INSTITUTE OF ENERGY FOR SOUTH-EAST EUROPE

IENE Briefing Note No1

Global and Regional Natural Gas Developments

December 2012

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1.Introduction

In this first Briefing Note IENE looks at the latest global and regional natural gas developments. Gas is fast becoming the fuel of choice for many countries, not only in Europe where developments are largely driven by environmental commitments, but also in other parts of the world. Notably in North America, where progress over the last few years on new supplies is based on shale gas exploration has been phenomenal to say the least. Natural gas is also gaining ground in SE Europe which imports increasingly more quantities, mainly from Russia but also from Iran and Azerbaijan, as is the case with Turkey, and through LNG. Latest available figures suggest that the 12 SE European countries, which are monitored by IENE, between them consumed some 70.0 BCM's, of which 80% was imported. That means that a sizeable fiscal expenditure is required for these imports with efforts to discover and exploit indigenous gas deposits already being accelerated in several countries of the region.

In this Briefing Note, the first of its kind that IENE has prepared, we attempt, (i) to present a concise view of the global gas scene, and (ii) to throw some light on latest regional gas developments. In our task we have been greatly assisted by some latest IEA work, which is fully quoted in the reference section, but also through direct contacts with various companies and organizations in the region to whom we are grateful.

2 . Global Gas Developments

World natural gas demand climbed to an estimated 3 361 billion cubic meters (bcm) in 2011, translating into an annual growth rate of 2%, much lower than the 7% recorded in 2010. This growth does not quite put natural gas demand back on its pre-crisis track, when natural gas demand was growing at 3% per year. These are some of the main conclusions of IEA's Medium – Term Market Report for 2012.

According to the same IEA report natural gas demand increased in all regions; in particular, China's gas demand increased by 21%, reaching 130 bcm. However, it collapsed in Europe, where it plummeted by 9% to levels even lower than in 2009. The correction, which had been predicted in the *Medium-Term Oil and Gas Markets Report 2011*, can be attributed to a mixture of low economic growth and higher gas prices and was exacerbated by mild weather. In particular, gas-fired plants have been affected by sluggish European power demand and the strong growth of renewables, as well as increasing difficulties competing against coal-fired plants due to both relatively high gas prices and extremely low CO2 prices. Even the decommissioning of a number of German nuclear power plants in early 2011 did not translate into increasing gas demand in the German power sector. The OECD Americas region benefitted from low gas prices, which boosted the share of gas in the power generation and industrial sectors, notably in the United States. In OECD Asia Oceania, additional demand mostly originated from Japan, as the country replaced missing nuclear generation partly by gas-fired generation, following the earthquake and tsunami and the subsequent incidents at the Fukushima Daichi plant. Higher consumption in non-OECD regions was driven by economic growth and increasing needs in both the power and industrial sectors. Gas markets grew strongly in Asia, the Middle East and in Africa, but more moderately in Latin America and Former Soviet Union (FSU)/Non-OECD Europe.

Global gas supply increased by 3% in 2011, reaching 3 375 bcm. The 93 bcm increase was almost entirely from three countries: the United States, Russia and Qatar. Global gas supply increased actually faster than demand, as additional gas was needed to replenish gas storage facilities in Europe, which were below normal levels in early 2011, while the United States faced an unprecedented surplus of gas in its storage facilities at end-2011. From a regional perspective, gas production increased significantly in OECD Americas, the FSU/Non-OECD Europe and the Middle East, but quite marginally in Latin America, and OECD Asia Oceania. However, European gas production declined sharply by 9.3% from 2010.

The IEA observes that the situation in 2011 was nothing like "business as usual" on the supply side, given the unrest in North Africa and the Middle East. Although attention was very much on oil following the disruption of 1.5 million barrels per day (mb/d) of Libyan oil, some shortages were also observed on the gas side. In particular, gas production dropped sharply in Libya and Syria, resulting in Libyan supplies to Italy being disrupted during several months in 2011. Meanwhile, the repeated bombing of the Arab Gas Pipeline linking Egypt to Israel, Jordan, Syria and Lebanon deprived these countries of part of their natural gas imports, which in some cases constituted most of their gas supplies.

A major finding of IEA's Mid Term gas report was that unconventional gas represented 16% of global gas production as of 2011. Despite the growing interest in shale gas, half of unconventional gas production consisted actually of tight gas. Production increases in 2011 came mostly from North America, where shale gas continues to boom despite record low gas prices and the reduction in the number of rigs. In addition to shale gas and tight gas, associated gas from light tight oil plays is also growing in importance. Together, production from these three sources now more than compensates for the decline in US conventional gas production. Over the medium term, unconventional gas production is expected to continue to expand, again coming primarily from North America, where US shale gas production continues to boom. Outside this region, tight gas and coal bed methane (CBM) will be the largest contributors to incremental production. In the Middle East, Africa and Latin America, tight gas could complement existing conventional gas, while CBM is projected to increase markedly in China and Australia. Other countries with significant shale gas potential face a number of challenges in addition to environmental issues, such as pricing, lack of transport infrastructure, upstream competition or the more active presence of a mature service industry. Consequently, new shale gas production developments are projected to be somewhat limited over the next five years, with the most likely developments taking place in China and Poland.

Another key IEA finding is that the global trade balance is visibly shifting to Asia, which is now not only attracting increasing flows of liquefied natural gas (LNG), but also of pipeline gas. Global LNG trade increased by 9.4% to reach 327 bcm in 2011, which represents a significant slowdown compared to the record 21% increase in 2010. The reason behind this slowdown is that only a single new liquefaction plant came on line in 2011, in Qatar, but additional LNG was still being produced from those started in 2010 and progressively reaching plateau during 2011. Nevertheless, LNG trade was still increasing faster than global gas demand. The bulk of these additional LNG supplies went to the hungry Asian markets, notably to Japan, which needed to import more LNG as nuclear generation steadily collapsed in that country following Fukushima. Meanwhile, the United States imported even lower LNG volumes and European LNG imports remained flat. This stability is actually remarkable considering the collapse of European demand and of its import requirements. On the pipeline side, Turkmenistan's exports to China more than tripled from 2010 levels following the expansion of the Central Asia Gas Pipeline.

With regard to gas prices it is becoming increasingly clear that price differentials is the order of the day. Throughout 2011 regional gas prices continued to drift further apart, as Henry Hub (HH) gas prices reached levels below USD 2 per million British thermal units (MBtu) – the lowest prices in a decade, while European spot and contract gas prices stabilised at between USD 8 and USD 10/MBtu and average import prices in Japan reached USD 17/MBtu during the second half of 2011. The gap between Japanese LNG prices and HH prices actually widened, from around USD 7/MBtu in January 2011 to over USD 14/MBtu in March 2012. Regional prices are increasingly determined by their respective regional dynamics. Although oil and gas prices are no longer as correlated as before 2009, European gas prices continue to be influenced by oil price movements. The weaker influence of oil prices reflects an increase in both volumes sold at the different continental spot markets and spot indexation in some long-term supply contracts. Despite the increasing LNG volumes available on global markets, the prospect of a global gas price not only did not materialise, but also looks increasingly less plausible. The IEA notes that North American gas market is expected to remain disconnected from other regional markets, while Asia still needs to develop a true market price, reflecting natural gas supply/demand balances rather than the fundamentals of the oil market.

Volumes of natural gas traded on European spot markets increased markedly in 2011, driven by the price differential between oil-indexed gas and gas traded on hubs and regulatory developments, which continued to facilitate hub trading. In 2011, physical volumes traded on the European continent grew by 8%, reaching 162 bcm, while traded volumes jumped by around a third to 542 bcm – a level higher than total European gas demand. Despite these positive developments, most European spot markets still lack liquidity. The National Balancing Point (NBP) is the only truly liquid spot market. Meanwhile, continental European spot markets have generally low churn rates and an insufficient number of products that can be traded.

IEA projects global gas demand to reach 3 937 bcm by 2017, which is 576 bcm higher than today. These forecasts for natural gas demand over 2011-17 reflect three significant anticipated developments:

• ***Gas demand surges in the United States, increasing by around 90 bcm**, **with the power generation sector being the primary driver contributing to nearly three-quarters of this growth.***

• ***China remains the fastest growing market as its gas consumption doubles from 130 bcm in 2011 to 273 bcm in 2017, translating into an annual growth rate of 13% per year.***

• ***There is no "Golden Age of Gas" scenario in Europe, as gas demand remains below 2010 levels during the whole projection period.*** *Gas consumption is hit by the triple whammy of (1) low economic growth translating into slow power demand increases and sluggish development of the industrial sector, (2) high gas prices, notably over the coming two years, and (3) the strong growth of renewables.*

Many Asian, Middle Eastern, African and Latin American countries share the potential risk that, given low domestic gas prices and in some cases, more difficult fields to develop, domestic gas supply does not increase sufficiently to meet their potential gas demand. This leaves

them with two options, besides fixing their gas policies: either curb gas demand or import (often more expensive) gas. IEA Notes that over the coming five years, many South Asian countries will become LNG importers, including current exporters such as Malaysia and Indonesia. More than half the Middle Eastern countries are importing or will import natural gas, either from outside the region through LNG or via pipeline from Egypt, Turkmenistan, or from the region, *i.e.* from Qatar, the only country able to handle increasing domestic and export demand. Middle Eastern demand grows faster than production over the medium term. Rapidly increasing domestic gas demand also leaves very little room for additional exports from Algeria and Egypt, while Latin American countries have to import increasing amounts of LNG.

On the production side, the FSU/Non-OECD Europe and OECD Americas regions will be the most important providers of additional gas supplies, as they represent 43% of the additional production reaching markets during 2011-17. Russia is projected to start major projects such as the Yamal Peninsula, although it has yet to take Final Investment Decisions (FIDs) on the next projects. Given the gloomy demand perspectives in Europe, Russia's main export market, the country is likely to turn more proactively to other export possibilities, namely LNG and Asian markets. Despite the record low gas prices and number of rigs, US gas production growth has been accelerating, boosted by the development of light tight oil, a trend that is expected to continue over the coming five years, putting the United States slightly ahead of Russia in terms of natural gas production in 2017. While Middle Eastern gas production is projected to grow significantly, there are still considerable uncertainties, notably concerning developments in Iraq and Iran. Over the coming years, there will be increasing interest in the development of the next new promising production centre – the African East coast.

IEA predicts that global LNG trade will slow down considerably over the coming three years before abruptly accelerating again in 2015, as both the new wave of Australian LNG and exports from the United States are projected to come on line. This slowdown is due to limited new LNG capacity (25 bcm) starting over 2012-13. There are 13 LNG projects amounting to 114 bcm/y currently under construction worldwide (or already started in 2012), which are expected to be operational by 2017. In addition, new LNG capacity will start in North America, notably the Sabine Pass project, which received authorisation from the Federal Energy Regulatory Commission (FERC) in April 2012. Most of these new projects will not be cheap, with construction costs anticipated to be twice as high as those for plants which came online over 2009-11. Most will sell gas at oil-indexed prices. The exception, both in terms of capital costs and indexation, is the US gas project, because its pricing formula is based on HH gas prices.

The next five years will see growing needs to import gas in Asia and Europe, and in a more limited way, in the Middle East and Latin America. The main suppliers for these needs will be LNG, which will increase by one-third to 426 bcm by 2017, but also FSU pipeline exports, while exports from the Middle East are expected to remain flat. This requires in some cases building new interregional transport capacity comprised of both pipeline and LNG regasification terminals. At present, over 120 bcm of new regasification capacity is under construction as of early 2012, two-thirds of which is concentrated in Asia, notably China and India. Meanwhile, only three pipelines are under construction: the second part of the Nord Stream pipeline between Russia and Germany, the Central Asia Gas Pipeline between several Caspian countries and China, as well as the Myanmar to China pipeline. While China appears as a major centre for new imports, it also represents a major uncertainty for future investors if the shale gas revolution also takes place in China and reduces import needs over the longer term.

3. A concise view of global demand

Growth in world gas demand slowed significantly in 2011, increasing by only 2% year-on-year to reach around 3 361 bcm. In contrast, gas demand grew by 7% in 2010. Despite this slowdown, world gas demand is almost back to the growth path observed over the past decade.

Global gas demand is expected to continue to increase at a rather healthy pace, reaching 3 937 bcm by 2017, 576 bcm or 17% higher than in 2011 according to latest forecasts by the IEA. Non-OECD markets are predicted to generate 69% of incremental demand growth to 2017. Asia will be by far the fastest growing region, driven primarily by China which will emerge as the third largest gas user by 2013. The region's gas demand is projected to grow from 424 bcm to 634 bcm over 2011-17, a 50% increase. OECD Americas will be the second largest growing market in terms of incremental consumption. Meanwhile, the Middle East region will be the third largest growing region, taking advantage of huge regional gas resources, but this growth of 79 bcm (or 20%) will be very much contingent on the successful development of new and more expensive gas fields.

Fig. 3.1 Natural Gas Consumption 1965-2011

Demand growth trends in other non-OECD regions such as Latin America and Africa are likely to exhibit wide disparities among the different countries. The FSU/Non-OECD Europe region is a relatively mature market and is forecast to continue to experience moderate demand growth at 0.7% per year over 2011-17. Market analysts note that Europe is unlikely to experience a “Golden Age of Gas” over the period. In that sense industrial gas demand is projected to decline over the next few years before recovering, while demand in the residential and commercial sectors is forecast to remain moderate after recovering from the mild weather conditions in 2011. The most dramatic change may occur in the power generation sector, where production from gas-fired power plants is being increasingly displaced by renewables. Even if nuclear power plants are phased out over 2012-17, generation from combustible fuels declines and gas-coal competition becomes the key determinant of gas demand in this sector.

4. Global gas supply

Global gas supply increased by 3% in 2011, reaching 3 375 bcm. The 93 bcm increase was largely supplied by three countries: the United States, Russia and Qatar. From a regional perspective, gas production increased significantly in OECD Americas, FSU countries and the Middle East. OECD Latin America and OECD Asia Oceania recorded marginal supply increases. Supply remained stable in Asia, while declining in Africa and in Europe. Global gas supply increased much faster than demand (2%), with the difference used to increase or refill storage.

On the other hand unconventional gas production is expected to continue to expand over the medium term, led by developments in North America. Beyond this region, production growth will mostly come from tight gas and coalbed methane and from Asia Oceania, in particular, Australia, China, India and Indonesia. Shale gas developments in the medium term will be limited, with the most likely developments taking place in China and Poland. Countries with significant shale gas potential face a certain number of challenges on top of environmental issues, including pricing, infrastructure, and lack of upstream competition or an under-developed service industry.

Global gas production is projected to increase by 562 bcm over 2011-17, in line with global gas demand. Gas production is expected to increases in all regions, except in Europe. OECD regions are expected to provide 30% of the growth in global production capacity over the projection period, changing the trend of the previous decade where non-OECD and especially Middle Eastern producers were the main incremental suppliers.

The United States is forecast to be one of the largest sources of incremental supply to 2017, where gas production continues to boom despite a difficult gas pricing environment. High oil prices, driving the production of gas associated with light tight oil extraction, combined with substantial domestic consumption and new international opportunities, are expected to underpin continued expansion of US gas production over the period.

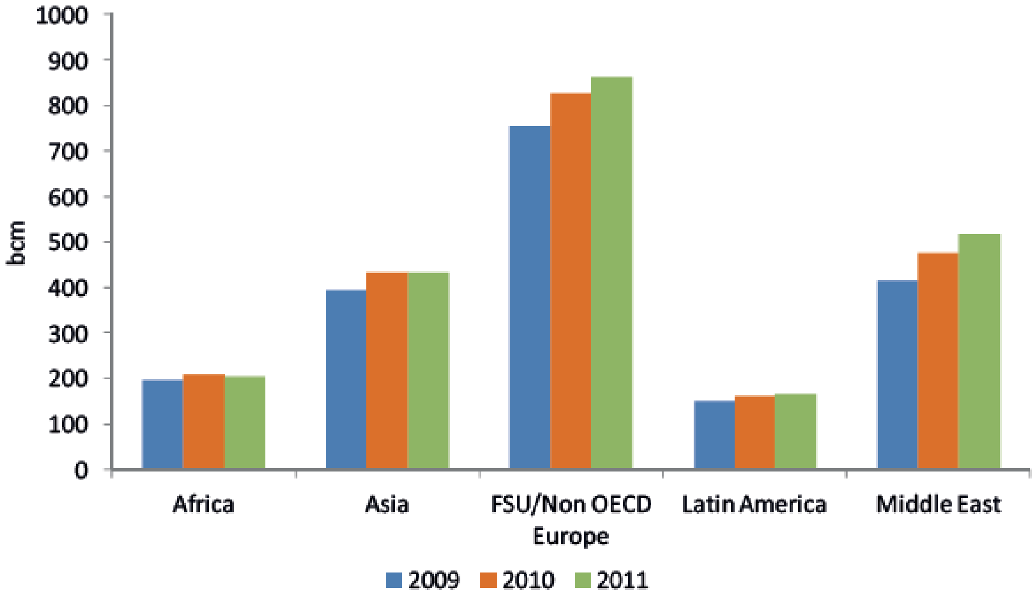

Fig. 4.1 Non-OECD gas production, 2009-11

Russia and the Caspian region remain important sources of incremental gas supply over 2011-17, as FSU/Non-OECD Europe's production increases by 129 bcm. However, moderate growth in domestic and European export markets, combined with limited access to alternative global markets, especially in North Asia, is likely to constrain production growth over the projection period. In the Caspian region, natural gas production in Turkmenistan, Uzbekistan and Kazakhstan benefits from its connection to China, unlike Azerbaijan, where the infrastructure needed to facilitate exports to Europe is not yet under construction.

Natural gas production increases in the Middle East and Africa by 72 bcm and 57 bcm, respectively. While this enables Africa to increase its net LNG exports, this increase fails to meet incremental gas demand in the Middle East. Asia's gas output increases by 26% (111 bcm), with 61 bcm coming from China alone. In contrast, India struggles to restore its production to current levels. Meanwhile, Latin American gas production records the slowest rate of increase – only 15% (25 bcm) over 2011-17.

5. Gas demand and supply in SE Europe

Europe, will need to replace around 100 bcma by 2025 due to both the decline in domestic production as well as the increase in demand. The demand in Europe is forecasted to increase despite the recent economic crisis. Particularly in Greece, the demand rose from 3.6 bcma in 2010 to 4.4 bcma in 2011 despite the economic malfunction and the sharp drop in energy demand.

On the other hand, the export quantities from existing gas suppliers are not expected to be further increased. As a result, Europe will face a supply gap by 2020 which will grow larger by 2025. Some 20 bcma from that supply gap will come from the SEE region and Italy, which also happen to be the closest markets to the Southern Gas Corridor.

Table 5.1 Natural Gas Production and Consumption in SE Europe

COUNTRY	**GAS PRODUCTION** (bcm/year) [2011]	**GAS CONSUMPTION** (bcm/year) [2011]
ALBANIA	0.05	0.03
BOSNIA & HERZEGOVINA	0	0.2
BULGARIA	0.2	2.5
CROATIA	2.0	3.0
CYPRUS	0	0
F.Y.R.O.M.	0	0.1
GREECE	0	4.4
MONTENEGRO	0	0
ROMANIA	10.0	12.9
SERBIA & KOSOVO	0.5	2.4
TURKEY	0.8	43.5
TOTAL	**13.55**	**69.03**

Six of the SE European countries (Greece, Croatia, Bulgaria, Romania, Turkey and Serbia) already use natural gas having well established markets, with supplies coming primarily through imports from Russia and in the case of Turkey from Iran and Azerbaijan also. Two countries have a significant proportion of demand met from domestic supplies (Croatia, Romania) and three others cover small percentage shares from domestic gas (Bulgaria, Serbia, Turkey). In projecting future demand for gas in the region, one of the main issues is the extent to which availability of gas would make possible the displacement of other fuels in various categories of demand such as power generation and residential, commercial and industrial applications. Relative prices and competing fuels lie at the heart of analysis, although potential growth in demand for gas will also be driven by other factors, including environmental aspects and national policies.

Regarding the upstream sector, consistant efforts are now in evidence in Romania, Bulgaria, Croatia and Turkey to exploit existing fields but also identify new ones.

The discovery of substantial offshore natural gas deposits in the Eastern Mediterranean (mainly in Israel and Cyprus) seems to have changed completely the natural gas game in Europe and SE in particular. According to the United States Geological Survey, the gas finds offshore in Israel and Cyprus belong to the massive Levant Basin Province field and could bring major changes in the energy sector of several regional countries. The United States Geological Survey (USGS) estimates the entire Leviathan Basin holds a mean approximation of 1.7 billion barrels of recoverable oil and a mean of 37 trillion cubic meters of recoverable gas or 1.2 trillion cubic metres.

The Mari B and Noa reservoirs of the Yam Tethys joint venture propelled the Israeli offshore into the oil and gas game for the very first time and introduced natural gas to the Israeli market. These reservoirs, Mari B (discovered in February 2000) and Noa (discovered in June 1999) with approximately 33.5 bcm of the highest quality gas reserves marked the start of a new era. Yam Tethys has been supplying natural gas to Israeli market since 2004. Major clients include the IEC (Israeli Electric Corporation), ICL (Israel Chemicals) and other Israeli IPP. Yam Tethys's current supply is at a rate of approximately 3.0 – 3.5 bcma.

Israel, having demarcated her maritime borders with Cyprus in 2010, is now in the process (in 2012/13) of building the infrastructure for natural gas production in the Tamar field which was discovered in 2009. The natural gas contained in the Tamar field which is estimated at 9.0 tcf or 0,25 tcm, can alone cover the country's energy needs for at least two decades. So far, Israel is in a compromised position regarding energy supplies because the country depends 95% on imports. This is all goins to change following the start of production from Tamar and later from the giant Leviathan field.

More specifically, the Leviathan Natural Gas Field, which was discovered in 2010, is situated at a depth of 1,645m of water also in the Levantine Basin, approximately 130km west of Haifa. Production is expected to commence in 2017. The Leviathan gas field's natural gas reserves are estimated to be about 0,5 tcm. Besides natural gas, the field is said to contain 600 million barrels of oil beneath the gas layer. In total Israel's estimated reserves from the Leviathan, Tamar, Tanin and Dalit fields stand at 27,6 tct or 0,77 tcm.

Figure 5.1 : The three main gas fields in Israel's EEZ

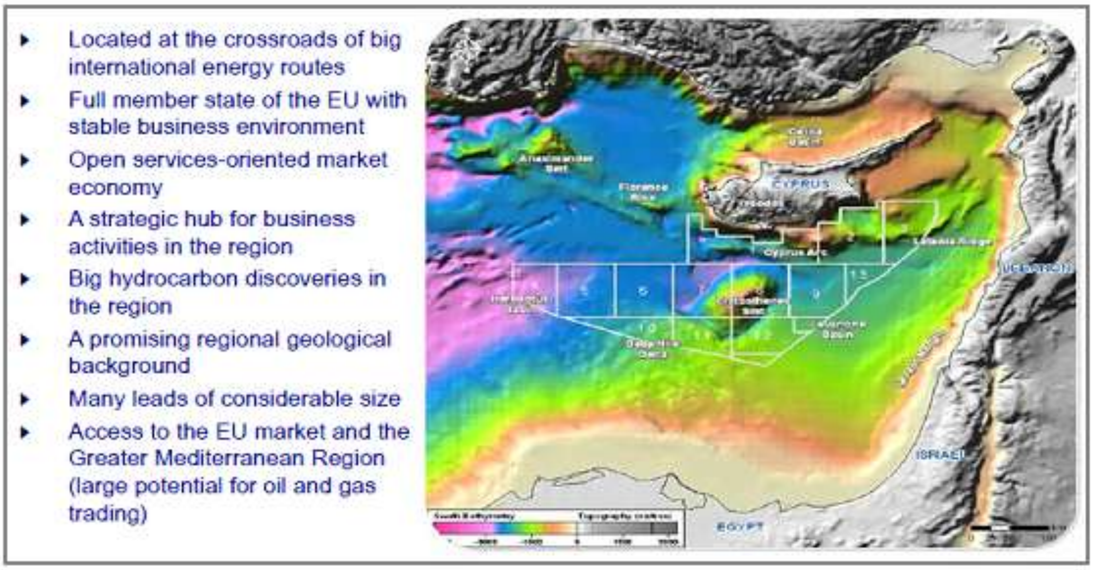

Figure 5.2: Offshore Cyprus: A new natural gas frontier

Consequently, Israel has expressed strong interest in becoming a gas export country and to collaborate with European and US firms in building the necessary infrastructure. The Israel government is also discussing the option of transporting natural gas to Europe via underwater pipeline to Cyprus and Greece. Discussions on this project continued during the latest official visit to Greece by Israel's president Simon Peres in early August this year.

In 2008 Cyprus licensed Noble Energy to proceed with the first phase of hydrocarbon and exploration for an offshore block south of the island and within its EEZ. In December 2011 Cyprus reported a major offshore gas field discovery in Block 12, also known as Aphrodite, whose estimated size is at 7.0 tcf or 0.20 tcm. According to Noble Energy, which holds the licence for Block 12, the find forms part of the same geological formation as that of Leviathan in Israel. A revised upward estimate for Block 12 is expected following a second appraisal well scheduled for drilling in the first half of 2013. The government of the Republic of Cyprus is hopeful that further gas finds will soon be reported once exploration work gets underway following a successfully 2nd licensing round which was completed earlier this year.

The combined Israeli and Cyprus natural gas deposits which have been discovered over the last five years, estimated at approx 37 tcf gross mean estimated resources, or 1.0 tcm, are significant not only in terms of size, as they are of comparable magnitude to Azerbaijan's gas deposits, but also in terms of geopolitical significance. The new gas resource area, when fully explored and its full potential is known, will present an important paradigm shift in Middle East's Arab dominated oil and gas trade. For the first time we have a situation where oil and gas export flows could be envisaged outside an Arab controlled area. This promising outlook will strengthen the two countries' geopolitical role and could prove pivotal for the long term financial stability and economic growth, which is not unconnected to EU's prospects for economic recovery.

Bulgaria

During the last two years (2010 – 2011) natural gas demand in Bulgaria showed a significant drop compared to previous years. In 2008 Bulgaria consumed almost 3,5 billion cubic meters (bcm). Of these 0,211 bcm have been covered by indigenous production, while the rest of the quantities have been imported from Russia. In 2010 the consumption of natural gas in Bulgaria declined sharply to 2,4 bcm, while in 2011 there was a small increase compared to 2010, as total gas demand expanded to 2,5 bcm.

The greatest amount of the gas in Bulgaria is used to satisfy industrial and the public sector needs, while a significant proportion is used for power generation. The forecasts are that during 2011 - 2025 the demand for natural gas will rise on average by about 3,2% per year, reaching 6,3 bcm by the end of the period. This will accelerate the development of the gas-related infrastructure and will increase the consumption rate of natural gas in the country. Bulgarian gas consumption is rising well ahead of domestic supply. Although gas output may reach 1.2bcm by 2014/15, net imports by 2016 could reach 2.3bcm, rising further to a possible 3.4bcm by 2021.[1]

[1] (Bulgaria Oil and Gas Report Q3 2012, *Business Monitor International*)

The use of natural gas accounts to about 14% of the primary energy consumption in Bulgaria. Generally, natural gas consumption in the country is on the rise, as it is being used more and more in the residential sector, but also in industry and for power generation. Currently less than 2% of the households in Bulgaria are gasified, which is far below the average rates of the European Union, which stands between 27%-50%. Furthermore, only about 16% of the municipalities in the country have access to natural gas, compared to 27% to 80% for the rest of EU.

Bulgaria plays an active role in regional projects such as the one to connect the gas distribution networks of the country with Serbia. Upcoming projects include the construction of interconnections with the Romanian and the Greek gas network.

At the same time, the country participates in trans-regional initiatives such as the gas pipelines "Nabucco" and "South Stream". The realization of these projects is important for Bulgaria as it will be able to diversify its sources of natural gas, as well as the supply routes, which in turn will enhance the security of natural gas supply to the national market.

Greece

Gas consumption in Greece, reached 4.2 bcm in 2008. However, there has been a sharp decline, since reaching 3.5 in 2009 (16% less than in 2008) while a slight increase was noted in 2010 to 3.6 bcm. In 2011 gas consumption recouped and surpassed the 2008 level, reaching 4.4 bcm.
Gas imports account for about 100% of the total volumes of consumed gas in Greece. Most of Greece´s gas imports are being realised via pipeline, and 29% is imported via LNG through the Revithousa terminal. Greece's gas pipeline imports come mainly from Russia and a small portion of 0.8 bcm from Azerbaijan through Turkey, while most LNG originates from Algeria and Qatar. The share of Russian gas in Greece's gas imports contracted to 54% in 2010 (slight decrease from 2009, when it was 57%), while the share of Algerian gas in Greece's imports increased quite significantly from 14.79% in 2009 to 20.08% in 2010.

Greece has an extensive portfolio of energy exploration projects for the future, though the present financial crisis has put a damper on these for now. Greece's domestic natural gas consumption as indicated above is steadily increasing- from 2.0 bcm in 2000 to 3.6 bcm in 2010 according to the "BP Statistical Review of World Energy 2011", and 4,4 bcm in 2011.

Realizing the huge potential of the Levantine Basin, Greece started discussions with Israel in early 2011 to explore opportunities for transiting Israel's natural gas exports to Europe. This is an interesting concept, but hardly feasible without some sort of participation or at least tacit agreement from Turkey. Beside the question of distributing the gas and the export revenues between the Greek and the Turkish occupied north part of Cyprus, a direct pipeline from Cyprus to Greece would have to be very long in order to avoid any Turkish territorial waters, or waters under conflicting claims. Turkey and Greece have no agreement on their long maritime border and have appear to conflicting claims in many areas.

Such a pipeline would also be very expensive, as it would partially be installed in very deep waters (more than 2,000 m), at least until it reaches the shallower waters of the Dodecanese archipelago. Although it is very difficult to estimate costs at this early stage, a Cyprus-Greece pipeline would probably be as long as the offshore portion of the South Stream gas pipeline in the Black Sea which will carry natural gas through deep waters as well, and which could cost at least 10 billion euros, according to industry estimates.

The other option would be to export LNG from the Levantine Basin to the Revithoussa LNG terminal in Greece. This currently has a capacity of a slightly more than 5 bcm/year, but these exports would only cover the import requirements of Greece, and potentially the needs of some of the smaller Western Balkans countries neighbouring Greece (i.e Albania, FYROM).

Therefore, mass re-exports from Revithoussa to other European markets would not make sense, as they would be more expensive than gas coming through one of the previously mentioned transit pipelines or directly by LNG from Cyprus to one of the Italian, French or Spanish terminals.

Croatia

Gas production looks set to peak over the next five years, with production expected to rise from 2.0bn cubic metres (bcm) in 2010 to 3.0bcm in 2015.
Natural gas is produced in Croatia from 16 on-shore and nine off-shore gas fields, is currently meeting 71.9% of total domestic demand according to the ministry's 2011 annual energy report. There were 37 companies licensed for distribution of natural gas in Croatia last year.
Consumption is also set to rise, from 2.85bcm in 2010 and 3.0 bcm in 2011 to 4.3 bcm by 2015 and then to 5.4bcm by 2021, meaning that Croatia's import dependency will increase from 0.85bcm of imports to 1.28bcm over the same period. This is somewhat more than the 1.11bcm that Croatia was importing as recently as 2000, due to gas production rising from around 1.66bcm at the time.

Consumption of natural gas in Croatia in 2010 rose by 9.5% to 3.2 bcm compared to 2009.

Serbia

In 2010, Serbia imported 1,68 bcm natural gas representing 91.7% of its domestic consumption. All of Serbia's gas imports are being accomplished via pipeline and as it is a landlocked country there are no LNG imports. In 2010, 98.81% of Serbia's gas imports originated from Russia and similar proportions hold true for 2009 and 2008. In 2007 and 2006, all of the gas imported into Serbia originated from Russia.

Romania

Romania holds 595 bcm of gas reserves, the 3rd largest natural gas reserve in Europe (after Norway and the Netherlands) and the 30th worldwide. According to Cedigaz, Romania's natural gas reserves represent approximately 0.31% of the world total reserves. The reserves-to-production ratio* for Romania is 54.4 years, significantly higher than the EU's average R/P-ratio of 14 years. [2]

A sharp decline in natural gas imports in Romania has taken place since 2006 while the domestic production has remained almost the same with very small changes. In 2006 natural gas consumption in Romania was 18 bcm of which 6 bcm were imported and the rest 12 bcm came from domestic production. However, in 2008 the imports fell to 4,4 and there was a slight decrease in domestic production to 11,3 bcm. In 2009 there was further reduction in imports that reached the 2,0 bcm but this was offset by increased domestic production of about 13,2 bcm. In 2010, Romania imported 2,1 bcm of natural gas representing 15.5% of its domestic consumption while domestic production reached the 10,0 bcm. Finally, in 2011, there was an increase in imports by 2,9 bcm while the domestic production remained unchanged.

All of Romania's gas imports are being accomplished via pipeline. So far there are no LNG imports. The proportion of imported gas in Romania's consumption decreased from 30.2% in 2007 to 15.5% in 2010. The vast majority of the gas pipeline imports originate from Russia. In 2010, all of Romania's gas imports originated from Russia while in 2009, Romania had imported 1.35% of its gas from Turkmenistan (the rest came from Russia). So far no exports are being realised.

It must further be noted that in 2011 Romania produced 10,1 bcm of natural gas, in 2011,which is almost three times less than in 1973 when it produced 30.00 bcm. It must also be pointed out that according recent studies, domestic production in Romania is expected to decline by 2.0 or 3.0 bcma by 2025. However, there are some new, potentially significant, offshore discoveries in Romania but their effect on the market of the region still remains in question.

Three very promising offshore gas fields, Doina and Ana, and the adjoining Domino are located on the continental shelf of the Black Sea in block XV all part of the Neptun formation. Doina was discovered in 1990 and developed by Petrom. It began production in 1995 and produces natural gas and condensates. The total proven reserves of the Doina gas field are around 98 billion cubic feet, and production is around 17.7 million cubic feet/day. On the other hand Ana was discovered in 2010 and developed by Sterling Resources. It began production in 2010 and it produces natural gas and condensates. The total proven reserves of the Ana gas field are around 247 billion cubic feet, and production is slated to be around 110 million cubic feet/day. According to Sterling Ltd Ana and Doina fields are vital for opening up the Black Sea gas business in Romania. Nevertheless, it is almost certain that without offshore development and energy efficiency measures in Romania gas imports will grow dramatically from 2015. In February 2012 it was reported that the Domino-1 well had encountered 72m of net gas pay, suggesting as a preliminary estimate that the field could hold between 1.5 and 3 Tcf of gas. The discovery lies in the Neptun Block, about 170 km offshore, in the western Black Sea. The block covers an area of 9,900 $km^2$and has water depths varying from 50 to 1,700m, being about 930m at the well location. Between 2009 and 2010 the partners obtained more than 3,000 $km^2$of 3D seismic over the Neptun block, the largest seismic programme ever undertaken in Romania.

Fig. 5.3 Romania's offshore Neptun block

On the other hand Romania is set to start exploring its shale gas reserves in a drive for energy independence, despite local protests against the potential risks and Europe-wide concerns about the technology used to exploit unconventional gas sources.

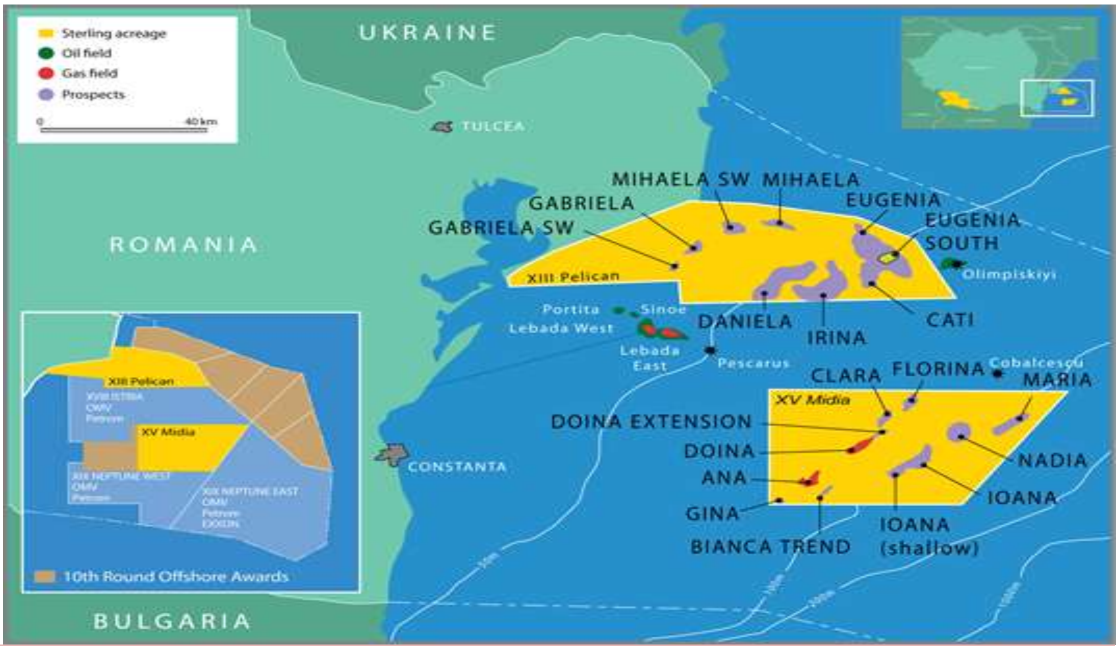

Fig. 5.4 Romania’s offshore gas fields

Several oil companies have expressed interest in exploring what is believed to be the country’s significant potential. According to an assessment by the U.S. Energy Information Administration (EIA), Romania, Bulgaria and Hungary may together be sitting on top of about 538 billion cubic meters, or 19 trillion cubic feet, of technically recoverable shale gas reserves.

The U.S. energy company Chevron has, since 2010, obtained concessions in Romania, covering a combined area of 870,000 hectares, or 2.2 million acres, in the Eastern plains and the Black Sea coastal region of the country.

Turkey

Turkey is the most important player in natural gas in SE Europe. In 2010 Turkey consumed a total of 38.10 bcm of natural gas, an 8.6% increase compared to 2009 when total natural gas consumption amounted to 35.10 bcm. Consumption in 2009 was approximately 4% lower compared to 2008, when natural gas consumption yielded 36.60 bcm. Of total natural gas consumption in 2009, 19.80 bcm were used for transformation (including power generation) and 1.56 for the industry while 7.89 bcm were consumed by other sectors. The largest amount was supplied by Russia (17.57 bcm). Turkey imports natural gas both via pipelines and LNG. The share of pipeline imports was 79% against 21% for LNG in 2010.

Fig. 5.5 Turkey's existing and planned oil & natural gas pipelines and infrastructures

According to Energy Market Regulatory Agency, Turkey in 2011 imported some 40 bcm gas and consumed 43.5 bcm while in 2012, the consumption is expected to reach 48.5 bcm. It should be noted that approximately 50% of Turkey's electricity is produced from natural gas, while more than half of its gas imports are used for power generation.

The most important supplier of natural gas in 2010 was Russia. The imports from Iran, the second largest supplier, have been problematic. Upon failure to bridge the differences in negotiations that were in progress, the Energy Minister Taner Yildiz announced in January 2012 that Turkey had decided to take Iran to the International Court of Arbitration. The negotiations pertained to two interrelated issues. While Turkey is contracted to import 10 billion cubic meters (bcm) annually gas from Iran, it maintains that Tehran fell short of meeting that target and it exported around 7 bcm to 8 bcm per annum. Ankara wanted somehow to import the excess amount accumulated in the last two years.

Electricity producers argue that Turkey urgently needs to reduce the share of gas in electricity generation to around 30 percent through greater use of renewables, domestic solid fuel resources and nuclear power. This is a problem which has been recognized a long time ago by policy makers and energy strategy documents note that it is the government's objective to reduce dependence on gas. There is a broad consensus inside Turkey on the need to significantly revise its energy policies, but it seems there is less agreement on "how" and "how soon" Turkey should achieve a more balanced energy mix.

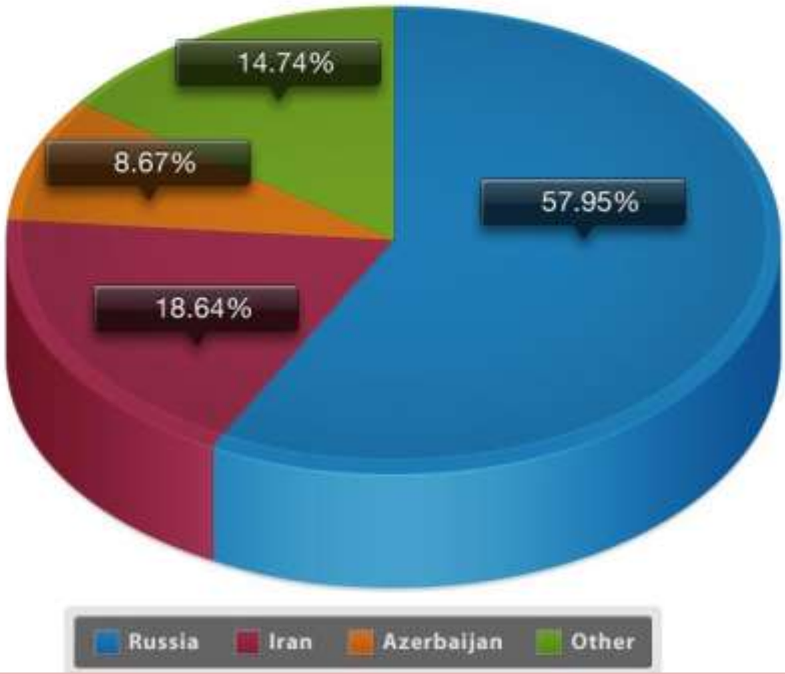

Fig. 5.6 Turkey's Natural Gas Imports by country of origin 2011

Moreover, shortcomings in reserves were also revealed during the February's 2012 crisis. Turkey's underground storage facilities in Silivri have a capacity of 2.6 bcm and BOTAS was expected to keep 2.1 bcm in reserves, which is enough to meet Turkey's needs for around two weeks. As Turkey tapped these reserves in response to declining deliveries, it has been argued that BOTAS' failure to fill it to full capacity before last winter was a major mistake. However, BOTAS issued a statement, maintaining that it stored sufficient quantities, above the minimum levels required by existing legal provisions (Zaman, February 9). Granted, this development underscores Turkey's problems in managing effectively its strategic reserves.

Turkey is one of the countries directly concerned by the offshore oil and gas potential in the Eastern Mediterranean. It is already clear that from 2018 onwards there will be significant natural gas volumes (5-25 bcm/year) available for export from the Levantine Basin. And, as exploration continues, the companies involved believe that there will be more gas and potentially oil discoveries in the same area. Some of these gas fields are located very close to Cyprus's offshore deposits and therefore the development of a common export infrastructure might make sense.

At the same time the Black Sea offshore basin is considered of high importance with estimated reserves of about 10 billion barrels of oil and 1.5 billion cubic meters of natural gas. TPAO started exploration in the Black Sea offshore areas in late 1960s-early 1970s and 4 wells were drilled. In the early 90s the Central Black Sea attracted interest, when drilling technology was not fully developed to test it. Major activity has been going on lately with BP shifting its commitments to Eastern margin in 2001 and Petrobras entering the Black Sea region in 2005. In addition, ExxonMobil signed PSA's for two blocks in 2008. Today, Turkey produces some 0.7 bcm from the offshore Akcakoca field. The first economic discovery in the Turkish sector of the Black Sea. However, efforts to accelerate exploration in deep water area in Turkey's Black Sea zone appear to face problems lately due to unsatisfactory results so far.

Turkey's interest in natural gas remains strong both from a customer point of view but also as a transit country to European markets. According to the "**BP Statistical Review of World Energy 2011**", natural gas consumption in Turkey has rapidly increased from 14.6 bcm in 2000 to 39 bcm in 2010 and to 43,5 bcm in 2011

In future, gas consumption is expected to increase as more regions in Turkey are connected to natural gas distribution networks and new gas-fired power generation capacity continues to come on stream throughout the country. Most of the gas is currently imported by pipeline from Russia, Azerbaijan and Iran but Turkey also has two important LNG import terminals. On the transit side, virtually all of the various pipeline projects which plan to transport Caspian natural gas to the European markets involve Turkey as a transit country – Nabucco, ITGI, TAP, SEEP, the Trans-Anatolian Pipeline, (to be built by BOTAS and by Azerbaijan's SOCAR), even South Stream (its offshore portion passes through the Turkish EEZ in the Black Sea).

6.Opening up the South Corridor

The South Gas Corridor

Europe sees an important opportunity to meet its energy needs by developing the southern gas corridor, at the core of which are gas supplies from the Caspian area (including Azerbaijan, Turkmenistan, and Kazakhstan) and possibly from the Middle East (Egypt, and the Mashreq countries). To diversify gas supplies from Russia, the European Commission envisions that the southern corridor pipelines would potentially provide capacity to deliver 60 to 120 billion cubic meters per year of gas from these regions directly to Europe. Such projections might be overly optimistic given the outstanding problems with securing committed resources and funding and the not insignificant geopolitical and domestic hurdles faced by prospective suppliers. Compounding the problem, the economic downturn in Europe may mean that not all the above vast volumes of gas may be required nor all the planned pipelines in the southern gas corridor may be necessary especially as they face substantial financial and political problems.

According to the current state of play in South Eastern Europe forecasts predict that the demand will grow continuously up to 2025 at a rate of 1% each year. Italy, Romania and Greece remain the biggest markets and there will be around 12 bcma that the region shall need to source from different players.

Further to the 12 bcma, the need of the region to enhance its supply security, which is heavily dependent on pipe-gas from Russia, allows even more room for new players to enter this market. Regarding the Italian market, even though it is currently oversupplied, there is a strong need for further diversification and the promotion of strong gas to gas competition. As a result Italy and SE European region remain an attractive market with room for new sources.

Currently, the most realistic source of natural gas that may come online and provide sizable export quantities to Europe is Azerbaijan and specifically the Shah Deniz 2 gas field. Azerbaijan’s gas resources can supply a significant part of the above markets over the next few years. Even from the 1st phase of the Shah Deniz field, Azerbaijan already supplies gas to Turkey but also to Greece where it pumps limited quantities. From the 2nd phase of Shah Deniz, some 10 bcma are destined for Europe. Apart from the Shah Deniz field, two wholly undeveloped deposits in Azerbaijan, Absheron and Umid, have been undergoing exploration and are credibly estimated to contain 350 bcm of natural gas each. Azerbaijan expects to increase its production to 50 bcm/y by 2025 on the strength of exploiting these two news fields. Consequently, Azerbaijan current deposits appear to hold 2,0 – 2,5 trillion cm of exploitable gas deposits[2].

Fig. 6.1 The South Corridor pipelines

On the other hand Iran is potentially another important source of gas, but due to political reasons, it cannot at that stage be considered as a source until such matters have been resolved. Iraq is experiencing some problems in exporting its gas to Europe, mainly due to the government's decision to prioritise domestic demand over exports. Turkmenistan although it has considerable natural gas resources, it may not be in position to export to Europe, before 2025.

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[2] Marika Karayanni, ***"The Caspian Basin the Case of Azerbaijan as the Alternative Energy Supplier for the E.U.",*** IENE Research Note No1,July 2012

There is however a new source that has been recently discovered that may provide a solid solution for the opening of the Southern Gas Corridor. The new fields in Eastern Mediterranean, Tamar, Leviathan and Cyprus Block 12 are three of the top five world's largest discoveries in this decade. All together they have proven reserves of around 940bcm. According to United States Geological Survey the total reserves at the Levantine basin could be three times more than that. Greece also has recently issued tenders for onshore and offshore deposits in Western Greece which further increase the interest in the East Mediterranean region.

Project	Capacity (bcm/y)	Distance (kms)	Gas Origin	Estimated Project Cost (in Billion Euro)	Sponsors	Anticipated Start Up Date
ITGI	10-16	796	Algeria	1.70	DEPA. EDISON	2017
TAP	10 – 20	791	-Shah Deniz II	1.70	EGL, STATOIL, E.ON	2017
Nabucco West	10 – 23	1.300	-Shah Deniz II -Iraq -Turkmenistan	5.5	OMV, TRANSGAZ, BEH, MOL, RWE, BOTAS	2017
South Stream	63	2.950	-Russian Fields	15.0	Gazprom, ENI, Wintershall, EDF	2016
White Stream	8 – 32	1.440	-Azerbaijan -Turkmenistan -Iraq	n.a	Not Disclosed	2016
AGRI	5 – 8		-Azerbaijan	4 – 6	SOCAR, GOGC, ROMGAZ, MVM	2016
SEEP	10	~1.000	-Shah Deniz II	1.0 – 1.5	BP	2017

Table 6.1 Basic Characteristics of the Original South Corridor Natural Gas Projects

As for the Russian gas transport projects in Europe, the planned South Stream pipeline although it aims to redirect existing quantities to Europe, some additional quantities also may be added, allowing more Russian gas to reach the market. Nevertheless Gazprom recently announced (12/11/12) that Greece has been removed completely from construction plans of the South Stream pipeline.

Furthermore, traditional exporters to Europe, such as Egypt, Algeria, Libya and even Russia are not expected increase dramatically their export capacities by 2025. As a result the only realistic additional sources of gas to Europe before 2025 are the 2nd Phase of Shah Deniz field, the other two Azeri fields and possibly the newly discovered fields in East Mediterranean.

In short, the infrastructure currently under development or planned which will be used to connect the supply sources to European markets include the following:

Interconnector Greece Bulgaria (IGB) which will supply Bulgaria and hence South Eastern Europe region with up to 5 bcma will be operational by the end of 2014. The project includes the construction of a trans-border reverse flow gas pipeline with length of about 168.5 km (140 km in Bulgaria, 28.5 km in Greece), connecting the Greek gas network in the area of Komotini with the Bulgarian gas network in the area of Stara Zagora. The capacity of the gas pipeline is foreseen to be 3 up to 5 billion m3/year, with a pipe diameter of 700 mm (28").

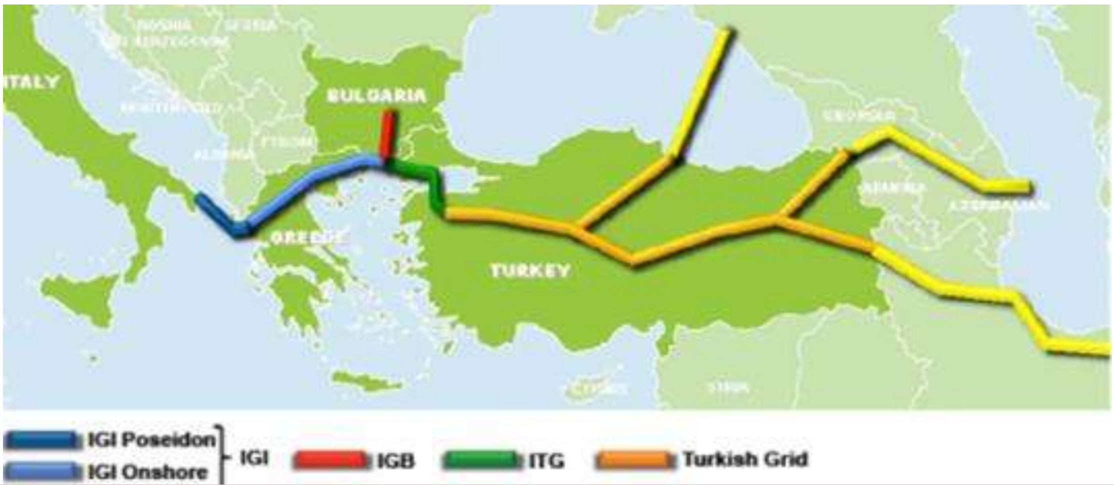

Fig. 6.2 The ITGI pipeline system including the IGB

The total indicative value of this project is 150-160 million. Funding is secured from the European Energy Recovery Programme and the amount of EUR 45 million has already been earmarked (Decision C (2010) 5813 of the European Commission on 30.08.2010).
The construction of the Greece - Bulgaria Interconnection Pipeline will help Bulgaria to achieve real diversification of natural gas supply source as it will allow the delivery of additional natural gas through the Southern Gas Corridor. This interconnector will also help Bulgaria access LNG gas from Greece by allowing direct purchases from suppliers. In addition the Greek – Bulgaria interconnector will help develop a more liquid market in the region.

Gas from the interconnector may originate from:

(a) the 1st phase of Shah Deniz.
(b) as early as 2014, contracts with LNG suppliers may be made using the existing storage terminal in Revythousa.
(c) In late 2015, even more gas may be contracted through LNG, from a Floating Storage and re-gasification terminal, under developments to be located offshore near in Alexandroupolis, in Northern Greece.
(d) Should by 2017-2018, the link between Greece and Italy be operational it will be possible to access Algerian gas through Italy.

Nabucco West - The Nabucco consortium has recently submitted a proposal to the Shah Deniz Consortium for Nabucco "West", which is an alternative to the Nabucco classic which originally started at the Georgian - Turkish border. Instead the "Nabucco West" pipeline aims to bring Caspian gas from the Turkish-Bulgarian border to the European Gas turntable in Austria and beyond. Nabucco West will run from the Turkish-Bulgarian border to the vicinity of the gas hub at Baumgarten near Vienna, Austria. The pipeline will pass through Bulgaria, Romania and Hungary before it reaches Austria. This pipeline is competitive with the TAP pipeline.

Trans Adriatic Pipeline (TAP). TAP has been selected by the SD2 consortium in case the Southern route for exports to Italy is selected, instead of the northern route (Nabucco West). The pipeline will tie up in Greece, cross Albania and the Adriatic Sea and come ashore in southern Italy, allowing gas to flow directly from the Caspian region to European markets.

Interconnector Greece-Italy (IGI) – The shareholders of IGI (DEPA and Edison) have decided to continue the development of IGI Poseidon, based on the maturity of the project and the strong belief that it is a crucial project for the security of supply of the entire region, even though this project was excluded by the SD2 consortium. IGI Poseidon remains open to export natural gas from alternative sources of gas.

East Med Pipeline - Finally, there is a strong possibility that alternative gas resouces from the East Med may find their way to Greece and through Greece to the rest of Europe. The timing for this project largely depends on political and commercial decisions by the producing countries and companies. This pipeline project will be in position to carry approx. 8 bcm/y and will have a length of approximately 1.100 kms. It may also include a landfall in Crete, before its final destination in the mainland of Greece, which could also allow for the off-take of gas in Crete.

Natural Gas from Algeria

The Algerian natural gas company Sonatrach appears to be interested in supplying significant amounts of natural gas to the Southeastern European market via Greece, a move that may involve a modified ITGI pipeline project. According to press information, officials from Greece's DEPA's have unofficially indicated that Sonatrach is indeed in talks of a "nascent" nature to proceed in that direction.

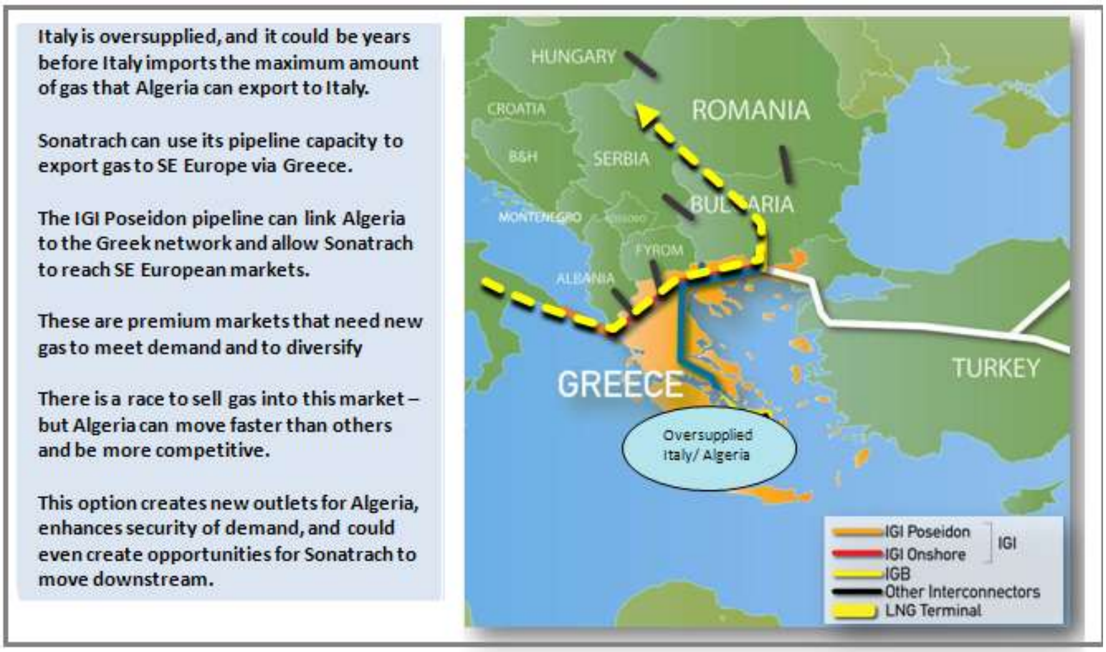

Fig.6.3 Algerian Gas via Pipeline to SE Europe

The Algerian company has been supplying the Italian gas market via the Trans Mediterranean pipeline with a yearly capacity of 30 bcm. According to DEPA gas demand in Italy has decreased by 6.5% in 2011. DEPA sources further observe that the massive use of renewable energy resources in Italy has resulted in a drop in natural gas consumption thus making this market less attractive for future importation projects. With the Italian markets trending towards a slowdown, Sonatrach is seeking alternative and emerging markets for its gas.

On the other hand, Southeastern European markets appear to have increased supply requirements, as well as diversification policies in order to reduce their dependency on Russian gas imports. Sonatrach, which has long term contracts with DEPA to deliver 1 bcm of gas annually, is optimistic it will be able to use the Greek-Bulgarian Interconnector, which is due to be operational by early 2014 and will have a final capacity of 5 bcm, to open new markets. In this scenario, DEPA as a wholesale importer would manage the exportation of gas to the Bulgarian and Romanian markets.

Sonatrach estimates that Algerian gas resources can reach the Bulgarian market with a cost of transfer around 1.4 USD per mmbtu and the Romanian market with a cost of 1.7 USD per mmbtu, which it considers as an attractive pricing given today's market coditions. However, this scenario would depend on long-term contracts between Sonatrach and DEPA and the rest of the regional companies. DEPA has been anxious to advance plans to revive the ITGI project since it was rejected by the Shah Deniz consortium in March 2012. Lastly, it should be noted that Sonatrach's intention of playing a role in the supply of the region has been reinforced as it is one of the official bidders in the impeding privatization of DEPA.

7. The South Stream

The South Stream gas pipeline system is clearly emerging as the most advanced project of all Southern Corridor pipelines. This is most evident judging from the advanced engineering design, the available gas supplies, thanks to Gazprom, and the secure funding. Originally South Stream was designed to have two main branches, following its crossing through the Black Sea, from Anapa in Russia to Galata in Bulgaria. The North branch running across Bulgaria, Serbia, Hungary, Slovenia and ending up in Italy and the second, the South branch, going through Bulgaria, Greece and underwater, through the Adriatic, to South Italy.

Following the Final Investment Decision (FID) on November 14, 2012 the South Stream Offshore Pipeline is now going full speed ahead with construction in the Black Sea scheduled to start on December 7, 2012. South Stream Transport B.V. which is the pipeline's operator, will implement the offshore gas pipeline through the Black Sea. Based on the taken decisions project implementation will proceed according to the agreed schedule aiming at transporting the first gas through the Black Sea by the end of 2015.

Fig. 7.1 The South Stream pipelines project

The South Stream Offshore Gas Pipeline through the Black Sea is the offshore section of the South Stream Gas Pipeline System, which will transport gas from Russia to countries in Central and South-Eastern Europe. The length of the offshore pipeline will be 925 kilometres and a designed capacity to transport 63 billion cubic metres of natural gas per year.

South Stream Transport is an international consortium consisting of four major energy companies: OAO Gazprom (Russia), Eni S.p.A. (Italy), EDF (France) and Wintershall Holding GmbH (BASF Group) (Germany). In the interests of the EU's long-term energy security, these exporters and importers of natural gas are combining their experience and expertise to ensure the best technology, safety and corporate governance standards for the project.

According to a consortium statement the underwater gas pipeline is a safe and environmentally responsible way of delivering natural gas to the EU energy grid. When fully operational, the gas pipeline should be supplying – approximately 10% of the EU's estimated total gas consumption in 2020. The company’s stated goals in relation to the South Stream Pipeline can be summarized as follows:

- Secure the long-term energy supply to Central and South-Eastern Europe in a reliable and sustainable way

- Provide consumers and industries with safe energy supplies at a competitive price

- Support the EU in achieving its climate policy goals

At the same time South Stream Transport will:

- Provide leadership for the safe, economical, and punctual implementation of the Project and guarantee safe operation for many decades

- Meet internationally recognized standards for Health, Safety, Security, Social, Environmental, and financial performance

- Engage in a transparent and respectful dialogue with members of the public, non-governmental organizations, contractors, and other interests parties throughout the project's lifecycle

The South Stream Facts and Figures

- Length: over **900 km** under the surface of the Black Sea
- Number of gas pipeline strings: **4**
- Transport capacity of each line: **15.75 billion cubic metres** of natural gas per year
- Total transportation capacity: **63 billion cubic metres** of natural gas per year
- Planning, construction and operation: South Stream Transport B.V. (Amsterdam, Netherlands)
- Shareholders: OAO Gazprom, Russia - **50%**, Eni S.p.A., Italy - **20%**, EDF, France - **15%**, Wintershall Holding GmbH (BASF Group), Germany - **15%**
- Final Shareholder Agreement: signed in **September 2011**
- Feasibility Studies: completed in **Q4 2011**
- Front End Engineering and Design (FEED): starting **Q1 2012**
- Start of commercial operations (first line): **End 2015**
- Achievement of full capacity: **End 2018**
- Design life: Minimum **50 years**
- Design basis: DNV Offshore Standard DNV-OS-F101, Submarine Pipeline Systems 2010
- Maximum depth: **2,250 metres**
- Length of each pipe segment: **12 metres**
- Number of pipes for each line: approx. **76,000**
- Total number of pipes for all lines: approx. **304,000**
- Cost to European taxpayers: **Zero**

The South Stream Timeline:

Date	Event
June 23, 2007	OAO Gazprom and Eni S.p.A. sign a Memorandum of Understanding on the implementation of the South Stream project
June 19, 2010	OAO Gazprom, Eni S.p.A. and EDF sign a Memorandum of Understanding providing for the latter's participation in the construction of the offshore section of the South Stream Gas Pipeline
March 21, 2011	OAO Gazprom and BASF sign a Memorandum of Understanding providing for Wintershall's entry into the shareholding consortium for the offshore section of the South Stream Gas Pipeline
September 16, 2011	OAO Gazprom, Eni S.p.A., EDF and Wintershall Holding GmbH (BASF Group) sign the shareholder agreement for South Stream Transport in Sochi, Russia
Late 2012	Final Investment Decision
Late 2012	Start of construction
End 2015	Start of commercial operations: some 15 billion cubic metres of natural gas will flow from Russia to Europe through the first string of the gas pipeline
End 2018	Full capacity achieved: 63 billion cubic metres of natural gas will be delivered to European countries through the 4 parallel gas lines running through the Black Sea

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