Gas Works?

Policy Exchange

Shale gas and its policy implications

Simon Moore
Edited by Simon Less

Gas Works?

Shale gas and its policy implications

Simon Moore
Edited by Simon Less

Policy Exchange is an independent think tank whose mission is to develop and promote new policy ideas which will foster a free society based on strong communities, personal freedom, limited government, national self-confidence and an enterprise culture. Registered charity no: 1096300.

Policy Exchange is committed to an evidence-based approach to policy development. We work in partnership with academics and other experts and commission major studies involving thorough empirical research of alternative policy outcomes. We believe that the policy experience of other countries offers important lessons for government in the UK. We also believe that government has much to learn from business and the voluntary sector.

About the Authors

Simon Moore joined Policy Exchange in August 2010 as a Research Fellow for the Environment and Energy Unit. Before joining Policy Exchange Simon worked for London-based think tank The Stockholm Network. He has a Master's degree in Public Policy from the University of Maryland and a Bachelor's degree in Politics from Lancaster University, where he was awarded the Oakeshott Prize for best overall performance in political theory and comparative politics.

Simon Less is Head of the Environment and Energy Unit, directing Policy Exchange's research on energy, environment and utilities policy and regulation. He was previously a Director at Ofwat, leading market reform in the water sector, and has held a number of Senior Civil Service positions in the Treasury, including leading on energy policy, and in the Ministry of Justice. Simon is a Senior Research Associate at the Regulatory Policy Institute in Oxford; an independent regulatory policy consultant; and a trustee of ReStore Community Projects, a London furniture reuse charity. He has a PhD from Cambridge University in chemistry, and an MBA from Imperial College Business School.

Published by
Policy Exchange, Clutha House, 10 Storey's Gate, London SW1P 3AY
www.policyexchange.org.uk

ISBN: 978-1-907689-16-1

Printed by Heron, Dawson and Sawyer
Designed by Soapbox, www.soapbox.co.uk

Contents

Policy Exchange's Environment and Energy Unit

Policy Exchange's Environment and Energy Unit conducts innovative and independent policy research into a wide range of environmental, infrastructure and regulatory challenges. Our objective is to influence policy making and to shape debate. We produce publications, organise events and use the media to promote our findings and policy proposals.

A key focus of our work is to identify ways to tackle environmental challenges effectively, while minimising adverse impact on living standards. We promote well-designed regulation to exploit the power of markets to achieve environmental outcomes innovatively and cost-effectively.

If you would like to find out more about our work, please contact:

Dr Simon Less
Head of the Environment and Energy Unit
Policy Exchange
Clutha House
10 Storey's Gate
London SW1P 3AY

Email: info@policyexchange.org.uk
Telephone: 0207 340 2650
Fax: 020 7222 5859
www.policyexchange.org.uk

Acknowledgments

The authors would like to thank all those who gave their time and expertise to inform the research, including Nic Bilham, Martin Diaper, Matt Georges, Nathan Hultman, Mark Miller, David Odling, Michael Stoppard and Juliet Sychrava.

Executive Summary

Shale gas has significant potential…

The overall potential for shale gas is still being uncovered and remains uncertain. The initial impact on North American gas markets has been profound in a very few years, where a tight market has been transformed to a gas glut. Shale gas production has expanded dramatically in the US, rising from 28 billion cubic metres (bcm) in 2006 to 140 bcm, or 23 percent of total US natural gas production, in 2010. Shale reserves now comprise about 21% of overall US natural gas proved reserves, which are now at their highest since 1971.

In the US, oil and gas prices appear to have become decoupled. Since December 2008, US gas prices dropped by 25% while oil prices, which have spent almost all that time above $75/barrel, have risen by up to 175% at their peak. However, outside the US, it is too early to know what the full consequences will be. The US has stopped drawing on international Liquefied Natural Gas supplies, and so those resources can be shipped elsewhere. There are also early signs of substantial shale gas resources around the world, including in the UK. As exploration proceeds, the scale and economics of global resources will become better understood.

In the US, projections for reserves of shale gas have a history of being surpassed. This has now begun to happen in the UK. When the Energy and Climate Change Select Committee released its report in May 2011, it referred to British Geological Society estimates that the UK has a reserve potential of up to 150 bcm, and a US Energy Information Agency estimate of 560 bcm of technically recoverable UK resources. Since then, Cuadrilla Resources, which is exploring parts of the North West of England for shale gas, estimated the gas in place in its licence area in the Bowland Basin near Blackpool at around 5,600 bcm. This is comparable in scale to the gas in place in the Barnett shale in Texas, currently the second most productive US field. While this estimate has not been independently verified, nor intended as an indication of the volumes that will ultimately prove producible, even a tenth of that amount would dramatically reshape the UK gas supply picture.

Exploration is proceeding in many other countries. Regardless of whether domestic shale production becomes significant, however, shale gas has the potential to have far-reaching implications for the UK and European energy markets.

… But there is considerable uncertainty which needs to be reflected in policy

The future for natural gas is clouded with uncertainty: about future gas production and trade levels; about future demand, particularly from Asia; about government policies towards shale gas and competing energy technologies; and, as a consequence, about future gas prices.

For example, the international Energy Agency's forecast for gas prices in 2030 with the emergence of unconventional gas is a fifth lower than in its previous, pre-shale projections. DECC's 2011 central projections project gas prices in 2030 at 11% higher than they are currently; in the 2010 projections, 2030 projections were 21% above current (i.e. 2011) prices. So in the passage of only one year, gas market developments, including shale gas, have had a marked impact on DECC's outlook for long term gas prices.

The uncertain direction of future gas prices is something that has to be reflected in government policy design. Assumptions about future gas prices have a major impact on the expected costs and benefits of government energy policy proposals. It is important therefore that close attention is paid to the net costs of proposed policies under a *range* of future gas price scenarios. Policies should be chosen, not simply on the basis that they might provide an optimal outcome should one particular central projection prove correct, but rather because they are overall least cost under a range of uncertain futures.

Analysis of the costs and benefits of various policies is completely changed by different assumptions about gas prices. For example, DECC's Impact Assessment of the Renewable Energy Strategy found that under high fossil fuel prices, the cumulative net benefit to 2030 is -£12 billion (i.e. a £12 billion net loss), under central prices it is -£56 billion, while with low fossil fuel prices the net benefit would be -£95 billion – an £83 billion difference between high and low assumptions.

Shale gas reinforces the importance of long-term, credible climate policy…

Is it possible to make use of shale gas while still pursuing a decarbonising pathway? To the extent that gas displaces coal in the global energy mix, it could constrain greenhouse gas emissions. For example, switching China's use of coal to gas would on its own reduce emissions by more than five times the UK's entire emissions. However, gas could also displace deployment of zero carbon technologies. Gas as a transition fuel is only useful if it means that the coal is never burned, rather than just burned later.

To take full advantage of the potential benefits from any low gas price future, and to ensure that the development of gas is consistent with carbon emissions reduction targets, it is even more important that long-term climate policy is enhanced.

(There are ongoing debates about the relative merits of cap-and-trade versus carbon tax mechanisms as a method of enforcing credible long-term carbon pricing. For example, Professor Dieter Helm has made arguments in favour of a carbon tax model; more recently, Professor George Yarrow set out a thought provoking case for the merits of cap-and-trade.)

In the European context, it is the EU Emissions Trading Scheme (ETS) cap-and-trade arrangement that is supposed to provide the main building block of abatement policy. (Although on top of this have been layered a large number of other policies, including technology specific scale-deployment policies, which are less cost-effective and severely limit the ETS pricing signal.) The immediate focus for the UK and other member states should be on creating a more long term, more certain carbon cap, under the Emissions Trading Scheme. Providing a credible carbon cap is in place far enough ahead, gas generation will be able to play whatever role turns out to be consistent both with its future costs and with required long-term emissions reductions. Investors would be able to take a commercial view about whether to invest in gas generation, with the prospect that the plant could in due course need to fit Carbon Capture and Storage technology, run as back-up or retire early.

The Emissions Trading Scheme already provides the legal mechanisms to enforce its carbon cap, but to date caps have been set over relatively short timescales, inconsistent with long investment horizons. The current cap runs out in 2020. There should always be complete clarity on the ETS carbon cap at least 15-years in advance to reflect investment payback periods. Given that the EU continues to back the ETS, the EU should begin work immediately on establishing the Phase IV cap, with the intent to establish a certain cap through to at least 2035, at a level in accordance with scientific understanding about required emissions reductions. (Renewable subsidies guaranteed over 20 or 25 year periods are common, so there should be little objection in principle to commitments of that length.) Committing to a longer term Emissions Trading System is a far stronger commitment to reduce emissions than simply setting a carbon target.

Recent discussions of the ETS have focussed heavily on reducing the number of permits in the near term, with the possible objective of aiming to cut emissions by 30% by 2020 compared with 1990 (rather than the 20% implied by the current trajectory). Increasing the durability of the ETS, however, is at least as important as the shorter-term cap. Establishing a longer term, more certain cap, as well as effective banking and borrowing mechanisms, should also have the effect of bringing permit prices up today – one of the objectives of those arguing for a tighter 2020 cap.

If after Phase IV negotiations it becomes clear that the political or market design challenges to the ETS have not been overcome, and if the ETS, in the wider policy context, remains inadequate to the task of providing a long-term, credible carbon pricing framework, then the arguments for shifting to a carbon tax are likely to become stronger. Either way, the key is to have a credible long term pricing framework.

... But highlights the flaws in the proposed UK Electricity Market Reform

The possibility of large shale gas resources adds weight to questions about the UK's approach to energy policy – particularly its proposed Electricity Market Reform. This is not because shale gas will certainly be a game-changer, but because it could be.

The government's proposal for Electricity Market Reform (EMR), based effectively on signing long-term fixed price contracts (Contracts for Difference) with its preferred mix of generators, is unsuited to a world of uncertainty. It is predicated on an assumption of relatively high future gas prices. It risks imposing large expense on UK energy billpayers if that assumption proves wrong.

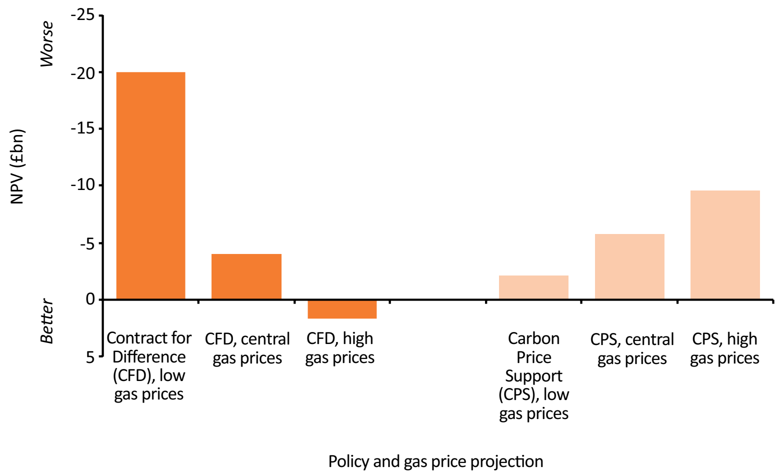
Electricity Market Reform (EMR) should be recast in a way that enables the market to deliver electricity market decarbonisation (under the EU ETS cap) in the most cost-effective ways, including through using gas as a greater or lesser transition fuel, depending on whether future gas prices follow a high path, or lower path than EMR assumes.

Energy policy needs to reflect uncertainty about the future. The long-term central planning approach of the government's proposed EMR is much less able to handle uncertainty than alternative approaches where the market makes decisions – be it a carbon cap or other carbon pricing approach.

Policy Exchange analysed the expected policy costs of the government's proposed approach to EMR under different future gas prices scenarios. These were compared with an alternative, carbon pricing-based, approach to delivering broadly similar electricity emissions reductions, using DECC's own figures.

While under a future high gas price assumption DECC's figures show its preferred approach to EMR to be around £11 billion *cheaper* than the carbon pricing alternative tested, under a scenario of low carbon prices EMR was £18 billion more *expensive* than the carbon pricing alternative (the first and fourth bars in the chart).

Figure ES1: Cost (NPV) of EMR policies under different gas price projections



If one could be confident about future high gas prices, this analysis could be one part of a case for the government's approach. (However, there are important reasons to believe that the government's central planning approach, with its weaknesses compared to a market approach in relation to information, incentives and dynamism, would not in practice deliver such savings). But given that the future is uncertain, and given the potential of shale gas, both high and low gas price scenarios are relevant. Including consideration of the range of possible futures, it looks perverse to choose a policy approach that appears to carry the greater overall risks.

Under a central gas price assumption the costs of the two policy approaches were quite similar, with DECC's figures giving its approach the edge by £1.8 billion. This difference is tiny given the potential for unintended consequences from the radical changes represented by the return to central planning under EMR, compared to the alternative more evolutionary change which would preserve the market. The difference is also insignificant compared to the £43 billion total net cost of the government's Renewable Electricity Strategy, which EMR is intended to help deliver.

The government portrays its proposed EMR approach as being a way of reducing risk, by reducing exposure to future high gas prices. But, it seems more likely that this policy is exposing energy bill-payers to greater risk. The government's EMR approach exposes bill-payers to policy costs at least £10bn higher if gas prices are low, than an alternative carbon cap or pricing policy would cost in a high gas price scenario (based on DECC's figures). On top of this, DECC's figures do not take into account the additional risk posed by eliminating the market's ability to respond effectively to new information and price signals, and instead inserting government decision making in its place.

Local environmental and health concerns can be addressed through effective regulation…

Shale gas development has proven controversial. Concerns about the impact of production on local communities and environments are central to that controversy. There are several specific complaints.

One much discussed study argued the greenhouse gas emissions from shale were much higher than other gas. However detailed examination of this and other studies suggests this is not the case. Nonetheless, industry and regulations should take steps to improve the quality of information on issues like fugitive emissions

The use of rock-fracturing drilling techniques and underground injection of chemical compounds have led to worries about contamination of water supplies in the US. Allegations of poisoning and other health impacts have drawn media coverage, as have visually compelling examples of inflammable methane in water supplies. Hydraulic fracturing has now been confirmed as the cause of a pair of small earth tremors in northwest England in the spring of 2011.

Many of the local environmental problems cited with shale gas are perhaps better understood as problems with the featherweight regulation prevalent in parts of the US. Future production in Europe (and elsewhere) will be able to learn from the US, not just about best and safest production practices, but also about appropriate regulation. Industry could also do more: perception of the shale gas industry as a bad neighbour is likely to hinder its ability to secure drilling sites, as demonstrated in October 2011 when an application by Coast Oil and Gas to carry out test drilling near Llantwit Major, Glamorgan, was denied by the local council amid fears over water pollution.

Concerns about risks from shale gas production in relation to water quality, seismic activity and water scarcity need to be taken seriously, but on the basis of current evidence, do not justify imposing a moratorium on shale gas production.

Government and the industry should focus on effective and more rigorous regulation than has been seen in parts of the US. Groundwater protections and waste treatment regulations are stronger in the UK. Likewise, requirements about chemical disclosure are much more forceful.

The costs of complying with such regulation should be a price worth paying for the industry, to protect investments in exploration and production, and something that the industry should actively seek where there are any gaps. Looking to the future, it is important that the UK maintain a strong and effective regulatory regime, which addresses any new issues that arise, and enables a safe shale production sector to develop. In particular, future exploration and drilling should feature the strict real-time monitoring and seismicity-conscious operating procedures suggested by the inquiry into the 2011 tremors.

The reassurance that effective regulation provides the public – and the avoidance of confidence-destroying incidents – is critical for the development of the shale gas industry and for securing the benefits it offers.

Shale gas can be part of more globally relevant UK climate policies…

The direct impact that UK domestic decarbonisation can have on the global climate is limited. The value of actions taken in the UK must primarily be measured against other criteria – whether we are successfully developing and reducing the cost of low carbon technologies of global scalability, and whether we are setting an example in low carbon policy design and implementation compelling enough that other governments will want to follow.

It may not be intuitive how utilising more gas generation in the UK would be compatible with these objectives of leadership and innovation. And indeed, if the only change were to build more gas generation, an opportunity would be lost. But gas generation is currently much cheaper than most mass-deployed renewable generation (most relevantly, hugely expensive offshore wind). Shale gas developments may lead to this situation continuing into the longer-term. The relative savings in energy costs from utilising gas generation – consistent with meeting a long-term EU carbon cap – could effectively provide a large pot of resources which society could then choose how to deploy. It could be invested in effective low carbon innovation support – research, development and demonstration, and early stage deployment of a range of low carbon technologies with global potential. The global climate impact of such an approach could be far greater than focusing our resources disproportionately on domestically deploying expensive offshore wind (which is just one technology which might, but probably will not, become a major global contributor to carbon reduction). Carbon emissions from electricity, under the EU ETS cap, would be the same under either approach.

Worldwide growth in coal and gas generation makes research of carbon capture and storage (CCS) technologies ever more important. It is clearly a difficult technology to master, though the potential payoff is substantial. The IEA estimates that without CCS, the costs of reducing emissions to 2005 levels by 2050 increase by 70%. Policy Exchange has previously argued that the UK and other EU governments should devote greater resources and political will to CCS research. The size of that commitment should reflect the current shortfall in research development and demonstration (RD&D) investment, which the IEA estimates at between $8 billion and $17 billion per year globally. The UK government's continued commitment to a future prize fund for CCS demonstration is a welcome start, and opening it to coal and gas entrants reflects the shifting global generation mix. However, with such a large potential contribution to worldwide decarbonisation, CCS RD&D is still under-resourced.

1
Introduction

In the past decade, a shale gas revolution has upended the US gas market. Import terminals built to receive shiploads of gas from the Middle East and Africa now sit idle, made redundant by developments in America's shale basins. Instead, America is in the midst of a domestic gas glut, driven in large part by the improvement of two engineering techniques – hydraulic fracturing ('fracking') and horizontal drilling – which have made vast swathes of gas trapped in shale rocks across the continent accessible and affordable. Today, the prospect of large shale gas resources looms over the UK's energy policy. The possibility of domestic production is one part of this – early stage exploration has yielded positive resource projections in the North West of England, near to Blackpool. The evolution of liquid international markets for gas, topped up by shale gas developments across the world, is the other. The implications of these changes on UK energy policy are both highly uncertain and potentially transformative.

They come at a time when the UK government is attempting to drive dramatic changes of its own design through Britain's energy markets. Most notable of these are the proposals for Electricity Market Reform, based on Whitehall officials mapping out their desired electricity generation contributions from nuclear, renewable and fossil fuel technologies and backing their choices with long-term guaranteed prices for generators. A key argument put forward for these proposals is that they will protect customers from future high gas prices.

Developments and uncertainty in the gas sector call this approach into question. This is not because shale gas in the UK, nor globally, will definitely be a game changer. It is because it could be. The future direction of gas prices is very unclear, with different global trends pulling in opposite directions. The technological developments that have enabled shale gas production should increase supply, pushing prices down. Competition for liquefied natural gas (LNG) cargoes from the Far East increases demand, pulling them up. Which trend will dominate is unknowable. But UK policy is gambling with high stakes on one future scenario.

This paper looks at the interactions between policy and future gas scenarios. It focuses particularly on the consequences of developments in shale gas for UK and EU electricity policy. It also examines the environmental controversies surrounding shale gas production, from both global greenhouse gas and local environmental and health perspectives. It builds on landmark work that has preceded it, most notably the comprehensive report conducted by the parliamentary Energy and Climate Change Select Committee. It introduces new analysis on the risks of government policy.

This report concludes by identifying a policy approach that aims to maximise benefits from future shale gas developments, both economic and environmental. It recognises and incorporates uncertainty, not just about gas prices but also other aspects of energy policy. It counsels against policy predicated on long-term central plans whose ability to respond to constant new information and rapid change – such as has been seen with shale gas production in the US – is severely limited.

2

The Emergence of Unconventional Gas

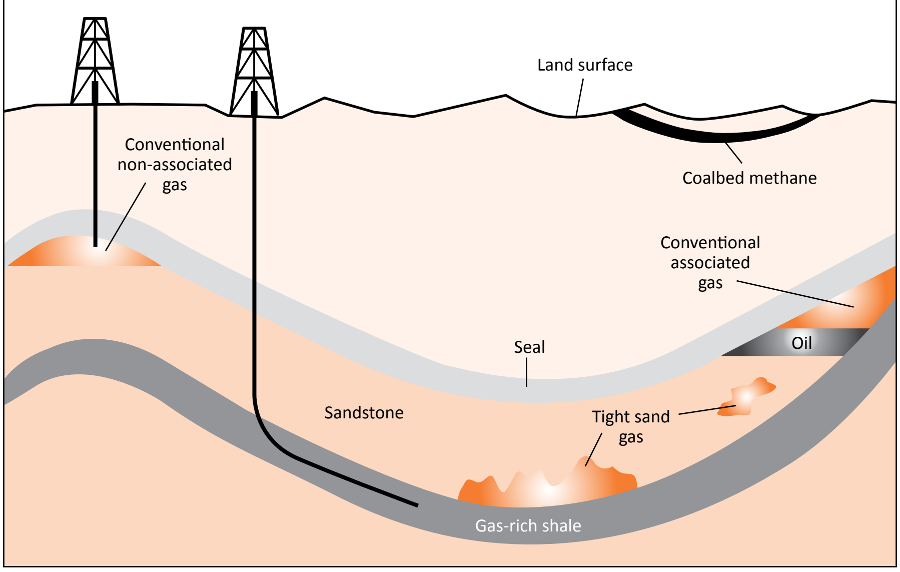
One of the most significant developments in the entire energy sector over the past few decades has been the massive increase in production of unconventional gas, especially shale gas. From 2006 to 2010, shale gas production in the USA almost quintupled (from 28 billion cubic metres (bcm) in 2006 to 140 bcm in 2010), now making up almost a quarter of all gas production.

These resources have been known about for decades, as have some of the production techniques used to extract them, but it has only been in the past few years that technology has advanced sufficiently to make widespread production economical.

Recovery of unconventional gas

Several types of gas resources are collectively referred to as unconventional gas resources (Figure 2.1). One common feature is that, unlike conventional fields, gas in unconventional fields (or 'plays' in the industry terminology) does not flow through the well under natural pressure, but requires regular 'working' to free it from the surrounding rock or clay.

Figure 2.1: Geology of natural gas resources[1]



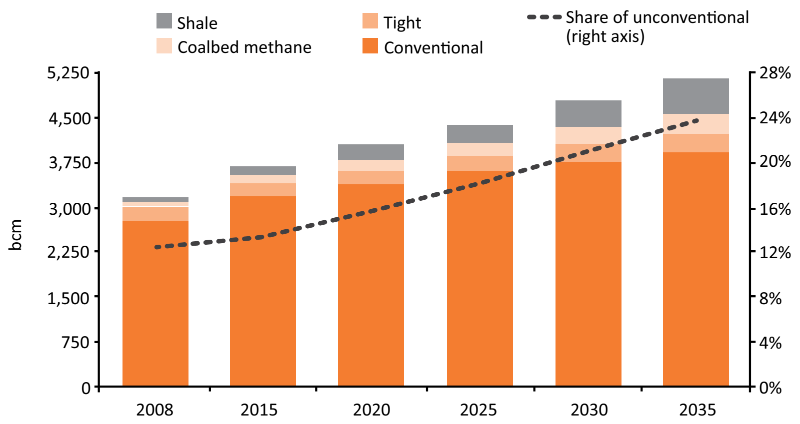
1 Energy Information Administration and US Geological Survey; http://www.eia.gov/todayinenergy/detail.cfm?id=110

For centuries one of the many dangers of coal mining was the risk posed by methane trapped in coal seams. "Coal bed methane" (CBM) production extracts that methane, separating it from the coal into which it is adsorbed. Pumping pressurised water into the coal seam creates fissures in the coal along which gas can travel, emerging at the surface along with the used water. Coal beds are typically found at far shallower depths than shale or tight gas reservoirs. China, Indonesia and Australia all have large CBM deposits.

"Tight gas" is sometimes considered distinct from, and other times to include, "shale gas". Definitions vary from country to country as to what constitutes tight gas. However, the International Energy Agency offers a "working definition" of "a natural gas reservoir that cannot be developed profitably with conventional vertical wells, due to low flow rates."[2]

"Shale gas" is the most well known of the unconventional gas types, being the type with the greatest current production, and, according to the IEA, with the greatest future potential (see Figure 2.2). Natural gas molecules can be found trapped in dense, low-permeability shale clays. Gas bearing shale formations are typically found 1–4 km below the Earth's surface, although some shallower shales have been tapped.

Figure 2.2: Global natural gas production by type in the International Energy Agency's GAS scenario[3]



Horizontal drilling techniques (as in Figure 2.1) allow individual well sites to access broader expanses of gas-bearing shales underground. By combining multiple wells on one site, a two-hectare drilling pad is able to tap a gas field of around 400 hectares. Hydraulic fracturing techniques separate the gas from shale clays by injecting a pressurized mix of water, sand, and sometimes other chemicals (see Chapter 7 for more detail), into the shale, freeing gas molecules to flow to the surface. Both techniques have lengthy histories – hydraulic fracturing has been carried out since 1903, and commercially since the 1940s, while horizontal drilling has been practiced in the oil industry since the 1930s, but have only recently become widespread.

With refinements in these techniques in recent years, shale gas production has expanded dramatically in the US, rising from 28 billion cubic metres (bcm) in 2006 to 140 bcm, or 23 percent of total US natural gas production, in 2010.[4]

2 International Energy Agency; *World Energy Outlook 2009*; Paris; 2009; p. 398

3 International Energy Agency; *Are We Entering A Golden Age of Gas?*; Paris; 2011; p. 30

4 1000 cubic feet (ft^3) of natural gas = 28.32 cubic metres (m^3) = 1.034 MMBtu (million British thermal units)

Proved shale gas reserves increased from 660 bcm in 2007 to about 1720 bcm by the end of 2009.[5] Shale reserves now comprise about 21 percent of overall US natural gas proved reserves, which are now at their highest since 1971.[6] The expansion of shale production in the US has reshaped the gas market there. Liquefied Natural Gas (LNG) terminals, built on the expectation of needing to import increasing quantities of gas from overseas, now sit idle, with some operators talking about the possibility of converting them to use for exporting now-abundant gas supplies. US LNG imports have dropped from a high in 2007 of 60 million cubic metres per day to 20 million m^3 per day in autumn 2011.

With the rapid expansion of shale production being such a recent phenomenon, it is unsurprising that knowledge is constantly evolving. In the early stages of the industry, for example, some analysts expressed concern that shale wells were being depleted much more rapidly than had been expected, imperilling the financial calculations of the industry. However, with the benefit of experience, those high decline rates once thought to spell trouble for the industry are now incorporated into the business model (see Box 2.1). Chemical compounds that form the 'fracking fluid' injected into the shale to create the fractures through which gas can flow are being adapted in response to results from the field and public concern about some of their contents. The engineering of wells is changing to enable a wider area to be tapped from one wellpad, reducing the visual impact of drilling operations. Further improvements seem inevitable as the unconventional gas industry expands its reach to new continents and new industrial and policy cultures. Rapid change has been a key characteristic of the shale business, challenging regulators and policymakers to keep up.

Box 2.1: Decline rates

A controversy surrounding the rate at which production from shale wells declines has been reported extensively. In the summer of 2011 it formed the basis of a series of *New York Times* articles expressing scepticism about the soundness of the shale gas business model. The reporter, Ian Urbina, had gathered emails from industry sources and US regulators.[7]

In the early days of shale production it was discovered that initially high production volumes from shale wells tailed off rapidly – much more so than was the case with conventional wells. The discovery of these different characteristics was to some extent unexpected. Emails from 2008 and 2009, which Urbina cites in his article, reflect that surprise. However, as industry experience has accumulated, concerns about decline rates have alleviated.

Production from horizontal shale wells does indeed decline more rapidly than from conventional wells. This is only problematic, though, if investors had been expecting to see conventional well-like production characteristics. If anticipated and accounted for in the business case for each well, there is nothing about rapid decline rates *per se* that makes the sector economically unsustainable. (UK shale gas firm Cuadrilla Resources told the Energy and Climate Change Select Committee that a typical shale gas well "will witness steep early production decline rates," but they evidently do not see this as a fatal to their business plan.)[8] The continued flurry of investment in the sector in the years since decline rates became better understood is a strong indication that companies with money at stake do not perceive decline rate patterns to be an obstacle to profitable shale gas production.

5 Energy Information Administration; *Shale Gas, Proved Reserves;* Washington DC; 2010; http://www.eia.gov/dnav/ng/ng_enr_shalegas_a_EPG0_R5301_Bcf_a.htm

6 I.e. discovered fields with a greater than 90% chance of being produced under current political economic and technological conditions. This represents only a small fraction of known or expected gas in place resources. Energy Information Administration*; Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays*; July 8, 2011; Washington DC; http://www.eia.gov/analysis/studies/usshalegas/

7 Urbina, Ian; "Insiders Sound an Alarm Amid a Natural Gas Rush" in the *New York Times*; 25 June 2011; New York

8 Energy and Climate Change Committee; *Fifth Report – Shale Gas*; London; 2011; http://www.publications.parliament.uk/pa/cm201012/cmselect/cmenergy/795/79502.htm; Paragraph 39. See also Levi, Michael; "Is Shale Gas a Ponzi Scheme"; Council on Foreign Relations; New York; 2011 http://blogs.cfr.org/levi/2011/06/27/is-shale-gas-a-ponzi-scheme/

While shale production in the US has gone through rapid expansion in a very small number of years, elsewhere it remains in the early stages of development. Shale extraction projects are being considered in many diverse locations, including China, South Africa, and Poland. The UK has seen some exploratory drilling in the Fylde basin near Blackpool, Lancashire, with substantial gas in place (industry terminology for the total volume of gas originally in the reservoir) announced in late 2011. A further discovery at Ince, near Ellesmere Port, Cheshire was announced in January 2012.[9]

However, the rise in prominence of the shale gas industry means public concern about shale gas has also heightened, with controversies emerging around the environmental consequences of hydraulic fracturing, and of unconventional gas production. Chapters 6 and 7 will address those issues in detail. A consequence of increased public and political awareness, and of pressure from environmental groups, is that the unknown severity of future regulation adds uncertainty to the future of the shale gas sector.

Economics of unconventional gas

Almost every major petrochemicals and mining company has now invested in shale gas production, either by developing their own projects, or by acquiring firms with existing shale gas expertise. Clearly the industry has confidence in the future profitability of shale gas production in the US. But the price at which profitable extraction of major shale gas reserves is reached (if reached at all) has implications for the future wholesale price of gas. When the Energy and Climate Change Select Committee conducted hearings into shale gas, they heard a range of gas prices from organisations attempting to estimate the point at which shale production would break even (Table 2.1).

Table 2.1: Estimates of gas price at which shale production becomes economical[10]

Organisation	Price (US$)	Price (GB£ Conversion)[11]	Notes
International Energy Agency	\$0.11–0.32/m³	£0.07–0.20/m³	
Oxford Institute for Energy Studies	\$0.29–0.43/ m³	£0.19–0.27/ m³	
Wood McKenzie	\$0.18/ m³	£0.11/ m³	Estimate for production in the US – costs will be higher in Europe
Devon Energy	\$0.13/ m³	£0.08/ m³	

For most of 2011, prices in the US have been hovering around the \$0.14 (£0.09)/m³ mark, whilst in the UK prices have fluctuated between £0.14–0.27/m³ (so \$0.22–\$0.42) on the wholesale market over the past two years.

As we have seen, large quantities of shale gas are being produced in the US. If, as some of the organisations who gave evidence to the Select Committee claim, production is not economical at that price, why would it be happening?

9 Rigzone; 'IGas Makes Shale Find at Ince Marshes'; 26 January 2012; http://www.rigzone.com/news/article.asp?a_id=114616

10 Energy and Climate Change Committee; *Fifth Report – Shale Gas*; London; 2011; http://www.publications.parliament.uk/pa/cm201012/cmselect/cmenergy/795/79502.htm; Paragraphs 59–63

11 1 GB£ = 1.56621 US$

There are rational explanations for production happening in the US at a loss. First, the leasing terms for many American fields require drilling, and the firms who are operating them may prefer to produce at a loss now, rather than relinquish the territory and the ability to produce there in the future when prices may have risen.[12] Second, the shale business is characterised by many small, independent producers. Many of those have taken on large amounts of debt to finance acquisition of land leases. To service those debts, the companies need a revenue stream. They have to produce, even if it is not economical at current prices (which also creates a feedback loop of oversupply that keeps prices suppressed). Third, operators who sold their production on forward contracts at a time when prices were higher are able to keep producing, because they are not exposed to the spot price, even as their production serves to keep spot prices down.[13] Fourth, in some instances production of oil and 'natural gas liquids' from shales can be so profitable that associated gas can be sold at rock-bottom prices.

Production costs in the US are also not necessarily indicative of the likely costs in other parts of the world. The scale of reserves in the most productive American basins is unrivalled by anything being operated elsewhere, although early reports from other territories, including the UK, suggest the US may not hold the monopoly on prolific fields for long. Europe's higher population density in many parts means that land is more costly than in the US. State ownership of mineral rights in Europe reduces motivations to sell licences quickly. The oilfield service industry is less well developed outside of the US, meaning access to necessary expertise and equipment is in shorter supply. For example there are a little over 100 drilling rigs in Europe compared with almost 2000 in the USA (and a further 700 in Canada), as of the start of 2012. Access to gas pipelines may also be a constraint in less well-connected parts of Europe. Finally, the regulatory regime in Europe is more rigorous than in most states in the US, implying higher compliance costs.

At the same time, large-scale shale gas production is a relatively new phenomenon. We would expect to see continued innovation in techniques and the potential for continued falls in the costs of shale gas extraction.

There is considerable uncertainty about the future economic scale of any shale gas 'boom', particularly in Europe, and thus the influence unconventional gas will have on the wider gas sector. Policy-making must take into account that future gas price trajectories are not clear.

Effects of shale gas production on gas prices so far

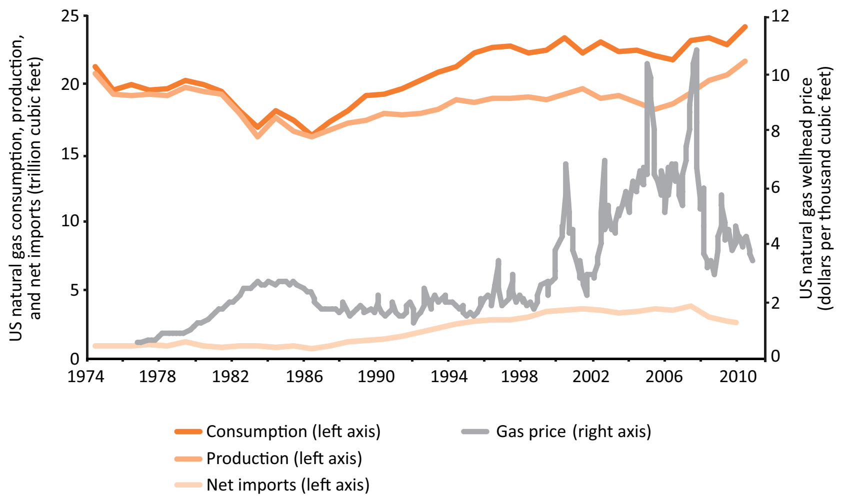
What impact has shale gas had on wholesale gas prices? So far evidence is limited, with only the results of one case study to consider, and without knowing the counterfactual of where they would have been had the shale boom not happened. Nevertheless, the trends are striking (Figure. 2.3).

Production of gas in the US has risen steadily since 2005, and reached a 36-year high in 2010. Wellhead prices have followed a more volatile pattern, with peaks in the winter of 2005 and the summer of 2008. Since January 2009, though, only one month has seen the wellhead price above \$0.18/m^3 (£0.11/m^3). The trends are not over a sustained period of time, but the shale boom is a very recent phenomenon. The US trend of prices stabilising and imports declining while consumption continues to climb (see Figure 2.3) is what has roused such excitement about the potential for unconventional gas to deliver similar outcomes in other parts of the world.

12 Levine, Steve; "Gas Is Great, But Can it Make Money"; *Foreign Policy*; 2011 http://oilandglory.foreignpolicy.com/posts/2011/06/01/gas_is_great_but_can_it_make_money

13 Levi, Michael; "Is Shale Gas a Ponzi Scheme"; Council on Foreign Relations; New York; 2011 http://blogs.cfr.org/levi/2011/06/27/is-shale-gas-a-ponzi-scheme/

Figure 2.3: US gas production and net imports 1974–2010

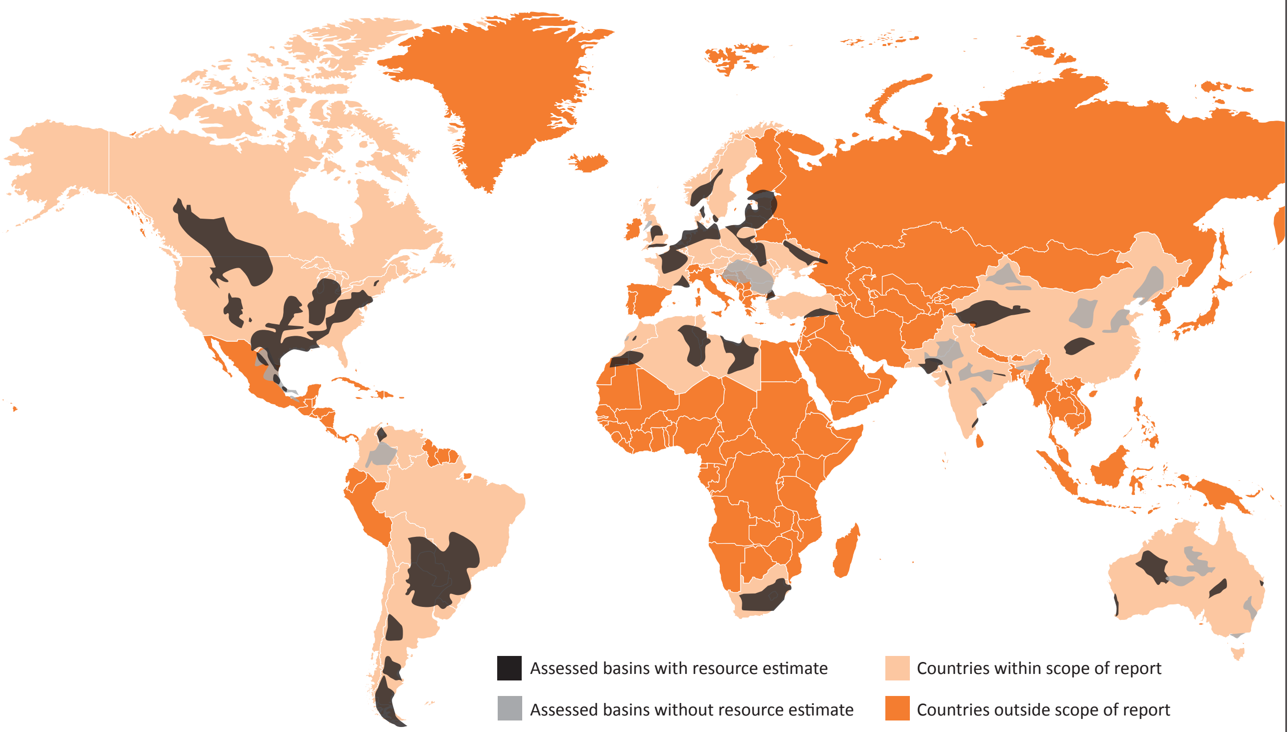


Global shale gas resources

The scale of unconventional gas resource worldwide is poorly understood. With the exception of the continental USA, few areas have been extensively surveyed. In spring 2011, the US Energy Information Administration released a superficial initial assessment of 32 countries outside the United States (Figure 2.4).[14]

14 Energy Information Administration; *World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States*; Washington DC; 201 1; p. 3

Figure 2.4: Map of 48 major shale basins in 32 countries



As a first cut, this is useful in identifying areas that may be of exploration interest. But only commercially-driven exploration will provide the information needed to understand what is economically recoverable. That work will be conducted over the coming years, as energy firms seek new opportunities to bolster their reserves. It could be a decade or more before the world has a good idea about the overall scale of shale gas resources.

UK shale gas resources

In the US, projections for volumes of shale gas resources have a history of being surpassed. This has now begun to happen in the UK. When the Select Committee released its report in May 2011, it referred to British Geological Society estimates that the UK has a reserve potential of up to 150 billion cubic metres (bcm), and a US Energy Information Agency estimate of 560 bcm of technically recoverable resources.[15] Since then, Cuadrilla Resources, which is exploring parts of the North West of England for shale gas, estimated the gas in place in its licence area in the Bowland Basin near Blackpool, Lancashire at around 5600 bcm.[16] This is comparable in scale to the gas in place in the Barnett shale in Texas, currently the second most productive US field.[17] While the Cuadrilla estimate has not been independently verified, nor intended as an indication of the volumes that will ultimately prove producible, even a tenth of that amount would dramatically reshape the UK gas supply picture (see also Chapter 8). And that does not account for any other productive UK shale basins which may be discovered.

The next stage in Cuadrilla's exploration process is to determine what the producible volumes are likely to be. More drilling and further analysis will be needed before any decisions about commercial operation can be made. That decision will not come until the middle of 2012. Other firms, meanwhile, are looking to acquire exploration permits in other parts of the country, including parts of Wales, Somerset and south east England. If recent history is any guide, the estimates for Britain's shale potential may continue to exceed forecasts.

Local access and acceptance

A key difference in local acceptance of shale production in the UK (and Europe) in comparison to the US is the allocation of property rights. In the US, landowners own the oil and gas under their land. In addition to private landowners, entities such as school boards and local county authorities can benefit from leasing or selling their land to developers. In the UK, however, the subsurface hydrocarbons are owned by the Crown, with DECC granting licences for exploration and extraction.[18] A prospective driller also needs to come to agreement with the landowner for access on the surface.

In Europe, the state (rather than the landowner) is the licensor of mineral resources, and consequently stands to gain a greater share of the proceeds of any drilling. While this might in theory incentivise the government to facilitate production, it diminishes the rationale for local communities to welcome extraction. In the UK landowners and local residents have, through the planning and access-granting processes, ample means to block or slow shale gas development, but potentially less ability to benefit from it, with the government extracting its take through the licensing process. In most parts of the US there are two parties to the acquisition of property for drilling – the gas firm and the

15 Energy and Climate Change Committee; *Fifth Report – Shale Gas;* London; 2011; http://www.publications.parliament.uk/pa/cm201012/cmselect/cmenergy/795/79502.htm; p. 11

16 This is comparable in scale to the gas in place figures for the Barnett shale in Texas. Robertson, Helen; 'Cuadrilla unveils huge new UK gas resources' at *Petroleum Economist*; Blackpool; 21 September 2011; http://www.petroleum-economist.com/Article/2904268/Cuadrilla-unveils-huge-new-UK-gas-resources.html

17 150 bcm ≈ 5.2 trillion cubic feet (tcf). 560 bcm ≈ 20 tcf. 5600 bcm ≈ 200 tcf. Note that each of these values – for reserves, technically recoverable resources, and for gas in place – estimates something different. See Society of Petroleum Engineers; *Petroleum Reserves Definitions*; 1997; http://www.spe.org/spe-site/spe/spe/industry/reserves/Petroleum_Reserves_Definitions_1997.pdf for more information on different definitions

18 Petroleum Act 1998; http://www.legislation.gov.uk/ukpga/1998/17/contents

landowner, with (usually state) government acting as a regulator. In the UK there are three parties; the gas firm, the landowner (having the property rights on the surface where drilling equipment would be located) and the government (having the property rights to the mineral resources underground).[19]

So far, there seem to be enough landowners willing to deal with extractors that this does not pose a major constraint on development, though the industry in the UK is obviously at a very early stage and the extent of that constraint may only become apparent with significant expansion of shale drilling. The more widespread, and visibly safe the industry becomes, the better its chances of securing land access. Conversely, perception of the shale gas industry as a bad neighbour is likely to hinder its ability to secure drilling sites, as demonstrated in October 2011 when an application by Coast Oil and Gas to carry out test drilling near Llantwit Major, Glamorgan, was denied by the local council amid fears over water pollution. Fracking has proven more controversial in the parts of the US less accustomed to oil and gas production – it has been in New York and Pennsylvania, rather than Texas and Oklahoma, where the controversy has been at its fiercest. With the UK and large parts of continental Europe similarly unused to onshore oil and gas production, prospective drillers may find public opinion challenging to win over.

“The scale of the boom in shale gas is still being uncovered. The initial impact on North American gas markets has been profound in a short number of years. Supply tensions have been alleviated, as a tight market has been transformed into a gas glut”

Conclusions

The scale of the boom in shale gas is still being uncovered. The initial impact on North American gas markets has been profound in a short number of years. Supply tensions have been alleviated, as a tight market has been transformed into a gas glut. Outside the US, it is too early to know what the consequences will be. There are early signs of substantial shale gas resources around the world, including in the UK. There may be additional costs of shale gas operations in Europe compared to the US, but not necessarily prohibitively so.

As exploration proceeds, the scale of global resources will become better understood. As the track record of operations lengthens, costs will be better understood, and probably decline. The British government is reviewing its appraisals of the scale of resource, in light of the astonishing find claimed in Lancashire. Other countries are conducting their own reviews, while exploration companies investigate how much of the resource it will be economical to extract.

Shale gas may have far-reaching implications for the UK and Europe, regardless of whether domestic shale production becomes significant. The next chapter places shale gas developments within a wider context of gas market developments in the US, UK and Europe.

19 House of Commons Energy and Climate Change Committee; *Shale Gas: Fifth Report of Session 2010–12*; p. 48

3
Uncertain Economics of Gas

Since the discovery of gas under the North Sea, gas has come to occupy an increasingly pivotal part of the UK energy mix, from household heating and cooking to industrial applications, to now supplying almost half the UK's electricity. Worldwide, utilisation of gas has also expanded, taking it from being an undesirable and valueless by-product of oil production, commonly burned off ('flared') or vented into the atmosphere, to becoming a high-tech global industry, which is reshaping energy economics and geopolitics.

This chapter will look at economic change in the gas sector. It will highlight the main areas of uncertainty around future projections for gas prices. It will look at the prospects for the gas market to move away from oil-linked pricing, which remains dominant in continental Europe and the Middle East, and towards a more prominent spot-pricing structure. It will also look at the role of Liquefied Natural Gas shipping in linking the historically discrete continental gas markets. It finds that, in a period of such flux, betting policy on one trajectory is unwise, and that a flexible policy environment is preferable to accommodate these changes.

Uncertainty

As with many areas of energy, there are many uncertainties about the future for natural gas. Decision-makers in both the industry and policy worlds have to attempt to manage that uncertainty while delivering the objectives which shareholders or the public desire. Uncertainty derives from several sources:

Supply uncertainty: What levels of future production can be achieved? How will markets develop to connect producers and customers in geographically distant places? Will new technologies emerge that can reshape the gas business in future decades, in the way both liquefied natural gas (LNG) transport and shale gas production have in the last decade?

Demand uncertainty: What will future demand be, given expectations about economic growth in Asia and the developing world? How will greenhouse gas reduction efforts affect gas demand? What will happen in relation to competing types of electricity generation, including coal, nuclear and renewables?

Price uncertainty: The interaction of the variables of supply and demand will affect prices, but in what direction will they head? Can new technologies and new supplies constrain rises, or even bring prices down? Or will ever-rising demand keep prices on an upward trajectory? Will a world market and a global price emerge, as with oil pricing, or will the world remain divided into regional or national markets with sometimes wide disparities in price?

Policy uncertainty: How will governments around the world respond to the uncertainty inherent in the gas sector? Will they try to avoid it by reducing the role of gas as far as possible? Will they embrace gas as a lower-carbon alternative to coal, or reject it as being still too polluting an energy source? What tools do governments have to address these uncertainties and what is the likelihood of their use?

These uncertainties are intertwined – changes to one of them affect the others. Changes to the supply or demand position, either globally or within the regional markets, which are even now only partially interlinked, change prices in those markets. Those changes can also affect policy, which may be trying to achieve one or several objectives. In the UK, for instance, policy relevant to the gas sector may relate to decarbonisation, energy affordability and security of supply. Additionally, gas market developments and policy have significant implications for the electricity sector.

Managing this tangled web of interconnections and consequences would be challenging enough if future trends were predictable. But there are high degrees of uncertainty. Five years is a long time in energy markets. Five years ago few predicted the current scale of shale gas. Five years after the Sizewell B planning enquiry, where the prospects of gas generation did not feature, gas turbines were virtually the only generation being built. In the course of five years in the early 2000s, government went from considering new nuclear generation to be useful, to unnecessary, to essential.

Policy based on the government predicting the future and attempting to manipulate outcomes amid the complex interconnections is liable to lead to unforeseen and costly outcomes. History is littered with instances of governments attempting to bet energy policy on the latest trend, only to have to reverse when those trends proved temporary, from the rosy predictions of the cost of nuclear power in the 1950s and 60s to the fears of permanently high oil prices following the embargoes of the 1970s.

One of the key areas of uncertainty, and attempted prediction, is future prices.

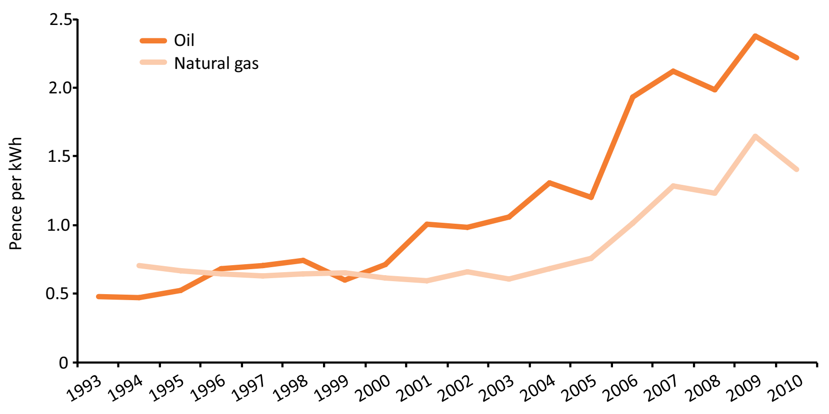
The relationship between gas and oil prices

Historically, long-term gas contract prices have been indexed to spot oil prices, both in Europe and North America. This pattern reflected a number of characteristics of the gas business – markets were illiberal and frequently monopolised, transport connections were (and still mostly are) fixed long-distance pipelines, and sources of supply could not be easily switched. Overlapping uses meant that oil and gas were often substitutes. However, developments in more recent years have loosened the oil and gas price link, particularly in the US. Evidence suggests that a similar shift may be starting to take hold in Europe, widening the price gap between oil and gas in the pricing basis for oil-linked gas contracts.

A number of factors have contributed to the growing divergence between oil and gas prices in the US. Large quantities of unconventional gas reaching the American market have eased supply concerns. Weak economic growth, and high gas storage kept prices down. The North American gas market is also more insulated from global trends than the oil market – higher (LNG) gas transport costs relative to oil shipping have prevented surging East Asian demand from pulling gas prices up in the way that has occurred with oil prices. Since December 2008, US gas prices dropped by 25% while oil prices, which have spent almost all that time above $75/barrel, have risen by up to 175% at their peak. The uses for oil and gas have also shifted, with oil seldom used for power generation, and of decreasing appeal in industrial applications due to its cost, and becoming predominantly a transport fuel, while gas increasingly occupies electricity generation role, alongside heating and industrial applications.

Europe differs from the US in important ways. It is not self-sufficient in gas in the way the US is, and so the high costs of LNG transport remain a factor. However, access to LNG is reducing market power, in particular that of Russia's Gazprom, meaning that competitive pressure exists on the supply side.[20] Long-term contracts with pipeline and LNG suppliers are still predominantly oil linked. Spot pricing of gas in European countries remains a small part of the total market – in 2008 10% of OECD Europe's gas was spot traded – but is steadily increasing, with the UK's spot market being Europe's largest and most liquid.[21] A recent IMF Working Paper hypothesised that "the decoupling of gas prices from oil prices witnessed in the US could take place in Europe as a changing buyer base puts pressure on suppliers to sell at prices reflecting total gas supply, new gas deregulation laws, environmental concerns, and cost of other energy sources rather than the evolution of spot oil."[22] But major gas producers are not willing to see this happen without a fight. Addressing the Gas Exporting Countries Forum (the fledgling attempt to create a 'gas OPEC' led by Russia, Qatar and Iran), the Qatari Emir Sheikh Hamad Bin Khalifa al-Thani told the audience, "gas exporters should not give up their demand for a fair price of gas that is equivalent to oil and to use all available means to achieve this end."[23] Whether this can be accomplished at a time of increasing scale and number of LNG suppliers is far from clear.

Figure 3.1: Chart of average prices of fuels purchased by major UK power producers[24]



20 De Bock, Reinout and Gijón, José; *Will Natural Gas Prices Decouple from Oil Prices across the Pond?* IMF Working Paper; International Monetary Fund; Washington DC; 201

21 International Energy Agency; *Natural Gas Market Review* 2009; Paris; 2009; http://www.iea.org/textbase/nppdf/free/2009/gasmarket2009.pdf p.28

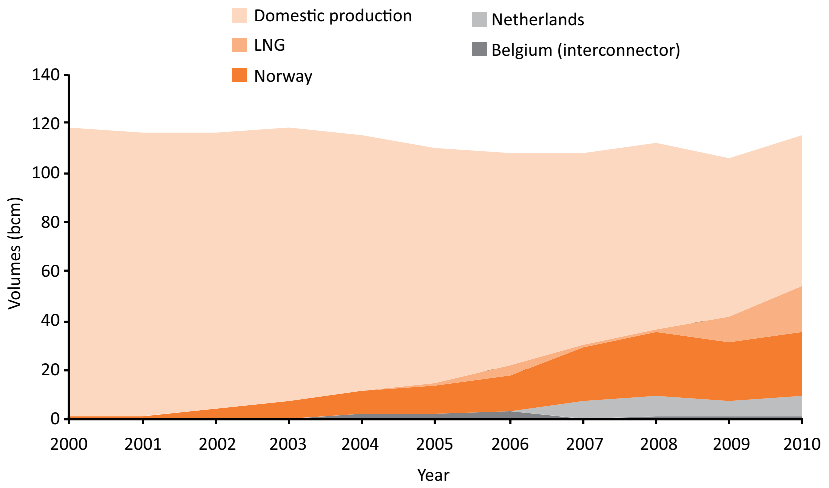
22 De Bock, Reinout and Gijón, José; *Will Natural Gas Prices Decouple from Oil Prices across the Pond?* IMF Working Paper; International Monetary Fund; Washington DC; 2011

23 Platts; 'Qatari emir urges gas exporters to strive toward oil price parity' at Platts.com; 15 November 2011; Doha; 2011; http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/8582739

24 Department for Energy and Climate Change; *Average prices of fuels purchased by the major UK power producers and of gas at UK delivery points*; London; 2011; http://www.decc.gov.uk/media/viewfile.ashx?filepath=statistics/source/prices/qep321.xls&filetype=4&minwidth=true

In the UK, as Figure 3.1 illustrates, the gap between oil and gas prices is widening, though prices still move in approximate synchronisation. The rate of any continued move away from oil-linked pricing of gas is a key source of uncertainty about the future gas market. Changing patterns of import dependency are relevant to this, as production from old fields declines and ends, while new sources become available elsewhere. For the UK, this has involved reduced reliance on North Sea production, and an increasing proportion of gas being imported, with new pipelines from Norway and the Netherlands and, increasingly, LNG terminals making up the difference (see Figure 3.2).[25] What proportion of those future import prices will be subject to oil-linked pricing and what proportion will be more market-driven is impossible to predict.

Figure 3.2: Changing sources of UK gas supply over the past decade



It would be going too far to state with certainty that the trends outlined in this section will inevitably lead to lower gas prices, or even that divergent oil and gas prices will become the norm. But it can no longer be taken for granted that gas and oil prices will remain entwined.

LNG

Although shale gas has been the main driver of recent gas price trends in the US, elsewhere liquefied natural gas (LNG) has been the technological change making the biggest difference to global gas markets. The process involves chilling natural gas to -162°C, condensing it into a liquid form which can be transported in ships. LNG has enabled international trade between producers and consumers not connected by pipelines, and created the opportunity for previously segmented regional markets (Asia, Europe, North America) to become connected.[26] Though LNG is a more expensive means of transporting gas than pipelines, in places where pipeline connections to producing countries are impractical (for example, customer islands like Japan and Taiwan, or producer islands such as Trinidad and Tobago) or where pipeline-delivered volumes are insufficient to meet demand, LNG is a competitive resource. Thirty-one percent of internationally traded gas is now shipped as LNG.[27]

25 Department for Energy and Climate Change; *Natural Gas Production and Supply and Natural Gas Imports and Exports;* London; 2011; http://www.decc.gov.uk/en/content/cms/statistics/energy_stats/source/gas/gas.aspx

26 Yergin, Daniel; *The Quest*; Allen Lane; 2011; p. 313

27 BP; *Statistical Review of World Energy*; London; 2011; p. 28

The cost of moving gas in LNG ships is approximately equivalent to the cost of moving it 3000 to 5000 km by pipeline.[28] In theory, with sufficient LNG capacity, the gas market could become much more analogous to the oil market, with cargoes being able to be redirected to respond to price fluctuations creating a true spot market. With the costs of shipping still comparatively high, though, the stability and reassurance provided by long-term contracting remains valuable.

> "The gas sector is in a period of change… The move in the US from import-dependence and reliance on global trading markets to self-sufficiency occurred with such speed that many are still trying to adjust to the consequences"

There is the prospect of the US even becoming a gas exporter to Europe as a result of its unconventional gas boom, but a diversity of opinion on how likely this is. Some view it as inevitable if price differentials make it economical, but others cite the lack of export-oriented US infrastructure and a perceived political preference for retaining self-sufficiency rather than becoming a major exporter. This tension is characterised in one company's comments about a new LNG export project. Discussing the proposed Sabine Pass, Louisiana liquefaction facility, outspoken Chesapeake Energy chairman Aubrey McClendon told reporters, "I want the right to export natural gas, but I am really hopeful that we never do… If for some reason [the US] refuses to use this wonderful fuel… I have to put my gas up for sale to somebody."[29] If this were to occur, even if Europe took steps to curtail domestic production, European generators could still find themselves burning shale gas, only it will have travelled much further to get to them.

Conclusion

The gas sector is in a period of change. The extent of that change is, at this point, difficult to predict. Some effects may prove short-lived; others lead to a permanent reshaping of the industry. The early indications from the US at least show unconventional gas leading to a lasting reshaping of the market there, as many of the biggest energy companies acquire independent unconventional gas producers and place their gas operations at the forefront of their business model. The move in the US from import-dependence and reliance on global trading markets to self-sufficiency occurred with such speed that many are still trying to adjust to the consequences.

This chapter has outlined some of the many sources of uncertainty in relation to the future of the gas market and gas prices.

UK North Sea production continues to decline; from supplying virtually all UK demand a decade ago it covers barely half today. The UK faces the prospect of importing a majority of its gas for the first time in decades. All other things being equal, concern about price rises would be legitimate in a world of increasing gas demand. But the emergence of shale gas, both globally and domestically, as well as the evolution of LNG trading, decoupling oil and gas prices, mean other things are not equal. Price rises, if they occur in the future, may be constrained by newly accessible supplies. The trajectory of future prices is not certainly upward; it is not certainly downward either.

The uncertain direction of future gas prices is something that has to be reflected in government policy design. The next chapter looks at the International Energy Agency's assessment of possible energy futures.

28 International Energy Agency; *World Energy Outlook 2009*; Paris; 2009; p. 416; http://www.iea.org/textbase/nppdf/free/2009/weo2009.pdf.

29 McAlister, Edward; 'Chesapeake chief opposes exporting US natural gas' at Reuters.com; 16 November 2011; New York; 2011; http://uk.reuters.com/article/2011/11/16/natgas-export-chesapeake-idUKN1E7AF1L720111116

4

International Energy Agency Projections of Global Gas Trends

The International Energy Agency (IEA) was established by the Organisation for Economic Cooperation and Development in response to the oil crisis of 1973. It continues to be the forum through which OECD member states collaborate and coordinate on energy policy issues, including energy security, economic and environmental issues. In its flagship annual *World Energy Outlook* publication, it assembles historical statistics and future projection scenarios about global energy usage.

The IEA has published two recent global energy scenarios. The first is the 'New Policies Scenario' (NPS) which includes countries' existing government policies and all declared future policies and targets for reducing greenhouse gas emissions and policies to phase out fossil fuel subsidies that had been announced by the summer of 2010.[30] The second ('GAS') was released in 2011, in a special report, *Are We Entering a Golden Age of Gas?* It "describes a future in which natural gas plays a more prominent role in meeting the world's energy needs to 2035".[31] In it, the IEA attempts to quantify some of the trends described in the previous chapter. The same caution that should be applied to interpretation of any model applies equally to the following discussion of these models.

The GAS scenario changes three policy assumptions compared to the previous NPS. The first reflects China's ambition to increase the use of gas to meet its rising future energy demand (to achieve 8.3% of its overall primary energy from gas by 2015 compared to 2.8% in 2008, and 5.3% in the NPS). The second assumes lower nuclear power generation than the NPS, as some governments back away from nuclear expansion plans, and in some cases close plants earlier, in response to the Fukushima disaster of March 2011. The third change alters the number of natural gas vehicles in the model, from 30 million to 70 million in 2035, as the IEA perceives "significant scope for faster penetration [of gas-fuelled vehicles globally] if there is both a favourable price differential between natural gas and oil… and direct government support."[32]

However, accompanying these increases in demand, supply also rises in the GAS scenario compared with the NPS, with additional investment in conventional and unconventional production.[33] Unconventional gas becomes increasingly important in the GAS Scenario, "accounting for 25% of global supply in 2035 [from 12% in 2008] and meeting more than 40% of the increase in demand" (1.2 trillion cubic metres (tcm) in 2035).[34]

The key way in which the GAS projections differ from those under the NPS is that gas is projected to make up 25% of the world's fuel mix in 2035, compared

30 International Energy Agency; *World Energy Outlook 2010*; Paris; 2010

31 International Energy Agency; *Are We Entering A Golden Age of Gas?*; Paris; 2011

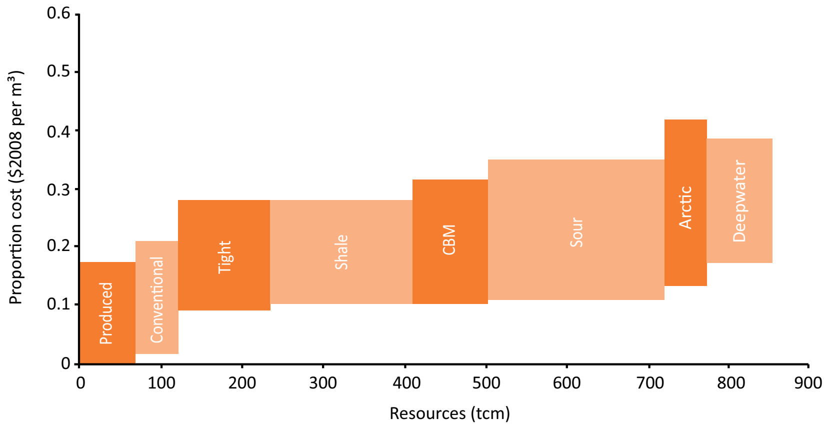
32 Ibid p. 16

33 Ibid pp. 26–29

34 International Energy Agency; Are We Entering A Golden Age of Gas?; Paris; 2011; pp. 29, 42

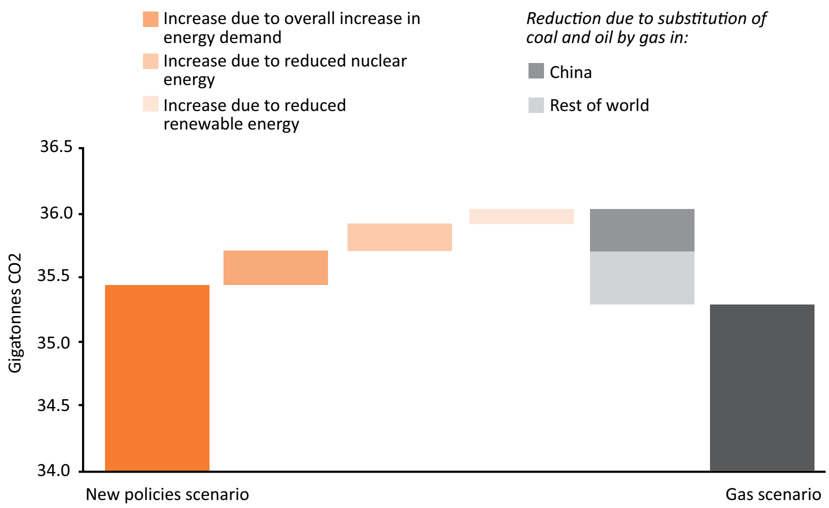
to 22% in the NPS (it is at 21% today). The role played by unconventional gas grows significantly through the period covered by the IEA study, beginning in North America and later spreading elsewhere. Initially, the effect of this is to keep the USA and Canada to a minor role in LNG trade, leaving LNG cargoes to serve Europe, the Middle East, and increasingly, China and East Asia.

Figure 4.1: Long term gas supply cost curve – production cost[35]



The projections derived from both scenarios are heavily dependent on a wide range of other assumptions about a number of uncertain factors, including economic growth rates, technological improvements and costs, fossil fuel prices and so on. The costs and availability of gas resources are another key consideration. The IEA's assumptions about these are shown in Figure 4.1.

Figure 4.2: CO_2 emissions in the GAS Scenario relative to the New Policies Scenario, 2035[36]



35 International Energy Agency; *World Energy Outlook 2009*; Paris; 2009; p. 416; http://www.iea.org/textbase/nppdf/free/2009/weo2009.pdf

36 International Energy Agency; *Are We Entering A Golden Age of Gas?*; Paris; 2011; p. 38

Alongside its projection of an increased role for gas globally, the GAS scenario also makes projections about global GHG emissions. The IEA finds a small decrease in global carbon emissions under both its scenarios. A projected 35.3 gigatonnes (Gt) of CO_2 is emitted in the GAS scenario compared with an almost identical 35.4 Gt in the NPS in 2035. Overall, increased energy demand and reductions in expected nuclear and renewable energy are offset by gas substituting for coal (largely in China) in the IEA analysis (Figure 4.2).[37]

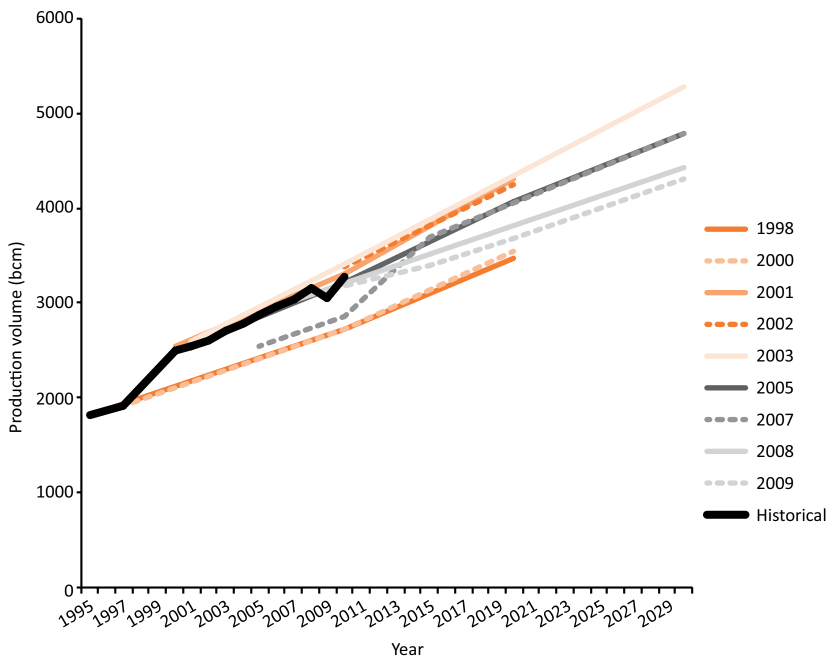
It should be recognised that neither IEA scenario, despite assuming that all the pledges on GHG reduction made by countries around the world are met, keeps probable global average temperature rises below 3.5°C, let alone the 2°C target.

Box 4.1: Optimism bias? The IEA's track record of estimating gas production

Being wrong is inevitable for organisations in the energy modelling business. However, when the errors fall into a pattern of consistent over- or underestimation, rather than, as should be expected, being sometimes high and sometimes low, it may be a sign of problems in the organisation's methodology or editorial processes. The IEA's reputation, in some quarters, is for erring on the side of optimism – high production volumes and low prices – in its fossil fuel forecasts.[38] Is this justified? Looking at the record of forecasts in the *World Energy Outlook* series provides a few clues, but little in the way of definitive proof.

The *World Energy Outlook* series is relatively recent, meaning that few projections have had the chance to be tested. The earliest publications in the series gave 2010 as the first year estimated, which is the only data point we can compare with the eventual outturn.

Figure 4.1.1: IEA Projections of gas production volume in World Energy Outlook series compared with historical outturn



37 Ibid pp. 16–38

38 For example, Strahan, David; *The Last Oil Shock;* John Murray, 2007

For gas, predictions about 2010 production were underestimated in reports issued from 1998–2000, overestimated from 2001–2004, and underestimated again in 2007. Accuracy ranged from being within 1% of the final outturn (2001) to being out by nearly 17% (1998, 2000). The closest they got to the final outturn in 2010 was in the 2001 WEO. Obviously several factors changed in the intervening years between many of the projections being made and the year being projected for – the September 11th attacks, wars, multiple recessions – all of which had major impacts on world energy patterns. Does the failure of the IEA to predict September 11th or the current economic crises reflect a flaw in its methodology or a flaw in the projections concept? It seems harsh to discredit the organisation on the basis of the inability to foresee such events. On this evidence, slight as it is, the accusation of consistent over-optimism appears unproven. For gas at least, as should be the case, sometimes the IEA's projections are on the high side and sometimes on the low.

As with most modeling work, the most interesting results are not the point outcomes (which are of very limited reliability), but rather the contrast between different runs of the same model made using different assumptions.

The IEA analysis suggests that increasing use of natural gas (including shale gas) may be compatible with reducing greenhouse gas emissions. It also implies that it would cost less to reduce emissions – after all, if shale proves to be more expensive than other energy sources it will not be produced – meaning that the money saved could be used, either to pursue further emissions reductions or other policy objectives. This does not by itself constitute a solution to the world's energy challenges, but it does suggest shale has a role to play in reaching a low-carbon energy system, under some sets of assumptions. In Chapter 5 we will look at some of the other things that will need to be done to ensure the role played by shale gas is a positive one for the climate.

We will return to official projections in Chapter 9, when we look at the picture of the UK provided by its government's analysis.

5 Making Shale Gas Work for the World

Economic benefits from a future of more abundant gas

Access to affordable energy remains a significant constraint to economic development and human wellbeing in large parts of the world. Any technology that increases the world's energy supply has some value in those terms alone. If shale gas proves less affordable than other energy sources it will not end up being produced – shale gas generally receives no subsidy, and lives and dies on its own economic case. Therefore, if substantial quantities of shale gas are produced in the future, it means that it is contributing to lower world energy costs than would otherwise have been the case.

Cheaper energy costs leave households with more disposable income to spend. Businesses are left with more money to invest in other productive ways, including potentially new employees. Cheaper energy encourages economic growth and boosts living standards. Access to reliable and affordable energy is a key development indicator. In many parts of the world it is key to keeping populations happy (as shown in 2012 with riots in Nigeria as subsidies for oil were taken away). As disposable income and public expectations rise, providing energy at low costs is a primary public policy objective of many governments.

New resources can also alleviate security of supply worries (see also Chapter 8). In countries where dependency on imports is high, and supply sources not diversified, the emergence of new producers, and potentially an expansion of cross-border trading, will be welcome. Increased flexibility and availability of energy sources also makes responding to crises easier. These could be supply disruptions caused by war or weather, or demand disruptions (either from weather again, or something more dramatic like the Fukushima disaster and subsequent nuclear shutdown in Japan, which led to a substantial increase in demand for LNG to replace lost nuclear capacity).

Switching from coal to gas generation could help address the air quality problems that have plagued rapidly developing countries, most prominently China. The suffocating smog that envelops cities where rapid, coal-driven industrialisation has taken place is a serious public health issue.[39]

For all these reasons, if shale gas can be affordably and safely produced at large scale, then there are compelling economic and social welfare reasons for doing so.

The next section looks at the compatibility of wider use of natural gas with measures to decarbonise the economy, at the European and global scales.

39 This has echoes of UK history, when the Great Smog in London in 1952 led to a move away from coal use in homes and industry and increasing utilisation of electricity and gas.

Climate change implications of using more gas

Discussion of the costs of energy choices should take place in the context of the climate change implications of energy choices. Is it possible to make use of shale gas (or more gas in general) while still pursuing a decarbonising pathway?

In considering the climate implications of a potential high gas future, driven by shale gas, there are a number of factors to take into account:

- Which other energy technologies is gas most likely to displace?
- How are the economic benefits from a high gas future to be deployed?

The answer to these questions is dependent on the policy settings.

Gas substituting for coal in electricity generation reduces GHG emissions (for a sense of how much, energy consultancy CERA has calculated that converting all coal and oil power generation in Europe to CCGTs would produce a 58% cut in emissions from power generation relative to 1990); gas substituting for nuclear or renewable generation results in increased emissions.[40] Under the IEA's assumptions (see Chapter 4) these trends are projected to cancel each other out – the result of its scenario with widespread expansion of gas use would be a tiny reduction in emissions. The IEA's projections assume current global policy settings and proposals. There is obviously much uncertainty around such projections.

What is implicit in the IEA's calculations is that any switch to a more gas-oriented energy system would result in cash savings. There will only be a more gas-oriented future if gas is cheaper than other energy choices. How these savings – effectively the economic benefits from cheap gas – are used is a key component of assessing the climate change impact of using more gas.

Lower energy costs (than would otherwise have been the case) free up resources that could (and should, at least in part) be used to support low carbon innovation. For example, additional resources could be devoted to supporting research, development and demonstration, and promising early stage technology deployment.

So one appropriate policy setting, under a scenario of global gas expansion, is high policy support for low carbon innovation. In other words, we use the period of lower-than-expected energy costs to fund the low carbon innovation we will need to meet 2050 decarbonisation targets. Zero carbon technologies will need to become more cost-competitive, in order to be able to replace gas on a global scale, and this will require further innovation.

The Tyndall Centre has already pointed to a second appropriate policy setting for a high gas future. It has said that, "providing that any carbon caps are strictly adhered to then shale gas would make no difference [to overall emissions levels] as the source of emissions would be inconsequential."[41] In other words, as long we have broad and long-term carbon caps – or adequate other approach to carbon pricing – then (a) gas will be brought forward only to the extent consistent with the carbon cap, and (b) reduction of the carbon cap or target over time will ensure that unabated gas is a transition fuel: that it either needs to retrofit Carbon Capture and Storage, be used at times of peak demand or to back up renewables on still days, or be retired.

The additional global warming potential from newly accessible shale reserves, and the prospect for consequential lower than expected energy costs:

40 IHS CERA; *Sound Energy Policy for Europe;* Cambridge, MA; 2011

41 Wood, Ruth et al; *Shale gas: a provisional assessment of climate change and environmental impacts;* The Tyndall Centre for Climate Change Research, University of Manchester; 2011; http://www.tyndall.ac.uk/sites/default/files/coop_shale_gas_report_final_200111.pdf; p. 74

- make it both even more important and acceptable to have in place appropriately tough and long-term carbon capping/pricing frameworks;
- make it less appropriate for policy to be dominated instead by technology-specific deployment subsidies for renewable, or even zero-carbon technologies. Such subsidies fail to enable the potential for cheap gas to be revealed and to play its role in delivering a cost-effective decarbonisation pathway to 2050.

EU emissions trading system: the current state of play

There are ongoing debates about the relative merits of cap-and-trade versus carbon tax mechanisms as a method of enforcing credible long-term carbon pricing. (For example, Professor Dieter Helm has made arguments in favour of a carbon tax model; more recently, Professor George Yarrow set out a thought provoking case for the merits of cap-and-trade.)[42] It is beyond the scope of this paper to go into that debate in detail, but both sides of that debate should agree that, in order for shale gas to be developed without compromising climate change policy objectives, a form of credible long-term carbon pricing framework is necessary.

In the European context, it is the EU Emissions Trading Scheme (ETS) cap-and-trade arrangement that is supposed to provide the main building block of abatement policy. However, a principal shortcoming associated with it is lack of investor confidence in the long-term signals it gives. This problem is a result of a number of factors, including the undermining of the current and future permit price by a gamut of additional current and expected future policy interventions, in relation to renewable subsidies, national carbon price floors, directives on energy efficiency, and numerous others. There have been other problems associated with the design of the ETS, such as the volume of freely allocated permits and the verification of 'Clean Development Mechanism' projects amongst others, which are beyond the scope of this report, but which do not appear unsolvable. But the most significant problem is a lack of certainty in relation to the long-term existence and level of the EU ETS carbon cap. A longer-term cap ensures carbon levels (with or without gas playing a major role in the energy mix) will decline, consistent with the limits set by the cap.

The prospect, driven in part by shale gas, of plentiful future gas makes establishing a more certain carbon cap much further into the future an even higher priority.

To date the ETS schedule has produced firm caps over a shorter timescale than is desirable. The first two Phases ran from 2005–2007 and 2008–2012. Phase III is planned to run from 2013–2020. Over the rest of the period, the cap will decrease each year by 1.74% of the average annual total quantity of allowances issued by EU Member States in 2008–2012. This annual reduction is supposed to continue beyond 2020. However, it is scheduled to be reviewed in 2025 at the latest and the requirement for this review builds in uncertainty about the rate of reduction of the cap and even the existence of the ETS in the longer term. Furthermore, there is discussion about earlier revisions to the carbon cap before 2020 which would have implications for the longer term trajectory. The long term shape of the ETS remains insufficiently certain. Recent discussions of the ETS have focussed heavily on reducing the number of permits in the near term, with the possible objective of aiming to cut emissions by 30%

42 Yarrow, George; The UK's carbon price floor policy; Regulatory Policy Institute Letters and Notes on Regulation; January 2012; http://www.rpieurope.org/Publications/Letters_and_Notes/Yarrow_UK_carbon_price_floor_policy_Jan_2012.pdf

by 2020 compared with 1990 levels (rather than the 20% implied by the current trajectory). Increasing the durability of the ETS, however, is at least as important as the shorter-term cap level.

Given that the EU intends to continue with the ETS as the principle carbon pricing framework, the immediate focus of the UK and other member states should be on creating a longer term, more certain carbon cap. Ensuring effective banking and borrowing mechanisms should also have the effect of bringing permit prices up today – one of the objectives of those arguing for a tighter 2020 cap. Furthermore, as Yarrow argues, the ability of market participants to bank permits bought today "can be expected to provide incentives to seek out more cost-efficient abatement paths. If abatement costs are expected to increase in the future, this will tend to drive up carbon prices today, and hence stimulate more abatement activity today. If a cost-reducing technological advance occurs, carbon prices today will tend to fall even though the innovation may take a number of years to accomplish, associated with some deferral of abatement activity to periods when it can be done at lower cost."[43]

(The Energy and Climate Change Select Committee made similar arguments about strengthening the ETS in its report on the Emissions Trading System, published early in 2012.)[44]

New generating plant has an investment payback period of around 15 years (some technologies, most notably nuclear, longer). Logically the ETS carbon cap should be set far enough out always to cover that investment payback period: there should always be clarity about the cap level at least 15 years in advance.

Phase III of the ETS has set the cap and covered industrial sectors and countries through to 2020.

As the ETS is set to continue, work should begin immediately on establishing the Phase IV cap, with the intent to establish a cap through to at least 2035, at a level in accordance with scientific understanding about required emissions reductions. By so doing, investors in major generating plant, including gas generation that has been a focus for this paper, can do so in full knowledge of the carbon constraints they will face over the lifetime of their plant. Governments around Europe have shown themselves to be willing to make energy policy commitments over that length of time in other areas. Renewable subsidies (such as the UK's feed-in tariffs for small-scale generation) guaranteed over 20 or 25-year periods are common, so politicians clearly have no objection in principle to commitments of that length. The flagship decarbonisation policy for the EU should be subject to a similar strength of commitment.

If after Phase IV negotiations, it becomes clear that the political or market design challenges to the ETS have not been overcome, and the ETS, in the wider policy context, remains inadequate to the task of providing a long-term, credible carbon pricing framework, then the arguments for shifting to a carbon tax are likely to become stronger. Either way, the key is to have a credible long term pricing framework.

Establishing a credible carbon cap over a longer time, with banking and borrowing provisions in place, is a useful method of dealing with one of the other main criticisms levelled at policy that accepts an expanded role for gas generation over the coming couple of decades – that of 'lock-in'. 'Lock-in' describes the idea that, once plant of a certain type (in this case gas generation) is built, we will be stuck with their emissions far into the future, when they are 'unaffordable' in

43 Ibid

44 House of Commons Energy and Climate Change Committee; *The EU Emissions Trading System: Tenth Report of Session 2010–12*

relation to projected carbon constraints.[45] A credible long-term carbon cap goes a long way to addressing that risk, by giving investors clarity about the level of emissions that will be tolerated in future years.

For an investor today, that might mean weighing up whether:

- a new gas plant can continue to operate beyond, say, 15 years from now, because it will still be economical to operate while paying the permit price;
- a new gas plant can operate for a period before having to reduce its usage profile (ie can operate as baseload but need to move to being backup as carbon permit costs increase);
- a new gas plant has to be shut early ('stranded') because the carbon costs will be unaffordable;
- a new gas plant will have to be retrofitted in the future with Carbon Capture and Storage (CCS) Technology if it is to remain operable.

There is no good reason for government to prevent investors from investing because of any of these expectations. With a clear cap in place, and with suitable banking and borrowing mechanisms, the government has certainty about the important thing – emissions of greenhouse gases. How investors opt to allocate their money in the market, knowing the constraints they will face in the future, is not the government's problem. It is not at all clear why government policy should be to protect these investors from the consequences of their own decisions – risk sometimes nets reward; at other times, it nets failure. With the payback period on a gas plant usually around 10–15 years, the threat of stranding assets beyond that time should not deter investment in capacity now.

> "With a clear cap in place, and with suitable banking and borrowing mechanisms, the government has certainty about the important thing – emissions of greenhouse gases. How investors opt to allocate their money in the market, knowing the constraints they will face in the future, is not the government's problem"

Another argument to do with lock-in is to do with political economy. By retaining a significant place for gas generation in the market, it could be argued that the lobbying capacity of gas generators will be retained or increased. However, the alternative seemingly preferred by European governments of allocating subsidy support to chosen low-carbon generators is also awash with lobbying activity and 'rent seeking'. While the worry about excess influence for gas generators may be genuine, it does not seem qualitatively different from the excess influence granted to the array of technology-specific lobbyists under any system requiring widespread government intervention and decision making. An ETS-based decarbonisation strategy that preserves the functions of the electricity market is less susceptible to lobbying than one where a central agency takes far more of the key investment decisions, as is the case under the UK government's Electricity Market Reform plans.

Committing to a longer ETS period is a far stronger commitment to reduce emissions than the simple setting of a carbon target. By reinforcing the policy mechanism, and through the creation of allowances, the legal level of carbon in the market, European governments can send the strongest signal yet to investors about the viability of their projects in the context of the ETS.

45 See for example Cary, Rachel and Benton, Dustin; *Avoiding Gas Lock-In – Why a Second Dash for Gas Is not in the UK's Interest*; Green Alliance; 2011; http://www.green-alliance.org.uk/grea_p.aspx?id=5857

A backup plan?

Given that carbon pricing has proven imperfect so far, is there a case for targeting shale for special restrictions if credible long term carbon pricing/capping cannot be delivered?

In the absence of a more meaningful carbon cap, constraining shale production could have a limited impact, holding back a small volume of potential emissions. Furthermore, targeting shale production might be politically expedient, in that as a new industry to the UK the constituency to defend it is less strong than in other, established industries. But from a climate perspective there is little logic behind banning shale production but not, for example, coal mining, or extraction of any other GHG producing fuel sources. Only overall emissions matter – the specific fuel source or the country of origin is irrelevant. Preventing shale gas exploitation in one small jurisdiction does nothing to substantially change overall emissions. Whatever other arguments are advanced for curtailing shale production (we will look at the rest in Chapter 8), claiming it is justified on climate grounds is highly spurious.

Regulation to reduce greenhouse gas emissions should be aimed directly at the problem. Trying to restrain GHGs by regulating industry-by-industry is inefficient. Given the existence of the European cap from the Emissions Trading Scheme, it is also ineffective, as emissions saved in an industry already covered by the cap will be compensated for elsewhere. Dealing with the GHG problem at the highest possible level allows the market to locate the cheapest emissions savings regardless of geography or industry type. If tightening carbon caps make shale gas uneconomical, that is a consequence of the market working – if government regulation suppresses shale production, we will never have known whether it could in fact have helped decarbonise more affordably.

Ultimately, it cannot be escaped that extra produced hydrocarbon resources merely amount to more carbon that can go into the atmosphere. If we burn all of our hydrocarbon reserves (without using CCS technologies) it seems that severe climate change would be unavoidable. But that would be true with or without unconventional gas. What it may do is to buy time for those zero-carbon technologies to further improve output and reduce in cost.

The emissions reductions that can be achieved globally with coal to gas switching are vast – indeed, it was going through that process in the 1990s that put the UK on track to comfortably meet its Kyoto commitments. The emissions reduction from either China or the US swapping their coal consumption to gas would be greater than from the UK achieving 100% decarbonisation (see Figure 5.1).[46] Switching China's coal to gas alone would reduce emissions by more than five times the UK's entire emissions. These data are based on 2010 consumption, and so do not reflect anticipated growth in coal consumption in the future.

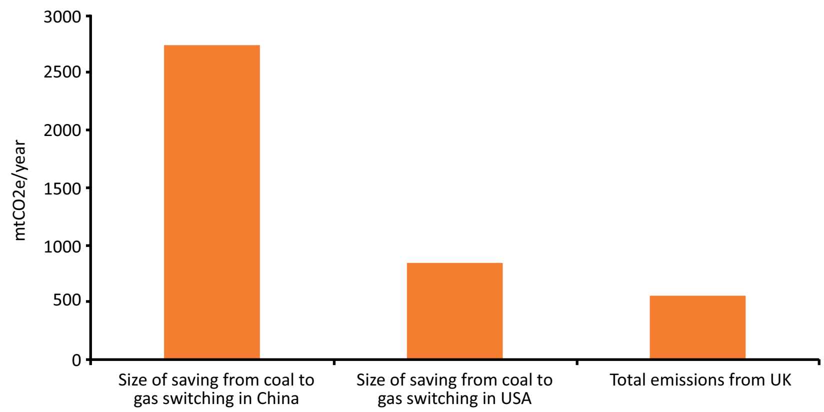
Worldwide growth in coal and gas generation makes research of carbon capture and storage (CCS) technologies ever more important. It is clearly a difficult technology to master, though the potential payoff is substantial. The IEA estimates that without CCS, the costs of reducing emissions to 2005 levels by 2050 increase by 70%.[47] Policy Exchange has previously argued that the UK and other EU governments should devote greater resources and political will to CCS research. The size of that commitment should reflect the current shortfall in research

46 Using gross calorific value basis for coal and gas, rather than the carbon content of coal and gas-generated electricity. Because gas generation has a higher thermal efficiency than gas generation, using the electricity comparison would show an even more marked saving from coal to gas switching. BP; *Statistical Review of World Energy 2011*; London; 2011

47 International Energy Agency; *Technology Roadmap: Carbon Capture and Storage*; Paris; 2009; p. 4

development and demonstration (RD&D) investment, which the IEA estimates at between $8 billion and $17 billion per year globally.[48] The UK government's continued commitment to a future prize fund for CCS demonstration is a welcome start, and opening it to coal and gas entrants reflects the shifting global generation mix. However, with such a large potential contribution to *worldwide* decarbonisation, CCS RD&D is still under-resourced.

Figure 5.1: Comparison of potential for greenhouse gas emissions savings



Again, this is only useful if it means that the coal is never burned, rather than just burned later. Using gas as a transition fuel can buy extra time to develop low carbon technologies by reducing emissions in the near future, while cheapening gas leaves more resources available to fund development of those low carbon technologies.

What the emergence of unconventional gas, and the possibility of cheaper than anticipated gas prices in the future emphasises is the value of effective, long-term carbon pricing. With clarity about the emissions cap or price, not just this decade, but decades from now, actors in the market can decide whether or not investment in gas or any other generation is sensible, without detailed decisions needing to be directed by the government.

We will turn next to key concerns in relation to current development of unconventional gas: the local environmental health impacts of extraction; its carbon emissions; and the consequences for security of energy supply.

Recommendations

1. The emergence of shale gas challenges presumptions that have been made about the future role of gas in the global and domestic energy mix. While much uncertainty remains, predictions of rising prices cannot be taken as inevitable. A future scenario of relatively plentiful gas would have economic benefits in terms of more affordable energy. To the extent that gas would displace coal in the global energy mix, it could have substantial benefits in constraining green house gas emissions.

48 See Moselle, Boaz; *Climate Change Policy – Time for Plan B*; Policy Exchange; London; 2011

To reinforce and take full advantage of its potential benefits, and to ensure that the development of gas is consistent with carbon emissions reduction targets, it is even more important that climate policy is enhanced in two key ways:

a) There needs to be an increasing focus on credible, consistent and long-term carbon pricing frameworks, which enable gas to play a positive role as a lower carbon transition fuel, but ensure that investors have clear signals about the long-term carbon reductions needed. Given that the UK and other member states are going to continue with the ETS, their focus should be on creating a longer term, more certain carbon cap. Creating effective banking and borrowing mechanisms should also have the effect of bringing permit prices up today – one of the objectives of those arguing for a tighter 2020 cap. There should at all times be clarity about the cap or price at least 15 years in advance. Work should begin immediately on establishing the Phase IV cap, with the intent to establish that cap through to at least 2035 at a level in accordance with scientific understanding about required emissions reductions. If after Phase IV negotiations, it becomes clear that the political or market design challenges to the ETS have not been overcome, and the ETS, in the wider policy context, remains inadequate to the task of providing a long-term, credible carbon pricing framework, then the arguments for shifting to an EU-wide carbon tax are likely to become stronger. Either way, the key is to have a credible long term pricing framework.
b) The economic benefits from any substantial expansion of gas's role in the energy mix ought to help fund boost investment in researching, developing, demonstrating and early deployment of promising new low carbon technologies, with potential to be cost-competitive and have global impact.

2. In the context of a potentially increasing gas penetration, it makes sense to prioritise support for research, development and demonstration into gas carbon capture and storage technologies, so that it might be possible for gas to play a role as a long-term low carbon fuel. The UK and other EU governments should devote greater resources and political will to CCS research. The size of that commitment should reflect the current shortfall in research development and demonstration (RD&D) investment, which the IEA estimates at between \$8 billion and \$17 billion per year globally. The UK government's continued commitment to a future prize fund for CCS demonstration is a welcome start, and opening it to coal and gas entrants reflects the shifting global generation mix. However, with such a large potential contribution to worldwide decarbonisation, CCS RD&D is still under-resourced.

6
Unconventional Gas 'Fugitive' Emissions

The most vociferous opposition to exploiting shale gas reserves has come from the environmental movement. Despite many of the merits highlighted in the previous chapters, concern about environmental impacts – at a global level, on climate, and at a local level, on ecosystems and water resources – have led many environmental NGOs to oppose shale gas development.

There has been debate in the scientific community about the climate change impact that harnessing unconventional gas resources will have. There are two parts to this debate. The first is whether the process of extraction of unconventional gas results in more greenhouse gases (GHGs) being emitted in comparison to conventional gas, with leakage of methane (i.e. 'fugitive emissions') being a prominent concern. The second is the impact a move to a more gas-centred energy system, enabled by a boom in shale gas production, would have on carbon emissions as the gas is consumed. The latter concern was discussed in the previous chapter with reference to the need for a robust, long-term carbon pricing framework to ensure shale gas can play a constructive role in the transition to a low carbon economy.

At the combustion stage, there is no difference between the greenhouse gas emissions of conventional and unconventional gas. However, recent prominent research has claimed that the way unconventional gas is extracted means it has a higher climate change impact than conventional gas extraction, though that claim has been disputed.

Studies on unconventional gas emissions

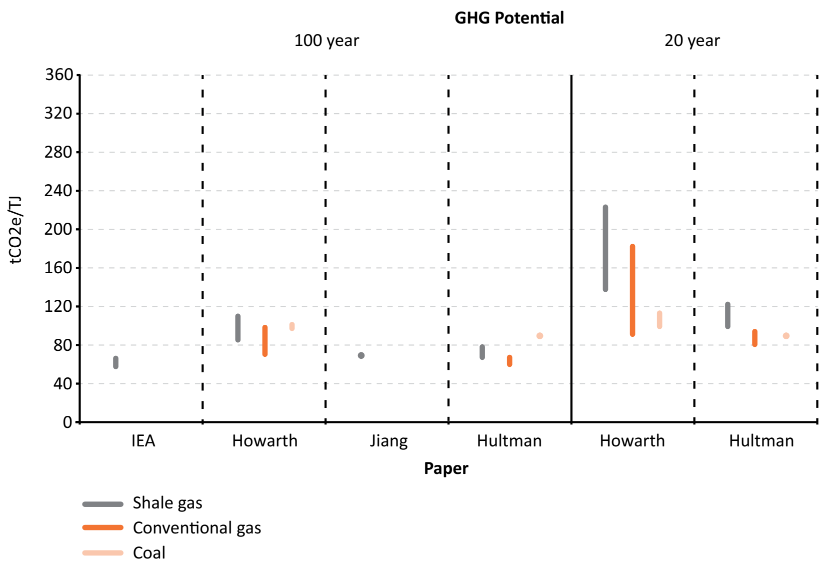
A number of studies have attempted to assess the contribution of shale gas to climate change, including work conducted by the International Energy Agency, the US Department of Energy's National Energy Technology Laboratory, the Tyndall Centre for Climate Change at the University of Manchester, and groups at several American universities.

While there have been a range of estimates of the extra climate impact of shale gas compared with conventional natural gas (see Figure 6.1), most studies have concluded that the additional climate impact is modest – higher, but "unlikely to be markedly so" in the words of one recent report.[49] If that picture is accurate, substituting shale gas generation for coal would be beneficial for the climate, but would have a small extra climate impact compared to other sources of gas.

49 Wood, Ruth et al; *Shale gas: a provisional assessment of climate change and environmental impacts*; The Tyndall Centre for Climate Change Research, University of Manchester; 2011; http://www.tyndall.ac.uk/sites/default/files/coop_shale_gas_report_final_200111.pdf; p. 38

The most prominent dissent is a much-cited paper by Howarth et al of Cornell University, which argues that "[c]ompared to coal, the [greenhouse gas] footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years".[50] The authors attribute this greater carbon footprint predominantly to methane released from wells during drilling for shale gas, or leaked from transport pipelines. Figure 6.1 shows the findings of the Howarth et al paper alongside estimates from others' comparable research. The chart shows that Howarth's low-end estimates for shale are higher than the high-end of other estimates over both 20 and 100-year time horizons. It also shows the Howarth paper to be an outlier in the relative positioning of coal and gas GHG emissions. It also highlights the scale of difference opting for a 20-year, rather than 100 year, global warming potential makes to Howarth's findings.

Figure 6.1: Comparison of GHG emissions estimates from selected shale gas impact studies[51]



Though each study conducts its accounting using different methodologies, all are broadly attempting to estimate the 'whole life' climate change impact of shale gas (i.e. all emissions from the extraction process, transport and combustion for energy). A report by the University of Manchester's Tyndall Centre for Climate Change identified three categories of ('indirect') emissions from shale extraction:

1. "Combustion of fossil fuels to drive the engines of the drills, pumps and compressors, etc., required to extract natural gas onsite, and to transport equipment, resources on and off the well site;"
2. "Fugitive emissions" of natural gas that escape unintentionally during the well construction and production stages; and

50 Howarth, Robert, et al; "Methane and the greenhouse-gas footprint of natural gas from shale formations" in *Climatic Change* (2011) 106:679–690. The report garnered media coverage from a multitude of news organizations including the BBC, *The Guardian* and the *New York Times.*

51 International Energy Agency; *Are We Entering a Golden Age of Gas?*; Paris; 2011; http://www.iea.org/weo/docs/weo2011/WEO2011_GoldenAgeofGasReport.pdf, Howarth, Robert, et al; "Methane and the greenhouse-gas footprint of natural gas from shale formations" in *Climatic Change* (2011) 106:679–690, Hultman, Nathan et al; "The greenhouse impact of unconventional gas for electricity generation"; *Environmental Research Letters*; 6 (October-December 2011); 2011; http://iopscience.iop.org/1748-9326/6/4/044008/fulltext#erl396513bib23, Jiang, Mohan et al; 'Life cycle greenhouse gas emissions of Marcellus shale gas' in *Environmental Research Letters* 6 034014; http://iopscience.iop.org/1748-9326/6/3/034014

3. "Vented emissions" resulting from the natural gas that is collected and combusted on site or vented directly into the atmosphere in a controlled way.[52]

Howarth et al come to markedly different conclusions to the other research teams about the size of the indirect emissions impact of shale gas, and consequently its climate change impact compared to coal, considered over both 20-year and 100-year time horizons.

The difference in findings derives from three main choices by Howarth and his colleagues, as Council on Foreign Relations energy expert Michael Levi has explained.[53]

First, Howarth emphasises his finding of a much greater climate impact of shale gas over a 20 year horizon. While these are not contradictory, a 20 year horizon is unusually short in climate science, where impacts over 50 or 100 years are usually considered more relevant. Assessment over a 20-year horizon emphasises the impact of any increased 'indirect' methane emissions from shale gas extraction. Methane is shorter-lived in the atmosphere, but with a higher climate change forcing factor than CO_2.[54] A 20-year assessment would only be the most relevant if reaching a climate 'tipping point' was considered a serious short-term risk. But in that scenario, much more drastic short-term action ought to be on the agenda than most existing climate policies. Over a 100-year time horizon, Howarth's estimates of the climate change impact premium of shale gas are lower. When compared on 100-year timelines, though, Howarth's estimates are still higher than those in others' assessments are.

The second cause of Howarth's different findings is the method used to account for methane leaked, both from extraction sites and from transmission pipelines. The poor availability of data for leakage is a weakness of the research acknowledged by Howarth et al (see below). Howarth et al assume leakage rates from transport and distribution is three times higher than official US (and UK) statistics.[55] Data for losses at the well site are less well established, though again industry organisations dispute Howarth's figures for losses during well completion and production.

The third, and most problematic, difference in Howarth's approach is his assumption about the efficiency of gas generation. Howarth's team chose not to account for gas generation's greater efficiency than coal generation, in terms of the conversion rate to useable energy. Accounting for the emissions on the basis of a kWh of generated electricity, rather than the raw resource "strongly tilts Howarth's calculations back toward gas, even if you accept everything else he says".[56] Figure 6.2 shows comparisons made by Hultman et al of emissions intensity for conventional, unconventional gas and coal. These are subdivided by the global warming potential time horizon (20, 100, or 500 years), the generation fleet efficiency (current average, current marginal generation, and anticipated future build), under low, medium, and high estimates.[57] As Hultman et al explain "One must assume relatively inefficient gas combustion technology and a high-end 20 y[ear] G[lobal Warming Potential] to realise gas emissions in excess of coal, which is similar to what Howarth et al found."

52 Wood, Ruth et al; *Shale gas: a provisional assessment of climate change and environmental impacts*; The Tyndall Centre for Climate Change Research, University of Manchester; 2011; http://www.tyndall.ac.uk/sites/default/files/coop_shale_gas_report_final_200111.pdf; p. 38

53 Levi, Michael; "Some Thoughts on the Howarth Shale Paper" at the Council on Foreign Relations website; New York; 2011; http://blogs.cfr.org/levi/2011/04/15/some-thoughts-on-the-howarth-shale-gas-paper/

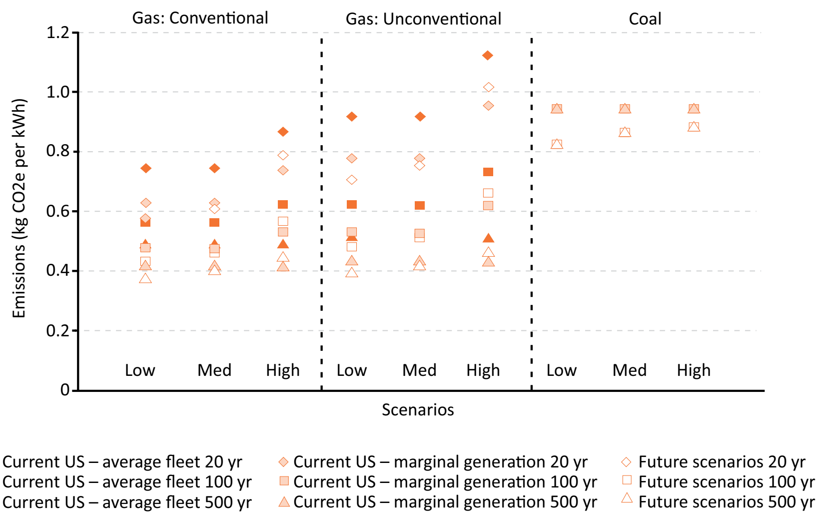
54 Under a 20-year basis, shorter-lived pollutants including methane and black carbon are more consequential to temperature rises, and thus mitigation efforts, than under a 100-year basis. Which timescale is more appropriate to climate policy decision making is an open debate.

55 Howarth et al assume 1.4% of produced gas to be the lower bound of his transmission leakage range, compared to 0.35% according to the US Environment Protection Agency's (EPA's) 1996 estimates (currently being reviewed), and a 0.49% from DECC's 2011 *Digest of United Kingdom Energy Statistics*. Howarth, Robert, et al; "Methane and the greenhouse-gas footprint of natural gas from shale formations" in *Climatic Change* (2011), p. 684. A revised set of EPA estimates are expected in 2012. Department for Energy and Climate Change; *Digest of United Kingdom Energy Statistics*; London; 2011, p. 99

56 Levi, Michael; "Some Thoughts on the Howarth Shale Paper" at the Council on Foreign Relations website; New York; 2011; http://blogs.cfr.org/levi/2011/04/15/some-thoughts-on-the-howarth-shale-gas-paper/

57 Hultman, Nathan et al; "The greenhouse impact of unconventional gas for electricity generation"; *Environmental Research Letters*; 6 (October-December 2011); 2011; http://iopscience.iop.org/1748-9326/6/4/044008/fulltext#erl396513bib23

Figure 6.2: Comparison of combustion emissions intensity ($kg\ CO_2$ equivalent per kWh electricity generated) ranges under different technology and GWP assumptions[58]



Further support for this point can be found in the US National Energy Technology Laboratory's assessment of the relative global warming potential (GWP) of coal and gas. It finds that, "natural gas **baseload power generation** has a life cycle GWP 54% lower than average coal **baseload power generation**" (emphasis added).[59] Figure 6.3 shows how the efficiency of gas-fired electricity generation compares to coal. Values for global warming potential that were roughly equal when considered on a pure energy content basis (as in Figure 6.1) become much more favourable to gas when the efficiency of generation is factored in. As mentioned earlier, Howarth et al did not calculate figures for electricity generation. Comparing Figure 6.3 with Figure 6.1, the big difference that applying generation efficiencies makes to the relative cleanness of gas compared with coal is starkly visible.

The poor quality and availability of data has constrained robust appraisal of comparisons of shale gas' life-cycle carbon emissions. Shale gas producers (and other extractive industries) in the US have resisted strengthening of reporting requirements. As shale extraction becomes more widespread, improving the quality of data available will be vital to understanding the climate impacts of unconventional gas more accurately.

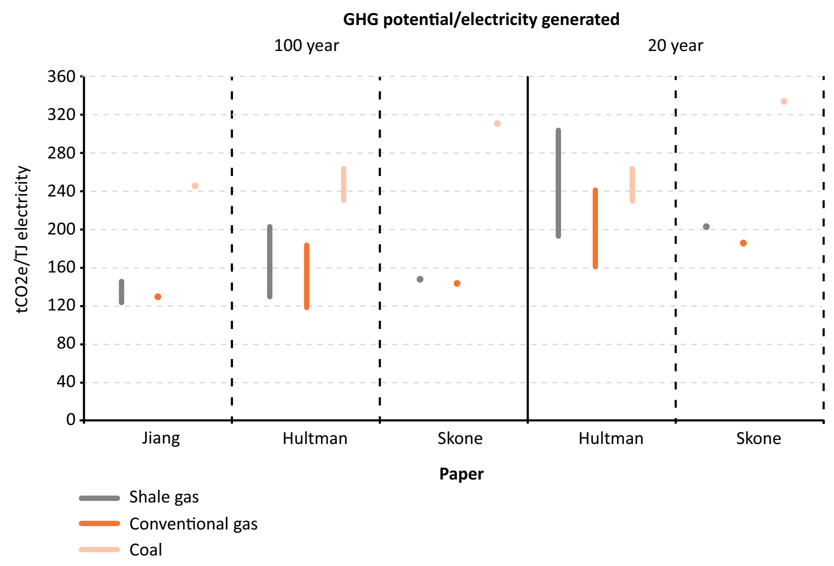
In raising the issue of the greenhouse gas implications of shale gas, and particularly in drawing attention to fugitive emissions, Howarth and his co-authors opened up an important debate. Regulators in the US and in Europe committed to investigating the issue more closely. More recent peer-reviewed research has built on, refined, and moderated the Howarth group's findings.

The 'dirtier than coal' argument appears to be a red herring. But how does unconventional gas compare with conventional gas? So far, the best information suggests the additional greenhouse gas impact from shale gas compared with conventional gas is modest, less than 3% higher where gas is flared during well completion, up to 13% higher when that gas is vented. Shale gas therefore results in much lower emissions than coal.

58 Ibid

59 Skone, Timothy; "Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction and Delivery in the United States"; National Energy Technology Laboratory, US Department of Energy; 2011; http://www.netl.doe.gov/energy-analyses/pubs/NG_LC_GHG_PRES_12MAY11.pdf; pp. 26–35

Figure 6.3: Comparison of GHG emissions estimates from selected shale gas impact studies, adjusted for electricity generation efficiencies



Avoiding venting is already recognised as best practice – ideally all of the gas would be captured for sale, but flaring is considered preferable, in terms of greenhouse gas emissions, to venting in situations where, for example, safety concerns mean flaring or venting must be undertaken. Improved leak monitoring of gas facilities around the world, including production sites, compressors, and the pipelines themselves, could enable further improvements to this figure. As production techniques continue getting better at snaring all the gas at a drilling site, the impact of fugitive emissions will be less troublesome.

Policy approaches

If shale gas has slightly higher GHG emissions than conventional gas, as a result of fugitive emissions, is there a case for taking policy steps to account for the difference in climate impact, so that conventional and unconventional gas each pay their environmental costs on a level playing field?

The European Commission intends to adopt such an approach regarding oil, to penalise oil derived from tar sands projects and shale oil.[60] Should the Commission's approach be confirmed, oil from tar sands would be assigned a GHG emission value 23% higher than conventional crude oil; shale oil would be given a value 50% higher. (Companies involved in tar sands production argue that its GHG impact is closer to 5–15% higher than conventional crude). This measure has been advocated on the ground that life cycle emissions of such oils are higher than average crudes. The extra impact is due to the energy intensive extraction process, rather than the combustion of the final product.[61]

If such an approach was applied to shale gas, an additional levy on shale gas could be applied to reflect its slightly higher life-cycle emissions. But the scale of the differential for best practice shale gas extraction compared with conventional gas is much smaller at 3–13% rather than tar sands' 23% greater emissions than

60 Taylor, Simon; 'Commission targets tar sands' in *European Voice*; Brussels; 4 October 2011; http://www.europeanvoice.com/article/2011/october/commission-targets-tar-sands/72180.aspx

61 Brandt, Adam; *Upstream greenhouse gas (GHG) emissions from Canadian oil sands as a feedstock for European refineries*; https://circabc.europa.eu/d/d/workspace/SpacesStore/db806977-6418-44db-a464-20267139b34d/Brandt_Oil_Sands_GHGs_Final.pdf; p.4

conventional oil. There is also significant variation in emissions intensity on a well-to-well basis depending on local geological conditions and infrastructure. A rule applied to broad categories of 'shale' and 'conventional' gas would fail to reflect that some conventional wells can be less clean than some shale wells.

There are many potential ways in which carbon reporting and pricing could be inaccurate by as little as 3%, and there is a range practical difficulties and costs (including difficulty in monitoring imports) associated with applying a differentiated carbon pricing approach to shale gas. And, given the paucity of good data on indirect emissions, doing it accurately would be hugely challenging. Such an approach would therefore appear disproportionate in relation to shale gas, and would impose significant compliance costs on the gas sector as a whole.

> "Industry and regulators should take steps to improve the quality of information on fugitive emissions from drilling sites to help ensure methane losses are minimised"

Rather, the best approach must be to ensure that all wells conform to the best practices of the industry. In line with DECC commitments in the conventional oil and gas industry, shale producers should avoid all unnecessary or wasteful flaring and venting of gas. Where some release is unavoidable (for well safety reasons, for example) flaring is far preferable to venting, and should be carried out wherever possible.

Gathering better data on fugitive emissions should also be a priority. The analysis in this chapter reflects the most up-to-date science in the area, but it is an area in which the paucity of data is widely acknowledged as a limit to scientific understanding. Relevant UK agencies (DECC and/or the Environment Agency) should collect data on emissions at production sites, either directly or by establishing a requirement on producers to do so. The Environment Agency is investigating ways in which this might be conducted and the American EPA is already taking steps to do this. Information sharing is essential between government bodies carrying this out, and best practice from around the world should be shared. Companies must also be forthcoming with relevant data. This process should be undertaken in coordination with similar efforts occurring overseas (especially in the US) and aim to complement rather than duplicate work being conducted there. Improved data on fugitive emissions would also make possible better-informed judgement on whether shale production sites and methane emissions should be included under the ETS in future Phases. If on-site emissions are sufficiently large to make shale drilling sites comparable to other facilities entered in the ETS, they should be brought into the cap-and-trade mechanism.

Recommendation

1. Industry and regulators should take steps to improve the quality of information on fugitive emissions from drilling sites to help ensure methane losses are minimised. Relevant UK agencies should collect data on emissions at production sites, either directly or by establishing a requirement on producers to do so. Best practice from around the world should be shared. Companies must also be forthcoming with relevant data. This process should be undertaken in coordination with similar efforts occurring overseas (especially in the US).

7

Local Environmental and Health Impacts of Unconventional Gas Production

Shale gas development has proven controversial in some quarters. Concerns about the impact of production on local communities and the local environment are central to much of that controversy. There are several specific complaints. The use of rock-fracturing drilling techniques and underground injection of chemical compounds have led to worries about contamination of water supplies. Allegations of poisoning and other health impacts have drawn media coverage, as have visually-compelling cases of inflammable methane getting into water supplies. Hydraulic fracturing has now been confirmed as the cause of a pair of small earth tremors in the north west of England in the spring of 2011. For some, these concerns have been sufficient to draw calls to prohibit shale production.

This chapter reviews these and related issues. We draw heavily on the work of the Energy and Climate Change Select Committee inquiry into shale gas, which remains the best overall assessment of UK shale gas conditions. We have added relevant new information that has come to light since the inquiry, and tried to reflect some of the debate that followed its publication.

Because shale gas production has so far been confined almost exclusively to the USA, the environmental concerns that have been raised derive in large part from experiences there. Hostility to shale gas development in the US has picked up popular resonance, most evident in the Academy Award nominated documentary *Gasland*, with 'made for Youtube' moments of combustible kitchen taps.[62] However, with the exception of one or two State administrations' scepticism (see Table 7.1), for the most part shale gas has been heralded by US authorities as a means to bring down gas prices, increase supply security, and, for those fortunate enough to be able to lease their property to a developer, provide a tidy income stream. Of course, many states (and their residents) are used to and largely accustomed to conventional oil and gas production, meaning that unconventional gas has been seen as part and parcel of technological advance in that sector. Much of the soul-searching has come in areas of the US previously unaccustomed to hydrocarbon extraction.

Local regulatory conditions play a significant role in determining the environmental impacts of shale gas production. Regulatory approaches differ

62 Fox, Josh; *Gasland*; HBO Documentary Films; 2010. A sequel to *Gasland* is due to be released in 2012.

between the many countries contemplating the merits of unconventional gas. Indeed, there are wide discrepancies between states in the US. It is beyond the scope of this paper to assess the regulatory situation in all relevant countries. We assess the key issues, and look at possible implications for shale gas production in the UK (though, as already discussed, UK production alone is far from the only way any 'shale boom' could affect UK energy policy). This chapter finds that many of the local environmental problems cited with shale gas are perhaps better understood as problems with the featherweight regulation prevalent in some US states, which vary widely in the strength of regulation and the rigour of implementation and enforcement. Future production in Europe (and elsewhere) will be able to learn from the US, not just about best production practices, but also about appropriate regulation.

Groundwater pollution

One commonly expressed concern is that underground drinking water aquifers (i.e. rock formations that yield significant quantities of drinking water to wells or springs) could become polluted either by chemicals used in fracking, or by gas or other naturally occurring substances, which are released by fracking, moving into aquifers. The Tyndall Centre offer several possible mechanisms by which this might occur:

- *"catastrophic failure or full/partial loss of integrity of the wellbore (during construction, hydraulic fracturing, production or after decommissioning); and*
- *migration of contaminants away from the target fracture formation through subsurface pathways including:*
  - *the outside of the wellbore itself;*
  - *other wellbores (such as incomplete, poorly constructed, or older/poorly plugged wellbores);*
  - *fractures created during the hydraulic fracturing process; or*
  - *natural cracks, fissures and interconnected pore spaces"*[63]

Some of these mechanisms are more contentious than others. It is widely accepted that poorly constructed wells can lead to water contamination, though how often it has occurred is disputed. The idea that contamination can be transmitted from the frack-site to aquifers through the intervening rock (either by extension of fractures or naturally-occurring fissures) is more contentious. The Geological Society has dismissed such concerns, saying there is "no recorded evidence" of it happening, and that it is unlikely to occur because "the process takes place at depths of many hundreds of metres below the aquifer".[64]

Water that is drawn from aquifers for human use, if polluted, could have damaging health or environmental effects. In rural parts of the US, where shale extraction has been most common, many households take water supplies from private wells, and the water is treated less thoroughly than would be the case with mains water systems. These households would therefore be at greater risk than most UK households.

Fears about the risk of water poisoning need to be taken very seriously. It is important, however, to properly understand the risks.

63 Wood, Ruth et al; *Shale gas: a provisional assessment of climate change and environmental impacts*; The Tyndall Centre for Climate Change Research, University of Manchester; 2011; http://www.tyndall.ac.uk/sites/default/files/coop_shale_gas_report_final_200111.pdf; p. 59

64 House of Commons Energy and Climate Change Committee; *Shale Gas: Fifth Report of Session 2010–12*; p. 40

Experiments to determine the impact of shale drilling on water supplies are beginning to be published. Research conducted by Osborn et al, reviewing 68 wells in Pennsylvania and New York state, found evidence of increased concentrations of methane in well water in areas where drilling had taken place, compared with geologically similar locations where drilling had not occurred. They found no evidence for contamination of drinking water with fracturing fluids or deep-saline brines.[65]

In contrast, in a second study, a group at Penn State University (commissioned by the Center for Rural Pennsylvania, a legislative agency of the Pennsylvania state legislature), found no statistically significant change in the methane content of well water between locations which have and have not had hydraulic fracturing take place. The study sampled 233 wells in the Marcellus Shale in Pennsylvania, some in locations where shale production had occurred and some control sites where shale wells were not drilled. It concluded that concentrations of methane, as well as common water quality indicators (chloride, barium and 'total dissolved solids') did not increase following hydraulic fracturing. Levels of bromide on the other hand did rise, but were still far from approaching dangerous concentrations. The study concluded that the presence of methane in water appears to be a risk arising from having water wells near natural shale gas formations, rather than having them next to shale gas drilling sites.[66]

The findings of the UK's Energy and Climate Change Select Committee (ECCC) investigation into the risks of water contamination (released in 2011) observed that well integrity, rather than the hydraulic fracturing process itself, was the main cause for concern. The ECCC emphasised the importance of well integrity, and the role of the Health and Safety Executive in appraising design and inspecting construction of shale gas wells, as it does with conventional oil and gas production. Ensuring well integrity must be a priority for shale producers, just as it is for other oil and gas producers operating in the UK.

In the UK the Environment Agency (EA) regulates groundwater impacts under two main pieces of legislation. The Water Resources Act (1991) requires mineral drillers and miners to notify the Environment Agency of intent to "construct or extend a boring", which the EA can respond to by demanding "reasonable measures" to protect water resources.[67] The Environmental Permitting Regulations (2010) require disclosure of activities that potentially involve pollutants being discharged into the ground. The EA then determines whether a permit is required for that activity to proceed.[68] Not all drilling activity in areas where groundwater is present will be subject to permitting. If, for instance, the target of drilling is far beneath the aquifer, or if no pollutant injection is planned, the EA may not require a permit. Not all shale gas production will impinge on groundwater. Cuadrilla's present drilling sites are not in an area where potable groundwater is present. (The aquifer beneath the drilling pads is saline, and as such not used for drinking water).

Chemicals

Another of the concerns that has arisen about the production of shale gas, particularly in the US, is in relation to the chemical contents of the fluids injected into the ground during the hydraulic fracturing process ('fracking fluids').[69] The

65 Osborn, Stephen et al; 'Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing' in *Proceedings of the National Academy of Sciences*; 9 May 2011; http://www.pnas.org/content/early/2011/05/02/1100682108.full.pdf+html

66 Boyer, Elizabeth et al; *The Impact of Marcellus Gas Drilling on Rural Drinking Water Supplies*; The Center for Rural Pennsylvania; October 2011

67 Water Resources Act; 1991; London; http://www.legislation.gov.uk/ukpga/1991/57/contents; Article 199

68 Environmental Permitting Regulations (England and Wales) 2010; London; http://www.legislation.gov.uk/ukdsi/2010/9780111491423/contents; See especially Schedule 22, paragraphs 3 and 10

69 Some main functions served by the use of chemicals in fracking fluid include: to eliminate bacteria in the water (biocides), to reduce friction in the well (friction reducers), to thicken water in order to suspend the sand (gelling agents), to regulate acidity levels of the fluids (pH adjustors), or to prevent limescale in pipes and well equipment (scale inhibitors). Most of the chemicals used in fracking fluid are common in industrial and even domestic applications

concern has been that the chemicals used could remain underground after production has ended, or leak into aquifers or land around the well-site. This could happen either by migrating from the shale, by leaking from the well pipe, or leaking from storage containers at ground level. Consequently, the nature of the fluids being pumped underground has come under increasing scrutiny.

In the US, firms are responding – though arguably too slowly – to public pressure for transparency about fracking chemicals. In the UK, as the government explains, mandatory disclosure rules are more forceful:

> *"Injection into groundwater of water containing pollutants, including fracturing fluids, requires authorisation. Any application for authorisation must be accompanied by information on the type and concentration of these pollutants.*
>
> *In England and Wales where a permit is required, information on the type, concentration and volume of all the substances that they intend to discharge to ground, including frack fluids, will be included on the public register. Where frack fluids are injected into formations that do not contain groundwater a permit may not be required. The Environment Agency still expects companies to disclose the nature and composition of the discharge and can use powers under the Environmental Permitting Regulations to obtain such information…*[70]
>
> *The environment agencies do not routinely monitor the chemical content of return fracking fluid if it is not being disposed of directly to the environment. However, it will be necessary for operators to undertake their own analysis to allow them to dispose of waste fracking fluid via an appropriate waste management route (disposal off site)."*[71]

As well as disclosure requirements, rules about chemical registration and permitting are much stricter in the UK than in some parts of the US, due to both UK and EU-level regulation.

Disclosure rules help ensure that the environment is adequately protected and build public trust in the industry, and are relatively low cost regulation. Increasing disclosure in the US has upped the pressure on drillers and service firms to reduce the environmental impacts of their fracking fluids. Indeed, it could be beneficial for both the government and for companies wanting to drill in the UK to institute mandatory disclosure in relation to discharges even in non-groundwater bearing formations.[72]

Other necessary regulation may carry higher compliance costs. But the general reassurance that effective regulation provides the public – and the avoidance of confidence-destroying incidents – could be critical for the development of the shale gas industry.

Effective and rigorous regulation should be a price worth paying, given the costs of exploration and production, and something which the industry should actively seek where there are any gaps.

Water use and disposal

The volume of water required by shale gas production has also come under scrutiny. At a time of increasing water scarcity, when many rivers and natural environments are suffering damage on a regular basis as a result of over-abstraction of water, major additional water demand could have harmful consequences.[73]

70 House of Commons Energy and Climate Change Committee; *Shale Gas: Government Response to the Committee's Fifth Report of Session 2010–12*; p. 8

71 Ibid p. 9

72 Cuadrilla has published the chemical composition of its fracking fluids on its website. "The fracing fluids used by Cuadrilla is [sic] 99.75% composed of fresh water and sand. This water and sand combination is supplemented with microscopic amounts of everyday chemicals typically found in people's homes: Polyacrylamide friction reducers (00.075%), commonly used in cosmetics and facial creams, Hydrochloric acid (00.125%), frequently found in swimming pools and drinking water wells, Biocide (00.005%), used on rare occasions when the water provided from the local supplier needs to be further purified." Cuadrilla Resources; 'Fracturing Fluid'; http://www.cuadrillaresources.com/what-we-do/technology/fracturing-fluid/ and http://www.cuadrillaresources.com/cms/wp-content/uploads/2011/02/Chemical-Disclosure-PH-1.jpg

73 See also Less, S; *Untapped Potential;* Policy Exchange; London; 2011; http://www.policyexchange.org.uk/images/publications/pdfs/Untapped_Potential.pdf

Box 7.1: Water consumption rates

5 million (US) gallons (≈19,000 cubic metres) of water is:

- The amount needed to operate a hydraulically fractured shale well for a decade.[74]
- The amount needed to water a golf course for a month.
- The amount needed to run a 1000 MW coal-fired power plant for 12 hours.
- The amount lost to leaks in United Utilities' region in northwest England every hour.[75]

While shale production is undeniably a water intensive business, it still requires much less water than many other, more familiar, water consumers (see Box 7.1).

The Environment Agency and DECC have stated that they do not expect adverse effects from shale gas production on water supplies. In locations where a sustainable water abstraction from the environment is not available, a licence would not be granted. Usage of mains supplies requires the agreement of the water company, and that such supplies are available.[76]

Furthermore, and importantly, the pattern of water usage of shale gas extraction is helpful in fitting with water availability. Environmental water scarcity is usually highly variable over time. Water may be scarce in a dry summer, but plentiful in winter in the same local area.[77] The hydraulic fracturing process, which uses the vast majority of the operations' total water consumption, is short and it is therefore possible for drillers to choose when precisely they conduct the hydraulic fracturing operations to avoid periods where they would exacerbate water scarcity.

In Cuadrilla's case, they intend to use mains water (which requires fewer additives to be used as it is pre-treated), and recognise that they would be one of United Utilities' first customers to have their supply curtailed in the event of drought conditions. (However, this does not always eliminate the need for trucking water to the site, as in most locations it is unlikely that there will be a mains supply of sufficient capacity close to the drilling site). The need to truck water in and out for use in shale wells has been one of the causes of public disquiet about shale production in the US, and is something producers need to plan to minimise as far as possible.

The way that waste water is dealt with after it is no longer required is also an important challenge for shale producers. The quantity and hazardousness of water returning to the surface during and following shale production varies from site to site. Because, the flowback fluid contains any compounds used in the injected fracking fluids, plus any naturally-occurring substances dislodged underground and brought back to the surface, "the toxicity profile of flowback fluid is likely to be of greater concern that that of the fracturing fluid itself".[78] In its evidence to the Energy and Climate Change Select Committee's investigation into shale gas, the Environment Agency explained the rules currently in place:

74 The number of wells one drilling pad can hold has risen as production experience has increased. With current technology up to 10 wells can be drilled from one pad covering 4–5 acres on the ground, but reaching a rectangular underground area of ½ x 2 miles.

75 United Utilities; *Corporate Responsibility Report 2010*; http://corporateresponsibility2010.unitedutilities.com/leakage.aspx and Chesapeake Energy; 'Water Use in Deep Shale Gas Exploration'; http://www.chk.com/Media/Educational-Library/Fact-Sheets/Corporate/Water_Use_Fact_Sheet.pdf

76 House of Commons Energy and Climate Change Committee; *Shale Gas: Government Response to the Committee's Fifth Report of Session 2010–12;* p. 6

77 Le Quesne, Tom, et al; *The Itchen Initiative;* WWF; 2011

78 Wood, Ruth et al; *Shale gas: a provisional assessment of climate change and environmental impacts;* The Tyndall Centre for Climate Change Research, University of Manchester; 2011; http://www.tyndall.ac.uk/sites/default/files/coop_shale_gas_report_final_200111.pdf; p. 58

"Waste water treatment and disposal options will vary depending on the nature of the waste and local environmental conditions. The Environment Agency will assess this on a case by case basis and in accordance with the [Environmental Permitting Regulations] 2010.

- *An environmental permit would be required for a discharge into a surface environment, for example to a local watercourse. Pre-treatment is likely to be needed to ensure the discharge can meet environmental standards.*
- *Operators may be allowed to dispose of waste water back into the strata from which it has been extracted, subject to environmental safeguards and providing only waste directly from the shale gas extraction operation is involved.*[79]
- *If groundwater is present in the strata then the disposal would become a groundwater activity under EPR 2010 and a permit would be required.*
- *Where an operator needs to transfer waste fracking water offsite for treatment, they will need to satisfy any conditions required by the waste receiver/treatment facility, who in turn will be operating under an environmental permit. It will be necessary for the waste receiver to ensure that the waste is suitable for treatment at their facility and that they can continue to meet their own responsibilities under the legislation."*[80]

Flowback water currently is stored initially at the production site in double-skinned tanks, from where it can either be treated in place, or transported by truck to water treatment facilities. Open-air wastewater storage ponds, of the kind often seen in American shale plays, are not permitted in the UK. From Cuadrilla's site near Blackpool, wastewater had previously be trucked to the Davyhulme specialist water treatment plant. However, a change in regulations in October 2011 means that Cuadrilla would require a permit to continue disposing of their flowback water in this way. While activity at the site is paused pending permission to move onto the next stage in their operations, Cuadrilla is re-evaluating its future water disposal options.[81] Wastewater is tested at the drilling site by the water treatment operators, and the Environment Agency can also carry out random spot checks.

The Energy and Climate Change Select Committee enquiry into shale gas found that facilities built to handle waste from the offshore oil and gas industry would have ample capacity to cope with the demands of shale gas, "even if it got pretty active".[82] The burden of shale fluids to industrial water treatment centres is not especially onerous. The 'liquor' of waste products from a hydraulic fracturing operation is more dilute than much other wastewater types produced by industrial activity in the UK.

Seismic activity

On April 1st 2011, a small earth tremor, registering 2.3 on the Richter Scale, was detected near to an exploration drilling site being operated by Cuadrilla Resources at Preese Hall. A 100 metre x 100 metre area of ground shifted by about a centimetre. The following month, a second, even smaller tremor was detected at the site near Blackpool. At that point, Cuadrilla opted to suspend drilling while a DECC inquiry was launched into whether the tremors and hydraulic fracturing work at the site were connected. (Cuadrilla also commissioned technical reports from five independent geological consultancy firms, which were synthesised into a final report by two of the consultants.) The tremors, which rated 2.3 and 1.5 on the Richter Scale – "generally recorded but not felt," by the standard

79 Used fracking fluid or flowback fluid that returns to the surface cannot be disposed of back to the strata from which it arose because it contains additives. Only produced water that has no added chemicals may be considered for disposal by this route.

80 Environment Agency; 'Supplementary memorandum submitted by the Environment Agency' in response to House of Commons Energy and Climate Change Committee; http://www.publications.parliament.uk/pa/cm201012/cmselect/cmenergy/795/795we16.htm

81 Environment Agency; 'Shale Gas – North West Monitoring of Flow Back Water'; 3 November 2011; http://www.environment-agency.gov.uk/static/documents/Business/Flow_back_water_analysis_011111.pdf

82 House of Commons Energy and Climate Change Committee; *Shale Gas: Fifth Report of Session 2010–2*; p. 44

description– were of a strength observed on average 20–30 times a year in the UK. The independent inquiry into the earthquakes concluded that they were indeed triggered by Cuadrilla's drilling work.[83]

The word 'earthquake' is an emotionally freighted one. The Lancashire earthquakes however, bore little resemblance to the popular image of an earthquake – they could barely be felt from the surface without the aid of sophisticated detection equipment.

It is an unusual case – only in two previous instances have drilling operations come near creating the same degree of seismicity, and they were undergoing much more powerful hydraulic fracturing. The widespread expansion of hydraulic fracturing technology in the past decade has not been matched by notable incidents of seismicity before the case at the Cuadrilla site at Preese Hall.[84]

According to the geologists' report, the characteristics of the Preese Hall site made it particularly vulnerable to seismic events. The well site was constructed over a "critically stressed fault", which shifted when hydraulic fracturing fluid put pressure on it. The report found that while the likelihood of other drilling sites encountering similarly susceptible geological conditions was slim, "the maximum magnitude [of any induced seismicity] is likely to not exceed" three on the Richter scale. At this maximum level, damage to property is rare, although such a degree of seismicity can usually be felt at the surface.

The report rejects the possibility of fluids flowing into formations nearer the surface, including the saltwater aquifers present in the area, as a result of earth movements and additional pressure on underground equipment. The dense layers of impermeable rock separating the target shales from more sensitive geological structures insulated them from the effects of the tremors.

The report suggested several measures that could be taken to mitigate the magnitude of seismic events:

> *"From the observations and modelling we can identify two potential mitigation measures: rapid fluid flow back after the treatments and reducing the treatment volume. Furthermore, intervals close to a fault (as identified with image logs) should be avoided.*
>
> *Mitigation of seismicity can be achieved by monitoring seismicity during the treatments and taking appropriate action when seismic magnitude exceeds the limit set by the so-called traffic light system:*
>
> - *[Less than 0 on the Richter Scale]: regular operation*
> - *[Between 0 and 1.7 on the Richter Scale]: continue monitoring after the treatment for at least 2 days until the seismicity rate falls below one event per day.*
> - *[Above 1.7 on the Richter Scale]: stop pumping and bleed off the well, while continuing monitoring.*
>
> *An important result from the identified mechanism is that measurable seismicity is unlikely to occur in the next wells. The induced seismicity depends on three factors: presence of a critically stressed fault, a fault that is transmissible so that it accepts large quantities of fluid and a fault that is brittle enough to fail seismically. One of the reasons seismicity in propped fracture treatments is weak is that most fluid is pumped with significant sand concentration. Therefore it is likely that the slurry cannot easily enter a fault which will have a much smaller aperture than a hydraulic fracture. The seismic events imply that in the Preese Hall well a large fraction of the fluid entered a fault and this is one of the key factors that are unlikely to occur again in the other wells in the Bowland Shale.*

83 De Pater, CJ and Baisch, Stefan; *Geomechanical Study of Bowland Shale Seismicity*; http://www.cuadrillaresources.com/cms/wp-content/uploads/2011/11/Final_Report_Bowland_Seismicity_02-11-11.pdf

84 Ibid p. iii

It is possible that the seismicity originated in the basement and that the hard limestone strata played a role in the seismicity. Future monitoring of treatments should resolve the depth location, which could help mitigating seismicity by avoiding injection into strata that are prone to strong induced seismicity."[85]

Should the measures Cuadrilla has agreed to implement to reduce the seismic impact of shale production fail, DECC has suggested that hydraulic fracturing operations would have to be reconsidered. Fortunately we are not yet at that stage, and there are plenty of engineering options that can be tried before such a step needs to be considered.

Bans and moratoria

There have been many calls for bans or moratoria on shale gas production. Often underpinning arguments against shale production is the 'precautionary principle'. The argument is that we do not yet know enough about the risks, so production should be halted until we learn more.

The precautionary principle is referred to in the Amsterdam Treaty (1997): "Community policy on the environment shall … be based on the precautionary principle..."[86] Since 2000 the European Commission has offered official guidance as to how member states should incorporate the precautionary principle into their policy making. The Commission states that the precautionary principle applies, "where scientific evidence is insufficient, inconclusive or uncertain and there are indications through preliminary objective scientific evaluation that there are reasonable grounds for concern that the potentially dangerous effects on the environment, human, animal or plant health may be inconsistent with the chosen level of protection."[87]

Politicians and regulators deciding when to intervene need to be able to distinguish situations where there is adequate, objective scientific evidence, even if inconclusive, for potentially dangerous effects. Unless such a rigorous test is applied here, then the precautionary principle would simply become a counsel of 'don't try anything'.[88]

Allegations of harm by NGOs, or anecdotal evidence, should not alone be sufficient grounds for a moratorium on an industry's economic activities. So far the UK government and Parliament have taken a measured and responsible approach, rejecting calls for a moratorium on drilling due to a lack of scientific backing for links between hydraulic fracturing and water contamination.

On both water quality and seismicity issues, investigating the facts, and identifying safe production methods rather than responding with knee-jerk prohibitions is the appropriate first response to concerns.

However, some other governments have taken the view that the possible risks of unconventional gas production are too great and that an extreme precautionary approach is required. They have imposed bans or moratoria on hydraulic fracturing or shale production (see Table 7.1). Calls for similar bans or moratoria have been heard in virtually every new territory for shale exploration.

What purpose is served by such bans? In the best cases, they buy time for both sides of the debate to marshal their evidence, and when more information is available, for the best decision to be made. In other cases they can be pragmatic, putting off making a decision until a more politically expedient time, or buying

85 Ibid p. v

86 European Union; Treaty of Amsterdam Amending the Treaty on European Union, the Treaties Establishing the European Communities and Related Acts; 1997; Article 130r(2); http://eur-lex.europa.eu/en/treaties/dat/11997D/htm/11997D.html

87 Commission of the European *Communities; Communication from the Commission on the Precautionary Principle*; Brussels; 2000; http://ec.europa.eu/dgs/health_consumer/library/pub/pub07_en.pdf

88 Scruton, Roger; *Green Philosophy*; Atlantic Books; 2012

time for a controversy to defuse. And in some cases they are pure political symbolism, as seen in New Jersey, where a moratorium was imposed despite no planned drilling and no shale prospects.

But very widespread bans could pose a potential obstacle to the safe expansion of unconventional gas production to new regions if they prevent the very experimentation and investigation which could identify and solve any risks.

Fortunately, in those territories not subject to bans, investigation and experience has so far led to most, if not all risks raised having solutions.

Table 7.1: Bans or moratoria on hydraulic fracturing and shale production, by jurisdiction

Jurisdiction	Notes
France	Hydraulic fracturing suspended in 2011
South Africa	Moratorium on hydraulic fracturing extended for six months in August 2011, pending results of government study into its effects. Exploration and drilling projects been proposed in the Karoo region of western South Africa
Bulgaria	Indefinite ban on hydraulic fracturing imposed in January 2012
Northern Ireland	The Northern Irish Assembly voted for a moratorium on hydraulic fracturing pending an environmental assessment in December 2011
New York (USA)	Moratorium on hydraulic fracturing pending outcome of environmental review, expected late 2011 or first half of 2012. Drilling proposed in Marcellus shale formations in western New York
New Jersey (USA)	One year moratorium on hydraulic fracturing imposed in August 2011, despite there being no proposals for drilling in the state
Quebec (Canada)	Moratorium on hydraulic fracturing imposed in March 2011 pending outcome of environmental revie
Fribourg (Switzerland)	Indefinite moratorium on exploration and drilling
New South Wales (Australia)	Moratorium on hydraulic fracturing (directed at coalbed methane production), alongside ban on specified chemicals (benzene, toluene, ethylbenzene and xylenes)

US transparency and industry defensiveness

The US industry has done itself few favours throughout the burgeoning controversy over its practices. Clearly the US political environment is different from that in the UK and Europe, with different norms and expectations. However, the way that issues have been addressed, and a lack of transparency, has repercussions for international expansion of the shale gas sector.

For years, the US industry insisted on secrecy about the contents of fracking fluids. Attempts to defend competitive advantage ultimately led to suspicion about what they were 'hiding'. The pressure on firms in recent years over this issue has led to them being more forthcoming about the chemicals they use. Industry-led initiatives such as the Fracfocus website are beginning to publish information on the contents of fracking fluids, though participation is far from universal. Other, 'mandatory' systems are yet to be comprehensive enough. Texas – the spiritual home of the American oil and gas sector – recently introduced a law requiring companies to disclose the chemicals they use. Except, all chemicals won't be disclosed – firms can decline to disclose proprietary mixtures. As a result, the PR benefits of the exercise are negated. As one analyst points out, "you cannot pull just one hand from behind your back and say, 'See, no weapons!' One needs to see both."[89]

Likewise, the industry's defensiveness in the face of water pollution stories has caused reputational damage. A direct line runs from the failure adequately to address water pollution concerns in the US to the bans being imposed elsewhere in the world. Hostility to regulation (in a notorious case, the lobbied-for and granted exemption of hydraulic fracturing from the US Safe Drinking Water Act), and a reluctance to take on bad apples within the industry, have tarnished the industry's reputation elsewhere. Securing a cosy regulatory regime in Washington or state capitals may backfire, should it mean other countries refuse to let the industry in. Lobbying to gain freedom of action in the short term can lead to far tighter constraints in the long term if that freedom is seen to have been abused.

> "It is important that the UK maintain a strong and effective regulatory regime, which addresses any new problems that arise, and enables a safe shale production sector to develop"

The perceptions that have grown about the US industry may well be in large part unfair. The vast majority of hydraulically fracked US wells operate without incident or complaint. While some environmental NGOs have raised awareness of genuine environmental problems, have also sometimes been guilty of distortions and, arguably, scaremongering, that does not excuse the industry's failings. As a 2011 report for the US Department of Energy concluded, "an industry response that hydraulic fracturing has been performed safely for decades rather than engaging the range of issues concerning the public will not succeed."[90] Ensuring future standards – and improving perceptions is a key task for the US industry, as well as governments, to tackle.

Conclusions

Concerns about risks from shale gas production in relation to water quality, seismic activity and water scarcity need to be taken seriously, but, on the basis of current evidence, do not justify a moratorium on shale gas production.

Instead, government and the industry should focus on effective and more rigorous regulation than has been seen in parts of the US. The costs of complying with such regulation should be a price worth paying for the industry, to protect investments in exploration and production, and something which the industry should actively seek where there are any gaps.

Many of the failings of the shale experience in the US have been failures of regulation, not of the shale production technologies themselves. The UK government has struck the right balance in its attitude to shale production in the UK. The regulatory regime, developed in considerable part from the experiences of the North Sea, sets strong but sensible boundaries for producers. Groundwater protections and waste treatment regulations are stronger in the UK than in parts

89 Levine, Steve; 'Will shale gas be a shake or mere stir?' on Foreignpolicy.com; 2011; http://oilandglory.foreignpolicy.com/posts/2011/06/19/will_shale_gas_be_a_shake_or_a_mere_stir

90 Shale Gas Subcommittee of the Secretary of Energy Advisory Board; *The Shale Gas Subcommittee Ninety-Day Report;* 2011; http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf; p. 13

of the US. Likewise, requirements about chemical disclosure are much more forceful in the UK

It is important that the UK maintain a strong and effective regulatory regime, which addresses any new problems that arise, and enables a safe shale production sector to develop. In particular, future exploration and drilling should feature the strict real-time monitoring and seismicity-conscious operating procedures suggested by the inquiry into the Preese Hall tremors.

Recommendations

1. Concerns about risks from shale gas production in relation to water quality, seismic activity and water scarcity need to be taken seriously, but, on the basis of current evidence, do not justify a moratorium on shale gas production.
2. Many of the failings of the shale experience in the US have been failures of regulation. In contrast, the UK regulatory regime, developed in part from the experiences of the North Sea and in part from the far smaller, but nevertheless lengthy, UK experiences of onshore oil and gas production and mining activity, sets strong but sensible boundaries for producers. Groundwater protections and waste treatment regulations are stronger in the UK than many parts of the US. Likewise, requirements about chemical disclosure are more forceful in the UK. Looking to the future, it is important that the UK maintains a strong and effective regulatory regime, which addresses any new problems that arise, and enables a safe shale production sector to develop. The review that the Environment Agency is currently conducting of the body of regulation to ensure that it fully covers the exploitation of shale gas is a welcome step. In particular, future exploration and drilling should feature the strict real-time monitoring and seismicity-conscious operating procedures suggested by the inquiry into the Preese Hall tremors.

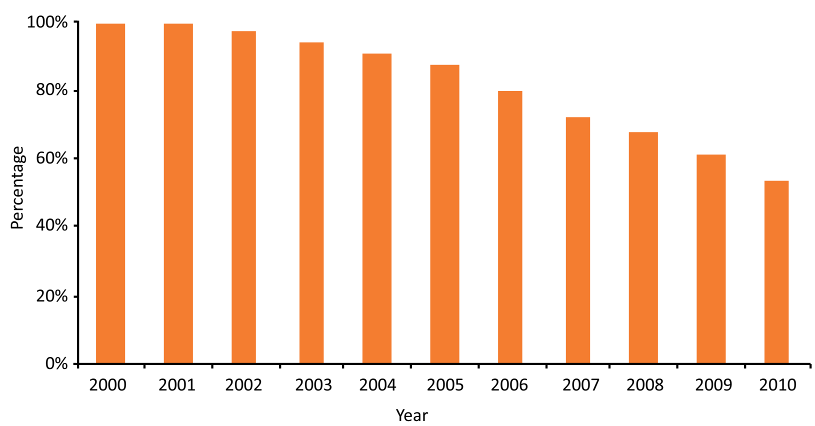
8
Security of Supply

The previous chapters have described the potential for shale gas and other developments in the gas market to be positive both economically and for mitigating climate change (provided carbon policy is appropriately designed).

One concern that is often raised, particularly in relation to further development of gas generation in the UK and EU, is about future security of supply. 'Security of supply' is a term that covers a range of perceived concerns, from dependence on imported energy supplies, through Russian malfeasance to concern about future wholesale gas prices.

The UK's North Sea gas production will soon account for less than half of UK supplies, having provided over 95% of UK supply as recently as 2002 (see Figure 8.1). Is this in itself a problem that requires government intervention?[91]

Figure 8.1: UK gas production as a proportion of total UK supply



In fact, the scale of the response delivered by the liberalised UK gas market has been huge, with a 500% increase in import capacity over the past decade, all built privately as a result of market processes. Analysis conducted by Pöyry Consulting for DECC in 2010 found no capacity problem in gas supply infrastructure until at least 2025.[92] Access to LNG imports gives the UK great diversity of supply sources (Table 8.1). In the event that one supplier proves to be unreliable, or is forced offline, many others can fill the gap.

91 Department for Energy and Climate Change; *Natural Gas Production and Supply and Natural Gas Imports and Exports;* London; 2011; http://www.decc.gov.uk/en/content/cms/statistics/energy_stats/source/gas/gas.aspx

92 Pöyry Consulting; Security of Gas Supply: European Scenarios, Policy Drivers and Impact on GB; http://www.decc.gov.uk/assets/decc/what%20we%20do/uk%20energy%20supply/energy%20markets/gas_markets/115-poyry-europe.pdf esp. pp. 79–104

Table 8.1: UK gas sources in 2010[93]

Country (LNG if specified)	Volume (bcm)
UK production	57.1
Norway	26.6
Qatar (LNG)	13.9
Netherlands	8.1
Trinidad and Tobago (LNG)	1.6
Belgium	1.3
Algeria (LNG)	1.3
Nigeria (LNG)	0.4
Yemen (LNG)	0.3
USA (LNG)	0.2
Egypt (LNG)	0.1
Total	**110.7**
Total minus exports	**95.1**

Concerns about the behaviour of Russia and some of its neighbours, while troublesome for some central and eastern European countries, with less access to alternative sources of supply, have little direct consequence for the UK. The UK is not a destination for Russian or Caspian volumes. The countries at the other end of our major gas pipelines – Norway and the Netherlands – are not prone to capricious interference with their energy exports.

Of course the UK gas market is linked to other European markets and may thus to a degree be affected by those markets. The main effect to date has been for UK gas exports to Europe to rise in recent years, despite decreasing North Sea production. The UK has become Europe's 'Western Gas Corridor'. The lack of attention that this development has drawn is evidence of its success, in comparison to the conspicuous but flawed Eastern Corridor connecting to Russia and/or Caspian Sea producers. The liberalised UK market has no difficulty attracting supplies from other parts of the world, and indeed exports of gas from the UK now challenge oil-indexed volumes in continental Europe.[94]

Polling from YouGov and Chatham House in 2011 shows that public opinion does not reflect this state of affairs. Interruptions to oil and gas supplies ranked second, behind only international terrorism, among perceived "current or possible future threats to the British way of life".[95] It is a narrative that seems to have become so widely accepted that nobody is particularly concerned about whether it is true. The narrative has been encouraged by politicians. Politicians often go further and promote 'energy independence', a phrase that frequently appeared in former Energy and Climate Change Secretary Chris Huhne's speeches.[96] This is despite the fact that domestic events such as industrial action and outages, rather than dependence on foreigners, have historically been a greater threat to energy supply security.

93 BP; *Statistical Review of World Energy 2011*; London; 2011; pp. 22–28

94 Noël, Pierre; *Gas Supply Security Policy*; Presentation to EPRG Conference; London; 23 September 2011; http://www.eprg.group.cam.ac.uk/wp-content/uploads/2011/09/PN_GasSecurityPolicy_UKDebate_EURegulation_PTD.pdf

95 Chatham House and Yougov; *British Attitudes Towards the UK's International Priorities*; London; 2011; pp. 38–40

96 For example, Huhne, Chris; *Green Growth: The Transition to a Sustainable Economy*; 2 November 2010; http://www.decc.gov.uk/en/content/cms/news/lse_chspeech/lse_chspeech.aspx, *Speech for the CPRE Annual Lecture*; 24 March 2011; http://www.decc.gov.uk/en/content/cms/news/ch_cpre_lect/ch_cpre_lect.aspx, *The Economics of Climate Change;* 29 June 2011; http://www.decc.gov.uk/en/content/cms/news/ec_cc_ch/ec_cc_ch.aspx

Politicians have used this narrative to justify proposing a range of interventions such as supplier obligations to compel more gas storage and obligations around use of more long term contracting, potentially undermining the market based approach to security of gas supply that has succeeded cost-effectively to date.[97] In 2009–10, the market dealt successfully with disruptions to Norwegian supply occurring during the severest winter for 31 years. Economic history demonstrates that security of supply of commodities and goods is rarely better (and is usually worse) supplied through government intervention than through the operation of effective market processes. A Pöyry study concluded that the proposed policy interventions to improve security of supply are in fact likely to damage it. The key to supply security is diversity of supply sources, and, as has been discussed, the gas market is delivering this.

When politicians, and others, talk about security of supply, what they often mean is price. The UK market has no difficulty attracting gas supplies *for a price*. And it is this uncertain price, not security per se that unnerves politicians. As Noël points out, there are two ways of viewing the situation. One sees price rises in response to supply shortages as the solution – a way of attracting more supplies (via LNG or interconnectors) and of suppressing demand. The other sees price spikes with an unknown peak as being the problem, because of their possible economic, but more especially their political implications.[98] The issue was made plain when former Energy and Climate Change Secretary Chris Huhne said that, "left as it is, the electricity market would allow a new dash for gas, exposing us to further import dependence and volatile prices," to justify a heavily subsidised reorientation of electricity generation away from gas.[99]

Are the risks from gas price volatility a reason to eschew the benefits that shale gas, and other gas market developments, may bring? There are a number of aspects to this.

First, are the costs of potential gas price volatility greater than the costs of the alternatives? Economist Dieter Helm told an Energy and Climate Change Select Committee hearing, "people like stability in prices. But if they have stable very high prices, they prefer volatile low ones."[100] The government's policies such as massive short-term deployment of offshore wind generation, justified in part by the objective of protecting customers from volatile prices, will lead to higher energy prices, as discussed further in the next chapter.

Second, is it actually feasible to substantially reduce the impact of gas price volatility? Gas generation is likely generally to set the marginal price for wholesale electricity for the next two decades under almost any scenario.

Third, how economically costly is gas price volatility? Gas price fluctuations send signals about real world circumstances. If gas is scarce, as a result of a demand spike or supply outage, then it is economically efficient for prices to signal that, so that those gas users who value gas least can reduce energy usage or switch to other energy sources. Customers who place a high value on stable prices are already able to fix their energy prices over the short to medium term. Those who argue that gas price volatility may damage economic growth need to demonstrate that such volatility is more damaging than the guaranteed high prices of alternative policies.

Fourth, moving towards a greater reliance on renewable generation trades the risk of geopolitical disruptions for the more mundane but more commonplace

97 Noël, Pierre; *Gas Supply Security Policy; Presentation to EPRG Conference*; London; 23 September 2011; http://www.eprg.group.cam.ac.uk/wp-content/uploads/2011/09/PN_GasSecurityPolicy_UKDebate_EURegulation_PTD.pdf

98 Ibid

99 Department for Energy and Climate Change; *Chris Huhne's speech to the Guardian's Cleantech Energy Summit*; London; 2010; http://www.decc.gov.uk/en/content/cms/news/cleantech/cleantech.aspx

100 Helm, Dieter (2011), Minutes of Evidence Taken Before the Energy and Climate Change Committee, http://www.publications.parliament.uk/pa/cm201011/cmselect/cmenergy/uc742-ii/uc74201.htm

risk of uncooperative British weather, and thus substantial associated price volatility.

Fifth, an increasingly contested market for imports from various LNG shippers will help constrain the duration and size of any spike in prices. Unconventional production elsewhere could eventually lead to new exporters emerging. And domestic shale gas production might also act as a brake on price spikes in the way that North Sea production has historically, although it is too early to tell whether the size of the UK producible resource will enable that.

Security of supply concerns have a tendency to be both misunderstood and overblown in British political debate. The global developments in shale gas, and gas generally, coupled with the UK's open gas market, large new import infrastructure and diversity of potential gas suppliers mean that security of supply is not expected to be a key concern in relation to UK's gas supplies. DECC, in its response to the recent parliamentary shale gas enquiry, said it "does not believe that security of supply considerations will be the main driver of policy in relation to the exploitation of shale gas in the UK".[101] It would be reassuring if a similarly measured approach were taken in relation to wider political debate and energy policy formation.

101 Department for Energy and Climate Change; Shale Gas: Government Response to the Committee's Fifth Report of Session 2010–12; London; 2011; http://www.publications.parliament.uk/pa/cm201012/cmselect/cmenergy/1449/144904.htm

9

UK Government Projections of Gas Trends

Nobody knows what the effect on UK gas prices of the developments in unconventional gas globally and domestically will be. Of course plenty of organisations and companies are placing their bets. UK energy companies more generally are considering their future commercial strategies in relation to their mix of energy sources. A diversity of strategies is emerging.

While competing companies and investors betting on future trends – prices, technological innovations, new discoveries – is a key component of a functioning market, it is of concern when government starts making similar bets. It is troubling because when government makes bets, it is betting with taxpayers' money, not its own. Government is also not subject to competitive pressures, has far weaker incentives to make the right bets, and suffers relatively less in the way of repercussions if it blunders. Central planning, based on central forecasts, damages market processes of discovery and adaption to new information – processes which are always desirable for cost containment, but are even more critical when low carbon technological innovation and development is a key motivator of policy.

The uncertainty in future gas prices contrasts to a number of statements by DECC Ministers about inevitable much higher gas prices (see Box 9.1).

This chapter looks at how projections of future gas prices are made and used in policy making.

Box 9.1: Comparing ministerial rhetoric and departmental statements on gas prices

There appears to be an increasing disconnect between the rhetoric used by DECC ministers about future gas prices and the official departmental projections. The threat of inevitably rising gas prices, was frequently deployed by Chris Huhne to support interventions and spending, in particular on large-scale subsidies for expensive renewable energy. Yet under DECC's latest Central (and designated most probable) case projection gas prices settle at around 24.7p/m³ (70p/therm) through 2020 and 2030, compared with around 23.0p/m³ (65p/therm) today (and 24.0p/m³ (68p/therm) at times in recent months). This hardly seems to support some of the ministerial rhetoric.[102]

On the one hand DECC is non-committal…

"The Government does not take a view of what prices will be set in competitive global markets." – DECC[103]

102 Department for Energy and Climate Change; *DECC fossil fuel price projections:* summary; London; 2011; http://www.decc.gov.uk/assets/decc/11/about-us/economics-social-research/2933-fossil-fuel-price-projections-summary.pdf

103 Department for Energy and Climate Change; *Notes on price assumptions*; London; 2009; http://www.decc.gov.uk/assets/decc/statistics/projections/1_20090715101435_e_@@_tablee.xls

"These illustrative scenarios are meant to capture the uncertainty around future fossil fuel prices. Given the uncertainty associated with the projections, we encourage analysts to use the full range of figures, rather than simply focussing on the "central" case." – DECC[104]

… while on the other, Mr Huhne was certain…

"… rising world gas prices will push up bills. But our policies will moderate this rise…" – Chris Huhne[105]

"…Y ou can't simply say 'look, we're going to lose or gain in ten or twenty years time,' because it depends on what the price will be if we don't do anything. And I think the price is going to be very high and very nasty." – Chris Huhne[106]

"I'm not in the forecasting business over a period as long as that [by the next election], but we know that energy bills at the moment – the official government forecast is that gas prices will rise in the medium term because after all fossil fuel (oil and gas) is running out, and we need to move over to alternative, nationally-produced sources of energy" – Chris Huhne[107]

"… We end up with a better deal for British consumers on the most likely progression of gas prices worldwide" – Chris Huhne[108]

… most of the time

"… it is so important that we continue to have a portfolio of different approaches, that we are not betting the farm on one particular technology or one particular approach or one particular view of the world-be it a low gas price view of the world or a high gas price view of the world. We need to have a framework for energy policy that can adjust over time…" – Chris Huhne[109]

Government assumptions about future gas prices

Assumptions about future gas prices are an important driver for much of the UK government's energy policy. For example, estimated net costs or benefits from the deployment of low carbon generation technologies depend heavily on expectations about the future costs of gas (see Table 9. 1 later).

The Department for Energy and Climate Change (DECC) supplies a set of future fossil fuel price cases for use in policy preparation and analysis.[110] These are, the Department emphasises, "not intended to be detailed forecasts or predictions and should not be released as forecast retail prices since the government does not take a view of what prices will be set in competitive global markets. They are presented as modelling assumptions." They are, it says, compiled "employ[ing] a number of different methods to produce figures using considered judgement… subject to peer review".

104 Department for Energy and Climate Change; *DECC fossil fuel price projections: summary*; London; 2011; http://www.decc.gov.uk/assets/decc/11/about-us/economics-social-research/2933-fossil-fuel-price-projections-summary.pdf; p. 2

105 Huhne, Chris*; 2011 Annual Energy Statement;* 23 November 2011; http://www.decc.gov.uk/en/content/cms/news/aes_2011/aes_2011.aspx

106 Huhne, Chris; *The Andrew Marr Show*; BBC; 1 August 2010; http://news.bbc.co.uk/1/hi/programmes/andrew_marr_show/8875000.stm

107 Huhne, Chris; *Channel 4 News*; 17 October 2011; http://www.channel4.com/news/government-pledges-to-bring-down-energy-bills (at 0:40)

108 Huhne, Chris; *The Politics Show*; 18 September 2011; BBC; 2011; http://www.bbc.co.uk/news/uk-politics-14965108 (at 5:20)

109 Huhne, Chris; Oral Evidence Taken Before the Energy and Climate Change Committee; 2 November 2011; London; http://www.publications.parliament.uk/pa/cm201012/cmselect/cmenergy/uc1623-i/uc162301.htm

110 Department for Energy and Climate Change; *Energy and Emissions Projections*; London; 2010; http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/en_emis_projs/en_emis_projs.aspx

Figure 9.1 shows DECC's future gas price projections, made in 2010 and 2011. The 2010 projections show a Central case rising steadily from 21 to 26p/m^3 between 2010 and 2030, in other words rising by about 29% over a 20 year period. A low case considers a rapid drop to 11.3p/m^3 by 2013 followed by a slow rise to 15.9p/m^3 by 2030. A high case sees prices rise sharply from 25.2p/m^3 in 2010 to 34.9p/m^3 in 2020, where they stabilize. A high-high case sees prices stabilized at 42.8p/m^3 from 2015 through 2030.[111]

Having previously presented four pricing pathways – low, central, high and high-high – in 2011 the high-high case was abandoned. Other changes from 2010 to 2011 include the addition of a bulge in gas prices projected in the Central scenario between 2012 and 2018 (perhaps reflecting, at least in part, the timescale before which DECC expects significant unconventional production to occur). Longer term, though, the central gas price case adjusts expectations down compared with the 2010 numbers. The 2011 central projections place gas prices in 2030 at 11% higher than they are currently; in the 2010 projections, 2030 projections were 21% above current (ie 2011) prices.[112] Low and high scenarios were virtually unchanged. So in the passage of only one year, gas market developments, including shale gas, have had a marked impact on DECC's outlook for gas prices.

Figure 9.1: DECC gas price projections (2011 and 2010)

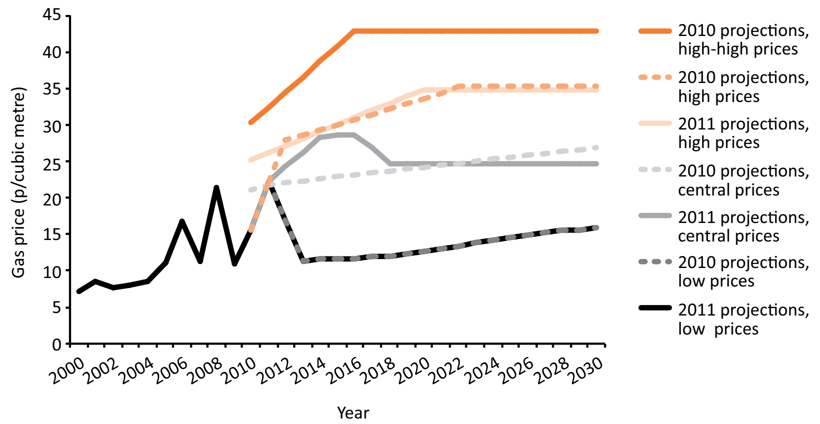


Figure 9.2 shows how DECC's projections compare with the IEA's projections for Europe (the UK has historically been towards the low end of European prices). It shows that DECC's Central projections feature notably higher prices than the IEA's NPS scenario throughout the time period. The IEA's GAS Scenario projects even cheaper prices (for more discussion on the IEA Scenarios see Chapter 4).The DECC Central case is arguably overly pessimistic when compared with the international data.[113]

DECC's price projections are an important tool in the policymaking process. They enable policymakers to test the resilience of proposals to different assumed price futures. Table 9.1 shows the differing ways they have been employed in published policy analyses in recent years.

111 1 therm = 2.832m3

112 Both figures compared against the gas price for 2011 presented in the 2011 document.

113 IEA data converted from 2009 US$ to GB£ at a 2009 rate of $1= £0.693062, and adjusted for inflation.

Figure 9.2: Gas price projections from the IEA and DECC compared

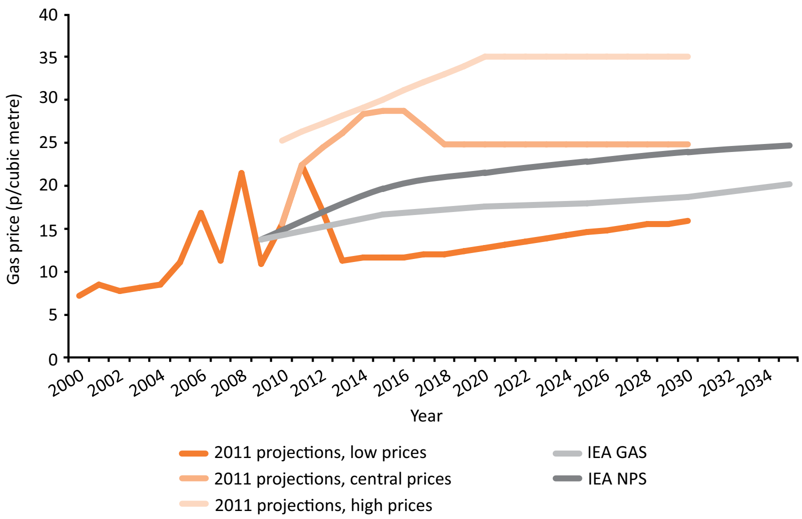


Table 9.1: Analysis of policy proposals using DECC gas price cases

Document	Gas/fossil fuel price assumption impacts on assessment
Green Deal Impact Assessment[114]	With capital and carbon prices held constant, the Impact Assessment finds that the Green Deal results in a net benefit of £1.46bn under low energy prices, £15.87bn under high energy prices, and £22.12bn under high-high energy prices.
Renewable Energy Strategy – Renewable Heat Impact Assessment[115]	The IA assesses the target of 12% renewable heat in 2020 against low, central and high-high fossil fuel prices. Under high-high prices it finds a net present value (NPV) to 2030 from policy of £5.2 billion, under central fossil fuel prices it finds an NPV of -£7.7 billion (i.e. a £7.7 billion net loss) and under low fossil fuel prices an NPV of -£11.7 billion.
Renewable Energy Strategy Overall Impact Assessment[116]	Developing the previous findings, DECC's benchmark 'Scenario A' was subjected to fossil fuel price sensitivity analysis. This found that under high fossil fuel prices, the cumulative net benefit to 2030 is -£12 billion (i.e. a £12 billion net loss), under central prices it is -£56 billion, while with low fossil fuel prices the net benefit would be -£95 billion.
Fourth Carbon Budget[117]	The Committee on Climate Change compared their Medium Abatement Scenario under high and low fossil fuel prices. Under high fossil fuel prices, the Scenario represents a saving of 0–0.1% of GDP to 2025; under low fossil fuel prices it has a cost of 0.5% of GDP to 2025.
Electricity Market Reform Analysis of Policy Options[118] and Electricity Market Reform Impact Assessment[119]	The EMR IA contained resiliency analyses for low and high gas price scenarios, which will be analysed in more detail in the next Chapter.

The first key point to note from Table 9.1 is how assumptions about future gas prices have a major impact on the expected net costs/benefits of a given policy. If policymaking relies on modelling for cost-benefit assessments, assumptions

114 Department for Energy and Climate Change; *Energy Bill – Green Deal Impact Assessment;* London; 2010; pp. 126-127; http://www.decc.gov.uk/assets/decc/legislation/energybill/1002-energy-bill-2011-ia-green-deal.pdf

115 Department for Energy and Climate Change; *Impact Assessment of Proposals for a UK Renewable Energy Strategy – Renewable Heat;* London; 2009; http://www.decc.gov.uk/assets/decc/What%20we%20do/UK%20energy%20supply/Energy%20mix/Renewable%20energy/Renewable%20Energy%20

116 Department for Energy and Climate Change; *Impact Assessment of Proposals for a UK Renewable Energy Strategy;* 2009; http://www.decc.gov.uk/assets/decc/What%20we%20do/UK%20energy%20supply/Energy%20mix/Renewable%20energy/Renewable%20Energy%20

117 Committee on Climate Change; *The Fourth Carbon Budget;* London; 2011; http://downloads.theccc.org.uk.s3.amazonaws.com/4th%20Budget/CCC_4th-Budget_interactive.pdf p. 145

118 Redpoint Energy; *Electricity Market Reform Analysis of Policy Options*; London; 2010

119 Department for Energy and Climate Change and HM Treasury; *Electricity Market Reform – options for ensuring electricity security of supply and promoting investment in low-carbon generation*; London; 2010

made about the future can have a big influence on policies estimated costs and benefits. Resilience testing of the assumptions made about the future is thus very important. For example, policies expected to be net beneficial under one future price scenario (including carbon reduction benefits), could have large net costs under an alternative assumption about the future. This kind of resilience analysis can highlight vulnerabilities of particular policy choices. In the next chapter we will see how options considered under the government's Electricity Market Reform proposals show quite different vulnerability to future gas price uncertainty.

Second, there is a lack of consistency in the way such resilience analyses are presented in Impact Assessments (IAs) and similar documents. Sometimes specifically gas prices are used; other times fossil fuel prices generally. Sometimes all four (low, central, high and high-high) scenarios are presented – other times just a selection is used. Furthermore, as Platchkov et al have also noted, recommended options are not always subject to gas price sensitivity analysis. DECC's Electricity Market Reform IA did not present high/low gas price sensitivity analysis for the preferred policy combination (Contracts for Difference, Emissions Performance Standard, Carbon Price Support and the Capacity Tender), only for the individual components.[120] In an uncertain world, such resilience analyses should always be both conducted and published. Central scenarios are insufficient to make fully informed decisions about the relative desirability of particular policy options. Resilience analysis exposes weaknesses that would otherwise remain obscured. If policy is dependent on one particular future happening to make sense, it is not good policy.

Conclusions

This chapter looked at how projections of future gas prices are made and used in policy-making.

Assumptions about future gas prices have a major impact on the expected net costs/benefits of a proposed energy policy. For example, the government's Renewable Energy Strategy is projected to cost the UK £83 billion more (NPV) under low gas prices than under high.

DECC makes a range of projections for future gas prices. These appear to be slightly higher than the IEA's, but not substantially so, particularly since DECC's 2011 revision. DECC's central case now sees gas prices being very little higher in 2020 than today, and not consistent with alarmist talk of dramatically rising gas prices.

Nevertheless, as the previous chapter on uncertainty emphasises, prediction of future prices is impossible. Developments in relation to unconventional gas, in particular, and global demand mean that future prices could be high or they could be low. Overemphasising the Central case risks overlooking risks caused by policy if gas prices follow a higher or lower trajectory. It is important that clear attention is paid to the net costs/benefits of proposed policies under a range of future price scenarios.

Policy should be designed in a way that takes into account the major uncertainties. Options should be chosen, not on the basis that they might provide an optimal outcome should one particular projection prove correct, but rather because they are overall least harmful under the range of possible futures.

In Chapter 10 we turn to the question of policy design looking at the most recent major example – Electricity Market Reform.

120 Platchkov, Laura, et al; *The Implications of Recent UK Energy Policy for the Consumer*; Electricity Policy Research Group and the Consumers' Association; Cambridge; 2011; http://www.eprg.group.cam.ac.uk/wp-content/uploads/2011/05/ReportforCAFinal100511EPRG.pdf, p. 17.

10

Some Implications for UK Energy Policy of Global Gas Market Developments

The previous chapters have described the potential for shale gas and other global developments in the gas market to be positive both economically and for mitigating climate change, provided carbon policy is appropriately designed. This chapter focuses in more detail on some implications of future gas market scenarios for UK climate and renewable policies – specifically in relation to electricity generation.

Generation accounted for 34% of total demand for gas in the UK in 2010, a figure that has risen from 1% in 1990. Electricity generation has so far been the major focus for government carbon reduction and renewable energy policies. At present the most important policies for delivering electricity decarbonisation are the EU Emissions Trading Scheme (ETS), now linked to the UK carbon price floor, and the Renewables Obligation (RO). Further proposals (Electricity Market Reform (EMR)) are under development for a much larger government intervention in the market, to deliver low-carbon and renewable generation technologies.

When DECC consulted on its Electricity Market Reform (EMR) proposals, in December 2010, it modelled the costs and benefits to society of several policy options, testing them for resilience to the different gas price trajectories described in Chapter 9. (In 2011 updated EMR calculations were released, with some revised assumptions. We use the 2010 numbers as they are the only models under which the full range of policy options were assessed.)[121]

Those options were as follows:[122]

- *Carbon Price Support, reaching £50/tonne CO_2 in 2020 and £70/tonne in 2030 (CPS50)* "Carbon Price Support places a minimum price on the cost of carbon emitted by generators, thus increasing confidence in low-carbon investment. By underpinning future carbon prices it should better align government and investor future price expectations."
- *Premium Feed in Tariff (PFIT)*: "... [provide] additional revenues to low-carbon generators on top of those received by selling electricity into the wholesale market. The Premium Payments are designed to cover the additional costs of low-carbon generation relative to cheaper fossil fuel alternatives, including the higher perceived investment risk... The premia could be paid based on output, as is the case under the RO, or could be paid based on availability."

121 After significantly amending the 'business as usual' baseline case assumptions, e.g. in relation to various technology costs, the 2011 numbers made the government's preferred policy appear more cost-effective than in the 2010 figures. But nothing in the government's documents leads us to believe that these changed assumptions, had they been applied to all the original policy options, would have substantially altered their relative NPVs.

122 All descriptions from Redpoint Energy; *Electricity Market Reform Analysis of Policy Options*; London; 2010; http://www.decc.gov.uk/assets/decc/Consultations/emr/1043-emr-analysis-policy-options.pdf, pp. 32-47

- *Fixed Feed in Tariff (FFIT)*: "Fixed Payments, or feed-in tariffs, are payments made to low-carbon generators for their output. These payments are an alternative to selling electricity in the market and would involve a long-term contract between the generator and a central buying agency. This agency would be responsible for selling the aggregated physical output into the market."
- *Feed in Tariff with Contracts for Difference (CfD)*: "The principle behind Contracts for Difference is similar to Fixed Payments, in that it is a scheme for providing a stable earnings stream for low-carbon generation. The key difference is that generators retain responsibility for selling their physical output into the market. Under Contracts for Difference, the generator swaps an electricity index price for a fixed strike price and receives an additional Premium Payments depending on the technology type." In terms of the long-term prices received by generators, this option is quite similar to the fixed feed-in tariff.
- *Emissions Performance Standard (EPS)*: "An Emissions Performance Standard (EPS) would place limits on the amounts of carbon dioxide that could be emitted from generating plant. Its objective would be to discourage investment in high carbon generating plant, and thus incentivise investment in low-carbon technologies."

The work in this paper will largely concentrate on two of these options – CfDs, which emerged from the consultation as the government's preferred policy option, and carbon price support, as the most market-oriented option considered.[123]

Clearly, the government has announced that there will be a carbon price floor in addition to any CfDs. But this floor will be set at a less ambitious level than that modelled in the EMR, with the focus on near term revenue-raising rather than signalling long-term carbon pricing. It does not constitute a full and effective carbon pricing approach to electricity decarbonisation.

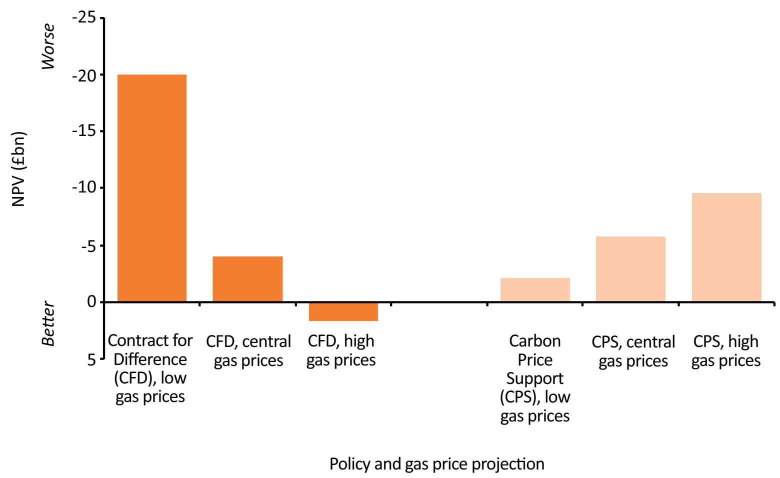
Why revisit a decision that the government appear to have made? First, legislation for Electricity Market Reform has yet to be published and much of the design is still to be decided. But second, as we have explored throughout this paper, circumstances have changed significantly. The development of shale gas production technologies has transformed gas markets overseas, and may do so in the UK. The government's presumption that gas price rises were inevitable was always questionable, but the developments in the gas market outlined in this paper make them more uncertain than ever. It is important that the future energy policy framework is capable of handling this uncertainty, which is why we have contrasted the rigid central planning approach of the government's CfD policy with the more flexible and adaptable market processes implied by a focus on effective carbon pricing, whether the latter is through a carbon price floor or (ideally) improvements to the EU ETS.

EMR cost-benefit analysis

The EMR Impact Assessment considers the costs and benefits of different policy options. It also assesses their sensitivities to different assumptions about a range of variables, including, of most relevance to this report, DECC's gas price projections (as reviewed in Chapter 9). DECC's Net Present Value (NPV) calculations for the CfD and CPS policy options under different future gas price scenarios are shown in Figure 10.1.

123 One distinction between CfDs and carbon pricing is that, while a carbon pricing approach solely targets greenhouse gas emissions, CfDs potentially allow for subordinate policy goals – for instance requirements for renewable generation to operate within the policy. As it is unclear what legitimate public policy purpose such subordinate objectives might have, its inferior method of tackling the key challenge of climate change mitigation is the focus of our discussion throughout this chapter.

Figure 10.1: Cost (NPV) of EMR policies under different gas price projections[124]



Accepting for the moment DECC's underlying estimated costs of the policies, Figure 10.1 shows CfDs offering a modest saving compared to CPS of £1.8bn under central gas price assumptions, and a more significant £11.3bn saving under high gas price assumptions. However CfDs are £17.9bn more expensive than CPS under low gas price assumptions.

If one could be sure that high gas prices were coming, this analysis would be one part of a case for CfDs. (However there are important reasons to believe that a central planning approach, with its weaknesses compared to the market in relation to information, incentives and dynamism, would not in practice deliver such savings). Under central prices the two are close enough in cost-benefit for this analysis to say little to inform a preference (the difference being, for example, the cost of 0.6 GW of Round 3 offshore wind today, or 0.8 GW in 2020, under Mott MacDonald's estimated learning trajectory).[125] Unlike carbon pricing, CfDs would be a substantial change to the market, and so would need a substantial net benefit to justify the risk of unintended consequences. Under low gas prices, the carbon pricing system looks much more attractive, using the assumptions in the cost benefit analysis. Both options lead to similar modelled carbon intensity of electricity in 2030 (i.e. the amount of carbon emitted to generate a unit of electricity).[126]

Given the future uncertainty about gas prices, all the modelled scenarios should play an important role in taking a policy decision. In addition, the ongoing changes in the gas business make a low price scenario, while by no means a certainty, more likely than it was a year or two ago. Yet DECC's policy conclusions in the EMR consultation appear to discount the very large policy costs of its preferred CfD option, compared to a carbon pricing approach, under a low gas price future. DECC has to consider a high gas price scenario to be far more likely than a low price scenario, or to discount the low and high gas price scenarios almost entirely, to justify preferring CfDs to a carbon pricing focused approach on an NPV basis.

124 Data from Redpoint Energy; *Electricity Market Reform Analysis of Policy Options*; London; 2010; http://www.decc.gov.uk/assets/decc/Consultations/emr/1043-emranalysis-policy-options.pdf, pp. 137-138

125 Difference in cost £1.815bn. Mott MacDonald estimates costs of Round 3 offshore wind at £3088/MW in 2011, and £2237/MW in 2020. Mott MacDonald; *Costs of Low-Carbon Generation Technologies*; 2011; http://hmccc.s3.amazonaws.com/Renewables%20Review/MML%20final%20report%20for%20CCC%209%20may%202011.pdf; p. 3–6

126 CfDs are projected to lead to 105 gCo2e/kWh in 2030 under low gas prices, 98 gCo2e/kWh under central gas prices and 150 gCO2e/kWh under high gas prices. CPS50 is projected to lead to 170 gCo2e/kWh in 2030 under low gas prices, 100 gCo2e/kWh under central gas prices and 90 gCO2e/kWh under high gas prices.

The EMR costs (benefits) are not total policy costs, but are increments to the cost of the government's existing policy settings. This mainly consists of the existing 2020 Renewable Energy Strategy for centralised electricity, which was estimated to cost a huge £45.7 billion (negative NPV).[127] Figure 10.1 should not therefore be taken to represent anything like the total costs of government electricity policies.

The government portrays its choice of CfDs as being a way of reducing risk, by reducing exposure to future high (and volatile) gas prices. But, as Figure 10.1 shows, it appears to be choosing a risky option. If gas prices fail to rise by as much as the government is betting on, its preferred approach to Electricity Market Reform will impose very large additional policy costs on the public, on top of unnecessarily high carbon reduction policy costs already in place in the Renewable Energy Strategy. Using DECC's own figures, opting for CfDs exposes bill payers to potential policy costs more than £10bn higher, if gas prices are low, than a carbon pricing approach would if gas prices turned out instead to be high The carbon pricing structure appears the better of these options as this approach does not over-emphasise one future scenario, but tries to take into account the range of possible scenarios. As such, it represent a gamble on gas prices a decade and more from now – one being made with billpayers' money.

Problems with contracts for difference

The government's preferred (CfD) approach also carries another important type of risk. The approach requires a central decision maker (government or a quasi-government agency) to take decisions on capacity levels, generation mix and prices paid, instead of the market. This substantially reduces the market's role in responding to price signals and new information as that emerges, including about fossil fuel prices, technology costs. Such new information should be feeding into market decision-making in a timely way, so that market players can begin to respond by altering investment and innovation plans and portfolios, and operation decisions. Instead a central planner has less information and fewer incentives to make and adapt decisions in a way which minimises the costs of keeping the lights on and reducing carbon.

Furthermore, the change to a CfD system requires a much more fundamental overhaul of the UK electricity market than a carbon pricing focused policy approach. The risk of unintended consequences is higher, the more profound the reform undertaken. DECC should therefore be looking not just for a small positive NPV under its central case (and robustness to possible high and low carbon price scenarios) but a substantial overall positive benefits to justify a change as drastic as is proposed for CfDs. It is hard to see that the case has been made.

So far, the analysis presented has accepted the modelled numbers from the Electricity Market Reform Impact Assessment at face value. However, there are assumptions, made in the course of that analysis that cast further doubt on the estimates of costs and benefits in the IA.

DECC's model constrained investor confidence in the carbon price to five years out – the length of a Parliament – on the assumption that government could alter the carbon price at any time.[128] A more long-term certain carbon price would deliver more effective signals for low carbon investment at any given carbon pricing level, making this policy option more attractive relative to

127 Department for Energy and Climate Change; *Impact Assessment of proposals for a UK Renewable Energy Strategy – Renewable Electricity*; http://www.ialibrary.bis.gov.uk/

128 "There is a possibility that investors would discount stated future price levels on the basis that these could be changed as a result of future government decisions. For the purposes of our modelling, we assume that investors have certainty in the Carbon Price Support level for a five year period, but do not assume any increase beyond that. (We have also modelled a sensitivity where investors believe that the Carbon Price Support falls away completely after five years.)" Redpoint Energy; *Electricity Market Reform Analysis of Policy Options*; London; 2010; http://www.decc.gov.uk/assets/decc/Consultations/emr/1043-emr-analysis-policy-options.pdf, p. 34

the others than DECC's modelling found. For example, a carbon price as high as £50 in 2020 might not be required. But policy options for directly increasing confidence in the carbon price for a longer time horizon were not considered in the EMR consultation. For example, the government could have looked in addition at contracting to guarantee the *carbon price* for a period longer than five years, rather than the whole electricity price as they propose.[129]

> "The change to a CfD system requires a much more fundamental overhaul of the UK electricity market than a carbon pricing focused policy approach. The risk of unintended consequences is higher, the more profound the reform undertaken"

The assumption of a 5 year carbon price horizon drives some of the estimated benefits of the CfD option over and above the carbon pricing approach, and therefore an alternative assumption could be expected to reduce the benefits of the CfD option in comparison to carbon pricing.

Moreover, the assumption that CfDs would lead to a more certain platform for investment, and thus lead to lower finance costs, seems at least debatable. The market would seem unlikely to view contracts for difference (backed or enforced in some form by the government) as long-term certain, because of the risk that they turn out to be much more expensive than market prices and thus are politically unsustainable. This lack of certainty is reinforced by the apparent reticence of HM Treasury even to underwrite these long-term contracts.

Finally, the effect of the CfD is not to remove risk, merely to reallocate it. By shifting the risk away from generators and on to customers, the cost of capital may fall for generators, but the risk has not disappeared. Customers, instead of generators, will pay for the risks and any mistakes in investment decisions.

Making decisions under uncertainty

There is, however, a more fundamental problem with the entire approach, one which Professor John Kay diagnosed in testimony to the House of Commons Public Administration Select Committee. That problem is the reliance for policymaking on models of the future that "pretend we know things we don't", "quantifying things that aren't sensibly quantified". The models that DECC uses are very impressive in their degree of detail, and very authoritative-sounding in the numbers they produce. Much of that amounts to what Kay describes as "bogus rationality". "We work out all the information we'd ideally need to make this decision, [but] we know we don't know any of it, so you build a model and make it all up so that every cell in the spreadsheet gets filled in."

Kay concludes, "these models are basically rubbish. The right way to think about it is to say 'let us think about the things we don't know, and can't know', and ensure that though there's a wide range of possible developments about fuel prices and greenhouse gas emissions and nuclear security, whatever happened we would have outcomes that would be relatively robust to these."[130] Technology-neutral and effective climate and energy policies enable markets to adapt as knowledge evolves and emerges accomplish this. The government's proposed approach fails this test.

129 Redpoint Energy; *Electricity Market Reform Analysis of Policy Options;* London; 2010; http://www.decc.gov.uk/assets/decc/Consultations/emr/1043-emr-analysis-policy-options.pdf, p. 81

130 Kay, John; Testimony to the Public Administration Select Committee; 24 January 2012; http://www.johnkay.com/2012/01/24/public-administration-select-committee

UK carbon target implications

The government is currently trying to meet a number of binding and non-binding targets and aspirations for decarbonising the UK economy. These include:

- Carbon budgets stipulating the permissible greenhouse gas emissions over a five-year period, which have been set through to 2027. These require a 34% reduction in UK emissions by 2020 and a 50% reduction in emissions by the 2023–2027 budget.
- EU target for greenhouse gas reduction, in part set through the Emissions Trading Scheme, to reduce EU-wide emissions 20% between 1990 and 2020.
- EU target for renewable energy to account for 15% of final energy consumption (implying around 35% of electricity generation) by 2020.
- An 80% reduction in greenhouse gas emissions by 2050.

Would a carbon pricing based policy approach, implying the use of more unabated gas in the pre-2030 period, jeopardise these targets?

The 2020 renewable energy target would certainly be more difficult to meet in the absence of huge subsidy specifically for renewable generation. However, as previous Policy Exchange work has concluded, meeting the 2020 Renewable Energy Target is neither necessary nor desirable for meeting the UK's 2020 or 2050 carbon targets.[131]

The Committee on Climate Change has recommended that – as a staging post to the UK's 2050 carbon target – UK electricity should carry a carbon content of less than 50g/kWh in 2030, while the government's analysis of EMR policy options assumed a target of 100g/kWh. As discussed earlier, DECC's analysis of EMR policy options has suggested that a carbon pricing focused approach, which would enable significant new gas generation provided gas prices were low enough, could be consistent with 100g/kWh in 2030. But such an approach would not give *certainty* of meeting such a target.

How important is certainty is meeting a target in 2030 for carbon emissions in one particular sector, the *UK electricity sector*? In terms of direct impact on climate change, the level of the overall EU ETS cap (which includes UK electricity emissions) matters much more. And as already discussed, unilateral UK policy action in relation to electricity emissions will not affect whether that cap is met.

In theory, one can make the argument that, if the UK was successful in meeting a more stringent UK electricity decarbonisation target in 2030, then the EU as a whole *might* agree to accelerate the reduction in the EU cap in the 2040s. But what seems much more important than this tenuous argument is how the UK goes about meeting any of its targets.

The UK accounts for a small proportion of global emissions (around 2%), so the direct impact UK decarbonisation can have on the global climate is very limited. The value of actions taken in the UK must therefore primarily be measured against other criteria – whether we are developing and reducing the cost of technologies of global scalability, and whether we are setting an example in policy design or implementation compelling enough that other governments will want to follow. For example, one could argue that reaching 120g/kWh in 2030 but developing a cost-competitive coal carbon capture and storage technology that could be used to reduce emissions from coal generation around the world would be more

131 Moore, S; *2020 Hindsight*; 2011; http://www.policyexchange.org.uk/publications/publication.cgi?id=239

valuable than reaching 50g/kWh in 2030 with technologies that are either too expensive to attract other countries, or inappropriate to their geography. (Carbon emissions in EU electricity sector will be unaffected in 2030 either way.)

Of course, it may not be obvious to everyone how utilising more gas generation in the UK would be compatible with these objectives of low carbon leadership and innovation. And indeed, if the only outcome was more gas generation then relatively little would be gained. But we need to remember that gas generation is presently much cheaper than most renewable generation (most relevantly, the marginal renewable, offshore wind). It is roughly comparable with nuclear once a carbon price has been applied, but far more straightforward to install. Using Mott MacDonald's levelised cost estimates for DECC, a TWh of gas generation comes in around half the cost of the same amount of Round 3 offshore wind generation today, under Central gas and carbon price estimates.[132]

The savings in energy costs from utilising gas generation effectively provide a large pot of resources which society can choose to deploy. Invested in effective innovation support – research, development and demonstration, and early stage deployment of a range of low carbon technologies with global potential. The climate impact could be far greater than spending the money mass deploying hugely expensive offshore wind, which seems unlikely to become a cost-competitive major global contributor to carbon reduction. And carbon emissions from electricity, under the EU ETS cap, would be the same under either approach.

The European Commission's 2050 'Energy Roadmap' also shows, in its 'Diversified Supply Technologies' scenario that an *increase* in gas fired-generation compared with today at an EU-wide level, is compatible with 80–95% carbon reduction compared with 1990 levels. This is the outcome the Commission's modellers projections, unless some other technology group is given preferential treatment.[133]

Conclusions

The government's proposals for Electricity Market Reform based on Contracts for Difference are unsuited to a world of considerable uncertainty, in particular about future gas prices. They gamble with bill-payers money on a high gas price future and risk imposing a high policy cost on consumers if that does not materialise.

As long as the UK is part of the EU ETS, no unilateral action to drive faster UK electricity decarbonisation, including CfDs, will result in lower EU emissions than set by the ETS cap. All it can do is to alter how much of the burden for meeting that cap is borne within UK borders. Higher UK-only carbon prices and all other national emissions reduction policies in industrial sectors covered by the ETS, have zero impact on overall EU carbon emission up to 2020.

So given the assumption that the ETS continues, and the desirability of a geographically broad carbon market, the policy should be to focus on bolstering carbon pricing using the ETS mechanism. Focusing on a strengthened EU ETS would, if gas prices turn out to be cheaper than previously expected, allow gas generation to play a substantial role as a transition fuel, while ensuring required emissions reductions are achieved. Lower gas prices could feed through to lower energy costs. And lower energy costs enable more resources to be devoted to stimulating the low carbon innovation needed to achieve 2050 carbon targets.

132 The two key Mott MacDonald levelised cost publications, the *Costs of Low-Carbon Generation Technologies* (2011) and *UK Electricity Generation Costs Update* (2010) do not give information that is exactly comparable. The 2011 document is preferred where possible, but does not include data for non-CCS gas generation, making it insufficient for this comparison. The 2010 document does present costs for offshore wind and unabated gas generation, but does so for different years, and with older assumptions than the more recent document. The 2011 document suggests a range of around £140–180/MWh for offshore wind today, £80–140/MWh for offshore wind in 2020. The 2010 document put the costs of a CCGT gas plant (including carbon costs) at £80/MWh with a 2009 start date, rising to £110/MWh by 2023 (with the difference made up predominantly by the carbon price, rather than the capital or fuel costs).

133 European Commission; *Energy Roadmap 2050*; 2011; p. 11

Recommendation

1. The government should recast its proposed approach to Electricity Market Reform proposals in a way that enables the market to deliver electricity market decarbonisation (subject to the EU ETS cap) in the most cost-effective ways. The government's proposals for Electricity Market Reform (EMR) based on Contracts for Difference are unsuited to a world of considerable uncertainty, in particular about future gas prices. They gamble with bill-payers money on a high gas price future, and risk imposing a very high policy cost on consumers if that does not materialise. Using DECC's own figures, the government's preferred EMR policy option would cost £18 billion more if gas prices are low in future, than an alternative carbon pricing focused approach – around £7 billion more than any estimated saving if gas prices turned out to be high despite shale gas developments.

11

Summary of Policy Recommendations

- **Harness potential economic benefits of shale gas production, both in the UK and worldwide.** The emergence of shale gas challenges presumptions that have been made about the future role of gas in the global and domestic energy mix. While much uncertainty remains, predictions of rising prices cannot be taken as inevitable. A future scenario of relatively plentiful gas would have economic benefits in terms of more affordable energy. To the extent that gas would displace coal in the global energy mix, it could have substantial benefits in constraining green house gas emissions.
- **Commit to longer-term carbon pricing framework.** There needs to be an increasing focus on credible, consistent and long-term carbon pricing frameworks, which enable gas to play a positive role as a cheap, lower carbon transition fuel, but ensure that investors have clear signals about the long-term carbon reductions needed. Given that the UK and other member states are going to continue with the ETS, their focus should be on creating a longer term, more certain carbon cap. Creating effective banking and borrowing mechanisms, should also have the effect of bringing permit prices up today – one of the objectives of those arguing for a tighter 2020 cap. There should at all times be clarity about the cap or price at least 15 years in advance. Work should begin immediately on establishing the Phase IV cap, with the intent to establish that cap through to at least 2035 at a level in accordance with scientific understanding about required emissions reductions. If after Phase IV negotiations, it becomes clear that the political or market design challenges to the ETS have not been overcome, and the ETS, in the wider policy context, remains inadequate to the task of providing a long-term, credible carbon pricing framework, then the arguments for shifting to an EU-wide carbon tax are likely to become stronger. Either way, the key is to have a credible long term pricing framework.
- **Deploy potential savings from greater use of gas to fund research and development with global potential.** The economic benefits from any substantial expansion of gas's role in the energy mix ought to help fund investment in researching, developing, demonstrating and early deployment of promising new low carbon technologies, with potential to be cost-competitive and have global impact.
- **Devote more resources to Carbon Capture and Storage for *both* coal and gas generation.** In the context of potentially increasing gas penetration, it makes

sense to prioritise support for research, development and demonstration into gas carbon capture and storage technologies, so that it might be possible for gas to play a role a long-term low carbon fuel. The UK and other EU governments should devote greater resources and political will to CCS research. The size of that commitment should reflect the current shortfall in research development and demonstration (RD&D) investment, which the IEA estimates at between $8 billion and $17 billion per year globally. The UK government's continued commitment to a future prize fund for CCS demonstration is a welcome start, and opening it to coal and gas entrants reflects the shifting global generation mix. However, with such a large potential contribution to worldwide decarbonisation, CCS RD&D is still under-resourced.

- **The government should recast its proposed approach to Electricity Market Reform proposals** in a way that enables the market to deliver electricity market decarbonisation (subject to the EU ETS cap) in the most cost-effective ways. The government's proposals for Electricity Market Reform (EMR) based on Contracts for Difference are unsuited to a world of considerable uncertainty, in particular about future gas prices. They gamble with bill-payers money on a high gas price future, and risk imposing a very high policy cost on consumers if that does not materialise. Using DECC's own figures, the government's preferred EMR policy option would cost £18 billion more if gas prices are low in future, than an alternative carbon pricing focused approach – around £7 billion more than any estimated saving if gas prices turned out to be high despite shale gas developments.
- **There is currently no need for a moratorium on shale gas production.** Concerns about risks from shale gas production in relation to water quality, seismic activity and water scarcity need to be taken seriously, but, on the basis of current evidence, do not justify a moratorium on shale gas production.
- **Maintain strong regulatory regime.** Many of the failings of the shale experience in the US have been failures of regulation. In contrast, the UK regulatory regime, developed in part from the experiences of the North Sea and in part from the far smaller, but nevertheless lengthy, UK experiences of onshore oil and gas production and mining activity, sets strong but sensible boundaries for producers. Groundwater protections and waste treatment regulations are stronger in the UK than many parts of the US. Likewise, requirements about chemical disclosure are more forceful in the UK. Looking to the future, it is important that the UK maintains a strong and effective regulatory regime, which addresses any new problems that arise, and enables a safe shale production sector to develop. The review that the Environment Agency is currently conducting of the body of regulation to ensure that it fully covers the exploitation of shale gas is a welcome step. In particular, future exploration and drilling should feature the strict real-time monitoring and seismicity-conscious operating procedures suggested by the inquiry into the Preese Hall tremors.
- **Improve data on fugitive emissions.** Industry and regulators should take steps to improve the quality of information on fugitive emissions from drilling sites to help ensure methane losses are minimised. Relevant UK agencies should collect data on emissions at production sites, either directly

or by establishing a requirement on producers to do so. Best practice from around the world should be shared. Companies must also be forthcoming with relevant data. This process should be undertaken in coordination with similar efforts occurring overseas (especially in the US).

The technological developments that have led to the emergence of shale gas have great potential to shape the future of the energy market. While a lot of uncertainty remains about the future, presumptions that have been made about inevitably high future gas prices need to re-examined. *Gas Works?* finds that any future scenario of relatively plentiful gas would have significant economic benefits, with more affordable energy prices than have been expected. And to the extent that gas displaces coal in the global energy mix, it could constrain greenhouse gas emissions.

The report finds that it is even more important that long-term climate policy is enhanced. to take full advantage of the potential benefits, and to ensure that the development of gas is consistent with carbon emissions reduction targets. In the EU, a longer-term, more certain Emissions Trading System cap is needed. The carbon cap needs to be extended as soon as possible to at least 2035, at a level consistent with scientific understanding about required emissions reductions. This would allow gas to play its role as a transition fuel in electricity generation consistent with long-term carbon reduction targets. There also needs to be a greater focus on stimulating the most promising low carbon innovations.

This report also finds that the risks from shale gas production in relation to water quality, seismic activity and water scarcity need to be taken seriously, but on the basis of current evidence, do not justify a moratorium on production. Many of the failings of the shale gas experience in the US have been failures of regulation. In contrast, the UK regulatory regime, developed in considerable part from the experiences of the North Sea, sets strong boundaries for producers. The UK government has so far struck roughly the right balance in its approach to shale gas production in the UK. It must maintain a strong and effective regulatory regime, which addresses any new issues that arise, and enables a safe shale gas production sector to develop in which the public can have confidence.

£10.00
ISBN: 978-1-907689-16-1

Policy Exchange
Clutha House
10 Storey's Gate
London SW1P 3AY

www.policyexchange.org.uk