Gas Routes to Europe: Real Needs and Political Jockeying

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The Energy Roadmap 2050 released by the Commission in December 2011 says it all: we will need more gas until 2030. Gas represents the default solution for a transition to an energy system with less GHG emissions. It also has great value as a back up for intermittent renewable power generation. Therefore, stating that Europe still needs large quantities of gas means checking if supply volumes are available to satisfy growing demand.

Internationally there was an extraordinary abundance of gas in 2011, due to the expansion of US shale gas output. At the European level, the economic crisis and the particularly mild winter (until February 2012) further amplified this situation. European gas prices were far cheaper on spot markets and large volumes were still available in most countries.

Despite this context, European gas demand is set to increase and gas will represent one of the main energies in the fuel mix, in the years to come. In fact, situations differ from country to country, while European legislation aiming at lowering the carbon content of our economies and of our energy mixes will push member states (like Poland) to replace progressively more polluting fuels (coal and oil) with gas. Other political choices may influence gas demand, such as Germany's exit from nuclear power. In fact, one of the fastest and cheapest solutions to replace base load nuclear generation is the construction of Combined Cycle Gas power plants.

As carbon capture storage is still waiting for favorable price signals,[1] and as domestic gas production is diminishing rapidly in all Member States and EEA countries, attention is clearly focusing on the security of supply and on import infrastructures.

The author takes full responsibility for the opinions expressed in this text.

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[1] Bob Pegler, General Manager – Europe, the Global CCS Institute at the IFRI Annual Conference, February 16, 2012.

Investments are made to get to where consumption takes place, especially in gas. Pipelines have been constructed from producers to consumers, using a sort of highway approach. The typical structure of these investments used to be based on broader, bilateral intergovernmental agreements with the view to providing stable and long term legal frameworks for commercial agreements between the national gas “champions” and monopolistic producer companies in third countries. Nevertheless, in the last decade, this process has progressively changed, giving way to project type management of these investments. Intergovernmental agreements are limited to projects, while investment decisions may be held up since the changing legal environment does not give clear signals. This has of course resulted in more uncertainty, penalizing investments and consumers, and it has prompted the establishment of more coordination in the assessment of infrastructure. The ENTSOG Ten Year Network Development Plan (TYNDP) prescribed in the 2009 legislation (Third Package) is a first step in this direction.[2] Although it can be largely improved, its assessment provides some guidance to European regulators and national authorities in assessing infrastructural needs.

Many projects are expected to come on stream in the next ten years. ENTSOG TYNDP 2011-2020 showed that most of these projects are needed if disruptions and congestion are to be avoided. If the TYNDP proves right then, for projects like South Stream and Nabucco, the problem is more one of where the gas is going to come from since Gazprom has not increased investments upstream,[3] it may be asked how pipelines will be filled. The same applies to Nabucco, unless other fields are discovered and Azeri production is boosted.[4] In another words: Will the investments occur and will the fields be ready for production to meet demand? Shaz Deniz 2 will start production in 2018-2019, and the needs for Europe by 2020 will be 11% higher compared to current levels: i.e. almost 570 bcm per year according to ENTSOG estimates.[5]

For this study, the perimeter of the gas supply infrastructures will be restricted to pipelines. This paper will thus start by recalling the main steps of the decision-making process for supply pipeline projects. It will then analyze two aspects that characterize the assessment of gas needs: demand and the diversification of supply. Section 2 will thus try to assess the main centers of demand in Europe, while the third section will offer a rapid overview of the current infrastructural gaps, noting the high degree of dependence of some European Member States on one supplier. The time horizon of this paper is 2030 for demand trends, and 2012 to 2020 for the infrastructural projects, as further investments will largely depend on the

[2] ENTSOG, European Network of Transmission System Operators for Gas is the association representing European TSOs. Created on Dec 1, 2009 (in application of Gas regulation 715/2009), it uncludes 39 TSOs and 2 Associated Partners from 24 European countries and 3 Observers from EU affiliate countries.
[3] For the 6 month period ending June 30, 2011 and 2010, total expenditure in production fell by 8.8%, OAO Gazprom Q2 / H1 2011 IFRS Results
[4] Shaz Deniz 2 is going to produce 16 bcm of which only 10 bcm are expected to reach the European market.
[5] EU 27. NB: ENTSOG takes 1 in 2 climatic conditions as references for annual demand (as prescribed by the REG-SoS).

implementation of current projects and the development of future legislation.[6] Finally, by recalling needs and their geographic location, the paper will present the current pipeline projects.

Infrastructure and Decision-Makers

Infrastructural developments of national gas systems are assessed by national Transport System Operators (TSOs) and are based on a regulated framework: TSOs' tariffs, as well as their returns on investments (ROI) are approved by regulators, according to TSO development plans. In contrast, supply pipelines represent very risky and therefore costly projects that are promoted by private investors, mainly international Oil & Gas companies (such as BP, Shell, Total or Eni) or smaller players (in the gas sector) seeking direct access to gas sources (such as EDF, EGL, Edison, Enel).

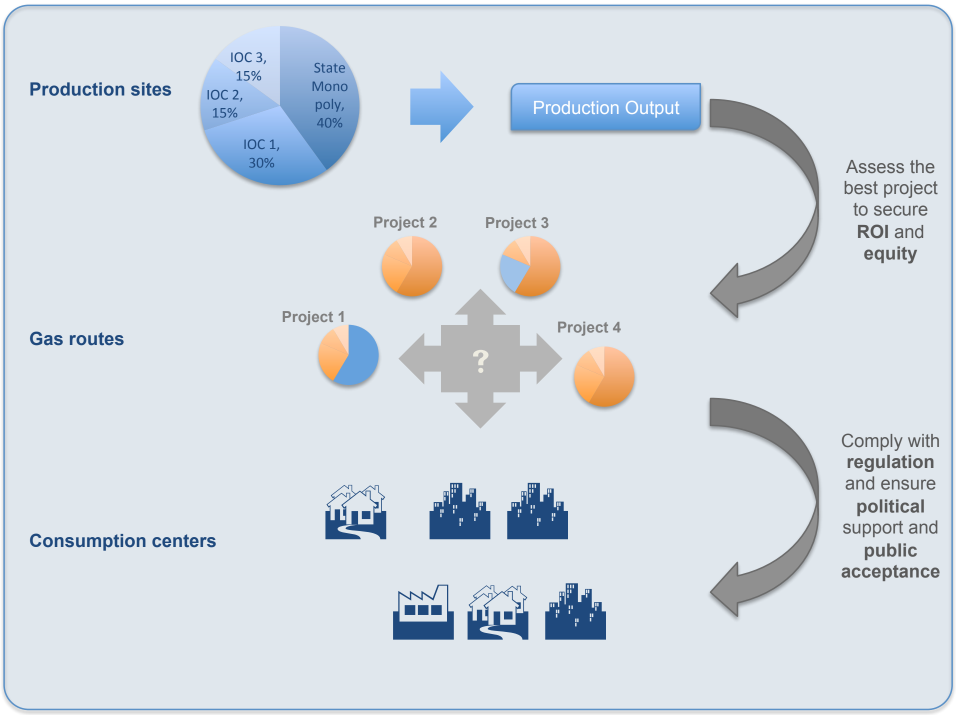
This is one of the key differences between gas and electricity. While electricity can be generated nationally, gas always has an external dimension, which is, to different degrees, state-to-state. Gas supplies therefore depend on imports from third countries and often state-owned companies.

This situation helps to explain the typical structure of such projects (Figure 1). This will often involve a consortium being in charge of the development and operation of the gas fields, and composed of international O&G companies and the monopolistic state producer. On the other hand, different possibilities may be envisaged and various projects can be proposed to transport the gas from the fields to the consumption centers. These projects usually compete for the gas through open bids. A field consortium usually makes its selection based on a series of criteria, including: return on equity, transit partners' reliability, the existence or not of intergovernmental agreements (i.e.: the status of the project), respect of European Union and transit countries' laws, etc. However, political backing and public acceptance in countries concerned by the project are also relevant. For a project to get through the authorization process successfully, which starts once the Final Investment Decision (FID) is taken, it has to seek approval at national and local administrative levels. A project must acquire the political and civil support from transit and receiving countries, which is maybe the hardest part of the entire cycle. This is particularly true when "exit" points in local transport systems are envisaged. A pipeline can pass through a country without providing gas to the domestic system. But, if an interconnection is planned and gas flows into the national market, the project will usually seek Third Party Access exemption. If TPA exemption is demanded, it will have to be granted in each country where exits exist. National regulators are in

[6] In particular, the "Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC", the so-called "Infrastructure Package", is under evaluation at the European Parliament and will replace the TEN-E regulation. The key aspects are: the introduction of a three-year limit to granting permits; and the "Project of Common Interest" definition, which allows establishing a list of priority projects at regional level to be established.

charge of this decision, but it is then the DG Energy of the European Commission that examines the case and gives its (almost binding) advice.

Figure 1 – The Project Investment cycle



Source: IFRI.

Before the whole process starts at all, however, investors making investment decisions (either about developing production fields or constructing pipelines) need to be sure that the gas will be bought. This means that every investment decision has to assess the evolution of the market. Will demand increase? Will policies change and promote gas use? Where are consumers located? Where are the infrastructural gaps? This analysis allows sizing the project in an appropriate way and lowers risks of over capacity and over supply. It therefore focuses on two main issues: **demand trends** with the localization of consumption centers (see the next section); **supply diversification** by identifying infrastructural gaps and **congestion** points.

Assessing Needs: Demand

To assess the needs in future gas pipelines, it is essential to look at the evolution of demand. In one graph, TYNDP 2011-2020 summarized key scenarios produced by reference organizations in the sector, such as the International Energy Agency (IEA), Eurogas and the European Commission. It then combined them with ENTSOG’s expected demand, which corresponds to the aggregate of countries’ demand expectations (outlooks) calculated by national TSO’s (Graph 1). These models differ from that by ENTSOG, as they all have a top-down approach, while ENTSOG’s assumptions are bottom-up.

Among the top-down scenarios, basic assumptions such as the extent of energy efficiency measures, oil prices, GDP growth or other policies are not the same. It has also to be stressed that the year of reference may change from one scenario to another (as shown in Box 1).

Box 1 – Assumptions for Top-Down Scenarios

The European Commission Primes scenarios differ from one another as the first one takes into consideration policies up until April 2009 (Primes Baseline), while the other includes policies after 2009 (Primes Reference). In particular, it "assumes that national targets under the Renewables directive 2009/28/EC and the GHG Effort sharing decision 2009/406/EC are achieved in 2020". GDP is forecast to grow at a pace of 1.7% until 2012, rising to 2.2% through to 2020. International fuel prices are projected to grow in line with oil prices, reaching $88/bbl in 2020 and $106/bbl in 2030. Gas prices follow a trajectory similar to oil prices reaching $62/boe in 2020 and $77/boe in 2030, while coal prices increase during the economic recovery to reach almost $26/boe in 2020, but then stabilize at $29/boe in 2030. (All prices are stated in 2008 US dollars.)

The International Energy Agency (IEA New Policies Scenario, 2010) takes into account national policies and the general commitment in reducing GHG emission, but takes a cautious approach to the implementation of these measures. The IEA 450 Climatic scenario allows for the capping of CO2 emissions at 450 ppm CO2 equivalent, thus avoiding a 2°C increase in temperature. This model assumes a CO2 price of $50 per tonne. Oil, gas and coal prices are similar to the European Commission's assumptions.

The Eurogas scenarios are quite optimistic about the evolution of gas demand, with "the balance of gas demand and supply" considered with reference to the following prices expressed in real terms: oil at $60 bbl in 2015 and $80 bbl in 2030, and CO2 prices at €20/t in 2015 and €30/t in 2030 for the Eurogas Long Term Outlook 2007-2030 Base Case. This case is rather conservative as it also assumes that "long-term agreements remain the basis for supplies" in most countries, that "oil prices are the leading indicator in the energy market" and "fuels are competing with each other". For the Eurogas Long Term Outlook 2007-2030 Environmental, price assumptions are $70 bbl in 2015 and $100 bbl in 2030, while CO2 would be €30/t and €50/t in the same years. More gas-friendly policies and a more rapid economic recovery are envisaged with respect to the base scenario, leading to an increase in gas demand.

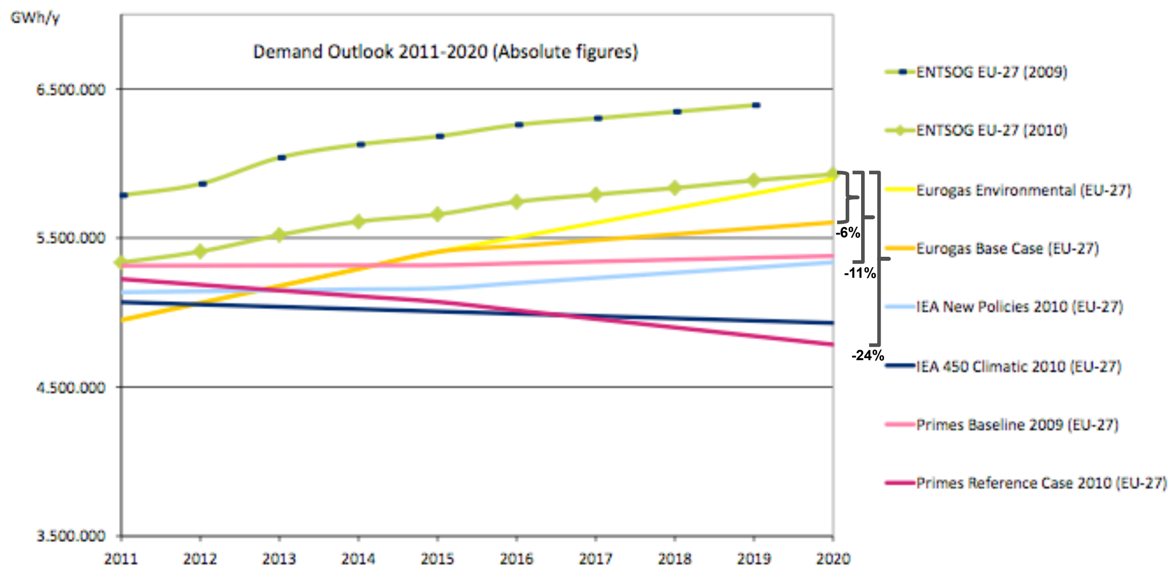
The bottom-up approach of ENTSOG is based on gas demand calculated by TSOs as the development of connections (off-takes) in the system,[7] and on the basis of TSOs' knowledge of their national market. In general, infrastructural needs are designed by TSOs according to peak **capacity** demand, which is driven by climatic conditions, trading flexibility requirements and supply disruption management. This last element has been translated into additional measures that have been required by the Security of Supply (SoS) Directive, following the gas disruptions in 2009. This Directive requires the presence of stored gas that could be released to customers for 30 days, in case of emergency situations.[8]

[7] The points that connect the transport and distribution systems in order to withdraw gas, i.e. industries, storage facilities, thermal plants, etc.

[8] REG-SoS has several limits: prescribed measures are artificial since it is not clear which customers would be given priority in case of disruption: who is going to be obliged to stop consumption and not receive gas? See the

For these reasons, the ENTSOG scenario results are the highest, with an expected 11% increase in gas demand, reaching 5,927,196 GWh in 2020. In absolute terms, this represents a difference of 104 bcm with respect to the lowest demand projection of the European Commission Primes Reference Case 2010 (464.56 bcm). The 2011-2020 (ENTSOG EU-27 2010) Outlook expects lower demand than the previous outlook (ENTSOG EU-27 2009). This reduction results from the gas demand decrease witnessed in 2009 and 2010. Demand expectations have thus been revised downwards.

Graph 1 – European Gas Demand Scenarios 2011 – 2020



Source: ENTSOG, TYNDP 2011-2020

Graph 1 shows the uncertainties the gas market is facing, as investment decisions can be made for political reasons (climate change, IEA 450 Climatic), rather than for infrastructural needs to meet high daily demand (ENTSOG outlook). The current economic and fiscal crisis in Europe has progressively switched the debate from fighting climate change to more pragmatic and economic rationales. Although high oil prices still mean high gas prices in Europe, and since intermittent renewables are still being deployed and are not yet competitive in all Member States' markets, the assumption used here is that gas demand will increase according to a demand increase scenario (+11% between 2010 and 2020), as the ENTSOG 2010 outlook points out.

The following section analyzes in more detail the main consumption centers and the evolution of their markets. This makes it possible to understand in which direction gas will flow.

author's editorial on the Italian reaction to the February gas disruption, "Gas pains in Europe: coping is not managing", www.ifri.org.

However, it would be simplistic to look only at demand as the main driver of investments. In fact, gas needs in Europe can be of two kinds: an answer to demand increases and a way to reduce current vulnerabilities to gas disruptions (such as the lack of reverse flows or the dependence on just one source of supply); in other words, the diversification of supplies. Drawing on these two criteria, as ENTSOG pointed out in its outlook, it is possible to simulate flow patterns and identify gaps and congestions. These infrastructural gaps will be assessed in the Section entitled "Key congestion areas and diversification of gas sources".

Table 1 - Final Consumption

Final consumption - Bcm (Billion cubic metres)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
United Kingdom	96,9	96,4	95,1	95,4	97,4	95,0	90,1	91,1	93,8	86,7	93,8
Germany	79,5	82,9	82,6	85,5	85,9	86,2	87,2	82,9	81,2	78,0	81,3
Italy	64,9	65,0	64,6	71,2	73,9	79,1	77,4	77,8	77,8	71,5	76,1
France	39,3	41,9	40,5	43,0	45,1	44,0	42,1	42,4	43,8	42,2	46,9
Poland	11,1	11,5	11,2	12,5	13,2	13,6	13,7	13,8	13,9	13,4	14,3

Source: BP Statistical Review of World Energy 2011

Consumption centers

The main European gas consumers are the United Kingdom, Germany and Italy, followed by France. Poland is included in the analysis as it might play a strategic role in future shale gas development. For all these countries, the share of gas in the trade balance is going to increase, since their national production is falling progressively.

In the case of **Germany**, the decision to close nuclear facilities has given some hope to the gas lobbies that gas will initially replace nuclear power and then more CO2 emitting coal plants. These hopes are nevertheless challenged by the projections of gas consumption in Germany by 2020 and 2030, given by the Reference Scenario of the *EU Energy Trends to 2030.*[9] In fact, figures show that German consumption will diminish rather than rise, as very ambitious policies on energy efficiency are being promoted.[10] These trends have not discouraged big infrastructural projects such as Nord Stream, whose capacity will be way beyond the needs of the German market: 55 bcm will be brought into the German system by April 2012, if operational schedules are respected. In this way, Germany will increase its dependence on Russian gas, which already represents 40% of its imports,[11] and it will not diversify its supply.[12] The key to understanding this investment is the progressive shift of Germany and other countries from being a consumer and net receiver, to being at

[9] EU Energy trends to 2030, p. 144.
[10] CRUCIANI. M. "Evolution de la situation énergétique allemande : paramètre et incertitudes pour la période 2012-2020", Paris, Ifri, March 2012, p. 11.
[11] IEA Database, year 2010.
[12] Germany has 3 main import sources: Russia (40%), Norway (33%) and the Netherlands (24%).

the center of the European gas system.[13] In fact, thanks to the progressive construction of the internal market and the increasing role of spot and future markets, Germany will be able to trade its abundant gas volumes with its neighboring countries. Moreover, the application of the Third Package through the Network Codes that are being written and that will be applied by 2014 implies that the current transit system will be opened (as capacity allocation will have to be available in the short term as well), blurring the difference between transit pipelines and transport pipelines (see Box 2: "Old Pipelines, New Deals"). Only entry points connected directly to non-European countries will be thus partially exempted by this process.

Box 2: Old Pipelines, New Deals

The distinction between transit/supply pipelines and transport pipelines is useful in understanding the transformation that is going on in the European internal gas market and how this is affecting big infrastructural projects.

The transport system is a high-pressure infrastructure that lies within the national borders of a country, and which is regulated by national regulatory authorities. It is responsible for dispatching gas to distribution systems, with customers being directly connected to the transport system.

Supply pipelines are the international infrastructures that have been built by national champions to supply local, domestic markets with gas coming from third-country suppliers. In most cases, the entire capacity and volumes have been destined for the main investor, which has used them to supply the national wholesale and retail markets. For this reason, pipelines used to have only one flow direction and were managed by the Vertically Integrated Companies (VICs).

A **supply pipeline** can be **onshore** or **offshore** and it is a direct link from the producer country to the consumer country. A good example of a recently-built, offshore direct supply pipeline is Nord Stream. This type of pipeline does not cross transit countries, as is the case for most of the old onshore pipelines, such as Brotherhood or Russian Yamal, which becomes Europol and crosses Belarus and Poland to go to Germany. For most of the inland countries, these pipelines were the only way to get supplies. These are thus considered "**transit pipelines**" since they pass through countries without delivering gas (most of the time) to national gas markets. The interconnection points help linking the supply pipelines to the national transport system, which lies within the national borders. The same transit pipeline can supply different countries but it is not open to competition (as it is also the case for Eurstream, which connects Brotherhood from the Ukrainian/Slovakian border to Baumgarten).

This situation has been changing in the last years, due to the gas disruptions in 2006 and 2009. More efforts are being made to create reverse flows at interconnection points, and to free short-term capacity in order to acquire more flexibility for gas shortages. Furthermore, the 2009/73 Regulation sets the legal framework for the creation of an open and competitive internal market. This applies not only to national transport systems linked by interconnection points, but also to supply/transit pipelines that were once owned by VICs and that ensured national supplies.

The Italian gas infrastructure is very representative of the redefinition of transit pipelines to transport ones.

In the Italian system, there are offshore supply pipelines such as Greenstream or Transmed, the pipelines connecting respectively Libyan and Algerian production to the Italian market, or TENP /

[13] See ENTSOG TYNDP 2011-2020 p.70.

Transitgas and Trans-Austria Gas pipeline (TAG), which provide Italy with gas coming from the Netherlands, Norwegian and Russian gas fields. ENI, the Italian incumbent, was the main stakeholder in all these pipelines. Progressively, due to European regulation, it had to sell its stakes in order to allow access to more capacity at the interconnection points. These measures especially concerned **cross-border interconnection points** through which **transit pipelines** passed. In particular, Eni agreed to sell its 89 percent stake in TAG[14] (which crosses Austria from the Slovak border to the Italian frontier, bringing gas from Russia) to Italian state lender Cassa Depositi e Prestiti SpA, settling a dispute with European regulators. Moreover, Eni and Fluxys G (the Belgium TSO) have signed purchase agreements involving the sale to Fluxys Europe of Eni's 46% stake in the Transitgas (Switzerland) and 100% stake in TENP (Germany) gas pipelines.[15]

The case of the **UK** is peculiar as imports are going to increase massively due to the sharp decrease in national production. If shale gas were to be discovered in large quantities in Scotland (and if Scotland does not become independent),[16] this tendency could be partially reversed. The solution for the UK is to improve the existing LNG terminals and create new ones, as its insular position does not allow pipelines to reach the country easily.

Even if **Italy** had Europe's largest installed photovoltaic capacity in 2011 (beating Germany), it nevertheless relies on gas for its thermal power plants, its industry and for household heating. Unless consumers dramatically change their habits and CHP, geothermic and other renewable heating technologies become a lot cheaper and easier to install in housing, gas will remain a key component of the Italian energy mix. As nuclear power has been excluded from the future mix (at least for the moment),[17] gas could still be playing an important role, at least until 2030.[18]

France's gas market is expanding, with thermal power taking the lead in backing up the intermittence of Renewable Energy Sources (RES). This trend will continue at least until 2030, as wind power is expected to grow, beating hydroelectric power as the main renewable source, and as nuclear generation cannot cope with the intermittence of RES. However, as France lacks direct borders with exporting third countries and proximity allowing for the construction of pipelines, it is investing in LNG terminals and in increasing interconnection capacity with Spain and Belgium, given its position as a crossroads.[19]

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[14] http://www.eni.com/en_IT/media/press-releases/2011/09/2011-09-22-Eni-Transitgas-TENP-Fluxys.shtml

[15] http://www.bloomberg.com/news/2011-06-10/eni-sells-89-stake-in-tag-pipeline-to-state-lender-cdp-ending-eu-dispute.html

[16] The Scottish Government intends to hold a referendum of the Scottish electorate on the issue of independence from the United Kingdom in the autumn of 2014.

[17] The Environment Minister of the Monti Government, Corrado Clini, has stressed the importance of nuclear technology and nuclear research programs, November 2011.

[18] The *EU Energy Trends to 2030* of the European Commission included nuclear power as an energy source in the Italian mix. Even if renewable energy were to increase, it would be hard to replace the expected output of 4 nuclear plants (10.6% of the gross inland consumption in 2030, in the Reference scenario), as was originally expected by the launching of the nuclear program by the Berlusconi government.

[19] TIGF (France's second TSO) and Enagas (the Spanish TSO), have planned to double the current capacity at their interconnection points, in both directions to attain full reverse flow (while at present, capacity is bigger, running from France to Spain). See *GRIP South 2011-2020,*p.42, for further details.

The shale gas moratorium that was approved by the authorities in 2011 has for now prevented the use of "fracking" (hydraulic fracturing), by utilities in shale gas exploration, thus hampering any further assessment of French shale gas reserves. More recently (March 2012), the French government allowed scientific exploration "under public control", in order to assess reserves as well as to test the fracking technique. French utilities are already adapting the system to eventual gas reserves (as was the case in 2010 and 2011) by transforming two LNG terminals to export LNG (one on the Atlantic coast, and the other on the Mediterranean).[20]

Poland has been added to the list of main gas consuming countries given its current over-dependence on Russian imports (90%) and its development of shale gas. In fact, although its present gas consumption is not high, it will progressively increase as gas will probably be chosen as a substitute to coal in power generation.[21] In order to diversify its sources, Poland has already decided to build an LNG terminal and it has begun exploration for shale gas. However, as recently shown by the refusal to commit to further targets decreasing GHG emissions by 2030 (40%) and 2050 (85%), promoted by the "Roadmap toward a low carbon economy", the shift to the use of more gas will take some time (the average duration for building a CCG plant is 6 to 7 years). In particular, the transformation will require the requalification and training of employees in the coal sector, in order to comply with gas sector standards.

Key Congestion Areas and Diversification of Gas Sources

Demand is not the only element that is taken into account when considering the development of systems. Congestion problems and bottlenecks at countries' borders, a result of the lack of appropriate infrastructure, can increase the needs of diversifying routes and the sources of supply. The TYNDP has identified several gaps in the current system where flexibility could be lower than 1%, were technical problems or a disruption from one particular source to occur.[22] Diversification is then a solution to these kinds of occurrences. However, not every region or country can solve its problems by building new pipelines, as this does not necessarily mean that sources are diversified.

TYNDP has been chosen as a reference for infrastructural gaps, since other documents, such as the TEN-E, show that almost anything is strategic and of European interest. So far, European gas infrastructure developments have satisfied the needs of Germany's growing industrial economy.[23] But after the operational start of Nord Stream in November 2011 and its huge gas volumes, which it will supply Germany (equal to more than half of final consumption in 2010, Table 1), this is becoming less true. The focus is thus now shifting to more sensitive zones like the

[20] Respectively for the Atlantic Montoir-de-Bretagne, 100% Elengy – GDF Suez, and for the Mediterranean Fosmax LNG (70% Elengy – GDF Suez, 30% TGEHF (Total Gaz Electricité Holding France)).
[21] Poland has currently only one CCS Demonstration project, the Bełchatów CCS Project; www.ccsnetwork.eu.
[22] ENTSOG TYNDP describes flexibility as "unused part of the technical capacity under a given scenario and flow pattern".
[23] The simplification of the existing internal infrastructure in the *ENTSOG tool handbook on TYNDP 2012-2022*, available on the ENTSOG web page under the section *TYNDP*, shows this historic trend very well.

Baltic region, East European countries, the Balkans and South-Eastern Europe.

The Baltics

In Northern Europe, Baltic countries suffer from an over-dependence on Russia. In case of a disruption of Russian supply, Baltic countries are incapable of providing gas to their customers, since their remaining flexibility would not allow meeting peak needs. Being separated from the European system by Belarus, these countries have to sacrifice economic rationale to geopolitical challenges. For this reason, an LNG terminal is planned for construction in one of the three countries,[24] along with a pipeline, and the Baltic interconnector which connects Estonia with Finland. This pipeline should be able to transport 2 bcm of gas per year. Ideally, this gas would come from the LNG terminal that is to be constructed.

One might ask if the construction of an LNG terminal is less costly than a pipeline with Poland, which currently does not exist. The reality is that an LNG terminal is indeed more expensive, but a single Poland-Lithuania pipeline would represent a partial solution since it would not solve the problem of the diversification of supply. Concerning the overall cost of infrastructure, security of supply could be then included as a cost in itself. If it is difficult to estimate,[25] in this case it might be considered as equivalent to the construction cost of the LNG terminal (€950m),[26] compared to that of a pipeline.[27]

The Balkans and South Eastern countries

The TYNDP has stressed the lack of infrastructure and diversification of supply in the Balkans and South Eastern countries. The cold spell that hit Europe in February 2012 confirmed once more the need to diversify sources and improve reverse-flow in these countries.

In particular, Romania and Bulgaria have a sort of “one way” transport system (see Map 1), since gas can only follow a predetermined path by entering the system from one side (Ukraine for Romania and Romania itself for Bulgaria, green arrows) and exit the system at other precise points (red arrows).

Taking into account these countries in the Southern corridor project is thus essential to acquiring legitimacy, and must be considered as a project of common interest. Therefore these countries will be key players in the race for the Southern corridor as transit or receiving countries (or both). This will be the case for Serbia in the South Stream and Albania for the Trans Adriatic Pipeline (TAP).[28]

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[24] Limes, Aiget, 19/01/2012

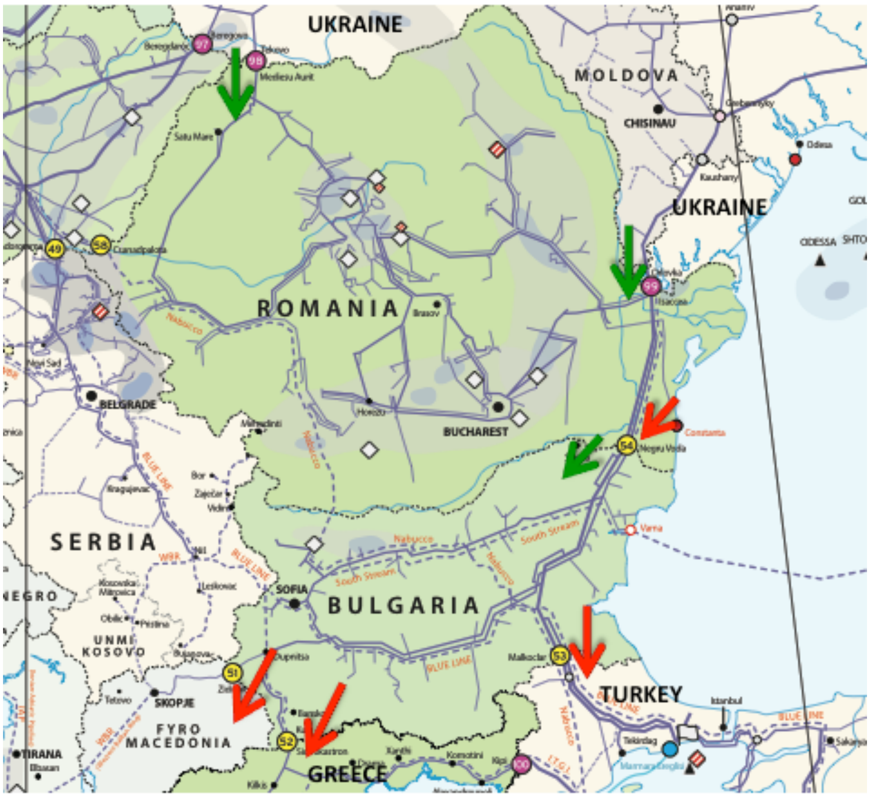
[25] The EIB has conducted a study (not yet public) to elaborate a formula for calculating the cost of securing supply.

[26] www.hydrocarbons-technology.com

[27] The pipeline between Lithuania and Poland is still waiting for a Final Investment Decision (FID), expected in 2013, but is subject to interest in the markets (GRIP, CEE, Annex B, p. 52)

[28] For the moment it is not clear if offtakes are planned in these countries and they will therefore benefit from the Russian or Azeri gas passing through these pipelines.

Map 1 – Romania and Bulgaria Gas system



Source: ENTSOG The European Natural Gas Network (Capacities at cross-border points on the primary market; version: February 2012)

As will be shown below, by looking more closely at the projects proposed for the Southern Corridor, a certain complementarity may be noted, as gaps are taken into account only partially by each project. In fact, TAP passes through Albania to reach the Adriatic sea without creating new exits in Greece; ITGI connects Greece to Bulgaria, by adding a side pipeline; Nabucco will ease supply in Bulgaria and Romania but will do little for the Balkans; and South Stream will pass through Serbia and Romania to reach either Hungary or Austria (at TAG's Arnoldstein interconnection point) through Slovenia.

Greece

Greek dependence on Turkish transit has been tested recently, showing once again the impossibility of relying entirely on its neighbor.[29] This unstable relationship comes on top of dependence on one major supply source, namely Russian gas. The 147.5 Gwh/d LNG terminal in Revythoussa is sufficient to diversify sources and limit shortages. Out of the 4.05 bcm imported into the Greek national gas system, 60%

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still comes from Russia.[30] Furthermore, Greece has only one exit from its system and does not have a reverse flow with Bulgarian or Turkish interconnection points.

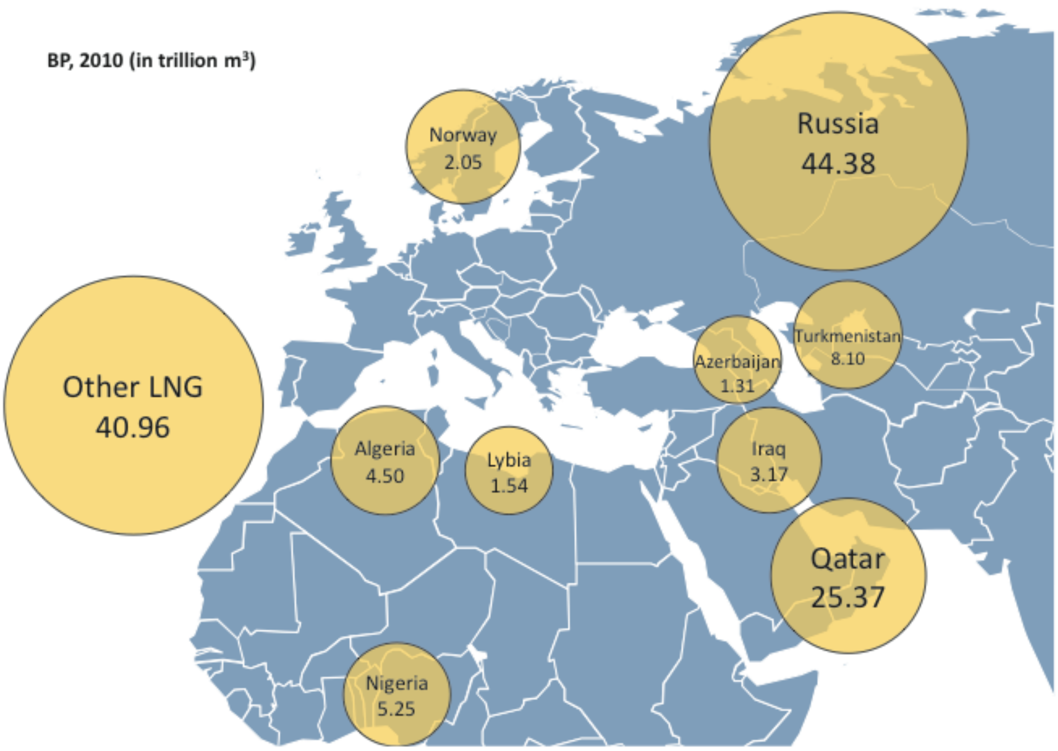
Italy

Italy is not only one of the biggest European markets (with amongst the highest prices) but it is also strongly dependent on Russian imports (40%), and lacks a real market structure. To secure supplies, Italy has therefore to diversify and increase sources either by constructing new routes or by opening up its market, or both.

These two tendencies are currently being developed in parallel. The opening of the market is driven by the implementation of the Third package of reforms while investments in new infrastructures are pushed by Italy's historical national oil & gas company, Eni, and smaller gas players such as Edison and Enel (though they are Italy's biggest electricity suppliers). The latter are willing to go directly to sources to procure fuel for their cogeneration and conventional thermal power plants.

Pipeline Projects and Upstream Investments

Map 2 – Estimated gas reserves



Source: ENTSOG, TYNDP 2011-2020 (data BP, 2010)

[30] DESFA, *off-takes, deliveries, variation in the stored quantities at nngs, 01/01/2011 – 01/01/2012,* www.desfa.gr

Several projects, mainly with their final investment decision (FID) not yet taken, may meet the demand, congestion and supply diversification needs described above. Central and South-Eastern countries are the ones most affected both in terms of demand and of infrastructural gaps. Given the importance of this, the next section studies the pipeline projects that are currently proposed by project promoters in this region.

For the European Commission, nearly €70 billion are needed "for high pressure gas transmission pipelines (coming into the EU and between EU Member states), storage, liquefied/compressed natural gas (LNG/CNG) terminals and reverse flow infrastructure." Much more is needed to develop gas fields in the main producing countries.[31] This raises the question of how much Russia, Algeria, Azerbaijan and other European utilities (Total, Eni, OMV, Repsol, Statoil, BP, etc.) are investing in the development of gas fields. Will these investments be enough to satisfy demand and enable the project pipelines to have sufficient ROI?

The race in Caspian

For the Central Asia and Caspian Sea region, producing countries have two options: to construct new and long pipelines to get to Europe's markets with high prices, or to sell gas to Russia's Gazprom. The examples of Turkmenistan[32] and other CIS countries have discouraged Azerbaijan from taking the second option for tapping its vast, unexploited gas resources.[33] That is why Azerbaijan wants to cooperate with the EU and is massively investing in political and economic ties with it. Despite these efforts, though, Azerbaijan has already contracted up to supply 4 Bcm of its gas production to Gazprom, in an attempt to ease relations with its neighbor. Gazprom's *divide et impera* policy will certainly play an important role in the development of EU-Azerbaijan relations. The EU's interest, on the other hand, is to avoid gas flowing from Russia to China, which would put Europe in a fragile position. But at the same time, it is as well for Europe to diminish the share of its Russian imports, currently as high as 40%.

The Caspian has been seen, therefore, as one of the solutions to Europe's supply diversification dilemma. It has been included in the list of priority corridors and in the External Energy Policy. Several projects have thus been put forward to reach Caspian gas (Trans Adriatic Pipeline - TAP, Interconnector Turkey Greece Italy - ITGI, South East Europe Pipeline - SEEP, Nabucco, see the Annex for details) and all have participated in the bid opened by Azerbaijan authorities for the Shaz Deniz field, in October 2011.

Shaz Deniz Stage 2 is expected to produce 16 bcm/y from 2017, out of which only

[31] Proposal infrastructure package, "Proposal on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC".
[32] VASÁNCZKI L., "Gas Exports in Turkmenistan", Paris, Ifri, 2011, p. 8.
[33] Reserves-to-production (R/P) ratio of Azerbaijan is 84,2 versus Russian's 76, BP Statistical Review, 2011.

10 bcm are to reach the European market.[34] The ensuing beauty contest has seen every project trying to convince the Consortium[35] responsible for the field's production about its ability to supply big European markets and to ensure (cheap) transport of Azerbaijani gas. That is why almost every project claims to have a transport capacity of around 10-12 bcm, as well as being able to construct the pipeline for the year the Shaz Deniz 2 field starts production (with all the bilateral intergovernmental agreements that are necessary in each transit country).

One piece of the puzzle has been revealed recently,[36] as the Consortium announced that TAP is the pipeline chosen for the supply of the Italian market.[37] This excludes ITGI *de facto* from the race.

Although Greek officials reiterated their willingness to support the ITGI project,[38] the Consortium probably wondered how Greece's DEPA utility would raise money and would be able to upgrade its grid and construct an entire new pipeline, given the Greek crisis. Furthermore, with Turkey announcing its willingness to disinvest in gas by up to 50% by 2030,[39] one can question the realism of the project and the efforts that Turkey will make in order to improve its part of the pipeline.[40] Finally, recent gas disruptions have made relations between the two neighbors even colder.[41] However, this raises the question of whether Edison, DEPA's partner in the ITGI project, is going to give up on Azeri gas. Edison is one of Italy's main electricity producers and has been positioning itself on new pipelines and LNG projects (like the Galsi project – see the next paragraph). EDF, now 100% owner of Edison, does not see any contradiction with its shares in South Stream, since Azeri gas would only represent 10 bcm of the overall EDF/Edison gas supply. Press sources note that Edison enjoys the support of the Italian Government, which still backs ITGI as the most favorable project for Italian gas needs, in contrast to the Shaz Deniz Consortium's choice of TAP.

As has already been noted, TAP only partially meets South-Eastern congestion problems, since it reaches Italy but it does not deliver gas to Greece or to East European Countries. Another intriguing issue, given that transport capacity would be 10 bcm, concerns supplies left for the non-Italian routes, which are covered by other competing projects. How much will they supply?

If we take the hypothesis that there is enough gas, then the competition boils down

[34] An agreement was reached between Shaz Deniz and Turkish BOTAS over the transit, on October 21, 2011.
[35] BP 25.5%, Statoil 25,5%, SOCAR 10%, Total 10%, LukAgip (a joint venture by Italy's ENI and Russia's Lukoil) 10%, NIOC of Iran 10%, TPAO of Turkey 9%.
[36] *Kjetil Tugland : South Stream est inutile*, Euractiv.com, 29 February 2012.
[37] TAP is sponsored by Statoil, one of the Consortium's companies, EGL and EON Ruhrgas.
[38] "Greece reaffirms support for ITGI project", Staff Writers,18/01/2012 http://www.energy-daily.com
[39] Energy market news.
[40] Although the Commission stressed, in its EU External energy policy communication, the importance of reinforcing partnership and integration of energy policies in the association process, Turkey does not seem to be a reliable partner for some companies and the delays in association negotiations are not reassuring.
[41] Harry Sachinis, CEO of DEPA, complained in an interview with Georgi Gotev of Euractiv.com on February 27, 2012 that Turkey is not a reliable partner.

to Nabucco versus SEEP[42] for the route to Baumgarten.

Table 2 – Pipeline Project and Infrastructure Gap Comparisons

	ITGI	TAP	SEEP	Nabucco	South Stream
Greece connection to the European market	✓				✓
Italy supply diversification	✓	✓			
Romania supply diversification			✓	✓	
Bulgaria diversification	✓		✓	✓	
Hungary diversification			✓	✓	✓
Balkans increase in flexibility		✓	✓		✓

Source: IFRI.

Nabucco is a sad story. It was to be the adventure of the European Union acting as one big purchaser with one single voice that finally frees Eastern Europe from the Russian yoke.[43] As of now, the story has not gone this way and there is no happy end. Many think Nabucco's survival depends on the Consortium's decision over Shaz Deniz 2. However, its fate could also hang on to the French oil & gas giant Total, which recently discovered a huge gas field in Absheron.[44] France's gas strategy has been a political riddle for the Commission, with EDF's decision to enter the South Stream consortium, after GDF Suez had already teamed up with the Russian producer in the Nord Stream pipeline. Nevertheless these signals confirm that French gas policy is currently mostly left to private companies rather than being government oriented. If Nabucco were to find its way to Absheron gas, it would then have enough quantities to fill the huge 31 bcm pipeline and hence an economic reason to exist.

Subsequently, a solution for the EU backed project was reached by reducing Nabucco's length, from the original 3900 km (see Annex I) to roughly 1300 km. This new version, also called Nabucco West (Nabucchino), could be possible thanks to the construction of the Trans Anatolian Pipeline (TANAP). The Turkish and

[42] SEEP is the latest project introduced in the bid and is sponsored by BP.
[43] *There is life for the Southern Corridor after Nabucco*, Alan Riley, EER, 12 March 2012.
[44] *Azerbaijan: Total makes a major gas discovery in the Caspian Sea*, Total press release, 9 September 2011.

Azerbaijan governments back this pipeline, which would carry 16 bcm of gas, almost entirely accessible to Third Parties.

Russian production: is there enough gas to fill the pipelines?

Gazprom has stepped on the accelerator for the construction of the South Stream project and has announced that construction will start by the end of 2012, aiming at commercial operations by the end of 2015. The final investment decision, though, has not been made yet, but it is set for the end of 2012.

Gazprom has two ways to convince investors of the realism of the project: one is political, the other commercial.

The political aim is probably the strongest. South Stream is a means to put pressure on Ukraine's rebellious behavior. 2015 is an election year in Ukraine and the Russian authorities want to state firmly their influence over Ukraine, through the strategic arm of Gazprom. By creating a brand new 63 bcm pipeline, in addition to the 55 bcm of Nordstream, Russia intends to divert gas from the Ukrainian system and drastically reduce Ukraine's transit annuity.

On the commercial side, the European market still represents an enormous source of revenue for Russia, with high prices and reliable partners. This is even more important, since negotiations with China are stalling and no deal has yet been reached.

But it needs to be asked whether investments are actually being made to supply all this gas. The answer is no. Gazprom is not investing in its upstream fields nor in its ageing infrastructure. And its main justification is Europe negative legal attitude. As the website of the project writes: "The project's cost-effectiveness to a large extent depends on the exemption from the third party access principle being mandatory in the EU. The exemption will provide the gas pipeline owner with an exclusive right to use its full throughput capacity (over an extended period of time as a rule). Therefore, South Stream representatives will approach regulators in each and every host country with a respective request."[45]

Furthermore, in an open letter to the Italian newspaper "Il Sole 24 Ore"[46] Alexander Medvedev, Gazprom Vice President, reaffirmed the long term structure of the gas market, with huge investments needed to develop new fields and a stable legal framework to rely on. He added that, since the European Union has not yet made clear what the role of natural gas will be once the current contracts end, Gazprom has abandoned the development of the Bovanenkovo field in the Yamal peninsula.

Finally, if one looks at the current investments, even Nord Stream risks running aground. In fact, the Yuzhno-Russkoye field from which Nord Stream gets its gas, is

[45] www.south-stream.info, 30/11/2010, modified 12/01/2012.
[46] Alexander Medvedev, *Illusioni europee infrante dal gelo*, Il Sole 24 Ore, 6 March 2012.

meant to produce 25 bcm/y.[47] The two deposits hold reserves of up to 800 billion cubic meters of gas, which means that, at current consumption and production, the fields can only satisfy half the pipeline's capacity, for only 30 years (in contrast to the announced duration of 50 years).

Wherever the fault lies, the sad reality is that developments are not being made upstream in the Russian system, and this will lead to more disruptions. Diversification of supply seems therefore even more necessary.

Algeria's reach

Southern Europe can count on another partner in order to diversify its sources: Algeria.

Algeria represents already 17% of EU 27 gas imports. Its proximity with the European market, however, favors the construction of direct pipelines that cross the sea, avoiding transit countries. After the 8 bcm Medgaz pipeline, which connects Algeria to Spain and whose operations started in March 2011, the Galsi project is currently the only pipeline which is under study.

This project, whose completion is expected by 2014, will ensure the direct connection of Algeria to Italy and France (2016) for smaller suppliers such as Enel, Edison and Hera.[48] Its 8 bcm/y will come from the giant Hass'r Mell gas field (which is the source of Medgaz too). The Algerian authorities have been increasing announcements of upstream investments, especially related to the potential of shale gas in this region.[49] Algeria would like to exploit this potential via LNG exports.

Conclusion

European gas needs will grow steadily until 2030. Poland's recent refusal to approve the "Roadmap to a Low Carbon economy" says a lot about what role fossil fuels will play in the next twenty years. Gas, emitting less CO2 than other fuels, will certainly have a good place in the European energy mix, at least as long as CO2 ETS prices are low.

New pipeline projects however highlight the needs for upstream investments in order to satisfy this increasing demand. Unfortunately, the key European supplier, Russia, seems to willing to miss the opportunity and is trying to put pressure on its European counterparts.

The analysis of the gas needs in the European Union thus helps understanding the

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[47] The gas field is developed by Severneftegazprom , a joint venture project between Gazprom, E.ON Ruhrgas and Wintershall.

[48] The project shareholders are: 41,6% Algerian SONATRACH, 20,8% EDISON, 15,6% ENEL PRODUZIONE, 11,6% SFIRS (a local utility from Sardinia), 10,4 % GRUPPO HERA (a regional Italian utility).

[49] *Algeria eyes huge domestic shale gas reserves*, Reuters, 9 March 2012.

meaning of “security of supply”. Security of supply is therefore not only a question of volumes but also a degree of independence, which means diversifying the routes and the suppliers.

This explains why, while there are some states and European companies that engage in more Russian gas supply, others seek to free themselves from the Gazprom dependence by creating LNG terminals (Baltic states, Poland) or by seeking new sources of gas (Caspian sea, Southern corridor). What is the real price of gas then? Should that include the costs of independence? Dealing with this question will be one of the main future issues for the European External Energy policy and the implementation of the internal gas market.

In some ways, in fact, the European Commission is responding to the dilemma with these two measures. On the one hand, the September 2011 communication proposes a regulation that would eventually centralize intergovernmental agreements on gas supplies through an information system. This proposal, however, lacks the support of many Member States and of some big utilities, which see it as a way for the Commission to strengthen its powers.

On the other hand, the reinforcement of the internal gas market would promote the creation of European hubs where gas would be traded from hub-to-hub rather than from country-to-country. It could develop internal trading and favor the movement of gas from one market to another, based on needs and price differentials, with less impediments from physical infrastructures. It would therefore diminish the relationship between consumer countries and producing countries, with gas directly shipped to the hub and not to the border. Alternatively, it could also give third party producing countries an opportunity to trade directly with the European internal gas hub. This would give an advantage to big producer countries’ companies, whose markets are still closed to competition and dominated by state monopolies.

Unless these risks are taken into account, the Commission’s measures could miss the objective of securing supplies and put the whole system under strain.

Annex I – Projects in Northern Europe

Project	Partners	Gas origin/Field	Project start date	Construction Start date	Expected Completion date	Pipeline route	Transit Country	Pipeline length:	Transmission capacity:	Investment:	TPA exemptions	Compressor stations:
Nord Stream	Gazprom 51%, Wintershall Holding GmbH (a BASF subsidiary) 15,5%, E.ON Ruhrgas AG 15,5%, N.V. Gasunie 9%; GDF SUEZ 9%	Yuzhno-Russkoye field **25 bcm/y** (The gas field is developed by Severneftegazprom, a joint venture project between Gazprom, E.ON Ruhrgas and Wintershall). The two deposits hold reserves of up to 800 billion cubic meters of gas	November 2006	April 2010	11/2011 - 04/2012 Pipeline life: 50 years	Russia, Finland, Sweden, Denmark and Germany, as well as the territorial waters of Russia, Denmark, and Germany		Two 1,224-kilometre offshore pipelines; 917-kilometre onshore in Russia;	**55 bcm** (27,5 bcm*2)	Offshore pipeline € 7.4 billion		Lubmin, Germany
OPAL Ostsee-Pipeline-Anbindungs-Leitung – Baltic Sea Pipeline Link	OPAL by EON 20% Wingas 80%	Nord Stream - Russia			2011	Greifswald to Olbernhau (Germany), Check border	Germany	470 km	36 Bcm/y		OPAL pipelinee third-party access (TPA) exemption for 80% of its capacity for 22 years	
NEL (Nordeuropäische Erdgas-Leitung – North-European Gas Pipeline)	WINGAS (51%); Belgium's transmission system operator Fluxys (19%); Dutch state gas company Gasunie (20%) and E.ON Ruhrgas (10%);	Nord Stream - Russia			2012	Greifswald to Achim/Rehden to Netherlands	Germany	370 km	20 Bcm/y		No	

Annex II - Projects in South- Eastern Europe

Project	Partners	Gas origin/Field	Project start date	Construction Start date	Expected Completion date	Pipeline route	Transit Country	Pipeline length:	Transmission capacity:	Investment:	TPA exemptions	Compressor stations:
South Stream	Gazprom 50% Eni 20% EDF 15% Wintershall 15%	?	2007	December 2012 (1)	2015	Beregovaya (Russia), Black Sea, Varna (Bulgaria)	Bulgaria - Greece / Romania - Hungary - Slovakia / Ex- Yugoslavia	900 km (offshore)	63 bcm/y (2) (2009 addendum; it was 30 in 2007) (3) - 160.8 Mcm/d (TYNDP)	Offshore € 10 billion and Onshore sections € 5.5 billion (4)		
TAP Trans Atlantic Pipeline	Statoil 42,5% - EOn Ruhrgas 15%-EGL 42,5%	Shaz Deniz II (10 bcm)	2003 (pre feasibility study)		2017 (TYNDP)	From DEFSA grid in Greece (connected to Turkey) to the Adriatic Sea coast, crossing Albania then offshore from the Albanian city of Fier via the Adriatic Sea to Italy's gas grid SNAM ReteGas	Greece - Albania	800 kilometres in length (Approx.: Greece 478 km; Albania 204 km; offshore Adriatic Sea 105 km; Italy 4 km)	10 bcm/y (up to 20 bcm)			2 compressors station (a third one to upgrade to 20 bcm)
ITGI Interconnector Turkey Greece Italy	Edison, Depa (IGI Poseidon SA)	Shaz Deniz II (10 bcm)	2003		ITGI 2017 (IEA); IGB 2014 (Margheri, 2011); 2016 (TYNDP)	Upgrade of the Turkish grid, for Italy and Greece + ITG (Interconnector Turkey-Greece, November 2007, transport capacity of about 11.5 bcm/y, current 3 bcm) + IGI (Interconnector Greece-Italy) project 9 bcm/y across the Ionian Sea + IGB (Interconnector Greece-Bulgaria)	Turkey - Greece	IGI: 800 kilometres IGI Onshore: 600 km onshore Greek territory (to be developed by Desfa, the Greek TSO); IGI Poseidon: 207 km offshore pipeline IGB 160 km	11,5 bcm/y onshore (Edison.it), 12 bcm/y (IEA) 9 bcm/y offshore (Edison.it), 8-12 (M. Margheri); IGB 3-5 bcm/y		X (25 years) 80% Edison, 20% DEPA	
SEEP South-East Europe Pipeline	BP	Shaz Deniz II (10 bcm)	1/09/2011 (6)		2017	Western Turkey - Bulgaria - Romania - Hungary - Croatia		1300 km new pipelines over 3800 total km pipelines (6)				
Nabucco	Bulgarian Energy Holding (Bulgaria), Botas (Turkey), FGSZ1 (Hungary), OMV (Austria), RWE (Germany), Transgaz (Romania) 16.67%	Shaz Deniz II (10 bcm) (Absheron?); Iraq	2002 first agreemnts and feasibility studies; Nabucco Gas Pipeline International GmbH (NIC) 24 June 2004	2013	2015 (TYNDP) 2017 (Nabucco.pipeline) Pipeline life: 50 years	Ahiboz Turkey- Bulgaria - Romania - Hungary - Austria Baumgarten	Turkey- Bulgaria - Romania - Hungary -	Turkey 2,581 km; Bulgaria 412 km; Romania 469 km; Hungary 384 km;Austria 47 km	26-31 bcm/y - 84.9 Mcm/d (TYNDP)	7.9 billion € (estimates under revision, Nabucco project --> 70% financed by financial institutions); 14 billion € -$19.28 billion (7)	X (50% of the capacity up to 25 years contracts)	11
TANAP Trans Anatolian Gas Pipeline	SOCAR - Turkish company								16-17 bcm	5-6 billion $ (5)	X 16 bcm/ year for Third Party Access	
Transcapian Pipeline	Botas	Turkmenistan				Turkmenistan - Turkey	Azerbaijan - Georgia	1700 of which 230 offshore	31 bcm/y (IEA)	2-3 billion $ (IEA)		
GALSI	41,6% SONATRACH 20,8% EDISON 15,6% ENEL PRODUZIONE 11,6% SFIRS 10,4 % GRUPPO HERA	Hass'r'Mell - Algeria (?? Bcm)	2003-2006 (feasibility study) 2009	2014	2014 (TYNDP) - 2016 (link Sardinia-Corsica)	From Algeria to Italy (Sardinia)	No transit countries	Algeria - Sardina (Italy) 285 km depth: 2824 m; Onshore Sardinia 285 km; Offshore Sardinia-Tuscany 280 km depth 878 m	8 bcm/y			Koudiet Draouche (Algeria); Olbia (Italy)

(1) V. Putin' statement, December 30, 2011
(2) IEA Golden Age of Gas 2011; 2015 is Ukraine's election
(3) Offshore section
(4) South-stream.info, 30/11/2010
(5) Soltanov, 2012
(6) Vladimir Socor, *South-East Europe Pipeline: A Downsized Nabucco Proposed By BP*, Eurasia Daily Monitor Volume: 8 Issue: 202 November 2, 2011
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