Centre on Regulation in Europe
Improving network industries regulation

# *Challenges for Natural Gas in the Context of the Energy Union*

## *Project Report*


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# Executive summary

The favourable-to-coal carbon content of natural gas and the recent worldwide growth of unconventional gas are both attractive for reducing greenhouse gas (GHG) emissions and increasing security of supply. The future role of natural gas in Europe is, however, unclear, with respect to market developments and policy design. Amid rising renewable energy production in Europe, competition between fossil fuels for remaining market shares is intensifying. In addition, substitution possibilities at the consumer end are increasing. As a consequence, the competitiveness of natural gas, its role in security of supply, and its role in the EU's transition to a low-carbon energy economy are challenged.

This report sheds light on recent policy and market developments to examine the prospects for natural gas in Europe. First, a review of market and policy risks for natural gas, for transmission networks, LNG, gas storage, and power markets is provided. The report then discusses how natural gas can contribute to the low-carbon energy landscape and whether, given current regulation, the benefits of natural gas can be exploited during the energy transition. While the analysis takes a European perspective, global gas market trends, and the extent to which they play out on the European market, are also included.

The uncertain future of the gas sector stems from current market developments as well as from regulatory risk. Supply, despite decreasing production within the EU, can be expected to increase, especially via additional LNG imports. Import routes and sources are, however, likely to change, altering current trade and flow patterns. EU gas consumption has recovered after four years of decline and increased again in 2015 by 4.3%. Despite this recent recovery of gas demand, consumption could go back to earlier, lower levels should gas consumption in power markets or the heating sector further decrease. In the heating market, the penetration rate of rival renewable heating technologies will be crucial for market shares of gas. Higher penetration necessarily implies a reduced share. In the power market, EU and national regulations on carbon pricing and emissions standards could, in contrast, cause upward trends in gas demand. Ultimately, consumption trends will likely differ across EU member states due to different residential demand for gas in the heating sector and varying national power market regulation.

This report specifically discusses three areas for regulatory debate: the need for additional infrastructure investments, the design of short-term markets, and the interaction between gas and power markets.

First, the current development of gas demand *per se* does not justify further infrastructure. However, additional investment to ensure security of supply and diversified import routes may be needed. Bottlenecks and system operability issues will differ locally, and therefore investments in each location should be subject to careful cost-benefit analysis. In particular, future investment needs may arise in Central and Eastern Europe, but also include local LNG investments to guarantee flexibility in natural gas imports. In addition, as a consequence of

changing gas import routes and flow patterns, network usage will be reduced in some member states of the EU. In this case, new network pricing options might be required, especially for those regions with declining local demand and network usage.

Second, a move towards short-term trading is apparent in gas markets, especially at the interface of the power market. The operation of flexible gas-fired plants requires the alignment of short-term gas and power market design. EU energy regulation has to account for this move towards short-termism. However, as of today a number of regulatory issues around short-term market mechanisms are still to be resolved. In fact, the detailed regime for gas and power short-term markets differs widely across EU member states. In addition, there is no consensus on how to ensure flexible and secure peak load power generation within the EU. Current approaches range from standard energy-only market designs, to power markets with full-fledged capacity market designs. Capacity markets will not influence the merit order and as such will not incentivise higher capacity factors of gas-fired power plants. Instead, high ETS prices remain the ideal policy to exploit the benefits of natural gas relative to coal.

Finally, another area for regulatory debate is the interplay of networks for gas and power. Flexible, short-term energy markets can be fostered via better cooperation between system operators across both power and gas markets. Such cooperation could allow for improved information on power and gas flows and thus offer synergies in system operation. A strengthened cooperation between gas and power TSOs is particularly important once one acknowledges that the gas market is moving to shorter-term transactions with more volatile prices, similar to the power market. In future power markets with high shares of intermittent renewables, natural gas has to be readily available to quickly offer gas-fired generation to the market.

In sum, there is a need to review the regulation, the market design, and network operation, to reap the benefits of natural gas during this energy transition period. Given uncertain times for natural gas markets, it seems important to implement a short-term market regulation (at the intraday time frame) to guarantee liquid and competitive markets for natural gas. These should be backed by adequate infrastructure – where further needs may arise locally to account for changing flow and import patterns. Ultimately, the future of natural gas will also depend on the economic feasibility of innovations in gas (such as CCS) and the extent to which carbon prices incentivise the use of natural gas.

# 1. Introduction

Amid rising renewable energy production in Europe, competition between fossil fuels for remaining market shares is intensifying. As a consequence, the role of natural gas in Europe's energy future is unclear with respect to both market developments and policy design. The favourable-to-coal carbon content of gas and the recent worldwide growth of unconventional gas are attractive attributes for reducing greenhouse gas (GHG) emissions whilst increasing security of supply. Despite this, natural gas competitiveness has been challenged in recent years, especially by cheap coal, and by increasing substitution possibilities both in the power and the heating market.

This report sheds light on recent policy and market developments to examine the prospects for natural gas in Europe. What role should natural gas have in the ever-evolving EU low-carbon energy landscape? What are the regulatory barriers, if any, towards gas market fruition? While the analysis takes a European perspective, global gas market trends, and the extent to which they play out on the European market, are also included.

The Energy Roadmap 2050 (EC, 2011) lays out ambitious climate goals for Europe; a reduction of 80-95% of greenhouse gases by 2050 as compared to 1990 levels. In the impact assessment accompanying the Energy Roadmap, natural gas however presents only one of many resources to harvest (EC, 2011b). In the latest EU Reference Scenarios (EU, 2016b), natural gas in Europe will maintain a share of about 22% of all fuels in total energy consumption. However, prospects for natural gas differ across countries (depending on national power generation mixes) and sectors (in particular, power generation and heating). In addition, European energy technology policy (e.g. the SET-plan) supports rival low-carbon technologies, focusing on a variety of further technology options other than gas to achieve climate targets (e.g. Ruester et al. 2014). Moreover, reliance on pipeline gas is sometimes viewed critically with respect to security of supply (e.g. Austvik, 2016).

Yet, during this energy transition period, the European gas market could play a significant role if its design and infrastructure are adequate. In a recent report, Fabra and Moraga (2015) discuss the role of natural gas in this context and find that natural gas will likely play a reduced role up to 2050. This report adds to their discussion and sheds further light on regulatory options for market design and infrastructure in EU natural gas markets.

The European gas market is facing significant market and regulatory uncertainty that needs to be resolved for gas to play a role.[1] The gas sector has experienced significant changes over the last decade: the discovery of shale gas in the US, which strengthened the competitiveness of

[1] Note that if gas innovations such as green gases (biomethane, bio-synthetic natural gas, hydrogen) and carbon capture and storage (CCS) become affordable in the future, natural gas may remain a key part in Europe's energy mix. This report does not address such innovations as this might warrant analyses beyond the scope of this report.

coal in Europe; the increased share of renewable energies in the power system; the emergence of advanced heating technologies; and, crucially, the persistence of low carbon prices.

The remainder of this report is structured as follows. Section two presents the changes that the gas sector underwent. It lays out topical developments in European (and world) gas markets but also in the EU power sector as a major determinant of gas demand. Section three analyses regulatory and political risk. It examines the current energy regulation and whether it is adapted to the evolving challenges faced by gas market-actors. Section four then discusses regulatory areas that need to be adjusted to reap the full benefits of natural gas. Section five concludes.

# 2. Market risks for natural gas in Europe

Policymakers and scholars have seen natural gas as the best-suited fuel to back-up the European energy transition. Recent developments on EU energy markets have, at least partly, challenged such beliefs. This section reviews these developments and the extent to which they cause uncertainty for the European gas sector.

Global natural gas production has shown solid growth in 2015 – even against the trend of falling world energy demand. Coal, in contrast, has experienced its largest fall in the share of primary energy production in more than a decade (BP, 2016). At the global scale, this development well assists decarbonisation efforts. When used to generate power, gas-fired plants emit less than half the $CO_2$ emissions of their coal-fired counterparts.[2]

Yet during recent years, gas markets largely remained regional markets (Li et al, 2014), and supply and demand patterns in the EU market differ from the overall global picture. In fact, both EU consumption and production have been declining over recent years (albeit the first signs of recovery are appearing, at least with respect to gas demand).

## 2.1 Abundant supply in EU, with uncertain origins and prices

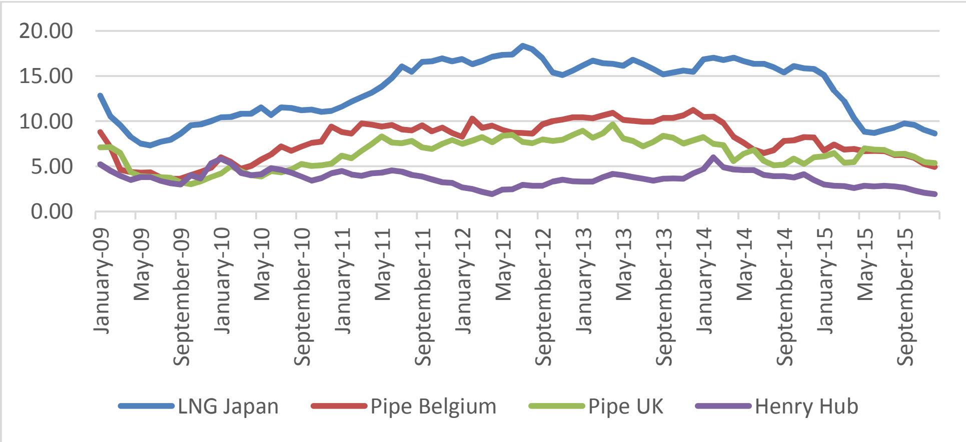
There are different elements that characterise current gas supply in Europe: the uncertain shale gas development, decreasing domestic supply, and further evolving LNG trade. The resulting net effect of the above developments on future gas prices in Europe remains unclear. Yet today, there is abundance of natural gas in Europe. Current oversupply can partially be attributed to high market expectations on gas demand that have not been met. The World Energy Outlook 2010 (IEA, 2010) predicted 562 bcm of natural gas demand for 2015; Eurostat reports significantly lower realised consumption of only 477bcm for 2015. Consequently, current market prices for natural gas are relatively low in Europe.

The growing LNG trade also established the first signs of renewed price convergence of EU to world prices – after years of diverging prices. Figure 1 illustrates the price trends in different regions, starting in 2009 shortly after the advent of shale gas. In 2009 and with shale production taking off, gas prices began to diverge significantly across regions.[3] Shale gas in the US reduced LNG import needs and eased global LNG markets. As the US did not export, American and other markets disconnected. While prices at the Henry Hub declined, prices in Japan began to increase. The latter increase was amplified by the Fukushima accident and emerging gas needs as nuclear generation had to be substituted (Neumann and von Hirschhausen, 2015). Fukushima also led to the redirection of LNG trades from Europe to Japan and to a tightening of LNG

[2] Emissions depend on the plant type and are often modelled around 0.4 and 0.9 tons of $CO_2$ per MWh generated for gas and coal power plants, respectively.
[3] Richter (2015) notes that the shale boom already began as of 2005. Strong price effects only occurred in the following years as shale gas increasingly entered the US market.

markets in Europe. During this period, EU prices lay between Henry Hub and Japan prices. The observed diverging price patterns are in stark contrast with converging price trends that had been observed before the advent of shale gas (Neumann, 2008).

**Figure 1: Gas prices at Henry Hub, Pipeline Belgium, UK, and LNG into Japan (in USD/MBtu)**




*Source: Own depiction, data from IEA Natural Gas Information and www.eia.gov.*

Recently, prices show converging patterns again, which can partly be attributed to the high number of regasification terminals that allow for arbitrage. Nonetheless, the direction of EU gas prices in the coming years remains an open question. Divergence may occur again if global supply and demand patterns change – a case especially relevant for emerging regional markets. Therefore, despite the abundance of gas, some supply risks remain as the origins of gas imports and import prices are uncertain.

**Can shale gas change supply in Europe?**

Gas production within Europe is declining. The Netherlands, as one of the European Union's traditionally largest suppliers, has used 80% of its reserves. Dutch production is falling and future extraction limited by the government.[4]

In addition, unconventional gas production in Europe does not exist at large scale and its prospects remain low. Fields with unconventional gas exist, for instance in France and Poland. However, drilling costs can differ drastically from the US and may not allow for the US experience to repeat in Europe. There are diverging opinions about the competitiveness of shale gas in Europe. Geny (2010) estimates that costs of developing shale gas in Germany or Poland are two to three times higher than in the US. In contrast, Chyong and Reiner (2015) stress that such scepticism might be overstated as findings can be very sensitive to important assumptions, like drilling costs. Uncertainty on the economic viability of shale gas in Europe is amplified by uncertainty on future political decisions in favour or against EU shale production in various

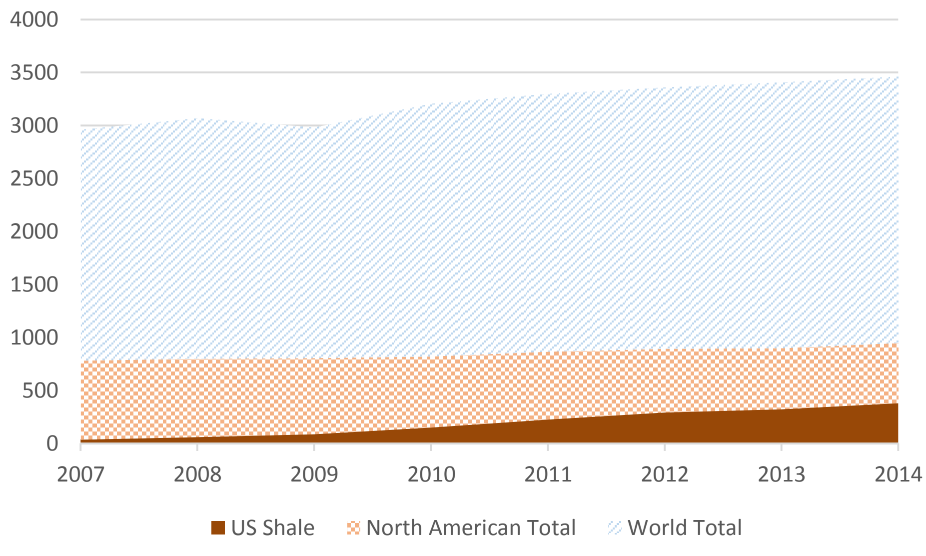
[4] Reported by Bloomberg (2016), www.bloomberg.com/news/articles/2016-09-16/europe-s-biggest-natural-gas-producer-is-running-out-of-fuel

member states. As a result, both production costs (private and social) and regulatory environments are ambiguous, but as of today, EU shale gas does not play a role in European gas prices.

Likewise, scholars recently began to doubt that imported US shale gas would become a game-changer in the EU market. Shale gas extraction in the US experienced almost linear growth in recent years. Figure 2 illustrates the importance of US shale gas relative to total world gas production. It also reveals that shale gas has replaced conventional US production, so that total US gas production remained somewhat constant. In 2014, shale gas accounted for more than 50% of total US (conventional plus shale) gas production, increasing from only 7% in 2007.[5]

While shale drastically changed gas and power markets in the US (e.g. Joskow, 2013), direct consequences for European gas markets have so far been very limited, for a number of reasons. First, gas exports from the US have so far been marginal. In 2015, LNG exports from the US represented less than 1% of total US production (BP, 2016). The extent to which future exports from the US will increase strongly depends on how successfully interest groups can voice their arguments for or against exporting, how regulators will evaluate benefits for competitiveness and supply security (when not exporting), and how timely relevant agencies will (or will not) issue the necessary permits for exports (Joskow, 2015).[6]

**Figure 2: World and North American gas production, in bcm**




*Source: Own depiction. Data from EIA and BP (2016).*

[5] Not shown in Figure 2 is data for 2015, where shale gas production increased to about 431 bcm, yet again an increase of about 13% to 2014 (381 bcm). While much of the global shale gas production is located in the US, Canada, and more recently China and Argentina, have started extracting at larger scales. Mexico and Algeria are expected to follow the trend in the near future. These six countries are estimated to account for about 70% of global shale gas production by 2040, see www.eia.gov.

[6] The Wall Street Journal reports that a first LNG shipment from the US to Europe was underway in summer 2016, http://www.wsj.com/articles/first-u-s-gas-shipment-en-route-to-europe-1461253153.

Second, even in a scenario of growing US LNG exports, regions with higher prices will be served first. Currently the Asian basin – and especially Japan – prices are higher relative to European gas prices (see Figure 1 above). Whether this price differential will persist depends on Japanese energy policy in the aftermath of Fukushima. If Japan decides to abandon large-scale nuclear power generation, prices for gas are likely to remain high in this area, as Japan's alternative generation options will include high shares of gas-fired generation (Kuramochi, 2015).

Third, some scholars have raised arguments that the shale boom in the US might not be sustainable. Hughes (2013) analyses 30 shale gas fields in the US and finds that the shale gas revolution will be hard to sustain as field productivity is prone to steep declines, and production and capital costs have to rise as exploration continues. Boersma and Johnson (2012) stress the possibility of leakage and the resulting long-run environmental impacts of fracking. Also, Richter (2015) critically assesses the shale boom and discusses economic and environmental challenges. Taken together, the direct effects of shale gas on the EU gas market have been limited so far and will remain so unless the US changes current export policies and shale gas extraction flourishes further.

**Development of LNG trade**

With low European gas production and limited imports from the US, could growing worldwide LNG imports to Europe increase supply? Since LNG capacity in the EU has not been fully utilised despite existing price differentials, it can be doubted whether LNG imports will contribute "cheap" gas to Europe. CEER (2013) provides figures for 18 European LNG terminals, where 65% of full technical capacity is the highest utilisation rate. Remaining price differentials between EU and world gas prices may thus partly be attributed to the fact that LNG gas is more expensive than pipeline gas, so that regional price differences can prevail despite vivid LNG trade.[7]

While current capacity is not utilised, however, strong growth is predicted for LNG imports to Europe, backed by an increase in LNG terminals.[8] Reasons for investing in LNG terminals may not only be driven by economic rationales. Even when not always fully utilised, LNG terminals can increase security of supply, if pipeline supplies are not viewed as sufficiently secure. The Security of Supply Energy Package (EC, 2016b) and a number of LNG projects of common interest illustrate the strategic dimension of additional LNG terminals.[9]

To summarise, the European gas market has remained a regional market in recent years. There is abundance of gas in Europe. The origin of supplies and import volumes are uncertain. Changes in EU supply may ultimately come from LNG imports. Alternatively, imports might increase from Russia if EU production further declines (while production from Norway will continue to be large, see Holz et al. (2015)). Shale extraction may take off in selected EU countries but

[7] LNG prices in this context establish a ceiling price for EU pipeline gas.
[8] GSE lists 60 LNG terminals that are either "planned" or "under construction". See the GSE investment database at www.gie.eu.
[9] It should be noted that most LNG terminals so far have been built on a purely commercial basis.

estimates for its potential are low. The net effect on European natural gas prices remains to be seen.

## 2.2 Uncertain market shares for natural gas

Demand for natural gas will depend on (at least) three crucial parameters: i) future carbon pricing or emission standards, in particular the ETS price (about one third of all emission certificates are used in the power market); ii) coal prices relative to gas; and iii) market penetration of new low-carbon heating technologies. This section discusses how these different market drivers and policy parameters will affect gas demand, and how they bring uncertainty to the sector.

European natural gas consumption was increasing in 2015 after 4 years of decline. For once, the reductions of previous years underlay general, structural trends, such as the economic recession. Honoré (2014) shows how gas consumption declined significantly in the aftermath of the financial crisis in 2009.[10] In 2015, the gas demand in EU increased again by 4.3% (Eurostat, 2016) but whether this trend will continue depends on the developments in the heating and power market.

**Demand from the heating sector**

Demand projections for the heating sector differ across member states. In some countries like the UK, gas will remain the primary fuel for heating until at least 2040 (National Grid, 2016) and should be recommended for new-build residential construction (Eurogas, 2016). At the European level, three EU directives will have significant consequences on future gas demand in the heating sector (Lucha et al. 2016): The Renewable Energy Directive, the Energy Efficiency Directive and the Energy Performance of Buildings Directive. The latter two foster efficient heating and consequently lower demand for natural gas. In line with this, JRC (2012) foresees declining demand for space heating for family homes up to 2030 across Europe. The Renewable Energy Directive supports rival technologies for household customers such as biomass, which currently constitutes the most widespread renewable heating technology, especially in Scandinavian countries. In addition, heat pumps will have a demand reducing effect on gas in the heating sector, as will electric heating appliances and heating from solar appliances. Thus, residential heating demand for natural gas is unlikely to increase significantly in the medium and long-term. In contrast, it seems more likely that rival technologies will gain market shares, with the pace of change and regional variations being a key consideration.

These developments in the heating market are rather young and thus difficult to predict. In 2010, traditional heating technologies based on fossil fuels still accounted for about 70% of all energy consumed for space heating. Against this status quo, according to the EU's SET-Plan

[10] Gas demand not only decreased from power and heat markets, but also from industry. Neumann and Hirschhauen (2015) find that about 20% of gas in the EU is consumed by industry. For industry, gas is largely providing high-temperature heat and low local and global emissions.

information system, the share of renewable heating technologies in EU heat consumption is expected to increase to 30% and 50% by 2030 and 2050, respectively.

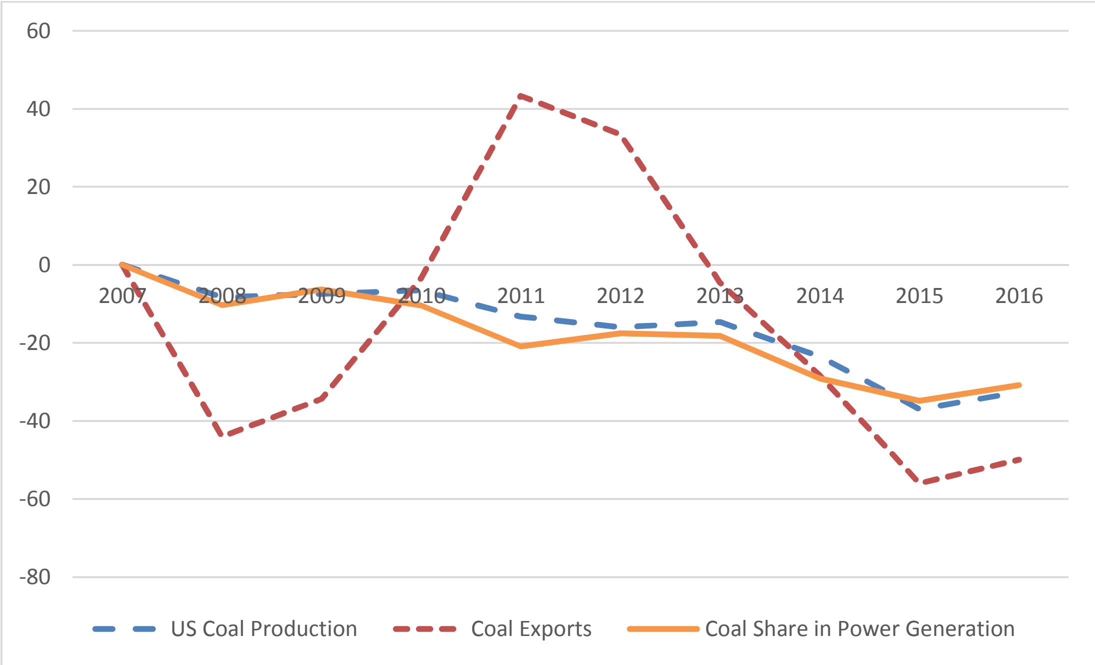
How rapidly these developments will turn out to shape European heat markets will largely depend on how capital expenses evolve for the different technologies. Heat pumps currently show rather stable capital expenditures of around EUR 1,400 per kW installed, as a recent study for DECC (2016) reports. For solar thermal, the same study reports cost figures that show decreasing or stabilising patterns since 2008, and falling capital costs for biomass. While a full cost comparison of different renewable heating technologies as compared to fossil fuels with different capital and operating expenses is outside the scope of this report, increasing substitution possibilities for heating show strong signs of growth and may lead to falling demand for natural gas in the heating market (again with regional variations across Europe).

**The quest for competitiveness of gas relative to coal**

Natural gas demand in the EU is affected by the competitiveness of gas *vis-a-vis* coal. In recent years, cheap US coal has overloaded the European energy market and coal thus gained momentum in its relative cost efficiency to gas. Figure 3 shows that coal exports from the US drastically climbed with the advent of shale gas. This has partly been a result of declining coal demand from the US power sector as a consequence of a shift towards low-price shale gas in power generation. Extra coal supply has put further pressure on European gas. Cheap coal gained shares in power generation (in combination with low ETS prices), gas demand declined, and oversupply and low gas prices prevailed. Indeed, coal prices in the US remained low since 2008, so that exporting to the EU proved viable, putting downward pressure on prices in Europe.[11] Where coal and natural gas are short-run substitutes, as in the power market, this manifests a strong effect of shale gas on European gas via its substitute fuel, coal. However, as Figure 3 shows, pressure from US coal on the European markets might cease in the near future. This is because US coal production has adjusted downwards, and exports have shown downward trends.

[11] In addition to this direct effect of coal imports from the US on EU coal and gas consumption, EU gas prices were also falling because US demand for LNG imports decreased.

**Figure 3: Coal in US power mix, US coal export, and US coal production (in % relative to 2007)**



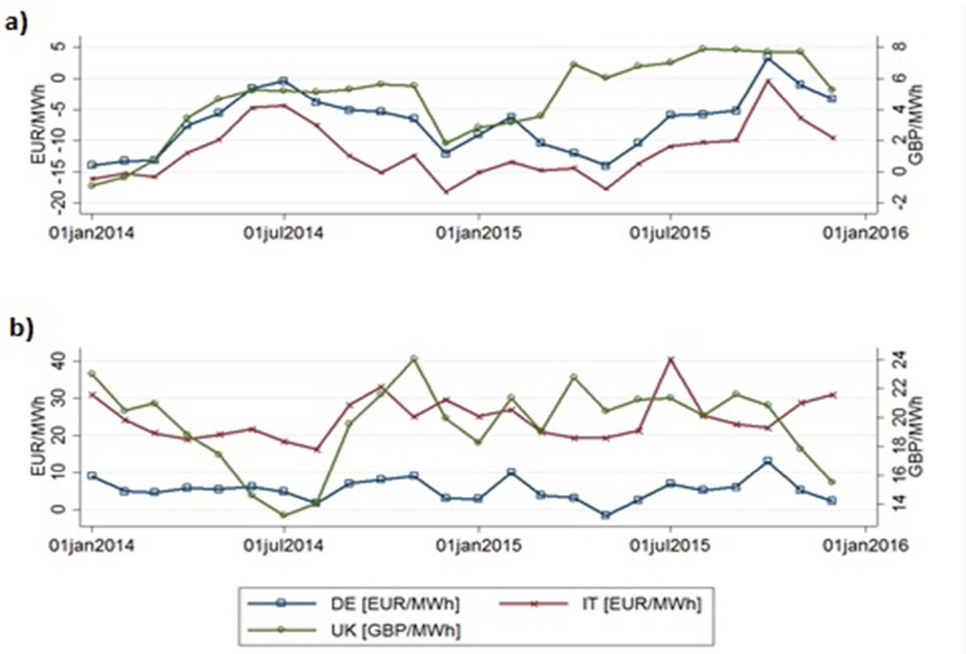

*Source: Own depiction, data from www.eia.gov.*

High gas prices relative to coal imply (given current ETS prices) that coal-fired generation is the more economical choice for power generation. Gas-fired power plants, then, are only dispatched once coal reaches capacity constraints. As a result, gas-fired power plants have in many EU states been pushed out of the market, often rendered unviable.

Figure 4 plots the clean dark and clean spark spread and illustrates that gas power plants in Germany, the largest EU power market, are largely unprofitable. Also, the UK and Italy are plotted. These three countries are traditionally the largest gas consumers in Europe. As evident, with the exception of the UK,[12] spark spreads are largely negative and hence gas-fired generation runs at a loss.

[12] Note that in the UK, a strategy consultation was published in November 2016 with the aim of closing all remaining coal stations in GB by 2025 (see https://www.gov.uk/government/consultations/coal-generation-in-great-britain-the-pathway-to-a-low-carbon-future). Spark spreads in the UK will thus likely experience upward trends in the years to come.

**Figure 4: Clean spark spreads (a) and dark spreads (b) in the UK, Germany, and Italy in 2014 and 2015**




*Source: Own depiction.*[13]

It is worth mentioning that these fundamental demand determinants can however be eroded due to policy evolution in carbon pricing and technology development in carbon capture and storage. First, the profitability of gas vs. coal power plants is highly sensitive to ETS prices. A carbon floor price, as recently discussed or implemented by some European countries, could radically change the merit order in power markets and boost gas demand. Further, the market stability reserve for the EU ETS market has the potential to lift ETS prices again. In the end, this will depend on political will.

Of course, carbon capture and storage (CCS) could have a radical impact on the merit order. The Energy Roadmap 2050 first includes CCS, in some scenarios, from 2025 onwards only. CCS, if ever viable, could indeed play a crucial role in meeting carbon targets, especially in countries which delay the construction of new nuclear power plants or phase out the latter. Consequently, for sufficiently high ETS prices, gas demand can be boosted; if ETS prices remain low, so will gas demand in the power sector; if CCS becomes economical, ETS prices are negligible for gas demand from the power sector.

[13] Data downloaded from Datastream. Baseload power prices from EEX, UK APX and Italian GME; gas prices from UK NBP, TTF for Germany and PSV for Italy. API2 used as coal price for all countries.

## 2.3 Increasing risks in the power sector

The former section argued that the competitiveness of natural gas relative to coal is ambiguous and will depend heavily on developments in the power sector. The power sector, however, deserves a closer look as natural gas faces various competing technologies other than coal. To this end, these power market specific factors are discussed in more detail with a focus on the recent growth of renewable energy in power markets and the alternatives to gas power plants as a back-up technology.

During the last decade, the way electricity is produced has been diversified as shares of renewable generation have been growing across European power markets. With technological progress and renewable support schemes to decrease $CO_2$ emissions, wind or solar energies are now credible and competing alternatives to energy produced from coal, gas or oil.

Gas-fired generation is one prime candidate as flexible back-up power to manage the intermittency inherent to solar and wind energy sources. However, gas-fired power plants must rely on a few peak hours only to break-even and recover investment costs.[14] This new development has been triggered by several changes in the functioning of the electricity market that directly affected gas power plants' profits.

First, renewable technology has put downward pressure on energy prices because of the merit order effect, that is, via displacing expensive generation with low marginal cost wind or solar generation. Lower power prices have reduced the incentives to invest in and operate conventional power plants, which are nonetheless necessary in 'low wind' states and states with little solar output, mostly in January or February.

Second, the intermittency of wind and solar generation often increased price volatility in short-term markets. Also, costs for conventional generators increased due to their dynamic generation costs, that is, their start-up and shut-down costs as for instance analysed in Reguant (2014). In the German power market, this phenomenon has caused power prices to become negative. Owners of conventional plants prefer to pay money for running continuously, as long as payments are below the costs of having to start-up their generation facility.

**Alternatives to gas in power markets**

Nuclear as a zero-carbon emission technology may be considered as a credible alternative for some European countries, such as France or the UK. Nuclear is a highly capital-intensive technology, and many studies show that levelised costs of nuclear generation have never been competitive (Davis, 2012). However, most of the strategic nuclear investments are now sunk. Yet, especially in a post-Fukushima context, nuclear will not be an option for many EU member states, and so it is unlikely that nuclear generation will become a large-scale solution at the European level.

[14] This might require prices spikes significantly above generation costs in certain hours and stresses the role for forward markets to hedge against spikes and lock-in revenues (costs) for producers (consumers).

Additionally, investment in new storage technologies would also allow for further integration of renewable energy assets and would increase flexibility in the network for its users. However, several studies on the German market, for instance, show that significant additional storage capacity is only needed for RES penetration at levels above 80% of total power generation.[15]

An active use of demand response will likely also be part of the solution to tackle generation intermittency. So far, the results of demand response programs are rather inconclusive. Commercially viable demand response business has been limited to industry and services and markets where capacity payments exist. At the residential level, in contrast, demand response via smart-metering is not yet rolled out. Studies, however, confirm potential for demand reduction. Wolak (2015) reports that consumers with information on real-time usage consumed about 4% less as compared to a control group. Potential for demand response can become significant especially when decentralised sources such as storage and electric vehicles show further growth and are aggregated to serve as large virtual back-up plants.

Last, it should be noted that (aggregated) electric vehicles will not only become a competitor for gas plants, as at the same time more electricity will be consumed for larger levels of electric mobility. Electric mobility is often considered a key part of the solution to tackle emissions in the transportation sector. If this technology is widely adopted, a major switch from oil to electricity is expected in transportation. The environmental benefits will be ensured only if electric energy is produced from renewable and clean sources. Moreover, e-mobility will become a reality if the required infrastructure (easy charging method, efficient communication software) as well as a common interface between the distribution grid and electric vehicles are properly developed in all of Europe.

At this stage of the market and infrastructure development, many alternative fuel solutions to oil are possible; not only electricity but also hydrogen, natural gas, etc. Here, LNG and CNG for land transport (duty vehicles) and water transport (deep-sea trading vessels and inland waterways) are discussed in particular (ACER, 2014). Further development of gas in transport will depend significantly on taxation policies at the national level. Shares of gas in road and marine transport are not yet significant in the EU and any future change will likely be subject to public policy decisions, e.g. on infrastructure investments. Overall, future EU transport strategy is unclear.[16] The winter package encourages the use of alternative fuels in transport, but concrete proposals are yet to be drafted.

To conclude, investors in gas-fired power generation not only face considerable uncertainty with respect to input costs of gas. They also face risky revenues because of volatile electricity prices

[15] Schill (2015) reports results from three studies that vary in their findings (and assumptions). They find that no additional power storage capacity is needed for levels below 40%, 60%, and 70% of RES penetration, and that significant new storage capacity would only be needed for RES penetration levels above 80%, 88%, and 90%, respectively.

[16] See EU Directive from 2014, http://ec.europa.eu/transport/themes/urban/cpt_en.

and rivalry with alternative back-up technologies that can potentially run during low output from renewable sources.

Ultimately, changes in the gas sector have not only lead to increased market risks, they have also triggered the need for regulatory guidance. The next section discusses regulatory and political risks that currently affect the European gas sector.

# 3. Regulatory and political risk in the gas sector

Due to drastic changes and resulting market uncertainties in the gas sector mentioned above, the European energy regulation may have to be adjusted to reach decarbonisation goals for 2030 and 2050. Before discussing possible changes in section four, this section briefly reviews the current legislation.

## 3.1 Evolving regulatory frameworks for short-term markets

Liquidity is crucial to guarantee sustainable competition on forward or spot markets. Traditionally, gas trade was done by long-term contractual agreements. This is, however, changing as more and more short-term transactions are taking place on gas hubs.

Neumann and von Hirschhausen (2015) use European data, covering rich observations on gas contracts over the last years. They find that the duration of these contracts steadily decreased over time.[17] Miriello and Polo (2015) study the evolution of gas hubs in the EU since deregulation, looking specifically at the main hubs in the UK, the Netherlands, Germany, and Italy. They find that with a higher number of competing gas firms, the short-run gas market trade increases. Intuitively, whereas a monopolist gas supplier can make use of large portfolio effects to internally balance contractual positions in the short run, several smaller firms cannot, and thus have to purchase gas on short notice to fulfil their contracts. With the gas market being liberalised and fragmented, it is the short-term market that allows market participants to have balanced portfolios. Hartley (2013) furthermore notes that due to shale gas – and the resulting consequences for gas market prices – the traditional oil-linked contracts might become outdated.

It is interesting to note that similar trends hold for power markets. Balancing effects of generation schedules play an important role. Neuhoff et al. (2016) illustrate the need for more short-term trading, as information on wind and solar production usually increases in precision only at the intraday time frame. Accordingly, the regulation in recent years has experienced a shift in its focus on short-term markets, both in gas and power. The EU Target Models for Gas and Electricity exemplify this trend.

## 3.2 Continuously changing energy market design

At the heart of European energy regulation still lies the creation of the internal market. This holds for both electricity and natural gas.

For electricity, the goal has been to finalise the common European power market by 2014. Much has been achieved, especially on day-ahead markets that, as of today, are fully integrated

[17] They also show similar trends for the Asian market.

throughout Europe. The price coupling of regions – with its underlying clearing algorithm EUPHEMIA – guarantees liquid day-ahead markets that signal scarcity within each bidding zone.

However, many uncertain factors remain for trading at shorter maturity (at intraday and balancing timeframes). The Target Model for Electricity has established network codes to harmonise short-term market clearing. Yet, these are still to be fully implemented and many national system operators still use entirely different protocols and rules, for instance when it comes to procuring reserve power and activating and pricing balancing power. Also, intraday market mechanisms still differ drastically across EU member states.

This divergence in short-term market functioning brings disadvantages given that, with the growing share of renewable power, the need for trading and balancing day-ahead trades against weather updates increased significantly. At EPEX spot, the intraday trade volume rose continuously in recent years, and the introduction of intraday auctions further spurred the interest to trade intraday. Thus, while – as for gas markets – short-termism is building up, the regulation and design of intraday markets for electricity need to be harmonised.

Uncertainty not only prevails with respect to short-term markets but also with regards to investment. By limiting subsidies that deter investment and by strengthening the European regulatory body ACER, the recent winter package attempts to address these two crucial features in the EU power market. While these efforts certainly go into the right direction, the implementation is still difficult. National TSOs and regulatory bodies will play an important role for the coordination of short-term markets and operative alignment of network operation across borders. Given the diverging market rules in Europe, it will remain open to what extent this coordination and cooperation will happen.

Ultimately, these uncertainties imply for gas markets that investment into gas-fired plants remains risky; and that their operation on the short-term market likewise is exposed to fragmented European short-term energy or reserve markets. Some form of capacity remuneration mechanism may be needed to safeguard EU power markets and secure installed generation capacity. The role of gas-fired plants in these mechanisms may yet again differ across EU member states.

Similar regulatory risks also hold for gas markets, despite the Target Model for gas developed in 2011 (Glachant, 2011). Like the Target Model for power, the gas model provides an overarching framework for the European gas market, implemented via a number of network codes that organise gas trading and shipping. Given the changing gas market trends since the development of the network codes, ACER has recently reviewed and updated the Target Model (ACER, 2015).

Crucial pieces of legislation are the Capacity Allocation Mechanism (CAM) network code and the Congestion Management Procedures (CMP) code. The former, in particular, describes the allocation of transmission capacity to shippers within the entry-exit zone regime in Europe.[18]

[18] See EC Regulation 984-2013.

The code establishes auction-based allocation of capacity as a function of the shippers' willingness-to-pay expressed in the bids for network capacity. Within each zone, that is, within each virtual trading hub, gas has one price.

However, many virtual hubs are illiquid markets. Furthermore, while the northern hubs (TTF, German hubs, and Zeebrugge) are integrated markets, price correlation of other hubs with this core group is mixed (Petrovich, 2014). This lack of integration may have many reasons (e.g., transactions cost, market power) but it also reflects the lack of harmonisation of the capacity allocation procedures. Exemptions to the allocation of transmission capacity via auctions still exist.[19] These developments could lead to a non-optimal use of existing infrastructure. These issues are being tackled, as the European Commission has just initiated a discussion on the gas market design for Europe.[20]

## 3.3 Lack of common energy policy

The European gas market depends highly on how energy policy as a whole will develop. Indeed, it may be difficult for a common energy policy to simultaneously ensure sustainability, energy security and competitiveness. This energy policy triangle often raises political conflicts between member states, which again adds further regulatory risk.

**The EU ETS market**

Increases in gas demand may abruptly occur as a result from high carbon prices that make a fuel switch profitable. Recent policy efforts both at EU level (e.g. the market stability reserve) and at national level (e.g. the debate on national carbon price floors) suggest that at least the possibility of higher ETS prices exists. Indeed, also in the different Energy Roadmap 2050 scenarios, the ETS price assumptions vary in between 50 and 310 EUR (2008) per ton $CO_2$ and thus highlight earlier policy efforts for higher ETS prices. While so far, initiatives such as the carbon floor have been unilateral as in France and the UK, Europe might also implement such floors, thereby again boosting demand for natural gas. However, a common approach to more aggressive carbon pricing seems highly unlikely, again failing to provide more clarity for natural gas. Note that, similar to higher ETS prices, tight emissions performance standards would increase the competitiveness of gas-fired plants, as compared to coal-fired power generation. Recent initiatives have mostly occurred at national level however, such as the Emissions Performance Standard in the UK.

**The challenging mix of energy security and sustainability**

Following the International Energy Agency's definition, energy security is the "uninterrupted availability of energy sources at an affordable price". Sustainability is the way to guarantee real

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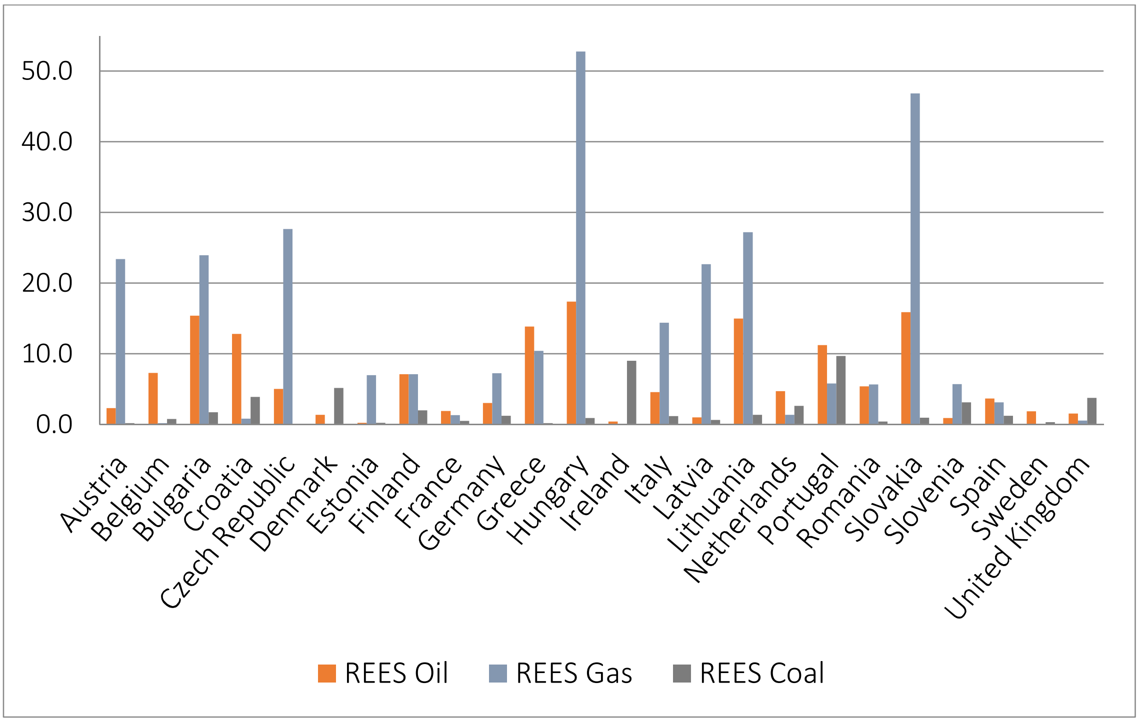
[19] First-come-first served and point-to-point contracts remain part of the sector.
[20] See the recent EC tender "Quo vadis, EU gas market regulatory framework – study on a Gas Market Design for Europe".

carbon savings and protect biodiversity. Not surprisingly, those two definitions may be contradictory in some context, and in fact are in the case of European gas consumption.

This last point is illustrated by looking at the energy risk exposure of different member states for their energy consumption. Consider the Risky External Energy Supply (REES), developed by Le Coq and Paltseva (2009) to measure the short-term impact of external energy supply disruption. Figure 5 illustrates the REES index estimates for 2013 for most EU Member States, for three types of fuels - oil, gas, and coal. This figure shows that the exposure to energy risk is not the same across EU.

**Figure 5: Energy risk exposure within the EU: REES index by fuel (2013)**




*Source: Le Coq and Paltseva (2015).*

This different energy risk exposure across EU member states is crucial when deciding the regulatory framework. For example, while more pipeline and LNG investments might be favoured by Eastern member states to decrease dependency on Russian gas, the Western focus within the Energy Union lies more on creating a single market and fighting climate change (Austvik, 2016). The divide between member states in this regard adds further uncertainty to the future gas market in Europe even though there are measures (review of the regulation 994/2010, ENTSOG early warning system, stress tests, platforms, etc.) designed or currently being designed for ensuring security of supply and improving solidarity among member states.

Moreover, Figure 5 shows that energy risk exposure associated with natural gas is the highest when looking at EU external energy security. The reason is twofold. First, so far, most of the natural gas consumed in the EU is supplied via pipeline, making gas not easy to substitute in case of a supply disruption. Second, many EU member states have highly concentrated gas imports (e.g., in Central and Eastern Europe, as well as in some of the Western-European countries, such as Austria, most of the natural gas originates from Russia). But the situation is expected to improve significantly, due to recent investments, especially in vulnerable states in Eastern Europe (terminalling, reverse flows, storage).

To conclude, current market conditions and regulatory and political evidence suggest that uncertainty prevails in the EU gas sector. If market and regulatory uncertainty is not addressed in a structured way, the reliance on gas may well decline faster than needed to manage the transition to 2030 and 2050 goals. Uncertainty also comes from the interplay between power and gas markets. Therefore, a more holistic approach combining power and gas markets could prove useful.

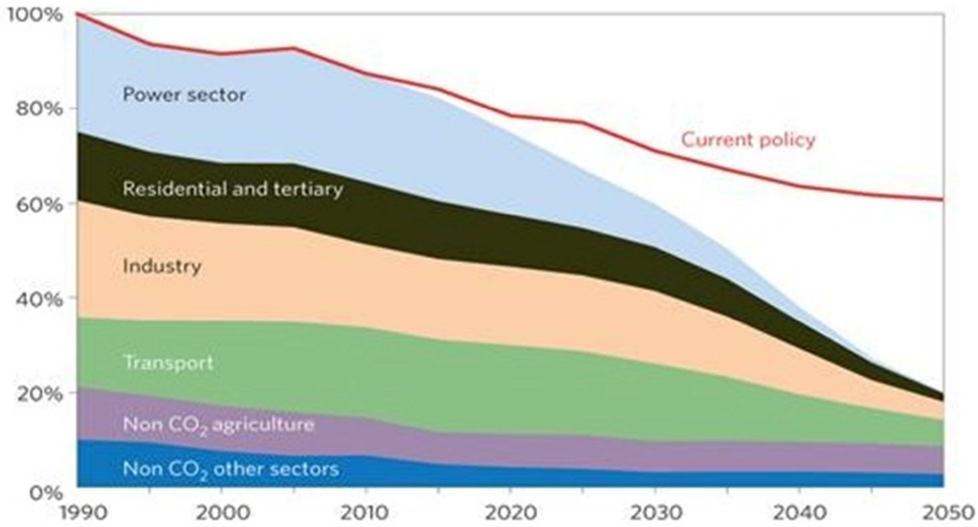
# 4. Policy challenges for the near future

The Energy Union package already provides a holistic approach to energy markets, covering a number of overarching action plans to increase sustainability, security of supply and competitiveness. The detailed implementation remains ambiguous, in particular in the gas market's case. Given its advantages for decarbonisation, gas could remain a key player, especially for the power market.

## 4.1 Prevent ETS prices that are 'too' low

Several roadmaps to 2050 have stressed power market's role to achieve an economy wide reduction of 80-95% of greenhouse gases (see e.g. Ruester et al. 2013). Figure 6 plots the required percentage point reductions in GHG emissions to achieve reduction goals across all sectors.

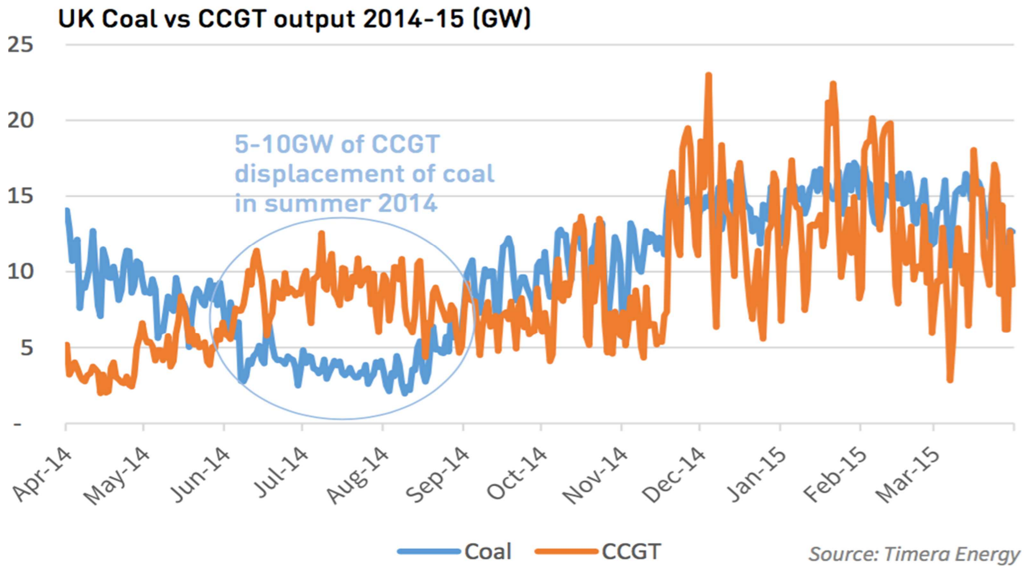
**Figure 6: Projected GHG reductions until 2050, by sector**




*Source: European Commission.*

The power sector contributes the most to the reduction of greenhouse gas emissions. As stressed earlier, natural gas will only play a role in this power market decarbonisation if ETS prices are sufficiently high. Small changes in design parameters can have large effects. This is the case with the recent introduction of a carbon price floor of 18 GBP/tonCO2 in the UK power market. Gas power plants regained partial competitiveness *vis-à-vis* coal plants. According to a recent analysis (see Figure 7), a fuel switch from coal to gas already took place in 2014 because of downward pressure on the gas price, illustrating the potential implications of higher ETS prices.

**Figure 7: Fuel switch in the UK market in summer 2014**




*Source: Taken from Timera Energy (2015).*

Therefore, given increasing ETS prices or tightening carbon price regulation, an elaborate short-term market design that guarantees liquid local gas markets and flexible gas transmission access can further incentivise gas-favouring switches in the merit order across Europe.

## 4.2 Facilitate the integration of gas and power markets

The power market is central to the future of the gas sector, and so is the interaction between the power and gas market, especially as heating and cooling markets are further electrified.

To this end, flexible energy short-term markets are needed and this will also involve a better cooperation of system operators across both power and gas markets, to allow for more synergies and information flows.

ACER, with its gas target model review, moves to a better cooperation of system operators both in gas and power, to allow for more synergies and information flows. A strengthened cooperation between gas and power TSOs is particularly important once one acknowledges that the gas market is moving to shorter-term transactions with more volatile prices; as does the power market. As a result, investors in gas-fired generation find themselves between two complex market environments: whenever renewables underperform and demand peaks, gas has to be available to quickly offer power to the intraday market. If not, such illiquid markets could endanger security of supply. In addition, gas-fired power plants operating in a strategic reserve or under capacity payments often face severe financial penalties in case of non-delivery. Thus, it would be beneficial if gas and power TSOs shared information on potential scarcity conditions in either market. Upon receiving such information, power and gas flows could be re-organised to account for safety margins for transmission capacity that might be needed to guarantee secure supply.

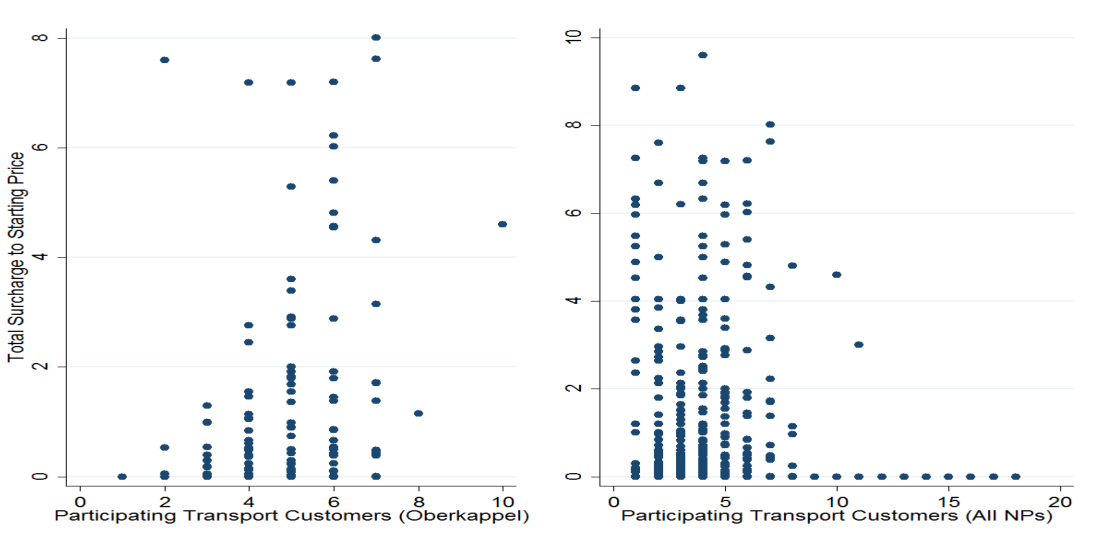
## 4.3 Revisit network capacity allocation

At the core of the EU gas market trade are the entry-exit system and virtual gas trading hubs.[21] For trading across hubs, following the framework guidelines on capacity allocation mechanisms for European gas transmission networks, transmission capacity has to be auctioned off. Initially, three booking platforms for transport capacities emerged (Trac-X, Capsquare and Link4Hubs). Out of those three, the common platform PRISMA evolved and started operation in April 2013. As of today, it comprises more than one hundred interconnection points of entry-exit zones and auctions off capacity for more than twenty transmission system operators. According to Regulation 984/2013 which established the network code on capacity allocation mechanisms (CAM), starting from November 2015, all technically available capacity for natural gas transport in the EU shall be allocated based on auction procedures.[22]

However, the capacity requested in these auctions is currently low. In addition, it seems that the bidding patterns are not very informative as for those network points with positive capacity demand, prices for gas transmission often are higher than actual scarcity conditions would suggest. Figure 8 plots the auction prices over the number of bidders for network points that were auctioned off at PRISMA during the gas year 2014-2015. Only auctions with positive demand are shown. The left side plots data for a representative, liquid (liquid at the Day-ahead stage) network point (entry/exit at German-Austrian border “Oberkappel”). The right side plots data pooled across all day-ahead auctions at all network points. For the selected liquid network point, the auction price increases with the number of bidders, as one would intuitively expect. Thus, shippers in this liquid market have gained experience in bidding and show bidding patterns that imply vivid competition. This, however, does not seem to be the case for all network points. As can be seen, over all auctions (right plot), there seems to be considerable uncertainty with respect to the number of competing bidders and the bidding amount required to be among the winning bidders for transmission capacity: even for low numbers of competing shippers, auctions prices are in many cases high.[23]

[21] The entry-exit is the model of choice under the EU Regulation No 715/2009.
[22] These procedures differ with respect to the duration and type of transport capacity. Long-term products such as yearly and quarterly allocation proceeds via dynamic ascending price multi-unit auctions. Short-term products, such as the day-ahead auctions, employ conventional multi-unit uniform price auctions.
[23] Note that we did not control for the different competing capacity products.

**Figure 8: Auction prices for all day-ahead transmission capacity auctions with positive demand at a representative network point (left) and for all network points (right)**




*Source: Own depiction, data from www.corporate.prisma-capacity.eu.*

It seems that for a number of auctions, standard market mechanisms do not hold. This warrants a deeper analysis of the PRISMA auctions and – ultimately – their ability to signal investment needs in new transmission capacity. At the moment, PRISMA auctions do not appear to be providing informative price signals in at least some auctions. The above stresses the importance of liquid short-term market designs that not only allow for operative efficiency, but also for making visible scarcity conditions and investment needs.[24]

## 4.4 Allow for cost recovery from energy prices

The merit order effect, in combination with low energy demand, has impacted the financial viability of gas power plants, and the capacity factor of CCGTs has been significantly reduced. It is, however, unclear whether capacity markets can guarantee secure supply at affordable prices as capacity markets, depending on the design, often are prone to the exercise of market power (Schwenen, 2015). In addition, capacity markets, as a tool to safeguard the power system, are rather disconnected from sustainability. Capacity markets currently do not take into account any low-carbon merits of certain generation technologies. Hence, as long as coal and lignite plants show lower marginal cost patterns, their capacity factors remain high.

Next to capacity markets, smaller capacity products have been developed in Europe to make reliable capacity available to the market. In UK, the supplemental balancing reserve was created to ensure balance between supply and demand across the country, and implicitly supports gas-

[24] For the latter, an in-depth analysis of the forward markets for capacity allocation would also be warranted. Further analysis on the efficiency of network allocation is out of the scope of this report but could prove useful. Precondition is that rich data is made available on the allocation process.

fired power plants that would otherwise be closed down before 2018 (see Caldecott and McDaniel, 2014). It is, however, unclear whether such strategic reserve mechanisms can trigger the right amount of investment that remains for the market to decide upon.

The European gas plant fleet is mostly dispatched as mid-merit or peaking capacity and so their asset value is mostly realised on the day-ahead, intraday, balancing, or reserve markets. As such, the value of gas assets should include the ability of assets to capture hourly price shapes, to respond to price volatility or to receive capacity payments in reserve or capacity markets. This stresses again the requirements of functioning short-term markets, both for energy and reserves, rather than debating fully-fledged capacity markets. In this context, the winter package already points to the possibility for intraday auctions for power next to continuous trading. Such auctions also offer the option to clear power markets based on complex bids, where start-up costs (e.g. of gas-fired plants) could be included in the clearing mechanism. Furthermore, if a series of intraday auctions are conducted, weather updates could be incorporated into the trading strategies.

Taken together, capacity markets are unfit for the purpose of reviving gas-fired generation in countries with a sizable coal-generation fleet, such as Germany or Poland. Rather, and as discussed earlier, liquid and competitive short-term markets, plus adequately high ETS prices, will form the base for flourishing gas and power market interaction in the long-run.

## 4.5 Ensure import diversification and infrastructure viability

Is there a need for further infrastructure investment in the European gas market? Could underinvestment in natural gas infrastructure hamper the fruitful interaction between gas and power, and ultimately the transition to a low carbon energy economy?

First, the current development of gas demand *per se* does not justify further infrastructure. As discussed, space heating undergoes a structural move that will potentially lead to alternative technologies to gas heating. Therefore, the current gas network *within* the EU seems to suffice and congestion is rather local, only occurring at selected network points. This becomes apparent when re-considering the auctions prices for network allocation. In line with short-termism discussed above, the most liquid auctions are the day-ahead auctions for network capacity. Even though the day-ahead auctions are the most liquid allocation mechanism, demand has been very low. Low demand for network capacity resulted in auction prices that are often equal to the reserve price (that assures that TSOs receive at least their network tariff).

In the gas year from October 2014 to September 2015, about 183,000 GWh/h were offered by TSOs at the day-ahead stage, while only about 8625 GWh/h were allocated via auctions. Total demand in nearly all 70.000 day-ahead auctions of this year for all EU entry/exit capacity was only 8841 GWh/h, indicating that only very few bids for transportation capacity had to be rationed. As a consequence, competition for network capacity has been limited. In less than 1% of all conducted day-ahead auctions, the auction price (the surcharge to the regulated tariff) was positive.[25] Hence, auction results, to the extent that they signal true underlying scarcity conditions, do not show any current need for additional investment in gas transport in Europe.

While current network constraints within the EU seem to be negligible, additional investment may still be needed to ensure security of supply and diversified import routes. Network constraints and system operability issues differ locally, so investment in each location should be subject to careful cost-benefit analysis. For example, constraints can arise in Central and Eastern Europe – a region mostly dependent on one supplier and not so well connected to Western Europe. Moreover, Holz et al. (2016) document that if gas demand in Asia grows, European gas imports may increasingly come from Africa and the Caspian region, leading to new infrastructure requirements.[26] Security of supply considerations should include LNG and gas storage capacities. As discussed above, a number of LNG projects are already planned. For gas storage on the other hand, market prices currently provide no incentives for new investments. The seasonal spread is well above the cost required to operate and maintain underground storage facilities. This may explain why we have observed a tight situation during the cold winter of 2013 (GIE, 2015).

In addition, the instalment of reverse flow technology will add flexibility to the existing network, in particular for countries dependent on a single source of gas. Reverse flows would also be beneficial for fostering market liquidity within Europe.[27]

Finally, an additional challenge is to decide between decommissioning parts of the network (given current demand and flow patterns) or maintaining the network to keep options open for future market needs (for example, to transport hydrogen). [28]

Similar investment needs apply for electricity, albeit at the distribution level. The structural move away from gas space heating will increase the usage of electric space heating and thus the usage of power distribution grids. Moreover, replacing the energy currently provided by gas for heating may require significant investments in the distribution networks.[29] While for gas the major infrastructure challenge will relate to being flexible *vis-à-vis* foreign supply sources, for power, the challenges lie at the very local and decentralised distribution level.

A paramount challenge, given these changing usage patterns for both power and gas, will be to provide sufficient remuneration to the network owners. For gas networks with falling usage, and where the returns on infrastructure investments were usually calculated for a 40 to 50-year period, the amortisation period may be too long. Where stranded assets are to be avoided, it

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[25] The scarce participation in auctions might be explained through many still existing point-to-point contracts that system operators have to accommodate for. Second, many operators might also apply first-come-first-served allocation. Note that current price signals of capacity bottlenecks may be too short-term to signal future scarcity and also yearly and quarterly products can signal investment needs.

[26] Of course, investments may also be required for maintenance and incremental capacity upgrades, which we do not discuss explicitly here.

[27] Reverse flows have already been implemented in parts of Central and Eastern Europe.

[28] KPMG (2016) in a recent report argues that, for the UK, a scenario where the use of alternative gases such as hydrogen and biogas increases, "continuing to use the gas network offers significant savings versus alternative heating sources".

[29] See Pudjianto et al. (2012) for numerical simulations for Great Britain's distribution networks.

remains crucial to find regulatory arrangements and tariffs that are based on breaking even in shorter time frames. At the same time, this implies that the costs of new investment are born in a shorter time duration and by fewer customers: a vicious circle that has to be avoided. Consumers might otherwise prematurely leave the gas market.

# 5. Policy implications and areas for future research

This report stresses the challenges faced by the gas sector as the EU moves forward with its Energy Union agenda. European gas production is falling but LNG imports are expected to increase, so gas supply is likely to be sufficient in the long term. Given this, much of the recent debate around natural gas has centred on the level of overall demand in Europe. After several years of decline, EU consumption has increased again in 2015. While this increase gives rise to optimism, challenges remain for exploiting the benefits of natural gas during the energy transition. These challenges relate to the competitiveness of natural gas in the heating and power sector, and to its relative emissions to other fuels and rival energy technologies. Ultimately, the future of natural gas will also depend on the economic feasibility of the innovations in gas (such as CCS) and the extent to which carbon prices incentivise the use of natural gas.

At the same time, gas trade is increasingly taking place on short-term markets and less under long-term contract regimes. This new trend requires the implementation of consistent short-term market designs throughout Europe, as regulatory uncertainty should not add to already uncertain market developments. In this sense, the review "Quo Vadis, EU Gas Market Design" currently undertaken by the European Commission should shed light on this issue. In this context, there is also a need for a debate about gas network pricing, especially for regions with falling demand for network usage.

In line with the outlook for EU gas demand, this report finds only limited and mostly local needs for additional investment in gas infrastructure. Thereby, investment needs largely arise due to changing import routes into Europe, rather than to account for network constraints within the EU. More importantly, gas networks should be operated in the context of a strong cooperation among electricity and gas transmission operators, so as to guarantee flexible operation of gas-fired power stations.

As further evidenced by the European Commission's Clean Energy Package published in November 2016, the overall policy direction remains firmly one of decarbonisation. So far, natural gas as a fossil fuel remains central, both to the power sector and the space-heating sector in many member states. While market entry of new renewable heating technologies supports EU decarbonisation policy, in contrast, developments in power markets are counteracting decarbonisation efforts. As the report has set out, coal-fired generation has been displacing gas power plants in many European power markets. Member states with carbon price floors – like the UK – seem to reverse this trend. Efforts to strengthen carbon pricing should continuously be undertaken also at EU level.

The developments of the heating and power markets discussed in this report suggest, at least, three areas that could be analysed further by policy makers but also by the gas sector itself. First, carbon pricing (e.g. the EU ETS) needs to be revisited and the market stability reserve forcefully implemented. Second, possibilities should be explored to push innovations in gas to maintain attractiveness of natural gas, both in power markets and in space heating. Last, it seems important to investigate how the development of consistent gas short-term market design and improved cooperation of transmission operators in gas and electricity could further foster efficient natural gas markets in Europe.

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