A UK 'DASH' FOR SMART GAS

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http://www.lse.ac.uk/GranthamInstitute/wp-content/uploads/2014/03/PB-uk-dash-for-smart-gas.pdf

Abstract

This paper investigates the renewed interest in a 'dash' for gas-generated power, as well as the recent expectations on shale gas resources in the UK. The analysis takes into account UK and European Union carbon constraints, gas market dynamics, environmental impacts, and technological progress, as well as recent evidence on natural gas resources and prices. It concludes that the best option to ensure a clean, affordable and secure power system is a 'dash' for *smart* gas, where natural gas is used strategically in those areas where it adds most value and in compliance with emission targets and environmental legislation.

1. Introduction

The UK's resurgent interest in natural gas has been fuelled by the recent shale gas 'boom' in the United States, which has transformed global perceptions about gas future role in global energy systems.

A renewed focus on natural gas, or what the media has called a new 'dash' for gas[2], is hoped to bring prices down, reduce emissions and make up for falling conventional domestic resources. But can natural gas fulfil these promises in a similar way to which it has in the United States? This policy brief aims to explore what a new 'dash' for gas really means for the UK, including its potential to change recent trends in production and consumption, its impacts on the energy system as a whole, and its implications for environmental responsibility.

To achieve some analytical clarity, this brief analyses two aspects that appear to be driving the debate: the interest in a renewed 'dash' for gas-generated power; and the interest in a 'dash' to exploit indigenous shale gas resources.

Although the two are linked, each is discussed separately to better exemplify their implications in terms of costs, energy security and environmental impacts in the UK.

The analysis is based on a review of the most recent and robust evidence about the opportunities and challenges of an increasing role for conventional and unconventional

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[2] Independent, 9th September 2012: http://www.independent.co.uk/environment/climate-change/tories-dash-for-gas-risks-climate-target-8120153.html

sources of natural gas. The paper takes into account UK and European Union carbon constraints, gas market dynamics, environmental impacts, and learning (technological progress). The brief also proposes a range of recommendations for UK energy policy.

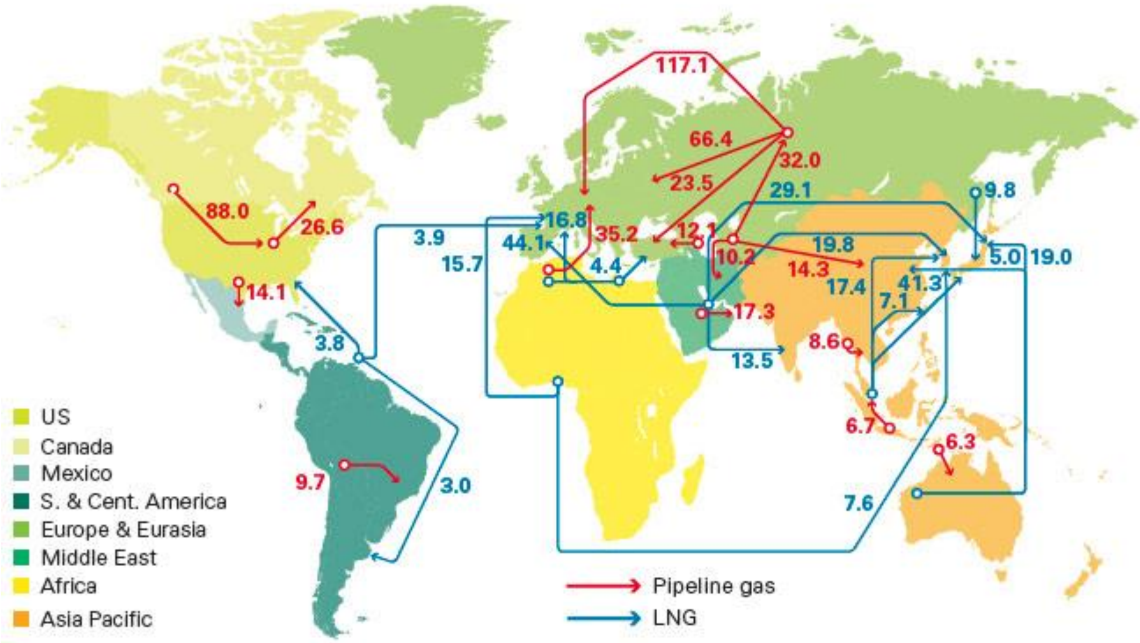
2. A 'dash' for gas-generated power

2.1 Energy costs: market dynamics and gas prices

There is large uncertainty as to whether UK and, more broadly, European gas prices will decline in the same way as they have in the United States[2] – thanks to new unconventional gas supplies.

International trade in natural gas is constrained by high transportation and storage costs, arising from pipeline systems and expensive liquefaction processes. As a result, only one-third of global gas supplies are traded across borders, compared with two-thirds of oil (Rogers, 2012) (see Figure 1). The natural gas industry is therefore dominated by geographically segmented market structures, rather than globally integrated markets. There are three broad regional markets: North America, Europe and Asia. The UK could be considered as a fourth market as it is significantly more liberalised than the European one (see e.g. MIT, 2011).

Figure 1 LNG and pipeline gas - major trade flows worldwide (bcm), 2011



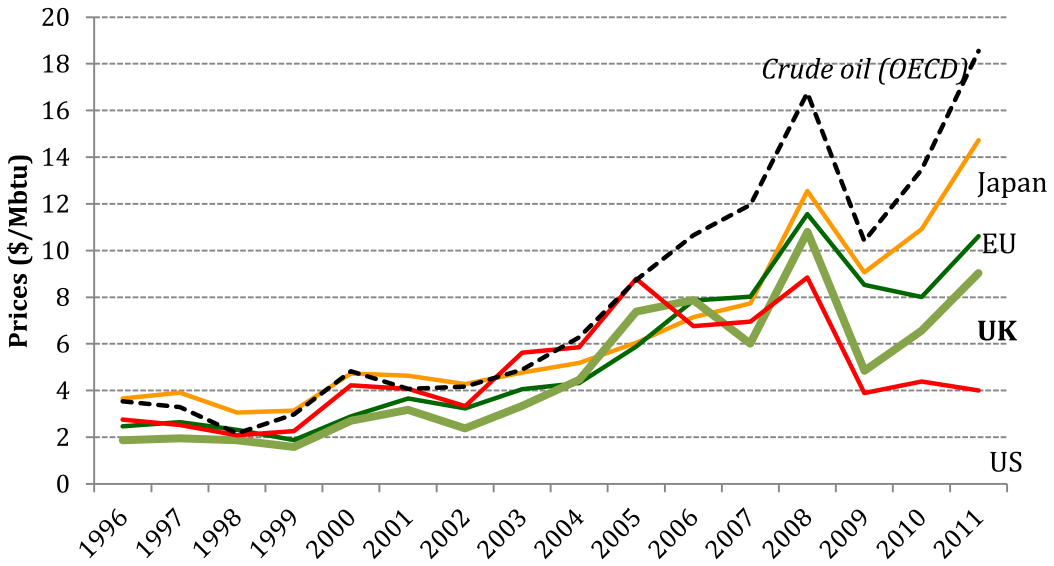
Source: BP (2012:29)

As gas markets are segmented, there is no global wholesale price, and gas prices vary widely between regions (see Figure 2). In June 2012 spot gas was trading at as little as US$2.10 per million British thermal units[3] (MBtu) in the United States, compared with

[3] A British thermal unit (Btu) is the energy required to heat 1 pound of water by 1 degree Fahrenheit. It corresponds to around 1,055 joules. It should be noted that while we use Btu (a

US$9.90 per MBtu in the UK, US$12 per MBtu for spot LNG in the Mediterranean and US$17.40 per MBtu for spot LNG in northeast Asia (IEA, 2012b).

Figure 2 Wholesale prices for natural gas, 1994 - 2011 ($/MBtu)



Note: US prices are based on the Henry Hub (HH) index; UK prices on the National Balancing Point (NBP); Continental European prices are proxied by the German border price (BAFA); Asian LNG contracts are long-term contracts indexed to a basket of crudes imported to Japan (the 'Japanese Crude Cocktail').

Source: BP Statistical Review 2012

According to the International Energy Agency (2012a), in Europe, whether unconventional gas resources like shale gas (see Section 3) are successfully exploited or not, future import gas prices in 2035 are expected to reach between US$10.80 and US$13.10 per MBtu, compared to US$7.50 in 2010. Interestingly, in 2011 prices already reached US$9.03 in the UK and US$10.61 in the European markets (BP, 2012). Greater unconventional gas supplies will have a moderating impact in reducing gas prices. Nevertheless, some of the existing natural gas import contracts based on oil indexation will continue to remain in force for many years, preventing prices from freely adjusting to changes in gas supply.

In the UK, the central scenario devised by the Department of Energy and Climate Change (2012g) suggests that UK wholesale gas prices could follow a path similar to continental Europe, reaching US$11.50 per MBtu by 2018, and remaining stable at that level until 2030.

Estimates by the UK Government Office for Budget Responsibility (Her Majesty's Treasury, 2012) suggest prices would decrease. This forecast, however, is only for a short five-year horizon and is based on a slightly more simplified approach which takes into account only trends in oil futures prices and the Office for Budget Responsibility's own projections of oil prices, which are expected to decline (see Table 1).

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measure of energy) for prices, we use cubic meters, a measure of volume, for gas quantities. A conversion table is provided in Annex I.

Table 1. Natural gas wholesale price forecasts by various sources (US$ per MBtu)

Source	Scenario	2013	2014	2015	2016	2017	2018	2020	2030	2035
IEA (Europe)	Golden Rules	–	–	–	–	–	–	10.5	–	10.8
	Low Unconventional	–	–	–	–	–	–	11.6	–	13.1
DECC (UK)	Low	8.1	7.8	7.5	7.2	6.9	6.6	6.6	6.6	–
	Central	11.0	12.2	12.3	12.4	12.0	11.5	11.5	11.5	–
	High	13.9	14.3	14.6	15.0	15.3	15.7	16.5	16.5	–
OBR(UK)	–	9.27	8.97	8.53	8.15	7.84	7.60	–	–	–

Source: IEA (2012a), DECC (2012d), HM Treasury (2012).

2.2 Energy security: managing fluctuating demand and supply

Over the coming decades, the UK electricity system is expected to undergo a significant transformation. Older power plants will close down, electricity demand will rise due to the electrification of heating and transport, and the energy mix and characteristics of supply will change. In particular, the share of intermittent renewable sources will significantly increase.

Although compliance with UK carbon budgets will require a decrease in the share of gas in electricity generation, official estimates forecast an increase in the capacity from gas-fired power plants (e.g. National Grid, 2012; DECC, 2012c). Why is this so?

First, new power stations will be required to replace older ones. Around 12 GW of oil and coal-fired plants will close by 2016 under the Large Combustion Plant Directive.[4] Furthermore, 4 GW from aging nuclear power stations is due to be lost by the end of 2020. Beyond this, further coal-fired plant closures are likely because of tighter environmental requirements introduced by the Industrial Emission Directive.[5] Overall, more than one-fifth of the UK's electricity generating capacity will be retired within the next 10 years. Ofgem (2012) has warned that there could be an imminent drop in spare electricity capacity from a margin of 14 per cent at present to only 4 per cent by 2015/16.

Some of the new power plants will be low-carbon (i.e. nuclear and renewables), while others will be fired by fossil fuels such as natural gas. Overall, emissions are expected to fall as these new plants will replace more carbon-intensive installations that currently run on coal – which on average produce 57 per cent more carbon dioxide per kWh than those fired by natural gas (DECC, 2012a).

Secondly, in the coming years, electricity generation capacity will need to increase due to the increasing intermittency of supply (due to a higher share of renewables) and higher demand (as more sectors will rely on electricity). National Grid (2012) envisages an increase in total UK electricity generation capacity from about 94 GW in 2012 (generating around 350 TWh) to almost 152 GW by 2030 (expected to generate about 400 TWh).

[4] 2001/80/EC
[5] 2010/75/EU

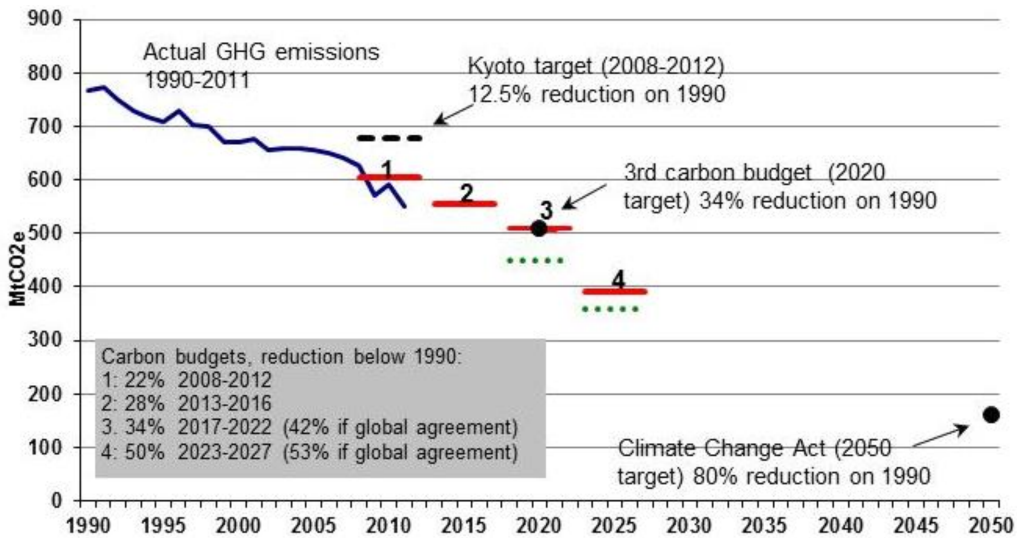
Gas-fired power stations - specifically combined cycle gas turbine (CCGT) plants - can help to improve the flexibility of the electricity system, as supply can be ramped up and down quickly to meet sudden peaks of demand or make up for variability in renewable generation.

In light of these new challenges, the UK Gas Generation Strategy (DECC, 2012c) laid out three possible scenarios for the future composition of gas-fired power plant capacity. These would lead to different levels of 'decarbonisation' of the electricity system by 2030, namely 50, 100 or 200g CO_2/kWh. The 100g CO_2/kWh outcome would imply the construction of about 26 GW of new gas-fired plants, such that capacity will be around 15 per cent higher in 2030 than today (see Figure 12). But as gas-fired power plants will have to be increasingly used for balancing, the actual output will be lower than today i.e. they will be used less efficiently.

2.3 Environmental responsibility: constraints from UK carbon budgets

Ambitions for a large-scale increase in gas-generated electricity need to be consistent with the Climate Change Act (Her Majesty's Government, 2008), which commits the UK to reducing its annual greenhouse gas emissions by at least 80 per cent by 2050 compared with 1990 levels (Her Majesty's Government, 2008). A series of five-year carbon budgets[6], the levels of which are recommended by the Committee on Climate Change and subsequently legislated by Parliament, define the path to 2050 (see Figure 3).

Figure 3 UK carbon budgets and targets to 2050



Source: Based on Bowen and Rydge (2011).

Meeting the economy-wide carbon budgets will require a gradual reshaping of the UK's energy infrastructure. The power sector, in particular, will need to play a central role in meeting the budgets, since it is a major source of carbon emissions (about a quarter of total 2011 emissions; DECC, 2012b) and it offers mitigation opportunities at the lowest potential cost (CCC, 2010). Furthermore, low-carbon electricity is assumed to provide the basis for the decarbonisation of other parts of the economy, such as surface transport, residential heating and perhaps parts of industry.

6 http://www.theccc.org.uk/carbon-budgets

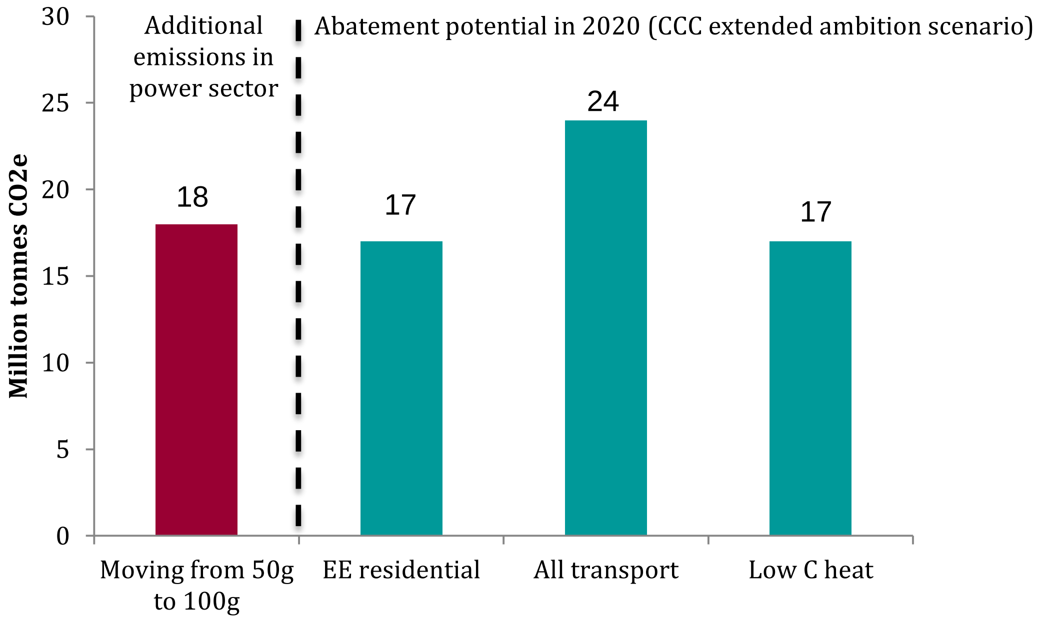
According to the Committee on Climate Change, the UK's fourth carbon budget implies that the power sector will need to be decarbonised during the 2020s, by adding between 30 and 40 GW of low-carbon plant capacity, assuming an electricity demand around 450 TWh. This is expected to reduce the average emissions intensity of electricity generation from around 500g CO_2/kWh today to around 50g CO_2/kWh by 2030 (CCC, 2010).

A decarbonisation target of 100g CO_2/kWh (as considered in the Central scenario of the UK Gas Generation Strategy) instead of 50g CO_2/kWh, for instance, would imply additional emissions of 18 million tonnes of CO_2e from the power sector in 2030. Figure 4 illustrates how such additional emissions would negate the benefits of reductions that could be achieved through some of the measures recommended by the Committee on Climate Change (2010); such as, energy efficiency measures in residential buildings, low-carbon heat targets (about 12 per cent of heat from low-carbon technologies by 2030), or all transport-related policies (including biofuels and fuel efficiency targets, eco-driving and rail efficiency measures).

To be able to meet the overall fourth carbon budget, the additional emissions from the power sector would need to be offset by additional cuts in other sectors. Whether this would be economically sensible will depend on the future price of gas, which remains uncertain, as well as on the cost-effectiveness of alternative emission abatement measures in other sectors. Furthermore, some of the alternative mitigation measures may still be linked to the decarbonisation in the power sector (for example, in the case of switching to electric cars and heating), so higher carbon intensity for electricity generation could have further knock-on effects on their cost and feasibility.

The future role of gas-fired power plants will also depend on whether their emissions can be captured with CCS technology. If CCS is effective and implemented, then a sustained use of gas for electricity generation could well be consistent with carbon budgets.

Figure 4 Policy implications of a less ambitious decarbonisation target for the power sector



Source: Calculations based on CCC (2010: pp.106-107)

3. A 'dash' for shale gas

3.1 Overview: what is shale gas?

In the last three to four decades, formerly inaccessible 'unconventional' gas resources, such as shale gas, have become profitable to exploit thanks to improved exploration and extraction technologies, especially horizontal drilling and hydraulic fracturing (or fracking).

There are, however, substantial uncertainties about the recoverable volumes of unconventional gas, given the absence of production experience in most regions of the world. In this regard, it is important to make a distinction between the information regarding the amount of gas stored underground and the volumes that can actually be extracted. Three key definitions are frequently used:

- Gas in place (or simply *resources*): the entire volume of gas contained in a rock formation, regardless of the ability to extract it.

- Technically recoverable resources: the volume of gas resources considered to be recoverable with available technology.

- Proven reserves (or simply *reserves*): the volume of technically recoverable resources demonstrated to be economically and legally producible under existing economic and operating conditions (Royal Society, 2012).

3.2 Energy costs: shale gas implications for wholesale prices and consumer bills

The costs of producing unconventional gas are usually higher than for conventional gas because of the additional expense of multistage hydraulic fracturing. They can vary greatly from one location to the next, and in Europe they could be about 50 per cent higher than in the United States (IEA, 2012a), because of a different geology, population density and regulation.

European break-even costs for shale gas (i.e. the market value required to provide an adequate real return on capital for a new project) are expected to range between \$5.00 and \$10.00 per MBtu. These are likely to be within the same range as the future break-even costs for conventional gas, as domestic resources are depleted and new projects begin in less accessible, and therefore more expensive to exploit, Norwegian Arctic region gas fields (IEA, 2012a; see Table 2).

Table 2. Indicative natural gas wellhead development and production costs in selected regions (in 2010 values)

	Conventional gas ($/MBtu)	Shale gas ($/MBtu)
United States	3-7	3-7
Europe	5-9	5-10
China	4-8	4-8
Russia	0-2; 3-7*	–
Qatar	0-2	–

*The lower range for Russia represents production in the traditional regions of Western Siberia and the Volga-Urals; the higher range is for projects in new onshore regions such as Eastern Siberia, offshore regions, and Arctic developments.

Source: Based on IEA (2012a).

As long as the UK remains a substantial net importer of gas, it is reasonable to assume that its wholesale gas prices will largely depend on prices charged by foreign suppliers. Although domestic shale gas production could benefit the economy by generating jobs and tax revenues while displacing imports, it is unlikely that gas consumers would see much, if any, benefit in terms of reduced gas and electricity bills.

Of course, if proven reserves turn out to be significantly larger than current official estimates, or if UK shale gas production was part of a major increase in unconventional gas production around the world, there could be a significant effect, at least (on projections by the International Energy Agency, 2012a) in moderating the increase in wholesale gas prices that would otherwise have taken place.

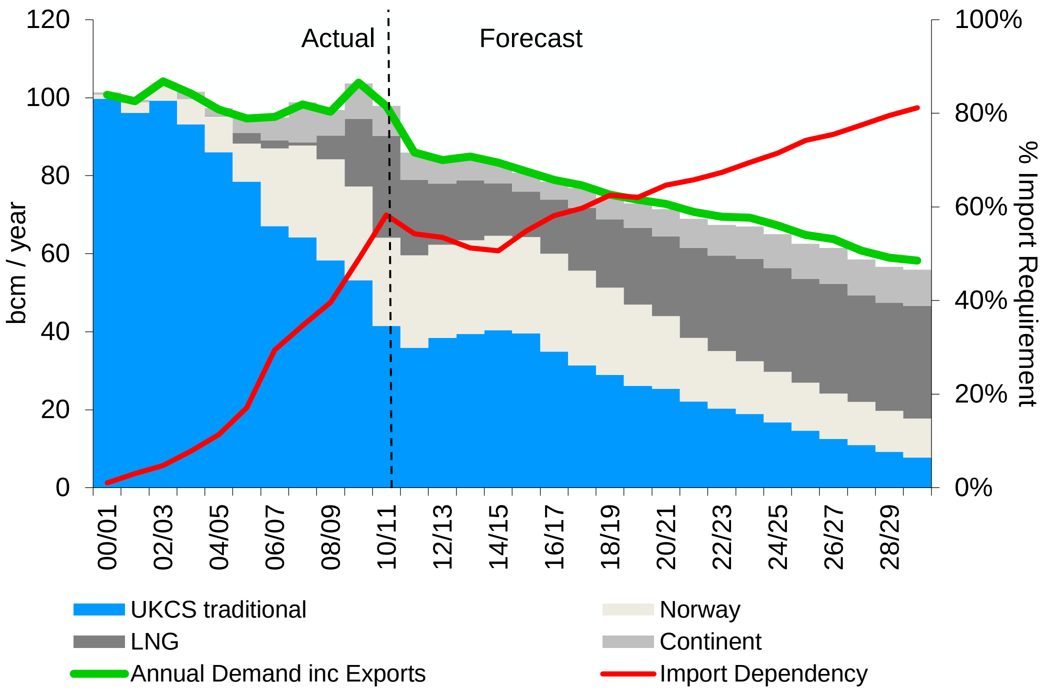
In the United States, shale gas has led to a reduction in the wellhead price over the past few years. There is some evidence that this has reduced the price of gas purchased by power companies. However, monitoring by the United States Energy Information Administration (2012e) suggests that there has been little impact on the average price of electricity for households (which increased by about 4 per cent in real terms between 2007 and 2011), although the effect on gas for consumers has been marked (the average residential retail price of gas decreased by about 23 per cent in real terms between 2007 and 2011).

3.3 Energy security: impact of shale gas on gas imports

Conventional gas resources in the UK are depleting fast. Yearly production from the UK Continental Shelf declined from around 100 bcm in 2000-01 to 36 bcm in 2011-12 (National Grid, 2012). Due to decreasing extraction, the UK has become a net importer of natural gas since 2004, and net imports in 2011 accounted for over 40 per cent of UK demand (National Grid, 2012).

In the coming years, estimates based on data from Oil and Gas UK suggest that gas production from the UK Continental Shelf will fall further to 25 bcm in 2020-21, and to around 8 bcm in 2029/30 (National Grid, 2012) (see Figure 5).

Figure 5 Annual gas supply forecast ('Gone Green' scenario)

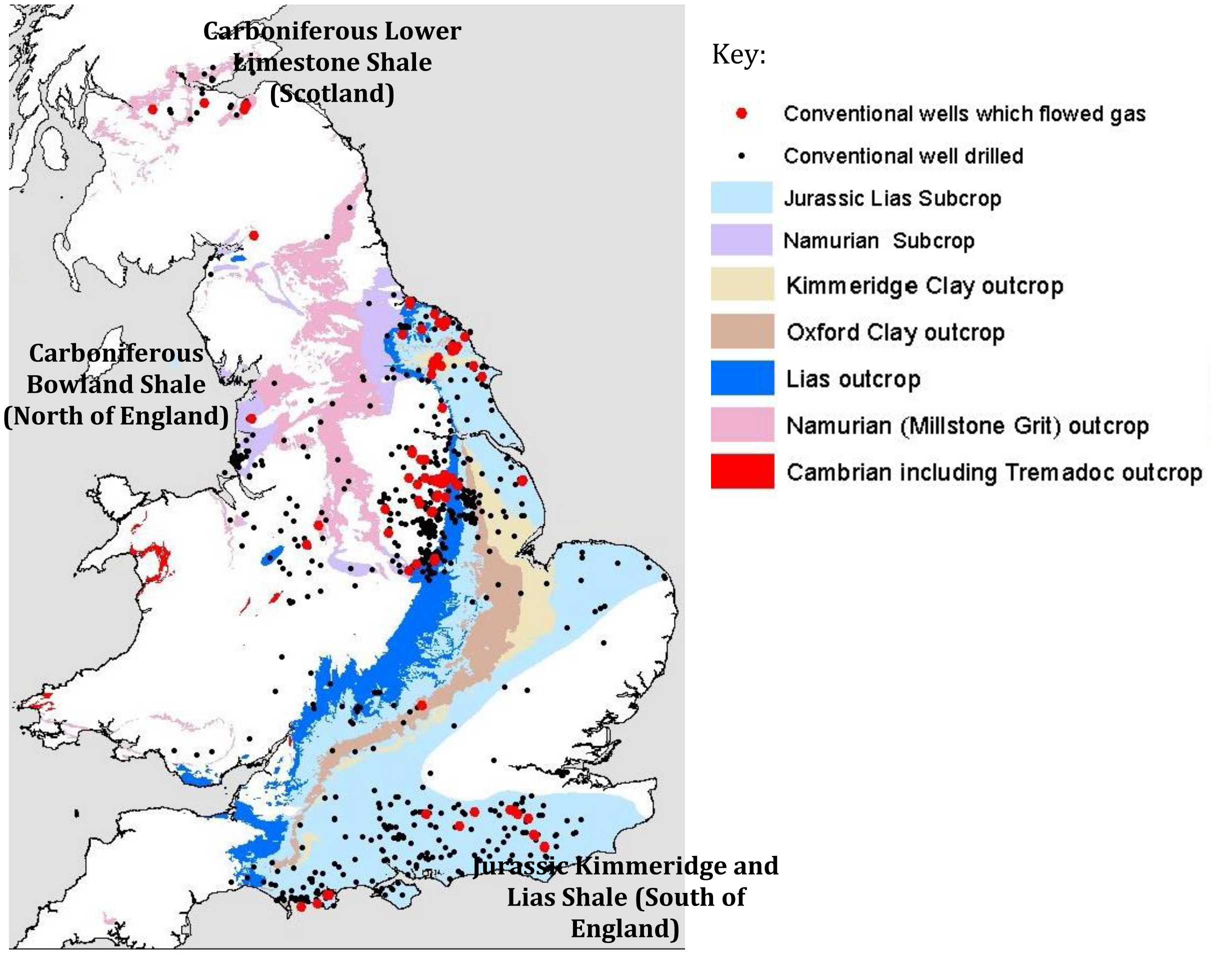


Source: Based on National Grid (2012: p77)

Any further increase in the use of gas for power generation, without additional indigenous supply of natural gas, will require increased imports from outside the UK. New domestic shale gas resources could therefore be seen as a welcome contribution. But how much shale gas could come into play?

Three areas in the UK were considered promising for shale gas exploitation: the Bowland Shale in central Britain, the Midland Valley in Scotland, and the Weald Basin in southern England (see map in Figure 6).

Figure 6 Shale gas potential in Great Britain



Source: DECC (2012c)

Actual exploration has been carried out in the Bowland shale only, where an oil and gas company, Cuadrilla, drilled two wells. More wells, however, will be needed for an accurate evaluation. Other assessments are based on estimation techniques like 3D geological models, like the recent work by the British Geological Society for DECC (Andrews, 2013, 2014; Monaghan, 2014), or on similarities with similar geological formations, like the analysis by the US Energy Information Administration (EIA, 2011), and earlier estimates by the British Geological Society and DECC (DECC, 2012e). Table 3 shows the variability across these estimates.

Table 3. Estimates of shale gas potential in the UK (bcm)

		EIA	Cuadrilla	BGS/DECC
Bowland Shale	Gas in place	2,690	5,660	37,600[7]
	Technically recoverable	540	900-1,200[8]	80-200
Weald Basin	Gas in place	60	n/a	0
	Technically recoverable	30	n/a	0
Midland Valley (Scotland)	Gas in place	n/a	n/a	2,270
	Technically recoverable	n/a	n/a	n/a
Total UK	Gas in place	2,750	5,660	39,870
	Technically recoverable	570	900-1,200[9]	n/a

Note: n/a = not available

Sources: EIA (2011), Cuadrilla (2011), ECC (2012), BGS/DECC: gas in place from Andrews (2013, 2014) and Monaghan (2014); technically recoverable from DECC (2012e)

The most reliable estimates of technically recoverable resources, so far, have been carried out by Cuadrilla. At today's level of UK demand for natural gas (around 80 bcm per year), these would be equivalent to between 2 and 14 years of domestic gas consumption, assuming that it would be possible to extract all the gas.

BGS/DECC estimates for gas in place are more optimistic than Cuadrilla's, but the authors do not make any assessment of technically recoverable resources. Following a similar assumption as Cuadrilla's – that 15 to 20 per cent of the gas in place could be technically recoverable – would suggest that technically recoverable resources could be around 6,000-8,000 bcm.

In practice, the amount of gas that could be effectively produced (i.e. the proven reserves) is likely to be much less, because of economic, environmental and legislative constraints.

For the purpose of illustration, the United States Energy Information Administration (2012d) estimated proven reserves of shale gas in the United States to be around 2.8 tcm in 2010, almost one-tenth of its technically recoverable resources of 24.4 tcm. If a similar proportion could be extracted in the UK, the gas effectively produced would be equivalent to no more than 1.5 years of current demand, on the basis of Cuadrilla's estimates. Using our higher estimates, based on BGS/DECC data, the gas produced could be equivalent to about 8-10 years.

The timing of gas extraction in the UK is also uncertain. The International Energy Agency does not expect significant production of shale gas in Europe before 2020, due to the time

[7] Central estimate (Andrews, 2013)

[8] Based on Cuadrilla's assumption that between 15 and 20 per cent of the gas in place could be extracted (Energy and Climate Change Committee, 2012).

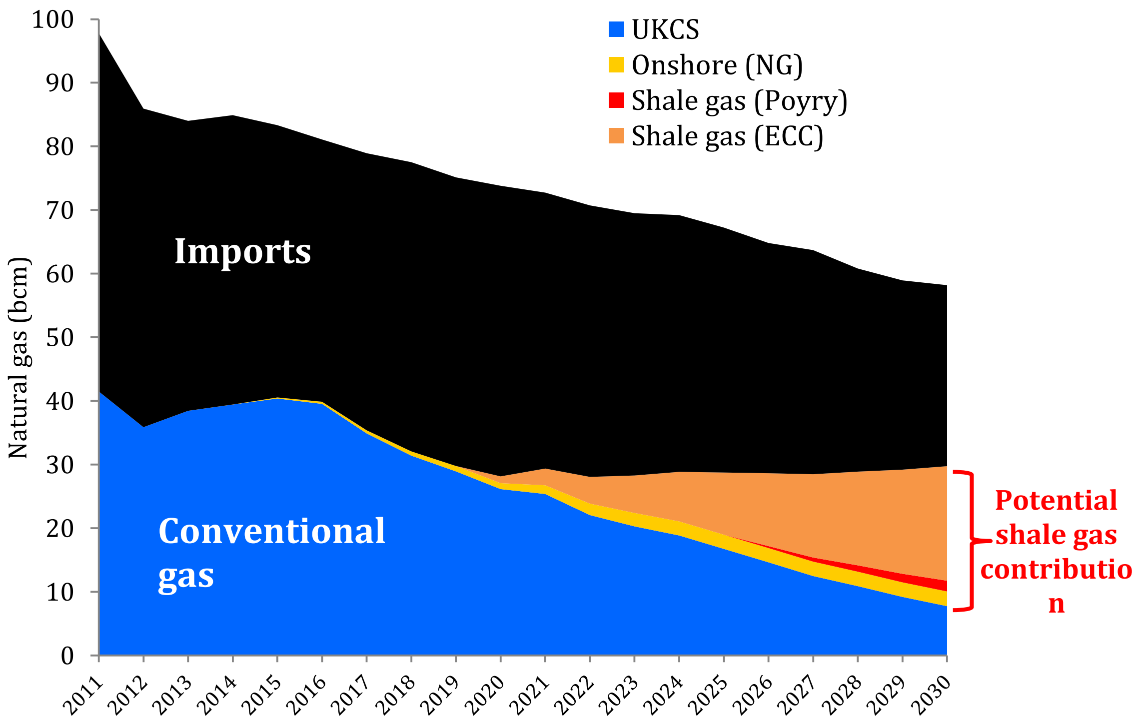
[9] Based on Cuadrilla's assumption that between 15 and 20 per cent of the gas in place could be extracted (Energy and Climate Change Committee, 2012).

needed for resource appraisal and development, and associated technical, environmental and regulatory issues (IEA, 2011).

National Grid (2012) forecasts that production of 'onshore' gas (a mix of shale gas, CBM and biogas) could start from 2013-14 and gradually reach 2.3 bcm per year by 2030. The expectation of Pöyry (2011) is that between 1 and 4 bcm per year could be produced by 2030. A more optimistic estimate by the Energy Contract Company envisages that production could hit 21.7 bcm per year by 2030, equivalent to about half of current domestic production of conventional gas.

At the same time, as mentioned above, reserves of conventional gas in the UK Continental Shelf are depleting. By 2030 domestic reserves of conventional gas are expected to satisfy no more than 13 per cent of demand (National Grid, 2012). Shale gas could help diversify domestic resources and therefore contribute to the UK's energy security. But its potential should not be exaggerated. Current data suggests that, even in the most optimistic scenario, shale gas might at best compensate for the decrease in domestic production of conventional gas (see Figure 7), while imports will continue to meet a significant share of demand in the coming decades.

Figure 7 Future UK gas supply and demand



Source: Calculations based on National Grid (2012), Pöyry (2011) and ECC (2012)

3.4 Environmental responsibility: greenhouse gas emissions and other impacts

Several concerns have been raised about the environmental impacts associated with unconventional gas production. Some of these are similar to those experienced with conventional onshore gas production, while others are specific to shale gas operations – particularly fracking.

First, the production of shale gas involves higher greenhouse gas emissions than conventional gas. This is because it involves a larger number of wells and more hydraulic fracturing operations, both of which require energy, typically from diesel motors, which emit carbon dioxide. And, importantly, shale gas operations lead to more venting of gas during well completion. There is evidence that shale gas development in the United States has led to significant 'fugitive' methane emissions (e.g. EPA, 2012; Howarth et al., 2011; Clark, 2011; Pétron, 2012).

Some analysts have concluded that these have been so great as to eliminate the lifecycle greenhouse gas emission benefits of shale gas compared with coal for power generation (e.g., see Howarth et al, 2011), although this has been disputed (e.g. by Clark et al, 2011).

Given the lack of reliable data, there is a large variation in the estimates of historical impacts on climate change from shale gas production. It is apparent, however, that the consequences of shale gas exploitation for greenhouse gas emissions will depend crucially on effective regulation of production operations, especially venting.

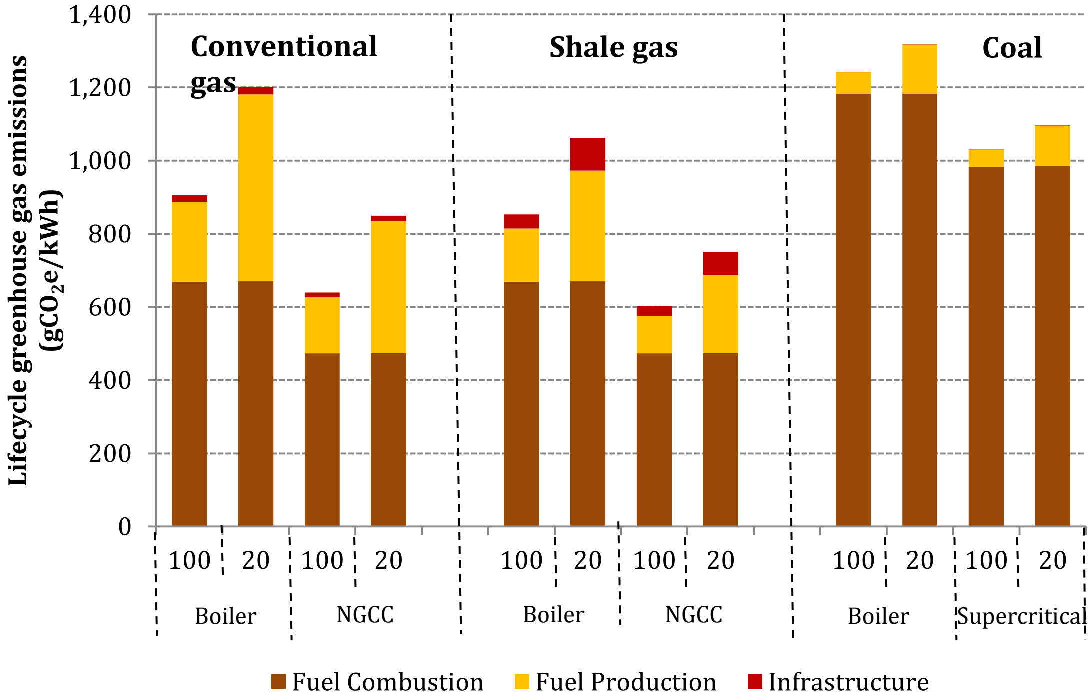
In the European Union, a recent analysis for the European Commission (AEA et al., 2012a) found that lifecycle greenhouse gas emissions from shale gas can be slightly higher than those from conventional gas, but significantly lower than emissions from coal. Greenhouse gas emissions per kWh of electricity generated from shale gas are estimated to be between 4 and 8 per cent higher than those from conventional gas obtained from within the European Union. However, if emissions from well completion are mitigated and utilised, the difference in emissions can be reduced to between 1 and 5 per cent (AEA et al., 2012a). In such a case, lifecycle emissions from European Union shale gas can also be 2 to 10 per cent lower than emissions from electricity generated from conventional pipeline gas obtained from non-Member States, notably Russia and Algeria. Lifecycle emissions from power generation that is fuelled by shale gas are estimated to be almost 41 to 49 per cent lower than those of electricity generated from coal.[10]

This is consistent with a comparison between lifecycle greenhouse gas emissions for different time horizons (20 and 100 years)[11] carried out by Clark et al. (2011), which indicates that emissions from power generated from shale gas can actually be equal to or lower than those from conventional gas (see Figure 8).

[10] On the basis of a representative 100-year measure of global warming potential for methane.

[11] When comparing the impacts of emissions from different fuels, a time frame must be specified as greenhouse gases (e.g. carbon dioxide and methane) have different lifetimes in the atmosphere. The Intergovernmental Panel on Climate Change recommends using a 100-year time horizon when calculating greenhouse emissions in order to evaluate various climate change mitigation policies. When using a 20-year timeframe, the effects of methane are amplified as it has a relatively short perturbation lifetime (12 years), whereas carbon dioxide can last in the atmosphere for a long time (Clark et al., 2011).

Figure 8 Lifecycle greenhouse gas emissions per kWh of electricity produced for 100- year and 20-year timescales of global warming potential



Note: NGCC = Natural Gas Combined Cycle

Source: Based on Clark et al., 2011

It should also be noted that, in coal-producing countries like the United States, a switch from coal to gas generation can simply shift emissions elsewhere if the unburned coal is exported. This was confirmed in a study by Broderick and Anderson (2012), which suggests that more than half of the emissions avoided in the United States power sector may have been exported as coal.

Besides greenhouse gas emissions, shale gas production can have a number of other environmental impacts. The possibility of water pollution is perhaps the issue that has received the widest public attention. This could be caused, for instance, by fracking fluid, faulty well construction (Royal Society, 2012; Osborn et al., 2011), or gas migration (Davies, 2011). There is much anecdotal evidence from the United States of water being polluted with methane, although the extent to which this is due to shale gas exploitation rather than natural causes is hotly disputed. At least one official report (EPA,2011) has concluded that fracking was a likely cause of ground water pollution in the United States. However, in the UK most aquifers used for drinking water lie within 300 metres of the surface, while fracking would normally take place at a depth of more than two kilometres. A joint report by the Royal Society and the Royal Academy of Engineering (2012) concluded that water contamination from fracking is ‘highly unlikely’.

Fracking, however, requires greater water volumes than conventional gas production, with potential impacts on supplies. Recent analyses reveal that the production of 9 bcm/year of shale gas (equivalent to about 10 per cent of current gas demand) would require about 0.01 per cent of the licenced annual water abstraction for England and Wales (Broderick et al., 2011; Ward, 2012). While this appears to be a relatively small amount, impacts on water supplies may still be significant locally.

Shale gas extraction can also lead to earth tremors. These are considered highly unlikely to cause structural damage (AEA et al., 2012b; British Geological Society, 2012), but can have significant impacts on public acceptability. Notably, two small earthquakes were triggered by the first shale gas operations in Lancashire in the UK, and led to a temporary suspension of operations. Blowouts are also possible, although their occurrences are considered to be rare (Royal Society & Royal Academy of Engineering, 2012). Furthermore, shale gas developments can lead to harmful emissions beside greenhouse gases, such as ozone precursors, diesel fumes, and other hazardous pollutants.

Other environmental impacts are related to land take and disturbance, given the larger number of wells required for extraction compared to conventional gas. In the UK, the Institution of Mechanical Engineers (2012) has concluded that 200 to 800 rigs would be needed for a moderate level of production of shale gas by 2025. Commercial shale gas extraction in the Lancashire area alone is expected to require around 400 production wells to be drilled at 40 sites (Regeneris Consulting, 2011). Each site (well pad) would likely cover several acres and include a containment pond, condensate storage tanks and compressor stations (Deutsche Bank, 2011). This could be of potentially major significance for large shale gas developments, especially in densely populated areas.

Noise can also be an issue. It is estimated that each well pad, assuming 10 wells per pad, would require 800 to 2,500 days of noisy activity (AEA et al., 2012b). Finally, shale gas developments can have negative impacts on local biodiversity and lead to higher traffic (due to lorry movements), with potentially significant consequences for the local population (AEA et al., 2012b).

Greenhouse gas emissions and other environmental impacts can be mitigated with existing technology. The International Energy Agency (2012) estimates that the additional cost of applying appropriate mitigation measures (a set of ‘Golden Rules’) would be limited. The overall financial cost of a typical shale gas well could increase by no more than 7 per cent, and possibly less in case of larger development projects. But accurate monitoring and implementation of suitable regulations, as well as careful planning, will be necessary to avoid or limit environmental damage.

4. A ‘dash’ for smart gas

To deliver a future power system that is clean, secure and costs effective a different approach is required, referred to here as a ‘dash’ for *smart* gas. This acknowledges that gas has an important role to play in displacing coal in power generation and providing flexibility to an electricity system supplied by a growing amount of intermittent renewable sources, as well as the need to meet the UK emissions targets.

An energy policy that is cost-efficient and consistent with climate change objectives should take into account all the opportunities and challenges that future investments in additional gas capacity and generation would create. The analysis of the available evidence presented in this brief allows a number of recommendations to be drawn which can help inform decisions about the future role of natural gas UK electricity generation.

Ensure the electricity system is able to meet demand. Natural gas will continue to play an important role in UK electricity generation over the coming decades, under all scenarios, both for homes and businesses, and it will help to balance fluctuating supply and demand. Should gas prices fall, for example as a consequence of increasing supply of unconventional gas worldwide, this could have positive effects on the UK economy. Investment in additional technologies and measures to increase the flexibility of the electricity system will also be essential to meet demand, achieve climate change targets and ensure cost-efficiency. Several analyses (Pöyry, 2010; Strbac, 2012; Buckle and Thompson, 2009) have highlighted that the delivery of improved flexibility by 2030 requires decisions to be taken now, including about investment in energy storage, the upgrade of distributional networks and the development of infrastructure, particularly smart meters.

Prepare for higher gas prices. Low gas prices are not guaranteed. Several estimates, including by the International Energy Agency (2012a), indicate that gas prices in the UK and in the European Union are more likely to increase, than fall, over the next two decades. The exploitation of unconventional gas resources has the potential to moderate such price increases, but the trend is still expected to be upwards. While projections should generally be considered with caution, given the high degree of uncertainty surrounding energy prices, current evidence suggests that betting on a sustained decrease in the wholesale price of natural gas would be very risky. This would also be inconsistent with the UK Government's objective of diversifying energy price risks, and might increase the likelihood of locking the UK into a potentially expensive high-carbon future. Furthermore, evidence from the United States, and past experience in the UK, suggests that any reduction in the wholesale price of natural gas may not result in commensurate falls in electricity and heating bills for households and businesses.

Meet the carbon budgets. The UK carbon budgets set an upper limit on greenhouse gas emissions. Extensive gas-generated power, operating without CCS, would not be consistent with these targets. In the short run, some emissions from electricity generation can be reduced by replacing coal with gas, as has happened in the last few years in the United States. But in the medium term, gas without CCS will be too carbon-intensive to play a big role in the decarbonisation of the UK's power sector. Strong UK Government support for research, development and deployment across a number of CCS pilot projects will be crucial to prove this technology is commercially viable, and to bring down costs (Imperial College London, 2011). Interestingly, the need to run CCGT plants with unabated emissions at low efficiency levels, in order to meet future carbon targets, makes the efficiency penalty imposed by CCS (which would allow the plant to operate at a higher load factor) more attractive. However CCS has a high capital cost and involves a significant loss of efficiency compared with fossil fuel plants that have unabated emissions. Market forces alone will not lead to its development and government support is essential for its implementation on the scale and at the pace required. Additional intervention will be needed, at least in the short term, to spur investments. The Member States of the European Union should also coordinate their CCS efforts and push ahead with pilot schemes, particularly for gas, including technology that can be retrofitted. Furthermore, while this policy brief does not consider whether or not a mandatory decarbonisation target for the power sector in 2030 would help to ensure that enough investment is made in low-carbon electricity generation, it should be noted that relaxing the emissions constraint for the power sector would require an attendant increase in emission reductions in other sectors of the economy, which could be more expensive to deliver. A detailed analysis is required of the most cost-effective options for compensating for the additional emissions from the power sector if its carbon intensity is not reduced to 50g/kWh by 2030.

Keep shale gas development within environmental and social constraints. The size of the shale gas resource that can be commercially exploited in the UK is unclear. However, it is likely to be relatively small in comparison with current and future levels of consumption. Therefore, while domestic shale gas production is undoubtedly worth investigating, and may be able to make a useful contribution to the UK economy, its potential should not be exaggerated. Current estimates suggest that shale gas could, at best, compensate for the gradual depletion of conventional reserves from the UK Continental Shelf. Furthermore, the production of shale gas will likely take more than a decade to develop in the UK. There are also significant social and environmental concerns that will need to be addressed if it is to be developed responsibly in the UK and Europe (IEA, 2012a), including risks of water pollution and fugitive emissions, and impacts on the landscape and local communities, which will need to be adequately regulated.

Overall future energy policy will require a coherent portfolio approach, as any decisions about electricity generation will have important repercussions on the whole energy system and on UK society.

6. Conclusions

The UK energy sector, particularly power generation, faces a period of transformation over the coming decades, in response to a number of driving pressures. First, there is a need to shift towards low-carbon energy sources to meet the UK's mandatory carbon target for 2050. Second, a large share of the UK's ageing power plants and other energy infrastructure will have to be replaced over the coming decade as they reach the end of their lifetimes, requiring large amounts of investment. Third, there are concerns about the affordability and availability of electricity and heating for homes and businesses, particularly as the UK becomes more dependent on imports of natural gas.

All three drivers mean that there is an opportunity to overhaul the sector and shape it for the future, with a shift to low-carbon electricity generation. But this transformation will bring challenges, such as managing increased intermittency of electricity supplied by renewables and the relative inflexibility of nuclear power plants, while also meeting increasing demand. This will require changes in how the power sector operates.

There are several reasons why some form of 'dash' for gas would be appealing for the UK. This paper analysed two aspects that appear to be driving the debate: interest in a renewed 'dash' for gas-generated power, motivated by the belief that there will be an abundant future supply of natural gas which will offer a sustainable price advantage over other forms of electricity generation; and interest in a 'dash' to exploit indigenous shale gas resources, motivated by the prospect of increased energy security and reduced exposure to international energy price volatility. The assumptions behind both are misguided.

We conclude that, while it is clear that gas will continue to be an important energy source during the transition to low-carbon electricity, it would be very risky for the UK to choose a 'dash' for gas-generated power and/or for shale gas on the assumption that European wholesale gas prices will be low in the future. If the UK is to achieve its emissions reduction target for 2050 in a least-cost way, there is only a short window for unabated gas in power generation, during which time it could usefully displace coal.

If the government were to opt for a 'dash' for gas, this should be a 'dash' for *smart* gas i.e. a scenario in which natural gas is used to the greatest value in helping to decarbonise the UK economy and is accompanied by the implementation of strong upstream (e.g. at the wellhead) and downstream (e.g. capturing and strong carbon at gas fired power stations) environmental measures to protect against fugitive emissions and other forms of pollution. This will require adequate policies to (i) maintain strict environmental, health and safety standards, including for shale gas exploration and extraction, and (ii) accelerate rapidly carbon capture and storage (CCS) technology research, development, demonstration and deployment, as well as research into the full range of options for improving the flexibility of the power sector.

A coherent energy policy is of paramount importance if the UK is to successfully channel investment into a portfolio of energy measures and technologies that will ensure a future energy system which is reliable, cost-efficient and environmentally sustainable. While the replacement of coal-fired power stations with those fuelled by natural gas would help to reduce the UK's emissions, there are dangers of locking-in high-carbon electricity generation assets. This could be perceived by the private sector as a significant policy risk and discourage investment in new low-carbon plants and infrastructure. A weakened ambition for the power sector decarbonisation would require more rapid emission reductions after the 2020s, which may prove to be costly, in order to achieve the 2050 target.

While the science and economics of climate change, and the need for decarbonisation, are increasingly clear, many of the economic, financial, environmental and technological factors that shape the energy sector remain highly uncertain. Maintaining options in the face of this great uncertainty would be very valuable for the UK's economy.

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