House of Commons

Energy and Climate Change Committee

The Impact of Shale Gas on Energy Markets

Seventh Report of Session 2012–13

Volume I

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The Energy and Climate Change Committee

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Contacts

All correspondence should be addressed to the Clerk of the Energy and Climate Change Committee, House of Commons, 7 Millbank, London SW1P 3JA. The telephone number for general enquiries is 020 7219 2569; the Committee's email address is ecc@parliament.uk

Contents

Report

Conclusions and Recommendations

The US shale gas revolution

1. We conclude that because the US is the only country to have developed a shale gas industry, it can serve as a useful case study when considering how a shale gas industry might develop in the UK. Some of the factors which facilitated the US revolution, however, do not apply to the UK and so development of the UK's shale gas industry is likely to be different to the experience of the US. *The UK should learn the lessons of the US experience, including creating a favourable climate for companies to operate in, while ensuring environmental damage is avoided.* (Paragraph 13)

Defining shale gas estimates

2. We conclude that it is right for the Government to exercise caution over shale gas estimates given the uncertainty and confusion over definitions. *If and when the Government does decide to issue estimates of UK shale gas resources it should set a good example and ensure that it is explicit about which definition it is using. We recommend that it should use the definition which is most relevant to the general public, which in our opinion is recoverable resources. The Government should also clearly communicate the uncertainty inherent in some of these figures by emphasising the difficulty of producing an accurate estimate of shale gas.* (Paragraph 16)

Calculating shale gas estimates

3. We conclude that it is impossible to determine reliable estimates of shale gas in the UK unless and until we have practical production experience. *Therefore, if companies can demonstrate that they can meet the required standards the Government should encourage exploratory shale gas operations to proceed in order to improve current estimates, providing that public concern over environmental impacts is recognised and taken into account. It should require shale gas companies to share their gas content and production figures with relevant research bodies (subject to commercial confidentiality).* (Paragraph 21)

Latest shale gas estimates

4. While it is unlikely that offshore shale gas will be pursued in the near future, strategically, it may have the most potential for the UK in the medium- to long-term, especially if it avoids public opposition associated with onshore operations. *We repeat the recommendation made in our previous report that DECC encourage the development of the offshore shale gas industry in the UK, working with the Treasury to explore the impacts of tax breaks to the sector. This must be done before the UK's North Sea oil and gas platforms are decommissioned, otherwise the opportunity to utilise the UK's offshore oil and gas assets may pass.* (Paragraph 29)

Public perception

5. One key to community acceptance will be a robust factual response by government to scare stories. The other key to ensuring public acceptance of the shale gas industry is community engagement. Engagement should be early and businesses need to be able to demonstrate that they are both listening and responding to community concerns. *The Government should consider whether it would be appropriate for the new Office of Unconventional Gas and Oil to provide advice and support to local communities living near potential shale gas developments, taking into account the need to address perceptions that the Office may be too closely linked to industry.* (Paragraph 34)

6. Communities who are affected by shale gas development should expect to receive, and share in, some of the benefits of the development. We support the Government's intention to ensure that local communities will benefit from shale gas projects in their area. *We recommend that the Government explores ways of sharing substantial material benefits with local communities. In the same vein as the recommendation in our Building New Nuclear report, one option the Government could consider is extending the scope of its proposal to allow local authorities hosting renewable energy projects to retain business rates to include shale gas developments. A mechanism for sharing substantial material benefits with local communities should be ready to be offered to communities in time to encourage them to take a positive view of the prospect of commercial shale gas operations beginning in their locality.* (Paragraph 37)

Regulation

7. We welcome the Government's attempts to minimise the regulatory burden on companies by streamlining processes and avoiding duplication where possible. However, robust regulation of the sector in order to protect the environment and ensure the health and safety of workers is absolutely essential in itself as well as to ensure that the shale gas industry is to be accepted by the general public. *We recommend that the Government maintains the highest standards of protection in environment and health and safety procedures. When the Government provides detail of the objectives, remit and responsibilities of the Office of Unconventional Gas and Oil should include clear lines of accountability to a single Minister responsible for the Office. The Government must also demonstrate how it intends to avoid any potential conflict of interest arising from the different roles of the Office.* (Paragraph 43)

Tax

8. *The Government should make an assessment of whether these tax breaks will continue to be required during commercialisation.* (Paragraph 47)

Impact of foreign shale gas on UK gas prices

9. We conclude the shale gas revolution in the US has the potential to influence the nature of gas markets around the world. In particular, it could stimulate greater use of gas-to-gas competition in spot markets to determine gas prices rather than oil-

indexation. However, this would not necessarily guarantee that the price of gas will fall. (Paragraph 52)

10. We conclude that if the US were to begin exporting its shale gas as LNG, the UK might find it economically attractive to import some of this gas. However, the significant transportation costs associated with shipping LNG, combined with expected demand for LNG from Asia, means that the price for this gas in the UK is likely to be significantly higher than that experienced in the US. (Paragraph 56)

Impact of domestic shale gas on UK gas prices

11. We conclude that it is too early to say whether domestic production of shale gas could result in cheaper gas prices in the UK. It is unlikely that the US experience will be directly replicated in the UK because of differences in geology, public attitudes, regulations and technological uncertainties. Shale oil is likely to be present in the UK but it remains uncertain whether industry will consider shale oil economically worthwhile to explore. (Paragraph 61)

Impact of foreign and domestic shale gas on UK gas markets

12. We conclude that there remains substantial uncertainty about the impact shale gas will have on gas prices, both internationally and domestically, and it is by no means certain that prices will fall a result of foreign or domestic shale gas development *It would be wrong for the Government to base policy decisions at this stage on the assumption that gas prices will fall (it is possible that they will rise) in the future. However, if large quantities are found they will either bring down prices in the UK, or generate substantial tax revenues, or both – and will certainly reduce imports with benefits to our balance of payments and energy security. For all these reasons the Government should encourage exploration to establish whether significant recoverable reserves exist.* (Paragraph 64)

Global emissions

13. We conclude that although development of shale gas in the US has reduced America's greenhouse emissions this may have been offset by increased use of the coal in Europe. This highlights the importance of improving the EU ETS to ensure it is able to deter the consumption of unabated coal for electricity generation. (Paragraph 68)

UK emissions

14. *We recommend that the Government should complete its research into the impact which shale gas extraction could have on greenhouse gas emissions as quickly as possible so that the data can be used when considering applications for licenses for commercial scale extraction. Policies on flaring and venting of methane should be reviewed in light of the study in order to ensure that fugitive emissions from fracking are kept as close to zero as possible. DECC should also monitor the methane emissions of those companies that are currently exploring for shale gas. It should be possible, by*

way of regulation, to ensure that fugitive emissions are prevented by outlawing venting. (Paragraph 73)

15. We conclude that the Government needs to recognise that the unchecked development of gas-fired generation, which the development of shale gas may facilitate, might be incompatible with meeting the UK's climate change obligations. *As we have recommended before the Government should implement an emissions performance standard (EPS) that gets tighter over time so as to include unabated gas-fired plant and avoid excessive gas "lock-in". However we do recognise there will be a role for unabated gas as peaking plant and to balance intermittent renewable sources. If shale gas does prove to be plentiful and either cheap or yielding substantial tax revenues it would be sensible to put far more emphasis on developing CCS.* (Paragraph 77)

16. We share SSE's frustration at how long it is taking to develop CCS especially as it is clear that the Prime Minister sees it as critical to meeting our future climate change targets. The speed of commercial development of CCS will affect whether it can play a meaningful role in the UK's energy mix and how much gas we can rely on without conflicting with the UK's climate change targets. While we are pleased to hear in the Budget that the Government will take two CCS projects to the next stage of the CCS commercialisation competition, *we recommend the Government needs to conclude its CCS competition as soon as possible and bring forward CCS demonstration projects to allow it to be deployed in time to contribute towards meeting our carbon budgets. Unless progress towards economically viable CCS accelerates rapidly in the next three years, it will become impossible to base UK energy policy on the assumption that it will be available in time to help meet the decarbonisation recommendations of the Committee on Climate Change. We intend to keep a close eye on DECC's progress in this area.* (Paragraph 81)

17. *We recommend the Government push through its reforms to the electricity market, as set out in the Energy Bill, without delay. This will discourage the unchecked development of unabated gas-fired generation and create a favourable investment climate for low carbon technologies which could help to avoid gas "lock-in".* (Paragraph 86)

Security of supply

18. *We recommend that Government should not rely on shale gas contributing to the UK's energy system when making strategic plans for energy security. We welcome the commitment made by the Minister that the new Office for Unconventional Oil and Gas will assess the effects of shale gas development on the UK's security of supply – providing we can be reassured that that the Office does not have a conflict of interest.* (Paragraph 90)

Economic benefits

19. *We recommend that Government encourage partnerships such as the one between Cuadrilla and the University of Central Lancashire to ensure the skills required to develop the shale gas industry are available. Government should make an assessment of the need for skills development and should work with industry and the relevant sector skills council to develop a skills action plan for shale gas similar to the Nuclear Supply Chain Action Plan which the Government has recently published.* (Paragraph 93)

20. If shale gas development produces cheaper gas prices in the UK, as a result of the export of shale gas from the US and the development of shale gas in the UK, the energy intensive industries could benefit from lower electricity and chemicals prices. (Paragraph 96)

1 Introduction

1. We last examined the issue of shale gas in 2010-11.[1] At that time we concluded that, even though shale gas resources in the UK could be considerable, they were unlikely to be a "game changer" to the same extent as they have been in the US. Our Report focused mainly on the environmental impact of shale gas in response to public concern at that time. Since that inquiry there have been two significant changes. First, there have been new shale gas estimates both in the UK, and globally, which have fluctuated significantly, and second, there is speculation that a "shale gas revolution" will bring an era of abundant, cheap gas. Our aim was to investigate these claims.

2. We launched our inquiry in September 2012. We received 35 submissions of written evidence, for which we are grateful.[2] We held three oral evidence sessions. A full list of witnesses can be found at the end of this report.[3] We would like to express our thanks to all those who contributed to our evidence-gathering.

3. In this Report we consider the implications of the "shale gas revolution" for energy markets around the world. In chapter 3 we review the prospects of shale gas assessing the reliability of new figures in the context of significant uncertainty. In chapters 4 and 5 we assess the potential impact of shale gas on energy markets and climate change mitigation globally, in Europe and in the UK. In chapters 6 and 7 we also consider other potential impacts on the UK and key issues the Government will need to consider when developing its own shale gas industry.

1 Energy and Climate Change Committee, Fifth Report of Session 2010-12, Shale Gas, HC 795

2 List of written evidence, p 48

3 Witnesses, p 47

2 Background

The US shale gas revolution

4. The United States (US) is one of the few countries to have developed shale gas at a commercial scale. The impact shale gas has had on US energy market and its wider economy has been described in terms of a "revolution" which could have impacts globally. Mr Yeager, Chief Executive of Petroleum and Group Executive Officer of BHP Billiton, told us that, "there is a huge abundance of shale gas and it will have a worldwide impact."[4] The US has a specific set of circumstances which allowed the industry to develop and which, importantly, differ to other countries especially the UK. Nevertheless, as the only example of a fully functioning shale gas industry, the US experience serves as a useful comparator when looking at how a shale gas industry might develop in the UK.

5. The US shale gas revolution has been roughly twenty years in the making.[5] Previously, US production of conventional oil and gas was in decline.[6] In response, the US Federal Government sponsored research and development methods to estimate the volume of gas in unconventional natural gas reservoirs and to improve ways to extract the gas.[7] An unconventional fuel production credit was introduced that applied to certain unconventional fuels including, for a time, natural gas produced from, "... Devonian shale,[8] coal seams, or a tight formation...".[9] These measures were designed to incentivise the development of US unconventional resources, though some witnesses suggested they did not play any significant part in accelerating shale gas development.

6. Rapid technological progress, supply chain development, a favourable regulatory regime, low population density, and mineral rights (which generally confer to the landowner), allowed the shale gas industry to flourish.[10] Mr Yeager described how the regulatory regime in the US is stringent but reasonable and has a "let's get it done" approach.[11] He also explained that most areas that are being drilled are sparsely populated and in some places have "more cows than people."[12]

7. The development of shale gas has prompted a strong resurgence in domestic production and, the US is now heading towards self-sufficiency.[13] In fact, the US is now looking at the potential to export its shale gas as liquefied natural gas (LNG).[14] The LNG import terminals

4 Annex 1: note of informal meeting with BHP Billiton

5 Q 78 [Professor Stevens]

6 Ev 81; Annex 1: note of informal meeting with BHP Billiton

7 Q 58 [Professor Stevens]; Qq 91-92; Department of Energy, Shale Gas: Applying Technology to Solve America's Energy Challenges, March 2011, www.netl.doe.gov

8 Devonian refers to rocks formed during the Devonian period of geologic time (approximately 350 million years ago).

9 Q 70; Ev w20; Congressional Research Service, Energy Tax Policy: Historical Perspectives on and Current Status of Energy Tax Expenditures, 7 May 2010, www.crs.gov

10 Q 63 [Professor Stevens]; Q 108 [Mr Tiley]; Q 307 [Chris Barton]; Annex 1: note of informal meeting with BHP Billiton

11 Annex 1: note of informal meeting with BHP Billiton

12 Annex 1: note of informal meeting with BHP Billiton

13 Ev w20; Annex 1: note of informal meeting with BHP Billiton

14 Ev 81

which were built prior to the shale gas revolution (in order to compensate for the decline in indigenous production) are now underused and many are applying to be converted into export terminals.[15] The large quantity of shale gas coming onto the US market, combined with an inability to export the gas has seen the US gas price reduce from around $12 to $3 per million British thermal units (Btu) in just a few years.[16] The US now has the cheapest gas market in the world.[17]

8. Cheap gas prices in the US have had a significant impact on its economy and according to the Minister, "it has arguably increased American competitiveness." This includes, for example, providing feedstocks to the petrochemical industry which has seen a revival.[18] A report by IHS Global Insight found that in 2010 the US shale gas industry had supported 600,000 jobs, contributed $76 billion to GDP and generated roughly $19 billion in federal, state and local government tax and federal royalty revenues.[19]

9. Its abundance has seen gas displace coal as the favoured fossil fuel for electricity generation contributing to the dramatic reduction in US greenhouse gas emissions.[20] Mr Yeager pointed out that, "in the US, we have met our Kyoto targets, despite never signing the agreement; due to coal consumption being replaced by natural gas."[21]

10. Witnesses told us that some companies are making a loss because the cost of production is higher than the market price of gas.[22] Despite this, production of shale gas in the US has continued to grow as a result of both improvements in technology and the co-production of shale oil.[23] Many places in the US which have shale gas also have shale oil. It has been suggested that shale oil is now the main target of US shale gas companies because it currently commands a higher price than shale gas.[24] Professor Stevens of Chatham House told us that whether the shale gas revolution will continue to be economic depends on:

> "How much money you can make out of the liquids that you are producing during the shale gas operations. If the shale gas is fairly wet then, even though the dry gas you are selling is not earning you any money, you will earn a lot of money from producing the liquids and that is the key to the continuation of the revolution in the US at the moment."[25]

15 Q 59; Q 72; Q136 [Mr Tiley]; Ev 81

16 Q 231 [Mr Parsons; Mr Pibworth]; Q 293

17 Q 61 [Dr Bros]

18 A feedstock is a basic material from which a product is manufactured. This material is usually in an unprocessed or minimally processed state. In the case of the petrochemical industry a feedstock could include ethane, propane or butane obtained primarily from natural gas processing plants.

19 Q 61 [Professor Bradshaw]; Q 62 [Professor Stevens]; Q 293; Annex 1: note of informal meeting with BHP Billiton; Ev w20

20 Q 61 [Mr Moore]; Q 63 [Dr Bros]; Q 73 [Dr Bros]; Ev w20

21 Annex 1: note of informal meeting with BHP Billiton

22 Q 6 [Mr Smith]; Q 23 [Professor Davies]; Q 61 [Dr Bros]; Q 160 [Professor Anderson]; Ev 136

23 Q 30; Q 61 [Dr Bros]

24 Q 6 [Mr Smith]; Q 23 [Professor Davies]; Q 30; Q 61 [Professor Bradshaw]; Q 252 [Mr Parsons]

25 Q 63 [Professor Stevens]

11. According to Mr Parsons of National Grid, shale gas is, "not necessarily cheap gas" and tends to cost more than conventional gas to produce.[26] It may be that the current glut of gas in the US market which has been caused by shale gas and which has caused prices to fall as low as they have, is only temporary. Gas prices could, therefore, rise again in the future. Companies may decide to scale back production in response to low prices. Gas prices could, therefore, rise again in the future to a level at which development is economic - though that is probably well below the world price. Tightening environmental regulations in relation to shale gas production, depletion of easier sources of gas and development of US export potential could also contribute to price rises.[27] Mr Yeager is confident that shale gas in the US has a long future. He told us that, "our great grandchildren will be drilling for shale gas.".[28]

12. Concerns were expressed about the environmental sustainability and social impact of shale gas extraction in the US.[29] These concerns include the potential for ground water contamination and seismic activity.[30] The industry recognises that its operations have the potential to adversely affect individuals, communities and the environment but it says it works hard to mitigate any potential negative impacts.[31] Mr Yeager told us that:

> "The social piece is a huge component and constitutes a large part of the US onshore shale gas business. The powerful benefits of the shale gas industry cannot override confidence and citizen acceptance and we work very hard to make sure that our operations are safe.".[32]

13. **We conclude that because the US is the only country to have developed a shale gas industry, it can serve as a useful case study when considering how a shale gas industry might develop in the UK. Some of the factors which facilitated the US revolution, however, do not apply to the UK and so development of the UK's shale gas industry is likely to be different to the experience of the US.** ***The UK should learn the lessons of the US experience, including creating a favourable climate for companies to operate in, while ensuring environmental damage is avoided.***

26 Q 231 [Mr Parsons]

27 Q 63 [Professor Bradshaw]; Q 232 [Mr Spence]

28 Annex 1: note of informal meeting with BHP Billiton

29 Ev w20; Annex 1: note of informal meeting with BHP Billiton

30 Annex 1: note of informal meeting with BHP Billiton

31 Q 140 [Mr Tiley]; Ev w20; Annex 1: note of informal meeting with BHP Billiton

32 Annex 1: note of informal meeting with BHP Billiton

3 The Prospects for shale gas

14. The use of different definitions when reporting shale gas estimates in the media has caused confusion. This a key issue in relation to public acceptance (discussed in chapter 4). Estimates of shale gas are uncertain but current estimates put European technically recoverable resource between 2.3 trillion cubic metres (tcm) (81.22 trillion cubic feet – tcf) and 19.8 tcm (699.2 tcf).[33] These are significant but small in compared to global technically recoverable resources of between 188 tcm (6,639.2 tcf) and 208 tcm (7,345.5 tcf). One trillion cubic metres (35.32 tcf) is equivalent to roughly 10 years of UK gas consumption at current demand levels.[34]

Defining shale gas estimates

15. There are two principle terms used when discussing the quantity of shale gas: resource and reserve. Neither has a single agreed definition (see box 1 for basic definitions). There is often considerable overlap between estimates of the two. This is exacerbated by the use of imprecise or ambiguous terminology which limits the ability to compare figures. Consequently, different estimates, using different definitions are often compared in the media as though they were equivalent. This creates disagreement and confusion.[35] WWF suggested that media reports, which refer to huge finds of shale gas often fail to appreciate the distinction between 'gas in place' and 'technically recoverable reserves'. The Minister told us that the Government is exercising caution over shale gas estimates in the UK.[36]

16. **We conclude that it is right for the Government to exercise caution over shale gas estimates given the uncertainty and confusion over definitions.** ***If and when the Government does decide to issue estimates of UK shale gas resources it should set a good example and ensure that it is explicit about which definition it is using. We recommend that it should use the definition which is most relevant to the general public, which in our opinion is recoverable resources. The Government should also clearly communicate the uncertainty inherent in some of these figures by emphasising the difficulty of producing an accurate estimate of shale gas.***

33 UKERC (ISG 24A)

34 Assuming that UK total demand for natural gas is approximately 1,000,000 GWh [giga/billion Watt-hours] of energy. This is equivalent to approximately 10tcm.

35 Ev 72; Ev 136; Ev 129

36 Q 299

Box 1 - Definition of resource and reserve

Resource, refers to the total volume of natural gas that is underground prior to development.[37] Resource is also sometimes referred to as *gas in place* . Some of the resource might never be accessible.[38]

Recoverable resources is a commonly used term.[39] It is usually broken down into either 'technically recoverable' or 'economically recoverable' resources. The former is larger than the latter.[40] Calculations of recoverable resources do not usually account for social and political factors which might influence how much of the gas is recoverable in practice.[41]

Reserve refers to a group of resources that are estimated to have a specified probability of being produced.[42] They are quoted to three levels of confidence: possible, probable and proven.[43] Estimates of reserves can change over time.[44] In addition to changes to estimates resulting from additional drilling and seismic, the size of a reserve is influenced by technological, economic, social and political factors which can make it more or less likely that the gas will be extracted.[45] The changing nature of reserves makes them inherently uncertain.[46]

Calculating shale gas estimates

17. Estimates of shale gas are uncertain and will ultimately need to be checked by practical production experience.[47] Shale gas resources are hard to determine because they are located in heterogeneous rock formations which are extensive and hard to map.[48] A UK Energy Research Centre (UKERC) review which looked at studies that provided original estimates of regional and global shale resources concluded that existing estimates had a very high level of uncertainty because of a lack of production experience and should, therefore, be treated with considerable caution.[49] In practice, the amount of shale gas which can be extracted will be subject to technological, economic, social and political factors.[50]

37 Ev 129
38 Ev 62
39 Ev 129
40 Ev 126
41 Q 6
42 Ev 129
43 Ev 94
44 Qq 96-97
45 Ev 94
46 Ev 94
47 Ev 81; Ev 62
48 Q158
49 Ev 124
50 Q 3; Ev w45

18. The case of Poland provides an early example of how original estimates can change once testing starts. An original assessment of Poland's recoverable resource of 5.3 tcm (187.2 tcf) has recently been reduced significantly to 0.35-0.77 tcm (12.36-27.19 tcf).[51] This change in prospects has been corroborated by the experience of ExxonMobil. Mr Smith of the British Geological Survey (BGS) suggested that "Exxon[Mobil] have pulled out of Poland after drilling two wells" because, "gas flows were not high enough" and that the technology they had developed in the US was not working particularly well in Europe.[52] However, Mr Yeager warned us that: "the first well is likely to be poor, the second a little better and the hundredth brilliant. This could be part of what we have seen with ExxonMobil in Poland – lots of drilling is needed to build an accurate picture.".[53]

19. In the UK context, current shale gas estimates are very uncertain. We will only know how great the potential is after significant further drilling has been undertaken. However, Mr Smith observed that, "the speed of activity is so slow in the UK", especially compared to the US.[54] On 13 December 2012 the Secretary of State, the Rt Hon Edward Davey, said:

> "I am satisfied that fracking for shale gas can now in principle resume, and I will be prepared to consent to new proposals, subject to case-by-case scrutiny by my Department, to the new requirements to mitigate seismic hazards, and to confirmation that all other necessary permissions and consents are in place.[55]

When asked whether DECC would issue licences to other shale gas companies the Minister of State, John Hayes, said he, "would expect companies to come forward".[56] However, he also said, "it would not be appropriate for me to make a prediction about timescale."[57]

20. In order to get a better estimate of shale gas in the UK, Mr Smith of the BGS told the Committee that he would like to see more sharing of information, such as gas content and production figures, with shale gas companies.[58] We were astonished that the BGS did not routinely have access to the test results of all shale gas wells drilled in the UK. Mr Smith suggested that the BGS had previously received information from oil and gas companies but , "that is not the case now". However, Mr Egan of Cuadrilla thought that they had already reported their data but added that if, "they [BSG] are looking for data from us, we do not have a problem providing them with that data" as long as commercially confidential data is protected.[59]

51 Ev 62

52 Q 32

53 Annex 1: note of informal meeting with BHP Billiton

54 Q 27

55 HC Deb, 13 December 2012, col44WS

56 Q 300

57 Q 296

58 Q 17

59 Q 100

21. **We conclude that it is impossible to determine reliable estimates of shale gas in the UK unless and until we have practical production experience.** ***Therefore, if companies can demonstrate that they can meet the required standards the Government should encourage exploratory shale gas operations to proceed in order to improve current estimates, providing that public concern over environmental impacts is recognised and taken into account. It should require shale gas companies to share their gas content and production figures with relevant research bodies (subject to commercial confidentiality).***

Latest shale gas estimates

Onshore estimates

22. Global estimates of shale gas have been described by Mr Smith of the British Geological Society (BGS) as, "massive" and technically recoverable resource estimates range from 188 trillion cubic meters (tcm) (6,639.2 trillion cubic feet –tcf) to 208 tcm (7,345.5 tcf).[60] By comparison, the globally technically recoverable resource of conventional gas[61] is estimated at 432 tcm (15,256 tcf).[62]

23. European shale gas estimates are not at that scale but, nonetheless, significant.[63] The UK Energy Research Centre report includes estimates which range from 2.3 tcm (81.22 tcf) to 19.8 tcm (699.2 tcf).[64] In the UK, estimates of technically recoverable resources range from 0.15 tcm (5.29 tcf) to 1.15 tcm (40.61 tcf).[65] The BGS derived an early estimate of potentially recoverable resource for specific parts of the UK of 0.15 tcm (5.29 tcf) by comparing similar geological structures in the US and the UK. This excluded Wales, Scotland and Northern Ireland). The BGS was keen to point out, however, that because, "no UK drilling had taken place at the time of this estimate [the figure was] tentative.".[66] Cuadrilla have stated that exploration has shown that the Bowland Shale in Lancashire is over a mile thick - far thicker than any comparable US shale.[67] This could affect what is technically recoverable and reduce the visual impact of development. For example, Cuadrilla went on to suggest that, "this opens the possibility of developing [shale gas] with a much lower-density surface "footprint" than US shale plays.".[68]

24. A number of shale gas companies in the UK have started to produce resource (or gas in place) estimates. Cuadrilla, for example, has estimated a resource figure of 5.67 tcm (200.2

60 Q32; A 2011 report, *World Shale Gas Resources: An Initial Assessment of 14 Regions outside the US,* by the US EIA estimated technically recoverable resources of shale gas which amount to 188tcm. This was revised up by a 2012 report, G*olden Rules for a Golden Age of Gas, by the IEA* which estimated a remaining technically recoverable resources of shale gas amount to 208tcm.

61 Conventional gas is typically "free gas" trapped in multiple, relatively small, porous zones in various naturally occurring rock formations such as carbonates, sandstones, and siltstones. By contrast, unconventional gas reservoirs include tight gas, coal bed methane, gas hydrates, and shale gas.

62 Ev 129

63 Q 21

64 Ev 129

65 Ev 129

66 Ev 62

67 Ev 68

68 Ev 68

tcf) in Lancashire which has been described as "highly significant".[69] Mr Smith of the BGS said that this figure was, more reliable than the original BGS estimate.[70] The BGS is currently finalising a study looking a shale gas resource estimates for the whole of the UK's Bowland shale. It has been suggested that their figure will be of a similar order of magnitude to Cuadrilla's estimate. IGas has estimated 0.26 tcm (9.23 tcf) in the north west of England (the actual area is unknown and could include some offshore sites), Eden energy/UK Methane in south Wales has estimated 0.97 tcm (34.19 tcf) and Dart energy which has licences in Scotland and England has estimated 1.86 tcm (65.56 tcf).[71]

Offshore estimates

25. There is currently no reported offshore exploration activity for unconventional gas anywhere in the world. Offshore shale gas resources are excluded from global estimates. [72] This is unlikely to change in the near future because there are a number of logistical and operational hurdles which make the cost of exploration and development uneconomic.[73] In the UK, the BGS has suggested that offshore shale formations are larger than those onshore and have offered a tentative resource estimate of 28.32 tcm (1,000 tcf) for the east Irish Sea Basin (based on Cuadrilla's figures on their adjacent onshore acreage).[74]

26. With the UK's high population density and the possibility of public opposition to onshore shale gas development, the UK's offshore resources might become attractive in the future because extraction of them might avoid much of the public concern associated with the environmental impact of onshore operations.[75] Professor Davies of the Geological Society suggested that, "the economic hurdle may be the key [factor] but, of course, just like wind energy, it is easier done offshore in terms of social acceptability."[76]

27. Some witnesses pointed out that the UK could develop its offshore resources by taking advantage of the skills and expertise already developed in the North Sea oil and gas industry.[77] Mr Smith of the BGS posed the question "what do you do with those platforms [in the North Sea] when they come to the end of their life?". He suggested that, "there are a lot of competing ideas for the use of these platforms" which includes using them for shale gas extraction.[78] Professor Davies of the Geological Society highlighted that the "window to grab this opportunity is probably in the next 10 to 15 years" because companies will start to decommission their platforms over this period.[79]

69 Q 34

70 Q 14

71 Ev 62

72 Ev 72

73 Q 38; Ev w45

74 Ev 62

75 Qq 38-42

76 Q 41

77 Qq 38-41

78 Q 38

79 Q 41

28. Société Générale suggested, "companies could use fracking techniques for offshore fields."[80] Similarly the UK onshore Operators Group said, "offshore unconventional gas may be commercially viable in the future subject to developing technology bringing down the cost of operations and access to the gas networks."[81] DECC highlighted that, "if shale gas development can be proven to be technically and commercially viable onshore, it is possible that the industry may look to the offshore for future exploration, and further study could be merited at that time."[82] The Geological Society warned, however, that, "should the UK attempt to exploit offshore unconventional resources, this would nonetheless require us to pioneer offshore shale gas exploration and production, which would be no small undertaking.".[83]

29. **While it is unlikely that offshore shale gas will be pursued in the near future, strategically, it may have the most potential for the UK in the medium- to long-term, especially if it avoids public opposition associated with onshore operations.** ***We repeat the recommendation made in our previous report that DECC encourage the development of the offshore shale gas industry in the UK, working with the Treasury to explore the impacts of tax breaks to the sector. This must be done before the UK's North Sea oil and gas platforms are decommissioned, otherwise the opportunity to utilise the UK's offshore oil and gas assets may pass.***

80 Ev 81

81 Ev w53

82 Ev 72

83 Ev 92

4 Developing shale gas in the UK

30. In addition to below-ground factors (see chapter 3) there are also a number of above-ground factors which will be critical to determining how much shale gas can be recovered.

Public perception

31. Public acceptance of the shale gas industry will be key to ensuring its success in the UK. To date, there has been public concern over, and local opposition to, shale gas developments. Mr Taylor of the Institute of Directors, for example, suggested that, "community concerns around shale gas are probably the No. 1 issue that needs addressing."[84] The Société Générale highlighted that the shale gas industry needs a "social licence" to operate.[85] This is something Cuadrilla, which started drilling in Lancashire in 2010, has already had to address. Cuadrilla was responsible for triggering a small earth tremor in 2011 which caused concern.[86] A small number of opinion polls have shown that the UK public is more in favour of certain renewable energy technologies than shale gas.[87]We concluded in our previous report that:

> "We conclude that hydraulic fracturing itself does not pose a direct risk to water aquifers, provided that the well-casing is intact before this commences. Rather, any risks that do arise are related to the integrity of the well, and are no different to issues encountered when exploring for hydrocarbons in conventional geological formations." [88]

32. Part of the problem, according to Professor Anderson of the Tyndall Centre, is that there is a lot of uncertainty about how the industry will develop and what this will mean for the communities which live in close proximity to it.[89] Professor Anderson suggested that there was a need to be "absolutely candid and direct" with the public about what the shale gas industry is likely to entail.[90] He suggested that the public might not believe industry descriptions of what shale gas might mean for the community because the industry has a vested interested in promoting it.[91] DECC has established an Office of Unconventional Gas and Oil, which the Minister told us would play a role in, "dispelling some of the myths [...] in countering misassumptions and misinformation.".[92] If the Office is perceived to be acting as both regulator and promoter of the industry (see Regulation section below), however, it is unlikely to be trusted.

84 Q 109 [Mr Taylor]

85 Ev 81

86 Ev 68

87 Qq 173-174

88 Energy and Climate Change Committee, Fifth Report of Session 2010-12, Shale Gas, HC 795, para 113

89 Qq 177-179

90 Q 175

91 Q 176

92 Q 329

Community engagement

33. One way the shale gas industry is trying to minimise some of these potential issues is through effective community engagement. Witnesses representing companies with interests in different energy technologies highlighted their experience of, the benefits of community engagement. Mr Spence of EDF Energy, for example, explained the importance of early consultation, getting the facts out about what the proposals are, what the impacts are and what it might mean for the community. He also suggested that a developer should be willing to listen, make changes and respond to concerns. [93] Mr Parsons of National Grid said that they were proactive in engaging with communities and special interest groups to try to take their views on board all the way through the life cycle of a project.[94] The Minister told the Committee that he expected businesses to play a full role in community engagement.[95] Lessons from Hinkley C nuclear power station, which some of the Committee visited and which are outlined in our report, *Building New Nuclear: the challenges ahead*, suggested, however, that business engagement with the community was sometimes lacking and needed to be improved.[96]

34. **One key to community acceptance will be a robust factual response by government to scare stories. The other key to ensuring public acceptance of the shale gas industry is community engagement. Engagement should be early and businesses need to be able to demonstrate that they are both listening and responding to community concerns.** ***The Government should consider whether it would be appropriate for the new Office of Unconventional Gas and Oil to provide advice and support to local communities living near potential shale gas developments, taking into account the need to address perceptions that the Office may be too closely linked to industry.***

Community benefit

35. In addition to community engagement there was strong agreement that communities affected by development should receive some tangible benefits.[97] An analogy was drawn between shale gas and onshore wind where community benefits schemes have been explored as a way of reducing local opposition.[98] Dis-benefits relating to shale gas could include; visual and noise intrusion, impact of lorries travelling to and from shale gas sites. In the US, it is generally the case that mineral rights belong to the landowner. The company then pays the landowner a royalty for the shale gas they extract. Mr Yeager of BHP Billiton told us that landowners are, "our partners and they have a share in the profits.".[99] These contracts between landowner and shale gas company also contain

93 Q 234 [Mr Spence]

94 Q 234 [Mr Parsons]

95 Q 324

96 Energy and Climate Change Committee, Sixth Report of Session 2012-13, Building New Nuclear: the challenges ahead, HC 117, para 71-82

97 Q 109 [Mr Taylor]; Ev w49

98 Q 110 [Mr Egan; Mr Taylor]

99 Annex 1: note of informal meeting with BHP Billiton

provisions on how the company will leave the land once operations have ceased.[100] There is, therefore, a big incentive for the landowner to allow shale gas operations on their land.

36. In the UK, mineral rights belong to the Crown. Transferring mineral rights for shale gas from the Crown to the landowner, even for a short time would be according to the Minister an, "extremely radical change."[101] He added that, "it would not be reasonable to see the community as the landowner. We have to take a rather more permissive view of benefit".[102] Mr Crotty of INEOS Olefins & Polymers Europe suggested that as a result the industry in the UK needed to go the "extra mile."[103] This included going beyond what would be required by way of compensation under the planning system.[104] Mr Taylor of the Institute of Directors said:

> "One other aspect that would be useful is being able to provide tangible benefits to communities that have shale-gas wells in their neighbourhood, whether that is through lower gas bills or some other mechanism, such as local amenities—some way that communities can get compensated for the disturbance from the development.".[105]

The Minister suggested that DECC was looking at the association between infrastructure investment and community benefit and that, "it would be inconsistent if we did not do so in respect of shale gas.".[106] The Chancellor, Rt Hon George Osbourne, confirmed in the budget his intention to, "develop proposals by summer 2013 to ensure that local communities will benefit from shale gas projects in their area".

37. **Communities who are affected by shale gas development should expect to receive, and share in, some of the benefits of the development. We support the Government's intention to ensure that local communities will benefit from shale gas projects in their area.** ***We recommend that the Government explores ways of sharing substantial material benefits with local communities. In the same vein as the recommendation in our Building New Nuclear report, one option the Government could consider is extending the scope of its proposal to allow local authorities hosting renewable energy projects to retain business rates to include shale gas developments. A mechanism for sharing substantial material benefits with local communities should be ready to be offered to communities in time to encourage them to take a positive view of the prospect of commercial shale gas operations beginning in their locality.***

100 Annex 1: note of informal meeting with BHP Billiton

101 Q 327

102 Q 331

103 Q 235

104 Q 234 [Mr Spence]

105 Q 109 [Mr Taylor]

106 Q 325

Regulation

38. The UK is still in the very early stages of developing a shale gas industry. With only a few wells drilled so far, the exploration phase has barely even begun. Nevertheless, earth tremors at Cuadrilla's site in Lancashire, combined with suggestions of environmental damage including waste water contamination from the US and concern over the types of chemicals used in fracking has fuelled concern around the possible environmental impacts of the industry. In addition to our conclusions on the construction of wells, in our previous shale gas report we concluded that some of these concerns including, for example, the amount of water used in fracking operations were warranted and needed to be managed carefully. On balance, however, we concluded that an effective regulatory regime could be established and that a moratorium on shale gas exploration was not justified.[107] Since then the 2012 Royal Society report, Shale Gas Extraction in the UK, said:

> "The health, safety and environmental risks associated with hydraulic fracturing (often termed 'fracking') as a means to extract shale gas can be managed effectively in the UK as long as operational best practices are implemented and enforced through regulation.". [108]

Ensuring effective regulation of the shale gas industry as it develops – which will prevent environmental damage and minimise disruption to local communities – is critical to ensuring public confidence in the industry. We welcome the recent publication of the UK Onshore Operators Group, *UK Onshore Shale Gas Well Guidelines*[109], which we believe provides some evidence that the industry is seeking to keep its house in order.

39. In the US, the regulatory regime varies between States making it difficult to generalise. Regulations which apply across all States are concerned with air emissions and chemical usage. Mr Yeager of BHP Billiton suggested that their intent was to create a level of transparency which led to 'public acceptance'.[110] ExxonMobil also highlighted how the industry in the US had responded to public concerns over the chemical additives to fracturing fluids by voluntarily submitting data to the www.fracfocus.org national online registry.[111] Mr Yeager told us, however, that even though there was a tough regime in place which was similar to that applying to the UK's North Sea operations and which has a high level of confidence, "once we are satisfactorily within the constraints of the regulations we are free to proceed" and that this approach "allows you to proceed with developing your assets." The regulatory regime is therefore stringent but reasonable and has been described as having a "let's get it done" approach.[112]

40. Cuadrilla, a shale gas company which has direct experience with the current regulatory regime in the UK, has stated its belief that the regulation is "effective and everything is

107 Energy and Climate Change Committee, Fifth Report of Session 2010-12, Shale Gas, HC 795, para 17

108 The Royal Society and The Royal Academy of Engineering, Shale gas extraction in the UK: a review of hydraulic fracturing, June 2012, www.royalsociety.org/

109 United Kingdom Onshore Operators Group, UK Onshore Shale Gas Well Guidelines: Exploration and appraisal phase, February 2013, www.ukoog.org.uk

110 Annex 1: note of informal meeting with BHP Billiton

111 Ev w20

112 Annex 1: note of informal meeting with BHP Billiton

covered."[113] Mr Egan of Cuadrilla told us that "the UK is widely recognised in the oil and gas industry as having the strongest regulatory system."[114] Cuadrilla believed, however, that there was room for improvement. Mr Egan was keen to emphasise that he was not looking for "radical change" but that there was some overlap between regulatory agencies such as the Environment Agency and the Health and Safety Executive (HSE) especially in terms of environmental impact assessments which could be streamlined.[115] Others were less confident believing that it was too early to conclude whether the regulation was "going to be up to it."[116] Professor Anderson of the Tyndall Centre said that it will be a, "learning by doing approach to ensure the regulation is appropriate."[117]

41. According to the Government the new Office for Unconventional Gas and Oil will work with Defra and other Government Departments, join up responsibilities across Government, provide a single point of contact for investors and ensure a simplified and streamlined regulatory process. [118] However, the Minister reassured us that the normal planning rules would continue to apply and the new Office would not supersede the legal responsibilities of the Environment Agency or the HSE.[119] The Minister explained that the Office would play a coordinating role, giving coherence to the Government's strategy and providing consistency in its approach to the subject of shale gas. It would also bring together safety and security measures and would engage with industry to ensure that these were achieved.[120]

42. Some environmental organisations were concerned that this new Office would act as both a regulator and promoter of the shale gas industry. Professor Anderson felt it was "the fox looking after the chickens" and that "few people would suggest that is wise."[121] Responding to these criticisms the Minister stated that he was confident there would be no conflict of interest and was unapologetic about the Office engaging with the industry arguing that it was an important factor in ensuring effective regulation.[122] Mr Egan of Cuadrilla, however, suggest that it was something which "needs to be managed carefully. Promotion and regulation [...] are two different things."[123] The Chancellor confirmed in the Budget that the Government will, "provide detail of the objectives, remit and responsibilities of the Office of Unconventional Gas and Oil."

43. **We welcome the Government's attempts to minimise the regulatory burden on companies by streamlining processes and avoiding duplication where possible. However, robust regulation of the sector in order to protect the environment and ensure the health and safety of workers is absolutely essential in itself as well as to**

113 Q 109 [Mr Egan]

114 Q 109 [Mr Egan]

115 Q 112

116 Q 167 [Mr Bosworth]

117 Q 167 [Professor Anderson]

118 Department for Energy and Climate Change, Gas Generation Strategy, December 2012, p 57

119 Q 283; Q 328

120 Qq 280-281

121 Q 196 [Professor Anderson]

122 Q2 281-282

123 Q 114

ensure that the shale gas industry is to be accepted by the general public. ***We recommend that the Government maintains the highest standards of protection in environment and health and safety procedures. When the Government provides detail of the objectives, remit and responsibilities of the Office of Unconventional Gas and Oil should include clear lines of accountability to a single Minister responsible for the Office. The Government must also demonstrate how it intends to avoid any potential conflict of interest arising from the different roles of the Office.***

Tax

44. Taxation is a key factor in determining whether a shale gas industry will develop. Professor Bradshaw of the UK Energy Research Centre (UKERC) suggested, for example, that the fiscal regime determines whether industry will be willing to make the investment in exploration, as well as commercial scale extraction.[124] In the US, the tax regime is according to Mr Tiley of Shell, "generally friendly to the industry".[125] However, it is difficult to make generalisations because tax is split between the Federal Government and individual States. In the past the US Federal Government offered tax credits that applied to certain unconventional fuels including for a time natural gas produced from, among other things, "... Devonian[126] shale, coal seams, or a tight formation..." which were designed to incentivise the development of these resources.[127] However, it is not clear whether they played any significant part in the development of the shale gas industry. They were in any case abandoned in 2008. [128] The shale gas industry in the US now generates a significant amount of public revenue. In 2011, a report from IHS Global Insight highlighted that in 2010 shale gas production contributed about $19 billion in federal, state and local government tax and federal royalty revenues. By 2035, these receipts were estimated to more than triple to just over $57 billion.[129]

45. It is currently unclear how shale gas will be taxed in the UK. Professor Stevens of Chatham House told us that, "shale gas is excluded from the normal petroleum regulations. It is in a world of its own, and until the fiscal system and the regulations begin to catch up, it is not clear to me what the fiscal system for shale gas would be."[130] DECC stated that, "the Treasury has made no recent estimate of potential tax revenues from shale gas."[131] The Government has, however, indicated that the tax regime for shale gas should be designed to encourage the development of the industry.[132] The 2012 Autumn Statement and the Gas Generation Strategy confirmed that a new tax regime was currently being developed in consultation with industry. DECC has said that it will "support new ways of

124 Q 69 [Professor Bradshaw]

125 Q 131 [Mr Tiley]

126 Devonian refers to rocks formed during the Devonian period of geologic time (approximately 350 million years ago).

127 Q 70; Ev w20; Congressional Research Service, Energy Tax Policy: Historical Perspectives on and Current Status of Energy Tax Expenditures, 7 May 2010, www.crs.gov

128 Congressional Research Service, Energy Tax Policy: Historical Perspectives on and Current Status of Energy Tax Expenditures, 7 May 2010, www.crs.gov

129 Q132 [Mr Taylor]; Ev w20

130 Q68

131 Ev 72

132 Q 285; Ev 72

tapping our indigenous resources" by engaging with, "companies to develop a targeted tax regime for any future shale gas industry."[133] The Chancellor confirmed in the Budget that he intended to:

> "introduce a new shale gas field allowance and extend the ring-fence expenditure supplement from six to ten years for shale gas projects to promote investment in this industry at an early stage of its development."

46. If the shale gas industry develops, the energy intensive sector believes the tax revenue could have "profound impacts for the UK economy" which "would include bolstering Government income through the collection of additional tax and mineral rights revenues.".[134] Cuadrilla similarly highlighted that shale gas will create, "substantial tax revenues for the Treasury".[135] Mr Egan of Cuadrilla suggested that any new tax regime should recognise, "both the potential of the industry but also the stage it is at." He suggested that the UK is on the verge of potentially developing a significant new shale gas industry and, "if allowed to grow up into a tax-paying adult, it will pay a lot of tax, but it is in its infancy and there is a concern that that infant could be strangled at birth.".[136]

47. ***The Government should make an assessment of whether these tax breaks will continue to be required during commercialisation.***

133 Annual Energy Statement, DECC, November 2012

134 Ev w1

135 Ev 68

136 Q 127

5 Impact on energy market and prices

48. Shale gas is one part of a wider global gas industry. The US shale gas revolution has seen gas prices fall from around $12 to $3 per million British thermal units (Btu) over a short period of time.[137] This has led many to speculate about what impact shale gas might have on other gas prices around the world and in the UK. [138]

Box 2 - Markets and trading

Unlike oil, gas is not currently a globalised market. Historically there have been three regional markets (US, Europe and Asia) with relatively little trade between them. This is because unlike oil, gas tends to be transported by pipeline, which makes inter-regional trading of gas difficult and expensive (although liquefied natural gas - LNG - can be shipped).

Most gas is traded using long-term contracts. This is because gas is difficult and, therefore, expensive to move around requiring long-term commitments from buyers and suppliers. The use of long-term contracts can prevent buyers and sellers from determining a spot market price of gas.

Long-term contracts for gas are often indexed to the price of oil (generally referred to as oil-indexation) which is easier and cheaper to move around. This is especially the case in mainland Europe and Asia. In practice, indexing gas prices to oil prices means that if the price of oil goes up, so does the price of gas, and if the price of oil goes down, so does the price of gas.[139] In general though, oil-indexed prices are considered to be more stable than spot or hub prices for gas.

The majority of liquefied natural gas (LNG) is also traded using long-term contracts (which are also indexed to oil prices). However, an increasing proportion is being traded on the spot market.[140] In the US and the UK, for example, the price of gas is determined using wholesale trading hubs known as the Henry Hub price and the Net Balancing Point (NBP) respectively. These determine the price of gas based on gas-to-gas competition (i.e. market forces). The combination of long-term contracts, spot markets and the limited trade between regions has created price differences across these regions.

Impact of foreign shale gas on UK gas prices

49. There are two main ways in which cheap US gas prices could affect UK gas prices: changes to the way gas is traded and development of exports from the US.

Changes to the way gas is traded

50. The price of gas in the US is based on gas-to-gas competition (often referred to as a spot market). This makes it easier to determine a market price for gas compared to a rigid mechanism of determining gas prices indexed to the price of oil (see box 2). Countries in Europe and Asia where the price of gas tends to be index linked to oil prices are now looking at gas prices in the US and questioning the high price they are paying by

137 Q 231 [Mr Parsons; Mr Pibworth]; Q 293

138 Ev 68

139 Ev 111

140 Q 136 [Mr Tiley]

comparison. Professor Bradshaw of UK Energy Research Centre (UKERC)suggested, for example, that Japan's attitude towards paying for gas was changing.[141] Dr Bros of Société Générale told us that Asian buyers were increasingly unwilling to use oil-indexation as a basis for purchasing long-term contracts and were looking for new ways to price gas. [142] Similarly, in Europe, companies were seeking to renegotiate the terms of their long-term gas contracts with suppliers to reflect the lower prices available on spot markets.[143] According to Oil and Gas UK, this has been something the European Energy Department is actively encouraging.[144] Dr Bros suggested that as a result oil-indexation was, in his words, "going to fade".[145] However, because in Europe the volume of gas currently traded using oil-indexed prices, delivered through pipelines, is significantly larger than spot traded LNG the fading of oil-indexation will take a long time.[146]

51. Increased gas-to-gas competition does not necessarily mean that low gas prices will result. In fact, spot prices tend to be more volatile. It is preferred by some because it helps to determine a market price of gas.

52. **We conclude the shale gas revolution in the US has the potential to influence the nature of gas markets around the world. In particular, it could stimulate greater use of gas-to-gas competition in spot markets to determine gas prices rather than oil-indexation. However, this would not necessarily guarantee that the price of gas will fall.**

Exports of US gas

53. The price of gas is also affected by the cost of transporting it. In the case of LNG liquefaction, shipping and regasification of the gas all have significant costs. According to the Chemical Industries Association:

> "The necessary export terminals with liquefaction facilities, specialised shipping with pressurised, cooled containment and import terminals with re-gasification and storage capacity are all expensive investments".[147]

54. According to Professor Stevens of Chatham House and Dr Bros of Société Générale transporting gas from the US to the UK could add ~$6 per million Btu to the original price of gas in the US (~$3 per million Btu).[148] Whether this price is higher or lower than the UK price (roughly ~$8-10 per million Btu) will determine whether it is economic to import gas from the US. If it is economic, Mr Crotty of INEOS Olefins & Polymers Europe suggested that the UK was, "extremely well placed" to exploit any potential benefits arising from the

141 Q 87 [Professor Bradshaw]

142 Q 75 [Dr Bros]; Q 87 [Dr Bros]

143 Ev 124

144 Ev w45

145 Q 75 [Dr Bros]; Ev 72

146 Ev 72

147 Ev w6

148 Q 75 [Professor Bradshaw; Dr Bros]

impact of shale gas on gas markets because the UK has the infrastructure to continue to import gas.[149]

55. The US shale gas "revolution" also saw the US withdraw from the LNG market. LNG that was expected to be imported by the US was subsequently made available to Europe and Asia creating a "short-term glut" in the market and therefore reducing the price of gas and making it attractive to import. However, most of this LNG was subsequently absorbed by Japan following the Fukushima nuclear incident, bringing an end to these price reductions.[150] The withdrawal of the US from the LNG market, combined with the future export potential of its shale gas could exert further downward pressure on gas prices. It is uncertain whether this will outpace rises in the level of demand, particularly from Asia, which could limit any potential future price reductions.

56. **We conclude that if the US were to begin exporting its shale gas as LNG, the UK might find it economically attractive to import some of this gas. However, the significant transportation costs associated with shipping LNG, combined with expected demand for LNG from Asia, means that the price for this gas in the UK is likely to be significantly higher than that experienced in the US.**

Impact of domestic shale gas on UK gas prices

57. Some believe that developing a UK shale gas industry could reduce the risk of gas prices being determined by the price of imported gas (whether as LNG or by pipeline).[151] It could also enable the UK to enjoy the energy security benefits of domestically produced gas (as discussed further in chapter 7). A key question is how much shale gas production in the UK is likely to cost and, therefore, whether the cheap gas prices experienced in the US can be replicated in the UK.

58. We have heard that shale gas is "not necessarily cheap gas".[152] It is generally agreed that it is more expensive to produce than conventional gas. The low prices experienced in the US are a consequence of a unique set of factors (as discussed in the background section) which differ markedly to the UK. A recent report by Wood Mackenzie suggests that the commercial viability of the UK's shale gas resources are yet to be proven and the key determinant will be the quality of the shale and the performance of the wells. They concluded:

> "Commercially viable UK shale gas development will only be possible if the subsurface is as good as the very best shale plays in North America. Wood Mackenzie's economic assessment shows that due to higher costs in the UK, average performing plays would need gas prices in excess of US$9 per thousand cubic feet (mcf) to break even."[153]

149 Q 219 [Mr Crotty]

150 Q 72; Q 87 [Professor Stevens]; Q 136 [Mr Tiley]

151 Q 137 [Mr Egan]

152 Q 231 [Mr Parsons]

153 Wood Mackenzie press release, UK Shale Gas – fiscal incentives unlikely to be enough', 20 December 2012, www.woodmacresearch.com/

59. It is not yet clear whether the UK regulatory system will be more costly than in the US. Higher population densities may impose greater environmental obligation but will also reduce transport/pipeline costs to market. The Wood Mackenzie report identifies several necessary steps required to make developing the UK's shale gas industry is economically viable:

> "Creating a transparent, streamlined regulatory system that satisfies both a concerned public and operators; carrying out further work on the Strategic Environmental Assessment (SEA), necessary for the 14th Onshore Licensing Round, and enabling a wider range of operators to become involved in assessing the potential of the shales; and designing a fiscal system that makes future investment worthwhile.".[154]

60. There has been speculation that some US shale gas companies are actually making a loss because the cost of production is higher than the market price of gas which has collapsed as a result of oversupply (see background section).[155] As a result many shale gas companies are also producing shale oil because it currently commands a higher price than shale gas.[156] It is not yet known whether the UK has any shale oil reserves. Mr Smith of the British Geological Society (BGS) told us that no estimates have been made of shale oil potential in the UK but that this is something they were looking at.[157] The Geological Society reported:

> "It is very probable that there are shale oil resources in the UK, particularly in the East Midlands and in the Scottish Midland Valley. However, given the difficulty and cost of extracting shale oil, the likely environmental and social constraints, and the relatively extensive shale gas resources available, it seems very unlikely that these will be considered worthwhile to explore.".[158]

61. **We conclude that it is too early to say whether domestic production of shale gas could result in cheaper gas prices in the UK. It is unlikely that the US experience will be directly replicated in the UK because of differences in geology, public attitudes, regulations and technological uncertainties. Shale oil is likely to be present in the UK but it remains uncertain whether industry will consider shale oil economically worthwhile to explore.**

Impact of foreign and domestic shale gas on UK gas markets

62. UK gas prices are generally determined by the spot price of the Net Balancing Point (NBP) (see box 2). As UK production of natural gas declines the UK will become increasingly dependent on imported gas either as LNG or via the gas pipeline interconnector to mainland Europe.[159] Pipeline imports are, and are likely to remain, much

154 Wood Mackenzie, Press release, UK Shale Gas – fiscal incentives unlikely to be enough', 20 December 2012, www.woodmacresearch.com/

155 Q 6 [Mr Smith]; Q 23 [Professor Davies]; Q 61 [Dr Bros]; Q 160 [Professor Anderson]; Ev 136

156 Q 6 [Mr Smith]; Q 23 [Professor Davies]; Q 30; Q 61 [Professor Bradshaw]; Q 252 [Mr Parsons]

157 Q 25

158 Ev 94

159 Q 64

larger than LNG imports so the price of gas in the UK is more likely to be influenced by the price of gas in Europe than the price of LNG imports from other parts of the world.[160]

63. According to EDF Energy the development of shale gas will, "only curb the extent of price rises in the longer-term rather than drive prices down from current levels."[161] WWF highlighted their view that this will increase the UK's exposure to "volatile global fossil fuel prices.".[162] The Minister told us, "the likely impact from widespread exploitation of shale needs to be measured against the consensus of forecasts, which suggests that the gas price will continue to be tight.".[163]

64. **We conclude that there remains substantial uncertainty about the impact shale gas will have on gas prices, both internationally and domestically, and it is by no means certain that prices will fall a result of foreign or domestic shale gas development** ***It would be wrong for the Government to base policy decisions at this stage on the assumption that gas prices will fall (it is possible that they will rise) in the future. However, if large quantities are found they will either bring down prices in the UK, or generate substantial tax revenues, or both – and will certainly reduce imports with benefits to our balance of payments and energy security. For all these reasons the Government should encourage exploration to establish whether significant recoverable reserves exist.***

160 Q 64

161 Ev 87

162 Ev 136

163 Q 322

6 Impact on climate change mitigation

65. The US shale gas revolution has seen significant reduction in the country's greenhouse gas emissions. This has led some to speculate what role shale gas might have in helping the UK to meet its legally binding climate change targets.

Global emissions

66. The shale gas revolution has led to a dramatic fall in the US's greenhouse gas emissions. This has happened because low gas prices have made gas more competitive in the power generation sector than coal, which has been displaced as a result.[164] ExxonMobil suggested that the US power generation market responded quickly and markedly to lower gas prices in 2012, increasing the amount of gas and decreasing the amount of coal consumed in power generation.[165] This has been a key factor in helping the US to reduce its greenhouse gas emissions in recent years (since the emissions from burning gas are about half of those from burning coal) and according to the Tyndall Centre, could have contributed, "up to half of the total [emission] reductions in the US energy system".[166] Mr Tiley of Shell told us that, "a switch from coal to gas is probably the most important thing one can do at the moment for reducing overall emissions.[167]

67. Fuel switching in the US, however, has not necessarily resulted in less coal being consumed globally. Increased coal exports from the US combined with reduced demand from China have caused the global price of coal to fall.[168] Within the EU, which has continued to experience high gas prices, coal is now a more attractive option for power generation.[169] The very low carbon price in the EU Emissions Trading System (EU ETS – Europe's main mechanism for reducing greenhouse gas emissions) has failed to provide a strong enough disincentive to the continued use of coal. It has, therefore, failed to stop switching in the opposite direction - from gas to coal - which has occurred in the European power sector.

68. **We conclude that although development of shale gas in the US has reduced America's greenhouse emissions this may have been offset by increased use of the coal in Europe. This highlights the importance of improving the EU ETS to ensure it is able to deter the consumption of unabated coal for electricity generation.**

164 Ev 97

165 Ev w20

166 Ev 126

167 Q 140

168 Q 73; Ev w25; "The unwelcome renaissance", The Economist Online, 5 January 2013, www.economist.com

169 Q 81; Qq 266-273

UK emissions

Fugitive emissions

69. The greatest source of uncertainty is around the impact of so-called " fugitive" methane emissions. In addition to potential fugitive emissions from conventional gas production, shale gas production may involve deliberate venting. Since methane is a more potent greenhouse gas than carbon dioxide, any such emissions have a significant impact on the lifecycle emissions associated with shale gas.

70. A 2011 study from Cornell University claimed that the greenhouse gas footprint of shale gas was larger than that of conventional gas, oil, and, over a 20-year time frame, coal. This was supported by a study from the US National Oceanic and Atmospheric Administration (NOAA) which came to a similar conclusion.[170] A more recent study, however, by the Massachusetts Institute of Technology (MIT) argued that these claims have been exaggerated because they had not given sufficient consideration to whether companies attempted to capture their fugitive emissions. The study found that companies were capturing around 70% of their would-be emissions either for regulatory or economic reasons.[171] Cuadrilla stated:

> "The largest source of emissions from shale gas and the methane emissions in the US comes from the practice of storing flow-back water, so this is the water that comes back with the gas, in open pits during the initial periods of flow back. The practice has changed certainly in the US of late and it is our practice in the UK that all flow-back water passes through a four-stage separator and that the gas is separated out in the separator and is, during testing at least, sent to the flare system.".[172]

Professor Anderson of the Tyndall Centre told the committee, "If I was put on the spot I would say that if the choice was a straightforward one between Putin's gas regulated in Russia or gas from the UK produced by shale, I would say from a regulatory point of view my preference would be to go for domestic production, from a purely regulatory point of view.

71. Given the lack of conclusive evidence either way, it comes as no surprise that the carbon footprint of shale gas remains a source of controversy.[173] WWF suggested that, despite a number of studies attempting to quantify the life cycle emissions which had been undertaken since our last inquiry, there was still a high degree of uncertainty and "significantly more good quality data and peer reviewed evidence is needed". [174]

72. Professor Stevens of Chatham House told us that the extent of fugitive emissions is essentially a regulatory issue.[175] In a UK context therefore, Professor Bradshaw

170 "Air sampling reveals high emissions from gas field", Nature, 7 February 2012, www.nature.com; "Study: 'Fugitive' methane from shale gas production less than previously thought", MIT, 29 November 2012, web.mit.ed

171 "Study: 'Fugitive' methane from shale gas production less than previously thought", MIT, 29 November 2012, web.mit.ed

172 Q 93

173 Q 80 [Professor Bradshaw]

174 Ev 136

175 Q 80 {Professor Stevens]

commented, we cannot predict the scale of fugitive emissions of shale gas because shale gas production has not yet started[176] In his Ministerial Statement on shale gas the Secretary of State said that all shale gas operations in the UK would be subject to the Government's policy on flaring and venting of methane, which requires venting of methane to be kept to a technical and economic minimum.[177] The Secretary of State also set out his intention to commission a study into the possible impacts of shale gas extraction on UK greenhouse gas emissions.[178] The Minister told us that "the evidence from America is that some of the claims made about methane are exaggerated, but let us wait to see what our own study reveals."[179]

73. ***We recommend that the Government should complete its research into the impact which shale gas extraction could have on greenhouse gas emissions as quickly as possible so that the data can be used when considering applications for licenses for commercial scale extraction. Policies on flaring and venting of methane should be reviewed in light of the study in order to ensure that fugitive emissions from fracking are kept as close to zero as possible. DECC should also monitor the methane emissions of those companies that are currently exploring for shale gas. It should be possible, by way of regulation, to ensure that fugitive emissions are prevented by outlawing venting.***

Meeting climate change obligations

74. There is a role for gas in the UK's future energy mix. Even in the scenario where the UK significantly decarbonises its power sector, gas with carbon capture and storage (CCS) could be part of the generation mix, and a small amount of unabated gas could be used for balancing purposes.[180] According to Professor Bradshaw of the UK Energy Research Centre (UKERC), "it is not a question of gas or no gas. It is how much gas and in what role."[181] Professor Bradshaw advocated looking at "the whole energy system" and "the role that gas plays and then, within that, what shale gas is contributing."[182] Domestically produced shale gas which displaced imported gas could make a positive contribution. Mr Egan of Cuadrilla argued, for example, that it would be beneficial for the UK to produce its own gas because emissions would be, "about 10% less than imported gas" (whether liquefied natural gas or pipeline).[183]

75. An unchecked increase in gas-fired generation, driven by shale gas development, however, could make it more difficult for the UK to meet its climate change obligations. According to Dr Kennedy of the Committee on Climate Change:

176 Q 80 [Professor Bradshaw]

177 HC Deb, 13 December 2012, col44WS

178 HC Deb, 13 December 2012, col44WS

179 Q 336

180 Q 78 [Professor Bradshaw]; Q 101; Q 214 [Mr Bosworth]; Q 227 [Parsons]; Q 256 [Mr Spence]; Q 260 [Mr Parsons]

181 Q 84 [Professor Bradshaw]

182 Q 80 [Professor Bradshaw]

183 Q 140 [Mr Egan]

> "The gas-generation strategy includes scenarios which model early power sector decarbonisation. These are economically sensible and compatible with meeting legislated carbon budgets. It also includes a scenario which reflects a new dash for gas, with very limited investment in low-carbon technologies through the 2020s. This would not be economically sensible, and would entail unnecessary costs and price increases. Neither would it be compatible with meeting carbon budgets and the 2050 target. Early decarbonisation of the power sector should be plan A – and the dash for gas Plan Z. Including these very different investment paths in the strategy exacerbates mixed signals already given by the Government and is damaging for the sector investment climate. It will be essential going forward to ensure that the Electricity Market Reform is aimed at achieving a carbon intensity of 50 gCO2/kWh in 2030 through investment in a portfolio of low-carbon technologies, rather than a dash for gas which would raise long term costs and risks.".[184]

76. There are different policy options to address the risk of a UK 'dash for gas' which would expose consumers to the risk of higher fossil fuel prices, and the benefits of lower prices if they materialise, and could be harmful to meeting the UK's statutory climate change targets. Mr Moore of Policy Exchange suggested that restricting shale gas would not help reduce emissions because they would be emitted elsewhere in Europe. He agreed that it would be better to focus on improving the EU ETS to control emissions from the electricity sector.[185] Professor Anderson, however, described the EU ETS as a "damp squib" because the price of carbon was so low as to make it irrelevant.[186] Professor Anderson suggested that focusing on price (as a mechanism for reducing greenhouse gas emissions) was a mistake because it was not able to incentivise the large step-changes required to tackle climate change. Instead, Professor Anderson promoted the idea of setting standards in terms of emissions which could apply to electricity generation. These could be technology neutral and could get stricter each year.[187]

77. **We conclude that the Government needs to recognise that the unchecked development of gas-fired generation, which the development of shale gas may facilitate, might be incompatible with meeting the UK's climate change obligations.** ***As we have recommended before the Government should implement an emissions performance standard (EPS) that gets tighter over time so as to include unabated gas-fired plant and avoid excessive gas "lock-in". However we do recognise there will be a role for unabated gas as peaking plant and to balance intermittent renewable sources. If shale gas does prove to be plentiful and either cheap or yielding substantial tax revenues it would be sensible to put far more emphasis on developing CCS.***

Carbon Capture and Storage

78. The extent to which gas is used to generate electricity in the future will depend heavily on whether carbon capture and storage (CCS) technology can be proven at scale and

184 CCC says early decarbonisation of the power sector should be plan A – and the dash for gas Plan Z, 5 December 2012, www.theccc.org.uk

185 Q 80 [Mr Moore]

186 Q 189 [Professor Anderson]

187 Qq 181-189

become economic to use. In oral evidence to the Liaison Committee the Prime Minister, the Rt Hon David Cameron, said:

> "The key question that no one can fully answer about gas is, if you knew how well carbon capture and storage would go, then actually how much gas you have wouldn't really matter, because it would not be contributing to carbon.".[188]

79. National Grid said that it believed shale gas could coexist with low-carbon generation as long as the majority of fossil fuel generation had CCS.[189] Furthermore, it is SSE's belief that if there is significant development of shale gas in the UK or elsewhere in the world, then the importance of developing gas CCS increases.[190] Mr Pibworth of SSE, for example, told us that the benefits of developing CCS included helping to meet the UK's climate change obligations, "strengthening the academic knowledge base, potentially exporting that technology going forward, and also taking advantage of the current very good standard of offshore gas engineering that we have in this country."[191]

80. CCS is not currently proved at commercial scale: something that will require significant capital support. It is hoped that over time, costs will come down as the technological know-how improves and economies of scale are realised.[192] The Government's attempts to fund CCS demonstration projects have been subject to repeated delays. We are pleased to hear in the Budget that the Government will take two projects to the next stage of the CCS commercialisation competition. Despite this the availability of commercial CCS in the near-future still appears extremely unlikely. Mr MacLean of SSE told us that "we very quickly need to get to a point where we are not talking theoretically about whether CCS works, technically and economically, but that we are getting on and demonstrating it. It is quite frustrating how long that is taking."[193] We share this frustration especially because it appears that the Prime Minister is banking on shale gas to meet our statutory climate change targets. In oral evidence to the Liaison Committee he said:

> "Those arguing for a firm decarbonisation target are betting that carbon capture and storage is available. If not, you are in quite serious water, because you would be only relying on nuclear and renewables. If carbon capture and storage didn't come forward and you had a very tough carbon target, you would have no unabated gas at all.".[194]

The speed of commercial development of CCS will affect whether it can play a meaningful role in the UK's energy mix and how much gas we can rely on without conflicting with

188 Uncorrected transcript of oral evidence taken before the Liaison Committee on 11 December 2012, HC (2012-13) 484-ii, Q 36

189 Ev 110

190 Ev 122

191 Q 258

192 Q 258; Q 275

193 Oral evidence taken before the Energy and Climate change Committee on 13 February 2013, HC (2010-12) 987-i, Q 61 [Mr MacLean]

194 Uncorrected transcript of oral evidence taken before the Liaison Committee on 11 December 2012, HC (2012-13) 484-ii, Q 37

UK's climate change targets. Unfortunately, there is no sign that an economically viable form of CCS will be available in the next ten years.

81. **We share SSE's frustration at how long it is taking to develop CCS especially as it is clear that the Prime Minister sees it as critical to meeting our future climate change targets. The speed of commercial development of CCS will affect whether it can play a meaningful role in the UK's energy mix and how much gas we can rely on without conflicting with the UK's climate change targets. While we are pleased to hear in the Budget that the Government will take two CCS projects to the next stage of the CCS commercialisation competition, *we recommend the Government needs to conclude its CCS competition as soon as possible and bring forward CCS demonstration projects to allow it to be deployed in time to contribute towards meeting our carbon budgets. Unless progress towards economically viable CCS accelerates rapidly in the next three years, it will become impossible to base UK energy policy on the assumption that it will be available in time to help meet the decarbonisation recommendations of the Committee on Climate Change. We intend to keep a close eye on DECC's progress in this area.***

Displacing lower carbon technologies

82. While emissions from gas-fired electricity plants are lower than those of other fossil fuels, such as coal, they are still significantly higher than low-carbon technologies, such as nuclear and renewables. We heard a range of views about the role that gas should play in decarbonising the UK's electricity system.

83. Mr Moore of Policy Exchange advocated greater use of gas in the short-term (rather than more expensive technologies, such as offshore wind), with this plant being retired early to avoid excessive emissions in the medium-term.[195] However, this could create stranded assets in the future and, as Professor Bradshaw of the UKERC warned, this kind of approach could require state intervention to remove the plant from the system in the future. [196] Dr Kennedy of the Committee on Climate Change emphasised that using a portfolio of different low-carbon technologies could protect the UK from gas price increases in the future. He argued that gas prices were likely to rise in the future and so too great a reliance on gas-fired generation could leave consumers paying the price:

> "Gas is carbon intense and, as long as we are in a carbon constrained world, a gas-based system must be subject to an increasing carbon price and will be more and more expensive over time." .[197]

84. Some witnesses were worried that increased levels of investment in gas, potentially stimulated by shale gas, could squeeze out investment in renewable and energy efficiency. This might result in a prolonged use of gas and therefore increase emissions.[198] The Tyndall Centre estimated, for example, that between £19bn and £31bn could be diverted as a result of developing shale gas in the UK. WWF also suggested that future expectations about

195 Q 81

196 Q 80 [Professor Bradshaw]

197 Oral evidence taken before the Energy and Climate change Committee on 13 February 2013, HC (2010-12) 987-i, Q 14 [Dr Kennedy]

198 Q 80 [Professor Bradshaw]

shale gas could undermine the case for investment in low carbon generation or energy efficiency. [199] Professor Anderson of the Tyndall Centre warned that continuing to invest in gas made it, "more strenuous to get off the curve and gives more reason to avoid getting off the curve."[200]

85. Several witnesses disagreed with this argument and Professor Stevens of Chatham House told us that the most important factor driving investment in decarbonisation was regulation and policy.[201] DECC contended that the Government support mechanisms such as feed-in tariffs would continue to make low-carbon options attractive to investors, even if the price of gas were to fall. Mr Barton from DECC told us that he did not think that shale gas, or gas in general, would reduce investment in renewables. He believed instead that, "increased use of gas can go hand-in-hand with increased renewable deployment".[202] In contrast, Ms Banks of WWF stressed uncertainty about long term support for renewables beyond 2020 which could undermine investor confidence.[203]

86. ***We recommend the Government push through its reforms to the electricity market, as set out in the Energy Bill, without delay. This will discourage the unchecked development of unabated gas-fired generation and create a favourable investment climate for low carbon technologies which could help to avoid gas "lock-in".***

199 Ev 136

200 Q 184 [Professor Anderson]

201 Q 81 [Professor Stevens]; Q 143 [Mr Taylor]

202 Q 313 [Mr Barton]

203 Q 192 [Ms Banks]

7 Additional Impacts on the UK

Security of Supply

87. Exploitation of shale gas both within the UK and in other countries could lead to some energy security benefits for the UK.

Increased global production of shale gas

88. Development of shale gas at a global scale could increase the amount of gas available for the UK to import. This would enhance energy security because the UK would be able to access gas from a more diverse range of sources, thereby reducing dependence on any one supplier. Shell believed that the UK was in a good position to connect to, and benefit from, this potentially increasing supply of gas, evidenced by the "abundance of regasification terminals [needed in order to be able to import LNG, which is transported by boat rather than pipeline]" and the "global diversity of supplies available to the UK.".[204] The UK currently moves a lot of LNG through the country via pipleine into Europe because the UK has a significant number of regasification terminals. Professor Bradshaw of the UK Energy Research Centre (UKERC) reported to us that, "if we are the first port of call for a substantial amount of LNG, that must only reinforce our security of supply.".[205] The only question is how much we are willing to pay in order to attract this LNG in a tight global market. When giving oral evidence to us, Alistair Buchanan, of Ofgem, stressed that, "I think you will be able to get the gas but it is more about price. [...] There is an expectation that you will get the gas but there is going to be a squeeze on the price .".[206]

Increased domestic production of shale gas

89. Increased domestic production of shale gas could contribute to the UK's energy security by reducing our dependence on imported gas. However, domestic production in Europe and the UK will not, according to Mr Egan of Cuadrilla, "completely negate the need for imports" and will at best, "replace the decline of conventional production" and, as such, it is unlikely to result in Europe becoming self sufficient in gas.[207] Even though shale gas development, both at home and abroad, has the potential to improve Europe's and the UK's security of supply, the future of the sector is still sufficiently uncertain to make it unwise to rely on these benefits (see chapter 3 and 4). If the price of foreign gas imports are high (see chapter 5), and domestic production is slow to develop or is not as significant as expected, and if investment is diverted from low carbon technologies (see chapter 6) then the UK could still face security of supply risks.

90. ***We recommend that Government should not rely on shale gas contributing to the UK's energy system when making strategic plans for energy security. We welcome the commitment made by the Minister that the new Office for Unconventional Oil and Gas***

204 Ev 87

205 Q 76 [Professor Bradshaw]

206 Oral evidence taken before the Energy and Climate Change Committee on 26 February 2013, HC (2012-13) 1009-i, Q 7

207 Q 105 [Mr Egan]; Q 77

will assess the effects of shale gas development on the UK's security of supply – providing we can be reassured that that the Office does not have a conflict of interest.[208]

Economic benefits

Jobs and skills

91. The US has experienced significant job growth as a result of the shale gas industry. Analysis by IHS Global Insight looking at the economic and employment contributions of unconventional gas development in the US estimated that, "in 2010, unconventional gas activity supported 1 million jobs; this will grow to nearly 1.5 million jobs in 2015 and to over 2.4 million in 2035."[209] While it is difficult to say with any accuracy how many jobs a successful UK shale gas industry would create, estimates range from the thousands to the tens of thousands.[210] Estimates are high because shale gas is a labour intensive industry and requires jobs across the spectrum including in the supply chain industry to support the shale gas industry.[211]

92. The UK already has extensive drilling experience from the conventional gas industry in the North Sea, some of which could be transferable to the onshore industry.[212] If the shale gas industry is slow to develop some of this experience could be lost.[213] According to Professor Davies of the Geological Society, if the "size of the prize is big enough" then it is likely that shale gas will attract the large companies which have the skills to develop the industry.[214] Mr Egan of Cuadrilla suggested, however, that the ability to import skills is limited. Instead the UK needs to develop its own skills. This could be achieved in two ways. Firstly, by training a new generation of engineers, which Mr Egan believed requires coordination and includes a role for both academia and the Government.[215] Secondly, through "on the job" experience. Mr Tiley of Shell described how shale gas in the US had brought in a, "whole new generation", many of whom "have only ever worked in unconventional gas".[216]Mr Taylor suggested that the UK had already done this in relation to the North Sea industry and other industries such as the nuclear industry.[217]

93. ***We recommend that Government encourage partnerships such as the one between Cuadrilla and the University of Central Lancashire to ensure the skills required to develop the shale gas industry are available. Government should make an assessment of the need for skills development and should work with industry and the relevant sector***

208 Q 320

209 The Economic and Employment Contributions of Unconventional Gas Development in State Economies, IHS Inc, June 2012, http://www.ihs.com/images/State_Unconv_Gas_Economic_Contribution_Main.pdf

210 Q 106 [Mr Egan]

211 Q 106 [Mr Egan; Mr Tiley]

212 Q 54

213 Q 56

214 Q 52

215 Q 107 [Mr Egan]

216 Q 108 [Mr Tiley]

217 Q 107 [Mr Taylor]

skills council to develop a skills action plan for shale gas similar to the Nuclear Supply Chain Action Plan which the Government has recently published.

Energy Intensive Industries

94. In the US the shale gas revolution has had a transformative impact on the manufacturing sector especially the energy intensive industries and in particular the chemicals industries.[218] The benefits include cheaper electricity prices but also cheaper chemical prices both of which have fallen in the US as a result of shale gas. INEOS Olefins & Polymers UK highlighted, for example, that lower gas prices have resulted in a lowering of electricity prices, giving a massive competitive advantage to the US electro-intensive industries.[219] Mr Crotty of INEOS Olefins & Polymers UK explained to us how lower chemical prices in the US have also been carried over to the UK:

> "For the chemical raw-material use, where it is the ethane we are after, the import of ethane from US shale gas extraction is more than economic. After all the liquefaction and re-gasification costs, we can land it far cheaper than we can buy it locally.".[220]

95. The UK energy intensive industries are increasingly feeling under pressure from rising energy prices.[221] The Energy Intensive Users Group highlighted that developing a shale gas industry in the UK has the potential to deliver secure, internationally competitive energy and feedstock supplies that are vital for energy intensive and petrochemicals sectors."[222] INEOS Olefins & Polymers UK were similarly optimistic about shale gas development in the UK and suggested that it had the ability to be transformational.[223] Mr Crotty of INEOS Olefins & Polymers UK told us:

> "It is the non-methane elements that are of value to us: it is the ethane and the propane. For example, in the US those elements are fractionated out and we can use them as raw materials to build chemicals with. We are hopeful that the UK shale deposits would allow us to do the same. As an industry in the UK, the problem we have at the moment is that the quantity of ethane coming out of the North Sea supply has declined dramatically in the last 10 to 15 years to the point where it is almost non-existent now. Therefore, getting a new localised supply would be a massive potential benefit.".[224]

96. **If shale gas development produces cheaper gas prices in the UK, as a result of the export of shale gas from the US and the development of shale gas in the UK, the energy intensive industries could benefit from lower electricity and chemicals prices.**

218 Q 61 [Professor Bradshaw]; Q 87 [Dr Bros]; Q 106 [Mr Tiley]; Q 220

219 Ev 97

220 Q 229

221 Q 220

222 Ev w13

223 Ev 97

224 Q 245 [Mr Crotty]

8 Conclusion

97. It has been two years since we last reported on shale gas. In the meantime progress has been slow, largely because of the 18 month moratorium on drilling. We do not believe that it was necessary to take so long to establish the safety of fracking. Hundreds of thousands of wells have been drilled in the USA providing an unprecedented test bed for this technology. In that respect it is different from other new technologies like nuclear where there are rarely more than one or two examples of new reactor types in operation. Had there been any serious consequences they would have come to light. The length of the moratorium has conveyed the impression that the case for and against proceeding with shale gas exploration is finely balanced when this is simply not the case. Care is required to ensure that the shale gas industry in the UK develops more quickly in the future while doing everything possible to allay unwarranted concerns of local communities. But the lack of progress over the past two years is disappointing. The Government has signalled that it sees a role for conventional and unconventional gas in the UK's future energy mix, but it has been slow to establish the framework within which the shale gas industry will operate.

98. Shale gas offers potentially substantial benefits to the UK. Based on the US experience it is likely that development of shale gas in the UK could improve the UK's security of supply, provide employment, create additional revenue for the Exchequer, and support the energy intensive sector. However, the unique set of circumstances which brought about the US shale gas revolution limit the ability to draw comparisons. Given that the US is the only country so far to significantly develop its shale gas resources, we believe that it is still too early to predict the effect of either internationally or domestically produced shale gas on the UK.

99. Below-ground, despite the very large estimates, there are significant uncertainties around how much shale gas can be technically recovered due to a lack of production experience outside of the US. This situation will improve as exploration continues. The experience of Poland demonstrates how prospects can change for the worse over a short period of time. For this reason we remain very cautious about some of the more optimistic shale gas estimates in the UK. We are keen to see exploration proceed quickly to validate current estimates and establish the true potential of shale gas in the UK. While it is unlikely that the UK's offshore resources will be economically attractive in the short-term, we believe that they may have medium- to long-term potential especially if they prove to be more acceptable to the public than onshore operations.

100. Above-ground factors add an additional layer of complexity. The UK shale gas industry can only be developed with the support of the public. Communities affected by shale gas developments should receive and share in some of the benefits. The Government must ensure that the public have confidence in the new Office of Unconventional Gas and Oil, demonstrating clearly that any potential conflicts of interest are avoided. We have previously concluded that the current regulatory framework is sufficient to allow exploration to proceed. We emphasise that, as the industry develops, the regulatory framework will have to strike the right balance between the safeguards necessary to ensure effective environmental protection and the risks of placing unnecessary burdens on business. Similarly taxation policy should strike a balance between ensuring appropriate returns for the Exchequer while avoiding "strangling the industry at birth".

101. It is still too early to conclude what effect shale gas will have on gas prices in the UK. However, due to a combination of factors including geological differences , population density and environmental safeguards, it cannot be assumed the UK will enjoy the low gas prices experienced in the US. For this reason we believe that it would be wrong for the Government to base energy policy decisions on the expectation that shale gas will be sufficient either to bring down prices or generate significant revenues in the future.

102. Shale gas also presents challenges to the ability of the UK to meet its statutory climate change targets. While the US has seen a significant reduction in greenhouse gas emissions as cheap gas has displaced coal in the electricity sector, in the UK the opposite has occurred: cheap coal from the US has displaced gas. Moreover, debates over the life cycle emissions of shale gas (arising from so called fugitive emissions) combined with concerns that it will stimulate a new 'dash for gas' mean that these risks will have to be carefully managed. We share SSE's frustration at the slow pace of carbon capture and storage (CCS) development. As highlighted by the Prime Minister, developing CCS at commercial scale will be critical in determining what role gas can play in the UK's future energy mix.

9 Annex 1: note of informal meeting with BHP Billiton

Attraction of shale gas

Shale gas is the largest and most significant phenomenon in the oil and gas sector in recent history. There is a huge abundance of shale gas and it will have a worldwide impact. We now have twice the oil and gas reserves we thought we had. It is a 'game changer' and as a result dependable low cost fuel is available where it wasn't before. It's going to reverse production declines in oil and gas. The US is heading toward self-sufficiency and could be producing over 10 million barrels of oil equivalent a day in the next 5 years.

Regulatory regime

The regulatory regime in the US is stringent but reasonable and reliable. It is similar to the regulatory regime in the UK's North Sea which has a high level of confidence. There is a "let's get it done" approach. The regulations outline specific standards for drilling and reporting requirements. These are backed up by spot checks. Air emissions are also regulated in a tightly permitted way. Most companies in the US appreciate that this tough regime is in place but once we are satisfactorily within the constraints of the regulations we are free to proceed. The regulatory regime allows you to proceed with developing your assets.

The regulatory regime has the same basic requirements across all states. The Federal government has primary oversight responsibility for air emissions and chemical usage. Their intent is to create transparency which allows informed stakeholders' acceptance.

Relationship between company and landowner

In the US, the landowner generally owns all the minerals under their land. In order to access the shale gas we lease the land from the landowner. We pay the landowner a royalty for the shale gas we extract. Royalties can be the biggest deduction from revenue and can range from 10-25 percent – reflecting the quality of the mineral rights.

The lease agreement also usually contains provisions on how we will use and leave the land during and after operations. We aim to have minimal impact on the land and agree to restore the land to its original state once operations have finished. The footprint of shale gas is, therefore, very small.

Fiscal regime

With regards to the fiscal regime in the US, there is no cap on revenue unlike some countries. If gas prices double, we get the benefit along with the royalty owner. If they half, we bear the investment risk. The biggest deduction to our profit goes to the landowner (see above). There is a small State related tax (between 2-5 per cent of revenue). There is also a federal corporation tax (between 30-35 per cent).

There has never been an additional tax incentive other than what has been described above. There has been no real tax incentives related to shale gas directly. The only role of the Federal government has been to develop a regulatory framework and let the industry invest and conduct its own research. The amount of research going into shale gas is phenomenal. There is "space age" amounts of research going into shale gas in the US every day.

Technical developments

Hydraulic fracturing technology has existed for a long time. Over this period we have seen incremental improvements in the technology. 20 years ago we were able to slant the drill. Now we can drill horizontally in any direction. The development of horizontal drilling and being able to place it with increasing accuracy and precision has enabled us to take advantage of shale gas. In fact, it has seen a quantum leap regarding the economic viability of the shale gas industry. For example, we used to have to move a rig to another location, which can take several days. Today, on multi well pads, we can move a rig in a matter of hours and begin directional drilling from the same site.

The learning and development of shale gas exploration and extraction experienced in the US will accelerate the development of shale gas industries in other countries. Exploration, however, still takes time because all wells are a little different. The first well is likely to be poor, the second a little better and the hundredth brilliant. This could be part of what we have seen with ExxonMobil in Poland – lots of drilling is needed to build an accurate picture.

Markets

The price of gas has fallen in America as a result of the shale gas revolution. We do assess and adjust to ensure our investment decisions are appropriate. However, because gas has displaced coal in the US and there has been up take of the petrochemical industry we are confident that demand for gas will increase over time.

Moreover, most shale gas operations also produce liquids. A lot of our wells produce equal amounts of gas and liquid. For example, we are producing 1000 barrels of oil a day off of just two wells. There is a substantial amount of liquids production. These liquids are more valuable and so allows associated shale gas production to stay economic. Oil is produced in exactly the same way as gas. Most of the shale production, however, was not in the US 5-7 years ago.

Further investment

There will be further investments in shale gas. People are going to be drilling for shale gas for at least the next 50 years. Our great-grandchildren will be drilling for shale gas. This is indicated by the major oil and gas companies interest in shale gas. ExxonMobil is looking at every major shale play. Shell is following suit. The reason is the hydrocarbons are there and prospects for extracting them are constantly improving. Every year the industry is a little better, producing a little more and is becoming a little more efficient. Yes, not only BHP Billiton but the entire industry will be pushing forward.

Social impacts

The social piece is a huge component and constitutes a large part of the US onshore shale gas business. The powerful benefits of the shale gas industry cannot override confidence and citizen acceptance and we work very hard to make sure that our operations are safe.

Geology is just the start. When we lease the land in the United States from landowners who also own the minerals (see above), they are our partners and they have a share in the profits. They want us there as a result. Most of the areas we work in are sparsely populated. In some cases there are "more cows that people". Despite this the impacts of shale development on people living in the area is the biggest thing that we deal with.

In terms of ground water, there has been no substantiated damage. There have been claims. But there is concrete and steel to protect the ground water and all of it is subject to regulation. If there are problems it will be because of the same techniques used to extract conventional oil and gas, not because of hydraulic fracturing.

People have concerns about seismic activity. What happens is that there are stresses in the rock and they try to move. This is normal seismic activity but if we put lubricants across the existing faults that helps it to move. We have learnt that when this occurs we are able to understand where the fault is and we move away from the area. It is the disposal of produced waste water deep into permitted disposal wells that is the main issue in the US, not the fracturing. Moving away from fault areas and removing the lubricant takes this problem away. We are now putting sensors on these wells and so we are able to monitor the activity and get forewarning. It's real and therefore an important social concern and something we worry about a lot but as such we are learning to manage around it.

The most serious problem is injury in the work place. The shale gas industry is less mature than the conventional gas industry. The number of people which work in the sector is an order of magnitude larger. As a result we have more vehicle incidents than anything else. The rigs have 65 different pieces of equipment and the only way to construct them and disassemble them is with people. The large volume of moving parts and a larger proportion of less experienced workers means that as an industry, shale gas development can be less safe than, for example, the conventional offshore oil and gas industry. Unfortunately, sometimes people are hurt and sometimes killed. This situation is unacceptable, and the very best companies like us are making huge inroads daily to making it safer. We recognize this is part of our social obligations and today our company is already performing far above the industry average. So quickly we are gaining confidence that it will get as good as it is offshore.

Despite some of these negative aspects, it is important to remember that everyone in the US is benefiting from the shale gas revolution. In the US, we have met our Kyoto targets, despite never signing the agreement; due to coal consumption being replaced by natural gas. We have created a million highly skilled jobs with a long career ahead of them. We also hire people and support local communities.

In Europe, the social environment is different. In the US, our 45 rigs can go wherever they want and there is no one lying in front of the rig. In Europe it is different. They will have to prove to the average citizen and governments that there is an abundance and that the processes which allow it to be extracted are safe.

Game changer in EU?

In the US we are discovering new things about shale gas continually. The Haynesville Bossier, for example, was not known about 5 years ago. Today, however, one shale play (Bakken) produces more oil than 3 OPEC countries combined. Knowledge about how much oil & gas is in the ground is becoming better understood and is continually changing on a monthly basis. This is because you have to actually drill in order to understand not only how much oil & gas is in the ground but how much is possible to get out. Shale plays require drilling, delineating and then testing their production capability in order to understand how much there is.

The US map of shale basins has developed over time as drilling has taken place and they have been able to develop an increasingly accurate picture of how much shale oil & gas there is. In Europe, however, because so little drilling has taken place it is still unknown how much shale gas there is. Caudrilla's project, for example, is an early view of the American experience. It will take years and years to develop it. American shale plays have thousands of wells and have been delineated over time. All of this would have to happen in the UK and EU.

Conclusion

Progress is made in the US shale gas industry every day. We are living it every day and we can do it right. There is, however, an enormous responsibility on the government to make sure that the framework is right and can be relied upon for long term investments. We spend a lot of time every day working on the various issues around shale. If the proper framework is there we can do it safely and do it well. Social, technical and economic parts of the industry have and will continue to move forward.

Formal Minutes

Tuesday 23 April 2013

Members present:

Mr Tim Yeo, in the Chair

Dan Byles	Christopher Pincher
Ian Lavery	Sir Robert Smith
Dr Phillip Lee	Dr Alan Whitehead
Mr Peter Lilley	

The following declarations of interest relating to the inquiry were made:

Dan Byles declared a non pecuniary interest as Chair of the All Party Parliamentary Group on Unconventional Oil & Gas.

Sir Robert Smith declared interests, as listed in the Register of Members' Interests, in the oil and gas industry, in particular a shareholding in Shell transport and Trading (oil integrated).

Mr Tim Yeo declared interests, as listed in the Register of Members' Interests, including as Director of ITI Energy Limited (unremunerated), suppliers of gasification equipment; Director AFC Energy; company developing alkaline fuel cell technology; Non-Executive Director, Groupe Eurotunnel SA; and Chairman of TMO Renewables Limited. Shareholdings in Anacol Holdings Ltd.; AFC Energy (share option); Eco City Vehicles plc.) and Groupe Eurotunnel SA.

Draft Report (*The Impact of Shale Gas on Energy Markets*), proposed by the Chair, brought up and read.

Ordered, That the draft Report be read a second time, paragraph by paragraph.

Paragraphs 1 to 102 read and agreed to.

Annex agreed to.

Resolved, That the Report be the Seventh Report of the Committee to the House.

Ordered, That the Chair make the Report to the House.

Ordered, That embargoed copies of the Report be made available, in accordance with the provisions of Standing Order No. 134.

Written evidence was ordered to be reported to the House for printing with the Report (in addition to that ordered to be reported for publishing on 16 and 30 October, 6 and 27 November, and 11 December 2012, and 16 January.

[Adjourned till Thursday 9 May at 9.00 am

Witnesses

Tuesday 27 November 2012

Page

Mr Nigel Smith, Seismic/Basin Analyst, British Geological Survey, and **Professor Richard Davies**, representative from The Geological Society — Ev 1

Professor Mike Bradshaw, Professor of Human Geography, UK Energy Research Centre, **Simon Moore**, Research Fellow, Environment and Energy Unit, Policy Exchange, **Dr Thierry Bros**, Senior Analyst, European Gas and LNG, Société Générale, and **Professor Paul Stevens**, Senior Fellow, Chatham House — Ev 9

Tuesday 11 December 2012

Francis Egan, Chief Executive Officer, Cuadrilla Resources Ltd, **Corin Taylor**, Senior Economic Advisor, Institute of Directors, and **Graham Tiley**, General Manager (Ukraine), Shell International Ltd — Ev 18

Professor Kevin Anderson, Deputy Director, UK Tyndall Centre, University of Manchester, **Jenny Banks**, Energy and Climate Change Policy Officer, WWF UK, and **Tony Bosworth**, Climate and Energy Campaigner, Friends of the Earth — Ev 28

Wednesday 16 January 2013

Paul Spence, Director of Strategy and Corporate Affairs, EDF Energy, **Tom Crotty**, Chief Executive Officer, INEOS Olefins & Polymers Europe, **Martin Pibworth**, Deputy Managing Director for Energy Portfolio Management, SSE, and **Peter Parsons**, Forecasting Manager, National Grid — Ev 41

John Hayes MP, Minister of State, Department of Energy and Climate Change, **Simon Toole**, Director of Oil and Gas Licensing, Exploration and Development, Department of Energy and Climate Change, DECC, and **Chris Barton**, Head of International Energy Security — Ev 50

List of printed written evidence

List of additional written evidence

(published in Volume II on the Committee's website www.parliament.uk/ecc)

List of Reports from the Committee during the current Parliament

The reference number of the Government's response to each Report is printed in brackets after the HC printing number.

Session 2010–12

First Report	Emissions Performance Standards	HC 523 (807)
Second Report	UK Deepwater Drilling–Implications of the Gulf of Mexico Oil Spill	HC 450 (882)
Third Report	The revised draft National Policy Statements on energy	HC 648
Fourth Report	Electricity Market Reform	HC 742 (1448)
Fifth Report	Shale Gas	HC 795 (1449)
Sixth Report	Ofgem's Retail Market Review	HC 1046 (1544)
Seventh Report	A European Supergrid	HC 1040 (1684)
Eighth Report	The UK's Energy Supply: Security or Independence?	HC 1065 (1813)
Ninth Report	Solar Power Feed-In Tariffs	HC 1605 (1815)
Tenth Report	The EU Emissions Trading System	HC 1476
Eleventh Report	The Future of Marine Renewables in the UK	HC 1624
Twelfth Report	Consumption-Based Emissions Reporting	HC 1646
First Special Report	Low carbon technologies in a green economy: Government Response to the Committee's Fourth Report of Session 2009–10	HC 455
Second Special Report	Fuel Poverty: Government Response to the Committee's Fifth Report of Session 2009–10	HC 541
Third Special Report	The future of Britain's electricity networks: Government Response to the Committee's Second Report of Session 2009–10	HC 629

Session 2012–13

First Special Report	The Future of Marine Renewables in the UK: Government Response to the Committee's Eleventh Report of Session 2010–13	HC 93
First Report	Draft Energy Bill: Pre-legislative Scrutiny	HC 275
Second Report	The road to UNFCCC COP 18 and beyond	HC 88
Second Special Report	Consumption-Based Emissions Reporting: Government Response to the Committee's Twelfth Report of Session 2010–12	HC 488
Third Report	Low-Carbon Growth Links with China	HC 529

Fourth Report	Pre-appointment hearing with the Government's preferred candidate for Chair of the Committee on Climate Change	HC 555
Third Special Report	The road to UNFCCC COP 18 and beyond: Government Response to the Committee's Second Report of Session 2012–13	HC 633
Fourth Special Report	Low-Carbon Growth Links with China: Government Response to the Committee's Third Report of Session 2012–13	HC 748
Fifth Report	Consumer Engagement with Energy Markets	HC 554
Sixth Report	Building New Nuclear: the challenges ahead	HC 117

Oral evidence

Taken before the Energy and Climate Change Committee

on Tuesday 27 November 2012

Members present:

Mr Tim Yeo (Chair)

Ian Lavery	Christopher Pincher
Mr Peter Lilley	Sir Robert Smith
Albert Owen	Dr Alan Whitehead

Examination of Witnesses

Witnesses: **Mr Nigel Smith**, Seismic/Basin Analyst, British Geological Survey, and **Professor Richard Davies**, representative from The Geological Society, gave evidence.

Q1 Chair: Good morning and welcome. Thank you for coming in. As you know, this is our second inquiry on shale gas. In fact we had some help from you on the previous inquiry last year, but I think it would be helpful if perhaps you just introduce yourselves very briefly to the Committee.

Mr Smith: I am Nigel Smith from the British Geological Survey; I have been working on shale gas since 2008.

Professor Davies: I am Richard Davies, I am a Professor at Durham University and I used to work in Exxon Mobil before I became an academic. I have been working extensively across Eastern Europe talking to members of the public and to companies about shale gas.

Q2 Chair: Thank you. Before we get on to the interesting question of how much shale gas may be under the ground, I wonder if you would just like to explain the different ways of defining how much shale gas there is—there is a certain amount of technicality here—and how those ways differ from each other.

Mr Smith: The first method would be to compare a basin in America—for example, the Barnett Shale in the Fort Worth basin, which I think you visited last year—with a similar basin in this country, which would be the Pennine basin, and see what the productivity is in America, work out the area that we think has shale gas in the rocks here and produce a figure. That figure would be like a reserve figure in our table that we have provided for you. The companies can even produce a resource figure, which is going to be much bigger. It is the total amount of gas that is in the ground and they can even produce that before they have drilled. They will work out the thickness of the shale, they will guess how much the gas content is, they will have their area of their licence and they will be keen to publish that for the shareholders' benefit. When they drill, for example IGas have drilled in Lancashire and they have doubled their figure that they had originally after they drilled one well and tested some of the shales. I think those are the critical differences.

When you start to get production going then you can be a little bit more secure as to what the reserve figure is going to be. Mine was just a guess, the original reserve figure, because no drilling had taken place in this country; so you are using information from another country, another continent, which might not be relevant here.

Professor Davies: Just to reiterate some of the points that Nigel has made, there are two key terms—one is resource and one is reserve, and they are entirely different. Just to reiterate for everyone's benefit, resource is the amount of gas underground. Just like the coal mining industry or any other extractive industry, that is not the same as the amount of gas you could extract. That is called the reserve and that is dependent upon a number of factors, economic, social in the case of the UK and many other parts of the world, and technological. The amount you can produce, which is called the reserve, is usually a fraction of what is there underground.

Companies that are listed on the New York Stock Exchange have to follow guidelines for what they can call reserve, the SEC guidelines. I have been involved in my previous career in industry in booking reserves, defining reserves, and it is a very closely monitored and policed activity in the companies because it relates to the value of their company. Reserves are a different number from resource. Reserves are something you have to be extremely confident you can economically extract from the ground.

Q3 Chair: That includes, therefore, the price as one of the factors?

Professor Davies: To be frank, that is one of the key factors so you can continue producing until you hit an economic threshold. You can look at the decline curve of your production—you usually start with very high rates of production from a shale gas well—and you can extrapolate it to the point where it is economically not viable. Of course, that depends upon the fiscal regime in place, as we know from the North Sea. It is also related to technology and your ability to produce the reserves with the technology you have. There are a number of factors. Most important here is to state that reserves are completely different from resources.

Q4 Chair: Is the New York Stock Exchange definition one that is commonly accepted?

Professor Davies: Yes, the SEC guidelines are followed by companies listed on the New York Stock Exchange and then closely followed by companies

who, of course, want investors to be confident in the reserves because the reserves is a critical number that increases the value of your business. If a company was to make a mistake in estimating the reserves that has a huge impact, and we have seen evidence for that in the past—large companies overestimating reserves. You all know, for example, Shell did that around 10 years ago where they overestimated that critical number.

Q5 Chair: Apart from the price, what other key factors would determine what a reserve is?
Professor Davies: At this point geology is a key factor. Very close to the top of the list is how much gas is in the rock and how the rock behaves when you fracture it and, therefore, how much gas can come out of a volume of rock, but what may be a key determinant is the ability to drill wells; in other words the limitations on drilling wells that may be related to how populated a region is, how acceptable drilling is. In the United States you drill a few wells. You can then book the reserves there and say, "We have proven that volume," and the surrounding areas become probable volumes and behind that will be possible reserves and volumes. It spreads out in that way from a central area as you are drilling wells.
It is a bit like a chessboard. You are then proving different areas as you grow the production and that is quite different from how it has been done for conventional hydrocarbons, which is what the North Sea, of course, is. That is a different mechanism. It is proven by drilling wells. You can book 80 acres per well. That is the area you can book and that is what the SEC guidelines say and American companies listed on the New York Stock Exchange will follow them.

Q6 Chair: Is there a further description between recoverable reserves and reserves?
Professor Davies: No, reserves are recoverable. I think for this conversation they are the same thing. Recoverable reserves and reserves are the same thing. The only other term you may hear is "technically recoverable". If you hear the term "technically recoverable", that is saying, "With the present technology what can we get?" That is not the same as reserve. Reserve is about economics and political regime and so on. You may hear the term "technical reserves", which is what technically we can get out, but the key thing is the term "reserve", which means what we can get out in the present economic regime.
Mr Smith: I think at the moment, because the price of gas has plummeted in the US, they are now switching to looking for shale oil. They will stop looking for shale gas because the price is too low. It is the point that you made.

Q7 Chair: Given that the reserves depend on the price, which clearly is unknown more than a fairly short time ahead, and secondly, on things you mentioned like the density of the population, which must be a pretty subjective judgment, even the SEC definition seems to be a fairly moveable feast.
Professor Davies: The SEC definition is if you have a patch of land with nothing on it—and I am basically agreeing with you—you can book that. Every time you drill a well and fracture it and start producing you have proven a certain volume. That becomes far more complicated if there is land and land use issues. In Europe we are in a different regime from the US in terms of land ownership and mineral rights ownership, so it is going to be a bit more complicated and probably slower in taking off—a lot slower.

Q8 Chair: Without being too cynical, the proximity of potential reserves to a council estate in Lancashire and those to Notting Hill might be regarded as having a different order of influence.
Professor Davies: You are probably more expert than I am, but there are probably parts of the UK that have better prospects for booking reserves than others.
Mr Smith: I think, once again, the Americans are pioneering drilling in close to urban areas. They even drill under Fort Worth, Dallas Airport.
Chair: We saw some of that when we were there.
Mr Smith: Yes. In a way, although the population density in America is eight times lower than ours, I think they are still showing us the way—that it could be done without interfering with people's property, safely and successfully.
Professor Davies: There is a large oilfield in Los Angeles that is camouflaged by buildings and you would not know it was there, but that is the United States.

Q9 Sir Robert Smith: I remind the Committee of my interest in the Register of Members' Interests to do with the oil and gas industry, in particular a shareholding in Shell. I suppose the one-off Bournemouth is another example of where we are in a sensitive area by long directional drilling.
Mr Smith: Exactly, yes—Wytch Farm. It would be much more difficult to get that approved now. Things have moved on since the 1970s.
Professor Davies: In fact Wytch Farm was a great example of us leading in the technology of horizontal drilling. Those were the longest horizontal wells drilled in the world and, of course, everyone understands a combination of horizontal drilling and fracturing that has opened up this technology. We were leading with that.

Q10 Sir Robert Smith: What sorts of factors make it more uncertain in shale gas than in conventional gas? Is it the fact that you have to prove all the geology with drilling?
Mr Smith: You have to define the source rock area, so that probably requires a lot more drilling, even with pad drilling, compared with conventional exploration. It is a bit like, if I can use the analogy of cooking and kitchens, you are looking for the kitchen because the kitchen has a lot of food in it, it is in the fridge, it is in various places, compared to the dining room, which is just a place where people are sitting. They are the individual oilfields, like Wytch Farm, and you have a timing problem there because your hydrocarbons are migrating from the source rock to the dining room and you have to be able to drill just at the time when somebody is eating their food in order to get the

hydrocarbons there. The hydrocarbons in the kitchen should always be there.

Professor Davies: May I add to that? In the last 20 years the industry developed something called 3D seismic data. It is like a picture of this room but the scale bars would be 40 km by 40 km and 5 km, 6 km deep. That 3D seismic data gives clues as to where to find conventional hydrocarbons. You can see it. It takes a picture. It would take a picture of the room and show us where the table is in the middle and you would drill into the table, and the table is well defined. The extent of the hydrocarbons is defined.

Q11 Sir Robert Smith: More potential still?

Professor Davies: Absolutely right, it would be a resource until you drilled it and produced some to prove it could be produced. But with shale gas, the geology has lagged behind. It is a drilling and an engineering discipline to a large extent. The geology is lagging behind. We can't be predictive quite in the way we have been with conventionals and therefore, as Nigel said, you have to drill wells and you have to fracture them and it is a very empirical process: you learn by experience. You fracture. If it doesn't quite work as well as you thought. You modify your design. You start again on another well. It is very empirical and not very predictive. Does that help a little bit?

Mr Smith: I think initially the companies will probably go in close to an existing well in order to make sure that the shale is present. If they can't follow it on the seismic—you can to some extent but it is not so easily defined. The reflectors are not good in shale, so you can't be absolutely certain if you go 10 km away from an existing well that the shale will be as thick or in the same facies; in other words the same type of mudstone, not a sandstone, not a limestone. It is all coming together to make the companies, initially anyway, drill close to an existing well.

Q12 Sir Robert Smith: Is there more that the British Geological Survey and the Geological Society could do to get on top of some of the uncertainties?

Mr Smith: We can always drill more boreholes. We can always look at more of the legacy data that we have. We are working for DECC at the moment and we are looking at the geochemistry, which I think is a crucial aspect.

Professor Davies: I think it is a wonderful research opportunity. I would say that, I am an academic, but I really do mean it because the oil industry is focused on sands, which usually contain the oil and gas, and limestones, and the shales have been ignored. In fact the shales were the reason that the oil was kept underground. I would say there is a huge opportunity to understand shales—a huge opportunity for UK academics and SMEs and so on to get up to speed and to help our Eastern European colleagues who probably are not quite as advanced as the UK is. There is plenty to be done; lots of things that are not understood.

Q13 Sir Robert Smith: If until you have drilled you do not know what you are going to get, why are so many people so optimistic about the potential?

Mr Smith: There are lead zinc mines, for example, in Derbyshire that started off in the carbonates, the limestone, and went down into the shales and, as soon as they get into the shales, they had methane explosions. There are hydrocarbon shows in shales.

Professor Davies: In the North Sea you drill through the shales to get to the reservoirs and as you drilled through the shale there were indicators as you were drilling through that there was gas that was moving into the well bore. Also the Cuadrilla well in Lancashire drilled an extensive thickness and did a fracturing operation and showed that the right conditions are there. I don't think the question is whether it is there; it is whether it can be economically, socially and so on produced from underground.

Q14 Christopher Pincher: A number of us went up to Lancashire a year or so ago to visit Cuadrilla and look at their Bowland field shale play, and it was quite interesting to see what they are doing there. I think BGS did a survey of the reserve estimate in the Bowland field and you came up with an estimate of 5.3 trillion cubic feet for quite a large area. Cuadrilla have subsequently said that there is something like 200 trillion cubic feet of, I suspect, reserve that can be exploited. Why are the numbers so very different? Is that because they have done some drilling and their estimate is that much more accurate?

Mr Smith: Yes, essentially. My figure originally was a reserve figure before any drilling had taken place, so it was just a comparison with what was going on in America. Whereas Cuadrilla, by the time they released that figure, had drilled two wells. They have now drilled three, I think, so they have the gas content in those shales. They have also identified a lot more shales. I just took one example and compared it with America. They have a much greater thickness of shales. It is like a stacked sequence, which is more comparable, if you like, with the American basins conventional oilfields where they have stacked reservoirs. The greater thickness of shale, the more gas you are going to get. Their figure, in my opinion, is more reliable than mine.

Professor Davies: I am pretty confident the 200 tcf is a resource. This is not a reserve. Again, to reiterate, they are saying 200 trillion cubic feet underground. They are then saying they could perhaps extract 15% or 20%, which equates to more like 20 or 30 tcf. One of the reasons the numbers are so different is that we are not comparing apples with apples. I am pretty sure in the statement they made it is a resource not a reserve.

Q15 Christopher Pincher: You say they have drilled three wells now?

Mr Smith: They have started the fourth and they have had problems. They are going to have to move the drilling site a few hundred yards away and then start again.

Q16 Christopher Pincher: What I was going to get at is, at what point in the drilling process are you able to accurately estimate what is there and what is exploitable, do you think?

Mr Smith: They have 1,200 square kilometres and they have drilled in about, say, 20 square kilometres.

It is still a bit of an exaggeration, if you like, to extrapolate it to the rest of the licence area.

Q17 Christopher Pincher: When can we be clear, as clear as one can be, just what sort of resource is exploitable under Lancashire and under the sea?
Mr Smith: I would like to see the gas content figures published and I would like to see the actual production figures published as well for many of the wells that they have drilled. They have only drilled vertical wells at the moment. The Anna's Road well that they are drilling at the moment will have a horizontal leg to it. When they drill these and when they are allowed to hydraulically fracture them they will put them on test and we will start to get the first figures, which then will be comparable or more comparable with what has happened in America. You start to get what is called the initial production. You start to be able to put it statistically somewhere on a graph where all the American wells have been plotted and then we can see where it is heading.

Q18 Christopher Pincher: When do you think we can see that? How far forward is—
Mr Smith: When they publish the figures. Hopefully they will be allowed to resume fracking soon and they will also drill these extra wells. I think it will be probably next year, assuming they are allowed to resume.

Q19 Christopher Pincher: I think what we want to understand is just what extent there is there for shale gas in the UK and right now it seems that nobody is very sure.
Mr Smith: I think one of the problems is we have had the 14th round of licensing delayed. If that had been enacted, lots of companies would have taken out licences, probably covering most of the country. There are obviously some places they would not be going, but we would be quite a bit further down the road of knowing how much shale gas we are going to have in this country if the companies had their licences. It has taken Cuadrilla three years to get to the stage of drilling and getting a result, even if they have not published fully what we need.

Q20 Christopher Pincher: Based on what we do know and based on your estimate that there is an exploitable reserve of, let's say, something like 30 trillion cubic feet, if it is somewhere like 15% of what they estimate is there, how does that compare with conventional reserves of gas under the North Sea?
Professor Davies: I can give you one statistic. The maximum production from the North Sea was around 1999 and it was just less than 4 tcf.
Christopher Pincher: Four?
Professor Davies: Four. Annual production from the UK. I looked it up. And that was our peak. You know we have gone past peak now. It was just less than 4 tcf.

Q21 Christopher Pincher: On that basis, there is quite a lot of potential for shale gas in the UK and under the Bowland field specifically?
Professor Davies: If you made the assumption you have 10% to 20% recoverable from a 200 tcf resource, that is a significant amount but it is not globally significant. The Marcellus is hundreds of tcf and Barnett—all the shale gas provinces in the US are probably a lot bigger than that.

Q22 Christopher Pincher: One last question. If the reserve estimates are what they are, if the price of gas changes significantly could that change the reserve estimates?
Mr Smith: In a sense, yes. It would just delay the actual production, I think, because the more marginal fields would not come into production.

Q23 Christopher Pincher: For that to happen, the price just has to go up?
Mr Smith: I think so, yes.
Professor Davies: As the price goes up things become economic again and people start drilling. When the price goes down it tends to reduce the amount of drilling. In the US they have had a massive drop in the gas price and people are now looking for liquids, which have more value. People are starting to say some of the shale gas is not economic, some of it; depending on the cost related to that development.

Q24 Mr Lilley: I declare my interest. Is it not the case that in many countries you have to reveal to the state authorities the sort of figures you were talking about, the gas flows, your wide-arm log details and all that? Is that not the case in this country? Do not BGS get these figures before they are made public?
Mr Smith: We used to, but I would not say that is the case now. It is normally five years before the well is released, but even then the company can hold that back for a few years.

Q25 Mr Lilley: You mentioned liquids. Have any estimates been made of shale oil potential in this country?
Mr Smith: Not yet, but we are doing it, yes.

Q26 Mr Lilley: Finally, in my experience things like resource estimates are almost like shutting your eyes and plucking a figure out of the air. They vary hugely and the only real thing is just drill a few holes. So why don't we just drill more holes and then we will know? Why waste so much time speculating when you will not know until you have drilled anyway?
Mr Smith: Exactly.
Professor Davies: Yes. The best way of communicating resources is to do it on a graph, I am afraid, and to have a min and a max and have a whole range. These numbers we have heard are called "deterministic numbers" and it is wrong, of course, because we do not know. It is a range. The best way of communicating resources or reserves is to say, "We have a 99% chance of this and a 1% chance of that and a 50/50 chance of this volume," because there is so much uncertainty. But, as I said in my opening comments, the only way to book your reserve is to drill wells, which is agreeing with what you just said.

Q27 Chair: The suggestion of the *Spectator* recently that we have 65 years' supply in the UK is a bit speculative, is it?
Professor Davies: It is totally speculative because it is dependent on a number of factors that I do not think we can predict: the economic regime, the political regime, the social acceptability and so on. That is for reserves. Unfortunately it is only partly about the geology. There is a whole set of other factors.
Mr Smith: You can see how slowly things are going in this country compared with America where they drill thousands of wells. I know it is a continent and we are only talking about a few small islands here, but the speed of activity is so slow in the UK.

Q28 Sir Robert Smith: Given that it is onshore, it is not the cost of drilling that is holding it back. It is the regulation.
Mr Smith: The cost of drilling is higher than it is in America, so that is an additional factor for the companies to take into account, but the gas price is higher as well. I think that would balance out.

Q29 Sir Robert Smith: Even if you drilled, what is the knowledge nowadays of the tail that will come? Obviously when you first drill and you start to get production it flows quite nicely, but then you have to work on keeping it going. How do you build into the estimates that tail?
Mr Smith: You are going to have to keep drilling because there is quite a steep tail to shale gas wells. They decline very rapidly and they may go on for a long time, so you have to keep up the speed of drilling. You have to keep adding wells in order to keep production up.
Professor Davies: You can do infill drilling and refracking. You can do multiple stages of fracking, so you could go back and fill in the gaps between your wells to keep the production going. But my understanding is if the tail goes on and on and on for a long time, the cut-off will be an economic one where the rates are so low and the costs are—

Q30 Sir Robert Smith: But in making your estimates of what you are likely to be able to recover, is there an understanding of that—having drilled and seen the first, can you be more certain?
Mr Smith: I think technology will come into play then. If technology improves, as it has in America—the wells that were drilled in 2005, 2006 had a much lower productivity than those that are being drilled now. The question is where Cuadrilla's and other companies' wells in this country sit on this particular graph and that is what we are keen to know.

Q31 Sir Robert Smith: You mentioned Cuadrilla had a problem with—
Mr Smith: Yes, it is a drilling problem on Anna's Road, according to their website. They terminated in the aquifer and capped it and they are moving to another site.
Sir Robert Smith: There is no more detail?
Mr Smith: No, we don't know any more.
Chair: Your point about the speed is well taken by this Committee since it is over a year and a half since we recommended the Government should go ahead with approving exploitation of shale gas in the UK, and we are still waiting for a decision.

Q32 Ian Lavery: The issue about reserves and resources concerns me greatly because, being from the coal mining industry, with collieries with millions and millions of tonnes of reserves, if the overnight world price of coal changed then reserves automatically converted to resources and then the colliery became unviable and then they closed it. If we look at it in the same sort of scenario in a reverse order way, we really do not know what we have in terms of resources and reserves because it depends on the economic climate, which is concerning as far as I am concerned. With regard to the estimates, what are the global and European shale gas estimates and how do they compare with the estimates here in the UK?
Mr Smith: There are some massive figures. For Europe, technically recoverable resources 2,587 tcf and that is recoverable 624 tcf. That was Advance Resources, a company in America in 2011. We were talking about recovery factors before. They have assumed 24% recovery for the whole of Europe, but it is based on next to nothing. There are a few wells in Poland now, but where is the released information on the gas content and the production? We do not know it. Exxon have pulled out of Poland after drilling two wells because, they say, the gas flows were not high enough, but we do not know what they were.

Q33 Ian Lavery: Their estimates are based on basically nothing, you say? Does that mean they are probably wholly inaccurate?
Mr Smith: I won't say they are totally inaccurate but the Advance Resources estimate—when they are looking at the whole world, they can't devote a lot of attention to any particular one country. They can't look in detail at all the wells. They can't look in detail at the thickness of the shales. They won't know what the gas content of the shales is because that is all held confidential by the companies. There is so much data that could be used to get a better figure that will not have been available to them.
Professor Davies: Drilling a well in Lancashire or in Poland or wherever is like putting a needle into this room. It doesn't tell us where we are sitting. It doesn't tell us how many people are in the room. A borehole is eight and half inches wide and it tells you about eight and half inches and a little bit into the rock formation and that is the problem. You can characterise that smaller amount of rock, but you can't characterise the basin and hence the uncertainty. If you have the right amount of data you can make good estimates but you are always data-poor until you have finished producing your last oil and gas.
Ian Lavery: So it is highly uncertain?
Professor Davies: Yes.

Q34 Ian Lavery: All the figures are highly, highly uncertain. Anyway, moving on, how do the figures for unconventional gas compare to the estimates for conventional gas?

Professor Davies: I don't have the numbers on the UK total production of oil and gas to date. The only thing I will say is that 200 tcf is highly significant compared to the North Sea. They are comparable numbers, I just don't have the exact data. If you would like me to respond to that, I can do that and get some detailed data for you. I would say the number 200 tcf is a very comparable number to the resources of the North Sea and the Southern North Sea. They are big numbers.

Q35 Ian Lavery: Thanks. How will developments in other countries around the world and in the EU affect shale gas developments here in the UK?
Professor Davies: I think that is a very good question. I have been around Eastern Europe. I have been to about 10 different meetings. I have met the Bulgarian Government Committee on Shale Gas and a number of other organisations. I would just make a couple of comments on that. I think the UK is respected in terms of our regulatory regime and we have a lot of experience, and other countries around Eastern Europe will be looking to see what we do. We have an opportunity to lead in terms of guidelines and regulations, if indeed we do go ahead. I know there are decisions to be made. I think there is a good opportunity for the UK, firstly in terms of leadership in the regulatory area and also in terms of the science and small companies getting involved and so on.
I just wanted to comment a bit further on that. In Eastern Europe there is real mistrust and a lack of confidence in developing shale gas due to the Soviets and a history of things that have gone wrong and I think they do look to the UK to see what we will do and to get our advice. There is an opportunity there.

Q36 Sir Robert Smith: There is obviously conventional gas and then there is unconventional gas and one of the unconventionals is shale. Is it a discrete silo or is it you are starting in one area?
Mr Smith: It is not in America. There is a giant field, the Sandy Gas field in Kentucky, which has some conventional gas as well as some shale gas. That was discovered in 1914 or about that time. They are combined in some places. It depends on the relation of the conventional reservoirs to the source rock and how far the hydrocarbons have migrated.
Professor Davies: There are continuums as well. Coal and very organic rich shale, geologically these are end members and there are continuums. You can get sands that need to be fractured and that has been going on in the UK, I think, since the 1990s without any issues. "Unconventionals" is a very broad term that captures a lot of different types of rock.

Q37 Albert Owen: If I could just move to the potential offshore. What kind of work have you been doing on that and what kind of figures do we have?
Mr Smith: We haven't done a lot of work on it. I have just rapidly put together what I included in the notes for you. We put in a proposal to BIS that we hoped would get funded that would have helped some of the assisted areas around Liverpool, but that was turned down. I don't know whether we are going to take that any further forward. The way I saw it was that we would have to look at everything. It was not just the geology. We would be looking at the economics of it, whether you could start by drilling near the coast and deviating offshore. In the case of horizontal wells, that probably would not be any more costly than drilling horizontal wells totally onshore, but you would not get the full coverage. You would only get about 180 degrees coverage because you would be trying to keep it offshore perhaps.

Q38 Albert Owen: How does this compare to offshore in other countries? Obviously America, as you said, is a continent, but some of the other areas may have produced this. Have they come forward with offshore?
Mr Smith: No, I don't think any other countries will need to look offshore. I said about the population density here. Maybe some other countries that have a very high population density might be tempted to look offshore, but I think it is the economics at the moment. Certainly within the industry they feel that the economics does not stack up. There is already production in platforms offshore. There is the option, what do you do with those platforms when they come to the end of their life? There is a CCS, carbon sequestration option. You could go out there, perhaps underground coal gasification. There are a lot of competing ideas for the use of these platforms as well as perhaps using them for shale gas.

Q39 Albert Owen: Why do you think there is a lack of enthusiasm from BIS? I am paraphrasing what you said.
Mr Smith: They have a set pot of money to allocate.

Q40 Albert Owen: Fine. It is all about their resource more than anything else. The potential now, we are talking here about vertical and horizontal—something you never had on other gases that you are getting now. We are waiting for this gas strategy. Are there companies who have exhausted their fields likely to be interested in this shale gas revolution?
Mr Smith: Offshore, I don't know. Once again, it is the economics.

Q41 Albert Owen: It is the economics but, Professor Davies, you also mentioned the drawbacks with onshore and certainly those do not apply offshore, and particularly you mentioned population and socially acceptability. Because we have not developed onshore in the way of America and many others, shouldn't we take that quantum leap and go offshore and be one of the leaders?
Professor Davies: Yes. One of the ideas I heard from industry is that, believe it or not, some platforms do not have enough fuel sources to power turbines and that is a limiting factor. It could be used as a local support source of energy initially to at least power turbines on the platform. I think probably it is an economic hurdle. The important thing to say is that the window to grab the opportunity is probably in the next 10 to 15 years because decommissioning—I don't know if you have ever seen a map of the shrinkage of the North Sea as decommissioning takes place and it is relevant to CCS as well, of course—is

critical. The economic hurdle may be the key one but, of course, just like wind energy, it is easier done offshore in terms of social acceptability.

Q42 Albert Owen: We are looking at some negatives. Are there any real positives of offshore in comparison?
Mr Smith: Yes, no opposition.
Dr Whitehead: It is a serious one, though, and it is one where we could take advantage, as I say, because it is underdeveloped in this country.
Professor Davies: We also have thousands and thousands of wells. I would say our database is far more accurate offshore. Some of the questions you have asked about the uncertainty I think would be reduced offshore. There is a positive there because it is probably one of the best-studied offshore regions in the world, simply because we have drilled a lot of wells and shot a lot of seismic data. I think the big hurdle is the economics.
Mr Smith: The thickness of shale might be greater offshore as well, so the geology might be better offshore.

Q43 Dr Whitehead: I just wanted to think for a moment about the volumes of water involved in the fracking process. Clearly, if you do that onshore, the perceived wisdom, so I understand, is that you dispose of the water with the chemicals in it by deep injection, or you can do that. That is done to some extent in America.
Mr Smith: It is done in America but it would not be allowed here, I don't think, by the Environment Agency.
Dr Whitehead: Or it is cleaned up in specialist filtration arrangements. If you drilled offshore, presumably you would have to continue to bring the water ashore or would you just put it in the sea?
Mr Smith: I think you would frack using seawater, but that is a technological development that we would have to pioneer probably.
Professor Davies: What happens offshore, for example if you produce oil that has a lot of water in it, you can reinject the water into the oilfield—there is an analogy there—or you could re-inject it into a sand that doesn't have any oil in it. It is just a nice unit deep down. The problem with flow-back water, which I think is where your question is coming from, is that in the UK we are not allowed to inject that unless it is going into a depleted oilfield to maintain the pressure in that oilfield. We will be faced with the same issue that Pennsylvania has. It has five or eight injection wells, which is nowhere near enough to handle the flow-back water, and so if it is onshore, the UK will have to process the water and clean it up, as has happened with the Cuadrilla well in Lancashire. We will probably not have enough oilfields onshore to handle the flow-back water. We would have a developing industry in cleaning water, which is what has happened in Pennsylvania. It has led to innovation and it has led to industry and development of an industry around that.
Mr Smith: I think there is a development also in America to recycle the water, to keep it in a closed loop, which means that they have to deal with saline water as the fracking fluid. I think that is an environmentally positive move, which we should encourage.

Q44 Dr Whitehead: Is there a point at which you can't recycle water any further? Presumably it becomes more and more concentrated with the fracking fluid in it.
Mr Smith: Those are the problems the Americans are grappling with at the moment, yes.

Q45 Christopher Pincher: Water recycling is a challenge, but are the Americans not also experimenting with dry fracking using gases? The US Department of Energy has a specific team looking at that. What do you think the opportunities are there?
Professor Davies: I have heard about that and I have heard of new technology. The honest answer is I don't know whether that is going to be likely. Already the fracking fluid technology has moved on from gels into what is called slick water. It has already moved on and there is a lot of investment. I don't know enough about that new technology as to whether it is going to reap dividends. At the moment we have flow-back water and I think what we have to do is be innovative about reusing the flow-back water, possibly using other industrial waste water if we can. I don't know enough about that technology, I am afraid. If you want we can get back to you.
Dr Whitehead: That would be interesting.

Q46 Sir Robert Smith: Just on comparison, you mentioned earlier how in the North Sea they drilled through quite a lot of shale and had records. That is a positive. What is the difference in operating costs, though, of trying to do a shale production in the middle of the North Sea as compared with near Blackpool? What is the order of magnitude?
Professor Davies: It depends if you have an existing infrastructure in the North Sea. If you had to commission a semi-submersible rig and drill the first well, rig costs have been extremely high: hundreds of thousands of pounds per day. If you had a platform and you were drilling from an existing platform and it was just another well, then the costs are far lower because you are there and established. It is difficult to answer that question because it depends what the starting point is.

Q47 Sir Robert Smith: The existing infrastructure, does it have the potential and is there a particular part of the North Sea that showed promise for shale or is it a general—
Professor Davies: It would be the Kimmeridge clay. Anyone from Dorset will have perhaps been down to Kimmeridge Bay and the Kimmeridge clay is a world-class source from off the North Sea and has been considered and it would be in the report that BGS are doing, no doubt, as a potential. You have to drill through the Kimmeridge clay to get to some of our most prolific conventional resources. The Brent Fields and Piper all had to drill through the Kimmeridge clay on the way through to those reservoirs.
Sir Robert Smith: The Brent is about to decommissioned.

Professor Davies: Yes, but you can see why there is such a huge database, because they have had to drill through these rocks over and over again. They may not have collected exactly the right data but they certainly would have a lot more than we would have onshore.

Q48 Sir Robert Smith: Geological still has the storage of the original cores?
Mr Smith: Yes, we have—if they have taken cores in the shale, of course, which they may not.
Professor Davies: They sometimes do by accident. Spotting where to start coring is a fine art and it is quite easy to core the wrong thing and to get some shale.

Q49 Sir Robert Smith: Originally it would have been just treated as waste?
Professor Davies: Yes. As I said, the industry spent the last 100 years looking at sands and limestones and hence this area is such a fantastically exciting research area because it hasn't been studied enough.

Q50 Albert Owen: Just before moving on to skills, one last point on economics. Do you recognise the figures, Professor Davies—I know you will because you supplied them, Mr Smith—that five to 10 times higher volumes are available offshore, but that the cost of getting it is 10 times higher than onshore?
Professor Davies: When you say 10 times more, I would say it really depends on what the starting point is, what the water depth is and what the depth of the reservoir is. There are a number of factors.

Q51 Albert Owen: Okay. Do you think they have factored in existing platforms that will be out of commission and can be used?
Professor Davies: Sorry?
Albert Owen: Have they factored in the existing infrastructure?
Professor Davies: I don't know.
Albert Owen: We will be interested to know.
Mr Smith: No.
Professor Davies: They have not factored it in?
Mr Smith: No.

Q52 Albert Owen: Can we move on to the skills base? Are you happy that the people who work in the North Sea now and the companies could quite easily switch over to shale from the conventional gas that they have been experts in for many decades?
Mr Smith: No.[1]
Professor Davies: I slightly disagree with Nigel's answer. I think the large corporations have expertise in the US in shale gas and developing expertise in Eastern Europe and they have the people to do it. It is really whether the size of the prize is big enough. At the moment the general trend in the North Sea is that smaller companies are going in to mop up and to make businesses out of what is left. The large corporations, the super majors and the majors, are less and less interested as a general rule. I think the expertise is there. It is whether the opportunity is big enough for them.

[1] See supplemaentary evidence from BGS ISG 17a

Q53 Albert Owen: You say the data is available, so there would be less need for research.
Professor Davies: I am sure they would say that there is additional data to collect, of course, because the specific measurements you need would not have been taken because they drilled through it—they were not really that interested—but the database is substantial.

Q54 Albert Owen: Is the high skill base offshore unconventional mainly British and could it easily adapt to onshore shale gas in the UK?
Professor Davies: I didn't catch the first bit.
Albert Owen: The decommissioning of the fields offshore; is the skill base predominantly British and would it easily adapt here or would they be tempted to go elsewhere in Europe and across the world into shale gas?
Professor Davies: Is the skill base offshore British? Was that the—
Albert Owen: Yes, mainly—
Professor Davies: For what part of the business?
Albert Owen: For drilling, for extracting it. We are in very early days. We need to identify whether it is there. It is frustrating for us because a year and a half ago we did this and we collated all this information and passed it on to Government, and they seem to be sitting on it and we are none the wiser than we were 18 months ago. That is why I am asking you very elementary questions.
Professor Davies: Firstly, there is a huge amount of British expertise in drilling, geoscience, all of the above. Because of an industry since the 1960s, we have been training people who are now working internationally and in the UK, in Aberdeen for example. The expertise is there and, if it is not there, it is in the US and in an international corporation and would be brought back if the size of the prize was big enough to make the North Sea viable.

Q55 Sir Robert Smith: In the current climate the problem is the other way. They need more skills in the North Sea at the moment. The recruitment crisis and the retirement—
Professor Davies: There is a demographic issue as a general rule in the oil and gas industry. The number of people retiring over the next 10 years is an issue.

Q56 Albert Owen: If we do not proceed with this there is a danger that some of that skill base in the North Sea will go to America and other places for shale?
Professor Davies: It is a good point. I think eventually that would happen.

Q57 Sir Robert Smith: At the offshore Europe exhibition in Aberdeen last year, which is the main industry showcase, the only people a lot of the majors had on their stands were the global recruitment consultants. They have no other expertise.
Professor Davies: Yes. I think it is interesting that if you look at the UK, the onshore operators are small organisations. If you go to Eastern Europe, you then see some of the bigger companies in there, Chevron and Shell, and that reflects the size of the opportunity as they see it.

Mr Smith: It also reflects the fact that we haven't had the 14th round, so these other companies have not had the chance to come in. We know they're interested but they have not had the chance.

Chair: Thank you very much. You have been very helpful indeed and I am sure we will maintain a dialogue with you.

Examination of Witnesses

Witnesses: **Professor Mike Bradshaw,** Professor of Human Geography, UK Energy Research Centre, **Simon Moore**, Research Fellow, Environment and Energy Unit, Policy Exchange, **Dr Thierry Bros**, Senior Analyst, European Gas and LNG, Société Générale, and **Professor Paul Stevens**, Senior Fellow, Chatham House, gave evidence.

Q58 Chair: Good morning and welcome. You have heard what has gone before. Would you like to introduce yourselves in a couple of sentences, please, starting on the left?

Professor Stevens: I am Paul Stevens, Emeritus Professor at the University of Dundee and Senior Research Fellow at Chatham House. I have been producing a couple of reports on shale gas over the last two years through Chatham House.

Dr Bros: Good morning. My name is Thierry Bros. I am the Senior Analyst for European Gas and LNG for Societe Generale and I have worked in this industry on the research, on the Government side, for 20 years and I have published a book recently.

Mr Moore: I am Simon Moore. I am an Energy and Environment Research Fellow at Policy Exchange and I published a report at the beginning of this year on shale gas and its implications for UK energy policy.

Professor Bradshaw: I am Mike Bradshaw. I am a Professor of Human Geography at the University of Leicester. I also lead a UKERK (UK Energy Research Centre)-funded research project on global gas security, which includes case studies of US shale and also the globalisation of LNG.

Q59 Chair: Perhaps we may start by talking about America and much of the news in connection with shale gas. What was America going to do about the declining gas production before the shale revolution came along?

Professor Stevens: The short answer was build LNG re-gas plants, I think, but then—and I think this is a very relevant point—the US Government put a huge amount of money into research and development on low-permeability operations, funding the sort of scientific research that private companies normally would not do. It was that that made a major contribution to the development of the shale gas revolution in the United States.

Q60 Chair: That research programme was a response to what would otherwise have been a greater dependence on imports?

Professor Stevens: Yes.

Q61 Chair: Does anyone else want to comment? How has the development of shale gas now affected the gas market in the US?

Dr Bros: As you have heard earlier, the price has plummeted. We could say that we even had prices that did not reflect cost in the US in terms of production cost earlier this year. Today it is around $3.7 per million Btu and it could be around the cost of production. The question is, "What is exactly the cost of production?" but we could say that, due to the technology efficiencies and the fact that wells are producing more and more, we are around the cost of production today.

Mr Moore: One of the consequences of that has been a switch in the energy system, particularly the electricity system, away from coal and towards gas as it has been much cheaper and more competitive.

Dr Bros: I may add the US is the cheapest gas market on a worldwide basis. We are paying wherever we are on a worldwide basis, be it in the UK, in Europe or in Japan, much higher prices on gas but also, as you have heard earlier, we are moving from the shale gas to the shale oil and the same thing is happening in the US with WTI, which is the reference price being lower than the Brent reference price for oil in Europe.

Professor Bradshaw: They are also seeking out reserves that have other gas liquids—ethane, propane, butane—again because they have a greater value. What is happening is that the drilling of dry gas without those associated liquids has fallen quite rapidly and the drilling rigs are moving to other areas. When you are looking at the economic viability in this low-price environment, the opportunity to gain value from other sources of liquids is also important and that becomes a critical feedstock into the petrochemicals industry, which also adds to the debate about gas providing the basis for new jobs and the reindustrialisation in the US. It is not just about providing the gas, for example, to drive a power station. It is about the wider impacts of that gas on the economy.

Q62 Chair: The effect of this is to cut costs for those industries in America that are big energy users, with all the competitive advantage that that bestows?

Professor Stevens: Absolutely, and in fact, if you went back five to 10 years the idea there would be a revival in US petrochemical industries would have been regarded as unrealistic, but now it is a very serious—it is not a serious possibility. It is happening.

Q63 Chair: Is there a prospect, however, that the price of gas may fall so far that the revolution will be halted because it becomes uneconomic to produce it?

Professor Stevens: The issue here is how much money you can make out of the liquids that you are producing during the shale gas operations. If the shale gas is fairly wet then, even though the dry gas you are selling is not earning you any money, you will earn a lot of money from producing the liquids and that is

the key to the continuation of the revolution in the US at the moment.

Dr Bros: Yes. The amount of gas produced in the US is still growing even this year versus last year. This is happening partly because wells are becoming more and more productive, you have more production per well, but you also have more oil production and with the oil production you get at least 11% gas production.

Professor Bradshaw: The question is about the longer-term sustainability of the system. Obviously there is a balance to be struck between a price that is low, which grows demand either in the power industry, in petrochemicals or even as a transport fuel, on the one hand, but is high enough to encourage drilling and production. Obviously there are changes to technology that potentially drive down cost, but also there may be increases in cost as the regulatory regime in the United States is tightened up. At the moment, the current break-even cost varies depending on where you are, your drilling costs and so on. What the cost in the future will be is uncertain in terms of what the regulatory costs will be. The IEA in their "Golden Rules for Gas" report suggested that the implementation of their golden rules would only add 7% to costs, which does seem low, but they are suggesting that an effective regime will not make gas increasingly expensive. Striking this balance to sustain the future is the question in terms of sustaining the level of output in the United States and perhaps having output that could then be exported.

Professor Stevens: The story of the US shale gas revolution is an astonishing story of technological improvement, and technology has been bringing costs down dramatically over the last five-plus years, a process that is continuing. Even with lower gas prices, the technology is bringing the production costs down.

Mr Moore: I think the point that Professor Bradshaw touched on at the end about people looking for export opportunities is also worth drawing attention to. The difference in prices between the situation in the US where prices are, as we have heard, at a historical low, or have been earlier this year, and markets in Asia and to a lesser extent than Europe where prices are significantly higher, creates these opportunities for arbitrage that are certainly being looked at.

Q64 Mr Lilley: Could you tell us a bit about how the price of gas is determined in the UK and what impact on the UK gas price would significant discoveries of shale and development of shale gas in the UK and indeed in Europe have?

Dr Bros: I would say that the price in the UK is based on a spot level, which has been the case since liberalisation of the UK, but I would like to add that the price of gas in the UK is becoming more and more like the price in continental Europe for three reasons. Firstly, you have interconnectors that allow your gas to be shipped one way or the other. Also, we used to have in Europe some oil-indexation and this is fading, so we have more and more spot indexation. Thirdly, as you have heard before, the UK production, domestic production, is declining. Therefore, you are importing more and more gas and, therefore, you are becoming more like continental Europe even if there the level of spot price is still limited.

Q65 Mr Lilley: What impact would shale gas development have, firstly if we discovered a lot here, and secondly if they discover a lot on continental Europe?

Dr Bros: I think it will do the same as in the US. It will drive competition because, as I said, the price is based on spot but if you are relying on major, whatever you want to name them, foreign producers. If you manage to grow domestic production you will come back to what you had 10 or 20 years ago. You will have more competition inside and the price should go lower. I do not think that the price today is reflecting the cost structure in the UK.

Q66 Mr Lilley: DECC says that even if we find a lot of shale gas here it will not bring the price down. It will merely displace continental supplies and LNG supplies, but the price will be determined by continental supplies.

Professor Stevens: It will depend upon the price in Europe because the existence of interconnectors allows a degree of arbitrage, so the prices will tend towards each other.

Q67 Mr Lilley: None the less, there would presumably be an advantage even if the price remained at the European level in that, firstly, it would be domestic gas displacing imported gas, and secondly there would be the tax revenues generated by that gas, which would mean they would be able to put other taxes down. Knowing Governments they would increase expenditure, but it is supposedly an advantage.

Dr Bros: Exactly, plus I think if you manage to get more gas produced you would increase competition.

Q68 Mr Lilley: There may be enough competition as it is, but even if the price remains at the world level or the European level—I do not know what proportion of the take of gas goes to the state. Is there a royalty? Is it purely corporation tax? Is there any petroleum revenue tax just on the North Sea that does not apply onshore? Am I correct on those things?

Professor Stevens: I do not know what the fiscal system is for shale gas, to be perfectly honest. It is the property of the state and I assume that there will be some sort of a royalty accruing to the state but I am not sure—part of the problem is that shale gas is excluded from the normal petroleum regulations. It is in a world of its own, and until the fiscal system and the regulations begin to catch up, it is not clear to me what the fiscal system for shale gas would be.

Q69 Mr Lilley: It must be in the Cuadrilla licence terms. It must state whether there is a royalty or not.

Professor Stevens: One would assume so.

Professor Bradshaw: Presumably that is one of the key above-ground factors we heard about earlier in determining the actual reserve base. It is a fact for the United States there were and are still tax breaks to get the thing going. It certainly is not just a case of an environmental regulatory regime. It is always a case of the fiscal regime, in terms of providing an attractive enough proposition for people to want to initially make the investment in exploration, but then the

decision about commerciality is, in large part, determined by that tax regime. It is clearly something for Government to look at in terms of striking a balance and I would assume that in the Europe-wide context different countries will be competing to attract exploration activity and investment and that is the way of the world. It is something to be looked at in terms of how one might create a regime to attract the initial exploration activity and then the decisions on commerciality can only be made once you have answered many of those questions that were asked. Of course, the levels of uncertainty with unconventionals, with shale, are much higher than with conventional gas in terms of how future production will play out as you are drilling to prove up reserve.

Q70 Mr Lilley: Are you saying there is a special tax regime for shale in the States?
Professor Stevens: The 1980 Energy Act in the States gave tax credits up to 50 cents per million Btu on unconventional oil and gas and that was in place up until 2002. That was at a time when the domestic gas price was around $2.50. A 50 cents tax credit was quite a significant incentive to persuade people to go out and start thinking about unconventionals.

Q71 Mr Lilley: Maybe, Chairman, we should ask for a paper on the fiscal regime in the States and indeed as it currently applies in here.
Professor Stevens: Just to add, in the US it is very different because the subsoil minerals are the property of the landowner and not the state, as is the case in Europe.
Chair: That might produce a dramatic difference in attitudes.

Q72 Sir Robert Smith: What sort of effect has the change in the US gas market had on the UK? Has there been much?
Professor Bradshaw: It is a bit like moving the bits around in a Rubik's Cube as to how you get the answer in some ways because, as we have already pointed out, the expectation was the United States would start to import gas and much of it would be LNG. They built all these re-gas terminals to receive the LNG, about 150 bcm-plus, of which, at the moment, they are only using about 10% of the capacity. What has happened is the US market disappeared but at the same time there were LNG projects, particularly in Qatar, being developed to meet that demand. That provided a short-term glut of LNG at the time when the UK was also investing in new re-gas terminals itself. The opportunity that we have taken over the last few years to import liquefied natural gas to diversify our portfolio has been realised. The only caveat is that post-Fukushima a lot of that oversupply in the market has been consumed by deliveries going to Japan and continuing growth of consumption elsewhere and also in gas-exporting countries. At the moment we are talking about being in a tight market, having been in a period of relative glut caused by US shale in the first instance. It is the indirect consequence of the loss of the US market.

Q73 Sir Robert Smith: The market would be even tighter without the US shale?
Professor Bradshaw: Yes.
Dr Bros: May I add that, as the witness mentioned, what we are seeing in the US is utilities burning more gas versus coal for power generation, which means that coal is available and this coal is shipped into Europe and in fact what we are seeing, a consequence of that cheap US gas, is the fact that the US is exporting coal into Europe and we are burning more coal to generate our electricity versus gas.

Q74 Sir Robert Smith: It has taken some of the edge off the gas demand in mainland Europe?
Dr Bros: In mainland Europe and in the UK.

Q75 Sir Robert Smith: It always struck me as amazing that when they built the interconnector, people were surprised the gas flowed from the lower price to the higher price. I do not know quite why they were not expecting it. Longer term, quite a lot of the evidence we have received, though, is saying there was always this theory that LNG would mean the end of regional gas prices and you would end up with a global gas market, but then the witnesses are saying that you have the extra costs of liquefaction and the re-gasification and the shipping costs and it is not comparable to just having a long pipeline.
Professor Stevens: Exactly. If you think roughly the domestic price of gas in the US is say $3.50 and the cost of shipping it in LNG to Europe was $3 to $4, then you are getting similar prices. The point being that the cost of transport is so high that this would inhibit the actual physical movement of gas, and a similar story for Asia as well. It is down to the cost of transport as to whether you would get physical arbitrage.
Dr Bros: I think what I have written in the paper is if you add the cost of transport, the cost of liquefaction and the cost of re-gasification, because you have to compare gas to gas at the end for the consuming countries, if it is, as we have heard, between $3 and $4 in the US, I think it could be plus $6 per million Btu; so something like $10 in Europe and something like plus $7, i.e. $11 per million Btu in Asia. It does not mean that it will be the same price all over the world. It will mean that we will have a unique reference and that the oil indexation, which we were using in continental Europe and that the Asians are using, is going to fade. We are seeing, very recently, Asian buyers not willing to go for full oil indexation in their LNG purchase, long-term purchase.
Mr Moore: I was just going to add to that one of the big mysteries is whether what has been seen in the United States can be replicated in Europe, but also whether it can be replicated in Asia where some of these other consumer markets are, because that could, again, have consequences of a demand for LNG subsequently for the balance of supply and demand in that market.

Q76 Sir Robert Smith: Should we be doing anything to make sure that we are still a place where LNG comes to keep ourselves fully flexible in our exposure to the global market?

Professor Bradshaw: It is an important source of flexibility for the UK, but also the UK plays a bridgehead role in terms of, as you mentioned, the interconnector. We were in a position in 2011 of exporting more gas than in 2000 after gas production domestically peaked simply because we were moving LNG through the country into Europe. If we are the port of first call for a substantial amount of LNG, that must only reinforce our security of supply. The issue is how much we would have to pay for it. In the LNG market you are competing globally to attract those cargoes and so in a tight market that is the uncertainty. At the moment, because demand is depressed by the economic situation but also by the high amount of coal being burnt, it is quite fortuitous in some ways because Japan has been taking a lot more of Qatari gas that in the past we were taking. It may be when these things work their way through, maybe when, if, the nuclear power stations come back online in Japan—and Japan is pretty much at the physical limit of how much LNG it can import anyway—as things change in the future then our relative position as an LNG importer will change.

Professor Stevens: Last year something like 15% of UK gas consumption came through the Straits of Hormuz; so one can raise issues of security and other dimensions.

Q77 Sir Robert Smith: In the long term, if we want to see the full benefit of shale gas, we cannot just rely on a global market. We have to develop our own shale gas to its full potential?

Professor Bradshaw: That is one way of looking at it and another way is to say we have already benefited. We have seen the situation that occurred in the US and the impact of the Fukushima disaster. It was a short-term shortage, but if you look at the projects due to come online by the end of the decade we could be back in a situation with a large amount of LNG out there and the United States and shale gas might play their part. Most of the modelling work that is done, certainly the reports done for the European Commission, on shale and its impact globally, suggests that shale increases domestic production in markets and therefore depresses the amount of import, the extreme being the United States where it becomes pretty much self-sufficient and then moves to exports. Say in the case of China, the Chinese demand and their ambitions are so great, but it may reduce, perhaps, the amount of LNG that China wants if there was going to be a shale gas revolution in China. There are other factors at play there, like pipeline gas from Russia.

In a European context, the Commission's work suggests that what shale gas will do at best is replace the decline of conventional production and therefore they are saying, in the report they produced, that we would still, as Europe, remain 60% import-dependent. I think we have to be realistic and there is a very clear statement that shale gas will not result in the European Union becoming self-sufficient in gas—nowhere near it. We simply do not know, as we have heard earlier, what the reserve base is in the UK but I guess the point is that shale is one of a set of factors that could mean that there is—it is the golden age of gas scenario, if you like—available gas for the UK to import and that may be more cost-effective and environmentally effective than developing our own reserves, but we do not know the answer to that yet because we have not found out the extent of our reserves.

Sir Robert Smith: Do you have very similar views?

Dr Bros: Yes. Exploration is needed to find the resource and to see if it is commercially producible at prices that are acceptable. You were mentioning that DECC was saying the prices could stay around this level. It depends on what the cost of production of the shale gas is in the UK.

Professor Bradshaw: An important part of the story is that about three months ago the head of Exxon Mobil stood up in public and said that basically the technology they had developed in the US was not working particularly well in Europe, which means that the technology would have to be revisited. In other words, somebody is going to have to pay for the research and development to develop the technology to meet the different geology that exists in Europe. Whether that will happen is another matter.

Q78 Christopher Pincher: Some observers say that the British energy policy is outdated because it assumes large quantities of imported gas, gas at a high price and an exposure to international price volatility. From what I think most of you have said, you would disagree with that view. You would think that Britain has the right assumptions around gas pricing and that shale gas will not make much of a difference to our domestic energy prices. Is that correct?

Professor Stevens: I did not know we had an energy policy.

Christopher Pincher: We might have one next week.

Professor Stevens: We might have one, yes.

Dr Bros: I would not comment on this one, but I would say that it depends on the timeframe. If you are talking from now to 2020, yes, I do not think we can go for exploration and production in a big way. Again, we have time to look at what is under the ground, to see if it is cost-effective and, after 2020, to see the kind and the amount we can produce.

Mr Moore: I think one of the key findings from some of the analysis that we have done of the changes that are being made to the UK energy policy is we are very concerned about the inflexibility that is inherent in the EMR process and the inability to respond to change in circumstances. Shale gas has been recently by far the most prominent of these changes that have disrupted what the energy picture looks like and may have far-reaching consequences for the UK, or it may not. We do not really know yet, but this is also a concern potentially for other technologies that could emerge in the future. I think one of the main things that we are worried about is the inability of the system that is being proposed under electricity market reform to respond to this new information as it emerges.

Professor Bradshaw: I think I would say, basing everything on the assumption that gas prices will go up, why would you make that assumption? They could equally go down. There is a strong groundswell of opinion internationally, from the likes of the International Energy Agency for one, that there is a

set of conditions that could result in a cheap, plentiful supply of gas. That might not be directly in the UK. It might be elsewhere globally with the knock-on effects that I talked about. We perhaps need to be more flexible. We already have an infrastructure. We have 51 bcm of LNG import capacity. That is much more than we actually need.

There are perhaps other things we could do in terms of domestic storage. Also making our own national transmission system more flexible because it is primarily aimed at the North Sea and they have to realign it to different sources of supply. In that context, shale gas production would be a bonus in a sense but I cannot see a sudden rapid increase in domestic production from shale. Even if it got to 9 bcm, which is a figure that was mentioned in a few studies—Tyndall Centre mentioned a study projecting 9 bcm—that is not a game changer. The other uncertainty here is how much gas we are going to need in 2020 and beyond. That comes back to the wider energy strategy and what role gas plays.

We will need gas because gas is the obvious backup for intermittent renewable supply, but if you look at the projections of the National Grid, for example, in their 10-year statement the range of uncertainty about how much gas we need is huge. Therefore, how do you plan effectively to invest in the infrastructure with that level of uncertainty, but equally to devise policy if you cannot be more certain about how much gas? Once you know how much gas and you have a clearer view of how much shale you might potentially have, then you may reach a decision as to whether you want to develop indigenous shale or not or whether, in fact, the international market and the flexibility you have in your infrastructure is enough and your gas demand might be lower if you pursued low-carbon nuclear and renewables.

Professor Stevens: The timing issue here is crucial. People talk about the US shale gas revolution as though it happened over four to five years. It has been over 20 years in the making. It took a long time to get it off the ground and I suspect it is going to be even longer to get it off the ground in the UK.

Q79 Christopher Pincher: Certainly the experience we have had since we conducted our first inquiry would suggest that. Do you think that DECC has the flexibility and the breadth of vision in its national policy statements and the silos between nuclear and gas, within gas, shale gas and gas storage and the other renewable forms of energy to exploit the opportunity internationally?

Professor Stevens: I think there is a lack of joined-up thinking in energy policy in this country and has been for well over 20 years. Everybody has looked at individual subsectors but nobody has sat down and tried to do some joined-up policy thinking on it.

Professor Bradshaw: I think I would also say gas seems to be the default position when policies fail. When there is concern about building new nuclear the concern is, "If we do not do that we are going to have to import more gas or if we are not making the progress we want on renewables," or, for example, if the efficiency policies do not deliver, the fallback is we will then have to use more gas. There is probably a view at DECC that we will use more gas in the future than we have been saying, for a variety of reasons, and then a concern about where that gas comes from. It is the default fallback when other things do not work.

Mr Moore: One of the policy instruments that has been reasonably useful at bridging those various different silos to some extent has been the EU Emissions Trading System, which sits above all the different specific policy areas, renewables promotion and so forth, and has the potential, at least, to provide more of a steer about the kind of investment decisions that were being talked about earlier, if it can be made more long term, if perhaps the price signal can be strengthened over that period, but that is something that has not happened to date and does not seem to have been as great a priority as it perhaps should be relative to some of the other things that get focused on.

Q80 Dr Whitehead: I am trying to figure out best what the long-term effect of shale gas might be in terms of relative reduction in carbon emissions as we move towards a much lower-carbon economy. It appears to be the case in the US that that is displacing a substantial amount of coal, although the US is exporting coal as a result. There are suggestions that, among other things, the way that shale is extracted in the US, particularly in small fields and transportation and considerable leakage in the process, the actual emissions are about as high as coal. Would that be the case in the UK and, bearing in mind that coal plants are closing anyway, what sort of displacement effect might there be between gas and coal in the UK and what would the emissions difference be?

Professor Stevens: One of the reasons there is so much debate over the shale gas contribution to greenhouse gases is because there is a big debate over the extent of fugitive emissions in shale gas operations. It appears from some of the studies I have seen, this arises from poor well completion rather than other sources and this essentially is a regulatory issue. To answer the question, it is for who has the tougher and the better regulatory system, the UK or the US, to answer that particular one. That is purely in terms of the greenhouse gas emissions from shale operations, leaving aside issues to do with displacing coal.

Mr Moore: I echo those comments on the role of the Environment Agency and local regulation. The part that guides emissions from combustion, particularly within the electricity system as I have just mentioned, is the European Union's ETS cap. Strengthening that, making it longer term should be our main priority for trying to control emissions from the electricity sector at whatever level we think is appropriate given our carbon ambitions. I think the proposals to try to limit that either by constraining particular technologies like shale or to impose UK-only targets or regulations that end up just steering emissions elsewhere in continental Europe are less useful as a way of conveying the message that this is the amount of gas that we are prepared to put up with given our climate goals.

Professor Bradshaw: I think it is important to look at it in a whole energy system in the sense of the role that a gas plays and then, within that, what shale gas is contributing. The actual emissions profile from shale gas drilling in the United States, as you have alluded to, is a source of great controversy at the moment as to how much the level of fugitive emissions might be and there is a lot of work being done to get answers to that. It is likely to be higher than the conventional simply because, as you have heard this morning, you have to drill a lot more and that drilling consumes energy. The net return on energy invested is lower than in conventional gas production. When you take it back into the UK energy systems and ask the question about gas, it is, "What role is gas playing in that energy mix?" If it is replacing coal for good then that is bringing a decarbonisation effect, but the concerns of many of the environmentalists, when they talk about this second dash for gas, is that that investment in new gas squeezes out investment in renewables and efficiency and prolongs the amount of gas that is in the mix and thus increases emissions.

In a specific context of emissions from shale gas drilling in the UK we do not know the answer because, as you heard this morning and you only know too well, we do not have a large-scale exploratory programme in the UK, let alone test production. We do not know under UK conditions what the emissions would be and that would certainly be part of any future research programme, to get the answers to that question; to know where, for example, burning shale gas versus imported LNG, which has higher emissions than domestic conventional production, versus coal stands in terms of their emissions in the UK. That is the question we need to answer, I think, to come to a decision as to what the climate change benefits are. They may be lower with shale gas than with domestic conventional, but if we do not have any of that, then you are looking at other alternatives of supply.

Mr Moore: Just to touch on the gas lock-in question briefly, we conducted some analysis on this earlier in the year and one of the situations we looked at was reducing ambition on offshore wind; the more expensive of the technologies we are currently trying to mass deploy from 13 gigawatts to 9 gigawatts, about halving the remaining deployment of that and using gas in its stead and then retiring that gas earlier, 2030 or so. One of the conclusions from that report was that the financial savings implied by that, while keeping emissions at the European level exactly the same, would allow you to double energy R&D, insulate 360,000 lofts and buy and retire carbon permits worth six times the emissions implied by the savings from the offshore wind in the first place. The financial savings that are implied by moving from more expensive energy sources to potentially using more gas, be it shale or otherwise, can have a potential benefit for our climate ambitions.

Dr Whitehead: Yes, and this presumably implies a massive state intervention around 2030 of dealing with a large number of stranded assets at that point.

Professor Bradshaw: That is the problem, is it not? A new business model for gas moving forward when you have to retire the plant, and that presumably has to be part of any energy policy that is going to be paying them for the capacity to be there and it is probably looking at the shorter term, gas as this bridge or transition fuel, then to a longer term, but making that switch, as you are implying, suggests state intervention because you have a lot of assets which still have life left in them.

Mr Moore: That is true, but state intervention need not be so heavy-handed in the decision making that it takes all the decisions out of the hand of the commercial players. Again, I emphasise the ETS cap as one of the best ways of doing this. If in 2030 we want to have this level of emissions, individual operators can decide whether they think that their particular gas plant is or is not commercially viable given those constraints.

Q81 Dr Whitehead: I guess you do not often have commercial operators volunteering to remove their plants when they still have quite a lot of commercial life in them unless there are considerable restraints placed around them. I wonder whether the more specific question of investment in shale gas as such is or might be seen to be an issue in terms of investment in other forms of lower-carbon energy. The Tyndall Centre has suggested, I think, between £13 billion and £19 billion of investment in renewables and other forms of low-carbon energy might conceivably be diverted into shale gas. Is that an equation you would recognise or is that something that is perhaps a wider feature of investment in different forms of energy? Is there a specific issue relating to people saying, "Right, we are now going to invest in shale gas exploitation in the UK and we will put those funds in instead of doing other things"?

Mr Moore: I think the most important thing to focus on is the most cost-effective approaches to reducing the carbon emissions inherent in our energy system and if doing that through gas or shale gas is a more cost-effective way than doing it through, particularly, renewable technology then I do not necessarily see that as a particularly bad thing if we accomplish those climate objectives at the end of it.

Professor Stevens: Let us face it, the investment is being done for the most part by private companies and they are basically interested in maximising shareholder returns and whether that will have an impact on greenhouse gas emissions and so on depends on the regulatory framework and the price of carbon rather than anything else.

Dr Bros: To add on this one, what we are seeing with the EU ETS is it is today more profitable to run a coal-fired power plant than a gas-fired power plant and so therefore companies that are investing for the future are looking at what is more profitable and they are not planning any new gas-fired power plants. If they had the choice they would go for more coal-fired power plants in Europe, which is defeating any climate change strategies.

Professor Stevens: That is likely to be reinforced if we are going to see a lot of coal exports coming out of the US as a result of the shale gas revolution.

Q82 Mr Lilley: Our brief gives some ballpark figures for what the scenario might be in 2030 and suggests we might get 40% of our electricity from nuclear, 40% from renewables, largely wind, 15% from plants with carbon capture and storage fitted and 5% with unabated gas. Let us suppose all the 15% with CCS and the 5% is gas. That is 20% of our electricity supplied by gas and 40% largely by wind; so normally 20% supplied by gas. Would anybody really invest in shale if they thought that by 2030 only 20% of our electricity was going to come from gas? Secondly, on the days when the wind does not blow across Europe we will need three times the gas-generating capacity that we have normally. Who would invest in that generating capacity, distribution capacity and storage capacity to enable us to do that?

Dr Bros: I think I can take the first question as to who invests in shale. I think it is not only on the electricity mix. What you are seeing in the US is, because of this huge shale gas production, of shale increase in terms of production, people are trying to find new ways of using it. Ways could be exports.

Mr Lilley: But they do not have these targets that we have.

Dr Bros: I am coming back to targets. They are using gas as a fuel for transport. We are seeing buses and trucks operating on LNG and this could help you in your targets to achieve a greener world.

Professor Bradshaw: I guess the other question would be how much electricity, because one of the consequences of decarbonisation strategies in the UK is via electrification. We need more electricity. That 20% could be quite significant in volume terms. I think you are absolutely right that the evidence suggests substantial amounts of capacity in place as gas-powered backup, but that comes back to creating a regime where you are paying companies for capacity and that has to then be put on to the price of electricity. That becomes one of the consequences of renewable electricity generation. When the wind blows the renewable will always ship first, but when it stops then you fall back. We are all aware of these weather patterns we get in north-west Europe in the winter: a blocking high, the wind does not blow anywhere. Interconnection, for example, with the grid cannot be that helpful either.

There will need to be a substantial amount of capacity for gas-powered generation in place and there will need to be some mechanism to pay for that capacity. Equally, the type of storage that we might need is also likely to change in that we will need short-term storage to provide gas in a relatively short period of time that fills up and empties quite quickly. There is a view that we do not have enough storage anyway in this country. We relied on surge production from the North Sea. That is declining. Equally, it is the view that in an intermittent system you not only have renewable intermittency, you have gas intermittency. That is something we need to manage and plan for because, as has been suggested, when you build your plant you want to utilise it as much as possible, unless someone is going to pay your otherwise. That has to be factored in, I think, into the cost of renewable or low-carbon electricity in the future.

Q83 Mr Lilley: Do you think it has been factored in?

Professor Bradshaw: I have seen plenty of studies looking at scenarios, but I cannot say I have seen a rigorous modelling exercise to tell you what that cost would be, no.

Q84 Sir Robert Smith: What percentage of the gas would be going to direct heating as opposed to electric?

Professor Bradshaw: That again depends on the effectiveness of other strategies. At the moment it is a third into power generation, a third into industry and a third into the household sector and we are supposed to be electrifying heat, for example, so that all our gas-fired appliances, heating systems or whatever in the longer term would be replaced by electricity. We all have them. We are not going to go and rip them up. That will take a while, but then again, it comes back to only if you decarbonise your electricity supply have you achieved your targets. This comes back to the comments earlier about joined-up thinking. You have to join these bits up. There are statements that electricity demand could double by 2050 as a consequence of the electrification path. How do you satisfy that demand? Obviously low-carbon sources include new nuclear and they include a lot of renewables and a lot of that would be wind, which will require the gas backup. That is why it is not a question of gas or no gas. It is how much gas and in what role.

Professor Stevens: The problem with the whole thing is that if you leave it to market forces it simply is not going to work because the energy sector is riddled with market failure and the function of Government is to intervene to offset that market failure.

Q85 Dr Whitehead: Just briefly, looking at the cost that we know about producing shale, one of the issues is that it becomes cost-effective in a fairly high price gas economy, less effective, as we see beginning in America, in the beginning of a low gas price economy. What is the comparative cost of producing a known amount of shale gas compared with, say, producing a known amount of biogas?

Professor Stevens: The view in the US now, it depends who you are.

Dr Whitehead: The ideal gasification.

Professor Stevens: Okay. The general view in the US now is that in many cases shale gas is cheaper than conventional gas.

Q86 Dr Whitehead: We have alongside this the parallel development of AD systems, gasification systems, Prolite systems, which are not cheap but nevertheless could produce a fair amount of volume of gas, for example for injection into the grid. I would be interested to know the relative cost of the two techniques, both of which are at the relatively high end of gas although there are issues on what shale gas is going to look like in the future. Are there, in your view, any known comparisons or figures available that might shed some light on this?

Professor Bradshaw: Not that I have seen. I think it is an interesting point and obviously much of our unconventional production at the moment in the UK

is biogas and it is figuring in the statistics and it is growing. It is obviously a local solution in many cases or an opportunity rather than a national programme as such, but it is part of that wanting to stack up all the options. In terms of cost, it is imported LNG and where that comes from. It is what is left of the conventional production. It is domestic shale. It is biogas. Also, the carbon consequences of those will differ.

Q87 Ian Lavery: Getting back to the Fukushima incident, which we seem to get back to in every single inquiry we have on every single issue, what effect do you think the Fukushima incident has had on gas markets?

Professor Stevens: I think the first impact is that it absorbed a lot of the surplus LNG. The Japanese went into the market and started to buy LNG big time and Japan is likely to continue to do that because in the short run, if you have to replace nuclear, the only option economically and technically is gas-fired combined-cycle gas turbine. What it has done in effect is save the global LNG market from a very serious downside. That is the immediate effect.

Mr Moore: One of the less direct impacts that we have seen is with some other countries that have, in response to Fukushima, altered their energy policy strategy, particularly Germany, which has said it is looking to close down all its nuclear power stations on a relatively short time scale. That has consequences for what they choose to replace that with. If that is gas, there will be more gas demand. If it is coal, it will be more coal demand and more emissions. There are those indirect consequences of Fukushima as well as the direct Fukushima consequences.

Professor Bradshaw: I think it has also had a quite dramatic impact on Japan's attitude to how LNG is priced. I was at a conference on Sakhalin Island in the Russian far east in September, where one of the projects being discussed was an old idea of building a pipeline from Sakhalin to Hokkaido to take pipeline gas into Japan, but a very senior official from METI stood and up said basically that this additional LNG they have had to import and the additional oil and so forth is the major reason why they have had a trade deficit in Japan. They have experienced very high costs to secure this LNG and it has made them think, "We do not want to continue with this form of price formation." The only problem is that no one can come up with a good alternative. As has already been alluded to, they have this gaze towards the Gulf of Mexico and US LNG exports at Henry Hub prices. They think that one of the solutions is that they will want to get access to cheaper LNG from the United States. They have even had meetings with other LNG-importing companies and countries in Asia to discuss this.

One of the consequences is additional pressure on oil indexation on long-term contracts, which we also see in Europe. But the problem for the LNG supply chain, as I think has already been alluded to, is it is expensive gas and therefore one of the benefits of oil indexation is that it provides a return on a very capital-intensive source of gas. A question going forward will be what will happen to the pricing of LNG. There is a growing share of spot LNG available that Japan has used but, for example, I understand from talking to people in the industry that some of the Qatari LNG coming to the UK is in contracts to Japan now, tied up for a long term and paying a higher price. One of the consequences is further pressure on the pricing of gas and oil indexation on long-term contracts.

Dr Bros: I would like to add a few numbers. Gas demand increased a lot in Japan, plus 12% last year due to this, and what you mention is absolutely right. It is still increasing, something like 12% again this year, and we are seeing much less LNG coming into Europe—something like minus 38% of the LNG coming into Europe. That is the first point. The second point is back to competitiveness. We started with saying that shale gas allowed the US manufacturing plant or petrochemical plant back into the US. What the Japanese are feeling, as you mentioned, is the fact that now, due to those high imports in terms of LNG and oil, they are losing in terms of competiveness and there is trade imbalance. This is why they are trying to find new ways of sourcing gas but also pricing that gas. And we are hearing that it is already starting in Japan and South Korea that those oil linked contracts that were built for security of supply, you were adding a premium to be sure to get those volumes, because those were two islands (Japan is an island and South Korea is nearly an island because you cannot build any pipes through North Korea) and they are trying to find new ways of pricing the gas. It could be under, as you mentioned, Henry Hub plus something, and the "plus something" could be enough for those projects in the US to be competitive and to be profitable.

Q88 Ian Lavery: Some organisations, such as No Hot Air and Greystar, suggest now that Fukushima has been extremely significant in terms of the world gas price index. No Hot Air suggests that if it was not for Fukushima we would have seen a collapse in world gas prices. Greystar says that Fukushima has had the effect of artificially keeping the price high. Do you agree with those comments?

Professor Stevens: I do not agree with the first one—that there would have been a gas price collapse. Fukushima prevented significant downward pressure on LNG prices, but do not forget: most LNG prices are contractual and, outside of the US and the UK and a few other places, linked into oil prices. It would have taken some time for the impact to feed through into LNG prices.

Professor Bradshaw: In a European context with the Russian supply oil indexed, it is the high price of oil that is the cause of the problem in the sense that that is what is creating a high price for gas that cannot compete with coal. Fukushima's impact is on LNG. It is not on pipeline gas into Europe from Russia. As I say, high oil price is the problem.

Q89 Ian Lavery: How resilient do you think the gas market is likely to be if we have another major incident like Fukushima?

Professor Stevens: It depends where. The other fear, of course, is if you get a major LNG accident that might do to LNG what Chernobyl did to nuclear for

some time, but that is another issue. It tends to be neglected. Everybody assumes it is going to be swimmingly wonderful and LNG is going to increase and increase. If you get a very big bang somewhere, and then a lot of people are going to be rethinking.

Professor Bradshaw: There is a focus on the Straits of Hormuz as the weak point in the LNG supply chain. People tend to think that if that happens it affects obviously gas and oil in so many countries that it will not be prolonged, but if something happened to the LNG facilities in Qatar, by military action for example, it would take five or six years to rebuild the facilities. That is a very significant impact. One of the things to think about is that the industry, the LNG supply side certainly, has little or no spare surge capacity. In Europe, like it or not, we have the benefit of the pipelines from Russia and Russia has a lot of gas. In that sense what might happen in the UK, you could speculate, if the LNG stopped coming is that the interconnectors would be bringing gas through the continental system, Nord Stream would help by bringing gas into north-west Europe and we would be paying for a lot of expensive continental gas that was coming from Russia.

It comes back to my earlier point that we have resilience in the system; we have diversity of supply. Obviously we have pipelines direct from Norway, as well as our own pipelines and the interconnectors. So our exposure to LNG can be balanced and vice versa. LNG can balance our exposure to what might happen in continental Europe. So compared to many European countries, as we become import-dependent, we are in a much stronger position because of that diversity and it could be that some domestic shale adds to the portfolio and increases the resilience but, given that we do not even know if we have enough at the moment that is worth developing, that can only be speculation.

Dr Bros: A few numbers again, minus 38% in terms of LNG berthing into Europe, is a huge number and we have been able to cope with prices that did not increase and, as the other witness mentioned, we have seen, for example when we had war in Libya last year, the cut off of the Libyan pipe bringing Libyan gas into Italy, this has been managed with more Russian gas coming into Italy. So the European system is flexible and allows all those things to happen.

Q90 Chair: Just one last point. We expect to have the gas strategy published, maybe even next week with your statement. How important will that be in developing the shale gas industry?

Mr Moore: It depends what it says.

Chair: Do you expect it to say something that will directly have an impact?

Professor Bradshaw: The Chancellor has indicated, as he did at the Conservative party conference, the desire to create a tax regime to encourage—to encourage what I am not sure, but perhaps we could speculate it is exploratory drilling. That will also require all the other above-the-ground issues because the other thing it will encourage is a lot of reaction against shale gas drilling. It has to be ready for that. To deal with the uncertainties that were discussed in the first part of this session we need to do some drilling, even if it is just to know that it is too costly or it is too environmentally damaging. I assume the first thing the gas strategy should do is to try and get some answers to those questions.

Professor Stevens: We also, I think, need to imitate the experience of the United States and get some money into research and development into low-permeability operations in the context of UK geology. That, I think, is quite urgent.

Q91 Mr Lilley: I am puzzled by the suggestion that there is any need for a special tax regime. Drilling costs can be written off against corporation tax at present and so, I think, can research and development costs. Why should they require any special incentive? If it is profitable, let them go and do it. If it is not profitable they should not do it.

Professor Stevens: But some research and development is basic science and private companies will not invest in that sort of R&D.

Mr Lilley: They have done in the States, haven't they?

Professor Stevens: No, it was the US Government that put the millions of dollars into low-permeability operations precisely because the private sector would not, and should not indeed, invest in that sort of basic scientific research. This is the function of government.

Q92 Mr Lilley: So the US Government foresaw the possibility of a shale gas revolution, invested in the relevant expertise and it came about?

Professor Stevens: It did not foresee it, but it was certainly looking around to see what might be done to offset the inevitable decline in conventional gas production in the US.

Mr Lilley: The US Government did not see it but still invested it.

Professor Stevens: No, they foresaw a decline in conventional gas production in the US and thought, "How are we going to get around this? There is a lot of unconventional gas, of which shale is only one aspect. There is a lot of other unconventional gas. Let us put research and development money into low-permeability operations and see what happens."

Chair: Thank you very much indeed for a very interesting session. Your time is appreciated.

Tuesday 11 December 2012

Members present:

Mr Tim Yeo (Chair)

Dan Byles
Ian Lavery
Dr Phillip Lee
Mr Peter Lilley
Albert Owen
Christopher Pincher
John Robertson
Sir Robert Smith
Dr Alan Whitehead

Examination of Witnesses

Witnesses: **Francis Egan**, Chief Executive Officer, Cuadrilla Resources Ltd, **Corin Taylor**, Senior Economic Advisor, Institute of Directors, and **Graham Tiley**, General Manager (Ukraine), Shell International Ltd, gave evidence.

Q93 Chair: Good morning and welcome to the Committee. Thank you for coming in. As the session is being broadcast live, can I ask you very briefly just to introduce yourselves for the benefit of people who are picking this up on a feed rather than present in the room?
Graham Tiley: Yes, my name is Graham Tiley. I work for Royal Dutch Shell. I have a PhD in Geological Sciences. I have spent 25 years working for Shell in the exploration business in Africa, Europe and the Middle East. I am currently Shell's general manager for our Ukraine venture, which is an unconventional gas project, and I am the country chairman in Ukraine.
Francis Egan: Good morning. I am Francis Egan. I am the CEO of Cuadrilla Resources. We are the company exploring for shale gas in Lancashire, amongst other places.
Corin Taylor: Thank you very much for inviting me. I am Corin Taylor. I am a Senior Economic Advisor at the Institute of Directors and we recently wrote a report on the prospects for shale gas in the UK

Q94 Chair: We are concerned to get our terminology accurate and correct here and obviously draw the distinction between resources and reserves. Why is it that shale gas companies tend to talk in terms of resources and not reserves?
Francis Egan: Well, if I can speak for the example in the UK, at the moment everything is a resource because nothing has been produced. As we begin to produce them, of course, they get translated into reserves. The stage that we are at is an early stage in the exploration process and we have determined that there is of the order of 200 trillion cubic feet of resources—gas in place. In order to translate that into reserves, we will need some further data, principally some flow rates while testing. It is possible to draw analogues with similar plays in the United States but to get definitive information you need more data and that is what we hope to do as part of the ongoing exploration programme.

Q95 Chair: But you said that in your licence alone, you could supply a quarter of the UK's gas demand.
Francis Egan: I think we said we had the potential to supply up to a quarter, yes. If you take 200 trillion cubic feet, or possibly higher than that, the annual UK gas demand is 3, so a quarter of that is less than 1. So you do not need a very high recovery rate from 200 trillion cubic feet to get to that.

Q96 Chair: You do not think that claim was premature in any way?
Francis Egan: I think we said we had the potential to do that and I believe we do have the potential to do that.

Q97 Chair: Though you said in your first answer that you could not be sure what the reserves were.
Francis Egan: The reserves in any field, conventional or unconventional, are not defined and locked down in time for ever. Reserves are a function of a number of things. We said this in our report. They are a function of technology. They are a function of what time you actually measure the reserves. Generally what you find in conventional oil and gas, and I am sure shale will be no different, is that, over time, reserve estimates tend to increase as technology improves.
Graham Tiley: If I could maybe add something to this, it is important to realise that reserves tends to be quite a formalistic definition. It is important then also to talk about what definition of reserves you are using. Previous witnesses have talked about the SEC reserves. That, of course is one particular definition of a reserve and companies have to follow quite strict rules when defining what can be counted as reserves. That is often a function of price. It is a function of whether or not you have a credible development plan for those volumes. The definition of reserves changes from place to place. Somewhere like Russia or Ukraine have their own reserve definition criteria.
Resources is a more loose term and, as Francis said, in the industry we often talk about in-place resources as being, perhaps, the loosest definition of the possible gas that is in the ground because then that takes you away from commercial technology or other constraints that then have to be applied before you can translate resources into reserves.

Q98 Chair: The British Geological Survey would like to have access to Cuadrilla's data. Is that something you would be willing to publish?
Francis Egan: I think we have already provided our data to the British Geological Survey. We certainly have provided it to the Department of Energy and

Climate Change and I believe that they are working with the BGS on updating estimates for UK resources.

Q99 Chair: When they gave evidence to us two weeks ago, I quote directly, he said, "I would like to see the gas content figures published and I would like to see the actual production figures published as well for many of the wells that they've drilled".
Francis Egan: Well, we would like to see some production figures published too but unfortunately we are not able to produce them at the moment.

Q100 Chair: The gas content figures published?
Francis Egan: If they are looking for data from us, we do not have a problem providing them with data. Some of the data is commercially confidential, so as long as that can be protected, that is fine.

Q101 Chair: So that is a step forward in that case. Do you think the Government's Gas Generation Strategy, which was unveiled last week, is going to be helpful?
Francis Egan: I guess the gas generation strategy envisages a role for gas, clearly. At Cuadrilla we believe that there will be a role for gas in the UK not just in generation but in domestic and industrial sectors and you will be aware, if you look at the gas demand in the UK, generation accounts for only about a third of gas demand in the UK. So, virtually every home in the country, probably everybody in the room here is using gas either for heating or cooking or both. So the fact is that gas will be needed in the UK and it will be needed for decades. Even if we could generate all our electricity without gas, which we cannot, we would still need gas.

Q102 Chair: I do not think that is in doubt. I was asking whether you thought that the gas strategy was going to be helpful or not.
Francis Egan: I think in that it acknowledges that gas will have a role it is helpful.

Q103 Chair: We hardly needed a new strategy to acknowledge that, did we? I do not think anyone was disputing the fact that gas had a role.
Francis Egan: Cuadrilla is not in the business of working out the energy strategy for the country. We are here saying that we have found gas. We believe it can be developed safely and sensibly. If the country thinks there is a market for gas, then we will be able to provide it.

Q104 Chair: So, Cuadrilla really did not care whether there was a gas generation strategy or not?
Francis Egan: I am not saying we do not care whether there is a gas generation strategy. I am saying our role is, and we have a licence from the Government, to look for gas and if we are given a licence to develop the gas, then we will do that in accordance with the Government's wishes.

Q105 Sir Robert Smith: Yes, I had better remind the Committee of my entries in the Register of Members' Interests to do with the oil and gas industry and in particular a shareholding in Shell. Just on the wider debate about shale gas, there is talk of benefits for the UK. What sort of benefits do you see coming forward from shale gas?
Francis Egan: Well, you will be aware that the UK is importing most of its gas and in 10, 20, 30 years' time it will be importing all of its gas or virtually all of its gas. So there are benefits in security of supply. There are benefits in balance of payments. Instead of spending billions importing gas, we will be able to generate at least some of that in the UK. I am not sure we will be able to, and probably will not be able to, completely negate the needs for imports but at least some of them; and of course, if it is successfully developed, generate significant tax revenues and employment.
Corin Taylor: Just to add to that, if you look at the OBR's long-term fiscal projections that they put out with the autumn statement, the North Sea tax revenue is projected to fall from just over £11 billion last year to just under £5 billion in 2015. That is obviously a massive gap. A developing shale gas industry can help to fill at least some of that gap as it can with jobs in the North Sea too.

Q106 Sir Robert Smith: What is the jobs potential of shale gas? Obviously my constituency is just outside Aberdeen, so we have seen a huge jobs potential over the life of the North Sea and there is still a long tail but it is past its peak. Onshore is obviously less intensive. What kind of job impact would a reasonable take-off of shale gas have?
Francis Egan: There are varying estimates and I am sure you will have seen them from the Regeneris study that was done for Cuadrilla to the IoD estimates and they vary from thousands to tens of thousands of jobs. I think for any industry, at this stage, it is difficult, if not impossible, to be definitive about how many jobs. Will it be 4,000 or 5,057? But we talked earlier about the potential for the resource and the potential to supply up to 25%—20% to 25%—of the UK's gas demand. You cannot do that without creating thousands of jobs. The oil and gas industry, and you will be aware of this from Aberdeen, creates jobs across the full range of disciplines: engineering jobs, accounting jobs, technician jobs, security guard jobs and out from that into the supply business. Equally, if the UK is the first to do shale gas in a proper regulated manner in Europe, it has the opportunity to create service centres for other European—and there have already been companies approaching Cuadrilla and Lancashire County Council discussing the possibility about setting up service industries based out of Lancashire for shale.
Graham Tiley: I think maybe it is also useful to look at the experience in North America where, as you know, Shell has a number of projects and there have been quite a few studies done in states like Pennsylvania that look at the economic benefit and, indeed, the jobs tend to be measured in the tens of thousands. It is quite labour intensive. I am not sure whether it is less or more than the offshore. It is certainly a little bit different. I think, as Francis said, the supply chain is a key area. It is not opening just the jobs involved within the company, like Shell, but it is all of the service industry that is required to

support it, the tens, or perhaps hundreds, of rigs, ultimately required to do the drilling. Then in the United States, of course, what they are also seeing is this resurgence in the industry that is then benefiting from the cheap gas prices, the petrochemical industry and other energy-intensive industries. So there is a further knock-on effect on GDP and jobs simply from having a lower-cost supply of energy.

Corin Taylor: I very much concur with that and also I think a lot of these jobs would be in parts of the UK that really need them, so it is an important part of helping to rebalance the economy.

Q107 Sir Robert Smith: There is at the moment a skills shortage globally for the oil and gas industry, however, and if you go to Aberdeen there is a desperate desire to recruit people. We have virtually no unemployment locally. There is difficulty getting enough skills into this, projects are being held back almost by it. Do you think the skills base would be able to cope with the take-off of shale gas?

Francis Egan: It needs to be co-ordinated. I think it is a really good point. We are already working with the University of Lancaster about the skills and they will produce a skills study for us within the next two or three months. It will not happen by accident, let me put it that way. It needs to be planned for and people need to be trained. That should be not just the industry but also academia and Government probably also has a role to play in that.

Corin Taylor: We have done this before as well obviously with the North Sea industry in the first place and of course with other industries like the nuclear industry. It is very much something that needs doing but it is something that we can achieve.

Q108 Sir Robert Smith: The North Sea took advantage of the collapse of ship building in its early days and now if you go to an oil and gas exhibition in Aberdeen and you go to a company like Shell's stand, you find the only people on the stand are the global human resources department looking to poach skills from the UK to other parts of the world.

Graham Tiley: If I can comment from the international perspective, you are absolutely correct. There has been a major demographic crisis in the oil and gas industry, particularly in the developed countries. What we are seeing in Shell, of course, is that we are developing a whole new generation of engineers in the countries where we operate. That is something I am looking at. In the Ukraine context, for example, I am also looking at how I am going to develop the people, the skills that I will need there. In the UK context, I would expect it to be achievable. When I talk to my colleagues from North America, for example, what we find now is we are bringing in a whole new generation. Many of the people working unconventional gas in North America for companies like Shell have only ever worked unconventional gas, so there is a new bulge of workers coming through for whom that is their new core skill.

Francis Egan: It would be a high-class problem if we put it that way; jobs chasing people rather than the other way round.

Q109 Dan Byles: It seems to me that getting the right regulation for unconventional gas on the mainland UK is essential for public safety but also for public acceptance. Do you think that the UK regulatory regime currently strikes the right balance between not being an excessive burden on business but adequately protecting the environment?

Francis Egan: From our experience so far, and I need to stress we are in the exploration phase—we have drilled three wells, currently drilling a fourth and looking to hydraulically fracture and test a couple or three wells—and I have said this before, I think it is effective in that I think everything is covered. The efficiency could be improved in that some things are covered twice, if not three times by different agencies.

Dan Byles: Welcome to government.

Francis Egan: I do think it is effective. The UK also has the advantage of having a very strong regulatory system. I was in Aberdeen in 1988 when Piper Alpha happened. I was working offshore at the time. That, and the Cullen report, was a defining moment in regulation in the UK. Since then, the UK is widely recognised in the oil and gas industry as having the strongest regulatory system. We have the opportunity onshore to build on that foundation in the UK and also on what has been learned from 10 years' experience in the US. So you will hear a lot about, "This happened in the US, that happened in the US and, ergo, it must happen in the UK". I do not subscribe to that opinion at all.

Corin Taylor: The community concerns around shale gas are probably the No. 1 issue that needs addressing. The regulatory system we have is very good. There is merit in having an Office for Unconventional Gas, which was set out in the gas strategy, bringing it into one place; also providing very much a level playing field and I think helping to reassure communities. One other aspect that would be useful is being able to provide tangible benefits to communities that have shale-gas wells in their neighbourhood, whether that is through lower gas bills or some other mechanism, such as local amenities—some way that communities can get compensated for the disturbance from the development.

Q110 Dan Byles: Do you see an analogy with community benefit for wind farms and the whole discussion going on there?

Corin Taylor: Very much so, yes.

Francis Egan: It is an absolutely key part and there is an analogy.

Q111 Dan Byles: Graham, do you have a view on the current regulatory system? Do you think we can get the balance right?

Graham Tiley: I do not know the UK system. I have not worked in the industry here.

Q112 Dan Byles: Cuadrilla has specifically called for greater co-ordination between the different regulatory bodies. Could you give us an idea of specifically what you would like to see changed in terms of regulation? You have mentioned the possibility that you are already ticking multiple boxes.

Francis Egan: Well, I do not think we are looking for radical change in the regulation. We are in favour of strict regulation for the shale gas industry. We have demonstrated that by our actions. But I will give you an example. At the moment, for the two well tests that we are looking to do, we are doing environmental impact assessments for Lancashire County Council, two of. We will do an environmental risk assessment for DECC, two of. We will do another environmental permitting study with the Environment Agency, two of. There you have six separate environmental studies involving three separate agencies to flow-test two wells for 30 days each. I think it could be improved.

Q113 Dan Byles: Is that the sort of thing that you think perhaps this one-stop Office of Unconventional Gas might be able to help with?
Francis Egan: I think it absolutely can help with that, yes.

Q114 Dan Byles: Do you think there is a danger in having an organisation set up that seems to both regulate the industry but also to promote the industry?
Francis Egan: That is a very good point. It needs to be managed carefully. Promotion and regulation, as you are well aware, are two different things.

Q115 Dan Byles: In terms of reassuring communities, Corin, you made the point that perhaps the biggest public issue around shale is this fear for local communities. Do you see a problem when things like the environmental impact assessments are being conducted by the industry? Do you think that there is a problem that local communities might have a trust issue in terms of who, for example, is conducting these environmental impact studies?
Francis Egan: Sorry for interrupting, but the environmental impact assessments are not conducted by the—we have put them in.

Q116 Dan Byles: You commissioned them?
Francis Egan: The environmental permits of the Environment Agency are subject to public consultation, in fact will be subject to two separate public consultations. The environmental impact assessment is subject to public consultation, two separate public consultations. The environmental risk assessment involves members of the public participating and coming up with a range of risks that they see, associated with this. There is fairly extensive public involvement in this. This is not Cuadrilla writing its own environmental impact assessment and signing it off by any stretch of the imagination.

Q117 Dan Byles: In your experience so far, how much buy-in does the local community take to that? What I am really getting at here is about credibility. Is there something more that can be done to reassure communities that this sort of work is robust and independent?
Francis Egan: I think the transparency is good: the recognition of what the issues are and how they are being addressed. I think the real proof of the pudding will be in actually doing it and demonstrating that it can be done safely.

Q118 Dan Byles: Demonstrating you can be good neighbours basically?
Francis Egan: Yes. That is the case for any industry that is starting up. You have to do it, show that you are doing it properly and then you win trust. We cannot talk the gas out of the ground.

Q119 Dan Byles: If we could, we would not need you. We would be able to do it.
Francis Egan: We would have produced about a quarter of the UK gas supply.

Q120 Dan Byles: One final question: there have been a group of MEPs who have recently called for robust fracking rules, MEPs, I am sure you have seen this. They have stated that, "Environmental protection should be paid for entirely by the industry" in their words. Is that something you have looked at what they mean by that and do you agree with them, that the totality of environmental protection in this should be paid for by the industry?
Francis Egan: Honestly, I have not looked at it. I think that the industry is certainly paying for the environmental assessments. We are paying for the mitigations associated with those environmental assessments. I do not know what else they are expecting the industry to pay for, to be honest, but the industry is paying for that right now.

Q121 Dan Byles: So effectively you are stepping up and paying for all of this?
Francis Egan: We are paying for the assessments. We are paying for anything that needs to be done as a consequence of those assessments and we do not object to that.
Corin Taylor: There have obviously been calls to regulate fracking on a pan-European basis, and I am not sure that is necessary. If you look at the UK's regime, I think making sure that is strengthened and is suitable for the UK would be the right way to go. If conditions differ in other EU member states, then they should look at their own regulatory regimes.
Graham Tiley: I tend to agree. Shell would very much support strong regulation, and consistent regulation is helpful. It also helps build public confidence, of course, if you do not see too many differences between country A or B but we believe that strong regulation is important and we are very pleased to comply with such regulation.

Q122 Chair: On this point, when we looked at the offshore regulation regime, we concluded that the UK had a robust and probably superior system to quite a lot of others. We were very hostile to the idea that there might be an EU role to try to impose an EU-wide revision. It seems to me it is slightly different in the case of shale. Looking across Europe as a whole, if we think it is desirable to try to facilitate the exploitation of shale gas, is it easier for operating companies if they have a broadly similar regulating regime in different countries or would it not matter if in Poland or France there was a very different approach?
Francis Egan: It is a good question. It depends on the nature of the regulatory regime. When Lord Cullen

completed his report into Piper Alpha, one of his key conclusions was that we should have a goal-setting regime; in other words, the regulatory system should not be telling operators how many times to turn a valve and which valve is turned, but it should set goals and then ensure that those goals were enforced. Now, if the regulatory regime is kept to that level, then it is entirely appropriate and easy, in fact, to have a consistent set of standards. If the regulatory regime is attempting to tell you what colour boiler suit you should put on in the morning, that will never work in one country let alone a dozen countries. I think there is a danger that we get into that. The industry and the regulator need to co-operate. The regulator needs to set the rules and strongly enforce those rules and the industry needs to be aware of the rules and comply with them.

Q123 Chair: One potential advantage of the UK being ahead of the field is that we might be able to set a regulatory standard that other countries then find it convenient to adopt using the principles you have just mentioned.

Francis Egan: That is absolutely true.

Graham Tiley: I can give you examples of that already; we, through the diplomatic mission in Ukraine, help bring out UK experts to Kiev to introduce to Ukraine Government officials to start that dialogue regulator to regulator. That is something that we think is very, very powerful.

Q124 Sir Robert Smith: In definition terms, how discrete is fracking or unconventional gas from other gas? The integrity of the well bore has to be the same whatever the process. The flaring consents have to be the same whatever the process. It is what is happening underground in terms of management of the well that has a different process. Is it really a discrete thing that needs a body of unconventional gas regulation as opposed to oil and gas regulation?

Graham Tiley: Perhaps I will try to address that one and I would look at two different areas. From a technical point of view, there are not substantial differences between a conventional well and an unconventional well. Certainly drilling and, for example, correct isolation of your drilling from the groundwater, is the same whether you are drilling a conventional oil or gas well, or unconventional. Fracking is also, of course, something that has been used for decades in conventional-type gas. I have been involved in projects myself in North Africa and the Middle East where we have used fracking for so-called conventional- type gas. So that part of the technical side, the engineering side, is not fundamentally different between the two projects.

What is very different though is the economic behaviour. That is where you start to get into the need to look a little at the regulation. The thing about very tight gas wells, unconventional gas wells, is you are producing relatively low volumes of gas per well and low rates over long lifetimes; quite different from the way a conventional oil and gas field behaves. So the regulations and, in particular, the fiscal environment need some adaption to deal with, let us say, the economic realities of the unconventional gas business. But the engineering is by and large stuff we have been doing for decades.

Q125 Christopher Pincher: In terms of public opinion as to how you use the term, "public confidence" do you think that the industry does itself no favours in terms of the terminology that is used, which we have been using in this inquiry this morning? The mysterious term "unconventional gas", and mysterious terms like "fracking", at best confuse people, at worst alienate them. Gas is gas, is it not? So shouldn't we be saying it is gas like any other gas and that possibly it is home-grown gas, it is British-produced gas, in order to explain it much more simply to people and to win over public opinion?

Graham Tiley: I have to fully agree with you.

Francis Egan: Equally, I could not agree more. The terminology is repeated often outside the industry, so that is just the way it is. The gas is natural gas. There is nothing unconventional about it. It is normal gas the same as produced from the North Sea. The unconventional phrase comes from the fact that the rock it comes from is not what gas has conventionally been produced from.

Graham Tiley: Francis, can I jump in because I am very passionate about this topic? I believe that definitions matter, words matter. I understand the public concern because, indeed, it is a communication issue. The term "unconventional" has a very specific meaning. It means "unconventionally trapped hydrocarbons". That was the usage that was being done in the geo-scientific and oil industry community. So it is effectively the difference between oil and gas that is trapped in fields beneath seals, the normal stuff that we deal with in the North Sea, and unconventionally trapped gas that is in these very tight rocks, the shales or the deep, tight clastic rocks. So it was actually the trapping mechanism that led to the use of the term "unconventional". But of course you are absolutely correct; it is fine between a bunch of geologists to throw these words around but when it comes out into a public sphere it leads to concern and unease.

"Hydraulic fracturing" is a very descriptive and straightforward term. That is exactly what you do. You use water to fracture the rock, hydraulic fracturing. Unfortunately the shorthand version of "fracking" has become, in effect, almost an accepted swear word these days.

So yes, terminology is obviously not something we think about as scientists when we are first putting these things together. What the industry has recognised is that we did do a very poor job of communicating our activities to the public. I have been through this learning myself personally in a number of projects. We have come a long way in the last couple of years. In companies like Shell, we have gone a long way now to reaching out to the public. In Ukraine, I deal regularly with the communities, with NGOs, the media, the Government, academia; having sessions to basically talk everybody through the principles of what we are doing and what our operations are. But yes, it took some negative reactions to, in a way, wake us up to this issue.

Chair: I should also remind Members and others of my interest in the Register of Members' Interests.

Q126 Mr Lilley: Turning to the tax regime about which the Government tells us it is consulting with the industry at the moment to ensure an appropriate regime, could you give us your thoughts and what you think an appropriate fiscal framework would be for onshore shale gas extraction?

Francis Egan: I think the framework should recognise both the potential of the industry but also the stage that it is at. Effectively, we are at the point of potentially starting a whole new industry in the UK. We have used this phrase internally; if the industry is allowed to grow up into a tax-paying adult, it will pay a lot of tax, but it is in its infancy and there is concern that that infant could be strangled at birth if the tax system is not appropriate to do that. By that I mean the capital costs at the early stage of the industry tend to be high because you are establishing a new industry in a new basin and, over time, those costs will come down.

The consultation that is going on with the Treasury is to set that appropriate balance between making sure that the industry is capable of taking off but not, as I said, potentially killed off at birth.

Q127 Mr Lilley: Why should there be anything special? A lot of businesses have high up-front capital costs. Parts of the oil industry do. You are allowed to write off your exploration costs against profit in the year they are incurred. Why is there any need for a special regime?

Francis Egan: Some of the companies that are operating will not have exploration costs to write off against profit in the UK certainly to start with onshore.

Q128 Mr Lilley: That means exploration costs were lower, not that they were higher.

Francis Egan: We are not asking for a special regime. The Treasury is deciding whether the existing offshore regime should be applied to the onshore and what alterations might be made to recognise the onshore situation.

Q129 Mr Lilley: So would petroleum revenue tax, then, be the default position of the Treasury that PRT applies onshore?

Francis Egan: I do not know what their default position is. That is the consultation process.

Corin Taylor: My understanding is the default position would be the 30% corporation tax, 32% supplementary charge without change and then I suppose two obvious levers you can look at are potentially the level of the supplementary charge and the field allowances, which is obviously a mechanism that is used offshore. Those are two ways in which you can look at it. Industry will still be paying tax but perhaps at a lower rate than some of the mature fields in the North Sea.

Q130 Mr Lilley: Were any special tax breaks provided in the United States and were they significant? Were they a make or break issue as far as the development of the industry was concerned?

Francis Egan: I am not familiar with the United States' tax regime.

Graham Tiley: I would not claim to be an expert on it. My understanding is that there would not generally—because obviously you have differences from state to state, so it is very hard to give a blanket answer. My understanding is that in general there were not special tax regimes for unconventional gas but the tax regime in the US is generally friendly to the industry and, of course, that is part of what stimulated the early exploration efforts into these plays—that and the high gas price at the time.

I am not going to comment on the UK tax regime as I do not know it. Again, I will come back to one difference. If you look at the economics of an unconventional gas development versus a conventional, the cash flow profile is different. Typically you have a longer period of expenditure followed by a longer period of production. So there are reasons to look at how a particular tax regime impacts a particular project or a particular type of project and you may find that you need to adjust it because, for example, a lot of the production with an unconventional gas well comes over the decades of long-term production. Now, at a certain point it becomes a simple economic question of does that well continue to pay for itself in terms of the revenue you make as a company versus the operating costs every year for that well. Now, if the tax regime is not set correctly, you are not making money and you turn that well off and then you lose that remaining production. So it is worth, let us say, looking at type examples of how these projects behave to see whether the tax regime gives the desired result.

Q131 Mr Lilley: Other than defining the appropriate amortisation period for investment, other industries do not have special regimes. I am puzzled at the thought that there is any need for a special regime for shale gas. If they cannot make profits at double the American price, perhaps you ought to be looking elsewhere.

Sir Robert Smith: But they do pay a much higher tax rate than any other industry.

Mr Lilley: If petroleum revenue tax applies.

Sir Robert Smith: Well no, because corporation tax is higher and the supplemental to the corporation—so it is something like 62%.

Corin Taylor: Even if you completely abolished supplementary charge, you would still be paying a higher tax rate than other industries across the general economy. One point about the US, generally speaking, is they have a pretty competitive tax regime although I do not know the details of how it was set up. The shale industry does create a lot of tax revenues and just looking at a report from IHS Global Insight, which was released recently, in 2010 the industry contributed about $18 billion of tax revenue, about $8 billion of that to the States, $9 billion to the Federal Government. In 2015, that figure is projected to rise to just over $28 billion—a sizeable number. Whatever you get in the early years, I think if the industry does develop, the Treasury would get a lot of tax revenue from it.

Q132 Mr Lilley: One final question, are you at present impeded or does it slow down the rate at which you are exploring the tax regime or, indeed, any other aspects of the regulatory regime? I would very enthusiastically go ahead, so I do not want to tax you too much or regulate you too much and I just want to know how much tax we can squeeze out of you and what the minimum regulation we can impose on you is.
Francis Egan: We would love to be able to pay tax because that would mean we are making profit but right now we cannot even flow-test a well. We are not impeded by the tax regime, we are impeded by the fact that we are awaiting a decision from the Department of Energy and Climate Change.

Q133 Mr Lilley: But you are drilling wells?
Francis Egan: We are allowed to drill but we are not able to fracture and flow test them all. So, we can tell you how much is in the ground but we cannot tell you how much will flow out of the ground.

Q134 Chair: You will be aware that it is almost two years since this Committee recommended that you should be allowed to do those things but that is the pace of decision making, I am afraid.
Just on this point about tax though, I do not think you are suggesting that this industry should be regarded as the same for tax purposes as other industries because you are having access to a natural resource.
Corin Taylor: Indeed. Exactly, yes. Very much so.

Q135 Ian Lavery: Looking at the potential for global gas markets, shale gas is only one part of the wider global gas industry and there is a huge potential for a global gas market. Do you think then that the development of shale gas could lead to the creation of a global gas market?
Francis Egan: That is an interesting question. The development in the UK—the market for the gas will be primarily, but not exclusively, in the UK. Of course, the UK is connected to Europe, as you well know, in gas terms, so the impact for development in other European countries could be to assist in the development of a global gas market. We already have a global gas market to a certain degree. Cargoes of LNG are coming into the UK from the Middle East. We import pipeline gas from Norway. We are connected by pipeline to Russia and gas is flowing from the Middle East to Asia and from Australia to Asia. So that market already exists. The development of UK shale reserves will not have a huge impact on that, I do not think, but will probably have a small, positive impact on it.
Graham Tiley: At the moment, gas markets tend to be regional, although LNG is starting to develop something that looks like a global market. I think less than 10% of gas moves as LNG at the moment. The majority of that is still on some form of longer-term contracts. So, although we have seen a spot market develop—something like 25% of LNG is traded on the spot market—we are quite a long way from a global, single market developing.
Shale gas will have impact in the regions where it becomes developed. We see the most obvious example of that is the US where people have switched their attention from building regasification terminals to thinking about LNG export terminals. We are already seeing cargoes of LNG that might have gone to the US market starting to go to other markets. The shale gas revolution in the US has already changed that market dynamic and makes more LNG available into Asia or Europe. China is also developing fast its own unconventional gas resources, which will have an impact indeed on its own appetite for LNG perhaps or other forms of fuel.
Shell's position is it will take quite a long time before we would see a truly global gas market but, as I say, in the regional theatres that we have at the moment, shale gas will have an impact if it becomes a substantial part of the supply.
Corin Taylor: A big issue to talk about is price. Obviously we would see the oil market as being a global market and yet there is about a 25% price differential between West Texas Intermediate and Brent Crude. In terms of gas, you have the Asian LNG, which is at the highest level, about $15, Europe and the UK paying $9 or $10 and the US paying about $4 at the moment. We will see a trend over time towards de-linking gas and oil. It has obviously already happened in the US. The Japanese are now starting to negotiate contracts for LNG based on Henry hub, obviously with a premium on that, but based on Henry hub rather than fluctuating oil price. You have seen Putin talk about Russia needing to develop a strategy to deal with shale. You have seen price cuts for some German utilities, some Italian utilities. The price trends are quite positive. Clearly with the cost of liquefying, transporting, regasifying LNG, you are not going to necessarily see US-type prices around the rest of the world but you could see some conversions downwards.

Q136 Ian Lavery: Oil and Gas UK have said, and I will quote exactly what they say, "Irrespective of the actual pace and contribution that LNG from unconventional sources makes to the global gas market, it remains of critical importance that the market structure in the UK allows it to compete for future LNG supplies from these sources". How can the UK ensure that it is best placed to compete for any future LNG?
Francis Egan: The best thing the UK could do is develop its indigenous resources and reduce its reliance on imported LNG. That is the most positive step it could take because if you are a buyer of LNG, then you will need to pay the market price for LNG.
Corin Taylor: The UK imports about half of its gas at the moment and that is projected to go up to about three-quarters over the next 20 years. If we develop shale in the UK, we may be able to keep imports at about the current level. They may go up a bit but they would not go up as far as three-quarters. Making sure we can buy LNG will still be very, very important but what shale can do is improve our energy security.

Q137 Ian Lavery: The reduction in the price in gas in the US, has that had a dramatic impact on the UK gas prices?

Francis Egan: The most dramatic impact it has had is that we are burning more coal in the UK because coal prices have fallen in the US as a consequence, or they cannot sell coal in the US, and they are exporting it to the UK. So, you will hear talk of a dash for gas. What we have is a dash for coal in the UK right now. In terms of gas prices in the UK, not a huge impact, I do not think.

Q138 Ian Lavery: Finally to Mr Taylor, the Institute of Directors said to this Committee that if the UK wants to benefit from the shale gas boom rather than wait for a global market, probably a better way to do it is to increase domestic production. Can you explain that?

Corin Taylor: Yes, I very much agree with that. If you look at the cost of transporting LNG from the Gulf of Mexico to the UK, for example, it could be about $4 to $5. Add on to that Henry hub price of about $4 at the moment and a lot of analysts expect that to go up a little bit, maybe towards about $5, and you are on $8, $9, $10, which is not that far off what we are paying at the moment, so the potential we have for getting a lot of cheap gas from the US is, perhaps, limited in that respect. We can obviously free-ride on shale gas production in other countries to some extent. That would be benign. But I think it is most important we do increase production of our indigenous gas to really maximise the benefits, not just in terms of price, of course, but in terms of things like balance of payments and jobs and so on in the UK as well.

Q139 Dr Whitehead: You mentioned, Mr Egan, the effect of shale gas in the US of transferring coal from elsewhere in the world to the UK. We have also seen a number of life-cycle studies, mainly in the US, on shale gas production relating to emissions that arise from the whole process; for example the fact that there are a large number of wells drilled as opposed to the small number in conventional and the question of transporting that gas and collecting it and the escape points that intervene and, of course, the loss of gas during the drilling and processing for production. Firstly, what measures do you think may take place in the UK, as opposed to the US, to ensure that that sort of escape is minimised and, secondly, what sort of estimate do you make about those overall emissions from the life cycle of shale gas particularly relating to what you are doing?

Francis Egan: I think the studies that you are referring to, and there are many, as you are well aware, generally agree that the largest source of emissions from shale gas and the methane emissions in the US comes from the practice of storing flow-back water, so this is the water that comes back with the gas, in open pits during the initial periods of flow back. The practice has changed certainly in the US of late and it is our practice in the UK that all flow-back water passes through a four-stage separator and that the gas is separated out in the separator and is, during testing at least, sent to the flare system. I think those studies conclude that if you do that, which is not that difficult frankly, you reduce emissions in that phase of the operation by about 90%. That is by far and away the largest source of emissions identified in any of these studies. The studies conclude that with that alone, shale gas production, the emissions are about 10% less than imported LNG and about the same reduction Vs pipeline imports. From an emissions point of view, it makes sense for the UK to produce its own indigenous gas rather than importing gas from Qatar in LNG ships, where it has to be liquified, transported and de-liquified, or in pipelines from Russia.

On your second point, our estimate—and this gets back to the earlier questions on the regulatory regime—the difference, if we exploit our own reserves, is that we will do it in a properly regulated environment that controls how we do it. Apart from the example I just gave you—which could be passed into regulation tomorrow, I do not think that it is in regulation but Cuadrilla follows that practice in the UK—the other sources of emissions are typically compressor stations, which again is just sound engineering in terms of the seals and how you maintain and manage that, and we can do all that in the UK. The point is we are in control of our own emissions or the emissions rather than relying on gasification processes in Doha or compressor stations in Siberia.

Graham Tiley: If I can add, emissions is one of Shell's onshore operating principles. It is an area where we have a number of stated standards that we adopt globally. We believe the IEA numbers are broadly correct, which say that if you follow good practices, then the overall well-to-wire impact of unconventional gas versus conventional need only be a few per cent. difference and certainly a lot lower than coal, for example. In our view, particularly a switch from coal to gas is probably the most important thing one can do at the moment for reducing overall emissions. Of course that explains why the US has seen the fastest drop in overall emissions in any country in recent years.

Q140 Dr Whitehead: But that is not particularly relevant to the UK, is it, bearing in mind that there are no plans, as far as we know, to build more coal-fired power stations?

Francis Egan: There aren't but we are burning over 40% of our electricity with coal right now and it is also relevant in that we are importing more and more gas in pipelines and LNG. Producing your own gas, there is probably 10% less emissions.

Q141 Dr Whitehead: Yes; it is an LNG effect. But bearing in mind what we have heard about the displacement of coal around the world from the US and secondly, less certainty for future developments—we do not have a coal regime upcoming—the question of colonising that area with gas does not look like it is going to arise. What do you think the overall effect of a coal displacement looks like in the UK?

Francis Egan: If we displace coal in the UK, that is good for emissions, and how we do that, frankly, does not matter. If you can displace the coal, you will reduce the coal emissions. If you displace it to renewables—and there is a role for gas and renewables, I strongly believe that—no one fuel is either going to supply all the energy of the country or

should be allowed to because it is important to have diversity of fuel as well as source.

Q142 Dr Whitehead: Do you, or any of the panel, go along at all with the suggestion that investment in unconventional gas is likely to be opposed to investment in renewables or do you think they are compatible with each other?

Corin Taylor: I think they are complementary. If you look at the US, they have had quite large development of renewables over exactly the same time period as they have developed shale gas. That is obviously going to be the case in the UK. The biggest driver of renewables investment is policy and that is also true in the US. If you keep the policy incentives for renewables, then you will see renewable deployment.

Francis Egan: I can speak from our example. One of our largest investors is Riverstone who are also probably the largest investor in renewables in private equity. It is entirely, in their minds, logical to invest in both.

Graham Tiley: I cannot give a UK-specific answer but globally, of course, what we are seeing is renewables are about 13% of the energy mix today. In Shell, we think it could rise to between 20% and 30% by 2050. But even to do that on a global scale will require huge investment both in the technology as well as the development of the renewable sector. So, in our view, the two are going to go together for a long time.

There are also very specific advantages. We know that gas, as a power-generating source, is easy basically to turn on and off. With intermittent wind or solar, gas is a perfect complement to those renewable sources. Gas plants are relatively cheap and easy to build, so they are a good way to keep your balance in your overall supply of power generation.

Corin Taylor: If you look at the International Energy Agency projections and their *Golden Rules for a Golden Age of Gas* report, under the scenario in which you get a lot of shale gas development outside of the US, they see gas meeting 31% of global primary energy demand growth by 2035 and renewables, including hydro and biomass, accounting for 34%. Gas and renewables are the two big global growth stories over the next 25 years.

Q143 Dr Whitehead: What is the profile for Shell in terms of investment in shale and unconventional, and renewables?

Graham Tiley: I am afraid I do not have figures in terms of overall investments. I know we are investing—I think we have invested just over $2 billion in the technologies, various technologies like CCS as well as renewable energy in the last four or five years—but I do not have an investment number for you, sorry.

Q144 Sir Robert Smith: Some of our earlier witnesses highlighted how the US Government has led a lot of the basic research into conventional gas processes. They are also suggesting that there is some talk that the lessons learned in the US do not necessarily read across to European production and that we are going to need different processes for making sure we can get the gas out in the EU. Is that something you would agree with?

Graham Tiley: I think there will be differences. I would highlight two factors: first, their licensing regime, which is quite unique, with all the small licences, which drives a very fast pace of drilling and a big focus on drilling. Secondly, the availability of an existing contractor industry with many rigs, frack units available, has driven a certain approach in the US. As we go into Europe, we will have to be more technologically minded. It is a little bit like the difference between a US muscle car and a European sports car. What we will find in Europe is we throw less horse power at the problem and have to be a little bit more sophisticated in the engineering because costs will be higher, so we have to be a little bit smarter in the way we do it. I agree that there will be differences as we transfer from the US to the global shale gas possibilities, yes.

Francis Egan: If we look at Lancashire, the geology in Lancashire is somewhat unique. I read in one of the articles over the weekend that shale gas will be difficult in the UK because it is too thin. The shale formation in Lancashire is over a mile thick. It is probably unique in shale. There is nothing in the US that can compare with it. Typically, shales in the US are a couple of hundred feet thick. So there is an opportunity in Lancashire, in particular, to do things differently. The two technologies that have driven the shale industry in the US are horizontal drilling and hydraulic fracturing and the ability to improve on both. Certainly the horizontal drilling in Lancashire, because the shale is so thick, opens up the opportunities of drilling not just at one horizontal level but at many horizontal levels within the same shale. What that means is you have a much lower surface footprint. For one vertical well at the surface, it is like the arms of an octopus, you have many laterals. To visualise it, these laterals are eight inches in diameter. This is not mining; this is equivalent to keyhole surgery. This is small holes carefully placed. They can exist at multiple levels because of the thickness of the shale. So we have a unique opportunity in the UK and in Lancashire in particular, because of the geology. It is different. It is better.

Q145 Sir Robert Smith: Do we need government research or is the industry going to be able to meet the challenge?

Francis Egan: I would perhaps characterise the UK as a fast second-mover. We can take what we have from the US. We can customise it and we can improve on it as needed.

Corin Taylor: I do not have anything much to add. There was a report by the Breakthrough Institute in California that made the argument that at key stages there had been public money that was put at the problem of hydraulic fracturing and horizontal drilling in the 1970s and 1980s and that helped pave the way for George Mitchell to pioneer the process economically. I am sure there was government involvement at that stage. For the UK, it is a bit like the internet, which was invented in the US and we obviously benefit from that. There is some read across from that in this context as well.

Q146 Sir Robert Smith: Finally, the British Geological Survey were saying that Cuadrilla had had problems at Anna's Road with a well? Is that problem to do with the unconventional side of it?
Francis Egan: No, it is nothing to do with the unconventional side of it. We drilled down to about 2,000 feet. We needed to run a pressure test to prove that the cement bond was good. We proved it was good but unfortunately the packer, a piece of kit that was run into the hole, got stuck and we were unable to retrieve it. So we needed to start again. It is not commonplace but it happens in drilling. It is nothing to do with fracturing, nothing to do with shale. We were nowhere near the shale.

Q147 Chair: You sounded a bit frustrated earlier on about the fact that you cannot yet start doing flow tests. Once you are, assuming you get the go-ahead to do that, will that rapidly improve the information you have and the judgments you can make about the actual recoverable reserves?
Francis Egan: Once—I say once, I should say if—the Government approves the go-ahead, we need to go through a planning process with Lancashire County Council, so that is going to take several months to work through and there will be, as I mentioned earlier, various environmental impact assessments and public consultations as part of that. We plan to fracture and flow-test most likely two wells. That is not going to be the end of the story. There will be some initial data that we would hope to have by the middle of next year. That is not going to be the definitive answer. As I said, reserves are not a fixed number. They evolve over time but certainly it will give some good opening data, UK data.

Q148 Chair: Given the potential importance of this, obviously there are a wide variety of guesses about what it might be, one of the concerns of this Committee is that the UK needs to invest quite a lot in new-generation capacity quite quickly now. It would clearly be helpful to have reasonably accurate data about this as a background in which to make those decisions about future investment.
Francis Egan: Yes. Well, we will give you the data as soon as you let us start.

Q149 Chair: Are you concerned about what has happened in Poland? I am told Exxon were very disappointed with the results in Poland.
Francis Egan: We have licences in Poland and we are at a fairly early stage. I cannot speak for Exxon's experience in Poland.
Graham Tiley: There will be disappointments. That is why it is called exploration. We drilled three shale-gas wells in southern Sweden and did not find the gas content in the shale and exited that project. Not every shale is going to work and this indeed is one of the reasons it is quite a difficult subject for us all because these resource estimates are sometimes enormous but indeed until we get to frack and test these reservoirs, and not just in one well but a number of wells, it is often talked about as being a bit of a statistical game. At the end of the day, if you have drilled your 1,000 wells, the question is does the average recovery per well exceed your economic threshold. That is the test you need to apply to see whether you have a viable project. Some wells will come in lower. A few wells will hopefully come in much higher. But the absolute critical factor is your average recovery per well. Even after one well, you have an average of one that is not statistically a very stable sample. Ideally, over time, you build up a number of wells upon which to base your predictions.
Francis Egan: So far we have drilled three wells. We have the data from two offset wells. We have taken 1,200 feet of core. We have logged all the three wells. We have completed a 3D seismic survey over 100 square kilometres. So we know the geology is good and we know it is gas bearing and we know it is a mile thick and we know it is gas bearing throughout. In fact, we have not even reached the bottom of it. We have not been able to drill to the bottom of the shale formation because we have not gone that deep yet. So the geology is good. We need to establish flow rates. Some wells will be better than other wells, over time. That is undoubtedly the case. But the geology and the gas exist across the licence area.

Q150 Dr Whitehead: When you first drilled your wells—this question is directed to Mr Egan—you very early on produced some estimates about the total amounts of shale gas for the UK. I assume that was a resource estimate rather than—
Francis Egan: For the UK?
Dr Whitehead: For the UK. You publicly said 200—
Francis Egan: We have never produced an estimate for the UK. We have given an estimate for our licence area in Lancashire alone.

Q151 Dr Whitehead: Right. So, those reports were newspaper embellishments?
Francis Egan: I am not even aware of newspaper reports quoting us as giving a UK estimate. We have certainly given an estimate of 200. That is just for our licence area in Lancashire alone.

Q152 Dr Whitehead: But certainly the impression I am getting, from what we are hearing this morning, although we may have some thoughts about resource in terms of reserves, bearing in mind what we have heard about the uneven nature of production in various places offset against the known reserve that you have identified in Lancashire, is that this is still a pretty inexact process as far as saying anything about recoverable reserves, say from the UK, are concerned?
Francis Egan: I have not done a good job in explaining myself. We have not published any reserves number for Lancashire. We produced a number of 200 trillion cubic feet resource. We did not produce that quite quickly. We had drilled wells and taken 1,200 feet of core and had logged all the wells. We were somewhat ridiculed at the time and people said, I think, it will be three or four. I will be surprised if BGS does not come up with a number that is at least our number. What we are saying today is we are doing exactly the same thing. I could sit here and guestimate reserves all day long. You need to get some data and that is what we are asking for approval to do. If the country does not want the data, tell us.

Q153 Dan Byles: Is there a time limit beyond which if the Government continued to delay, you are going to pack your bags and go away?
Francis Egan: I was asked and, again, quoted as saying we would walk away. The question I was asked was if the Government said no, what will we do and I said we would have no choice but to walk away. We hope the Government will make a decision soon.
Chair: That has been very instructive for us. Thank you very much for coming in and I am sure we shall stay in close contact with you all.

Examination of Witnesses

Witnesses: **Professor Kevin Anderson**, Deputy Director, UK Tyndall Centre, University of Manchester, **Jenny Banks**, Energy and Climate Change Policy Officer, WWF UK, and **Tony Bosworth**, Climate and Energy Campaigner, Friends of the Earth, gave evidence.

Q154 Chair: Good morning. Thank you for coming in. As with the previous group, could you just very briefly, for the benefit of the broadcasters, introduce yourselves?
Tony Bosworth: Good morning. I am Tony Bosworth. I am a climate and energy campaigner at Friends of the Earth.
Professor Kevin Anderson: Kevin Anderson. I am Professor of Energy and Climate Change, University of Manchester and Deputy Director of the Tyndall Centre and I should also express that I used to work offshore with Francis on the same oil platform in the 1980s.
Jenny Banks: Jenny Banks from WWF. I work on energy policy.

Q155 Chair: You have heard and read, of course, of the claims that have been made about the scale of the contribution that shale and, particularly the discoveries in Lancashire, could make to total UK gas demand. WWF have, I think, referred to this speculation as hype. Is that correct? Why do you think it is hype?
Jenny Banks: I am not necessarily calling Cuadrilla's estimates hype. I think what we were referring to as hype was more the general expectation around shale and some of the rather optimistic reports that have been written about what we might get out of the ground. At the moment we have been looking at the BGS estimates as the only ones that are produced by a scientific organisation. All of the other estimates have been produced by companies and clearly there is a lot of uncertainty around what is going to be produced. Francis himself earlier acknowledged that there is a lot of uncertainty even for them about what they will get out of the ground.

Q156 Chair: But the BGS told us two weeks ago, and I quote, referring to Cuadrilla's figures, "Their figure, in my opinion, is more reliable than mine".
Jenny Banks: I was very interested to watch that.
Chair: Pardon?
Jenny Banks: I was very interested to watch that session but obviously we had not heard that from them at that point.
Chair: We have heard it now.
Jenny Banks: Yes.

Q157 Chair: So are you still casting doubt on Cuadrilla?
Jenny Banks: Well, Cuadrilla have drilled two wells, now three possibly, and they themselves are the first to acknowledge there is a lot of uncertainty about what will eventually be got out of the ground or the total gas in place.
Tony Bosworth: The other point we could make on this is that the numbers are notoriously volatile numbers for shale gas reserves and it has been pointed out already that the estimates of gas in Poland have been cut significantly earlier this year by 85%. But even in the more mature fields such as the Marcellus Shale, they are having significant cuts in their estimates. So, the numbers are notoriously volatile. What is a reserve figure today or a recoverable resource figure today might not be the same in a few years' time given improved data.
Professor Kevin Anderson: It is also my own experience from talking to a lot of academic geologists, quite a few who have been involved with BGS would suggest that you have a number of levels of uncertainties. In fact, we were talking in the House about this last week with Professor Taylor, one of my colleagues in Manchester who is a geologist, saying, if you think about it, you have big uncertainties on the resources. You also have big uncertainties on the reserves and what part of that you can mobilise. I think natural gas is about 30% recovery rate. I gather the US is giving about 6% recovery rate at the moment. So what you think is actually down there, we can get about 6% out. Now you can refracture and you might be able to get those numbers up. They will not be up towards 30%. The problem there now, as was pointed out before, is that the shale is heterogeneous. Some of it is quite ductile. If it is fissile shale, you will not get the gas out. It has to be quite brittle shale. You then have a lot of population in the UK, so the analogy to the US is very different. So at every level what you see are considerable uncertainties.
Now that does not mean to say that of course the estimates could not turn out be correct. They may or may not be. They could be higher, they could be lower. What that does mean is that we are very uncertain and we will remain with a high degree of uncertainty because it is not natural. It is natural gas in terms of what comes out, it is the same material, but the place that it is held is unconventional as was pointed out before and, therefore, we do not have a lot of experience with that and it will remain heterogeneous. We will learn by examples and lessons.

Q158 Chair: When we talk about recovery and reserves, is that figure affected by the price?
Professor Kevin Anderson: As is always the case with the hydrocarbon industry, you can do a lot more. If you want to get more out of it, you can spend more money trying to get it out of the ground. Yes, the price does impact what is available.

Q159 Chair: So, have the recent cuts about reserves that you referred to in America been the result of the fact that the price has collapsed?
Tony Bosworth: As I understand it, the recent cuts are down to improved data on drilling and production. It is information from the US Energy Department citing improved data on drilling and production and that has led to the changes in the estimates.
Professor Kevin Anderson: But my colleague last week was pointing out that it makes a loss now in the States. The shale gas production is a loss. One of the reasons they are doing it is effectively because of the tight oil is also in the reservoirs. So they are producing at about $2 to $3 per million BTUs at the moment and it needs to get up towards $6 to make it break even. So I think in the US at the moment there are lots of uncertainties as to why it is the price has dropped to that level. It is certainly unsustainable in the long term economically.

Q160 Chair: Since we need more data to establish exactly what the reserves in the UK are likely to be, isn't that a very powerful reason for giving the companies permission to get on with their work?
Professor Kevin Anderson: It depends on your other sets of concerns around it. From a climate change perspective, I would say no, not at all. If you are interested in energy security, you might argue there is some legitimacy to their case.

Q161 Chair: Even from a climate point of view though, if we did have significant domestic gas reserves that might help to lower prices relative to what they otherwise might be, if we were relying very heavily on imports, given that that reduces energy bills, doesn't that actually make it easier for us to support a renewable energy industry alongside it if overall costs are lower rather than higher?
Jenny Banks: If you look at the International Energy Agency, for example, they produced a report earlier this year called *the Golden Rules for the Golden Age of Gas*, which looked at two scenarios: in one there is a global dash for gas; in the other there is not; both came up with climate change being around 3.5 degrees. One of the interesting things about that report was that in the dash for gas scenario, gas prices were lower and the reason that the carbon saving was not greater and, therefore, that climate change was still likely to be around 3.5 degrees was that it undermined investment in low-carbon generation because the gas price was lower. So, I would say the IEA are suggesting exactly the opposite to that.

Q162 Chair: It depends on the policy, of course, does it not, that is pursued?
Jenny Banks: Yes, absolutely.

Q163 Chair: If you simply bank the gain from lower gas prices it does not help, but if you say that has restrained the rise in household bills or industry costs, you can then afford the support for other forms of low carbon energy.
Professor Kevin Anderson: You would first have to assume that shale gas was cheaper than other forms of generation. We would argue that if you take the full capital costs into account, even ignoring the operating costs, that that is not the case for shale gas and that is using Cuadrilla's own data on the costs for their pads and combine that with Bickerstaff's estimates that certainly DECC have been using for cost of CCGTs with and without CCS. So I think that is not the case necessarily with shale gas.
The other concern, of course, is do you necessarily want the prices to be lower? We just take these things as a given but we are sat in this modern room with the blinds closed and the lights on, so clearly energy prices are not particularly significant here. There are too many people in the 20% of housing in the UK that are in fuel poverty. To them energy prices are very significant and if, of course, prices go down we end up consuming more so, again, it depends on what your questions are. If your question is about climate change, consumption of energy is a major issue so you may not necessarily want the prices to go down for everyone. Clearly here you might make an argument there are things we could do to respond to the price signal today.
Tony Bosworth: I think it is also worth pointing out that it is at least unclear whether shale gas is going to be cheaper than other forms of gas or not. I think the general consensus of view is that the costs are going to be a lot higher in the UK than they are in the US due to things like labour costs, the lack of a well-developed drilling sector; issues like that. Some analysts have said that they cannot see shale gas coming on to the market at much less than the current wholesale cost of gas. So is shale going to lead to lower prices? I think that might be one of the areas where there has been a certain amount of hype.

Q164 Dan Byles: If all domestic UK shale gas production does is offset imports of gas, do you think that effectively would mean it is a neutral change as far as emissions and climate change, if it basically means we do not necessarily burn more gas but we burn our own rather than Qatari gas?
Professor Anderson: It depends how much credence you give to basic economics because if it is a supply and demand issue you simply say if we are not consuming the gas, we are in the world market, and that means there is more gas out there in the world market and someone else will burn it. The lights go out around the world at the moment because a lot of people around the world do not have enough energy. In a world that is energy hungry with rapidly growing economies it seems—I am not suggesting you are saying this—incredibly naive to assume that any fossil fuel we get out of the ground will not be burnt. I think it is naive to say that any fossil fuel we are aware we can get from the ground will not be burnt, in the absence of some of the criteria around that. If we don't run the gas here it will be burnt elsewhere, so there is

no reduction in emissions. In fact I would suggest it is an increase in global emissions as a result.

Q165 Dan Byles: Is the counter-argument that if we do not produce more gas there are going to be shortages?
Professor Anderson: If we don't produce more gas?
Dan Byles: If we do not produce more gas globally, there is going to be energy shortages, you just said so.
Professor Anderson: Unless we invest in other forms of—generation of course is only part of the energy system that we use. There are energy shortages today. People go hungry, people have the lights out. There are other things we can do. Of course those people have also suffered the impacts of climate change so you have to relate these things and see it from a system perspective but at the moment it is fairly clear that if we burn more indigenous gas here, that other gas will be burnt elsewhere and the carbon dioxide emissions will just go up.

Q166 Dan Byles: I want to explore with you some of the similar issues I explored with the first panel about the regulatory regime. I am quite keen to know your view. The view we heard from the first panel was that the regulatory regime is pretty robust; that there were some frustrations around it but that on the whole the previous panel were pretty united in saying, "We have a gold standard, pretty tough regulatory regime here in the UK". I am curious to know whether you agree.
Jenny Banks: The Environment Agency has been very proactive engaging with environmental NGOs and other groups. If you look at the stage they are at now, they are currently pulling together their guidance for all of the different bits of regulation and how it will apply to shale gas just for exploratory drilling. So two years ago when the Committee first met, the Environment Agency were at a relatively early stage; they had very little dedicated resource. The reason for that—and I am not blaming them at all—was because we did not have a history of shale gas in the UK and it has taken them some time to catch up and to work this through. They are even now currently considering questions of, for example, will flow-back fluids be allowed to be stored in open pits. When I spoke to them they were not totally clear on what the regulation on that meant. So I think for us it is difficult to draw a conclusion as yet, particularly because there is still uncertainty in the US. For example, the US EPA is still yet to publish the findings of its review, even the preliminary findings of its review, on the environmental impacts of shale. I think for us it is an early stage still. The Environment Agency are trying their best but we have not yet seen even their preliminary guidance for exploration.
Tony Bosworth: I think that point applies equally to the Health and Safety Executive, again they are still developing their guidance through the UK Onshore Operators Group. They are developing their guidance on shale gas activities. That is something which we have not seen yet, it is still too early to say whether or not that regulation is going to be up to it; how they are going to respond to the recommendations of the Royal Society and people like that. It is too early to say whether the regulation is up to it. The Government is saying it wants to have a regulatory regime that is simplified and streamlined but we must ensure that does not mean that it is not robust.
Professor Anderson: I would suggest that again going back to Francis' comments earlier, we don't know a lot about what the production of shale gas would look like in the UK so the regulatory process will have to be one that very slowly learns from how we proceed, if we decide to proceed and go ahead with it.
The other thing I would suggest to be aware of, and this is my understanding anyway, is that the monitoring of the levels of methane, particularly the fugitive emissions, around sites is done for health and safety reasons, obviously for the operators and for the local community, and that is in order of magnitude higher than the level you would want to monitor for environmental emissions. So if you are wanting to include in your regulations the environmental concerns then you would have to have a much, much more stringent monitoring regime for the levels of fugitive emissions than I understand is currently in place. There is a lot more that needs to be done yet and it will be a learning by doing approach to ensure the regulation is appropriate.
Tony Bosworth: If I could just make one final comment. Early regulation has a role in making fracking safer but I am not sure whether it can make it safe and that is something that the United Nations environment programme has recently said. When they said, and I am quoting, "Hydrological fracking may result in unavoidable environmental impacts if extracted properly and more so if done inadequately". Even if risk can be reduced theoretically many accidents will occur from leaky or malfunctioning equipment or from bad practice. So we can make it safer but not necessarily safe.

Q167 Dan Byles: Would you say that is more so for shale gas than for conventional oil and gas production, or is that something that could be said for the whole of the oil and gas industry?
Professor Anderson: I would have to say I think it could be said for the whole of the oil and gas industry. If I was put on the spot I would say that if the choice was a straightforward one between Putin's gas regulated in Russia or gas from the UK produced by shale, I would say from a regulatory point of view my preference would be to go for domestic production, from a purely regulatory point of view.

Q168 Dan Byles: Because we can control it, we can be robust and—
Professor Anderson: We can indeed, yes.
Dan Byles:—we would probably do so better than Putin's Government?
Professor Anderson: Yes, indeed. Of course we would have to renege on any regulations on climate change because it would not fit with those but if we did that, then fine, yes.

Q169 Dan Byles: Do you take the point made by industry, because I have had it made to me a number of times outside Committee, that they are very keen for very robust regulation because what they do not

want is a cowboy operator coming in, publicly doing something wrong and shutting down the industry for everybody because there would inevitably be a public backlash? Do you think there is going to be a degree of self-regulation imposed simply because if the companies want to carry on fracking they need to be seen to be doing so safely?
Professor Anderson: You would like to think self-regulation works well but we are awash with instances from the hydrocarbon industry to the press to many other organisations who will remain nameless, who are not particularly good at self-regulating. I think by and large we are poor as organisations in self-regulation and I think it is not the way we should go.

Q170 Dan Byles: A similar question as put to the first panel about the recent report by a group of MEPs about where the cost should lie in terms of environment protection. I can guess what your answer is going to be, but where do you believe the responsibility for environmental protection should lie in terms of who pays for it?
Jenny Banks: It is not an issue I have particularly thought about or looked into but it would seem reasonable for the industry to shoulder the costs.

Q171 Dan Byles: Even if Government is going to be reaping a tidy tax sum from the industry? Do you not think perhaps Government should say, "Well, perhaps some of those taxes could be recycled into paying some of the costs of environmental protection"?
Jenny Banks: I am not really an expert in this area.
Tony Bosworth: Nothing to add.
Professor Anderson: There is a complete mismatch in these things because sometimes we cover environmental costs and sometimes they are covered by the public purse and others by the private purse, and this is another one of those where it would be a complete hotch-potch as is always the case and it is very difficult to get some set rules on it. But I doubt, for instance, that they will paying for the climate change impacts, if that is what you are thinking about. I doubt they will be paying for coastal defences in Bangladesh, which would of course fit with the recent discussions in Doha. I think we have to be quite careful where we think about these sorts of things and see it right across the industry. Who pays for decommissioning costs for nuclear power? Who pays for the climate change impact of other sorts of power generation that we are using? Indeed, who pays for the impacts of some of the renewables? It is not a straightforward, easy answer to give.

Q172 Dan Byles: Briefly on the issue of public acceptability, community views, that sort of thing, the stronger and more robust the environmental regulations are seen to be, the greater confidence one would hope that might give to local communities. What do you think the current state of play is? There is obviously a lot of fear. There are a lot of competing claims about what fracking does and does not mean to local communities. Where would you say the current state of play is? What do you think that the industry and Government could do to perhaps better reassure communities that if fracking does go ahead, it is being done safely?
Jenny Banks: There was quite an interesting poll by ICM, which came out quite recently.

Q173 Dan Byles: That is the one, "I would rather live by a wind farm than a fracking pad". Is it that one?
Jenny Banks: Yes, the very same.
Dan Byles: I do wonder how many people who answered it either live next to a wind farm or a fracking pad and therefore what they were basing their answers on.
Jenny Banks: I think it provides a snapshot of what public opinion is at the moment and people's views. For anyone who didn't see it, it was basically that 11% of people would rather live near shale gas and 67% said they would rather live near a wind turbine. Now, I can't comment on it apart from the fact that you would assume a poll would be representative of public opinion.
Tony Bosworth: Those figures are also echoed more broadly if you are looking at what people's views are about the broader direction of energy policy, that people want to see much more of their power coming from renewables. There is a much greater percentage of people wanting to see more power coming from renewables than want to see that additional power coming from gas. If you are looking more broadly at the opinion of shale gas, I think the overwhelming conclusion is that there is a lot of uncertainty. People do not know what shale gas is; they don't know what potential risks and benefits there are and they don't know whether they think it should go ahead. There are a huge amount of unknowns or people who don't know in these surveys.

Q174 Dan Byles: Who do you think should be responsible for improving public awareness? If we say to industry, "You need to educate and improve" are people going to simply not believe what they say because they are going to say, "Well, that's the industry". Should it be people like the University of Manchester perhaps, coming forward producing independent research and independent papers on it?
Professor Anderson: Yes, I and colleagues do engage in such events. I have not done one on shale gas particularly but I know other colleagues that have. I think the most important thing is you have to be absolutely candid and direct. We should never try and hoodwink the public. We all think this publicly and then privately we say something different and do something different. But I think that is real mistake. We never learn by that.

Q175 Dan Byles: Do you think there is a role for industry in public education here or do you think people simply will not accept if the oil and gas industry come forward and say, "This is what shale gas really is, this is what fracking really is"?
Professor Anderson: It is more difficult to accept it from industry. Obviously some people in society are given more trust than others. But I think if we all try and be as honest as possible, warts and all, that is a good thing. I think one of the big problems with shale

gas at the moment is literally the uncertainty. It is not necessarily just the initial operations but it is the refracking. So we do not know how often you would have to refrack and that refracking will mean lots more trucks, more water, lots more local disturbances. That is going to be quite a challenge because you don't know what that is going to look like and Francis and Cuadrilla don't know either. So we are uncertain about the future if you live near one of these, what that will mean for you locally. We can't do anything about that at the moment. So I think again we should be honest about that uncertainty. It comes back to Tony's point. That makes it very challenging for people who live nearby because all we can say is, "Well, we don't know what your future will be like for the next 10 or 20 years in terms of trucks and other movements around the site". That is true, we do not.

Tony Bosworth: One of the conclusions of the recent Royal Society report was that one of the precursors they said to the decision-making on shale gas, one of the benefits, would be greater knowledge about the public acceptability of the risks, whether that was environmental risks, health and safety risks or climate change risks. I think, as Kevin has said, we need an objective and honest debate about that. I think the industry has a role to play in that but so do we. We should not be relying simply on the industry.

Jenny Banks: I think there are two facets, in a way, of people saying, "We don't want shale gas drilling near us". People tend to object to a lot of forms of development near them, whether it's a crematorium or a wind farm or a gas field. People generally don't like change that involves big things that bring traffic.

Q176 Dan Byles: I am very struck by the people who answer in the abstract that they like the idea of more wind but who often do not necessarily follow through when it is going to be at the bottom of their garden.

Jenny Banks: Yes, sure. So maybe that is more of an indication of whether people in general prefer renewables theoretically to gas. But I think there are two things here, there is the general opposition that people tend to have to anything being built near them, and then there is the people's fear about the environmental impacts and I think what the industry needs to do is to show, if indeed it can do, that that is not a legitimate concern. We obviously have reservations about whether it is or not but I think time will tell on that one.

We did a few calculations, (we have a high import dependence, as you are all aware now, on gas) looking at how many wells would need to be drilled to keep gas import dependence at current levels out to 2030. There is quite a disparity on how much gas wells will yield. So we looked at, for example, some industry figures, which were 3.5 times higher than what the US geological survey was coming up with in terms of average well years. So if you use the US geological survey figures, it came up with around 7,000 wells, which we assume would be about 700 well pads, whereas the industry figures were about 1,936 new wells. So there is a big disparity and I think that is quite relevant in terms of public opinion and how many wells that means.

Tony Bosworth: That is relevant also to what Cuadrilla are saying about what could happen in Lancashire. Kevin and his colleagues at Tyndall have said that if we wanted to produce 10% of the UK's current gas demand from shale gas, we could be needing 2,500 to 3,000 wells. That is for 10%. Cuadrilla have said they can produce 25% of the UK's gas from their area in Lancashire but the maximum number of wells they have talked about is 800. So I think if you are talking about 25%, you could be talking about a lot more than 800, and that is something that the local MP has certainly said would be unacceptable.

Q177 Dan Byles: Does that take into account what Mr Egan said about the thickness of the shale and each pad being able to have multiple levels?

Professor Anderson: Yes, we used their data.

Chair: That is very interesting, thank you.

Q178 Sir Robert Smith: In the previous evidence session, not today but an earlier evidence session, there was a suggestion that you could not necessarily read across the number of wells from the States to here because of their land ownership rules and therefore in the States you had everyone wanting a well because they would get the income from it. With horizontal drilling the number of pads to achieve the same effect in the UK could be a lot less.

Dan Byles: Every half mile.

Professor Anderson: Yes, I think as was said earlier, you cannot simply take what has happened in the US and just superimpose that on the UK. I think everyone would accept that is the case.

Jenny Banks: We had to use something so I had a look at the US figures, I discounted about two-thirds of the lower performing wells just because I thought probably they are not very economic, but, yes, there is a big disparity between different shale plays and we would not know what shale wells in the UK would be yielding until it was done.

Q179 Dr Whitehead: Just before we move on, have you done any work or is there any work that you know of that scopes that sort of ambition to provide a certain percentage of UK's either domestic or domestic and industrial gas supply with, say, the ambitions that the biogas industry has to supply a similar percentage of gas from anaerobic digesters and produce therefore biogas that is injectable into the gas mains? Are there any figures? You have mentioned, say, 800 wells in Lancashire. Are there any figures that you know of which would say that is equivalent of 400 bio digesters or 200 large AD plants or whatever?

Tony Bosworth: I know that the National Grid produced a report in 2009 saying that the bio renewable gas could meet up to 50% of UK residential gas demand. I don't know about how many AD plants that would involve.

Jenny Banks: It sounds like analysis we should go away and do.

Q180 Dr Whitehead: We have heard that a gas regime could serve effectively as a transitional instrument to the low carbon economy; that is you

introduce gas, it displaces some existing coal, it produces a cheaper option for consumers and therefore you can do lots of things that lead to a transition and at that point you turn the gas off. That is a slight oversimplification, but what is your view on that particular scenario?

Professor Anderson: I am very clear about this. From a UK perspective, it is simply wrong. I think it is probably appropriate in the non-annex 1 countries, China, India, some of the poorer parts of the world. For the annex 1, the wealthy parts of the world, if we are serious about climate change—and of course the whole thing on climate change pivots on what do we mean by it, by this nebulous expression—if we quantify it in relation to say our international commitments then we can be absolutely categorical mathematically that shale gas cannot be a transition fuel to meet our international obligations. There is not enough emission space for it to play any role whatsoever in that. That is not the case for China and other parts of the world where it may well have a role to play because they have a larger emission space because obviously their level of development, their income per capita, their welfare per capita and even their emissions per capita are much lower than in the West. So we can make a very categorical mathematical statement relating to our international commitments. So if we renege on those and say we do want to go to a slightly lower carbon Britain but not very much lower then you might argue it has some role to play. But I think we would have to be absolutely clear as to what our starting position is about what we mean by climate change and by and large the UK has a muddled set of targets. It has different targets internationally to what it has domestically. I think the statute only has the 80% target, and that is not clear either. 80% of what? Does it include aviation and shipping or not? DECC, I think, are looking at that at the moment.

Jenny Banks: It was pointed out earlier that obviously we are not planning to build any new unabated coal fire power stations, so the question in the UK is more to do with to what extent are we burning coal and using more coal as a result of the coal price going down. A simple solution to that is having a higher carbon price, preferably through the EU ETS but we all know what the issues are with that at the moment.

Professor Anderson: I think what you could seriously consider is putting a standard in place. I wish we had done that right from the beginning. I find it slightly odd that a Government that has a rhetoric around free markets then chooses to pick winners as to which energy ideology it prefers. I find that quite a clash of ideologies but I am an engineer so I wouldn't know. But it would seem wise to me the thing to do would be to set a standard in terms of emissions. If it was for electricity, for instance, it could be grams of carbon per kilowatt hour. Just set that standard and say to the industry, "You can use what you want. You can use nuclear power, you can use gas with carbon capture storage or you can use renewable powers but you will meet 350 grams per kilowatt hour or not sell it from your portfolio next year and the year after that it will be 10% stricter and the year after that it will be 10% stricter". You give a real clear dynamic signal to the industry and let it run. So then you can have your gas if you want but you won't get your gas down the levels that we need for our international commitments. That is the concern that it is technically impossible to do that.

Q181 Dr Whitehead: Yes, but we do have an EPS coming forward in the Energy Bill, have we not?

Professor Anderson: Not related to our climate change commitments, no. These are just angels on the heads of pins.

Q182 Dr Whitehead: Would you like to expand on that?

Professor Anderson: Yes, internationally we, and of course every other country who signed the Copenhagen accord are committed to a very high probability of not exceeding 2 degrees Centigrade, which if you use the language of the IPCC, to which we are a major contributor, then than is not more than a 10% chance of exceeding 2 degrees Centigrade. We from that can very clearly work out what the carbon budgets are and from those we can attribute those to the UK and then say there is no emission space available for the UK. We knew this. We have been saying the same thing to committees like this for many years and we in the UK and elsewhere have fundamentally failed to control our emissions. They have gone out of control in the UK and globally.

Tony Bosworth: The UK targets, the 80% cut by 2050 target, gives it a 50:50 chance of temperatures rising by more than 2 degrees and we think that is effectively a toss of the coin, which is something that is far too risky for something that this Government has said we must—underlined must—not do.

Professor Anderson: I have to say I would disagree with my colleague there, that in fact the 80% reduction for the UK by 2050 is premised on a very inequitable distribution of global emissions to the UK, which again we would be reneging on our commitments under the Copenhagen Accord, which has very clear statements about the poor parts of the world be given more space to grow their emissions and the wealthy parts of the world having to compensate for that. The UK legislation does not take that into account. It thinks it is appropriate that Ghana and the UK have as similar proportion attributed to it.

Q183 Dr Whitehead: The fact that there is an energy performance standard coming in the Energy Bill but at a level, as it happens at the moment, that enables unabated gas to continue further, is that mitigated in any way by the commitment to review in 2015 and review that level downwards?

Professor Anderson: The problem with these things is by 2015 we will have invested in more power plants. We have to get off that curve now. Every hour that we delay makes it more strenuous to get off the curve and gives us more reason to avoid getting off the curve. So I think we know what those standards should be now, we have had these discussions repeatedly over many, many years and we should have put them in place previously and we need now to put ones in place that are stringent and ones that you

cannot get around. They need to be much stricter than the ones we are talking about.

Tony Bosworth: Friends of the Earth did some calculations a couple of years ago in a report we called *Reckless Gamblers* that looked at what cuts we needed to make if we wanted to meet the targets that Kevin is talking about. If we wanted a two in three chance of staying under 2 degrees and giving ourselves maybe a one in four chance of temperatures rising no more than 1.5 degrees, which science having moved on maybe now says it is the limit we should be looking at, then the UK needs to be making emission cuts of 7.5% a year from now on, and that was in 2010, but things have moved on since then.

Q184 Dr Whitehead: On the basis of that sort of analysis, what do you think of the suggestion that we improve the European ETS significantly and let people get on with it—i.e. the ETS is then the judge of whether someone invests long-term in gas and the argument then goes that that potentially avoids lock-in in terms of setting the ETS level against likely investment decisions?

Jenny Banks: The ETS at the moment is not a reliable investment signal for anyone. I think we would all support a move to 30% but as things are Poland is blocking progress and it is very ineffectual, which is why I would—and I do not want to get too off topic here—disagree with Kevin about the picking-winners point because I think investors in general do not consider market price for carbon as a good signal to invest on and it is currently too low. They do not view it with any particular certainty. We launched a report (On Picking Winners) that was written by Dr Rob Gross of Imperial College just over a month ago that made that point and said you do need support, particularly for emerging renewable technologies in absence of an effective EPS or a strong carbon price to drive investment in genuinely low-carbon generation.

Professor Anderson: Well, we would actually agree. I do not think price is the right signal to use at all. I think there are some real problems with it. The ETS was not set up to resolve climate change. It was set up to meet our international targets. The caps it has are woefully inadequate and far removed from anything that all members of the EU are signed up to in the Copenhagen Accord and the Cancun Agreement, and indeed our own low carbon transition plan must stay lower than 2 degrees centigrade as it states in there. So it has nothing to do with that framing of climate change and if it did then you might argue that the signals are moving in the right direction but the equity implications would be dire. People are already suffering. 20% of the population are already suffering from fuel poverty. These people will be in a much worse situation if the price went up significantly for energy. The rest of us are thinking it probably would be a good thing.

I would go back to the route that we should be setting standards and use those. I think price is a complete mistake here because price is fine if you want marginal change, if you want small change. The whole theory of neoclassical market economics is premised on very small changes, marginal changes and what we talked about here are very radical, large-step changes and you would not apply theories that have been worked out for small changes to issues where you need big changes. I use the Newtonian analogy here. You would not use Newton physics to understand particle physics. Yet economists repeatedly use price and margin economics to understand the step-change reductions that we need to make if we do not want to renege on our international commitments. Remember they are not my targets, they are our targets; we have all signed up to them.

Tony Bosworth: I think what this means in the UK is the absolute minimum we should be doing is keeping to the 50 grams of CO_2 per kilowatt hour in 2030. That is the minimum we should be doing and we need policy certainty around that to signal the direction that the energy sector needs to go.

Q185 Dr Whitehead: That would imply, for example, a much stronger performance standard?

Tony Bosworth: Yes.

Professor Anderson: It is also interesting about the 50 grams, I think Jeff Hammond's paper that came out just a couple of months ago in energy policy—he was looking at lifecycle assessment emissions for different power sources—and he makes the point quite clearly that shale gas is probably very similar to other forms of production of natural gas; there is not much difference in them. Nevertheless if you burn gas in a combined-cycle gas turbine at pretty high efficiency, if you carbon-capture storage it and take account of the lifecycle emissions, about as low as you can get is 80 grams. So even if we could do carbon-capture storage, which we have not done anywhere around the world in any significant scale yet, the best you could probably hope for is something like 80 grams, which is way outside of what we would need. If the whole of the UK's grid was supplied by carbon-capture storage gas then we will probably still be talking about 30 to 40 million tonnes of carbon dioxide pumped into the atmosphere in the UK's register each year.

Q186 Dan Byles: Does that not mean that 50 grams by 2030 is simply impracticable? If we came out with that as a Government target, it would simply be not credible?

Professor Anderson: It depends on what you think about climate change. I would argue that Fatih Birol, the Chief Economist for the IEA, when he said we are on a trend, perfectly in line with 6 degrees Centigrade this century that is also not politically credible. So we have got ourselves into a position where the future is politically incredible; the mitigation rates are politically incredible and the dealing with climate change is politically incredible.

Q187 Dan Byles: He also said the development of unconventional oil and gas is the biggest thing to hit the energy market since World War 2 and is more important even than nuclear power?

Professor Anderson: Yes, and he also pointed it out—we could do Fatih's quotes repeatedly—in his *Golden Age for Gas*, this was not a golden age for climate change; that we are heading to at least 3.5 degrees Centigrade, which he refers to one as having devastating consequences to the planet. What I am

saying here is that all the futures are unrealistic and let's be realistic about it today, we should have done something about this a long time ago. We did not.

Chair: Can we just return to the subject of shale gas, please.

Q188 Sir Robert Smith: With all the other known levers you are talking about, if we just do them in the UK while still being part of the EU ETS we then just reduce the cost of carbon for our European neighbours and do not impact on emissions from the EU as a whole?

Professor Anderson: It is hard to imagine reducing the cost of carbon in the EU at the moment because it is virtually nothing and it has been nothing for a long time. So at the moment the EU ETS is damp squib of a thing. If there was a significant price in the EU ETS I think your concerns would be ones we would have to reflect on. But at the moment the price in the EU ETS is irrelevant.

Q189 Sir Robert Smith: We have done a lot of this already but what is the impact of the Government's gas strategy?

Professor Anderson: I would not call it a strategy, or a gas policy. It is a promote and provide strategy or policy. I do not think it is part of a coherent energy policy or strategy for the UK. It is completely at odds to what we signed up to internationally. George Osborne suggests, I think, 37 gigawatts of new gas is just incompatible in the recommendations coming through the Committee on Climate Change. Ed Davey is now saying 26 gigawatts might be viable; he previously said 20. I do not think we have a clear view from this gas strategy as to what direction we are going in.

Q190 Sir Robert Smith: Do you see, though, it is the use you make of the generation because if the wind is not blowing you need something at that time but you do not need it all the time when the wind is blowing, so the overall emissions?

Jenny Banks: You do need flexibility, of course. I think we all know that. But the issue is partly if you build too much gas then there is a temptation not to build the low-carbon generation alongside it, particularly when we all know that there are divisions within the Government on the direction of energy policy.

Q191 Sir Robert Smith: But if you are offering a contract for difference to build a renewable, which gives you are return on capital, the fact that someone is building a gas power station does not make much difference because you are getting a return on your capital from the contract for difference.

Jenny Banks: Yes, up to 2020 I think that is the case. I think beyond that there is an uncertainty as to what incentives for low-carbon generation there will be. There are other forms of flexibility as well. Demand side response, storage. Currently we have nothing in the Energy Bill that promotes energy efficiency but reducing demand could be a very effective way of reducing the amount of gas generation we need. I think we would argue that diversifying your flexibility should be prioritised and things like demand side response, storage and interconnection should all be prioritised over simply building gas generation, which would probably—it is unclear as far but we may need a capacity mechanism and the reason for that would be that the gas was operating at low-load factors. If you have less gas and you can use other forms of flexibility then that is a much better way of doing it.

Tony Bosworth: I agree with what Jenny says. We definitely need flexibility but seeing flexibility as only being provided by gas is a rather blinkered view and I think we can see, as Jenny said, demand side response, interconnections and storage but also the use of a basket of renewables options; not putting a whole range of renewables options as being another way of providing that flexibility.

Professor Anderson: I think the big problem is that we are thinking about 21st century problems with a 20th century mindset, which has traditionally been supply. There is this idea that you think of it as a system, and the system is the energy system not just the supply system. When you start thinking like that you might have intelligent metering and active demand management, you might have different progressive metering tariffs that could be available, which we have virtually never had or even if we have had we have hardly ever used. If you start to look at wind, if you spread the wind out you get some benefits from that but you still get very lengthy anticyclones and problems with that. Then if you look at wave power, the wave collects the energy over a much longer period of time. So wave and wind, there is some benefit there, producing a level of intermittency. If you use tidal stream, tidal barrage, you start to develop a portfolio of supply technologies that can help reduce the level of intermittency but not solve them altogether. You have to think about issues of storage. Can you produce hydrogen or can you use biogas that you can run through a turbine? I think you have to think of it like that. Unfortunately we have never done that and I expect no other country has either, but I think we have to start to think differently about the systemic problem, the systemic issues that we are looking at today rather than just using one hammer to crack one bit of it and then surprisingly there is another bit over here that you have to hit with a different tool. We need to step back from it and think of it in a much more systemic, sophisticated and intelligent way than we have done traditionally.

Tony Bosworth: Going back to Mr Byles' earlier point, I think if we take that approach, the approach of having a range of options, a range of technologies, then the 50 grams target is not unrealistic. It is something that we definitely—

Q192 Dan Byles: By 2030? You are talking about technologies that are a long way off being commercially viable.

Tony Bosworth: No, it is certainly achievable by 2030. Friends of the Earth has developed one path, we have looked at one model, one scenario, that does get us down to 50 grams by 2030, even with having an increase in—

Q193 Dan Byles: At an affordable cost to the consumer?
Tony Bosworth: Certainly it is an affordable cost to the consumer if you are talking about a potentially increasing gas price.
Dan Byles: And if you are not?
Tony Bosworth: Well, we are also talking about decreasing costs of onshore and offshore wind and solar coming down to grid parity. That means solar coming down to grid parity very soon; onshore wind coming down to grid parity very soon; offshore wind coming down a lot over the next 10 years.
Professor Anderson: When you say "realistic"—

Q194 Dan Byles: My concern is that that is not realistic and therefore—
Professor Anderson: I do not think the alternative is either; both are very challenging. We are talking about a suite of new nuclear power stations. Some people would suggest that is unrealistic. We know technically how to do it and there are lots of challenges to go ahead with it but we can also of course build a Severn barrage that you could argue with the RSPB—
Chair: We have debated these other issues on a large number of occasions and we will do so again but I want to finish session in the next 10 minutes, if we can, so please address the questions of shale gas, and answer the questions of shale gas too.
Professor Anderson: We are just responding to the questions that we are asked.

Q195 Sir Robert Smith: I suppose that is the problem, that it all interconnects, but on the specifics of shale gas what do you think the role of this body of office for unconventional gas and oil will be? Will it be a poacher or a gamekeeper?
Professor Anderson: Disturbingly it is both and that is the concern. It is the fox looking after the chickens. It does seem an odd thing to set up something that will promote and regulate. That is not to say you may want to have a separate regulatory agency, there are merits and protocols there because it is another separate agency. People were talking before about the problems of regulation, that there are many people regulating and now you have a new one regulating, there will be some crossovers with others. But to have both wrapped up in the same one, I think very few people would suggest that is wise.
Tony Bosworth: It comes back to the point, the three words that we used in the Government's gas generation strategy, we were saying that regulation would be robust but that the aim of the office for unconventional gas would be to simplify and streamline this. I think, as Kevin was saying, there is a potential conflict.

Q196 Mr Lilley: You began by talking down the prospects of shale gas saying there was probably far less of it than the companies are saying; that it would be more difficult to extract; it would cost more, it would run out sooner. Yet you then said if we give so much as a hint that we are going to allow its development no one will do anything else because it is so attractive. Which half of your thesis should we believe because the two are incompatible?
Professor Anderson: I do not think I said any of the things you just said.

Q197 Mr Lilley: I am sorry, I am not saying just you. Jenny Banks said she believes that geological estimates are not accurate. I think you were saying that it was going to be much shorter lived and uncertain than the industry and the so-called hype say. Mr Bosworth, who can speak for himself, has been talking it down. If you were talking it up I would say you are not a very good salesman.
Professor Anderson: I think we said it is very uncertain; that the future is very uncertain.

Q198 Mr Lilley: But it sounds as if even the prospect of this uncertainty is more attractive than the certainty, in your minds, that the cost of wind is going to come down to economic levels.
Professor Anderson: I think in the evidence we submitted to you would suggest the cost of wind—when we did not look at the operating costs, we were purely looking at the capital costs—would tend to err in favour of the shale. If you take account of the power station, of the CCS plant and of the actual capital cost of the well pads to provide per kilowatt of capacity, it is about the same as offshore wind. But people never do that.

Q199 Mr Lilley: Somebody must in the system because they are bearing the cost. Who is subsidising gas if you are saying that these costs are not somehow borne even though they exceed the costs or equal the costs of offshore wind? If people will not go ahead with offshore wind but will go ahead with all these excessive costs of gas, someone is bearing those costs.
Professor Anderson: No one is going ahead with excessive costs of shale gas at the moment, we have just—
Mr Lilley: But you are saying they would if they were allowed to. I thought you were trying to dissuade us from us allowing it to go ahead.
Professor Anderson: No. I am trying to from a climate change perspective, yes, without a doubt. But I thought you were talking purely about economics now.

Q200 Mr Lilley: You were talking about economics. Is it backing up what you said earlier or what you just said now? You said that the total cost was as great or greater than offshore wind.
Professor Anderson: Yes, the capital costs are. These are quarterly estimates from the consultants used by Cuadrilla for estimating their costs per well pad, not our estimates. If you add them up I am simply making the very straightforward statement—

Q201 Mr Lilley: Why is there the remotest chance then of shale gas being exploited in preference to offshore wind?
Professor Anderson: Well, for the same costs, if you were an industry that has done that for the last umpteen years, you might think, "Actually, we know how to do that". We know this from all the social science and institutional work out there. We get locked into certain ways of doing things. So

effectively if you are a hydrocarbon country, which we are, as most countries in the world are, then the things we are familiar with are innately more attractive to us and indeed to industries as well. All I am simply saying is if you add up the costs given by independent consultants, not by us on this, they are the same capital cost roughly as offshore wind. Whether we like that or not we can go back to the consultants they employed and say, "Did you get the numbers wrong?" but we are using their data.

Q202 Mr Lilley: They have a much higher tax burden, so it is sheer stupidity on the part of the industry that they are going to go ahead.
Professor Anderson: We do not know if they are going to go ahead; they are just doing exploration at the moment.

Q203 Mr Lilley: That is right, but we can let them go ahead because they will only go ahead if they are stupid.
Professor Anderson: Sorry, in the States, my understanding at the moment—again all the people who worked on this could be wrong, you may well be correct—that they are making a loss on virtually all of their shale production in the US.
Mr Lilley: But production is half the price here.
Professor Anderson: No, I am saying they are making a loss. The practice in the States is the companies are making loss over a relatively long period of time now and are still proceeding with it.

Q204 Mr Lilley: If you seriously believe that the oil industry in the United States is so altruistic they produce gas at a loss—because they have made a capital investment they produce it, and because it is a co-product of shale oil they produce it. That is not making a loss, that is a co-product of shale oil.
Professor Anderson: On most of their wells at the moment they say it is unsustainable for them to carry on like that and effectively they expect the price to go up to a level where they can make it sustainable. But they have not for quite a long time, that is the point I am trying to make to you here.
Jenny Banks: The point that I was trying to make is that there are two things. There is what is actually happening on the ground now, which is that we have a lot of uncertainty about how much shale gas there is and how much will be economic or socially acceptable to get out of the ground and it may or may not be that significant amounts of shale come out of the ground but the concern that we have at the moment is what is happening politically. We have just had the gas strategy come out, which has two scenarios that are not compatible with what the Climate Change Committee has recommended and are looking at much higher gas scenarios than we think are compatible with meeting our carbon budgets, or indeed the CCC think are compatible with meeting carbon budgets. What concerns us is UK energy policy going in a direction that is predicated on there being large amounts of cheap gas in the future when to us it is very unclear whether that is going to be the case or not.

Q205 Mr Lilley: Just one final question. Say in a year or two year's time, they have done lots more drilling, they have tested and fracked and found what the extraction rates are, if you were sure that there was going to be a lot of gas there available at a much lower price than the current price, would you still be against us exploiting and using it?
Jenny Banks: On climate change grounds, yes.
Professor Anderson: I would ask you collectively what your commitments were on climate change. I know what they are at the moment and I would ask you to restate them explicitly and then I can do the analysis for you on those grounds. But at the moment if we stuck to the commitments you and others have signed up to, we have all signed up to, via our democratic processes, then at the moment it is absolutely, categorically clear that shale gas cannot be part of that portfolio of energy for the UK or other annex 1 countries. There is no doubt about that.

Q206 Chair: Not any part of it?
Professor Anderson: No, not part. This is the big problem in the UK is that we have not got around to understanding the plethora of targets that pick randomly to fit whatever we are trying to look at. So in the UK we have the carbon budgets that are premised on a global view that we are going to have a 63% chance of exceeding 2 degrees Centigrade. That is according to the Government's own stats using their own modelling. So that is all the Government views on that, 63% chance. That is the global number. But then it has allocated the proportion to the UK, a part of that cake that is completely at odds with the Copenhagen Accord components to do with equity. So that is completely unfair, what we have done to the UK. That again is not in agreement with what we have signed up to internationally. So we have carbon budgets here that are inappropriate for what we have signed up internationally and we have never yet—

Q207 Mr Lilley: Sorry, they are not severe enough, is what you are saying?
Professor Anderson: The carbon budgets fall far, far short of what we signed up to internationally and you can see a very clear causal link, in the science each time you go along—a numerical account of it—and you can show what it should look like for the UK. The budgets we have here are far, far weaker.

Q208 Chair: Be that as it may, I want to just pursue this point. You say there is no role for shale gas at all?
Professor Anderson: Absolutely, categorically, there is no role for shale gas at all in the UK because we are already exceeding the budgets that we should be allowed under what we have signed up to internationally. But even if you give a bit of flexibility and the probability of 2 degrees C, which is what you have to do in the world we live in today.

Q209 Chair: No, I am just asking about whether there is any role for shale gas. Never mind about 2 degrees or 4 degrees. You are saying there is no role for shale gas at all?
Professor Anderson: Under our international commitments, no.

Q210 Chair: But we could, technically, achieve a carbon intensity target from electricity of 50 grams even incorporating some contributions from gas, could we not?
Professor Anderson: For 50 grams you could but that would not be keeping to the carbon budget we have signed up to internationally.
Tony Bosworth: I think if we go for a 50 grams target then, yes, there is a role for gas, but the proviso is what Kevin is saying about whether that target is compatible with our international commitments. But if we assume that is the target we are going for, then, yes, there is a potential role for gas, a small role for gas on that system but it is nothing like the role that the gas generation strategy foresees. It is a role as balancing, not as baseload.
Professor Anderson: I will agree with Tony there, if you broadly stick with the CCC's budget, which, as I say, are far removed from our international commitments, then there is a potential small role for gas in that. A small role. If you stick to international ones, there is no role.

Q211 Albert Owen: If there are only small roles for gas but not for baseload, what is going to provide that baseload? One thing that we have not discussed since I have been here this morning is the large price increases in electricity. If we are going to just develop into renewables, is that a given that they are going to continue to rise and rise if we do not have an alternative source of baseload?
Tony Bosworth: We have a scenario in which we are talking about 75% of our power coming from renewables with offshore wind forming the bulk of that but also with the balance of technologies, which I talked about earlier, there is also a role for wave, tidal, hydro, solar, onshore wind.

Q212 Albert Owen: Sure, and I personally support that, but they are underdeveloped.
Tony Bosworth: Yes.
Albert Owen: The high cost of electricity is what industry and the consumer is facing at the moment. Are you suggesting that we forgo an opportunity to extract gas and continue with this development of renewables alone, and that will provide the base as well as providing the low carbon in the future?
Tony Bosworth: I am suggesting that the way in which we provide our electricity in the future has to be overwhelmingly based on renewables, yes. The projections for the cost of that show—and it is not Friends of Earth projections, it is Friends of the Earth analysis of independent projections—the cost of renewables continuing to fall in coming years.

Q213 Albert Owen: But do you not accept there will be a period where there will be gap and it will be difficult to produce the baseload for electricity and that we would have to import that and there will be a cost on the market? That we will pay market price and each household will be paying more?
Tony Bosworth: There is going to continue to be a role for gas out to 2030, the question is how we provide that gas. I think it is an open question about whether we decide that we want to carry on importing that gas or whether we want to develop that with shale gas. I say we should not be going down the shale gas route because of the potential of things like the local environmental impacts.
Jenny Banks: The Committee on Climate Change have estimated that up to 2020 there will be around £100 on the total energy bill as a result of environmental policies. After that I think it is much more uncertain but we commissioned a report from Cambridge Econometrics that came out last week, which suggested two scenarios, one of which you rely heavily on gas, the second one after 2020 you continue to invest in offshore wind as you have done up to 2020 to meet the renewable energy target. The difference between overall energy bills in 2025 in that scenario is 3.5% reducing to only 1% in 2030. So by that point, because the cost of renewables, including offshore wind, has fallen to that extent, there is a very small difference in bills and GDP was found to be £20bn higher in the offshore wind one.

Q214 Albert Owen: What would be providing the baseload? I am still not clear from what both Mr Bosworth and yourself are telling me. You are quoting various reports and scenarios but what would be providing the baseload. It would either be imported gas or it would be nuclear or it would be dirty coal.
Jenny Banks: In a scenario where you meet climate change targets you don't have gas providing baseload any more, you have gas providing backup. Depending on what scenario you look at, if you look at the CCC scenarios, for example, then you have nuclear providing a lot of the baseload. Obviously environmental NGOs like ourselves do not support nuclear. You have a lot of renewables on the system. As Kevin said earlier, you are really moving to a different kind of electricity system to the one we have seen before.
Professor Anderson: One needs to bear in mind that if we talking about 2030, which I think is what you are talking about, is it not? If we imagine by 2030 the CCC suggests a lot of heating—and I am not saying this is good or bad thing—
Albert Owen: I am talking about between now and 2030 as well.
Professor Anderson: Yes, and one thing for that is having life extensions for some of the nuclear power plants. My big suggestion would always be the cheapest thing to do at every time on this is going to be energy demand. But if we park the low hanging fruit for a moment then I think the life extension is certainly one way forward. If you have a portfolio of renewables you can start, if it is wind, it is offshore wind and it is geographically spread, to derive some baseload capacity from those but you will get times when they go off, in the same way that nuclear power stations went off and the lights went out in Marseilles because the river water was too warm a few years ago. So these things do happen from all supply systems, but I think we have to make this almost mindset shift from where we are today to where we going to be heading to 2030, by which time if we did imagine that heating and transport were also partly on the grid then there are certain storage and inertia benefits that come along with that that fit with a different way of thinking

about the grid; batteries in cars can be used to store and feed back into the grid and with heating you get thermal inertia if you stored it in water, for instance, for heating. That gives you some capacity for flexibility for a slightly more intermittent baseload system. So we have to think quite differently about this but I think the points that you raise are very important ones as to how we are going to proceed to that particular period and I think there are a lot of uncertainties still about what that system could look like.

Tony Bosworth: I gave you the figures for where, if you like, the end point is by 2030, about what the various shares of capacity would be. We have the figures for the intervening points up to 2030, I do not have them with me but I would be very happy to send them in, if that would be useful.

Q215 Mr Lilley: According to my colleague's app here, at this moment the electricity and heating we are consuming in this room, the electricity is 47% provided by coal, 34% by gas, 15% by nuclear and 0.4% by wind. If you are seriously suggesting we can expand wind and there is another 0.6% from storage and hydro to replace not only all coal but all gas, do you not think you might just possibly be living in a dream world?

Professor Anderson: Sorry, are you suggesting that we are making the point that wind should provide heating?

Mr Lilley: Wind or other things. Ms Banks wants to get rid of nuclear as well. What I am saying is we have to replace more than 90% of our capacity by 2030 if you are going to have a gas-free future, a nuclear-free future and a coal-free future. We do not have any significant reliable, continuous, non-conventional energy.

Professor Anderson: I am sure you know the figures, but as you are aware the renewables in the UK are about 1.5 times larger of the energy we demand than nuclear.

Mr Lilley: Not now.

Professor Anderson: No, no, they both begin in "e" and they both end in "y" but one is electricity and one is energy. Electricity represents 18% of the energy we consume and the other 82% is not electricity. I think we have to be quite careful we do not muddle these things up.

Mr Lilley: Yes, change the equation by all means but—

Professor Anderson: No, I was referring to the energy system not just to the electricity system. I think we often get those muddled up; we focus just on one particular small part of the energy system. As was pointed out earlier, most of the gas in the UK is not used in the electricity system, it is used in the heating system.

Jenny Banks: We launched a report last year called *Positive Energy*, which was basically looking to answer the very question that you have asked. Clearly we do get these anticyclonic periods in the winter, particularly where it is a day exactly like today. As you correctly point out the wind is not blowing. So, yes, we need the flexibility to meet demand and in the scenarios that we looked at—we had modelling done by an energy consultancy to do that—there were two key ways of meeting the demand when the wind was not blowing. One of them was simply building a lot of gas generation, but we have discussed today some of the issues with doing that, having to run the gas at low load factor. The other one was having a significant amount of gas generation but also importing electricity from the Continent.

Mr Lilley: None is coming through at the moment from either France or Ireland; they are using all theirs. When you said only a third of the gas is used in electricity, that means the problem with replacing it is three times bigger, not smaller, than just replacing it in electricity.

Professor Anderson: No, I think it is really important for there to be a debate about this, and I do not have a problem with people pointing that out. It is not quite three times bigger because I think the opportunities for doing something about heating are probably better than they are for other areas in terms of reducing the demand for heating and indeed cooling, because the cooling load in London is higher in the summer now than the heating in the winter.

These are huge challenges. I do not think anyone is pretending otherwise than that these are enormous challenges. There are enormous challenges if you can provide them all with nuclear. They are enormous challenges if you are you going to provide them all with this extremely uncertain shale gas of which we one exploratory well somewhere in Lancashire. To bet your future on an exploratory well in the middle of Lancashire I think is also tricky. So whatever route you go down the future is awash with very major energy challenges. We all know we should have done these things a long time ago, we did not. We are where we are today. There is an array of ways of doing this, some of them are a nuclear routes, some of them are gas routes. We may have to use a lot more imports if the shale gas does not play out but we do not know whether they will or will not, and other routes are that we can go down a much more renewable route. We then have to think of that in relation to other things that may be important; price, affordability, security, and climate change. We have to relate into those and if we have particular climate change commitments, which we have, we can do the maths around whether some of those scenarios are viable or not. The gas one is not for climate change. The nuclear and renewable ones are. They are still enormously challenging and there may be ways to bring together in some sort of synergistic way of thinking of these things, but the other part that must go with this all the time is the energy demand side and we have to think how does that work with a flexible supply system. But we must think about energy not just electricity because, as you note, if we have to put the heating on to the grid, domestic heating in the UK is the same size as the total electricity consumption in the UK. So if you shoved that on the grid the grid would have to be twice as big if there was no improvement in efficiency and then there is another side of heating that is not domestic.

So these are enormous challenges. No one is trying to say otherwise and the sort of work that we have done, and we have done our work very differently, using

different types of technologies and different assumptions of demand, show that there are alternative ways of skinning this cat but they are all going to be difficult, they are all challenging, and I do not think anyone is pretending otherwise.

Q216 Chair: You can be sure that we are very seized of the contributions that can be made from the demand side. We had a private discussion about the DECC pathways to 2050 model last week, which, among other things, pointed out that that getting people to heat their houses to a slightly lower temperature has a dramatic effect on emissions, much greater than what we talk about.

Professor Anderson: No, I agree. I have spoken to Dave MacKay before and others in the strategy team there, the level 4 energy demand is one they could imagine being ratcheted up quite considerably. The level 4 on some of the supply targets, the solar one for example, is pretty high but they recognise there is scope for going further with the demand one.

Q217 Sir Robert Smith: But it is not the low-hanging fruit because otherwise we would have picked it by now. I agree with you, it is the obvious and crucial thing to do because reducing demand solves your supply problem much more effectively but I think we have to be realistic that we are going to have to work very hard to achieve it because I have gone out to promote warm homes and I have watched them put a chain down between that and the neighbouring house to make sure it doesn't get any cavity-wall insulation because the neighbour did not want it.

Professor Anderson: I think it is fair to say the demand side is never going to be easy but I think it is also fair to say that for lots of us out there it is awash with low-hanging fruit. For most of us energy prices are basically irrelevant in our lives, and for others it is not the case, and I think we have to find different ways of incentivising changes in behaviour, progressive metering tariffs and so on. But this is getting away from shale so I will stop there.

Q218 Chair: Do any of my colleagues have any further questions they want to ask?

Dan Byles: On shale gas.

Chair: On shale gas indeed. Okay, thank you very much. A very useful exchange and we look forward to seeing you all again in due course.

Professor Anderson: Thank you very much.

Wednesday 16 January 2013

Members present:

Mr Tim Yeo (Chair)

Dan Byles	Albert Owen
Barry Gardiner	Christopher Pincher
Ian Lavery	Sir Robert Smith
Dr Phillip Lee	Dr Alan Whitehead
Mr Peter Lilley	

Examination of Witnesses

Witnesses: **Paul Spence**, Director of Strategy and Corporate Affairs, EDF Energy, **Tom Crotty**, Chief Executive Officer, INEOS Olefins & Polymers Europe, **Martin Pibworth**, Deputy Managing Director for Energy Portfolio Management, SSE, and **Peter Parsons**, Forecasting Manager, National Grid, gave evidence.

Q219 Chair: Good afternoon, and welcome—welcome back in the case of some of you—to the Committee. Thank you for making the time to come in. We are in the middle of this further inquiry into shale gas on which we expressed strong views a couple of years ago. To begin with, perhaps you could tell us how you think that shale gas might affect how gas is traded, either globally or regionally.

Martin Pibworth: Can I take that question?

Chair: By all means.

Martin Pibworth: We do not necessarily see a big impact or change in trading in the UK specifically, and I accept you asked the question globally. The UK markets and European markets are liquid and increasingly liquid. There is clearly opportunity for different trading hubs to develop as time goes on, and may be a better international connection between markets. But in our opinion, certainly, the UK and the European markets are liquid and relatively deep.

Tom Crotty: Just to add to that, I think from our end we are obviously energy-intensive users. It is very difficult to know the degree of impact. Our view is there must be an improvement in liquidity. We would hope that improvement in liquidity would improve energy prices, but there is no guarantee of that. I suspect it will not be anything like as dramatic as we have seen in the US, because that is very much a liquids-driven issue. That is chasing oil with associated gas. But I think it will improve liquidity and, therefore, it should improve the market for large users like us.

Paul Spence: To echo those points, we would see it as being a contributor to liquidity in the market, but it is not going to be a game-changer. It is not going to be something that fundamentally changes either the global position or the European or UK position.

Q220 Chair: Do you think it might restrict the extent to which prices might otherwise rise in the European market?

Tom Crotty: My personal view is, yes. That is our biggest worry. But if you look at what is happening in the European market today, prices are rising inexorably. For producers of chemicals or steel, we find ourselves in an increasingly uncompetitive position as a result of those prices. Something needs to happen to address that. We would hope that, at a minimum, it would stop that further rise. I should say, from a chemicals point of view, we must not forget the other aspect of shale gas, which is potentially a key raw material for the chemicals industry, not from its energy content but from its chemical content. That has probably been the most transformational impact of it on the US chemical industry.

Q221 Chair: I should draw attention to my entry in the Register of Members' Interests in the energy industry.

As far as Britain is concerned, do you think that we are well placed to connect to and take advantage of an increasingly liquid market? Is that something that would particularly affect us?

Martin Pibworth: My opinion is more or less the same. The UK is already in a global gas market. I accept that US prices seem to imply that is not the case, but US gas is currently islanded and, therefore, I think if you go back pre-the shale gas revolution you saw quite a strong correlation between US and UK prices. Therefore, for us, UK and European prices reflect global fundamentals. Shale gas production in the UK would not necessarily change prices in perhaps the way that has been described. We are a little bit more neutral on that, and that is partly because the UK imports significant amounts of gas anyway. For the UK to end up in a similar situation to the States we would have to displace all of those imports first, and it seems unlikely to us that the UK shale prospects are that vast.

Tom Crotty: Answering your specific question, I think the UK is extremely well placed. We have a long history, clearly through the North Sea, of developing a very suitable infrastructure. We have an infrastructure that links us through to continental Europe through the interconnector. Up until 1997 the interconnector was a means of exporting excess gas. Since 1997 that flow obviously reversed, but it does mean we have that capability. We have no idea what the quantities of shale gas might be but, regardless of where they are, we have the infrastructure that can allow us to continue to be an importer or—in a wonderful scenario—become an exporter again.

Q222 Dan Byles: I want to explore a little bit more the difference between what is happening in the US and the UK. Mr Crotty, your evidence has pointed out the massive advantage that a lot of American

companies are now getting because of the structurally lower energy costs. What is it precisely that is going to prevent the UK from potentially being in the same position? Is it simply the quantity of shale gas available that makes you—and perhaps Mr Pibworth—believe that is not going to have the same effect here, or are there other factors?

Tom Crotty: I will let some of the experts in.

Peter Parsons: From a national perspective, it is a case of looking at the volumes. The US has a massive indigenous conventional gas production, and the additional shale gas that has been produced here has tipped the balance. In the UK, we currently import about 60% of our gas needs. Therefore, the volumes required would be considerable.

Q223 Dan Byles: Is that the cost of the margins? We are not able to shift the cost of the margins. Is that the point?

Peter Parsons: It is a case of how much additional gas would have to be developed from shale to make an impact, in terms of the levels of imports we currently experience.

Q224 Dan Byles: Is it a sheer quantity issue that you are saying is likely to stop it having the same dramatic impact on energy prices?

Paul Spence: I think there are three or four important differences between the US and our situation. The first is the relative quantities and import dependence. The second is the difference we have seen in the US in the exploitation of gas that is associated with liquids. Therefore, there is a support effect that the gas is a relatively cheap by-product of the liquids production. There is a very mature gas exploration and production industry in the US, there are different land ownership and land access rights, different environmental considerations, different environment rules and different population densities.

Dan Byles: That still comes down to a quantity issue, about the quantity of extractable gas rather than—

Paul Spence: It is not just what is technically available. It is what is economically recoverable, and what is environmentally acceptably recoverable. All of those factors are different and, therefore, have a different effect on the quantity that might end up being produced and producible here in the UK.

Q225 Dan Byles: The Policy Exchange has said that if the UK is going to position ourselves to potentially benefit from cheaper gas prices, which may come about under a low gas pricing scenario in the future, as a result of shale gas development at home or abroad, we need to remain—in their words—adaptable to a range of possibilities. Do you think the Government's current energy policy will allow the UK to take advantage of cheap gas, should that become available as a result of a shale gas boom, but also allow us to develop alternative sources of energy should it not?

Paul Spence: Given that my company is very heavily involved in all of the different sorts of energy generation—gas-fired, we are just finishing building a gas CCGT; we build renewables and we build and operate nuclear power stations—it is clear that an energy policy founded on having a diverse mix then gives you flexibility to respond to the changing circumstances.

Q226 Dan Byles: The question is about current UK energy policy. Are you satisfied that the current direction of the UK's energy policy will enable us to maintain that—

Paul Spence: I think the broad direction is the right direction. Clearly, we need to get there as quickly as we possibly can. The Energy Bill that is going through at the moment is at the heart of trying to make that happen. We need to get that right, and get that right quickly to have the policy in place. I think making that policy real is the issue.

Q227 Dan Byles: We have already agreed with that. Should there be a great shale gas bonanza and cheap energy, we are not cutting ourselves off from that through current policy?

Peter Parsons: I would say that there is very much a future for gas, and we see that that is not necessarily impeded by the current policies.

Tom Crotty: I would say the same. Gas has a very important role to play in the future energy mix. Shale gas will improve the liquidity and potentially localise the supply of that gas so that, rather than imported gas, it is UK gas with the benefits flowing to the UK economy and UK revenues coming in. As part of the future mix it is critical. This week the International Renewable Energy Agency was publicly saying that low-cost shale gas can help create a hybrid system. Solar or wind can complement gas-fired generation by running when available. I think it works very well.

Q228 Dan Byles: WWF have said that any shale gas extracted in the UK will simply go to partially offset declining North Sea oil, rather than perhaps increasing the total amount of gas that we are digging out. Do you think that is a fair assessment? Are some people overstating the benefits, in terms of energy security and import dependency of shale?

Martin Pibworth: We do not know the answer to that, but we are concerned to see that there is a feeling that shale gas will provide the cure. We believe that it is possible that it might displace other marginal sources of gas, not only in the North Sea but more conventionally around the world, so more marginal projects, which perhaps would get the green light in a non-shale world, may possibly get pushed out and deferred. For us, we see a state where it might be effectively a gas-on-gas competition, where the best projects come forward and others are deferred.

Tom Crotty: It would not surprise you that, as a user, that is of less concern for me. Gas-to-gas competition will happen anyway, regardless of what the UK does on shale gas, because the world is developing shale gas and US shale gas will become increasingly tradable. As a company, we are already starting to set up mechanisms for bringing US gas into Europe.

Q229 Dan Byles: Even with the liquefaction and re-gasification costs, is that still looking attractive?

Tom Crotty: For the chemical raw-material use, where it is the ethane we are after, the import of ethane from

US shale gas extraction is more than economic. After all the liquefaction and re-gasification costs, we can land it far cheaper than we can buy it locally.

Dan Byles: That is very interesting.

Peter Parsons: From our perspective, shale gas production in the UK will enhance security of supply and also enhance diversity of supply. That is an important factor.

Q230 Christopher Pincher: You seem to all agree that there is no policy impediment to the exportation of shale gas, and indeed conventional hydrocarbons. Do you think that the lack of a recent licensing round is an impediment to more players coming into the market to explore for shale gas, and to explore what opportunities there might be?

Peter Parsons: I am personally not in a position to answer that in terms of exploration licences.

Martin Pibworth: Unfortunately, I am in a similar position. I do not have any colour I can add to that.

Paul Spence: I am not qualified, I am afraid.

Tom Crotty: The same for me. It is not our area.

Christopher Pincher: Benign ignorance.

Tom Crotty: Clearly there is an argument for saying that the licences that are there at the moment will, over the next couple of years, prove or disprove whether this is a viable technology for the UK to develop. Whether you have a series of more going out now I suspect is a moot point. Let us see how this develops over the next year or so.

Q231 Dr Whitehead: The Wood Mackenzie consultancy recently produced a report putting question marks against the likely production costs of shale gas in the UK, as opposed to the costs of the very best players in the US. The report suggested that it may not be commercial to produce in the UK, unless the reserves in the UK were found to be comparable to those of the best players in the US. Is that your view, or do you think that is excessively alarming?

Peter Parsons: I think you have to identify that the US has a much more mature gas market in terms of developing their own resources than we have in the UK, particularly for onshore. It needs to be identified that shale gas is not necessarily cheap gas. Shale gas tends to cost more than conventional sources. It is the abundance of gas in the US, from all sources, that gives the US these low prices at the moment.

Martin Pibworth: I completely agree with that. I would also add to that—to pick up on a previous point—one of the features of the US shale gas boom, and the cheap prices they have seen, is the speed at which the US shale revolution occurred. Suddenly vast quantities of gas came on to the American market, with them having no way to export that gas. Obviously over the next four years we may see a change in that. For me, the situation in the US is extraordinary. I would not necessarily base any assumption on shale gas elsewhere in the world on what happened in the US. In terms of the specific question about the costs of shale gas, we would not be surprised if the Wood Mackenzie report was proved to be true, but we do not have an expert view on that.

Q232 Dr Whitehead: In general, the cost of gas in the US is because of the plentiful nature of supply in the US now, so I understand that the number of rigs that are presently being deployed in US shale gas has halved over the recent period. Does that suggest that shale gas in the US is finding it difficult to compete on price on what else is coming up in the US? Certainly, in terms of UK production in the future, that will be exacerbated by the nature of what we have in the UK as opposed to what there is in the US. Do you think that is an inherent feature in the likely landscape of shale gas production in the UK in the future?

Tom Crotty: It is very difficult to draw comparisons. We have already mentioned that a lot of the drivers of shale gas development in the UK are liquids. It is oil, and $100 oil is paying for a lot of exploration and production. The gas is an associate and, therefore, you are almost getting gas as the by-product. So you are less concerned about the costs, but that will not be the case with the UK. Counterbalancing that, a lot of the recent information coming out on the geology in the UK suggests, for example, that UK deposits are significantly thicker than US deposits. For one access point on the surface you probably have five times the volume of gas to access, which will have a significant cost impact. There are swings and roundabouts, and I am certainly not expert enough to take a view on that, but clearly the people who are looking at it—companies like Cuadrilla and IGAS—believe that it is going to be economically viable.

Paul Spence: One of the consistent themes that certainly I am hearing is that there is a lot that we do not know at this stage. Given there is so much that we do not know here in the UK, doing the work to understand what the reality of the costs are going to be here seems to us a very sensible thing to do, and a very sensible thing for the country.

Going back to your question about the US, certainly we have seen a lot of reports that suggest that the extraordinary set of conditions we see in the US at the moment are not what the long-term position will be in the US. The costs of gas in the US could be expected to rise as export becomes available and as the easier sources of gas are depleted, as it is more about production of gas for the sake of gas. As we see those three factors start to come into play, that would look like it would change pricing in the States as well.

Q233 Mr Lilley: Wouldn't you agree that, if there are substantial amounts of shale gas that can be produced in this country, it must be immensely beneficial to the British economy? Either it will reduce the cost of gas or, if prices do not come down, it will increase Government revenues from that source, reducing the need for revenues elsewhere in the economy. First, do you not think it will be beneficial? We have been talking in a terribly drab way, in the English way. Any great bonanza on our doorstep is something we should shout about. Secondly, wouldn't you say it is absolutely irresponsible, at a time when the British economy is in as dire straits as in the 1930s, that we have sat on this for nearly two years, since this Committee—which I was not on at the time—said we should go

ahead, doing absolutely nothing about it? We should be moving ahead with all due speed, and should now do so with even greater speed, to realise this bonanza if it is there. We will not know if it is there until we drill the holes.

Tom Crotty: I agree with you 100%. I wish I could have put it as eloquently as you have. Regardless of the quantity, the fact that potentially we have hydrocarbon resources on our doorstep, which could displace imported gas, seems to me to be a no-brainer from a UK economic point of view.

Q234 Sir Robert Smith: I should remind the Committee of my entry in the Register of Members' Interests to do with oil and gas and, in particular, a shareholding in Shell. One of the points put to us that could be a barrier—as it is with so many other projects in this country—is the perception of the community that will be involved in this event of going ahead with it. You are all involved in large infrastructure projects. Do you have any advice or suggestions as to how that community fear could be engaged?

Peter Parsons: It is not my specialist area. But National Grid are very proactive, in engaging with local communities and special interest groups, to try to take their information on board all the way through the life cycle of a project. We are very active in our engagement with various parties to try to bring everything together.

Paul Spence: Certainly, from my company's perspective, we have been very heavily involved in a major consultation exercise as you know. I think that the lessons are that the combination of early consultation, and getting the facts out there about what the impacts are, what the proposals are, and what it might mean for the community—a developer who is willing to listen, make changes and respond to concern. Then I think the third component is the one that says that, if you are hosting infrastructure, there should be a benefit for the community. Beyond the requirement to mitigate within the planning system that there is already, there should be some benefit in the standard of living of the people who are affected by any form of infrastructure. We believe that should apply to shale gas as much as it does to nuclear power stations or to wind farms.

Martin Pibworth: I totally agree. SSE is obviously involved in onshore wind development, and has a history of positive engagement with local communities. In our experience, the earlier that is done, the more feedback you get from local communities, and the fact that you can get them to share in the benefit of it, of course, is very positive for the project.

Q235 Sir Robert Smith: It was put to us, by Mr Yeager of BHP Billiton that of course, in America landowners are partners who share in the profits of what is going on on their doorstep. Do you think that is something we should be looking at?

Tom Crotty: I think that is why we do need to do exactly as everyone else has suggested. The US situation is quite different because they have mineral rights that would not exist in the UK. They are in a position where the law would simply protect them from the disturbance and would compensate them for that. Therefore, I think there is a need to try to go the extra mile. You need people to understand the economic benefits, locally as well as nationally. We need people in those areas to be as welcoming of shale gas as the residents of Aberdeen are for the North Sea development because they can see there is a strong economic imperative, locally as well as nationally.

Sir Robert Smith: Yes. That is shared by the rest of the panel?

Tom Crotty: Yes.

Q236 Sir Robert Smith: The industry talk is the availability of the specialist rigs that would suit production in the UK, and whether that is going to be a barrier to take on for this industry.

Paul Spence: Again, the lesson of the States is it has taken quite a long time, 20 to 30 years, for the States to build up the capability, the capacity and the supply chain. We are not in the same position here in the UK. It should not take us long, but it will take time for us to build up enough rigs available to take advantage of any exploration and production we want to do here.

Tom Crotty: Clearly, there are a lot of countries around the world that are having exactly the same discussions that are occurring here and they are looking strongly at shale gas. I think we do have a benefit in the UK, in that it looks like the technical problems with extraction are probably much simpler for us than they are in many other countries. I was in China last year. It is quite clear that there are serious concerns that the deposits there are in mountainous areas and areas with too little water, so that will restrict their development. I believe there are technical problems in the Ukraine. I think the issue you raise is a real one, but, in terms of international competition for the rigs that are available, we should be very well placed.

Q237 Dr Lee: You might not be able to answer this. A lot of the challenges in exploring shale gas and exploiting reserves are going to be similar politically with regards to onshore wind. I think I am right in saying that the geology indicates that significant shale gas reserves are under the North Sea. I am told that, technically, at the moment that is not accessible. Should we be incentivising developing that technique instead of incentivising offshore wind, in view of the fact that reserves could be significant and you would not have the same landowner issues, community issues and the like?

Peter Parsons: Putting on an engineering hat, it would obviously be achievable but it would be done at far greater cost. Shale wells are not like conventional gas wells, whereby the productivity from them declines quite quickly. Therefore, you would have to drill an awful lot of wells, and offshore wells cost an awful lot more than onshore wells. So it is just a question of economics.

Q238 Dr Lee: Is it so significantly expensive? We are paying £165 per MWh for wind farms. That is a significant subsidy. Are we saying that it is significantly more than that?

Peter Parsons: All I am pointing out is that all offshore operations come at a far greater cost than their onshore equivalent. The production profiles from shale wells falls off quite quickly, so you would have to have a continuous drilling operation to sustain that level of production offshore.

Martin Pibworth: I will pick up on that point if I may. The first point I would make is I would reiterate that our belief is that we are in a quasi-global market. For me, there are probably cheaper alternatives globally, in terms of supply, than there would be going for offshore shale in the North Sea. In terms of the point about a comparison with renewables, I think there should be a real march in the UK to have a diverse suite of generation options and energy options, and clearly the offshore example you gave is helpful in the UK achieving its eventual decarbonisation targets. For me, I would probably try not to link the two as a comparator.

Q239 Dr Lee: It is helpful but it is costly, is my point. It also needs to be underwritten by gas, by definition, because it is intermittent. I am not suggesting it is cheap, but, in view of the quasi-global market you talk about, that depends upon the global market being stable in the areas that produce the gas, retaining stability in terms of their Governments. I would suggest that is a big question for most of the conventional gas reserves we know of. I just wonder how expensive it is. There is no shortage of water, obviously, so you do not have the same challenges in that regard, but it would be politically a darn sight easier to bring about than the onshore. Looking at the map of where shale gas is, I do not think the people of Sussex are going to be particularly enthusiastic about shale gas drilling. However much I share Peter's view that it is a resource that we should tap if we can, the politics of it are going to be quite challenging.

Tom Crotty: Speaking as a resident of Cheshire, which is sitting on a shale gas deposit, I would be very welcoming. There is a reality that says you need to access what is economically viable. Onshore shale gas is potentially economically viable. I suspect offshore at this stage is not. There are other onshore options as we move forward, things like coal bed methane. We have a huge amount of coal deposits in the north-east of England that are now not exploited. That could offer options for coal bed methane. That whole unconventional gas economy onshore is probably going to be a much more economically viable option for the country.

There is unquestionably a trade-off. The politics are difficult because onshore is causing disruption for people. It goes back to the question we raised earlier: how do you get people to share in that benefit?

Q240 Sir Robert Smith: While we are still in the declining stage, there is still a long tail in the North Sea and west of Shetland. We must not lose the incentive to get the last drops out.

Tom Crotty: That is absolutely right. Clearly, speaking as the company that sits on the end of the Fortis pipeline system and takes the associated gas, we will continue to do that, because that is going to be the lowest-cost gas that we can access and will continue to be the lowest-cost gas.

Q241 Albert Owen: To pursue this line of questioning a little longer, one or two of you said earlier on, "We could put the rigs there pretty quickly", but the rigs are offshore. My understanding is—and I am certainly no engineer or technical expert—they have actually gone through the shale to get at some of the conventional oil and gas, so they know where it is. Perhaps they did not collate the data at the time; they did not think it was important. But it could save some significant costs. Here we are decommissioning some of these rigs. They are already available there. Surely, that is something we could look at, and perhaps we could be world leaders in it, because America and others will go on their resources on land and we can become specialists and experts in it. Do you have a view on that?

Peter Parsons: I think you need to talk to companies who are experts in exploration, because it is a very technical area.

Q242 Albert Owen: It is finding these people. I will be honest with you. This is our second inquiry, as somebody commented. Perhaps if they had listened to us the first time around, we would have been well advanced on this.

I will move on particularly to the Grid. Mr Parsons, do you see the development of shale gas affecting investment in the development of the gas networks?

Peter Parsons: Not necessarily, no. It is in a good location on the network and National Grid has a well defined policy for entry for new sources of gas. To us, gas is gas. It does not really matter whether it is unconventional from shale, whether it is coal bed methane, or gas that you get out of the North Sea. As it stands, the area that we are talking about is close to large areas of consumption. The north-west is one of our biggest areas of consumption. We used to have gas coming on to the network from Morecambe Bay at considerable rates, and so it—

Q243 Albert Owen: What about the rest of the country? Although I accept fully that that is likely to be the first area.

Peter Parsons: Like I say, we have a well-recognised policy for handling gas at any location. You only have to look at the storage sites that have made inquiries to have entry on to our network. They are from Dorset right across to the east coast. So many areas of the country have already been covered for storage sites, and there is no real difference between a storage site and a shale site. We have recognised procedures for entry, so it should not be a barrier.

Q244 Albert Owen: What about the quality of the gas?

Peter Parsons: It has to meet our specifications. That is, again, the same for all types of gas.

Q245 Albert Owen: Can you just develop that? What does that mean? The North Sea gas was a specific type of gas. I remember the meters being changed, and that went on. Would we have to be

changing meters? Would we have to change our gas supply in the house because there is going to be—

Peter Parsons: That would be highly unlikely. We had a debate recently about whether the gas quality specs need changing or meters need changing. DECC themselves identified that there would not be any change to the gas quality parameters through to 2020. Most of the imports that we currently receive in the UK are modified to some extent. The LNG has a small amount of nitrogen added to it for ballasting purposes. Some of the richer gas that comes into Scotland on occasion has a little bit of CO_2 removal. It is nothing new, and it should not be identified that shale gas is materially different in terms of its composition from conventional gas.

Tom Crotty: I would add on the quality issue, from a chemicals point of view, clearly, we like to see gas that is not just pure methane. It is the non-methane elements that are of value to us: it is the ethane and the propane. For example, in the US those elements are fractionated out and we can use them as raw materials to build chemicals with. We are hopeful that the UK shale deposits would allow us to do the same. As an industry in the UK, the problem we have at the moment is that the quantity of ethane coming out of the North Sea supply has declined dramatically in the last 10 to 15 years to the point where it is almost non-existent now. Therefore, getting a new localised supply would be a massive potential benefit.

Q246 Albert Owen: So could you use some of the by-products and the shale gas would come to us purified?

Tom Crotty: That's right. As things stand at the moment—as Peter has already said—a lot of gas is processed to remove some of those by-products now. The Norwegian gas supplies that come through the Europipe system are at source in Kårstø. They have the ethane extracted. That is actually where we buy quite a lot of our ethane today.

Q247 Albert Owen: Back to Mr Parsons; you said the availability to connecting that is pretty easy. You believe you can overcome the quality issue, but the developers need to give you timescales for when it is likely to come on, once they have their licence. Are you concerned about that lack of information at the moment?

Peter Parsons: We are having some dialogue with Cuadrilla regarding entry for—shall we say—modest volumes to start with, potentially for their exploratory wells. The issue we have would be getting planning through, if it were to be massive volumes, to actually accommodate large infrastructure projects. It is a question of planning. Over recent years, we have had difficulty in obtaining planning permission for the various pipelines that we have put in. People can book entry capacity on our network for approximately four to five years ahead, and we then have a commitment to provide that entry capacity. We have great difficulty building something large over that sort of timescale. If it was massive volumes, we could have difficulty in accommodating that. We would probably need more like six or seven years.

Q248 Albert Owen: A final point to you, with regard to the Government's role. What role does the Government have? We heard an announcement in the autumn statement. You are saying it could be seven years hence before we expand to the large—

Peter Parsons: That was for a massive volume.

Q249 Albert Owen: Yes, but if we are going to benefit from it, we have to assume that there are going to be larger quantities. So what role does Government have in the planning of giving incentives? Are you sitting down closely and working with DECC on this?

Peter Parsons: Again, some of my colleagues are involved.

Albert Owen: Yes, not you personally.

Peter Parsons: We raise it as an issue. To deliver large infrastructure projects for the benefit of the UK is not easy and can take time, even for gas pipelines. Once they are completed they are largely unobtrusive.

Q250 Albert Owen: Specifically on the Government announcement, are they backing it up with dialogue with you to make this happen, or are they just talking the talk?

Peter Parsons: I would not like to be specifically drawn on that. You would have to refer it to my colleagues who deal with the planning side.

Q251 Albert Owen: They do have a proactive role, and they should live up to it.

Peter Parsons: As I said, I am sure my colleagues are involved in that area.

Albert Owen: Thank you.

Q252 Sir Robert Smith: Back to the quality issue and the different products that are coming out, obviously your pipeline takes away the pure methane that is going to heat people's homes and industries. You want the other products. How does it get from the well-head to your processing plant?

Peter Parsons: Shall I answer that?

Tom Crotty: Yes. I will just say that we actually want both because we are energy consumers as well; but please, Peter.

Peter Parsons: My background is chemical engineering with gas processing. With gas reservoirs, it very much depends on what is down in the ground. You can get anything from essentially dry gas, which essentially has a very high methane content, right through to reservoirs at the other end. You have bitumen, and then you have heavy oil. Then you have this bit in between that is a sort of mixture. It is like fizzy pop, where you have liquids plus gas. It depends on the type of reservoir you access. You will have all different types, as a contribution of predominantly methane and the liquids associated with that.

In the US, initially, a lot of the shale gas was predominantly gas. However, all the shale in there that has been targeted has a higher liquid content associated with it. People have already said that much of the shale produced in the US now is a by-product, with liquids as the primary production.

Q253 Sir Robert Smith: Does that mean the footprint of the well-head development being larger, in the sense of the process and the export? How do all these other products—

Peter Parsons: You are right: if there were an increased level of liquids—shall we say—there would be slightly more onshore facilities to handle that level of liquids.

Q254 Sir Robert Smith: Also, how does it get from there to the market?

Peter Parsons: Obviously the gas is piped out, and the liquid would depend on the volumes. For instance, not many people realise that we have the largest onshore oilfield in the UK at Wytch Farm. That goes out by rail. In Lincolnshire, there are quite a few places where oil is produced. Some of that goes out by road tanker, so it all depends on the volume.

Tom Crotty: Again, just building on that, in terms of a mixed gas or a wet gas—as we would describe it—where you have more ethane and propane in there, as well as the methane, in the US there is a very well-established system of fractionators, which take those fractions away. In our US business, we own our own fractionator and we take the gas from the gas markets, do the fractionation, return the methane, and take the ethane and propane away.

Q255 Sir Robert Smith: That is a pipeline of wet gas rather than the National Grid pipeline?

Tom Crotty: There are lots of ways to do it. For example, I am not suggesting this is an investment strategy that we have, but our major site in the north-west is in Runcorn, which is not a million miles away from where a lot of development is going on. You could conceivably see us running a fractionator on that site, as an example. Those are the sorts of things that you could think about doing.

Q256 Christopher Pincher: We have heard from other witnesses—David Kennedy from the CCC and the Tyndall Centre—about their concern at the effect that the long-term use of gas, including shale gas, will have on obligations to meet our 2013 decarbonisation targets. Given their concerns, do you have concerns that there is a future for gas in a low-carbon energy market?

Paul Spence: If I can start on that, I think that we see that there is a clear and continuing need for gas generation as part of the market as we look forward, some of that to generate in its own right, some of that to provide support when the wind is not blowing and the renewables are not generating. Looking forward, DECC themselves have set out a strategy that involves having extra gas generation capacity on the system, having that run on average at about 27% of the time. That is a very clear role for gas, as part of a balanced and diverse mix alongside the low-carbon sources. That does help us to get towards the very low-carbon intensity targets that we need to meet. If we are going to get to the very lowest level, then we need to be capturing and storing the CO_2 that is coming out of that.

Martin Pibworth: For our part, clearly, we would agree with that. The Committee will be aware of the current position we are in, in terms of the competition with DECC on that. We see gas as absolutely part of the future. It is essential in providing back-up generation but also flexibility to the system, and we see a clear role for abated gas going forward in that, which is why we are pursuing our current projects.

Q257 Christopher Pincher: Mr Spence, you mentioned the need to use gas for peaking capacity going forward, dealing with the vagaries of wind, as wind becomes a larger part of our energy mix. If we apply CCS technology—and let us keep away from whether it is technically and commercially viable at the moment; we will get back to that—to gas stations to abate their carbon emissions, does that not then make it very difficult for them to be dialled up and dialled down, in order to provide that peaking capacity when the wind is not blowing? Do we have a problem then?

Paul Spence: As I understand it, it is still technically possible to capture and store. What it is not possible to do is to take advantage of things like enhanced recovery, so using the gas or the carbon that you are capturing to then do something for you as well as just putting it into the hole. Clearly, there is a penalty associated with the energy involved and the transportation of the gas, and that penalty makes it less attractive to be running CCS plant as very flexible. That is all part of the modelling of the mix.

If I may, it is all part of what we have to do and what I think is the Government's responsibility, which is to think about a complete system and the carbon intensity of that complete system under these different circumstances. Clearly, my company believes that, with the right amount of very low-carbon base load from nuclear, we can hit the targets. We can do that with gas as part of that mix.

Tom Crotty: I am surrounded by generators. I will not comment. I will just say that, clearly in the medium term, there is a significant benefit. We have seen the major impact in the US has been a significant reduction in CO_2 emissions due to the displacement of coal. I think we would see displacement of coal if there was more abundant gas; plus the fact, if you are using domestically produced gas rather than gas that has come halfway across the world, there has to be a CO_2 saving in that.

Q258 Christopher Pincher: We would still not get down to the 50 grams per kWh, which I think is the 2030 target. We would be building in that higher level of carbon emission into our energy mix without abated gas.

Let us talk a little bit then about the viability of CCS. Do you think it is going to be commercially viable within the foreseeable future, so that we can abate gas stations and so that we can meet our 2030 targets, or is that not going to be a sustainable proposition?

Martin Pibworth: Currently, CCS technology has not been proven at scale and, in our view, it needs capital support to bring it to commercial viability. We anticipate that, once that is achieved, and CCS as a concept is proven at scale, then the commercial costs

of running that technology come down with the experience and the expertise that is gathered. We will also probably see other advantages in pursuing CCS, in terms of strengthening the academic knowledge base, potentially exporting that technology going forward, and also taking advantage of the current very good standard of offshore gas engineering that we have in this country.

Q259 Christopher Pincher: Do you think we can do it in the timescales that require us to bridge the energy gap and meet out 2030 targets, or do you think we will be running with unabated gas for a period of time, which means we are not going to hit those targets?
Martin Pibworth: I believe we can, but we need to get moving on that process. There is obviously a role. CCS is not going to cure all ills in the next five to six years. Clearly, it is going to take much longer than that. We are hopeful that CCS will be a very good addition to the current suite of energy generation options that the UK has.

Q260 Christopher Pincher: I am assuming that—not to put words into your mouth—they are going to fall out quite happily and readily by themselves, but do you think that, if we are unable to prove CCS technology at scale in a reasonable timeframe, then the only alternative that we have to reducing carbon footprints is to restrict the exploitation of shale gas?
Martin Pibworth: No, I think there are other options. There are other low-carbon technologies and, clearly, we would also see nuclear as part of that mix, if it came at the right price and was in customer interest. Personally, I would probably try to avoid a direct comparison between each different technology. All of them have a role to play in achieving the targets going through in the next 20 years.
Peter Parsons: I would like to add, going forward, it is very difficult to have a world without the use of gas, as part of the important role it has in terms of heat, both domestic and in other areas. If you look at the amount of gas used, it is about four times that of electricity on a cold day. Of that, the vast majority, about two thirds, is used for domestic heat. It is very, very difficult, even with increased electrification and the use of heat pumps in houses, to have a position whereby gas would not have an enduring role to play in our networks.
Tom Crotty: We should not forget there is a significant heavy industrial use of gas that will continue as well.
Paul Spence: If I may, I suppose I don't think I would be doing my job if I didn't point out that the most material thing we can do to get ourselves towards our longer-term targets for carbon emissions is to make sure we take the shovel-ready projects, like Hinkley Point, forward as quickly as we possibly can.

Q261 Christopher Pincher: That seems to find popular support around the table. Just one last question if I may: you were talking about the importance of cheaper gas earlier. The Policy Exchange think tank has suggested that gas is a good transition fuel to keep costs low as we move through a period of time into a low-carbon energy economy. Is there not a risk that cheap and plentiful gas means that investment will be diverted from those very renewable energy sources that we hope will help us decarbonise and stay decarbonised? I think the Tyndall Centre says that there may be a diversion of anywhere between £19 billion and £31 billion. Do they have a point, or are they just telling a tall tale?
Peter Parsons: I am happy to leave the figures to other members, because I am not too familiar with them, but I think we can identify that gas has a role to play going forward. Whether it is to support renewables through intermittent generation, we see it as having a role to play, including providing heat.
Tom Crotty: Personally, I think it is a slightly dangerous argument, because it can lead you to make some very poor decisions that could, in the medium term, increase emissions in this country rather than reduce them. As we go forward, we will have an increasing need for new capacity, and that has to come from somewhere. It would be great if Paul goes out and builds 10 nuclear power stations in the next five years, but I do not think it is going to happen. What we do not want is to end up burning a lot more coal, as an example, which will increase emissions rather than reduce them.
Dan Byles: Like Germany do.
Tom Crotty: Yes.

Q262 Chair: Mr Spence, in the interests of making sure the shovel-ready projects are brought to a swift conclusion, does that mean you are about to agree with DECC a strike price of £80?
Paul Spence: It would not be appropriate for me to comment on the ongoing discussions with DECC. We are making good progress with them on the review of our project, the review of the costs of the project and the other aspects of what will be the contract for difference, making as quick progress as we can. We made fantastic progress on the other aspects of having the project shovel-ready before the new year. We are down to a very small number of things that now need to be in place to allow us to take the investment decision and to take the project forward.

Q263 Chair: This Committee does not claim any particular insights into these matters, but it appears to us possible that one of the small number of issues remaining is the negotiation of the strike price. Were you ready to agree a price of £80, it is my impression that DECC might be able to bring the matter to a swift conclusion themselves.
Paul Spence: It needs to be a price that is fair for all—and that means fair.

Q264 Chair: You mean more than £80.
Paul Spence: I cannot comment on the price. What I can say is that it needs to work for consumers. It needs to work for the Government and it needs to work for investors in the project as well.

Q265 Mr Lilley: Can you confirm it will be a multiple of the cost if we were using gas?
Paul Spence: I have been in the energy industry 30 years, and one of the things I have learned is not to predict the price of any of the fossil fuels.

Q266 Barry Gardiner: The Climate Change Committee has told us that extensive use—I think was their word—of unabated gas would mean that we bust our carbon targets apart. Is that your view, Mr Crotty?
Tom Crotty: I suppose it depends on what you define as that type of use. As I said before, having gas as a key part of the mix is essential.

Q267 Barry Gardiner: What about 26 GW?
Tom Crotty: I could not comment.

Q268 Barry Gardiner: That is DECC's figure, is it not?
Tom Crotty: I have no idea.

Q269 Barry Gardiner: That is extensive, is it not?
Paul Spence: It depends how it is used.

Q270 Barry Gardiner: It depends how it is used; you mean if it is balancing capacity and kept there as a strategic reserve simply to balance the system after all the renewables that we are going to have?
Paul Spence: In our scenario that meets Government targets, we have a similar level of CCGTs—however they are used—in a much more intermittent role than what you have described in your first comments.

Q271 Barry Gardiner: No, they were not my comments; they were the Climate Change Committee's. They talked about the extensive use. Let me probe that a bit further. You would see a role for gas as a balancing fuel to compensate for the intermittency of renewables. Certainly, I would share that view. Then let us talk about prioritising in the merit order and supply, then, Mr Parsons, because the Climate Change Committee has also told us that we could reduce the carbon intensity at the moment without any new plant coming on stream by 200 grams per kWh, if we simply gave priority to renewables coming through on to the grid. Is that right? Would you share that view?
Paul Spence: First, I would say it is not National Grid's role to identify any merit order of generation. That is for the market to determine. Generally speaking, nuclear and new—

Q272 Barry Gardiner: No, but the Climate Change Committee would have said, if you did determine a merit order, you would reduce the intensity of emissions by 200 grams per kWh. I asked you if that was correct.
Paul Spence: I do not know if it is specifically correct, but what I can say is the general merit order is that nuclear and renewables take priority over other forms of generation.
Barry Gardiner: And that is why?
Paul Spence: The cost is lower than any of the others.

Q273 Barry Gardiner: Yes, but the key here is you have gas no longer coming before coal, have you? At the moment, coal is so cheap that it is the other way around.
Peter Parsons: That is primarily as a consequence of shale gas developments in the US, which is exporting coal to Europe.

Q274 Barry Gardiner: Yes. Mr Pibworth, SSE has said that, if there is significant development of shale gas in the UK, then the importance of developing gas CCS increases. We do not even have one coal-fired CCS. Everybody thought we were going to have one. It was top 10 in Europe, was it not, and it did not go ahead? Was that £1 billion ever there, do you think?
Martin Pibworth: In terms of the economics of gas generation and the picture of gas generation going forward, there is clearly a requirement for gas generation going forward to meet the needs of the system, as you have clearly observed. In our view, to hit the 2030 targets, that gas will need to be abated. Clearly, this has not been proved on any large scale yet, and that is why we are in the current process we are in.

Q275 Barry Gardiner: There seems to be confusion here about whether our energy policy is a policy, in and of itself, or whether it is about the wider economy. If it is about the wider economy, if it is about producing something that we can export all around the world, then all around the world coal is going to drive energy for the next 30 or 40 years, and it makes sense to be developing not gas CCS but coal CCS, to ensure that we have something, a technology, that we can export that is actually going to do something about climate change, does it not? That is about the UK economy. Yet the Government seems fixated at the moment. The reason they gave for not doing the coal-fired CCS was, "We see this role for gas and perhaps we ought to have a gas-fired CCS". That is what you are backing them up on. That is what I am saying is the short-term, limited view, which does not look at the wider needs of the economy but only at the phlebotomy—the flow of blood, of energy, around the system. You are a phlebotomist not a GP, Mr Pibworth. That is what I am accusing you of.
Martin Pibworth: I am certainly not a GP, Mr Gardiner. Estimates of global gas reserves are increasing all the time. While we are unsure about shale gas in the UK and the effect on price, clearly we think a global shale boom would exert downwards pressure, which would make the economics of CCS more attractive. I would also say that, because it is an unproven, large technology at this stage, we would hope that, as it becomes proven as it operates, the costs of running CCS would come down over time.

Q276 Barry Gardiner: So if CCS is not developed—and let's face it, we do not seem to be seeing a great deal of the progress that we thought might be taking place by now—quickly enough to allow it to play that meaningful role in helping the UK to meet its climate change obligations, which you just outlined, should the extraction of shale gas be restricted?
Martin Pibworth: In my opinion, there is no reason why shale gas should be restricted.

Q277 Barry Gardiner: What about the fact that we will not meet our climate change obligations?
Martin Pibworth: I guess, I am making an assumption that there is going to be a role for gas generation going forward. It includes all the diverse range of generation options we have. If we get through an abatement, and can prove it, that would be very good for all the priorities we are looking to achieve as a country at the moment. *[Interruption.]*
Chair: We are going to have to end this session. Thank you very much indeed for coming in. The Committee is adjourned until 4.15pm, but please come back promptly after the Division. Thank you.

Examination of Witnesses

Witnesses: **John Hayes MP**, Minister of State, Department of Energy and Climate Change, **Simon Toole**, Director of Oil and Gas Licensing, Exploration and Development, Department of Energy and Climate Change, DECC, and **Chris Barton**, Head of International Energy Security, gave evidence.

Q278 Chair: Welcome back, and apologies for the unavoidable interruption. Thank you very much for coming in. As you know, there is a lot of interest in this subject. I know you have a busy agenda on the Bill as well at the moment, so we are grateful to you for fitting us in.
Can I start with a question about the *Gas Generation Strategy* that is obviously directly relevant to this inquiry? What is the actual level of new gas-fired generation the Government is now intending? Is it 20 GW, 26 GW or 37 GW?
John Hayes: As you know, Chairman, the *Gas Generation Strategy* sets out a plan for additional gas generation, a great deal of which is to replace ageing stock, some of which is to provide new gas, as an important part of an energy mix that we think is sustainable because it provides resilience. I would say up to 26 GW is the figure that we would want you to be aware of. Of course that depends—as you implied in your opening remarks—on the success of our reforms to the market, which are embedded in the Energy Bill to encourage sufficient investment to get that new capacity.

Q279 Chair: There is, among commentators, the academic world and the NGOs, some concern that this *Gas Generation Strategy* rests uneasily with some of the commitments that have been made to a drive to more investment in low-carbon electricity generation, and it is even characterised sometimes as the Treasury saying, "Let's have lots of nice cheap gas", and DECC, perhaps with a slightly greener approach, saying, "We are committed to substantial greenhouse gas reductions in the long term, and if we bill lots of gas now, post-2030 that will leave us with some difficulties".
John Hayes: There are three points in answer to that. First is the assumption implicit in that analysis that gas will be cheap. That is not certain. Gas prices have been volatile and may continue to be so. The second point to be made is that much of this gas will replace coal generation. As you know, currently coal is providing a very substantial amount of our energy needs, and new gas, which is of course—although a carbon fuel—in emission terms much preferable to coal, will replace that coal-fired power. Thirdly, because of the intermittence of renewables, the flexibility that gas offers is an important part of the mix I mentioned earlier. You might even argue the renewable part of our plans could not be successful without the flexibility provided by gas. Indeed, I think the renewable industry themselves acknowledge that mix is of value.

Q280 Chair: You will know—because I know that when you took this job on, you were kind enough to take a close interest in some of the reports that this Committee had written in the past—that when we expressed our support for exploiting Britain's shale gas reserves in our report in 2011, we did make a number of points about the need for a robust regulatory regime so we avoided some of the mistakes that may have been made in the US. The combination of roles in the Office for Unconventional Gas and Oil, which appears to be acting as a cheerleader for the industry as well as a regulator: is that one in which they are going to find it easy to reconcile those different functions?
John Hayes: The principal role of the new office is to act as a co-ordinator: so, to co-ordinate, give coherence to the strategy, bringing together both the necessary safety and security measures that you recommended in your report—which I have with me—and also, of course, to ensure that across Government there is consistency in our approach to the potential of shale. Your report, which you mentioned earlier, Chairman, says, "We conclude that shale gas resources in the UK could be considerable". It does go on to make very clear they need to be exploited in a sensible, reasonable, safe, secure way, and the Government entirely concurs.

Q281 Chair: That view expressed in that conclusion that you have just referred to—I think we would feel that even more strongly today, in the light of what has happened. From whatever standpoint you start this, if we want to see these shale gas reserves exploited to the full, it is going to be crucial to carry the confidence of local communities, particularly in more densely populated areas. Therefore, if the regulator does have in some respects—as a sort of co-ordinator—at least part of their function appearing to be to promote the industry, that seems to many people an uneasy fit if they are also looking at the regulatory side as well.
John Hayes: Regulation in the energy sector has always been about engagement with providers, both in primary-source terms—and one thinks of the North Sea—and in terms of power generators because, of course, in order to get a regulatory regime that works, that is deliverable, there has to be a proper level of

engagement. So, I would not be apologetic about the level of engagement. Indeed, I have met Cuadrilla, who have been drilling in Fylde, and, as a result of that, have pressed on them the need for their approach to be a responsible, safe and secure one. I am very happy to say that they acknowledged the need for the tightest possible regulation in respect of safety. So I think there has to be an engagement and the office should play its part in that engagement; and if it is to co-ordinate in the way I describe, part of that co-ordination is—as well being across Government, between Government and the other agents involved—to co-ordinate, of course, private businesses.

Q282 Chair: You are confident that any possibility of any conflict between these different aspects of what their job will be can be avoided all right?
John Hayes: Yes, I am confident of that. Although I will just say this: it is an interesting point you make, and one might argue the very fact that we set up the office is an acknowledgement the Government sees this as an important, exciting potential. So, there is a sense in which the concentration of effort, in terms of public policy, is indicative of Government's belief that this is something that we need to explore. In terms of the executive function, I am confident the office will be about co-ordination and coherence rather than, as you describe—I am inferring from what you said—playing a sales and marketing role.

Q283 Sir Robert Smith: It would still be an independent HSC that would be looking after safety, and when it comes to onshore, it would be the Environment Agency dealing with policing environmental emissions?
John Hayes: Absolutely, yes. For example, the licences that are necessary for various parts of the process involved in extraction will be granted in the way they have been. The Environment Agency will continue to play the role that it has, as you know, the legal responsibility to do, so that is unchanged. The office does not change any of the things you described, Robert, but I believe it does give a better chance of a coherent, consistent, well-organised approach.

Q284 Dan Byles: John, very interestingly, in the context of the Office of Unconventional Gas and Oil, I am a bit uncertain as to where that sits in terms of ministerial responsibility and Department responsibility. Is this going to be Defra body, a DECC body? Is there going to be an individual Minister with overall political responsibility?
John Hayes: It is a cross-departmental body, Dan. We have yet to decide which Minister should play a part in the process you describe. If this Committee felt that ought to be me, I would be immensely flattered. I am quite unconventional. There would be a fit there.

Q285 Dan Byles: Excellent. We have spoken with Cuadrilla here in Committee as well, and the CEO, Francis Egan, told us that the tax regime for shale gas must recognise the early stage of the industry so that—in his words—it does not "strangle it at birth". Can you update the Committee on where you are with your discussions with Treasury and where the new tax regime is currently?
John Hayes: Yes. You will know that the Chancellor announced the Treasury were looking at a range of measures to encourage and, indeed, incentivise exploration. I would emphasise that there is a big gap between exploration and production, but the cost associated with exploration will be significant. Of course, when we speak of unconventional gas, in essence, we are not speaking about a different or less conventional drilling process, nor are we talking about different kinds of gas. This is largely methane. It is a natural gas. We are talking about where the gas is stored and, therefore, how it is extracted. As I say, the Treasury have announced they are looking at that. Those details have yet to be finalised but, as you suggest, we are in discussion with Treasury to look at the most appropriate ways forward.

Q286 Dan Byles: Do you know when we might start seeing some details of that?
John Hayes: I am hopeful that in this spring we will know more.

Q287 Dan Byles: Is it specifically a shale gas tax regime, or is it an unconventional gas tax regime? Because I know that some of the cobalt methane companies feel they might be left out in the cold.
John Hayes: I think it would be difficult to distinguish between types of unconventional gas for the purposes of a fiscal instrument, and so—I do not want to be definitive because, as I say, these things are still being discussed—my expectation would be that it will be an unconventional gas measure.

Q288 Dan Byles: That is interesting. Do you know if the Treasury—or whether DECC might even be recommending this—have any specific plans for hypothecating the revenue from this tax? For example, a lot of people have suggested some sort of wealth fund, along the lines of the Norwegian fossil fuel wealth fund. It might be an exciting opportunity to set something like that up. Are you aware of any discussions along those lines?
John Hayes: Not at the very beginning but very early in my career in this House, I learned not to stray too far from one's purview and certainly not, as a shadow Minister or Minister, to confirm anything that was outside my competence.

Q289 Dan Byles: In other words, ask the Treasury.
John Hayes: I guess, perhaps more courteously, I might say, Chairman, "Watch this space".

Q290 Dan Byles: It has not been ruled out? Would that be a reasonable—
John Hayes: I really would not want to speak on behalf of the Treasury. We are in discussions with the Treasury. Of course, all matters are being debated and considered.

Q291 Sir Robert Smith: When we have sought to speak to Treasury Ministers, they have made the point that DECC speaks for them when it comes to this Committee.

John Hayes: Again, the flattery is endless. I am immensely flattered by that. Let me say, because you know how much how I value this Committee, as a direct result of that inquiry I will meet my colleague, the Economic Secretary, again to discuss precisely these matters, and I will cite your comment, Sir Robert, as the cause, indeed the catalyst, for that meeting.

Q292 Dan Byles: We can probably get a copy of the letter in which they say that the reason they do not need to send us a Minister is that DECC can answer all such questions. Would that be helpful?
John Hayes: That would be wonderful.

Q293 Mr Lilley: On that particular issue, or on the issue of tax, is not one of the great potential benefits of shale—if there is a large amount of it available in this country—that it will either reduce the price of gas, thereby helping the Prime Minister, as he said in his evidence to the Chairman of the Select Committee, helping to rejuvenate British manufacturing; or, if prices come down it will mean significant tax revenue, but only so long as we do tax these companies? I hope there is no suggestion that we are going to give unnecessary tax breaks to an industry that is perfectly capable of operating within a reasonable tax system that generates large tax revenues from a natural resource that is owned by the community.
John Hayes: Your Committee's fifth report of session 2010–12 on shale gas, to which the Chairman and I have already referred, says, "We conclude that a glut in shale gas production could drive the price of conventional gas down, but there is uncertainty as to the extent of this". As you know, in the United States, over a period of around 12 years, there has been quite a dramatic change there. The price of gas units has fallen very dramatically from $12 to $3, and that has had an effect on, of course, overhead costs for businesses. It has arguably increased American competitiveness. But I think it would be wrong, as your report also concludes, to assume that the pattern in America would be followed exactly here, for three reasons: the geography is different; the geology is different; and the land ownership is different; also, if I might add a suffix, the cost of extraction here may be higher. Nevertheless, if the Government did not think there was potential in this and a significant opportunity, we would not have made the statement my right hon. Friend the Secretary of State made to the House, leading to the possibility of further exploration. Nor would we be taking this matter as seriously, in the terms just described, in respect of incentives and so on. So, this is an improvement opportunity. It could have a profound economic effect. We need to move forward with a degree of caution but not so cautiously that we miss the boat.

Q294 Mr Lilley: On the question of caution, would you agree that, given the potential benefit of this industry, should there be large extractable amounts of shale gas, to the British economy, both in rejuvenating manufacturing and generating tax revenues, at a time when the British economy is in the doldrums as the result of a world economic crisis, it is being hugely irresponsible of the powers that be—we do not blame you, because you were not there—not to have taken the advice of this Committee nearly two years ago and moved straight ahead on developing shale gas? Can you give us an assurance you are going to move forward with all due dispatch on what could be the one new industry that this country has, prospectively, on any scale, up its sleeve?
John Hayes: I cannot speak about my predecessors. You would not expect me to do so. I arrived in the Department in September. By December, there was a statement to the House enlivening this whole subject. What more can be said than that?

Q295 Mr Lilley: You can say that that is not the end of it, we are going to keep pushing forward and they are going to be drilling wells very soon.
John Hayes: Yes. As you will know, Peter, from what is already in the public domain, there is uncertainty about how much of the gas, which has been identified by the studies that have already taken place, can be extracted with commercial viability. Until we have been through the exploratory process, it will not be clear how big the potential is. But certainly we should move ahead with appropriate speed, allowing for a regulatory regime that ensures safety and security, and, by the way—as was mentioned earlier by the Chairman—with the engagement of the local community, which I take very seriously and I know the Government as a whole does too. But you are right; we should not miss the boat.

Q296 Mr Lilley: We heard from BHP Billiton in the States, who are one of the biggest people involved in this, that the first well in any new geological formation is usually disappointing. The second well is not much better. By the time you have drilled 100 wells, you have mastered the geology and you are producing substantial quantities. When are we going to drill two—let alone, 100—wells and test them?
John Hayes: It would not be appropriate for me to make a prediction about timescale. As I mentioned earlier, the pace of change in the United States was remarkable. To be fair, though, that was partly because of the land ownership in the United States, which is rather different from here, partly because the geography of the United States has allowed a great deal of that drilling to take place in areas that are very sparsely populated—a point that the Chairman made, by implication, earlier is that that is not typically the case where shale is found in the United Kingdom—and partly because the cost of extraction in the United States is arguably rather lower. So, one would not want to make direct comparisons with the speed or scale of the exploitation in the United States. Nevertheless, I do agree that we need to move ahead with appropriate alacrity to explore and, if possible, take advantage of this exciting opportunity.

Q297 Christopher Pincher: Minister, in order to meet your objective of exploring the scope of shale gas opportunities—and pursuant to Peter's point that we are going to start taxing the IGases and the Cuadrillas of this world, as and when they find and extract shale gas—first of all, we need to issue

licences to more Cuadrillas and IGases, so we have the scope of operation to do the kind of exploration that you want and get the sort of tax revenues that Peter wants. Are we going to move ahead with another licensing round expeditiously so that we can get those companies into the marketplace?

John Hayes: Yes, absolutely. However, as you know, Chris, there are planning issues too. The local mineral planning authority, which in this case in Lancashire is the local council, will need to consider these matters through the normal planning process. As far as the licensing process is concerned, yes, we are doing the environmental assessment now, and we will move ahead with the speed you describe.

Q298 Albert Owen: Mr Lilley and Mr Pincher have encroached on some of the questions I wanted to ask, but I still want you to answer some of the points that have been raised about estimates and uncertainty. You referred to our report, some 18 months ago, when I think we correctly referred, based on evidence, to these uncertainties. There is a lot of confusion about the figures surrounding how much gas is available. As Government, what can you do to improve people's understanding for the future because, if we do not have clarity, then there is a vacuum that is going to be filled by those who are pro-gas and those who are anti-gas, and there is going to be a lot of speculation. So, what is your responsible role as a Government Minister and as a Department to improve people's understanding?

John Hayes: First, to be clear about the process, part of the reason for this new office is to provide that function. It is not about marketing; it is more about co-ordinating, being clear about the process. There is confusion about the difference between exploration and production. We have to be absolutely clear about that. The second thing, while not inhibiting the exploration, is not to exaggerate either the scale or the pace at which we might travel. As I am sure you know, the science on this is fascinating, and I have been fascinated, indeed, to consider issues of porosity and permeability, as I am sure you have too. Trying to make the science more widely available and comprehensible is—

Q299 Albert Owen: Yes. We tried that in our first report. As you know, it is quite an in-depth report. We have had experts in front of us already in this inquiry, and they were not able to give us any exact figures. We understand that, but the estimates vary considerably. The Secretary of State has acknowledged that it is possible to make a meaningful estimate of recoverable resources of shale gas that can be fracked. To what extent are your policies now based on those existing estimates of resources, or are you just holding off to get more accurate figures?

John Hayes: Clearly, we cannot give figures until we test it, until we have explored it. One of your witnesses—one of the people you have just referred to—pointed out that in the United States in 2007 to 2009 the estimates of available resources grew by 40%, so in just two years there was a very different estimate of the likely potential, which is why we are exercising such caution. Until we have tested, I think it would be irresponsible for us to issue any figures. This Committee would not expect anything other than that from a Government that was doing this properly. So, partly, the direct answer to your question is the function I described.

It is very important in explaining the science that we dispel some of the widely publicised myths, misassumptions and misapprehensions about this—widely publicised perhaps by people who have a very particular view about it. So I think clarity about the science is important in engaging the community.

Q300 Albert Owen: The practical steps are what I am really trying to get from you. We took evidence from Cuadrilla in our first session, and they have now had the green light. Things were put on hold because of the geology of the area and the earthquakes. In the meantime, your Department has been developing policies. Do you now envisage, now that Cuadrilla have their green light, that a number of licences that have been applied for will be issued—subject to all the conditions of safety—rather more quickly now that they have had the green light? I do not want exact figures from you, but how many of these licences do you see, and how spread out across the country will those licences be?

John Hayes: Yes. I would expect companies to come forward, subject to the process that you have just described. To be clear about the actions: establishing the new office, which plays the co-ordinating role I have described; clarity about the licensing regime; as a result of the Secretary of State's announcement that we are issuing licences to restart drilling, analysis of the results of that, which inform further work; being very clear about the science, and the safety and security associated with it; and proper engagement with the community on community benefit. That seems to me to be important too. These are parts of a logical, appropriate process that moves us ahead with the kind of alacrity I described to Peter, but does so in a way that I think we could properly describe as reasonable and responsible.

Q301 Albert Owen: A specific question; we know Cuadrilla was put on hold. Was your Department holding back on these licences for obvious reasons, and were they always thinking about setting up this office for a tax regime? Was that always the case, or is this something new, because I do not remember hearing it from DECC? Or did they wait for you to come along and push all this forward?

John Hayes: No. Of course, the Treasury are interested in this, not least for the reasons that Peter gave earlier. This may have significant economic benefits.

Q302 Albert Owen: But my specific question is: why have we waited until autumn this year to hear this statement? Why was this not developed or this information given to us in previous reports?

John Hayes: Well, I cannot be a Minister in every Department.

Q303 Albert Owen: I am not asking you to be a Minister. I am asking you to be the spokesman of DECC. Was this always a plan that you had?
Another point, the final point, if I may: in response to Dan you mentioned that this tax regime is available for all unconventional gas.
John Hayes: I said it is likely to be. We are in discussion, but I think it will be difficult to distinguish.

Q304 Albert Owen: It has not been developed, that policy? Is there going to be a shale gas tax, or is it going to be for all unconventional gas?
John Hayes: I would anticipate it being for all unconventional gas, because to distinguish between them in an instrument of that kind would be extremely difficult. We have already said that the nature of the definition of unconventional gas is about the location, the reservoir. It is not about the gas itself.

Q305 Albert Owen: Some of that coal bed methane—we know how much is there, we know where it is, and the companies tell us it has been uneconomical to extract it in the past. So this is a financial incentive for that to happen, yes?
John Hayes: That is what the Chancellor suggested, but I think we need to continue those discussions, bring them to a conclusion and hear what the Treasury have to say before I give any definitive commitments as to exactly what that will look like.

Q306 Albert Owen: Well, you have today; that is why I am exploring it with you.
John Hayes: We know that the Chancellor is considering these mechanisms. We know they are designed to incentivise further exploration. I said I think it is likely. I anticipate that being for unconventional gas. The exact nature of the instrument is not something I can be definitive about today, as you know.
Albert Owen: Thank you.

Q307 Sir Robert Smith: Obviously, in achieving the potential that is possibly there for the shale gas, there is the physical constraint of the equipment needed to get it out of the ground, and there are some in the industry that talk about how the US had a long history of onshore drilling rigs available, and also the debate about the kind of drilling rigs, the quality of drilling rigs that will be necessary for operation in the UK. Do you see that as holding back the potential if initial findings look good?
John Hayes: Two things, Robert: first, we need to look at best practice and that includes internationally. Part of what I hope this new office will do is to explore that best practice, in terms of extraction techniques among other things. Secondly, there will be a sense in which this will have its own momentum. Success will bring further rigs and further investment. As the potential opens up, should it open up in the way that this Committee thought it might in its original report, I think there will be further investment in the technology. We have already talked, a moment ago, about the instruments the Government might bring to bear to incentivise that process. In terms of the specific technology, the drilling technology is rather like the drilling technology used for other gas extraction. There is an onshore industry in this country. As you know, Dorset has a significant onshore industry. Inasmuch as there are specific requirements around technology, we want to look at the best available worldwide and see what could be applied here. I feel slightly guilty that my two colleagues have not commented. They may have some blindingly insightful understanding of the technology.
Chris Barton: First of all, in terms of the supply chain, clearly the US supply chain is a lot more developed. That is one of the reasons why, at least in the near term, we would not expect quite the same experience outside the US as we have had elsewhere. Then again, supply chains can develop, and we can learn from experience elsewhere, so if there is sufficient opportunity here or elsewhere internationally, we would expect the supply chain to be a time-limited rather than a "for ever" constraint.
Simon Toole: Rigs do not wait around waiting for someone to drill a well; as the Minister said, if there is success, rigs will arrive and we will be able to drill. Also I think we will find that some of the features of the UK shales, if they are proved to be successful—I think you heard from Cuadrilla that their shale is very thick, much thicker than the shales exploited in the US—will call for new technologies to be developed. That has not been done before. All the components of that technology are probably available, but putting them together in the right way is going to be something that the UK will need to do if we have success. So there will be an evolution of our supply chain and of our technological application, as we find out what we have and what we are dealing with.

Q308 Dr Whitehead: I am a little unclear about how DECC's overall strategy is going to proceed, in terms of the uncertainties that we know there still are, as far as not just shale gas availability but extractability and—most crucially—the price of that extraction. Therefore: the extent to which people will come and do more than just explore to see what is there, and will start extracting it commercially and placing it on the market. Indeed, a recent report—the Wood Mackenzie report, which I am sure you are aware of—has suggested that, in UK conditions, it appears likely that the cost of shale gas per cubic metre is likely to be substantially higher than the present gas prices would suggest. Therefore, shale gas may be a concomitant of higher gas prices rather than a harbinger of lower gas prices. Is that your view, or how are you planning in DECC to take care of those eventualities? That seems to suggest to me that you may not get the production, even if there is the availability in the immediate future.
John Hayes: Of course in the end it will be a matter for the companies. If companies explore and come to the conclusion that extraction is not commercially viable, they will be unlikely to proceed. That might be affected by scale. We have talked in energy across a whole range of areas about how scale can drag down cost. If the scale is sufficient, it could be that costs can be driven down. We mentioned the technology a few moments ago. As the technology matures, it is

likely the cost of some of the initial investment may fall. We have spoken of what Government might do to catalyse that, to stimulate that to offset those costs. You are right, there may be geological reasons for a difference in cost, either related to the ability of the rock to transmit fluid or the character of the spaces where the gas is stored, which are particulars, different geologies. It could be that in the United Kingdom the profile of the geology is such that costs are higher.

There may be other business costs—not least the regulatory regime—that are different. I have already mentioned land ownership, which has implications for cost, and geography. If you can do things in wide open spaces as opposed to populated areas, costs may differ. In the end, all those are matters for the market. While Government can play its part in creating a context in which those things can be considered, viability and commerciality will be features of the market. The specifics that I described, in terms of geology, will be measured by these businesses in terms of flow potential because, as someone said earlier, flow potential will define how much value there is in each well against the cost of opening up that well. These are complex matters but, as the industry begins to unfold, all of the things I have described will become clearer. Chris, I do not know if you want to add to that regarding cost?

Chris Barton: Just more generally, for all the predictions and studies that we do, we all have to recognise that predicting future prices is extremely difficult and almost every prediction turns out to be wrong. I think, from a Government perspective, we need to be in a position that we are not trying to dictate exactly what different outcomes are, that we have an overall framework within which different technologies can compete on the basis of cost, and be flexible to that. It also points to the wisdom of ensuring that we have overall diversity in the energy mix because, even if we think today, for example, that some people think that gas prices are going to go down, perhaps that is right, perhaps it is not. Ultimately we do not know, so we should not be putting all our eggs in any one basket, and we need that mixture of the overall energy mix.

Q309 Dr Whitehead: I think that anticipates my next question, in that we have heard overall that it appears that, even if there is a reasonably substantial extraction of shale gas in the UK, then it will do no more than counteract the decline of gas production from the North Sea, which is a revenue loss to Treasury, so perhaps a revenue gain for shale gas will counterbalance that, and that is the sort of possible scenario that results in the future.

I presume, in terms of the market determining whether shale gas is developed in the way that you described, there could be a fair amount of development or not much, depending on who takes a punt on what price, and what the overall price and the overall long-term scenario is. However, in DECC, you are in the unfortunate position of having to at least make some contingency planning for those various different possible outcomes. Therefore, you require that flexibility that you have mentioned regarding those different outcomes. How will you be able to do that, in terms of having the flexibility of perhaps being able to encourage that exploitation if it turns out that it is cheaper than one thinks, or the other prices of gas go up higher than one might think and, therefore, it becomes marginally economically viable? Alternatively, it might not, and, therefore, other forms of energy need to be fast-tracked to deal with that outcome.

John Hayes: By the way, in terms of a proper consideration of the implications for shale gas, other unconventional gas and gas more generally—and, as you suggest, the wider effect that might have, which is highlighted in your report, and in others' views on these things and on the energy market more generally. You make the point that a change in the price of gas will not only have a potential displacement effect on other sources of gas—which could be beneficial, by the way; there might be less imported gas, for example—but is likely to have an effect on coal, as it has in America, where we know that coal for power has been quite significantly affected, and a broader effect still. So, the need for scrupulous attention to changing circumstances, which is essentially what you are calling for, is I think a pressing need. Part of the role of this office that has been established, in co-ordinating the process, will be to monitor and, through monitoring, assess the need for the application of the flexibilities that Chris just spoke of. So, my judgment is that, as well as establishing a framework, our job is to establish a public policy infrastructure that allows for exactly the kind of response that you have described, Alan.

Q310 Dr Whitehead: Do you envisage the assistance that may be forthcoming from Treasury—we have discussed the fact that that is by no means finalised in terms of what it looks like and how it might work—for the beginnings of exploitation of shale gas to develop into any sort of underwriting, so that a price can be stabilised over a period for shale gas production, or do you see it as an aid to exploration, finding out what there is and how it might be best established?

John Hayes: The way it is being envisaged currently is as a means of stimulating exploration but, of course, as time goes on, with the diligent monitoring of events of a type that we have just been speaking of, Government as a whole will need to continue to look at these things. It is part of the reason for the need for a cross-departmental approach. The Environment Agency falls within the purview of Defra. It has a vital role to play in the regulatory regime. The things you have been speaking of also have a connection to Treasury, and Peter said there is a significant wider economic interest associated with this. DECC has its role to play in the licensing regime that we enjoy. So, I think a need for co-ordination, as well as a need for the kind of diligence you describe, is critical. As I have said before, the new office will indeed be a cross-departmental body.

Q311 Barry Gardiner: Mr Barton, as I understand, you are responsible for security of supply. Is that right?

Chris Barton: Yes.

Q312 Barry Gardiner: Therefore, you will have seen the figures from a number of people, but Tyndall in particular, that say that the investment in new gas could see between £19 billion and £31 billion-worth of investment knocked off renewables. Given that we are looking for £110 billion in total, that is a sizeable chunk to come out of just renewables, is it not? What does that tell you about the prognosis for security of supply?
John Hayes: Well, I think—
Barry Gardiner: No, I asked Mr Barton.
John Hayes: I will ask my colleagues to comment too, but all of this needs to be considered in terms of DECC and the Government's energy strategy. You are very familiar with the argument that lies at the heart of the Bill, which you and I are both looking at in some detail currently. That argument is that we need a mixed economy in generating resource, not only because that is important for energy security but because it is vitally important to meet the emissions targets that we have agreed. So, the context in which we debate the matter of shale gas and the *Gas Generation Strategy* more generally is an unchanged context—the context where we need to meet our targets. We need to do so in a way that is affordable, with an eye to any security. I think you are right: if, for example, gas were to become the only means—I am exaggerating, of course, for the sake of clarity—by which we generated energy, that would lead to a vulnerability. There needs to be—

Q313 Barry Gardiner: Minister, sorry, that was not my question. You have very skilfully shielded Mr Barton from my question, and tried to divert it in a different direction. My question was really quite simple. It was: if there were, as is predicted in the *Tyndall Report*, a £19 billion to £31 billion reduction in investment going into renewables in particular, what would that do for your role, Mr Barton, as having to look to security of supply?
John Hayes: Barry, contrary to the more colourful stereotypes, civil servants are grown up. I do not need shielding, so Chris will answer.
Chris Barton: Thank you very much. Two things, if I may. First of all, just to address the suggestion that shale gas would, or indeed increased gas use itself will, necessarily spell a reduction in investment in renewables, I do not think that is necessarily the case. Indeed, increased gas use can go hand in hand with increased renewable deployment in that, as was alluded to earlier on, some more gas generation will be needed to facilitate the extra renewable deployment that we need.

Q314 Barry Gardiner: You and I both know that that is in a marginal capacity to make up for intermittency. Are you saying that the Tyndall Report was wrong? Are you saying that their prediction of a £20 billion to £30 billion reduction in investment in renewables has no basis? At least, let us take the argument head-on rather than to say, "Well, there is a different scenario in which it may not be the case".
Chris Barton: I will confess I have not read the Tyndall Report, so I would not want to comment one way or another on its merits. But, okay, even if we accepted that there was a reduction in investment in renewables; what impact would that have on overall energy security? Again, I think you have to see it—and this is not seeking to dodge the question—in the context of the overall energy mix, and, in general, greater diversity is helpful for energy security. On the other hand, you need to look at how the different technologies are—

Q315 Barry Gardiner: What figure do you have pencilled in, Mr Barton? Of the £110 billion of new investment in the electricity infrastructure: what figure do you have currently pencilled in for renewables out of that £110 billion?
Chris Barton: I do not know exactly how much is on renewables, but we do know for up to 2020, we have a clear target for 15% of our energy to come from renewables by then, so it would be—

Q316 Barry Gardiner: No. I was asking for a percentage of the £110 billion that is required, because it seems to me that if you are taking £20 billion to £30 billion out, and that is just from renewables, that is a sizeable chunk of your investment as a whole, and I would have suspected it means the death of investment in renewables.
Chris Barton: I do not have a figure for the split of that £110 billion between different technologies, but I would say—

Q317 Barry Gardiner: Could you send it to the Committee?
Chris Barton: I can see if we have one, yes. Although I would say that the fundamental driver of our renewable deployment, to 2020 and beyond, is going to be our overall renewable energy policies. If we hypothesise a situation where there is a massive reduction in investment in renewables, then, sure, there will be less renewables than we expected, which comes back to my first point, really, that I would not take it as a given—

Q318 Barry Gardiner: The point, rather, is that we take the right fork in the road at the right time.
Chris Barton: Yes, exactly, but also I do not think we should take it as a given that there is going to be a reduction in investment in renewables. Indeed, we have a whole suite of policies to ensure that we maintain that investment in renewables. Indeed, under the levy control framework we have a tripling of support between now and 2020 for low carbon. We are not anticipating a slowdown in renewables. We are anticipating a very significant increase in renewables, and that will stand whether shale gas is exploited at the upper or lower limit of expectations. So I think it does come back to that first point: do we think there is going to be that very significant reduction in renewable investment? Our position is, no.

Q319 Ian Lavery: Looking at the gas markets and the trading, the gas trading and the prices, there have been many predictions with regards to each one of those. DECC have suggested that large-scale unconventional gas production—in the main, I believe

they mean shale gas—could impact heavily on inter-regional trade. This is basically because of the reduction in the need for imports. Listening to the evidence today, this is likely to happen. Have DECC made an assessment of the security of supply indications if cheap gas prices reduce inter-regional gas trading?

John Hayes: If you look at America, Ian, what has happened because of shale is, first, it decreased or de-placed supply of gas from other sources. Shale gas has become the dominant source of gas. You are right that that pattern might be repeated. It would depend on scale, and we have already said that scale is something we cannot make a definitive assessment of until we know a bit more about the relationship between what is there and what is commercially viable to extract. You are right that the pattern in America might be repeated here.

The other effect then, Barry, is on other means of generating energy, but I would argue—rather contrary to your assertion—that it would provide a more secure source of supply. This is domestic supply of gas, and surely we would not want to turn our back on the possibility of a significant source of domestic energy. I see it as potentially advantageous, in terms of energy security, rather than disadvantageous.

Q320 Ian Lavery: I am certainly not suggesting that anybody turns their back on this. That really was not the question. The question basically is: have DECC made an assessment of security of supply if indeed cheap gas prices do reduce inter-regional gas trading? I do not think anybody is suggesting that anybody turns their back on this issue.

John Hayes: No, I think you are right. It is something one needs to look at closely. In answer to Alan's question, I have already talked about the need to monitor the situation closely and regularly, because things could change quite rapidly once we move from exploration to production. You are right that part of that monitoring must be an assessment of the likely effect on other sources of gas. I will commit to that as a direct result of your question—that, as this moves on, I will make sure that the Office for Unconventional Gas, as part of its work, makes an assessment of those effects. We will only be able to do that down the line when we know more, but it seems to me that it would be less than responsible not to do it.

Chris Barton: This is something the IEA has looked at in its *Golden Rules for a Golden Age of Gas*—considering what the impact would be on inter-regional trade. One of the prime reasons why it envisages a reduction in inter-regional trade, compared to what would otherwise have been the case, is the widespread nature of unconventional gas in their golden-age scenario. So, if there is unconventional gas in all sorts of places around the world, the need for inter-regional trade is slightly reduced. But first, the overall level of inter-regional trade then would be greater than it is today; and secondly, if we were in that world, the overall security of gas would be in a healthier position because there would be a lot more gas and at lower prices, so the net effect would be a positive one on energy security at the international level.

Q321 Ian Lavery: Evidence has shown that shale gas might increase liquidity. As a country, is the UK in a good position to connect to an increasingly liquid market and, therefore, benefit from potentially cheaper gas prices?

John Hayes: I think that is true. It is quite possible that a number of companies may enter the market, creating more plurality and more liquidity. That is a very healthy thing. Typically, that sort of competitive pressure would drive prices down. Chris has mentioned that extra supply may do that, both locally and more widely internationally. So, I think you are right. I think you are spot-on, actually. There is a possible positive implication for greater competitive pressure within the market, and I think that is something that we would welcome.

Q322 Ian Lavery: Looking at the basis on which the Government makes its predictions—we have discussed predictions a lot today, and I think it was Mr Barton who said that most of them are wrong—and at the price predictions, DECC have said that their future projections are that gas prices will increase, and the Office of Budgetary Responsibility are sure that gas prices will reduce. I wonder—and I am sure the Committee would welcome your comments—on what basis you make your policy decisions in relation to the future of gas prices, and why.

John Hayes: Predicting gas prices is an inexact science. If you look at some of the predictions for gas prices, historically, they have not been followed by the events they anticipated. Nevertheless, notwithstanding the different scenarios, the likely impact from widespread exploitation of shale needs to be measured against the consensus of forecasts, which suggest that the gas price will continue to be tight. That is not least because demand for energy is growing rapidly in emerging economies and elsewhere. I do not want to get into the realms of fiction, still less fantasy, but it may be that China or another large, growing, emerging economy starts to invest in unconventional gas. That is not something that we could anticipate in our considerations here with any certainty or confidence. The consensus view is that the gas price is going to be tight, although you are absolutely right that shale locally could have significant impact.

Q323 Sir Robert Smith: Mr Williams has emphasised the benefits, in our domestic gas production, of balance of trade and of tax revenue in getting value out of the commodity in the ground in this country. Do you agree with what previous witnesses said this afternoon: that there may be over-excitement and misunderstanding in looking at the US effect? In an island without the export potential for gas and a lot of associated gas coming out with liquids production, the collapse in the gas price in the US is unlikely to read across as a consequence of shale gas taking off in this country?

John Hayes: Yes, I think a measured approach is necessary. It is easy to look at the United States and assume, without taking into account the important

differences I have tried to highlight today, that the effect there could be replicated here, both in terms of speed and volume. There is significant potential here. It is what this Committee has said, it is what the Government has repeatedly said and, indeed, I hope that has become clear today: it would be unwise to assume that what has happened in the States, in very short order, will happen here. The Government is moving ahead with enthusiasm but with appropriate caution. It is the desire to preserve with the willingness to improve, which I think Burke said was the mark of a statesman, by the way, Mr Chairman.

Q324 Sir Robert Smith: On that difference with the States, which you have alluded to already, you mentioned population density and the acceptability of developments for the local community. Do you think there is anything the industry should be doing to make sure that communities will be less hostile to this kind of development on their doorstep?
John Hayes: Yes, absolutely. I would expect businesses to play a full role in that kind of community engagement, and I made that very clear to Cuadrilla when they came to meet me. By the way, I think it is true across the whole range of different energy infrastructure investment, not just gas or shale gas in particular. We would expect good practice to be identified and shared. We would expect good businesses to engage in the communities of which they are a part.

Q325 Sir Robert Smith: In the US mineral rights are with the landowner, so they obviously get a share in what is going on on their doorstep. Do you see anything that the Government could do to make a community benefit greater than just compensation for disruption—one where they can actually see on their doorstep the economic benefit of what is going on?
John Hayes: It is something we are looking at in respect of nuclear new-builds, nuclear waste disposal and, as you know, onshore wind, where we will be responding to the call for evidence in due course. In a whole range of areas we are looking at the association between infrastructure investment and community benefit. It would be inconsistent if we did not do so in respect of shale gas. Sectors of the industry are looking closely at this too. The planning regime gives us some help here. As you know, it provides for community benefits from section106 agreements.

Q326 Sir Robert Smith: That is more on mitigating disruption.
John Hayes: You anticipated my next sentence. I was about to say that that is not entirely fitted to this kind of work, so, yes, it is something that we are considering closely and where further progress needs to be made.

Q327 Sir Robert Smith: Do you think there is scope for changing the mineral rights on a temporary basis at the start of production?
John Hayes: I am not sure I would go that far. I mentioned earlier that one of the differences between here and the United States is exactly as you described it. I described it as land ownership; you have described it as mineral rights. It would be an extremely radical change. I think there are other ways of achieving our ambitions.

Q328 Mr Lilley: Clearly, the speed with which we can go ahead with development does depend on the planning regime. It is necessary to get planning permission for these things. In the States the landowner owns the resource and therefore has an incentive to allow his land to be used, and to persuade the local planning authority to give all the planning permissions locally for pipelines and access and that sort of thing. In this country the community, through the Crown, owns the resource. Surely therefore we, the community, have an incentive to encourage the planning authorities to give approval and not to give any locality the right of vetoing the go-ahead. Can you confirm that they will not have the right of veto—that it will be normal planning procedures; that a local planning authority will only be to able to object if there are valid planning reasons to object to an industry like this being developed; and that they will not be able to concoct spurious safety fears that are dealt with at a national level?
John Hayes: Yes, the normal planning process will apply, but I do not think that that is inconsistent with the proper engagement with the community.

Q329 Mr Lilley: It is not, and we clearly need to. But in the States, at least some members of the community cream off the economic rent of ownership, and they have an incentive to persuade all their neighbours to let them do this, whereas here the whole community is going to get the benefit of ownership, or it should do if we have our structure, tax system and royalties right, and so on. We have an incentive to push ahead with it, not to say, "Let the people of Hitchin prevent it if they do not particularly want it to go ahead". As far as I know, there is no shale gas under Hitchin, but I hope there is. That is important. Secondly, is it not the duty of the Government, as the custodian and steward of all this resource, not to allow unwarranted fears and concerns to be propagated? Hasn't the moratorium of two years given a spurious credibility to the idea that there is something peculiarly dangerous about hydraulic fracking, when it is one of the most widely tested forms? Some 100,000 wells were drilled in the States, and not a single person has lost their life or been poisoned by poisoned water courses, or has seen gas come out of their taps as a result. Shouldn't the Government be putting forward the truth, rather than giving spurious credibility to fears generated by people who are just against development?
John Hayes: There are two distinct points there, Peter, and I will try to deal with them both. You are right, of course, that one of the disadvantages with the American model, in terms of mineral rights—to which Robert made reference a moment ago—is that only a few benefit. The mineral rights are owned by the landowner, and that is a very different arrangement to the arrangement that prevails in the United Kingdom where the mineral rights are in the ownership of the Crown. You are right, too, that it is important that communities do benefit more widely from this

opportunity. By the way, we have not spoken about it today, and perhaps we will have a chance to do so another time, but of course there is a benefit in terms of jobs and skills too, which should not be underestimated. That is one of the reasons that I think I suggested, in answer to the previous question, that I do not see a need to change the core assumptions about minerals rights that prevail here.

One of the points I made earlier, about the role of the new Office for Unconventional Gas, was that it was important that it played a role in dispelling some of the myths you describe, in countering misassumptions and misinformation. I think you are right. That will become more straightforward as this process is normalised. It is by its nature currently exceptional, and exceptional circumstances can alarm people. In terms of what you described as the peculiarities of some of the responses, peculiarity is a feature of the human condition, is it not, and without peculiarity humankind would be altogether more bland and rather boring.

Q330 Chair: Just directly arising from Peter's question, supposing we were concerned about a lack of enthusiasm for exploiting shale gas, and this Committee believes that it can be safely done, would there be an advantage, perhaps for a temporary period—a decade, say—to giving the landowner a direct interest in the profits to be generated from exploiting shale gas? That might be a way of kick-starting the whole process. I can imagine it would transform the views of some landowners if they thought that, instead of having some disagreeable development over their garden, they might be profiting very substantially from allowing it.

John Hayes: The difference between the United States and the United Kingdom, in those terms, is not only the difference around mineral rights; it is also around land ownership, which is why I described it thus earlier. Very often landowners own larger parcels of land, and if you look at the patterns of ownership in the United States around shale gas exploitation, people have often owned land that has contained a large number of wells. Given the topography of the United Kingdom, that would be less likely to be true here; not entirely unlikely, but less likely to be true. That would have a consequent effect on the advantages, the benefits that you just described, Chairman. Nevertheless, I think the issue of benefit and incentive is one that needs to be considered closely. There must be a sense in which the benefit from this is shared as widely as possible, as part of the normalisation that I spoke of when I answered Peter's earlier question.

In addition, one might say more information and more understanding—clearly the Royal Society of Engineers' report has been helpful, the Durham University study has been helpful, and, as things move on, I suspect provision of more information will lead to a greater degree of engagement. That engagement will lead to the kind of benefits you describe.

Q331 Chair: Nevertheless, one of the difficulties about planning and development in this country, generally, is that the costs are sometimes borne disproportionately by local communities. We have an active debate in my constituency about pylons going across beautiful parts of the countryside. The main beneficiaries of those pylons are electricity consumers in London, who are not really bearing much of the cost. In the same way we might see applications for shale gas development, where the cost was perceived to be borne mainly by the local community but the benefits, if it was owned by the whole community, are rather more dispersed.

John Hayes: Yes. I see all of life really through an aesthetic prism, and so I care about the beauty of the countryside, not least because I think beauty is the expression of truth by the way, but let us not get too philosophical. You are right: that balancing effectuates value perceived as an actual cost against result is critically important in these considerations. For example, that is why I mentioned jobs and skills a moment ago. People's engagement, as I described it earlier, is going to be about the wider benefit that they enjoy and the term of that benefit. This may go on for a considerable time, and so they have to see this as a long-term opportunity too.

Focusing on the specific point you made, though, there is an interesting issue here around landowners and the wider community. It would not be reasonable to see the community as the landowner. We have to take a rather more permissive view of benefit than that, I think. We are considering, as I mentioned a moment ago—I do not want to be too repetitive; I do not want to be repetitive at all, actually—a whole range of areas, new build nuclear, nuclear disposal, obviously renewables, so getting this right requires a consistent approach across a whole range of areas. I talked to you earlier about cross-departmental engagement. One area of cross-departmental engagement of course is planning. The Planning Minister would have an interest in these matters, as he made clear recently.

Q332 Chair: I know that aesthetic considerations have been important in helping shape your views about, for example, onshore wind turbines. If there were any eccentrics in Britain who felt as strongly against the aesthetic impact of shale gas exploration rigs—unlikely, but perhaps it is just possible they might—would they be given the same degree of protection against these developments by your public statements and by the planning system?

John Hayes: There are considerable differences between different kinds of infrastructure, not least how permanent or temporary that infrastructure is. One of the arguments that is often made about shale is that, because of the nature of extraction, you drill a well and you exhaust that well much more quickly than we are used to. North Sea oil and gas is a good example. So these things do have to be considered on a case-by-case, type-by-type basis, for that sort of reason and in many other instances too. Certainly it is true that the debate across Government, around the character of landscape and townscape and around aesthetics, needs to be one that we have more confidently.

Q333 Dan Byles: There are a couple of points on this, but I find this fascinating. I find the similarities with some of the arguments about onshore wind very interesting. Minister, would you agree that the evidence, through our experience of onshore wind, is that the landowner benefiting does not necessarily lead to wider community acceptance? In fact, quite often, the farmer who is perceived to be making the money from the wind turbine, for example—you do not see neighbours thinking, "Good old Jack, he is making money, so I will not oppose this". On the contrary, it often leads to greater resentment and greater community splits. It is not as simple as just saying that if the landowner benefits, the community will be more appreciative.

John Hayes: To say anything about onshore wind specifically, ahead of our response to the call for evidence, would be unwise and premature.

Dan Byles: I will not tempt you, then.

John Hayes: You are right that the debate about community benefit has to be a debate not only about utility but also about aesthetics. I make no apology for the advocacy of the proper and proud consideration of beauty in all we do. Why would we apologise for that? The Chairman has put it rather more practically. He spoke about the calibre and quality of the landscape and the countryside. Many people make that argument. You have heard it made to this Committee. It is important that the Government is conscious of that and sensitive to it.

Q334 Dan Byles: Just sticking there with the point about the difference in land ownership between the US and the UK, it is often highlighted as a reason why perhaps it might be harder to exploit shale in the UK. Do you not think, Minister, that there is an argument that it might be the other way round: that if you look at an aerial photograph of Pennsylvania, there is a shale pad every half mile, and the reason is that every farmer has sold his bit of shale to a different company? Whereas, because in the UK we do not have the same land rights, a single shale pad can hoover up a much larger radius of shale, so that in some ways, particularly given the thickness of the shale in the UK, we might see much larger extraction rates per individual pad in the UK than we have been seeing in the States.

John Hayes: That is an interesting argument, so I will let Simon answer. Before he does so, I will add to it if I might. There is also an argument that the character of the geology might be beneficial in the United Kingdom. It could be, for example, that thicker shale leads to a greater flow. It may be that the permeability here is different and, indeed, that that might—as you have described it—make some of what is done here even more productive. That is speculative. It is early days, but I would not want to assume that all the circumstances in Britain are disadvantageous in terms of the exploitation of this resource.

Simon Toole: I would agree that in the States sometimes the density of pads is the result that very few wells are drilled from each of those pads, and that is the way the economics works in the States. You can afford to do that. Here in the UK it is much more likely that there will be fewer pads per area developed, but many more wells sitting on each pad. Your point about the thickness of the shale is also true. It is very unfortunate that some of the aerial photos from the States, showing almost a bomb pattern of well sites, is what is assumed will happen here in the UK. I feel pretty sure that will not happen. It will be focused on fewer pads, with higher densities of wells within the area of a football pitch.

Q335 Chair: If we succeed in developing the shale gas industry, is there a risk that that might encourage a faster dash for gas in the next few years and that in the long term, after 2030, that might leave us with some stranded assets and we face possibly even decommissioning costs for gas-fired power stations?

John Hayes: I have heard that argument put. I think it is possible that the exploitation of shale, with the consequent effect on price, might change investor assumptions about energy production. I have already made it clear that I think the first effect of that would be likely to be on other gas. I think there would be a parallel effect on coal. We have seen that in the United States, and of course, in a sense—if I might put it that way—already it is going with the flow to some degree. Sorry for the use of words. I think it would be premature to suggest much more than that. The nature of the gas generation strategy makes it clear that we need further gas investment, not only to fill the gap in meeting our energy security needs in the medium term, but also to replace existing infrastructure. I would not take the view that stranded assets, as you put it, would be the likely effect of this. I think it would be more likely that we would achieve our ambitions through additional means, and those additional means would be the provision of a domestic supply of gas in the form of shale gas.

Q336 Chair: An air of uncertainty about shale gas concerns methane emissions. I understand that DECC is planning to carry out some research on that. Can you tell us when that may be completed?

John Hayes: Yes; I will ask Simon to talk about that. I am sure you will come to it in a moment, but the two principal arguments that have been put by the sceptics are around methane and the effect on the water supply. Of course we consider those matters very seriously. Our further work will come to a conclusion in the spring, in April or May. We are more than happy to make that available to the Committee as soon as we have it, in advance of publication. The evidence from America is that some of the claims made about methane are exaggerated, but let us wait to see what our own study reveals.

Q337 Chair: One means of unlocking the full potential of our gas reserves—and hopefully those will turn out to be substantial—would be if we successfully developed carbon capture and storage of gas. Given that that would bestow such an enormous advantage, do you feel that we are putting enough emphasis on CCS in our overall strategy?

John Hayes: We have a £1 billion competition, which you are familiar with, Chairman. In that competition, we are pursuing projects that are gas-based and coal-based. If the success of those projects is such that we

can move to commercial viability quickly, you are right that it will be a saviour in the strategy. I am a great enthusiast for carbon capture and storage. Getting the technology right, of course, is the first step, but then ensuring that the scale is sufficient to build a commercially viable industry is the second. It would allow us not only to satisfy our ambitions in respect of emissions, while maintaining our investment in gas—directly related to this inquiry, and what I understand is going to be your further inquiry on gas, which I heard about today—but it would also allow us to maintain an interest in coal. We should not ignore the potential of clean coal in those terms. I would be delighted if, as a result of the success of carbon capture and storage, I could be the Minister that brought coal to the Coalition.

Q338 Chair: You mentioned the £1 billion. Could you give us an update on whether that money might be awarded to one of the projects currently shortlisted? It has been going a long time, this whole process, and there has been some frustration about the enthusiasm of the industry.

John Hayes: The outcome is likely to be that we support one or more of the projects, but it would be very inappropriate for me to comment on specifics, given that the competition is ongoing. You will know that we have reduced the number we shortlisted, and, as I have already mentioned, those shortlisted projects include both coal and gas projects. My officials are talking to people involved in the projects, to ensure that we have worked to the best effect, but until that comes to a conclusion I think it would be inappropriate for me to say much more. Except this, actually: that I have had discussions in Europe to ensure that any support that the EU offers—and there is a chance of further EU support this year—is mindful of what we are doing. We would like to take advantage of any further funding opportunity from the EU, and I have initiated discussions to that effect.

Q339 Chair: We have come to the end of our questions about shale gas. Could we just trespass very briefly on your good will? Robert would like to ask a question about the Brent pipeline.

Sir Robert Smith: Yes. Obviously, there is a commonality with the oil leak that, fortunately, has not involved any life-threatening situation and has not impacted on the environment because it is contained in the line. It has led to the shutdown of the Brent pipeline. I wonder if the Department had any observations on that.

John Hayes: Yes. You will know the details. They have been widely publicised, Robert, in the media and elsewhere. We are pleased the incident was discovered quickly, of course, and it has been dealt with robustly. You will know that non-essential personnel have been removed from the Cormorant Alpha installation, where there has been no release of oil or chemicals into the sea, as far as we are aware, so there seems to be no pollution impact. In terms of the overall impact, we would expect the temporary closure to affect something between 5% and 7% of oil production and 2% or 3% of gas production. That gives you some idea of the scale. It is too soon to say when the pipeline will reopen, but we are pleased that the operator has taken swift action to investigate the cause of the leak, and, as I say, these things have been dealt with promptly and efficiently.

Would it be helpful, Chairman, if, as soon as I do know more, I inform this Committee? I am more than happy to do that if you feel that that would be helpful.

Chair: That would be much appreciated.

John Hayes: I would be delighted to do that. I firmly commit to advise the Committee with appropriate speed as soon as we know more.

Q340 Sir Robert Smith: I suppose it is an important reminder of just how dependent we are on old infrastructure for the hubs and export potential for future developments, and how crucial it is to make sure investment in integrity is maintained.

John Hayes: Yes. I understand that the reason why 25 different pipes are affected is that the interconnections are around the pumping capacity, which, as a result of the closure, has been taken out of the system. As I say, in percentage terms it is significant, but a small part of production. I do not know if Simon wants to add to that?

Simon Toole: No. You have covered all the points.

Chair: Thank you very much. As ever, you have been very generous with your time. It has been very interesting for us, and we look forward to seeing you again soon.

Written evidence

Written evidence submitted by the British Geological Survey (ISG 17)

SUMMARY

Estimates for the amount of shale gas are variable both for parts of Britain and for Britain as a whole. Estimates for other parts of the world also vary. This reflects the difficulties of precise resource or reserve estimation in the early days of shale gas exploration and production.

In simple terms the resource estimate is the amount of gas in the ground (some of which might never be accessible), while the reserve estimate is a more sophisticated measure which describes the amount of gas that you might be able extract given economics and other factors. The recovery factor is a measure of the proportion of the total gas resource that can be extracted and is often expressed as a percentage. The recovery factor is a function of geological, economic, cultural, logistical and other factors. The recovery factor is likely to fluctuate, with a tendency to increase with time, particularly as experience and technology improves or public acceptance increases. US recovery factors are typically around 10% but it is too early to be sure of British recovery factors.

It is possible that prospects for shale gas are better offshore than onshore in the UK. This is because the sedimentary basins and the deep structures where gas is generated are larger offshore, for example for the gas-bearing Kimmeridge Clay and Carboniferous formations.

Question 1. First Part: *What are the estimates for the amount of shale gas in place in the UK, Europe, and the rest of the world?*

1.1 Introduction

Variations in potential shale gas yield as implied by figures released by DECC, oil and gas companies and other organisations have caused confusion in the media and amongst the general public. Occasionally this has resulted from reserve figures being confused with resource figures (Table 1). In simple terms the resource estimate is the amount of gas in the ground (some of which might never be accessible), while the reserve estimate is a more sophisticated measure which describes the amount of gas that you might be able extract given economics and other factors. The recovery factor is a measure of the proportion of the total gas resource that can be extracted and is often expressed as a percentage. To some extent the ability to obtain reserve or resource figures is determined by the stage of exploration and degree of production uncertainty. Gas in place (GIP) or Gas Initially In Place (GIIP) figures are normally derived for an exploration licence area, perhaps even before drilling takes place, for the benefit of shareholders and investors. These values often find their way into the media. When substantive data from drilling becomes available, more reliable figures for reserves and resources can be calculated. But if few wells are drilled there is a risk that the data they reveal are considered representative of large undrilled areas. A third measure of the amount of gas is the concept of "technically recoverable resources" (Table 1) which the agency Advanced Resources (2011) has used to determine how much gas is likely to be extracted. Various recovery factors have been used and Advanced Resources (2011) lists a few of the considerations made in selecting these factors. Technically or economically recovered resources will fluctuate in time according to technological advances and prices.

Table 1

TERMS USED IN SHALE GAS ESTIMATION

Terms for resources and reserves	*Term*	*Acronym*	*Summary*	*Excludes*
Resource	Original gas in place	OGIP	Total volume of gas	
"How much	Gas (initially) in place	GIIP/GIP	Total volume of gas	
gas is in the ground"	Ultimately recoverable		Total recoverable volume	Gas not expected to be recovered
	Technically recoverable		Limited by technology	Ditto, as well as gas not recoverable with current technology
	Economically recoverable		Limited by economics	Ditto, as well as gas not economic to recover
Reserve	Reserves		Total producible gas	Ditto
"How much	Proved reserves	1P	Probability of reserves (proven)	Probable and possible reserves
gas could be extracted"	Median figure of reserves	2P	Proven and probable	Possible reserves
	High figure of reserves	3P	Proved, probable and possible	

Note: In the US, technically and economically recoverable resources are known as "contingent resources", contingent on for example a high gas price.

1.2 United Kingdom estimates

1.2.1 BGS estimates for DECC in 2010

(see DECC. 2010. http://og.decc.gov.uk/assets/og/bo/onshore-paper/uk-onshore-shalegas.pdf)

BGS used a comparison method to calculate potential shale gas yield in different parts of Britain. For example by comparing the shale gas production per unit area of land in the US Carboniferous Barnett Shale of the Fort Worth Basin, Texas, a figure of 4.7 trillion cubic feet (tcf—equal to 132 BCM) was suggested as an approximate reserve figure for the Upper Bowland Shale of the Carboniferous Pennine Basin (DECC 2010). Similar methods were applied to southern England basins and the Cambrian shales of central England but not Wales, Scotland or Northern Ireland. The approximate reserve figure for these shales was estimated at 5.3 tcf (150 BCM). No UK drilling had taken place at the time of this estimate, and so the BGS figures were necessarily defined as tentative. Unfortunately commentators have subsequently quoted the estimates without reference to their tentative nature.

The other widely publicised estimate for Britain's shale gas resource is that of Advanced Resources (2011) which listed 97 tcf GIP and 20 tcf recoverable resources for the UK (using a relatively low 21% recovery factor). We are not aware of the precise method used by Advanced Resources (2011) but we assume that the lower recovery factor (in relation to other countries), was probably derived from an estimate of the influence of the UK's high population density which would restrict exploitation.

1.2.2 Resource estimates for parts of the UK

We presume the following released figures represent Gas in Place (GIP). In most cases calculation methods used are not revealed on company websites, where figures are displayed. Understandably websites are the preferred means for informing investors and shareholders of the values of potential assets, and therefore do not attempt to give the detailed scientific derivation of the GIP figures. Note that the estimates below do not cover all of the prospective shales identified previously (see Smith et al, 2011; DECC 2010), because these areas have not been explored and licences have not been awarded.

1.2.2.1 Cuadrilla's Lancashire licence

The UK shale gas company Cuadrilla drilled two wells in 2010–11 (Preese Hall and Grange Hill) from which (we presume) the company derived gas content values for shale and figures for the thickness of shales. We assume that they extrapolated these values over their 1200 square kilometres licence area. The resultant figure for their licence area was 200 tcf GIP (Cuadrilla 2011).

1.2.2.2 IGas licences in NW England

Before drilling in IGas acreage in the North West of England the company firstly suggested shale GIIP of c.800mmboe. The company IGas recently drilled the "Ince Marshes-1" well and changed this initial estimate to c.1,600mmboe (millions barrels of oil equivalent) (IGas 2012). The latter figure is equivalent to 9.23 tcf. The exact area of NW England that this figure applies to is not known, as this company has offshore licences also. This reason for the revision of GIIP figure relates to pre-drilling calculations and an upward revision with data from the above well (relevant also to Question 2).

1.2.2.3 Eden Energy/UK Methane

Eden Energy reported the following figures for Namurian age shales for their 7 licences in South Wales (Eden 2012): "Volume of Gas Initially in Place (GIIP)—34.198 tcf and Recoverable Volume—12.799 tcf of gas". It is not known what data was used to produce these figures, but the expected percentage recovery (37%) is higher than predicted for all US shales.

1.2.2.4 Dart Energy

Dart Energy took over Composite Energy in 2011, which had several licences in Scotland (PEDL 133) and England (Cheshire Basin and Gainsborough Trough), previously targeted on coalbed methane. Evaluations of shale gas provided figures of Original Gas in Place (OGIP) of 65.56 tcf, including 0.7 tcf in PEDL 133. An OGIP of 12 tcf is also recorded on their website and it is not clear whether these figures might apply to European licences also (Dart Energy 2012). No new well data was available on these licences.

1.3 Europe

Technically recoverable resources for the whole of Europe were calculated at 2587 tcf GIP and 624 tcf recoverable (Advanced Resources 2011; with a 24% recovery factor).

1.3.1 Poland

Poland has been assessed as possessing 792 tcf GIP and 187 tcf recoverable (Advanced Resources 2011; 24% recovery factor), but this was revised down by the Polish Geological Institute (PGI 2012) to 346–768

billion cubic metres (BCM, 12.2–27.1 tcf). PGI (2012) also admitted that not all the relevant data were available on Polish shales and that figures derived from comparison with US shales were used.

1.3.2 Germany

In Germany the Federal Institute for Geosciences and Natural Resources (BGR) reported that between 0.7 trillion and 2.3 trillion cubic metres of gas (24.7–81 tcf) could be technically extracted across the whole country. This represents a 10% recovery factor achievable from the 6.8 -22.6 trillion cubic metres of shale gas resources (240–798 tcf). Advanced Resources (2011) previously estimated 33 tcf GIP and 8 tcf technically recoverable (24% recovery factor) for Germany.

1.3.3 Austria

In Austria oil company OMV has suggested a potential recoverable shale gas resource of 15 tcf in the Vienna Basin, from an in-place resource of 200–300 tcf. Their recovery factor is about 6%.

1.3.4 Netherlands

In the Netherlands, TNO's (the Dutch national geological survey) estimate for producible gas in place in high potential areas is 198 tcf from an estimated gas in place resource of 3,950 tcf. Their recovery factor is about 5%.

1.4 Outside Europe and global estimates

In the first assessment Rogner (1997) estimated total global shale gas at 16,112 tcf GIP including the Middle East and former Soviet Union. Advanced Resources for the US Department of Energy (2011) made estimates for the majority of the world's shale gas basins but excluded Russia and the Middle East because they assumed that their conventional reserves would limit their need for unconventional production in the short term. Advanced Resources (2011) found a cumulative total for 33 countries of 25300 tcf GIP with 6,622 tcf recoverable (26% recovery factor, Advanced Resources 2011).

Argentina is estimated to have 2732 tcf GIP and recoverable resources of 774 tcf (Advanced Resources 2011, 28% recovery factor). Chevron is drilling, and YPF recently stated it has made a second discovery there.

China estimated (in 2012) that its reserves were 25.08 trillion cubic metres (tcm = 886 tcf) from resources of 134.42 tcm (= 4747 tcf; Bloomberg, 2012). China's exploration of shale gas is still at an early stage, and the 12th Five-Year Plan period (2011–2015), targets an output of 6.5 billion cubic metres per year (0.229 tcf). The recovery factor applied is 18.6%. Advanced Resources (2011) estimated 5101 tcf GIP and recoverable resources at 1275 tcf (25% recovery factor).

South Africa, which recently lifted its ban on hydraulic fracturing, has 1834 tcf GIP and reserves of 485 tcf (Advanced Resources 2011, recovery factor 26%); or 450 tcf (report for Shell, 2012, probably reserves).

Question 1. Second Part: *What proportion is recoverable?*

The recovery factor is a function of geological, economic, cultural, logistical and other factors associated with obtaining gas from shales. The recovery factor is likely to fluctuate, with a tendency to increase with time, particularly as experience and technology improves or public acceptance increases. It is worth noting that the USA has a long history of onshore conventional hydrocarbon exploration and production, and relatively high levels of public acceptance (due in part to landowner benefits). UK landowners do not directly benefit from onshore oil and gas and the UK public in general is less familiar with energy from this source. Often after initial hostility in the exploration phase, onshore production becomes acceptable as part of the landscape. At the Wytch Farm conventional oilfield in Dorset, for example, underground oil deposits have been accessed which extend under an Area of Outstanding Natural Beauty and sensitive wildlife reserves in Poole Harbour.

Both resource (Cuadrilla 200 tcf) and approximate reserve (DECC 4.7 tcf) figures for the Pennine Basin (see above) may turn out to be correct. But final figures of this order would suggest a recovery factor for the Upper Bowland Shale of 2.35%. US recovery factors are typically nearer 10% and higher. In the US, where horizontal drilling and hydraulic fracturing has been established for about a decade, the ultimate productivity (in other words the absolute yield of the shale) is not known (INTEK, 2011). In the USA 862 tcf of technically recoverable resources was calculated, including 35 tcf of proved reserves (INTEK, 2011). Improvements in completion and drilling will, no doubt, lead to higher recovery factors.

Question 2. *Why are the estimates for shale gas so changeable (different)?*

Before UK drilling results were available, figures based on comparison with US shales, where production already existed, were provided for DECC by BGS (DECC, 2010). These were approximate reserve figures, based on US shales in production. GIP or GIIP figures provided by companies during exploration phases in the UK were essentially resource figures. As discussed in Question 1 and Table 1, reserves relate to what could be produced given economic conditions whereas resources are the total amount of gas present.

US shales have very variable characteristics, and it is likely that British shales will be similarly variable. Prior to targeted drilling this variation may not be known in detail. Variations in permeability and gas content

and type are likely to occur within or between basins but need to be assessed by direct measurement from inside wells and from cores of rock extracted from the shale. Even when drilling data are available, wells do not necessarily drill through the full section of prospective shales, which may vary in thickness within and between licences. Compared to conventional hydrocarbons which are found in discrete, mappable structures and discovered by a few wells, unconventional hydrocarbons extend over larger areas but may be limited by changes in characteristics that cannot be quantified by a few wells.

What this means is that it is likely that estimates for reserves and resources will likely change for many years to come.

Factors other than geology are also important: the economics of gas has been transformed and the gas price lowered in the USA, by rapid discovery success, reducing the profitability of some marginal shale prospects. This might affect how much of a shale basin is economically prospective.

Question 3. *What are the prospects for offshore shale gas in the UK continental shelf?*

It is possible that prospects for shale gas are better offshore than onshore in the UK. This is because the sedimentary basins and the deep structures where gas is generated are larger offshore, for example for the gas-bearing Kimmeridge Clay and Carboniferous formations. The Pennine Basin which contains shale gas-bearing Carboniferous rocks extends westwards under the east Irish Sea towards the Dublin Basin in Ireland (Figures 1 and 2). Similarly it extends eastwards beneath the Southern North Sea towards the Netherlands.

The BGS is not aware of any offshore assessment for shale gas. We believe that companies are already considering the option of shallow coal-bed methane (gas from coal seams) offshore in the UK, but only in a few licence areas. These companies may be unwilling to share their experience at this relatively early exploration stage. Advanced Resources (2011) specifically excluded offshore areas and those parts of basins which extend offshore from their global study. The US has no need to look offshore because of the plentiful production onshore. It is likely that the offshore option has been ignored because the successful US shale gas exploration model does not include the offshore and because offshore costs are considered to be higher. Even if offshore costs can be reduced by complementary drilling from existing offshore (conventional hydrocarbon) facilities or drilling deviated wells from onshore, there are a number of other logistical and operational hurdles to overcome. These include different onshore and offshore licensing regimes and issues relating to the use of seawater as hydraulic fracturing fluid. On the other hand, perceived environmental problems and land access problems will likely be less offshore compared to onshore, for example in Lancashire and Sussex.

If the offshore is economically prospective for shale we anticipate exploration in areas offshore from the Weald Basin (Kent and Sussex) and the Wessex Basin (Isle of Wight and Dorset). Other areas include the Central and Northern North Sea along the median line and west of Shetland, where Upper Jurassic source rocks are present. Carboniferous strata are present offshore in the Solway Basin (offshore Carlisle), offshore from the Midland Valley of Scotland, and in the southern North Sea and east Irish Sea Basin. BGS is considering a project to analyse the feasibility of offshore shale gas in the east Irish Sea Basin.

The east Irish Sea Basin lies off the NW coast of England between the north Wales coast and the Isle of Man (Figure 1).

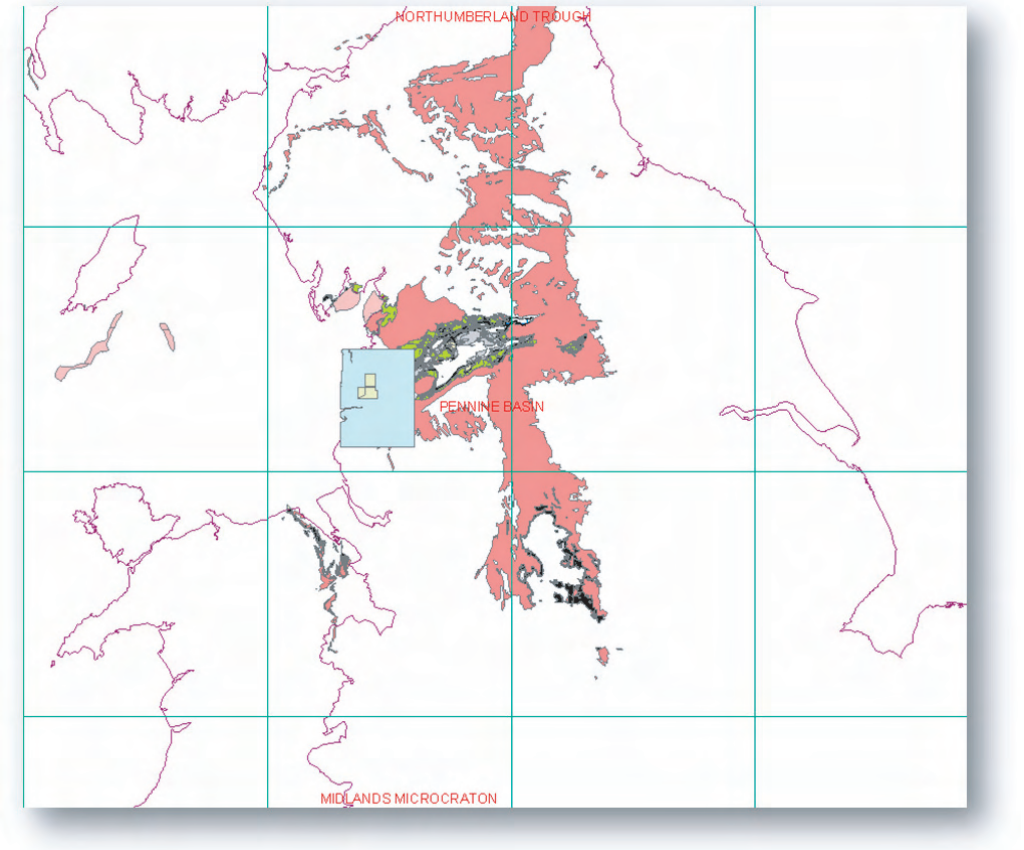

Figure 1 Red indicates the outcrop of the Carboniferous (Namurian) shale onshore. The pink areas indicate Namurian shale outcrops at the seabed. Although Namurian shale outcrops only in small areas at the seabed, it is present below much of the east Irish Sea under the seabed. The green and blue rectangles are licence blocks.

A number of conventional fields (eg the Morecambe Gas Field) were discovered in the centre of the basin and have supplied gas since 1985 and are expected to be exhausted in about 40 years. More recently the company Hamilton discovered a line of fields off the North Wales coast, with production beginning in 1996 (Figure 2).

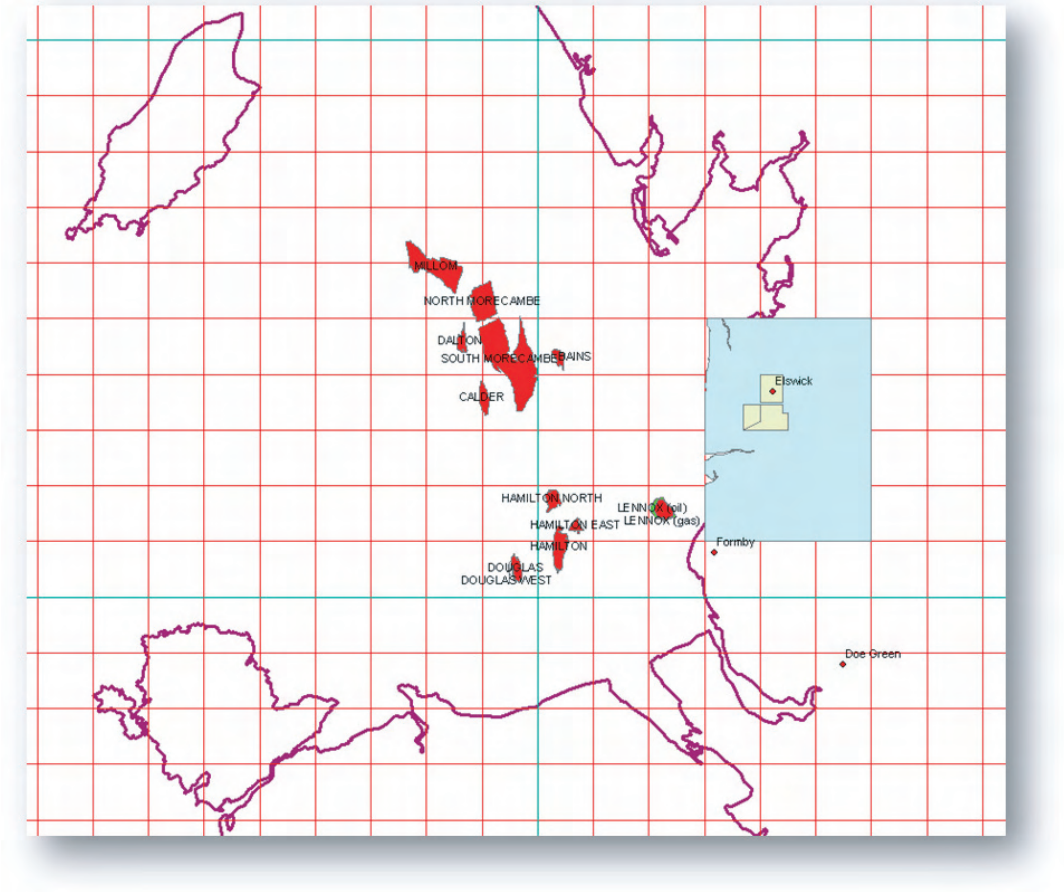

Figure 2 Morecambe and Hamilton gasfields in the East Irish Sea. Their extents indicate the absolute minimum prospective area of Namurian shale in the East Irish Sea Basin because the gas they contain is probably from shale located directly below. The green and blue rectangles are licence blocks.

The source rock for these hydrocarbons is likely to be Carboniferous shale because there are relatively small areas of Coal Measures at depth (the source rock in the southern North Sea) in the basin. The extents of the gasfields indicate the absolute minimum prospective area of Namurian shale in the East Irish Sea Basin because the gas they contain is probably from shale located directly below. The shale prospectivity of the east Irish Sea Basin, which has an area in excess of 6000 km^2 is not known because the geology is insufficiently mapped, but using Cuadrilla's figures on their adjacent onshore acreage (200 tcf/1200=0.17 tcf/km^2) a tentative resource of 1000 tcf is suggested.

Seawater hydraulic fracturing may be possible offshore. Although there is existing infrastructure offshore in the form of drilling platforms it is probably too early to expect these to be used, but deviated drilling from the onshore may be possible. BGS is planning an investigation of the feasibility of offshore shale gas accessed from the coast by deviated drilling from the Lancashire coast.

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October 2012

Supplementary evidence from Nigel Smith, British Geological Survey (ISG17a)

QUESTIONS NOT ANSWERED OR ANSWERED FULLY AT THE COMMITTEE MEETING 271–12–012

Question not appearing in transcript:

Fracking using gas? (question from Mr Lilley)

Answer:

Yes it is possible. Fracturing in the US Appalachian shales has evolved from nitroglycerine or judamite up to the early 1970s, water fracturing (aka light sand); then to nitrogen-based foam fracturing (lower water content) and to nitrogen gas fracturing (eg. in Tennessee). Liquefied gelled petroleum is also an alternative to massive hydraulic fractures and slickwater fractures. Liquefied carbon dioxide might also be effective because it could combine sequestration of climate-changing CO2 with displacement of valuable oil in shales.

Question 52 Albert Owen: Are you happy that the people who work in the North Sea now and the companies could quite easily switch over to shale from the conventional gas that they have been experts in for many decades?

To add to 'No'

Many of these people are still needed for work there or on conventional hydrocarbons elsewhere. The onshore has been alien territory to quite a few companies, particularly the larger ones and they also were slow to appreciate the breakthrough made in shale gas in the US, so I would say the great knowledge of shale gas has not been vested with the conventional large company explorers. They have now bought in or taken over companies with expertise and this may continue if success is forthcoming in Europe. Hydraulic fracturing whilst undertaken offshore in conventional reservoirs has not perhaps needed to be fine tuned to different and difficult formations and the geochemistry of source rocks had become a moribund discipline as the North Sea matured and everyone knew the source rocks were Kimmeridge Clay (for the oil) and coals in the Coal Measures (for the gas). Other shales were just the cap rocks to the fields. So I don't think the expertise is necessarily appropriate to move.

Written evidence submitted by Cuadrilla Resources (ISG 15)

This is Cuadrilla's response to the call for evidence by the Energy and Climate Change Select Committee on the impact of shale gas on energy markets. We welcome the opportunity to discuss the potential for shale gas in the UK and in Europe. While much of the future impact of shale on energy prices is hard to predict, we are keen to make the case for UK shale as a potential valuable contributor to the UK's future energy mix.

EXECUTIVE SUMMARY

Cuadrilla's team consists of highly experienced shale gas explorers and engineers, integrated with a risk management team and process that works with regulators and communities to manage and minimize health, safety and environmental issues. We adopt a structured and robust approach to identifying, assessing and mitigating potential health, safety and environmental risks. We are committed to ensuring that all stakeholders across Government and Parliament, along with the general public are fully informed about the practice of shale exploration, development and production in the UK. We understand the need for transparency and openness and endeavour to adopt this ethic at all stages of the process.

Cuadrilla is focused on the geological, engineering and social challenges of exploring appraising and developing tight gas and oil reservoirs in Europe. Our focus is to demonstrate that shale gas in the UK can be

developed safely and sensibly in an environmentally responsible manner. As such, we are very interested in, but not necessarily the authorities on, the potential wider economic impact of shale gas on the UK economy.

It is apparent from our exploration and appraisal of the Bowland Shale formation in Lancashire that the UK has a very large amount of onshore gas in place. Our prior estimate for gas in place (OGIP) in the Bowland licence area alone was 200 TCF. We will review this estimate after further analysis of the 3D seismic survey we completed over the licence area, as well as analysis of data from the next well, which we are drilling at the Anna's Road site near Blackpool.

It is clear to us that the UK shale gas industry could provide tangible benefits to the UK in terms of 1) enhancing energy security, 2) reducing import dependency, 3) potentially lowering the cost and price volatility of energy to consumers, 4) reducing greenhouse gas emissions, and 5) job creation and economic contribution. By being the early mover, outside of the US, the UK could be at the forefront of an emerging global industry and set a world class standard.

The UK currently has a first-mover advantage in Europe, while being able to rely and improve upon expertise developed in the United States. However, the full potential for shale gas in the UK is still yet to be determined. This is largely due to the fact that it has not yet been properly commercially tested in this country and has yet to become an accepted norm for energy production by the British public.

Cuadrilla's ambition is to set a standard of operational and social excellence for other Shale operators to work towards in the future, and we are continually investing to ensure that remains the case. We believe the operating practices and models of regulatory and community cooperation we are developing will be replicable by other operators.

Response to Inquiry

1. *What are the estimates for the amount of shale gas in place in the UK, Europe, and the rest of the world, and what proportion is recoverable?*

1.1 Cuadrilla believes that the prospects for shale gas in the UK and in parts of continental Europe are very promising, based on assessments of a number of geological formations that are not dissimilar in scale to US and Canadian sites where major deposits of natural gas have been discovered.

1.2 While the full economic benefits of shale gas have not yet been fully ascertained, based on prior estimates and research, we believe there are at least 200 trillion cubic feet (TCF) of original gas in place (OGIP) in the Bowland basin. We will review this estimate after further analysis of the 3D seismic survey completed over the licence area, and analysis of data from the next well, which we are drilling at the Anna's Road site near Blackpool.

1.3 The recoverable reserve is a function of shale geology and as much, if not more a function of the number of horizontal wells that can be drilled and fractured. However, this in turn depends on the economic and social constraints of such development. Our exploration has shown that the Bowland shale in Lancashire is significantly thicker than any comparable US shale. This opens the possibility of developing with a much lower-density surface "footprint" than US shale plays.

1.4 Cuadrilla understands that economies of scale and advances in technology will drive down development costs over time and that recovery estimates of 15 to 20% may in time prove to be conservative. Furthermore, a recovery factor of even 15% would yield a reserve of some 45 TCF from the Bowland shale alone. This is some five times larger than the UK's booked gas reserves of 8.7 TCF (proven reserves), and almost double the 25 TCF at a maximum (proven + probable + possible). (Source: DECC —UK Gas Reserves and Estimated Ultimate Recovery 2012)

2. *Why are the estimates for shale gas so changeable?*

2.1.1 Estimates for mineral resources have always been dependent on the technical ability, at time of estimate, to both make assessments of and extract the resource. For example, while the resource itself remains the same, our ability to comprehend how much is there and what is viable to extract on economic grounds does change. Oil and gas fields are never abandoned because they have run out of oil and gas. It becomes a question of the economics of extracting the remaining reserve. Therefore, we believe a more appropriate question could be: why is the estimate for *recoverable* shale gas so changeable?

2.1.2 Estimates of recoverable shale gas are changeable because in addition to the technical and economic factors discussed above, the regulatory and socio-political context carries a much greater degree of uncertainty. Each of these factors impacts in its own way on the amount of shale that can finally be recovered. Technological improvement, better well design, multi-well strategies, greater political support and public confidence borne out of successful, incident free, operations all impact positively on recoverability.

2.1.3 The experience of the shale gas industry in North America is that improved knowledge, a product of continuous technical development and operating experience, leads to better recovery and some mature shale plays now have recovery estimates of up to 40%.

2.2 The technical context of recoverability

2.2.1 The technical limitations depend upon subsurface shale characteristics; the well deliverability, operational issues such as the pace of new drills; and the industry's capacity to field rigs, fracturing equipment and crews. These factors in particular are what distinguish onshore shale gas extraction from the conventional deposits offshore.

2.2.2 The most important factors for determining whether shale gas is present and the scale of the resource is dependent on (1) the thickness of the shale; (2) the natural fracture intensity (high fracture intensity allows for increased production rates and recoverable reserves); (3) the "frac-ability" meaning how brittle and easily the rock will crack; (4) the structural setting (extensional, compressional or strike-slip); (5) the total gas volume; (6) the amount of carbon remaining in the rock or total organic content (TOC); (7) the temperature and depths of the shale reserve; and (8) the reservoir pressure and its stress regime. All these factors and others interrelate in potential recoverability.

2.2.3 Shale is usually rendered by artists as a series of coherent horizontal layers. Overall this is a fair picture, but the reality under the ground is much more complex as the layers themselves have been disturbed by sedimentation and the displacements of fault lines in the subsurface. In the UK, Cuadrilla's geoscience team has recently completed a major 3D seismic survey in the Fylde with the specific objective of accurately mapping this subsurface complexity. But even the best seismic view is only indicative. Recovery of shale is the product of continuous operating experience coming from both appraisal and production drilling. We drill horizontally, but the process of finding and "surfing" the best layers takes investment and experience.

2.2.4 There is a limit to the skills that can be imported. At the end of the day, development of UK shale will require the experience of an industry that has learned about our own particular shale sequences through empirical study. Some three hundred wells were necessary to learn how to optimise development of the Barnett shale in Texas. Recoverability depends on investment and continuous experimentation with the geology.

2.3 The development context of recoverability

2.3.1 Individual shale gas wells typically decline in production rapidly in the first year or two, then attenuate gradually as they continue to produce gas at lower rates for the next 20 or more years. Maintaining or growing production therefore depends on on-going drilling to penetrate the layers of shale and creating the sub-surface area through fracturing that allows the gas to escape.

2.3.2 In the case of onshore shale development, on-going drilling of new wells does not mean populating the countryside with ever-increasing drilling locations. Horizontal wells can radiate from the same well bore like the tines of a fork, and radially in several directions. Because, as we said above, we have learned the Bowland shale is unusually thick, this can be repeated at different vertical levels, so called "vertically stacked" horizontal wells. One pad can manage around 36 such horizontal wells, using present day technology, and as technology evolves, more in the future. Each horizontal well is equivalent to a piece of keyhole surgery. The "drill" is a remotely controlled turbine whose position may be two kilometres down and three kilometres away, but whose location is always precisely known. The horizontal wellbore is comparatively narrow, about eight inches in diameter. All fractures are typically thousands of feet below aquifers. Above the Bowland shale formation in Lancashire lies the Manchester Marl, a thick impermeable rock forming the "regional seal", a barrier between the hydrocarbons trapped in the Shale rock below and the aquifer a further several thousand feet above. A lot of development can thus take place from a single pad —hence our view that the UK offers a low-density development opportunity.

2.3.3 Shale gas operations need to be commercially viable in order for them to be practical. Therefore, it is necessary to take into account development costs, market prices from gas and other liquids and other financial incentives and burdens. Importantly, the industry needs the efficiency of a small number of pads as much as citizens require it.

2.4 The regulatory and environmental context

2.4.1 The UK has a strict regulatory framework governing offshore and onshore oil and gas exploration and production, and this also covers onshore shale gas operations. Any associated risks with shale exploration are heavily regulated and closely scrutinised by the relevant independent bodies. With proper management risks should be minimal.

2.4.2 There is a stringent licensing and planning approval process for all stages of exploration and the surround environment highly safeguarded. Cuadrilla is committed to working closely with the regulator, DECC, HSE and DEFRA. The planning process itself requires approval from the Environment Agency in order to ascertain that the impact to the local environment will be minimal. A licence for exploration is also required from the Department for Energy and Climate Change alongside permission from the Health and Safety Executive prior to engaging in any drilling operations.

2.4.3 Cuadrilla also implements a number of precautionary steps to manage any potential risk of water contamination. We consider it exceedingly unlikely that hydrocarbons or fracturing fluid could leak into shallow aquifer water as a result of the fracturing process.

2.4.4 Regulation of course continually evolves over time in all industries and all countries with the objective of becoming ever more effective and more efficient ie regulating the right things the right way. Cuadrilla plans to be an active partner with the UK Regulators in that on-going evolution process within the Shale Gas Industry.

2.5 The socio-political context

2.5.1 At Cuadrilla we believe there are two key aspects needed to make the case for shale: (1) to prove that gas is present, technically recoverable and of a predictable quality and quantity, and (2) to prove the commercial, regulatory, and socio-political context is conducive.

2.5.2 The limitations of UK shale are highly dependent upon the level of public and political acceptance In the US, exploration firms have traditionally excelled at the technical side of shale development, but less so at understanding and effectively managing the socio-political context. In the UK, we need shale to tell a different story. Onshore shale development is a relatively new phenomenon across Europe, and because the sector attracted its share of controversy from the outset, Cuadrilla has fast come to grips with the challenges of what we term the "social license to operate".

2.5.3 We are in the process of creating an integrated offering of technical expertise and social sensitivity. This is why we are focused on listening to a wide number of stakeholders at every stage. This gives us a unique understanding of the issues in play. We have learned that all stakeholders have a great deal to learn about onshore gas, and that easy comparisons with offshore gas, or indeed with US Shale gas experience, are often misleading. There are different challenges and barriers to onshore development in the UK that are not prevalent offshore, such as the degree of consideration that needs to be given to local communities and surrounding areas. It has become clear that perceptions are hard to change without evidence of what development will look like and we are working hard to ensure that an honest and transparent account is given of what this might be.

2.5.4 A consequence of what we have learned from our stakeholders, is the need for a form of "industrial education" so that Government, opposition, industry bodies, academia, and our supply chain have the opportunity to learn from each other, and can work together to enlist the engagement and understanding of the local and national population. There is a good deal of mis-information and a number of myths about shale gas. Only a more informed population will understand all the issues and how they are being addressed.

3. *What have been the effects of shale gas on the LNG industry?*

3.1 With the US now effectively self-sufficient in natural gas, more liquified natural gas (LNG) has become available on world markets. This has increased options for consuming countries to source natural gas while at the same time reducing global gas prices. Since gas-fired power stations tend to set electricity prices in the UK, this has led to a reduction in wholesale electricity prices compared with earlier levels and we believe that further production of shale will increase these trends. Provisional results from independent research indicate that a growing UK shale industry could potentially decrease the reliance of the UK on imported LNG.

4. *What is the potential impact on climate change objectives of greater use of shale gas?*

4.1 Shale gas, like all natural gas, has significantly lower carbon content per unit of energy generated when compared with other fossil fuels such as coal or oil. Research into the UK Electricity market indicates that shale gas production will displace coal in electricity generation and reduce reliance on imported pipeline and liquefied gas. Both outcomes would be positive in reducing CO_2. Gas is likely to continue to play an important part in the UK's energy mix for some decades to come and Cuadrilla believes that producing indigenous Shale gas will prove to be a less CO_2 intensive way of filling that UK demand than gas imports.

5. Conclusion

5.1 As a socially responsible company, Cuadrilla has made it a key goal to demonstrate that shale gas from the its UK Bowland and Bolney licenses can be developed safely and in an environmentally responsible fashion that is acceptable to all affected communities. As we have outlined there are two journeys in this mission, the technical journey and the socio-political.

5.2 While the full economic benefits of shale gas have not yet been fully ascertained, based on prior estimates and research, we believe there are at least 200 trillion cubic feet (TCF) of original gas in place (OGIP) in the Bowland basin. We will review this estimate after further analysis of the 3D seismic survey completed over the licence area and from data from the next well we are drilling at the Anna's Road site, near Blackpool. We have every reason to believe that the aggregate of onshore UK shale natural gas resources is a multiple of our estimate for the Bowland formation. This resource estimate is not the amount of recoverable gas. This can only be reliably determined by further development and production testing.

5.3 We await operational clearance to resume our fracturing operations so we can prove that this gas can be hydro-fractured and will flow successfully. Achieving one or two proven flowing shale gas wells will be a major milestone for Cuadrilla and for the UK.

5.4 Maximising the benefit of shale gas for the UK will require a process of on-going and long-term investment and technological innovation and improvement by Cuadrilla and others. Shale gas specific expertise can be imported from the US, but the UK has significant oil and gas knowledge and can and must further develop its own shale gas capabilities. These capabilities can then be employed not just in the UK but also in the wider European and Global shale markets as they emerge. Shale has the potential to make a major difference to the UK over the next 50 years, but developing and sustaining this capability will take investment and patience.

5.5 Socio-politically, we are a society that has respect for the environmental regulatory regime, and looks to it for leadership in managing risk for all stakeholders. Cuadrilla's ambition is to set a standard of operational, environmental and social excellence for other operators to work towards in the future, and we are continually investing to ensure that remains the case. We believe the models of regulatory cooperation we are developing will be replicable by other operators.

5.6 We additionally believe there are upsides to development of an indigenous shale gas industry:

— reducing our import dependency, through lower-than-anticipated imports of LNG and pipeline gas;

— a decreased carbon footprint as indigenous natural gas displaces coal and gas imports;

— an opportunity to make the UK a leading centre of shale expertise for Europe and the developing world; and

— substantial tax revenues for the Treasury and significant employment opportunities.

5.7 The UK currently has a first-mover advantage in Europe, while being able to rely and improve upon expertise developed in the United States. However, Cuadrilla recognises that shale gas is a sovereign resource, and ultimately the decision over whether or not to develop it, and at what speed, is a political one. The balancing of local concerns with national priorities is a difficult act. In this, we err on the side of the communities that we are in the process of becoming part of. Their interests and our interests are the most closely intertwined. At the same time, clear directives from the centre regarding the national interest, alongside stable and pragmatic policies, will give us the confidence to invest in those communities for the long term.

October 2012

Written evidence submitted by the Department of Energy and Climate Change (DECC) (ISG 01)

INTRODUCTION

1. This Memorandum sets out some general information relevant to the Committee's inquiry and responds to the specific questions posed by the Committee in their call for evidence.

Shale gas and the UK energy markets policy

2. In the UK, as elsewhere in Europe, shale gas development is still at a very early stage. The technical and economic prospects for production are uncertain, and the scale of potential production equally so. Shale gas clearly does have the potential to contribute to the diversity of our energy supply, and Government therefore aims to facilitate exploration work to properly delineate this resource, while ensuring that extraction can be carried out safely and with all proper protection for the environment. But it is still too early to come to firm conclusions on whether shale gas production in the UK or elsewhere in Europe is likely to have a significant effect on overall UK energy production, security of supply and prices.

3. Since our 2009 unconventional gas Call for Evidence, the Department has continued to monitor developments in the UK, Europe and globally in order to assess the potential impacts on the gas markets. We have considered a range of studies produced recently on this subject (by the IEA, Poyry, Wood Mackenzie) and have commissioned further analysis (see contract notice http://www.contractsfinder.businesslink.gov.uk/Common/View%20Notice.aspx?site=1000&lang=en&NoticeId=618713). We will continue to consider the implications of shale gas development in the coming months as we develop our gas generation and energy security strategies.

Global Unconventional development

4. Large scale global development of unconventional[1] gas would improve an already benign global gas supply picture. The IEA has described the global gas resource base as "vast and widely dispersed geographically", estimating that conventional recoverable resources are equivalent to more than 120 years of current global consumption, and added that the total recoverable resources (conventional and unconventional) could sustain today's production for over 250 years.

5. The US boom in unconventional production was supported by favourable geology, low population density, a competitive supply industry which has developed significant advantages of scale, variable levels of environmental regulation, and strong development incentives for landowners. With the possible exception of

[1] Shale gas, coal bed methane and tight gas are classified as unconventional gas

the geology, these factors do not, at least for the time being, obtain elsewhere. Various analysts estimate serious exploitation in the EU to be a decade away. In addition, global gas demand is forecast to rise dramatically (by 55% by 2035, according to IEA).

6. The combination of high levels of shale gas production and a lack of export infrastructure has pushed US wholesale gas prices to levels much lower than those in the UK. If proposed US export facilities do develop this will put downward pressure on UK and global gas prices, and will improve the economics of further shale gas production in the US, but there are constraints on developing capacity.

Implications for gas markets, prices and decarbonisation strategy

7. The development of shale gas in the US has helped depress UK and global spot wholesale gas prices since 2009 by reducing the US need for LNG imports. Since then, however, gas markets have tightened with UK wholesale prices increasing due to growing demand from emerging economies such as China (and more recently Japan, following the nuclear shutdowns). However, the impact of low US gas prices on other markets has been more limited than might be expected in large part due to a lack of US export infrastructure.

8. There is great uncertainty associated with predicting the effects of unconventional gas globally on UK and EU gas prices and markets. Consensus forecasts suggest prices will go up over the coming decades, but increases in unconventional gas production make it likely that this growth will be more moderate than in the absence of unconventional gas and it will also increase the chance of falling gas prices.

9. At least for the next decade, and due to the range of constraints set out in paragraph 5, EU shale gas production is not expected to have as great an impact on EU gas prices as has been the case with US shale gas production on Henry Hub prices. EU gas prices influence UK prices strongly due to our physical connection to European gas markets through the IUK interconnector.

10. Lower gas prices would reduce the overall costs of our energy supplies. They would necessitate higher incentive payments to make nuclear and renewable generation and renewable heat competitive, but reduce the incentives needed for gas CCS. Low gas prices would also encourage switching from coal.

11. Shale gas could have a beneficial effect on global emissions where it displaces coal, and does not lead to a weakening of policy support for, and investment in, lower carbon options such as renewables and nuclear. The IEA in its recent report on shale gas concluded that the net effect on emissions would be positive.

Responses to the Committee's Questions

What are the estimates for the amount of shale gas in place in the UK, Europe, and the rest of the world, and what proportion is recoverable?

12. See table at Annex A for estimates from the US Energy Information Administration of proved natural gas reserves and of technically recoverable shale gas in the UK, Europe and other regions of the world.

Global estimates

13. Based on data from several sources, the IEA[2] estimate that remaining ultimately recoverable resources of shale gas worldwide amount to 208 tcm, coalbed methane (CBM) 47 tcm and tight gas 76 tcm.

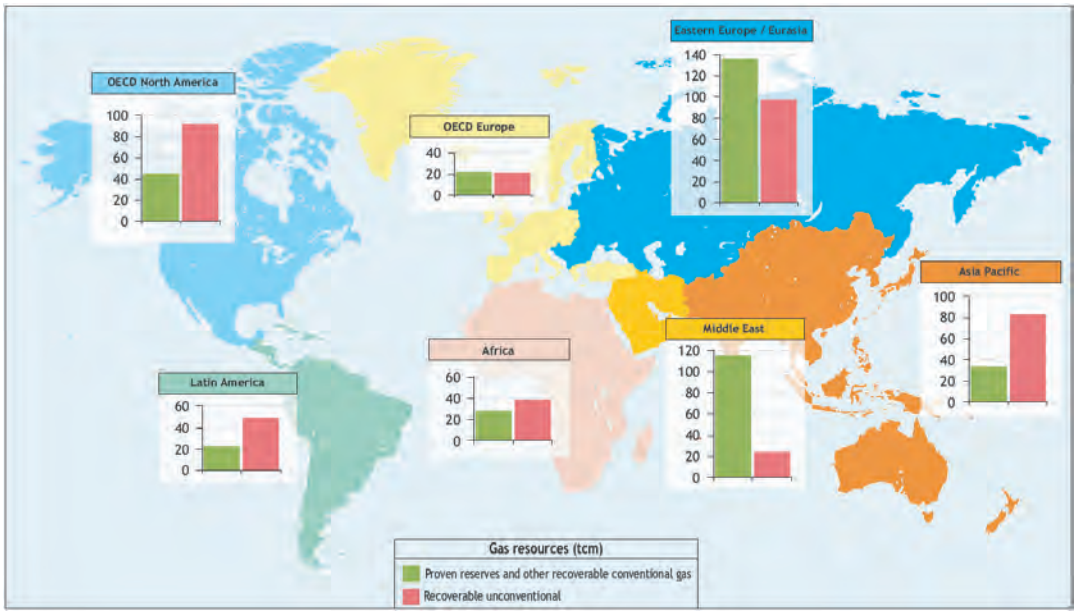
REMAINING TECHNICALLY RECOVERABLE NATURAL GAS RESOURCES BY TYPE AND REGION (END 2011)

	Total		Unconventional		
	Conventional	Unconventional	Tight Gas	Shale Gas	Coalbed methane
E.Europe/Eurasia	131	43	10	12	20
Middle East	125	12	8	4	-
Asia/Pacific	35	93	20	57	16
OECD Americas	45	77	12	56	9
Africa	37	37	7	30	0
Latin America	23	48	15	33	-
OECD Europe	24	21	3	16	2
World	**421**	**331**	**76**	**208**	**47**

Source: IEA analysis

[2] *Golden Rules for a Golden Age of Gas* May 2012 http://www.worldenergyoutlook.org/media/weowebsite/2012/goldenrules/WEO2012_GoldenRulesReport.pdf

14. The IEA assessment for its June 2011 publication *Are we entering a Golden Age of Gas?*[3] covered 48 shale gas basins in 32 countries and put technically recoverable shale gas resources in those countries and in the US at 187 tcm; China was seen as having the biggest resources (36 tcm), followed by the US (24 tcm), Argentina (22 tcm) and Mexico (19 tcm). More than half of the world's proven reserves are concentrated in Russia, Iran and Qatar in large conventional gas fields. North America and Europe are at the lower end of the proven reserves, even though North America has benefitted from substantial additions of unconventional gas. Unconventional gas now accounts for nearly one-quarter of the total North American proven gas reserves. The IEA highlighted that the extent to which countries exploit their unconventional resources will be a key determinant of future global gas supplies.



Source: IEA

UK estimates

15. In 2010 DECC commissioned the British Geological Survey (BGS) to carry out a survey of landward shale gas potential. In that context, the BGS provided a first estimate of the production potential for shale gas in the UK, based on a simple analogy with US shales, of up to 150 bcm (5 tcf). This estimate compared the production per area of a possibly analogous play in the US to the area of the UK shales under consideration. The Carboniferous Bowland shale in northern England is thought to be the most promising, but intervals in the Jurassic in the Weald and Wessex basins of southern England are also considered to be prospective. Deeper shales occur widely in the subsurface, but their potential is largely unknown.

16. In April 2011, the US EIA estimated that there is 20 tcf of Technically Recoverable Resources in the UK (http://www.eia.gov/analysis/studies/worldshalegas/). (See below on the meaning of Technically Recoverable Resources).

17. DECC has commissioned the BGS to provide a better estimate of the Bowland Shale resource (ie, the gas in the rocks). Study of the prospectivity of other shales will be considered after this work is published towards the end of 2012.

18. However, until commercial UK shale gas development can be proven, and the production profiles can be compared to other producing basins, any estimate of the amount of gas which could potentially be produced is subject to substantial uncertainties (see the answer below to your question on why the estimates are so changeable).

EU estimates

19. Poland, as the EU Member State which seems to have the most significant prospectivity, is the most advanced as regards exploration of unconventional gas reserves and have a very active programme of drilling. They are also reinforcing the regulatory framework for exploration and production of both conventional and unconventional gas (and oil) reserves which may alleviate some of the environmental concerns in that country. In other Member States there remains significant concern over impacts of shale gas exploration and exploitation with some Member States either having a moratorium or de facto moratorium in place.

[3] http://www.iea.org/publications/freepublications/publication/WEO2011_GoldenAgeofGasReport.pdf

Why are the estimates for shale gas so changeable?

20. The first major reason is a frequent confusion between reserves and the total resource. Some reports cite estimates of how much gas is in the ground and some of how much might be extracted. The latter will be much smaller than the former, particularly if the estimate is of economically rather than technically recoverable reserves.

21. In discussing estimates, several different terms are used to describe the volume of gas present. These differentiate the various methods according to how much information is available, technical assessment of how much might be producible and finally if it is commercially viable to do so.

- Total Resources (gas-in-place): the total volume of gas estimated to be present for a particular accumulation.
- Technically Recoverable Resources: the estimated volume of gas that might be recovered from the total resource, by reference only to the technical feasibility of recovery.
- Reserves: the fraction of the potentially recoverable resources that are deemed to be commercially recoverable. This can be further sub-divided into proven, potential and possible reserves based on the confidence that reserves will be recoverable. Proven reserves are considered almost certain to be recoverable. Reserves may thus be discussed with a much greater level of certainty than potentially recoverable resources. (see DECC website for detail http://og.decc.gov.uk/en/olgs/cms/data_maps/field_data/uk_oil_gas_res/uk_oil_gas_res.aspx)

22. As noted earlier, a 2010 report prepared by BGS for DECC estimated shale gas production potential by a simple analogy: "The UK Carboniferous (Upper Bowland Shale) shale gas play, if equivalent to the Barnett Shale of Texas, could potentially yield up to 150 bcm (5 tcf) shale gas."

23. This cannot be compared to the 2011 Cuadrilla estimate of 200 TCF of total resource (gas-in-place) on their licence. The Cuadrilla estimate does not indicate how much they think they may actually be able to recover, nor take into account the development costs, and whether the deliverability and gas price are high enough to justify drilling all the wells which would be needed to produce the gas, nor consider which gas is in areas which cannot be accessed.

24. DECC does make estimates of undiscovered resources for conventional hydrocarbons, which are published on our website, but those estimates do not to date include any estimate of UK shale gas, because of the absence of data on the production performance of UK shales.

25. The second major reason for the variability is that reserves estimates for shale gas are subject to greater uncertainty than estimates for conventional oil and gas. The US EIA estimates Technically Recoverable Resources for areas across the world by multiplying the risked gas-in-place by a shale gas recovery factor, which incorporates a number of geological inputs and analogues that are appropriate to each shale gas basin and formation. But for most areas of the world outside North America, the information available for such analyses is much more limited, or absent, and the uncertainties correspondingly greater.

26. There is also a methodological issue. The recovery factor methodology, which has developed over a century or so to enable reserves estimates to be made for conventional oil and gas resources, does not seem to apply with equal success to shale gas, shale oil and coal bed methane. These unconventional resources are more extensive than conventional oil and gas resources, which have the character of accumulations in a specific and relatively limited space. The unconventional resources, however, are very extensive spatially, with more significant variations of properties across that area (the phenomenon of "sweet spots").

27. The US Geological Survey, which has the most experience in estimation of petroleum reserves, has developed a different methodology for reserves estimation in these extensive petroleum resources, based on a reservoir performance model of wells, which predicts the capability for the summation of these wells with variable deliverability to produce gas. When sufficient drilling and production data is not available, information from analogous accumulations is used. The USGS describe their technically recoverable resource estimates as a work in progress, changing as more production experience becomes available and as new technologies are applied to extract these resources. The development of USGS estimates using this new methodology has led to substantial reductions in previous US estimates, notably for the Marcellus shale.

28. DECC has now commissioned a BGS team to provide a more detailed analysis and estimate of the entire Bowland Shale gas total resource potential (gas-in-place) to better understand the potential future contribution to the UK energy mix. This work is due to be completed towards the end of 2012 and will provide an independent assessment of the total resource. However this work will not produce a reserve estimate, that is, how much of this gas will be technically and economically viable to produce. Until there is shale gas production in the UK, any estimates of recoverable reserves must be considered as highly uncertain. It can take many years to establish real decline curves and trends across wells in a given play and so even after several years of production, estimates will still be prone to large fluctuations.

What are the prospects for offshore shale gas in the UK Continental Shelf?

29. Offshore costs are many times that of onshore and that unless there are significant changes in technology, costs and gas price it is difficult to see how offshore shale gas might become a real prospect within the next few decades. Some shale gas under the sea however might be accessible from land-based operations.

30. At the present time there is no known offshore exploration activity for unconventional gas anywhere in the world. The EIA excluded offshore portions of assessed shale gas basins, and shale gas basins that exist entirely offshore, from their World Shale Gas estimates. If shale gas development can be proven to be technically and commercially viable onshore, it is possible that the industry may look to the offshore for future exploration, and further study could be merited at that time.

Should the UK consider setting up a wealth fund with the tax revenue from shale gas?

31. The Treasury has made no recent estimate of potential tax revenues from shale gas. As a general principle, tax revenues flow to the Consolidated Fund.

What have been the effects of shale gas on the LNG industry?

32. The majority of unconventional gas production is located in United States and Canada. IEA data suggests that 14% of global gas production came from unconventional sources in 2010 with 90% of this produced in the US or Canada. As a result, the major impacts of unconventional gas have come about due to increases in the availability of gas in these countries.

33. As recently as 2008, it was widely expected that import requirement for LNG in the United States was likely to increase over the coming decades. However, the "shale gas revolution" in North America has made the US the world's largest gas producer (overtaking Russia) and has turned the US from being a gas importer to becoming virtually self sufficient. This unexpected growth reduced the US need for LNG imports and freed up LNG in the global market. This has increased supply and has put downward pressure on oil-linked contracts, resulting in the renegotiation of some contracts, particularly in Europe. Some commentators argue that increased availability of LNG cargoes also accelerated an increase in the proportion of global LNG sold on the spot market.

34. US LNG exports would put further price pressure on the Atlantic market. One project, the Sabine Pass in Louisiana, has been granted all the permits required to export LNG from the US. Cheniere Energy, the developers, took Final Investment Decision on the project on 30 July and expect to commence operations by 2015 with a target of c. 20 bcm/y by 2017–2018. Seven further projects await Department of Energy export approval, totalling in excess of 120 bcm/y of capacity.

35. Elsewhere in North America, Canada (endowed with large unconventional gas resources of all three types and formerly an exporter of gas to the US) has approved two LNG export projects in British Columbia, amounting to around 9 bcm/y. Given the projected growth in demand from for natural gas in China and India, and assuming that some of Japan's nuclear capacity remains offline, it is likely that demand for natural gas will outpace the incremental supply.[4]

Could shale gas lead to the emergence of a single, global gas market?

36. While trade in natural gas is generally expected to increase, the impact of unconventional gas production on trading patterns is unclear. Russia and the Middle East account for the majority of the remaining reserves of conventional gas, while significant gas discoveries have recently been made in other parts of the world (for instance in East Africa). However, unconventional gas resources are more evenly spread. As a result, it is possible that large scale production from unconventional sources could decrease inter-regional trade by reducing the need for imports. In the IEA's Golden Rules Scenario, the total volume of inter regional trade increases by almost 50% out to 2035. However, this is 15% lower than compared to the baseline case.

37. For the moment, production of unconventional gas is still overwhelmingly a North American phenomenon. Virtually all of the world's existing shale gas production currently takes place in the US and Canada. According to the IEA,[5] in 2010 76% of global unconventional gas output came from the United States (360 bcm) and a further 13% from Canada (60 bcm). Beyond North America, the largest contribution to unconventional gas production came from China and Australia, producing around 10 bcm and 5 bcm of coalbed methane, respectively.

38. Future uncertainties make it difficult to predict how the global unconventional resource will be developed in the coming years, and therefore the extent to which it will shape the global gas market. Prohibitions are currently in force in parts of Europe. In parts of Canada, the United States and Australia moratoria have been placed on hydraulic fracturing, pending the results of additional studies on the environmental impact of the technology. The IEA notes that if these concerns are not addressed, the lack of public acceptance in some countries could mean that unconventional production is slow to take off. See Annex B for assessments on the potential impact of unconventional development on the global market by the IEA and Wood Mackenzie.

[4] Source: Liquid Markets: assessing the Case for US Exports of Liquefied Natural Gas, Energy Security Initiative, May 2012
[5] May 2012

What are the effects on investment in lower-carbon energy technologies?

39. If there were to be a significant increase in the supply of shale gas and if this led to low wholesale gas prices in the European market, the impact would be the same as if low gas prices came about through another scenario.

40. From the energy efficiency perspective, for an individual consumer (either a firm or a household) lower energy prices reduce the incentive to invest in energy efficiency. However, the wider benefits of energy efficiency would be maintained: companies would still benefit from lower costs, and greater productivity from investing in energy efficiency, and households from lower energy bills and greater comfort from insulated homes. Energy efficiency could still be cost-effective in terms of carbon abatement so would still be good for society to pursue energy efficiency (for example, insulation measures would save on carbon emissions) and these societal benefits could be more important if the gas itself is cheaper as gas demand would increase.

41. Exploitation of unconventional gas is expected to lower the price of gas relative to those of other fuels, including renewables. This will increase demand for gas as well as increasing the relative cost of switching to alternative renewable heat and electricity technologies (although for some technologies which use electricity as a fuel source (such as heat pumps) a fall in gas prices would also lead to a reduction in the electricity costs (assuming gas CCGT is the marginal generation technology).

42. As CCGT plant set the wholesale electricity price for much of the year in the UK, lower wholesale gas prices would lead to lower average wholesale electricity prices. However, as explained below, with low carbon generation supported by the new FIT with CfD mechanism, investment in low carbon plant would not be expected to be very significantly affected by changes in wholesale electricity prices.

43. Investment in renewable electricity is currently driven by the Renewables Obligation (RO), which will remain open to new projects until 2017. From 2014, the new FIT with CfD mechanism will drive investment in low carbon generation. Unlike investment under the RO (where projects are remunerated with a relatively fixed top-up to the wholesale price), investment in renewables and nuclear plant under the CfDs will be largely unaffected by changes in the wholesale price, as project revenues would only be affected during the period of the remaining operational lifetime after the end of the CfD contract. These later years are heavily discounted in investment decision-making.

44. However, the amount of revenue support for low carbon generation required in addition to the wholesale price, ie the CfD support cost, would be affected by lower gas prices. The total price consumers pay for low carbon renewable and nuclear generation (during the terms of CfD contracts) would not be affected, just the amount they pay relative to the wholesale price. This CfD support cost for nuclear and renewables would rise under a low gas price scenario.

45. The impact of lower gas prices on investment in gas CCS plants will depend on whether the terms of their CfD contracts include a linking of the strike price to wholesale gas prices. If there is such a link, then lower gas prices would be expected to have no impact on investment in gas CCS. If, on the on the other hand, there was no link, then lower gas prices might lead to more investment in gas CCS until such time as the strike price on offer for new plants was reviewed and lowered in line with the lower gas prices, ie only for a few years at most.

46. As the strike price for new plant ultimately falls in either case, the total cost to consumers of supporting gas CCS will decrease. The CfD support cost would also be expected to fall slightly, due to the lower efficiency of gas CCS plants compared to unabated CCGT. This means that gas forms a greater proportion of CCS plant costs than unabated plant costs, and so a fall in wholesale gas prices would allow gas CCS strike prices to fall by more than the long-run marginal cost of CCGT falls and hence by more than average wholesale prices more. A smaller gap between the wholesale price and the gas CCS strike price equates to a reduction in CfD support costs.

47. The dispatch of low carbon generation will not be affected by low gas prices as long as the low gas price does not change the ordering of plants in the merit curve, which is determined by plants' marginal revenues and marginal costs. With their CfD revenue support and low short-run marginal costs, wind and nuclear generation would generally always be expected to dispatch ahead of CCGTs. Similarly, with RO and/or CfD support for biomass generation, it would take some combination of high biomass prices and low gas/carbon prices for biomass and CCGTs to switch places in the merit curve.

48. As noted above, gas CCS plants incur additional fuel costs related to the CCS technology compared to an unabated CCGT plant, and hence the gas CCS plant's short-run marginal cost falls relatively more as a result of lower gas prices than that of unabated CCGT, and if gas CCS is the marginal plant in the future then wholesale prices would fall as a result. Whether gas CCS or unabated CCGT dispatches first will depend largely on the level of CfD strike prices and carbon prices. In any case, investment in gas CCS on CfDs would not be affected by low gas prices, regardless of the impact on wholesale prices, if the strike price on the CfDs is indexed to the gas fuel price. Without such indexation, gas CCS investment would look more attractive in a low gas fuel price world.

49. Finally, it is perhaps worth noting that as long as unabated CCGT is assumed to set wholesale prices as the marginal plant, a low gas price scenario would not necessarily lead to more investment in unabated CCGT as their revenues would reduce in line with their lower fuel costs.

What is the potential impact on climate change objectives of greater use of shale gas?

50. The IEA estimates that, provided methane emissions from shale wells are minimised by using appropriate technology, shale gas will have well-to-burner emissions that are 3.5% to 12% higher than the equivalent for conventional gas. However shale gas should have a greenhouse gas footprint significantly below coal over a 100 year time horizon. Shale gas could therefore have a beneficial effect on global emissions where it displaces coal, and does not lead to a weakening of policy support for, and investment in, lower carbon options such as renewables and nuclear. Its greater use in these contexts, particularly where coal is the only realistic alternative, should therefore be welcomed. The IEA concluded that the net effect on emissions would be positive.

51. In the UK, we will be required to include any methane emissions from unconventional gas exploration and production in the UK's greenhouse gas inventory, which is used to meet both our international and domestic reporting obligations, and compliance with greenhouse gas targets under EU legislation and UK Carbon Budgets. This means that any increase in emissions from greater use of shale gas would require greater emission reductions to be delivered elsewhere.

52. However, increased use of gas will not by itself be enough to put the world on course for 2°C, as recognised in the IEA's recent report on shale gas. While our modelling suggests that unabated gas could retain a significant role in electricity generation through the 2020s, potentially still producing up to two thirds of today's generation levels in 2030, and highlights that unabated gas may still be needed for back up even in 2050, it would need to be combined with increased use of low carbon generation including renewables and nuclear energy. Gas could also be combined with CCS to make a greater contribution to emissions reductions in the long term.

Summary and Way Ahead

53. As indicated in the evidence above, Government considers that it is still too early to say whether shale gas production in the UK, Europe and globally will be economic on any significant scale (other than in the US), and therefore what impact it will have on the energy markets. Even if economic reserves are confirmed, there are reasons to think that the development of shale gas in the UK, and in Europe, will be slower to develop and more constrained than in the US: the supply industries are much less well-developed, population densities are higher and land use patterns typically more diverse, and environmental regulation is generally tighter.

54. Nevertheless, we consider that unconventional gas could play a positive role in economic, energy security and sustainability terms. Government therefore aims to facilitate exploration work to properly delineate this resource, while ensuring that extraction can be carried out safely and with all proper protection for the environment. To this end, Government aims to reach a conclusion as soon as possible on the future of fracking activity for shale gas

55. The Government is committed to publish a new gas generation strategy in the autumn of 2012. This will focus on the role of gas in the electricity market, and will take account of the latest information on gas supply prospects, including any prospective contribution from unconventional supplies.

Annex A

EIA World Shale Gas Estimates (bcm), April 2011

	Proved Natural Gas reserves	*Technically recoverable shale gas*
Europe		
France	6	5097
Germany	176	227
Netherlands	1388	481
Norway	2039	2350
UK	255	566
Denmark	59	651
Sweden		1161
Poland	164	5295
Turkey	6	425
Ukraine	1104	1189
Lithuania		
Others	77	538
North America		
United States	7716	24409
Canada	1756	10987
Mexico	340	19284
Asia		

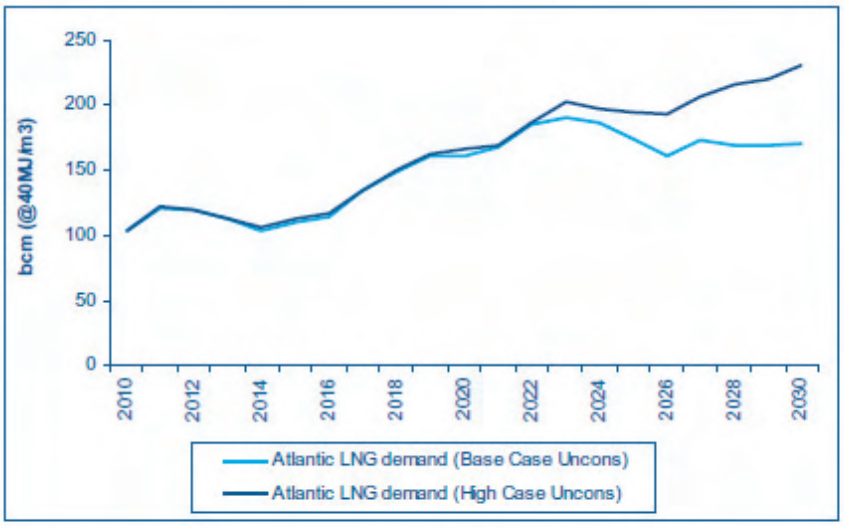
EIA World Shale Gas Estimates (bcm), April 2011	*Proved Natural Gas reserves*	*Technically recoverable shale gas*
China	3030	36104
India	1073	1784
Pakistan	841	1444
Australia	3115	11213
Africa		
South Africa		13734
Libya	1549	8212
Tunisia	64	510
Algeria	4502	6541
Morocco	3	311
Western Sahara		198
Mauritania	28	
South America		
Venezuela	5066	311
Colombia	113	538
Argentina	379	21917
Brazil	365	6400
Chile	99	1812
Uruguay		595
Paraguay		1756
Bolivia	750	1359
Total of above areas	36064	187512

Source: The Impacts of Unconventional in Europe, A Report to Ofgem
Poyry, June 2011

Annex B

IEA AND WOOD MACKENZIE VIEWS ON THE IMPACT OF SHALE GAS ON THE GLOBAL MARKET

Wood Mackenzie[6] said that an increase in indigenous unconventional supply in Europe, combined with the increased availability of LNG to the Atlantic (in the high case they modelled) would put pressure on the major piped suppliers. Their assessment is that the impact of unconventional gas on the European gas market dynamics is more likely to be incremental rather than disruptive, particularly over the next 15 years. This would increase competition among suppliers and could result in lower hub prices in Europe, renewed pressure on traditional levels of oil-indexation and a drop in the uncontracted gas price both in Europe and in the linked Pacific market, but is not likely until after 2025.



*Source: Wood Mackenzie - *Atlantic LNG Availability from H2 2010 base case*

[6] April 2011

Globally, Wood Mackenzie consider that an unconventional production profile in line with their high case would also make an incremental impact on global gas market dynamics, rather than a disruptive change. They estimate that in the Pacific basin additional unconventional gas production of 100 bcm in 2030 in the high case would displace 50 bcm of more expensive LNG imports. The additional Chinese and Indian unconventional gas in their high case would reduce the requirement for LNG in the Pacific basin in the longer term and increase LNG availability to the Atlantic.

Figure 2a: Base and High Case Unconventional Production Profile*

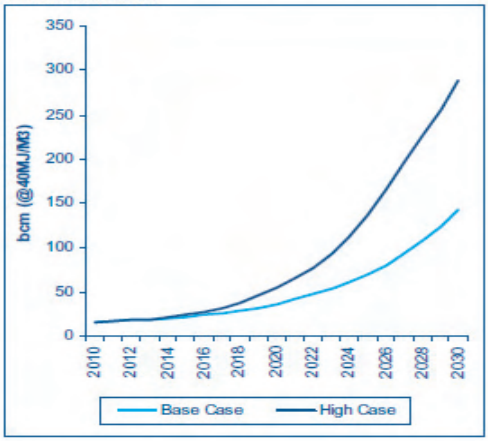
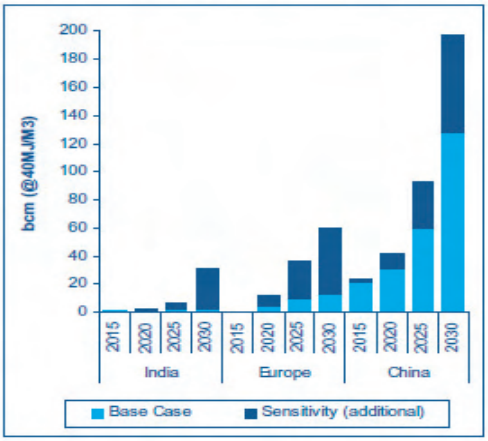
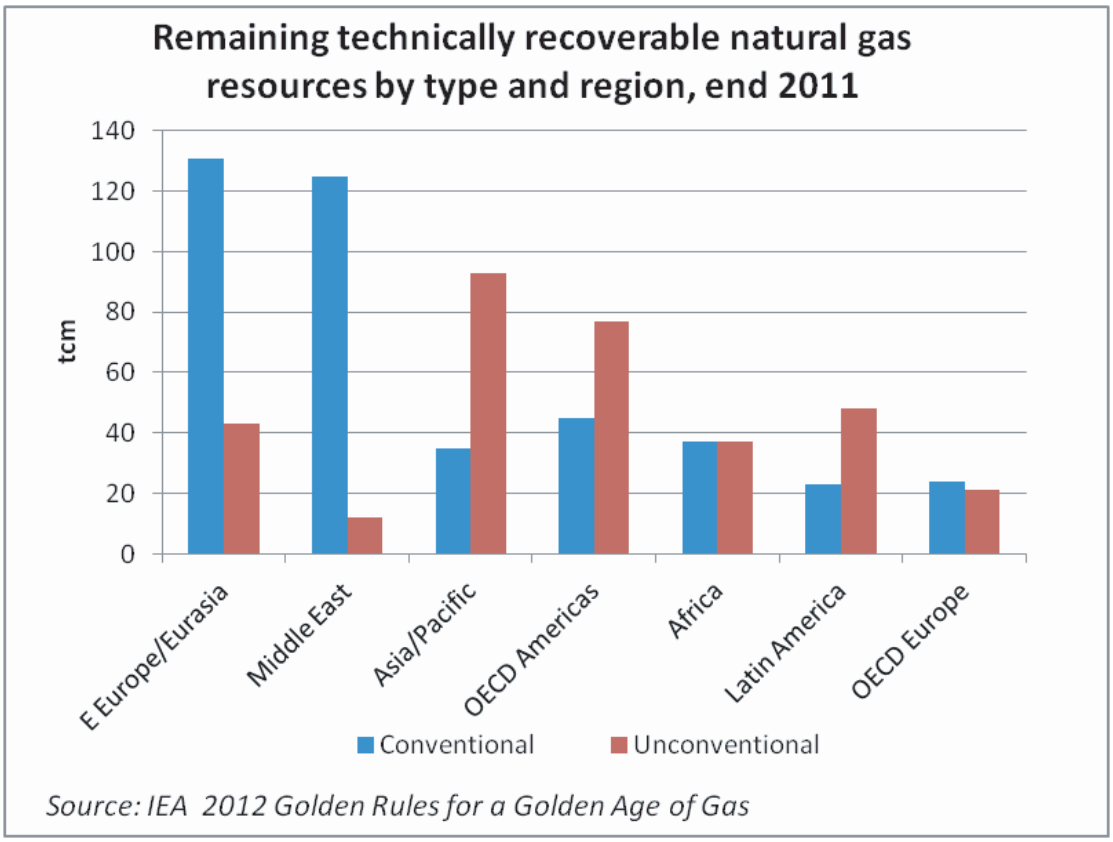


Figure 2b: Base and High Case by Geography



*Source: Wood Mackenzie - *Coverage – China, India and Europe*

Even in the IEA Golden Age of Gas Scenario,[7] which models significant production, natural gas markets would become more global and regional prices are expected to show signs of increased convergence, but the market does not become truly globalised. Pricing mechanisms are likely to become more reflective of market conditions, including the prices of competing energy sources, such as coal, other gas supplies, and in some cases oil. The pace and extent of this change will hinge to some degree on how long the overcapacity in global gas supply persists. North America would remain largely self-sufficient and is therefore likely to be essentially isolated for inter-regional trade. However, there are pressures and uncertainties about the level of future exports from that country which will affect the impact the US can have on the global gas market.



October 2012

Written evidence submitted by Dr. Thierry Bros, Senior Analyst, European Gas and LNG, Société Générale (ISG 02)

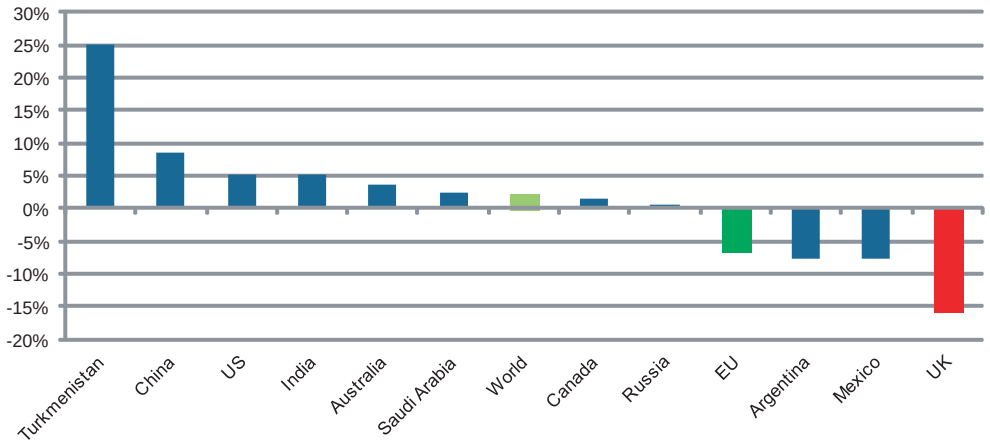
Executive Summary

Shale gas production has transformed the US gas industry in recent years, boosting both production rates and booked reserves. The country was changed from a growing importer to a possible exporter, while US gas prices have dropped to 2 $/MBtu, against 9 $/MBtu in Europe. The UK is facing not only a severe drop in gas production (-8.1% CAGR in 2001–2011) but also a record drop in gas proven reserves (-15.6% CAGR in 2001–2011). As shale gas reserves are only estimates and need to be validated by effective drilling at each field, the only way to check the real potential in the UK for shale gas is to allow fracking. But this new production process needs to be tightly regulated, with a systematic program for the disclosure of chemicals used in unconventional gas production. Tight environmental standards mean that this business will not be as profitable as conventional gas production in major resource-holder countries… but the risks (financial, security, etc.) are much lower in Europe than in other gas producing countries. European shale gas production could also be the only answer to the ill functioning EU gas market where four foreign National Oil Companies control c.50% of the supply. After the US shale gas revolution, companies are now investing to allow the US to become a major LNG exporter. If this happens, the US could be the cheapest gas market until the end of the decade; other markets will be linked via the cost of arbitrage (liquefaction, transport and regasification). If a single, global gas market is to be achieved then all countries need to follow the US route by producing shale gas, something that seems improbable before 2020e.

[7] The Golden Age of Gas Scenario (GAS Scenario), departing from the WEO-2010 New Policies Scenario (the base case) incorporates a combination of new assumptions that underpin a more positive future outlook for gas. These are implementation by China of an ambitious policy for gas use, lower growth of nuclear power and more use of natural gas in road transport.

THE UK IS FACING A MAJOR DROP IN GAS PROVEN RESERVES AND PRODUCTION

2001–2011 CAGR OF GAS PROVEN RESERVES IN SELECTED COUNTRIES

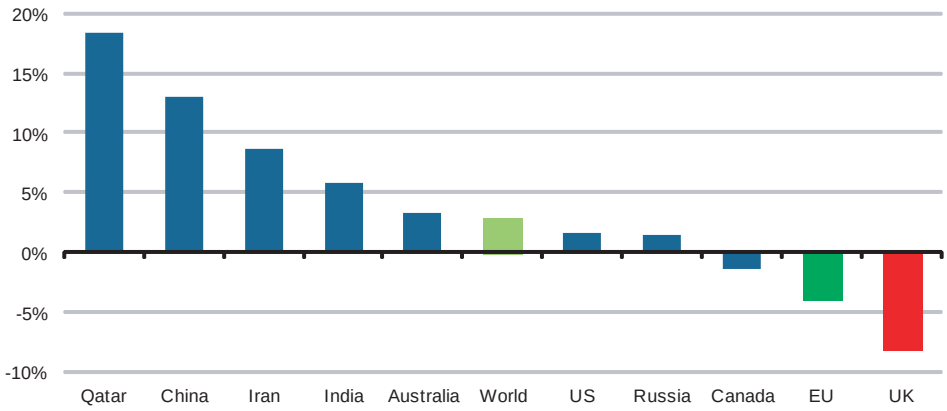


Source: BP Statistical Review

Turkmenistan huge growth comes from an area that wasn't explored much under the Soviet regime and that should hold the second biggest gas reservoir on a worldwide level. Albeit from a very low level, China gas reserves have been rising by 8.4% CAGR in 2001–2011. This high growth (coming from conventional and unconventional gas and from fields along the East-West new pipeline that can now be produced) is laying a solid foundation for the further expansion of China gas production. US growth, more than twice the worldwide average, comes from the unconventional gas resources that are now been deemed recoverable thanks to innovative technologies. This high growth has allowed the US to overtake Saudi Arabia as the fourth reserve holder on a worldwide basis. Australia growth is recent (2008) and comes from the huge capex private companies are dedicating to new LNG projects. The EU (and particularly the UK with -15.6% CAGR) saw its gas proven reserves reduced over 2001–2011 as it was producing more gas than it was finding reserves. The world record decline in terms of gas proven reserves is held by the UK even worse than Argentina, where the government decided earlier this year to nationalize the local oil company (YPF). Not a positive start!

For the top four reserve holders (Russia, Qatar, Iran and Turkmenistan), the R/P ratio is over 73 years. Then comes the US (number five) where the R/P is "only" 13 years. This is because, in the US, private companies are geared at monetising resources rapidly; hence, the timing between booking and production is faster than anywhere else. This doesn't mean that in 14 years the US won't have any more gas reserves because, by then, some resources should have been booked into reserves thanks to companies' capex programs. For the EU, the ratio R/P is 12 years but, if the EU continues to fail to replace its gas production (and to ban unconventional gas at large), this could mean that in 13 years' time, EU domestic production could be insignificant. And, for the UK, the R/P ratio has reached a record low of 4.5 years.

2001–2011 CAGR OF GAS PRODUCTION IN SELECTED COUNTRIES



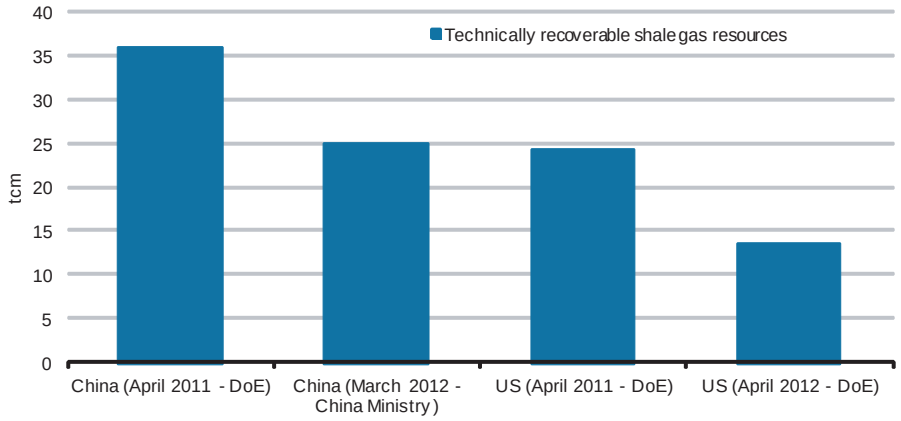
Source: BP Statistical Review

On the production level, the UK is again, for 2001–2011, the worst in class with—8.1% pa vs worldwide growth of 2.8% pa… It is therefore time to review the situation as the clock is ticking…

Shale Gas Recoverable Resources are Just Estimates That Need to be Checked by Drilling

On March 2012, the Chinese Ministry of Land and Resources announced that according to its survey, China's onshore exploitable shale gas reserves are 25 tcm. Although the Chinese figure is lower than the US Department of Energy (DoE) number, it confirms that China has the largest shale gas reserves in the world.

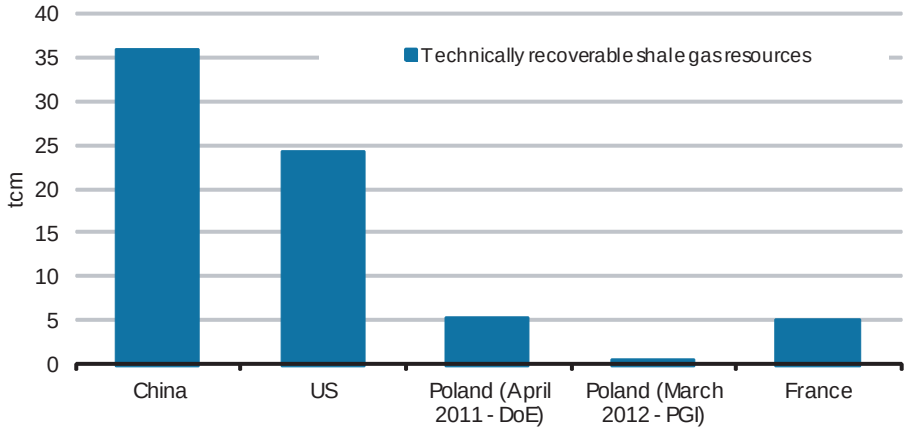
SHALE GAS RECOVERABLE RESOURCES ARE JUST ESTIMATES



Source: US DoE 2011 and China Ministry of Land and Resources

According to the US DoE (April 2011), Poland has the largest estimated recoverable shale gas reserves in Europe. But Poland's recoverable shale gas reserves could be lower than estimated by the US DoE (5.2 tcm) as, in March 2012, the Polish Geological Institute (PGI) estimated the shale gas resources to be between 346 bcm and 1.9 tcm. Both numbers are still estimates and more drilling is required to have a better view. So, when we restate US DoE data to take account of new Polish data, we end up with France having the largest estimated recoverable shale gas reserves in Europe.

POLAND OR FRANCE, FIRST IN EUROPE?



Source: US DoE 2011 and PGI

As shale reserves are just estimates that need to be checked at each field level by drilling, EU countries will need to allow fracking if we want to stop this massive decline in proven reserves and production. Some unconventional production was tried in the UK but stopped due to tremors. Problems were raised in the UK over potential links to earthquake activity, as well as the chemicals included in fracking fluids. But offshore fracking technologies could mitigate the rate of decline of conventional fields in the UK. Even if onshore unconventional production is unlikely, companies could use fracking techniques for offshore fields. This could perhaps help stop the decline of the European gas proven reserves that we have witnessed since 1999.

In Europe, shale gas could supply a useful diversification to boost energy security. With shale gas development in its early stages in Europe, the resource has the potential to play a marginal role in helping meet Europe's energy requirements this decade. The aim is to protect the environment while capturing the economic benefit. European shale gas production could also be the only answer to the ill functioning EU gas market where 4 foreign National Oil Companies (Gazprom from Russia, Statoil from Norway, QP from Qatar

and Sonatrach from Algeria) control c.50% of supply. Unfortunately the EU is pushing for a single energy market but not for domestic shale gas production...

Like any human activity, shale needs a "social license" to operate and the industry should be aware that its least successful player, in the eyes of the general public, defines the industry as a whole. The way the industry operates in the first countries to allow fracking will have a major impact for further shale (oil &) gas production throughout Europe. A tightly regulated production process, with a systematic program for the disclosure of chemicals used in unconventional gas production, could help this industry to expand in Europe. The move to reveal the make-up of fluids used in hydraulic fracturing of shale gas reserves (a similar initiative as the US fracfocus website (fracfocus.org)) could be developed to head off criticism of the new gas production method, which is attracting growing attention in European countries. A comprehensive disclosure program would allow citizens and communities to assess this technology. Only this could lead to open discussion about environmental protection and risk management, and the potential benefits of shale development in Europe. Any environmental issue would have a dramatic effect on shale production throughout Europe. The industry must understand that tighter environmental standards (and potential reduction in oil-linked prices) will mean that this business will not be as profitable as conventional gas production in major resource-holder countries, but the risks (financial, security, etc.) are much lower in Europe than in other gas producing countries.

It took 30 years of Research & Development in the US to unlock the shale gas resources. As understanding of unconventional resources improves, Europe could find a way to extract shale in a greener way (less water and air pollution) perhaps by the end of this decade. And even if costs turn out to be higher than in the US, technology improvement could help to reduce these.

Continued Growth in Production Should Enable the US to Become a LNG Exporter

Recent developments in the US and Canada could lead to North America becoming a major LNG exporter. For a liquefaction facility to be built in the US, a wide range of authorizations are needed:

- An important one is granted by the DoE to allow exports as any state has permanent sovereignty over its natural resources. An application for export authorisation has to be filed by companies that want to build and operate an LNG export terminal. The DoE can grant authorization either to countries with which the US has a free trade agreement (FTA countries are Australia, Bahrain, Canada, Chile, Costa Rica, Dominican Republic, El Salvador, Guatemala, Honduras, Israel, Jordan, Mexico, Morocco, Nicaragua, Oman, Peru, Singapore and South Korea. Colombia and Panama should join the FTA countries once all legislation is passed) or to all countries with which trade is not prohibited by US law.
- Another one is granted by the US Federal Energy Regulatory Commission (FERC) to site, construct and operate facilities for the liquefaction and export of domestically produced natural gas. This process takes more than a year and costs tens of millions of dollars.

In less than four months, Cheniere, that was the first company to be granted a DoE authorization to export US LNG to FTA and non-FTA countries, managed to sell all its LNG (16 mtpa) under a US spot- linked (Henry Hub) formula (LNG delivered Free On Board: 115% HH + fixed fee). The 115% HH covers the gas sourcing (100% at the hub), the cost of fuel gas needed for the process (10%) and additional transportation cost to the liquefaction terminal (5%). The fixed fee is for the remuneration of the liquefaction plant that will therefore operate as a tolling plant. As Cheniere took a Final Investment Decision in July 2012 on Sabine Pass Phase 1 ($5.6 billion), US LNG should arrive as early as 2016e.

In April 2012, Cameron LNG signed commercial development agreements with Mitsubishi and Mitsui to develop and construct a liquefaction export facility in Louisiana. The commercial development agreements bind the parties to fund all development expenses, as well as to negotiate 20-year tolling agreements. Each tolling agreement would be for 4 mtpa (5.4 bcm/y). In May 2012, GDF SUEZ signed with Cameron LNG an agreement to negotiate a 20-year liquefaction contract for 4 mtpa (5.4 bcm/y). The completed liquefaction facility is expected to be comprised of three liquefaction trains with a total export capability of 12 mtpa (16.2 bcm/y). Cameron LNG expects to receive the required permits from the DoE and the FERC and enter into a turnkey contract in 2013 for engineering and construction services for the project. In July 2012, Freeport LNG announced that it had executed 20-year liquefaction tolling agreements with Osaka Gas and Chubu Electric for the first liquefaction train (4.4 mtpa). Freeport LNG is also in exclusive negotiations with respect to the second and third liquefaction trains. Freeport LNG expects to receive all regulatory approvals by mid-2013, and to begin construction in Q3 2013. This shows that major downstream market players (especially Japanese companies) are increasingly willing to access US LNG directly.

Several projects with a total capacity of 113 mtpa have filed applications with the US DoE seeking authorization to export LNG. If all these projects were approved and built, the US would become the number one LNG producer, far ahead of current number one (with 77 mtpa or 104 bcm/y) Qatar!

Federal law gives the US DoE the authority to revisit liquefied natural gas export applications it has approved. We believe this is unlikely as:

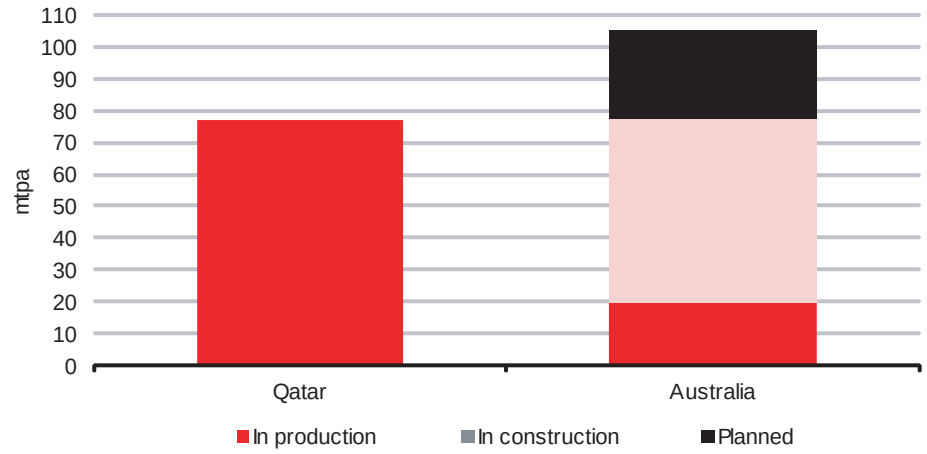
- Cheniere's Henry Hub linked formula will not make the US gas market oil-indexed dependent.

— A claw-back would have to mitigate a very serious threat where gas would not be available even for US citizens, and in this case HH would have gone up so much that exports would be uneconomical anyway!

— The US is already a net gas pipe exporter to Mexico (14.1 bcm in 2011).

Thanks to unconventional gas, Australia is set to become the next growth area for LNG from 2015e. Australia's current 20 mtpa (27 bcm/y) capacity is set to grow, as 57 mtpa (77 bcm/y) capacity is already in construction and another 28 mtpa (38 bcm/y) could materialize before 2020e. This adds up to 107 mtpa (144 bcm/y) and could make Australia the number one LNG producer in 2020e. Future Australian LNG has already been sold mainly on an oil-indexation basis in Asia. So this extra gas shouldn't have an impact on future pricing.

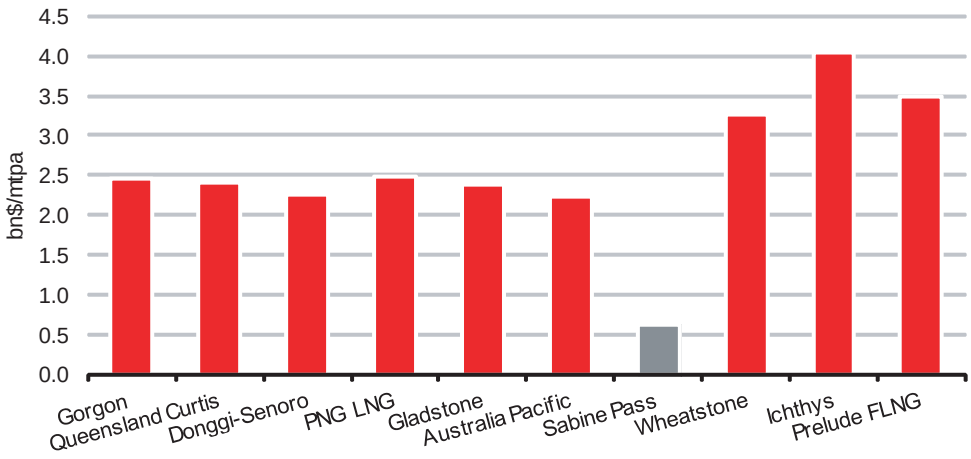
QATAR VS AUSTRALIA: LNG CAPACITY



Source: SG Cross Asset Research

As Qatar, the lowest cost producer, was not prepared to compromise on a strategy of seeking prices close to crude oil parity, the highest cost producer, Australia, was able to stay in the competition and achieve prices that make economic sense for the investment in its new projects. But recent developments in the US and Canada could lead to North America becoming a major LNG exporter. US LNG should be much cheaper to build as: 1/the upstream, transportation and LNG infrastructure (jetty, tanks) are already there; 2/cost of labour is cheaper than in Australia. Finally, competition for water supplies (agriculture, industry and humans) is a major issue in Australia, as water management from unconventional production is an ongoing and expensive operation.

DISCLOSED CAPEX OF LNG PROJECTS



Source: SG Cross Asset Research, companies data

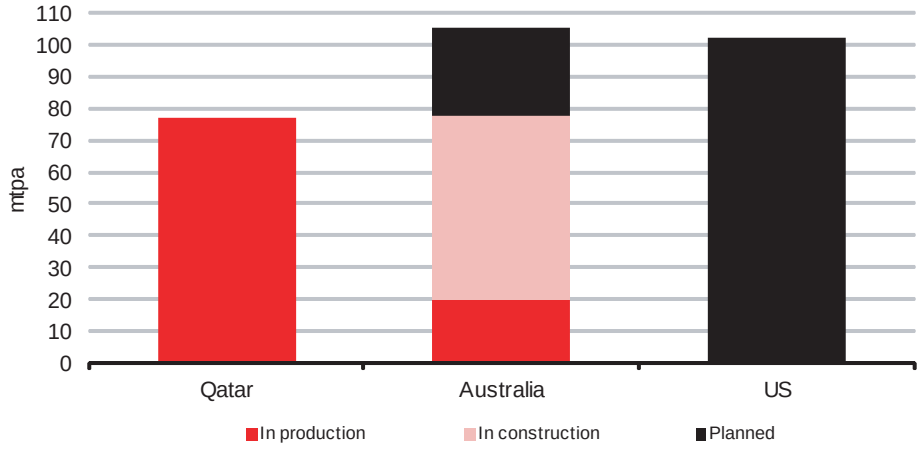
Given their high capex requirements, Australian producers can only offer oil-linked LNG contracts, whereas Cheniere (and perhaps other US projects) are selling (and could sell) LNG under a Henry Hub linked formula. We therefore believe that US LNG supply could grow quickly over 2016–2020e.

In May 2012, BG announced a 36% rise in its Queensland Curtis LNG project since the Final Investment Decision (October 2010). This announcement could be followed by other Australian projects increases. And Ichthys could be the last greenfield LNG project sanctioned in Australia because, with rampant cost inflation and faced with an increasingly price-sensitive customer base, these large-scale, expensive projects simply look cumbersome and out-dated in the context of intensifying global competition. As a result, Australian projects are being priced out of the market. This, coupled with delays, is eroding returns from the country's already marginal developments. In the last two years, Qatar's pricing policy has meant that the highest cost producer, Australia, has been able to undercut the lowest cost producer, Qatar. The emergence of the US and Canada as potentially major LNG exporters will create a new environment in which Australia will find it more difficult to compete.

Thanks to the shale gas revolution, the US has become a low cost energy producer on a global basis. The US could mitigate Russia power on the international gas scene by delaying its entrance on the Chinese market as China could view the US LNG as cheaper and safer than pipe gas from Russia or LNG from the Middle East.

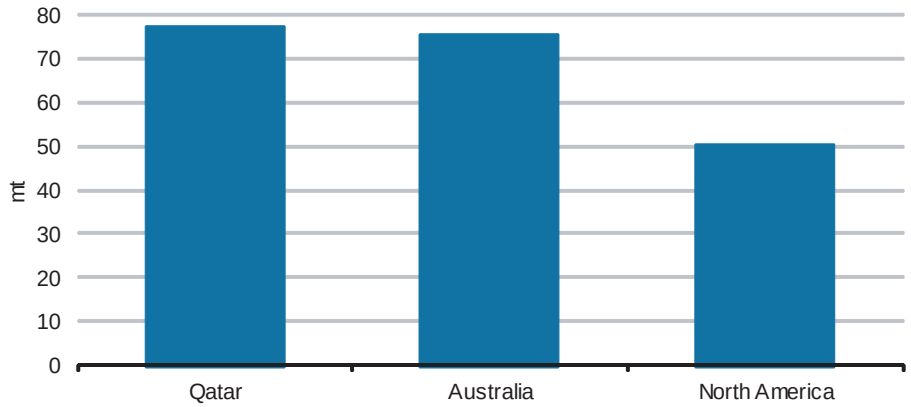
Also, as greenfield projects in Australia are going to be delayed or derailed by the cheaper US LNG export projects, it is possible that, in 2020e, Qatar would still be the number 1 LNG producer worldwide, followed by Australia and North America.

QATAR, AUSTRALIA OR NORTH AMERICA: WHO COULD BE FIRST LNG PRODUCER IN 2020E?



Source: SG Cross Asset Research

2020E LNG PRODUCTION: 3 FIRST PRODUCERS



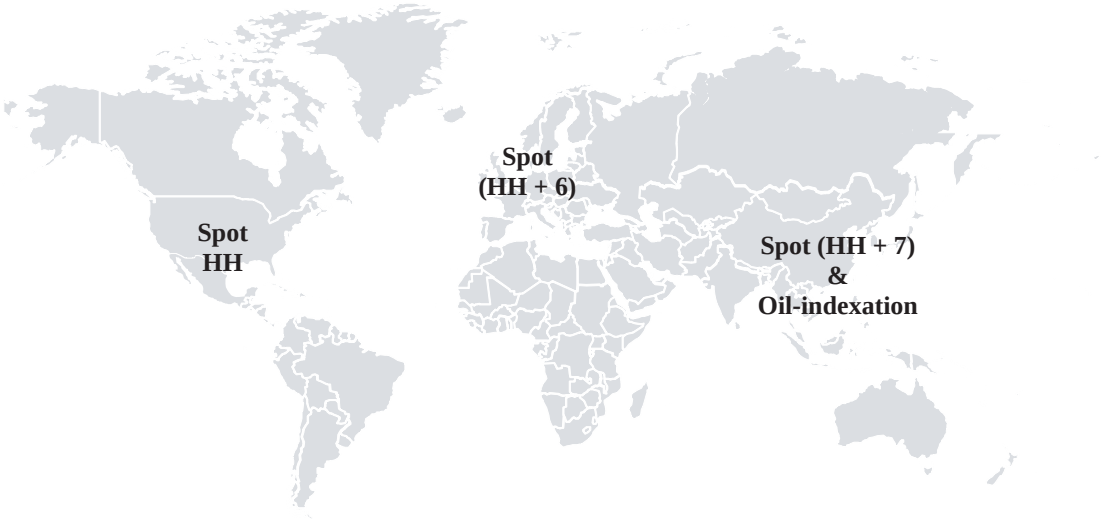
Source: T. Bros/After the US shale gas revolution

IN THE FUTURE, MARKETS COULD BE LINKED VIA THE COST OF LNG ARBITRAGE

By directly sourcing US LNG priced under an HH formula, Asian customers are cutting out the middle man, the LNG aggregator. And, if the US becomes a major LNG producer as we believe, then this change in business model could start to reduce oil-indexation in Asia, as we are seeing in Europe.

The US could be the cheapest gas market by the end of the decade; other markets will be linked via the cost of arbitrage (liquefaction, transport and regasification).

OVERVIEW OF GAS PRICES IN 2020E (WITH ESTIMATED SPREADS IN $/MBTU)



Source: T. Bros/After the US shale gas revolution

To supply growing markets, the major resource holder, Russia, is now in direct competition with the major gas producer, the US. China has the potential not only to select the winner but also to decide the pricing principle for all Asian buyers in 2020e. As China is a new and growing gas importer and has a lower price tolerance than historical Asian buyers (Japan and South Korea), it is highly possible that, contrary to what basic geography would suggest, China selects waterborne US LNG vs close Russian pipe gas, to achieve lower import prices.

The Singapore LNG terminal should start operations in 2013. The main role of the terminal is to supply the Singapore market, but the functionality of the terminal to operate as a trading hub has been built into the design and the commercial arrangements. Singapore will help balance supply and demand in Asia by allowing arbitrages of LNG cargoes.

Until the shale gas revolution, net importers were bound to become more and more energy dependent. The shale gas revolution changed this dependency paradigm forever and is offering an alternative. The US has chosen to reduce its dependency on foreign (oil &) gas. China will use this new technology to mitigate its growing gas dependency. Only Western Europe (excluding Poland) has, so far, chosen to avoid this technology and to keep its growing dependency on gas importers. EU gas proven reserves, which have decline 6.6% CAGR over 2001–2011, can only grow if the region decides to go for shale gas. And, European gas market will never be fully functioning without enough domestic shale production.

Also submitted: "After the US shale gas revolution" which deals with all of these issues.

September 2012

Written evidence submitted by EDF Energy (ISG 18)

EXECUTIVE SUMMARY

- EDF Energy believes that the level of technically recoverable shale gas resources around the world is potentially significant. However, based on the currently available evidence, we believe that the conclusion of the Committee's previous report in May 2011 remains correct, namely that shale gas is unlikely to be a "game changer" for the UK and that we are unlikely to replicate the production experience of the USA.
- European shale gas production costs are likely to be higher than those in the USA. Reasons include differences in regulatory, fiscal, labour and environmental regimes, as well as land and resource access issues pertaining to geology and population density.
- While shale gas may make a contribution towards the EU's energy needs, the region is forecast to be dependent on imports of gas for at least 60% of its demand by 2030.[1] Global conditions will therefore continue to influence regional market prices. Gas prices currently remain strong despite weak gas and power demand as a result of the world recession.

— Future European gas prices are likely to be set by the marginal cost of importing gas from Norway and Russia, as well as by LNG. Although the volume of gas available worldwide may be increasing, once the costs of LNG transportation (and re-gasification) to Europe is taken into account, this may only curb the extent of price rises in the longer-term rather than drive prices down from current levels. In addition, it is likely that LNG cargoes diverted from the USA will be used to meet growing demand in Asia rather than go to Europe.

— Gas-fired generation (whether fuelled by conventional or shale gas) will play an important role in the transition towards a decarbonised power sector in the 2030s by providing the reliable and flexible backup generation required for balancing the electricity system.

— However, further investment in any unabated gas generation plant, beyond the minimum that is required to bridge the gap to the transition to low carbon technologies, would introduce significant challenges in meeting the UK's legally-binding climate change objectives. Such investment substantially increases the risk that the UK's long term emissions reduction targets will not be met, or at least be met in a cost-effective manner. This is either because the carbon emissions from these new assets will be 'locked in' or, alternatively, because it increases the risk of stranded assets.

— The carbon footprint of long distance gas transportation systems, including LNG and pipelines will have to be considered. This could be significant in some cases, as the UK starts increasingly to move away from UK Continental Shelf (UKCS) supply to a greater reliance on imported gas. We also support the Committee's previous recommendation that adequate regulatory safeguards should be in place to monitor and mitigate some of the other environmental concerns associated with shale gas, including methane leakage.

— We believe that the largest opportunity for gas generation in the longer term will be when it is fitted with carbon capture and storage (CCS), since this could allow gas to take a larger share of the market if other low carbon options do not come forward, or if they prove to be more expensive.

— It is imperative that the Government maintains its continued momentum on Electricity Market Reform (EMR). Reform of the existing electricity market arrangements is necessary to ensure the market is capable of delivering the reliable diverse energy mix required to deliver the UK's energy policy objectives. The Government's proposals will provide the investment framework that is crucial for the low carbon investment that the country needs, and will keep costs down for consumers.

— EDF Energy believes that the Government's commitment to move to a low carbon economy is likely to mean that fossil fuel plant such as CCGTs will in the future operate at lower load factors than historically has been the case. This is likely to lead to increased revenue uncertainty and this could lead to under-investment and lower levels of reliable capacity. We therefore welcome the Government's proposal to introduce a capacity market to help address security of supply concerns, and look forward to seeing its design preference by the end of the year.

About EDF Energy

EDF Energy is one of the UK's largest energy companies with activities throughout the energy chain. We provide 50% of the UK's low carbon generation. Our interests include nuclear, coal and gas-fired electricity generation, renewables, and energy supply to end users. We have over five million electricity and gas customer accounts in the UK, including both residential and business users.

EDF Energy's Response to Your Questions

Q1. *What are the estimates for the amount of shale gas in place in the UK, Europe, and the rest of the world, and what proportion is recoverable?*

1. In lieu of access to primary data, EDF Energy has conducted a comprehensive review of the available literature on shale gas and other unconventional gas resources. However, no one report is viewed as a definitive reference source and most of the reports reviewed contain sufficient caveats to acknowledge that the estimates provided are liable to change.

2. The literature suggests that the shale gas volumes in place in the UK are substantial, up to 5 trillion cubic metres (tcm).[2] However, estimates of technically recoverable reserves range between 150 billion cubic metres (bcm)[3] and 570 bcm,[4] and this represents two to seven years of UK gas demand in 2011.[5] As annual production volumes are likely to be small (Pöyry forecasts a maximum 4 bcm per annum[6]), the UK will still need to import around three quarters of its forecast gas demand by 2030.[7]

3. The estimates for the amount of shale gas in Europe are also wide-ranging, and range from 16 tcm[8] to 157 tcm.[9] Within this, technically recoverable gas is estimated at around 3.8 tcm[10] to 17.7 tcm,[11] and commercially recoverable volumes up to 4.4[12] tcm. In the most optimistic scenario, shale gas will offset the decline in EU domestic gas production, leaving a need to import at least 60% of gas demand by 2030.[13] This is likely to come from Norway and Russia, or by diverting LNG cargoes away from Asia.

4. The USA has made the greatest advances in fulfilling the potential of shale gas, and has seen shale gas production increase from 28 bcm in 2006 to 140 bcm in 2010. However, despite having 30 years experience in shale gas extraction, the true size of potentially extractable shale gas reserves remains uncertain and is still being discovered. The range of technically recoverable shale gas reserves are estimated at between 13–50 tcm,[14] out of total resources of 109–202 tcm.[15]

5. With regard to the rest of the world, although shale gas resources appear to be abundant across the globe, the most significant are in China with recoverable reserves estimated at 1.6[16]–36[17] tcm (albeit with relatively few studies available). However, it is important to note that the most promising area, the Tarim basin, is located in an arid region and therefore does not have easy access to the large volumes of water required during the hydraulic fracturing process.

6. EDF Energy believes that the level of technically recoverable shale gas resources around the world is potentially significant. However, based on the currently available evidence, it is our view that the production experience of the USA is unlikely to be replicated elsewhere because there are still considerable obstacles that must be overcome. Besides the ongoing need to address a number of wider environmental concerns associated with hydraulic fracturing (such as groundwater contamination), the commercial viability of extraction is variable across countries because it is dependant on specific local issues, including access to land, environmental constraints, technological knowledge and expertise, cost of production, access to market and fiscal terms. Public support, and ultimately social acceptability, will also remain key factors that will have to be considered.

Q2. *Why are the estimates for shale so changeable?*

7. Although the presence of unconventional gas resources have been known for decades, the shale gas industry is still in its relative infancy, and this is reflected in the uncertain nature of the data and forecasts available. We would expect the quality of the forecasts to improve as further exploration and drilling proceeds. This has been reflected in the general global upward trend in shale gas resource estimates over the last two decades as the quality of data available from actual production experience (as opposed to modelling and inference) improves.

8. A recent report by the European Commission Joint Research Centre (JRC)[18] highlights some of the difficulties involved in making accurate estimates and the subsequent variability in estimates. This includes a "lack of comprehensive and independently corroborated data on geology, the results of exploration drilling and the long term production levels of wells". The report also suggests that "industry practice is evolving so rapidly that ultimate recovery rates and unit costs of produced unconventional gas are moving targets with some forecasts predicated on the anticipation of future technological progress".

9. The JRC also notes differences in the resource assessment methodologies (eg bottom-up analysis of geological parameters or extrapolation of production experience) and assumptions used by the various sources. We agree that it is likely that such lack of consensus will contribute to the large variation in estimates. For example, the report highlights the inconsistencies in the definitions used for commonly used terms in the available literature. This makes it difficult to compare different estimates (eg ambiguity over the definition for "technically recoverable resources"). The authors also point out that, bar the US Energy Information Administration (EIA), there are few organisations that provide resource estimates for unconventional gas on a regular basis. This also makes comparison between estimates difficult, given the general assumption that the most recent report represents the most accurate information available.

10. All the relevant sources that we reviewed stated that European shale gas production costs are likely to be higher than those in the USA, with the most commonly stated prediction being around 50% higher.[19] Reasons include differences in regulatory, fiscal, labour and environmental regimes, as well as land and resource access issues pertaining to geology and population density. It is also important to highlight that the low gas price in the USA (~18p/therm versus ~61p/therm in the UK) is due to current overproduction and oversupply, and partly driven by the fact that shale gas is being extracted as a by-product from shale oil production. The current price is perceived by several market analysts to be below break-even and unsustainable for dry (ie non-oil associated) shale production, and this has likely contributed to the recent $5.5bn write down in value of shale gas assets by a number of major energy companies.[20]

Q3. *Should the UK consider setting up a wealth fund with the tax revenue from shale gas?*

11. EDF Energy is aware of the use of Stabilisation Funds in countries around the world (such as Norway) to control the revenue stream resulting from commodity sales. The aim is to smooth out the effect of windfalls and shortfalls caused by fluctuations in commodity prices. The Funds help governments try and stabilise their expenditure over time so that during boom periods, the excess revenue is not spent and instead can be drawn upon during leaner times. As a result, Government spending does not have to be cut during such austere periods. This also has the additional benefit of helping check inflationary pressures.

12. We believe that this is an option that the Government may wish to consider in the future, once the forecasts of UK shale gas production and its impact on UK and European gas prices (and hence actual tax revenue) are more certain.

Q4. *What have been the effects of the shale gas on the LNG industry?*

13. The increase in unconventional gas production in the USA over the last decade has had a knock-on effect on LNG imports into the country, and together with the global economic recession has led to a global surplus of LNG capacity. However, according to Chatham House,[21] some of the surplus LNG capacity has been absorbed by an increase in Japanese demand for gas to replace the loss of generation capacity as a result of the tsunami and earthquake in March 2011.

14. In the last decade, US domestic gas production was originally forecast to decline. This led to a surge in LNG re-gas capacity investment in the USA, with corresponding investment in those countries, such as Qatar, that were looking to export gas. However, as a result of increased shale gas production, the USA actually only imported 13 bcm of LNG in 2009 (out of a LNG re-gasification capacity of nearly 150 bcm[22]). There are now plans for US producers to add export capabilities, and the EIA forecasts that the USA will become a net exporter of LNG in 2016.

15. With this new dynamic, the JRC forecasts that it is likely that Europe will replace the USA to become the second largest regional market after Asia for LNG in terms of import/re-gasification potential. The International Energy Agency (IEA)[23] predicts that the trend in liquefaction (ie export) growth will continue to grow for the foreseeable future with overall capacity expected to grow by 50% between 2008 and 2013.

Q5. *Could shale gas lead to the emergence of a single, global gas market?*

16. The rapid growth of liquefaction and re-gasification LNG capacity around the world, and corresponding global LNG trade volumes over the past decade, have helped break down the regional and fragmented nature of gas markets. However, it is too early to suggest that this growth, along with current developments in shale gas, is likely to lead to a global gas market in the foreseeable future. Even if a global gas market were to develop, significant price differentials between the US, European and Asian markets would persist as the costs of producing, shipping and re-gasifying LNG are significant. We believe that a move away from traditional oil-indexed gas contracts, as is starting to emerge in the EU, will help because as the JRC notes, "a weaker [oil-gas price] link implies greater potential for shale gas to induce a significant growth of gas use in [LNG] transportation".

17. It will be important to consider the carbon footprint of long distance gas transportation systems, including LNG and pipelines. This could be significant in some cases, as the UK starts increasingly to move away from UK Continental Shelf (UKCS) supply to a greater reliance on imported gas.

18. Based on the currently available evidence, we believe that the conclusion of the Committee's previous report in May 2011 remains correct, namely that shale gas is unlikely to be a "game changer" for the UK. While shale gas may make a contribution towards the EU's energy needs, the region will continue to be dependent on imports of gas. We believe that global conditions will continue to influence regional market prices. Gas prices currently remain strong despite weak gas and power demand as a result of the world recession.

19. In the short to medium term, Europe is likely to be caught between downward pressures through LNG cargoes diverted away from the USA (and the development of LNG supply from Qatar and Australia), and upward pressure from growing demand for gas from Asia. However, although the volume of gas available worldwide may be increasing, it is important to note that, once the cost of transportation to Europe is taken into account, this may only curb the extent of price rises in the longer-term rather than drive prices down from current levels.

Q6. *What are the effects on investment in lower-carbon energy technologies?*

Please see our response to Question 7.

Q7. *What is the potential impact on climate change objectives of greater use of shale gas?*

20. EDF Energy is committed to delivering affordable, secure, and low carbon supplies based on a diverse energy mix, including nuclear and renewables. As part of this, we believe that unabated gas fired generation (including that from shale gas) will play an important role in the transition towards a decarbonised power sector in the 2030s by providing the reliable and flexible backup generation required for balancing the electricity system.

21. In addition to its role in electricity generation, gas also plays a significant role in heating, with 81% of home heating[24] fuelled by this source. However, we support DECC's ambitions to move away from fossil fuel heating. EDF Energy has long supported early action on renewable heat, as we believe that this is a sector which can make a significant and cost effective contribution to the UK meeting its 2020 renewable energy target, especially through the use of heat pumps.

22. Further investment in any unabated gas generation plant (whether fuelled by conventional or shale gas), beyond the minimum that is required to bridge the gap to the transition to low carbon technologies, would introduce significant challenges in meeting the UK's legally-binding climate change objectives (as set out in the Climate Change Act 2008). This is because while gas fired generation has lower carbon dioxide emissions

than old coal fired generation, without carbon capture and storage (CCS) it is still a significant source of carbon emissions in its own right.

23. Such investment in unabated gas generation plant substantially increases the risk that the UK's long term emissions reduction targets will not be met, or at least be met in a cost effective manner. This is either because the carbon emissions from these new assets will be 'locked in' or, alternatively, because it increases the risk of stranded assets.

24. As recognised in the Committee's previous report, we note that there is a large divergence in opinion with regard to the lifecycle greenhouse gas footprint of shale gas (including direct and indirect emissions of both carbon dioxide and methane), and the issue of such leakages will need to be investigated further.

25. It is imperative that the Government maintains its continued momentum on Electricity Market Reform (EMR). Reform of the existing electricity market arrangements is necessary to ensure the market is capable of delivering the reliable diverse energy mix required to deliver the UK's energy policy objectives. The Government's proposals will provide the investment framework that is crucial for the low carbon investment that the country needs, and will keep costs down for consumers.

26. The Government's commitment to move to a low carbon economy is likely to mean that fossil fuel plant such as CCGTs will in the future operate at lower load factors than historically has been the case. This is likely to lead to increased revenue uncertainty and this could lead to under-investment and lower levels of reliable capacity. We therefore welcome the Government's proposal to introduce a capacity market to help address security of supply concerns. A well designed capacity market will deliver a higher reliability standard in a sustainable and cost effective way. It is vital that the capacity market is designed to provide adequate capacity to ensure security of supply and we look forward to seeing the Government's design preference by the end of the year.

27. The potential emergence of large volumes of shale gas reinforces the need to establish a credible and enduring carbon price signal so that investors are able to make well-informed investment decisions. It is commonly accepted that the current EU ETS price is not providing the long-term signal to make the relevant investments in low carbon generation. While the introduction of the carbon price floor in the UK helps restore the long-term price signal that the EU ETS was expected to achieve, it does not remove the need for reform of the EU ETS at the European level.

28. EDF Energy therefore supports initiatives that would help remedy some of the defects of the EU ETS at the European-wide level, and would encourage the Government to pursue these. For example, we agree with the Government that the UK should work with its EU partners to arrive at a robust agreement for domestic carbon dioxide reductions across the EU, including a more ambitious reduction target for 2020 relative to 1990 levels.

29. In addition, as the supply side of the EU ETS is totally inelastic, we believe a supply response mechanism, based on transparent and objective criteria, and resulting in a minimum level of scarcity, would help UK industry avoid any unnecessary differential competitive impacts and help address carbon leakage concerns. The EU ETS cap should be able to adjust to compensate for the impacts of other EU energy policy initiatives (eg renewable and energy efficiency targets), resulting in cuts in emissions, to ensure that carbon price signals are not undermined.

October 2012

References

[1] IHS CERA, Breaking with Convention, 2011

[2] Ibid.

[3] British Geological Survey, The Unconventional Hydrocarbon Resources of Britain's Onshore Basins, Shale Gas, 2011

[4] EIA, World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States, April 2011

[5] BP Statistical Review of the World 2012 states 2011 UK gas consumption at 80.2 bcm

[6] Pöyry, The Impact of Unconventional Gas on Europe, June 2011

[7] IHS CERA, Breaking with Convention, 2011

[8] EIA—World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States, April 2011

[9] IHS CERA, Breaking with Convention, 2011

[10] Wood Mackenzie total unconventional resource

[11] EIA, World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States, April 2011

[12] IHS CERA, Breaking with Convention, 2011

[13] Ibid.

[14] IEA, EIA, IHS CERA and Advanced Resources International Estimates

[15] EIA, World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States, April 2011

[16] European Commission Joint Research Centre, Unconventional Gas: Potential Energy Market Impacts in the European Union, September 2012

[17] EIA, World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States, April 2011

[18] European Commission Joint Research Centre, Unconventional Gas: Potential Energy Market Impacts in the European Union, September 2012

[19] Pöyry, The Impact of Unconventional Gas on Europe, June 2011
IEA Golden Rules for a Gold Age of Gas and EU Commission, Unconventional Gas: Potential Energy Market Impacts in the European Union, p129. "cost estimates are in line with current break-even costs for shale gas production in Europe of … $5–12/MBtu" which is approximately 50% higher than the $3–6/MBtu quoted for the US on page 191.

[20] http://www.arcticgas.gov/2012/companies-write-down-value-shale-gas-assets

[21] Chatham House, The 'Shale Gas Revolution': Development and Changes Briefing Paper, August 2012

[22] European Commission Joint Research Centre, Unconventional Gas: Potential Energy Market Impacts in the European Union, September 2012

[23] IEA, Medium-Term Oil and Gas Markets, 2010

[24] DECC, The Future of Heating: A strategic framework for low carbon heat in the UK, March 2012

Written evidence submitted by the Geological Society (ISG 28)

1. This submission has been produced jointly by the Geological Society of London and the Petroleum Exploration Society of Great Britain:

(i) The Geological Society of London (GSL) is the national learned and professional body for geoscience, with over 10,500 Fellows (members) worldwide. The Fellowship encompasses those working in industry, academia and government, with a wide range of perspectives and views on policy-relevant geoscience, and the Society is a leading communicator of this science to government bodies and other non-technical audiences.

(ii) The Petroleum Exploration Society of Great Britain (PESGB) represents the national community of Earth scientists working in the oil and gas industry, with over 5,000 members worldwide. The objective of the Society is to promote, for the public benefit, education in the scientific and technical aspects of petroleum exploration. To achieve this objective the PESGB makes regular charitable disbursements, holds monthly lecture meetings in London and Aberdeen and both organises and sponsors other conferences, seminars, workshops, field trips and publications.

2. Since the start of 2011, our two organisations have worked together when appropriate in communicating with the government, parliamentary committees and others on matters relating to petroleum geoscience. Both our organisations routinely bring together the best geoscientists from across academia, industry and government to exchange and debate research findings, through scientific meetings and publications.

3. Our submission focuses on the geoscience relating to shale gas exploration and extraction, and on the interface between geoscientific and other factors (eg economic geology). Several of the questions in the Committee's call for evidence are outside the competence of the GSL and PESGB. Others are better placed to advise on matters such as likely downstream impacts on gas markets.

What are the estimates for the amount of shale gas in place in the UK, Europe, and the rest of the world, and what proportion is recoverable? Why are these estimates so changeable?

4. The answers to these interrelated questions depend not just on geological knowledge of what lies beneath the Earth's surface, but also on economics and technology. Estimates of geological resources are always uncertain, and vary over time, but the level of uncertainty is currently greater for shale gas than for conventional hydrocarbon resources.

5. Estimates can be made of the total resource in the ground, based on geology and on information gathered through exploration and production activity. The technically recoverable resource is smaller, and will vary depending on the technology available at any point in time. "Reserves" refers to the amount of a resource which can be economically extracted using current technologies and under current regulatory regimes, and will therefore also depend on cost of extraction and market price.

6. It is known that there are large sedimentary basins in the UK, containing significant shale formations in which natural gas is likely to occur. Although in general our knowledge of the subsurface of the UK is more extensive than that in most other countries, work to explore specifically for shale gas remains in its early stages. Shale gas occurs in different types of geological formation from conventional hydrocarbons, in more extensive and less clearly defined "plays" rather than discrete reservoirs. The way in which natural gas is trapped within shale also differs from conventional gas. The hydrocarbons industry has well-established techniques to locate, characterise and quantify conventional resources, but not all of these are readily applicable to shale gas. The geology of shales, and the nature of the pore systems within them, is variable and complex, and techniques to assess their permeability and porosity are relatively undeveloped. As a result of all these factors, data about the extent and ease of recovery of shale gas resources in the UK are limited, and geologists' interpretations of these data vary widely. The same is true of other countries outside the US, to varying degrees.

7. DECC has commissioned a British Geological Survey (BGS) team to provide a more detailed analysis and estimate of the entire Bowland Shale gas total resource potential (gas-in-place) to better understand the potential future contribution to the UK energy mix. This work is due to be completed by the end of 2012 and will provide an independent assessment of the total resource.

8. The United States Geological Survey (USGS) has surveyed the considerably more extensive sedimentary basins in the US. They have developed geology-based assessment methodologies to estimate the quantity of as yet undiscovered hydrocarbon resources (both conventional and unconventional), in the US and globally. For example, in June 2012 they reported an estimated mean undiscovered natural gas resource of 3.9 trillion cubic feet within five East Coast basins (see http://pubs.usgs.gov/fs/2012/3075/). This analysis formed part of a nationwide project to assess domestic resources in hydrocarbon-bearing basins using a standardised methodology and protocol. Estimates of this kind are necessarily very approximate. They can subsequently be refined in light of data gathered through exploration activity, and later in the production phase. (It is true, though unhelpful, to say that the total quantity of technically recoverable resource in a shale gas play or conventional reservoir cannot accurately be known until it has all been recovered.)

9. The proportion of resource in place which is technically recoverable can vary by as much as a factor of 10 (see US Energy Information Administration report at ftp://ftp.eia.doe.gov/natgas/usshaleplays.pdf, for example). Recovery factors vary not just between plays, but from well to well, and are understood more poorly for unconventional hydrocarbons (including shale gas) than for conventional resources, especially outside the US. This is due in part to the fact that decline curves (the rate at which gas flows from a well throughout its lifetime) for shale gas differ considerably from those for conventional gas (and will also vary from case to case).

10. The economics of shale gas and conventional gas also differ. Conventional gas requires high effort to find, but relatively low effort to produce. Shale gas is relatively easy to find (in that we can expect to find it in many shale formations, and these are widespread), but requires high effort to produce. The economic and regulatory environment will determine the amount of effort which it is worthwhile to apply both to finding and producing resources. Feedbacks such as that currently operating in the US (where the huge amounts of shale gas coming onto the market has depressed prices) may exacerbate fluctuations in reserves (economically recoverable resources).

11. Furthermore, there are feedbacks between technological and economic drivers. For example, as the shale gas industry matures, new technologies are likely to improve its ability to target "sweet spots" in gas plays, meaning that drilling and completion of wells (installation of equipment and readying them for production) will become cheaper and more efficient, reducing production costs.

12. Geoscientists are used to dealing with uncertainty, whether due to incomplete data, or the conceptual and structural interpretation of these data. Indeed, such uncertainty drives research and further data gathering. However, uncertainty can also undermine public and stakeholder confidence in cases where economic and environmental risks and benefits must be weighed, especially where the regulation and governance of novel technologies is under examination, and it can disrupt market mechanisms. It is important that geoscientists work with other specialists and decision-makers to communicate effectively to the public the nature of such uncertainty and how it can be constrained. In the case of shale gas, geological uncertainty may relate not only to the extent of shale gas resources, but also to the possible effects of its extraction (eg extent and nature of induced seismicity and fracture propagation). These uncertainties are only likely to be significantly reduced through conducting further research and data gathering in the context of careful, well-regulated exploration.

What are the prospects for shale gas in the UK Continental Shelf?

13. There is likely to be a significant amount of offshore shale gas in place, and evidence of gas in offshore mudlogs in shales is not uncommon. However, we are not aware of any targeted data collection to date to quantify this, although potentially useful background data will have been gathered in the context of conventional hydrocarbon exploration. We understand that a proposal is under consideration for BGS to carry out a detailed assessment for a selected offshore area.

14. Although the existing North Sea expertise and infrastructure for conventional hydrocarbons would confer some advantage should the UK attempt to exploit offshore unconventional resources, this would nonetheless require us to pioneer offshore shale gas exploration and production, which would be no small undertaking. (Given the extent of onshore resources in the US, they have no need to look for offshore resources.) It is highly

unlikely that it would become economic to drill wells offshore at the spacing presently required to produce shale gas at volume, so any future offshore production is likely to depend on the development of new technologies.

What is the potential impact on climate change objectives of greater use of shale gas?

15. The July 2012 report on "Climate impact of potential shale gas production in the EU", prepared for the European Commission by AEA, provides a useful overview of the widely varying conclusions of existing studies of carbon emissions resulting from the extraction and use of shale gas. It notes that this variation is largely due to authors' selection of narrow sets of data, different interpretations of such data and different framing assumptions. It also points out that "overall, the emissions from shale gas are dominated by the combustion stage" (p iv). Shale gas and conventional gas have the same composition (mainly methane, though in both cases the exact proportions of gases present will vary), albeit found and extracted in different geological settings, so the emissions from their combustion are the same. Emissions at stages prior to combustion include fugitive emissions of methane (a considerably more potent greenhouse gas than carbon dioxide) at the point of extraction, those resulting from processing (eg liquefaction), and from its transmission/transport. Fugitive emissions (ie gas which escapes into the atmosphere from the well or through equipment at the well site) have been found in some studies to be higher than for conventional gas.

16. Looking at the range of studies, it is uncertain whether total emissions from shale gas are greater or less than those from imported conventional gas, for instance. In fact this is likely to vary from case-to-case, as the level of fugitive emissions will depend on factors such as well integrity and the design of production processes, and those resulting from transport will depend on its mode and distance. As with other potential environmental impacts of shale gas extraction, appropriate and effective regulation is required to minimise fugitive emissions. The comparison with coal is more clear-cut—emissions resulting from the extraction and use of shale gas are considerably less.

17. This does not mean that natural gas (whether conventional or unconventional) can be extracted and used with impunity, in the absence of carbon capture and storage (CCS). Both nationally and globally, we will continue to be dependent on fossil fuels for several decades, and if the resulting carbon emissions are not sequestered this is likely to have very significant negative effects on our environment. The geological record contains abundant evidence of the environmental changes associated with rapid periods of release of carbon into the atmosphere in the deep past. (See the Geological Society's Climate Change Statement at www.geolsoc.org.uk/policy_statements.) We agree with the comments of the chair of the Energy and Climate Change Committee that given sufficient care and attention, shale gas could be safely produced, but that the emergence of shale gas as a major fossil fuel increases the "urgency of bringing carbon capture and storage technology to the market and making it work for gas as well as coal" (Select Committee Announcement 45a, 23 May 2011).

Other Comments

18. Since the Committee's previous inquiry into shale gas, GSL and PESGB have been active in communicating the relevant geoscience to public and other audiences.

19. The Geological Society held a public briefing meeting in June on the geoscience relating to shale gas, its extraction, and the potential environmental risks. This meeting was well received, and attracted a wide audience including elected representatives and officials from local and central government, and those from regulatory bodies, NGOs, water utilities, and the hydrocarbons and energy supply chain. A statement resulting from this meeting, as well as all the presentations and additional material, can be found at www.geolsoc.org.uk/shalegas.

20. Among other activities, we have also submitted joint responses to the DECC consultation on the expert review on induced seismicity, and to the Royal Society and Royal Academy of Engineering review of whether the risks associated with shale gas extraction can be managed effectively.

21. We would be pleased to discuss further any of the points raised in this submission, to provide more detailed information, or to suggest oral witnesses and other specialist contacts.

October 2012

Supplementary written evidence submitted by the Geological Society (ISG28a)

Unconventional and Conventional Gas Resource and Reserve Estimates for the UK

1. Unconventional gas includes tight gas, coal bed methane and shale gas. Of these, shale gas currently has the most significant growth prospects because relatively novel applications of existing technologies (coupling fracking with horizontal drilling) have enabled economically viable extraction of gas from shales, which have much lower permeability than conventional gas reservoirs.

2. As discussed at the evidence session on 27 November 2012, it is important to draw a distinction between resources and reserves. **Resource** is the amount of gas underground. **Reserve** is the amount of gas which can be produced economically—that is, which we can realistically expect to extract from the ground given current

technological, economic and social/regulatory constraints. Another term which is sometimes used is 'technically recoverable' resource—this is the amount which could be extracted given current technology, but without reference to economics (cost of extraction and price) or social acceptability.

3. As set out in our main written evidence, and discussed at the 27 November evidence session, policy-makers looking to establish how much of a resource is available to come to market (that is, reserves) are faced with several types of uncertainty:

(a) The amount of **resource** in place in the ground can be more or less well defined, depending on how well the geology is understood, and the type and extent of exploration carried out for the resource in question. Typically, resources are considered in terms of discovered resource (irrespective of whether these are thought likely to be technically or economically recoverable), and undiscovered resource (based on mapped leads and knowledge of the geology, and necessarily much less reliable).

(b) **Reserve** estimation is much less certain (and more probabilistic) than the estimation of resources, as it depends on a wide variety of geological, technological, economic and socio-political factors. This is not to suggest a lack of sophistication in reserve assessment, which is the subject of a great deal of highly expert work in hydrocarbons companies (where strict standards apply—see comments on SEC guidelines at paragraph 20 below). Reserves are typically classified as proven, probable or possible (depending on the assessed probability of their being technically and economically producible).

(c) In the case of shale gas, the uncertainties are exacerbated by the different nature of the resources compared with conventional hydrocarbons, where seismic imaging of the subsurface has a major role in defining resources and reserves, and the fact that shale gas resources have been much less explored (see our original written submission and the oral evidence session for further details).

(d) A further complicating factor is that different government bodies, surveys, international organisations, academic studies and commercial companies have adopted different bases for reporting their assessments, variously including or excluding: gas already produced; reserves; technically recoverable resources; discovered and undiscovered resources; onshore and offshore resources; and different geological settings for hydrocarbon resources (eg shale gas, all unconventional gas, or all gas including conventional gas). They often also use different units—in our comments below, we have converted all figures to trillion cubic feet (tcf) (or trillion cubic feet in gas equivalent (tcfg) for liquids).

4. With all this in mind, it is impossible to provide a single set of figures indicating how much shale gas or other unconventional gas might be economically recovered (and how this compares to reserves of conventional gas), either in the UK or more widely. In the paragraphs which follow, we have identified some sources of quantitative information which may help the Committee assess the possible impact of shale gas on UK energy markets, and which we believe are well-founded (within the limitations we have set out above and caveats attached to the sources themselves).

5. DECC provides estimated aggregate data on UK reserves and resources at http://og.decc.gov.uk/en/olgs/cms/data_maps/field_data/uk_oil_gas_res/uk_oil_gas_res.aspx. These include estimates of oil and gas reserves, potential additional resources (that is, discovered resources which are not currently technically or economically producible) and undiscovered resources. Regarding undiscovered resources, from looking at the gas fields listed and the amounts cited, we assume that these refer to conventional resources (and do not include existing DECC estimates of shale and other unconventional gas)—although this is not made explicitly clear. The figures for gas reserves are said to include 'a small amount from coal bed methane projects'—we assume therefore that most unconventional gas, including all shale gas, is excluded from these figures, although again this is not explicit. The Committee may wish to raise with DECC the ambiguity attached to the scope of these figures, and how the data themselves might be presented more clearly.

6. DECC's figures give a central estimate for UK reserves (ie proven and probable), possible reserves (less certain to be produced), potential additional resources (discovered but not currently technically recoverable), undiscovered resources, and cumulative production (total past production to date from UK oil and gas fields) at the end of 2011 as follows:

Oil: Reserves—34 tcfg
(Possible reserves—13 tcfg)
(Potential additional resources—13 tcfg)
(Undiscovered resources—32 tcfg)
(Cumulative production—152 tcfg)

Gas: Reserves—17 tcf
(Possible reserves—8 tcf)
(Potential additional resources—7 tcf)
(Undiscovered resources—20 tcf)
(Cumulative production—84 tcf)

(These figures may include some rounding errors due to unit conversions. Figures for oil include liquids from gas fields. Figures for gas include gas from oil fields.)

7. Estimates of shale gas resource are less certain than those for conventional resources (for the reasons referred to above), and this is even more true of reserve estimates. A British Geological Survey (BGS) report for DECC in 2010, which predated any exploratory drilling for shale gas in the UK, tentatively estimated 4.7 tcf shale gas reserves in the Upper Bowland Shale of the Carboniferous Pennine Basin and 5.3 tcf elsewhere in England (southern England basins and the Cambrian shales of central England—note that these figures exclude Wales, Scotland and Northern Ireland). (See http://og.decc.gov.uk/assets/og/bo/onshore-paper/uk-onshore-shalegas.pdf).

8. Estimates of world shale gas resources made by Advanced Resources International, Inc. in 2011 (for the US Energy Information Administration at the Department of Energy) put the total shale gas resource in place in the UK at 97 tcf. They assume a modest 21% recovery factor, which would result in reserves of 20 tcf.

9. Cuadrilla Resources estimates at least 200 tcf shale gas resource in place in the Bowland basin. In their submission to the present inquiry (para 1.4) they say that a conservative recovery factor of 15% would yield a reserve of 45 tcf, although by our calculation a 15% recovery rate on 200 tcf of resource would in fact yield 30 tcf.

10. In summary, the three estimates of UK shale gas reserve quoted here are around 10 tcf (England only), 20 tcf (UK) and 30 tcf (Bowland basin only), compared with DECC's central estimate of 17 tcf of conventional gas reserves in the UK.

11. DECC has commissioned a BGS team to provide a more detailed analysis and estimate of the entire Bowland Shale gas resource in place, to better understand the potential future contribution to the UK energy mix. This work is due to be completed by the end of 2012 and will provide an independent assessment of the total resource. We have tried to discover the expected publication date of their report, but BGS tell us that this will be determined by DECC.

12. Regarding other unconventional gas, the European Centre for Energy Resource Security (EUCERS) Strategy paper 'Strategic Perspectives of Unconventional Gas' (http://www.kcl.ac.uk/sspp/departments/warstudies/research/groups/eucers/strategy-paper-1.pdf) provides resource estimates for two coal bed methane prospects—Cheshire (4 tcf) and the Midland Valley (2 tcf).

Global Shale Gas Resource Estimates

13. The most widely used current estimates of global shale gas resources are provided by the US Energy Information Administration (EIA), although as with other estimates cited here, these are highly uncertain (see http://www.eia.gov/analysis/studies/worldshalegas). The EIA has estimated the **technically recoverable** shale gas resources for basins in 32 countries. The ten largest estimates of shale gas resource (by country) are listed below, together with the estimates of proven natural gas reserves. The UK estimates from the same source are also shown. (All figures in tcf. Technically recoverable shale gas estimates *exclude* offshore resources. For comparison, the EIA quotes proven natural gas estimates from the Oil and Gas Journal's annual survey 2010, which *include* offshore resources.)

Country	*Technically recoverable shale gas resources (EIA estimate, tcf)*	*Proven natural gas (EIA estimate, tcf)*
China	1275	107
USA	862	273
Argentina	774	13
Mexico	681	12
South Africa	485	N/A
Australia	396	110
Canada	388	62
Libya	290	55
Algeria	231	159
Brazil	226	13
UK	20	9

14. The USGS estimates undiscovered technically recoverable resources of unconventional gas in the USA of 695 tcf, compared to mean undiscovered technically recoverable resources of conventional gas of 411 tcf (see http://energy.usgs.gov/OilGas/AssessmentsData/NationalOilGasAssessment/AssessmentUpdates.aspx).

15. Other useful recent reviews of regional and global unconventional gas estimates are:

— https://workspace.imperial.ac.uk/icept/Public/121022%20Unconventional%20gas%20-%20A%20review%20of%20estimates%20%28ICEPT%20working%20paper%29.pdf (Imperial College Centre for Energy Policy and Technology working paper)

— www.ukerc.ac.uk/support/tiki-download_file.php?fileId=2672 (UK Energy Research Centre report to Energy Security Unit of the Joint Research Centre of the European Commission—same authors as the ICERT working paper)

Innovative Hydraulic Fracturing Technologies

16. Hydraulic fracturing is not a new technology, and has been in use in the oil and gas industry for several decades. Shale gas exploration and production have stimulated research to improve fracking techniques and horizontal drilling technologies. Several US resource companies are working on projects to improve the environmental friendliness of fracturing fluids. An example is Chesapeake Energy's GreenFrac program—see http://www.chk.com/environment/drilling-and-production/pages/green-frac.aspx.

17. The company GASFRAC have patented a new fracturing technology which uses LPG (liquified petroleum gas) gel as the fracking fluid for shale gas extraction instead of water. There are two potential advantages to this method. The first is in terms of gas production: after fracturing, the well is opened up to produce gas and the pressure drop means that the LPG gel returns to its gaseous state, and becomes part of the flow of gas from the rock. When water is used, 10–50% remains trapped in the rock and this reduces the effectiveness of the fractures in producing gas. The second potential advantage relates to potential environmental impact: LPG gels reduce the reliance on water supplies, and would lead to reduced flowback water. (See www.gasfrac.com. See also SPE conference paper by Tudor et al, a copy of which we will send with this memorandum. For information on Schlumberger fracking technologies, see http://www.slb.com/~/media/Files/stimulation/product_sheets/unconventionalgas/openfrac_ps.pdf.)

Shale Oil Potential in the UK and USA

18. In the USA, the main shale oil play is the Bakken. It is very probable that there are shale oil resources in the UK, particularly in the East Midlands and in the Scottish Midland Valley. However, given the difficulty and cost of extracting shale oil, the likely environmental and social constraints, and the relatively extensive shale gas resources available, it seems very unlikely that these will be considered worthwhile to explore.

19. It is reasonably likely that some liquids will be co-produced with shale gas, without looking for them. In the USA, in some provinces the shale oil is in the same reservoir as the shale gas, but in a shallower belt that has simply not undergone the same burial depths. In some cases, the by-product oil is more valuable than the gas. In the USA oil is now targeted because the price of gas has dropped significantly in recent years.

Background Information on the SEC Guidelines

20. The Final Rule for the Modernization of Oil and Gas Reporting published in 2009 by the SEC (U.S. Securities and Exchange Commission) supercedes previous guidelines. A short guide to new rules can be found here http://www.spee.org/wp-content/uploads/pdf/ReferencesResources/OilGas_Reporting.pdf and the full report on modernisation of oil and gas reporting can be found here http://www.sec.gov/rules/final/2008/33–8995.pdf.

December 2012

Written evidence submitted by INEOS Olefins & Polymers UK (ISG 10)

1. Executive Summary

1.1 UK industry need secure supplies of competitively priced energy to survive and prosper in international markets. Similarly the petrochemicals sector requires competitively priced feedstocks.

1.2 Since the 1970's North Sea oil and gas has provided the petrochemical industry with advantaged ethane and liquefied petroleum gases (propane and butane) feedstocks that have seen a successful petrochemical manufacturing industry grow based on a competitive olefins (ethylene and propylene) market.

1.3 This has been able to support downstream derivative manufacturing even though such products may be disadvantaged by distribution costs. UK derivatives today are exposed to global competition from low cost regions such as United States and Middle East E. The UK derivative portfolio (polyethylene, polypropylene, polyethylene vinyl chloride (PVC), ethanol, ethyl acetate (ETAC) and vinyl acetate monomer (VAM) in particular) cannot compete with low cost product unless the upstream feeds are competitive. Therefore, if feed costs into UK olefins manufacturing were to level with the rest of Europe, these derivatives would be outcompeted not only by their US and ME competitors, but also lose out against mainland European competitors who would then have similar costs but more differentiated derivatives and lower freight costs to serve the market.

1.4 Production forecasts for these advantaged petrochemical feedstocks from the North Sea show a marked decline at the end of this decade. Without a replacement advantaged feedstock the inevitable decline in UK olefins manufacturing industry, and therefore the associated downstream derivatives, is likely to follow.

1.5 For many years the UK has had access to locally sourced supplies of natural gas which have provided consumers with competitively priced energy supplies. As conventional reserves have declined, however, UK import dependency has increased with ever-greater volumes of gas being sourced from Norway and through LNG. As a result UK natural gas prices have become increasingly uncompetitive on a global scale.

1.6 The Government recognises that natural gas will play a vital part in the UK's energy mix in the medium term (for both power generation and heat) ahead of the wider development of new nuclear and renewables.

1.7 In sharp contrast to the UK, the USA has seen energy and feedstock prices fall, import facilities converted for exportation and a rapid growth in petrochemicals manufacture all due to the extraction of shale gas. Furthermore, with gas prices falling below coal prices, the United States has seen overall CO_2 emissions fall significantly as power generation switches to natural gas where possible.

1.8 It is clear that the UK potentially has very significant reserves of shale gas based on the results of surveys to date. It is likely that the UK's shale deposits could contain higher weight hydrocarbons—essential feedstocks for the petrochemicals industry. Shale Gas deposits can contain these higher molecular-weight hydrocarbons (in addition to natural gas) that would re-invigorate the UK olefins and derivatives petrochemicals market.

1.9 INEOS believe it is this step change in advantaged feedstock for the petrochemicals market in the UK that is required and we will actively pursue both the import of such materials (in the short term) and the availability of UK supplies (in the long term) to maintain our UK manufacturing base

1.10 UK shale reserves have the potential to provide the UK with a secure, indigenous and highly competitive source of energy and hydrocarbon feedstocks—in essence providing a replacement for declining output from conventional North Sea reserves. Rather than requiring support and subsidy (like renewables), or requiring energy to be bought externally, UK shale would provide a vital source of income to UK plc.

1.11 The UK energy intensive and petrochemicals sectors require certainty that energy and feedstocks will be secure and competitive in the medium term. Without that certainty then it is likely that these sectors will decline and reducing the manufacturing capacity. However if shale develops positively then the prospects for manufacturing to build and grow on the current significant UK supply infrastructure are good.

1.12 The UK has a proven track record of technological development in oil and gas production and manufacturing. Recent reports show that shale gas is no riskier than current fuel extraction technologies and can be managed safely.

1.13 It is vital that UK government supports and encourages the responsible development of shale gas.

2. The Importance of Natural Gas and Hydrocarbon Feedstocks

2.1 For many years natural gas has been a key part of the UK's primary fuel mix. Large indigenous reserves in the North Sea have provided the UK with a competitive source of energy for power generation.

2.2 In addition to natural gas, the North Sea provides other hydrocarbons such as ethane and propane which are vital feedstocks for the petrochemicals and plastics industry. Availability of these feedstocks has resulted in the UK having had a successful petrochemicals sector.

2.3 However forecasts of these fundamental advantaged feedstocks show a steep decline at the turn of the decade. It is imperative that alternatives are found to sustain UK manufacturing and exports in these sectors.

2.4 The so called "dash for gas" saw a transformation of the power generation industry with the widespread displacement of coal resulting in a significant fall in UK carbon emissions.

2.5 UK government policy is to further decarbonise the UK economy—and much of this will have to be achieved through the decarbonisation of the power generation sector.

2.6 In the medium term the UK Government recognises that natural gas will continue to play a vital role in power generation, both as a back-up for interruptible renewables and ahead of the deployment of a new generation of nuclear stations in UK (excluding Scotland) and Scottish Governments off shore wind and wave generation.

2.7 As a critical "bridging fuel" it is essential that natural gas prices remain competitive in the UK Gas prices determine wholesale electricity prices and critically important for the energy intensive sector.

3. UK and the US—Contrasting Recent History of Natural Gas

3.1 Following the discovery of natural gas in the North Sea, the UK for many years enjoyed the benefits of plentiful gas supplies. This resulted in gas prices which were relatively competitive. The construction of the UK to Belgium interconnector also enabled large volumes of gas to be sold and exported to the wider European market.

3.2 During the mid 2010's UK indigenous production was seen to decline quite rapidly as field depletion exceeded new discoveries. As a result the UK has moved to becoming a net gas importer. This has resulted in prices being on average higher and exposed to external global factors.

3.3 In particular the UK is now increasingly dependent upon imports of Liquefied Natural Gas (LNG). While there is no recognised global market for LNG (as there is for oil for example) it is very clear that the price and availability of LNG is affected by the global supply and demand balance and other risk factors. For example following the global financial collapse of 2008, LNG availability kept UK prices relatively low and competitive whereas after the Fukushima nuclear incident, increased demand for LNG has seen a significantly tightening of the LNG market and prices increasing.

3.4 This tightening of the LNG supply/demand balance has caused UK prices to rise significantly. (Price evolution is shown in Addendum 1).

3.5 Natural gas prices have now risen above the equivalent cost of coal for the generation of power. This has resulted in power generators increasing power generation on coal stations and reducing generation on gas stations. With coal stations emitting more carbon dioxide per unit of power generated, this has resulted in UK emissions increasing (we estimate that UK CO_2 emissions increased by around 25 million tonnes in 2011 alone).

3.6 The gas price is critical in determining the price of wholesale electricity. Increasing wholesale gas prices have caused wholesale electricity prices to increase. With the UK generation mix being more dependent on gas than most of other European markets, this has resulted in UK wholesale prices rising to highly uncompetitive levels. When tax policy is taken into account the situation in the UK is even worse. (Electricity price comparisons are shown in Addendum 2).

3.7 In the United States the situation is nearly the complete reverse. In the late 2010s the US expected that it would need to import large quantities of LNG and as a result a number of import terminals were built.

3.8 At the same time, advances were made in the recovery of shale gas. Development was so rapid that by the time terminals were constructed, US shale gas production had grown enough that imports were simply not required and the new terminals remained very largely unused.

3.9 The growth of shale gas also pushed prices down very significantly—far more than many had predicted. The contrast is now stark with the US enjoying natural gas prices which are around 30% of the levels we see in the UK.

3.10 In addition to the extraction of natural gas (methane), large quantities of larger hydrocarbon molecules are being extracted (ethane and propane). This advantaged feedstock has helped to drive a resurgence in US olefin production and the downstream olefin-derivative industries. The next few years will see the US bring on line olefin production based on shale gas, and will see the US challenge the Middle East for the title of low-cost producer of olefins and therefore olefin-derivatives.

4. Impact of Shale in the US

4.1 The growth of shale gas in the US has had profound impacts.

4.2 The increased availability of chemical feedstocks has seen investment increase significantly in ethane crackers announced. For example on 1 June 2012 ICIS Heren reported that "US-based ExxonMobil Chemical's announcement of a new 1.5m tonne/year cracker in Texas by 2016 brings the tally of new US ethylene capacity announcements to 33% of existing capacity".

4.3 US natural gas prices have fallen dramatically and are now around the lowest in the world—certainly of the transparent liquidly traded markets.

4.4 Rather than being a net importer, the US is now expected to be a net gas exporter, with a number of major liquefaction projects announced (in part using the terminals that were constructed to import gas). Thus, rather than exporting money to buy gas, the US will have a large new revenue stream.

4.5 Lower gas prices have resulted in a lowering of electricity prices, giving a massive competitive advantage to the US electro-intensive industries

4.6 Natural gas is now more competitive than coal for power generation in the US—so gas has displaced coal in the power generation sector. As a result the US has seen a significant reduction in CO_2 emissions.

4.7 There are a number of other reports that show the impact of shale gas is having on the US manufacturing sector which is now clearly growing. Selections of these are quoted in Addendum 4.

5. Shale Gas Potential in the UK

5.1 Shale gas in the UK has the ability to be transformational in delivering secure and competitive energy and feedstock supplies which are vital for the energy intensive and petrochemicals sectors.

5.2 It is apparent, albeit on limited surveys that the UK has significant and world class shale deposits. The Bowland shale for example is reported to be five times the thickness of the Marcellus shale in the US.

5.3 Technically, there are reports from respected bodies that shale extraction can be achieved with no greater risk than current extractive technologies. Indeed the UK has well established arrangements in a wide variety of industries for responsibly managing environmental and other risks. The US has demonstrated the technology which should be readily transferable. Indeed, shale gas extraction has been undertaken in Germany for many years without technical or environmental issues.

5.4 Furthermore, the UK has a very strong track record when it comes to putting new infrastructure in place. The development of a massive oil and gas production and transmission infrastructure was achieved in a relatively short period in arguably a much more challenging environment. There is no reason to suggest that given the right climate that this could not be replicated for shale gas production.

5.5 The UK should be looking to achieve "first mover" advantage. With an established gas and petrochemicals infrastructure already in place we only require a competitive source of supply to replace dwindling indigenous North Sea reserves to sustain our remaining energy intensive and petrochemicals sectors.

5.6 The benefits to industry are only part of the story with many wider spin-off benefits, which seem certain to enhance the prospects of the UK manufacturing and wider economy.

6 Conclusions

6.1 UK olefins manufacturing in the UK is sustained by advantaged feedstock pricing from North Sea gases (ethane, propane and butane) that provides support to the associated UK olefins derivatives manufacturing base (that are disadvantaged by greater transportation and freight costs to the inland European market). If feed costs into UK olefins manufacturing were to level with the rest of Europe, these derivatives would be outcompeted not only by their US and ME competitors, but also lose out against mainland European competitors who would then have similar costs but more differentiated derivatives and lower freight costs to serve the market. New sources of advantaged feedstock are required to maintain a UK olefins and derivatives manufacturing base.

6.2 UK energy prices are already uncompetitive. The UK's energy tax and policy framework indicate that the competiveness gap is only set to increase.

6.3 For energy intensive manufacturers, such as olefins and derivatives producers, energy is a major component of productions costs: accessing competitively priced energy is simply business critical.

6.4 Shale gas offers an opportunity that must not be rejected if the UK is to remain a competitive location for energy intensive industries.

6.5 INEOS strongly supports the responsible development of shale gas in the UK. We consider it vital to the long-term success of our manufacturing operations in the UK.

6.6 We encourage UK Government to support the development of shale gas. Unlike renewables and new nuclear, this support will not need to be financial. Rather the need will be in areas such as licensing and planning. Indeed, UK plc will reap massive financial benefit from a successful shale gas industry.

7 Responses to Questions

In response to the questions raised by the Committee we have provided comments below (where we feel it is appropriate to comment).

What are the estimates for the amount of shale gas in place in the UK, Europe, and the rest of the world, and what proportion is recoverable?

We are not experts in this area and only have access to information that has been made publically available.

In the UK it is apparent that information on reserves is evolving as test drilling is required in order to gather concrete information on shale quality. It is apparent that views are changing rapidly but generally new information is leading to ever more optimistic forecasts.

The proportion of recoverable reserves is also uncertain. However, assuming conservatively that just 10% of reserves are recoverable then we estimate that the Bowland Shale has the capacity to produce 30% of the volume of gas that has been extracted from UK conventional fields since 1970. In view of this we think it is reasonable to say that extracting shale gas would be comparable to rediscovering the North Sea.

Globally, new information is published on a near daily basis indicating that massive shale deposits lie across the planet. China, for example has the largest reserves, and with a gas market of similar size to the UK, reserves to demand ratios are around 250 years.

Germany also has significant reserves and with shale extraction having been undertaken for many years, we anticipate that shale development will see further growth.

Why are the estimates for shale gas so changeable?

We are not experts but exploration to date is limited. As exploration continues it is apparent that shale deposits are large, tend to surpass expectations and are globally diverse.

It is clear that other countries are likely to pursue shale development (as the US has done) and we see it as essential that the UK, with a strong track record on gas production and an existing good infrastructure that we seize early mover advantage.

What are the prospects for offshore shale gas in the UK Continental Shelf?

We have no particular view on the relative merits of off-shore versus on-shore shale gas extraction. However, in either case we think it essential that UK Government support the development of the industry particularly through the granting of exploration and development licences.

Should the UK consider setting up a wealth fund with the tax revenue from shale gas?

We have no strong view on the merits of setting up specifically a wealth fund. However, it is apparent that the UK economy will boosted significantly if we continue to produce (and potentially export) indigenous gas rather than import supplies from other parts of the globe at higher and uncompetitive prices.

What have been the effects of shale gas on the LNG industry?

As already discussed, the US will become a gas exporter of natural gas. Others will follow. Better that the UK is an early mover.

Could shale gas lead to the emergence of a single, global gas market?

Potentially shale could improve the prospects of a global gas market developing. However, if we do not embrace indigenous shale gas extraction we will remain a large importer forced to accept prices and exposed to geo-political risk.

Further, local gas production has the very clear potential to grow local industry through production and providing competitive energy and feedstock supplies for energy intensive and petrochemical sectors.

What are the effects on investment in lower-carbon energy technologies?

The development of shale gas should be seen as providing the bridge to a lower carbon economy. UK carbon emissions were reduced massively in the period known as "the dash for gas". We have already noted that with gas prices currently higher than coal, carbon emissions in 2011 were higher than they would otherwise have been.

Further, it is clear that the deployment of significant levels of low carbon generation infrastructure remains many years away. Renewables will inevitably require back-up generation and any new nuclear seems very unlikely before 2020. Gas will be required to provide the bridge in the short to medium term—and shale gas can provide this without the need for expensive economic support mechanisms.

In the long term, whether gas will affect the deployment of new nuclear and renewables will have to be determined by policy and economic views. For example, will cheap gas combined with Carbon Capture and Storage provide a more economic, secure and acceptable source of power generation?

Predicting the future is without question uncertain. However, shale gas can offer another route to secure, competitive and lower carbon energy—and it should not be ruled out of the energy mix at this stage

What is the potential impact on climate change objectives of greater use of shale gas?

Again the US offers a view of potential benefits. We note two examples.

First, shale gas has lowered prices such that natural gas is now the preferred fuel for power generation. As a result US carbon dioxide emissions have fallen massively. Increased use of shale gas in the UK or ROW has the ability to reduce coal burn provided it is cheaper than coal.

Secondly, gas is already being used as an alternative to liquid hydrocarbon fuels, offering reductions in emissions.

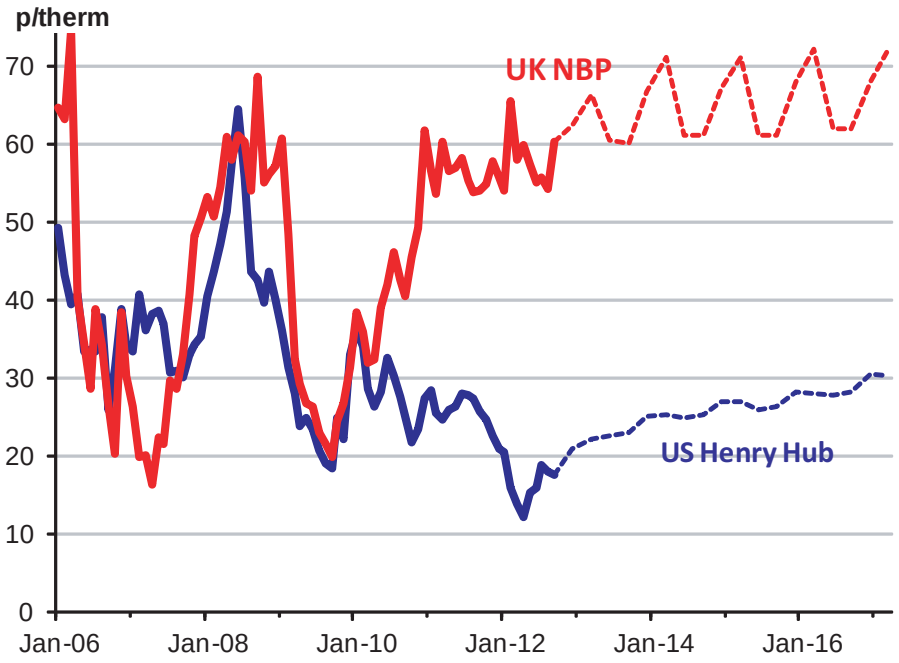
Thus, greater use of shale gas can provide a route to lower carbon emissions by displacing use of fuels with higher carbon intensity.

Of course shale gas is not carbon free. While Carbon Capture and Storage is still to be proven on a commercial scale, it would be an obvious partner to shale gas in providing a zero carbon but secure energy supply in the longer term.

Addendum 1

WHOLESALE GAS PRICE COMPARISONS

The chart below shows the evolution of UK and US natural gas prices since 2006.

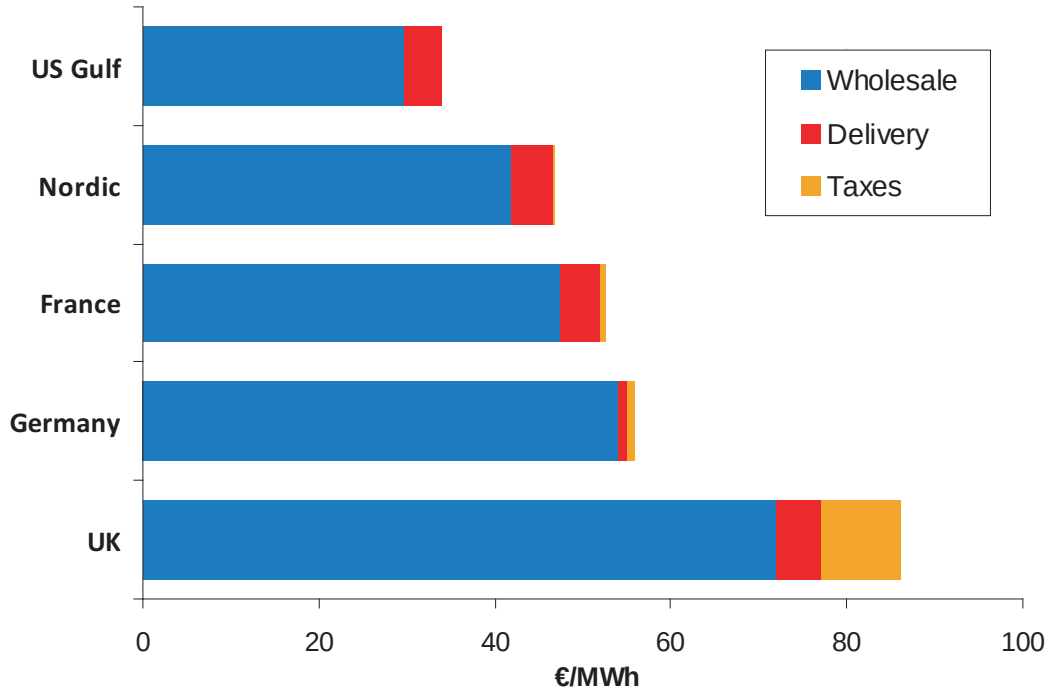


Addendum 2

WHOLESALE ELECTRICITY PRICE COMPARISONS -2015

(Source: INEOS)

The chart below shows our view of delivered electricity prices (for a very large user) in 2015.



Addendum 3

ETHYLENE CRACKER INVESTMENTS

Company	*Project*	*Capacity*	*Location*	*Cost*	*Start-up*
ExxonMobil Chemical	New cracker	1.5 tonnes	Baytown, Texas	NA	2016
Chevron Phillips Chemical	New cracker	1.5m tonnes	Cedar Bayou, Texas	NA	Q1 2017
Dow Chemical	New cracker	World-scale	US Gulf Coast	NA	2016–2017
Shell	New cracker	World-scale	US Northeast	NA	2016–2017
Formosa Plastics	New cracker	800,000 tonnes	Point Comfort, Texas	$1.7bn	2016
Dow Chemical	Restart	390,000 tonnes	St. Charles, Louisiana	NA	end 2012
Westlake Chemical	Expansion	108,863 tonnes	Lake Charles, Louisiana	NA	H2 2012
Williams	Expansion	272,158 tonnes	Geismar, Louisiana	$350m-$400m	Q3 2013
INEOS	Debottleneck	115,000 tonnes	Chocolate Bayou, Texas	NA	end 2013
Westlake Chemical	Expansion	113,399 tonnes	Lake Charles, Louisiana	NA	2014
LyondellBasell	Expansion	386,000 tonnes	La Porte, Texas	NA	2014
		Considered expansions			
Sasol	New cracker	1.0m-1.4m tonnes	Lake Charles, Louisiana	$3.5bn-$4.5bn	NA
Indorama Ventures	New cracker	1.3m tonnes	NA	NA	2018
LyondellBasell	Expansion	NA	Channelview, Texas	NA	NA
SABIC	New cracker	World-scale	US	NA	NA
Braskem	New cracker	NA	US	NA	NA
Occidental Chemical	New cracker	NA	Ingleside, Texas	NA	NA
Aither Chemicals, Renewable	New cracker	NA	US Northeast	$750m	2016

(Source: CIA)

Announced ethylene expansions based shale gas

Addendum 4

US ECONOMIC BENEFITS

The quotes below from recent reports and US media give an indication of the positive effect that shale gas has had on the US economy and petrochemical sector.

U.S. energy supplies have been transformed in less than a decade, driven by advances in technology, and the economic implications are only beginning to be understood. U.S. natural gas production will expand to a record this year and oil output swelled in July to its highest point since 1999. Citigroup estimated in a March report that a "reindustrialization" of America could add as many as 3.6 million jobs by 2020 and increase the gross domestic product by as much as 3 percent.

Bloomberg

Chemical companies from around the world are flocking to the Houston area to lay down millions, and sometimes billions, in investments to take advantage of vast amounts of cheap natural gas, which is used as a chemical feedstock.

Thousands of jobs have been proposed in the Houston area from recently announced plants and expansions from chemical companies such as Irving-based Celanese Corp. (NYSE: CE) and The Dow Chemical Co. (NYSE: DOW), based in Midland, Mich.

Houston Business Journal

[L]ow and stable gas prices in the U.S. are contributing to a 10 percent reduction in electricity costs to consumers and a 1.1 percent increase in the level of 2012 GDP. Perhaps more importantly, it is encouraging manufacturers to expand operations in the U.S., building new production facilities, or reopen plants that were shuttered during the recession.

In its 2012 study, the IHS found that shale gas production alone will contribute $332 billion to U.S. gross domestic product (GDP) by 2035

CNBC

The increase in US gas production has also led to the rebirth of the domestic chemical and manufacturing sectors, Ken Bromfield, North American commercial director with Dow Chemical, said.
"We have an unprecedented opportunity with shale gas to push the reset button on the US energy economy," he said.
"Manufacturing is back," he added, saying industry has announced plans to build about $80 billion of projects in the next five years, as a result of reasonably priced natural gas. Dow alone has announced $4 billion of new manufacturing projects, Bromfield said.

Platt's

Access to vast, new supplies of natural gas from previously untapped shale deposits is one of the most exciting domestic energy developments of the past 50 years. After years of high, volatile natural gas prices, the new economics of shale gas are a "game changer," creating a competitive advantage for U.S. petrochemical manufacturers, leading to greater U.S. investment and industry growth.

America's chemical companies use ethane, a natural gas liquid derived from shale gas, as a feedstock in numerous applications. Its relatively low price gives U.S. manufacturers an advantage over many competitors around the world that rely on naphtha, a more expensive, oil-based feedstock. Growth in domestic shale gas production is helping to reduce U.S. natural gas prices and create a more stable supply of natural gas and ethane.

American Chemical Council

Unconventional gas activity is having a dramatic impact on employment and economic growth across the US lower 48 states and the District of Columbia, in terms of jobs and its contribution to gross state product (GSP) and, by extension, US gross domestic product (GDP).

In 2010, unconventional gas activity supported 1 million jobs; this will grow to nearly 1.5 million jobs in 2015 and to over 2.4 million in 2035.

By 2015, unconventional gas activities will contribute nearly $50 billion in federal, state and local government tax and federal royalty revenue; between 2010 and 2035, continued development of unconventional gas will generate a cumulative total of nearly $1.5 trillion in federal, state, and local tax and royalty revenue.

IHS

September 2012

Further written evidence submitted by INEOS Olefins & Polymers UK (ISG 10a)

1. INEOS is submitting supplementary evidence having recently completed construction of an ethylene storage facility in Europe, and signed an international ethane supply agreement, which will enable the company to import petrochemical feedstock derived from US shale gas. We wish to draw the Committee's attention to these new developments to illustrate the dramatic effect that shale gas has had on the price of petrochemical feedstock in the USA, and establish how important it is to the petrochemicals industry to have access to competitively priced raw materials.

2. Having access to competitively priced feedstock (such as ethane and propane) is essential for the petrochemicals sector to thrive. The North Sea has provided affordable feedstock for many years, allowing the UK petrochemicals sector to prosper, but reserves are now dwindling, causing prices to rise and eroding the competitiveness of the industry.

3. At the same time, the Middle East and the USA are sourcing ethane from cheap natural gas rather than naphtha, meaning prices of feedstock are significantly lower than in Europe. This in turn means ethylene production is much more competitive in these locations. The average cash cost of producing a tonne of ethylene (year end 2011) in the Middle East was $300, in the USA $625, and the rest of the world $750–1250.

4. The competitiveness gap with the USA is widening as a result of the USA deriving ethane from cheap shale gas. This has led to massive investment in ethylene crackers and downstream petrochemical facilities in the USA, while Europe is not seeing this sort of investment. The price difference in ethane is now so dramatic that it makes business sense for INEOS to import ethane from the USA rather than buying it in Europe, even though this requires very significant investment in infrastructure, and importation itself involves additional costs.

5. INEOS has invested $80m in an ethylene storage terminal in Antwerp to allow us to access more competitive feedstock from outside Europe. Construction finished last month and the facility will be fully operational in the last quarter of 2012. The 1m tonne/year facility will enable INEOS to import ethylene from a wide range of international sources for use as raw material in our European businesses.

6. INEOS has also recently signed supply and infrastructure agreements that will secure a significant volume of ethane feedstock from the USA for use in our European crackers. This comprises a long-term deal with Range Resources—Appalachia LLC for the lifting of ethane from the Marcus Hook Facility from 2015, and Pipeline Transportation Services and Terminal Services Agreements for the shipping of ethane from Houston, Pennsylvania. It is expected that when complete, the project will transport approximately 70,000 barrels per day of ethane and propane sourced from the Marcellus Shale.

7. These large investments and long-term agreements are a clear indication of the importance of competitively priced feedstock to INEOS, and the competitiveness gap that currently exists between Europe and the USA as a result of the extraction of shale gas. Shale gas has been a "game changer" in the USA when it comes to feedstock prices. Extraction in the UK is an opportunity to replicate these benefits that we cannot afford to miss.

8. Extracting shale gas in the UK would lower domestic feedstock prices allowing the petrochemicals sector to compete more effectively without having to import feedstock at considerable expense. This would support the UK gas industry and promote investment in cracking and downstream petrochemical facilities in the UK, as has been seen in the USA, driving economic growth and recovery.

November 2012

Written evidence submitted by the Institute of Directors (IoD) (ISG 06)

IoD Member Survey

In April 2012, the IoD polled 1,095 IoD members for their views on the potential of UK shale gas. While there were some mixed views, and a degree of uncertainty, members were positive overall:

- 58% said that extensive development of the UK's shale gas resources would have a positive or very positive impact on British businesses. By contrast, just 7% thought it would have a negative or very negative impact on business, while 22% said it would be neither positive nor negative.
- Views were mixed on the possible safety and environmental risks of hydraulic fracturing. 36% thought that the risks were significant, compared with 17% who thought they were insignificant and 27% who felt they were neither significant nor insignificant.
- Overall, almost half (48%) of IoD members agreed that the benefits outweighed the risks, compared to 18% who thought that the risks outweighed the benefits, and 15% who neither agreed nor disagreed with the question.
- Regionally, IoD member views are very similar. In all regions of the UK:
  - More than 50% of members think that shale gas will have a positive impact on business.
  - Less than 40% of members think that the risks of fracking are significant.
  - At least 45% of members think that the benefits outweigh the risks.

General Comments

On 21 September 2012, the IoD published a report, Britain's shale gas potential, which can be found here http://www.iod.com/Influencing/Press-Office/Press-releases/British-shale-gas-could-create-35000-jobs-reduce-carbon-emissions-and-lower-energy-prices

The IoD's overall view can be summarised as follows:

- The UK has a major opportunity to develop a cheap and reliable domestic source of energy, creating jobs, reducing the need for gas imports and improving the environment by replacing coal in electricity generation. Shale gas will not solve all our problems, but it can be an important part of the energy mix.
- Cheap gas-fired turbines powered by UK shale resources could also prove to be the perfect complement to renewable generation, providing power when the wind isn't blowing and the sun isn't shining.
- The risks of hydraulic fracturing should be viewed alongside those of conventional oil and gas extraction. Provided industry best practice is followed, and strong regulation and monitoring are in place to enforce this, fracking should be permitted to proceed.
- Overall, we should be enthusiastic about developing a new domestic source of energy.

ANSWERS TO SPECIFIC QUESTIONS

1. *What are the estimates for the amount of shale gas in place in the UK, Europe, and the rest of the world, and what proportion is recoverable?*

The International Energy Agency has published the following table of global technically-recoverable reserves of natural gas (see Table 1), which is the most recent global estimate that we know of. I have highlighted the column for shale gas. Note that global production is currently 3.3 trillion cubic metres a year.[8]

Shale accounts for 28% of global natural gas reserves—a significant portion—and is very well distributed, with large resources in all parts of the world, apart from the Middle East (Note that the IEA divides Europe in two).

In the US, shale accounts for nearly a quarter of natural gas production. If shale were to account for 25% of the current level of global natural gas production, assuming a recovery rate of just 10%, current shale gas resources would be sufficient to meet 25 years of global production.

In the US, shale gas recovery rates have averaged 18%.[9] If this was replicated globally, then shale resources would meet 25% of current global natural gas production for 40 years.

Table 1

REMAINING TECHNICALLY RECOVERABLE NATURAL GAS RESOURCES BY TYPE AND REGION, END-2011[10]

Trillion cubic metres	*Total*		*Unconventional*			
	Total reserves	*Conventional reserves*	*Unconventional reserves*	*Tight gas*	*Shale gas*	*Coalbed methane*
Eastern Europe/ Eurasia	174	131	43	10	12	20
Middle East	137	125	12	8	4	0
Asia/Pacific	128	35	93	20	57	16
OECD Americas	122	45	77	12	56	9
Africa	74	37	37	7	30	0
Latin America	71	23	48	15	33	0
OECD Europe	56	24	32	3	16	2
World	752	421	331	76	208	47

In the UK, in 2010 the British Geological Survey (BGS) estimated onshore shale reserves at 5.3 trillion cubic feet.[11] The BGS is set to revise its onshore data substantially upwards later this year, possibly to as high as 200 trillion cubic feet.

Meanwhile the exploration companies have identified far higher resources:

- Cuadrilla—200 trillion cubic feet.
- Eden Energy—12.8 trillion cubic feet.
- IGas—10 trillion cubic feet.
- Dart Energy International—66 trillion cubic feet.[12]

These resources add up to nearly 300 trillion cubic feet in total, compared to UK natural gas consumption in 2011 of less than 3 trillion cubic feet.

Assuming that recovery rates averaged 10%, then the resources identified by the exploration companies would meet 25% of the UK's gas needs for around 40 years. If recovery rates averaged 18%, as in the US, then 25% of the UK's gas needs could be met for around 75 years.

Assuming a lower penetration of shale gas, with shale gas meeting 10% of the UK's gas consumption, the resources identified by the exploration companies would be enough for 100 years if recovery rates averaged 10%.

The main point is that, whichever way you look at it, there is a lot of shale gas around the world, and a lot in the UK, even if we assume a relatively low recovery rate. Shale does have the potential to meet a significant

[8] International Energy Agency, Golden Rules for a Golden Age of Gas, 2012, Table 2.6 http://www.worldenergyoutlook.org/media/weowebsite/2012/goldenrules/WEO2012_GoldenRulesReport.pdf

[9] Centre for Global Energy Studies, July 2010 http://www.cges.co.uk/resources/articles/2010/07/22/what-is-shale-gas

[10] International Energy Agency, Golden Rules for a Golden Age of Gas, 2012, Table 2.1 http://www.worldenergyoutlook.org/media/weowebsite/2012/goldenrules/WEO2012_GoldenRulesReport.pdf

[11] British Geological Survey, The unconventional hydrocarbon resources are

[12] Institute of Directors, Britain's shale gas potential, September 2012, p.27 http://www.iod.com/Influencing/Policy-papers/Infrastructure/Britains-shale-gas-potential

portion of our natural gas consumption, both in the UK and globally. As a new report, published today, has stated, shale gas could account for a quarter of UK gas consumption in 20 years.[13]

2. *Why are the estimates for shale gas so changeable?*

It is completely true that the estimates of shale gas resources are frequently being revised upwards and, sometimes, downwards. This is not really surprising. Globally, the shale industry is still in its infancy. In the UK, for example, only a small number of exploration wells have been drilled. The more exploration drilling that is permitted, the better our picture of shale resources will be.

In the US, production is far more advanced, but estimates are still subject to change. For example, in 2011, the US Energy Information Administration estimated that the US had 827 trillion cubic feet of *technically recoverable* shale reserves, but has now revised that figure downwards to 482 trillion cubic feet (still a very significant figure).[14] At the same time, the most recent data shows that *proved reserves* of natural gas have increased from 284 trillion cubic feet at the end of 2009 to 318 trillion cubic feet at the end of 2010—this increase is entirely accounted for by increases to proved reserves of shale gas, which have risen from 61 to 97 trillion cubic feet over a single year.[15]

It is also worth pointing out that conventional hydrocarbon resource estimates are also subject to change. As price rises incentivise companies to invest more in exploration, estimates of reserves tend to increase. It is worth remembering the many predictions over recent decades that the world would soon run out of, for example, oil—invariably, these predictions have proved to be too pessimistic.

Over the long run, as exploration increases and the hydraulic fracturing technology improves, we would expect the quantity of shale gas reserves that are economic to extract to increase.

3. *What are the prospects for offshore shale gas in the UK Continental Shelf?*

It is difficult to say with any certainty at the moment. The British Geological Survey has said that offshore shale gas reserves could be five–10 times higher than onshore reserves[16]—in other words, a big number. But it is far more difficult and expensive to extract, and at current oil and gas prices and current levels of technology, it seems to us unlikely that significant offshore shale gas development will take place. Technological development could, however, change our view of offshore shale gas prospects.

4. *Should the UK consider setting up a wealth fund with the tax revenue from shale gas?*

The immediate temptation would be to use any tax revenue from shale gas development to offset falling North Sea revenue to help reduce the deficit. Given the size of the deficit, that may be the best thing to do.

Long-term, though, a wealth fund earmarked to help fund pay-as-you-go pension schemes would be a better option. The UK's long run public spending liabilities, particularly on pensions, health and other age-related spending, are very large. Meeting these commitments in an affordable way is dependent on a long run GDP growth projection that may fail to materialise. Moving from pay-as-you-go to funded provision is clearly the long-term solution, but raises the problem of one generation effectively paying twice. A wealth fund could ease this transition.

Alternatively, a wealth fund could be used to pay for much-needed infrastructure improvements, which would tend to raise the UK's rate of growth, so making the age-related spending commitments easier to meet in the long-term.

It's worth noting that Norway's management of its North Sea revenues has been far superior to the UK's, although Norway does have a far smaller population. The UK made short-term choices when North Sea production took off more than three decades ago. Now may be the time for the government to take wiser decisions.

[13] The Energy Contract Company, UK Shale Gas—An Assessment of Production and Reserve Potential, September 2010 http://www.energy-contract.com/publications-news. This report, which is behind a paywall, was cited in the Financial Times of 26 September 2012, with a somewhat misleading headline http://www.ft.com/cms/s/0/287378ee-0708–11e2–92ef-00144feabdc0.html#axzz27a1ZSOuM

[14] US Energy Information Administration, Annual Energy Outlook 2011 and Annual Energy Outlook 2012 http://www.eia.gov/forecasts/aeo/

[15] US Energy Information Administration, US Crude Oil, Natural Gas, and NG Liquids Proved Reserves, August 2012 http://www.eia.gov/naturalgas/crudeoilreserves/

[16] Nigel Smith, Geophysicist, British Geological Survey, Oral evidence to the Energy and Climate Change Select Committee, 9 February 2011
http://www.publications.parliament.uk/pa/cm201012/cmselect/cmenergy/795/11020902.htm

5. *What have been the effects of shale gas on the LNG industry?*

And

6. *Could shale gas lead to the emergence of a single, global gas market?*

The simple answer to these two questions is that time will tell. If shale production is carried out at scale outside of North America, the impacts could be huge, releasing a massive amount of new supply onto global markets, leading to large price reductions. If not, the impacts will be smaller.

In the US, the biggest impact of shale on the LNG market has been to make redundant vast investments in LNG import infrastructure. LNG import terminals are now being refitted for export.

Forecasts for future exports are enormous. Cheniere alone has agreements with four global buyers to export 2 billion cubic feet a day for 20 years—equivalent to over 0.7 trillion cubic feet a year. Meanwhile nine other companies, including Freeport LNG, Gulf Coast LNG and Cameron LNG, are seeking approval to export gas. According to the US Energy Information Administration, the capacity sum of potential exports from these nine companies and Cheniere amounts to 14 billion cubic feet a day or over 5 trillion cubic feet a year[17]—about 1.5 times total UK annual gas consumption. The US is expected to become an LNG net exporter in 2016.[18]

There are a number of potential benefits from these developments, some of which we are already starting to see:

- De-linking of natural gas prices from oil prices. In the US, as oil prices have risen, natural gas prices have fallen. This will start to happen elsewhere.
- Reductions in Asia-Pacific natural gas prices. Pacific Basin gas prices can be as high as $16 per Million British Thermal Units, compared with around $9 in the UK and around $3 in the US. US LNG exports are likely to go to Asia, reducing prices there. Indeed, Japan is already looking to reduce the price it pays for LNG supplies.
- Reduction in the pricing power of Russia, Qatar and other major gas suppliers. This year, Russia has reduced the prices it charges for natural gas to German utilities,[19] and Qatar has reduced the price it charges to a major Italian utility.[20] More price reductions will inevitably follow, as oil-linked gas contracts are superseded. European gas prices could start to fall.

Nevertheless, a single, global gas market may be some way off. It costs around $4–5 per Million British Thermal Units to liquefy, transport and re-gasify LNG. So, for instance, if US Henry Hub prices increase to, say, $5 per MMBTU, then US LNG would have no price advantage over the UK's National Balancing Point.

Regional production will therefore be important. The best way for the UK (and Europe) to reduce natural gas prices is to increase its own production of shale.

7. *What are the effects on investment in lower-carbon energy technologies?*

The biggest driver of low-carbon energy investment is policy designed to meet carbon reduction and renewables objectives—the Renewables Obligation and the forthcoming EMR, together with the Carbon Price Floor and the EU ETS. Shale development does not in itself change these policies, so there is no reason to believe that it will affect the level of low-carbon investment.

In the US, it is noticeable that renewables development has proceeded at a rapid pace, at the same time as increasing quantities of shale gas have reached the market. Between 2006 and 2011, the share of US electricity generation from natural gas rose from 22% to 25%, and the share from renewables rose from 9% to 13%.[21] The big threat to renewables investment in the US is the forthcoming expiry of the Production Tax Credit—in the US, it is also policy that has driven renewables investment.

There is no reason to see a conflict between natural gas and renewables, especially since natural gas will be an important provider of back-up power when the wind isn't blowing. Globally, natural gas and renewables are set to be the biggest energy growth stories.

- According to the International Energy Agency, provided shale development does proceed at scale outside the US, gas is projected to meet 31% of global primary energy demand growth by 2035, with renewables (including hydro and biomass) accounting for 34%.[22]

[17] US Energy Information Administration, Project sponsors are seeking Federal approval to export domestic natural gas, 24 April 2012 http://www.eia.gov/todayinenergy/detail.cfm?id=5970

[18] US Energy Information Administration, Annual Energy Outlook 2012: Early Release Overview, p.2 http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2012).pdf

[19] See Financial Times, 3 July 2012 http://www.ft.com/cms/s/0/80dd9b44-c4fb-11e1-b8fd-00144feabdc0.html

[20] See Financial Times, 11 September 2012 http://www.ft.com/cms/s/0/ae84f762-fc1a-11e1-af33–00144feabdc0.html#axzz27a1ZSOuM

[21] US Energy Information Administration, July 2012 Monthly Energy Review (Net electricity generation by energy source) http://www.eia.gov/electricity/data.cfm#generation

[22] International Energy Agency, Golden Rules for a Golden Age of Gas, 2012, Table 2.5 http://www.worldenergyoutlook.org/media/weowebsite/2012/goldenrules/WEO2012_GoldenRulesReport.pdf

— According to BP, natural gas will account for 31% of global energy growth by 2030, while renewables and nuclear will together account for 34% of demand growth.[23]

Of course, it is possible that a glut of cheap gas will spur calls to reduce the level of subsidy provided to renewables and nuclear. In that sense, shale gas could have a negative impact on low-carbon development. But again, that's a matter for policy.

DECC's energy and emissions projections see natural gas without CCS contributing 128 TWh of electricity generation in 2030, a fall from its 2011 level of 149 TWh, but still significant.[24] At the same time, gas import dependency is expected to rise to 74% by 2030.[25] Unless policy towards low-carbon energy investment changes, the biggest impact of shale gas (apart from on price) will be to slow, halt, or reverse the rise of gas imports as a proportion of the UK's gas consumption.

8. *What is the potential impact on climate change objectives of greater use of shale gas?*

The question states "climate change objectives" rather than "the UK's decarbonisation objectives". The difference is important. Climate change is a global rather than a local problem—if China was to reduce its greenhouse gas emissions by 20%, climate change objectives would be closer to being met than if the UK was to reduce its greenhouse gas emissions by 80%. The problem is that the UK has taken too parochial a view of the climate change problem—the UK certainly needs to play its part, but the biggest impact will come from changes made in other parts of the world.

We believe that shale gas has the potential to help countries to reduce carbon emissions (and improve air quality) by complementing renewables and nuclear in replacing coal. Coal accounts for 27% of the world's primary energy supply, but is responsible for 43% of global CO_2 emissions. Natural gas, by contrast, accounts for 21% of global primary energy supply and 20% of global CO_2 emissions.[26] At today's level of energy consumption, replacing coal entirely with natural gas would save around 17% of global CO_2 emissions.

The potential is much higher than this. Emissions from oil used in road transport can be reduced by using natural gas vehicles (and electric cars). And in practice, coal is likely to be gradually replaced by a combination of gas, renewables and nuclear. Cheap gas will help heavy coal-using countries, such as China, to reduce their dependence on coal more quickly.

In the US, CO_2 emissions have fallen by 450 million tonnes over the last five years, more than any other country. There have been a number of reasons for this, including the recession, more efficient technology, and the displacement of coal by gas and renewables in electricity generation. Over this period, as a share of US electricity, coal generation fell from 49% to 42%, while natural gas generation rose from 22% to 25% and renewable generation rose from 9% to 13%.[27]

Other countries can follow suit, with shale gas complementing renewables in reducing the quantity of coal used. Other challenges remain, including the need to moderate energy demand growth, but shale gas can play a part in helping the world to move to a lower-carbon energy mix.

Concluding Thoughts

It is not possibly to predict precisely the quantity of UK shale gas resources that will prove economic to extract, nor the impacts on price that shale gas development will have in the UK and globally. But if we allow development to go ahead, we will start to find out.

The big picture is that shale gas could release a large quantity of new supply onto gas markets, leading to a reduction in price. That has to be a beneficial development that, in the UK, we should be excited about. Shale will not solve all our energy problems—it is unlikely to account for even a majority of our gas usage—but it can make a major positive difference. Shale has helped to transform the US's energy prospects—it could do the same in the UK, if we allow a properly regulated shale gas industry to develop.

September 2012

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[23] BP, Energy Outlook 2030, January 2012 http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/O/2012_2030_energy_outlook_booklet.pdf

[24] Department of Energy and Climate Change, Updated Energy & Emissions Projections, October 2011, Annex E—total electricity generation by source (central scenario) http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/en_emis_projs/en_emis_projs.aspx

[25] Department of Energy and Climate Change, UK Oil and Net Gas Production and Demand, March 2012 http://og.decc.gov.uk/assets/og/data-maps/chapters/production-projections.pdf

[26] International Energy Agency, CO2 Emissions from Fuel Combustion—Highlights, 2011, Figure 13 (refers to 2009) http://www.iea.org/co2highlights/CO2highlights.pdf

[27] US Energy Information Administration, July 2012 Monthly Energy Review (Net electricity generation by energy source) http://www.eia.gov/electricity/data.cfm#generation

Written evidence submitted by National Grid (ISG 26)

1. Introduction to National Grid

1.1 National Grid owns and manages the grids to which many different energy sources are connected. In Britain we run systems that deliver gas and electricity across the entire country. In the North East US, we provide power directly to millions of customers. We hold a vital position at the centre of the energy system. We join everything up.

1.2 That puts National Grid at the heart of one of the greatest challenges facing our society; supporting the creation of new sustainable energy solutions for the future and developing an energy system that can underpin our economic prosperity in the 21st century. First and foremost this is a scientific and engineering challenge. Decisions around the future of our energy infrastructure—its cost, local impacts, objectives and risks—will of course involve most of society.

1.3 In the UK, National Grid's primary duties under the Electricity and Gas Acts are to develop and maintain efficient networks and also facilitate competition in the generation and supply of electricity and the supply of gas. Activities include the residual balancing in close to real time of the electricity and gas markets.

1.4 Through our subsidiaries, National Grid also own and maintain the electricity Interconnector between England and France, and a Liquid Natural Gas importation terminal at the Isle of Grain. The wholly owned subsidiary National Grid Carbon Limited has advanced the transportation and storage elements of the Carbon Capture and Storage (CCS) supply chain.

Shale gas

1.5 The economic and energy security impact of the US shale gas exploration has created huge interest in other areas of the world in the potential for shale gas production.

1.6 If UK produced shale gas can be developed economically then it could make a useful contribution to the UK's gas supply in terms of diversity and security of supply. There are likely to be technical and development challenges associated with the production of shale gas, this may include the UK's requirements for gas quality for National Transmission System (NTS) entry. However we do not anticipate that these should be insurmountable given the experience of working with shale gas from our US operations which may be beneficial in developing the use of this new source of gas in the UK.

1.7 If shale gas becomes a significant contributor to UK gas supplies, this would represent an important development that we would need to take account of in relation to future network investment—potentially in relation to both the NTS and the Distribution Networks, so it will be important that developers provide us with a clear understanding of the scale, timing and locations of shale gas developments.

1.8 The existing network arrangements for gas entry to the NTS should also be applicable to shale gas or other "unconventional" sources. Therefore network entry (subject to meeting existing arrangements) should not be seen as a barrier for shale gas development.

1.9 In the UK Future Energy Scenarios published September 2012 the gas supply forecasts include a modest contribution from onshore gas sources, specifically shale, coal bed methane (CBM) and biogas. The "greener" agendas of "Gone Green" and "Accelerated Growth" favour biogas with a bias towards CBM in "Slow Progression". Shale is assumed to make a small contribution in both "Slow Progression" (from about 2015) and "Gone Green" (from about 2020). For all three onshore gas sources there is considerable uncertainty over development timescales and potential volumes, hence the assumed modest contributions could be significantly understated. As a proportion of UK demand, the contribution of onshore gas sources in the scenarios increases from near zero today to about 1–2% in 2020 and about 3–4% in 2030, with the highest proportion being associated with "Slow Progression" and "Gone Green". For further information please see page 70 of National Grid's Future Energy Scenarios publication: http://www.nationalgrid.com/NR/rdonlyres/2450AADD-FBA3–49C1–8D63–7160A081C1F2/56766/UKFutureEnergyScenarios2014.pdf

2. Questions Posed by this Inquiry

What have been the effects of shale gas on the LNG industry?

2.1 To date only shale developments in the US have had any impact on the LNG industry. The US was expected to import significant volumes of LNG and numerous import terminals were built. With the emergence of shale gas these have only been utilised to a limited extent. One terminal is now being converted to export low cost US gas as LNG and other plans are under consideration. Hence the effect of shale gas on the LNG industry has been less LNG to the US and more to other markets with the prospect of more LNG to global markets in the future.

2.2 The liquefaction plants will have an expected life of 25 years, so are a long term investment.

Could shale gas lead to the emergence of a single, global gas market?

2.3 Increased shale development and therefore more traded LNG rather than contracted LNG could promote market developments. It is too early to say if this could "lead to the emergence of a single, global gas market".

2.4 As US prices are so low, cargos could well be diverted to Europe/UK during the winter months.

What are the effects on investment in lower-carbon energy technologies?

2.5 Anecdotal evidence from the venture capital and cleantech communities in the US who we work with closely suggests that the emergence of shale gas has had a negative impact on cleantech investments. Business cases for new and emerging clean technologies are based on the high cost of traditional fossil fuels. As this falls, the business case for cleantech erodes and they find difficulty in attracting investors. As the corollary to high and uncertain gas prices driving investment in alternative fuels and solutions, it appears low and sustained gas prices have the opposite effect. Given the uncertainty in US clean energy policy, the link is difficult to formally establish.

2.6 Shale gas and low carbon generation can co-exist providing there is certainty in policy around overall carbon emission targets and that the majority of fossil fuel generation has carbon capture and storage.

October 2012

Written evidence submitted by Policy Exchange (ISG 11)

INTRODUCTION

1. Policy Exchange is one of the UK's leading think tanks. We are an educational charity whose mission is to develop and promote new policy ideas that will deliver better public services, a stronger society and a more dynamic economy.

2. Earlier this year we published a research paper on what the development of shale gas might mean for the UK's energy and carbon policy, *Gas Works? Shale Gas and its policy implications.*[28]

3. That report concluded that shale gas, and gas more generally, has the potential to serve as a transitional fuel while remaining consistent with required emissions reductions. However, commentators who argue with great certainty that shale gas is the answer to future energy needs fail to recognise uncertainty about the future and neglect the importance of developing zero carbon technologies to meet long term emissions reduction goals. But gas sector developments do present the prospect of gas becoming a cheaper than previously expected transition fuel to a low carbon future.

SPECIFIC QUESTIONS

What are the estimates for the amount of shale gas in place in the UK, Europe, and the rest of the world, and what proportion is recoverable?

4. Other organisations are better placed to answer this, although it is probably worth noting that, given the pace with which new information is uncovered, any estimate submitted to this review is liable to be out of date by the time it is published.

Why are the estimates for shale gas so changeable?

5. Estimates for shale gas resources and reserves are so changeable because the business is still at a very early stage. Comprehensive assessments of gas in place have been conducted in very few fields outside the United States. Shale businesses outside the US are predominantly focused on exploration, rather than production. The costs of production that factor in to producible reserve estimates are also evolving as technology improves. This changeability is unlikely to subside in the near term, as exploration and innovation processes continue.

What are the prospects for offshore shale gas in the UK Continental Shelf?

6. Offshore shale gas production remains a tougher technical and economic prospect than onshore shale production. At a time when we have yet to see any onshore production occur in the UK, or offshore production occur anywhere in the world, it seems premature to be speculating about this option. Government should prioritise making the necessary regulatory decisions around onshore shale gas production, and about the wider role of gas in the UK energy sector.

[28] Moore, Simon; *Gas Works? Shale Gas and its Policy Implications*; Policy Exchange; 2012 http://www.policyexchange.org.uk/publications/category/item/gas-works-shale-gas-and-its-policy-implications?category_id=24

Should the UK consider setting up a wealth fund with the tax revenue from shale gas?

7. Policy Exchange has no view on this.

What have been the effects of shale gas on the LNG industry?

8. The major initial impact of shale gas on the LNG industry has been the effective cessation of LNG imports into the United States. This has freed LNG cargoes to go elsewhere in the world. However, this is at a very early stage in shale gas development, when the United States remains the only significant producer of gas from shale.

9. If other countries also develop shale gas production industries, the effects on LNG demand (and, potentially, supply) may become much more complex and far-reaching. US firms are developing plans for LNG export facilities (mostly oriented towards Asia from the Pacific coast). New exporters could emerge. Countries which are presently major importers (most notably, China) could see their reliance on LNG reduced by the development of large-scale domestic shale gas production.

10. At this stage of development, most predictions about the impact of shale on LNG markets are speculative and inherently uncertain. The scale of potential for production outside the US is poorly understood. From a UK policy perspective, it is worth being prepared for and adaptable to a range of possibilities, as competing trends in gas supply and demand around the world interact, leaving the price that UK firms will need to pay to secure LNG cargoes unpredictable. Cheaper LNG is a possibility we should be in position to take advantage of should it materialise, but is not a certainty to rely on.

Could shale gas lead to the emergence of a single, global gas market?

11. Alongside other developments in the gas business, shale gas could contribute to deeper integration of gas markets by increasing the volume of gas able to be produced, and the number of potential producers.

12. 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.[29]

13. 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 volumes in 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, had 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. Whereas oil has become predominantly a transport fuel, gas increasingly occupies a role in electricity generation, alongside heating and industrial applications.

14. 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 Gazprom, meaning that competitive pressure exists on the supply side. 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. 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."

15. In the UK, the gap between oil and gas prices is widening. 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. 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.

16. It would be going too far to state with certainty that these trends will inevitably lead to lower gas prices. But it can no longer be taken for granted that gas and oil prices will remain entwined.

[29] For a more detailed discussion of these arguments, see this IMF Working Paper http://www.imf.org/external/pubs/ft/wp/2011/wp11143.pdf

What are the effects on investment in lower-carbon energy technologies?

17. Successful development of shale gas at a large scale will inevitably have consequences for other energy technologies. The objective of UK and EU policy should be ensuring that any utilisation of shale gas occurs within the constraints of carbon reduction targets. Properly done, this will ensure that shale gas drives out coal and less cost-effective methods of decarbonisation. The main mechanism for accomplishing this is the EU Emissions Trading Scheme (ETS). By capping Europe-wide greenhouse gas emissions, it effectively also caps the extent that gas (including shale gas) can be burned in Europe. It also provides a mechanism to ensure that gas is a transition fuel, giving the incentive for its removal from the energy system in later years as the cap tightens.

18. Cheaper-than-expected gas would enable lower-cost short term emissions reductions. 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). Europe-wide, carbon emissions from electricity, capped under the EU ETS, would be the same under either approach.

19. Implied in that would be some scaling back of immediate deployment ambitions for other low-carbon technologies (most likely offshore wind, as the most costly technology planned for large-scale deployment).[30]

20. More important than the outcome in terms of which technologies account for which proportion of the UK energy system, is the process by which that outcome is reached. 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.

21. The Government's proposal for Electricity Market Reform (EMR), based 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 bill-payers if that assumption proves wrong.

22. 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 higher or lower cost-path than EMR assumes.

23. Energy policy needs to reflect uncertainty about the future. The long-term centrally planned approach of the Government's proposed EMR is much less able to handle uncertainty than market-based approaches.

What is the potential impact on climate change objectives of greater use of shale gas?

24. 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 (ie "fugitive emissions") being a prominent concern. The second is the impact a move to a more gas-oriented energy system, enabled by a boom in shale gas production, would have on carbon emissions as the gas is consumed.

25. At the combustion stage, there is no difference between the greenhouse gas emissions of conventional and unconventional 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. 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). However, the role of fugitive emissions is relatively minor in the context of the overall climate burden of gas use.[31]

26. 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

[30] See Less, Simon; *Fuelling Transition*; Policy Exchange; 2012; http://www.policyexchange.org.uk/publications/category/item/fuelling-transition-prioritising-resources-for-carbon-emissions-reduction?category_id=24

[31] See Moore, Simon; *Gas Works? Shale Gas and its Policy Implications*; Policy Exchange; 2012 http://www.policyexchange.org.uk/publications/category/item/gas-works-shale-gas-and-its-policy-implications?category_id=24 pp. 39–44 for a more detailed analysis including comparison of fugitive emissions studies

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.

27. 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.

28. In the European context, the EU Emissions Trading Scheme (ETS) 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, run as back-up or retire early.

29. 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.

30. 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 around Europe, so governments are evidently comfortable at least with the principle of that length of commitment.) Committing to a longer term Emissions Trading System is a far stronger commitment to reduce emissions than simply setting a carbon target.

31. Recent discussions of the ETS have focused 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.

32. 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.[32]

September 2012

Written evidence submitted by Shell (ISG 23)

EXECUTIVE SUMMARY

(i) Subject to market price, technological advances and the degree of appraisal of individual resources there will always be some uncertainty over the estimate of global tight/shale gas reserves. However, it is clear that the global potential for tight/shale gas is significant and tight/shale gas will have a significant impact on world energy markets, though this may vary by region.

(ii) Shell believes that tight/shale gas operations can and must be carried out safely, and we appreciate that communities and stakeholders have legitimate questions and concerns including on the environmental impacts of tight/shale gas operations. The regulator is often looked to for answers, and we believe the UK Government is taking the correct approach by reviewing potential impacts and seeking expert advice on the options available to mitigate them.

(iii) Based on the successful development of tight/shale gas in North America in recent years Shell also recognises the potential opportunity that the exploration and development of such resources could provide for the UK. Though exploration in the UK is at a very early stage and the extent of the resource is still uncertain, it could potentially provide many social, economic, trade and energy security benefits, if developed in a socially and environmentally responsible manner. Government, industry and communities need to work together to this end.

(iv) There are many benefits to the UK of maintaining a large role for natural gas in the energy mix, and in the electricity sector in particular. Natural gas can help with all three of the UK's energy objectives. Gas has the potential to contribute significantly, and in a cost effective manner, to helping the UK meet its CO_2 targets by displacing coal-fired generation. Gas fired power stations are, on a per MWh basis, one of

[32] See Moore, Simon; *Gas Works? Shale Gas and its Policy Implications*; Policy Exchange; 2012 http://www.policyexchange.org.uk/publications/category/item/gas-works-shale-gas-and-its-policy-implications?category_id=24 pp. 31–38 for more detail on these arguments.

the cheapest electricity generation technologies to build,[33] keeping costs down for consumers, whilst also being flexible and quick to build, which can help to ensure security of supply. Longer term, Shell believes that electricity generated from gas will be an essential part of the energy mix as one of the only realistic means of supporting the increased volume of electricity from intermittent renewables. We also believe that gas with carbon capture and storage (CCS) will be a competitive low-carbon technology, that can help achieve even greater cuts in carbon dioxide emissions. To achieve this we need to demonstrate gas CCS as quickly as possible, so that it is ready to deploy on a large scale in the late 2020s.

Q1. *What are the estimates for the amount of shale gas in place in the UK, Europe, and the rest of the world, and what proportion is recoverable?*

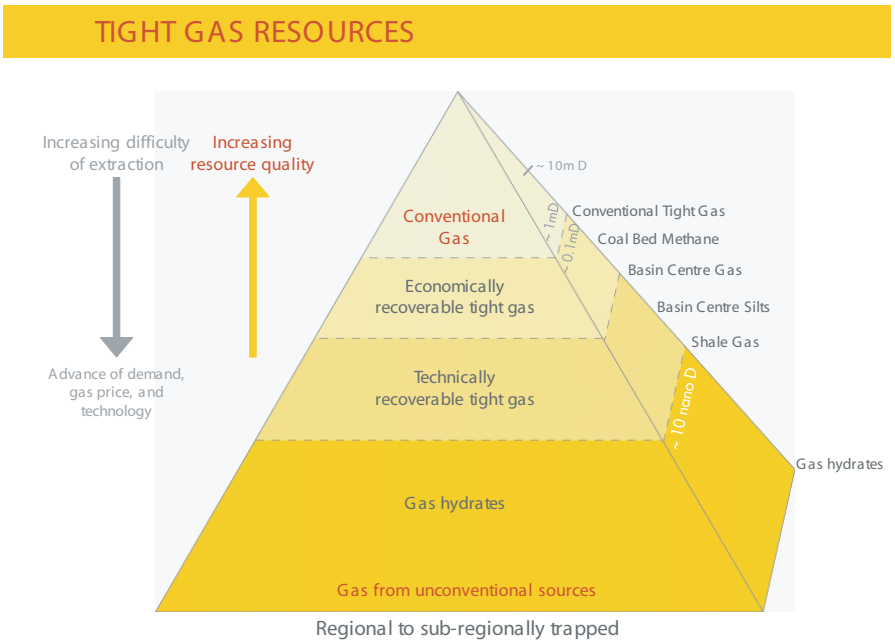
1. There are three basic forms of so-called "unconventional gas (UCG)": coal bed methane (CBM), basin centered gas and shale gas. In addition, there is a related form of liquids rich shales (more correctly termed light tight oil). These forms of natural gas (or oil) are referred to as "unconventional" because the natural gas (or oil) is not trapped in the same way as it is in the natural gas fields we are familiar with across the Southern North Sea which have formed the backbone of UK natural gas supply in recent decades. The methane produced from unconventional sources is no different than that produced from conventional sources. In general unconventional hydrocarbons are trapped regionally or sub-regionally in low permeability (ie fluids do not flow through them easily) and porosity rocks, whereas the so-called "conventional" hydrocarbons are typically trapped in structures of much smaller areal extent and in rocks with higher porosity and permeability.

Volumes and their significance

2. Masters (1979) was the first person to suggest that the distribution of hydrocarbons was log-normally distributed which implied that the conventional oil and natural gas reserves were the tip of a hydrocarbon iceberg that expanded in volume terms as the more difficult hydrocarbons were examined. This view has manifested itself as the so called resource triangle or tetrahedron (Fig. 1).

Figure 1

RESOURCE TETRAHEDRA



3. Rogner (1997) made the first attempt to assess the volumes of unconventional gas and the results were startling, indicating a huge volume potential. Since then there have been many studies that have either reworked these results or produced new ones, key amongst these additional studies are Kawata et al., 2001, Holditch (2006), NPC Global Oil and Gas Study (2007), Holditch and Mandani (2010), IEA (2009), and EIA (2011). All of these studies have concluded that there are indeed vast volumes of natural gas trapped in the subsurface.

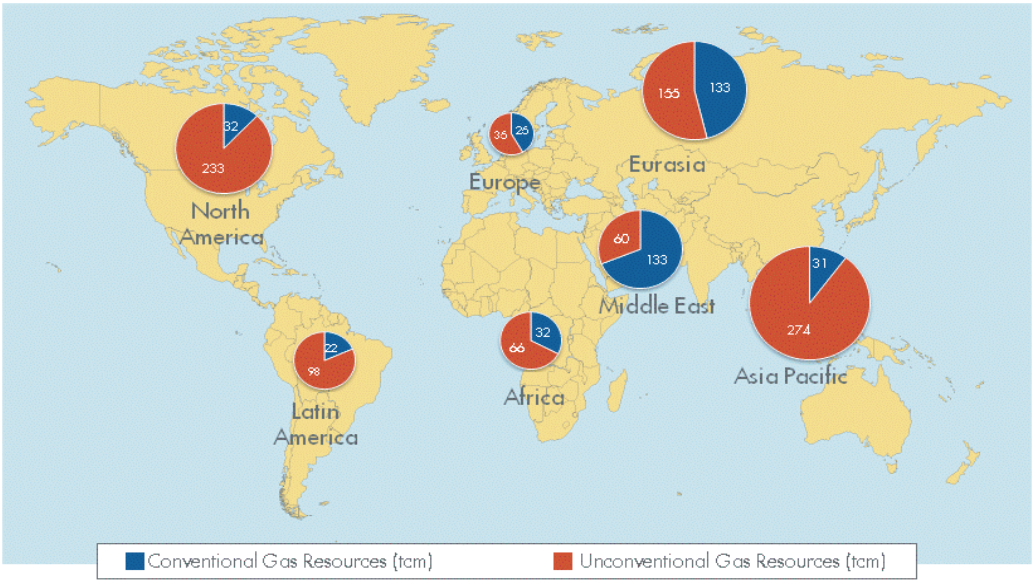
4. The Shell view of global UCG resources is similar with that put forward by the International Energy Agency (IEA) in its extensive look at natural gas markets in 2009 (see figure 2). The IEA estimate recoverable resources of tight gas, shale gas and coalbed methane globally to be more than 380 trillion cubic metres (tcm) (13,700 trillion cubic feet (tcf)), out of a total estimate resource base of 920 tcm (33,100 tcf). This is equivalent

[33] Mott Macdonald (2010). UK Electricity Generation Costs Update.

to 123 years of current global production, which when added to recoverable conventional gas resources, is estimated to be equivalent to over 250 years of current global production. UCG resources are more widely dispersed compared with conventional. The regions with the largest share of these UCG resources are North America, Asia-Pacific and the Former Soviet Union (FSU).

Figure 2

INTERNATIONAL ENERGY AGENCY ESTIMATES OF UNCONVENTIONAL GAS RESERVES[34]



IEA estimates 250 years global supply at current production levels*

* Source: IEA World Energy Outlook

5. As well as the success seen in tight/shale gas production in North America, Shell also sees potential for tight/shale gas development across the globe, although it is not expected that the growth will be uniform. This growth will heavily depend on domestic natural gas price developments in different countries and regions, local natural gas infrastructure, government and community support, fiscal regimes and the extent to which environmental issues can be effectively addressed. If sufficient amounts of natural gas are found, Shell's view is that it is possible to extract tight/shale gas in an economically, environmentally and socially responsible way.

Unconventional Gas in Europe

6. We are not aware of any commercial tight/shale gas production currently in Europe. European geological history is complex, and unlike North America, suffers from a paucity of critical data to assess accurately whether tight/shale gas can ultimately be developed commercially. Given the early stage of exploration there is still great uncertainty over the volumes of economically recoverable natural gas in Europe, illustrated by the variable estimates in the literature.

7. The key geological components appear to be present in many sedimentary basins, but simple extrapolation from North American analogues is difficult. At this time, it is not evident which areas of Europe will ultimately host commercial UCG production. Better assessment of UCG potential will first require early (one–four years) investment in seismic operations, exploration drilling and geological studies across many potential areas, followed by significant investment in appraisal drilling and production testing (two–five years). It is estimated that 20–40 wells (exploration, appraisal and pilot) will be required to prove commerciality in many basins. Exploration and production companies with diversified portfolios and stronger revenues are better able to absorb this exposure, but to succeed they will also need government support to enable the right fiscal framework and appropriate permitting and other regulatory conditions.

8. The volumes of natural gas in place need to be turned into economically accessible volumes. To do this requires some additional assumptions:

(1) Recovery factor and drainage area values need to enable the volume of technically recoverable natural gas to be estimated.

(2) The total surface area of the accumulation needs to be discounted for the area that is not developable due to terrain, population, infrastructure (eg roads), regulations (ie distance from

[34] International Energy Agency (2009). World Energy Outlook 2009.

buildings), areas where drilling is not allowed (eg typically national parks), or critical water resources.

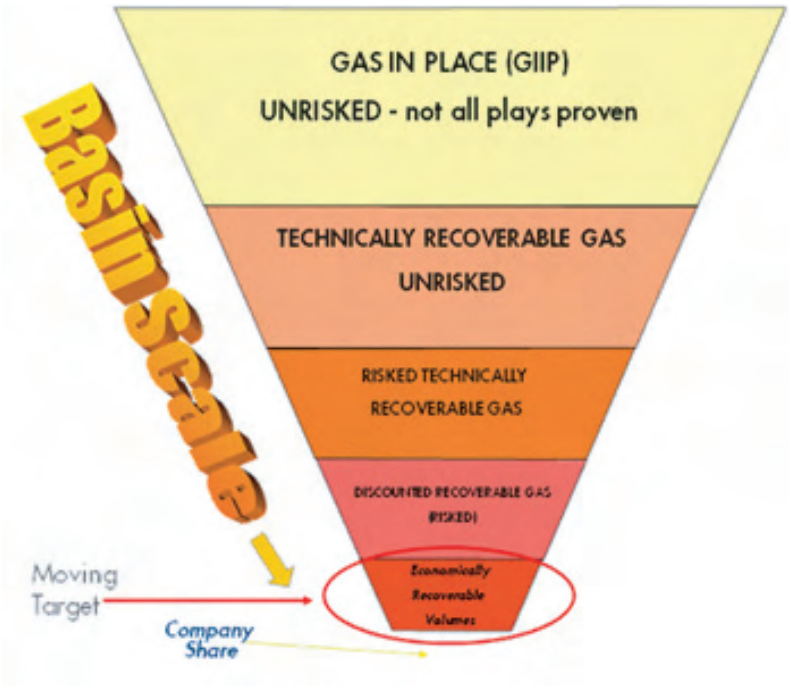
(3) Evaluation of the fraction of the technically recoverable and accessible volumes that is economically accessible.

(4) Other constraints such as the availability of infrastructure, equipment, knowledge etc need to be taken into consideration.

9. An inverted pyramid (Fig. 3 below) best describes the volumes that are economically recoverable.

Figure 3

MOVING FROM NATURAL GAS IN PLACE TO ECONOMICALLY RECOVERABLE VOLUMES



10. Estimating the proportion of the technically recoverable and accessible volumes that are also economic is no easy matter. There is no single answer because a large number of other variables may come into play, many of which vary significantly with time. The economics of tight/shale gas depend largely on five factors:

— The total recoverable natural gas per well—typically the total recoverable natural gas per well from developed tight/shale gas fields is in the range one to 10 bcf/well, but the recovery rate varies significantly with geology and can therefore vary within any given resource.

— Average long term natural gas price—the typically low ultimate recoveries achieved per well mean that a continual focus is required on unit cost reduction and technology deployment to increase ultimate recovery. In this environment fluctuations in gas price can therefore have a large impact on project economics, requiring investment decisions in these resources to take a long term view of natural gas prices.

— The well costs—well and completion costs typically make up 70–90% of the total project costs and so have a huge impact on the economic viability of a project. The principle variable controlling well costs is the total depth of the well and the length of any horizontal section.

— Infrastructure costs—successful North American developments to date have typically benefited from a local abundance of natural gas distribution networks and of mid-stream companies willing to develop infrastructure. Elsewhere in the world such infrastructure may not exist at the outset putting a heavy financial burden on any tight/shale gas project.

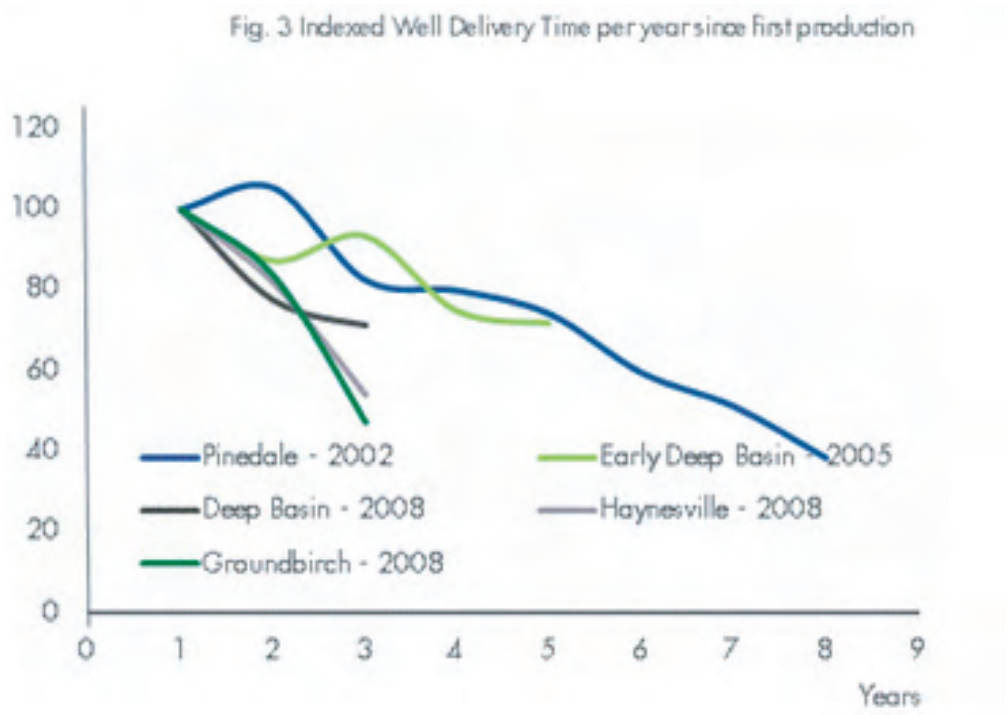
— Terms and conditions—the fiscal regimes for natural gas development vary greatly around the world and this will impact whether or not some of the tight/shale gas volumes present will ever be developed.

11. As well and completion costs dominate the average project's economics, their reduction over time can be extremely important in improving the profitability of a project. So-called learning curves need to be built into forward looking economic assessments of opportunities. These take into account a risk assessment that with time, in any given project, it will be possible to build up experience and drill wells faster and cheaper, streamlining and optimizing designs without compromising safety or productivity. Our experience has taught us that it is not only possible to learn within a given project but to cross-learn between projects to accelerate learning considerably as shown in Figure 4, which illustrates how drill time (normalized to 100 days) can

reduce over the development of an asset and across assets. Another benefit of learning curves is that areas of the resource that were once thought to be uneconomic, may become economic later in the development program as operational efficiency and engineering effectiveness increases.

Figure 4

WELL DELIVERY TIME LEARNING CURVES IN NORTH AMERICAN UNCONVENTIONAL GAS PLAYS



12. Advances in technology which increase the recovery factor per well or decrease costs will increase the volumes of economically recoverable natural gas. For instance, in the Barnett shale the average productivity per well has steadily increased as a result of increasing the length of the horizontal sections of the wells and the number of hydraulic fracture stages used.

Liquid Rich Shales otherwise known as (Light) Tight Oil

13. In recent years there has been a growth in the production of oil from tight rocks. These rocks can be tight sandstone reservoirs, shale analogous to shale gas, tight carbonates such as the Eagle Ford, or silicilite such as the Monteray in California. Shell terms all these types Liquid Rich Shales, while industry in general uses the term tight oil. With the exception of coalbed methane, there are oil equivalents to all the forms of UCG we have already discussed. We now know a lot about how to estimate the volumes of natural gas trapped and how to produce it as there are now many active fields in North America. The same technology, ie long horizontal wells and hydraulic fracturing, has also been used to produce oil from tight rocks in North America sparking the reversal in the decline of North American onshore oil production.

14. Some publications have suggested that there are significant amounts of light tight oil yet to be found. Although it is certain that oil can be produced there are fundamental reservoir engineering reasons why it is unlikely to be as prolific as tight/shale gas. The industry is at an early stage of development in North America and time will be needed to determine how this oil resource might be developed. Potential does also exist globally, but it is also too early to determine what the true potential might be.

Q2. *Why are the estimates for shale gas so changeable?*

15. It should be noted that, outside of North America and with the exception of Australia where CBM developments are moving apace, elsewhere in the world there is no large scale tight/shale gas production. There are many tests going on around the world currently eg in Poland and China, but it remains to be seen how these speculative volumes quoted in the global studies translate to delivered volumes. To understand the speculative character of these numbers it is important to appreciate how these numbers are estimated. There are a number of ways that have been employed to estimate the volumes of gas in place, and in approximate order of increasing reliability these are:

(a) Simple scaling between what is known of North American basins and those outside North America.

(b) Geological analogue approach—finding a North American analogue for a given basin and scaling the result.

(c) Comparison of a given formation within a basin against a set of conditions necessary for the presence of UCG eg of the volume of natural gas generated from the source rock, and then extrapolation of the volumes present from an estimation of the porosity, natural gas saturation, thickness and extent.

(d) Data from well logs on the presence of natural gas, its saturation and the porosity that can then be extrapolated over the likely extent of the accumulation.

(e) As per (d) but with the addition of production data most notably the estimated ultimate recovery per well for the formation in question.

(f) Estimates based purely on the distribution of estimated ultimate recoveries for a given formation based on production data for that formation extrapolated over the resource area.

16. The data requirements grow significantly from method (a) to (f), such that methods based on (e) or (f) are only possible in established North American resources.

17. So the range of values quoted by different sources reflect a number of different factors:

(1) The method of analysis chosen, noting that only methods (a) to (c) (maybe in some areas (d)) are possible outside of North America.

(2) The level of detail versus extrapolation ie how many basins were actually looked at in detail versus how many used extrapolation to estimate their potential.

(3) Cut-off values eg thickness of the shale concerned could vary between studies.

(4) What volume is being discussed, in place volumes, recoverable volumes, or economic volumes (if so, at what commodity price and other cost assumptions of drilling).

(5) Is only shale gas being included or all forms of unconventional gas?

18. Given the lack of data to accurately assess reserves outside of North America, it will take some time before more accurate estimates become available and the estimates start converging. Nevertheless the consensus is that the potential resource is large.

Q3. *What are the prospects for offshore shale gas in the UK and the Continental Shelf?*

19. In Europe, the exploration of tight/shale gas is still in its early stage and no commercial production is taking place at present and a significant period will be required for development. Over the period 2005 to 2011 there were of the order of 25 shale gas wells drilled in Europe, all of them exploratory, while in the same period in North America, in the major shale gas resources alone, some 40,000 wells were drilled.

20. So far all tight/shale gas developments that we are aware of are onshore. This does not mean that tight/shale gas does not exist offshore, it almost certainly does. The development of tight/shale gas resources requires a relatively high well density with multi-well pads being positioned every few kms. This far exceeds the well density that is currently economically feasible on an offshore platform and of course the costs rise dramatically with the number of platforms needed. As a result in the medium to long term, without any significant technological breakthroughs, it is unlikely that large UCG accumulations will be economically viable offshore.

Q4. *Should the UK consider setting up a wealth fund with the tax revenue from shale gas?*

21. We consider that how the tax revenues are used, is a matter for government to determine.

Q5. *What have been the effects of shale gas on the LNG industry?*

22. As mentioned previously, the tight/shale gas revolution means the world now has an estimated 250 years of worldwide recoverable natural gas resources at current production rates.[35] The biggest impact has been in the US, where many now believe that 100+ years of reserves can be economically produced. The growth in the production of shale gas in the US has increased the disparity between North American natural gas prices and European natural gas or Asian Liquified Natural Gas (LNG) prices. In addition, the increase in North American natural gas supplies has boosted confidence in natural gas and is paving the way to demand growth in North America. For example, it increased attractiveness for: natural gas to power, natural gas moving into the transport sector, the potential for natural gas to liquids and natural gas to chemicals.

23. The impact on the global LNG market will depend on the success of current efforts to export LNG from North America. These exports will be produced by greenfield projects as for example the Shell-led LNG Canada project, as well as conversion of existing LNG import terminals in the United States. New liquefaction export capacity in the United States may begin to operate as early as 2015. A wide range of US LNG export projects have been announced totalling 16.83 billion cubic feet per day[36] (bcfd). Currently only one, the Sabina Pass project, has received a 9 million tonnes per annum (mtpa) export license for LNG exports to countries not governed by a free trade agreement with the United States.

[35] International Energy Agency (2009).World Energy Outlook 2009.

[36] Federal Energy Regulatory Commission (2012). Proposed/Potential North American LNG Import/Export Terminals.

24. Through eventual North American LNG export capacity, the North American tight/shale gas resources help to create the opportunity for global LNG buyers to further diversify supply sources. Already today we see LNG volumes, destined for the United States, being diverted to meet the growing LNG import requirements of other markets, such as Europe and Asia.

25. In addition, LNG exports from Australia will increase significantly after 2014,[37] partly fuelled by the production of CBM. Australia also has other forms of tight/shale gas potential but the development of the CBM resources there is more advanced.

26. In terms of price impacts on markets it is too early to know exactly what the impact of tight/shale gas will be. It is likely that development of these resources will encounter different challenges in different parts of the world, almost all being more complex than in the United States (technical, community, regulatory). Hence the speed and cost of developing tight/shale gas will vary around the world.

Q6. *Could shale gas lead to the emergence of a single, global gas market?*

27. The recent growth in the LNG market has increased the diversity of supply sources and allowed more flexibility in the natural gas supply chain, enabling more interconnection between regional markets. The emergence of tight/shale gas in the United States has increased the availability of divertible LNG cargoes that were previously destined to supply the United States. The availability of divertible LNG cargoes helps the global LNG market to balance more effectively. For example, diversions of LNG cargoes helped Japan to satisfy additional natural gas demand following last year's earthquake.

28. The regional price disparities we see today are based on supply and demand in the various regional markets, and due to regulatory differences between different markets. The complexity and costs associated with moving natural gas long distances (primarily via LNG) and the relatively small percentage of natural gas moved as LNG (<10% of total natural gas production[38]), the impact LNG can have in smoothing out these regional differences is limited. As the proportion of the natural gas market that is traded through LNG increases in future (estimated to grow to ~16% of total natural gas production by 2025[39]), further connectivity will also develop.

29. The key question, however, is whether the UK (and North West Europe) can connect into a wider global natural gas/LNG market. This is possible already today given the abundance of regasification terminals in the region and the increase of shorter term trades in the LNG market. As published by GIIGNL,[40] the spot market for LNG increased to 25% of global LNG trade in 2011. In addition, in 2011 the UK received LNG from Algeria, Egypt, Nigeria, Norway, Trinidad & Tobago, Qatar, Yemen and US, which demonstrates the global diversity of supplies available to the UK.

30. What is clear is that the recent additions to global natural gas reserves due to sUCG and the increased diversity of new upstream supply areas will likely increase the importance of natural gas in the global energy mix.

Q7. *What are the effects on investment in lower-carbon energy technologies?*

31. We believe that there is a vital long term role for natural gas in a low-carbon economy, particularly in the power sector as the natural complement to intermittent renewables which need back-up power. Natural gas can help maintain the stability of the electricity system as it is flexible and reliable and can therefore respond during the extended periods when the electricity output from wind decreases, a service that will be required more frequently in the future as the share of renewables in the electricity mix increases. Natural gas is viewed as one of the least carbon intensive technologies to use for helping balance the electricity grid, and if this role is not appropriately recognized in policy it may lead to more carbon intensive forms of load balancing, such as coal.

32. So natural gas and renewables generation technologies should not be seen as being in competition, as they are both required to meet the UK's energy goals of affordable, secure and low-carbon energy. In addition, the major energy transformations that are required both in the UK and the rest of the Europe to meet both climate and energy security goals carry significant risks and uncertainties. A key way to mitigate these is to incorporate into the transition process the knowledge gained as sector learning curves for new technologies develop and supply chains evolve. Growth in natural gas-fired power in the short to medium term enables a more measured transition to renewables and nuclear, allowing the optimization of technology and driving down of cost.

[37] Energy Delta Institute. http://www.energydelta.org/mainmenu/energy-knowledge/country-gas-profiles/country-gas-profile-australia

[38] Shell analysis.

[39] Shell analysis.

[40] International Group of Liquefied Natural Gas Importers (GIIGNL). "The LNG Industry in 2011". http://www.giignl.org/fileadmin/user_upload/pdf/A_PUBLIC_INFORMATION/LNG_Industry/GIIGNL_The_LNG_Industry_2011.pdf

Q8. *What is the potential impact on climate change objectives of greater use of shale gas?*

33. According to the IEA, natural gas currently provides about 20% of the global primary energy demand[41] and accounts for 20% of total global Greenhouse Gas (GHG) emissions from the energy sector. Tight/shale gas accounts for less than 5% of total GHG emissions from the energy sector. In contrast, coal accounts for 27% of the energy demand but 43% of GHG emissions.[42]

34. There are many benefits to the UK energy sector and wider economy in maintaining an important role for natural gas in the UK electricity mix. The benefits that the use of natural gas can bring from a macro-economic perspective are often underestimated. With deficits and government debt at historically high levels, there is an acute need for strict budget discipline. Maintaining the affordability of electricity prices is also important from a competitive perspective. Any increases in UK electricity prices that are not mirrored in other countries could impact industry's competitiveness and have a negative impact on jobs. Most countries will find that natural gas is far more affordable than any other source of electricity, especially in front-end (capital cost) investment terms. There are also significant benefits of developing domestic tight/shale gas resources, as highlighted by a recent report from the Institute of Directors that indicated UK tight/shale gas reserves could create up to 35,000 jobs.[43]

35. The security of supply benefits of natural gas have been outlined in our response to the previous question. In terms of its contribution to the reduction in emissions, replacing coal-fired generation with natural gas is the fastest and cheapest way of achieving immediate reductions, given that, on average, gas emits 50% less CO_2 than coal when used to produce the same amount of electricity.[44]

36. Longer-term, natural gas fired power plants may be retrofitted with CCS which has potential to reduce emissions by up to 90%. CCS is technically established (all elements are well proven) but the market still has to see scaled-up demonstrations and then widespread application. This may be achievable in the 2020s and, provided the appropriate regulatory framework and government support is established, we may see large scale CCS take off by 2030. In the longer term, as these technologies move to "nth of a kind status" (or mature status), the levelised costs of CCS equipped plant should make them very cost competitive with other technologies such as offshore wind and solar PV.[45]

37. So in the period to 2030 there are several arguments for unabated natural gas generation. This is consistent with meeting the UK's 2050 targets, since CCS may be retrofitted to natural gas plants after 2030 and reduce their carbon footprint. Shell analysis has shown that the UK 2050 target would need CCS build-out rates of one to two GW per year from 2030 to 2050 which is equivalent to 1.5% to 3% of current UK fossil fuel generation capacity. This needed CCS build rate is realistic when compared to the UK's natural gas fired power build activity from 1991–2002 which was between 0.5 and 3.5 GW a year.

38. These benefits can be provided by tight/shale gas as well. According to the IEA, the emissions incurred from producing tight/shale gas are not significantly different from conventional natural gas. The IEA has estimated that well-to-burner emissions from tight/shale gas exceed those from conventional natural gas by as little as 3.5% in best case scenario and by 12% in worst.[46] At Shell we endeavour to manage our operations to reduce emissions and we measure, catalogue and report emissions to the relevant authorities. GHG emissions from shale gas-fired power are still only around half of those from coal, across the lifecycle from production to use.[47] Shifting to natural gas can have a significant impact on emissions. For example, according to the IEA, US emissions have now fallen by 430 Mt (7.7%) since 2006, the largest reduction of all countries or regions. This development has arisen from lower oil use in the transport sector (linked to efficiency improvements) and a substantial shift from coal to natural gas in the power sector.

[41] International Energy Agency (2011). World Energy Outlook 2011.
[42] International Energy Agency (2011). World Energy Outlook 2011.
[43] Institute of Directors (2012). "Britain's shale gas potential".
[44] Stephenson T, Vale JE, Riera-Palou X (2011). "Modelling the relevant GHG emissions of conventional and shale gas production." Environmental Science and Technology.
[45] Mott MacDonald (2011). "Costs of low-carbon generation technologies".
[46] International Energy Agency (2012). "Golden Rules for a Golden Age of Gas".
[47] Stephenson T, Vale JE, Riera-Palou X (2011). "Modelling the relevant GHG emissions of conventional and shale gas production." Environmental Science and Technology.
[48] Shell Onshore Tight Sand/Shale Oil and Gas Operating Principles- www.shell.us/home/content/usa/aboutshell/shell_businesses/onshore/principles/

39. Shell published in mid-2011, its Onshore Tight Sand/Shale Oil and Gas Operating Principles.[49] We believe that a similar approach taken across the industry would help improve standards, reduce the environmental risks and promote public confidence in this sector.

October 2012

Written evidence submitted by SSE (ISG 29)

1. SSE is a UK owned and based company operating in the UK and Ireland. It has interests in the generation, transmission, distribution and supply of gas and electricity. SSE is currently the UK's second largest generator of electricity and the second largest supplier of gas and electricity. SSE also has interests in upstream gas, with North Sea production assets, however it is currently not involved in the extraction of shale gas.

2. Gas has a vital role in the UK electricity sector. However, developing CCS on gas is vital to ensuring the decarbonisation of the electricity sector and maintaining security of supply. SSE has submitted a bid into DECC's CCS competition for a retrofit project on its gas power station at Peterhead, Aberdeenshire, in collaboration with Shell. If there is significant development of shale gas in the UK, then the importance of developing gas CCS increases.

SUMMARY

3. Shale gas extraction has potential to impact on the UK gas market through domestic extraction, but is more likely to influence it through extraction elsewhere in the world, as was seen by the indirect impact on the UK of the US shale gas boom. To mitigate the short to medium-term impacts of potential cheap shale gas extraction elsewhere in the world and to avoid jeopardising the UK's ability to meet its long-term objectives of decarbonisation and security of supply, the UK needs to ensure that the following policy supports are in place:

3.1 Robust carbon price and low carbon support

The shale gas boom in the US, coupled with a weak EU ETS carbon price, has led to an increase in coal-fired coal generation in the UK as a result of reduced coal use in US electricity market. If it extends for a significant period of time due to the lower gas prices caused by an excess of supply worldwide then there is a risk of carbon lock-in and a delay in investment in low-carbon electricity generation. This would have long-term impacts on electricity decarbonisation and would increase the risk of price volatility from imported fossil fuels. Therefore the UK needs to lead European efforts to strengthen the EU ETS and ensure that emerging low carbon technologies receive the required support to bring them to economic viability in the future.

3.2 Development of gas CCS

Given the importance of gas to the UK's electricity system, developing CCS on gas is vital to ensuring the decarbonisation of the electricity sector and maintaining security of supply. If there is significant development of shale gas in the UK or elsewhere in the world, then the importance of developing gas CCS increases as does the UK's opportunity of developing a world-leading export industry. Full-chain CCS has yet, to be proven at a commercial scale and therefore requires upfront capital support to bring it to economic viability and give policy makers the confidence that new gas plant can become low carbon at an appropriate stage.

What are the estimates for the amount of shale gas in place in the UK, Europe and the rest of the world, and what proportion is recoverable?

4. It is widely remarked that the UK shale plays could provide significant volumes of gas into the UK market. However, the resource is not as easily accessible as it is in the US and the population density of the UK and Western Europe would make it more difficult to mitigate the local impacts of drilling than is the case in the US.

5. The volumes of shale gas recoverable will depend on the gas price. At current market prices, shale gas extraction in the UK will likely not be economically viable due to higher production costs in the UK than the US. Higher gas prices in the future could allow for the extraction of higher cost unconventional shale gas, although large volumes of cheap shale gas extraction as seen in the US looks unlikely.

Why are the estimates for shale gas so changeable?

6. Estimating potential resources and recovery rates is not an exact science and an understanding of recovery rates is only reached after there is has been significant investment in an individual well. Given the absence of production experience outside of the US, resource estimates should be treated with caution.

[49] Shell Onshore Tight Sand/Shale Oil and Gas Operating Principles- www.shell.us/home/content/usa/aboutshell/shell_businesses/onshore/principles/

What are the prospects for offshore shale gas in the UK Continental Shelf?

7. The prospects for offshore shale gas exploration appear limited because of the higher costs of offshore operations on top of the higher production costs of extracting unconventional gas. As with onshore shale gas, while offshore resources may be uneconomic at present, they could become economically viable if gas prices rise into the future.

What have been the effects of shale gas on the LNG industry?

8. The success of shale gas in the US has led to a reduction in demand for LNG in the Atlantic Basin. This has put a downward pressure on the UK market, but it is unlikely that shale gas volumes seen in the US will be replicated in Europe or elsewhere. This effect on the LNG market would be the same if any volume of natural gas were to be extracted and is not limited to shale gas or any form of unconventional gas.

Could shale gas lead to the emergence of a single, global gas market?

9. Large discoveries of natural gas of any source have the potential to moderate the global trade of natural gas, particularly the interregional flows of LNG, but there is limited evidence to suggest that it could lead to the emergence of a single global gas market. The large transport costs associated with gas would be the most obvious barrier to a single global gas market.

Should the UK consider setting up a wealth fund with the tax revenue from shale gas?

10. It would appear unlikely that shale gas extraction would be a sufficiently lucrative activity to make it worthwhile to consider setting up a wealth fund. It is unclear why setting up a national wealth fund would be considered for shale gas, and not conventional oil and gas.

What are the effects on investment in lower-carbon energy technologies?

11. Given that extraction of significant volumes of shale gas in UK would only become reality at higher gas prices, it would appear that investment in UK shale gas would limit negative impacts on investment in low carbon electricity generation.

12. However, if shale gas extraction is cheaper elsewhere and exerts a downward pressure on the UK gas market indirectly, as happened with shale gas extraction in the US, this could deter investment in low-carbon electricity and energy efficiency. This impact would be mitigated if there was a robust Europe-wide carbon price. A weak carbon price coupled with low gas prices would damage low-carbon investment and energy efficiency uptake significantly, and would leave both the UK and the rest of EU overexposed to gas price volatility in the medium to long term. Therefore, it is imperative that the UK leads Europe in attempts to strengthen the EU ETS and to encourage low-carbon generation and energy efficiency to insulate the UK from potential price volatility.

13. Although a carbon price signal corrects the negative market externality created by carbon emissions, it does not provide support for the development of emerging technologies and industries, such as renewables and CCS. These emerging technologies require support for them to be brought to economic viability. Therefore, a transparent support mechanism with a clear trajectory is required to bring forward technologies to market while developing UK supply chains and the associated economic benefits of jobs and growth.

What is the potential impact on climate change objectives of greater use of shale gas?

14. At the point of use, the carbon footprint of shale gas will be the same as conventional gas, where it prevents investment in low carbon electricity, it would be to the detriment of the long-term decarbonisation of the UK power sector, although where shale gas is encouraging coal to gas switching for power generation it would bring emission reductions in the short to medium term. Coal to gas fuel switching has significant importance to the reduction of carbon emissions of other national markets, which unlike the UK do not have a significant proportion of gas-fired electricity generation capacity currently on their system.

15. Electricity sector decarbonisation is vital to meeting legally binding 2030 carbon targets, as there is a greater push for the electrification of heat and transport. New gas plant will be required on the system before 2030 to balance the greater penetration of intermittent renewables and ensure security of supply with planned capacity closures. To ensure that flexible gas plant can balance the system at times of supply shortage post 2030, it is important that gas CCS is available at an appropriate stage so that gas plant are able to be retrofitted with carbon abatement technology. This alone makes developing CCS on gas vital for meeting the UK's legally binding carbon targets, and if shale gas extraction occurs in volume anywhere in the world, developing CCS on gas will not only develop in importance in the UK but for other countries as they increasingly switch from coal to gas for electricity generation.

16. The UK has a distinct comparative advantage on developing gas CCS, given its strong academic knowledge base, existing offshore oil and gas engineering expertise, accessible offshore storage sites and existing penetration of gas plant on the electricity system. If there is appropriate government support, gas CCS

can prove to be a strong export opportunity for the UK and play a vital role in ensuring the electricity system is decarbonised by 2030.

October 2012

Written evidence submitted by the UK Energy Research Centre (ISG 24)

UKERC Response

This document sets out part one of a two part response of the UK Energy Research Centre (UKERC) to the Energy and Climate Change Committee's call for evidence on the Impact of Shale Gas on Energy Markets.

The overall submission of both parts is under the control of Professor Michael Bradshaw from the University of Leicester. Part two includes contributions from multiple experts.

Professor Bradshaw is leading a research project on *The Geopolitical Economy of Global Gas Security and Governance: Implications of the UK*, which is being funded by UKERC. This submission is based on that project.

Summary

This submission focuses on the potential impact of shale gas production on the global gas industry. Firstly, it suggests that the rapid development of shale gas production in the United States (US) has had a significant impact as it has resulted in the loss of a major market for LNG exporters. Events in Japan post-Fukushima are also an important factor in explaining the current situation. Secondly, the very low price for gas in the US, as a result of shale gas production, is putting pressure on gas price formation, both in Europe in relation to long-term oil-indexed pipeline imports and in the Asia-Pacific region in relation to long-term oil-indexed LNG imports. However, the high-price of oil is also a key factor in the current debate over the future pricing of natural gas. To conclude, the potential for significant shale gas production is an important factor in the current uncertainty over the future of the global gas industry, but it is not the only factor at play and any assessment of shale gas must be made in the wider context of multiple uncertainties.

1. *What have been the effects of shale gas on the LNG industry?*

1.1 The impact of shale gas on the LNG industry needs to be seen in the wider context of the potential transformation of the global gas industry. The first, and most direct, consequence of the rapid expansion of shale gas production in the US has been the loss of the US as a major market for LNG imports. Previously it was expected that the US would have to import significant amounts of LNG and about 150 bcms of re-gasification capacity was constructed. Today the US uses less than 10% of that capacity and there are plans to re-construct some of the re-gasification terminals as LNG export terminals. This is the case with the Cheniere Energy project at Sabine Pass in Louisiana. Now the issue under discussion is the extent that the US should be an exporter of LNG. A combination of this loss of market and the fall in gas demand as a consequence of the global financial crisis in 2008 onwards resulted in a surplus of LNG on the market. Much of this surplus LNG found its way to European markets and the UK was a beneficiary of this "gas glut." However, this period of plenty was short-lived as the Great East Japan Earthquake in March 2011 and the disaster at the Fukushima nuclear power station resulted in the shutdown of Japan's nuclear fleet. By July 2012 there were no nuclear power stations operating in Japan, now two plants are back in operation, but the future is uncertain. Japan has turned to increased fossil fuel use and LNG now provides 48% of Japan's power generation. As a result LNG demand in Japan increased by 20% in 2010–11. Qatar supplied 50% of this incremental demand. This is significant because a combination of increased European LNG imports, growing Asian demand and additional Japanese demand have consumed the earlier "gas glut," resulting in a tight market until 2015–16 when new production comes on line. In fact, by 2020 we will likely be in a situation of over-supply in the global LNG market and shale gas exports from North America will be potentially be part of that scenario.

1.2 The second impact of shale gas in the US is that it is contributing to the destabilisation of the gas price formation model in both European and Asian markets. As implied by the next question, gas is not a globalized market. Rather, in simple terms, there are four major regional pricing systems, and within these, price structures that are specific to national markets and even individual supply chains (for a detailed analysis see Stern 2012). In the US the Henry Hub price is based on gas-to-gas competition. This is also the case in the UK with the Net Balancing Point (NBP) as the benchmark price. Continental Europe is a combination of long-term prices indexed to the oil price, which currently predominate, and a growing amount of spot trading on emerging gas hubs. Prices of LNG supplies to Asia are also based on long-term oil indexed prices, with a growing amount of LNG spot trading. As a result of shale gas production in the US pushing down the Henry Hub prices, in combination with high oil prices, there is now growing pressure on the logic of oil price indexation. This pressure is being felt in Europe as companies seek to renegotiate the terms of their long-term contracts with suppliers such as Gazprom to reflect the lower prices available on spot markets. Gazprom's pricing and contract behavior is now the subject of investigation by the European Commission. In Japan the cumulative consequence of having to source additional LNG in a tight market has made the cost of electricity an important political issue (Hosoe 2012). The Japanese Government now wants to revisit the expensive terms by which it has

previously guaranteed security of gas supply. Part of the solution for Japan is to source future LNG from North America at a lower price (Ando 2012).

1.3 Shale gas is a key part of a complex set of processes that are destabilising the current pricing mechanism within the LNG supply chain. The problem is that LNG is a capital intensive business that requires a long-term commitment between supplier and buyer and at present the industry has no viable alternative to oil indexation. In a UK context this is relevant as it is becoming increasingly reliant on imports of LNG and is also playing a role as a western bridgehead for LNG entering the European Continental market via the interconnectors. Short-term, UK consumers may suffer from companies having to source high-cost LNG in a tight market, but post 2020—thanks to the development of new LNG projects based on conventional gas—there could be a plentiful market for LNG in the Atlantic basin. Of course, if US shale gas turns out to be a short-lived boom and the US has to start importing substantial amounts of LNG this would deny a cheaper source of exports for both Atlantic and Pacific basins and also a source of competition for LNG deliveries. Finally, there is considerable debate in the US about the wisdom of exporting LNG (see Ebinger et al. 2012 and Medlock 2012b), however, should it not become a substantial net exporter there are plenty of other projects in Australia, Canada, East Africa and Russia, for example, that will provide new supplies. The question is then at what cost to the consumer?

2. *Could shale gas lead to the emergence of a single, global gas market?*

2.1 The current global gas supply system is based on a series of regional markets and we have a largely self-contained North American market dominated by pipeline gas. At present, the direct impact of shale gas production is confined to this market. We have a European market that is supplied by domestic production, in combination with pipeline gas supplies from Norway, North Africa and Russia, with a growing amount of LNG. Finally, we have an Asia-Pacific market that is dominated by LNG supplies, the major consumers being Japan, South Korea and China. There is also now pipeline gas supplying China from Central Asia, which is to be supplemented by supplies from Myanmar and potentially Russia. Mapped onto these markets we have a global LNG supply system that is currently divided into the Atlantic Basin and the Pacific Basin. It is the LNG trading system that provides flexibility as pipeline supplies are physically fixed. The expansion of Qatari LNG has provided a substantial amount of gas that can supply either basin, thus there are signs of greater integration. As noted above, the recent gas glut allowed European buyers to purchase cheaper LNG from Qatar. However, as a consequence of Fukushima and growing demand in Asia, buyers in the APR have sourced a growing amount of LNG from outside of the Pacific basin—in 2011 Japan received 67% of its LNG from within the APR and in 2010 the figure was 75—this situation is likely to remain until at least 2016 (Hosoe 2012, 49). After 2016 new production from Australia and Papua New Guinea will rebalance the situation. Longer term LNG supplies from Canada, the US, East Africa and Russia will provide even more supply. This could result in over-supply in the Pacific basin, which would make more Middle Eastern and African LNG (and possibly US LNG) available to European buyers.

2.2 What impact might shale gas production have on this situation? The modeling exercise conducted by Gracceva and Zeniewski (2012) assumes that most shale gas production will be consumed within producing states, which seems reasonable. Even in the US future LNG exports are likely to be modest against total domestic production and it is uncertain what impact they will have on the global LNG market. Certainly, in Europe and in China shale gas production will be consumed domestically. Thus, shale gas is unlikely to impact significantly on the supply side of the LNG system; however, it may serve to dampen down demand for LNG imports in new shale gas producing counties. Gracceva and Zeniewski (2012, 196) conclude: "…if high reserves and low production costs stimulate considerable [shale] gas production in all regions, this may dilute the importance of LNG by challenging the profitability of long distance interregional trade." This suggests that substantial shale gas will dampen the "globalising" tendencies that have been seen in the LNG system. Gracceva and Zeniewski (2012, 219) make clear that shale gas in Europe will only serve to stabilize Europe's gas import dependence at around 60%.

2.3 The important point here is that the potential impact of shale gas is part of a wider set of issues that are driving the transformation of the global gas industry. There is currently a high degree of uncertainty about the future in terms of the pricing and contracting of natural gas, but there is also an abundance of reserves of conventional gas, let alone the prospects for unconventional gas. Given the differences between the North American, European and Asian gas markets it is unlikely that we will see a truly global market for gas anytime soon. The possibility of substantial shale gas production is critical in challenging the current pricing and contracting system, but in reality it has served to destabilise a system that was increasingly unsustainable. At present, one could argue that it is the consequences of high oil prices and oil-price indexation that are fuelling demands by gas consumers in both Europe and Asia to change the system, not the belief that a shale gas revolution is around the corner.

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Written evidence submitted by the Tyndall Centre for Climate Change Research, University of Manchester (ISG 30)

Executive Summary

Tyndall Manchester has been investigating the climate change implications of shale gas developments for the past two years. We have raised concerns around the cumulative quantities of emissions that may be released by the extraction and combustion of shale gas and the implications for climate change mitigation of a widespread expansion of the industry in two reports. The most recent report (Broderick et al., 2011) contains research of relevance to two specific questions raised by the committee, namely:

(i) What are the effects on investment in lower-carbon energy technologies?

(ii) What is the potential impact on climate change objectives of greater use of shale gas?

This submission is a précis of the conclusions drawn by Broderick et al (2011) with additional material from a forthcoming report (Broderick and Anderson, 2012) examining the impact of shale gas on US energy system emissions. We conclude that the issues of lock-in to unabated gas generation, the importance of other drivers of US emissions reductions and the consequence of export of displaced fossil fuels, indicate that novel sources of gas production are problematic from climate change mitigation. It is clear that the production of fossil fuels of all sorts needs to be curtailed in the absence of strict and coordinated international greenhouse gas emissions caps.

Ultimately, the UK's international commitments, under the Copenhagen Accord and Cancun Agreements, cannot be reconciled with the large scale exploitation of shale gas, even with carbon capture and storage. In many respects the response of the UK Government to the prospect of indigenous shale gas production is a bellwether of the veracity or otherwise of the UK's commitments and leadership on climate change.

(i) *What are the effects on investment in lower-carbon energy technologies?*

1. The Energy and Climate Change Committee (2011) has previously noted that a substantial move to exploit newshale gas reserves could attract investment that might otherwise go to renewable energy. The 2011 report states that "…shale gas has the potential to shift the balance in the energy markets that the Department has tried to create away from low carbon electricity generation".

2. In our updated report (Broderick et al. 2011) we estimated the potential scale of such a diversion by assessing the capital costs of gas powerstations burning the output of a mature shale gas industry (ie 9bcm/year sustained over a 20 year time period). We refer the committee to section 3.4 of Broderick et al. (2011) for full details and summarise the conclusions below.

3. In total, potential resource substitution was found to be £19 billion to £31 billion, depending upon the discount rate applied to future investment. The higher figure relates to a Treasury Green Book discount rate of 3.5%, arguably the most appropriate rate for assessing public policy.

4. Table 3.11, reproduced below, illustrates the scale of potential wind energy foregone if capital is diverted to shale gas. Given the need for climate mitigation, the costs of CCGTs with carbon capture and storage (CCS) was also considered. CCS has an energy penalty in operation, in the order of 10% to 20% hence 7GW capacity could be sustained with 9bcm/year gas, and substantially increases capital costs. In the absence of large scale demonstration plants there are considerable uncertainties in the technology's cost and efficiency parameters.

Table 3.11

INVESTMENT EQUIVALENTS IN GAS AND RENEWABLE CAPACITY

	10% Discount rate		*3.5% Discount rate*	
	8GW CCGT	*7GW CCGT +CCS*	*8GW CCGT*	*7GW CCGT +CCS*
Onshore wind (GW)	12.5	16.5	16.8	20.8
Onshore wind (3MW turbines)	4,172	5,503	5,594	6,925
Offshore wind (GW)	7.0	9.2	9.4	11.6
Offshore wind (5MW turbines)	1,401	1,849	1,879	2,326

5. The potential scale of displacement is comparable to the 2020 ranges in UK Renewable Energy Road Map; 10–13 GW onshore wind and 11–18 GW offshore (potentially 40 GW).

6. If the cost of CCS is included and a 3.5% public discount rate used, then the equivalent 21 GW of onshore wind capacity could generate up to 27% more electricity per annum considering representative capacity factors of 70% for gas and 30% for wind. 12GW of offshore turbine capacity would be expected to generate 5% less electricity than the equivalent gas infrastructure.

7. So as not to renege on UK climate change commitments, it is imperative that investment is directed towards very low and zero carbon energy infrastructure. Construction without CCS would place much greater pressure on other parts of the economy to decarbonise and risk gas infrastructure worth £19 to £26 billion becoming "stranded assets". However, as we describe below it cannot be assumed that CCS will provide sufficient levels of abatement for gas-fired electricity to continue to be a major energy source in the long term.

8. Our analysis considered only capital costs, not operating costs; a simplification that significantly favoured gas over wind as the latter has much lower operating costs as a percentage of total costs. The levelised cost estimates for gas CCGT (Parsons Brinkerhoff, 2011), with 10% discount rate, suggest that fuel costs account for 88% of the total cost per MWh of electricity. In contrast, the operating costs for wind generation make up only 6% of total costs (Arup 2011). Costs of transmission and distribution infrastructure for both gas and electricity were also excluded.

(ii) *What is the potential impact on climate change objectives of greater use of shale gas?*

9. Much of the discussion on the climate change impact of shale gas centres on its relative emissions intensity compared with other fuel sources. This issue is of interest, but must not distract from the most climatically relevant issue of absolute quantities of emissions from the global energy system.

10. There are important concerns about the possibility of additional climate change impacts from gas produced by hydraulic fracturing; this remains a contentious topic in the academic literature. Life cycle analysis studies include *inter alia* emissions from energy required to produce and distribute the gas, for instance those embodied in water transported to the well pad, and releases of methane itself to the atmosphere both deliberately and inadvertently during the full fuel production, transmission and distribution cycle.

11. Methane is a more potent GHG than CO_2 but with a shorter atmospheric life span, with the potential to substantially influence the conclusions drawn by a given study. A conversion factor is required to relate the climate change impact of fugitive methane emissions to the carbon dioxide emissions from other activities and a number of different metrics are available to compare the impact of different greenhouse gases. A gas's contribution to global warming depends upon its absorption of infrared radiation, its longevity and its ability to influence other atmospheric components physically and chemically. The most widely used metric is the Global Warming Potential (GWP) which is the ratio of the change in radiation balance from a pulse release of a given gas, integrated over a specified future time period, against the same change for a release of the same mass of carbon dioxide. GWP is frequently used in climate policy as a way of comparing well mixed, long lived greenhouse gases like carbon dioxide, nitrous oxide and methane. Typically a one hundred year time period is used for the calculation and revised estimates of GWPs are prepared as atmospheric science progresses. Whilst, these conversion factors are not inherent properties of the gas, their selection can have significant impacts on the conclusions drawn by research and policy.

12. There has been some dispute in the scientific literature of the appropriate GWP timescale to use when comparing conventional with unconventional gas production techniques. There is also a shortage of independent primary research on the actual quantities of such emissions, and many studies use the same underlying empirical data that is recognised to be limited in scope and applicability. Our previous research provides a fuller discussion of this topic (Broderick et al. 2011, Section 3.2.4) as well as an estimate of the additional emissions due to hydraulic fracturing. This estimate is compared with others in a review prepared for the European Commission DG Clima (AEA 2012). A recent comparative statistical approach has concluded that it is difficult to distinguish between the life cycle emissions impact of different gas production and distribution methods and that attention should be paid to energy system impacts (Weber & Clavin 2012).

13. Regardless of the unavoidably contextual framing of life cycle GHG impact, either per unit of gas produced or per unit of electricity generated, the direct carbon content of shale gas means that its widespread use would is incompatible with the UK's international climate change commitments.

14. The absolute necessity of decarbonisation means that technologies with orders of magnitude lower emissions are required to provide energy to UK households and industry in the short to medium term. The Committee on Climate Change (2008) has advised "that any path to an 80% reduction by 2050 requires that electricity generation is almost entirely decarbonised by 2030". Decarbonisation of the electrical supply is an effective way of rapidly reducing emissions. Renewable supply technologies, with very low associated emissions, are available now and are compatible with existing infrastructure. The efficiency of transport and heating can be improved through the deployment of new electric vehicle and heat pump technologies respectively.

15. Understanding timescales is pivotal from a cumulative emission (carbon budget) perspective. The CCC argues that the transition to a very low carbon grid, with an intensity of the order of 50g CO_2/kWh, should take place by 2030. Scenarios described by the MARKAL economic optimisation model identify this point as being on the way to a zero carbon grid soon after. It is worth noting that the CCC acknowledges a low probability of keeping below 2°C of warming on the basis of their budgets, this is despite their assumption of unrealistically early global peaking dates (~2016).

16. Accounting for an emissions floor for food production and making fair (but still very challenging) allowance for emissions from non-Annex 1 nations, Anderson and Bows (2011, C+6 scenario) find that complete decarbonisation of Annex 1 energy systems must be accomplished rapidly (ie within a decade) for even a 50% chance of avoiding 2°C of warming.

17. It is sometimes argued that shale gas could be burned safely in the short term, however this is not the case. Given that shale gas is yet to be exploited commercially outside the US, limitations on the availability of equipment mean that it is very unlikely it could provide other than a marginal contribution to UK supply before 2020. However, gas fired power stations produce emissions of approximately 440gCO_2e/kWh of electricity and typically have a lifespan of over 25 years. Therefore, unless allied with carbon capture and storage (CCS) technologies, as yet unproven at a large scale, all new powerstations intended to burn shale gas would need to cease generating within five to fifteen years of construction, and at the latest be decommissioned by 2030. Green Alliance scenarios (2011) indicate that if there is a second "dash for gas", emissions from the grid could still be 302gCO_2e/kWh in 2030 necessitating 95% deployment of CCS to meet our fourth period emissions budgets (2023–2027). In this respect, the "golden age" may turn out to be a gilded cage, locking the UK into a high carbon future.

18. Even CCS is problematic when such low carbon electricity is required. At commercial scale CCS will be significantly less than 100% effective at capturing carbon dioxide. Moreover, it will always add costs to electricity production by reducing the efficiency of the power station requiring additional energy input in transportation and injection of the captured carbon dioxide. Best case emissions performance for gas CCS is in the range 35–75gCO_2/kWh (80–90% capture efficiency on 55% efficient CCGT with 10% energy penalty for capture).

19. CCS therefore also increases the net quantity of upstream emissions of gas or coal production and transport; reduced efficiency means that greater quantities of fuel must be used for equal electricity output, increasing emissions over and above those from the fuel combustion. For unconventional gas production these have the potential to be significant if mitigation is not in place; Broderick et al (2011) estimate up to an additional 17gCO_2e/MJ of gas produced, equivalent to an additional 120gCO_2e per kWh of electricity generated depending upon mitigation during production.

20. With regards to using shale gas for heating purposes, the CCC (2008) note that as the grid decarbonises it is "more carbon efficient to provide hot water and space heating with electricity than with gas burned in a condensing boiler". Non-energy uses accounted for less than 1% of total UK demand for natural gas in 2010 (DUKES 2010). It is therefore reasonable to assume that new gas production in the UK will be combusted and, in the absence of carbon capture and storage, released to the atmosphere.

21. Shale gas has the potential to contribute substantial additional emissions to the atmosphere. Global estimates of reserves suggest this may be up to 30% of a global emissions budget with a 50% chance of avoiding dangerous climate change (Broderick et al. 2011, Section 3.3.2).

22. Substitution between fuel sources cannot necessarily be assumed to reduce emissions in absolute terms. Our forthcoming report (Broderick and Anderson, 2012) explores the CO_2 emissions consequences of fuel switching in the US power sector using two simple methodologies. The analysis presented is conditional upon its internal assumptions, but provides an indication of the scale of potential impacts. It suggests that emissions avoided at a national scale due to fuel switching in the power sector may be up to half of the total reduction in US energy system CO_2 emissions of 8.6% since their peak in 2005. Since 2007, the production of shale gas in large volumes has substantially reduced the wholesale price of natural gas in the US. The suppression of gas prices through shale gas availability is a plausible causative mechanism for at least part of this reduction in emissions. Although we were not able to isolate the proportion of fuel switching due to this effect other studies note that between 35% and 50% of the difference between peak and present power sector emissions may be due to shale gas price effects. Substantial increases in renewable generation and capacity appear to have had an effect of similar magnitude through policy and cost competitiveness. Air quality regulations, energy efficiency and demand management, and the impact of the recession are cited to have played a considerable part in driving this change.

23. It is essential to note that there has also been a substantial increase in coal exports from the US over this same time period. Without a meaningful cap on global carbon emissions, the exploitation of shale gas reserves is likely to increase total emissions. For this not to be the case, consumption of displaced fuels must be reduced globally and remain suppressed indefinitely, *in effect displaced coal must stay in the ground*. Our calculations suggest that more than half of the potential emissions avoided in the US power sector may actually have been exported as coal. Summing the quantity of implicit emissions exported over the period 2008 to 2011 suggests that approximately 340 $MtCO_2$ of the 650 $MtCO_2$ of potential emissions avoided may be added elsewhere. It is clear that the production of fossil fuels of all sorts needs to be curtailed in the absence of strict and coordinated international GHG emissions caps.

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October 2012

Further written evidence submitted by the UK Energy Research Centre (ISG 24a)

Summary

This response addresses the first two questions of the call for evidence on the impact of shale gas on energy markets: firstly what estimates exist for the amount of shale gas in place in the UK, Europe, and the rest of the world, and what proportion is recoverable; and secondly why estimates for shale gas are so changeable.

UKERC recently conducted a comprehensive review of 62 studies that provide original estimates of regional and global shale gas resources.[1] While the majority of these studies focus upon North America, the review found 11 studies that provided estimates of global shale gas resources. Each of these covered different countries and regions, however none provided a truly global estimate since each excluded some regions. Relatively few studies were found to have provided estimates of the recoverable shale gas resource within Europe and even fewer studies provide shale gas resource estimates for the UK. Only one country wide estimate of the shale gas in place in the UK has been undertaken (2.7 Tcm). Recovery factors that have been applied to gas in place estimates by various sources vary widely from 15–40%.

The main conclusions of the UKERC study were the very high level of uncertainty in existing estimates, the inadequate treatment of this uncertainty by the majority of studies, the difficulties in comparing and combining estimates from different studies, and the limitations of currently available estimation methodologies. Given the absence of production experience in most regions of the world, and the number and magnitude of uncertainties that currently exist, estimates of recoverable unconventional gas resources should be treated with considerable caution.

What are the estimates for the amount of shale gas in place in the UK, Europe, and the rest of the world, and what proportion is recoverable?

1. To answer this question it is necessary to both present and compare the currently available resource estimates for shale gas and to critically examine the competing definitions of "resources" upon which these estimates are based.

Resource Definitions

2. A number of terms are used to define unconventional gas resources, and an additional set of terms is used to define unconventional gas reserves. The definition of these terms is far from standardised and there is considerable overlap between estimates of different types of resource/reserve from different sources. The use of imprecise or ambiguous terminology is commonplace and confusion frequently results from employing terminology that has been developed for conventional oil and gas but is not necessarily appropriate for unconventional resources. For example, the term "undiscovered resources", is much less appropriate for continuous shale gas formations than for discrete reservoirs of conventional gas, since the existence of those formations is usually well-known and most of the formation may be expected to contain at least some recoverable gas.

3. Our interpretation of these different terms is summarised below and in Table 1.

4. *Original Gas in Place (OGIP)* is the total volume of natural gas that is estimated to be physically present in a given field, play[50] or region, prior to development. The percentage of this gas that is estimated to be technically recoverable is a key variable in resource estimates and is commonly referred to as the *recovery factor.* Given the relatively early stage of development of shale gas resources, recovery factors remain highly uncertain. Moreover, these factors can vary widely between different geological formations and depend upon the technology that is employed.

5. *Ultimately Recoverable Resources (URR)* is the sum of all gas expected to be produced from a field or region from when production begins to when it finally ends. Estimates of URR are commonly understood to include discovered gas that is not economically producible at present but is expected to become so in the future. Estimates of URR at the regional level also include undiscovered gas that is expected to be both discovered and produced in the future. In principle, therefore, this definition is sensitive to assumption about future gas prices, technological developments and discovery rates. An alternative term for URR is *Estimated Ultimate Recovery (EUR),* with the latter being more commonly used to refer to a single well.

6. *Technically Recoverable Resources (TRR)* is the gas estimated to be producible with current technology, ignoring economic constraints. When applied at the regional level, there is some ambiguity as to whether this classification includes undiscovered gas, with contradictory statements appearing in some reports.[3] However the majority of evidence suggests that regional estimates of TRR include undiscovered gas. There is comparable ambiguity regarding whether cumulative production is included in TRR estimates, but for most regions of the world this makes little difference. If necessary, *Remaining Technically Recoverable Resources (RTRR)* can be used to explicitly exclude cumulative production.

7. *Economically Recoverable Resources (ERR*) is a subset of TRR and defines the resource that is estimated to be both technically *and* economically producible from a field or region. Such estimates are sensitive to assumptions about technical and economic conditions and may be expected to change over time. Since at least some estimates of regional ERR include undiscovered resources, [4–8] we include them in our definition.

8. *Reserves* refer to a subset of *discovered* resources that are estimated to have a specified probability of being produced. Reserve estimates are commonly quoted to three levels of confidence, namely *proved* reserves (1P), *proved and probable* reserves (2P) and *proved, probable and possible* reserves (3P) although these terms are interpreted in different ways by different organisations. Under a probabilistic interpretation, 1P (or P90) reserves represent an estimate that is considered to have a 90% probability of being exceeded, 2P (P50) estimates have a 50% chance of being exceeded, and 3P (P10) estimates a 10% chance. Shale gas resources are only classified as proved reserves in North America and these currently comprise only a small proportion of the estimated TRR.

Table 1

INTERPRETATION OF RESOURCE AND RESERVE DEFINITIONS FOR NATURAL GAS

Name	*Short description*	*Includes gas in undiscovered formations*	*Includes gas not economically recoverable with current technology*	*Includes gas that is not recoverable with current technology*	*Includes gas that is not expected to become recoverable*
Original gas in place	Total volume present	?	?	?	?
Ultimately recoverable resources	Total volume recoverable over all time	?	?	?	
Technically recoverable resources	Recoverable with current technology	?	?		

[50] A geological play is defined as "A set of known or postulated oil and gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type."[2]

Name	*Short description*	*Includes gas in undiscovered formations*	*Includes gas not economically recoverable with current technology*	*Includes gas that is not recoverable with current technology*	*Includes gas that is not expected to become recoverable*
Economically recoverable resources	Economically recoverable with current technology	?			
1P/2P/3P reserves	Specific probability of being produced				

Shale gas resource estimates

9. The majority of studies from UKERC's comprehensive review [1] focus upon North America, where exploration is most advanced. The review demonstrated that there are multiple and substantial uncertainties in assessing the recoverable volumes of shale gas at both the regional and global level. Even in United States, there is significant uncertainty over the size of the resource for currently producing regions and considerable variation in the available estimates for those regions. For undeveloped regions where less research has been conducted there may only be a single estimate of resources available, making it impossible to characterise the range of uncertainty. For several regions of the world there are no estimates at all, but this does not necessarily mean that such regions contain only insignificant resources.

10. It is important to recognise that there are two predominant methods used to generate estimates of the recoverable resources of shale gas. The first is based upon a bottom up analysis of geological parameters and generates an estimate of the shale gas in place to which a "recovery factor", the estimated fraction of the OGIP that is recoverable, is applied. The second bypasses the need to generate separate estimates of the gas in place and recovery factor and directly estimates recoverable resources either through extrapolating production data from adjacent areas for which data is available to undeveloped areas of the same region, or through the use of data from a geologically similar region.

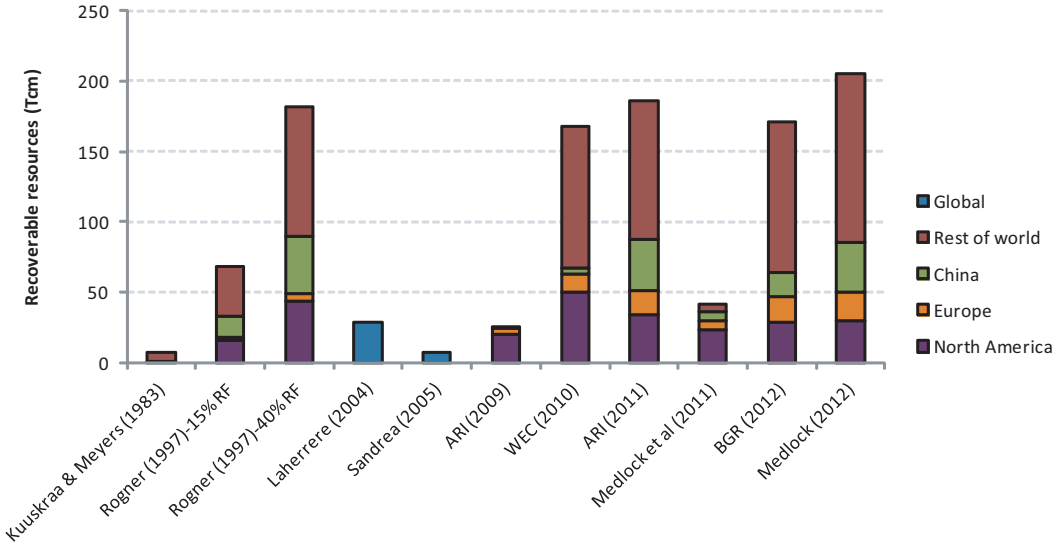
Global resources

11. The UKERC review found 11 studies that provided estimates of global shale gas resources, either in aggregate or broken down by region (Figure 1). Each of these studies covered different countries and regions and none provided a truly global estimate since each excluded some regions. For example, ARI [9] ignored regions where there were large quantities of conventional gas reserves (Russia and the Middle East) or where there was insufficient information to carry out an assessment.

12. The earliest and most cited global estimates are by Rogner,[10] but these were produced using a relatively crude methodology and in the absence of any significant drilling experience for any region of the world. Rogner only estimated OGIP and made no assumptions about recovery factors. However, several authors have subsequently applied recovery factors to Rogner's figures to generate estimates of the TRR, including 15% by Mohr and Evans,[11] 10–35% by MIT,[6] and 40% by ARI [12] and the IEA.[13] For comparison, ARI [9] uses a range of 15%—35% for the recovery of shale gas from different geological areas while recovery factors for conventional gas can be as high as 70–80%.[14] In Figure 3 we present estimates applying both 15 and 40% recovery factors to Rogner's OGIP.

Figure 1

ESTIMATES OF GLOBAL SHALE GAS RESOURCES



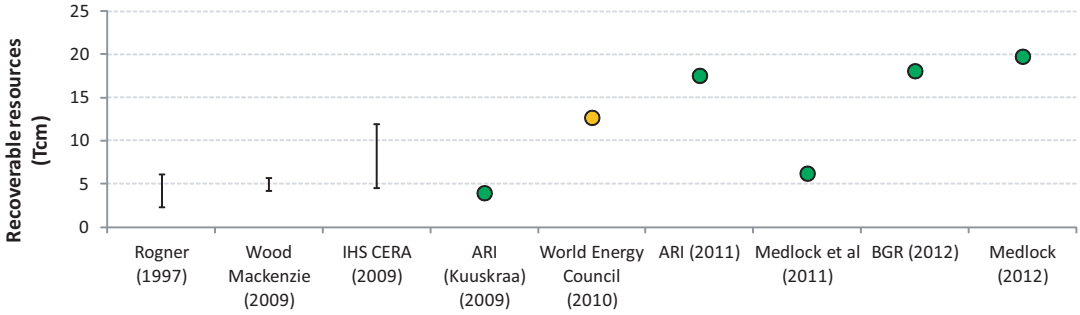
Note: *Resource definitions also differ; both in terms of what is reported and how this is defined and estimated. Laherrere's estimate is URR, while Medlock's are likely to be closer to ERR. The OGIP estimate by Rogner is converted to TRR using 15% and 40% recovery factors and the WEC's estimate to ERR using a 40% recovery factor.*

European resources

13. Relatively few studies have provided estimates of the technically recoverable shale gas resource within Europe. The available estimates are summarised in Figure 2, and range from 2.3 Tcm to 19.8 Tcm, with a mean of 10.6 Tcm. Note that ARI's estimate from 2009 ignored a number of plays.

Figure 2

ESTIMATES OF THE TECHNICALLY RECOVERABLE RESOURCE OF SHALE GAS WITHIN EUROPE



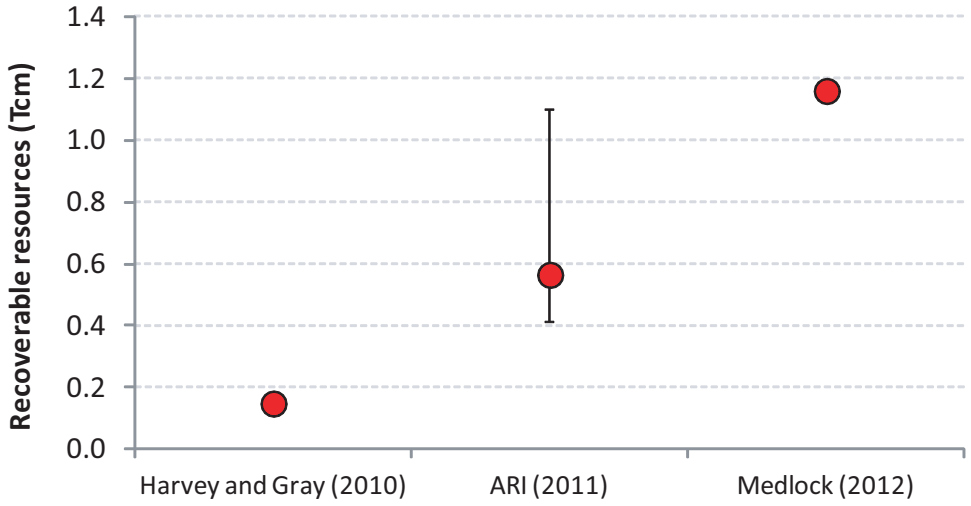
Note: *Range for Rogner's estimate is derived using a 15–40% recovery factor within Western and Eastern Europe. Values for Wood Mackenzie and IHS CERA are from Weijermars et al. [15]. Point in yellow corresponds to an estimate of ERR*

UK resources

14. Even fewer studies provide shale gas resource estimates for the UK (Figure 3). The three estimates represented by red data points [9, 16–17] are for TRR and range from 0.15 Tcm to 1.15 Tcm. The range around the ARI (2011) estimate represents the range derived by applying the 15—40% recovery factor range to the OGIP estimate of this study.

Figure 3

ESTIMATES OF THE TECHNICALLY RECOVERABLE RESOURCES OF SHALE GAS WITHIN THE UK



Note: *The range for ARI (2011) is derived using a 15—40% recovery factor applied to an estimate of OGIP (95Tcm). All other estimates are TRR. Medlock [16] indicates the economics of extraction of different proportions of the resource, using 3-step cost curves. This concludes that the last proportion of the resource indicated in this figure will be significantly more expensive. Medlock (2012) then estimates on the basis of this cost curve that the ERR is 60% of the total TRR. Harvey and Grey [17] use simple analogues from the United States to generate their estimate.*

Best Estimates

15. Our summary of current "best" estimates of regional technically recoverable resources is presented in Table 2. This suggests that the global TRR of shale gas may be in the region of 193 Tcm. For comparison, the global technically recoverable resource of conventional gas is estimated at 432 Tcm (of which around 190 Tcm are classified as proved reserves). Combined with estimates of tight gas and coal bed methane (~90 Tcm) this implies a global TRR for natural gas of >700Tcm. These figures refer to technically recoverable resources and a range of factors could lead the economically recoverable resource to be substantially less. However, the main conclusions of the UKERC study are the very high level of uncertainty in these estimates, the inadequate treatment of this uncertainty by the majority of studies, the difficulties in comparing and combining estimates from different studies, and the limitations of currently available estimation methodologies.

16. The UKERC review suggests the United States holds around 10% of the global TRR of shale gas, while Europe holds around 8%. While shale gas may provide around 28% of the global TRR of all natural gas it can be much more important at the regional level. For example, using our best central estimates, shale gas may represent 34% of the remaining TRR of natural gas in China, 36% in Canada, 48% in Europe and 31% in the United States. As an illustration of the uncertainty in these estimates, the high and low US shale gas estimates are 246% and 72% of the best central estimate respectively—and this is the best characterised resource.

Table 2

ESTIMATES OF THE REMAINING TECHNICALLY RECOVERABLE RESOURCES OF CONVENTIONAL, CBM, TIGHT AND THE RANGES RESULTING FROM CHOOSING THE MOST APPROPRIATE CURRENT ESTIMATES FOR SHALE GAS (TCM)

Region	*Shale—Best estimates*		
	Low	*Central*	*High*
Africa		29.3	
Australia		11.2	
Canada	3.6	12.0	28.3
China	6.5	17.8	36.1
CIS		11.6	
CSA		35.6	
Europe		15.9	
India	0.2	1.8	2.4
Japan		0.0	
Middle East	2.8		28.7

Region	*Shale—Best estimates*		
	Low	*Central*	*High*
Mexico	4.2	11.4	19.3
ODA	1.3		22.1
South Korea		0.0	
United States	13.8	19.3	47.4
Global		**193.2**	

Notes: *CSA = Central and South America, CIS = Commonwealth of Independent States, ODA = Other Developing Asia*

Notes:

(a) In some regions it was not possible to develop a central estimate due to an absence of sufficient information, but we provide here a mid-point of high and low estimates for these regions

(b) All estimates refer to technically recoverable resources, they take no account of economic viability or any other constraints on resource recovery

(c) The reasons for choosing these particular estimates and/or manner in which they were derived are discussed in detail in [18]

Why are the estimates for shale gas so changeable?

17. Shale gas is a new resource and the production experience to date is relatively limited. This, together with limited geological information and rapidly evolving technology leads to considerable uncertainty over the potential size of the recoverable resource—even in regions where production is relatively advanced. This uncertainty is hidden by the majority of studies which provide point estimates of resource size, rather than a range.

18. Further complications are introduced by the continuing ambiguity over resource definitions, thereby creating the risk of comparing "apples and oranges". As indicated above, the use of different resource definitions will lead to very different resource estimates for the same geological formation. It is not uncommon for different definitions to be compared as though they were equivalent, creating further disagreement and confusion.

19. For most shale gas formations, there is a paucity of reliable geological data. Many of the formations which are thought to contain shale gas have not had extensive analysis through the drilling of wells, the testing of core samples and the assessment of well bore pressures and other variables key to estimating the OGIP and its producible fractions (ERR, TRR, URR, etc.). As first hand geological knowledge of these formations improves the uncertainty surrounding the potentially available resource should begin to reduce.

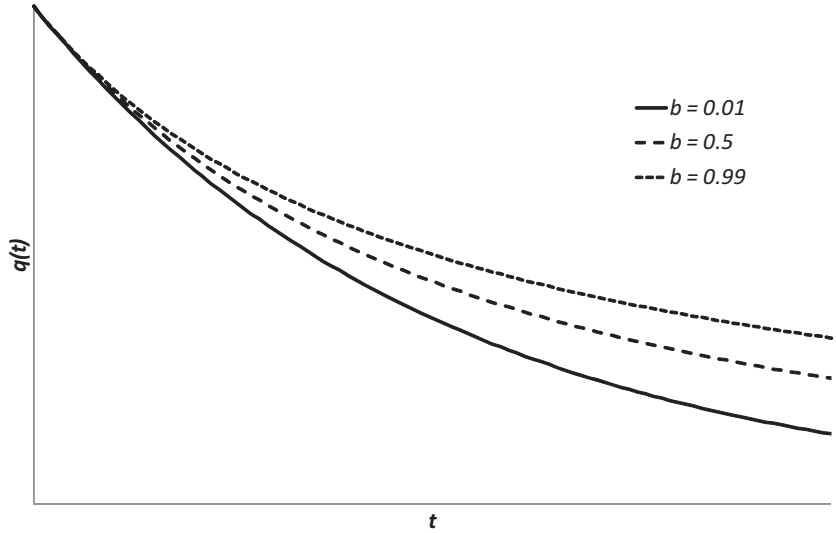
20. In the absence of new geological data, desk-based studies applying new assumptions to older studies are often produced. This is the most common approach to developing estimates for regions outside North America, but many of those regions continue to lack sufficient geological information. The results are also sensitive to the assumptions used, including the recovery factor. As demonstrated above (Figure 1), average recovery factors between 15 and 40% are plausible, but this produces global TRR estimates in the range 70 to 180 Tcm. At present there is little evidence to suggest which end of this range is more likely.

21. Once production in a region is underway, more reliable resource estimates may be derived by analysing the production experience to date and extrapolating this experience to undeveloped areas of the same region. As discussed above, a similar approach can be used to estimate resource size in separate but geologically similar regions (analogues). Given the wide variations in productivity within and between shale plays and the difficulty in estimating some geological parameters, the results are very sensitive to the particular analogue that is chosen.

22. Regional resource estimates using this approach are dependent upon the assumed EUR from individual wells. These are typically estimated by statistically fitting a curve to the historical production from a well or group of wells and extrapolating this forward into the future (Figure 4). These "decline curves" are commonly used to predict the point at which the well will cease production, together with total gas that will be produced over its operating life. When combined with assumptions about average well spacing within the region, this analysis can be used to provide an estimate of the regional TRR. However, the appropriate shape of this "production decline curve" has become a focus of considerable controversy in United States, with several commentators suggesting that the rate of production decline has been underestimated and hence both the longevity of wells and the EUR per well has been overestimated. To the extent that regional resource estimates are based upon EUR estimates for individual wells, this creates the risk that the regional URR will be overestimated as well. Other commentators have contested this interpretation, but the empirical evidence remains equivocal to date owing to the relatively limited production experience.

Figure 4

VARIATION OF HYPERBOLIC DECLINE WITH THE VALUE OF B



23. An example of these uncertainties can be seen in the controversy surrounding two recent resource estimates for the Marcellus Shale in the United States. The United States Geological Survey (USGS) estimate the technically recoverable resources of the Marcellus to be 2.4 Tcm while the consultancy INTEK estimated a much higher figure of 11.6 Tcm. There are three major reasons for this difference. First, the two organisations, subdivided the Marcellus in different ways. Second, the USGS excluded the shale gas in less productive areas of the play, despite this making up 57% of the total INTEK estimate. Third, INTEK assumed that the EUR from wells in the most productive areas would be three times greater than was assumed by the USGS.

24. Overall, given the absence of production experience in most regions of the world, and the number and magnitude of uncertainties that currently exist, estimates of recoverable unconventional gas resources should be treated with considerable caution.

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October 2012

Written evidence submitted by WWF UK (ISG 05)

SUMMARY

1.1 The rapid growth of shale gas in the US and Canada has led to a great deal of speculation and hype about the potential impact of shale here in the UK. Unfortunately, much of this speculation either entirely ignores the need to rapidly reduce emissions to address climate change, or relies on the rather lazy and incoherent argument that because shale gas may have lower emissions than coal it is "good for the climate". This is an argument, which in particular, does not stand up to scrutiny in the UK where there are no plans to build new coal fired power generation.

1.2 Furthermore, there are a large number of uncertainties linked to shale gas, which together, would indicate that gambling on cheap and abundant future gas supplies would be unwise. These uncertainties include but are not limited to local environmental risks and lifecycle greenhouse gas emissions which are not yet well understood, what the UK's technically recoverable shale gas resources actually are and to what extent, assuming that the issues factors above were satisfactorily addressed, shale gas can actually be extracted economically.

CLIMATE CHANGE

1.3 The UK has a legally binding target under the Climate Change Act to reduce greenhouse gas emissions by 80% on 1990 levels by 2050. The Committee on Climate Change provides advice on how to achieve this goal including recommendations on interim milestones, one of which is that the UK power sector should be largely decarbonised by 2030. The level of decarbonisation which the Committee has recommended is 50gCO2/kWh by this date. Whilst it is possible to reach this target with gas in the energy mix, at this point any unabated gas would need to provide flexibility and not baseload power. This is in contrast to the UK's current overreliance on gas which currently provides 41% of power generation and over 80% of UK heating needs.[i]

1.4 Concerns have been raised about apparent incoherence between statements from some sections of the government about the future role of gas and the need to meet UK climate change goals. A statement from David Kennedy in May made this very clear: *"the role for unabated gas fired power generation should be limited to balancing the system in 2030, by which time the share of unabated gas generation in the total should be no more than 10%, compared to 40% today".*[ii] *Lord Deben, the new chair of the Committee then wrote to Ed Davey in September to express his concern at a government statement suggesting "that it sees gas as continuing to play an important role in the energy mix well into and beyond 2030...[not] restricted to providing back up to renewables*". Lord Deben's letter then went on to state that "*Extensive use of unabated gas-fired capacity…in 2030 and beyond would be incompatible with meeting legislated carbon budgets*".[iii]

1.5 On the global scale, it is notable that the greenhouse gas emissions forecast in the "gas" scenario in the IEA's Golden Rules for a Golden Age of Gas report, which envisages a surge in global gas use, are only negligibly lower than the emissions forecast in an alternative low gas scenario. Both scenarios are roughly consistent with 3.5 degrees of warming, which is significantly above the objective of preventing temperature rises in excess of 2ºC, supported by a growing number of countries following the UNFCCC talks in Durban. The argument that more use of gas is good for the climate is therefore highly questionable. The IEA report highlighted that whilst gas might displace coal, it is also the case that "*lower natural gas prices lead to slightly higher overall consumption of energy and, in some instances, to displacement of lower-carbon fuels, such as renewable energy sources and nuclear power*".[iv] Critically, the IEA report did not consider additional greenhouse gas warming potential of shale gas, mainly in the form of leaked or vented methane.

Impacts on Investment in Low Carbon Energy

1.6 The impacts of shale gas on investment in low carbon technologies can largely be broken down into two categories. The real impact is largely limited to the current lower spot price of LNG due to a lower than anticipated demand for gas imports from the US due to shale. The arguably more serious impact is that of expectation whereby promises of future cheap and abundant shale gas, which may never materialise, negatively impact on investment certainty for those looking to develop low carbon technologies.

1.7 When these promises of cheap and abundant gas are scrutinised it becomes clear that there are a number of significant uncertainties in practice. For example in the context of the progressive decline in UK conventional gas production, even optimistic projections of UK shale gas resources and extraction appear to only partially offset this decline. It is therefore very unlikely that shale gas will reduce UK gas import dependence. Furthermore, the price at which gas can be extracted in the UK is highly uncertain and is thought to be significantly higher than in the US. It is also the case that due to the current glut, gas prices in the US are at a level which is unprofitable for most producers, leading to shale gas assets being written down and speculation that "the bubble is bursting".[v] In this context it appears likely that the US gas price will not remain at their current low levels.

Response to Specific Questions

WWF chose not to answer questions 1–6 as these are not within our area of expertise.

7. *What are the effects on investment in lower-carbon energy technologies?*

7.1 The current impact of shale gas on investment in lower carbon technologies can largely be split into two categories. These two categories are very distinct from one another, the first being the impact which shale gas extraction underway or currently in the pipeline is actually having, the second being the impact of expectations and hype around the potential for shale gas to be a "game changer" or not in the future.

Current trends

7.2 The two are distinct. There is currently no significant commercial production of shale gas anywhere in the world apart from the US and Canada. The impact of this extraction on the US has been significant with shale gas rising from less than 1% of US natural gas production in 2000[vi] to 23% in 2010.[vii] This has led to a major reduction in US gas import dependence, leading to LNG import terminals sitting idle and providers of gas which was intended for the US looking to other markets. The actual impact of shale gas on the UK and Europe (putting aside the hype) has therefore so far been limited largely to market impacts such as spot gas prices falling to 25% below oil indexed gas due in the most part to a temporary glut of LNG on the market. Lower than anticipated LNG prices have led to the cancellation of some conventional gas projects such as Shtokman in Russia.[viii]

7.3 However, it is unlikely that the current low prices in the US will last or that they will be duplicated in the UK or Europe. The ongoing glut has hit the profits of shale gas operators with a number recently announcing their intention to write down the value of their shale gas assets.[ix] Even in 2009 when US gas prices were significantly higher, a study found that "*half of the horizontal wells drilled were unprofitable, even at 2009 gas price of $6 per MBtu*".[x]

Hype and expectation

7.4 The bigger impact of shale gas on the UK so far has been driven by the significant hype created around shale gas primarily by those connected to the oil and gas industry.[xi] Amongst those pushing shale gas most strongly are those who are known to be hostile to moves to address climate change. Key messages repeated tend to be along the lines of the following:

- Shale gas is good for the climate because emissions from gas are approximately 50% of those from coal.
- Shale gas will mean years of cheap and abundant natural gas.

7.5 Judgements in energy and climate change policy are, by necessity, heavily informed by future expectations. Therefore suggestions that shale gas is a silver bullet solution to climate change, will push down gas prices or reverse the downward trend in UK gas production, all have the potential to undermine the case for investment in low carbon generation or energy efficiency if they are believed.

7.6 Most low carbon technologies currently require some policy support. In order to attract investment, this support must be perceived as stable and predictable. The suitability of the policy instrument is crucial in this respect but so too is Government commitment. Therefore, if decision makers begin to be convinced by the arguments put forward by proponents of shale gas, as it appears elements within the Treasury have been, then this clearly has a negative impact on investor perceptions of the UK's commitment to transitioning to a predominantly low carbon energy system. Actual policy uncertainty, such as the recent public disagreement over ROC banding levels serves to further erode investor confidence.

7.7 On this rationale, it is important to assess whether the claims made as to the future potential of shale gas have any factual basis. In the remainder of our response to this question, we examine the evidence base behind the claims outlined above (although the climate change impacts of shale gas are covered in our response to question 8).

Years of abundant gas?

7.8 The UK is currently heavily dependent on gas to meet its energy needs. Approximately 80% of UK heat comes from gas[xii] and in 2011 41% of electricity came from gas.[xiii] Against this backdrop, UK production of conventional gas has steadily declined since 2000. As a result, the UK is increasingly dependent on imported gas with recently released DECC statistics revealing that for the first time since 1967, imports of gas exceeded production in 2011.[xiv] In this context, there is an increasingly strong argument for moving away from dependence on gas not just on climate grounds but also on grounds of energy security and exposure to volatile global fossil fuel prices. Some however, suggest that there is no need to do this because shale gas will be able to fill the gap.

7.9 UK shale gas resources are currently highly uncertain. The British Geological Survey (BGS) is currently updating its estimate of resource levels but current published figures suggest that technically recoverable resources are approximately 150bcm, which equates to approximately 1.5 years of current UK gas consumption. Suggestions that resource estimates will be revised upwards considerably appear to be purely speculative at this stage. When approached by WWF-UK BGS stated "we haven't even finished the study yet, there has been no information released by BGS". Media reports, which reference huge finds of shale gas by onshore licence holders such as Cuadrilla, often fail to appreciate the distinction between "gas in place" and "technically recoverable reserves" (estimated at around 10% of gas in place). The proportion of these technically recoverable reserves which are practical, environmentally acceptable and economic to recover will further reduce the volume of gas which is actually extracted. Even in the most optimistic reports, large shale gas extraction only serves to partially offset declines in UK conventional gas production.[xv]

7.10 At the European level, the IEA recently published a report, "Golden Rules for a Golden Age of Gas", which indicated that even in the most optimistic "gas" scenario (one in which there is rapid growth in shale gas production and emissions are consistent with global temperature rises of 3.5 degrees) "the upward trend in net gas imports into the EU continues throughout the projection period (to 2035)".[xvi] The implications are clear—even in the most "optimistic" shale gas scenario, the EU will only succeed in slowing down its increasing gas dependency.

Too cheap to meter?

7.11 As highlighted above, the glut of shale gas seen on the US market has driven down prices to unprofitable levels. Clearly, if shale gas production in the US is to continue, market prices can be expected to rebound to a level which is profitable and will not persist at such low levels. Most assessments have agreed that the so called shale gas revolution will not be repeated in Europe. For example a recent study by Deutsche Bank suggested that *"those waiting for a shale-gas "revolution" outside the US will likely be disappointed, in terms of both price and the speed at which high-volume production can be achieved"*.[xvii]

7.12 Most forecasts agree that the UK/EU breakeven price will be higher and that there are considerable question marks as to whether gas prices will be lower than they would have otherwise been. Gas prices are forecast to continue to rise steadily to 2035 even if projections from the IEA and others reflect the current view that these rises may be more moderate than originally projected.[xviii] This is of course against the backdrop that future gas forecasts can never be relied upon and that failing to reduce the UK's overall reliance on gas is a highly risky strategy.

Conclusion

7.13 Low carbon forms of electricity generation and in particular renewables generally share two characteristics which differentiate them from gas generation. They have high capital costs and low operating costs and they are not yet mature. These technologies must overcome a certain amount of technological and institutional "lock-in", which is present in a system that has co-evolved around the needs of incumbent centralised fossil fuel based generation technologies which have benefitted from decades of refinement, allowing them to drive down their costs relative to newer alternatives.

7.14 The costs of many forms of renewable technologies like onshore wind and solar are falling rapidly[xix] whilst others such as offshore wind could soon follow suit under stable investment conditions. However, they cannot yet compete with gas generation without support, especially as marginal electricity prices follow fluctuations in the wholesale price of gas, which gives gas generators a natural hedge compared to renewable generators**.**

7.15 As a result, despite their declining costs, renewables currently need predictable support for investors to consider them attractive to invest in. Here we come full circle to the point made above that stable government commitment to policies which support the low carbon transition are essential to attract the capital required.

7.16 The factual basis behind the claims made about the future potential shale gas reserves are questionable and this narrative is pushed largely by those who for ideological or financial reasons do not wish lower carbon energy technologies to become the norm. Any claims that shale gas can have a positive impact on UK emissions are particularly without foundation but are discussed in our response to question 8 below. However, if governments become convinced by the promises made by shale gas proponents and if as a result the commitment to the transition towards a low carbon energy system becomes shaky, then in the words of Professor Paul Stevens, "the anticipation of cheap natural gas could inhibit investment in renewables". Professor Stevens then continues to warn that "*if the revolution fails to deliver a lot of cheap gas, by the time this is realized it could well be too late to revert to a solution to climate change based on renewables*"[xx]

8. *What is the potential impact on climate change objectives of greater use of shale gas?*

8.1 The climate change risks resulting from a greater use of shale gas fall into two categories. The first question is concerned with the climate impacts of shale gas as an addition to global conventional gas reserves. This is a broad question which requires understanding the extent up to which gas can be used in a way which is consistent with addressing climate goals.

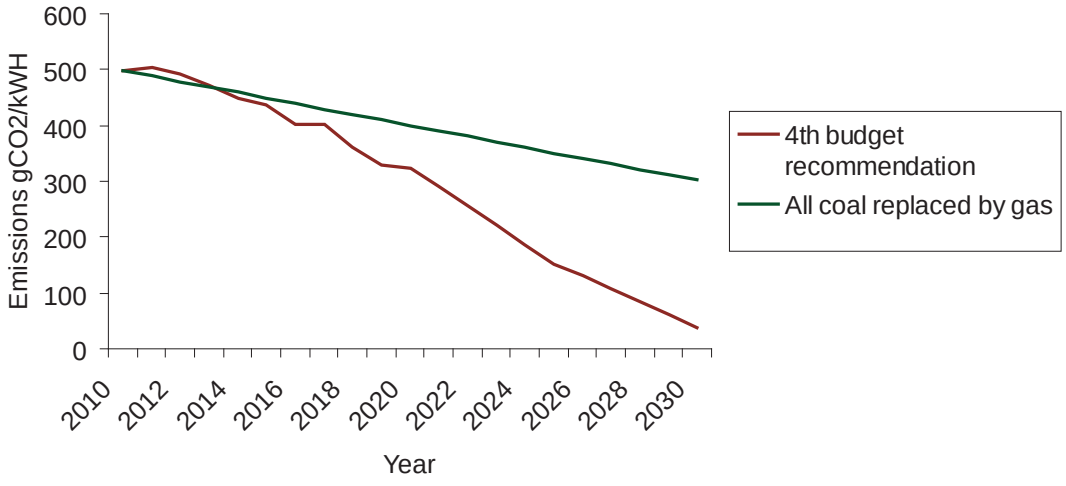
8.2 The second is the question around the extent to which the climate impact of shale gas is greater than that of conventional gas and to what extent the lifecycle emissions vary from well to well and what can be done to minimise this impact.

Gas as a "low carbon" fuel??

8.3 The suggestion that shale gas is good for the climate does not stand up to scrutiny when applied to the UK context. It is only legitimate to claim that using more gas reduces emissions if there is evidence that this gas actually displaces coal generation—for example, in the case of plans to build a new coal fired power station being scrapped in favour of a gas one. There is no prospect of this occurring in the UK given that on environmental and climate grounds, there are no plans to build any new coal fired power generation. It is therefore far more logical to conclude that in the UK context, any increase in our already heavy reliance on gas will be at the expense of genuinely low carbon generation or investment in energy efficiency. The potential for shale gas to have any long term positive impact on UK carbon emissions is therefore effectively zero.

8.4 The UK has a Climate Change Act committing it to at least 80% GHG emission reductions by 2050 compared to 1990 levels. In order to achieve this target, the Committee on Climate Change (CCC) has been tasked with providing advice to government on the pathway to meeting this goal (through the publishing of carbon budgets) and has also provided sector by sector proposals on how best to meet this goal. One such recommendation is that a near-decarbonisation of the power sector should be achieved by 2030. This need to decarbonise has been recognised and is currently one of the three objectives of the Electricity Market Reform process. The 2030 carbon intensity recommended by the CCC is 50gCO2/kWh.

8.5 The graph below which draws on supporting data published by the CCC in their 4th budget report,[xxi] demonstrates that a simple switch from coal to unabated gas only would leave emissions from the UK power sector around six times higher than the level recommended by the Committee. The black line represents emissions level if the only change to the power mix between now and 2030 were to be coal power being replaced by gas.



8.6 Given the long lifetime of gas fired power generation, there is a risk that building too much capacity today will lock the UK into emission levels in the 2020s and 2030s, which are incompatible with climate change targets. According to the Committee on Climate Change, "*the role for unabated gas fired power generation should be limited to balancing the system in 2030, by which time the share of unabated gas generation in the total should be no more than 10%, compared to 40% today. A second dash for gas, resulting in a higher share of unabated gas in 2030, would neither be economically sensible nor compatible with our legislated carbon budgets*." [xxii]

8.7 It is therefore clear that the UK must rapidly reduce and not increase its reliance on gas (from any source) to stay on course to meet its Climate Change Act commitments. Any greater use of gas as a result of the actual or anticipated impacts of shale gas would not be consistent with addressing climate change.

Shale gas—lifecycle emissions and climate impacts

8.8 There has been considerable debate as to the lifecycle emissions and therefore climate impacts arising from the extraction of shale gas. The number of studies which have been undertaken on this subject has increased significantly since the Energy and Climate Change Select Committee's initial enquiry in 2010. Despite this, a high degree of uncertainty remains and significantly more good quality data and peer reviewed evidence is still needed.

8.9 The key elements of shale gas drilling which differ from conventional drilling are outlined in detail in the evidence presented to the Environment Agency on monitoring and control of fugitive methane from unconventional gas operations.[xxiii] These elements can largely be divided into two categories. These are the increase in emissions due to higher energy use in the shale gas extraction process and the question of fugitive methane emissions which occur at the well completion and gas transportation phases of the process. Estimates of both vary significantly but it is generally agreed that the latter have a larger impact on emissions than the former.

8.10 There is however, a large disparity between the conclusions drawn by the various attempts to quantify lifecycle emissions. Estimates by Robert Howarth are at the high end whilst industry backed estimates such as URS[xxiv] appear unfeasibly low (this particular study has been found to contain errors). Reasons for these disparities include differences in the characteristics of individual sites and shale plays, practices used by shale gas operators and the lack of a standardised methodology or set of assumptions by those seeking to quantify emissions. The raw data used for many estimates appears to be relatively poor. AEA's report to the EU states that the main factors affecting lifecycle GHG emissions are:

- Overall lifetime shale gas production of the well.
- Methane emissions during well completion which are dependent on the quantity of methane in the flow back liquid and the treatment of this methane (eg. Venting, flaring or green completion).
- Number of re-fracturing events and the associated increase in productivity which result from these.

8.11 Of these three factors, the emissions arising at the well completion stage is the most controversial. According to a report on methane emission produced for the Environment Agency,[xxv] "*The flowback step is the primary methane emission source present in unconventional gas extraction that is not present in conventional gas extraction*". At this stage, the volume of emissions released at this point will depend on a number of variables some of which, flow rate for example, depend on the characteristics of the individual well. Others variables are however within the operator's control, chiefly whether the operator vents the gas, flares it or uses methods known as reduced emission completions.

8.12 The Environment Agency report goes on to say that "*it was estimated that 210,000m3 methane (112 tonnes) are emitted per unmitigated well completion. This would be reduced by about 90% with reduced emission completions*".[xxvi] This is backed up by evidence from the US EPA Gas Star programme which again suggests a 90% reduction is possible.[xxvii] Reduced Emission Completions are now mandatory in the US. It would therefore appear reasonable that if shale gas drilling does proceed in the UK, operators should be required to ensure that reduced emission completions methods are employed.

8.13 The report to the Environment Agency recommended that "*the Environment Agency should require operators of unconventional gas extraction facilities to carry out surveys to measure ambient methane levels before operations commence; during drilling, hydraulic fracturing and completion; and during production*".

The global warming potential of methane

8.14 One study, produced by Robert Howarth of Cornell University in 2011,[xxviii] caused controversy in part but not solely due to its consideration of the global warming potential of methane over both the standard 100 year period used by the IPCC and the alternative 20 year one. The relevance of this assumption is that where the 20 year timeframe is used, the impact of fugitive emissions released at the well completion stage has a global warming potential at 72 compared to 25 at the 20 year timeframe (Howarth uses slightly higher figures based on Shindell 2009).[xxix]

8.15 We do not go into detail on the assumptions made in the Howarth study and the other reasons why it found the global warming impact of shale gas to be higher than other studies but given that the next few decades are a critical time in terms of reducing emissions, considering the 20 year timeframe would certainly have some merit. The AEA study backed this up stating that "*averaged over 20 years the Global Warming Potential (GWP) estimated by the IPCC is 72. This figure can be argued to be more relevant to the evaluation of the significance of methane emissions in the next two or three decades which will be the most critical to determine whether the world can still reach the objective of limiting the long-term increase in average surface temperatures to 2 degrees Celsius*".[xxx] The AEA study does however, despite this assertion go on to measure the global warming potential based on a 100 year timeframe.

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