THE EUROPEAN GAS MARKET LOOKING FOR ITS GOLDEN AGE ?

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Table of Contents

Summary

The European energy market has to face numerous challenges to achieve a successful energy transition, preserve its competitiveness and ensure its security of supply. While the EU Communication on Energy Union published in February 2015 has today given new impetus to Europe's gas policy, this policy has to deal with a new environment both in terms of supply and demand.

On the supply side, the new strategy must henceforth deal with complex relations with Russia. Tensions between Russia and Ukraine along with economic sanctions against Russia have led Gazprom – the EU's leading supplier – to review its strategy towards Europe. While the "Power of Siberia" project is already underway, Russia's own pivot towards Asia as announced by Vladimir Putin is turning out to be more difficult than expected: China and Russia have still not been able to find an agreement on the Western route. For some time, Gazprom seemed to want to cut its involvement in European gas assets significantly, due to problems with market liberalization rules. Today, Moscow is sending mixed messages to Europe, first by announcing the Turkish Stream project to deliver gas to Europe's gates, and then by extending the Nord Stream pipeline. The renewed interest in the EU market by Gazprom is indicative of the importance of this market, which provides the Russian company with the bulk of its gas revenues.

Europe also has to deal with faster than expected declines in its own output. The Groningen field in the Netherlands, the EU's main gas producer, has suffered major restrictions since January 2014, due to significant earthquake risks. The Dutch government has to ensure the safety of the inhabitants of the region, secure gas supplies and respect contractual obligations to its European clients. The annual production ceiling for 2015 is enough to satisfy Dutch and European needs, by drawing more on stocks and imports. However, strong uncertainties remain on future output, clouding the visibility concerning short- to medium-term supplies of European gas.

Exploiting potential shale gas resources would allow the decline in domestic output to be offset. But the commercialization of shale gas in Europe is still far off, with disappointing results in Poland and Denmark. The United Kingdom is accelerating the use of its resources, but other countries are not moving forward on the whole. There are still many challenges to be met, and an American-style revolution is unlikely to occur. But European shale gas could well improve the security of gas supplies. However, the social

acceptability of shale projects continues to be a prerequisite for any development of these resources.

The fall in oil prices is a further distinctive factor to have occurred since 2014, impacting the gas market considerably, especially for liquefied natural gas (LNG). Lower oil prices are affecting gas and LNG prices, and are altering the competition between Asian and European buyers. Along with the slowdown in Asian demand, the fall in prices on international markets has ended the price arbitrage in favor of Asia, which was predominant from 2011 until now. The European market has once again become attractive for LNG. LNG has many advantages and is well placed to meet supply diversification problems, provided that Europe can position itself as a global actor on the international market, and that the European market remains attractive for LNG exporters. This is all the more the case given that lower oil prices risk postponing, or even cancelling, investments in new LNG export projects. Though the market today is characterized by surpluses, this trend could change by the end of the decade.

Gas supplies are abundant at the European level, but strong uncertainties hang over their evolution. While Europe intends to invest considerable sums to diversity its supplies, strengthen its transport infrastructure – in particular to allow greater volumes of gas to be shipped from west to east – and to construct electricity capacity to meet the energy transition, European gas demand has fallen strongly since 2010. This decline is linked to the economic slowdown, but above all to lower needs in the electricity sector. Here, the expansion of renewables, the lower competitiveness of gas compared to coal, but also weak electricity demand, have reduced the demand for gas. Despite the recent falls in gas prices, coal-fired electricity plants continue to be more competitive, given that the price of coal has also fallen strongly, while CO_L prices are also relatively low. This situation could weigh on the risks to future electricity supplies, as with the rapid expansion of renewables, present market price signals do not favor investment in the output capacity of flexible, low CO_L emitting production.

The European gas market has to deal with this new situation, characterized by uncertainties over supply and demand trends. While European markets today demonstrate higher gas price volatility, the long term effects could be important, as such poor visibility, combined with lower prices could prevent the financing of necessary investment both on the demand and supply sides. Natural gas has suffered from past EU policies. Today, it may be asked if the new impetus given by the Energy-Climate 2030 Framework, the reform of the CO_L market, the launching of the Energy Union and the new design of electricity markets will finally allow natural gas to find a key position in Europe's electricity balance, and contribute fully to the energy transition.

Introduction

In the wake of the Ukrainian crisis, the European Commission reviewed its energy security strategy in May 2014. Special emphasis was put on gas security, and a clear willingness to reduce the EU's dependency on Russian gas was manifest. This strategy was reiterated in a Communication on Energy Union in February 2015, opening up a new chapter in Europe's gas policy. As of April 2014, Donald Tusk put forward the idea of creating an Energy Union aimed at guaranteeing gas supplies, based on the fact that Europe is currently excessively dependent on Russian gas.[1] The Energy Union project primarily looked to the possibility of Europe developing a common purchase gas mechanism, in order to negotiate jointly with Russia, to guarantee solidarity among European Member States in the case of supply cuts, and to sign agreements with emerging suppliers. Subsequently, the Energy Union came to be seen as an opportunity to cover a much broader field and so to construct finally a unified energy policy at the European level. This policy would facilitate reconciling the goals of security of supplies, competitiveness, environmental protection; and the promotion of a better cooperative dialogue between Member States relating to their national choices for energy transition.

Europe's new strategy, however, now needs to take into account shifts in the supply of gas, as major changes have taken place in Europe's gas industry since 2014.

First, given the state of tension between Russia and Ukraine, as well as western economic sanctions placed on Russia, relations between the European Union (EU) and its major supplier have been transformed, and appear now to be at a crossroads.

Another key event has been the fall in oil prices since June 2014, which has considerable consequences for the gas industry. In the first instance, it affects the price of gas, and modifies competition between Asia and Europe in terms of deliveries of liquefied natural gas (LNG), to Europe's advantage. Between 2011 and 2014, supplies of LNG to Europe were marginal. But this could now change, given global supply surpluses, and the slowdown of growth in Asia. Falls in oil prices also have major impacts on gas projects, especially

1. See Donald Tusk's article in *The Financial Times*, "A united Europe can end Russia's energy stranglehold", 21 April 2014, available at: <www.ft.com>.

programs to exploit shale gas in a certain number of European countries.

Moreover, supplies of gas to Europe face further uncertainty since 2014, following from the Dutch government's decision to impose restrictions on output in Groningen, due to earthquake risks associated with its production. Europe's domestic production is therefore falling at a faster rate than expected.

Thus, whereas the European gas market had been built on Dutch and Russian (ex-USSR) exports,[2] these two key sources now face considerable uncertainties for very different reasons. On top of this set of changes, the demand for gas in Europe has actually been weak since 2011, due mainly to the slow upturn in the European economy, the rapid development of renewable energy and the poorer competitiveness of gas compared to goal in electricity generation.

This study examines these five fundamental and recent changes in Europe's gas industry, namely: i) Russia's strategy towards Europe; ii) the return of LNG in Europe; iii) the reduction of the Netherlands domestic production; iv) the development of European shale gas; and v) the outlook for European demand for gas. It also examines the role Energy Union can play given this new set of circumstances, to secure EU energy supplies while allowing natural gas to fully play its role in the energy transition.

2. On top of gas supplies from Norway and Algeria.

Relations with Russia at a Crossroads

Given its geographic situation and immense oil and gas reserves,[3] Russia had been considered as a natural partner for Europe for several decades. Cooperation with Russia was a strategic pillar in Europe's energy security as of the early 2000s.[4] But then 2014 marked a turning point in the strategies of both parties, which are henceforth looking to diversify their partners.

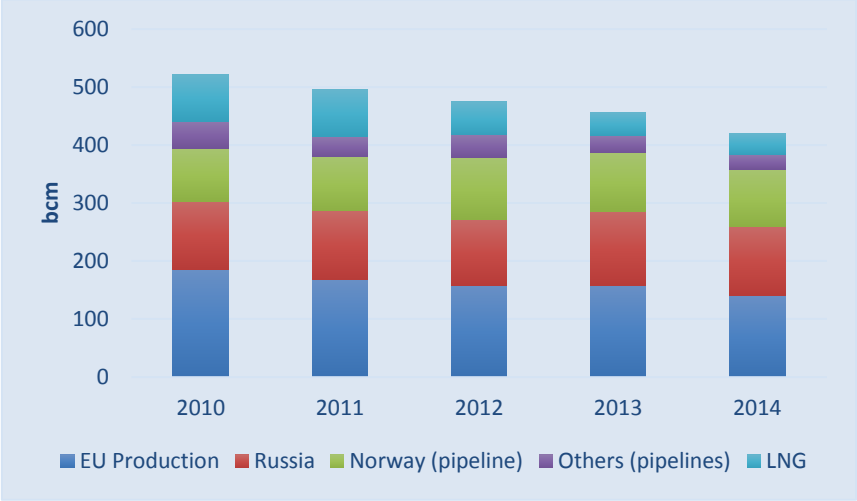
Given Europe's new policy of seeking to escape Russia's grip and the imposition of western sanctions, Russia's decision announced in December 2014 by Vladimir Poutine to abandon the South Stream project,[5] and its commitment in the Turkish Stream to pipe gas to the gates of Europe, suggested a shift in Gazprom's policy towards Europe. The Russian company appeared also for some time to want to reduce its downstream gas activities in Europe. However, since the summer of 2015, Gazprom has been sending a new message to Europe, by signing in particular an agreement with several companies to extend the Nord Stream pipeline, and to ship additional quantities of Russian gas to Germany.

Europe's dependency on Russian gas

The EU imports nearly 70% of the gas it consumes, and Russian gas represented 29% of supplies in 2014, compared to 23% from Norway, 4% from Algeria and 10% in the form of LNG.[6] Europe's import needs have fallen, despite the 25% reduction in its domestic output between 2010 and 2014. Total EU imports thus fell to about 280 billion cubic meters (bcm) in 2014 (compared to 336 bcm in 2010).

3. In 2014, Russia had 103 billion barrels of proven oil reserves, equivalent to 6% of total world reserves. Its proven gas reserves were 32 trillion cubic meters (tcm), equivalent to 17% of global reserves (BP, 2015).
4. As shown, for example in the Green Paper published by the European Commission in 2000, "Towards a European strategy for the security of energy supply", COM/2000/0769.
5. The South Stream had a planned capacity of 63 bcm and was meant to link Russia to Europe via the Black Sea, bypassing Ukraine, and crossing Bulgaria, Serbia, Hungary towards Italy and Austria.
6. CEDIGAZ estimations for 2014, available at: <www.cedigaz.org>.

FIGURE 1: EUROPEAN GAS SUPPLIES (2010-2014)



Source: Eurogas, BP, Cedigaz

Gazprom is Europe's top supplier, delivering 119 bcm in 2014, but supplies vary strongly across countries, with the main clients being Germany (38.5 bcm), Italy (21.3 bcm) and Poland (8.9 bcm). Turkey is Gazprom's second trade partner, importing 27 bcm.[7] This relationship was established with the Soviet Union, during the Cold War, and is based on long term contracts (sometimes running to 25 or even 30 years), on gas prices indexed on the oil prices and on take-or-pay clauses.[8] Today, Russia's export capacity to Europe is more than 190 bcm, passing through Ukraine, Belarus and Germany:[9]

- Brotherhood began operating in 1967 and is the most important pipeline. It goes through Ukraine and supplies countries in Central and Western Europe, as well as in South-East Europe through to Turkey. Its annual capacity is 100 bcm.

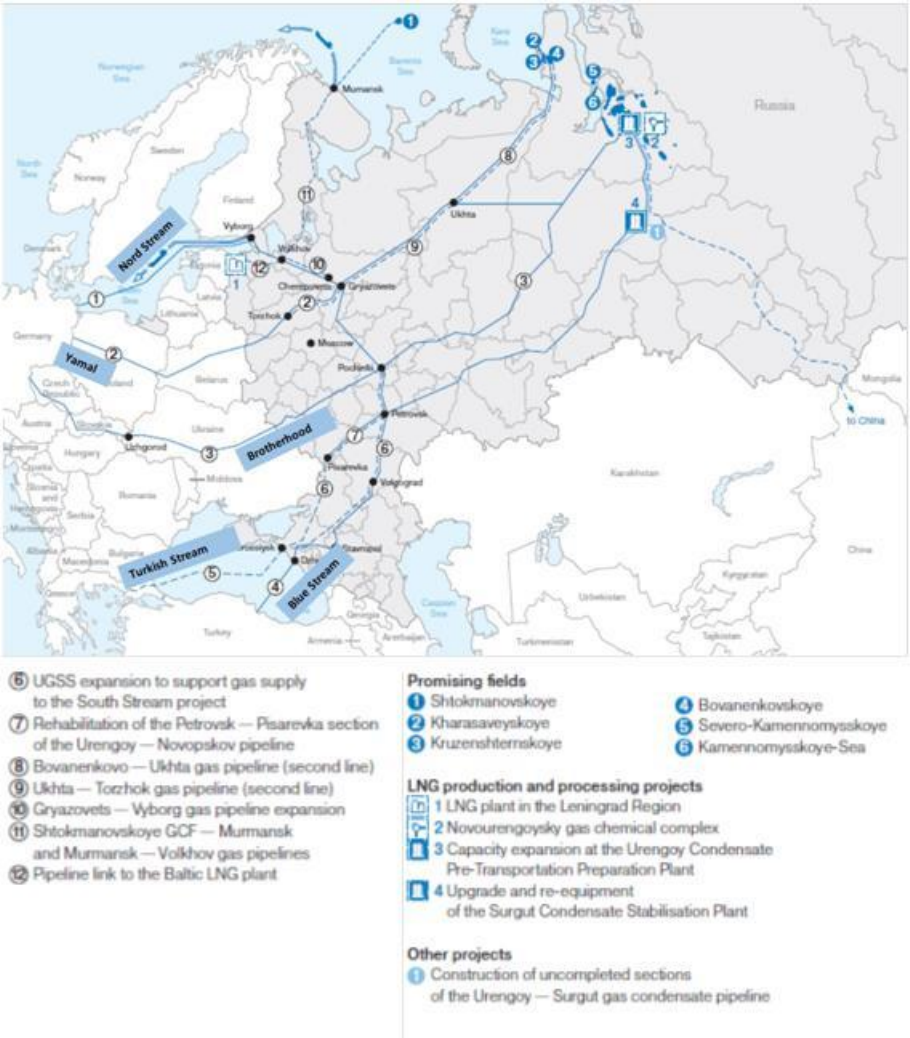
- The Yamal-Europe I (2,000 km) pipeline began operating in 1994 and has an annual capacity of 33 bcm, piping Russian gas to Poland and Germany via Belarus.

- The Nord Stream pipeline (1,220 km) is owned by Gazprom, Engie, with Germany's E.ON and Wintershall, and the Dutch Gasunie. It was

7. BP figures for 2015, excluding Turkey which imported 27 bcm of Russian gas in 2014.
8. These clauses commit the supplier to provide gas to the buyer, and a guarantee by the latter to pay for a minimal amount of energy, whether the shipment is taken or not.
9. According to ENTSOG's 10 year network development plan.

commissioned in 2012, and can pipe up to 55 bcm per year from Russia directly to Germany, via the Baltic Sea, thus passing round the Baltic States, Poland and Ukraine.

MAP 1: THE MAIN SUPPLY ROUTES OF RUSSIAN GAS TO EUROPE



Source: Gazprom

Gas crises between Russia and Ukraine

Historically, interruptions in gas supplies have been rare. But the reliability of Russia as a supplier was strongly tested in 2006 and especially 2009. In both cases, there were disputes over the settling of gas debts by the Ukrainian company Naftogaz, the price granted to Ukraine and transit costs. In contrast to the long term contracts and indexed price formula with its European clients, Gazprom negotiated its contracts annually with Ukraine during the 2000s, with contract

provisions changing subject to political relations between the two countries.

During the first gas conflict between Kiev and Moscow in 2006, Russian gas passing through Ukraine was only stopped for one day, and so did not really affect European supplies, as storages were able to make up for the lost quantities. In contrast, the scale of the crisis in 2009 was unprecedented. On 1st January 2009, Gazprom started by cutting deliveries to Ukraine, while accusing the latter of siphoning off gas destined for Europe. The Russian producer ended by cutting off supplies across the border completely. As a result, the EU saw its supplies fall by 20% for 14 days – in the middle of winter.[10]

The signature of two contracts for the period 2009-2019 ended this crisis. The first contract relates to Russian gas supplies to Ukraine, and includes: the goal of aligning the price paid by Naftogaz on prices offered to Central European countries by Gazprom, as of 1st January 2010, and a take-or-pay obligation for Ukraine covering 80% of deliveries, which was softened in 2010. The second contract includes increased transit payments that Gazprom makes to Ukraine, to off-set the price increase in shipments to Ukraine. Ukraine finally managed to obtain a rebate of 30% in April 2010, in exchange for use of the port of Sebastopol by the Russian navy. In December 2013, a further 30% discount on gas prices was provided to Ukraine by Russia (equivalent to $268.50 per 1,000 m^3) when President Viktor Yanukovych refused to sign the EU association agreement.

The destitution of Viktor Yanukovych and the annexation of the Crimea were followed by Gazprom raising its gas price by 80% to $485/1,000 m^3. It should be recalled that the average price at which Gazprom was selling gas to its European clients was $381.50 in 2013 and $355.20 in 2014 (Gazprom, 2015). Following fierce, tripartite negotiations between Russia, Ukraine and the EU in May and June 2014 over the size of gas debt and the price applied to Ukraine, Gazprom introduced a system of prepayments[11] for Ukraine on 16 June 2014, while also launching proceedings at the Stockholm arbitration tribunal in order to recover debts owed to it, estimated at $4.5 billion. This tribunal is set to rule during the second quarter of 2016.

Since 2014, the European gas market was paced by these tripartite meetings, and with the signature of agreements temporarily removing the specter of crisis. On 30 October 2014, an initial temporary agreement was reached to cover the winter through to 15 March 2015, with Russia supplying at least 4 bcm of gas at a price of $378/1000$m^3$. In exchange, it was granted repayments of debts

10. See "The January 2009 gas supply disruption to the EU: An assessment", Commission Staff Working Document, COM (2009) 363, European Commission.
11. This means that Naftogaz only receives volumes of gas paid for in advance.

running to $3.1 billion and a renunciation of the *take-or-pay* clause during this period. The winter agreement was extended to the 2nd quarter 2015, at a price of $248/1000 m^3. The tripartite meeting on 30 June, however, did end with a further extension, as Moscow and Kiev were unable to reach a price agreement. An agreement covering Russian gas deliveries to Ukraine during the winter of 2015-2016 was finally reached on 25 September 2015.

During the interruption of flows from June to December 2014, Ukraine was able to turn to reverse flows (5.1 bcm), to its national production and to the withdrawals of gas storages. In 2014, Ukraine only imported 14.5 bcm of Russian gas, compared to 28.8 bcm in 2013 (International Energy Agency (IEA), 2015). This fall in imports is partly linked to the collapse of the demand in the country, down from 60 bcm in 2011 to 40 bcm in 2014, as a result of the economic recession, financial difficulties and energy saving measures.

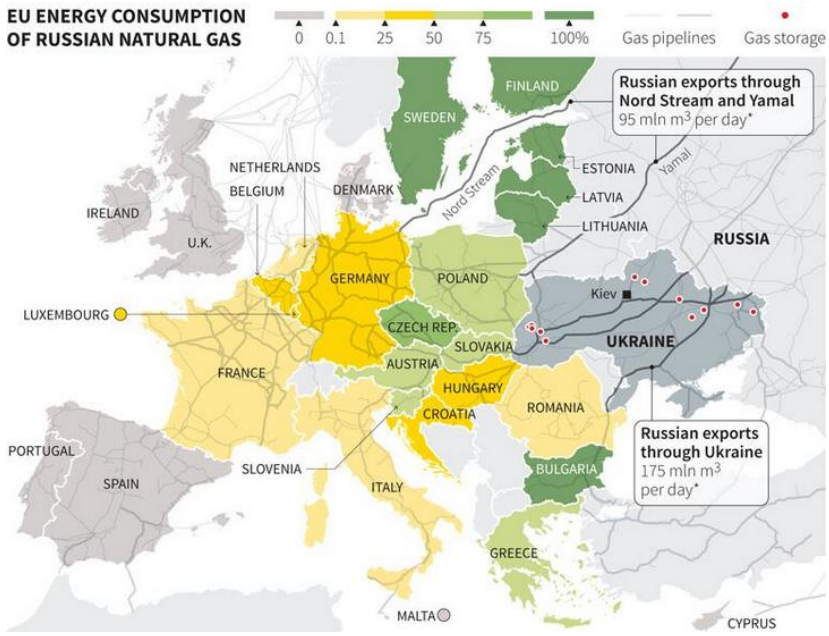
The resilience of the European system to shortages in gas supplies

Despite political problems, the crisis in 2014 between Russia and Ukraine did not lead to interruptions in deliveries to Europe. Yet European worries were strong, and Brussels examined all means of optimizing its system for meeting potential supply cuts. Compared to 2009, Europe was better prepared, notably with higher levels of storages, but also because less Russian gas was passing through the Ukraine network, thanks to Nord Stream. In 2014, 40% of Russian gas piped to Europe transited through the Ukrainian network. This level was the lowest historically, in comparison with 70% of Russian deliveries shipped to Europe via Ukraine up until 2012 and the opening of Nord Stream (IEA, 2015).

In the autumn of 2014, EU Member States undertook tests to assess their resilience to cuts in Russian gas in the middle of winter (September to February), with a two-week cold spell in February. Two scenarios were studied: a complete stop in Russian exports, including via the Nord Stream to the EU and members of the Energy Community (Ukraine, Moldavia and the Balkans); and the closure of routes through Ukraine. The results of the simulations suggest that on the whole, the European system is resilient to these crises, due notably to higher levels of storages in 2014/15 compared to 2013/14. However, northern and south-eastern Europe appear to be more vulnerable. The countries most strongly affected in this scenario are in the south-east of the EU, Finland and the Baltic States which have dependency rates on Russia gas that are close to 100%. By contrast, countries in the west, like Spain and Portugal, only get marginal quantities of gas from Russia and so are little exposed. The situation in France is satisfactory, as long as storages are sufficiently filled and

the country receives minimal LNG deliveries.[12] The simulation exercise also revealed that a lack of enhanced cooperation among Member States would lead to more important consequences.

FIGURE 2: THE DEPENDENCE OF EU COUNTRIES ON RUSSIAN GAS



Source: Gas Infrastructure in Europe, Reuters 2014.

Measures implemented in recent years have allowed Europe's security of supply to be strengthened. The regulation on security of supply adopted in 2010 has led in particular to the preparation of emergency plans in case of breakdowns in supply sources at the Union level. Infrastructure standards (rule N-1) reflect the network's capacity to meet peak demand in case of infrastructure failures, while also obliging Member States to ensure the reversibility of flows at cross border interconnections.[13] Between 2009 and 2014, the share of bidirectional interconnection points on the European gas transport network rose from 24% to 40%.[14] This allows countries like Poland, the Czech Republic and Slovakia to be supplied from Western Europe. The report by the European Commission about the implementation of the regulation of security of supply has indeed confirmed the improvements in the European situation, both in terms of preparing for possible cuts and in limiting their effects.

12. See the ten-year transport network development plan, GRTgaz 2014-2023.
13. EU Rule No 994/2010 on measures aiming to guarantee supply security of natural gas at: <http://eur-lex.europa.eu>.
14. European Commission, Staff Working Document, "Report on the implementation of Regulation (EU) 994/2010 and its contribution to solidarity and preparedness for gas disruptions in the EU", COM (2014) 654, October 2014.

Drawing on these findings, the Commission today is seeking to improve the resilience of the gas European system by enhancing solidarity between Member States, and the development of concerted collective action in crisis situations. A revision of the gas security of supply rules is underway (see Box 1).[15]

Brussels' goal of re-examining the place of Russian gas in Europe's energy mix is also reflected in its decisions to support financing of infrastructure projects which are labeled as priorities at the European level. As part of the energy infrastructures package adopted in 2013, the first list of projects of common interest (PCIs) selected by the Commission in November 2014 will benefit from €647 million, and gives pride of place to projects aimed at reducing bottlenecks in the gas transport network.[16] These concern the Baltic States especially (which will receive €339 million), countries in Central and Eastern Europe (€13.5 million) and countries concerned by the "Southern Corridor" (€3.7 million).

15. The results of the consultation are available at: <https://ec.europa.eu>.
16. PCIs are essential infrastructure projects that allow market integration and competition to be strengthened, while improving security of supply and reducing CO_L emissions, according to the European Regulation No 347/2013 of 17 April 2013 on guidelines for trans-European energy infrastructures. Following a selection process, an initial list of 248 electricity and gas projects was adopted in October 2013. These projects will benefit from facilitated procedures and more effective licensing and better standards of regulation. They can also qualify for EU financial support as part of the Connecting Europe Facility (Connecting Europe Facility) amounting to €5.85 billion over the period 2014-2020: <http://ec.europa.eu>.

BOX 1: ALTERNATIVE GAS SUPPLY SOURCES FOR EUROPE

In its Communication on Energy Union, the European Commission aims to draw on a "revitalization of its diplomacy" to reinforce its energy security, by developing energy partnerships with present and potential suppliers as well as transit countries. For several months, efforts have been undertaken by the High Representative of the Union for Foreign Affairs, the Vice-President for the Energy Union and the Commissioner for Climate Action and Energy which testify to the political will to reduce dependency on Moscow. Significant efforts were made in 2015 to promote the development of the southern gas corridor and to increase supplies from countries in the Caspian, as borne out by the Achgabat declaration signed in May 2015 between Turkmenistan, Azerbaijan, Turkey and the EU.[17] Similarly, Europe is reinforcing its diplomatic actions by launching a Euro-Mediterranean gas platform, and engaging in discussions with Algeria and Turkey.

However, in the short term the possibilities of replacing Russian gas are limited. Europe's domestic production continues to decline, and shale gas will not be able to turn the situation around (see the following chapters). With its own demand increasing too, gas output in North Africa is no longer being sent to Europe as before: exports from Algeria are falling sharply. Algeria's hydrocarbon sector is facing a number of challenges, including a legal framework that is not very favorable, security problems and financial scandals. As a result, the country is having problems attracting foreign investment. The capacity of the national company Sonatrach is insufficient to generate the resources required for Algeria's development.[18]

The "Southern Corridor" projects will pipe natural gas from Azerbaijan (10 bcm to the EU via the Trans-Adriatic pipeline, as of 2018). These hold out real, though somewhat limited, prospects for diversifying gas supply sources. In the long term, the corridor could transport important resources from Turkmenistan, Iran and Iraq. But the development of these resources is subject to numerous geopolitical uncertainties, and Europe is also in competition with Asia buyers.

The pursuit of pipeline and LNG projects in the eastern Mediterranean would be very positive for EU supplies, if investment decisions are made;[19] The resources in the region (Israel, Cyprus and Lebanon) are advantageous in terms of shipment costs, if they are delivered to southern Europe. This would allow compensation of the dominant projects based on long term contracts with Asian clients, including Atlantic projects. The recent discoveries by Eni in Egypt also change the energy picture in the region considerably and could lead to additional volumes of gas going to the European market[20]. Moreover, the end to sanctions on Iran and the recent signing of an agreement by Total to develop the Pars LNG project will allow access in the long term to Iran's vast gas reserves.

17. See at: <https://ec.europa.eu>.
18. « L'Algérie, un état pétrolier en danger », Benjamin Augé, *Actuelle de l'Ifri*, July 2015.
19. The partners of Aphrodite, in Cyprus, have recently declared the commercial field and should shortly take investment and export decisions. Similarly, the decision to export from the Tamar and Leviathan fields in Israel is expected shortly.
20. See *Pétrostrategies* 1414, « La découverte d'Eni au large de l'Égypte bouleverse la donne gazière et géopolitique en Méditerranée », 7 September 2015.

The impact of EU rules on Gazprom

Aside tensions concerning the transit of gas through Ukraine, European rules to create an integrated European gas market have been the cause of several disputes between Russia and the EU during the last two decades. Through the single market, Brussels' objective is to stimulate the trade in gas, generate competition between different sources of supply and reduce obstacles to gas circulating within the European network. The integration of European gas markets is based on a target model which emerged from the work to implement the third legislative package.[21] It has been adopted by European regulators with the aim of creating liquid and interconnected market places. In particular, it establishes the main criteria for defining an efficient market place, including annual consumption of at least 20 bcm and access to at least three different sources of supply. Transmission capacities have to be bundled at interconnections and allocated through the same auction mechanism, with an implicit allocation for short term products. The new rules therefore aim to introduce a new model for European gas trade, giving greater importance to exchanges for short term products. While this approach has shown itself to be relevant for the electricity market and the optimization of production means, it has led to heated debates in recent years concerning gas, at the European level. In contrast to electricity, the supply of gas to Europe often comes from countries outside the EU, primarily Russia, and the cost of production is not a determining parameter in arbitrating between different sources of supply.[22]

Russia takes a very dim view of this market-liberalization policy, in particular because it completely challenges the Gazprom model based on long term contracts. Gazprom also has to comply with new European rules and its strategy of bypassing Ukraine must henceforth conform to the norms of the third package in terms of unbundling activities.

What future for long term contracts?

With the development of hub trading and significant LNG import capacity, Europe has gained a number of alternatives to Russian gas. In the countries of north-western Europe,[23] the share of oil indexation in the gas price fixation mechanisms was reduced to only 12% in 2014. In central Europe (Austria, the Czech Republic, Hungary,

21. The background work on the European gas target model is available at: <www.acer.europa.eu>.
22. See Esnault B., « Gouvernance énergétique européenne, les enseignements du troisième paquet législatif », in *Économies et Sociétés*, Série « Économie de l'Énergie », EN, n°12, 02/2013, p. 221-236 and Parmigiani L., "The European gas market: a reality check", *Note de l'Ifri*, May 2013.
23. Belgium, Denmark, France, Germany, Ireland, Netherlands, United Kingdom.

Poland, Slovakia and Switzerland), the share of market prices indexation represented more than 50% in 2014, with growing imports coming from Germany (IGU, 2015).

This progressive development of hub trading, combined with lower demand for gas (see Chapter 5) and excess supply worldwide due to the development of non-conventional sources in the United States, has profoundly changed the European gas market in recent years. This new environment has led to downward pressure on European wholesale prices, and an important spread with long term prices indexed on petroleum products. Gazprom has had to adapt to this new context: between 2011 and 2014, the Russian company was constrained to introducing some indexing based on market prices in its long term contracts, given the growing difference between prices set in long term contracts and prevailing market prices. Thus, the indexation on spot prices accounted for 15% of the final price in contract with E.ON, in 2010. The revision of the price formula was subsequently applied to other contracts with European buyers (eni, RWE and Engie), but was applied only to volumes exceeding the take-or pay obligations (Franza, 2014 and Vavilov, 2014).

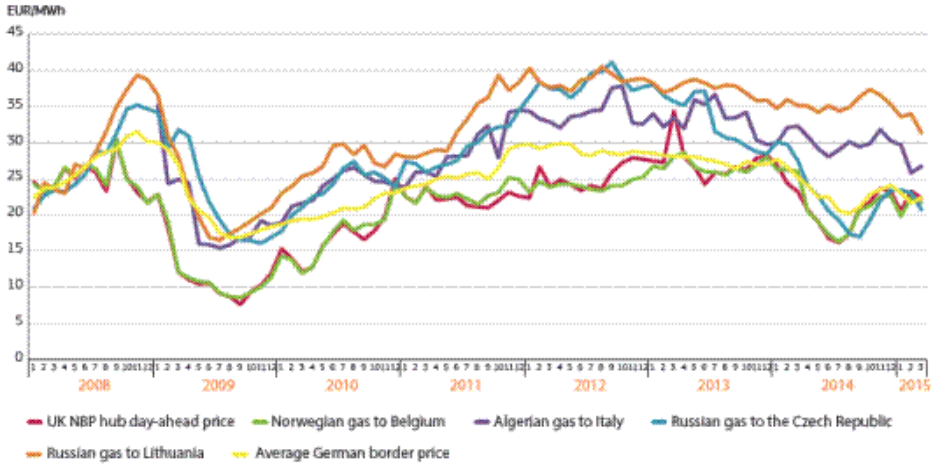
Other gas suppliers, such as the Norwegian firm Statoil, were more flexible in their negotiations with their European partners, offering price rebates of up to 30% as of 2009 and 2010 (Vailov and Trofimov, 2014). At the end of 2013, Statoil declared that a large majority of its contracts were based, at least partly, on spot market indexation. Its contract with the German firm Wintershall concluded in 2012 is entirely based on the market price (Franza, 2014).

Rebates granted by Gazprom came much later and often after tough negotiations. According to Mitrova (2015), nearly 60 signed contracts between Gazprom and 40 European clients were revised between 2009 and 2014, involving price cuts, a reduction in take-or-pay obligations or the introduction of spot indexation in the price formula. Accordingly, Gazprom granted rebates of 16% on average in 2013 and 20% in 2014 for its European clients, compared to the prices indexed on oil products in the long term contracts before 2008.

However, not all European countries benefit from the same rebates offered by Gazprom. As they have few alternatives to Russian gas, most countries in Eastern Europe continue to pay high prices. The commissioning of a floating LNG terminal in Klaipeda (in Lithuania) is however starting to have a downward pressure to some extent on the price provided by Gazprom[24], but the impact could be more important in the future, especially as Lithuania has signed a non-binding agreement to buy American LNG.

24. According to the EC Quarterly Report on European Gas markets Q2 2015, the estimated price in Lithuania was about 7 €/MWh higher than in Czech Republic in June 2015, while in September 2014, this difference was 19 €/MWh.

FIGURE 3: COMPARISON OF EUROPEAN WHOLESALE PRICES



Source: Quarterly report on European gas markets, DG Energy, Volume 8, Issue 1, 1st quarter 2015

The difficult coexistence of Gazprom and European regulation

The EU Gas Directive of 2009 set out for a specified period and under certain conditions exemption from rules for third parties access for gas infrastructures that increase competition in gas supplies and improve security of supplies. The project promoter has to show that the level of risk linked to investment is such that the project cannot go ahead without benefitting from such derogations[25].

Referring to this measure, Gazprom sought to shelter the OPAL pipeline from third party access. This pipeline has a capacity of 36 bcm, and links Germany to Czech Republic, extending the Nord Stream pipeline. In 2009, the German regulator (Bundesnetzagentur) did indeed provide OPAL Gastransport (a subsidiary of Gazprom and the German company Wintershall) with an exemption allowing the company sole use of the OPAL pipeline for 22 years. The Commission, however, decided to limit the exemption to 50% of the total pipeline capacity. After long negotiations, and by invoking security of supply reasons, the Commission finally changed its position and agreed to a complete exemption, given also the lack of interest expressed by third parties at the auction for half the pipeline's carrying capacity. Yet, the final decision on exemption was never taken by the Commission, in view of the deteriorating relations between Russia and the EU in 2014.

Given these prevarications over OPAL, Gazprom decided to launch the South Stream project, based on bilateral agreements with

25. Article 36 on new infrastructures, Directive 2009/73/CE.

six countries: Austria, Bulgaria, Croatia, Greece, Hungary and Slovenia. The Commission did not consider these agreements to be compatible with European rules relating to the unbundling of ownership, third party access and tariff structures and therefore asked the countries concerned to renegotiate them. In June 2014, the Commission opened an infringement procedure against Bulgaria, arguing that the calls for tender for the construction of the Bulgaria segment of South Stream did not comply with EU legislation. Similarly the Commission claimed that third-party access regulations were not respected either. Bulgaria ended by suspending construction in its territory.

Given these events, the Commission decided in its Communication on Energy Union to review the Decision adopted in 2012 concerning information exchange mechanism on inter-governmental agreements concluded between Member States and third countries. Henceforth, Brussels wants to be involved in the early stages of negotiations, in order to ensure better compatibility with European regulations.[26]

Lastly, the anti-trust case launched by the Commission in September 2011 is another symptom of the profound disagreement which exists between the Commission and Gazprom. The case was launched following raids on Gazprom subsidiaries in Germany, Poland, the Czech Republic, Slovakia, Austria, Hungary, Bulgaria, Latvia, Estonia and Lithuania. A year later, the Commission formally launched an enquiry into Gazprom for abusing its market dominance and for anti-competitive practices in eastern European countries. In April 2015, against a background of strong tensions between Europe and Russia, the Commission sent a statement of objections to Gazprom, with penalties potentially equal to 10% of the company's annual income.[27] Brussels suspects Gazprom of hindering competition in gas markets in eight central and east European Member States.

The Commission's first concern relate to supply contracts with clauses forbidding gas exports: clients are obliged to use all gas in their own countries, and can only sell gas to purchasers in their own country unless they obtain authorization from Gazprom. The Commission also accuses Gazprom of practicing unfair prices, with higher tariffs being applied to Bulgaria, Estonia, Latvia, Lithuania and Poland. Lastly, Brussels suspects Gazprom of having subordinated its gas supplies to the participation of the Bulgarian incumbent wholesaler in the South Stream project, despite its high economic

26. A consultation is presently underway for the review of Decision No 994/2012/UE which establishes an information exchange amechanism with regard to inter-governmental agreements between Member States and third countries in the field of energy. See at: <https://ec.europa.eu>.
27. See at: <http://europa.eu>.

costs and uncertain economic outlook. Similarly, according to the Commission, Gazprom has subordinated its gas supplies to Poland to maintain control over investment decisions in the Yamal pipeline.

Thus, European legislation on competition and liberalization has been a real obstacle to Gazprom's business strategy in the European market. The third legislative energy package proved to be incompatible with the European ambitions of the Russian energy giant, and in particular its strategy for bypassing Ukraine and supplying Western Europe.

Gazprom's strategy in the downstream gas sector in Europe

Since the end of the 1980s, Gazprom has acquired downstream assets extensively in the European market, in order to access customers directly, to control costs and to diversify its earnings throughout the gas value chain. In parallel to the market liberalization process, the group has enhanced its presence in distribution, transport, storage and supplies. It also created several joint subsidiaries with European partners in the early 1990s, such as Wingas, resulting from an association with the German firm Wintershall, a subsidiary of BASF. Gazprom has entered markets through joint ventures with European partners, or through equity participation in numerous countries, including Austria, Finland, France, Hungary, Italy, Poland, the Czech Republic and the United Kingdom.

As a result, Gazprom has become a major actor in European gas markets, both in the wholesale markets, as well as in retail markets for gas and electricity.[28] Accordingly, it delivered 3.4 bcm of natural gas to the United Kingdom, Ireland, France and the Netherlands, as well as 2.9 billion kWh of electricity to the UK, Germany and the Netherlands, in 2014. Its presence on European electricity exchanges was strengthened in 2014, when it traded 339 billion kWh[29].

Since 2006, Gazprom has been investing in storage infrastructures, close to areas of consumption in Europe, with the aim of smoothing seasonal demand, optimizing the use of pipelines and developing arbitrage possibilities between different supply sources. The acquisition of European storage facilities proved all the more important to the company during the cold spell in February 2012, when the installations it was renting in Ukraine (capable of storing up to 31 bcm) were insufficient for Gazprom to honor its commitments to its European clients. Gazprom raised its storage capacity in Europe

28. See Bros A., « Gazprom in Europe: a business doomed to fail? », *Russie.Nei.Reports No. 18*, July 2014.
29. Data from Gazprom Germania.

from 1.4 bcm in 2006 to 5.4 bcm in 2014.[30] These facilities include: Rehden in Germany (4.8 bcm) and Katarina (0.6 bcm), Haidach in Austria (2.64 bcm), and Banatsky Dvor in Serbia (0.5 bcm). Gazprom has also booked 1.9 bcm in Bergermeer, a storage facility in the Netherlands commissioned in April 2015. Other projects are also underway in the Czech Republic and Germany.

Once again, Gazprom's ambitions in the European market ran into opposition from the European Commission. The latter has repeatedly made it known that the Russian giant's strategy did not comply with the requirements of the third package, especially in terms of unbundling. Thus, when Gazprom tried to acquire a 50% stake in the Central European Gas Hub (a distribution platform operated by the Austrian company OMV in Baumgarten, Austria) in June 2011, Brussels judged the acquisition to be incompatible with European legislation. The Commission argued that Gazprom's dominant position on the European market risked affecting competition in this gas exchange.

The worsening relations between the EU and Russia in 2014 also had an impact on the penetration of Europe's midstream and downstream sectors by Gazprom. The announcement that South Stream was to be scrapped in December 2014 was followed by the cancellation of share exchanges set out in the accords between BASF and Gazprom in December 2013. This transaction is crucial to Gazprom because it would allow the company to increase its share of Wingas to 100% and to control storage in Rehden, the largest gas storage facility in Western Europe. In exchange, Wintershall would have received shares in two gas fields in Siberia.[31] Similarly, at the end of July 2015, Gazprom's shares (10.52%) in the German distribution company VNG, which supplies gas to Germany, but also to other European countries, were officially sold for about €200 million.[32] This follows the official strategy of the group to withdraw from the downstream European market.

Up until June 2015, Russia therefore was pursuing a new strategy with regard to Europe, reflecting the message given by Vladimir Putin in December 2014, and confirmed by the CEO of Gazprom Alexei Miller in April 2015.[33] Gazprom would seek to develop a new business model with Europe, based on "pure diversification" of producers and customers, transmission routes and end consumption products, in order to replace the "interdependence model" which had dominated during the previous decades.

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30. See at: <www.gazpromexport.ru> and the annual report for 2014 of Gazprom Germania.
31. See at: <www.basf.com>.
32. See at: <www.ewe.com>.
33. Conference organized by the Club of Valdai on energy security in Europe and Eurasia, in Berlin, 13 April 2015. See at: <www.gazprom.com>.

What strategy for Russia?

The deterioration of relations with the EU, its main client, can be particularly costly to the Russian supplier. This is mainly an economic problem, as gas exports to the EU account for 60% of Gazprom earnings from gas sales (Gazprom, 2015). Although gas is far less important as a source of earnings for Russia's government, compared to oil (gas only contributes to 6% of public earnings, compared to 35% for crude oil and 9% for petroleum products), gas remains the dominant factor in the domestic economy, as it provides 50% of Russia's energy supplies[34]. This gives Russian industries, which are heavy users of energy, a significant comparative advantage. Natural gas earnings are therefore a pillar of the Russian economy and a major foundation of domestic politics, as well as being a key source of influence internationally and regionally.

The difficult pivot to Asia

Announced as a key pivot to the East, the signature in May 2014 of a protocol between the Russian and Chinese governments for "cooperation on the Sino-Russian gas pipeline", as well as the contract signed by Gazprom and CNPC, along with the construction of a "Power of Siberia" pipeline (the route to the East) came after 10 years of negotiations between the two countries. Russia had therefore already turned towards the Asian market to sell part of its output, well before the Ukraine crisis. This move followed on from sluggish growth in the European market, compared to a rapidly-expanding Chinese market. This $400 billion contract is based on Russia developing gas transmission capacity (4,000 km across its territory), capable to piping 38 bcm per year via the route to the East, over a period of 30 years. This capacity could also be raised to 60 bcm per year. Work on the pipeline began in September 2014, but numerous significant challenges have to be overcome before it begins operations.

On the Russian side, investments to develop gas fields and for the construction of the infrastructure needed for deliveries are set to run to $55 billion, with China making a pre-payment of $25 billion. This payment, however, was finally cancelled in November 2014. Furthermore, the development of the Chayanda deposit in Yakutia has turned out to be more complicated than expected, given that it is eccentric to central Siberia, so that extraction costs are now evaluated at $4/MBtu. With piping costs running to $5/MBtu to the Chinese border (Milov, 2015), the whole economics of the project is thrown into question within the general context of declining oil prices:

34. See ERI RAS (2014), The Energy Research institute of the Russian Academy of Sciences, "Global and Russian Energy Outlook to 2040", see at: <www.eriras.ru>.

it should be recalled that, according to estimates,[35] the average price of gas linked to this contract is $350/1,000 m^3, the equivalent of $10/MBtu, with an oil price of $100 per barrel.

This contract was supposed to launch long term cooperation between China and Russia. In November 2014, Gazprom and CNPC signed a protocol agreement with the aim of piping 30 bcm of gas per year, for a period of 30 years, drawing gas from fields in western Siberia, using the "route to the West". This is Gazprom's preferred route, with lower costs than the route to the East, as the fields are already developed and the transport infrastructure is already largely existent. This offers Gazprom a real alternative market to Europe to sell of surplus supplies. But no contract has yet been signed by the parties, as they have not agreed on the price. There is little hope of finding an agreement in the short term, given the context of slowing Chinese gas demand and surplus global LNG supplies (see Chapter 2). Moreover, China is also banking on a partnership that is developing rapidly with Turkmenistan and which will allow it to import 55 bcm of Turkmen gas as of 2016. Further trade agreements will raise this capacity to 65 bcm, from 2020 onwards.

The present context of western sanctions and low oil prices is not favorable to the development to Russian LNG projects either, whose output is necessarily destined for Asia, in part. Yamal LNG is the only project that is likely to go ahead in the medium term, according to forecasts by the IEA, with an output volume of 7.5 bcm expected for 2017-2018, despite significant financing problems. Russia also drew on its sovereign wealth fund in 2014, the National Welfare Fund, to inject $2.3 billion into this project.[36] However, the financial needs of the consortium including Total, Novatek and CNPC remain substantial.

Generally speaking, financing for Russian gas projects is not easy in the present context of Western sanctions. Russia naturally turned towards China in 2014, but loans by Chinese banks have been limited and have not allowed Russia to do without Western financing. Apart from the Power of Siberia project, numerous observers doubt whether a substantial Sino-Russian partnership is likely to emerge in the medium term.

An uncertain strategy concerning Europe

The South Stream project was a pillar of Russia's gas export strategy towards Europe from 2006 onwards. It would have allowed Gazprom to free itself from transiting supplies through Ukraine. In 2014, total costs were estimated at $40 billion, for a capacity of 63 bcm per year,

35. See IEA (2015) and Cornot-Gandolphe (2014).
36. See the graph: <https://infogr.am>.

so that this pipeline was the most important infrastructure project to export gas to Europe. In December 2014, Vladimir Putin announced that the pipeline would be replaced by a pipeline with similar capacity, following the same route under the Black Sea, except for the last 250 km which would end henceforth in Turkey (Turkish Stream). As the only expanding market in Europe, the Turkish market has become a priority for Russia, given its 7% annual rate of growth in 2014. Thus, in 2014, Russia exported 27 bcm of gas to Turkey, of which 13.7% went through Blue Stream and the rest via the Trans-Balkan pipeline, which reaches Turkey via Romania, Ukraine and Moldavia. Turkish Stream is to have four parallel lines of similar capacity (15.75 bcm per year). It will allow Russia to secure supplies to Turkey without any transit risks.

In parallel to this project, Gazprom has given notice that it will stop piping gas via Ukraine in 2019, when its transit agreement with Ukraine is set to end. The initial idea for Gazprom was to sell gas at Europe's borders and to end any responsibility for the transit of gas to Europe, be it through Ukraine, Turkey or Greece, thus transferring transit responsibility to European importers. However, numerous obstacles have made this strategy undoable for the Russians.

Alexis Tsipras did get Moscow's green light for the financing of an extension of Turkish Stream to Greece, at the summit in Saint Petersburg in June 2015. However, many doubts still hang over the project. These stem partly from the fact that the transport infrastructures still have to be built in the Balkans, countries in central Europe and Italy, in order for gas to reach its markets. Italy's position on this issue is crucial, as it is Russia's leading importer of gas transiting through Ukraine.

Moreover, the long term contracts between Gazprom and its European clients set out clear points of delivery, while these agreements are set to go well beyond 2019. The switching of Russian gas flows towards Turkish Stream implies in particular the renegotiation of contracts concluded with its Bulgarian and Romanian partners, which are set to expire in 2022 and 2030 respectively, and whose delivery points lie at the interconnections between Romania and Moldavia, as well as between Romania and Bulgaria (Stern, Pirani and Yafimava, 2015). Lastly, negotiations on the price of gas to be sold by Gazprom to Botas seem to be more difficult than expected.

In June 2015, the European gas market was once more taken aback by decisions announced by Russia, as well as renewed interest in the European market.

- First, the expansion of the Nord Stream project to 55 bcm was first announced at the Saint Petersburg forums. This comes on top of direct supplies to Germany and Western Europe of Russian gas. And it was officialized by a shareholder pact on

11 September 2015, between BASF, ENGIE, OMV, and Shell on the one hand with Gazprom on the other hand.

- In addition, in early September 2015, discussions re-started between BASF and Gazprom, and the exchange of shares was set to occur before the end of 2015.

- Finally, Gazprom used for the first time a new mechanism for selling natural gas to Europe, via an auction covering a capacity of 3.24 bcm with three delivery points in Germany. At the end of the process, a total volume of 1 bcm was sold to 15 clients for the winter period from October 2015 to March 2016. Gazprom declared that these results confirmed the complementarity of pricing mechanisms based on prices defined in long term supply contracts and spot prices.[37]

In fact, this auction related to delivery points situated on the Nel and OPAL pipelines. As the auction results only showed up relatively weak interest on the part of buyers, Gazprom could use them to restart discussions with the European Commission concerning the thorny issue of asking for an exemption to third-party access to the OPAL and Nel pipelines. Gazprom could then use these pipelines almost entirely to transport gas in Nord Stream 2.[38]

This turnaround in the Russian position reveals the extent to which the European market remains essential to Russia. Given the present context of low prices and Western sanctions, Russia is not in a strong position in negotiating with its partners. Access to the Asian market is turning out to be more complicated than expected for the Russians and the Turkish Stream project has run into a number of obstacles. At the start of September 2015, Turkey announced a freeze in discussions with Moscow about the project.

When considering all projects for transporting gas to Europe together, Gazprom will have a supplementary export annual capacity over today's levels of 118 bcm (or 121 bcm when taking into account the increase in capacity of Blue Stream from 16 bcm to 19 bcm). It is unlikely that all these projects will go ahead given the present environment of low prices. Several experts (IEA, 2015; Milov, 2015) now consider that only two lines in the Turkish Stream project are

37. See the website of Gazprom Export: <www.gazpromexport.ru>.
38. See *Pétrostrategies*, 14 September 2015.

likely to go ahead, which will reduce the amount of Russian gas transiting through Ukraine by 13 bcm, down to 27 bcm, by 2020[39].

The constraints of the Russian energy sector and Gazprom's weakening position

Russia's energy sector faces numerous challenges. The constraints are first of all linked to the situation of gas overproduction the country is experiencing, with the greater position of Rosneft and Novatek, which today provide nearly 30% of Russian gas output, and nearly half of domestic supplies. Gazprom's strategy in recent years has been spearheaded by the exploitation of the Bovanenkovo deposit in the Yamal peninsula. It allows the company to expand output capacity by an extra 90 bcm per year, though only 40 bcm were sold in 2014 (IEA, 2015). Given the economic crisis which Russia itself is facing, domestic demand is incapable of absorbing such extra supply. The IEA is forecasting a contraction of Russian demand of 0.2% per year, between 2014 and 2020. This extra supply will not be sold into the European market, given the present political context. Nor will it find outlets among the Community of Independent States (CIS), whose imports of Russian gas fell from 101 bcm in 2006 to 48 bcm in 2014. Gazprom will therefore have to wait until the Power of Siberia pipeline starts operating fully in 2024 (with a capacity of 38 bcm) to sell off this output.

There are also internal constraints on the Russian gas sector, as the sector is less attractive and less profitable, suffering from the poor economic outlook, the depreciation of the ruble and the freezing of gas prices decided by the government in 2013.

Lastly, the economic sanctions implemented by the West since the annexation of Crimea and the Ukraine crisis in 2014, along with the fall in crude oil prices since June 2014 strongly limit the investment capacities of Russian industry and will doubtless lead to the postponement of several major gas projects in the Russian energy sector. The growing demands for the State to provide financial support to several companies will surely affect Gazprom's finances.

The company has recorded significant cuts in its export revenues from European markets and CIS countries, running to $14 billion in 2014, with estimates at between $20 billion and $25 billion for 2015, compared to 2013 (IEA, 2015). Furthermore, Gazprom has announced an output goal of 450 bcm for 2015, which is well below its initial forecasts. It is similar to its production level in 2014, which was 444 bcm, down 9% on output in 2012 and 2013 (487 bcm).[40]

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39. It should be recalled that in 2014, the volume of the Russian gas transiting through Ukraine to Europe was 62 bcm.
40. According to *Petrostratégies* N°1404 and Gazprom's annual report in 2014.

Conclusion: compromises to be found

Given all these constraints here, Gazprom will surely have to make choices concerning its numerous projects in Asia and Europe. Europe will remain its key partner. Apart from its commitments under long term contracts with its European clients, the company generates most of its earnings by sales to Europe.[41] This situation is likely to last, despite the fall in Russian gas prices linked to lower oil prices. Announcements made in the autumn of 2015 confirm that Gazprom is not likely to give up on its European clients. While there is little hope that all its export projects will be successful, they do provide the Russia giant with some power of negotiation with difficult partners like China and Turkey.

For Europe, Russia remains a major partner in the medium term, as fallback solutions are not many and will not allow to replace Russian gas. The recent developments concerning Nord Stream show once again that market pragmatism often overrides political considerations when it comes to gas. Europe's energy diplomacy should reach a common position vis-à-vis this Russian giant, and continue to act as an intermediary between Kiev and Moscow. The Turkish Stream and the expansion of Nord Stream are first tests for Energy Union from this point of view. Countries in Eastern Europe, led by Poland, have already expressed their discontent with recent agreements between companies in Western Europe and Russia. The divide between Eastern and Western Europe is therefore still open.

41. According to the OIES, the take-or-pay volumes in Russian contracts fell on average from 85% to 70%, after 2008. This suggests that European buyers are committed to acquiring more than 115 bcm in 2020, and nearly 65 bcm in 2030.

The Return of LNG in Europe

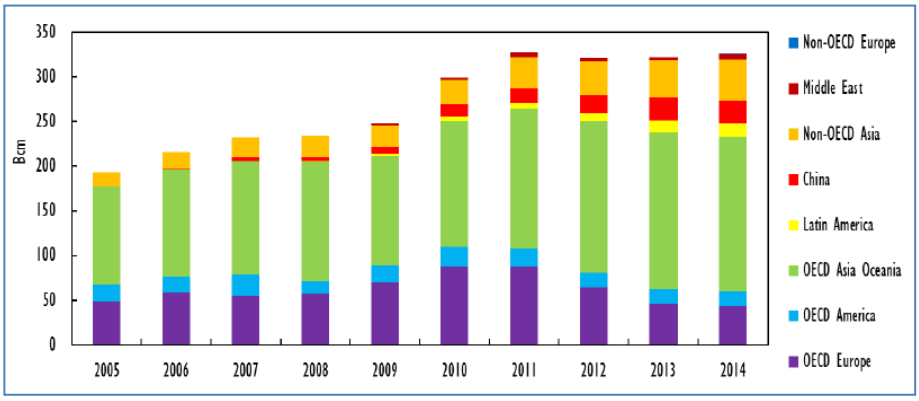
After having fallen substantially in the last three years in favor of more profitable exports to the Pacific Basin, LNG deliveries to Europe have risen strongly since November 2014. This turnaround has followed the fall in oil prices, and hence Asian LNG contracts that are indexed on oil, as well as supply surpluses in the Pacific Basin. The European spot prices are higher than prices in Asia, which is very unusual from a historic point of view, given trends in prices in the two regions. The Asian market still has greater growth potential for LNG demand. But for the moment, Europe offers better business prospects. Over time, LNG is expected to play a major role in Europe in diversifying and safeguarding gas supplies, especially in light of the uncertainties over Russian supplies.

The turnaround in the global LNG market in 2014

Global market volume for LNG is 325 bcm, of which 75% were imported by the Pacific Asian region (GIIGNL, 2015).[42] This occurs mainly with long term contracts indexed on oil prices. In the last ten years, global demand has risen by 72%, even though volumes stagnated after 2011, due to constraints on LNG supplies. Imports from the EU accounted for 11% of the global market (net imports of 37 bcm) in 2014.

42. Source: GIIGNL, 2015. Original data in Million tonnes (Mt) of LNG, converted on the basis of 1 bcm (gaseous) of LNG = 1.36 Mt.

FIGURE 4: IMPORTS OF LNG BY MAJOR REGIONAL MARKETS (2005-2014)



Source: IEA

Since 2005, the market for LNG has been affected by three major developments.

- First, the US shale gas revolution completely over-turned forecasts for US demand for LNG. In 2005, the United States was set to become a major importer of LNG and American operators were preparing for this (regasification capacity of 200 bcm per year had been built). Subsequently, however, the rapid increase in shale gas output brought LNG imports to an end (in 2014 these only stood at 1.6 bcm). In fact, the United States is turning into a major LNG exporter, and today 35 export projects are currently in different stages of development, with five under construction (FERC, 2015). The first is planned to start delivering shipments at the end of 2015. Exporting countries such as Qatar, in particular, had built new liquefaction capacity in order to meet American demand. Their production has therefore been re-exported towards other regional markets (mainly in Asia and Europe). Nevertheless, the withdrawal of the United States led to a bubble on the international market, with capacity largely exceeding demand. This bubble dried up at the beginning of the 2010s, as world demand grew more quickly than supply.

- In 2011, the Fukushima catastrophe led to a strong rise in LNG imports by Japan, which replaced lost nuclear electricity generating capacity with electricity generating plants fired by gas, oil and coal. Japan has limited reserves of gas and so relies heavily on LNG imports for nearly all of its supplies in gas. Its demand for LNG grew strongly, rising from 93 bcm in 2010 to 104 bcm in 2011 and 116 bcm in 2012. This rise in only two years was equivalent to more than four liquefaction trains. The sudden and explosive rise dried

up reserve margins in liquefaction units and stretched the international LNG market. Along with the rise in oil prices, on which LNG is indexed in Japan, the price rose strongly from $10.9/MBtu in 2010 to $16.6/MBtu in 2013 and 2014, despite the stabilization of Japanese imports (119 bcm and 121 bcm respectively). This increase led to a rising price differential across the three major global regions (Asia, Europe and the United States). In 2014, the price of imported LNG in Japan (for long term contracts) was about four times as high as the gas price in the United States, and 60% higher than in Europe. This situation led Japanese firms to look for ways of reducing their supply costs and eliminating the "Asian premium". For example, they have developed a strategy of grouped procurement between Japanese buyers, but also with other buyers in the region (Korea and India), in order to strengthen their bargaining power vis-à-vis exporters. Recently, TEPCO and Chubu Electric have linked their activities, creating one of the world's largest LNG importers. They have also bought shares in upstream gas projects and liquefaction projects, in order to make supplies more secure. As the prices of LNG under long term contracts are linked to oil prices with time-lags, their current level is falling strongly and should be about $10/MBtu in 2015.

- The third important element is the fall in European demand, down by 24% between 2010 and 2014 (see Chapter 5). The European market has become unattractive for LNG exporters, with a spot price of $9 to $11/MBtu between 2011 and 2014. The price spread between Asia and Europe (about $5 to $6/MBtu) favored exports to Asia. LNG imports also became less interesting for European buyers, given their high prices relative to pipeline supplies, following renegotiations of contracts with piped gas suppliers (see Chapter 1). Thus piped gas imports fell by only 5% between 2010 and 2014. In contrast, LNG imports, which are more flexible, have been a vector of adjustment and have fallen by 55% since their all-time high in 2011, to stand at 37 bcm in 2014 (net imports). They were down by 9% compared to 2013, which actually indicated a slowdown in the fall (-29% in 2013 and -30% in 2012). In contrast, European re-exports of LNG towards more attractive markets in Asia and Latin

America rose to reach 8.2 bcm in 2014.[43] As a result, LNG supplies in the EU became marginal (providing only 13% of supplies in 2014, compared to 24% in 2010), while the number of sources has fallen too, with only Russia and Norway accounting for 80% of gas supplies from outside the EU (see Figure 1).

Following a period of strong growth in Asian demand for LNG in the wake of Fukushima, a saturation effect seems to have set in. Growth in Asian demand has slowed in recent months. The result is a turnaround in the global LNG market, which had been very tight until recently, but is now experiencing over-capacity. The limited rise in global demand for LNG (+1% in 2014) has occurred with no problems due to new liquefaction capacity coming on line in Papua New Guinea. From 2015, the supply of LNG is set to rise rapidly (see Section 5). As a result, a paradigm change is underway: while the supply of LNG has determined demand since 2011 (available cargo was exported towards the market offering the best commercial prospects), today it is demand that is governing the LNG market. This new situation has important implications for prices and the security of gas supplies, especially in Europe.

The convergence of prices in Asia and Europe and the end of arbitrage in favor of Asia

The real radical change in 2014, however, took place on the LNG spot market. It is taking an increasing share of supplies: 95 bcm in 2014, or 29% of trade (compared to 18% in 2010). This concerns spot and short-term sales of LNG producers and re-shipped cargos by LNG importers, mainly from Europe and the United States towards Asia. On this market, LNG shipments reflect the balance of supply and demand, and not the oil price.

In Asia, spot prices for LNG started to fall in the second quarter of 2014, well before the falls in oil prices, due to the slowdown in the growth of gas consumption in the region (only +2% in 2014). The slowdown is even more pronounced for LNG imports. Japan, the world's leading importer, accounting for 37% of the world market, has seen its LNG demand stagnating. Since Fukushima, gas-fired power stations have been operating at full capacity, and Japan does not need additional imports. Moreover, the return to nuclear power (the first reactor in Sendai was brought into service in August 2015) will limit the country's future LNG needs.[44] In China, the demand for gas "only" rose by 8% in 2014. Moreover, LNG imports only increased by

43. Some LNG contracts include destination clauses, obliging buyers to discharge LNG before re-shipping it to more lucrative markets.
44. See Cornot-Gandolphe S. and Mathieu C., "Japan's Energy and Climate Policy: Towards Dispelling the Uncertainties", *Note de l'Ifri*, May 2015.

8% compared to 25% in 2013. The slowdown in Asian demand led to a fall in LNG spot prices: from a peak of $19-$20/MBtu in January/February 2014, the JKM (Japan Korea Marker which is the reference price for LNG in Asia) dropped to $12/MBtu in June 2014 and even to $10 during the summer. The fall in crude oil prices compounded the reductions in JKM price: down to $7 to $8/MBtu at the start of 2015. In March 2015, it fell below the level British spot price (NBP), a situation which had not occurred since the Fukushima catastrophe in March 2011.

In Europe, most contracts are indexed on the gas hubs (NBP and TTF especially), which are decoupled from the oil price. This decoupling stood out in 2014: the prices of oil and European spot gas prices evolved in opposing directions for much of the year. As mentioned in Chapter 1, the share of indexation on oil prices in the price fixing mechanism is falling steadily to the benefit of indexation on market prices. European spot prices fell in the 1st half of 2014 (from $11/MBtu in January to $6-$6.5/MBtu in July for the NBP), and then rose from August 2014 (to a range from $7-$9/MBtu). In early 2015, prices spanned $7-$8/MBtu. They were very volatile, reacting to tensions (real and announced) concerning Russian supplies and accelerated falls in production in Groningen (see Chapters 1 and 4).

FIGURE 5: THE PRICE OF OIL AND THE SPOT PRICE OF NATURAL GAS IN THE THREE MAJOR REGIONAL MARKETS

Source: EIA, Platts

Since the end of 2014, the strong fall in the spread between prices in Asia and Europe has led to a closure of the price arbitrage in favor of Asia, and to LNG "returning" to Europe, which has become a more attractive market.[45] The tendency strengthened at the start of

45. The reshipping to Asia of LNG cargoes originally destined to Europe has a cost of about $3/MBtu. This means that the spread between the Asian spot price and the European spot price has to be greater than this amount in order for arbitrage towards

2015, following the pronounced fall of JKM, while European prices remained volatile. During the 1st semester of 2015, net LNG imports in Europe rose by 28% compared to the same period in 2014 (CEDIGAZ, 2015). Daily emissions from European LNG terminals rose by 45% during the first four months of 2015, compared to the same period in 2014 (GLE, 2015).[46] This has had major consequences on the security and diversification of European supplies: in times of oversupplied market (as was the case in 2015), Europe's security of supply is reinforced by the return of LNG. But the European market remains exposed to fluctuations in the global market: if tensions arise in Asia, the LNG spot price may rise strongly in the two zones that are in competition for supplementary shipments.

Global supply and demand: fully adequate levels of supply in the years ahead

The global supply of LNG is diversified. At the end of 2014, it included 92 liquefaction trains with a total capacity of 405 bcm per year, spread across 20 exporting countries (GIIGNL, 2015).[47] While supply was stretched between 2011 and mid-2014, a new wave of liquefaction terminals are coming on-line from 2015 onwards, mainly in Australia and the United States, and will contribute to loosening supply constraints further. 18 liquefaction projects are being constructed and will add 190 bcm in capacity by 2020 (situation as of June 2015). More than 80% of the new capacity is located in the United States and in Australia, which is set to become the world's largest exporter by the end of the decade, ahead of Qatar (see Annex 1).

Global supply capacity should therefore rise to 600 bcm per year by 2020, although delays are to be expected. LNG projects are highly capitalistic and complex, and are traditionally subject to delays and cost overruns compared to initial production schedules and budgets. The fall in LNG prices is also leading to the postponement of projects, in anticipation of a future rise in the price of oil. That said, output could be close to 510 bcm by 2020 (85% of capacity when delays, maintenance and unavailable capacity are taken into account). As a result, market conditions should be relatively comfortable in the years ahead.

Asia to be profitable. This was often the case from 2011 to 2014. Thus European re-exports of LNG increased regularly and reached 8.2 bcm in 2014 (18% of imports).

46. GLE is a European association bringing together LNG terminal operators. In cooperation with its members, GLE launched a very-detailed information platform on LNG. It covers not only physical market data, but also investments, capacities, access modes to terminals and pricing conditions (<http://lngdataplatform.gie.eu>).

47. After a limited rise between 2011 and 2013, capacity expanded to 21.7 bcm in 2014. Four new trains were inaugurated (one in Algeria, with a capacity of 6.4 bcm, two trains in Papua New Guinea with a capacity 9.5 bcm per year and the first train (5.8 bcm per year) of the Australian Queensland Curtis LNG project.

Global demand for LNG should continue to rise at a fairly brisk pace. According to the IEA, it should reach 473 bcm in 2020, with an annual growth rate of 6.5% between 2014 and 2020 (IEA, 2015). Demand outside Europe would reach 382 bcm by 2020, a rise of 5.3% per year between 2014 and 2020, drawn by demand in China, India and the new importing countries in south-east Asia and the Middle East.[48] According to these hypotheses, nearly 130 bcm per year will be available for Europe (including Turkey) in 2020, a rise of 80 bcm over 2014. In this scenario, the availability of LNG in Europe will remain fully adequate until 2020. However, if Asian demand rises more quickly than expected (due to low LNG prices) and supplies do not rise so rapidly, then new tensions could emerge on the LNG market by the end of the decade. Thus, given the lack of visibility on future LNG prices (linked to the oil price trends and to prices in Asia), Europe faces uncertainty concerning future global LNG demand, especially in China. The signing of an agreement between Russia and China in May 2014 related to imports of 38 bcm per year by pipeline (see Chapter 1), reduces China's demand by a similar amount. In addition, China has not yet signed any contracts with American LNG exporters but is exploring this possibility.[49]

It needs to be pointed out that since 2012, not only LNG has been redirected away from Europe towards more lucrative markets, but also few of the LNG liquefaction projects currently under construction, including around the Atlantic basin, are aimed at long-term exports towards Europe. The lack of supplies based on long-term contracts makes LNG supplies to Europe more vulnerable, in case Asian domestic demand picks up or tensions re-emerge in the LNG market.

Beyond the current capacities under construction (see Annex 1), whose completion is assured, even if delays may occur, the fall in oil (and LNG) prices does raise fears about the possible repercussions on investments in new units. These may be delayed or even cancelled, and the market may therefore face renewed tension towards the end of the decade. That said, numerous projects are being planned: capacity of more than 700 bcm per year is under consideration, of which 30 projects in the United States, 22 in Canada, about ten in Australia, as well as projects in East Africa, Russia and 20 floating LNG (FLNG) projects around the globe. In recent years, the finance to increase capacity by about 30 bcm per year has been approved. 2015 is a test year for investment decisions in new units to be on-stream after 2018-2019. Until now, decisions have been mixed. In the United States, Cheniere decided in May 2015 to build the first two trains of its new LNG project at Corpus

48. The global capacity to receive LNG was already very high at the start of 2015 (1,014 bcm per year). It will increase rapidly with the ongoing construction of 21 new terminals, including fifteen in Asia.
49. Reuters, "China looks to secure 1st U.S. LNG supplies from Cheniere by 2020", 19 May 2015, see at: <www.reuters.com>.

Christi Freeport and Freeport LNG has requested authorization from the FERC to build a fourth liquefaction train. In Canada, the Pacific Northwest LNG project took FID decision at the end of June 2015. What is sure, however, is that the low price environment will delay investment decisions and may also lead to cancellations. Thus the developers of the Excelerate project in the United States and the Browse LNG project in Australia, as well as the Prince Rupert project in Canada have decided to postpone their investment decision as long as the outlook of LNG prices remains uncertain. At current prices, these projects are not viable, and it may be feared that projects in Canada (despite the tax rebate provided by the government), in Australia and in the United States (the second wave of LNG projects, after those currently under construction) are postponed or cancelled until the market has become sufficiently tight for prices to rise durably. A certain number of projects have already been cancelled in Australia (Arrow LNG, Bonaparte LNG and PTTEP Cash Maple).

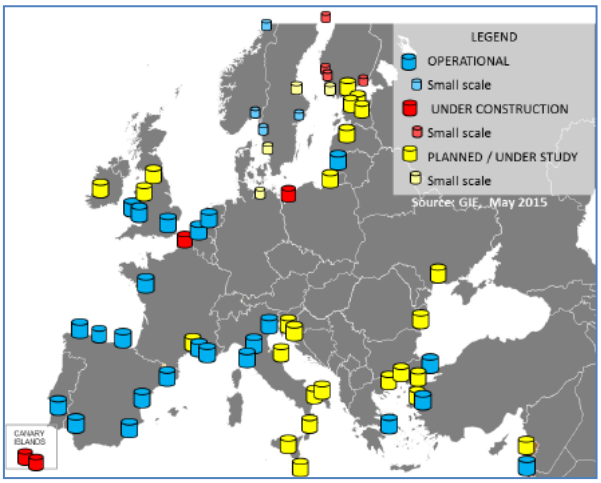
The low price of LNG and the high cost of new planned projects (which are 40% higher than those of a new terminal in the United States) are discouraging the trend to new investment. Thus, following a period when liquefaction capacity rose strongly, the years after 2018 could lead to a phase of weak investments that will impact trade after 2020.

The development of LNG receiving terminals in the EU

Europe has built significant regasification capacity. In early 2015, there were 23 LNG receiving terminals in the EU, with a capacity of 195 bcm per year for the big-scale terminals (GLE, 2015).[50] This capacity has risen by 57% since early 2009, thanks to the construction of new terminals, especially in the United Kingdom, the Netherlands, Italy and France. Most of these terminals are situated in Western Europe (see map and Annex 2). Despite the strong rise in capacity, countries in Northern Europe (the Baltic States and Finland, with the recent exception of Lithuania) and in south-eastern Europe do not have access to this type of energy yet.

50. Small-sized terminals are also constructed in Europe to meet specific needs for new outlets in natural gas, such as bunkers for sea transport, and LNG fuel for road transport.

MAP 2: LNG RECEIVING TERMINALS IN EUROPE

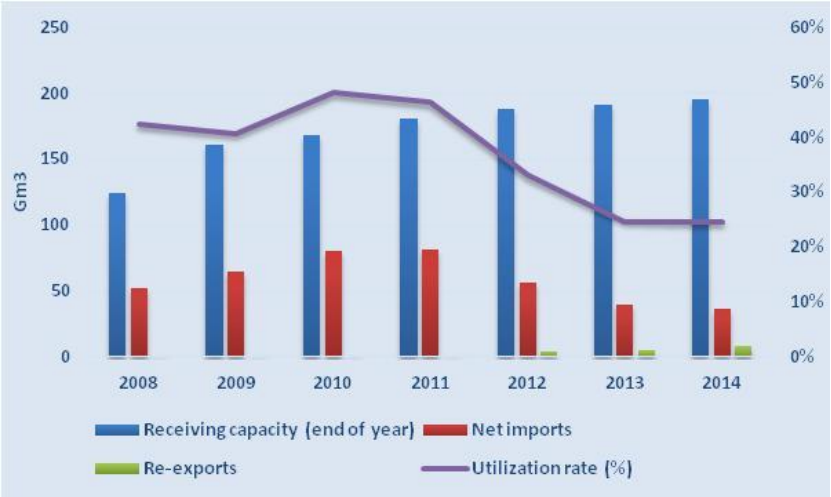


Source: GLE

These terminals have a storage capacity of 8.3 million m^3 of LNG (equivalent to 4.9 bcm of gas). This capacity is limited with respect to the capacity provided by underground gas storage (108 bcm in early 2015), the main task of the terminals being to feed gas into networks, rather than actually store it. Nevertheless, these storage capacities play an important role in certain countries (Spain and the UK) which have low underground gas storage capacities.

EU imports in 2014 ran to 45 bcm (net imports plus re-exports), and the utilization rate of capacity was low (24%), corresponding to only 16% of the daily emission rate of terminals (GLE, 2015). This utilization rate has fallen strongly since 2010, when it stood at 48%.

FIGURE 6: THE USE OF LNG TERMINALS IN THE EU



Source: GLE, GIIGNL.

Faced with the low utilization rates of the terminals, operators have looked for ways to make their assets more profitable, and have developed new services (reloading and transshipment of LNG, storage and reloading services on behalf of LNG exporters, loading of trucks to transport LNG in small quantities for industrial use, development of small-scale terminals or jetties destined to the loading of LNG of bunkering ships to supply LNG-fuelled ships or LNG bunkering facilities for vessels).

The role of LNG in Europe's gas security of supply

LNG plays an important role in the security and diversification of supply. It has numerous advantages, both for importing countries as well as for exporters. It allows gas to be transported over long distances at competitive prices, and so supply far-off regions which do not have gas resources, or which are far from major transport networks. It also allows regions to diversify supplies, or to limit disruptions in supplies as LNG can be provided from many sources. LNG also allows gas reserves far from the main consuming markets to be exploited and also avoids risks linked to transit and transport via pipelines. LNG's flexibility, which means that cargos can be redirected to high value markets (or those most in need in times of crisis) raises security too for LNG importing countries. This flexibility stretches to LNG contracts, with a rise in spot sales of LNG and more flexible durations for long-term contracts.

Thus, in spite of more adequate capacity in the EU, four new import terminals were under construction in Europe in early 2015 (with a capacity of 23 bcm, including a terminal in Dunkirk in France, and a terminal in Swinoujscie in Poland), and numerous other terminals are planned (146 bcm). All the planned terminals will not be built: some were proposed to meet rising European demand, which has not occurred in the last four years, and which remains uncertain in the medium to long term (see Chapter 5). But new terminals are going to increase security of supply, especially in regions that depend entirely or mainly on Russian supplies (the Baltic States and Finland, south-east Europe and Poland). Theoretically, Europe has sufficient LNG receiving capacity to replace Russian flows in case of supply cuts (unused capacity of the LNG receiving terminals in 2014 was 163 bcm, whereas the EU imported 119 bcm from Russia). There are however two problems.

First, there are limits on Europe's transport network for transporting gas from the terminals towards the markets which are most in need (Europe's transmission network was designed historically to transport gas from the east to the west, and not vice-versa). Investment decisions to reduce bottlenecks in the transmission network are not always easy to make, as needs are so high in the network, and require investments that are sometimes

substantial. These have to be paid by consumers in a particular EU member state, whereas the benefits go to Europe as a whole.

Second, the availability of LNG on the international market has been limited until now, even though the situation is improving as explained above.

BOX 2: THE ENERGY UNION AND THE NEW LNG STRATEGY

As part of the consultation on the regulation on security of gas supply mentioned in Chapter 1, the European Commission is seeking to evaluate if existing LNG capacities in the EU are sufficient, and to explore means for improving their contribution to EU security of supply, to improve LNG purchasing contracts in order to facilitate and accelerate responses to a crisis situation. More generally, the responses by market actors who have participated in the consultation favor a preventive approach (based on market mechanisms), rather than mitigation (through state intervention).[51] This is especially so for gas storage which plays a fundamental role in security of supply, but whose situation varies strongly from one region to another. The completion of the single market is held to be essential to any security of supply strategy by the EU (with the full application of the third energy package and network codes). This is especially the case of LNG, for which the price signal is necessary to attract cargos, and more generally to encourage investment.

LNG is seen as a key alternative to diversify supplies and to ensure security of supply in case of a major crisis. However, there is no common framework for an LNG strategy at the European level. The Commission aims to correct this with the preparation of an overall strategy for LNG and storage, to be published at the beginning of 2016.

According to the IEA, volumes of LNG imported into Europe could double by 2020, to reach 90 bcm (imports for OECD Europe, and so including Turkish imports of 7.3 bcm in 2014). European imports would thus return to their levels in 2010. In the long term, LNG should pursue its growth in the European supplies, thanks to its many advantages.

Thus, since concerns have begun over Russian supplies, countries in central and south-eastern Europe, as well as the Baltic States, which are strongly or totally dependent on Russian gas, have been looking for new supply sources, available almost immediately, in order to meet potential cuts in Russian supplies. Some countries have decided to build floating LNG receiving terminals (Floating Storage and Regasification Units [FSRUs]). These terminals require limited investments and can be built in about 18 months. In December 2014, Lithuania inaugurated its new FSRU terminal in Klaipeda. Other new FSRU terminals are also being planned in Europe (especially in Albania, Greece and Croatia).

51. European Commission, Consultation on the Revision of Regulation (EU) No 994/2010 concerning measures to safeguard security of gas supply, 2014 and 2015, available at: <https://ec.europa.eu>.

Estonia imports about 20% of its supplies via the Klaipeda terminal and the rest from Russia. In May 2015, it decided to construct a new regional terminal, which should receive its first shipments in 2019.[52] At a cost of $335 million, it could receive 5% to 15% co-financing from European funds. However, the construction of the terminal is subject to the decision to construct a regional terminal in Finland, complementing the construction of the new *BalticConnector* pipeline from Finland (financed by the programme *Connecting Europe Facility*). Poland will inaugurate its first receiving LNG terminal at Swinoujscie in 2015. Romania also has a project to import LNG.

Conclusion: a rising role for LNG, but with eventual uncertainties

The European LNG market is changing profoundly. While LNG demand has fallen strongly since 2012, it is likely to rise significantly in the next years, in order to diversify supplies and improve gas security for an increased number of European countries. Brussels intends to raise the role of LNG in European gas supplies, which is an initiative that is taking place at a time the world market is favoring such a trend. The fall in crude oil prices has made Europe more attractive than Asia for LNG exporters in the Atlantic basin. This is closing the price arbitrage between the two regions and is favoring a "return" of LNG to Europe. In the short term, the rise in international LNG supplies and the slowdown in the growth of needs in Asia will allow Europe to access new sources of LNG (especially from the United States). In the medium term, the fall in oil prices and those of LNG make investment in new liquefaction projects more uncertain, while at the same time, they will be needed to meet rising global demand. If this situation continues, then renewed tensions could affect the market at the turn of the decade, and Europe would be confronted with tougher competition from Asian buyers, which remain the main driver of growth in the market.

52. Natural Gas Europe, "Estonia to build own LNG terminal", 1 May 2015, available at: <www.naturalgaseurope.com>.

The Fall in Europe's Domestic Supplies: the Strong Cut in Output by Groningen

Gas production in Europe is now in a phase of structural decline, given the progressive depletion of conventional gas reserves. In large producing countries, apart from Norway and the Netherlands, output has already fallen rapidly. In the United Kingdom, output peaked at 108 bcm in 2000, and was only 35 bcm in 2014. But the big change that has occurred since 2014 is the accelerating fall in Dutch output. The Groningen field was Europe's largest gas field and an emblem of the birth of Europe's natural gas industry. But its output is now falling strongly due to seismic tremors and earthquakes in the area, whose intensity and frequency have increased. Since January 2014, the Dutch government has decided (on several occasions) to put a ceiling on production in order to avoid any risks. In 2015, this cap was 30 bcm, and the authorities should announce future extraction levels at the end of the year. This chapter analyzes the consequences of this ceiling on Dutch and European gas market.

Groningen: Europe's supply pillar

The Groningen field is in the north-east of the Netherlands. It was discovered in 1959 and is Europe's most important gas field, being among the world's 10 largest. Its reserves were initially estimated at 2,800 bcm. Since it came into operation in 1963, more than 2,000 bcm have been produced. Remaining proven reserves are estimated at 726 bcm (as of 1st January 2014).[53] Groningen is at the origin of the European natural gas industry, thanks to the first gas export contracts signed during the second half of the 1960s, between the field's operator NAM (Shell and Exxon Mobil which both have equal shares), and its European clients. These contracts allowed the first trans-border networks to be built.

The gas produced by Groningen has a low calorific value (initially 35.17 MJ/Nm^3), and is called "L-gas". In contrast, other gases produced or imported in the Netherlands and Europe have a high

53. Figures for cubic meters in this chapter refer to Groningen equivalent gas, with a calorific value of 35.17 MJ/Nm^3 initially, and 35.08 MJ/Nm^3 for the field's remaining reserves.

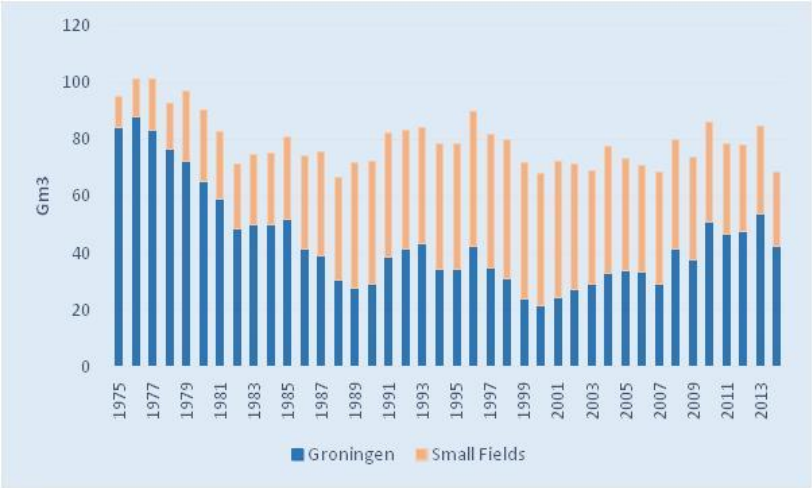
calorific value ("H-gas"). These two types of gas have distinct transportation networks.

Output in Groningen peaked in 1976 at 88 bcm. In 1974, the Dutch government launched the so-called "small fields" policy. Its aim was to exploit smaller fields and to extend the operating life of Groningen, so as to optimize the depletion of the country's gas resources. Since then, Groningen has ensured the difference between demand at any given time and production in the small fields, thus acting as a "swing producer". Its output is very flexible and can be easily adjusted in a relatively short period of time, due to the number of producing wells and the field's connection to dedicated storage facilities. Production in winter is roughly three times as high as in summer. Groningen thus plays a very important role in covering the flexibility needs of north-western Europe, and contributes to balancing seasonal fluctuations in demand in the region.

The small fields policy has permitted many fields to be developed, which have provided an increasingly large share of Dutch output. The Netherlands produce about 80 bcm per year. At their peak in 2000, the small fields provided nearly 70% of all output. Since then, their production has been declining and is set to fall further.

Dutch output was 84.5 bcm in 2013, of which nearly two thirds came from Groningen (53.9 bcm). In 2014, Dutch output fell by nearly 19% to 68.7 bcm, with the cap on Groningen's production at 42.5 bcm applied by the government in January 2014, following earthquakes in the region.

FIGURE 7: THE EVOLUTION OF PRODUCTION BY GRONINGEN AND THE SMALL FIELDS (1975-2014)



Source: NAM, NLOG

The Groningen field is part of the integrated system of GasTerra, the main Dutch company for selling gas: GasTerra operates in the European market, while ensuring a major share of Dutch supplies. The company is notably the only firm selling Groningen's output. Its mission is to maximize the value of Dutch natural gas. The firm has a public function in implementing the small fields policy. These have priority over production from the Groningen field. In contrast to Groningen production, producers of small fields can also sell their gas to other marketing companies. But GasTerra is legally obliged to buy gas from the small fields at the market price.

Groningen's integrated system includes gas storage facilities in Norg and Grijpskerk (operated by NAM and considered to be an integral part of production: their access is reserved to producers), as well as storage at Alkmaar (operated by TAQA). The maximum production capacity of the system is about 425 million m^3 per day (Mm^3/d). The integrated system acts as a swing supplier within GasTerra's portfolio. This means that adjustments in demand are met by the output of the system (Groningen and the storage facilities). The production volume of Groningen thus depends on demand from GasTerra, which itself is conditioned by the maximum limit of Groningen output, short term market demand, the production of other fields, imports, the utilization of underground storage facilities (including by third parties) and the weather (winter temperatures).

FIGURE 8: MONTHLY PRODUCTION OF GAS IN THE NETHERLANDS

(JANUARY 2010-JANUARY 2015)

Source: CBS

As part of its small field policy, the government had set an output quota for Groningen of 425 bcm in 2010, covering the period of 2011 to 2020. The quota was supplemented by 20.7 bcm, which corresponds to the quota not produced in the previous period. In 2013, the quota was equivalent to an annual production ceiling of 43.9 bcm, from 2013 to 2020. Taking into account the contribution of small fields, Dutch output should fall to 62 bcm in 2020 and to 27 bcm

in 2030 (NLOG, 2015). These forecasts have been downgraded within the framework of the new cap on Groningen's annual production (the "winningsplan").

GasTerra is the main gas exporter and sole exporter of Groningen's gas. In 2014, the company sold 81.3 bcm, of which 47 bcm was destined for its European clients. Its supplies came mainly from Groningen (52%), the small fields (30%) and imports (18%). A large share of Groningen's output goes to the Dutch market (mainly to consumers in the residential/tertiary sectors). The rest is exported to Germany, Belgium and France. GasTerra also sells a large amount of H-gas coming from the small fields or imported from Russia and Norway. This gas is used by industries/power stations, and is also exported to Switzerland, the United Kingdom and Italy.

TABLE 1: SALES OF GAS BY GASTERRA (2012-2014)

bcm	2012	2013	2014
Netherlands	34,8	36,1	34,3
Germany	19,3	22,4	18,1
France	6,1	6,5	4,9
Belgium	4,7	5,4	5,4
Italy	8,2	8,6	8,3
United Kingdom	9,6	9,5	9,5
Switzerland	0,7	0,8	0,8
TOTAL	**83,4**	**89,3**	**81,3**
of which exports	**48,6**	**53,2**	**47,0**

Source: GasTerra

Groningen's output alone is capable of meeting 10% of Europe's demand (17% for all Dutch output). Gas production (onshore and offshore) is an important source of income for the Dutch government, and represents about €12 to €14 billion per year, of which €10 to €12 billion comes from the sale of Groningen's gas, both in the Netherlands and abroad. Groningen's remaining reserves are estimated to be worth €180 billion (based on a price of 0.25 €/m^3). The Netherland's gas industry employs 16,000 people (directly and indirectly).

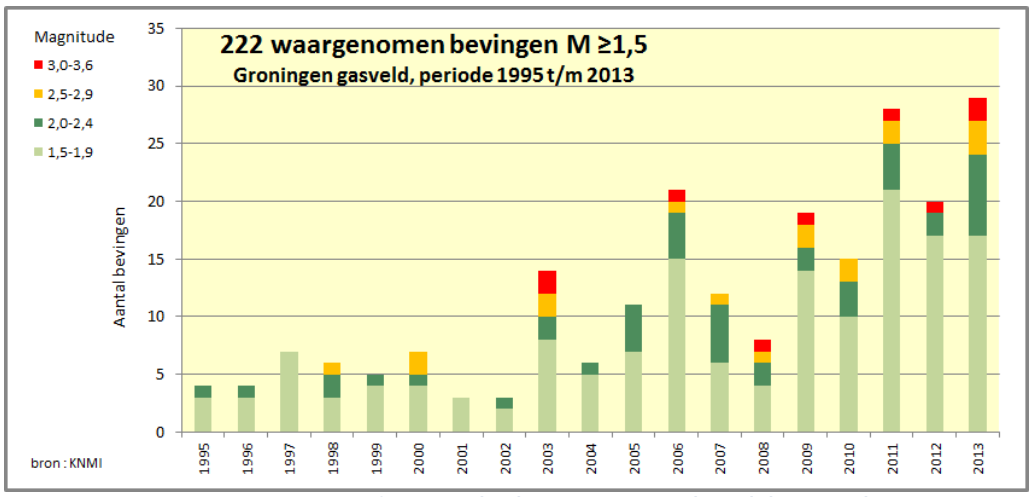
Earthquake risks and the cap on Groningen's production

The extraction of gas in Groningen has greatly contributed to the Netherlands' prosperity: it provided government with €265 billion in fiscal revenues between 1963 and 2013. But it presents a risk for

inhabitants of the region. Of the 1,012 seismic tremors and earthquakes recorded in the Netherlands between 1986 and 2013, 720 occurred in the Groningen region.[54] These are linked to gas extraction in Groningen (about 50% of the province's surface area is above the gas field). Previously tremors were weak according to the Richter scale, and imperceptible to the population. But, they have grown in strength and are generating more and more damage, especially for dwellings. On 16 August 2012, the village of Huizinge, in the province of Groningen was hit by an earthquake with a force of 3.6 on the Richter scale. This was the largest quake since gas operations started in Groningen. It damaged quite a lot of dwellings and worsened residents' anxieties. Following the earthquake, the residents trust in the safety of gas extraction in Groningen and in the national government (the Ministry of Economic Affairs which is the national body responsible for approving operators' production plans) fell to a low point. Despite repeated warnings by engineers and geologists, it was only in 2013 that the government recognized the link between gas extraction in Groningen (the collapse of underground pockets emptied of their gas and the problem of compaction: i.e. the tension accumulated underground which is released through earthquakes) and the risk of earthquakes in the region. Furthermore, recent reports by experts have indicated that earthquakes could rise to between 4 and 5 on the Richter scale, with a soil movement ratio rising to 0.12 *g* (where *g* stands for the acceleration due to gravity). According to the State Supervision of Mines – the national authority responsible for the safety of mining activities – unlimited output from the Groningen field could lead to further damage to dwellings and possibly to dikes.

54. Of the 720 earthquakes and tremors, 234 had a magnitude of 1.5 or more on the Richter scale.

FIGURE 9: EARTHQUAKES AND TREMORS RECORDED IN THE GRONINGEN REGION (1995-2013)



Note: 222 tremors of a magnitude over 1.5 on the Richter scale, between 1995 and 2013.
Source: KNMI (Royal Institute for Meteorology of the Netherlands).

In January 2014, the Dutch government took a set of measures concerning seismic risks in the Groningen region. It decided to reduce the field's production, capping it at 42.5 bcm per year in 2014 and 2015, and at 40 bcm in 2016 (53.87 bcm was produced in 2013).[55] Output was cut especially around the area of Loppersum, the epicenter of important tremors, being reduced by 80% from 15 bcm per year to 3 bcm per year. Moreover, the Dutch government announced the creation of a compensation fund to "restore the quality of life" in the region, with €144 million per year over five years. Of a total of €1.2 billion, the fund is also financed by NAM. The reduction in output is equivalent to a loss in government revenue of €2.3 billion over the three years 2014-2016. On 19 December 2014, the minister announced further cuts in output from Groningen, to 39.4 bcm per year in 2015 and 2016.

But these measures were not enough to restore the trust of residents in the government and in the operators. Such trust was undermined by the publication of a report by the Netherlands Council of Security which concluded that, up until 2013, companies and the public authorities involved in the extraction of gas in Groningen had favored profits at the cost of public safety.[56] After the report was

55. In the Minister's letter dated 17 January 2014, the maximum use of conversion installations would allow extraction from the Groningen gas field to be cut to 30 bcm per year. This can only be achieved if the flexibility of the Groningen field can be exploited. If however the production has to remain stable throughout the year, then a minimum output of 40 bcm per year is required in order to ensure the security of supplies during the winter period.
56. The report on the survey of seismic risk in Groningen looked at the decision-making process concerning gas extraction in Groningen and the way security of

published on 9 February 2015, the Minister of Economic Affairs ordered a new production cap of 16.5 bcm for the 1st semester of 2015. The Minister also announced that existing buildings at risk would be reinforced and set out new, anti-earthquake construction standards.

However, in response to complaints filed by residents in the Groningen region, the State Council of the Netherlands (the highest court of appeal) ordered a complete stop to production around Loppersum (3 bcm per year) on 14 April 2015.[57] At the same time, the Court judged that the total cessation of production from the Groningen field, requested by residents, would compromise security of supply. This was a preliminary decision and followed the examination of two complaints out of 40, which the tribunal was set to examine in September 2015. It should reach its ruling by the end of 2015. To comply immediately with the Court's decision, the Minister ordered an end to all production around Loppersum on 21 April 2015, and indicated that output from Groningen should not exceed 36.4 bcm in 2015. Subsequently, on 23 June 2015, the Minister set out a second cap of 13.5 bcm for the 2nd semester of 2015, setting out the path to the 30 bcm cap advised by the State Supervision of Mines. This level is less than required by what Gasunie Transport Services (GTS), the national TSO, considers to be necessary to ensure the safety of supplies (33 bcm). Thanks to the option of drawing 3 bcm from the Norg's gas storage, the cap imposed by the Minister ensures this level of security. Storage at Norg is now used to store L-gas in the Netherlands. Furthermore, additional output of 2 bcm may be extracted from Groningen (on top of the 30 bcm) in case of technical problems in the gas system.

Thus in 2015, output from Groningen will be cut by 12.5 bcm compared to 2014, and by 24 bcm compared to 2013. The next step is the decision that the Minister has to take at the end of 2015. The government is examining if it is possible to reduce output even more, the main difficulty being the 33 bcm floor needed to ensure security of supply. The Minister of Economic Affairs is studying the possibility of changing the extraction method and the possibility of raising gas imports. Groningen could then be used as a supplier of last resort, once the output of L-gas conversion units is fully used. This would require increasing H-gas imports, and would reduce pressure to extract large volumes of gas from Groningen, when other sources are available to meet demand and smooth out the production of the Groningen field, thus avoiding risks of earthquakes linked to large variations in production. The Minister has requested the Dutch

residents facing seismic risk is taken into account. The survey covers the period from the discovery of the field in 1959 through to the presentation of measures by the Minister of Economic Affairs in January 2014. See at: <www.onderzoeksraad.nl>.

57. Production will be maintained at a minimal level in order to ensure supply security in case of emergency.

Council of Security to study the impacts on security of supply of this policy. The study is to be finalized in December 2015. The issue is subject to debate in the Netherlands, because a rise in imports could lead to growth in imports from Russia.

The impact of the reduction in production on the Dutch and European gas markets

The consequences of the reduction in production from Groningen remain of course uncertain as long as decisions on the role of the field, the method of extraction and the level of future production are unknown. Moreover, the effects of this reduction need to be placed in the context of the depletion of the field's reserves. Prior to the recent decisions to cap output, the Dutch government had already taken into account the natural decline of the field's output. In 2005, it had set out a long term policy and vision – the "gas roundabout" – which took into account the progressive depletion of the country's reserves, its consequences on the Dutch economy, and the gas industry in particular. More generally, it set out the transition of the Netherlands from being a net exporter of gas to being a net importer, albeit with a dynamic gas industry using means that are technical (networks and storage), commercial (market liberalization and a large number of actors), and human (gas expertise). The government thus defined the concept of the "Dutch gas hub", aiming to turn the Netherlands into the gas hub for north-western Europe. This strategy met both the concerns of ensuring security of supply linked to the decline of Dutch output, and the safeguard of economic benefits linked to gas activities, thanks to investments and income induced by the new strategy. The latter favors the commercialization of Dutch expertise and experience in the gas chain, both upstream and downstream. This includes integration of "green gas". In particular, the policy led to the Netherlands building its first LNG import terminal (GATE Terminal, inaugurated in 2011, with a capacity of 12 bcm per year, with an expansion to 16 bcm per year by 2019), and signing supply contracts with global suppliers of LNG, thus diversifying the country's supplies. The strategy allowed the Netherlands' virtual hub – TTF (Title Transfer Facility) – to become Europe's leading gas hub in 2014, overtaking the British hub (NBP) in over-the-counter (OTC) trade. In 2014, OTC trade on the TTF reached a record volume of nearly 1,400 bcm. Physical trading ran to 44 bcm. The *churn ratio* (the ratio of volumes traded and physical quantities which measures a hub's liquidity) has risen considerably, increasing from 18.5 in 2013 to 32 in 2014. The strategy is being pursued currently in the search for "green" sources for gas ("green gas", such as biogas incorporated into the natural gas network, bio-LNG for transport and "power-to-gas").

The Dutch gas industry had thus already taken into account a fall of Groningen's output. Decisions taken today are accelerating this transition, but also raise other questions, especially the question of

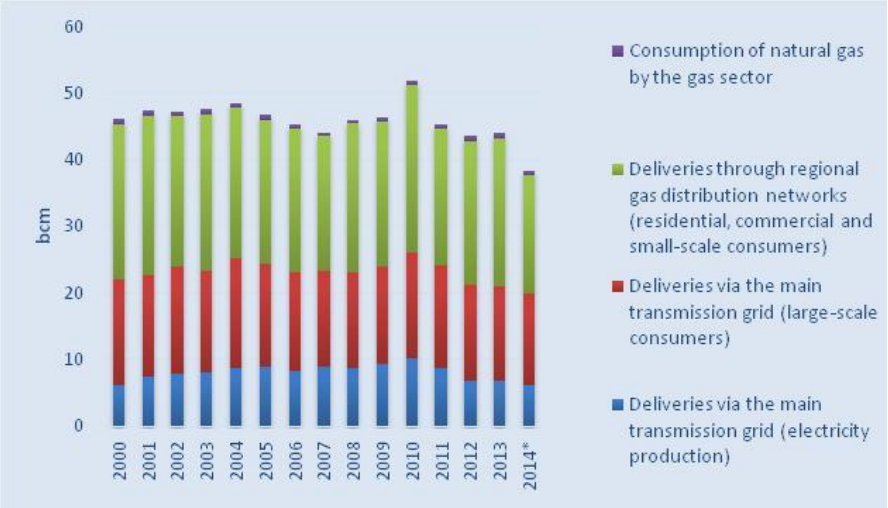
energy policy and the future role of gas in the Netherlands. The question to moving towards a new energy mix is thus raised (exploiting non-conventional gas resources or replacing gas progressively by other sources of energy, combined with supplementary efforts to increase energy efficiency) and further reinforced by the context of a fall in gas demand in the Netherlands. The Energy Agreement signed in 2014 between central government, local governments and representatives from industry and the civil society calls for: i) energy savings of 1.5% per year; ii) a rise in the share of renewable energy sources from 4% to 14% by 2020; and iii) a cut in CO_L emissions of between 80% and 95% by 2050, allowed by the closure of five coal-fired power plants built in the 1980s, amongst other measures (the plants will nevertheless be replaced by three highly efficient coal-fired stations). According to forecasts by the ECN carried out in 2014, gas consumption should fall progressively to 36.3 bcm in 2020 and to 31.1 bcm in 2030. The question of security of supply (with greater dependency on imports) is also raised, with the need to diversify supply sources. These issues are also influenced by the public image of natural gas, which is presently poor in the Netherlands. Furthermore, the issue of the availability of L-gas is also important, though it is more specific to the Netherlands and north-western Europe.

The consequences of the reduction of Groningen production must therefore be analyzed at four levels: the Dutch gas market, the L-gas market in north-western Europe, exports to European clients and the fall in flexibility.

The consequences for the Dutch gas market

The Netherlands is Europe's fifth largest gas consumer. The share of gas in the energy and electricity mix is very high (43.2% and 53% respectively in 2013). Furthermore, nearly all Dutch households are connected to the gas network, and use gas for heating, cooking and hot water. Households account for half of the country's gas consumption. Industry is also an important customer, especially petrochemicals which use gas in the production of fertilizers. In 2014, consumption was 38.4 bcm, down by 13% compared to 2013, and at its lowest level since 1982, as a result of the mild winter compared to the previous year (total energy consumption was down 6% in 2014). The mild winter reduced strongly heating needs by residential and commercial users. Furthermore, the demand of the electricity sector was also lower, due to the increased use of coal, up by 15% in 2014. As in other countries, this progression was due to the competitiveness of coal compared to natural gas, reinforced by the low prices of CO_L quotas. Even though the price of gas has fallen since 2014, the competitiveness of coal has not been challenged, as its price too has fallen (see Chapter 5).

FIGURE 10: EVOLUTION OF NATURAL GAS CONSUMPTION IN THE NETHERLANDS (2000-2014)



Source: CBS

The Dutch transmission network has two distinct networks: one for L-gas and one for H-gas. The two networks are connected by blending stations which allow the quality of the gas to be adjusted. Users in the residential and commercial sectors use L-gas. Their demand fluctuates strongly with outside temperatures. Their supply is guaranteed thanks to the flexibility of Groningen (and storage associated with the GasTerra system), as well as by conversion facilities which convert H-gas into L-gas (through the injection of nitrogen into H-gas). GTS is responsible for adjusting the quality of gas to meet consumer needs. But these capacities are limited and GTS, which has published its first network development plan (NOP 2015) is planning to raise capacity.[58]

The accelerated reduction in Groningen output (and its flexibility) could compromise winter security of supply.[59] It is obliging the various operators to develop new means for ensuring security. At the behest of the Ministry of Economic Affairs, GTS has begun to prepare the expansion of its production capacities in nitrogen, in order to convert H-gas into L-gas. Operations are set to start in 2019, for security of supply to be guaranteed from 2020.

Furthermore, gas storage also contributes to supply flexibility. The Netherlands has five underground gas storage facilities and a

58. GTS, Network Development Plan 2015 (NOP 2015), Consultation document, 13 May 2015.
59. In January 2014, the Ministry of Economic Affairs indicated that the complete end to operations around Loppersum would raise security of supply issues in winter time to cover peak demand. For this reason it was judged necessary to authorize limited production of 3 bcm per year in Loppersum, in order to be able to meet demand peaks rapidly.

peak shaving facility. The underground storage capacity has recently been increased to 12.9 bcm, following the commissioning of Bergermeer storage in April 2015. It is being exploited by TAQA and EBN (the Dutch State), and has a capacity of 4.1 bcm. This large storage facility is geared to smoothing out seasonal fluctuations in demand. The Netherlands also has storage capacity in Germany (Epe storage). NAM has recently indicated that storage capacity at Norg will be increased to 7 bcm per year.[60] Similarly, Gasunie is planning to expand the withdrawal capacity of its peak storage at Zuidwending, operated by EnergyStock.

TABLE 2: UNDERGROUND GAS STORAGE IN THE NETHERLANDS, AS AT 1 APRIL 2015

Storage	Commissioning date	Type of storage	Operator	Technical capacity, working gas volume (million m^3)	Withdrawal technical capacity (million m^3/day)
Zuidwending	2011	Salt Cavern	EnergyStock BV	300	43.2
Grijpskerk	1997	Gas Field	NAM	2,400	62.0
Norg (Langelo)	1997	Gas Field	NAM	5,600	76.0
Alkmaar	1997	Depleted Field	TAQA Energy BV	500	36.0
Bergermeer	2015	Depleted Field	TAQA Energy BV	4,100	57.0
TOTAL				**12900**	**274.2**

Source: GSE

In the longer term, the fall in L-gas output requires a more complete transition: the conversion of the network and storage facilities from L-gas to H-gas, and the adaptation (or replacement) of domestic appliances using L-gas. This transition is being planned in the Netherlands to start in 2030. Before this, GTS must ensure that the market is supplied with gas that is of similar quality than Groningen's.

Following the fall in domestic production, imports will grow strongly. The Netherlands should become a net importer in around 2025. However, the accelerated reduction of Groningen and the necessity of mixing H-gas and nitrogen to obtain L-gas in order to achieve security of supply could well bring this date forward. The gas hub concept for north-western Europe developed by the government takes this new dimension into account. Dutch infrastructure is already being adapted to meet this change. Capacity at border entry points (pipelines and LNG) is being expanded, in order to raise import flows, and storage capacity is also being expanded, so that demand can be adjusted to less flexible supply. The government's strategy moreover

60. This was done by October 2015.

provides for the gradual replacement of income from natural gas sales by revenue created by the new status of the Netherlands as a gas hub for north-western Europe (transportation and storage services, transit, re-exports, etc.).

The L-gas market in north-western Europe

As the majority of the gas supply in north-western Europe originally came from Groningen, neighboring countries (Germany, Belgium and France) have developed some of their infrastructure according to this gas quality and have built specific L-gas networks. They too are now facing the challenge of managing the decline in Groningen production. The L-gas market in north-western Europe represents about 70 bcm per year, of which 30 bcm are consumed in the Netherlands, 30 bcm in Germany, 5 bcm in Belgium, and 5 bcm in northern France. The Groningen field is the main supply source of this market (60%-70%). Other L-gas production comes from Germany (about 10 bcm per year, which is also declining), and from conversion facilities of H-gas into L-gas.

The planned decline in the production of Groningen after 2020 (and expiry of import contracts for L-gas by the end of the next decade) already required a transition in the market from L-gas to H-gas. The accelerated reduction in the production of Groningen precipitates the timing of this transition. This is a long and complex process, since it involves adapting L-gas transport and distribution networks, storage facilities and equipment to new sources of H-gas. This in turn involves many actors and must be carefully planned. Gas infrastructures in the countries of north-western Europe are closely connected, and all countries must work together to find optimal solutions.

In the short term, output reductions from Groningen can be offset by converting H-gas imported into the Netherlands. Apart from the increase in imports, this requires raising the capacities of gas conversion stations and of nitrogen production. GTS is currently preparing for this.

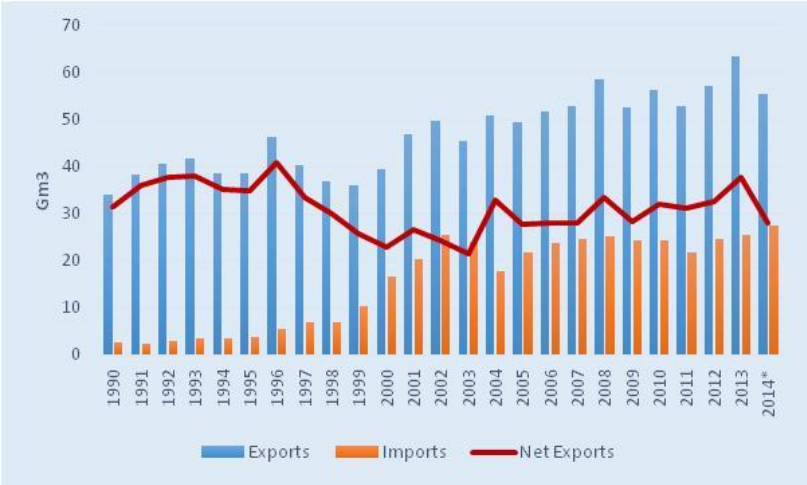
In the longer term, new transitional measures are being developed. They involve investments to convert fully or partially the L-gas infrastructure to H-gas and to increase H-gas delivery capacity (total volumes and peak capacity). Timing differs across countries. The conversion will begin in Germany in 2015, while it is not expected until later in Belgium and France (2021), and later still in the Netherlands (2030). In 2013, the German operators of the gas transmission network developed a joint plan for the conversion of the network from L-gas to H-gas. Under the plan, conversion will start with a pilot project in October 2015 to offset the decline of L-gas production from German fields. It will continue in other regional networks in 2016 and 2017, in accordance with the plan. By 2025, German operators plan to invest €3.5 billion in order to increase the system's capacity in H-gas. In France, preliminary studies are

underway and a first schedule was set out according to the deadlines announced by the Dutch authorities. The implementation schedule set out in a first scenario provide for studies to be conducted in 2015 and 2016. These are to be followed by a substantial experimental phase from 2017 to 2019, the formulation of an industrial strategy based on this experimental phase from 2019 to 2020, and finally a generalized conversion phase from 2021 to 2029.

Exports and prices

Thanks to the discovery of Groningen, the Netherlands became a major exporter of gas to Europe. In 2014, these exports totaled 55.4 bcm (a decrease of 12.7% compared to 2013). The Netherlands is also a major importer/re-exporter of gas: 27.4 bcm in 2014. More recently it has become an LNG importer and re-exporter. Gas imported by pipeline comes mainly from Russia and Norway on the basis of long-term contracts. Net exports from the Netherlands fell 25% in 2014 to 28 bcm: this was down nearly 10 bcm compared to 2013, due to the reduced production of Groningen and a mild winter, which reduced European demand.

FIGURE 11: EVOLUTION OF GAS EXPORTS AND IMPORTS IN THE NETHERLANDS (1990-2014)



Source: CBS

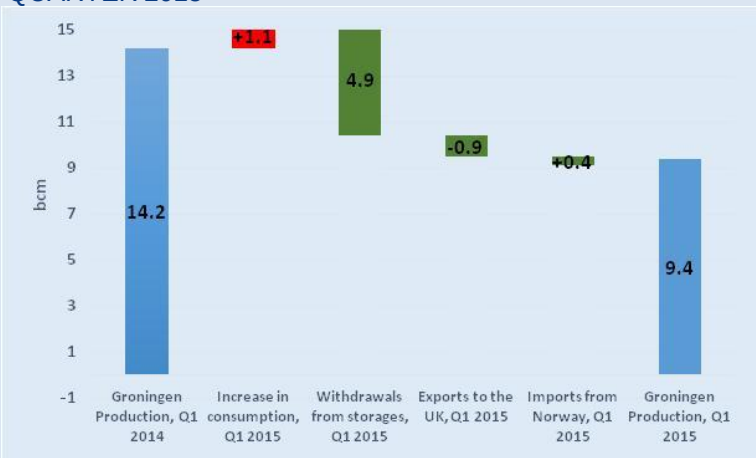
Given the oversupplied European market, replacing the missing gas volumes from Groningen (11.5 bcm in 2014 compared to 2013) was not a problem, given the mild winter and the reduction of Dutch and European demand (-6 bcm and -52 bcm respectively). European spot prices indeed also fell by 22% in 2014, despite the Russian-Ukrainian crisis. On the TTF, prices recorded an annual average of €21/MWh, compared to €27/MWh in 2013. Spot prices were however very volatile reacting to tensions between Russia and Ukraine.

The supply reduction expected in 2015 (12.5 bcm, assuming Groningen production at 30 bcm), should not create supply problems. But it requires an increased role of storage facilities and increased imports. LNG imports can easily compensate for this shortage, aided also by arbitrage between Asia and Europe in favor of Europe (see Chapter 2). Storage is expected to play a major role in covering demand fluctuations, as was indeed observed in 1st quarter 2015.

BOX 3: REDUCTIONS IN GRONINGEN OUTPUT, 1ST QUARTER 2015

The reduced production of Groningen in 2014 occurred in a context of declining demand and therefore did not disrupt the European market. In the 1st quarter of 2015, the production of Groningen was cut by 5 bcm compared to 1st quarter 2014, while European consumption increased in the same period. Dutch consumption increased by 1.1 bcm over the previous winter. The missing volumes were replaced by a significant increase in gas withdrawn from storage, a decrease in exports to the UK and a slight increase in imports from Norway. The Norg storage, in particular, was fully used to offset the decline of Groningen.

FIGURE 12: REMPLACEMENT OF GRONINGEN OUTPUT IN THE 1ST QUARTER 2015



Source: PLATT'S

In reaction to the announcement of the capping of Groningen production at 16.5 bcm in the 1st half 2015, spot gas prices jumped by almost 20% in mid-February. GasTerra was forced to buy gas on the spot market to meet its contractual obligations. Moreover, this announcement was made in a context of declining Russian flows. The immediate impact on prices faded very quickly, thanks to the mildness of the end of winter, additional deliveries of LNG, but also increased Russian flows at the beginning of March 2015.

The announcement of the cessation of production in Loppersum in April 2015 had no effect on the spot price. By contrast, the impact on price volatility was high. Uncertainties related to production (and flexibility) of Groningen have added to uncertainties about Russian supplies. Similarly, the price spread between winter and summer increased sharply in the 1st half 2014 (up to €8/MWh), but has fallen to lower levels since early 2015: less than €2/MWh on the basis of forward contracts.

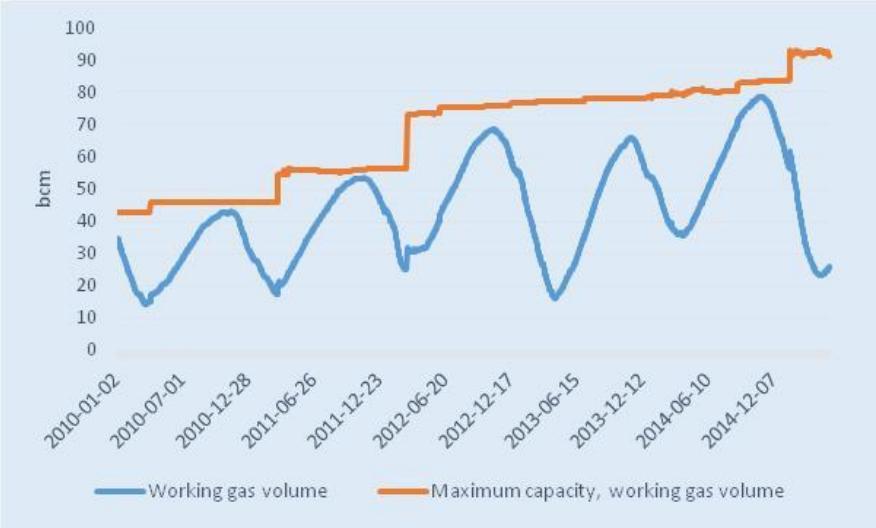
Despite the decrease in Groningen production, GasTerra has been able to meet its long-term contracts, which relate to the supply of 40-60 bcm per year (L-gas and H-gas), by converting more H-gas into L-gas. In the longer term, GasTerra has said the company will not sign new export contracts, nor extend the term or increase its existing contracts. The contracts expire at the end of the next decade. GasTerra's long-term contracts have been indexed on European gas hubs since the renegotiations between GasTerra and European buyers. These renegotiations involve not only a change in the indexation formula, but also in the structure of contracts. Flexibility is no longer part of the new contracts indexed on gas hubs and must now be purchased on the markets.

Flexibility

One of the strengths of the Groningen field is its high production flexibility. This flexibility is compromised by the current and future reduction of production. In a report on the impact of production by Groningen on seismic activity, the State Supervision of Mines observed that "the highest magnitude earthquakes seem to occur with a delay of six to nine months, after a peak production period in winter". If this observation is verified by current surveys, it would undermine the flexibility provided by production adjustments of Groningen to fluctuations in demand. In early 2014, the Minister of Economic Affairs estimated that the Dutch network could face a reduction to 30 bcm per year, provided that the production of the field could fluctuate depending on demand. Pending results of further investigation, the production flexibility of Groningen is therefore uncertain, although it has already been reduced *de facto* by the production caps. This implies that the Netherlands and Europe must find other sources of flexibility. Natural gas storage and LNG imports are the two key ways of overcoming this reduction.

At European level (EU28), the working gas storage capacity reached 108 bcm (GSE) in April 2015, an increase of 27% on 2010, and a maximum withdrawal rate of 1,683 m^3 per day. This capacity is equal to 26% of consumption in 2014: almost 100 days of average consumption. Storage was underutilized in 2012 and 2013, but filling rates of storage were already high at the end of the winter 2013/14. These rates rose to 94% at the beginning of winter 2014/15 (1st November) as operators anticipated problems with Russian gas supplies. The underutilization of storage facilities was largely due to the fall of the spread in winter/summer gas prices (over €6/ MWh in 2008-09 but less than €2/MWh in 2013-14, which is far from sufficient to pay for the cost of storage).

FIGURE 13: THE EVOLUTION OF STORAGE CAPACITIES IN EUROPE (2010-2015)



Source: GSE

LNG regasification capacity in Europe is also now well-developed (see Chapter 2 and Appendix 2). Since 2009, capacity has increased by 57%, driven mainly by the Netherlands and the United Kingdom, and reached 195 bcm per year in January 2015. Regasification capacity can also make up for part of the reduction in flexibility, caused by the decline in Groningen production. Since the 4th quarter 2014, European LNG imports have been rising again, after having declined in the two previous years. These means should be sufficient to ensure security of supply and coverage of seasonal fluctuations in demand, despite the decline in production and the flexibility of Groningen. This assumes of course that operators continue to fill storage capacity and that the LNG price arbitrage continues to favor Europe.

Conclusion: an additional uncertainty

The Dutch government is seeking the most appropriate solutions to reconcile the need for the safety of inhabitants in the Groningen region, the security of gas supply in the Netherlands, and the respect of its contractual obligations towards its European customers. The Netherlands and Europe can cope with the reduced production of Groningen as presently envisaged (30 bcm per year), thanks to storage and LNG imports. But the scale of the reduction in total volumes and flexibility remain uncertain and raise many questions. These are related to the security of European gas supplies, the more or less rapid conversion to H-gas and the investment necessary for the conversion/replacement of infrastructure (volumes and flexibility). This uncertainty comes on top of that linked to Russian supplies, and generates increased volatility in European gas prices.

The Mixed Developments of Shale Gas

In a context marked by the desire to diversify and secure European gas supplies, shale gas stands out as a key asset, given that Europe is estimated to hold 13 trillion cubic meters (tcm) of such resources. The Communication of the European Commission on the Energy Union indeed calls for increasing domestic energy production. This includes the production of unconventional hydrocarbons for countries that have made this choice, provided that the problems linked to their acceptance by local populations and the environmental impact find appropriate solutions.

This chapter takes stock of the significant progress of the sector in Europe, since the last two notes published by the IFRI on this subject.[61] More specifically, it focuses on the possible impact of shale gas on security of gas supply in Europe.

Minimum principles applicable to shale gas

In January 2014, the Commission adopted a recommendation (not a directive) on the exploration and production (E&P) of shale oil and gas using a high rate of hydraulic fracturing.[62] This recommendation aims to ensure the implementation of appropriate measures for the protection of the environment and the climate. It introduces rules in the form of minimum principles for the sector, providing a clearer framework for investors. The recommendation adopted calls on Member States to:

- plan projects and assess the potential cumulative effects before issuing permits;
- assess rigorously the environmental impacts and associated risks;

61. Cornot-Gandolphe S., « Gaz de schiste en Pologne, au Royaume-Uni et au Danemark : vers un modèle européen ? », *Note de l'Ifri*, November 2013 and Parmigiani L., "Dynamics and drivers of shale gas development in three European countries: can a European policy be imagined?", *Actuelles de l'Ifri*, 17 November 2013.
62. European Commission, "Environment: the European Commission sets out minimal principles applicable to shale gas", 22 January 2014, available at: <http://europa.eu>.

- ensure that wells' integrity corresponds to the application of best practices;
- monitor locally the quality of water, air, soil before the start of activities in order to detect possible changes and to counter emerging risks;
- limit air emissions, including emissions of greenhouse gases, by capturing gas;
- inform the public of chemicals used in the various wells; and
- ensure that operators apply good practices throughout the project.

Member States were invited to apply the principles formulated within six months, starting in December 2014, and to inform the Commission annually of the measures they have taken. The Commission shall monitor the implementation of the recommendations using a scoreboard available to the public, to compare the situation in different Member States. It also plans to review the effectiveness of this approach in 2015.

The first Scoreboard was published in February 2015.[63] It shows that Europe is moving forward in small steps on this issue: only five countries (Denmark, the Netherlands, Poland, Romania and the United Kingdom) have allowed the award of exploration permits for shale gas; six other countries (Austria, Germany, Hungary, Lithuania, Portugal and Spain) are considering such authorizations; and three countries have banned hydraulic fracturing on their territory (France, Bulgaria and the Czech Republic). The other countries have not taken any specific action vis-à-vis shale gas and do not intend to do so.

Furthermore, in February 2014, two major associations in the sector, OGP (International Association of Oil & Gas Producers) and IPIECA (International Petroleum Industry Environmental Conservation Association) published good practice principles for the development of shale oil and gas.[64] These guidelines provide global principles for E&P activities, and provide advice on how the oil and gas industry can manage the risks associated with these activities. These principles include all areas related to the development of shale resources, including the protection of water and wastewater management, the integrity of wells, air emissions and the involvement of stakeholders.

63. See at: <https://ec.europa.eu>.
64. See at: <www.ogp.org.uk>.

Shale gas resources in Europe

Europe has significant potential resources of unconventional gas. The technically recoverable resources of shale gas were estimated by the American EIA in 2011, and reassessed in 2013.[65] The latest study estimates EU resources to be 13.3 tcm. A study by Pöyry Management Consulting (Pöyry) and Cambridge Econometrics (CE), on behalf of OGP, evaluates resources at between 8.1 tcm and 10.8 tcm.[66] This study is based not only on the research of the EIA, but also on studies conducted by national institutes of geology (in Poland and Germany, in particular) and taking into account technical and administrative barriers.

TABLE 3: TECHNICALLY RECOVERABLE RESOURCES OF SHALE GAS AND PROVEN RESERVES OF CONVENTIONAL GAS IN THE EU

	Proven reserves (bcm)	Technically recoverable resources (bcm)
	Conventional gas	Shale gas (EIA 2013)(EIA 2013)
Poland	99	4,190
France	10	3,880
Romania	295	1,444
Denmark	132	900
United Kingdom	531	740
Netherlands	1,327	740
Bulgaria	5	481
Germany	169	480
Sweden	0	280
Others	222	175
TOTAL EU	2,790	13,310

Source: BP, EIA.

The main resources are estimated to be located in Poland and France. But these estimates are based on simple volumetric calculations and remain imprecise. They must be viewed with caution. Only data acquired during exploration drilling will clarify the available resources. However, exploration activities are at an early stage (even non-existent in some countries) and more refined assessments are not available.

65. EIA (2013), "Technically recoverable shale oil and shale gas resources: an assessment of 137 shale formations in 41 countries outside the United States", EIA/DOE, Washington DC, June 2013.
66. See at: <www.poyry.co.uk>.
66. See at: <www.poyry.co.uk>.
67. See at: <http://pubs.usgs.gov>.

BOX 4: RESOURCES IN THE PARIS BASIN

The US Geological Survey (USGS) recently evaluated the potential of undiscovered and technically recoverable oil and gas resources and in the Paris Basin, where more than 35 conventional oil and gas fields have been discovered since the 1950s.[67] The results of the quantitative assessment of the USGS show that the Paris Basin contains on average 222 million barrels of unconventional oil and 2,092 billion cubic feet of unconventional gas (59 bcm). There are also smaller volumes of conventional oil and gas. The estimation ranges are large and reflect the geological uncertainty of the rock trapping systems. Based on the latest estimates of recovery, potential areas, drainage areas and drilling success rates, the USGS estimates that about 6,400 wells with hydraulic fracturing would be needed, on average, to exploit the oil and gas resources in the Paris Basin.[68]

Recent developments in Europe

European countries have very different approaches vis-à-vis the E&P of shale gas. Some encourage the development of these resources, while others have banned hydraulic fracturing. Among the five countries (Denmark, Netherlands, Poland, Romania and the United Kingdom) that have awarded exploration licenses, Poland, the UK and Denmark are the most advanced. Yet even in these countries, exploration of shale gas is still in its infancy. No commercial production of shale gas has yet been achieved in Europe.

Poland is the country with the greatest potential. The EIA had initially estimated the technically recoverable resources at 5.3 tcm. The update in 2013, based on improved geological information, reduced this level to 4.2 tcm. The Polish Institute of Geology has evaluated these resources at between 346 bcm and 768 bcm. The current level of exploration has not yet allowed better specification of these values. But initial explorations of wells have been disappointing and indicate that the rock is more difficult to exploit than in the US. Furthermore, the absence, until 2014, of a clear regulatory framework has prompted some operators to stop their activities related to shale gas in this country. The decline in crude oil prices also played a role: US companies have reduced their CAPEX and have refocused their efforts on their market. Chevron thus recently announced its withdrawal from the shale gas business in Poland, Romania, Lithuania and Ukraine. In total, eight of the 11 international companies that operated in Poland – including Chevron, Exxon, Talisman, Marathon, Eni and Total – have withdrawn from the sector. The exploration of shale resources is now being continued by the Polish companies, primarily by the national company PGNiG and independent companies. The withdrawal of international companies

67. See at: <http://pubs.usgs.gov>.
68. In other words 200 to 300 pads.

risks limiting investment in the area. Since 2010 and until the end of 2014, 70 exploration wells were drilled, including 16 horizontal wells and 54 vertical wells. Hydraulic fracturing was performed in 25 wells (37% of all the wells drilled). Exploration has slowed markedly in the last two years. While 24 wells had been drilled in 2012, only 14 and 15 wells were drilled in 2013 and 2014 respectively. On 1 April 2015, there were 47 exploration and/or evaluation concessions for shale gas (compared to 100 in early 2010). These concessions were allocated to 14 companies (including 11 held by PGNiG, eight by Orlen Upstream and seven by Lotos SA Petrobaltic).

The legal framework of shale gas E&P was clarified in 2014. In order to encourage the exploration of shale gas, the Polish government has established favorable regulations, which provide, *inter alia*, a tax exemption on extraction until the end of 2020, and thereafter a tax rate limited to 40% at the most. In August 2014, Poland changed its geological and mining law of 2011, to streamline procedures for granting licenses while strengthening supervisory powers. The idea of creating a state-owned entity – a national operator of fossil fuels (NOKE) – was finally set aside by the government. Environmental procedures have been simplified. The Polish government hopes that this new legislation will facilitate the E&P of shale gas in the country, and will encourage operators to invest in Poland. Following this new law, the European Commission has started legal proceedings against Poland, on the grounds that the law does not comply with the Directive on the assessment of the environmental impact drilling. This is because the law allows drilling to depths of up to 5,000 meters without the potential impact on the environment being assessed. A majority of Poles support the exploitation of shale gas, which they consider strategic to reduce dependency on Russian gas.

In the UK, E&P for shale gas is continuing. The government (former and newly elected) favors its development, seeing shale gas as a source of income and jobs, as conventional oil and gas are in decline. Public opinion is more divided on the issue.[69] In order to accelerate the exploitation of shale gas, the British government announced in August 2015 that it was going to deliver a series of shale gas exploration licenses covering 27 blocks, with a total area of 2,700 km^2. Most are in the north of England. In all, 95 candidates (from 47 companies) have applied for these licenses. The companies include Engie, IGAS, Ineos, Cuadrilla Resources and Egdon Resources. The official attribution of licenses should take place by the end of 2015.[70]

69. A survey by Greenpeace in March 2015 showed that 42% of respondents support such activity, while 35% are against it.
70. Pétrostratégies, « Le Royaume-Uni va accorder 27 licences d'exploration dans les schistes », 31 August 2015.

So far only seven shale gas wells have been drilled in Lancashire and Cheshire. This relatively small number is mainly due to the introduction of new rules in previous years and in early 2015. It should be recalled that the exploration of shale gas in the United Kingdom was suspended in May 2011, following micro-seismic activity after hydraulic fracturing. After studies and recommendations by the Royal Society and the Royal Academy of Engineering, the government lifted the temporary ban in December 2012 and implemented strict regulation of the activity, including the creation of a new office dedicated to the development of unconventional oil and gas (UKOOG). The government also passed legislation encouraging activity, including a tax break for the E&P of shale gas and incentives for local communities. In February 2015, the government adopted the Infrastructure Act 2015, which put an end to uncertainty about the use of hydraulic fracturing in the UK. However, Scotland and Wales have banned fracturing on their territories. The 2015 Act authorizes the use of land to a level of 300 meters or less for the extraction of energy, including by hydraulic fracturing, while it prevents activities in protected areas. An assessment of the impact on the environment and an independent inspection of wells' integrity must be performed before licenses can be granted.

Although there are still obstacles, and in particular the mixed support of local communities, interest in UK shale gas is high. Major players (Total, Engie and Centrica) have entered the sector in partnership with the independent producers present in the UK (Cuadrilla, IGAS, Third Energy and Celtic Energy). Moreover, Ineos, owner of the Grangemouth petrochemical refinery in Scotland, has recently signed an agreement with IGAS. Under this agreement, the Swiss company acquired 50% of the mining rights of IGAS in the seven exploration licenses in the Bowland Basin, the most promising area. The British Geological Survey (BGS) estimated gas resources of the basin to be up to 38 tcm. By assuming a 10% recovery rate, these resources would cover gas demand in the UK (67 bcm in 2014) for 57 years. According to the industry, it will take five years and the drilling of 30 to 40 fracturing wells to judge whether the UK has a viable shale gas industry. According to a report by Ernst & Young (EY), published in April 2014, an investment of £33 billion is needed to develop the shale gas industry in the UK.[71] In particular, this would involve drilling 4,000 wells (with 200 pads) over a period of 18 years. Potentially, 64,000 new jobs could be created (direct, indirect and induced).

The decline in the price of oil (and gas) should not affect this development: the commercial production is not expected in the immediate future and the decisions taken today are probably not based on current oil or gas prices, but on the expected gas demand over the next 20 to 40 years. Cuadrilla, which plans to drill eight wells in 2015, has indicated that the oil price fall and the slowdown in North

71. See at: <www.ey.com>.

Sea production should lead to a very significant drop in the costs of services. Thus, the current price of oil is less relevant for this nascent industry than the regulatory framework and support from local communities.

In **Denmark**, Total is the only company exploring shale gas. The oil company acquired two exploration concessions in 2010, for a period of six years: one in the north (the North Jutland region) and the second near Copenhagen (the North Zealand region). Total is the operator and holds 80% of the stake. The remaining 20% is held by the national oil company Nordsøfonden. The geological appraisal studies undertaken in 2013/14 on the concession of the North Zealand region did not confirm the characteristics necessary for economic production of shale gas and Total intends dropping the concession. In the North Jutland region, the first well began working in early May 2015, but did not yield significant results: shale gas is there indeed, but not in sufficient quantity and Total is considering stopping the exploration.[72] This well was initially scheduled for 2013, but was delayed by a request from the Council of Frederikshavn (the competent local authority for licenses in North Jutland) that a full environmental study (VVM in Danish) is carried out prior to drilling. Though such a VVM is not required in Denmark for onshore exploration, Total and Nordsøfonden did not appeal the decision and undertook the study. It was published in February 2014 and approved in June 2014.

In the **Netherlands**, the exploration of shale gas has been suspended, pending a report (scheduled for late 2015) on its environmental and social impacts.

Romania, in 2013, lifted the ban on E&P for shale gas which it had introduced a year earlier, and the government supports its development. But Chevron, which had begun exploratory work, withdrew from the sector in early 2015, undermining the development of shale gas in the short term.

The **Spanish Government** also supports the development of shale gas. About 70 exploration licenses (for all types of hydrocarbons) have been awarded, and 75 are awaiting authorization, according to the Spanish Oil and Gas Association (ACIEP). The shale gas resources are mostly located in northern Spain. In 2013, the Cantabria region banned hydraulic fracturing, but the Spanish Constitutional Court declared this ban unconstitutional in June 2014. BNK Espana intends to invest €250 million in the resource assessment of shale gas in six sites on its licenses in Urraca y Sedano, north of Burgos. A study of the economic potential of shale gas in Spain suggests the country could become

72. Euractiv, « Total jette l'éponge sur son projet gaz de schiste au Danemark », 19 August 2015, available at: <www.euractiv.fr>.

independent from gas imports by 2030 (net imports amounted to 25 bcm in 2014).

In **Germany**, unlike France, shale gas is no longer taboo. New legislation, adopted in April 2015, authorizes the use of hydraulic fracturing for the exploitation of unconventional gas. But it prohibits use of hydraulic fracturing at depths less than/ 3,000 meters and in some protected areas, except authorizations for exploratory tests.

Lithuania is currently defining regulations on shale gas that are more "investor friendly". Chevron, which won a tender to explore for shale gas in the country, withdrew from the sector citing an uncertain legal framework.

Forecasts for the production and macroeconomic contribution of shale gas

Possible production in Europe

As shale gas in Europe is still in the exploratory stage, it is difficult to estimate future production. The IEA publication of 2012 ("Golden rules for a golden age of gas") foresaw that it would be possible to produce 78 bcm in the EU (the total of all unconventional gas). However, the latest World Energy Outlook (November 2014) envisages a production of only 17 bcm in 2040. BP shares this view in its forecasts (Energy Outlook 2035), published in February 2015.

The study by Pöyry and CE published at the end of 2013 offers an extensive view of the possible contribution of shale gas to Europe's gas supply and to the European economy.[73] The study identifies two potential production scenarios in Europe.[74] It also compares them to a scenario without the production of shale gas. This makes it possible to assess the macroeconomic impact of shale gas. In the first "Some shale" scenario, production reaches about 60 Bcm in 2035. In the second "Shale boom" scenario, it rises to about 150 bcm. The large difference between these forecasts reflects the high degree of uncertainty surrounding shale gas in Europe.

The contribution to the European economy

The scenarios of Pöyry and CE are then compared to the "without shale gas" scenario. The study suggests that between 400,000 and 800,000 new jobs could be created in the sector and related activities by 2035, rising to between 600,000 and 1.1 million in 2050. In addition, shale gas could contribute up to €1,700 billion and €3,800 billion to the European economy between 2020 and 2050. The impact

73. *Op. cit.*, see at: <www.poyry.co.uk>.
74. These scenarios are based on different assumptions about recoverable resources. The authors take environmental, regulatory and technical obstacles into account. Their output scenarios are derived from the analysis of production costs for shale gas relative to other supply sources.

on Europe's annual economic growth by 2035 is 0.3% in the "Some shale" scenario and 0.8% in the "Shale boom" scenario.

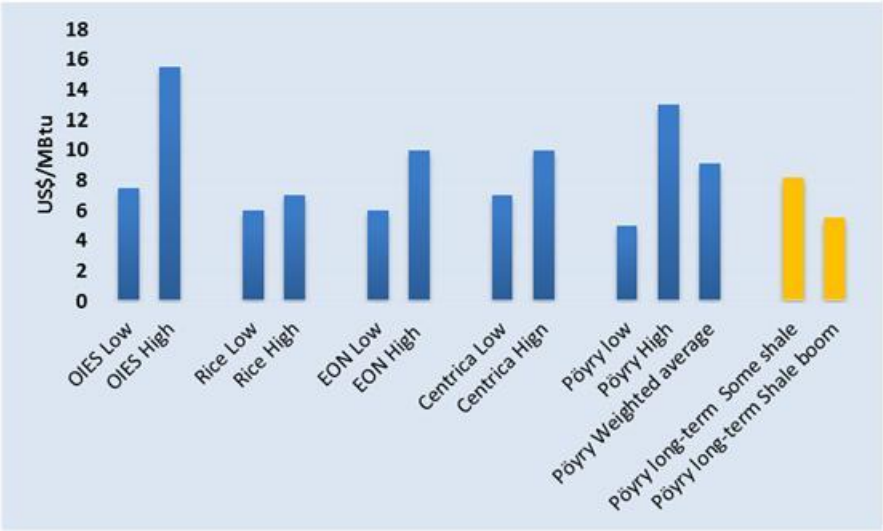
The study also shows that production of shale gas in both scenarios would not contribute substantially to a reduction in the wholesale gas price, as has been observed in the United States. On average over the period 2020-2050, the production of shale gas leads to a reduction in the price of gas by 6.2% in the "Some shale" scenario, and by 13.8% in the "Shale boom" scenario. These price falls are not negligible. But they reveal that the expected benefits of the development of shale gas in Europe are linked to other macroeconomic effects: reductions in imports and improvements in gas trade balances; increased security of supply; job creation, increased value added and taxes in the economies concerned. It should be stressed, however, that even a moderate decrease in gas prices – and a stronger bargaining position towards non-EU gas suppliers – would benefit EU countries, particularly those that are highly dependent on imports. It would also help consumers and businesses, especially in energy-intensive industries.

BOX 5: COST UNCERTAINTIES OF SHALE GAS IN EUROPE

A key uncertainty is the cost of shale gas in Europe. As commercial production has not yet started, only indicative costs can be given. The IEA provides a wide range of forecasts, from $5/Mbtu to $10/MBtu, according to basins and operating conditions.[75] The Pöyry and CE study provides cost estimates calculated by different operators and think-tanks, as well as estimates by Pöyry for current and long term production costs. Although costs can only be indicative at this stage, these estimates show two important results: current average production costs are certainly high ($9.1/MBtu), but the spread is large, with estimates for the lowest costs at $5/MBtu, a level that makes production very profitable even at current prices. Moreover, costs are expected to decline over the long term, as technologies become more mature and efficient. Pöyry estimates costs will be between $5.5 and $8.2/MBtu in the long term (2035-2050), depending on the assumptions made about future production.

75. IEA (2012), *op. cit*.

FIGURE 14: ESTIMATION OF SHALE GAS PRODUCTION COSTS IN EUROPE: CURRENT AND LONG TERM

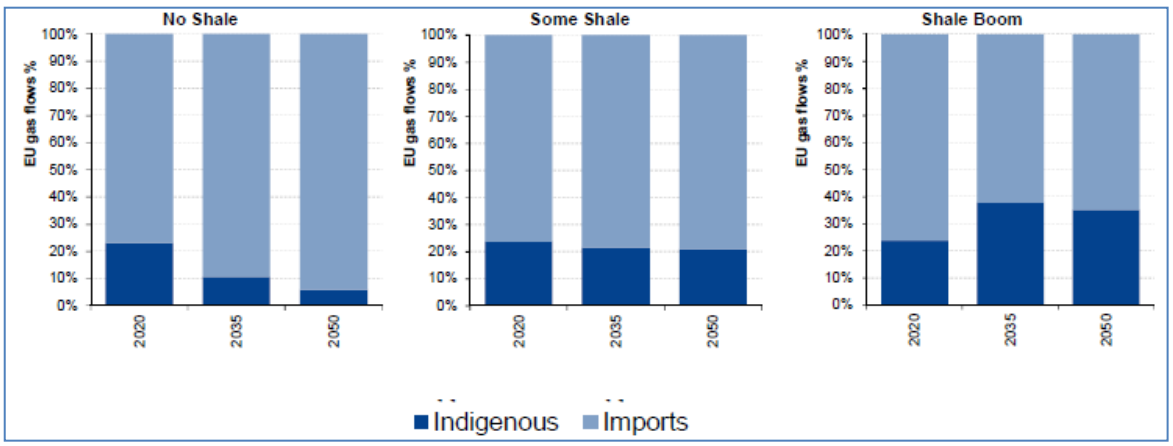


Source: Pöyry/CE

The contribution to the security of gas supplies

Shale gas can contribute to security and diversity of European gas supplies by increasing domestic sources. It can also help to offset the decline in the European production of conventional gas. The study by Pöyry and CE shows that the dependency on imports could be reduced to 62% in 2035 in the "Shale boom" scenario, compared to 90% with no shale gas. In the "Some shale" scenario, European shale gas production could compensate for the decline in domestic production and limit the dependency of the EU vis-à-vis external suppliers to 78%. The impact on the trade balance is very significant: it could represent a reduction in gas bills for the EU28 of €15.6 billion per year on average, and €484 billion over the period (under the "Some shale" scenario).

FIGURE 15: EU GAS INDEPENDENCE



Source: Pöyry/CE

The challenge of social acceptability

The development of shale gas in Europe depends largely on how regulatory, economic and social issues are treated.[76] European opinion is still divided and strongly so on shale gas. Thus, in a vote in May 2015 by the Committee on Industry, Research and Energy (ITRE) of the EPP Group in the European Parliament (responsible for the report on energy security), an amendment to introduce a moratorium on fracking in Europe received as many votes for as against.

As one leading report of the European Academy of Sciences (EASAC) highlighted in November 2014, there are three possible impacts associated with the production of shale gas, which are more specific to Europe than other parts of the world. These are: the territorial footprint and use of water; the emissions of greenhouse gases; and the social acceptability of shale gas. All three dominate debate in Europe. The EASAC report concluded that its analysis does not provide any scientific and technical basis for prohibiting the exploration of shale gas or its extraction using hydraulic fracturing. The Academy supported calls for the effective regulation of the activity and called for the development of pilot projects in Europe, which are needed to demonstrate and test best practices, while allowing close monitoring by the authorities.

Conclusion: Europe is divided on the shale gas question

The knowledge about hydraulic fracturing has been greatly enriched now that the activity has a production history of nearly ten years in the United States, which is about to become gas exporter thanks to shale gas revolution. Yet despite the exploration effort in some European countries since the end of the last decade (especially Poland), the new regulations implemented by the governments concerned; the minimum principles for E&P adopted by the European Commission; and the principles of good practices developed by the industry, the outlook for the development of shale gas in Europe is mixed and does not suggest that an American-style revolution will occur. This finding was clear at the beginning of exploration in Europe. But after five years of effort and controversy in many countries, it must be noted that enthusiasm for shale gas has evaporated, with some notable exceptions, including the UK. Europe remains divided between countries opposed to hydraulic fracturing and those which consider shale gas as a possible source of diversification and energy independence, job creation and added value.

76. Voir sur ce sujet la note d'Insight E, Nagy S. *et al*., "Shale gas prospects for Europe", Hot Energy Topic, Insight_E, October 2014, available at: <www.insightenergy.org>.

Trust in the operating companies is of crucial importance for the social acceptance of projects. This trust can only be built if concrete projects are developed, proving the technological solidity and reliability of operations and their operators. Otherwise, Europe risks to miss out on a technological revolution which could bring it some respite in the search for energy independence.

European Gas Demand Continues to Fall

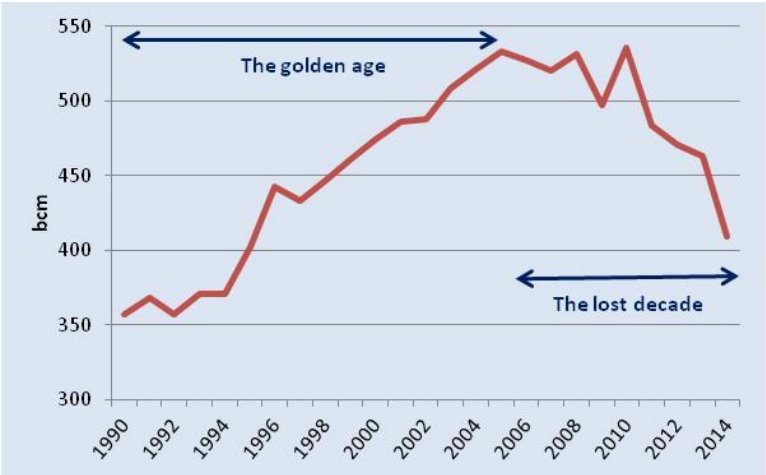
The consumption of natural gas in Europe has been declining since 2010. Natural gas has lost its competitiveness vis-à-vis coal in the power sector, electricity demand is stagnating and renewable energy sources are taking an ever bigger market share. The IEA predicts that the level of gas consumption in 2010 will not be reached again before 2035. Gas in Europe has become a great forgotten energy issue, while consumption has continued to increase in other parts of the world.

European demand at its lowest since 1995

In 2014, EU gas consumption fell for the fourth consecutive year, due mainly to weather conditions, the limited recovery of the European economy and the low competitiveness of gas in the electricity sector. Down by 11%, consumption amounted to 409 bcm (Eurogas, 2015). This was the lowest level since 1995 and represented a fall of 126 bcm compared to 2010. In 2014, natural gas only provided 21.6% of European energy needs, compared to 25.4% in 2010 (BP, June 2015).

FIGURE 16: EVOLUTION OF EUROPEAN GAS CONSUMPTION

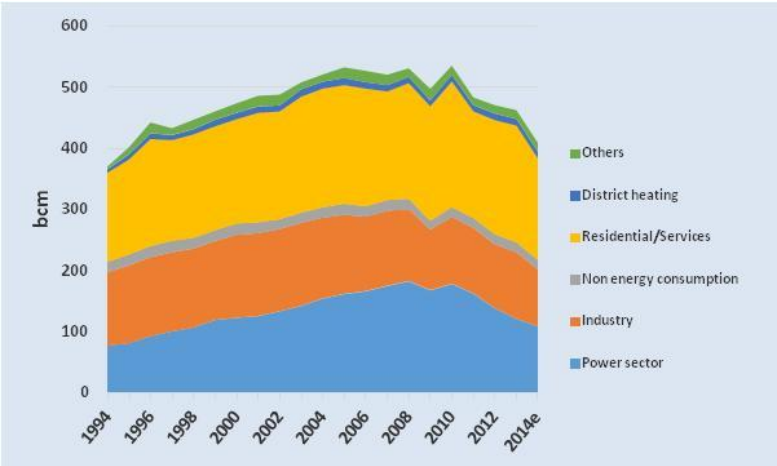
(1990-2014)



Source: Eurostat, Eurogas

The residential/tertiary sector represents 42% of European gas demand, while industry (including petrochemicals) accounts for 27% of demand and the electricity sector 26%. The drop in demand is due to structural and cyclical phenomena. The power sector recorded its largest decline in four years, with stagnation in electricity demand, the rapid development of renewables and the loss of natural gas competitiveness vis-à-vis coal. The needs of the industrial sector have also stagnated in line with the weak economic growth in Europe. In addition, the winter of 2013/2014 was very mild, compared to the very cold winter of 2012/2013. As a result, the heating needs of the residential/commercial sector fell, as did the demand for electricity.

FIGURE 17: EVOLUTION OF EUROPEAN DEMAND BY MAJOR SECTOR (1994-2014)



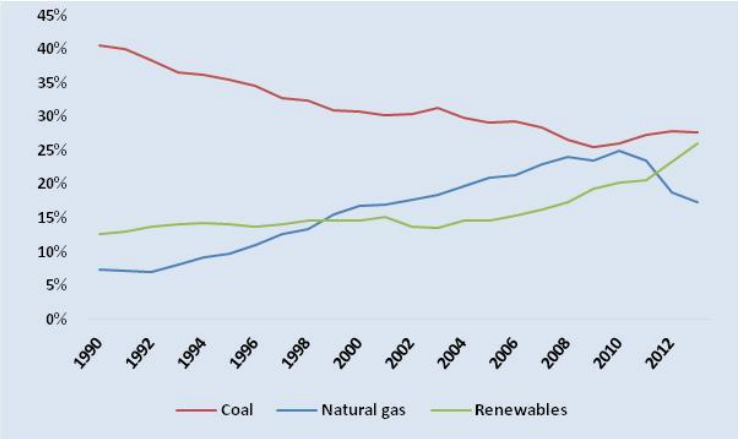
Source: EUROSTAT, 2014 estimations

Natural gas has lost its competitiveness over coal

The share of gas in the production of European electricity grew steadily until 2010, rising from 7.4% in 1990, to 15.8% in 2000, and on to 22.6% in 2010. Since 2011, however, gas demand by the sector has fallen sharply, despite the advantages of gas in power generation, including: high thermal efficiency (about 60% for the latest combined cycle power plants (CCGT) compared to 43%-45% for coal), CO_L emissions that are less than half those of coal, lower capital costs for gas power stations and the possibility to build modular units. Gas plants also offer more flexibility than coal plants in adapting their production to the needs of increased variability in the electricity system, coming from the increase of intermittent sources of electricity generation (wind and photovoltaic power). Yet despite its many advantages, gas has become less competitive vis-à-vis coal, which offers lower fuel costs. The share of gas in European electricity generation was only 18% in 2012, and dropped to 16% in 2013 (EURELECTRIC, 2015). The share of coal, which has been falling

since 1990, has instead risen since 2010, to reach 28% of European electricity generation. This situation was such that it was possible to speak of a “return of coal”, but coal consumption slowed down in 2013 and fell in 2014. Given the rise of renewable energy sources (27% in 2013), the share of conventional electricity generation is declining.

FIGURE 18 : THE CONTRIBUTIONS OF NATURAL GAS, COAL AND RENEWABLE ENERGY SOURCES IN EUROPE’S ELECTRICITY BALANCE (1993-2013)



Source: EUROSTAT, EURELECTRIC

Between 2010 and 2013, gas demand of European power producers fell by 58 bcm, corresponding to a third of its historical level. This represents a reduction that is greater than the entire French gas market. By contrast, the power sector’s demand for coal increased by 10% between 2010 and 2012. But it then declined by 5% in 2013. These developments have put an end to the downward trend in CO_L emissions in the power sector in some key countries, despite the rapid increase in renewable energy sources. Initial figures for 2014 indicate a further drop in gas supplies to power stations, with, for example, a 42% decrease in deliveries in France. Though the demand for gas in the power sector fell at the European level, it increased in the UK by 8% in 2014. The UK government introduced a carbon tax in April 2013, paid in addition to CO_L market prices. This tax, which aims to counter the low price of CO_L, amounted to £4.94 per tonne when it was introduced. It increased to £9.55 per tonne in April 2014 and to £18.08 per tonne in April 2015 (i.e. €25 per tonne). Since gas emits less CO_L than coal (about 0.206 tonne of CO_L per MWh for gas compared to 0.343 tonne for coal), this tax has had the effect of penalizing coal more, and thereby making natural gas more competitive.

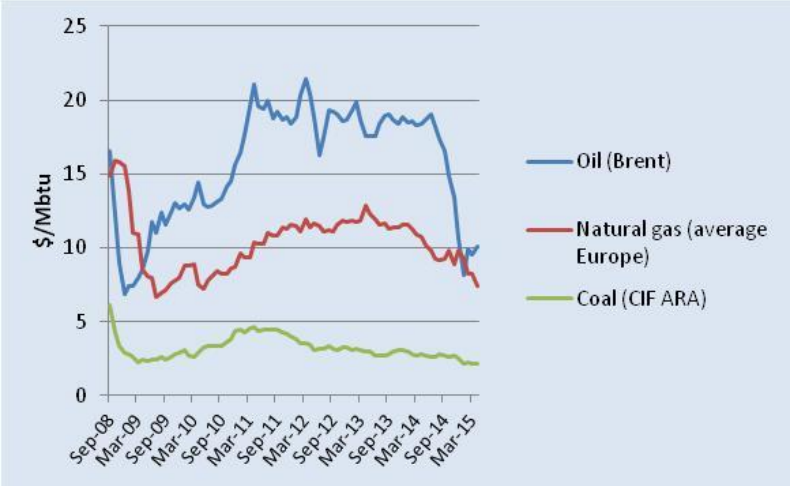
TABLE 4: EVOLUTION OF GAS DEMAND IN THE POWER SECTOR (MAJOR MARKETS IN WESTERN EUROPE, 2008-2014)

bcm	2008	2009	2010	2011	2012	2013	2014
Italy	33.4	28.7	29.8	27.5	24.2	20.1	16.8
United Kingdom	24.8	23.1	25.3	19.5	13.2	13.1	14.2
Spain	16	13.7	11.6	9.4	7.2	4.8	4.4
Belgium	n.d.	n.d.	n.d.	7.1	8.4	7.4	6.4
France	n.d.	n.d.	2.2	2.5	1.5	1.2	0.7
Germany	15.3	13.9	14.7	13.8	12.6	11.0	9
Netherlands	8.6	9.4	10.2	8.8	6.8	6.8	6.3

Source: European Commission, CBS, ag-energibilanzen

The relationships between the prices of coal, gas and CO_L are a key factor determining the substitution between gas and coal in the power sector. Since 2010, the relative change in gas and coal prices has led to a loss of competitiveness of gas, reinforced by the collapse of the CO_L price. The price of coal imported into Europe has fallen sharply (down from $125 per tonne in early 2011 to about $80 per tonne in 2013). In contrast, the price of imported gas to Europe has increased ($9.5/MBtu to $11.8/MBtu). In energy equivalence, coal was four times cheaper than gas in 2013. The competitiveness of coal has also been reinforced by falling prices of CO_L allowances, which dropped from €14.3 per tonne in 2010, to €4.5 per tonne in 2013. The situation was similar in 2014 and early 2015. Coal plants are still more profitable than gas-fired power plants despite larger falls in gas prices than for coal (due to low demand and excess supply, compounded by falling oil prices since mid-2014), and a rise in the price of CO_L (€7 per tonne in July 2015). Coal is still more than three times less expensive than natural gas in energy equivalence, as its price dropped to less than $60 per tonne in mid-2015.

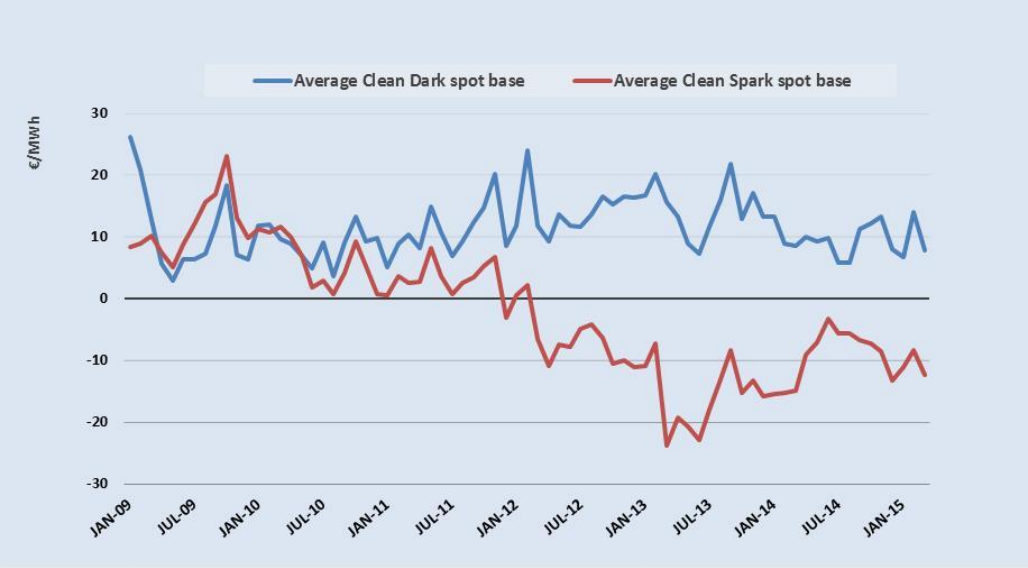
FIGURE 19: COMPARISON OF FOSSIL FUELS PRICES OF IN EUROPE (2008-2015)



Source: World Bank, Mc Closkey

The *clean spark spread* measures the profitability of gas power plants, and represents the difference between the wholesale market price of electricity and the variable cost of production, including the cost of CO_L. This spread has been negative since 2012. Conversely, due to lower coal prices and the collapse of CO_L prices, the *clean dark spread* (the measure of the profitability of coal power plants) remained positive (despite lower wholesale electricity prices), although it did fall in 2014/2015. The loss of profitability in gas-fired power plants has plunged the sector into a deep crisis.

FIGURE 20: CLEAN DARK SPREADS AND CLEAN SPARK SPREADS IN GERMANY (2009-2015)



Source: Tendances Carbone CDC Climat Recherche, Thomson Reuters

In 2014, with the adoption of short-term measures (*backloading*), and the European Council's definition of a clear regulatory framework giving a central role to the EU Emissions Trading System, as well as the establishment of an instrument aiming to stabilize the market, the European Commission and the Council hope to correct the current shortcomings of the carbon market and to promote an effective market.[77] This market should provide a robust price signal for future investment in the electricity sector, which should help to achieve the objective of a 40% reduction in CO_L

77. Following years of low economic growth and a generous distribution of allowances, there is a surplus of 2 million CO_L allowances which is preventing the European carbon market from functioning effectively and from sending price signals to operators to invest in low carbon-emitting technologies. As of 2019, the Market Stability Reserve (MSR) will strive to provide the European trading scheme of allowances with an automatic adjustment mechanism in supply relative to demand, allowing prices to adjust less violently in the wake of demand shocks.

emissions by 2030, in line with the new European commitment.[78] However, CO_L prices have only been approximately €7 per tonne since the beginning of 2015, whereas a level above €40 per tonne is needed to encourage the substitution of coal by gas, given the energy prices observed in July 2015. Yet such a CO_L price level is neither achievable nor desirable in the short term.

Renewable energy sources are pushing natural gas out of the electricity system

Beyond its loss of vis-à-vis more competitive coal, natural gas is a victim of the rapid deployment of renewable energy sources. The European electricity mix is undergoing profound change towards a decarbonized system, in which renewables occupy a key position. Since the adoption in 2009 of the energy-climate framework for 2020, investment in renewable energy sources has grown strongly (€470 billion in 2010-2013). In 2013, renewable energy sources thus provided 27% of European electricity generation, compared to 20% in 2010.

Renewables have generally benefited from guaranteed purchase prices (feed-in tariffs, or FITs). Moreover, their production has priority dispatch into the power grid. This mechanism has the effect of pushing out energy sources with the highest variable costs, and natural gas in particular, from the electricity system (applying the logic known as the *merit order*). Gas-fired power plants therefore are used only a few hours per year, meaning that they are no longer profitable. In Spain, for example, the average operating rate of CCGTs was historically over 50%, but by 2013 it had plunged to 11%. In Germany, the rate dropped to 21%. The low use of gas-fired power plants no longer allows operators to make profits on their assets. This loss of profitability is accentuated by the decline in wholesale electricity prices. Renewable energy sources have low or zero marginal costs. As a result, their rapid increase means that, most often, electricity prices are set by energy sources with low marginal costs. This prevents gas-fired power operators from recovering their fixed costs, and in some cases, even their operating costs (the so-called *missing money* problem).

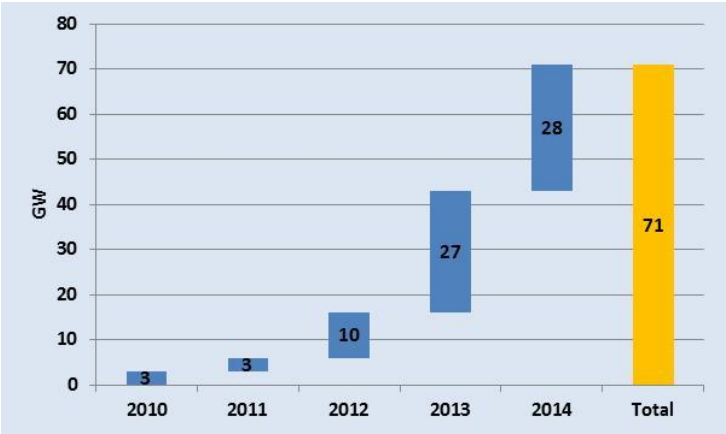
78. Based on the objectives set for 2020 by the previous energy-climate package and the roadmap for energy through to 2050, the Heads of State and Government of the EU adopted new goals for 2030, in October 2014. These are to establish "competitive, secure and low-carbon EU economy". They include: a reduction of at least 40% of emissions of greenhouse gases compared to 1990 levels; a share of at least 27% of renewable energies to achieved at the European level; an improvement of energy efficiency by 27% (against 30% originally envisaged); and a target of 15% interconnection between European energy networks.

Yet, wind and photovoltaic electricity is intermittent, and there is a need for back-up power plants, usually using natural gas. It is also necessary to adapt means of electricity production to the intermittency of renewables. Again, it is usually flexible gas plants that allow such adaptation. But, although they are necessary to the rapid deployment of renewable energy sources, the current system does not allow gas-fired power plants to operate profitably and so has led to massive closures of capacity. In late 2013, gas-fired power plants that were mothballed, closed or at risk of closure, had a combined power capacity of 24.7 GW, or 14% of the gas-fired power capacity installed in the EU. They were mainly in north-western Europe. The first plant closures did indeed affect older plants. But the deterioration in market conditions has led operators to mothball new plants, even when they have very high thermal efficiencies. If all the gas-fired power plants threatened with closure do actually close, then this would lead to a drop in installed capacity of about 50 GW by 2015-2016. But at the same time, this capacity is necessary to ensure the safety of electricity supplies.

Coal plants have so far been relatively spared, due to the low prices of coal and CO_L. But, the expansion of renewables and lower wholesale electricity prices are now eroding their profitability too. This trend is reinforced by European regulations for air quality: the Large Combustion Plants Directive (LCPD) limits emissions of local pollutants; and the Industrial Emissions Directive (IED) that will succeed the LCPD on 1st January 2016. For older coal plants (40% of the fleet is over 40 years old), there is no financial incentive to invest in pollution control equipment and about 50-55 GW of capacity could close by 2020/2023 at the latest, in addition to 16 GW already closed by the end of 2015.

In 2014, despite the slowdown in renewable energy development and revision of the FITs in a number of countries to limit the cost of subsidies to renewables, the mothballing and closure of thermal plants have accelerated, reaching 28 GW (UBS, 2015). This means that a total capacity of about 70 GW has been closed since 2010.

FIGURE 21: GAS-FIRED AND COAL-FIRED CAPACITY MOTHBALLED OR CLOSED IN THE EU (2010-2014)



Source: UBS

Beyond 2014, about 120 GW of thermal capacity could close in the coming years, representing almost 30% of the EU's thermal capacity. These closures are a serious challenge to the security of electricity supply. The rapid expansion of renewables requires the strengthening of flexible production capacity, but current market signals do not permit investment in these capacities. This could lead to a major structural crisis.

The need for a new market design

- Thirty years of liberalization of the electricity and gas markets, despite efficiency gains and increased competition, have failed to produce better results than regulated systems in terms of investment, security of supply and environmental performance. As the market does not provide the signals needed for investment in the required capacities and flexibilities, a new market design needs to be defined. Awareness of the present European paradox – increased coal consumption and a reduction of gas demand in the power sector – has started to shift European and national energy policies. To address the immediate problem of security of electricity supplies, many EU countries are introducing capacity markets intended to provide additional financial incentives for investors and ensure that capacity for security of supply is available. The design of such mechanisms is however very complicated, and requires:

- determining the capacity needed in view of ensuring security of supply without compromising the options for demand-response at a higher price;

- integrating interconnection capacities and development of cross-border trades in order to achieve an EU internal market.

Other mechanisms are also being put forward, such as long-term contracts for capacity development. These mechanisms respond only to the immediate concerns however, namely to ensure security of supply. A more far-reaching reform of the power system will nevertheless be necessary, including a structural reform of the European CO_L allowances trading system to ensure the functioning of the market. The further liberalization of gas markets and the diversification of supply (aided by the launching in February 2015 of the Energy Union and an investment plan of €1,000 billion over five years), should allow gas prices to be determined solely by market fundamentals, enhance market liquidity, and allow electricity producers to access supplies directly in the market. These are necessary conditions for the use of gas in the electricity sector.

Future levels of consumption are still uncertain

While the new 2030 climate and energy framework is being put in place, regulatory uncertainties still weigh on the European power sector. These make gas consumption forecasts by the power sector difficult, and therefore also forecasts of total European gas demand. The demand forecasts of the IEA *World Energy Outlook* 2014 illustrate these uncertainties. Global gas demand is set to increase in all scenarios (5,400 bcm in the *New Policies Scenario*).[79] Gas is likely to become the second energy source by 2040 (24% of the global energy mix), dethroning coal. Projections for Europe, however, are much more mixed and include a wide range of uncertainty, according to the energy and climate policies adopted, but also depending on the success of their implementation.

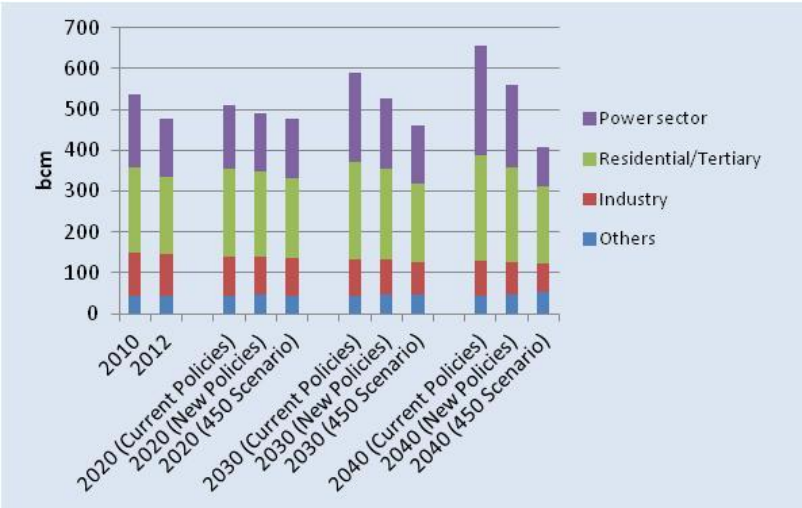
In the *New Policies Scenario* – the IEA's central scenario – EU gas consumption will only regain its 2010 level in 2035, which will then be 546 bcm. This will be driven by demand growth for electricity generation, made possible by the rise in the price of CO_L (to $30 per tonne in 2025 and $50 per tonne in 2040), and the replacement of the aging fleet of coal and nuclear power plants. In other consuming sectors, the demand for gas increases in the residential/tertiary sector, through the substitution of petroleum products. On the other hand, consumption in the industrial sector decreases, due to

79. The IEA sets out three scenarios:
The *Current Policies Scenario* takes into account energy and climate policies adopted in mid-2014.
The *New Policies Scenario* takes into account the energy and climate policies adopted in mid-2014, as well as policies put forward.
The *450 scenario* defines an energy path with a 50% chance of leading to long term climate warming limited to 2°C compared to the pre-industrial era.

moderate growth in European economic activity, efficiency gains and increased competition from other regions with lower energy costs. Only the transport sector is set to experience a significant increase in its gas demand. But this sector is only a very small part of demand in the central scenario of the IEA. Transport could, however, be a significant new market for gas demand in Europe. A study by the Oxford Institute for Energy Studies (Le Fevre, 2014) estimates that the demand for gas in the transport sector in Europe (compressed natural gas and LNG) could reach 41 bcm in 2025 in a central scenario, and up to 88 bcm in a favorable scenario

The IEA points to two major uncertainties that could reduce demand for European gas: the incomplete implementation of the 2030 climate and energy package, and potential actions taken to reduce dependence vis-à-vis Russian gas. Further uncertainties are related to the evolution of energy prices. Thus, the three scenarios of future demand differ widely. In the *New Policies Scenario*, gas provides 30% of EU energy demand in 2040 (with a consumption of 559 bcm, this is only 4.4% higher than in 2010); 24% in the *450 scenario* (with a consumption of 407 bcm, which is 24% lower than in 2010); and 33% in the *Current Policies Scenario* (with a consumption of 657 bcm, or 23% higher than in 2010). The main difference between the scenarios is derived from the demand for gas in the electricity sector, and to a lesser extent, the residential/ commercial sector, whose consumption is limited in the *450 scenario* by improved energy efficiency and the increased use of renewables (including biogas).

FIGURE 22: DEMAND FOR NATURAL GAS IN THE EU BY MAJOR SECTORS AND SCENARIOS (2010-2040)

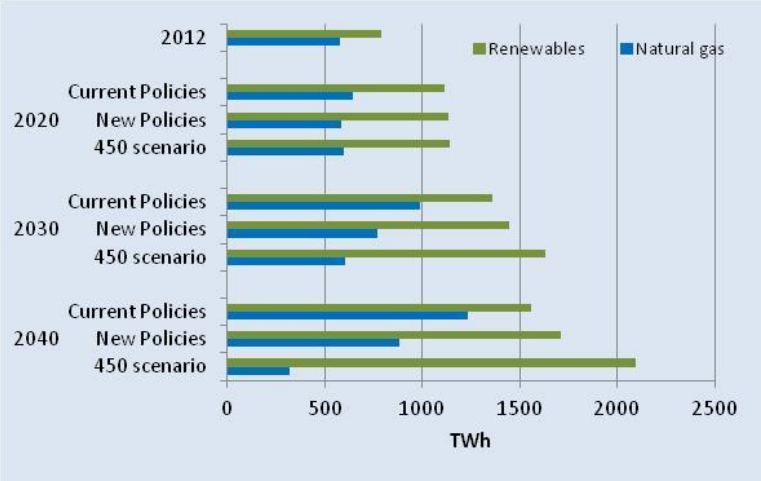


Source: WEO 2014 (original data in Mtoe)

Thus the evolution of the electricity mix will be the main determinant of future demand for natural gas. This mix varies strongly according to the three scenarios. While the contribution of renewable

energy sources increases in all scenarios, it differs widely between them. By 2040, renewables will provide 59% of electricity production in the *450 scenario*, compared to 37.5% in the *Current Policies Scenario,* and 46% in the *New Policies Scenario*. This corresponds to a difference of 536 TWh, which is almost equivalent to the current production of electricity from natural gas. The residual demand addressed to other energy sources, and therefore to gas-fired plants, varies significantly depending on the scenario.

FIGURE 23: ELECTRICITY PRODUCTION IN THE EU FROM GAS AND RENEWABLES (2012-2040)



Source: WEO 2014

According to the IEA, in 2020, the production of electricity from natural gas will have increased marginally compared to 2012 (from 0% to 11% depending on the scenario). The contribution of coal decreases in all scenarios, and falls strongly at the 2030/2040 horizon. But this does not mean an automatic increase in the contribution of natural gas. In the *450 Scenario*, the production of electricity from gas (and therefore gas demand by the power sector) will fall by almost half in 2040, compared to 2012, and is replaced by renewable energy sources. Natural gas is the back-up to renewables, requiring an increase in electricity production capacity from gas, though such capacity will be seldom used, and will not lead to increased demand for gas in the sector. Gas demand does increase by almost 50% in the *New Policies Scenario* and by 112% in the *Current Policies Scenario*. The share of gas in the electricity mix therefore varies greatly, from 9% to 30% in 2040 (with a 24% share in the *New Policies Scenario*). The objectives of the 2030 climate and energy framework are similar – but not identical – to the assumptions of the *450 Scenario*. The latter includes: a 30% reduction in greenhouse gas emissions by 2020 (compared to 1990); a strengthening of the European carbon market in line with the road map for 2050; and the full implementation of the 2030 climate and energy package as well as the Energy Efficiency Directive.

Conclusion: high investment needs in an uncertain context

It is in this very uncertain context that the European gas industry has to invest in the capacities required to support the energy transition. Such investment is needed especially for back-up facilities for intermittent energy sources, and in new infrastructure to diversify gas supplies and offset the decline in European production. The IEA estimates investment needs to be nearly $650 billion between 2014 and 2035 (WEO2014). Natural gas has suffered from past policies. As a result, it may be asked if the new momentum of the 2030 climate and energy framework, the planned reform of the carbon market and the launch of the Energy Union will be sufficient to ensure that these investments are made, and whether they will allow natural gas to regain a privileged position in the European energy and electricity balance.

Conclusion

The EU's energy policy has to deal with a new gas landscape, in terms of both supply and demand.

As regards gas supplies, the Ukrainian crisis has deeply affected the EU's relations with its main supplier, Russia. In response to the new direction Europe has taken to reduce its dependence on Russian gas, Gazprom has also shown a new strategy with respect to Europe by diversifying its partners. But Russia's change of tack is turning out to be far more complicated than expected: while the "Power of Siberia" project is already underway, the great turn towards Asia as announced by Vladimir Putin is difficult. China and Russia have still not agreed on the western route. Similarly, the Turkish Stream project remains subject to strong uncertainties. While Gazprom seemed to want to reduce significantly its involvement in European gas assets, being upset by the liberalization rules of the European market, Moscow is now sending a new message to Europe, reflecting an easing of gas relations. The renewed interest by the Russian supplier in the European market is indicative of the importance of this market for Russia, which provides the bulk of its gas revenues.

Investments in large-scale projects are not easy for Gazprom, given the current context of Western sanctions and the decline in oil prices. The company will have to choose between its many projects especially as its position is weakened in favor of independent Novatek and Rosneft. On the European side, the alternatives to Russian gas are not very numerous. The Southern Corridor will certainly allow for additional deliveries of gas from Central Asian countries, but it will not replace the Russian gas.

Europe must also cope with a faster-than-expected decline in its domestic production, as the Groningen field has been subject to significant production restrictions since January 2014, due to high risks of earthquakes. The Dutch government must therefore preserve the safety of the inhabitants of the region, secure the gas supplies of the country and meet its contractual obligations to European customers. Today the production ceiling decided for 2015 can meet Dutch and Europeans needs, by drawing more on stored gas and imports. But there is strong uncertainty concerning the evolution of future production, and this reduces visibility over the short to medium-term European gas supply.

The exploitation of potential shale gas resources would partially offset the decline in domestic production. European countries are not moving forward together on the subject, and the commercialization of shale gas in Europe is still far off. The results so far have been rather disappointing in Poland and Denmark, though the United Kingdom is accelerating the exploitation of its resources. The challenges are still numerous; they are related in particular to formulating the right regulatory framework which will enable the development of concrete projects. There will surely not be an American-style revolution, but European shale gas could improve security of gas supplies and strengthen the bargaining power of some countries vis-a-vis of Russia. However, the road is still long before views converge on this issue in Europe. The social acceptability of these projects is today a prerequisite for the development of shale resources. This acceptance can only come from increased public confidence in the management of risks related to shale gas extraction by operators. And this confidence can only be built on the transparency of information and stakeholder engagement from the start of projects.

Given these constraints on European production, a compromise with Russia is desirable for Europe, in order to normalize gas relations between the two parties. This does not mean that Europe should give up its diversification projects, which will no doubt focus on LNG supplies. Falling oil prices and slower growth in Asian demand have ended the arbitration in favor of Asia, which has dominated the world market since 2011. So the European market has become attractive for LNG. With its many advantages, LNG is well positioned to meet the diversification problems of European supplies, provided that Europe is able to emerge as a global player on the international market, and that the European market remains attractive for LNG exporters.

In this context, a European energy diplomacy will be useful not only to deal with crisis situations, but also to meet future challenges. The global energy scene is changing fast and Europe has little influence on the evolution of world prices. The growing rise of Asian energy needs could easily absorb US LNG exports. New consumers are emerging on the global stage and competition is becoming increasingly fierce in guaranteeing the security of supplies. The strengthening of diplomatic actions of the Energy Union is therefore a crucial asset for Europe.

However, the commitment to the diversification policy faces a major hurdle in the path of the European gas demand. The consumption of natural gas has been falling sharply since 2010. This is due to the slowdown in economic activity, and especially to the lower need for gas in the electricity-generating sector, with the development of renewable energies and the loss of competitiveness of gas over coal. The increase in coal consumption in the power

sector at the expense of natural gas is mainly due to falling prices of imported coal in recent years, compared to an increase in gas prices. The latter, despite their recent decline, remain higher than those of competing coal. The profitability of coal is even more important as the CO_L price remains relatively low. This situation poses a risk to the security of electricity supply, as the rapid expansion of renewables requires flexible back-up capacity with low CO_L emissions. Yet current market signals do not favor investment in such production capacity. The capacity markets set up in several European countries to provide additional incentives to investments have to meet several challenges, particularly in terms of cross-border interconnections.

Thus, the gas market has to deal with a new operating context, dominated by uncertainty over the evolution of supply and demand. If European markets react today with increased volatility in gas prices, then the long run effects will be more important, because the present lack of visibility may hamper the financing of necessary investments in gas projects to support diversification policies and compensate for the fall in European production. This is particularly the case for transport infrastructures necessary to enable the network to route potential new flows of LNG across the continent. This risk also weighs on the electricity sector and its supply security, as flexible gas plants needed to deal with the intermittency of renewable energies are not profitable in the current context. If well-planned, the much-expected new design of electricity markets for Europe, coupled with reform of the market for CO_L allowances, will remove uncertainties in the gas market. Natural gas could then play its full role in Europe's energy transition

Annex 1: LNG Export Projects under Construction across the World

Seven new export projects are under construction in Australia, three of which should begin production in 2015. In total, they should add a capacity of 77 bcm by 2018. These projects focus mainly on Asian markets and are based on long-term contracts indexed to oil prices. However, these contracts have more flexibility than the first contracts signed by Australia, particularly concerning destination clauses. The projects include conventional LNG projects in Western Australia, a large floating terminal, developed by Shell and located off the coast of Browse, and three unconventional projects using gas from coal (coalbed methane) in Queensland, one of which started in December 2014. These projects are very expensive ($43 billion for Gorgon LNG) because of their complexity, their remoteness from gas fields supplying the new units, the cost of labor in Australia and the increase in the price of equipment which has occurred in recent years. However, they should be finalized despite lower LNG prices. Most of the projects have indeed been partially financed by Asian LNG buyers who want to secure their supplies from a politically safe country.

In the US, the increase in the production of shale gas has been faster than the growth of domestic demand. Together with the high price of LNG until 2014, this has led producers to find new markets and to develop export projects. Five projects are now under construction, with a total capacity of 78 bcm. Chenière, the project operator at Corpus Christi, decided to invest $11 billion in the construction of two first trains of the project in May 2015, despite today's more difficult environment. The initial deliveries of these new projects are expected for late 2015, via the first train in Sabine Pass. These terminals benefit from lower costs than the new liquefaction projects in the US and from projects in the rest of the world because they are located on former LNG receiving terminals. They therefore benefit from the existing infrastructure.

These US projects offer a lot of flexibility to buyers. The latter have generally signed contracts with *tolling*, i.e. booking liquefaction capacity at a fixed rate, for durations ranging from 15 to 20 years. If a customer chooses to give up buying the LNG, it will only have to pay the fixed charge booking ($3/MBtu), instead of the full cost of LNG found in conventional contracts with take-or-pay clauses. The customer may also ship the LNG to a market of its choice, as these

contracts do not include destination clauses. These US projects are also targeting Asian markets, but a significant portion of capacity has been reserved by LNG aggregators, and will then be sold to the most lucrative markets. Moreover, the US contracts are indexed on the spot price of US gas and so allow buyers to diversify prices relative to contracts indexed on oil. This indexing is not currently competitive for the US LNG, as the price of contracts indexed on oil is less than that of US LNG delivered to consumer markets. Buyers, however, continue to be interested in such a diversification of prices, given the uncertainties surrounding the evolution of oil prices. Finally, LNG buyers consider the US as a very reliable source of diversification. This is the case for Europe's new importing countries (the Baltic States and Poland), where the American LNG is seen as a way to secure gas supplies.

Other export projects have a combined capacity of 37 bcm per year, and are under construction in Malaysia (including two small floating terminals), Indonesia, Colombia and Russia (Yamal LNG). Yamal LNG has three liquefaction trains, and the first train should start operating at end of 2017. But this date is still subject to the finalization of project financing.

TABLE 5: LNG EXPORT PROJECTS UNDER CONSTRUCTION (JUNE 2015)

Country	Project	Capacity (bcm/year)	Sponsor	Commissioning date
Australia	Queensland Curtis LNG (Train 2)	5.8	BG, CNOOC, Tokyo Gas	2015
Australia	Gorgon LNG	20.4	Chevron, Shell, ExxonMobil, Osaka Gas, Tokyo Gas, Chubu Electric	2015-2016
Australia	Gladstone LNG	10.6	Santos, Petronas, Total, Kogas	2015-2016
Australia	Australia Pacific LNG	12.2	ConocoPhillips, Origin, Sinopec	2015-2016
Indonesia	Donggi-Senoro LNG	2.7	Mitsubishi, Pertamina, Kogas, Medco	2015
Indonesia	Sengkang	2.7	Energy World Corporation	2015
Colombia	Carribbean FLNG	0.7	Pacific Rubiales, Exmar	2015
Malaysia	MLNG Train 9	4.9	Petronas	2015
United States	Sabine Pass LNG	24.5	Cheniere Energy	2015-2017
Malaysia	PFLNG1	1.6	Petronas	2016
Australia	Wheatstone LNG	12.1	Chevron, Apache, Pan Pacific Energy, KUFPEC, Shell, Kyushu Electric	2016-2017
Australia	Prelude FLNG	4.9	Shell, Inpex, Kogas, CPC	2017
Australia	Ichthys	11.4	Inpex, Total, Tokyo Gas, CPC, Osaka Gas, Chubu Electric, Toho Gas	2017-2018
Russia	Yamal LNG	22.4	Novatek, Total, CNPC	2017-2019
Malaysia	PFLNG2	2.1	Petronas, Murphy Oil Corporation	2018
United States	Cove Point LNG	7.1	Dominion	2018
United States	Cameron LNG	16.3	Sempra Energy, Mitsubishi, Mitsui, Engie	2018-2019
United States	Freeport LNG	18	Freeport, Osaka Gas, Chubu Electric, Macquarie	2018-2019
United States	Corpus Christi	12.3	Cheniere Energy	2019-2020
TOTAL	TOTAL	18		

Source: IEA, IGU, press.

Annex 2: Regasification Terminals in Europe

TABLE 6: REGASIFICATION CAPACITY IN THE EU BY COUNTRY AND BY IMPORTS IN 2014

Country	Name of the terminal	Commissioning	Operator	Annual capacity (bcp)	Net imports in 2014 (bcm)	Access regime
Belgium	Zeebrugge LNG Terminal	1987	Fluxys LNG	9,00	1.3192	regulated
Spain	Barcelona LNG Terminal	1968	Enagás	17.1		regulated
Spain	Huelva LNG Terminal	1988	Enagás	11.8		regulated
Spain	Cartagena LNG Terminal	1989	Enagás	11.8		regulated
Spain	Bilbao LNG terminal	2003	BBG	8.8		regulated
Spain	Sagunto LNG terminal	2006	saggas	8.8		regulated
Spain	Mugardos LNG Terminal	2007	Reganosa	3.6		regulated
Spain	Gijón (Musel) LNG terminal	2012 (a)	Enagás	7,00		regulated
			Total Spain	68.9	10.744	
France	Fos-Tonkin LNG Terminal	1972	Elengy	3.4		regulated
France	Montoir-de-Bretagne LNG Terminal	1980	Elengy	10,00		regulated
France	Fos Cavaou LNG Terminal	2010	Fosmax LNG	8.25		regulated
			Total France	21.65	6.2288	
Greece	Revithoussa LNG Terminal	2000	DESFA	5,00	0.5168	regulated
Italy	Panigaglia LNG terminal	1971	GNL Italia	3.4		regulated
Italy	Porto Levante LNG terminal	2009	Adriatic LNG	7.56		mixed
Italy	FSRU OLT Offshore LNG Toscana	2013	OLT Offshore LNG Toscana	3.75		exempted
			Total Italy	14.71	4.4472	
Lithuania	FSRU Independence	2014	Klaipedos Nafta	4,00	0.1496	regulated
Netherlands	Gate terminal, Rotterdam	2011	Gate terminal	12,00	0.5712	exempted
Portugal	Sines LNG Terminal	2004	REN Atlantico	7.9	1.3192	regulated
United Kingdon	Isle of Grain LNG terminal	2005	Grain LNG	19.5		exempted
United Kingdon	Teesside LNG port	2007	Excelerate Energy	4.2		exempted
United Kingdon	Milford Haven - Dragon LNG terminal	2009	Dragon LNG	7.6		exempted
United Kingdon	Milford Haven - South Hook LNG terminal	2009	South Hook LNG	21,00		exempted
			Total United Kingdom	52.3	11.424	
				195,46	36.72	

(a) The construction of a terminal was completed in 2012, but the terminal has not started operating because of the low use of its capacity.

Source: GLE, GIIGNL

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List of Tables, Figures, Maps and Boxes