
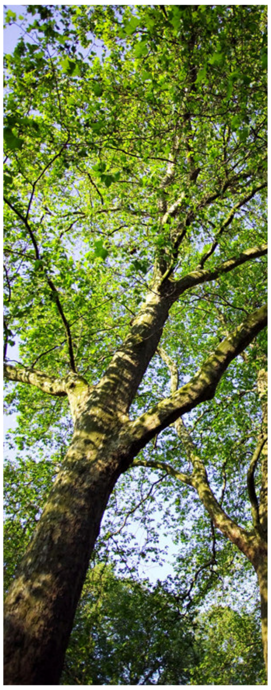


Supplying the EU Natural Gas Market

Final Report

November 2010

Mott MacDonald

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Overall Conclusions

The objective of this study was to analyse the impact on the EU internal market and the market feasibility of an integrated Mediterranean energy ring in gas, analyse technical aspects and prepare a suggestion for how to progress the ring. In addition, the technical sizing of such a ring was to be analysed within the context increasing transportation of natural gas from the Middle East and Africa to Europe.

In terms of "value for money" to be invested and potentially available resources, our analysis suggests the following projects be pursued or encouraged:

1. Algerian gas exports, available immediately, with no additional EU public investment required to enable supply to the European gas systems.

2. Iraqi Exports, available as early as 2016, using a phased approach to connect Kurdish gas to Nabucco in Phase One and associated gas in Iraq's southern fields in Phase Two.

3. Completion of the Arab gas Pipeline (AGP) supplied by Egyptian/Iraqi gas, available in 2020.

The key data and information used to reach these overall conclusions are summarized below.

European Gas Demand

According to the PRIMES models, there is little expected growth in European gas demand up to 2030. Increased consumption is expected to be balanced by reductions due to increased renewables and nuclear power displacing gas fired power generation. Annual gas demand is expected to increase from 527-531 bcm in 2010 to 479-538 bcm in 2020, and then fall to 457-510 bcm in 2030.

European Gas Production

European Gas Production is expected to fall from 191 bcm in 2010 to 129 bcm in 2020 and 87-88 bcm in 2030, with the widening "supply gap" being met by imports.

European Gas Imports

As per the PRIMES models, Europe is projected to import 335-341 bcm/y in 2010 increasing to 370-423 bcm/y by 2030.

European Gas Import Sources in southern Mediterranean

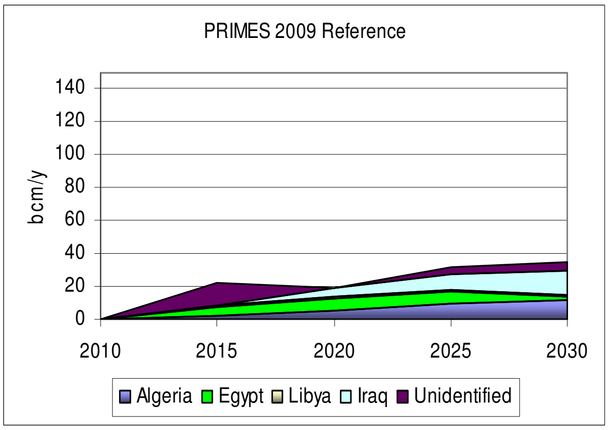
In the southern and eastern Mediterranean countries, we have analysed the current and potential total export volumes to be:[1]

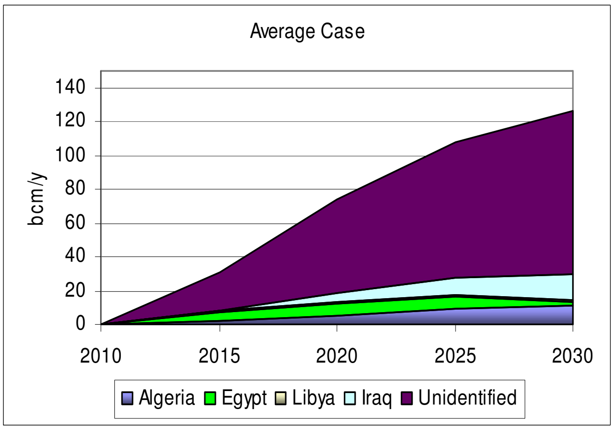
	Current Exports 2009	Base Case 2030	Optimistic Case 2030
Algeria	53	72	90
Libya	10	10	40
Egypt	18	26	60
Iraq	0	15	30
Total	**81**	**123**	**250**

Total EU Import balance is made up from sources in Russia, Norway and various LNG suppliers (e.g. Qatar, Nigeria, and Trinidad).

First Additional Gas from South Mediterranean and Iraq

We have compared the forecasted base case scenarios with EU import cases. South Mediterranean countries and Iraq can almost meet the increased import demands from Europe based on the PRIMES 2009 Reference Case. We have shown both the PRIMES 2009 Reference case along with our "average case" which is defined as the average between import requirements of the PRIMES 2009 Reference and Eurogas 2010 Environmental cases.



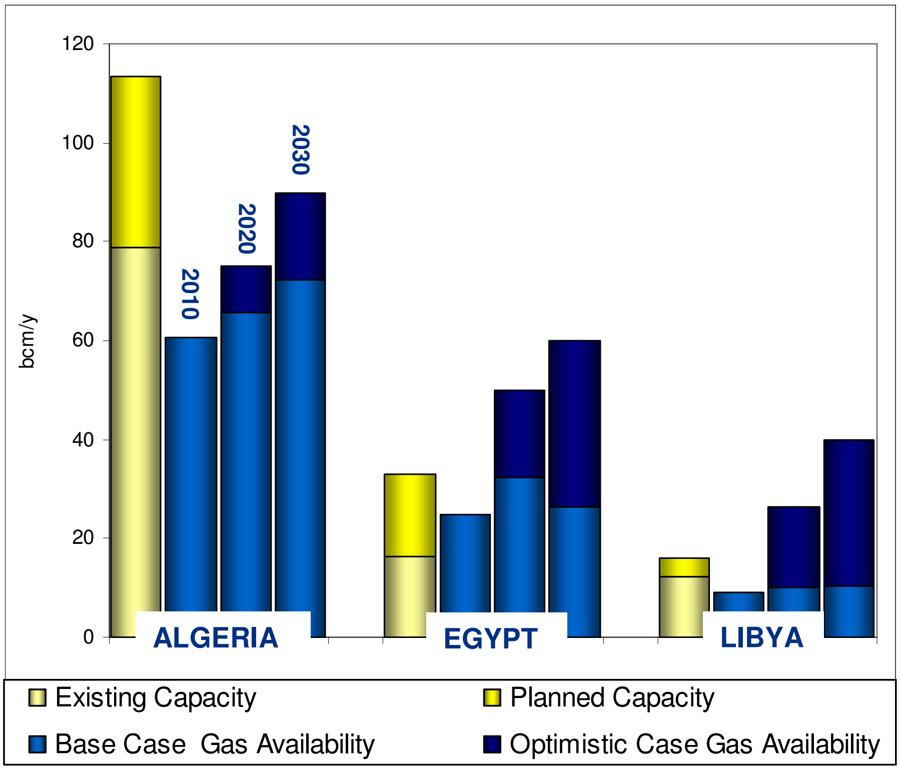


[1] We have not allowed for additional supplies from the Trans-Saharan as our analysis suggested that it was not economically attractive.

As can be seen, Iraq and Algeria are, by 2030, the most important countries in this study for supplying gas to the EU. Algeria and Iraq could supply 27 bcm in 2030 over and above their 2010 exports. This accounts for 77% of the additional supplies needed using the PRIMES 2009 reference case, and 21% of the additional supplies as defined by the 'average; case.

Medring Countries – Existing and Planned Infrastructure

We have evaluated the existing and planned infrastructure in Algeria, Libya, and Egypt in comparison with their projected gas export volume availability and summarize this below:



Algeria has infrastructure already available to meet an export potential of 79 bcm which is sufficient to meet the base case export volumes of 72 bcm available in 2030. This is 26 bcm above the 2009 exports of 53 bcm from Algeria.

Its planned export infrastructure, if fully utilised, could also accommodate most of the additional potential export capacity (up to 30 bcm) of the Trans-Sahara Gas Pipeline (TSGP). Algeria, therefore, believes that it has made or committed already the necessary infrastructure investment decisions to enable its export potential and sees the lack of demand from EU countries as the main 'bottleneck' to it achieving it.

Algeria has the most to offer in terms of additional export potentials and does not seem to require EU supported public investments.

Libya currently has infrastructure to support maximum export of 12.5 bcm/y to EU countries. The current and planned infrastructure is sufficient to support base case export availability; however, new projects would be necessary in order to transport the optimistic case total export potential by 2030 of 40 bcm. Plans for development are not fully clear from the information we have been able to gather for Libya.

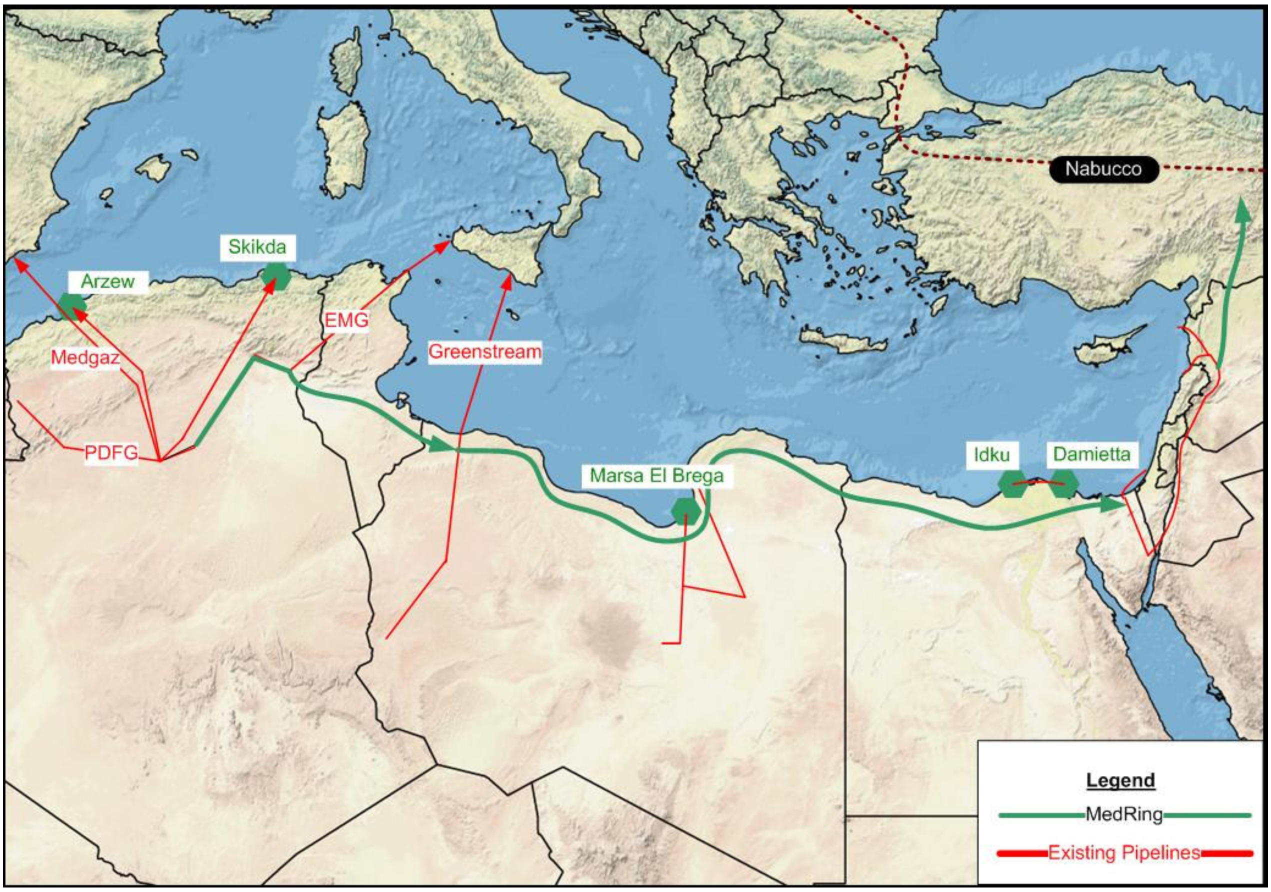
Egypt currently exports LNG to EU countries and also has total export potential of up to 10 bcm through the Arab Gas Pipeline (AGP, 1200km, 36") which only supplied 3.7 bcm to Syria, Jordan and Lebanon in 2009. The AGP has not been fully completed and there are currently no specific plans to do so because there is no agreement to supply gas to Turkey for onward transmission to EU. With completed AGP and LNG expansions, Egypt will have sufficient infrastructure to meet their high case projected 2030 export volumes. However, new project investment would be needed for Egypt to meet its optimistic 2030 gas export case.

Gas to delivery to Europe

We have evaluated several infrastructure scenarios to deliver gas from South Mediterranean and Iraq including a **"Mediterranean Integrated Gas Ring" (**"Medgas Ring").

An integrated pipelines to connect all potential exporters would involve:

- Connection of existing Algerian export pipelines via Tunisia to Libya (Mellitah);
- A new pipeline from Mellitah, Libya to Al Arish, Egypt to connect to AGP;
- Additional Compressor Stations to increase export capacity (to Nabucco) of completed AGP to 15 bcm/y or an additional parallel pipeline should the throughput required be above 15 bcm/y.

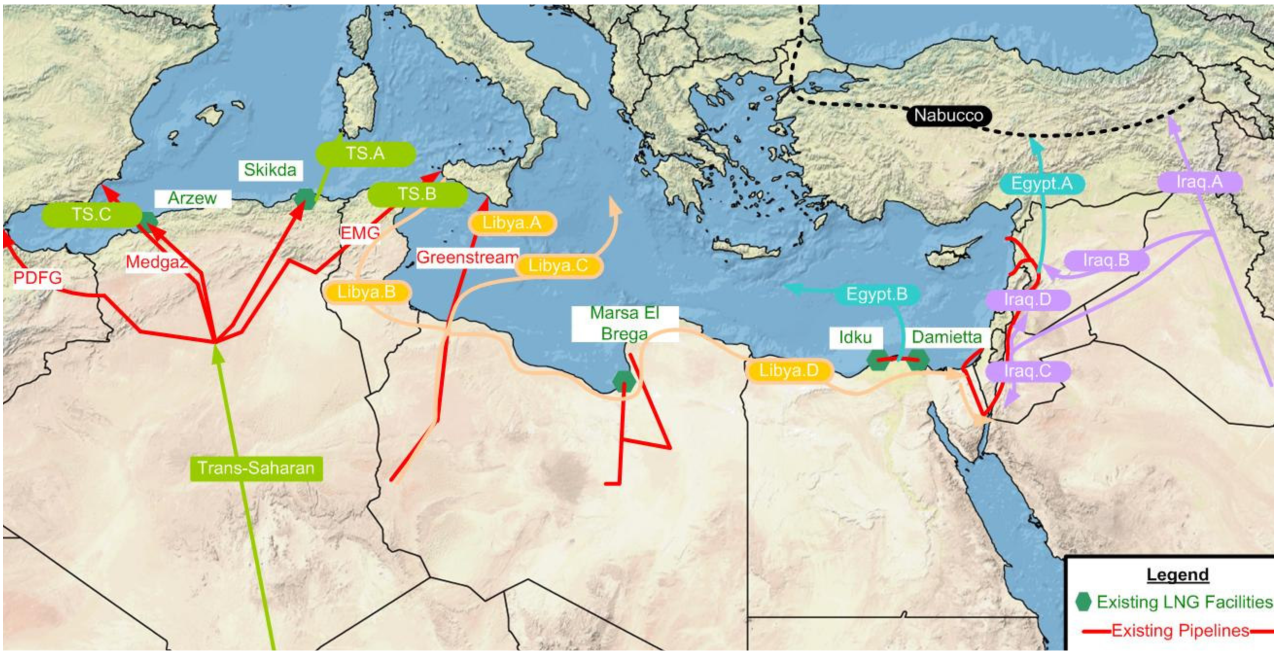


Our analysis strongly suggests that a Mediterranean Gas Ring in its overall concept - extending from Algeria through Libya and Egypt to Turkey - is not economically feasible.

- The CAPEX for a 1350 km, 15 bcm pipeline from Hassi R'Mel, Algeria to Mellitah, Libya is over €3 billion, resulting in a levelised cost of transportation of c. €27/ '000m^3
- Transportation Costs from Libya – Egypt - Nabucco (15 bcm) are c. €58/ '000m^3, and involve CAPEX of over €6 billion.
- Therefore, a total transportation cost of €85/'000m^3 to complete the Mediterranean gas ring, connecting from Algeria to the Nabucco system in Turkey.
- An increased throughput capacity of 30 bcm/y results in lower costs of transport of €75/ 000m^3.
- The cost of transportation through Nabucco and other EU infrastructure must also be added to these figures.

However, many of the constituent projects of the "Medgas Ring" are potentially viable, with the key exception of the pipeline connection between Libya and Egypt for onward connection to Nabucco, and there are already proposed infrastructural developments that will extend and improve the existing ability to export gas from the region to European and other markets.

We have evaluated several infrastructure scenarios which we defined as “**Small Gas Ring Scenarios**” as shown in the figure below.



Algeria: We consider the existing and planned infrastructure is sufficient to meet export potential. It appears that no additional investments will be needed.

Libya: In order to deliver the available export volumes to European markets, we have considered four options:

- Additional LNG liquefaction capacity (10 - 15 bcm) at a new export terminal at Mellitah. Assuming a long term agreement to supply European markets, this project could be economically viable. This project results in liquefaction costs of approximately €55/’000m^3.
- Mellitah to Tunisia pipeline (750 km) plus new Transmed pipelines, up to 24 bcm capacity. Assuming the practicality of additional “Transmed” pipelines, this project results in the lowest transportation costs for gas export from Libya of €37-46/.’000m^3 (depending on volumes).
- Additional parallel Greenstream pipelines, up to 24 bcm. This project appears very marginal, as the offshore distance of 520km increases the CAPEX significantly. The transportation costs were approximately €85/’000m^3.
- New pipeline (2,800 km) from Mellitah to Egypt connecting to AGP system, up to 15 bcm. This project is very marginal in comparison to additional liquefaction capacity in Libya or connecting to the Transmed system when total costs of export are considered.

Egypt: In order to deliver the available export volumes to European markets, we have considered three options:

- Expansion of LNG liquefaction capacity (10 - 30 bcm additional capacity). Assuming a long term agreement to supply European markets, this project could be economically viable.

Depending on liquefaction capacity, the transportation costs of additional LNG range from € 46/ ’000m^3 to € 58/ ’000m^3.

- Complete and upgrade AGP capacity by addition of compressor stations. The maximum practical capacity which can be achieved with the existing pipeline is 15 bcm but gas demand from Syria, Jordan and Lebanon may act as a bottleneck for available gas to EU. The transportation costs of an upgraded and completed AGP are €36/’000m^3
- Use existing AGP for ‘local’ supply (Syria, Jordan, Lebanon) and build new parallel 56” pipeline system for connection to Nabucco. The total investment of €4 billion is economically viable, with a transportation cost of just under €20/’000m^3. It is unlikely that Egypt alone would have 30 bcm/y to support the AGP. This project would likely need significant amounts of natural gas from Iraq or other Middle East locations.

Egypt is also currently curtailing gas exports to meet domestic power demand and has projects underway to significantly increase domestic (power, industry and household) gas consumption. Export growth potential is, therefore, difficult to predict and is considered more likely to be via LNG than by any expansion of AGP.

It should be noted that no confirmatory data has been provided by either the Egyptian Ministry of Petroleum and Mineral Resources or EGAS in Egypt despite repeated requests.

Iraq currently has no significant export infrastructure although its total export potential in future could be significant. There are three possible export routes which could be developed to provide the necessary output:

- 589 km, 56” pipeline from Kirkuk (northern fields) to Nabucco. This project is economically viable. The transportation costs are €8-15/ ’000m^3 depending on export volumes.
- 1,390 km, 56” pipeline from Basrah (Southern Fields) to Nabucco. This project could be economically viable. The transportation costs are €18-35/’000m^3 depending on export volumes.
- 1,852 km, 56” pipeline from Kirkuk fields to Akkas to Syria to Nabucco. This project could be economically viable. The transportation costs are €14-20/’000m^3 depending on export volumes.
- 1,578 km, 56” pipeline from Kirkuk (northern fields) to Akkas to Jordan and then via upgraded (additional compressors) AGP to Damietta for export as LNG (we assume that some gas would be used to supply the Syria, Jordan and Lebanon markets under a ‘swap’ arrangement with Egypt). This project is less economically attractive, with transportation costs ranging from €63 – 84/ ’000m^3.

The transportation costs for the first 3 options above are significantly more attractive for the European Union than the fourth option. Some of these options could be combined to increase export capacity if available volumes are greater than anticipated.

Trans-Saharan Gas Pipeline (TSGP): Transportation costs of the TSGP alone are €52/’000m3. In addition to the costs of transportation from Hassi R’mel to either Italy or Spain suggest that LNG directly from Nigeria could be a more economical option

Morocco, Tunisia, Syria and Jordan are (and will remain) net importers of gas and have no significant future export potential for the EU.

Infrastructure Recommendations Our analysis in particular supports the following projects:

- **Algeria exports**: Algeria has infrastructure capacity to immediately meet EU supply gap and does not seem to need support of public investments.
- **New gas pipelines from Iraq to Turkey**. There is some uncertainty as to how much gas Iraq will produce for export; however, assuming adequate volumes available, Iraqi Gas via Turkey results in the lowest transportation costs of all scenarios considered. Should the gas be sourced from Northern Iraq (Kirkuk fields and Kurdistan), the transportation costs to Erzurum, Turkey are as low as € 8.4/'000m^3. We view this as a two phase project, with Phase 1 including Kurdish gas, and Phase 2 including associated gas from Southern Iraq. Discounting political challenges, Phase One could start in 2013 ending in 2016 (delivery of first gas), Phase Two could start in 2016, for gas delivery in 2020.
- The completion and upgrading of the **Arab Gas Pipeline (AGP)** to Turkey, enabling access to Nabucco and/or the other proposed export pipelines to the EU. Our technical analysis concludes that the AGP can support up to 15 bcm/y by additional compressor solutions. The transportation costs for this solution is €36/'000m^3. Gas from both Iraq (Akkas field) and Egypt could potentially be available for EU around 2020.

The only "missing link" in the Med Gas Ring would then be a pipeline linking Algeria, Libya and Egypt. However, at this point in time, this does not appear to be feasible in comparison to other options and scenarios and we do not believe the absence of this connection to be a serious deficiency in terms of the ability of the infrastructure required to exports to Europe.

Gas Interconnections within Europe: We believe it will be essential for there to be improvements in European gas transmission system interconnection for the full export potential from the southern Mediterranean region to be utilised. We have not studied these requirements because they were not a part of our remit for this assignment. However, concerns were raised, particularly in Algeria, about the bottlenecks which currently exist in Europe to prevent full utilisation of its existing or planned export infrastructure. Particular emphasis should be placed on the ability to transport gas from both Spain and Italy to other parts of Europe because there is a significant over-capacity in import infrastructure in those countries compared to their projected domestic demand, the direction of flow of key transmission lines may need to be changed and the capacity of pipelines may need to be reinforced.

1. Introduction

1.1 Objective

As stated in the Terms of Reference (ToR), the objective of the current study is –

"Analyse the impact on the EU internal market and the market feasibility of an integrated Mediterranean energy ring in gas, analyse technical aspects and prepare a suggestion for how to progress the ring and secure an adequate dimensioning hereof, while foreseeing increasing transport of natural gas from the Middle East and Africa to Europe.

The aim is to prepare a suggestion on how to progress the missing parts; to finish the ring with adequate dimensioning and in view of the desired increased transport of natural gas from the Middle East and Northern Africa to Europe. The study shall furthermore include LNG. LNG shall be considered equal to piped gas as it is deemed appropriate."

More specifically, "the study shall include the following:

- a plan for the establishment of the Euro-North African Gas Pipeline, i.e. the South-Western part of the MEDRING, connecting it to the Arab Gas Pipeline. It shall be noted that the Arab Gas Pipeline connecting Egypt to Syria is finalised and that work is underway for the section that will connect Syria with Turkey. The interconnection from turkey to the EU will be covered by the Nabucco project and it hence not part of the present analysis;
- a suggestion for the inclusion of Iraqi gas resources beyond the natural gas resources from Eastern Iraq (Akkas), namely along the Baija-Hadithah-Amman route;
- indications of pipeline options, taking into account a larger geographical scope (notably regional gas supply possibilities). It will in particular elaborate a Large Ring configuration with gas connections through North African countries, connecting to Spain, i.e. Syria to Morocco-Spain, versus a Small Ring configuration with Algeria exporting like at present;
- Recommendations for upgrading, rehabilitations, compressor solutions, commenting on and suggesting possible re-dimensioning of main lines related to a fully integrated set of gas interconnections (small versus large ring)."

1.2 Structure of the Final Report

This report is structured in the following manner

Chapter 1 Introduction
Chapter 2 European Union Gas Demand
Chapter 3 Gas Supply Analysis
Chapter 4 Technical Analysis
Chapter 5 Financial Analysis
Chapter 6 Doing Business

2. European Union Gas Demand

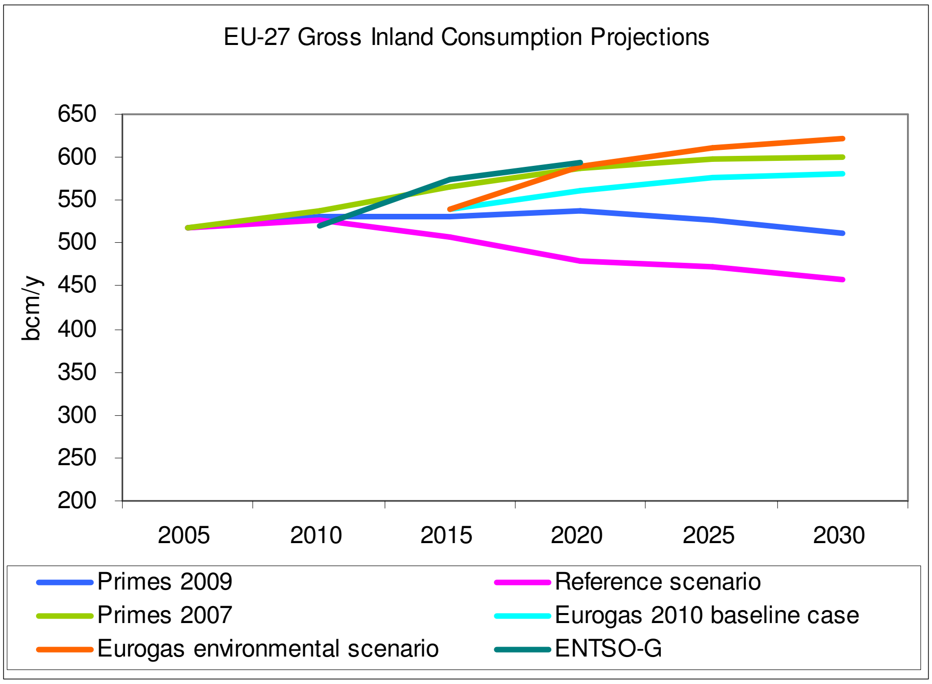
The Task Specifications stated that “the study shall be based on most recent energy scenarios for natural gas supply, demand and prices, including LNG market scenarios. Its network configuration shall be considered on the basis of realistic assumptions on **gas import requirements,** making use of DG TREN’s PRIMES, IEA, OME and Eurogas assessments of such, considering different scenarios.”

The Task Specifications also stated that “Europe’s natural gas demand is projected to grow over the next decade, while at the same time the EU domestic production is declining, thus implying increased requirements for new gas, additional routes and more suppliers.”

The Consultant has not produced its own forecasts of gas consumption, production and imports in the European Union (EU) but rather reviewed those already available from reliable sources. In particular, DG ENER officials provided the Consultant with a presentation of the latest PRIMES projections and we believe that they are the most appropriate for this study. The most relevant PRIMES projections are summarised below.

PRIMES is a partial equilibrium model of the EU energy system providing projections up to 2050. It was built and is operated by the E3MLab of the National Technical University of Athens. The last publicly available projections were made in 2009 and published in 2010. Two scenarios have been developed - (1) a baseline scenario showing effects under current trends and policies and (2) a reference scenario which assumes that two binding targets on RES share and GHG emissions are met. Both scenarios fully reflect the economic crisis and include all adopted and implemented legislation until April 2009 for the baseline and until end 2009 for the Reference scenario.

Figure 2.1: EU gas demand in baseline scenarios



Source: Directorate-General for Energy and Transport, Presentation on EU Energy Scenarios

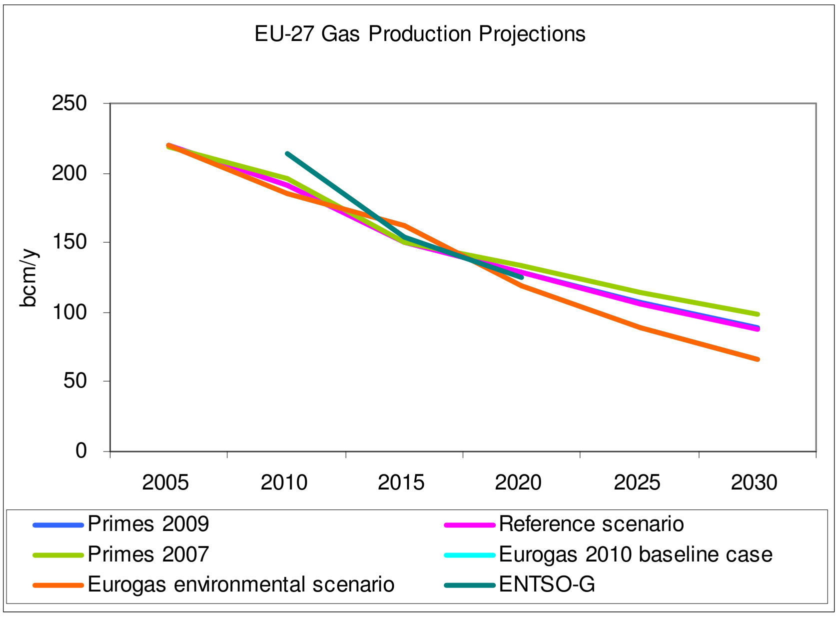
The figure shows the PRIMES 2007 and 2009 projections of EU gas demand, with other forecasts from:

- WEO = World Economic Outlook from the International Energy Agency (IEA)
- ENTSO-G = European Network of Transmission System Operators for Gas
- Eurogas are the representative body for the gas industry in the EU.

It will be seen that there is a wide range of forecasts. Gas demand in 2020 is predicted to range from about 590 bcm (Eurogas Environmental Scenario) to 479 bcm (PRIMES Reference). The range for 2030 is from 622 bcm (Eurogas) to 457 bcm (PRIMES Reference).

The DG ENER presentation also gave forecasts/projections of gas production in the EU, as reproduced in Figure 2.2. There is much more agreement on this, with all showing a continuing decline, although at different rates. The most pessimistic forecasts are those of Eurogas, which show EU gas output falling from 220 bcm in 2005 to 119 bcm in 2020 and 66 bcm in 2030.

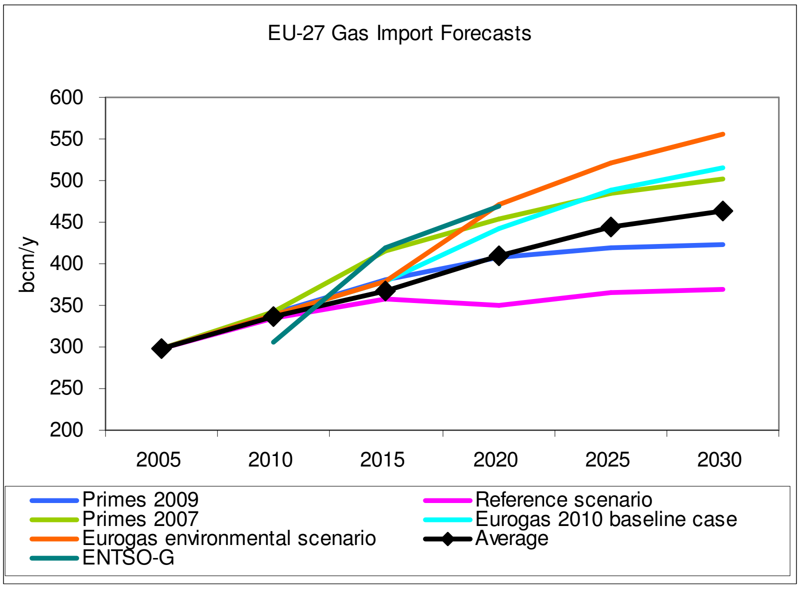
Figure 2.2: Gas Production in the EU



Source: Directorate-General for Energy and Transport, Presentation on EU Energy Scenarios

.In order to compare the gas import requirements of the EU, we have similarly looked at the projections as shown in the table below.

Figure 2.3: Forecast of gas imports into the EU



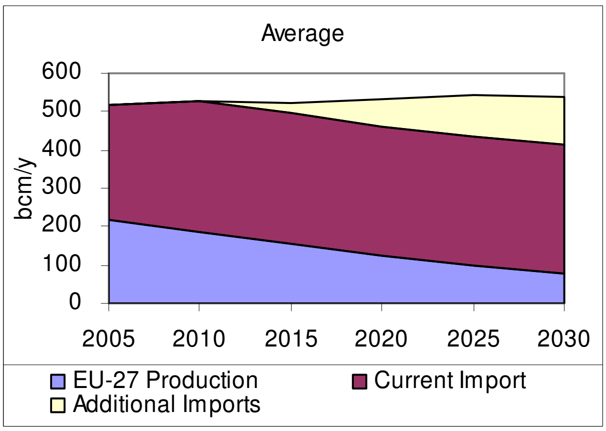
Source: Directorate-General for Energy and Transport, Presentation on EU Energy

We have used the following forecasts in our analysis of EU gas imports:

- Primes 2009 Reference Scenario
- Average of Primes 2009 Reference Scenario and Eurogas 2010 Baseline Scenario.

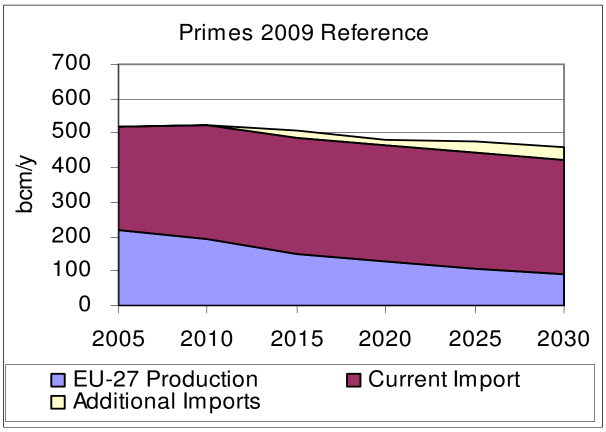
As shown in Figure 2.4 and Figure 2.5 below, should the current imports remain constant, EU will need to contract additional volumes to meet overall demand. These additional volumes are summarized in Table 2.1.

Figure 2.4: Additional EU Gas Imports (Average), 2005-2030



Source: DG ENER, MML Analysis

Figure 2.5: Additional EU Gas Imports (PRIMES 2009), 2005-2030



Source: DG ENER, MML Analysis

Table 2.1: Additional Gas Imports, 2010-2030

	2010	2020	2030
Primes Reference 2009	0 bcm	15 bcm	35 bcm
Eurogas Environmental 2010	0 bcm	133 bcm	218 bcm
Average	**0 bcm**	**74 bcm**	**126 bcm**

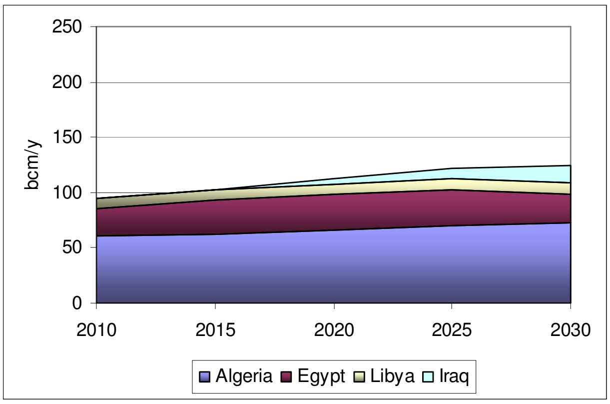
Using our average case, imports are expected to increase by 74 bcm/y by 2020 and by a further 52 bcm in the next decade to 2030. Not all of those increases will be from the Mediterranean region, of course, but those possibilities are discussed later in this report.

3. Gas Supply Analysis

3.1 European Gas Supply

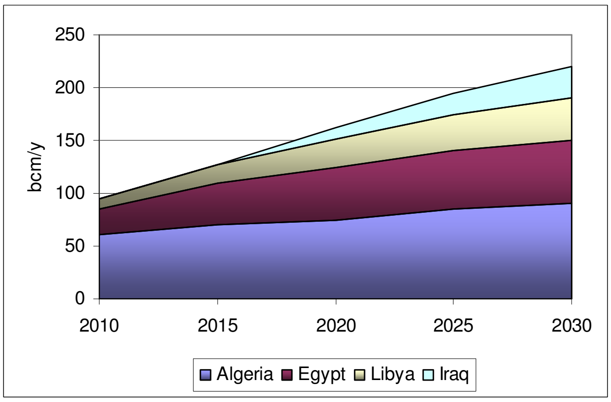
There are four key gas suppliers in this study - Algeria, Egypt, Iraq and Libya. We have discussed country specifics in Section 3.2 below and in more detail in the Appendices. The graph below summarises the cumulative base and high case scenarios from the four suppliers in the region.

Figure 3.1: Potential Total Gas Exports, Base Case



Source: MML Analysis

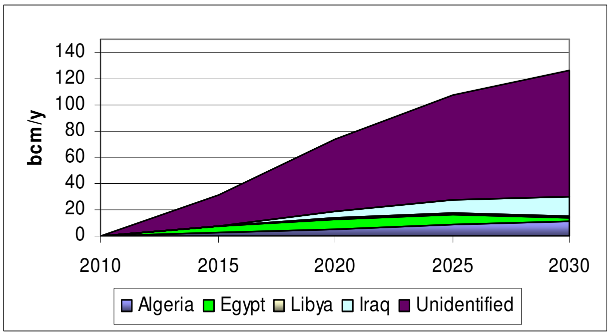
Figure 3.2: Potential Total Gas Exports, High Case



Source: MML Analysis

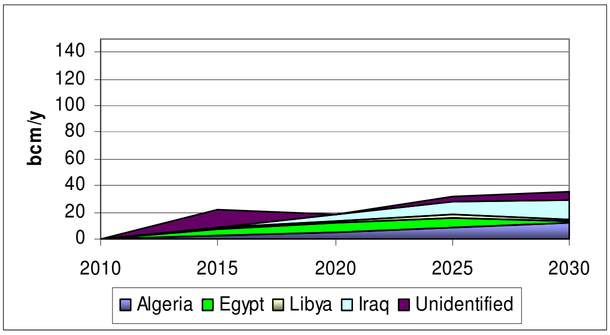
The following tables compare the additional gas imports needed by the EU, with the above supply forecasts for Algeria, Egypt, Libya and Iraq. The overall tables can be also used as potential time lines for projects. Please note that not all the exports shown will be to the EU, although most will be. In particular some of the LNG exports could be shipped to non-EU countries.

Figure 3.3: Total Supplies to the EU-27, Average Case Imports, Base Case Supplies



Source: MML Analysis

Figure 3.4: Total Supplies to the EU-27, Primes 2009 Reference Imports, Base Case Supplies



Source: MML Analysis

As seen above, the Supply Base case almost completely meets the import requirements based on the Primes 2009 Reference forecasts.

3.2 Country Overviews

The Southern Mediterranean countries exported an estimated 89.7 bcm of gas in 2008 and 84.8 bcm in 2009. Of those exports, 63 bcm went to the European Union (EU-27).

The 2009 total was 4.5% lower than in the previous year because of the downturn in demand in the EU. It may be better to regard the 2008 total as more representative of the longer term trends.

Three countries – **Algeria, Egypt and Libya** – accounted for all the gas exports, with the following breakdown:

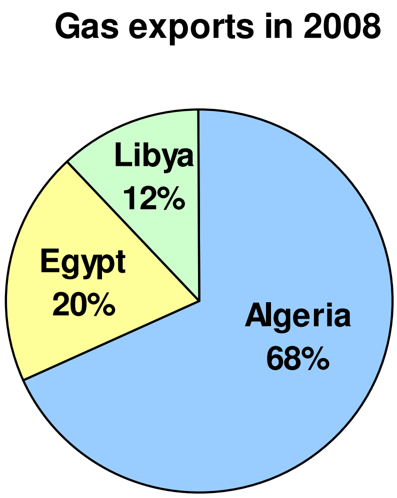
Table 3.1: Gas Exports from Algeria, Egypt and Libya

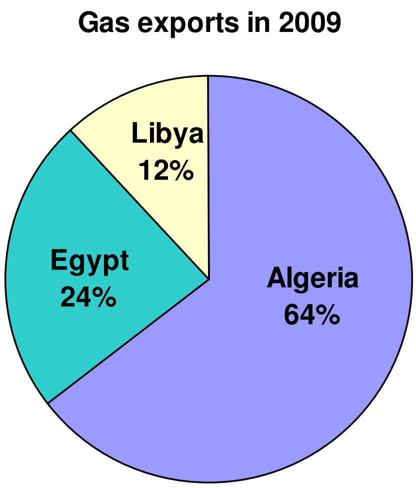
	2008	2009	% change
Algeria	61.1	54.7	-10.5
Egypt	18.2	20.2	11.0
Libya	10.4	9.9	-4.8
Total	89.7	84.5	-4.8

Source: BP Statistical Review

Algeria was the largest exporter, accounting for 68% of the total in 2008 and 65% in 2009. Egypt accounted for 20% and 24% respectively, with Libya supplying the remaining 12% in both years.

Figure 3.5: Gas Exports from Egypt, Algeria and Libya





All the other countries covered in this report were net importers of gas, namely **Morocco, Tunisia, Jordan, and Syria.** It is possible that Tunisia and Syria could become gas exporters on a small scale, although we doubt that. Mention should also be made of **Israel**, which currently imports gas from Egypt but could become an exporter following recent discoveries offshore in the Mediterranean.

The study has also assessed the possibility of **Iraq** exporting gas to the EU, although it only produces gas on a very small scale at the present time.

Detailed country reviews are given in the appendices. The following is a brief overview, concentrating mainly on Algeria, Egypt and Libya.

3.2.1 Algeria

Algeria is clearly the most important country in the study, accounting for about two thirds of the region's gas exports. That dominance is unlikely to change over the next few years.

The country exported about 60 bcm of gas in 2008 and 55 bcm in 2009. The BP Statistical Review shows gas pipeline exports of 31.8 bcm in 2009 and LNG exports of 20.9 bcm.

Of the pipeline exports, 21.4 bcm went to Italy, 6.9 bcm to Spain, 1.3 bcm to Portugal, 1.3 bcm to Tunisia and 0.9 bcm elsewhere. The LNG exports were more geographically dispersed, including 7.7 bcm to France, 5.2 bcm to Spain and 4.2 bcm to Turkey, with smaller quantities going to Japan, India, South Korea and elsewhere.

Algeria's gas export capacity is currently about 79 bcm/ year. That should rise to 89 bcm/y by 2013 and 113.5bcm/y by 2030, following the completion of current investment programmes.

Algeria is increasing its gas export capacity. However, there are some doubts over the country's ability to increase gas exports because of the rapidly rising domestic gas demand. This issue is discussed in detail in the country review in the appendix. Our scenarios for Algeria are set out in the table below. The base case shows an increase in gas exports from 60.6 bcm in 2010 to 72.3 bcm in 2030. The high case is very similar to the Algerian Government's official forecasts, showing exports rising to 90 bcm in 2030. The low case shows exports falling to 40 bcm in 2020 and 20 bcm in 2030.

Table 3.2: Algerian Supply and Demand Scenarios, 2010-2030

Algeria	2010	2015	2020	2025	2030
Gas supply, bcm/year					
High case	85.8	100.0	115.0	125.0	135.0
Base case	85.8	95.0	105.0	115.0	125.0
Low case	85.8	85.0	85.0	85.0	85.0
Gas demand, bcm/year					
High case	25.2	35.0	45.0	55.0	65.0
Base case	25.2	32.2	39.2	45.4	52.7
Low case	25.2	30.0	35.0	40.0	45.0
Gas export availability, bcm/year					
High case	60.6	70.0	75.0	85.0	90.0
Base case	60.6	62.8	65.8	69.6	72.3
Low case	60.6	50.0	40.0	30.0	20.0

Algeria has two gas export pipelines and four LNG plants. Another pipeline is currently under construction and should be ready later in 2010 and a fourth is in the planning stages.

The two existing export pipelines are:
- **Enrico Mattei Gasline (EMG**; previously known as Transmed) from Algeria via Tunisia to Italy; and
- **Pedro Duran Farell Gasline (PDFG**; previously known as Gasoduc Maghreb) from Algeria via Morocco to Spain.

The pipeline currently under construction is:
- **Medgaz**, from Algeria to Spain.

The planned pipeline is:
- **Galsi**, from Algeria to Sardinia and mainland Italy.

Mention should also be made of the proposed:
- **Trans-Sahara Gas Pipeline (TSGP**) from Nigeria to Algeria.

These pipelines are further described in Section 4.

The four LNG plants are:
- Arzew
- Skikda
- Bethioua
- Gassi Touil.

The **Enrico Mattei Gasline** (EMG, initially named Transmed) to Italy crossing Tunisia was completed in 1986. Its 27 bcm per year capacity in the Tunisian section between Qued Saf in Algeria and the Cap Bon in Tunisia was increased recently by 6.5 bcm per year, bringing its total capacity to 33.5 bcm.

The **Pedro Duran Farell Gasline** (PDFG, formerly called Gasoduc Maghreb Europe) to Spain crossing Morocco was completed in 1996. Its initial capacity was 8.5 bcm per year. It was upgraded to 11.5 bcm per year in February 2005 after a third compression station was commissioned in the Algerian section (at Mecheria). The pipeline can be reinforced step by step to enable it to carry up to 20 bcm of gas per year.

The **Medgaz** pipeline will bring gas from Haasi R'Mel to Beni Saf on the western Mediterranean coast of Algeria to Almeria on the Spanish coast. It should have been operational by the end of 2009 but that has been delayed until later in 2010.

The **Galsi** pipeline from El Kala on the Algerian Mediterranean coast to Sardinia and then to Pescaia in Tuscany Italy, will have a capacity of 8 bcm per year. It was originally expected to be on line in 2009, but it experienced difficulties and delays from local authorities in obtaining authorisation for the route and landing points in Sardinia and Tuscany.

The Galsi Project has been included among the TEN-E priority projects for the European Union and within the relevant national strategic infrastructures for the Italian and Algerian governments. An intergovernmental agreement to carry out the project was signed between Algeria and Italy on 14 November 2007.

A construction contract for the 837 kilometre pipeline was reportedly awarded to Snam Reta Gas. However, no final investment decision has been made yet and there have been increasing rumours in the industry that the project will be postponed and possibly even cancelled.

The **Trans-Saharan Gas Pipeline** (TSGP) could open up a new route to export gas to Europe by connecting the Niger Delta in Southern Nigeria (Warri/Abuja) to Algeria's Mediterranean coast at Beni Saf through Niger and Hassi R'Mel and on to Europe. The 4400 km line would transport gas from Nigeria to Algeria and Europe. Cost estimates for the project are US$10-$13 billion. According to the feasibility report published by Penspen Consulting, the line would comprise a 48-56 inch pipeline up to Beni Saf and subsea pipelines to 20 inches between Beni Saf and Spain.

3.2.2 Egypt

Egypt is the second most important gas exporter in the region. The country exported 20.2 bcm in 2009, which was 24% of the regional total.

About 70% of the gas was exported as LNG and 30% by pipeline. The latter went to Jordan, Syria and Lebanon via the Arab Gas Pipeline (AGP).

The LNG exports went to a wide range of countries, with the largest importers being the USA (4.5 bcm in 2009), Spain (4.1 bcm) and France (1.6 bcm).

Our scenarios for Egypt are set out below. The base case shows an increase in gas exports from 24.8 bcm in 2010 to 32.2 bcm in 2020 but then a fall to 26.4 bcm in 2030 because of the continuing growth in domestic demand.

However, the high case scenario shows gas exports more than doubling to 50 bcm in 2020 and 60 bcm in 2030. The low case shows a requirement of 25 bcm imports in 2030

Most of this gas will be exported as LNG. Pipeline exports are expected to be limited to an expansion of the Arab Gas Pipeline (AGP), as discussed elsewhere in this report.

Table 3.3: Egyptian Gas Supply Projections

Egypt	2010	2015	2020	2025	2030
Gas supply, bcm/year					
High case	65.0	85.0	100.0	110.0	120.0
Base case	65.0	79.1	91.7	101.2	106.4
Low case	65.0	70.0	70.0	70.0	70.0
Gas demand, bcm/year					
High case	40.2	50.0	65.0	80.0	95.0
Base case	40.2	48.9	59.5	69.0	80.0
Low case	40.2	45.0	50.0	55.0	60.0
Gas export availability, bcm/year					
High case	24.8	40.0	50.0	55.0	60.0
Base case	24.8	30.2	32.2	32.2	26.4
Low case	24.8	20.0	5.0	-10.0	-25.0

Egypt currently has two gas export pipelines and two LNG plants, which are shown on the map on the following page.

The pipelines are:
- The Arab Gas Pipeline (AGP) which exports gas to Jordan, Syria and Lebanon
- The Arish-Ashkelon pipeline to Israel.

There are plans to extend the AGP from Syria to turkey and link up with the pipeline network there.

The two LNG plants are:
- ELNG (Egyptian Liquefied Natural Gas Company) at Idku
- SEGAS (Spanish Egyptian Gas Company) at Damietta.

There are plans to expand these two facilities and also to build other LNG plants.

The Arab Gas Pipeline (AGP) exports gas from Egypt to Jordan, Syria and Lebanon, and work is underway to extend it to Turkey where it would join the gas pipeline network there. The total length will be approximately 1,200 kilometres and the initial estimated cost was $1.2 billion. The design capacity of the AGP is 10 bcm per year, although the throughput in 2009 was only 3.8 bcm.

The original Memorandum of Understanding (MOU) on the AGP was signed in 2001. The project has been developed in phases. These phases are described in Section 4: Technical Analysis.

The Arish-Ashkelon Pipeline exports gas from Egypt to Israel. The throughput in 2009 was 1.7 bcm.

However, Israel appears to have found significant gas reserves offshore the country and could itself become a net gas exporter. If so, the gas exports from Egypt could be made available elsewhere.

The **ELNG plant at Idku** has two trains with an annual capacity of 7.2 million tonnes or 9.8 bcm. It began production in 2005.

Train 1 is owned by the El-Behara joint venture, which comprises BG (35.5%), Petronas (35.5%), EGPC (12%), EGAS (12%) and Gaz de France (5%). The output has been sold to Gaz de France (GdF).[2]

Train 2 is owned by the Idku joint venture, which comprises BG (38%), Petronas (38%), EGPC (12%) and EGAS (12%). The output has been sold to BG. It was originally intended to supply the company's import terminal in Louisiana in the USA but that may have changed because of the recent major changes in the US gas market.

There is space for four more trains at the Idku plant. **The SEGAS plant at Damietta** has one train with an annual capacity of 4.8 million tonnes.

The SEGAS plant at Damietta has one train with an annual capacity of 4.8 million tonnes or 6.5 bcm. It also began production in 2005. The owners of SEGAS are Union Fenosa of Spain (40%), ENI of Italy (40%), EGAS (10%) and EGPC (10%).

An agreement was signed in 2006 for a second train at Damietta.

Gas production/supply in Egypt has increased substantially over the last few years since the LNG terminals came onstream. That growth is predicted to continue, particularly from offshore fields in the Mediterranean.

[2] Allbusiness.com, January 2010

However, domestic consumption/demand has also been growing rapidly and is also predicted to continue to increase because of government policies to switch electricity generation to gas-fired plants from oil-fired. Those policies could therefore limit the amount of gas available for export.

3.2.3 Libya

Libya is a small gas exporter at the present time. Total exports in 2009 were about 9.9 bcm, which was 12% of the regional total.

Of that total 9.2 bcm were exported to Italy via the Greenstream pipeline and 0.7 bcm to Spain as LNG.

There appears to be substantial potential to increase gas production in and exports from Libya. For example, the gas reserves: production (R:P) ratio exceeds 100, implying that the country could produce gas for at least another 100 years at the current level of output.

The development of Libya's gas industry has been held back by two main factors. Firstly, the oil industry is on a much larger scale and has been given a much higher priority. Secondly, the earlier UN sanctions have limited LNG production. Both of these factors are now much less important and therefore it appears likely that there will be substantial increases in both Libyan gas production and exports over the next 20 years.

Our scenarios for Libya are set out below.

Table 3.4: Libya Supply Scenarios

Libya	2010	2015	2020	2025	2030
Gas supply, bcm/year					
High case	15.9	25.0	35.0	45.0	55.5
Base case	15.9	17.6	20.4	23.7	27.4
Low case	15.9	16.0	17.0	19.0	20.0
Gas demand, bcm/year					
High case	6.9	10.0	20.0	30.0	40.0
Base case	6.9	8.2	10.5	13.3	17.0
Low case	6.9	7.5	8.5	10.0	15.0
Gas export availability, bcm/year					
High case	9.0	17.5	26.5	35.0	40.0
Base case	9.0	9.4	9.9	10.4	10.4
Low case	9.0	6.0	-3.0	-11.0	-20.0

The base case shows gas exports increasing slightly from 9.0 bcm in 2010 to 10.4 bcm in 2025 and 2030. However, the high case shows a big increase to 26.5 bcm in 2025 and further to 40 bcm in 2030. In contrast, the low case shows **import** requirements of 3 bcm in 2020 and 20 bcm in 2030

Any significant increase in gas exports from Libya will require a similar increase in export capacity, as discussed later in this report.

The pipeline possibilities include:
- expansion of Greenstream capacity
- a pipeline from Libya to Tunisia to link up with the existing Transmed pipeline to Italy
- a new pipeline from Libya to Italy.

The LNG possibilities include:
- expansion of the existing plant at Marsa El Brega
- a new plant, probably at Mellitah.

3.2.4 Morocco

Morocco is a small country in the context of the study. Its main importance is that one of the gas pipelines from Algeria to Spain crosses Morocco. That is the Pedro Duran Farell Gasline (PDFG), which is also known as the Maghreb-Europe Gas Pipeline.

The country currently consumes about 1.0 bcm gas per year. That is projected to increase to 10 bcm per year by 2030.

All the gas is imported (from Algeria), as is all the oil and virtually all other energy requirements but there are opportunities for solar and wind energy production.

At the present time it appears that all future gas requirements will be imported from Algeria. However, during our mission to the country we were informed that there are plans to build a LNG import (regasification) terminal to reduce the dependence on Algeria.

3.2.5 Tunisia

Tunisia is a small oil and gas producer in North Africa. It currently produces about 100,000 barrels of oil per day (bpd), of which about 75% is exported. Gas production is on a smaller scale and the country is a net importer of gas.

Tunisia's main significance in the context of our study is as a transit country for the Transmed pipeline which supplies gas from Algeria to Sicily and mainland Italy. The route of the pipeline is shown and discussed in Section 4: Technical Analysis.

Tunisia's gas production in 2010 is estimated to be approximately 3.4 bcm, consumption 5.3 bcm and imports 1.9 bcm. The imports are in the form of transit payments by Algeria for the Transmed pipeline.

The Tunisian authorities are optimistic about increasing domestic gas production. However, in our base case we have assumed continuing imports, rising to 2.6 bcm in 2020 and 3.9 bcm in 2030.

Mention should be made of the proposal for a new gas pipeline from Libya to Tunisia, as shown in the map above and discussed in detail later I this report. That could enable Libya to export gas via an expanded Transmed line.

3.2.6 Jordan

Jordan is also a net importer of gas, in this case from Egypt via the Arab Gas Pipeline (AGP). Gas consumption in 2010 is expected to be about 4.2 bcm and production just 0.2 bcm, with imports of 4.0 bcm. Our base case shows imports rising to 5.6 bcm in 2020 and 8.1 bcm in 2030.

The projected growth in domestic gas consumption may therefore reduce the export capacity of the AGP. This issue is discussed elsewhere in this report and in more detail in the appendix.

Mention should be made of the possibility of gas from Iraq transiting through Jordan, which is also discussed in detail in the Iraq country review.

3.2.7 Syria

Syria also imports gas from Egypt via the Arab Gas Pipeline (AGP). However, it is a significant gas producer with hopes of becoming a net gas exporter in the near future.

Syria also has plans to be an important gas transit country in the region, notably by the extension of the AGP to Turkey and the import of transit gas from Iraq.

Gas consumption in 2010 is expected to be about 7.0 bcm and domestic production 6.0 bcm, with imports of 1.0 bcm. Our base case shows the latter rising to 4.4 bcm in 2020 and 10.9 bcm in 2030.

As with Jordan, the projected growth in domestic gas consumption could reduce the export capacity of the AGP. However, the Syrian officials we met are more optimistic about domestic production than shown in our base case. There is also the proposal to import gas from Iraq.

Syria is strongly in favour of extending the AGP to Turkey, as discussed later in this report.

3.2.8 Lebanon

Lebanon recently began importing gas from Syria via a spur line of the Arab Gas Pipeline (AGP). Imports are expected to be approximately 0.2 bcm in 2010, rising to 1.0 bcm in 2020 and 2.0 bcm in 2030.

There is no gas production in Lebanon at the present time. However, there are hopes of offshore production from the Mediterranean, following the recent discoveries offshore Israel, mentioned below.

3.2.9 Israel

Israel currently imports about 1.7 bcm of gas per year from Egypt via the **Arish-Ashkelon** pipeline and there were plans to increase that to about 4 bcm per year.

However, the recent discovery of the Tamar field offshore Israel has raised hopes that the country will become self-sufficient in gas and possibly even be a net exporter. It has been estimated that the field has recoverable reserves of about 240 bcm, which could be sufficient to meet the country's need for about 20 years. The group involved, led by Noble Energy, also made another gas discovery (Leviathan) earlier in 2010.

Thus the gas exports from Egypt to Israel could probably be made available elsewhere.

3.2.10 Iraq

The task specifications for the study include:

- **a suggestion for the inclusion of Iraqi gas resources beyond the natural gas resources from Eastern Iraq (Akkas), namely along the Baija-Hadithah-Amman route.**

Iraq is currently the 13th largest oil producer in the world. The country, including the oil and gas industry, has been very severely affected by the war in 2003 and subsequent political problems.

The gas industry is and has been on a very small scale, with priority given to the oil industry, although there are believed to be large gas reserves. The BP Statistical Review of World Energy gives an estimate of 3.2 trillion cubic metres (tcm) proved gas reserves, with a reserve to production (R/P) ratio of over 100. No gas production statistics are given in the review, however, but gas production is currently on a very small scale.

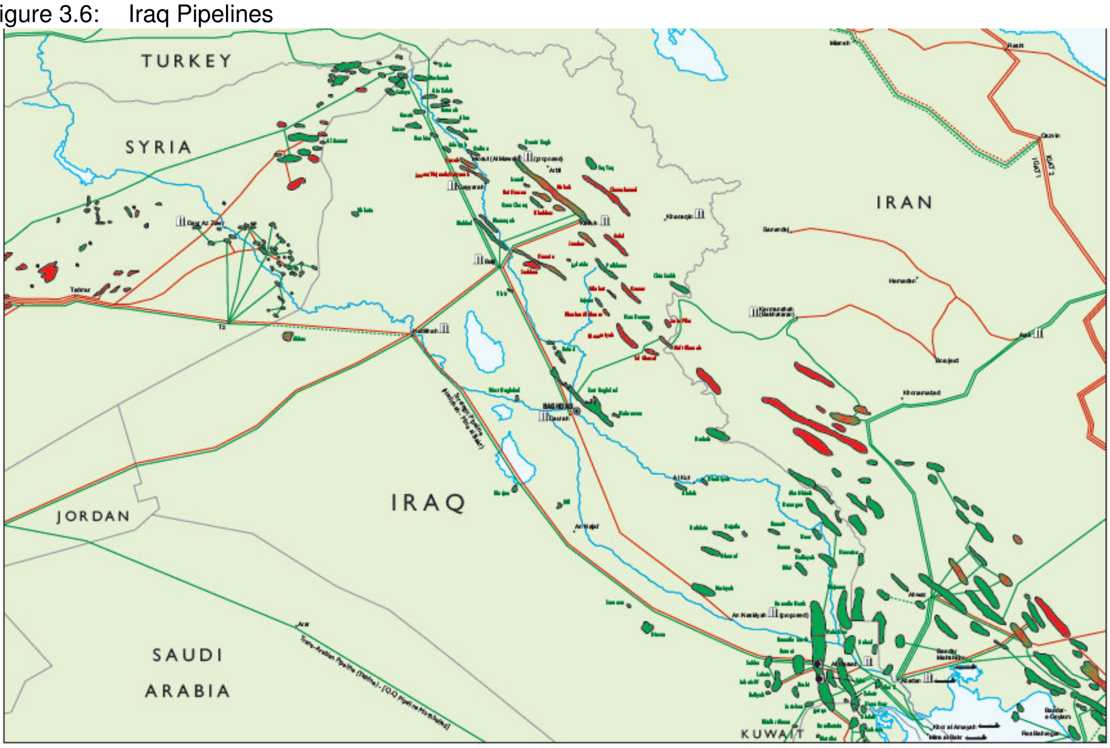
In January 2010 the EU and Iraq signed a **Strategic Energy Partnership Memorandum of Understanding.** The areas of cooperation covered by the MOU include:

- Identifying sources and supply routes for gas from Iraq to the EU
- Updated Iraqi gas development programme.

Earlier, in July 2009 Iraqi Prime Minister Nouri al-Maliki announced in Ankara to prospective Nabucco users that his country could provide up to 530 bcf (15 bcm) by 2015. That is half the pipeline's planned capacity.

The map below shows the known oil and gas fields in Iraq, with the gas fields in red and the oil fields in green. Most of the dry, non-associated gas fields appear to be in the north, notably in the area around Kirkuk. However, most of the known gas reserves are in the oil fields in the south of the country.

Figure 3.6: Iraq Pipelines



Source: Petroleum Economist

The map shows various gas pipelines, including
- Hadithah – Syria
- Hadithah – Jordan

These are obviously very relevant to our study. The TOR refers specifically to the Baija-Hadithah-Amman pipeline but not the one to Syria.

It is obviously very difficult to predict future gas exports from Iraq. In Section 4 we assess three scenarios ranging from 10-30 bcm per year.

We also assess four possible supply routes:
- direct line to Turkey
- interconnection in Syria with the AGP
- interconnection via Jordan and Egypt
- Interconnection via Jordan and Syria.

3.3 North Mediterranean

3.3.1 Spanish Demand and Bottleneck

Although the transmission systems in Spain were not part of our terms of reference (ToR) it should be noted that during the Algeria mission concern was raised on the ability of the Spanish system to transit gas further to France and other parts of Europe. Using the PRIMES 2009 model, we considered the existing infrastructure available to supply gas to Spain and their demand up to 2030.

Table 3.5: Spanish Demand and Infrastructure

Spanish Import Gas Demand (bcm)[3]		Spanish Import Infrastructure		
2010	2030		2010	2030
38	**44.6-46.1**	Regasification LNG	60 bcm	80 bcm
		Pipeline	11.5 bcm (PDFG/MEG) 8 bcm (MEDGAZ)	11.5 bcm + 8.5 bcm (PDFG/MEG) 8 + 8 bcm (MEDGAZ)
		Total	**79.5 bcm**	**116 bcm**

Source: PRIMES 2009, Stakeholder Consultations, Public Available Information

As seen above, there is more than sufficient regasification infrastructure to meet Spanish import demands. Our recommendation would be to model the Spanish gas transmission network in order to determine the feasibility of transiting additional gas through to France and beyond. Additionally, this spare regasification capacity supports the case that LNG from the Middle East and North Africa could be imported via Spain.

3.3.2 Italian Bottlenecks and Demand

Although the transmission system in Italy was not part of the ToR, the ability of the Italian system to transit gas further into Europe should be investigated. Using the PRIMES 2009 model, we considered the existing infrastructure available to supply gas to Italy and Italian demand up to 2030.

Italian Import Gas Demand (bcm)[4]		Italian Import Infrastructure		
2010	2030		2010	2030
72.5	**70.6-79**	Regasification LNG	11.5 bcm	16 bcm
		Pipeline	11.5 bcm (Greenstream) 27.5 bcm (Tran Mediterranean) 17 bcm Transitgas pipeline 26 bcm Trans-Austrian Gas Pipeline (TAG)	11.5 bcm (Greenstream) 27.5 bcm (Tran Mediterranean) 8 bcm GALSI 17 bcm Transitgas pipeline 26 bcm +6.5 bcm Trans-Austrian Gas Pipeline (TAG) 10 – 20 bcm (TAP) 12 bcm (IGI)
		Total	**93.5 bcm**	**134.5 - 144.5 bcm**

[3] Original PRIMES data in ktoe (conversion used: 1 Bcm = 885.9 ktoe)

[4] Original PRIMES data in ktoe (conversion used: 1 Bcm = 885.9 ktoe)

As seen above, there is more than sufficient regasification and pipeline infrastructure existing to meet Italian import demands by 2030. Our recommendation would be to model the Italian gas transmission network in order to determine the feasibility of transiting additional gas through to Europe.

4. Technical Analysis

4.1 Existing State of Play on Gas Interconnections in the Southern Mediterranean including Iraq

4.1.1 Pipelines

Our work has involved the research and collation of publicly available data on existing and projected import pipeline systems, particularly the technical characteristics of the existing pipelines, including:

- dimensioning,
- quality
- transport capacity,
- potential for connection to Europe

Through the meetings with the stakeholder Ministries and Companies during the country visits, we have validated this information.

The following map and table highlight the existing gas interconnections and planned gas interconnections in the Southern Mediterranean.

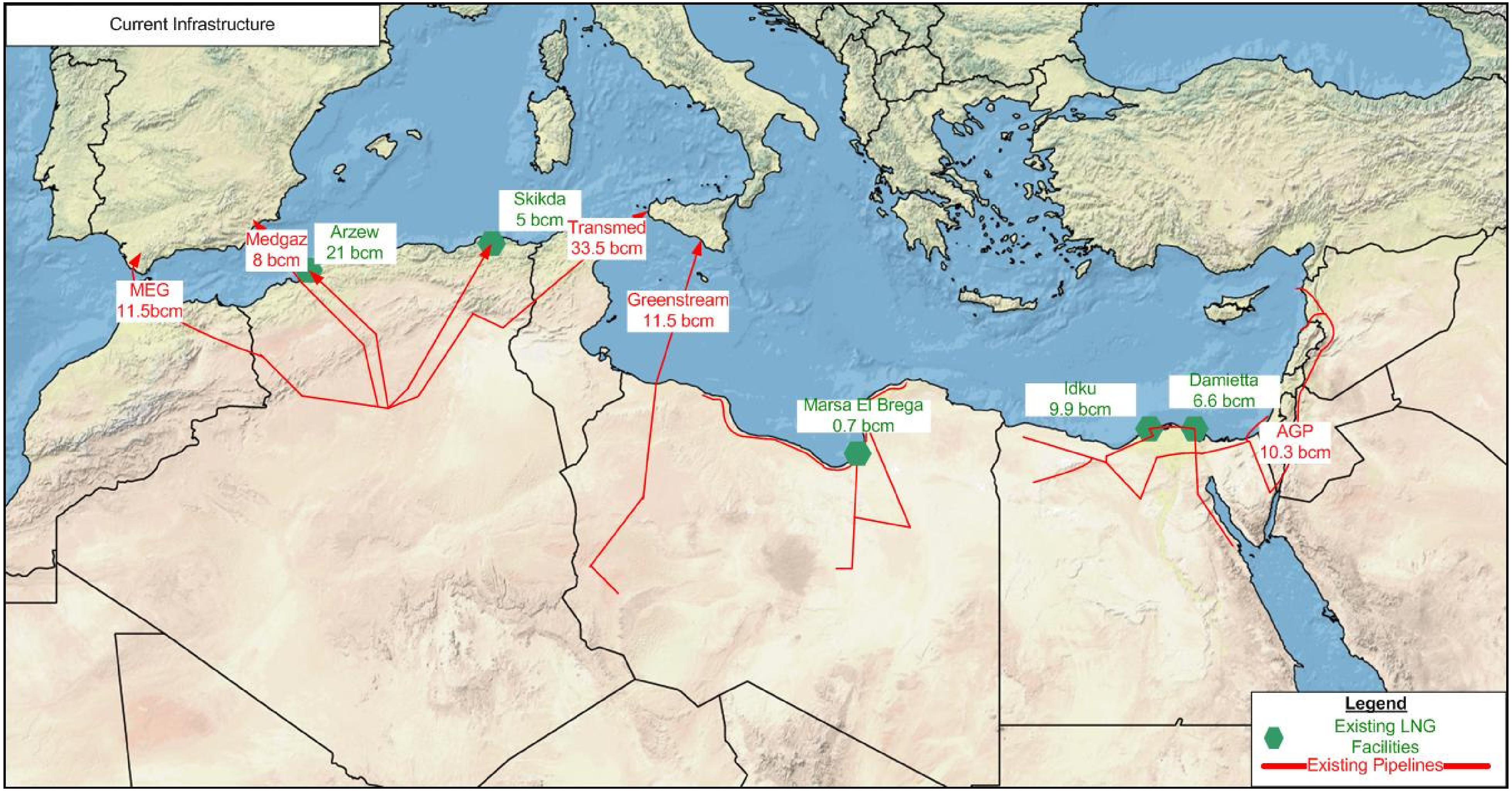
4.1.2 Pipeline system condition and quality

During the course of the data collection for our study, we have also recorded the available data on the developers of the infrastructure and its age. Typically the infrastructure has been developed by a combination of international operators or contractors and state agencies. The international partners in these developments have generally been responsible for the ‘technical’ aspects of the projects and generally those parties have been European based organisations so it is reasonable to assume that international and/or European standards have been applied during design, construction, operation and maintenance.

In addition we have considered the age of the systems in question and the majority of them are less than 20 years old with many being much younger than that. Although some facilities are older, they are not ‘critical’ and generally would only require upgrading to be able to provide the capacity needed to meet the latest and projected expectations of any export infrastructure. In general terms, pipeline systems are designed for a minimum 50 year life and gas pipelines are also designed to conservative safety standards because of the nature of the product they are transporting. Experience also shows that modern gas pipeline systems which meet international standards display minimal signs of deterioration and preventative maintenance systems are generally rigorously applied. Our research in the countries in question has not found any indications of any significant incidents on gas export related infrastructure, other than one concerning a gas liquefaction plant in Algeria. However, Algeria has continued, since that incident, to be a major and reliable exporter of gas to Europe and the remainder of its infrastructure has proved very reliable.

Our terms of reference did not include any detailed examination of the maintenance records of the existing operating companies or their facilities and it would have been completely impractical to have contemplated such a study. Based on the data we have observed, however, there is no reason to suppose that the major export infrastructures on which Europe relies for its gas supplies from this region are likely to be susceptible to failure in the immediately foreseeable future.

Figure 4.1: Current Export Infrastructure from South Mediterranean and Iraq to Europe, 2010



Source: Picture courtesy of Natural Earth

Table 4.1: Current Existing Infrastructure in South Mediterranean and Iraq Connecting to Europe

Pipeline Name	Description	Diameter (inches)	Length (km)	Capacity (bcm/y)	Comments
Maghreb – Europe Gas (MEG) Pipeline (aka PDFG)	Hassi R'mel, Algeria – Morocco Border	48	515	11.5	The Algerian section of the pipeline is owned and operated by the Algerian energy company, Sonatrach. The Moroccan transit section is operated by Metragaz, a joint venture between Sagane (a subsidiary of Spanish Gas Natural), Transgas (Portugal), and SNPP (Morocco). The further offshore section crossing the Strait of Gibraltar is owned jointly by Enagás (Spain), Transgas, and the Moroccan state.
	Moroccan Section	48	522		
	Offshore – Tarifa TSO, Spain	22	45		
Medgaz Pipeline	Algeria Hassi R'mel – Beni-Saf	48	547	8	The pipeline is owned by the consortium of Sonatrach (36 %), CEPSA (20 %), Iberdrola (20 %), Endsea (12 %) and Gaz de France (12 %), forming a joint company 'MEDGAZ'. This pipeline should be operational in 2010.
	Offshore Beni-Saf – Almeria, Spain	24	210		
Trans-Mediterranean Pipeline	Algeria – Hassi R'Mel – Algeria/Tunisia Border	48	550	33.0	The Trans-Mediterranean pipeline was conceived in 1972 when Algeria and Italy initiated cooperation for building a new pipeline across Mediterranean deliver gas to Sicily. Tunisia agreed to act as the transit country and negotiations followed before construction began and the pipeline became operational in 1983, making it the deepest sub-sea pipeline in the world at the time. The Algerian section of Trans-Med is operated by Sonatrach. The Tunisian section is owned by Sotugat and operated by Sergaz. The section across the Channel of Sicily is operated by TMPC (a joint venture of Eni and Sonatrach). The Italian section is operated by Eni's subsidiary Snam Rete Gas
	Onshore Tunisia Transit Section	48	370		
	Offshore Section	3x20 2x26	155		
Greenstream	Wafa – Mellitah (Onshore)	32"	550	11.5	Greenstream is owned by Agip Gas BV, a joint venture of Eni and the National Oil Corporation (NOC) of Libya while Italy's Edison gas, Sorgenia and Gaz de France had signed up for take-or pay contracts to receive 8 bcm per year. The project was conceived in the 1970s after Eni's offshore oil and gas discoveries in Libya's Mediterranean basin.
	Mellitah – Gela (Offshore)	32"	520		

Source: Stakeholder Consultations, Enagas, Hayes (2004), GIE

4.2 Planned pipeline and LNG connections

The following table highlights the current and planned infrastructure in comparison to the base and high case export availability from Algeria, Egypt and Libya.

Table 4.2: Current and Planned Infrastructure

Algeria			Libya			Egypt		
	Current (bcm/y)	2030 (bcm/y)		Current(bcm/y)	2030(bc m/y)		Current (bcm/y)	2030 (bcm/y)
LNG	26	36	LNG	0.7	4.4	LNG	16.4	22.9
PDFG	11.5	11.5 + 9.5	Greenstream	11.5	11.5	AGP	10.0	10.0
Transmed	33.5	33.5						
Medgaz	8	8+8						
Galsi	0	8						
Total	79	113.5	Total	12.2	15.9	Total	13.0	32.9

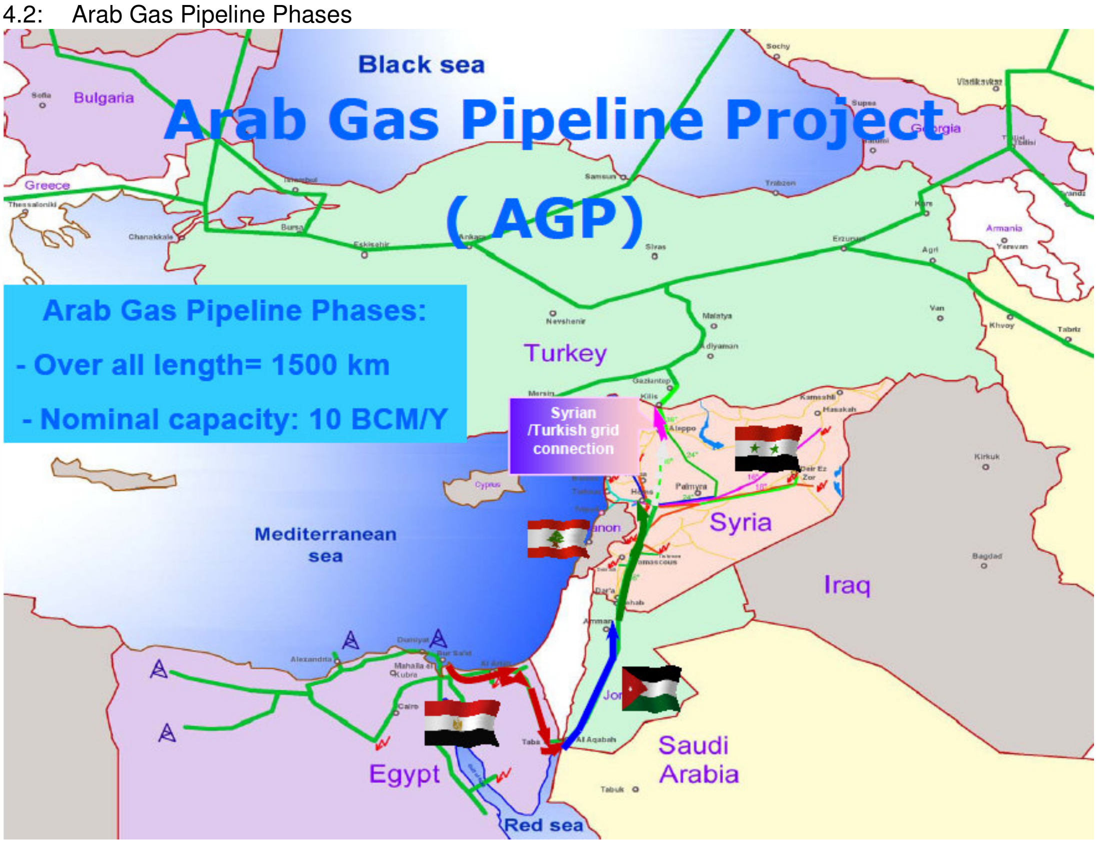
Source: MML Analysis

4.2.1 Arab Gas Pipeline (AGP)

The most significant export pipeline in Egypt is the AGP. It was established in early 2001 with a Memorandum of Understanding signed by the governments of Egypt, Jordan, Syria and Lebanon. Currently Egypt exports between 1.1 to 3 bcm per year through the AGP. The AGP, pipe diameter 900 DN, has been developed in phases as detailed below and illustrated by Figure 4.2.

- The first section of approximately 265 km goes from Arish in Egypt to Aqaba in Jordan and was completed in 2003 at a cost of approximately $220 million.
- The second section of 390 km goes from Aqaba through Amman to El Rehab near the border with Syria. It was completed in 2005 at a cost of $300 million.
- The third section of 320 km goes from El Rehab via Damascus to Homs in Syria. It was completed in 2008.
- The fourth section is a branch line from Homs to Tripoli in Lebanon. It is a 64 km pipeline built by a local firm Argosy-Hawi at a cost of about $13.7 million.

Figure 4.2: Arab Gas Pipeline Phases



Source: Ministry of energy and Mineral Resources – Jordan

In terms of infrastructure, we established that the planned final section in Syria between Homs and Aleppo (construction of a 36 inch pipeline section) has been postponed because there are no sales or transit agreements between Egypt and Turkey for the export of gas. Instead, as a short-term measure, a 600 DN section of the existing Syrian gas network is being used to create the connection to Aleppo although this existing pipeline has very limited capacity. The AGP was being extended at the time of writing from Aleppo to the Syrian border with Turkey. BOTAS in Turkey, however, advised us that they had no current plans to finance the 70 km pipeline required to link the AGP with the Turkish gas pipeline network or potentially, the proposed Nabucco system.

There is a further branch of the AGP which supplies gas to Israel. It is a submarine line, approx. 100km in length and runs from Arish to Ashkelon. It has no significant value for exports to Europe unless it could be used to send gas from future Israeli fields back to Egypt for onward transmission.

4.2.2 Trans-Saharan Gas Pipeline

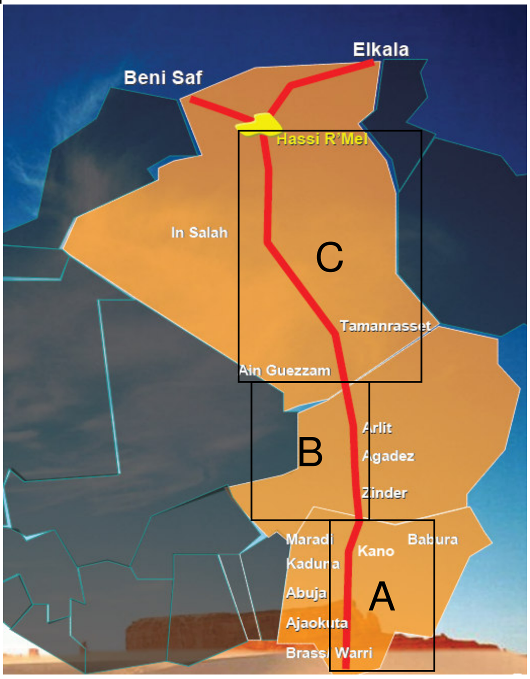
The Trans-Saharan gas pipeline (TSGP) has been under consideration for many years and is conceived to run from Nigeria to Algeria through Niger. The proposed pipeline would begin from the Delta region in south-west Nigeria and connect to Hassi R'Mel in Algeria to feed gas into the MEG, Trans-Med, Medgaz and Galsi pipelines from Algeria to Southern Europe. The pipeline would traverse a total of approximately 4000km and include 10 compressor stations.

The pipeline is proposed to be built and operated jointly by the Nigerian National Petroleum Corporation (NNPC) and Sonatrach. The Niger State is planned to hold a 10% stake in the project. Recently, the

Russian gas company Gazprom, India's gas company GAIL, France's Total S.A., Italy's Eni SpA and Royal Dutch Shell have expressed interest in the project. TSGP could transport 20-30 bcm of rich and low sulphur Nigerian gas to Algeria and Europe. The reserve for the pipeline's capacity is estimated at 425 bcm in total for initial 20 years.

However, there are significant political, economic and technical hurdles which the project must overcome before it could be implemented.

Figure 4.3: Specification of trans-Saharan



Block C: Algerian section
Track length: 2310 km
Block B. Niger section
Track length: 841km
Block A. Nigerian section
Track length: 1037km

Image Source: Sonatrach

4.2.3 GALSI Pipeline –

The GALSI pipeline project was first conceived in 2001 with a MoU between Sonatrach, the Algerian oil and gas company and Edison, the Italian gas utility. The pipeline is proposed to transport natural gas from Algeria's Hassi R'mel field under the Mediterranean Sea to Sardinia and the Italian mainland gas grid at Tuscany.

By late November 2006, GALSI was able to secure the sale of 90% of its capacity and is now proposed as a joint venture with three Italian firms, Edison (20.8%), Enel (15.6%) and Hera Trading (10.4%) where Sonatrach retains 41.6% stakes. The Sardinian authorities hold the remaining 11.6%.

Table 4.3: Technical details of GALSI pipeline

Particulars	Description
Length	Onshore section (Algeria): 640km Offshore section (El Kala to Cagliari): 310km Onshore section (Cagliari to Olbia): 300km Offshore section (Olbia to Castiglione della Pescaia): 220km
Diameter	Vary between 22inches (560mm) and 48inches (1220mm)

Particulars	Description
	Thickness of onshore pipe:16.1mm Thickness of offshore pipe: 17 to 37mm
Capacity	8 bcm per year
Connection to Europe	Will connect Europe at Cagliari in Sardinia, Italy.

Source: Ministry of Energy and Mining, Algeria[5]

The pipeline will constitute two offshore sections – one from El-Kala to Cagliari and the other one from Oblia to Castiglione della Pescaia. It will extend through waters up to 2,800 meters in depth and will comprise conduit thickness up to 37mm. GALSI will have a capacity of 8 bcm per year to once it becomes operational but we understand that there is some doubt about when construction is likely to begin.

4.2.4 Alexandria to Tobruk Pipeline

An agreement was made between Egypt and Libya to build a new gas pipeline between Alexandria in Egypt and the eastern Libyan city of Tobruk to import gas from the Nile Delta region and the Mediterranean deepwater area.

Eni has promoted linking the reserves of both Egypt and Libya to Italy by pipeline. An agreement in principle to link Egypt and Libya's gas grids was reached in June 1997. Desk research has failed to identify evidence of clear forward progress.

4.2.5 Mellitah-Gabes Pipeline

The proposed Mellitah-Gabes trans-national gas pipeline project, a 266 km pipeline with initial capacity of 2 bcm per year from Mellitah on Libya's coast to the Gabes industrial zone in Tunisia, has also been on the drawing board since 1997. However, there is still no certainty on this project, no real progress has been made and the future of the project is dependant on the Libyan Government guaranteeing the gas supplies.

Prior to the project being started, Tunisia and Libya signed an agreement for around 70 billion cubic feet (about 2 bcm) of natural gas per year to be delivered from Libyan gas fields to Tunisia.

4.3 Liquefied Natural Gas (LNG)

4.3.1 Imports

The European Union imported approximately 63 bcm of LNG (liquefied natural gas) in 2009.

Spain was the biggest EU importer of LNG in 2009, with 27 bcm or 43% of the EU's total imports. France was the second largest, with 13 bcm (20%), and the United Kingdom imported 10 bcm. Four other Member States imported much smaller quantities, namely Portugal 2.8 bcm, Belgium 6.5 bcm, Italy 2.9 bcm, and Greece 0.74 bcm.

The EU imported approximately 62.94 bcm of gas in 2009 from Algeria, Egypt and Libya, as summarised in the table below. Of that, 39.19 bcm was imported by pipeline and 23.75bcm as LNG

[5] Ministry website (no date) "Projet GALSI / Gazoduc Algérie - Italie via la Sardaigne" [Available from: http://www.mem-algeria.org/english/index.php?page=galsi, accessed on 11 February 2010]

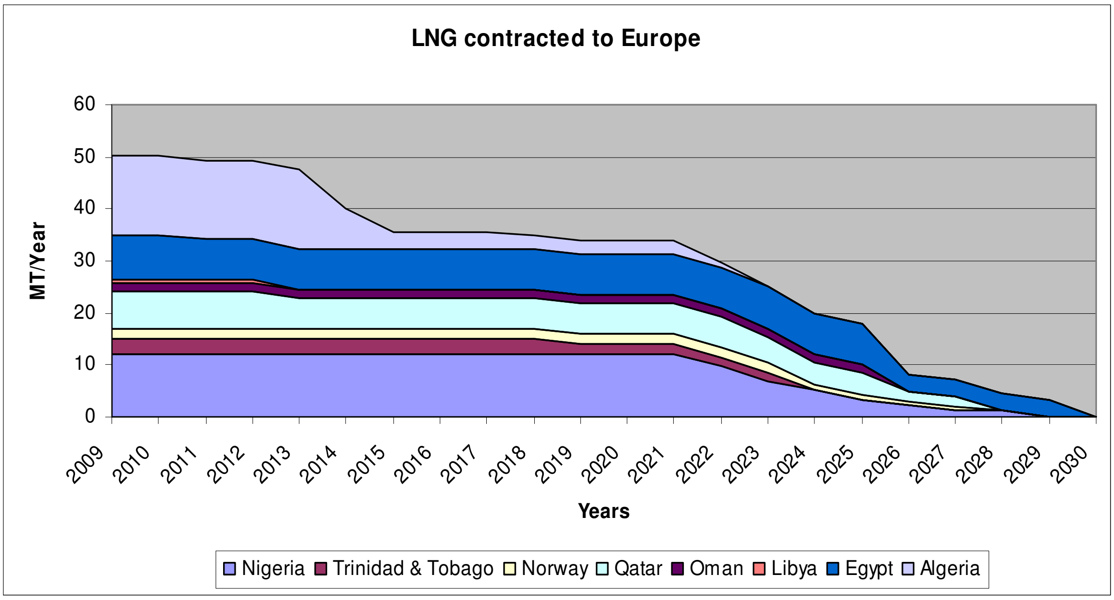
Table 4.4: EU imports from three South Med countries

country	Pipeline	LNG	Total
Algeria	30.02	16.45	46.47
Egypt	0	6.58	6.58
Libya	9.17	0.72	9.89
Total	39.19	23.75	62.94

Source: BP Statistical Review of World Energy 2010

Many of the current LNG imports are on long term contracts, although some of those will come to an end during the period to 2030 as shown in Figure 4.4.

Figure 4.4: Long-term and medium-term contracts in force in 2008



Source: GIIGNL

4.3.2 LNG Regasification Capacity

By the end of 2009 **total world re-gasification capacity totalled 542 bcm/y, of which only 42% was utilised.**

Regasification capacity also increased in 2009, with 11 new regasification terminals starting operation and the enlargement of some existing terminals. Despite the global recession, 2009 was a year of expansion for the LNG market, with new infrastructure developments in the world. EU share of total world re-gasification capacity accounts for 29% of the total with an average utilisation rate of 31%.

The combined maximum capacity of the existing terminals is just under 150 bcm per year, which is treble the volume of actual imports in 2008. Currently spare capacity accounts for approximately 100 bcm. Thus, there is already substantial spare capacity, even ignoring the other facilities under construction and planned.

Spain accounts for about 45 bcm capacity - 45% of the EU total - in six separate terminals. The country imported 28.7 bcm LNG in 2008 from a wide range of locations.

The other import terminals shown in Table 4.5 are located in six different countries, including the UK where there has been a substantial increase in capacity in recent years. That is clearly related directly to declining gas production from the UK sector of the North Sea.

Table 4.5: LNG import/regasification terminals in the EU

country	location	owner	start-up	Capacity (bcm/y)
Spain	Barcelona	Enagas	1968, 2008	17.0
	Huelva	Enagas	1988, 2008	11.8
	Cartagena	Enagas	1989, 2009	10.5
	Bilbao	BBG	2003	7.0
	El Ferrol	Reganosa	2007	3.6
	Sagunto	Union Fenosa	2007, 2009	8.0
France	Fos-Tonkin	Elengy (GdF Suez)	1972	7.0
	Montoir de Bretagne	Elengy (GdF Suez)	1982	10.0
	Fos-Cavaou	Elengy (GdF Suez)	2010	8.25
Portugal	Sines	Galp Energy	2004	5.4
Belgium	Zeebrugge	GDF Suez	1987, 2008	9.0
Italy	Panigaglia	GNL Italia	1969	3.5
	Porto Levante	Adriatic LNG	2009	8.0
UK	Isle of Grain	NG Transco	2005, 2008	13.5
	Teesside	Excelerate Energy	2007	4.6
	Milford Haven	South Hook LNG	2009	10.5
	Milford Haven	Dragon LNG	2009	6.0
Greece	Revithoussa	DEPA	2000	5.3
Total				**148.95**

Source: Mott Mac Donald team analysis

The following import terminals are currently under construction in the EU.

Table 4.6: LNG import/regasification terminals currently under construction in the EU

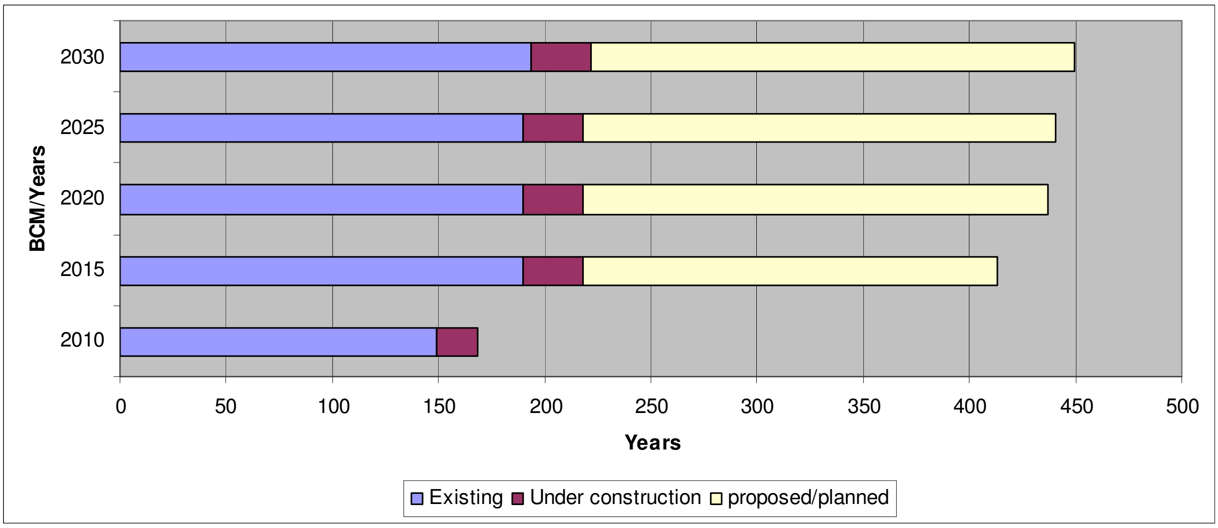
country	location	owner	start-up	capacity (bcm/year)
Italy	Tuscany Offshore	Offshore LNG Toscana	2011	3.8
Netherlands	Rotterdam	Gate LNG	2010	12.0
Poland	Swinoujscie	Polskie LNG	2014	5.0

country	location	owner	start-up	capacity (bcm/year)
UK	Isle of Grain expansion (3)	National Grid	2010-11	7.4

Source: Mott Mac Donald team analyses

There are also plans to expand many of the existing facilities but we do not expect all of those projects to proceed before 2020. Similarly, there is a long list of proposed new LNG terminals, as shown in Figure 4.5, and we also expect very few of those to actually go ahead, at least before 2020.

Figure 4.5: LNG import/regasification terminals in the EU



Source: GIE, GIIGNL, Oil & Gas Journal

All the proposed expansions and new facilities, if completed, would increase the total LNG regasification capacity in the EU to more than 450 bcm per year by 2030, which is nine times the 50 bcm actual imports in 2008.

It is difficult to predict which of the proposed projects will go ahead. The most likely are considered to be those in Member States currently without LNG facilities, such as Germany, Poland and Sweden. Most of the decisions, however, must be taken on the commercial interests of the companies involved or by consideration of the value the stored gas in terms of supply security. The current 31% utilisation rate, however, cannot be efficient for many of the existing LNG operators

4.3.3 Liquefaction

Apart from the Snohvit LNG plant in Norway, the nearest LNG liquefaction plants to the EU are those on the southern shore of the Mediterranean, namely:

- Arzew, Algeria
- Skikda, Algeria
- Marsa El Braga, Libya
- Damietta, Egypt

- Idku, Egypt.

Algeria was the largest LNG supplier to the EU in 2008 – mainly to France and Spain – in addition to gas exports by pipeline to both Spain and Italy

Egypt was the fourth largest LNG supplier to the EU in 2008, after Nigeria and Qatar. Most of those exports went to Spain.

Libya was only a small LNG supplier in 2008 because of the sanctions imposed on the country. LNG exports are likely to be much greater in the future. Libya also exports gas to Italy by pipeline.

4.3.4 Algeria

In Algeria, Sonatrach operates the largest gas field, the Hassi R'Mel which accounts for around half of Algeria's 4.5 trillion cm of proved natural gas reserves. Because of a perceived lack of demand from Europe, Algeria needs more outlets for gas exports to capitalise on its natural resources, and LNG liquefaction terminals offer more scope for diversification.

Table 4.7: Algeria LNG liquefaction facilities

Existing	Start-up	Number of trains	Capacity (bcm/y)
ArzewGL1Z (Bethouia)	1977	6	10.5
Arzew GL2Z	1981	6	10.5
Arzew GL4Z (not operational)	1964	3	0.0
Skikda GL1K phase I & II	1972	3 (6)	5.0 (7.8)
Under Construction			
SkikdaGL1K	2012	1	4.9
Arzew GL3Z	2012/13	1	4.9
Total (by 2013)			35.8 bcm

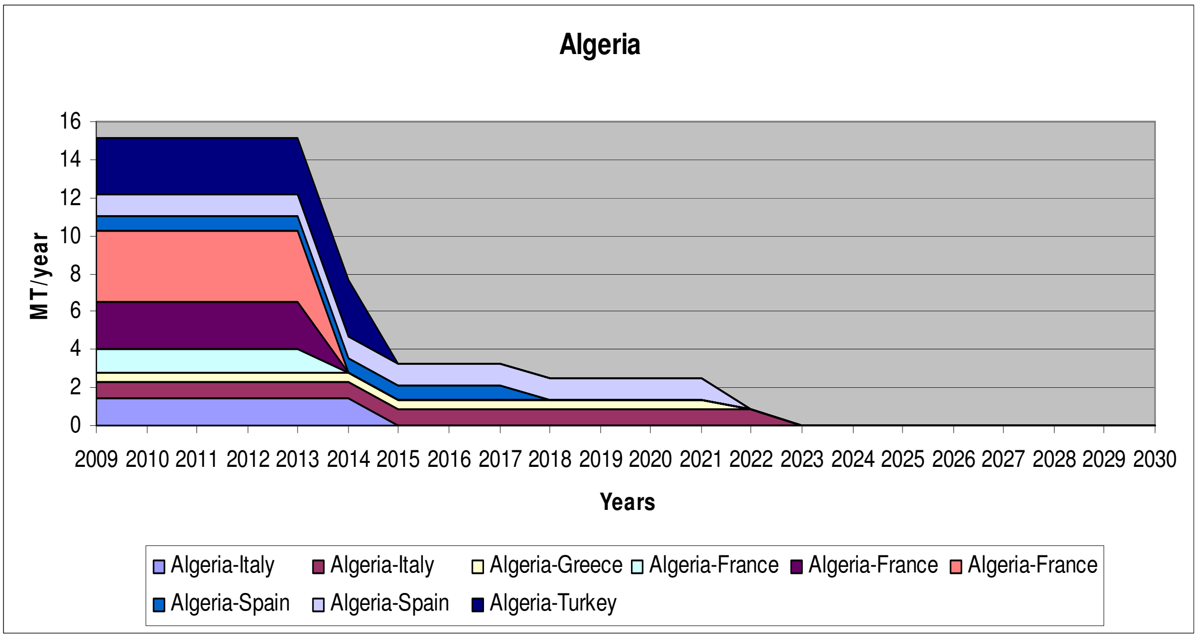
Source: Stakeholder Consultations in Algiers

The original LNG plant at Arzew (commissioned 1964) is no longer operational. The two other plants GL1Z and GL2Z have both been recently revamped and capacity increased to 10.5 bcm each. The original 6 trains at Skikda (capacity 7.8 bcm) were reduced to 3 operational following an explosion in 2004 and the current capacity is 5.0 bcm.

Two new plants are under construction with a capacity of 4.9 bcm each. One at Skikda is due to be completed in 2012 whilst the second one (at Arzew – Gassi Touil) is now due for completion the following year.

Several of Sonatrach's long-term LNG contracts are set to expire over the next five years(Figure 4.6) Renegotiating them in what seems likely to be a well-supplied market characterised by relatively weak prices will not be easy – especially if the spot and short-term markets continue to grow.

Figure 4.6: Long –term and medium-term contracts in force in 2008 in Algeria



Source: GIIGNL

4.3.5 Egypt

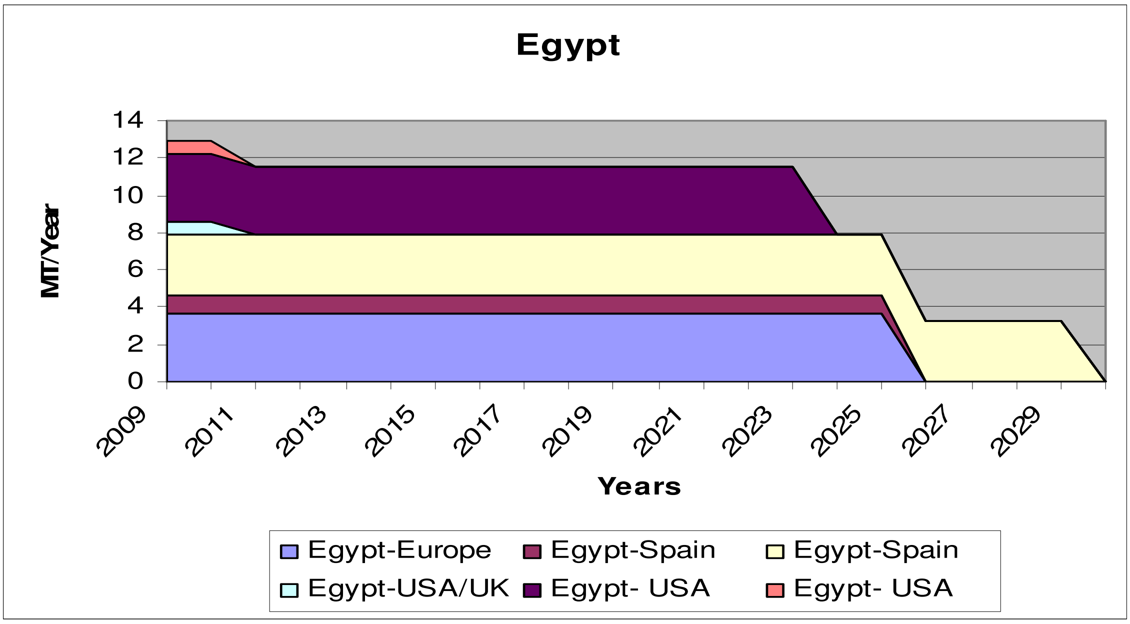
Egyptian LNG is Egypt's largest liquefied natural gas joint venture comprising of both local shareholders, such as EGPC, EGAS and foreign shareholders, such as BG Group plc, PETRONAS and Gaz de France (GDF), all of which are prominent international players in the industry.

Damietta terminal (first train), began operations in the end of 2004 with a capacity to produce 6.5 bcm equivalent LNG. First LNG cargo was sent in Jan 2005. An agreement has been signed in 2006 for a second train with capacity of 6.8 bcm per year to be constructed in 2011 but the plans for this project are currently on hold.

The liquefaction and export capacity of the existing facility has already been sold for the next 25 years (Figure 4.7) with output principally being supplied to Europe (Spain, UK) and USA.

Another plant is located at Idku, 50km east of Alexandria. Egyptian LNG can accommodate an expansion of up to six trains at this location with potentially different ownerships and sources of feedgas. The first two trains are operational and have a capacity of 7.2mtpa (9.9 bcm) with LNG being supplied to France and USA.

Figure 4.7: Long –term and medium-term contracts in force in 2008 in Egypt

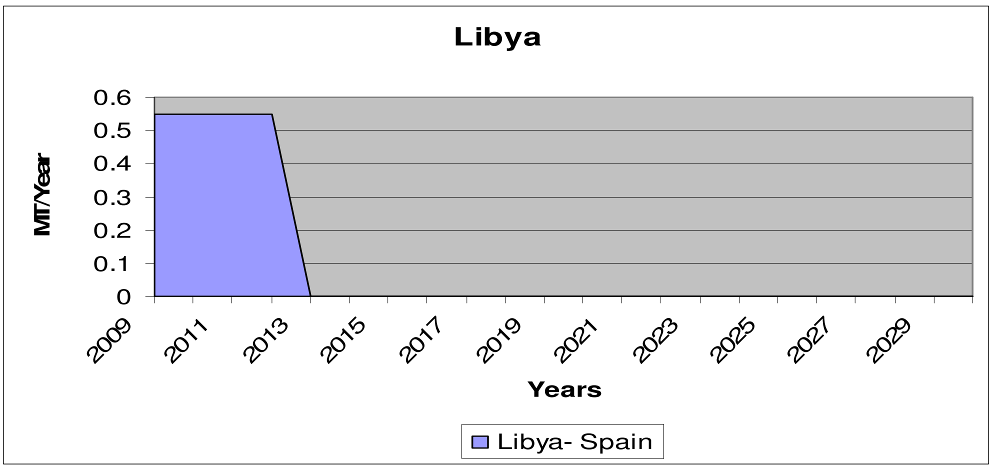


Source: GIE, GIIGNL, Oil & Gas Journal

4.3.6 Libya

The LNG plant at Marsa El Brega was originally built in the late 1960s by Esso (Exxon) with a capacity of about 3.5 bcm. There have been plans to upgrade the plant for many years but in 2008, Shell and NOC announced an agreement on the creation of a joint operating company made up of NOC, its operating unit Sirte Oil Co. (SOC) and Shell Exploration & Production Libya. The agreement stipulates that SOC operates the LNG plant at Marsa el-Brega during rejuvenation and upgrade. The project aims to increase the lifespan of the Marsa el-Brega plant by 25 years with a capacity of 3.2mtpa (4.5 bcm), from 0.7mtpa.

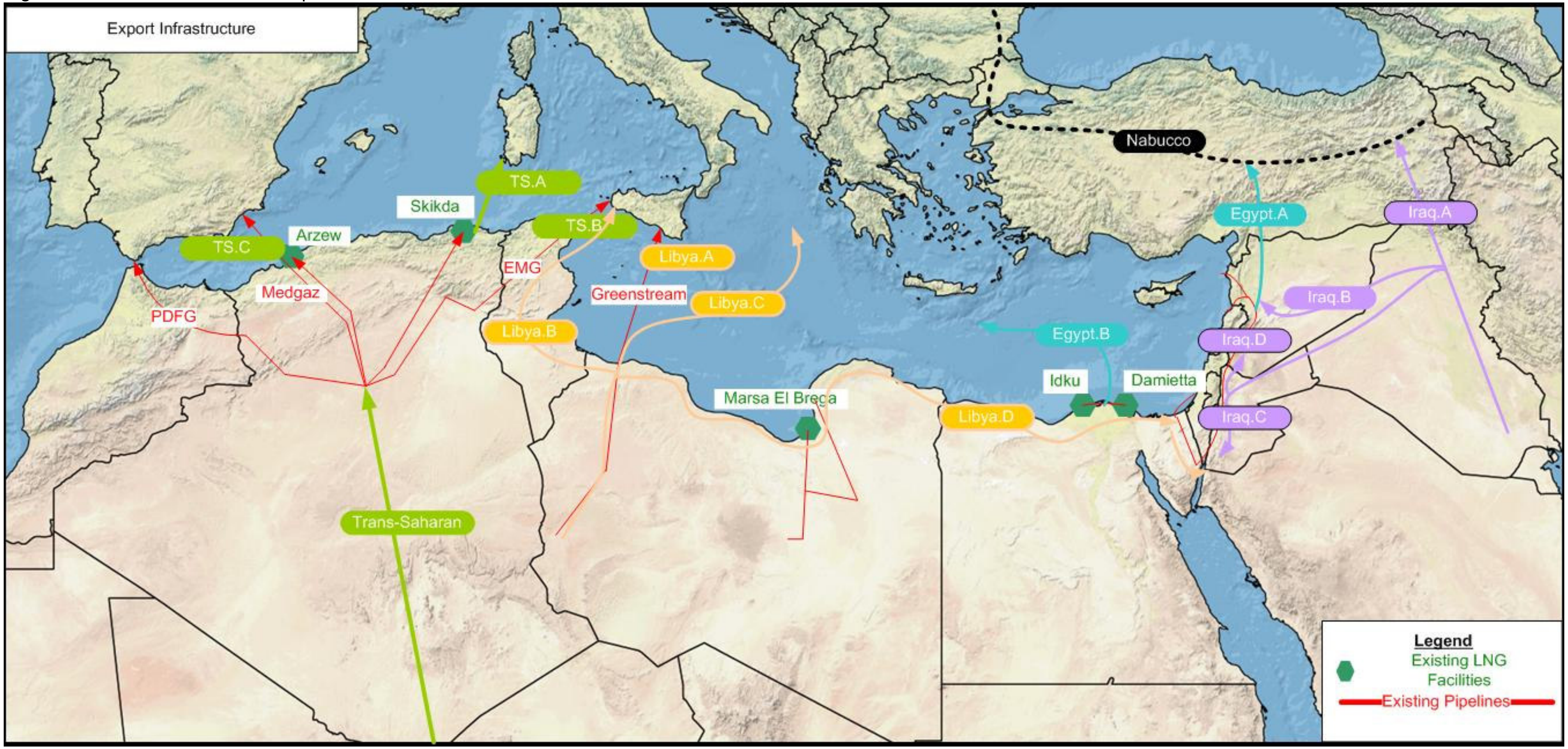
Figure 4.8: Long-term and medium-term contracts in force in 2008 in Libya



Source: GIIGNL

4.4 Transport Corridor Options Summary

Figure 4.9: Schematics of Transportation Corridors



Source: MML Analysis, Picture courtesy of Natural Earth

4.4.1 Introduction

In parallel with our Country Analysis and Economic Analysis, Mott MacDonald has built models of the existing pipeline networks using the "**SynerGEE" Gas Pipeline Network modelling software**.

The sections below outline our assumptions, summary methodology and findings to date.

4.4.1.1 Assumptions

1. For a conceptual study, high pressure pipeline length is estimated from maps with an accuracy of ±10% which is considered adequate with no material significance on network analysis results within this range.

2. The topography of the pipeline corridors are taken as flat negating any elevation issues. For proposed lines, corridors are drawn with attention to the geographical terrain conditions.

3. Compressor station numbers and locations are established when the operating pressures are too low or infeasible (i.e. lower than atmospheric pressure) Further study is essential to optimise the solutions; however, for this study, we have assumed the following for new gas pipelines:

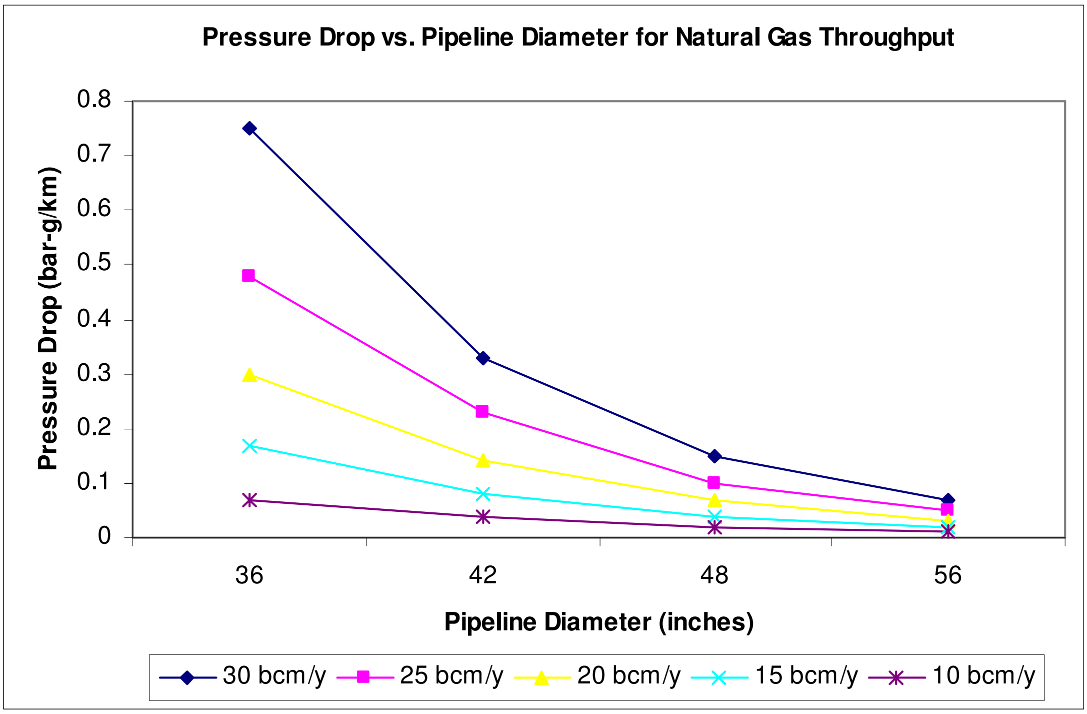
   a. Based on the required gas flow, we have assumed an initial pipeline diameter that resulted in maximum compression ratios in the range of approximately 1.3-1.6 (suction to discharge pressure)

   b. Compressor stations would be built and spaced every four to five hundred kilometers along the pipeline, where possible. This would allow for additional compressors to be added in future if the flow increases.

   c. Pipeline diameters have been limited to max. 56" DN

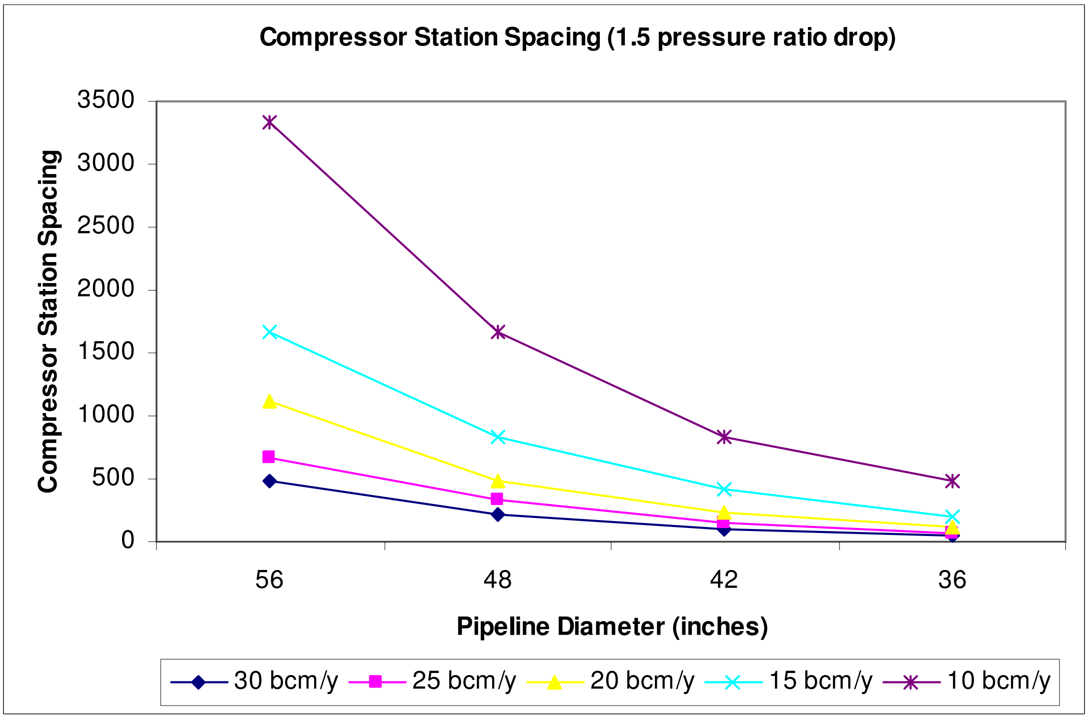
   Figure 4.10 shows the pressure drop per kilometer for different pipeline diameters and for different flow rates. Figure 4.11 graphically shows the necessary compressor station spacing (in kilometers) based on a compression ratio of 1.5.

Figure 4.10: Pressure Drop per Kilometre for Different Pipeline Diameters and Natural Gas Flow rates



Source: MML Analysis using SYNERGEE

Figure 4.11: Compressor Station Spacing based on Pipeline Diameters, Flow Rates, and 1.5 Compression Ratio



Source: MML Analysis using SYNERGEE

4.4.1.2 Methodology

1. A scaled map background is geo-referenced so that pipeline routes can be plotted directly into the model with pipe lengths being scaled off automatically in "SynerGEE Editor".

2. Once "corridors" are outlined, the network model is completed by adding 'supply' and 'demand' points and transmission 'facilities' (such as compressor stations, pressure regulating stations, etc. where applicable).

4.4.2 Egypt

4.4.2.1 Impact of Jordan, Lebanon and Syria's Growing Imports on the Arab Gas Pipeline

As a base case, Jordan, Lebanon and Syria is expected to import 21 bcm by 2030. This places a significant restriction on the AGP as it is currently designed and constructed since its maximum delivery capacity is restricted to 10 bcm per year. Without considerable additional expenditure on reinforcements involving additional compressor stations and/or pipeline looping, it is not possible for this extra gas to come from Egypt.

However, it is more realistic to assume that the required gas will be supplied from Iraq. The new pipeline systems which could deliver this gas from Iraq are discussed below in section 4.4.4. .

However, it is clear that, unless additional local production or alternative sources of energy supply can be established, Jordan, Syria and Lebanon will require the majority of the supply capacity of AGP in the future.

4.4.2.2 Egypt Transportation Corridor Scenarios

For Egypt, we have looked at 4 incremental export cases, from the current state of exporting 26.4 bcm to the high case of exporting 60 bcm by 2030. The table and picture below highlights the solutions for increased export gas from Egypt, which only occurs in the economic high-cases. In each case, we have looked at several combinations of both LNG and piped gas via the Arab Gas Pipeline.

In order to model the scenarios, we have assumed the following:

- The AGP will be completed, i.e. the section from Homs to Aleppo and the onward connection to the Nabucco pipeline in Turkey will be constructed although we have calculated an appropriate size of pipe for the given flow regime as opposed to assuming that the original design would be maintained..
- The infrastructure in Egypt will include the currently proposed expansions of the Damietta and Idku LNG terminals. This will result in Egypt having a liquefaction capacity of 28 bcm/y by 2018 and a piped-gas export capacity of 10.3 bcm/y.
- Europe's increase in imports for natural gas is 35 - 126 bcm from 2009 -2030 as per our PRIMES 2009 Reference Case and our "average" import scenario. As Europe has an over-capacity of LNG regasification facilities, it could be possible to receive additional LNG from Egypt.
- We have assumed that the pipelines from the producing fields to the liquefaction facilities are sufficient to handle increased liquefaction capacity/demand.
- Israel is not included as a gas exporter in this scenario; however, it could potentially become an important player in the region.
- Egypt's preference for exporting gas is via LNG.

Scenario Egypt. A – Arab Gas Pipeline

We have simulated three cases, where the Arab Gas Pipeline (AGP) exports 10.3 bcm, 15 bcm and 20 bcm from Egypt. In each case, we have increased the export capacity by adding additional compression to the existing 900DN pipeline from Arish to Homs, Syria and made recommendations to the sizing of the pipeline to be built from Homs, Syria to Nabucco.

Scenario Egypt. B – Egypt Liquefaction – We have estimated increases of up to 30 bcm in liquefaction potential in Egypt. In this case, we have assumed that the supply is offshore, close to either liquefaction terminals, and limited pipeline is needed to reach the facility.

Table 4.8: Egypt Results

Scenarios	10 bcm	15 bcm	15 bcm (option 2)	20 bcm	30 bcm
Scenario Egypt.AGP – Completion of AGP					
LEG 1 – Al-Arish – Homs, Syria 975km	Existing 36" pipeline Compressors: 6 Separation: 198km	Existing 36" pipeline Compressors: 11 Separation: 97.5km	Existing 36" pipeline Compressors:4	Existing 36" pipeline Compressors: 6	Length: 1586 km Diameter: 56" Compressors: 5
			Add New 36" pipeline Compressors: 4	New 36" pipeline Compressors: 6	
LEG 2 –Homs, Syria – Nabucco 611 km	Diameter: 36" Compressors: 4	Diameter: 48" Compressors: 3	Diameter: 56" Compressors: 3	Diameter: 56" Compressors: 3	

As seen above, the existing AGP from Al-Arish to Homs cannot handle more than 15 bcm/y of natural gas without having to build an additional pipeline along side. In the case where 15 bcm/y is being transported through the AGP, we have evaluated 2 scenarios:

- Option 1, where additional compressor stations are added every 97.5 km
- Option 2: A parallel pipeline is built next to the existing AGP

In order to evaluate these options, we have compared the levelised costs, as in Section 5.

4.4.3 Iraq

For Iraq, we have estimated as a base case and high case of 15 bcm to 30 bcm of natural gas available for export by 2030. Additionally, we have assumed that Nabucco can handle up to 30 bcm of additional gas. As such, we have developed the following scenarios, as highlighted in the map and table below.

Scenario *Iraq.A*: Iraq interconnection in Turkey – This scenario looks at the simulation where Iraqi gas is transported directly to Turkey and connects into Nabucco at Erzurum. Several flow rate scenarios are modelled for this interconnection (10bcm, 15 bcm, 20 bcm, and 30bcm), in addition to two different sources of gas in Iraq:

- A.1: Associated gas produced in Southern Iraq near Basrah
- A.2: Gas produced in Kirkuk, and non-associated gas fields in Kurdistan region such as Chemchemal and Khor Mor

As this scenario ties directly into Nabucco, we have assumed that the design pressure of any pipeline tying into Nabucco will have a delivery pressure of 100 barg at Erzurum.

Scenario A is very interesting in term of both volumes and CAPEX. A phased approach could be taken to allow Iraqi gas to be transported to Nabucco as follows:

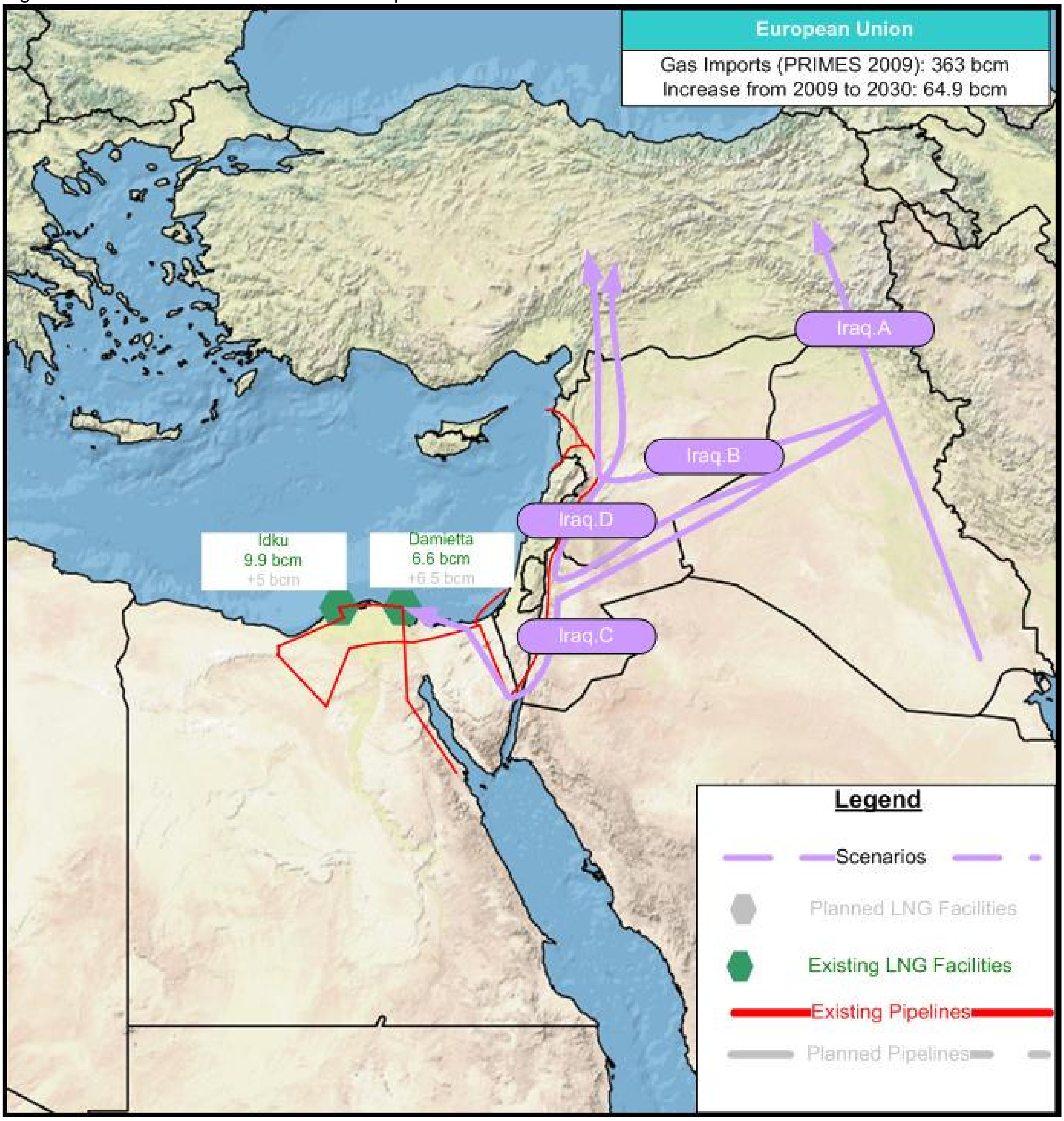
- Immediately begin construction of a 589km pipeline from Kirkuk fields to Nabucco, with gas primarily being supplied from Kurdistan
- As gas flaring and shrinkage from the Southern fields is being captured and monetised, connect the southern fields with the aforementioned pipeline (a distance of 801km)

Scenario *Iraq.B*: Iraqi Interconnection via Syria and AGP – This scenario looks at the simulation where Iraqi gas is transported via Syria, connecting with the AGP near Homs. Several flow rate scenarios are modelled for this interconnection (10bcm, 15 bcm, 20 bcm, and 30bcm). It has been assumed that gas sources are from Northern Iraq (Kirkuk) in addition to the Akkas field. As this pipeline ties into the AGP, which has a design pressure of 75 barg, we have assumed a delivery pressure of 75 barg for simulations.

Scenario *Iraq.C*: Iraqi Interconnection via Jordan and Egypt – This scenario looks at the simulation where Iraqi gas is transported to Amman, Jordan where the AGP flow regime is reversed so that gas can be further transported to Egypt for liquefaction and export. Several flow rate scenarios are modelled for this interconnection (10bcm, 15 bcm, 20 bcm, and 30bcm). It has been assumed that gas sources are from Northern Iraq (Kirkuk) in addition to the Akkas field. As this pipeline ties into the AGP, which has a design pressure of 75 barg, we have assumed a delivery pressure of 75 barg for simulations

Scenario *Iraq.D*: Iraqi Interconnection via Jordan and Syria – This scenario looks at the situation where Iraqi gas is transported to Amman, Jordan, connecting to the AGP and then transported via Syria to Turkey where it connects to Nabucco. Several flow rate scenarios are modelled for this interconnection (10bcm, 15 bcm, 20 bcm, and 30bcm). It has been assumed that gas sources are from Northern Iraq (Kirkuk) in addition to the Akkas field. Again, a delivery pressure of 75 barg is assumed. As the pipeline from Amman, Jordan to Homs, Syria has already been constructed and commissioned; we have considered adding compression stations or additional parallel pipelines to deliver the flow rates.

Figure 4.12: Infrastructure Scenarios in Iraq



Source: Picture Courtesy of Natural Earth

Table 4.9: Iraq Scenarios

Scenarios	10 bcm	15 bcm	20 bcm	30 bcm
Scenario Iraq A.1 - Basrah - Erzerum, Turkey, Design Pressure: 100 barg, Distance: 1390km				
	Diameter: 42” Compressors: 3	Diameter: 48” Compressors: 3	Diameter: 48” Compressors: 3	Diameter: 56” Compressors: 5
Scenarios Iraq.A.2 – Kirkuk – Erzerum – Turkey, Design Pressure: 100 barg, Distance: 589km				
	Diameter: 42” Compressors: 2	Diameter: 48” Compressors: 2	Diameter: 56 Compressors: 2	Diameter: 56” Compressors: 3
Scenario Iraq.B -Kirkuk - AGP, Homs, Syria, Design Pressure 75 barg				
Leg 1 – Kirkuk – Homs, Syria Distance: 780 km	Diameter: 42” Compressors: 3	Diameter: 48” Compressors: 3	Diameter: 56” Compressors: 3	Diameter: 56” Compressors: 5
Leg 2 - AGP - Nabucco (Homs - Nabucco yet to be complete) Distance: 611 km	Diameter: 36” Compressors: 4	Diameter: 48” Compressors: 3	Diameter: 56” Compressors: 3	Diameter: 56” Compressors: 4
Scenario Iraq.C -Kirkuk – Amman, Amman – Alexandria, Alexandria – Liquefaction, Design Pressure 75 barg				
Leg 1 – Kirkuk – Amman, Jordan Distance: 984 km	Diameter: 42” Compressors: 3	Diameter: 48” Compressors: 3	Diameter: 56” Compressors: 3	Diameter: 56” Compressors: 6
Leg 2 – Amman, Jordan – Alexandria via AGP reversal Distance: 594km	Existing 36” pipeline Compressors: 2	Existing 36” pipeline Compressors: 5	Existing 36” pipeline Compressors: 2	Existing 36” pipeline Compressors: 2
			New 36” pipeline Compressors: 2	New 56” pipeline Compressors: 2
Leg 3 – Liquefaction trains	Additional 10 bcm	Additional 15 bcm	Additional 20 bcm	Additional 30 bcm
Scenario Iraq.D -Kirkuk – Amman, Amman via Syria – Nabucco (AGP), Design Pressure 75 barg				
Leg 1 – Kirkuk – Amman, Jordan Distance: 984 km	Diameter: 42” Compressors: 3	Diameter: 48” Compressors: 3	Diameter: 56” Compressors: 3	Distance: 1852 km Diameter: 56” Compressors: 7
Leg 2 – Amman, AGP – Homs, Syria Distance: 257 km	Existing and planned 36” pipeline Compressors: 2	Existing and planned 36” x2 pipeline Compressors: 1	Existing and planned 36” x 2 pipeline Compressors: 2	
Leg 3 – Homs, Syria – Nabucco Distance: 611km	Diameter: 36” Compressors: 4	Diameter: 48” Compressors: 3	Diameter: 56” Compressors: 3	

Source: MML Analysis

For each option, the transportation costs for each technical solution will be compared in order to prioritise the least-cost options.

4.4.4 Algeria

For Algeria, we looked at 3 incremental supply cases, from the current level of exporting 60.5 bcm to the high projected case of exporting 90 bcm in 2030.

However, as already discussed elsewhere in this report, by 2013 the export infrastructure in Algeria will have sufficient capacity to handle 89 bcm of natural gas export, either via LNG or piped-gas to Europe. There is therefore no need to model any additional scenarios for gas export to Europe based on Algerian gas-export availability.

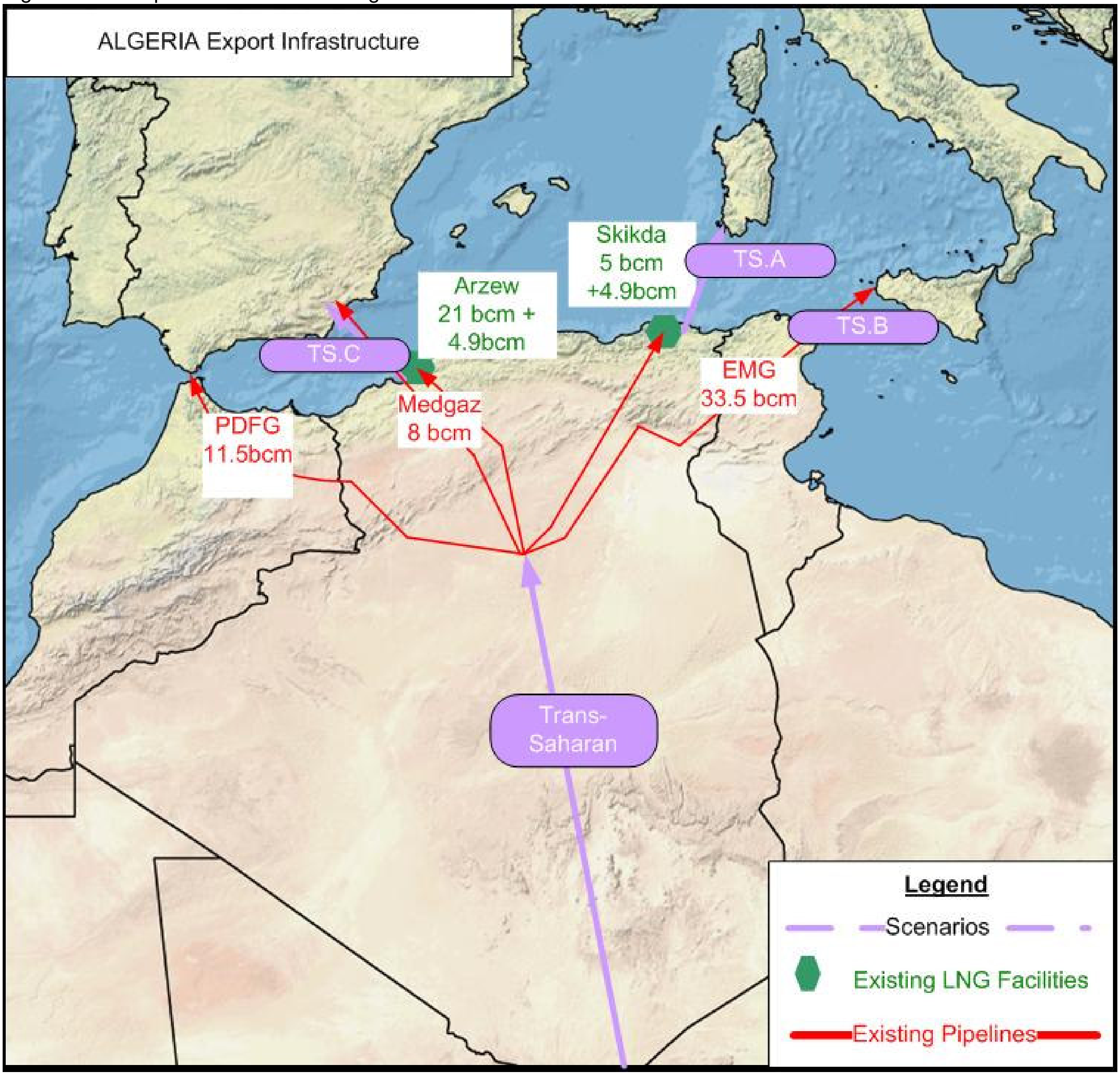
Should the TSGP project be realised, an additional 30 bcm travelling through Algerian pipelines to Europe would need to be accommodated. We have assumed that export by LNG in Algeria would not be an option for this gas, as it would be more feasible to build the liquefaction plants in Nigeria. In this case, we have further modelled the situation where Algeria would need to handle 100bcm, 110bcm, and 120 bcm of export (i.e. up to 30 bcm above that of the high-export case of Algerian gas). Figure 4.13 schematically reviews the different infrastructure scenarios as described below

Scenario TS.A: Galsi Pipeline – Infrastructure required based on various export volume scenarios.

Scenario TS.B: Expansion of Trans-Mediterranean Pipeline – Additional subsea pipelines could be added to the Trans-Med pipeline system

Scenario TS.C: Expansion of Medgaz Pipeline – Additional subsea pipelines could be added to the existing Medgaz system.

Figure 4.13: Export Infrastructure in Algeria



Source: MML Analysis

The following table highlights the technical solutions for the transmission of gas (up to an extra 30 bcm) from the Trans-Saharan Pipeline.

Table 4.10: Transmission Scenarios of Trans-Saharan Pipelines

Scenarios	Additional 8 bcm (Export Capacity: 96.5 bcm)	Additional 16 bcm (Export Capacity: 104.5 bcm)
Scenario TS.A: Galsi Pipeline – Onshore Design Pressure: 75 bar-g, offshore: 200 bar-g		
LEG 1 – Hassi-R'Mel – El-Kala, Algeria 640km	Planned 48"	Planned 48"
LEG 2 – El-Kala – Cagliari, Italy 310 km	26" offshore	2x26" offshore
LEG 3 - Onshore section (Cagliari to Olbia): 300km	Planned 48"	Planned 48"
LEG 4 - Offshore section (Olbia to Castiglione della Pescaia): 220km	32" offshore	2x32" offshore
Scenario TS.B: Expansion of Trans-Mediterranean Pipeline Design Pressure 150 bar-g		
LEG 1 – Hassi R'Mel – Tunisia Onshore:	Existing 48" sufficient 5 Compressor Stations Total Capacity (41 bcm)	Existing 48" sufficient 7 Compressor Stations Total Capacity (49 bcm)
LEG 2 – Hassi R'Mel – Offshore	1x26"	2x26"
Scenario TS.C: Expansion of Medgaz Pipeline Design Pressure 150 bar-g		
LEG 1 – Hassi R'Mel – Tunisia Onshore:	Existing 48" 2 Compressor Stations	Existing 48" 2 Compressor Stations
LEG 2 – Hassi R'Mel – Offshore	1x24"	2x24"

Source: MML Analysis

The transportation costs for these options are discussed in Section 5 below.

4.4.4.1 Moroccan Bottleneck on PDFG Pipeline

It is our understanding from in-country visits that Moroccan demand is expected to grow to 10 bcm by 2030. However, in order to fully meet this demand, there are currently plans under discussion to build a LNG regasification terminal. Assuming this goes ahead, Morocco is not likely to be any bottleneck for the existing MEG/ PDFG pipeline transiting through the country and supplying gas to Spain.

4.4.5 Libya

Libya currently exports 9 bcm/y of natural gas via the Greenstream pipeline; however, the base and high cases suggest that Libya could be exporting up to 40 bcm/y by 2030. We have assumed that the majority of the gas is being produced in the Western fields of Libya.

By 2015, the current infrastructure in Libya will have the capacity to handle approximately 16 bcm of natural gas export, either via LNG or piped-gas to Europe. The capacity of the infrastructure is highlighted in the table below:

Table 4.11: Libya Export Infrastructure to Europe, Current - 2015

Export Infrastructure (to Europe)	Current (bcm/y)	Planned Expansions
LNG	0.7	4.4
Greenstream	11.5	11.5
Total	**12.2**	**15.9**

Source: Stakeholder Consultations and Publicly Available Information

In order to export up to 40 bcm/y from Libya, additional infrastructure will be needed. We have looked at the following scenarios for increased Libyan export:

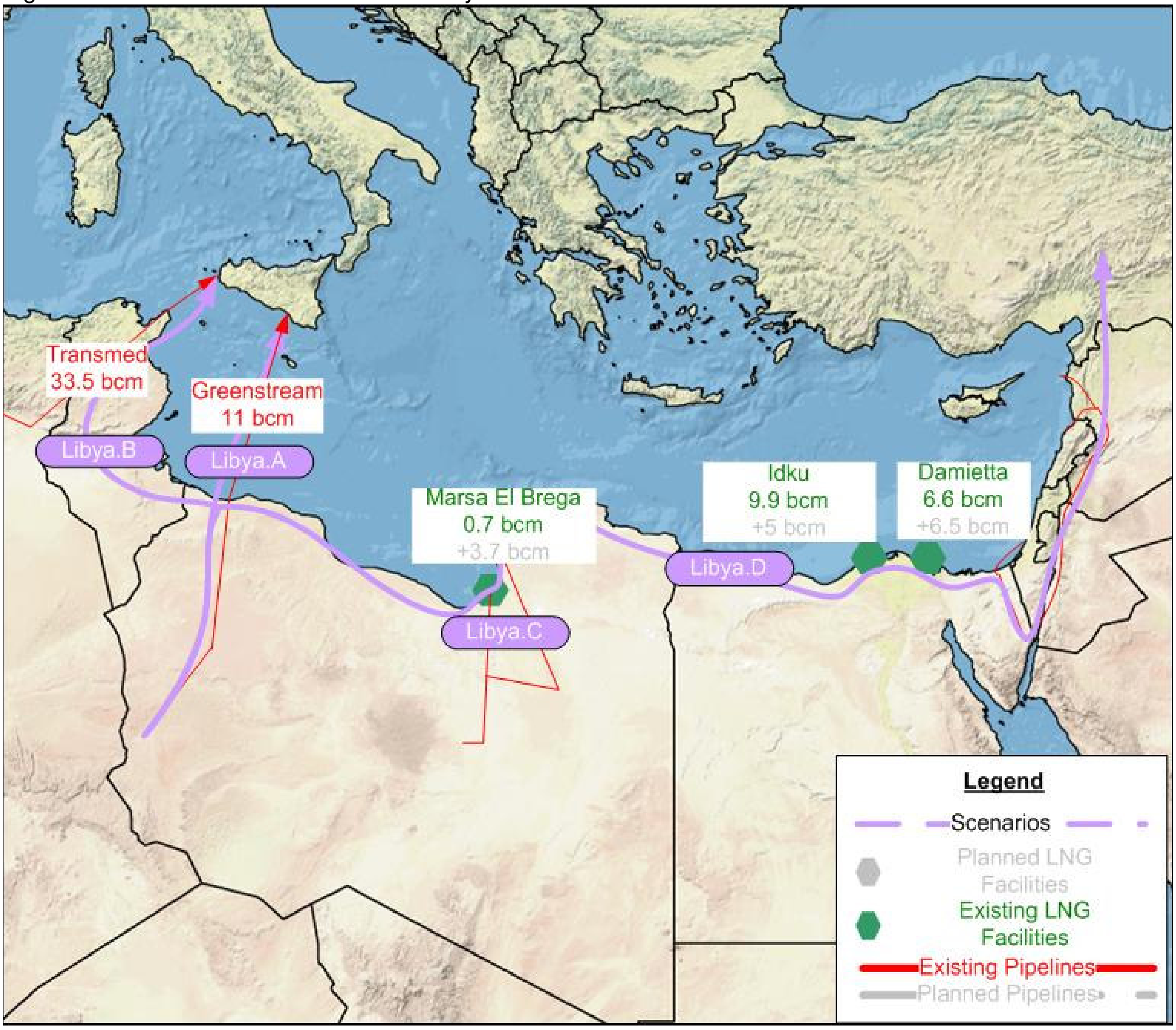
Scenario Libya.A Libya Tunisia Italy Interconnection: In this scenario, we consider the potential interconnection requirement from Libya via Tunisia to Italy (increasing Trans-Mediterranean pipeline system capacity) to complete a South-West Mediterranean gas transmission ring. We have modelled an increase of 12 bcm and 24 bcm flowing through this system giving Libya an export capacity of 28bcm and 40 bcm respectively.

Scenario Libya.B Libya – Italy In this scenario, the capacity of Greenstream is increased by 12bcm and 24 bcm giving Libya an export capacity of 28bcm and 40 bcm respectively.

Scenario Libya.C – Liquefied Natural Gas: In this scenario, the liquefaction capacities are increased from 4.7 bcm to 30 bcm in Mellitah. We have assumed this Greenfield location in order to minimise pipelines from the western fields of Libya to the existing site at Marsa El Brega.

Scenario Libya.D – Libya – Egypt – AGP – Nabucco: In this scenario, consider a pipeline to connect with the Arab Gas Pipeline in Arish, Egypt and onward transmission to Turkey via AGP.

Figure 4.14: Infrastructure Scenarios in Libya



Source: Picture Courtesy of Natural Earth

The following table highlights the technical solutions needed to handle additional throughput capacity from Libya as per the scenarios described above.

Table 4.12: Libya Transportation Corridor Options Summary

Option	Additional 12 bcm	Additional 24 bcm
Libya.A Libya Tunisia Italy Interconnection Design Pressure: 150 bar-g		
LEG 1 – Onshore Distance: 750km	Diameter: 36” Compressors: 2	Diameter: 42” Compressors: 3
LEG 2 – Offshore Distance: 155km	1x20” 1x26”	3x 26”
Libya.B Libya – Italy Interconnection (Greenstream)		
LEG 1 – Onshore Distance: 550 km	Diameter: 32” (existing) Compressors: 4	Diameter: 32” (existing) Compressors: 2
		Diameter: 40” (new) Compressors: 2
LEG 2 – Offshore Distance: 520 km	1x32”	2x32”
Option	**Additional 10 bcm**	**Additional 15 bcm**
Libya.C Libya – Egypt Interconnection (the missing link)		
Leg 1 – Western Fields – Arish, Egypt Distance: 2800 km	Diameter: 42” Compressors: 4	Diameter: 48” Compressors: 5
Leg 2 – Completion of AGP	Please see Table 4.8	Please see Table 4.8
Libya.D Libya – Liquefied Natural Gas in Mellitah		

Source: MML Analysis

The levelised costs are compared in Section 5, where financial feasibility of each of the options is compared and discussed. Discussion on the Italian demand is discussed in Section 3.3.2.

4.4.6 Trans-Mediterranean Ring

An integrated pipeline to connect all potential exporters would involve, as shown in the schematic below:

- Connection of existing Algerian export pipelines via Tunisia to Libya (Mellitah);
- A new pipeline from Mellitah, Libya to Al Arish, Egypt to connect to AGP;
- Additional Compressor Stations to increase export capacity to Nabucco of completed AGP to 15 bcm/y or additional parallel pipeline should the throughput be above 15 bcm/y.

The following table highlights the technical solutions needed to handle additional throughput capacity from Algeria through to Nabucco as per the scenario described above.

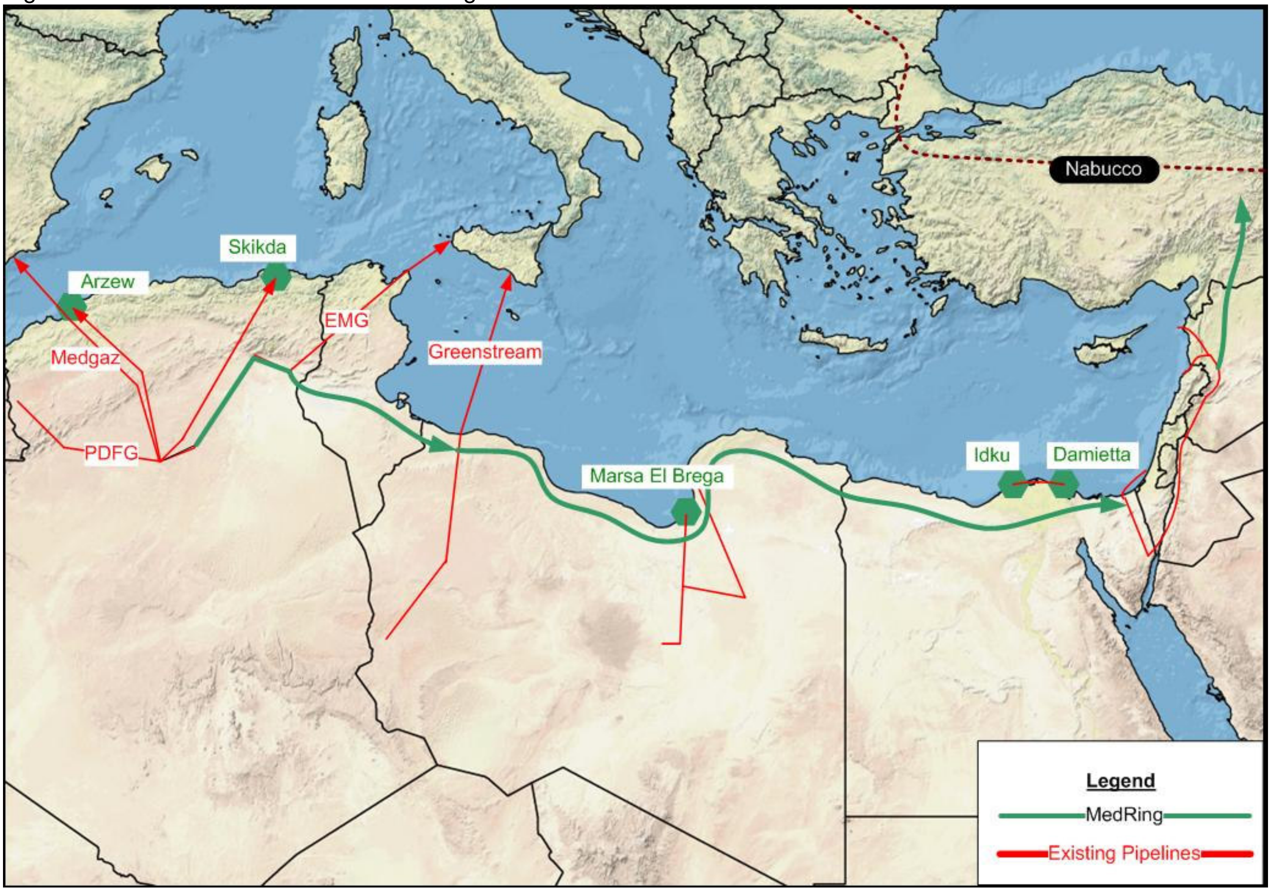
Table 4.13: Completed Trans-Mediterranean Gas Ring

Option	15 bcm
LEG 1 – Hassi R’Mel – Mellitah Length: 1350km	Diameter: 48” Compressors: 3
LEG 2 – Mellitah – Nabucco (via AGP)	As per **Libya.C Libya – Egypt Interconnection (the missing link)**

Source: MML Analysis

The levelised costs are discussed in Section 5.

Figure 4.15: Trans Mediterranean Gas Ring



Source: MML Analysis and Photo Courtesy and Natural Images

4.4.7 Qatar via Saudi Arabia and Iran

During our discussions in Syria and Jordan, the possibility of direct pipeline connections from either Saudi Arabia or Qatar was raised. The Ministry in Syria, in particular, stated that they considered these to be realistic options to increase supplies of gas to the eastern Mediterranean countries as well as for possible export to Europe if the pipeline systems were capable of providing the extra capacity.

It is our opinion that there are significant political obstacles to these possibilities together with potential commercial problems but technically, there should be no real reason why a pipeline system could not deliver the volumes of gas required. We have not attempted to model this possible extension to the infrastructure which is outside of our terms of reference.

5. Financial Analysis

A financial analysis of the project has been carried out, through the development of an Excel spreadsheet model (the Model). The Model is in the form of a discounted cash flow model, which applies a number of key assumptions to generate a forecast for cash flows from and to the project over the development, construction and operating period.

These assumptions include:

- Capital costs, to include all equipment, civil works, development costs and environmental and social mitigation costs where applicable.
- Operating costs over the life of the project, including all fixed and variable costs and environment and social mitigation costs where applicable.
- Typical Project schedules and associated capital cost milestone payment schedules.
- Estimated weighted cost of capital applicable to the Project.

For the purposes of the Model, the Project is defined as solely the gas pipeline and compression stations or the LNG terminals, or a combination there-of. Each project is assumed to stand alone as a legal and financial entity. The boundaries of the Project are therefore defined at the point of delivery to the European Union or Nabucco pipeline for pipeline projects, and LNG liquefaction plant only.

The key output from the financial model is the levelised cost of gas transportation inclusive of taxes. This allows a comparison of each scenario to determine the lowest cost scenario for gas transportation to Europe. The levelised cost is defined as the total discounted cost of operating transportation facilities, including capital and operating costs, over its operating life, divided by the total discounted thousand cubic metres of gas transported. It can be considered as a 'break-even' transportation tariff for pipeline/LNG facilities, at which the required returns to lenders and equity investors are achieved. During this report, we have called these levelised costs either 'transportation costs' for pipelines or 'liquefaction costs' for LNG terminals.

5.1 Model Assumptions

5.1.1 Capital costs

The capital cost assumptions for the options considered in the Model are summarised below. These are 'high-level' costs that have been used in order to compare each scenario.

Table 5.1: Generic Capital Cost Assumptions

Facility	CAPEX (€million)
Compressor Cost (per MW of compression)	€0.72
LNG	
10 bcm	€1,200
15 bcm	€1,680
20 bcm	€2,000
30 bcm	€2,240
Onshore Pipelines	**Total Rate per km (Supply and Install)**
22 inch	€0.792
26 inch	€0.880
30 inch	€1.024

Facility	CAPEX (€million)
36 inch	€1.312
42 inch	€1.760
48 inch	€2.160
56 inch	€2.480
Offshore Pipelines	**Total Rate per km (Supply and Install)**
20 inch	€8.400
22 inch	€9.680
26 inch	€10.720
36 inch	€12.500

As such, the CAPEX for the following scenarios as described in section 4 is highlighted in the tables below.

Table 5.2: CAPEX for Egyptian Scenarios (€ millions)

Flow Rates	Egypt.AGP	Egypt.LNG
10 bcm	€ 2,194.32	€ 1,200.00
15 bcm	€ 2,805.26	€ 1,680.00
15 bcm (opt 2)	€ 3,971.49	
20 bcm	€ 4,235.91	€ 2,000.00
30 bcm	€ 3,987.64	€ 2,240.00

Table 5.3: CAPEX for Iraq Scenarios (€ millions)

Flow Rates	Iraq A.1	Iraq A.2	Iraq B	Iraq C	Iraq D
10 bcm	€ 2,472.97	€ 1,050.57	€ 1,402.58	€ 3,746.74	€ 2,940.81
15 bcm	€ 3,045.82	€ 1,296.01	€ 1,734.34	€ 4,755.86	€ 4,201.77
20 bcm	€ 3,101.76	€ 1,486.19	€ 1,987.87	€ 6,083.03	€ 4,732.06
30 bcm	€ 3,556.28	€ 1,526.32	€ 2,083.35	€ 5,701.16	€ 4,618.66

Table 5.4: CAPEX for Trans-Saharan (€ millions)

Flow Rates	
30 bcm	€ 10,614.48

Table 5.5: CAPEX for Algerian Scenarios (€ millions)

Flow Rates	TS.A	TS.B	TS.C
Offshore CAPEX (EUR Million)			
8 bcm	€ 6,073.20	€ 1,581.00	€ 2,142.00
16 bcm	€ 9,396.40	€ 3,162.00	€ 2,438.10
Onshore CAPEX (EUR Million)			
8 bcm	€ 2,073.60		
16 bcm	€ 2,116.80		€ 1,187.57
24 bcm			€ 1,248.54
41 bcm		€ 2,026.80	
49 bcm		€ 2,098.08	

It should be noted that for the following scenarios, TS.B and TS.C, existing infrastructure with additional compression solutions was used. For this reason, for the purpose of calculating and comparing levelised costs, the actual flow rates were taken into consideration.

Table 5.6: CAPEX for Libyan Scenarios

Flow Rates	Libya.A	Libya.B	Libya.C	Libya.D
Add 12 bcm (Export 28 bcm)	€ 3,979.14	€ 7,210.36		
Add 24 bcm (Export 40 bcm)	€ 6,376.08	€ 14,715.52		
Add 10 bcm			€ 6,309.48	€ 1,200.00
Add 15 bcm (Opt 1)			€ 8,905.46	€ 1,680.00
Add 15 bcm (Opt 2)			€ 10,071.69	

Table 5.7: CAPEX for Mediterranean Gas Ring

Flow Rate	Hassi R'Mel – Mellitah	Mellitah - Nabucco
15 bcm	€2,941.00	€ 8,905.46

5.1.2 Project Schedule

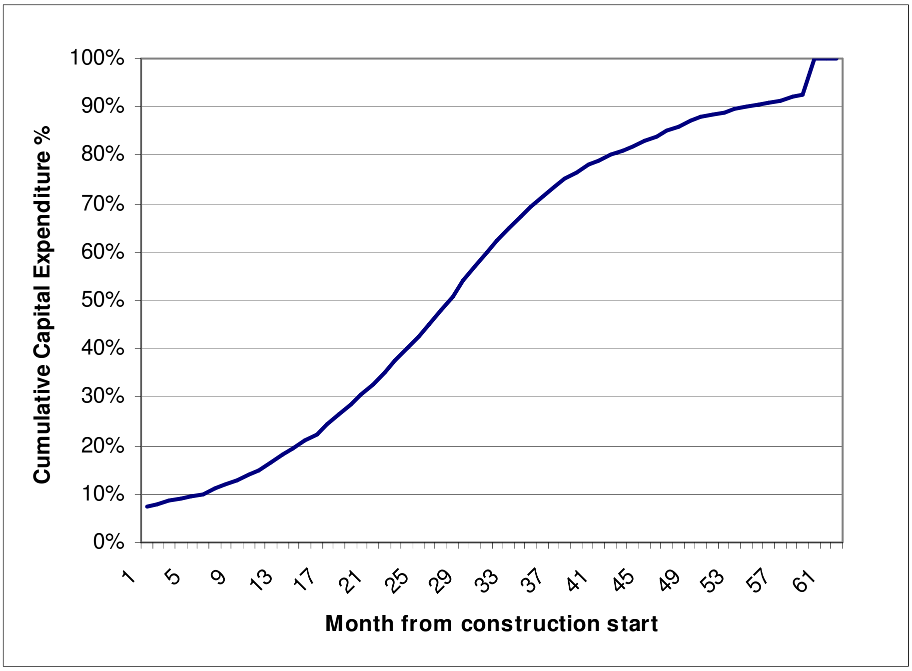
The project schedule assumed in the Model is summarised in Table 5-8.

Table 5-8: Project Schedule

	Site B3
Model Start Date	1 January 2012
Project Development Start	1 January 2013
Development and Construction Period	60 month
Commercial Operation	1 January 2018
Plant Life	30 years
Plant Decommissioning	31 December 2047

Typical implementation and payment milestone schedules for the key items of expenditure have been estimated and applied in the Model, and are summarised in Figure 5.1.

Figure 5.1: Capital Costs Payment Profile



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It has been assumed that net decommissioning costs at the end of the project life will be zero, as demolition costs are offset by the scrap value of equipment. It has also been assumed that no significant additional capital expenditure is required in order to operate the plant for 30 years.

5.1.3 Operating Costs

We have provided a very high-level OPEX to be considered a very high-level rough order of magnitude (ROM) estimate of the potential operating costs. Caution should be exercised in the use of this ROM estimate for investment decisions since it is based on preliminary data

In general, approximately 95% of operating costs are due to compression along the pipeline. In order to estimate the amount gas used for these compressor stations, we modelled the compressors using HYSYS and the following assumptions:

- The discharge pressure is fixed at the design pressure of the pipeline. The various cases are run varying the feed pressure to the compression station. This is repeated for various flow-rates in bcm
- Assumption that the compressor is a gas turbine driven compressor with assumed loss-of-performance allowances and auxiliaries.
- The turbine operates at rated conditions 45℃ and 55% relative humidity
- Gas price at 5$(US)/MMBTU
- Pressure rise limited to a single stage of compression at a station.
- Performance loss over life time is maximised. Probably assuming half of this value would give a fairer assessment. This would give a further 3.5% reduction in power consumption.

Table 5.9: OPEX for Egyptian Scenarios (€ millions)

Flow Rates	Egypt.AGP	Egypt.LNG
10 bcm	€ 52.73	€ 284.00
15 bcm	€ 110.97	€ 404.00
15 bcm (opt 2)	€ 45.88	
20 bcm	€ 79.95	€ 520.00
30 bcm	€ 28.73	€ 720.00

Table 5.10: OPEX for Iraqi Scenarios (€ millions)

Flow Rates	Iraq A.1	Iraq A.2	Iraq B	Iraq C	Iraq D
10 bcm	€ 13.49	€ 7.03	€ 36.44	€ 301.39	€ 34.39
15 bcm	€ 20.89	€ 11.36	€ 40.99	€ 488.90	€ 40.30
20 bcm	€ 48.41	€ 12.00	€ 44.30	€ 561.30	€ 49.78
30 bcm	€ 51.97	€ 31.18	€ 140.55	€ 843.69	€ 86.46

Table 5.11: OPEX for Trans Saharan (to Hassi R'Mel), € millions

Flow Rates	Trans-Saharan
30 bcm	€ 108.71

Table 5.12: OPEX for Algerian Scenarios (€millions)

Flow Rates	TS.A	TS.B	TS.C
8 bcm	€ 42.12		
16 bcm	€ 84.24		€ 3.05
24 bcm			€ 33.53
41 bcm		€ 101.97	
49 bcm		€ 154.37	

Table 5.13: OPEX for Libyan Scenarios (€ millions)

Flow Rates	Libya.A	Libya.B	Libya.C	Libya.D
Add 12 bcm (Export 28 bcm)	€ 15.84	€ 47.11		
Add 24 bcm (Export 40 bcm)	€ 35.81	€ 47.11		
Add 10 bcm			€ 47.60	€ 284.00
Add 15 bcm			€ 135.78	€ 404.00
Add 15 bcm (Opt 2)			€ 70.69	

Table 5.14: OPEX for Mediterranean Gas Ring

Flow Raet	Hassi R'Mel – Mellitah	Mellitah - Nabucco
15 bcm	€11.5	€ 135.78

5.2 Economic Assumptions

A key assumption in a cash flow model is the discount rate chosen. The discount rate reflects the time value of money and, as such, will need to reflect a number of factors:

- The proposed financing structure of the project, i.e. the debt to equity ratio and the manner in which this changes over the lifetime of the project.
- The cost of borrowing for the debt component, which will depend upon both market conditions, the perceived risk of the project and the debt to equity ratio.
- The rate of return required by investors, which will depend upon similar factors to the cost of borrowing, but will tend to be higher as the equity investment carries a higher risk.

Due to the early stage of the project, it is not possible to determine these factors with any degree of accuracy. However, it is possible to form a broad view as to an appropriate discount rate, based on experience of other projects, and a high-level assessment of the factors outlined above. Following this approach, the following table highlights MMLs approach to debt and equity assumptions.

Table 5.15: Debt and Equity Assumptions

Debt & Equity Assumptions	Units	Assumptions
Loan Financing	%	80%
Equity Financing	%	20%
Loan Interest Rate	annual %	7.0%
Real Post-tax Required ROE	%	12%
Inflation	%	2.0%
Nominal Post-tax Required ROE	%	14.0%
WACC	%	8.4%

Additionally, the following taxation assumptions have been made.

Table 5.16: Taxation Assumptions

Taxation Assumptions		
Corporation Tax	%	30.0%
Tax depreciation	% p.a.	3.3%
Accounting Depreciation	% p.a.	3.3%

5.3 Model Results

The primary indicator used to assess the potential scenarios is the levelised cost per thousand cubic metres of gas transported. The levelised cost is defined as the total discounted cost of operating transportation facilities, including capital and operating costs, over its operating life, divided by the total discounted thousand cubic metres of gas transported. It can be considered as a ‘break-even’ transportation tariff for pipeline/LNG facilities, at which the required returns to lenders and equity investors are achieved.

The levelised cost measure allows the lowest cost method of constructing and operating the plant to be identified. It can be considered as the average tariff that must be charged if the plant is to achieve an FIRR equal to the discount rate, or alternatively a zero Net Present Value (NPV) using the given discount rate. It should be noted that for existing pipelines, we used an equivalent levelised cost to them being brand new, as these pipelines would still incur transportation costs.

The levelised costs for each scenario are shown below.

5.3.1 Egypt

Table 5.17: Levelised Costs of Egyptian Scenarios

Levelised Costs (€/'000m3)	Egypt.AGP	Egypt.LNG
10 bcm	€ 37.23	€ 57.99
15 bcm	€ 36.02	€ 54.75
15 bcm (opt 2)	€ 40.06	
20 bcm	€ 34.33	€ 51.76
30 bcm	€ 18.85	€ 46.13
Entrance to European Transmission System	Nabucco	LNG at Point of Export

For Egyptian gas travelling to Europe, the levelised costs in order to complete the AGP in comparison to LNG. However, the transport costs from the tie-in point of Nabucco versus to Europe have not been included in this analysis. Should up to 15 bcm/y travel via the AGP, the existing pipeline to Homs, Syria can be used with additional compressor stations every 97.5km. Although this increases the OPEX dramatically, it still results in a lower levelised cost that building a parallel pipeline alongside.

5.3.2 Iraq

Table 5.18: Levelised Costs of Iraqi Scenarios

Levelised Costs (€/'000m3)	Iraq A.1	Iraq A.2	Iraq B	Iraq C	Iraq D
10 bcm	€ 35.19	€ 15.14	€ 20.41	€ 84.40	€ 44.55
15 bcm	€ 29.31	€ 12.72	€ 16.45	€ 84.03	€ 41.57
20 bcm	€ 32.52	€ 9.60	€ 12.59	€ 69.78	€ 35.44
30 bcm	€ 18.47	€ 8.36	€ 14.02	€ 63.76	€ 24.92
Point of Entry	Nabucco	Nabucco	Nabucco	LNG at Alexandria	Nabucco

For Iraqi gas travelling to Europe, all options except for Scenario Iraq.C have economical levelised costs. Political implications of gas sources in Iraq would need to be further discussed with Ministry of Oil. There is a large uncertainty of the availability of natural gas that will be available in Iraq by 2030. We would recommend a conservative approach (larger pipeline diameters with less compression) that can be scaled up as Iraq becomes a more prominent exporter in the region.

5.3.3 Algeria

Table 5.19: Levelised Costs for Trans-Saharan Pipeline

Flow Rate	Levelised Costs (€/'000m3)
30 bcm	€ 51.92
Point of Entry	Hassi R'Mel - Algeria

Levelised costs of the trans-Saharan alone are €51.92/'000m^3. In addition to the costs of transportation from Hassi R'mel to either Italy or Spain suggest that LNG directly from Nigeria could be a better option.

The following levelised costs are shown for each scenario in Algeria (i.e. travelling from Hassi R'Mel to Italy or Spain.

Table 5.20: Levelised Costs for Algerian Scenarios (€/'000m^3)

Flow Rates	TS.A	TS.B	TS.C
8 bcm (+trans-Saharan)	€ 144.48 (+€ 51.92)	€ 36.83 (+€ 51.92)	€ 46.20 (+€ 51.92)
16 bcm (+trans-Saharan)	€ 104.37 (+€ 51.92)	€ 36.92 (+€ 51.92)	€ 29.50 (+€ 51.92)
Point of Entry	Italy	Italy	Spain

As seen above, GALSI pipeline is not economically feasible; especially should the gas originate from Algeria. Although both MEDGAZ and Transmed are more feasible, the levelised costs of LNG directly from Nigeria would likely make more economic sense for European Union Imports.

5.3.4 Libya

The levelised costs for all Libyan Scenarios are shown in the table below.

Table 5.21: Levelised Costs for Libyan Scenarios (€/'000m^3)

Flow Rates	Libya.A	Libya.B	Libya.C	Libya.D
Add 12 bcm (Export 28 bcm)	€ 46.47	€ 85.84		
Add 24 bcm (Export 40 bcm)	€ 37.87	€ 86.10		
Add 10 bcm			€ 76.85	€ 57.99
Add 15 bcm			€ 57.59	€ 54.75
Add 15 bcm (Opt 2)			€ 72.82	

Should Libya build to connect with the Transmed system in Tunisia, there is a significantly lower levelised cost than Greenstream due to offshore distances. Although constructing a pipeline from Libya to Arish through AGP is technical difficult, the levelised costs are less than Greenstream. However, the preferred options (financially) appear to be either Libya.A (Transmed) or LNG at Mellitah.

5.3.5 Mediterranean Gas Ring

The levelised costs for the Mediterranean Gas Ring are shown in the table below.

Table 5.22: Levelised Costs for the Mediterranean Gas Ring (€/'000m^3)

Flow Rate	Hassi R'Mel – Mellitah	Mellitah - Nabucco
15 bcm	€27.12	€ 57.59

As seen above, to move gas from Hassi R'Mel to Nabucco via Libya and the Arab Gas Pipeline has a high levelised cost of €84.71/'000m^3. Although this could prove to be marginally viable, there are other options with much lower levelised costs. In our view, it is not imperative to complete the Mediterranean Gas ring.

6. Doing Business

6.1 Algeria

In 2005 the Algerian parliament adopted a new hydrocarbon law (loi n°05-07 du 28 avril 2005 relative aux hydrocarbures, the '2005 Hydrocarbons Law') which sought to improve transparency in contract awards, simplify the legal and tax regime and establish a liberalised market by ending Sonatrach's monopoly, and thus allowing more involvement from IOCs. However increasing resource nationalism led to a reversal of initial market friendly reforms in 2006, and consequently the market liberalisation has been almost entirely abandoned. The institutional framework and the new contractual regime remained.

The gas transport network supplying the national market is a monopoly managed by GRTG SPA, a subsidiary of the state owned company, Sonelgaz. Transportation activities for gas export require a concession from the Ministry of Energy and Mining which can only be awarded to Sonatrach or a local company which is at least 51% owned by Sonatrach. Non concession holders can have access to gas transportation facilities on the grounds of a Third Party Access (TPA) right. There is no specific regulatory framework relating to LNG facilities. However, the Hydrocarbon Law allows authorised entities to undertake "refining and transformation activities", and considers gas liquefaction as a form of hydrocarbon "transformation".

6.2 Tunisia

The Ministry of Industry & Technology regulates the oil and gas industry in Tunisia. The state owned company, L'Enterprise Tunisienne d'Activites Petrolieres (ETAP), is responsible for the management of oil and gas exploration and production activities. The national electricity and gas utility, Société Tunisienne de l'Electricité et du Gaz (STEG), is responsible for management of the gas network infrastructure.

Tunisia's stable political and business environment makes planning and long term investment easier. Tunisia has an open policy towards IOCs, with favourable terms including flexible joint venture or production sharing agreements, progressive taxation with priority given to investors to recover costs.

6.3 Libya

In March this year the head of the state owned National Oil Corporation (NOC) announced that the Libyan government will be introducing a new hydrocarbon law as part of its first stage of oil and gas sector reforms to improve productivity and efficiency. The original hydrocarbon law dated back to 1955 and even though it had been amended, a replacement was needed to bring it up to date with the modern energy industry, particularly as it did not include for natural gas.

Following the lifting of UN sanctions and restoration of full diplomatic relations with the West, Libya reopened its markets to foreign investments including its oil and gas sector which is still the main driver of Libyan economy. Libya has begun to respond to international, political and economic pressure, adopting market orientated reforms and introducing initial liberalization of the socialist-oriented economy.

6.4 Egypt

The Egyptian Holding Company for Natural Gas (EGAS), owned by the Egyptian General Petroleum Corporation (EGPC), regulates the development of natural gas resources under the supervision of the Ministry of Petroleum. EGAS is responsible for planning and developing upstream and downstream gas projects, including gas transmission and LNG. The Ganoub El Wadi Holding Petroleum Company (GANOUPE) has oil and gas rights below line 28 latitude.

Private investor(s) need to agree concession agreements for oil and gas exploration and production between EGAS, EGPC or GABOUPE on the one hand, and the Egyptian government on the other. Under the Egyptian constitution, foreign companies are required to set aside a third of any reserves discovered to supply the domestic market, and a third is to be kept in the ground as strategic reserves for future generations, leaving only a third to be sold on the international gas market.

The concessionaire is responsible for constructing pipelines from the development area to the nearest access point in the national grid, or to an export point. Under the supervision of EGAS, transportation pipelines and associated infrastructures are constructed and operated the Petroleum Pipelines Company (PPC) and other licensed companies, who are owned by the petroleum sector. The terms upon which natural gas is transported are regulated by EGAS and EGPC. LNG facilities must be licensed by EGPC. There are no specific price restrictions on LNG, but in general the restrictions applicable to natural gas are also applicable to LNG.

6.5 Jordan

Under the supervision of The Ministry of Energy and Mineral Resources (MEMR), the Natural Resources Authority (NRA) is responsible for all activities related to the exploration and development of minerals and hydrocarbon deposits, and is entitled to lease rights for the exploration and exploitation of oil and gas.

The Jordanian National Petroleum Company (JNPC) was established for the exploration and exploitation of oil and gas. Its objective is to negotiate joint ventures with international companies for the generation of investments, as well as to ensure the flow of new equipment and technology.

MEMR relies on private companies to build and operate Jordan’s gas infrastructure, such as the Arab Gas Pipeline. The Al Fajr Company was established in 2003 with responsibility for the second phase of the Arab Gas Pipeline on a Build Own Operate Transfer (BOOT) basis over 30 years.

6.6 Syria

The structure of Syria’s oil and gas sector has changed relatively little since 1973/74. All oil and gas revenues accrue directly to the government. Upstream and downstream gas sectors are controlled by the Ministry of Petroleum and Mineral Resources (MPMR) and state owned companies. The Syrian Petroleum Company (SPC) owns the oil and gas reserves on behalf of the MPMR, and until recently it was also the owner and operator of all pipelines. All gas found in oil E&P blocks in Syria is handled by the Syrian Gas Company (SGC).

There are signs that the situation is slowing improving for Syria; in June this year, the US appointed its first ambassador to Damascus for four years. Saudi Arabia is also resuming full diplomatic relations – an important marker for Syria's rehabilitation within the Arab world. IOCs still face bureaucracy in Syria’s petroleum industry but the situation has been improving as Syria’s petroleum companies gain expertise to deal with international capital. However, unappealing contract terms are also undermining efforts to boost investment, as are the ever-present threat of new US sanctions.