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Outlook for Oil and Gas in Southern and Eastern Mediterranean Countries

Manfred Hafner, Simone Tagliapietra and El Habib El Elandaloussi

MEDPRO Technical Report No. 18/October 2012

Abstract

The aim of this report is to elaborate the MEDPRO Energy Reference Scenario for oil and gas supply and demand up to 2030 for southern and eastern Mediterranean countries. The report gives an assessment of

- oil and gas reserves by country;
- oil and gas production, domestic demand and export scenarios by country; and
- the existing and planned infrastructure for oil and gas exports.

Finally, the report presents some insights on the future role of the Mediterranean as an oil and gas transit region.

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Outlook for Oil and Gas in Southern and Eastern Mediterranean Countries

Manfred Hafner, Simone Tagliapietra and El Habib El Elandaloussi*

MEDPRO Technical Report No. 18/October 2012

Executive Summary

The aim of this report, finalised in early 2012 and mainly based on research carried out in 2011, is to elaborate the MEDPRO Energy Reference Scenario for oil and gas supply and demand up to 2030, by country and sector, for southern and eastern Mediterranean countries. This report is thus complementary to MEDPRO Technical Report No. 16 on the *Outlook for Electricity and Renewable Energy in Southern and Eastern Mediterranean Countries*.

The present report assesses oil and gas reserves, and develops detailed oil and gas development scenarios up to 2030 for production potential, the evolution of domestic demand by sector and the export prospects for southern and eastern Mediterranean countries. In addition, the oil and gas export scenarios are based on an assessment of the existing and planned infrastructure for oil and gas exports. Finally, the report also presents some insights on the future role of the Mediterranean as an oil and gas transit region.

The MEDPRO Energy Reference Scenario developed for this report is based upon a critical assessment of the ongoing and committed energy projects and official plans, targets and objectives officially announced by the countries under study, as well as an estimation of production capacity based upon reserve potential and investment capabilities. The MEDPRO Energy Reference Scenario thus uses a 'bottom-up' approach and a disaggregation by subsector and source of energy. The data come mainly from national sources (government ministries, energy utilities and other energy agencies) and international organisations such as UNEP Plan Bleu, with which the MEDPRO team has closely coordinated in developing this Reference Scenario. Some of the information published in this report has also been obtained through confidential contacts with experts, who agreed to provide it as part of this research in exchange for being granted anonymity. The MEDPRO Energy Reference Scenario was developed in 2011, in the midst of the Arab Spring; at the time of finalising this report it is still too early to clearly understand what impact these uprisings will have on the energy development scenarios.

In this report we divide the Mediterranean basin into two areas (e.g. Figure 1):

- northern Mediterranean countries (NMCs), composed of EU countries (Cyprus, France, Greece, Italy, Malta, Portugal, Slovenia and Spain) and non-EU Mediterranean countries (Albania, Bosnia and Herzegovina, Croatia, Macedonia and Serbia); and
- 11 southern and eastern Mediterranean countries (MED-11), comprising Algeria, Egypt, Libya, Morocco, Tunisia and Turkey along with 5 other south-eastern Mediterranean countries (collectively referred to as OSE), which are Israel, Jordan, Lebanon, Palestine and Syria.

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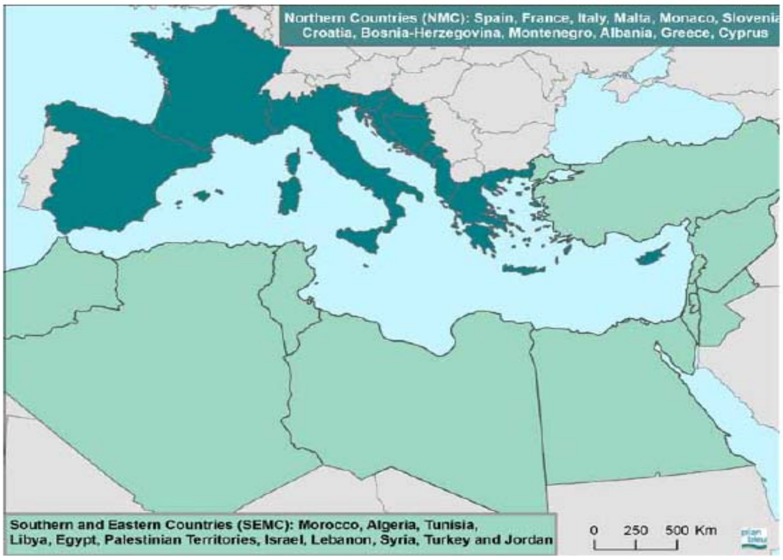
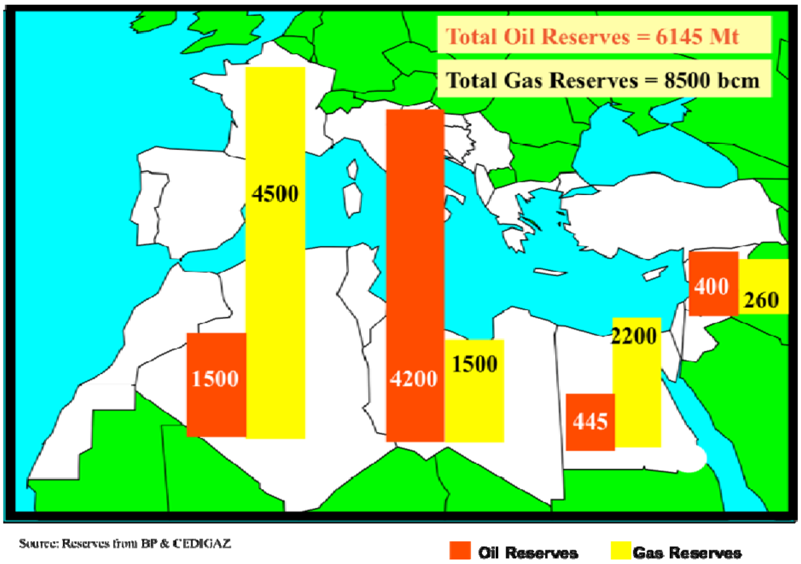
Figure 1. Mediterranean Basin



Source: El Elandaloussi (2010).

The MED-11 area has almost 5% of the world's proven oil reserves (about 6,145 Mt) and nearly 5% of the world's proven gas reserves (about 8,500 bcm), accounting for most of the hydrocarbon reserves of the overall Mediterranean region.[1] Most of these reserves are located in three North African countries: Libya, Algeria and Egypt (Figure 2).

Figure 2. MED-11 oil and gas reserves



Sources: Own elaborations based on data from BP and Cedigaz.

Currently, the MED-11 area accounts for 31% of the Mediterranean region's overall energy demand,[2] a level set to rise to 47% by 2030 according to the MEDPRO Energy Reference Scenario – growing by an average annual rate of 3.3% between 2009 and 2030 (e.g. Table 1).

[1] Data sources: *Statistical Review of World Energy*, BP (2011) and Cedigaz.

[2] Data source: BP (2011).

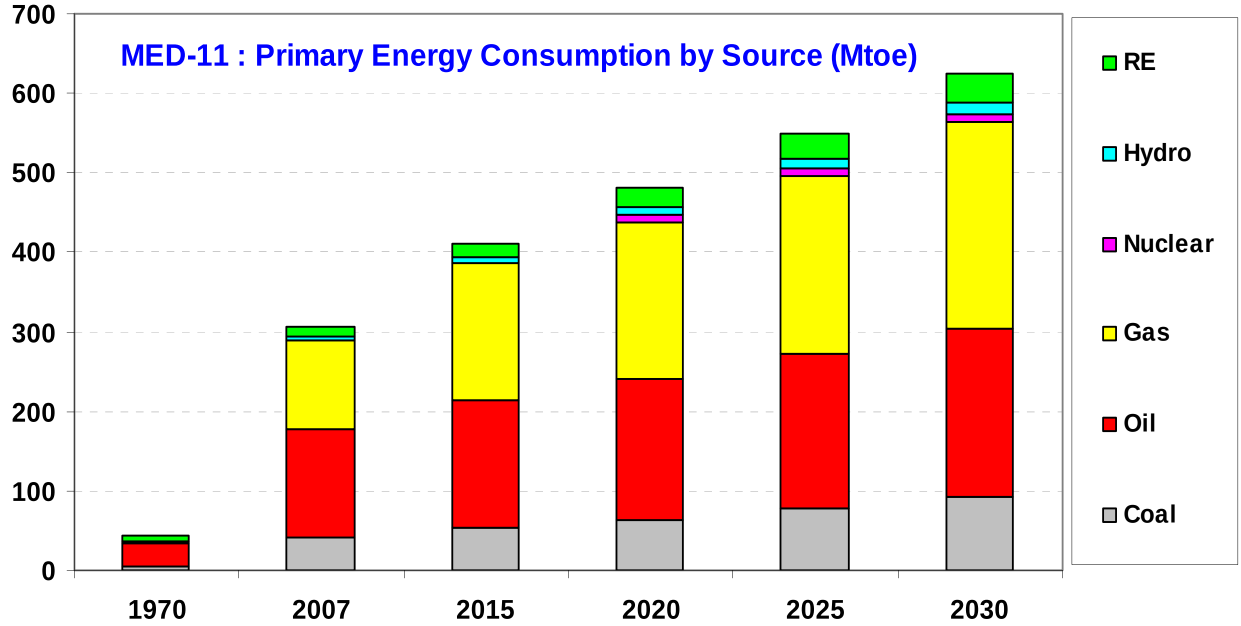
Table 1. Primary energy demand in the MED-11 (Mtoe)

	1970	2009	2015	2020	2025	2030	Average annual growth rate (%) 1970–2009	2009–30
Coal	5	43	53	67	79	95	5,5	3,3
Oil	29	139	167	185	200	214	4,1	3,9
Natural gas	2	114	154	177	207	239	11,0	2,1
Nuclear	0	0	0	3	7	15	-	3,6
Hydro	1	5	8	10	13	17	4,4	-
Renewable	7	10	13	19	24	29	0,7	6,0
MED-11	**45**	**311**	**395**	**462**	**529**	**609**	**5,1**	**3,3**

Source: Own elaborations for the MEDPRO Energy Reference Scenario.

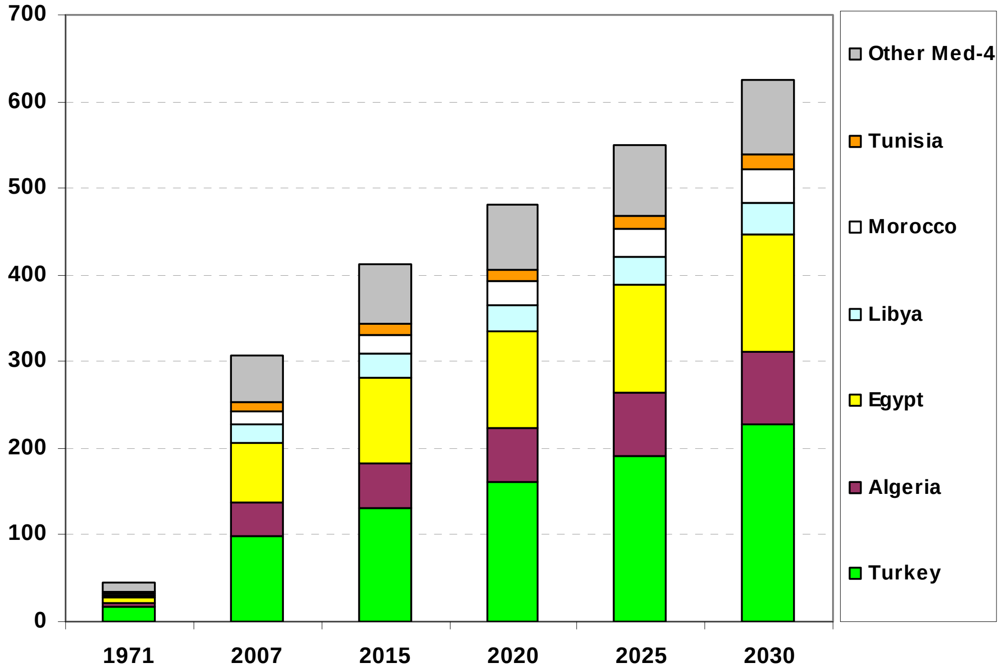
In 2030, hydrocarbons are expected to remain the dominant source of energy in the MED-11 primary energy mix (e.g. Figures 3 and 4), accounting for 90% (a level slightly lower than the 95% recorded in 2009). Also, if MED-11 oil demand is likely to increase – particularly because of an expanding transportation sector – natural gas is set to overtake oil as the dominant fuel by 2030 in the MEDPRO Energy Reference Scenario. In fact, natural gas is expected to rise significantly in the primary energy mix over the next two decades, reaching 38% of the MED-11 energy demand by 2030.

Figure 3. MED-11 primary energy consumption (Mtoe)



Source: Own elaborations for the MEDPRO Energy Reference Scenario.

Figure 4. MED-11 primary energy consumption by country (Mtoe)



Source: Own elaborations for the MEDPRO Energy Reference Scenario.

Encouraged by incentives and proactive policies (national solar plans as part of the master plan drawn by the Mediterranean Solar Plan), in some MED-11 countries the renewable energy sources (including hydro) are expected to experience strong growth by 2030. The MEDPRO Energy Reference Scenario estimates that renewable energy sources are set to grow on average by 5.6% per year, reaching 8-10% of the MED-11 energy mix by 2030.[3]

The share of nuclear energy in the overall Mediterranean energy mix slightly decreased over the last two decades, from 14% in 1990 to 12% in 2009[4] (after a considerable expansion during the 1970s, largely due to massive nuclear development in France) and is set to remain at this level over the next decades. At present, no MED-11 country has a nuclear power plant. Plans for several new nuclear power plants have been announced in Turkey and Egypt, however. If these programmes are implemented, nuclear power could come online only after 2020 in the case of Turkey and after 2025 in the case of Egypt. Still, is worth considering that particularly after the recent events in Fukushima, the governments of MED-11 countries may delay their plans to develop nuclear power production capacity.

The MEDPRO Energy Reference Scenario suggests that the largest part of the increase in Mediterranean hydrocarbon production will occur in MED-11 countries (primarily in Algeria, Libya, Egypt and Syria). Since 1970, MED-11 fossil fuel production has increased at an annual average rate of 4.4%, reaching 400 Mtoe in 2009.[5] Looking towards the future, this trend is expected to continue, to reach 611 Mtoe by 2030. In the MEDPRO Reference Scenario, MED-11 oil production will rise from 249 Mtoe in 2009 to 318 Mtoe in 2030, while natural gas production will grow even faster, from 150 Mtoe in 2009 to 294 Mtoe in 2030 (e.g. Table 2).

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[3] For 1a detailed analysis, refer to Hafner et al. (2012).

[4] Data source: BP (2011).

[5] Ibid.

Table 2. Fossil fuel production in the MED-11 (Mtoe)

	Oil 2009	Gas 2009	Total 2009	Oil 2030	Gas 2030	Total 2030
Algeria	97	74	**171**	93	146	**238**
Egypt	35	52	**87**	32	82	**114**
Libya	90	16	**106**	167	35	**201**
Morocco	0	0	**0**	0	0	**0**
Tunisia	6	3	**9**	4	3	**8**
Turkey	2	0	**2**	0	0	**0**
OSE	19	5	**24**	22	28	**50**
MED-11	**249**	**150**	**400**	**318**	**294**	**611**

Source: Own elaborations for the MEDPRO Energy Reference Scenario.

Meanwhile, according to the MEDPRO Energy Reference Scenario, MED-11 gas demand will grow from 114 Mtoe in 2009 to 177 Mtoe in 2020 and to 239 Mtoe in 2030 (e.g. Table 3). In 2009, Egypt was the primary gas consumer of the region, followed by Turkey, Algeria and Libya. By 2030, Turkey's gas consumption will have dramatically increased, becoming the top gas-consuming country in the region at 71 Mtoe (from 30 Mtoe in 2009), followed by Egypt (54 Mtoe), Algeria (53 Mtoe) and Libya (16 Mtoe).

Table 3. MED-11 Reference Scenario for natural gas

	Natural gas Production/Imports–Exports/Demand					
(Mtoe)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–30 (%)**
Gas production	150	184	227	261	294	3,2
Gas net imports/exports	-38	-30	-50	-54	-55	1,8
Gas demand	114	154	177	207	239	3,6
Gas inputs in power plants	-58	-78	-90	-105	-121	3,6
Gas in other transformation & losses	-13	-13	-13	-14	-15	0,9
Gas final consumption	43	63	74	88	103	4,3
Transport	*2*	*3*	*4*	*5*	*6*	*5,0*
Residential	*15*	*28*	*33*	*39*	*45*	*5,3*
Industry	*22*	*27*	*30*	*35*	*40*	*2,9*
Other consumption	*3*	*5*	*7*	*8*	*11*	*6,0*
Gas elect. output (TWh)	291	409	464	562	670	4,1

Source: Own elaborations for the MEDPRO Energy Reference Scenario.

In the MEDPRO Energy Reference Scenario, MED-11 total final consumption of oil will grow from 105 Mtoe in 2009 to 144 Mtoe in 2020 and to 168 Mtoe in 2030 (e.g. Table 4). Over the period considered, Turkey will remain the largest oil consumer in the MED-11 (49 Mtoe in 2030, from 29 Mtoe in 2009), followed by Egypt (37 Mtoe in 2030 from 24 Mtoe in 2009), Algeria (20 Mtoe in 2030 from 11 Mtoe in 2009) and Morocco (19 Mtoe in 2030 from 9 Mtoe in 2009).

Table 4. MED-11 Reference Scenario for oil

	Oil Production/Imports–Exports/Demand					
(Mtoe)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–30 (%)**
Oil production	249,4	277,2	308,6	318,5	317,7	1,2
Net imports/exports	-110,5	-110,0	-123,2	-118,2	-103,4	-0,3
Total oil supplies	138,9	167,1	185,5	200,4	214,3	2,1
Electricity plants (inputs)	-22,2	-28,8	-32,0	-34,6	-36,6	2,4
Other transformation & losses	-8,4	-8,7	-9,0	-9,3	-9,6	0,6
Total final consumption	105,2	129,6	144,4	156,5	168,1	2,3
Transport	*54,2*	*65,7*	*73,1*	*80,1*	*87,3*	*2,3*
Residential	*16,3*	*19,7*	*21,5*	*22,3*	*23,0*	*1,6*
Industry	*15,9*	*21,5*	*23,4*	*24,2*	*24,1*	*2,0*
Other consumption	*19,8*	*22,7*	*26,4*	*30,0*	*33,8*	*2,6*
Electricity output (TWh)	103	121	136	147	155	2,0
Installed capacity (oil) (MW)	10.115	13.988	15.982	17.994	19.500	3,2

Source: Own elaborations for the MEDPRO Energy Reference Scenario.

The MEDPRO Energy Reference Scenario estimates that the power generation of the overall Mediterranean region is set to reach 3,353 TWh by 2030 (with an average, annual growth rate of 2.8%), while MED-11 power generation is expected to expand from 556 TWh in 2009 to 1,501 TWh in 2030 (with an average, annual growth rate of 4.8%) (e.g. Table 5). The power generation mix of the Mediterranean region is heterogeneous and presents significant differences between the NMCs and the MED-11 countries. The MED-11 power generation mix is mainly based on hydrocarbons, with natural gas accounting for the largest share (45%). In the MEDPRO Energy Reference Scenario, renewable energy sources are expected to grow substantially in the MED-11 power generation mix, increasing from 61 TWh in 2009 (11% of the power generation mix) to 354 TWh in 2030 (24% of the power generation mix).

Table 5. Reference Scenario for power generation in the MED-11 in 2009–30 (TWh)

	2009	**2015**	**2020**	**2025**	**2030**	**Additional (2009–30)**
Coal	101	118	182	221	263	162
Oil	103	121	136	147	155	52
Gas	291	409	464	562	670	379
Nuclear	0	0	13	27	59	59
Hydro	57	93	118	152	196	139
Renewable energy (RE)	4	22	67	109	158	154
Elec. output (TWh)	*556*	*763*	*980*	*1218*	*1501*	*945*
of which RE+hydro	61	115	185	261	354	293

Source: Own elaborations for the MEDPRO Energy Reference Scenario.

Again according to the MEDPRO Energy Reference Scenario, by 2030 more than 193 GW of electricity capacity will need to be added to the MED-11 energy system. About three-quarters of this additional power is likely to come from gas-fired power plants (+72 GW) and power plants based on renewable energy (+71 GW), with the remainder coming from coal power plants (+27 GW), oil power plants (+13 GW) and nuclear power plants (+9 GW). Obviously the need for new power plants over the next 20-year period is even greater, given that some existing power plants will need to be replaced (e.g. Table 6).

Table 6. Reference Scenario for power generation in the MED-11 for 2009–30 (GW)

	2009	2015	2020	2025	2030	Additional (2009–30)
Coal	17,1	21,4	26,5	33,9	43,8	26,7
Oil	22,4	28,1	31,1	34,1	35,7	13,2
Gas	56,8	74,7	87,2	107,5	129,2	72,4
Nuclear	-	-	1,8	3,7	9,2	9,2
Hydro	20,6	23,6	28,6	31,3	36,3	15,7
RE	1,9	8,2	25,1	40,4	57,6	55,7
Installed cap. (GW)	*118,8*	*156,1*	*200,4*	*251,1*	*311,9*	*193*
of which RE+hydro	22,5	31,8	53,6	71,7	93,9	71,4

Source: Own elaborations for the MEDPRO Energy Reference Scenario.

Mediterranean countries currently import half of their oil and gas requirements,[6] and continue to depend on these imports to cover growing domestic demand. The infrastructure for both oil and gas (ranging from pipelines to liquefied natural gas (LNG) terminals, and from oil tankers to oil export terminals) is significantly expanding across the region. Considering that the overall potential for MED-11 oil and gas exports is projected to rise from 236 Mtoe in 2009 to 339 Mtoe in 2030, it is possible to realise the great prospects within the Mediterranean region for energy cooperation between oil- and gas-producing countries on the one hand and oil- and gas-consuming countries on the other. Concerning gas, Algeria, Egypt and Libya are – and will remain – net gas exporters. Israel may have the potential to become a new gas exporter in the region, if the recent announcements of gas reserve discoveries are confirmed.

The MEDPRO Energy Reference Scenario expects the potential gas exports by the MED-11 to increase from 72 Mtoe in 2009 to about 130 Mtoe in 2030. Oil exports by the MED-11 are projected to increase from 166 Mtoe in 2009 to 203 Mtoe in 2030, with Egypt having become a net oil importer in 2010 and thus leaving only Algeria and Libya as net oil exporters in the region (e.g. Table 7).

Table 7. Exports of fossil fuels by MED-11 (Mtoe)

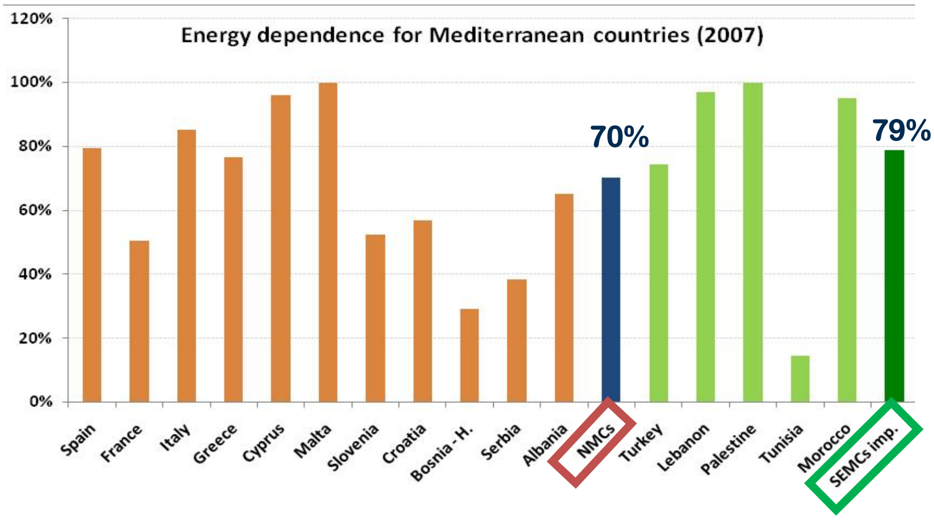
	Oil 2009	Gas 2009	Total 2009	Oil 2030	Gas 2030	Total 2030
Algeria	85	48	**133**	71	88	**159**
Egypt	3	16	**19**	-18	22	**4**
Libya	77	8	**85**	150	17	**167**
Tunisia	1	-	**1**	-	-	-
OSE	-	-	-	-	3	**3**
MED-11	**166**	**72**	**238**	**203**	**130**	**333**
Share (%)	70	30	**100**	61	39	**100**

Source: Own elaborations for the MEDPRO Energy Reference Scenario.

[6] Data source: BP (2011).

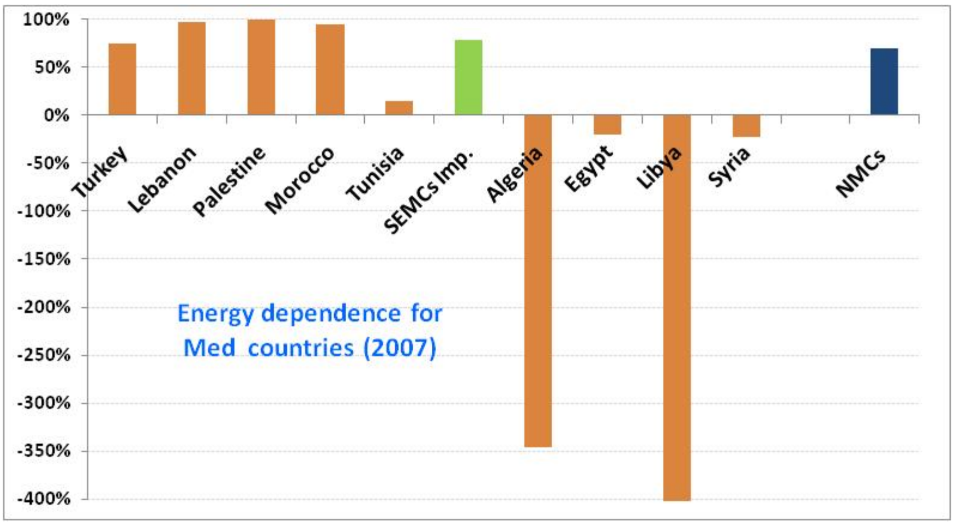
The overall Mediterranean region is dependent on fossil fuels: its imports exceed its exports (e.g. Figure 5). Yet while all northern Mediterranean countries are net importers, the situation varies among the MED-11 countries, with large exports from such producer countries as Algeria, Libya and Egypt and heavy reliance on fossil fuel imports in all other countries (e.g. Figure 6).

Figure 5. Energy dependence of Mediterranean countries



Note: SEMCs = southern and eastern Mediterranean countries; NMCs = northern Mediterranean countries.
Source: Own elaborations based on data from the International Energy Agency (IEA).

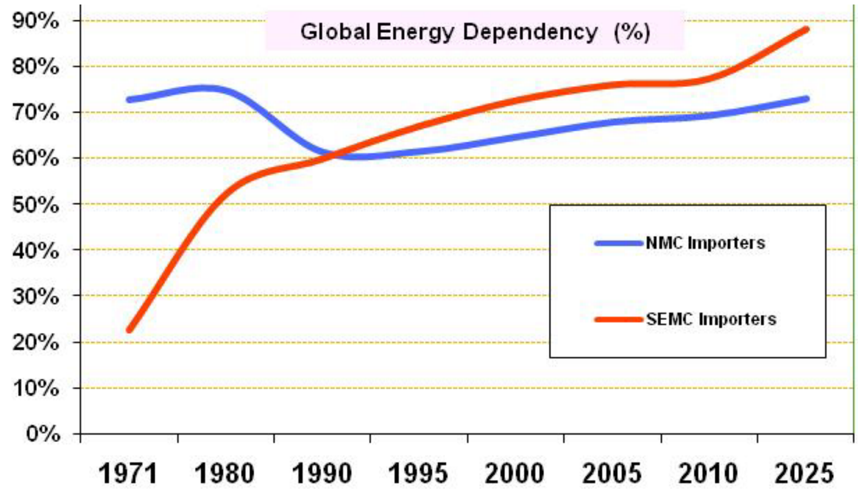
Figure 6. Energy dependence of MED-11 countries



Note: SEMCs = southern and eastern Mediterranean countries; NMCs = northern Mediterranean countries.
Source: Own elaborations based on data from the IEA.

Moreover, energy dependency in the MED-11 countries that are net energy importers is set to increase over the coming years (e.g. Figure 7), even faster than in northern Mediterranean countries. This trend mainly stems from the dramatic rise in domestic demand for oil and gas in the MED-11, as described above.

Figure 7. Overall energy dependency in the Mediterranean



Note: SEMCs = southern and eastern Mediterranean countries; NMCs = northern Mediterranean countries.

Sources: Own elaborations based on data from the IEA and MEDPRO Energy Reference Scenario.

Given the crucial importance of some MED-11 countries in energy transit, the last part of this report is entirely devoted to the Mediterranean as region for oil and gas transit. In particular, the report focuses on three key countries: Turkey, Algeria and Egypt.

Turkey is increasingly at the crossroads of the world's energy trade (Figure 8). A web of pipelines already crosses Turkey, carrying hydrocarbons along east–west and north–south energy corridors. Indeed, because of tanker traffic through the Bosporus and Dardanelles Straits, Turkey has become an important north–south transit route for oil.[7] Traffic through the Straits has grown as the crude production and exports of Azerbaijan and Kazakhstan have risen. Moreover, the Baku–Tbilisi–Ceyhan (BTC) oil and Baku–Tbilisi–Erzurum natural gas pipelines make Turkey an important east–west route as well. Other pipelines already operative include the Kirkuk–Ceyhan oil pipeline and the Blue Stream gas pipeline. A terminal located in Ceyhan – on Turkey's Mediterranean coast – allows the country to export oil from Iraqi and Caspian sources: the first route extends from northern Iraq via a pipeline from Kirkuk and the second route from Azerbaijan via the BTC pipeline.

Egypt plays a strategic role in the scenario for regional energy transit, notably because of three important structures: the Suez Canal, the Suez–Mediterranean (SUMED) oil pipeline and the Arab Gas Pipeline. The Suez Canal is increasingly significant for LNG trade. In 2010, about 30 bcm of LNG from Qatar crossed the Canal for the EU market.[8] This represented more than a third of total European LNG imports. For the UK and Belgium, LNG from Qatar crossing the Suez Canal represents about 80% of these countries' LNG imports.

Algeria is a major oil and gas exporter in the region and has a well-established system of infrastructure. Algeria is also looking forward to solidifying its standing as a regional transit hub for West African gas and its access to the Mediterranean and European markets. This aspiration explains the planned Trans-Saharan Pipeline, a proposed 4,128-km-long gas pipeline from Nigeria to Algeria with an annual capacity of 30 bcm per year.

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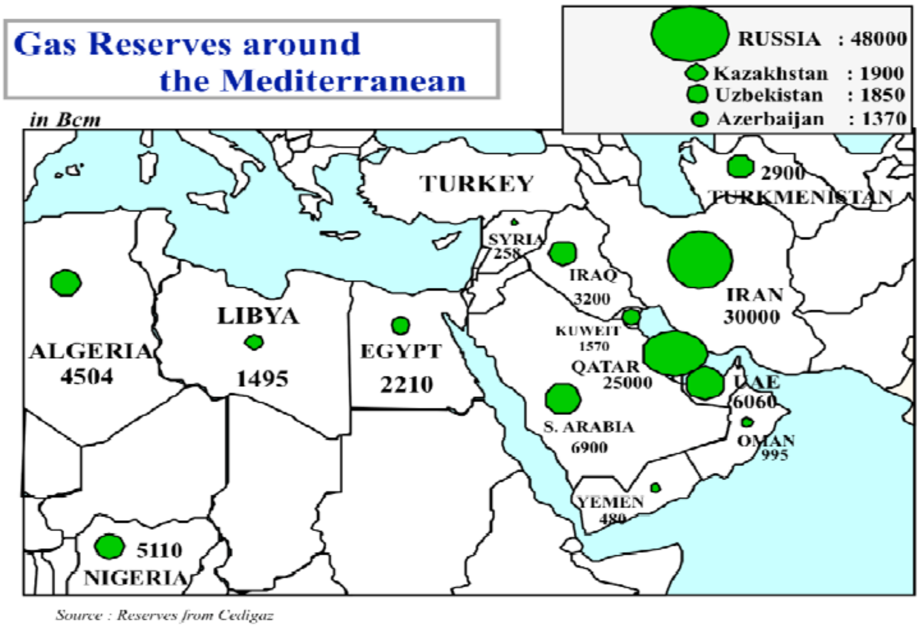
[7] For a broad discussion of the role of Turkey in the Mediterranean energy landscape, refer to Tagliapietra (2012).

[8] Data source: BP (2011).

Figure 8. Gas reserves around the Mediterranean



Source: Own elaborations based on Cedigaz data.

Part A. Natural Gas

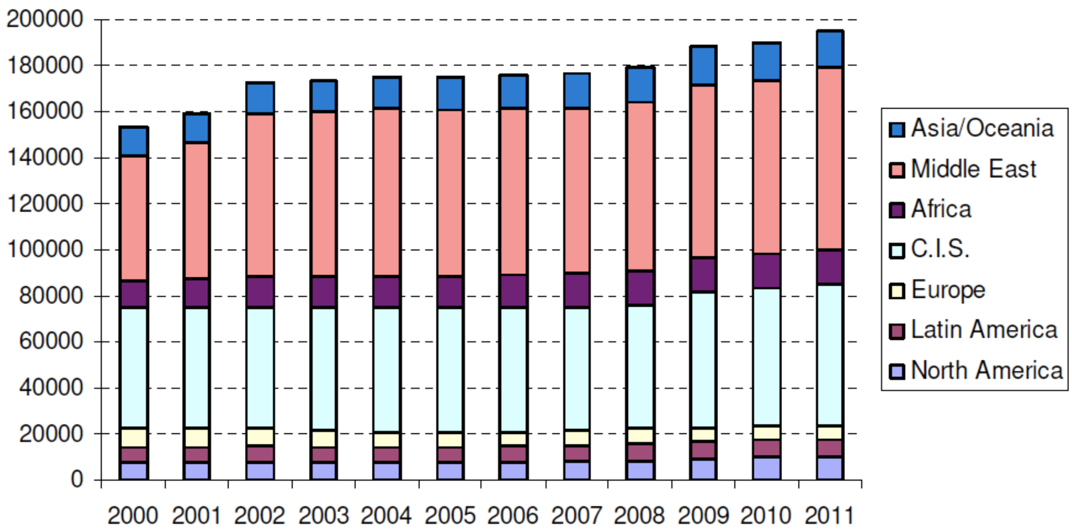
1. Assessment of natural gas reserves

1.1 MED-11 in the wider regional context

Considering the increasing level of interconnection of regional gas markets worldwide, before assessing the gas outlook of the MED-11 area it is worth providing a wider framework for analysis. In particular, it is important to keep in mind the role of gas-producing countries in Europe, Africa and the Middle East. The relations between these gas-producing countries and the MED-11 area become even more important considering the future role of the Mediterranean as a region for oil and gas transit.

Concerning the world's overall proven gas reserves, Figure 9 shows the increase in reserves by geographical area between 2000 and 2011. According to Cedigaz (2011), the Middle East was the fastest-growing exploration area in the world over the period, with proven gas reserves surging by 33.6% (from 59.4 tcm in 2001 to 78.9 tcm in 2011), raising the regional share of world reserves from 31.4% to 40.4%. The largest reserve additions are those of Qatar (+10.8 tcm), Iran (+7.1 tcm) and Saudi Arabia (+1.7 tcm).[9]

Figure 9. Evolution of proven reserves by major geographical area, 2000–11 (tcm)



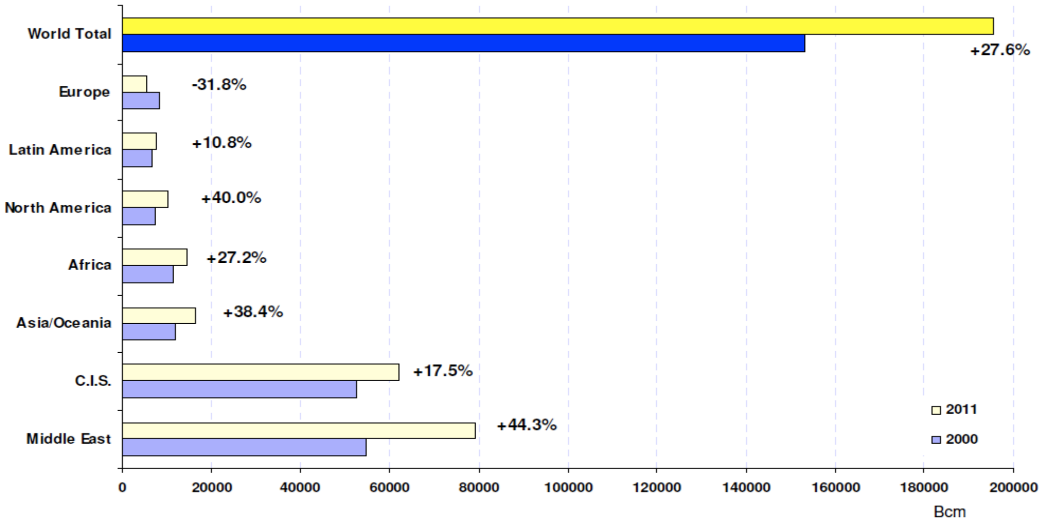
Source: Cedigaz (2011).

The second most successful region in providing new gas reserves during the last decade was the Commonwealth of Independent States (CIS), mainly because of substantial discoveries in Turkmenistan (+7.3 tcm) and Russia (+2.2 tcm). Asia/Oceania recorded 34.4% growth (+4.2 tcm) from 2000, as a result of substantial discoveries in China (+1.3 tcm) and Australia (+1.5 tcm). From 2001, proven gas reserves grew by 35.9% in North America, mainly because of extensive, unconventional gas discoveries. While in Africa proven gas reserves grew by 16.7% from 2001 – primarily because of Nigeria (+1 tcm) and Egypt (+777 bcm) – in Latin America they grew by 9.3% (mainly because of Venezuela). Cedigaz notes that Europe is distinguished by a 30.4% cut in proven reserves over the 2000–11 period. Europe's proven gas reserves (estimated at 7,958 bcm in 2001) showed an average decline rate of 3.2% per year over the period. This negative trend is mainly due to

[9] Unless otherwise stated, all statistics in Part A stem from Cedigaz (2011).

the natural depletion of mature fields, especially in the British North Sea, where proven reserves reduced by 56.6% between 2000 and 2011 (e.g. Figure 10).

Figure 10. Evolution of proven gas reserves by major geographical zone, 2000–11 (bcm)



Source: Cedigaz (2011).

1.1.1 Europe

Again according to Cedigaz, in 2011 European gas reserves amounted to 5,534 bcm (222 bcm less than in 2010). The North Sea area is considered mature and Western European gas reserves are declining, accounting for only 2.5% of world reserves in January 2011 compared with 4.9% in 2001.

Norway

Norway accounts for 57% of Europe's proven gas reserves. The country exported in 2010 about 100 bcm of gas, almost twice the amount of a decade ago. Yet Norway has not made a significant gas discovery since that of the Ormen Langen field in 1997. The Norwegian Petroleum Directorate (NPD) holds that about half the Norwegian continental shelf has rocks with a potential for finding petroleum, but there is no way to accurately predict how much gas can be produced from it. Considerable uncertainty is associated with such factors as geology, reservoir conditions, technology and knowledge development, costs and commodity prices. Some studies have been carried out in the recent past, however, to provide a forecast of future Norwegian gas production. The Global Energy Systems Center of the University of Uppsala expects that Norwegian gas production will peak at a range of 124-135 bcm a year in 2015–20 and will then fall dramatically.[10] Otherwise, according to the NPD, Norwegian gas production will peak around 2020. At that time, annual gas production is estimated at between 105 and 130 bcm a year, while the production level after 2020 will largely be determined by the new discoveries made in the years to come.[11]

Netherlands

The Netherlands ranks second among European countries for proven gas reserves, estimated at 1,161 bcm in 2011 (86 bcm less than in 2010). The most important field is the Groningen field, which accounted for nearly 75% of the country's total reserves. Other small onshore fields held a volume of 122 bcm, while the Dutch continental shelf held 163 bcm in 2011.

[10] Refer to *A New Architecture for EU Gas Security of Supply*, Glachant et al. (2012).

[11] Ibid.

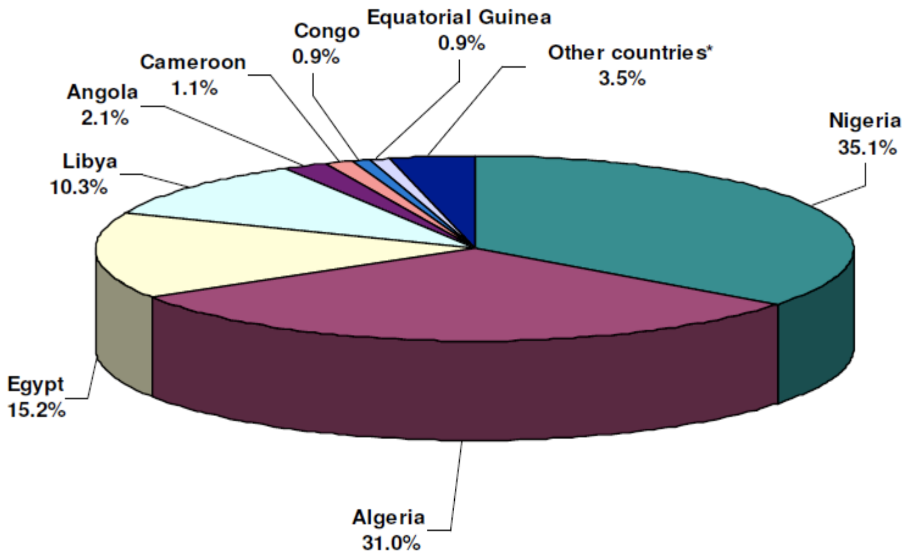
United Kingdom

The proven gas reserves of the UK have dramatically decreased over the last decade, but remain the third-largest European reserves. British proven gas reserves have shown a 7.8% per year depletion rate since the year 2000, reaching 564 bcm in 2010. About 79% of dry gas reserves are concentrated in the southern area of the North Sea, where discoveries under appraisal hold an estimated volume of 48 bcm, compared with 58 bcm a year before. To give a further boost to the UK's offshore oil and gas industries, the 2010 round of offshore licensing included areas of the continental shelf as yet unexplored. In addition, the British government announced a package of tax incentives aimed at unlocking oil and gas reserves in the Atlantic frontier west of Shetland – an area estimated to contain 20% of the country's remaining, unexploited oil and gas reserves.

1.1.2 Africa

According to Cedigaz, gas reserves in Africa amounted at 14,541 bcm in 2011. Nigeria, Algeria, Egypt and Libya together hold about 92% of the continent's reserves (e.g. Figure 11), with 13,319 bcm.

Figure 11. Proven gas reserves in Africa



* Other countries: Ethiopia, Gabon, Ghana, Ivory Coast, Mozambique, Namibia, Rwanda, Senegal, Sudan, Somalia, South Africa, Tanzania, Tunisia and Uganda

Source: Cedigaz (2011).

Nigeria

Nigeria's proven gas reserves were estimated at 5,110 bcm in 2011 (183 bcm less than in 2010), representing almost 35% of the proven gas reserves of the African continent, putting Nigeria in first place among the gas producers in Africa and ninth in the world. About 60% of these reserves are associated gas. As reported by Cedigaz (2011), the Department of Petroleum Resources, which regulates the petroleum sector in Nigeria, estimates the gas reserves at between 5,235 and 5,348 bcm; a US Geological Survey study also estimates that the Nigerian gas reserve potential could be as high as 16,980 bcm.

To date, there has not been any dedicated exploration for gas and the majority of proven gas reserves have been discovered in relation to exploration for oil. A large chunk of Nigeria's proven and probable gas reserves are situated in the Niger Delta in onshore (Soku, Obite and Ibewa) and offshore fields (Bonga, Amenam and Akpo). After more than 57 years of intensive exploration, it is considered that the main prospects are restricted to the Niger Delta and its adjacent offshore area.

The Nigerian offshore area being explored and considered highly promising is at least 1,000 metres below sea level and then another 4,000 metres underground. The distribution of field sizes in the Niger Delta is uniform. It should be noted that a large fraction of the proven reserves cannot be made easily available to markets (domestic and exports), at least without massive investments in infrastructure and processing.

A significant portion of Nigeria's marketed natural gas is processed into LNG (in 2010 the country exported 24 bcm of LNG). Nigeria's main facility for natural gas is the Nigeria Liquefied Natural Gas (NLNG) complex located on Bonny Island. The complex currently has six trains, with a total capacity of 21 Mt/year. A seventh train is under construction but this addition has been delayed beyond 2012. Three further LNG plants with a total of seven trains were expected to come online after 2012, but their start-ups have been postponed beyond 2016. Plans included the OK LNG (four trains), Brass LNG (two trains) and Progress LNG (one train). These are in varying stages of development and investment decisions will depend heavily on security, world LNG markets and the final outcome of the Petroleum Industry Bill. The availability of natural gas will also depend on Nigerian efforts to expand the use of natural gas for domestic electricity generation – efforts that are included in both the Gas Master Plan and the Petroleum Industry Bill.

The 4,128-km-long Trans-Saharan Gas Pipeline (with an annual capacity of 30 bcm/year) has been planned in order to transport Nigerian gas to Algeria and farther on to Europe. The pipeline would start in the Warri region in Nigeria and would run north through Niger to Hassi R'Mel in Algeria. In Hassi R'Mel, the pipeline would connect to the existing Trans-Mediterranean, Maghreb–Europe and Medgaz Pipelines (which supply Europe from the gas transmission hubs at El Kale and Beni Saf on Algeria's Mediterranean coast). The pipeline (proposed to be operational by 2015) is to be built and operated by a partnership between the Nigerian National Petroleum Corporation and Sonatrach.

Algeria, Egypt and Libya

These three countries are discussed in section 1.2 below.

1.1.3 Middle East

Qatar

Proven gas reserves in Qatar were estimated at 25 tcm 2010.[12] Almost 99% of national reserves are concentrated offshore in the non-associated North Field gas reservoir, whose production started up in 1991. Additional associated gas reserves are located in the offshore Idd al-Shargi, Maydan Mahzam and Bul Hanine associated gas fields, as well as the onshore Dukhan field. In 2005, Qatar placed a moratorium on further projects for natural gas development in the North Field to allow time to study field development optimisation. The giant gas field is shared with Iran. Rapid development could reduce reservoir pressure and possibly damage its long-term production potential. The reserves and structural assessment were initially not expected to end until after 2009, a period after all the planned North Field gas projects had been brought on-stream. By the end of 2009, however, Qatar extended the five-year moratorium on further development to 2014 as part of its gas production strategy to sustain the field's reserves. In 2010, Qatar produced 117 bcm of gas, four times the amount produced in 2000. In the same year Qatar exported 95 bcm of gas, of which 76 bcm was through LNG.

[12] Data source: BP (2011).

The primary destinations for Qatar's gas exports in 2010 were the UAE (17 bcm), the UK (14 bcm), Japan (10 bcm), South Korea (10 bcm), India (10 bcm), Belgium (6 bcm), Spain (6 bcm) and Italy (6 bcm). Qatar is a dynamic country with a wide international horizon. The latest example of this feature is represented by the engagement of the country in a discussion with Russia's biggest independent gas producer, Novatek, for buying a stake of the company and its 15 million tons/year Yamal LNG – a major project expected to be devoted to the European market and an operation that would link the world's largest gas producer with the world's largest LNG exporter, creating an innovative prospect of cooperation.

Iran

Iran is the second-largest holder of gas reserves in the world. The country has 30 tcm of proven gas reserves, with commercial production standing at 140 bcm in 2010. Since the Islamic revolution in 1979, the production of gas in Iran has mainly been to meet the domestic demand. At the end of 2001, Iran began to export gas to Turkey by a 10 bcm/year capacity pipeline linking the countries. In 2010, Iran's exports to Turkey amounted to 7.8 bcm of gas to the country. With its expanding economy, Iranian energy demand increased at an annual average of 6.8% during the last decade. Large amounts of gas are injected in oil fields to increase oil reservoir pressure in order to maximise oil exports. Natural gas has become the most important source in the Iranian energy mix, making the country the third-largest gas consumer in the world. Domestic demand for natural gas has increased at an average rate of 10% per year over the last decade. The country also has several LNG export projects on its drawing board, but unless there is a change to a more cooperative international approach, the realisation of any of these Iranian export projects will be a huge challenge.

Iraq

Iraq's proven natural gas reserves were estimated at 3.2 tcm in 2010. The country's natural gas production decreased substantially over the last decade, from 3.2 bcm in 2000 to 1.3 bcm in 2010. Some of the extracted natural gas is used as fuel for power generation, and some is re-injected to enhance oil recovery. Over 40% of the production in 2008 was flared due to a lack of sufficient infrastructure to utilise it for consumption and export. For this reason, in November 2011 Iraq signed a final deal with Royal Dutch Shell and Mitsubishi to capture flared gas at southern oilfields (Rumaila, as well as Zubair and West Qurna), a project that should boost production of needed electricity. The Iraqi natural gas outlook seems to be radically changing because of the enormous gas finds recorded in Kurdistan. In fact, between 2.8 and 5.6 tcm of gas resources are estimated to be located in the semi-autonomous territory at the confluence of Iraq, Iran and Turkey. Once established, Kurdistan's gas reserves would first be exploited to fuel new power plants in the region. In fact, the Kurdistan Regional Government has already more than tripled its 2015 target for installed, gas-fired generating capacity. The region's gas potential seems to be so large, however, that the only way to monetise it fully will be to develop export capacity. Consequently, Turkey would be the natural direction for exports of gas from the region to the European market. As an overall trend, Iraq's plans to export natural gas remain controversial owing to the amount of idle and suboptimally-fired electricity generation capacity in the country. Prior to the 1990–91 Gulf War, Iraq exported natural gas to Kuwait. The gas came from Rumaila through a 170-km, 4-bcm/year pipeline to Kuwait's central processing centre at Ahmadi. In 2007, the ministry of oil announced an agreement to fund a feasibility study on the revival of the mothballed pipeline. Iraq has eyed northern export routes, such as the proposed Nabucco pipeline through Turkey to Europe. A second option is to feed into the Arab Gas Pipeline (AGP) project. The proposed AGP project would deliver gas from Iraq's Akkas field to Syria, where it could connect to the AGP (which currently links Syria and Lebanon) in order to carry gas to the Turkish border, and then on to Europe. Other proposals have included building LNG exporting facilities in the Basra region.

Saudi Arabia

Saudi Arabia has 8 tcm of proven gas reserves, the fourth largest in the world behind Russia, Iran and Qatar. As reported by Cedigaz (2011), the US Energy Information Administration estimates that about 55% of the natural gas in Saudi Arabia is associated with petroleum deposits – or has been found in the same fields as crude oil. Plans to increase the production of this type of gas thus remain linked to an increase in oil production. About 60% of the Saudi proven gas reserves consist of associated gas at the giant onshore Ghawar field and the offshore Safaniya and Zuluf fields.

Saudi Aramco forecasts that natural gas demand in the country is to more than double by 2030. To free up oil for export, all current and future gas supplies reportedly remain earmarked for use in domestic industrial consumption and desalination.

The UAE

The UAE holds 6 tcm of proven gas reserves. The majority of these reserves are located in Abu Dhabi, with marginal amounts found in Sharjah, Dubai and Ras al-Khaimah. According to BP, in 2010 the UAE produced 51 bcm of natural gas, an amount lower than the domestic consumption, which is estimated at 60 bcm.[13] Indeed the domestic gas consumption of the country is growing rapidly, mainly because of the electricity demand connected with economic expansion and the high rate of population growth. In 2010, the UAE exported 8 bcm of gas, while 17 bcm were imported. This net deficit of 9 bcm is likely to widen in the future unless new supplies are exploited. The gas exports of the UAE are entirely in the form of LNG from the ADGAS project at Das Island. Imports are both piped and transported LNG, in each case mainly from Qatar (17 bcm in 2010, according to BP).[14]

Other Middle Eastern gas exporters

Other Middle Eastern gas exporters include Oman and Yemen. In 2011, Oman's natural gas reserves were estimated at 850 bcm. In the same year, Oman produced about 25 bcm of natural gas. Much of the remaining natural gas reserves are locked in geological formations that are smaller and more difficult to access. In Oman natural gas consumption rose rapidly over the past decade, seeing a 135% increase from 2000 to 2010. This increase is largely attributable to economic expansion and population growth, while reinjection of natural gas to increase oil production takes up a rising proportion of domestic production. A lack of natural gas resources has impeded progress in economic diversification, especially in the industrial sector. Although Oman is a net exporter of natural gas, it also imports small volumes of natural gas through the Dolphin Pipeline system, which transports 22 bcm/year of natural gas from Qatar to neighbouring UAE and to Oman.

Yemen's proven gas reserves were estimated at 0.5 tcm in 2011. Most of Yemen's natural gas reserves are associated gas concentrated in the Marib-Jawf oil fields. Success in developing the LNG sector is likely to increase interest in further natural gas exploration and production. In 2010, Yemen produced an estimated 32 bcm of natural gas, of which 25 bcm was re-injected to provide enhanced oil recovery and 7 bcm was marketed, including 5.5 bcm exported as LNG. The Yemeni government's plans for increased domestic use of its natural gas reserves include the transition of power generation from diesel fuel oil to natural gas.

1.2 Gas reserves in the MED-11

MED-11 gas reserves, estimated at 8,500 bcm, are predominantly located in Algeria, Egypt and Libya.[15] As explained below, however, the region is still largely underexplored and it is thus not possible to give an exact and really comprehensive estimation of the regional gas reserves. In 2000, for instance, the US Geological Survey estimated the MED-11 gas resources at 2,715 bcm, with a high

[13] Data source: BP (2011).

[14] Ibid.

[15] Ibid.

and low range of 5,765 bcm and 685 bcm, respectively.[16] Since this study was done, about 1,100 bcm of new reserves have already been discovered.

In particular, in the case of Libya the US Geological Survey admits that its assessment is incomplete owing to a serious lack of information, and data are mainly based on research completed in the 1970s, which has never been updated. The Libyan National Oil Corporation, based on the geological, seismic and geochemical research studies conducted by its teams and its foreign partners in the country's different sedimentary basins, assesses the existence of undiscovered gas resources at about 3,300-3,500 bcm.[17]

In the case of Egypt, the proven gas reserves increased immensely over the last two decades, from 265 bcm in 1986 to 2,210 bcm in 2010. Moreover, recent discoveries in the Nile Delta, together with unexpected good discoveries in the Western Desert, are making this area a new and promising petroleum province. Algerian, Libyan and Syrian gas reserves have remained more or less constant over the last decade; this implies that these countries have been able to add as much new gas reserves as they have produced gas (e.g. Table 8).

Table 8. MED-11 gas reserves (bcm)

Country	Bcm
Algeria	4504
Libya	1495
Egypt	2210
Syria	258
Total	**8467**

Sources: BP (2011) and Cedigaz (2011).

1.2.1 Algeria

Algeria's proven gas reserves were estimated at about 4,504 bcm in 2011, around 31% of the estimated proven gas reserves of the entire African continent.[18] This figure is likely to grow in the near future, as the country better assesses its shale gas reserves. In fact, Algeria is committed to developing technology-intensive shale gas and offshore production, and it currently favours allowing foreign oil majors to help achieve these goals. In 2011, Sonatrach signed an agreement with Italy's Eni to help carry out shale gas exploration and it has now started talks with Royal Dutch Shell and ExxonMobil on further exploration. Different studies have estimated Algeria's recoverable shale gas reserves at more than 600 tcf at a recovery rate of 20%.[19] If this figure is confirmed, Algeria's gas reserves will thus increase by a factor of four in the near future.

[16] Sources: US Geological Survey (USGS), with values coming from the initial 2000 "USGS World Petroleum Assessment 2000" (USGS, 2003). In March 2012, an updated study was published by USGS, "An Estimate of Undiscovered Conventional Oil and Gas Resources of the World, 2012" (USGS, 2012).

[17] Source: *Libya Oil and Gas Strategic Report*, Bayphase Ltd (2012).

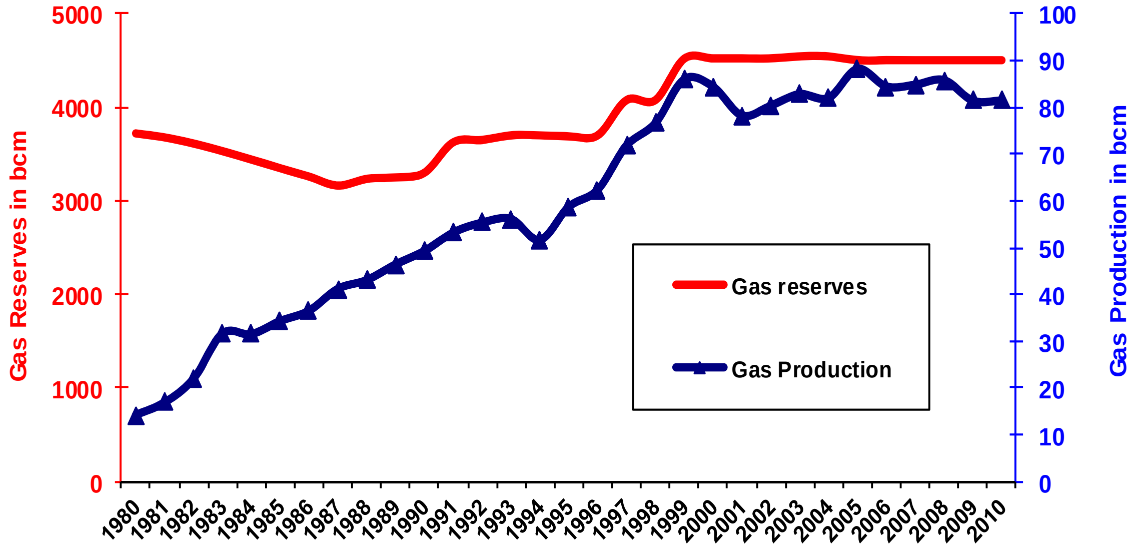
[18] Data sources of this subsection unless otherwise indicated: *Harnessing energy resources for sustainable development in Africa*, UNECA (2009) and "Afrique: Pourquoi les riches sont-ils pauvres?", Agenzia Fides (2004).

[19] Platts, *International Gas Report*, Issue 701 (2012).

Cedigaz estimates that in 2010 its commercial gas production reached 80 bcm, of which 70% was exported and 30% was consumed domestically (e.g. Figure 12). Algeria's largest gas field is Hassi R'Mel, discovered in 1956; the domestic pipeline system centres on this field. The largest pipeline systems connect Hassi R'Mel to LNG export terminals along the Mediterranean Sea. Hassi R'Mel is the hub of Algeria's entire network for natural gas transport, so pipelines connect to it from the country's major gas-producing regions. Almost two-thirds of Algeria's total exports of natural gas currently move through three natural gas pipeline connections operating between Algeria and Europe; the remaining third of total exports of natural gas is exported in the form of LNG. The export pipelines are the Enrico Mattei Pipeline (from Hassi R'Mel, via Tunisia and Sicily, to mainland Italy), the Pedro Duran Farell Pipeline (from Hassi R'mel via Morocco to mainland Spain) and the Medgaz pipeline, which became operational in early 2011 (connecting Spain to Algeria directly across the Mediterranean without any transit country).

Domestic demand is growing strongly in Algeria, while at the same time the country has found it difficult to increase production in recent years. Exports have thus been declining. In 2010, Algeria exported natural gas mainly to Italy (28 bcm), Spain (12 bcm), France (6 bcm) and Turkey (4 bcm). Minor volumes went to the UK, Portugal and Tunisia.

Figure 12. Algeria – Gas reserves and gas production (bcm)



Sources: Cedigaz and BP.

1.2.2 Egypt

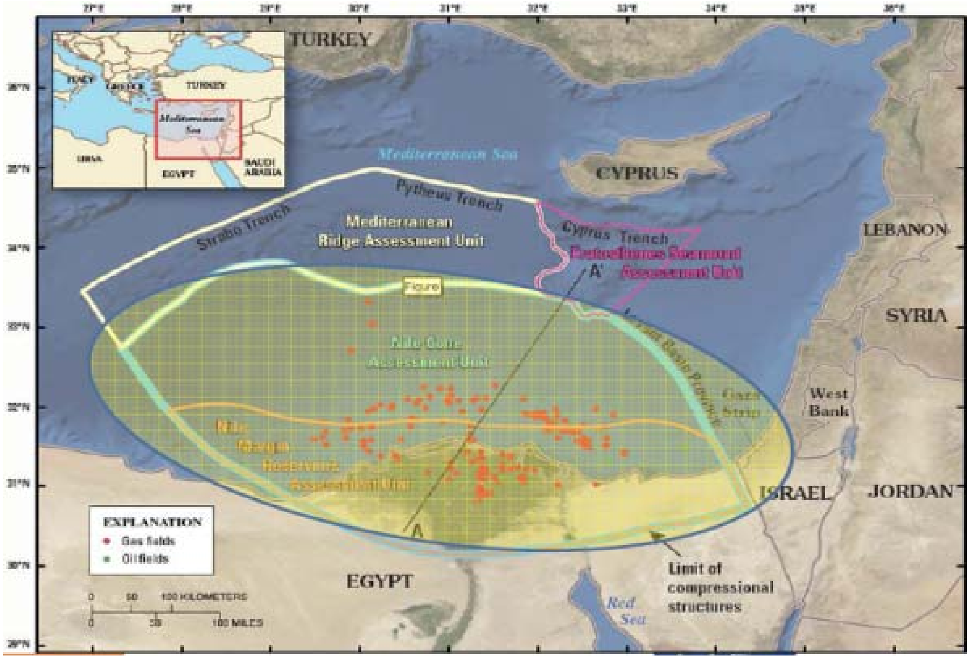
Egypt's natural gas sector has expanded rapidly, with production quadrupling between 1998 and 2011.[20] Egypt's proven gas reserves were estimated at 2.2 tcm in 2011, representing the third-largest reserves in Africa after Nigeria and Algeria. Furthermore, the region is still largely underexplored and new natural gas discoveries are taking place in the Egyptian Nile Delta, offshore (e.g. Figure 13).

In 2010, Egypt produced roughly 61.3 bcm of natural gas, of which 45.1 bcm was consumed domestically. In 2010, Egypt exported 15.1 bcm of natural gas (of which 9.71 bcm was via LNG and 5.46 bcm via pipeline). Egyptian pipeline exports mainly travel through the Arab Gas Pipeline, an infrastructure of 1,200 km that provides gas to Lebanon, Jordan and Syria. In addition, a subsea gas pipeline – the Arish–Ashkelon Pipeline – connects the country with Israel.

[20] Data source of this subsection: BP (2011).

Egypt's LNG exports are based on the large Damietta and Idku liquefaction plants. This combined LNG export capacity is close to 23.4 bcm per year. In 2010, Egypt exported natural gas via LNG (for a total of 9.7 bcm) mainly to Spain (2.62 bcm), the US (2.07 bcm), South Korea (0.97 bcm), France (0.73 bcm) and Italy (0.72 bcm), while minor volumes went to Japan, Kuwait, Turkey, Belgium, the UK, Greece and China. In the same year, Egypt exported natural gas via pipeline (for a total of 5.4 bcm) mainly to Jordan (2.52 bcm), Israel (2.10 bcm), Syria (0.59 bcm) and Lebanon (0.15 bcm).

Figure 13. Resources offshore in the Egyptian Nile Delta



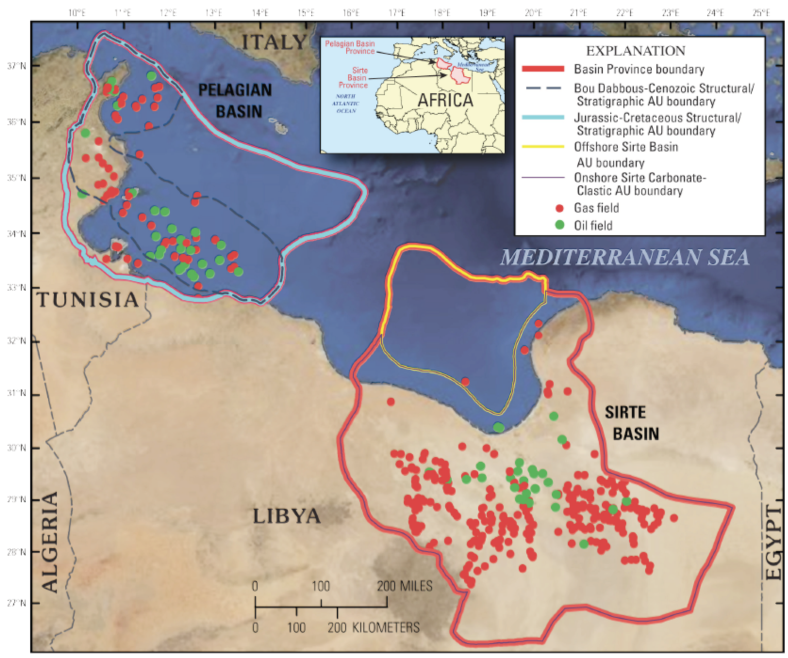
Source: US Geological Survey.

1.2.3 Libya

Libya's proven natural gas reserves were estimated at 1.49 tcm in 2011, but recent new discoveries are expected to raise these estimates in the near term (e.g. Figure 14).[21] Libya's natural gas production has grown substantially in the last few years, reaching 15.8 bcm in 2010. Natural gas currently accounts for 45% of the country's generated electricity. In the past, the Libyan government planned to increase natural gas production in order to expand the use of this fuel in the power sector, thereby freeing up more oil for export. Yet project delays (and also the recent political turmoil) and infrastructure limitations have kept consumption in this sector relatively stable over the past years. In 2010, Libya exported 9.41 bcm of natural gas to Italy (via pipeline) and 0.34 bcm to Spain (via LNG). Natural gas is piped from the Wafa concession and the offshore Bahr es Salam fields to Mellitah, where it is treated for export. The amount of natural gas exports to Italy has grown considerably over the past several years through the 540-km-long Greenstream (underwater) natural gas pipeline from Mellitah to Gela in Sicily, operated by Eni in partnership with Libya's National Oil Corporation. The capacity of this pipeline has recently been upgraded to 8-10 bcm/year. There are also several projects to increase the LNG export capacity.

[21] Data sources: USGS (2011) estimates and Bayphase Ltd (2012).

Figure 14. Locations of the Sirte and Pelagian Basin Provinces



Source: US Geological Survey.

1.2.4 Syria

Syria's proven gas reserves were estimated at 258 bcm in 2011, a level that has remained constant over the last two decades. Non-associated gas accounts for 58% of the total, while gas cap reserves and associated gas account respectively for 26% and 16%. Some two-thirds of the country's non-associated gas reserves are located in the Syrian Petroleum Company's concession area, containing the Palmyra fields in the centre of the country. The Cherrife and Ash Shaer fields, also in the central part of the country, are another large source of non-associated gas, with more than 30 bcm of reserves. Gas cap reserves are mainly located in the north-eastern part of the country, as are most of the country's associated gas reserves, which can be found in the Deir ez-Zor region as well as around the Rumaila and Suweidiyeh fields. The gas produced fluctuated between 5 and 6 bcm/year over the last decade and in 2010 increased to 7.8 bcm.

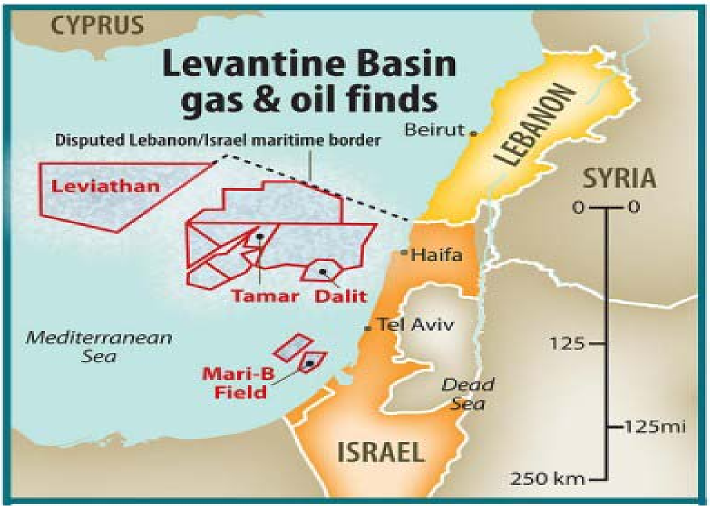
1.2.5 The Levantine Basin

An important geological reassessment of the oil and gas potential of the eastern Mediterranean area is presently underway. If the expectations are confirmed, the area could become a world-class hydrocarbon province. For instance, recent exploratory activity in the offshore area encompassed between Israel and Cyprus has confirmed major natural gas fields that could radically change the energy outlook of the area. Israel's Natural Gas Authority estimates that these offshore gas reserves could reach 1.3 tcm within the next few years[22] (e.g. Figure 15).

A large natural gas field – the so-called 'Leviathan field' with estimated reserves of 453 bcm – was discovered in late 2010 and is expected to be operative in 2017. The Cyprus Energy Department has already submitted to the Cypriot government a proposal to cooperate with Israel for the construction of a LNG plant near Vassilikos, on the island's southern coast. Noble Energy and Israel's Delek Group have proposed the construction of a 15-million-ton/year LNG facility that would process gas from the Leviathan field and any gas from offshore Cyprus. There is thus important upside potential for the OSE countries in terms of future gas production and export levels.

[22] Data source: Israel's Ministry of Energy and Water Resources (http://energy.gov.il/English/).

Figure 15. Levantine Basin gas and oil finds



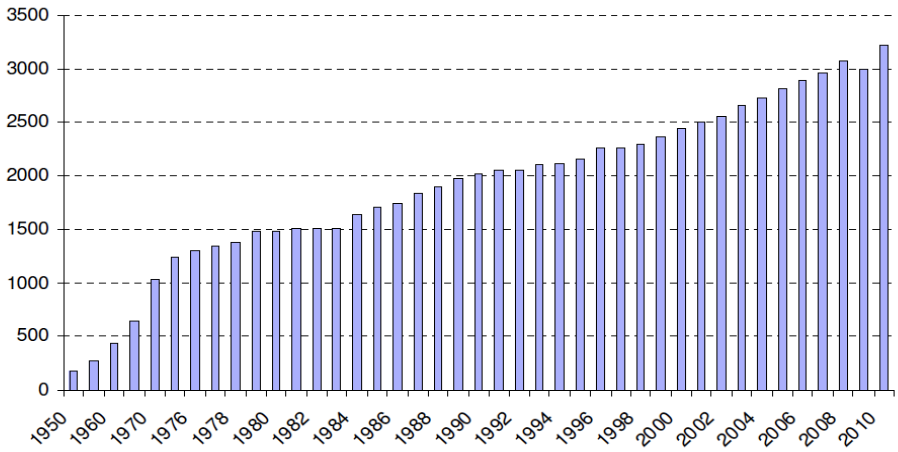
Source: Noble Energy Inc.

2. Assessment of natural gas production, demand and exports

2.1 Major trends in world natural gas production

World gross gas production amounted to 4,041 bcm in 2010, while the marketed production (derived from gross production by deducting the reinjection volumes, the flared gas and the shrinkage and upstream losses) amounted to about 3,215 bcm in the same year (e.g. Figure 16).

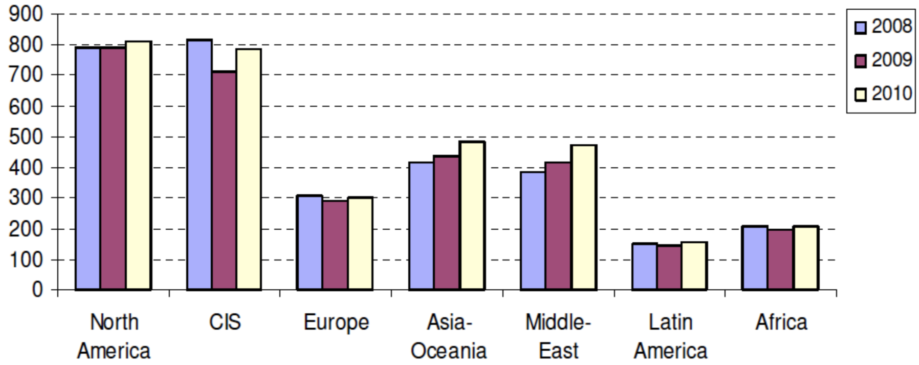
Figure 16. Evolution of world marketed gas production, 1975–2010 (bcm)



Source: Cedigaz (2011).

After an exceptional 2008, world gas production drastically declined in 2009 mainly because of the economic crisis that followed the financial crisis of 2008. In 2009, the impact upon natural gas production varied greatly among the regions, with Asian emergent economies being less affected by the crisis, showing a 5% increase of their own marketed production, and the Middle East (+6.1%) facing both growing domestic consumption and foreign demand. North America was of course strongly affected by the economic crisis, but the expanded domestic production the US pursued along with the growing production of shale gas and the subsequent low gas prices discouraged the Canadian producers. In 2010, world gas production recovered from the historic decline of 2009, adding 224 bcm to the level recorded in the previous year, reaching 4,041 bcm. According to Cedigaz, major regional developments concerning the supply of natural gas in 2010 were as follows: i) the increasing shale gas development in North America (+4.8%), ii) a rebound in natural gas production in CIS countries (+9.8%), and iii) an acceleration in supply from the Middle East (+13.2%) (e.g. Figure 17).

Figure 17. Evolution of natural gas production by region (bcm)



Source: Cedigaz (2011).

2.2 MED-11: Natural gas production, demand and exports

2.2.1 MED-11 overview

Natural gas production and demand: Current situation

MED-11 gas-producing countries (Algeria, Egypt, Libya, Tunisia and Syria) produced about 166 bcm of gas in 2009 [23] (e.g. Table 9). Their production rose by 11.6% per year between 1970 and 2009 (see also Figure 18). Over this period, the largest production gains were recorded in Egypt (+45.9 bcm), mainly due to significant discoveries and to the development of liquefaction plants. Egypt was also a fast-growing consuming market, as national demand rose sharply from 16 bcm to 44 bcm over the ten-year period, pushed up by the power generation sector. Egypt and Tunisia significantly increased their own production, while Algeria's output declined by 5.9%.

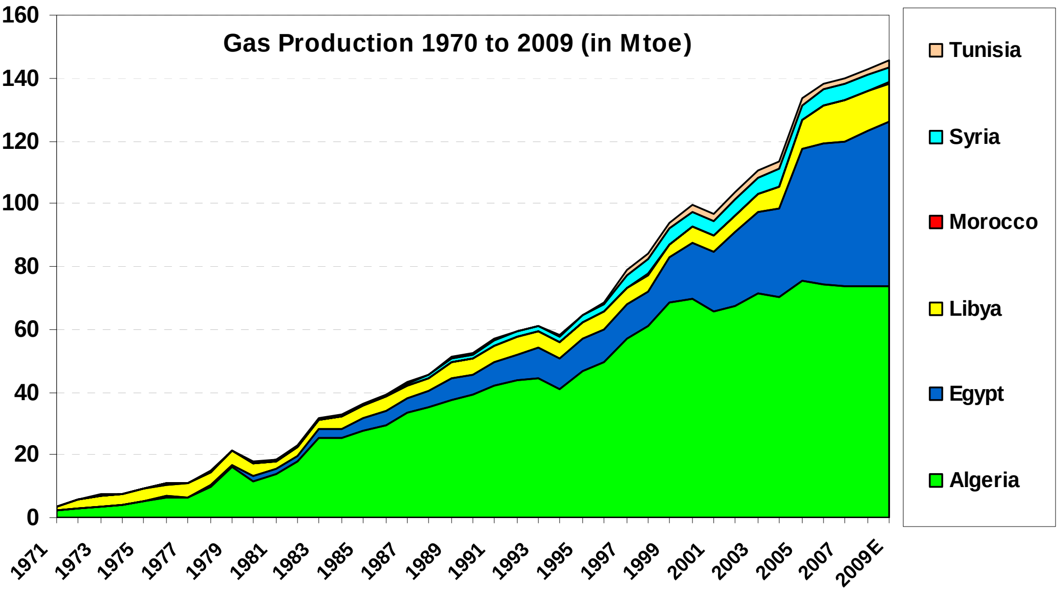
Table 9. MED-11 natural gas balance (1970/2009)

(Bcm)	**1970**	**2009**	**Average annual growth 1970–2009 (%)**
Gas production	2.3	165.5	11.6
Gas net imports/exports	-0.1	-41.4	17.9
Gas demand	2.1	125.9	11.0
Gas inputs in power plants	-0.3	-63.8	15.0
Gas in other transformation & losses	-1.2	-13.8	6.6
Gas final consumption	0.7	47.0	11.4
Transport	-	*2.5*	-
Residential	*0.1*	*16.9*	*15.2*
Industry	*0.5*	*24.2*	*10.3*
Other consumption	*0.1*	*3.4*	*9.1*
Gas electricity output (TWh)	0.7	290.7	18.8

Source: Own elaborations based on data from the IEA.

[23] Data source: BP (2011).

Figure 18. MED-11 gas production 1970–2009 (Mtoe)



Source: Own elaborations based on data from the IEA.

The MED-11's growing gas demand amounted to nearly 126 bcm in 2009. It was split as follows: 64 bcm for power generation, 14 bcm for other transformation industries and losses, and 47 bcm for final gas consumption (of which 17 bcm was for residential and other commercial sectors, 24 bcm for industries and 2.5 bcm for the transport sector). The MED-11's electricity production based on natural gas reached nearly 291 TWh in 2009, with 64 bcm of gas being burnt in power plants.

Natural gas production and demand: Prospects up to 2030

Table 10 presents the prospects for MED-11 natural gas production and demand up to 2030, as suggested by the MEDPRO Energy Reference Scenario.

Table 10. MED-11 Reference Scenario for natural gas

	Natural gas Production/Imports–Exports/Demand					
(Mtoe)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–30 (%)**
Gas production	150	184	227	261	294	3,2
Gas net imports/exports	-38	-30	-50	-54	-55	1,8
Gas demand	114	154	177	207	239	3,6
Gas inputs in power plants	-58	-78	-90	-105	-121	3,6
Gas in other transformation & losses	-13	-13	-13	-14	-15	0,9
Gas final consumption	43	63	74	88	103	4,3
Transport	*2*	*3*	*4*	*5*	*6*	*5,0*
Residential	*15*	*28*	*33*	*39*	*45*	*5,3*
Industry	*22*	*27*	*30*	*35*	*40*	*2,9*
Other consumption	*3*	*5*	*7*	*8*	*11*	*6,0*
Gas elect. output (TWh)	291	409	464	562	670	4,1

Source: Own elaborations for the MEDPRO Energy Reference Scenario.

In the MEDPRO Energy Reference Scenario, all parameters concerning natural gas are set to double by 2030, compared with the present situation. MED-11 gas production is expected to grow from 150 Mtoe in 2009 to 227 Mtoe in 2020 and to 294 Mtoe in 2030. MED-11 gas demand is set to rise from 114 Mtoe in 2009 to 177 Mtoe in 2020 and to 239 Mtoe in 2030.

2.2.2 Algeria

Natural gas production and demand: Current situation

Algeria's marketed gas production rapidly increased – by more than 10% per year – during the 1980s, slowing down during the 1990s and rapidly increasing again in recent years.[24] Gas production reached 84.6 bcm in 2010 (an increase of 3.9% from the previous year). Currently, about 75% of Algeria's marketed output comes from Sonatrach-operated fields, which include the Hassi R'Mel (the massive field located in central Algeria), the Rhourde Nouss field, the Alrar field (close to the border with Libya) and Tin Fouye-Tabankort. Sonatrach dominates the production and wholesale distribution of natural gas in Algeria, while the state company Sonelgaz controls retail distribution. The Algerian government has always encouraged the use of natural gas in the power generation sector. Since the late 1990s, Algeria has thus encouraged foreign investments in the oil and gas sector (BHP Billiton, BP, Eni, Repsol, Statoil and Total have concluded many partnership agreements with Sonatrach). In line with the reform of the hydrocarbon sector in 2005, Sonatrach retains ownership of 51% of each project's production. Algeria has several plans with regard to the development of the gas sector, in particular in the south-west of the country: the Reggane project led by Repsol (10 bcm/year), the Timimoun project led by Total (57 bcm/year) and the Touat project led by Gaz de France (160 bcm/year). Other major producing fields operated by international oil companies in association with Sonatrach include the following:

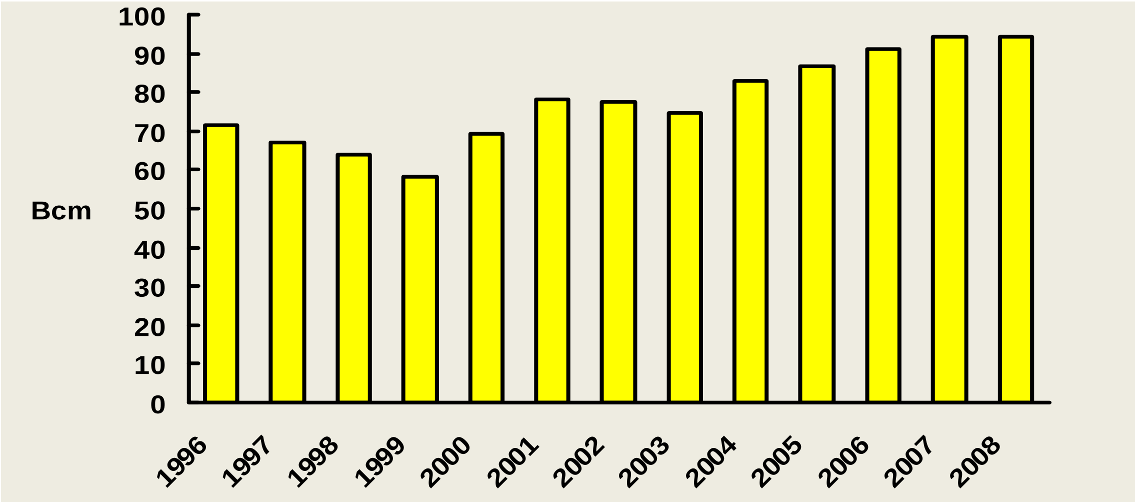
- In Salah, in southern Algeria, through an association of BP–Statoil and Sonatrach (about 9% of marketed production), which entered into production in 2004;
- the In Amenas fields, in south-eastern Algeria, also through an association of BP–Statoil and Sonatrach, which entered into production in 2006 (about 9% of marketed gas);
- Ohanet, in south-eastern Algeria (about 100 km west of the Libyan border), through an association of BHP Billiton and Sonatrach, which entered into production in 2003 (about 7% of marketed gas); and
- the Gassi Touil project, which formed part of Algeria's strategy for increasing its gas export capacity to around 85 bcm/year in the short term. The future substantial expansion of Algerian gas production will also rely on the continued exploitation of the In Salah and In Amenas fields, and the development of the promising Blocks (in association with Sonatrach):
    - the Block 405b fields (Menzel Ledmet East) in the Berkine Basin, acquired by Eni;
    - the Touat fields (Blocks 352a/353), with GDF Suez;
    - Reggane North, with Repsol YPF (and RWE Dea, Edison); and
    - the Timimoun project (Blocks 325a/329) with Total and Cepsa.

Algeria's domestic gas demand was 28.7 bcm in 2009 and is expected to reach about 45 bcm by 2020 and 64 bcm by 2030, according to the MEDPRO Reference Scenario. One specific aspect is that almost all the Algerian power generation is based on gas-fired stations (12.5 bcm in 2009 and 23.1 bcm in 2030), although concentrated solar power is expected to provide about a quarter of Algeria's power generation. Other local uses are shared between the residential and the commercial sectors, transport and industry (including use as a raw material for the petrochemical industry). Specifically, 97% of Algeria's electricity generation is based on natural gas. In 2009, electricity demand was about 34 TWh (up 3.8% compared with 2008) and electricity production reached 41.7 TWh (10.858 MW).

[24] Data source of this subsection: *Annual Report*, Sonatrach (2010).

Over the last decade, Algeria has implemented a plan to reduce gas flaring. The gas previously flared is re-injected. Today, Algeria re-injects the most gas globally among the 20 largest gas producers: in 2009, near 47% of the gross production was re-injected, equalling about 93 bcm (e.g. Figure 19). In addition to being a solution to preventing gas flaring, gas reinjection is necessary for maintaining oil and condensates field pressure and thus production levels. With the increasing national gas demand and export targets, we expect a step-by-step switch to other reinjection techniques. Carbon dioxide injection is being tested at In Salah by the joint venture between BP and Sonatrach.

Figure 19. Algeria – Evolution of re-injected gas



Source: Sonatrach.

Natural gas production and demand: Prospects up to 2030

In the MEDPRO Energy Reference Scenario, Algeria's total gas production potential is set to reach 93 Mtoe (102 bcm) in 2015, 113 Mtoe (124 bcm) in 2020 and 146 Mtoe (160 bcm) in 2030. This also takes into account the potential development of shale gas in the country, as described above in subsection 1.2.1. Between 2009 and 2030, Algeria's gas production is thus expected to grow at an annual average rate of 3.3%. By 2030, Hassi R'Mel is expected to still represent some 46% of Algeria's gross production of conventional gas, followed by the Hassi Messaoud field (17%), In Amenas (18%) and the new In Salah/Ahnet field (17%).

Natural gas exports

Algeria has been a pioneer in LNG trade, with the first commercial plant in the world completed at Arzew in 1964 (the GL4Z plant), and has gained a competitive position over many years. Algeria's LNG exports, which currently represent about a third of the country's total exports of natural gas, are currently based on four LNG plants located in Arzew and Skikda:

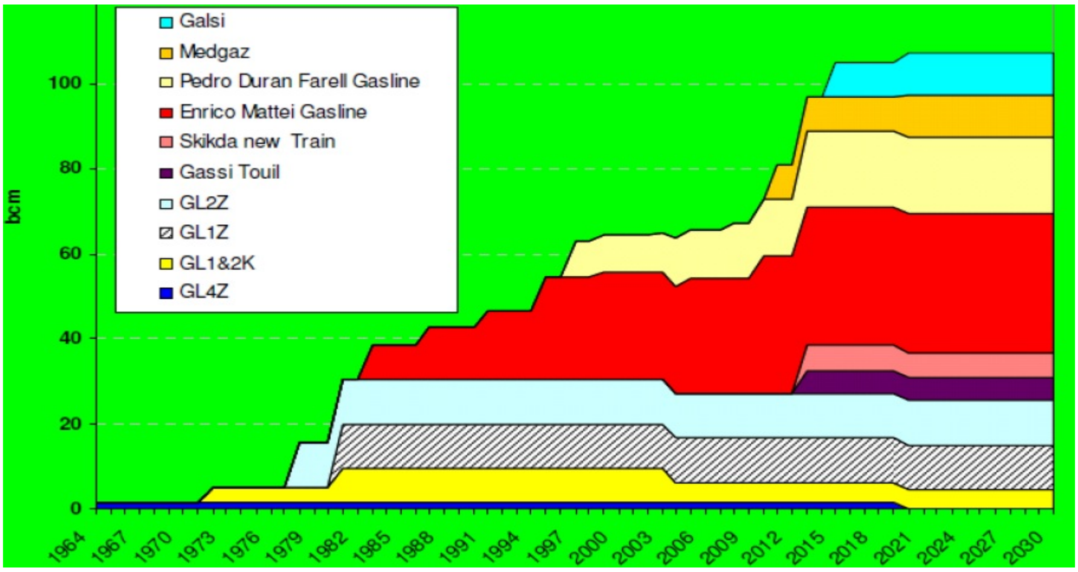
- GL4Z (Arzew-1, 1964; three trains, 1.7 bcm/year);
- GL1Z (Arzew-2, 1978; six trains, 10.5 bcm/year);
- GL2Z (Arzew-3, 1981; six trains, 10.5 bcm/year); and
- GL1K II (Skikda, 1972; one train, 4.4 bcm/year).

Part of the Skikda plant is now being rebuilt after an explosion occurred in 2004. The incident resulted in the loss of 3.3 bcm, 5% of the country's total export capacity. But by 2014, the rebuilt Skikda facility and an expansion of Arzew-3 could give Algeria an added 12.4 bcm/year of LNG capacity.

About 19 bcm of LNG was exported from Algeria in 2010, mainly to Europe. Sonatrach has LNG export contracts with Gaz de France, Belgium's Distrigaz, Spain's Enagas, Turkey's BOTAŞ, Italy's Snam and Greece's DEPA. With regard to the country's future capacity for gas exports, the following plans have been announced (see also Figure 20):

- to increase the capacity of the Transmed/Enrico Mattei pipeline by about 4 bcm/year;
- to increase the capacity of the MEG/Pedro Duran Farell Gasline by about 6 bcm/year;
- to double the capacity of the recent submarine Medgaz pipeline, directly linking Algeria to Spain with an 8-bcm/year initial capacity (a multi-partner project involving Sonatrach, Cepsa, BP, Total, Endesa, GdF & Iberdrola), but this only makes sense if a major gas interconnection pipeline from Spain to France is built; and
- to build another new submarine pipeline (named Galsi) from Algeria to Italy via Sardinia and Corsica, initially of 8 bcm/year and later 16 bcm/year. The construction of this pipeline has been repeatedly postponed, and as long as the European market signals do not improve, Algeria will most probably not go ahead with it.

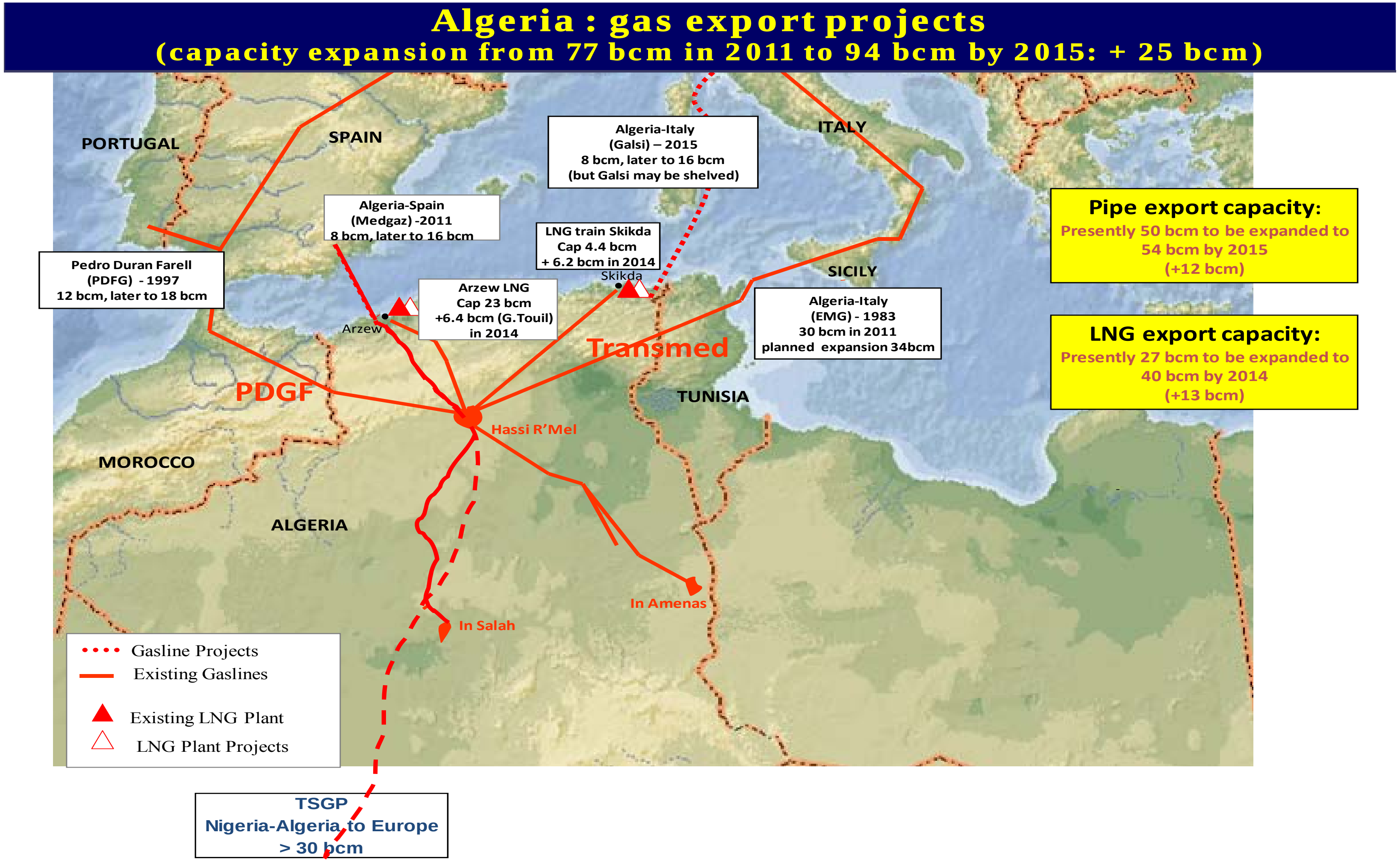
Figure 20. Algeria's gas export capacities according to announced plans (LNG and pipelines)



Source: Sonatrach.

That being stated, it should be noted that Algeria has experienced several difficulties over the last decade in increasing its gas production and exports. These difficulties were aggravated by the management problems at the ministry and Sonatrach during 2010, as well as by the present general disorders in the country. This has and will continue to cause delays. Difficulties will thus persist at a time when important investment decisions are needed to keep the gas supply constant, let alone to increase it. Algeria will try to export as much gas as it can through the existing pipelines. This implies filling the Enrico Mattei pipeline to Italy and trying to fill the Pedro Duran Farell pipeline as well as the Medgaz pipeline to Spain (e.g. Figure 21). Filling the pipelines to Spain will be a challenge as long as there is no connection between Spain and France. Algeria will also try to use the existing LNG plants as much as possible to export LNG and attach new markets (e.g. north-west Europe). In this framework Algeria could be expected to reach its export potential of 85 bcm/year (originally targeted by 2010) sometime between 2020 and 2035 (by that time European gas demand will also have sufficiently recovered to need additional imports, even if such a development is not enough to justify the construction of the Galsi pipeline). According to the MEDPRO Reference Scenario, by 2030 Algeria could have an export level of nearly 88 Mtoe (97 bcm) (e.g. Table 11 and Figure 22).

Figure 21. Gas export projects in Algeria



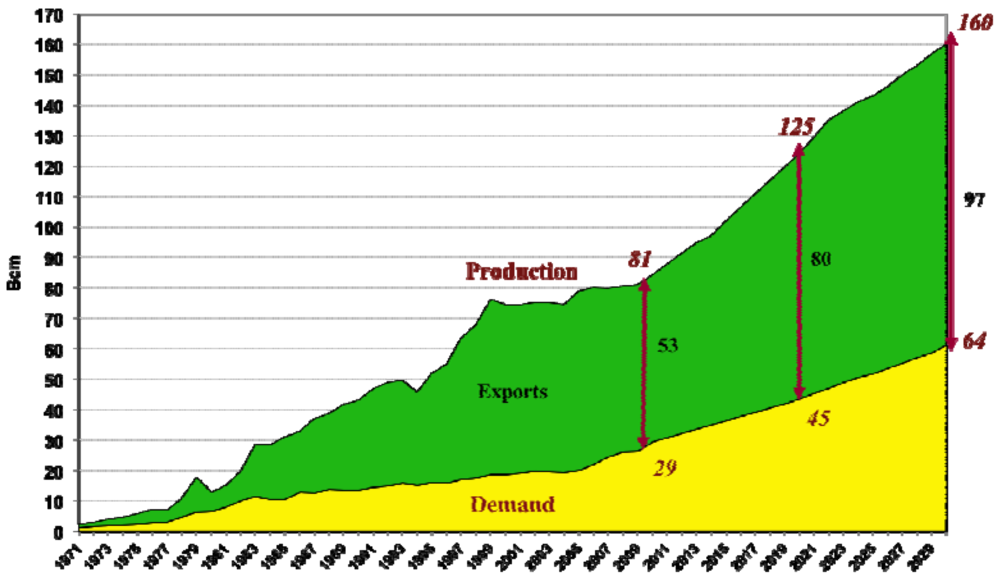
Source: Own elaborations based on Cedigaz (2011) and BP (2011).

Table 11. Algeria – Reference Scenario for natural gas

	Natural gas Production/Imports–Exports/Demand						
(Bcm)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–20 (%)**	**Average annual growth rate 2009–30 (%)**
Gas production	81,4	102,3	124,3	143	160,6	4,0	3,3
Gas imports/exports	-52,8	-64,9	-80,3	-89,1	-96,8	3,9	2,9
Gas demand	28,6	37,4	45,1	53,9	63,8	4,1	3,9
Electricity plants	-12,1	-14,3	-16,5	-19,8	-23,1	2,6	3,0
Gas transformation & losses	-5,5	-6,6	-7,7	-8,8	-8,8	2,4	2,3
Gas final consumption	11	16,5	20,9	25,3	30,8	6,0	5,1
Transport	*2,2*	*3,3*	*3,3*	*4,4*	*6,6*	*6,6*	*5,9*
Residential	*5,5*	*6,6*	*8,8*	*11*	*13,2*	*4,8*	*4,5*
Industry	*2,2*	*3,3*	*3,3*	*4,4*	*4,4*	*3,1*	*2,2*
Other consumption	*2,2*	*3,3*	*4,4*	*6,6*	*7,7*	*9,5*	*7,3*
Gas elect. output (TWh)	41,693	49	58,7	70	82	3,2	3,3
Gas inst. cap. (MW)	10.858	12.076	13.471	15.997	18.150	2,0	2,5

Source: Own elaborations for the MEDPRO Energy Reference Scenario.

Figure 22. Algeria – Gas production, demand and export potential (bcm)



Source: Own elaborations for the MEDPRO Energy Reference Scenario.

2.2.3 Egypt

Natural gas production and demand: Current situation

Egypt's marketed gas production was estimated at 61.3 bcm in 2010. Major producing areas are located in the West Delta Deep Marine concession, where five reservoirs – Scarab, Saffron, Simian, Sienna and Sapphire – were brought into production between 2003 and 2005.[25] Other major producing areas include the Western Desert, the Nile Delta and the Gulf of Suez oil fields. The country's gas production still has the potential to grow in the coming years with the following fields to overcompensate for the decline of more mature fields:

- in the Western Desert – the Khalda area and Alam El Shawish West;
- in the Nile Delta and Mediterranean Sea – Abu Qir, North Alexandria, North Bardawil, North Idku, Temsah, West El Manzala and the West Mediterranean Block 1 offshore; and
- offshore North Sinai – ONS (Seti Plio Tao and Kamose).

The Alam El Shawish concession is located in Egypt's Western Desert area. The production phase began in late 2007 and work is already underway to bring Alam El Shawish gas on-stream. In January 2010, a deal to transfer a 20% share of GDF Suez's Alam El Shawish concession to Shell Egypt was expected to allow the partners to accelerate the development of the Alam El Shawish gas discoveries. The new consortium will hence include Shell Egypt, which will become an operator with 40%, GDF Suez and Vegas Oil & Gas (35%). In 2010, BP signed a new agreement with the Egyptian authorities to develop the significant hydrocarbon resources in the North Alexandria and West Mediterranean deepwater concessions. According to BP (2011), production from the West Nile Delta development will provide a major new source of gas for the Egyptian market. Because of the stable consolidation of natural gas reserves following the discovery of several prolific gas fields in the offshore Mediterranean area, Egypt has emerged as an important LNG supplier since the mid-2000s, while its local gas industry has undergone remarkable development and become one of the most dynamic sectors of the economy. Yet the system of energy subsidies raises serious questions and challenges regarding the future prospects of natural gas supply in Egypt, especially after the end of the moratorium on new gas exports set in 2008.

Natural gas production and demand: Prospects up to 2030

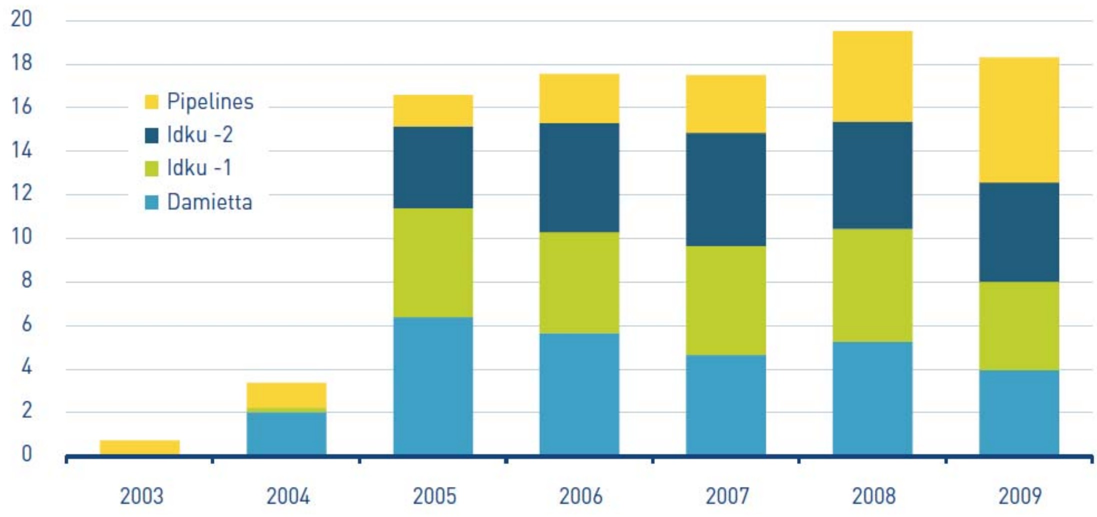
The MEDPRO Reference Scenario expects Egypt's gas production (which grew by 18% a year between 1970 and 2009) to reach 76 bcm in 2020 and nearly 90 bcm in 2030 (growing by 2.2% a year between 2009 and 2030). At the same time, the domestic gas demand is forecasted to grow from 40 bcm in 2009 to 65 bcm in 2030.

Natural gas exports

Egypt began exporting natural gas in 2003, at less than 1 bcm a year, through the Arab Gas Pipeline (AGP). Its gas exports have risen over time, reaching 18.3 bcm in 2009 (thanks to new LNG plants). LNG exports started in 2004 from two major complexes at 2.3 bcm in 2004 and grew to more than 15 bcm in 2008, and then fell to 12.6 bcm in 2009 and 9.7 bcm in 2010 due to lower market demand abroad and difficulties in increasing domestic production to satisfy the strong rise in Egyptian domestic demand. LNG accounted for 68% of the country's total natural gas exports in 2009 (e.g. Figure 23).

[25] Data source of this subsection: *Natural Gas Liquids: Supply Outlook 2008-2015*, IEA (2010).

Figure 23. Egypt's gas export developments (bcm)



Source: OME (2011a).

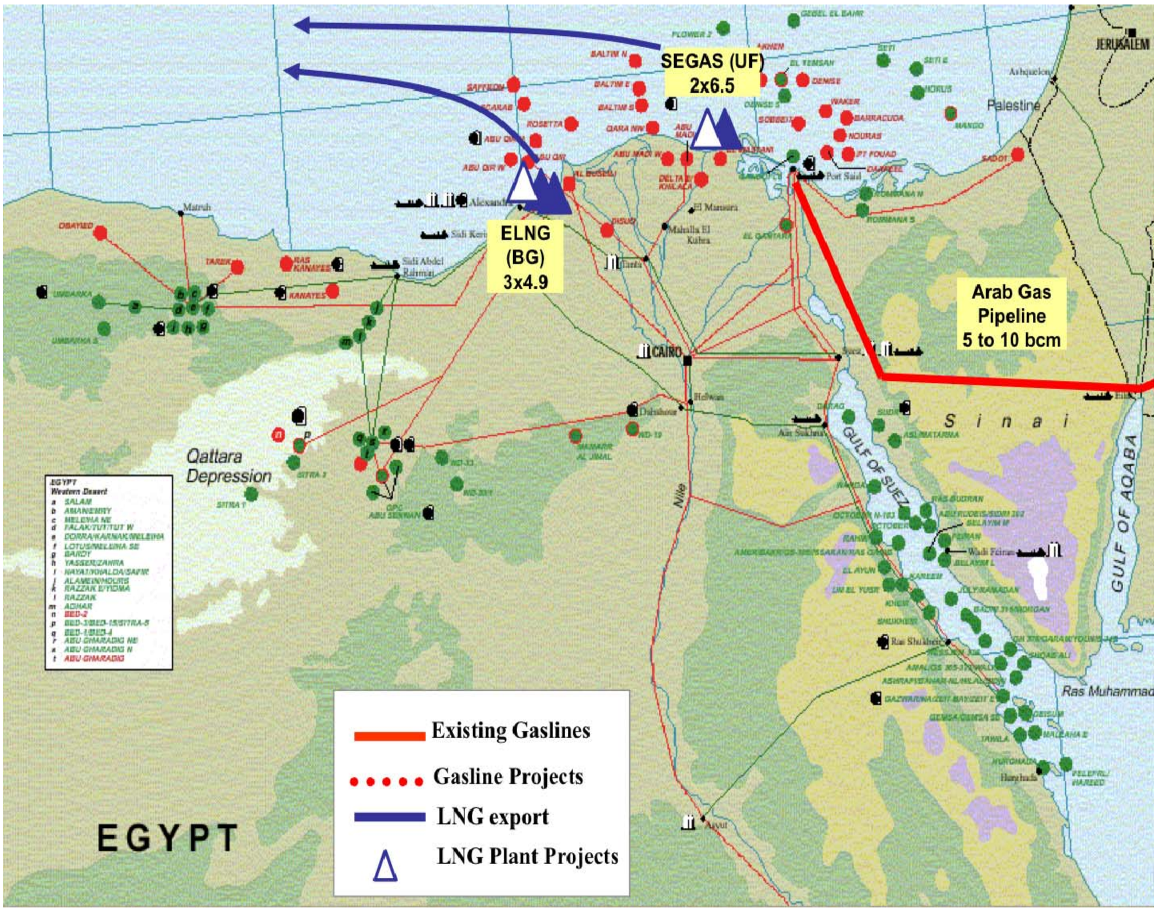
- Pipelines

  The AGP connects Egypt with neighbouring countries Jordan, Syria and Lebanon, while the subsea Arish–Ashkelon gas pipeline connects Egypt with Israel. Natural gas exports by pipeline started through the AGP in 2003 to Jordan. Egyptian gas – via the AGP – reached Syria in 2008 and Lebanon in 2009. Egypt's pipeline gas exports increased from less than 1 bcm in 2003 to nearly 6 bcm in 2009. To date, however, gas transportation via the AGP has been far below its design capacity of 10 bcm/year. The East Mediterranean Pipeline (Arish–Ashkelon) is a 90 km-long infrastructure with a capacity of 7 bcm. The pipeline is owned and operated by the East Mediterranean Gas Company, a joint stock company of Egyptian and Israeli interests organised in 2000. Operational since May 2008, the East Mediterranean Gas Company buys Egyptian gas for resale in Israel.

- LNG

  Egypt's LNG exports are based on the large Damietta and Idku liquefaction plants. The Damietta facility (60 km west of Port Said – see Figure 24) is owned by SEGAS (the Spanish–Egyptian Gas Company). The complex exports LNG to the Spanish market via a receiving terminal at Sagunto in Spain. The complex includes two trains, each with a capacity of 5 Mt/year. The Idku LNG facility (50 km east of Alexandria) can accommodate an expansion of up to six trains in total with potentially different ownership and sources of feed gas. Currently, two trains are up and running, each with a capacity of 3.6 Mt/year (e.g. Table 12). The facility is owned by Egyptian LNG, a joint venture comprising local shareholders (such as the Egyptian General Petroleum Company and EGAS) and foreign shareholders (such as BG Group, PETRONAS and Gaz de France).

Figure 24. Egypt's gas export infrastructure



Source: Own elaborations based on
Petroleum Economist (2011).

Table 12. LNG plants in Egypt

Site	No. of trains	Capacity (bcm/year)	Capacity (Mt/year)
Damietta	2	2x6,9	2x5
Idku – east of Alexandria	1	4,8	3,6
	1	4,8	3,6

Source: SEGAS and Egyptian LNG.

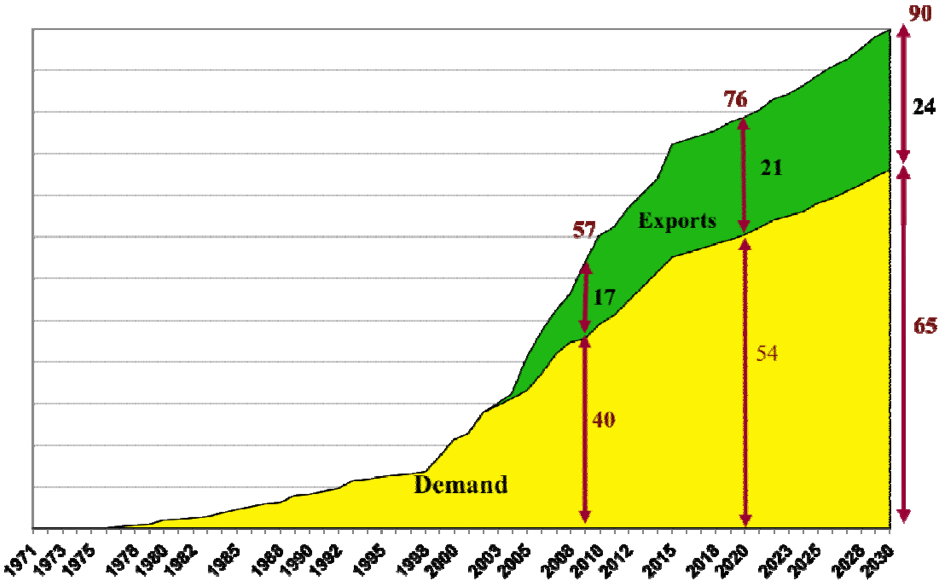
Egyptian gas exports could reach 24 bcm by 2030, by both pipeline to its eastern neighbours and LNG to world markets (e.g. Table 13 and Figure 25).

Table 13. Egypt – Reference Scenario for natural gas

(Bcm)	**Egypt – Natural gas Production/Exports/Demand**					
	2009	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–30 (%)**
Gas production	57,2	64,9	75,9	83,6	90,2	2,2
Gas net imports/exports	-17,6	-17,6	-22	-23,1	-24,2	1,7
Gas demand	39,6	47,3	55	60,5	64,9	2,4
Gas inputs in power plants	-20,9	-27,5	-33	-35,2	-37,4	2,8
Gas in transformation & losses	-6,6	-6,6	-5,5	-5,5	-5,5	-1,2
Gas final consumption	12,1	14,3	16,5	19,8	22	2,9
Transport	-	-	-	-	-	-
Residential	*1,1*	*1,1*	*1,1*	*2,2*	*2,2*	*6,7*
Industry	*11*	*12,1*	*13,2*	*16,5*	*17,6*	*2,3*
Other consumption	*0*	*0*	*1,1*	*1,1*	*1,1*	*15,3*
Gas electricity output (TWh)	90	141	156	174	188	3,6
Gas installed capacity (MW)	18 213	28 840	34 724	40 330	45 591	4,5

Source: Own elaborations for the MEDPRO Energy Reference Scenario.

Figure 25. Egypt – Gas production, demand and export potential (bcm)



Source: Own elaborations for the MEDPRO Energy Reference Scenario.

2.2.4 Libya

Natural gas production and demand: Current situation

Libya's marketed production was estimated at 18 bcm in 2009. Associated gas with oil represents about three-quarters of this production, explaining the large portion of flared losses (11% of the gross output) and reinjection (12%).[26] The Sirte Basin is the most important production area for the domestic market and the LNG plant in Marsa el-Brega. Production in the Sirte Basin includes these non-associated gas fields: Attahaddy (3 bcm/year), Hatiba, Sahl, and Assumud, and associated gas from the oil fields of Defa-Waha and Zelten. In the eastern part of the country, the onshore Wafa field in the south and the offshore Bahr Essalam field supply the Greenstream export pipeline and are expected to supply gas for power generation (the Western Libya Gas Project). The capacity of the two fields is estimated at 10-11 bcm/year. Expansion of natural gas production is a high priority for Libya, in order to increase its exports – mainly to Europe – and to use natural gas instead of oil for domestic power generation (freeing up more crude oil for export).

Besides Eni, which is leading the field among private companies as regards the exploitation of Libya's gas resources, the government has attracted some foreign companies to carry out exploration and development activities. In May 2005, Shell signed an agreement with the National Oil Corporation to carry out an integrated gas project comprising the renovation of the existing LNG plant at Marsa el-Brega, possible development of a new one and the exploration of five blocks in the Sirte Basin. In May 2007, an exploration agreement signed with BP provides for it to explore extensive areas of the Sirte and Ghadames Basins.

Because of its small population (about 6 million people, the lowest in North Africa), Libya's domestic gas consumption remains quite low, at about 8.7 bcm per year (mostly for fertilizer and power plants). Forecasts predict possible growth in domestic demand up to 14 bcm by 2020 and 20 bcm by 2030. The most important increase in gas demand will come from the power generation sector (from 3 bcm in 2009 to more than 10 bcm in 2030). An even more important increase in domestic gas demand would mainly depend on the expansion of Libya's gas distribution network, especially a coastal pipeline eastward to Benghazi, which would cover all industrial plants (from 4.9 bcm of gas needed in 2009 to 8.3 bcm in 2030).

Natural gas production and demand: Prospects up to 2030

According to the MEDPRO Reference Scenario, Libya's gas production is likely to reach 29 bcm in 2020 and nearly 39 bcm in 2030. The country's domestic gas demand is set to grow to almost 20 bcm in 2030 (of which 10 bcm will be needed by the power generation sector).

Natural gas exports

In 2010, Libya exported 9.41 bcm of natural gas to Italy (via pipeline) and 0.34 bcm to Spain (via LNG). The amount of natural gas exported to Italy has grown considerably over the past several years and currently covers 12% of Italy's total gas demand. Once the situation in Libya stabilises from the recent political uprising and the national economy recovers, the level of gas exports could undoubtedly increase.

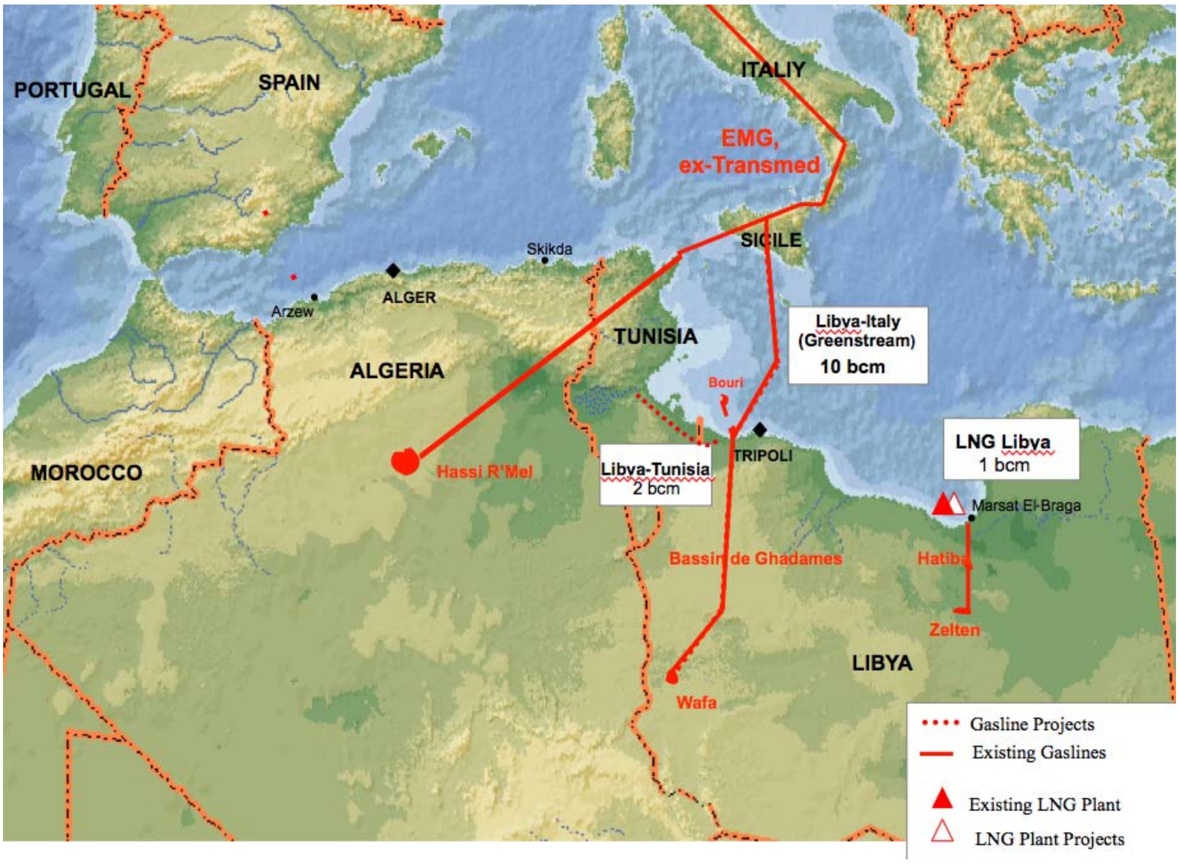
Libyan natural gas is piped from the Wafa concession and the offshore Bahr es Salam fields to Mellitah, where it is treated for export. Libya has one LNG terminal (operative since 1971) located in Marsa El Brega, with a capacity of 1 bcm/year. This capacity is projected to increase up to 4.3 bcm/year by 2013. A second LNG terminal is being planned in Mellitah. The country is linked to Europe through the Greenstream offshore pipeline. The pipeline, operative since 2004, runs from Mellitah to Gela (Sicily). Its current capacity is 10 bcm/year and take-or-pay contracts are set with Edison Gas (4 bcm/year), Sorgenia (2 bcm/year) and GDF (2 bcm/year).

A transnational, onshore gas pipeline connecting Mellitah to Gabes (Tunisia) has been proposed. The pipeline would be 266 km long, and would have an initial capacity of 2 bcm per year. There is still no certainty about this project, however; no real progress has been made and the future of the project is dependent on the Libyan government guaranteeing the gas supplies.

[26] Data sources: IEA (2010) and Bayphase Ltd (2012).

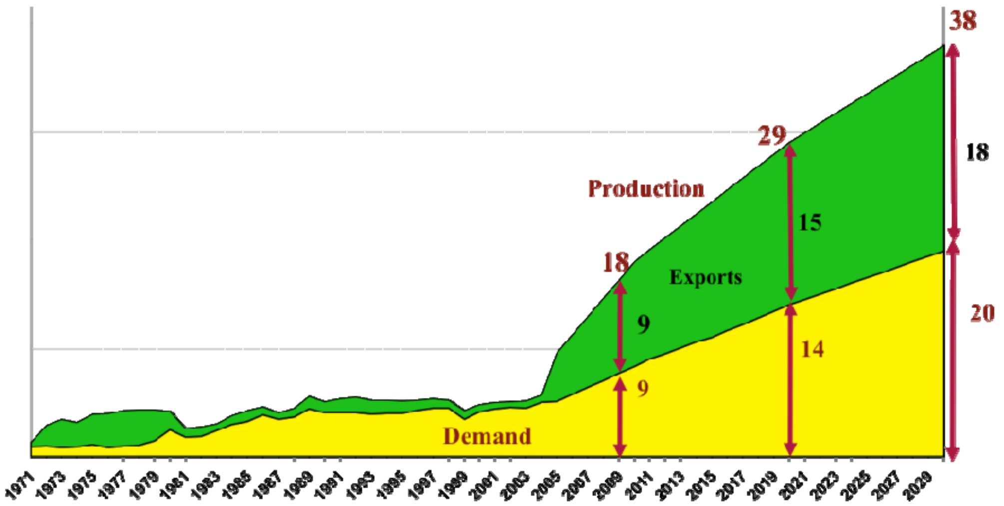
The MEDPRO Reference Scenario expects that by 2020, Libyan gas export capacity could reach nearly 15 bcm. Because of Libya's gas reserves and resource base, along with the economic competitiveness of its exports to Europe (thanks to its proximity), the export potential of Libya is expected to reach about 19 bcm by 2030 (e.g. Figures 26 and 27, and Table 14).

Figure 26. Libya's gas export infrastructure



Source: Own elaborations based on BP data.

Figure 27. Libya – Gas production, demand and export potential (bcm)



Source: Own elaborations for the MEDPRO Energy Reference Scenario.

Table 14. Libya – Reference scenario for natural gas

	Natural gas Production/Exports/Demand					
(Bcm)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–30 (%)**
Gas production	17,6	22	28,6	31,9	38,5	3,7
Gas net imports/exports	-8,8	-9,9	-14,3	-14,3	-18,7	3,4
Gas demand	8,8	11	14,3	16,5	19,8	4,0
Gas inputs in power plants	-3,3	-4,4	-6,6	-7,7	-9,9	6,0
Gas in other transformation & losses	-1,1	-1,1	-1,1	-1,1	-1,1	2,5
Gas final consumption	4,4	6,6	6,6	7,7	8,8	2,5
Transport	-	-	-	-	-	-
Residential	-	-	-	-	-	-
Industry	*4,4*	*6,6*	*6,6*	*7,7*	*8,8*	*2,5*
Other consumption	-	-	-	-	-	-
Gas electricity output (TWh)	10	15	22	30	40	6,9
Gas-based capacity (MW)	2 430	3 750	5 500	7 500	10 000	7,0

Source: Own elaborations for the MEDPRO Energy Reference Scenario.

2.2.5 Tunisia

Natural gas production and demand: Current situation and prospects up to 2030

In Tunisia, marketed production increased from 2.97 bcm in 2000 to 3.6 bcm in 2009.[27] This expansion was supported by production from the offshore Miskar field (Gulf of Gabes), which provides around 40% of domestic gas, and the offshore Hasdrubal field that came on-stream in 2009 (e.g. Table 15).

BG Group is the largest foreign gas company in Tunisia. It owns 100% interest in the Miskar field and 50% in the Hasdrubal field. Eni and Perenco are the other main foreign companies involved in the gas sector (in association with Tunisia's national oil company, ETAP). There are a few other fields that could be developed in the future, such as the Jugurtha field (20 km west of Miskar), although it contains a high fraction of carbon dioxide. Tunisia is substituting natural gas for petroleum products (fossil-fuelled power generation has been switching to natural gas and LPG is expected to be substituted in small industry and in the commercial and housing sectors).

In the MEDPRO Reference Scenario, Tunisia's gas production will stay at around 4 bcm over the next decade or so, declining to 3.3 bcm around 2030. The country's gas demand is expected to rise over the coming years, from 4.4 bcm in 2009 to 6.6 bcm in 2020 and to 7.5 bcm in 2030. This rise is mainly due to gas electricity output, set to grow from 13 TWh in 2009 to 28 TWh in 2030.

[27] Data source: IEA (2010).

Table 15. Tunisia – Reference scenario for natural gas

	Natural gas Production/Exports/Demand				
(Bcm)	**2009**	**2015**	**2020**	**2025**	**2030**
Gas production	3,15	3,6	3,9	4,3	3,7
Gas net imports/exports	1,2	2,1	2,1	2,7	3,7
Gas demand	4,4	5,7	6,1	7,1	7,5
Electricity plants (gas input)	-3,6	-4,4	-4,5	-5,3	-5,5
Other gas transformation & losses	0	0	0	0	0
Gas final consumption	1,2	1,3	1,5	1,8	1,9
Transport	*0*	*0*	*0*	*0*	*0*
Residential	*0*	*0*	*0*	*0*	*0*
Industry	*0,7*	*0,9*	*1,1*	*1,3*	*1,4*
Other consumption	*0*	*0*	*0*	*0*	*0*
Gas electricity output (TWh)	13	19,8	21	25	28
Gas-burning installed capacity (MW)	2.269	3.348	4.048	4.250	5.787

Source: Own elaborations for the MEDPRO Energy Reference Scenario.

2.2.6 Turkey

Natural gas demand and imports: Current situation and prospects up to 2030

Turkish natural gas reserves were estimated at 6 bcm in 2011. The growth of energy demand in Turkey has been among the fastest in the world, although the recent economic downturn has dampened some of this growth.[28] Turkey produces a very small amount of natural gas, with the total production amounting to 0.7 bcm in 2010. There are 14 gas fields in Turkey, the largest of which is Marmara Kuzey, an offshore field in the Sea of Marmara in the Thrace–Gallipoli Basin. Gas production is mainly carried out by three companies: TPAO, BP and Shell. Turkey's gas demand has increased rapidly, hitting a peak of 37 bcm in 2009, up from 12 bcm in 2000. Natural gas is mainly used in power generation and space heating, and consumption growth is expected to remain strong as rising electricity consumption and new power plants will continue to spur demand. Most of Turkey's gas imports come from Russia, with Gazprom sending gas to north-west Turkey via the Balkans as well as to central Turkey via the Blue Stream pipeline that links Russia to Turkey across the Black Sea. Turkey also imports gas via pipeline from Iran and Azerbaijan, as well as LNG supplies under contract with Algeria and Nigeria. Turkey began receiving gas from Azerbaijan's Shah Deniz field in 2007 to help offset rising consumption. Rising demand combined with often irregular deliveries of gas from Iran have periodically forced Turkey to request additional deliveries of gas from Russia to meet domestic demand requirements. The MEDPRO Reference Scenario expects Turkey's gas demand to reach about 55 bcm in 2020 and nearly 78 bcm in 2030 (e.g. Table 16).

[28] Refer to Tagliapietra (2012).

Table 16. Turkey – Reference scenario for natural gas

	Natural gas Imports/Demand				
(Bcm)	**2009**	**2015**	**2020**	**2025**	**2030**
Gas net imports/exports	30,4	48,7	54,6	65,4	77,7
Gas demand	32,5	49,1	54,6	65,4	77,7
Electricity plants (gas input)	-17,2	-14,9	-20,1	-21,1	-27,9
Gas final consumption	15,4	28,6	33	37,4	40,7
Transport	0	0	0	0	0
Residential	10,9	10,9	22,5	25,7	28,6
Industry	4,1	5,8	7,2	8,1	8,9
Other consumption	0	0	0	0	0
Gas electricity output (TWh)	94	115	122	165	217
Gas-burning installed capacity (MW)	14.204	14.507	15.380	21.158	28.246

Source: Own elaborations for the MEDPRO Energy Reference Scenario.

2.2.7 Other south-eastern Mediterranean countries

Natural gas production and demand: Current situation and prospects up to 2030

Natural gas production in the OSE countries (Israel, Jordan, Lebanon, the Palestinian Territories and Syria) was estimated at 5.5 bcm in 2009.[29] The MEDPRO Reference Scenario estimates that this production level could reach nearly 16 bcm in 2020 and 31 bcm in 2030. As mentioned above (e.g. section 1.2.5 on the Levantine Basin), an important geological reassessment of the oil and gas potential of the eastern Mediterranean area is presently underway. If the expectations are confirmed, the area could become a world-class hydrocarbon province, consequently changing the regional energy and geopolitical scenario.

According to the MEDPRO Reference Scenario, the gas demand in the OSE countries will dramatically increase over the next decades, from 11 bcm in 2009 to 20 bcm in 2020 and to 28 bcm in 2030. This trend mainly stems from a massive increase in gas-based electricity generation, expected to surge from 30 TWh in 2009 to 105 TWh in 2030 (e.g. Table 17).

Table 17. OSE countries – Reference scenario for natural gas

	Natural gas Production/Imports–Exports/Demand					
(Bcm)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–30 (%)**
Gas production	5,6	9,1	15,7	24,4	31,1	8,4
Gas net imports/exports	5,2	8,1	3,8	-1,6	-3,8	-1,9
Gas demand	10,9	17,3	19,6	22,7	27,2	4,5
Electricity plants (gas input)	-8,7	-15,1	-17,1	-17,9	-19,5	3,9

[29] Data sources of this subsection: Cedigaz and BP (2011).

Table 17. cont'd.

Gas final consumption	2,0	2,1	2,3	4,6	7,5	6,6
Transport	*0*	*0*	*0*	*0*	*0*	-
Residential	*0*	*0*	*0*	*1,1*	*2,2*	-
Industry	*1,1*	*1,1*	*1,1*	*2,2*	*3,3*	*8,6*
Other consumption	*1,1*	*1,1*	*2,2*	*2,2*	*2,2*	*2,4*
Gas electricity output (TWh)	39	65	78	91	105	4,8
Gas-burning installed capacity (MW)	7.958	11.000	13.000	17.000	20.000	4,5

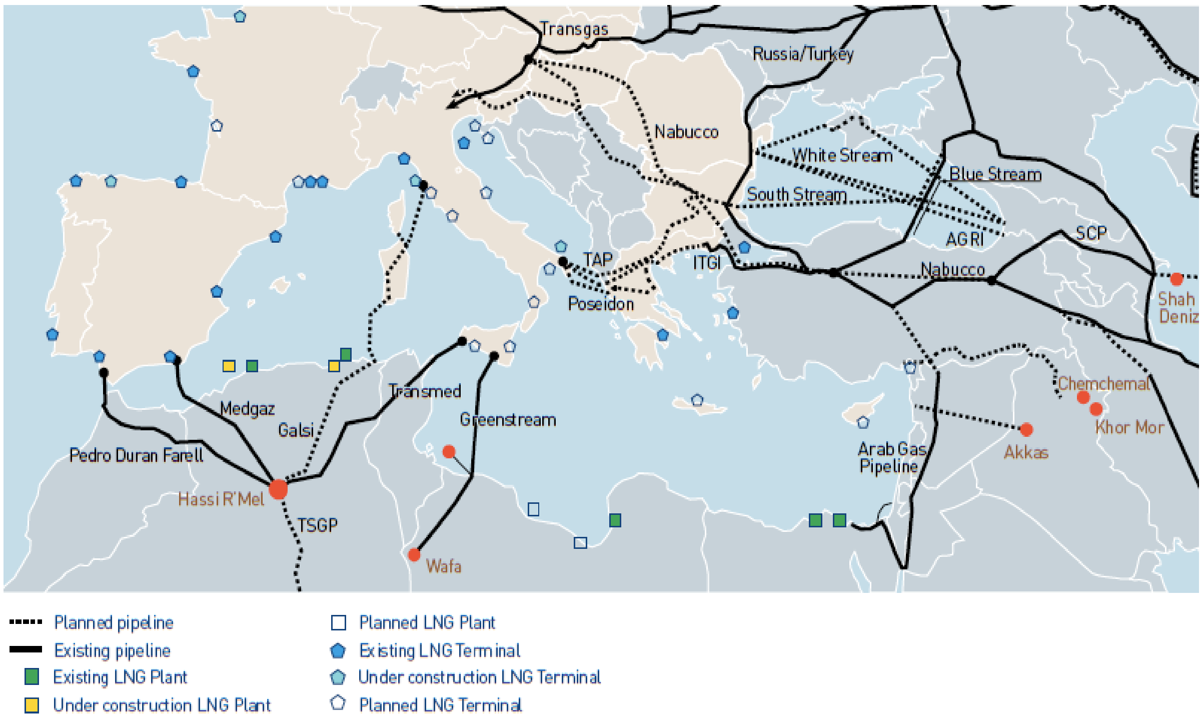
Source: Own elaborations for the MEDPRO Energy Reference Scenario.

2.3 MED-11: Natural gas infrastructure

2.3.1 MED-11 overview

The capacity of the existing infrastructure for gas exports in the MED-11 is nearly 160 bcm/year, of which 116 bcm/year relates to ten international pipelines and 44 bcm/year to seven LNG plants located on the Mediterranean coast.[30] The majority of this overall 160-bcm/year export capacity is concentrated in North African countries (nearly 110 bcm/year): Algeria, with 77 bcm/year (three pipelines and four LNG plants); Egypt, with 21 bcm/year (one pipeline and two LNG plants); and Libya, with 12 bcm/year (one pipeline and one LNG plant) (e.g. Figure 28).

Figure 28. Natural gas infrastructure in the Mediterranean region



Source: OME (2011b).

[30] See *Infrastructures & sustainable energy development in the Mediterranean: Outlook 2025*, El Elandaloussi (2010).

2.3.2 Gas pipeline infrastructure

In the Mediterranean region, nine pipelines are in operation:

- Enrico Mattei Pipeline (Algeria–Italy, via Tunisia), 1983, 30 bcm/year;
- Pedro Duran Farell Pipeline (Algeria–Spain, via Morocco), 1997, 12 bcm/year;
- Medgaz (Algeria–Spain, direct submarine pipeline), end 2010, 8 bcm/year;
- Greenstream Pipeline (Libya–Italy, direct submarine), 2004, 11 bcm/year;
- Arab Gas Pipeline (Egypt–Jordan–Lebanon–Syria), 2003, 6 bcm/year;
- Russia–Turkey (first onshore pipeline to Turkey), 1987, 14 bcm/year;
- Blue Stream (Russia–Turkey, direct submarine), 2004, 16 bcm/year;
- South Caucasus Gas Pipeline (Shah Deniz, Azerbaijan–Erzurum, Turkey), 2007, 7 bcm/year; and
- the Egypt–Israel Pipeline (Arish–Ashkelon, submarine), 7 bcm/year; 2008.

2.3.3 LNG infrastructure

Given the global dimension of the LNG industry, it is necessary to place the MED-11 LNG infrastructure system in the broader context of the global LNG industry.[31] At the end of 2011, the world LNG industry included 17 exporting countries, for a total liquefaction capacity of 280 Mt/year. Algeria is the pioneer in the LNG industry, while Libya entered this market in 1971 and Egypt in 2005.

In northern Mediterranean countries, many expansions of the existing LNG terminals have occurred over the last few years (from 82 bcm in 2007 to 120 bcm in 2009, expected to reach 189 bcm by 2015). The largest share of the future additions to capacity concern Italy (+16 bcm), Spain (+13.6 bcm), Portugal (+5 bcm) and France (+4.5 bcm).

Table 18. Projected evolution of the regasification capacity in Europe over 2009–15 (Mt/year)

	2007	2008	End 2009	2010	2011	2012	2013	2014	2015	Additional capacity 2009 - 2010	Additional capacity 2010 - 2015	Under construction 2010 - 2015
Europe	**81.5**	**93.6**	**120.3**	**133.1**	**153**	**153**	**160.6**	**184.9**	**189.65**	**12.8**	**56.6**	**23.9**
France	12.8	12.8	19	19	19	19	19	23.5	23.5	0	4.5	
Belgium	4.5	8	8	8	8	8	8	8	8	0	0.0	
Greece	1	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	0	0.0	
Italy	2.7	2.7	8.7	8.7	11.6	11.6	11.6	21.6	25.4	0	16.7	2.9
Portugal	3.9	3.9	3.9	3.9	3.9	3.9	8.9	8.9	8.9	0	5.0	5.0
Spain	40	40	42.3	42.3	50.3	50.3	52.9	54.9	55.9	0	13.6	7.0
Turkey	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	0	0.0	
UK	7.5	13.9	26.1	38.9	38.9	38.9	38.9	42.9	42.9	12.8	4.0	
Poland & Lithuania								3.75	5.25	0	5.3	
Netherlands	0	0	0	0	9	9	9	9	9	0	9.0	9.0

Source: Cedigaz (2011).

[31] Data sources of this subsection: *The LNG Industry in 2011*, GIIGNL (2011); Cedigaz (2011).

Despite the world economic recession and its impact on overall energy demand, the world LNG trade recorded strong expansion worldwide. In fact, according to Cedigaz (2011) it reached a volume of 296 bcm in 2010 (54 bcm or 22% more than in 2009) (e.g. Table 19).

Table 19. Evolution of LNG exports by main exporting country, 2009–10

	bcm		%		
Exports	**2009**	**2010**	**2009**	**2010**	**Growth**
Qatar	49.44	75.75	20.4%	25.6%	53.2%
Indonesia	26.00	31.56	10.7%	10.7%	21.4%
Malaysia	29.53	30.54	12.2%	10.3%	3.4%
Australia	24.24	25.36	10.0%	8.6%	4.6%
Nigeria	15.99	23.89	6.6%	8.1%	49.4%
T. & Tobago	19.74	20.38	8.1%	6.9%	3.2%
Algeria	20.90	19.31	8.6%	6.5%	-7.6%
Russia	6.61	13.40	2.7%	4.5%	102.7%
Oman	11.54	11.49	4.8%	3.9%	-0.4%
Egypt	12.82	9.71	5.3%	3.3%	-24.3%
Others	25.72	34.88	10.6%	11.8%	35.6%
TOTAL	**242.53**	**296.27**	**100.0%**	**100.0%**	**22.2%**

Source: Cedigaz (2011).

Qatargas 4 (QG4), which started producing LNG in January 2011, has completed the planned LNG expansion programme in Qatar. The QG4 project involved the construction of a new LNG mega-train (train 7) with a production capacity of 7.8 Mt/year. At the same time, Australia's Pluto train 1 came online in mid-2011, with a capacity of 4.3 Mt/year. Furthermore, between January 2012 and December 2015, ten new liquefaction plants, currently under construction, are expected to come on-stream, providing additional LNG production capacity of 36.1 Mt/year. The building schedule of these LNG plants during this period is as follows: the Angola LNG train 1 in the second quarter of 2012 (+5.2 Mt/year); the Skikda train rebuild by 2014 (+4.5 Mt); Algeria's Arzew 3 in the third quarter of 2013 (+4.7 Mt/year); the Gorgon train 1 in the last quarter of 2014; the PNG trains 1 and 2 in 2015. Following these developments, the global liquefaction capacity is forecast to reach 320 Mt by the end of 2015.

There are seven LNG plants in the MED-11, for a total capacity of more than 44 bcm/year (more than 13% of the world's capacity installed – 330 bcm/year in 2010). Four LNG plants are located in Algeria, another two in Egypt and one in Libya. In 2010, MED-11 gas-producing countries (Algeria, Egypt and Libya) exported 29 bcm of gas by LNG. By 2014, two new LNG plants – currently under construction in Algeria – are expected to come on-stream, providing additional LNG production of +9.2 Mt/year: the first concerns Algeria's Skikda train rebuild and the second is Algeria's Arzew 3 (both described above). The LNG plant planned in Egypt in addition to the existing facilities of Damietta and Idku has been postponed. In Libya, the project to restore the existing LNG plant in Marsat El Brega and the project to build another LNG plant have been frozen since the recent political uprising (e.g. Table 20).

Table 20. Natural gas: Trade movements from Algeria, Egypt and Libya in 2010 (bcm)

	To	**Algeria**	**Egypt**	**Libya**	**Total MED-11**	**Pipeline imports**	**LNG imports**	**Total imports**
1	US	-	2,07	-	2,1	93,3	12	105
2	Mexico	-	0,16	-	0,2	9,4	6	15
3	Chile	0,17	0,55	-	0,7	0,3	3	3
4	Belgium	-	0,17	-	0,2	18,1	6	25
5	France	6,27	0,73	-	7,0	35,0	14	49
6	Greece	1,0	0,08	-	1,1	2,7	1	4
7	Italy	27,6	0,72	9,41	37,7	66,3	9	75
8	Portugal	1,4	-	-	1,4	2,0	3	5
9	Slovenia	0,4	-	-	0,4	0,9	0	1
10	Spain	12,1	2,62	0,34	15,0	8,9	28	36
11	Turkey	3,9	0,27	-	4,1	28,8	8	37
12	UK	1,3	0,12	-	1,4	35,0	19	54
13	Morocco	0,5	-	-	0,5	0,5	0	1
14	Tunisia	1,3	-	-	1,3	1,3	0	1
15	Israel	-	2,10	-	2,1	2,1	0	2
16	Jordan	-	2,5	-	2,5	2,5	0	3
17	Kuwait	-	0,3	-	0,3	0,0	3	3
18	Lebanon	-	0,2	-	0,2	0,2	0	0
19	Syria	-	0,7	-	0,7	0,7	0	1
	Pipeline exports	**36,5**	**5,5**	**9,4**	**51,4**	**678**	**-**	**-**
	LNG exports	**19,3**	**9,7**	**0,3**	**29,4**	**-**	**298**	**-**
	Total exports	***55,8***	***15,2***	***9,8***	**-**	***678***	***298***	***975***

Source: Cedigaz and BP (2011).

Part B. Oil

3. Oil in the MED-11

3.1 Overview

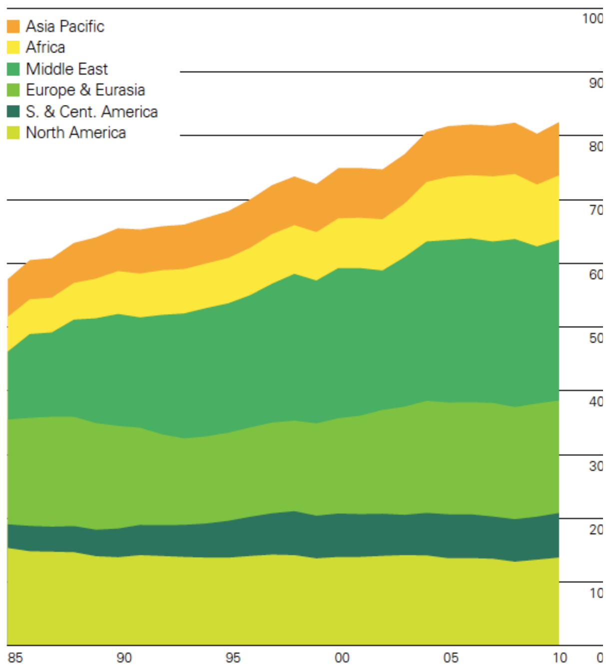
The Mediterranean region accounted for nearly 6% of global oil production in 2011. The main oil-producing and exporting countries in the region are Algeria, Libya and Egypt.[32] Precisely, in 2010 Algeria was the 16th oil-producing country in the world at 1,809 million barrels per day (bbl/d) and Libya was the 18th producing country at 1,659 million bbl/d (e.g. Table 21, Figure 29).

Table 21. Oil production (million barrels daily)

1.	Russian Federation	10.270
2.	Saudi Arabia	10.007
3.	US	7.513
4.	Iran	4.245
5.	China	4.071
6.	Canada	3.336
7.	Mexico	2.958
8.	UAE	2.849
9.	Kuwait	2.508
10.	Venezuela	2.471
11.	Iraq	2.460
12.	Nigeria	2.402
13.	Norway	2.137
14.	Brazil	2.137
15.	Angola	1.851
16.	Algeria	**1.809**
17.	Kazakhstan	1.757
18.	Libya	**1.659**
19.	Qatar	1.569

Source: BP (2011).

Figure 29. Oil production by region (million barrels daily)



Source: BP (2011).

3.2 MED-11 oil production

The MEDPRO Energy Reference Scenario estimates that the oil production of the MED-11 increased from 66 Mtoe in 1970 to 249 Mtoe in 2009 (e.g. Figure 30). In 2009, MED-11 oil production was led by Algeria (97 Mtoe), followed by Libya (90 Mtoe), Egypt (35 Mtoe), OSE countries (19 Mtoe) and Tunisia (6 Mtoe).[33]

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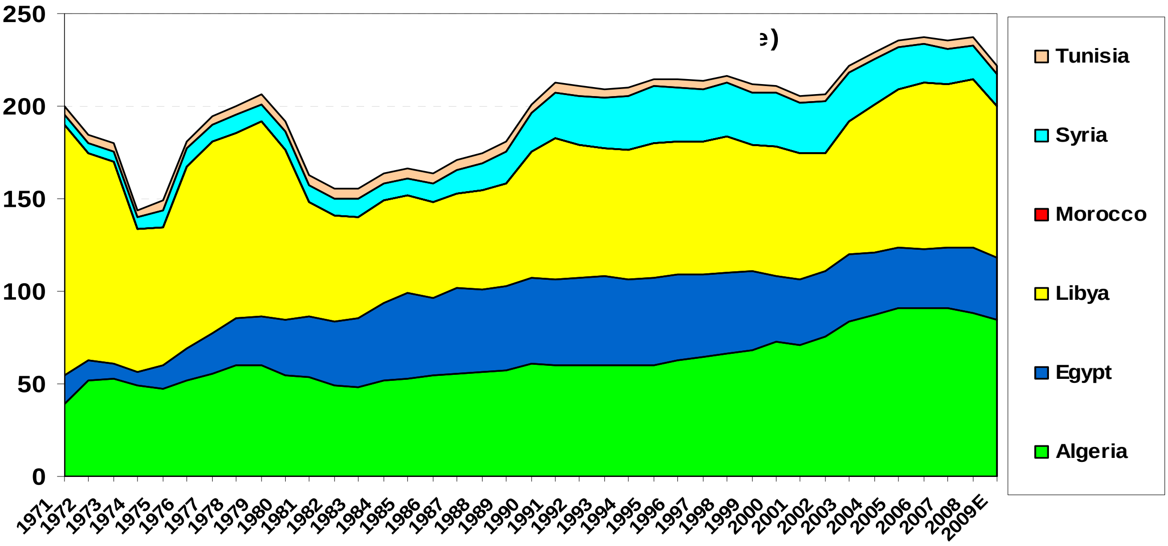
[32] Data sources of this section: BP (2011) and Sonatrach (2010).

[33] Data source: BP (2011).

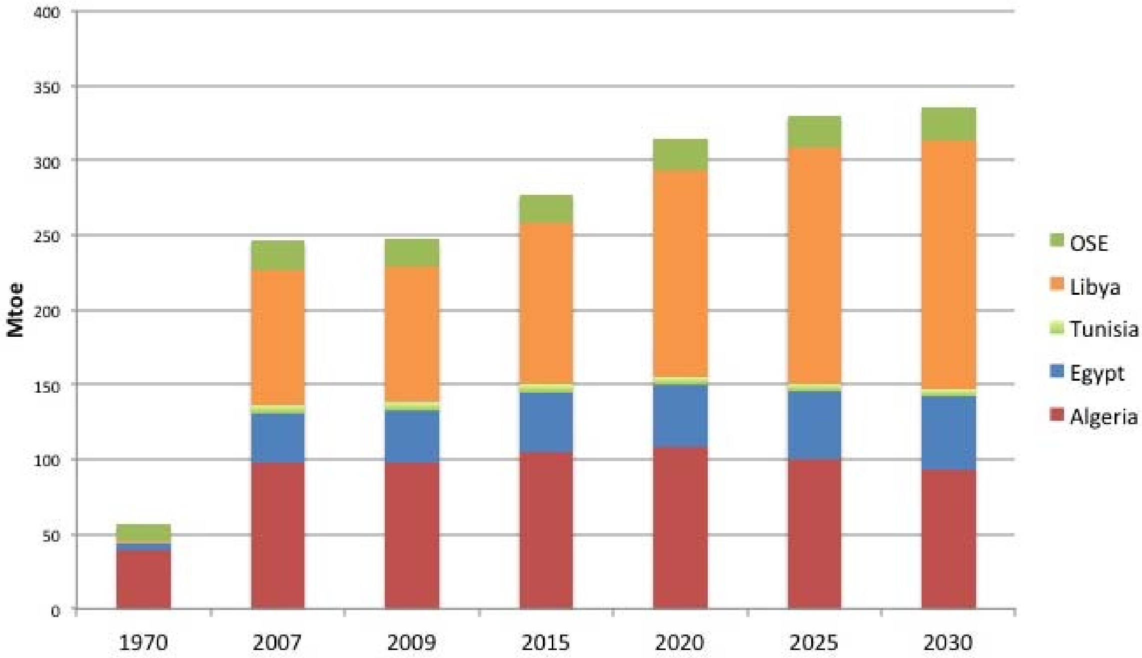
Figure 30. MED-11 crude oil production 1970–2009, by country



Source: Own elaborations based on data from the IEA.

In the MEDPRO Reference Scenario, MED-11 oil production will reach 309 Mtoe in 2020 and 318 Mtoe in 2030 (e.g. Figure 31). In that year, Libya is expected to produce about 167 Mtoe of oil, followed by Algeria (93 Mtoe), Egypt (32 Mtoe), OSE countries (22 Mtoe) and Tunisia (4 Mtoe).

Figure 31. Oil production in the MED-11 (1970–2030)



Source: Own elaborations for the MEDPRO Energy Reference Scenario.

Table 22. MED-11 Energy Reference Scenario for oil

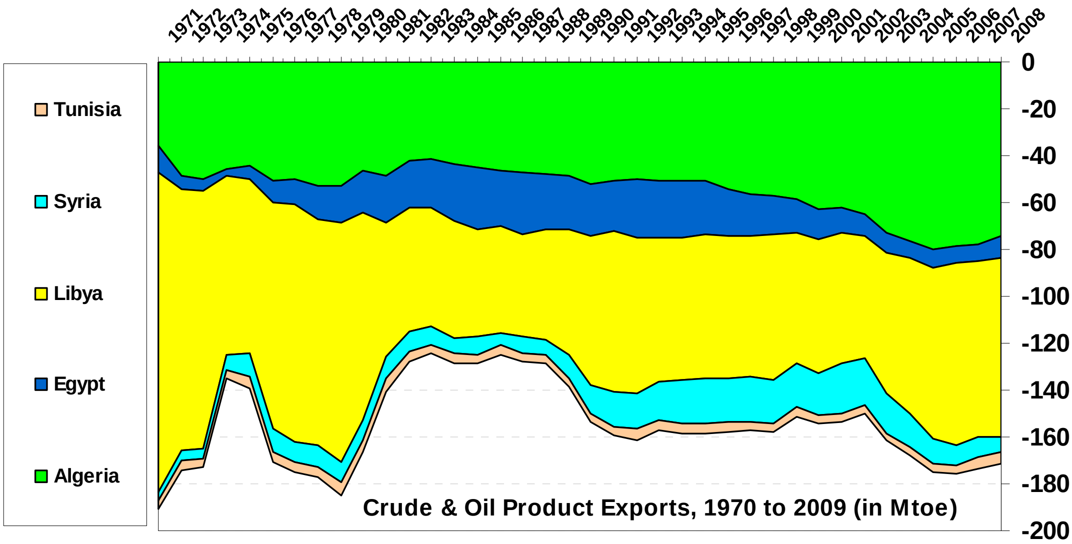
	Oil Production/Imports–Exports/Demand					
(Mtoe)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–30 (%)**
Oil production	249	277	309	319	318	1,2
Net imports/exports	-111	-110	-123	-118	-103	-0,3
Total oil supplies	139	167	185	200	214	2,1
Electricity plants (inputs)	-22	-29	-32	-35	-37	2,4
Other transformation & losses	-8	-9	-9	-9	-10	0,6
Total final consumption	105	130	144	156	168	2,3
Transport	54,2	66	73	80	87	2,3
Residential	16,3	20	22	22	23	1,6
Industry	15,9	22	23	24	24	2,0
Other consumption	19,8	23	26	30	34	2,6
Electricity output (oil) (TWh)	103	121	136	147	155	2,0
Installed capacity (oil) (MW)	10115	13988	15982	17994	19500	3,2

Source: Own elaborations for the MEDPRO Energy Reference Scenario.

3.3 MED-11 oil trade

The overall Mediterranean region is a net oil importer: in 2009 it imported more than 170 Mtoe of combined crude and oil products (e.g. Figures 32 and 33).[34] The MEDPRO Energy Reference Scenario estimates that the region will remain a net oil importer also in the period up to 2030, mainly owing to Turkey and Israel. Yet the net oil balance of MED-11 countries will maintain an upward trend, primarily due to the oil production of Algeria and Libya.

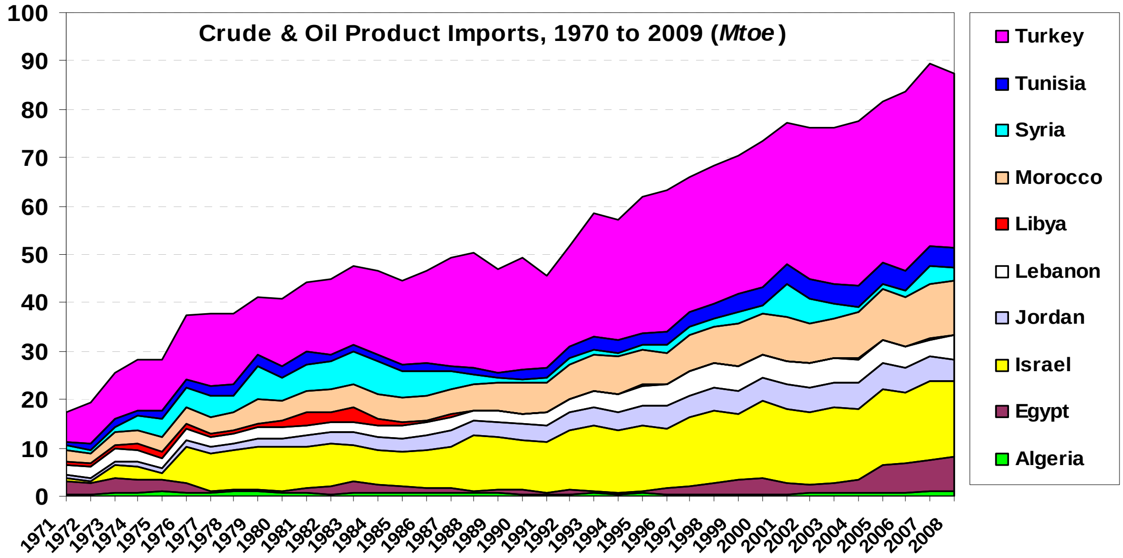
Figure 32. MED-11 oil exports 1970–2009, by country (Mtoe)



Source: Own elaborations based on data from the IEA.

[34] Data sources of this section: totalising from the source of the figures, *Energy Balances of Non-OECD Countries*, statistics publication and CD-ROMs, IEA (2012); BP (2011).

Figure 33. MED-11 oil imports 1970–2009, by country (Mtoe)

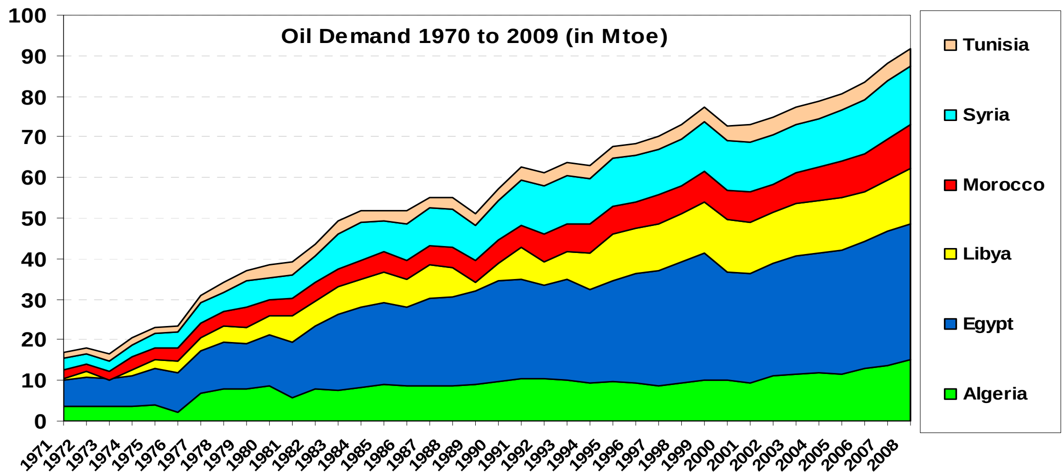


Source: Own elaborations based on data from the IEA.

3.4 MED-11 oil demand

MED-11 oil demand increased on average by 4.1% per year from 1970 to 2009 – from 29 Mtoe in 1970 to 139 Mtoe in 2009 (e.g. Figure 34).[35] MED-11 oil consumption in the transport sector increased on average by 4.7% per year from 1970 to 2009, reaching 54 Mtoe in 2009. The industry sector was the second-largest consumer of petroleum products at the beginning of the 1970s, with a share of total oil demand over 20% – a share that had dropped to 11% by 2009. Although oil use in the residential and the power generation sectors increased in absolute values, their shares in total oil consumption slightly decreased over the period.

Figure 34. Oil demand 1970–2009, by country (Mtoe)



Source: Own elaborations based on data from the IEA.

In the MEDPRO Reference Scenario, MED-11 oil demand will grow steadily at around 2.2% per year between 2009 and 2030, to reach 215 Mtoe in 2030, with Turkey (+20 Mtoe), Egypt (+18 Mtoe) and Algeria (+10 Mtoe) fixed as the main contributors to the growth. Transportation is expected to remain the largest oil-consuming sector in 2030, followed by the industrial sector and the residential sector.

[35] Data sources of this section: IEA Statistics, "Energy Balances", by country (http://iea.org/stats/); BP (2011).

MED-11 final oil consumption for the power generation sector is set to increase somewhat over the next decades, as it is assumed that there will be no more market for these products in OECD countries and that Mediterranean refineries (because of their refining structure) will continue to produce a large amount of heavy fuel oil. For this reason, heavy fuel oil prices will be very low, allowing MED-11 countries to use it in dual-fuel power plants.

3.5 MED-11 oil transport infrastructure

Several different, international oil pipelines connect the Mediterranean region with neighbouring countries and regions[36] (see also Figure 35). Two pipelines are located in the northern Mediterranean area (the Transalpine Pipeline and South Europe Pipeline), one in the south-east (Suez–Mediterranean or SUMED Pipeline), two in the north-east (the Iraq–Turkey Pipeline and Baku–Tbilisi–Ceyhan Pipeline) and finally, two in the eastern Mediterranean (the Trans-Arabian Crude Oil Pipeline and the Iraq–Syria pipeline), as outlined below.

- ***Northern Mediterranean area***

  Transalpine Pipeline. This 752-km-long pipeline starts from the marine terminal in Trieste, connecting Italy, Austria and Germany. It has a capacity of about 35 Mt/year of crude oil. The pipeline is owned by a consortium of eight oil companies (OMV, Royal Dutch Shell, ExxonMobil, Ruhr Oel, Eni, BP, ConocoPhilips and Total S.A.).

  South Europe Pipeline. This 769-km-long pipeline has a capacity of about 22 Mt/year and runs from the Fos-sur-Mer terminal in France to Switzerland and Germany.

- ***Eastern Mediterranean area***

  SUMED Pipeline. Running from the Ain Sukhna terminal on the Gulf of Suez to offshore Sidi Kerir (west of Alexandria), the SUMED pipeline provides an alternative to the Suez Canal for those cargos too large to transit the Canal. The pipeline, with a capacity of 2.5 million bbl/d, is owned by the Arab Petroleum Pipeline Company, a joint venture between the Egyptian General Petroleum Corporation, Saudi Aramco, Abu Dhabi's National Oil Company and Kuwaiti companies.

  Suez Canal. The Suez Canal connects the Red Sea and Gulf of Suez with the Mediterranean Sea, spanning 193 km. In 2010, petroleum (both crude oil and refined products) as well as LNG accounted for 13% and 11% of Suez cargos, measured by cargo tonnage, respectively. The total petroleum transit volume was close to 2 million bbl/d, or just below 5% of seaborne oil trade in 2010. Almost 20% of the ships that transited the Suez Canal in 2010 were petroleum tankers and 5% were LNG tankers. At only 300 metres at its narrowest point, the Canal is unable to handle the VLCC (very large crude carriers) or ULCC (ultra large crude carriers) classes of crude oil tankers. The Suez Canal Authority is continuing enhancement and enlargement projects on the Canal, and extended the depth to 20 metres in 2010 to allow over 60% of all tankers to use the Canal. Closure of the Suez Canal and the SUMED Pipeline would divert oil tankers around the southern tip of Africa (the Cape of Good Hope), adding approximately 9,700 km to the transit, increasing both costs and shipping time. As noted by the IEA (2010), shipping around Africa would add 15 days of transit to Europe and 8-10 days to the US.

  Iraq–Turkey Pipeline. This 970-km-long pipeline connects Iraq's large oil field of Kirkuk with the Turkish port of Ceyhan, where Iraqi crude is loaded onto tankers for export. The pipeline system (two pipes with diameters of 1,170 mm and 1,020 mm) has been a sabotage target since

[36] Data sources of this section: *An Assessment of the Gas and Oil Pipelines in Europe,* Bjørnmose et al. (2009); "Major oil pipeline projects", Ruceveska et al. (2007); *Oil Transport Infrastructure,* Transnafta (2010); US Energy Information Administration (EIA), "Country Analysis Brief[s]", profiles for Algeria (http://www.eia.gov/countries/cab.cfm?fips=AG), Turkey (http://www.eia.gov/countries/cab.cfm?fips=TU) and Egypt (http://www.eia.gov/countries/cab.cfm?fips=EG).

2003 and requires extensive rehabilitation and upgrading. For this reason, the pipeline is currently is underutilised.

Baku–Tbilisi–Ceyhan Pipeline. At 1,768 km long, this pipeline is capable of carrying 1.2 million bbl/d of oil. The pipeline (operative since 2006) runs from the Azeri–Chirag–Guneshli oil field in the Caspian Sea via Georgia to the Turkish coast on the Mediterranean Sea.

Trans-Arabian Crude Oil Pipeline. Currently not operational, this pipeline – inaugurated in 1950 – transported Saudi Arabian oil from the Gulf fields to the terminal at Zahrani south of Saida. From there it was shipped to the markets of Europe and the eastern US seaboard (the route of the pipeline was designed to circumvent Palestine and for this reason it went through Jordan, over the Golan Heights in Syria to end at Sidon in Lebanon). At the peak of its operations the pipeline transported nearly 30% of Aramco's oil production. After years of continual bickering between Saudi Arabia, Syria and Lebanon over transit fees, and amidst the emergence of oil supertankers and pipeline breakdowns, the section of the line beyond Jordan ceased operation in 1976. The remainder of the line between Saudi Arabia and Jordan continued to transport modest amounts of oil until 1990, when Saudi Arabia cut off the pipeline in response to Jordan's support of Iraq during the first Gulf War.

Iraq–Syria or Kirkuk–Baniyas Pipeline. This crude oil pipeline runs from the Kirkuk oil field in Iraq to the port of Baniyas in Syria. The pipeline is 800 km long and has a capacity of 300,000 barrels per day. The pipeline, operative since 1952, was damaged during the US air strikes of 2003 and has remained out of operation since then. In 2007, Syria and Iraq agreed to restore the pipeline; however, Stroytransgaz failed to start the restoration and the contract was nullified in 2009. As the restoration of the existing pipeline turned out to be more costly than building a new one, in September 2010 Iraq and Syria agreed to build two new Kirkuk–Baniyas pipelines. One pipeline, with a capacity of 1.5 million bbl/d is to carry heavier crude oil, while another pipeline with a capacity of 1.25 million bbl/d is to carry lighter crude oil.

Figure 35. Oil pipelines in the south-eastern Mediterranean and the Persian Gulf

Source: US Department of Energy.

4. Algeria

4.1 Oil reserves

According to the *Oil & Gas Journal* (2011) and BP, Algeria's oil reserves amounted to 12.2 billion barrels as of January 2011 (see also Figure 36), the third-largest oil reserves in Africa (after Libya and Nigeria).[37] These reserves are mainly located in the south-eastern part of the country, near the Libyan border, in particular in the Hassi Messaoud Basin and the Berkine Basin. The Hassi Messaoud field, with over 60% of Algeria's proven reserves, is the largest oil field in the country. The Ourhoud field, located in the Berkine Basin, is Algeria's second-largest oil field. This field has been the site of many recent discoveries over the last decade, enabling the country to raise significantly its oil production since 2003 (e.g. Figure 37).

Figure 36. Algeria's proven oil reserves (1,000 barrels)

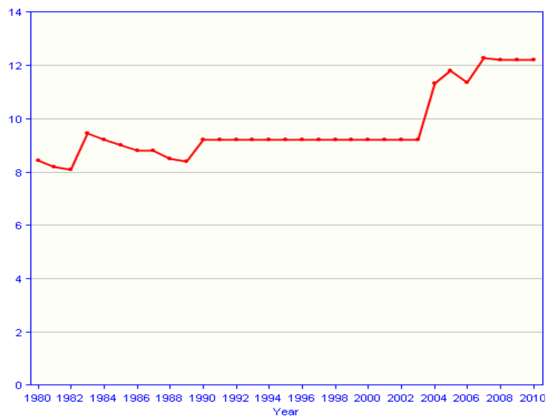
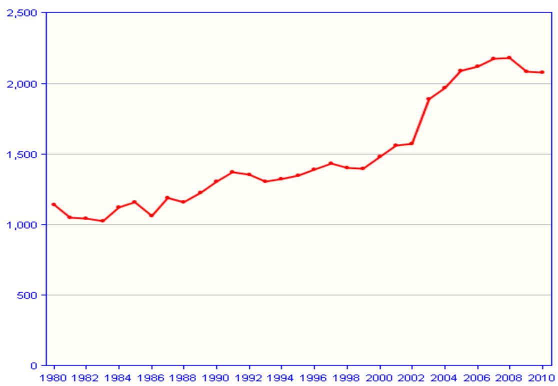


Figure 37. Algeria's total oil production (1,000 barrels/day)



Source: US Energy Information Administration, "International Energy Statistics" (http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm).

4.2 Oil production and demand

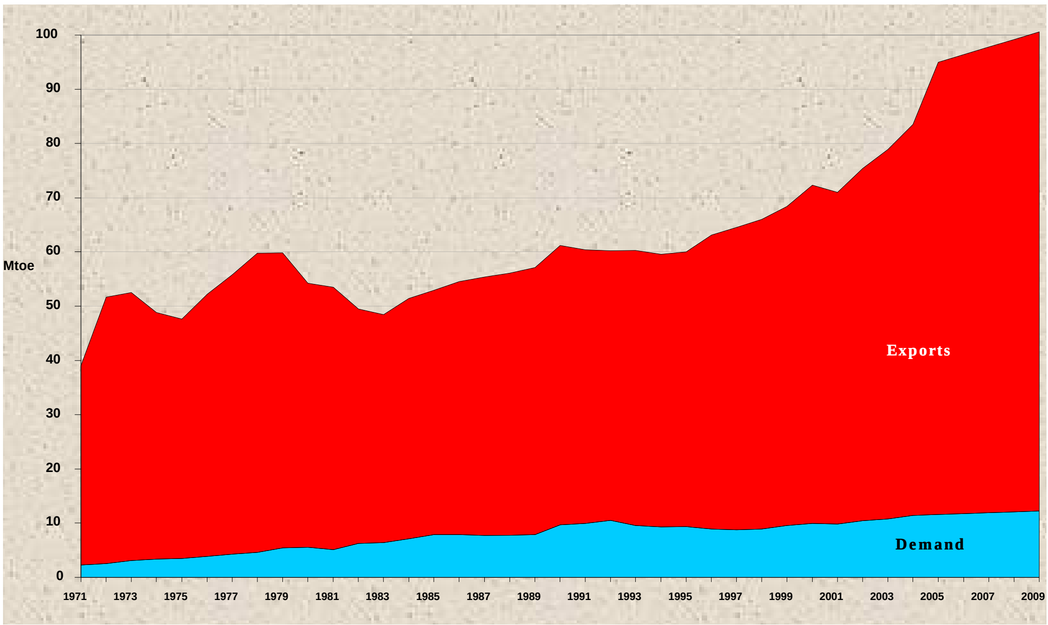
Algeria's oil production increased substantially after the oil discoveries in the Ourhoud field in 2003[38] (see also Figure 38). Algeria produced 97 Mtoe of oil in 2009, and according to the MEDPRO Reference Scenario, the country is expected to raise its production to 108 Mtoe in 2020 and then gradually to decrease it to 93 Mtoe in 2030.

In the MEDPRO Energy Reference Scenario, Algeria's final oil consumption will increase from 12 Mtoe in 2009 to 17 Mtoe in 2020 and to 22 Mtoe in 2030. This increase will mainly come from a progressive expansion of Algeria's transport sector and from developments in the residential sector, as the urbanisation of the country is expected to improve over the next decades.

[37] Data source: BP (2011).

[38] Data source of this section: US EIA, "Country Analysis Brief" for Algeria (www.eia.gov/countries/cab.cfm?fips=AG).

Figure 38. Algeria – Oil demand and hydrocarbon liquid exports 1970–2009 (Mtoe)



Source: Own elaborations based on data from the IEA.

4.3 Oil infrastructure and exports

Algeria's major oil fields are Hassi Messaoud, Hassi Berkine, Ourhoud, Bir Hebaa, Gassi El Agreb/Zotti and Menzel Ledjmet.[39] Surrounding these fields, a substantial oil infrastructure has been built over the years, such as oil export pipelines, refineries and oil ports.

The Algerian domestic network of pipelines facilitates oil transfer from production fields to export terminals. Sonatrach operates over 3,200 km of oil pipelines in the country. Most pipelines carry crude oil from the Hassi Messaoud field to export terminals. Sonatrach also operates oil condensate and LPG pipeline networks that link Hassi R'Mel and other fields to Arzew. Sonatrach has expanded the Hassi Messaoud–Arzew pipeline (the longest in the country), including a second parallel line in order to double the current capacity of the pipeline. The main existing pipelines for oil exports are as follows:

- Haoud el Hamra–Arzew (800 km);
- the second parallel line in Haoud el Hamra–Arzew (822 km);
- Haoud el Hamra–Bejaia (667 km);
- In Amenas–La Skhirra–Tunisia (775 km); and
- Haoud el Hamra–Skikda (643 km).

The more recent oil pipeline put on-stream on 2010 is the LPG LZ2, a 24-inch pipeline from Hassi R'Mel to Arzew. In 2010, for the transmission activity, the development of the network concerned the advancement of gas pipeline projects GK3 (Hassi R'Mel–Skikda–El Kala) and GR4 (from Rhourde Nouss to Hassi R'Mel), the LPG LZ2 oil pipeline described above and the construction of six storage tanks in Haoud El Hamra.

[39] Data sources of this section: US EIA, "Country Analysis Brief[s]" for Algeria (http://www.eia.gov/countries/cab.cfm?fips=AG), Egypt (http://www.eia.gov/countries/cab.cfm?fips=EG) and Turkey (http://www.eia.gov/countries/cab.cfm?fips=TU).

All the pipelines transported about 152 Mtoe in 2010 from the south to the north of the country: i) 53.2 Mt of crude oil, of which 39% was delivered to refineries in the north; ii) 83.5 bcm of natural gas; iii) 10.9 Mt of condensates; and iv) 6.8 Mt of LPG. Algeria has the following major refineries:

- Naftec–Skikda, RA1K (with a capacity of 300,000 bbl/d);
- Naftec–Algiers, RA1G (with a capacity of 60,000 bbl/d);
- Naftec–Arzew, RA1Z (with a capacity of 60,000 bbl/d); and
- Naftec–Hassi Messaoud (with a capacity of 30,000 bbl/d).

In 2010, the volumes of crude oil treated by the three northern refineries (the Skikda RA1K, the Arzew RA1Z and the Algiers RA1G) reached 20.8 Mt of crude. The volumes of condensates treated by the Skikda unit for the topping of condensates reached 4.66 Mt in 2010.

Algeria's largest port for crude oil exports is located in Arzew (handling about 40% of the country's total hydrocarbon exports). Other major ports are Skikda, Algiers, Annaba, Oran and Bejaia.

Algeria is an important oil exporter in the region. The total oil exports (including crude, condensate and oil products) reached about 1.8 million bbl/d in 2009 (a fall of 2% was registered in 2010). In 2009, Algeria exported to the US (488,000 bbl/d), OECD countries (1.1 million bbl/d, of which 482,000 bbl/d was to European OECD countries such as France, Germany, Italy and the UK), Canada (149,000 bbl/d) and Japan and Korea (61,000 bbl/d).

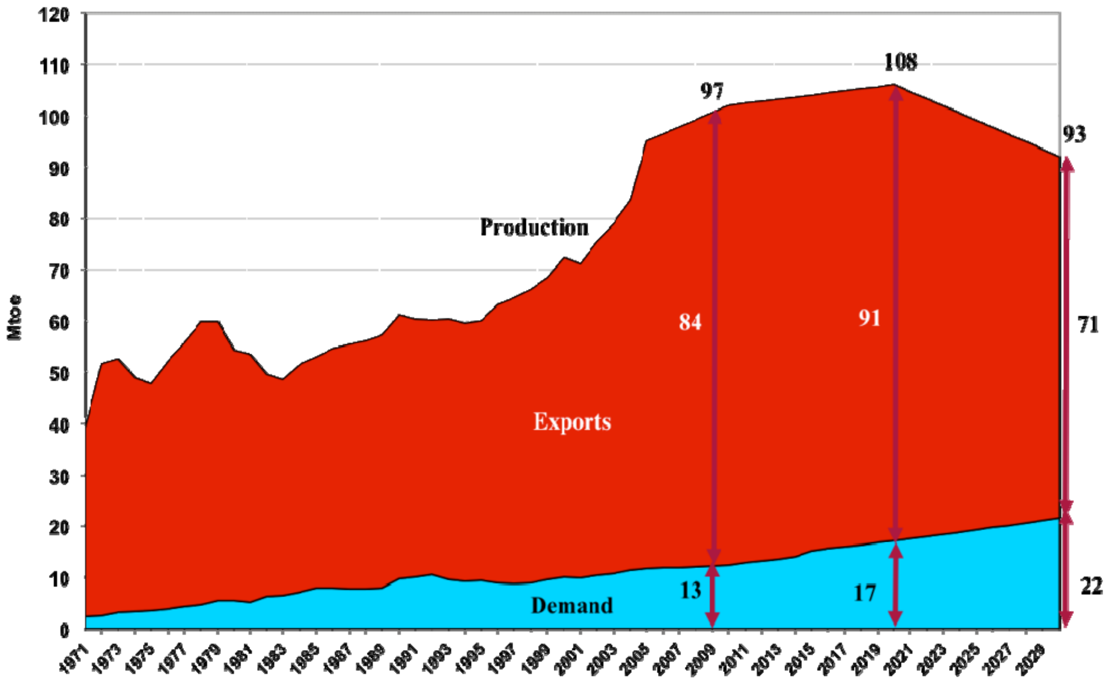
The MEDPRO Reference Scenario expects Algeria's oil exports to grow over the next decade (reaching 91 Mtoe in 2020) and then gradually decrease to 71 Mtoe in 2030 (e.g. Table 23, Figure 39).

Table 23. Algeria – Reference Scenario for oil

	Oil Production/Exports/Demand					
(Mtoe)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–30 (%)**
Oil production	97,4	105,2	108,1	100,2	92,6	-0,2
Net imports/exports	-85,0	-90,0	-91,0	-81,0	-71,0	-0,9
Total oil supplies	12,4	15,2	17,1	19,2	21,6	2,7
Electricity plants (inputs)	-0,1	-0,2	-0,2	-0,2	-0,1	1,3
Other transformation & losses	-1,1	-1,3	-1,2	-1,2	-1,2	0,3
Total final consumption	11,0	13,7	15,8	17,9	20,3	3,0
Transport	*6,0*	*7,9*	*9,3*	*10,8*	*12,6*	*3,6*
Residential	*3,3*	*4,1*	*4,5*	*4,8*	*5,1*	*2,1*
Industry	*1,2*	*1,3*	*1,5*	*1,7*	*2,0*	*2,5*
Other consumption	*0,2*	*0,4*	*0,5*	*0,5*	*0,6*	*4,8*
Electricity output (TWh)	0,736	1	0,6	1	1	1,4
Installed capacity (MW)	239	395	396	400	405	2,5

Source: Own elaborations for the MEDPRO Energy Reference Scenario.

Figure 39. Algeria – Oil production, demand and export potential



Source: Own elaborations for the MEDPRO Energy Reference Scenario.

5. Egypt

5.1 Oil reserves

Egypt's proven crude oil and condensate reserves are estimated at 4.5 billion barrels, the third-largest oil reserves of the Mediterranean region.[40] Since the start of commercial production in 1910, a little more than 10 billion barrels of oil have been produced. More than 75% of all the crude oil and condensate produced has originated from fields in the Gulf of Suez and in the Sinai Peninsula, which currently hold over 40% of the remaining oil reserves.

Egypt has great potential for additional hydrocarbon discoveries, as the country is still relatively underexplored. For instance, in 2010 the US Geological Survey [41] estimated that in the Nile Delta Basin offshore there is potential for resources to be discovered, amounting to 6,321 bcm of natural gas, 1,763 Gb (billion barrels) of oil and 5.9 Gb of natural gas liquids (see for example Figure 40).[42]

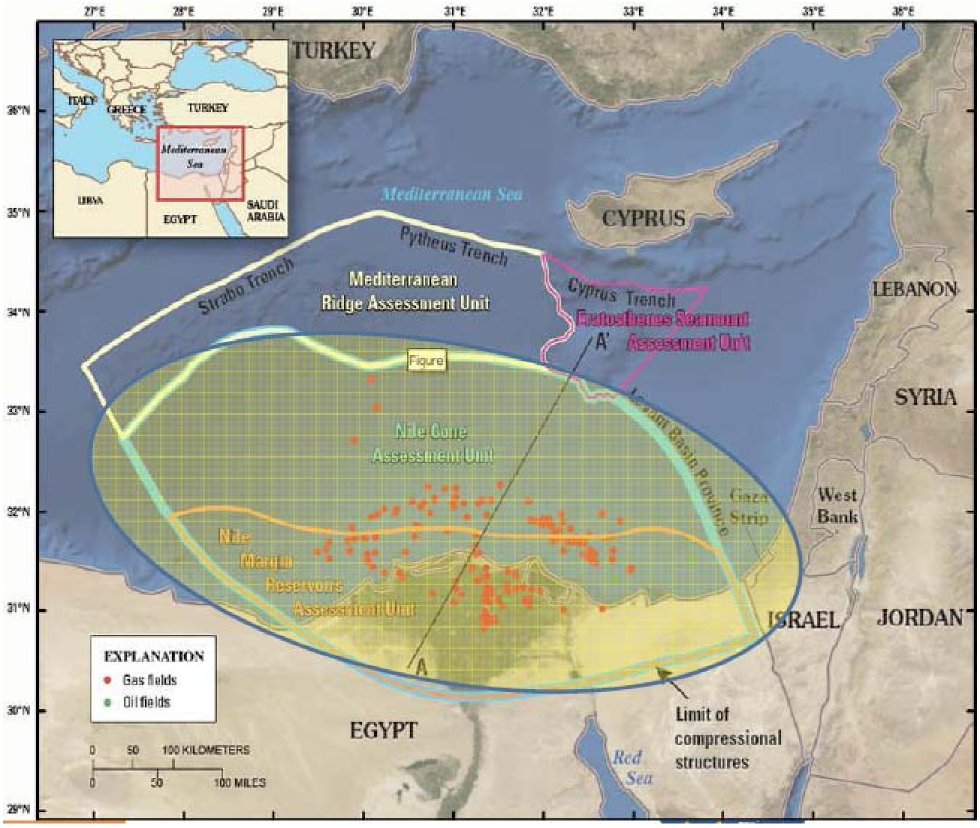
The main challenges that Egypt's petroleum industry faces are adopting an effective upstream policy and encouraging the efficient use of resources in an environment that is currently characterised by a high degree of bureaucracy and highly subsidised domestic prices.

[40] Data source: BP (2011).

[41] "Assessment of Undiscovered Oil and Gas Resources of the Nile Delta Basin Province, Eastern Mediterranean", USGS (2010).

[42] Refer also to Glachant et al. (2012).

Figure 40. US Geological Survey assessment units in the Nile Delta Basin



Source: US Geological Survey.

5.2 Oil production and demand

Egyptian oil production comes from five main areas: primarily the Gulf of Suez and the Nile Delta, but also the Western Desert, the Eastern Desert and the Mediterranean Sea.[43] Most Egyptian production is derived from mature, relatively small fields that are connected to larger, regional production systems. Overall production is in decline, particularly from the older fields in the Gulf of Suez. Some declines, however, have been offset by small yet commercially viable discoveries in all producing areas (e.g. Figure 41).

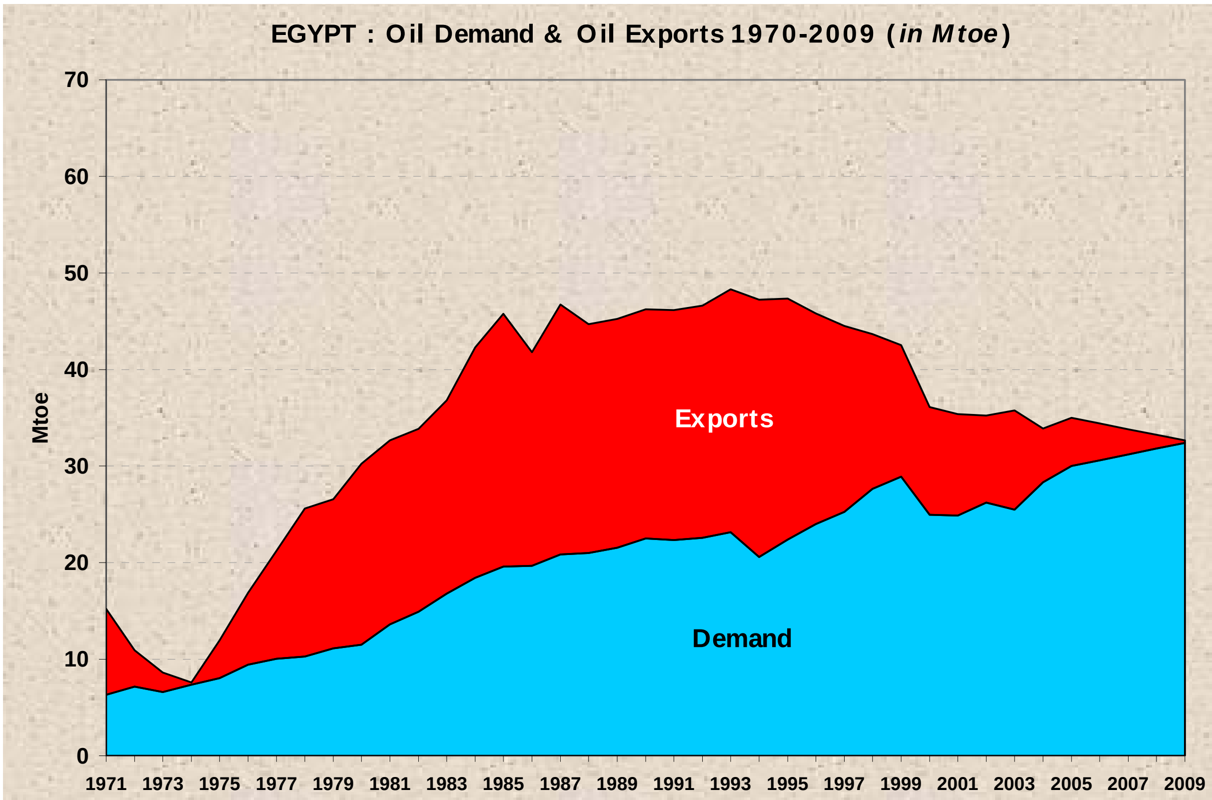
Finding ways to slow the decline is a key focus of Egypt's oil sector; approaches include enhanced recovery and reservoir management techniques, and possible development of oil shale resources. Egyptian outlooks indicate that the decline in crude oil production is unlikely to be reversed for a sustained period. Currently, the fast-growing domestic demand for oil (stimulated by subsidised prices), in combination with declining production, is a principal concern. Falling domestic oil production, strong demand and oil subsidies led Egypt to become a net oil importer in 2010.

In the MEDPRO Reference Scenario, Egypt's oil production will reach 38 Mtoe in 2015 and then decline to 35 Mtoe in 2020 and to 32 Mtoe in 2030. Given the increase in domestic oil demand (from 32 Mtoe in 2009 to 50 Mtoe in 2030), Egypt will have to import 6 Mtoe of oil in 2020 and 18 Mtoe in 2030.

The MEDPRO Reference Scenario projects that Egypt's oil demand will increase from 32 Mtoe in 2009 to 41 Mtoe in 2020 and to 50 Mtoe in 2030. This growth will mainly come from oil inputs to electricity power plants (from 5 Mtoe in 2009 to 10 Mtoe in 2030) and from expansion of the transport sector (from 12 Mtoe in 2009 to 22 Mtoe in 2030).

[43] Data source: US EIA, "Country Analysis Brief" for Egypt (http://www.eia.gov/countries/cab.cfm?fips=EG).

Figure 41. Egypt – Oil demand and exports, 1970–2009



Source: Own elaborations based on data from the IEA.

5.3 Oil infrastructure and exports

Since 2010, Egypt has been reliant upon oil imports to meet domestic energy demand.[44] According to the *Oil & Gas Journal* (2011), Egypt's oil consumption totalled 710,000 bbl/d, a level slightly higher than production. In the MEDPRO Reference Scenario, Egypt will largely maintain the equilibrium of the oil import/export balance in the medium- to long-term scenario (1 Mtoe less in 2020, 1 Mtoe more in 2030). Egypt has the largest refining sector on the African continent, with ten refineries and a combined crude oil-processing capacity of 975,000 bbl/d. The largest refinery is the 146,300-bbl/d El-Nasr refinery at Suez, which is owned by the Egyptian government through the Egyptian General Petroleum Corporation and operated by its subsidiary, the El Nasr Petroleum Company. The government has plans to increase the production of lighter products, petrochemicals and higher-octane gasoline by expanding and upgrading existing facilities and promoting new projects. Current plans call for the expansion of refining capacity by over 600,000 bbl/d by 2016 and even further expansions into the next decade, requiring large amounts of foreign investment.

Given the growing importance of Egypt as a transit country, its other oil infrastructure (such as the Suez Canal and the SUMED Pipeline) is discussed in Part C, which is entirely devoted to the Mediterranean as an oil and gas transit region (e.g. Table 24, Figure 42).

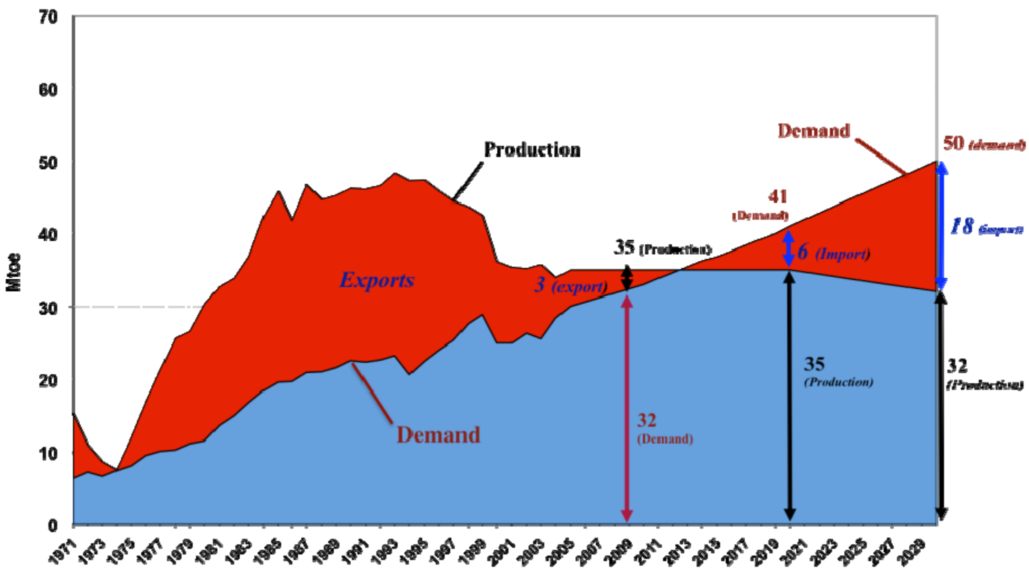
[44] Data source: US EIA, "Country Analysis Brief" for Egypt (http://www.eia.gov/countries/cab.cfm?fips=EG).

Table 24. Egypt – Reference Scenario for oil

MEDPRO Reference Scenario	**Oil Production/Exports/Demand**					
(Mtoe)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–30 (%)**
Oil production	35,2	37,5	35,0	34,0	32,0	-0,5
Net imports/exports	-3,1	0,0	5,9	11,6	18,3	-209
Total oil supplies	32,1	37,5	40,9	45,6	50,3	2,2
Electricity plants (inputs)	-5,1	-5,3	-6,1	-8,2	-10,5	2,2
Other transformation & losses	-2,6	-2,1	-2,2	-2,3	-2,4	-0,4
Total final consumption	-2,6	-2,1	-2,2	-2,3	-2,4	2,1
Transport	*12,5*	*16,1*	*18,0*	*19,9*	*21,7*	*2,7*
Residential	*4,9*	*5,3*	*5,5*	*5,7*	*5,8*	*0,8*
Industry	*6,9*	*8,5*	*8,9*	*9,3*	*9,7*	*1,6*
Other consumption	*0,1*	*0,2*	*0,2*	*0,2*	*0,2*	*2,3*
Electricity output (TWh)	26	22	27	35	40	2,1
Installed capacity (MW)	2 316	4 045	5 300	6 900	8 000	2,1

Source: Own elaborations on MEDPRO Energy Reference Scenario.

Figure 42. Egypt – Oil production, demand and import/export potential



Source: Own elaborations for the MEDPRO Energy Reference Scenario.

6. Libya

6.1 Oil reserves

Libya owns the largest proven oil reserves of the entire African continent, followed by Nigeria and Algeria.[45] Moreover, in this regard the country remains largely underexplored. According to BP and

[45] Data source of this section, except where otherwise indicated: BP (2011).

the *Oil & Gas Journal* (2011), Libya owns 46.4 billion barrels of proven oil reserves (as of January 2011). Nearly 80% of Libya's proven oil reserves are located in the Sirte Basin, which accounts for most of the country's oil output.

Libya's oil production potential could be increased by implementing exploration activities in established oil-producing areas as well as in more remote parts of the country. Using a geology-based assessment methodology, the US Geological Survey has estimated that there are 3.97 billion barrels of undiscovered oil across the Libyan Sirte Basin, the Tunisian Pelagian Basin and western Libya[46] (e.g. Table 25, Figure 43).

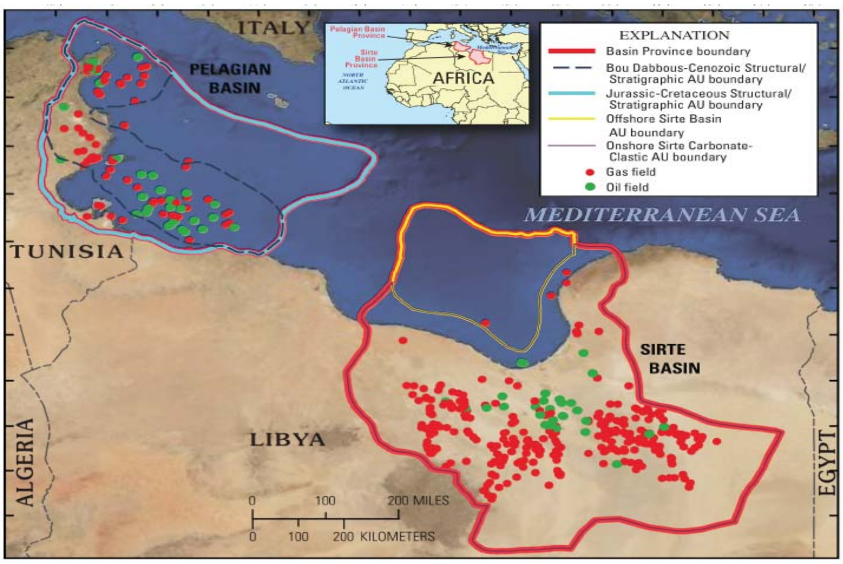
Table 25. Libya and Tunisia assessment results

[MMBO, million barrels of oil. BCFG, billion cubic feet of gas. MMBNGL, million barrels of natural gas liquids. Results shown are fully risked estimates. For gas accumulations, all liquids are included as NGL (natural gas liquids). Undiscovered gas resources are the sum of nonassociated and associated gas. F95 represents a 95-percent chance of at least the amount tabulated; other fractiles are defined similarly. Largest expected oil field in MMBO; largest expected gas field in BCFG. TPS, total petroleum system; AU, assessment unit. Gray shading indicates not applicable]

Total petroleum systems (TPS) and assessment units (AU)	Field type	Largest expected mean field size	Total undiscovered resources											
			Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Sirte-Rachmat Composite TPS														
Onshore Sirte Carbonate-Clastic AU	Oil	432	364	1,087	2,823	1,278	418	1,338	4,035	1,673	22	74	240	96
	Gas	2,042					1,267	4,179	12,569	5,169	44	151	478	192
Offshore Sirte Basin AU	Oil	857	563	1,838	5,457	2,267	633	2,250	7,677	2,972	34	124	454	170
	Gas	6,843					6,591	19,540	49,077	22,637	233	709	1,903	840
Bou Dabbous-Cenozoic TPS														
Bou Dabbous-Cenozoic Structural/Stratigraphic AU	Oil	60	130	283	552	305	45	113	274	131	1	3	8	4
	Gas	616					1,443	2,933	5,405	3,119	37	75	140	80
Jurassic-Cretaceous Composite TPS														
Jurassic-Cretaceous Structural/Stratigraphic AU	Oil	13	62	116	212	124	79	154	287	165	2	4	7	4
	Gas	569					1,044	2,409	5,023	2,643	32	73	154	80
Total conventional resources			1,119	3,324	9,044	3,974	11,520	32,916	84,347	38,509	405	1,213	3,384	1,466

Source: US Geological Survey (2010).

Figure 43. Assessment of resources in the Sirte and Pelagian Basin Provinces



Source: US Geological Survey (2010).

[46] See USGS (2010).

6.2 Oil production and demand

Despite the large amount of its oil reserves, Libya's oil production peaked at over 3 million bbl/d in the late 1960s and since that time it has gradually declined.[47] The National Oil Corporation would like to return the country's oil production capacity back to 3 million bbl/d, but this target has been delayed until 2017. Nonetheless, crude oil capacity increased somewhat over the past decade from 1.43 million bbl/d in 2000 to 1.8 million bbl/d in 2010.

Libya's oil production was approximately 1.65 million bbl/d in 2010, about 150,000 bbl/d below its capacity but still above the production quota set by OPEC, currently at 1.47 million bbl/d. Most of the short-term increases in oil production are expected to come from enhanced oil recovery processes and any major new production in Libya will require additional pipeline capacity for exports. About two-thirds of the Libyan oil production comes from the Sirte Basin, with about 25% coming from the Murzuq Basin and most of the remainder from the offshore Pelagian Shelf Basin near Tripoli.

The MEDPRO Reference Scenario forecasts that Libya's oil demand will not grow considerably over the next decades, just increasing from 14 Mtoe in 2009 to 17 Mtoe in 2030.

6.3 Oil infrastructure and exports

With domestic consumption estimated at 270,000 bbl/d, Libya's net exports (including all liquids) were slightly over 1.5 million bbl/d in 2010. According to the IEA (2010), the vast majority (around 85%) of Libyan oil exports are sold to European countries, namely Italy, Germany, France and Spain. With the lifting of sanctions against Libya in 2004, the US increased its imports of Libyan oil. The US Energy Information Administration reported that the US imported an average of 71,000 bbl/d from Libya in 2010 (of which, 44,000 bbl/d was crude), up from 56,000 bbl/d in 2005. The Libyan oil infrastructure is briefly summarised below.

Refining sector

Libya owns five refineries, with a total combined capacity of 378,000 bbl/d:

- the Ras Lanuf export refinery, completed in 1984 and located on the Gulf of Sirte, with a crude oil refining capacity of 220,000 bbl/d;
- the Az Zawiya refinery, completed in 1974 and located in north-western Libya, with a crude processing capacity of 120,000 bbl/d;
- the Tobruk refinery, with a crude capacity of 20,000 bbl/d;
- Sarir, a topping facility with a capacity of 10,000 bbl/d; and
- Brega, the oldest refinery in Libya, located near Tobruk and having a crude capacity of 18,000 bbl/d.

Libya's refining sector was affected by UN sanctions (specifically UN Resolution 883 of 11 November 1993), which banned Libya from importing refinery equipment. Libya is seeking a comprehensive upgrade of its entire refining system, with a particular aim of increasing the output of gasoline and other light products.

Major oil terminals

Libya's major oil terminals are Es Sider, Marsa el-Brega, Tobruk, Ras Lanuf, Zawiya and Zuetina.

Oil exports

Libya is the most important supplier of oil in the Mediterranean region and one of the 15 largest exporters of crude oil in the world. Civil unrest in Libya in 2011 had a significant impact on oil market

[47] Data source: US EIA, "Country Analysis Brief" for Libya (http://www.eia.gov/countries/cab.cfm?fips=LY).

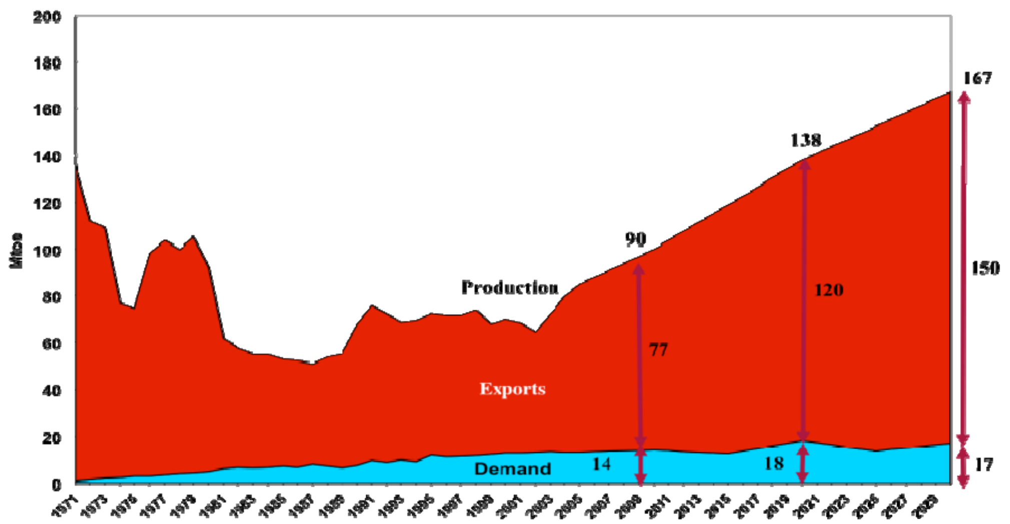
expectations and drove up oil prices. It is expected that the new government will favour oil exports in order to earn revenues to develop the country. Presently, Libya's crude oil exports are over 1.1 million bbl/d. In 2010, about a quarter of Libyan oil was exported to Italy (covering almost 22% of Italy's total oil imports). In the same year, a third of Libyan crude oil exports went to Germany, France and Spain.[48] In the MEDPRO Reference Scenario, Libyan oil exports are expected to grow significantly over the next decades, from 77 Mtoe in 2009 to 120 Mtoe in 2020 and to 150 Mtoe in 2030 (e.g. Table 26, Figure 44).

Table 26. Libya – Reference Scenario for oil

	Oil Production/Exports/Demand					
(Mtoe)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–30 (%)**
Oil production	90,3	108,0	138,3	157,7	166,5	3,0
Net imports/exports	-76,6	-90,0	-120,0	-140,0	-150,0	3,3
Total oil supplies	13,7	18,0	18,3	17,7	16,5	0,9
Electricity plants (inputs)	-5,3	-7,2	-6,6	-5,1	-3,2	-2,3
Other transformation & losses	-1,7	-2,0	-2,2	-2,3	-2,5	1,8
Total final consumption	7,4	8,8	9,5	10,2	10,8	1,8
Transport	*4,2*	*5,2*	*5,7*	*6,1*	*6,5*	*2,0*
Residential	*1,0*	*1,3*	*1,5*	*1,7*	*1,8*	*2,9*
Industry	*1,2*	*1,0*	*0,9*	*0,9*	*0,9*	*-1,5*
Other consumption	*0,9*	*1,2*	*1,4*	*1,5*	*1,7*	*2,8*
Electricity output (TWh)	21	23	21	16	10	-3,4
Installed capacity (oil) (MW)	3.843	3.800	3.330	2.600	1.600	-4,0

Source: Own elaborations for the MEDPRO Energy Reference Scenario.

Figure 44. Libya – Oil production, demand and export potential



Source: Own elaborations for the MEDPRO Energy Reference Scenario.

[48] Refer to Glachant et al. (2012).

Part C. The Mediterranean as a Region for Oil and Gas Transit

7. Turkey

Turkey is increasingly at the crossroads of the world energy trade. A web of pipelines already crosses Turkey, carrying hydrocarbons along east–west and north–south energy corridors (e.g. Figures 45 and 46).[49]

Indeed, because of tanker traffic through the Bosporus and Dardanelles Straits, Turkey has become an important north–south transit route for oil. Approximately 2.9 million bbl/d flowed through the Bosporus in 2009, 2.5 million bbl/d of which was crude oil.[50] Traffic through the Straits has increased as the crude production and exports of Azerbaijan and Kazakhstan have risen. Moreover, the Baku–Tbilisi–Ceyhan (BTC) oil and Baku–Tbilisi–Erzurum natural gas pipelines make Turkey an important east–west route as well (e.g. Figures 47 and 48). Another important pipeline is the Turkey–Greece interconnector, which has the capacity to transport 11.5 bcm of natural gas from Azerbaijan's Shah Deniz field. Other pipelines that are already operative include the Kirkuk–Ceyhan oil pipeline and the Blue Stream gas pipeline.

Figure 45. Oil & gas pipelines and pipeline projects to and across Turkey

Source: men (2009).

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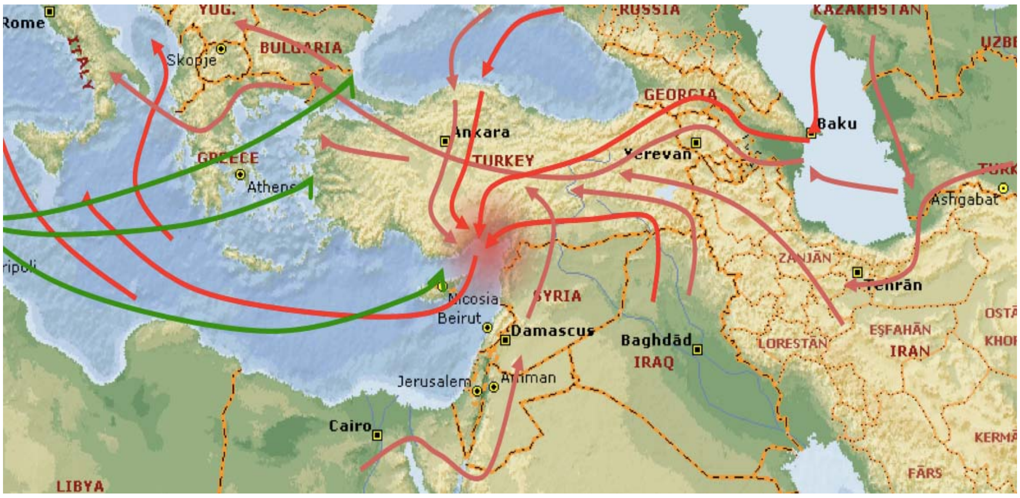
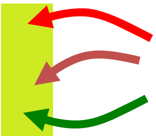
[49] Data source: "Energy and Energy Security: Turkey's Role", men (2009).

[50] See BP (2011).

Figure 46. Turkey: Energy hub, corridor and terminal





OIL

NATURAL GAS

LNG

Source: BOTAŞ Petroleum Pipeline Corporation.

Figure 47. Baku–Tbilisi–Ceyhan crude oil pipeline

Source: Wikipedia.

Figure 48. Baku–Tbilisi–Erzurum natural gas pipeline (in brown)

Source: Own elaboration.

A terminal located in Ceyhan – on Turkey's Mediterranean coast – allows the country to export oil from Iraqi and Caspian sources: the first route extends from northern Iraq via a pipeline from Kirkuk and the second route from Azerbaijan via the BTC pipeline. The Kirkuk–Ceyhan pipeline is Turkey's largest oil pipeline (by capacity) and serves as a transport pipeline of Iraqi oil (e.g. Figure 49). It is approximately 965 km long and has a capacity of 1.65 million bbl/d. Frequent attacks on the pipeline's Iraq section, however, regularly result in operation disruptions. The second oil pipeline, the BTC Pipeline, is more recent and connects Baku in Azerbaijan with the Turkish port of Ceyhan via Georgia.

Figure 49. Iraq–Turkey crude oil pipeline

Source: Business Insider (www.businessinsider.com).

The Iraq–Turkey pipeline is a 970-km-long pipeline that connects Iraq's large oil field of Kirkuk with the Turkish port of Ceyhan, where Iraqi crude is loaded on tankers for export. The pipeline system (two pipes with diameters of 1,170 mm and 1,020 mm) has been a sabotage target since 2003 and requires extensive rehabilitation and upgrading. For this reason the pipeline is currently underutilised.

The BTC is a 1,768-km-long pipeline, capable of carrying 1.2 million bbl/d of oil. The pipeline (operative since 2006) runs from the Azeri–Chirag–Guneshli oil field in the Caspian Sea via Georgia to the Turkish coast on the Mediterranean Sea (e.g. Figure 50).

Figure 50. Turkey – Crude oil pipelines

A :	I. KERKUK-CEYHAN CRUDE OIL PL	40"	641 KM	71 MTA CAPACITY
B :	II. KERKUK-CEYHAN CRUDE OIL PL	46"	656 KM	
C :	BAKU TBILISI CEYHAN CRUDE OIL PL	30"-42"-46"	1076 KM	50 MTA CAPACITY
D :	SELMO-BATMAN CRUDE OIL PL	6"-9 5/8"-12"	41 KM	0.8 MTA CAPACITY
E :	BATMAN-DORTYOL CRUDE OIL PL	18"	511 KM	4.5 MTA CAPACITY
F :	CEYHAN-KIRIKKALE CRUDE OIL PL	24"	448 KM	7.2 MTA CAPACITY

Source: BOTAŞ Petroleum Pipeline Corporation.

Bypass routes

The Istanbul (Bosporus) Strait is approximately 31 km long, with an average width of 1.5 km. At its narrowest point it measures a mere 698 m.[51] It takes several sharp turns, sometimes forcing ships to execute turns of up to 80 degrees. Navigation is particularly difficult at the narrowest point, as the vessels approaching from opposite directions cannot see each other around the treacherous bends.

The Turkish Straits provide the only maritime link between the Black Sea riparian states and the Mediterranean Sea, forcing the states to rely on the Straits for foreign trade. The opening of the Main–Danube Canal has linked the Rhine to the Danube, connecting the North Sea and Black Sea. An alarming increase in traffic has been observed in the number of vessels carrying dangerous cargoes. Currently, large amounts of oil from Russia, Azerbaijan and Kazakhstan reach the international market through the Turkish Straits.

To ease increasing oil traffic through the Bosporus Strait, a number of Bosporus bypass options are under consideration in Bulgaria, Romania, Ukraine and Turkey itself (e.g. Figure 51). The BTC Pipeline, which bypasses the Bosporus Strait chokepoint, is the first of numerous planned or proposed bypass pipelines to be constructed. In addition, the Turkish government approved construction plans for the proposed Samsun–Ceyhan pipeline that, according to some estimates, would reduce oil tanker traffic in the Bosporus Straits by up to 50%. The Samsun–Ceyhan bypass would transport oil from Turkey's Black Sea port of Samsun to Ceyhan on the Mediterranean coast. The project includes the construction of a 563-km oil pipeline, a new terminal for receiving oil at Samsun and a terminal for exporting the oil, and a storage plant at Ceyhan. The oil pipeline will have a maximum, initial transportation capacity of 1 million bbl/d, which can eventually be increased to 1.5 million bbl/d.

Figure 51. Proposed options to bypass the Bosporus

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[51] For more information, refer to Ulusçu et al., *Transit Vessel Scheduling in the Strait of Istanbul*, Rutgers University, Piscataway, NJ (undated) (http://ie.rutgers.edu/resource/research_paper/paper_08-012.pdf).

The port of Ceyhan has become an important outlet for Caspian oil exports as well as Iraqi oil shipments from Kirkuk. Turkey is seeking to build up Ceyhan as a regional energy hub, with private investors receiving approval to build several refineries at the oil terminal, adding revenue beyond transit fees.

Turkey has six refineries with a combined processing capacity of 714,275 barrels per day. Major refineries (by capacity in bbl/d) are Izmit (251,600), Izmir–Aliaga (226,440), Kirikkale (113,220), ATAS (Mersin) (95,000) and Batman (22,000). The Turkish Petroleum Refineries Company (Tupras) is Turkey's dominant refining firm, operating about 85% of the total refining capacity. Turkey's refining sector is in the process of being privatised, with the majority of shares (51%) of the formerly state-owned Tupras currently owned by a consortium of companies, including Koc Holding, Avgaz and Shell. The remaining 49% of shares are publicly traded.[52]

Refineries in Turkey are also undergoing modernisation, with the aim of improving Turkey's refined products to meet EU environmental and fuel-quality standards. New refinery construction is planned for Ceyhan, which is the terminus of two existing pipelines (the Kirkuk–Ceyhan and the BTC), as well as the ongoing Samsun–Ceyhan project. There are at least three proposals for new refineries in Ceyhan. Additionally, the state-run Indian Oil Corporation recently expressed interest in participating in a project to build a new $5 billion refinery near Ceyhan.

The Samsun–Ceyhan oil pipeline project (e.g. Figure 52), one of the different projects seeking to decrease the tanker traffic through the Turkish Straits, is characterised as follows:

- There are favourable loading conditions in Ceyhan.
- The groundbreaking ceremony took place on 24 April 2007.
- A protocol was signed between Turkey and Russia on 6 August 2009, which foresees throughput by the Russian Federation.
- An agreement was signed by Eni, Çalık, Transneft and Rosneft on 19 October 2009 in Milan regarding the realisation of the pipeline.
- Intergovernmental Agreement negotiations started on 24 September 2010 among Turkey, Russia and Italy.

Figure 52. Samsun–Ceyhan crude oil pipeline project

Source: Wikipedia.

Natural gas

With the launch of Azerbaijani gas exports to Europe through the Turkey–Greece gas pipeline interconnector in 2007, Turkey began to make progress on its goal of becoming an energy bridge for

[52] Ibid.

gas supplies from the Caspian region to Europe. The major gas pipelines in Turkey are summarised in Table 27.

To diversify its sources of gas imports, Turkey imports LNG from Algeria and Nigeria. There are two LNG regasification terminals operating in Turkey with an aggregate nominal capacity of 12.2 bcm/year. The first LNG terminal, located at the Marmara Ereglisi site and owned by BOTAŞ, has a capacity of 6.2 bcm. The second LNG terminal, located at Aliaga/Izmir, has a capacity of 6 bcm and is owned by Egegaz.

To function as a gas transit state, Turkey must be able to import enough gas to satisfy both domestic demand and any re-export commitments, as well as provide enough pipeline capacity to transport Caspian and Middle Eastern gas across Turkey to Europe. Turkey currently enjoys considerable excess import capacity. As Turkish demand increases, however, surplus capacity is expected to decline; it could disappear altogether within the next decade without additional investments in the infrastructure system.

Table 27. Major gas pipelines in Turkey

Major Turkish Gas Pipelines			
Name	**Capacity**	**Route**	**Notes**
Baku-Tbilisi-Erzurum Pipeline (BTE)	1.05 Tcf	Azerbaijan-Georgia-Turkey	Connects Azerbaijan's offshore Shah Deniz gas field to Turkey via Georgia. Construction of the pipeline was completed in 2006 and began operating in 2007.
Blue Stream Pipeline	1.1 Tcf	Russia-Turkey via the Balck Sea	Became operational in 2003. Volumes via the pipeline have been well below capacity because of a price dispute between Turkey and Russia, although supplies have been increasing. Russia and Turkey have discussed a potential "Blue Stream-2" pipeline that would extend the pipeline to Israel via the Mediterranean Sea.
Iran-Turkey Pipeline	49 Bcf	Iran-Turkey	The pipeline runs from the Iranian city of Tabriz to the Turkish capital of Ankara. Turkey took its first Iranian gas delivery in December 2001. Iranian supplies have been periodically disrupted either because of disputes between the two countries or without any explanation from Iran, particularly in winter when Iran's own demand increases. Several explosions on the line near the Turkey-Iran border have also disrupted supplies temporarily in the past.
Romania-Bulgaria-Turkey Pipeline	630 Bcf	Romania-Bulgaria-Turkey	Pipeline carries Russian gas into Istanbul and north-western Turkey. Pipeline length includes the common transit pipeline from the Bulgaria-Romania border to Greece and Macedonia and the loop transit pipeline to Turkey.
Bursa-Komotini	420 Bcf	Turkey-Greece	Pipeline launched in late 2007, allowing Turkey become an energy bridge to Europe. The Turkey-Greece interconnector is expected to be a vital part of the South Europe Gas Ring Project, which also envisions a subsea pipeline connecting Greece to Italy.

Source: IHS Global Insight.

8. Egypt

Egypt has a strategic role in the regional energy transit scenario, notably because of three important structures: the Suez Canal and the SUMED oil pipeline (which, if combined, are responsible for over 3 million bbl/d of crude oil flows into the Mediterranean), plus the Arab Gas Pipeline.[53]

Suez Canal

The Suez Canal (owned and managed by the Suez Canal Authority) is an important transit route for oil and LNG from the Middle East to Europe. The Suez Canal is a 193-km one-lane waterway in Egypt, connecting Port Said on the Mediterranean Sea with Port Toufiq on the Red Sea. The Canal allows marine transport between Europe and Asia without navigating around the southern tip of Africa, and therefore is strategically important in world trade. In the BP (2011) report, total oil flows from the Suez Canal amounted to about 2 million bbl/d on average in 2010; in that year, 17,993 vessels passed through the Canal, well below the record number in 1982. Traffic was up about 5% per year in the 2000s other than during the period of the global financial crisis. Of the total, there were more than 3,500 oil tankers carrying more than 100 Mt of crude oil and petroleum products through the Suez Canal. According to the US Energy Information Administration (2008), this volume was slightly less than 5% of the global seaborne oil trade. The majority was refined products. Southbound trade accounted for about 42 Mt, whereas northbound trade was more than 55 Mt. The majority of crude oil flows transiting the Canal travel northbound, towards markets in the Mediterranean and North America.

In recent years, the Suez Canal has become increasingly important for LNG tankers in general, which are smaller than crude oil tankers and do not face size restrictions. LNG volumes transported via the Suez Canal almost doubled in 2010 to reach 91 Mt. In fact, LNG transit through the Suez Canal has been on the rise since 2008, with the number of tankers increasing from approximately 430 to 760, and volumes of LNG travelling northbound (laden tankers) increasing more than four-fold. Southbound LNG transit originates in Algeria and Egypt, destined for Asian markets, while northbound transit is mostly from Qatar and Oman, destined for European and North American markets. The rapid growth in LNG flows over the period is due to the start-up of five LNG trains in Qatar in 2009–10. The only alternate route for LNG tankers would be around Africa, as there is no pipeline infrastructure to offset any Suez Canal disruptions. Countries such as the UK and Italy receive most of their total LNG imports via the Suez Canal while over 90% of Belgium's LNG imports transit through the Canal.

An increase in the Suez Canal depth to 20 metres has enabled all container vessels to pass through the Canal since January 2010. The Suez Canal Authority (SCA) has been progressively widening and further deepening the Canal to 22 metres by 2012. When complete, about 99% of all methods used in maritime transport will be able to sail through the Canal, including fully laden supertankers like the ultra-large crude carriers. Another project envisaged by the SCA is to add a bypass channel in the middle of the Canal to make transit possible in both directions. But no development plans have been announced so far.

SUMED oil pipeline

The SUMED pipeline is an oil transit pipeline running across Egypt parallel to the Suez Canal from the Ain al-Sokhna terminal on the Gulf of Suez to the Sidi Kerir terminal on the Mediterranean coast, west of Alexandria. The pipeline allows large tankers to unload their cargoes fully or partially into the pipeline at Ain al-Sokhna, to navigate the Suez Canal in ballast or partly laden, and to reload the cargoes to full capacity at Sidi Kerir. Alternatively, supertankers can unload oil into the pipeline at Ain al-Sokhna and other vessels transport oil from Sidi Kerir to Europe or other destinations. BP (2011) estimated the level of oil flows through the SUMED to be about 1.1 million bbl/d in 2010. Throughputs of the SUMED pipeline are expected to increase, as European countries import more oil from the Middle East.

[53] Data source: *Restrictions of Passage, Accidents and Oil Transportation Norms,* Luciani (2011).

The SUMED pipeline came online in 1977 and is operated by the Arab Petroleum Pipeline Company. It is 320 km long, consists of two parallel 42-inch lines and has a capacity of about 120 Mt/year. The pipeline system has about 153 Mt of storage capacity in 21 tanks at the two terminals. Reflecting the economic downturn, only 58 Mt of crude oil transited through SUMED in 2010, about half of its capacity. According to the IEA (2010), Iran supplied 53% and Saudi Arabia 36% of those flows. Approximately 70% of the crude oil shipped via the SUMED was refined in Mediterranean refineries.

9. Algeria

Algeria is a major oil and gas exporter in the region and has a well-established oil and gas infrastructure.[54] The country's total oil exports (including crude, condensate and oil products) reached about 1.8 million bbl/d in 2009. The US imported from Algeria 488,000 bbl/d of oil, OECD countries 1,120,000 bbl/d (482,000 bbl/d by the European OECD countries France, Germany, Italy and the UK), Canada 149,000 bbl/d, and Japan and Korea 61,000 bbl/d.

The Algerian oil and gas networks transported, from the south to the north of the country, about 152 Mtoe in 2010, distributed as follows:

- crude oil (53.2 Mt), of which 39% went to refineries in the north;
- natural gas (83.5 bcm), of which 29% was delivered to LNG plants and 45% dedicated to gas exports by gas pipeline;
- condensate (10.9 Mt); and
- LPG (6.8 Mt).

Algeria's gas pipeline transport system is well-established and links gas fields in the extreme south-eastern region at In-Amenas via the hub at the giant Hassi R'Mel field to the following locations:

- the LNG plants of Arzew and Skikda (which supply mainly France, Spain, Italy and the UK);
- Italy via the Enrico Mattei (formerly Trasmed) gas pipeline; and
- Spain and Portugal via the Pedro Duran Farell (formerly GME) gas pipeline.

Tunisia and Morocco are supplied as transit countries: volumes correspond to transit fees in addition to commercial contracts.

Furthermore, the new deepwater Medgaz pipeline, which started in March 2011, allows Algeria to supply the Spanish market without having to transit other countries. The Galsi pipeline from El Kala to Sardinia, if and when completed, would provide direct access to the Italian gas market.

Algeria is also looking forward to solidifying its standing as a regional transit hub for West African gas and its access to the Mediterranean and European markets. This aspiration could surge if and when the planned Trans-Saharan Pipeline – a 4.128-km-long gas pipeline from Nigeria to Algeria with an annual capacity of 30 bcm/year – is completed (e.g. Figure 53).

The idea of the Trans-Saharan Pipeline was first proposed in the 1970s, but it was not until 2002 that the Nigerian National Petroleum Corporation (NNPC) and Sonatrach signed a Memorandum of Understanding for preparations for the project. The pipeline would start in the Warri region in Nigeria and would run north through Niger to Hassi R'Mel in Algeria. In Hassi R'Mel the pipeline would connect to the existing Enrico Mattei pipeline, the Pedro Duran Farrell pipeline and the Medgaz pipeline (which supply Europe from the gas transmission hubs at El Kale and Beni Saf on Algeria's Mediterranean coast). The pipeline (proposed to be operational by 2015) would be built and operated by the partnership between the NNPC and Sonatrach. The company would also include the Republic of Niger.

[54] Data source of this section: Sonatrach (2010).

The pipeline was proposed by Algeria's President Abdelaziz Bouteflika, for the development of the Sub-Saharan region between Nigeria and Algeria. While this pipeline project was discussed intensively in the first half of the last decade, it is presently on hold. Looking towards the future, however, it cannot be ruled out that the project will re-emerge, even if it implies important security issues that may hinder the construction of such a pipeline.

Figure 53. The planned Trans-Saharan pipeline

Source: Wikipedia.

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Appendix. MEDPRO Energy Reference Scenario – Tables

Table A1. MED-11 Reference Scenario for natural gas

MED-11 Reference Scenario	**Natural gas Production/Imports–Exports/Demand**					
(Mtoe)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–30 (%)**
Gas production	150	184	227	261	294	3,2
Gas net imports/exports	-38	-30	-50	-54	-55	1,8
Gas demand	114	154	177	207	239	3,6
Gas inputs in power plants	-58	-78	-90	-105	-121	3,6
Gas in other transformation & losses	-13	-13	-13	-14	-15	0,9
Gas final consumption	43	63	74	88	103	4,3
Transport	*2*	*3*	*4*	*5*	*6*	*5,0*
Residential	*15*	*28*	*33*	*39*	*45*	*5,3*
Industry	*22*	*27*	*30*	*35*	*40*	*2,9*
Other consumption	*3*	*5*	*7*	*8*	*11*	*6,0*
Electricity output (gas) (TWh)	291	409	464	562	670	4,1
Installed capacity (gas) (MW)	56.782	74.653	87.256	107.485	129.224	4,0

Source: Own elaborations.

Table A2. MED-11 Reference Scenario for oil

MED-11 Reference Scenario	**Oil Production/Imports–Exports/Demand**					
(Mtoe)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–30 (%)**
Oil production	249,4	277,2	308,6	318,5	317,7	1,2
Net imports/exports	-110,5	-110,0	-123,2	-118,2	-103,4	-0,3
Total oil supplies	138,9	167,1	185,5	200,4	214,3	2,1
Electricity plants (inputs)	-22,2	-28,8	-32,0	-34,6	-36,6	2,4
Other transformation & losses	-8,4	-8,7	-9,0	-9,3	-9,6	0,6
Total final consumption	105,2	129,6	144,4	156,5	168,1	2,3
Transport	*54,2*	*65,7*	*73,1*	*80,1*	*87,3*	*2,3*
Residential	*16,3*	*19,7*	*21,5*	*22,3*	*23,0*	*1,6*
Industry	*15,9*	*21,5*	*23,4*	*24,2*	*24,1*	*2,0*
Other consumption	*19,8*	*22,7*	*26,4*	*30,0*	*33,8*	*2,6*
Electricity output (oil) (TWh)	103	121	136	147	155	2,0
Installed capacity (oil) (MW)	10.115	13.988	15.982	17.994	19.500	3,2

Source: Own elaborations.

Table A3. Algeria – Reference Scenario for natural gas

MEDPRO Reference Scenario	**Algeria – Natural gas Production/Imports–Exports/Demand**						
(Bcm)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–20 (%)**	**Average annual growth rate 2009–30 (%)**
Gas production	81,4	102,3	124,3	143	160,6	4,0	3,3
Gas imports/exports	-52,8	-64,9	-80,3	-89,1	-96,8	3,9	2,9
Gas demand	28,6	37,4	45,1	53,9	63,8	4,1	3,9
Electricity plants	-12,1	-14,3	-16,5	-19,8	-23,1	2,6	3,0
Gas in transformation & losses	-5,5	-6,6	-7,7	-8,8	-8,8	2,4	2,3
Gas final consumption	11	16,5	20,9	25,3	30,8	6,0	5,1
Transport	*2,2*	*3,3*	*3,3*	*4,4*	*6,6*	*6,6*	*5,9*
Residential	*5,5*	*6,6*	*8,8*	*11*	*13,2*	*4,8*	*4,5*
Industry	*2,2*	*3,3*	*3,3*	*4,4*	*4,4*	*3,1*	*2,2*
Other consumption	*2,2*	*3,3*	*4,4*	*6,6*	*7,7*	*9,5*	*7,3*
Electricity output (gas) (TWh)	41,693	49	58,7	70	82	3,2	3,3
Installed capacity (gas) (MW)	10.858	12.076	13.471	15.997	18.150	2,5	2,0

Source: Own elaborations.

Table A4. Algeria – Reference Scenario for oil

MEDPRO Reference Scenario	**Algeria – Oil Production/Exports/Demand**					
(Mtoe)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–30 (%)**
Oil production	97,4	105,2	108,1	100,2	92,6	-0,2
Net imports/exports	-85,0	-90,0	-91,0	-81,0	-71,0	-0,9
Total oil supplies	12,4	15,2	17,1	19,2	21,6	2,7
Electricity plants (inputs)	-0,1	-0,2	-0,2	-0,2	-0,1	1,3
Other transformation & losses	-1,1	-1,3	-1,2	-1,2	-1,2	0,3
Total final consumption	11,0	13,7	15,8	17,9	20,3	3,0
Transport	*6,0*	*7,9*	*9,3*	*10,8*	*12,6*	*3,6*
Residential	*3,3*	*4,1*	*4,5*	*4,8*	*5,1*	*2,1*
Industry	*1,2*	*1,3*	*1,5*	*1,7*	*2,0*	*2,5*
Other consumption	*0,2*	*0,4*	*0,5*	*0,5*	*0,6*	*4,8*
Electricity output (oil) (TWh)	0,736	1	0,6	1	1	1,4
Installed capacity (oil) (MW)	239	395	396	400	405	2,5

Source: Own elaborations.

Table A5. Egypt – Reference Scenario for natural gas

MEDPRO Reference Scenario	**Egypt – Natural gas Production/Exports/Demand**					
(Bcm)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–30 (%)**
Gas production	57,2	64,9	75,9	83,6	90,2	2,2
Gas net imports/exports	-17,6	-17,6	-22	-23,1	-24,2	1,7
Gas demand	39,6	47,3	55	60,5	64,9	2,4
Gas inputs in power plants	-20,9	-27,5	-33	-35,2	-37,4	2,8
Gas in transformation & losses	-6,6	-6,6	-5,5	-5,5	-5,5	-1,2
Gas final consumption	12,1	14,3	16,5	19,8	22	2,9
Transport	-	-	-	-	-	-
Residential	*1,1*	*1,1*	*1,1*	*2,2*	*2,2*	*6,7*
Industry	*11*	*12,1*	*13,2*	*16,5*	*17,6*	*2,3*
Other consumption	*0*	*0*	*1,1*	*1,1*	*1,1*	*15,3*
Electricity output (gas) (TWh)	90	141	156	174	188	3,6
Installed capacity (gas) (MW)	18 213	28 840	34 724	40 330	45 591	4,5

Source: Own elaborations.

Table A6. Egypt – Reference Scenario for oil

MEDPRO Reference Scenario	**Egypt – Oil Production/Exports/Demand**					
(Mtoe)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–30 (%)**
Oil production	35,2	37,5	35,0	34,0	32,0	-0,5
Net imports/exports	-3,1	0,0	5,9	11,6	18,3	-209
Total oil supplies	32,1	37,5	40,9	45,6	50,3	2,2
Electricity plants (inputs)	-5,1	-5,3	-6,1	-8,2	-10,5	2,2
Other transformation & losses	-2,6	-2,1	-2,2	-2,3	-2,4	-0,4
Total final consumption	-2,6	-2,1	-2,2	-2,3	-2,4	2,1
Transport	*12,5*	*16,1*	*18,0*	*19,9*	*21,7*	*2,7*
Residential	*4,9*	*5,3*	*5,5*	*5,7*	*5,8*	*0,8*
Industry	*6,9*	*8,5*	*8,9*	*9,3*	*9,7*	*1,6*
Other consumption	*0,1*	*0,2*	*0,2*	*0,2*	*0,2*	*2,3*
Electricity output (oil) (TWh)	26	22	27	35	40	2,1
Installed capacity (oil) (MW)	2 316	4 045	5 300	6 900	8 000	2,1

Source: Own elaborations.

Table A7. Libya – Reference Scenario for natural gas

MEDPRO Reference Scenario	**Libya – Natural gas Production/Exports/Demand**					
(Bcm)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–30 (%)**
Gas production	17,6	22	28,6	31,9	38,5	3,7
Gas net imports/exports	-8,8	-9,9	-14,3	-14,3	-18,7	3,4
Gas demand	8,8	11	14,3	16,5	19,8	4,0
Gas inputs in power plants	-3,3	-4,4	-6,6	-7,7	-9,9	6,0
Gas in other transformation & losses	-1,1	-1,1	-1,1	-1,1	-1,1	2,5
Gas final consumption	4,4	6,6	6,6	7,7	8,8	2,5
Transport	-	-	-	-	-	-
Residential	-	-	-	-	-	-
Industry	*4,4*	*6,6*	*6,6*	*7,7*	*8,8*	*2,5*
Other consumption	-	-	-	-	-	-
Electricity output (gas) (TWh)	10	15	22	30	40	6,9
Capacity (gas-based) (MW)	2 430	3 750	5 500	7 500	10 000	7,0

Source: Own elaborations.

Table A8. Libya – Reference Scenario for oil

MEDPRO Reference Scenario	**Libya – Oil Production/Exports/Demand**					
(Mtoe)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–30 (%)**
Oil production	90,3	108,0	138,3	157,7	166,5	3,0
Net imports/exports	-76,6	-90,0	-120,0	-140,0	-150,0	3,3
Total oil supplies	13,7	18,0	18,3	17,7	16,5	0,9
Electricity plants (inputs)	-5,3	-7,2	-6,6	-5,1	-3,2	-2,3
Other transformation & losses	-1,7	-2,0	-2,2	-2,3	-2,5	1,8
Total final consumption	7,4	8,8	9,5	10,2	10,8	1,8
Transport	*4,2*	*5,2*	*5,7*	*6,1*	*6,5*	*2,0*
Residential	*1,0*	*1,3*	*1,5*	*1,7*	*1,8*	*2,9*
Industry	*1,2*	*1,0*	*0,9*	*0,9*	*0,9*	*-1,5*
Other consumption	*0,9*	*1,2*	*1,4*	*1,5*	*1,7*	*2,8*
Electricity output (oil) (TWh)	21	23	21	16	10	-3,4
Installed capacity (oil) (MW)	3.843	3.800	3.330	2.600	1.600	-4,0

Source: Own elaborations.

Table A9. Morocco – Reference Scenario for natural gas

MEDPRO Reference Scenario	**Morocco – Natural gas Production/Imports–Exports/Demand**				
(Bcm)	**2009**	**2015**	**2020**	**2025**	**2030**
Gas production	-	-	-	-	-
Gas net imports/exports	-	-	1	1	1
Gas demand	-	1	1	1	1
Electricity plants (gas input)	-	-1	-1	-1	-1
Gas final consumption	-	-	-	-	-
Transport	-	-	-	-	-
Residential	-	-	-	-	-
Industry	-	-	-	-	-
Other consumption	-	-	-	-	-
Electricity output (gas) (TWh)	3	5	6	8	10
Installed capacity (gas-burning) (MW)	850	1.132	1.132	1.250	1.450

Source: Own elaborations.

Table A10. Morocco – Reference Scenario for oil

MEDPRO Reference Scenario	**Morocco – Oil Production/Imports–Exports/Demand**				
(Mtoe)	**2009**	**2015**	**2020**	**2025**	**2030**
Oil production	0,0	0,0	0,0	0,0	0,0
Net imports/exports	10,6	14,0	16,7	19,5	22,6
Total oil supplies	10,6	14,0	16,7	19,5	22,6
Electricity plants (inputs)	-0,9	-1,7	-2,1	-2,6	-3,1
Other transformation & losses	-0,1	-0,2	-0,2	-0,2	-0,3
Total final consumption	8,7	12,1	14,4	16,7	19,2
Transport	*1,1*	*1,6*	*1,9*	*2,3*	*2,8*
Residential	*1,7*	*2,5*	*3,0*	*3,6*	*4,3*
Industry	*1,5*	*2,3*	*2,7*	*3,2*	*3,6*
Other consumption	*3,8*	*5,7*	*6,7*	*7,6*	*8,5*
Electricity output (oil) (TWh)	4	7	9	11	14
Installed capacity (oil) (MW)	1.701	1.395	1.700	1.800	2.100

Source: Own elaborations.

Table A11. OSE countries – Reference Scenario for natural gas

MEDPRO Reference Scenario	**OSE countries – Natural gas Production/Imports–Exports/Demand**					
(Bcm)	**2009**	**2015**	**2020**	**2025**	**2030**	**Average annual growth rate 2009–30 (%)**
Gas production	5,6	9,1	15,7	24,4	31,1	8,4
Gas net imports/exports	5,2	8,1	3,8	-1,6	-3,8	-1,9
Gas demand	10,9	17,3	19,6	22,7	27,2	4,5
Electricity plants (gas input)	-8,7	-15,1	-17,1	-17,9	-19,5	-3,9
Gas final consumption	2,0	2,1	2,3	4,6	7,5	6,6
Transport	*0*	*0*	*0*	*0*	*0*	-
Residential	*0*	*0*	*0*	*1,1*	*2,2*	-
Industry	*1,1*	*1,1*	*1,1*	*2,2*	*3,3*	*8,6*
Other consumption	*1,1*	*1,1*	*2,2*	*2,2*	*2,2*	*2,4*
Electricity output (gas) (TWh)	39	65	78	91	105	4,8
Installed capacity (gas-burning) (MW)	7.958	11.000	13.000	17.000	20.000	4,5

Source: Own elaborations.

Table A12. OSE countries – Reference Scenario for oil

MEDPRO Reference Scenario	**OSE countries – Oil Production/Imports–Exports/Demand**				
(Mtoe)	**2009**	**2015**	**2020**	**2025**	**2030**
Oil production	18,7	18,8	21,1	21,7	22,2
Net imports/exports	16,1	23,0	24,0	24,0	23,0
Total oil supplies	34,8	41,8	45,1	45,7	45,2
Electricity plants (inputs)	-9,4	-11,9	-13,8	-15,5	-17,0
Other transformation & losses	-9,4	-11,9	-13,8	-15,5	-17,0
Total final consumption	21,8	27,5	28,9	27,7	25,7
Transport	*12,3*	*14,4*	*15,2*	*15,2*	*15,3*
Residential	*3,2*	*4,2*	*4,7*	*4,2*	*3,8*
Industry	*3,2*	*3,5*	*3,6*	*2,7*	*0,9*
Other consumption	*4,8*	*5,3*	*5,4*	*5,6*	*5,8*
Electricity output (oil) (TWh)	44	57	65	72	79
Installed capacity (oil) (MW)	10.115	13.988	15.982	17.994	19.500

Source: Own elaborations.

Table A13. Tunisia – Reference Scenario for natural gas

MEDPRO Reference Scenario	**Tunisia – Natural gas Production/Imports/Demand**				
(Bcm)	**2009**	**2015**	**2020**	**2025**	**2030**
Gas production	3,15	3,6	3,9	4,3	3,7
Gas net imports/exports	1,2	2,1	2,1	2,7	3,7
Gas demand	4,4	5,7	6,1	7,1	7,5
Electricity plants (gas input)	-3,6	-4,4	-4,5	-5,3	-5,5
Gas in other transformation & losses	0	0	0	0	0
Gas final consumption	1,2	1,3	1,5	1,8	1,9
Transport	*0*	*0*	*0*	*0*	*0*
Residential	*0*	*0*	*0*	*0*	*0*
Industry	*0,7*	*0,9*	*1,1*	*1,3*	*1,4*
Other consumption	*0*	*0*	*0*	*0*	*0*
Electricity output (gas) (TWh)	13	19,8	21	25	28
Installed capacity (gas) (MW)	2.269	3.348	4.048	4.250	5.787

Source: Own elaborations.

Table A14. Tunisia – Reference Scenario for oil

MEDPRO Reference Scenario	**Tunisia – Oil Production/Imports–Exports/Demand**				
(Mtoe)	**2009**	**2015**	**2020**	**2025**	**2030**
Oil production	5,7	5,8	5,2	5,0	4,3
Net imports/exports	-1,2	-0,5	1,4	2,0	2,7
Total oil supplies	4,5	5,3	6,6	7,0	7,0
Electricity plants (inputs)	-0,1	-0,7	-1,6	-1,6	-1,3
Other transformation & losses	-0,1	-0,1	-0,1	-0,1	-0,1
Total final consumption	3,4	4,4	4,8	5,2	5,6
Transport	*1,8*	*2,2*	*2,4*	*2,6*	*2,8*
Residential	*0,5*	*0,6*	*0,7*	*0,7*	*0,7*
Industry	*0,5*	*0,7*	*0,8*	*0,9*	*0,9*
Other consumption	*0,8*	*0,9*	*1,0*	*1,1*	*1,1*
Electricity output (oil) (TWh)	1	2,8	6	6	5
Installed capacity (oil) (MW)	1.090	1.342	1.342	1.342	960

Source: Own elaborations.

Table A15. Turkey – Reference Scenario for natural gas

MEDPRO Reference Scenario	**Turkey – Natural gas Production/Imports/Demand**				
(Bcm)	**2009**	**2015**	**2020**	**2025**	**2030**
Gas net imports/exports	30,4	48,7	54,6	65,4	77,7
Gas demand	32,5	49,1	54,6	65,4	77,7
Electricity plants (gas input)	-17,2	-14,9	-20,1	-21,1	-27,9
Gas final consumption	15,4	28,6	33	37,4	40,7
Transport	*0*	*0*	*0*	*0*	*0*
Residential	*10,9*	*10,9*	*22,5*	*25,7*	*28,6*
Industry	*4,1*	*5,8*	*7,2*	*8,1*	*8,9*
Other consumption	*0*	*0*	*0*	*0*	*0*
Electricity output (gas) (TWh)	94	115	122	165	217
Installed capacity (gas-burning) (MW)	14.204	14.507	15.380	21.158	28.246

Source: Own elaborations.

Table A16. Turkey – Reference Scenario for oil

MEDPRO Reference Scenario	**Turkey – Oil Production/Imports/Demand**				
(Mtoe)	**2009**	**2015**	**2020**	**2025**	**2030**
Oil production	2,1	2,0	1,0	0,0	0,0
Net imports/exports	28,7	33,5	39,8	45,8	51,0
Total oil supplies	30,8	35,5	40,8	45,8	51,0
Electricity plants (inputs)	-1,3	-1,8	-1,7	-1,5	-1,2
Other transformation & losses	-0,8	-0,7	-0,7	-0,7	-0,7
Total final consumption	28,5	33,0	38,4	43,6	49,1
Transport	*16,2*	*18,3*	*20,7*	*23,1*	*25,6*
Residential	*1,7*	*1,6*	*1,6*	*1,5*	*1,5*
Industry	*1,4*	*4,2*	*4,9*	*5,5*	*6,1*
Other consumption	*9,1*	*9,0*	*11,3*	*13,4*	*15,9*
Electricity output (oil) (TWh)	7	9	8	7	6
Installed capacity (oil) (MW)	3.115	3.135	3.135	3.135	3.135

Source: Own elaborations.

About MEDPRO

MEDPRO – Mediterranean Prospects – is a consortium of 17 highly reputed institutions from throughout the Mediterranean funded under the EU's 7th Framework Programme and coordinated by the Centre for European Policy Studies based in Brussels. At its core, MEDPRO explores the key challenges facing the countries in the Southern Mediterranean region in the coming decades. Towards this end, MEDPRO will undertake a prospective analysis, building on scenarios for regional integration and cooperation with the EU up to 2030 and on various impact assessments. A multi-disciplinary approach is taken to the research, which is organised into seven fields of study: geopolitics and governance; demography, health and ageing; management of environment and natural resources; energy and climate change mitigation; economic integration, trade, investment and sectoral analyses; financial services and capital markets; human capital, social protection, inequality and migration. By carrying out this work, MEDPRO aims to deliver a sound scientific underpinning for future policy decisions at both domestic and EU levels.

Title	MEDPRO – Prospective Analysis for the Mediterranean Region
Description	MEDPRO explores the challenges facing the countries in the South Mediterranean region in the coming decades. The project will undertake a comprehensive foresight analysis to provide a sound scientific underpinning for future policy decisions at both domestic and EU levels.
Mediterranean countries covered	Algeria, Egypt, Israel, Jordan, Lebanon, Libya, Morocco, Palestine, Syria, Tunisia and Turkey
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Consortium	Centre for European Policy Studies, **CEPS**, Belgium; Center for Social and Economic Research, **CASE**, Poland; Cyprus Center for European and International Affairs, **CCEIA**, Cyprus; Fondazione Eni Enrico Mattei, **FEEM**, Italy; Forum Euro-Méditerranéen des Instituts de Sciences Economiques, **FEMISE**, France; Faculty of Economics and Political Sciences, **FEPS**, Egypt; Istituto Affari Internazionali, **IAI**, Italy; Institute of Communication and Computer Systems, **ICCS/NTUA**, Greece; Institut Europeu de la Mediterrania, **IEMed**, Spain; Institut Marocain des Relations Internationales, **IMRI**, Morocco; Istituto di Studi per l'Integrazione dei Sistemi, **ISIS**, Italy; Institut Tunisien de la Compétitivité et des Etudes Quantitatives, **ITCEQ**, Tunisia; Mediterranean Agronomic Institute of Bari, **MAIB**, Italy; Palestine Economic Policy Research Institute, **MAS**, Palestine; Netherlands Interdisciplinary Demographic Institute, **NIDI**, Netherlands; Universidad Politecnica de Madrid, **UPM**, Spain; Centre for European Economic Research, **ZEW**, Germany
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