

Gas and Coal Competition in the EU Power Sector

Sylvie Cornot-Gandolphe
June 2014



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EXECUTIVE SUMMARY

This report reviews gas and coal competition in the EU power sector. It looks at recent developments and analyses the key drivers determining the future dynamics of this competition: gas, coal and carbon dioxide (CO₂) prices, EU regulation, in particular on emissions of local pollutants, national policies, technical and financial aspects. It highlights the deepness of the crisis of the EU electricity system and that of natural gas in the power sector:

- Gas and coal competition does not favour gas which has seen its demand by the power sector shrinking in the past three years;
- Security of electricity supply is at risk as unprofitable gas power plants are closing and old coal stations are being retired, while at the same time flexible generation is needed to back-up intermittent renewable energy sources (RES).

The European paradox

Technical, environmental and financing parameters favour natural gas over coal...

Natural gas has many advantages over coal in the power sector. Combined cycle gas turbine plants (CCGTs) offer higher efficiency, lower CO₂ emissions, relatively quick and cheaper construction, modularity, less local resistance to the siting of new plants, and more flexibility for quick ramp up of production.

Power capacity expansion in the past thirteen years clearly indicates that gas was expected to facilitate the large-scale deployment of variable RES. Since 2000, RES and natural gas installed power capacity has increased by 169 GW and 121 GW respectively. Over the same period, the coal fleet has been reduced by 13 GW.

...but economics dictates a preference for coal

Despite the numerous advantages of natural gas over coal, the evolution of commodity and carbon prices and the fast development of RES have made gas-fired generation a loss-making business, even for the most efficient and newly-built gas-fired plants.

- **High gas prices relative to coal and the collapse of CO₂ prices have eroded gas competitiveness**

Gas competitiveness has been eroded by the decrease in coal prices. The collapse of CO₂ prices since 2012 has reinforced the competitiveness of coal against natural gas. US shale gas production has displaced coal in the country's power mix. Faced with a shrinking market at home, American coal mining companies have turned to overseas coal markets. The inflow of US coal, on a market already well supplied, has created a supply glut and led to a sharp decline in coal prices. Coal prices declined by 32% between the middle of 2011 and the end of 2013. At the opposite, gas prices, still largely linked to oil prices, increased by 42% between 2010 and 2013, in line with oil prices. **The recent fall in gas prices (a decline of 29% for spot prices in the first four months of 2014) does not change the competitiveness of coal over natural gas. As coal prices have also declined, coal is three times cheaper than natural gas on an energy equivalence basis.**

- **Gas demand by the power sector has shrunk by one third**

During the past three years, gas demand by EU power generators decreased by 51 billion cubic meters (bcm), or one third from the historical peak reached in 2010. This is a reduction equivalent to the total French gas market. The share of natural gas in the EU electricity mix fell from 23.6% in 2010

to 19% in 2012. At the opposite, coal-fired power stations had been operated at high loads, increasing coal demand by the sector. Coal demand increased by 10% between 2010 and 2012 (it decreased in 2013) and the share of coal in electricity generation amounted to 28% in 2012.

These trends have put a halt on the declining trend in CO₂ emissions from the power sector in some key countries despite the fast rise of RES.

■ RES push natural gas out of the merit order

In 2012, RES (including hydro) generated 23.5% of EU electricity and overtook natural gas for the first time. The fast deployment of wind and solar has displaced peak and mid-merit conventional power plants and contributed to a fall in wholesale electricity prices.

Low power prices have reduced the profitability of power generation. The trend has been particularly acute for gas power generators which have been faced with increasing gas prices. The clean spark spread (the measure of profitability of gas power plants) has been negative since the beginning of 2012, meaning that on average gas power plants have lost money. At the opposite, thanks to the decrease in coal prices and the collapse in CO₂ prices, the clean dark spread (the measure of profitability of coal power plants) has remained positive.

RES, which have low or zero marginal costs, push out energy sources with higher marginal costs, in the merit order dispatch of power plants. **Gas-fired power plants, which have high marginal costs, have been the first to be pushed out from the system, decreasing their running hours.** In Germany, the average load factor of gas-fired power plants declined to 21% in 2013. In Spain, the load factor of combined cycle gas turbine (CCGT) plants has plunged from rates consistently over 50% until 2008 to an average of just 11% in 2013. The rapid increase in RES also means that more often the price of electricity is set by lower marginal cost energy sources, preventing gas-fired power plants to recoup their fixed costs, and even in some cases, their operating costs.

Security of electricity supply at risk with closure of unprofitable gas plants and retirement of ageing coal fleet

■ Massive closures of gas capacity

Faced with low running hours and declining/negative margins, gas power operators have started to mothball or close their loss-making plants. **At the end of 2013, 24.7 GW of gas-fired power capacity were idled, closed or at risk of closure, most of them in northwest Europe. This represents 14% of the EU installed capacity.** The first plants to be closed were the old plants which have lower efficiencies than new builds. However, the further deterioration of market conditions has led utilities to mothball new build plants with efficiency of 58-60%. **If all gas power plants currently under review by major European utilities are closed, this may lead to the closure of about 50 GW of capacity by 2015/16, or 28% of the current capacity,** while at the same time this capacity is needed to ensure security of supply when wind and sun are not producing.

■ Coal renaissance may be short lived

While coal plants have been operated at high loads so far, **RES development is starting to push out hard coal from the merit order.** In 2013, EU coal demand decreased by an estimated 5%. In Spain, wind became the first primary source of electricity in 2013 (21% market share), while coal saw its share falling to 14.6% from 19% in 2012. Moreover, the rapid development of RES, which so far had only impacted gas-fired power plants, is starting to take its toll on hard coal power plants' profitability.

This trend is reinforced by EU regulation on air quality. The impact of the Large Combustion Plant Directive (LCPD), which restricts the emissions of local pollutants (SO_x, NO_x emissions and small particulates), is already felt on the EU ageing coal fleet: 15.8 GW of coal-fired capacity will be closed by the end of 2015 at the latest, mainly in the United Kingdom and France (several plants are already closed). The Industrial Emission Directive (IED), which succeeds the LCPD from 1 January 2016, will further restrict the emissions limits. For old coal power plants (40% of the coal fleet is more than 40 years old), there will be no incentive to invest in depollution equipment and an **estimated 50 to 55 GW of coal power capacity may close by 2020/2023 at the latest. Overall, the current capacity may be reduced by about 65 to 70 GW, due to the combined effect of the LCPD and IED, representing a third of the coal fleet capacity.**

■ 115-120 GW of gas and coal capacity to close/at risk of closure

Altogether a capacity of 115-120 GW is closing or at risk of closure, representing a third of gas and coal capacity in the EU. These trends pose a serious challenge for security of supply as thermal power generation is needed to back-up variable RES. The building of flexible power capacity required to support the development of RES is threatened by the lack of market signals and adverse investment environment. The current situation has the potential to unfold into a major structural crisis.

Although reserve margins are still adequate in most countries, when the anticipated mothballing/closure of uneconomic plants, retirement of ageing coal plants, as well as delays or cancellations of new projects, are taken into account, the situation is different in several countries. In the UK, for instance, despite the expansion of RES, the reserve margin is falling. While old coal plants are closing (as expected), the (unexpected) mothballing and early closure of gas plants is reducing the power margin from 6% in 2013/2014 to 4% in 2015/2016, a level which puts the UK system at risk.

■ Power utilities are no more investing in thermal power generation in the EU

The lack of future for some gas and coal power plants has led some European power utilities to write down power generation assets. In 2013 only, key utilities in the EU reported power generation asset impairments of €15 billion, the same level in one year than what they reported in the 2010-2012 period. Faced with adverse market conditions in the EU, power utilities are adapting their strategy to the new conditions. They are moving from the traditional business model based on large-scale electricity generation to new business models focused on renewable generation and new sustainable and smart products and services. They are no more investing in thermal power plants in the EU. They focus thermal power generation expansion away from the region with investment in growth markets (Turkey, Russia, Eastern Europe, Latin America, Asia). **There is an urgent need to rebuild confidence in the European electricity market.**

■ A new market design is required

As the market does not provide the right signal for investment in conventional capacity, a new market design is urgently needed. A sustainable electricity market design needs to ensure that low-carbon and fossil fuel-fired power plants have viable business models with manageable investment risks.

To address the immediate security of supply concerns, several EU countries are introducing capacity markets in order to provide additional stimulus to investors and ensure that a sufficient amount of capacity will be available. The design of such mechanisms is however extremely complex with the need i) to balance the amount of capacity needed to ensure security of supply with demand-side response

and ii) to integrate interconnection capacity and the development of cross-border trade with the aim of achieving a fully EU integrated Internal Electricity Market.

These mechanisms do answer to the immediate concern: keeping the lights on. A more profound reform of the entire power system will nevertheless be necessary, including structural reform of the EU ETS, integration of RES into the market, and completion of the Internal Electricity and Gas Markets.

Gas and coal prices trends will continue favouring coal

The relationship between coal, gas and CO₂ prices is a key determinant of the competition between gas and coal in the power sector and will remain a driver of fuel switching. Although there are many uncertainties in the evolution of gas and coal prices, **coal is expected to retain its competitiveness against natural gas in the future too**. CO₂ prices, which are mainly driven by policy decisions, may change this situation, depending on structural reforms of the EU ETS.

■ Downward pressure on gas prices

There is downward pressure on future European gas prices, coming from indexation on gas hubs, a wave of new supplies (pipeline and above all LNG) and potential shale gas production in the EU.

At short term, the influence of oil prices will still dominate for several years. Despite the declining share of European supplies tied to oil prices, long-term contracts that make most of European pipeline imports, some of them running up to 2030, are still 50% linked to oil. In the coming years, marginal supplies needed to cover an increase in European gas demand (or decline in EU production) will be determined by supplies which either are linked to oil (pipeline gas from Russia) or have to compete with Asia (and Latin America) where LNG prices are still linked to oil prices and much higher than European prices. Seasonal drops in gas prices, as currently experienced, can be expected depending on the availability of uncontracted LNG supplies.

At medium/long-term, with a growing share of gas supplies sold based on hub prices, prices will be determined to a much larger degree by actual supply and demand fundamentals and by gas-on-gas competition between various suppliers competing for market shares. The move to gas-on-gas competition needs to be accompanied with the development of supply sources, both domestic ones and new sources, in particular in southeast Europe, and investment in new pipelines and interconnectors, to allow a wider range of supply sources to reach EU gas customers and competition between supplies to develop. A higher share of LNG imports is foreseen. This is in line with the high regasification capacity available in Europe which theoretically would allow the imports of 199 bcm/a. Numerous LNG export projects are being developed by new sellers (US, East and West Africa) that will offer the possibility to further diversify EU gas supplies. In addition to new supplies from the Caspian region, East and West Africa, the Mediterranean, possible production of shale gas in the EU and LNG exports from the US based on Henry Hub prices may add competitive pressure and put a cap on European prices, although it is unlikely that this translates into large reductions in prices.

■ Coal prices have reached a bottom

In contrast with natural gas, the coal market is a global and competitive one. Prices are similar on the Pacific and the Atlantic basins. The supply glut that has developed on international markets has led to a large decline in coal prices.

China, which was still a net exporter in 2008, has become a net importer since 2009 and **became the world's largest coal importer in 2011**. It now represents almost a quarter of world steam coal imports. Due to its size on the international coal market, China has become a price setter for steam coal and **policy decisions taken in Beijing affect the price of coal delivered to other Asian countries and**

European buyers. Yet China remains the world's largest producer of coal. Its imports are only a small part of its supply. They are driven by **coal price arbitrage between domestic and international coal prices**. This makes difficult the forecast of future global steam coal trade and prices as it depends on China's market development and government policies. The Chinese government is determined to reduce the share of coal in the energy mix. This may drastically reduce China's coal imports. However, while the commitment of the government is clear, the speed of change remains uncertain.

Despite these uncertainties, the growth in global trade is expected to slow down in the next few years. The global supply overhang is expected to persist in 2014 and 2015. As prices have certainly reached a bottom, no further declines are expected. Mining companies have started to close their highest cost mines and focus on cost reductions. The rebalancing of the market is not expected before 2016 and **only a slight recovery in coal prices** is expected as there are plenty of new coal mine developments in the pipeline.

■ CO₂: Can the Phoenix rise from the ashes?

While the EU Emission Trading Scheme (EU ETS) was introduced to provide a price signal for investment in low-carbon technologies, the massive oversupply of allowances has driven down carbon prices to such low levels that **the EU ETS plays virtually no role at all in influencing investments into new generation capacities**. With the adoption, at the beginning of 2014, of short-term measures (backloading) and proposed in-depth structural reforms, the European Commission hopes to address the present EU ETS flaws and promote a well-functioning carbon market. The reform is urgently needed to give the appropriate signal for future investment in the power sector. However, while CO₂ prices have settled at €5-6/t since the beginning of 2014, a level of €30/t would be required to foster switching from coal to gas at prices observed at the beginning of May 2014 (€50/t at gas and coal prices in January 2014), a level which is not attainable, nor desirable, at short term. It should also be mentioned that before any major investment decisions in the power sector are made based on the EU ETS, the price needs to reach a significant level and stay there for a prolonged period of time.

Competition between gas and coal is not driven by commodity and CO₂ prices only: governments play a key role

Taxes on fossil-fuel generation and other national policy measures play a key role in shaping the competition between coal and gas in the power sector, in addition to the EU overarching climate and energy policies. Taxes (carbon tax) can reverse the current competitiveness of coal against gas. The introduction of emissions performance standards (EPS) can even prevent the building of new unabated coal stations.

The three largest EU coal consuming countries – Germany, Poland and the United Kingdom – have mixed approaches on the role of coal in their electricity mix. **The analysis of their national energy policies shows clearly that the path to a low carbon economy can be achieved differently and at different timeframes according to national preferences for one source of energy and trade-offs between the objectives of sustainability, competitiveness and security of supply.**

In Germany, competition between coal and gas is left to market forces and is not specifically addressed by the *Energiewende*. The fast expansion of wind and solar has pushed out natural gas from the merit order. This has resulted in increased coal consumption by the power sector. The country is closing its old inefficient coal-fired plants and replaces them by high-efficient ones, which will help reducing CO₂ emissions. Germany is also developing its lignite resources, the second largest in the world, to feed its new lignite-fired power plants. The carbon emission target of the German energy sector will fall below

the current CO₂ emissions from coal power plants before 2030. CCS may have helped to decarbonise the electricity mix. However, it encounters widespread opposition, above all against carbon storage, throughout large sections of the population. As a result, without the application of CCS technology, it can be expected that coal consumption for power generation will be restricted in the long term.

Coal dominates the electricity mix in Poland. For security of supply and independence objectives, exacerbated by the Russia-Ukraine crisis, this role is expected to continue in the future. The new Polish energy strategy, released in November 2013, concludes that coal provides the cheapest and therefore the optimal, solution to supply Poland's power also in the long term. Diversification of the energy mix is nevertheless pursued and includes renewables, LNG, shale gas, and nuclear. The Polish power sector faces many challenges. One of the urgent issues is to replace the ageing coal fleet. As most options to diversify the energy mix are medium to long term ones, there are few alternatives to building new coal fired power plants. Nevertheless Poland's overwhelming reliance on coal could potentially drop following the further coupling of the regional power markets and increased cross-border electricity flows.

In the United Kingdom, by contrast, the energy and climate policy does not encourage the use of coal. The introduction of a carbon tax in 2013 penalises coal burning. The increase in the carbon floor price, despite its recent freezing, is expected to reverse the current balance between clean spark and dark spreads to the benefit of natural gas. Furthermore, generators with old coal plants will have little incentive to invest in depollution equipment and may choose to close their plants. Gas burning is expected to increase with the closure of coal plants. The UK is implementing a capacity market to address the issue of generation adequacy, which may allow mothballed gas plants to restart operations and fosters investment in new gas plants. The government has also adopted an EPS which prevents the construction of new unabated coal stations. At longer term, the efforts deployed by the government to develop a CCS industry, may well allow clean coal resurgence.

Future gas and coal contest: reinventing a business case for gas in the power sector

Regulatory uncertainties make the future role of gas in the power sector very difficult to predict. Projections by major institutions (IEA, EUROGAS, EURELECTRIC) show that a resurgence of gas demand in the EU electricity mix is not foreseen during this decade. At longer term, the role of gas depends on a complex interplay of global and European market forces, and of European and national energy policies and market designs. **While coal plant closures do not depict a bright future for coal use in the power sector, they do not mean higher gas demand by the power sector due to poor economics of gas-fired generation and regulatory uncertainties.**

Three main conditions are needed to reverse this situation and allow clean and flexible natural gas to play its role as an enabler of the transition to a low carbon economy:

■ Decarbonisation and reform of the EU ETS

The reform of the EU ETS, which is urgently needed, should allow natural gas to play a key role in the decarbonisation of the EU electricity system. A reduction of CO₂ emissions by 40% by 2030 could hardly be met otherwise.

■ Gas prices and market liberalisation

The further liberalisation of gas markets and supply diversification should allow gas prices to be determined by market fundamentals and liquid gas markets to further developed, a condition for the use of gas in the EU power sector characterised by a growing level of variable generation.

The competitiveness of natural gas in the power sector must be addressed, for instance by developing partnerships between suppliers and utilities and exploring new sales and purchase agreements including the specificities of the EU electricity sector. This requires, however, that gas exporters and importers share the same vision on the evolving EU gas and electricity market and are ready to cooperate to rebuild the competitiveness of natural gas in the power segment. The power sector is still the segment which offers the largest opportunity to increase gas consumption.

The exploration and production of shale gas in Europe, under sustainable conditions, would allow Europe to reduce its external dependence and provides a new source of gas to the market.

■ Investment and electricity market design

Addressing the investment issue is of utmost importance to ensure future security of electricity supply. Capacity markets, properly designed, should allow a recovery of investment in gas capacity, and in particular, to restart the numerous mothballed gas plants and unlock frozen CCGT projects.

STRUCTURE OF THE REPORT

This report focuses on the competition between gas and coal in the EU electricity mix. It looks at recent developments and analyses the key drivers shaping the future dynamics of this competition.

The report includes six main parts:

A brief introduction recalls major developments in global energy markets and the evolution of EU energy and climate policy since 2008 with a focus on electricity markets.

The first chapter provides detailed information on the evolution of the EU electricity market. The first sections (Sections 1.1 to 1.3) provide background information on the EU electricity market, the evolution of power generation supply and demand, power capacity and wholesale electricity prices. Sections 1.4 and 1.5 analyse the main factors explaining the lack of competitiveness of gas relative to coal and assess the operational impact on gas-fired power plants. Section 1.6 focuses on regulatory aspects that will impact the future use of coal by European utilities. It first looks at European regulations on emissions of pollutants (LCPD and IED) and their impact on the ageing coal fleet. It also reviews the current coal capacity addition boom and future prospects. An Annex reviews national policies restricting the use of coal, or at the opposite, securing domestic coal supplies. Energy policies of Germany, Poland and the UK, the three largest EU coal consuming countries, are studied. Section 1.7 looks at environmental and technical aspects and investigates the ability of gas and coal power plants to accommodate the new needs of the EU electricity market. It reviews the increased efficiencies and flexibility of new thermal power plants and also gives an assessment of the development of CCS in the EU. Section 1.8 analyses the financial impact of the crisis in the EU power market on power utilities. Section 1.9 highlights the security of electricity supply issue and looks at approaches taken by several governments to address the issue.

Gas, coal and CO₂ prices play a key role in the competition between gas and coal in the power sector. The second, third and fourth chapters are devoted to an analysis of gas, coal and CO₂ markets and prices. The objective is to look at key factors and trends that will influence their prices.

Chapter 2 reviews recent development in gas pricing and analyses how new gas supplies (shale gas production in the EU and new LNG supplies) may impact gas pricing and future gas prices. An Annex gives detailed information on the European gas market.

Chapter 3 focuses on steam coal trade and prices in Europe. Due to the importance of global (and Chinese) trends on European import steam coal prices, it first reviews trends in global supply and demand. Then, it analyses future trends in global steam coal trade and prices. An Annex gives detailed information on coal demand and supply in the EU.

Chapter 4 analyses the EU ETS market and the evolution of CO₂ prices. It reviews the current flaws in the EU ETS and measures proposed by the European Commission to reform the scheme. It discusses possible outcome of these reforms and impact on gas and coal competition.

The final chapter compares the projections for gas and coal demand in the EU electricity sector carried out by the most renowned international and European institutions. **It draws conclusions on the contest between gas and coal at short and medium/long term and highlights necessary conditions for gas to renew with growth in the power sector.**

PREAMBLE

Although CEDIGAZ statistical and outlook analysis traditionally looks at the situation in the European region including 35 countries, this report focuses on the EU only. This is a deliberate choice as Turkey and south-eastern European countries, not members of the EU, have a different dynamics than most EU countries, such as fast growth in electricity and gas demand in Turkey, which may mask some major trends when figures are aggregated at regional level.

Likewise, unless specified, the data refer to EU27, and not EU28, as most historical data and studies analysed in this report cover EU27.

INTRODUCTION

THE EU ENERGY AND CLIMATE POLICY

IN THE GLOBAL CONTEXT

EU ENERGY POLICY AND WORLD ENERGY DEVELOPMENTS SINCE 2008

The European energy policy context has changed dramatically since 2008, under the influence of the EU energy and climate policy and world economic and energy developments. The EU has a larger role in Member States energy policy since the adoption of the Directives on the Internal Energy Market and the 2020 targets for greenhouse gas (GHG) reductions, renewable energy sources (RES) development and energy efficiency. The global energy landscape has undergone major changes that have a large impact on EU energy markets and were not expected when the EU climate and energy policy was adopted in 2008¹.

The global energy landscape is undergoing major changes

The global economic crisis had significant impacts on the EU energy and electricity sector. It significantly reduced electricity demand, reduced CO₂ emissions through lower industrial output and reduced consumers' ability to pay the high cost of subsidised RES. Power utilities, which had consolidated during the past decade, were left with high debt and lower electricity sales, a reduction exacerbated by the fast growing expansion of RES.

The US shale gas revolution has far-reaching impacts on the energy markets, the economy and geopolitics. Shale gas resources have moved global gas markets from scarcity to abundance of resources. Falling gas prices in the US have given a renewed competitiveness to North American economy while Europe has been struggling with high energy prices. Energy-intensive industries are re-shoring in the US, which is now one of the lowest cost producers of petrochemicals and its derivatives. Thanks to its large shale gas resources, the US is becoming an LNG (liquefied natural gas) exporter. Potential exports are huge with major impacts on European and global gas markets. US shale gas has displaced coal in the domestic power sector. US coal miners have increasingly turned to the international market. This has provoked an influx of cheap coal on the European market, displacing natural gas in the power sector. While the US shale gas revolution allows the US to reduce its CO₂ emissions by substituting natural gas to coal, the opposite has happened in Europe.

The Fukushima catastrophe has brutally stopped the expansion of nuclear power in the EU. The decision by several EU countries to phase out nuclear power adds challenges to the EU electricity system. The decision by the German government to stop eight nuclear power plants in the wake of the Fukushima accident, to completely phase out its nuclear power plants by 2022 and to accelerate its *Energiewende* has already put pressure on the regional electricity grid. The need by Japan to replace its lost nuclear capacity has had a large impact on the LNG market. The "LNG bubble" which characterised the market at the end of the 2000s has disappeared and the market is so tight that demand is constrained by supply. The premium paid by Asian buyers has made Europe a less attractive destination for LNG suppliers.

Global climate action has been fragmented and customised to specific economic conditions. Thirty-eight developed countries, including the EU, have taken on legally-binding emission commitments for a second period under the Kyoto Protocol amounting to an average reduction of at least 18% below 1990 levels. However, Japan, New Zealand and the Russian Federation have not made new commitments. While the need to decarbonise the global economy is undisputable, fossil fuels still

¹ See the analysis carried out for the French government: Policy Planning Commission (2014), *The Crisis of the European Electricity System - Diagnosis and possible ways forward*, Commissariat général à la stratégie et à la prospective, Paris, January 2014

dominate the energy mix and the International Energy Agency outlook for 2035² shows that this domination is not expected to fall significantly. Under the New Policies Scenario, the share of fossil fuels in the global energy mix decreases from 82% in 2011 to 76% by 2035. With a view to limit climate change, the World Bank and other multilateral financing institutions have adopted emissions performance standards or stricter conditions for lending money to new coal power plants.

The Arab Spring has reminded that security of supply and geopolitics are still predominant. Oil and gas exports by some suppliers to Europe were cut or reduced. **The Russia-Ukraine crisis** reinforces security of supply issues and is challenging EU energy and gas import dependence from Russia. It highlights the external dimension of gas security of supply.

There has been a decisive **shift in the centre of gravity of global energy demand** towards emerging economics, notably China and India. It is clear that in the period until 2030 energy demand will increase globally, in particular in Asia, with expected strong rise in hydrocarbons imports.

This is under this challenging context that the new EU Commission, to be elected in May, will have to negotiate the 2030 climate and energy framework.

The EU energy and climate policy

The so-called “three pillars” (or “energy trilemma”) – sustainability, competitiveness and security of supply – are the core principles of the European Union energy policy. In addition, the EU has committed itself to a decarbonisation path that will see an 80 to 95% reduction in its CO₂ emissions by 2050. The construction of an integrated and liberalised electricity market, initiated in the early nineties, and the Climate and Energy Package, adopted in 2008, are the cornerstone of the EU energy policy. But it is now obvious that both no longer meet their original objectives: security of supply, affordability and sustainability³. Instead, even security of electricity supply is threatened, although electricity is produced regionally.

A brief overview of the two cornerstones is given hereunder with a focus on electricity markets.

The Internal Energy Market

The liberalisation process in the energy sector was initiated by the European Commission in the 1990s to create an integrated **Internal Energy Market (IEM)**. By allowing competition and thus increasing the number of players in the market, the main expected benefit was that retail prices would lower for final consumers. Moreover, liberalisation was also expected to provide more secure supplies with more players in the market. Since late 1990s, the European Commission gradually put in place an Internal Energy Market for electricity and gas. Regarding electricity, it started with Directive 96/92/EC, later replaced by Directive 2003/54/EC, which laid down a regulatory framework and some common rules for the internal market, notably regulated third party access, unbundling and liberalisation of supply. A new legislative package, the **“Third Energy Package”** adopted in July 2009, aimed at introducing common rules for the generation and transmission (with notably unbundling of transmission networks and generation of electricity), distribution and supply of electricity. It established National Regulatory Authorities in each Member State and implemented an Agency for the Cooperation of Energy Regulators (ACER), as well as the European Network of Transmission System Operators in Electricity (ENTSO-E) and gas (ENTSO-G).

² IEA (2013), World Energy Outlook 2013, IEA/OCDE, Paris, November 2013

³ Policy Planning Commission (2014), op. cit.

The Third Energy Package set forward a plan to implement a Target Model for electricity and gas markets in Europe by 2015. As far as electricity is concerned, the main objective is to ensure the optimal use of power generation plants and transmission infrastructure across Europe through the optimal use of transmission network capacity in a coordinated way, achieving reliable prices and liquidity in the day-ahead market (with market coupling) and achieving efficient forward market and intraday market (with a European platform for continuous trade with implicit allocation of capacity). As part of this plan, ENTSO-E is thus tasked to define legally binding network codes, in accordance with the framework guidelines defined by ACER.

Market coupling on a regional basis has developed since then and led to stronger price convergence between coupled markets. On 4 February 2014, a major step was achieved in that direction when the coupling of day-ahead power markets of North-Western Europe and South-Western Europe was successfully launched. These markets account for about 75% of European electricity demand.

Despite recent major advances, however, full integration of Europe's energy markets networks and systems and opening up energy markets are not yet achieved. Europe is still characterised by a large number of differing national market designs and the priorities of each country are reflected in the structure and organisation of their electricity markets. Much more must be done to integrate markets, improve competition and respond to new challenges.

The Climate and Energy Package

In December 2008, the European leaders committed to turn Europe into a highly efficient and low carbon economy and to that end, adopted the **Climate Change Package with its three targets for 2020**: reducing EU GHG emissions from 1990 levels by 20%, raising the share of EU energy consumption produced from RES to 20%, and improving the EU's energy efficiency by 20% by 2020.

The Climate Change Package added a set of new Directives on top of the IEM process. These included: the EU European Trading Scheme (EU ETS), the renewables directive, the energy efficiency directive (in 2012) and the carbon target. Except for the energy efficiency component, EU Member States seem to be on track to meet these targets. **However, due to the interference between the three targets of the Climate Package, as well as international developments, none of the objectives of the IEM are being delivered.**

The EU ETS has not driven investments in low-carbon technologies. At the opposite, the collapse of CO₂ prices has facilitated a gas-to-coal switching since 2010, increasing CO₂ emissions of power operators participating in the EU ETS. The absence of market signals has increased the likelihood of national interventions that undermine the market integration process.

RES have developed rapidly thanks to financial supports put in place by governments. However, the level of subsidies has exploded leading to high energy prices for the industry and households. Electricity prices for EU industrial users are almost double those in the US, compromising the competitiveness of the EU. Consumers' bills have also increased dramatically.

The development of RES, subsidised by Feed-in-Tariffs (FIT) and with priority of dispatch and access to the grid in some countries, has distorted the functioning of the energy-only market. Gas-fired power plants, which can no more recoup their fixed costs (and in some cases, even their O&M costs), are being closed or mothballed. This threatens security of electricity supply as these flexible plants are needed to ensure capacity adequacy. In the absence of a long-term market signal, there is no investment in new thermal power plants which are needed to back-up the increasing level of intermittent RES.

As a consequence, the three core objectives of the European energy policy are under serious threat. The 2030 framework, currently under negotiation, is expected to address the distortions that overlapping targets have created on the functioning of the European energy markets. The **new 2030 climate and energy policy goals**, published in January 2014, recommends a reduction by 40% of GHG by 2030, a binding target of 27% at EU-level for RES, but not at national level, and no new energy efficiency targets at this stage. In addition, the Commission has proposed reforming the EU ETS. This approach has been generally well accepted, however, there is no consensus between Member States. Thirteen Member States (Germany, France, UK and the other members of the so-called “Green Growth Group”) want the EU to agree on the broad outlines of a 2030 climate and energy policy as soon as possible. But at least four (the so-called “Visegrad Group”, including Poland, Czech Republic, Hungary and Slovakia) argue all decisions should be put on hold until UN climate talks in Paris in 2015. As reforming the EU energy and climate policy is urgently needed, **the new Commission will have to find a compromise taking into account the imperative of competitiveness and security of supply when transiting to a low carbon economy.**

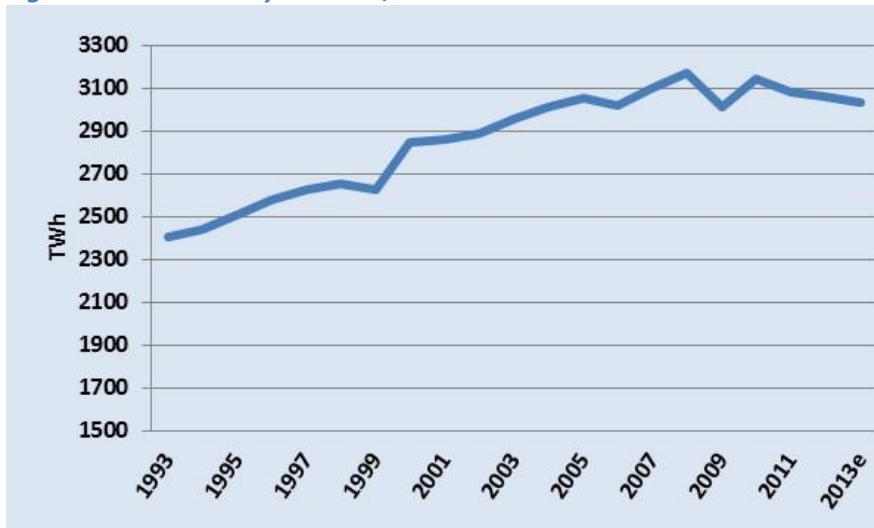
1. THE EU ELECTRICITY MARKET

1.1. EU ELECTRICITY DEMAND

EU electricity demand has flattened

The growth in EU electricity demand⁴ has slowed down since the beginning of the 2000s after decades of strong growth. After a compounded annual growth rate (CAGR) of 2% in the 1990s, demand increased by a CAGR of 1.35% only during 2000-2008, when it reached a peak of 3168 TWh. After its plunge in 2009, electricity demand partially recovered in 2010⁵, but has fallen since then: -2.2% in 2011, -0.6% in 2012 and an estimated -0.9% to 3029 TWh in 2013 (provisional). Overall, EU electricity demand increased by 29% at CAGR of 1.1% from 1990 to 2013.

Figure 1: EU electricity demand, 1993-2013



Source: EURELECTRIC, EUROSTAT. 2013: provisional

The main cause of the decline is the **European economic slowdown**. In 2012, real gross domestic product (GDP) in the EU shrunk by 0.4% compared with 2011. In 2013, the EU came out of recession in the second quarter of 2013 but the recovery was very weak. GDP rose by 0.1% in the EU, but fell by 0.4% in the euro area. Production in important energy consumer sectors, such as industry and construction, decreased again in 2013 (-0.5% and -2.2%, year-on-year).

Structural trend: Rising energy efficiency

While electricity demand is strongly dependent on economic activity, the historic relationship has loosened as **energy efficiency rises** and the structural shift to less energy-intensive industries has reduced energy and electricity demand.

The EU has pledged to cut its energy consumption by 20% (compared with baseline levels) by 2020. Although it is not certain that the target will be reached, energy efficiency investment has already delivered significant reductions in energy demand. Energy efficiency improved by 16% at EU level between 2000 and 2011 (1.5%/year)⁶. In the manufacturing industry, one of the largest electricity user,

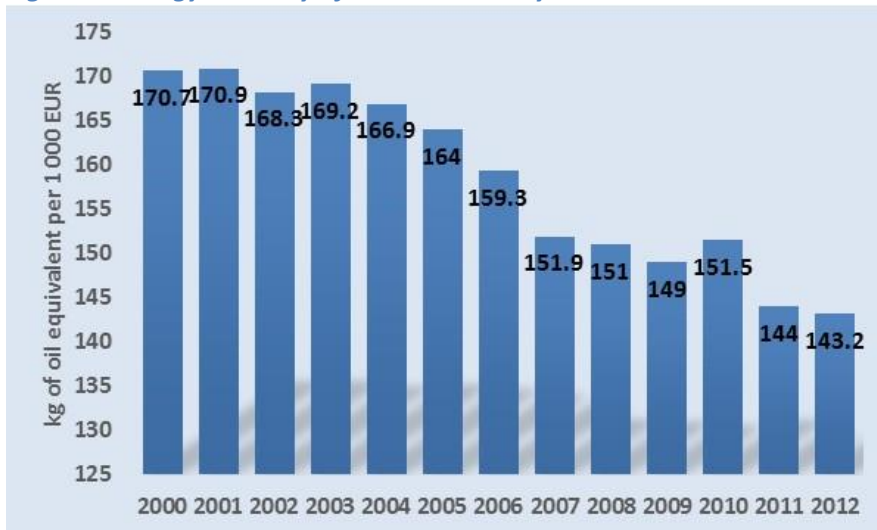
⁴ Calculated as the total net electricity generation (excludes power station own use) less exports plus imports. This apparent electricity demand includes transmission and distribution losses.

⁵ Part of the recovery in 2010 was due to weather patterns. The winter of 2009/2010 was unusually cold in Europe whereas in the summer 2010 many parts of Europe experienced above average temperatures.

⁶ There has been a net slowdown in the energy efficiency progress since the economic crisis: 0.6%/year since 2007, compared to 1.5%/year between 2000 and 2007. Source: ENERDATA (2012), Overall Energy Efficiency Trends in the EU, September 2012 and updated Eurostat data up to 2011.

energy efficiency improved by 1.3%/year over the period 2000-2010⁷. A shift towards less energy-intensive branches contributed to reduce energy intensity in most countries⁸.

Figure 2: Energy intensity of the EU economy



Source: EUROSTAT, 2013

Rising energy efficiency has led to a **decoupling of electricity demand and economic activity**, and this, prior to the financial and economic crisis.

The outlook for electricity demand is uncertain

Amid these changing macro-economic conditions, but also in light of the on-going transition of the energy system at large, **forecasting electricity demand is proving extremely difficult** and, sometimes, erratic⁹. Over the past two years, EURELECTRIC, the Union of the Electricity Industry, has twice revised its demand forecast for 2020 downwards: first, by 5% in 2012 compared to the 2011 estimate and again by 2% in 2013 compared to the 2012 estimate. Demand in 2020 is now estimated at 3251 TWh, a CAGR of 0.55% in the current decade¹⁰. EURELECTRIC's forecast for electricity demand in 2020 by major EU countries is shown below.

⁷ ENERDATA (2012), Energy Efficiency Trends in industry in the EU, September 2012

⁸ Between 2000 and 2008 structural changes towards less energy-intensive branches contributed to reducing the industrial energy intensity in most European countries. Since 2009, structural changes were generally significant but not all in the same direction. In some European countries, the rebound of industrial growth resulted in an increase of the energy intensity, driven both by structural changes to more intensive branches and lower energy performance.

⁹ EURELECTRIC (2012), Power Statistics and Trends 2012 Edition, Brussels, December 2012

¹⁰ EURELECTRIC (2013), Power Statistics and Trends 2013 Edition, Brussels, December 2013

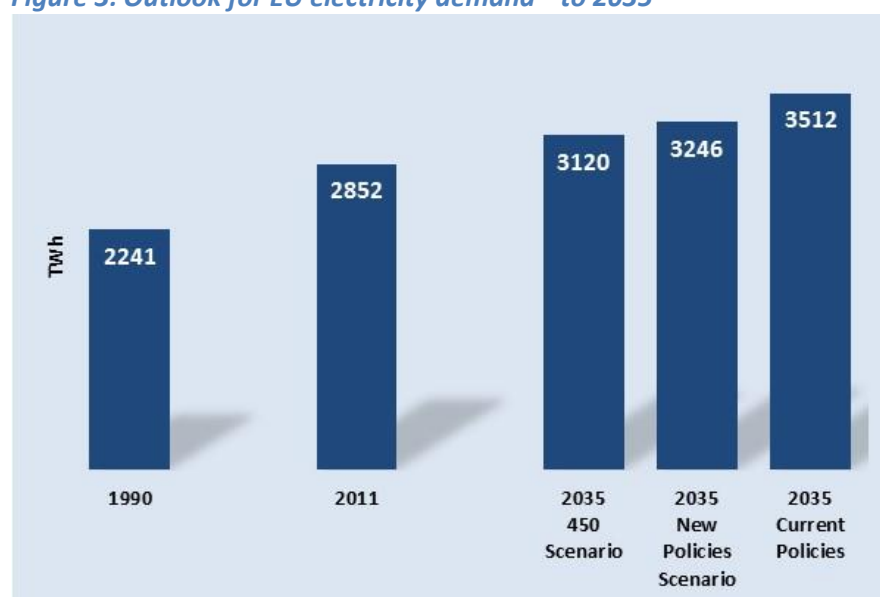
Table 1: EURELECTRIC outlook for EU electricity demand in 2020

TWh	2010	2011	2012	2020	Annual Growth rate 2010/2020
Austria	65.0	65.0	65.6	72.8	1.20%
Belgium	90.1	87.4	79.9	94.3	0.47%
Czech Republic	59.3	58.6	58.8	77.5	3.07%
Finland	87.7	84.2	85.2	99.0	1.29%
France	513.2	479.2	489.5	507.9	0.38%
Germany	568.5	962.9	551.2	507.0	-1.08%
Italy	330.4	334.6	328.2	329.0	0.02%
Netherlands	117.1	118.2	115.1	124.7	0.83%
Poland	142.0	143.3	142.4	160.7	1.29%
Spain	280.0	273.0	271.0	340.0	2.14%
Sweden	147.0	140.3	142.5	144.4	0.13%
United Kingdom	380.2	369.8	371.9	345.7	-0.91%
TOTAL EU	3159.3	3095.6	3081.7	3250.8	0.55%

(main EU markets: demand above 65 TWh in 2020)

Source: EURELECTRIC (2013)

The International Energy Agency in its latest World Energy Outlook 2013¹¹ also foresees a limited increase in EU electricity demand over the period 2011-2035. In the New Policies Scenario, demand increases by a CAGR of 0.5% during the period 2011-2035 to 3246 TWh in 2035.

Figure 3: Outlook for EU electricity demand¹² to 2035

Source: IEA, World Energy Outlook 2013 (WEO 2013)

¹¹ International Energy Agency (2013), World Energy Outlook 2013, IEA/OCDE, Paris, November 2013

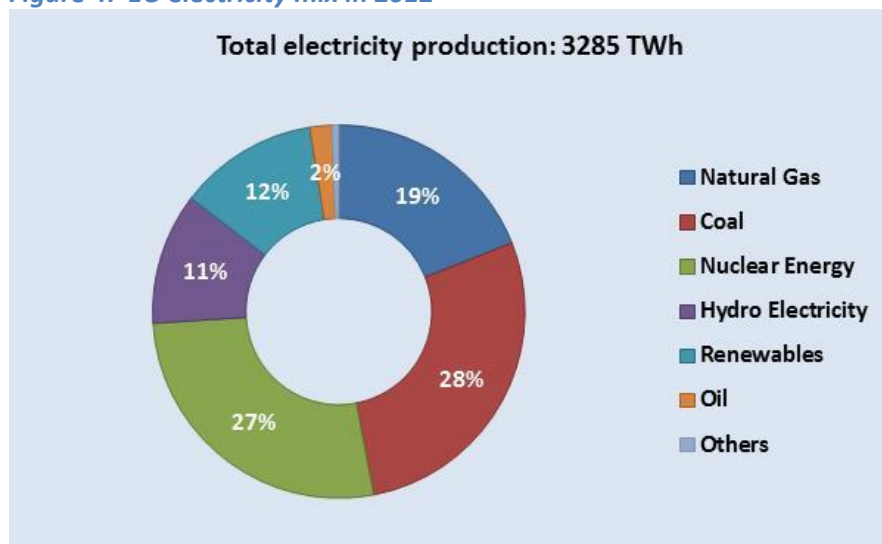
¹² Demand is defined as gross electricity generation less own use less transmission and distribution losses.

1.2. EU ELECTRICITY SUPPLY

EU electricity generation: Renewables overtook natural gas in 2012

The EU electricity generation has followed the trend in electricity demand as electricity trade with countries outside the EU is limited. Total gross electricity production increased by 26% at a CAGR of 1.1% from 1990 to 2012. It reached 3285 TWh in 2012.

Figure 4: EU electricity mix in 2012



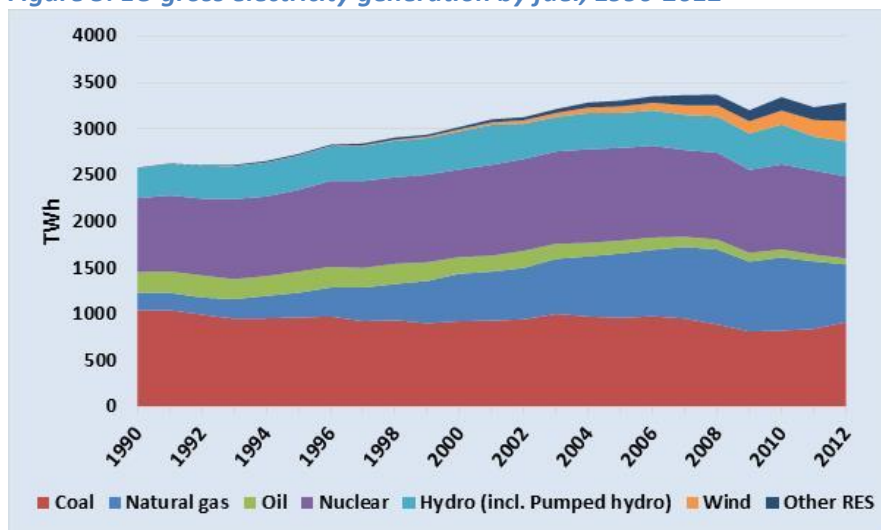
Source: EUROSTAT, provisional

The mix has changed dramatically since the beginning of the 2000s, with the fast deployment of RES. In 2012, RES accounted for 23.5% of total gross power generation compared with 15.1% in 2000. It overtook natural gas for the first time in the EU history. Generation from RES grew by 7% in 2012 year-on-year. Fossil fuel-fired generation decreased by 3% and made up less than half of total generation for the first time in the history of the EU. It still dominates the electricity generation mix with a share of 49% in 2012.

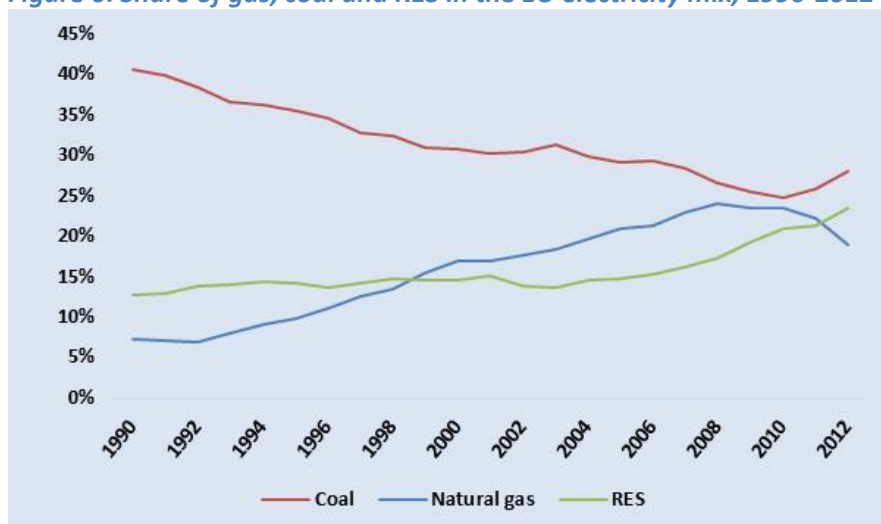
Natural gas¹³ saw its share rising strongly during the period 1990 to 2008. It accounted for 24% of total electricity generation in 2008, its highest historical share, compared with 8.6% in 1990. However, since 2009 the share of gas has decreased to only 19% in 2012 (provisional figures). Natural gas-fired generation decreased by 14% in 2012. By contrast, coal-fired generation increased by 8%. The share of coal has increased over the past three years and reached 28% in 2012. However, the increase in coal-fired generation should be put in perspective: it was 41% in 1990. In 2012, power generation from coal rose by 22% in Spain and 31% in the United Kingdom (only 1% in Germany that year). These increases are explained by specific economic, regulatory and weather-related factors (see Chapter 3, Annex 3).

Despite EU commitment to greener electricity, there has been a shift among fossil fuels from gas-fired to coal-fired generation over the past three years. The rise in coal-fired generation in some countries has increased their CO₂ emissions from electricity production.

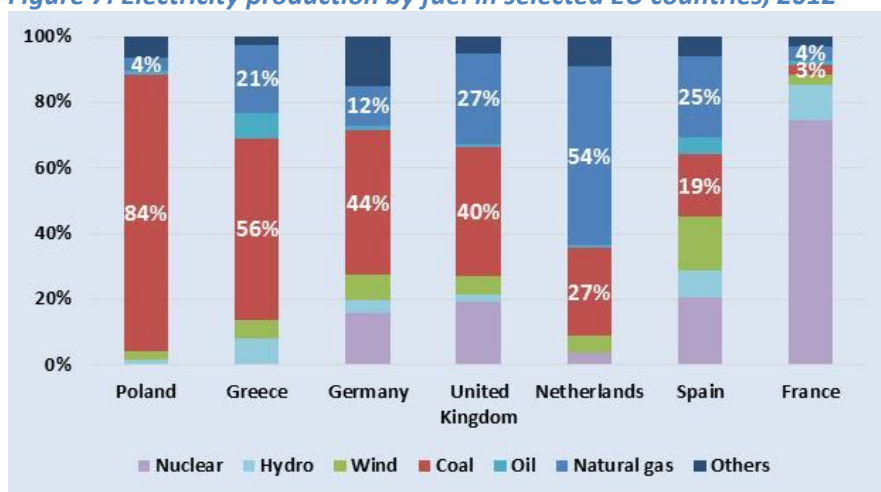
¹³ EUROSTAT data includes all gases: natural gas and derived gas.

Figure 5: EU gross electricity generation by fuel, 1990-2012

Source: 1990-2011: EUROSTAT, 2012: EUROSTAT, provisional

Figure 6: Share of gas, coal and RES in the EU electricity mix, 1990-2012

Source: 1990-2011: EUROSTAT, 2012: EUROSTAT, provisional

Figure 7: Electricity production by fuel in selected EU countries, 2012

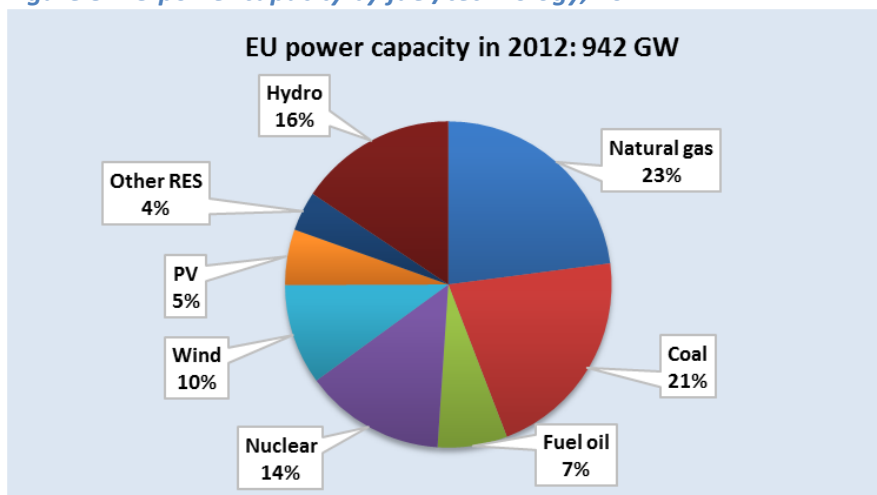
Source: EUROSTAT

Trends in power generation capacities 2000-2012

The rapid development of renewable capacity...

At the beginning of 2012, EU power capacity totalled 942 GW, a 38% increase on 2000. **Fossil fuels dominate the capacity mix with a share of 51%. However, this share is decreasing with the rising deployment of RES.** The fast and large increase in RES capacity, from 160 GW in 2000 to 330 GW in 2012, has been encouraged by the binding EC target of 20% of electricity generation by 2020 and governments' support to RES development, including Feed-in-Tariffs (FIT). The expansion of RES, however, has slowed down since 2012, following changes to government support schemes in several European countries. In 2012, renewable capacity expanded by only 11%, compared to 15% in 2011.

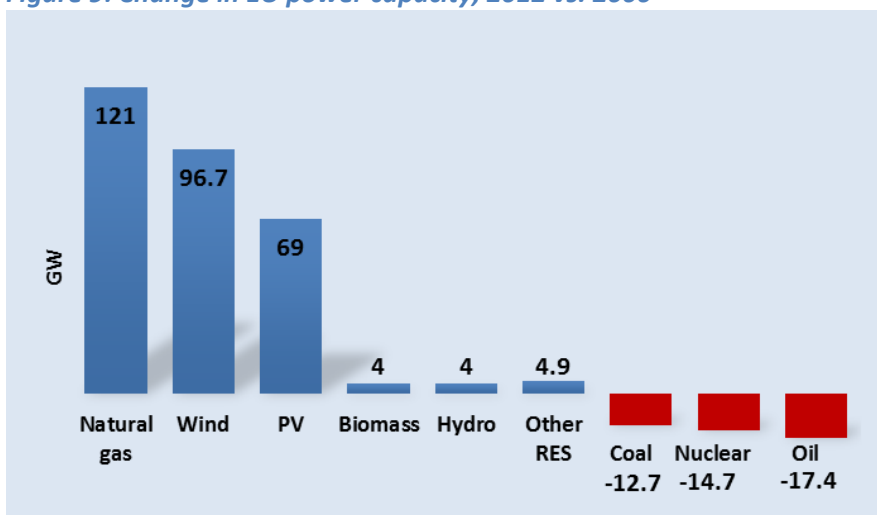
Figure 8: EU power capacity by fuel/technology, 2012



Source: IEA

Over the past decade, the EU's power sector has moved away from coal, fuel oil, and nuclear while increasing its total installed generating capacity with gas, wind, solar PV and other renewables¹⁴.

Figure 9: Change in EU power capacity, 2012 vs. 2000



New build less decommissioning.

¹⁴ EWEA (2013), Wind in power, 2012 Figures, February 2013

Source: EWEA (2013)

Gas-fired power capacity commissioned during the past five years (and especially in 2010 when additions to capacity reached 29 GW) was built under completely different assumptions. Before the global economic crisis and recession in Europe, EU electricity demand was expected to continue growing at more than 1%/year in average over the period 2005-2015, and natural gas was expected to take the lion's share in this increase, rising by 3%/year in average by 2015 (see WEO 2007, reference scenario). At the opposite, coal's share in the electricity mix was expected to decrease.

...Leads to overcapacity in some markets

The increase in EU power capacity combined with flat demand over the past five years has led to **over-capacity in generating capacity in major markets**, particularly pronounced in countries where RES has developed quickly (Germany, Netherlands, Spain). The following table from ENTSO-E¹⁵ shows that currently security of electricity supply was adequate in all EU countries, either from national generation or cross-border imports in 2013. The main findings of ENTSO-E Winter Outlook Report 2013/14 concluded that Europe was sufficiently supplied with generation to meet both normal and severe scenarios in winter 2013/14 and that countries which required imports to cover the expected demand, had sufficient cross-border capacity to accommodate them.

Table 2: Net generation capacity, reliable available capacity, peak load and import capacity (main EU markets, 2013)

GW	Winter reference point				Summer reference point			
	Net generating capacity	Reliable available capacity	Peak load	Import capacity	Net generating capacity	Reliable available capacity	Peak load	Import capacity
Austria	23.30	17.60	10.70	0.00	23.30	17.20	9.90	0.00
Belgium	19.84	12.33	13.79	3.50	21.86	14.34	11.82	3.00
Bulgaria	12.73	11.27	6.95	1.45	13.83	9.63	4.32	1.45
Czech Republic	18.20	11.65	10.30	3.00	18.20	13.65	8.10	2.80
Denmark	11.76	5.38	6.23	5.68	11.76	4.03	5.26	5.68
Finland	17.66	13.31	15.00	4.70	17.66	8.76	11.00	4.70
France	128.10	96.60	83.00	8.00	127.40	76.60	57.70	8.00
Germany	182.16	93.04	91.77	16.90	186.66	83.18	76.86	16.90
Greece	15.88	11.04	8.83	1.50	16.48	12.32	10.20	1.50
Italy	126.30	67.30	58.60	10.50	127.80	85.30	60.40	9.50
Netherlands	31.28	26.37	18.40	5.17	31.28	26.37	16.93	5.17
Poland	35.72	26.15	24.48	0.82	36.11	20.84	20.17	0.82
Portugal	17.92	11.42	8.43	1.28	18.00	9.89	6.88	1.60
Romania	18.54	11.60	8.93	1.50	18.96	11.14	7.51	1.90
Spain	99.60	51.80	44.60	2.90	100.60	53.20	41.50	2.60
Sweden	38.67	27.21	26.00	9.70	38.89	25.54	17.82	9.70
United Kingdom	80.75	61.99	57.70	4.19	80.75	46.90	25.68	4.19

Source: EC (2013), Generation Adequacy in the internal electricity market - guidance on public interventions, SWD 438 final, November 2013 (from ENTSO-E)

However, this overall European picture differs from country to country and even from region to region. In Germany, while the capacity is (still) comfortable at national level, South Germany lacks generating capacities to cover the local demand. The same is true in Belgium where decommissioning

¹⁵ ENTSO-E (2013), Winter Outlook Report 2013/14 and 2013 Summer Review, November 2013

of nuclear and old thermal plants leads to security issues. In France, where peak demand has increased fast and cannot be met by nuclear plants, the decommissioning of old oil and coal plants under the LCPD directive, leads to security issues to cover peak demand in extreme cases. The same applies in the United Kingdom where 11.2 GW of old oil and coal-fired capacity are closing.

In addition, the early closure or mothballing of gas stations for economic reasons and that of old coal plants for environmental reasons, or because they have reached the end of their technical lifetime, will radically reverse this situation (see Sections 1.5 and 1.6).

1.3. WHOLESALE ELECTRICITY PRICES

Wholesale base and peak-load electricity prices have declined significantly

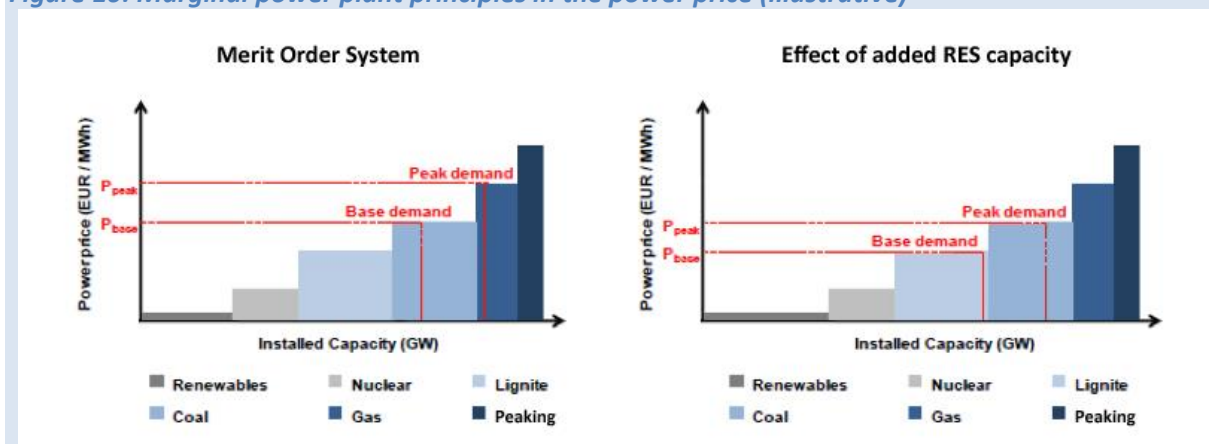
The boom in RES and the falling prices of hard coal and EU Allowances (EUAs) have sent wholesale electricity prices to very low levels in 2012 and 2013, although electricity bills are booming. **On the German spot market, wholesale power prices fell by 17% in 2012 and by 12% in 2013.** German day-ahead OTC power prices for baseload delivery averaged €37.78/MWh in 2013 down from €42.67/MWh in 2012 and €51.14/MWh in 2011. Day-Ahead prices in 2013 were the lowest since 2004 and almost half the prices of the record year 2008 (see Figure 11).

The fall in power prices is mainly explained by the expansion of RES in the electricity mix and the way power prices are set by the market: the marginal power plant principle (Box 1).

Box 1: Electricity price formation on the wholesale market: the 'Marginal Power Plant' principle and impact of RES expansion

Daily demand on the European regional power markets is met by a large number of electricity products based on a variety of energy sources. Every type of power plant (nuclear, gas, coal, etc.) has marginal costs, primarily determined by the variable costs of fuel including CO₂ and operating asset costs that are incurred when the power station is up and running and must at least be earned back. On the regional power markets, the cheapest source (RES or nuclear) is plugged in first, then comes the second cheapest and so on until the demand is met, according to the **merit order principle**. The offer price of the last power station needed to satisfy this demand ("marginal power plant") determines the market price for all the other power stations. Power prices are thus the result of the point at which supply and demand intersect. Therefore, to cover high demand, a plant with relatively high marginal costs will tend to determine prices, whereas to cover low demand, a lower marginal costs power station will determine prices.

Figure 10: Marginal power plant principles in the power price (illustrative)



Source: adapted and redrawn from RWE

When RES capacity is added to the system (right graph), it alters the supply curve for electricity generation. It increases the supplied capacity at low marginal costs (left side of the graph), since RES have very low marginal costs, and it pushes capacity with higher marginal costs (natural gas and peaking) to the right, out of the merit order.

Financial support to RES have in some cases, been accompanied by priority dispatch arrangements, whereby the variable output of RES has priority over all other forms of generation in the electricity merit order (this is the case in Germany). Even if priority dispatch is not applied, RES generation has an advantage over other forms of generation due to its very low marginal cost. With a guaranteed price for its output – in case of a FIT – it can effectively bid in at a market price of zero (or below when possible) to push other generation down the merit order, thus ensuring it is always the first to run. Overall, power prices decrease (at equal demand). The process is dynamic: when there is no wind and no sun, the price increases again.

Negative electricity prices

Occasionally, the spot price of electricity is even negative. This occurs when wind and/or solar production is above power demand. As solar and wind have marginal costs close to zero and receive Feed-in support, they are not incentivised to reduce their production when demand is low. Negative prices are the consequence of opportunity costs: power utilities operating low-flexibility plants often prefer to pay money (i.e. to make bids with negative prices) to get rid of their electricity rather than have to shut down and then restart their power plants, which is expensive and increases wear and tear as well as the risk of accidents¹⁶. Negative prices are also caused by both the general market design and the design of the support schemes to remunerate RES generation: in Denmark, for instance, wind plant operators do not receive any revenue when prices are negative, an incentive to consider other options such as storage.

The introduction of RES in the electricity system also leads to a **decrease in peak prices and lower peaking price periods**. Normally, electricity prices spike during peak hours (the middle of the day and early evening), falling at night as demand falls. But the middle of the day is when solar generation is the strongest. Thanks to grid priority, solar covers part or all of that peak demand and has lowered the price spike. In Germany in 2008, peak-hour prices were €14 per MWh above baseload prices. In 2013, the premium was €4.36 only, an historical low¹⁷. So not only average electricity prices have fallen by half since 2008, but the peak premium has also fallen by two-thirds. This is again at the expense of gas-fired power plants which are run (and earn money) during peak periods in electricity demand.

Most power utilities sell a large part (up to three quarters) of their electricity production to their major customers one to three years in advance **on the forward market with prices based on forward year-ahead calendar prices**. This has insulated them from the full impact of the recent falls in electricity prices as forward prices were higher than they currently stand. On the forward market, the average 2013 forward price in 2012 was €49/MWh for base-load power and €61/MWh for peak-load power (German market). This was €7 and €8 less than what had to be paid for the corresponding 2012 forwards in 2011. In 2013, even sharper declines were recorded. Average prices for deliveries of base load electricity in 2014 fell to €37.3/MWh, €11.7 lower (23%) than the prior-year period. The peak load

¹⁶ Johannes Mayer et al., Kohleverstromung zu Zeiten niedriger Strompreise, Fraunhofer-ISE (2013)

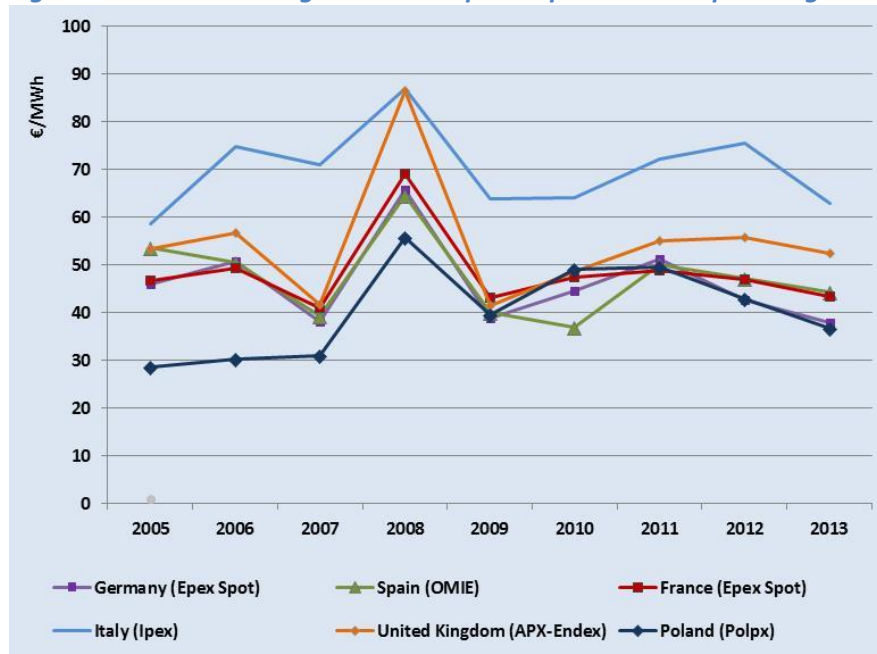
¹⁷ Fraunhofer Institute for Solar Energy Systems ISE (2014), Electricity Spot-Prices and Production Data in Germany 2013, Dipl. Phys. oec. Johannes Mayer, 16 January 2014

price for 2014 was quoted at €48.6/MWh, a fall of €12. Therefore the decline in power prices has not yet been fully felt in power utilities financial results, which may fall in 2014.

A general trend toward declining prices, although regional differences persist

Although electricity prices vary from one market to another according to supply and demand fundamentals, **the trend towards decreasing spot prices was observed on all European markets.**

Figure 11: Annual average wholesale power prices in European regional markets



Source: CycloOpe 2014

The regional differences are mainly explained by local circumstances, such as supply and demand fundamentals and the mix of power plants at national level. The lack of market integration which prevents trade of electricity between regions (congestion or lack of cross-border transmission capacity) is also a key factor. **The coupling of more regional markets into one EU integrated electricity market** will allow lowering the regional price differences. On 4 February 2014, a major step was achieved in that direction when the coupling of day-ahead power markets of North-Western Europe and South-Western Europe was launched successfully. This coupling will facilitate optimal utilisation of interconnectors between regional markets, covering around 75% of Europe's electricity demand. The market integration now stretches from France to Finland and from the UK to Germany and Austria, covering the region of CWE (Central West Europe, covering Benelux, France and Germany), the Nordics and the Baltics.

High and growing cost of subsidies

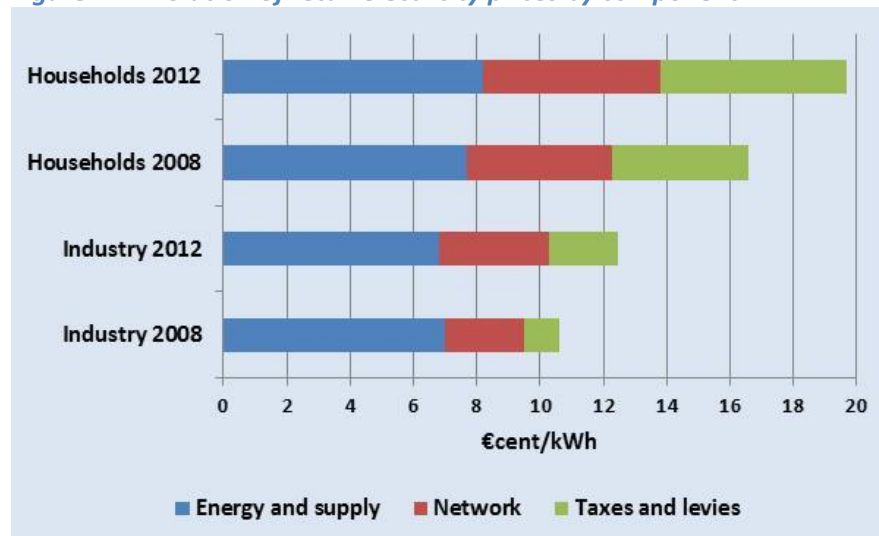
The EU has committed to increase the share of RES to 20% in final energy consumption by 2020 at the European level. This overall target has been divided up nationally according to different countries' renewable energy potential, their energy mix, different starting points and their GDP. Member States reported their strategy on the deployment of RES in **National Renewable Energy Action Plans (NREAPs)**, which assess the role of RES in the electricity (RESe), heat and transport sectors. **To reach the 2020 goal, 34% of the EU's electricity will need to be generated from RES (23.5% in 2012).** To fast track the development of RES, European countries have implemented support policies and subsidies, such as feed-in-tariffs (FIT), guaranteeing a higher price to RES producers than market prices for a

specific term (typically 20 years). Such support policies have triggered large-scale deployment of RES, which has in turn translated into an impressive cost decrease of different technologies, in particular onshore wind and PV. For instance, investment costs for solar PV decreased in Germany from €5000/kW to €2000/kW between 2006 and 2012¹⁸. However, the cost of subsidies directed to support RES development in the EU has exploded. **The IEA estimates RES received US\$ 101 billion in 2012 in subsidies at global level, of which almost 60% (\$57 billion, or €45 billion) in the European Union.** The cost of subsidies in the EU has become too heavy. The resulting higher electricity prices paid by consumers jeopardize EU competitiveness and inflate electricity bills, putting more households at risk of energy poverty.

Large increase in retail electricity prices

In the EU on average, household electricity prices have risen 4% a year for the period 2008-2012¹⁹. For industry, retail electricity prices rose by approximately 3.5% a year in the same period. **These average European price increases hide significant variation between price components** (energy and supply, network costs and taxes and levies). Figure 12 shows the increase in electricity retail prices in the EU for households and industrial users by price components.

Figure 12: Evolution of retail electricity prices by component



Includes taxes in the case of households; excludes VAT and other recoverable taxes in the case of industry but other industry exemptions are not included (not available).

Source: EC (2014)

At EU level, whereas the energy component of electricity prices remained the most important element in the end consumer bill, its relative share registered significant decreases during the period 2008-2012 (more than 10 % for industrial consumers and about half as much for households). The relative share of network costs remained relatively stable, representing about a third of the bill. But the taxation component surged during the five years, especially for industrial users²⁰. **The tax/levy component increased by +36.5% for households and +127% (before exemptions) for industry for the EU weighted**

¹⁸ Knopf B. and all (2013), Transforming the European energy system: Member states' prospects within the EU framework, Postdam Institute for Climate Impact research (PIK), Postdam, December 2013

¹⁹ European Commission (2014), Energy prices and costs in Europe, Commission Staff Working Document, EC, January 2014.

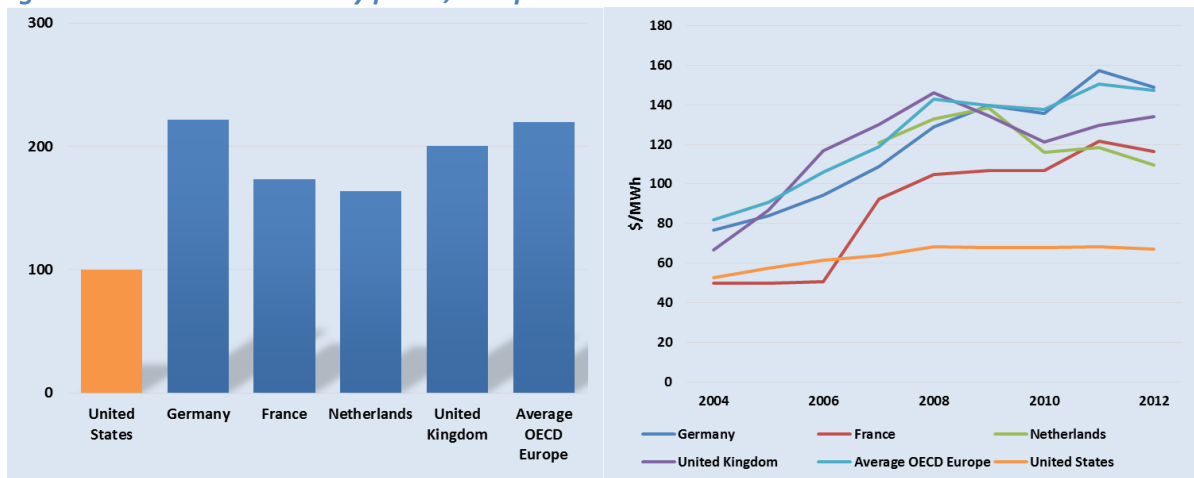
²⁰ European Commission (2014), Energy prices and costs in Europe, Commission Staff Working Document, EC, January 2014.

average electricity price²¹. In the period 2009-2012 the share of levies and charges used to support RESe has increased, rather abruptly in some Member States.

High cost of electricity threatens the competitiveness of energy-intensive industries

Figure 13 shows that **European industrial users pay twice as much for their electricity than US customers**. The differential has widened since 2007, weakening the position of the European industry with respect to the US. The situation is particularly tricky for industries that are energy intensive consumers and which are exposed to international competition, such as chemicals²², non-ferrous metal, steel, etc. The loss of competitiveness threatens energy-intensive industries. The effect is that there have been many closure announcements in the industry in several EU countries. The recent fall in wholesale electricity prices on the European market is largely insufficient to remove the US competitive advantage which benefits from cheap shale gas supplies (see Chapter 2).

Figure 13: Industrial electricity prices, Europe vs. United States



Left graph: average 2012; indexed prices: United States = 100

Source: International Energy Agency (IEA) (2013)²³

Household bills are exploding

European consumers' electricity prices have risen and are still rising. Whilst almost all Member States have seen a consistent rise in consumer prices of electricity, the differences between different national prices remain large: consumers in the highest priced Member States are paying 2.5 to 4 times as much as those in the lowest priced Member States. Figure 14 shows the evolution of retail electricity prices for households in Germany from 2007 to 2013. Taxes have increased by 73% since 2007 and now represent half the price paid by household customers.

²¹ For industry, this percentage change excludes VAT and other recoverable taxes. This percentage does not take account of industry exemptions. Whilst consistent national data on exemptions is not available, a number of Member States provide significant tax and levy exemptions for some energy intensive industries which substantially mitigate the tax/levy price rises. EC (2014), *ibid*.

²² IFRI (2013), *Impact of the US shale gas revolution on the EU petrochemical industry*, Paris, October 2013

²³ IEA (2013), *Energy prices and taxes, 2013, second quarter*, IEA/OCDE, Paris.

Figure 14: Evolution of German electricity retail prices paid by households

Households: Band DC: 2 500 kWh < Consumption < 5 000 kWh

Source: EUROSTAT

The surcharge for Germany's Renewable Energy Act (EEG) that taxes households to subsidise RES production increased by 50% between 2012 and 2013 – from €3.6 cents to €5.28 cents per kilowatt hour, costing a German family of four about €250 per year, including sales tax. The German government raised the surcharge again at the start of 2014 by 18% to €6.24 cents per kilowatt hour, making the total feed-in tariff support for 2014 equals to €21.5 billion. The government is now reforming the EEG to reduce the surcharge.

Phase-out of subsidies to the more mature renewable energy sources

Faced with this severe situation, many governments are now limiting or even stopping (in the case of Spain) subsidies to RES. According to EURELECTRIC, as many as 13 EU Member States have opted for retroactive changes or moratoria to their RES support schemes as of the beginning of 2014. **There is a general move towards ending subsidies to the more mature RES (onshore wind).** However, the increased share of RES in the energy mix is still triggering higher and higher subsidy amounts. The EC State Aid Communication of April 2014 recommends incentivising the market integration of RESe and subjecting them to market obligations (system balancing). This includes the gradual phase-out of subsidies and exemptions from balancing responsibilities to RESe which are becoming grid-competitive²⁴.

1.4. GAS AND COAL COMPETITION IN THE POWER SECTOR

Gas has lost its competitiveness in the power sector

The price of gas in Europe is still predominantly linked to oil products and has risen by 36% since 2009 (see Chapter 2). Average European gas import price reached \$11.82/MBtu (million of British thermal units) in 2013. At the opposite, the price of coal, which is determined by market forces, has significantly declined since the middle of 2011 as coal supplies have been abundant on the international market (see Chapter 3). European coal import prices (CIF, ARA²⁵) decreased from \$125/t in August 2011 to \$84.6/t (the equivalent of \$3/MBtu) in December 2013. This represents a fall of 32%. The US shale gas

²⁴ EC (2014), Guidelines on State aid for environmental protection and energy 2014-2020, C (2014) 2322, Brussels, 9 April 2014.

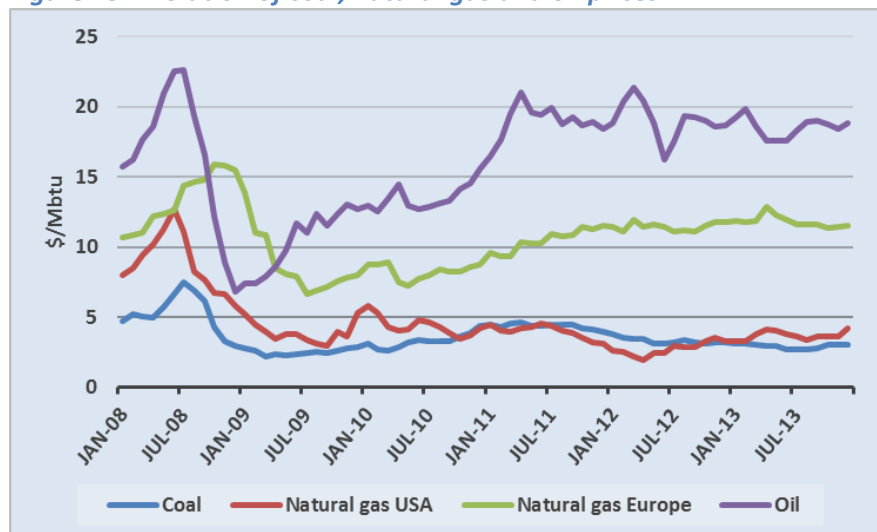
²⁵ CIF ARA: Coal Insurance Freight, Amsterdam, Rotterdam, Antwerp.

revolution has displaced coal in the power sector of the country, resulting from a decrease in US coal consumption by 200 Mt (a fifth) since 2008. This amount is equivalent to the total EU steam coal imports. Faced with a decreasing coal demand on their domestic market, US mining companies have looked to other markets and started exporting large volumes of coal to Europe since 2011. The availability of US coal, combined with already ample supplies from other suppliers, has created a supply glut on the international coal market and pushed prices down.

On average, coal prices delivered to Europe are three times lower than gas prices on an energy equivalence basis: coal prices averaged \$3.73/MBtu in 2013 while gas prices averaged \$11.82 (Figure 15).

The collapse of the price of EUAs (EU Allowances) to less than €5/t in 2013 has reinforced the competitiveness of coal against natural gas. Since 2009, the price has collapsed due to the economic recession which has decreased electricity demand (and production), the rising share of RES in the electricity sector and rising energy efficiency. All these factors have contributed to the creation of a large surplus of EUAs which has undermined their price (see Chapter 4).

Figure 15: Evolution of coal, natural gas and oil prices



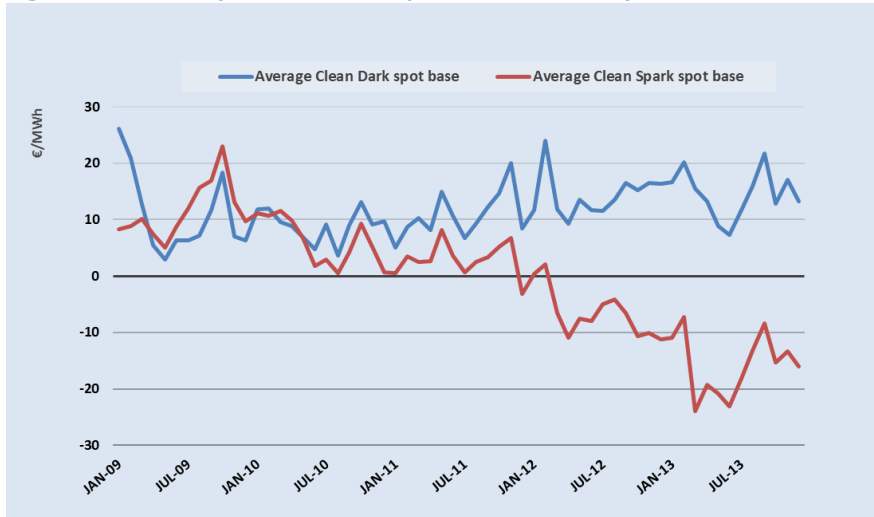
Coal: European marker, CIF ARA; Natural gas USA: spot Henry Hub

Natural gas Europe: Average import price; Oil: Brent dated

Source: MCR, USDOE, World Bank

Clean spark and dark spreads

The decrease in wholesale power prices combined with high gas prices and low CO₂ prices has led to **the collapse of clean spark spreads**, the measure of profitability of gas-fired power plants (see box 2). On the German market, they have been negative since the beginning of 2012, meaning that running a gas-fired power plant has become a loss-making business. Coal-fired power plants have performed better with a sustained clean dark spread over the past two years. This situation is illustrated on the following figure which shows the historical evolution of clean dark and spark spreads in Germany.

Figure 16: Clean spark and dark spreads in Germany²⁶

Source: CDC Climat Research/Tendances Carbone

Figure 17 shows the price of CO₂ required to switch from coal to gas at observed coal and gas prices each month. It clearly shows that under the current weak carbon market conditions, power generators are incentivised to run their coal plants instead of their gas plants, a situation that has lasted for the past three years.

Figure 17: Theoretical CO₂ allowance switching price on the German market

Source: CDC Climat Research/Tendances Carbone

Box 2: Calculation of clean dark and spark spreads

The clean dark spread, expressed in €/MWh, represents the difference between the price of electricity and the price of coal used to generate that electricity, taking into account the efficiency rate of the coal plant, and adjusted with the impact of CO₂, by subtracting the carbon emission costs.

$$\text{Clean dark spread} = [\text{Power price} - (\text{Coal price expressed in € per MWh} / \text{Coal plant efficiency rate})] - \text{Carbon price} \times \text{coal CO}_2 \text{ emissions factor}$$

²⁶ The monthly spreads published in Tendances Carbone correspond to the monthly average of daily spreads.

The Clean spark spread, expressed in €/MWh, represents the difference between the price of electricity and the price of natural gas used to generate that electricity, corrected for the energy output of the gas-fired plant and the carbon emission costs (CO₂-adjusted).

$$\text{Clean spark spread} = [\text{Power price} - (\text{Gas price per MWh} / \text{Gas plant efficiency rate})] - \text{Carbon price} \times \text{gas CO}_2 \text{ emissions factor}$$

The following parameters are used for the calculation:

For Germany

- Net thermal efficiency of a conventional coal-fired plant: 36%²⁷
- Net thermal efficiency of a conventional gas-fired plant: 50%
- Emissions factor (CO₂/MWh) of a conventional coal-fired plant: 0.96 t CO₂/MWh
- Emissions factor (CO₂/MWh) of a conventional gas-fired plant: 0.37 t CO₂/MWh

For the United Kingdom

- Net thermal efficiency of a conventional coal-fired plant: 35%
- Net thermal efficiency of a conventional gas-fired plant: 49.13%
- Emissions factor (CO₂/MWh) of a conventional coal-fired plant: 0.98 t CO₂/MWh
- Emissions factor (CO₂/MWh) of a conventional gas-fired plant: 0.38 t CO₂/MWh

CO₂ allowance switching price

The “switching price” is an indicative CO₂ allowance price which indicates when a switch from coal to natural gas or from natural gas to coal is economically advantageous to an electric power producer.

Mathematically, this indicator is the fictional daily price of CO₂ that would establish equality between the clean dark spread and the clean spark spread.

In the short term, it is advantageous to switch from:

- coal to natural gas, when the daily CO₂ price is above carbon switch
- natural gas to coal, when the daily CO₂ price is below carbon switch

It is calculated for each day as follows:

$$\text{Switching Price} = [(\text{cost gas/MWh} - \text{cost coal/MWh}) / (\text{CO}_2 \text{ coal/MWh} - \text{CO}_2 \text{ gas /MWh})]$$

With:

Cost gas: Production cost of one MWh of electricity on base of net CO₂ emissions of gas in €/MWh

Cost coal: Production cost of one MWh of electricity on base of net CO₂ emissions of coal in €/MWh

CO₂ coal: Emissions factor (CO₂/MWh) of a conventional coal-fired plant

CO₂ gas: Emissions factor (CO₂/MWh) of a conventional gas-fired plant

Source: CDC Climat Research/Tendances Carbone, January 2013²⁸

²⁷ The efficiency rates of coal and gas power plants are based on the average efficiency of the German and UK fleet. They differ from one power plant to another and have increased recently with the retirement of old coal plants in both markets and the commissioning of highly efficient coal plants in Germany. The emission factor also varies from one plant to another and has decreased recently in line with the higher efficiency rates.

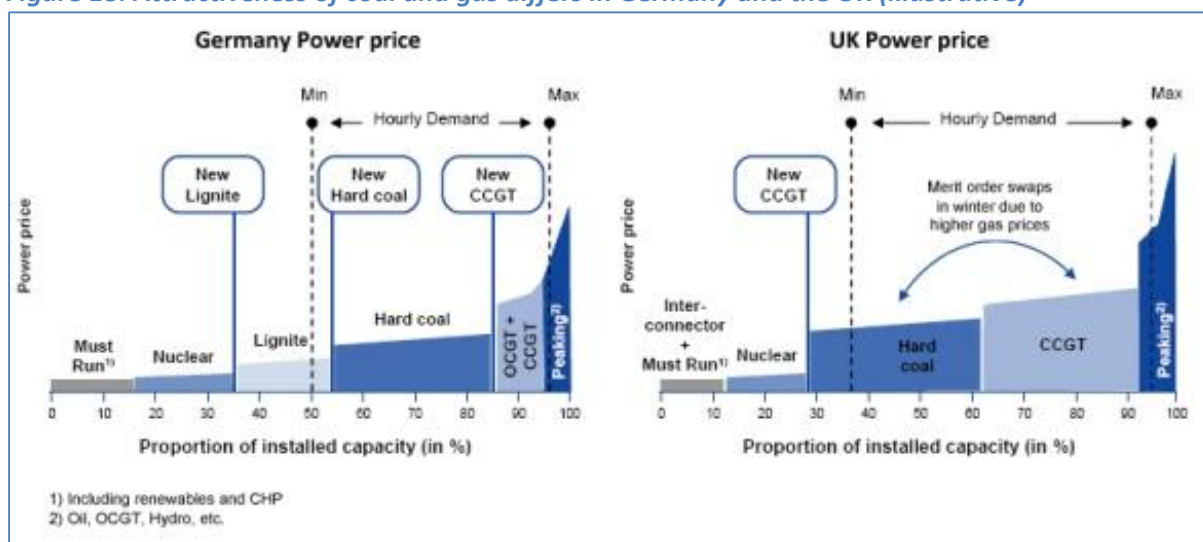
²⁸ CDC Climat Research/Tendances Carbone, (2013), Methodology Tendances Carbone, January 2013

The attractiveness of coal and gas differs in each market

The attractiveness of coal and gas differs in each regional electricity market according to the mix of installed capacity, the marginal costs of each plant, which are primarily determined by the variable cost of fuel (including CO₂) and operating assets costs that are incurred when the power station is up and running and must at least be earned back. An illustration of these regional differences is given in Figure 18 which shows the attractiveness of coal versus gas in Germany and the United Kingdom.

In Germany, a large and increasing proportion of low marginal cost plant from wind, PV, nuclear, CHP plants and lignite pushes plants with higher marginal costs (mainly CCGTs and OCGTs) outside the merit order for power dispatch. Load factors for gas plants have been very low since 2012, leading to plant closures (see Section 1.5). In the United Kingdom, there is a higher share of high marginal cost plants. New gas plants in the UK have therefore significantly higher load factors than those in Germany. In winter time, higher gas prices push CCGTs at the end of the capacity curve, while in summer time they are more attractive.

Figure 18: Attractiveness of coal and gas differs in Germany and the UK (illustrative)



Source: adapted and redrawn from RWE

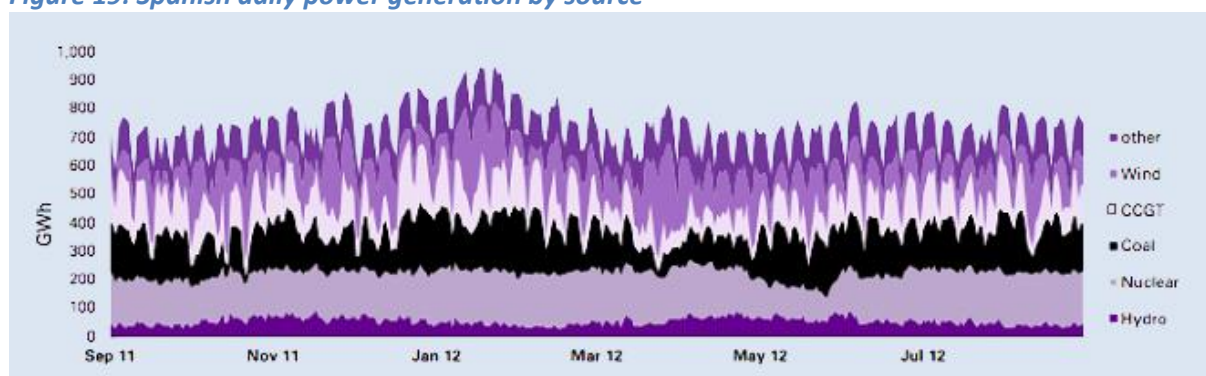
1.5. OPERATIONAL IMPACT ON GAS POWER PLANTS

Renewable energy sources displace gas-fired power generation out of the merit order

The fast deployment of RES pushes gas-fired power plants out of the merit order. CCGTs are used for peak or back-up capacities, while they were initially conceived as base- or mid-load units running about 5,000 hours per year. This phenomenon increases year on year and seems now irreversible, even if the development of RES slows down.

Figure 19 illustrates the squeeze of natural gas by the fast development of RES in Spain where CCGTs are now used at very low loads when wind is not blowing.

Figure 19: Spanish daily power generation by source



Source: Red Eléctrica de España

Very low load factors for gas-fired power plants

Since power plants using nuclear fuel or brown coal are designed to run at base-load, so **the burden of adjustment of variable RES falls on gas-fired power plants mainly**, and to some extent, on hard-coal power plants. This situation leads to very low utilisation rates for gas-fired power plants and losses for their operators.

In **Germany**, the average load factor of gas-fired power plants declined to 21% in 2013. In other terms, these plants were off 4 days in 5²⁹. RWE reported an average capacity utilisation of its gas-fired power plants (excluding CHP units) slightly below 10% in 2012³⁰.

Table 3: Average load factor of RWE's gas- and coal-fired power plants

	2010	2011	2012	Jan-Sept 2013
RWE in Germany				
Gas (%)	26.7	25.8	18	14.3
Coal (%)	60.1	60.3	71.2	71.4
RWE Group				
Gas (%)	41.7	37	29	22.3
Coal (%)	55.2	56.6	69.7	75.1

Source: author's own calculations based on RWE annual reports (includes CHP plants)

In **Spain**, the load factor of CCGTs has plunged from rates consistently over 50% in the past couple of years to an average of just 17% in 2012. Although the Spanish government suspended all subsidies for new renewable energy installations in 2012, it could not be a quick fix for the market distortion. In 2013 again, the load factor of CCGTs collapsed to 11%, as the existing capacities of wind and solar were big enough to continue pushing out conventional power generation out of the system. In addition, in 2013, hydro was more available than in 2012.

²⁹ Source: <http://infocusrevue.com/2013/11/21/gas-fiasco-threatens-power-supply-in-the-eu/>

³⁰ RWE (2013), Annual report 2012.

Figure 20: Running hours of Spanish CCGT plants

Source: REE

The contribution of gas to the **UK's** power generation mix plunged by 32% in 2012 from 2011 level, accounting for 28% of total generation. The average load factor of gas-fired power plants was 36% in 2012. By contrast, electricity generation from coal rose by 32% and coal accounted for 39% of UK power generation. The average load factor of coal-fired power plants was 56% in 2012, boosted by the low price of imported coal and the fall in CO₂ prices. Power utilities were also encouraged to use the maximum or all of the remaining hours of their opt-out plants before 2013. Starting on 1 January 2013, EUAs are no more granted free of charge and from 1 April 2013, UK utilities also have to pay an additional carbon tax.

The decrease in load factors leads to rising full and variable costs. According to VGB³¹, the power generation unit costs for a plant designed for base load operation with some 6,000 full load hours doubles if the plant is utilised for 2,000 hours only. If the plant is used even less, some 1000 hours, the unit cost increases by a factor of 4. The largest cost increase is due to capital costs. The falling load factors have therefore particularly negative impacts on the high-efficient, new build CCGTs which have to cope with the extra financial burden caused by high fixed costs, while in the case of old plants, most, or all, capital costs have already been depreciated. Variable costs are also higher with lower utilisation rates as variable costs not only include fuel costs but also O&M costs which increase with lower rate of utilisation. This is an additional burden for operators.

Closure of old, but also new build high-efficient CCGTs

The low utilisation rate of gas-fired power plants prevents utilities from recovering their full costs, and even their variable costs. This is resulting in a drastic fall in revenues for gas power plants operators. At the current wholesale electricity price of less than €40/MWh, most conventional new power plants make losses. As a reference, a gas-fired plant requires a minimum of €65, a hard coal-fired plant €50 and a lignite-fired plant needs around €40 in order to continue functioning³². The consequence is that

³¹ VGB, Electricity generation 2013/2014

³² German Coal and Gas-fired Plants Shut Down as Electricity Prices Drop, 19 August 2013, <http://www.greenoptimistic.com/2013/08/19/german-coal-and-gas-fired-plants-shut-down-as-electricity-prices-drop/#.UvkLdfI5QSo>

And estimates from VGB https://www.vgb.org/vgbmultimedia/download/LCOE_Final_version_status_09_2012-p-5414.pdf

even highly efficient gas-burning plants are being mothballed as utilities are reducing their costs. **At the end of 2013, 24.7 GW of gas-fired power capacity are idled, closed or at risk of closure, most of them in northwest Europe. This represents 14% of the installed capacity (177 GW at end 2013)** (Table 4).

The first plants to close were the old gas-fired power plants which have a lower efficiency than new-built ones. However, the further deterioration of the market conditions has led utilities to close/mothball new build plants with efficiency of 58-60%. In Germany, even the recent and most efficient CCGT power plant at Irshing in Bavaria was at risk of being mothballed. An agreement was reached between the plant's owners and the grid operator Tennet to ensure that the plant will stay on line for the next three years. In the Czech Republic, the Pocerady new CCGT plant was less lucky as it was mothballed as soon as its construction finished in summer 2013 and the number of new build plants being mothballed after their commissioning is increasing.

According to Gérard Mestrallet, CEO of GDF Suez and leader of the "Magritte Group"³³, as much as 51 GW of thermal power capacity have been mothballed/closed in Europe³⁴ by the 12 European utilities forming the Magritte Group. GDF Suez closed down 12 GW between 2009 and 2013, decided to close an additional 2 GW in the third quarter of 2013 and has put another 5 to 7 GW under review³⁵. EON may decommission 30 units until 2015, representing 13 GW of capacity – or one fourth of its entire conventional fleet – and decided a moratorium on all new gas-fired power plant investment³⁶. The company has already shut 7.4 GW of gas plant capacity. RWE is assessing 10 GW of capacity in Europe for potential closure³⁷. Enel announced it may reduce its conventional power capacity by 6 GW by 2017. **If all plants under review are closed, this may lead to the closure of about 50 GW of capacity, almost 30% of the current capacity.**

A study by IHS CERA estimates that about 113 GW of thermal capacity across Europe are currently not recovering their fixed costs and are at a risk of closure, with 25 GW likely to close by 2014³⁸.

The gas fleet is younger than the coal fleet. However, under current market conditions, the oldest gas-fired power plants are at risk of early retirement. At the end of 2013, 14% (25.5 GW) of the fleet is more than 20 years (see Figure 21).

These massive closures are a threat for future security of electricity supply at times of peak demand, especially when RESe are not available (see Section 1.9).

³³ The Magritte Group includes the CEOs of 12 leading European energy utilities that have joined their efforts to make concrete proposals to reform the European energy and climate policy. Initially, the Group included the CEOs of 10 companies: CEZ, Enel, ENI, E.ON, Gas Natural Fenosa, Gas Terra, GDF Suez, Iberdrola, Vattenfall and RWE. In November 2013, they were joined by Fortum and OMV. The Heads of the Magritte Group have highlighted the risks of the EU's current energy policy: energy security of supply is no longer guaranteed, CO₂ emissions are on the rise, investments in the energy sector are not happening and energy bills are rising sharply. Facing the triple failure of the European energy policy, the energy companies have formulated concrete proposals to revitalise Europe's energy policy now.

³⁴ The 51 GW refers to electricity capacity and so may include some coal and oil-fired power capacity (see next section for a list of closed coal-fired capacity). Although, it is not mentioned, the figure certainly refers to closure since 2009, the beginning of the crisis for power utilities.

³⁵ GDF (2013), Report on financial results Q3 2013

³⁶ EON (2014), Annual Report 2013

³⁷ RWE (2013), Report on financial results Q3 2013

³⁸ IHS CERA Private Report, Gas-fired power on life support, May 2013 quoted in IHS CERA Special Report, 2013, The Energy Investment Imperative, 2013.

Table 4: Current and announced mothballing and closures of gas-fired power plants, by major company and country (status at end 2013)

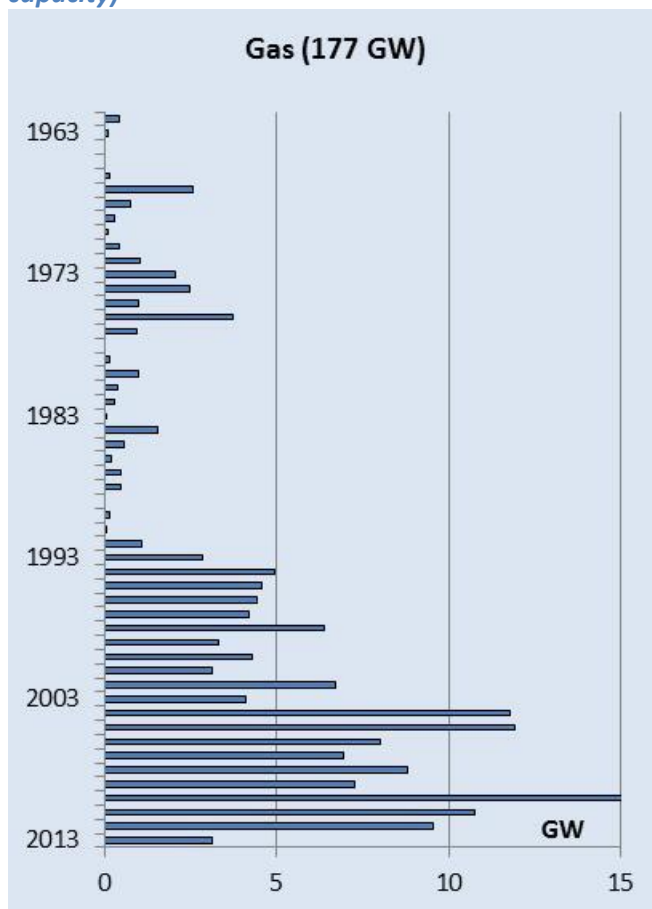
Company/ Country	Power plant	Capacity (MW)	Date of commissioning (a)	Comments
Statkraft				
Germany	Knapsack 1	800	2007	Put into wet reserve (b)
Germany	Knapsack 2	430	June 2013	Put into wet reserve
Germany	Herdecke	417	2007	Put into wet reserve
Germany	Robert Frank (Landesbergen)	510	1962	Put into cold reserve (c)
Germany	Emden	450	1972	Closed
	TOTAL Statkraft	2607		
RWE				
Germany	Gersteinwerk F	355	1973	Long-term mothballing Q3 2013 (closure)
Germany	Gersteinwerk G	355	1973	Long-term mothballing Q2 2014 (closure)
Germany	Weisweiler G	270	2007	Long-term mothballing Q3 2013 (closure)
Germany	Weisweiler H	270	2007	Long-term mothballing Q3 2013 (closure)
Germany	Emsland B	360	1974	Summer mothballed in Q2 2014
Germany	Emsland C	360	1975	Summer mothballed in Q2 2014
	TOTAL Germany	1970		
Netherlands	Moerdijk 2	430	2012	Long-term mothballing Q4 2013 (closure)
Netherlands	2 mid-size units	85		Long-term mothballing Q1 2013 (closure)
Netherlands	Claus C	1300	2012	Mothballed from 1 July 2014
	Total Netherlands	1815		
	TOTAL RWE	3785		
EON				
Belgium	Vilvorde	385		Closed 2014
France	not defined (Emile Huchet)	575	385	Mothballed in 2014 (long term reserve)
Slovakia	Malcenize	418	2011	Mothballed October 2013
Italy	Fiume Santo 5-6	80	2005	Closed Q1 2013
Italy	Tavazzano 8	300	2005	Mothballed in Q2 2013
Italy	Ostiglia 4	330	1974	Closed Q4 2012 (gas and oil)
Germany	Staudinger 4	650	1977	Converted into standby plant until March 2016
Germany	Veltheim 4	390	1975	Closed Q4 2012
Germany	Irshing 4	540	2011	EON wanted to mothball the Irshing plant in 2013. A deal was struck with the regulator to keep the two units for backup
Germany	Irshing 5	850	2010	
	TOTAL EON	4518		
GDF SUEZ				
France	Cycofos (Fos-sur-Mer)	490	2010	Mothballed
France	Combigolfe (Fos-sur-Mer)	424	2011	Operating in winter months only
France	Montoir de Bretagne	435	2010	Operating in winter months only
Belgium	Les Arwis 5	294	1973	Closed in 2013
United Kingdom	Shotton	210	2001	Closed 2012
United Kingdom	Derwent	210	1995	Closed 2012
United Kingdom	Teesside	1875	1993	Closed 2013 (the plant run at a fraction of its capacity since 2009)
Netherlands	Bergum BG 10-20	504	1975	Closed 2012
Netherlands	Harculo HC 60	263	1982	Closed 2012
Netherlands	Eems EC20	530	1987	Closed 2012
Hungary	Dunamenti F 9-12	826	1974	Closed 2012 (gas/LFO)
	TOTAL GDF SUEZ	6061		
ENBW				
Germany	Marbach 2 & 3	424	1971	Closed asap (unit 2: oil cogen)
Germany	RDk-4, Karlsruhe	363	1988	Proposed to be mothballed
	TOTAL ENBW	787		
Vattenfall				
Netherlands	Magnum	1311	End 2012	Only one of the three units put into commercial operation
	TOTAL Vattenfall	1311		
CEZ				
Czech Republic	Pocedary	840	2013	Mothballed since construction finished in summer 2013
	TOTAL CEZ	840		
SSE				
United Kingdom	Keadby	735	1996	Mothballed summer 2013
	Peterhead	1840	1980	Power reduced to 2/3 capacity from end March 2013
	TOTAL SSE	2575		
CENTRICA				
United Kingdom	King's Lynn	325	1997	Mothballed
United Kingdom	Roosecote	229	1991	Closed
	TOTAL CENTRICA	554		
VERBUND				
France	Pont-sur-sambre	420	2009	Sale of asset under consideration
France	Toul	422	2012	Sale of asset under consideration
Austria	Mellach	832	2012	Considered to be mothballed
	TOTAL VERBUND	1674		
	TOTAL	24712		

(a) Date of commissioning of the first unit. (b) Wet reserve: could be restarted in a relatively short time

(c) Cold reserve: mothballed

Source: Companies' announcements and annual reports

Figure 21: EU gas power plants in operation at the end of 2013, by year of commissioning (net capacity)

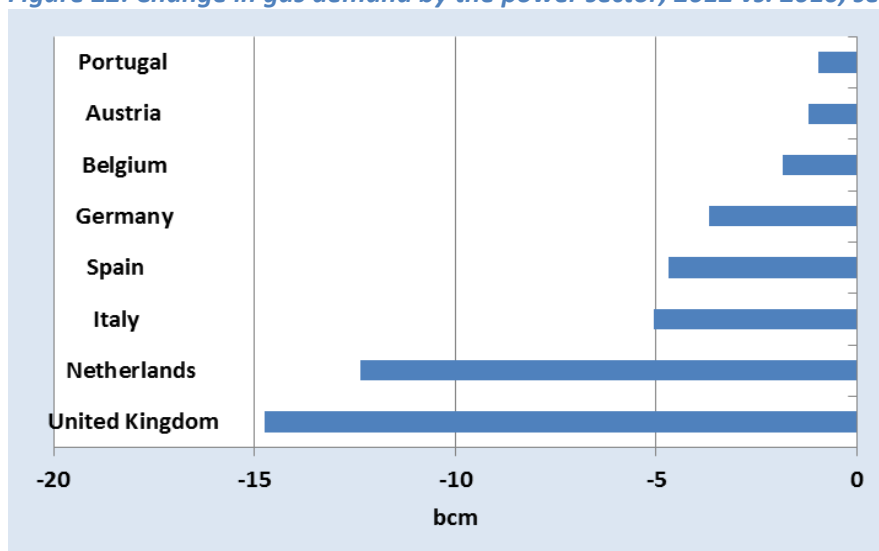


Source: ENERDATA (2014)

A sharp decline in EU gas demand by power plants

Since 2010, gas demand by the power sector has declined sharply. It fell by 51 bcm, or one third between 2010 and 2013. Almost all countries registered decreases in their demand. The UK, Spain and Italy registered the largest drops (see Chapter 2, Annex 2).

Figure 22: Change in gas demand by the power sector, 2012 vs. 2010, selected countries

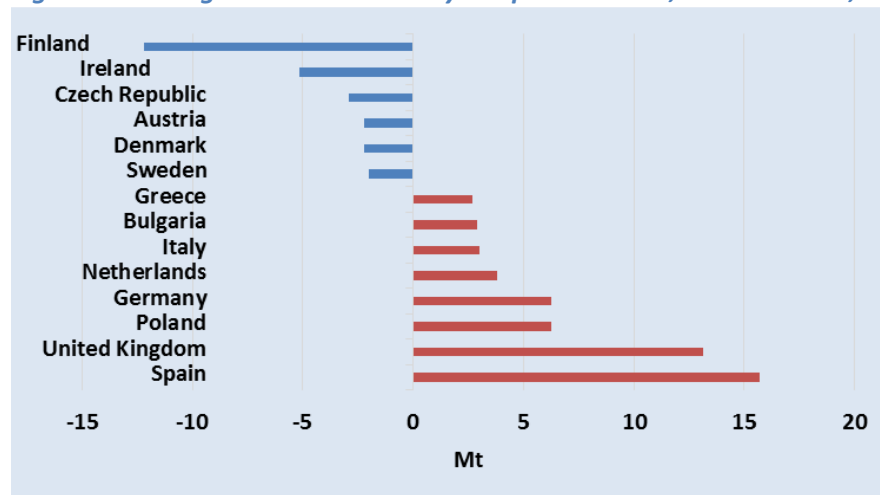


Source: EUROSTAT, EUROGAS

A resurgence in coal consumption in 2011 and 2012

At the opposite, **coal demand increased by 10% between 2010 and 2012** (see Chapter 3, Annex 3). Coal demand however decreased in 2013 by an estimated 5%. As for gas demand, there are large discrepancies between EU countries. The five countries that decreased their gas consumption the most, in addition to Poland, are responsible for most of the increase in EU coal demand during the period. As seen in Figure 23, not all countries increased their coal demand. Scandinavian countries, in particular, registered a sharp decline in their coal use, mainly due to the conversion of their coal plants to biomass.

Figure 23: Change in coal demand by the power sector, 2012 vs. 2010, main countries



Coal includes hard coal and lignite, measured on a tonnage basis (i.e., without taking account of calorific values). Main countries means change above 1 or – 1 Mt.

Source: EUROSTAT

The resurgence in coal use is mainly explained by the competitiveness of coal against natural gas, reinforced by the low price of CO₂. However, regulation aimed at limiting pollution and global warming has also indirectly encouraged this boom, although the impact was short-lived. The Large Combustion Plants Directive (LCPD) requires opt-out plants to close by the end of 2015 or earlier if their allocated maximum number of operating hours is reached before (see Section 1.6). The LCPD has a strong impact on UK coal plants as seven coal plants opted-out with a total capacity of 8.3 GW. The owners of these plants increased the running hours of their plants (and coal use) in 2012 to avoid the UK carbon tax, decided by the UK government in 2011, and that power utilities have to pay since 1 April 2013. Because of this new tax, they were incentivised to use all the remaining hours of their opt-out plants before the end of March 2013 and close their plants before April 2013. Four large power plants (Kingsnorth, 1940 MW, Cockerzie, 1200 MW, Didcot A, 2000 MW and Iron Bridge, 940 MW) closed between December 2012 and March 2013. Coal plant owners in the Netherlands were also incentivised to run their plants at higher load before the introduction of a carbon tax on 1 January 2013.

1.6. A SHORT-LIVED RENAISSANCE: 2013, A TURNING POINT FOR COAL REVIVAL?

While so far only gas-fired power plants have been impacted by the rapid development of RES and low returns, **2013 seems to be a turning point for coal plants**. It seems to indicate the start of the long decline of coal use in the EU, although at very different speeds according to national energy policies

and future EU policy on climate change. **EU coal demand by the power sector decreased by an estimated 5% in 2013** (see Chapter 3).

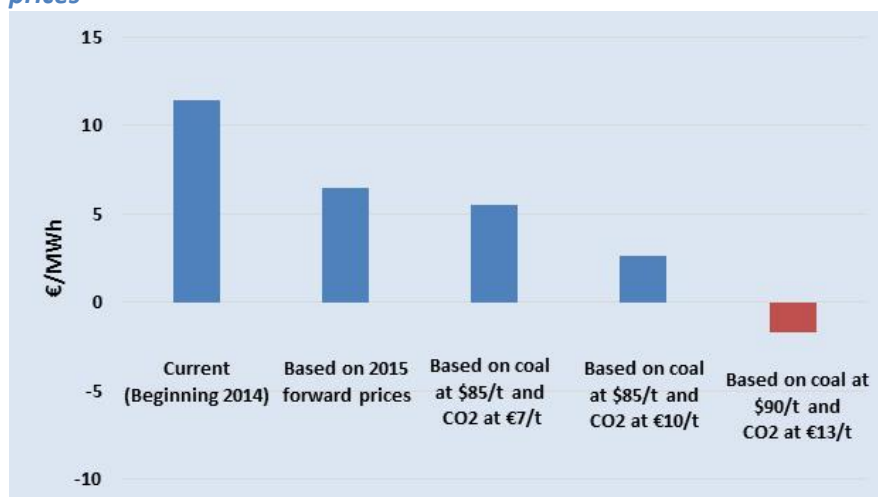
The future use of coal will be restricted by a combination of economic, technical, environmental, regulatory and policy-driven factors. However, competitiveness and security of supply (in particular for EU coal producing countries) argue in favour of coal in some EU countries. The Russia-Ukraine crisis may well support this trend.

Market conditions are becoming less attractive for coal

Clean dark spreads are declining

On the German market, the 2015 base-load forward price is trading at around €36.65/MWh (as of beginning of 2014), less than the €40/MWh for the 2014 forward price at the same time last year. As most German electricity sales contracts are based on year-ahead electricity prices, the power sales are going to offer poor returns for both gas and coal. In the case of coal, the clean dark spark is reduced to around €6.5/MWh. Depending on the evolution of coal and CO₂ prices, the clean dark spread could turn negative. If CO₂ prices rise to €13/t, and coal prices to \$90/t, the clean dark spread amounts to -€2/MWh.

Figure 24: Clean dark spread scenario for old hard-coal power plants (a) based on 2015 forward prices



(a) Efficiency 36%

Source: own calculations

Full cost of EUAs is an additional burden

The evolution of CO₂ prices and therefore the implementation and impact of the backloading of EUAs and EU ETS reform will be key to the profitability of coal-fired power plants in the future (the backloading and EU ETS reform are analysed in Chapter 4). But even at the low CO₂ prices observed in 2013, the end of free allocation of EUAs since 1 January 2013 reduces earnings from coal power generation. The additional cost for power utilities is significant. RWE, which produced 61% of its electricity generation from coal in 2013, indicated that the company had received free allocations of EUAs equivalent to €1.2 billion in 2012, and almost none in 2013. It largely explains the 58% decrease in operating results reported from power generation in 2013 compared with 2012³⁹.

³⁹ RWE (2014), Annual Report 2013, March 2014.

Closure of coal power plants due to weak profitability

Market conditions have deteriorated and are becoming even worse for all conventional power plants. The continued decrease of wholesale power prices reduces margins for all plants.

So far, mothballing and closure of power stations due to poor economic conditions involved gas plants mainly, coal was relatively immune from the negative economic environment. However, this period of grace is ending, in particular for old hard-coal power plants. Very few closures of coal power plants due to poor economic conditions had been reported before 2013. However, **during 2013, several companies announced the closure of coal-fired units due to their weak profitability**. While most of these plants were old plants (30 years), they were compliant with the existing air regulation and could have continued operating. The technical lifetime of a coal power plant is 40 years and some units run for longer (48 years in the case of EON's Staudinger 1 plant closed in 2013).

Table 5: Closure of coal plants in 2013 (excluding opt-out plants)

	Plants	Owner	Capacity (MW)	Status/Comments
Belgium				
	Ruien 3-4	GDF SUEZ	252	Closed in 2012
	Ruien 5-6-7	GDF SUEZ	627	Coal/Biomass. Closed in August 2013
Finland				
	Inkoo	Fortrum	1000	Unit four closed in March 2013. Units 1 to 3 closed in February 2014
Germany				
	Walheim	EnBW	244	To be closed at the earliest possible
	Heilbronn	EnBW	250	To be closed at the earliest possible
	Staudinger 1	EON	300	Decommissioned. April 2013. Old plant (48 years of operation).
	Shamrock 1-4	EON	120	Closed in April 2013
	Veltheim 2	EON	93	Closed in Q4 2012
	Staudinger 2-3	EON	500	Closed in Q4 2012
		RWE	(1170)	Termination of 3 hard coal contracts
Netherlands				
	Buggenum	Vattenfall	253	Closure on 1 April 2013. Coal gasification plant commissioned in 1993
		TOTAL	3639	

Source: Companies' announcements and annual reports

This trend is expected to accelerate. Several factors, such as falling forward electricity prices in Germany and the continued rise in renewable energies will make difficult for some hard coal power plants to recover their costs, even for new builds. Trianel, the owner of the recently commissioned Lünen hard coal-fired power plant in Germany stated that "it [the plant] will be the most efficient coal power station in Germany with efficiency of nearly 46% and will operate for 7,000 full load hours in the first year of operation, but will nevertheless be loss-making"⁴⁰.

The outlook for hard coal generation presented by EURELECTRIC's members in the 2013 report of the Association indicates a reduction by nearly 50% of EU hard coal generation by 2020 (see Figure 99, Chapter 5). This would be a dramatic change compared with the past three years.

The coal fleet is ageing

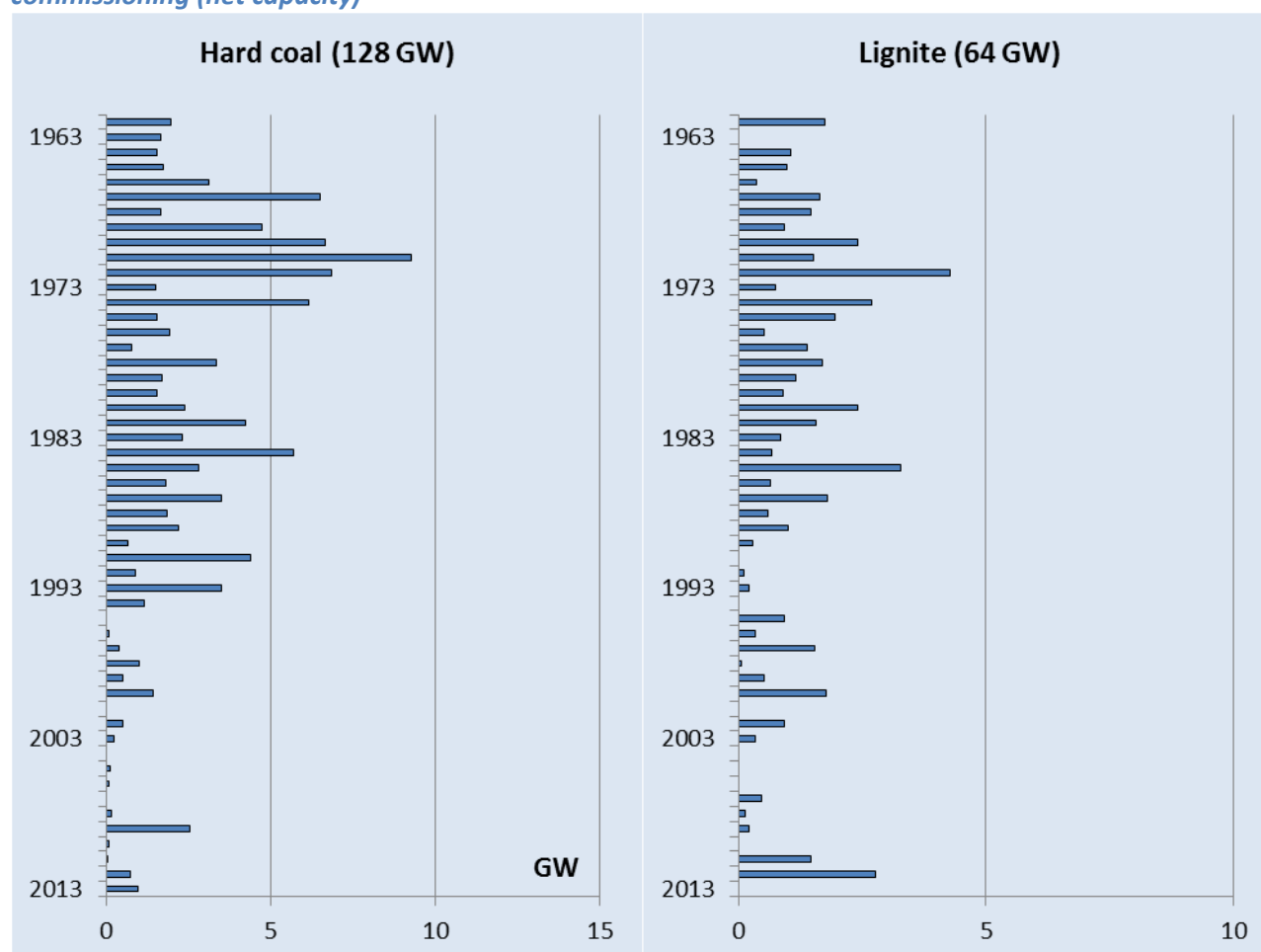
The European conventional fleet is ageing, in particular the coal fleet. **About 40% of the coal fleet is more than 40 years old** (Figure 25). It should be mentioned, however, that several power plants have been refurbished⁴¹ and can continue operating.

⁴⁰ McCloskey Coal Report, 8 February 2013.

⁴¹ Replacement of main plant equipment such as boilers and turbines

Due to its old vintage – the booming years for coal build occurred in the 1970s and 1980s – a large part of the coal plant fleet will be decommissioned in the next five to ten years, most of them in response to stringent local environment regulations (LCPD and IED). From January 2009 to December 2013, 18.8 GW of old coal-fired plants were decommissioned, including some opt-out plants. In Germany, the closure of old coal plants was a condition to build new plants on the same plant site.

Figure 25: EU hard coal and lignite power plants in operation at the end of 2013, by year of commissioning (net capacity)



Source: ENERDATA (2014)

Regulation on air quality

Stringent air quality regulation will drastically reduce the EU coal fleet in the coming years. The **Large Combustion Plant Directive** (LCPD) is currently having a major impact on the existing coal fleet, in particular in the UK, which is going to close almost one third of its coal capacity before the end of 2015 or earlier⁴². The **Industrial Emission Directive** (IED), which succeeds the LCPD from 1 January 2016, is leading to further closures by 2020/ 2023.

Impact of the Large Combustion Plant Directive

The LCPD was introduced by the European Parliament and Council in October 2001. It introduced measures to control the emissions of nitrogen oxides (NO_x), sulphur dioxide (SO_x) and particulates from large combustion plants (i.e. plants with a rated thermal input of equal to or greater than 50 MWth).

⁴² Most of the capacity is already closed.

The aim of the LCPD is to reduce the emissions of these pollutants, as they are known to damage human health and contribute to acid rain.

Operators of existing plants were given the option either to meet the requirements of the LCPD by complying with the Emissions Limit Values (ELVs) by January 2016, or to be exempted from compliance with the emission limits on condition that they undertake not to operate plants for more than 20,000 hours between 1 January 2008 and 31 December 2015. Plants whose investment was authorised after 27 November 2002 had to comply with the emission limits set out in the LCPD.

The LCPD has a major impact on the oldest coal plants with low thermal efficiency, for which it is not economic to invest in Flue Gas Desulphurisation (FGD) equipment. The only solution is to take the second option and close such plants by the end of 2015 at the latest. **In the UK, 8.3 GW of coal capacity opted out**, thus requiring such plants to close by 2015 or earlier if their allocated maximum number of operating hours was reached before then. Normally, most plants would have been expected to run until 2015 since these old and relatively inefficient plants were only expected to run during periods of high demand such as the winter months. However, four large plants were formally closed before March 2013 as they had used up their hours well ahead of the 2015 deadline⁴³. The other plants are expected to close in 2014.

Other countries where the LCPD has a major impact include France and Poland. In France, E.ON France closed its Hornaing power plant (210 MW) in March 2013. The company is planning to close Lucy (245 MW) in March 2014 and two units of Emile-Huchet (445 MW) in 2015. EDF is also going to close its nine smallest old coal units (250 MW each) as well as one 600 MW unit. In Poland, the impact of the LCPD is postponed as some plants got an exemption to comply with the ELVs for some pollutants until 2018. In 2013, the government estimated that 1.1 GW of old coal units had to close by the end of 2015⁴⁴ due to the implementation of the LCPD. PSE, the Polish grid operator, put the figure at 1.6 GW in its ten-year development plan⁴⁵. In Germany, the LCPD prompted utilities to upgrade their plants early, so no plants are affected by the 2015 deadline. The same applied to the Czech Republic where CEZ implemented a massive environmental upgrade programme during the 1990s, investing €1.7 billion over the 1992-1998 period, thus eliminating the need for any opt-outs from the LCPD.

Overall, the LCPD leads to the closure of 15.8 GW of coal plants by the end of 2015 at the latest; i.e. 6.2%⁴⁶ of the capacity in 2012. From 2008 to end 2012, 3.6 GW were closed, so 12.2 GW will have to close before the end of 2015 (already a large share was removed from the grid in 2013 in the UK).

⁴³ Prospects for New Coal Power Plants in Europe: Weakness in Core Markets but Emerging Opportunities on Europe's Periphery, 8 August 2013, Harald Thaler, Industry Director for Power Generation, Frost & Sullivan

⁴⁴ Polish Ministry of Economy, Status of Coal-Fired Power Plants in Poland, 2013 US-Poland Energy Roundtable

⁴⁵ PSE, Development plan for purposes of meeting current and future electricity demand in the period 2010 – 2025, March 2010

⁴⁶ The percentage is based on the coal power capacity at the end of 2012 (198 GW) and takes into account capacity which was already closed before the end of 2012 (3.6 GW).

Table 6: Closure of coal-fired power plants under the LCPD

	Opt-out plants	Owner	Capacity (MW)	Status	Comments
Belgium					
	MOL	Electrabel	260	Closed in 2008/09	
Bulgaria					
	Brikel		200	Closed in 2011	lignite
	Maritza 3		120	Unknown	lignite
	Varna 1-3	CEZ	630	Closed after 2013	hard coal. Varna 4-6 equipped to run until 2023
		TOTAL Bulgaria	950		
France					
	Lucy 3	EON	245	Closed in Mar 2014	
	Emile Huchet 4	EON	115	Closed in June 2015	
	Emile Huchet 5	EON	330	Closed in Mar 2014	
	Provence 4	EON	230	Closed in Q1 2013	Converted to biomass (150 MW)
	Hornaing 3	EON	235	Close in March 2013	
	Bouchain	EDF	250	Closed 2015	
	Le Havre 1	EDF	250	Closed March 2013	
	Le Havre 2	EDF	600	Closed July 2013	
	Vitry 3-4	EDF	500	Closed 2015	
	Blenod 2-4	EDF	500	Closed 2015	
	La Maxe 1-2	EDF	500	Closed 2015	
		TOTAL France	3755		
Poland		TOTAL Poland	1100	est. (Polish Ministry of Economy)	
Spain					
	Escucha	EON	160	Closed Q4 2012	
	Lada 3	Iberdrola	513	Closed 2012	
	Pasajes	Iberdrola	217	Closed 2013	
	Cers	EON	162	Closed	
	Soto Ribera	HCenergia	361	Closed in 2008	
		TOTAL Spain	1413		
United Kingdom					
	Kingsnorth	E.ON UK	1940	Closed Dec-12	
	Ironbridge	E.ON UK	940	Closed March 2013. Converted to biomass (700 MW).	
	Didcot A	RWE npower	1940	Closed Mar-13	
	Tilbury	RWE npower	1,020	Converted to biomass (750 MW) in 2011. Closed Jul-13	
	Ferrybridge	SSE	980	The 2 units will close by end 2015	
	Cockenzie	Scottish Power	1152	Closed March 2013	
	Uskmouth SSE	SSE	363	1 unit closed Mar-13	
		TOTAL UK	8335		
		TOTAL EU	15813		

Source: own calculations

Impact of the Industrial Emissions Directive

From 1 January 2016, the Industrial Emissions Directive (IED, Directive 2010/75/EU) will succeed to the LCPD and lead to additional closures of power plants. The IED, endorsed by the European Parliament in July 2010, recasts seven existing EU directives on industrial emissions, including the LCPD. It entered into force on 6 January 2011. EU Member States then had two years to translate it into national law. Several countries missed the January 2013 deadline. However, most countries implemented new laws transposing the IED during 2013. **The IED establishes a further tightening of emissions limits for SO_x and NO_x and particulates at EU-wide level**, which will become effective for all new and existing thermal plants from 2016.

For new pulverised hard coal-fired power plants above 500 MW, the IED reduces emission limits for SO_x and NO_x by 50 mg/Nm³ to 150 mg/Nm³ for both SO_x and NO_x, compared to the LCPD. Particulate

limits are reduced by 10 mg/Nm³ to 10 mg/Nm³. In order for an operator to get a permit for operating or constructing a combustion plant from the national authorities, it has to demonstrate that the plant at least complies with those ELVs and, for all pollutants, applies best available technology (BAT). Lignite burning plants are a special case, along with any other high sulphur fuelled plants: they fall under the requirement for desulphurisation rates (96 - 97% for plants above 300 MW) which means that they don't have to comply with the emission limit values for SO_x.

For existing hard-coal plants, the new ELVs for NO_x emissions are significantly tightened. For plants above 300 MW, the new limits are 200 mg/Nm³ for SO_x and NO_x and 20 mg/Nm³ for particulates. All coal plants which have opted into the LCPD (and which will therefore remain open from 2016 onwards) must comply with the new ELVs by 1 January 2016. However, as it was the case with the LCPD, the IED includes some flexibility. All plants unable to meet these criteria would be given two options:

- Opt out by committing to operate for a maximum of 17,500 hours between 2016 and 2023 (the "limited life derogation", LLD);
- The "peak-plant derogation" which allows opted-out plants to operate for up to 1500 hours per year over five years.

In addition, operators can opt in by entering into a Transitional National Plan (TNP) from 1 January 2016 to 30 June 2020 and agreeing to comply with IED ELVs from 1 July 2020. The TNP is intended to allow operators enough time to comply with the IED's reduced ELVs. Member States had to communicate their draft TNP to the Commission by 31 December 2013. Each TNP defines an overall cap on emissions of SO_x, NO_x and particulates in each year from the beginning of 2016 to June 2020. The total cap will be defined for each year, with the 2016 cap based on existing ELVs and trending downwards. After July 2020, all opted-in plant must comply with the IED ELVs. The IED also applies to gas plants which must comply with the new ELVs. Old gas plants have therefore to invest in SCR equipment, which may foster their early retirement.

As of beginning of February 2014, on the 15 TNP (for part or all their thermal fleet) which were communicated by governments to the Commission, six plans were approved (Slovak, Slovenian, Irish, Greek, Hungarian, and Lithuanian plans), two were rejected (Spain and the United Kingdom) and decisions on the remaining seven TNP had not yet been communicated. The TNPs of Spain and the United Kingdom can be adapted and re-submitted within half a year.

Coal stations that have opted in the LCPD have already installed FGD equipment. For this reason, it is mainly the need to comply with the NO_x limits in the IED which will be the major reason for further investment in NO_x reducing technology for generators who do not already meet the IED's ELV limits. Selective Catalytic Reduction (SCR) equipment⁴⁷ may represent an investment of €100 to 150 million for a 1000 MW plant. Under current market conditions, operators of thermal power plants may find it hard to assess whether investing in new technology is worthwhile given the difficulties in predicting plant operation. In addition, growth in the renewables industry increasingly leads to a decline in the demand for conventional plants, increasing the risk of investing in plants which will hardly run. Under such uncertainties, not so many companies are going to choose to invest in SCR. For the oldest coal- and gas- fired power plants, this will result in more closures.

⁴⁷ Selective Catalytic Reduction technology uses a simple chemical reaction to neutralise the NO_x in the exhaust. The catalyst promotes the reaction between NO_x and a reducing agent such as ammonia at the relatively low temperatures of an exhaust stream. This process produces harmless nitrogen and water. Highly efficient, SCR is capable of removing up to 99% of the NO_x.

Where the cost of investing in new emission abatement technology outweighs the financial benefits of running plants for longer periods, operators may choose to opt out of the IED and run their plants at high load factors while carbon prices remain relatively low and then close upon reaching the allotted number of hours. Another option for coal power generators is to convert their coal-fired plants to biomass. Work is underway in countries including the UK, Poland, Denmark and France (see next point in this Section). The decisions to be taken by power operators are complex since the IED is only one of the environmental and energy policies to be taken into account. Other key policies and market trends also interact on coal attractiveness and play a key role in the decision-making process, for instance, the availability of financial support granted to conversion of plants to biomass, or the possibility to keep the plant in standby and be remunerated by doing that.

At this stage, it is difficult to fully estimate the impact of the IED on the EU coal fleet. The difficulty is reinforced by the transitional two-year period, until the end of 2015, under which power generators which have entered the TNP may reverse their decision. This situation is clearly illustrated by the UK case.

Box 3: Implementation of the IED in the United Kingdom

In the UK, four key policies will shape the fate of the 20 GW of coal-fired power plants that opt-in the LCPD and thus remain open after 2016: the carbon tax, biomass energy subsidies, the establishment and design of the capacity market and support to CCS. In particular, conversion of coal plants to biomass and CCS projects are eligible to Contracts-for-Difference, CfDs, the new scheme put in place by the UK government to support low-carbon investment⁴⁸. As these key policies are not yet finalised, most operators have chosen to enter into the TNP which give them the possibility to change their initial decisions until the end of 2015.

Table 7: Status of UK coal-fired power plants under the IED

Plant	Owner	Capacity (MW)	Status at the beginning of 2014
Eggborough	Eggborough Power Ltd	2000	Uncertain. Considering biomass conversion. One unit closed in 2014
Uksmouth	SSE	240	LDD option
Drax	Drax Power	3960	3 units converted to biomass (with CfD support), 3 units to be defined
Cottam	EDF	1948	LDD option
West Burton	EDF	1924	LDD option
Ferrybridge (units 3 and 4)	SSE	980	LDD option
Ratcliffe	EON	2000	Opt in. Already compliant
Rugeley	GDF Suez	996	Biomass conversion cancelled. Opt in. Needs some upgrade
Aberthaw	RWE	1386	LDD option
Longannet	Scottish Power	2400	Testing new technology to be compliant
Fiddlers Ferry	SSE	2400	LDD option. Upgrading to be compliant
		20234	

Source: Companies' press releases

At the beginning of 2014, RWE, SSE and EDF announced their decision to opt out and exercise the limited life derogation option (17,500 hours) for some of their plants. Other generators (EON, GDF Suez and Scottish Power) announced plans to opt-in. EON's Ratcliffe plant is already compliant with the new

⁴⁸ The UK government is replacing its renewables support mechanism called the Renewables Obligation Contract (ROCs) with a new scheme called "contracts-for-difference" (CfDs), a system of fixed-price, long-term contracts for electricity. In the transition period from 2014 to 2017, 10 projects have been selected for early CfD support. In CfDs, there is a contractually guaranteed fee that power producers receive for the electricity fed into the system. If the price realised on the wholesale market is below the fee, they are paid the difference. However, if it exceeds the fee, the generator is retrospectively obliged to reimburse the difference. Each CfD has a set 'strike price' (a price per unit of electricity generated) which is set at the level determined to be necessary to support the particular technologies or projects supported by the scheme.

ELVs. GDF Suez's Rugeley and Scottish Power's Longannet will need to upgrade. SSE's Fiddlers Ferry has also received planning permission for necessary works. Other generators announced plans to convert their plants to biomass (Eggborough, Drax). Drax is converting three units into biomass. Eggborough plans are less certain as the plant has not been selected by the UK government to get early CfDs. The prospect of Eggborough Power closing all units at its 2 GW coal-fired station by the end of 2015 appears increasingly likely, with one of its 500 MW units to come offline in September 2014.

All in all, **12.4 GW** may be closed or converted to biomass by 2023 (assuming that RWE, SSE and EDF confirm their decision to opt-out), of which 4 GW may be closed at end 2015 (Eggborough and three units of Drax).

In Germany, both the law as well as its associated series of decrees for the implementation of the IED came into force on 2 May 2013. A large part of the coal fleet is already largely in compliance with the new standards. It is estimated that **30 GW of capacity were already equipped with SCR already in 2010**. However, old coal plants will need to invest in depollution equipment to comply with the new limits. Based on BNA scenarios for the development of power capacity by 2024⁴⁹, an **estimated 12-13 GW** of old plants (hard coal and lignite) may be retired from the grid by 2023, of which 4 GW are going to retire from 2013 to 2016. A large part of the lost capacity will be replaced by the new coal capacity currently built in Germany. The new hard-coal power plants commissioned in 2013 and under construction will add 8.4 GW by 2015.

The Netherlands translated the IED into national law within the time limit. The country's emissions thresholds are stricter than those of the Directive, but existing plants must only comply with the threshold values established in their operating permits. So the IED has no impact on the conventional fleet. However, five old coal plants (2.8 GW) are going to close, according to the new agreement signed by the government and 40 organisations in September 2013 (see Annex 1).

In Spain, to comply with the IED, Spanish authorities have drawn up a draft Transitional National Plan for the period from 1 January 2016 to 30 June 2020, initially covering all coal-fired power plants and some other installations. The plan and its amended versions submitted to the EC were rejected by the EC in January 2014. It can be adapted and re-submitted within half a year. As in the UK, it is expected that power generators will opt all their coal capacity out of the IED and leave the final decision for 2015. The oldest plants will likely exercise the limited life time derogation and close at the end of 2023 at the latest. **Capacity reductions of approximately 4.7 GW are assumed.**

In France, in 2013, EDF initiated an extensive program to modernize Le Havre 4 and Cordomais 4 and 5 units to extend their operating life by 20 years to 2035. These three units are the largest coal-fired units in the EDF fleet and were built to an identical design in the early 1980s. Each has a generating capacity of 600 MW. EON France's Emile Huchet and Provence 5 may also be equipped with SRC equipment.

In Italy, ENEL has started to modernize some of its coal plants (Sulcis). However, it is expected that the oldest plants will close (around 1.5 GW). In addition, more plants may close due to local environmental regulation (Tirreno Savona power plant).

Generators in **central and eastern Europe**, by contrast, will be much more keen to modernise their coal-fired power plants, mainly in view of locally-sourced coal (Poland, Czech Republic), the lack of economically viable alternatives and the difficulty to build new coal plants (see Box 4).

⁴⁹ BNA, szenariorahmen für den netzentwicklungsplan strom 2014, entwurf, 28 March 2013

In the **Czech Republic**, CEZ, one of the region's top utilities, is considering extending the lifespans of some power plants. The company has signed a contract for depollution equipment for its Počerady power plant. Alpiq Generation is also modernising its power plant at Kladno.

In **Poland**, the environment for building new coal plants is not favourable since the decision of the European Commission in July 2012 not to include several new coal plants in the National Investment Plan for the modernisation of the Polish energy system. This decision meant the plants would not receive free CO₂ emissions allowances. This has led private foreign power utilities to cancel their coal projects and replace them by selective investment in depollution equipment. EDF has frozen its plan to build a €1.8 billion, 900 MW supercritical coal fired power plant at its existing Rybnik facility. Instead the company is currently modernising the plant. Poland has a coal and lignite capacity of 28.5 GW (end of 2012), 40% of which is more than 40 years old. Given the reliance on domestic coal (lignite and hard coal) and the uncertainties surrounding natural gas (imported gas or shale gas produced domestically), Poland will certainly keep a high share of its coal fleet open by fitting cleaner technology. Polish grid operator PSE expects that **6.6 GW** of the current installed capacity will be taken off the grid by 2020 as outdated plants close. PGE⁵⁰ and Tauron are expected to extend the lifespan of some of their older plants in order to provide back-up capacity for the grid and avoid shortage of power supply, which may range from 1.9 to 2.5 GW in 2016.

In **Greece**, the newest lignite-fired units at Meliti Florina and Megalopolis III and IV have recently completed major environmental investments, and now fully comply with the IED's provisions. The IED provisions have a greater impact on older lignite fired units, which are expected to operate after 2016 (Kardia, Amyntaion and Agios Dimitrios). Big scale and costly environmental investments are needed for these units in order to comply with the IED. Under the Greek TNP, the plants have until July 2020 to comply with the new EVLs. However, the oldest units are expected to be closed (**2 to 3 GW**) by 2020.

At EU-wide level, **an estimated 50 to 55 GW of coal power capacity may be closed by 2020/2023 at the latest. Overall**, the current capacity may be reduced by about **65 to 70 GW** by 2020/2023, due to **the combined effect of the LCPD and IED, representing a third of the coal fleet capacity in 2012**. Some of this capacity however will not be closed: some plants may be reserved for stand-by operation; others may be converted to biomass.

Biomass conversion: a new life for old coal plants

Biomass co-firing is increasingly widespread in Europe. About two thirds of all co-firing plants are located in Europe alone, especially CHP plants in Northern Europe, Germany, Poland and Austria. It is an interesting option to mitigate CO₂ emissions. Biomass, as a renewable energy source, does not emit CO₂⁵¹, lowering the overall CO₂ emissions of the plant, as well as giving rights to support schemes in some countries. In addition, co-firing offers a higher efficiency than direct firing of biomass in dedicated plants. Whereas typical conversion efficiencies of biomass-fired power plants are around 25%, average conversion efficiencies of conventional coal-fired power plants are about 38% in the EU and recent state-of-the-art plants reach 46%. The extent of co-firing is however limited by technical parameters: 5 to 20% of biomass can be mixed with coal without creating major technical issues, such

⁵⁰ PGE is currently involved in the modernisation of its existing fleet. The largest modernisation project comprises the expansion of the Bełchatów, Dolna Odra and Opole (existing units) power plants. The other plans provide for the refurbishment and overhaul of generation assets in the Lublin-Wroclaw, Zgierz, Kielce and Gorzów CHPs.

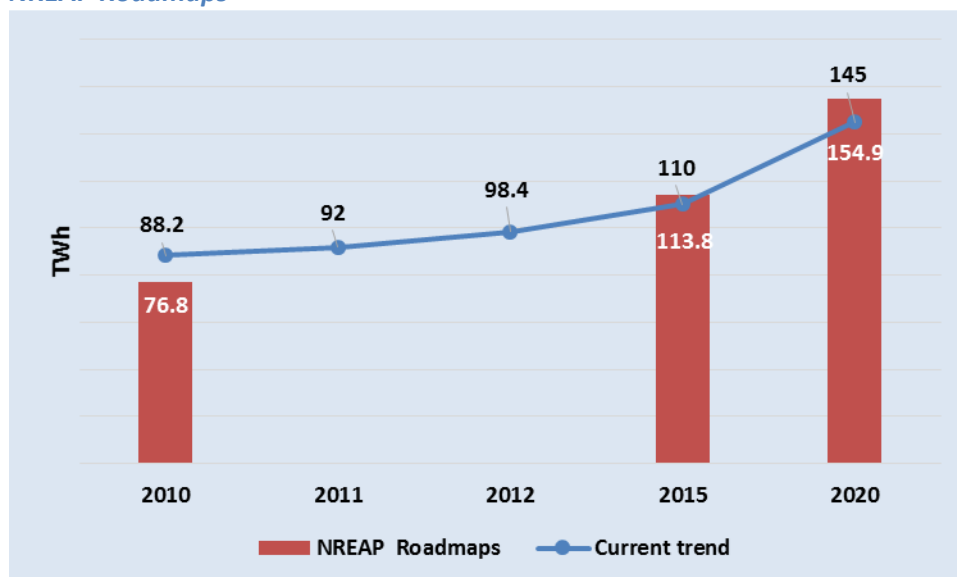
⁵¹ Biomass is considered to be a CO₂-neutral fuel because it emits the same amount of CO₂ from burning, which it absorbed during growth.

as fooling, slagging and corrosion. Larger amounts are possible but require major modifications of the burners.

Faced with stringent environmental regulation, **several utilities envisage 100% biomass conversion of their coal plants as a way to re-use existing assets, reduce their CO₂ emissions and contribute to RESe (electricity from RES)**. The main advantage is the use of existing plant infrastructure adapted to biomass operation and longer operations of the plant site. Biomass is also of particular interest for electricity supply since it is not subject to problems of intermittency when used to generate electricity as opposed to other RES. Biomass plants therefore do not require back-up power capacity. In the case of conversion of coal plants, another advantage is that the plants are already connected to the grid.

According to the national renewables energy action plans (NREAPs), the share of RESe coming from solid biomass and waste amounts to 232 TWh by 2020 (of which 155 TWh from solid biomass, including dedicated biomass plants, co-firing and conversion of plants, compared with 98 TWh in 2012).

Figure 26: Comparison of the current trend in electricity production from solid biomass against the NREAP Roadmaps



The data include an estimate of RESe from waste incineration units

Source: EurObserv'Er 2013 and 2012.

The conversion of coal power plants to biomass offers the largest potential to achieve the 2020 target. **The technology is well proven.** The conversion of coal-fired stations to biomass was tested in many European countries in the late 1990s and beginning of the 2000s. **The economics of conversion, however, is highly dependent on the availability and price of sustainable biomass⁵².** It is also highly dependent on financial support granted to biomass which differs from one country to another and may change with time. At current commodity (coal and biomass) and CO₂ prices, the conversion would not be justified in most countries. In this context, several announced projects of conversions of coal plants

⁵² The lack of steady raw material supply in Europe is a key issue. While some countries have a huge forest industry (Finland), others have to rely on imported biomass (mainly wood pellets from North America). So far the lack of binding criteria for sustainable and durable biomass has jeopardised the development of biopower. The European Commission is developing binding sustainable criteria to be introduced in Europe and published a draft directive in August 2013, but the text has not been adopted yet. This uncertainty is an obstacle for the sector development (see EurObserver, Solid biomass barometer, December 2013).

have recently been cancelled. RWE's Tilbury coal-fired power plant in the UK, an opt-out plant, is an illustration of the economic dependence of projects on supporting schemes⁵³.

Currently, the largest ongoing project in Europe is the conversion of the Drax coal-fired plant in the **United Kingdom**. The power plant is the largest coal-fired power plant in the UK. It has six units with a capacity of 660 MW each and provides 7% of UK electricity. The Drax Group Plc, owner of the Drax plant, plans to convert three of its coal-fired units to 100% biomass. The first, funded through the ROCs (renewable obligation certificate) scheme, was converted in July 2013. The second and third units could be converted by 2014 and 2015. Drax's two converted units have been selected in the list of eligible projects for CfDs, which guarantee a fixed price of £105/MWh.⁵⁴ Several other operators in EU countries are converting coal power plants into biomass-firing. In **France**, E.ON France is converting the Provence 4 coal power plant into a 100% biomass plant. With a capacity of 150 MW, it will be the largest biomass plant of the country. In **Poland**, in 2011, GDF Suez converted to biomass one of the eight units of the Polaniec power plant (190 MW) and there are several CHP coal-fired plants that have been converted to biomass, partially or fully. In **Belgium**, in 2011, GDF Suez converted the 180 MW Rodenhuize plant to 100% biomass (Maxgreen project). E.ON plans to convert the last remaining coal plant in Belgium, the 556 MW Langerlo plant, into 100% biomass. In the **Netherlands**, co-firing is widespread in almost all coal power plants which use 20% or more of biomass in addition to coal (Amer, Gelderland). Full conversion to biomass is not envisaged as the old coal plants are going to close.

A strategy followed by Scandinavian countries

In **Denmark**, the Energy Strategy 2050, published in 2011, aims at 100 % renewable sources in the energy and transport sectors by 2050. As part of this strategy, oil for heating purposes and coal are to be phased out by 2030, and electricity and heating supply is to be 100% covered by renewable energy by 2035. DONG Energy, the first power and heat producer of the country, plans to convert two coal- and one gas-fired power plant to 100% biomass by 2015. The company expects to replace about 1 Mt of coal with approximately 1.5 Mt of wood pellets at Avedøre and Studstrup coal power stations. Vattenfall's two large Danish CHP plants, Fynsverket and Nordjyllandsverket, are expected to be converted to biomass too.

In **Finland**, the government wants to phase out the use of coal in electricity and heat production by 2025. Use of coal in power plants will be for the most part replaced with new emission-free energy production, such as nuclear power and wind power. Most coal used for heat generation will be replaced by biomass⁵⁵. The Energy and Climate Strategy also foresees a decreasing role for natural gas. Approximately 10% of natural gas will be replaced with biomass-based solutions (SNG) which will

⁵³ The plant was converted to 100% biomass in 2011, making it the largest biomass power plant in the world with a capacity of 732 MW. Although biomass produces almost no CO₂ emissions, the plant was not exempted from closure at the end of 2015 as the LCPD relates to SO_x and NO_x emissions. RWE planned to retrofit the plant to reduce its SO_x and NO_x levels to comply with LCPD requirements. However, the UK government announced that the plant was not eligible for contracts for difference (CfDs). In light of this decision, RWE decided to close the plant after it had used all its remaining operating hours (July 2013). The same future is foreseen for EON's 900 MW Iron bridge opt-out plant. The plant, which has been converted into a 700 MW biomass plant since May 2013, will close at the end of 2015 or earlier as required by the LCPD.

⁵⁴ At the end of April 2014, however, the government said the project for converting Drax's Unit 3 at the plant did not meet all its assessment criteria for the new CfD scheme. It recommended that Drax continue to use the current direct subsidy scheme. Drax has started legal proceedings against the government over the decision but said that regardless of the outcome of the legal challenge, it would continue with the biomass conversion project. Source: Reuters, *Drax sues Britain over U-turn on converting coal unit*, 23 April 2014

⁵⁵ National Energy and Climate Strategy, Government report to Parliament, Finland, 20 March 2013

enable the replacement of imported gas (for electricity purposes) while utilising the current gas pipelines and power plants.

The country uses 4 to 5 Mt of steam coal per year, imported from Russia mainly. Coal is used for electricity production only at one power plant, Meri-Pori, since Fortum, the largest Finnish heat and power company, decided to close the second coal-fired plant at Inkoo. Coal is also used in several CHP plants, which operate with high overall efficiencies of 80% to 90%. Most coal-fired CHP plants already co-fire biomass in large quantities. As coal is heavily taxed in the country, biomass boilers operate on market conditions.

Several CHP plants are being converted to biomass. Fortum and Turun Seudun Energiantuotanto Oy's (TSE) are building a new multifuel CHP plant in Naantali. The plant will replace the 50-year-old coal-fired power plant. The new multifuel power plant can be fuelled by biomass, coal and high-quality recycled waste. The plant, to be commissioned in 2017, has a capacity of 142 MW electricity and 244 MW heat. Voima Oy, the second power utility in the country, is also converting its coal CHP plants to biomass. A new biomass gasification plant has been constructed in Vaskiluoto, Vaasa, next to an existing coal-fired power plant. Two coal CHP plants (Salmisaari and Hanasaari), operated by Helsingin Energia, the power company of Helsinki, are being modernised to use biomass.

As shown above, **retrofitting of coal-fired power plants to 100% biomass is gaining in importance all over Europe but is strongly linked to support schemes or phase-out of coal in Scandinavia.** An alternative strategy is the use of new material, such as torrefied wood pellets and biocoal, which allow coal-fired power plants to burn 100% RES fuels without modifications of the boilers. Refined biomass has a much higher energy density and can be easier integrated into existing power plant processes. These developments, although limited, are adding another dimension to the coal and gas competition. **Coal plants converted to biomass reduce electricity demand addressed to conventional power plants. This strategy is followed by Scandinavian countries which benefit from large domestic biomass resources.**

Limited investment in new coal-fired power plants after the ongoing capacity addition boom

The EU is adding 16 GW of new coal-fired power plants

There is significant coal capacity under construction, in particular in Germany, the Netherlands and Poland, with most of this new capacity coming online in late 2013 and 2014. Overall, **the EU is going to add 16 GW of new capacity between 2013 and 2019.** In addition, two lignite-fired plants were completed in Germany in 2012. RWE's lignite-fired 2200 MW Neurath plant was completed in August 2012. Vattenfall's 675 MW Boxberg plant was commissioned in late 2012.

Germany will add 8.4 GW of new hard coal-fired capacity over the period 2013-2015 (including E.ON's Datteln 4 which still encounters permitting challenges). Most of these coal projects were planned almost a decade ago after Germany decided for the first time to exit nuclear power. A number of projects were delayed due to either quality problems with the specific steel used in the boilers (all plants are supercritical plants requiring high temperatures), or lengthy environmental permitting process. The Netherlands is adding three plants with a capacity of 3.5 GW. All of them have the ability to co-fire up to 50% of biomass. In Poland, the capacity under construction more than doubled in January 2014 after the board of PGE, the largest power company in Poland, approved a program of internal financing to build two 900-MW generators in a \$3.78 billion expansion of the Opole plant. PGE's former chief executive officer rejected the project in April 2013 as unprofitable. The Polish

government, however, deemed the project important to Poland's energy security and necessary to avoid future energy shortages as demand rises.

Table 8: Coal plants recently commissioned and under construction (status at the beginning of 2014)

Country	Location	Operator	Capacity (MW)	Main fuel	Start-up date
Germany	Lünen	Trianel	750	Hard coal	2013
Germany	Karlsruhe (Rheinhafen RDK8)	EnBW	912	Hard coal	2014
Germany	Wilhelmshaven	GDF Suez	800	Hard coal	2014
Germany	Duisburg (Walsum 10 unit)	STEAG	725	Hard coal	2013
Germany	Hamm (Westfalen D)	RWE	800	Hard coal	2014
Germany	Hamburg (Moorburg 3)	Vattenfall	840	Hard coal	2014
Germany	Hamburg (Moorburg 4)	Vattenfall	800	Hard coal	2014
Germany	Hamm (Westfalen E)	RWE	800	Hard coal	2014
Germany	Mannheim (GKM 9)	GKM	911	Hard coal	2015
Germany	Datteln 4	E.ON	1055	Hard coal	not yet known (Built but has to re-apply permission)
Netherlands	Maasvlakte	GDF Suez	750	Hard coal	2013
Netherlands	Eemshaven (2 units)	RWE	1600	Hard coal	2014
Netherlands	Maasvlakte 3	E.ON	1100	Hard coal	2014
Czech Republic	Ledvice 4	CEZ	660	Lignite	2013
Czech Republic	Kladno	Alpiq	125	Hard coal	2014
Slovenia	Sostanj (TES 6)	HSE	600	Lignite	2016
Poland	Kozienice 11	ENEA	1075	Lignite	2017
Poland	Opole 5	PGE	900	Hard coal	2018 (Contract awarded to Alstom in January 2014)
Poland	Opole 6	PGE	900	Hard coal	2019 (Contract awarded to Alstom in January 2014)
TOTAL			16103		

Source: Companies' annual reports and press releases

Weak projects pipeline amid limited conventional power needs and financial restrictions to coal power plants

Beyond what is currently under construction, however, **the future projects pipeline looks fairly weak. Planned hard coal and lignite projects total 33 GW⁵⁶**, in particular in Poland. It should be noted, though, that **not all of the projects in the pipeline will proceed to the construction phase**. At current wholesale electricity prices, the new projects will hardly be developed without government support. Financial restrictions to coal power plants from public and private banks may hamper the financing of some projects (see Box 4). The cost inflation of new coal projects is an additional barrier. Finally, the evolution of market conditions, and especially the price of CO₂, may lower the profitability of coal power plants in the future and, in line with the development of RES, increases the risks of building stranded assets.

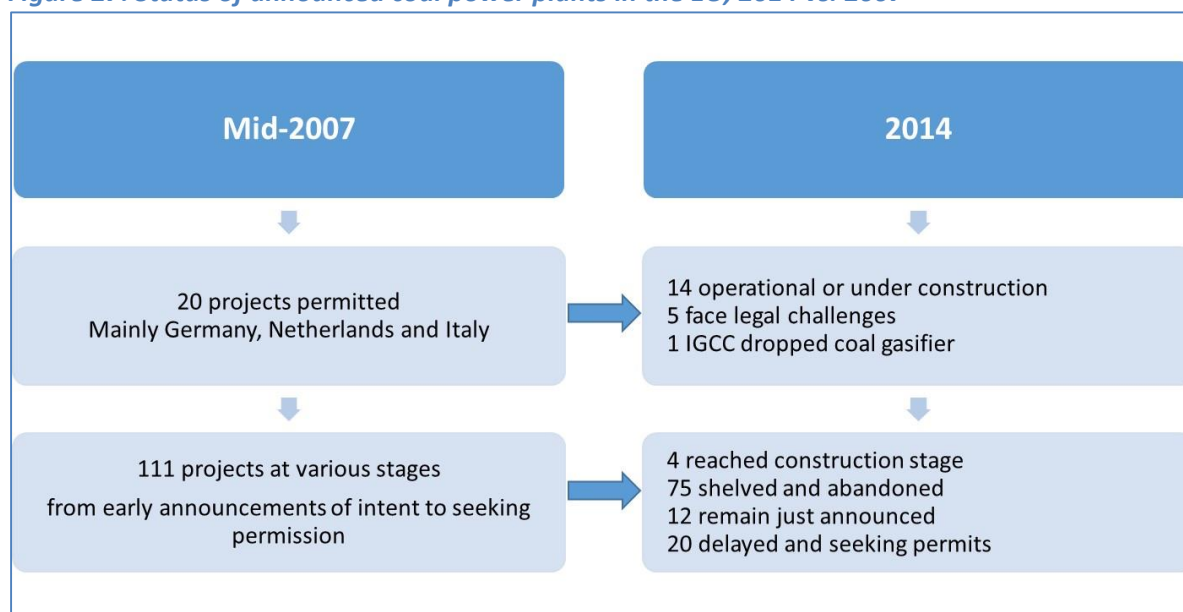
In view of stringent environmental and financial conditions, the future of coal in the EU is strongly linked with the successful commercialisation of CCS which would reignite coal projects development. However, there is limited interest and investment in CCS across Europe (see Section 1.7).

Finally, local resistance to greenfield coal-fired power plants has significantly increased in the past couple of years and is reinforced by the decisions taken by key international development banks to restrict funding to coal-fired power plants. This is the background to the numerous coal project

⁵⁶ VGB, 2014

cancellations that Europe has seen over the past seven years. Although 131 coal-fired projects were announced in 2007, only 19 are currently operational/under construction (five of them still face legal challenges) and 75 have been shelved or abandoned.

Figure 27: Status of announced coal power plants in the EU, 2014 vs. 2007



Source: EIB, EC, press

The prospects for coal plant orders over the next few years are therefore extremely limited, except in Poland, although cancellations even there have slowed down investment. Poland had plans to build approximately 11 GW of new coal facilities by 2020. However EU regulation and the controversial public procurement law have led to delays, postponements and cancellations instead. Nevertheless, Tauron's 910 MW Jaworzno III project and PGE's Turow may go ahead in 2014. The new Polish energy strategy, released in November 2013, concludes that coal provides the cheapest, and therefore the optimal, solution to supply Poland's power up to 2060.

Box 4: Financing of new coal-fired power plants is becoming more difficult

Following review of energy strategies and financing for coal by key international and European development banks, investment in new coal plants is becoming much more difficult. **In the EU, the new financing conditions mean that new coal plants without CCS can only be financed by owner's equity.**

During 2013, rising concerns over the environmental risks posed by surging global coal demand and the willingness of address the impact of climate change pushed key international and European financial institutions to adopt measures to restrict financing of coal power plants. Commercial banks can only follow suit as the risk would become too high of financing stranded assets. Efforts to fight climate change by international development banks and some national governments have targeted coal as it produces about double the amount of CO₂ than natural gas. By contrast, financing of gas-fired power plants should be encouraged by the new lending policies as natural gas is recognised as the fuel to support the transition to a low carbon economy.

The move started in June 2013 in the United States, when President Barack Obama unveiled his Climate Action Plan, which included an end to financing for new coal plants overseas with public funds, such as financing by the US Export-Import Bank, the US Trade and Development Agency and the US Treasury Department. On the heels of this announcement, in July 2013, the World Bank adopted a new energy

strategy that will limit financing of coal-fired power plants to "rare circumstances", restricting financial support to countries that have "no feasible alternatives" to coal, as it seeks to balance environmental efforts with the energy needs of poor countries. The Bank's lending portfolio includes a lignite-fired power plant in Kosovo for which a decision to provide loan guarantees should be taken in 2014.

Also in July 2013, the European Investment Bank (EIB), whose the majority of financing is directed to EU Member States, announced its own restrictions to funding power plants. The EIB has introduced an emissions performance standard (EPS) of 550 gCO₂/kWh for all fossil fuel power plants. The new lending criteria represent an alignment of the EIB's energy investment with the EU energy and climate policy. The new EPS means that only coal plants co-burning biomass would be eligible, or coal plants using CCS (even partially). The EIB has introduced derogations to the rule. Plants which contribute to the security of supply may be exempted from the EPS limit, as well as plants located in isolated energy systems.

The European Bank for Reconstruction and Development (EBRD) has followed the move and announced in December 2013 a new strategy that will guide its energy sector investments for the next five years. The bank will limit its financing of coal-fired power generation projects to "rare and exceptional circumstances in which there is no economically feasible alternative energy sources"⁵⁷. Instead of the EIB's EPS, the EBRD uses three criteria to decide whether to support a coal project, whether a greenfield or existing coal power plant:

- It has to be the least carbon-intensive of realistically available options.
- It has to use best available techniques.
- It has to comply with EU requirements in relation to CCS readiness.

In addition, the Bank will use a shadow price for carbon and other emissions to assess whether investments are economically viable. The coal decision is part of a wider EBRD's investment strategy which focuses on energy efficiency and clean technology.

Several EU countries have taken similar action including the UK, Sweden, Norway and Finland. And there is pressure on the KfW, the German government-owned development bank, to phase-out its support to coal-fired power plants.

For plants outside the EU, there is still public and private funding available for coal projects. The Asian Development Bank and the Japan Bank for International Cooperation have not announced an end to their coal financing. Likewise, China, which wants to export coal power plant technology, may ramp up support and fill some of the funding gap.

In the EU and surrounding countries, this dramatic shift will make financing of new coal plants extremely difficult for countries that previously relied on funding by the EIB and the EBRD. It will restrict new build potential to projects owned (and guaranteed) by state-owned utilities (PGE's Opole power plant in Poland for instance) or private investors willing to invest in these assets (Polnoc power plant in Poland), or projects which may be exempted from the new funding restrictions, for security of supply reasons, for instance.

⁵⁷ Both the EIB and EBRD are involved in the several lignite power plants which are under consideration in the Balkans: Kolubara B lignite power plant in Serbia, Kosova e Re lignite power plant in Kosovo.

ANNEX 1. NATIONAL ENERGY POLICIES

Taxes on fossil-fuel generation and other national policy measures play a determinant role in shaping the role of gas and coal in national electricity mix and competition between the two fuels, in addition to the EU overarching climate and energy policies. There is a **growing momentum of environmental regulation in the power sector** that threatens the long-term profitability of coal-fired power plants. Taxes (carbon tax) can reverse the current competitiveness of coal against gas. The introduction of emissions performance standards (EPS) can even prevent the building of new unabated coal stations. At the extreme, national policies mandating the phase-out of coal in the electricity mix obviously end the use of coal.

Table 9: Different ways to influence the fuel mix and reduce demand for coal

Regulation	Description	Impact
CO ₂ Emissions Trading Scheme (ETS)	Power utilities must pay the market price for any emissions they generate over their annual allocation.	A price on CO ₂ emissions penalises all fossil-fuel plants. Coal-fired plants are penalised more than gas-fired plants, and older, less efficient plants are penalised more than newer plants.
Carbon tax	Power utilities must pay a fixed price for any emissions they generate.	Idem
Emissions Performance Standards (EPS)	An EPS limits the amount of CO ₂ that can be emitted per MWh of output.	A mild EPS will force new coal-fired plants to be high efficiency ultra-supercritical plants, while a more stringent EPS will prohibit the construction of new coal-fired plants unless they are fitted with carbon capture or partial carbon capture or will force co-firing of biomass.
SO _x and NO _x limits	The amount of sulphur and nitrogen emissions can be limited either via an ETS (as in the US) or an EPS (as in Europe).	Power plants often must invest in emissions control equipment such as flue gas desulphurisation (FGD) and selective catalytic converters (SCR), resulting in higher capital costs, lower plant efficiency and higher costs per MWh.
Renewable Energy Targets (RET)	Mandatory targets to achieve a minimum threshold level of electricity from renewable sources.	RETs reduce the amount of future demand for which coal-fired plants can compete, and act as a disincentive to investment in new generating capacity
Energy Efficiency Target (EET)	Mandatory targets to achieve a reduction of electricity consumed per unit	EETs reduce the amount of future demand for which coal-fired plants can compete
Capacity markets	Mechanisms aimed at remunerating power operators to ensure generation adequacy	Depending on their design, capacity markets favour natural gas
Phase-out	Mandatory phase-out of coal/fossil fuel in the electricity mix	Obviously ends the use of coal/fossil fuel

Source: adapted from Goldman Sachs, 2013⁵⁸

The review of some policy measures in the three main EU coal consuming countries (Germany, Poland and the United Kingdom) illustrates the key role of national policies. Altogether, these three countries consumed 246 Mtce (million tonnes of coal equivalent) of coal in 2012, i.e. 59% of EU total. The share of coal in their electricity mix is largely above the EU average: 84% in Poland, 44% in Germany and 39.4% in the UK, compared with 28% on average in the EU (2012 data). They account for 57% of the electricity generated from coal in the EU. They are also large producers of coal (87% of EU hard coal production and 57% of lignite production⁵⁹). **The three countries have very different strategies to address their reliance on coal.** Germany is closing its old inefficient coal-fired plants and replaces them by high-efficient ones. Poland plans to rely on coal in the long-term as well and has to replace its ageing coal fleet. Its coal imports are increasing, while investment required to maintain its own production is increasing. The United Kingdom has introduced a carbon tax which may gradually reverse the advantage of coal against natural gas. The government has also adopted an EPS which prevents the construction of new unabated coal stations.

⁵⁸ Goldman Sachs Global Economics (2013), The window for thermal coal investment is closing, 24 July 2013

⁵⁹ UK does not produce lignite.

Other recent examples of policy measures aiming at reducing coal use in the EU are given for Spain and the Netherlands. **These country-cases show that there are different ways and timeframes to move from the current electricity mix, mainly determined by national historical factors, to a low-carbon one.**

Box 5: National energy mix determined by Member States

The EU has set an aspirational goal of an 80-95% reduction in GHG emissions by 2050 relative to 1990 levels. The EC Roadmap outlines different pathways to decarbonise the European energy system by 2050, depending on specific technology setting. In most scenarios, natural gas is the bridge fuel to the transition to a low-carbon economy.

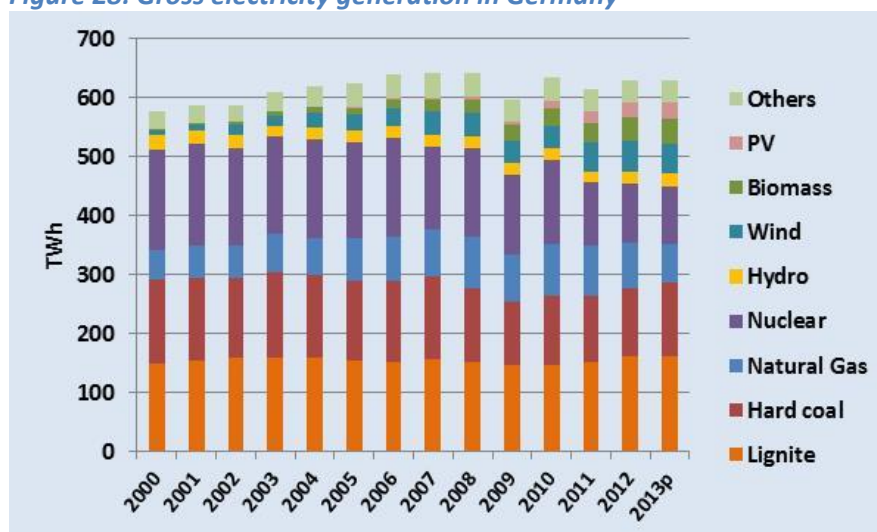
Despite the fact that the European Commission sees the Energy Roadmap 2050 as “the basis for developing a long-term European framework”, aspects related to energy strategies remain national responsibilities. According to Article 194 of the Treaty on the Functioning of the EU (European Union, 2010) all measures needed to preserve and improve the environment “shall not affect a Member State’s right to determine the conditions for exploiting its energy resources, its choice between different energy sources and the general structure of its energy supply”. Thus, the domestic energy/electricity mix ultimately lies within the sovereignty of Member States. This is an important prerogative in the debate about the use of coal in the EU. Its security of supply and competitiveness aspects reinforces the willingness of several EU countries to keep coal in their electricity mix. The existence of large coal reserves in the EU (mainly lignite, see Chapter 3) at low prices is obviously an advantage for the countries concerned. It is counterbalanced by the higher CO₂ emissions of coal-fired plants, an issue that requires a reinforcement of R&D and investment in CCS technologies.

Germany: the *Energiewende* and the role of coal

Electricity generation and capacity

Germany is the largest electricity market in the EU and has also the largest cross-border trade with neighbouring countries. Despite the rapid expansion of RESe, the electricity mix is still dominated by coal.

Figure 28: Gross electricity generation in Germany



Source: BDEW, 2014

In 2013, power generation was 629 TWh (flat compared with 2012), dominated by lignite (25.8%, up from 25.5% in 2012), hard coal (19.7% up from 18.5%), nuclear power (15.4%, down 0.4 percentage points) and gas (10.5% compared with 12.1% in 2012). Despite a clear growth of their installed capacity (+10 GW), wind and solar generation was up by only 1.3% (+10 TWh) due to bad weather conditions. Hydropower and renewables contributed 23.4% and oil 1.1%. Total electricity supplies totalled 596 TWh in 2013 (-1.8% compared to 2012).

As Figure 28 shows, the increase in coal use by the power sector needs to be put into perspective: the share of coal (hard coal and lignite) has actually decreased since 2000, from 50.5% in 2000 to 45.5% in 2013, as wind, PV and biomass have expanded. What the figure also shows is the shrinking share of gas, in particular in 2013, and its relatively low contribution to the German electricity mix (varying between 8.5% and 14.1% during the period). Although Germany is the largest EU gas market, natural gas in the country is mainly used by industrial, commercial and household users.

Net installed power capacity amounted to 188.4 GW at the beginning of 2014⁶⁰, of which 21 GW for lignite, 26 GW for hard coal and 28 GW for natural gas. Nuclear power capacity amounts to 12 GW. A total of 83.2 GW comes from RES. Wind and solar capacity has continued to be installed at a high speed and reached 34 GW and 37 GW respectively at the beginning of 2014.

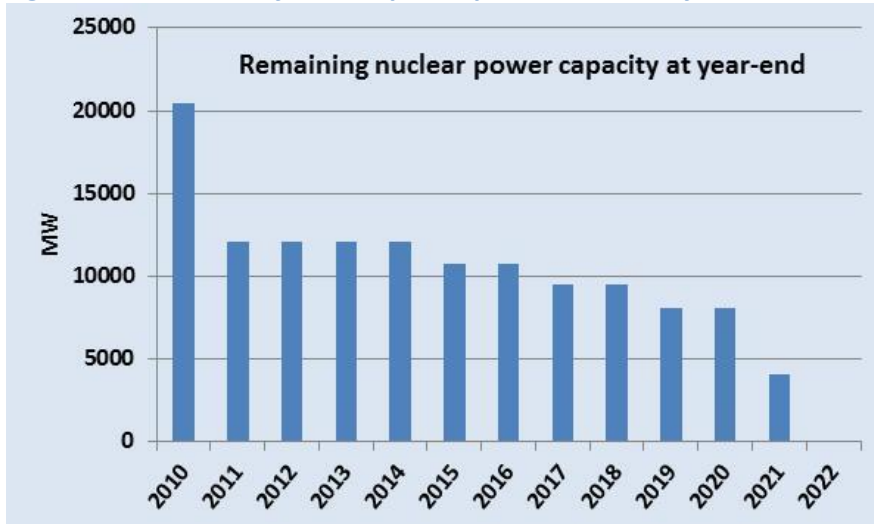
Cross-border trade plays an essential role in balancing supply and demand of electricity on the German market, both to release excess generation of wind and to meet demand when variable RES are not available. Germany is therefore both the largest exporter and importer of electricity in the EU. Electricity exports to neighbouring countries strongly impact gas and coal competition in these markets. In the Netherlands, the share of gas in the electricity mix has decreased while imports of (cheap) electricity from Germany have increased.

The nuclear phase-out

The decision to phase-out nuclear power dates back from the beginning of 2000. The German government, at that time led by the Social Democrats (SPD) and the Green Party, announced its intention to phase out nuclear power. Legislation mandating the terms of the process was enacted in 2002. In 2010, however, the centre-right government led by the Christian Democrats (CDU/CSU) and the Liberals prolonged the lifetime of nuclear power plants by an average of 12 years.

After the Fukushima accident, Chancellor Angela Merkel reversed her administration's position and embraced a nuclear phase-out policy even more ambitious than that of 2002. Eight nuclear power plants (8.4 GW) were shut down in the aftermath of the accident and the **complete phase-out of the remaining plants (12 GW) is planned by the end of 2022**.

⁶⁰ Federal Network Agency (Kraftwerksliste 2014). Generation plants permanently closed since 2011 are still included in the list. This comprises a total of 3.3 GW as of 2 April 2014.

Figure 29: Phase-out of nuclear power plants in Germany, 2011-2022

Source: data from the Federal Network Agency (kraftwerkliste, 2012 to 2014)

The *Energiewende*

Development since 2010

The first version of the *Energiewende* was adopted in September 2010. It sets out Germany's energy policy until 2050 and defines very ambitious goals for the future energy mix:

- An increase in RESe to at least 35% in 2020, a figure that should rise to 80% by 2050.
- A reduction in GHG emissions by 40% by 2020, and by 80% to 95% by 2050, with respect to their 1990 levels.
- An increase in energy efficiency by an average of 2% per year to cut Germany's total energy consumption by half by 2050 (compared with 2008).

In the first version, nuclear power had a bridging role to the “age of renewable energies”. After the decision to phase-out nuclear power plants, the government adopted “The Energy Package of 2011”, which concentrated on five major spheres of action: upgraded electricity grid infrastructure, a flexible electricity system, growing renewable energies, increased energy efficiency and greater investment in research and development, notably in storage technologies. **The Renewable Energy Sources Act (EEG)** was amended to accelerate the development of RES. Acceleration Acts were also enacted, in particular for wind power expansion and power grid expansion.

To meet the *Energiewende* targets in the power sector, Germany's entire power supply system must be overhauled. Investments must be made in modernising the power plant fleet, adding back-up fossil-fuelled capacities, building new power grids, extending interconnections with neighbouring countries, and above all expanding renewables.

A broad amendment to the Renewable Energy Sources Act (known as EEG 2012), which became effective on 1 January 2012, made the targets set out in the *Energiewende* legally binding: by 2020 at the latest at least 35%, by 2040 65%, and by 2050 80% of German power supply is to be provided by renewable energies. It also introduced new instruments to better integrate RESe on a voluntary basis.

The EEG 2.0

The new CDU/CSU-SPD coalition government elected in 2013 has confirmed the long-term objectives of the *Energiewende*. In its coalition agreement the new government underscores that Germany is

solidly on the way towards further strong growth in renewables and greater energy efficiency, while staying on track with the nuclear phase-out. The new corridors of a 40-45% renewable electricity share by 2025 and a 55-60% share by 2035 are basically in line with the 2020-30-40 corridors of the 2011 energy concept. Long-term goals for the reduction of greenhouse gas emissions (-40% by 2020, -80% to -95% by 2050) have been confirmed. **Cost-efficiency and security of supply have been given equal importance.** So while keeping the main goal of the *Energiewende*, the new government has announced substantial reforms of the EEG, aiming at decreasing the costs of the *Energiewende* and better integrating RES in the market. The Renewable Energy Act Reform, approved by German Cabinet on 8 April 2014, shall be submitted to Parliament and the Federal Council so as to enter into force on 1 August 2014.

While the EEG is maintained, it is also reformed substantially. The government wants to reduce EEG-related costs, in particular the renewable surcharge (EEG-surcharge), better integrate RES (mandatory direct marketing obligation for new renewable power plants), while at the same time ensuring reliable renewable growth and a rising share of renewable energy supply in line with the *Energiewende*. The reform pursues a two-pronged strategy focusing on the main problem of renewables expansion in Germany: the ballooning costs and – in this connection – the uneven distribution of levies imposed on electricity consumers.

The reform includes caps on the expansion of RES, to 2.5 GW per year for onshore wind power and PV, respectively. For offshore wind, the ambition has been reduced compared with previous plans from 10 GW to 6.5 GW by 2020 and from 25 GW to 15 GW by 2030. The second lever of the reform focuses on the increasing "inflation" of the EEG-surcharge and exemption regimes associated with the EEG levy. The reform includes plans to reduce the average remuneration to RES from 17 cents/kWh in 2014 to 12 cents/kWh⁶¹.

Better integration of RES is also a main focus of the reform. The government recognises that renewables should be exposed more to market forces. To this end, the reform foresees the mandatory direct marketing for new renewable energy plants, first those with a capacity over 500 kW (from August 2014 onwards). From 2016 onward, this will also apply to installations over 250 kW and from 2017 installations over 100kW. The government foresees a change of the renewable energy policy approach from the FIT to a tender or quota system by 2017.

The government also intends to adopt a National Action Plan for Energy Efficiency in 2014, which should become the second pillar of the *Energiewende*. It remains committed to the ambitious goal of achieving 25% of electricity from cogeneration by 2020, favouring the expansion of efficient district heating systems. It will also increase the budget of the investment grants and soft loans provided by the German government-owned development bank KfW for energy efficiency measures in buildings.

When presenting the reform of the EEG, the Minister of Economics and Energy also stressed that "favourable legal conditions for controllable (non-volatile) power plants (of all kinds) were necessary" and that his government was considering mechanisms to ensure medium/long-term capacity adequacy and the competitiveness of conventional power plants, without deciding on certain technologies.

⁶¹ Initial plans. The final compromise may reduce the decrease.

Coal and gas competition left to market forces

The *Energiewende* recognises the essential role played by conventional power plants, but does not clearly define a role for gas or coal in the transition⁶². The *Energiewende* relates to “fossil-fuelled” or “gas and coal power plants”: “Investment in flexible gas- and coal-fired power stations is essential to ensure a secure power supply, as fossil-fuelled power plants must make up some of the short-fall arising from the phase-out of nuclear power. Furthermore, they must smooth out intermittent electricity generation from renewable energy sources⁶³”. Coal and gas competition is essentially left to market forces.

There are no plans to replace coal-fired generation with gas, as it is the case in the UK. At the opposite, the role of coal is reinforced by the phase-out of nuclear power plants. When he announced the reform of the EEG in January 2014, the Minister of Economics and Energy said that “phasing out nuclear and coal at the same time would be irresponsible⁶⁴” and added “we need the 8 to 10 power plants currently being built.”

The decarbonisation of the German electricity system is left open to different technologies without mandating the development or phase-out of any fuels.

Domestic coal

Germany has almost no domestic oil and little gas resources, but it does have **very large coal reserves**. With 40,500 Mt of lignite reserves, Germany owns 14% of global lignite reserves. Lignite therefore plays a key role in enhancing security of supply. While hard coal production is subsidised, this is not the case of lignite production.

To prevent coal mines closures, the government has subsidised the hard coal mining industry for the last 40 years, offsetting the difference between world steam coal prices and the high costs of the German industry. In compliance with EC regulation, the subsidies are being phased out and will end in 2018, putting an end to hard coal production in Germany. This means that coal imports are going to increase to feed the new hard coal power plants that are commissioned from 2013 to 2015.

Lignite mining in contrast is profitable and new mines have been opened recently. Production amounted to 183 Mt in 2013 and accounted for about 20% of global lignite production and 72% of the EU production. Despite its environmental footprint, lignite benefits from abundant reserves, low prices, regional economic interests and political backing.

New efficient coal power plants

After almost a decade without any new commissioned coal power plants, Germany is adding 8.4 GW of new hard coal-fired capacity over the period 2013-2015 (including E.ON’s Datteln 4 which still encounters permitting challenges), after having added 2.7 GW of lignite-fired capacity in 2012 (see Table 8). Most of these coal projects were planned almost a decade ago after Germany decided for the first time to exit nuclear power.

Most of these new plants are replacing old less efficient plants. Their owners have adopted the latest advanced technologies for all their new coal-fired power plants. Thermal efficiencies are up to 46% for the hard coal plants and 43% for the lignite ones. This results in significant reductions in CO₂ emissions,

⁶² See OIES (2014), The new German energy policy, What role for gas in the decarbonisation energy policy, Ralf Dickel, OIES Paper NG 85, Oxford, March 2014.

⁶³ BMWI, Germany’s new energy policy, Heading towards 2050 with secure, affordable and environmentally sound energy, April 2012

⁶⁴ <http://www.zeit.de/wirtschaft/2014-01/gabriel-oekostrom-energiewende/komplettansicht>

about 33%, when new efficient lignite plants replace old lignite plants. In addition, while lignite tends to run base-load owing to the high fixed costs and vertical integration between mining and power generation, load following operation of hard-coal power plants plays a significant role in providing the flexibility for renewables in the German power system. This new generation of coal plants means that coal will remain a key component of Germany's electricity mix.

After this booming period, however, no new coal plants are expected to come on line during the decade. Although there are still some projects in the pipeline (including new lignite power plants), the current economic and financial conditions prevent the building of new thermal plants. Since 2007, 26 announced projects have been shelved/abandoned, representing a capacity of 25.7 GW.

Winter reserves and system relevant plants

Security of electricity supply is currently ensured by an amendment to the German Energy Act (EnWG) adopted in late 2012, and the Ordinance on Reserve Power Plants (ResKV) passed in June 2013. The Federal Network Agency (Bundesnetzagentur or BNetzA) has been tasked with the role of continuously monitoring generating capacity developments and, based on information from the four German electricity TSOs, to determine the winter reserve capacity requirement, above the ordinary reserve capacity.

The EnWG and the ResKV make provision whereby final shutdowns must be announced at least 12 months in advance to the relevant transmission system operator and the Federal Network Agency. In the next step, the TSO then examines the **power plants' system relevance**⁶⁵, and determines the timing of the shutdown in coordination with the Federal Network Agency. System-relevant power plants can be included in the network reserve of the German Reserve Power Plant Directive with corresponding payment until their final shutdown.

The ResKV foresees that when all other options are exhausted, the responsible TSO is entitled and within its capabilities obliged to procure new reserve power plants, by issuing an invitation for tender. The new regulation also includes the possibility that generation adequacy is provided with contractual load reductions. Since the regulation is a temporary one – it shall expire in 2017 –, a discussion about incentives for conventional power plants has been going on in Germany for some time.

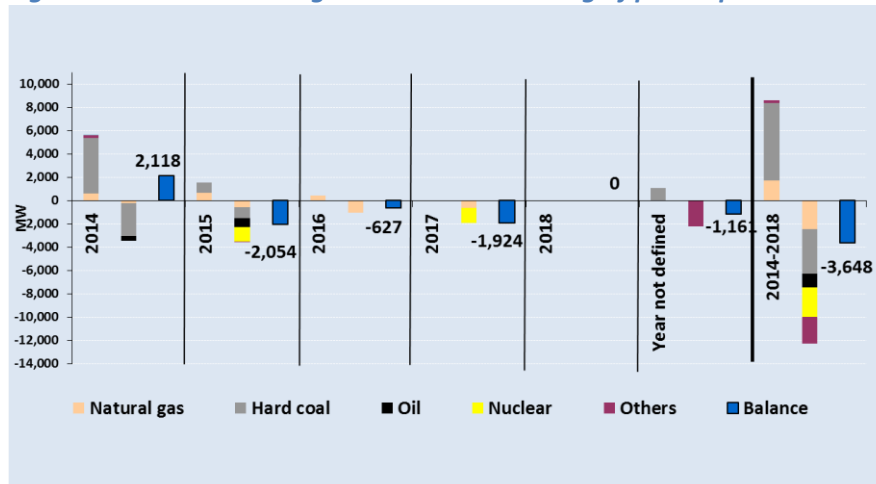
A large amount of capacity decommissioning

Germany is still characterised by over-supply (except in south Germany). However, the latest update of the Federal Network Agency shows that, despite the current construction boom, **decommissioning of more than 12 GW by 2018 could result in a negative net total of –3,648 MW nationwide**⁶⁶. The issue of security of supply, which came initially from the shutdown of nuclear plants, is now moving to a more structural issue. As RES has priority dispatch and access to the grid, the growing amount of fluctuating RES has rendered many conventional power plants economically unattractive. A large number of conventional plants, mainly gas plants, are being mothballed or retired before the end of their technical lifetime. As of April 2014, BNetzA, had closure applications for 7.7 GW⁶⁷. At the same time they are needed to compensate for low-wind and sun-deficient hours and to meet demand.

⁶⁵ i.e. if it is sufficiently likely that a permanent closure would lead to a substantial danger for or an interference with the safety or reliability of the electricity supply system and cannot be overcome by other suitable measures.

⁶⁶ It should also be noted that, so far, seven power plant units with a total capacity of 1440 MW have been confirmed as systemically relevant according to section 13a of the Energy Act; these units cannot be closed for the time being and therefore reduce the aforementioned negative balance.

⁶⁷ According to the Energy Act, such formal notifications, combined with a waiting period of, generally, twelve months, are required for the implementation of closure plans.

Figure 30: Commissioning and decommissioning of power plants in Germany (2014-2018)

Source: BNetzA, 2014

Capacity market

The Ordinance on Reserve Power Plants shall expire by 2017, and represents a temporary regulation until a decision about amendments of the regulatory framework for energy, including the Renewable Energy Sources Act (EEG), is made. In order to ensure security of supply, sufficient capacity must always be available. This can be non-fluctuating renewable energies, fossil backup capacity, power storage, and sliding loads. There is a risk that the energy-only market cannot ensure an adequate security of supply. Moreover, the question of necessary capacity to ensure security of supply in Germany has a special relevance. **From 2015 to 2022 all of the remaining nuclear capacity will be phased out, relieving the system of 12 GW of capacity. And most of that capacity (8 GW) will go offline in a very short period, namely from 2020 to 2022.** So while the current reliable capacity in Germany is still sufficient to cover peak demand (83 GW in 2013, ENTSO-E, 2014), the situation may quickly deteriorate by the end of the decade. The Federal Association of the Energy and Water Industry's (BDEW)⁶⁸ has calculated that reliable capacity may decline by 13.6 GW by the time Germany will have phased out nuclear power in 2022.

Hence a discussion about **incentives for conventional power plants** has been going on in Germany for some time. However, there is no consensus yet on the type of mechanisms to be implemented, nor on the amount of capacity needed. The Federal Association of the Energy and Water Industry (BDEW) had proposed a strategic reserve model, based on reversed auction. The Federal Association of New Energy Suppliers (BNE) called for "competitive capacity mechanisms". The Scientific Advisory Committee to the Federal Ministry of Economics and Technology (BMWi) submitted a report on the long-term management of the security of supply, in which it highlights the current positive situation, but recommends introducing a capacity market to ensure the long-term security of supply. The Committee stresses that despite its recommendation in favour of a capacity market in the long-run, it was worried that its introduction might delay necessary complementary reforms regarding the promotion of renewable energy, efficient use of grids and investments in national and cross-border grid expansion, cross-border interoperability and the regulation of non-discriminatory grid access, regulation and optimisation of operating reserve and real-time markets.

⁶⁸ BDEW, April 2014.

The implementation and the design of a capacity market may impact the competition between coal and gas on the German market with possible effects on the larger North-western regional electricity market. At the time of writing, however, the discussion is still ongoing in Germany.

Short-term gas and coal competition

The competition between gas and coal is left to market forces and thus **coal consumption is strongly favoured at the expense of gas**. However, the continued expansion of RES and efficiency gains are going to reduce the residual load addressed to conventional plants. And there is no nuclear plant closure before May 2015 when 1.3 GW will be retired from the market. Up to now, RESe has largely offset power from natural gas in accordance with the merit order in Germany, but peak solar and wind power production is starting to push out hard coal plants out of the merit order. At short-term, RES development may translate in reduction of both gas and coal generation (assuming normal weather conditions). The main uncertainty is the level of exports to neighbouring countries, which despite lower demand for coal generation in Germany, may still increase coal contribution in the German power mix.

At mid-term, the phase-out of nuclear plants means that 12 GW of reliable capacity will be retired from the market by 2022. Besides the capacity issue, these plants generated about 100 TWh in 2013. This additional residual load – although reduced by the expansion of RES, energy efficiency and other means developed to make demand more responsive – will leave more room for coal and gas production. By 2020, the competition between the two fuels will highly depends on policy development in the EU ETS.

No development of CCS

At longer term, **CCS will be required to meet the decarbonisation goal of the *Energiewende***. Despite efforts deployed by the government and the private sector at the end of the 2000s, CCS has not progressed in Germany. There is widespread opposition, above all against carbon storage, throughout large sections of the population. Vattenfall, which was the only remaining utility proceeding with plans for a large scale CCS plant at Jämschwalde, cancelled it in December 2011, the reason being the political controversy about a CCS law. Germany has actually encountered significant resistance in developing and adopting a legal and regulatory framework for CCS. The CCS Act, which finally entered into force in 2012 following a protracted legislative process, only allows for CCS on a test basis, restricts the amount of CO₂ to be stored to 1.3 Mt a year per storage site (up to a maximum of 4 Mt nationwide per year), and allows individual Länder to exclude parts of the state territory from CO₂ storage provided that the exclusion is based on objective reasons. The CCS Act thus allows for a maximum of two or three medium-sized demonstration projects to be realised. Germany is continuing CCS-related R&D but there are no plans for demonstration projects at present.

The new coal power plants will have a technical lifetime until 2050. The carbon emission target of the German energy sector will fall below the current CO₂ emissions from the coal power plants before 2030. **As a result, without the application of CCS technology, it can be expected that coal would play only a small role for power generation in the long term.**

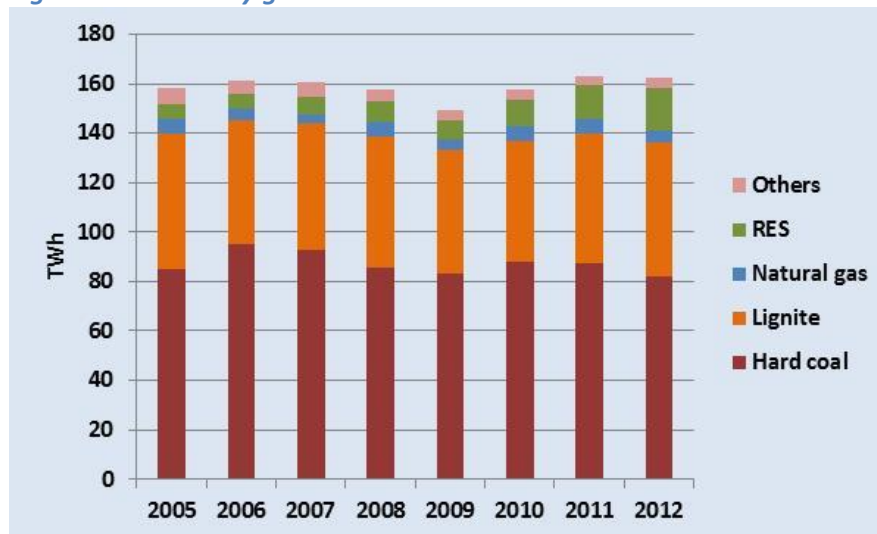
Poland: coal and security of supply

Electricity mix dominated by coal

Poland relies on coal for 84% of its electricity and 54% of its primary energy supply (2012 data). The dominant position of coal is explained by a significant, although declining, domestic production of hard coal and lignite. In 2012, total electricity generation amounted to 162 TWh, and domestic consumption to 159 TWh, resulting in 3 TWh of net electricity exports (Ministry of Economy, 2013). Hard coal and lignite dominate the Polish power mix with respective shares of 50.6% and 33.5%. In 2012, the share

of lignite in the electricity production increased as a result of decreased profitability of hard coal-based electricity generation. Generation from renewables has been increasing, but remains small with a share of 10.6% in 2012.

Figure 31: Electricity generation in Poland



Source: Ministry of Economy, 2013

Aging coal fleet

The installed capacity totalled 38 GW at end 2012, of which 28.5 GW of coal capacity (20 GW of hard coal-fired plants) and 0.7 GW of gas capacity. The total installed capacity of RES reached 4 GW in 2012, of which 2.6 GW of wind energy. The electricity sector faces many challenges, among which the need for new investment is the most pressing. The coal fleet is ageing: **40% of Poland's coal burning plants are more than 40 years old, with very low efficiency and high level of CO₂ emissions.** A number of coal power plants have been and will be forced out of the market by the LCPD and IED. The costs of compliance are prohibitive for some, also in view of the recent decline in power market prices. The Polish grid operator PSE estimates that 6.6 GW of the current installed capacity will be taken off the grid by 2020 as outdated plants close. PGE and Tauron, the largest power producers with ENEA, ENERGA and EDF, are expected to extend the lifespan of some of their older plants in order to provide back-up capacity for the grid and avoid shortage of power supply. The Ministry of Economy has warned that there is a risk of power shortages in the years 2016-17 which may range from 1.9 to 2.5 GW in 2016. According to a study by the Energy Market Agency, about half (13.7 GW) of the currently installed coal capacity will be phased out by 2030 in light of technical and environmental constraints. Thus, the highly political question of **how such capacities should be replaced** has to be answered in the near future and will impact Poland's production portfolio for the following decades.

New build

Three coal power plants are under construction (2 units at PGE's Opole and ENEA's Kozienice, see Table 8). They will add 2.9 GW of capacity by 2019. In addition, Tauron's Jaworzno III project (910 MW) and PGE's Turow (460 MW) may start construction works in 2014. PGE, the biggest Polish power utility, has re-focussed its strategy on coal (and away from gas) and plans to invest mainly in coal and lignite-fired assets, as both fuels remain most cost-competitive sources of energy.

At the beginning of 2010, Poland had plans to build approximately 11 GW of new coal facilities by 2020. However, EU regulation and the controversial public procurement law have led to delays and cancellations of projects. Building new conventional power plants has also become much more difficult

since the decision of major financial institutions not to lend money for new coal-fired power plants. Above all, market conditions were not favourable for investors with declining electricity prices in 2013. Beyond the projects mentioned above, projects under consideration include PGE's two new lignite power plants at Zloczew and Gubin, Energa's Ostrołęka hard coal plant (1000 MW), ENEA lignite projects (2400 MW), Elektrownia Północ hard coal plant (now applying for permits for one 800 MW unit) and Kompania Węglowa's 900 MW plant at Wola. The timing of their realisation is still uncertain.

Co-firing

Despite the strong growth in wind since 2010, **biomass co-firing still makes up the largest share of renewable power generation**. In 2011, GDF Suez converted to biomass one of the eight units of the Polaniec power plant in Poland (190 MW) and there are several CHP coal-fired plants that have been converted to biomass, partially or fully. The consumption of biomass in Poland jumped from 1.7 Mt in 2006 to 5.1 Mt in 2011, a large share being imported. The government considers this development unsustainable. In the past two years, various drafts of the new Polish renewable energy law proposed new rules to restrict co-firing.

Energy policy development

Energy security is the guiding principle of the Polish energy policy. The country addresses its concerns about energy security with a two-pronged strategy: diversification of energy supply and reduction of energy imports, in particular natural gas from Russia. The priority is to become as energy-independent as possible using various available options such as conventional fossil fuels, unconventional gas and nuclear power. Poland imports 65% of its gas supplies from Russia. The Russia-Ukraine crisis has reinforced the willingness of Poland to limit its dependence on Russian gas.

Poland adopted an energy policy to 2030 in 2009 and updated it in 2011. The government is now revising it. The new policy is expected to be approved in 2014. According to the 2009 energy policy to 2030, electricity production should shift gradually from partly-imported coal towards a more diverse mix including nuclear, unconventional gas and renewables. However, a recent energy strategy to 2060, released by the government in November 2013, concludes that **coal provides the cheapest, and therefore the optimal, solution to supply Poland's power up to 2060**.

So far, Poland has fulfilled all of the GHG limits set by the Kyoto Protocol, but mainly as an outcome of the economy's transformation after 1989 and the decrease in the role of heavy industry. However, the government claims that future EU climate policy and further decreases of CO₂ emissions will be too great a burden on the Polish economy. The government strongly opposes recent efforts to reform and strengthen the EU ETS as well as to decide on any further target on CO₂ emissions reduction before a more worldwide agreement is reached in 2015.

The government insists that Poland will keep domestic coal as its main energy source. However, despite its significant hard coal production, Poland's import dependency has grown substantially over the last two decades. Until 2010, its domestic hard coal production was heavily subsidised. Now, it has to compete with international coal. Mining companies have suffered in the past two years due to low international coal prices. Despite all attempts by the government to stop it, coal production levels have been falling steadily since 1989. In 2013, Polish coal operators produced 66 Mt of lignite and 76 Mt of hard coal. Hard coal production is expected to decline to around 20 Mtpa by 2030 and lignite production may decline even further. Substantial investment would be required to modernize existing coal mines and purchase new equipment, as well as for construction of new mines. But the mining sector is struggling with financial losses and can only rely on State investment. Alternatively, more coal would have to be imported which would increase dependency from Russia. In 2012, 67% of coal

imports came from Russia. However, in contrast with gas, the coal market is a global and highly competitive one.

Diversification of the electricity mix is pursued and includes shale gas, LNG, nuclear and renewables.

Under the Polish National Renewable Energy Action Plan, Poland has a target to reach 15% of RES in its final energy consumption by 2020 and 19% of its electricity generation.

Poland had hoped to become Europe's main producer of shale gas, but so far exploratory work has been disappointing (see Chapter 2). Potential shale investors including Exxon Mobil, Marathon Oil, Talisman Energy, ENI and Total all withdrew from shale gas exploration in the country. Nevertheless, the government has recently adopted a draft bill which encourages E&P of shale gas resources and expects some production by 2015. To further diversify its gas supplies, Poland is building an LNG terminal on the Baltic Sea. The terminal in Swinoujscie, a port in the western part of Poland's Baltic coast, is expected to start operating in 2015 and will provide access to 5 bcm gas annually. The Polish government also intends to build nuclear power capacity. In January 2014, the Polish Council of Ministers approved the Polish Nuclear Program. The document defines parts of the regulatory and institutional framework. It includes a schedule for the construction of two plants, according to which the first reactor would go online at the end of 2024, and the second one by 2035. The nuclear program however does not contain any decision about the most difficult issue: who shall bear the financial risk of the construction and how.

As most options to diversify the energy mix are medium to long term ones, **there are few alternatives to building new coal fired power plants.** Nevertheless Poland's overwhelming reliance on coal could potentially drop following the further coupling of the regional power markets and increased cross-border electricity flows.

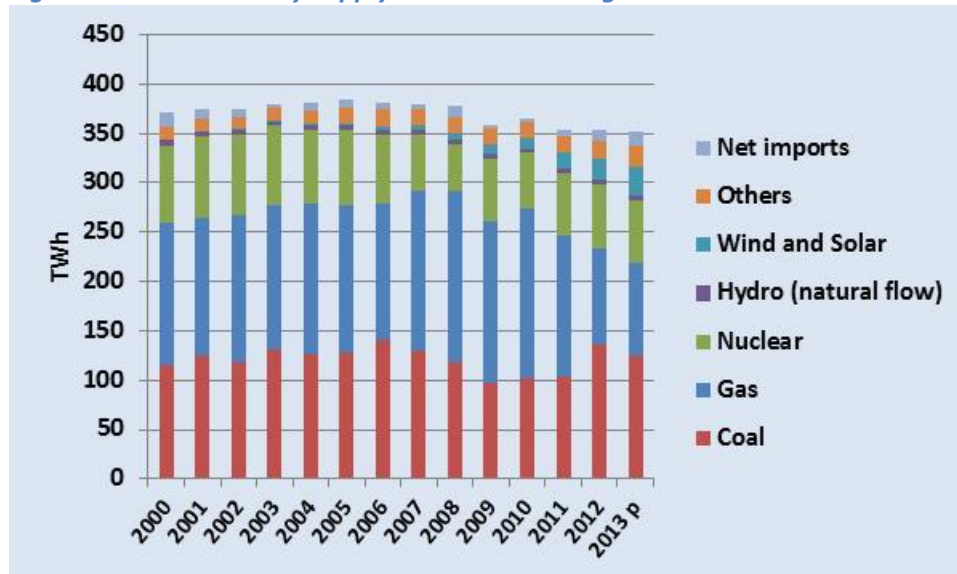
United Kingdom: carbon tax and Electricity Market Reform

Power generation and coal capacity

Power generation in the UK reflects a diverse energy mix. In 2013, power generation was 357 TWh (down 2% from 2012), dominated by coal (36.3% down 3%⁶⁹), gas (26.8% down 1%) and nuclear power (19.8%, up 1%). Wind and solar generation was up by 41.7% (+8.7 TWh) with increased capacity compared to 2012. Hydropower and renewables contributed 11.4%, oil 1.0% and net imports provided 3.4% of electricity supplied.

⁶⁹ Coal's share of generation decreased from 39.4% to 36.3%. Despite the decrease in coal use, the contribution of coal to the UK's electricity mix remains high compared to recent years (between 2008-2011 coal provided around 30% of the UK's electricity generation).

Figure 32: Net electricity supply in the United Kingdom



Source: DECC

The installed power capacity totalled 89 GW at the end of 2012⁷⁰, of which 23 GW for coal and 35 GW for CCGTs. The coal fleet is ageing: a capacity of 5 GW closed between December 2012 and March 2013 to meet the requirements of the LCPD, having utilised their 20,000 hours allowed under the opt-out derogation. A further 3 GW is expected to close or be converted to biomass by the end of 2015 at the latest, when 20 GW of unabated coal capacity is expected to remain in operation.

The Electricity Market Reform

The UK is committed to reduce GHG emissions by at least 80% of 1990 levels by 2050⁷¹. In November 2012, the UK parliament passed an **Energy Bill** establishing the cornerstones of a fundamental reform of the UK electricity market (**Electricity Market Reform**). The main goal is to strengthen climate protection. The Bill did not specify the main details of the reform, which was set out in a second legislative procedure, the Energy Act of December 2013. By reforming the electricity market, the government aims to reduce the CO₂ intensity of UK electricity production from 500 gCO₂ per kWh at present to 100 gCO₂ by 2030. There is no binding reduction target for the time being. Another goal is to increase the share of primary energy consumption covered by renewables to at least 15% and to have them account for at least 30% of electricity generation in 2020.

Box 6: The Energy Act⁷²

The Energy Act puts in place measures to attract the £110 billion investment which is needed to replace current generating capacity and upgrade the grid by 2020, and to cope with a rising demand for electricity. This includes provisions for:

⁷⁰ DECC, 2013

⁷¹ In order to keep the UK on a pathway to achieve its 2050 target, the Climate Change Act introduced a system of Carbon Budgets, which provide legally-binding limits on the quantity of GHG that may be emitted in successive five year periods. The government has set the first four carbon budgets in law, covering the period from 2008 to 2027, and must set the fifth carbon budget (2028 to 2032) in law by June 2016. The 2011 Carbon Plan set out proposals for achieving the emissions reductions committed to in the first four carbon budgets, on a pathway consistent with meeting the 2050 target.

⁷² Source : UK Government, December 2013, <https://www.gov.uk/government/collections/energy-act>

- Contracts for Difference (CfDs): long-term contracts to provide stable and predictable incentives for companies to invest in low-carbon generation;
- Capacity Market: to ensure the security of electricity supply including provisions to allow Electricity Demand Reduction to be delivered;
- Conflicts of Interest and Contingency Arrangements: to ensure the institution which will deliver these schemes is fit for purpose;
- Investment Contracts: long-term contracts to enable early investment in advance of the CfD regime coming into force in 2014;
- Access to Markets: This includes Power Purchase Agreements (PPAs), to ensure the availability of long-term contracts for independent renewable generators, and liquidity measures to enable the Government to take action to improve the liquidity of the electricity market, should it prove necessary;
- Renewables Transitional: transition arrangements for investments under the Renewables Obligation scheme; and
- Emissions Performance Standard (EPS): to limit carbon dioxide emissions from new fossil fuel power stations.

Carbon tax

As part of the Energy Market Reform, a new **Carbon Price Floor (CPF)** mechanism has been introduced since 1 April 2013. The CPF, announced in the Budget 2011, is designed to provide an incentive to invest in low-carbon power generation by providing greater support and certainty to the carbon price in the UK's electricity generation sector. The CPF puts a minimum price on CO₂ emitted by the power sector. It is a top-up tax: if the EUA price drops below this level, companies pay the difference to the UK Treasury, the so-called carbon price support (CPS). The CPS rates reflect the differential between the future market price of carbon and the floor price determined by the Government. The rates are set two years in advance to allow generators time to plan hedging strategies. The CPF was initially designed to ensure that whatever happened with European carbon prices, power producers in Britain would pay £30/tCO₂ in 2020, rising to £70/tCO₂ in 2030 (real 2009 prices). However, in March 2014, the government decided to **freeze the carbon tax at 2015 levels until the end of the decade**. The CPS rate for 2013/2014 was equivalent to £4.94/tCO₂. It has increased to £9.55/tCO₂ since 1 April 2014 and will amount £18.08/tCO₂ from 1 April 2015 until the end of the decade. The tax is levied through the Climate Change Levy (CCL) and applies to supplies of fossil fuels used in electricity generation at relevant CPS rates, depending on the type of the fossil fuel used, which is determined by the average carbon content of each fossil fuel.

The tax means that gas-fired power plants regain some attractiveness. However, in 2013 (and beginning of 2014), the price of gas compared with that of coal was still too high to offset the advantage of coal-fired power plants. This however, may change by 2015 when the CPS reaches £18.08/tCO₂ (€22.3). At this level, additional cost amounts to €21.4/MWh for a coal power plant (efficiency 36%), compared with €8.3/MWh for a gas power station (efficiency 49%). The carbon tax may push out coal plants, depending on how coal and gas prices have evolved by then. Furthermore, at a level of £18.08/t, generators with coal plants will have little incentive to invest in depollution equipment and may choose to close their plants earlier (by 2020 if they opt-out from the IED).

Capacity market

In addition to the carbon tax and the IED – which may lead to the closure of 12.4 GW of coal capacity by 2020 (see Section 1.6) –, a third key policy may impact coal and gas competition: the

implementation of a **capacity market**. The expansion of wind and solar has reduced the margins of conventional power plants and several CCGTs have recently been mothballed. In addition, the closures of old coal and oil plants, have increased fears that the UK is vulnerable to blackouts over the next few years as the country's amount of spare generation at peak times has fallen to 6% in 2013/14 and is foreseen to fall to 4% in 2015/16⁷³. The government is introducing a capacity market to ensure generation adequacy. **Auctions will be held** at which power plant operators sell capacity which they must keep on standby in case of shortage. The first auctions are expected to take place in December 2014, for delivery of capacity in 2018 or 2019. Capacity providers will then be compensated for keeping reliable power station capacity on standby to produce energy when capacity is tight. While intended to encourage new gas plants, it could potentially be attractive for old coal plants, too. Capacity payments could then make it worthwhile for plants to invest to meet the IED requirements and stay operating longer. At the time of writing, the details of the mechanism are not yet known so it is not possible to assess if the incentive will be enough to offset the effects of the higher carbon tax.

Emissions performance standard

The electricity market reform also includes the introduction of an **emissions performance standard**. The allowable carbon emissions of new power stations are to be limited to 450 gCO₂ per kWh of electricity generated. This means that new coal-fired power stations can only be built if they capture and store at least a part of the carbon dioxide produced. Due to this limitation, there are no unabated coal plant projects in the UK.

Contracts for difference and CCS

To boost investment in climate-friendly electricity generation from RES and nuclear power, as well as from CCS, the government is replacing its renewables support mechanism called the Renewables Obligation Contract (ROCs) with a new scheme called "**contracts-for-difference**" (CfDs)⁷⁴, a system of fixed-price, long-term contracts for electricity. To avoid any pause in low-carbon energy generation while the transition is taking place from 2014 to 2017, the government has ranked 10 RES projects to get early CfDs in late 2014. The 10 projects include biomass conversion at two units of the Drax coal-fired power station; biomass conversion at Lynemouth Power Station; a biomass dedicated plant at Teesside and offshore wind farm projects. Under this scheme, coal-to-biomass conversion is attractive, but remains subject to regulatory uncertainties (see Section 1.6).

CCS projects are eligible for CfDs under the 2013 Act. The two selected projects under the Competition launched by the government in 2013 (the Peterhead CCGT Project in Aberdeenshire and the White Rose Coal Project in Yorkshire) will have to negotiate CfD with the government, when FEED is finalised. The strike price for UK CCS projects will be determined initially on a case-by-case basis, with a progressive move to competitive allocation in line with the development of the technology. CCS development in the UK (as in Europe) remains highly uncertain (see Section 1.7). Without CCS, coal capacity is expected to decrease significantly by 2030.

All in all, if unabated coal still has a future in UK, its role is expected to decrease significantly after 2015, under the combined effect of the carbon tax, the LCPD/IED and the continued expansion of RES. This

⁷³ OFGEM (2013), Electricity Capacity Assessment Report 2013, 27 June 2013.

⁷⁴ In CfDs, there is a contractually guaranteed fee that power producers receive for the electricity fed into the system. If the price realised on the wholesale market is below the fee, they are paid the difference. However, if it exceeds the fee, the generator is retrospectively obliged to reimburse the difference. Each CfD has a set 'strike price' (a price per unit of electricity generated) which is set at the level determined to be necessary to support the particular technologies or projects supported by the scheme.

will allow an increase in gas use by the power sector, although constrained by the increase of RES and efficiency.

Spain: tax on CO₂ and end of subsidies to the coal sector by 2018

Spain's primary energy consumption was 144.8 Mtoe in 2012, 9.3% less than its peak in 2007. The economic crisis has been particularly harsh in Spain and the government has been forced to introduce many austerity measures which have had a direct impact on the coal industry. Since the beginning of 2012, the Spanish government has introduced many new measures, including taxes, into the power generation sector and implemented urgent measures with the aim of tackling the so-called tariff electricity deficit and to re-establish the balance between the costs and revenues within the electricity sector. The tariff deficit reached €27 billion at the end of 2012 due mainly – but not only – to subsidies for renewable energy. The government put a halt on any subsidies for new renewable projects in January 2012. In addition, a new electricity sector law passed in 2013 introduced deep cuts to the subsidies paid to renewable projects that are already installed in order to reduce the deficit. Since August 2013, electricity generated by grid-connected solar panels or other renewable sources and used on-site has even to pay a fee.

In the coal sector, the Law 15/2012 on fiscal measures for energy sustainability came into force on 1 January 2013. This law introduces a general tax of 7% on the value of electricity production and affects all electricity generation technologies. Additionally a set of taxes has been introduced affecting hydro-electric production, nuclear wastes and fossil fuel used for electricity generation. **A tax of €0.65/GJ applies to natural gas and coal used for electricity production** (“the green cent”). These measures and tax have significantly reduced the earnings of power utilities in the country.

Spain is highly dependent on imported oil and natural gas. It has an overall import dependence of 76.4%, well above the EU average. This places a burden on the Spanish economy by increasing its trade deficit and foreign indebtedness. The only significant indigenous energy resource that Spain possesses is coal, with proven reserves of 1.18 billion tonnes at the beginning of 2012. In 2012, coal met 13.3% of the country's energy demand.

The total power capacity of the country reached 103 GW at the end of 2013, of which 11 GW are coal-fired power plants and 25.4 GW are CCGTs. RES capacity has increased very fast in the past few years and reached 49 GW. In Spain, there is **fierce competition between coal-fired and natural gas-fired power generation** for the market that remains after nuclear, hydro and must-run renewables have supplied electricity to the market. With a system capacity margin of 136%, there is plenty of room for switching between energy sources. In 2012, the level of hydro was particularly low and coal-fired generation increased its contribution to 19.6% of electricity demand. The opposite situation occurred in 2013, both hydro and wind energy were abundant reducing the need for fossil fuelled generation. The CCGT plants have lost their competitiveness and are hardly used: they supplied only 9.6% of electricity demand in 2013, while coal provided 14.6%. The green cent introduced at the beginning of 2013 did not change the attractiveness of coal against natural gas.

A drastic reduction of State aid to the coal sector

The coal sector in Spain is subsidised through two main measures. The first one, the State aid to coal mining, relates to subsidies given to the coal mining sector to continue operation at uncompetitive hard coal mines. The second one ensures that domestic coal is used in priority over international coal in 10 power plants. This second scheme was highly criticised by power generators in Spain as it prevents them from buying coal on the free market.

Both schemes were reviewed in 2013 and State aid to the production of hard coal was cut dramatically. The government and the coal sector representatives negotiated a new plan for the coal sector for the period 2013-2018. While the government intended to end the priority given to domestic coal in power generation, the coal plan foresees that this priority will be maintained in 2013 and 2014. From 2015, however, coal mining companies will have to negotiate directly with power utilities. The following box describes the two support schemes and their evolution.

Box 7: State aid to the coal sector in Spain

The main source of support for the coal sector in Spain is the financial assistance to coal mining. This assistance is subject to EU rules on state aid and approval by the European Commission, according to the European Commission decision on state aid of 2010 (Council Decision 2010/787/EU). The decision regulates State aid to the coal mining sector in the EU and orders the closure of all subsidised uncompetitive hard-coal mines by the end of 2018. State aid in Spain is defined in multiannual plans negotiated between the government and the coal mining sector. The latest plan, the National Plan for Coal 2013-18, sets out targeted reductions in production, staffing and subsidies, supply guarantees and economic restructuring policies for the coal-mining regions. The plan aims to reduce production from 6.6 Mt in 2013 to 5.9 Mt by 2018.

In 2012, the Spanish government dramatically reduced subsidies paid to coal mining companies, by 63%. The State aid was reduced again in 2013. Over the course of the two years, State aid to the coal mining sector has been reduced by over 80%, from €300 million in 2011 to €55 million in 2013⁷⁵. There are already coal mines operating without State aid. Aid was foreseen to end completely in 2014, threatening the viability of many coal mines, especially those underground. A law passed in November 2013, however, allows uncompetitive coal mines to receive financial assistance until 2018 provided they agree to close by the end of 2018. The Spanish Government will reduce the amount of subsidy deep-mined coal receives from €30/t in 2013 to €5/t by 2018. Opencast coal will be subsidised at €1/t during 2013, which will be reduced to €0.5/t from 2014.

Another form of aid to domestic coal is the Royal Decree on security of supply constraints adopted in 2010 by the former government in an attempt to ensure the continuous operation of Spanish coal mines and force the use of indigenous coal by ten power plants. The scheme involved about €2 billion-worth of government aid over a four-year period (2011-2014). In 2013, the government announced its intention not to renew this scheme and already cut State aid to utilities and mining firms by 15% in 2013 (€400 million against just under €500mn in 2012). Under the Spanish law passed in 2013, Spanish coal will be guaranteed a 7.5% share of the electricity mix in 2013 and 2014. According to the agreement with the coal mining sector, 20.5 TWh will be generated by domestic coal in 2013, and a further 22.2 TWh in 2014. However, from 2015, coal mining companies will have to negotiate directly with the power generators for the quantities of local coal sold for electricity generation.

The green tax, the reduction of State aid to electricity generation from domestic coal and the fast development of RES in electricity generation (and in 2013 the favourable hydro situation) led to a sharp decline in coal-fired generation in 2013, for both domestic and imported coal. The contribution of coal decreased to 14.6% in 2013 from 19.3% in 2012.

While the National Plan for Coal 2013-18 ensures a status-quo situation until the end of 2014, **it is really by 2015 that dramatic changes may occur**, as local hard coal will have to compete with international coal. Although some mines are currently competitive with international coal, their future

⁷⁵ EURACOAL, 2013

competitiveness will depend on the future development of coal prices on the international market. These developments will not modify the competitiveness of coal against natural gas as local coal may simply be replaced by international coal. Nevertheless, several plants which have to take domestic coal are old and have low efficiencies. Most coal plants in Spain were built in the 1970s and 1980s. Power generators may choose to opt-out from the IED, run their plants for the allowed 17,500 hours and close them by 2023. An estimated capacity of 4.7 GW is at risk of closing. An additional significant threat to the use of coal in power generation is the rise of renewables which also displaces coal from base to mid-merit order. **This may trigger the closure of power plants which cannot compete if not used for base load.**

Netherlands: coal tax and new accord to close old coal plants

Coal had a 27% share of the Dutch power generation market, which totalled 102 TWh in 2012, and a smaller share of the heat supply market⁷⁶. There are five large coal power plants in the Netherlands totalling 3.97 GW at the end of 2013. The 253 MW Buggenum plant – one of the world's few integrated coal gasification combined cycle (IGCC) plants – was closed in 2013 by its owner NUON due to its high operating costs and low electricity prices. Three new high-efficient coal plants are under construction and will add 3.45 GW of capacity in 2014 (see Table 8). The Dutch power market is currently characterised by substantial overcapacity. This, combined with the increased share of renewable electricity from the domestic market and growing imports from the German market, further erodes power prices in the Netherlands.

Since 1 January 2013, the exemption to the coal tax granted to coal plants with an efficiency of over 30% has been lifted. The removal was decided by the former Dutch government and was part of a broader package to reduce the government's deficit. **The coal tax is set at €13.73/t.** Removal of the exemption adds about €5/MWh to the costs of a plant with a 38% efficiency (old plants) and €4.2/MWh to the costs of a plant with a 46% efficiency (new plants). While it hurts profit margins for producers, it has not shifted the merit order from coal- to gas-fired power plants. In 2013, it was still cheaper to run coal-fired plants than gas-fired plants.

A more radical change will come from the new **Energy Accord** (*Energieakkoord*) the Dutch Government, private sector and NGOs signed on 6 September 2013. This agreement is the result of eight months of negotiations led by the Dutch Social Economic Council (SER) and was signed by more than forty Dutch organisations representing the energy and construction sector, labour unions and NGOs. The core feature of the Agreement is a set of broadly-supported provisions regarding energy saving, clean technology and climate policy. The Energy Accord targets a 14% share of renewable energy in 2020, in line with EU obligations, to be increased to 16% in 2023.

Under the Energy Accord, **utilities agreed to close 2.8 GW of coal-fired capacity** before the end of their economic life cycle. Three coal-fired units — GDF Suez's 592MW Gelderland, RWE's 645 MW Amer 8, and Dutch firm EPZ's 408 MW Borssele 12 — would close permanently before 31 December 2015. EON's Maasvlakte 1 (555MW) and 2 (555MW) units could remain open longer — until July 2017 — as they have supply agreements with municipal heating companies. In return for closing the units, the tax on coal-fired generation, introduced on 1 January 2013, would be scrapped from 1 January 2016. After these closures, only two old plants built in the 1990s would remain in operation (unit Amer 9 and Amsterdam, with a combined capacity of 1.2 GW), in addition to the three new plants. Both plants co-

⁷⁶ EURACOAL

fire large quantities of biomass. RWE's Amer 9 co-fire 30% of biomass currently and may increase to 80% in the long term.

In the Energy Accord, co-firing of biomass is capped at 25 PJ per year, equivalent to only 1.5 Mt of wood pellets. Biomass co-firing is funded through the Support Sustainable Energy Production (SDE+) program. It is anticipated that these funds will be available from 2014 to 2023. Funding of biomass co-firing will be limited to power plants build after the 1990's. Co-firing will be key to reach the RES target by 2020.

1.7. GAS AND COAL COMPETITION AS FLEXIBLE AND LOW CARBON OPTIONS

The ability of conventional power plants to respond to the new needs of the EU power sector will be a determinant factor for their future use. Three main requirements are key:

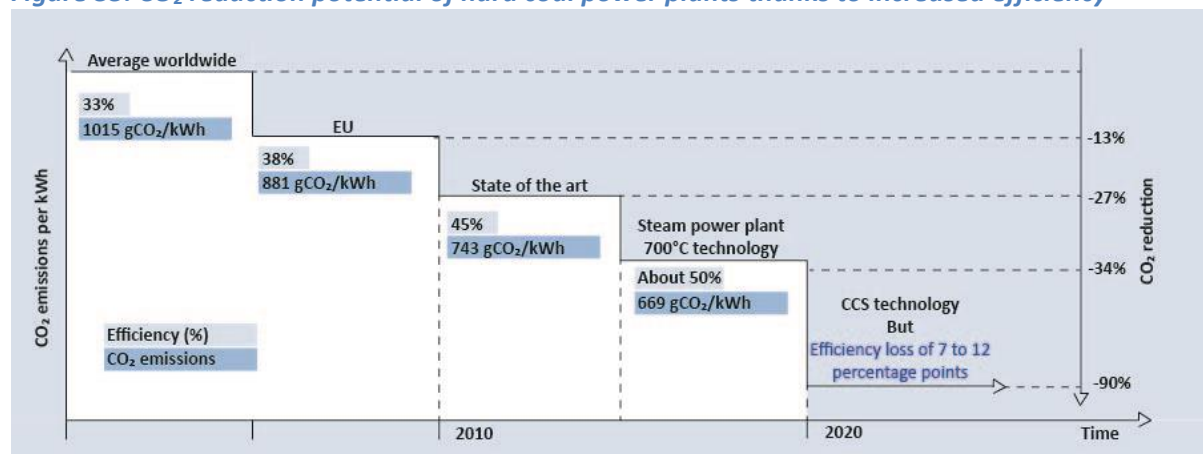
- Low CO₂ emissions and high efficiencies
- The flexibility of power plants and their ability to adapt their production to variable RES (load following)
- The economics of gas and coal power plants equipped with CCS.

Higher efficiency and reduced CO₂ emissions

CCGT and USC-PC (ultra-supercritical pulverised coal) plants have achieved great progress in thermal efficiency allowing a significant reduction in CO₂ emissions. State-of-the-art CCGTs can achieve net efficiency above 60% (lower heating value, LHV)⁷⁷, compared with 49% for the old fleet, while thermal efficiencies of 46% are achieved with new hard coal plants (38% for the old fleet) and 43% for new lignite power plants (30% for the old fleet).

These improvements have allowed a significant reduction of CO₂ emissions compared with the existing fleet, as illustrated by the following figure in the case of hard-coal power plants.

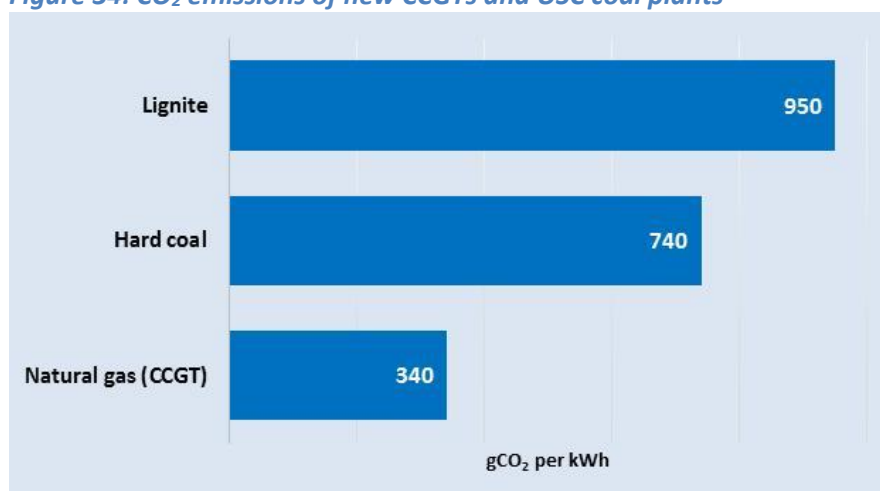
Figure 33: CO₂ reduction potential of hard coal power plants thanks to increased efficiency



Source: VGB PowerTech

Natural gas nevertheless remains much cleaner to burn than coal. Even with state-of-the art plants, compared with hard coal-fired generation, natural gas produces half as much CO₂ at the power plant.

⁷⁷ <http://www.powerengineeringint.com/articles/print/volume-18/issue-3/features/ccgt-breaking-the-60-per-cent-efficiency-barrier.html>

Figure 34: CO₂ emissions of new CCGTs and USC coal plants

Source: IEA, VGB Power

Gas power plants have also shorter construction time than coal: typically 24 to 36 months for gas, compared with 42 to 54 months for coal. The capital expenditure for new gas plants is less expensive: €800/kW for new gas plants compared with €1300-1400/kW for hard-coal and lignite respectively⁷⁸, despite the increase in CAPEX for both technologies in the past few years. In addition, coal power plants have become much more difficult to finance. Main multilateral financial institutions recently reviewed their strategy for financing new power plants and put in place either stringent EPS or strict conditions which make almost impossible lending money to new coal-fired power plants in the EU (see Box 4).

CCGTs can also be built in a modular way, which has been a key advantage of natural gas over coal in the first decade of the 2000s marked by gas market liberalisation and the entrance of new players in the market. Finally, the siting of new gas plants has encountered less local resistance than coal, a trend which has strengthened in the past couple of years.

Flexibility of gas and coal power plants

Increased variable generation presents significant operating challenges

In order for the electricity grid to function properly, demand and supply have to be matched at any instant. If this not ensured, any imbalance could lead to either severe voltage fluctuations or grid failure (brownouts or blackouts). The increasing contribution of renewables in power generation has important implications on other generating units on the electricity grid – both existing and future ones – because of the variable nature or variability of the output of several renewables-based technologies, such as wind and solar. Wind and solar are intermittent in nature – their output fluctuates as a result of weather conditions⁷⁹. **Variable renewables (v-RES) add degree of unpredictable⁸⁰ and variable input on the supply side to variability on the demand side.** The impact will be far more significant as large amounts of v-RES are fed in the system, requiring flexible means to change the level of electricity generation or consumption to ensure a stable electricity network. Hydropower (pumped storage) and cross-border interconnections offer flexibility where they are available. Demand Side Response (DSR), electricity storage means, such as CAES (Compressed Air Energy Storage), Power-to-Gas, batteries,

⁷⁸ VGB, Survey 2012 Investment and Operation Cost Figures – Generation Portfolio, VGB PowerTech e.V., September 2012

⁷⁹ The output of wind turbines fluctuates with changes in wind speed, while solar PV output fluctuates as varying cloud cover impacts light intensity.

⁸⁰ Efforts are made to better predict the stochastic variation of wind power.

could have significant potential in the medium to long term. But thermal generation will still be indispensable for providing flexible energy in the future. So the power industry is searching for ways to make the conventional generation portfolio more flexible. The load following capability of gas and coal power plants is therefore gaining in importance with the growing level of v-RES in the EU power mix.

Typical flexibility of new natural gas CCGTs and USC coal plants⁸¹

Typically, gas and coal power plants built in the past were designed for base load operation, favouring higher efficiency and lower capital costs, with the main objective of minimising the cost of electricity production. Therefore their efficiency at partial load is significantly lower increasing CO₂ emissions and other pollutants⁸². With new requirements stemming from higher amount of v-RES, new power plants need to operate as cycling units over their lifetime, increasing load during the day (or peak hours for CCGTs) when demand is higher and/or when there is no wind and reducing it to the minimum or shutdown during the night and/or when wind production is high. Equipment suppliers have responded to operators' requirements for greater flexibility and the flexibility of new CCGT and USC-PC plants has greatly improved in recent years.

Modern CCGTs are typically capable of fast start-up, shut-down and load cycling. As an answer to the changed market requirements, cycling capability in CCGTs has been optimised to fulfil the load reductions or shutdowns. Ramp rates have improved and now reach 38 MW per minute. Time required for hot start-up (after night shutdown) has been reduced to less than 30 minutes⁸³ and less than to two hours for cold start-up⁸⁴. As local pollutants emissions increase with part load, the minimum operating load ranges between 40% and 50% of the full capacity. It is constrained by increasing emissions of NO_x and CO (carbon oxide) at low loads and is thus determined by the technical minimum conditions at which the gas turbine is able to operate, still meeting the environmental limits. Equipment suppliers are working on solutions to reduce NO_x emissions at lower loads (down to 40%) allowing more flexibility for plants operators.

Part-load operation of old CCGTs leads to efficiency loss. With the new build CCGTs, the efficiency reduction at partial load is lower, as the plant achieves an overall efficiency of 55-56% even at 60-65% of the load. Actually, the efficiency penalty corresponding to a load reduction down to 60% is only a few percentage points (2-3%) lower than the base load operation.

While initially coal plants were not considered as possible flexible plants, **both hard coal and lignite USC-PC plants have achieved much greater flexibility than old coal plants** and can even compete with

⁸¹ Information in this section is based on: IEA (2012), Operating flexibility of power plants with CSS, IEA GHG, Report 2012/6, June 2012; EURELECTRIC(2011), Flexible generation: backing up renewables, Brussels, October 2011 and IEA (2013), 21st Century Coal, Advanced Technology and Global Energy Solution, IEA Coal Industry Advisory Board (CIAB), Insight Series, 2013

⁸² More part-load operation of old thermal power plants leads to efficiency loss and economy penalties as the investment is under-utilised. Next, pollution control systems work less effectively when flue-gas temperatures and pressures vary with sudden changes in load. In addition, the sudden changes in temperature damages parts in the boilers and turbines. The damage can be minimised, but cannot be entirely eliminated. At the minimum, the damage will require higher spending for replacement parts or repairs during scheduled outages. Increased wear and tear also shortens the lifetime of the plants. As a consequence higher, maintenance, operational and capital, costs per unit of power generation is incurred.

⁸³ To enable faster start-up, CCGT manufacturers have decoupled the gas turbine start-up from the heat recovery steam generator (HRSG) and steam turbine warm-up.

⁸⁴ EURELECTRIC(2011), Flexible generation: backing up renewables, Brussels, October 2011

gas plants in some markets, as illustrated by the flexible use of coal-fired power plants in Germany⁸⁵. USC-PC plants have achieved good cycling capabilities and start-up times. Compared with other coal-fired technologies, supercritical or ultra-supercritical facilities can achieve quick load changes, even up to 8% per minute when the turbine is suitably designed, and are much more suitable for quick start-up. Ramp rates now average 26 MW per minute for hard-coal plants and 30 MW per minute for lignite plants. Typical hot start-up time for a supercritical PC boiler power plant now reaches 90 minutes and about six hours for cold start-up (for hard coal plants). Efficiencies of supercritical and ultra-supercritical power plants are less affected by partial load operation. Reduction in plant efficiency of supercritical units is about 2% at 75% load. The environmental penalty is lower than that of CCGTs, allowing a minimum load of 30%.

Table 10: Typical operating flexibilities of natural gas and coal power plants

	CCGTs	USC-PC
Cold start-up time, hours	< 2	6-7 (hard coal) 10 (lignite)
Hot start-up time, hours	0.5-1	1.2-2.5
Ramp-up, % per minute	4-6 (40-85% load)	2-3 (30-50% load)
	2-3 (85-100% load)	4-8 (50-90% load)
		3-5 (90-100% load)
Minimal load (%)	40-50	30

Source: IEA (2012), EURELECTRIC (2011)

From the viewpoint of engineering, the new generation of thermal power plants allows very flexible operation of the plants. **Both new gas and coal plants can deliver the necessary load following required to match the customer daily variations and the variable input from the increasing wind capacity. New CCGTs provide more operational flexibility with faster ramp-up rates and lower start-up time than new USC PC.**

However, more part-load operation of thermal power plants leads to increased maintenance, operational and capital costs per unit of power generation. In addition, cycling power plants must recover their more expensive operating costs as well as their capital costs, while getting paid for fewer hours of generation per year. All in all, operating new thermal plants to follow the load is feasible but increases costs. The economic issue needs to be addressed for these new plants to be built (see Section 1.9).

Carbon Capture and Storage

Poor records in Europe

Despite the potential of CCS, the technology has not developed as quickly in the EU as ministers had hoped back in 2007 when they agreed to support 10-12 demonstration projects. **Most projects proposed at the end of the 2000s have been cancelled⁸⁶**, due to the economic crisis, the low price of

⁸⁵ In Germany, combined load and generation adjustments have risen as high as 50 GW in an eight-to-10-hour period - equivalent to more than 60% of the country's peak power consumption. In response, production from coal plants has been successfully turned down to just 20-60% of normal output. See IEA (2013), 21st Century Coal, Advanced Technology and Global Energy Solution, IEA Coal Industry Advisory Board (CIAB), Insight Series, 2013

⁸⁶ Several major European projects have been cancelled since 2011, among them Longannet Project (Scotland) cancelled, Vattenfall Jämschwalde (Germany) project cancelled in December 2011, RWE IGCC pre-combustion project near Cologne, Peel Energy post-combustion project in UK, Belchatow project in Poland, Compostilla Project in Spain, the Porto Tolle Project in Italy, the Getica CCS Demonstration Project in Romania and the Full-

CO₂, costs issues, financing gaps and regulatory uncertainties. Since October 2013, five projects have been cancelled or put on hold in Europe. The EC still expects CCS to be applied in the power sector by 2030 at the latest with successful CCS demonstration projects in this decade. It published a communication on the future of CCS in Europe in March 2013⁸⁷ to seek ways of stimulating investments. In April 2013, it launched a second call for proposals under the NER300 programme⁸⁸. However, only one CCS project has successfully applied, the UK White Rose Coal project, which is expected to receive grants in 2014.

Despite considerable R&D efforts (ZEP platform⁸⁹ for instance), the establishment of an EU-wide legal framework (the CCS Directive) and funding for a CCS demonstration programme, **the EU lags behind other regions**. As of February 2014, the Global CCS Institute identified 60 large-scale CCS projects around the world at various stages of the project life-cycle, 26 of them in North America and 12 in China⁹⁰. Over the past few years, there has been a notable advance in the number of large-scale CCS projects that are either in operation or construction – from 12 in 2010 to 21 in 2013. Of these 21 projects in operation or under construction, 14 are in North America, where public policy efforts have been supported by market opportunities to utilise CO₂ as a commodity with value (specifically for use in enhanced oil recovery (EOR) techniques). This 'tandem approach' has facilitated the application of CCS offsetting the significant costs associated with CO₂ capture, compression, and transportation. In the EU, however, EOR has not been a driver for CCS deployment so far.

In 2014, two large scale projects should be complete: Boundary Dam 3 (Estevan, Canada), the world's first commercial scale post-combustion carbon capture project at a 110 MW coal-fired station (estimated cost: US\$1.24 billion), and Kemper County (Mississippi), the only IGCC with CCS under construction worldwide (582 MW, coal-based).

Like other low-carbon technologies, CCS is costly, but the continued use of fossil fuels both in the EU and the world means that **CCS remains a key option to decarbonise the electricity mix**. CCS is therefore highly important, especially for coal, as the introduction of EPS by several financial institutions will make difficult the financing of new unabated coal plants in several regions in the world. In the EU, the power sector accounts for 37% of EU total CO₂ emissions. **Coal is responsible for 70% of the emissions and natural gas for 24%**. While there is no EPS at EU-level, some countries have adopted one for new thermal plants. The UK government has adopted an EPS for new thermal plants of 450 gCO₂/kWh, preventing the building of new coal power plants without partial CCS.

scale CO₂ Capture Mongstad Project in Norway. These cancellations are a major setback for the deployment of CCS technology in Europe.

⁸⁷ EC, Communication on the future of Carbon Capture and Storage in Europe, COM(2013) 180 final, 27 March 2013

⁸⁸ A CCS project in the EU may apply to receive funding from two CCS funding programs: the EU Energy Program for Recovery (EEPR) and the NER300. In 2008, the EU agreed to set aside 300 million EUAs from the New Entrant Reserve (NER) under the EU ETS Directive. The first round of allocations of the NER 300 programme in 2012 failed to award funds to CCS projects as Member states were unable to confirm their CCS projects due to funding gaps and uncertainties on regulatory issues. In December 2009, a total of €1 billion of the funds of the EEPR were granted to six CCS demonstration projects in Poland, Germany, the Netherlands, Spain, Italy and the UK.

⁸⁹ Together with the European Commission, major electricity companies in Europe have created the "Technology Platform Zero Emission Fossil Fuel Power Plants (ZEP)", a knowledge-sharing network for large-scale CCS demonstration projects that has developed a strategy for research and implementation of CCS in the field of electricity production.

⁹⁰ Global CCS Institute (2014), The Global status of CCS, Brussels, February 2014

The **key challenges faced by CCS in the EU** include lack of public acceptance of onshore CO₂ storage, the cost of the technology and the financing gap. Funding from the two CCS funding programs (EEPR and NER300) do not cover the total cost of a CCS demonstration project and projects still require government support and private investment. However, the current crisis in the power sector prevents most utilities from investing in CCS. For many of them, this is not a priority as they are re-orienting their core business in Europe towards renewables and efficiency services, away from thermal generation. Vattenfall decided recently to discontinue its R&D activities on coal power with CCS to focus its efforts on other technologies, such as smart grid, wind (mainly onshore), hydro, nuclear and coal (without CCS)⁹¹.

Box 8: CCS technology

CCS technology involves:

- Capturing the CO₂ emitted at power plants and large industrial plants using fossil fuels;
- Transporting it to a suitable storage site; and finally,
- Injecting it in deep geological formations to be securely and permanently stored away from the atmosphere in rock.

There are three technologies to capture CO₂: pre-combustion, post-combustion and oxyfuel. All of these technologies can capture at least 90% of the CO₂ emitted. However, capture technologies reduce the efficiency of the plant by 7 to 12 percentage points, depending on the technology. It is therefore crucial to start with improving the efficiency of the plants. The three technologies are demonstrated in pilot plants and current research programmes aim at halving the cost of capture.

CO₂ is preferably transported by pipeline, with ships being used when a source of CO₂ is too far from a suitable storage site. The transportation of CO₂ has been practiced by the oil and gas industry for over 40 years to maintain or increase production by injecting CO₂ into oil fields. However, the EU will need to build an extensive CO₂ pipeline network from the plants to storage sites, most probably located offshore. Its complexity and lead-time should not be underestimated. To facilitate the building of CO₂ pipelines, CO₂ transport pipelines have been included in the Europe's Energy Infrastructure Priorities (EIP) (2010) and in the Regulation on "Guidelines for Trans-European Energy Infrastructure" (2013). Transport infrastructure can also benefit from EU funding such as the Connecting Europe Facility and any potential successor.

There are three means for storing CO₂: depleted oil and gas fields, deep saline aquifers and unmined coal seams. The largest storage capacities are in saline aquifers. As CO₂ has to be stored permanently, the CCS Directive demands that CO₂ storage is closely monitored. An appraisal of CO₂ storage capacity was provided by the EU GeoCapacity project, which estimated the potential geological storage capacity at over 300 Gt (of which 200 Gt under the North Sea), whereas the conservative storage capacity is estimated at 117 Gt. Total CO₂ emissions from EU power generation and industry are around 2.2 Gt annually and hence would allow for storage of all the CO₂ captured in the EU for decades to come.

Public opposition to onshore CO₂ storage

The Directive 2009/31/EC on the geological storage of CO₂ (the so-called "**CCS Directive**") establishes a legal framework for the environmentally safe geological storage of CO₂. It covers all CO₂ storage in geological situations in the EU, and lays down requirements covering the entire lifetime of a storage site. Existing legal frameworks are used to regulate the capture and transport components of CCS. The

⁹¹ Power International Engineering, Vattenfall ditches research into CCS, 6 May 2014

CCS Directive also includes an article on new fossil fuel power plants which requires that any new plant with a capacity of 300 MW or more is built, so that CCS can be retrofitted at a later stage: the so-called Carbon Capture Ready (CCR) requirement.

All Member States were required to transpose the obligations included in the CCS Directive into their national legislation by 25 June 2011. Only one country did actually transpose the Directive in due time. By 2014, all Member States have notified transposition measures to the Commission. Transposition of the CCS Directive has been a difficult exercise in several countries, where storage of CO₂ remains an issue, due to national geological conditions and public opposition. Whereas most Member States do allow geological storage of CO₂, some have reported a decision not to allow CO₂ storage on their territory or part of it due to unsuitability of their geology for CO₂ storage (Finland, Luxembourg and the Brussels Capital Region of Belgium). Some other Member States have also not allowed geological storage of CO₂ (Austria, Estonia, Ireland, Latvia, Slovenia, Sweden) or restricted it (Czech Republic, Germany)⁹².

Europe has experienced marked public opposition to onshore storage (NIMBY: not in my backyard). This opposition was certainly a factor in the cancellation of the German CCS demonstration projects. All of the UK CCS projects and the Maasvlakte project in the Netherlands plan to either store the captured CO₂ in depleted gas fields or use it for EOR in the North Sea. This has not been particularly controversial. However, the costs for offshore storage or use appear to be much higher than earlier estimates and the high cost of transporting and storing the CO₂ offshore was cited as one of the reasons for the cancellation of the Scotland's Longannet CCS project.

Uncertain costs of CCS

Economic data for CCS plant remain uncertain. American studies (WorleyParsons and NETL) tend to favour gas plants relatively to coal plants and on the contrary, the European study (ZEP, 2011) tends to favour coal plants relatively to gas plants. Even if assumptions and results differ, one common outcome of all studies is that CCS is costly. **The cost estimates are much higher than had been anticipated a few years ago** when many of the CCS projects were initiated. One factor is the general capital cost escalation but there has also been a major increase as a result of the completion of detailed engineering studies on what is necessary to build such projects. One area of major cost increase has been CO₂ transportation and injection. These costs are very site specific with short onshore transportation being generally the lowest cost and offshore more expensive.

A report by Climate Economic Chair/Paris Dauphine⁹³, analysing and comparing public studies (IEA, DOE-NETL, ZEP, WorleyParsons) on coal and gas power plants with and without CCS shows that a CCS plant undergoes significant increase in both investment and O&M costs. In average the cost of electricity from a new coal power plant with CSS is 60% higher than a new coal plant without CCS (40% in the case of natural gas)⁹⁴. It should be noted however that even if CCS technologies remain capital intensive and costly, they can be competitive on a levelised cost of electricity (LCoE) basis with other low-carbon technologies under development.

⁹²EC (2014), Report on the implementation of Directive 2009/31/EC on the geological storage of carbon dioxide, COM/2014/099 final, February 2014

⁹³ Chaire Economie et Climat/Université Paris Dauphine (2013), Quel prix du CO₂ pour le déploiement des techniques de captage, transport et stockage géologique du CO₂ ?, Série Informations et Débats, N° 25, juin 2013

⁹⁴ These costs represent 'nth-of-a-kind' (NOAK) costs, meaning the costs after the technology has matured and several installations have occurred.

Box 9: Average increase of investment and O&M costs of power plants equipped with CCS

A CCS plant undergoes an increase in both investment and O&M costs.

- The overnight cost increases on average by 70% for coal and 100% for gas;
- Variable costs: Net efficiency penalties of 9 percentage points for coal plants vs. 8 points for gas plants which imply an increase of respectively 25% vs 15 % in fuel costs.
- O&M costs increase on average by 80% for coal plants and 100% for gas plants.

By adding CCS, LCoE increases on average by 60% for coal and 40% for gas.

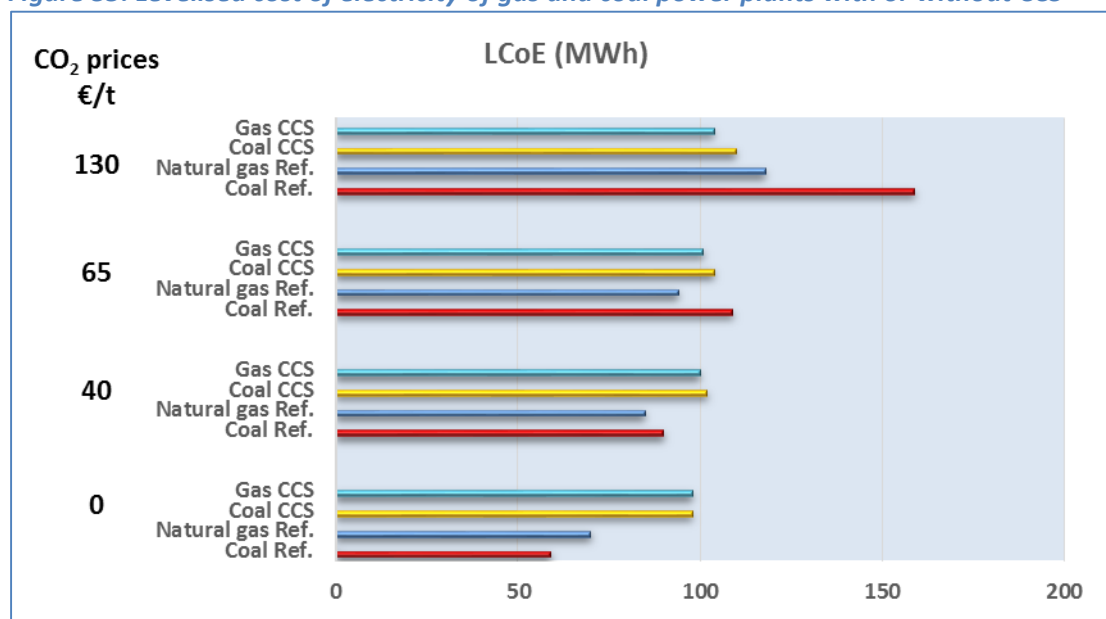
CCS requires a CO₂ price of €60-70/t to breakeven in the case of coal and a price of €80-100/t in the case of gas.

Source: Chaire Economie et Climat/Université Paris Dauphine (2013)

The report also shows that under the assumptions taken for commodity prices⁹⁵:

- Coal plants without CCS remain the most competitive option until CO₂ price reaches €29/t.
- Then gas plants without CCS become the most competitive option. Even at a price of CO₂ of €60/t (the breakeven price for coal with CCS), the gas plant without CCS is more competitive.
- It is only at a CO₂ price of €85/t that the gas plant with CCS becomes the most competitive options among all others.

Figure 35: Levelised cost of electricity of gas and coal power plants with or without CCS



Source: adapted from Chaire Economie et Climat/Université Paris Dauphine (2013)⁹⁶, based on IEA calculations⁹⁷

Beyond the added cost, adding CO₂ capture to a given generating unit induces a reduction in plant output and efficiency and decreased reliability and availability. CCS technologies reduce the efficiency of new coal-fired plants by an average 9 percentage points and that of gas-fired by an average 8

⁹⁵ Prices in US\$2011/GJ: 4.34 for coal (corresponding to US\$108.5/t) and 11.61 for natural gas (corresponding to US\$11/MBtu). With the parameters used in the report, the LCoE of the gas plant without CCS is €70/MWh and that of the coal plant is €59/MWh.

⁹⁶ Chaire Economie et Climat/Université Paris Dauphine (2013), op.cit.

⁹⁷ IEA (2011), Cost and Performance of Carbon Dioxide Capture from Power Generation, IEA/OCDE, 2011

percentage points. The penalty is even higher for retrofitted plants. This results in a loss of the electricity sent out from a power station. The associated loss of revenue – in addition to the capital cost of installing CO₂ capture equipment – needs to be addressed to make the projects economically viable.

Capture may also reduce the flexibility of power plants. Much of the flexibility of CCS plants will not be fully understood until such time as full-scale capture plants are demonstrated and operators begin to become familiar with the potential bottlenecks and restrictions associated with start-up, shutdown and varying plant loads. Currently, modelling activities are the tools to best understand the potential limitations of these evolving technologies. In general, increased dynamic operation implies lower capacity factors, and with the capital intensity of plants with CCS, lower capacity factors could pose a large cost barrier to running at lower loads⁹⁸.

As far as transport and storage are concerned, gas is favoured over coal as for the same amount of electricity produced, gas plants emit twice less emissions than coal plants, requiring lower investment in transportation and storage.

UK leadership in CCS projects

Despite the recent efforts by the EC to re-launch CCS in Europe, the technology is not the priority for most European governments and energy utilities. After a wave of cancellations of CCS projects in Europe since 2011, the second call for proposals under the NER300 programme did not attract a lot of interest. Currently, governmental funding required for the deployment of the CCS technology is limited. **Only the UK, and to a lesser extent the Netherlands, give financial support to CCS projects.**

The United Kingdom, with a CCS roadmap and several on-going projects, leads CCS deployment in the EU and appears as the only European country with a complete CCS policy aiming at creating a UK's CCS industry. The government has put several regulatory frameworks in place to underpin CCS development on an industrial scale. After disappointing results with the first competition for CCS demonstration projects⁹⁹, the 2012 CCS Roadmap¹⁰⁰ has confirmed the commitment of the UK government to supporting the development of a robust CCS sector, provided that technology can be shown to be cost competitive with other low carbon technologies. To this end, the UK Department of Energy and Climate Change (DECC) has established the Cost Reduction Task Force to identify opportunities for cost reduction across the CCS value chain.

The government re-launched a CCS Competition for the UK's £1bn Carbon Capture and Storage Commercialisation Programme in 2012 and selected two projects in March 2013: the Peterhead CCGT Project in Aberdeenshire and the White Rose Coal Project in Yorkshire. The two selected projects have now signed Front End Engineering Design (FEED) contracts with the government. Once FEED is complete both of these projects could be eligible for further capital and operational support through a CfD. FID will be taken by the government in early 2015. DECC expects the construction of the projects

⁹⁸ IEA, OECD/IEA 2013 21st Century Coal, Advanced Technology and Global Energy Solution, CIAB, Insight Series, 2013

⁹⁹ The competition, started in 2007, came to an end in 2011 after two FEED studies were completed but with no construction contract award when DECC and preferred bidder, ScottishPower, failed to reach an agreement. The selected project at the Longannet coal-fired power station on the Forth Estuary would have captured 1.8 Mt/y of CO₂ for a period of ten years. It was to be stored permanently over two kilometres below the seabed of the North Sea in a depleted gas field.

¹⁰⁰ DECC (Department of Energy and Climate Change), CCS Roadmap: Supporting deployment of Carbon Capture and Storage in the UK, London, April 2012.

to commence in 2015 and the projects to become operational by 2020. In addition there are two reserve bidder projects, namely the Captain Clean Energy Project and Teesside CCS Project, and there is one project which was not taken forward, the Don Valley Project. These projects are now seeking other ways to progress outside the Competition. But their prospects are unclear. Latest modelling from the UK's Electricity Market Reform Delivery Plan¹⁰¹ expects up to 13 GW of CCS could be deployed in the UK by 2030. However, there is a wide range of uncertainties on the future of CCS. In a scenario where the CO₂ intensity of UK electricity production is reduced to 200 gCO₂ by 2030, instead of 100 gCO₂ aimed by the government, less than 1 GW of CCS is deployed by 2030.

Besides the UK projects, only the Netherlands has one on-going CCS project at commercial scale, the ROAD project, which expects to take final investment decision by 2015.

The experience gained so far demonstrates that a value for CO₂, as well as a clear direction of its future level, is clearly needed for widespread commercial deployment of CCS. Ultimately, in order to get over the hurdle and achieve the cost reductions brought by technology maturity, it will be necessary for governments to specifically support CCS demonstration projects with capital grants as well as support for the power prices. **Under the current power market conditions, CCS in the EU remains an uncertain option.**

1.8. FINANCIAL IMPACT ON POWER UTILITIES

Write-downs of conventional plants

The loss of profitability of gas-fired power plants has led many European power utilities to write down gas assets. The uncertainty surrounding coal future in some countries also led to coal assets write-downs. In summer 2013, the Swedish state-owned energy group Vattenfall, announced a write-down of SKr29.7 billion (€3.4 billion), or 6% of its total assets value, with about half the impairment charge related to write down 17% of the value of its investment in Dutch utility Nuon¹⁰². The difficult earnings situation in conventional electricity generation in Europe is clearly reflected in GDF Suez and RWE financial results for 2013. GDF Suez announced a total impairment of €14.9 billion for 2013, corresponding to 12% of its total asset value, of which €8.1 billion in assets, mainly power capacity and gas storage¹⁰³. The Group also reported a net loss of €9.7 billion for 2013, after impairments. The Group stated that “it considers that the deterioration of gas storage and thermal-energy production in Europe is deep and long-lasting. The level of the impairment is a measure of GDF Suez’s determination to change radically and rapidly the business model of the Group”¹⁰⁴.

In 2013, RWE reported its first net loss (€2.8 billion) in more than 60 years¹⁰⁵. This is attributable to impairment losses of some €4.8 billion, which RWE had to recognise for the full year, mainly in respect of its power plant fleet. About €3.4 billion in impairments are attributable to the conventional power generation segment and owed to the significant deterioration in earnings in the Continental European power plant sector.

¹⁰¹ DECC (2013), Electricity Market Reform Delivery Plan, London, December 2013

¹⁰² Of the write-downs, SKr14.5 billion relates to coal and gas power plants in the Netherlands, including the new Magnum power plant, SKr4.1 billion to coal plants in Germany, SKr2.5 billion to combined heat and power plants in the Nordic countries, and SKr6.8 billion to goodwill primarily in trading operations.

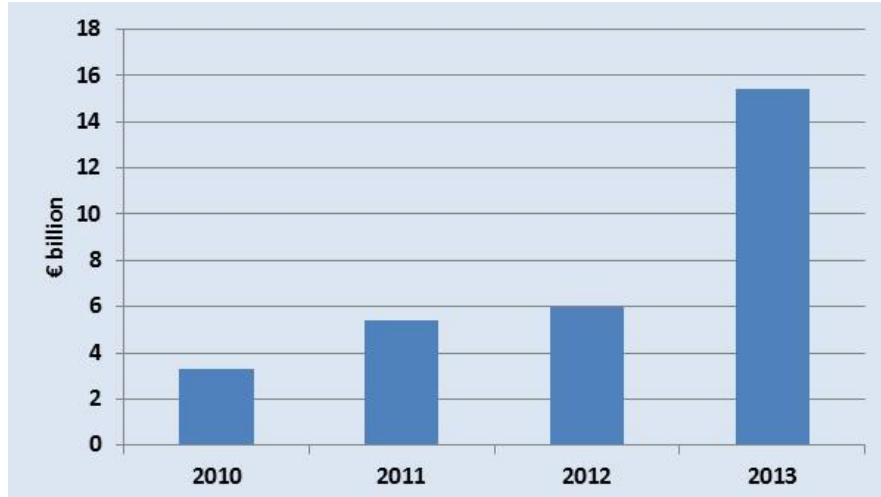
¹⁰³ GDF Suez (2014), Annual Report 2013, 27 February 2014

¹⁰⁴ Gérard Mestrallet, CEO, GDF SUEZ – Annual Results – Analyst Meeting, 27 February 2014.

¹⁰⁵ RWE (2014), Annual Report 2013, March 2014

A study by Ernst and Young on 16 major EU power utilities reported generation asset and goodwill impairments of €14.6 billion during 2010-2012¹⁰⁶, of which €6 billion in 2012. As market conditions for thermal power generation further deteriorated in 2013, the trend has amplified with an estimated **€15 billion impairment charge on EU thermal plants** (excluding goodwill).

Figure 36: Generation asset write-downs of major EU utilities, 2010-2013



Source: Ernst & Young, 2013: author's own calculations (indicative)

Value destruction

Power utilities in Europe saw their financial valuation collapsing during the past five years, in particular companies which own thermal power plants and are not diversified in other regions. The value of the companies shown in Figure 37 has plunged by 60%-70% since the beginning of 2008. They have also underperformed the stock market. In October 2013, The Economist¹⁰⁷ estimated that the top 20 European utilities valuation has plunged by half from their peak in 2008 (at their peak in 2008, they were worth roughly €1 trillion).

Figure 37: Valuation of key European utilities since 2008 against the stock market



Source: Yahoofinance.com

¹⁰⁶ Ernst and Young (2013), Benchmarking EU utility asset impairment: Lessons from 2012. London, UK

¹⁰⁷ The Economist, *How to lose half a trillion euros*, 12 October 2013.

In addition to losing value, since the beginning of 2012, major power utilities have been downgraded by credit agencies, due to the increasing risk of the sector. In 2008, the top ten European utilities all had credit ratings of A or better. Now only five do¹⁰⁸.

Focus on cost reductions and divestments

EU power utilities are responding to this adverse environment by cutting operating costs, improving efficiency, mothballing plants and in some cases closing or selling assets.

The key immediate focus is on cash flow and margin preservation. Costs reductions and improving efficiency are common themes for all power utilities. **The most visible reduction relates to the closure of unprofitable power plants and reductions in workforce.**

Reduction of the huge debts built up during a decade of consolidation before the global and financial crisis, has been a key strategy of utilities. Whether the aim is to reduce debt, focus on core operations or free up capital to invest in emerging markets and technologies, **divestment of assets** is a common trend in the restructuring process. Some companies are splitting their operations to allow divestment of gas assets or the entrance of business partners.

In 2010, E.ON adopted an asset disposal programme of €15 billion to be performed by end 2013. At that date, the company had fully completed and even exceeded its programme. GDF Suez has managed average asset disposals of about €5 billion per year over 2010-13. Both companies have dramatically reduced their debt over the period.

Divestment programme of European utilities initially related to the sale of transmission networks to non-traditional buyers, such as private equity, infrastructure and pension funds. These buyers are attracted by the predictable cash flows and earnings of regulated assets. In May 2012, E.ON sold Open Grid Europe for US\$3.7bn to a group composed of Macquarie Group Limited, Abu Dhabi Investment Authority, Meag Munich Ergo Asset Management GmbH and British Columbia Investment Management Corporation. The acquisitions of transmission assets continued in 2013 with Total's sale of TIGF in France to Snam, lead partner in a consortium with GIC, the Singaporean sovereign fund and EDF (US\$ 3.3bn), and that of RWE's Net4Gas in the Czech Republic for US\$2.1bn to a consortium of Allianz and Borealis Infrastructure, the investment arm of Canadian pension fund Ontario Municipal Employees Retirement System. The sale of 49% stake in the Slovakian energy company SPP by E.ON and GDF Suez was part of their divestment programmes. The stakes were bought by Czech company EPH for US\$3.5bn.

Gas power plants bought by non-traditional buyers

EU energy utilities are also divesting their thermal power assets. Sales of power generation assets started in the UK. They involved sales of gas and coal-fired power assets to banks, trading companies and China's groups. These non-traditional buyers bet on a recovery in power prices and on guaranteed returns resulting from capacity market auctions that are being implemented or designed in several EU countries. The trend has now moved to continental Europe. It involves sales of conventional power assets to trading houses and gas suppliers. Gazprom, in particular, is interested in the acquisition of power plants in Europe as this fulfils its long-held ambition to further integrate its activities in its largest market.

¹⁰⁸ University of Oxford (2014), Stranded generation assets: Implications for European capacity mechanisms, energy markets and climate policy, Working Paper, January 2014

In 2013, GDF Suez sold 50% of its power plant portfolio in Portugal including gas-fired, coal and renewable power plants to the Japanese trading house Marubeni. In March 2013, Italy's Enel announced a €6 billion disposal programme as part of its 2013-2017 plan. Enel plans to reduce its generation capacity in Europe by 11.9% in the next five years, from 59 GW in 2012 to 52 GW in 2017. In June 2013, the company announced a provisional agreement with Gazprom for the sale of its 405-MW Marcinelle CCGT plant in Belgium. Gazprom is also reported as one of the bidders for the acquisition of two CCGTs in France that Austrian utility Verbund put up for sale in December 2013. The two gas-fired power plants, Pont-sur-Sambre and Toul, have a total capacity of 842 MW. Verbund is also evaluating the sale of its Mellach gas-fired power plant in Austria.

In February 2013, the Danish company DONG Energy announced its intention to divest non-core activities of a value of DKK 10 billion in 2013-2014. In July 2013, DONG Energy sold to Statoil its stake in the Norwegian gas-fired power plant Energiverk Mongstad. In December 2013, the company sold its UK Uskmouth power station to a consortium of investors led by Macquarie Group's Infrastructure and Real Assets business. In January 2014, DONG sold 19% of its equity to US bank Goldman Sacks, a deal which received strong resistance from the Danes.

In September 2013, EnBW announced that the company is going to divest €1.7 billion in conventional power capacity/participation from 2013 to 2020. Its conventional power capacity is planned to decrease from 7 GW in 2012 to 4.1 GW in 2020. The revenues of the electricity generation and trading segment of the company are planned to plunge by 80% by 2020¹⁰⁹.

At the beginning of 2014, Vattenfall completed the sale of its Polish assets after disposing its minority stake in the Polish utility, Enea. Vattenfall is also reported to be considering the sale of its continental Europe and UK operations to focus on its home market and reduce its debt. The company announced in July 2013 it would split into two units - one for Sweden and one for the rest of Europe - by the end of 2013 in what was seen as a first step towards divesting the latter.

In the long list of generation asset disposals, E.ON is said to be considering the sale of its power assets in Italy and Spain. In Italy, E.ON has seven power stations with a total generation capacity of over 6 GW, mainly based on natural gas and coal. Potential buyers include French-owned Edison, Russia's Gazprom and ENI¹¹⁰.

The sale of thermal power plants in Europe may continue as long as the low price of electricity makes gas assets unprofitable. For potential investors, despite the current conditions, gas assets remain an attractive long-term investment opportunity. A number of factors point to their value increasing over a medium term time horizon, such as the closure of several coal-fired power plants mandated by the LCPD and the IED, governments' support for gas plants through measures such as capacity mechanisms, the evolution of CO₂ prices with the backloading programme and reform of the EU ETS. Finally as back up capacity remains necessary until a proven and economic technology for electricity storage is developed, investors bet on the key role gas-fired power plants are expected to play as the most efficient and least pollutant energy source to support renewables development.

¹⁰⁹ EnBW, Investors Factbook, September 2013

¹¹⁰ Financial Times, 28 November 2013

A new business model in the EU and growth in thermal power generation outside Europe

With no recovery of market conditions in the foreseeable future, **power utilities in the EU have changed their strategy and are adapting their business model to the new market conditions.** The re-orientation takes different forms depending on the geographic and sectorial diversification of utilities' activities.

In Europe, they are moving from the traditional business model based on large-scale electricity generation to new business models focused on renewable generation and new sustainable and smart products and services. **They reorient their strategy from their traditional energy-supplier role to focus on customers' demand.** Their strategy is to become their customers' preferred energy partner able to respond to customer requirements. A shift away from investment in conventional fuel to renewables generation is a common theme, with growing investment in wind, solar and biomass. Utilities expand their business in distributing generation. Demand-side management and energy efficiency products and services are amongst the new offers of key utilities.

Most utilities have pooled all their conventional (and nuclear, in the case of German utilities) electricity generation and created a new segment for these power stations to react more quickly to the significant changes in the energy sector and **optimise their power fleet.** They look for efficient and flexible generation and procurement portfolio, able to react quickly to market changes. RWE, for instance, established RWE Generation SE from 1 January 2013. At the same date, EnBW combines the business of generating and trading in electricity into a Generation and Trading segment.

For some companies, the change is drastic. EnBW said that EBITDA of its Generation and Trading segment is likely to decline by around 80%, from € 1.2 billion in 2012 to approximately € 0.3 billion by 2020.

EU power utilities focus conventional power generation expansion outside of the region with investment in growth markets (Turkey, Russia, Eastern Europe, Latin America, Asia).

1.9. INVESTMENT IN NEW THERMAL PLANTS AT RISK

The missing money problem

In energy-only markets, producers are paid only for the energy they produce. This is an effective way to support the least-cost conventional power plant, but is no longer compatible with a system including a large share of feed-in RES electricity.

There are a few problems with energy-only markets with a higher share of feed-in RES. First is what is described in economic literature as the “**missing money problem**”¹¹¹. Energy-only markets would function perfectly if prices were free to rise well above the short-run marginal costs to the “Value of Lost Load (VOLL)”¹¹² during periods of very high demand (scarcity hours). During these hours, all plants in the merit-order (e.g. base-load, intermediate and peaking plants) would receive a price which also contributes to recover their fixed costs (scarcity rents). However, for several reasons – ranging from

¹¹¹ The “missing money problem” is not new but the issue is coming at centre stage due to the increasing level of RESe with feed-in support (so outside the market) in combination with a decommissioning of conventional production capacity.

¹¹² VOLL is defined as the value attributed by consumers to unsupplied energy. Therefore, it represents the maximum price that consumers are willing to pay to be supplied with energy and at that price they are indifferent between, on the one hand, being supplied and paying the price and, on the other hand, not being supplied (and pay nothing). VOLL is typically quite high (e.g. several thousand euros per MWh).

operational price caps to the political unacceptability of very high power prices – in current electricity markets such “scarcity prices” are not allowed in practice to reach the VOLL, leading to a chronic shortage of revenue for plant operators.

The second issue comes from the fast expansion of feed-in RES in the electricity system. The expansion of RESe, with low or zero marginal costs and/or priority dispatch, **drives down wholesale electricity prices and pushes out thermal plants from the system**, in particular gas plants needed to maintain reliability when solar and wind are not producing. As CCGTs are pushed out, their average load factors decrease and their profitability is reduced. In addition, expansion of solar reduces the periods and levels of peak prices when CCGTs can recoup their fixed costs. The feed-in system, as well as the current price levels of electricity, fuels and CO₂, create market conditions resulting in low (or negative) revenues for CCGTs. Revenues remain well below fixed costs incorporating investment, and sometimes even below fixed O&M cost, leading to the closure/mothballing of many plants. As seen previously, at the end of 2013, about 25 GW of gas-fired power capacity is idled, closed or at risk of closing, most of them in northwest Europe.

The final problem is that **the increasingly lower wholesale electricity prices discourage new investment in conventional plants** at a time when the EU needs significant investment to replace the existing ageing fleet. The decarbonisation of the power sector means that thermal plants can expect to run at lower load factors in the future too and so would need to recover a greater proportion of their fixed costs through scarcity rents. But the markets do not provide the correct long-term investment signals. If this situation persists, the necessary flexible and back-up generation capacity will continue closing and will not be replaced by new investments needed to guarantee security of supply and the backup of variable renewables. The current situation has the potential to unfold into a major structural crisis.

Security of supply threatened

Reserve margins are still adequate in most countries¹¹³. However, the mothballing/closure of uneconomic plants, the retirement of ageing coal power stations, the phase-out of nuclear capacity in some countries, as well as delays or cancellations of new projects, mean that **the relative overcapacity on the European market may soon disappear**. A capacity of 115-120 GW is closing or at risk of closing, in the EU and there is little investment in new thermal plants. These trends pose a serious challenge for security of supply. Despite the extensive rise in RES, natural gas, coal and nuclear power remain the most important primary energy sources for reliable and programmable electricity generation and thermal power generation is needed to back-up variable RES. The current situation leads to decreasing reserve margins which may result in either severe voltage fluctuations or grid failure (brownouts or blackouts).

Box 10: Security of supply issues in the United Kingdom, Germany and France

The issue of generation adequacy and its urgency differ from one country to another as illustrated by the three following examples.

In the **United Kingdom**, the security of supply issue is due to the retirement of coal and oil power plants due to the LCPD and to mothballing/closure of gas plants. Around a fifth of capacity available in 2011 has to close over the decade. Despite the expansion of RES, there is a capacity issue as the reserve

¹¹³ ENTSO-E's Scenario Outlook & Adequacy Forecast (SO&AF) 2013-2030, released on 3 April 2013 shows that, under the European TSOs' best estimates of the load and generation evolution, generation adequacy will be maintained in 2020.

margin is falling. According to Ofgem's Reference Scenario, de-rated capacity margins are expected to fall from their anticipated level of around 6% in 2013/14 to around 4% in 2015/16, before recovering to around 8% by 2018/19¹¹⁴. There is a significant risk that the market will no longer deliver an adequate level of security of supply as it has done historically, principally because potential revenues in the energy-only market may no longer incentivise sufficient investment in capacity¹¹⁵. Even in a high interconnection scenario, DECC's modelling suggests the UK market would still need to bring on 21 GW of new gas plant between 2018 and 2030. The market may also fail to provide incentive for capacity built to be sufficiently reliable, flexible and available when needed. The UK is therefore implementing a capacity market to mitigate these risks.

In **Germany**, the security of supply issue came initially from the shutdown of eight nuclear plants in 2011 in the wake of the nuclear accident in Fukushima. It is now moving to a more structural issue. As RES has priority dispatch and access to the grid, the growing amount of v-RES has rendered many conventional power plants economically unattractive. A large number of conventional plants, mainly gas plants, are being mothballed or retired before the end of their technical lifetime. As of April 2014, BNetzA, the regulator, had closure applications for 7.7 GW. Although Germany is still characterised by over-supply (except in south Germany), BDEW's latest list¹¹⁶ of power plant projects planned until 2020, published in 2014, shows that the situation may change rapidly. A larger number of projects are becoming uncertain (43% of all power plant projects), whereas only 22 projects were called into question in the same list in 2013. BDEW has calculated that reliable capacity will decline by 13.6 GW by the time Germany will have phased out nuclear power in 2022.

Security of supply is currently ensured by an amendment to the German Energy Act (EnWG) adopted in 2012, which prohibits the shutdown of power plants if the responsible TSO and BNetzA declare the plant "system-relevant"¹¹⁷. Since the regulation is a temporary one – it shall expire in 2017 –, a discussion about incentives for conventional power plants has been going on in Germany for some time. The government is studying the introduction of a capacity market.

In **France**, the issue is different. While capacity is adequate, the most present issue is to deal with the increasing peak load, which increases faster than total consumption. The peak load increased by 33% in the past ten years, compared with a 15% increase in consumption. This is mainly due to the massive use of electric heating and the increasing number of electronic devices in French households. This peak load is an issue for a limited number of hours per year. It has nevertheless to be covered by generation or demand side response. France is therefore introducing a capacity market to ensure physical adequacy and security of supply.

A huge investment in generation is needed

Ageing infrastructure in the EU means major investment decisions must be taken now. In the New Energy Policies Scenario of WEO 2013, the IEA estimates that the EU requires an estimated 835 GW of gross capacity additions, as 530 GW of old plants are retired during the 2013-2035 period (based on

¹¹⁴ <https://www.ofgem.gov.uk/publications-and-updates/electricity-capacity-assessment-report-2013>

Ofgem defines the de-rated capacity margin in the Electricity Capacity Assessment as the excess of available generation capacity over demand. Available generation capacity is the part of the installed capacity that can in principle be accessible in reasonable operational timelines, i.e. it is not decommissioned or offline due to maintenance or forced outage.

¹¹⁵ DECC (2013), Electricity Market Reform – Capacity Market, Impact Assessment, October 2013

¹¹⁶ BDEW (Federal Association of the Energy and Water Industry), April 2014.

¹¹⁷ i.e. if it is sufficiently likely that a permanent closure would lead to a substantial danger for or an interference with the safety or reliability of the electricity supply system and cannot be overcome by other suitable measures.

estimated technical lifetime¹¹⁸). In addition, the grid infrastructure will need both refurbishment and replacement of old lines and new investments to accommodate the expansion of RES. The best sites for some RESe are located far from demand centres and additional high-voltage transmission lines are needed to exploit them. Additional investment will be needed to ensure co-ordination between grid infrastructure and renewable projects. T&D (transmission and distribution) networks play a fundamental part in enhancing system flexibility and in providing for increased use of RES. Future grids are expected increasingly to deploy smart grid technologies such as digital communication and control technologies, to co-ordinate the needs and capabilities of electricity generators, end-users and grid operators. Better integration of the power markets, allowing trade between countries, will also require investment in cross-border lines. In addition to investment in the power sector itself, additional gas transmission lines, interconnectors and storage facilities will be required to import new gas supplies and better integrate European gas markets.

The investment challenge is huge. IHS CERA estimates that €1 trillion of investment in new power and gas infrastructure is needed by the end of the decade¹¹⁹ just to maintain the current levels of gas and electricity supply. The emerging EU generation gap could be closed by the construction of the numerous projects of new announced power plant capacities. VGB Power estimates the projected and announced power plant capacities in Europe at 240 GW¹²⁰ as of September 2013. Gas-fired power plants still have the largest share with some 72,400 MW in new build conventional plants, followed by nuclear power with a share of some 24 % (57,200 MW). Hard coal and lignite-fired units are in the third place with a total share of some 14 % (33,380 MW).

However, **the market signal for building the required future capacity of conventional plants is missing** as the current market design does not ensure correct price signals for future investment, nor allow return on investment of existing flexible plants.

A new market design is required

As the market alone does not provide the right signal for investment in conventional capacity, **a new market design is urgently needed.** A sustainable electricity market design needs to ensure that low-carbon and fossil fuel-fired power plants have viable business models with manageable investment risks.

To address the immediate security of supply concerns, several EU countries are introducing **Capacity Remuneration Mechanisms** (“CRMs”) in order to provide additional stimulus to investors and ensure that a sufficient amount of capacity will be available. The design of such mechanisms is however extremely complex with the need i) to balance the amount of capacity needed to ensure security of supply with demand-side management response and ii) to integrate interconnection capacity and the development of cross-border trade with the aim of reaching an EU integrated Internal Electricity Market.

These mechanisms do answer to the immediate concern: keeping the lights on. **A more profound reform of the entire power system will nevertheless be necessary**, including structural reform of the

¹¹⁸ Generating capacity is retired once it reaches the end of its technical lifetime. The technical lifetimes of hydropower, coal and nuclear plants are longest (assumed to be 70 years for hydropower, 50 years for coal, and 40-60 years for nuclear depending on the country), followed by gas plants (40 years) and, wind turbines and solar PV installations (20 years).

¹¹⁹ IHS CERA (2013), the energy investment imperative. Toward a competitive and consistent policy framework, IHS CERA Special Report, 2013

¹²⁰ VGB Powertech (2013), Electricity generation 2013/14 : Facts and Figures, September 2013

EU ETS and that of the RES feed-in tariffs, as well as completion of the internal energy market for electricity and gas.

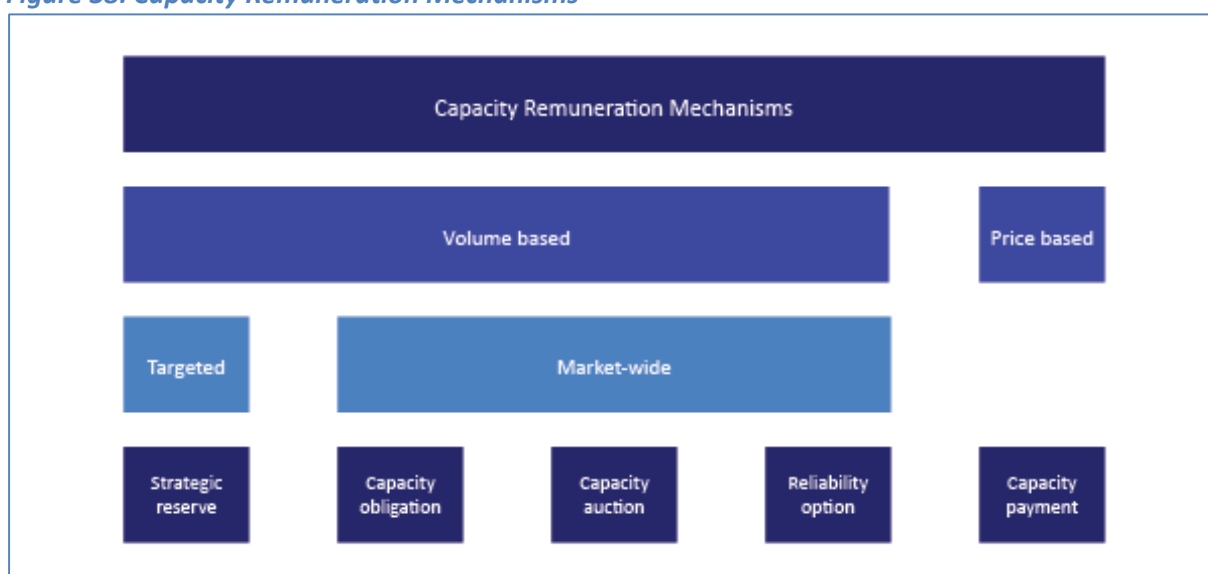
Market pricing, based on marginal cost pricing, is not adapted to secure investment in large CAPEX but low marginal cost assets (RES, nuclear) which face the risk of not being able to refinance themselves on today's wholesale electricity prices. Some analysts recommend long-term contracts and vertical integration as a way to maintain incentives to invest in all the technology mix by helping risk management and risk sharing. However, market liberalisation limits long-term contracts and vertical integration between generators, retailers and large consumers for allowing entries and development of effective competition. Future reforms of European electricity markets will need to explore alternative models of competition allowing investment in the technology mix.

Different forms of capacity mechanisms

Capacity mechanisms are a form of public intervention aimed at keeping sufficient dispatchable generation capacity online and stimulating investment in new generation capacity. In energy-only markets, producers are paid only for the energy they produce. With capacity mechanisms, **an additional source of income comes from a capacity payment**, where capacity owners receive money if they are willing to make their capacity available to the system.

A variety of CRMs is being designed and implemented in Europe. They can be classified according to whether they are volume-based or price-based. Volume-based CRMs can be further grouped in targeted and market-wide categories¹²¹. As a result, five different types of CRMs can be defined, as presented in Figure 38 and Table 11.

Figure 38: Capacity Remuneration Mechanisms



Source: adapted from ACER (2013)

¹²¹ ACER (2013), Capacity Remuneration Mechanisms and the Internal Market for Electricity, July 2013

Table 11: Characteristics of Capacity Remuneration Markets

CRM type	Characteristics
Strategic reserve	Generation capacity is set aside to ensure security of supply in exceptional circumstances by an independent body (the TSO for example) and is procured via a tender.
Capacity obligations	A decentralised scheme where obligations are imposed on large consumers and on suppliers to contract certain capacity including a reserve margin, with penalties for non-availability and possibly with a secondary market for capacity certificates.
Capacity auctions	A centralised scheme in which the total required capacity is set in advance of supply and procured through an auction by an independent body.
Reliability options	An auction-based system in which a financial instrument is used to cap the electricity purchase price in peak periods. Generators must be available when called in situations when the spot price exceeds the strike price, or pay the difference between the two prices.
Capacity payments	A fixed price is paid to generators/consumers for available capacity.

Source: adapted from ACER (2013)

So far some 14 of the 28 EU countries, including Belgium, France, Germany and the UK, have in place, have considered or are planning some form of capacity mechanism. Ireland and Greece introduced capacity payments in 2005, for example, while Spain introduced them in 1996, reformed them in 2007 and is discussing further reforms. Portugal introduced the same capacity payments system as Spain in 2010, while Romania has had a capacity market since 2007. Italy introduced capacity payments in 2004, but is now considering an auction model, with first auctions expected in 2014 for delivery in 2017. Finland, Poland and Sweden have a strategic reserve mechanism, while the Netherlands developed a strategic reserve model in 2003, but never activated it.

The UK government first envisaged a strategic reserve, but rejected that option as it does not address the missing money problem. It is now implementing capacity auctions. First auctions are expected at the end of 2014 with capacity delivery in 2018/19. In France, capacity obligations were adopted by the government at the end of 2013 and the first call for tenders organised by CRE, the French Regulator, are expected to take place in winter 2015/2016 for capacity delivery in 2016/17. Germany has winter reserves and is now discussing the introduction of a capacity market.

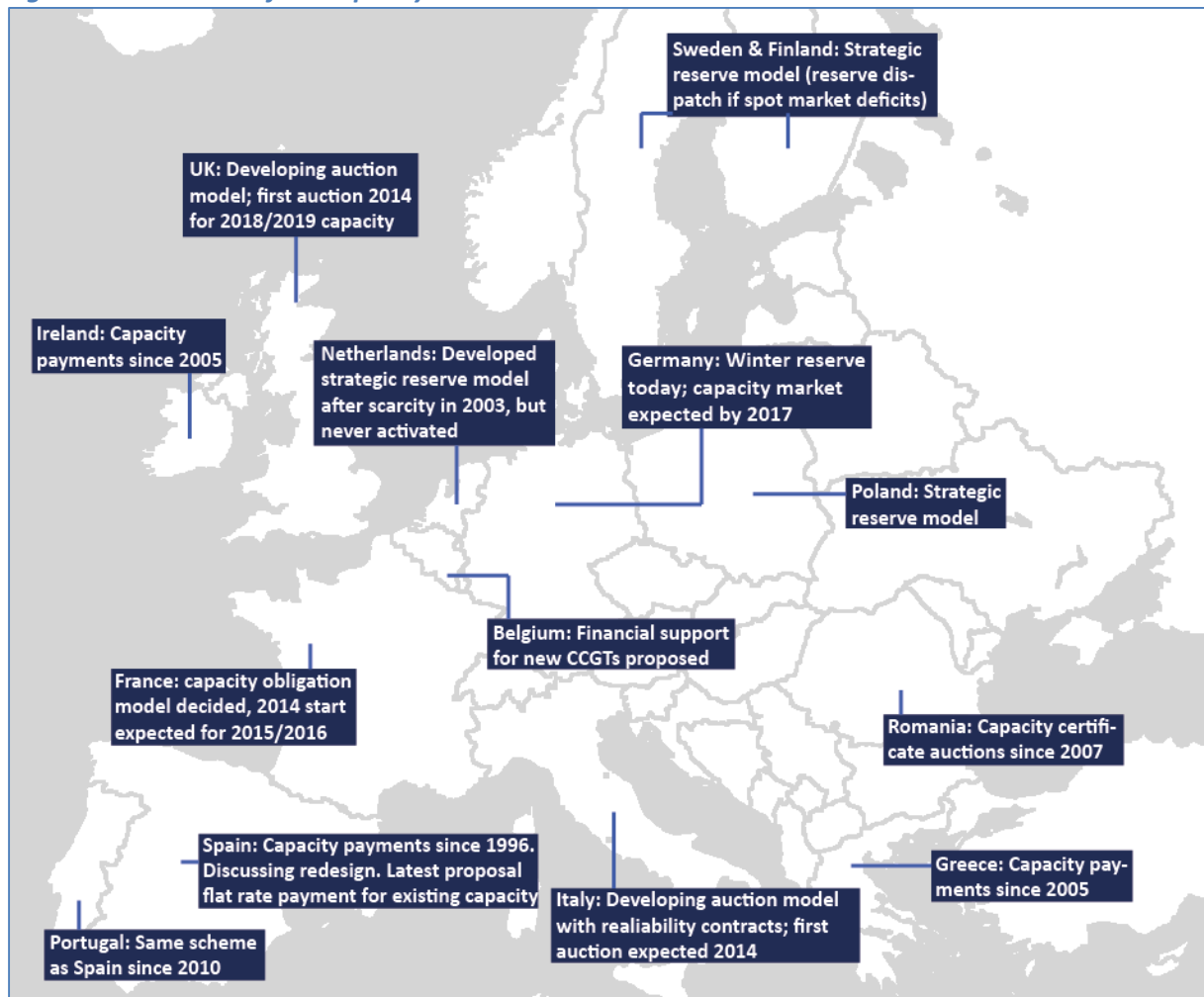
The existing CRMs are to a large extent tailored to a specific market situation (see Box 10). As a result there is a large variation in the existing CRMs' design features. Figure 39 illustrates the diversity of approaches from one Member States to another.

Governments pursue sometimes different and multiple policy targets with their CRMs. For example, CRMs may not only aim at addressing the problem of adequacy, but also the issue of flexibility and the reduction of risk and price volatility¹²². Security of supply threats in systems with high penetration of RES are not in generation adequacy alone but also in flexibility, voltage control and transient stability. Therefore "capacity" is not only the ability to generate active power (MW) but also the quality of available generation capacity, i.e. the provision of flexibility, reactive power (for voltage control) and stability¹²³.

¹²² "Adequacy" refers to CRMs which aim at ensuring sufficient generation capacity in the electricity system to meet demand at all times, including at peak load periods; "Flexibility" (or reliability) refers to CRMs which aim at maintaining sufficient system flexibility to balance the electricity system notably in response to (sudden) demand variations or unexpected outages; and "Reduced risk and price volatility" refers to CRMs which aim at de-risking new investment and avoiding the price volatility associated with generators that run only periodically recovering their fixed costs over a short period of time. Source: ACER, 2013

¹²³ ENTSO-E (2013), Response to the EC Public Consultation on Generation Adequacy, Capacity Mechanisms and the Internal Market in Electricity, February 2013

Figure 39: Overview of EU Capacity Remuneration Mechanisms



Source: adapted from Platt's, 19 February 2014

In all cases, capacity mechanisms are likely to come with additional cost for energy consumers on top of the energy only market¹²⁴. This cost is required to ensure generation adequacy in the system and should be compensated.

National CRMs and the Internal Electricity Market

The focus of the Internal Electricity Market is to integrate markets by implementing the target model for electricity and increasing interconnection capacity between Member States. Whereas the Internal Electricity Market implies increased efficiency by sharing resources across Member States and control areas, current CRM initiatives focus on security of supply based on internal sources of generation, only some take into account cross-border interconnections¹²⁵. **There is a risk that national CRMs of all designs distort cross-border trade** in two main ways:

¹²⁴ The way in which any cost of the CRM are recovered depends on the specific form the CRM takes, but, typically, the bill ends up being paid by energy consumers. Source: ACER (2013), Capacity Remuneration Mechanisms and the Internal Market for Electricity, July 2013

¹²⁵ France's planned mechanism will be open to cross-border participation. According to the French law (NOME Law), "the capacity mechanism takes into account the interconnection of the French and other European markets".

- By causing over-capacity: regulators are likely to overestimate the necessary domestic capacity reserve margin and to underestimate the contribution from cross-border trade.
- By distorting allocation of investments: investments are likely to shift to markets with CRMs, thereby increasing total costs and distorting cross-border trade.

The adverse effects may result even if markets implement the same capacity mechanism, but with different design parameters. Different capacity payment levels, different strike prices, and different reliability standards are examples of design parameters that would distort investment incentives, prices and trade.

This shortcoming is addressed in the guidelines on State Aid published by the EC in April 2014¹²⁶ which gives some guidelines on how the justification of CRMs must be documented. National governments will be required to show that they have considered the options outside their borders when assessing their generation adequacy and need for CRMs¹²⁷.

DSR, storage and generation

Another issue in the design of CRMs is the need to balance generation need with other means. The Commission states that the measure (aid to generation adequacy) should be open to and provide adequate incentives to both existing and future generators and to operators using substitutable technologies, such as demand-side response (DSR) or storage solutions.

Existing (fossil-fuel) plants vs. new capacity

The EC is concerned that these mechanisms may ‘lock-in’ generation mix in fossil fuels. “A particular concern as regards public interventions with the aim to ensure generation adequacy is that they may lock-in (fossil) generation based solution that end up being stranded in the medium to long term when additional CO₂ free capacity, interconnection capacity or demand and storage based solutions are expected to come on stream. This means that carbon prices reflecting the climate objective should be included in the relevant cost and revenue calculations”. The EC recognises that in certain situations, it can be more cost-effective to retrofit or retain existing generation capacity, which would otherwise shut down, to keep it operational. This can also help potentially to avoid the lock-in effects of constructing new (fossil fuel) generation capacity¹²⁸.

The design of capacity markets will play an important role for existing plants. At short-term, dispatchable back-up capacity may come from existing assets, which are a mix of gas and coal power plants, or from new assets. In some countries, keeping some fossil fuels (including coal) power plants in stand-by may be the only solution (Poland) or the least-cost solution. The implementation of CRMs

¹²⁶ EC (2014), Guidelines on State aid for environmental protection and energy 2014-2020, Communication from the Commission, C(2014) 2322, 9 April 2014

¹²⁷ In particular, the EC guidelines recommends “the participation by operators from other Member States where such participation is physically possible in particular in the regional context, that is to say, where the capacity can be physically provided to the Member State implementing the measure and the obligations set out in the measure can be enforced”. The details of the elements to be provided by Member States to the EC to justify the generation adequacy problem and therefore the need for State aid include “an assessment of the actual or potential existence of interconnectors, including a description of projects under construction and planned. The measure should also take into account to what extent interconnection capacity could remedy any possible problem of generation adequacy”. In a footnote, the guidelines also specify that “schemes should be adjusted in the event that common arrangements are adopted to facilitate cross-border participation in such schemes”.

¹²⁸ EC (2013), Generation Adequacy in the internal electricity market - guidance on public interventions, SWD 438 final, November 2013

could create market-design risks for power operators if there is a focus on specific generation technologies or if some existing assets are not included¹²⁹.

Finally, as stated by the IEA¹³⁰, “all the different capacity mechanisms that are being discussed/implemented have nevertheless one thing in common: even if they improve the business cases of existing and new power plants, they will not cause a significant increase in gas consumption. What these different capacity mechanisms have in common is that they all aim at **assuring availability of sufficient capacity and not necessarily productivity of this capacity**. In the short term, the relative fuel economics will still determine if gas or coal is being dispatched more frequently. Only a serious reduction in the marginal production costs of gas-fired plants might cause a significant increase of gas consumption, although this would also depend on developments in coal markets. In the longer term, however, maintaining sufficient gas-fired generation capacity is not a guarantee but at least a precondition for the recovery of gas demand in the power sector. As the United States has shown in 2012, when the fuel economics change, the power sector more than any other sectors is able to respond rapidly to a changed (pricing) environment, but only of course as long as the generation capacity is in place”.

¹²⁹ The UK's model, for example, involves separate yearly auctions for demand-side response, new and existing capacity. There may be a risk that new investment leads to early closure of existing plants. There is equal treatment of all capacity providers in the French model, but it leaves open an option to tender for new capacity, which again threatens generators' investment in existing capacity. This is also an issue generators have with Belgium's proposals, which include a tender for new capacity alongside a mandatory strategic reserve. The tender may just replace existing capacity. Source: Platts, 19 February 2014

¹³⁰ IEA (2013), Medium-Term Gas Market Report, IEA/OCDE, Paris, 2013

2. GAS PRICES IN EUROPE:

WHAT WILL BE THE IMPACT OF ADDITIONAL GAS AND LNG SUPPLIES?

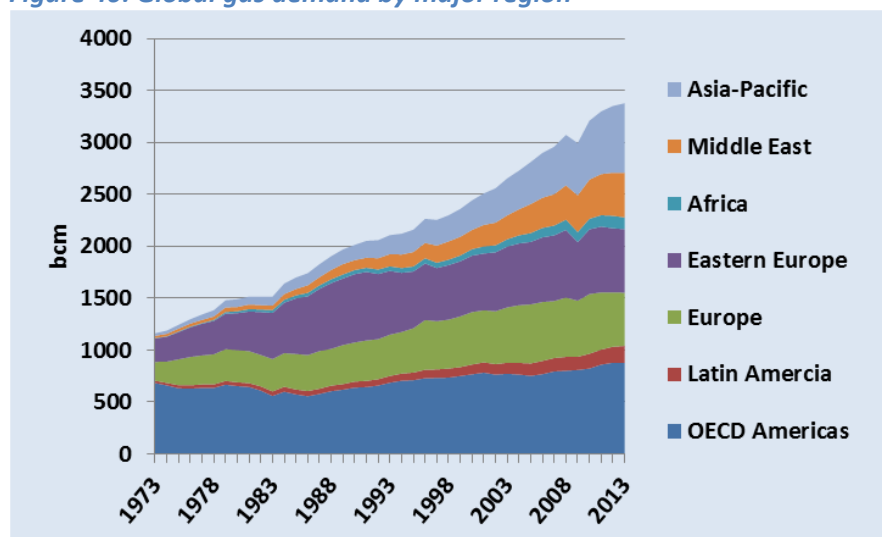
As we have seen previously, EU gas demand by the power sector has sharply declined since 2010, partly due to a loss of competitiveness against coal. This Chapter looks at recent development in gas pricing and analyses how new gas supplies (shale gas production in the EU and new LNG supplies) may impact gas pricing and future gas prices. An Annex gives detailed information on the European gas market.

2.1. MAIN DEVELOPMENTS IN THE GLOBAL GAS MARKET

Global gas demand on the rise

Gas is an important component of the global energy supply. It currently accounts for 24% of global energy consumption. Global natural gas demand has increased steadily since 1990 at an annual average growth rates of 2.4%. Despite a slowdown in 2012 and 2013, global demand reached 3377 bcm in 2013 (CEDIGAZ, first estimates). Since 2000, the growth has been particularly pronounced in non-OCDE countries which now account for more than half of global demand. China, in particular, has increased its gas demand from 27 bcm in 2000 to 169 bcm in 2013.

Figure 40: Global gas demand by major region



Source: CEDIGAZ

Gas demand is expected to continue growing steadily in the next two decades. According to the IEA World Energy Outlook¹³¹, gas demand is expected to reach about 5000 bcm by 2035 (New Policies Scenario). In fact, natural gas is the only fuel whose demand increases in the three IEA scenarios. The rise of natural gas demand is due to the availability of its reserves, restructuring and decarbonisation of energy systems worldwide. Natural gas is widely available and flexible as it can be used in electricity generation, manufacturing, transport, and private households. Compared to other fossil fuels, natural gas produces relatively low carbon dioxide emissions during combustion. For this reason, the natural gas sector also has an important supportive role to play in the energy transition towards a low-carbon economy.

Huge gas resources

Global gas markets have been through a major transformation, driven largely by North America, where technological developments have enabled extensive utilisation of shale gas resources. This has enabled a rapid and large increase in US gas production which has increased by 20% since 2008 to 724 bcm in 2013. This has contributed to a rapid decline in gas prices in the US and, more significantly, essentially

¹³¹ IEA (2013), World Energy Outlook 2013 (WEO 2013), IEA/OCDE, November 2013

removed the US from the international liquefied natural gas (LNG) import market. The US is now in a position to export LNG, with a number of projects at varying levels of development. The shale gas revolution in the US has driven interest all over the world to apply the same technologies to develop shale gas resources. There are many shale gas basins, from South America to China, from Europe to Africa. Global resources of shale gas and other unconventional gas are now estimated at 343 trillion cubic meters (tcm). This has dramatically changed the gas scene as gas resources are now available in large quantities all over the world, modifying the geopolitics of natural gas, previously dominated by conventional gas reserves in two regions only (Eastern Europe/Eurasia and the Middle East). In addition, new E&P technologies, mainly offshore, have allowed discovering large gas fields in East Africa, and East Mediterranean. This has increased the number of countries owning large conventional gas reserves and developing supplies for export markets. At the end of 2012, total remaining technically recoverable resources of gas stood at 810 tcm, i.e. more than four times larger than proved reserves (200 tcm) and equivalent to around **235 years of production at current rates**.

Table 12: Proved reserves and remaining technically recoverable resources of gas at the end of 2012

	Proved reserves (tcm)	Remaining technically recoverable natural gas resources (tcm)					
		Conventional	Unconventional				Total
			Tight gas	Shale gas	Coalbed methane	Sub-total	
E. Europe/Eurasia	64.8	143	11	45	20	46	190
Middle East	80.1	124	9	4	0	13	137
Asia-Pacific	17	44	21	53	21	95	138
OECD Americas	11.2	46	11	48	7	66	112
Africa	14.5	52	10	39	0	49	101
Latin America	7.6	32	15	40	0	55	86
OECD Europe	4.6	26	4	13	2	19	46
World	199.8	468	81	212	50	343	810

Source: CEDIGAZ, IEA

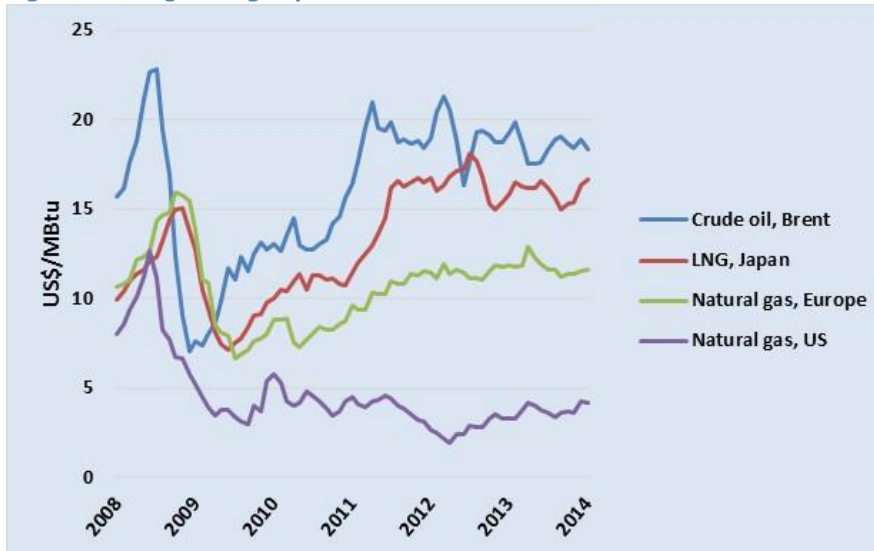
A global LNG market has emerged

Over the past few decades, international gas trade has grown rapidly, initially through large diameter transcontinental pipeline exports, and more recently as LNG. LNG now represents about 10% of total gas supply. Since 2005, LNG trade has surged thanks to the development of large export capacities, mainly in Qatar. Despite its slowdown in 2012 and 2013, international LNG trade reached 313 bcm in 2013 (see below). The development of new supplies, initially dedicated to the US gas market, created an LNG bubble at the end of 2000s/beginning of 2010s and enabled more liquidity and flexibility in LNG trade. **LNG suppliers have been able to redirect LNG supplies to markets with the highest demand**, creating the conditions for the emergence of a global LNG market and for more flexibility in contracts, in particular with the removal of destination clauses in some contracts. The Great East Japan Earthquake in 2011 has tightened the market as Japan replaced part of the lost nuclear power by LNG. This has resulted in a fast growing LNG demand that LNG supply contracted by Asian buyers was not able to cover. The tightness of the Asian LNG market has resulted in a surge in spot LNG prices delivered to Asia/Japan and diversion of LNG supplies from Europe to Asia. European LNG imports collapsed in 2012 and 2013, after their peak in 2011, as numerous cargoes were diverted to more lucrative markets, mainly Asia but also Latin America.

Gas prices divergence

Despite linkage of regional markets through LNG trade, prices on the three main markets diverge dramatically and the spread between regional prices has risen since 2011, reflecting regional market pricing. The average LNG import prices in Japan amounted to US\$16/MBtu in 2013 compared with an average import price of US\$11.8 in Europe and a domestic price of US\$3.73 in the US.

Figure 41: Regional gas prices



Source: EIA, World Bank

The majority of trade outside the US and the UK relies on long term contracts, often with a link to oil/oil products prices. The changing dynamics of global gas markets have raised questions about the sustainability of traditional pricing mechanisms. In particular, there is growing pressure on traditional oil-linked pricing mechanisms in Europe and the Asia-Pacific.

2.2. GAS PRICING

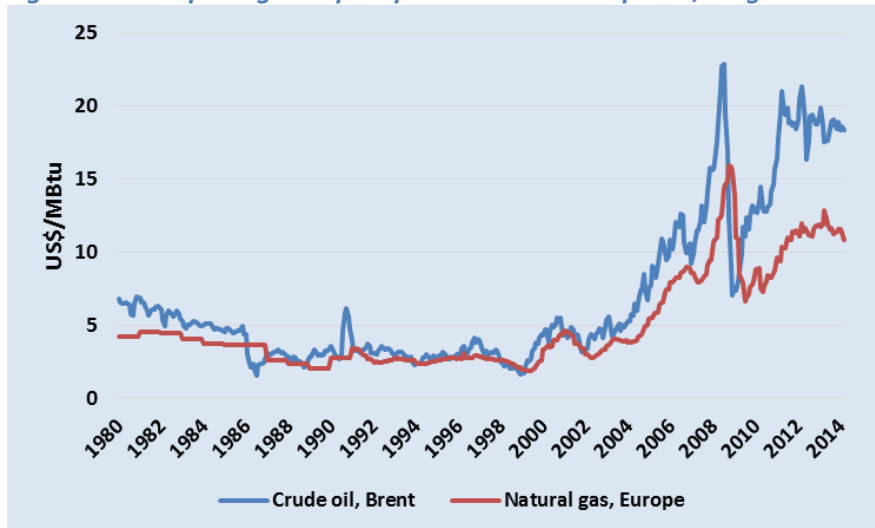
A historical linkage with oil

The first European gas export contracts¹³² for the sale of Groningen gas, signed at the end of the 1960s, linked the price of natural gas to the price of oil products, its main competitors in the heating sector. The Dutch government, together with Esso and Shell, developed the concept of replacement, or market value pricing, and the concept of long-term contracts with a minimum pay based on a netback/replacement value pricing, with regular review possibilities to adjust pricing to the originally sought balance. **The motivation behind these long-term contracts was a risk-sharing between the sellers and the buyers.** Typically, the seller was taking risks and chances of price development via the replacement value pricing concept (price risks), while the buyer was taking the obligation to market a defined volume via the minimum take-or-pay obligation (market risk). The Dutch export contracts served as a point of reference for most gas export contracts to Continental Europe which followed over the next four decades: both pipeline gas exports and LNG supplies. Changes in market conditions were reflected in the new contracts concluded and by regular price reviews for existing contracts. Most

¹³² See Energy Charter (2007), Putting a Price on Energy: International Pricing Mechanisms for Oil and Gas, Chapter 4: Gas pricing, 2007 and Rice University (2013), The Politics of Natural Gas Development in the European Union, Andreas Goldthau, James A. Baker III Institute for Public Policy, Rice University, October 2013

typical contracts were – and still are for a large share of European gas imports – long-term contracts, with duration up to 30 years and included take-or-pay clauses under which a certain quantity (80 to 90%) had to be paid whether the gas was taken or not. They also included some flexibility, on both annual and daily contractual deliveries. The link with oil products or crude oil prevailed until the end of the 2000s.

Figure 42: European gas import prices vs. crude oil prices, long-term evolution



Source: World Bank, EIA

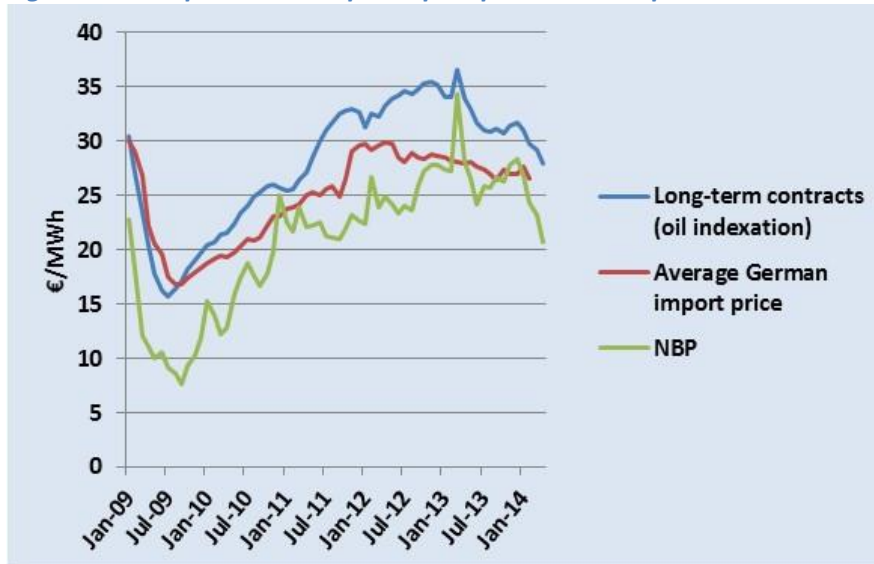
Major changes since 2009

Since 2009, however, **oil indexation has been under pressure as major changes occurred in the marketplace**. Two key factors are causal: the EU's gas market liberalisation and international market developments. The restructuring of the EU gas market, in the context of the EU Gas directives, and particularly the Third Energy Package, has pushed for full market liberalisation and increasing gas-on-gas competition. These reforms improved third-party access to gas infrastructure, established secondary markets for pipeline and storage capacity, and eventually allowed new players to emerge as important market actors, challenging incumbent wholesale and distribution companies. These measures, combined with the elimination of destination clauses entailed in long-term contracts, radically transformed the regulatory and market context in which the existing contracts were operated. The emergence of gas hubs with transparent prices and full market opening resulted in a situation where customers increasingly had a credible choice of suppliers, and fierce competition developed between wholesalers particularly for large customers.

The EU's liberalisation policies coincided with the surge in domestic natural gas production in the US allowed by the shale gas revolution. The rapid increase in US shale gas production from 2008 led to rapidly declining import needs in North America. LNG cargoes destined for the US market, mainly from new capacity built in Qatar, ended up supplying the European and Asian market instead, and European LNG imports increased from 53 bcm in 2007 to 88 bcm in 2011, their historical annual record. Coupled with decreasing demand due to the global and financial crisis, the European gas market became oversupplied and prices at European gas hubs declined while prices of long-term contracts continued rising in line with the increase in oil/oil products prices. Oil prices were up 39% in 2011, from US\$80/barrel in 2010 to US\$111/barrel in 2011. This has been a key factor in the development of hub liquidity and transparency and opened a gap between long term contracts based on oil and short term contract prices. These trends, market liberalisation and a significant divergence between gas hub prices

and oil-pegged prices, created a “perfect storm” for incumbent gas utilities. On one hand, they had to pay oil-pegged prices to their suppliers; on the other hand they could only sell gas at hub prices to their major consumers (industrial and power sectors). At the same time they registered decreasing market share due to reduced gas demand and competition from new entrants.

Figure 43: Gas prices in Europe: import prices vs. hub prices



Source: IFPEN, 2014

As a result, European wholesalers were no longer able to take off contractually agreed volumes, nor pay oil-pegged prices. This situation led to serious take-or-pay issues and triggered **renegotiation of long-term contracts with key international suppliers**. Norway’s Statoil has been more willing to accept increasing levels of hub indexation in its existing contracts with EU buyers than Gazprom and traditional LNG and pipeline suppliers. The majority of Statoil’s existing long-term gas supply contracts have moved to hub prices but with much reduced (or no) flexibility. Statoil has also adopted hub indexation for its new contracts. In November 2012, the company signed a 10-year contract with Wintershall for the delivery of 45 bcm of natural gas supply. The price of gas is linked to German and North-western gas hubs. This move has played an important role in undermining established pricing patterns by offering larger shares of contracted gas at hub prices. This resulted in a competitive edge for Norwegian supplies over Russian piped gas as gas hub prices have been lower than oil-indexed prices. In 2012, Norwegian exports to the EU rose 12%, while Russian exports declined by 10%.

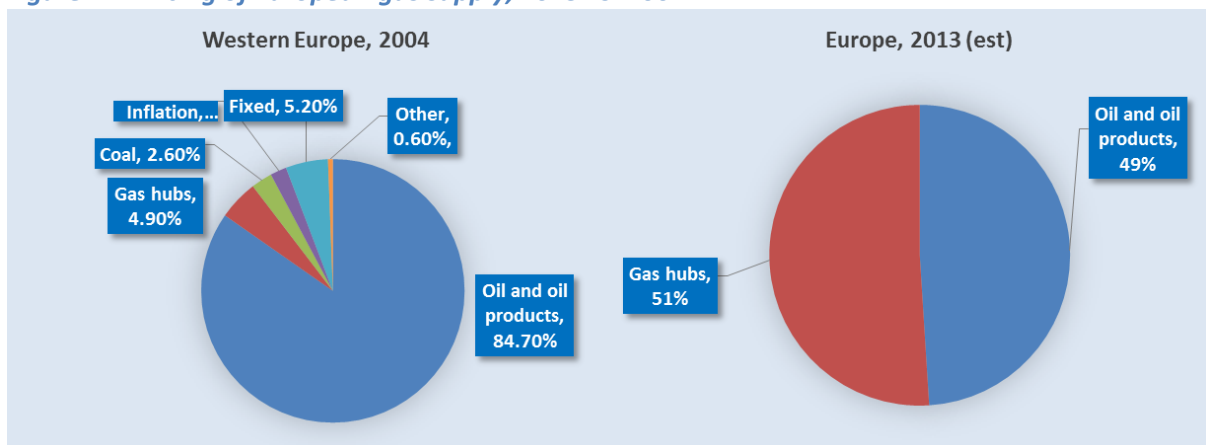
Since 2009, renegotiation of contracts for existing contractual supplies has taken place between Gazprom and its traditional EU buyers, which had demanded both reductions in take-or-pay obligations and reductions in prices. Some of these renegotiations led to international arbitration, others were conducted at companies’ level. As a result of these renegotiations, Gazprom has granted price reductions, more flexibility in take-or-pay volumes and partial indexation of gas prices on hub prices, although the company insists on the principle of oil-indexed pricing. Furthermore, a mechanism was introduced in Russian contracts by which the buyer receives compensation if the gap between contract and hub prices becomes too large. In 2012, price rebates granted by Gazprom amounted to US\$3.3 billion and an estimated US\$4.7 billion in 2013. The new price of Russian gas and/or discounts granted by Gazprom to its customers allowed Russian supplies to recover an increased share of the European

market in 2013. Russian exports reached a record level: 162 bcm¹³³. Moreover, in 2012, the marketing and trading arm of Gazprom in Germany signed a 3-year deal with Centrica - a new customer - for the supply of 2.4 bcm of gas to the UK priced at the NBP hub. This is in line with the hybrid pricing concept supported by Gazprom¹³⁴. Under this concept, oil-linked and hub-based pricing coexist in Europe.

Prices of Algerian and Libyan supplies by pipeline have remained linked to crude oil or oil products. However, several buyers have started international price arbitrations in view of reducing gas prices. LNG prices of long-term contracts are also mainly linked to oil prices, except Qatar's LNG sales to the UK and some EU customers, which are linked to NBP prices, however with an option to sell to non-European markets.

In all, it is almost impossible to get an accurate assessment of gas indexation level and its growth in existing long-term contracts as these contracts are confidential. Various analysts estimate that **around half of European gas supplies are based on hub prices**, the other half remains oil-indexed. This represents a key change compared with the situation which prevailed in 2004, where only 5% of Western European gas contracts were indexed to spot gas prices.

Figure 44: Pricing of European gas supply, 2013 vs. 2004



Source: European Commission, DG COMP. Energy Sector Inquiry 2005/2006 and Bros, Flame 2013 from European Commission report, LT/ST markets in gas, KEMA, July 2013

In line with the objectives of the Gas Target Model¹³⁵, the completion of the internal gas market will be accompanied by a **gradual transition to hub-based pricing**, which is still lagging in some central European countries. On 10 September 2013, the European Parliament adopted a resolution on making the internal energy market work¹³⁶. Calling for a review of the existing gas contracts “based on obsolete pricing mechanisms”, the report states that oil indexation “imposes high prices on the consumers”. In this context, the report calls for the “decoupling of the gas pricing mechanism from the oil indexation to more flexible alternatives, while respecting the freedom of commercial exchange”.

¹³³ Includes Turkey, but excludes the Baltic countries. Source: Gazprom, 2014.

¹³⁴ Komlev S., Pricing the “invisible” commodity, Gazprom Export, Discussion paper, 11 January 2013

¹³⁵ CEER (Council of European Energy Regulators), CEER Vision for a European Gas Target Model, Brussels, December 2011

¹³⁶ European Parliament (2013), Resolution on making the internal energy market work, European Parliament, 10 September 2013.

Whether full gas–hub pricing emerges in Europe has been largely discussed in the past few years and is still subject of debate¹³⁷. The clear trend is towards more widespread adoption of hub-based pricing for new contracts, as illustrated by the contracts signed between Centrica and Gazprom, Statoil and Wintershall or more recently by the promoters of the Azerbaijan’s Shah Deniz gas project¹³⁸ with GDF Suez. The 25-year contract, signed in April 2014, tied the price of the 2.6 bcm/year deliveries to Western Europe’s gas hub prices.

With a growing share of European gas supplies sold based on hub prices, in the future, prices will be determined to a much larger degree by actual supply and demand fundamentals and by gas-on-gas competition between various (external) suppliers competing for market shares.

Hub pricing means market-driven prices

Moving to gas-on-gas competition on the European gas market does not automatically translate into lower prices. Linking long-term contracts to gas hub prices is, however, an insurance for wholesalers that the cost of their supplies will match their sale prices. Under hub-pricing, **gas prices are determined by the supply and demand balance**. This means low prices in oversupplied markets and high prices in tight markets, as can be observed in other commodity markets, such as coal (see Chapter 3). In import markets, such as the European gas market, the supply factor is of paramount importance. As domestic production is declining, EU dependency on gas imports is increasing. The EU’s growing dependence on gas imports could contribute to price increases, as the European gas market will gradually become more reliant on increasingly integrated international markets through LNG supplies. As stated in the European parliament report on the internal energy market, the move to gas-on-gas competition needs to be accompanied with the development of supply sources, both domestic ones and new sources, in particular in southeast Europe, and investment in new pipelines and interconnectors, to allow a wider range of supply sources to reach EU gas customers and competition between supplies to develop.

In this context, important questions are whether Europe is able to develop new domestic sources (shale gas resources) and at which prices, attract LNG shipments at prices lower than those of piped gas and how oil-indexation which still prevails in the Asian LNG market will influence European gas prices.

Recent fall in European gas prices: a taste of a liquid and global gas market

Despite the Russia-Ukraine crisis and fears about a possible cut in Russian deliveries, **European spot gas prices have fallen since the beginning of 2014**, with sharp fall in April 2014. On average, UK NBP day-ahead spot gas price stood at €20.72/MWh in April 2014 (equivalent to less than \$8/MBtu), its lowest level for 3 years (see Figure 43). Spot continental European prices have also fallen significantly, from €26.7/MWh at the beginning of the year to levels close to €19/MWh at the beginning of May 2014, a decline of 29% in just four months. Long-term prices (still partially indexed to oil) have also

¹³⁷ See OIES (2011), The Transition to Hub-Based Gas Pricing in Continental Europe, Jonathan Stern and Howard Rogers, OIES, March 2011; Stern J. (2012), The Pricing of Internationally Traded Gas, Oxford University Press, 2012 and OIES (2013), The Transition to Hub-Based Gas Pricing in Continental Europe, a response to Sergei Komlev of Gazprom Export, Jonathan Stern and Howard Rogers, OIES, February 2013 2012 for a detailed discussion on pricing trends on the European gas market)

¹³⁸ BP holds 28.8 percent of the Shah Deniz project, while Norway’s Statoil has a 15.5 percent stake. Azerbaijan’s state oil company Socar has 16.7 percent and Total holds a 10 percent stake. The other shareholders are Russia’s OAO Lukoil and the state oil companies of Turkey and Iran. The Shah Deniz partners have agreements to sell more than 10 bcm/year starting in 2019 to nine different buyers, including Italy’s Enel and Germany’s EON.

declined, although the decline is less pronounced as oil prices have remained very stable since the beginning of 2014.

These falls are explained by three main factors which are the three key determining factors of gas prices in liberalised markets (supply, demand and storage):

- **Gas demand has been weak** since the beginning of the year as a mild winter season reduced gas demand for heating purposes, compared with last year which was characterised by a long winter season. Demand by the power sector has remained low. Despite the significant decline in gas prices, the low levels of coal and CO₂ prices (\$75.5/t at the beginning of May 2014 and €5.3/t respectively) still favour coal burning.
- **Storage has largely contributed to the fall in gas prices.** In contrast with 2013, storage inventory remained high in winter 2013/14 as the weather was mild. At the beginning of May, EU storage levels stood at 41 bcm¹³⁹, or 51% of their maximum working capacity, a very high level at this time of the year (last year at the same date, storage levels amounted to 19 bcm, only 25% of their working capacity). In the UK, the mild weather left gas stocks at 63% of their capacity on 1 May 2014 versus last year's 17%, pulling down prices. This means that very little injections needs will be required to fill storage before the winter 2014/15 season, pushing gas prices down¹⁴⁰.
- Supplies of gas on the European market is abundant relative to gas demand. **LNG plays here an important role.** As the price of LNG in Asia is relatively low due to seasonal weakness in demand, LNG sellers, in particular Qatar, do not want to further undermine Asian LNG prices, by sending their excess uncontracted production to Asia, their largest current and future LNG consumer. Instead of selling these flexible supplies to Asia, they sell spot cargoes to Europe, mainly the UK, further undermining European gas prices.

The recent fall cannot yet be interpreted as a structural evolution of gas prices in Europe, as still half of external supplies is linked to oil prices. However, in the absence of geopolitical crisis, prices are expected to remain low until the winter season as injection into storage is expected to remain weak, coal burning is still favoured (although the situation may reverse in the UK) and the heating season has ended. A rebound in Asian LNG demand and prices this summer may push European prices higher.

Although **coal burning is still favoured** at the beginning of May 2014, the recent fall in gas prices illustrates the determinant role the price of gas (and that of CO₂) plays in the contest with coal. The CO₂ switching price from coal to gas is now €30/t, whereas it was €50/t in January. The switching price from an old coal power plant to a new CCGT is even reduced to €20/t.

2.3. SHALE GAS PRODUCTION IN THE EU

Significant shale gas resources in Europe

The shale gas revolution in the US has sparked interest all around the world and in particular in some European countries, potentially well-endowed with shale resources. Although many factors make the US large-scale production not replicable elsewhere, several EU countries have started exploration of their shale basins. **The potential resources of unconventional gas in Europe are believed to be large.**

¹³⁹ Source: Gas Storage Europe (GSE), AGSI+ Aggregated Gas Storage Inventory

¹⁴⁰ For operational and safety reasons, the filling of storage is done progressively over the spring/summer months. Only flexible storage (salt cavities) can be cycled rapidly. Even if gas suppliers want to buy gas at low price to fully fill their stocks, there is a technical limit.

Risked shale gas resources¹⁴¹ and technically recoverable shale gas resources¹⁴² in Europe have been estimated by the US EIA in 2011 and updated in 2013¹⁴³. The latest study estimates technically recoverable shale resources in the EU at 13.3 tcm.

Table 13: Technically recoverable resources of shale gas vs. proved gas reserves in the EU

	Proved reserves (bcm)	Technically recoverable resources (bcm)
	Conventional gas	Shale gas (ARI 2013)
Poland	73	4,190
France	10	3,880
Romania	102	1,444
Denmark	91	900
United Kingdom	461	740
Netherlands	1,131	740
Bulgaria	5	481
Sweden	-	280
Germany	71	480
Others	148	175
TOTAL EU	2,092	13,310

Source: CEDIGAZ, EIA

As the EIA study suggests, shale gas deposits in Europe are promising, especially in the Carpathian-Balkan Basin stretching across Bulgaria, Hungary, and Romania; the Baltic Basin, which includes Poland and Lithuania; and France's Paris Basin. Denmark, the Netherlands, Germany, and the UK hold deposits as well. However exploration activities are at an early stage and therefore the exact values of recoverable reserves are not currently available. Moreover, **the development of unconventional sources in Europe will depend on how the regulatory, social and economic aspects are treated.**

Potential European production, costs and impact on gas prices

So far, **exploration of shale gas resources in Europe has been rather limited for technical reasons and due to local opposition to hydraulic fracturing in some countries.** However, the Ukraine crisis may spur renewed interest in shale gas resources and their ability to increase gas independence in the EU.

Shale gas is subject to a lot of controversy in the EU and the level of **local opposition** is strong in some countries. France and Bulgaria have actually adopted a ban on exploration and production of shale gas. One key issue is public acceptance of the hydraulic fracturing technology. Environmental opposition to shale gas mostly relates to fears of water contamination. To address these concerns, in January 2014, the European Commission adopted a Recommendation aiming to ensure that proper environmental

¹⁴¹ The term 'risked resources' is used to define the shale gas resources in place that take in to account the shale play success probability factor (high enough flow rates) and the prospective area success factor (relating to geological complications that reduces availability).

¹⁴² The term "technically recoverable shale gas resources" refers to the share of the risked shale gas resources in place which can be extracted on the basis of their shale mineralogy, reservoir properties, and geological complexities with current technologies.

¹⁴³ EIA (2011), 'World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States' and EIA (2013), 'Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States'

and climate safeguards are in place for hydraulic fracturing used in shale gas operations. The Recommendation is twofold. The first specific objective is to ensure that environmental impacts and risks arising from the techniques used for exploration and exploitation activities, both as regards individual projects and cumulative developments, are adequately identified and managed. The second specific objective is to clarify the EU legal framework, so that investments in shale gas developments across the EU can take place within a predictable setting. The Recommendation includes **minimum principles for shale gas exploration and exploitation**. The IEA has also published a set of recommendations (“**the golden rules**”) to apply when exploring and exploiting shale gas resources which allow a safe and environmental-friendly production of shale gas¹⁴⁴.

A number of EU countries are in the process of granting or have granted concessions and/or prospection/exploration licences over the past three years: Denmark, Germany, Hungary, Netherlands, Poland, Portugal, Romania, Spain, Sweden and the United Kingdom¹⁴⁵. However, not all license holders have started concrete prospection or exploration activities. Currently, such activities (at prospection or exploration stages) have taken place or are ongoing in Denmark, Germany, Poland, Romania, Sweden and the UK. As yet, there is no commercial production of shale gas in Europe, although a few pilot production tests have already been conducted, for instance in Poland. Commercial production could start in 2015-17 in certain countries (e.g. Poland, UK)¹⁴⁶. Poland is considered as a front-runner in shale gas in Europe, although the country has encountered disappointing results since it started shale gas exploration. The UK, although less advanced in terms of exploration activity, has nevertheless put in place a complete framework for the exploration and exploitation of shale gas resources. This has led international oil companies and European energy companies to invest in exploration in the country (see Box 11).

Estimates of potential production in the EU vary to a large degree between the IEA WEO2013 (New Policies Scenario) which expects shale gas production in the EU to amount 20 bcm by 2035 (including CBM and tight gas) and the IEA Golden rules for a golden age (best case scenario) which projects a level of 78 bcm by 2035 (also including other non-conventional gas). Even with the most optimistic view, the EU will not become self-sufficient in natural gas. However, shale gas production could partially compensate the decline in conventional gas production and limit EU's reliance on gas imports. In the best case scenario, shale gas production is able to contribute almost half of the EU's total gas production and meet about around 10% of the EU gas demand by 2035¹⁴⁷. It could offer some EU countries with a high import dependency the possibility to diversify their energy sources and enhance their security of supply.

Box 11: Poland and UK: two front-runners for shale gas in the EU

Poland is widely regarded as the country with the most substantial resources of shale gas in the EU. While the EIA initially estimated technical recoverable resources at 5.3 tcm, its updated evaluation based on better geologic information has reduced this level to 4.2 tcm. The Polish Gas Institute has evaluated these resources at 346-768 bcm. The accurate level of resources is difficult to estimate. While about 60 drillings have been made in Poland so far, at least 200 are required to assess the scale of the country's shale gas reserves. Industry participants regard the low number of drillings mainly a

¹⁴⁴ IEA (2012), Golden rules for a golden age of gas, WEO2012 Special Report, Paris, 2012

¹⁴⁵ Licences granted by Bulgaria and France were subsequently revoked by laws banning hydraulic fracturing.

¹⁴⁶ European Commission, Exploration and production of hydrocarbons (such as shale gas) using high volume hydraulic fracturing, January 2014

¹⁴⁷ IEA (2012), op. cit.

consequence of the unclear legislation that had covered the sector so far. Exploration of shale gas basins started at the end of the 2000s, and more than 100 concessions have been granted since then to Polish and international companies. However, the legal framework for E&P of shale gas has been under discussion since that date with several different drafts proposed during the past three years. The lack of a legal framework and some poor initial drilling results prompted Marathon Oil, Talisman Energy, Exxon Mobil, ENI and, more recently, Total to withdraw from shale gas activity in the country. On 11 March 2014, the Polish government adopted a draft Bill to amend the Geological and Mining Law (the "Amending Bill") and a draft Bill on Special Hydrocarbon Tax (the "Tax Bill"). The proposed legislation aims to both regulate and facilitate activity in the shale gas industry. The new Bills, still to be approved by the parliament, include a new procedure for granting E&P concessions. The idea of establishing a state-owned entity – namely, the National Operator of the Energy Fossils (NOKE) – was finally shelved by the government. Environmental procedures have been simplified. According to the new Tax Bill, the exploitation of shale gas will be tax-free until the year 2020. As of the year 2020, the amount of tax on hydrocarbons will depend mostly on the profitability of the hydrocarbons deposit. The Polish government expects that the adoption of the new legislation will facilitate the activities of the country's shale gas industry and encourage entrepreneurs to invest in Poland.

In the United Kingdom, shale gas exploration was suspended in May 2011 when a fracked well provoked small seismic activity. After studies and recommendations by The Royal Society and The Royal Academy of Engineering, the government lifted the temporary ban in December 2012 and put in place strict regulation of the activity, including the creation of a new office dealing with unconventional oil and gas development. The government also adopted an encouraging legislation providing tax relief for shale gas E&P and incentives for local communities. Since then, several companies, among them, Centrica, GDF Suez and Total, have acquired licences to explore for shale gas resources. So far, exploration has been very limited: only four wells were drilled at the end of 2013. However, the incentives and framework put in place by the government should enable a quick start of exploration in the country. Resources have been estimated at 740 bcm by the EIA (2013). The British Geological Survey (BGS) has estimated gas in place of the Bowland shale basin, the most promising area, at 38,000 bcm.

A key uncertainty is the cost of shale gas in Europe. As no commercial production has started yet, only indicative costs can be given. The IEA gives a wide range of costs, spreading from US\$5/Mbtu to US\$10/Mbtu¹⁴⁸. The International Association of Oil and Gas Producers (OGP) has published a study on different possible scenarios for shale gas production in Europe and their macroeconomic impacts¹⁴⁹. The study, conducted by Pöyry Management Consulting (Pöyry) and Cambridge Econometrics (CE), examines the impact of potential shale gas production on energy prices and macroeconomic indicators for the EU28 countries for the period 2020 to 2050. The study analyses two potential shale gas scenarios: a 'Some Shale' scenario, where the potential of shale gas production reaches around 60 bcm/year in 2035 and a 'Shale Boom' scenario where the potential reaches around 150 bcm/year by 2035. These scenarios are based on assumption of technically and economically recoverable resources. The authors take into account potential environmental, technical and practical barriers. Their

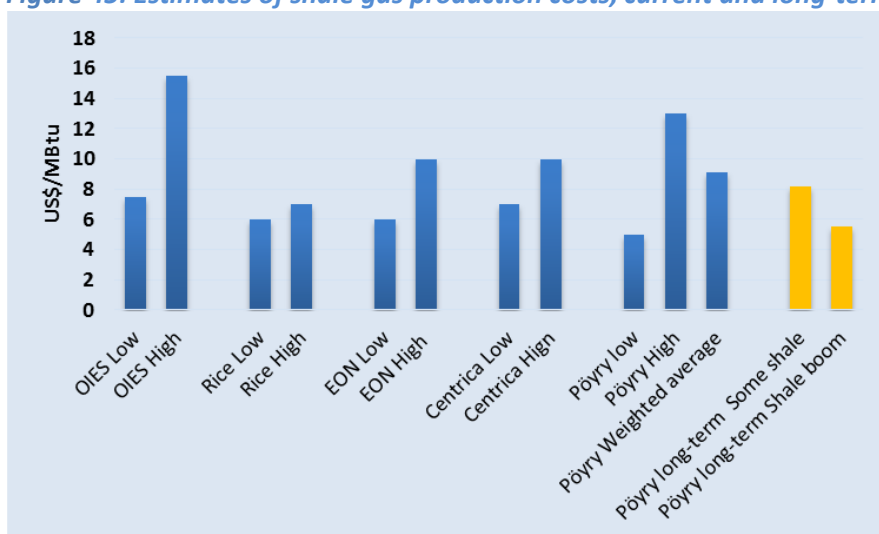
¹⁴⁸ IEA (2012), op. cit.

¹⁴⁹ Pöyry Management Consulting (Pöyry) and Cambridge Econometrics (CE), Macroeconomic effects of European shale gas production, a report to the International Association of Oil and Gas Producers (OGP), November 2013

production scenarios are derived from an analysis of shale gas production costs compared with alternative supplies.

The OGP study includes cost estimates by a range of companies 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, Pöyry cost estimates show two key interesting results: while the average current production costs are high (US\$9.1/MBtu), the range of costs is large, with lowest cost estimates at US\$5/MBtu, a level that would make production quite profitable. Secondly, costs are expected to decrease in the long term as technologies become more mature and efficient. Pöyry assumes a decline to an average of US\$5.5 to 8.2/MBu in the long term (2035 to 2050), depending on assumptions of future production.

Figure 45: Estimates of shale gas production costs, current and long-term



Source: OGP/Pöyry

These scenarios are then compared to a “no shale scenario” to evaluate the key macroeconomic impacts of shale gas production. While it is difficult to conclude at this stage of exploration in the EU, the study shows that shale gas production in both the Some Shale and Shale Boom Scenarios results in reductions in wholesale gas and electricity prices when compared to the No Shale Scenario. Wholesale gas prices in the Some Shale Scenario are only slightly lower than the No Shale prices until the mid-2030s after which there is a larger reduction as shale gas production increases. In the Shale Boom Scenario, prices diverge from the No Shale Scenario by the mid-2020s and remain substantially lower for the remainder of the reference period. On average over the period from 2020 to 2050, shale gas production causes a reduction in gas prices of 6.2% in the Some Shale Scenario and 13.8% in the Shale Boom Scenario.

While these reductions are not negligible, they also show that – at the current level of knowledge on shale gas in Europe - **a major reduction in prices as seen in the US cannot be expected in Europe**. The advantages of developing shale gas in Europe lie in other macroeconomic effects (increasing domestic production, reduction in imports and energy bills, jobs creation, etc.). **But even a moderate decrease or avoided increase in gas prices** – for instance through an increased or maintained negotiation

position towards non-EU gas suppliers - **would be beneficial for EU countries**, in particular for those highly reliant on imports, and for consumers and businesses, especially energy intensive industries¹⁵⁰.

2.4. A NEW WAVE OF LNG SUPPLIES

The LNG industry in 2013

Growth in demand restricted by supply

After a steady and sustained growth for more than 30 years, **the global LNG trade contracted in 2012 and remained flat in 2013** due to supply constraints. With 313 bcm in 2012, LNG imports were down 2.5%. They remained at this level in 2013. The tightness in LNG supply has constrained growth in LNG demand.

Figure 46: LNG imports vs. liquefaction capacity



Source: CEDIGAZ, GIIGNL

On the supply side, global liquefaction capacity rose sharply in the second half of the 2000s from 231 bcm at end 2005 to 358 bcm at end 2010 (+9.2%/year), driven by a spectacular increase in Qatar's LNG capacity, which has become the world's first LNG exporter. However, global LNG capacity showed a much more modest increase in 2011 (+3%), 2012 (+1%) and 2013 (+2%). Little new capacity entered the market in the past three years. In 2013, only the Angola LNG project and the 4.5 Mtpa (million tonnes per annum) new train at Algeria's Skikda came on stream. However, both projects encountered difficulties to ramp-up production. In addition, LNG supplies were constrained by feed gas shortage and restricted gas supply at some liquefaction plants (Egypt, Algeria, Indonesia) due to growing competition for resources between exports and domestic markets, and unscheduled outages at LNG plants (Nigeria, Norway) or pipeline breakdown due to political unrest (Yemen in 2012). These supply constraints have reduced the availability of liquefaction capacity.

The sharp increase in global consumption of LNG in 2010 (+21%) and 2011 (+9%) had virtually dried up the LNG reserve margin (the excess of liquefaction capacity installed relative to consumption). The modest increase in liquefaction capacity in 2012 and 2013 could therefore only allow a modest increase in consumption.

¹⁵⁰ European Commission (2014), Communication from the Commission to the Council and the European Parliament on the exploration and production of hydrocarbons (such as shale gas) using high volume hydraulic fracturing in the EU, EC, Brussels, January 2014.

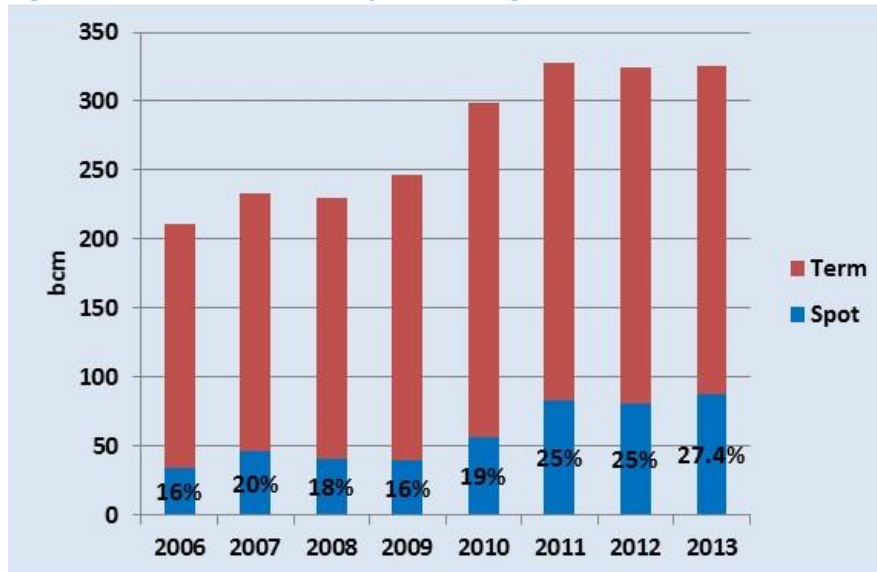
On the demand side, the Asia-Pacific region has made the largest contribution to the growth in global LNG imports, doubling its imports over the period 2005-2013. Today, more than 70% of global LNG volumes are directed to Asia. The region reinforced its market leadership position in 2013. The market share of Asia-Pacific in total imports reached 74%, while Europe recorded a 5 percentage point loss to 15%. Although still modest, the share of Latin America in world LNG trade increased from 3% in 2011 to 6% in 2013.

Growing natural gas demand in the Asia-Pacific over the 2011-2013 period, in particular Japan's increased reliance on gas-fired electricity generation, along with delays in the commissioning of new LNG liquefaction facilities contributed to a tightening of the Asia-Pacific LNG market which brought fundamental changes on the global LNG market. The Asian region attracted higher amounts of LNG, diverting them away from Europe, where LNG imports declined sharply in 2013 for the second consecutive year. European LNG imports totalled 47 bcm in 2013 (-27%) and 64 bcm in 2012 (-27%). At the opposite, Asian imports increased to 233 bcm in 2013 (+ 56 bcm compared to 2010). Whereas Japan's utilities have increased their reliance on LNG since the March 2011 Fukushima Daiichi earthquake and tsunami, their LNG imports increased by only 0.2% in 2013, as the country diversified its fossil fuels imports towards less costly energy sources and increased the share of coal in its electricity mix. Japan has also approached a ceiling on both the volume of LNG the country can receive and its CCGT capacity. China and South Korea were the key engine of growth of Asian LNG imports in 2013. In China, Beijing's desire to improve air quality and move away from coal in the key provinces of the east coast of the country pushed LNG imports to 24 bcm in 2013, a surge by 22.5% compared with 2012. In South Korea, the shutdown of several nuclear plants for safety checks increased gas demand and LNG imports.

The Asia-Pacific market tightness is reflected in the higher price of LNG imported by Japan compared to the other regional gas prices. These price differences have increased significantly since 2011, particularly with respect to North America (see Figure 41 above). Such a divergence in regional gas prices and the high level of prices in Asia, in particular for spot cargoes, have pushed Asian buyers to reconsider their purchasing strategy in order to reduce import costs and remain competitive.

These price increases correspond with an **increase in the quantity of LNG delivered through spot market and short-term contracts** (up to four years) globally. Currently, around three-quarters of all LNG continues to be supplied under 20-25 year contracts, but the share of sales under spot and short-term contracts is steadily increasing and reached 25% in 2012 and 27.4% in 2013¹⁵¹.

¹⁵¹ GIIGNL, The LNG industry in 2013, April 2014

Figure 47: Global LNG trade, spot and long-term volumes

Source: GIIGNL, annual reports

The short-term LNG market has experienced dramatic shifts towards Asia since 2011. In 2013 about 27% of Asia-Pacific's LNG imports were on a spot and short-term delivery basis. Latin America has challenged Asia for spot volume demand (65% of its supplies in 2013) and flexible volume availability has reduced. In winter 2013/2014, the price of spot LNG deliveries in Asia exceeded US\$20/MBtu, thus higher than oil prices. With the production outlook set to tighten in 2014, the price of spot deliveries may again skyrocket during Asian winter.

At short-term, global liquefaction capacity still grows slower than demand

After its weak growth in 2013, **global liquefaction capacity is expected to remain a bottleneck and only increase marginally in 2014 (+3%)**. Three new projects are expected to come on stream in 2014: Papua New Guinea's LNG project, Algeria's second train at Arzew (GL3Z, 4.7 Mtpa) and the Australian Queensland Curtis LNG project (in late 2014). Indonesia's Donggi-Senoro LNG project, initially targeted to commence production in 2014, has been delayed to March 2015. Moreover, global supply performance will again depend on unplanned outages and continuing declines in gas supply in some LNG producing countries. The world liquefaction capacity will also be reduced by the closure of ageing plants (Arun in Indonesia in 2014).

The tight market conditions will persist until at least 2016 when significant new capacity will be commissioned. From 2016, it is expected that booming supply will allow a rapid growth in LNG trade. The tightness of the market may however last longer as commissioning of new LNG plants may be delayed as it occurs frequently. Only 2 of the last 12 LNG projects have been delivered on time and budget¹⁵².

From 2015/16, a new wave of LNG

But the pace of growth in export capacity will accelerate over the period 2015-2020 with several new sellers entering the stage. **The increase will come mainly from Australia and the United States.** In addition projects in other Asia-Pacific countries, Canada, Russia, East Africa (Mozambique and Tanzania) and East Mediterranean are expected to come on stream at the turn of the decade.

¹⁵² Ernst & Young (EY) (2013), Global LNG, Will new demand and new supply mean new pricing ?, 2013.

Projects under construction total 133 bcm and may increase liquefaction capacity to around 600 bcm by the end of the decade. In addition, around 850 bcm of LNG projects are at the planning stage worldwide¹⁵³, some at preliminary phases of development and others well advanced and close to FID. Although it is unrealistic to expect all of them to materialise, some of them, in particular in the US, could take FID decisions in 2014 and start before the end of the decade (see Box 12).

While LNG demand increases rapidly by 2020, it is outweighed by the forecast increase in LNG supply, resulting in a significantly less tight global market by 2020, provided that projects are commissioned on time. Due to the complexity of projects, mainly in Australia, but also in Russia (Yamal LNG in the Arctic), delays may be expected, extending market tightness for longer than expected. However, it is also expected that more than one US project will be commissioned before the end of the decade, despite lengthy permitting procedures.

Table 14: LNG projects under construction (as of March 2014)

Country	Project	Capacity (bcm/year)	Major stakeholders	Online date
Algeria	Gassi Touil (GL3Z)	6.4	Sonatrach	2014
Papua New Guinea	PNG LNG	9.4	ExxonMobil, Oil Search, PNG government	2014-15
Australia	Queensland Curtis LNG	11.6	BG, CNOOC, Tokyo Gas	2014-15
Indonesia	Donggi-Senoro LNG	2.7	Mitsubishi, Pertamina, Kogas, Medco	Mar-15
Malaysia	MLNG Train 9	4.9	Petronas	End 2015
Malaysia	FLNG1*	1.6	Petronas	End 2015
Australia	Gorgon LNG	20.4	Chevron, Shell, ExxonMobil	2015-16
United States	Sabine Pass LNG	24.5	Cheniere Energy	2015-17
Australia	Gladstone LNG	10.6	Santos, Petronas, Total, Kogas	2015-16
Australia	Australia Pacific LNG	12.2	ConocoPhillips, Origin, Sinopec	2015-16
Australia	Wheatstone	12.1	Chevron, Apache, KUFPEC, Shell	2016-17
Australia	Prelude LNG*	4.9	Shell, Inpex, Kogas, PCP	2017
Australia	Ichthys	11.4	Inpex, Total	2017-18
TOTAL		132.7		

* Floating LNG project

Source: IEA, companies' websites

In the US, the Sabine Pass project is currently under construction and another six projects have received non-FTA export approval from the US Government (see Box 12). Canada also has plans to begin exports this decade. The National Energy Board (NEB) has to date granted export licences to seven greenfield projects based on the west coast of Canada, four of them approved in December 2013. The projects now need to be approved by the British Colombian government. None of the approved projects, however, are in the construction stage, or has taken FID decision. In Russia, the government passed legislation in December 2013 allowing private companies to export LNG in a move to enter growing Asian markets.

Russia has granted export licenses to Rosneft and Novatek, de facto ending Gazprom's monopoly on gas exports, although Gazprom retains its monopoly on gas exports by pipeline. Three LNG projects are being developed. Novatek's Yamal LNG facility to be located in the Arctic (5.5 Mtpa, increasing to 16.5 Mtpa) is due to start in 2017, following investment decision taken in 2013. The two other proposed projects are located in Russia's Far East: Rosneft's Sakhalin LNG (5 Mtpa) and Gazprom's Vladivostok LNG (10 to 15 Mtpa). Due to its strategic position, Yamal LNG has signed long-term

¹⁵³ IEA (2013), Medium-Term Gas Market Report, IEA/OCDE, Paris, 2013

contracts with both Asian and European buyers. The government expects Russia to increase its global market share in LNG to 10% by 2020 by producing 35-40 Mt, with output rising to 70-80 Mt by 2030.

But most of the current projects under construction are located in Australia and will result in Australian liquefaction capacity more than tripling to become the largest in the world towards the end of the decade. Australia could challenge the world's top LNG exporter, Qatar, by reaching annual export volume above 100 bcm by 2020. However, most of this LNG will become available after 2015 and the complexity of the projects may postpone their expected commissioning dates. In addition to the seven projects under construction, there are eight projects with a combined capacity of about 80 bcmpa planned in Australia.

Prospects for additional projects to come on stream before the end of this decade are weak (except for the US) due to long lead time of greenfield projects. Two new regions may enter the LNG scene at the turn of the 2020s: East Africa and the East Mediterranean, the areas where most of the major gas discoveries have been made over the past three years. However, geopolitical challenges, potential changes in fiscal policies, the inexperience of their administration, and finally, the costs of developing the new infrastructure are the most significant issues which could defer production to beyond 2020¹⁵⁴.

This wave of new supplies is expected to lead to strong competition between potential exporters later this decade. In the Asian LNG market, after a period characterised by extreme supply tightness and sellers' power, imports of US LNG, based on Henry Hub gas prices, and the desire of Asian buyers to move away from oil indexation may radically modify the way LNG is priced.

Box 12: LNG export projects in the US

In the US, exports of LNG to countries that do not have a free trade agreement (FTA)¹⁵⁵ with the US are conditional to approval by the US Department of Energy (DOE). The DOE has approved seven export applications so far, the latest one at the end of March 2014, when the Agency approved LNG exports from the proposed Jordan Cove Energy Project in Coos Bay. The export capacity to non-FTA countries of the approved projects totals 96 bcm/year. Authorisations are conditional until they are reviewed and approved by the Federal Energy Regulatory Commission (FERC).

Only one of the approved terminal, Cheniere's Sabine Pass, has unconditional approval from FERC for the export of LNG, which is expected to begin in late 2015. In addition, as of beginning of April 2014, the DOE has applications pending from another 23 terminals looking to export 275 bcm/year to non-FTA countries.

The export capacity of the approved projects is expected to be raised shortly as some projects (Corpus Christi, Magnolia LNG, Excelerate Liquefaction, Golden Pass, Sabine Pass Liquefaction) are expected to start up before the end of the decade. It should be mentioned, however, that the lengthy administrative authorisation process, has delayed the date of commissioning of most projects, despite an accelerated trend of DOE approvals in the past few months.

¹⁵⁴ IEA (2013), Medium-Term Gas Market Report, IEA/OCDE, Paris, 2013

¹⁵⁵ All current Asian and European LNG importers, except South Korea and Singapore.

Table 15: US LNG export projects under review by DOE

Projects	Total approved quantity (to FTA and non-FTA), bcm/year	Quantity to non-FTA, bcm/year	Expected start-up date (first train)
Approved for FTA and non-FTA			
Cheniere, Sabine Pass	22.7	22.7	Late 2015
Freeport LNG Expansion and FLNG liquefaction, Texas	14.5	14.5	2018
Freeport LNG Expansion and FLNG liquefaction, Texas	18.6	4.1	
Lake Charles (BG)	20.7	20.7	2019
Dominion Cove Point	18.3	8.0	2017
Sempra Cameron LNG	17.6	17.6	2018
Jordan Cove Energy	20.7	8.3	2019
Total approved for FTA and non-FTA	133.0	95.8	
Approved for FTA. Under DOE review for non-FTA (largest projects only)			
Gulf Coast LNG Export	28.9	28.9	
Gulf LNG Liquefaction	15.5	15.5	
LNG Development Company	12.9	12.9	
Southern LNG Company	5.2	5.2	
Excelerate Liquefaction Solutions	14.3	14.3	
Golden Pass Products	26.9	26.9	
Corpus Christi, Cheniere	21.7	21.7	
CE FLNG	11.1	11.1	
Pangea LNG	11.3	11.3	
Main Pass/Freeport-McMoRan Energy	33.3	33.3	
Sabine Pass Liquefaction	14.3	14.3	
Venture Global LNG	6.9	6.9	
Eos LNG	16.5	16.5	
Barca LNG	16.5	16.5	
Delfin LNG	18.6	18.6	
Magnolia LNG	16.7	11.2	
Total US projects	398.0	370.6	

Source: USDOE, companies' websites

The potential for significant amounts of LNG to be exported over the medium-term is huge. The DOE has recently revised upwards the projected level of US LNG exports¹⁵⁶. In the AEO2014 Reference case, the US becomes a net exporter of LNG in 2016 and LNG exports rise to a level of 55 bcm in 2020 and reached 95 bcm/year by 2029. Although lower than the potential export volumes, this is a sharp rise compared with the level estimated one year earlier (45 bcm/year by 2027 in the AEO2013). According to the DOE, US cumulative net LNG exports from 2012 to 2040 are up by 160% in the AEO2014 compared with the AEO2013, supported by increased use of LNG in markets outside North America, strong domestic production, and low US natural gas prices relative to other global markets.

The level of exports is still uncertain as it depends on gas availability for both domestic and export markets. Several major US industrial users are opposed to LNG exports, fearing that such exports will increase the price of natural gas on the domestic market and reduce their competitive advantage over other regions. The DOE has studied the macroeconomic effects of gas exports¹⁵⁷ and determined that the impact on domestic gas prices will be mild. Its studies show a net economic benefit from exporting gas, though those benefits are concentrated among gas producers and gas producing states. These studies, criticised by some market participants as using outdated data, have been updated by NERA in

¹⁵⁶ EIA (2013), Annual Energy Outlook 2014 (AEO2014), EIA/DOE, Washington DC, December 2013.

¹⁵⁷ NERA Economic Consulting (2012), Macroeconomic Impacts of LNG Exports from the United States, a report prepared for the US Department of Energy, December 2012.

March 2014¹⁵⁸. The findings of the updated study confirm and extend the findings of previous studies. In all the 63 scenarios analysed by NERA, LNG exports provide net economic benefits, and the greater the level of exports, the greater the benefits. The study also shows that the market for LNG exports is self-limiting, in that little or no natural gas will be exported if the price of natural gas in the US increases much above current expectations. High levels of exports can be expected only if natural gas is plentiful and inexpensive enough to produce so that prices remain below current levels, even with high levels of exports¹⁵⁹.

Obviously, there is great interest from LNG buyers all around the world to import US LNG to diversify their supply sources and above all, reduce their LNG import costs. A key feature of US LNG export contracts is the indexation of prices on US Henry Hub gas prices. This new indexation is a radical change with the more traditional oil-indexation of LNG contracts (see below).

Future LNG demand driven by Asia

By 2020, global LNG demand is forecast to have expanded by 50%, to reach 470 bcm (CEDIGAZ, April 2014). Worldwide, more than 25 new terminals or terminal expansions are under construction with possible start-up by the end of 2015.

Figure 48: Future LNG demand by importing region



Other emerging markets: Latin America and the Middle East

Source: CEDIGAZ, April 2014

Asia is the key and most promising LNG market for the coming and next decades. Within Asia, China has a leading role in terms of growth due to the youth of its LNG industry and the constant and sustained building of new facilities to receive LNG. The country, which is already the world's top energy user but is so far only a small LNG player, is keen to curb use of coal and aims to increase the use of natural gas to 300 bcm by 2020, with nearly a third of that having to be imported as LNG. The level of LNG imports, however, depends on competition with pipeline gas imported from central Asia and Russia, the level of LNG prices, and in the longer term the development of shale gas. The expected signature of a contract to import 38 bcm/year from Russia may limit LNG imports. Japan, Korea and Taiwan will continue to provide a major outlet to global LNG supplies. Increased LNG imports will depend on future energy policy and in particular the role devoted to nuclear power (see Box 13) and

¹⁵⁸ NERA Economic Consulting (2014), Updated Macroeconomic Impacts of LNG Exports from the United States, a report prepared for Cheniere, March 2014.

¹⁵⁹ NERA Economic Consulting (2014), Updated Macroeconomic Impacts of LNG Exports from the United States, a report prepared for Cheniere, March 2014.

competition with coal. India is a candidate for reasonable LNG growth, if price levels fit the customers' requirements in the country. Other new comers, which may see a growth in their LNG imports, are the South-eastern Asian countries which are building new LNG import terminals, Indonesia, Malaysia, Thailand, Singapore and Vietnam.

In the Americas, import demand is rising especially in Mexico and Argentina where domestic production is dropping while demand is on the up. There are also numerous small LNG import terminals planned in the region to allow access to new gas supplies.

At short term, the level of LNG imports in Europe is quite uncertain. Uncertainty on Russian supplies following the Ukraine crisis calls for increased LNG supplies. The existing capacity of LNG import terminals is very high (199 bcm/year) compared with current low imports. Moreover, new terminals in central and eastern Europe are built to reduce dependence from Russia. However, Europe will continue to be considered as a last-resort buyer for LNG as long as Asia offers a price premium. The current situation (May 2014) shows that global LNG sellers may sell their surplus uncontracted production to Europe when demand in Asia is seasonally weak. However, they will turn back to Asia, their largest consumer, as soon as Asian demand and spot prices increase. Hence diversification and security of supply may trigger more LNG imports into Europe, however at higher prices than current hub prices. At medium and long term, European LNG imports are expected to increase to offset the decline of domestic production and to diversify gas supplies. The capacity of European LNG terminals could reach 276-369 bcm/year by 2022 (GLE, 2013).

Box 13: Japan new energy policy

Since the Great East Japan Earthquake in 2011, Japan has shut down all its nuclear power plants (the latest one in September 2013) which were used to provide around 30% of its electricity supply. The country relies more on thermal power. Currently fossil fuels provide 90% of Japan's electricity generation. As Japan has limited natural resources, it had to import larger volumes of oil, LNG and coal. Japan is the world's largest importer of LNG, third largest coal importer and the third largest net importer of oil. A large share of Japan's LNG is consumed in electricity generation. LNG imports have therefore increased dramatically since March 2011 from 96 bcm in 2010 to close to 116 bcm in 2013. Rising oil prices have increased the cost of imported LNG - the price of LNG imported in Japan surged from US\$11/Mbtu in 2010 to US\$16/Mbtu in 2013, contributing to a surge in Japan's annual LNG bill and rising trade deficit. Japan posted its first trade deficit in 31 years in 2011. The trade deficit jump 65% in 2013 to US\$112 billion because of increased fossil fuels needs and the weakness of the yen. This high burden undermines economic recovery.

Under this background, Japan's cabinet approved a new national energy strategy on 11 April 2014 that designates nuclear power as an important energy source of base load electricity supply and commits to restart idled reactors from 2014, subject to stringent safety regulations. The new strategy, first proposed by the government of Prime Minister Shinzo Abe in February, scraps a promise made by a previous government after the 2011 Fukushima nuclear disaster to phase out nuclear power. Of Japan's 48 operable reactors, applications for restarts have been made for 17. Nuclear power plants will only be allowed to recommence operation after the new Nuclear Regulation Authority (NRA) has assured their safety. The NRA has not announced a firm schedule for the completion of these assessments and it is uncertain when any plants will be restarted, although August 2014 is looking most likely for the first plant/s to restart.

Other priority areas include accelerated uptake of renewable energy, electricity market deregulation, and energy efficiency and conservation. The new policy states Japan will cut its nuclear dependency as

much as possible and that the most reliable energy mix for Japan would contain a combination of nuclear, renewable energy and fossil fuels. It does not define targeted shares for energy sources because of uncertainties about the number of nuclear restarts and the pace of renewable development. But the government aims to introduce renewable energy at levels that further exceed previously announced targets. The previous plan published in 2010 envisioned Japan getting about 20% of its electricity from renewables by 2030.

LNG import volumes will decrease if nuclear power plants are restarted, but the impact depends on the pace and timing of restarts. At short term, if, as expected, the government permits the 17 nuclear reactors to restart over the next two years, the impact is likely to be predominantly a displacement of oil consumption currently used in power generation. Japan's current LNG import capacity is constrained by infrastructure, berthing, and ship size. To meet growing import requirements and increase flexibility, five LNG import terminals are under construction with a combined capacity of 10 bcm/year. At longer term, the role of natural gas will depend on the ability of power utilities to secure low cost gas and the role devoted to renewables, coal and nuclear in the electricity mix.

The new energy plan also designates coal as an important long-term electricity source to keep energy costs stable. The government is currently promoting coal-fired technology to improve the use of economically efficient coal-fired power generation and as a key export under 'Abenomics'. Abe's government is supporting the development and export of advanced coal technology from Japan. According to a growth strategy released in June 2013 by the prime minister, the nation intends during the 2020s to commercialize A-USC (advanced ultra-supercritical) technology¹⁶⁰. It's also seeking to sell equipment that combines fuel cells with integrated gasification combined cycle to improve the efficiency of power generation.

IGCC (Integrated Gasification Combined Cycle) is also at the heart of Japan's renewed hopes for coal. TEPCO plans to add two more IGCC generators at its Nakoso and Hirono stations, in Fukushima. A more traditional 600-MW coal-fired generator at the Hirono site began operating in December 2013.

Downward pressure on prices

The tight supply conditions prevailing in the Asian LNG market will be replaced by excess supply later this decade when (and if) all announced export projects are commissioned. This is likely to place significant downward pressure on prices as competition develops between LNG suppliers. In addition, two factors are expected to add more downward pressure: the indexation of US LNG exports on spot Henry Hub prices and the desire from Asia-Pacific buyers, the largest consuming buyers, to reduce their LNG import bills and move away from full oil-indexation. However, the fact that most LNG of the projects currently under construction is linked to oil prices implies that oil indexation is likely to continue to dominate.

New pricing of US LNG exports

The pricing arrangements adopted for the US projects, based on Henry Hub (HH) gas prices and liquefaction tolling fees, constitute a revolution in the LNG market, so far dominated by oil-indexation prices. The agreements signed by Cheniere with its customers include a fixed charge for the annual capacity allocated at the export LNG facility (varying between US\$ 2.25 and 3/MBtu in the first signed contracts) and a contract sales price for LNG purchases based on 115% of HH gas price. The 15% covers fuel consumption and transportation costs of the gas to the export facility. In these agreements, LNG

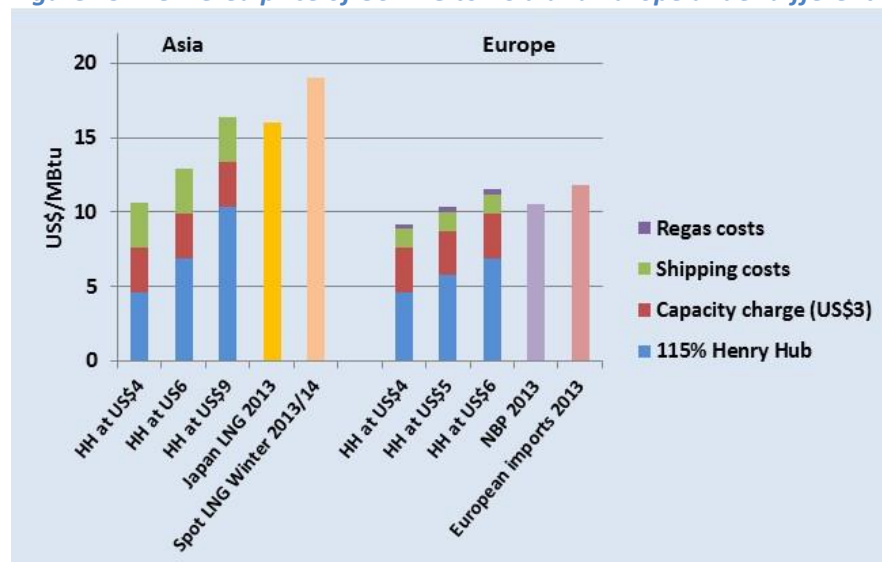
¹⁶⁰ The technology known as A-USC burns coal to produce a higher temperature steam and allows efficiency close to 48% (LHV), decreasing CO₂ emissions per unit (669 gCO₂/kWh).

is sold on a Free-On-Board (FOB) basis and buyers get the option – but not the obligation – to receive and ship LNG on their own to any destination (no traditional take-or-pay or restricted destination clauses). The agreements are structured in a way that the seller is able to recoup its capital investment thanks to the annual fixed capacity charge and the buyer has the opportunity to secure competitively priced LNG, as well as to take advantage of the regional price differentials on the LNG markets as there are no destination clauses. The contracts are long-term contracts: 20 years with an option for an additional 10 years. The contracts signed with other US LNG producers have similar structure.

Such contracts open up an opportunity for a new pricing scheme, challenging the traditional oil linkage. Even though HH's volatility is high and there is no guarantee that HH prices will remain relatively low in the future, diversification of price mechanism is also important for buyers to optimize the price risks of their LNG procurements. In addition, this new pricing scheme gives more power to LNG buyers in their negotiations with non-US LNG sellers over LNG prices and indexation. The new pricing mechanism can also serve as a reference for new gas sales, not based on US gas. For instance, BP Singapore has negotiated a 15-year contract to supply 0.5 Mtpa of LNG to Kansai Electric Power Co. (KEPCO) at a price linked to HH prices, even if the gas is not supplied from the US. If such contracts become more common, HH price could possibly become a global spot price for LNG trade at new export facilities and not just for contracted supply from the US. It is however unlikely that the LNG sellers outside the US will accept the US benchmark. These deals will certainly be confined to aggregators of LNG supplies.

How this HH indexation will affect price remains to be seen. As more LNG comes on the market, expensive Asian LNG prices should come down. Obviously, the decline depends on the evolution of HH prices. Figure 49 illustrates the price of LNG delivered to Asia (CIF prices) and Europe (CIF prices including regasification costs) for different HH price scenarios.

Figure 49: Delivered price of US LNG to Asia and Europe under different Henry Hub price scenarios



Source: own calculations

The figure shows that the average price paid by Asian buyers in 2013 and that of spot deliveries in winter 2013/14 are much higher than the expected delivered price of US LNG. It is only at a HH price of around US\$9/Mbtu that US LNG becomes more expensive than other suppliers (\$11.4 for spot deliveries). US LNG exports should therefore exert a downward pressure on Asian LNG prices. The outcome is less obvious in Europe. The delivered price of US LNG (including regasification costs to be

comparable with gas traded on hubs) is not far from average hub prices in 2013 (NBP prices) and above hub prices as soon as HH prices exceed US\$5.1/MBtu. US LNG exports should therefore rather act as a cap for future European gas prices. In addition, as US contracts do not include destination clauses, LNG aggregators/portfolio suppliers will not have any incentives to sell gas on the European market, unless the growing Asian market is saturated. If this is not the case, Europe will have to pay Asian prices (at whatever level) to attract spot cargoes above its contracted purchases¹⁶¹. This situation occurred in 2013 when southern Europe (Spain and south of France) was short of supply. Due to congestion of the North to South network in France, European regional buyers had to pay LNG at Asian parity to attract spot cargoes. In the future, due to the expected oversupply on the Asian LNG market later this decade, the price of spot LNG cargoes is expected to decline from the high level reached in winter 2013/14. It is likely to fall well below the oil-linked contract prices expected to prevail in the Asian market and should increasingly reflect the marginal producer's cost of production¹⁶².

Asian market desire to move away from oil indexation

Oil indexation is being increasingly challenged in Asia (and continues to be in Europe) given the high price of LNG in the region and the burden imposed on these countries' economies.

In the Asia-Pacific market, LNG prices under long-term contracts are traditionally based on crude oil prices (Japanese Crude Cocktail, JCC prices) with the use of discounting coefficients, known as the slope. The slope defines the relationship between oil and gas prices on the basis of energy contents and is traditionally expressed in a percentage. On average, one MBtu of gas has about 17% of the energy content of a barrel of oil (on the basis of 5.86 MBtu for one barrel). So if the heat-parity was used, the slope would be 17%. In other words, at a price of oil of US\$100/barrel, the price of LNG would be US\$17/MBtu. Contract slopes are typically less than 17%, usually around 14 to 15%. Asian contracts also include mechanisms to protect the buyer in case of a sharp rise in oil prices, and the seller in case of a collapse in oil prices ("S curve"). The contracts also include a fixed element (less than US\$1/MBtu) that takes into account the cost of transportation.

The increase in oil prices since 2011 has led to a sharp rise in LNG prices. Japan's LNG import prices averaged US\$16/MBtu in 2013, more than four times US spot prices. The price for spot LNG deliveries was even higher, at US\$19-20 in winter 2013/14. As a consequence of the large price spreads between Asia-Pacific LNG and gas in other regions, **Japan and other Asian buyers have strongly expressed their desire to move away from long-term contracts linked to crude oil prices**, to an alternative pricing arrangement based on HH gas price or an Asia-Pacific regional gas hub price index.

In Japan, where the LNG bill exploded in the past three years, reducing the cost of energy imports, and in particular that of LNG imports, has been a prime focus of the government. Japan has increasingly focused on supply diversification, greater flexibility in contracts and investments overseas to ensure secure supply and to reduce the cost of LNG imports. Japan's LNG import mix is currently dominated by Middle Eastern supply but this is expected to shift towards Australia, with significant growth in US supply by 2020. Japan is also looking at options in a range of countries including Canada, Russia and Mozambique. Japanese utilities have also developed a strategy for securing lower-cost gas, with LNG imports from the US seen as a key way to reduce prices. In addition to the contract signed by Kansai Electric with BP Singapore (see above), Japanese utilities and trading houses have signed several

¹⁶¹ Most contracts signed by US LNG suppliers are with Asian buyers and LNG aggregators. Only Gas Natural, (Spain) Centrica (UK) and GFD Suez (France) have long-term contracts with US LNG producers. These contracts also offer the possibility to divert LNG supplies to more lucrative markets.

¹⁶² BREE (2014)

contracts with US LNG suppliers based on HH prices. Osaka Gas and Chubu Electric have long-term contracts with Freeport LNG project (4.4 Mt/year), Tokyo Gas and Sumitomo Corp with Cove Point (2 Mt/year) and Mitsui Corp and Mitsubishi with Cameron LNG (4 Mt/year each). Altogether, they now have a portfolio of 14.9 Mt/year based on HH prices, representing 17% of their LNG imports in 2013. At HH price of US\$4/MBtu, this would have reduced the LNG import bill by US\$ 5 billion in 2013.

Japanese utilities are also pushing for the **removal of destination clauses** to get more flexibility in their supplies and facilitate the development of a regional trading hub. Japan is also encouraging joint purchasing, both between Japanese buyers and with purchasers from other countries, such as South Korea and India. Joint purchasing is seen as a means to achieve discounted prices and increase buyers' bargaining power. In January 2013, Chubu Electric and Kogas executed a tripartite LNG SPA (Supply and Purchase Agreement) with ENI. This is the first international joint purchase of LNG in Asia, and the two companies will be able to relocate LNG between themselves.

Efforts are also devoted to develop an **Asian LNG trading hub**, encouraging a more liquid market and the emergence of an Asian hub price reference, which in contrast with HH would reflect Asian market conditions, not US conditions. Singapore is seen as the most likely country for such a hub. In 2013, Singapore officially opened a 6 Mtpa LNG terminal – three storage tanks – with the aim of becoming a regional LNG hub for supplying short-term LNG to the region, and intends to expand the facility to 9 Mtpa. Terminal operators plan to break bulk LNG shipments, offering smaller quantities to regional buyers with limited import capacity. However, it will take time before a credible Asian hub price index develops as it has been observed in Europe. There are a number of prerequisites to fulfil, such as putting in place third-party access to infrastructure, liberalising wholesale gas prices and possibly the power sector (an important and growing user of natural gas in Asia), and having an arms-length relationship with the government. This also requires sufficient flexible LNG available on global gas markets¹⁶³. While Singapore may become the first regional hub in the region, other candidates may emerge in the coming years, in particular China, which is, by far, the largest growth area for new LNG supplies. China also offers the necessary conditions to create a liquid trading hub, with diversified sources of supply, including domestic production, pipeline gas and several LNG receiving terminals. The strategy of Chinese traders in other key commodities (coal, iron ore) also demonstrates a preference for spot/short term deals based on market conditions, a trend that may spread to natural gas as the Chinese gas market grows. For the time being, China's National Development and Reform Commission (NDRC) has told its LNG buyers not to pay above 14% of crude oil for long-term supply, and to go for hybrid agreements where possible.

But high costs of some new greenfield LNG projects

It is very likely that the price of new LNG supplies, at least for Australian projects, will be high. **LNG costs have increased dramatically** since the last wave of LNG projects. Historically LNG projects were characterised by decreasing unit costs thanks to economies of scale as projects became bigger and bigger and technology matured. However, the current wave of new projects is at the opposite characterised by increasing costs. LNG project costs have quadrupled from a low point of US\$300/tpa in 2000 to an average of US\$1200/tpa in 2013, which is twice higher than the rate of cost increase of other upstream oil and gas facilities during that period¹⁶⁴. A report by the Oxford Institute for Energy

¹⁶³ IEA (2013), World Energy Outlook and Medium-Term Gas Market Report, IEA/OCDE, Paris, 2013

¹⁶⁴ Oxford Institute for Energy Studies (OIES) (2014), LNG plant cost escalation, Brian Songhurst, OIES Paper N° 83, February 2014

Studies (OIES)¹⁶⁵, analysing LNG plant cost escalation, shows that the cost of projects currently under construction differ largely from high-cost projects, mostly all Australian projects and Papua New Guinea's LNG project, to other projects (US Sabine Pass, Malaysia 9 and Indonesia). For some of the current Australian liquefaction projects, construction and engineering costs are as high as 50-60% of total project costs, which is considerably higher than the 30% share typically incurred by projects elsewhere. Projects based on CBM (coal bed methane) also present higher costs compared with projects based on conventional gas, due to the need to collect and transport CBM. OIES concludes that the very high cost of the current Australian projects is unique to that location and driven by a strengthening Australian dollar against the US dollar, the very high construction costs and the remote locations, far from any major infrastructure. The high Australian costs are not reflected in the plants under construction in the US, Malaysia and Indonesia. For these projects, the cost increase over the 2005-2012 period of approximately 100% is similar to those experienced in the upstream oil and gas industry generally and not the 200% experienced for the Australian projects.

OIES also highlights the **difference in costs between brownfield and greenfield projects**. A brownfield base liquefaction project may be 50% of the cost of a comparable greenfield project. Most liquefaction projects in the US that have so far been granted authorisation from the DOE are brownfield developments of regasification facilities with existing shipping and storage infrastructure, resulting in relatively lower costs and shorter construction times compared to proposed greenfield facilities and the Australian projects. Most of the projects that are now waiting for a non-FTA export authorisation are greenfield projects. This is the case of the latest project approved by the DOE (Jordan Cove Energy) which is a greenfield project based on the northwest coast, so benefitting from cheaper transportation costs to Asia.

This means, that although on average the cost of projects currently under construction, is higher than previous LNG projects, a large part of the forthcoming projects (all brownfield US projects in particular) will present **a competitive edge** over other LNG projects, enabling them to capture a higher share of the market. For importing countries tied to long-term contracts with US LNG suppliers, this may be an opportunity to import cheaper supplies.

Oil linkage still dominates, with lower slopes

The move to new indexation mechanisms for LNG supplies is clear. However, more than 80% of the LNG from the 13 projects currently under construction has already been **contracted on a long-term basis** and (with the exception of Sabine Pass) all this gas has been sold under contracts **with oil indexation**¹⁶⁶. So far, traditional LNG suppliers have stuck to the oil-indexation principle, but the price of new contracts is lower than existing supplies.

Despite growing competition, Qatar, the largest LNG exporter, has continued to sell LNG to Asia on oil-linked pricing. Qatar used to have substantial volumes of so-called "flexible LNG" with no long-term SPAs that were mainly directed to spot markets. This flexibility has been decreasing since 2012. In 2012, Qatar concluded five new long-term oil-linked SPAs with three Japanese power companies, as well as with Kogas and PTT. In 2013, Qatargas signed additional contracts with European buyers. The contracts signed in December 2013 with Centrica, Petronas UK and E.ON are based on gas market prices but are

¹⁶⁵ OIES (2014), *ibid.*

¹⁶⁶ IEA (2013), *Medium-Term Gas Market Report*, IEA/OCDE, Paris, 2013

fully divertible SPAs allowing Qatargas to meet the needs for LNG in Europe, while retaining the ability for Qatargas to respond to demand signals from other regions, such as Asia, by diverting LNG¹⁶⁷.

Due to the high costs of their projects, Australian LNG producers have refrained from moving away from oil-indexation for their LNG supplies. However, as competition between LNG suppliers develop, Australian sellers have agreed to include clauses that protect buyers from oil price spikes. Australian LNG contracts have a slope of 13 to 15% to the Japanese Crude Cocktail (JCC).

The latest deals signed by Novatek-operated Yamal LNG project and Chinese and Spanish buyers in October 2013 provide further evidence of downward price pressure. Yamal has sold 3 Mtpa to Chinese CNPC at an estimated slope of 12.2% plus a high fixed premium. Spain's Gas Natural Fenosa has got dual-pricing for its 2.5 Mtpa, linking supply to prices at the UK's NBP gas hub and Brent crude oil at a 12% slope.

The IEA has examined a **Gas Price Convergence Case**¹⁶⁸ in which convergence between different regional gas prices is more rapid than in the New Policies Scenario, underpinned by the assumption of higher LNG volumes from North America, faster changes to gas markets and pricing mechanisms in the Asia-Pacific region, and an easing of costs for liquefaction and LNG shipping. In this case, the IEA assumes that a global price signal emerges based on HH price, which becomes a reference point for global pricing that is transmitted to the various regional gas markets via LNG trade. Convergence in prices is assumed to be largely complete by the mid-2020s (although it takes longer to complete fully in the case of prices in the Asia-Pacific region). Because of higher levels of LNG exports from the United States, the HH price is higher than it is in the New Policies Scenario, but LNG import prices are lower in Europe and in the Asia-Pacific region. The average price of gas imported to Europe falls to US\$11/MBtu in the mid-2020s (real term, 2012 US\$), less US\$1/MBtu compared with the New Policies Scenario, while the Japanese import price falls to around US\$12/MBtu over the same timeframe (compared with US\$14.2/MBtu in the New Policies Scenario), remaining around this level before edging slightly higher after 2030. Due to the cost of liquefaction and that of transportation to different regions, even in a fully converged world of gas prices, there are still substantial differences in price between the HH price and the respective import prices in Europe and Japan. The differential between the US price and the European import price narrows to US\$4.5/MBtu, with an extra US\$1/MBtu to Asia-Pacific reflecting additional transport costs.

2.5. A NEW PARTNERSHIP FRAMEWORK FOR GAS PRICING INTO THE EU POWER SECTOR?

All in all, there are downward pressures on future European prices, coming from indexation on gas hubs, the wave of new supplies (pipeline and above all LNG) and potential shale gas production.

At short term, however, **despite the move to gas hub pricing in Europe, the influence of oil prices will still dominate for several years**. Firstly, despite the declining share of European supplies tied to oil prices, long-term contracts that make most European pipeline imports, some of them running up to 2030, are still 50% linked to oil. In the coming years, marginal supplies needed to cover an increase in European gas demand (or decline in EU production) will be determined by supplies which either are linked to oil (pipeline gas from Russia) or have to compete with Asia (and Latin America) where LNG prices are still linked to oil prices and much higher than European prices¹⁶⁹. Despite its high cost, LNG

¹⁶⁷ Bloomberg, Qatar to Boost Europe LNG Sales as Gas Trades at 7-Year High, 23 December 2013.

¹⁶⁸ IEA (2013), WEO 2013

¹⁶⁹ See Timera (2013), Gas indexation in Europe – a tipping point?, Timera blog, April 2013

can nevertheless help diversify sources of supply and in some cases reduce the import costs. This is particularly the case in central Europe where regasification terminals are under construction or planned (Poland, Lithuania, Bulgaria, Croatia, Estonia and Latvia). For most of these countries, one of the goals is clearly to reduce dependence vis-à-vis existing suppliers.

At medium, long-term, in addition to new supplies from the Caspian region, East Africa, the Mediterranean, possible production of shale gas and LNG exports from the US based on HH prices may add **competitive pressure** and put a cap on European prices, although it is unlikely that this translates into large reductions in prices.

For current gas suppliers to Europe, **LNG will pose a competitive challenge**, as was the case in 2008-2010 with the sharp increase in liquefaction capacity in Qatar. One way to relieve this competitive pressure is increasing the consumption of gas in new outlets (the transportation sector in particular and new LNG outlets) but also in the power generation, which, despite the recent current sharp decline, offers the biggest potential for increasing EU gas demand. The low price of coal relative to gas prices undermines this strategy if one only considers the future evolution of gas and coal prices (the outcome could be different if the EU ETS finally sends a strong price signal, see Chapter 4). The result can be quite different if **the gas supplier himself engages in the production of electricity**, obviously enjoying its much cheaper cost of supply. The current strategy of Gazprom in Europe seems to follow this logic. The company has signed a provisional agreement for the purchase of the 405-MW Marcinelle CCGT plant in Belgium and is among the companies interested in the acquisition of two CCGTs in France (Pont-sur-Sambre and Toul, with a total capacity of 842 MW) that Austrian utility Verbund put up for sale in December 2013. Vertical integration of European energy utilities deserves the same logic. This strategy can be seen from both sides, suppliers investing in the power sector to secure gas demand, and buyers moving upstream to secure part of their demand with their own resources.

As recognised in the study on ST-LT markets in gas¹⁷⁰, **“traded electricity markets are incompatible with long-term oil-indexed contracts in power generation**. In general, power producers in the EU seem to prefer spot markets and short-term trading enabling to be able to flexibly procure the fuels required and (temporarily) stop generating or switch between fuels”. Although the authors conclude that the spread of liquid gas markets in Europe should be a positive driver for the development of new CCGT plants, the recent experience in the UK, where a liquid gas market does exist, shows that this is not as simple. If liquid markets are a condition for the development of the use of natural gas in the power sector, the main driver remains the relative price of the commodities and the price of CO₂.

The report states that “several power producers suggested that market parties should not limit themselves to oil-based versus hub-based pricing, but be more innovative. The “market parties suggest **linking the gas price with the determinant of gas demand by the power sector**: a basket of coal, CO₂, electricity prices, GDP and inflation in contracts with a duration of 8 to 15 years.” The authors state that such a linkage could provide stable and growing gas volumes in this segment. But they acknowledge that such a linkage may lead to differences between the gas prices for power compared to other gas using segments. They also state that it is expected that these types of contracts will be mainly structured by vertical integration and/or tolling agreements.

While the indexation on the proposed baskets of indicators would perfectly fit the needs of power utilities, the acceptance by gas suppliers may be difficult to get. However, a new deal signed by Statoil

¹⁷⁰ DVN Kema (2013), Study on ST-LT markets in gas, DVN Kema in collaboration with COWI Belgium, Report for the European Commission, DG ENER, 31 August 2013

follows this logic. In 2013, Statoil and German's Stadtwerke Düsseldorf (SWD) signed a 15-year arrangement for the supply of natural gas to SWD's upcoming 600-MW CCGT in Lausward/Düsseldorf, Germany.

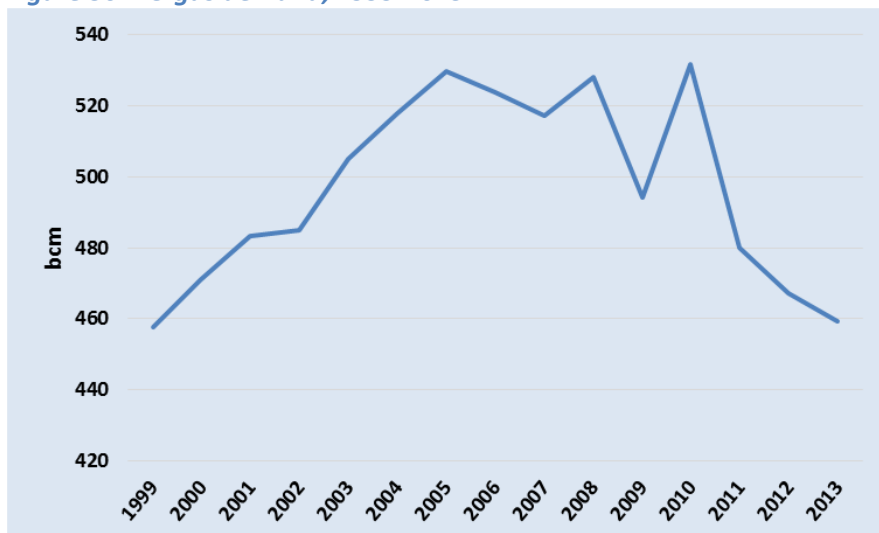
According to the Statoil's press release, "the agreement builds on the liberalising gas, power and emissions markets and the available market price indices to enable risk and reward sharing between parties. It represents a new type of partnership in the German gas-to-power market". While the detailed indexation of this contract is not published, it may include part or all the indices determinant for gas demand by the power sector in Germany (gas, coal, CO₂ and electricity prices). **This type of contract is an important step in Europe for increasing the share of gas in the power sector and stopping demand destruction in the segment.** As Statoil stated "Without highly efficient and flexible gas plants, the German *Energiewende* will not be successful. The contract illustrates Statoil's willingness to develop and enter into new commercial concepts in the gas-to-power segment. And – importantly for Statoil – this innovative deal creates value for our company." SDW also stated the importance of this innovative deal which "gives a clear positive signal towards the gas-to-power market. [...] This agreement materialises the partnership spirit between security of supply and security of demand with fully aligned interests on the long term."

ANNEX 2: EU GAS SUPPLY AND DEMAND TRENDS

Demand: the lost decade

EU27 gas consumption has decreased for the third consecutive year and totalled 459 bcm in 2013 (preliminary data). Total demand was down 1.7% in 2013, following a 9.7% and 2.7% decline in 2011 and 2012 respectively. The fall since 2010 has erased the growth registered before the global financial crisis. With an overall decline of 73 bcm since 2010, EU demand in 2013 is now at its 1999 level.

Figure 50: EU gas demand, 1999-2013

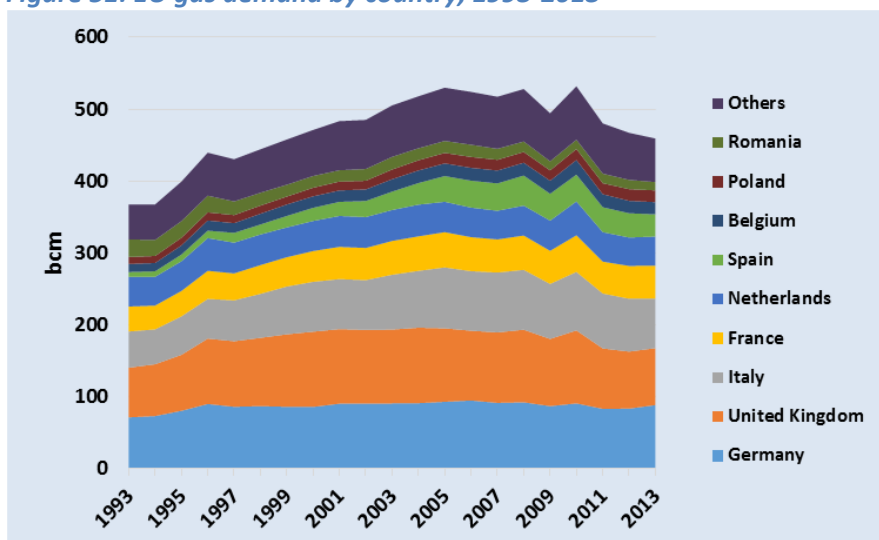


Demand after stock changes

Source: EUROSTAT, EUROGAS, 2013 preliminary

The decrease since 2010 has been particularly pronounced in the UK (-22 bcm), Italy (-13 bcm), the Netherlands (- 7 bcm), Spain (- 6 bcm) and France (- 5 bcm).

Figure 51: EU gas demand by country, 1993-2013

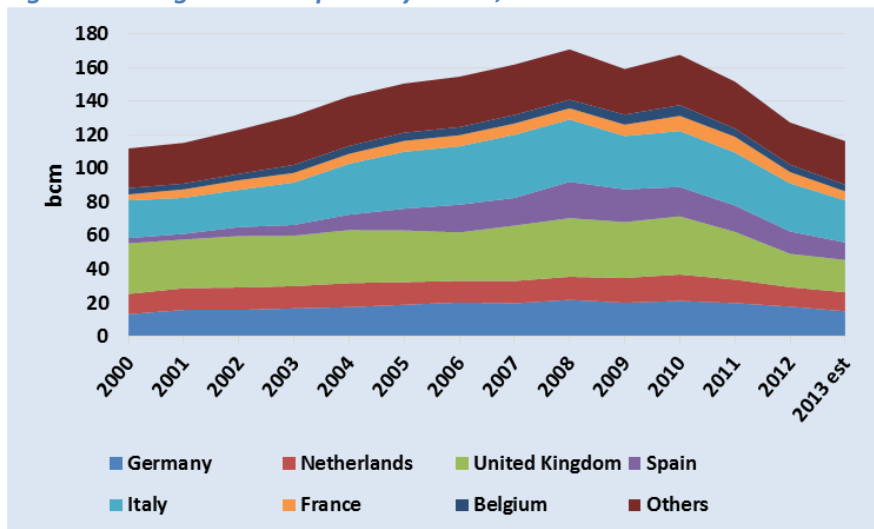


Source: EUROSTAT, EUROGAS (2013: preliminary data)

Despite this decline, natural gas plays an important role in the EU energy mix and made up 23.3% of primary energy consumption in 2012. Natural gas has diversified outlets compared with coal, which is mainly destined to the power sector. Natural gas is used in power generation (27.2%), district heating (2.2%), households (27.6%), industry (21%), the service sector (11.6%) and other sectors (10.4%).

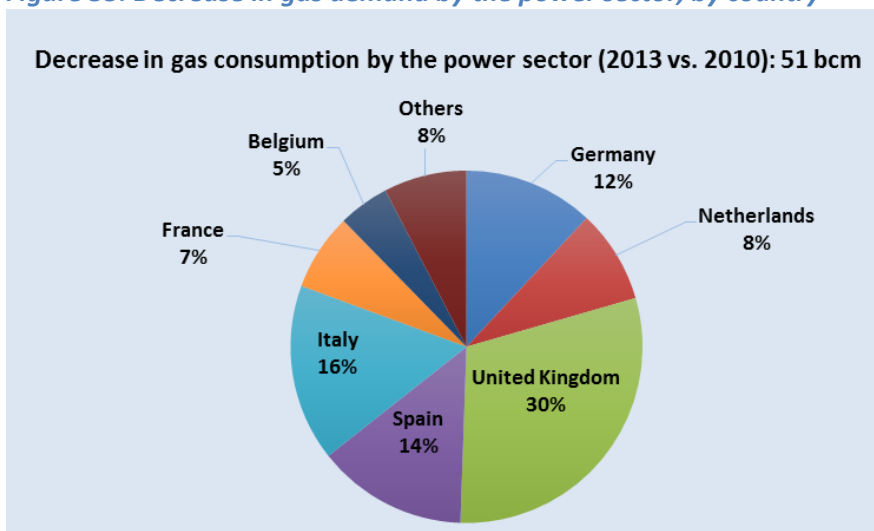
Since the beginning of 2011, gas demand in the power sector has been under pressure due to rising electricity production from RES and increased competition from coal. The decrease in electricity demand due to weak EU economic growth has also driven gas demand down. Gas demand by the power sector has declined by 30% (51 bcm) from 2010 to 2013. The sector consumed 116 bcm only in 2013. In the residential and services sector, the colder weather experienced across the EU in 2013 resulted in a higher demand for heating compared with 2012. The longer-lasting cold spell in spring was, however, counterbalanced by less severe winter temperatures during the fourth quarter of 2013. The 0.5% decrease in EU average industrial production in 2013 compared with 2012 again affected gas demand from industry¹⁷¹.

Figure 52: EU gas consumption by sector, 1993-2013



Source: EUROSTAT, 2013: own estimates based on major gas markets

Figure 53: Decrease in gas demand by the power sector, by country



Source: EUROSTAT, 2013: own estimates based on major gas markets

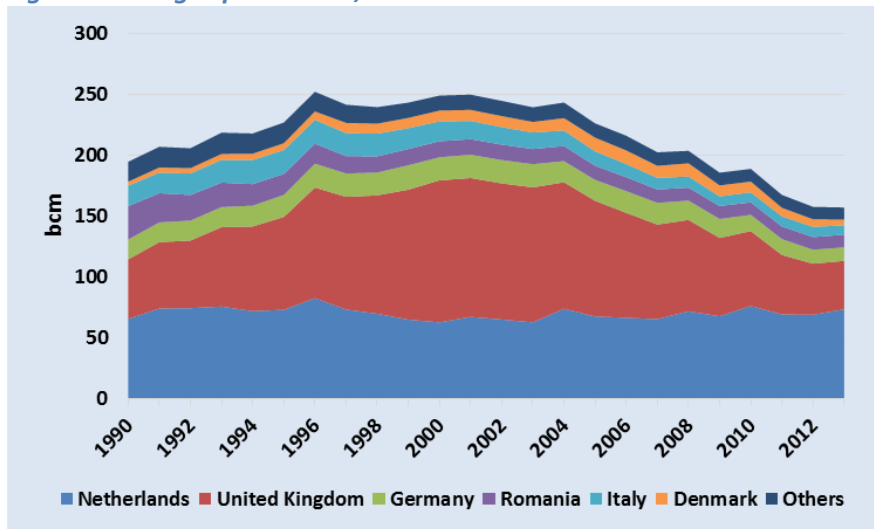
Major changes in gas supplies

On the supply side, the past three years were also marked by major changes in European supplies. While EU domestic production has continued its decline (160 bcm in 2013), imports flows from external

¹⁷¹ EUROGAS (2014), Drop in EU gas demand emphasizes need for swift change, press release, March 2014.

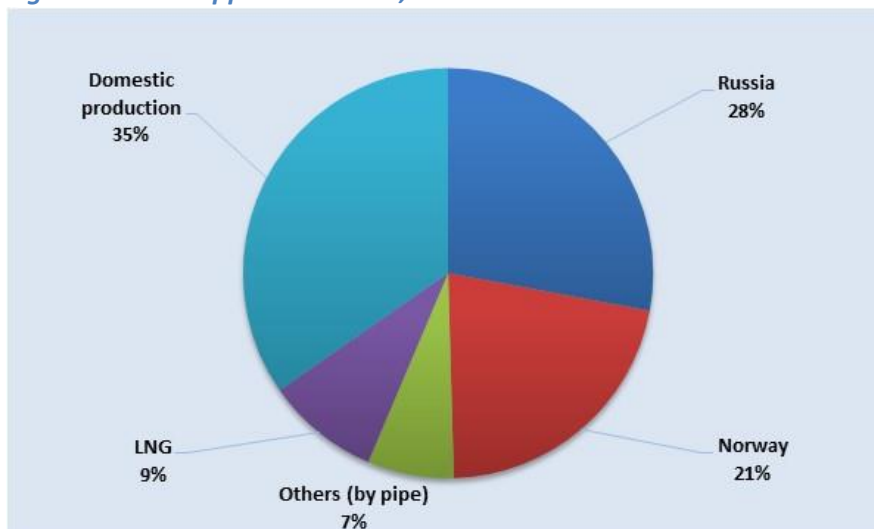
suppliers changed dramatically, illustrating both competition between suppliers on the EU market and globalisation of the LNG market.

Figure 54: EU gas production, 1993-2013



Source: CEDIGAZ

Figure 55: Gas supplies in the EU, 2013



Source: CEDIGAZ

Russian gas deliveries to the EU increased by 19% in 2013. This increase in Russian gas imports was driven by two key forces: the relative lower prices of Russian gas, which in 2013, converged towards hub prices, thanks to contract renegotiations and price reductions granted by Gazprom to most of its European customers. The second driving force was lower LNG imports. The decline in demand for LNG in Europe was motivated by weak gas consumption and high LNG prices. LNG producers and traders have been focusing on the growing Asia LNG markets and some LNG cargoes designated for Europe have been reloaded and redirected to Asia and Latin America. This trade is emerging as an important additional supply source for Asia and Latin America. In 2013, cargoes destined to Europe were either directly sold to Asia (and Latin America) or reloaded in regasification terminals in Europe and redirected to other markets when destination clauses prevented direct sales to other markets (78 LNG cargoes,

or 5.4 bcm, were reloaded in 2013¹⁷²). Thus net LNG imports fell 27% to 42 bcm in 2013 (EU only), their second year of sharp decline (-27% in 2012). Norwegian imports were also lower (-5%) after the record level reached in 2012, mainly due to foreseen maintenance at gas infrastructure. Other imports by pipeline from Algeria and Libya fell due to supply constraints and weak demand in southern Europe.

Future European gas supply and demand trend

European demand trend remains weak in the short/medium term. The IEA (MTGMR 2013¹⁷³) does not see a recovery of European gas demand in short/medium term and has revised downward its five-year forecasts (2013-2018) compared with the ones done in 2012. OECD European gas demand¹⁷⁴ is expected to reach 525 bcm by 2018 (versus 561 bcm by 2017 in the MTGMR 2012). In the power generation sector, renewable generation exceeds limited demand growth by 13% over 2012-18, which leaves less room for combustible fuels. All in all, after bottoming out in 2013, European gas demand embarks on a slow journey back to pre-crisis levels which will not be completed within the forecast period. At longer term, the IEA (WEO2013, New Policies Scenario) expects EU gas demand to reach 494 bcm in 2020 and only exceeds its pre-crisis level by 2030 (537 bcm) and reaches 554 bcm in 2035.

On the supply side, EU domestic production is expected to continue declining. The decline in UK production of conventional gas has been particularly steep, although this is now levelling off into an extended late-life production tail. The giant Groningen field in the Netherlands is expected to reach a plateau by 2016. Potential shale gas production (see Section 2.3) may only limit the rate of decline of EU conventional gas production. The IEA expects EU natural gas production to reach 104 bcm in 2035 (WEO2013, New Policies Scenario) and is relatively cautious about the level of shale gas production in the EU. As a corollary, the EU's import needs will rise to around 80% of total supplies in the long term. Compared with the 302 bcm of net imports in 2013 (a level which takes into account 78 re-exported LNG cargoes for an amount of 5.4 bcm), EU annual demand for additional gas imports may reach 57 bcm by 2020 and surpass 148 bcm by 2035. Europe is well placed to secure this supply from a variety of sources, including traditional suppliers such as Norway (with a portfolio of large projects in the Arctic Barents Sea, it is able to sustain its production at above 100 bcm/year throughout the 2012-2035 WEO projection period), Russia and Algeria, as well as from the international LNG market.

In the context of the Ukraine crisis and in view of the current political desire to limit energy dependency from Russia, it may be expected that the share of Russian pipeline gas in European consumption remains roughly stable in the short/medium term, before growing diversification in the form of LNG and new pipeline sources is available. The crisis has cast doubts on the realisation of the South Stream pipeline, which would cross the Black Sea to reach Bulgaria and other EU members beyond and export 63 bcm/year of Russian gas, with first volumes expected in 2015. While the new pipeline does not fit with current EU policy, it increases security of supply in south-eastern Europe as it removes the region's vulnerability to Ukrainian problems and interruptions. As such, the project has attracted a lot of attention since the beginning of the Ukraine crisis with some EU leaders wanting to block the project while some Member States seeing it as a solution to supply disruptions via Ukraine.

There are also newcomers looking to supply Europe by pipeline, notably Azerbaijan and, potentially, also Iraq, along the so-called "southern corridor" through Turkey and the rest of southeast Europe. In December 2013, the Shah Deniz consortium took the final investment for the Stage 2 development of

¹⁷² GIIGNL (2014), The LNG industry in 2013, April 2014

¹⁷³ IEA (2013), Medium-Term Gas Market Report 2013 (MTGMR 2013), IEA/OCDE, Paris, 2013.

¹⁷⁴ OECD Europe. The MTGMR does not give a breakdown for the EU (Turkey consumed 43 bcm in 2013)

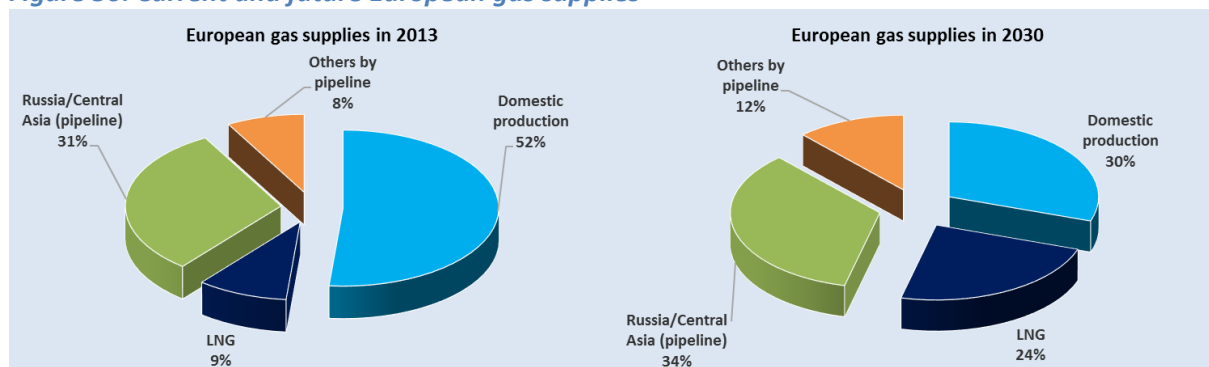
the Shah Deniz gas field in the Caspian Sea, offshore Azerbaijan. This decision triggers plans to expand the South Caucasus Pipeline through Azerbaijan and Georgia, to construct the Trans Anatolian Gas Pipeline (TANAP) across Turkey and to construct the Trans Adriatic Pipeline (TAP) across Greece, Albania and into Italy. Together these projects, as well as gas transmission infrastructure to Bulgaria, will create a new Southern Gas Corridor to Europe (16 bcm/year). First gas is targeted for late 2018, with sales to Georgia and Turkey; first deliveries to Europe would follow approximately a year later.

Iraq is another candidate to export gas to Europe, and could do so from the “southern corridor”. Iraq currently produces relatively small quantities of gas, most of which is kept for its domestic market, and flares off a large amount of associated gas from its vast oil fields. But the country is looking to ramp up exports of natural gas to fund reconstruction of its conflict-battered economy and infrastructure.

Gas from the recent discoveries in the Levante region (Israel, Lebanon and Cyprus) may also reach the EU by the end of the decade. The gas discoveries offshore Israel are huge, while the other countries so far have limited reserves (in the case of Cyprus, reserves of the Aphrodite field are estimated at about 100 bcm). Several export schemes are being developed in the region, envisaging both pipelines and LNG options. At the time being, however, there is no clear assessment of the volumes to be exported, or the destination of these exports.

LNG from various sources, including North America, Africa (east and west), the Middle East and other regions is viewed as the most important source of diversification of future supplies to the EU. Although LNG imports sharply declined in the past two years, they are expected to reach 140 bcm by 2030¹⁷⁵ (CEDIGAZ, April 2014). The capacity of regasification terminals is already much higher than the expected level of imports in 2030 (199 bcm/year at end 2013) and several additional terminals are under construction or planned in Europe. The development of a new wave of LNG supplies will facilitate this development (see above). At short-term, however, the market is expected to remain tight at least until 2016 as LNG is diverted to Asia and Latin America.

Figure 56: Current and future European gas supplies



Note: Europe35

Source: CEDIGAZ, January 2014

Box 14: The Ukraine crisis and dependency on Russian gas

The Ukraine crisis and the annexation of Crimea by Russia have triggered EU willingness to reduce its dependence on Russian energy supplies, and in particular gas supplies. The European Council has called on the European Commission “to present by June 2014 a comprehensive plan for the reduction of EU energy dependence”. This plan “should reflect the fact that the EU needs to accelerate further diversification of its energy supply, increase its bargaining power and energy efficiency, continue to

¹⁷⁵ Includes LNG imports by Turkey

develop renewable and other indigenous energy sources and coordinate the development of the infrastructure to support this diversification in a sustainable manner, including through the development of interconnections (...) In addition, further action should be taken to support the development of the Southern Corridor, including further spur routes through Eastern Europe, to examine ways to facilitate natural gas exports from North America to the EU and consider how this may best be reflected in TTIP, and increase the transparency of Intergovernmental Agreements in the field of energy.”

Russian supplies accounted for 28% of EU demand in 2013. Due to decrease in Norwegian, Algerian and LNG supplies in 2013, Russian exports accounted for 43% of EU external gas supplies (35% in 2012). At short term, a reduction of Russian supplies would require an increase in LNG supplies or in Norwegian imports as other supplies are not readily available, in particular new LNG supplies from the US will not be available before 2015/16 (and by that time supply will be limited). Norwegian production has some flexibility, estimated at 20 bcm/year. The price of Norwegian gas is more and more indexed to hub prices, so the additional cost would be whatever the market would ask for. In the case of LNG, attracting supplies above annual contractual deliveries would require competing with Asia, where the price is higher. Furthermore the LNG market is very tight and competition with Asia would mean even higher prices. Therefore a reduction in EU gas dependence from Russia seems very unlikely at short term, beyond any increase in Norwegian supplies.

At medium/longer term, a reduction in Russian gas deliveries can only be considered in the respect of long term contracts between Gazprom and European buyers as contracts have take-or-pay clauses. As most contracts have long-term duration – some last until 2030/35 –, the reduction of the gas dependency from Russia mainly concerns the renewal of long-term contracts that are going to expire in the 2020s. Some central European countries (Poland for instance) have contracts with Gazprom ending at the beginning of the 2020s and are looking at alternative supplies (LNG and domestic shale gas).

The dependency from Russian gas differs largely from one country to another. Central and northern European countries have usually a higher dependence on Russian supplies than western and southern European countries, which have diversified their gas supplies for years. Bulgaria, for instance, is fully dependent from Russia gas supplies, while Germany received 39% of its gas supplies from Russia in 2013.

In the future, Europe will require additional supplies to compensate for the decrease in domestic production and cover the increase in gas demand. How this new demand will be covered is not fixed yet. However, even before the Ukraine crisis, a higher share of LNG was foreseen. This is in line with the high regasification capacity available in Europe which theoretically would allow the imports of 199 bcmpa. Numerous LNG export projects are being developed by new sellers (US, East and West Africa) that will offer the possibility to further diversify EU gas supplies.

3. COAL PRICES

AMID CURRENT OVERSUPPLY

In contrast with natural gas, the coal market is a global one. Prices are similar on the Pacific basin and the Atlantic basin. Due to its size on the international coal market, China has become a price setter for steam coal. A change in climate and energy policy in China is therefore set to create waves in the global and European coal market. This chapter focuses on steam coal trade and prices in Europe. Due to the importance of global (and Chinese) trends on European import steam coal prices, it first reviews trends in global supply and demand, limiting the review to key trends relevant for prices in Europe. Then, it reviews the evolution of global steam coal trade and prices. An Annex gives detailed information on coal demand and supply in the EU.

3.1. GLOBAL COAL SUPPLY AND DEMAND

Global coal reserves are enough to fuel more than 100 years of current production

Coal is an abundant energy source worldwide and has the largest reserves and resources of all fossil fuels¹⁷⁶. Global coal reserves amounted to 1,038 billion tonnes (Gt) at the end of 2011¹⁷⁷, of which 755 Gt of hard coal and 283 Gt of lignite (see Box 16). The ratio of Reserves on Production (R/P) amounts to 114 years for hard coal and 264 years for lignite. Reserves and resources of hard coal and lignite are adequate to cover the foreseeable demand for many decades from a geological point of view. Global resources are huge (17,119 Gt for hard coal, 4,152 Gt for lignite). Coal reserves are also well distributed: coal deposits are found in all continents.

Box 15: Coal: units and conversions

Two units are commonly used in the coal scene: **tonne (t)** and **tonne coal equivalent (tce)**. When coal is measured in volume (tonne), the calorific value of the coal in question must be given as it differs largely from one type of coal to another.

Steam coal traded on the international market is usually expressed in tonne with a calorific value of 6000 kcal/kg. Low-grade coal refers to quality with a calorific value of 4500 kcal/kg (or below).

In coal statistics, coal volumes in tonnes are converted to tonnes of coal equivalent (tce). The conversion is done by multiplying the calorific value of the coal in question by its volume, measured in physical units (tonnes).

One tce has an energy content of 29.3 Gigajoules (GJ) or 7000 kcal and corresponds to 0.7 tonnes of oil equivalent (toe).

¹⁷⁶ Definition of Reserves and Resources

Reserves are energy resources which have been accurately recorded and which can be economically extracted using the current technical possibilities. Synonymously used expressions are recoverable (coal) as well as proved recoverable amounts/resources. The definition mentioned above means that the amount of reserves depends on the level of knowledge about the deposit, on commodity prices and on the present state of the technology. Resources are those amounts of an energy resource, which have been geologically proven, but which cannot be extracted economically at that time and the amounts, which have not been proven, but which can be expected for geological reasons in the areas concerned. For coal these are, generally, in-situ amounts, i.e. the total amounts independent of their recoverability.

¹⁷⁷ BGR (2013), *Annual Report Reserves, Resources and Availability of Energy Resources 2012*, DERA Rohstoffinformationen, Hannover, February 2013. www.bgr.bund.de/

Table 16: Global coal reserves at end 2011, by region and major country

Reserves					
		Hard coal (Gt)	% of world total	Lignite (Gt)	% of world total
Europe		20.05	2.7%	69.35	24.5%
of which	Germany	0.05	0.0%	40.50	14.3%
	Poland	14.71	1.9%	4.51	1.6%
CIS		121.31	16.1%	93.52	33.1%
of which	Russia	68.94	9.1%	91.18	32.2%
	Ukraine	32.04	4.2%	2.34	0.8%
	Kazakhstan	17.24	2.3%	n.s.	-
Africa		36.24	4.8%	0.07	0.0%
of which	South Africa	33.90	4.5%	-	-
Middle East		1.20	0.2%	-	-
North America		230.70	30.6%	32.96	11.6%
of which	United States	225.01	29.8%	30.67	10.8%
	Canada	4.35	0.6%	2.24	0.8%
Latin America		8.94	1.2%	5.07	1.8%
of which	Colombia	4.88	0.6%	-	-
	Brazil	1.55	0.2%	5.05	1.8%
Asia		336.15	44.5%	81.99	29.0%
of which	China	180.60	23.9%	11.00	3.9%
	Australia	57.54	7.6%	44.22	15.6%
	Indonesia	13.51	1.8%	9.00	3.2%
	India	77.20	10.2%	4.85	1.7%
WORLD		754.60	100.0%	282.96	100.0%

Source: BGR

Box 16: Different types of coal

Coal is a complex matter, and not a uniform one. It is divided into two categories: hard coal and lignite. Total coal designates hard coal and lignite.

Coal used by power utilities includes steam coal (classified in three ranks: anthracite, bituminous and sub-bituminous coal), as well as lignite.

HARD COAL

Hard coal is subdivided into two types of coal:

Steam (or thermal) coal, used primarily for power generation and in industrial applications; and

Metallurgical coal, or coking coal, used by the iron and steel industry as a feedstock in the production of coke which is used in traditional steel production (via the BOF process, basic oxygen furnace) as a fuel and reducing agent to smelt iron ore in a blast furnace.

Hard coal has an energy content above 4,500 kcal/kg and a water content lower than 35%.

Usually, only hard coal is traded internationally. However, in the past few years, some low-grade coal (lignite) has been exported, mainly from Indonesia.

The physical and chemical qualities of the different coals are important factors to determine their use and price (% of volatile matters, ash, sulphur, moisture, Fixed Carbon, grinding index HGI, calorific value, and coke strength - CSR value - for coking coal)

LIGNITE or BROWN COAL

Lignite has energy content lower than 4,500 kcal/kg, and water content above 35%. Therefore it is mainly used on regional/local markets and almost exclusively for power generation.

Since 2000, world coal production has increased by 70%

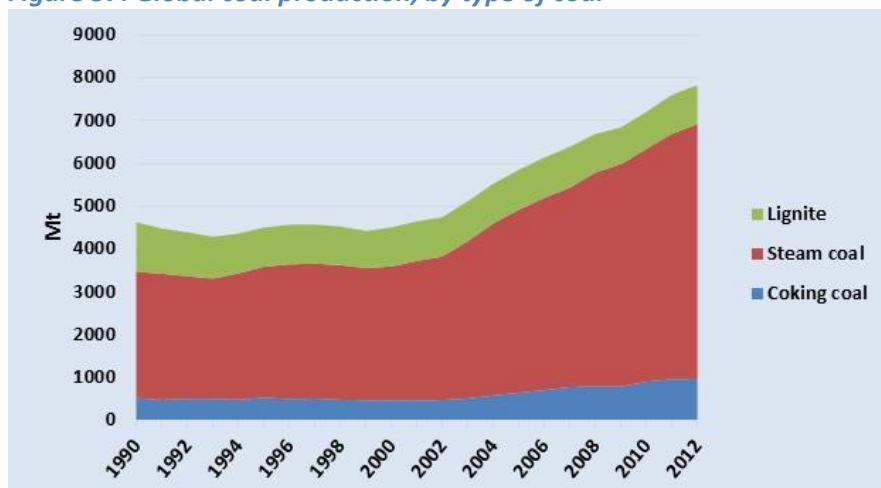
Global coal production reached 7.83 Gt in 2012 (equivalent to 5666 Mtce). This corresponds to 5942 Mt of steam coal, 984 Mt of coking coal and 904 Mt of lignite¹⁷⁸. Since 2000, total coal production has increased by around 70%, **mainly due to the surge in China's production**. China produced 3549 Mt in 2012 and accounted for around half of global coal production. Since 2000, its production has tripled. Despite the decrease in its production since 2008, the US remains the second largest producing country, with 935 Mt produced in 2012. India, the third largest producing country, produced 595 Mt in 2012. In the rest of the world, production sites are located in many countries and exploited by numerous companies, most often international or national private companies. Major producing countries, such as Australia, Indonesia, Russia, South Africa and Colombia, are also key exporting countries.

Table 17: Evolution of total coal production by major producing countries

Million tonnes		1990	2000	2010	2012	Share of global production in 2012
World		4668	4649	7210	7831	100%
Of which	China	1040	1354	3140	3549	45%
	United States	934	972	996	935	12%
	India	225	336	570	595	8%
	Australia	205	307	424	421	5%
	Indonesia	10	79	325	443	6%
	Russia	372	240	322	354	5%
	South Africa	175	224	255	259	3%
	Germany	434	205	182	197	3%
	Poland	215	163	133	144	2%
	Kazakhstan	131	77	111	126	2%
	Colombia	21	38	74	89	1%
	Ukraine	153	62	58	72	1%
	Canada	68	69	68	67	1%
	Greece	52	64	57	62	1%
	Czech Republic	101	65	55	55	1%

Source: IEA

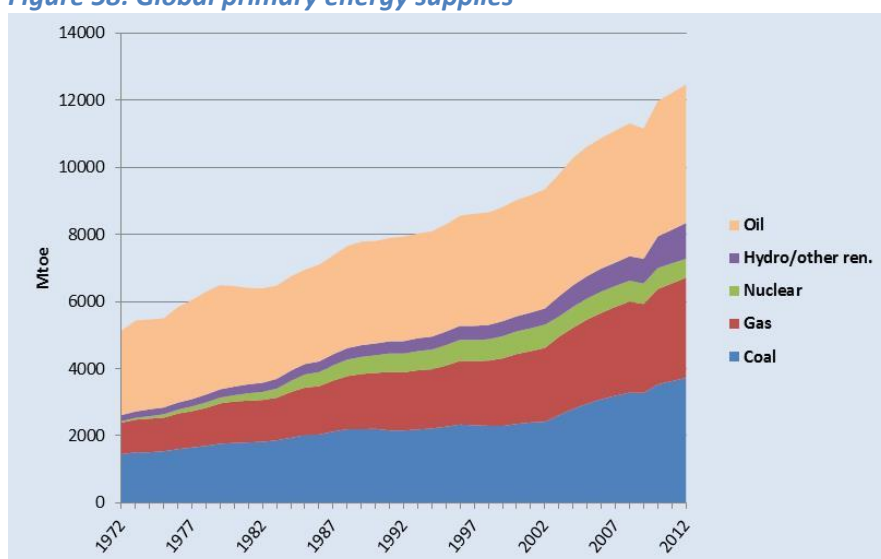
¹⁷⁸ IEA (2013), Coal Information, IEA/OECD, Paris, 2013.

Figure 57: Global coal production, by type of coal

Source: IEA

Coal is a dominant fuel in the global energy mix

Coal provided 30% of global primary energy supplies in 2012¹⁷⁹ and ranked second after oil as one of the major sources of primary energy. Global coal demand never decreased during the past four decades (it only paused in 2009) and reached 3.7 Gtoe (billion tonnes oil equivalent) in 2012.

Figure 58: Global primary energy supplies

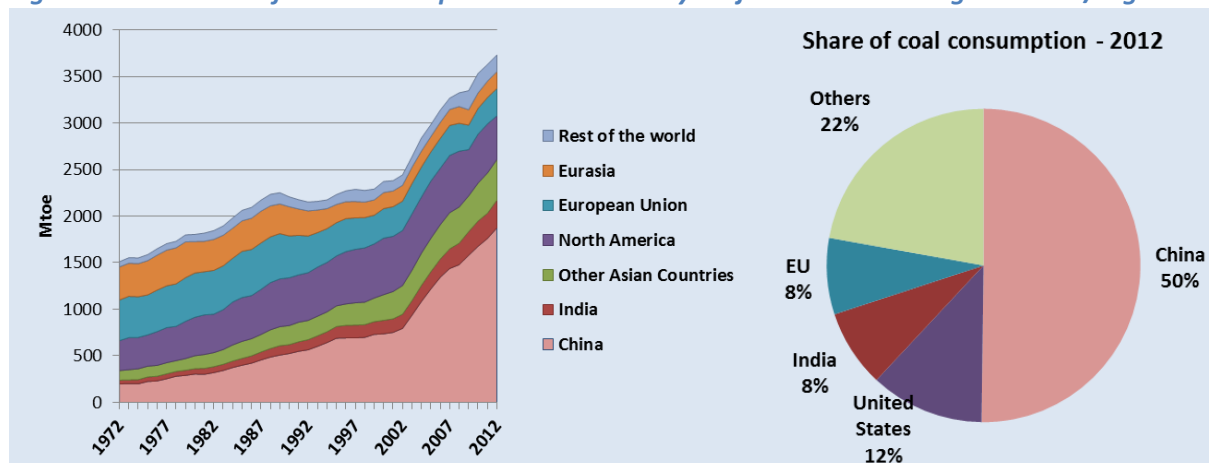
Source: BP Statistical Review, 2013

Global coal demand has increased tremendously over the past decade

Global coal demand has surged in the past 12 years, from 2.3 Gtoe in 2000 to 3.7 Gtoe in 2012. **China has been the driver of this growth, tripling its consumption over the past decade.**

¹⁷⁹ BP Statistical Review, 2013

Figure 59: Evolution of coal consumption in the world by major coal consuming countries/regions



Source: BP

Coal demand is dominated by a small number of countries/regions, although there are around 100 coal consuming countries in the world. The four largest consumers (China, the United States, India and the EU as a whole) account for 78% of total coal consumption in 2012.

Growth is concentrated in China

China has accounted for 84% of the growth in world coal consumption since 2000. Its coal consumption increased from 737 Mtoe in 2000 to 1873 Mtoe in 2012. India also played a role in the increasing global demand, but to a less extent. The country has accounted for 11% of the growth since 2000. Excluding these two countries, coal demand has only risen at an annual average rate of 0.9%. In the OECD countries, actually, coal consumption has declined since 2000 (-0.6% per year over the period), whereas non-OECD coal demand has more than doubled from 1210 Mtoe in 2000 to 2677 Mtoe in 2012 (+6.9% per year). Thus, non-OECD countries have increased their share and now account for 72% of total coal demand, against 50% in 2000.

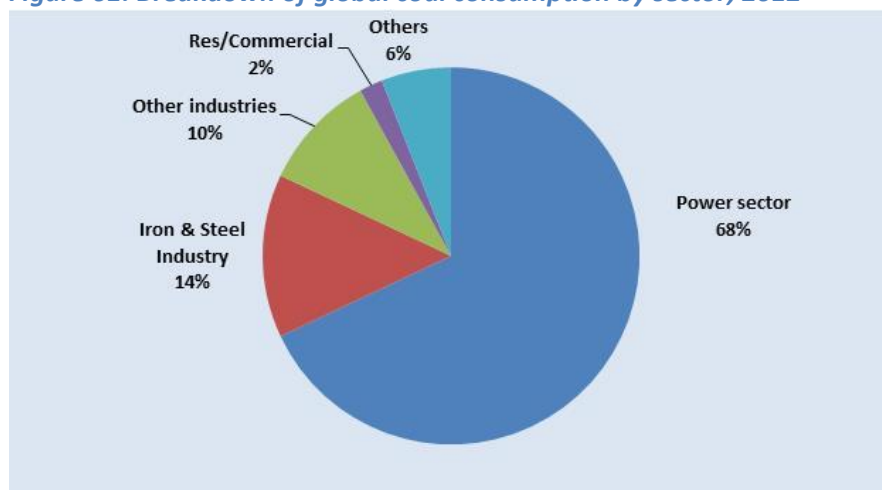
Figure 60: Annual growth in global coal demand, China vs. Rest of the World



Source: BP

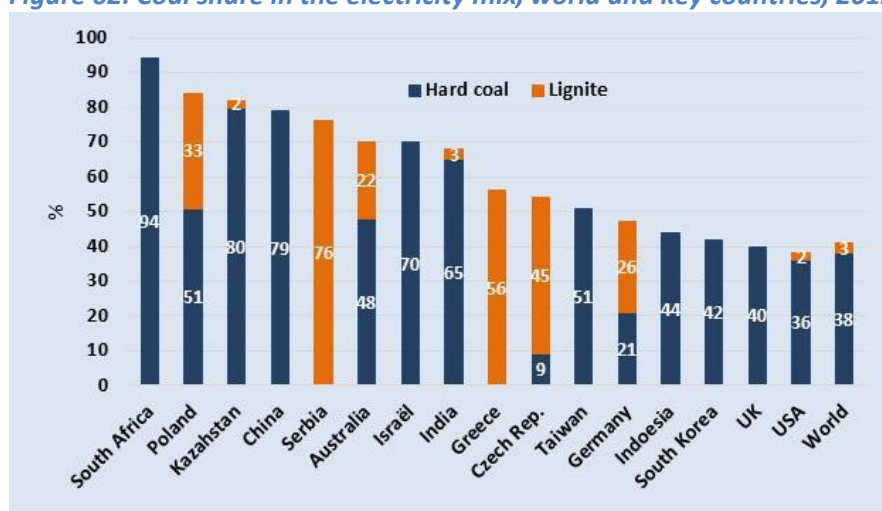
The power sector is leading the growth

Coal use is driven by the power sector which represents around **70% of world coal consumption**. The other large user is the iron and steel industry, where coal is used both as a raw material and as a fuel in the production of coke. Coal is also used by other industrial sectors, such as the cement and chemicals industries. Coal demand by residential/commercial users has almost disappeared as coal is replaced by more convenient sources of energy.

Figure 61: Breakdown of global coal consumption by sector, 2012

Source: IEA

At global level, coal is a major fuel in the power sector. In 2012, it represented **41% of total electricity generation** and this share was even higher in some coal-producing countries, such as South Africa or Poland, where coal accounted for 94% and 84% of total electricity generation respectively.

Figure 62: Coal share in the electricity mix, world and key countries, 2012

Source: EURACOAL

The key advantage of steam coal as an energy source in electricity generation is **its low cost**. Coal-fired generation benefits from significantly lower fuels costs relative to oil and natural gas-fired power plants in most markets. Moreover, coal is widely available and the infrastructure to transport and stockpile coal is relatively inexpensive when compared to LNG. These advantages outweigh the higher capital costs of coal fired plants and their lower efficiency rates compared with CCGTs. Coal environmental footprint is a key disadvantage compared with natural gas as coal combustion emits twice more CO₂ than gas. However, so far carbon costs have remained low in countries where carbon markets have been established. In Asia, where most of the growth in coal demand has occurred in the past decade, the environmental cost of burning coal was hardly taken into account. Hence, coal has been the fuel chosen in many Asian countries. Currently, there are more than 1000 coal-fired power plants under

consideration in the world, with a total installed capacity of 1400 GW¹⁸⁰. These projects are spread across 59 countries. China and India together account for 76% of the proposed new coal power capacities.

The share of coal and its evolution vary by region

The evolution of coal demand in the five major coal markets, China, the US, India, the EU and the Asian traditional coal importers (Japan, South Korea and Taiwan), has been contrasted over the past few years. While China, and India to a lesser extent, have led the growth in global coal demand, US demand has contracted since 2008. In the EU, despite its recent growth, coal demand has declined by 40% since 1990. The Asian coal buyers have increased their demand, mainly driven by Japan's needs to replace nuclear power.

China's government commitment to reduce coal share in the energy mix

China is the leader in the global coal market, accounting for 50% of the total demand for coal. Coal has fuelled the strong increase in China's economic activity and is the backbone of the economy: it accounted for 66.6% of the country's total primary energy supply in 2012 (68.4% in 2011)¹⁸¹. Its 2012 consumption reached 3.67 Gt and has more than tripled since 2000¹⁸². Chinese coal demand growth slowed, from 9.4% in 2011 to 4.7% in 2012. This is the second-lowest growth rate for China of the past ten years. Preliminary data for 2013 show that coal demand growth again slowed to 2.6%. The power sector is by far the largest coal user accounting for 54% of total coal consumption in 2011. Power demand is strongly linked with economic activity which resulted in the high growth observed over the past decade. Other large users include industrial sectors (43% of coal demand), such as the iron and steel industry, the cement and chemicals industries.

China intends to rebalance its economy towards a **more balanced and sustainable growth path**. To curb the fast growth in energy use and reform an economic structure that relies heavily on high energy-consuming industries, the Chinese government has set its energy consumption target at 4 Gtce¹⁸³ by 2015, and vowed to reduce energy use per unit of GDP by 16%.

This new policy will greatly affect future coal demand, which depends on three key factors: the evolution of economic activity, trends in energy and electricity mix and efforts to combat local pollution. The combined effect of these three factors suggests a drastic slowdown in the growth of coal demand. Economic growth is expected to decelerate to 7.3% in 2014 (IMF, October 2013) and a further slowdown is expected in the years to come. The second key factor is China's government commitment to reduce the share of coal in the energy mix and use more renewable and alternative fuels. The energy policy of China, released in October 2012 and the Energy Five-Year plan 2011-2015 (FYP) of January

¹⁸⁰ WRI (World Resources Institute), Global Coal Risk Assessment: Data Analysis and Market Research, WRI Working Paper, Washington DC, November 2012. <http://www.wri.org/publication/global-coal-risk-assessment>

¹⁸¹ National Energy Administration, 2013

¹⁸² IEA (2013), Coal Information

¹⁸³ The Chinese government publishes statistics of production and consumption of primary energy in tonnes of coal equivalent (tce). Data on production and consumption of oil, gas and coal are published in the reference units of each industry: toe for oil, m3 for natural gas and metric tonnes (t) for coal. The conversion factors used in China are based on the lower calorific value.

To convert toe in tec: 1 toe = 1.428 tce (41.87 GJ / toe)

To convert m3 in tec: 1 m3 = 1.33 kgec (38.98 GJ / 1,000 m3)

The average calorific value of a tonne of coal produced in China is about 20.5 GJ / t (it varies for each coal and, on average, tends to decrease due to the increased production of coal with low calorific value). Official data in tonnes differ from IEA data in tonnes as IEA makes some adjustments.

2013 foresee a major change in the energy mix of the country compared to previous trends. According to the FYP, China will increase the share of non-fossil fuels in primary energy consumption to 11.4% (up from 8.3% in 2010) by 2015. Nuclear, hydro, renewable energy sources and natural gas are expected to increase their share, while the **share of coal is expected to decrease to 65% by 2015**. The share of non-fossil fuels in generating capacity is expected to increase to 30% by 2015 (up from 20% in 2010). Efforts are focused on the development of hydropower, which allows for more than half of the increase in non-fossil energy consumption, and on nuclear. The installed generating capacity of wind power is expected to reach 100 GW and that of solar energy to exceed 21 GW by the end of 2015. Non-fossil energy capacity would therefore reach 451 GW, 30% of the 1,490 GW capacity installed by the end of 2015. Fossil fuel generation would still be dominated by coal. Around 300 GW of coal capacities are planned to be added by the end 2015, though coal's share in total capacity is expected to fall to 64% by 2015 from 68% in 2010.

One key element of the FYP is the intention of Chinese authorities to cap coal production and consumption at 3.9 Gt in 2015, compared with 3.1 Gt and 3.2 Gt in 2010 respectively.

Table 18: China's Energy Five-Year Plan, 2011-2015

Category	Indicators	Unit	2010	2015	Annual average growth 2010-2015 (%)	Status
Energy consumption	Primary energy consumption	billion tonnes coal equivalent (tce)	3.25	4	4.3%	expected
	Share of non fossil energy sources	%	8.6	11.4	(+2.8 points)	binding
	Electricity consumption	TWh	4200	6150	8%	expected
	Energy consumption per unit of GDP	tce per 10,000 yuan of GDP	0.81	0.68	(-16%)	binding
	Energy consumption per KWh	gce/kWh	333	323	-0.6%	expected
	Electricity losses	%	6.5	6.3	(-0.2 points)	expected
Energy capacity and production	Primary energy production	billion tce	2.97	3.66	4.3%	expected
	of which coal	billion tonnes	3.24	4.1 (a)	4.8%	expected
	oil	million toe	200	200	0%	expected
	natural gas	billion cubic meters	94.8	156.5	10.5%	expected
	non fossil energy sources	million tce	280	470	10.9%	expected
Electricity	Installed capacity	GW	970	1490	9.0%	expected
	of which coal		660	960	7.8%	expected
	hydro		220	290	5.7%	expected
	nuclear		10.82	40	29.9%	expected
	natural gas		26.42	46	16.2%	expected
	wind		31	100	26.4%	expected
	solar		0.86	21	89.5%	expected
Environment	CO2 emissions per unit of GDP				(-17%)	binding
	SOx emissions	g/kWh	2.9	1.5	-12.4%	binding
	NOx emissions	g/kWh	3.4	1.5	-15.1%	binding
Social	Electricity consumption per capita	kWh	3800	6200	10.3%	expected
	Green energy demonstration counties	Number of projects	108	200	13.1%	expected
	Access to natural gas	million inhabitants	180	250	6.8%	expected

(a) Capacity

Source: National Energy Administration, 2013

Moreover, the government is determined to combat pollution, which is becoming a major concern in large cities. Reducing emissions of SOx, NOx and small particulates is a key priority of the energy and climate policy, ahead of CO₂ emissions, although global warming is also addressed by policy makers. Carbon markets are established in major cities to check their effectiveness before extending them to the whole country. As coal mining and combustion are largely responsible for emissions of local pollutants, the government intends to curb coal use in the country. Aside from the reduced share of coal in power generation, the government deploys efforts to save energy in major industrial sectors,

such as steel, aluminium, chemicals and cement. Manufacturers must comply with new efficiency benchmarks or pay fines. Old inefficient plants are forced to close. China's priority has been to cut smog in key regions such as Beijing, Hebei and Tianjin. In 2013, Chinese authorities announced they would ban new coal-fired power plants from these three important industrial regions. Beijing has actually banned the use of coal in the city from 2015.

Furthermore, as concerns on pollution mounted in 2013, the National Energy Administration (NEA) released a plan in January 2014 aiming at capping energy consumption at 3.88 Gtce in 2014 and reducing the share of coal in primary energy consumption to less than 65% already in 2014, down from 0.7 percentage points from 2013, and a level which was foreseen to be reached only in 2015 (see Box 17).

This new policy will have a significant impact on future coal demand and the unbelievable peak coal demand in China may occur faster than expected. However, although the new policy marks a key change from past policies, coal consumption in absolute terms should continue to grow at short term, because Western China has few alternative energy sources to rely on, coal remains the cheapest fuel, and coal-to-gas chemical plants are planned. Nonetheless, this growth could be much lower than previous years' growth. There should be a move of coal consumption westwards. Western provinces are expected to increase their coal consumption while eastern provinces decrease theirs.

On the supply side, China is **consolidating** its coal industry by forming 10 coal firms with at least 100 Mt of annual production capacity each by 2015 and another 10 companies with about 50 Mt a year of capacity. These 20 companies will be responsible for 60% of the country's output of coal by 2015. China promotes mergers and acquisitions in the coal industry and the shutdown of small coal mines to eliminate outdated operations. The government also encourages integration between coal and power utilities. By the end of 2013, China had eight coal enterprises with at least 100 Mtpa of production capacity that produced 37% of the 2013 output, including Shenhua, China Coal, Datong Coal Mine, Shandong Energy, Jizhong Energy, Shaanxi Coal and Chemical Industry, Henan Energy and Shanxi Coking Coal.

The slowdown in economic activity since 2012 and lower coal demand from electricity companies, has led to oversupply in the Chinese market. Since then, Chinese miners have suffered from high production costs, low profits and competition from imported coal. The government is determined to **reduce overcapacity** in the coal sector, and for that, controls the growth of the coal industry. **Production is capped at 3.9 Gt by 2015** and capacity at 4.1 Gtpa. Production in 2013 rose very slightly to 3.7 Gt, against 3.66 Gt in 2012. Domestic railway bottlenecks, cheaper seaborne supplies, and the displacement of costlier miners were the main factors that contributed to the weak growth. Production from the leading mining province, Inner Mongolia, actually declined. To cope with the financial difficulties experienced by the domestic mining sector, in November 2013, the State Council announced a series of reforms aimed at eliminating excess production capacity by closing the least profitable small mines, tracking down illicit regional taxes, reducing production costs and limiting imports of low-quality coal (see Section 3.2).

While closing its outdated mines (110 Mtpa of outdated coal capacity will be phased out in 2014), China plans to add new coal-production capacity of 750 Mtpa in the five years ending 2015, with the total capacity limited to 4.1 Gt. The country will build 530 Mt a year of new capacity in the western regions (Xinjiang mainly) in the five-year period, accounting for 72% of total construction. About 25% of new-builds will be built in central regions and 3.3% in the east and northeast. The government approved construction of 101.3 Mtpa of new coal capacity in 2013, up from 16.6 Mtpa approved in 2012. The

development of coal production in Xinjiang is a major challenge: the Uygur Autonomous Region is located in the extreme northwest of the country, nearly 3,000 km away from major northeastern ports. Xinjiang holds 40% of the country's coal resources (2.19 trillion tonnes), but produced only 140 Mt in 2012. The government aims to build 17 super-large coal mines in the region, boosting annual coal output to 400 Mt by 2015. It remains to be seen, however, if this development is feasible. The region of Xinjiang is extremely dry. Water management will be a key issue for coal miners. Transportation of coal to the east of the country is another major bottleneck. The region is nearly 3,000 km away from the major ports in the north of the country.

If the government manages to actually **cap coal consumption at 3.9 Gt**, and develop its coal production in western China, the country could regain its self-sufficiency and almost withdraw from the international market. Imports in that case would be limited to specific coal qualities, mainly coking coal and high caloric value thermal coal, which are not widely available on the Chinese market. However, Chinese imports are mainly driven by price arbitrage between domestic and international prices, and so far domestic prices have been higher than international prices (see Section 3.3).

These **uncertainties**, with regard both to the evolution of Chinese demand, production and bans on low quality coal, make it very hard to estimate the level of Chinese imports in the coming years. This level not only depends on how international prices vary, but also on policies implemented by the Chinese government.

Box 17: Coal demand in China in 2013: the beginning of the levelling-off

Some interesting trends already emerged in 2013. Preliminary data from the NEA show that the country consumed a total of 3.76 Gtce in 2013, up 3.9% from the year before, while energy use per 10,000 yuan GDP dropped 3.7% year on year to 0.737 tce. Coal's share in the energy mix dropped 0.9 percentage point year on year to 65.7% in 2013, and is expected to fall below 65% in 2014. In 2013, non-fossil fuels accounted for 9.8% of China's primary energy use, up from 9.1% in 2012. They are set to grow to 10.7% in 2014.

China coal demand has already grown at a slower pace compared to other energy sources. Data from the Chinese National Coal Association show that coal consumption increased by only 2.6%, a modest growth compared with the average annual 9% recorded in the past decade.

For 2014, the plan released in January 2014 by the NEA foresees that total primary energy consumption will rise 3.2% to 3.88 Gtce, while energy production is expected to increase 4.3% to 3.54 Gtce. Energy use per unit of gross domestic product will decline 3.9% from 2013. Due to gains from energy efficiency and greater emphasis on sustainability, the NEA projects coal consumption growth of just 1.6% in 2014 to 3.8 Gt, while production may gain 2.7% to 3.8 Gt. The conclusion could be that China is going to be self-sufficient, already in 2014. However, quality issues may still favour imports. According to the NEA plan, the government will encourage imports of high-quality, less-polluting coal and limit fuel with high sulphur and ash content. Likewise, the level of domestic coal prices is higher than international prices favouring coal imports.

Table 19: NEA plan for China's energy consumption in 2014

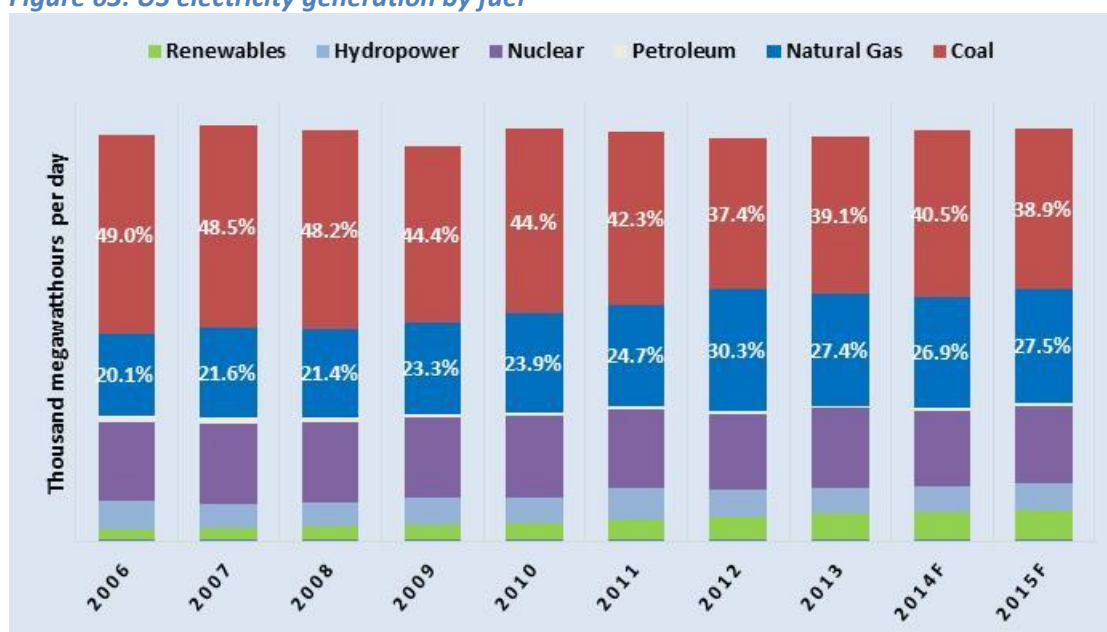
	2014 target	Change on 2013
Primary energy consumption (Gtec)	3.88	3.2%
Non-fossil fuel share in energy consumption	10.70%	+ 0.9 pct point
Coal share in energy consumption	Less than 65%	- 0.7 pct point
Share of non-fossil fuels in power production	32.70%	+ 2.1 pct point
Coal consumption (Gt)	3.8	1.6%
Coal production (Gt)	3.8	2.70%

Source: National Energy Administration, according to Chinese media, January 2014

US coal demand has contracted

The United States is the second largest coal market in the world and consumed 838 Mt in 2013. Coal is mostly used for power generation (92% of US coal demand). While coal ensured 50% of electricity generation until recently, the fast increase of gas production, linked to the shale gas revolution, resulted in a collapse of gas prices on the US market. This made coal uncompetitive and limited its use in the electricity sector. Since its peak in 2007, US coal consumption has decreased by almost 200 Mt (a fifth), leaving coal producers in the country in a distressed situation. Demand for coal by power utilities dropped 11% in 2012 and the share of coal in power generation fell to 37%, displaced by cheap gas, which increased its share to 31%. In 2013, however, consumption by coal power plants rose by 3.9%, thanks to its **improved competitiveness compared to natural gas**, the price of which increased by 35% to US\$3.75/million Btu on average in 2013. The share of coal in the electricity mix rose to 39%. But this growth is not likely to last. **Stricter environmental standards for coal** consumption in power plants cloud the future of coal in the country.

Figure 63: US electricity generation by fuel



Source: EIA, Short-Term Energy Outlook, March 2014

In December 2011, the US Environmental Protection Agency (EPA) decreed that all coal-fired power plants must meet new regulation on air pollution (the Cross-State Air Pollution Rule) by 2016. The regulation requires a drastic reduction in SO₂, NO_x and mercury emissions from power plants in twenty-seven East Coast states. The new Mercury and Air Toxics Standards (MATS) on air quality will

reduce the demand for coal by electricity companies from 2015. In response to these new air pollution regulations, 27 GW of coal-fired capacity will be closed between 2012 and 2016 and nearly 70 GW by 2020.

Additionally, in September 2013, the EPA issued new regulation for new power plants, which **proposes to limit emissions from new coal plants to about 500 kilograms (1100 pounds) per MWh**, and from gas plants, to 450 kg (1000 lbs) per MWh. The proposed EPA's regulation implies that no new coal plant could be built in the US unless it provides for partial carbon capture and storage (CSS).

Although the immediate impact of the regulation would be nil (there are no new coal-fired power plants being proposed in the US given cheaper natural gas supplies and rising local opposition to coal), it does not mean that the new proposal will be accepted by the industry easily. It nevertheless constitutes another argument in favour of gas at the expense of coal. In the coal business, this means that US miners will be incentivised to find new outlets for their production.

India struggling with increasing energy demand

India, the third largest coal market, consumed 753 Mt in 2012, accounting for 53% of its primary energy needs. Although India is the **world's third producer of coal**, domestic production is insufficient to cover the country's fast-growing needs, both for electric power producers and steel manufacturers. This was again illustrated by the large-scale blackout the country experienced in July 2012. Consequently India **increasingly calls on the international market** to make up the deficit of its internal coal market. Its steam coal imports are exploding: in the past three years, they increased by an average 21.6% per year and reached 145 Mt in 2013, making India the second largest importer, ahead of Japan. Imports could be much greater, but the depreciation of the rupee against the US dollar has resulted in a sharp increase in the price of imported coal in the local currency, constraining the import policies of Indian traders.

As 40% of the population still lacks access to electricity, the government has embarked on an **extensive construction program of large power plants**, most often located on the coast and powered by coal, resulting in a high demand for imported coal. In 2006 the government launched an initiative for the construction of 14 coal-based UMPPs (Ultra Mega Power Projects), each with a capacity of 4,000 MW. Although most plants were delayed, India's power capacity reached 215 GW at end 2012, with 54% based on coal (117 GW). The new 12th Five-Year Plan (FY2012/13-2016/17) has confirmed this program, with the aim of adding 64 GW of thermal capacity in the five years, 63 GW of which fuelled by coal. In 2013, India added 21 GW of new coal capacity. The problem, however, is not installed capacity, but the availability of coal.

Although India has large coal reserves, estimated at 113 billion tons (IGU, 2012), they are of poor quality (with a high ash content) and mainly confined to eastern and south central parts of the country, far away from centres of consumption. The inefficient inland transport puts regular pressure on domestic supply. Although India is the third largest producer in the world, with 595 Mt produced in 2012, domestic production is insufficient to meet its rapidly growing needs. The national company, Coal India Limited (CIL), produces 80% of domestic coal. The company has difficulties to increase its coal production which has stagnated since 2010. The government regularly introduces new reforms to improve the efficiency of the coal sector, but these have so far not borne fruit, due to the many hurdles to be surmounted. In order to secure domestic supply, the government is pursuing a threefold strategy: increasing production, establishing a coordinated import policy, and acquiring mines abroad. A large part of the supply is expected to come from the so-called captive mines policy, which has opened State mines to private investment. For various reasons, this policy has failed: out of over 200 coal blocks,

containing coal reserves of over 50 Gt, only 34 blocks had begun operating by 2011/12, with an annual output of only 36 Mt, compared with the original target of 105 Mt. India therefore increasingly turns to international market to cover the shortfall in the domestic market. Coal consumption could reach 842 Mt by 2016/17, in a base case scenario, and even 980 Mt in a high case scenario, a considerable increase from current demand (753 Mt in 2012). Given the growing shortfall in coal supplies, imports could reach and probably exceed 200 Mt by 2016/17. According to IEA forecasts, **India will become the world's largest importer of steam coal by the end of this decade**, surpassing China. Thus, India is taking a major role in the international coal market and in the medium term it could be the decisions taken in Calcutta that are crucial on the international coal scene.

Coal allows traditional Asian buyers to keep down their energy bills

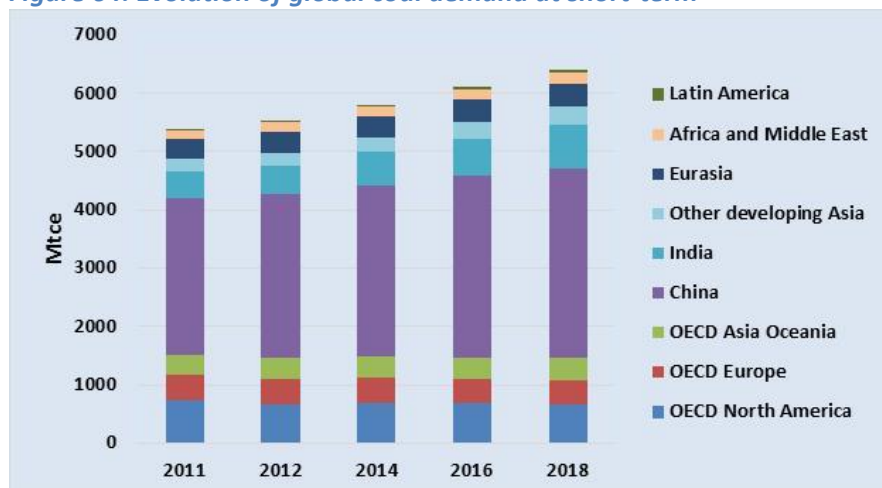
Japan, South Korea and Taiwan are the traditional Asian coal buyers and play an important role on the international market. These three countries do not produce any coal of their own and rely on imported coal for their power plants and blast furnaces. In 2012, the three countries imported 376 Mt, half of which imported by Japan. Japan was the world's largest importer of coal until 2011, when it was overtaken by China and, since 2013, by India. The Japanese energy bill has soared since the tragic Fukushima accident, as the country has resorted to higher imports of oil and LNG to fill the gap left by nuclear power. In 2013, **Japan used its coal-fired power plants to the maximum**, so as to limit costly LNG imports. Japanese coal imports amounted to 136 Mt.

Faced with a growing energy bill, Japan has thus had to rethink its energy policy: as well as the government-proposed reopening of a dozen reactors, the role of coal in its energy mix will be strengthened with the commissioning of new coal-fired plants. Two coal plants with a capacity of 1.6 GW came into operation in December 2013 and will increase the demand for coal by 3.7 Mt/year; and TEPCO recently announced the construction of a coal-fired power plant in Fukushima. While these new power plants will increase coal demand regionally, the re-opening of nuclear power plants may reduce both LNG and coal imports.

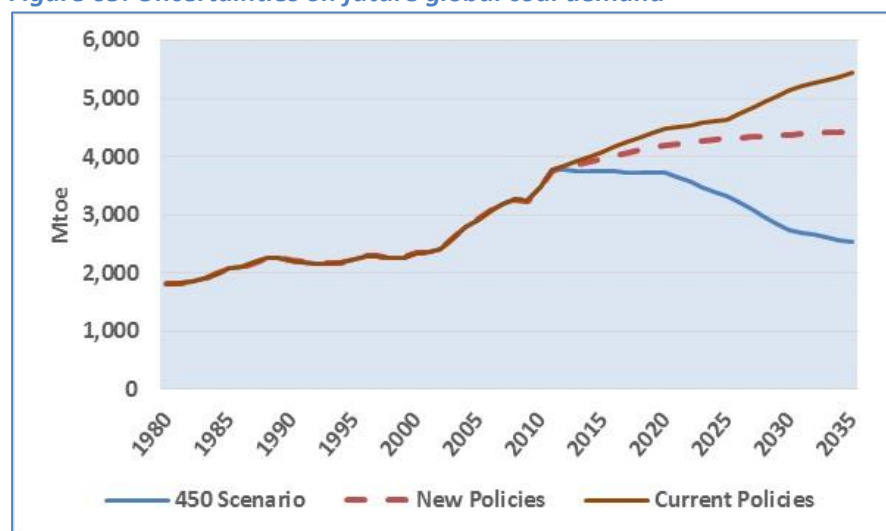
Global demand has transitioned from high growth to low growth and may move to negative rates

The recent evolution in global coal demand shows that **demand growth has started to slowdown**. The trend is expected to continue. The structural drivers behind this slowdown include a shift towards **greater energy efficiency**, the increasing pressure of **environmental regulation** for both local pollutants and CO₂ emissions, the **rise in renewables**, and last but not least, the **slowdown of coal demand growth in China**, which so far has been the engine of growth of the global coal market.

The IEA in its Medium Term Coal Market Report expects global coal demand to increase by only 2.3%/year on average in the period 2011-2018 (base case scenario). The global growth could even be more limited in a Chinese Low-demand case (only 1.9%/year). At longer term, depending on the evolution of environmental policies and CO₂ prices, world's demand may be reduced from its current level. The IEA/WEO 2013 illustrates the range of uncertainties for future coal demand. In the New Policies Scenario, global demand increases by only 17% over the period 2011-2035; in the Current Policies Scenario, the growth reaches 44%, while in the 450 Scenario, demand decreases by 33%.

Figure 64: Evolution of global coal demand at short-term

Source: IEA, Medium Term Coal Market Report

Figure 65: Uncertainties on future global coal demand

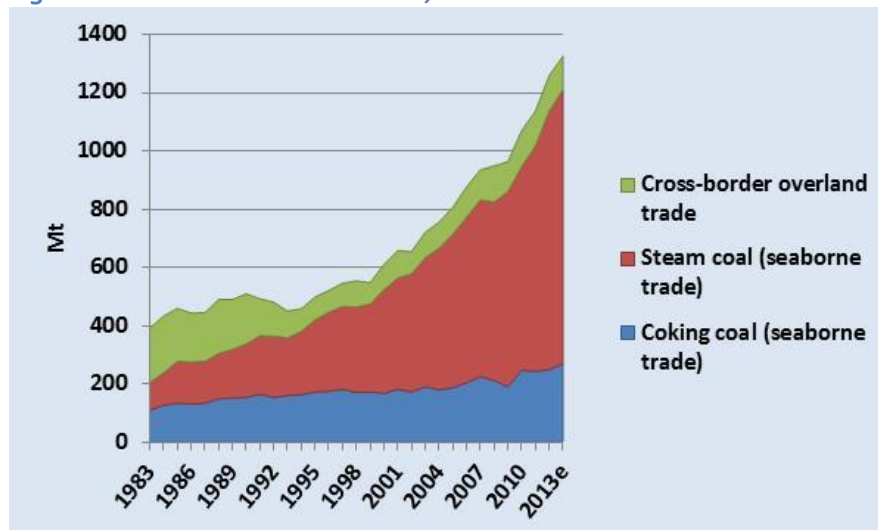
Source: IEA, WEO 2013

3.2 GROWTH IN STEAM COAL TRADE TO MODERATE

Global coal trade is growing but still represents a small share of total production

International hard coal trade has increased continuously over the past three decades driven by a sustained growth in steam coal trade. Total trade reached an estimated 1.3 Gt in 2013, of which 1017 Mt of steam coal and 309 Mt of coking coal. The seaborne steam coal trade tonnage is about 90% of total steam coal export sales worldwide. The remainder of the cross-border trade is done overland, usually by rail between neighbouring countries.

Despite its sustained growth, international hard coal trade is less developed than that of competing fuels: it accounts for **17% of hard coal production**, a much lower share than oil (more than 60%) and natural gas (30%). This is mainly due to the difficulties and costs associated with its inland transportation, which is often a bottleneck in the coal supply chain.

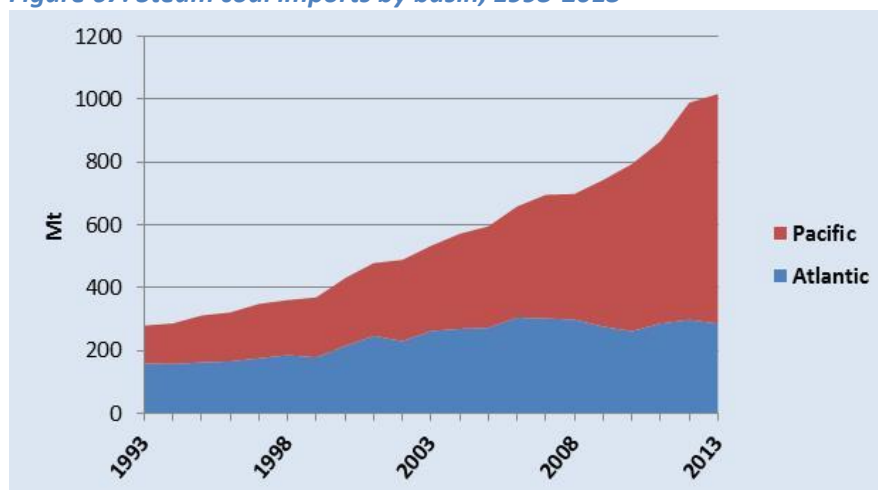
Figure 66: International coal trade, 1983-2013

Source: IEA, 2013: estimates.

Steam coal trade has increased fourfold since 1990, from 364 Mt in 1990 to an estimated 1017 Mt in 2013, at an average annual growth rate of 7.4%. While Europe and Japan accounted for the bulk of demand until 2000, Asia has accounted for most of the growth in the last decade. On the supply side, Indonesia has become the dominant world supplier of steam coal. Australia, Russia, Colombia, South Africa, and more recently the US are the other major suppliers to the international market.

A shift to the Pacific Basin

The steam coal market is split into two major markets, the Atlantic and the Pacific basins. The Atlantic basin is made up of utilities and traders from Europe (including the countries bordering the Mediterranean), the eastern seaboard of North, Central and South America, and the northern and western coasts of Africa. The Pacific Basin is made up of utilities from China, India, Japan, South Korea, and Taiwan. Other smaller buyers include Malaysia, Philippines, Thailand and the west coast of North America and South America.

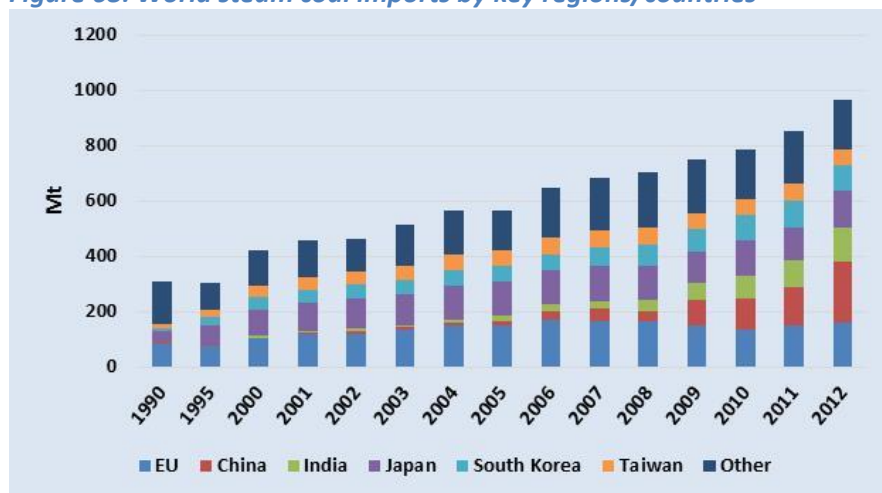
Figure 67: Steam coal imports by basin, 1993-2013

Notes: includes cross-border over-land trade.

Source: VDKI, IEA, BREE.

The surge of Asian imports has shifted the centre of gravity in international coal trade to the Pacific basin. With steam coal imports of 730 Mt in 2013, the Pacific basin has a leading position in the international market: it accounts for 72% of the steam coal trade, against 28% only in 1990. The trend was remarkable in the past five years, with an increase of the basin's share of 15 percentage points during 2008-2013, driven by the surge in China's imports. On the Atlantic basin, although Europe is still a major player on the international coal scene, its role is shrinking from year to year. Today, it accounts for 16% only of global steam coal imports, compared with 44% in 1990.

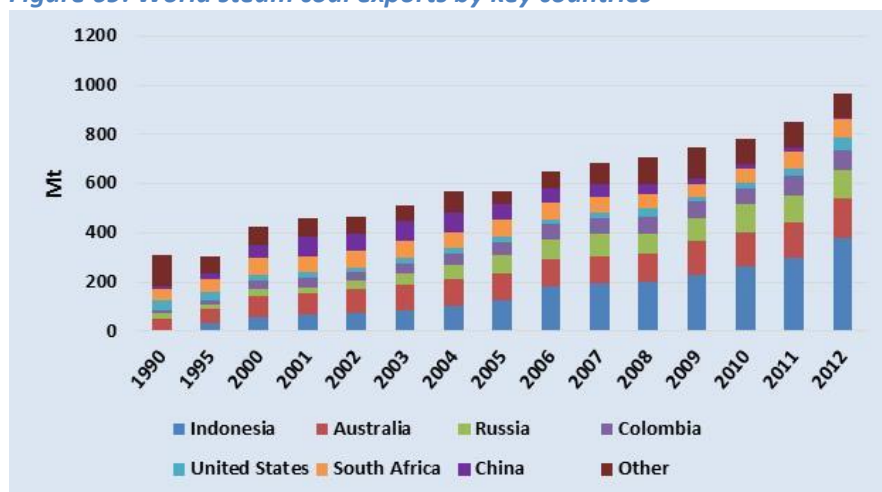
Figure 68: World steam coal imports by key regions/countries



Other: mainly cross-border over-land trade.

Source: IEA, EUROSTAT

Figure 69: World steam coal exports by key countries



Source: IEA

Six leading coal exporting countries

Major suppliers of the Pacific Basin include Indonesia, Australia, South Africa and Russia. Smaller supplies are also provided by Vietnam and recently the US. The Atlantic market is mainly supplied by Colombia, Russia, South Africa and in recent years the US. It also receives regular supplies from the Pacific Basin (mainly from Indonesia). Because of their geographic location, Russia and South Africa supply relevant volumes of coal to both basins. The Atlantic and Pacific markets also import coal from

neighbouring countries, transported by rail or truck (mainly from Poland in the Atlantic market and Mongolia in the Pacific market). The global steam coal trade is highly concentrated. Indonesia and Australia make up around 60% of the global seaborne trade.

Indonesia is the largest steam coal exporter in the world. Although the country is a relatively young coal producing country – it started coal production at the beginning of the 1990s, its strategic position in the centre of the Pacific basin and its abundant reserves of low-cost coal have allowed the country to take a lead position. In 2013, Indonesia strengthened its supremacy and exported 409 Mt of steam coal. The country now accounts for over 40% of world exports. Indonesia mainly exports to the Pacific basin. However, some Indonesian coal is imported by European utilities for blending purposes (around 7 Mt in 2013).

Australia is a major player in the international coal market. It was the world's largest exporter until 2011, when it was overtaken by Indonesia. However, Australia is still the largest exporter of coking coal. The country increased its steam coal exports by nearly 8% to 184 Mt in 2013, thanks to recent expansions of mines. Due to its proximity, Australian steam coal exports are dedicated to the Pacific market. Its exports to Europe are made up of coking coal only. Mining companies in Australia are faced with ever higher production costs and lower productivity. Australia began losing its competitive edge over its competitors with lower costs, such as Indonesia and South Africa in 2012. Since then, mining companies have reduced costs and expanded production at their lowest-cost mines.

Russia is the world's third largest exporter and the largest exporter to Europe. In 2013, its total coal exports reached 143 Mt, an increase of 12.3%, of which an increasing share went to Asia. In 2012, its seaborne hard coal exports totalled 117 Mt, of which 48 Mt exported to the EU. The rest of its coal export sales went to Turkey (10 Mt), Asia (45 Mt) and other smaller buyers. Most of the coal exported to Europe comes from the Kuznetsky Basin (Kuzbass) in the Kemerovo region. The high cost of overland transportation in Russia makes Russian coal at the highest of the supply cost curve. Faced with strong competition in Europe from low-cost suppliers, Russian exports are increasingly oriented to Asia, although competition from Asian low-cost suppliers, such as Indonesia and South Africa, is also fierce. Russia is thus counting on improving its rail network and expanding its port capacity, mainly on the Pacific coast so as to increase its exports. The export capacity of Pacific ports is planned to rise to 140 Mt/year. While the share of exports to Europe is likely to go on declining, Asian demand favours the expansion of exports, helped by Chinese investment in Russia's mining and infrastructure. The Russian Government has approved a long-term programme for the development of the coal industry for the period up to 2030, calling for domestic coal production to reach 355 Mt in its first stage (to 2015), 380 Mt in its second stage (to 2020) and 430 Mt in the third stage (to 2030). Most of the growth is expected in the eastern and far eastern regions and dedicated to Asian markets, as far as exports are concerned. With the introduction of new production centres, the regional structure of Russian coal mining will shift towards the east. While western Siberia's share of coal output will decrease from 58% to 45%, eastern Siberia will increase its share from 26% to 32% and the Far East region from 9.7% to 15.2%.

While **South Africa** has been a traditional supplier to Europe, its exports are now increasingly directed to Asian markets, mainly India. The EU accounts for only 18% of South African exports (13.7 Mt out of 76 Mt exported in 2012), whereas this share was still above 50% in 2008. The increase in domestic coal consumption and the inefficiency of the transportation network have limited export growth in recent years. In the future, the reserves of the Waterberg mines in the north of the country (Limpopo Province) are likely to be developed to supply both domestic and export needs. However, this development presents many challenges — such as water availability and the distance of the mines

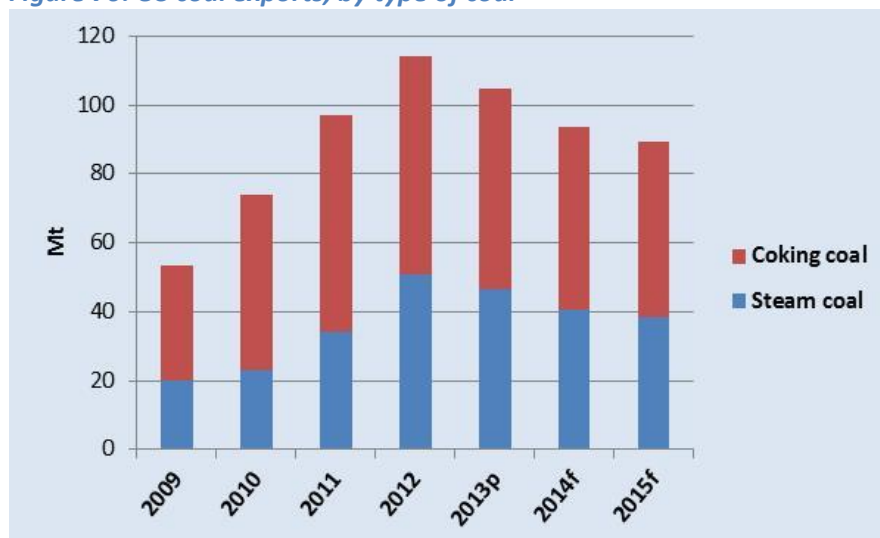
from centres of consumption and export ports – which so far have limited production from this new mining region.

Colombia is the world's fourth-largest exporter of steam coal. The country is a major and increasing supplier of steam coal to Europe. Although Colombia has diversified its export markets, the EU still accounts for the lion's share of coal sales. In 2012, the country exported 44 Mt to the EU, out of total steam coal sales of 79 Mt. Other importers included Turkey (8 Mt), West Africa, North and South America and Asia. 95% of Colombian coal is extracted for the export market and the sector is almost exclusively controlled by foreign companies. The four largest coal producers Cerrejón, Drummond, Prodeco and Colombian Natural Resources account for 93% of exports. Cerrejón is owned by Anglo American, BHP Billiton and Glencore Xstrata. Drummond is a family-owned business from the US. Prodeco is owned by Glencore and Colombian Natural Resources is owned by the US bank Goldman Sachs. The country has ambitious plans to increase its coal exports to 115 Mt by 2015. In 2013, however, exports fell to 77 Mt. Production and exports were reduced following strikes in the coal industry during the first half of the year, attacks against the railways used by mining companies and an accident at the port of Santa Marta at the beginning of the year. This accident led the government to introduce a new regulation for the loading of coal at ports. The new regulation, which came into force on 1 January 2014, has created uncertainty as to the level of Colombian exports in 2014. Drummond, which supplies a third of the country's exports, failed to complete its new loading system at the port of Santa Marta on time. Since Colombia exports mainly to Europe, this uncertainty pushed up the European CIF ARA price by US\$4/t as of early January 2014. Since then, Drummond has opened direct loading at its port and exports have returned to normal rate. In the future, the share of exports to Asia is expected to increase thanks to the expansion of the Panama Canal. The expansion, scheduled for completion in 2015, will make possible for smaller Capesize ships to use the Canal instead of having to sail around the Cape of Good Hope, decreasing transportation costs to the Pacific.

The **United States**, which had almost disappeared from the international steam coal scene at the beginning of the 2000s when coal prices were low, has actively developed its coal exports since 2010. Coal mining companies have turned to the export market to offset the loss of market share on their domestic market due to competition from natural gas. The US exports both steam and coking coal. Hard coal exports have surged since 2010 with strong increases recorded in 2010 (+38% over 2009), 2011 (+31%) and 2012 (+17%). They reached 114 Mt in 2012. US steam coal exports amounted to 50.7 Mt in 2012, of which 28.6 Mt were exported to the EU. Other buyers included Turkey, South America and increasingly Asia (25% of the sales in 2012).

Exported coal has mainly targeted Europe as the main export terminals are located in the east coast and the Gulf of Mexico. However, coal from the Appalachian basin, the main source of steam coal exports to Europe, has high production and inland transportation costs. At current coal prices on the Atlantic basin, steam coal exports are not profitable for several mines in the Appalachian basin. In 2013, steam coal exports to all regions declined by 8% to 47 Mt. The DOE expects further declines in 2014 and 2015 (40 Mt and 38 Mt respectively). Continuing economic weakness in Europe, slowing Asian demand growth, increasing coal output in other coal-exporting countries, and falling international coal prices are the primary reasons for the expected decline in US coal exports¹⁸⁴.

¹⁸⁴ EIA, Short-Term Energy Outlook, March 2014

Figure 70: US coal exports, by type of coal

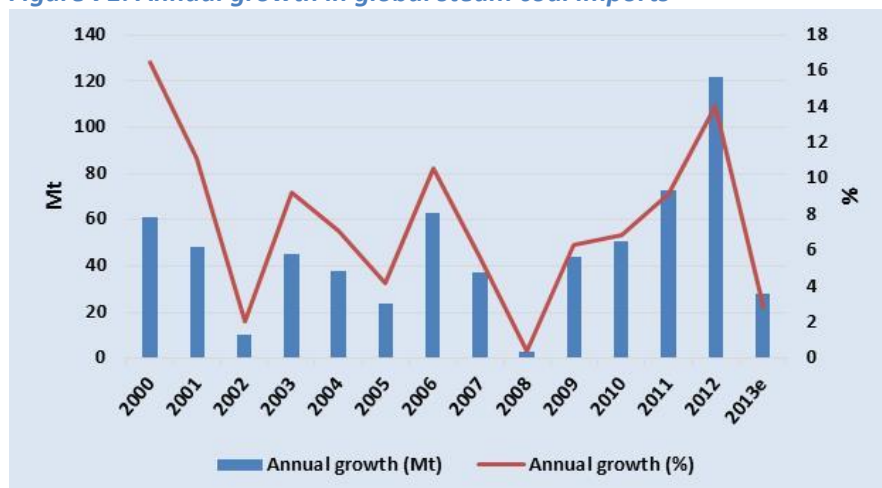
Source: EIA

The future level of US steam coal exports to the EU is strongly linked to prices of delivered coal in Europe. The reduction in US coal exports to the EU will last as long as prices remain low. The increase of US coal exports to the Pacific basin depends on the building of new export capacities on the US west coast enabling the country to remain competitive on the Asian coal market. Although projects of infrastructure are under consideration to export low-cost coal from the western states to the Pacific, they encounter challenging permitting issues and strong local opposition. The recent fall in international coal prices does not suggest a quick realisation of coal terminals on the US northwest coast. However, the commissioning of the Panama Canal in 2015 will create new opportunities to export coal from the eastern states to Asian countries.

Two new exporting countries, **Mongolia and Mozambique**, have entered the international coal scene. Both countries, but especially Mongolia, have huge reserves of coal, principally high quality coking coal, but also steam coal. While Mozambique has begun to export to overseas markets, Mongolia exports exclusively to China so far. The two countries are developing their transport infrastructure, which constitutes the main bottleneck.

A recent slowdown in steam coal trade

The growth in steam coal trade is slowing down. In 2013, the growth was only 2.8% as imports by **China slowed down drastically**. China imported 235 Mt of steam coal in 2013, still a huge amount but a mere 7.8% increase over 2012, in sharp contrast with the dazzling growth of 59% recorded in 2012. This slowdown fears the beginning of a period of decreasing imports by the world's largest coal importer.

Figure 71: Annual growth in global steam coal imports

Source: IEA, estimates

Exporters faced with overcapacity

The slowdown in the growth of steam coal imports occurs at a very bad time. Several greenfield and brownfield projects decided before the global financial and economic crisis have recently been commissioned, adding **export tonnage that the market cannot absorb**. This situation has been aggravated by the inflow of US coal which could not be marketed on the domestic market. This has led to an oversupply on the global steam coal market, and this, despite the exceptional growth of Chinese imports in 2012. Fierce competition between suppliers has developed and steam coal prices have started to fall. European prices decreased from US\$130/t at mid-2011 to less than US\$80 at the end of 2013 (see Section 3.3). Prices on the Pacific basin decreased in the same order of magnitude. The slowdown in trade and the fall of prices adversely hurt coal exporters, which also face rising production costs (see Section 3.3).

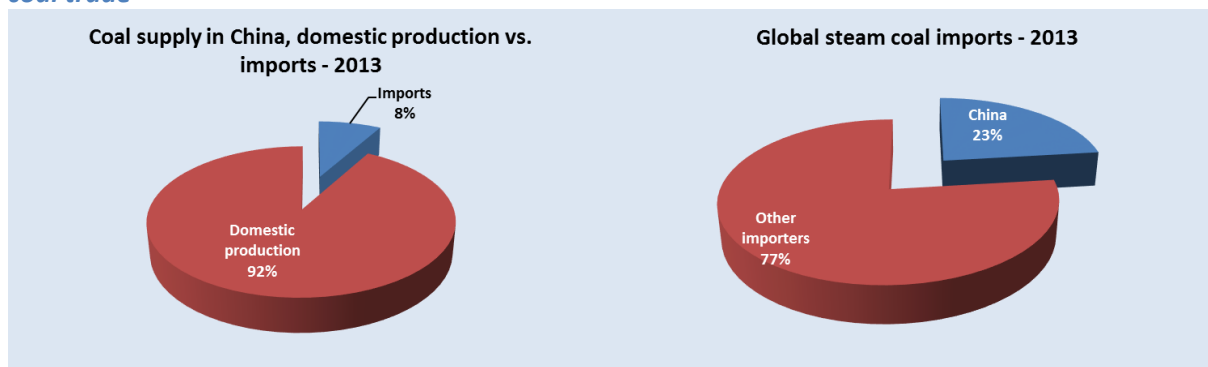
The key role of China on the international trade

China, which was still a net exporter in 2008, has become a net importer since 2009 and in significant quantities. **In 2011, it became the first largest coal importer, outpacing Japan**. Rising prices of domestic coal (encumbered by high transport costs) compared to international prices made imports more attractive, especially for the southern provinces of the country. Its imports have continued to increase steadily and reached 327 Mt in 2013, +13.5% compared with 2012, of which 235 Mt of steam coal.

Yet China remains the world's largest producer of coal (3.7 Gt produced in 2013, nearly half of world production). Its imports are only a small part of its supply, 8%, but on the narrow international coal market, China now represents 23% of the world steam coal trade. It thus has considerable power on the international market, and **policy decisions taken in Beijing affect the price of coal delivered to other Asian countries and European buyers**.

Figure 72: Chinese international coal imports and exports, 1993-2013

Source: IEA, 2013: China Customs data, own calculations.

Figure 73: Share of China on the international coal market vs. China's coal imports in the global steam coal trade

Source: estimates.

The reliance on international trade stems from commercial and logistical considerations. The bulk of China's production comes from the north of the country, while major consumption centres are located in the south-eastern provinces. Logistical constraints in this huge country restrict the transportation of coal to centres of consumption. Therefore, coal imports are favoured when international prices are lower than domestic ones. Chinese coal imports are driven by **coal price arbitrage between domestic and international coal prices** (see Section 3.3). This makes difficult the forecast of future global steam coal trade as it depends on China's market development and government policies. While the commitment of the government to reduce the share of coal in the energy mix is clear, the speed of change remains uncertain. Imports are expected to decline in coming years, as the domestic oversupply continues and policies such as the proposed ban on imports of low-grade coal are implemented (Box 18). The outcome of the ban however is still unclear.

Box 18: Chinese uncertainties: possible ban on low-grade coal

China may impose a ban on imports of low-grade coal, which may reshape China's coal supplies and import flows. Low-grade coal, with high sulphur and ash content, is sold on the international market at a very attractive price, but it exacerbates China's air pollution. In 2013, China imported 60 Mt of low-calorific value coal, mainly from Indonesia. The Chinese government has been trying to implement such measures since early 2013, releasing two drafts publicly, though both were shelved after strong

protests of utilities and traders among others. Plans to restrict the use and imports of low-grade coal are again gaining momentum in China. Faced with two key issues, pollution and over-capacity in the coal market, the government is working on a revised proposal to restrict the import and use of low-grade coal. Details of the restrictions have not been confirmed and could target a combination of energy content, sulphur content, and ash content.

According to the latest version of the proposal drafted in March 2014, lignite imports with caloric value lower than 3,941 kcal/kg NAR (net as received) and ash and sulphur contents above 20% and 1% would be banned. For all other types of coal, caloric value should be above 4,300 kcal NAR, while ash and sulphur content should be less than 30% and 2%. Thresholds are also set for chemicals, including mercury, phosphorus and chlorine.

In its current version, the proposal would mostly hit exporters of low-cal coal (Indonesia) and high sulphur coal (US).

What is new in the latest proposal is that the ban would also apply to domestic coal with transport distances above 600 km. The ban on domestic coal would reduce production from small producers and would help to solve the over-capacity issue on China's coal market.

If these plans are enacted, both imports and domestic production will be affected. Depending on the final quality requirements for imported coal, it is likely that Australian imports will need to fill the gap.

Global steam coal imports growth to moderate

The outlook for future steam coal trade is highly dependent on coal demand, linked with economic growth. It is also dependent on the cost of coal, relative to other sources of energy, and upon **limitation policies put in place throughout the world** and on the types of emissions reduction adopted in major consuming countries. The uncertainties on future coal demand by China, but also India, have led the IEA in its Medium Term Coal Market Outlook¹⁸⁵ to develop two sensitivity cases to quantify magnitudes of uncertainty on coal consumption, production and trade flows. The Base Case Scenario (BCS) and the two sensitivity cases are based on the same assumption on economic growth. In the Chinese Low-Demand Case (CLDC), electricity consumption in China is assumed to decouple from the Chinese GDP, which implies lower coal generation. In the Indian High-Demand Case (IHDC), larger capacities of coal-fired power plants compared with the BCS increase Indian coal demand. The table below shows the outcome of the BCS and the two sensitivity cases for world seaborne steam coal imports in the short /medium term.

As shown in Table 20, although **uncertainties in global steam coal trade are high**, the growth in global trade is expected to slow down drastically in the three cases. From 2007 to 2012, global steam coal trade increased by 8% per year on average. In the BCS, the annual growth is expected to slow down to 3.6%. In the CLDC case, the growth is only 2.8%. As we have seen previously, the Chinese government is strongly committed to reduce the share of coal in the energy and electricity mix, making the CLDC a highly probable trend.

¹⁸⁵ IEA (2013), Medium Term Coal Market Outlook, IEA/OCDE, Paris, December 2013

Table 20: Seaborne steam coal imports, 2011-2018

	2011	2012e	2014	2016	2018	CAGR (2011-2018)
Mtce	Base Case Scenario					
TOTAL	685	738	778	834	913	3.6%
Europe and Mediterranean	148	165	148	142	145	-2.1%
China	126	164	187	189	192	2.6%
India	73	90	107	140	175	11.7%
Japan/South Korea/Taiwan	237	242	249	260	273	2.0%
Other	101	77	87	103	128	3.4%
	Chinese Low-Demand Case					
TOTAL	685	738	755	781	870	2.8%
Europe and Mediterranean	148	165	149	144	150	-1.6%
China	126	164	147	115	116	-5.7%
India	73	90	120	152	191	13.4%
Japan/South Korea/Taiwan	237	242	252	264	282	2.5%
Other	101	77	87	106	131	3.8%
	Indian High-Demand Case					
TOTAL	685	738	785	844	940	4.1%
Europe and Mediterranean	148	165	148	141	143	-2.3%
China	126	164	174	155	150	-1.4%
India	73	90	128	186	249	18.5%
Japan/South Korea/Taiwan	237	242	249	259	271	1.9%
Other	101	77	86	103	127	3.3%

Note: The data in the table refers to Europe and Mediterranean countries. The IEA MTCMR does not give a breakdown for EU steam coal imports. The main difference between EU and Europe and Mediterranean countries imports consists in imports from Turkey mainly. Turkey imported 19.3 Mtce of steam coal in 2012 (IEA, Coal Information 2013) and its imports are expected to increase in the outlook period.

Source: IEA, Medium Term Coal Report, 2013

European coal imports to decline slightly

The global uncertainties have a limited impact on European and Mediterranean steam coal imports at short/medium term. In all cases, they are expected to decline, although the reduction is limited. In the BCS, the region's steam coal imports decline by an average 2.1% per year to 145 Mtce in 2018. The range of uncertainties is also limited (7 Mtce by 2018 between the CLDC and the IHDC). The region is more sensitive to higher Indian imports which may be explained by the swing role played by South Africa. Larger Indian imports may create some pressure on the Atlantic basin. The MTCMR expects OECD Europe coal and lignite power generation will remain at the high level of 2012 in the near future, but will become more bearish over the outlook period. Total consumption of lignite and thermal coal is projected to drop, from 371 Mtce in 2012 to 348 Mtce in 2018. As the IEA does not expect any major changes in commodities and CO₂ prices in the forecast period, or significant fuel switch from coal-to-gas, the decrease in coal demand by the power sector is explained by limited GDP growth, further energy efficiency gains and rising RES power generation.

In the longer term, the IEA's WEO 2013 expects a large decrease in EU hard coal imports from 170 Mtce in 2011 to 105 Mtce in 2035 (hard coal include met coal).

As the majority of import growth is centered on Asia, major steam coal exporters (Australia, Indonesia) as well as new suppliers (Mozambique and Mongolia) will supply this area. South African coal exports will most likely shift direction towards India rather than Europe. This is particularly the case in the IHDC.

Consequently, Colombia, Russia and the US are seen as the natural suppliers for EU thermal power plants in the future.

3.3. PRICE DYNAMICS

International steam coal prices are mainly determined by market forces. “Boom and bust” is the rule

International prices for steam coal are mainly determined by **market forces** (domestic prices may include subsidies). Due to long lead times for the development of new coal mines, railways and export capacity, coal prices are cyclical. When supply is tight, prices can rise steeply, incentivising investment in new infrastructure. At the opposite, excess supply leads to falls in prices until the market rebalances. At short term, prices are volatile. Supply constraints (flooding of mines for instance) make coal vulnerable to sudden shocks. On the demand side, lower electricity demand, high stocks may lead to a fall in international coal prices.

The graph below illustrates the long-term evolution of Australian FOB prices since 2000 and shows boom and bust cycles in coal prices. Since the middle of 2011, prices have fallen from US\$121/t in July 2011 to US\$73/t in March 2014.

Figure 74: Australian FOB¹⁸⁶ steam coal prices



FOB Newcastle

Source: World Bank

Box 19: Evolution of international steam coal prices since 2000

Demand and supply for steam coal were well balanced until the beginning of the 2000s and coal prices were stable at relatively low levels (US\$28/t for Australian export coal prices) essentially determined by mining and transportation costs. However, this situation changed radically in 2003. Increased domestic demand in major exporting countries (China, Russia), decreased production in the U.S, logistical bottlenecks in ports and railway systems in South Africa and Australia reduced export availability. At the same time, demand was pushed by unusual weather patterns in Europe and closure of several nuclear power plants for maintenance in Japan. In reaction to the supply/demand imbalance,

¹⁸⁶ FOB: Free-on-Board. Coal prices at export ports. Do not include maritime transportation costs.

prices doubled in 2004 (about US\$60/t). High oil and gas prices also contributed through a shift in demand and higher transportation costs for coal. In 2007/08, the imbalance between supply and demand of the Pacific basin and the sudden rise in Chinese coal imports pushed the coal production and transport infrastructure to the limit, and again provoked a strong increase in international coal prices, accentuated by a spike increase in freight rates. In July 2008, CIF ARA¹⁸⁷ coal prices reached an historical peak at US\$217/t. Maritime transportation (US\$60 to 70/t for most typical routes to Europe) represented 30 to 35% of the delivered price. Attracted by the high level of prices which prevailed in the 2000s, coal mining companies from all over the world invested billions of dollars to develop new mines and logistics infrastructure.

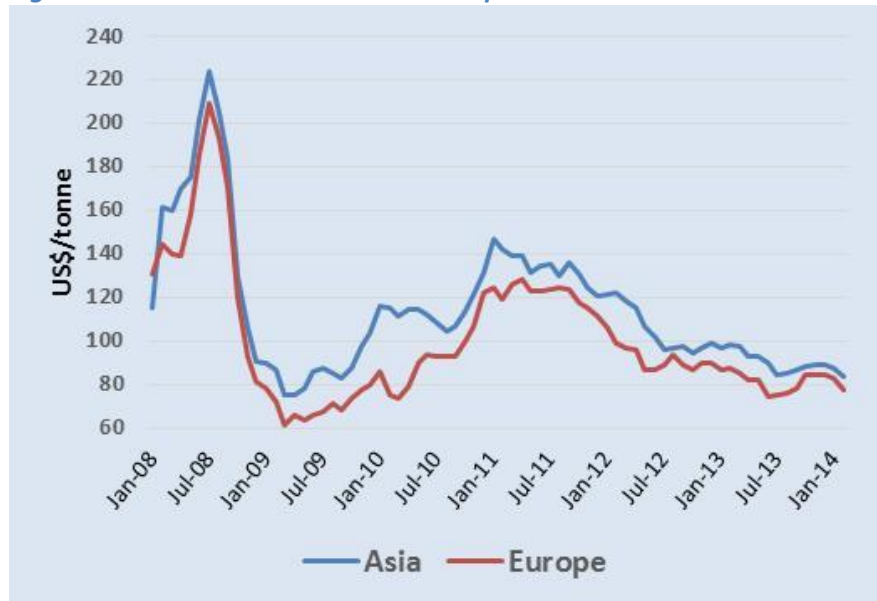
The collapse in coal prices in the second half of 2008, caused by the economic and financial crisis, was followed by a continued drop in 2009. The financial and economic crisis in 2009 reduced coal demand in some regions, but even that year traded volumes continued growing thanks to rising Chinese imports. The steep increase in China's demand for coal imports rapidly raised prices. High coal prices and profits, as well as the expectation that China's appetite for coal will continue to grow at a fast pace, encouraged several global miners to expand capacity and production during the 2009-2011 period. At the same time, the shale gas revolution in the US drove coal mining companies to turn to the international market. Growing supplies on the Pacific and the Atlantic markets led to a build-up of excess supply in the seaborne market, which drove a fall in steam coal prices in 2012. Since then, despite some cuts in production, the market has remained oversupplied.

The coal market is a global one: prices are similar on the Atlantic and Pacific basins

In contrast with natural gas, **the coal market is a global one**. Thanks to low maritime transportation costs, international steam coal prices are similar in the Atlantic and Pacific basins. The premium paid by Asian customers is low and has decreased since 2011 as both basins have been characterised by oversupply. Suppliers, such as Russia and South Africa, but also increasingly the US and Colombia, are able to swing some of their exports between the Atlantic and the Pacific markets and, in recent years, growing volumes of exports from these traditional suppliers of the Atlantic basin have been sold to Asian buyers. This has reinforced the links between the two basins.

Despite this strong relationship, at short term, prices do react to regional events on each market. In March 2011, when the Fukushima accident occurred and Germany announced the closure of seven nuclear reactors, European prices rose by US\$10/t to nearly US\$130/t, with the markets anticipating a shortage of coal in Europe, although paradoxically European demand was weak. In contrast, prices on the Pacific market continued declining.

¹⁸⁷ CIF ARA prices: Cost Insurance and Freight, Amsterdam, Rotterdam and Antwerp. Coal prices delivered at major European coal terminals.

Figure 75: International CIF steam coal prices

Asia: Asian price marker. Europe: European price marker

Source: McCloskey

China is the current price-setting country

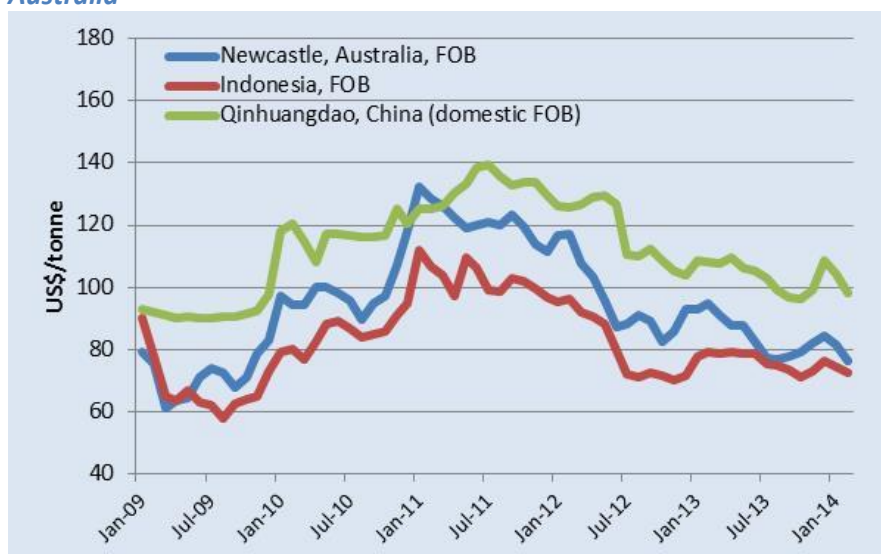
As seen previously, since 2009, China has turned from a net exporter to a net importer, and by a large margin. This shift has had a tremendous impact on global prices. **Since 2011, when China became the first largest coal importer, the country has become the price setter for steam coal.**

As the country is a big coal producer, Chinese coal imports are driven by **coal price arbitrage between domestic and international coal prices**. China is the “*swing buyer*” of the coal market, buying on the international market when international prices are lower than domestic prices and withdrawing from the market when the reverse occurs. **China domestic coal therefore sets a price cap for international steam coal prices.**

The figure below compares prices of domestic coal at Qinhuangdao¹⁸⁸ in China and export prices from Indonesia and Australia. As the figure shows, prices of Chinese coal at Qinhuangdao were higher than Indonesian and Australian prices for almost all the past four years, leading to the strong growth in China’s coal imports experienced during that period. Low maritime freight rates have reinforced the competitiveness of international coal. In early 2011, when Australian coal prices exploded following floods and supply cuts in Queensland, China was a net exporter, with Chinese traders reselling their coal cargoes to markets affected by the Australian flooding.

¹⁸⁸ Qinhuangdao is the largest port for the transport of coal from northern to southern China. In the Bohai Bay, there are seven major coal terminals with a handling capacity of 800 million tons a year. These ports “exported” 628 Mt in 2013 to the south-eastern provinces.

Figure 76: Comparison of coal prices in China (Qinhuangdao) with export prices from Indonesia and Australia



Note: FOB (Free on Board) prices, at 6,000 kcal/kg.

China applies a 17% VAT on imported coal prices.

Source: World Bank, McCloskey

Given its dual role as the largest importer of steam coal and the marginal buyer, China has a considerable power on the international steam coal trade and a change in China's energy and climate policy is set to create waves in the global coal market.

Excess supply has driven international coal prices downward

The ramp-up of several mines in Australia, the booming production in Indonesia, where output increased from 291 Mt in 2009 to 443 Mt in 2012, the surge in US, Colombian and Russian coal exports and additional supplies from new coal producing countries (mainly Mongolia) have created an imbalance in the global steam coal market. Despite high growth in Chinese imports in 2012, the global market has been oversupplied and prices have collapsed. European average import prices dropped to US\$92.6/t in 2012, down 24% compared to 2011 (US\$121.6/t). In 2013, they continued to decline and stood at US\$81.5/t CIF ARA on average, a 12% decrease compared to 2012. Asian prices have registered similar declines. On average CIF Asian prices were US\$91/t during 2013, down 14% from 2012. **Steam coal prices at the beginning of 2014 are still trended downward** (US\$75/t for European CIF ARA prices and US\$74/t for FOB Newcastle at mid-March).

Seaborne bulk freight rates have added to the decline of CIF prices. They collapsed in 2008 and have remained very low since then. They currently make a smaller share of delivered prices. A typical freight rate from US ports to Europe (based on Panamax vessels from Hampton Roads to ARA) costs US\$12/t in March 2014 (this is equivalent to US\$0.5/MBtu), compared with US\$16/t at mid-2011, and far below the peak of US\$60/t in June 2008.

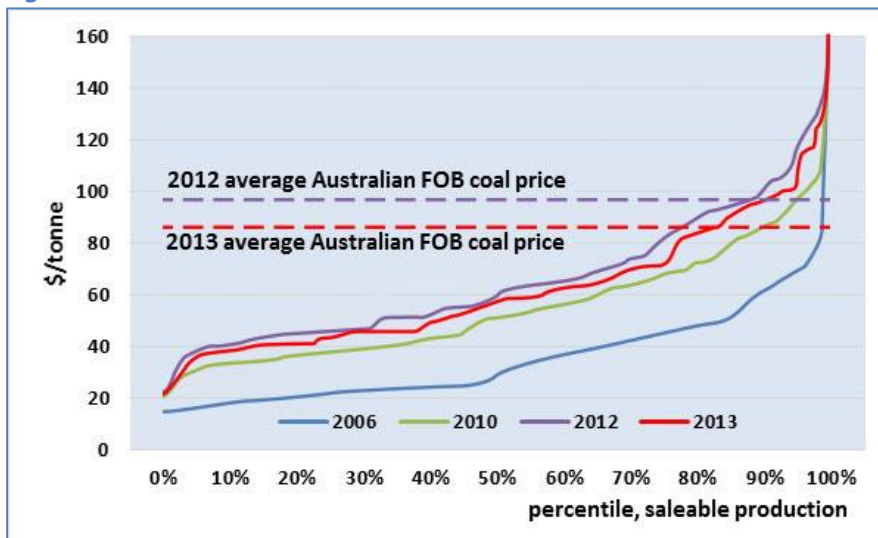
Production cost escalation has been a feature until 2012. Since then costs have been reduced

Relatively high coal prices in the period 2007-2011 were paralleled by **mining and inland transportation cost escalations**. There are several reasons explaining the rise. The industry had to move to lower quality deposits that are more costly to exploit. New developments were further away from major rail and port infrastructure increasing inland transportation costs. Input costs such as

labour, machinery, equipment's hire and diesel fuel have all increased dramatically. In Australia, the appreciation of the Australian dollar against the US dollar and escalation in capital costs as a result of the global mining and resources boom contributed to higher costs. Furthermore, healthy margins had taken off pressure from mining companies to increase productivity and cut costs in that period. Finally, strong coal demand kept high-cost mines in the market that were only marginally profitable, even at high prices. Consequently, falling prices since mid-2011 have squeezed margins and put pressure on the coal industry worldwide.

Figure 77 illustrates cash cost¹⁸⁹ curves in Australia. It shows that costs increased by around 60% from 2006 to 2012. Despite a small downward shift in the cost curve in 2013, driven by productivity gains and the depreciation of the Australian dollar against the US dollar in 2013, more than 20% of seaborne Australian coal producers are not covering cash costs at current prices.

Figure 77: Australian steam coal cash cost curves



Source: Merrill Lynch Global Research, own calculations

Slow, insufficient production cuts

Production cuts have been slow and less than expected in response to weak coal prices. Producers have rather increased their production at their lowest cost mines to maintain revenues and have decreased their costs radically. Some high-cost mines in the United States, but also in Australia, had been shut down.

Producers were reluctant to cut production as a contango market structure suggested a recovery in coal prices. At the beginning of 2013, forward CIF ARA prices for cal-2016 settled at US\$116/t. Depreciation of local currencies in producing countries also limited production cuts. Almost all currencies in coal producing countries depreciated against the US dollar in 2012/13. As coal trade around the world is transacted in US dollars, depreciation of local currencies has offset the impact of the decrease in steam coal prices. This has contributed to an extended period of oversupply and low prices. However, this extended period of low prices puts significant pressure on high-cost producers.

High costs and ample supply capacity are driving consolidation and restructuring of mining industries in many countries. The US experienced a wave of consolidation starting in 2012 with large-scale production cuts and mine closures, mainly in the Appalachian basins. Miners have refocused their sales

¹⁸⁹ Cash costs, in mining, are the costs of production, at site level, per unit of output. In the figure, inland transportation costs to the export terminal are included.

on the domestic market and decreased their steam coal exports in 2013. In Australia, Glencore Xstrata and Peabody announced workforce reduction in June 2013 corresponding to around 10 Mt/year of capacity. Other companies operating in Australia (Rio Tinto, Centennial Coal, New Hope) also announced production cuts in 2013 due to high production costs and weak prices. Additional cuts were announced by BHP Billiton, Glencore and Anglo American in March 2014. However, at the same time, ramp-up of production and commissioning of new mines, decided before the fall in coal prices, may still increase steam coal production and exports.

Russian producers also try to maintain their position by increasing exports, while reducing production at their highest-cost mines. In 2013, Russia increased its exports by 12.7%, although its production declined slightly. Lower prices were offset by the depreciation of the Russian rouble against the US dollar.

At current prices even some Indonesian producers are affected, despite the low cost of production in the country. The government first announced in January 2014 that it would cap coal output at about 400 Mt in 2014, 5% less than 2013's level, to stem declining prices¹⁹⁰. It however relaxed the cap at end February as Indonesian miners aim to boost production to compensate for continuing low prices. Most of them have low production costs and can still be profitable under current weak prices.

New projects are shelved or abandoned, but the projects pipeline for global thermal coal exports is large

Proposed new mine developments are shelved or abandoned. In 2012, BHP announced the indefinite postponement of a US\$20 billion investment in Australia's Port Hedland. In September 2013, Glencore Xstrata dropped its plans to expand the Wandoan mine in Queensland (a 30 Mt, 7 billion Australian dollar investment). Rio Tinto is pulling out of steam coal in Australia and sold its Clermont mine to Glencore Xstrata and Sumitomo for US\$1 billion.

Nonetheless, new export mining capacity of 120 Mt per year is expected to come online by 2018¹⁹¹. Half of the growth can be attributed to Australia. The Australian Bureau of Energy Resources (BREE)¹⁹² expects Australian steam coal production to increase from 239 Mt in 2013 to 296 Mt in 2019. Exports are forecast to increase from 182 Mt in 2013 to 244 Mt in 2019. Colombia also provides significant steam coal capacities. Its production (most of it is exported) could reach as much as 115 Mt in 2015 and 145 Mt by 2020. In addition, **the global projects pipeline is huge**. The IEA has identified more than 480 Mt per year of potential mining projects by 2018.

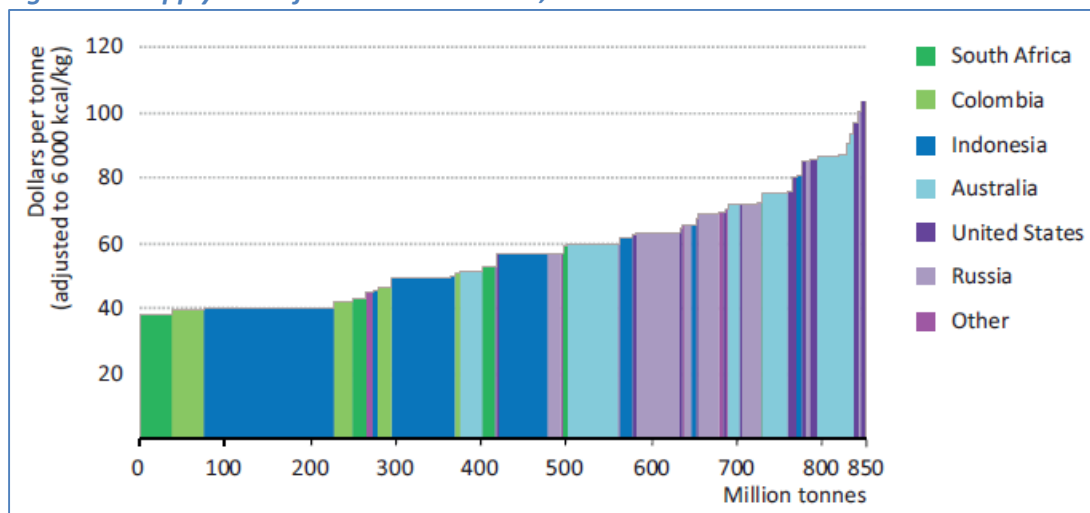
Current low price levels are not sustainable in the long run

Given the current cost structure in the international market, prevailing price levels are not sustainable in the long run without further reductions in high-cost supply. The foreseen slowdown, or even reduction in China's coal imports, may force **producers to adapt their production** more drastically. The supply curve for steam coal trade shows that several miners at the top of the cost curve in US, Australia and Russia, operated at a loss in 2012 and 2013.

¹⁹⁰ Bloomberg, Indonesia to Limit Coal Production This Year to Support Prices, 10 February 2014

¹⁹¹ IEA (2013), Medium-Term Coal Market Report, IEA/OCDE, Paris, December 2013

¹⁹² BREE (2014), Resources and Energy Quarterly March Quarter 2014, BREE, Canberra, March 2014

Figure 78: Supply curve for steam coal trade, 2012

Source: IEA, WEO 2013

Production cuts will determine the magnitude and timing for a recovery in the coal markets. As more production cuts would flow through the markets coal prices may start moving higher. There are however capped by domestic Chinese prices.

At short term, the market is expecting a slight recovery in prices, but many caveats

The Australian Bureau of Energy Resources (BREE) expects the global supply overhang to persist in 2014 and 2015, with prices forecast to further decline. **The rebalancing of the market is not expected before 2016.** BREE projects Australian contract prices to Japan at US\$89/t (in 2014 dollar terms) by 2019. BREE highlights the two major downward risks to this price outlook. On the supply side, if Indonesia's plans to curb production growth are unsuccessful, exports will grow at a faster pace than projected, which could reduce the possibility of higher prices post-2016. On the demand side, China's efforts to reduce air pollution and associated measures to reduce coal-use may force the transition away from coal at a faster pace than expected. Should this occur, growth in China's imports will be lower than projected, placing downward pressure on prices. In addition to China's uncertainties, the return into operation of some nuclear power plants in Japan may reduce its coal demand. In Europe, the expansion of RES and the impact of the backloading and the proposed EU ETS structural reform may decrease coal demand and imports more rapidly than expected.

These downward risks are not priced in current market price expectations. Forward CIF ARA prices for 2015 to 2017 are above the current very low spot price levels. They show a slight recovery in prices starting in 2016 and continuing in 2017 when quotations reach US\$87.5/t in. The market anticipates a continued well supplied market but expects that **prices have reached the bottom** and should recover from this low level.

Figure 79: Historical and forward CIF ARA prices

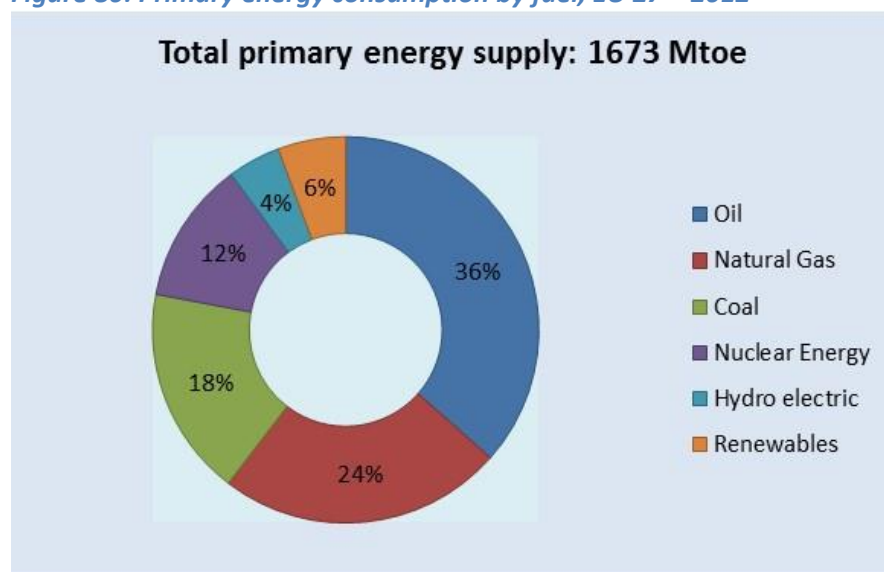
Source: World Bank, EEX

ANNEX 3: EU COAL DEMAND AND SUPPLY

Despite the recent coal renaissance, EU coal consumption has lost 40% since 1990

The EU consumed 795 Mt of coal, the equivalent of 420 Mtce in 2012. Europe is therefore the fourth largest coal market in the world. Coal, which fuelled the industrial revolution in the region, still accounts for 18% of the primary energy mix, against 30% at world's level. The share of coal in total primary energy supply (TPES) differs largely from one EU country to another. In 2012, coal accounted for 55% of Poland's TPES. The share of coal was also high in Bulgaria (39.2%), the Czech Republic (39.7%), Germany (25.4%), Greece (26%), Romania (19.8%), Slovakia (19%) and the UK (19.2%).

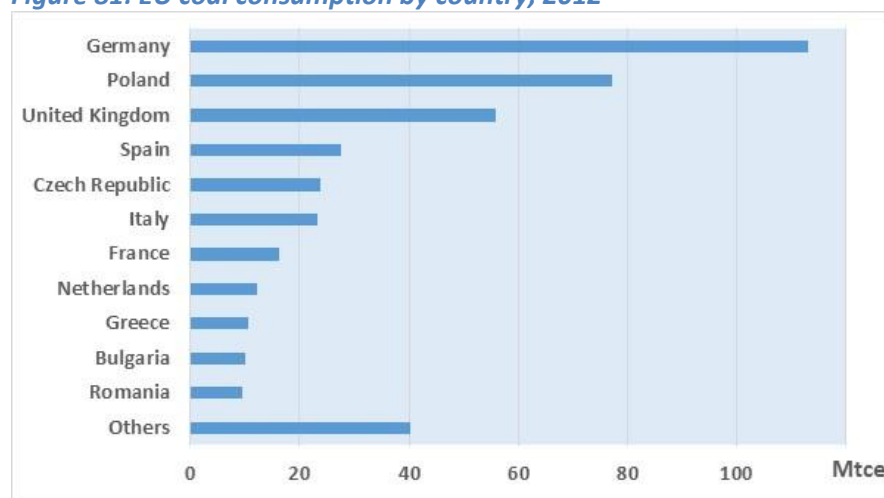
Figure 80: Primary energy consumption by fuel, EU 27 – 2012



Source: BP, EUROSTAT, EURACOAL.

In 2012, three countries (Germany, Poland and the UK) accounted for almost 60% of EU coal demand.

Figure 81: EU coal consumption by country, 2012

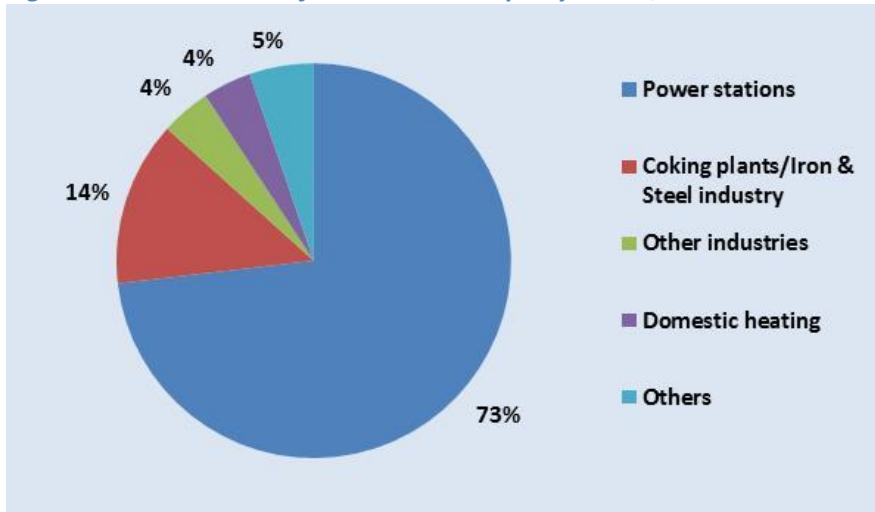


Source: BP

In contrast with natural gas which has diversified outlets, the use of steam coal is almost exclusively destined to the power sector, which accounted for three quarters of total EU coal demand in 2012. The other large user of coal (coking coal and PCI) is the iron and steel industry, where coal plays a major

role as a raw material in producing coke. The use of coal for domestic heating has almost disappeared in Europe, displaced by more convenient sources of energy.

Figure 82: Breakdown of coal use in Europe by sector, 2012

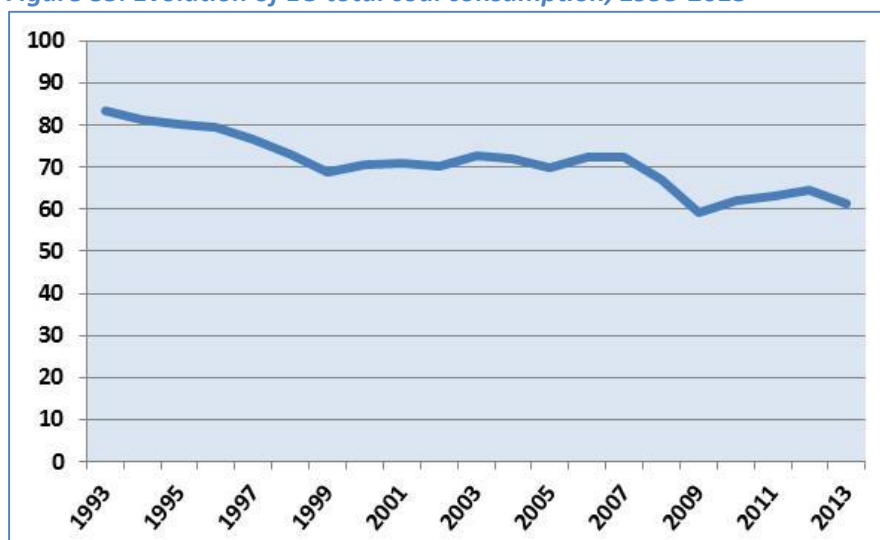


Source: Eurostat, own calculations

The use of coal in electricity generation varies widely across the EU Member States. In some countries, Poland, for instance, coal still accounts for 84% of electricity generation and 45% in Germany. In Greece, lignite still generates 54% of total electricity. On average, coal generates 28% of EU's electricity (see Figure 4), compared to 41% worldwide.

EU total coal consumption decreased steadily in the 1990s. Then, from 2000 to 2007, it remained relatively stable at about 450 Mtce. Further large decreases in consumption were observed once again in 2008 and, above all, in 2009, when consumption reached its lowest level at 371 Mtce, 41% less than in 1990. The decrease in coal consumption has stopped as coal demand by power utilities has risen again since 2011. However, preliminary data show that EU coal demand decreased by an estimated 5% in 2013.

Figure 83: Evolution of EU total coal consumption, 1993-2013

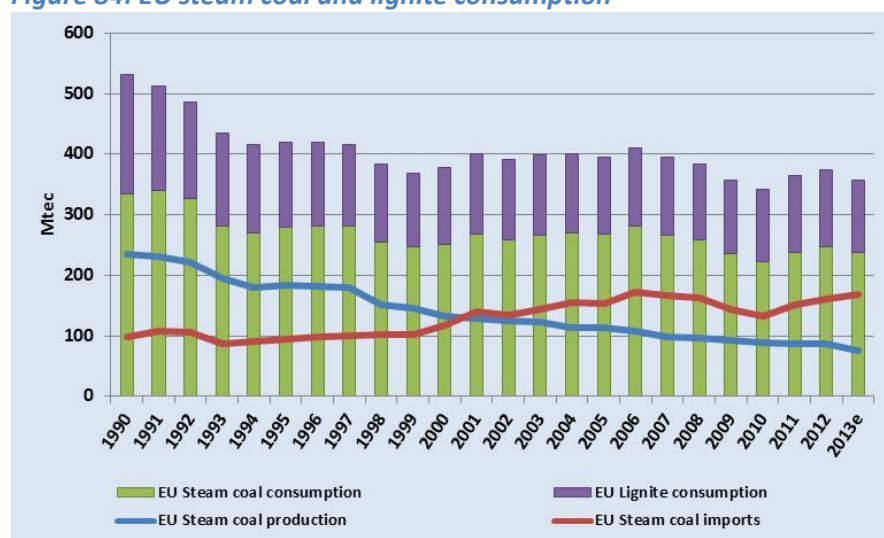


1990=100. Total coal consumption (hard coal and lignite, original data in Mtoe)

Source: EUROSTAT

Figure 84 shows the evolution of EU steam coal and lignite consumption, and steam coal production and imports. From 1990 to 2012, steam coal consumption (most of it consumed by power plants) has decreased by 26%, while lignite consumption has fallen by 36%. First estimates for 2013 show an additional contraction of coal demand (4% for hard coal and 6% for lignite). The figure also shows that steam coal imports have increased to compensate the decline in steam coal production. In 2013, the rise in steam coal imports mainly displaced higher-cost domestic production. Coal stocks at ports and power plants also increased.

Figure 84: EU steam coal and lignite consumption



Steam coal is the sum of anthracite, bituminous and sub-bituminous coal

Source: EUROSTAT, 2013: estimates

European coal reserves are significant. They are dominated by lignite

Europe holds 18.3 Gt of hard coal reserves at the end of 2011 (representing 140 years at current production levels), and 56 Gt of lignite reserves (132 years of production)¹⁹³. The region accounts for 20% of global lignite reserves and 2% only of hard coal reserves.

Table 21: EU hard coal and lignite reserves at end 2011, major countries

	Hard coal		Lignite	
	Mt	Share of EU total	Mt	Share of EU total
Bulgaria	192	1.1%	2174	3.8%
Czech Republic	1139	6.2%	2683	4.8%
Germany	48	0.3%	40500	71.7%
Greece	-	-	2876	5.1%
Hungary	276	1.5%	2633	4.7%
Netherlands	497	2.7%	4514	8.0%
Poland	14711	80.5%	-	-
Slovenia	56	0.3%	315	0.6%
Spain	868	4.7%	319	0.6%
United Kingdom	450	2.5%		0.0%
TOTAL EU	18277	100.0%	56473	100.0%

Source: BGR

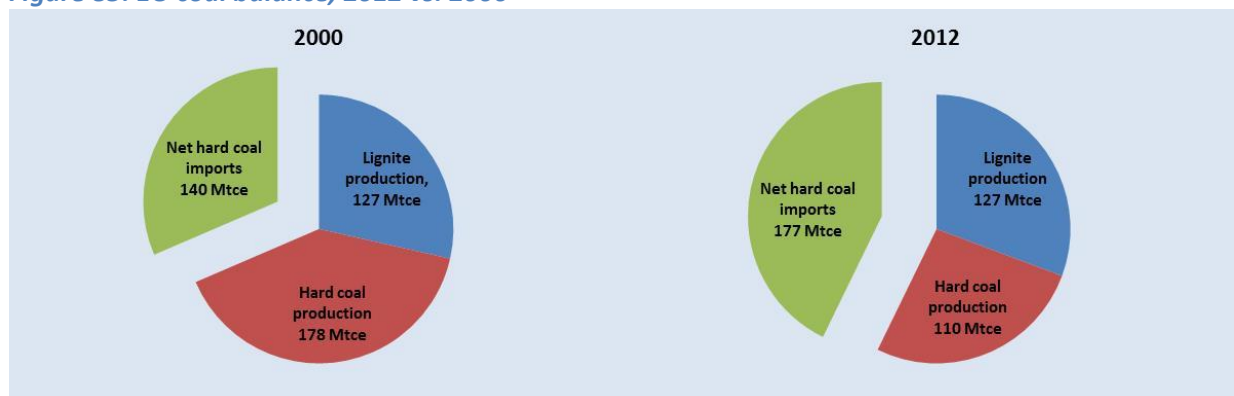
¹⁹³ BGR (2013), op.cit.

Five countries dominate: Germany (mainly lignite), Poland, Greece, the UK and the Czech Republic. Germany is the world's second largest holder of lignite, just after Australia and alone accounts for 72% of EU lignite reserves. Future EU lignite production will therefore be tied to developments in Germany. The same applies to Poland for hard coal; the country holds 80% of EU hard coal reserves.

EU coal production is falling but still represents around 60% of total demand

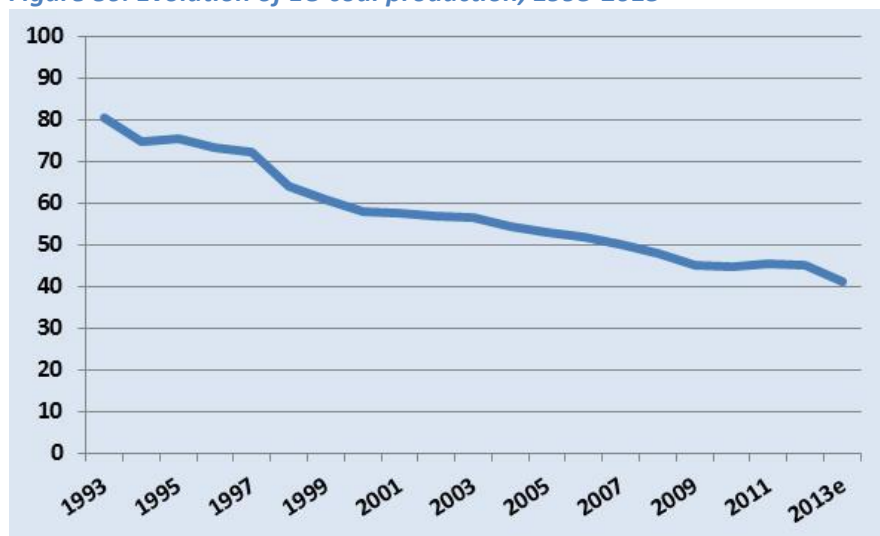
European total coal production amounted to 564 Mt in 2012 (equivalent to 237 Mtce), made up of 125 Mt of hard coal (of which 23.5 Mt of coking coal) and 439 Mt of lignite in 2012, 2% and 45% of worldwide production respectively. Preliminary data show that EU total coal production decreased by 9% to 216 Mtce. Hard coal production declined by an estimated 12% as EU domestic miners could not compete with international coal. Around 60% of EU coal consumption is covered by indigenous production, which makes coal a major contributor to EU security of supply. This rate of independence has decreased since 2000 as hard coal production declined and has been replaced by growing imports. The trend accelerated in 2013 as domestic hard coal production could not compete with cheap imports. UK production decreased by 25% to 13 Mt in 2013 compared with 2012. The sector struggled with financial losses which led UK biggest coal producer, UK Coal, to be placed in administration and smaller miners to be liquidated. In Poland, mining companies encountered the same competitiveness issues and posted negative financial results. In Germany, hard coal production declined too from 11.6 Mt to 8.3 Mt. However, this decline was expected as German hard coal production is going to cease completely by the end of 2018, in accordance with the Council Decision 2010/787/EU of 10 December 2010 on the closure of uncompetitive coal mines (see box 20).

Figure 85: EU coal balance, 2012 vs. 2000



Source: EURACOAL

Total coal production has decreased almost continuously since 1990 from 524 Mtce to 216 Mtce to 2013. In 2013, it was 40% that of 1990.

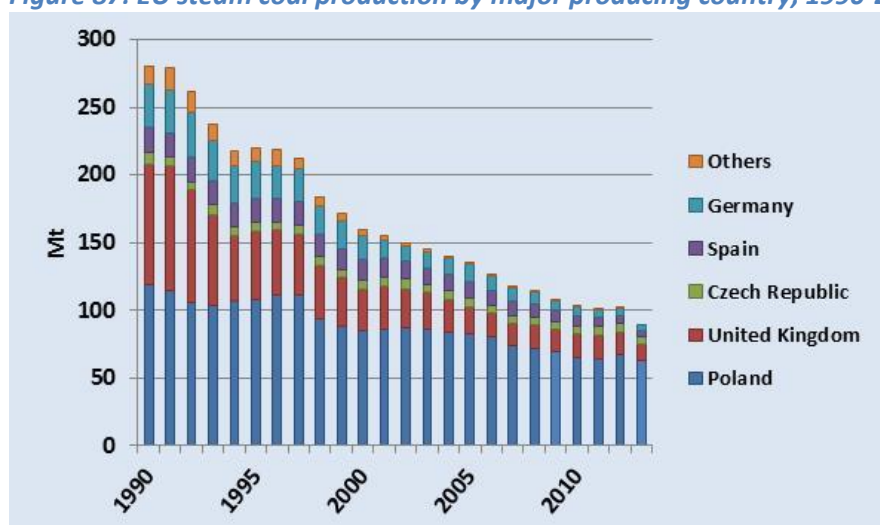
Figure 86: Evolution of EU coal production, 1993-2013

1990=100. Total coal production (hard coal and lignite, original data in Mtoe)

Source: EUROSTAT, 2013: estimates

Hard coal has been mined longer and more extensively in Europe than elsewhere, and most of the economically obtainable, high calorific value reserves have been tapped. As hard coal in Europe is recovered mainly from underground deposits, European coal miners are forced to work in deeper and in more difficult conditions to recover reserves of poorer quality coal, which increases costs. Production costs in some European hard coal mines are two to three times higher than prices for imported coal. Several EU countries have therefore ceased their hard coal production. In some hard coal producing countries, production is subsidised, but the subsidies are gradually being phased out (see Box 20). Where production is not subsidised, it cannot compete with current low international coal prices and several EU hard coal mines were closed in 2013.

Steam coal production has fallen since 1990 from 281 Mt to 101 Mt in 2012. In 2013, steam coal production declined sharply to 89 Mt (first estimates).

Figure 87: EU steam coal production by major producing country, 1990-2013

Note: Anthracite, bituminous and sub-bituminous coal. Excludes lignite and coking coal

Source: EUROSTAT. 2013: estimates

Box 20: End of subsidies to hard coal mining

Several EU hard coal mines are not economic and are subsidised. State aid to coal mining is regulated by the European Commission. The Council Regulation (EC) on State aid to the coal industry N° 1407/2002 of 23 July 2002 expired on 31 December 2010. It was succeeded by a Decision adopted at end 2010 by the Council on State aid (Council Decision 2010/787/EU of 10 December 2010 to facilitate the closure of uncompetitive coal mines). The Council Decision provides for aid within a closure plan, under certain conditions. The uncompetitive mines must be closed by 31 December 2018, and the coal production progressively reduced over the period. Subsidies have to be lowered by at least 25% until 2013, by 40% until 2015, by 60% by 2016 and by 75% by 2017.

The amount of production aid paid to support uncompetitive hard coal mines totalled €2.9 billion in 2010 (of which 1.75 billion in Germany and 816 million in Spain). These mines produced around 27 Mt. These subsidies apply neither to Bulgaria, the Czech Republic and the UK, nor to lignite mines which offer competitive yields and revenues.

State aid to EU hard coal mining companies is decreasing and will be phased out by the end of 2018. The Member States concerned continue to finance measures related to restructuring and consolidation of their subsidised coal sectors. A large part of the support is directed to environmental clean-up measures or early retirement schemes. Under present policies, about 27,000 mine workers still employed in Germany and Spain in 2010 will lose their jobs in the absence of production aid. In Romania, Hungary and Slovakia, a further 15 000 mine workers' jobs may be threatened by the end of subsidies.

The end of State aid has various consequences on national coal balances. Germany will substantially increase its imports to cover the loss of all domestic hard coal production by the end of 2018. Production amounted to 13.2 Mtce in 2010 and already fell to 7.8 Mtce in 2013. The cost of producing hard coal in Germany (lignite mining is not subsidised) is far higher than the price of imported coal: €180/tce compared with €79.12/tce on average in 2013. The difference is made up by a subsidy to RAG, the dominant producer. The cost of these subsidies peaked at €8.5 billion in 1996 and was €1.44 billion in 2012, in line with decreasing production.

In Spain, the National Plan for Coal 2013-18 sets out targeted reductions of hard coal production from 6.6 Mt in 2013 to 5.9 Mt by 2018. In Poland, imports have been rising and will likely continue to rise as inefficient mines are closed. However, privatisation of mines is expected to boost productivity and output at the remaining mines, so hard coal production should stabilise. In the other European countries, the majority of hard coal and lignite production is usually competitive with imports and State aid is relatively limited. However, the fall in import prices in 2012 and 2013 makes several mines uncompetitive leading to their closure.

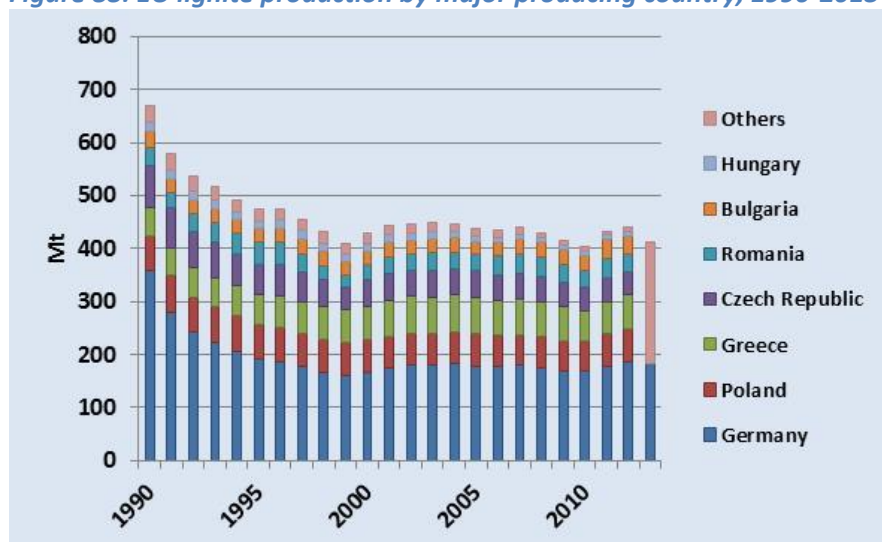
The case of lignite is different. EU reserves are huge and lignite in Europe is typically mined in open-cast sites, which keeps extraction costs low. European lignite production is generally cost-competitive with imports of hard coal without subsidies. As there is no international market for lignite (except for Indonesian low-cal exports to China), prices are not readily available. Both producer and consumer co-exist in a captive market and often form a single economic entity. The Czech power utility CEZ signed a long term supply contract with Czech Coal in March 2013 and reported a price of CZK 38.8/GJ (€1.41/GJ) for 2013, gradually increasing to 65% of coal import price in ARA¹⁹⁴. This is much lower than the average price of steam coal imported in ARA in 2013: €79.12/tce (€2.7/GJ). Consequently, lignite

¹⁹⁴ CEZ Group, Investors presentation, November 2013

production in the EU will most likely survive, unlike hard coal production. Lignite represents an important energy source for the EU, as it helps to reduce its energy import dependence. It is however a major source of CO₂ emissions. Old lignite-fired power plants emit 1100 kgCO₂/MWh. Emissions are reduced by 30% in the new high-efficient plants commissioned recently in Germany (Neurath and Boxberg).

EU lignite production amounted to 439 Mt in 2012, dominated by Germany, Poland and Greece. Production is estimated at 413 Mt in 2013. With some 183 Mt, lignite production in Germany was 1.5% lower than the previous year¹⁹⁵.

Figure 88: EU lignite production by major producing country, 1990-2013



Source: EUROSTAT, 2013: estimates

The IEA Medium-Term Coal Market Report expects total coal production (hard coal and lignite) in Europe OECD¹⁹⁶ to decrease slightly from 244 Mtce in 2011¹⁹⁷ to 233 Mtce in 2018 in the base case scenario, an annual average decline of 0.8%. In the WEO2013 (New Policy Scenario), EU production is expected to decline from 239 Mtce in 2011 to 202 Mtce in 2020 and to fall further to 103 Mtce by 2035 due to closure of old mines that have been producing for many decades.

Recent rise in European coal imports and a structural shift in coal supplies

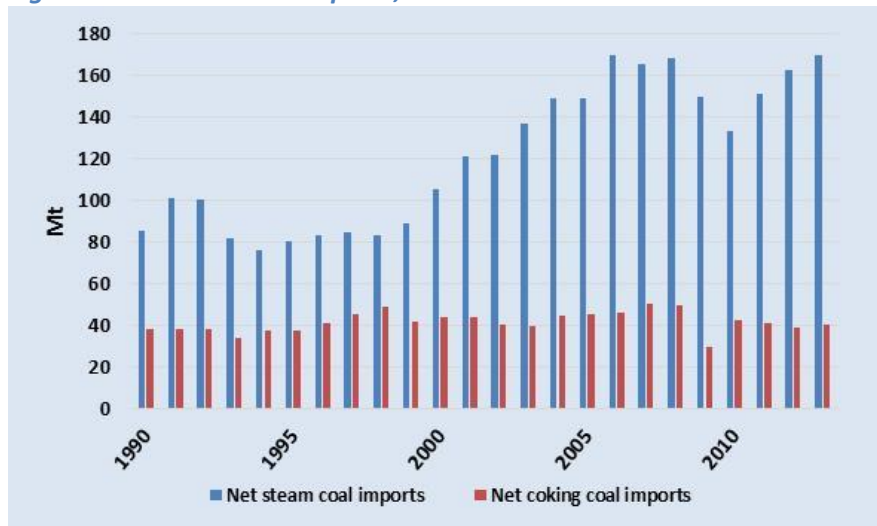
EU steam coal imports have risen since 2011, after two years of contraction in 2009 and 2010. Net steam coal imports¹⁹⁸ rose 13% from 133 Mt in 2010 to 151 Mt in 2011 and again by 8% to 163 Mt in 2012. Imports have grown under the combined effect of declining production, mainly in Germany, UK and Poland, and above all low coal prices which boosted demand by power utilities. First estimates for 2013 show that imports increased by around 4% to 169 Mt and widely varied by importing country (see Box 21). However, consumption decreased in 2013 and the rise in imports mainly displaced higher-cost domestic production. Coal stocks at ports and power plants also increased in 2013.

¹⁹⁵ DEBRIV, 2014.

¹⁹⁶ The IEA Medium Term Coal Market Report does not give a breakdown for EU countries only.

¹⁹⁷ 2011 is the reference year in the IEA Medium Term Coal Market Report and the WEO 2013

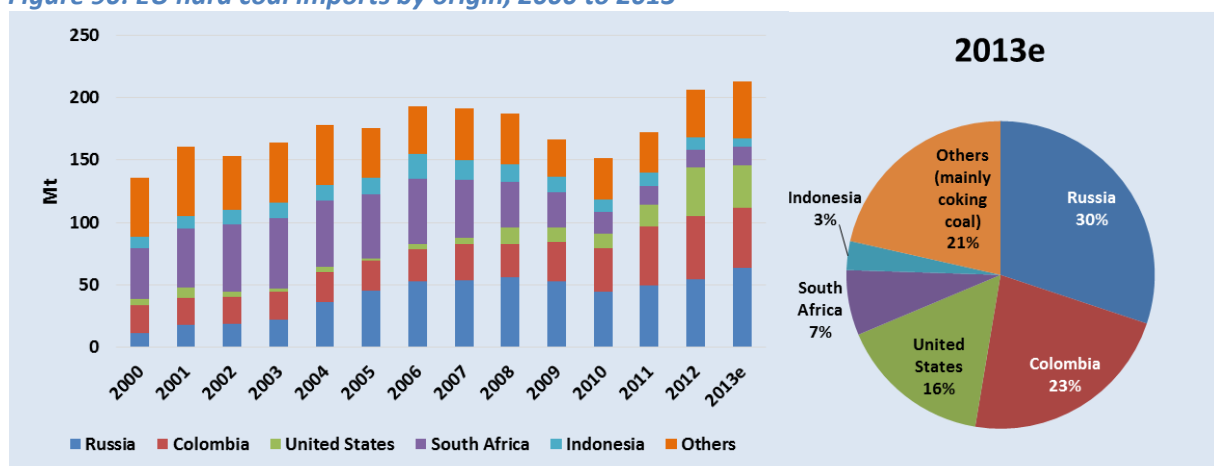
¹⁹⁸ Data refers to net imports, after subtraction of EU exports which consist in trade between EU countries.

Figure 89: EU hard coal imports, 1990-2013

Source: EUROSTAT, 2013: estimates

The UK, Germany, Italy, and Spain are the major steam coal importing countries. On the supply side, Russia and Colombia are the two leading sources. The US comes third. This new source of supply has brought additional liquidity to the European market. Competition between suppliers to the EU has been fierce over the past three years, as US coal has tried to displace Colombian and South African coal. The structure of hard coal imports¹⁹⁹ changed significantly during the past few years:

- US coal supplies to the EU increased sharply between 2010 and 2012 and the country has gained a higher share of the European market (19% in 2012). Despite the decrease in exports in 2013, the US still accounts for 16% of EU imports.
- Russia and Colombia remain the two leading sources, with shares of 30% and 23% respectively in 2013. Last year, Colombian exports declined due to supply constraints.
- Declining steam coal exports from Indonesia and South Africa over the past three years were replaced by greater supplies from Colombia, the United States and Russia.

Figure 90: EU hard coal imports by origin, 2000 to 2013

Source: Eurostat; 2013: estimates

¹⁹⁹ The breakdown between steam and coking coal imports by exporting country is not yet available for recent years. Coking coal exports are coming from Australia (almost all exports from the country), US and Russia.

Box 21: Evolution of steam coal imports by major EU importing countries in 2012 and 2013

In 2012 and 2013, steam coal imports by major European importers registered significant changes. The most dramatic one occurred in Spain, which after spectacular growth in imports in 2012 registered a sharp reduction in 2013.

The **United Kingdom** is the EU largest steam coal importer, just ahead of Germany. Its steam coal imports were 8.5% higher at 43 Mt in 2013 compared to 2012. This level reflects the declining contribution of domestic production in meeting demand from electricity generators. Domestic production fell 25% in 2013 in response to competition from cheap coal imports. There was an increase in steam coal imports from Russia of 9.8% and the US of 7.6%. Russia, the US and Colombia in 2013 represented 93% of steam coal imports²⁰⁰. Growing imports at low cost mainly replaced domestic production and increased coal stocks at power plants. Despite the rise in steam coal imports, demand for coal from electricity producers decreased by 8.8% in 2013 and the share of coal in electricity generation decreased from 39.4% in 2012 to 36.3% in 2013. Despite the decrease in coal use, the contribution of coal to the UK's electricity mix remained high compared to recent years. This trend continued the change observed in 2012 when the falling price of imported coal increased its competitiveness and led to a surge in coal use. That year, generators switched from gas to coal to reduce costs. Steam coal imports reached 39.6 Mt in 2012, a 50% rise over 2011.

In **Germany**, steam coal imports increased by 14% to 36.5 Mt in 2013²⁰¹ in response to declining domestic production and increased demand from power generating companies. Steam coal share in electricity generation rose to 19.6% in 2013, as against 18.5% in 2012. Hard coal imports (including coking coal) increased to 45 Mt in 2013 from 41 Mt in 2012. Russia (11.8 Mt in 2013), the US (10.4 Mt) and Colombia (8.1 Mt) are the major suppliers of hard coal. In the coming years, the role of coal will be reinforced by the phasing out of nuclear power. Exactly how Germany will replace generation from nuclear plants remains uncertain, but clearly, for now, coal is part of the answer. The decline in domestic production coupled with the start-up of new hard coal-fired plants will drive imports up.

In **Spain**, a radical change in coal imports occurred in 2013 as new regulations and levies unfavourable to coal burning and higher electricity production from hydro and renewables displaced coal consumption in the power sector. Wind power became the first primary source of electricity in 2013 (21% market share), while coal saw its share falling to 14.6% from 19% in 2012. Steam coal imports collapsed, down 48% to 10.2 Mt. The opposite situation occurred in 2012, when coal benefited from increased competitiveness in the power sector, helped by low hydro levels. Steam coal imports surged to 19.6 Mt in 2012, from 12.7 Mt in 2011. Coal imports depend on several factors such as electricity demand and hydro and RES electricity production, coal import prices, stocking capacity, and more importantly, domestic coal production, which under Spanish law has priority.

Italy's steam coal imports fell from 19 Mt in 2013 to 16 Mt (estimated) in 2012 in line with the sluggish economy. In 2012, they increased by 12%, boosted by demand from Enel's Torrealvaldiga Nord power plant, which saw its first calendar year at full capacity. The level of future imports is uncertain. They were expected to grow following the construction of two new coal-fired power stations – one in Saline Joniche in southern Italy, the other in Vado Ligure in the north. However, the current power over-capacity does not suggest a quick realisation of these projects.

²⁰⁰ DECC, Energy Trends, 27 March 2014

²⁰¹ BAFA, 2014

4. THE EU CO₂ MARKET

EU leaders have endorsed the objective of reducing Europe's GHG (greenhouse gas) emissions by 80-95% by 2050 compared to 1990 levels as part of efforts by developed countries as a group to reduce their emissions by a similar degree. Launched in 2005, the EU Emission Trading Scheme (EU ETS) was meant to be a key tool for reducing industrial GHG emissions by providing a price signal for investment in low-carbon technologies. Although CO₂ emissions have dropped by 18% since 1990 and the emissions reduction target by 2020 is expected to be met, these achievements owe more to a combination of economic and regulatory factors than to the implementation of the EU ETS. The development of subsidised renewable power, the economic crisis and the influx of Kyoto offset credits have created a massive oversupply of allowances and driven down carbon prices to levels that create no incentive for investments in low-carbon technologies or fuel switching from coal to gas. With the adoption, at the beginning of 2014, of short-term measures (backloading) and proposed in-depth structural reforms, the European Commission hopes to address the current flaws in the EU ETS and promote a well-functioning carbon market.

4.1. THE EU ETS

A cap and trade system

The EU ETS works on a "cap and trade" principle. It sets a cap to the CO₂ emissions that can be emitted by about 12,000 industrial installations (power plants, factories and other installations in the system). Within this cap, companies receive allowances (EU Allowance Units, EUAs) which they can sell to or buy from one another as needed. These industrial installations have to return each year as many allowances (1 allowance for 1 ton of CO₂ emitted) as their verified emissions of the previous year²⁰². From 2008, EU ETS installations have also been allowed to use Kyoto offset credits (Certified Emissions Reductions, CERs or Emissions Reduction Units, ERUs) up to a limit of 13.5% of their allocation on average. Altogether the EU ETS covers around 45% of total GHG emissions from the EU countries. The energy sector (power and heat production, refinery, coke furnaces) is the largest sector in the EU ETS.

During the two first periods of the EU ETS (2005-2007 and 2008-2012, corresponding to the Kyoto commitment period), EU ETS-covered installations received an annual allocation of emissions allowances, generally free of charge, which were fixed by National Allocation Plans (NAP), established under the supervision of the European Commission.

The third phase introduces significant changes for the power sector

The third phase of the EU ETS (2013-2020) builds upon the previous two phases but has been significantly revised to make a greater contribution to tackling climate change. The individual Member State allocation caps have been replaced by an EU-wide cap on allowances centralised by the European Commission and much more ambitious. It has been provisionally fixed at 2039 Mt for 2013 and will gradually decline by 1.74% per year by 2020 so that total emissions allocated in 2020 will be 21% lower than in 2005. Auctioning²⁰³ is the default method for allocating emission allowances to companies participating in the EU ETS, although the manufacturing sector will continue receiving some free allowances. For the power generation sector, full auctioning is the rule, which means that power utilities will need to purchase all their allowances up to their emissions cap, for a particular year, at

²⁰² They have to pay a fine per tonne in case of non-compliance.

²⁰³ Auctioning was recognised by the European Commission as the most transparent method of allocating allowances and the preferred method to avoid the "windfall profit" issue, by which power generators have been able to pass on the notional cost of allowances (opportunity cost) to customers even when they received them for free.

auction or on the secondary market. There is a temporary derogation to full auctioning for power plants located in eight new Member States that have made the request to the European Commission (namely Bulgaria, Cyprus, the Czech Republic, Estonia, Romania, Hungary, Poland, and Latvia) on the condition that an equivalent financial amount is invested in modernising their power generation industry. The auctioning rate for these States is set at a minimum of 30% of an installation's emissions cap in 2013, increasing to 100% by 2020. CHP plants will continue to receive free allowances for heat generation only and on the basis of benchmarks.

For the manufacturing industry, although auctioning is the default method for allocating emission allowances, the sector will continue to receive a share of allowances for free until 2020 and beyond. Free allocation is carried out on the basis of ambitious benchmarks of GHG performance. These benchmarks reward best practice in low-emission production. The free allocation decreases each year. The installations will receive 80% of their allowances for free in 2013, a proportion that will decrease in linear fashion each year to 30% in 2020. Sectors and sub-sectors facing competition from industries outside the EU which are not subject to comparable climate legislation will receive a higher share of free allowances than those which are not at risk of such 'carbon leakage.'

Already in 2013, more than 40% of allowances allocated under the EU ETS have been auctioned²⁰⁴ instead of being allocated free of charge and this share will rise progressively in the following years. Full auctioning for all installations covered by the EU ETS is foreseen by 2027. EEX (Leipzig) conducts the auctions for 26 Member States covering about two thirds of the total auctioned volume. For the remaining volume, Germany and the United Kingdom have appointed EEX and ICE Futures Europe (ICE, London) respectively.

Moreover, the use of Kyoto offset credits²⁰⁵ will be more tightly restricted in the third phase.

The third phase therefore will be a period of significant changes for power plant operators. The power sector, which was already short of allowances (see next point), will bear the full cost of its CO₂ emissions, except in the eight MS that will allocate free allowances to their power operators until 2019. This new burden does not favour coal, which emits twice as much CO₂ than natural gas. The financial charge obviously depends on CO₂ prices but even at the low level observed in 2013, the extra cost for power utilities operating large coal fleets is significant as they no longer benefit from the implicit

²⁰⁴ See European Commission, Auctions by the transitional common auction platform , 10th Report , December 2013

²⁰⁵ Mechanisms of the Kyoto Protocol

Mechanisms of the Kyoto Protocol or "Flexible mechanisms" refers to Emissions Trading, the Clean Development Mechanism (CDM) and Joint Implementation (JI). These are mechanisms defined under the Kyoto Protocol intended to lower the overall costs of achieving its emissions targets. These mechanisms enable Parties of the Kyoto Protocol to achieve emission reductions or to remove carbon from the atmosphere cost-effectively in other countries. While the cost of limiting emissions varies considerably from region to region, the benefit for the atmosphere is in principle the same, wherever the action is taken. Beyond the EU ETS, industrialised countries can earn Kyoto credits through two mechanisms:

Clean Development Mechanism (CDM)

CDM allows emission-reduction projects in developing countries to earn Certified Emission Reduction (CER) credits, which can be traded and sold, and used by industrialised countries to meet a part of their emission reduction targets.

Joint Implementation (JI)

JI enables industrialised countries to carry out joint implementation projects with other developed countries, and in that case to earn Emission Reduction Units (ERUs), which represents an emission reduction equivalent to one tonne of CO₂ equivalent.

subsidy in the form of freely allocated allowances. RWE, which generates 61% of its electricity from coal, states in its annual report 2013, that free allocations received by the company dropped from 121.4 Mt in 2012 to a mere 7.4 Mt in 2013. This resulted in a shortage of allowances of 155.9 Mt in 2013 compared to 58.4 Mt in the previous year, although RWE's fossil-fuel electricity generation and CO₂ emissions declined in 2013. This shortage was made up by buying certificates. This negatively impacted the financial result of RWE. The operating results of its conventional power generation segment in Germany, Netherlands, United Kingdom and Belgium fell 67% from €4.1 billion in 2012 to 1.4 billion in 2013, strongly impacted by the decline in electricity prices in Germany and the lack of freely allocated allowances. In 2012, free allowances had provided the company around €1.2 billion in relief²⁰⁶. Finally, the ongoing reform of the EU ETS is going to radically change the market (see Box 22 and Section 4.3).

Box 22: EU ETS policy

The European Commission proposed a structural reform of the ETS on 22 January 2014. It includes a plan to take 12% of surplus allowances out of the market, when the surplus is above 833 Mt, and place them in a reserve each year, starting in 2021. The allowances would be handed back to the market if the surplus falls below 400 Mt (Market Stability Reserve).

The Commission also wants to reduce the ETS cap by 2.2% each year, compared with 1.74% at present. This would apply from 2021 and corresponds to a reduction of 550 Mt during the fourth trading phase (2021-2030).

The proposals for EU ETS reforms need approval from the European Parliament and the 28 Member States in the European Council.

The European Parliament and the European Council approved in February 2014 the fast-track backloading regulation. The regulation will remove 900 Mt of allowances over the period 2014-2016 and hand back them to the market in 2019 and 2020.

RES development, the economic crisis and the influx of Kyoto offset credits resulted in a huge EUA surplus

Since 2009 the EU ETS has experienced a **growing surplus of allowances and international credits (CERs and ERUs) compared to emissions** which has significantly weakened the carbon price signal. CO₂ emissions by the installations covered by the EU ETS decreased significantly during the second phase from 2120 Mt in 2008 to 1867 Mt in 2012, i.e. a decrease by 11.9%, with a steep 11.4% fall in 2009. This resulted in a growing accumulated surplus of 1739 Mt of unused allowances from 2008 to 2012.

Table 22: EU ETS Phase 2 balance

	2008	2009	2010	2011	2012	2008-2012
EUAs allocated for free (million)	1958	1974	1998	2016	2049	9995
EUAs sold or auctioned by governments (million)	44	78	92	93	99	406
Available EUAs (million) [A]	2002	2052	2090	2109	2148	10401
Verified emissions (million tons) [B]	2120	1880	1939	1904	1867	9710
Compliance position [A-B]	-118	172	151	205	281	691
Allowances/Credits surrendered						
EUAs (million) [C]	2010	1839	1793	1637	1383	8662
CERs (million)	84	77	117	178	214	670
ERUs (million)	0	3	20	76	279	378
EUAs Shortage (-)/Surplus (+) (million) [A-C]	-8	213	297	472	765	1739

Source: Tendances Carbone/CDC Climat Research

²⁰⁶ RWE (2014), Annual Report 2013

In addition, the surplus grew to about 2.2 billion tons at the end of 2012, aggravated by the monetisation of allowances from the new entrants reserve (NER) for the third trading period for support of demonstration projects ('NER300'²⁰⁷), early auctioning of phase 3 allowances and release of allowances not needed in the NER for the second trading period.

Most observers (as well as the European Commission in its report on the state of the carbon market), attribute the growing surplus of allowances to the economic crisis that strongly affected industrial output. However, as explained by the authors of the working paper on *Governance of CO₂ markets: Lessons from the EU ETS*²⁰⁸, if the economic crisis is one significant factor explaining the surplus, other factors played an even more important role. There are **three main causes for the current surplus**.

- The first is effectively the unforeseen decline in industrial activity since the 2008 crisis.
- The second is the high use of Kyoto offset credits over a short period of time resulting from the unforeseen evolution of the international Kyoto system in conjunction with the time-flexibility left to participants for using offsets.
- The third reason is the interactions between the allowance system and other energy and climate policies, namely the renewable energy and energy efficiency policies that can drive EU ETS emissions down independently of the EUA price²⁰⁹. The fast rising of electricity generation from RES, driven by the RES directive and support schemes in Member States, has decreased the demand of electricity generation addressed to fossil fuels and, therefore, CO₂ emissions and demand for allowances of power plants in the EU ETS. The same interaction applies with the energy efficiency directive which reduces total electricity and energy demand of the sectors covered by the EU ETS and therefore their allowances needs. This interaction between policies automatically leads to the marginalisation of the EU ETS, because the emission base of the system is eroded by other policies whereas the supply of allowances remains fixed for the entire period of the trading phase (with determined declining rates per year).

Box 23: The role of RES and economic downturn in CO₂ emissions reduction

CDC Climat²¹⁰, an investment group owned by Caisse des Dépôts, has quantified the origin of the CO₂ emissions reduction during the period 2005-2011. Using an econometric analysis, CDC Climat shows that reductions of around 1.1-1.2 Gt CO₂ are likely to have been achieved within the scope of the installations covered by the EU ETS between 2005 and 2011, compared to a business-as-usual scenario. The main cause of the reduction was the contribution of RES to power generation, which accounted for an aggregated reduction of around 500 Mt (40 to 50% of all the reduction), followed by the economic downturn, which led to a reduction of around 300 Mt (around 20 to 30%) and then the improvement in the economy's energy efficiency, which resulted in a reduction of between 100 and 200 Mt (between 10 and 20%), along with a reduction of around 200 Mt (i.e. around 20%) via fuel-

²⁰⁷ "NER300" is a financing instrument managed jointly by the European Commission, European Investment Bank and Member States, so-called because Article 10(a) 8 of the revised Emissions Trading Directive 2009/29/EC contains the provision to set aside 300 million EUA in the New Entrants' Reserve of the EU ETS for subsidising installations of innovative renewable energy technology and CCS.

²⁰⁸ Climate Economic Chair (2013), Christian de Perthuis and Raphaël Trotignon, *Governance of CO₂ markets: Lessons from the EU ETS*, Working Paper Series N° 7/2013, Paris Dauphine University and Climate Economics Chair.

²⁰⁹ Climate Economic Chair (2013), op. cit.

²¹⁰ CDC Climat Research (2013), *Explanatory factors for the change in CO₂ emissions over both phases of the EU-ETS: an econometric analysis*, by O. Gloaguen and E. Alberola, Working Paper No. 15.

switching²¹¹. The impact of the carbon price was small (between 0 and 10%). The main effect of carbon prices was to promote fuel switching, from coal to gas. The EU carbon market also helped to reduce emissions outside of Europe (1048 Mt in the period under consideration), thanks to the flexible mechanisms of the Kyoto Protocol.

The surplus has plagued the market and led to a collapse in EUAs prices

The growing imbalance between supply and demand of allowances has led to a collapse in EUAs prices which fell from €25-30/t in 2008 to an average €7.9 in 2012 and €4.7 in 2013. **In the past three years, the price declined by 65%.** At these levels, given coal and natural gas prices, coal has become the most profitable way of generating electricity from conventional fuels.

Figure 91: Evolution of CO₂ prices (European Union Allowances): spot prices (2008-2014)



Source: BlueNext

4.2. THE POWER SECTOR IN THE EU ETS²¹²

The largest emitting sector in the ETS

The power sector is the largest emitter of CO₂ among the sectors covered by the EU ETS. In 2012, the power sector emitted 1120 Mt, representing 60% of total verified CO₂ emissions from the EU ETS installations. Linked to its historical emissions, the sector is also the one which receives the most of allowances allocated in the ETS: **electricity producers received approximately 50% of allowances** allocated in phase 2 (4900 Mt over the five years, i.e. 980 Mt per year).

Since 2005, 1,453 power and combined heat and power (CHP) generation plants have participated in the EU ETS. The capacity of the thermal plants covered by the EU ETS amounts to 419 GW at the end of 2012, representing almost the total installed thermal capacity in the EU as only plants with a capacity of less than 20 MW are excluded from the EU ETS. Thermal plants that use coal and natural gas as their primary fuel jointly account for 86% of the generation capacity included in the EU ETS, 43% each. The

²¹¹ The model tests reductions from 2005 to 2011, therefore includes years where the clean spark spread was higher than the dark spark spread, triggering substitution from coal to gas.

²¹² This section is based on an analysis carried out by CDC Climat Research, The power sector in phase 2 of the EU ETS: fewer CO₂ emissions but just as much coal, Climate Report N° 42, November 2013.

remaining 14% use oil as their primary fuel and fossil fuels (mainly gas) as their secondary fuel. There are 671 gas-fired power plants and 352 coal-fired ones.

Rising CO₂ emissions due to coal use compensated by reduced emissions from gas

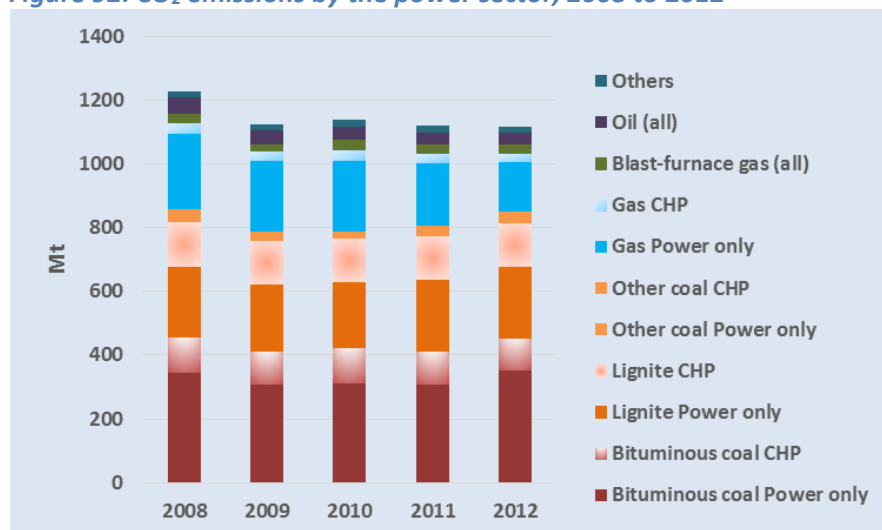
The power sector has experienced a significant decrease in its CO₂ emissions over the period 2008-2012. The sector's emissions fell by 8.9% or 110 Mt during the second trading phase, from 1230 Mt in 2008 to 1120 Mt in 2012. **The fall, however, was almost entirely explained by the economic recession** which resulted in a 5% decrease in power production in 2009. CO₂ emissions that year fell by 8.4% (or 103 Mt). Since then, they have remained at about 1.1 Gt/y.

CO₂ emissions from power generators participating in the EU ETS are mostly generated by coal-fired power plants. Coal-fired power plants emitted an average of 819 Mt/year between 2008 and 2012, equal to 70% of the total CO₂ emitted by the sector. Gas-fired power plants were responsible for 22% of the total emissions (236 Mt per year on average).

The reduction registered between 2008 and 2012 differs depending on the type of power plant and the fuel used:

- Plants that generate only electricity reduced their CO₂ emissions more significantly than CHP plants (9.7% and 6.8% respectively).
- Gas and oil-fired power plants experienced the sharpest decline in their CO₂ emissions, which fell by 34% and 30% respectively between 2008 and 2012. CO₂ emissions from gas-fired power plants fell from 273 to 175 Mt, mainly due to the decrease in electricity production from gas while emissions from oil-fired power plants fell from 50 to 37 Mt, mainly due to the closure of old oil-fired plants.
- After declining sharply in 2008 and 2009, primarily due to the economic downturn, CO₂ emissions from coal-fired power plants increased between 2009 and 2012, reaching 852 Mt in 2012, compared with 856 Mt in 2008 (789 Mt in 2009). This increase is explained by the rebound in coal competitiveness.

Figure 92: CO₂ emissions by the power sector, 2008 to 2012



Source: Climat Research, November 2013

While the EU ETS is long in EU allowances, the power sector has always been short

The power sector is the only sector in the EU ETS where the CO₂ emissions generated were greater than the allowances received. Despite the overall fall in its CO₂ emissions between 2008 and 2012, the power sector suffered from a structural allowance shortfall of 825 Mt at the end of phase 2, due to a lower allocation of free allowances than in phase 1. The sector was subject to a 20% decrease in free allowances allocated between phase 1 and phase 2, the tightest reduction of all EU ETS sectors. Allocations for the power generation sector have historically been less generous than those granted to other sectors. When drawing up their National Allocation Plans for phases 1 and 2, most States chose to reduce the allocations for power plant operators more significantly than those for other sectors between the initial two phases. The main reason is that the power sector is not exposed to international competition, and therefore there is no risk of “carbon leak”. Moreover, the power sector can pass on a greater portion of the additional cost to end-consumers.

Table 23: Emission-to-cap by EU ETS sector

Difference between distributed allocations of allowances and verified emissions

	2008	2009	2010	2011	2012	2008-2012
Combustion	-253.1	-113.5	-125.8	-76.9	-40.6	-609.9
of which power sector	-268	-165	-163	-130	-99	-825
Oil refining	-1.4	7.6	14.3	16	24.2	60.7
Coking plants	1.5	6.8	2.9	3.1	5.7	20
Metal ores	4.3	11	8.8	8.9	9.8	42.8
Steel production	51.6	89.3	71.4	72.8	74	359.1
Cement	20.9	61.4	61	62.8	74.1	280.2
Glass	2.5	6.1	5.5	5.4	6.4	25.9
Ceramic products	5.3	10	10.2	9.6	10.4	45.5
Paper	6.9	11.3	10	11.1	12.9	52.2
Other activities	0.2	4.3	1.3	-0.7	6.2	11.3
TOTAL (Mt)	-161.3	94.3	59.6	112.1	183.1	287.8

Note: “Combustion” is larger than the power sector. Combustion means any oxidation of fuels.

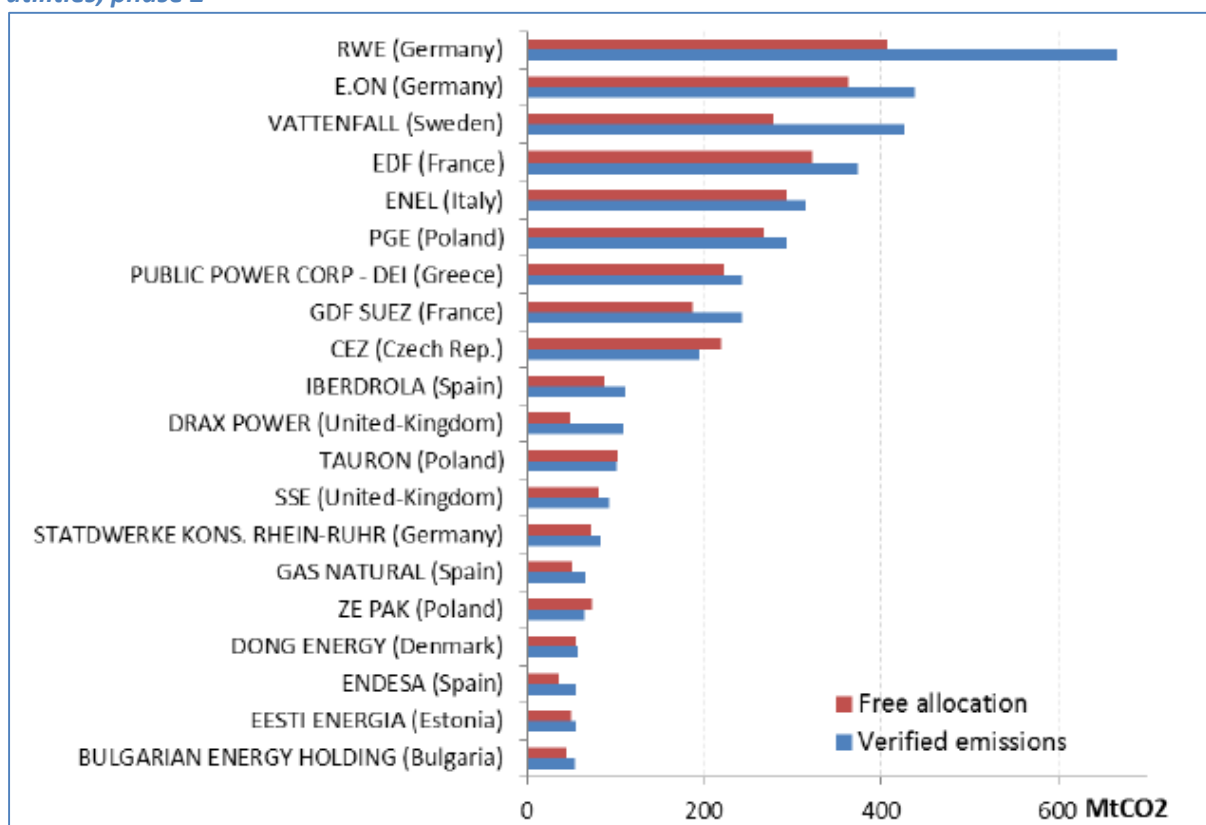
Source: Tendances Carbone/CDC Climat Research

Most of the allowance shortfall was borne by coal-fired power plants, while gas-fired power plants received more allowances overall than required by their CO₂ emissions. Although they represented 70% of the sector’s CO₂ emissions, coal-fired power plants accounted for 92% of the aggregate phase 2 allowance shortfall. Gas-fired power plants’ compliance position changed significantly between 2008 and 2012, switching from a shortfall of 26% to a surplus of 34% in 2012.

The shortfall of allowances has contracted over the period. Whereas installations in the power sector posted a 28% allowance shortfall in 2008, it was reduced to 9% in 2012, in line with the decrease in electricity production by both fuels compared with 2008.

The net position at power companies’ level is largely dependent on the composition of their power fleet and is also influenced by their geographical location as free allocation of allowances depends on national decisions (in phase 3, this is limited to the eight new Member States). The three largest power generators operating in Germany, E.ON, RWE and Vattenfall, had a combined compliance requirement of 490 Mt between 2008 and 2012, accounting for 58% of the shortfall for the sector as a whole.

Figure 93: Verified CO₂ emissions and free allowance allocations: 20 largest European power utilities, phase 2



Source: CDC Climat Research, based on EUTL and World Electric Power plant (Platts) data

A large use of international carbon credits

As the main source of demand for carbon assets (EUAs, CERs and ERUs credits), **the sector has returned 533 million Kyoto credits, thereby offsetting 65% of its shortfall**. Compared with returns consisting solely of EUAs, the use of international credits enabled power generators to save about €2 billion, including €1.2 billion in 2012 when international credits prices collapsed.

Table 24: Compliance position and cost of compliance of the power sector, phase 2

	2008	2009	2010	2011	2012	2008-2012
Available EUAs (free allocations and auctions) million, estimated	962	962	978	994	1021	4917
CO ₂ emissions, million t	1230	1127	1141	1124	1120	5742
Compliance position, million	-268	-165	-163	-130	-99	-825
Return of Kyoto credits and allowances						
CERs, million	45	48	67	80	126	366
ERUs, million	0	2	10	27	128	167
EUAs, million (estimated)	223	115	86	23	-155	292
Estimated compliance cost						
Average EUAs price (€/t)	22.34	13.18	14.34	12.96	7.5	14.06
Average CERs price (€/t)	18.29	11.64	12.28	9.62	2.63	10.89
Estimated compliance cost, billion €	5.8	2.1	2.2	1.3	-0.5	10.9
Saving thanks to CERs/ERUs, million €	182	77	159	357	1237	2012

Source: CDC Climat Research and own estimates

4.3. STRUCTURAL REFORM OF THE EU ETS

The malfunctioning of the EU ETS means that it is currently not a major factor driving low carbon investment decisions across the European Union. Instead it has become a residual policy, marginalised by RES and efficiency targets. The EC has proposed structural reforms of EU ETS to address the three main weaknesses that affect the functioning of the EU ETS: insufficient credibility of long-term scarcity, the consequences of interactions with other energy policies and the lack of regulatory clarity to respond to extraordinary demand conditions.

To address the supply/demand imbalance, the European Commission has taken action on two fronts. As a short-term measure, the Commission is postponing the auctioning of 900 million allowances until 2019-2020 to allow demand to pick up '**(backloading)**'. As backloading is only a temporary measure, the Commission has proposed to establish a **market stability reserve (MSR)** at the beginning of the next trading period in 2021, which could provide a sustainable solution to the surplus in the longer term. A legislative proposal was put forward on 22 January 2014 at the same time as the framework for climate and energy policies up to 2030 ("the 2030 framework").

Efforts to address the market imbalance will also be helped by the faster reduction in the EU ETS cap proposed in the 2030 framework. The **40% reduction in EU GHG emissions** by 2030 compared with 1990 levels will translate into a 43% emission reduction for the installations covered by the EU ETS, compared with 2005 levels. This will necessitate an increase in the linear reduction factor (i.e. the amount by which the ETS cap on emissions is reduced) from 1.74% currently to 2.2% per year from 2021. The additional effort compared to the existing situation represents reductions of 550 Mt over the period 2021-2030.

The Commission also said that the GHG reduction will be purely domestic, meaning there will be **no use of non-EU offsets** (Kyoto offset credits) beyond 2020 - unless the Paris negotiations necessitate a target greater than 40%, which would then partially be met through offsets.

900 Mt of allowances to be backloaded in 2014-16

After months of discussion on several proposals, in February 2014, EU ministers approved a regulation²¹³ aimed at postponing (or **backloading**) the auctioning of 900 Mt of allowances as an immediate first step to reform the EU ETS.

At short-term, the backloading operational objective is to adapt the EU ETS auction timetable to counter-act the rapid short-term increase of supply of allowances due merely to regulatory features associated with the transition from phase 2 into phase 3²¹⁴. **Auction volumes will be reduced by 400 Mt in 2014, 300 Mt in 2015 and 200 Mt in 2016.** According to the regulation, the allowances will not be permanently withdrawn out of the ETS over phase 3. They will instead be added to the volumes of allowances to be auctioned in 2019 (300 Mt) and 2020 (600 Mt)²¹⁵.

The backloading started in March 2014. So far the power sector is the only one which has moved to full auctioning of its allowances needs. The backloading reduces by more than half the number of

²¹³ Commission Regulation (EU) No 176/2014 of 25 February 2014 amending Regulation (EU) No 1031/2010 in particular to determine the volumes of greenhouse gas emission allowances to be auctioned in 2013-2020

²¹⁴ Mainly, the fast influx of Kyoto offset credit, the auctioning of allowances remaining in the new entrants reserves for the second period, early auctioning of phase 3 allowances, and sales of phase 3 allowances to generate funds for the NER300 programme. Source: Commission Regulation (EU) No 176/2014 of 25 February 2014.

²¹⁵ However, further reforms of the EU ETS may decrease the level to be added in 2019 and 2020.

auctioned volumes and presents both utilities and industrial companies with a radically different emissions trading environment compared to the one that has prevailed in recent years. The power sector emitted 1120 Mt in 2012 while auctions will be reduced to 543 Mt in 2014, 629 Mt in 2015 and 732 Mt in 2017.

Table 25: Auction volumes after backloading

Million allowances	2013	2014	2015	2016	2017	2018	2019	2020
Estimated auction volumes before backloading	808	943	929	932	935	939	945	972
Backloading		-400	-300	-200			300	600
Estimated auction volumes after backloading	808	543	629	732	935	939	1245	1572

Source: EC, November 2013²¹⁶

Further reforms: the market stability reserve

Backloading will only have a temporary impact, as the backloaded allowances will have to be sold in 2019-20. The EU has therefore proposed further reforms that would have a more permanent impact on the carbon market.

The EC proposes to establish a **market stability reserve (MSR)** at the beginning of the next ETS trading period in 2021. The reserve would both address the surplus of emission allowances that has built up in recent years and improve the system's resilience to major shocks (variations in demand and price shocks) by automatically adjusting the supply of allowances to be auctioned. It is essentially a move away from a fixed cap on EU ETS allowances to a flexible cap.

According to the proposal, the MSR would function by triggering **adjustments to annual auction volumes** in situations where the total number of allowances in circulation is outside a certain predefined range, namely 400 to 833 million certificates. It adds a third emergency threshold based on changes in the price of allowances. As long as the quantity of allowances in circulation is between the ranges, there is no intervention. In contrast, when the amount is outside these limits (below the low threshold or above the high threshold), the MSR enters into action and removes or adds allowances to the auctions of the current year.

- High threshold: when the quantity of allowances in circulation is greater than 833 Mt, 12% of the amount of allowances in circulation is removed from auctions of the current year and placed in the reserve. The amount withdrawn cannot be less than 100 Mt (amount withdrawn at the threshold level of 833 Mt). If the amount of allowances in circulation is greater than 833 Mt (at present it is about 2,000 Mt) this withdrawal will be higher (240 Mt for 2,000 Mt, 360 Mt for 3,000 Mt etc.).
- Low threshold: when the quantity of allowances in circulation is less than 400 Mt, 100 Mt are removed from the reserve and added to the auctions of the current year. This mechanism cannot lead to releasing more than 100 Mt from the reserve each year.
- Emergency threshold (price shocks): if for six consecutive months the allowance price is higher than three times its average value over the previous two years, 100 Mt are removed from the reserve and re-injected in the auctions of the current year²¹⁷.

²¹⁶ European Commission, Non-paper on the draft amendment of the Auctioning Regulation with regard to the implementation of back-loading, November 2013

²¹⁷ As noted by Chaire Economics Dauphine, when the price is low for long enough, it is possible that this threshold gets easily triggered (e.g. if the price goes from 5 to more than 15 €/tCO₂). In contrast, when the level of CO₂ is high, activation becomes less likely (a price increase from 25 to more than 75 €/tCO₂). As in the previous case, this mechanism cannot lead to releasing more than 100 Mt from the reserve in a given year. In addition, the

The proposal also contains further measures aimed at smoothening auctioning supply in the years around transitions between trading phases, and in particular when the allowances from backloading are reintroduced in the late 2010s. This provision specifies that, where average auction volumes in 2020 are more than 30% higher than expected volumes in 2021 and 2022, the 2020 volume should be reduced by two-thirds of the difference, with the reduced amount then returned in even instalments across each of the years 2021 and 2022.

Some Member States, like Germany, have already signalled they want the reform to come into effect earlier than 2021 and begin at the latest in 2016. Indeed, if the further reform of the EU ETS only starts in 2021, the period 2014-2020 will be marked again by price volatility and a likely collapse of prices when withdrawn volumes of allowances are re-injected in the system in 2019/20. At the beginning of March 2014, 13 Environment Ministers²¹⁸ from mainly western Member States, signed a more general statement saying the ETS "continues to require urgent and significant strengthening"²¹⁹.

The plan to adjust automatically the supply of carbon permits will start to be discussed by the EU Parliament in September 2014²²⁰. The measure needs qualified-majority support from Member States and majority backing from the EU Parliament to enter into force. An agreement in 2014 on the measure and its earlier introduction is a highly ambitious schedule. Analysts predict the MSR could add €11-13 or more to carbon prices over the next decade but it is likely to face opposition from heavy industry and mainly east European states over concern that higher prices will hamper the bloc's economic recovery.

4.4. INCREASES IN CO₂ PRICE, BUT INSUFFICIENT AT SHORT TERM FOR COAL-TO-GAS SWITCHING

Since the announcement of the backloading proposal by the EC in 2012, EUAs prices have reacted up or down according to the outcome of discussion and votes in Brussels. Since the beginning of 2014, the price of permits has gained 40% to €7/t (at the beginning of March 2014). The key question is the short-term and lasting impact of the backloading and other measures on EUAs prices and to which extent the expected increase is sufficient to drive coal-to-gas switching and investment in low carbon technologies. So far, the increase since the beginning of the year has not been sufficient to induce fuel switching from coal to gas. The effect is a further deterioration of gas plant revenues and a decrease in coal plant margins.

Backloading, impact assessment

In its 2012 impact assessment on backloading options²²¹, the European Commission provided estimates of the impact of different backloading options on prices, at that time envisaged over the period 2013-2015. In a perfect market involving rational participants, this measure should not have a

emergency threshold is only valid when the price is rising: the reserve will not withdraw additional allowances if the price is to be divided by three.

²¹⁸ The 13 environment ministers signing the Green Growth Group (as they call themselves) statement are from Belgium, Denmark, Estonia, Finland, France, Germany, Italy, Netherlands, Portugal, Slovenia, Spain, Sweden and United Kingdom.

²¹⁹ Deeper, faster' carbon market reform, 5 March 2014.

²²⁰ The battle for European carbon begins, Bloomberg New Energy Finance, 12 March 2014.

²²¹ European Commission (2012), Proportionate Impact Assessment accompanying the document Commission Regulation (EU) No .../.. of XXX amending Regulation (EU) No 1031/2010 in particular to determine the volumes of greenhouse gas emission allowances to be auctioned in 2013-2020, CSWD, 2012. The document assesses different backloading options, including the backloading of 900 million of allowances over the period 2013-2015.

significant impact on the EUAs price as the number of auctioned volumes is simply postponed (under the current regulation). As the 900 million EUAs will only be temporarily withheld, an efficient market should in principle balance out the gap with the existing oversupply, which is more than enough to offset the back-loaded volumes. However, analysts expect backloading to have a significant impact on European carbon prices. The rationale for this is that carbon markets are not efficient and are for the main part not driven by fundamentals but rather by the trading behaviour of market participants²²².

A new short-term equilibrium between allowances supply and demand could lead to a temporary increase in the price at the beginning of phase 3 and a sharp drop at the end of the trading phase when allowances would be re-injected into the market.

In January 2014, Bloomberg New Energy Finance anticipated European carbon prices would rise by more than 50% to average €7.5/t in 2014, compared with just under €5 at the beginning of the year²²³. At the beginning of February 2014, Thomson Reuter Point Carbon had a price projection of €6.5-7/t for 2014²²⁴. The increase would still leave the carbon price well short of the €40/t to €50/t analysts say will be needed to mobilize large scale low carbon investment, but it represents a sizable improvement on 2013 record lows.

Market stability reserve, impact assessment

If adopted, the proposals could prevent some of the backloaded allowances from being re-injected into the market before 2020, potentially delaying their return by up to two years. This would balance the bearish effect of a re-injection and it would significantly increase the value of backloading as a measure to work against the current oversupply. As market operators also react to expectations on future regulation, the new proposal and its effect on supply/demand balance, in particular its introduction before 2021 as requested by some stakeholders, are going to significantly influence carbon prices and this, not only by 2021, but already in the current trading phase.

The Commission has published an accompanying Assessment²²⁵ with the proposed MSR, which sets out in broad terms some possible impacts of such a reserve. This shows that it would remove allowances from the market in 2021, thereby reducing Member States' auction volumes, with the resultant increase in the carbon price being likely to increase the costs to firms of complying with the ETS, whilst the effect on Member States' auction revenues would depend on the balance between the magnitude of the change in auction volumes and the corresponding impacts on price. The Impact Assessment also refers to the mid to long-term operation of the reserve, when at some point allowances would be likely to return back to the market (and would thus be likely to lead to a fall in the carbon price and a reduction in the costs to firms of complying with the ETS). However, the Assessment does not quantitatively estimate the impacts on prices. The EC recognizes that the impact of the reserve on prices is hard to forecast as by definition it is very uncertain when a mechanism built to apply in cases of large-demand shocks only will apply. Furthermore, if a measure reduces auction supply to such an extent that those entities that are short of allowances (such as the power sector)

²²² ICIS, European Carbon Prices to Double by End of 2015 Following Back-loading Implementation, 8 January, 2014

²²³ <http://www.commodities-now.com/reports/environmental-markets/16017-carbon-markets-value-to-rise-again-in-2014.html>, 8 January 2014

²²⁴ Point Carbon, 400 million carbon allowances will be backloaded in 2014, 7 February 2014

²²⁵ European Commission, Impact Assessment accompanying the document Proposal for a Decision of the European Parliament and of the Council concerning the establishment and operation of a market stability reserve for the Union greenhouse gas emission trading scheme and amending Directive 2003/87/ECSWD (2014), 22 January 2014.

cannot buy sufficient amount of allowances in auctions, then prices will be driven to an extent by the financing needs of the entities that are holding surplus allowances (such as industry sectors) and the price levels that incite industry or other surplus owners to sell allowances. Prices will furthermore be influenced by the needs of the power companies and therefore changes in their hedging strategy driven by demand of allowances (and therefore production from fossil fuels). A further uncertainty relates to the extent that the market participants may adapt their behaviour to anticipate the impact of a reserve. Finally, the Commission notes that the exact impacts of a market stability reserve will depend on how such a mechanism is designed.

After the publication of the proposals, several estimates of the price expected after 2021 were published by carbon market analysts. Point Carbon predicted, in January 2014, a price increase of around 50% on the €26.50/t level expected without the MSR, i.e. an increase of €13.5 to €40/t on average between 2019 and 2030²²⁶.

The Climat Economics Chair/Paris Dauphine²²⁷ has carried out a simulation of carbon prices, using its ZEPHYR model which incorporates the behaviour of operators (see box). It shows that at short term, the EUAs price could reach €11 to 15/t in 2014, and even close to €20 in 2015 (in the high scenario) as market participants not only react to backloading of auctioned volumes but also anticipate the outcome of further reforms and choose to keep a large quantity of allowances for future use. In the fourth trading period, the EUAs price could exceed €50/t in the high scenario in the first years of the fourth trading period. In the low scenario, prices rise less (€20/t at the beginning of the fourth trading period) as participants in the EU ETS use fairly quickly the allowances they hold.

Box 24: Impact on EUAs prices of EU ETS policies²²⁸

To try to anticipate the possible impacts of the measures proposed by the Commission, Climat Economics Chair/Paris Dauphine has developed simulations using its ZEPHYR model, which simulates the supply and demand for allowances on the market, year after year. In the ZEPHYR model, the behaviour of covered installations is represented as follows: operators compare the carbon price to their reduction cost and reduce their emissions whenever that cost is less than the price of an allowance. The demand for allowances also takes into account the expectations of participants who may choose to keep unused allowances or purchase allowances to bank them, if they expect future price increases and/or if they choose to engage in early emission reduction. The amount of unused allowances ("banking") is therefore a key variable for understanding the inter-temporal market equilibrium, which depends on both technical and economic choices of operators and on their expectations.

The authors integrated in their simulations the measures that are already known: the allowance backloading over the third period and the proposed transition to a 2.2% annual reduction factor from 2021. From these assumptions, they constructed two reference scenarios (without MSR), on which are then grafted the introduction of a market stability reserve:

- **A high scenario** where participants' expectations lead them to reduce their emissions early and to keep a large quantity of allowances for a future use (high banking).

²²⁶ EU carbon buffer could add 13 euros to 2019-2030 CO₂ price, Reuters, 21 January 2014

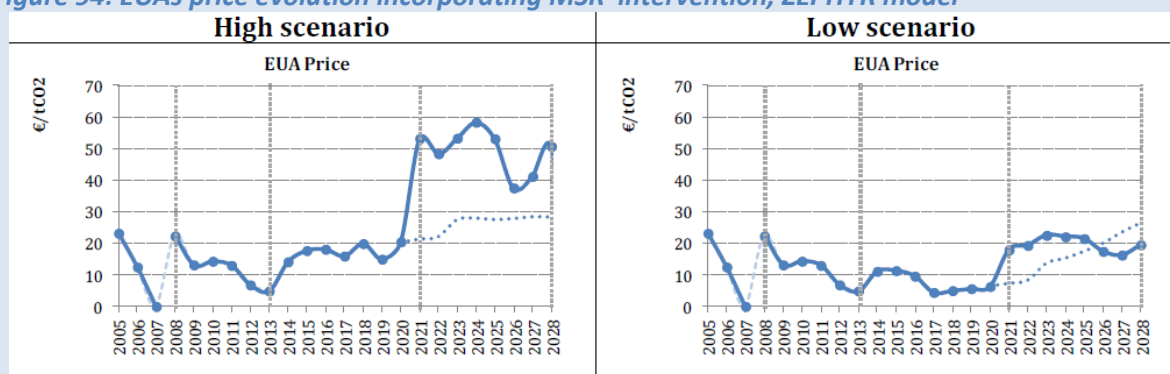
²²⁷ Chaire Economics Climat/Paris Dauphine, EU ETS reform in the Climate-Energy Package 2030: First lessons from the ZEPHYR model, Policy Brief N°1/2014, January 2014

²²⁸ Chaire Economics Climat/Paris Dauphine, op.cit.

- **A low scenario**, where participants do not consider it necessary to immediately reduce emissions or hold many allowances, where they use fairly quickly the allowances they hold (low banking).

The results of the simulations show that the MSR should lead to a significant price increase from 2021. It also reveals the risk of growing price volatility resulting from the automatically programmed interventions. It also clearly demonstrates that price levels are highly dependent on operators' expectations and their strategy on banking EUAs. In the high scenario, prices levels reach €50 in 2021 and remain above price levels in the baseline scenario until 2030; in the low scenario price rises less compared to the first case in 2021 before falling down below the reference price when the automatic rules lead to additional allowances entering the market.

Figure 94: EUAs price evolution incorporating MSR intervention, ZEPHYR model



Source: ZEPHYR model, Climate Economics Chair, 2014

Impact on the power sector

As a result of the backloading plan, governments will cut the supply of new carbon permits by 57% and sell only 543 million permits in 2014. Reduced auction supply means that the power sector will have to buy permits from the surplus that has been built up since 2008 or rely on its own reserves (banked allowances). It is estimated that **power companies will seek to buy around 900-950 million allowances in 2014²²⁹**, suggesting that they will have either to incentivise holders of the historical surplus to sell about 350-400 million allowances, or rely on their own reserves. Carbon prices in Europe will therefore increasingly depend on industrial firms' willingness to sell surplus permits that they received for free in the past²³⁰ and on strategies of operators (both from the power and manufacturing sectors) regarding their banked allowances. The reform of the ETS may well transform the long ETS market into a short one for more operators, including some manufacturing operators. Under these circumstances, the propensity of those who hold excess allowances to sell will depend on price expectations in the future. The prospect of further, more ambitious reforms of the EU ETS means that many of them will demand substantial premiums over the current price level. Power companies will be ready to pay such premiums as long as it remains cheaper to produce power with coal than to switch to lower-emitting gas-fired generation. Under the current depressed power market, it is difficult to see power producers paying substantial premiums. In addition, the power sector will be able to rely on its own banked allowances, at least until this reserve is exhausted. While the surplus of permits built up since 2008 reached an unprecedented 2.2 billion tons at the end of 2012, equivalent to roughly one year of emissions of the ETS market as a whole, it is estimated that half of the total is already tied up by power

²²⁹ The power sector emitted 1120 Mt in 2012, but since then some coal-fired power plants (in the UK mainly) have closed and more efficient power plants are replacing old coal plants in Germany. Furthermore, the power sector of eight Member States still receives free allowances (mainly Poland).

²³⁰ Bloomberg New Energy Finance (BNEF), Auction cuts breathe new life into EU ETS, 3 March 2014

utilities to cover future emissions²³¹. The manufacturing industry accrued roughly 900 Mt of spare allowances during the second trading phase, mainly the steel and cement industries which have an aggregated surplus of about 300 Mt each in phase 2 (see Table 24), although part of this surplus has already been sold. The power sector will also be able to rely on Kyoto offset credits, at least for a portion of their allowances needs. There are still over 500 million credits to be used in the third phase. The expected increase in EUAs prices will therefore depend on the behaviour of operators in an uncertain regulatory environment, and their aversion or not to risk, but also their needs for cash.

The higher CO₂ price expected for the 2014–2016 period would lead to higher production costs for utility companies participating in the ETS. However, it is quite likely that **they already have hedged against price increases for emissions in the 2014–2016 period** as most power producers safeguard their forward sales of electricity with allowances up to three years ahead. Moreover, the expected higher CO₂ price will increase wholesale electricity prices through the marginal power plant principle (see Box 1). The loss of demand is expected to be negligible as the price elasticity for electricity not only for end-consumers but also industry demand is low. Therefore, the negative impact of backloading on the power sector is likely to be limited at short term, depending on hedging strategies of power utilities, although as discussed below, it may trigger more closures of power plants.

Coal-to-gas switching?

At current gas, coal and EUAs prices, there is no incentive for power producers to switch from coal to gas. The theoretical switching price from an old hard coal power plant (efficiency of 36%) to a new CCGT plant (efficiency of 60%) is €30.4/t (calculated with forward cal-2015 prices, as of 14 March 2014 on EEX platform). A level of €60/t is required to incentivise the switch from a new hard coal plant to a new CCGT plant. At current power and commodity prices on the German market, the expected increase in EUAs prices means that **the margin of coal-fired power plants is going to decrease and could even be negative, while CCGTs will be even more unprofitable**. The following table, based on forward cal-2015 prices (as of 14 March 2014 on EEX platform for German power), shows the outcome of different EUAs prices on the margin of old and new thermal plants.

Table 26: Margin of thermal plants according to different CO₂ prices

EUAs prices (€/t)	7	10	15	20	25	30	35	40
New gas plant (efficiency 60%)	-9.0	-10.1	-11.8	-13.5	-15.2	-16.9	-18.6	-20.3
Old gas plant (efficiency 49%)	-18.7	-19.8	-21.7	-23.5	-25.4	-27.2	-29.1	-30.9
New coal plant (efficiency 45%)	11.7	9.4	5.7	2.0	-1.7	-5.4	-9.2	-12.9
Old coal plant (efficiency 36%)	5.5	2.6	-2.2	-7.0	-11.8	-16.6	-21.4	-26.2

Based on forward cal-2015 prices for power, gas and coal prices, as of 14 March 2014 (and assuming that electricity prices remain unchanged)

Source: author's own calculation

As the table shows, the increase in EUAs – assuming no change in electricity prices – will not incentivise coal-to-gas switching but will make old hard coal plants non profitable. For old coal plants, the margin becomes negative at carbon prices above €12.7/t. **It would therefore accelerate the closure of old hard coal plants**. This trend has already started with the announcement of closures of coal-fired power plants in Germany and Finland due to weak market conditions (see Chapter 1, Section 1.6). Overall, the picture is very poor for all thermal plants as long as power prices (in this case in Germany) remain depressed.

²³¹ Hydroprocessing, 14 February 2014

On a long-term basis, the EC and the IEA indicate a significant increase in CO₂ prices. In 2035, they reach €57/t (€2010) in the EC reference scenario and €31/t (€2012) in the IEA New Policies Scenario, levels that would incentivise investments in low carbon technologies. It should be mentioned however that before any major investment decisions in the power sector are made based on the EU ETS, the price needs to reach a significant level and stay there for a prolonged period of time.

Table 27: Long-term CO₂ prices in the EC and IEA scenarios

	2030	2035	2040	2050
EC (prices in €2010/t) (a)				
Reference scenario 2013	35	57	78	100
GHG40	40			264
GHG40EE	22			158
GHG40EERES30	11			152
IEA (prices in €2012/t) (b)				
New Policies Scenario	25	31		
Current Policies Scenario	19	23		
450 Scenario	73	96		

(a) EC projections do not take into account recent regulation (backloading and MSR).

(b) Original data in \$, converted in € (1€=1.3\$). Source: EC, 2013 and 2014²³², IEA (2013)²³³.

²³² EC (2013), EC Reference Scenario 2013, December 2013 and EC (2014), Impact assessment for a policy framework for climate and energy in the period from 2020 up to 2030, SWD, 22 January 2014

²³³ IEA (2013), World Energy Outlook 2013, IEA/OCDE, Paris, November 2013

5. GAS AND COAL COMPETITION IN THE FUTURE

The uncertainty on future EU electricity demand, energy policies, regulatory framework and investment climate makes the outlook for EU electricity supply and the competition between gas and coal extremely difficult to assess. The shape of the future electricity mix is highly dependent on EU and national policies and on the development of coal, gas and CO₂ prices. The long-term goal is well-known: moving to a low-carbon economy. In the power sector, gas and coal participate in this vision only if decarbonised, requiring CCS technologies to mature and their costs to decrease. **The road to this long-term objective is open and can be shaped quite differently according to EU energy and climate policies, but above all to national policies.** The analysis of national energy policies shows clearly that **the path to a low carbon economy can be achieved differently and at different timeframes** according to national preferences for one source of energy and trade-offs between the objectives of sustainability, competitiveness and security of supply.

In this Chapter, we review outlooks/visions published by the International Energy Agency, EUROGAS and EURELECTRIC members. Then we sum up the main trends for gas and coal competition at short and longer term and draw conclusions.

5.1. OUTLOOKS FOR GAS AND COAL IN THE POWER SECTOR

WEO 2013: high regulatory uncertainty

The IEA WEO2013 presents an assessment of the prospects for global energy markets in the period to 2035 and draws out the implications for energy security, environmental protection and economic development. The three main scenarios²³⁴ – the New Policies Scenario (NPS, central scenario), the Current Policies Scenario (CPS) and the 450 Scenario (450) – are underpinned by assumptions about economic and population growth, and about energy and climate policies and technology deployment. Energy prices are derived from a modelling process.

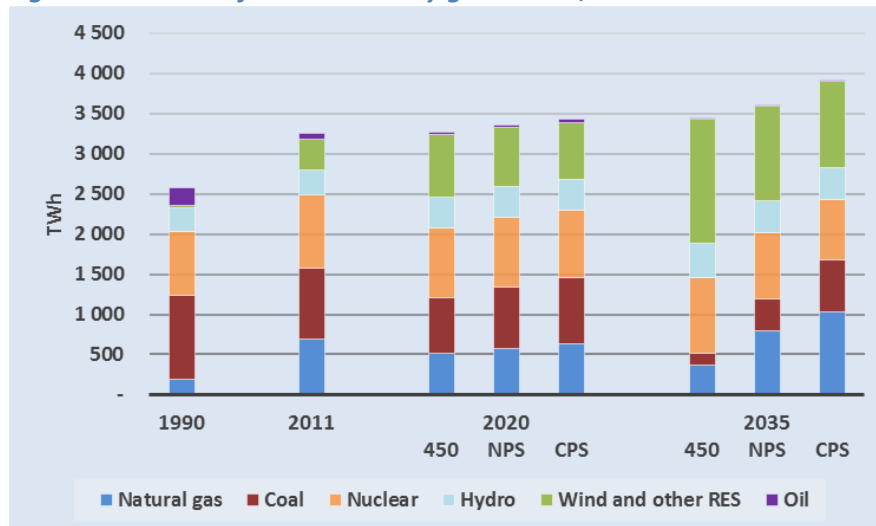
The uncertainty on future EU electricity supply is illustrated by the wide range of outlooks presented by the IEA. By 2020, the level of electricity generation does not vary greatly among the three scenarios. In 2020, EU electricity generation reaches 3357 TWh in the NPS scenario. Similar levels are foreseen in the CPS and 450 scenarios (3425 TWh and 3275 TWh respectively). A significant difference in the level of electricity generation is observed in 2035 with a range of around 500 TWh between the CPS and the 450 scenarios. The rate of electricity demand growth in the three scenarios depends primarily on the nature and extent of government interventions, particularly policies related to energy efficiency, the environment and energy security.

²³⁴ WEO2013 analyses three main scenarios highly linked to energy and climate policies:

The New Policies Scenario is the central scenario of the WEO. In addition to incorporating the policies and measures that affect energy markets and that had been adopted as of mid-2013, it also takes account of other relevant commitments that have been announced, even when the precise implementation measures have yet to be fully defined.

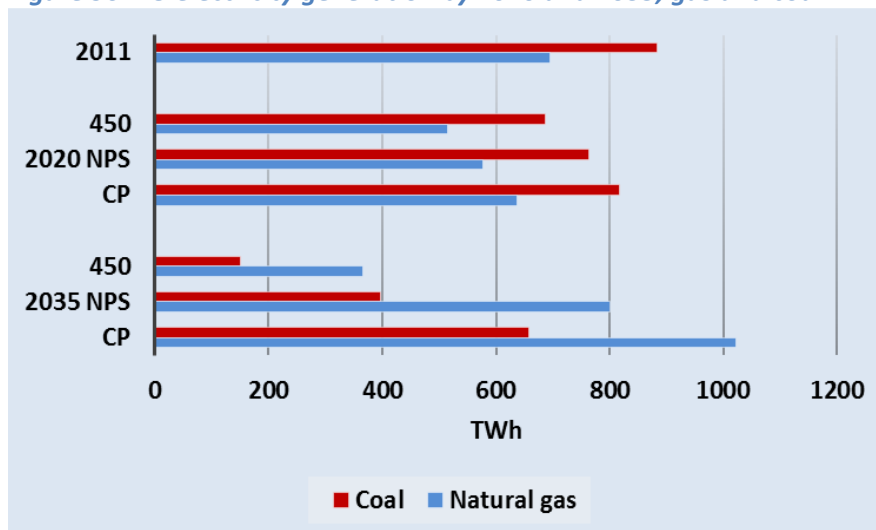
The Current Policies Scenario takes into account only those policies and measures affecting energy markets that were formally enacted as of mid-2013. This is therefore a baseline picture of how global energy markets would evolve if established trends in energy demand and supply continue unabated.

The 450 ppm Scenario shows what is needed to set the global energy sector on a course compatible with a near 50% chance of limiting the long-term increase in the average global temperature to two degrees Celsius (2°C).

Figure 95: Outlook for EU electricity generation, 2020 and 2035

Source: WEO 2013

The mix in electricity generation varies widely among the three scenarios and this, already in 2020. While the share of RES in electricity generation is rising in the three scenarios, it differs significantly depending on the scenarios: the share of RES (including hydro) fluctuates between 32% and 35.5% in 2020 (a difference of 70 TWh). In 2035, it accounts for 58% of total EU generation in the 450 scenario compared to 38% in CPS (44% in NPS). This corresponds to a difference of 513 TWh, or about three-quarters of gas-fired generation in 2011 (the reference year in WEO21013). Residual demand addressed to other sources therefore varies significantly in the three projections. Figure 96 shows the outlook for gas- and coal-fired generation by 2035.

Figure 96: EU electricity generation by 2020 and 2035, gas and coal

Source: WEO 2013

Electricity generation from both gas and coal decreases in 2020 compared to 2011, pushed out by the expansion of RES. This occurs in the three scenarios. Coal generation decreases only marginally by

2020, except in the 450 scenario. The contribution of gas remains very uncertain at this horizon: gas generation decreases by 8% to 26% compared with 2011, depending on the scenarios²³⁵.

In 2035, the picture is different for both fuels. A collapse in the contribution of coal is projected, except in CPS where coal-fired generation decreases by “only” 26% compared to 2011 and accounts for 17% of the electricity mix. At the opposite, in the 450 scenario, its share is reduced to only 4%. The contribution of gas by 2035 is rather uncertain. **A large increase in gas generation is expected in CPS: + 47% compared to 2011; the share of gas in the electricity mix reaches 26%. The increase is more moderate in NPS: gas accounts for 22% of electricity generation. In the 450 scenario, its share is only 11% and gas-fired generation halves compared with 2011.** It is worth to note that the policy assumptions behind the 450 scenario are close - but not the same - to the targets currently under discussion in the context of the 2030 EU climate and energy framework: they include a 30% reduction in GHG emissions by 2020 compared with 1990, strengthening of the EU ETS in line with the 2050 roadmap and full implementation of the EU Energy Efficiency Directive.

EUROGAS: a better outlook for gas...but not in this decade

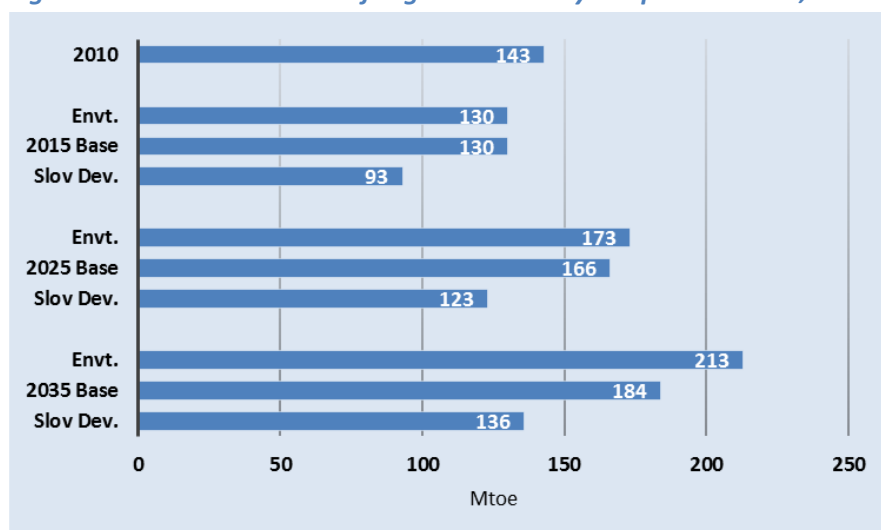
In October 2013, EUROGAS published a long-term outlook for gas to 2035²³⁶ where the association draws on its members' expertise, to gather their best assessments of how the EU gas markets are likely to develop under three “cases” that reflect diverse, yet plausible, conditions :

- The Base Case derives from current national energy policies, which show little or no investment in the gas sector in most parts of Europe in the next five to ten years.
- The Environmental Case anticipates a rebalancing of the energy mix towards more renewable and slightly less nuclear electricity, together with restored economic growth and a high rate of innovation in energy-efficient equipment (notably in the rapid deployment of efficient gas appliances in home and office heating).
- The Slow Developments Case projects gas becoming less competitive in Europe as a result of global developments, a policy environment that remains hostile to gas, weaker industrial performance in Europe and slow progress in energy efficiency.

For each of these three cases, the EUROGAS Outlook projects an expected level of gas demand in each sector of consumption: power generation, residential and commercial, industry and transport. EUROGAS indicates that uncertainty in the volume of gas sales to power generation is the main factor behind differences in the overall level of gas demand in each forecast case. The following figure shows the outlook for gas demand by 2035 according to the three cases.

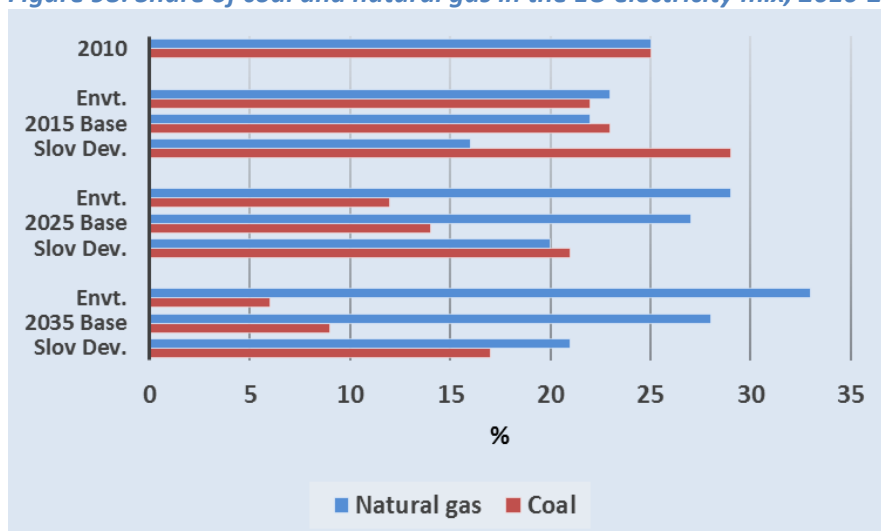
²³⁵ The year 2011 is the reference year for WEO2013. As electricity generation from gas fell in 2012, the projected level in 2020 is actually very close to generation in 2012.

²³⁶ Eurogas (2013), Long-term outlook for gas to 2035, Brussels, October 2013.

Figure 97: EUROGAS outlook for gas demand by the power sector, 2010-2035

Source: EUROGAS (2013)

While in all three cases, CO₂ emissions are reduced compared with 2010, thanks to the growing role of RES, **the three cases show contrasted views for the future of gas consumption in power generation.** In the Base Case, gas consumption in power generation rises from 143 Mtoe in 2010 to 184 Mtoe in 2035. In the Environmental Case, gas consumption increases to 213 Mtoe as a result of more fuel switching, with the result that CO₂ emissions decline further. Support of gas for flexible renewable sources and cover for a declining relative share of nuclear power are the main drivers. The Slow Developments Case, by contrast, reflects a smaller decrease in nuclear, a remaining competitive advantage for coal plants and a larger increase of renewables used for base-load generation. As a consequence, gas demand in power generation drops to 136 Mtoe in 2035, and the EU remains further away from its climate goals with a reduction of CO₂ emissions from the power sector by 19% only from 2010 to 2035. The share of coal in the electricity mix reaches 17% in 2035 in that case (Figure 98).

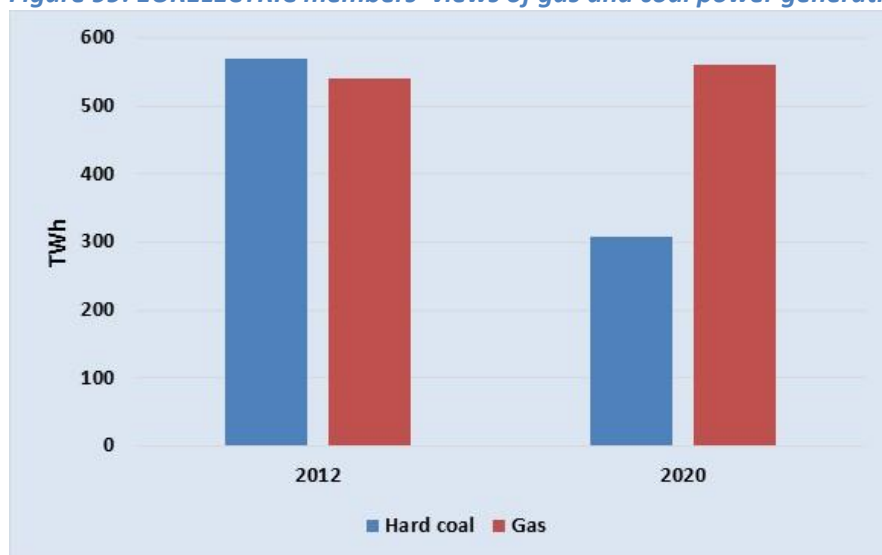
Figure 98: Share of coal and natural gas in the EU electricity mix, 2010-2035

Source: EUROGAS (2013)

EURELECTRIC: hard coal squeezed by 2020

A different and contrasted view is offered by EURELECTRIC members in the latest EURELECTRIC report on Power Statistics and Trends 2013²³⁷. **By 2020, gas overtakes hard-coal in the power generation mix** and by a large margin (Figure 99). EURELECTRIC members expect the ratio between coal- and gas-fired generation to shift to 1:1.8, with 307 TWh of coal- and 560 TWh of gas-fired generation in the EU-27 in 2020. As explained in the report, “assumptions by EURELECTRIC members regarding the role of coal and gas in the energy mix of 2020 are especially noteworthy in the light of recent developments pushing gas out of the merit order in power dispatch”. This contrasted view is not explained by a different view on CO₂ prices: “Despite the strong support of EURELECTRIC members for strengthening the ETS, confidence in this instrument without reform is low... members do not expect CO₂ emission prices to reach even as high as €30 by 2020”. The driver for more gas would rather be the “various effects of the Industrial Emissions Directive (IED) and newly set up capacity markets supportive to gas”. It is also worth noting that “the share of fossil fuels in EU power generation is foreseen to decrease sharply from 2012 to 2020. After a decrease to 48.4% in 2012 –less than 50% for the first time in the history of the EU – the share of fossil fuels in EU power generation is expected to fall to only 35% by 2020.”

Figure 99: EURELECTRIC members' views of gas and coal power generation in 2020



Note from the author: in the Figure, only hard coal (not lignite) is taken into account. Lignite-fired generation (incl. CHP) amounted to 344 TWh in 2011 (Eurostat) and an estimated 350 TWh in 2012, making total coal-fired generation at 920 TWh in 2012²³⁸.

Source EURELECTRIC, 2013

²³⁷ EURELECTRIC (2013), Power Statistics and Trends 2013, Brussels, December 2013

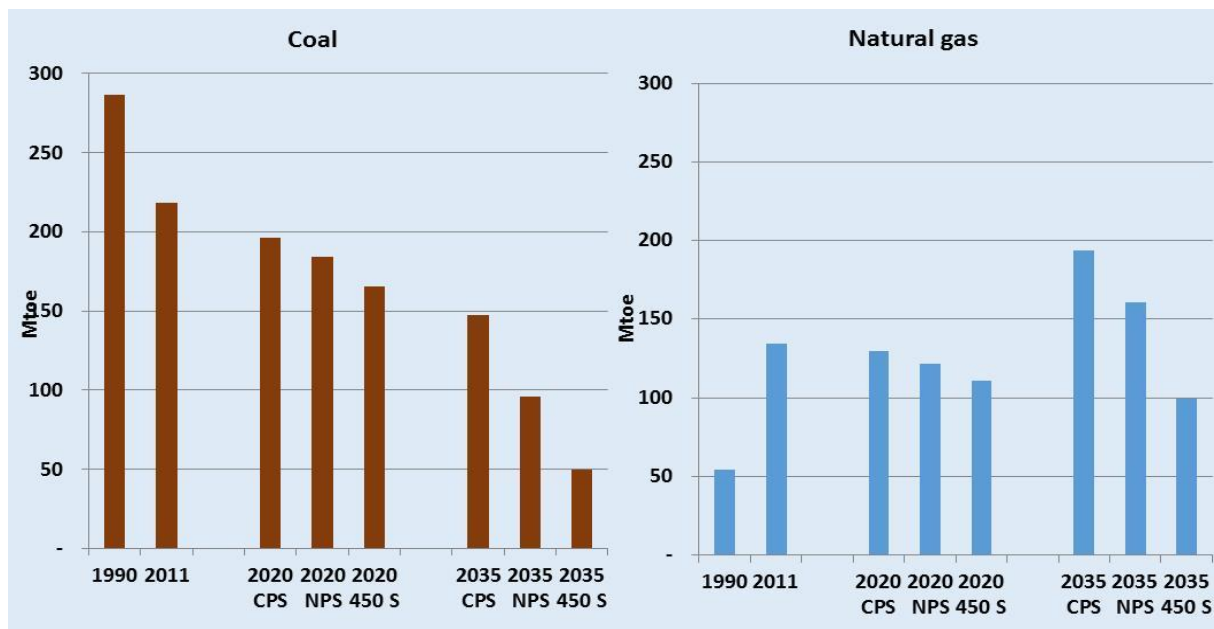
²³⁸ Lignite-fired generation mainly occurs in four countries: Germany: 148 TWh, Poland: 53 TWh, the Czech Republic: 41 TWh and Greece: 31 TWh (EUROSTAT, 2011 data). Lignite power generation has been very stable in the last ten years and can be expected to remain so in the next few years: old lignite power plants have been replaced by new ones (Germany). Lignite is produced locally, benefits from a low price and adds to energy independency (see coal chapter). It emits more CO₂ than hard-coal and natural gas. However, as new efficient plants replace old inefficient plants, CO₂ emissions per kWh are reduced.

A decrease in coal demand does not automatically translate into increased gas demand

The scenarios/visions presented above offer contrasted views of future gas and coal demand by the power sector depending on development of regulation mainly. They share the same vision on the short-term outlook of gas demand: no substantial recovery of gas demand can be expected by 2020. In the longer term, gas and coal prices, but above all policy decisions, will determine the future of gas and coal in the EU power sector.

The EU power sector is structurally changing. Limited growth in electricity demand is becoming a structural trend, driven by **energy efficiency**. The increase of **RESe**, even if it slows down, will continue to reduce residual load addressed to other energy sources. Under such market conditions, it is not certain that a decrease in coal use automatically translates into increased gas demand. Figure 100 shows future projections of gas and coal demand in the three IEA scenarios. At long term, **it highlights the decreasing role of coal, but also that of natural gas in a scenario with stringent environmental conditions**.

Figure 100: EU coal and gas demand in the three IEA scenarios



Source: WEO 2013

5.2. CONCLUSION: THE GAS AND COAL CONTEST

Renewables are the only winners

The power sector has entered into a deep crisis where there is no winner between gas and coal at short term. The coal renaissance may be short-lived. Already in 2013, coal demand by the power sector has dropped by an estimated 5%. The causes of the crisis are debatable. Some attribute the current crisis to a physical issue: the over-capacity created by the fast expansion of RES and gas capacity while at the same time the economic crisis (and energy efficiency) has reduced power demand. Others incriminate regulatory issues and the flaws in the energy-only market.

Obviously, the influx of new capacities decided before the economic crisis has weighed on prices. Equally obviously, a system where needed flexible capacity is forced out of the market and cannot recover its costs is not sustainable and must be reformed.

At short-term, the continued expansion of RES (even if it slows down as already observed in 2013) means that not only gas, but also hard-coal power generation, is going to be pushed out of the system. In 2013, some hard-coal plants were closed due to weak market conditions and more closures are foreseen, also due to air regulations or simply because the plants have reached the end of their technical lifetime. Under current market conditions, it is not expected that power operators will significantly invest in depollution equipment and refurbishment. About 65 to 70 GW is expected to close by 2020/23 at the latest, due to the combined effect of the LCPD and IED, representing a third of the coal fleet capacity. Coal plant closures do not automatically mean more gas demand: the UK closed 6 GW of old coal capacity between December 2012 and March 2013 and both coal and gas demand by the power sector decreased that year: electricity demand was flat and wind and solar increased their contribution. These two structural trends will heavily weight on demand addressed to conventional power plants in the future.

Coal and gas prices remain the key determinant at short term

Coal prices are expected to remain low thanks to abundant global supplies. Russia is the first and largest exporter of coal to the EU. This dependency, however, does not create security of supply issues as the coal market is a global and competitive one with many suppliers looking for new markets. The price of gas, still driven by oil prices to a large extent, is not expected to decline significantly, despite some downward pressure coming from the development of US LNG exports and possible European shale gas production. From a market perspective, the price of gas is simply too high for the power sector, an issue that gas suppliers should think about.

In the absence of a carbon price signal, gas demand is not expected to recover

One cannot be optimistic about short-term gas demand by the power sector. The prospects of gas and coal prices are definitely in favour of coal, even if prices are volatile. A CO₂ price of €40-50/t was required to switch from coal to gas at prices observed at the beginning of 2014²³⁹. Whatever the outcome of the EU ETS reform, such level is not attainable, neither desirable, in the short run: the burden would be too high for the EU economy. By 2020, therefore, gas demand in the power sector at EU level is not expected to recover from its current low level despite the end of the coal renaissance in some countries. The recent fall in gas prices is not sufficient to drive a coal-to-gas switching at current CO₂ prices.

Competition between gas and coal will continue to be contrasted depending on national energy policies

National policies contrast the EU-wise picture. The path to a low carbon economy can be achieved differently and at different timeframes according to national preferences for one source of energy and trade-offs between the objectives of sustainability, competitiveness and security of supply.

The opening of new coal plants in Germany in 2013/14, and the complete phase-out of nuclear power will create some room for conventional power generation, and reduce (eliminate?) the current German power over-capacity. Coal rather than gas should continue benefitting from any increase in conventional power generation in the country. As long as competition is left to market forces, coal has a clear competitive advantage, reinforced in Germany by the existence of large lignite resources.

²³⁹ The switching price from coal to gas has declined to €20-30/t at the beginning of May 2014, following the fall in gas prices from January to April 2014. It is however highly uncertain that the level of prices observed at the beginning of May 2014 will last.

Energy efficiency and the rapid development of RES may however limit the residual demand addressed to other sources.

In the United Kingdom, by contrast, the energy and climate policy does not encourage the use of coal. The introduction of a carbon tax in 2013 penalises coal burning. The increase in the carbon floor price, despite its recent freezing, is expected to reverse the current balance between clean spark and dark spreads to the benefit of natural gas. Gas burning should increase, in particular after 2015 when all opt-out coal plants are closed. The capacity market, being implemented in the UK, may allow mothballed gas plants to restart operations and new investment in gas-fired power plants. At longer term, the efforts deployed by the government to develop a CCS industry, may well allow clean coal resurgence.

In Poland, security of gas supply concerns, exacerbated by the Russia-Ukraine crisis, argue in favour of a continued use of coal in the power sector. Options to diversify the electricity mix at short term are currently limited. This may change in the future when diversification options (RES, LNG, shale gas, nuclear power) develop.

Security of electricity supply and investment issues must be addressed

Most of the closures of coal power plants linked with environment regulation (65-70 GW) will occur by 2020/2023 (or before if market conditions continue to deteriorate). This is in addition to the massive closure of gas plants which are no more profitable. If all gas plants under review are closed, this may lead to the closure of about 50 GW of gas capacity by 2015/16. Overall, gas and coal capacity could decline by 115-120 GW, almost a third of the current gas and coal capacity. While power capacity has been sufficient so far, this massive closure may quickly reduce the reserve margin, while at the same time back-up capacity is needed to ensure security of supply. The UK illustrates this situation: while old coal plants are closing (as expected), the (unexpected) mothballing and early closure of gas plants is reducing the power reserve margin from 6% in 2013/14 to 4% in 2015/16, a level which puts the UK system at risk. Investments in demand-side-response, electricity storage and new cross-border lines, may help to alleviate this issue, but will take time.

Addressing the issue of capacity adequacy is becoming urgent in several EU countries which have to replace their ageing coal fleet or are closing their nuclear power plants. In many countries, governments have chosen to implement capacity markets, to ensure there will be enough capacity to meet future demand. While there is a consensus about the fact that the energy-only market does not deliver the required long-term price signal for investment in capacity, there is no consensus about the necessity of these capacity markets, nor about the design of such mechanisms. The debate is becoming less relevant as many countries are implementing capacity markets. The key issue now is the design of these schemes in order to prevent possible distortions on cross-border trade and the Internal Electricity Market. As far as gas and coal competition is concerned, the design (and details) of these mechanisms is important, for instance the exclusion of some existing plants from participating in these schemes, or different conditions for existing and new plants.

Beyond the capacity issue, another key issue is the need to accommodate growing levels of variable generation as the share of wind and solar in the electricity mix increases. Gas plants have quicker start-up times than coal ones. They are also able to ramp production up or down faster than coal plants. The experience on the German market shows nevertheless that new coal plants (both hard coal and lignite) can also participate to the provision of flexibility. It remains that flexible operation of gas and coal plants is limited by economic, technical and environmental factors. The reduction in efficiency at low loads increases emissions and costs. These additional costs will need to be recovered.

Confidence in the power market has faded. Major power utilities are refocusing their thermal power business away from Europe. They are no more investing in power plants, except in chosen (subsidised) RES technologies and nuclear power. This is an additional issue for policy makers that have to rebuild confidence in the market.

At medium/long term, EU regulation on CO₂ or national decarbonisation policies will take the lead

EU policy makers are seeking to make deeper reductions in CO₂ emissions by 2030, with the ultimate goal of achieving a decarbonised economy by 2050. Coal is over twice as carbon intensive as gas, making gas a more attractive means of providing greater volumes of generation while emitting less CO₂ emissions. With the objective of a reduction by 40% of CO₂ emissions by 2030, as proposed by the European Commission in January 2014, gas capacity is preferred and it is therefore likely that gas power will increasingly dominate the EU electricity mix. On the other hand, the benefits of gas in terms of environment and flexibility are weighted against the cheaper cost of coal and its secured (domestic) supply. Maintaining both forms of generation also adds diversity and security benefits in view of current regulatory, economic and technical uncertainties, in particular on CCS.

The path and time frame towards a low decarbonised electricity system may vary significantly between countries. Reform of the EU ETS, or national policies in the absence of a well-functioning EU carbon market, will determine the competition between gas and coal at medium and long term.

Public acceptance and regulatory, technical, economic and financing issues currently prevent the development of CCS in the EU (except in the UK, and to a lesser extent the Netherlands), while CCS is much needed to achieve the goal of a decarbonised economy.

A future with gas: reinventing the business case

This decade appears as a lost decade for natural gas demand by the EU power sector. The golden age of gas everywhere else in the world makes the European situation even more bitter.

Three main conditions are needed to reverse this situation and allow clean and flexible natural gas to play its role as an enabler of the transition to a low carbon economy:

■ Decarbonisation and reform of the EU ETS

The reform of the EU ETS, which is urgently needed, should allow natural gas to play a key role in the decarbonisation of the EU electricity system. A reduction of CO₂ emissions by 40% by 2030 could hardly be met otherwise.

■ Gas prices and market liberalisation

The further liberalisation of gas markets and supply diversification should allow gas prices to be determined by market fundamentals and liquid gas markets to further developed, a condition for the use of gas in the EU power sector characterised by a growing level of variable generation.

The competitiveness of natural gas in the power sector must be addressed, for instance by developing partnerships between suppliers and utilities and exploring new sales and purchase agreements including the specificities of the EU electricity sector. This requires, however, that gas exporters and importers share the same vision on the evolving EU gas and electricity market and are ready to cooperate to rebuild the competitiveness of natural gas in the power segment. The power sector is still the segment which offers the largest opportunity to increase gas consumption.

The exploration and production of shale gas in Europe, under sustainable conditions, would allow Europe to reduce its external dependence and provides a new source of gas to the market.

■ Investment and electricity market design

Addressing the investment issue is of utmost importance to ensure future security of supply. Capacity markets, properly designed, should allow a recovery of investment in gas capacity, and in particular, to restart the numerous mothballed gas plants and unlock frozen CCGT projects.

ACRONYMS AND ABBREVIATIONS

ACER	Agency for the Cooperation of Energy Regulators
ARA	Amsterdam, Rotterdam, Antwerp (coal)
bcm	billion cubic meters
bcmpa	billion cubic meters per annum
BREE	Australian Bureau of Energy Resources
CAES	Compressed Air Energy Storage
CAGR	Compounded Annual Growth Rate
CAPEX	Capital Expenditures
CBM	Coal bed methane
CCR	Carbon Capture Ready
CCGTs	Combined cycle gas turbine (plants)
CCL	Climate change levy (UK)
CCS	Carbon Capture and Storage
CER	Certified Emission Reduction
CEER	Council of European Regulators
CfD	Contract-for-difference
CHP	Combined Heat and Power
CIF	Cost, Insurance and Freight (coal)
CIS	Commonwealth of Independent States
CME	Chicago Mercantile Exchange
CNPC	China National Petroleum Corporation
CO	Carbon oxide
CO ₂	Carbon dioxide
CPF	Carbon price floor (UK)
CPS	Carbon price support (UK)
CRM	Capacity Remuneration Mechanisms
DECC	Department of Energy and Climate Change (UK)
DSR	Demand-side response
EBRD	European Bank for Reconstruction and Development
EC	European Commission
EEG	Germany's Renewables Energy Act
EFET	European Federation of Energy Traders
EIA	Energy Information Administration (US)
EIB	European Investment Bank
ELV	Emissions Limit Values
ENTSO-E	European network of transmission system operators for electricity
ENTSO-G	European network of transmission system operators for gas
EnWG	German Energy Industry Act
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency (US)
EPS	Emissions Performance Standard
ERGEG	European regulatory group for electricity and gas

ERU	Emission Reduction Units
EU	European Union
EUA	European Union Allowances
EU ETS	European Union Emissions Trading Scheme
FGD	Flue Gas Desulphurisation (equipment)
FEED	Front End Engineering Design
FERC	Federal Energy Regulatory Commission (USA)
FID	Final Investment Decision
FIT	Feed-in-tariff
FOB	Free on Board (coal)
FSU	Former Soviet Union
GDP	Gross Domestic Product
GHG	Greenhouse gas (emissions)
GIE	Gas Infrastructure Europe
GSE	Gas Storage Europe
Gt	Giga tonnes
GTM	Gas Target Model
GW	Gigawatt
HH	Henry Hub (US spot price)
IEA	International Energy Agency
IED	Industrial Emissions Directive
IEM	Internal Energy Market (for electricity and gas)
IGCC	integrated Gasification Combined Cycle
IGU	International Gas Union
LCoE	Levelised cost of electricity
LCPD	Large Combustible Plants Directive
LHV	Low Heating Value
LLD	Limited Life Derogation (IED)
LNG	Liquefied natural gas
mcm	million cubic meters
mcm/d	million cubic meters per day
MBtu	Million British thermal units
MS	Member States (EU)
MSR	Market Stability Reserve (EU ETS)
Mt	million tonnes
Mtce	million tonne of coal equivalent
Mtoe	million tonnes oil equivalent
Mtpa	million tonnes per annum
MW	Megawatt
NAP	National Allocation Plans (EU ETS)
NDRC	National Development and Reform Commission (China)
NEA	National Energy Administration (China)
NEB	National Energy Board (Canada)
NGV	Natural gas vehicles
NBP	National balancing point (UK)

NOx	Nitrogen oxides
NREAPs	National Renewable Energy Action Plans
OCGT	Open Cycle Gas Turbine
OECD	Organisation for Economic and Cooperation Development
OGP	International Association of Oil and Gas Producers
OIES	Oxford Institute for Energy Studies
O&M	Operation and Maintenance (costs)
PV	Photovoltaic
RES	Renewable energy sources
RESe	Electricity from renewable energy sources
ROC	Renewable Obligation Contracts (UK)
SCR	Selective Catalytic Reduction (equipment)
SOx	Sulphur dioxide
TAP	Trans-Adriatic Pipeline
tcm	trillion cubic meters
TNP	Transitional National Plans (IED)
ToP	Take or Pay
TPA	Third party access
TSO	Transmission system operator
TTF	Title Transfer Facility
TWh	Terawatt hour
TYNDP	Ten Year Network Development Plan
UN	United Nations
USC PC	Ultra supercritical pulverised coal
USDOE	US Department of Energy
VOLL	Value of Lost Load
v-RES	Variable renewable energy sources
WEO	World Energy Outlook (IEA)

MAIN CONVERSIONS

Measurement conditions

Cubic meters (cm) of natural gas are taken in standard conditions, measured at 15°C, and 1,013 mbar.

1 standard cm = 1.055 normal cm

Volumes

1 cubic meter (cm) = 0.0283 cubic feet (cf)

1 billion cubic meters of gas = 1.33 million tons liquefied natural gas (t LNG)

Energy equivalences

1 ton oil equivalent (toe) = 0.9 * 1,000 cm of natural gas

1 cm of natural gas $\approx$ 39 GCV megajoules (MJ) $\approx$ 10.8 kWh

Quantities of heat

1 thermie (th) = 1,000 kcal

1 toe = 10,000 thermies NCV (Net Calorific Value)

Gross Calorific Value (GCV) and Net Calorific Value (NCV)

The following approximation can be used for a natural gas containing a small fraction of liquids:

NCV $\approx$ 0.9 GCV

Equivalent to	GJ	kWh	million Btu	th	therm
1 gigajoule (GJ)	1	277.8	0.948	238.9	9.479
1 kilowatt-hour (kWh)	$3.6 \cdot 10^{-3}$	1	$3.411 \cdot 10^{-3}$	0.86	$3.411 \cdot 10^{-2}$
1 million British thermal units (MBtu)	1.055	293.2	1	252	10
1 thermie (th)	$4.186 \cdot 10^{-3}$	1.162	$3.968 \cdot 10^{-3}$	1	$3.968 \cdot 10^{-2}$
1 therm	0.1055	29.32	$1 \cdot 10^{-1}$	25.2	1

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