</sup>. Following successful implementation of such stations, Sinopec will increase the number of LNG fuel stations based on the demand and development of the company's LNG businesses.

PetroChina and Kunlun have been deploying a "gas-for-oil substitution" strategy since 2011. Natural gas for these stations has been sourced from conventional gas fields, as well as coke oven gas, coalbed methane, and LNG terminals. Large and small provinces, including Shandong, Henan, Sichuan, Hebei, Shaanxi, Shanxi, Qinghai, Hubei, Inner Mongolia, Xinjiang, Hainan, and Guizhou have LNG stations under construction.

### 10.2.2. LNG as fuel for vessels

China is beginning to pay attention to the development of LNG as a vessel fuel, which should achieve coastal and inland shipping "green environmental protection". Vessel power changing to LNG would become the development trend.

<sup>13</sup> Gasoline and diesel.

Currently, the main experience carried out in China is “changing diesel to LNG” for vessel fuel. In 2009, usage of vessel power for diesel-LNG hybrid technology project in Suqian City, Jiangsu Province was officially launched. In 2010, "Su-Su goods 1260" freighter in the Northern section of the Grand Canal began real ship trials. Afterwards, a hybrid diesel-LNG ship, carrying 3,000 tons of sand, sailed from Suqian City into Huai'an City. Currently, some Chinese companies, such as Hubei Xilan, Beijing Youlu, Guilin Xin'ao, Xinjiang Guanghui, Fujian Zhongmin, are in the process to change some vessels of their fleet from oil to gas.

#### LNG as a vessel fuel projects

NO.	Project Practice Unit	Vessel Name	Usage	Area	Project Progress
1	Beijing Youlu Corp.	Su Su cargo boat No. 1260	Transportation	Canal	Alteration has been completed and put into operation
2	HubeiXilanNatural Gas Company Ltd.	Wulun drag boat No. 302	Drag Boat	Yangze River	Alteration has been completed and put into operation
3	Kunlun Energy "gasified Yangtze River" project	8 vessels	Transportation	Inland River	Most of Alteration has been completed and some vessels has been put into operation
4	Beijing Zhongxinhenghe Investment Co., Ltd.	Changxun cargo boat No.3	Transportation	Yangze River	Trials sailing was successful, and was about to convening feasibility studies via national experts
5	Guilin Xinao Natrual Gas Co.,Ltd.	Shangshui No.34	Yacht	Li River	Alteration has been completed and put into operation
6	Xinjiang Guanghui Corp.	Fisheries enforcement No.522kW	Fisheries enforcement	East Sea	Ship redesigned and reconstructed is ongoing
7	Fujian Zhongmin Transportation Co., Ltd.	TBD	Transportation	Min River	Project feasibility study has been completed, awaiting government approval

Source: Trends of LNG/CNG Application in the Transportation Industry in China Australia-China Natural Gas Technology Partnership Fund - 2013

In 2011, Kunlun Energy Company Limited, a CNPC subsidiary, Jichai Power Plant, Wuhan Transportation Development Group and Wuhan Ship Design Transportation Development Co., Ltd. signed a cooperation framework agreement in Wuhan city for the demonstration and application of LNG fuelled ships, and developing the "gasified Yangtze River strategy".

Yangtze River is the longest and busiest river in China. The Yangtze River Delta explains around 20% of China's GDP and in 2012; almost 1.8 billion tons of cargo were shipped on the waterway. The large number of ships (especially those with large tonnage), the high utilization rate and, hence, high fuel consumption, represent a huge potential market for LNG bunkering.

By the last quarter of 2014, the first bunkering station on the Yangtze was established in Nanjing by Haiqi Ganghua Gas Development. China Gas Holding is also expected to start LNG bunkering operations on the Yangtze during 2015. The station has a daily capacity of 4.8 MMscf and represented an investment of USD 20.5 million.



Source: ECO Environmental Investments Limited

Despite LNG represents many advantages as a marine power fuel its application and promotion is still facing many problems that should be solved in future. Firstly, the alternative cost of vessel is higher but the sailing time is too short. Although LNG storage tank volume is small, but the system is complex and layout is difficult. At the same time, installing cylindrical LNG storage tanks will reduce part of the carriage space. Secondly, the biggest obstacle for promoting LNG as a marine vessel fuel in China is a serious deficit of supplying facilities. Nowadays, gasoline facilities are very spread in the marine network, while LNG is still giving its first steps in this field.

In the next section, some lessons from USA and China developments in the small-scale LNG industry will be summarized.

## 11. LESSONS FROM USA AND CHINA

Based on the described experiences in USA and China, several lessons on the promotion of small volumes of LNG can be learned.

First of all, small-scale LNG is an already proved technology. It has been implemented in USA since 1950 and in China since 2000. However, its development curve has been extremely steep in this Asian country.

Secondly, small-scale LNG solutions have been implemented in the following way:

- Restrictions of infrastructure:
  - In USA, peak shaving was used to solve pipeline network restrictions or deficient storage capacity.
  - In China, domestic gas demand had a boom which could not be matched by the required infrastructure development (gas transportation and transmission). LNG virtual chain provided a transitional solution to solve the gap.
- Demand does not reach the minimum volume required to invest in traditional gas infrastructure transportation.

- Emission reduction policies (already implemented in China and expected in USA in the near future). It kind of policies can improve the economics of the projects.
- More competitive prices of natural gas in the transportation sector against petroleum derivatives.

Third, strategic public policies - through laws and national companies - were a relevant factor to reduce the “coordination problem” in the natural gas market, improving LNG penetration and creating critical mass for the emerging LNG market, mainly in the case of China. In the USA, LNG market was developed by mean of market incentives.

Last but not least, several barriers for the development of LNG have been found, such as: the “coordination problem” for investment decisions (for infrastructure development), the minimum scale (demand / supply) required assuring economic viability and the prices that the demand is willing to pay for the new equipment. In the case of China, the “coordination problem” was solved by the action of the state, the vast majority of times by means state-owned enterprises investments.

## 12. APPLICATIONS FOR OTHER COUNTRIES

The small volume LNG technologies existing in USA and China could be developed in countries with less developed infrastructure. In this respect, a particular analysis will be done for Nigeria, Iraq and Indonesia (small island-based markets) taking into account underlined lessons of USA and China in the previous.

Firstly, a brief general, energy and infrastructure outlook of those countries will be presented. It is essential to provide an understanding of the situation of potential suppliers, clients and current infrastructure (e.g.: transportation network) to introduce LNG technologies. Finally, a preliminary analysis of several opportunities for small scale LNG developments in those countries will be offered

## 12.1. Nigeria

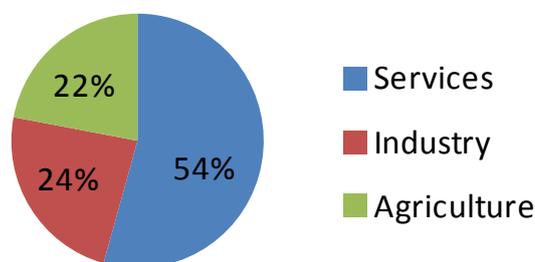
The Federal Republic of Nigeria is a federal constitutional republic of West Africa. It has 36 states and its capital is Abuja. Nigeria the Gulf of Guinea (Atlantic Ocean) and shares borders with Benin, Chad, Cameroon and Niger. As a tropical country, Nigeria's seasons are determinate by rainfalls<sup>14</sup> (South east receives more than 3.000mm a year, while the southwest 1.800mm<sup>15</sup>). Regarding the temperature, it does not present a significant variation in the south<sup>16</sup> (average 27.5°C) but, in the north, ranges can be very wide<sup>17</sup>. As a result, climate might not be a significant conditioning factor for the Nigeria energy sector<sup>18</sup>.

Nigeria has 173.6 million inhabitants, which become in the most populous country in Africa. The next table and graphs offer a geographical and general economic context.

Population (2013)	173.6 million
GDP, current USD (2013)	521.8 billion USD
GDP per capita, current USD (2013)	3,006 USD
Consumer Prices (2013)	8.5%
Unemployment (2013)	7.5%
Currency (2012)	158.8 Naira (NGN/USD)

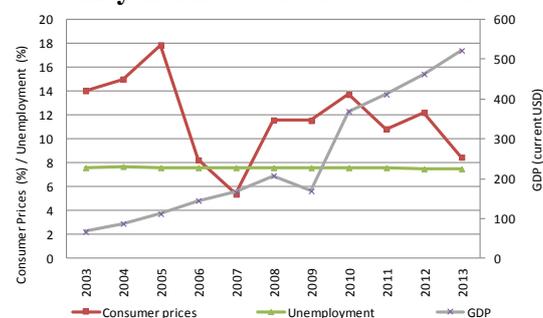


**GDP by sector (2012)**



Source: World Bank Data

**Key market variables evolution**



<sup>14</sup> Dry season from November to March and the rain season from April to October.

<sup>15</sup> Annual Abstract of Statistics – National Bureau of Statistics – Federal Republic of Nigeria – 2012.

<sup>16</sup> Temperature has a minimum of 22°C and a maximum of 33°C.

<sup>17</sup> During the hot months (April and May), temperature variations are considerable higher: minimum below 0°C at night and maximum of 38°C during the day.

<sup>18</sup> I.e.: transportation issues or seasonal electricity demand.

### 12.1.1. Macro perspectives

Nigeria became the largest economy in Africa in 2011<sup>19</sup>. Oil sector represents 96% of exports revenues, which makes the economy of the country very vulnerable and dependent on international oil prices. In fact, the international Monetary Fund (IMF) estimates Nigeria's growth rate will drop 5% in 2015 due to the oil's price fall and the expected depreciation of the currency.

However, the improvement of non-oil sectors (agriculture, trade and services and communication technology) might be the key factor to soften the drop of expected economy's growth<sup>20</sup>, in which the Government of Nigeria has been making efforts in this way<sup>21</sup>.

### 12.1.2. Industry sector

Based on the Nigeria Industrial Revolution Plan<sup>22</sup> (NIRP, 2014), manufacturing sector result weak in comparison with most developed manufacturing nations<sup>23</sup>. Power and transportation deficiencies seem to be the most important reason of this delay. Any effort aiming to accelerate the manufacturing sector will not be as efficient if these issues are not solved.

Industries are concentrated on the shore (especially in the southwest), and some cement textile and motor vehicle industries are spread in the center and northwest of Nigeria<sup>24</sup>.

### 12.1.3. Transportation network

Last decades, Nigeria has developed an extensive national road network. Its density is more than twice as high as these for resource-rich African countries, although only half of the levels found in Africa's middle-income countries.

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<sup>19</sup> World Bank Data

<sup>20</sup> African Economic Outlook - Nigeria - AfDB, OECD, UNPD

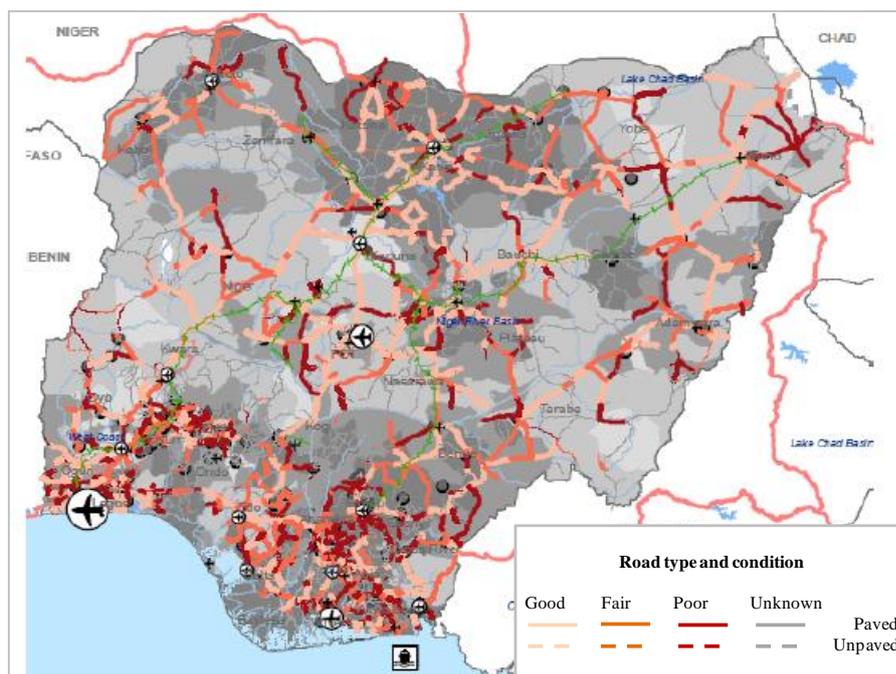
<sup>21</sup> Non oil sector contributed around unprecedented 40% to GDP in the third quarter of 2013 and it is expected significant results based on Agriculture Transformation Agenda (2011). The industrialization of the agriculture sector - main driver of non oil sector - could be the major boost to maintain GDP at acceptable levels.

<sup>22</sup> Nigeria is envisaging an industrialization of the country, particularly in adding values to its commodities, as the agriculture field.

<sup>23</sup> China's manufacturing share of GDP is 33%, while Nigeria's is less than 4% in 2010.

<sup>24</sup> Nigerian Industrial Revolution Plan (NIRP).

## Nigeria's road network



Source: World Bank<sup>25</sup>

The length of federal road network was 36,172 km in 2009. Nigeria's paved network represents 65% of the system (of which 2/3 is in fair/good condition). However, the unpaved network share is 35% (of which 1/3 is in fair/good condition).

Road maintenance remains underfunded and the network might suffer a significant fall in the quality of service level in the following years. In this regard, Nigeria created a federal road maintenance agency (FERMA), in order to aside the required budget to face the problem. FERMA has been addressing a reasonable amount for rehabilitation, but far deficient for prevent maintenance in countries in the region<sup>26</sup>.

In terms of security, theft and violence in the routes are not insignificant issues. Government reaction was to spread police officer all over the national network as "checkpoints"<sup>27</sup>.

Several transportation projects under Public Private Partnership<sup>28</sup> (PPP) framework are ongoing in Nigeria, i.e. toll road Lekki Epe<sup>29</sup>, Akuta bridge and Lagos State Blue Train<sup>30</sup>.

<sup>25</sup> Nigeria's infrastructure: a continental perspective - World Bank – 2011.

<sup>26</sup> Nigeria's Infrastructure: a Continental Perspective – Africa Infrastructure Country Diagnostic – 2011.

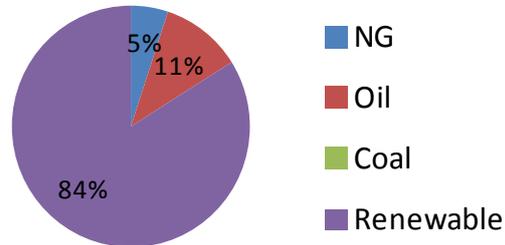
<sup>27</sup> Nonetheless, the problem is not solved and, furthermore, a large part of the users reported these checkpoints cause more traffic jam and a high rate of bribes - <http://thelawyerschronicle.com/checkpoints-in-nigeria-and-their-implication-on-security/>

<sup>28</sup> Privatization and public private partnership in Nigeria – Patrick Mgbenwelu, FBN Capital Limited – First bank of Nigeria.

<sup>29</sup> 50 km Expressway.

## 12.1.4. Energy matrix

**Primary energy consumption (2011)**



Source: U.S. Energy Information Administration

Renewable sources (biomass and waste), reach 84% of the total primary energy consumption, which is estimated at 4.3 quadrillion British thermal unit (Btu). A small share of Nigeria's inhabitants consume natural gas for domestic uses (cooking and heating).

## 12.1.5. Petroleum

Nigeria is the 12<sup>th</sup> largest producer of petroleum in the world<sup>31</sup> and it has the 11<sup>th</sup> largest proven reserves. Oil rents represent 15.3% of GDP<sup>32</sup>. The country is an OPEC member from since 1971.

**Main features (2012)**

Reserves	13,000 MB (2.2% of worldwide reserves)
Total production	2,371 thousands bpd (0.3% of worldwide production)
Domestic consumption	302 thousands bpd (1.7% of worldwide consumption)
Net exports	2,069 thousands bpd (6% of worldwide exports)

Source: U.S. Energy Information Administration and Organization of the Petroleum Exporting Countries (OPEC) - Annual Statistical Bulletin

Location of reserves are in Niger River Delta, Offshore in the Bight of Benin, Gulf of Guinea and Bight of Bonny

Currently, there are exploration activities in the Chad basin.



Source: U.S. Energy Information Administration

## 12.1.6. Gas

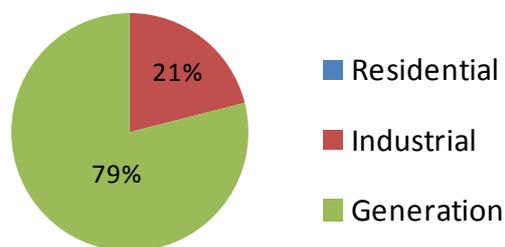
Nigeria is the 23<sup>th</sup> largest producer of gas in the world and has the 9<sup>th</sup> largest proven reserves.

<sup>30</sup> 27 km light rail service project (along the most densely travelled corridor in Nigeria: Okokomaiko – Marina).

<sup>31</sup> 1<sup>st</sup> producer in Africa.

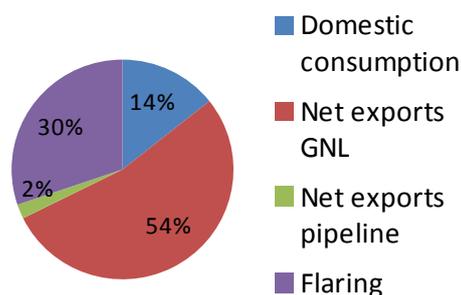
<sup>32</sup> World Bank Data.

### Uses of domestic gas consumption<sup>33</sup> (2012)



Source : US Energy Information Administration

### Gas use (2012)



Source : US Energy Information Administration

### Gas export & import facilities

Export facilities	Capacity (Bcf)	Sendout (Bcf)
<b>LNG facilities</b>		
Liquefaction plant Bonny island	1,026	910
Additional planned liquefaction facilities <sup>34</sup>	466	-
<b>Pipelines</b>		
West African Gas Pipeline (to Ghana)	131	36
Planned Trans-Saharan Pipeline <sup>35</sup>	1,050	-

Source: U.S. Energy Information Administration (EIA) and BP Statistical Review of World Energy

In the following maps, locations of flaring and existing/planned liquefaction plants (Bonny Island, Brass, 600 km away from Bonny Island and Olokola) are identified.

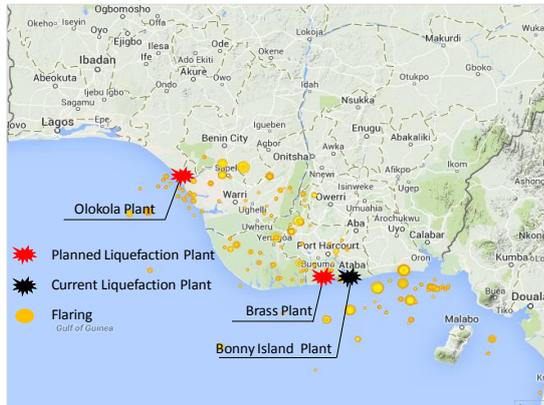
The route of the West African Gas Pipeline (WAGP), which delivers gas to Benin, Togo and Ghana from Nigeria, is also indicated.

<sup>33</sup> Industrial sector price: 2\$/MMBtu and power sector price: \$1/MMBtu, based on Nigerian National Petroleum Corporation. Nigeria to raise domestic gas prices to par with international market: NNPC.

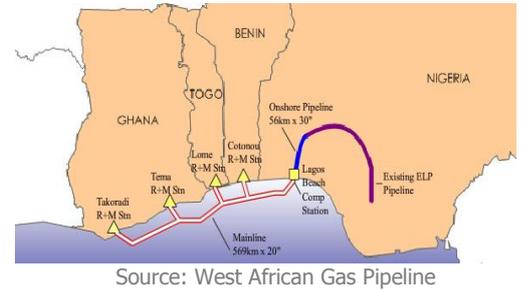
<sup>34</sup> The Brass LNG, Olokola LNG or a new regasification train for Bonny LNG. Delayed investment decision (FID).

<sup>35</sup> A pipeline, from Nigeria to LNG terminal in Algeria, to deliver gas for Europe. The project is delayed due to regulatory, political and security issues.

## Gas export facilities and flaring location

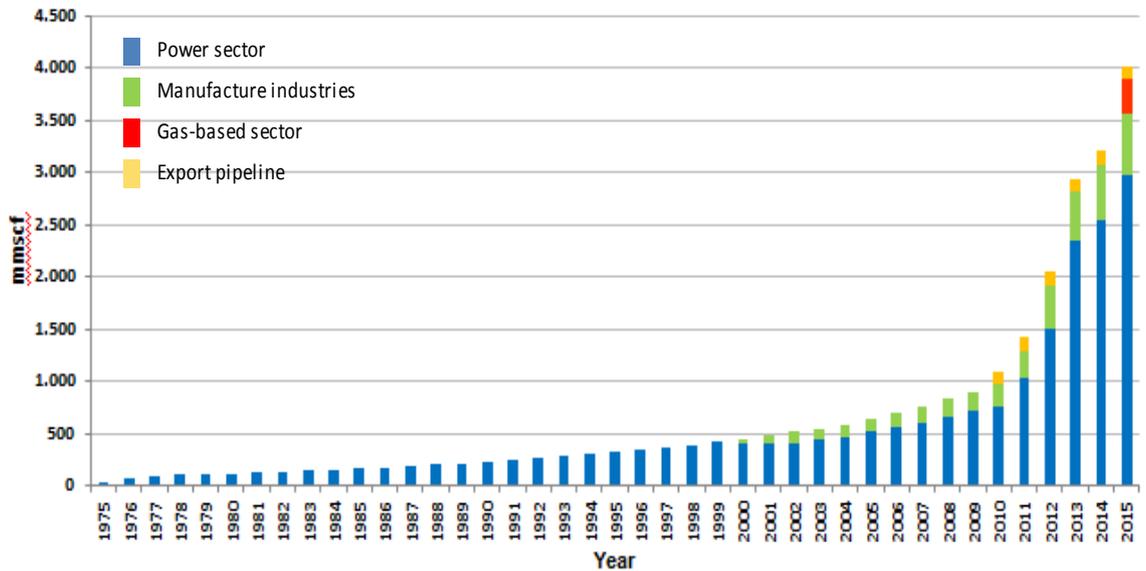


Source: <http://skytruth.org/viirs/> and GIGGLN



Source: West African Gas Pipeline

## Historical and Projected gas demand



Source: Gas Supply and Transportation Issues: Gas to Power Demand - Nigeria National Petroleum Corporation

### 12.1.6.1. GAS POLICIES

In 2008, Nigeria launched the National Gas Master Plan (GMP) in order to exploit the gas potential and accelerate the economic development. The GMP was followed by extra regulations that completed the gas framework: Domestic Gas Supply, Gas Pricing Framework, Gas Infrastructure Blueprint.

In February 2008, the Federal Executive Council approved the Domestic supply Obligation (Domgas), in order to set aside a percentage of the country's reserves and production for supply the domestic market, especially for the power generation. The Domgas also empowered the Ministry of Petroleum to periodically stipulate the quantity required and to penalize<sup>36</sup> International Oil Companies (IOC) which does not comply with their obligations. The regulation stipulated an increasing curve of domestic supply<sup>37</sup>. Since IOCs stated its disagreement<sup>38</sup> on the new law, the policy was revised and the initial obligation supply for 2009 dropped to less than half of the previous stipulation. In May 2013, the target stated by the Government was 942 MMscf/d<sup>39</sup> shared by IOCs, which shows a lack of compliance of the forecast developed in 2008.

In addition, a gas pricing framework was also approved. As a result, domestic market was categorized in the following groups:

- Cost of Supply Basis: addressed to strategic domestic sector, particularly power sector<sup>40</sup>.
- Product Netback Basis: strategic industrial sector (gas as feedstock)<sup>41</sup>.
- Alternative Fuels Basis: for commercial sector<sup>42</sup>.

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<sup>36</sup> With \$3.5/MMscf, restriction on exports or both.

<sup>37</sup> Starting at 3,000 MMscf/d in 2009 and forecasting an obligation supply of 5,000 MMscf/d by 2013 - The Nigerian Gas Policy: Issues, Challenges and Way Forward – Nigerian National Petroleum Corporation (NNPC).

<sup>38</sup> This policy was not welcomed by major operators due to the difficulty of breaking down long term contracts already signed. Furthermore, they stated the first step should be to secure the domestic gas supply infrastructure, and not to warrantee the gas supply.

<sup>39</sup> Maintaining Service Delivery& the early stabilization of the infant privatized Nigerian electricity supply market - Presidential task force on power - 2014  
<http://www.power.gov.ng/Power%20Summit/PTFP%2020140130%20CPTFP%20Power%20Summit.pdf>

<sup>40</sup> The stipulated price was USD 0.4/MMscf to power with gradual increase, in order to reach USD2/MMscf by 2013

<sup>40</sup>. In the period 2014-2016, the formula is expected to include the inflation rate of 5%.

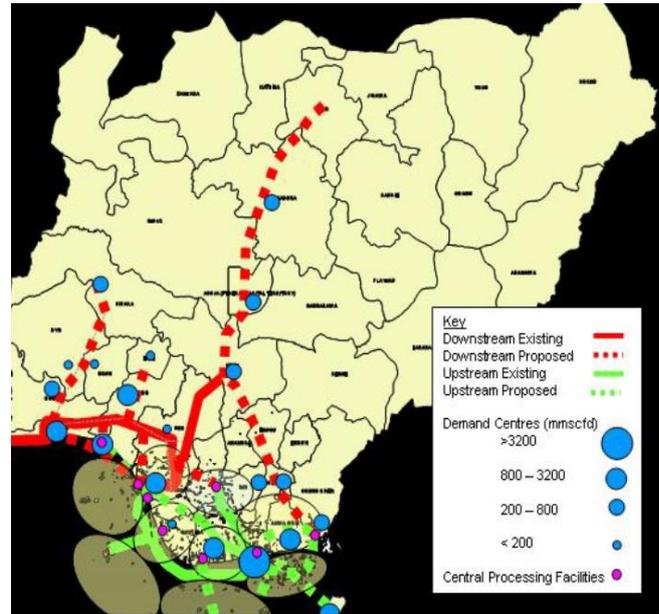
<sup>41</sup> The stipulated floor price was USD 0.9/MMscf and the capped price, USD3/MMscf.

<sup>42</sup> The stipulated price was USD 2/MMscf in 2010 stepping to USD 2.5/MMscf in 2013 and USD 3/MMscf by 2014.

## Master Plan Infrastructure Blue Print

The Infrastructure Blueprint consisted in setting the basis of the priorities' investments progress. The investment program includes gas gathering and processing facilities (CPF), strategically located within each cluster, in order to open access to all players for regulated tolling fee. These investment would replace incremental plant capacities upgrades<sup>43</sup>.

The Petroleum Industry Bill (PIB), which was approved in 2012, declared all regulation aspects of the 3 petroleum sectors (downstream, middle stream and downstream) were covered by a single regulation. This policy gave the Minister omnibus powers over the petroleum market<sup>44</sup>.



Source: The Nigerian Gas Policy: Issues, Challenges and Way Forward- NNPC

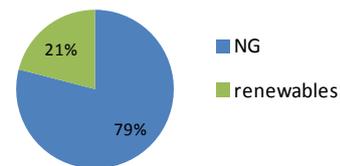
### 12.1.7. Electricity

#### Main features (2012)

Installed capacity	6,090 MW
Generation (average)	27 TWh
Consumption	25 TWh
Access to electricity	50%

Source: U.S. Energy Information Administration

#### Generation by source (2012)



Source : US Energy Information Administration

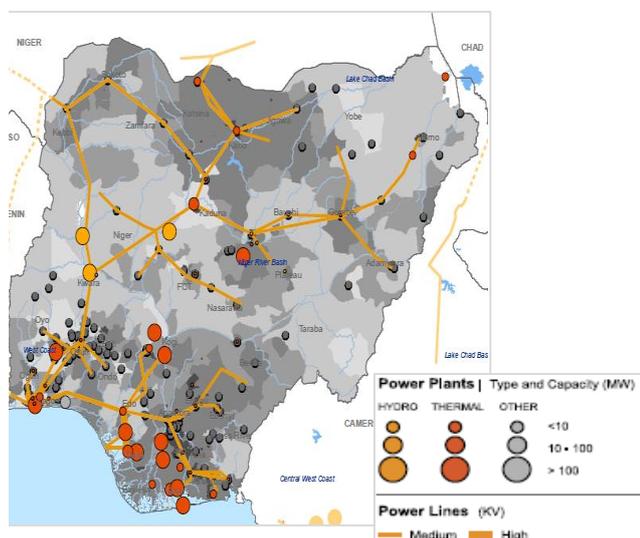
Nigeria has the lowest net electricity generation per capita in the world and frequently suffers blackouts and reliance on residential and commercial customer's private generators. In order to revert the insufficient power system and encourage investments in the sector, Nigeria launched the "Power Sector Reform Roadmap" in 2010, which major goal was unbundling the electricity sector chain and promote private investments. Furthermore, the reform included several fiscal incentives to investment, as 30% reduction tax for power plants using gas.

<sup>43</sup> The CPF identified were West Delta (Warri), Obiafu (North Port Harcourt) and Akwa Ibom /Calabar Area). In addition, transportation infrastructure was focused in 3 gas pipeline transmission systems: South North, Western System and interconnection.

<sup>44</sup> <http://www.nigeria-law.org/Legislation/LFN/2012/The%20Petroleum%20Industry%20Bill%20-%202012.pdf>

Nevertheless, certain issues remain as a challenge to accomplish the goal of improvement of the power system: security, transmission system and gas pipelines network.

### Power network and plants



Source: Nigeria's infrastructure: a continental perspective  
World Bank – 2011

In addition, the Federal Government of Nigeria (FGN) launched in 2010 the Nigerian Bulk Electricity Trading Plc (NBET), a FGN owned public liability company, “for trading licensee that holding a bulk of purchase and resale license”<sup>45</sup>. The entity’s payments obligation have been credit via commitment from Ministry of Finance and World Bank Partial Risk Guarantee. The major goal of the transitional organism (NBET) is “to engage in the purchase and resale of electrical power and ancillary services from independent power producers (IPP) and from successor generation companies”.

In other words, the role of the NBET is to drive private sector to invest in generation activities during the transitional stage of the Nigerian power sector reforms.

Regarding future projects, the International Finance Corporation (IFC) of the World Bank<sup>46</sup> has a plan to collaborate to the increase generation capacity by 1,500 MW in Nigeria, which would allow to provide electricity to 8 million households.

In addition, IFC and MIGA Board Executive directors approved<sup>47</sup> in 2014 loans and guarantees of USD 245 million and USD 150 million for 459 MW Azura Edo (Edo State) and 533 MW Qua Iboe (Akwa Ibom State) power plants, respectively, both gas fired. IFC’s investment and MIGA’s guarantee framework for Azura project could be the first of a replicable projects in Nigeria.

<sup>45</sup> Nigerian Bulk Electricity Trading PLC - <http://www.nbet.com.ng/about-us>

<sup>46</sup>[http://www.ifc.org/wps/wcm/connect/e692c80045edcb21bcdebd9916182e35/AM2014\\_IFCIssueBrief\\_Infrastructure.pdf?MOD=AJPERES](http://www.ifc.org/wps/wcm/connect/e692c80045edcb21bcdebd9916182e35/AM2014_IFCIssueBrief_Infrastructure.pdf?MOD=AJPERES)

<sup>47</sup><http://www.worldbank.org/en/news/press-release/2014/05/06/world-bank-group-project-series-local-power-output-nigeria>

## 12.2. Iraq

The Republic of Iraq, which is located in Middle East of Asia, is compounded by 18 provinces or governorates. Its capital is Bagdad and it shares borders with Syria, Turkey, Iran, Jordan and Suadi Arabia. Iraq has a small coast on the Persian Gulf. Its climate is broadly hot desert, and average rain fall are 240 mm per year. Temperature has a wide range between winter and summer. The average temperature is above 40°C in the hottest months, while during the winter temperature can drop below 0°C.

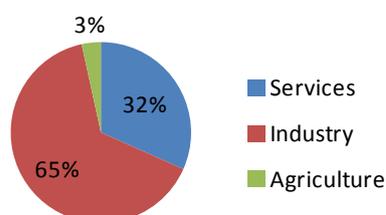
Since 1979, Iraq lived for almost 3 decades under a violent scenario that it has produced several problems for the energy infrastructure of the country.

The next table and graphs offer a geographical and general economic context of Iraq.

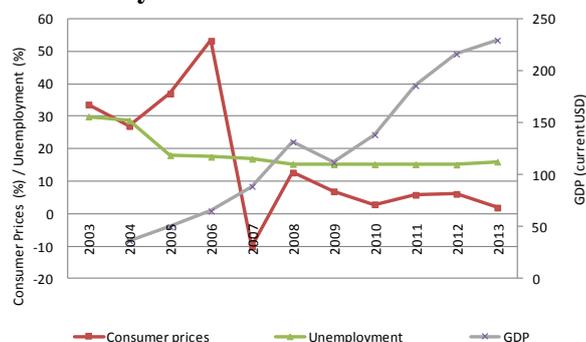
Population (2013)	33.42 million
GDP, current USD (2013)	229.3 million USD
GDP per capita (2013)	6,862 USD/capita
Consumer Prices (2013)	1.9%
Unemployment (2013)	16%
Currency/FX (2012)	1,164.0 Dina (IQD) IQD/USD



GDP by sector<sup>48</sup> (2012)



Key market variables evolution



Source: World Bank Data

<sup>48</sup> [http://www.theodora.com/wfbcurent/iraq/iraq\\_economy.html](http://www.theodora.com/wfbcurent/iraq/iraq_economy.html)

### 12.2.1. Macro perspectives<sup>49</sup>

After 3 decades of war, the Ministry of Planning developed a four years economic plan, which seeks the development of a better market economy by improving the foreign and transit trade, (creating free zones) and re-creating financial, fiscal and monetary policies.

Furthermore, the plan encourages the gradual shift towards the private sector, and the restructuring of state-owned industries by promoting strategic partnerships with foreign and local investors. It also aims to activate government-owned and private banks.

Regarding resources, the plan emphasizes on the wiliness to increase oil and gas production, in order to improve Iraq financial sustainability. Several politicians made focus on the importance of private investments attraction<sup>50</sup>.

### 12.2.2. Industry sector

Iraq was historically strong in petrochemical and military sectors. Oil sector contributed for 47% of the GDP, but less than 1% of Iraqi employment. However, both were devastated by the wars and internal conflicts. It is important to note that Iraq was by dominated state-owned enterprises, letting a small share to private sector<sup>51</sup>. The *private sector development program for Iraq (PSDP-I)*<sup>52</sup> sought to set an effective framework for private investment development in the country. UNIDO launched a project<sup>53</sup> aiming “to support promotion of investment and development of the private sector in the country” focusing in Baghdad and Basrah Governorates (Al Faw), with additional locations to be determined.

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<sup>49</sup> <http://iraqdinar.us/economic-laws-revive-the-market/>, <http://iraqdinar.us/develop-an-economic-plan-for-4-years/>, <http://iraqdinar.us/iraqi-attempts-to-invest/>, <http://iraqdinar.us/abadi-moving-to-restructure/>, <http://www.imf.org/external/pubs/ft/scr/2013/cr13217.pdf>

<sup>50</sup> Prime Minister affirmed at the World Economic Forum – Davos “We turn now from the system controlled by the government to a mixed economy more active, as we privatize key sectors, and explore partnerships between the public and private sectors, and entering into joint ventures with international companies (...)” and Mohammed Saleh adviser stated “the solution is the need for the development of commodity sectors, and today the state is moving strongly towards the revitalization of agriculture, manufacturing, and began a strong movement in this aspect.”

<sup>51</sup> These companies could not support the unstable business climate and keep working due to enormous subsidies given by the Government.

<sup>52</sup> Partners: Prime Minister's Advisory Commission (PMAC) and Task Force for Economic Reform with seven Working Groups, Central Bank, National Investment Commission, IOM, World Bank, OECD, IFC, USAID, SIDA, STC, Unioncamere, Embassies of the USA, Poland, Romania, EU Delegation, Sweden, Italy, ILO, UNIDO, FAO, UNOPS, UN-HABITAT, UNWOMEN and issued in 2013.

<sup>53</sup> *Enhancing Investment to Iraq through Industrial Zone Development (IZ)*, issued by United National Industrial Development Organization (UNIDO) in 2013.

In the province of Basrah are located some of the largest oil field, and the large majority of Iraq production are exported through the ports of the area. In addition, the port of Kohr Al Zubair is a free zone located 40km southwest of Basrah. Based on Investor Guide of Basrah<sup>54</sup> the major industries in the region are oil, oil processing, shipping, agriculture, tomato paste, dates, fishing and fisheries, and the potential area investments are plastics, fertilizers and other petrochemicals, expansion of existing port facilities, trade logistics and tourism.

### 12.2.3. Transportation network

The road network has 48,000km length. Poor maintenance of the network has enormously increased accidents in the country, placing Iraq as one of the highest road fatalities rates' countries. Currently, several agreements with World Bank and Islamic Development Bank are looking to improve the quality of certain roads and to develop a major trade-corridor (highway) in order to connect Iraq to its neighboring countries.



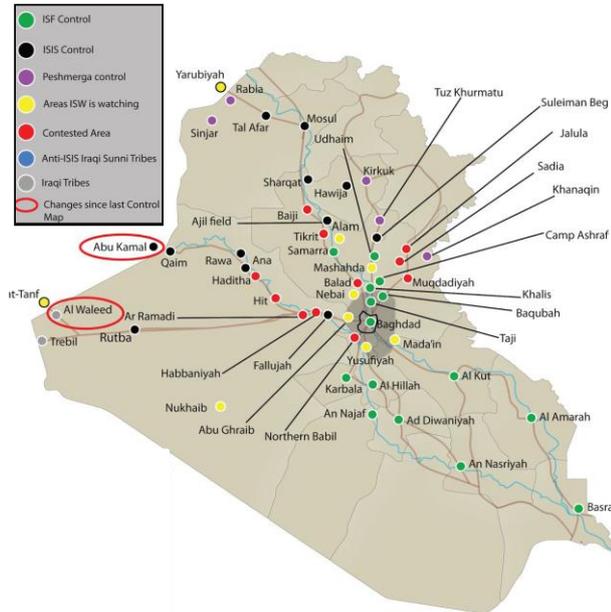
Source: Logistics Cluster and World Food Programme - 2013

In the case of Iraq, the current security situation should not be neglected. Due to serious conflicts in the country there is no guaranty of safety in the road network. The World Bank identified level and type of risk in the country: “Contested areas”<sup>55</sup> included the governorates of Kirkuk; Diyala; Anbar; Salah al Din and Ninewa.

<sup>54</sup> Basrah Investment Commission and Tijara Provincial Growth Program – 2012.

<sup>55</sup> “Contested areas are the areas controlled by non-government armed groups, notably by the Islamic State (formerly known as the Islamic State of Iraq and the Levant or Islamic State of Iraq and al-Sham, ISIS), and those territories where active internal armed conflict has occurred, or where control of territory has changed between government and non-government forces. It may also include territory that is highly likely to be contested imminently, based on an assessment of available, relevant, country facts”. Country Information and Guidance Iraq: *The security situation in the 'contested' areas of Iraq* issued in 2014.

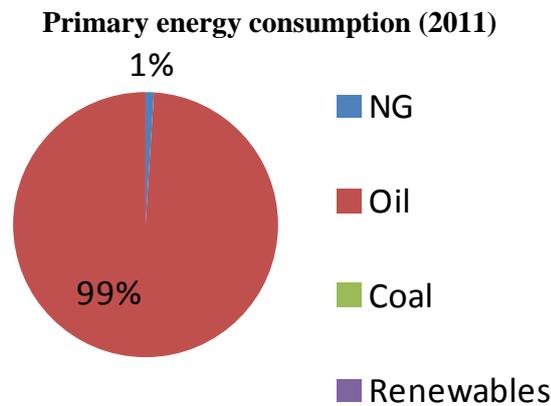
### Security in Iraq – Control of Terrain (2014)



Source: World Bank

According to the World Bank, travelling by roads in these areas has high risks, due to presence of armed groups (military operations and insurgents) setting up road blocks, mines or explosives. While security issues are extremely severe in the “contested areas”, the whole country, and its road network, remains insecure, which can be noted by the number of displacement last years (recently over 1,000,000 people).

### 12.2.4. Energy matrix



Source: U.S. Energy Information Administration

Iraq primary energy consumption matrix is nearly absolute defined by oil. A small share of natural gas is use for power generation.

## 12.2.5. Petroleum

Iraq is the 8<sup>th</sup> largest producer of crude oil in the world and has the 6<sup>th</sup> largest proven reserves. Oil rents represent 45.5% of GDP<sup>56</sup>.

### Main features (2012)

Reserves	140,000 MB (8.9% of worldwide reserves)
Total production	3,057 thousands bpd (2.0% of worldwide production)
Domestic consumption	769 thousands bpd (3.7% of worldwide consumption)
Net exports	2,288 thousands bpd (6.0% of worldwide exports)



Source: U.S. Energy Information Administration (EIA) and Organization of the Petroleum Exporting Countries (OPEC) - Annual Statistical Bulletin

Source: U.S. Energy Information Administration

Reserves are located in Kirkuk field (North of Iraq), the South Rumailia (south of Iraq) and North Rumaila fields in (South of Iraq).

It is important to note that 60% of the reserves are located in the South of the country, while the 17% of Iraqi oil is in Kurdistan area. There have been disagreements between regional and national government, and even other groups, over the rights of these resources that keep unsolved.

<sup>56</sup> World Bank Data

## 12.2.6. Gas

Iraq is the 50<sup>th</sup> largest producer of gas in the world and has the 12<sup>th</sup> largest proven reserves.

### Main features (2012)

Reserves	112 Tcf (1.7% of worldwide reserves)
Total production <sup>57</sup>	1,025Bcf (0.02% of worldwide production)
Domestic consumption	660 Bcf (0.88% of worldwide consumption)
Net exports GNL	0 Bcf
Net exports pipeline	0 Bcf
Flaring (2011)	365 Bcf (7.5% of the worldwide flaring <sup>58</sup> )
Associated gas	75%

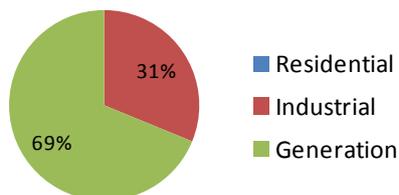
Source: U.S. Energy Information Administration and BP Statistical Review of World Energy - 2014



Source: U.S. Energy Information Administration

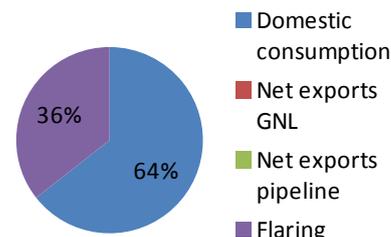
Location of gas reserves are in Ajil, Bai Hassan, Jambur, Chemchemical, Kor Mor, Khashem al-Ahmar, and al-Mansuriyah. (north of Iraq) and in Basrah Province (south of the country)

### Uses of domestic gas consumption<sup>59</sup> (2012)



Source : US Energy Information Administration

### Gas use (2012)



Source : US Energy Information Administration

Currently, there are no gas export facilities. But some ideas have been discussed last years. More than 3 decades ago, Iraq exported natural gas to Kuwait through a 160 km pipeline. Ministry of Oil proposed to rehabilitate the pipeline, but there was no progress on the idea. Furthermore, other projects are the Pipeline to Nabucci (Turkey)<sup>60</sup>, to link the network with Arab Gas Pipeline (Egypt)<sup>61</sup>, to export gas through a Liquefied Natural Gas plant in Basrah region, and finally, to participate of the Friendship Gas Pipeline.

<sup>57</sup> The consumption does not include re-injected share.

<sup>58</sup> Flaring was 140 bcm in 2011 according to World Bank – “World Bank sees Warning Sign in Gas Flaring Increase”

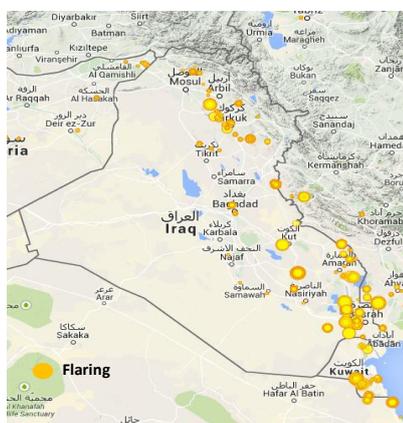
<sup>59</sup> Gas price was 1.2\$/MMBtu in 2013 based on IRAQ Gas Feedstock Assessment For Power, Petrochem, Industries, Oil Operations and Export – 2013.

<sup>60</sup> Pipeline to Nabucci (projected pipeline to Turkey): in order to send LGN to Europe (capacity 530 Bcf) from Rumalia.

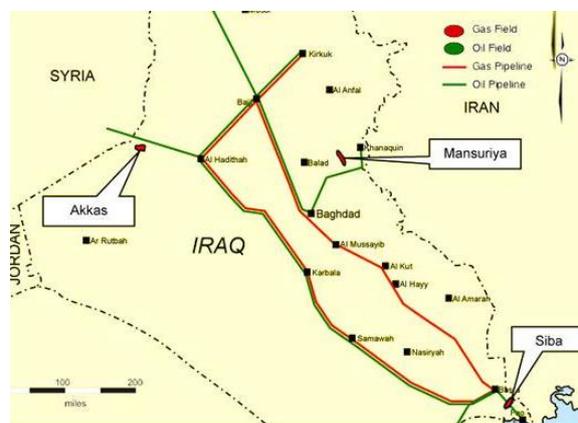
<sup>61</sup> To link the Iraqi network to Arab Gas Pipeline, that connects Egypt's gas grid with those of Jordan, Syria, and Lebanon. Under this plan, gas would be delivered from Iraq's Akkas field to the Turkish border and then on to Europe.

The 25 million cubic meters (Mcm) Iran-Iraq gas pipeline that will supply Al Mansoureh power plant in Iraq is already complete and both government expect to begin 7 Mcm exports from Iran in March 2015<sup>62</sup>.

### Gas export facilities and flaring location



Source: <http://skytruth.org/viirs/>



Source: Energy-Pedia News<sup>63</sup>

#### 12.2.6.1. GAS POLICIES

Iraqi gas policy is compounded by several laws and articles of the Constitution<sup>64</sup>. The lack of a unique gas framework let several ambiguities opened. As a result, Iraq have been experiencing the Kurdistan (KRG) - National Government disagreement<sup>65</sup> -, which focus on the rights of the resources. In 2007, new package of laws and a draft hydrocarbon framework were issued by the National Government in order to solve the differences with (KRG). However, the Council of Representative's Oil and Gas Committee stated it will not proceed until National Government and KRG reach a political agreement. The pressure to bring closer regional and central government had no success and regulatory framework keeps uncertain. As a result, every organism responsible for bidding and award moved forward. In 2009, Iraq launched a 20 years bid, where several foreign companies participated. Nowadays, the market is open to national and international investments.

<sup>62</sup> [https://www.zawya.com/story/Iranian\\_gas\\_export\\_to\\_Iraq\\_expected\\_by\\_March\\_2015-ZAWYA20140914044723/](https://www.zawya.com/story/Iranian_gas_export_to_Iraq_expected_by_March_2015-ZAWYA20140914044723/)

<sup>63</sup> <http://musingsoniraq.blogspot.com.ar/2011/03/iraqs-parliament-may-cancel-akkas.html>

<sup>64</sup> Sources: The Geopolitics of Natural Gas Natural Gas in the Republic of Iraq - Harvard University's Belfer Center and Rice University's Baker Institute Center for Energy Studies – 2013. Iraq: Oil and Gas Legislation, Revenue Sharing and US Policy. – Congressional Research Service.

<sup>65</sup> Based on the Art 111 interpretation: "Oil and gas are owned by all the people of Iraq in all the regions and governorates".

Recently, the Ministry of Oil of Iraq and Norway signed an agreement of institutional cooperation contract<sup>66</sup>. The program focuses on technical support, and also includes some environmental aspects. In 2012, GGFR<sup>67</sup>, which is a PPP between governments, state-owned companies and major international oil companies, included Iraq as partner<sup>68</sup>. In 2013, GGFR launched a study on gas pricing mechanisms in Iraq<sup>69</sup>. This study included several recommendations to create a Mini/Micro LNG industry and try to reduce flaring in small fields.

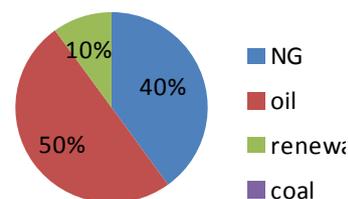
## 12.2.7. Electricity

### Main features (2012)

Installed capacity	12,000 MW
Generation (average)	58 TWh
Consumption	45 TWh
Access to electricity	98%

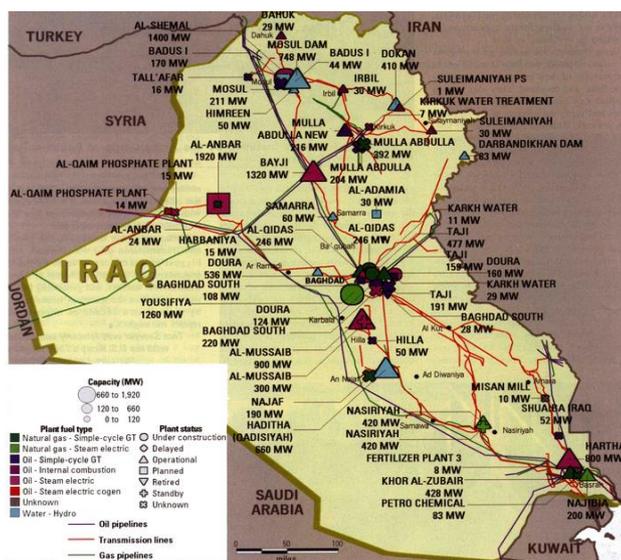
Source: U.S. Energy Information Administration

### Generation by source



Source : US Energy Information Administration

### Power network and plants



Source: [http://www.geni.org/globalenergy/library/national\\_energy\\_grid/iraq/iraqinationallelectricitygrid.shtml](http://www.geni.org/globalenergy/library/national_energy_grid/iraq/iraqinationallelectricitygrid.shtml)

Iraq faces a sharply rising demand of power. However, major power plants are shut down due to the lack of gas, and investments in the transmission and distribution networks are required. Daily outages lasting 16 hours have not been uncommon in Iraq. As a result, large and increasing number of privately-owned generators are contributing to the generation capacity (Baghdad has broadly 1 GW of private –owned generators capacity).

<sup>66</sup> It was based on the Norwegian Agency for Development Cooperation (2013).

<sup>67</sup> World bank-led Global Gas Flaring Reduction Partnership.

<sup>68</sup> [http://web.worldbank.org/WBSITE/EXTERNAL/COUNTRIES/MENAEXT/IRAQEXTN/0,,contentMDK:21801095~menuPK:50003484~pagePK:2865066~piPK:2865079~theSitePK:313105\\_00.html](http://web.worldbank.org/WBSITE/EXTERNAL/COUNTRIES/MENAEXT/IRAQEXTN/0,,contentMDK:21801095~menuPK:50003484~pagePK:2865066~piPK:2865079~theSitePK:313105_00.html)

<sup>69</sup> Providing a benchmark of international practices on gas pricing and regulation's issues - <http://www.norad.no/en/thematic-areas/energy/oil-for-development/where-we-are/iraq>

An expansion, especially based on natural gas fuelled turbines, is planned in the coming years, while the infrastructure enhancements to support this expansion have been lagging.

## 12.3. Indonesia

The Federal Republic of Indonesia is an archipelago country between South East Asia and Oceania. It is compounded by 34 provinces, which are spread in more than 17,000 islands. Its capital is Yakarta and it shares borders with Malaysia and Papua New Guinea. Indonesia has almost 250 million inhabitants, which make it the 4<sup>th</sup> most populated country in the world.

As a tropical country, Indonesia's seasons are determinate by rainfall (average of 2,700 mm per year). Regarding the temperature, it does not present a significant variation ranges (average of 27°C)<sup>70</sup>. It is important to note that Indonesia is almost entirely mountainous and tectonically speaking, highly unstable.

The following table and graphs offer a geographical and general economic context of Indonesia.

Population (2013)	249.9 million
GDP, current USD (2013)	868.3 million USD
GDP per capita (2013)	3475 USD
Consumer Prices (2013)	6.4%
Unemployment (2012)	6.3%
Currency (2012)	9363.9 Rupia (IDR) IDR/USD

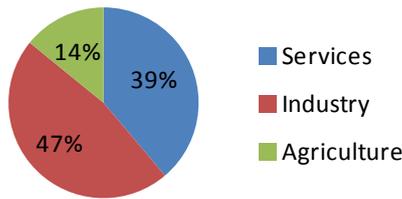
Source: World Bank Data



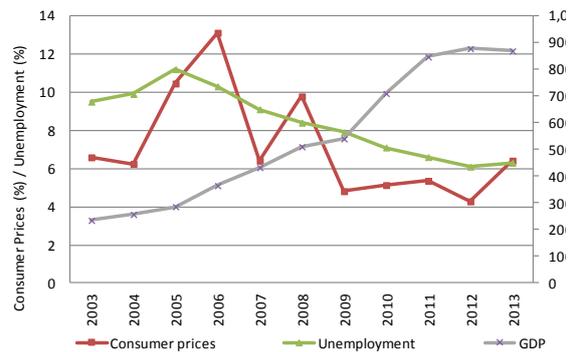
<sup>70</sup> The annual average temperature is 28°C in the coastal plain, 26°C inland and mountains and 23°C in the highest peaks.



**GDP by sector (2012)**



**Key market variables evolution (2012)**



Source: World Bank Data

### 12.3.1. Macro perspectives

Indonesia has reported an average GDP growth of 5.8% over the last 10 years and it is, currently, the largest economy in Southeast Asia. Although the international crude oil prices dropped, Indonesia could sustain its rate growth in the future, supported by the recovery of the investment demand and the raise of manufacture exports<sup>71</sup>.

Indonesia has undertaken a decade of economic (and political) changes. Reform package in almost every sector resulted in a substantial improvement on the climate for investment. In addition, new organisms have been created, in order to enhance transparency and efficiency by the implementation and enforcement of laws and regulation of newly-liberalized sectors<sup>72</sup>.

<sup>71</sup> International Monetary Fund (IMF) estimation.

<sup>72</sup> Furthermore, the government has taken several steps to boost PPP, which have been not possible till now, due to obstacles founded in the regulatory framework. November 2013 PPP Book listed 27 projects accounted in USD 47 billion in Indonesia.

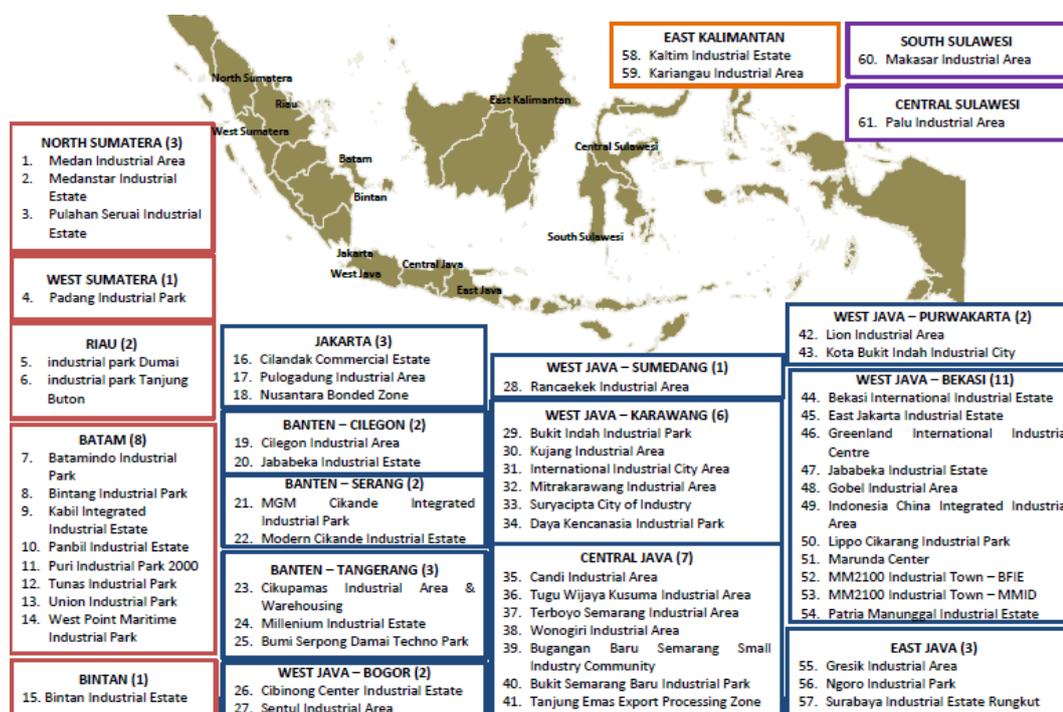
## 12.3.2. Industry sector

Regarding industrial sector, reforms<sup>73</sup> addressed to set a long term industrial development vision, declaring ambitious targets for 2025 to increase the current contribution of non oil and gas sector to industry share of the GDP<sup>74</sup> and become a high income country by 2020. Several strategies were stated, focusing in 8 main programs: agriculture, mining, industry, marine, tourism, telecommunication, and the development of strategic areas<sup>75</sup>.

Furthermore, Indonesia's industrial market is open to foreign investments, with the exception of sectors listed in the Negative List.

In 2012, manufacturing industry contributes for 23.6% of the economic activity in Indonesia. The industrial park in 2012 is shared as exposed in the following map<sup>76</sup>. However, power and transportation issues might be key barriers for accelerate industrial growing in Indonesia.

**Map of major Indonesia's Industrial Park**



Source: Indonesia Investment Coordination Board - KPGM – 2012

<sup>73</sup> National Industry Policy in 2008, Master Plan for Acceleration and Expansion of Indonesia Economic Development (MP3EI) in 2011 and a New Industrial Bill in 2014.

<sup>74</sup> From 61.9% to 95% by 2025.

<sup>75</sup> Industrial Policy in Indonesia: a global value chain perspective – Asian Development Bank – 2014.

<sup>76</sup> Investing in Indonesia - KPGM – 2013.

### 12.3.3. Transportation network

#### 12.3.3.1. ROAD NETWORK

In the 1980s, Indonesia's road network have been benefited by a significant expansion, which was followed by a liberalization of the sector in the 1990s and an economic Crisis in 1997. Over that decade investment declined and level and quality of services have never been recovered<sup>77</sup>.

In 2012, the length road network reported was 477,000 km. Its network's density<sup>78</sup> is internationally average; nonetheless, it keeps low compare with neighboring countries<sup>79</sup>.

Lack of investments in maintenance derived in an increasing share of poor condition roads. At the national level (8% of the global network in 2009), 88% of the network is in good condition. Nevertheless, 75% and 60% of provincial and district/city level (11% and 81% of the global network in 2009), respectively, are in fair/good condition.

In the case of Indonesia, it is important to note the share of the network for each island. As an interesting fact to be underlined, Java and Bali, which are the most populous islands (60%) have only 25% of the network share.

Island	Road network (%)	Population (%)	Land area (%)
Sumatra	34	21.4	25.2
Java & Bali	25	60	7.1
Kalimantan	11	5.6	28.5
Sulawesi	17	7	9.9
Maluku, NTT/NTB, Papua	13	6.1	29.4

Source: World Bank<sup>80</sup>

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<sup>77</sup> Particularly, in a country where 70% and 82% of freights (ton-km) and passenger (pax – km), respectively, are moved by road.

<sup>78</sup> 1.5 km/1,000 people and 190 km/ 1,000 km<sup>2</sup>.

<sup>79</sup> Investing in Indonesia's Roads Improving Efficiency and Closing the Financing Gap – World Bank - 2012

<sup>80</sup> Investing in Indonesia's Roads Improving Efficiency and Closing the Financing Gap – World Bank – 2012.

## Indonesia's road network



Source: Logistics Cluster and World Food Program - 2013

In the PPP Book<sup>81</sup> for 2014, several transportation projects were prioritized: 3 railway projects<sup>82</sup> (Java), a toll Bridge<sup>83</sup> (between Java and Sumatra) and 4 toll roads<sup>84</sup> (North Sulawesi, north Java, South Kalimantan and south Sumatra).

### 12.3.3.2. MARINE NETWORK

As an archipelago, the country strongly depends on sea transportation. Indonesia has approximately 1,700 seaports and had a trade volume of 968 million tons in 2009, from which 44% were domestic cargo and the rest international<sup>85</sup>. It is important to note that just a few ports dispatch international load and work as hubs. Thus, a significant share of the domestic shipping to these ports have, in fact, international final destination, and the volume bulk should be categorized as part of the international trade.

<sup>81</sup>[http://www.gbgindonesia.com/en/property/article/2014/indonesian\\_infrastructure\\_tremendous\\_ppp\\_opportunities.php](http://www.gbgindonesia.com/en/property/article/2014/indonesian_infrastructure_tremendous_ppp_opportunities.php)

<sup>82</sup> Manggari railway (Soekarno – Hatta International Airport) in Jakarta, Java; Gedebage Integrated Railway Terminal in West Java and Revitalization of rail station & Malioboro area in Yogyakarta.

<sup>83</sup> Sunda Strait Bridge (Sumatra-Java) and development of surrounding areas.

<sup>84</sup> Manado-Bitung Toll road in North Sulawesi; Tanjung Priok Access Toll Road in Jakarta; Balikpapan – Samarinda toll road and Kayu Agung – Palembang-Betung Toll Road in south Sumatra.

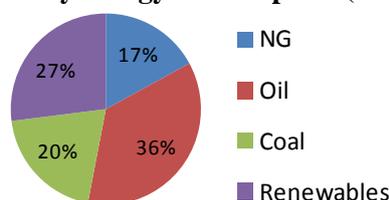
<sup>85</sup> Organization for Economic Co-Operation and Development (OECD), "Regulatory and competition issues in ports, rails and shipping for Indonesia".

Regarding inland infrastructure, in 2009, 5 ports concentrated 94% of the cargo: Tanjung Priok, Tanjung Perak and Tanjung Emas in Java and Belawan and Panjang in Sumatra. Based on World Bank Logistic Performance Index, the infrastructure quality of Indonesian ports is considerably lower than ASEAN+6's<sup>86</sup>. Regarding the fleet, the number of ships operated in Indonesia by local companies was 9,835 in 2010.

There are several private-owned ferry companies, which take the biggest share of passenger transportation volume. Pelayaran National Indonesia (PELNI) is the national shipping company, which provides goodies and passenger services, ensuring accessibility to the most remote islands.

### 12.3.4. Energy matrix

**Primary energy consumption (2011)**



Indonesia's primary energy consumption matrix is led by oil and renewable. As it can be noted in the graph, coal share is also relevant, since Indonesia is the 5<sup>th</sup> coal producer in the world. Natural gas is in the last place with 17% of the share.

Source: U.S. Energy Information Administration

### 12.3.5. Petroleum

Indonesia is the 23<sup>th</sup> largest producer of petroleum in the world and has the 27<sup>th</sup> largest proven reserves. Oil rents account for 2.6% of GDP<sup>87</sup>.

Location of the oil reserves are in Duri and Minas in the South Sumatra Basin (declining production), East Java Basin, Cepu Block in East Java (potential exploitation), deepwater in the Kutei Basin (coast of Kalimantan), deepwater in Western Papua, deepwater in Bonaparte Basin (adjacent to Australia).

<sup>86</sup> Association of Southeast Asian Nations: Indonesia, Malaysia, Philippines, Brunei Darussalam, Singapore and Thailand.

<sup>87</sup> World Bank Data.

### Main features (2012)

Reserves	3,500 MB (0.2% of worldwide reserves)
Total production	942 thousands bpd (0.3% of worldwide production)
Domestic consumption	1,660 thousands bpd (8% of worldwide consumption)
Net exports	-717 thousands bpd (6.0% of worldwide exports)

Source: U.S. Energy Information Administration and Organization of the Petroleum Exporting Countries (OPEC) - Annual Statistical Bulletin 2013



Source: U.S. Energy Information Administration

## 12.3.6. Gas

Indonesia is the 10th largest producer of gas in the world and the 8th largest exporter, and it has the 14th largest proven reserves.

### Main features (2012)

Reserves	104 Tcf (1.6% of worldwide)
Total production <sup>88</sup>	2,639Bcf (2.1% of worldwide production)
Domestic consumption	1,328 Bcf (1.1% of worldwide consumption)
Net exports GNL	998 Bcf (7.7% of worldwide consumption)
Net exports pipeline	313 Bcf(1.5% of worldwide consumption)
Flaring (2011)	80 Bcf (1.6% of the worldwide flaring <sup>89</sup> )
Associated gas	9%

Source: U.S. Energy Information Administration and Organization of the Petroleum Exporting Countries (OPEC) - Annual Statistical Bulletin 2013



Source: U.S. Energy Information Administration

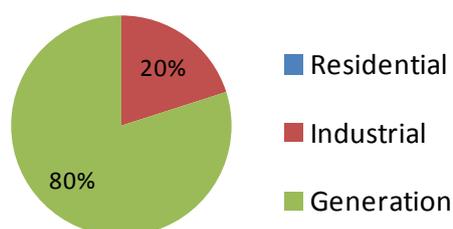
Location of gas reserves are in South Sumatra, Natuna Basin within the South China Sea, Bintuni Bay (located in West Papua), East Kalimantan (Mahakam block accounts for roughly one-fifth of Indonesia's dry natural gas production), Central Sulawesi region, West Papua, Arafura Sea in eastern Indonesia (underexplored).

It is important to note that Arun is the first conversion project (from liquefaction to regasification) in the world. In case of success of this experience, the project could be replicated in other plants in Indonesia and around the world.

<sup>88</sup> The consumption does not include re injected share.

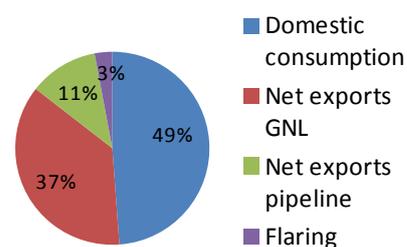
<sup>89</sup> Flaring was 140 bcm in 2011 according to World Bank – "World Bank sees Warning Sign in Gas Flaring Increase".

### Uses of domestic gas consumption<sup>90</sup> (2012)



Source : US Energy Information Administration

### Gas use (2012)



Source : US Energy Information Administration

### Gas export facilities

Export facilities	Capacity (Bcf)	Use factor/ Sendout (Bcf)
<b>LNG facilities</b>		
Liquefaction plant Bontang PT Badak NGL	1,233	770 <sup>91</sup>
Liquefaction plant Tangguh BP	420	N/D
Liquefaction Donggi Senoro and Sengkang (under construction)	111	-
Planned liquefaction plant Abadi	138	-
<b>Regasification facilities</b>		
Regasification Nusantara - Nusantara Regas/Golar	175	64 <sup>92</sup>
Regasification plant Lampung LNG	111	N/D <sup>93</sup>
Planned 8 small LNG receiving terminals	67	-
Regasification plant Arun (conversion in construction)	46	-

Source: U.S. Energy Information Administration (EIA) and BP Statistical Review of World Energy - 2014

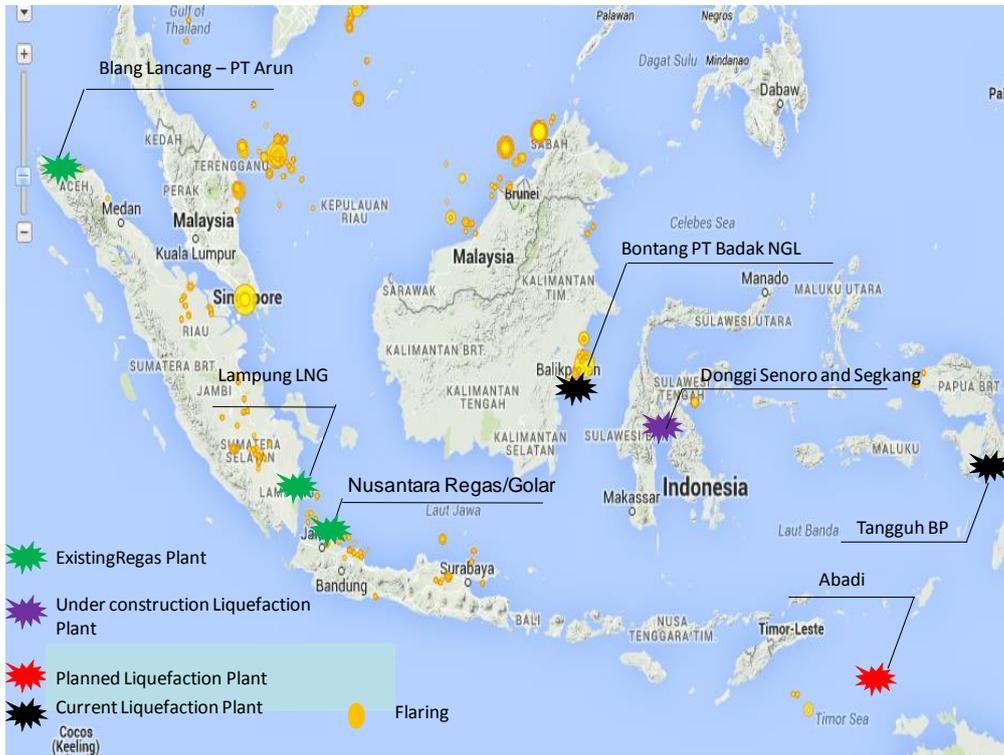
<sup>90</sup> Industrial sector gas price: 4\$/MMBtu and Power sector gas price: \$3/MMBtu - Can Indonesia's policy of reconfiguring its energy mix by increasing natural gas usage support its initiatives to reform energy subsidies? - University of Oxford - 2013.

<sup>91</sup> Badak LNG Statistics (2010) <http://www.badaklng.co.id/production.html>

<sup>92</sup> GIIGLN - The LNG Industry - 2013

<sup>93</sup> It was launched in 2014. No data of the send out.

## Gas export & import facilities and flaring locations

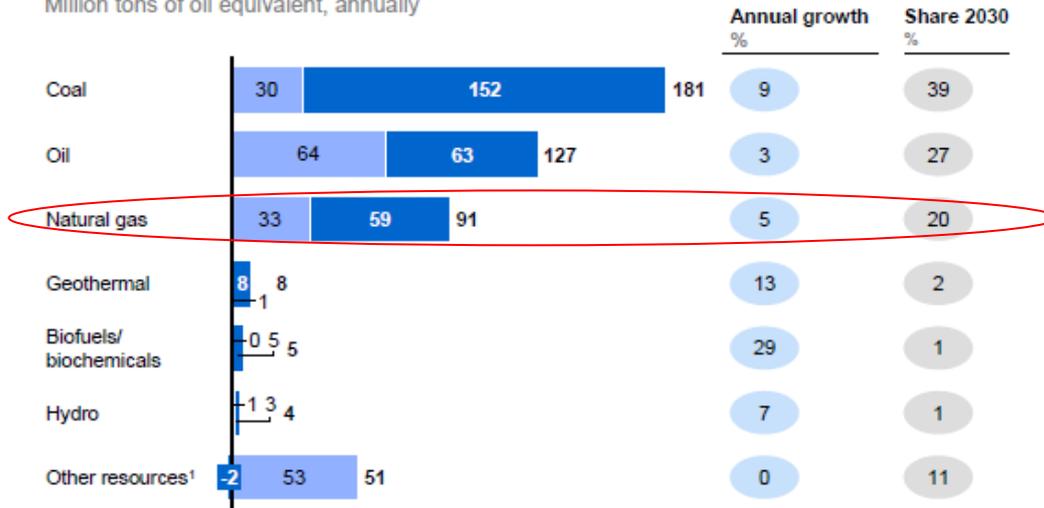


Source of flaring: <http://skytruth.org/viirs/> GIIGLN - LNG Industry- 2013

## Projected gas demand

### Indonesia's future energy and fuel mix will likely continue to be heavily dependent on oil and coal

Indonesian primary energy demand, 2030  
 Million tons of oil equivalent, annually



<sup>1</sup> Solar, fire wood, dung, and biomass for power (rice residues, sugar, rubber, palm oil, and agribusiness co-generation).  
 NOTE: Numbers may not sum due to rounding.

SOURCE: IEA; FACTS: ASEAN (Association of South East Asian Nations); McKinsey Global Institute analysis

Source: The archipelago economy: Unleashing Indonesia's potential – McKinsey Global Institute – 2012

### 12.3.6.1. GAS POLICIES

In 2012, BPMigas was dissolved and SKKMigas was created as an upstream Oil and Gas Regulatory Special Force. The new company acted as an interim regulator, managing Production Share Agreements (PSC). Among other decisions, SKKMigas rejected to renew some PSCs. The issue rose to the court, and the generalized climate got uncertain. The Government admitted revision of the laws and a package of reforms are required to attract investments. However, there have not been signals yet.

According to a survey by auditing firm PricewaterhouseCoopers, investors pointed the following challenges in Indonesia gas regulation: interference from other government agencies, contract sanctity, unclear roles (central and regional regulations), new regulations and uncertainty about cost recovery and BPMigas audit findings.

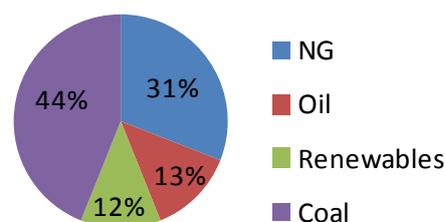
### 12.3.7. Electricity

Main features<sup>94</sup> (2012)

Installed capacity	47,700 MW
Generation (average)	86 TWh
Consumption	67 TWh
Access to electricity	73%

Source: U.S. Energy Information Administration

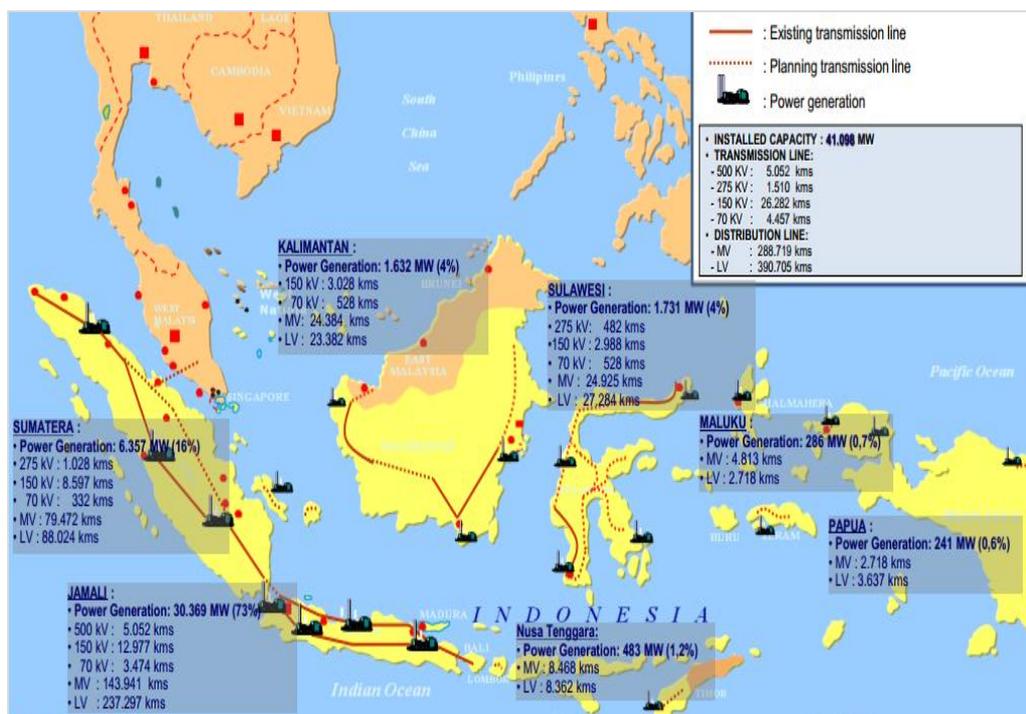
Generation by source (2012)



Source: U.S. Energy Information Administration

<sup>94</sup> Estimated demand estimated based on The Indonesian electricity system - a brief overview – Differ group – 2012.

## Power network and plants<sup>95</sup>



Source: Indonesia Electricity Infrastructure Development - Ministry Energy and Mineral Resources -2012

Indonesian electricity demand's growth has been increasing in a higher rate than generation, leading to frequent and long power shortages. An inadequate supporting infrastructure, difficulties in obtaining land-use permits, subsidized tariffs, and an uncertain regulatory environment were the main issues during the 2000 decade leading the country to the current electric status.

Finally, strictly regulated electricity market, subsidized selling prices and difficulties to diversify electric supply sources are key barriers that prevent a healthy development of the electricity sector.

In the next section, a preliminary analysis on small-scale opportunities to develop in Nigeria, Iraq and Indonesia will be offered, based on their special features and lessons learned from the experiences in USA and China.

## 12.4. Opportunities for small scale LNG

Considering experiences of USA and China on ways to economically seize small LNG volumes and main identified drivers, this section outlines some recommendations towards the development of this kind of market in less developed economies with smaller infrastructure, such as Nigeria, Iraq and Indonesia. Some barriers to the implementation of small scale LNG solutions will be underlined for Nigeria, Iraq and Indonesia.

<sup>95</sup> Data corresponds to 2011 energy picture in Indonesia.

### Lessons from China and USA and barriers to the implementation of small scale LNG solutions in Nigeria, Iraq and Indonesia

It is important to notice there is a main difference between USA and China cases that could be considered as a basic lesson regarding the implementation in less developed countries. In China, small scale LNG developments are mostly supported and carried out by State-owned companies as part as development policy. On the contrary, in the USA, development seems to be linked to decentralized market decisions (although peak shaving operations are framed in a regulatory scheme). Each alternative implies significant challenges and risks, especially in low and middle income economies.

In the market-type solution (the case of USA), a first issue to deal with is a coordination problem, frequently posed by economists at a theoretical level: the development of an efficient and sustainable scale means supply<sup>96</sup> and demand<sup>97</sup> decisions should be almost simultaneously taken. The weakness of this kind of strategy is when no one is willing to make the first move. The strength of the case of China is the weakness of USA: the coordination problem is “solved” - with diverse levels of efficiency - by the State, who acts as a “market-maker” enabling the existence of demand and/or supply until the industry reaches a sustainable scale.

Regardless environmental benefits and even lower operative costs in some cases, the differential in cost of capital to be afforded by the introduction of the new technology is another arising problem. As in any LNG development - no matter the scale -, investment represents an important share on LNG final price. Every asset is fully committed to the project and loses its value if any link of the chain breaks. For example, an LNG-fuelled truck would lose practically its total resale value, when its purchase cost would have been 40% higher. Once more, in China’s case the Government is able to finance and assume risks, becoming effective in developing the market - regardless the efficient or inefficient use of public resources -. Considering the Chinese economy and its high demand of energy required for growth and development, LNG projects proved to be the right bet.

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<sup>96</sup> Liquefaction plants, storage facilities, fuel stations, fuel tanker trucks, etc.

<sup>97</sup> Purchase of CNG-fuelled trucks, gas-fuelled ships, investments in conversion technologies, settlement of power generation facilities, etc.

However, state-based market creation solutions not always take into account the frequently diminished institutional capabilities present in developing countries, usually represented in the failure - or at least ineffectiveness - in the development and implementation of public policies, in this particular case, energy policies. Furthermore, some experiences show that foreign direct investment, usually performed by private companies, represents a way of transferring know-how, technology and financing for the implementation of a policy that the developing country could hardly achieve<sup>98</sup>. At the same time, some economists have argued that FDI contributes to economic growth only when a sufficient absorptive capability of the advanced technologies is available in the host economy<sup>99</sup>.

First, it must be pointed out that Nigeria and Iraq show very important flaring levels (ranked second and third, respectively in the world's flaring ranking list), in absolute as well as relative terms related to their natural gas production. Rather than Nigeria has many small flares near communities without electricity, Indonesia presents lower volumes perfectly suitable for small-scale LNG projects considering its marine network.

#### LNG for electricity generation

Other characteristics shared by Nigeria and Iraq - and therefore making them comparable - are the restrictions on power supply & transmission and security issues, hindering the development of the most economically suitable infrastructure for large scale flaring solutions (i.e. pipelines).

Regarding power supply, there are thermal generation assets with fuel supply problems, especially in Nigeria and Iraq. Although small scale LNG would not completely solve the issue of access to power supply in the country, it would certainly improve the situation. Depending on gas demand volume and distance to supply sites, a small LNG project could be feasible where a pipeline is not. A small LNG chain (up to 15 MMscf/d) could supply up to 70 MW average base. The same option would be available to replace liquid fuels-fired generation. In general terms, small LNG chains result competitive against diesel and fuel-oil. A more detailed analysis of flare locations/volumes compared regions without electricity supply could be made but it is beyond the scope and aims of this study.

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<sup>98</sup> Saggi, K. (2002), "Trade, Foreign Direct Investment, and International Technology Transfer: A Survey" World Bank Research Observer (2002) Volume 17, Issue 2, 191-235.

<sup>99</sup> Borensztein, E., De Gregorio, J. & Leec, J-W. (1998), "How does foreign direct investment affect economic growth?", Journal of International Economic, Volume 45, Issue 1, 1 June 1998, Pages 115-135.

As already mentioned, these countries present restrictions on power transmission as well. Therefore, some regions within each country operate as isolated subsystems. In most cases, these subsystems can be described as small demand supplied by diesel or fuel oil engines (scale is not enough to operate with several generation units and need flexibility to response to demand variations). Given geographical characteristics, Indonesia is a clear example of this situation. In the eastern part of the country, there are several islands consuming less than 200 MW and operating as isolated systems, considering there are no power connections between them. A small LNG chain involving maritime transportation could be analyzed to supply this area, achieving a competitive cost supply when comparing to diesel (currently used) and with lower levels of greenhouse effect emissions.

#### Other uses of Mini LNG: strengths & weaknesses

Indonesia's geography offers another opportunity for economic use: LNG as fuel for ships. Cargo maritime transportation is a particularly intense flow in this world's region. China's experience becomes greatly relevant in this case: the gasification project on the Yangtze River has an LNG supply station in operation, and other experiences on ship conversion developed by companies interested in the use of this technology.

On the other hand, experiences from China and USA were directed to supply residential, industrial and transport demand. Two characteristics of this technology worth highlighting are the "fast-track" implementation and the relatively reduced investment (compared to pipelines or large scale facilities), making possible the rapid settlement of industries with high positive impact on a country economic growth. For example, small LNG chains may enable the installation of fertilizer companies, boosting the food industry, or the installation / expansion of construction industry, a very dynamic sector of the economy of any country. Small scale LNG can replace other fuels, like LPG, in industries looking for clean combustion (food industry) or heat control (ceramic industry).

Regarding transportation sector, experience in China and USA shows natural gas as a competitive fuel against diesel and gasoline. The LNG, presenting less volume than CNG, is recommended in large vehicles, running long distance and, therefore, needing longer range. Giving the size of these countries' economies and the extension of their lands and routes, this kind of vehicle is a growing trend.

However, uncertainty arises when trying to assess the existence of a critical mass to make LNG a viable fuel for large vehicles in countries such as Nigeria, Iraq and Indonesia. In these cases, CNG for vehicles (VNG) would have more chance for success: is more suitable for light and mid vehicles, more numerous and with a range limited to urban areas. Nevertheless, LNG could be part of a transport supply chain if, considering distance from gas fields and demand size, the technology results the most convenient to supply VNG stations.

Regarding LNG road transportation, conditions of road infrastructure and security must be considered, especially in Nigeria and Iraq. Difficult access or temporary floods, for example, result on higher supply costs because of stock shortage or redundant storage and transport infrastructure. In terms of security, LNG chains - like any other fuel - are vulnerable to piracy and terrorism, worsened by the fact of being a flammable fuel. But LNG would have an advantage: it is not a fungible asset, meaning it cannot be consumed if not in proper facilities; therefore it would have practically no resale value for illegal markets. Nevertheless, the validation of this assumption would need a deeper study on the subject.

Other potential demand should be taken into account when outlining local market creation strategies for small scale LNG in Iraq and Nigeria. However, considering the volume to deal with, these measures would not solve the flaring issue.

When analyzing Indonesia, potential demand seems to be limited to power generation in some of the islands, especially considering existing plans for generation decentralization policies. In addition, existing China's experience on fuel substitution for the navy industry could be considered to apply in this country.

In the following subsections, some recommendations will be given to Nigeria, Iraq and, particularly, Indonesia.

### 12.4.1. Nigeria

From the point of Akinrogunde (2014), the most likely applications for small-scale and micro LNG in Nigeria are: the replacement of liquid fuels (diesel or gasoline) in transportation (i.e.: trucking, mining, marine and rail transport); and natural gas-based power generation for remote locations (virtual pipeline) both for industrial and residential use<sup>100</sup>. The reasons are: significant price advantages with liquid fuels and the non-grid power generation in parts of the country without pipeline of gas.

Akinrogunde have argued that the best opportunities for mini-LNG projects are in the industrial clusters located in parts of the south-east, middle-belt and northern Nigeria. Other parts of the country (south and south-west) have pipelines or they are already being served by Compressed Natural Gas (CNG). The key to develop Mini-LNG are the isolated big customers without pipelines and with too high requirements to be served by CNG. The use of LNG for power generation is quite difficult because the relatively low tariffs. However, there is room for private power plant operators serving industrial clients with higher willingness to pay for reliable electricity.

Additionally to the securing an anchor customer, some challenges remain for mini or micro LNG projects development in Nigeria, including: access to gas molecules, technology selection, securing project financing, road infrastructure and safety.

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<sup>100</sup> Akinrogunde, Afolabi (2014), "Creating a Mini or Micro-LNG Solution in Nigeria: Options & Strategies", Business Development Adviser at Shell Nigeria Gas Limited, <https://www.linkedin.com/pulse/creating-mini-micro-lng-solution-nigeria-options-afolabi-akinrogunde>, Dec 22, 2014.

Some international companies are analyzing casing & flare gas recovery opportunities in Nigeria by the hand of the, between others<sup>101</sup>, micro-LNG plants. For example, the firm Clearstone Engineering Ltd has accomplished a 2 years plan<sup>102</sup>. Particularly, the actions of the first year plan were: indentify strategic facilities to assess vent and flare gas, quantify flare/vent gas rates and compositions, develop a mitigation plan, make preliminary economic evaluations. The procedures of the second year plan were: potential small-scale demonstration project, piloting of a continuous monitoring system, actions to transfer technology (i.e.: workshops) and the development of policy and regulatory tools. As a result, the key findings were: a) an adequate time-series monitoring of casing-gas flows is important to determine the true potential production, and b) noteworthy amounts of heavier hydrocarbons were discovered in several casing gas cases. This last discovery should be underlined because it improves feasibility of casing-gas recovery projects because heavier hydrocarbons usually are 5 times more valuables than methane fraction. Additionally, a plant of LNG could be favored by gasoline and liquefied petroleum gas present in flaring and the possibility of substitution of diesel.

#### 12.4.2. Iraq

Opportunities for mini-micro LNG developments are not only an economic alternative but also an energy security option in Iraq. The actions of violent groups and its advance in the Northern and large part of the Central Iraq is a potential risk for possible disruptions of pipelines and other energy infrastructure. In fact, supply disruptions in the north escalated in 2014 (Iraq-Turkey -IT- oil pipeline flows were fully halted in March) and shut downs were caused in the northern in June.

Taking into consideration the underlined security risks, mini-micro LNG might be an alternative to offer a security of supply back up for some power generation plants and industries in the northern (including the Kurdish region). In the south, the problems are the inadequate midstream infrastructure (storage, pumping and pipeline capacity for natural gas), the sufficiency of power generation and the losses in the electricity distribution system.

Lack of enough infrastructures (pipelines and other infrastructure to facilitate consumption and export) is the main reason because natural gas is flared.

Alternatively, there are plans for large scale LNG utilization. An example is the initiative of Shell and Mitsubishi (Basrah Gas Company), who signed an agreement with the Iraqi state-owned South Gas Company, to capture, to process and sell gas for power generation. They could export the gas not bought for Iraqi power generation plants. However, this plan to export LNG remains controversial because natural gas is claimed to Iraq's electric power plants and there are delays in the pipelines developments.

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<sup>101</sup> Others alternatives are: small scale power generators and micro-condensers units.

<sup>102</sup> Picard, D. (2014), "Casing & flare gas recovery opportunities in China and Nigeria", PTAC, Clearstone Engineering Ltd., Sept 25, 2014, Calgary, Alberta, Canada.

The link between oil and gas production is power generation. Large scale increments in oil production need large increments in power generation. However, as it was explained before, Iraq suffers electricity shortages frequently because the electricity demand is growing faster than supply. The gap between electricity demand and supply is a key aspect to look for small scale LNG business opportunities in Iraq, especially in the oil sector. Iraq's authorities have allowed foreign oil companies to build small power plants for their operations. It might be an anchor demand for the development of the small scale LNG market in that country.

The vast majority of Iraq's electricity supply was generated from domestic power plants and it has increased from 2008 to 2012 (13% annual average), distribution losses have also increased (36% average of total electricity supply). In addition, on the demand side, summer peaks are greater than 50%. Residential and industries have expensive private, off-grid, diesel fuelled generation (an additional 1GW of capacity only in Baghdad). It could be other mini/micro LNG opportunity to develop a market in Iraq.

In this context, the government has launched a master plan to install new power generation (24.4 GW), adding steam and gas turbines capable of running on fuel oil or natural gas. However, one of the central problems to achieve those goals is the delay to build new natural gas infrastructure. Additionally, the government plan said that in the short term, Iraq will use only renewable energy (wind and solar) at remote off-grid locations.

All in all, solutions in off-grid power generation systems for residential and industrial demand and projects to supply isolated power generation for the oil sector appear to be the most reasonable anchor demands to develop a small scale LNG industry in Iraq. Additional demand can be studied analyzing the Kurdish electricity market, with lower problems than the rest of Iraq, but having taken into consideration back up alternatives of energy security to supply power generators. Military facilities could have similar problems to be supplied by pipelines or more expensive fuels in the conflictive north.

### 12.4.3. Indonesia

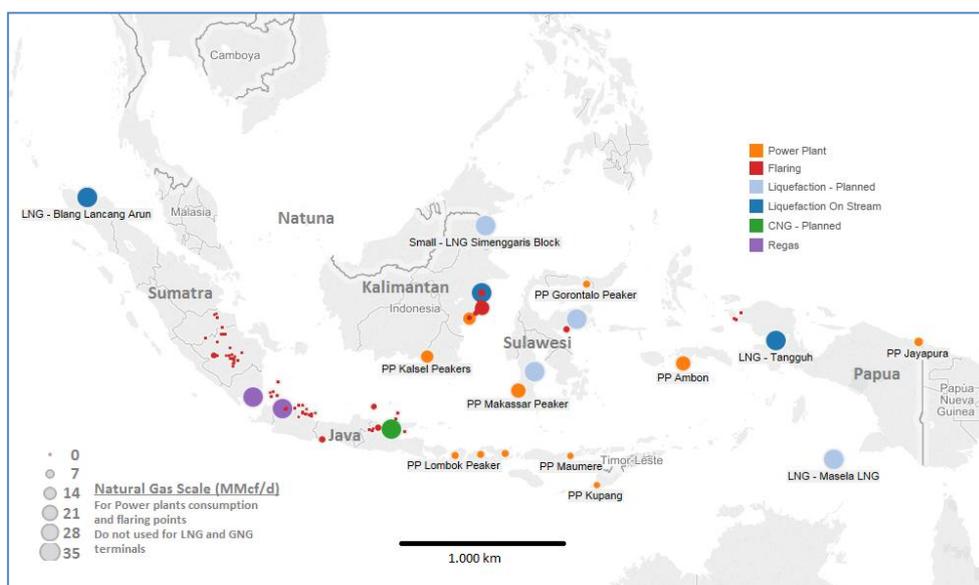
Indonesia has the 14<sup>th</sup> gas reserves in the world; spread in several fields (Natuna, South Sumatra, East Kalimantan and Tangguh Papua). A large share of these gas resources are committed to long term supply agreements with other countries (through LNG liquefaction terminals).

Regarding the domestic consumption, PLN<sup>103</sup> has been making efforts to supply its existing power plants (currently fuelled by liquids) with natural gas. However, the gas supply in some islands would be quite complex (especially in the east), due to the lack of close gas fields in the area and infrastructure to receive the resource from other part of the country.

In the following map, it is shown the flaring areas, power plants, regasification facilities and current and planned liquefaction plants in Indonesia.

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<sup>103</sup> Perusahaan Listrik Negara, State Electricity Company.



Source: Consultant development based on Perusahaan Listrik Negara Business Plan

As part of the main electrical plan, PLN seeks to implement small scale LNG plants in Kalimantan and Sulawesi, in order to generate supply existing power plants during the peak demand periods. The LNG source for those plants would come from Simenggaris (25 MMscf/d, on stream in 2017<sup>104</sup>) and Sengkang (128 MMscf/d, on stream in 2017) LNG projects. In Kalimantan, the estimated consumption of the 4 power plants included in this plan (100 MW each one) is between 3 and 9 MMscf/d<sup>105</sup>. In Sulawesi, the estimated consumption of the 2 power plants included in the plan (150 and 450 MW) is between 5 and 19 MMscf/d.

Regarding isolated electrical systems, PLN aims to use LNG as fuel in base load generation and peaks. The range of power plants in these cases can drop to 40-50 MW and the daily unitary gas requirement would be between 4 and 18 MMscf/d. The biggest demand of these electrical systems (18 MMscf/d) would be supply by Donggi Senoro LNG project (2 mtpa or 256 MMscf/d), which is under construction and the supply to PLN's plant would start in 2016.

Regarding compressed natural gas, PLN have a CNG project to supply Lombok Peaker power plant from Gresik CNG Plant (green spot on the above map) by a GNC vessel (1,000 km in round trip). The estimated demand would be around 4.5 MMscf/d.

It is important to note that there is no certainty on the other planned gas fueled power plants supply.

<sup>104</sup> Temporarily, it has put on hold to secure permits.

<sup>105</sup> They are peakers working between 20% and 40% of the time.

## 13. RECOMMENDATIONS FOR SMALL LNG TO SUPPLY SMALL ISLANDS IN INDONESIA

Gas flaring in Indonesia is around 400 MMscf/d. Unfortunately, it is disseminated in the west region and far away from the small islands in eastern Indonesia. However, several recommendations have been analyzed to encourage its use.

For a success implementation, it is important to achieve an anchor demand and to ensure a source of supply. As in many other parts of the world, the most important potential demand in the small islands of eastern Indonesia would be the electricity sector. Most of the energy generated in these areas is fuelled by diesel and fuel oil, which may be substituted for natural gas.

Regarding the offer, one of the most challenging achievements for small scale demand systems is to get an LNG supply source. Most of the power plants are located in the coast areas, due to the proximity to ports and facilities to manage fuels. LNG or CNG's receiving terminals can leverage its investments with existing thermal power plants.

The alternatives sources for small scale systems supply are large or small liquefaction plants and regas or FSRU. That is, the large-scale infrastructure can also be used to supply liquefied gas to mini-LNG. An objection to large liquefaction plant is that its output is usually already engaged in large GSA and, and as a result, it may require additional investments to load LNG small-scale vessels or containers. There are already three regas facilities dedicated to supply large power demands in Sumatra and Java, where additional storage could be accommodated via FSU. This new capacity might be used to load the LNG in small-scale vessels or containers. A small-scale liquefaction plant project should take into consideration the specific location of gas supply (production, reserves and infrastructure facilities)

It remains uncertain the gas supply of the power generation sector set by PLN plan, which considers a minimum of liquefaction capacity requirement of 4 MMscf/d or 0.03mtpa<sup>106</sup> in the east islands of Indonesia.

Last but not least, after the first stage of natural gas penetration in the electricity sector, it would be feasible to wider the gas supply to transportation or industrial fuel, in order to replace liquid fuels.

## 14. CONCLUSIONS

It is clear that LNG technology could be a solution to monetise small volumes of associated gas (1-15 MMscf/d) and thus to reduce the current gas flaring. It is a proven technology with very high safety records.

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<sup>106</sup> Corresponding to an aggregated liquefaction capacity around 50 MMscf/d or 0.4 MTPA

There are several options available in the market to liquefy associated gas in order to easily transport it to the consumers. These consumers could be isolated markets not connected to grid (domestic and/or industrial), power generators, LNG refuelling stations, etc.

The simplified processes and optimised design of the full LNG chain (liquefaction, distribution and receiving) make this type of projects economically viable.

Countries like United States and China are a good example of successful implementation of mini LNG applications. The lessons learnt in these countries could inspire similar solutions for less developed countries as Iraq, Nigeria and Indonesia.

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<http://www.lindeus-engineering.com/>
  - Cryostar: <http://www.cryostar.com/>
  - Black & Veatch: <http://bv.com/>
  - Chart: <http://www.chartlng.com/>
  - Wartsila: <http://www.wartsila.com/>
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