Scenario Description and Characterization

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DEC	Websites, patent fillings, videos, etc.	
OTHER		
ETHICS	Ethics requirements	
ORDP	Open Research Data Pilot	
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Author(s)		Nicolas Droushiotis
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Financial/Administrative Coordinator	
Project Coordinator Name	Mr. Loris COK
Project Coordinator Organization Name	NAVALPROGETTI Srl
Address	Via dei Papaveri, 21 34151 TRIESTE (Italy)
Phone Numbers	0039 040 212918
Email	loris.cok@navalprogetti.net; Gasvessel@navalprogetti.net
Project web-sites & other Access Points	www.gasvessel.eu

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Glossary, abbreviations and acronyms

EU	The European Commission or in general Europe
INEA	Innovation and Networks Executive Agency of European Commission
PO	Project Officer assigned by INEA to GASVESSEL Project
Partner	Company member of the GASVESSEL Project Consortium
Project	The GASVESSEL no. 723030 Project
CNG	Compressed Natural Gas
GA	Grant Agreement
CA	Consortium Agreement
PMS	Project Management System
PM	Project Management
TM	Team Management
PA	Project Administration
P&C	Planning and Controls
PR	Project Reporting
DC	Document Control
HSEQ	Health, Safety, Environment and Quality controls and assurance
PRM	Procurement Management
MM	Materials Management

WP	Work Package
NP	Navalprogetti Srl – Trieste – Italy – The Coordinator – Partner -Lead Beneficiary of WP1 and WP5
DOW	Dow Deutschland Anlaghengesellschaft mbH - Partner
DOWA	DowAksa Deutschland GMBH - Partner
PNO	PNO INNOVATION – Belgium – Partner – Lead Beneficiary WP9
VTG	VNIPITTRANSGAZ – Kyiv – Ukraine – Partner – Lead Beneficiary WP6
SINTEF	SINTEF OCEAN AS – Trondheim – Norway – Partner – Lead Beneficiary WP7
BMP	BM Plus Srl – Buttrio – Italy – Partner – Lead Beneficiary WP4
CNGV	CNGV d.o.o. – Izola – Slovenia – Partner – Lead Beneficiary WP3
CEN	CENERGY Srl – Trieste – Italy - Partner
HLL	Hanseatic Lloyd Schiffahrt GMBH & Co – Bremen – Germany - Partner
CHC	Cyprus Hydrocarbon Company – Nicosia – Cyprus – Partner – Lead Beneficiary of WP2
EST	ESTECO S.p.A. – Trieste – Italy - Partner
ABS	American Bureau of Shipping (Hellenic) – Athens – Greece – Partner – Lead Beneficiary WP8
O&G	Oil and Gas
WP1	Project Management
WP2	Scenario analyses
WP3	Prototyping activities, design of pressure cylinders and prototyping pilot line
WP4	Prototyping of pressure cylinders. Procurement/construction/arrangement of prototyping pilot line
WP5	Ship Design
WP6	Offshore & Onshore gas loading/unloading systems
WP7	Costs and Benefits Analysis
WP8	Class Design Review – Safety Assessments

WP9	Dissemination and Exploitation
QA	Quality Assurance
QC	Quality Control
CBA	Costs Benefits Analysis
Work Plan	Planning of Activities in Attachment 1 of Project Management Plan D1.2
WBS	Work Breakdown Structure

1. Introduction

This is the report for the marketing analysis on the 3 Geologistic Scenarios agreed to be reviewed as per the description of the Work Package 2 (WP2) of the Gasvessel Project. This report also includes the description of the decision support model that will incorporate the data collected from the geologistic locations and help with the design of a cost competitive vessel technology. The report is organized as per geologistic scenario investigated. Deliverable D2.2 describes the Decision Support Model.

1.1 General Overview

It is the intention of this report to investigate different possibilities regarding the sourcing of the natural gas, the possible transportation options, as well as the target market potential for each geologistic scenario concerning the Gasvessel project. Further to this, these possibilities will be filtered down to obtain the most viable scenarios for each geologistic approach with the intention of calculating the feasibility of those options after conducting cost and tariff estimation for comparison with alternative energy options currently available.

The resulting outcome of this report is to obtain the necessary data from all geologistic scenarios to feed into the Scenario Decision Support Model, which in return will provide numerical assessments for the Gasvessel project for the identified scenarios:

- East Mediterranean offshore fields
- Barents Sea offshore fields
- Black Sea region

The report is based on preliminary marketing screening tactics to conclude on different case studies per geologistic scenario and reporting costs across the supply and demand value chain by assuming certain technical parts of the CNG technology as well as including very rough estimations on the related costs. The aim of the report is to provide the Gasvessel partners general guidelines as to where the Gasvessel concept needs modifications or optimization to meet commercial thresholds either related to the target market gas prices or when competing with other monetization concepts such as offshore pipeline connections or LNG transportation. The CNG technology will be examined in detail during the WP 3-6, and the report will be updated to reflect information on the costs as well as any changes on market prices.

The ultimate goal is to use the commercial knowledge produced during WP2 and together with the technical knowledge acquired from WP 3-6 to better define CNG costs so that a cost benefit analysis is performed in WP7 to conclude on the commercial viability of the project.

General Assumptions for all Geologistic Scenarios

1. Gas Composition delivered at Gasvessel Concept

It is assumed that the gas for the Gasvessel Concept is fully processed upstream and is pressurized at Gasvessel specifications

2. Gas Loading System

It is assumed that the loading system will be investigated during the WPs 3-6. At this stage we assume that the gas will always be loaded to an intermediate floating CNG storage before it is loaded to the Gasvessel ship for transportation. Condensate handling has not been discussed yet.

3. Gas Unloading System

It is assumed that the unloading system will be investigated during the WP 3-6. At this stage we assume that gas will always be loaded to an intermediate floating CNG storage before it is unloaded to the market for distribution. Condensates handling has not been discussed yet.

4. Market Gas Specifications

It is assumed that gas carried by the Gasvessel is very lean and at the adequate specification for discharge to all market gas grid. At this stage we assume that for all Geologistic Scenarios the pressure at the grid is 50 bars.

2. East Mediterranean Geologistic Scenario

2.1 East Mediterranean Executive Summary

In the case of the East Mediterranean scenario, natural gas is assumed to be sourced from a possible target of the Cyprus Exclusive Economic Zone (EEZ) for purposes of practicality and simplicity. The target market for the East Mediterranean vicinity on the other hand, has undergone significant filtering in terms of volume and duration of demand, distance, infrastructure and so on. Following our methodology, Cyprus, Greece (islands), Lebanon, Egypt, Jordan, Israel, Italy and France (Corsica) have been considered. The resulting target markets, in combination or as individual markets, are concluded to be Cyprus, Greece (Crete), Lebanon and Egypt. In order to mark the location and capacity characteristics of each power plant, a number of sources have been utilised.

CHC has the general responsibility for data collection regarding the Eastern Mediterranean geologistic scenarios and the overview of the Barents Sea and the Black Sea Geologistic scenarios.

2.1.1 East Mediterranean Objectives

The objective of the East Mediterranean report segment, and consequently the target market methodology, is to identify and propose potential markets in the Eastern Mediterranean for the CNG Gasvessel project. In the specific geologistic scenario, the field screening process is less relevant than the target market screening. The methodology takes into account key filtering parameters across the value chain of supply and delivery aiming to propose attractive markets for further techno-economic evaluation. A simplified description of the logic is described in the diagram below, however, details for each parameter are presented in the following sections.

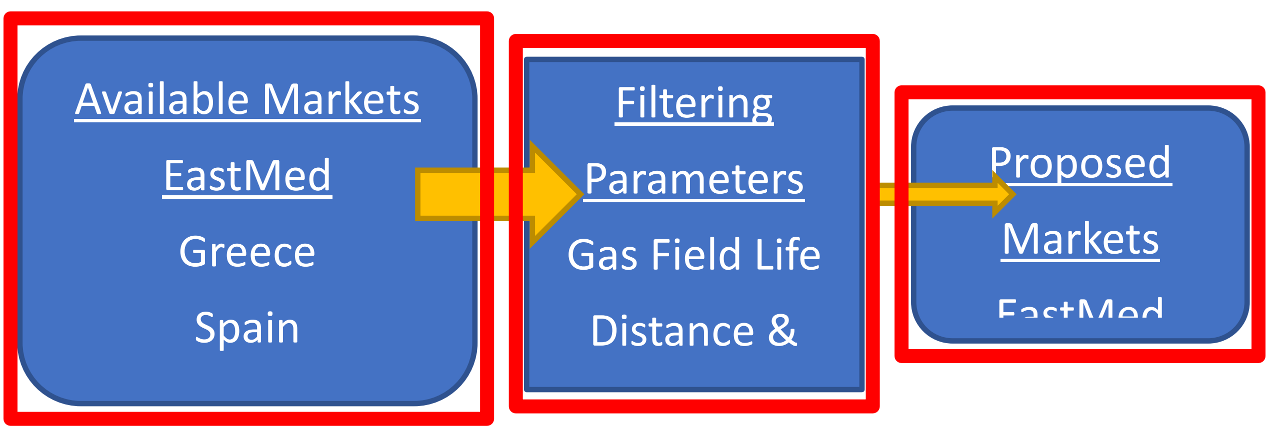


Figure 1: Schematic representation of screening methodology

2.2 Gas Field Screening Criteria

The objective of this section is to identify potential green gas field targets within the Cyprus EEZ We assume three gas volumes scenarios of 28, 57 and 113 bcm (1, 2 & 4 TCF) to accompany our scenarios to screen against minimum target market criteria and adequate gas life. It further intends to provide all the necessary information related to the gas loading locations that will help the Gasvessel partners to evaluate the design of the vessel, and the process of gas loading including logistics of delivery gas volumes to the gas unloading locations.

2.2.1 Gas Loading Options

We are investigating two gas loading options, offshore and onshore. The onshore loading concept will always be more expensive than the offshore loading option given that the producing gas field is offshore. The reason is because we have assumed an offshore pipeline to transport the gas from offshore to the onshore terminal, and this includes additional costs. Therefore, we have included the onshore loading option, although more expensive, to provide flexibility to the ship vessel designers since offshore loading is generally accepted but a more challenging option.

Proposed Gas Loading Sites

CHC proposes two gas-loading sites for the Eastern Mediterranean geologistic scenarios, which includes onshore and offshore options. The offshore loading site is located within the Cyprus EEZ, and the onshore gas loading site is located at Cyprus' proposed energy hub in the Vasilikos area. For the offshore loading site CHC will investigate the development of three production profiles based on 28.26, 56.52 and 113 bcm (1, 2 & 4 TCF) of gas in place. For the onshore location, similar production profiles will be assumed, with the difference that natural gas will be piped from offshore to Vasilikos energy hub and from there to domestic usage or export via the Gasvessel.

Figure 2: Offshore and onshore proposed gas-loading locations

2.2.1.1 Offshore Gas Loading

Offshore Gas Loading Location Characteristics

The theoretical offshore gas loading site is located offshore in the Cyprus EEZ with coordinates 33.99 latitude and 30.21 longitude. It is estimated to be 298 km (on a straight line) from Vasilikos proposed energy port. The same port of Vasilikos is also proposed here as the onshore gas loading site. The water depth at the specific location is estimated to be 2800 m, and the upper soil layer is evaluated to be extremely low strength clay.

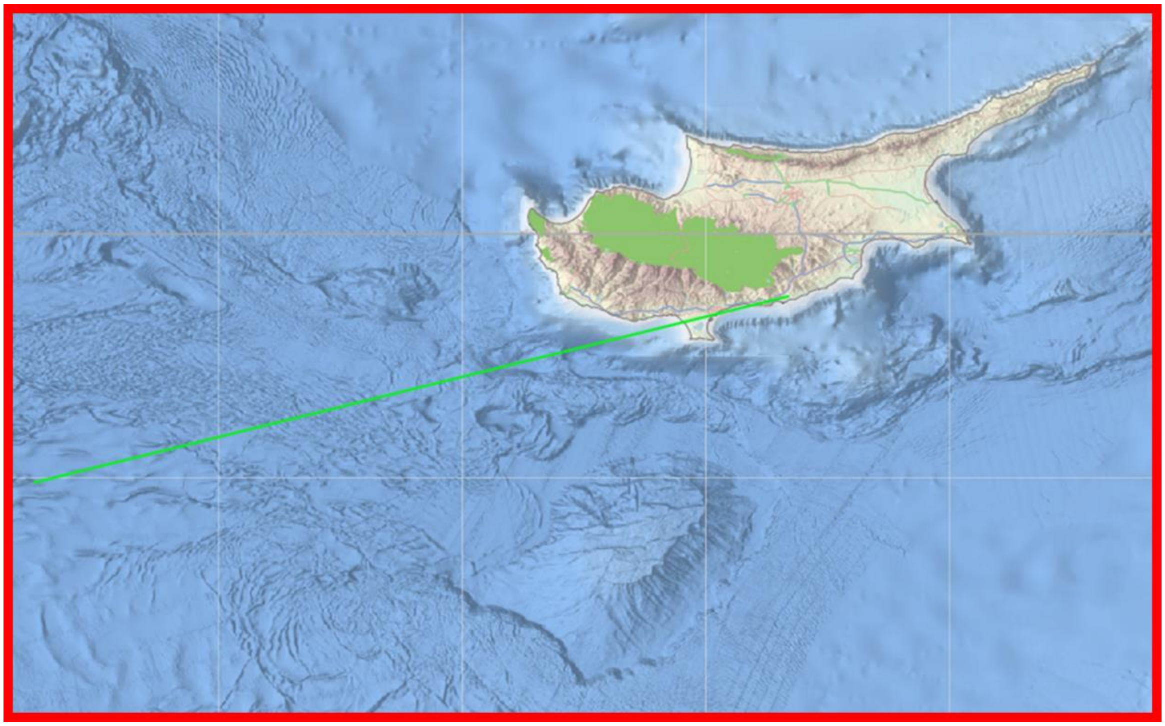


Figure 3: Distance of the offshore gas-loading and proposed Vasilikos Energy Port

Offshore Gas Composition and Reservoir Characteristics

The gas can be characterized as very lean, consisting of app. 97-99% methane and free of H2S, CO2 and mercury. It is assumed that full gas processing will take place upstream of the Gasvessel concept. Therefore, Gasvessel will receive gas at pressures and temperatures ready to store without the need to remove any condensates or other components from the gas stream. Relevant costs on gas processing will be charged upstream. Condensates handling has not been investigated yet. There is the thought that condensates will be transferred and stored separately at the Gasvessel ship and unloaded to the market together with the gas.

It is assumed here that the reservoir pressure and temperature will be reduced to the operating pressure and temperature of the offshore processing floating facility. The Gasvessel will receive the gas from an offshore CNG storage facility at a pressure and temperature similar to the pressure and temperature of the Gasvessel specifications.

Offshore Metocean Conditions

The Metocean conditions at the offshore gas loading site can be considered as per below. Please refer to **Errore. L'origine riferimento non è stata trovata.** and Figure 3 for the areas mentioned.

Extreme Conditions based on 10000 years

- Significant wave height, Hs = 11m
- Peak wave period, Tp= 16sec
- 1-hour wind speed = 30 m/s
- Associated current = 1.5. m/sec (surface)

Years	1	10	100	10000
Significant wave height (m)	4.8	6.5	8.5	11
Surface current (m/s)			1.2	1.5
WIND (m/s)	18	22.5	27	31

Operating Conditions

- Wind predominantly from the west avg. wind speed 5 m/s
- Waves predominantly due east (as wind is from the west) with 95% exceedance value for significant wave height is 1.5m
- Near surface current is predominantly west south west with mean current speed up to 0.25 m/s

Wave Height Range (m)	Frequency (Occurrences over period of record)	Percentage
0 to 0.2500	91	1.523
0.5000	1,132	18.9456
0.7500	2,183	36.5356
1.0000	1,388	23.2301
1.2500	565	9.4561
1.5000	261	4.3682
1.7500	140	2.3431
2.0000	69	1.1548
2.2500	52	0.8703
2.5000	21	0.3515
2.7500	14	0.2343
3.0000	10	0.1674
3.2500	11	0.1841
3.5000	4	0.0669

3.7500	7	0.1172
4.0000	11	0.1841
4.2500	9	0.1506
4.5000	6	0.1004
4.7500	1	0.0167
Total	**5,975**	**100%**

Table 1: Significant wave height and their frequency 2005-2008

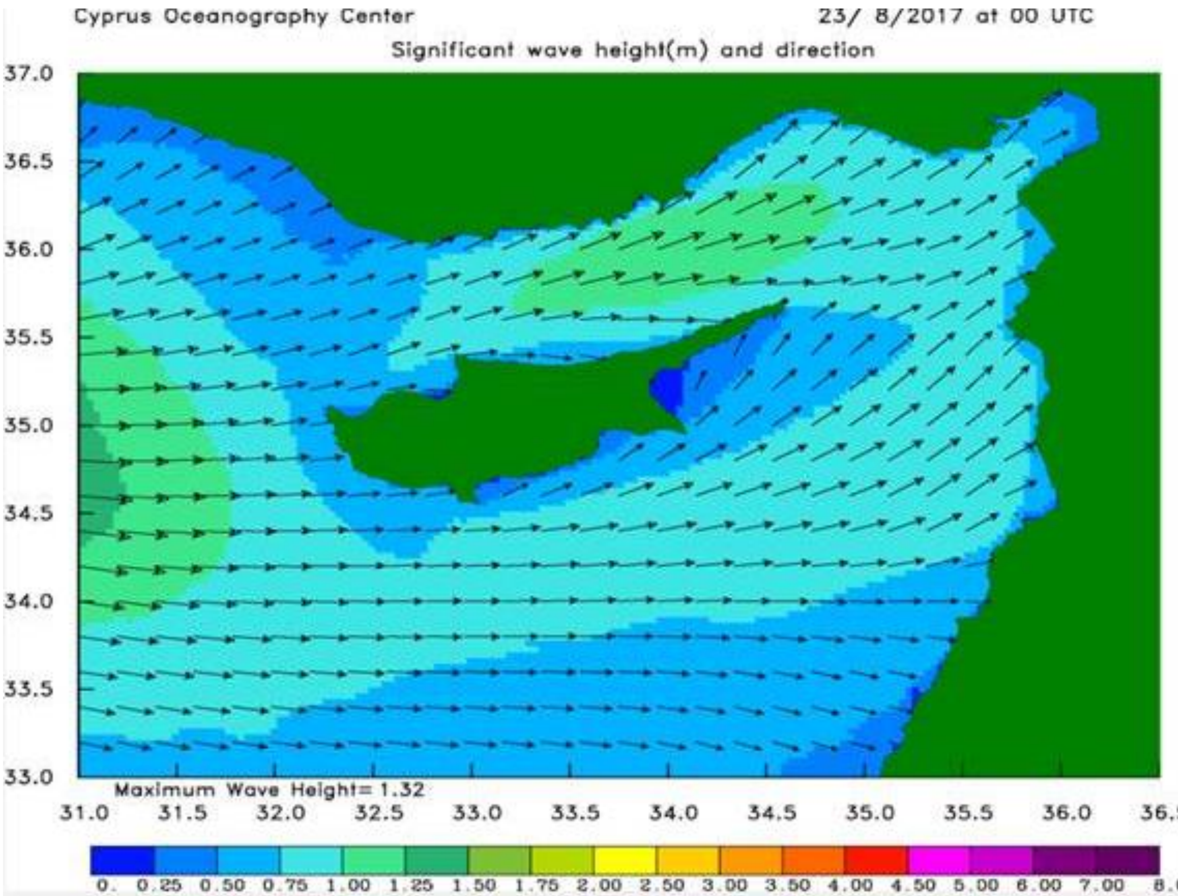


Figure 4: From Cyprus Oceanography Centre for wave direction. Similar direction for wind.

Figure 5: Onshore gas loading location of the proposed 'Vasilikos energy port'

2.2.1.2 Onshore Gas Loading

Onshore Gas Loading Location Characteristics

The onshore gas loading site is located at the proposed ‘Vasilikos energy port’ at Vasilikos bay, Cyprus with coordinates 34.73 latitude and 33.29 longitude. The location at Vasilikos bay provides a natural shelter for the marine industry. Vasilikos power plant is also located at the coast of the bay and in addition, a jetty owned by VTTI Vasilikos which operates storage and transhipment facilities for petroleum distillates has been built. The area between Vasilikos power plant and Zygi village along the coastline is planned by the government to become the energy port for Cyprus. Several proposed projects have been proposed such as onshore liquefaction terminals and FSRU. Figure 5 and Figure 6 are satellite pictures depicting the details at Vasilikos area with the existing infrastructure. A layout of the Vasilikos power plant, which is next to the proposed onshore gas loading site can be found in the Appendix (Appendix A, section I)

Figure 6: Vasilikos power plant (left) with the existing VTTI Jetty (middle to right)

Onshore Gas Composition

Gas will be processed to the same specifications as in the case of the offshore gas loading location.

Onshore Metocean Conditions

Extreme conditions:

Winds profile

- The values for return periods of 1, 5, 10, 25 and 50 years computed assuming a storm duration of 6 hours are given below.

Direction (*N)	Return period (years) – maximum speed in knots				
	1	5	10	25	50
(-15.) : 15.	13.8	17.8	19.5	21.7	23.4
15. : 45.	14.7	18.2	19.6	21.5	22.9
45. : 75.	14.4	17.7	19.1	20.8	22.2
75. : 105.	14.5	17.9	19.3	21.1	22.4
105. : 135.	13.3	17.5	19.3	21.7	23.5
135. : 165.	12.7	16.4	18.0	20.1	21.6
165. : 195.	13.9	18.2	20.0	22.3	24.0
195. : 225.	16.5	20.6	22.3	24.4	26.0
225. : 255.	19.6	24.1	26.0	28.4	30.3
255. : 285.	19.0	22.9	24.7	26.9	28.7
285. : 315.	16.8	20.1	21.4	23.2	24.5
315. : 345.	16.7	20.4	22.0	24.0	25.6
Total	**22.0**	**25.6**	**27.1**	**29.1**	**30.5**

Table 2: Winds profile with return periods

Table 2 is from a Metocean observation study in the area, however, it is not clear if this is applied for near shore Vasilikos Bay or open sea near Vasilikos Bay.

Wave profile

- Extreme wave heights were computed for return periods of 1, 5, 10, 25 and 50 years found in the table below.
- Most extreme conditions coming from south-western directions. These conditions may be associated with storm depressions travelling east in the northern half of the Mediterranean causing western and south-western winds at the south coast of Cyprus.
- We expect that in shallow water near the project site the extreme wave heights will be considerably lower to limitation of the wave height by the local depth.
- Extreme wave conditions in deep water near Zygi in the sector 75-255^{o}C for various return periods are given in the table below. These extremes are mainly determined by the sector 195-255 ^{o}C. In the other sectors the extreme wave heights are lower. It should be noted that near the port site the extreme wave conditions may be lower due to shallow water effects like refraction and breaking.

Return period (Years)	1	5	10	25	50
Significant wave height (m)	3.2	4	4.3	4.8	5.2

Operating conditions:

Winds profile

- The highest wind speeds in the northern sector will generally be lower at the coast than on open sea due to the sheltering effect of the mountain range close to the coast.

Nearshore Current Speed

- At 20 m depth (nearshore), near surface mean current speed about 0.1 m/s.

Current Direction (deg)	Current Velocity (m3/sec)								
	0-5	5-10	10-15	15-20	20-25	25-30	30-35	35-40	Total
0-30	1037	356	37	2					1432
30-60	1744	1259	390	108	9	5	3		13518
60-90	1796	3532	2460	1385	426	107	15	6	9727
90-120	1256	1809	561	132	31				3789
120-150	583	735	144	21					1483
150-180	444	411	17	2					874
180-210	466	290	8						764
210-240	656	556	57	14	1	1			1285
240-270	1446	1894	816	351	152	52	20	7	4738
270-300	2343	3913	2092	744	379	133	45	5	9654
300-330	1859	1250	194	8	3				3314
330-360	1074	361	12			1			1448
Total	14704	16366	6788	2767	1001	299	83	18	42026

Table 3: Frequency table of current velocity and direction

Waves Profile

- The nearshore (at Zygi area near Vasilikos) wave climate is considered representative for a water depth larger than about 20 m. In more shallow water the waves are further modified by bottom effects like refraction, bottom friction and surf breaking.
- The longer wave periods are mostly from southern to southeaster directions.
- Waves predominantly come from west with 95% exceedance value for wave height is 1.5m. Below the relevant measurements.
- In deep water near Zygi the sea is calm (Hs<0.25 m) for near 50% of time, waves with a significant wave height over 2 m occur about 1% of time (3.5 days per year) and are almost frequent in the sector 195-25^{o}C N.

Observed Wave Height (m)	Wave Direction (deg. N) -15.:15.	15.:45.	45.:75.	75.:105.	105.:135.	135.:165.	165.:195.	195.:225.	225.:255.	255.:285.	285.:315.	315.:345.	Total
< : 0.25	3.19	2.30	2.97	2.78	0.88	0.60	1.11	2.09	9.65	8.30	6.78	5.99	**46.65**
0.25 : 0.75	0.29	0.51	2.25	3.75	1.08	1.05	1.00	3.49	15.03	5.97	2.32	0.58	**37.32**
0.75 : 1.25			0.18	1.86	0.61	0.69	0.76	1.95	5.15	0.28	0.06		**11.54**
1.25 : 1.75			0.02	0.48	0.27	0.21	0.12	0.80	1.13				**3.03**
1.75 : 2.25				0.17	0.10	0.03	0.11	0.31	0.27				**0.99**
2.25 : 2.75				0.04	0.03	0.04	0.03	0.15	0.06				**0.36**
2.75 : 3.25				0.01			0.01	0.04	0.01				**0.08**
3.25 : 3.75							0.01						**0.02**
3.75 : 4.25								0.01					**0.01**
4.25 : 4.75								0.01					**0.01**
4.75 : 5.75								0.01					**0.01**
5.75 : 6.75													
6.75 : 7.75													
7.75 : 8.75													
8.75 : 9.75													
9.75 : 10.75													
10.75 : 12.75													
12.75 : 14.75													
Total	**3.48**	**2.81**	**5.41**	**9.09**	**2.96**	**2.62**	**3.16**	**8.87**	**31.32**	**14.56**	**9.16**	**6.58**	**100.00**

Table 4: Sea waves probability in given height and direction

2.3 Market Filtering Criteria

2.3.1 Target Market Methodology

The market strategy was to use the available information to calculate the demand in gas mmscmd (mmscfd) today (2017-18), and project volumes in the future, i.e. 2030, while having a view until 2040 (where possible). Filtering criteria will be based on the projections of year 2030, which we assume is the year which the CNG Gasvessel will be built and ready to operate.

Other assumptions regarding the screening exercise are the following:

- One offshore gas loading location located offshore Cyprus with three potential field sizes of 28, 57 and 113 bcm (1, 2 and 4 TCF) of gas in place.
- One onshore gas loading location located at Vasilikos Energy Port, Cyprus.
- Power plant efficiency is assumed to be 50% for gas turbines and 40% for fuel oil engines, unless specific information is available for the power plants in question.
- The annual load factor for each power plant is assumed to be 30% of the name plate capacity throughout the year, unless specific information is available for the power plant in question.

2.3.1.1 Target Markets

European energy supply system in mainland area consists of a mature energy production and supply network which allows for gas to be procured at low prices due to deregulated access to existing infrastructure, sufficient distribution channels from the gas transmission lines and access to affordable gas from both pipelines and LNG regasification terminals. Furthermore, European regulations that promote sustainable development support the investment in renewables and efficient utilization of energy thus energy in Europe is a dynamic system with many variables to consider. On the other hand, the Gasvessel concept supports European efforts in promoting green energy and the investment in low carbon fuels such as the use of natural gas over the use of petroleum distillates. In addition, Gasvessel can be considered as an additional supply method of energy thus enhancing Europe’s energy security of supply.

Based on the above, CHC believes that for the East Mediterranean geologistic scenario the Gasvessel concept is more likely to generate interest from gas buyers in isolated markets where targeted buyers have no access to pipeline gas but are willing to switch to natural gas either for power production or industrial feedstock as a cheaper alternative.

For this study we will consider a market, as isolated, if the distance from the main gas transmission line is over 100 km offshore and over 200 km onshore. These distances are generic and based on market research for various energy consumers in the East Mediterranean.

Furthermore, the market analysis will focus only on potential gas buyers that operate near shore to allow direct access to the vessel without major infrastructure investments.

2.3.1.2 Gas Field Life

In this scenario, the potential gas accumulations in the Eastern Mediterranean are located offshore Cyprus, and for the purpose of this research we assume that green field offshore projects such as the one proposed for the East Mediterranean will be developed under the same production contract regime which is currently being implemented in other licensed blocks in the region. Based on this, countries with exploitation licenses are granted operations for 25 years and it is fair to assume 25 years of production. This rationale will be used in order to calculate minimum production thresholds per field, in order to filter out markets that are too small to enable gas recovery before an exploitation license expires.

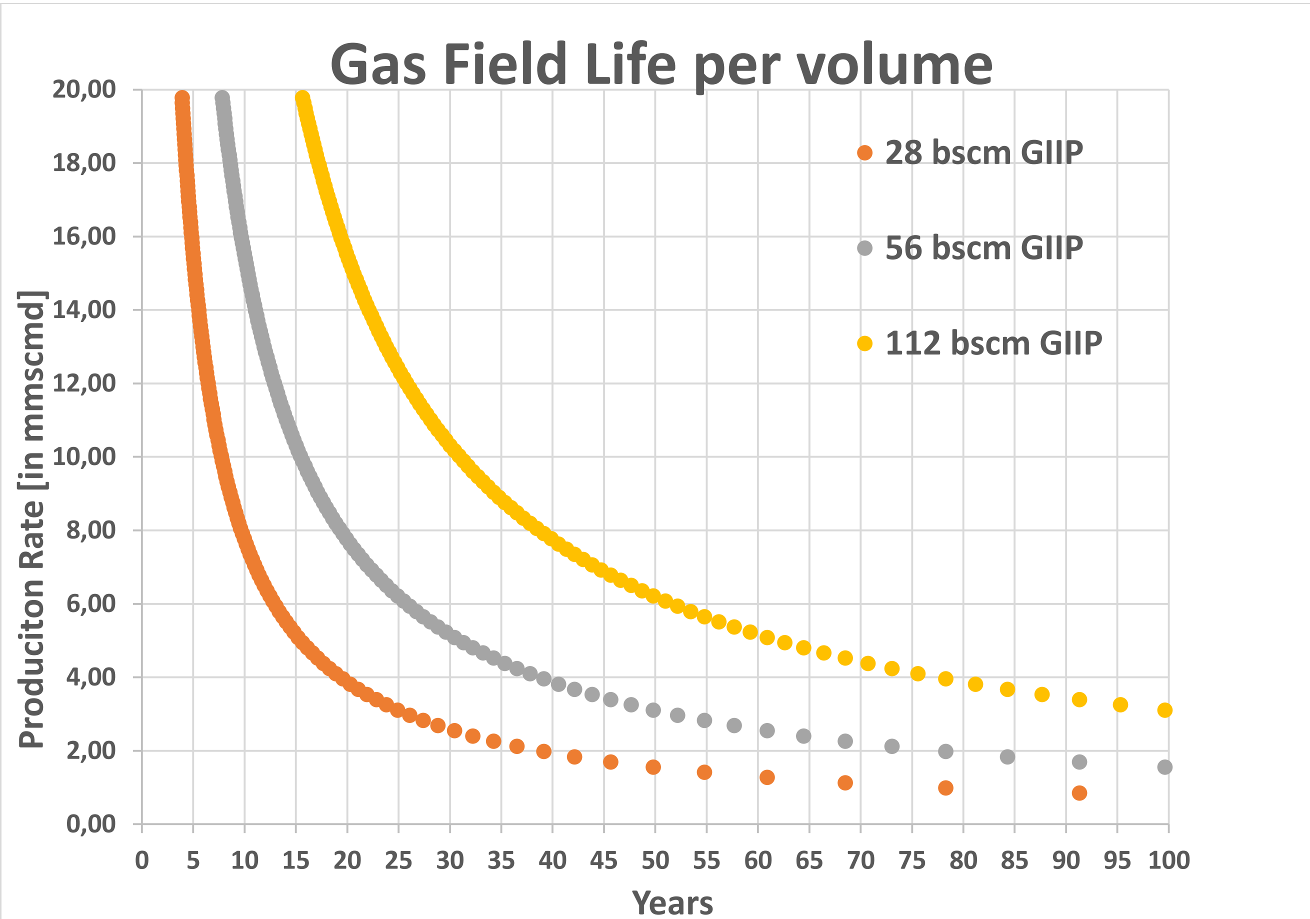


Figure 7: Gas Field life estimations based on three volume scenarios

Figure 7 shows the proposed gas field in terms of production rates and years of production per size of field in gas volumes. In summary:

Offshore location:

- Appr. 28 bcm (1TCF) → potential markets higher than app. 3 mmscmd (100 mmscfd)
- Appr. 57 bcm (2 TCF) → potential markets higher than app. 7 mmscmd (220 mmscfd)
- Appr. 112 bcm (4 TCF) → potential markets higher than app. 13 mmscmd (425 mmscfd)

2.3.1.3 Gasvessel Volumes and Distances

Regardless of geologistic scenario, the common characteristic in all cases is the use of CNG Technology to transport natural gas via the Gasvessel to the various selected target markets. Given this, the loading capacity of the Gasvessel ship, intermediate CNG storage and the distances travelled will allow us to assess the cases where the CNG technology is competitive.

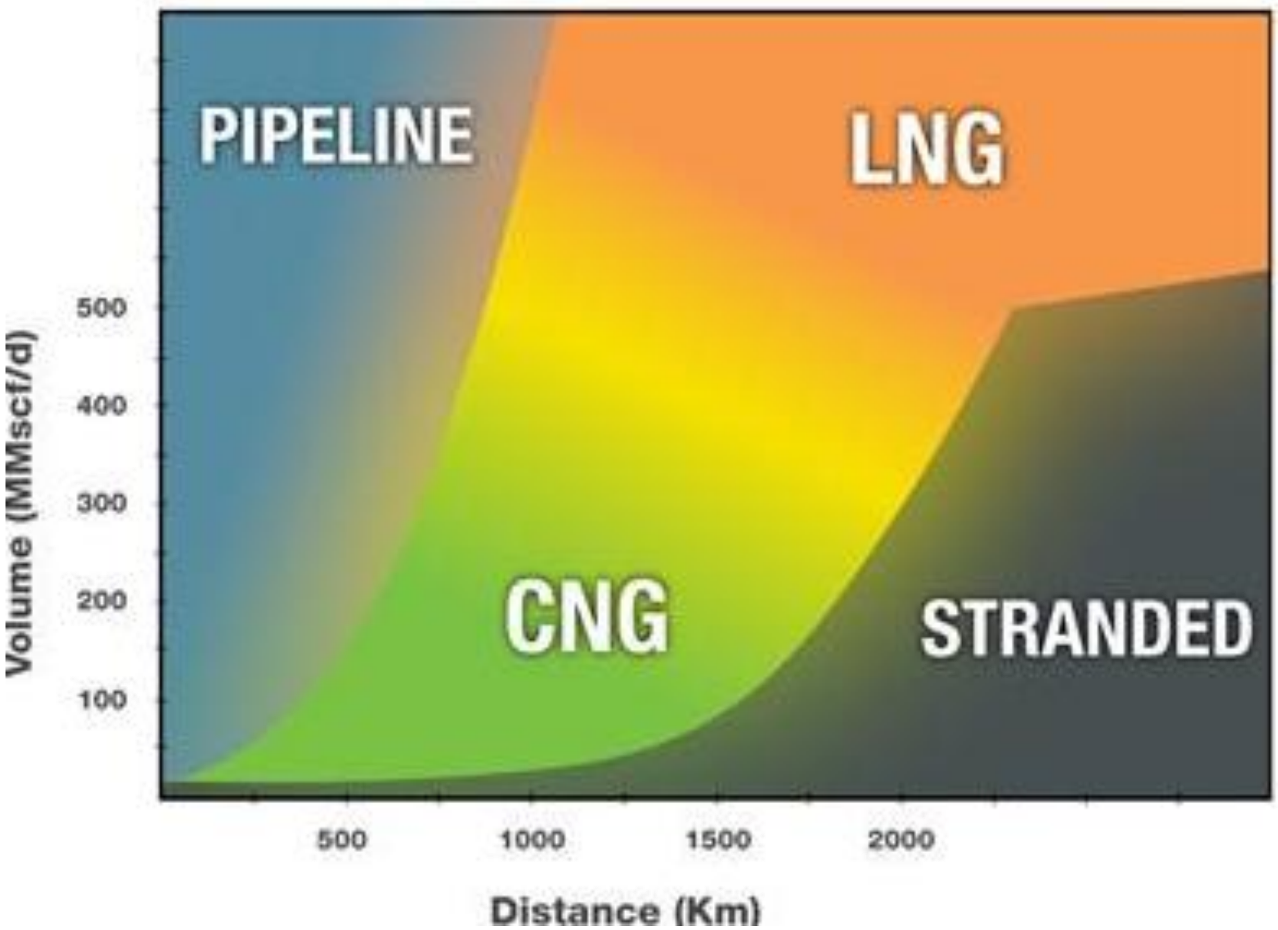


Figure 8: Marine Gas Transportation Market

The above graph was created by SeaNG, and illustrates the gas production rates and distances where CNG technology may theoretically have a competitive advantage against conventional technology such as pipelines and LNG. The specific diagram is based on old CNG technology and is out of date. Also, the Gasvessel partners do not have quantitative or qualitative information to confirm the validity of this diagram; however, based on the fact that similar diagrams have been generated by other proponents of Marine CNG technology, it will be used to filter out target markets which:

a. Have a gas demand below 1.5 mmscmd (50 mmscfd) or above 16.5 mmscmd (550 mmscfd) per day

b. Are located less than 150 km or more than 1750 km from the loading locations. Lower distances justify the built of a pipeline and higher distances justify the use of LNG.

2.3.1.4 Gasvessel Sizing

Based on simulation data provided by Navalprogetti as part of the original Horizon 2020 proposal, there is a range of gas flow rates for which the Gasvessl sizing concludes to financially feasible scenarios. The screening methodology will take into account whether the target market's demand and distance from the loading points are approximately similar, or not too far, to those presented in the previous Navalprogetti analyses.

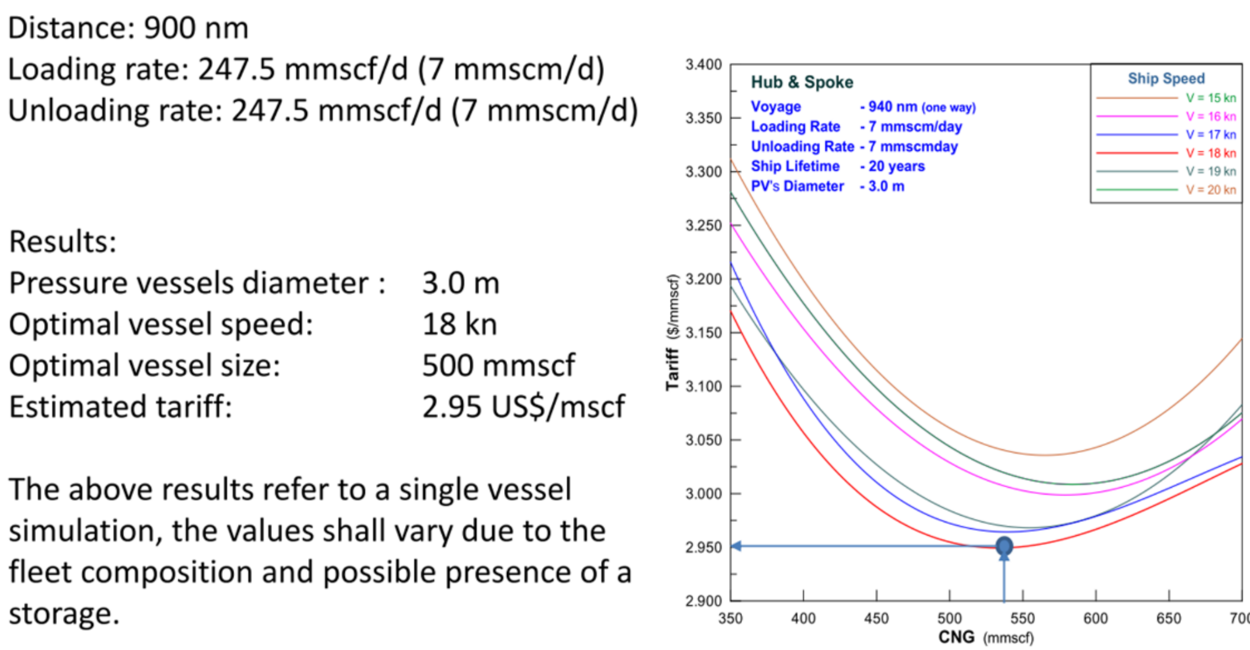


Figure 9: Optimum Gasvessel size for specific case study as part of Gasvessel pre-studies

2.3.1.5 Gas Unloading Characteristics

In the East Mediterranean geologistic scenario, information on unloading locations on the market side, i.e. location of the buyer such as ports or hubs, as well as gas grid specifications such as temperature, composition and pressure, is not readily available. However, as the sites proposed are all located near existing ports, it is assumed that the port technical characteristics will suffice for ship berthing but also that metocean conditions are generally suitable for the loading and unloading of ships. Regulation concerning the acceptance of CNG vessel at ports are not part of the scope of work for WP2. Furthermore, we assume that the CNG gas carried by the Gasvessel ship is at high specifications and ready to be injected into any national gas grid without additional processing. At this stage, we assume that for all markets the gas is required to be delivered at 50 bar pressure.

2.4 Eastern Mediterranean Proposed Target Market

Initially, the market research for the East Mediterranean geologistic scenario utilized the target market screening methodology to identify the most potential gas buyers in the area.

To identify which of the Mediterranean countries gather more potential to become targets for the Gasvessel project, CHC had an overview of the countries' power generation by gas and petroleum distillates. The countries included were Cyprus, Greece, Italy, French Islands, Jordan, Egypt and Lebanon. France mainland, Spain and Portugal, Morocco, Algeria, Tunisia and Libya were not included in the investigation because they were considered to be outside the distance range as already described, for the Gasvessel, having in mind that the loading sites are at the eastern side of the Mediterranean Sea. In addition, Tunisia and Libya are gas exporters and therefore unlikely to be considered targets for Gasvessel[1].

The primary evaluation of the marketing analysis is based mostly on the energy consumed by power plants and it is assumed that targeted gas buyers are either the power plants or wholesale gas distribution entities that re-sell gas to the power plants or industrial players. CHC has used the Global Energy Observatory[2] to mark the location and capacity characteristics of each power plant in the region and following the target screening methodology we have filtered out all the plants that are not located nearshore and not considered to be isolated markets. CHC also used data from several sources including The South East Europe Energy Outlook 2016/2017[3]. This report presents the analysis of the results and the recommendations by CHC for the primary targets for the Gasvessel project. As already mentioned, during the second phase of the marketing analysis CHC focused on the proposed market areas and tried to identify other gas potential buyers in each country, including household users, industrial consumers such as fertilizer plants, cement plants, etc. thus opening the market for the Gasvessel project.

For raw data concerning the filtering results concerning Italy and France (Corsica), details can be found on the Appendix section (Appendix A, sections III and IV).

2.4.1 Cyprus

Cyprus has three power stations[4], however, only 'Vasilikos' and 'Dhekelia' have generators in place which can be modified to enable the use of gas, however, the 'Dhekelia' units are considered to be of outmoded technology. Furthermore, future increases in electricity demand in Cyprus can be covered with the addition of a third gas turbine at Vasilikos, however, not yet confirmed. The smaller power plants of 'Moni' usually operates in stand by mode, but the old generators cannot be converted for gas consumption but only use Fuel Oil or Diesel Oil. Figure 10 shows the location of the existing power plants.

For raw data on the technical characteristics of the 3 power plants visit the Appendix (Appendix A, section I).

Figure 10: Cyprus' Selected Power Plants[5]

Figure 11 depicts the Cypriot power plants' characteristics against the target market screening criteria. The Y-axis represents the distance of the power plants in Cyprus from the closest European transmission line (Greece) and the X-axis, the mean average distance from the onshore and offshore gas loading sites. The size of the bubble represents the demand in mmscmd for each power plant based on the plants' capacities, assuming 50% energy efficiency for gas turbines and 40% for diesel turbines, while also assuming 30% utilisation of the power plants' capacities in a year. The 30% assumption is based on the ratio between total installed capacity and the actual demand in power in a year based on publicly available data from EAC's website[6]. The low load factor is something common with East-Mediterranean countries, especially in islands were demand for electricity is characterized by large demand swings due to seasonality between winter and summer months. Furthermore, the blue arrows show the distance battery limits based on the target market screening criteria, while the yellow bubble is a dummy representation of 2.83 mmscmd (100 mmscfd) used here as a reference to the smallest proposed production from the gas offshore loading site according to the upstream criteria.

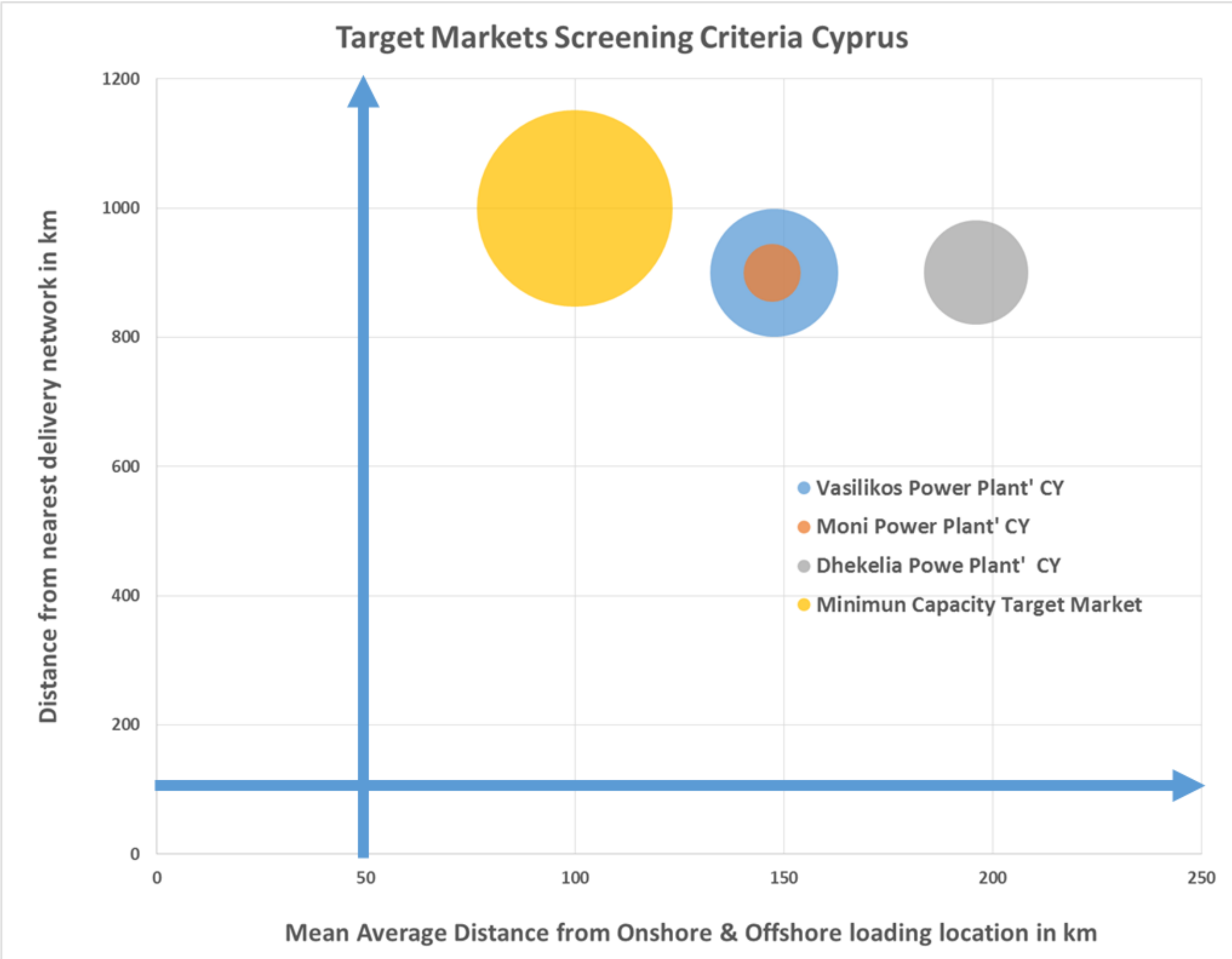


Figure 11: Power Plants in Cyprus based on market screening criteria

Figure 11 demonstrates that, even though, the total installed power capacity of Cyprus' power plants pass the screening criteria on isolated markets, none of the plants fulfil the minimum upstream criteria of 2.83 mmscmd (100 mmscfd). Vasilikos plant is estimated to be less than 1.41 mmscmd (50 mmscfd) while the second biggest plant, Dhekelia, less than 1.13 mmscmd (40 mmscfd). However, due to the close proximity of the plants (about 50 km onshore between Vasilikos and Dhekelia) we combine the volumes to a total of 2.26 mmscmd (80 mmscfd). Furthermore, we can also assume only one entry point at the proposed Vasilikos Energy Port[7] that would allow a relatively easy CNG connection to feed the Vasilikos plant and at the same time, with an onshore connection of less than 50 km distance, to feed Dhekelia. Moni Power Plant will not be considered as a targeted gas buyer in this report.

Even in the case of combining the demand volumes of the two plants in Cyprus, the upstream criteria are not met. However, CHC recommends Cyprus to be included in the target market list assuming that when the Gasvessel will be operational demand will grow towards 2.83 mmscmd (100 mmscfd)[8].

Overall Demand and Supply Profile

Even though natural gas has not yet reached the Cyprus market, we estimate that Cyprus' total domestic demand (including gas to power, heating, transportation, industrial) could range from 4.24 to 5.65 mmscmd (150 to 250 mmscfd), depending on the rate of fuel substitution by sector. Power generation will deliver the largest share of demand growth as the Electricity Authority of Cyprus (EAC) switches its plants to use gas, where power generation is the primary target for the Gasvessel project the expected demand is forecasted to grow to 2.83 mmscmd (100 mmscfd). As early as 2006, state-owned power utility EAC commissioned a regasification design study for a terminal situated in Vasilikos. The terminal and imports have not been materialized yet, however, EAC built a CCGT power station at Vasilikos which is mainly used fuel and diesel oil for power generation.

In the below table, we have inserted the total installed power generation capacity in Cyprus.

Power Station	Turbine Detail	MW	FUEL	HFO	Diesel	Waste Heat
Vasilikos	(STEAM TURBINE) UNIT 1	130.0	HFO	130.0		
Vasilikos	(STEAM TURBINE) UNIT 2	130.0	HFO	130.0		
Vasilikos	(STEAM TURBINE) UNIT 3	130.0	HFO	130.0		
Vasilikos	(GAS TURBINE) 1	37.5	DIESEL		37.5	
Vasilikos	(STEAM TURBINE) 40	75.0	Waste heat			75.0
Vasilikos	(GAS TURBINE) 41	72.5	DIESEL		72.5	
Vasilikos	(GAS TURBINE) 42	72.5	DIESEL		72.5	
Vasilikos	(STEAM TURBINE) 50	75.0	Waste heat			75.0
Vasilikos	(GAS TURBINE) 51	72.5	DIESEL		72.5	
Vasilikos	(GAS TURBINE) 52	72.5	DIESEL		72.5	
Dhekelia	(STEAM TURBINE) UNIT 1	60.0	HFO	60.0		
Dhekelia	(STEAM TURBINE) UNIT 2	60.0	HFO	60.0		
Dhekelia	(STEAM TURBINE) UNIT 3	60.0	HFO	60.0		
Dhekelia	(STEAM TURBINE) UNIT 4	60.0	HFO	60.0		
Dhekelia	(STEAM TURBINE) UNIT 5	60.0	HFO	60.0		
Dhekelia	(STEAM TURBINE) UNIT 6	60.0	HFO	60.0		
Dhekelia	(INTERNAL COMBANSION ENGINE - ICE) 1	17.0	HFO	17.0		
Dhekelia	(INTERNAL COMBANSION ENGINE - ICE) 2	17.0	HFO	17.0		
Dhekelia	(INTERNAL COMBANSION ENGINE - ICE) 3	17.0	HFO	17.0		
Dhekelia	(INTERNAL COMBANSION ENGINE - ICE) 4	17.0	HFO	17.0		
Dhekelia	(INTERNAL COMBANSION ENGINE - ICE) 5	17.0	HFO	17.0		
Dhekelia	(INTERNAL COMBANSION ENGINE - ICE) 6	17.0	HFO	17.0		
Moni	(GAS TURBINE) 1	37.5	DIESEL		37.5	
Moni	(GAS TURBINE) 2	37.5	DIESEL		37.5	
Moni	(GAS TURBINE) 3	37.5	DIESEL		37.5	
Moni	(GAS TURBINE) 4	37.5	DIESEL		37.5	
		12960		**7463.5**	**4182.9**	**1314.0**

Table 5: Total power generation in Cyprus by power station.

The base load for Cyprus for the Vassiliko Steam Turbines is 390 MWh (3 x 130 MWh). During peak demand an additional 542 MWh could be added.
Again for the purpose of the Gasvessel project we have agreed to set the base load demand to 2.83 mmscmd (100 mmscfd).

Demand

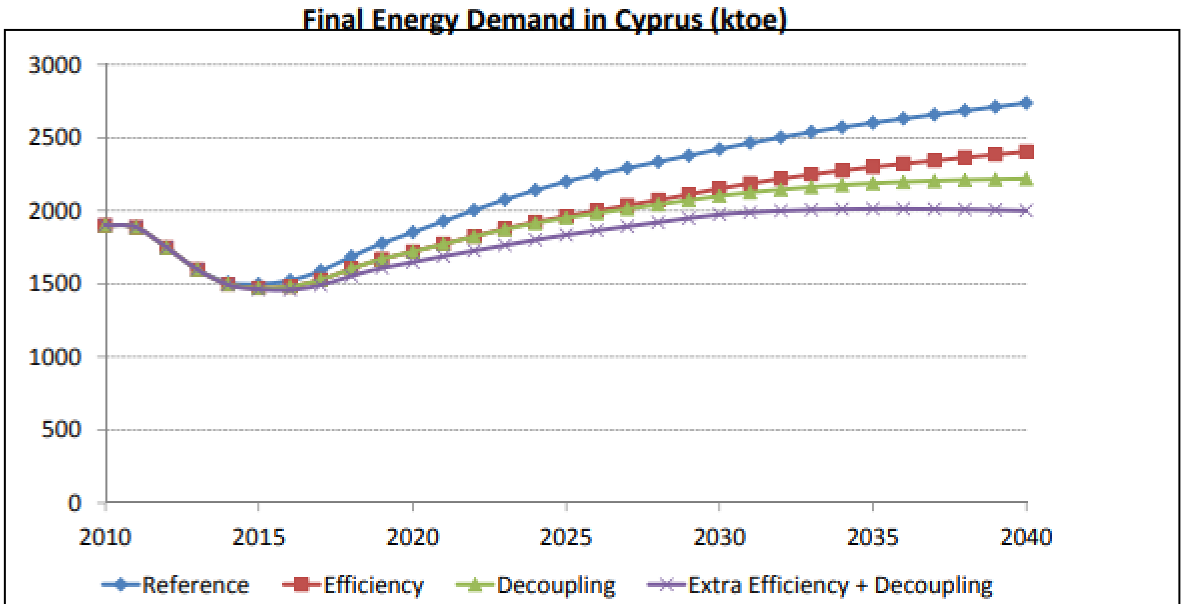


Figure 12: Projected Energy Demand in Cyprus

Following the pattern of energy demand we were able to extrapolate the equivalent natural gas demand for the years up to 2035 in low, mid and high consumption scenarios, as illustrated in Figure 12. Our mid case scenario is also in line with a recent report (reference) that estimates demand based on assumptions concerning the input of renewable energy in the country's future energy mix (reference). Furthermore, our estimated demand schedule shares similar trends with the Cyprus Energy Regulatory Authority's (CERA) forecasted energy production for the future years (expressed in MW and GW/h) (reference). The mid case scenario suggests current natural gas demand of over 2 mmscmd (72 mmscfd), with a steady increase to 2.83 mmscmd (100 mmscfd) by 2028 before reaching 3.39 mmscmd (120 mmscfd) by 2035. Visit the appendix for the table of figures on natural gas demand in Cyprus.

The below graph illustrates the demand profiles as described above, nevertheless it needs to be clarified that during the first years of the graph 2015-2019, although Cyprus does not consume any gas, we have converted the historical demand from MW to gas equivalent in mmscmd taking into account the thermal efficiency rates of about 50%.

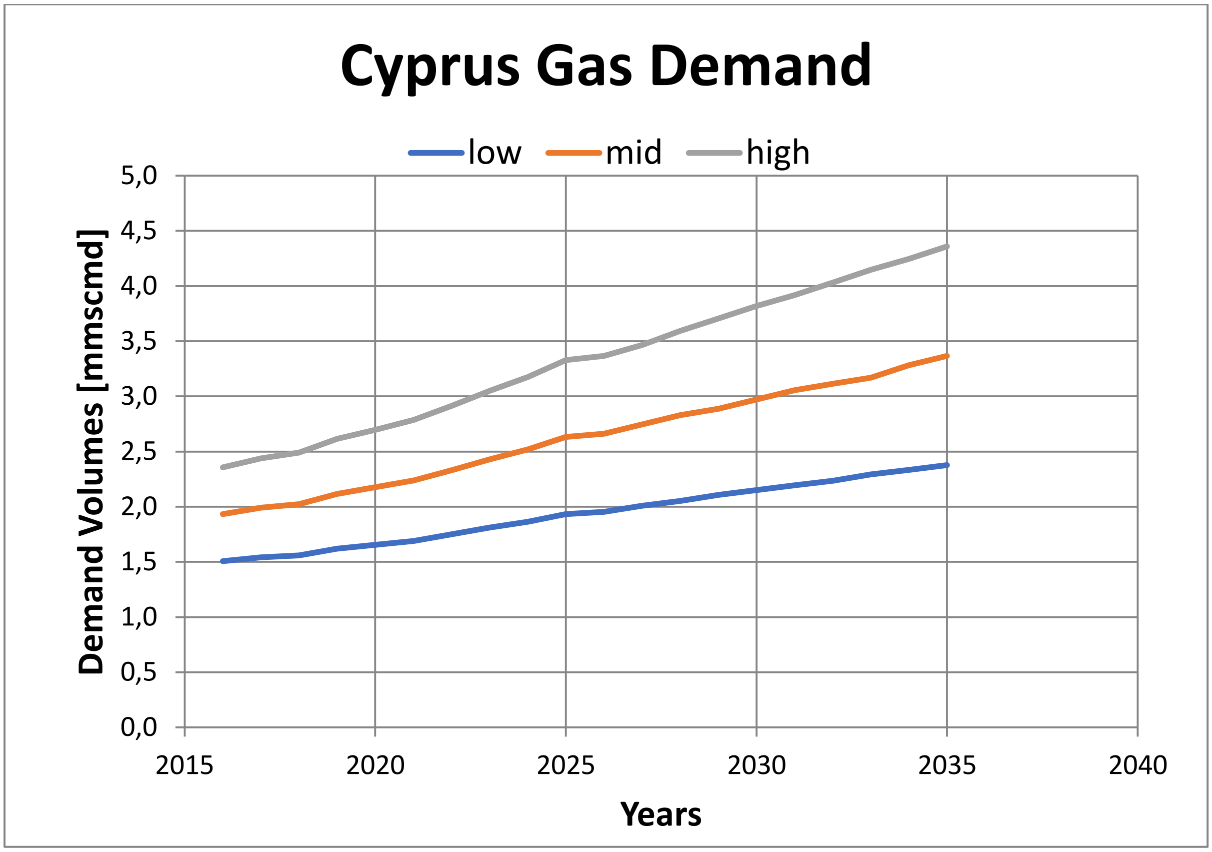


Figure 13: Forecasted Cyprus Energy Demand

Switching from oil to gas could yield several benefits for the economy. Most importantly, oil imports are a considerable burden. In 2017, Cyprus paid an estimated €1.6 billion to import "fuels and lubricants", making up 29% of the country's total import bill. Additionally, the substitution from oil to gas would provide an important stimulus to consumers, because not only does Cyprus have the highest electricity price in the European Union, but its power prices are twice as high as the European average. Mostly, this is due to the heavy dependence on oil for power generation (and this is further complicated by the use of older, less efficient turbines). Switching the energy mix to natural gas could easily reduce this price by a considerable margin.

Supply

Cyprus is currently not a gas consuming country and it is not being supplied by natural gas either from pipeline or seaborne imports so far. Although in the past there have been attempts to import gas from a proposed FSRU to be located in the Vassiliko area in the southern part of the island, the plans remained unmaterialised.

The Cyprus parliament approved in May 2018, a proposal by state-owned Natural Gas Public Company (DEFA) to proceed the soonest, with two tenders for the import of natural gas. The first tender will enable the creation of the necessary infrastructure and the second the procurement of

the natural gas supply. DEFA is currently in the process of pursuing two tenders, one for the regasification infrastructure, and the other one for long term LNG supply.
Aphrodite gas field is the first gas discovery in Cyprus and it is located at Block 12 of Cyprus' EEZ. The field development plan for Aphrodite gas field is to export the gas to Egypt via a direct offshore pipeline. targeting the liquefaction terminals at Idku or Damietta.Aphrodite's current development status restricts the use of the Gasvessel concept, nevertheless the concept might be applicable for future discoveries.

Infrastructure

Cyprus gas infrastructure is inexistent, since the island is based solely on oil products for power production from the two power plants in Vassiliko and Dhekeleia area. DEFA is the sole importer and distributor of natural gas in Cyprus and they have the right to proceed with securing the necessary natural gas quantities at the best commercial terms. DEFA has designed in the past an inland gas distribution network as shown below. The plan was to channel the gas from the proposed FSRU in Vassiliko to the two other power stations of the island in Moni and Dhekeleia.

Figure 14: Proposed Gas pipelines

A more detailed route of proposed pipeline is shown below. The pipelines can also serve the industrial regions which will be in logical proximity to the pipeline.

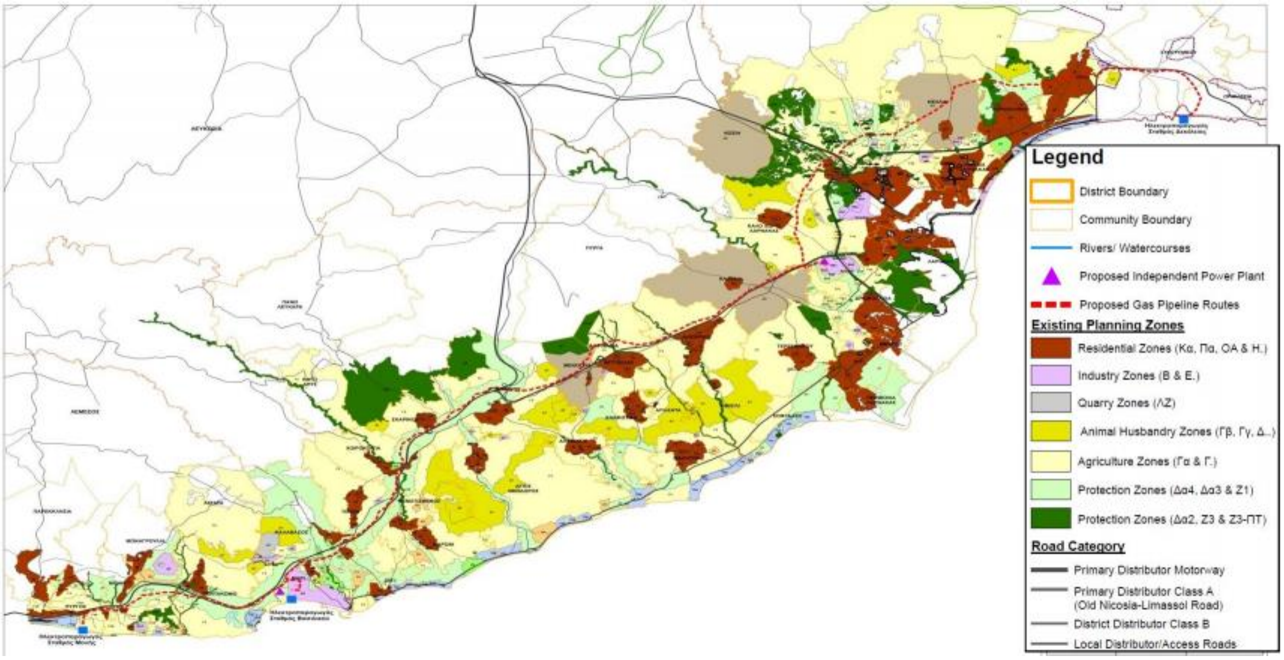


Figure 15: Proposed Gas pipelines (zones)

Cyprus, through DEFA, is missioned to secure sufficient natural gas supplies, at the lowest possible prices, to cover the needs for Electricity Power Generation (Phase “A”) and subsequently to also supply industries, hotels and households. The development of the necessary gas network infrastructure, is also on DEFA’s mandate.

The gas network will initially consist of 3 pipelines connecting the Gas Import Hub with the three existing downstream Power Stations. The estimated cost for “Phase A” of this project is around €60m. Towards this cost, DEFA has managed to secure a €10m grant from EU under the European Economic Programme for Recovery.

Vasilikos Power Station	Moni Power Station	Dhekelia Power Station
≈ 0.6 km pipeline	≈ 12 km pipeline	≈ 65 km pipeline

These are the preliminary infrastructure proposals in Cyprus but they have remained on paper thus far, suggesting that Cyprus is a long way from full gasification, but once the FSRU is in place it will then be a matter of time and financing to implement the infrastructure.

Regulations

As a member of the EU, Cyprus has aligned its energy policy with the cumulative body of EU laws and transposed all relevant EU Directives into national law.

Cyprus Energy Regulatory Authority (CERA) is responsible for regulating the gas market. Any person/company engaged in the following requires a licence from CERA:

- The import, storage or gasification of natural gas.
- The construction or operation of facilities for the import, storage or gasification of natural gas.

CERA's other responsibilities include:

- Setting the rules for the management and the distribution potential of interconnection, in consultation with the appropriate authority (ies) of the member states with which there is interconnection.
- Assuring control and transparency in the market to avoid possible misuse of dominant position, particularly misuse which is to the detriment of consumers.
- Determining the measures to be put in place if an unforeseen crisis occurs in the energy field, or when the safety of people, works, installations or the integrity of the networks are threatened.
- Monitoring:
    - security of supply, and especially the balance of supply and demand in the market;
    - the level of the expected future demand;
    - the availability of supply
    - the level of competition in the market.
- Protecting the interests of end users.
- Resolving disputes regarding access to the upstream network.
- Determining the minimum standards of technical design and operation for connection to the network and other natural gas installations.

However, an amendment in the Law on the Regulation of the Natural Gas Market provided most of the provisions of the Natural Gas Law to be suspended since the Council of Ministers assigned the import and supply of natural gas to Cyprus to a sole supplier, DEFA and designated one land terminal as the exclusive station for the delivery, storage and re-gasification of liquefied natural gas (LNG). It requires CERA to refrain from issuing licences to avoid jeopardising that goal. The subsequent establishment of DEFA as the monopoly supplier has effectively suspended CERA's regulatory role and powers with regards to the gas market.
Cyprus is therefore granted with the exception of EU Regulation for a period of 10 years being a market under development. The exception period starts from the day Cyprus will start importing gas.

Prices

Local natural gas prices are difficult to forecast, especially because of the absence of natural gas on the island today. Although a number of gas market indices are widely used we tend to believe that for the region of East Med the Brent linkage of gas is still quite strong. Therefore, as Cyprus is using Fuel and Diesel Oil for power production we can easily convert the imported prices into €/m3 ($/mmbtu) for safe proxy of maximum landed prices of the Gasvessel. Additionally we can forecast the values using the Brent forward curves. The results are shown on below graph.

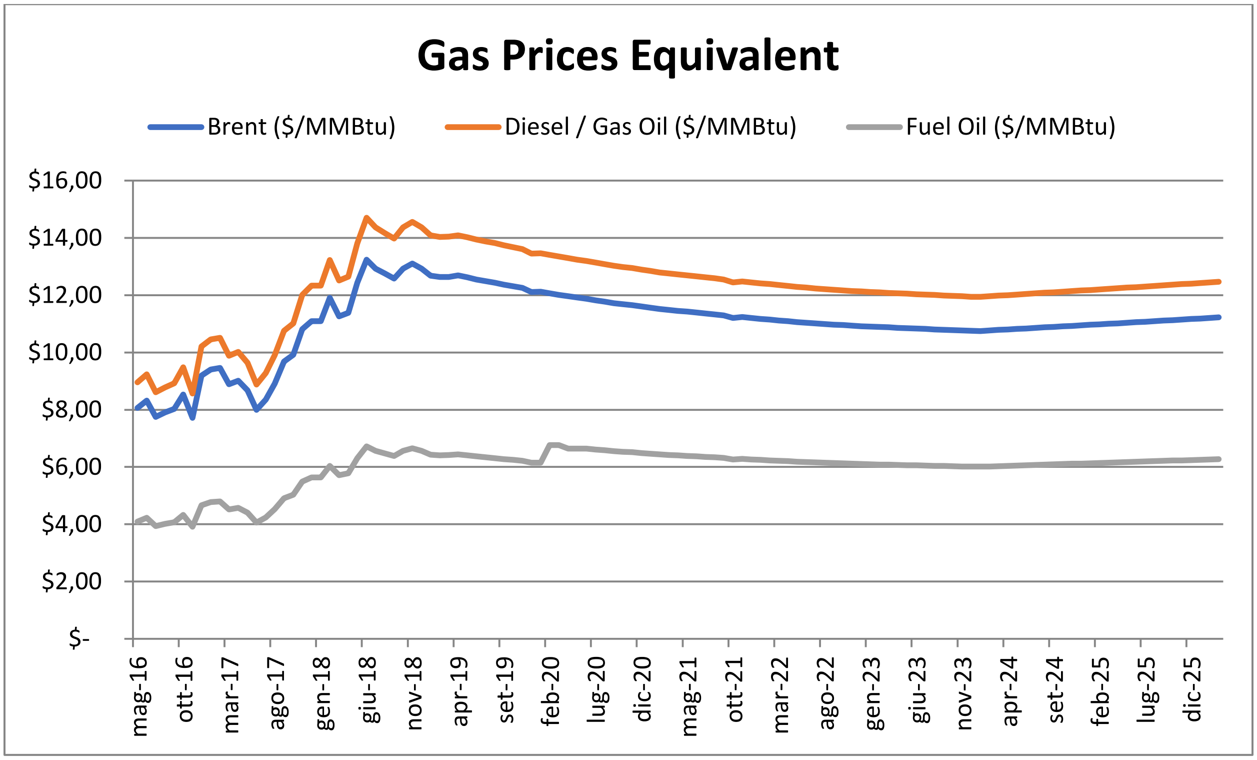


Figure 16: Diesel and Fuel Oil Prices Equivalent

For the Gasvessel, the value of the above lies on the set of the upper price limits, on fuel oil first as a cheaper substitute and on diesel oil as the second best choice as the direct competitors of CNG. CNG has to compete with the above values. For example, in May 2020, Brent price is forecasted to be $70/bbl, the Diesel Oil equivalent is $11.85/mmbtu (€0.35/m3) and the Fuel Oil $6.64/mmbtu (€0.20/m3).

Players

Natural Gas Public Company (DEFA)

DEFA's mission is to secure sufficient natural gas supplies, at the lowest possible prices, to cover the needs for Electricity Power Generation and subsequently to supply industries, hotels and households in Cyprus with natural gas. It aims to develop the necessary gas network infrastructure that will consist of 3 pipelines connecting the Gas Import Hub with the three existing downstream power stations. The scope of DEFA includes:

1. Buying, importing, holding, using, distributing, selling and supplying natural gas in any form.

2. Operation of the Natural Gas Transmission and Distribution Network.

3. Negotiating, buying, selling, managing, storing, importing, exporting, re-exporting etc. Any goods, tangible or intangible, including natural gas.

DEFA is also active in promoting natural gas usage in other sectors.

Other sectors: Gas to households

DEFA has progressed with the first phase of the natural gas pipeline development project. This is a feasibility study which includes the route selection, the estimated demand and size of network, preliminary environmental impact assessment, preliminary risk assessment and cost feasibilities. The first phase relates to the existing power plant infrastructure of Cyprus and licenses include individual power producers (IPPs). The additional demand for gas other than gas for power is not expected to significantly affect the demand profiles up to 2040 which have been described thus far. Roughly, the study shows a figure of about 20% on top of the gas-to-power demand figures. However, these numbers have to be reviewed later work packages.

Summary

This proposal could be investigated as described below:

a. Offshore gas loading location to serve Cyprus under the Gasvessel concept by optimizing the intermediate value chain dictated by the number of vessels, use of storage facilities, etc.

Wholesale Buyer	Application	Volume	Loading Location	Unloading Location
DEFA	Gas for Power	2.83 mmscmd (100 mmscfd)	Offshore location	Vasilikos Energy Port

2.4.2 Greece

Greece demand in electricity is mostly covered today by different energy resources such as coal, oil, gas, wind and solar power. The main gas transmission line coming from Turkey and Bulgaria feed much of the east side of the Greek mainland starting from the north and ending south covering the area around Athens.

In addition, the existing transmission gas network is also supported in the south of mainland Greece by Revithousa regasification terminal thus enhancing security in supply. Furthermore, projects are under construction to expand the existing network into the Peloponnese area, south of mainland Greece, while under development projects such as the Greece-Italy interconnector are under plan to feed the western side of Greece through gas pipelines[9]. Based on today's infrastructure, the power plants that can be considered as isolated gas buyers in Greece are the ones shown in Figure 17, and all happen to be located on Greek islands which are naturally disconnected from the existing infrastructure. Although the Alivery power plant (located near Athens, mainland) is an oil operated plant with high installed capacity, it is not included in the proposed list of the isolated buyers due to the project, already under construction, aimed at extending the existing gas network in Athens to feed also the Aleveri region[10]. More information on the Power Plants' characteristics and locations are found in Tables 14-18 in the Appendix (Appendix A, section II)

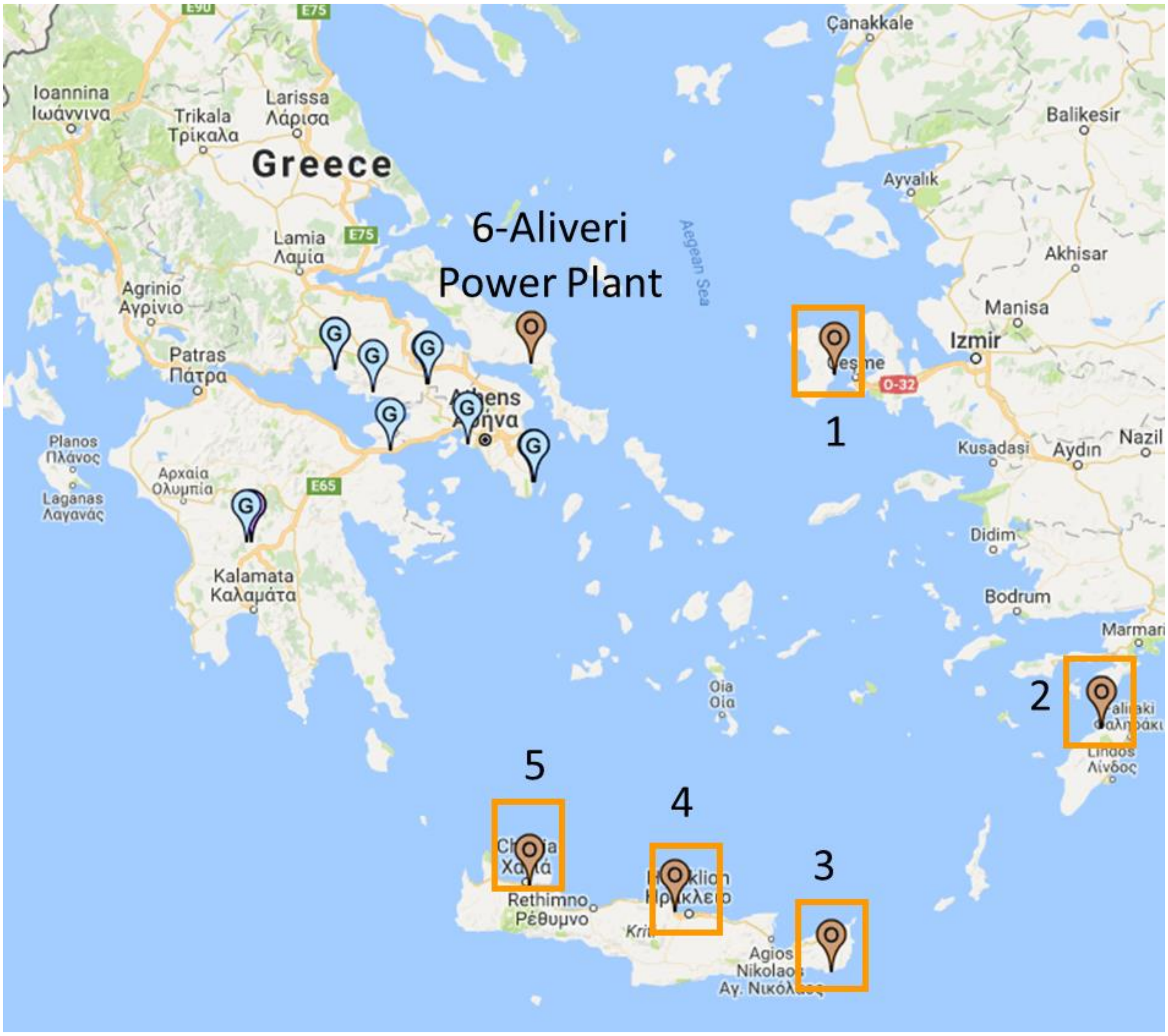


Figure 17: Power Plants in Greece

The analysis of the power plants' characteristics shows that none of the proposed plants satisfy the minimum upstream criteria of 2.83 mmscmd (100 mmscfd) in gas demand. Unfortunately, even the combination of all the plants' capacity total today is less than 1.41 mmscmd (50 mmscfd) based on todays installed capacity and the assumptions of energy efficiency conversion and the load factor we used for Cyprus case study.

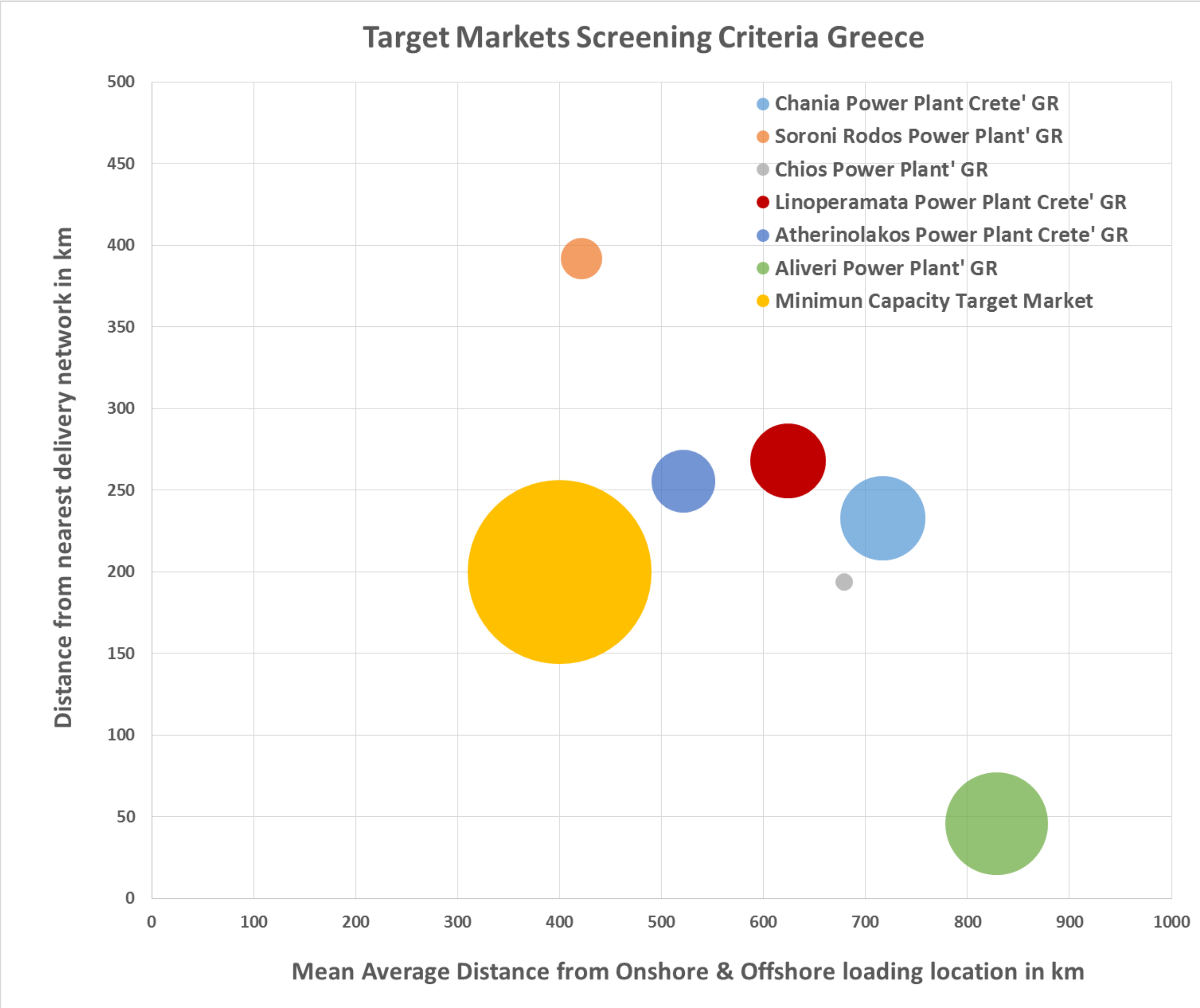


Figure 18: Power Plants in Greece based on market screening data

Based on Figure 18, CHC does not recommend these power plants to be included in the proposed target buyers as a stand-alone case. CHC recommends using only the three power plants located on the island of Crete and in combination with the demand in Cyprus, thus increasing the total demand for CNG transportation by ship. This proposal could be investigated in two different case studies;

a) Gas from the offshore gas location is transported to Cyprus by offshore pipelines to feed Cyprus' domestic needs and the resulting surplus to be converted into CNG and shipped from the proposed Vasilikos Energy Port to Crete.
b) Offshore gas loading location to serve directly both Cyprus and Crete under the Gasvessel concept by optimizing the intermediate value chain dictated by the number of vessels, use of storage facilities, etc.

Because of the close proximity of the three power plants at Grete, CHC will assume a single entry point near Heraklion area to feed the nearby power plant in Linoperamata and with an onshore gas connection the two other plants on the east and west side of the island.

CHC assumes about 1.41 mmscmd (50 mmscfd) in gas demand is an adequate approximation to cover the island's needs today.

In similar manner, we could propose a concept to include Chios or Rodos power plants and even create additional scenarios which accumulate the demand of the islands, however, CHC believes that at this stage using only Crete as an example is good enough to collect the information needed for the Gasvessel project.

Overall Demand and Supply Profile

Greece is a relatively small market for natural gas supplied through pipelines (from Russia via Bulgaria and Azerbaijan via Turkey), an LNG contract with Algeria, and occasional LNG spot purchases. Total natural gas demand in Greece fell from its peak of 4.6 bcm in 2011 to 2.9 bcm in 2015, following two years of strong growth to a record-high 4.7 bcm in 2017 driven by increasing gas-in-power demand and drops in coal and hydropower. Economic growth after years of recession have also helped drive renewed growth in industrial gas use.

Greece relies on imports for all of its natural gas, with around 60% in 2017 purchased from Gazprom. Greece's sole long-term LNG contract with Algeria's Sonatrach is for up to 0.44 mmtpa through 2019. Algerian gas comprises the majority of LNG imports, though Greece has exceeded its contract volume with Sonatrach in some years, such as 2017. Greece also buys limited amounts from other producers on the spot market.

The state-owned Public Gas Corporation of Greece (DEPA) has a pipeline contract with Gazprom for between 2.5 and 3.0 bcm/y through 2026. DEPA's contract with BOTAŞ is for 0.75 bcm/y of gas.

Gas consumption in Greece built on its growth in 2016 to reach new highs in early 2017 after years of decline caused in large part by economic stagnation. Demand (as reported by national gas grid operator DESFA) reached 617 mmcm in January 2017, the highest in history. This was due both to the residential demand spike and to high power use that led to the highest peak since July 2012 (9.4 GW). The government expects high consumption growth, with total demand more than doubling from 2016 over the next 15 years, including an 11% rise in 2018 due to greater gas-in-power use and an expanding gas distribution network.

Demand

Gas consumption in Greece is somewhat seasonal, reflecting weather-related demand from the residential sector, a relatively small contributor to overall demand compared to power. This effect was particularly significant in early 2017, as overall gas demand was up 44% due primarily to cold weather. DESFA reported that January 2017 broke Greece's record for gas demand at 0.62 bcm (up 52%).

In 2017, consumption reached a record high of 4.7 bcm, up from 2.9 bcm in 2015. A main driver has been strong gains in gas-in-power demand as coal-fired generation fell 23% in 2016 and hydropower dropped 36% over the two years. High weather-related residential demand and a rise of industrial demand due to the economic recovery have also contributed. Residential gas sales and gas-in-power were up 9% and 17% respectively in 2017. Industry showed the highest increase (75%) as its demand rose to 0.5 bcm.

Having dropped in 2014 due to the removal of state financial support for gas-fired power generation, gas-in-power demand returned above 2013 levels in 2016 before continuing this strong growth into 2017.

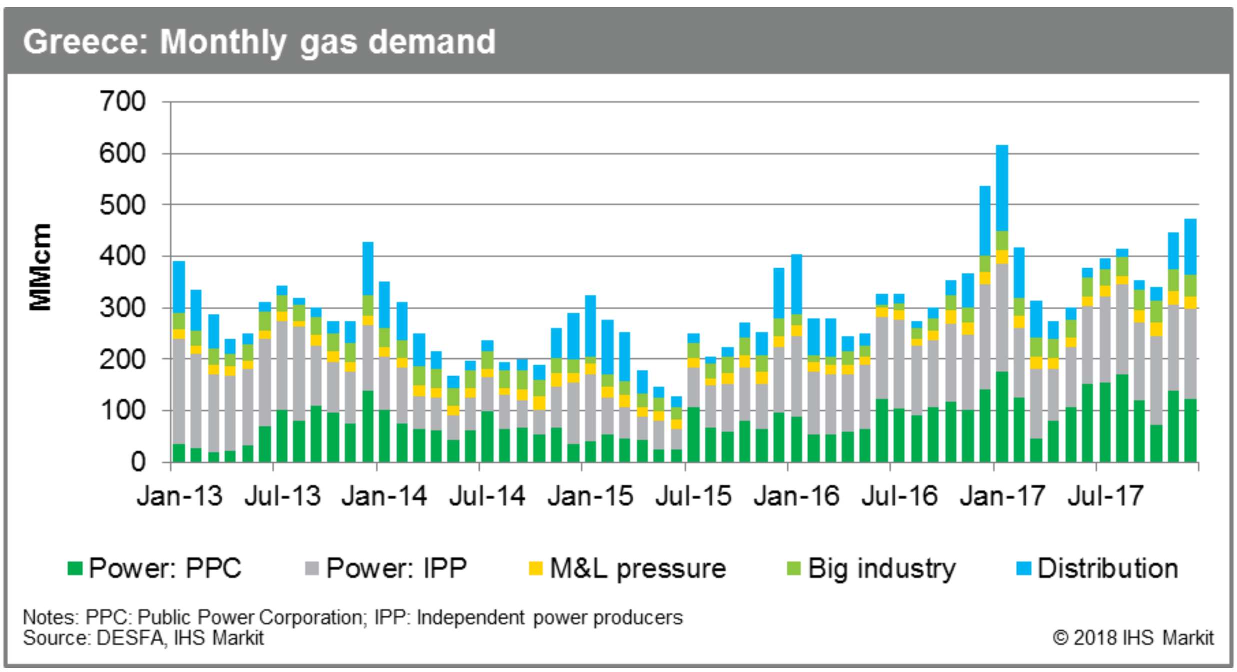


Figure 19: Greece Monthly Gas Demand by Segment

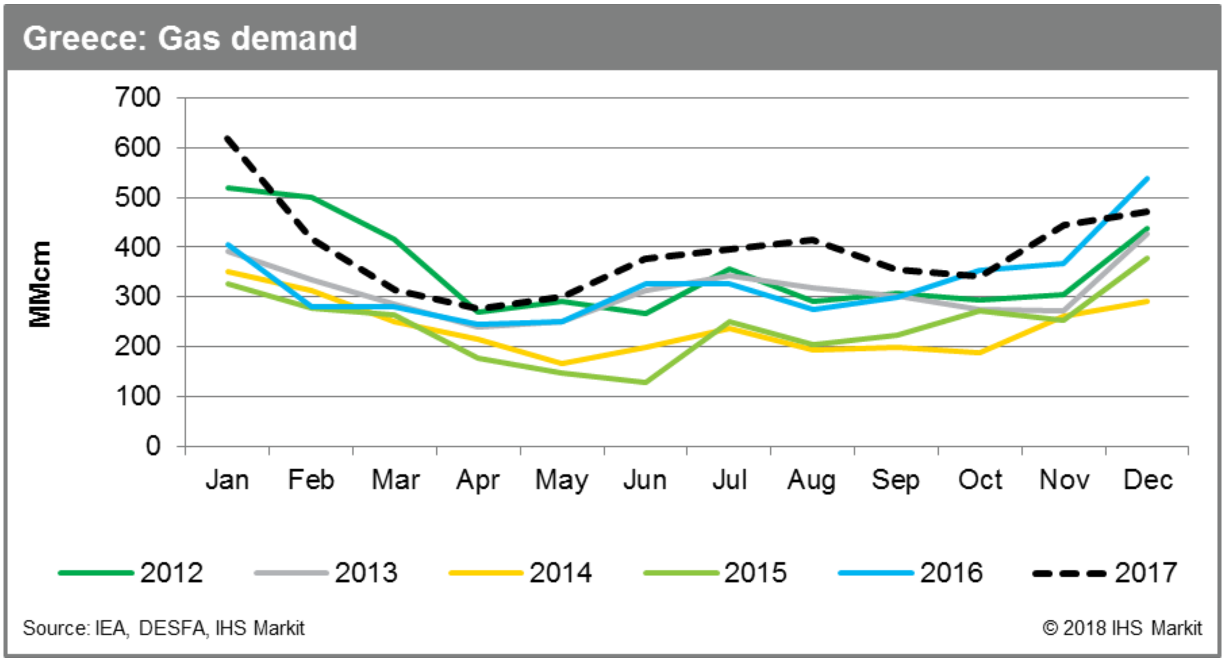


Figure 20: Gas Demand Greece: Yearly fluctuations

Overall gas demand in Greece is expected to increase around 15% from 2016 levels to peaks around 4.3 bcm in the late 2020s after dropping from the demand spike of 2017.

Crete Demand

As described on our geologistic scenario report for the Greek market, we are targeting the Power Market of Crete, the biggest island in terms of population with a significant power production capacity and we assume that the aforementioned forecasted demand growths in Greece in general will in proportional to the population terms apply for Crete as well.
More specifically we have concluded that Crete can switch its entire power production capacity to gas instead of liquid fuels which it is currently burning. A landing point has been strategically selected in the middle of the island where the biggest power plant is located and we therefore assume in-land pipeline distribution of the gas to the remaining power plants. The table below shows the list of the installed power capacity in the island of Crete.

Power Plant	Generator	Name Capacity MW	Fuel
Atherinolakkos	Foster Wheeler SD-36 Skoda MTD40C	46.5	Fuel oil
Atherinolakkos	Foster Wheeler SD-36 Skoda MTD40C	46.5	Fuel oil
Atherinolakkos	Mitsui Man B&W 12K90MC-S MK6	51.12	Fuel oil
Atherinolakkos	Mitsui Man B&W 12K90MC-S MK6	51.12	Fuel oil
		195.24	
Linoperamata	GE M5 5001	16.25	Diesel
Linoperamata	GE M5 5001	16.25	Diesel
Linoperamata	GE LM6000	43.3	Diesel
Linoperamata	ABB GT 35C1 Siemens SGT 500	14.72	Diesel
Linoperamata	GE LM2500	27.95	Diesel
Linoperamata	Sulzer 9RTAF58	12.28	Diesel
Linoperamata	Sulzer 9RTAF58	12.28	Fuel oil
Linoperamata	Sulzer 9RTAF58	12.28	Fuel oil
Linoperamata	Sulzer 9RTAF58	12.28	Fuel oil
Linoperamata	Boiler natural circulation Turbine K14000-2	15	Fuel oil
Linoperamata	Boiler natural circulation Turbine K14000-2	15	Fuel oil
Linoperamata	Rafako 00-110 Jugoturbina	25	Fuel oil
Linoperamata	BREDA two pass Puertollamno	25	Fuel oil
Linoperamata	BREDA two pass Puertollamno	25	Fuel oil
		272.59	
Chania	BBC	132	Diesel
Chania	BBC	16.2	Diesel
Chania	Thomassen PG 5341	20	Diesel
Chania	Fiat TG20	30	Diesel
Chania	Ansaldo 64.3	59.37	Diesel
Chania	Ansaldo 64.3	59.37	Diesel
Chania	GE LM2500	27.95	Diesel
		344.89	
	Grant Total (MW)	812.72	

Table 6: Power Generation by Capacity in Crete

The power demand in Crete has been extrapolated using an escalator factor of about 1% for the period the Gasvessel is going to be operational. The results all shown below.

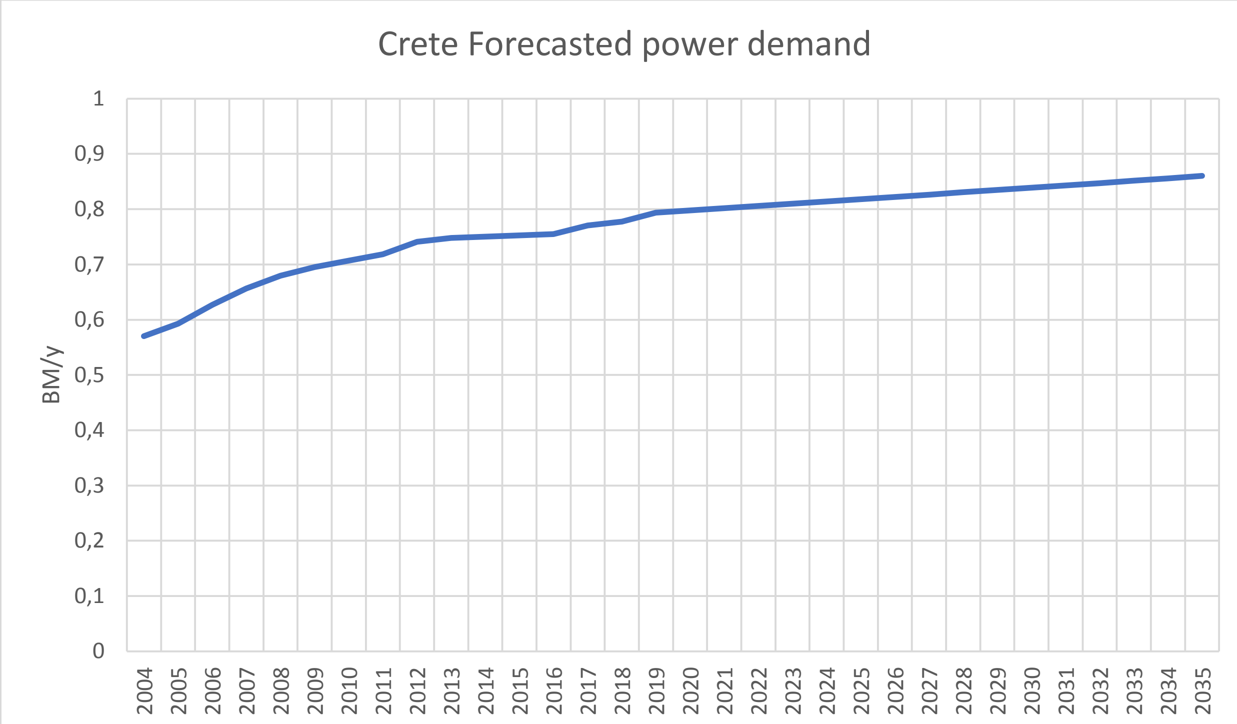


Figure 21: Crete Forecasted gas demand

Demand profile of Crete also follows an upward trend therefore this further justifies our selection of Crete as a sole target market which was also combined with the Cypriot market. More details on the geologistic scenario descriptions and assumptions can be found on the corresponding section.

Supply

Greece imports all of the natural gas it consumes. Imports from Russia are supplemented by Algerian and spot LNG, as well as pipeline gas from Azerbaijan via Turkey. Typically, LNG is used to compensate for pipeline shortages given the lack of gas storage within Greece. As demand spiked in 2017 to a new high due to the cold winter and higher gas-in-power needs, the limitations of pipeline capacity meant that LNG played a central role in meeting Greece's increased gas needs. This was supported by strong demand in other nations served by Russian and Azeri pipeline gas. With the nation's gas import needs rising 27% in 2017, Greece imported 96% more LNG over the period as the increase of Russian flows was limited.

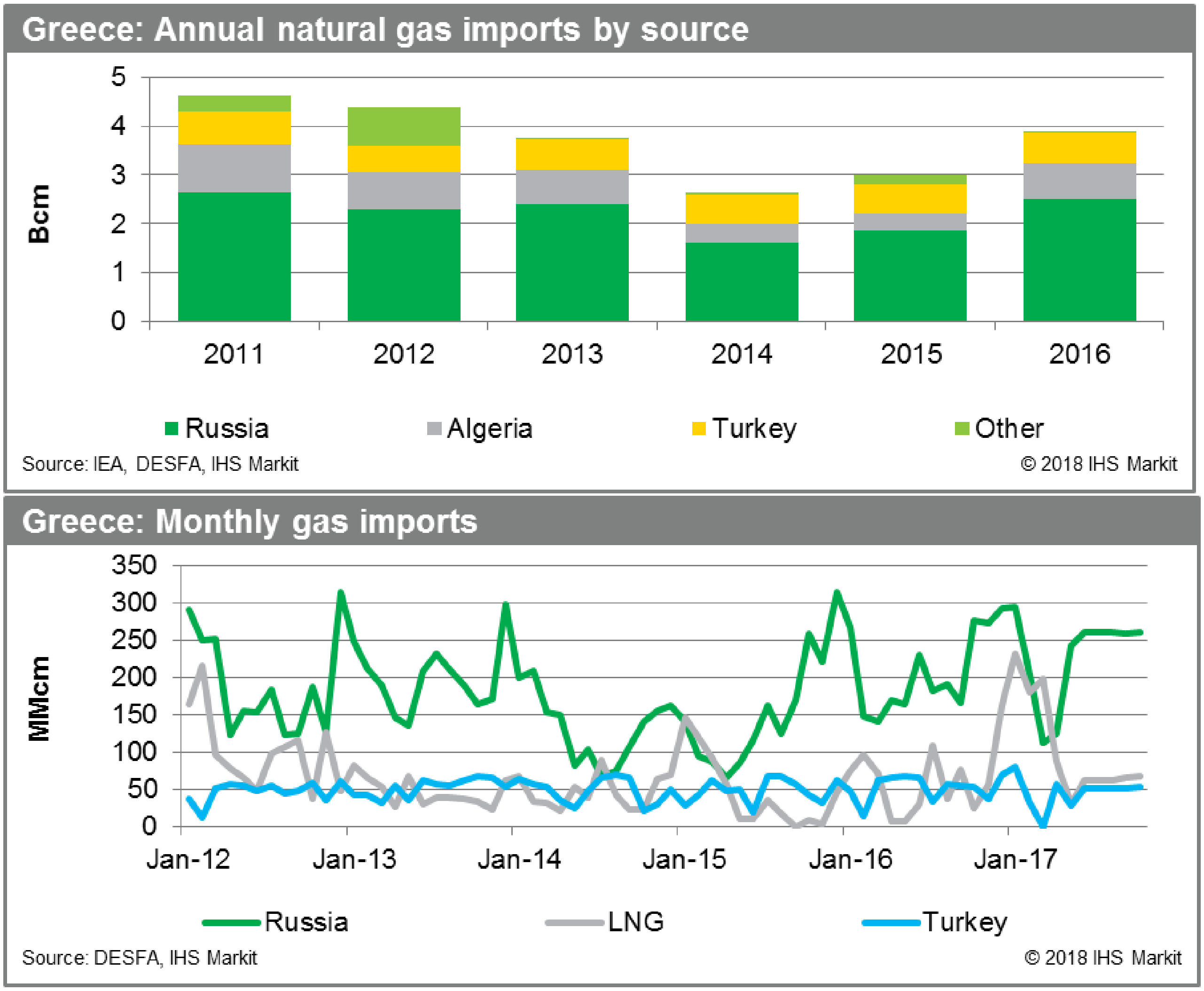


Figure 22: Natural gas imports Greece

Infrastructure

DEPA imports gas from Gazprom (via Bulgaria) at the Sidirokastro access point (3.8 bcm/y capacity). DEPA's original contract, set to expire in 2016, was extended for another ten years in February 2014. The deal provides for a more flexible take-or-pay agreement; Gazprom is now set to supply 2.5-3.0 bcm/y through 2026. The Interconnector Turkey-Greece (ITG) pipeline has contracts in place with DEPA to receive 0.75 bcm/y of Azerbaijani gas resold by BOTAŞ.

Two new pipeline interconnections (as well as three other proposals) could help Greece diversify its supply options and allow it to serve as a key gas transit route. However, the similar routes of TAP and ITGI, as well as questions over maximum demand in Western Europe, make it highly unlikely that all three will be built.

Trans-Adriatic Pipeline (TAP) (under construction): In June 2013, the Shah Deniz II consortium selected TAP over rival Nabucco West to bring Azerbaijani gas from the Trans Anatolian Pipeline (TANAP) to Europe. Its path traverses Greece, Albania and the Adriatic Sea to Italy. DEPA has contracted 10% (1.0 bcm/y) of the pipeline capacity under a 25-year agreement. TAP took FID and began construction in 2015. After delays, the 2020 target start for deliveries to Europe may not be met. With additional compression, the capacity of TAP could be raised from 10 bcm/y to 20 bcm/y. TAP's open-access commitments mean that the pipeline could end up expanding in order to transport Russian gas—delivered to Turkey via the Turkish Stream pipeline, now under construction—to the markets it serves.

Interconnector Greece Bulgaria (IGB) (proposed): IGB would connect the Bulgarian and Greek networks for bidirectional flow and could allow Azerbaijani gas to be delivered from TAP to meet its Bulgarian supply obligation of 1.0 bcm/y. A binding bid phase for capacity in December 2016 yielded firm requests of 1.57 bcm/y for the proposed 3 bcm/y pipeline. This appears to have been sufficient to trigger FID, and operator ICGB targets a 2018 construction start. The two shareholders of the IGB pipeline company are state-owned Bulgarian Energy Holding and IGI Poseidon, a 50-50 joint venture between DEPA and Edison. The IGB is also envisioned as a way for LNG to be distributed through the Balkans after being delivered and regasified at the proposed Alexandroupolis terminal. United States officials have vocally supported the project and offered technical and other support, seeing it as a way to boost US LNG exports and decrease the reliance of Balkan states on Russian gas.

Turkish Stream (under construction): In December 2014, Gazprom re-routed the South Stream pipeline project across the Black Sea to make landfall in Turkey rather than Bulgaria, renaming the pipeline Turkish Stream. Commercial disagreements and a collapse in the Turkish-Russian political relationship in November 2015 stalled the project for nearly a year before rapprochement was achieved. Turkish Stream is envisioned as two parallel pipelines totalling 31.5 bcm/y] in capacity, with roughly 14 bcm/y] of capacity allocated for the Turkish market (replacing current Russian deliveries through the Balkans) with additional capacity targeted at the EU and non-EU southeastern European countries. Various options are being considered for onward deliveries beyond Turkey, with access to TAP expanded capacity as one of the most likely options.

ITGI (proposed): In February 2016, DEPA, Gazprom, and Edison signed a Memorandum of Understanding (MoU) to revive the potential 8 bcm/y ITGI (Interconnector Turkey-Greece-Italy). Plans for the project date back to July 2007. This project would take Russian delivered via Turkey into Greece before reaching Italy via the Ionian Sea, and could allow for Middle Eastern or Caspian gas flows to Europe. In December 2016, Gazprom publicized talks it was having with DEPA and Italy's Edison for distribution of Russian gas to the two nations via Turkish Stream, and the Turkish government gave approval to the pipeline plan in September 2017. However, the existence of a major competitor already under construction in the form of TAP—which will be required to expand capacity if it receives firm commitments—represents a major hurdle to the proposal.

East Med Pipeline (proposed): In April 2017, ministers from Israel, Cyprus, Italy, and Greece signed a declaration supporting the development of a 14 bcm/y pipeline to bring Israeli and Cypriot gas to European markets. In December 2017, the four nations signed another preliminary agreement in support of developing the pipeline, 2025 is the targeted start date.

Figure 23: Greece gas distribution network

Regulations

DEPA controls the country's gas infrastructure via its subsidiary DESFA. DEPA was established in 1988 and its shareholders are the Greek government (65%) and Hellenic Petroleum (35%). DEPA has historically been responsible for 100% of Greece's gas imports. Starting in 2010, however, other players started importing LNG, including Greece's Public Power Corporation (PPC) and M&M Gas (a subsidiary of the private power generator Mytilineos Group, whose Aluminium subsidiary is also an importer).

In June, DEPA relaunched the tender to privatize DESFA via the sale of a 66% stake. As of August 2017, it was reported that six different investment groups had expressed interest, with two bidders shortlisted in September. In December DEPA reportedly pushed back the deadline for the two bidders to submit their offers to February 2018.

Prior efforts to privatize DESFA by selling a 66% stake to Azerbaijan's SOCAR collapsed in November 2016, after it had won a tender in June 2013 for €400 million. Later, due to SOCAR's stake in TAP, EU antitrust regulations forced it to bring Italian gas grid operator SNAM on as a minority shareholder, to reduce its own stake below 50%. However, after the Greek parliament passed a law in July 2016 limiting the country's gas tariff increases in 2017, SOCAR argued that this decreased the value of a 66% stake in DESFA to €260 million, causing a breakdown in the deal.

Prices

Gas prices in Greece can easily be identified given the supply sources which is published information. Gas import prices are Oil Indexed on long term contracts that have over time been renegotiated. Greece is also importing LNG on spot trading and those prices are related to the effective international spot prices at the time. A fair gas price assumption for Greece would be the 13.5% Brent indexation.

Although most of the gas is being used for power generation there still is a significant amount of fuel and diesel oil power generators in the Attica region and most importantly in the Aegean region of Greece where high-populated islands are located with domestic power production which are disconnected from the power grid.

Some of those power plants which for the Gasvessel project, the exact locations have been identified are the primary and only targets for the CNG concept for the Greek market. All the details on the target market location are described in detail in the geologistic scenario for Greece. Since those power stations are either using Diesel or Fuel for power generation we hereby plot a Brent curve with gas equivalent price for comparison purposes. We can easily convert the imported prices into $/mmbtu for safe comparison with the landing prices of the Gasvessel. Additionally we can forecast the values using the Brent forward curves. The results are shown on the below graph.

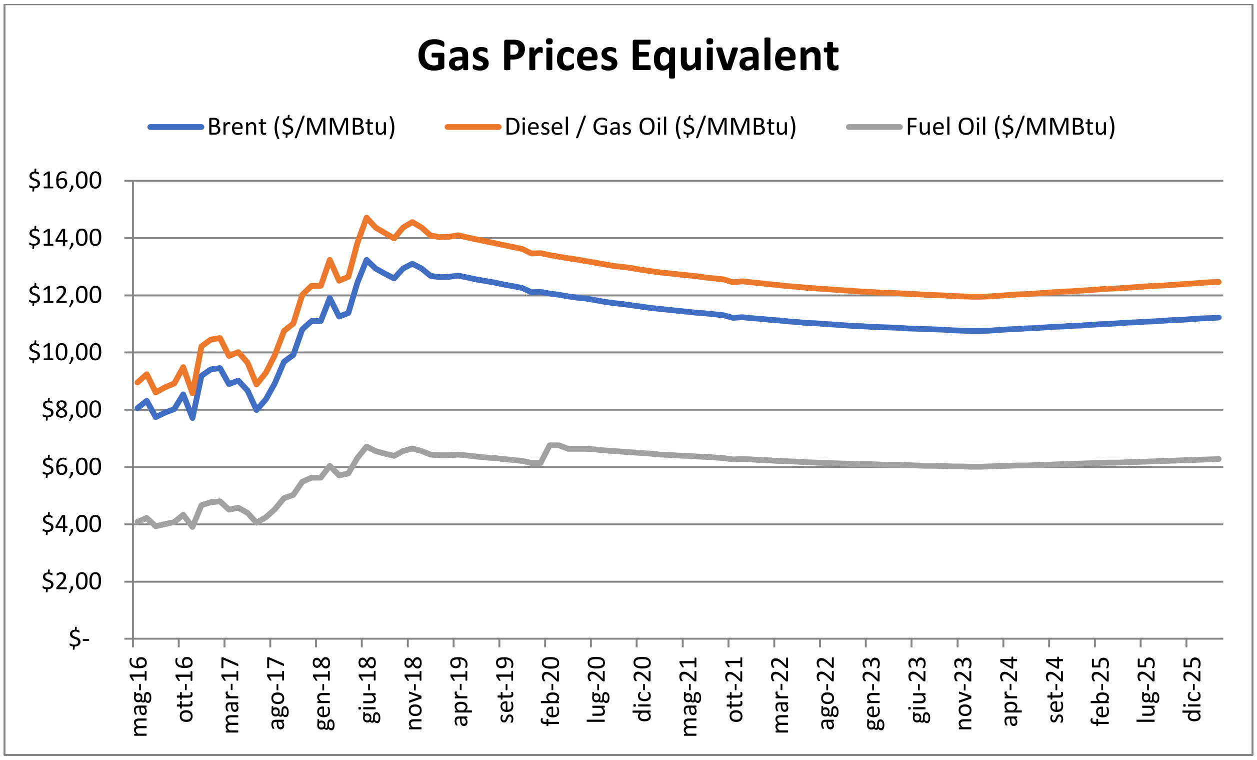
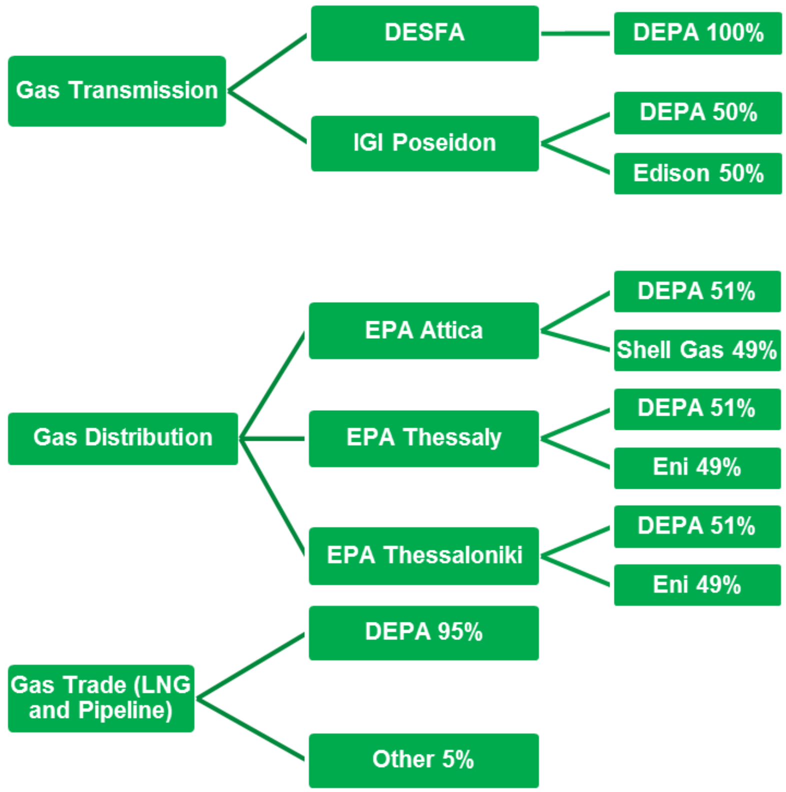


Figure 24: Forecast prices for Brent and Oil Equivalent

For the Gasvessel the value of the above lies on the set of the upper price limits, on fuel oil first as a cheaper substitute and on diesel oil as the second best choice as the direct competitors of CNG. CNG has to compete with the above values.

Players

In Greece, independent importers rely more on LNG imports than their DEPA counterpart, which dominates the pipeline import market. Despite an initial decrease in DEPA’s market share with the liberalization of gas imports in 2010, large increases in Russian pipeline imports 2011-2013 led DEPA to regain market share.



Summary

This proposal could be investigated in two different case studies;

a) Gas from the offshore gas location is transported to Cyprus by offshore pipelines to feed Cyprus' domestic needs and the resulting surplus to be converted into CNG and shipped from the proposed Vasilikos Energy Port to Crete.

b) Offshore gas loading location to serve directly both Cyprus and Crete under the Gasvessel concept by optimizing the intermediate value chain dictated by the number of vessels, use of storage facilities, etc.

Application	Volume	Loading Location	Unloading Location
Gas for Power	1.41 mmscmd (50 mmscfd) 2.83 mmscmd (100 mmscfd)	Offshore location	Linoperamata Port 35.35 Latitude 25.05 Longitude Vasilikos Energy Port 34.73 Latitude 3.29 Longitude
Gas for Power	1.41 mmscmd (50 mmscfd)	Vasilikos Energy Port	Linoperamata Port 35.35 Latitude 25.05 Longitude

2.4.3 Lebanon

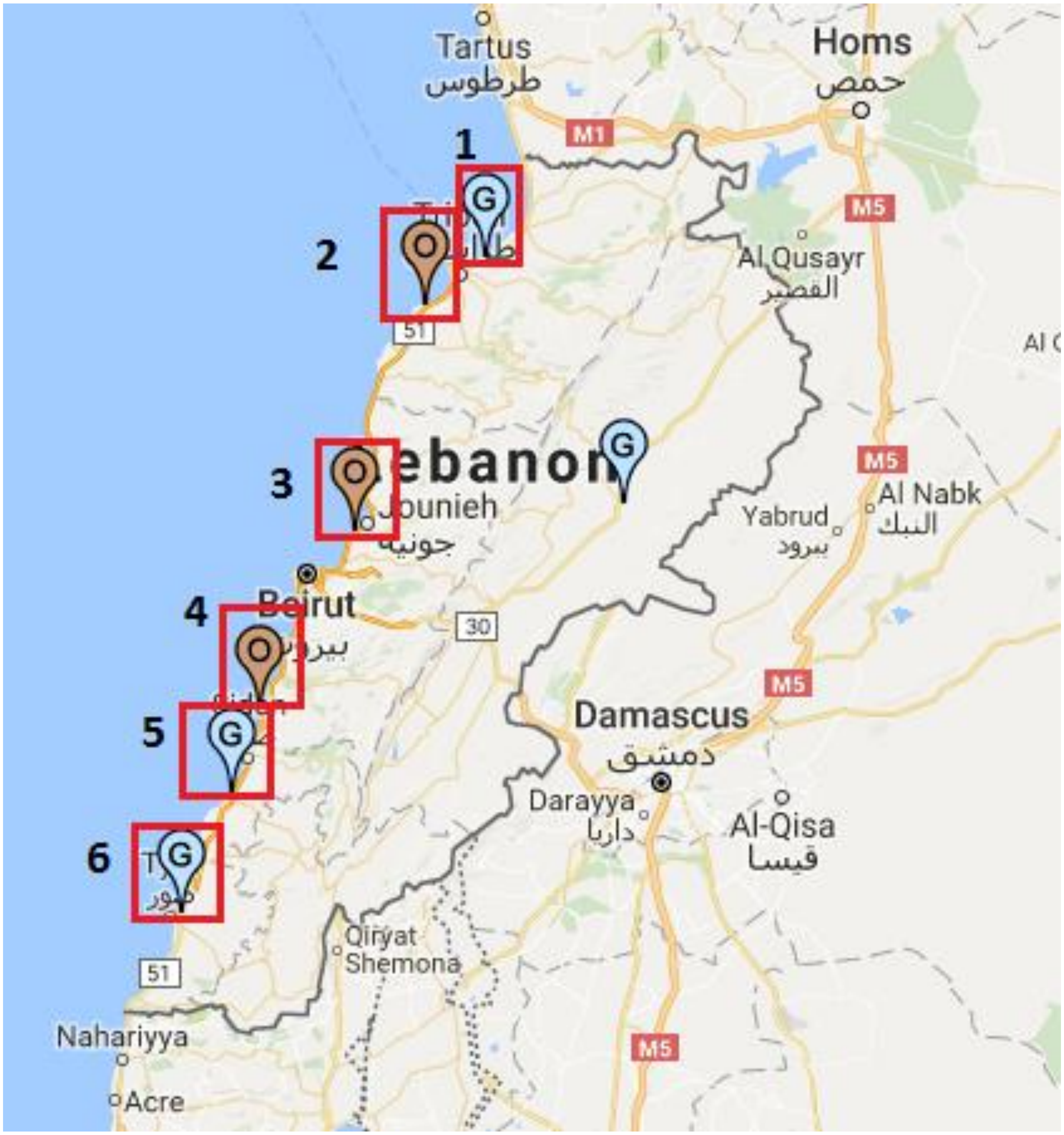


Figure 25: Lebanon's Power Plants[11]

Lebanon has seven power plants that operate today using liquid fuels. Even though, European regulations for switching oil power plants to gas for environmental mainly incentives may not apply for Lebanon, the country has introduced gas in its energy mix by converting four of its power plans to burn gas due to a combination of reasons including economic and energy security in supply motives. The move of partially gasifying the market was a concept which was initially developed in Lebanon during the operation of the Arab pipeline that connected Lebanon, Syria and Jordan to the Egyptian gas export network[12].

Furthermore, when the export production from Egypt stopped in 2011 Lebanon continued its plans to introduce gas into the market by evaluating the option of investing in a regasification terminal[13]. The figure below shows the location of the power plant that CHC included in the list of proposed target buyers. In addition, tables 29-34 in the Appendix (Appendix A, section V) compile characteristics of the proposed power plants such as distances from the gas loading sites and their power demand in gas[14].

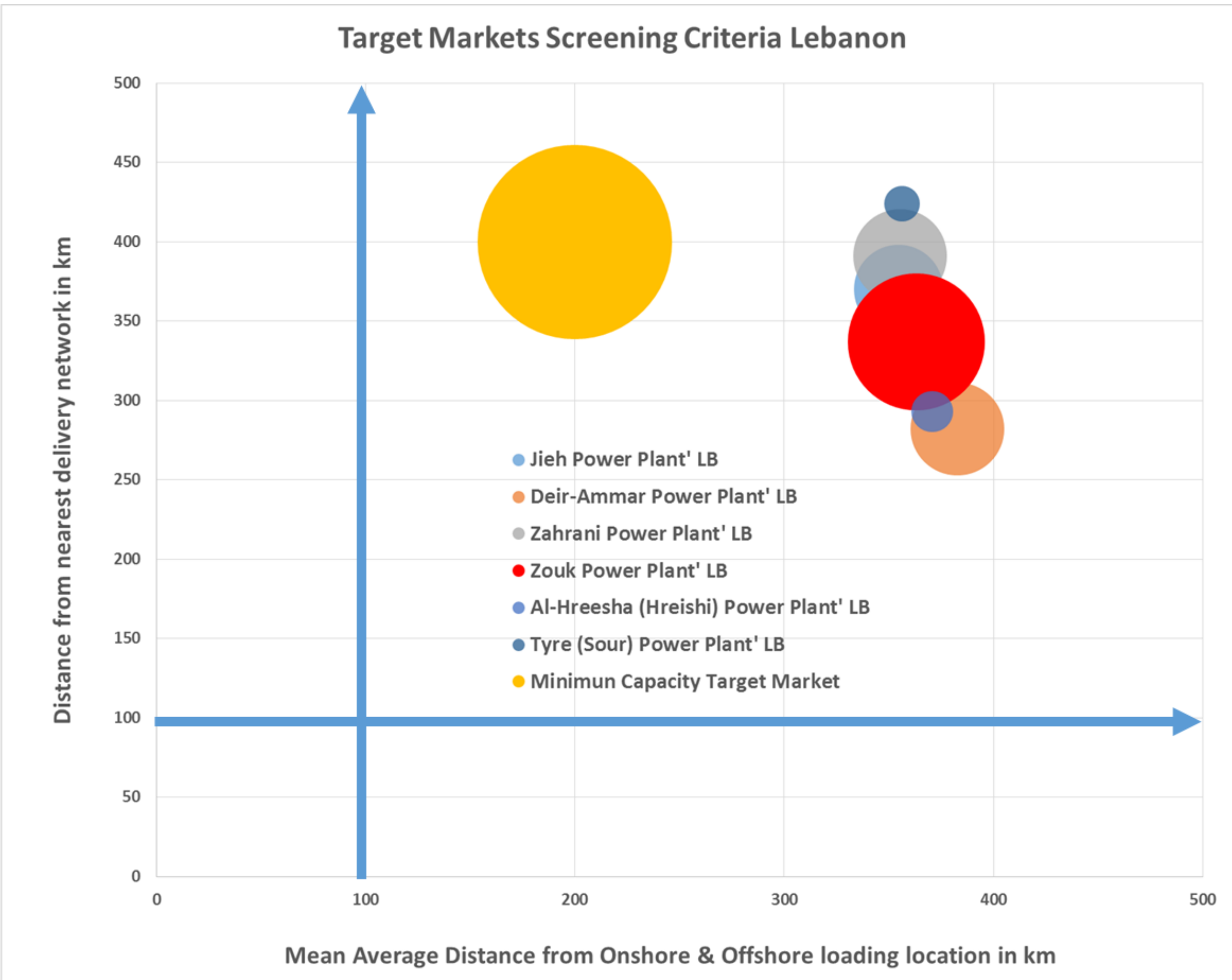


Figure 26: Power Plants in Lebanon based on market screening criteria

Lebanese gas power plants are all within the battery limits on distances according to our screening criteria. On the other hand, by analysing Lebanon's potential gas demand based on its power plant installed capacities and assuming the energy efficiencies and load factor as for the cases in

Cyprus and Crete, none of the plants alone can match the minimum upstream criteria, as Figure 26 shows.

However, all the proposed power plants are located along the coastline of Lebanon thus reducing complexity when investigating the idea of combining the demand volumes of the plants. It is interesting to note that with only one gas entry point near the Zouk terminal port, approximately in the middle of the Lebanese coastline, we can not only serve the biggest power plant, that of Zouk, but with onshore gas connection running along the coastline in the north and south of the country, can also feed the remaining plants. Furthermore, due to the close proximity with Cyprus, CHC proposes to investigate the Lebanese market together with the gas feeding market of Cyprus.

This proposal could be investigated in two different case studies;

a. Gas from the offshore gas location is transported to Cyprus by offshore pipelines to feed Cyprus' domestic needs and the resulting surplus to be converted into CNG and shipped from the proposed Vasilikos Energy Port to Lebanon.
b. Offshore gas loading location to serve directly both Cyprus and Lebanon under the Gasvessel concept by optimizing the intermediate value chain dictated by the number of vessels, use of storage facilities, etc.

In contrast to the proposed coastal power plants, Lebanon also has a number of other power plants which are not situated near the shore, as well as industrial players in the energy market that may present market opportunities for the Gasvessel concept. However, due to the lack of adequate distribution channels, it is not recommended to investigate the Lebanese industrial players independently from the existing gas infrastructure or the remaining power plants in land. CHC recommends instead prioritizing on the power plants located in the coastal areas to allow easy access for the Gasvessel. The enlarged potential of the Lebanese gas market will be investigated gradually, but at this stage, CHC proposes an indicative volume of 3.67 mmscm/day (130 mmscfd) in gas demand to be used for the time being.

Lebanon Supply and Demand Profile

Natural gas has played a very limited role in Lebanon's energy mix. The main constraint to the penetration of natural gas in its energy mix has been a lack of access to gas supplies. Lebanon has no proven natural gas reserves and its options to import gas from neighbouring countries have been limited. Furthermore, relatively low world market prices for oil during the 1980s and 1990s reduced the incentive to switch from the use of fuel oil in the power sector. Rapidly growing electricity demand and higher prices for crude oil and petroleum products in international markets from the mid-2000s, however, contributed to a reconsideration of Lebanon's energy supply options throughout the last decade. As end-user electricity prices are essentially determined by the government (at levels significantly below the full cost of generation) the state-owned power generating sector budget can save a significant amount of money by switching from oil to gas. The Ministry of Energy and Water (MEW) estimates that at the price of €76.34 ($90) per barrel, Lebanon can save €1.61 ($1.9) billion on its annual fuel bill if it switches its power generation to gas[15].

Demand

Despite the potential penetration of gas in other sectors of the economy, the future evolution of natural gas demand will be strongly interlinked with that of electricity demand. From 2000 and 2009, electricity demand in Lebanon increased at an annual average rate of 5.3%, slightly higher than the average real GDP growth rate during this period. This average number, however, masks some important trends, as most of the growth in electricity consumption occurred in the earlier years of the period. For instance, between 2004 and 2009, net electricity consumption grew on average by 2.15% per annum while real GDP expanded at an annual average rate of 5.7%. In Lebanon, installed Power Generation capacity effectively stagnated during the 2000s, increasing only marginally from about 2,29 MW in 2000 to 2,31 MW in 2009, equivalent to an average annual growth rate of only 0.25% during this period. Lebanon Electricity network also suffers from chronic underinvestment, which has prevented modernization of the grid and expanding power generation capacity. The slow pace of expansion in new generation capacity in the face of rapid electricity demand growth has had a large impact on the quality of electricity supply in Lebanon; estimates suggest that residential consumers suffer up to two hundred twenty days of interruption per year — the worst record in the MENA region. A similar situation prevails in the industrial sector which, despite heavy investment in private power plants for backup supplies, still suffers huge financial losses from power supply interruptions.

The Lebanese government has very ambitious plans to increase the share of gas in the power generation mix. A 2010 policy paper for the electricity sector prepared by the MEW proposes a diversified fuel supply, with an ambitious plan to increase the share of natural gas from its current level of zero to two-thirds of the fuel mix by 2030[16].

Government estimates that Lebanon's gas demand will reach 2.6 bcm/y in 2020, increasing to almost 4 bcm/y by 2035. The MEW puts the figure at the higher level of 5.8 bcm/y by 2030. The MEW also has ambitious plans to extend the use of natural gas to the industrial, commercial, and residential sectors, and to convert the nation's ground transport fleets to compressed natural gas (CNG). It is hence safe to assume that the power sector will remain the main source of gas demand.

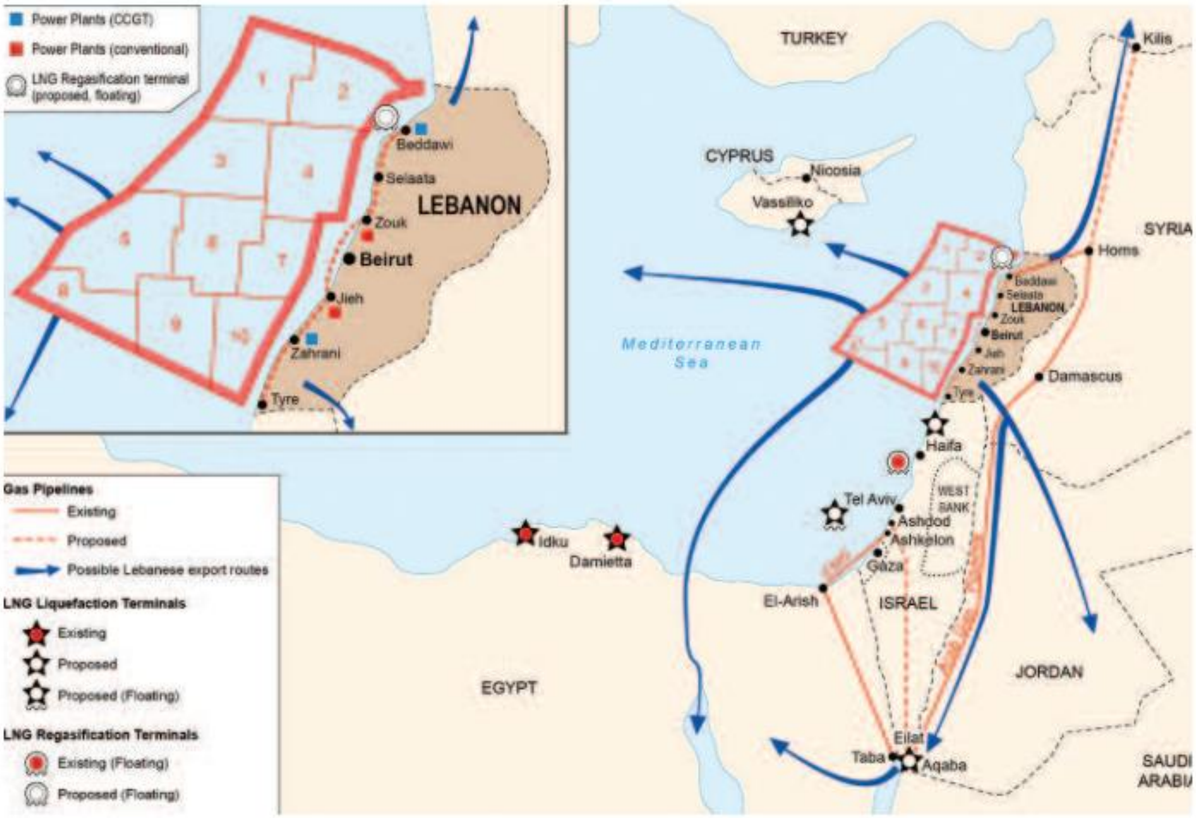
Supply

The main historical barrier to raising the share of gas in Lebanon's energy mix has been access to gas supplies. Natural gas entered the energy mix for the first time in 2009 when the Arab Gas Pipeline (AGP), which also supplies Jordan, started supplying some 200 mmcm of Egyptian gas to the Beddawi power plant. However, the entry of natural gas was very brief. Since 2009, the flow of Egyptian gas has been subject to frequent disruptions due to delays in payments and more recently due to a series of explosions targeting the AGP. The last delivery of Egyptian gas to Lebanon was made in November 2010, while Jordan has since been subject to frequent delivery cuts, reductions in contract volumes, and parallel price rises[17]. Due to political turmoil Arab Gas Pipeline (AGP) never resumed gas deliveries to Lebanon since 2010.

Other neighbouring countries seem increasingly short of gas themselves. In 2003, Lebanon signed a 25-year contract with Syria to import about 1.5 bcm/y of natural gas[18]. However, Syria has not been able to supply Lebanon with gas, as its production has not been sufficient to meet domestic consumption, and the country's ongoing civil conflict at the time of writing casts substantial doubt over Syria's ability to significantly change its natural gas supply picture within the next decade. Iran has been discussed as a potential gas supplier to Lebanon. A pipeline project carrying up to 25 bcm of Iranian gas to neighbouring Iraq and Syria (the 'Islamic pipeline') could have turned into a lifeline for Lebanon's gas industry. However, since its announced construction launch in November 2012, the project has suffered from a series of funding issues and from practical aboveground issues related to the continuing complicated security situation in Iraq and, since 2011, the deteriorating political and security situation in Syria. Similar considerations could be applied to eventual gas imports via Turkey, possibly with gas supplied by Russia, Azerbaijan, or Iraq. Plans for the connection of the existing AGP to Turkey have been discussed for many years and would, in practice, be straightforward and cost-effective, particularly when compared to more capital- and infrastructure-intensive LNG imports.

Infrastructure

For a short period, Lebanon imported natural gas from Egypt through Syria to generate electricity, using the Arab Gas Pipeline. However, natural gas imports were suspended in 2010 due to events in Egypt.



Source **Oxford Institute for Energy Studies**

Figure 27: Gas infrastructure network Lebanon

Regulations

Detailed information on regulations in Lebanon will follow in coming Work Packages.

Prices

A more detailed analysis concerning prices in Lebanon will follow in coming Work Packages.

Players

A detailed summary of the major players in the energy and natural gas industry in Lebanon will follow in upcoming Work Packages.

Summary

This proposal could be investigated in two different case studies;

a. Gas from the offshore gas location is transported to Cyprus by offshore pipelines to feed Cyprus' domestic needs and the resulting surplus to be converted into CNG and shipped from the proposed Vasilikos Energy Port to Lebanon.

b. Offshore gas loading location to serve directly both Cyprus and Lebanon under the Gasvessel concept by optimizing the intermediate value chain dictated by the number of vessels, use of storage facilities, etc.

Application	Volume	Loading Location	Unloading Location
Gas for Power	3.67 mmscmd (130 mmscfd) 2.83 mmscmd (100 mmscfd)	Offshore location	Zouk Port 33.973828 Latitude 35.602965 Longitude Vasilikos Energy Port 34.73 Latitude 3.29 Longitude
Gas for Power	3.67 mmscmd (130 mmscfd)	Vasilikos Energy Port	Zouk Port 33.973828 Latitude 35.602965 Longitude

Table 7: Summary of the Lebanese Market

2.4.4 Egypt

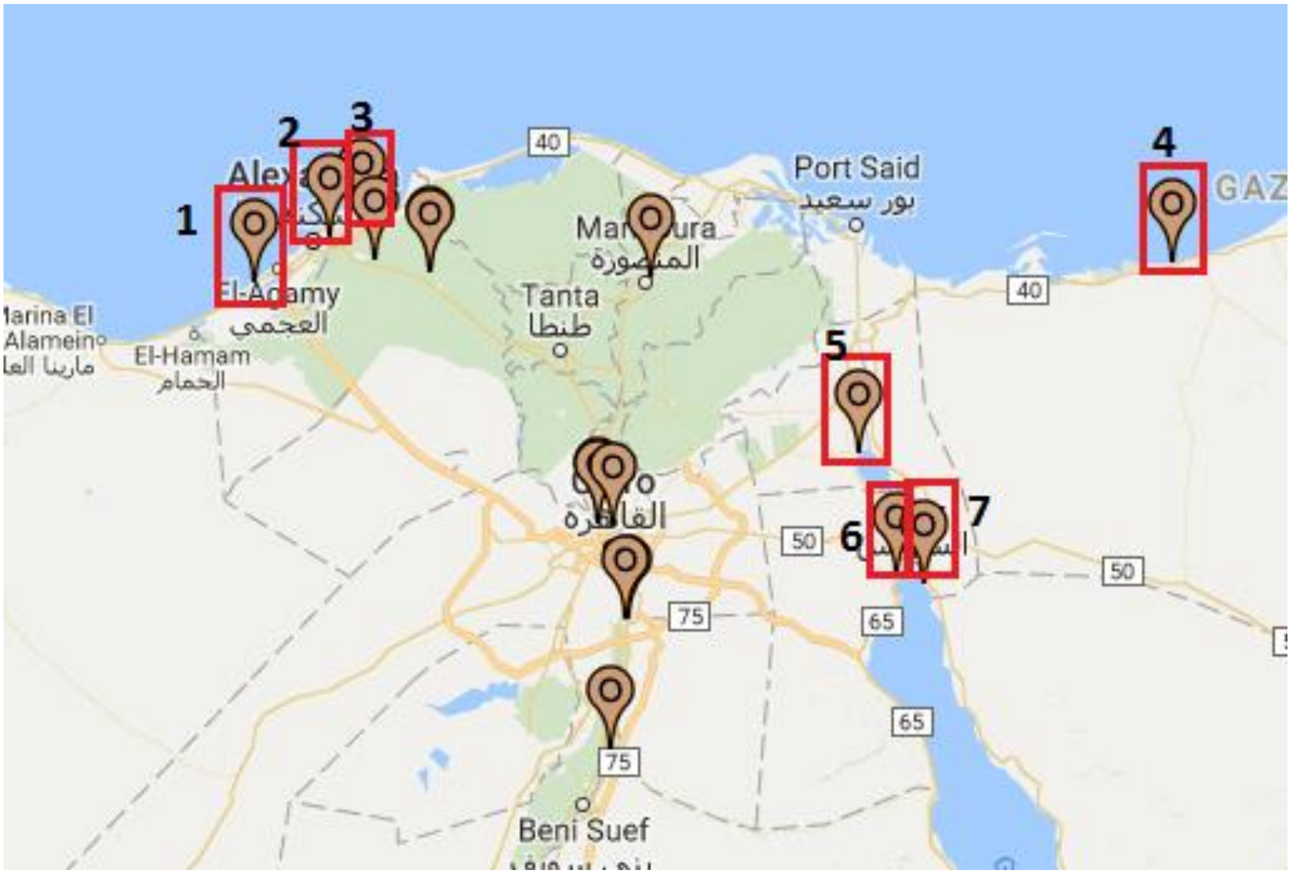


Figure 28: Egypt's Oil Power Plants[19]

Egypt is a gas producer that has historically covered its domestic needs and also exported gas in the form of LNG. Its growing domestic demand in combination with decline of gas production has reversed Egypt from an exporter to a gas importer. The above situation as well as its close proximity to Cyprus makes the Egyptian market an interesting target to look in terms of power demand as well as demand from heavy industries[20].

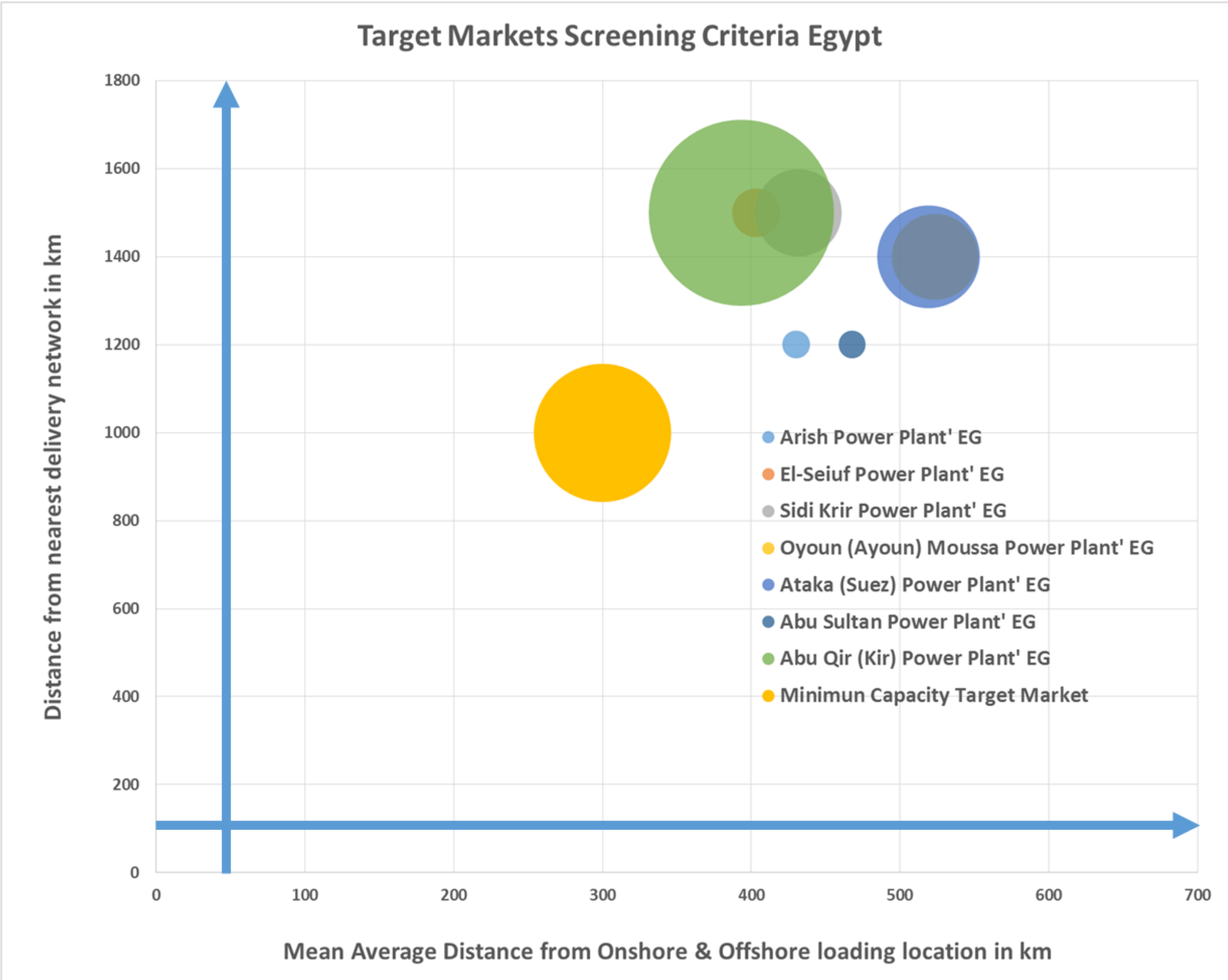


Figure 29: Power Plants in Egypt based on market screening criteria

Figure 28 shows the proposed oil-fired power plants following the target screening methodology thus emphasizing at power plants located at Mediterranean coastline and along Suez Canal, while tables 35-41 in Appendix A, section VI, represent their technical characteristics.

All the proposed plants meet the screening criteria on distances from the loading sites and the distances from an established gas network (the distance here was estimated from the transmission lines passing south of Turkey), however, only one plant meets the upstream criteria of the minimum target capacity in gas demand, Figure 29. Abu Qir power plant is located by the Mediterranean coastline west of Alexandria and very near to the Port of El Maadiya. This is the only plant which could be a single gas buyer for the Gasvessel project. Furthermore, we could combine the capacities of all the proposed plants in Egypt as in previous cases; however, at this point we should deviate from the initial approach and look at Egypt as a potential gas buyer at a bigger scale because of the extensive domestic gas transmission network and the regulatory changes that are currently underway regarding the gas market.

After a decade of regulatory and energy policy changes, Egypt is now back on track as the largest and fastest growing natural gas market in Africa and, in parallel, is enjoying a re-invigorated upstream gas sector based on the giant Zohr discovery, go ahead for West Nile Delta (WND) and a range of other gas developments. Despite the current global oversupply of gas and the number of large regional gas resources that depend on a large demand market, the Egyptian natural gas market is still attracting considerable interest from major players, a recent example is BP's (10%) and Rosneft's (30%) acquisitions of stakes in Zohr.

Egypt Supply and Demand Profile

Egypt is the most mature and gasified from all the target markets in the East Mediterranean geologistic scenarios. Its established pipeline network covers internal distribution and is also connected to neighbouring countries. It is a country with historically significant gas supply and demand profiles that are subject to various economic and geopolitical factors.

Demand

Egypt's domestic demand grew by an average of 10% per year between 2002 and 2009, driven by an aggressive gasification of the power generation fleet as well as by low gas prices. The power sector now makes up over half of all gas demand, overtaking the industrial and petroleum sectors.

Domestic consumption fell for two consecutive years between 2013 and 2015, as scarcity prompted the industrial sector to cut back its gas use significantly and the power sector increasingly turned to fuel oil to make up for the gas shortage.

To meet demand growth, Egypt began favouring the domestic market over its export requirements, slowly cutting off most pipeline exports, and then LNG exports from first Damietta LNG and then Egyptian LNG (ELNG), the latter of which has been operating at a fraction of capacity in 2016-2017 after sitting idle all of 2015. This move was accentuated by political changes which saw the increasing prioritization of domestic needs in order to maximize power availability and limit the duration of power cuts.

Power demand growth was over 5% per annum until 2012, and only then stalled because of the shortage of gas. Over the next 10 years, Egypt's population (currently around 92 million people) is set to grow by over 12 million and GDP by about 4% per annum. Population and economic growth, both key drivers of electricity consumption, are combining to create strong increased demand. Hydropower is arguably exhausted and, although there is a push for renewable generation, over the next 8 -10 years, the only viable option for large-scale power is gas, hence gas demand growth therefore is both very substantial and sustainable.

As a developing economy, the projections of growth in the gas-fired power generation sector in particular, correlate well with other nations that have followed a similar path of economic development. For example, in the US the measure of installed capacity per capita is around 3.5

GW per million of population, in the UK it's 1.34, in Turkey it's 0.8, while in Egypt today it's 0.3. Based on the long-term planning goals of the power authority, according to Gaffney, Cline & Associates (GCA), with an expectation to reach around 80-96 GW, dependent on energy efficiency by 2035, still looking at a figure less than the UK, and not much more than Turkey today.

Poor fiscal incentives have been stifling growth within the Egyptian industrial and electric power segments. For natural gas demand from power and industrial sectors to continue to grow, a stable energy policy, appropriate economic reward for investors, and additional confidence in the Egyptian market will need to be underpinned with steady investment and a more stable outlook generally for the country.

Gasification of cities remains a key policy, and one that has stood firm amidst many other policy setbacks. Over the last decade, in spite of considerable disruption, the Egyptian Government has prioritised development of the gas transmission system and the connection of large numbers of new customers; this is expected to continue, as it is a main pillar of the Government's goal to eradicate fuel subsidies (especially related to LPG, diesel and fuel oil). Despite the extension of the Egyptian gas distribution system (currently around 4 million connections) and plans to target 6 million connections assisted by World Bank funding, residential gas demand is relatively small.

For the chemical and industrial sectors, the view is that the growth potential is less certain. Media reports indicate a history of gas supply restrictions to gas consuming industries due to insufficient supplies and in the medium term there may be confidence issues in supply, even with Egypt's one LNG FSRU in operation. One positive is that cement manufacturers have been granted direct access to gas supplies from the FSRUs by paying a blend of the regulated rate and the international price, a kind of forerunner to market deregulation. Probably the most positive aspect of all round industrial and chemical demand is the proposed unbundling of the Egyptian gas transmission system. This should provide a big incentive for companies to negotiate their own supplies, creating a much more robust basis for growth.

In summary, significant gas demand growth is likely to be driven by growth in gas-fired power generation, growing industrial and chemical sector demand and an increased requirement for gas for LNG exports (at least in the medium term) from re-starting of liquefaction plants. The mid-case demand scenario shows gas demand in excess of supply by 2021 (deficit up to 0.2 bcfd by 2025 and 11 bcfd by 2035).

In the absence of new, low cost gas in Egypt, an increasing supply / demand gap could emerge. The outlook for Egypt can broadly be divided into two timeframes, characterised by the period from the present day to the early 2020s, and the period thereafter.

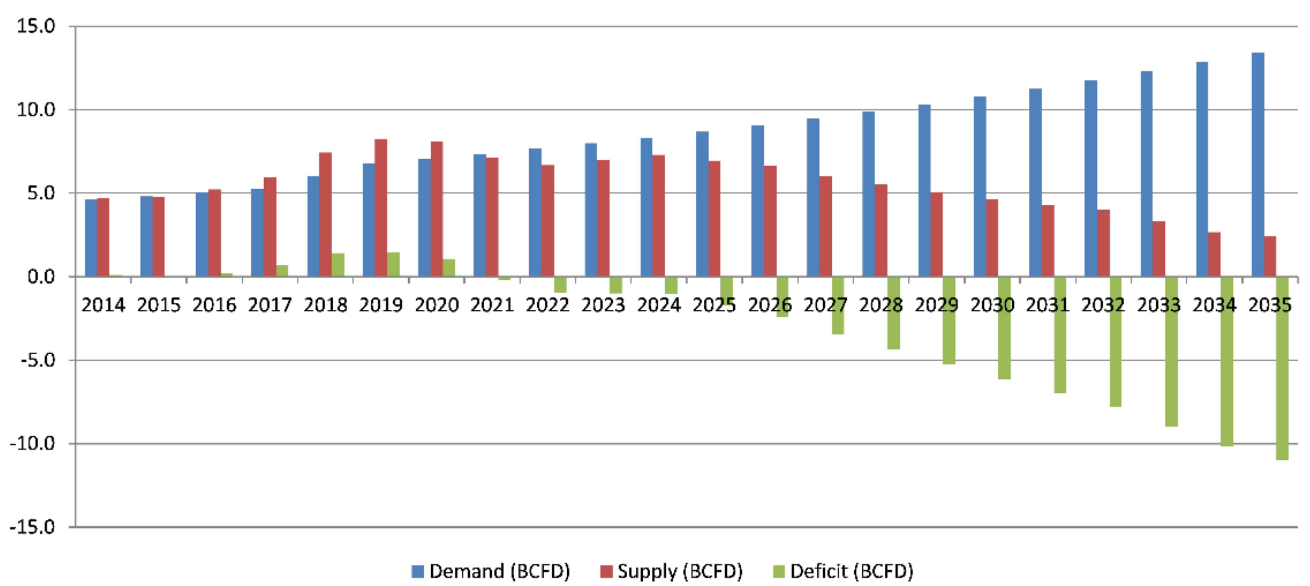
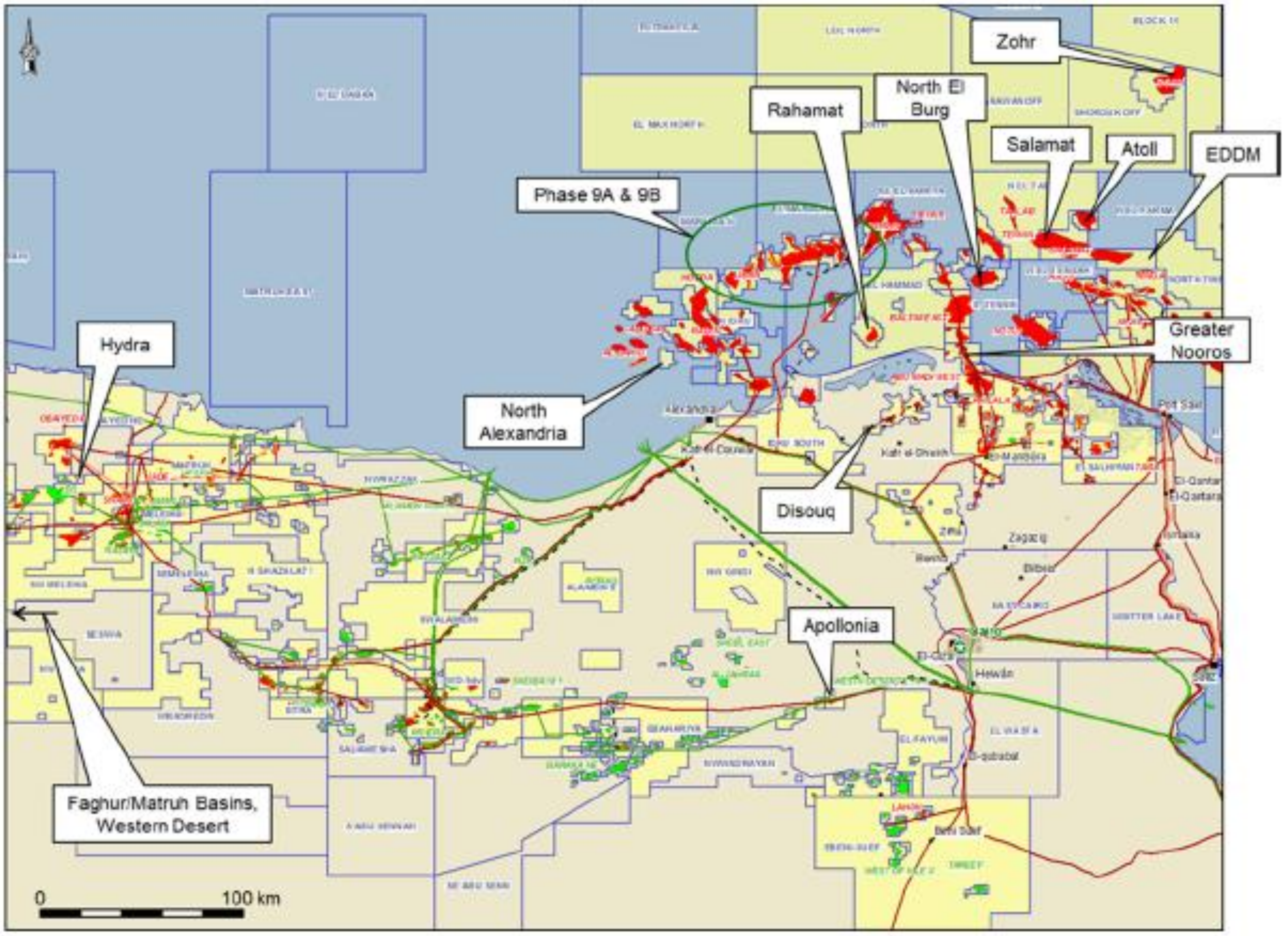


Figure 30: GCA's Mid case Supply/Demand forecast for Egypt[21]

As shown on the above figure, in the short to medium term, the chronic shortage of natural gas that has arisen as a result of reduced development caused by perceived political and commercial risks is addressed with LNG imports, being sought on a fast-track basis. Risks have reduced and therefore upstream investment is being delivered at an exceptionally rapid rate.
Longer term, as the chronic supply shortage is alleviated, based on our supply / demand analysis, is anticipated that Egypt will be able to secure substantial, cost effective domestic and regional gas supplies from Zohr and other developments, largely via pipeline connections within the Eastern Mediterranean.

Supply

Egypt has a long history of gas production growth; however, data from EGAS illustrates that gas production peaked at 170 mmscmd (6,100 mmscfd) in 2009. After this time, production then declined by around 30% to reach 120 mmscmd (4,300 mmscfd) in 2015. Existing fields are projected with production declines and the potential to bring on new fields from 2017-2035.
The recent Egyptian production decline will be halted in the near-term by development of gas resources near to existing infrastructure, supplemented by further developments including BP's WND and ENI's Zohr



Source: Wood Mackenzie PetroView

Figure 31: Existing Oil and Natural Gas Fields in Egypt

Gaffney, Cline & Associates (GCA) has run some forecast on various supply scenarios and the mid-case supply scenario suggests a peak supply of around 220 mmscmd (8 bcfd) in 2019/2020, and an ability to maintain gas availability at greater than 170 mmscmd (6.0 bcfd) until 2024. Adding in known, but as yet unsanctioned, gas developments could extend such rates until at least 2027 even without importing gas from neighbouring East Mediterranean gas discoveries outside of Egypt. As Figure 30 suggests, this could imply covering a deficit of about 84 mmscmd (3 bcfd) by the year 2027.

Several International Oil Companies (IOCs) have declared their commitment to invest billions of dollars within the Egyptian waters and adjacent territories, Israel, Lebanon and Cyprus with the potential to completely eliminate the decline in regional supplies up to 2035 or beyond. Figure 32 shows the future supply growth potential of the existing and under development fields in the Egyptian waters.

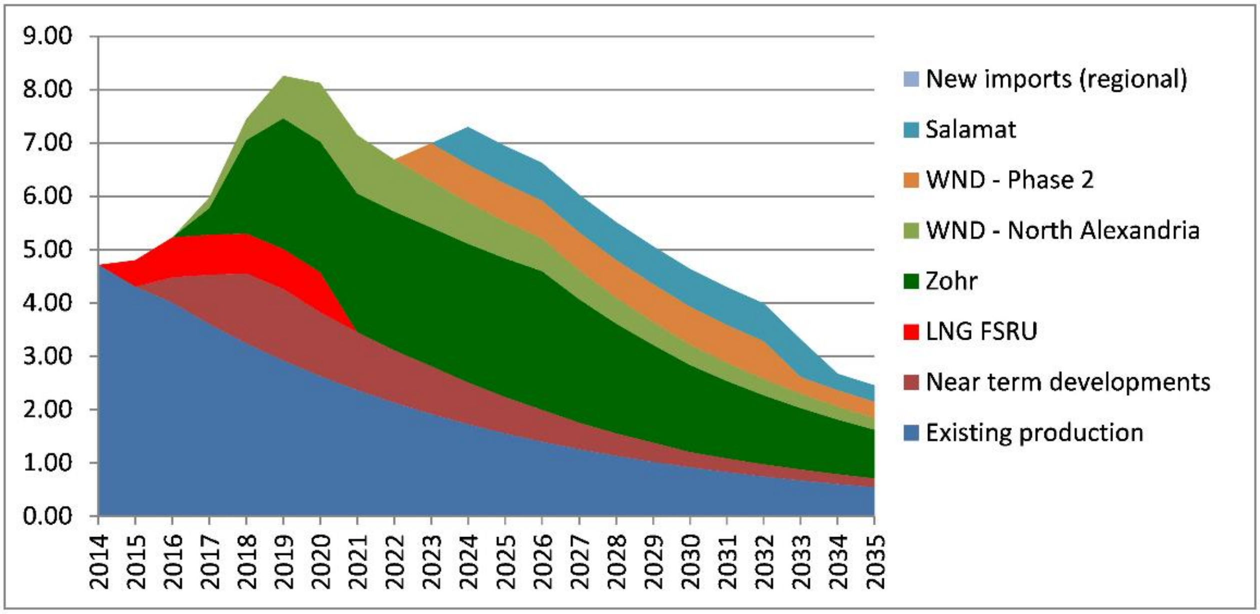


Figure 32: GCA's gas supply forecast for Egypt (mid-case scenario) in Bcf

Infrastructure

Major gas discoveries in the 1990s have contributed to the gasification maturity of Egypt's Oil and Gas sector and as mentioned above, Egypt is the most advanced target market for the Gasvessel project when it comes to infrastructure and legislations.

Egypt first began exports via pipeline in 2004 via the Arab Gas Pipeline (AGP), starting with exports to Jordan and following with an extension to Syria and Lebanon in 2009. Exports to Israel via the El Arish-Ashkelon pipeline started in 2008. Egypt also has two liquefaction facilities: Damietta LNG and Egyptian LNG (both online in 2005). However, as production growth began to slow, Egypt placed a moratorium on new export projects in 2008.
Both pipelines have suffered from repeated attacks since early 2011. Even prior to the attacks, the AGP's 28.25 mmscmd (1 bscfd) capacity and El Arish-Ashkelon's 19.21 mmscmd (680 mmscfd) capacity were highly underutilized. In April 2012, due to intense public opposition amid supply shortages at home, EGAS cancelled its contract with Israel. LNG utilization also dropped; Damietta was shuttered in 2012.
With domestic production recovering in H2 2016 and supply security bolstered by LNG imports, ELNG loaded 9 cargoes in 2016-7, after having been idle since end of 2014. After having set a target of loading a cargo every 20 days, ELNG had no loadings until the end of March in 2017, though it has followed an accelerated pace since, reaching 6 cargoes in 2017.

Additionally, in terms of regasification capacity Egypt has recently installed two FSRUs in the Gulf of Suez at the Northern end of Red Sea coast.

In April 2015, Egypt received its inaugural floating storage and regasification unit (FSRU), nearly three years after issuing its first FSRU tender. The Höegh Gallant—which has a regasification capacity of 15.54 mmscmd (550 mmscfd)—arrived under a five-year charter laden with Egypt's first LNG cargo. It is moored at the port of Ain Sokhna, in the Gulf of Suez.

With its LNG needs rapidly increasing, Egypt signed a charter with BW Gas for a second FSRU—the BW Singapore—four months after receiving its first one. The FSRU arrived in Egypt in late September 2015, and started commercial operations in October. Like the Höegh Gallant, it was moored at the port of Ain Sokhna.

The map below shows the existing pipeline network in the country as well as the two recently installed FSRUs in the Gulf of Suez.

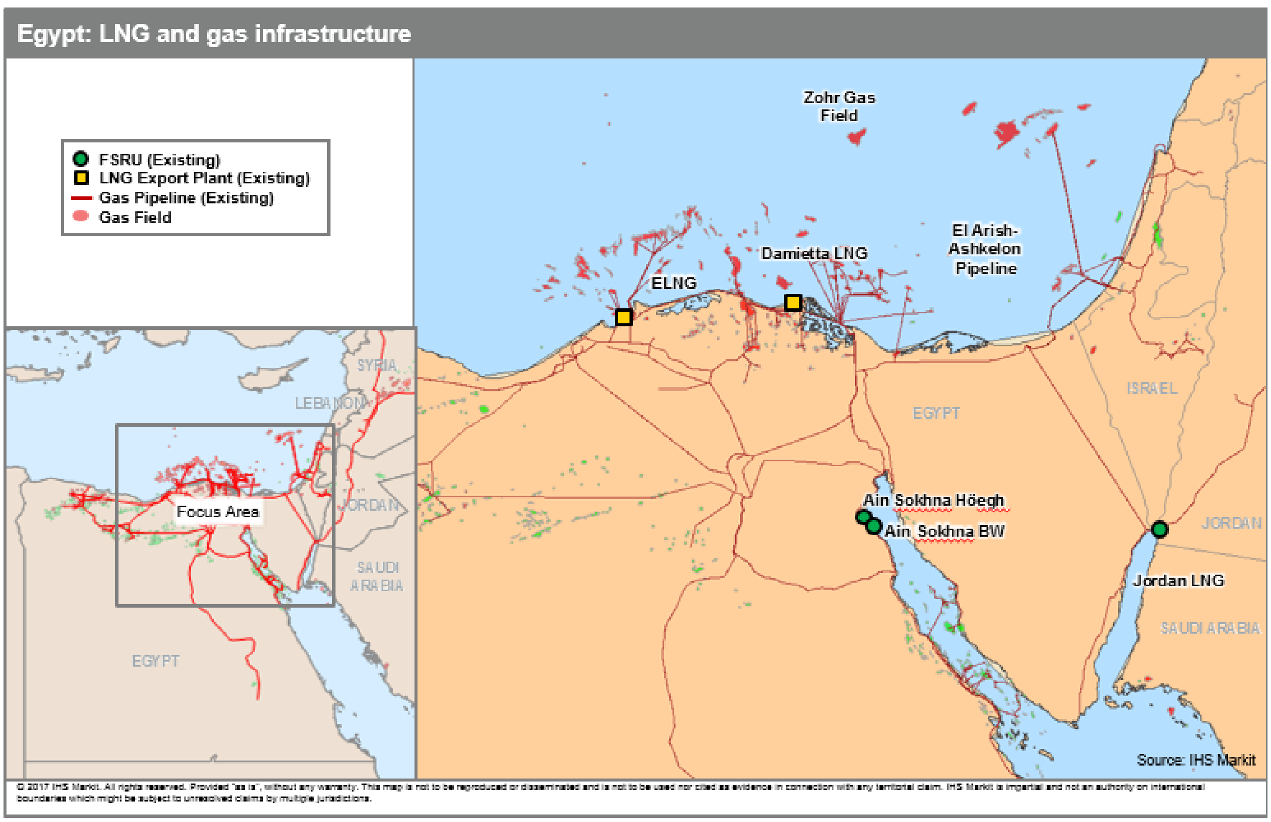


Figure 33: Egypt LNG and Gas Infrastructure

In combination with the above and by having a more detailed look at the country's existing infrastructure, for the purpose of the Gasvessel project we mapped the below gas processing facilities along with the corresponding operator and the capacity of each facility.

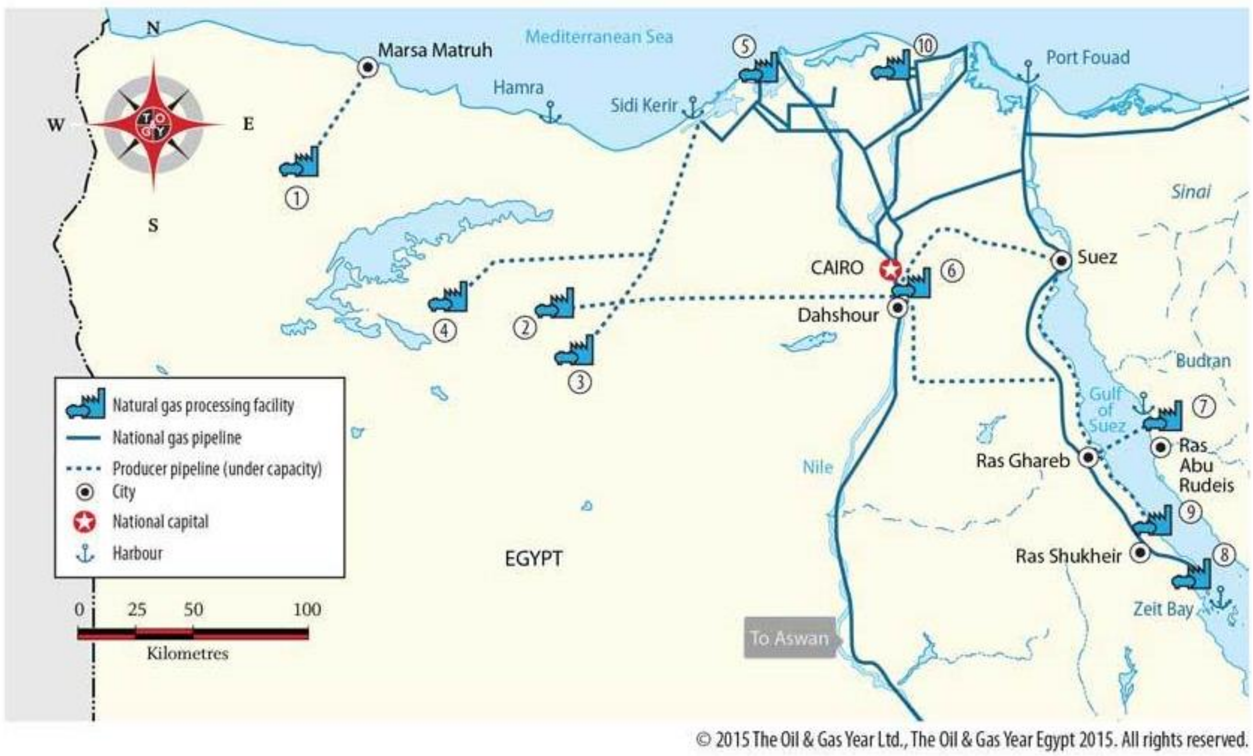


Figure 34: Egypt Natural Gas Processing Facilities

GAS FACILITIES:

1. SALAM GAS PROCESSING FACILITY
   Operator: Khalda Petroleum Company, a joint venture between the Egyptian General Petroleum Corporation (EGPC) and Apache Egypt
   Capacity: 1.68 mmscmd (600 mcfd)

2. ABU GHARADIG CONDENSATE EXTRACTION FACILITY
   Operator: Khalda Petroleum Company
   Capacity: 3.78 mmscmd (135 mcfd)

3. ABU SENNAN PROCESSING FACILITY
   Operator: General Petroleum Company
   Capacity: 2.38 mmscmd (85 mcfd)

4. BED-3 GAS CONDITIONING TRAINS
   Operator: EGPC
   Capacity: 5.04 mmscmd (180 mcfd)

5. ABU QIR MAEDIA GAS PLANT
   Operator: Western Desert Operating Petroleum Company
   Capacity: 10.78 mmscmd (385 mcfd)

6. DA HS HUR GAS PROCESSING PLANT
   Operator: Egyptian Natural Gas Holding Company
   Capacity: 3.78 mmscmd (135 mmscfd)

7. RAS BUDRAN PRODUCTION TREATMENT PLANT
   Operator: Suco Oil Company, a joint venture between RWE Dea and EGPC
   Capacity: 1.01 mmscmd (36 mmscfd)

8. ZEIT BAY
   Operator: Sum Oil Company
   Capacity: 3.36 mmscmd (120 mmscfd)

9. RAS SHUKHEIR PROCESSING FACILITY
   Operator: Gulf of Suez Petroleum Company
   Capacity: 7.03 mmscmd (251 mmscfd)

10. ABU MADI PROCESSING FACILITY
    Operator: ENI
    Capacity: 8.4 mmscmd (300 mmscfd)

Note: The facilities at WDDM and at Zohr onshore processing facilities near Port Said that have not been presented here, will be included in the updated version.

Pipeline Network

Egypt has a relatively open gas sector, with foreign companies investing in upstream and downstream developments. EGAS and EGPC receive the state's share of production from each development, with EGAS supplying the local market. State-owned GASCO has a monopoly on midstream developments and connects producers with end users. A mixture of private and public companies distribute gas in conjunction with GASCO. 10 Local Distribution Companies (LDCs) are currently operating in Egypt, with over 2.4 million customers connected to their networks.
GASCO was founded in 1997 and has since expanded the transmission network from 2,794 km (1,736 miles in 1997) to 7,060 km (4,387 miles) in 2014. GASCO also controls a ~ 11,024 km (6,850 mile) distribution network throughout Egypt. By 2014, the network has reached a capacity of 209.7 mmscmd (7.4 bscfd or 7,400 mmscfd).

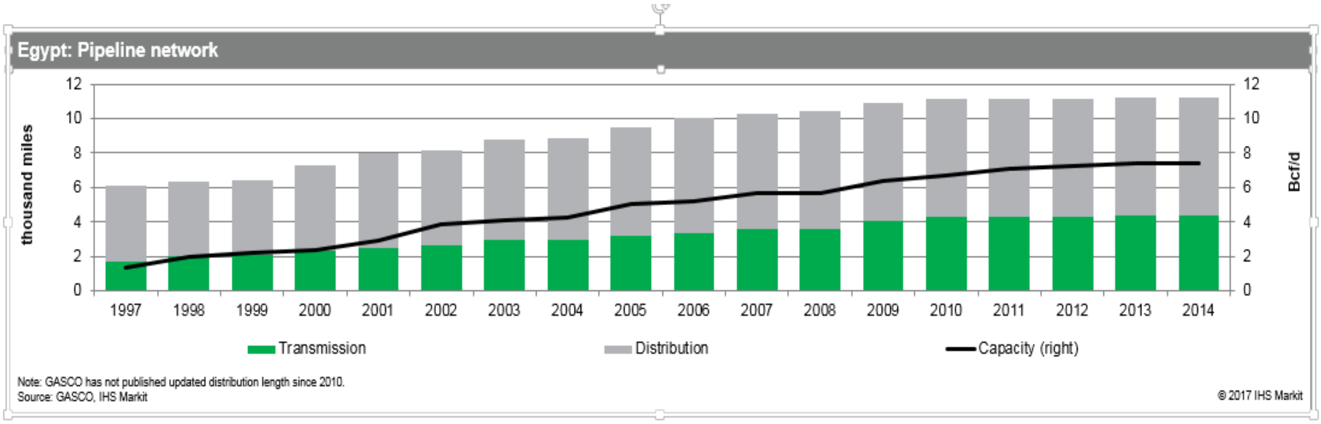


Figure 35: Egypt pipeline network

There are also some proposed pipeline import projects which if materialise can change the gas play in the region.

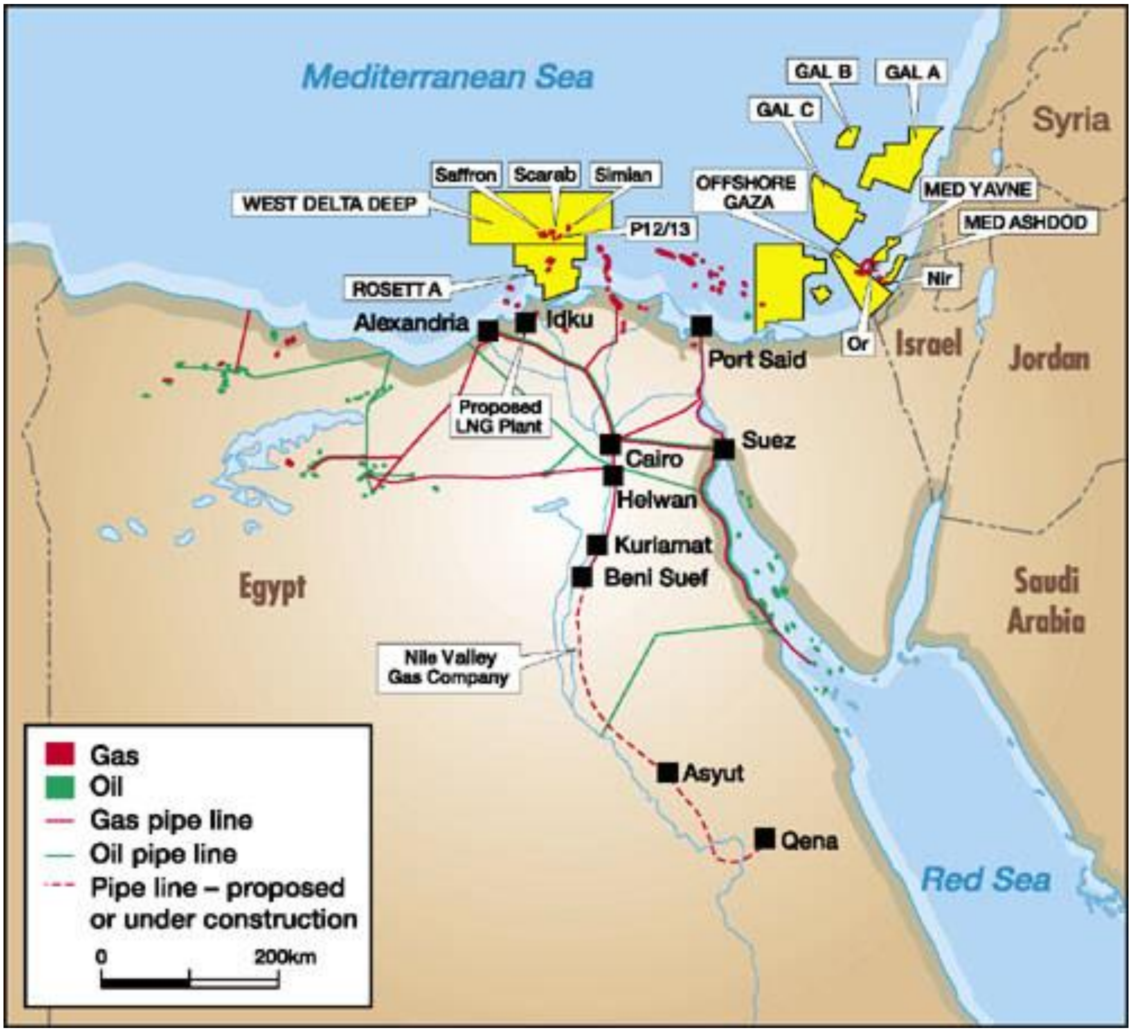


Figure 36: Gas and Oil Pipeline network in Egypt

Figure 36 above depicts the connection of Port Said to the internal pipeline network. Port Said is located in the northern part of Egypt by the Mediterranean Sea, near the Nile Delta region. It is considered to be an old energy hub having a direct access to the entire local gas distribution network, while through its connection to Arish, gas can be exported to Israel or to other countries in the area through the Arab Gas pipeline network. Figure 37 shows the connection of Egypt, through Port Said, to the export markets in the area. It can be considered an ideal case study for gas unloading from marine energy transportation such as the case of a Gasvessel unit. It should be noted that Port Said is being redeveloped and modernized after the Zohr gas field discovery since all the processing gas infrastructure is being built at the area.

Figure 37: Export pipeline network in Egypt

Cyprus – Egypt

The government of Cyprus plans a pipeline to Egypt as the most viable option to develop its offshore Aphrodite field in Block 12, estimated resources dwarfs domestic Cypriot energy needs. The idle capacity at IDKU and Damietta LNG on Egypt's Mediterranean coast is a target.

Israel – Egypt

Another potential source of gas supply for Egypt is regional pipeline imports from Israel. In December 2015, the Israeli government approved gas sales to Egypt from the Noble-operated Tamar offshore field.

Dolphinus, a group of private Egyptian companies, struck a deal in early 2015 with Noble, Delek Drilling, Avner Oil and Isramco Negev for at least 13.5 mmscmd (480 mmscfd) of gas to be piped from the Tamar field to Egypt in the first three years of a seven-year contract. Supply is expected to start by the end of 2019 but the transportation solution to be used is still uncertain.

As gas from the Zohr field will likely target the domestic market, Noble could decide to pipe its gas to the Zohr infrastructure as a cheaper solution than sending it to mainland Egypt, and eventually be used for export purposes.

Political issues plague Israeli gas development prospects and the feasibility of Israeli gas exports to Egypt. These have been compounded by the long-running dispute between Egypt and Israel over the cut-off of Egyptian pipeline exports in 2012.

Regulations

The extraction of oil and gas is regulated by the Egyptian Mining and Quarries Law 86 of 1956 and the terms and conditions set out under the relevant concession agreements.

The Ministry of Petroleum is the sole body with regulatory responsibility for the petroleum sector in Egypt through two principal public companies:

- Egyptian General Petroleum Company (EGPC).
- Egyptian Natural Gas Holding Company (EGAS).

Permission must be obtained first from the Ministry of Petroleum by the entity proposing to extract oil or gas. Permission usually takes the form of a concession agreement. For more information on regulation, fees, liabilities and rights to gas ownership, please consult the Appendix section (Appendix A, section VI).

Please note that more updates on the regulations will be provided in upcoming WPs.

Prices

In order to be able to narrow down to a satisfactory range of natural gas price in Egypt nowadays, we have taken into account a recent research paper that was published by Gaffneys and Cline Associates. A large number of Egyptian gas development options was carefully studied.

Specific gas prices per sector are being collected and will be presented in future WPs.

Players

Below there is the list of LDCs which can be potential buyers of the CNG landed in Egypt. We can identify the two state owned companies Town Gas and Egypt Gas, three independent companies and then another four distributors which are all under the Taqa umbrella.
Taqa is the Abu Dhabi National Energy Company, is a government controlled energy holding company of Abu Dhabi, United Arab Emirates.

Any of the below mentioned companies can be a buyer of the CNG sourced through the Gasvessel. Needless to say here that the players have a geographical dominance over various regions therefore, in order to avoid additional pipeline throughout expenses we can further target LDCs with proximity to the final landing position.

More information on gas distribution players will be reviewed in future WPs.

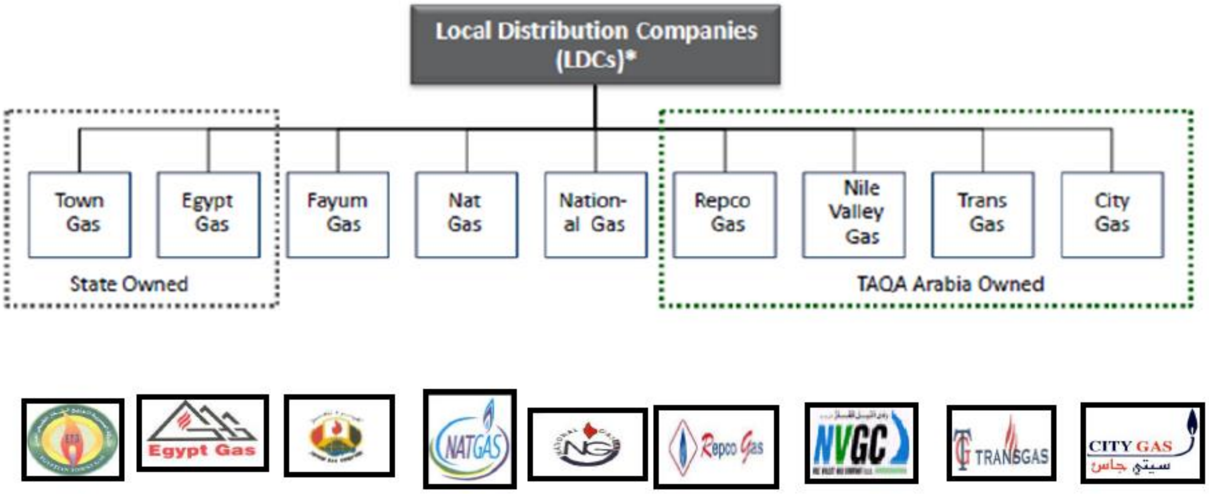


Figure 38: Egypt Local Distribution Companies

Summary

This proposal could be investigated in two different case studies;

a. Gas from the offshore gas locations is transported to Cyprus by offshore pipelines to feed Cyprus' domestic needs and the resulting surplus to be converted into CNG and shipped from the proposed Vasilikos Energy Port to Egypt.

b. Offshore gas loading locations to serve directly Egypt under the Gasvessel concept by optimizing the intermediate value chain dictated by the number of vessels, use of storage facilities, etc.

Egypt	Application	Volume	Loading Location	Unloading Location
Wholesale buyer i.e. EGAS	Gas for Power	2.83 mmscmd (100 mmscfd) 8.48 mmscmd (300 mmscfd) 16.95 mmscmd (600 mmscfd)	Offshore location and Onshore location	Port Said Latitude 31.32 Longitude 32.16
Abu Qir power plant	Gas for Power	4.05 mmscmd (135 mmscfd)	Offshore location	Latitude 31.27 Longitude 30.14

Table 8: Summary for Egyptian Power Plants

Based on the above analysis of the different countries, it is recommended that the below scenarios can be used for further techno economic analysis for the Gasvessel project.

2.5 Resulting Scenarios

	Offshore gas loading	**Onshore gas loading**	**Scenarios Number**	**Market Size CNG**	
Cyprus Vasilikos Area	YES	NO	1	**Offshore** 2.83 mmscmd (100 mmscfd)	
Crete Linoperamata Area	YES (in combination with Cyprus)	YES (in combination with Cyprus)	2	**Offshore** 4.24 mmscmd (150 mmscfd)	**Onshore** 1.41 mmscmd (50 mmscfd)
Lebanon Zouk Area	YES	YES	2	**Offshore** 3.67 mmscmd (130 mmscfd)	**Onshore** 3.67 mmscmd (130 mmscfd)
Lebanon Zouk Area	YES (in combination with Cyprus)	YES (in combination with Cyprus)	2	**Offshore** 6.50 mmscmd (230 mmscfd)	**Onshore** 3.67 mmscmd (130 mmscfd)
Egypt Port Said (1)	YES	YES	2	**Offshore** 2.83 mmscmd (100 mmscfd)	**Onshore** 2.83 mmscmd (100 mmscfd)
Egypt Port Said (2)	YES	YES	2	**Offshore** 8.48 mmscmd (300 mmscfd)	**Onshore** 8.48 mmscmd (300 mmscfd)
Egypt Port Said (3)	YES	YES	2	**Offshore** 16.95 mmscmd (900 mmscfd)	**Onshore** 16.95 mmscmd (900 mmscfd)
		Total Scenarios Proposed	**13**		

Table 9: Resulting Scenarios for Eastern Mediterranean

The resulting proposals concerning the Eastern Mediterranean Geologistic scenario include the target markets identified already, differentiated according to unloading location and ability to combine demand volumes in nearby target markets.

In the case of Cyprus, it can only be considered for the minimum demand volume of 2.83 mmscmd (100 mmscfd) from an offshore unloading location.

When it comes to the market of Crete, the demand volumes are very small to justify the development of a deep water gas field in the East Mediterranean, however, we have considered Crete in combination with the Cyprus market so that the offshore gas production is increased, and based on this concept we have proposed 2 possible scenarios. The first scenario is when gas for Gasvessel is loaded offshore, then the market for CNG is made up of Crete 1.41 mmscmd (50 mmscfd) and Cyprus 2.83 mmscmd (100 mmscfd), giving a total of 4.24 mmscmd (150 mmscfd).

On the other hand, if the gas for Gasvessel is loaded onshore from Cyprus, then the market demand volume from Crete for Gasvessel is only 1.41 mmscmd (50 mmscfd).

Lebanon's demand volume of 3.67 mmscmd (130 mmscfd) justifies a stand-alone scenario, however, the volumes for Gasvessel can be increased if combined with the Cyprus market. When Lebanon is investigated as a stand-alone option the volumes available for Gasvessel both loading from onshore and offshore is 3.67 mmscmd (130 mmscfd). Volumes change when the Lebanese market is investigated in combination with Cyprus. In this case, volumes change for the offshore and onshore scenarios. For example, if gas is loaded offshore, the market demand volume for Gasvessel is made up of Cyprus with 2.83 mmscmd (100 mmscfd) and Lebanon with 3.67 mmscmd (130 mmscfd), giving a total of 6.50 mmscmd (230 mmscfd) and when gas is loaded from onshore Cyprus then the market for Gasvessel is only Lebanon with 3.67 mmscmd (130mmscfd).

In the case of Egypt, the scenarios are differentiated according to volume demand 2.83, 8.48, 16.95 mmscmd (100, 300 and 600 mmscfd) and unloading location (onshore or offshore) to result in 6 possible scenarios. All scenarios stand-alone and are not combined with the Cyprus market.

2.6 Cost and Tariffs

The objective is to develop end-to-end estimates for a required tariff for the delivery of gas from the identified source locations to the identified markets, for both the Gasvessel concept and for competing options (alternative monetization options). This requires the development of cost estimates through the gas delivery chain, using consistent input assumptions, use of tools, and clarity of battery limits between each package and contributor. The flow chart below illustrates this logic.

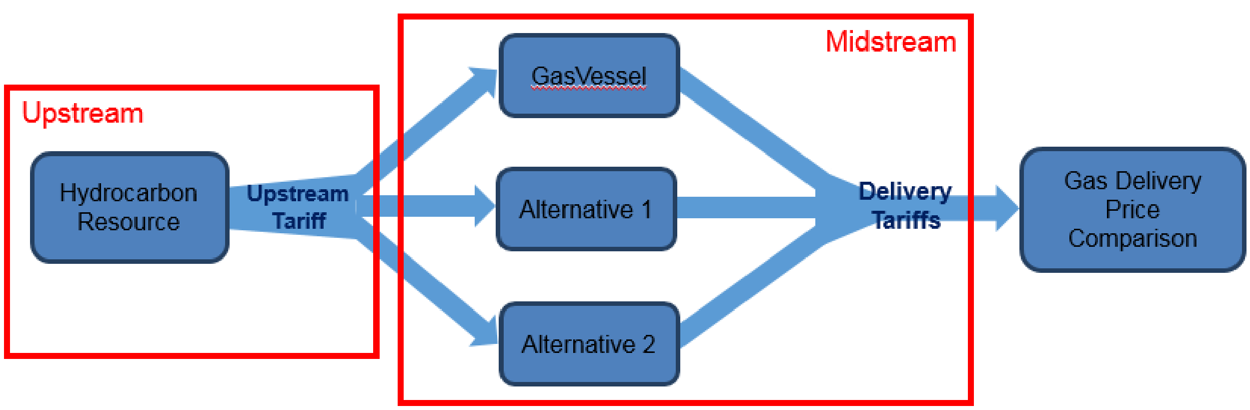


Figure 39: Tariff flow

Description of Cost and Tariff Headings

The data will generally contribute to the estimation of the following:

- Upstream Cost
- Midstream Cost
- Downstream Cost

The above elements, when taken as a whole, form the full gas value chain for delivery of gas from an offshore field to its end buyer.

1. **UPSTREAM COST** refers to the total cost of extracting natural gas from the gas field and delivering and ready for storage. However, depending on whether loading will be done offshore or onshore, these costs are differentiated.
   a) UPSTREAM COSTS (A) include all CAPEX and OPEX concerning subsea costs, production costs, gas conditioning and gas compression costs so that CNG is ready for loading from an offshore location, but does not include loading systems or storage costs.
   b) UPSTREAM COSTS (B) include all the above mentioned upstream costs (A), plus the pipeline costs (OPEX and CAPEX) to deliver the gas via pipeline to the onshore loading location, so that CNG is ready for loading from an onshore location but does not include loading systems or storage costs.

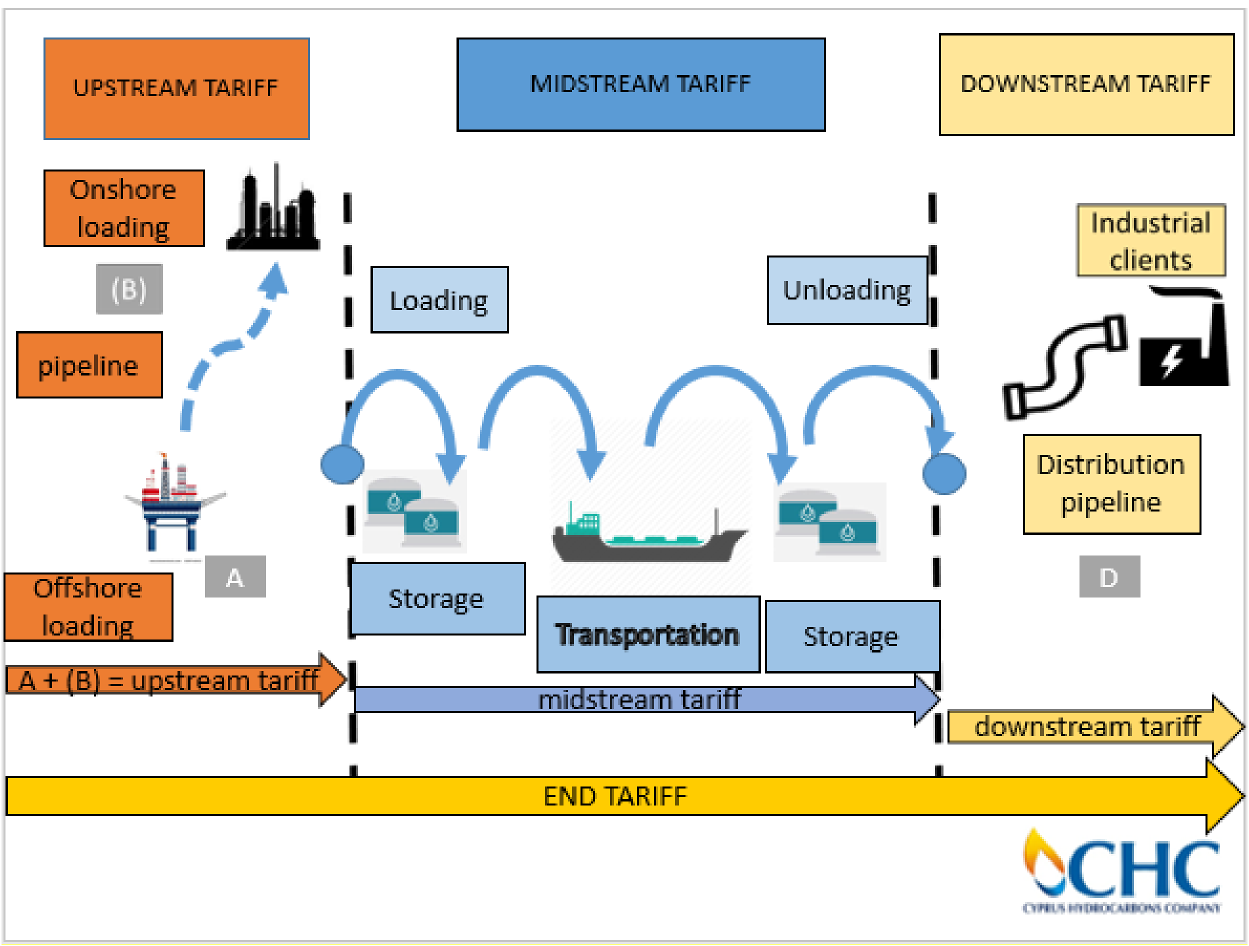
2. **CNG TRANSPORTATION COST or MIDSTREAM COST** refers to all the CAPEX and OPEX concerning the total cost of delivering the CNG from the field to a distribution network, from which it can be delivered to the end consumer. If compression and processing is undertaken on site, then these costs are not calculated in the field tariff. Specifically, the general CNG transportation costs include:
   - Upstream loading system costs (including upstream storage and vessel loading)
   - Transportation of gas (includes vessel construction costs and transportation costs)
   - Downstream unloading system costs (including downstream storage and vessel unloading

3. **DOWNSTREAM COST** refers to all CAPEX and OPEX costs concerning the costs of directing the natural gas through the distribution network to reach the end buyer. Note here that downstream costs for the East Mediterranean scenario have not been calculated due to short distances and lack of data availability. The report will be updated according to data availability for all scenarios as the project progresses.

4. **OTHER COSTS** relate to costs of the CNG after its delivery to its target market destination.

5. **END TARIFF** is the sum of all the preceding costs in the value chain, meaning all costs mentioned above from 1 – 4. This price estimation should be comparable with local natural gas prices (if applicable) or with alternative energy prices, in order to establish financial feasibility and profitability margins. This implies that end tariffs of the CNG value chain should be comparable with end tariffs calculated for other monetization options' value chain, such as LNG or direct pipeline supply.

The tariff comparisons between CNG and local gas prices or alternative energy sources are mainly for financial feasibility estimates. However, the choice of CNG as a part of a country's energy mix might stem from political, security, humanitarian, or other reasons and might thus not be subject to extensive financial comparison.



Note the following:

- Offshore upstream tariff = upstream costs (A)
- Onshore upstream tariff = upstream costs (A) + upstream costs (B)

Note here that midstream tariffs are identified as midstream costs here for the purposes of the project in order to specifically direct efforts into the calculation of these costs as they are critical. Thus, midstream tariff is calculated as:

- Midstream cost (upstream loading, upstream storage, vessel loading, transportation costs, vessel building costs, vessel unloading, downstream storage and downstream unloading).

Similarly, the downstream tariff is identified as the total cost of distribution to end clients after unloading.

The end tariff however, is considered to be the accumulation of upstream, midstream and downstream tariffs, such that:

- End tariff = (offshore upstream cost or onshore upstream cost) + midstream cost + downstream cost

Inputs

The following inputs will need to be defined for the generation of cost estimates for the various options as data from the demand profiles of the proposed target markets discussed above.

- Demand rate in mmscmd, on an average annual basis
- Gas Specification (Composition, temperature, pressure)
- Delivery location & existing infrastructure

Other assumptions made regarding the cost estimation exercise include the following:

- Cost escalation at 2% per annum (OPEX and CAPEX)
- No tariff escalators
- No Decommissioning costs included
- Taxes and/or royalty fees will not be incorporated in any cash flow calculations

2.6.1 Upstream Cost Estimation

The following table summarizes the potential components of an upstream cost estimate, the estimating tools to be used, and the key assumptions made in generating the estimate.

Parameter	Estimate made using:	Notes / Assumptions
Drilling	Que$tor	Assume N+1 wells are required Maximum well productivity of 4.24 mmscmd (150 mmscfd)
Subsea	Que$tor	
Pipelines	Que$tor	
Floating Production Unit	Que$tor	Moored Units assumed Non-Leased Construction in Asian shipyard
Onshore Reception/Processing	Que$tor	Land acquisition costs will not be included Onshore license will be available to CHC in late August
OPEX	Que$tor	OPEX costs will not include any ‘overhead’ costs associated with the upstream entity

An exception to the above will be the Black Sea scenarios, where the upstream costs will be developed by VGT, and a gas tariff for a delivery point on the Georgian shore of the Black Sea will be provided.

2.6.2 Midstream Cost Estimation

<table>
<tr><th>Parameter</th><th>Estimate made using</th><th>Notes</th></tr>
<tr><td>Risers</td><td colspan="2" rowspan="9">Navalprogetti to Advise</td></tr>
<tr><td>Compression</td></tr>
<tr><td>Offshore Floating Storage</td></tr>
<tr><td>Onshore Storage</td></tr>
<tr><td>Loading/Offloading Arms</td></tr>
<tr><td>SAL/STL Systems</td></tr>
<tr><td>Gas Storage system</td></tr>
<tr><td>CNG Ship</td></tr>
<tr><td>OPEX</td></tr>
</table>

2.6.3 Downstream Cost Estimation

All target markets in the East Mediterranean geologistic scenario have been intentionally selected so as to allow gas unloading near, or directly into, the corresponding local gas distribution network. Therefore, in gasified target markets, the downstream cost estimates consist mainly of the tariff charged to use the local distribution network. However, for future gasified target markets, the relevant CAPEX and OPEX costs to reach the local distribution network have to be calculated. These estimates are to be considered in later WPs.

2.6.4 Alternative Cost Estimation

Costs of delivering the gas to an identified market via alternative methods to the Gasvessel will be calculated in Euros and USD. The following table summarises the potential components of such a 'midstream' cost estimate, the estimating tools to be used, and the key assumptions made in generating the estimate.

Parameter	Estimate made using	Notes
Pipelines	Que$tor	
FLNG	Excel Based Tool	Existing/proposed FLNG units to be used to derive a $/throughput metric
Regasification Units	Excel Based Tool	Excel tool to be built, calculating (F)SRU CAPEX based on throughput size
OPEX	Que$tor, Excel	OPEX costs will not include any 'overhead' costs associated with the midstream entity

2.6.5 Other Costs

Given the early stages of the project, is important to account for uncertainties and hidden costs in the estimate. The following is a summary of what additional costs should be considered in the cost estimates, for both 'upstream' and 'midstream' elements.

Parameter	Estimate made using	Notes
Contingency	30% of underlying base costs	Considered appropriate for concept selection level costs
Project Management	15% of underlying base cost	Includes Certification and Insurance. In line with typical oil and gas industry experience
Engineering and Design	5% of underlying base cost	

2.6.6 Cost and Tariff Overview

Summary of Costs and Tariffs

FIELD	LOADING POINTS	END DESTINATION	PRODUCTION VOLUME (MMSCMD)	DELIVERY VOLUME (MMSCMD)
Offshore Cyprus	VASILIKOS (ONSHORE)	CYPRUS & CRETE	4.24	2.83 & 1.41
		LEBANON	3.67	3.67
		LEBANON & CYPRUS	6.50	3.67 & 2.83
		EGYPT 1	2.83	2.83
		EGYPT 2	8.48	8.48
		EGYPT 3	16.95	16.95
	OFFSHORE	CYPRUS	2.83	2.83
		CYPRUS/CRETE	4.24	4.24
		LEBANON	3.67	3.67
		LEBANON/CYPRUS	6.50	6.50
		EGYPT 1	2.83	2.83
		EGYPT 2	8.48	8.48
		EGYPT 3	16.95	16.95

The resulting proposals concerning the Eastern Mediterranean geologistic scenario are differentiated primarily according to unloading location (onshore and offshore), and then the resulting target markets.

Based on the minimum market gas volume requirement of 2.83 mmscmd (100 mmscfd), the Vasilikos onshore unloading point can service the following markets:

- Lebanon - 3.67 mmscmd (130 mmscfd)
- Egypt - 2.83, 8.48 and 16.95 mmscmd (100, 300 and 600 mmscfd)
- Combination of Cyprus and Crete - 4.24 mmscmd (150 mmscfd)
- Combination of Cyprus and Lebanon - 6.50 mmscmd (230 mmscfd)

In total, this creates six onshore scenarios.

It might be presumed that combined market scenarios will present lower upstream tariffs due to larger production volumes. However, in the case of combined markets, the gas volumes will be delivered separately thus having differentiated CNG delivery costs. For example, in the case of Cyprus and Crete, 2.83 mmscmd (100 mmscfd) will be delivered to Cyprus and 1.41 mmscmd (50 mmscfd) will be delivered to Crete, separately even though the production costs were estimated in aggregate for 4.24 mmscmd (150 mmscfd). Similarly, for the case of Lebanon and Cyprus, 3.67 mmscmd (130 mmscfd) will be delivered to Lebanon and 2.83 mmscmd (100 mmscfd) will be delivered to Cyprus, independently, even though production costs were estimated again in aggregate as 6.50 mmscmd (230 mmscfd).

Similarly, using the offshore unloading point, the following markets can be serviced:

- Cyprus - 2.83 mmscmd (100 mmscfd),
- Lebanon - 3.67 mmscmd (130 mmscfd)
- Egypt - 2.83, 8.48 and 16.95 mmscmd (100, 300, 600 mmscfd),
- Combination of Cyprus and Crete - 4.24 mmscmd (150 mmscfd)
- Combination of Cyprus and Lebanon - 6.50 mmscmd (230 mmscfd)

In total, this creates seven offshore scenarios.

UPSTREAM TARIFF	MIDSTREAM TARIFF	END DESTINATION	DEMAND	DOWNSTREAM TARIFF	FINAL DELIVERY PRICE
€/m^3	€/m^3		MMSCMD	€/m^3	€/m^3
ONSHORE					
0.16		CYPRUS/CRETE	4.24		
0.18		LEBANON	3.67		
0.14		LEBANON/CYPRUS	6.50		
0.21		EGYPT 1/	2.83		
0.12		EGYPT 2	8.48		
0.10		EGYPT 3	16.95		
OFFSHORE					
0.14		CYPRUS	2.83		
0.11		CYPRUS/CRETE	4.24		
0.12		LEBANON	3.67		
0.09		LEBANON/CYPRUS	6.50		
0.14		EGYPT 1/	2.83		
0.08		EGYPT 2	8.48		
0.07		EGYPT 3	16.95		

The table above depicts in summary the tariffs for each of the elements of the gas value chainper scenario. In yellow, we can see the upstream tariff acquired for each scenario, which is mostly affected by the demand volume, and whether the loading is onshore or offshore (onshore loading includes additional upstream costs). The upstream costs typically include field development and production costs. In the case of offshore loading, upstream tariffs are generally lower as they do not include pipeline costs to the onshore unloading location.

Midstream costs, in grey, are missing and typically involve all the relative costs (OPEX and CAPEX) of loading, transporting and unloading the CNG to the target market.

Downstream costs, also in grey, are missing and typically involve the distribution costs to the end client.

Since we are unable to compute the downstream tariff, and thus provide a possible market price for CNG to be compared with local gas prices or alternative energy prices, we will compute what the missing data should add up to (target tariff) to maintain price competitiveness with local gas suppliers and alternative energy providers. This will then allow the consortium to establish the feasibility of the Gasvessel option once midstream and downstream costs are further developed.

Calculation of maximum and minimum tariff targets:

Example

	MMSCMD	**Current End Tariff €/m^3**	**High Alt. price €/m3**	**Low Alt. price €/m3**	**MAX TARIFF TARGET €/m3**	**MIN TARIFF TARGET €/m3**
		Onshore	**ELNG & FSRU**	**FLNG & FSRU**		
Lebanon	**3.67**	0.22	0.27	0.16	(0.27-0.22)= 0.05	(0.16-0.22)=-(0.06)
		Offshore	**ELNG & FSRU**	**FLNG & FSRU**		
		0.15	0.27	0.16	((0.27-0.15)= 0.12	(0.16-0.15)= 0.01

ELNG – Egyptian LNG, closest LNG facility to the East Mediterranean market.
FLNG – Floating liquefied natural gas, considered when natural gas is liquefied above the offshore field
FSRU – Floating storage regasification unit, if LNG is a comparable option, all clients will need an FSRU system
Direct Pipeline – another monetization option

Each scenario is compared to its most expensive and cheapest alternative. For example, in the case of the Lebanese scenario (independent, not combined with Cyprus) with demand volume 3.67 mmscmd (130 mmscfd), the alternative is ELNG and FSRU in the case of onshore provision, with an indicative delivery price (used as an example) for the alternatives of €0.27/m^3 ($9.15/mmbtu). In the case of offshore provision the alternative is FLNG and FSRU with an indicative price (example) of €0.16/m3 ($5.25/mmbtu). Since the accumulation of our tariff thus far (only upstream costs) is €0.22/cm($7.52/mmbtu) for onshore CNG provision to Lebanon, and €0.15/m3 ($5.06/mmbtu) for offshore CNG provision to Lebanon, the tariff targets for the remaining costs (midstream and downstream) can be calculated by subtracting the current tariff from the relative alternative price. This is illustrated in the last two columns of the above table.

From the matrix we can establish that onshore CNG provision to Lebanon compares very poorly to the FLNG and FSRU alternative, since it already costs €0.06/m3 more ($2.27 more per mmbtu) for CNG than LNG, even though we have still not included midstream and downstream costs. On the other hand, offshore provision of CNG to Lebanon compares more favourably to ELNG and FSRU provision as an alternative since the margin of €0.12/m3 ($4.09 per mmbtu) of CNG can be estimated to cover midstream and downstream costs for CNG to be a financially viable option for the Lebanese power market. Similar calculations relate to the target markets of Lebanon & Cyprus and Cyprus & Crete.

In scenarios where there is only one alternative, like in the case of Egypt (all 3 scenarios) and Cyprus, the target tariff does not present a range but only one value.

	MMSCMD	**Current Tariff €/m3**	**High Alt. price €/m3**	**Low Alt. price €/m3**	**MAX TARIFF TARGET €/m3**	**MIN TARIFF TARGET €/m3**
		Onshore	**Direct Pipeline**	**Direct Pipeline**		
Egypt 1	**2.83**	0.26	0.25	0.25	(0.25-0.26)=-(0.01)	(0.25-0.26)=-(0.01)
		Offshore	**Direct Pipeline**	**Direct Pipeline**		
		0.17	0.25	0.25	(0.25-0.17)=0.08	(0.25-0.17)=0.08

For example, in the case of Egypt with 2.83 mmscmd (100 mmscfd) demand volume, the only other alternative investigared is provision by direct pipeline, estimated to cost €0.25/m3 ($8.34/mmbtu). When this is compared to onshore CNG provision €0.26/m3 ($8.66/mmbtu), it eventually yields a negative tariff margin of -€0.01/m3, (-$0.32/mmbtu), meaning that CNG provision is already more expensive, even before calculating midstream and upstream costs. On the other hand, comparing it with offshore CNG provision yields a tariff target of €0.08/m3 ($2.66/mmbtu) in order to cover midstream and downstream costs. Similar calculations relate to the other scenarios concerning Egypt as well as Cyprus.

END DESTINATION	MMSCMD	DOWNSTREAM TARIFF €/m3	LOCAL PRICE €/m3	ALTERNATIVE OPTIONS		ALTERNATIVE TARIFF €/m3		MAX TARIFF €/m3	MIN TARIFF €/m3
		ONSHORE						TARGET	TARGET
CYPRUS/CRETE	4.24	0.20	NA	ELNG & FSRU	FLNG & FSRU	0.25	0.15	0.05	- 0.05
LEBANON	3.67	0.22	NA	ELNG & FSRU	FLNG & FSRU	0.27	0.16	0.05	- 0.07
LEBANON/CYPRUS	6.50	0.17	NA	ELNG & FSRU	FLNG & FSRU	0.20	0.15	0.03	-0.02
EGYPT 1	2.83	0.26	NA	DIRECT PIPELINE	DIRECT PIPELINE	0.25	0.25	-0.01	-0.01
EGYPT 2	8.48	0.15	NA	DIRECT PIPELINE	DIRECT PIPELINE	0.14	0.14	-0.01	-0.01
EGYPT 3	16.95	0.12	NA	DIRECT PIPELINE	DIRECT PIPELINE	0.11	0.11	-0.01	-0.01
		OFFSHORE							
CYPRUS	2.83	0.17	NA	DIRECT PIPELINE	DIRECT PIPELINE	0.23	0.23	0.06	0.06
CYPRUS/CRETE	4.24	0.14	NA	ELNG & FSRU	FLNG & FSRU	0.25	0.15	0.11	0.01
LEBANON	3.67	0.15	NA	ELNG & FSRU	FLNG & FSRU	0.27	0.16	0.12	0.01
LEBANON/CYPRUS	6.50	0.12	NA	ELNG & FSRU	FLNG & FSRU	0.20	0.15	0.08	0.03
EGYPT 1	2.83	0.17	NA	DIRECT PIPELINE	DIRECT PIPELINE	0.25	0.25	0.08	0.08
EGYPT 2	8.48	0.10	NA	DIRECT PIPELINE	DIRECT PIPELINE	0.14	0.14	0.04	0.04
EGYPT 3	16.95	0.08	NA	DIRECT PIPELINE	DIRECT PIPELINE	0.11	0.11	0.03	0.03

Overall, we see that the most favourable comparisons are made for offshore provision of CNG to the target markets with all tariff targets yielding positive results, while onshore provision of CNG generally yields low or even negative tariff targets to cover midstream and downstream costs.

It should be noted however, that such comparisons are only made for financial feasibility estimates, and may not be the deciding factor in executive decisions concerning CNG provisions in cases where other priorities (political, security, humanitarian, etc.) are taken into account or if the above input data is differentiated (e.g., if alternative energy prices change).

3. Barents Sea Geologistic Scenario

3.1 Barents Sea Executive Summary

In the case of the Barents Sea Geologistic scenario, extensive filtering has been done both for potential gas sources in the Barents Sea, as well as for target markets in the Northe Sea region. More specifically, an associated gas field, J. Castberg, and a gas field, Alke, located in the Barents Sea were identified as potential gas sources for supplying potential target markets.

The target market selected is the United Kindgom due to the existing infrastructure that allows easy access to this well established gas market. It is expected that the UK market can absorb available gas production from Norway, frowm which it is already importing considerable amounts of natural gas.

The figure below summarizes the loading of gas from offshore and transporting it using the Gasvessel concept to the gas unloading location.

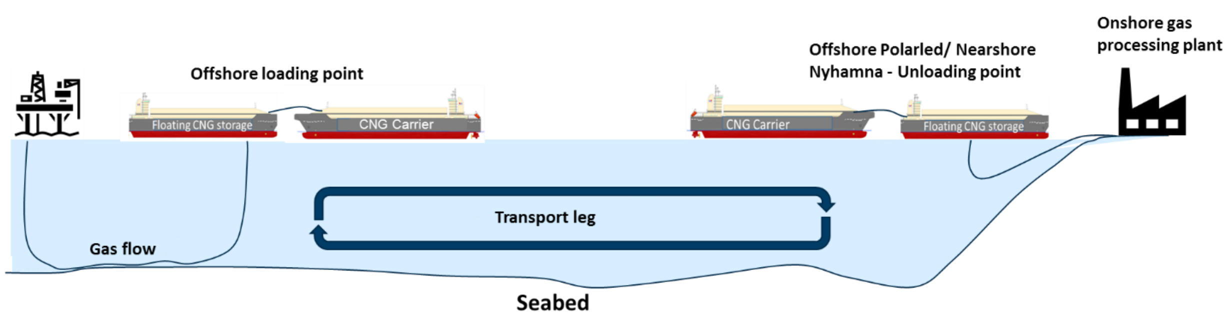


Figure 40: Main value chain aspects of Barents Sea scenarios

We would like to thank Sintef for their invaluable contribution and the overall responsibility regarding data collection, and future revision, regarding the Barents Sea Geologistic scenario.

3.1.1 Barents Sea Objectives

The objective of the Barents Sea report segment, and consequently the target market methodology, is to identify and propose potential markets in the region of North Sea for the CNG Gasvessel project. In this specific geologistic scenario, both the field screening process and target market screening played an equal role for the final selection of the scenarios. The methodology takes into account key filtering parameters across the value chain of supply and delivery aiming to propose attractive markets for further techno-economic evaluation.

3.2 Gas Field Screening Criteria

The area on focus is indicated by the red quadrant in Figure 41. Since all the potential oil and gas fields for Gasvessel are in the South West area of the Barents Sea, the area indicated is Barents Sea South West.

The reason for focusing on the Barents Sea is that it presents clear potential for monetizing stranded and associated gas due to lack of infrastructure and small volumes of gas discovered. The North Sea has not been considered, mainly since it is a well-established region served by an extensive network of pipelines.

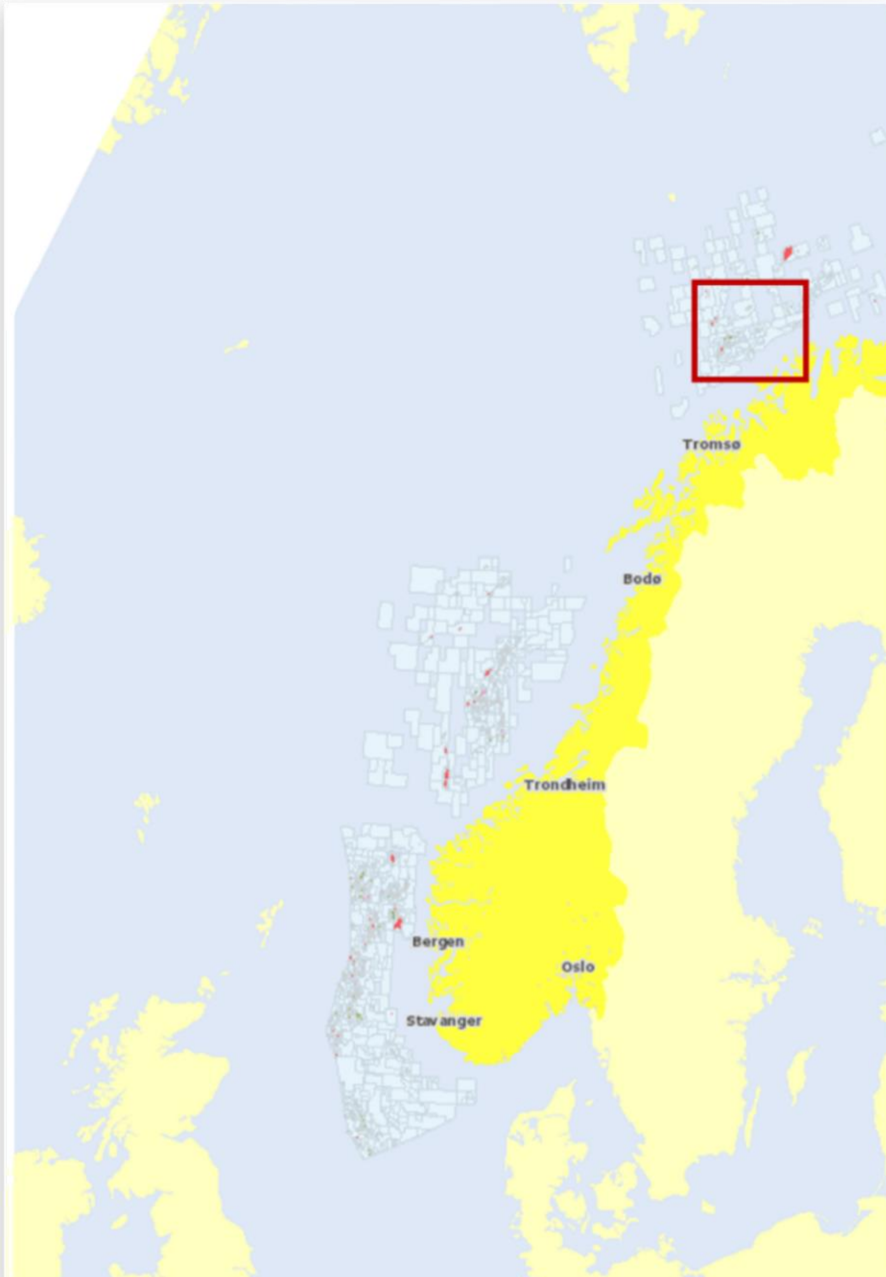


Figure 41: Barents Sea south-west

3.2.1 Gas Loading Options

The screening of fields consisted of a review of all discoveries containing gas made in the Barents Sea, based on data from the Norwegian Petroleum Directorate[22] (NPD) and from a previous feasibility study on the Barents Sea gas production and transport infrastructure[23].

The following approach for data gathering and assessment has been applied:

- Scope / area: Barents Sea, stranded and associated gas; discoveries without access to pipeline infrastructure; complementary to the cases identified in the two other regions in the Gasvessel Project (East Mediterranean and the Black Sea).
- Distance: Scenarios Barents Sea to Northern Europe need to fulfil the CNG feasibility distance criteria established by Gasvessel, approximately 81 – 162 nautical miles (nm), (150 – 1750 km).
- Volumes: the potential supply from selected loading points (offshore fields) must fulfil the CNG feasibility volume criteria established by Gasvessel: 1.5 mmscmd – 16.5 mmscmd (50 mmscfd – 550 mmscfd).

Figure 42 and Table 10: summarize the fields and discoveries considered. In the figure, the red quadrants are pure gas fields, and green are oil/gas fields. The quadrants with thick black border are categorized as "production unlikely" by the NPD. In addition, supportive information from the discovery and wellbore report(s) have been reviewed[24].

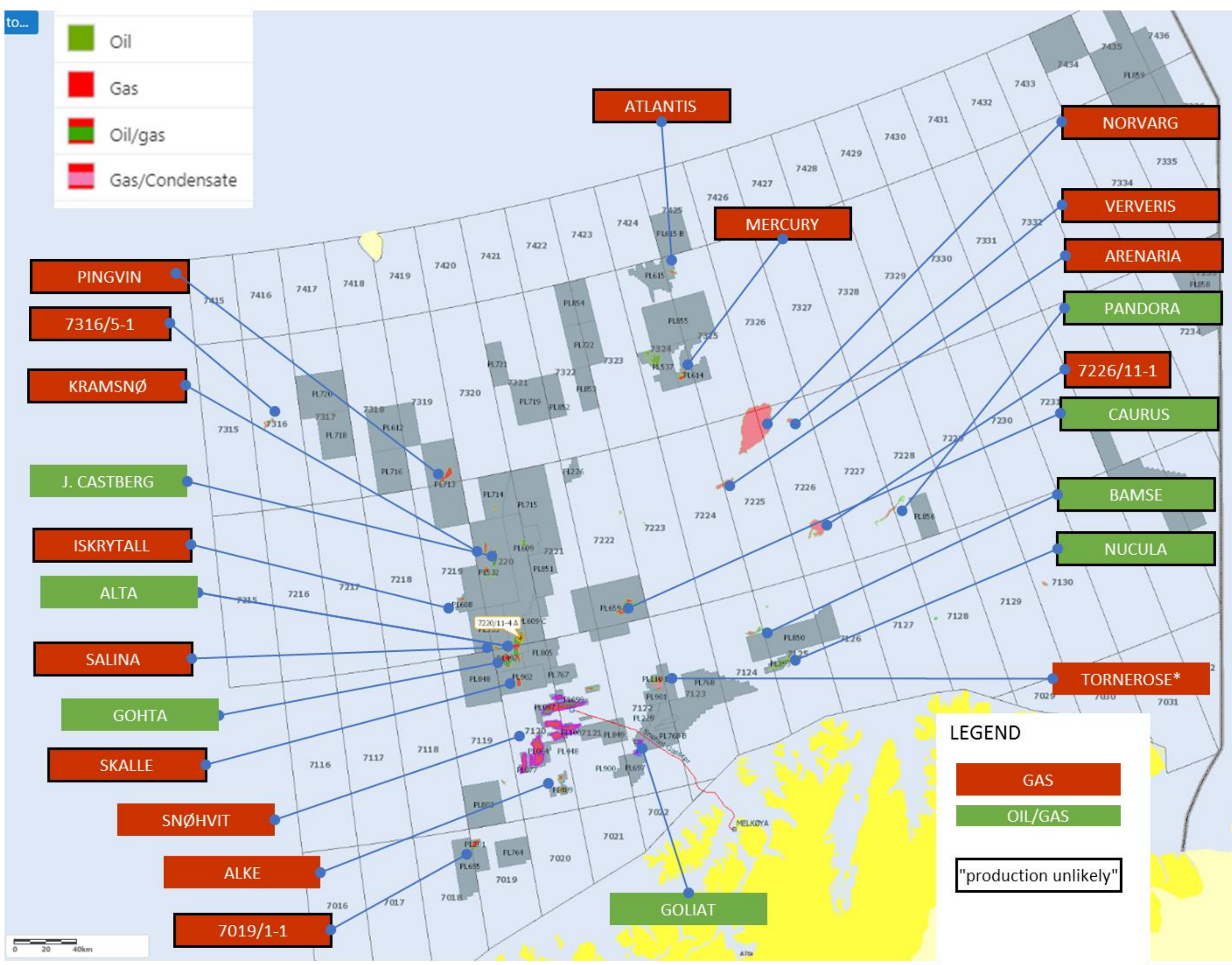


Figure 42: Map of oil/gas discoveries and fields reviewed as potential loading fields

Field	Status	Year	content	Resources – Recoverable Gas: bcm (TCF)	Location	Water depth (m)
ALKE (north, South)	Production likely, but unclarified	Discov. 1981	Gas / Condensate	11.4 (0,402)	71.1°N 22.7°E	164 /185
GOLIAT	Producing (Oil)	Start prod. 2000	Oil / Gas	10.7 associated gas (0,377)	71.30°N 22.30°E	400
SNØHVIT	Producing	Start prod. 2007	Gas	Remaining 182 (6,422) Orig. Recoverable 223 bcm (7,869)	71.56°N 21.23°E (Pipeline entry)	340
SKALLE	Production unlikely	Discov. 2011	Gas	2,5 - 7,9 (0,088-0,278)[25]	71.71°N 20.37°E	327
GOHTA	Production likely, but unclarified	Discov. 2013	Oil / Gas	6.22 (0,219)	71.93°N 20.19°E	342
ALTA	Production likely, but unclarified	Discov. 2014	Oil / Gas	9.70 (0,342) Max production rate: 48000sm3	72.0°N 21.55°E	388
SALINA	Production unlikely	Discov. 2012	Gas	6-8 (0,211-0,282)	72.0°N 20.0°E	341
ISKRYSTALL	Production unlikely	Discov. 2013	Gas	2,3 (0,081)[26]	72.32°N 19.60°E	344
KRAMSNØ	Production unlikely	Discov. 2014	Gas	2 – 4 (0,070-0,140)[27]	72.59°N 20.22°E	403
Johan CASTBERG	Production in clarification phase	Discov. 2011	Oil/ Gas	11.73 [0,414]	72.5°N 20.33°E	370
PINGVIN	Production unlikely	Discov. 2014	Gas	5-20 (0,176-0,705)[28]	73,0°N 19,74°E	422
NORVARG	Production unlikely poor permeability and well productivity	Discov. 2011	Gas	5-10 (0,175-0,352)	72,9°N 25,9°E	377
VERVERIS	Production unlikely	Discov. 2008	Gas	3,5 (0,124)[29]	72,8°N 26,6°E	341
ARENARIA	Production unlikely	Discov. 2008	Gas	0,5 (0,018)[29]	72,6°N 25,0°E	415
PANDORA	Production unlikely	Discov. 2001	Oil/ Gas		72,2°N 27,9°E	
CAURUS	Production unlikely	Discov. 2008	Oil/ Gas	2-14 (0,070-0,494)[29]	72,0°N 22,6°E	
BAMSE	Production unlikely	Discov. 1987	Oil/ Gas			
NUCULA	Production unlikely	Discov. 2007	Oil/ Gas			293
TORNEROSE	Production in clarification phase	Discov. 1987	Gas/ Condensate	3.69 (0,130)	71,6°N 22,85°E	400
SNØHVIT	Producing	Start prod. 2007	Gas	Remaining 182,40 (6,441) Orig. Recoverable 223,80 (7,903)	71.56°N 21.23°E (pipeline entry)	340

Table 10: List of Barents Sea South-West oil and gas discoveries and production[30]

Most of the fields identified have been so far classified as "not likely for production", with a relatively low level of gas reserve identified compared to what is necessary to justify infrastructure investment. There is also a lack of information concerning reservoir composition. Consequently,

- All fields classified as "not likely for production" are not further considered for Gasvessel scenario.
- Common assessment in cooperation with WP2 partners was carried out, based on information about discovery status, exploitation plan, volume of recoverable gas, field location with regards to distribution infrastructure
- Further filtering of potential fields for the Barents Sea Gasvessel scenario was based on a review of the reservoir and wellbore reports by Navalprogetti, localization of the field (not too far North East due to harsh weather, and not too close to the Snøhvit infrastructure which may represent a potential competing transport channel).

Based on data from Table 10: , and with regards to volume, localization, reservoir information, the following considerations have been made in cooperation with WP2 team:

- J. Castberg: oil & gas field approved for development, with start oil production planned for 2022 (operator: Statoil). The field is proposed for the Gasvessel project because of its associated gas. It resembles Goliat in terms of gas reserves, but still under development, and therefore still subject to a feasibility study regarding monetization of associated gas.
- Kramsnø (discovery 7220/4-1) and Salina (7220/10-1) due to the size of the identified reserves and their localization nearby J. Castberg.
- Alke Nor and Sør: classified as "production likely but unclarified". The identified gas reserve is comparable to that of J. Castberg. Despite its localization being rather close to the Snøhvit infrastructure (pipeline as alternative), ALKE is considered a highly realistic pure gas field as a CNG possibility and for Gasvessel.
- Tornerose is an interesting case and classified as "production likely". It was characterized as “feasible” in the Gassco study (2014[31]) but lacks information about the reservoir, and is located far north east in the area.
- Skalle (7120/2-3) and Norvarg (7225) have also been classified as “feasible” in the Gassco study (2014) and are also potential considerations for the Gasvessel project.
- Although listed in the above table above, the Snøhvit field has not been selected because it is already in production. Snøhvit infrastructure has been considered as an alternative distribution scenario, but the information available confirms that the infrastructure (pipeline and storage at Melkøya) is at its full capacity until 2040 and no expansion plans are known to date.
- Goliat is considered as a possibility, and has been subject to previous feasibility studies of monetization of its associated gas. The current strategy is reinjection of gas and no plans for gas production are known.
- Note that, in the case of Pingvin (7319-12), although the amount of reserve has been estimated as up to 20 bcm (0,706 TCF), the review of the wellbore report concludes otherwise, that is, that the net pay looks small (14m 967-953m) which indicates relatively low reserves; in addition, with a very well-defined gas/water contact (GWC 967m), one would expect fingering of water and early shut-in of wells.

3.2.1.1 Offshore Gas Loading

Based on technical data about offshore loading locations, and in accordance with the project partners, the following two gas fields have been selected as offshore gas loading locations for Gasvessel.

- ALKE – gas field
- JOHAN CASTBERG - Oil & Gas field with Associated gas

Note that to study and compare the potential for Gasvessel from distinct types of stranded gas, the project team recommended to consider both associated gas and pure gas field.

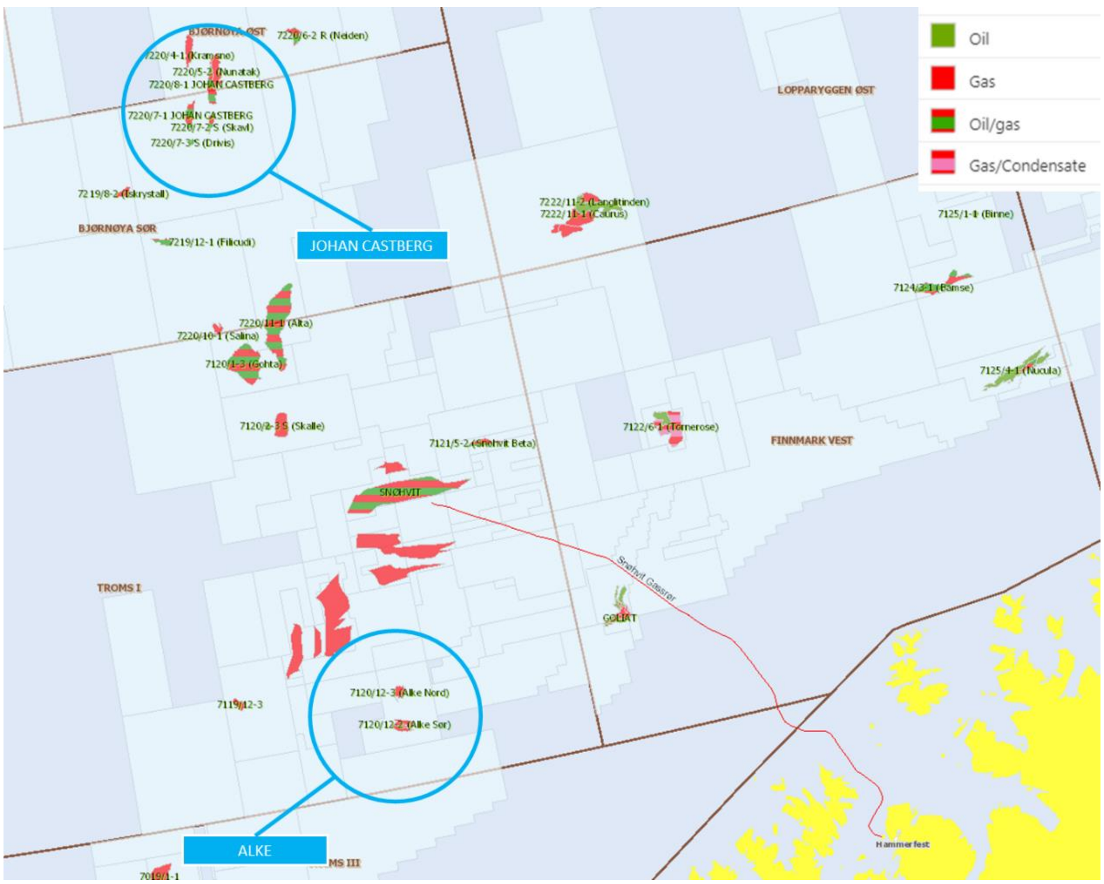


Figure 43: Map of the two suggested loading fields: JOHAN CASTBERG and ALKE

Information reported below includes field characteristics such as location, operator, reservoir characteristics, gas composition, and metocean data. In terms of gas composition, and to some extent reservoir characteristics, it has proven challenging to find information available to the public. During the preparation of this report, public information from NPD[32], NPD Factmap[33], industrial and research reports[34] have been used. The authors have also performed interviews with the operator of the pipeline distribution network for Norwegian gas, Gassco, and have been in close contact with the NPD.

Gas field – ALKE

Offshore Gas Loading Characteristics

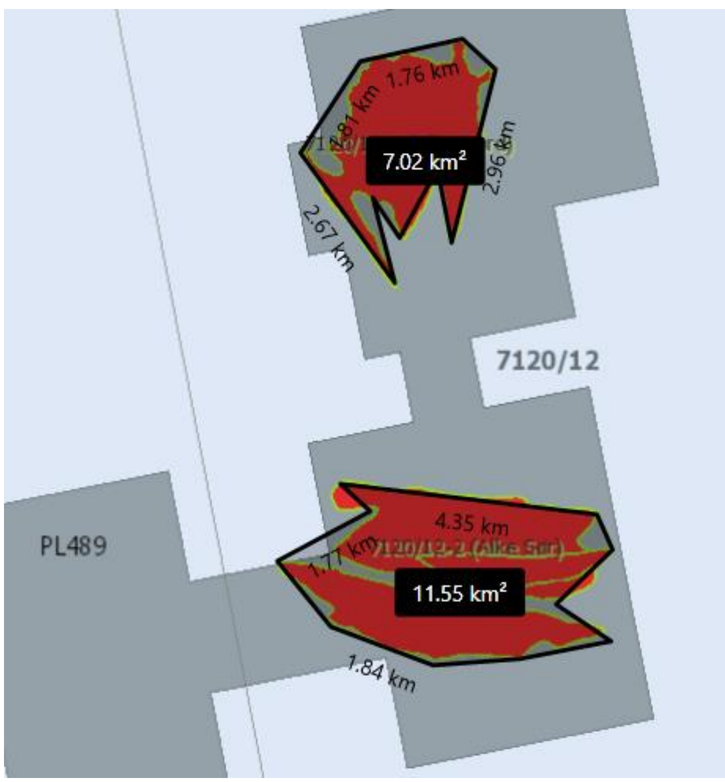


Figure 44: Alke pure gas field, North and South

Among the gas fields identified as possible for the Gasvessel project, ALKE is perceived as the most realistic. It is not too close to the Snøhvit infrastructure (entry to pipeline), a defendable size of reserve has been identified, while there is also a high likeliness for field development (which also implies more detailed information available on the field).

Name	ALKE
Type of Field	GAS/CONDENSATE
Block (license)	7120/12-2 (Alke South) and 7120/12-3 (Alke North)
Operator	Eni Norway
Year discovery	1981 (Alke North 1983)
Status	Production likely, but not identified
Reservoir	Limited information available
Recoverable gas	Wellbore/exploration: 1 gas (Alke Nord), 1 gas/condensate (Alke south) Reserves: Alke North: 11,4 bcm (0,402 TCF)
Localization	71° 7' 30.3'' N 20° 48' 19'' E
Water depth	Alke North: 185 m Alke South: 164 m
Size	Total area Alke Sør + Nor: outreach 27 km2, 11 km x 5 km
Depth	Alke North: 2523 m Alke South: 4680 m
Pressure	Alke North: Unspecified Alke South: Unspecified
Temperature	Alke North: 118 ºC (at 2523m) Alke South: 115 ºC (4680m), 77 ºC (2568m), 66 ºC (1985m) Sea water: 5-8 degrees at seabed

Table 11: Alke description and characteristics

Offshore Gas Composition and Reservoir Characteristics

Reservoir characteristics; Gas composition	Alke (North + South)[35]: • Gas: 11,4 bcm (0,402 TCF) • NGL: 0,6 Bill Ton • Condensate: 0,4 bcm (0,014 TCF) • 2562 m to 2568 m: 25.1 scmd condensate of gravity 55.92° API • 1944 m to 1950 m: 52.5 scmd condensate of gravity 64.4° API, See additional sources for field information in Appendix B.1, section II.

Table 12: Alke reservoir characteristics and gas composition

For gas delivery specifications the same assumptions as per Eastern Mediterranean geologistic scenario.

Associated gas field – JOHAN CASTBERG

Offshore Gas Loading Characteristics

The consideration of associated gas for the Barents Sea scenario is highly recommended for the Gasvessel project. In a producing oil field, especially offshore, associated gas represents a challenge because oil production implies gas production. When no easily accessible infrastructure is available (pipeline), the first step is to utilize the gas as a source of energy for the offshore facilities. This suggests that if there are no restrictions, the associated gas is usually flared, with negative environmental impacts and inefficient use of energy.

At present, however, most of the countries do not allow the flaring of the associated gas since it is a waste of energy, waste of money and a cause of pollution. In the North Sea, the oil companies have built a dense gathering system to collect the associated gas from various fields (Ekofisk, Forties, Sleipner etc.) and to transport it by pipeline to the consumers.

The situation is different for the fields in the Barents Sea already developed or in the phase of being developed. The Goliath field is a typical case, in which gas is used for the facilities but the remaining produced gas estimated around 7.06 mmscmd (250 mmscfd) is currently reinjected. Three alternatives are possible, building a pipeline is too expensive; building an LNG infrastructure would require higher gas quantity and is too expensive. Consequently, the only suitable alternative is to inject the associated gas into the producing formation. Reinjection of gas is used to maintain reservoir pressure and displace the oil, thus increasing effectiveness of oil recovery. In that way, the gas is stored for possible future gas recovery.

However, this requires deep and complex simulation studies knowing that the immiscible gas to oil displacement is an inefficient process. This is because the gas, compared to oil, is a highly mobile fluid resulting in a production characterized by continuous increase of the GOR (gas -oil ratio) due to fingering of the gas at the producing wells (gas cycling). In addition, the cost of drilling the injection wells as well as the high investment for compressors and the incremental operating cost is high. On the other hand, the immiscible gas injection technique is used as a secondary recovery process in fields containing under saturated oil, since the swelling of the oil in contact with the injected gas, might result in a high recovery factor for the field.

In conclusion, the petroleum industry has come a long way in increasing the recovery factor of an oil or condensate field since the first immiscible gas injection in 1930 in the US. Nowadays there are other EOR processes that could be applied successfully instead of utilizing associated gas, allowing for higher efficiency via the Gasvessel project.

Monetization of associated gas is difficult, but gas reinjection is not free. There are economic aspects of gas reinjection that should be mentioned[36]. For example, although injection wells are cheaper than production wells, gas must be cleaned and conditioned before being compressed and reinjected, which necessitates compressors normally driven by gas turbine (typically 3% of reinjected gas is used as fuel) or electrical motor.

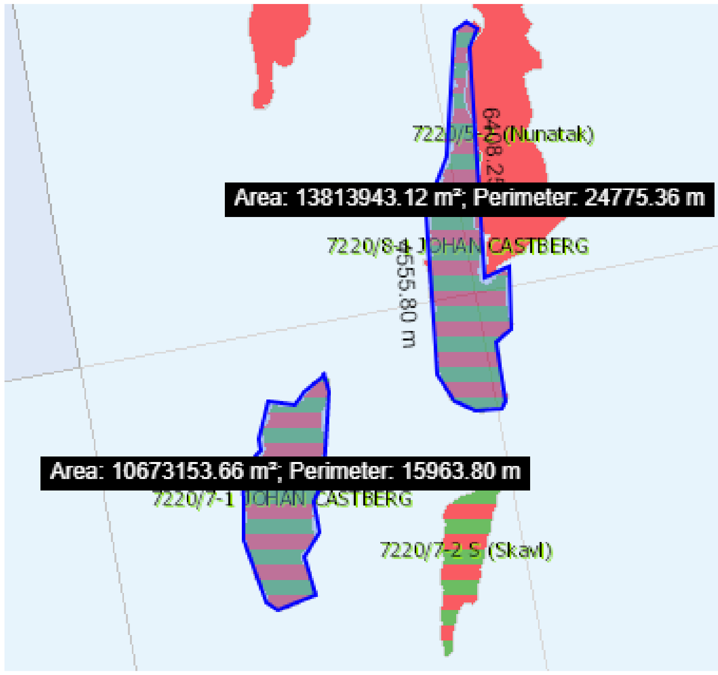


Figure 45: J. Castberg associated gas field

Name	JOHAN CASTBERG (Consisting of the fields Skrugard, Havis and Drivis)
Type of Field	Oil/Gas
Block (license)	7220/7 AND 7220/8
Operator	Statoil Petroleum AS
Year discovery	2011
Status	Production in clarification phase
Reservoir	Johan Castberg consists of three discoveries Skrugard, Havis and Drivis, proven in 2011 to 2013 in Lower to Middle Jurassic sandstone. The discoveries are planned to be developed together and the decision to continue (BoV) was taken in December 2016. The development concept includes a production, storage and offloading vessel (FPSO), with gas turbines as energy providers. The plan for development and operation (PDO) is planned to be submitted to the authorities in late 2017. The production of oil is currently based on reinjection of produced gas and water, in addition to treated seawater.
Recoverable gas	11,73 bcm (0,414 TCF) Gas from Johan Castberg is composed on light components (C2 to C4) (NILU, Statoil, 2017[37])
Localization	72.29°N 20.20°E

Water depth	370 m
Size	Distances: 7 km * 17 km, 130 square kilometres
Depth	7220/7-1: 2230 m 7220/8-1: 2222.0m
Pressure	Unspecified – estimated to be low.
Temperature	7220/7-1: 72 ºC (bottom hole) Sea water: 5-8 degrees at seabed

Table 13: Johan Castberg description and characteristics

The oil & gas field is approved for development, with start oil production planned for 2022 (operator: Statoil). The plan for Johan Castberg is to use gas turbines for power, but also to be enabled for future electrification if an economical and technical viable solution becomes available, at this stage, production of gas is not considered as part of the solution for extraction of the field's resources[38]. Gas is planned to be reinjected into the field for sustained pressure. According to documentation from Statoil, reinjection will be carried out via 5 wells[39]. Description of the gas wells is available in Figure 46, extracted from a presentation by Statoil of the production challenges of Johan Castberg ([40])

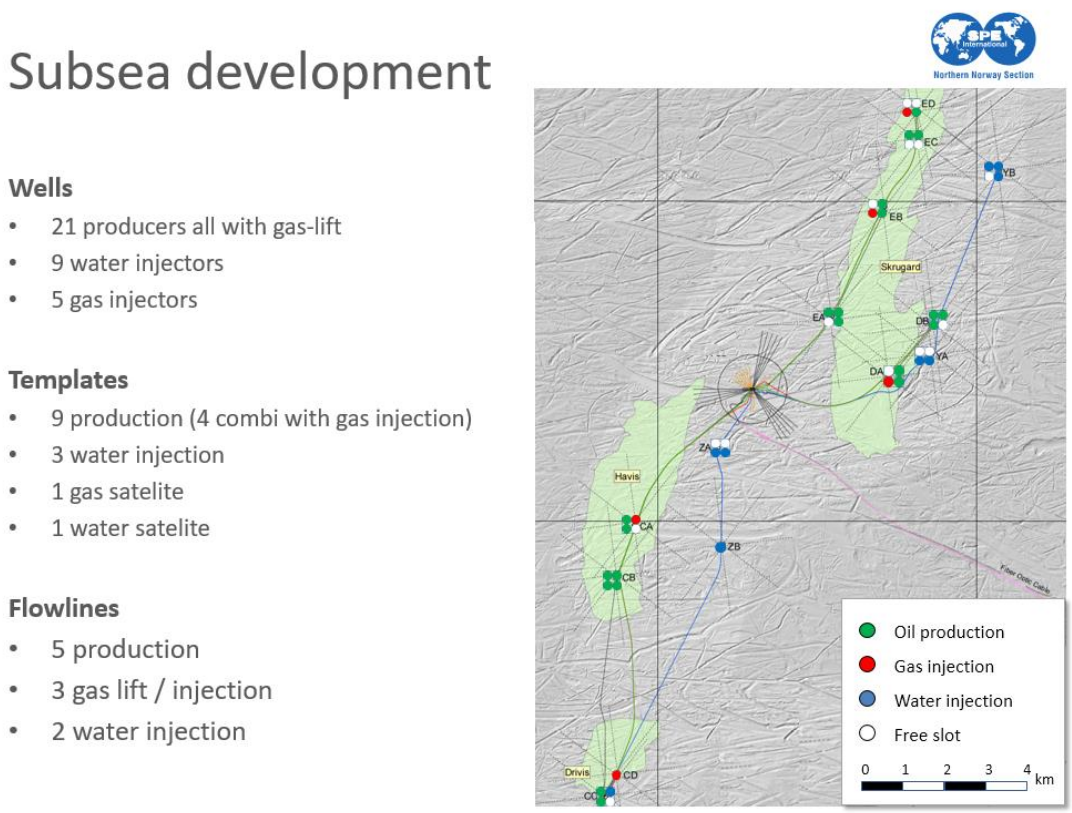


Figure 46: Johan Castberg – subsea development

Offshore Gas Composition and Reservoir Characteristics

Reservoir characteristics; Gas composition	Johan Castberg[41]: • Oil: 88,1 mmscm • Gas: 11,73 bcm (0,414 TCF) • NGL and Condensate: 0 See additional sources for field information in Appendix B, section II.

Table 14: J. Castberg reservoir characteristics and gas composition

For gas delivery specifications the same assumptions as per Eastern Mediterranean geologistic scenario.

Offshore Metocean Conditions – ALKE and Johan Castberg

The following information is to be considered relevant for both Johan Castberg and Alke.

The area on focus (Hammerfest Basin, Barents Sea Southwest) is characterized by shallow waters 300-400 m, cold climate, challenging conditions during winter including darkness, severe wind and waves, and fog during summer season. The flow of Atlantic (Gulf Stream) and Coastal waters is responsible for absence of ice formation and relatively middle temperatures. Information for the Goliat FPSO indicates that average air temperature varies from -2°C to 6°C, with min/max of approximately -15°C to +25°C. Sea water temperature lies in the range of 5-8 degrees at seabed and in the range of 1-10 degrees at sea level.

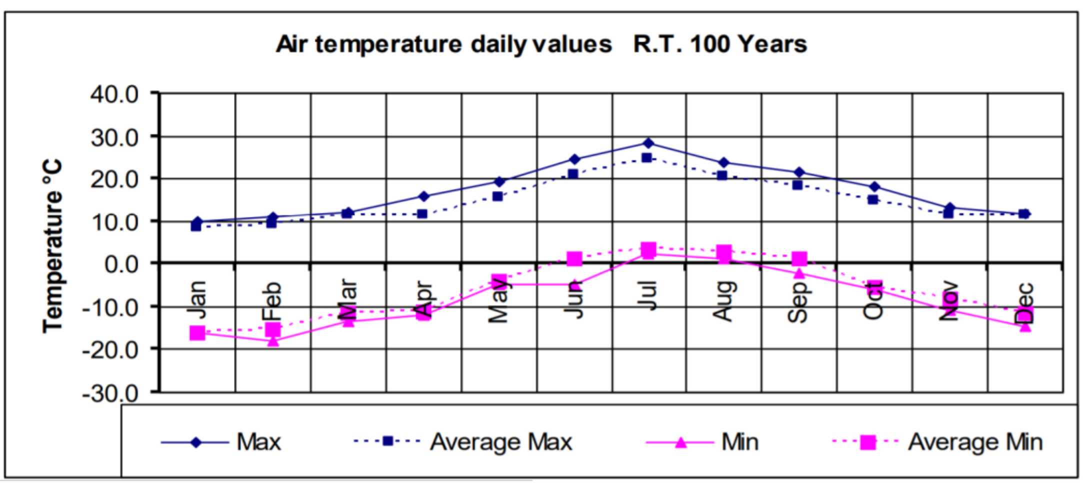


Figure 47: Air temperature Goliat FPSO

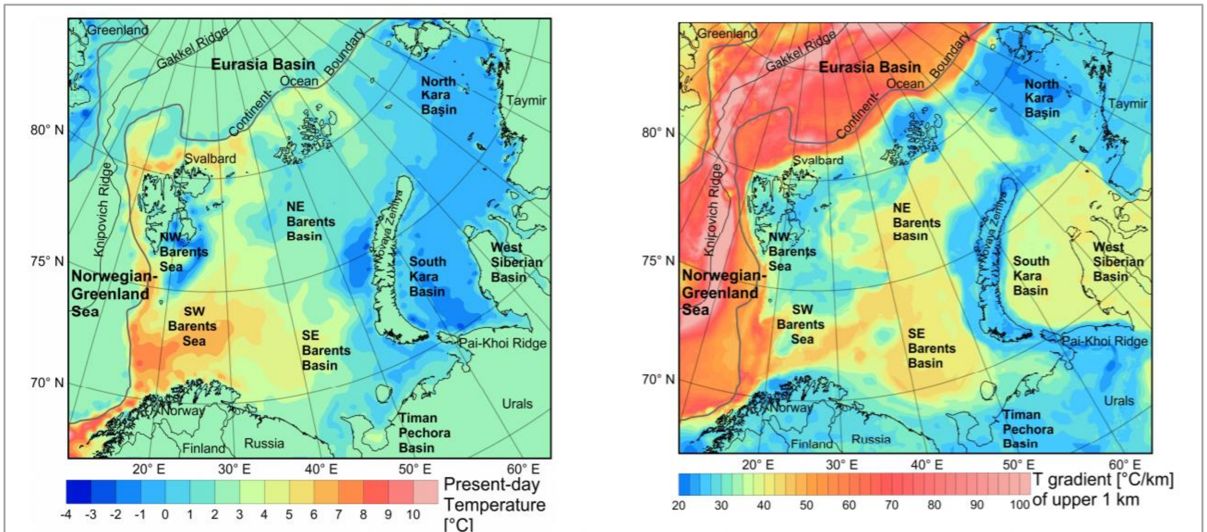


Fig. 2. (a) Present-day temperature distribution at the seafloor [28]; (b) Geothermal gradient of the uppermost 1 km below the topography.

Figure 48: Temperature distribution at seafloor, Barents Sea

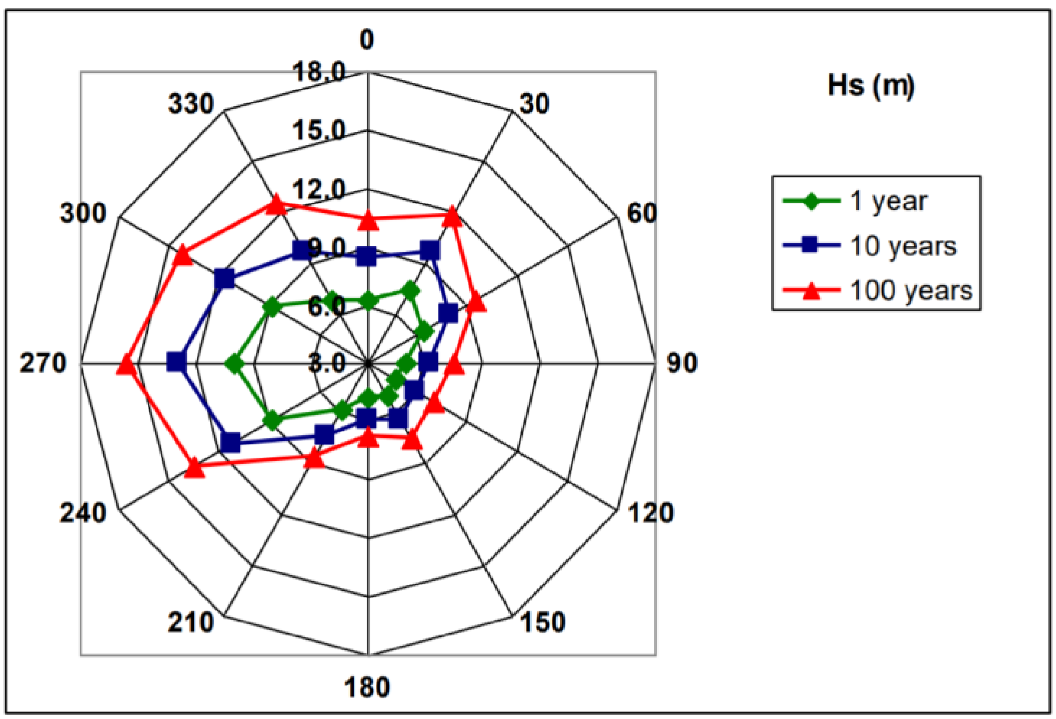


Figure 49: Wind speed, Goliat FPSO

The average wind speed in the Barents Sea southwest varies from 5 to 10m/s. With peaks at, for instance 28 m/s registered at GOLIAT FPSO (corresponding wind direct 260 degrees).

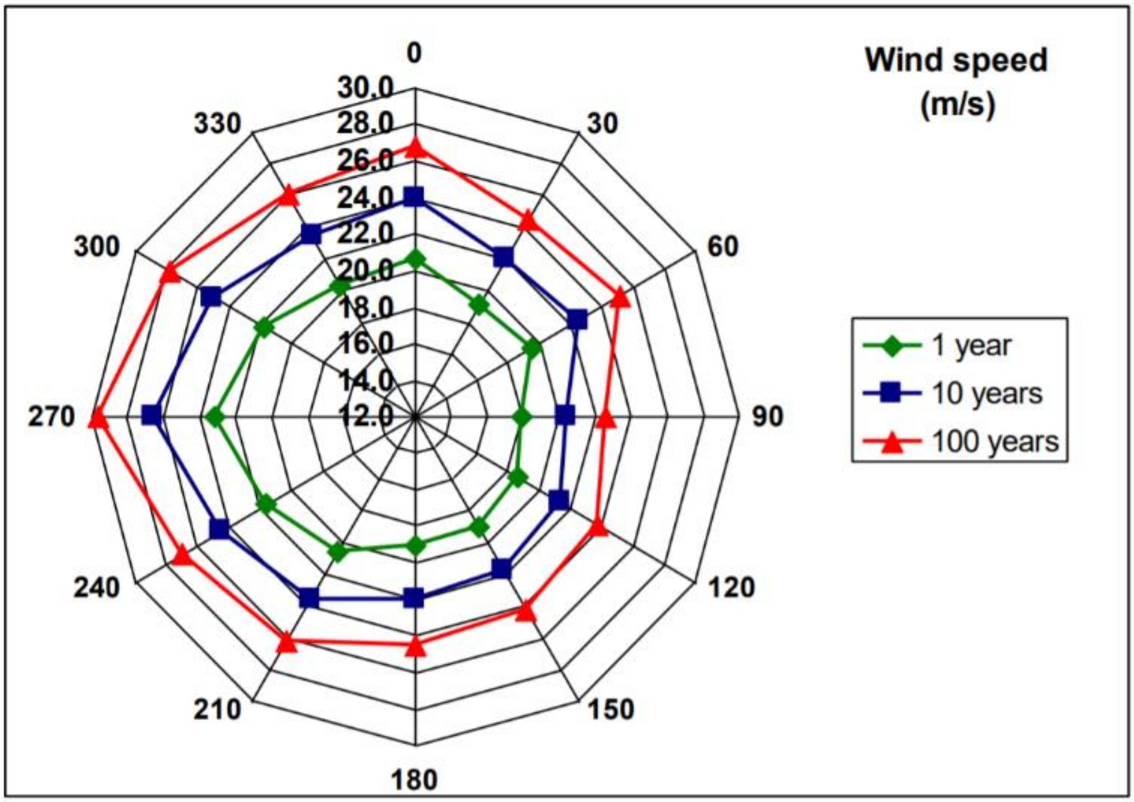


Figure 50: Significant Wave height, GOLIAT FPSO

Average significant wave height in Barents Sea Southwest varies from 1,5m to 3,3m. It should be noted that the significant wave height is generally higher in the Norwegian Sea compared to the Barents Sea.

3.3 Market Filtering Criteria

3.3.1 Target Market Methodology

The objective of the market screening conducted in the project period august-October 2017 was to identify and characterize potential target markets in North Europe for a Gasvessel project with gas loading locations situated in the Barents Sea. Countries reviewed included Norway and other Northern European countries were gas distribution is already established via the existing offshore pipeline network or where direct gas delivery by CNG vessel could be considered realistic. Market data and information included energy demand, current fuel type and energy prices, competing plans to satisfy the demand (including future government plans).

Priority was given to identify realistic cases, yet challenging due to the lack of published exploitation plans in the Northern region. Given the large quantity of fields under production and the well-established network and distribution infrastructure, the market analysis has not served to screen the entire potential market available for Norwegian gas, but rather interesting niches for CNG distribution by ship. The market analysis for this region has therefore focused on identifying opportunities not exploited today due to lack of infrastructure or transport solutions.

The two factors for identifying target markets during the screening work were: distance from loading to unloading point, and potential market size (delivery quantity).

Additionally, for this particular scenario of Brents Sea we have reached to the conclusion to progress with UK as the target market of the Gasvessel. UK being a well supplied country with a number of diversified sources, we are testing whether the landed prices of the CNG concept can compete with regional and imported prices.

3.3.1.1 Target Markets

The targeted distance criteria established by the project is approximately 81 – 163 nm (150 – 1750 km) from fields of loading (Barents Sea south west), to points of unloading. The distance from Barents Sea was estimated using the Goliat field as a reference point.

To identify relevant markets for gas from the Barents Sea south-west fields, the map below shows the point of loading (1), and the different unloading points that has been considered during the preparation of this report (2-12).

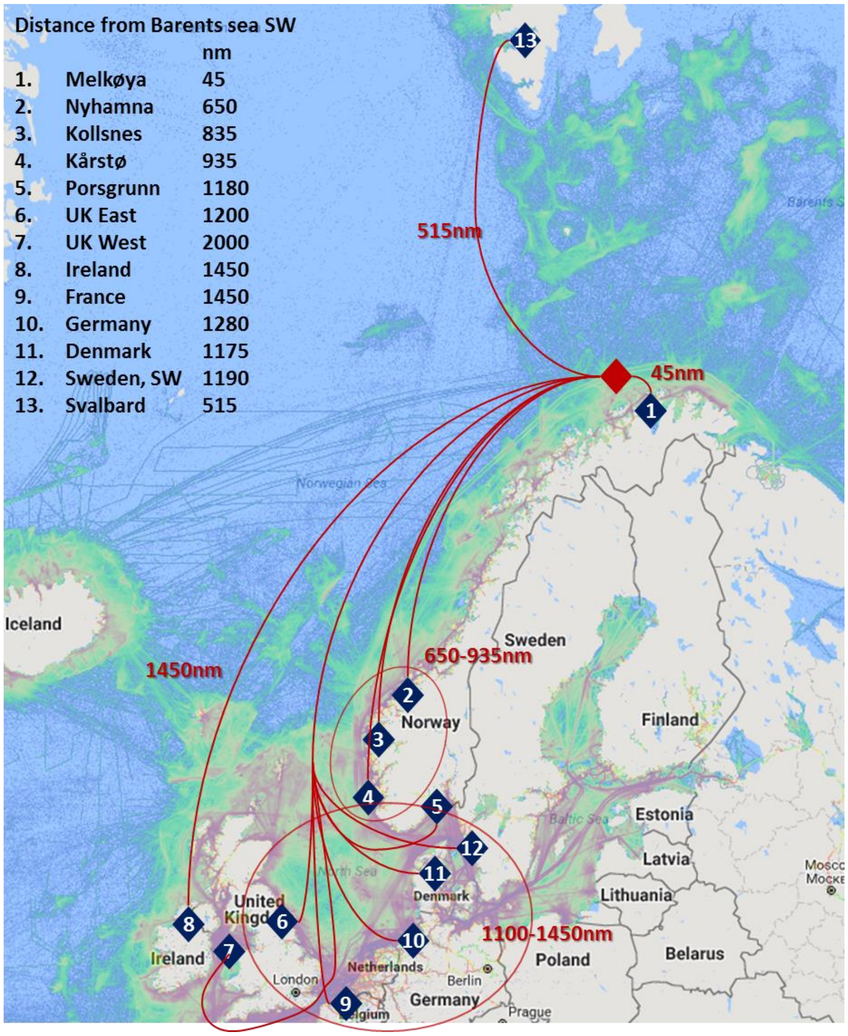


Figure 51: Potential CNG markets and distance (in nm) from Barents Sea gas field

After discussions with Gassco it became clear that out of the original distribution points in Figure 51 (Nyhama – 2, Kollsnes – 3, Kårstø – 4), the most probable point of unloading was Nyhamna (2) followed by delivery to end market – UK (6). This is due to shorter sailing distance and export capacity in the pipeline – Langeled. This resulted in the definition of the final two main scenarios (two distinct unloading points):

- Unloading direct delivery to Nyhamna.
- Unloading gas close to the Aasta Hansten field for utilization of the Polarled pipeline. Polarled was proposed as an alternative point for unloading of gas, since the pipeline is directly connected to Nyhamna, but also allowing for a considerable shorter sailing distance (sailing distance reduced with approximately 261 nm (482 km). Currently, only Aasta Hansteen is connected to the pipeline, but there is available capacity, and six additional tie-in points for new discoveries is established.

This process led to the abandonment of previous identified scenarios (See Appendix B2 for summary of market screening), including an additional scenario were gas was to be loaded from a gas production plant onshore near Kårstø (4), and unloaded at Herøya (5). The main rational behind this scenario was that it would open up for CNG supply to the Grenland region, with further distribution to the region and Oslo district. This was based on previous feasibility studies[42;43,44] and commercial attempts in the early 2000s[45,46]. However, given the evolution in the gas market of the targeted region, all previous commercial initiatives have been abandoned[47]. Indeed, LNG has expanded tremendously along the Norwegian coast (infrastructure), pushed by subvention for NOx-reduction initiatives. Biogas has also expanded and is benefiting from synergies with LNG infrastructure.

Potential market size

The targeted volume of gas for the Gasvessel project is 1.5 mmscmd – 16.5 mmscmd (50 mmscfd – 550 mmscfd). Hence, most of the work has being focusing on identifying potential local markets and specific annual demand/consumption. Information on energy consumption, forecast, energy price and on country energy dependency and energy strategy was reviewed. Potential customer analysis was based on a review of existing gas processing facilities, gas distributor, power plant (with potential for switching to gas, from coal of oil), manufactures with potential to switch for gas as energy source. The market screening carried out is summarized in Appendix B2. Despite some isolated market (power plants) identified, it was commonly agreed with project partners that these isolated markets were less realistic than delivery to pipeline entry point for further distribution from Norway to Northern Europe.

3.3.1.2 Gas Field Life

To estimate the daily rate of the gas field, an in-depth study would require more information from the operators, which is not easily accessible, and a very deep study taking into consideration geology, reserve, testing data of well(s). To estimate a theoretical daily gas production necessary for setting up a scenario for Gasvessel, the following approach has been taken: take the reserve data, assume the life of the field 25 years of production to the economic limit, and take a constant rate for 10 to 15 years then to decline the remaining reserve to the economic limit, [The economic limit is defined as the production rate beyond which the net operating cash flows (net revenue minus direct operating costs) from a project is negative].

For the ALKE reservoir, the published gas reserve is 11.4 bcm.

Well testing results publically available48 indicate the following: DST 1: 417700 m3/day; DST 3: 758000 scmd. Combining the two tests with assumed rate of 1.2 mmscmd (or 430 million per year), at constant rate for 15 years make a total production of roughly 6.5 bcm. The remaining reserve of 5 bcm taking into consideration the economic limit most likely we will decline around 3 bcm.

To check this approach, other producing field comparable to this case should be studied to check if the present calculation sound reasonable.

Estimated daily gas production: 430/365 = 1,18 mmscmd

Please note that methodology will be revised during the next work packages.

Estimated daily gas production rate Johan Castberg

Not information available. We suggest a theoretical figure assuming constant production over 25 years, in line with oil production. No deduction of gas necessary for energy production at the field or for reinjection, so this following figure is highly theoretical.

Estimated daily gas production: 11,73*1000 / 25 / 365 = 1,29 mmscmd

Please note that methodology will be revised during the next work packages.

Total potential

The graph below summarises the accumulated production and remaining gas at each field J. Castberg and Alke, as well as the combined accumulated production for both fields assuming the same start year. This is theoretical, given the current development state of the fields. The purpose of this exercise is to estimate a certain delivery quantity for the Gasvessel scenario.

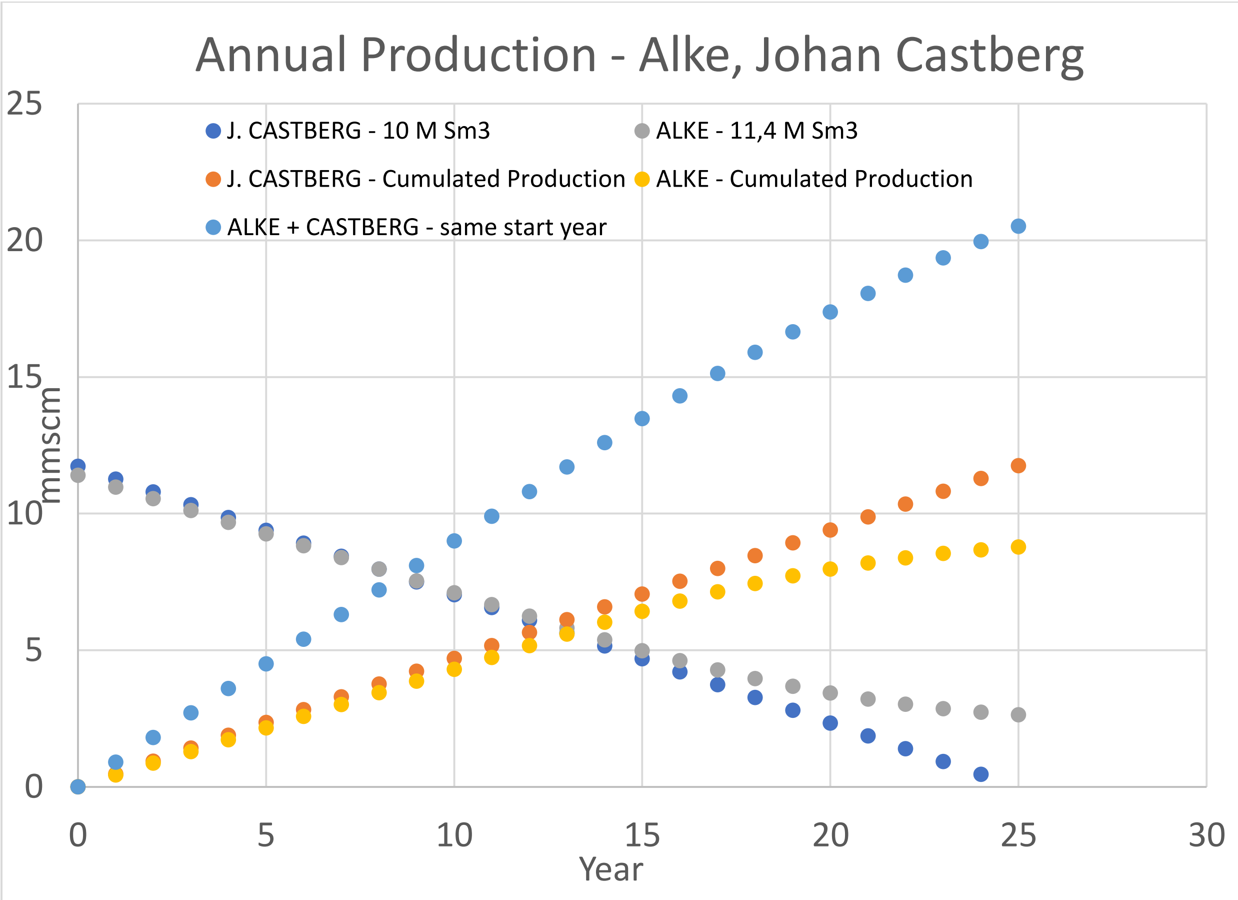


Figure 52: Theoretical accumulated annual production and remaining gas quantity

3.3.1.3 Gas Volumes and Distances

Gas volumes and distances undergo identical filtering as with the East Mediterranean scenario.

3.3.1.4 Gasvessel Sizing

Gas vessel sizing underwent identical filtering as with the East Mediterranean scenario.

3.3.2 Gas Unloading Characteristics

In the Barents Sea geologistic scenario, we have considered Nyhamna as the most relevant hub where gas can be injected, and through existing offshore pipeline network, be sent to the identified and proposed end market – Easington UK. Nyhamna accommodate, process and export gas via the Langeled pipeline. However, since Nyhamna now also handle gas volumes from the new pipeline Polarled, an alternative point of unloading is offshore close to the installation Aasta Hansten located in the Norwegian Sea, approximately 162 nm (300 km) from shore. Nyhamna accommodate, process and export gas via the Langeled North pipeline.

As such, two points of unloading are identified as relevant for both selected scenarios:

- Unloading through sea based unloading point at the Nyhamna processing plant for quality and quantity control before being further distributed via Langeled North Pipeline to the end market
- Unloading offshore close to Aasta Hansteen for distribution to Nyhamna processing plant via Polarled, followed by distribution to end marked.

For the market served by the offshore pipeline connection, the potential quantity of gas to be delivered at entry point has not been based on market demand forecast, but rather, calibrated by pipeline capacity and estimated daily production rate. The estimated daily production at the two fields Alke and Johan Castberg are 1,17 mmscm and 1,19 mmscm respectively. This corresponds to approximately 2% of Polarled and Langeled pipeline capacity each.

FACILITY	NYHAMNA	POLARLED (at Aasta Hansten)
LOCALISATION	62.27°N 5.44°E	67.057°N, 7.107°E
DISTANCE FROM J. Castberg / Alke in nm (km)	686 (1270) / 645 (1195)	422 (781) / 377 (698)
CAPACITY	70 mmscmd dry gas	70 mmscmd dry gas
Export, distribution	Pipeline to Easington, UK	Pipeline from Aasta Hansteen to Nyhamna
Theoretical daily production rate J. Castberg/ Alke mmsmd (mmsfmd)	1,29 (45)	1,18 (42)

Table 15: Potential gas volume delivery based on pipeline capacity

Melkøya LNG terminal, although with a capacity of 6 bcm LNG per year, was not considered a potential delivery point. This is since there is no available transport capacity before 2040, but also due to lack of information on future development plans. Especially with regards to capacity expansion of the existing pipeline network and LNG terminal.

The distance between the different unloading points – Polarled and Nyhamna are approximately 261 nm (482 km).

Unloading point - Nyhamna

Location:

- 62.850°N, 6.933°E
- Distance from:
    - Johan Castberg: 689 nm (1270 km)
    - Alke: 645 nm (1142 km)

The processing plant Nyhamna, mainly serving the Ormen Lange field, is a conventional facility for dewatering, compression, gas export, separation of condensate, stabilization, storage and fiscal metering of gas and condensates[49]. There is currently ongoing an expansion project to also enable handling of gas from the Polarled pipeline[50].

Figure 53: Nyhamna gas processing plant

Distribution by pipeline is presented in the table below, accounting for 20% of the UK demand.

Pipeline name	From – to	Capacity million Sm3/day	Dimension (inches)	Length (km)	Entry point location
Langeled North	Nyhamna - Sleipner	74,7	42	627	62.8513°N 6.9511°E
Langeled South (further from Sleipner)	Sleipner - Easington	72,1	44	543	58.36°N 1.91°E

Table 16: Pipeline distribution network[51]

After discussions with Gassco, the tariff for transporting gas through the pipeline also includes any processing costs. The pipeline tariff is 0.0036 €/m3. See appendix B4 for detailed tariff calculation.

Summary:

ENTRY POINT Nyhamna	DELIVERY POINT Easington, UK
Pipe(s) name	Langeled North + South
Pipeline Capacity to end destination (mmscmd)	74,7 and 72,1
Tariff (entry+exit in €/sm3)	0,00967+0,0069+0,0175= 0,034 NOK 18/m3 = 0,0036 €/m3
Destination	Easington, UK

Table 17: Nyhamna delivery point data

Nyhamna supplies 20% of UK gas, through the Langeled pipeline with daily capacity of 72.04 mmscmd (2550 mmscfd). This is approximately 26,365 mmscm per year, twice as much as the total estimated field/discovery reserve (up to12,000 mmscm). Therefore, it is necessary to determine the quantity /market size arbitrarily. Using "available capacity" as reference is not relevant because this seems to vary continuously and deliveries can be booked almost on the spot following regulations set by Gassco[52]. No minimum quantity required (data not found), but gas shipper must honour the quantity agreed in the contract. 1% to 3 % of the daily pipeline capacity would give the following:

- **1%** => 0.71 mmscmd (25 mmscfd)
- **2%** => 1.44 mmscmd (51 mmscfd)
- **3%** => 2.16 mmscmd (77mmscfd)

Metocean data and information for the Nyhamna region is summarized below.

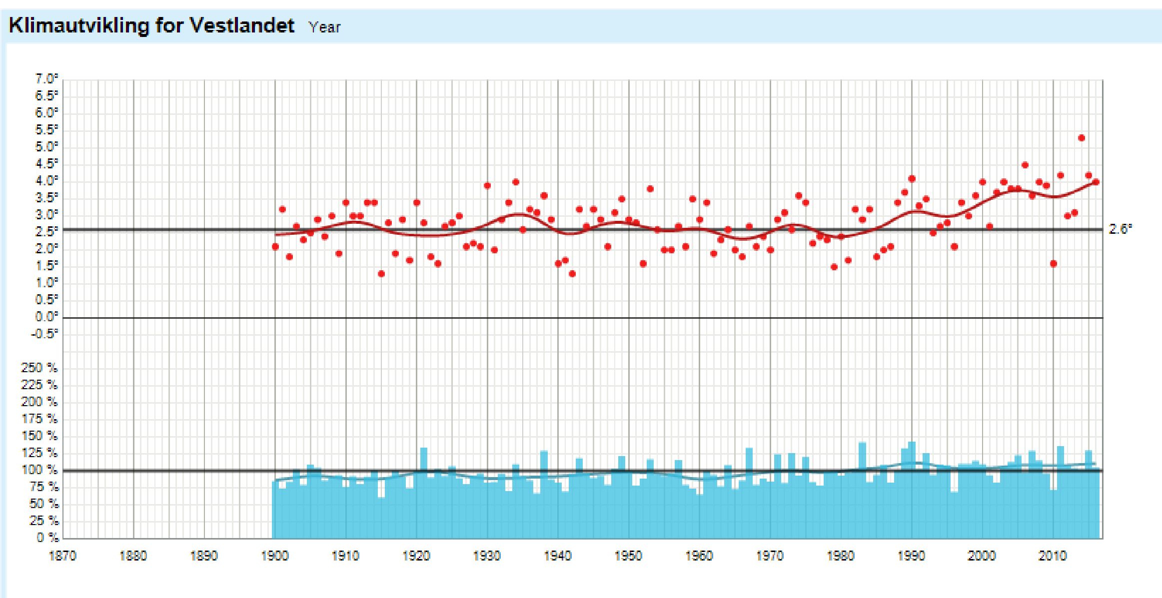


Figure 54: Temperature and precipitation, Vestlandet region

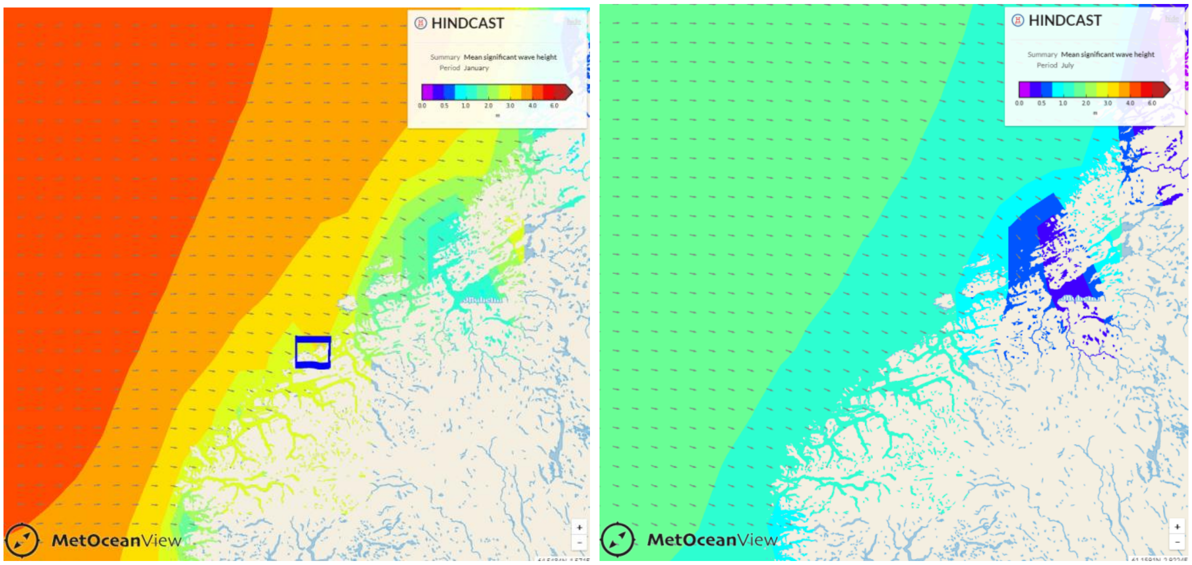


Figure 55: Mean significant wave height, Norwegian sea (Nyhmana blue quandrant)

Wind:

- Mean wind speed, annual: 10-12 kts
- 50**%** 10m wind speed: 12-14 kts
- 99% 10m wind speed: 25-30 kts
- RPV 10 year wind speed: 50-60 kts
- RPV 100 year wind speed: 50-60 kts

Unloading point - Polarled

The Polarled gas pipeline connects the Aasta Hansten field, operated by Statoil, with the Nyhamna processing plant. Starting at a water depth of 1300 meters, 162 nm (300 km) west of the city Bodø, it stretches for 419 nm (482 km) to Nyhamna. The construction of the pipeline is completed, and the operatorship is now formally transferred from Statoil to Gassco, the expected start-up is end of 2018[53]. Currently, only Aasta Hansten is connected to the pipeline, but there is available capacity, and six additional tie-in points for new discoveries is established.

Location:

- Coord. 67.057°N, 7.107°E (estimated entry point for unloading, near Aasta Hansten field)
- Distance [nm (km)] from:
  - Johan Castberg 422 (781)
  - Alke 377 (698)

Figure 56: Polarled connecting the Aasta Hansten field with Nyhamna

Pipeline name	From – to	Capacity million Sm3/day	Dimension (inches)	Length nm (km)	Tariff NOK18/Sm³ €/Sm3	Entry point location	Distance from fields
Polarled	Aasta Hansten - Nyhamna	70	36	261 (482)	0,0558 NOK18/Sm³ 0,0059 €/Sm3	67.057°N, 7.107°E	Castberg: 422 (781) Alke: 377 (698)

Since Polarled pipeline is not planned to come into operation before late 2018, no cost information is available for Gassco. Hence, the tariff for Polarled is assumed to be comparable to Haltenpipe (See appendix B4 for detailed tariff calculation).

Metocean data and information for the Polarled region is summarized below.

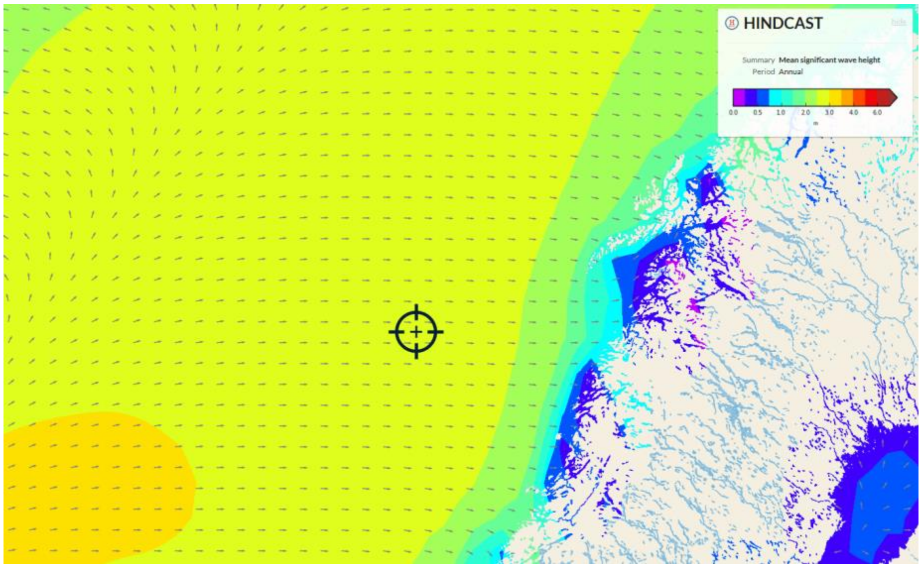


Figure 57: Annual mean significant wave height for the Polarled region

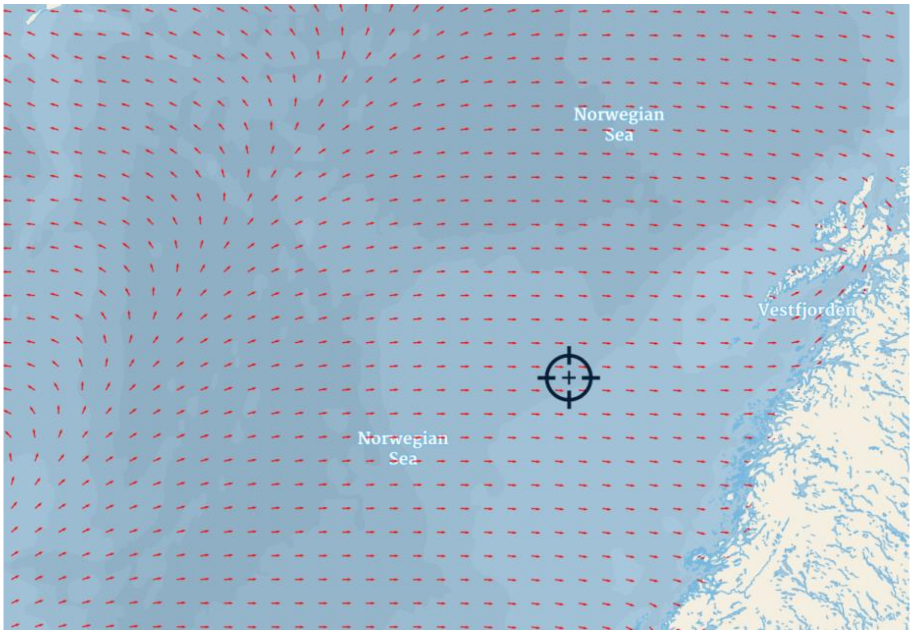


Figure 58: Annual mean wave direction for the Polarled region

Wind:

- Mean wind speed, annual: 12-16 kts.
- 50**%** 10m wind speed: 14-16 kts.
- 99% 10m wind speed: 25-30kts.
- RPV 10-year wind speed: 50-60 kts.

Temperature:
- Annual mean air: 6-10 °C
- Annual mean sea surface: 7,5-10 °C

3.4 Barents Sea Proposed Target Market

3.4.1 UK market profile

UK Overall Demand and Supply Profile

According to National Grid UK[54], the pattern of gas supply in Great Britain has changed dramatically in the past 15 years.

Great Britain has gone from being gas self-sufficient in 2000 to being dependent on imported gas for around half of its needs in 2016, with imports from Norway (29 bcm) making the biggest contribution to overall imports. Production from the UK Continental Shelf (UKCS) declined from 95 bcm in 2000 to 35 bcm in 2016. This has been replaced with gas from Norway, continental Europe, and the world market delivered as liquefied natural gas (LNG). We can expect a similar change looking forward. Over the next 30 years, the UKCS will continue to decline. A number of scenarios have been taken into consideration.

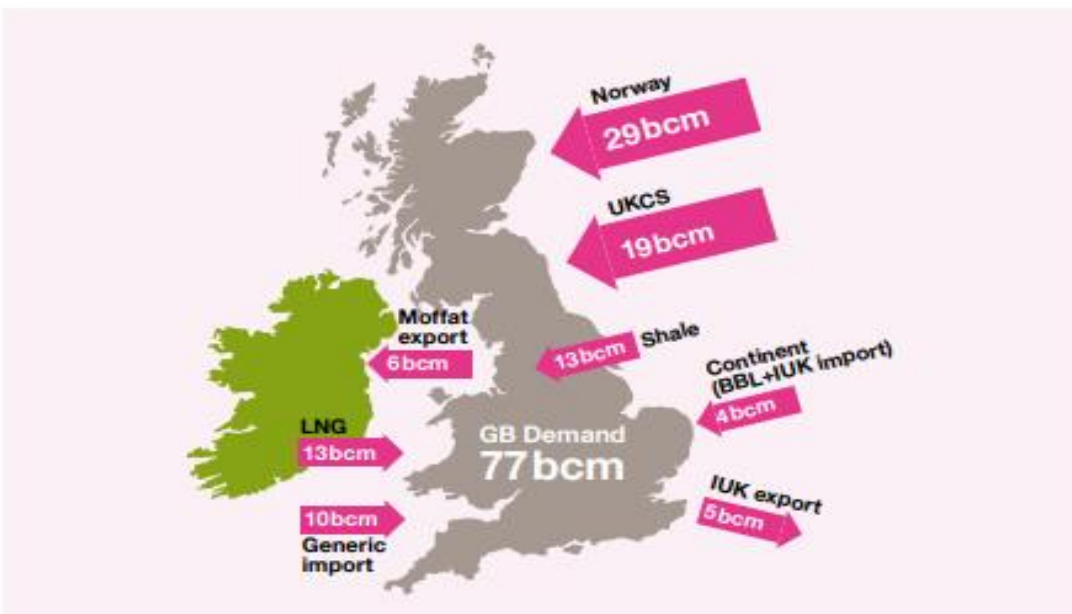


Figure 59: UK Gas import and export volumes

According to government reports, there are close to 8.4 billion barrels of oil equivalent (Bboe) of resources remaining in 491 unsanctioned discoveries across the UK continental shelf (UKCS), but only 30 (just over 1 Bboe in total) appear to be potentially commercial. As a result, although short-term increases in production might be clear, a precipitous decline is approaching and the overall reduction in the UK's hydrocarbon production will be substantial[55].

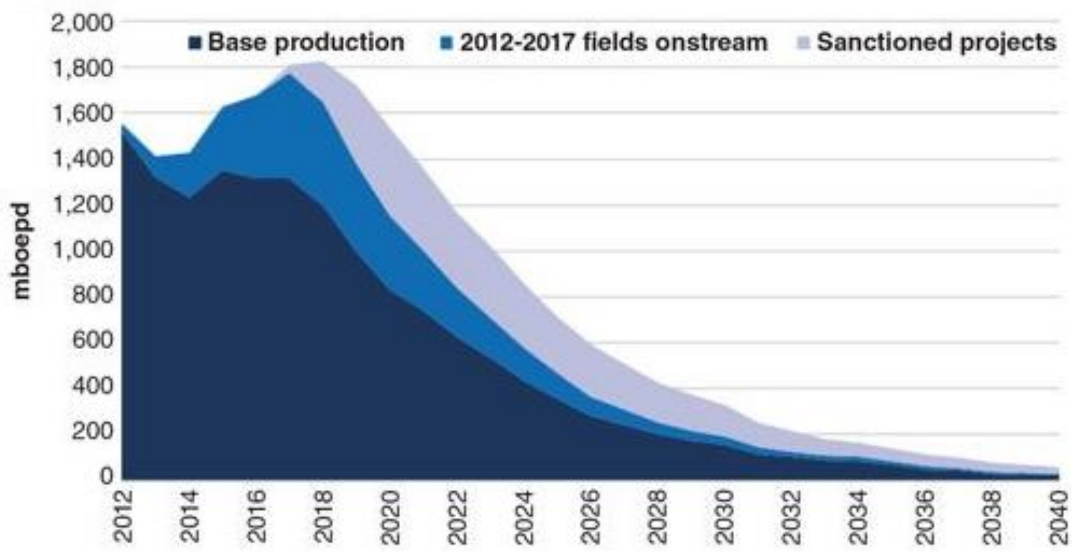


Figure 60: UKCS oil and gas production profile until 2040

The following Consumer Power analysis describes a scenario with high gas demand, but also where government policies are focused on indigenous energy supply. With the highest indigenous supply, this is the scenario with the lowest import dependency. According to this analysis, as seen in Figure 64, import dependence fluctuates around 50% until 2050. It is fair to assume that overall import dependency will lie somewhere between 50 - 80 %[56].

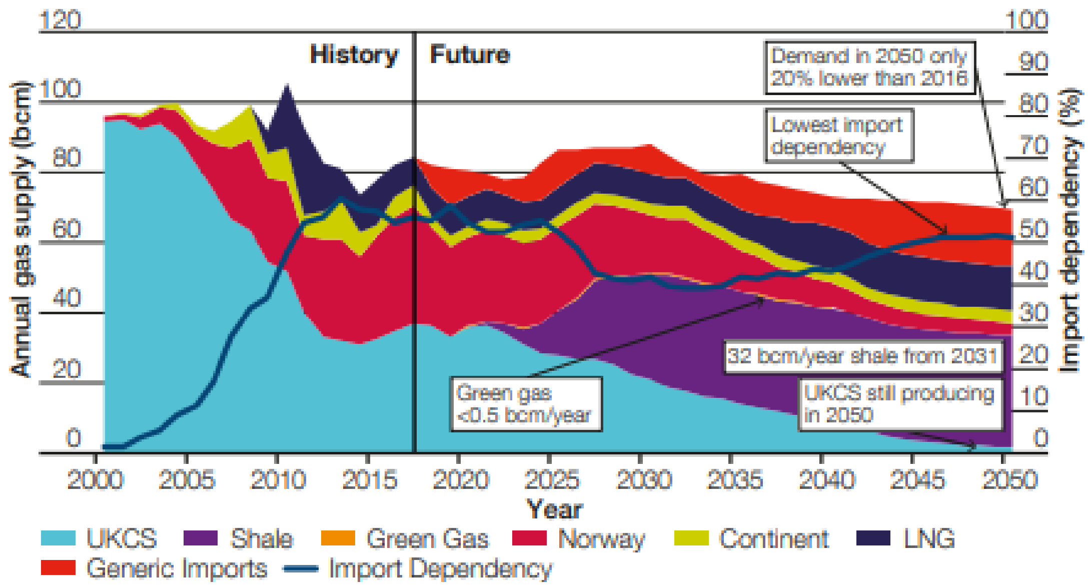


Figure 61: Consumer Power analysis of GB gas import dependency

Demand

The relative development of domestic production, gas imports and total demand is visualized below[57].

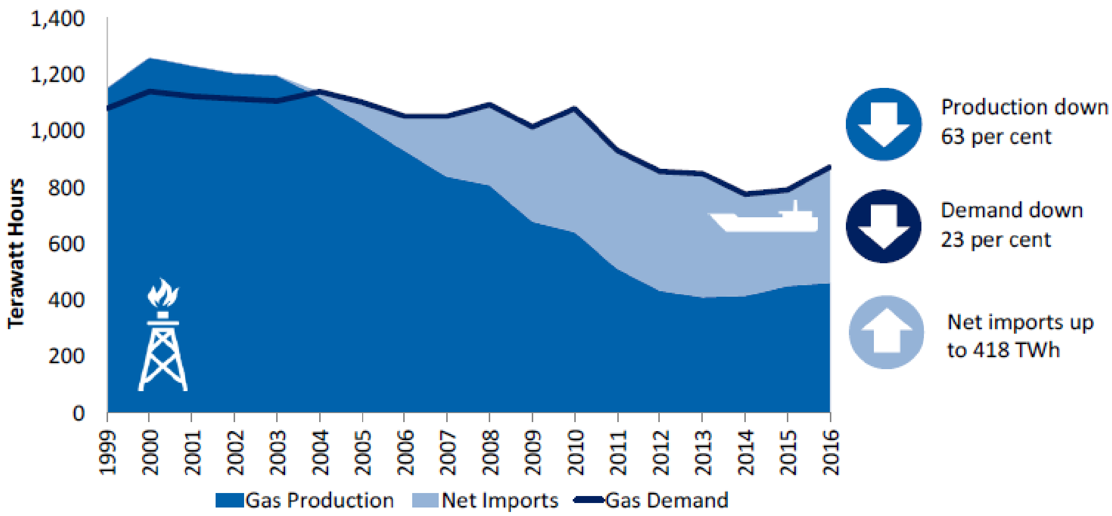


Figure 62: Changes over time in gas production and demand

Looking at main consumers of natural gas, power generation and households are by far largest consumers measured in terawatt hours.

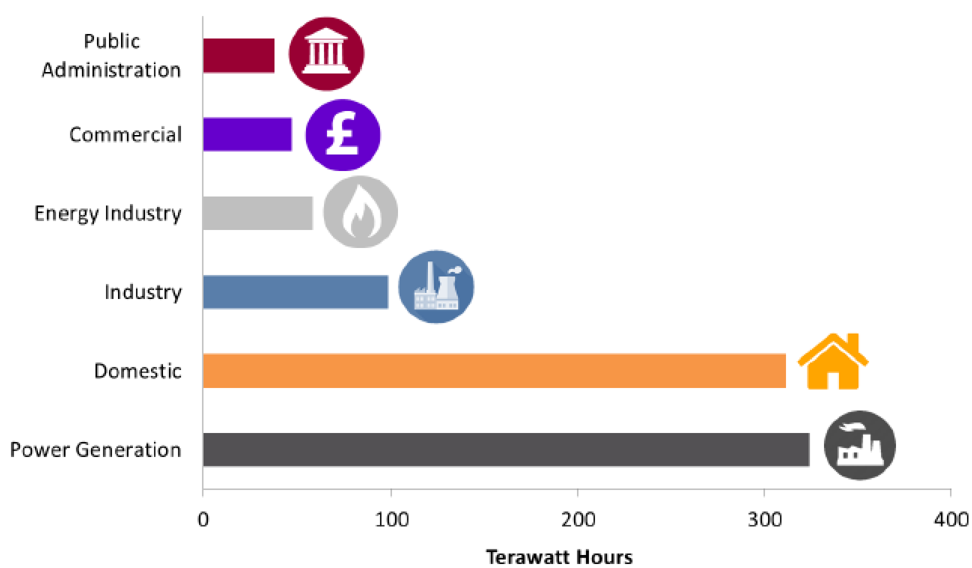


Figure 63: UK gas demand in 2016

Supply

The dominating nation of origin is Norway, with a total pipeline import volume in 2017 of 35.890 mill cubic meters. The import volumes per annum since 2006 are visualized below, with land and field of origin and relevant pipeline for import. The numbers also show volumes from Belgium and the Netherlands.

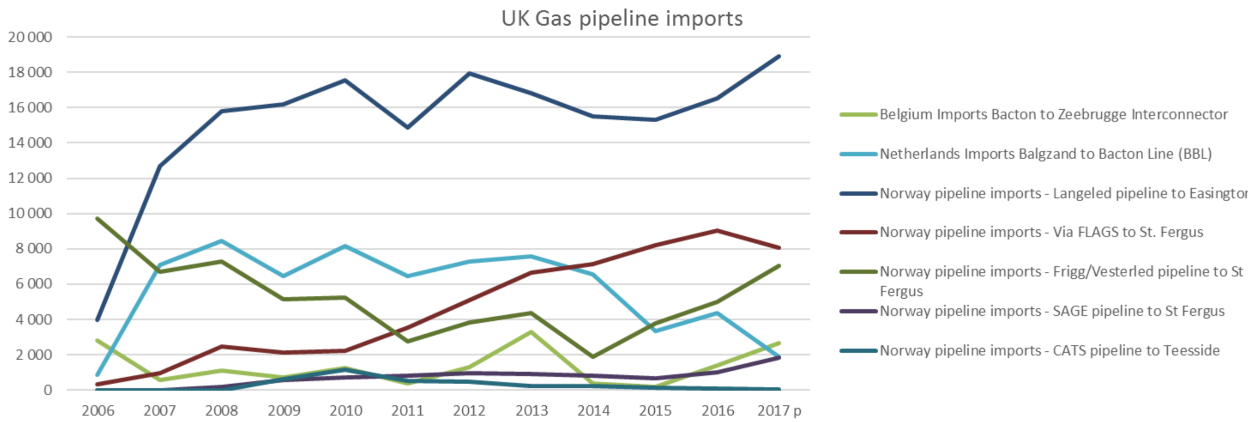


Figure 64: UK Gas imports by pipeline, in million cubic meters

Volume imports per pipeline:

Gas import pipeline	Volume in million cubic meters (2017)
Belgium Imports, Bacton to Zeebrugge Interconnector	2649
Netherlands Imports, Balgzand to Bacton Line (BBL)	1869
Pipeline imports from Norway, Langeled pipeline to Easington	18934
Pipeline imports from Norway, via FLAGS to St. Fergus	8052
Pipeline imports from Norway, Frigg/Vesterled pipeline to St. Fergus	7061
Pipeline imports from Norway, SAGE Pipeline to St. Fergus	1813
Pipeline imports from Norway, CATS pipeline to Teesside	29

Table 18: UK gas imports by pipeline in mmscm[58]

Infrastructure

- Norway
  - Vesterled pipeline (13.1 Bcm/y): from the Heimdal Riser platform in the North Sea to St Fergus in Scotland
  - Tampen pipeline (9.1 Bcm/y) – from the Statfjord field to the Flags pipeline system (landing at St Fergus in Scotland)
  - Langeled pipeline (25.9 Bcm/y) – from Ormen Lange via the Sleipner Riser platform in the North Sea to Easington, England
- Ireland (Interconnector)
  - UK Interconnector 1 and 2 (UK Export): 6 Bcm/a and 12 Bcm/y
- Belgium (Interconnector)
  - Zeebrugge-Bacton (UK import): 25.5 Bcm/y

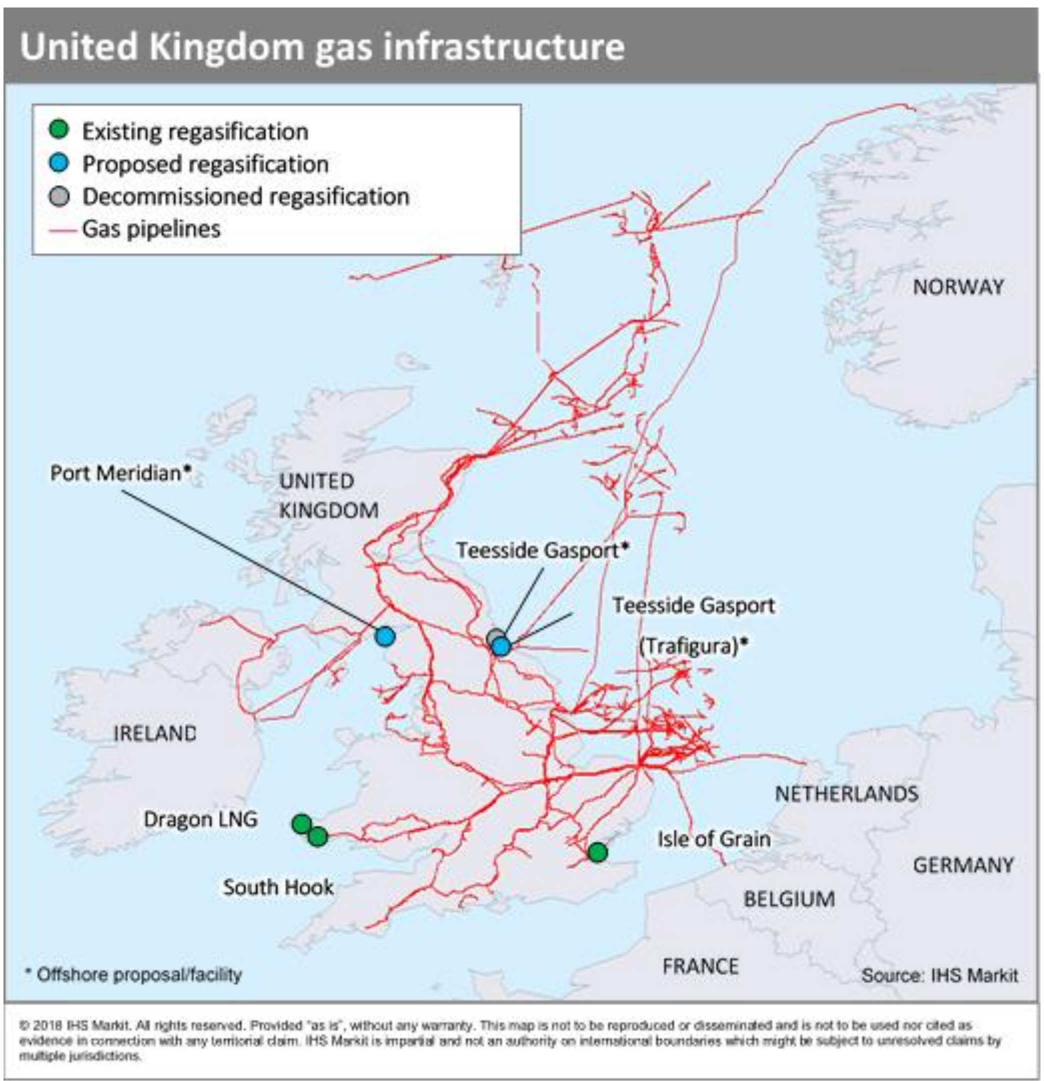


Figure 65: UK pipeline infrastructure

Regulations

Regulation of the Langeled pipeline

Gassco is the capacity allocator of the Langeled pipeline, required to provide access to the transport system on equal, objective and transparent terms for all shippers of gas. For shippers to book transport capacity there are two main approaches that can be applied, namely the primary- and secondary capacity market[59].

1. Primary capacity market: On a bi-annual basis, Gassco organizes bookingrounds where shippers can request spare capacity in the transport system on a medium to long term basis. Prior to these rounds, Gassco collects data which form the basis for estimating transport capacity requirements. Within this primary capacity market Gassco also handles shipper's requests for available capacity on a daily basis – when and if this is available. Terms and agreements for this are available on the Gassco official website. Moreover, the primary booking system allows shippers to:
    a. Book capacity in the primary market (day, short, medium and long term).
    b. Check their own bookings for any day at any time.
    c. Sell and buy their own capacity in the secondary market (day, short, medium and long terms), with deals closed in the market-place automatically confirmed by the TSO, and shown in the overview of the shipper's own bookings.
    d. Compare their own nominations with bookings.
    e. Check capacity position for any day (spare capacity, restrictions).
    f. Check their own capacity.
    g. Rebook capacity between points when spare capacity is available[60].
2. Secondary capacity market: This market includes the marketplace for capacity transactions facilitated by Gassco (providind available capacity in the system), and the ability for shippers to trade capacity between themselves. The following procedure describes the marketplace facilitated by Gassco:
    a. Only qualified shippers can participate in the secondary capacity market.
    b. The shipper requiring capacity must demonstrate Qualified Need.
    c. Bids and offers posted on the marketplace are valid until acceptance or withdrawal.
    d. All trades in the secondary market are subject to the “Standard Agreement for Trading of Capacity in the Secondary Market”.
    e. An offer to sell or a bid to buy is accepted at the moment they are accepted by the counterparty in the Gassco Booking System.
    f. Transfer of capacity rights take effect from such point in time when the transfer is registered on the Gassco Booking System[61].

In terms of invoicing, all shippers are invoiced for the capacity they have booked in accordance with latest tariff regulations.

Regulation of end user UK market

The end user market of UK is regulated by the Office of Gas and Electricity Markets (Ofgem), a non-ministerial government department and an independent National Regulatory Authority (recognised by EU Directives), with a principal objective of protecting interests of existing and future electricity and gas consumers. This is cared for in several ways:

- promoting value for money.

- promoting security of supply and sustainability, for present and future generations of consumers, domestic and industrial users.
- the supervision and development of markets and competition.
- regulation and the delivery of government schemes[62].

The information about this form of regulation is extensive and readily available on the internet[63] and also includes:

- Transmission networks, covering network price controls, entry and exit capacity, carbon capture and store, and information concerning forums, seminars and working groups.
- Distribution networks, presenting connections and competition, network price controls, charging arrangements and network innovation.

Hence, the project finds it most reasonable to provide a brief overview of information available, and where it can be accessed. This also secures that the most up-to-date information when needed.

Prices

UK gas spot prices are normally linked to the UK National Balancing Point (NBP) price, being the current price in the market at which natural gas can be traded for immediate delivery. In this "system", gas anywhere in the national transmission system within the UK counts as NBP gas. This allows for a simplification of the trading of gas, since both supply and demand are players in the same marketplace[64].

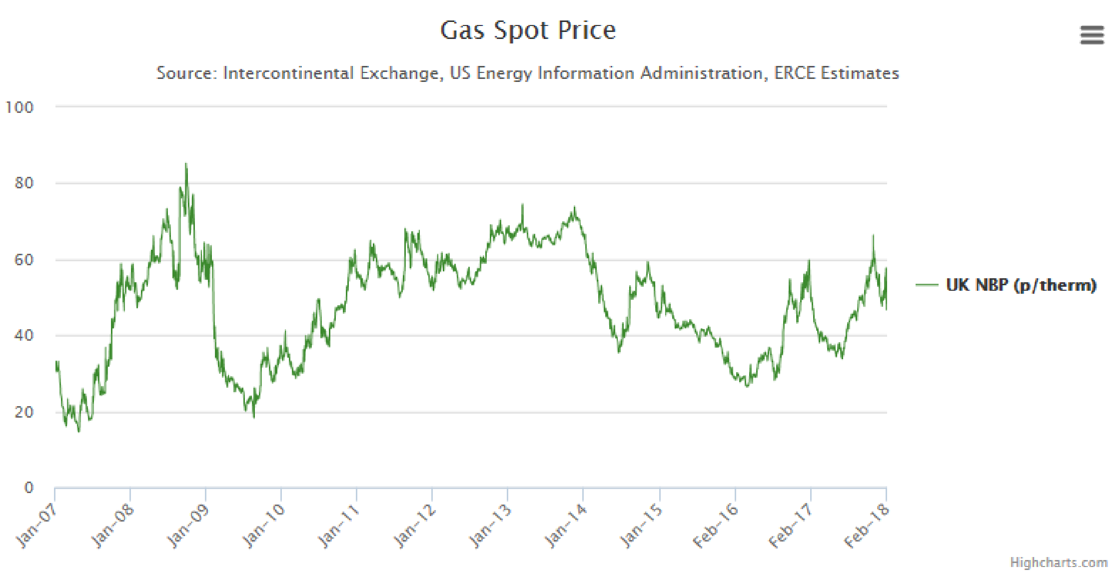


Figure 66: UK wholesale gas price

As the figure above indicates, the historic development of UK gas price has been relative volatile the last 10 years, ranging from just below 20 pence per thermal unit to approximately 85 pence per thermal unit. The NBP gas market permits trading from a wide range of participants; financial traders, industrial users, utilities, companies, power generators, LNG suppliers and oil and gas producers. Hence, the price indicated in the graph can be considered as the downstream tariff for Gasvessel.

Year	p/thermal	$/therm	$ Mcf	p/ Sm3	€/m3
jan.07	30,78	0,43	4,46	11,67	0,1167
jan.08	53,65	0,75	7,75	20,34	0,2034
jan.09	54,74	0,23	2,39	20,75	0,2075
jan.10	37,00	0,52	5,35	14,02	0,1402
jan.11	57,60	0,80	8,33	21,82	0,2182
jan.12	52,75	0,74	7,62	19,99	0,1999
jan.13	66,65	0,93	9,63	25,27	0,2527
jan.14	68,59	0,96	9,91	26	0,26
jan.15	46,28	0,64	6,69	17,55	0,1755
jan.16	33,29	0,46	4,81	12,62	0,1262
jan.17	50,68	0,79	8,21	19,21	0,1921
jan.18	54,42	0,76	7,86	20,63	0,2063

Table 19: UK wholesale gas price in € per cubic meter[65]

With regards to expected development of gas prices for the UK market, the following figure indicates a relative stable gas price around 45 pence per thermal unit for the coming 5 years.

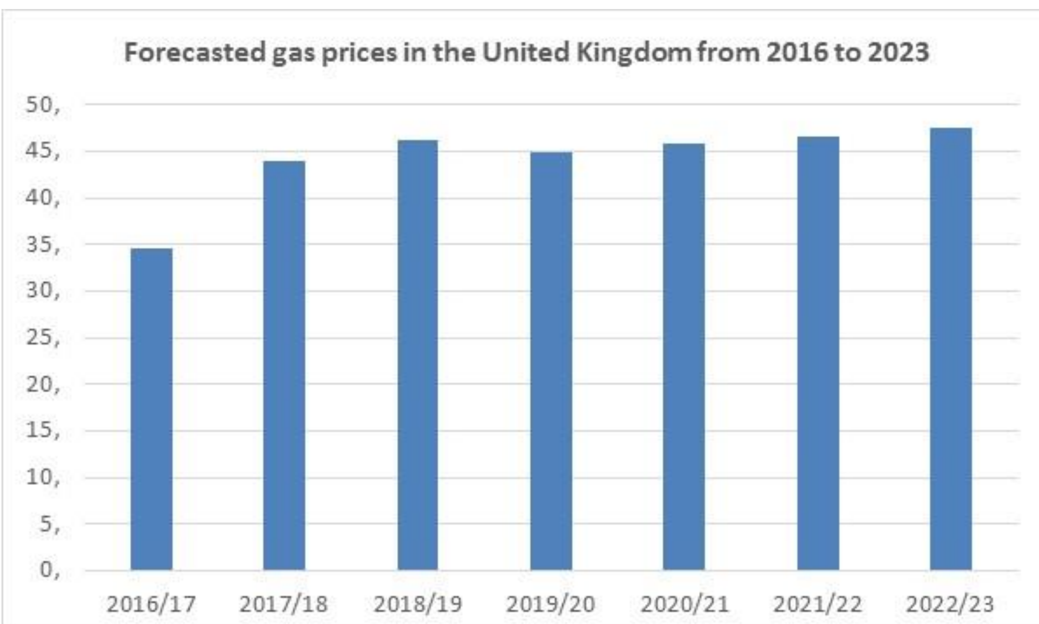
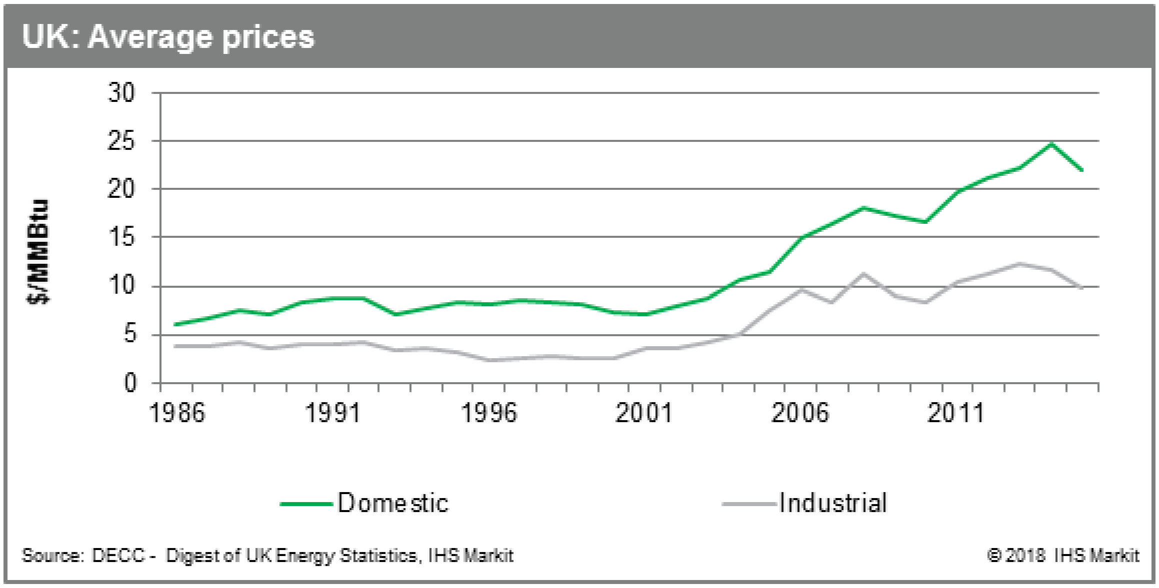


Figure 67: Forecasted UK gas prices - in pence per therm

Historical prices for domestic and industrial users



Players

Supplier	Customers in the UK (Million)	Parent	Other divisions and brands	Previous brands
British Gas	15	Centrica	Scottish Gas	
EDF Energy	5.6	EDF		SEEBOARD, SWEB energy & London Electricity
E.ON UK	4.6	E.ON		Powergen
Npower	6.5	innogy		Innogy, Northern Electric, Yorkshire Electricity
Scottish Power	5.3	Iberdrola	PPM Energy	MANWEB
SSE	9.1	SSE Group	SSE	Scottish and Southern, Southern Electric, SWALEC & Scottish Hydro

Table 20: UK Main Gas Suppliers

The above table depicts the six biggest gas distribution companies in the UK continent, in terms of population and customer numbers.

3.5 Resulting Scenarios

For the Barents Sea Geologistic Scenario we have proposed different case studies for the Gasvessel concept by collecting and analysing information related to gas source targets located mainly at Barents Sea and by filtering the energy market of countries around the North Sea area. We have identified 2 potential sources of gas one from an gas associated gas field called J. Castberg and another from a gas field called Alke. Regarding our investigations on the markets we have concluded to UK's gas market not only because it is considered to be growing gas demand market but also it retains an advanced pipeline distribution network that can allow transfer of Gas from Nowar to UK gas users. To connect the gas source at Barents Sea with the UK though the Gasvessel concept we have proposed the below options:

1. J.Castberg to Polarled/Nyhamna

Case Study 1 consists of two sub-cases:

- Case 1.1: offshore loading from a floating processing facility at Johan Castberg (A) field and offshore unloading at Polarled close to Aasta Hansteen (2) field for transport of gas by pipeline to Nyhamna – and via export pipeline Langeled to end market in UK, or

- Case 1.2: offshore loading from a floating processing facility at Johan Castberg (A) gas field with offloading nearshore to Nyhamna gas facility (1) for transport to end market in UK via gas export pipeline – Langeled.

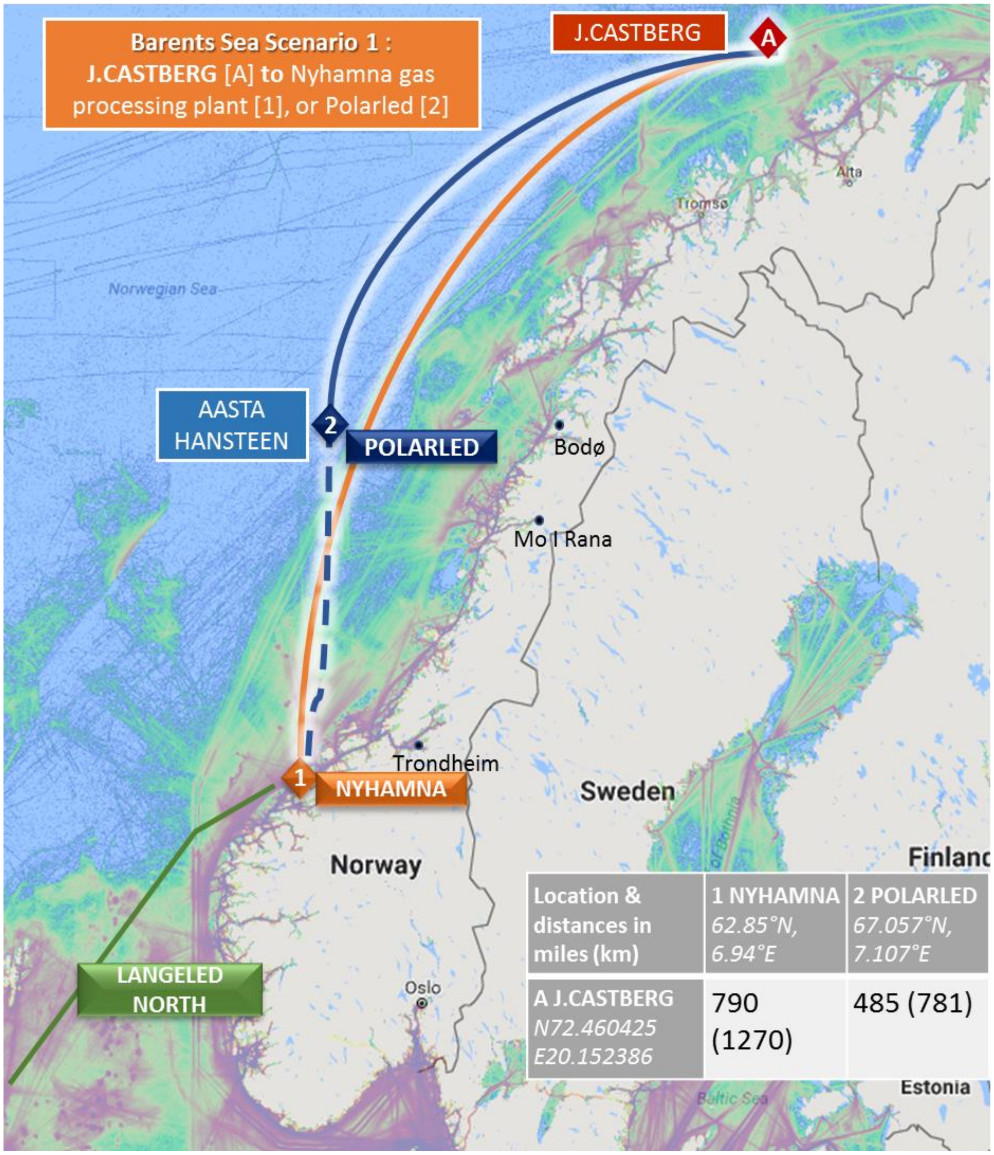


Figure 68: Scenario 1: Offshore (J. Castberg) to onshore pipeline entry point

LOADING POINT		**Polarled**	UNLOADING POINT **NYHAMNA**
JCastberg	Distance to unloading point nm (km)	422 (781)	686 (1270)
Gas Reserve 11,73 bcm	Delivery quantities/day mmsmd (mmscfd)	1,29 mmsmd	1,29 mmsmd

Table 21: J. Castberg delivery quantity estimation

2. Alke to Polarled/Nyhamna

Case Study 2 consists of two sub-cases:

- Case 2.1: offshore loading from FSO at Alke field (B) and offshore unloading at Polarled close to Aasta Hansteen (2) field for transport of gas by pipeline to Nyhamna – and further transportation via Langeled to end-market in UK, or
- Case 2.2: offshore loading from FSO at Alke field (B) with offloading nearshore to Nyhamna gas facility (1) for transport to end-market in UK via gas export pipeline – Langeled.

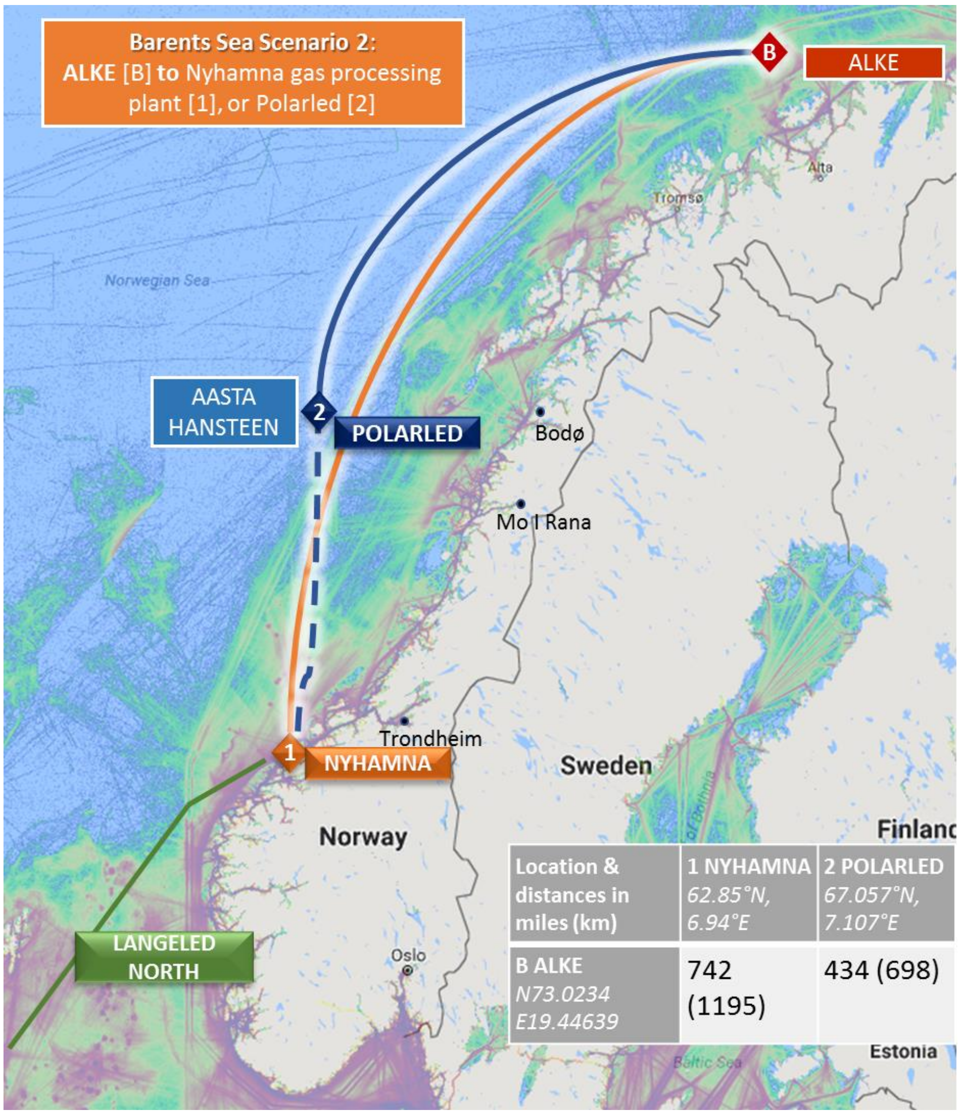


Figure 69: Scenario 2: Offshore (Alke) to onshore Pipeline entry point

		Polarled	UNLOADING POINT **NYHAMNA**
LOADING POINT **ALKE**	Distance to unloading point (Nm)	377 (698)	645 (1195)
Gas Reserve 11,37 bcm (401 bscf)	Delivery quantities/day mmscmd (mmscfd)	1,18 mmsmd	1,18 mmsmd

Table 22: Alke delivery quantity estimation

3.6 Costs and Tariffs

This chapter provides cost and tariff estimates for delivery of gas from the identified source locations to the identified markets. The calculation of end-to-end costs is based on the methodology set up by CHC.

Inputs

Description of Cost and Tariff Headings

The data will generally contribute to the estimation of the following:

- Upstream Cost
- Midstream Cost
- Downstream Cost

The above elements, when taken as a whole, form the full gas value chain for delivery of gas from an offshore field to its end buyer.

1. **UPSTREAM COST (A):** refers to the total CAPEX and OPEX cost of extracting natural gas from the gas field and delivering and ready for storage.

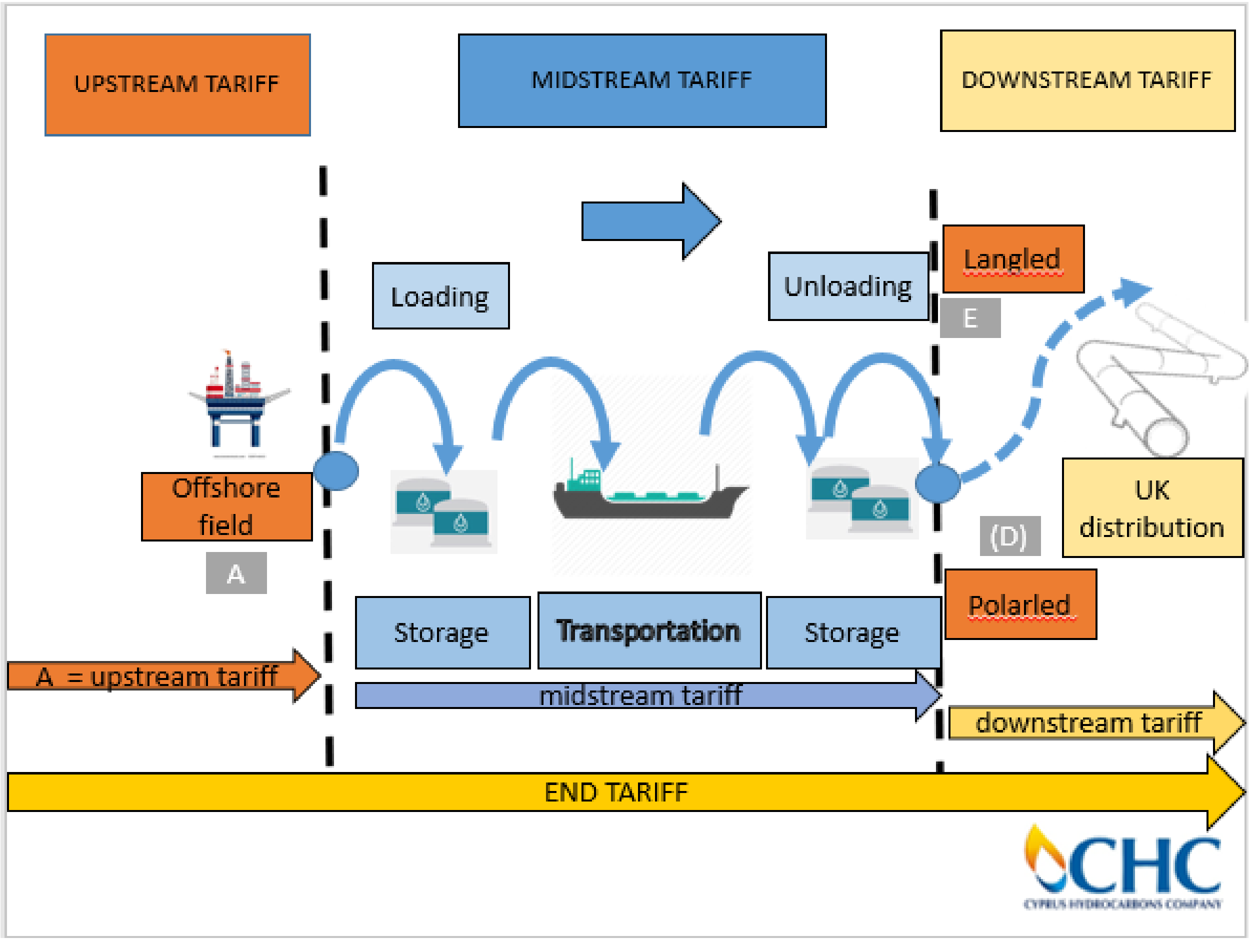
2. **CNG TRANSPORTATION COST or MIDSTREAM COST** refers to all the CAPEX and OPEX concerning the total cost of delivering the CNG from the field to a distribution network, from which it can be delivered to the end consumer. If compression and processing is undertaken on site, then these costs are not calculated in the field tariff. Specifically, the general CNG transportation costs include:
    - Upstream loading system costs (including upstream storage and vessel loading)
    - Transportation of gas (includes vessel construction costs and transportation costs)

- Downstream unloading system costs (including downstream storage and vessel unloading

3. **DOWNSTREAM COST** refers to all CAPEX and OPEX costs concerning the costs of directing the natural gas through the distribution network to reach UK through Langeled. Note here that these are already existing facilities therefore tariffs have been calculated already and should be used in computing the end tariff. In this case there are two gas unloading options with different costs.
   DOWNSTREAM COST (D): Gas is unloaded in Polarled offshore pipeline (tariff of using Polarled), in the case of Polarled use then the end tariff includes the end distribution tariff through Langeled to UK.
   DOWNSTREAM COST (E): tariff regarding distribution of gas to end consumers in UK through the Langeled pipeline. In the case where only Langeled pipeline is used, then (E) represents the entire downstream costs. In the case where gas is loaded first in Polarled and then to Langeled via Nyhamna, then the downstream cost to pipe the gas to the UK includes both (D) and (E).

4. **OTHER COSTS** relate to costs of the CNG after its delivery to its target market destination.

5. **END TARIFF** is the sum of all the preceding costs in the value chain, meaning all costs mentioned above from 1 – 4. This price estimation should be comparable with local natural gas prices (if applicable) or with alternative energy prices, in order to establish financial feasibility and profitability margins. This implies that end tariffs of the CNG value chain should be comparable with end tariffs calculated for other monetization options' value chain, such as LNG or direct pipeline supply.



Note the following:

- <u>Offshore Downstream</u> tariff = downstream costs (D) + downstream costs (E)
- <u>Onshore</u> Downstream tariff = downstream costs (E)

Note here that midstream tariffs are identified as midstream costs here for the purposes of the project in order to specifically direct efforts into the calculation of these costs as they are critical. Thus, midstream tariff is calculated as:

- Midstream cost (upstream loading, upstream storage, vessel loading, transportation costs, vessel building costs, vessel unloading, downstream storage and downstream unloading).

Similarly, the downstream tariff is identified as the total cost of distribution to end clients after unloading.

The end tariff however, is considered to be the accumulation of upstream, midstream and downstream tariffs, such that:

- End tariff = (offshore upstream cost or onshore upstream cost) + midstream cost + downstream cost

3.6.1 Upstream Cost Estimation

Despite the high uncertainty of upstream tariff due to many influence factors, the present section presents background information and suggested method for cost estimation.

In a recent study, Rystad Energy[66] depicts the average cost of production of a barrel of oil or gas equivalent, including gross taxes, capital spending, production costs, administrative/transportation costs. This is suggested to be used as reference for estimating upstream tariffs. Although those are average cost figures per country, it is suggested to use Norway figures as reference for upstream cost estimates for Gasvessel Barents Sea scenarios.

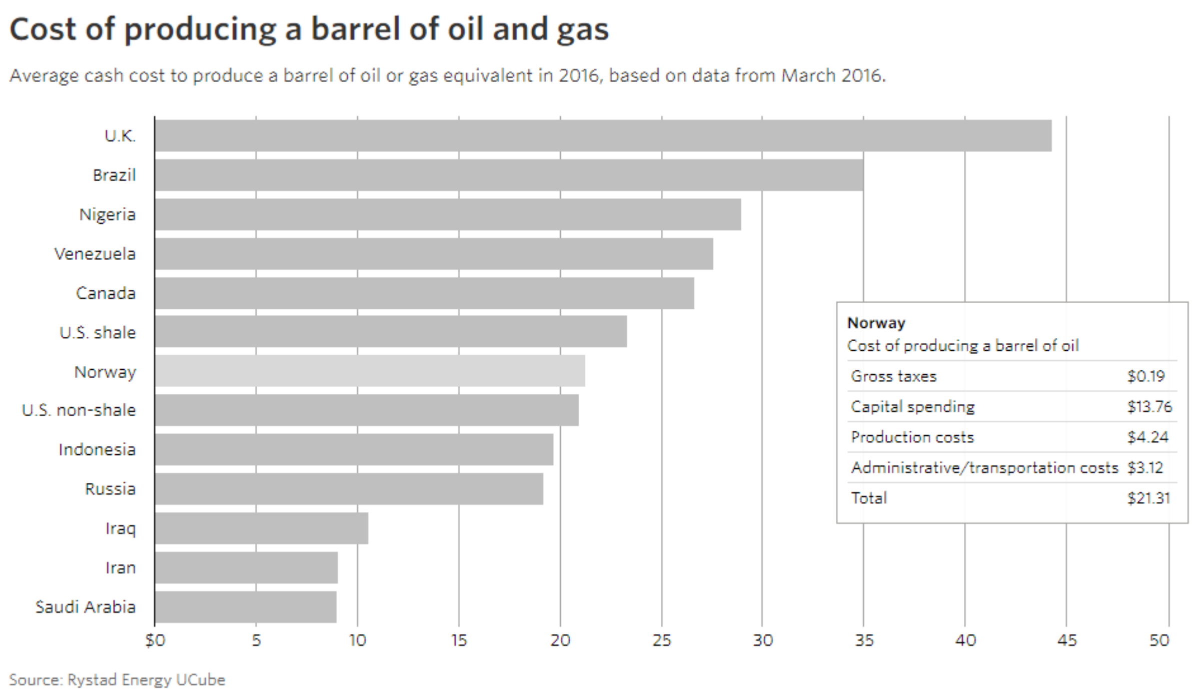


Figure 70: Cost of producing a barrel of oil and gas

Find below the cost of producing a barrel of oil and gas in Norway in €/cm[67].

	$/boe	€/cm	%
Gross taxes	0,19	0,001	1
Capital spending	13,76	0,071	65
Production costs	4,24	0,021	19
Administrative / Transportation costs	3,12	0,016	15
Total	21,31	0,11	100

Associated gas field: Johan Castberg

Statoil with its partners ENI and Petoro, have reduced the costs of the project in the past few years, dropping it from 80 $/bbl to around 35-30 $/bbl [68].

This cost figure is comparable to the average cost of producing a barrel of oil and gas identified by Rystad Energy (see Figure 70), for Norway (21,31$ per barrel of oil/gas). No information has so far been accessible with regards to tariff of associated gas. Therefore, to estimate the theoretical cost/tariff of the associated gas from Johan Castberg, it is suggested to assume that the costs of field development are included in the oil upstream tariff, i.e. not reflected in the upstream gas tariff, and that the main cost factor will be the cost of production. To estimate this cost, it is suggested to apply the ratio production costs/ total costs of barrel of oil & gas as defined by Rystad Energy for Norway, ie, 14% (based on national average). 14% of Johan Castberg's estimated barrel costs of 30 $/bbl gives an estimate of 4,2$ per boe, i.e. 0,021€/m3 (0,75$/mmbtu).

Please note that our assumptions thus far might have resulted in generic cost estimations and will be further revised in the future.

Alke: Gas field

For estimating the upstream cost of the gas from Alke, it is suggested to used Johan Castberg development costs as reference, since only this field and the Snøhvit field can be used as reference points in the same geographical area. As referred above, the development cost of Johan Castberg has been reported to be 30 $/bbl [69]. Based on this, the estimated upstream cost of gas at Alke for the present Gasvessel scenario is 0,154 €/m3 (5,4 $/mmbtu)

	ALKE (ref. cost = project cost J. Castberg)				J. Castberg (only cost of production = 14% of 30$)			
Cost of producing a bbl of oil&gas	**30**	**$**		**€**	4,2	**$**		€
cost per mmbtu	5,404081162	$/mmbtu	4,32326493	€/mmbtu	0,756571363	$/mmbtu	0,60525709	€/mmbtu
cost per Gm3	192857324,4	$/Gm3	154285859,5	€/Gm3	27000025,41	$/Gm3	21600020,3	€/Gm3
cost per m3	0,192857324	$/m3	0,154285859	€/m3	0,027000025	$/m3	0,02160002	€/m3
cost per ft3	0,005571434	$/ft3	0,004457147	€/ft3	0,000780001	$/ft3	0,000624	€/ft3

Please note that our assumptions thus far might have resulted in generic cost estimations and will be further revised in the future.

3.6.2 Midstream Tariff Calculation

This tariff element will be provided by Naval Progetti.

3.6.3 Downstream Tariff Calculation

Downstream tariff consists of the tariff of delivering the gas from the Gasvessel unloading point to the end market. In the Barents Sea scenario, unloading points are: Polarled (Aasta Hansteen field) or Nyhamna (nearshore). The end market is Easington (exit point for the subsea pipeline Langeled).

Tariff estimates are therefore based on pipeline tariffs, which are provided be Gassco and available (yearly updates) online[70]:

Appendix B4 provide details of the tariff estimate calculation. The following estimates are generated:

- Tariff estimate Polarled: 0,0059 €/m3
- Tariff estimate Langeled: Cost per €/m3 = 0,00967+0,0069+0,0175=0,034NOK18/m3 (2) = 0,0036 €/m3

This results to the following downstream costs estimates:

Scenario #	Unloading	Doawnstream transport	transport tariffs estimates
1.2 and 2.2	near Nyhamna	Langeled pipeline: Nyhamna-UK	0,0036 €/m3
1.1 and 2.1	Near Assta Hansteen	Polarled pipeline Aasta Hansteen + Langeled pipeline: Nyhamna-UK	0,0059 + 0,0036 = 0,0095 €/m3

3.6.4 Alternatives Cost Estimation

Alternative options considered: FLNG and Pipeline.

FLNG alternative

Alternative transport option based on LNG would consist of transporting the gas from field to Snøhvit, then into Snøhvit pipeline until gas facility at Melkøya. Note that this scenario has been rejected because of lack of available capacity.

An alternative to be compared will be FLNG-to-FSRU in UK.

For information:

Shipping costs

From Melkøya gas liquefaction plant to North West Europe including regasification, shipping costs were estimated by Gassco at 0.84 $/mmbtu [71] (approx. 0,15 €/m3).

Coordinates:

- Coordinates Melkøya: 70.6900°N 23.5990°E
- Coordinates Snøhvit: 71.56°N 21.23°E

Pipeline alternative

The reference figure identified is the cost of pipeline project Polarled in North Sea: 6,5 BillionNOK = 692 M€[72] (482 km, 260nm)

3.6.5 Other Costs

Given the early stages of the project, it is important to account for uncertainties and hidden costs in the estimate. As the project evolves through further WPs, these additional costs should be revised in the cost estimates, especially for ‘upstream’ and ‘midstream’ elements.

3.6.6 Cost and Tariff Overview

Summary of Costs and Tariffs

The upstream tariff calculation and alternative cost estimation will be reviewed in a similar methodology to that of the Eastern Mediterranean Geologistic scenario through the use of Questor and other cost estimator tools as part of Work Package 7, Cost and Benefit Analysis.

This section summarizes the end to end costs of each scenario (Loading points Johan Castberg and Alke; unloading points Aasta Hansteen and Nyhamna; end destination Easington), assuming 2-4% pipeline capacity. As explained in the ‘Gas Unloading Characteristics’ section (3.3.1.2), 2-4% corresponds to the rough estimate of daily gas production rate of Alke and Johan Castberg combined.

FIELD	UNLOADING POINTS	END DESTINATION	mmscmd	corresponding scenario#
J.C.	POLARLED	EASINGTON	1,29	Scenario 1.1
	NYHAMNA	EASINGTON	1,29	Scenario 1.2
ALKE	POLARLED	EASINGTON	1,18	Scenario 2.1
	NYHAMNA	EASINGTON	1,18	Scenario 2.2

Table 23: Barents Sea scenarios by unloading point and end destination

To estimate the end tariff to the final market, with the ultimate purpose to compare the figure with local natural gas or alternative prices to establish competitiveness, it is necessary to break down the costs accordingly. The end tariff is identified as the accumulation of the upstream tariff, the midstream tariff and the downstream tariff.

Midsteam costs have been calculated based on scenario simulation and optimization using the tool VOLTA developed by ESTECO. The annual gas demand used for scenario simulation was,

- Johan Castberg: 471 mmscm/year
- Alke: 430 mmscm/year

		UPSTREAM TARIFF €/m3	MIDSTREAM TARIFF €/m3	END DESTINATION	mmscmd	DOWNSTREAM TARIFF €/m3
BARENT SEA	J.C.	0,021	0,087	Easington from Nyhamna	1,29	0,0036
		0,021	0,087	Easington From Polarled through Nyhamna	1,29	0,0095
	ALKE	0,154	0,048	Easington from Nyhamna	1,18	0,0036
		0,154	0,048	Easington From Polarled through Nyhamna	1,18	0,0095

Table 24: Barents Sea Tariff Breakdown

The tariff breakdown is vital not only to compare natural gas end tariffs with local natural gas or alternative prices, but also to identify any margins of improvement in the cost structure. This is especially true in the case of midstream costs which include costs related to new technology and are relatively unknown.

END DESTINATION	mmscmd	END TARIFF €/m3	LOCAL PRICE €/m3	ALTERNATIVE OPTION	ALTERNATIVE TARIFF €/m3	MAX TARIFF TARGET €/m3	MIN TARIFF TARGET €/m3
EASINGTON	1,29	0,1116 (J.C.-UK via Nyhamna)	0,17	FLNG	0,15		
	1,18	0,1175 (J.C.-UK via Polarled)	0,17	FLNG	0,15		
	1,29	0,2056 (Alke.-UK via Nyhamna)	0,17	FLNG	0,15		
	1,18	0,2115 (Alke-UK via Polarled)	0,17	FLNG	0,15		
EASINGTON	1,29	0,1116 (J.C.-UK via Nyhamna)	0,17	DIRECT PIPELINE			
	1,18	0,1175 (J.C.-UK via Polarled)	0,17	DIRECT PIPELINE			
	1,29	0,2056 (Alke.-UK via Nyhamna)	0,17	DIRECT PIPELINE			
	1,18	0,2115 (Alke-UK via Polarled)	0,17	DIRECT PIPELINE			

Table 25: CNG tariff comparison with alternatives

As seen in Table 25: CNG tariff comparison with alternatives when the CNG end tariff is computed, it can be easily compared with alternative prices to show the margins of competitiveness. When CNG end tariffs are incomplete, e.g. the midstream tariff is not available, then, the tariff target shows the margin that the midstream tariff can have for CNG to still be competitive against alternatives in the local markets.

The current value chain tariff estimates from the above table indicate that both scenarios transporting the gas associated with oil production at Johan Castberg, with unloading near Nyhamna or near Aasta Hansteen (via Polarled) appear competitive against FLNG. However, the end tariff for the scenarios with gas loading at Alke are estimated to be around 80% higher than for J.Castberg, thus not competitive against FLNG.

4. Black Sea Geologistic Scenario

4.1 Black Sea Executive Summary

Among the several tasks concerning the Gasvessel project in the Black Sea area is the definition of sites for the placement of loading and unloading terminals. VTG conducted a preliminary research to study the presence of the developed gas infrastructure in the coastal zones of the Black Sea countries in order to ensure the loading and unloading of the Gasvessel.

Because of security of supply issues in the region, the purpose of this particular scenario is to provide the price that Gasvessel can provide to the target markets, which on this scenario will be Ukraine and wie will elaborate on our decision later on this report. The price is expected to be higher than existing sources but because of issues of security of supply it is not unreasonable to explore this scenario in order to identify the price.

We would like to thank VGT for their invaluable help and the general responsibility for the data collection and future revision regarding the Black Sea geologistic scenarios.

4.1.1 Black Sea Objectives

A potential source of natural gas was identified as the Shah Deniz field in Azerbaijan. From this source, gas is transported through the territory of Azerbaijan, Georgia where a pipeline shall be build to deliver the gas to the coastal region of Georgia, where the gas will be compressed and loading via the near shore loading onboard the Gasvessel . The shortest routes of the existing gas pipelines from the Shah Deniz field to the Black Sea coast are the Baku-Tbilisi-Erzurum and TANAP gas pipelines in the territory of Georgia. Thus, Georgia is selected as the country where the source terminal is to be located.

Ukraine was chosen as the target country where the unloading terminal will be located. Ukraine is one of the Black Sea countries most dependent on Russian natural gas imports. In order to successfully execute the loading and unloading of the Gasvessel, it is essential to create the necessary infrastructure connecting the existing gas transportation systems of Georgia and Ukraine with terminal sites.

The optimal location for the gas loading terminal is near the existing infrastructure of the Baku-Tbilisi-Erzurum main gas pipeline. The area near the Poti port, in Georgia, has been selected as an appropriate location for the gas loading terminal. For the gas unloading terminal, among several investigated sites, the vicinity of the Yuzhne port, in Ukraine, was chosen as the appropriate location.

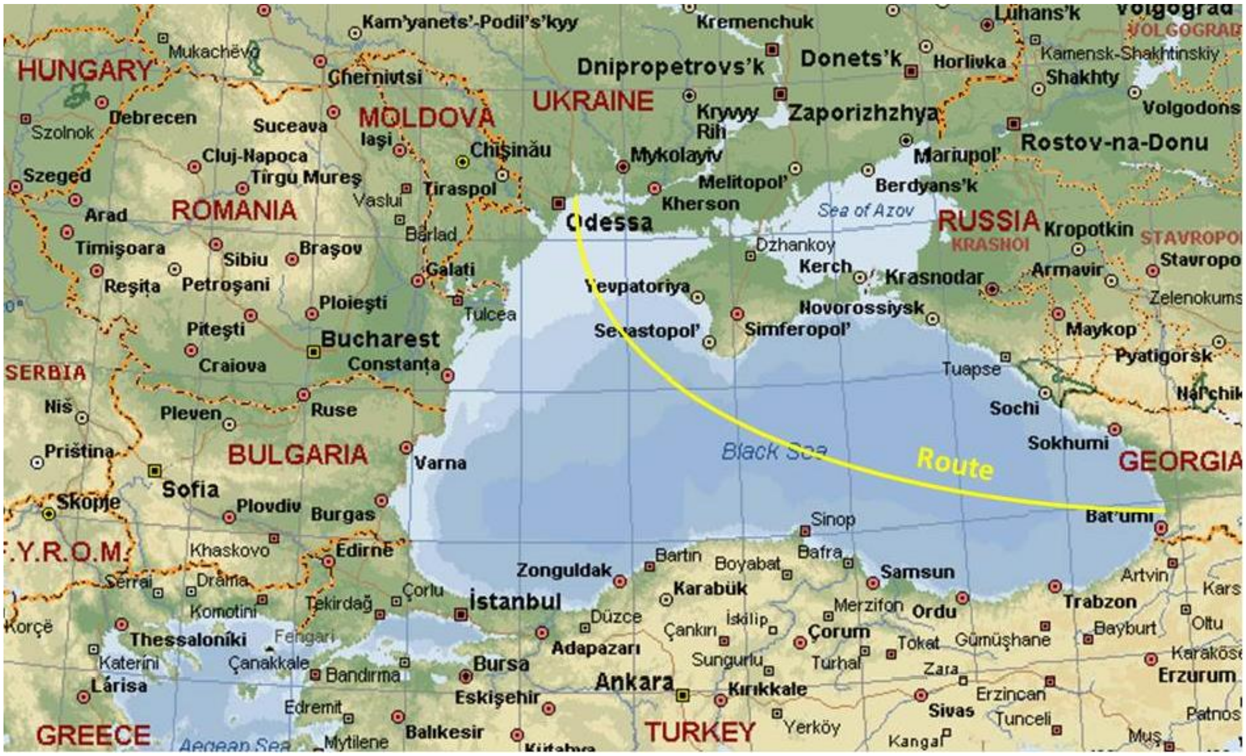


Figure 71: The concept map of gas transportation from Georgia to Ukraine

4.2 Gas Source Screening Criteria

Georgia is not a natural gas producer itself, but it is an ideal source from the Baku-Tbilisi-Erzurum gas pipeline. The pipeline has a diameter of 42 inches and is designed to transmit 7 bcm/y. The 692 kilometres South Caucasus Pipeline, which began operation at the end of 2006, transports gas from the Shah Deniz field in the Azerbaijan sector of the Caspian Sea to Turkey, through Georgia[73]. Shah Deniz, which is currently producing around 9 bcm/y at its plateau level, expects the next phase of development of the field to increase the plateau by some 17 bcm/y, to a total of more than 26 bcm/y from both phases from late 2018[74].

See in Figure 72, a geographical aspect of the natural gas supply routes within the territory of Georgia, whereby the ports of Georgia and further countries of the Black Sea basin are accessible.

4.2.1 Gas Loading Options

The loading scenario in the Black Sea geologistic setting occurring in Georgia, takes place nearshore. Existing gas pipeline infrastructure in Georgia and Ukraine are intended to be extended for onshore loading/unloading capability to accommodate the Gasvessel. Considering the fact that near the existing ports in Georgia there is no sufficient infrastructure of the main gas pipelines, it is necessary to envisage the creation of such infrastructure.

There are a few options for connecting a loading gas terminal to existing main gas pipelines and it is necessary to evaluate the best selected option for terminal placement.

Description of the existing Georgian gas infrastructure

The Georgian Oil and Gas Corporation (GOGC) is a state-owned company which is committed to ensure the energy security of Georgia. GOGC holds the legal status of the National Oil Company (NOC) and represents the state's interests in upstream Oil and Natural Gas projects in Georgia. GOGC was established to consolidate Georgia's energy assets under a single management.

Source: Company data, Galt & Taggart Research

Figure 72: Pipelines in Georgia – existing routes to loading terminals

Georgia's auspicious strategic location is a transport corridor for natural gas supplies to European markets. The transport corridor through Georgia allows the EU to diversify its supply, increasing energy security. Georgia's favourable location has prompted significant investments in its Oil and Gas Sector. To that end, GOGC represents the state in international energy transit projects. Georgia's main natural gas pipelines are:

Main Gas Pipeline System (MGPS) which is comprised of:

- North-South Gas Pipeline (NSGP), extending 235km and transporting gas from Russia to Armenia;
- East-West Gas Pipeline (EWGP);
- Southern branch;
- Kakheti branch;

South Caucasus Pipeline (SCP):

Stretches 692km (249km in Georgia) and transports natural gas from Azerbaijan to Turkey through Georgia and from Turkey further to the EU. The Southern Gas Corridor Project, aims at improving the security and diversity of the EU energy supply by bringing additional volumes of natural gas from the Caspian region to Europe. It is comprised of several separate energy projects, including the expansion of the SCP pipeline, which should bring additional volumes to GOGC as the pipeline capacity is expected to triple by 2021. The SCP pipeline will then be extended to reach Austria which this extension has been named Nabucco pipeline (see Figure 73). As of December of 2017 , the SCP expansion project was 100.0% completed in a territory of Georgia [75] [76].

Figure 73: SCP from Azerbaijan to EU

The established CNG supply chain in the Black Sea basin (area) assumes Georgia to be the potential sourcing country for such CNG. Actually, no gas is produced today in Georgia, however, its favourable geographical position makes it possible for Georgia to play a role as a regional transit partner.

4.2.1.1 Onshore Gas Loading

Main gas pipeline Baku-Tbilisi-Erzurum (BTE, SCP)

The main gas pipeline, Baku-Tbilisi-Erzurum (Project TRA-N-1138), with the gas pipeline future expansion (SCPX) including a Compressor Station (CS), (also known as South Caucasus

Pipeline, BTE pipeline, or Shah Deniz pipeline) is a natural gas pipeline from the Shah Deniz gas field in the Azerbaijan sector of the Caspian Sea to Turkey. The pipeline runs parallel and proximate to Baku-Tbilisi-Ceyhan (BTC) crude oil pipeline. The BTE originates at the Sangachal Terminal, which is located approximately 45 km to the south of Baku and traverses to Azerbaijan and Georgia before terminating at Erzurum in eastern Turkey. The lengths of Georgia's and Turkey's sections are 442 km and 248 km respectively. The total pipeline length is 980 km, and its diameter is 42 inches.

In addition to the pipeline's construction, the BTE project involved a number of above ground installations including two compressor stations (one each in Azerbaijan and Georgia) and an intermediate pigging station (cleaning and inspection).

The SCP Expansion (SCPX) Project is designed to increase the capacity of the South Caucasus Pipeline from the existing 7 bcm/yearear to 23 bcm/year[77], to transmit the gas that will be produced by the second stage of Shah Deniz, which is currently under development.

In order to increase the transmission capacity, a new 56 inches diameter pipeline will be laid beside the existing pipeline. The new pipeline will originate from the Georgian border and will be reconnected to the existing pipeline SCP near the gas reducing and metering point (Area 81) near the Turkish border (Vale village). In the GAZVESSEL project, the specific point will provide the tie-in and the beginning of the intermonitor to the gas loading point. Additionally, at the distance of approximately 48 km, the interconnector pipeline between SCPX and TANAP will be located.

Other components of the project include a new block valve (BV) at kilometer point (KP) 27, a pigging station at KP56 (the point where the new pipeline will be reconnected to the existing line), two new compressor stations and a new pressure reduction and metering station (PRMS) at the Georgian-Turkish border.

The expanded pipeline is likely to be fully operational in the fourth quarter of 2021.

Figure 74: Baku-Tbilisi-Erzurum Main Gas Pipeline

The expansion of the gas line might allow for further optimization using the Gasvessel project.

Technical Data of Baku-Tbilisi-Erzurum (BTE, SCP)

Transportation and Transfer Capacity after expansion: 23,0 bcm/yearear

- Daily Transfer Capacity: 62,1 mmscmd
- Plan/Design Factor: (as per ASME B31.8)
- System Design Pressure: 56,5 bar

Design/Diameter of the Line Pipe: API 5L X 70 I 42+56"

Construction of the gas interconnection line

For the purpose of connecting the existing main gas pipeline Baku-Tbilisi-Erzurum with the gas loading terminal, a special connecting line shall be constructed. Details and costs on the connecting gas pipeline will be calculated in the section "Main Gas Lines". This section will be developed by VTG in work package WP6.

According to a preliminary study, the approximate length of the gas interconnector will be about 140 km, the diameter will be determined in accordance with the need to fulfill scenarios for gas supply to Ukraine. The gas interconnector pipeline is proposed to be connected to the existing line of the SCP Main Gas pipeline at the gas measuring point No 80, located about 3 km to the south-west from the village of Vale.

Preliminary calculations show that the construction of a gas compressor station is necessary at the beginning of the interconnector. The capacity of the compressor station will be determined depending on the loading schedule of Gasvessel. The optimization of the parameters of the designed gas interconnector (diameter, pressure), will be optimized by performing hydraulic calculations of its operation modes with the gas loading terminal.

Below are described the options for laying the Gas interconnector between the point of connection to the BTE (SCPX) gas pipeline in the Vale area to the loading areas on the Georgian Black Sea coast.

Considerations regarding the onshore loading terminal

A number of locations for the loading terminal installation within the Black Sea coast of Georgia have been fully analysed and researched and we have concluded to the below three loading options with the corresponding justification for each location

The three locations which were considered for the onshore loading terminal are as per below:

Location A. Sea port of Batumi.

Location B. Sea port of Poti (1st site- North of the port)

Location C. Sea port of Poti (2nd site – South of the port)

The location of the onshore loading terminal is suggested after taking into account the following considerations:

- Availability of necessary infrastructure in the region (power supply, roads etc.);
- Easy access for Gasvessel to loading zone;
- Sea depth in designated loading zone;
- Year-round navigation and ice-free sea conditions in the area of the terminal;
- Acceptable marine climate conditions and waves height.

The terminal near the port of Poti, in Georgia (1st site, location B), has been selected as an option for the onshore loading terminal location because of the absence of residential infrastructure in its proximity (unlike location C) and for better convenience (than location A). For more information on location A and C, please visit Appendix C, Section II.

Selected loading location: Sea port of Poti (1st site)

The loading terminal site location finally chosen, is location B, on the north territory of Poti port, because the region southern of the Poti seaport, location C, is mostly residential and public access area. The territory to the south of the port of Poti is densely occupied by Sanatoriums, Hotels and Private buildings. The construction of the loading terminal will require its location at a safe distance (at least 500 m from residential buildings). In addition, the cost of land in the southern region is more expensive. The chosen site for the loading terminal allocation to the north of the port of Poti is a greenfield region, which counts as a major advantage for the final choice. Athough the terminal site is restrained by the Rioni river in the north, it has been decided to construct the gas loading terminal to the north of the Poti seaport, more specifically behind the river Rioni, in which case the terminal location will be equally distanced from both Poti seaport and the Kulevi oil terminal. Another element taken into account for the gas loading terminal location was the directions of the underwater streams, as well as sludge from the Rioni and Khobi rivers.

Figure 75: Gasvessel loading location and loading terminal site

Gas Interconnector characteristics

As already mentioned, the gas interconnector will be connected to the main gas pipeline BTE (SCP) in the area near the gas reduction point (Area 81). The pipeline will pass along the plain and mountainous terrain. The mountainous part of the pipeline will pass through a wooded area with the intersection of roads and open watercourses (rivers). The route of the gas pipeline will run at a safe distance from villages and agricultural farms.

The main technical parameters of the interconnecting gas pipeline:

- Total length – 130 km;
- The ratio of the mountain and plain parts of the route – 50/50%;
- Diameter: as per 3 scenarios (approximately 40 inches);
- The wall thickness and operating pressure of the pipeline: as per 3 scenarios (approximately 16-18mm, 54 Bar);

Design of the gas pipeline infrastructure:

- Main Compressor Station,
- Pig Launcher for pipeline cleaning and diagnostics;
- Necessary for the operation of the gas pipeline crane nodes and other structures of the linear part, crossings through roads and water obstacles;
- Control systems of the Gas pipeline and electrochemical protection against corrosion, etc.

Figure 76 below shows the area of the Metering Station on the SCP, there will be a future connection to the gas pipeline.

Figure 76: Metering Station (Area 81) in Georgia near Vale village

The yellow line at the figure below shows the allocation of the future gas interconnector between the tie-in point and the gas loading terminal near port of Poti.

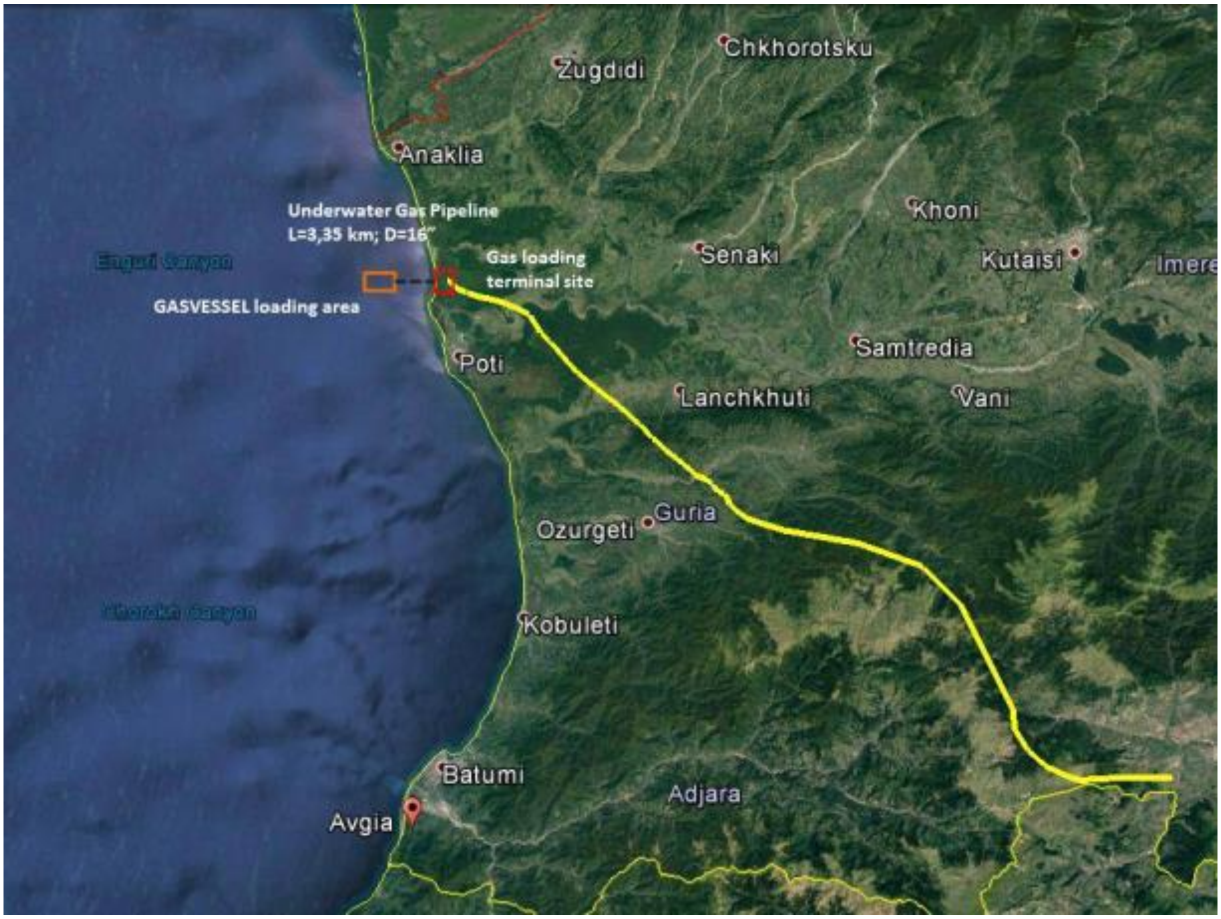


Figure 77: Poti Gas Interconnector SCP - Loading Terminal

The red rectangle in Figure 77 and Figure 78 shows the area of allocation for the gas loading terminal near port of Poti.

Figure 78: Poti gas loading terminal site location

The orange rectangle in Figure 79 shows the mooring area of the vessel and an approximate approach of the underwater gas pipeline.

Figure 79: Port of Poti gas loading point

Name: **Loading Terminal near port of Poti, Georgia**	Location: **Onshore**
Type of Gas source: **Gas Interconnector SCP-Loading Terminal**	Gas source: **Shah-Deniz Gas Fields**
Interconnector Characteristics:	

• Diameter • Length • Pressure • Capacity	• Approximately 40 inches • 130 km • To be determined • As per 3 scenarios
Location and coordinates of Gas loading terminal:	Latitude: 42°14'13.32"N Longitude: 41°39'47.55"E
Location and coordinates of Gas loading point:	Latitude: 42°14'24.98"N Longitude: 41°37'11.18"E
Water Depth of loading point	• 34 m
Distance from delivery port Port of Yuzne, Ukraine)	• 578nm [78]

Table 26: Loading terminal characteristics, Poti, Georgia

Onshore Gas Loading Composition

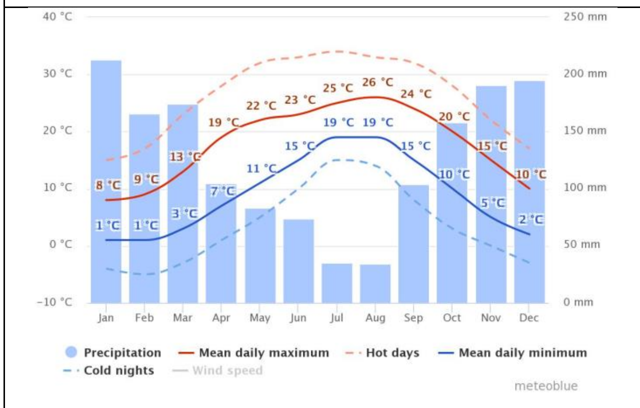
Gas composition	• 87-90 % Methane • no H_2S, no CO_2, no mercury

For gas delivery specifications the same assumptions are applied as per East Mediterranean Geologistic Scenario.

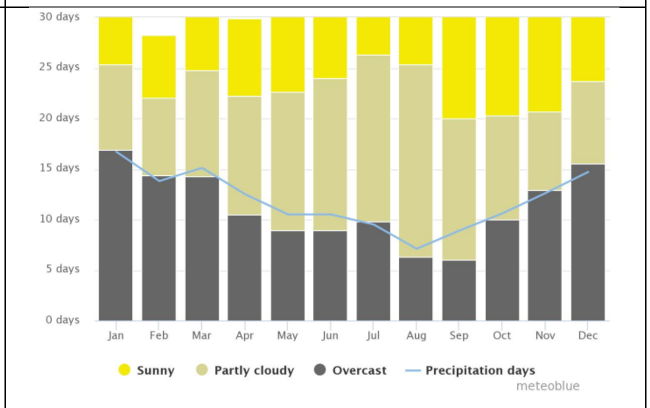
Onshore Loading Metocean Conditions

Climatic characteristics of the territory near the port of Poti:

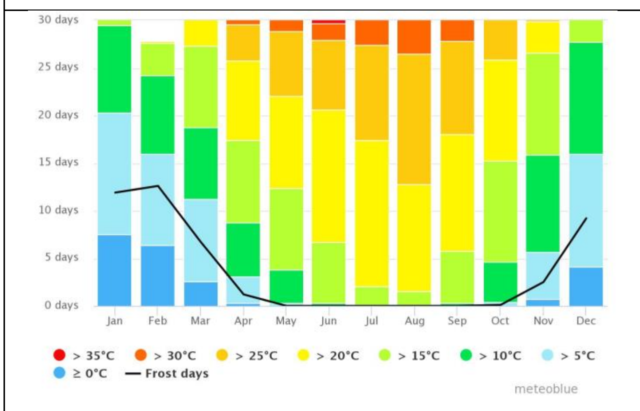
Average temperatures and precipitation



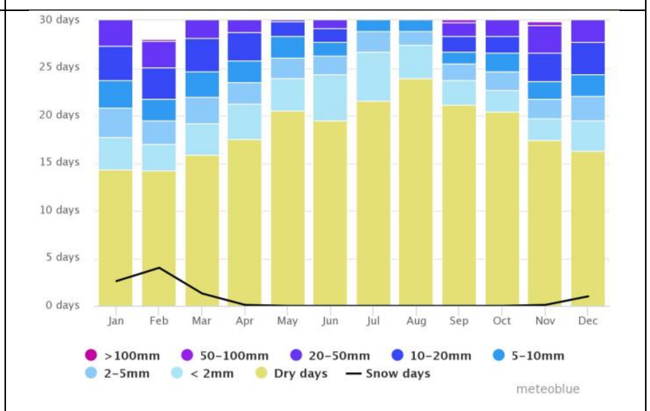
Cloudy, sunny, and precipitation days



Maximum temperatures



Precipitation amounts



Wind speed

Wind rose

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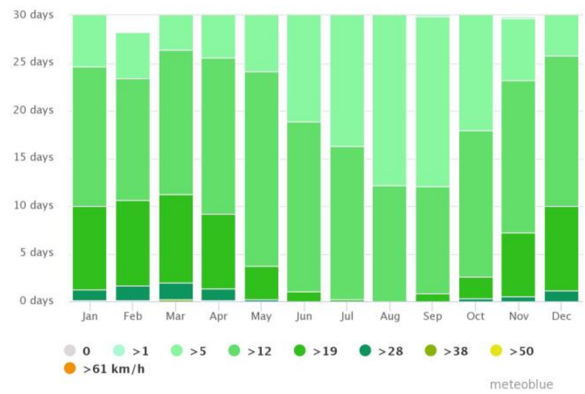
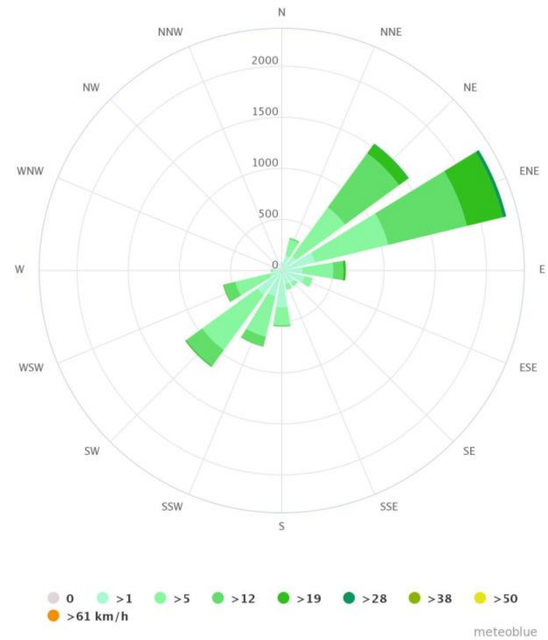
<tr><td></td><td></td></tr>
<tr><td></td><td>Wave height:</td></tr>
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4.3 Market Filtering Criteria

The target market is relatively narrow in the case of the Black Sea Geologistic Scenario, in the sense that the only country with existing network and infrastructure to accomodate the technical requirements and demand volumes of the Gasvessel is Ukraine. The Ukrainian domestic gas market generally qualifies as a target market also due to its natural gas deficit. This report will thus focus on the best possible choice regarding unloading options and distribution channels given the existing Ukrainian natural gas pipeline infrastructure.

4.3.1 Target Market Methodology

4.3.1.1 Target Markets

Although Ukraine as a coutnry has sufficient gas infastructure such as undergroudn storages, pipelines and distribution network in the inland territorial region of the country, the coastal gas infrastructure in the Black Sea region is inexistend. Since there is no existing gas pipeline infrastructure near the ports of Ukraine, it is necessary to envisage the creation of such a gas pipeline infrastructure to link the Gasvessel to the Ukrainian network. After considering several options for placing the unloading terminal in Ukraine, the decision of was finally chosen to be near the port of Yuzhny.

The existing infrastructure of the Ukraine gas transportation system is divided into sectors, which are confined by the existing main gas pipelines, and is aimed at covering gas consumption by all consumers located in such sectors. The southern regions of Ukraine are tied to the main gas pipeline Shebelinka - Dnepropetrovsk - Krivoy Rog - Izmail (SHDKRI), while the volume of gas consumption at the actual location of the main gas pipelines in the southern regions of Ukraine may be limited due to the possibility of gas consumption by existing consumers in the greater region.

4.3.1.2 Gas Field Life

2017 was a significant year for the Shah Deniz 2 and South Caucasus Pipeline Expansion (SCPX) projects. Both projects achieved significant construction, commissioning and handover milestones across the gas value chain.The projects are now entering the start-up phase in the run up to achieving first gas in 2018.

Shah Deniz 2 first gas scope is now 99 per cent complete, in terms of engineering, procurement, construction and commissioning. As part of the Shah Deniz-2 project, annual gas production will increase from 9 billion cubic meters in the first phase by an additional 16 billion cubic meters in the second phase. During its implementation, 16 billion cubic meters of Azerbaijani gas will be annually supplied to Western Turkey and southern Europe. Of these, 6 billion will be used by Turkey, while the remaining 10 billion cubic meters will continue its way to Southern Europe.

The commissioning of the new Shah Deniz 2 facilities is currently ongoing with the plans to start operations this year to be able to receive and process the additional gas volumes from Shah Deniz 2.

4.3.1.3 Gas Volumes and Distances

Gas volumes and distances undergo identical filtering as with the East Mediterranean scenario.

4.3.1.4 Gas Vessel Sizing

Gas vessel sizing underwent identical filtering as with the East Mediterranean scenario.

4.3.1.5 Gas Unloading Characteristics

Onshore Unloading Location Characteristics

Unloading site location

The choice of the location of the unloading terminal was dictated by a number of factors. After analyzing possible landing positions in the Northern part of the Black Sea (Bulgaria, Romania and Ukraine) we have considered Ukraine as the most relevant market due to the existing pipeline infrastucture in place and the maturity of the gas market. Additionally Ukraine as we describe further below are going through a trnasitioning phase in terms of gas demand following EU directives for energy supply diversification, which prompt Ukraine to become less dependant on Russian gas.

As we are finaly delivering the gas in the Southern part of country we have found that gas consumption in the southern region of Ukraine is about 3-3.5 bcm/yearear.

The possibility of gas connection to the existing grid is based on the multiple gas line system of SHDKRI, which actually consists of several gas lines. It is further planned to make a tie-in to a gas pipeline near the compressor station of 'Berezovka". For further technical information regarding the SHDKRI gas system, please visit Appendix C, Section IV.

Onshore Unloading Gas Composition

The gas composition is taken from one source and so, is the same for the upstream and downstream process. For example, the Mediterranean gas can be a different composition, according to gas incoming from different drills, but it must be in the limits of consumption standards.

Onshore Unloading Gas Intake Capacity

Gas intake capacity of the gas transportation system: The main gas pipeline network in the Odessa region is pretty extensive. It is based on the multiple gas line system of Shebelinka - Dnepropetrovsk - Krivoy Rog - Izmail (SHDKRI), which actually consists of several gas lines: Shebelinka - Dnepropetrovsk, Shebelinka – Dnepropetrovsk – Odessa, first and second branches, Shebelinka - Dnepropetrovsk - Krivoy Rog - Izmail, Razdelnaya – Izmail.

The mentioned gas pipelines have a various number of lines (from 2 to 4) and different diameters in different sections. The gas transport system map in southern Ukraine is shown in Figure 80.

Figure 80: The map of the Gas Transport System in South Ukraine

Through the gas pipeline system, gas is reaching consumers in Kharkov, Dnepropetrovsk, Zaporozhye, Kherson, Nikolayev, and the Odessa regions, as well as in the Republic of Moldova and the Balkan countries. Gas deliveries to the Autonomous Republic of Crimea, however, have been terminated at this time. The sources of gas supply to this system originate from the Russian Federation in many aspects.

Overall, the pipeline capacity of the existing system of gas branch pipelines is limited to 3 bcm/yearear, allowing transportation of gas from the unloading terminal near the “Yuzne” seaport through the separate gas pipeline to the area of the “Berezovka” compressor station (CS), where it can then be delivered to consumers through the existing SHDKRI gas system.

Unloading terminal near the port of Yuzne, Ukraine

Figure 81: Map of Yuzne port connection to Berezivka station

The unloading terminal site near the port of Yuzne in Ukraine will be located 0,7 km to the south-east from the village of Sychavka, and about 1,46 km from the village of Yuzne. This is dictated by the necessity to place the site out of environmentally protected areas on the sea coast.

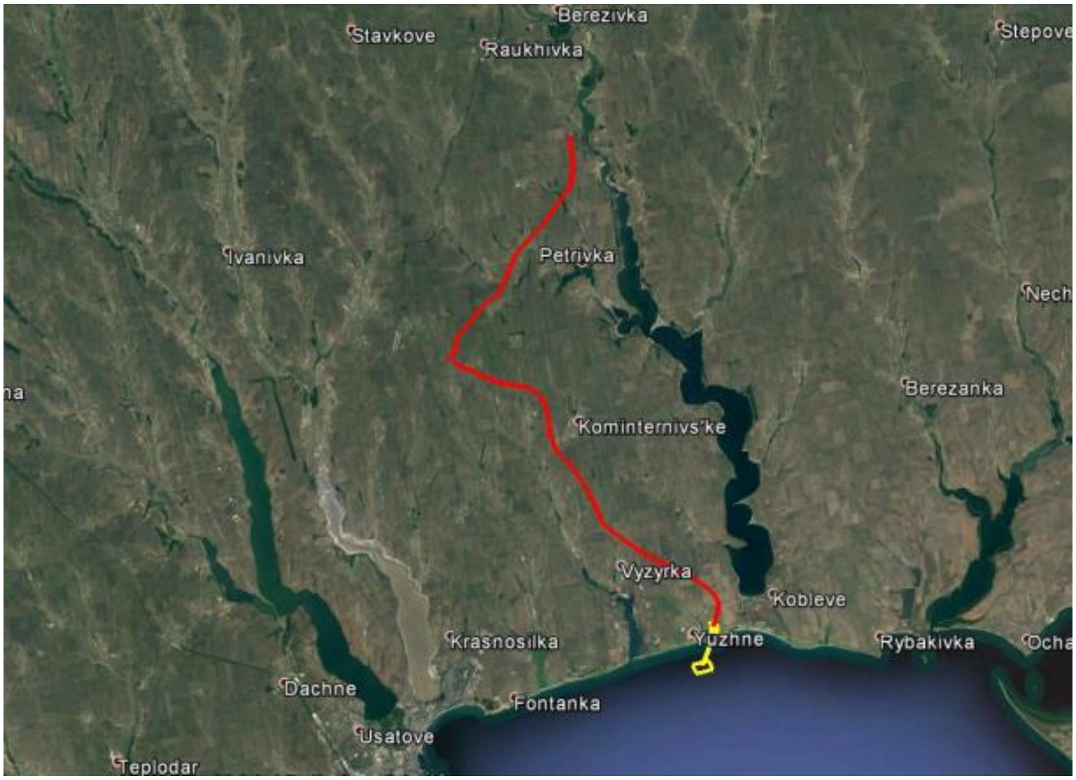


Figure 82: Unloading Interconnector, Yuzne, Ukraine

A depiction of the intended unloading interconnector at the port of Yuzne can be seen in Figure 82. The unloading system and interconnector in yellow is connected to the pipeline (in red, to be constructed) which further connects to the local gas network.

Figure 83: Gas unloading terminal, Yuzne, Ukraine

A more detailed picture of the gas interconnector and the unloading terminal zone can be seen in Figure 83. The proximity to the port of Yuzne and the area reserved for the unloading terminal can be noted. Figure 84 further depicts the intended unloading site near shore the port and the underwater gas pipeline to pipe the CNG to the unloading terminal next to the port, as explained above.

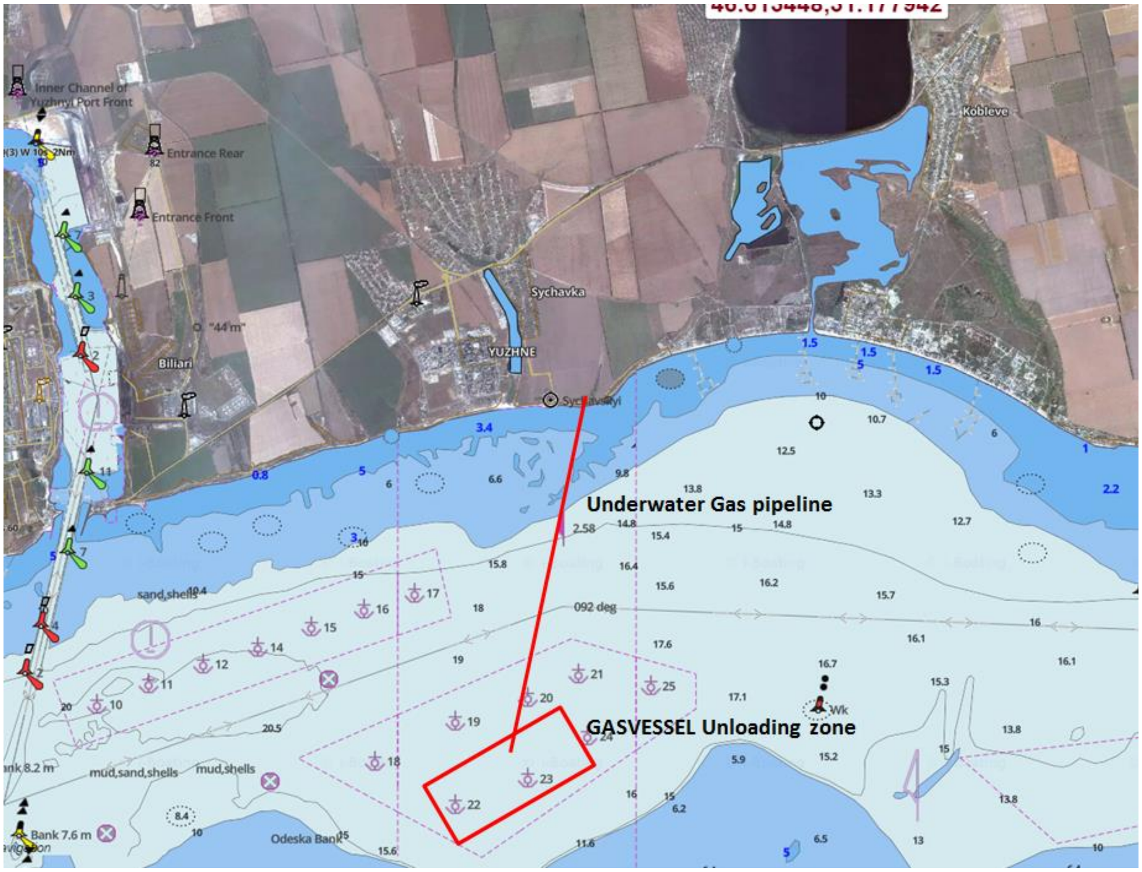


Figure 84: Gas unloading point, Yuzne, Ukraine

Name: Unloading Terminal near port of Yuzne, Ukraine	**Location:** Onshore
Type of Gas source: Gasvessel	**Gas source:** Shah-Deniz Gas Fields
Interconnector Characteristics: Diameter Length Pressure Capacity	 Approximately 40 “ 70 km As per 3 scenarios 10 billion meter cub per year
Location and coordinates of Gas unloading terminal:	Latitude: 46°37'38.96"N Longitude: 31° 7'38.01"E

Location and coordinates of Gas unloading point:	Latitude: 46°35'32.06"N Longitude: 31° 6'42.74"E
Water Depth of loading point	27 m

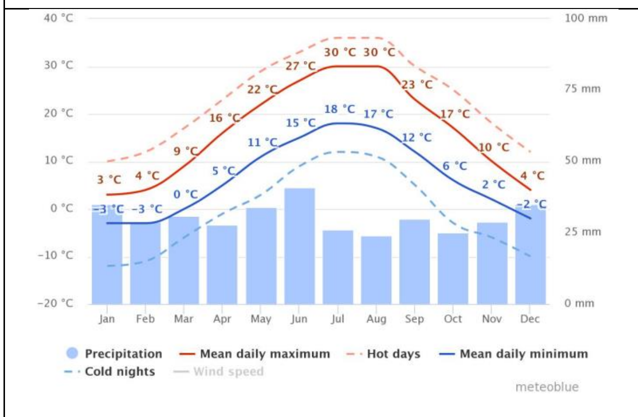
Table 27: Unloading Terminal characteristics, port of Yuzne, Ukraine

Errore. L'origine riferimento non è stata trovata. gives more details for the gas interconnector, he site of loading terminal, the underwater gas pipeline and the area of Gasvessel docking.

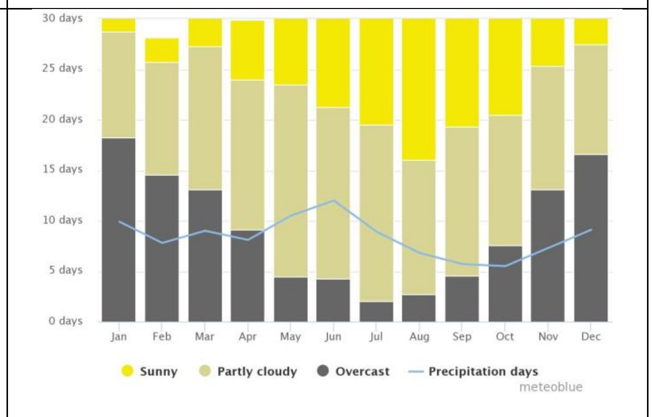
Onshore Gas Unloading Metocean Conditions

Climatic characteristics of the territory near the port of Yuzne:

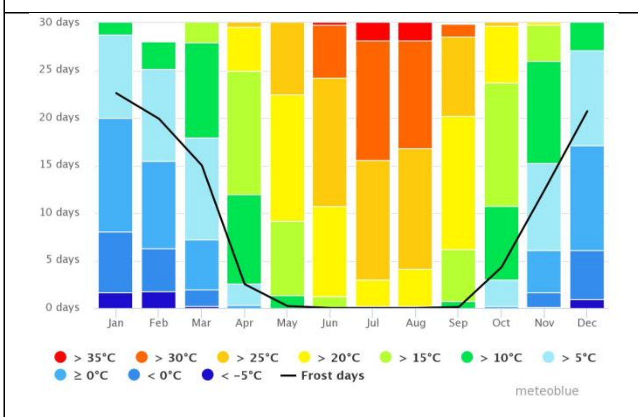
Average temperatures and precipitation



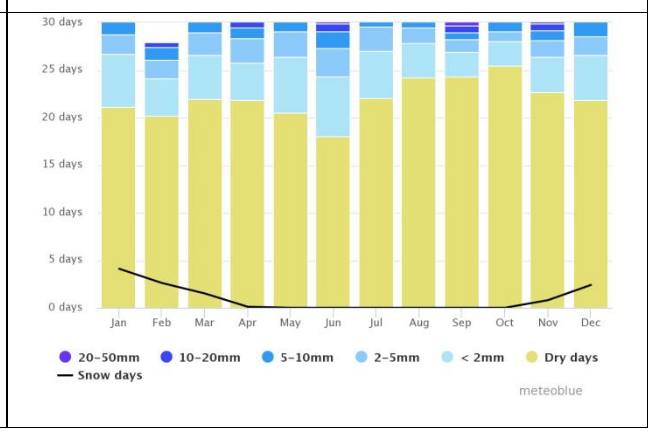
Cloudy, sunny, and precipitation days

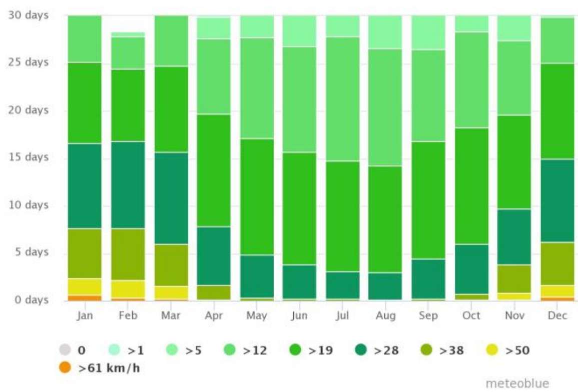
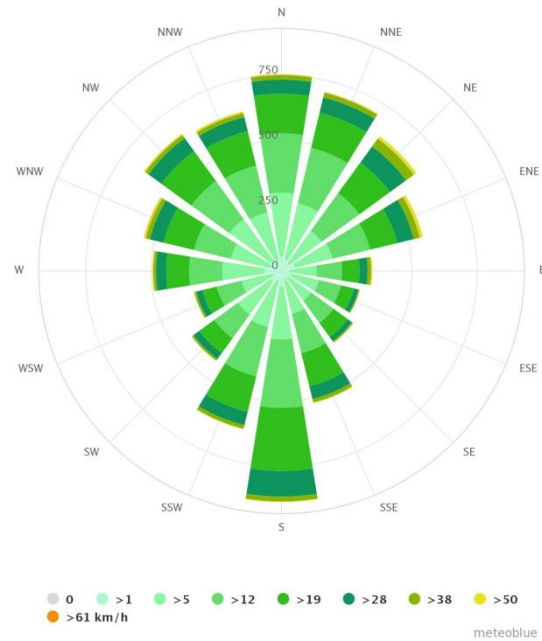


Maximum temperatures



Precipitation amounts



Wind speed	**Wind rose**
	
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4.4 Black Sea Proposed Target Market

4.4.1 Ukraine

Ukraine Overall Demand and Supply Profile

Ukraine, has historically been dependant on gas since their independence in 1991, with gas heavily subsidized and used in an extremely wasteful way. The domestic annual natural gas consumption of 118 bcm placed Ukraine as number 3 in the world at that time, after the U.S. and Russia. Since then, Ukrainian natural gas consumption has been decreasing.

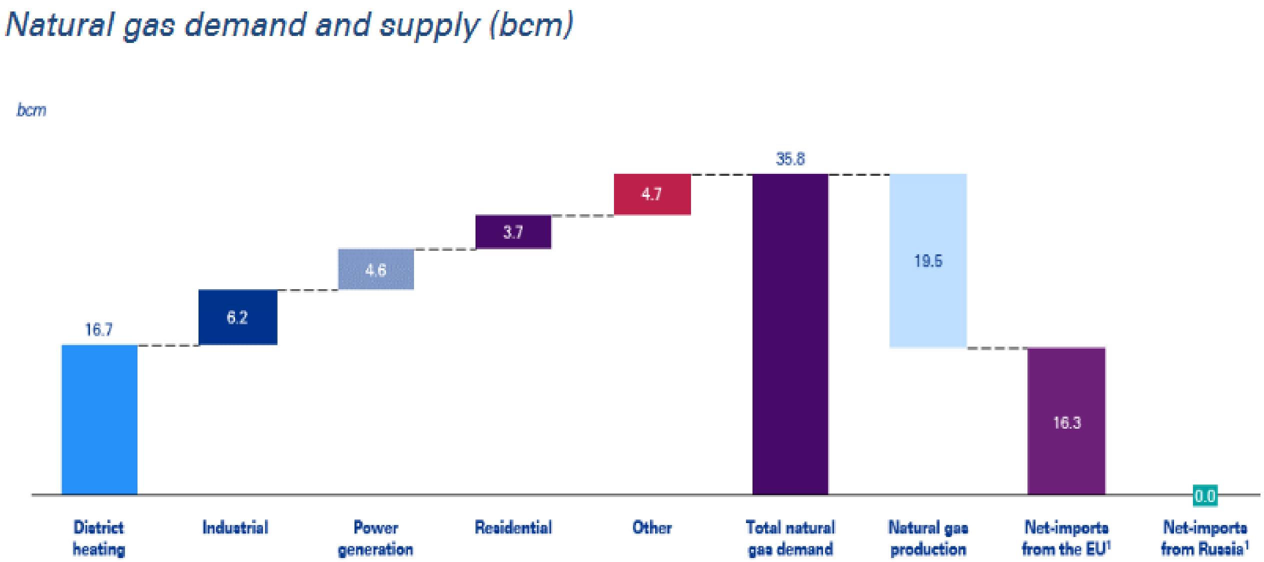


Figure 85: Natural gas demand and supply Ukraine

Overall, natural gas demand in 2020 is expected to reach 35.8 bcm, according to the figure above[79], which can be covered technically through domestic production and western inflows from the EU but without any Russian imports in 2020. This further suggests that Ukraine targets to cover its needs in natural gas and dependence on Russian natural gas will diminish by developing alternative energy sources, including importing natural gas with new options, possibly including CNG solutions.

Supply

Natural gas supply in the period 2010-2015 decreased by 8.2% in line with the decreasing demand pattern. The share of Russian net imports displayed the highest decrease with 29.5%, while imports from the EU were introduced (from Hungary, Slovakia and Poland) making up 28% (10.3 bcm) of Ukrainian natural gas demand by 2015. This diversification of natural gas imports was mainly driven by political issues.

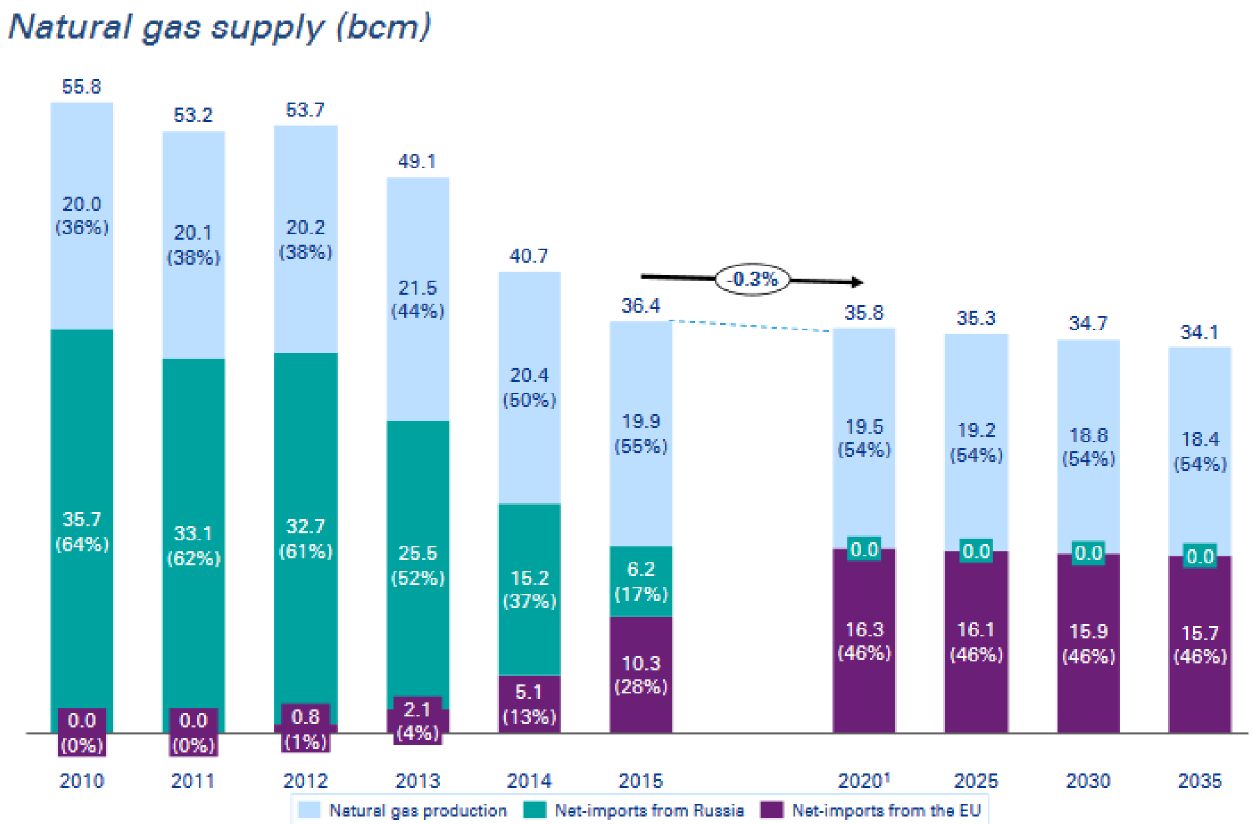


Figure 86: Natural gas supply Ukraine 2010-2035

Domestic supply remains relatively stable, with a small increase in 2013 due to the development of privately owned companies followed by a decrease until 2015 due to the loss of control over Chornomornaftogaz's assets located in the Crimea and increased tax payments on extraction by more than 70% between 2014 and 2015.

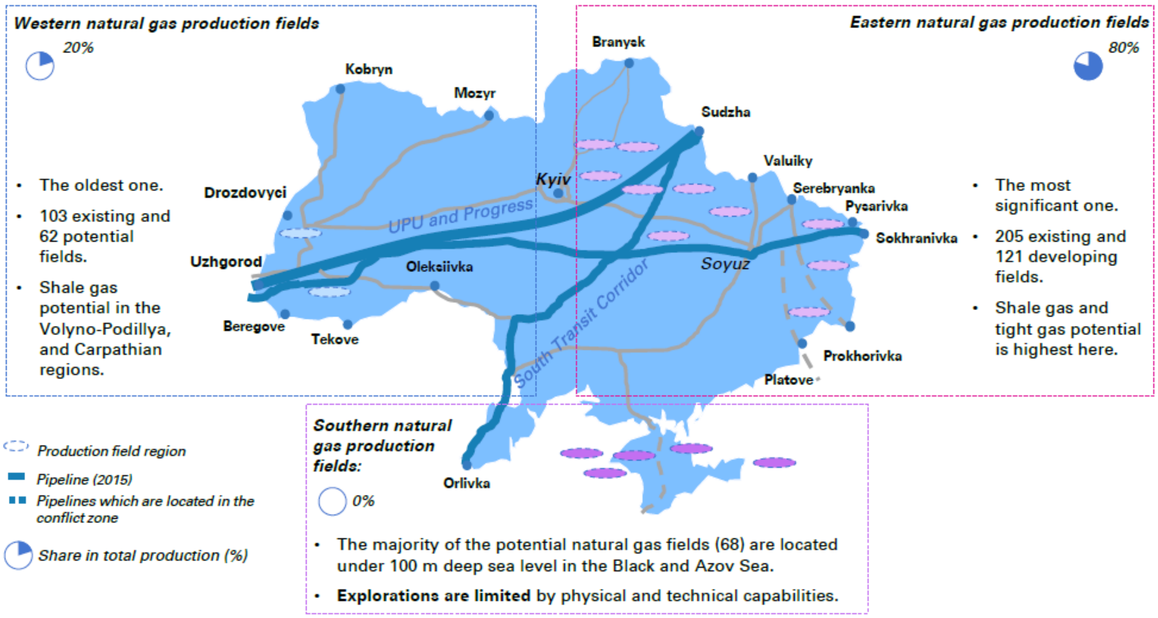


Figure 87: Natural gas production fields[80]

As Figure 87 depicts above, a number of natural gas production fields exist in Ukraine with the majority of the domestic natural gas originating from the Eastern natural gas production fields of the country.

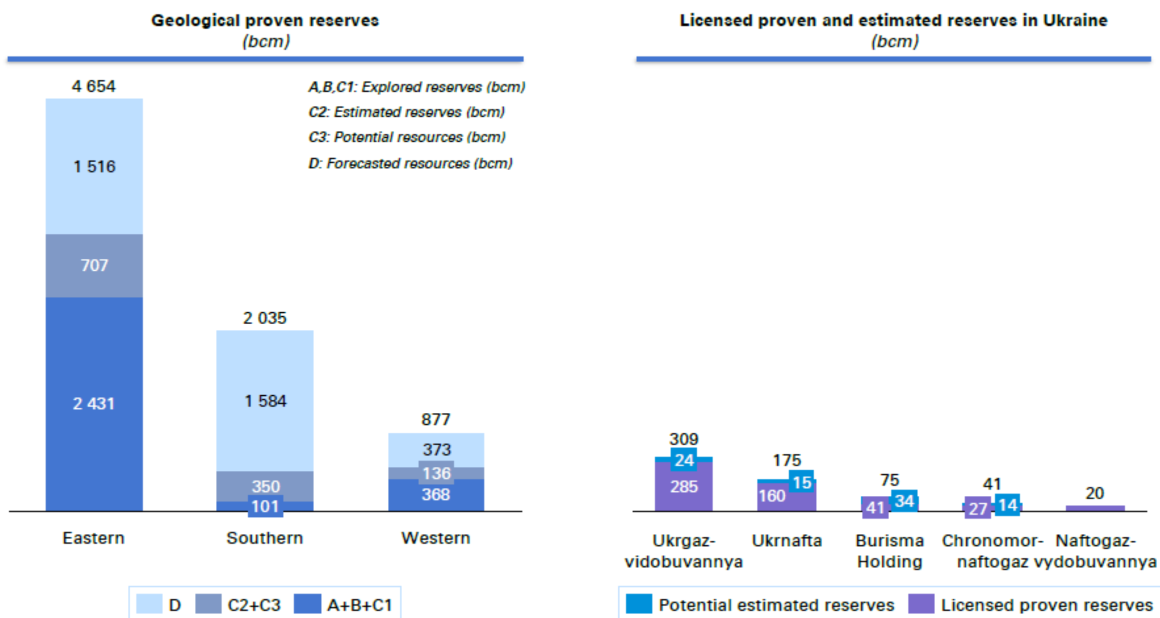


Figure 88: Natural gas reserves (bcm) [81]

Figure 88 depicts the proven geological reserves of the country, by geography and company license holder. Natural gas is transported from the fields to the consumers via the existing network of gas main pipeline shown in blue color in the figure. Serious concerns emerged throughout the years that the natural gas transportation system of Ukraine was in an inadequate condition due to its poor design and construction, as well as due to the low or insufficient level of maintenance funding. This resulted in the emergency rehabilitation and refurbishment of the Urengoy-Pomary-Uzhgorod (UPU) pipeline (30 bcm/y), even though there are significant financial gaps still. In Figure 89 we can see the seven year refurbishment and development plan intended to improve Ukraine's natural gas transportation system.

Seven-year refurbishment and development plan of main transmission and metering facilities (USD m)

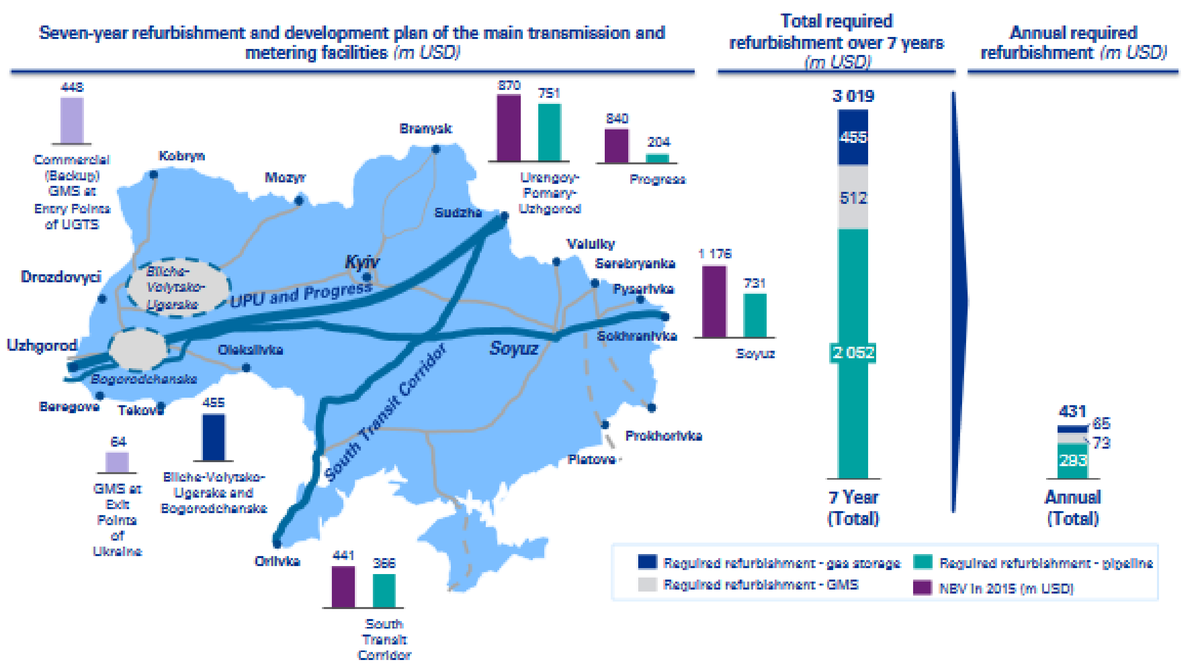


Figure 89: Seven-year refurbishment plan Ukraine

Russian Gas Supply and Transit

Total transit flows from Russia decreased by 7.4% between 2010-2015, with the most significant decrease taking place after 2013. This is mostly due to the Russian natural gas transit diversification policy, establishing and initiating alternative transit lines (Yamal, Nord Stream 1 and Blue Stream) as well as the declining natural gas demand in the EU-28[82].

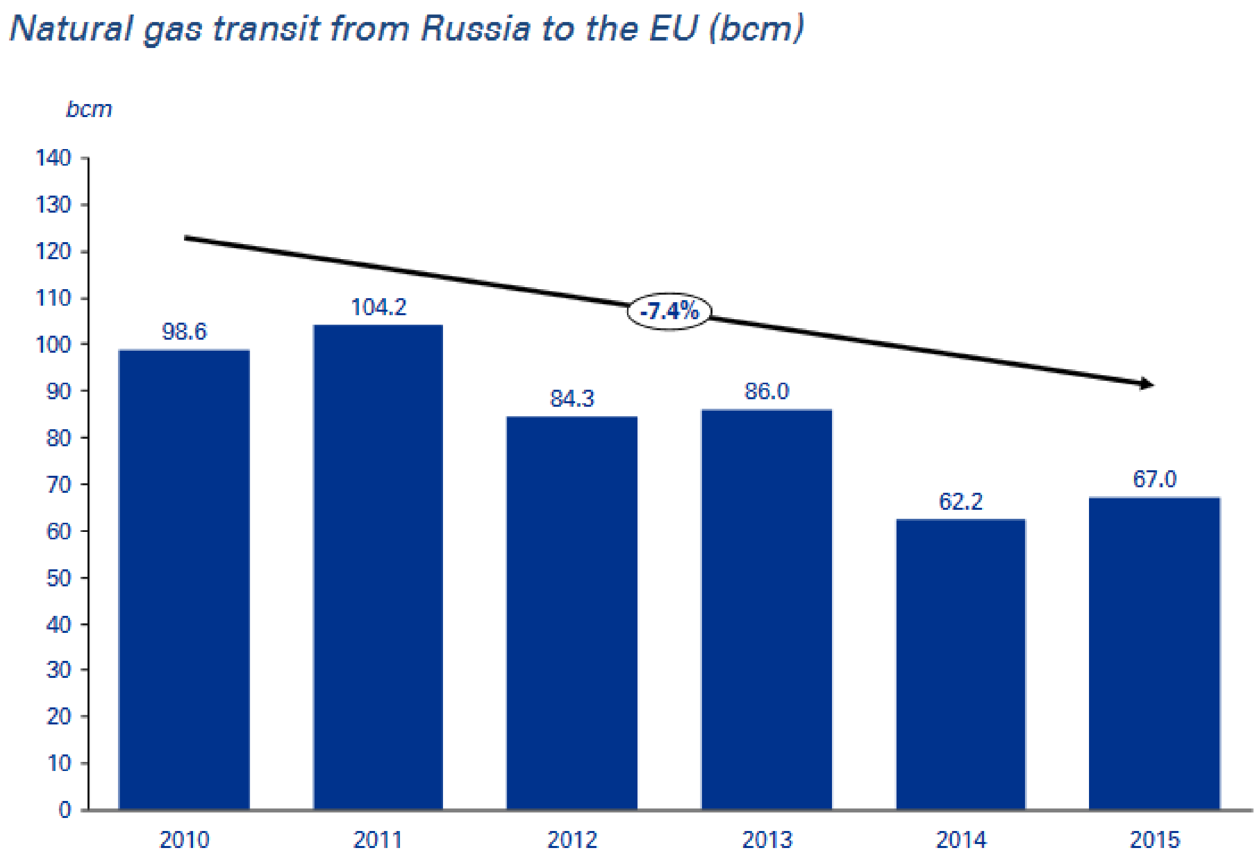


Figure 90: Ukraine - Natural gas transit from Russia to the EU (bcm)

Eventhough Ukraine is trying to become independent from Russian natural gas, volumes imported from the EU are often from Russia. Figure 90 shows the transit volumes from Russia to the EU, and depicts this general decreasing pattern intended by Ukraine and the EU in order to become independent from Russian natural gas imports. Substituting these volumes, presents an opportunity for the Gasvessel project as it will diversify its energy sources, and provide an additional option of natural gas, sourced from Azerbaijan. Although we foresee the landing price of natural gas delivered by Gasvessel to be higher than those of any Russian pipelined sourced natural gas, we still believe that there is a window of opportunity for the Gasvessel to provide an alternative source of natural gas for diversification and energy security reasons.

Demand

We note that the heavily gas reliant Ukrainian industry suffered tremendously from the 2008 financial crisis, with consumption almost halving between 2008 and 2009 but then quickly rebounding in the following years as economic growth recovered again. Household consumption, on the other hand, shows a much more stable pattern, explained by the price of gas for households in real terms being almost constant from 2008 until 2014.

Between 2013 and 2015, total consumption decreased by 33%, to 33.8 bcm (see Figure 91 below). One of the key drivers of this decrease is the loss of control over Crimea and areas in Donetsk and Luhansk, all heavy gas consuming regions. 30% of Donetsk and Luhansk (which is now under separatist control) in the time prior to the conflict was directly responsible for around 20% of total Ukrainian gas consumption. We estimate that the loss of areas in Donetsk and Luhansk and the loss of Crimea is responsible for around one third of the total decline in the period Most of the remaining decline was caused by industrial and household demand falling rapidly.

Between 2013 and 2015, industry output was in free fall, driving down industrial gas consumption by almost 40%. At the same time, households experienced a 119% weighted average USD increase in the tariffs for natural gas while simultaneously experiencing a decline of average per capita income of almost 50%. Last but not least, the winters of 2014 and 2015 were relatively milder than previously which further stimulated lower consumption. As a result, the hitherto relatively constant Ukrainian household consumption of natural gas has declined by some 31% from the 2013 level.

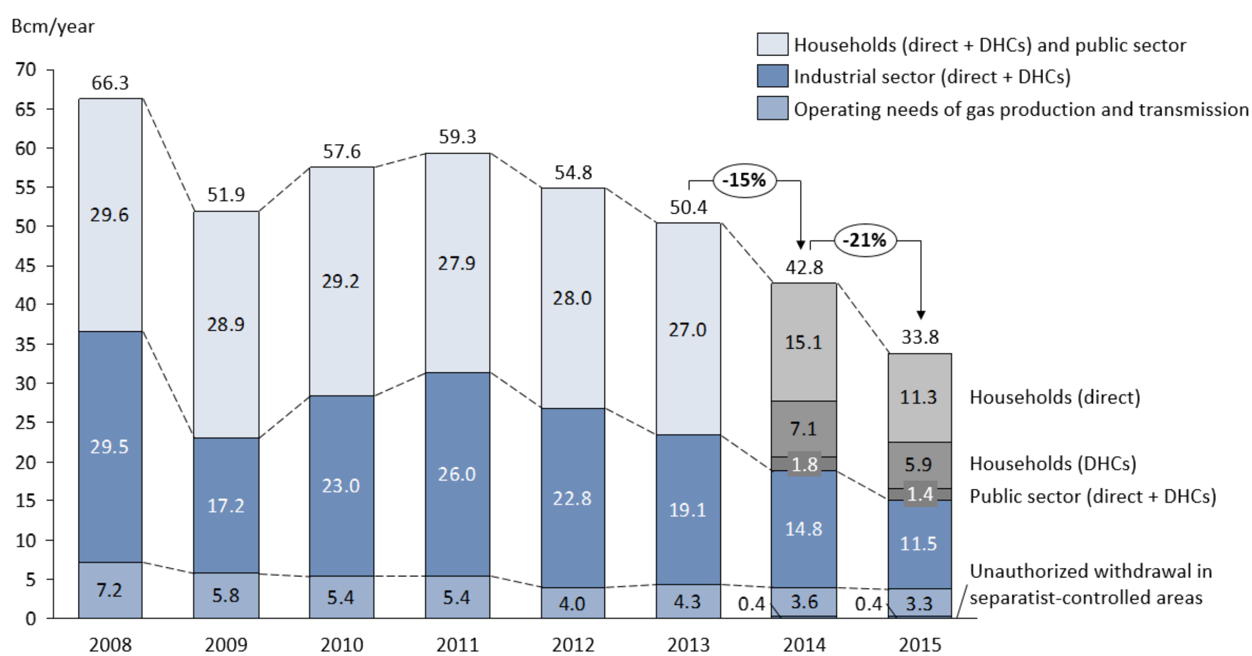


Figure 91: Natural gas consumption in Ukraine, 2008-2015

Looking at the regional distribution of the decline of consumption, in 2015, aggregate natural gas consumption in Ukraine decreased in all regions except in Odessa, where a small increase was observed[83]. The most dramatic decline is found in the Luhansk and Donetsk regions, portions of which remain controlled by separatists, which experienced gas consumption declines of –67% and –46%, respectively. It is worth noting that both these regions were heavy gas consumers prior to the military conflict, with large industrial gas consumption. When adding up the decrease from only these two regions, together, they account for a third of the decrease in total gas consumption between 2014 and 2015 (3.1 bcm)[84]. It is important to note that some of this decline in consumption stems from the fact that Ukraine has partly stopped supplying the separatist-controlled areas with gas[85], although the majority of the decline is still attributable to real decreases in the demand for gas.

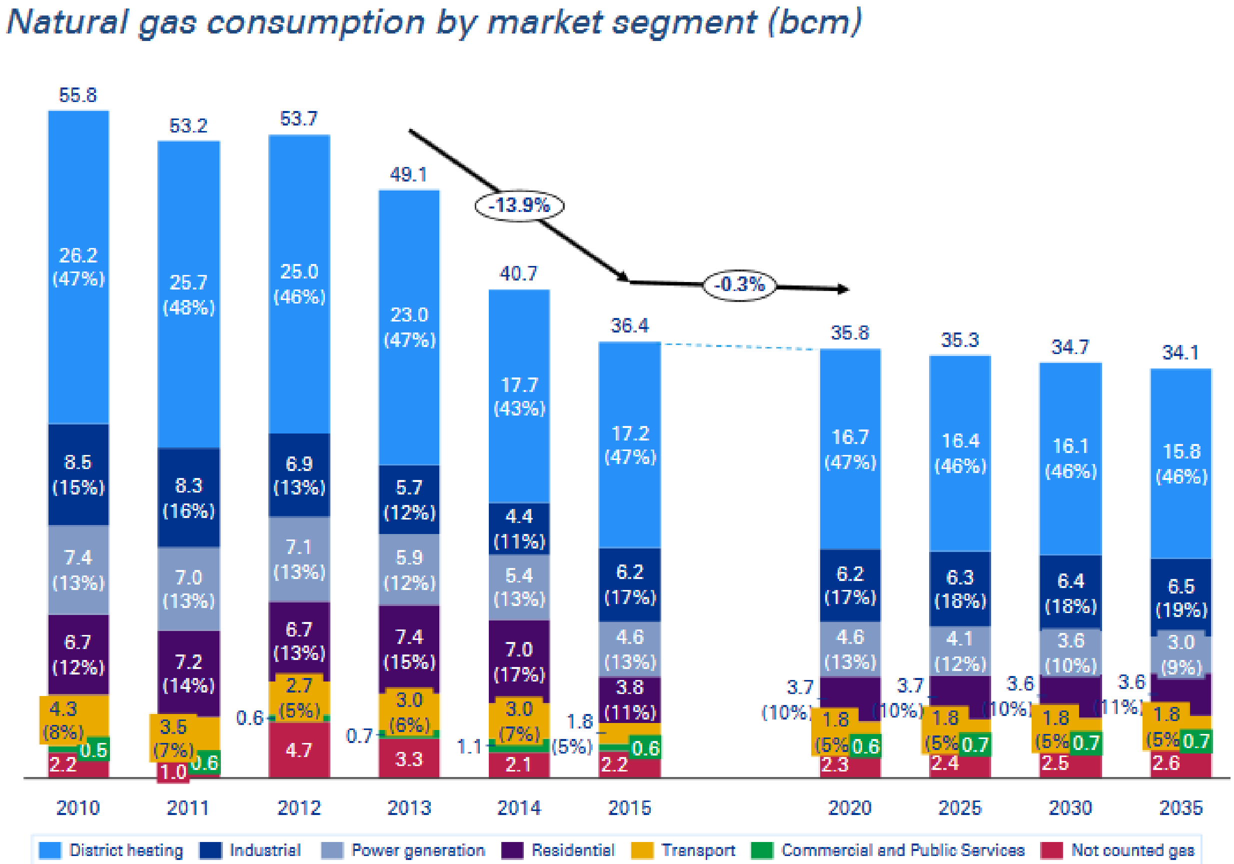


Figure 92: Natural gas consumption Ukraine by segment

The overall decrease in natural gas consumption between 2015-2035 (Figure 92) is the result of the effect of an energy efficiency inrease, the population decrease, housing insulations and a switch towards alternative fuels (biomass and biofuels) while the GDP is expected to have a positive inflluence on consumption.

Natural gas demand declined significantly between 2010-2015, mostly due to decreasing consumption in the conflict zones (Crimea, Donetsk and Lugansk regions). Additional factors in the period 2013-2015 where the influences of increased natural gas tariffs and the overall industrial slowdown due to the worsened economic situation.

Total energy consumption decreased between 2010-2015, mostly due to the decrease in natural gas and solid fuel (coal production), with renewable resources gaining higher share in the energy mix (Figure 93). This trend follows through more or less until 2035.

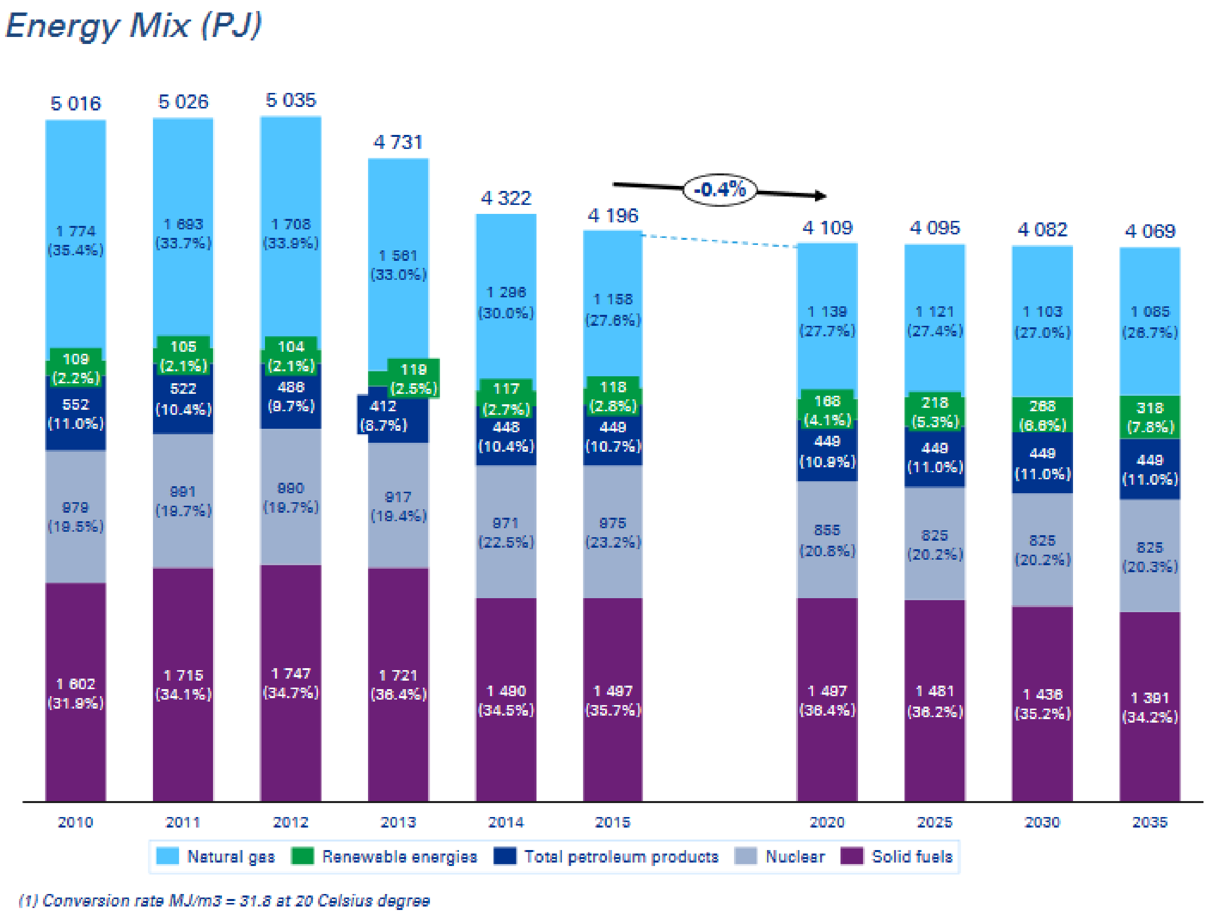


Figure 93: Energy Mix Ukraine, until 2035

Additional opportunities for the Gasvessel arise as we monitor the solid fuel contribution to the energy mix, and we strongly believe that once Ukraine enters the EU it will be obliged to comply with the Paris-EU Summit directives that gradually restrict the use of coal and other solid fuels to reach European standards.

Infrastructure

Ukraine has an extensive natural gas transit and transmission system and owns one of the largest natural gas underground storage facilities in Europe. The main transmission system consists of 15 pipelines which include the longest and most important transit pipelines, such as Soyuz, UPU and Progress. These pipelines mainly serve transit needs, transmitting natural gas from Russia (Gazprom) to the EU-based company (Gazprom), which in turn sells the gas to its EU-based customers.

The system has a theoretical high maximum entry and exit capacity (306.7 bcm/y and 183.9 bcm/y respectively). Nevertheless, the whole system is underutilised, which means there is 73% unutilised capacity at the entrance to the system, and 64% at the exit. The system is underutilised due to Ukraine's changed natural gas production volumes and its gradual transformation from a net exporter (1950-1970) to its current status, as net importer.

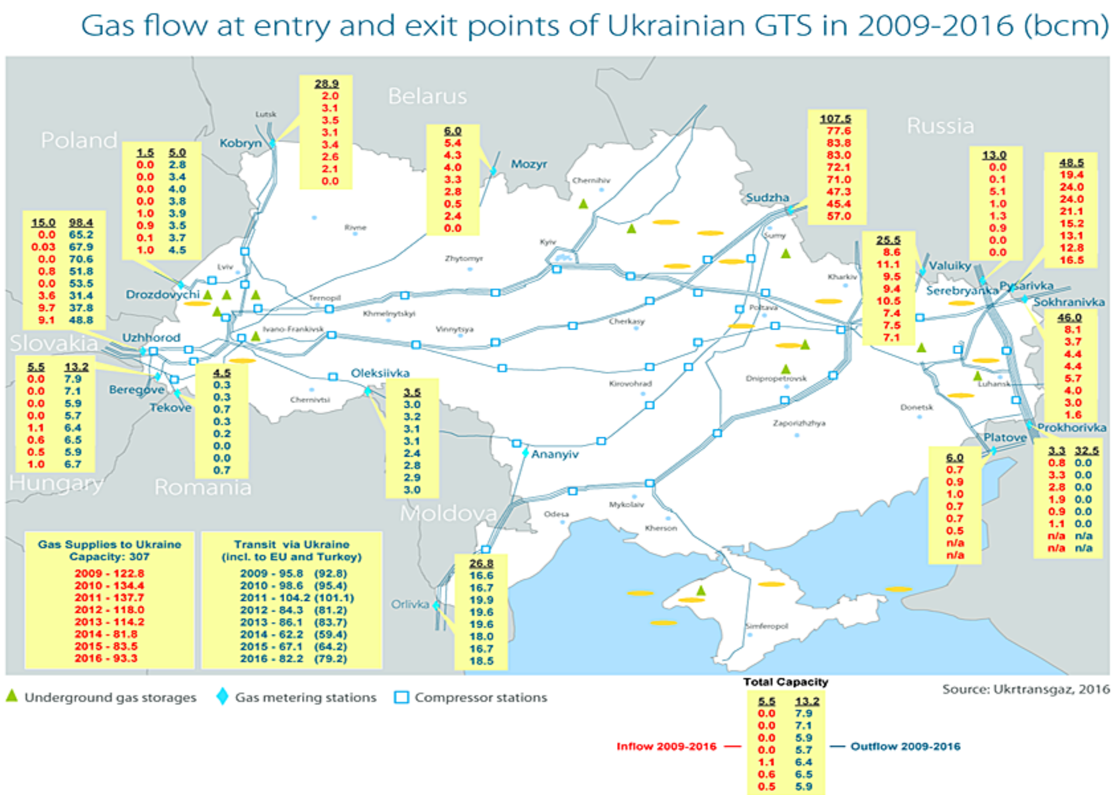


Figure 94: Ukraine gas infrastructure system, entry/exit flows[86]

According to Ukrtransgaz data as of May 2018, the gas balance in Ukraine is:

Supply from gas producers of Ukraine for 13.05.2018: 56,014 mmcm

EU gas inflow 13.05.2018: 34,338 mmcm;

Russian gas inflow and transit 13.05.2018: 237,389 mmcm;

OBA: -1,323 mmcm;

Transit total: 238712 mmcm.

Description of the Ukrainian Gas Infrastructure in the southern region of Ukraine

The main gas pipeline network in the Odessa region is pretty extensive. It is based on the multiple gas line system of Shebelinka - Dnepropetrovsk - Krivoy Rog - Izmail (SHDKRI), which actually consists of several gas lines: Shebelinka - Dnepropetrovsk, Shebelinka – Dnepropetrovsk – Odessa, first and second branches, Shebelinka - Dnepropetrovsk - Krivoy Rog - Izmail, Razdelnaya – Izmail. The mentioned gas pipelines have a various number of lines (from 2 to 4) and different diameters in different sections. The gas transport system map in southern Ukraine is shown in previous section.

Regulation

In 2015, Ukraine joined the (*European Network of Transmission System Operators for Gas)* ENTSOG, whose role is to facilitate and enhance cooperation between national gas transmission system operators (TSOs) across Europe in order to ensure the development of a pan-European transmission system in line with European Union energy goals. To comply with the organization's regulations, a number of regulatory changes were adopted from 1 January 2016.

ENTSOG network codes were implemented from 1 January 2016 to facilitate interoperability, congestion management (CPM) and capacity allocation (CAM). In addition to the regulations promoting international cooperation and trade on the Ukrainian natural gas market, some legislation on sanctioning certain parties was implemented. On 17 October 2016, the Law of Ukraine "On applying special economic and legal restrictions (sanctions) to physical and legal bodies' was adopted and came into force. The legislation introduced economic and legal sanctions against certain physical and legal bodies that (according to the Ukrainian parliament) were harming the economy and sovereignty of Ukraine. It was based on the Law of Ukraine "On sanctions", which was accepted on 10 September 2014 to determine the reasons that may result in economic and legal sanctions if they hinder the national and territorial sovereignty of Ukraine, result in damage to private and national property, or hinder the sustainable economic development of the country.

The types of sanctions which may be applied in the event of obstructions are freezing of financial assets and restricting trading activities, partial or complete termination/restriction of transit resources, flights and transport via Ukraine and cancellation or suspension of licenses, and prohibition from privatization. For more information on legislation and regulation prior to 1 January 2016, visit Appendix C, Section V for more details on Ukraine's market profile.

Prices

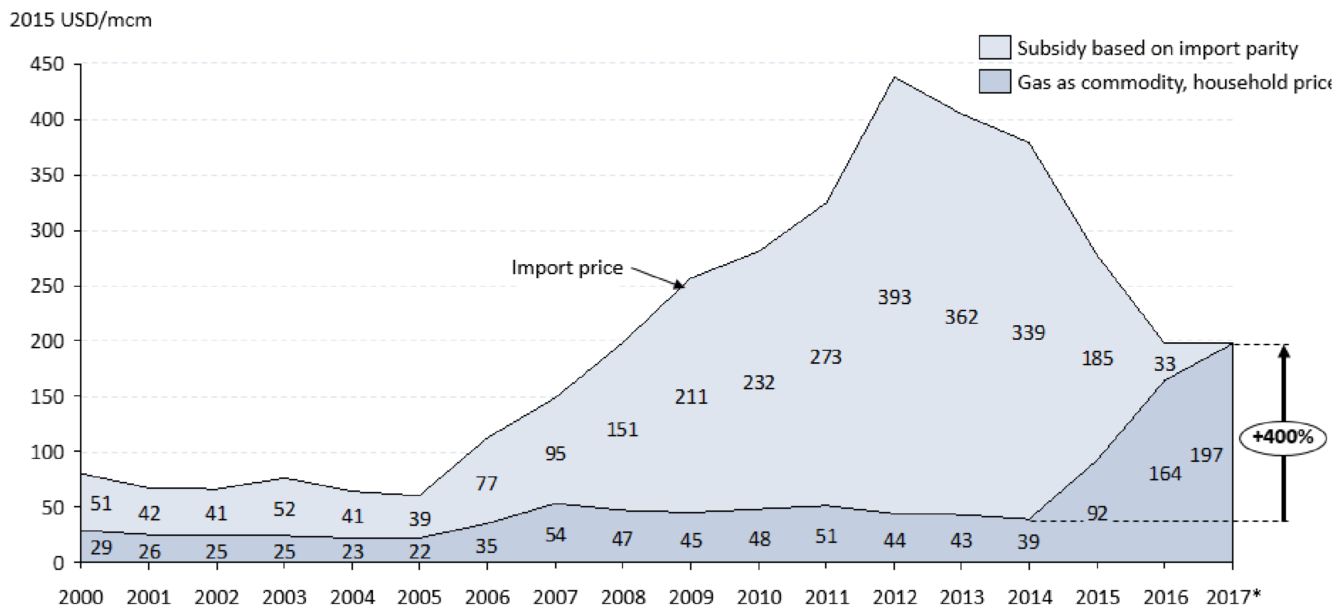


Figure 95: Gas prices by sector and import prices - Ukraine

Natural gas prices in the Ukraine seemed to be independent of the general gas trend prices globally. Historically, the provision of Russian natural gas at subsidized prices and often with political intention, have differentiated the local gas prices from the international based prices. This makes it very difficult to make accurate forecasts for the coming years. However, we identify the increasing trend of gas prices for household consumption and district heating, while also noticing the falling import prices.

Generally, the Black Sea geologistic scenario is not price driven, but rather focused on securing natural gas supplies for the southern region and Ukraine specifically. An estimation of the current average price of natural gas in the Ukraine is 0.29611 €/m3. These prices however are volatile and dependent on many factors, including the entry and exit point tariffs of the distribution network. A more detailed analysis into the entry and exit point tariffs follows.

Entry and exit point tariffs

The transportation tariffs are determined by the National Regulatory Authority (NERC) on a yearly basis based on the evaluation of the licensees (currently only the Ukrainian TSO Ukrstransgaz) and key indicators, submitted to the regulator twice a year.

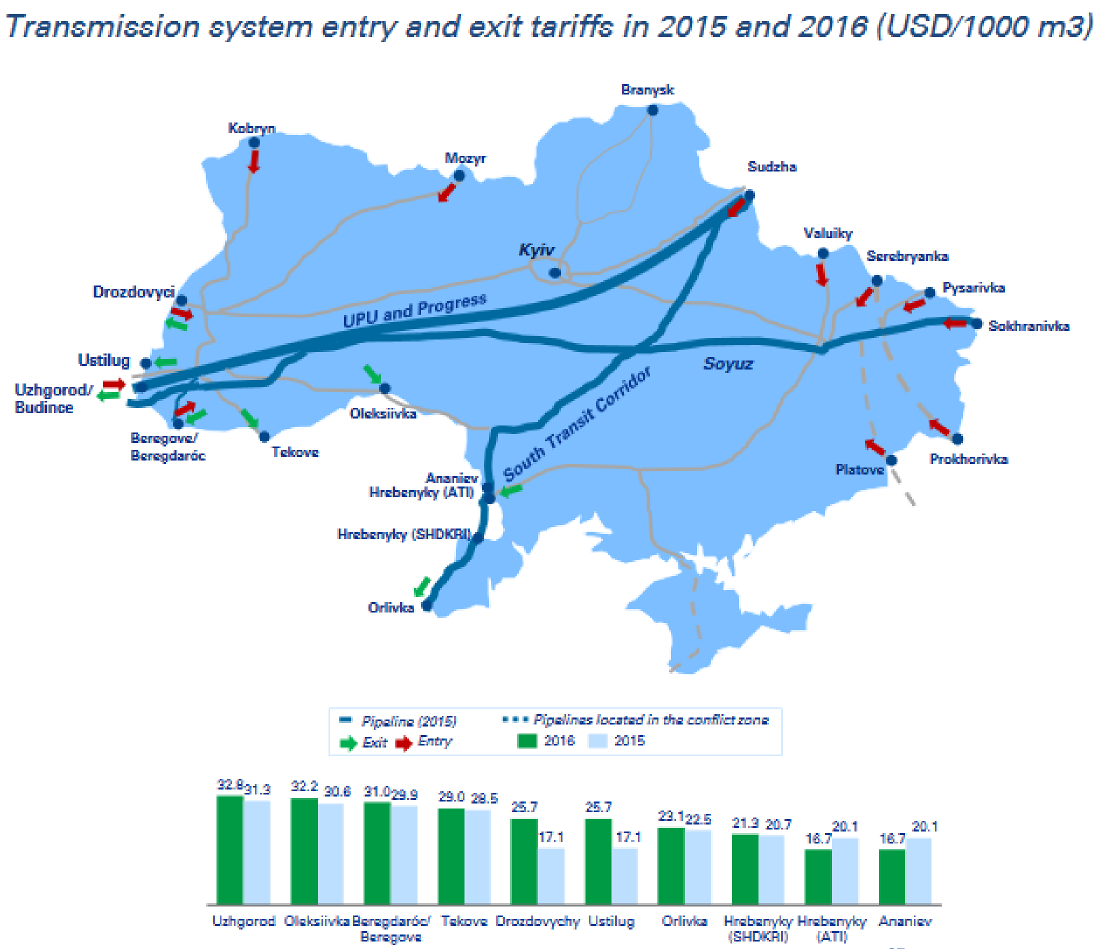


Figure 96: Ukraine gas transmission system, entry/exit tariffs[87]

Compared to 2015, entry/exit-point based natural gas transportation tariffs increased by almost 7% in 2016. For more information on transit tariffs on the main transit lines in Ukraine and in the EU visit the Appendix, Section IV. The overall buyer gas prices and tariffs in Ukraine as of February 1st, 2018 are listed below:

Buyer gas prices/tariffs in Ukraine: Price list for natural gas from February 1, 2018[88]

Consumer Categories		Pricing Terms		The price of natural gas as a commodity from the stock of Naftogaz of Ukraine, without VAT	VAT[89] to the price of gas as a commodity	Price of natural gas as a commodity with VAT
1		2	3	4	5	6
Industrial consumers and other subjects of economic activity that are not subject to the Regulation on the imposition of special duties on natural gas market subjects for the provision of general public interests in the process of functioning of the natural gas market	I	Monthly volumes of natural gas use: from 50 thousand cubic meters In the absence of debts to the Company for previous periods	Subject to prepayment before the period (calendar month) of gas delivery	224.17 €	44.83 €	269.00 €
			Subject to payment during or after the period (calendar month) of gas supplies	246.76 €	49.35 €	296.11 €
Industrial consumers and other subjects of economic activity that are not subject to the Regulation on the imposition of special duties on natural gas market subjects for the provision of general public interests in the process of functioning of the natural gas market	II	Monthly volumes of use of natural gas: up to 50 thousand cubic meters inclusive	In accordance with the concluded agreement	246.76 €	49.35 €	296.11 €
Suppliers for further gas sales to institutions and organizations funded by the state and government local budgets, industrial consumers	III	Monthly purchases of natural gas are not regulated	In accordance with the concluded agreement	246.76 €	49.35 €	296.11 €
Subsidiaries established by the National Joint-Stock Company "Naftogaz of Ukraine", in which one hundred percent of the authorized capital is owned by the Company	IV	Monthly purchases of natural gas are not regulated	In accordance with the concluded agreement	224.17 €	44.83 €	269.00 €

Table 28: Price list for natural gas from February 1, 2018[90]

Players

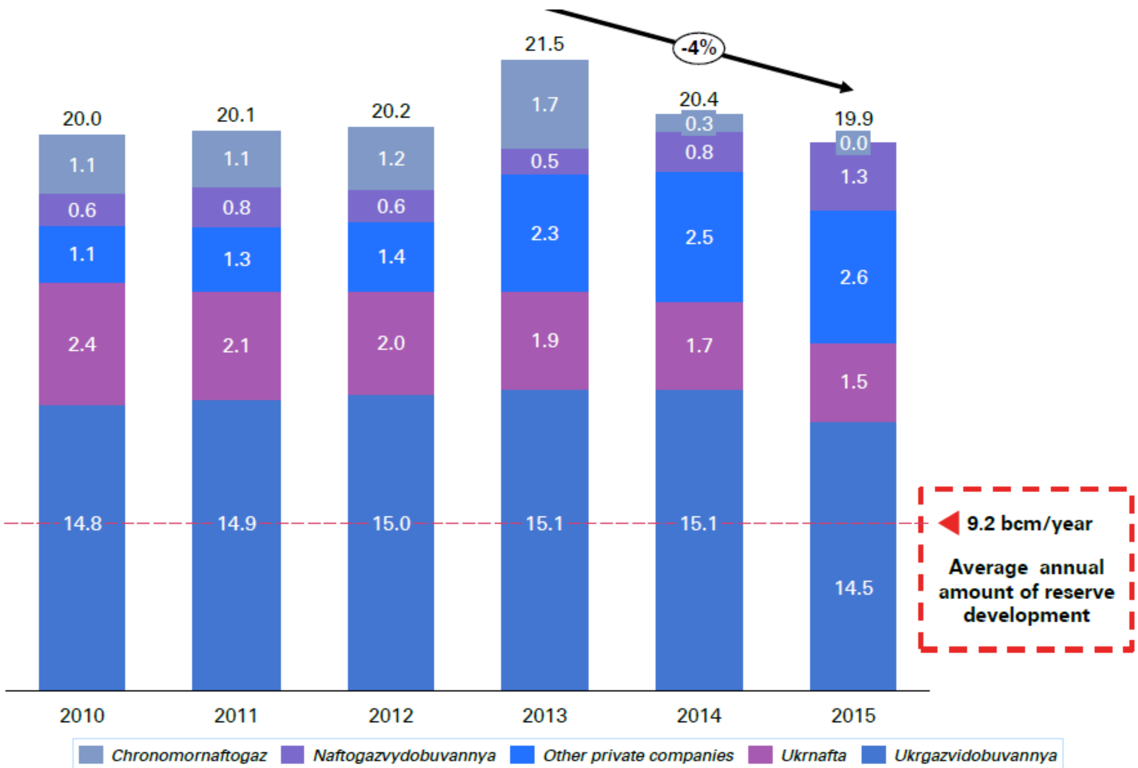


Figure 97: Natural gas production by company (bcm)

The players in the local natural gas market in Ukraine have remained relatively unchanged in the Ukraine in the past few years, other than Chronomornaftogaz which is directly affected by the Crimean crisis and disputes. Chronomornaftogaz was established in the USSR as a state owned company, but in February 2014 Naftogaz, Ukraine's state owned oil and gas company, sued Chornomornaftogaz for delayed debt payments (almost €1 billion), while the Crimean's region parliament seized the company following the crisis. The Crimean deputy prime minister announced that Russia's Gazprom will be the new owner of the company, followed by US and EU sanctions directed at reducing Gazprom's influence into the company and the provision of natural gas in the area in general.

As a result, Chronomornaftogaz's market share was steadily diminished by 2015. The market share seems to have been absorbed by Naftogazvydobuvannya as the other gas providers seemed to have generally declined their production in the period 2013-2015, while Naftogazvydobuvannya managed to increase its production in this period.

4.5 Resulting Scenarios

As described above we have concluded to proceed with the below scenarios for the geoligistic area of the Black Sea. We have identified a number of demand profiles for Ukraine and also taken into consideration the loading capacity in volume of the Gasvessel

Target Market Entry Point	Coordinates (onshore)	Gas Volumes MMSCMD (MMSCFD)
Ukraine, Yuzne Port	Latitude: 46°35'32.06"N Longitude: 31° 6'42.74"E	5.65 (200)
		11.30 (400)
		16.95 (600)
		22.60 (800)
Total Scenarios:		**4**

The Gasvessel loading terminal site location chosen is the territory to the north of the Poti port and the gas source is the Shah Deniz oil field in Azerbaijan. The natural gas will be piped through a tie-in to the South Caucasus Pipeline to reach a compressor station near the port of Poti from where the Gasvessel will be loaded near shore.

The resulting unloading terminal scenario is located near the port of Yuzne in Ukraine, where the multiple gas line system, SHDKRI will be used for distribution. The natural gas will be intended both for local consumption as well as for export markets such as the Republic of Moldova and various Balkan states.

The purpose of the proposed CNG route is to provide Ukraine an additional natural gas source option, namely, from Azerbaijan. This is vital to eliminate the Ukrainian dependency on Russian imports. Furthermore, the Gasvessel project could help provide additional alternatives from (non-Russian) EU imports that are currently substituting Russian imports and further assist in diversification and energy security.

4.6 Costs and Tariffs

Inputs

The composition of the upstream tariff includes the retail price of gas from the Shah Deniz field, gas transportation from the Shah Deniz field through the territory of Azerbaijan and Georgia to the loading terminal, CAPEX, OPEX of the gas interconnector, as well as CAPEX and OPEX of the gas loading terminal.

Midstream tariffs are mainly concerned with the components from gas loading from Georgia until gas unloading in Ukraine, with further details in the later sections. These components are largely estimations for now, while many figures are still to be computated and later revised.

A similar composition of the downstream tariff must be shown in the unloading system in Ukraine. The downstream tariff includes the retail price of gas in Gasvessel, the CAPEX and OPEX of the gas unloading terminal, the CAPEX and OPEX of the gas interconnector, and finally, the entry point tariff (compressor station "Berezivka") into the gas transportation system of Ukraine. This figure should also be used for comparison reasons.

It should also be noted that currently, a steady increasing trend in the cost of gas for consumers of all categories in Ukraine is taking place. Additionally, costs relating to loading and unloading systems will be considered as part of the midstream tariff calculations for WP2 to allow us to have more concrete estimates on upstream and downstream tariff calculations. For a breakdown of the tariff structure consult Figure 98.

Please note that our assumptions might have resulted in generic cost estimations and will be further revised in the future.

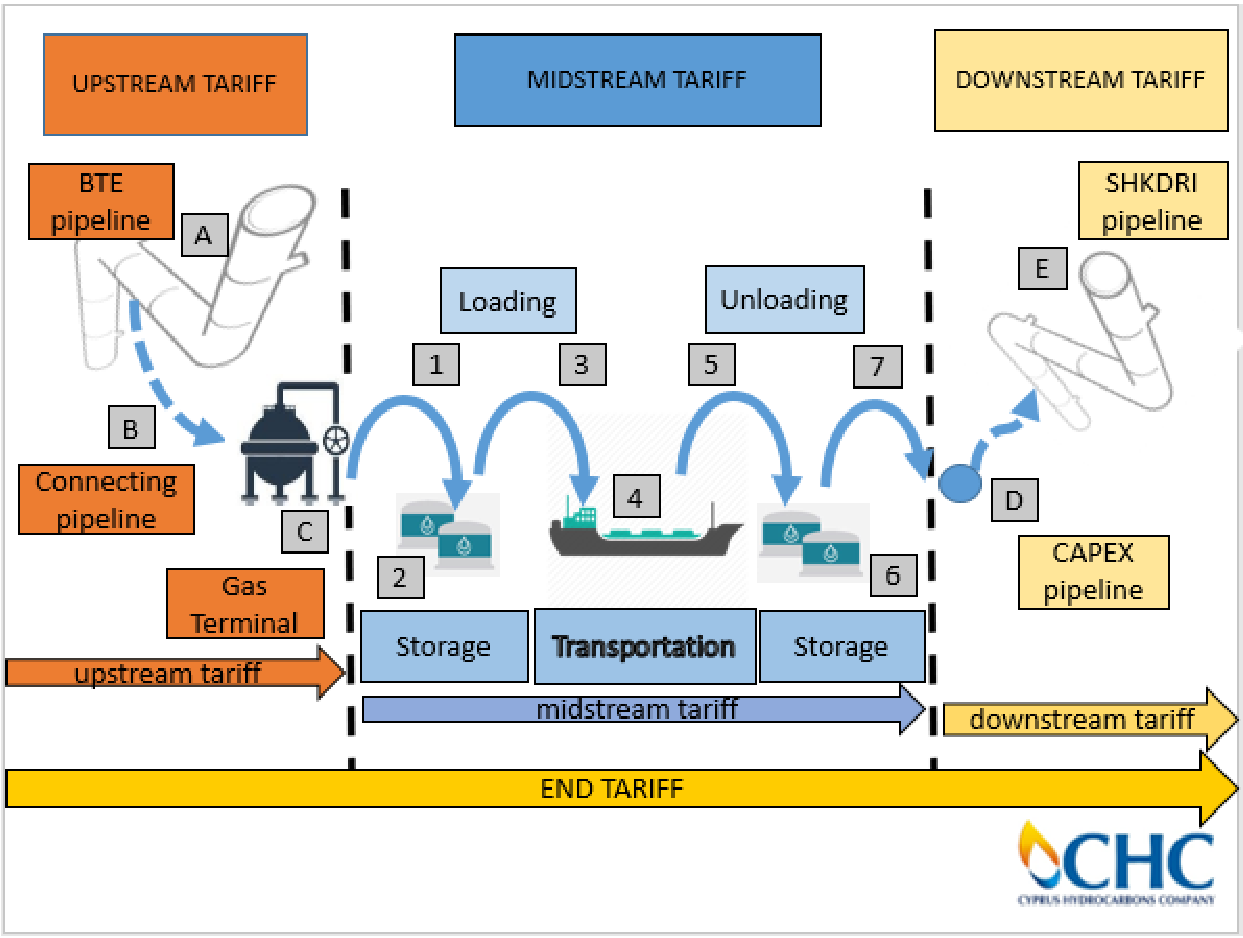


Figure 98: Tariff breakdown Black Sea

For the purpose of this report, tariff components have been segregated by scenario and by chain supply components (upstream, midstream and downstream). Upstream and downstream components have been simplified for practical reasons at this point and do not include any form of loading, unloading or storage costs. The above figure relates to the Black Sea geologistic scenario and separates the cost components as follows:

Upstream	Component	Notes
Cost of buying gas from BTE pipeline	A	Price of gas (50 bars) from BTE in Georgia
Cost of connecting pipeline in Georgia	B	Tie-in to be built
Gas compression terminal costs (CAPEX, OPEX)	C	Change pressure to (250 bars), provide gas to CNG specifications (this means gas is fully processed)
Midstream		
Loading to storage	1	To be calculated
Storage	2	To be calculated
Loading to vessel	3	To be calculated
Transportation	4	To be calculated
Unloading to storage	5	To be calculated
Storage	6	To be calculated
Unloading to Ukraine gas network	7	To be calculated
Downstream		
Cost of connecting pipeline in Ukraine	D	To be built
Network distribution costs in Ukraine	E	Delivered at 50 bars

4.6.1 Upstream Cost Estimation

The upstream cost estimation will require the computation of the cost of gas transportation from the Shah-Deniz oil and gas field in Baku, to the gas loading terminal in Georgia, as this is dictated by transiting volumes, regulations and ministry decisions.

Cost of Gas Transportation to the Gas loading terminal in Georgia

In this report, Georgia is not seen as a gas consumer, but only as a transmitter for the Gasvessel project, so we will only consider the transport tariff for gas pipelines owned by Georgian State companies. Gas pipelines are the sources of gas supplies to the loading terminal in the Poti region, and they are also considered as the State gas transportation system, so the tariffs for gas transportation will be the same.

Here, we make an assumption that the gas price offered in the market in Georgia will be equivalent to the gas price for gas supplied via the BTE gas pipeline since the gas source is the same (Shah Deniz fields).

The possibility of increasing the gas volumes transiting via the gas transportation system of Georgia is envisaged through the upgrading of the whole system. Despite the fact that attraction of the resources required thereto is set forth by plans of the national operator of the Gas Transportation System of Georgia, we consider only main gas lines, which may potentially transport gas to the Gasvessel loading terminal. Required adjustments and corrections may be made to the project upon determination of potential volumes of gas supplies via the Gasvessel system.

Natural gas consumer price has increased.

The consumer price of gas, as well as the gas transportation tariff has increased in Geogia following official decisions of the Ministry of Energy. The GNERC members have decided to increase transportation tariffs and consumer prices as of July 20, 2017, because of increased operational costs that are necessary for keeping the network in order.

Transportation is one of the components of consumer tariff. While GNERC will discuss final price of natural gas, the commission does not make comments on whether natural gas price will rise further for consumers, while experts expect the tariff to grow further. Gas distribution in Tbilisi is carried out by LLC KazTransGas Tbilisi, and by SOCAR Georgia Gas and SakOrgGas in the remaining regions. For the purpose of the Gasvessel project, gas distribution is carried out by SOCAR Georgia Gas. The total cost of gas in Georgia (supply from Azerbaijan) will be 0.1854 €/m3 or 0,008193 $/mmbtu. This includes all costs for the gas retail price and all transportation within for the Georgian territory. Additional transportation will be required to reach the loading terminal.

COMPONENT	**TARIFF**
Shah Deniz gas retail price	0.1854 €/m3 0.008193 $/mmbtu [91]
Transportation of gas up to loading terminal	0.0113 €/m3 0.000403 $/mmbtu [92]
Gas storage	To be calculated
CAPEX of interconnector	To be calculated
OPEX of interconnector	To be calculated
END UPSTREAM TARIFF	0.1967 €/m3 0.008596 $/mmbtu

- Green: data is available and reliable
- Yellow: data is available but not fully reliable yet
- Red: data is not yet available

The color coding system is introduced here with the purpose to slowly incorporate it into the data collection and revision process as the WPs progress. The aim is to identify the availability and reliability of data, with the end purpose to eliminate uncertainties in final computations.

4.6.2 Midstream Cost Estimation

Midstream cost estimation for WP2 includes all costs and tariffs from the gas loading system in Georgia until, and including, the gas unloading system in Ukraine. This tariff structure is to be revised according to the project needs in later Work Packages.

COMPONENT	**TARIFF**
Loading to storage costs	To be calculated
Upstream storage costs	To be calculated
Loading to Gasvessel	To be calculated
Transportation by Gasvessel	To be calculated
Transportation costs OPEX	To be calculated
Transportation costs CAPEX	To be calculated
Unloading to downstream storage	To be calculated
Unloading to downstream pipeline	To be calculated
END MIDSTREAM TARIFF	To be calculated

4.6.3 Downstream Cost Estimation

Downstream cost estimation concerns all the elements of gas transportation from the Gasvessel to the local distribution network. This includes the relative costs of the unloading system, onshore pipeline system to the distribution network and the delivery tariffs through the local distribution network.

COMPONENT	**TARIFF**
Tariff for gas transportation from point of connection to existing GTS to consumers	0.0113 €/m3 (0,000499 $/mmbtu)

Tariff for entry point	0.0100 €/m3 (0,000441 $/mmbtu)
CAPEX of unloading terminal	To be calculated
OPEX of unloading terminal	To be calculated
CAPEX of interconnector	To be calculated
OPEX of interconnector	To be calculated
END DOWNSTREAM TARIFF	0.0213 €/m3 (0,000499 $/mmbtu)

4.6.4 Alternatives Cost Estimation

The only viable alternative to CNG in Ukraine at the moment is pipeline natural gas as it is distributed via the established pipeline networks. As explained in previous sections, this is both domestically produced and imported to cover the country's demand needs.

4.6.5 Other Costs

Calculation of CAPEX in variants of different Scenarios

mmscfd	No.	Transportation system	New Infrtastructure Facilities	Gas price, €/m3	CAPEX mln €	Transport Tariff	Notes
200	Gas loading terminal in Georgia, near the port of Poti (source: Shah Deniz Gas fields)						
	1	Main Gas pipeline Baku-Tbilisi-Erzurum (BTE, SCP)	Existent	0,1854			Shah Deniz - Gas measuring point No 80
	2	Main Compressor Station	New		18,82		To be updated
	3	Gas interconnector to Gas loading terminal	New (L=140 km, D=28")		66,64		Gas measuring point No 80 - Gas loading terminal
	4	Gas loading terminal with Gas storage	New		36,45		To be updated
	5	Underwater gas pipeline	New (L=2,5 km, D=28")		1,68		Gas loading terminal - Underwater PLEM
	6	PLEM with SAL system	New		0,68		To be updated
400	Gas loading terminal in Georgia, near the port of Poti (source: Shah Deniz Gas fields)						
	1	Main Gas pipeline Baku-Tbilisi-Erzurum (BTE, SCP)	Existent	0,1854			Shah Deniz - Gas measuring point No 80
	2	Main Compressor Station	New		24,91		To be updated
	3	Gas interconnector to Gas loading terminal	New (L=140 km, D=32")		76,16		Gas measuring point No 80 - Gas loading terminal
	4	Gas loading terminal with Gas storage	New		48,4		To be updated
	5	Underwater gas pipeline	New (L=2,5 km, D=32")		1,92		Gas loading terminal - Underwater PLEM
	6	PLEM with SAL system	New		0,68		To be updated

600	Gas loading terminal in Georgia, near the port of Poti (source: Shah Deniz Gas fields)						
	1	Main Gas pipeline Baku-Tbilisi-Erzurum (BTE, SCP)	Existent	0,1854			Shah Deniz - Gas measuring point No 80
	2	Main Compressor Station	New		37,29		To be updated
	3	Gas interconnector to Gas loading terminal	New (L=140 km, D=32")		76,16		Gas measuring point No 80 - Gas loading terminal
	4	Gas loading terminal with Gas storage	New		64,31		To be updated
	5	Underwater gas pipeline	New (L=2,5 km, D=32")		1,92		Gas loading terminal - Underwater PLEM
	6	PLEM with SAL system	New		0,68		To be updated
800	Gas loading terminal in Georgia, near the port of Poti (source: Shah Deniz Gas fields)						
	1	Main Gas pipeline Baku-Tbilisi-Erzurum (BTE, SCP)	Existent	0,1854			Shah Deniz - Gas measuring point No 80
	2	Main Compressor Station	New		49,81		To be updated
	3	Gas interconnector to Gas loading terminal	New (L=140 km, D=40")		95,2		Gas measuring point No 80 - Gas loading terminal
	4	Gas loading terminal with Gas storage	New		82,1		To be updated
	5	Underwater gas pipeline	New (L=2,5 km, D=40")		2,41		Gas loading terminal - Underwater PLEM
	6	PLEM with SAL system	New		0,68		To be updated
200	Gas unloading terminal inUkraine, near the port of Yuzne (source: GASVESSEL)						
	1	Main Gas pipeline SHKDRI	Existent	0,2961			SHDKRI
	2	Gas interconnector from Gas unloading terminal	New (L=70 km, D=40")		33,6		Gas loading terminal -

							Compressor station "Berezivka"
	3	Gas unloading terminal	New		16,2		To be updated
	4	Underwater gas pipeline	New (L=3,54 km, D=20")		1,7		Underwater PLEM - Gas loading terminal
	5	PLEM with SAL system	New		0,68		To be updated
400	Gas unloading terminal inUkraine, near the port of Yuzne (source: GASVESSEL)						
	1	Main Gas pipeline SHKDRI	Existent	0,2961			SHDKRI
	2	Gas interconnector from Gas unloading terminal	New (L=70 km, D=40")		33,6		Gas loading terminal - Compressor station "Berezivka"
	3	Gas unloading terminal	New		16,2		To be updated
	4	Underwater gas pipeline	New (L=3,54 km, D=20")		1,7		Underwater PLEM - Gas loading terminal
	5	PLEM with SAL system	New		0,68		To be updated
600	Gas unloading terminal inUkraine, near the port of Yuzne (source: GASVESSEL)						
	1	Main Gas pipeline SHKDRI	Existent	0,2961			SHDKRI
	2	Gas interconnector from Gas unloading terminal	New (L=70 km, D=40")		33,6		Gas loading terminal - Compressor station "Berezivka"
	3	Gas unloading terminal	New		16,2		To be updated
	4	Underwater gas pipeline	New (L=3,54 km, D=20")		1,7		Underwater PLEM Gas loading terminal
	5	PLEM with SAL system	New		0,68		To be updated
800	Gas unloading terminal inUkraine, near the port of Yuzne (source: GASVESSEL)						

	1	Main Gas pipeline SHKDRI	Existent	0,2961			SHDKRI
	2	Gas interconnector from Gas unloading terminal	New (L=70 km, D=40")		33,6		Gas loading terminal Compressor station "Berezivka"
	3	Gas unloading terminal	New		16,2		To be updated
	4	Underwater gas pipeline	New (L=3,54 km, D=20")		1,7		Underwater PLEM Gas loading terminal
	5	PLEM with SAL system	New		0,68		To be updated

Table 29: Calculation of CAPEX in variants of different Scenarios

4.6.7 Costs and Tariffs Overview

Scenarios of Gas supply to Ukraine

Scenario:	LOADING POINT		Gas facility + pipeline entry UNLOADING POINT Yuzne	Gas storage facility UNLOADING POINT Poti	Gas tariff & cost estimate	Alternative transport options
SCENARIO 1 Gas consumption of 200 mmscfd	Loading terminal near port of Poti, Georgia	Distance (1)	578 nm	To be updated	Not identified	Main Gas Pipeline
SCENARIO 2 Gas consumption of 400 mmscfd	Loading terminal near port of Poti, Georgia	Distance (1)	578 nm	To be updated	Not identified	Main Gas Pipeline
SCENARIO 3 Gas consumption of 600 mmscfd	Loading terminal near port of Poti, Georgia	Distance (1)	578 nm	To be updated	Not identified	Main Gas Pipeline
SCENARIO 4 Gas consumption of 800 mmscfd	Loading terminal near port of Poti, Georgia	Distance (1)	578 nm	To be updated	Not identified	Main Gas Pipeline

The Black Sea micro-scenarios illustrated above will eventually help us compute the relative upstream, midstream and downstream tariffs. In the case of non-acquired data, as is mainly the case with midstream costs due to the early stages of the project, the computation will compile the tariffs available to come up with an end tariff.

BLACK SEA						
ORIGIN	UPSTREAM	MIDSTREAM	END DESTINATION	MMSCMD (MMSCFD)	DOWNSTREAM	END TARIFF
	TARIFF	TARIFF			TARIFF	€/m3
POTI	0.1967		ODESSA 1	5.65 (200)	0.0213	0.2197
POTI	0.1967		ODESSA 2	11.30 (400)	0.0213	0.2197
POTI	0.1967		ODESSA 3	16.95 (600)	0.0213	0.2197
POTI	0.1967		ODESSA 4	22.60 (800)	0.0213	0.2197

The upstream tariff include the gas purchasing price without the cost of bringing the gas through a new built pipeline to nearshore Georgia for the Gasvessel concept. So, they seem identical in the table above, but this will be differentiated considerably once the distribution costs are added per demand volume. The end tariff is of course incomplete, however, it is still useful for initial comparisons with prices of alternative energy sources, like pipeline natural gas sold in Ukraine.The tariff differential will display the margin allowable for the remaining tariffs and costs in order for the CNG to be price competitive.

CNG	LOCAL	ALTERNATIVE	ALTERNATIVE	MAX TARIFF	MIN TARIFF
END TARIFF	GAS PRICE	OPTION	TARIFF	TARGET	TARGET
0.2197	0.2961	-	-	0.0764	0.0764

From the above initial computations, we can make a rough estimate for the further progress of the market analysis. Specifically, the end tariff acquired thus far (0.2197 €/m3), compared to local gas prices via the pipeline network (0.2961 €/m3), allows the Gasvessel project a margin of 0.0764 €/m3 to cover midstream and other missing costs or tariffs. Additionally, as figures gradually become more reliable, we can return and edit the computations accordingly for a more accurate analysis.

This report describes the Ukrainian gas market as the main consumer of natural gas in the Black Sea region. It further describes technical feasibility of supplies and engineering aspects of the Gasvessel loading in the Black Sea, and outlines the methodology applied to identify the target markets in the Black Sea area.

Since Ukraine was chosen as the main gas consumer due to a number of existing political-economic problems in the region, the concept of the organization of natural gas deliveries to the existing Ukrainian gas transportation system was considered. The possibility of supplying natural gas from existing stable sources - main gas pipelines passing through Azerbaijan and Georgia, was duly analyzed. These pipelines are fed from the development of the second stage of the gas field in Azerbaijan, the Shakh-Deniz gas field.

The objective of this report is to present the technical possibilities of the existing gas transportation system in Ukraine to receive the required volume of gas on the market. Both domestic gas consumers and transit gas outside of Ukraine are considered, however, due to the analysis presented above, the export capacity of Ukraine is diminishing year on year, with the only gas volumes being exported to be Russian sourced gas which targets other European consumers. In brief, Ukraine is only being used as a transportation country for Russian gas and this will be maintained for the years to come, but as far as the domestic gas consumption is concerned, it is clearly visible that EU imports and domestic production are undoubtedly catching up to domestic consumption. The question here remains to be, when this domestic deficit will be completely covered by EU imports and local production. Until then, the opportunity for Gasvessel remains.

According to the preliminary analysis of the routes of the proposed gas interconnection pipelines to the site of the loading terminals near the port of Poti, and interconnection pipelines from the site of unloading terminal near the port of Yuzne in Ukraine, also the preliminary calculation of CAPEX, the following conclusions can be drawn:

- The route to the loading site terminal near the port of Poti is the best way of gas transportation to the coast of the Black Sea;
- Ukraine has increased its natural gas imports and its natural gas consumption.
- Ukraine has increased the natural gas transit.
- For the Gasvessel project, the Ukrainian gas market will be promising in respect to the growth of gas consumption.
- In the event of a reduction or cessation of Russian gas supplies to the largest gas main in southern Ukraine the SHKDRI, the Gasvessel project will play a major role both for supplying gas to the southern region of Ukraine and for exporting gas to Moldova and Romania.

DISCLAIMER:

Gasvessel Partners working on WP2 deliverables have made every effort to ensure that the estimations, calculations and projections presented herein are to the best of their knowledge in support of this particular research project. The scenarios presented here-in are scenarios based on energy demand and supply projections which are subject to a number of variables. As such Gasvessel Partners cannot guarantee the correctness of any such interpretations and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from the use of any of the interpretations, estimations, calculations and projections included here-in. The work produced so far in WP2 is to be considered in the context of all the Work Packages of the GASVESSEL project, and not in isolation, and with the expectation that the further progress of other work packages will result in further iterations of the work produced in WP2.

Appendix A: Additional information on the East Mediterranean geologistic scenario

I Technical Data for Cyprus

Country	Cyprus
Mainland/Island	Island
Target Buyer	Moni Power Station Cyprus Heavy Fuel Oil (HFO) Design Capacity of 140 MWe Existing turbines can not operate on gas
Location	Location Coordinates: Latitude = 34.71 / Longitude = 33.18 Description of the location: near shore no gas pipeline network no nearby port
Volume of gas based on 100 % gas conversion of the capacity	140 MWe = 3369 MWhd = 11.464 mmscfd = 324 mscmd
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 8.60 mmscfd = 242.92 mscmd
Distance from gas loading locations (km) http://andrew.hedges.name/experiments/haversine/ Table 30: Moni Power Station Cyprus	Offshore location: 284.45 Vasilikos Port: 10.03 (onshore)

Table 30: Moni Power Station Cyprus

Country	**Cyprus**
Mainland/Island	Island
Target Buyer	Vasilikos Power Plant Cyprus Heavy Fuel Oil (HFO) Design Capacity of 868 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 34.73 Longitude = 3.29 Description of the location: near shore no gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	868 MWe = 20832 MWhd = 71.079 mmscfd = 2008 mscmd
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency	= 42.65 mmscfd = 1204.88 mscmd

Distance from gas loading locations (km)Table 31: Vasilikos Power Plant Cyprus	Offshore location: 294.46 Vasilikos Port: -

Table 31: Vasilikos Power Plant Cyprus

Country	Cyprus
Mainland/Island	Island
Target Buyer	• Dhekelia Power Plant Cyprus Heavy Fuel Oil (HFO) Design Capacity of 460 MWe Possibility for Natural Gas Conversion
Location	• Location Coordinates: Latitude = 34.98 / Longitude = 33.74 • Description of the location: near shore no gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	460 MWe = 11040 MWhd = 37.668 mmscfd = 1064 mscmd
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 28.25 mmscfd = 798.16 mscmd
Distance from gas loading locations (km)	1. Offshore location: 342.17 2. Vasilikos Port: 50.04 (onshore)

Table 32: Dhekelia Power Plant Cyprus

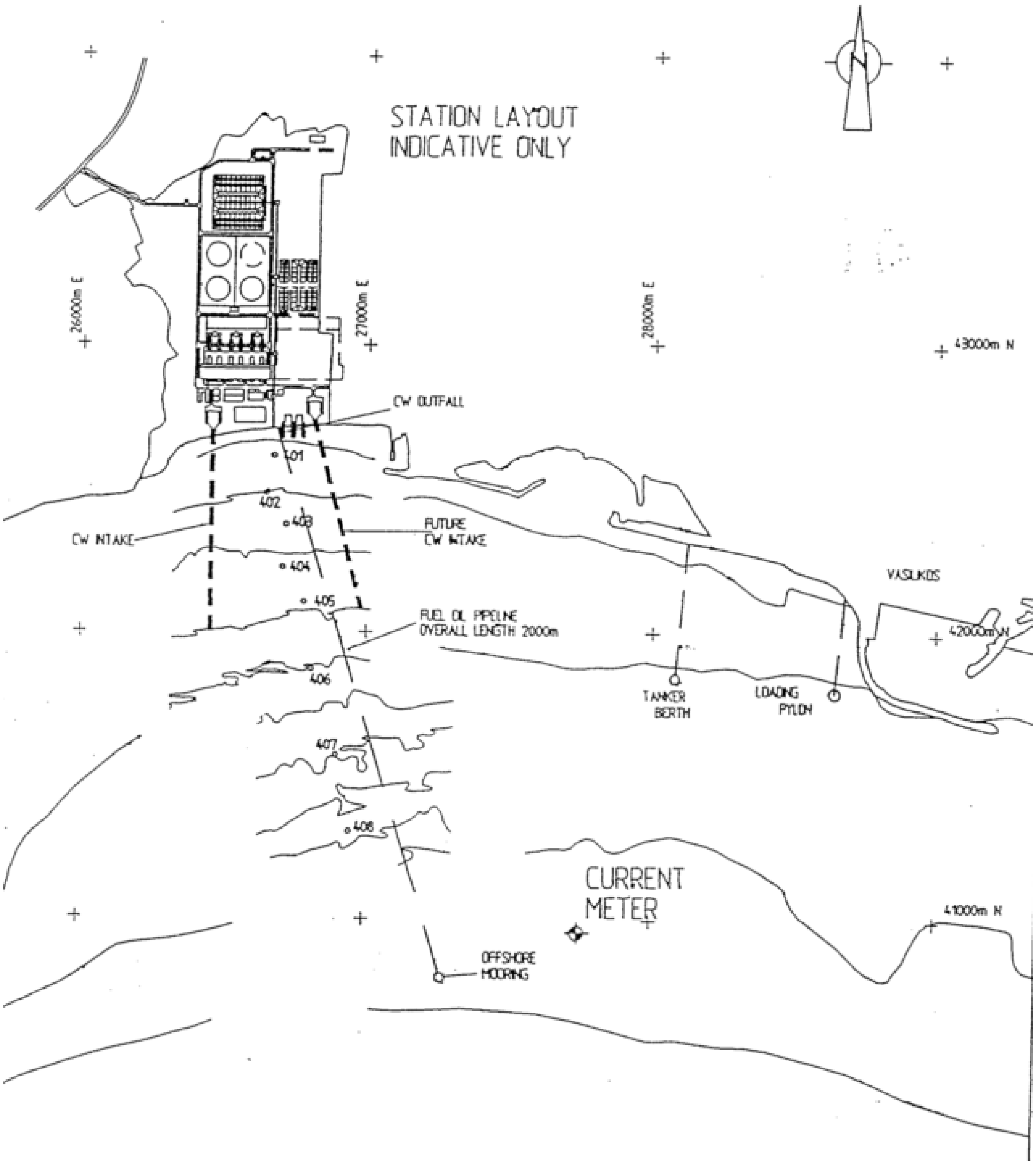


Figure 99: Layout of Vasilikos power plant near gas loading/unloading locations

Cyprus natural gas demand			
	mmscmd		
Year	low	mid	high
2016	1.508	1.933	2.358
2017	1.542	1.990	2.438
2018	1.558	2.024	2.490
2019	1.619	2.117	2.614
2020	1.654	2.176	2.698
2021	1.690	2.238	2.786
2022	1.749	2.332	2.915
2023	1.810	2.430	3.049
2024	1.865	2.520	3.175
2025	1.935	2.632	3.330
2026	1.953	2.660	3.368
2027	2.009	2.745	3.467
2028	2.052	2.830	3.594
2029	2.108	2.887	3.707
2030	2.151	2.972	3.821
2031	2.193	3.056	3.920
2032	2.236	3.113	4.033
2033	2.292	3.170	4.146
2034	2.335	3.283	4.245
2035	2.377	3.368	4.358

II Technical data for Greece

Country	**Greece**
Mainland/Island	Island
Target Buyer	Chios Extension Power Plant Greece Heavy Fuel Oil (HFO) Design Capacity of 14.8 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 38.33 / Longitude = 26.15 Description of the location: near shore - no gas pipeline network - nearby port
Volume of gas based on 100 % gas conversion of the capacity	14.8 MWe = 355 MWhd = 1.212 mmscfd = 34 mscmd
Volume of gas using the 30% loading factor	= 0.91 mmscfd

*Assuming diesel turbines 40% efficiency	= 25.68 mscmd
Distance from gas loading locations (km)	Offshore location: 604.50 Vasilikos Port: 752.86

Table 33: Chios Extension Power Plant Greece

Country	**Greece**
Mainland/Island	Island
Target Buyer	Soroni Rodos Power Plant Greece Heavy Fuel Oil (HFO) Design Capacity of 84 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 36.38 Longitude = 28.019 Description of the location: near shore no gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	84 MWe =2016 MWhd = 6.879 mmscfd = 194 mscmd
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency	= 5.16 mmscfd = 145.75 mscmd
Distance from gas loading locations (km)	Offshore location: 331.91 Vasilikos Port: 511.04

Table 34: Soroni Rodos Power Plant Greece

Country	**Greece**
Mainland/Island	Island
Target Buyer	Chania Power Plant Crete Greece Heavy Fuel Oil (HFO) Design Capacity of 345 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude=35.49/Longitude=24.04 Description of the location: near shore - no gas pipeline network - nearby port
Volume of gas based on 100 % gas conversion of the capacity	345 MWe = 8280 MWhd = 28.25 mmscfd = 798 mscmd
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 21.19 mmscfd = 598.62 mscmd
Distance from gas loading locations (km)	Offshore location: 587.99 Vasilikos Port: 845.75

Table 35: Chania Power Plant Crete Greece

Country	Greece
Mainland/Island	Island
Target Buyer	Linoperamata Power Plant Crete Heavy Fuel Oil (HFO) Design Capacity of 272 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 35.34 / Longitude = 25.05 Description of the location: near shore - no gas pipeline network - nearby port
Volume of gas based on 100 % gas conversion of the capacity	272 MWe = 6528 MWhd = 22.27 mmscfd = 629 mscmd
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 16.71 mmscfd = 471.96 mscmd
Distance from gas loading locations (km)	Offshore location: 495.01 Vasilikos Port: 753.11

Table 36: Linoperamata Power Plant Crete Greece

Country	Greece
Mainland/Island	Island
Target Buyer	Atherinolakkos IC Power Plant Greece Heavy Fuel Oil (HFO) Design Capacity of 195 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 35.00 / Longitude = 26.14 Description of the location: near shore - no gas pipeline network - nearby port
Volume of gas based on 100 % gas conversion of the capacity	195 MWe = 4680 MWhd = 15.97 mmscfd = 451 mscmd
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 11.98 mmscfd = 338.35 mscmd
Distance from gas loading locations (km)	Offshore location: 389.67 Vasilikos Port: 653.14

Table 37: Atherinolakkos IC Power Plant Greece

III Technical data for Italy

Located just opposite traditional gas exporters such as Algeria, Tunisia and Libya, Italy is among the well-gasified countries in Europe that introduced natural gas in its energy mix. The national gas network is supported from the north by gas pipelines coming from north, central and west Europe and on the south by North Africa countries. Italy has also three regasification terminals connected to the network that allow flexibility of supply especially when during demand swings. The existing gas transmission lines such as Trans-Mediterranean and Greenstream provide gas to Italy entering from the island of Sicily and then continue to the north until the other end of the country. In addition, Italy is producing oil and gas that partially feeds its domestic power plants thus is another element to consider when evaluating Italy as a potential gas buyer. Furthermore, the Island of Sardinia will potentially receive gas very soon from two proposed projects i.e Galsi gas pipeline that crosses through the island[93] and its opponent Sardinia small-scale regasification terminal[94]. Figure 100 shows the power plants have been evaluated for the first phase of the marketing analysis and tables 19-26 present their technical characteristics.

Figure 100: Italian Power Plants[95]

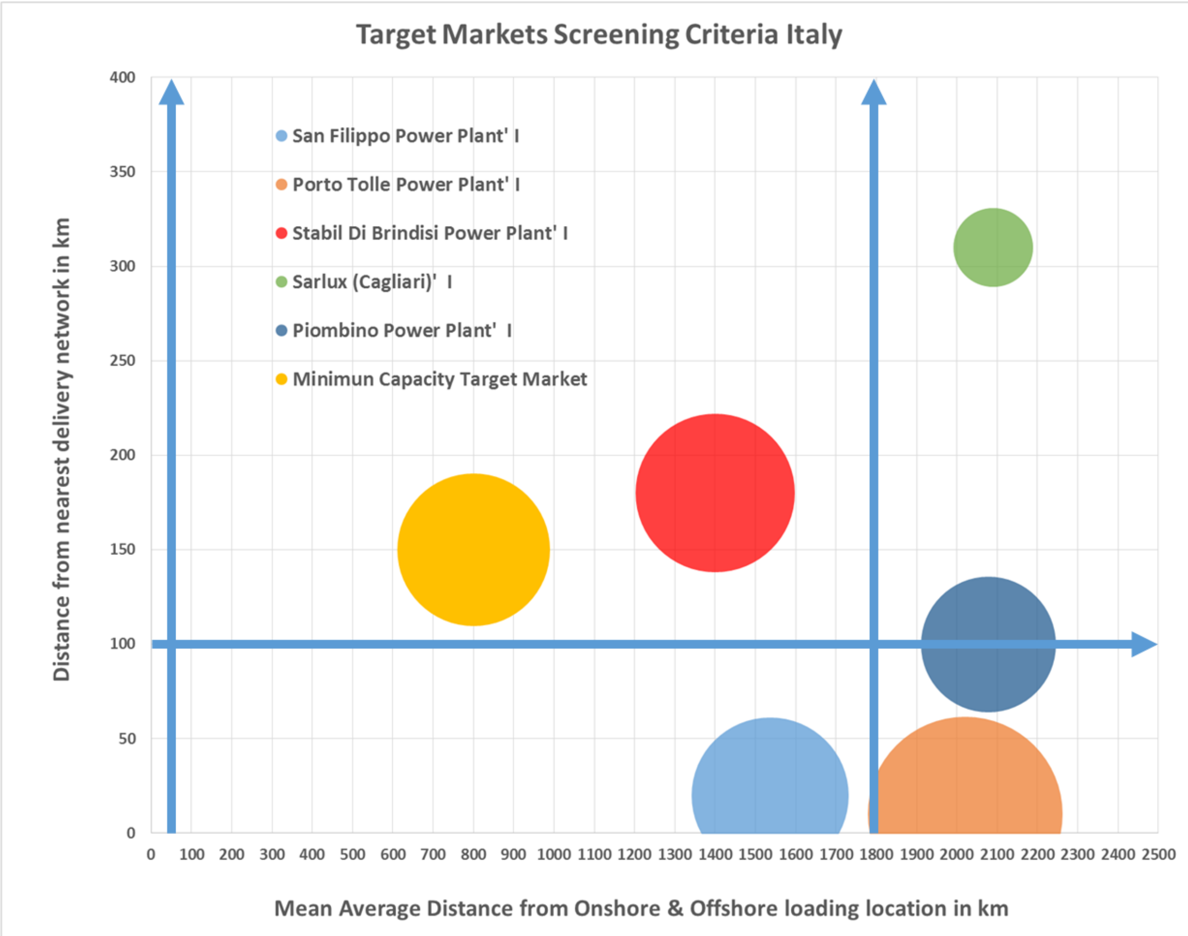


Figure 101: Power Plants in Italy based on market screening criteria

Country	**Italy**
Mainland/Island	Mainland
Target Buyer	ENEL Porto Tolle Thermal Power Plant Italy Heavy Fuel Oil (HFO) Design Capacity of 2640 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 44.96 / Longitude = 12.49 Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	2640 MWe = 63360 MWhd = 216.184 mmscfd = 6108 mscmd
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 162.14 mmscfd = 4580.75 mscmd
Distance from gas loading locations (km)	Offshore location: 1942.60 Vasilikos Port: 2100.03

Table 38: ENEL Porto Tolle Thermal Power Plant Italy

Country	**Italy [13]**
Mainland/Island	Mainland
Target Buyer	ENIPOWER S.P.A. Stabil. di Brindisi Italy Heavy Fuel Oil (HFO) Design Capacity of 1321 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 40.63 / Longitude = 18.00 Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	1321 MWe = 31704 MWhd = 108.174 mmscfd = 3056 mscmd
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 81.13 mmscfd = 2292.11 mscmd
Distance from gas loading locations (km)	Offshore location: 1306.14 Vasilikos Port: 1494.41

Table 39: ENIPOWER S.P.A. Stabil. Di Brindisi Italy

Country	**Italy**
Mainland/Island	Mainland
Target Buyer	Enel Marzocco Oil Power Plant Italy Heavy Fuel Oil (HFO) Design Capacity of 310 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 43.57 Longitude = 10.31 Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	310 MWe = 7440 MWhd = 25.385 mmscfd = 717 mscmd
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 19.04 mmscfd = 537.89 mscmd
Distance from gas loading locations (km)	Offshore location: 2019.80 Vasilikos Port: 2202.60

Table 40: Enel Marzocco Oil Power Plant Italy

Country	Italy
Mainland/Island	Mainland
Target Buyer	ENEL Piombino Thermal Power Plant Italy Heavy Fuel Oil (HFO) Design Capacity of 1280 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 42.96 / Longitude = 10.60 Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	1280 MWe = 30720 MWhd = 104.817 mmscfd = 2961 mscmd
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 78.61 mmscfd = 2220.97 mscmd
Distance from gas loading locations (km)	Offshore location: 1970.01 Vasilikos Port: 2158.91

Table 41: ENEL Piombino Thermal Power Plant Italy

Country	Italy
Mainland/Island	Island
Target Buyer	Sarlux (Cagliari) IGCC Power Plant Italy Heavy Fuel Oil (HFO) Design Capacity of 550 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 39.10 / Longitude = 9.00 Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	550 MWe = 13200 MWhd = 45.038 mmscfd = 1272 mscmd
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency	= 27.02 mmscfd = 763.46 mscmd
Distance from gas loading locations (km)	Offshore location: 1972.86 Vasilikos Port: 2206.57

Table 42: Sarlux (Cagliari) IGCC Power Plant Italy

Country	Italy
Mainland/Island	Island
Target Buyer	Ottana Oil CHP Power Plant Heavy Fuel Oil (HFO) Design Capacity of 140 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 40.239 Longitude = 9.02 Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	140 MWe = 3369 MWhd = 11.464 mmscfd = 324 mscmd
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 8.60 mmscfd = 242.92 mscmd
Distance from gas loading locations (km)	Offshore location: 1997.93 Vasilikos Port: 2220.35

Table 43: Ottana Oil CHP Power Plant

Country	Italy
Mainland/Island	Island
Target Buyer	Edipower San Filippo del Mela Thermal Power Plant Italy Heavy Fuel Oil (HFO) Design Capacity of 1280 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 38.20 / Longitude = 15.28 Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	1280 MWe = 30720 MWhd = 104.817 mmscfd = 2961 mscmd
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 78.61 mmscfd = 2220.97 mscmd
Distance from gas loading locations (km)	Offshore location: 1419.14 Vasilikos Port: 1653.69

Table 44: Edipower San Filippo del Mela Thermal Power Plant Italy

Country	Italy
Mainland/Island	Mainland
Target Buyer	ISAB Priolo Gargallo IGCC Power Plant Italy Heavy Fuel Oil (HFO) Design Capacity of 562.6 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 37.14 / Longitude = 15.22 Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	562.6 MWe = 63360 MWhd = 216.184 mmscfd = 6108 mscmd
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 162.14 mmscfd = 4580.75 mscmd
Distance from gas loading locations (km)	Offshore location: 1399.41 Vasilikos Port: 1647.13

Table 45: ISAB Priolo Gargallo IGCC Power Plant Italy

IV Technical data for France

Power Plants in Corsica

CHC considers France outside the feasible distances for the Gasvessel concept when gas is loaded from offshore Cyprus. Based on the target market screening criteria, distances at 1750 km may already be a borderline for the technology. France is located more than 2300 km away from Cyprus offshore gas loading location. Even though the island of Corsica is located at the very east-south site of France mainland is still about 2000 km away from Cyprus offshore gas loading location. However, CHC decided to have a closer look at the island of Corsica since based on the target market screening criteria it can be seen at a first look as isolated market. Furthermore, it is considered to be the largest island in the Mediterranean after Sicily, Sardinia, Cyprus and Crete. However, by looking closer at its potential gas demand, Corsica has two rather small power oil plants to cover its daily needs and recently (2012) a cable connection of equivalent of 300MW was installed between Italy mainland-Corsica-Sardinia to cover any additional needs in power. The long distance from loading location in combination with the very small potential in gas demand led CHC not to propose Corsica as a potential gas buyer for the Gasvessel concept. Figure 102 shows the location of the two oil power plants at the island and tables 27 and 28 provide their technical characteristics. Furthermore, the graph in Figure 103 shows the power demand of the two power plants against the target market screening criteria.

Figure 102: Corsica's Oil Power Plants[96]

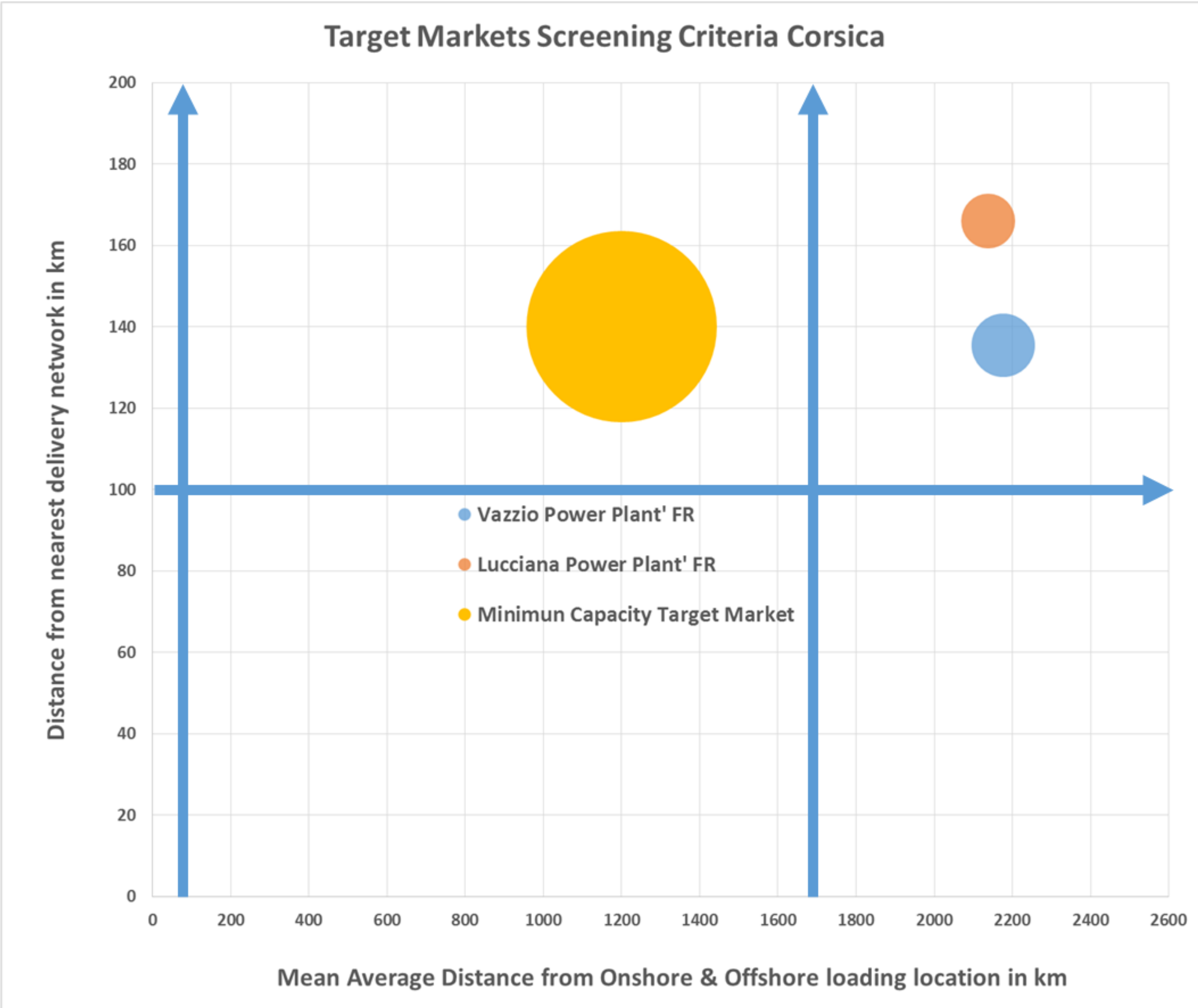


Figure 103: Power Plants in Corsica based on market screening criteria

Country	France
Mainland/Island	Island
Target Buyer	Lucciana Thermal Power Plant France Heavy Fuel Oil (HFO) Design Capacity of 131 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 42.53 / Longitude = 9.45 Description of the location: near shore no available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	131 MWe = 3144 MWd = 10.727 mmscfd = 303 mscmd
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 8.05 mmscfd = 227.3 mscmd
Distance from gas loading locations (km)	Offshore location: 2039.01 Vasilikos Port: 2236.12

Table 46: Lucciana Thermal Power Plant France

Country	France
Mainland/Island	Island
Target Buyer	Vazzio Thermal Power Plant France Heavy Fuel Oil (HFO) Design Capacity of 135.5 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 41.93 / Longitude = 8.72 Description of the location: near shore no available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	135.5 MWe = 3252 MWhd = 11.096 mmscfd = 313 mscmd
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 8.32 mmscfd = 235.11 mscmd
Distance from gas loading locations (km)	Offshore location: 2073.52 Vasilikos Port: 2278.83

Table 47: Vazzio Thermal Power Plant France

V Technical data for Lebanon

Lebanon Power Plants	Fuel Used
Deir-Ammar CCGT Power Plant	Heavy Fuel Oil (HFO)
Al-Hreesha (Hreishi) Thermal Power Plant	Heavy Fuel Oil (HFO)
Zouk Thermal Power Plant Lebanon	Heavy Fuel Oil (HFO)
Jieh Thermal Power Plant Lebanon	Heavy Fuel Oil (HFO)
Zahrani CCGT Power Plant Lebanon	Heavy Fuel Oil (HFO)
Tyre (Sour) Thermal Power Plant Lebanon	Heavy Fuel Oil (HFO)

Table 48: Summary of power plants and fuel used in Lebanon

Country	Lebanon
Mainland/Island	Mainland
Target Buyer	Deir-Ammar CCGT Power Plant Heavy Fuel Oil (HFO) Design Capacity of 470 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 34.47 / Longitude = 35.89 Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	470 MWe = 11280 MWhd = 38.487 mmscfd = 1087 mscmd
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 23.09 mmscfd = 652.41 mscmd
Distance from gas loading locations (km)	Offshore location: 525.35 Vasilikos Port: 240.23

Table 49: Deir-Ammar CCGT Power Plant Lebanon

Country	**Lebanon**
Mainland/Island	Mainland
Target Buyer	Al-Hreesha (Hreishi) Thermal Power Plant Heavy Fuel Oil (HFO) Design Capacity of 75 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 34.38 / Longitude = 35.76 Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	75 MWe = 1800 MWhd = 6.142 mmscfd = 174 mscmd
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 4.61 mmscfd = 130.14 mscmd
Distance from gas loading locations (km)	Offshore location: 512.30 Vasilikos Port: 229.43

Table 50: Al-Hreesha (Hreishi) Thermal Power Plant Lebanon

Country	**Lebanon**
Mainland/Island	Mainland
Target Buyer	Zouk Thermal Power Plant Lebanon Heavy Fuel Oil (HFO) Design Capacity of 607 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 33.97 / Longitude = 35.60 Description of the location: near shore no available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	607 MWe = 14568 MWhd = 49.706 mmscfd = 1404 mscmd
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 37.28 mmscfd = 1053.23 mscmd
Distance from gas loading locations (km)	Offshore location: 497.50 Vasilikos Port: 228.68

Table 51: Zouk Thermal Power Plant Lebanon

Country	**Lebanon**
Mainland/Island	Mainland
Target Buyer	Jieh Thermal Power Plant Lebanon Heavy Fuel Oil (HFO) Design Capacity of 346 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 33.65 / Longitude = 35.40 Description of the location: near shore no available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	346 MWe = 8304 MWhd = 28.333 mmscfd = 800 mscmd
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 21.25 mmscfd = 600.36 mscmd
Distance from gas loading locations (km)	Offshore location: 481.07 Vasilikos Port: 228.33

Table 52: Jieh Thermal Power Plant Lebanon

Country	**Lebanon**
Mainland/Island	Mainland
Target Buyer	Zahrani CCGT Power Plant Lebanon Heavy Fuel Oil (HFO) Design Capacity of 470 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 33.50 / Longitude = 35.34 Description of the location: near shore no available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	470 MWe = 11280 MWhd = 38.487 mmscfd = 1087 mscmd
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 23.09 mmscfd = 652.41 mscmd
Distance from gas loading locations (km)	Offshore location: 477.46 Vasilikos Port: 233.15

Table 53: Zahrani CCGT Power Plant Lebanon

Country	Lebanon
Mainland/Island	Mainland
Target Buyer	Tyre (Sour) Thermal Power Plant Lebanon Heavy Fuel Oil (HFO) Design Capacity of 70 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 33.28 / Longitude = 35.23 Description of the location: near shore no available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	70 MWe = 1680 MWhd = 5.732 mmscfd = 162 mscmd
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 3.44 mmscfd = 97.17 mscmd
Distance from gas loading locations (km)	Offshore location: 471.55 Vasilikos Port: 240.97

Table 54: Tyre (Sour) Thermal Power Plant Lebanon

VI Technical data for Egypt

Power Plants in Egypt

Country	Egypt [13]
Mainland/Island	Mainland
Target Buyer	Sidi Krir 1 and 2 Thermal Power Plant Heavy Fuel Oil (HFO) Design Capacity of 640 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 31.04 / Longitude = 29.66 Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	640 MWe = 15360 MWhd = 52.408 mmscfd = 1481 mscmd

Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 39.31 mmscfd = 1110.49 mscmd
Distance from gas loading locations (km)	Offshore location: 331.81 Vasilikos Port: 531.74

Table 55: Sidi Krir 1 and 2 Thermal Power Plant Egypt

Country	**Egypt**
Mainland/Island	Mainland
Target Buyer	El-Seiuf Thermal Power Plant Egypt (Shutdown) Heavy Fuel Oil (HFO) Design Capacity of 200 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 31.22 / Longitude = 30.00 Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	200 MWe = 4800 MWhd = 16.378 mmsc/d = 463 mscmd
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 12.28 mmscfd = 347.03 mscmd
Distance from gas loading locations (km)	Offshore location: 309.39 Vasilikos Port: 496.98

Table 56: El-Seiuf Thermal Power Plant Egypt (Shutdown)

Country	**Egypt**
Mainland/Island	Mainland
Target Buyer	Abu Qir (Kir) Thermal Power Plant Heavy Fuel Oil (HFO) Design Capacity of 2211 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 31.27 / Longitude = 30.14 Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	2211 MWe = 53064 MWhd = 181.054 mmscfd = 5115 mscmd
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40 % efficiency	= 135.79 mmscfd = 3836.38 mscmd
Distance from gas loading locations (km)	Offshore location: 302.87 Vasilikos Port: 484.02

Table 57: Abu Qir (Kir) Thermal Power Plant Egypt

Country	**Egypt**
Mainland/Island	Mainland
Target Buyer	Arish Thermal Power Plant Egypt Heavy Fuel Oil (HFO) Design Capacity of 66 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 31.11 / Longitude = 33.68 Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	66 MWe = 1584 MWhd = 5.405 mmscfd = 153 mscmd
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 4.05 mmscfd = 114.52 mscmd
Distance from gas loading locations (km)	Offshore location: 456.34 Vasilikos Port: 403.47

Table 58: Arish Thermal Power Plant Egypt

Country	**Egypt**
Mainland/Island	Mainland
Target Buyer	Abu Sultan Thermal Power Plant Egypt Heavy Fuel Oil (HFO) Design Capacity of 600 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 30.40 / Longitude = 32.31 Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	600 MWe = 14400 MWhd = 49.133 mmscfd = 1388 mscmd
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 36.85 mmscfd = 1041.08 mscmd
Distance from gas loading locations (km)	Offshore location: 445.4 Vasilikos Port: 489.90

Table 59: Abu Sultan Thermal Power Plant Egypt

Country	**Egypt**
Mainland/Island	Mainland
Target Buyer	Ataka (Suez) Thermal Power Plant Egypt Heavy Fuel Oil (HFO) Design Capacity of 900 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 29.934 / Longitude = 32.47 Description of the location: near shore - available gas pipeline network - nearby port
Volume of gas based on 100 % gas conversion of the capacity	900 MWe = 21600 MWhd = 73.699 mmscfd = 2082 mscmd
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 55.27 mmscfd = 1561.62 mscmd
Distance from gas loading locations (km)	Offshore location: 499.0 Vasilikos Port: 538.57

Table 60: Ataka (Suez) Thermal Power Plant Egypt

Country	Egypt
Mainland/Island	Mainland
Target Buyer	Oyoun (Ayoun) Moussa Thermal Power Plant Egypt Heavy Fuel Oil (HFO) Design Capacity of 640 MWe Possibility for Natural Gas Conversion
Location	Location Coordinates: Latitude = 29.91 / Longitude = 32.60 Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	640 MWe = 15360 MWhd = 52.408 mmscfd = 1481 mscmd
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 39.31 mmscfd = 1110.49 mscmd
Distance from gas loading locations (km)	Offshore location: 506.55 Vasilikos Port: 539.77

Table 61: Oyoun (Ayoun) Moussa Thermal Power Plant Egypt

Regulations/ownership rights/fees/liabilities for Egypt

The regulatory regime

Certain principal laws regulate the oil and gas sector. These include:

- Law No. 86 of 1958 organising Mines and Quarries and executive regulations.
- Law No. 20 of 1987 organising the Egyptian General Petroleum Company (EGPC).
- Law No. 217 of 1980 organising Natural Gas and executive regulations.
- Law No. 4 of 1988 regarding Oil Pipelines.

Regulation is mainly achieved by standard terms and provisions in the concession agreement signed by the Egyptian Minister of Petroleum and the Contractor. However, projects can differ from case to case.

Rights to oil and gas - Ownership

All minerals, including petroleum, existing mines and quarries in Egypt, including the territorial waters, and in the seabed subject to its jurisdiction and extending beyond the territorial waters, belong to the state (Mining and Quarries Law No. 66 of 1953).

The Mining and Quarries Law No. 66 of 1953 stipulates the terms and conditions that regulate and organise all procedures and approvals required for the exploration and exploitation of oil and gas. For example, the Government requires contractors to acquire a specific amount of any oil or gas discovered in accordance with a production sharing scheme. The contractor can sell and export its share according to the price valuation set out under the concession agreement.

The Minister of Petroleum, can, if authorised by a specific law passed by Parliament, enter into a concession or agreement that deviates from standard terms and conditions (Article 50, Mining and Quarries Law No. 66 of 1953).

Accordingly, all current oil and gas concession agreements include specific provisions to encourage foreign investors to enter into a bidding process announced by the Minister of Petroleum.

Nature of oil and gas rights

Lease/licence/concession term
The only mechanism and document that grants the contractor the right to carry out oil and gas exploration and exploitation activities is the concession agreement.

The term of the concession agreement is approved by Parliament and signed by the Egyptian Minister of Petroleum and the contractor. In general, the term for exploration ranges from seven to nine years, divided into three terms; the initial term and two extensions. However, if there is a commercial oil and gas discovery, the term may be 25 years to be extended to 35 years.

The contractor's rights can be assigned by a deed of assignment to a third party in accordance with the terms of the concession agreement after the approval of the Government.

The Egyptian General Petroleum Authority (EGPA) has the authority to apply the provisions and conditions pertaining to the exploration and exploitation of oil and gas set out under Law No. 66 of 1953 and Law No. 86 of 1956 (Law No. 167 of 1958). To obtain a legally binding concession agreement involves a two stage process:

- The Egyptian Parliament must pass a law, authorising the Minister of Petroleum to represent the Government in entering into a concession agreement with EGPC and the contractor.

- A contractor who wishes to obtain an oil and gas concession agreement must have the required financial and technical abilities set out in the concession agreement. A contractor granted a concession agreement must personally sign it; no other company, or a subsidiary of the Contractor, can sign the agreement on the contractor's behalf (Mining and Quarries Law No. 66 of 1953 and Law No. 86 of 1956).

Pursuant to the terms of the concession agreement, in cases where the contractor does not declare any commercial oil and gas discoveries during the initial exploration terms, the contractor must relinquish a percentage of the exploration area (usually 25%). This relinquishment also takes place if no discoveries are made during the other explorations terms until the whole area is relinquished at the end of the exploration term where no discoveries are made.

If withdrawal is intended after a commercial discovery, both EGPC and the contractor must mutually agree on the area to be relinquished.

If the contractor withdraws from the concession agreement, before the fulfilment of its obligations, the Government can consider such an act as a material breach (Article XXIX, Concession Agreement), cancel the agreement and claim all rights it may have against the Contractor.

The contractor is not obliged to obtain any further licences or approvals to carry out oil and gas exploration and exploitation activities if it has been granted the right to perform such activities by virtue of a specific law passed by Parliament.

The rights granted to a contractor under a concession agreement cannot be waived or assigned except in accordance with the conditions and procedures set out under the specific concession. Generally, the contractor has the right to assign all or part of its interests under a concession agreement if EGPA or the Egyptian Natural Gas Holding Company (EGAS) endorses the assignment and the Minister of Petroleum approves its provisions.

Fees

Generally, the contractor's financial liabilities are determined by virtue of the provisions of the concession agreement.

These are no specific fees payable by a contractor to acquire the right to carry out exploration and exploitation activities. However, the contractor is responsible for all costs relating to minimum exploration expenditures as determined by the concession agreement. The contractor must issue a letter of guarantee in favour of EGPC to ensure compliance with this financial obligation and has no right to reimbursement of expenses except in the event of a commercial discovery.

Liability

The contractor is considered a party to the concession agreement, which involves several contractual liabilities the contractor must satisfy according to the terms and conditions of the concession agreement. Accordingly, all the contractor's liabilities towards the other parties to the agreement (such as the Government, EGPC or EGAS) are of a contractual nature.

The rights and obligations of EGPC and the contractor are governed by the concession agreement and can only be altered or amended by the written mutual agreement of the contracting parties (Article 18, Concession Agreement).

As for dispute settlements methods, the concession agreement stipulates that any dispute, controversy or claim arises out of or relating to the concession between the contractor and the Government, must be referred to the appropriate court in Egypt.

However, if the dispute is between the contractor and EGPC or EGAS it must be resolved through arbitration according to the rules of the Cairo Regional Centre for International Arbitration.

In general, most concession agreements provide for common obligations, such as:

- Compensation applicable in the case of failure to pay or satisfy obligations under the concession agreement.
- Government entitlement to a certain percentage of the aggregate oil production. This percentage can differ.
- The contractor must report the amounts of oil discovered to the government on a regular basis.
- The contractor is subject to Egyptian tax laws.
- The contractor must usually commence his works in a certain period prescribed by the concession agreement.
- The contractor cannot assign the agreement to a third party unless with the approval of the Government.
- The contractor must disclose true information about the exploration and report the same to the Government.
- The contractor is responsible for any damage and harm incurred as a result of the excavation work.

Oil and gas concession agreements are awarded to contractors by a bidding process. Generally, the Egyptian General Petroleum Company (EGPC) and the Egyptian Natural Gas Holding Company (EGAS) announce specific tenders to solicit the best and most appropriate contractor.

The tender documents are usually offered in accordance with the provisions of the Egyptian Tender and Bids Law No. 89 of 1998 and its executive regulations.

On the announcement of the successful bidder, Parliament promulgates a law authorising the Minister of Petroleum to enter and sign the terms and conditions of the concession agreement with the contractor.

By signing the concession agreement, the contractor becomes responsible for the exploration and exploitation of oil or gas in the concession area, as described under the concession agreement.

Transfer of rights

All concession agreements stipulate the methods and procedures required for the assignment of the contractor's interests under the concession.

A contractor cannot assign, sell and transfer all or part of its interests (including any rights, privileges, duties or obligations) under a concession agreement to any person, firm or corporation except with the written consent of the Government. In all cases priority must be given to the Egyptian General Petroleum Company (EGPC) if it wishes to obtain the interest intended to be assigned, unless the assignee is an affiliated company or a member of the contractor group of companies.

All such assignments, sale or transfer are tax free including:

- Transfer, capital gains taxes or related taxes.
- Charges or fees.
- Income tax.
- Sales tax.
- Value added tax.
- Stamp duty or similar levies.

A restriction on assignment, sale or transfer arises only where the contractor has not already fully satisfied its obligations under the concession at the date of its request for Government consent.

Tax

The amount of taxes payable by the contractor on profits realised from its exploration and exploitation activities under the concession agreement are subject to a 40.55% tax rate (Egyptian Income Tax Law No. 91 of 2005).

Concession agreements stipulate that contractors are subject to Egyptian income tax law and must comply with the requirements to file returns, assess tax, keep and show books and records.

A contractor must prepare tax returns for the tax authority within the required due dates.

The Egyptian General Petroleum Company (EGPC) pays income tax on behalf of the contractor out of EGPC's share of the petroleum saved under the terms of the concession agreement. EGPC must provide the contractor with official receipts evidencing payment of the contractor's income tax for each tax year within 90 days following receipt by EGPC or GANOPE of the contractor's tax declaration for the preceding tax year.

GANOPE is one of five main entities of Petroleum Ministry. These organizations are responsible for all petroleum activities in Egypt.

Figure 104: Egyptian Petroleum Ministry Entities

Royalties

The Egyptian Government receives royalties from the contractor (in cash or kind) equivalent to 10% of the total quantity of petroleum produced and saved from the area covered by the concession during the development period including any renewal. This type of royalty is paid by EGPC and not the contractor.

In addition, the contractor must pay specific bonuses to EGPC or GANOPE. These include:

- Signature bonuses.
- Bonuses payable on the approval of each development lease.
- Production bonuses.

The amount of the bonuses can vary from one concession to another and their payment is not included in the expenses recoverable by the contractor.

In general, Article 7 of the concession agreement provides the contractor with the right to sell and export its entire share in the oil and gas produced, as determined by the terms of the share of production plan.

However, the Egyptian General Petroleum Company (EGPC), which is a public entity, and Egyptian Holding Natural Gas Company (EGAS), which is owned by the Government, have the right of first refusal to purchase the oil and gas to meet domestic need.

Usually EGPC notifies the contractor of the domestic quantity required 45 days before the beginning of the calendar semester as determined under the concession agreement.

With regard to joint ventures, the joint venture operating company usually approves the work programme and development plan prepared by the contractor. This details the total quantity of petroleum the operating company estimates can be produced. The oil is owned by both EGPC and the Contractor.

Under the concession agreement, the contractor must prepare tax returns. Only the Tax Authority has the right to audit these returns.

The tax return must include:

- Non-recoverable costs.
- Amounts derived from the sale or other disposition of all petroleum or gas acquired by the

Contractor under the provisions of the agreement that govern the sale of petroleum or gas.
The rate imposed on the profits realised by oil and gas exploration and exploitation companies is 40.55% (Article 49, Egyptian Tax Law No. 91 of 2005 and its Executive Regulation).

The concession agreement also stipulates that the contractor and operating company must both maintain at their business offices in Egypt, books of account, in accordance with the accounting procedures attached under an annex to the agreement.

Egypt's new Gas Law approved last August 2017

While for a time Egypt was reliant on natural gas imports to fulfill the ever-growing energy needs of domestic business, Egypt is now on track to leverage its gas windfall to not only to meet the country's growing demands but return to its previous status as a gas exporter. Egypt's largest producing field, Nooros, has been churning out a daily output of 900 million cubic feet and is soon to be joined by output from the development of fields in the West Nile Delta. Furthermore, the discovery of the huge Zohr gas field, the largest known in the Mediterranean and one of the world's biggest natural-gas finds, begins production later this year and could soon power Egypt's gas needs for decades.
In a step that will bring Egypt ever closer to its plan to become a regional hub for the trade of liquefied natural gas, the government has passed a law to clear the way to private participation in the sector. The measure, which reforms the regulations focused on the activities of the gas market, received parliamentary approval on 5 July and was subsequently signed into law by President Abdel Fattah el-Sisi on 7 August. Before the new law goes into effect later this year, the president of the Council of Ministers will issue specific regulations to President el-Sisi within the next six months.

Here are five things to know about the new law:

1. Backed by reforms: The law comes as part of Egypt's recent IMF backed reforms to spur investment in the country's ever-growing economy.

2. Independence: The new rule arises as a response to end years of gas shortfalls in Egypt and become once again self-sufficient by 2019.

3. Liberalization and competition: It establishes a new regulatory body, headquartered in Cairo, to supervise the liberalization of the Egyptian natural gas sector. As part of this, the body will give licenses and prevent any monopolies from forming.

4. Supply and demand: The law will facilitate increased flexibility and transparency in the market, as, instead of the government dictating the structure of the gas market, now the market will determine the true prices which will in turn provide customers with the ability to bargain.

5. Infrastructure: The measure provides the eventual opportunity for private companies to ship, store, distribute, and market gas in Egypt using the local pipeline network.

A long time coming, this new law serves to complement the many other sweeping reforms passed during the year aimed at stimulating the Egyptian economy and driving increased investment to the region. Looking towards the future, this action to open up the Egyptian gas market is a first step towards increasing the sector's competitiveness and efficiency, raising Egypt's presence in the global market as a natural gas leader.

VII Technical Data for Jordan

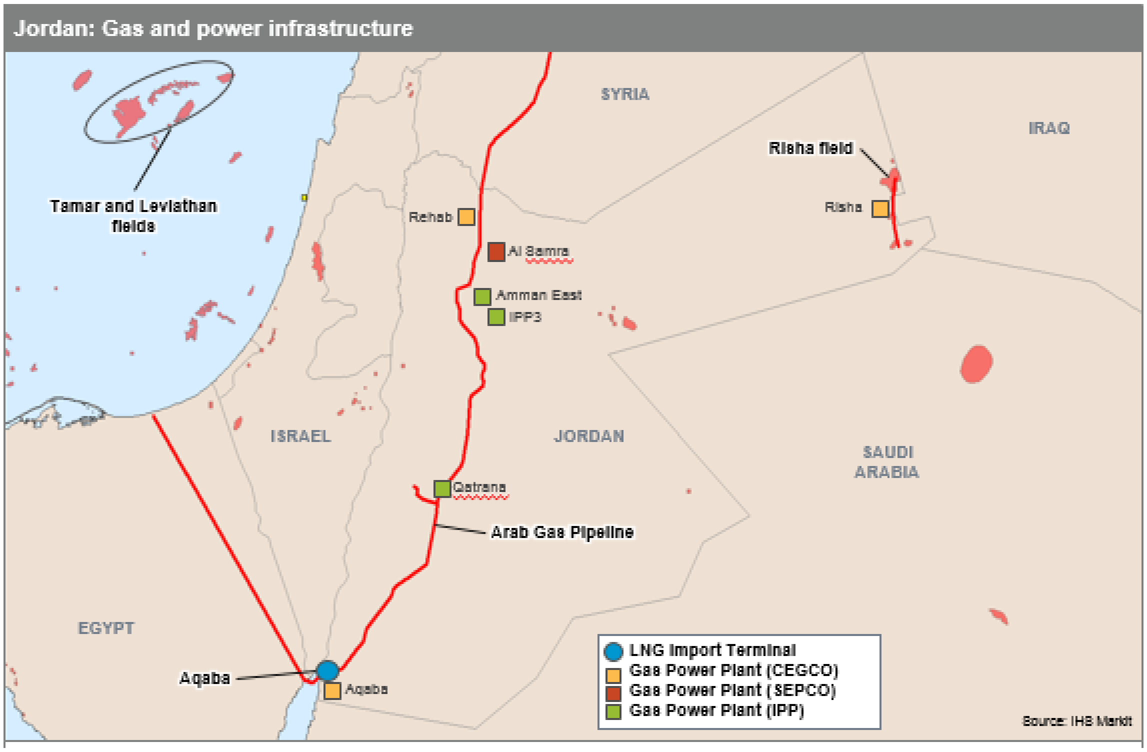


Figure 105: Gas and Power Infrastructure Jordan

Jordan, a growing consumer of LNG for use in power generation since it inaugurated its first FSRU in mid-2015, is poised to remain a steady buyer of LNG until less expensive pipeline imports become available. Jordan's lack of domestic oil and gas reserves means that the country is heavily dependent on imported energy to feed its swiftly growing population and economy. In the 1990s and early 2000s, the government prioritized the expansion of gas-fired power in order to decrease costly oil imports. As a result, gas-fired power capacity grew from 440 MW in 1995 to 1.2 GW in 2005, to 3.6 GW in 2015. The power sector is currently the only significant consumer of natural gas.

To meet its gas demand, Jordan turned to neighboring Egypt to provide gas through the Arab Gas Pipeline. Imports began in 2004, and ramped up to a peak of 130 MMcf/d in 2009. However, imports experienced a series of increasingly frequent disruptions owing to terrorist attacks through 2010, before falling off drastically in 2011 as Egypt's own gas demand rose rapidly. This forced the country to rely on heavy fuel oil and diesel for the majority of its power generation between 2011 and 2014, which vastly increased its energy bill and quickened the search for an alternative source of gas supply. LNG imports were originally proposed in 2010 as a more reliable gas supply source. Since nearly all gas supply had been cut off due to high Egyptian demand, LNG imports became Jordan's only near-term option for natural gas supply, and development of a regasification terminal proceeded quickly in 2013 and 2014.

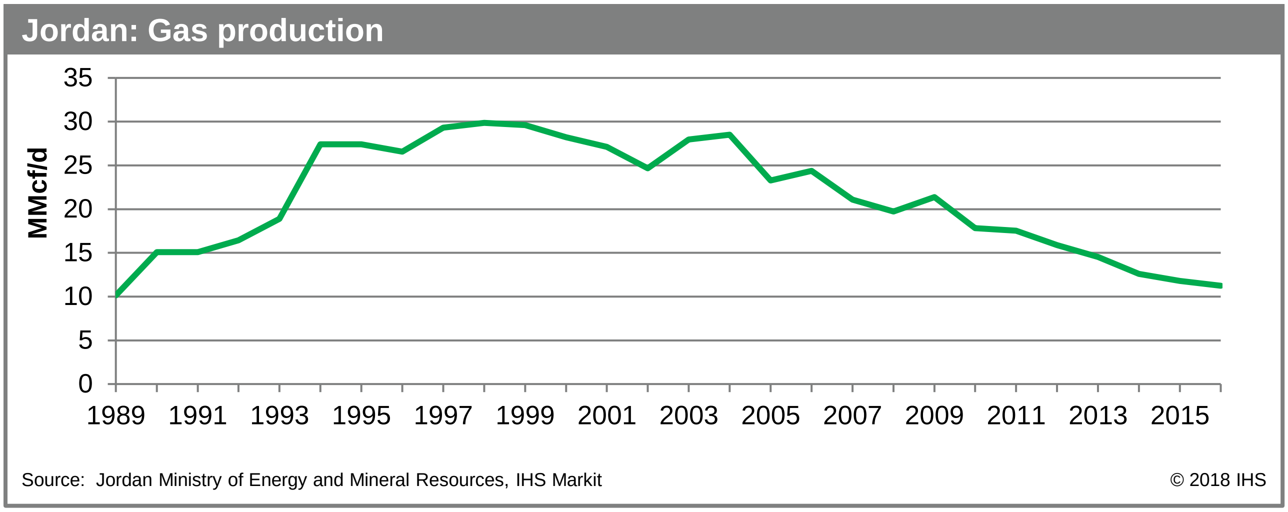


Figure 106: Gas Production Jordan

Jordan has very little gas production. Its only gas field in production is the Risha field in the far northeast, near the border with Iraq. All production feeds a nearby power plant.

Production from the field has been in decline since the early 2000s, and is not expected to be revitalized. Jordan had aimed to boost production at the technically-challenging field to 330 MMcf/d, but BP's exit in January 2014 has seriously damaged the prospects for a production increase. Gas production in 2016 was 11.2 mmcf/d.

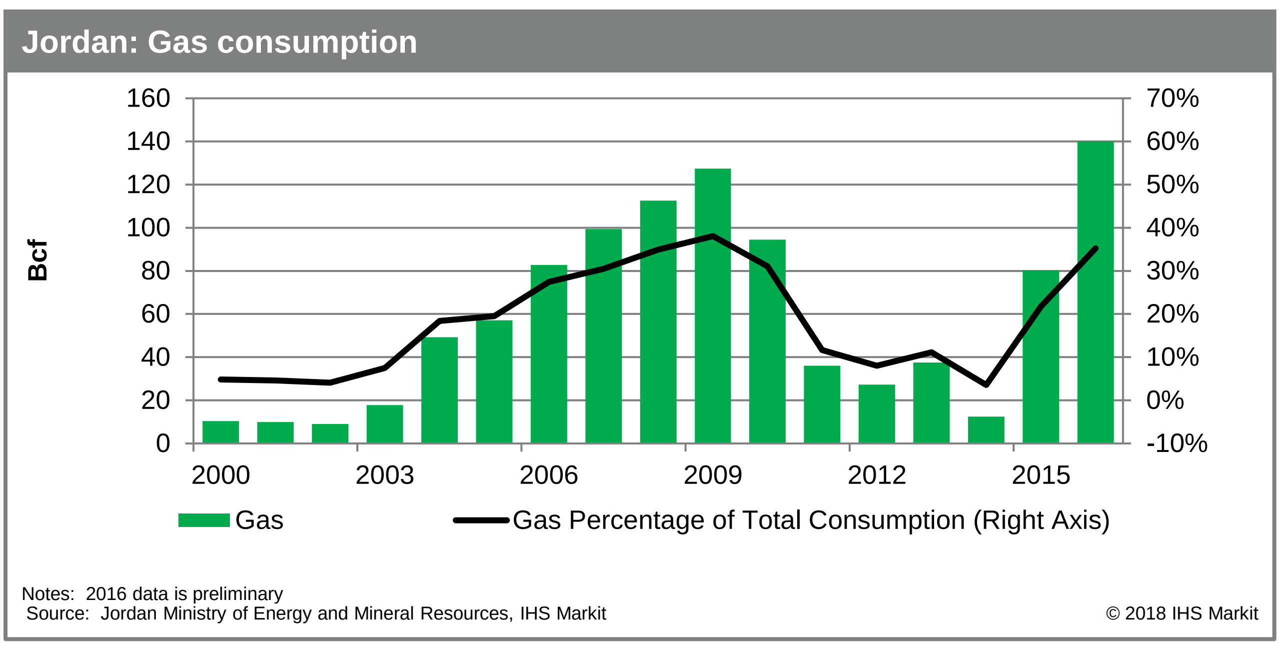


Figure 107: Jordan Gas Consumption

Jordanian gas demand is dictated by supply, and increased by more than 50% in 2016 due to increased availability in the first full year of the Aqaba FSRU's operation. Before 2015, Jordan sourced the vast majority of its gas supply from Egypt via pipeline imports. Gas consumption grew to a peak of 130 Bcf in 2009 before being limited by the lack of supply. With the start of LNG imports in April 2015, average gas consumption rose to 80 Bcf for 2015, and proceeded to reach a record high of 140 Bcf for 2016 as gas-fired power plants have had greater access to gas.

Historically gas consumption has been currently used exclusively for power generation, which includes generation within industrial plants. In August 2016, NEPCO signed a deal with Jordanian Egyptian FAJR for Natural Gas Transmission and Supply Company to provide upto 70 MMcf/d directly to Jordanian industrial customers for onsite power, in a move trumpeted by the Energy Ministry as being able to save companies 20% on their power costs.

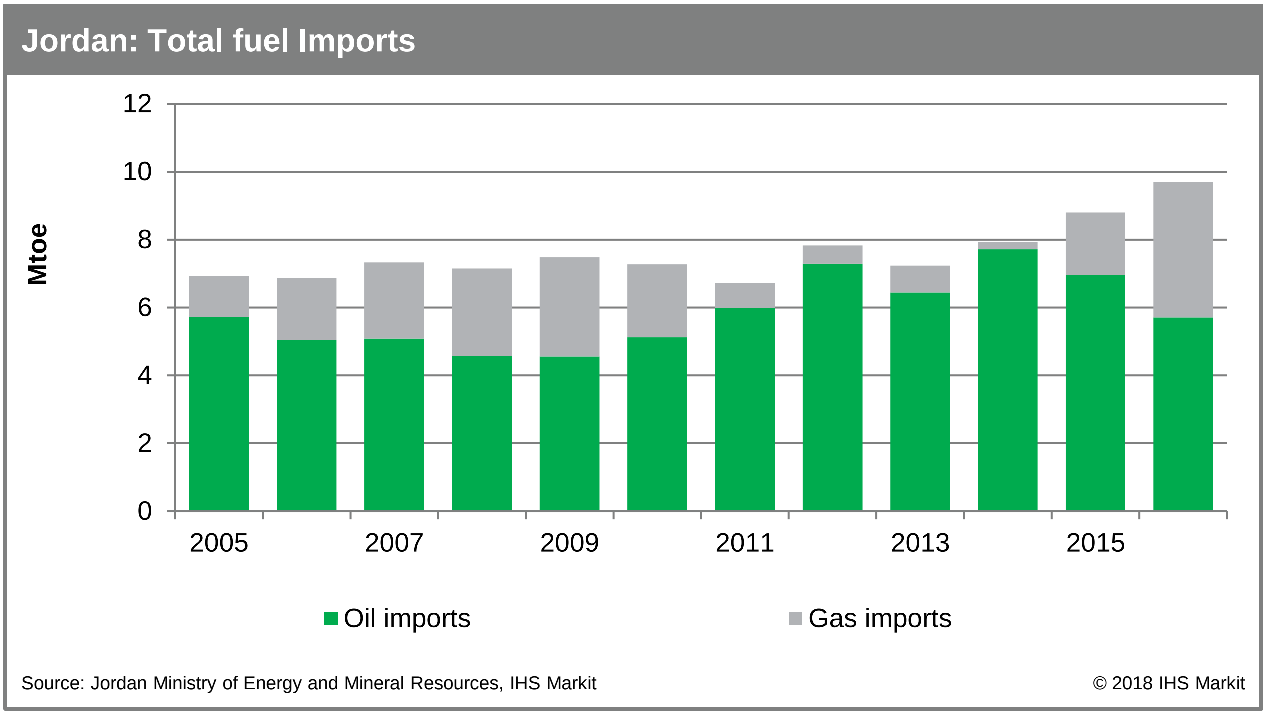


Figure 108: Jordan - Total Fuel Imports

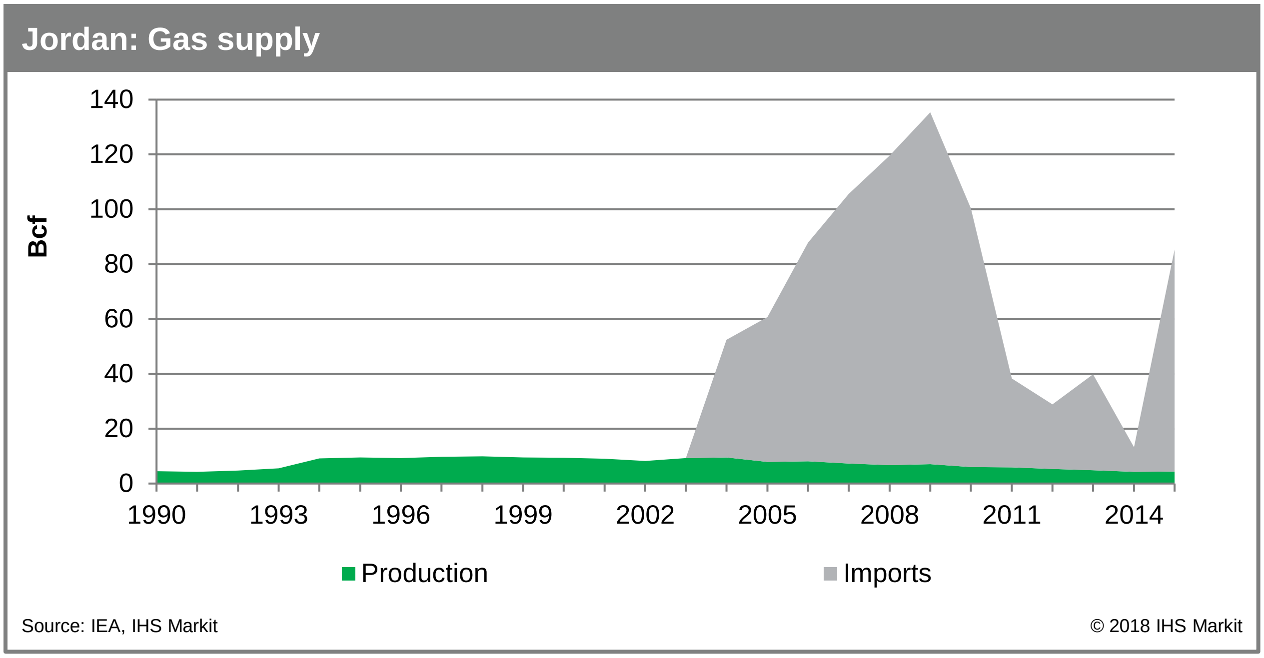


Figure 109: Gas Supply Jordan

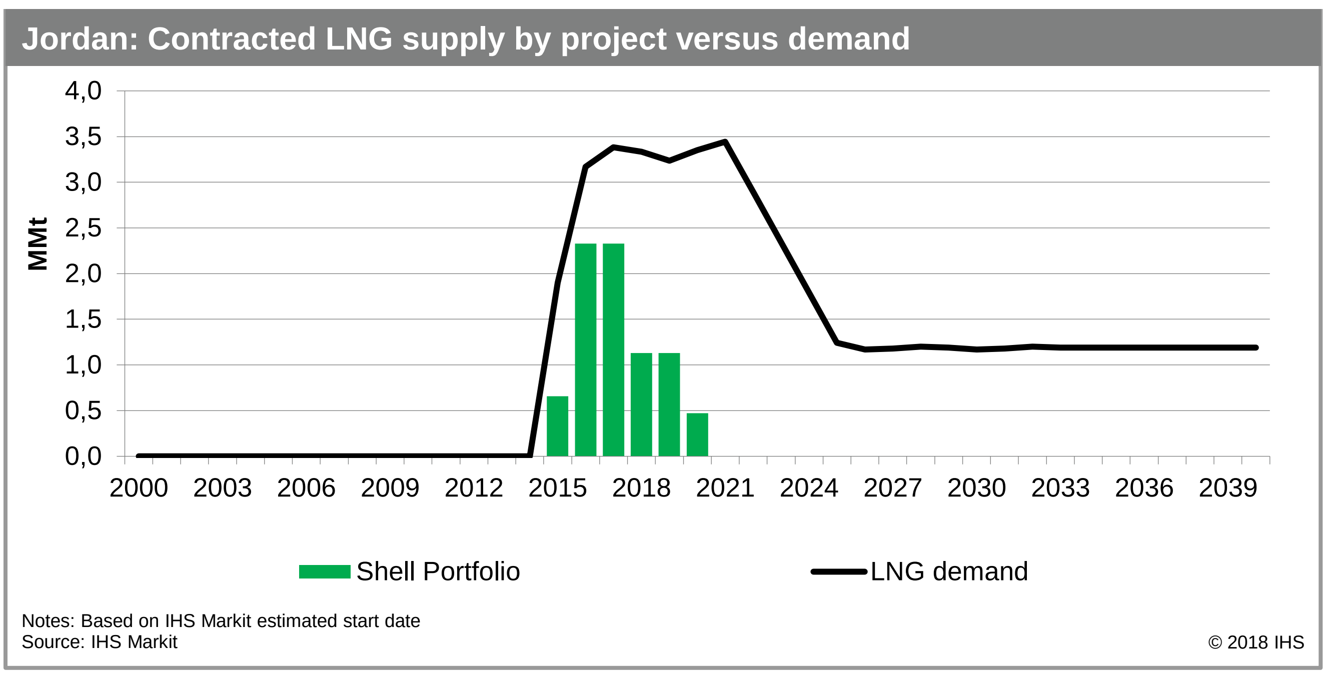


Figure 110: Jordan contracted LNG supply by project versus demand

Overall, Jordan's dependence on natural gas imports seems certain. However, the direct pipeline source from Egypt, regardless if it is currently being utilized, directs us to assume Jordan as a potential candidate in our target market but not an immediate target until further developments clarify Jordan's overall import profile.

Appendix B: Additional information on the Barents Sea geologistic scenario

B.1 Offshore Gas Composition and Reservoir Characteristics

Several Barents sea specific studies can be used as additional sources of information for gas composition and reservoir caracteristics in the region and fields studied for the Gasvessel Barents sea scenarios. :

- Rajan, et al., 2013[97].
- NPD.no, Gas hydrates in the Barents Sea [98]
- Vadakkepuliyambatta, 2014[99].

B.2 APPENDIX: SUMMARY OF MARKET SCREENING

The UK market (largest market for Norwegian exports and relatively more isolated than continental Europe) was reviewed extensively, in terms of coal-fueled power plants, gas distribution network and energy policy. A concrete case for direct delivery included 2 power plants located at a 2001 nm (3706 km) distance from Barents Sea.

In the case of Norway, following types of potential customers were included in the market: Industry located along the coast, at near proximity of a potential delivery point of Gasvessel; Regional market (identified in previous studies); Power plants, likely to switch primary enery source fossil fuel coal or oil to natural gas; Gas production and processing facilities. The vast majority of Norwegian power intensive industry uses CO2-free hydropower. New technology under development include Carbon capture and storage, biomass, hydrogen. In the current enery strategy debate, a strategy too reduce emissions from industry based on complete replacement of fossil-fuels by renewable energy sources (hydro, wind, biomass) coupled with carbon capture and storage is receiving more and more support. (Miljødirektorat, 2010 [100]). It was thefore conluded as not pertinent to consider these energy intensive industries as potential customers in the market study for Gasvessel. One direct delivery case was identified in Svalbard, but this was rather a highly theoretical scenario of CNG delivery to two power plants currently fueled by coal.

Finally, a potential market considered in the South-East coast of Norway was identified, not connected to any sub-sea gas pipeline, but with gas facilities that may enable the supply of gas by CNG ship.

Other potential international markets not connected to the subsea gas network were reviewed but no potential future demand for CNG distribution by ship was identified (Denmark, Sweden, Ireland). Most of the markets are already served well by the gas pipeline network of the Norwegian shelf (UK, France, Benelux, Germany), which implied that focus should be on direct delivery to a pipeline entry point on the Norwegian West coast and then further distribution by pipeline.

Regarding delivery to pipeline entry point, potential reception points include gas processing facilities on the west coast of Norway (Nyhamna, Kollsnes, Kårstø), all connected to gas pipeline for receiving gas from offshore gas fields, and exporting by pipeline to Northern Europe.

After a workshop with project partners in November 2017, it was agreed to abandon the scenarios with unloading points in markets already served by pipeline (UK, FR, GE, NL, IR), and rather focus on point of entry of pipeline: Nyhamna, Kolsnes, Kårstø on the west coast of Norway (points (2)(3)(4) on the map (41). The Svalbard scenario was also abandoned due to the existing competing options for phasing out of coal, as well as the physical and meteorological challenges associated. A new scenario was selected, switching from Barents Sea field to a gas processing plant (Kårstø) as the loading point.

In the second phase of the market screening (January-February), alternative entry points to pipeline distribution network were reduced to Nyhamna, based on discussion with GASSCO. In addition, after further information collected on the possible case of coastal transport in Norway from West to East, this scenario was also reconsidered as not pertinent (irrelevant market situation). Consequently, the sole end destination to be proposed for the Barents Sea scenario is Easington, UK, through Langeled pipeline.

B3 Midstream tariff – background information

This section provides input to Naval Progetti as background information for calculation of midstream tariff.

Midstream costs include Upstream loading system costs (incl. storage and vessel loading), Transportation of gas (incl. capex & opex, here calculated with VOLTA), and Downstream unloading system costs (incl. storage and vessel unloading).

- Upstream storage and loading system costs: assuming the use of a FSO, the estimated cost can be calculated based on FSO charter rate. In a study of long-term fso/fpso charter rate, Kurniawati et al. (2016) report an average charter rate of 28$/day. Divided by the estimated daily gas production rate, upstream storage and loading costs are estimate as follows:
    - Johan Castberg (436 million m3 /year; 1,19 Million sm3/day) => 0,019€/sm3
    - Alke (430 million m3 /year; 1,18 Million sm3/day) => 0,019€/m3

- Transportation of gas:
    - VOLTA cases: lowest Gasvessel transportation tariff identified
    - J.Castberg – Nyhamna 0,1116 €/m3
    - J.Castberg – Polarled>Nyhamna: 0,1175 €/m3
    - Alke – Nyhamna: 0,2056 €/m3
    - Alke - Polarled>Nyhamna: 0,2115 €/m3

- Downstream unloading system costs
    - Vessel unloading: Unloading cost estimate are based on the cost of insfrastructure investment. Both for the case of offshore and nearshore unloading, the same concept of Single Point Mooring is suggested, with further transfer by pipeline. SPM cost estimates are around 50-150 mill USD[101,102,103]), while pipeline cost depend on the length. To simplify the calculation, it is

assumed that the pipeline s approximately the same length, and the cost of installation is similar.
Total unloading cost:

- Storage cost: it is assumed direct transfer to pipeline or cost included in handling costs at Nyhamna before further transport to Langeled.

B4 Tariffs NCS pipelines

This appendix summarizes the methodology used to estimated pipeline tariffs used in the scenarios' downstream tariffs estimates.

The NCS pipeline network is managed by GASSCO and tariffs and contracts are administrated by GASSLED. The map below displays the pipeline network in distinct areas (colours) to which distinct tariffs apply.

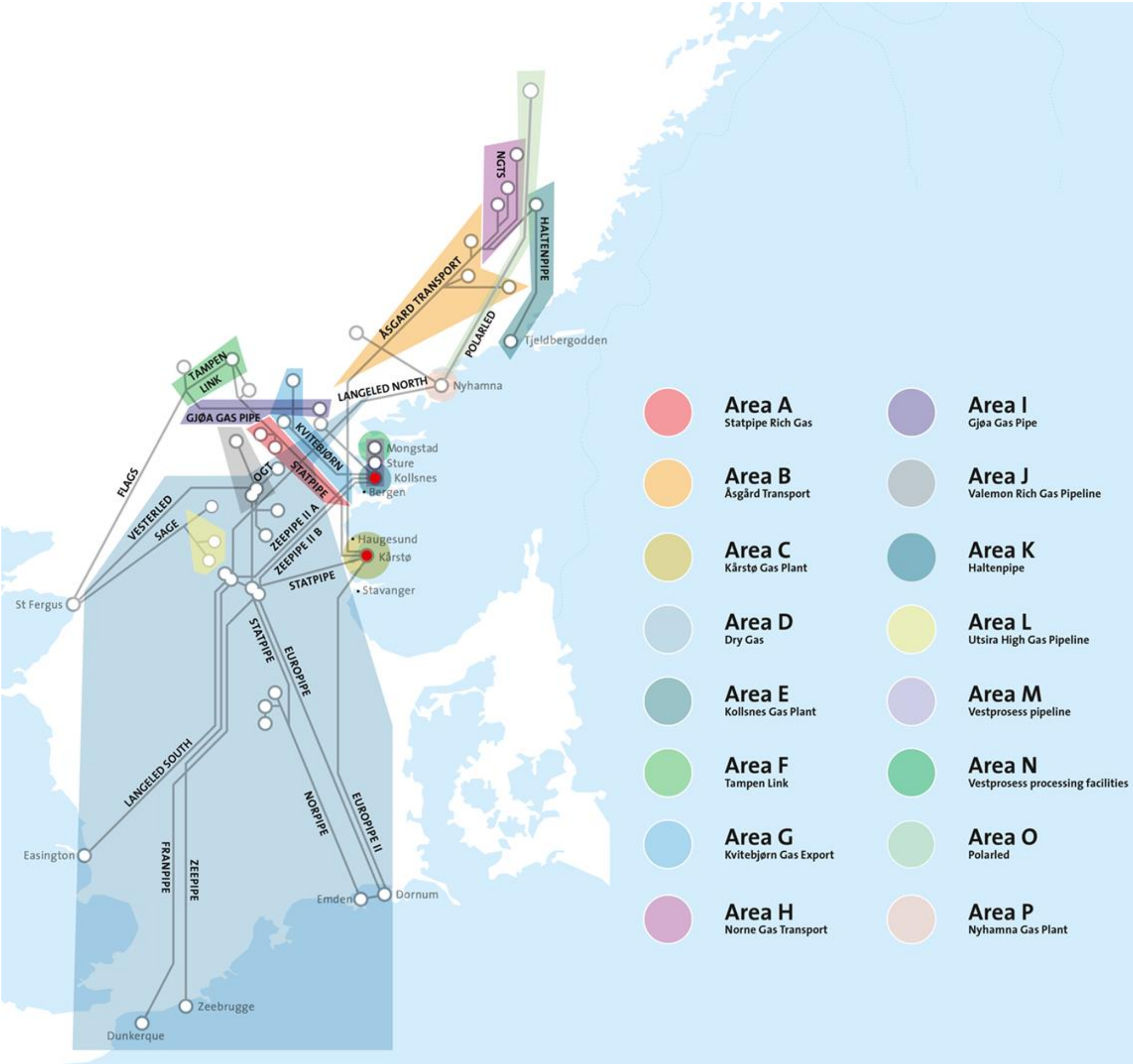


Figure 111: GASSCO's tariff areas[104]

An overview of tariffs for transport infrastructure is updated and published every year. The table below displays the unit tariff cost information for 2018.

Unit tariff cost 2018						
Area/Service	**Unit**	**Capital Cost (K)***	**Capital Cost (K)* old**	**Capital Cost (I)***	**Operating Cost (O)**	**Statfjord** Transit**
Area A	NOK$_{18}$/Sm^3	0,0074910	0,0749101	0,0051387	0,0193508	0,0203257
Area B	NOK$_{18}$/Sm^3	0,0047670	0,0476701	0,0008985	0,0020798	
Area C Services						
Area C - EXT	NOK$_{18}$/Sm^3	0,0136200	0,1362003	0,0074674	0,0135062	
Area C - ETSL	NOK$_{18}$/Tonne	217,9204108		110,9795135	14,0007635	
Area C - FSL	NOK$_{18}$/Tonne	40,8600770	408,6007702	96,9934167	84,2619419	
Area C - CSL Sleipner	NOK$_{18}$/Tonne	0,0000000		47,8633903	119,2350386	
Area C - CSL Other	NOK$_{18}$/Tonne	5,8566110		92,8724164	119,2350386	
Area C - CO2-R	NOK$_{18}$/Tonne	287,3825417		233,7382881	529,1675574	
Area C - CO2-B/D	NOK$_{18}$/Tonne	143,6912709		25,6465314	529,1675574	
Area C - H2S	NOK$_{18}$/kg				1399,5438753	
Area D - Entry						
Kollsnes	NOK$_{18}$/Sm^3	0,0000000	0,0262866			
Kårstø	NOK$_{18}$/Sm^3	0,0000000	0,0330967			
Oseberg	NOK$_{18}$/Sm^3	0,0000000	0,0330967			
Nyhamna	NOK$_{18}$/Sm^3	0,0000000	0,0000000			
Other entries	NOK$_{18}$/Sm^3	0,0000000	0,0058566			
Area D - Exit						
UK & Continental exits	NOK$_{18}$/Sm^3	0,0096702	0,0758635	0,0069372	0,0175085	
Grane	NOK$_{18}$/Sm^3	0,0096702	0,0758635	0,0069372	0,0175085	
Other exits	NOK$_{18}$/Sm^3	0,0000000		0,0069372	0,0175085	
Area D- H2S	NOK$_{18}$/kg	1362,0025674				
Area D - CO2	NOK$_{18}$/Tonne	204,3003851				
Area E	NOK$_{18}$/Sm^3	0,0061290			0,0319864	
Area E - H2S	NOK$_{18}$/kg	1362,0025674				
Area E - CO2	NOK$_{18}$/Tonne	204,3003851				
Area F	NOK$_{18}$/Sm^3	0,0817202			0,0341479	
Area G	NOK$_{18}$/Sm^3	0,0202938			0,0018742	
Area H	NOK$_{18}$/Sm^3	0,0476701		0,0622946	0,0053157	
Area I	NOK$_{18}$/Sm^3	0,0551611			0,0030504	
Area J Valemon	NOK$_{18}$/Sm^3	0,0517561			0,0032397	
Area K Haltenpipe	NOK$_{18}$/Sm^3	0,0558421			0,0994418	
Area L Utsira High	NOK$_{18}$/Sm^3	0,2696765			0,0041333	
Area M Vestprosess	NOK$_{18}$/Sm^3	10,1332991			12,7571953	
Area N Vestprosess						
Area N - Stab	NOK$_{18}$/Tonne	4,6580488			37,1889972	
Area N - FSL	NOK$_{18}$/Tonne	31,0400385			100,9468134	
Area P Nyhamna	NOK$_{18}$/Sm^3	0,1566303			0,0827699	

* Capital Cost is escalated every year with Norwegian Consumer Price Index
** Only on booking on Exit Points A2 and A3

Please follow the URL below to find further information about the booking and tariff regime:
http://www.lovdata.no/for/sf/oe/te-20021220-1724-0.html

Figure 112: Unit tariff cost 2018105

Since tariffs for Polarled are not yet available, it is suggested to use area K (Haltenpipe) as reference.

Tariff calculation and booking tariff regime are regulated by the oil and energy ministry of Norway. Further explanation on tariff calculation can be found on https://lovdata.no/forskrift/2002-12-20-1724/§4.

Hereunder is a copy of the formula for tariff calculation at entry and exit of each tariff area.

§ 4. ***Tariffer***

Tariffene fastsettes med følgende formel ved inngang til og/eller utgang fra områdene A, B, D, F, G, H, I, J, K og L og for behandling i område C og E:

$$t = \left(K + \frac{I}{Q} + U\right) \bullet E + \frac{O}{Q}$$

hvor:

t = tariff per enhet for rett til bruk av inngang, utgang eller behandling

K = fast del av kapitalelement per enhet

Q = estimert samlet reservert kapasitet for gjeldende år, for tjenesten fraksjonering, rensing, lagring og utskipning av etan skal Q være estimert samlet etan for gjeldende år

I = årlig element beregnet for investeringer for opprettholdelse av systemet

U = element beregnet for investeringer knyttet til utvidelser av systemet

E = eskaleringsfaktor

O = forventede driftskostnader.

Figure 113: Tariff calculation clix

- Tariff Haltenpipe (from Heidrun field to Tjeldbergodden, approximately 250km) (used as reference for Polarled, from Aasta Hansteen to Nyhamna):

0,0558 NOK18/Sm³ = 0,0059€/m3

- Tariff Langeled (from Nyhamna to Easington):

0,00967+0,0069+0,0175=0,034NOK18/m3 = 0,0036 €/m3

Appendix C: Additional information on the Black Sea geologistic scenario

Section I: Natural Gas pricing in Georgia

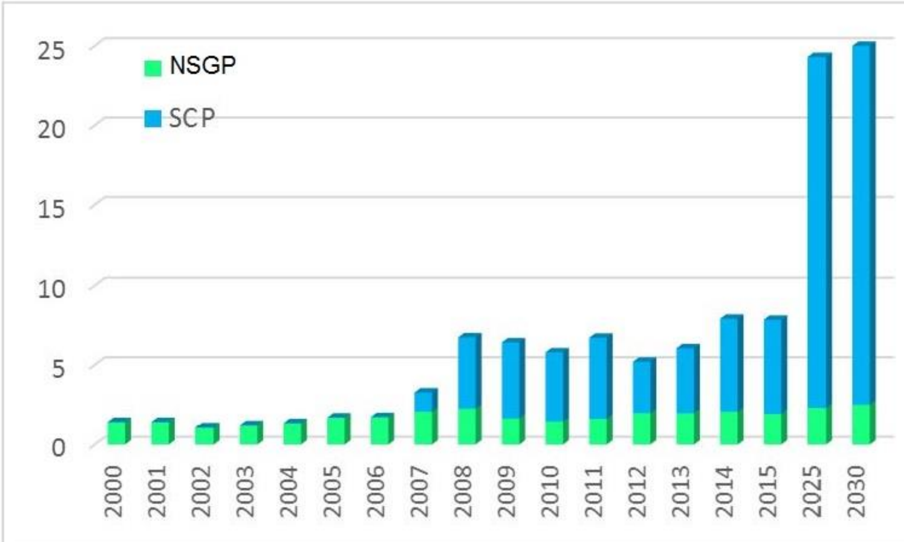


Figure 114: Natural Gas Transit, bscm per year through Georgian GTS

Before gas consumer price growth, gas transportation tariff was also raised and it affected the final price. The natural gas transportation tariff rose by 0.5 Tetri. GNERC members took a unanimous decision and starting July 20 (2017), gas distributor companies will pay 1.9 Tetri (0.003358 €/m3) for transporting one cubic meter. According to GNERC information, the tariff increased because of increased operational costs that are necessary for keeping the network in order. At the same time, gas companies expected the tariffs to rise more.

After determination of a new price of natural gas, the Ministry of Energy should take one more decision. Namely, the Ministry plans to annul the decree by former Energy Minister Aleko Khetaguri regarding gas tariff regulation. This signifies that in regions a unified tariff has been determined for all subscribers by GNERC. Before price growth, old subscribers used to pay 45 Tetri per cubic meter (who joined the network before 2008), while the new ones used to pay 5 Tetri. Under the new decision, Kztransgas Tbilisi subscribers in Tbilisi will pay 46 Tetri and 56-57 Tetri in regions. According to the tariff before July 20, Tbilisi residents used to pay about 45.620 Tetri for a cubic meter, while now GNERC has set 46.153 Tetri for a cubic meter (including VAT).

Gas distribution in Tbilisi is carried out by LLC KazTransGas Tbilisi, and in Regions – by SOCAR Georgia Gas and SakOrgGas.

LLC KazTransGas-Tbilisi is a subsidiary of JSC KazTransGas that has been serving a major number of consumers in Tbilisi since 2009. The determined gas tariffs came into force on July 20 and will be valid through December 31, 2018.

New tariffs of natural gas, starting July 20:

- KazTransGas Tbilisi – 46.153 Tetri **(0.1503 €/m3)**
- SOCAR Georgia Gas – regions – 56.94 Tetri **0.1854 (€/m3) = 0,008193 $/mmbtu**
- SakOrgGas – Gori – 57.015 Tetri **(0.2290 €/m3)**

Section II: Gas Pipeline data and Port Selection (upstream loading) in Georgia

Main gas pipeline Baku-Tbilisi-Erzurum (BTE, SCP)

The main gas pipeline, Baku-Tbilisi-Erzurum (Project TRA-N-1138), with the gas pipeline future expansion (SCPX) including a Compressor Station (CS), commissioned for Year 2021, (also known as South Caucasus Pipeline, BTE pipeline, or Shah Deniz pipeline) is a natural gas pipeline from the Shah Deniz gas field in the Azerbaijan sector of the Caspian Sea to Turkey. The pipeline runs parallel and proximate to Baku-Tbilisi-Ceyhan (BTC) crude oil pipeline. The BTE originates at the Sangachal Terminal, which is located approximately 45 km to the south of Baku and traverses to Azerbaijan and Georgia before terminating at Erzurum in eastern Turkey. The lengths of Georgia's and Turkey's sections are 442 km and 248 km respectively. The total pipeline length is 980 km, and its diameter is 42 inches.

In addition to the pipeline's construction, the BTE project involved a number of above ground installations including two compressor stations (one each in Azerbaijan and Georgia), an intermediate pigging station (cleaning and inspection) and 11 small block valves.

The SCP Expansion (SCPX) Project is designed to increase the capacity of the South Caucasus Pipeline from the existing 7 bcm/yearear to 23 bcm/yearear[106], to transmit the gas that will be produced by the second stage of Shah Deniz, which is currently under development.

In order to increase the transmission capacity, a new 56 inches diameter pipeline will be laid beside the existing pipeline. The new pipeline will originate from the Georgian border and will be reconnected to the existing pipeline SCP near the gas reducing and metering point (Area 81) near the Turkish border (Vale village). In the Gasvessel project, the specific point will provide the tie-in and the beginning of the intermonitor to the gas loading point. Additionally, at the distance of approximately 48 km, the interconnector pipeline between SCPX and TANAP will be located.

Other components of the project include a new block valve (BV) at kilometer point (KP) 27, a pigging station at KP56 (the point where the new pipeline will be reconnected to the existing line), two new compressor stations and a new pressure reduction and metering station (PRMS) at the Georgian-Turkish border.

The expanded pipeline is likely to be fully operational in the fourth quarter of 2021.

Figure 115: Baku-Tbilisi-Erzurum Main Gas Pipeline

The expansion of the gas line might allow for further optimization using the Gasvessel project.

Technical Data of Baku-Tbilisi-Erzurum (BTE, SCP)

Transportation and Transfer Capacity after expansion: 23,0 bcm/yearear:

- Daily Transfer Capacity: 62,1 mmscmd;
- Plan/Design Factor: (as per ASME B31.8);
- System Design Pressure: 56,5 bar;

Design/Diameter of the Line Pipe: API 5L X 70 I 42+56".

Construction of the gas interconnection line

For the purpose of connecting the existing main gas pipeline Baku-Tbilisi-Erzurum with the gas-loading terminal, a special connecting line shall be constructed. Estimated connecting gas line data shall be calculated in the section “Main Gas Lines”. This section will be developed by VTG in work package WP6.

According to a preliminary study, the approximate length of the gas interconnector will be about 140 km, the diameter will be determined in accordance with the need to fulfill scenarios for gas supply to Ukraine. The gas interconnector pipeline is proposed to be connected to the existing line of the SCP Main Gas pipeline at the gas measuring point No 80, located about 3 km to the south-west from the village of Vale.

Preliminary calculations show that the construction of a gas compressor station is necessary at the beginning of the interconnector. The capacity of the compressor station will be determined depending on the loading schedule of Gasvessel. The optimization of the parameters of the designed gas interconnector (diameter, pressure), will be optimized by performing hydraulic calculations of its operation modes with the gas loading terminal.

Below are described the options for laying the Gas interconnector between the point of connection to the BTE (SCPX) gas pipeline in the Vale area to the loading areas on the Georgian Black Sea coast.

Considerations regarding the onshore loading terminal

A number of locations for the loading terminal installation within the Black Sea coast of Georgia have been considered. Specifically:

Location A. Sea port of Batumi.

Location B. Sea port of Poti (1st site).

Location C. Sea port of Poti (2nd site).

Location A. Sea port of Batumi.

The location of the on-shore loading terminal is suggested due to the following considerations:

- Availability of necessary infrastructure in the region (power supply, roads etc.);
- Easy access for GASVESSEL to loading zone;
- Sea depth in loading zone;
- All Year-round navigation and the ice-free sea in the area of the terminal;
- Acceptable marine climate conditions and height of waves nearby.

The terminal near the port of Batumi, in Georgia, has been selected as an option for onshore loading terminal location.

Figure 116: Gasvessel loading terminal site and interconnector approach

The location of the site for the loading terminal and the loading area of the Gasvessel in the roadstead in the area of the seaport of Batumi was chosen based on the conditions regarding the convenience of approaching the vessel in the presence of sufficient sea depth. When choosing the place of the loading area of the vessel and the ground-loading terminal, the following requirements were taken into account:

1. The conventional approach of the vessel to the loading area using the existing approaches to the berthing facilities of the port, removal at a safe distance from the way of the vessels to the port, the depth at the loading area not to be not less than 20 m for the convenience of the PLEM;
2. The ground site of the gas loading terminal is chosen from the conditions of safe removal from housing, industrial facilities, as well as the availability of the necessary infrastructure for engineering support of the loading terminal.

Gas Interconnector characteristics.

As already mentioned, the gas interconnector will be connected to the main gas pipeline BTE (SCP) in the area near to the gas reduction point (Area 81). The pipeline will pass along the plain and mountainous terrain. The mountain part of the pipeline will pass through a wooded area with the intersection of roads and open watercourses (rivers). The route of the gas pipeline will run at a safe distance from villages and agricultural farms. The main technical parameters of the interconnect Gas pipeline:

Total length – 120 km;

The ratio of the mountain and plain parts of the route – 65/35%;

Diameter: as per 3 scenarios (approximately 40 inches);

The wall thickness and operating pressure of the pipeline: as per 3 scenarios (approximately 16-18mm, 54 Bar);

Design of the gas pipeline infrastructure:
Main Compressor Station,
Pig Launcher for pipeline cleaning and diagnostics;
Necessary for the operation of the gas pipeline crane nodes and other structures of the linear part, crossings through roads and water obstacles;
Control systems of the Gas pipeline and electrochemical protection against corrosion, etc.

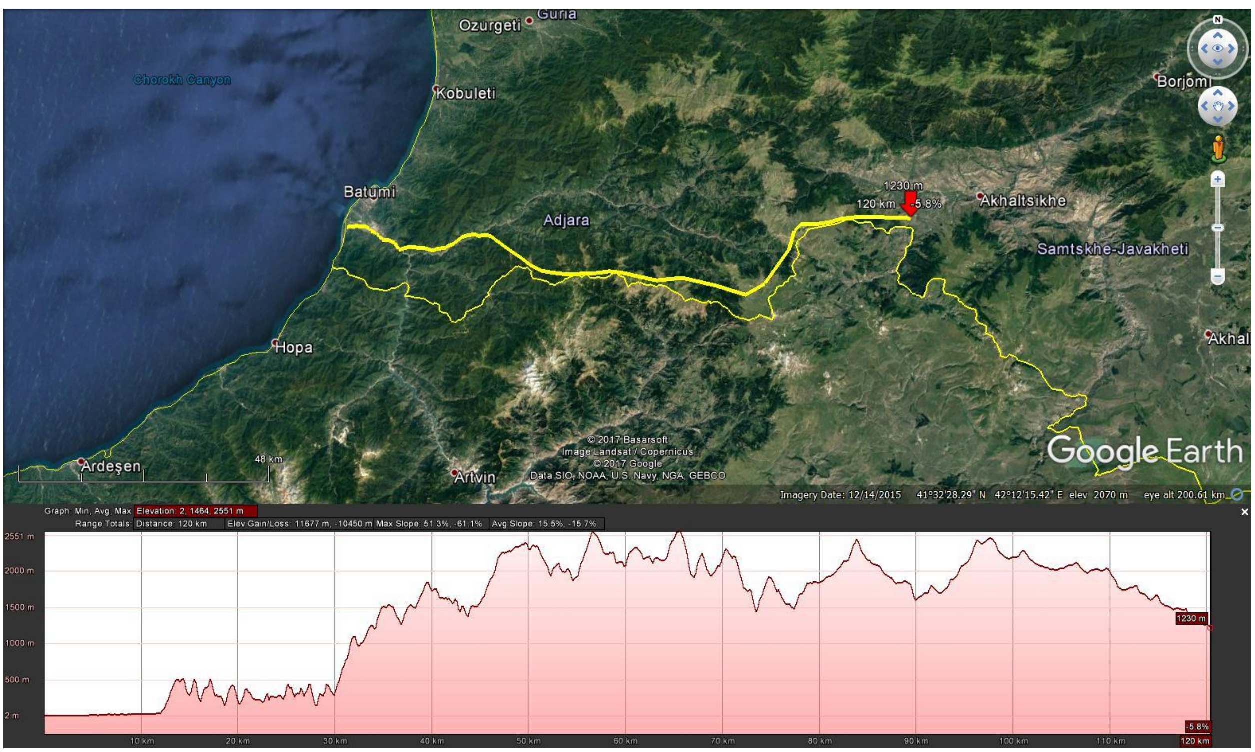


Figure 117: Batumi Gas Interconnector SCP - Loading Terminal

Figure 118: Gasvessel loading area and loading terminal site

Onshore Gas Loading Composition

Gas composition	• 87-90 % Methane • no H_2S, no CO_2, no mercury

Onshore Loading Metocean Conditions

Name: **Loading Terminal near port of Batumi, Georgia**	Location: **Onshore**
Type of gas source: **Gas Interconnector SCP-Loading Terminal**	Gas source: **Shah-Deniz Gas Fields**
• Interconnector Characteristics: • Diameter	• 40 “ • 120 km

• Length • Pressure • Capacity	• 54 Bar • As per 3 scenarios
Location and coordinates of gas loading terminal:	Latitude: 41°35'16.79"N Longitude: 41°34'40.57"E
Location and coordinates of gas loading point:	Latitude: 41°36'8.64"N Longitude: 41°33'34.79"E
Water Depth of loading point	• 30 m
Gas composition	• 87-90 % Methane • no H_2S, no CO_2, no mercury
Distance from delivery port Port of Yuzne, Ukraine)	• 590 nm[107]

Table 62. Loading terminal characteristics, Batumi, Georgia

Location C. Sea port of Poti (2nd site)

Location C (2nd site) the port of Poti will not practically differ from the previous option B (1 st site). A study of the map of the Black Sea coast of Georgia shows that the coast from the port of Batumi to the port of Poti (to the north of Batumi and to the south of Poti) has a fairly strong infrastructure of recreational zones, and has dense development along the coast. More or less free lands are either to the south of the port of Batumi or to the north from the port of Poti. Therefore, only two versions of the boot terminal are considered.

Section III: Midstream Tariff calculation

Cost of Gas Transportation from the Gas unloading terminal in Ukraine

As indicated, the natural gas is a strong candidate for the domestic market of Ukraine. So, transportation costs will be estimated for domestic markets.

The cost of gas for consumers in Ukraine will be determined as the sum of tariffs:
- purchase price of gas;
- cost of gas unloading (in later WPs);
- transportation of gas to the consumer via a new interconnector;
- the cost of amortization of new facilities (unloading terminal, interconnector).

The total tariff for gas, including all tariffs, will be:

End tariff: (to be calculated) – cost of gas delivered by GASVESSEL;
Tariff for entry point: 0.0100 €/m3 (0,000441 $/mmbtu);

Tariff for gas unloading: (to be calculated);
Tariff of gas transportation from unloading terminal to point of connection to existing GTS - 0.0113 €/m3 (0,000499 $/mmbtu);
(In case of gas transportation to indicated point or consumer, tariff will be: - 0.0229 €/m3);

Section IV: Technical information on the SHDKRI network in Ukraine

The design capacity of the SHDKRI gas pipeline system (excluding the intended additional gas pipelines) is up to 33 bln. m^3/year at its initial point and 7,3 bln. m^3/year at its endpoint. The rated operating pressure is 55 kg/$m3^2$. The SHDKRI gas system includes 9 compressor stations (CS) (“Shebelinka”, “Pavlograd”, “Krasnopolye”, “Radushnoye”, “Maryevka”, “Berezovka”, “Tiraspol-1”, “Vulkaneshty”, “Orlovka”), two of them: “Tiraspol-1” and “Vulkaneshty” are located in the territory of Moldova. The capacity of the compressor stations corresponds to the capacity of the linear part past the respective compressor stations (7,3 to 33 bln. m^3/year), while the developed pressure is 55 kg/cm^2. Most of the compressor stations are equipped with electric drive units, which makes this system independent of gas supplies for process needs. The (only one of 12) underground gas storage “Proletarskoe UGS” is integrated into the SHDKRI gas system and its storage capacity is 1 bln. m^3, which compensates for the seasonal irregularity of gas delivery through the gas pipelines. The gas transportation system operator plans to increase the storage capacity of this UGS by 2,6 times.

Section V: Ukraine Market Profile

PJSC UKRTRANSGAZ created a unified information platform, where the information about suppliers, that have concluded contracts with PJSC UKRTRANSGAZ, is provided. 145 natural gas suppliers and vendors are present today in the Ukrainian market. These include both traders and companies, which sell own produced gas. Large traders (selling and/or buying large volumes of gas to be supplied to industrial factories and energy generating companies) are shown in table below.
See below some performance showings of the Gas Transportation System of Ukraine:

№	Short Name	ID number	Country	Phone	E-mail	Web site
1	INOL ENERGY LLC	40298595	Ukraine	+38 044 586 9827	info@inol.com.ua	http://inol.com.ua
2	UKRGAZ GK LLC	39320386	Ukraine	+38 093 204 9946	office@ukrgaz.in.ua	http://ukg.com.ua
3	SKELA TERCIUM LLC	35247177	Ukraine	+38 044 221 4076	st2014@ukr.net	www.skela-tercium.org
4	ENSOL UKRAINE LLC	40692920	Ukraine	+38 044 222 8752	office@eneringroup.com	ensolgas.com
5	GAZPROMENERGO LLC	38703896	Ukraine	+38 044 461 9083 +38 067 489 6968	gazpromenergo@ukr.net	gazpromenergo.com.ua
6	GAZPOSTACH LLC	36527581	Ukraine	+38 044 593 2844 +38 067 208 3303	samsonuk@ukr.net	gazpostach.com
7	UKREASTGAS LLC	37994284	Ukraine	+38 044 456 7858	office@ukreastgas.com	ukreastgas.com
8	GEO ALLIANCE LLC	33100376	Ukraine	+38 044 490 4820	gas@geo-alliance.com.ua	geo-alliance.com.ua
9	NAFTOGAZVIDOBUVANNIYA LLC	32377038	Ukraine	+38 044224 6088	IvanschenkoSV@dtek.com	dtek.com
10	ENERGY OF UKRAINE LLC	34528630	Ukraine	+38 044 224 8134 +38 044 224 8133	info@uanergy.com	uanergy.com
11	VESTA LLC	30288313	Ukraine	+38 057 783 5091	vesta@ukrpost.net	www.vesta-gaz.com.ua

12	ENERGOSYNTEZ LLC	21671036	Ukraine	+38 044 285 4848 +38 067 423 1226	sintez@voliacable.com	energosintez.com.ua
13	POLTAVA PETROLEUM COMPANY (PPC) JV	20041662	Ukraine	+38 0532 501 123	commerc.gas@ppc.net.ua	www.ppc.net.ua
14	TRAILSTONE ENERGYLLC	39945401	Ukraine	+38 044 490 1236 +38 067 239 0389	oksana.gantseva@trailstonegroup.com, pawel.lewin@trailstonegroup.com	trailstonegroup.com
15	DEMETRA LLC	38805539	Ukraine	+38 067 658 7846 +38 044 500 2821	demetrakiev@gmail.com, ngg.demetra@gmail.com	http://ngg-demetra.com
16	ODESSAGAZPOSTACHANNYA LLC	39525257	Ukraine	+380487053631	postavka@odgaz.odessa.ua	postach.odgaz.odessa.ua
17	ARAB ENERGY ALLIANCE UA LLC	31511844	Ukraine	+380444906020	info@arabenergyalliance.com	arabenergyalliance.com
18	GAZPROMSERVICE LLC	31767581	Ukraine	+38 03435 24 153 +380 67 344 21 26	gazpromserv@ukr.net	gazpromservis.com.ua
19	INNGAZ LLC	36602752	Ukraine	+38 044 592 4070	inngaz.kiev@gmail.com	inngaz.com.ua
20	UKRNAFTOBURINNYA LLC	33152471	Ukraine	+38 044 225 7775	sales@unb.ua	www.unb.ua
21	NG TRADING LLC	40729007	Ukraine	+38 044 286 3863	office@ngtrading.com.ua	http://ngtrading.com.ua/
22	UGCCENTER LLC	41285283	Ukraine	+38 044 528 3545	office@ugccenter.com.ua	ugccenter.com.ua
23	NAFTOGAZPOSTACH LLC	40121452	Ukraine	+38 044 537 0553	info@naftogazpostach.com	www.naftogazpostach.com
24	PROMENERGORESOURCE LLC	38266407	Ukraine	+38 044 227 1662	per-office@ukr.net	http://www.promenergoresource.com

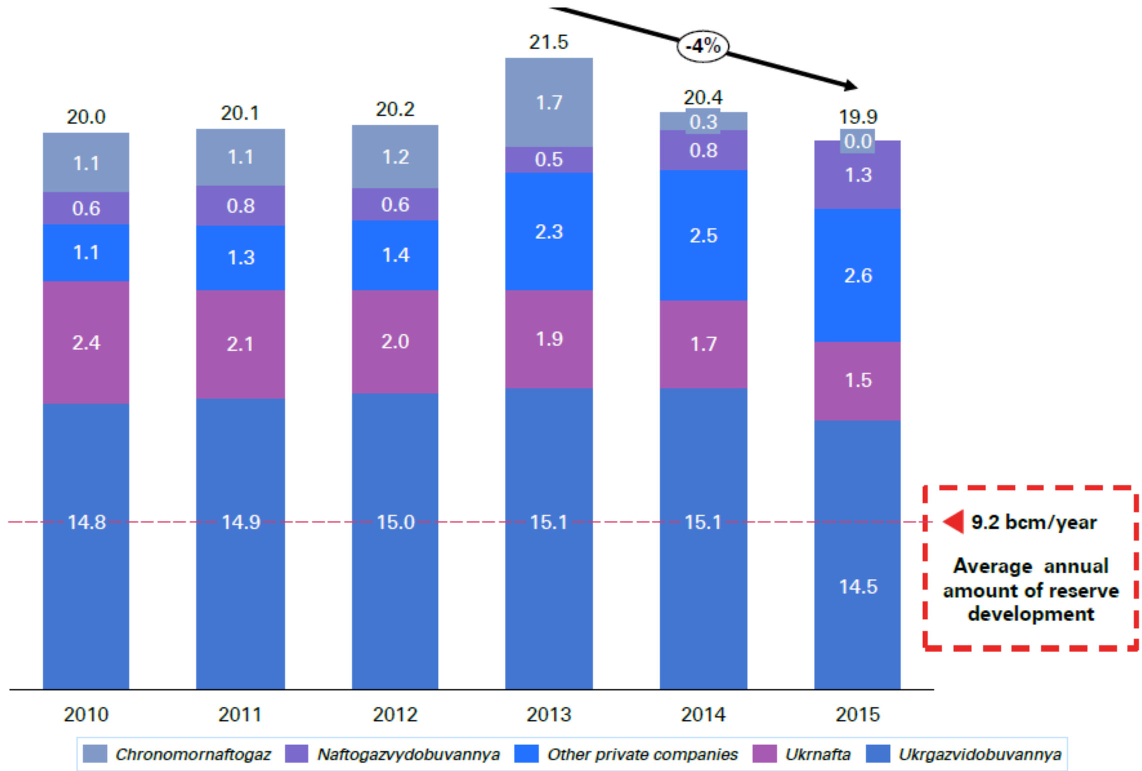


Figure 119: Natural gas production by company (bcm) [108]

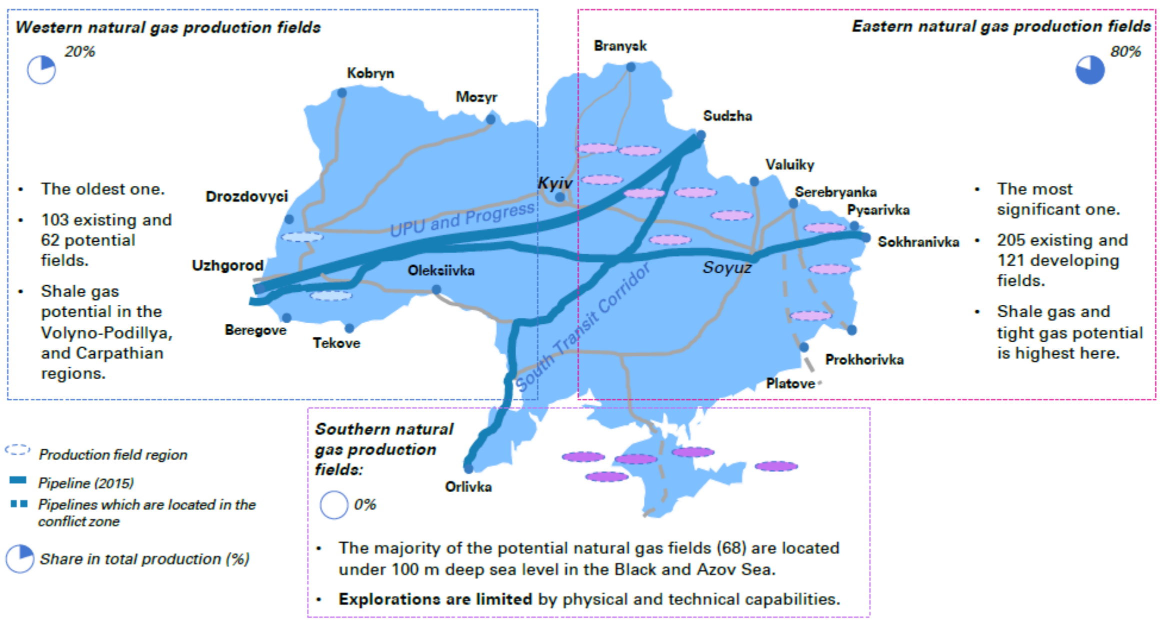


Figure 120: Natural gas production fields[109]

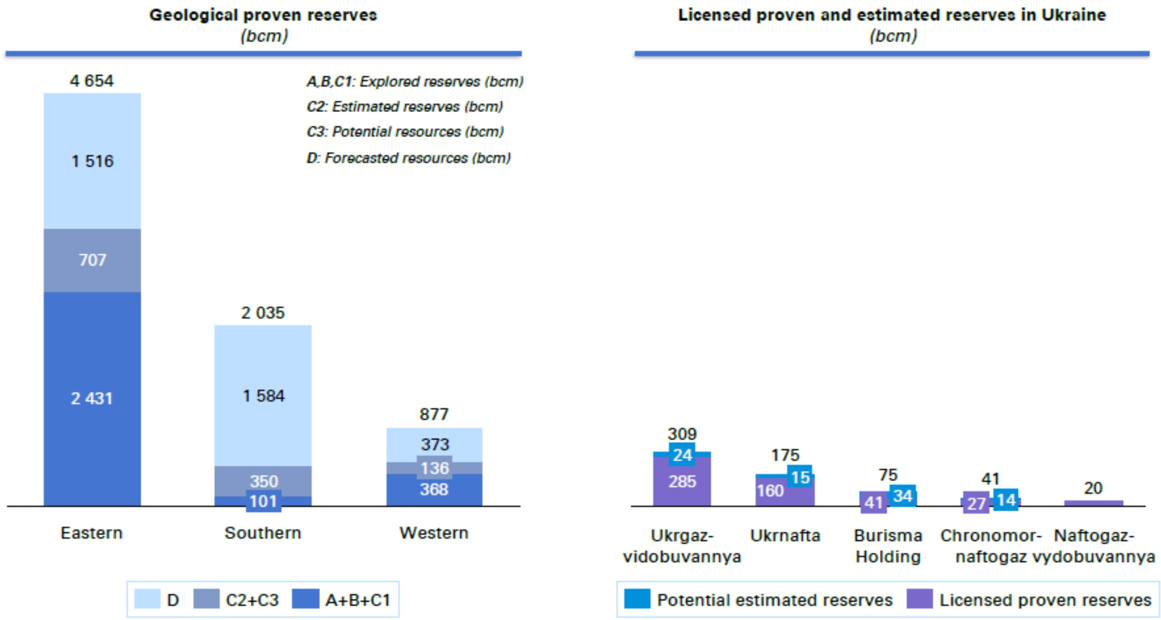


Figure 121: Natural gas reserves (bcm) [110]

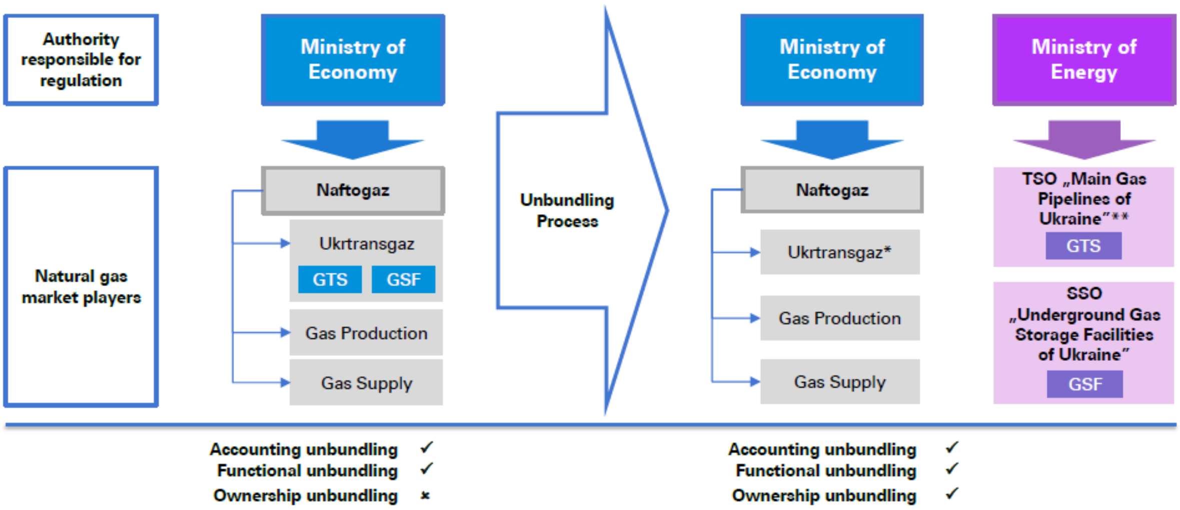


Figure 122: Map of the planned unbundling process [111]

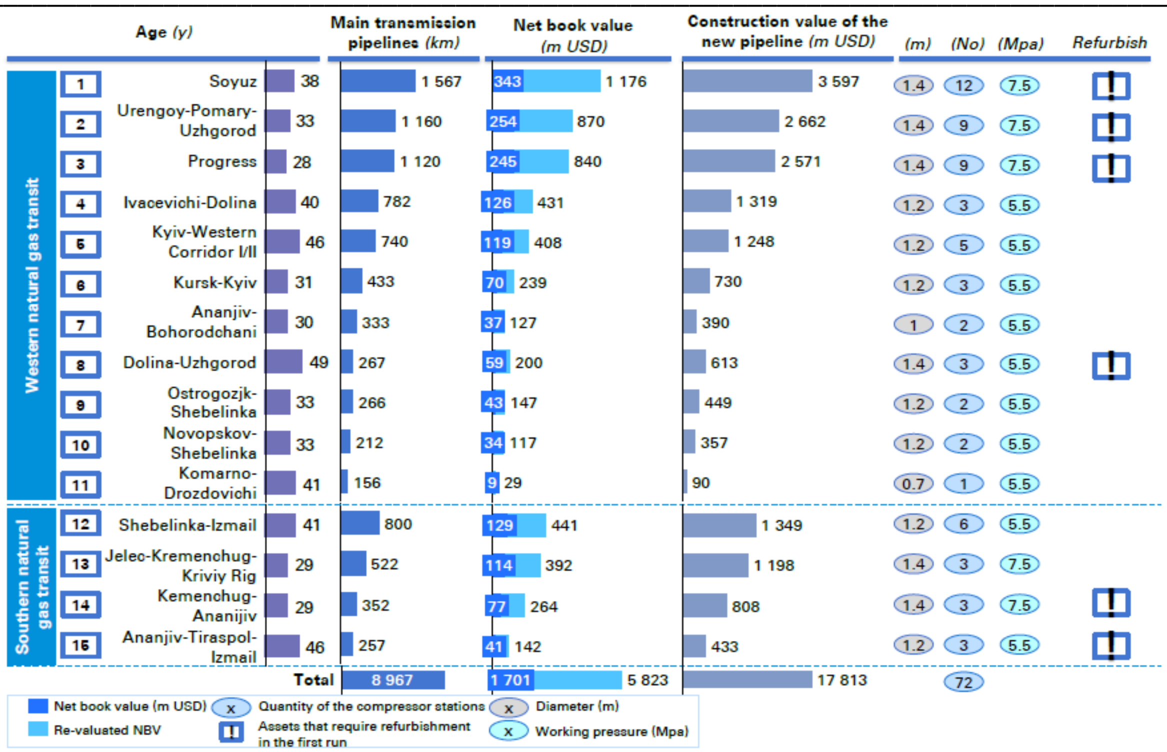


Figure 123: Technical characteristics of transit and transmission pipelines[112]

Legislation

Prior to 1 January 2016, the folllowing relative legislation concerning Ukrainian gas and oil.

On 15 May1996, the Law of Ukraine "On Pipeline Transport" was adopted, aiming to ensure the reliable and safe operation of the network along with improving the ecological security of the pipeline system. It also promotes international cooperation as part of pipeline transport. The law prohibits the privatisation of pipeline systems and defines the supervisory and control functions of the various state bodies. Moreover, the law declares that use of pipelines by foreign companies is regulated by legislative acts, while pipeline construction and repair permits are issued by the government directly.
The Law of Ukraine "On Oil and Gas", adopted on 12 July 2001 sets out the basic legal, economic and organisational foundations of oil and gas activity in Ukraine. The law regulates commercial activities linked to oil and gas production, storage, transportation, refining and conversion, along with the sale to customers and the employment of oil and gas industry workers.
Since 20 April 2000, the Law of Ukraine "On Natural Monopolies" regulates the supply of natural gas (and other substances) above a pre-defined volume. The purpose of this law is to ensure the efficient functioning of the markets, with a natural monopoly being more effective at meeting market demand.
The Law of Ukraine "On Commercial Metering of Natural Gas", adopted on 16 June 2011, governs the principles for ensuring the provision of natural gas metering stations to all customers, setting the foundations for a complete commercial accounting scheme covering all domestic and imported natural gas supply.
The most recent Law of Ukraine "On the Natural Gas Market", in effect since 9 April 2015, sets forth the legal foundations of the Ukrainian natural gas market based on the principles of free competition, subject to the protection of customers and supply security. Additionally, the law regulates the Ukrainian market's integration capability with markets of Energy Community member states, for example, with respect to the creation of regional natural gas markets. This law ensures the Ukrainian natural gas market's compliance with the EU's third energy package and permits the privatisation of 49% of shares in the country's TSO (Ukrtransgaz).

Section VI: GRP Pricing in Ukraine

In accordance with the GTS Code approved by the Resolution of NERC on 30.09.2015 No. 2493 (registered in the Ministry of Justice of Ukraine on 06.11.2015 No. 1378/27823), UKRTRANSGAZ PJSC informs that the Gas reference price (GRP) is: for February 2018 – 7953.00 UAH* excluding VAT for 1000 cubic meters, VAT – 1590,00 UAH, totally 9543.60 UAH (296,1092 €), including VAT.

The gas reference price (GRP) for September 2017 in Ukrainian Hryvnia (UAH) is as follows:

GRP 7 953,00 UAH per 1000 cubic meters;

VAT 1 590,60 UAH per 1000 cubic meters;

Total 9 543,60 UAH per 1000 cubic meters;

Services provided to PJSC UKRTRANSGAZ customers, included in the transportation tariff, are: transportation of natural gas, gas reception to the transmission system in entry points (at the sites of production, border gas stations, underground gas storages), volume control and quality of gas supplied; transmission of gas to exit points using gas pumping units and main gas networks; provision of gas, which is transmitted to the gas distribution stations and gas supply companies with gasification or clients directly connected to the high-pressure pipelines ; odorization of gas in case of need; balancing natural gas volumes (correspondence between the intake and consumption of gas).

Tariffs on Gas transportation in Ukraine

In euros, GRP is approximated to:

GRP € 0.246757/m3 ($0,010904/mmbtu);

VAT € 0,049351/m3;

Total € 0,296109/m3 ($0,013085/mmbtu);

Transportation to cross-border entry/exit points

PJSC UKRTRANSGAZ reported that according to the Resolution of the National Energy and Utilities Regulatory Commission of Ukraine No. 3158, dated 12.29.2015, new tariffs for entry/exit points, located at the state border of Ukraine and a unit commodity charge to cover own use gas for exit point were introduced from 1 January 2016.

No.	Name of entry/exit point	Tariff for entry point, €/m3	Tariff for exit point, €/m3	Unit commodity charge to cover own use gas, %
13	Orlivka	-	€0.01870 ($0,000826/mmbtu)	2,11

The point of export (exit) of gas in the gas transportation system of Ukraine is the “Orlivka” Gas Measuring Station.

Similarly, PJSC UKRTRANSGAZ reported that according to the decision of the National Energy and Utilities Regulatory Commission of Ukraine stated above, new tariffs have also been introduced for services of natural gas transportation to the distribution systems operator (DSO).

Transportation to DSO

Differentiated tariffs for transportation of natural gas via high-pressure pipelines of PJSC UKRTRANSGAZ according to the licensed territory of the DSO[113]:

No.	Name of licensed territory	Tariff excluding VAT, €/m3
23	PJSC "Odessagaz"	0.01128 ($0,000498/mmbtu)

The tariff for gas transportation for PJSC "Odessagaz" is 363.60 UAH/1000 mc = 11.2814 €/1000 m3 = 0.0113 €/m3.

Tariff for entry point to Ukrainian GTS

PJSC UKRTRANSGAZ reported that according to the Resolution of the National Energy and Utilities regulatory Commission of Ukraine No. 3158 dated 12.29.2015 new tariffs for entry/exit points, located at the state border of Ukraine and unit commodity charge to cover own use gas for exit point were introduced from 1 January 2016.

The tariff for entry point is 12,47 USD/1000 mc = 10.0703 €/1000 m3 = 0.0100 €/m3 = $0,000442/mmbtu)

Tariff for transportation to indicated point to directly connected clients

For consumers directly connected to the main pipelines of PJSC UKRTRANSGAZ - the tariff for transportation of natural gas is: 615,10 UAH for 1000 mc excluding the VAT; or with VAT = 0.0229 €/m3 = $0,001012/mmbtu)

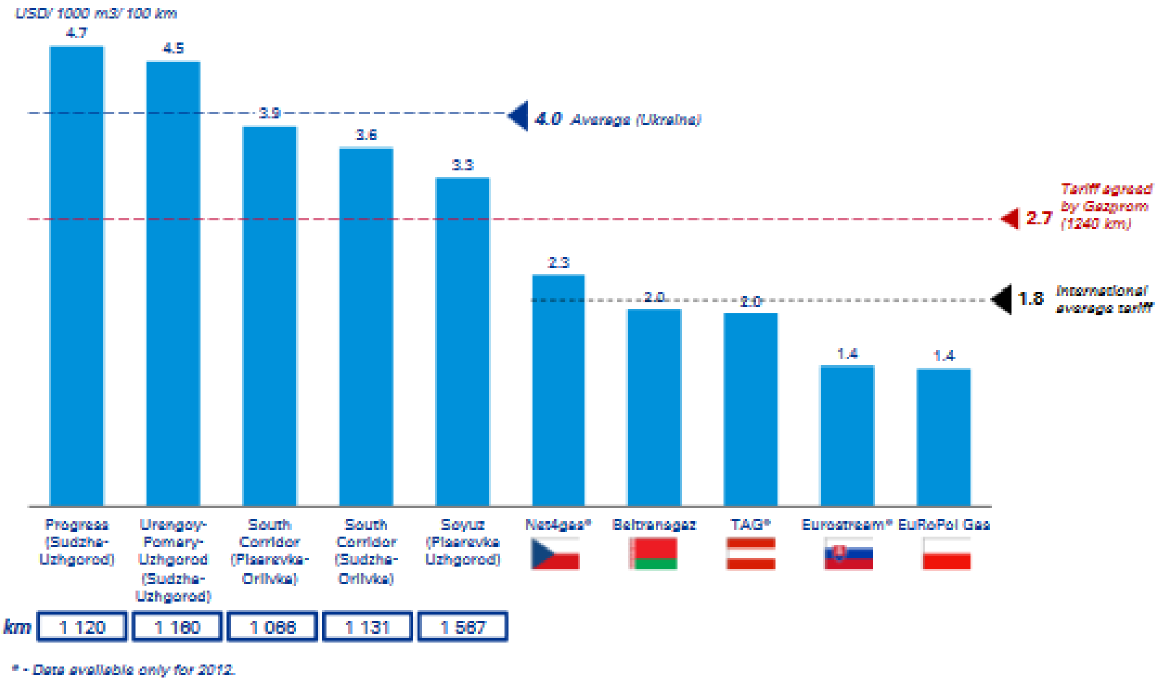
Tariff for injection, storage and withdrawal of gas

Name of service	Tariff excluding VAT, €/m3
Injection	0.0010
Storage	0.0014
Withdrawal	0.0010
Overall storage service	0.0035

- The final consumer must pay separately the cost of transportation of natural gas by main and distribution pipelines.

Naftogaz Ukrainy from March 1, 2018 will reduce the price of gas sold to industrial consumers on a prepayment basis by 14.1% (by UAH 1,300) compared to February, to UAH 7,896 (244.99 €) for 1,000 cubic meters (including VAT).
According to the updated price list of the company, this price is relevant for consumers buying gas on a prepayment basis in the amount of more than 50,000 cubic meters per month, if there are no debts to the company and to 100% subsidiaries of Naftogaz.
For other buyers, the price next month will decrease by 12.3% (by UAH 1,252), to UAH 8,890 (275.83 €) for 1,000 cubic meters (including VAT).
Earlier, on February 15, the company unveiled the price list for industrial enterprises for March, according to which the price for gas will decrease by 10.6-10.8% compared to the prices in February, to UAH 8,201 (254.45 €) per 1,000 cubic meters and UAH 9,064 (281.23 €) per 1,000 cubic meters (both including VAT) depending on the volume of purchase, terms of payment and the state of previous payments.

Transit tariffs for the main transit lines in Ukraine and in the EU (USD per 1000 m³ per 100 km)



Source: KPMG estimation based on Report on the evaluation of assets, BT (2012; Ukrtransgaz natural gas transportation tariffs (2016), Available at: http://utg.ua/utg/business-info/price-tariffs.html; Expert interview, Law of Ukraine on Pipeline Transport (1996), NERC regulation of natural gas transit tariffs (2016)

Figure 124: Transit tariff for the main transit lines in Ukraine and in the EU

Section VII: Ukraine Price Elasticities Calculation

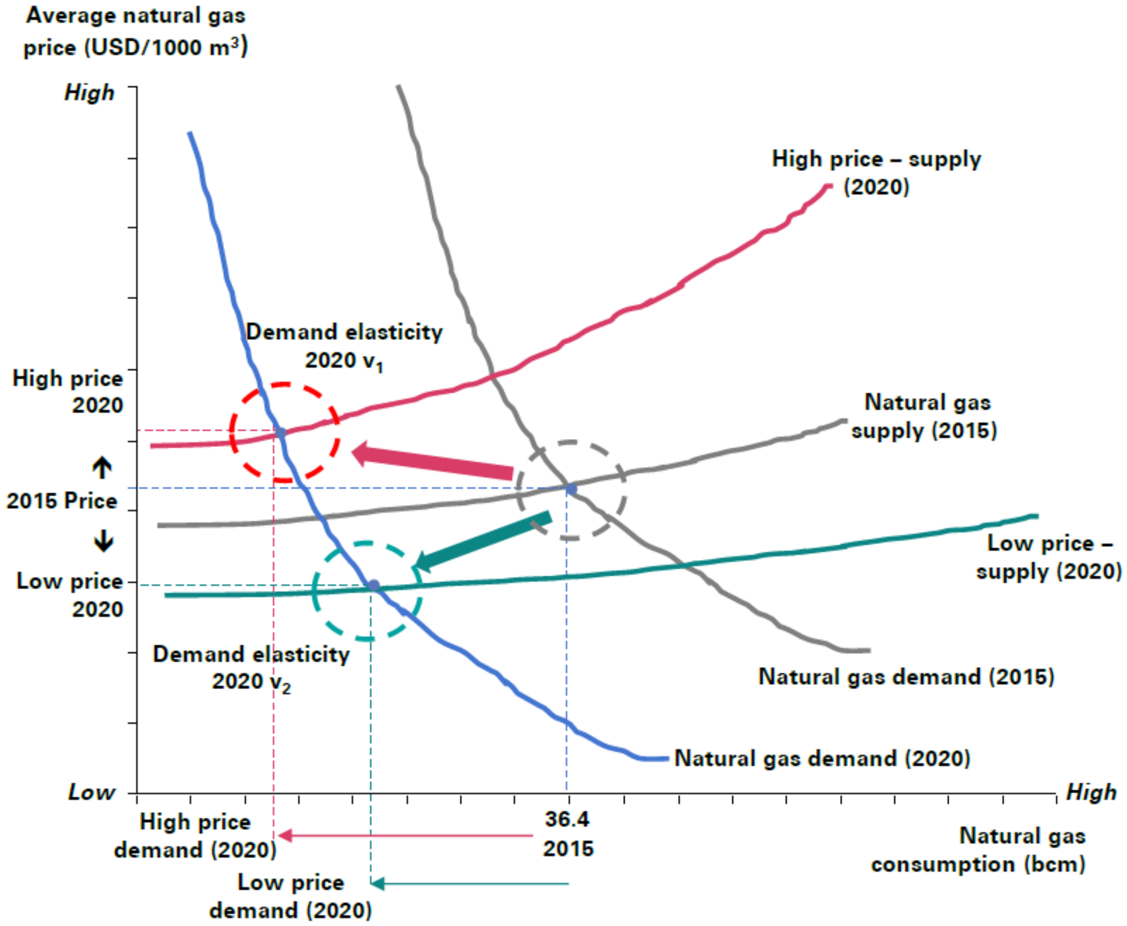


Figure 125: Supply and demand forecast; Development of natural gas demand elasticity

Section VIII: Currency Conversions

Artificially, as of April 18 2018 the exchange rate of the Hryvnia compared to the Euro at the rate of the National bank of Ukraine is:

1 EURO = 32,230 UAH;
1 UAH = 0,03102 EURO;

Artificially, as of April 18 2018 the exchange rate of the GEL compared to the Euro at the rate of the National bank of Georgia amount to:

1 EURO = 3,02 GEL = 302 Tetri;
1 GEL = 100 Tetri = 0,3311 EURO;

Artificially, as of April 18 2018 the exchange rate of the USD compared to the Euro at the rate of the Bloomberg[114] amount to:

1 EURO = 1,2383 USD;
1 USD = 0,8075 EURO;

1 Gm^3 NG = 35687347.874265 MMBtu[115]
1000 m cub = 35,687347874265 mmbtu

1 m3 = 0,035687347874265 mmbtu

1 EURO/m3 = 0,04419158359 $/mmbtu

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