Department of Energy & Climate Change

Potential Greenhouse Gas Emissions Associated with Shale Gas Extraction and Use

Professor David J C MacKay FRS

Dr Timothy J Stone CBE

9th September 2013

Department
of Energy &
Climate Change

Executive Summary

1. In December 2012, the Secretary of State for the Department of Energy and Climate Change (DECC) requested a study to gather available evidence on the potential greenhouse gas (GHG) emissions from production of shale gas in the UK, and the compatibility of future production and use of shale gas in the UK with climate change targets. This report presents the outcome of this study and provides recommendations to mitigate the climate change impacts of shale gas exploration, production and use in the UK.

2. This study examines local GHG emissions associated with shale gas exploration and production. The carbon footprint includes carbon dioxide (CO_2) and methane (CH_4). Methane has a global warming potential 25 times greater than CO_2, based on a 100-year time horizon[1]. It also studies the effect of shale gas use on overall GHG emissions rates and cumulative emissions.

3. Comparisons are made between the emissions associated with the use of shale gas, conventional gas, Liquefied Natural Gas (LNG), and coal.

4. Our conclusions are as follows:

Carbon footprint

a. If adequately regulated, local GHG emissions from shale gas operations should represent only a small proportion of the total carbon footprint of shale gas, which is likely to be dominated by CO_2 emissions associated with its combustion.

b. Any local GHG emissions from shale gas operations would fall within the non-traded sector of the UK's carbon budgets. If the carbon budgets impose a binding constraint, any increase in emissions associated with domestic shale gas operations would have to be offset by emissions cuts elsewhere in the economy.

c. The carbon footprint (emissions intensity) of shale gas extraction and use is likely to be in the range 200 – 253 g CO_2e per kWh of chemical energy, which makes shale gas's overall carbon footprint comparable to gas extracted from conventional sources (199 – 207 g $CO_2e/kWh_{(th)}$), and lower than the carbon footprint of Liquefied Natural Gas (233 - 270g $CO_2e/kWh_{(th)}$). When shale gas is used for electricity generation, its carbon footprint is likely to be in the range 423 – 535 g $CO_2e/kWh_{(e)}$, which is significantly lower than the carbon footprint of coal, 837 – 1130 g $CO_2e/kWh_{(e)}$.

[1] The 100 year global warming potential of CH_4 compared to CO_2 assumed in this study is consistent with an agreement at the United Nations Framework Convention on Climate Change to adopt the Intergovernmental Panel on Climate Change's 2007 fourth assessment report (AR4).

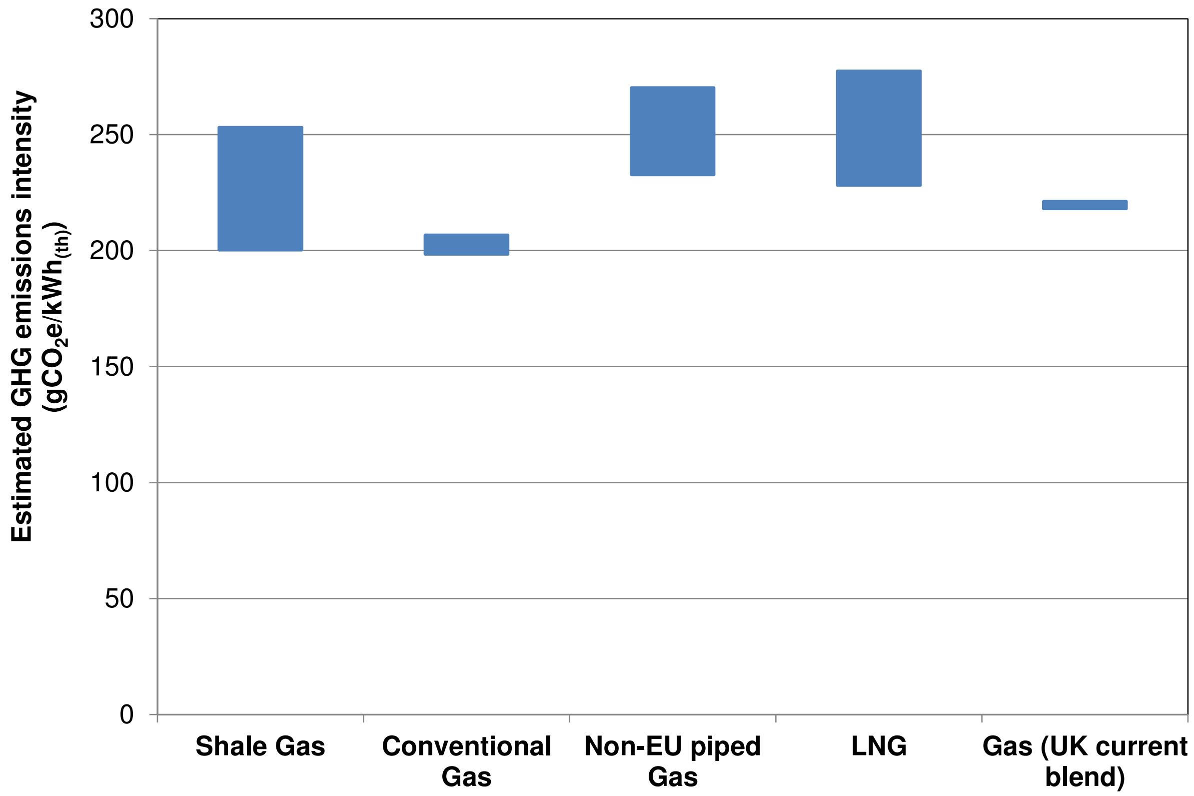

Figure a: Estimated greenhouse gas (GHG) emission intensity for various sources of gas. For shale gas the emissions intensity depends on the assumed completion method; here it has been assumed that methane released during completion would be 90% captured and flared. Alternative assumptions, especially "reduced emissions completion", are discussed in the report.

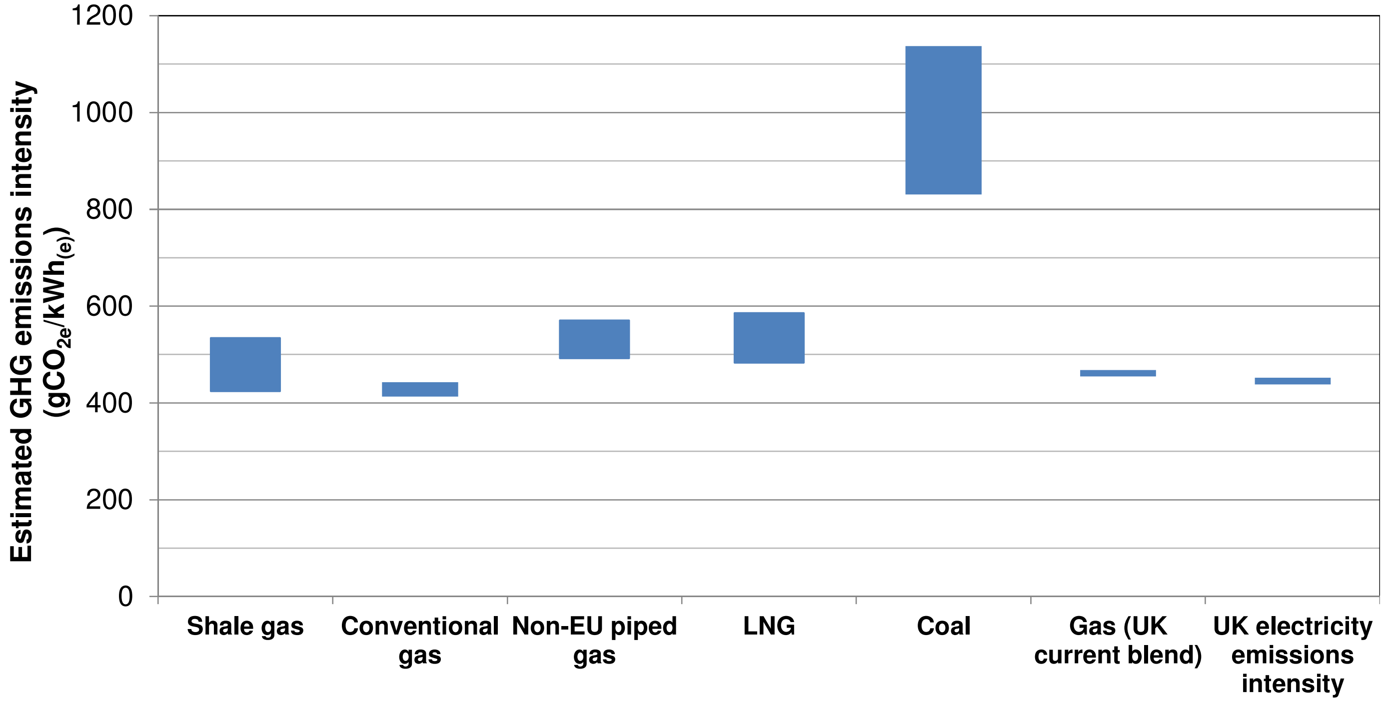

Figure b: Comparison of the life-cycle emissions for the production of electricity from various sources of gas, and coal. The same completion method for shale gas has been assumed as in Figure a.

Impact on national GHG emissions rates and cumulative emissions

d. If shale gas extraction is demonstrated by industry to be economic in the UK, some of the UK's reserve may be used nationally. Because the UK is well-connected to the Western European gas market, the effect of UK shale gas production on gas prices is likely to be small, and the principal effect of UK shale gas production and use will be that it displaces imported LNG, or possibly piped gas from outside Europe. The net effect on total UK GHG emissions rates is likely to be small.

e. The short-term and long-term effects of shale gas exploitation in the UK on global emissions rates are complex to predict and depend strongly on global climate policies. The short-term effect of shale gas use on global emissions depends on:

- the price of the shale gas relative to the prices of LNG imports to the European market and coal;
- the price elasticities of demand and supply of gas and coal;
- the transport costs of gas and coal; and
- the substitutability of gas and coal in different regional markets.

f. Long term global temperature rises are determined not by the rates of emissions but by cumulative global emissions of carbon over all time. The production of shale gas could increase global cumulative GHG emissions if the fossil fuels displaced by shale gas are used elsewhere. This potential issue is not specific to shale gas and would apply to the exploitation of any new fossil fuel reserve.

g. The potential increase in cumulative emissions could be counteracted if equivalent and additional emissions-reduction measures are made somewhere in the world. Such measures are well established in the scientific and policy literature and include: carbon capture and storage; carbon offsetting through additional reforestation or negative emissions technologies that reduce CO_2 concentrations; and other measures that would lead to fossil fuel reserves, that would have been developed under business-as-usual, remaining in the ground. The view of the authors is that without global climate policies (of the sort already advocated by the UK) new fossil fuel exploitation is likely to lead to an increase in cumulative GHG emissions and the risk of climate change.

Recommendations

5. We recommend:

a. in managing fugitive, vented or flared methane throughout the exploration, pre-production and production of shale gas, operators should adopt the principle of reducing emissions to as low a level as reasonably practicable (ALARP). In particular, "reduced emissions completions" (REC) or "green completions" should be adopted at all stages following exploration. Government should discuss with regulators appropriate mandatory requirements to be applied at each stage to ensure that the best technology is implemented in all cases;

b. shale gas exploration and production in the UK should be accompanied by careful monitoring and inspection of GHG emissions relating to all aspects of exploration, pre-production and production, at least until any particular production technique is well understood and documented in the context of UK usage (see Research, below);

c. thereafter operators should monitor their sites to: (1) ensure early warning of unexpected leakages; and (2) obtain emissions estimates for regulators and government;

d. shale gas production in the UK should be accompanied by research into development of more effective extraction techniques, such as improved REC and self-healing cements, which minimise wider environmental impacts including whole-life-cycle GHG emissions;

e. government and industry should actively pursue new techniques to minimise GHG emissions associated with exploration, pre-production and production of shale gas and also reduce the impact on local environment and infrastructure;

f. the shale gas industry should research methods to minimise water demand and vehicle movements, so as to reduce greenhouse gas emissions and the impact on local infrastructure;

g. there should be a detailed scientific research programme of methane measurement, aimed at better understanding and characterising sources and quantities of methane emissions associated with shale gas operations; and

h. this research programme should be independent and managed jointly between government and industry. The research should aim, for example, to reduce uncertainty associated with estimates of local methane emissions from shale gas operations and also to guide the optimisation of regulatory monitoring. The research could also provide information on the effectiveness of operators' actions to minimise methane emissions.

Contents

Potential Greenhouse Gas Emissions Associated with Shale gas Production and Use

1. DECC's Secretary of State requested in December 2012 a study to gather available evidence on the potential greenhouse gas emissions (GHG) from shale gas production and use in the UK and to assess the compatibility of shale gas production and use with UK climate change targets. This report presents the outcome of this study. It compares the emissions generated from extracting and using the shale gas resource with those generated by the use of the shale gas and with the life-cycle carbon emissions of other fossil fuels. It provides recommendations to mitigate the potential climate change impacts of shale gas exploration, production and use in the UK.

Background and context

2. Shale gas development has been of increasing importance in the USA for some years, but exploration has only just begun in the UK. To date, there has been no commercial production of shale gas in the UK, just exploratory drillings, but DECC is now taking steps to prepare for any future production phase.

3. The Secretary of State announced in December 2012 that exploratory hydraulic fracturing (fracking) for shale gas can resume in the UK, subject to new controls to mitigate the risk of seismic activity[2].

4. DECC commissioned more detailed work on the shale gas resources of Great Britain from the British Geological Survey (BGS) which was published on 27th June 2013[3]. The study evaluated the total volume of potentially productive Carboniferous Bowland-Hodder shale in central Britain using a three dimensional geological model generated using seismic mapping, integrated with outcrop and deep borehole information. The evaluation was further refined to identify which parts of the volume had been buried to sufficient depth for the organic material to generate gas. The BGS report estimates that the *resource* in the Bowland-Hodder shale formation is 1329 trillion cubic feet (tcf), about 38 000 billion cubic meters (bcm); the resource is an estimate of the gas in the ground; the BGS report did not estimate the *reserves*, the amount of gas which could in practice be produced economically from that resource. Until more exploration work has been performed in the Bowland-Hodder shale and in other geologically different shale gas prospects beneath the UK, it will not be possible to make any meaningful estimate of the likely shale gas *reserves* in the UK.

5. There are two kinds of principal concerns about the possible impacts of any future large-scale production of shale gas in the UK.

---

[2] https://www.gov.uk/government/speeches/written-ministerial-statement-by-edward-davey-exploration-for-shale-gas
[3] Andrews, I.J. (2013), "The Carboniferous Bowland Shale gas study: geology and resource estimation", British Geological Survey for Department of Energy and Climate Change, London, UK. https://www.gov.uk/government/publications/bowland-shale-gas-study

(1) Local or regional concerns such as:

- the potential impacts of: traffic movements associated with the transport of sand and water used in the drilling; noise; or night-time lighting;

- the potential impacts on the health of people living in the vicinity, for example from gas or fracking fluids escaping into groundwater or water aquifers;

- the potential impacts on regional water resources; and tourism and other aspects of the local economy.

(2) Wider concerns including the implications of large-scale shale gas production for the UK's climate change ambitions and for low carbon investment.

6. In 2012, the Royal Society carried out a review jointly with the Royal Academy of Engineering of the major risks associated with fracking, including geological risks, such as seismicity, and environmental risks, such as groundwater contamination.

7. The key findings of the Royal Society and Royal Academy of Engineering's review[4] are listed below.

   a. The health, safety and environmental risks of hydraulic fracturing can be managed effectively in the UK. Operational best practices must be implemented and enforced through strong regulation.

   b. Fracture propagation is unlikely to cause any contamination of aquifers. The risk of fractures propagating to reach overlying aquifers is very low provided that shale gas extraction takes place at depths of many hundreds of metres or several kilometres. Even if fractures reached overlying aquifers, the necessary pressure conditions for contaminants to flow are very unlikely to be met given the UK's shale gas hydrogeological environments.

   c. Well integrity is the highest priority. More likely causes of possible contamination include faulty wells. The UK's unique well examination scheme was set up so that independent, specialist experts could review the design of every well. This scheme must be made fit for purpose for onshore activities.

   d. Robust monitoring is vital. Monitoring should be carried out before, during and after shale gas operations to detect methane and other contaminants in groundwater and potential leakages of methane and other gases into the atmosphere.

   e. An Environmental Risk Assessment should be mandatory. Every shale gas operation should assess risks across the entire life-cycle of operations, from water use through to the disposal of wastes and the abandonment of wells.

   f. Seismic risks are low. Seismicity should be included in the Environmental Risk Assessment. Seismicity induced by hydraulic fracturing is likely to be of smaller

[4] http://royalsociety.org/policy/projects/shale gas-extraction/report/

magnitude than the UK's largest natural seismic events and those induced by coal mining.

g. Water requirements can be managed sustainably. Water use is already regulated by the Environment Agency. Integrated operational practices, such as recycling and reusing wastewaters where possible, would help to minimise water requirements further. Options for disposing of wastes should be planned from the outset. Should any onshore disposal wells be necessary in the UK, their construction, regulation and siting would need further consideration.

h. Regulation must be fit for purpose. Attention must be paid to the way in which risks scale up should a future shale gas industry develop nationwide. Regulatory co-ordination and capacity must be maintained.

i. Policy-making would benefit from further research. The carbon footprint of shale gas extraction needs further research. Further benefit would also be derived from research into the public acceptability of shale gas extraction and use, in the context of the UK's energy, climate and economic policies.

8. The Government accepted all of the Royal Society and Royal Academy of Engineering recommendations. In response to concerns about the climate change implications of potential shale gas exploration and production in the UK, the Secretary of State invited Professor David MacKay FRS, DECC's Chief Scientific Advisor, and Dr Timothy Stone CBE, the Senior Advisor to the Secretary of State, to undertake a study into the possible impacts of shale gas extraction on greenhouse gas emissions.

9. This report considers the available evidence on the life-cycle GHG emissions from shale gas extraction and use and the need for further research. Specifically, this report now examines two sets of GHG emissions: (1) those associated with the drilling for, removal and transportation of shale gas ('extraction') and (2) those associated with the use of shale gas. These shale emissions are compared with the GHG emissions from extraction and use of other fuels, including conventional gas drilling, Liquefied Natural Gas (LNG) and coal.

Terms of reference for this study

10. The terms of reference for the study are that it should report on the currently available evidence on the life-cycle GHG emissions per unit of energy delivered from shale gas exploration, production, and use; and the compatibility of these emissions with the UK's climate change targets. If the available evidence is insufficient to form a view on its compatibility with climate change targets, the study should make short-term recommendations on what further research is required to inform longer-term policy formulation.

Structure of report

11. This report, intended for a well-informed but non-technical audience, consists of sections that:

- put shale gas exploitation and potential production in context with other natural gas activities in the UK;
- describe the processes for extraction of shale gas;

- summarise the available evidence on the life-cycle GHG emissions of shale gas extraction;

- compare these emissions to those associated with other fossil fuels;

- discuss the potential impact of shale gas extraction and use on UK emissions, on global GHG emissions rates, and on cumulative global GHG emissions; and

- outline possible mitigation options for minimising the climate impacts of shale gas extraction in the UK.

12. Detailed evidence is presented in separate appendices to the main report.

Governance and quality assurance

13. This study was led by Professor David MacKay and Dr Timothy Stone and overseen by a steering group of DECC officials. The report was reviewed by independent, external experts who were asked (1) to comment on the literature and evidence used in the study, particularly if they knew of available evidence not considered in the study, and (2) to advise whether the study's conclusions and recommendations were appropriately supported by, and consistent with, available evidence. The responses of these reviewers were taken into account in the final version of the report.

14. The reviewers were:

    Alan Thomson; Craig Forrest; David Allen; Euan Nisbet; Grant Allen; Jim Penman; John Broderick; John Loughhead; John Shepherd; Kevin Anderson; Lisa Campbell; Nick Winser; and Stuart Haszeldine.

15. Professor MacKay and Dr Stone thank the reviewers for their contribution to the study. We also warmly acknowledge the work of DECC officials, especially Philip Cohen, Martin Meadows, Simon Toole, Damitha Adikaari, Toni Harvey, John Mackintosh, John Arnott, Duarte Figueira, Harshal Mehta, David Warrilow, Anna Stephenson and Mike Earp. We thank DECC's Chief Economist, Steven Fries for advice on this report. We are also grateful to Cuadrilla for openly sharing their own data and estimates on GHG emissions and to representatives from the UK Onshore Operators Group (UKOOG) and the Environment Agency for helpful discussions.

UK shale gas in context

16. Today, natural gas is a key part of the UK's energy supply. The total annual consumption of natural gas in the UK in 2011 was 101 bcm, generating 40% of the UK's electricity and fuelling the majority of residential heating[5]. Following the peak of domestic production in 2000, a growing fraction of the UK's gas has been imported. In 2011 imports exceeded production for the first time and contributed 53% of the UK's gas supply. 47% of the imports

[5] The high heating value of 1bcm of natural gas is 39 800 TJ or 11 060 GWh. 1 tcf = 28.3 bcm.

were supplied as LNG[6] with the vast majority of LNG imports coming from Qatar. The other major source (41% of imports) is piped gas from Norway.

17. The UK GHG emissions inventory reports that methane emissions from the UK energy supply sector contributed 1.3% (7.3 $MtCO_2e$) to UK GHG emissions in 2011[7], although this estimate is not based on well-audited measurements. The methane emissions associated with natural gas production are estimated to be about 9 $gCO_2e/kWh_{(th)}$.

18. Shale gas operations are subject to the Government's long-standing policy on flaring and venting of methane. DECC is committed to eliminating all unnecessary or wasteful flaring and venting of gas[8]. The Office of Unconventional Gas and Oil (OUGO) will ensure that policy on flaring and venting of shale gas works is consistent with new controls that may be introduced by the Environment Agency in applying their legislation, and that methane or CO_2 emissions from flaring will continue to be minimised.

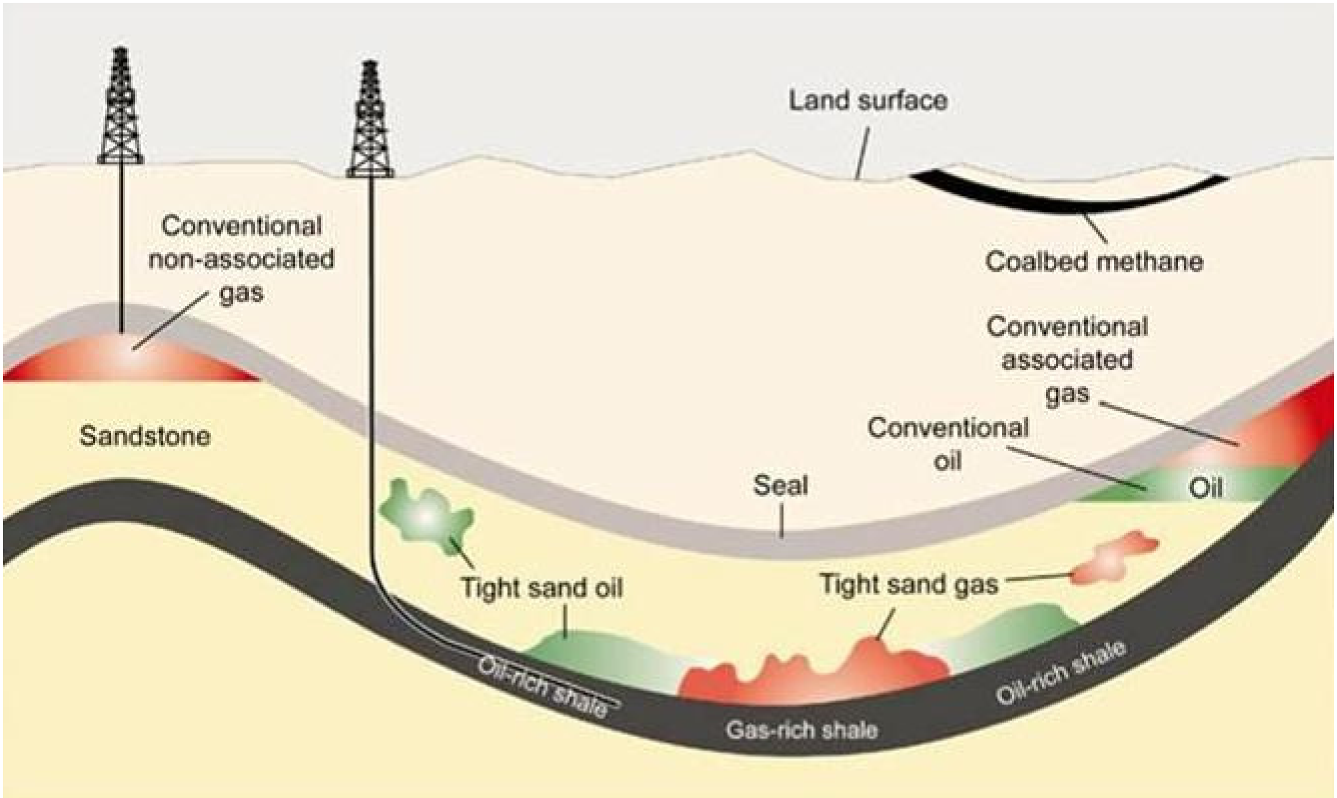

Figure 1: Geological settings for unconventional gas Source. US Energy Information Administration.

19. Natural gas is a fossil fuel and is a mixture of methane with other hydrocarbons, carbon dioxide, nitrogen, hydrogen sulphide and noble gases, the proportions of which vary

[6] Digest of UK Energy Statistics (DUKES) 2012, Chapter 4
[7] https://www.gov.uk/government/publications/final-uk-emissions-estimates
[8] https://www.gov.uk/oil-and-gas-fields-and-field-development

depending on the gas field. The vast majority of natural gas being produced is "conventional" gas. The term conventional refers to the source rather than the nature of the gas. Conventional gas is gas that is trapped in porous rocks, usually under pressure and often with oil, below an impermeable layer. The gas and oil migrate to the highest point of the trap. Exploration locates the traps, which can be drained by a well in the crest of the structure (see Figure 1).

20. Shale gas is an "unconventional" gas. In chemical composition, shale gas is similar to conventional gas but it requires subsurface engineering procedures to extract it, beyond regular drilling. Other unconventional sources of gas include tight gas, found trapped in very low permeability sandstone or limestone formations, and coal bed methane (CBM, where gas is produced from coal beds). These sources are outside the scope of this study.

21. Shale gas, sometimes together with shale oil, occurs in very fine-grained low-permeability organic-rich sediments, such as shales, mudstones, carbonates or silty mudstones, usually in deeper parts of basins. Gas formed when the organic matter within shales was subjected to high temperatures and pressures over millions of years. Some gas remained in the impermeable shale, so the shale is both the source rock and the reservoir. To release the gas, the rock is fractured with high pressure fluid to create an artificial, permeable reservoir of fine fractures. The specific local geological stress field, and the precise physical and chemical properties of the shale, influence the effectiveness of hydraulic fracturing Over the last three decades, over 2,000 wells have been drilled onshore in the UK, approximately 10 per cent of which have been hydraulically fractured, at small scale, to enhance recovery[9].

22. Many such unconventional sources of oil and gas were formerly too difficult or uneconomic to extract until recent advances in drilling technology, improved hydraulic fracturing technology, and an increased price for fossil fuels made extraction economic.

23. In the last decade, there has been a significant expansion of unconventional gas production in the USA. Shale gas rose from only 2% of US gas production in 2000 to 34% in 2011, and is forecast to continue rising to almost 50% by 2020[10].

UK resource of shale gas

24. The volume of gas bound within a specific shale (gas-in-place) is known as the gas *resource*. The *reserves* are the volume of gas that can be technically and economically produced. Reserves are therefore often much smaller than the resource. The ratio of reserves to resource varies widely between shale formations in the USA, with formations at higher pressure having a higher estimated ultimate recovery (EUR). The US Energy Information Administration estimate that 22 per cent of shale resources are technically recoverable. The economically recoverable fraction may be much smaller as it depends on gas prices and production costs. The factors affecting the ratio of reserve to resource are mainly geological. However, there are also non-geological factors that could affect the size of the reserve in the UK. These factors include: engineering design (such as the number of horizontal wells per pad and the techniques used for fracking); the effect of the new protocols for earthquake mitigation and monitoring; land access; environmental permit constraints; well costs; and the prices of gas and competing fuels.

[9] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/225850/Publication_RoyalSociety_2012-06-28-Shale-gas.pdf
[10] http://www.eia.gov/energy_in_brief/article/about_shale_gas.cfm

25. To date, there has been no commercial exploitation of shale gas in the UK. The latest report from BGS (2013)[11] gave a central estimate of 1329 tcf (38 000 bcm) gas-in-place resource in the Bowland Shale and does not comment on the potential reserve, for which no reliable estimates yet exist.

26. Cuadrilla, which is exploring a resource in Lancashire, has estimated the resource gas-in-place in shales within the scope of its licence to be 200 tcf (5660 bcm). However, more drilling and testing is needed before there is a reliable estimate of the reserve in this location.

27. There are other shale resources in the UK and in British overseas territories.

Shale gas exploration

28. Exploration of shale gas resource is required to establish whether gas can be extracted and whether it is economic to do so. Exploration initially involves drilling and taking core samples, followed by hydraulic fracturing to characterise the shale and its economic viability. In the USA it is common practice to drill many wells to find a 'sweet spot' (an area in the shale formation which is considered highly productive); due to space constraints in the UK it is likely that a more targeted approach to exploration would be undertaken.

Shale gas extraction

29. This section outlines the main processes needed to extract shale gas in the USA. While the process will be similar in the UK, differences in geology and other circumstances are likely to require that processes are modified or altered. There are three main phases in shale gas extraction: pre-production; production; and post-production.

Shale gas pre-production

30. Pre-production stages for shale gas include:

- **Exploration** – before a shale resource could be considered economic, many tests will need to be carried out which could include three dimensional seismology and the drilling of test wells.

- **Site preparation** – removal of vegetation, building of access roads and the well pad, drilling rig mobilization and demobilization.

- **Drilling and casing** – shale reserves are often at depths of approximately 2 km, which is deeper than conventional reserves. A typical well consists of a vertical section and a horizontal section of up to 3 km in length. Drilling is completed in stages with the shallower section having a greater diameter to allow for the additional casing to protect the groundwater. Once the well has been lined, accurately positioned holes are made in the horizontal section to enable hydraulic fracturing.

- **Hydraulic fracturing**– fluids (approximately 90% water with 1-2% chemical additives such as hydrochloric acid for pH control, glutaraldehyde as a

[11] Andrews, I.J. 2013. *The Carboniferous Bowland Shale gas study: geology and resource estimation*. British Geological Survey for Department of Energy and Climate Change, London, UK. https://www.gov.uk/government/publications/bowland-shale-gas-study

bactericide, guar gum as a gelling agent, and petroleum based surfactants[12]) together with a 'proppant' (approximately 8% by volume, normally sand) are pumped down the well at high pressure. This pressure breaks up the shale, creating fractures which can extend a few hundred metres. The fracture growth height is dependent on the geology and design (number and spacing of stages, fluid chemistry, and injection rates and volumes) with Davies et al. (2012) reporting a maximum recorded fracture height of 588 m in a study of US data, some with much larger hydraulic fracturing volumes than would ever be considered in the UK. Once the pressure is released, the proppant prevents the fractures from closing. Hydraulic fracturing is carried out in as many as 20 stages, starting from the furthest point and proceeding back towards the well head, as it is not usually possible to maintain the required downhole pressure to stimulate the whole length of a lateral in one stage. Each interval is isolated in sequence so that only a single section of the well is hydraulically fractured at a given time.

- **Well completion** - once pumping has stopped and hydraulic fracturing is complete, a proportion (dependent on the geology) of the injected fracturing fluid flows back to the surface. The EPA estimates that a flowback can last three to ten days (US EPA, 2011b). In some cases, however, the flow may continue during the life of the well. After the flowback period, the fluids produced from the well are primarily hydrocarbons.

- **Waste treatment** – Both drilling and well completion produces quantities of waste, which require careful disposal. The flowback fluids discharged from the well are saline and can include the fracturing fluid as well as naturally-occurring substances found within the shale, such as methane, trace metals, and naturally occurring radioactive material (NORM)[13]. The flowback of fluids, sometimes referred to as produced water, may continue during the production stage, and the liquid requires treatment before reuse or disposal.

Production phase

31. The gas in the shale formation is likely to be a variable mixture of: methane and other gaseous hydrocarbons; acidic gases (CO_2, sulphurous compounds); inert gases (including nitrogen); water vapour; condensed higher hydrocarbons; and entrained particles. Table 1 shows how the gas composition varies between formations as well as between wells in the same formation, in several US shale formations.

[12] http://www.straterra.co.nz/Fracking%20chemicals

[13] The discharge of radionuclides is subject to normal EA Radioactive Substances monitoring and control. Analysis carried out by the EA on Cuadrilla flowback fluids suggests that between 14-90 becquerel (Bq) per litre are present which is very small when compared to discharges from the medical sector. The activity of one banana is roughly 15 Bq.

Table 1: Raw shale gas composition as a percentage by volume, Bullin (2008) for the Annual Forum, Gas Processors Association–Houston Chapter[14].

	Barnett	Marcellus	Fayetteville	New Albany	Antrim	Haynesville	Mean
Methane (%)	87	85	97	90	62	95	**86**
Ethane (%)	7	11	1	1	4	0	**4**
Propane (%)	2	3	0	1	1	0	**1**
CO_2 (%)	2	0	1	8	4	5	**3**
N_2 (%)	3	0	1	-	29	0	**7**

32. For shale gas to be introduced in the National Transmission System it is required to meet the gas specifications[15]. The raw shale gas may be in a form where it could be directly blended into the National Transmission System or it may require processing similar to that for conventional gas. For instance, shale gas could require processing to remove pollutants (e.g. CO_2) or compression to increase the pressure of the gas prior to injection into the gas network.

33. The gas production rate from a well starts high and declines steeply; Baihly et al. (2010)[16] suggest the rate of decline is dependent on the shale formation.

34. Once the gas production flow rate declines significantly, the operators may give the well a workover to extend its life. This workover may involve "re-fracking" or "liquid unloading" to remove liquids and debris that have built up in the wellbore.

35. The US Geological Survey[17] reported that the average EUR for basins ranged between 0.04 and 2.60 bcf per well (1 – 74 million cubic meters)[18]. Due to the collapse in gas prices in the USA such small wells are now probably considered uneconomic. Economic factors such as equipment costs, access and environmental regulations in the UK are likely to result in the wells having an EUR in excess of 3.0 bcf (85 million cubic meters), with industry sources suggesting an even higher figure of 5.0 bcf (140 million cubic meters). According to research from Bloomberg New Energy Finance[19] *'the cost of shale gas extraction in the UK is likely to be significantly higher than in the US'* therefore areas with lower recovery (currently estimated to be below 2 bcf [57 million cubic meters]) are unlikely to be economically viable to develop.

Post-production

36. The post-production phase occurs once the operator deems the well uneconomic. The well is decommissioned by removing the equipment and distribution infrastructure. The well is then plugged with cement at various key points along the well to prevent fugitive emissions or future contamination.

---

[14] http://www.bre.com/portals/0/technicalarticles/Keith%20Bullin%20-
[15] https://www.ofgem.gov.uk/gas/wholesale-market/gas-quality
[16] Baihly et al. (2010), "Shale gas production decline trend comparison over time and basins", *SPE Annu. Tech. Conf. and Exhibition*
[17] USGS (2012) - Variability of Distributions of Well-Scale Estimated Ultimate Recovery for Continuous (Unconventional) Oil and Gas Resources in the United States
[18] Fracking techniques have improved considerably since the small EUR shale formations were first exploited.
[19] http://about.bnef.com/press-releases/uk-shale-gas-no-get-out-of-jail-free-card/

GHG emissions associated with shale gas extraction

37. The following section describes the categorisation of GHG emissions resulting directly from shale gas operations.

   a. **Vented emissions** of methane and CO_2. Vented emissions are intentional. Many processes associated with shale gas exploration and production can cause gases to be vented, where permitted. Examples include: release of gases during flowback, and release for safety reasons and during certain maintenance operations.

   b. **Emissions from combustion of fossil fuels on site.** These emissions come from engines (such as diesel engines used for drilling, hydraulic fracturing and natural gas compression) and from flaring of shale gas. This study assumes the combustion emissions would be mainly CO_2. However, incomplete combustion could result in other emissions such as methane, volatile organic compounds and carbon black, all of which would have global warming and air pollution impacts.

   c. **Fugitive emissions.** These emissions are unintentional gas leaks and are difficult to quantify and control. There are various potential sources of fugitive emissions, including leaks from valves, well heads and onsite accidents or accidental releases from the well casing into groundwater.[20] It has also been suggested that it may be possible for gas in the shale formation to escape into ground water due to fracking activities. (The likelihood of widespread significant releases by this mechanism has been widely questioned in literature[21]. No incidents of direct invasion of shallow water zones by fracture fluids during the fracturing process have been recorded.)

38. There are also indirect emissions, which result from product/processes used in the exploitation of shale gas. These emissions include the emissions from the energy used to treat and transport the water and wastewater, and to manufacture the chemicals and materials of construction.

Evidence base for GHG emissions associated with exploration and use

39. Many of the studies use life-cycle assessment (LCA) to analyse the GHG emissions associated with shale gas exploration and use.

40. It is important to note that there has been little measurement of direct or indirect methane emissions from shale gas exploration and production anywhere in the world. Outcomes of LCAs therefore carry some uncertainty.

41. A range of studies have detailed potential LCAs for GHG emissions from shale gas. Early studies (Howarth et al. 2011)[22] suggested that GHG emissions associated with shale gas production could result in shale gas having a greater carbon footprint than coal, when used

---

[20] Jackson et al (2013), "Increased stray gas abundance in a subset of drinking water wells near Marcellus shale gas extraction", *PNAS*, 110 (28), 11250-11255. http://www.pnas.org/content/110/28/11250.short.
A report by MIT "The Future of Natural Gas".
[21] Saiers et al. (2012), "Potential contaminant pathways from hydraulically fractured shale aquifers", *Ground Water*, 50(6), 826–828.
Warner et al. (2012), "Geochemical evidence for possible natural migration of Marcellus Formation brine to shallow aquifers in Pennsylvania", *PNAS*, 109(30), 11961-11966. http://www.pnas.org/content/109/30/11961.short
Carter et al. (2013) "Technical Rebuttal to Article Claiming a Link between Hydraulic Fracturing and Groundwater Contamination", *PCPG*
[22] Howarth et al. (2011), "Methane and the greenhouse gas footprint of natural gas from shale formations", *Climate Change*, 106(4), 679 -690.

for electricity generation. These findings have been strongly criticised by other experts (see Appendix A).

42. The current evidence base originates mainly from the USA, since shale activities elsewhere are only at the exploration phase. We have been cautious when extrapolating US LCA results to the UK, because many of the circumstances differ, for example geology and regulations that govern operation.

43. The USA LCA studies use a diverse range of primary research and data from shale gas studies. All authors consider that flowback could cause the highest proportion of emissions from shale gas exploration and extraction. There are however few quantifications of these emissions. These quantifications include the studies by Howarth et al. (2011) and Jiang et al. (2011)[23], which relied on secondary sources and governmental reports [EPA (2011b)[24] and NYSDEC (2011)[25]] for their estimates of methane emissions.

44. In a report for the EU in 2012, AEA Technology[26] produced a detailed assessment of all the LCA studies available. More recently, O'Sullivan and Paltsev (2012)[27] carried out a new set of calculations to estimate methane emissions during flowback. Our study mainly uses metadata collected for the AEA report, and data from O'Sullivan and Paltsev (2012).

45. All the above studies estimate GHG emissions from gas production flow rates, using an inventory process and engineering calculations.

46. A study by Petron et al. (2012)[28] was the first study to report atmospheric methane measurements for estimating oil and gas methane emissions. The measurements suggest that emissions are at least two times higher than estimated through the inventory process, whilst the authors acknowledge the difficulties of attributing the results to an exact source. New regulations have been put in place since the time of measurement[29]. A similar study by Karion et al. (2013)[30] sampling methane emissions over one day found that an oil and gas production field in Utah produced methane emission rates corresponding to 6-12% of the average production during one day of sampling[31]. The University of Texas have undertaken a more detailed study on GHG emissions from the natural gas industry, which is scheduled for publication in 2013.

---

[23] Jiang et al (2011), "Life cycle greenhouse gas emissions of Marcellus Shale gas", *Environmental Research Letters*, 6(034014). http://iopscience.iop.org/1748-9326/6/3/034014
[24] http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html
[25] http://www.dec.ny.gov/energy/75370.html
[26] AEA Technology, report for European Commission DG CLIMA, '*Climate impact of potential shale gas production in the EU*,' 2012
[27] O'Sullivan, F. and S. Paltsev, 2012, "Shale Gas Production: Potential versus Actual Greenhouse Gas Emissions," *Environmental Research Letters*, 7(044030), 1-6. http://iopscience.iop.org/1748-9326/7/4/044030/article
[28] Petron et al. (2012), "Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study", *Journal of Geophysical Atmospheres*, 117(D4).
[29] JISEA (2012) Natural Gas and the Transformation of the U.S. Energy Sector: Electricity
[30] Karion et al. (2013), "Methane emissions estimate from airborne measurements over a western United States natural gas field", *American Geophysical Union*
[31] http://www.nature.com/news/methane-leaks-erode-green-credentials-of-natural-gas-1.12123

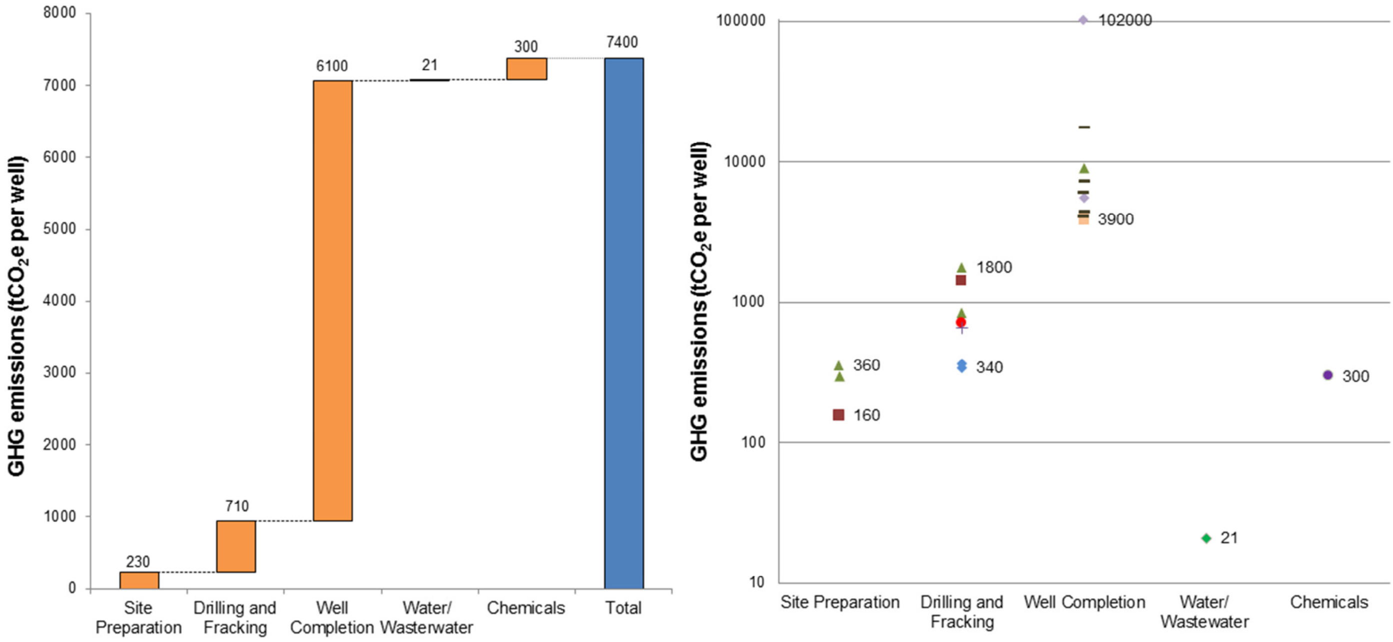

Figure 2: The figure on the left shows the median uncontrolled GHG emissions (assuming 100% of the gas during well completion is vented, i.e. a worst case scenario) and the figure on the right shows (on a logarithmic scale) the source data associated with each aspect of shale gas pre-production.

47. Figure 2 shows median values and the entire range of all the published pre-production emissions estimates and data the study has been able to consider up until March 2013. The literature indicates that the emissions during well completion vary widely between shale formations. Well completion is expected to dominate potential pre-production emissions, accounting for over 80% of GHG emissions (see paragraph 49 for further discussion). Figure 2 includes estimated emissions from well completion with venting. This scenario represents historic US practice and is unrepresentative of the regulatory regime in the UK. Variation among the studies of well completion emissions are the largest source of discrepancies between studies, estimates of pre-production emissions. The upper estimate from Howarth et al. (2011) is more than 11 times the median.

48. The key stages are discussed below, with further detail on the other stages described in Appendix A.

Well completion

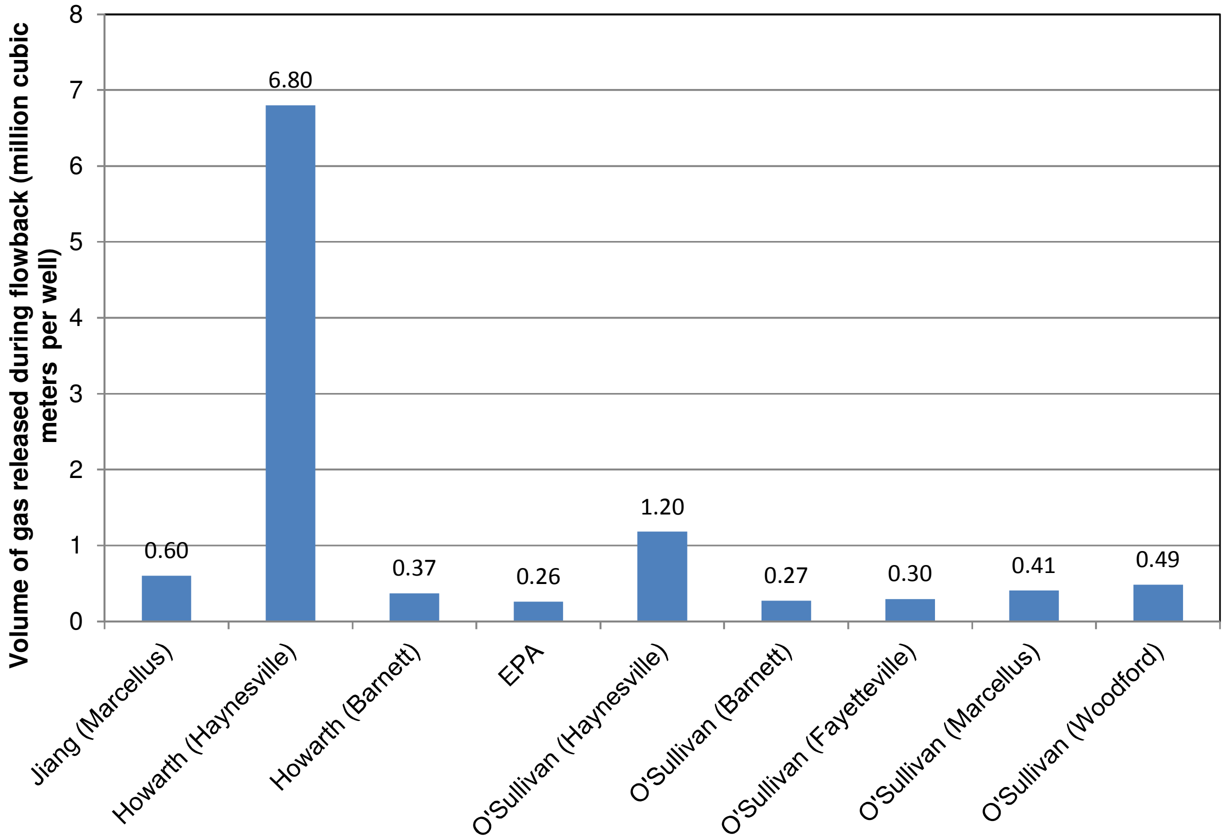

Figure 3: Published estimates of gas volumes released during well completion, versus respective references. Formation is shown in brackets where applicable. The Howarth Haynesville data is considered by many to be an outlier.

49. According to published data, the volume of gas released during well completion varies depending on the formation, as shown in Figure 3. The estimates of released gas are based on a set of assumptions about the well completion method including whether the gas associated with the flowback fluid is vented, flared or recovered. If the gas is recovered during flowback, the process is often referred to as 'reduced emissions completion', (REC), which is considered best practice. REC is also referred to as 'green completion' in the literature. Recovered gas is typically injected into a gas pipeline, although some sites may use a proportion of the recovered gas to power onsite equipment. The piped gas may require processing in order for it to meet sales gas specification. Recent developments in REC design have enabled its use on most shale formations including the majority of low pressure (low energy) reservoirs. Further research should enable REC processes to develop further so that REC can be used on all formations. It should be noted that during extraction, even with flaring or REC, some occasional limited venting might still be necessary, in particular for safety reasons.[32]

50. The highest estimate for GHG emissions from well completion was reported in the study by Howarth et al. (2011) on the Haynesville formation. This was found to be almost six times greater than the next highest estimate, which is from O'Sullivan and Paltsev (2012) and is

[32] http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf

also an estimate of emissions from Haynesville. The Howarth estimate may be unrealistically high, as discussed in Appendix A, and should be treated with caution.

51. Even discounting the Howarth Haynesville estimate as an outlier, there are widely varying estimates of well completion emissions. The variations are most likely due to different circumstances between study sites, for example geology and well-productivity. Therefore whilst the data collected are a guide to the range of emissions associated with shale gas extraction in the USA, a more reliable figure for the UK can be established only by appropriate field measurements in the UK.

Water / Wastewater transport and treatment

52. Hydraulic fracturing requires a large volume of water. Some studies suggest up to 29 000 m^3 of water are required per well (NYSDEC, 2011), and the NREL (2012)[33] calculated that the average demand is in the region of 15 000 m^3 per well[34]. As the volume of fracking water required varies both within and between geological formations, the average volume for the UK is not known yet. In the UK, depending on the proximity to the local water supply network or the availability of a ground water abstraction licence[35], the water may be transported to site by pipe or by road.

53. NREL (2012)[33] suggests that approximately 550 m^3 per well of the fracking fluid is being reused in Pennsylvania (the only state to monitor water reuse in the USA), representing 4% of the total water requirement. Cuadrilla, in a personal communication, suggested that the vast majority of water used during the hydraulic fracturing process could be reused, which could reduce the water demand to between 3800 m^3 and 14 000 m^3 per well. This is the approximate equivalent of the daily water demand of between 25 600 and 91 500 people, or between 128 and 457 tankers. The social consequences of transportation of water, especially in the context of water shortage in the UK and the more urban context than the USA, must also be considered by developers in pursuing improved techniques such as water reuse or waterless methods.

54. The wastewater resulting from fracking and the produced water (the water which is continually produced from an operational well) are highly saline and contain dissolved methane, as well as chemicals from the fracking fluid and geological strata, which include low levels of naturally occurring radioactive material. In the UK the wastewater would have to be responsibly managed and would require treatment before being discharged. Depending on the level of treatment the discharge could ultimately be to a local water course (under permit from the Environment Agency) or to a suitably sized sewage treatment works with a trade effluent agreement from the associated water company.

55. The transportation method for wastewater to the sewage treatment works would depend on the local sewage infrastructure. It is possible that the wastewater would have to be transported by road tanker, placing further demands on the local road infrastructure.

56. Defra[36] give emission factors for pumping water and treating wastewater of 0.34 $kgCO_2e/m^3$ and 0.71 $kgCO_2e/m^3$ respectively. If a volume of 15 000 m^3 is delivered

---

[33] Natural Gas and the Transformation of the U.S. Energy Sector: Electricity. http://www.nrel.gov/docs/fy13osti/55538.pdf
[34] 1m^3 of water weighs 1 tonne and is 1,000 litres.
[35] The water industry are under significant pressure from the Environment Agency and the regulator, Ofwat, to reduce abstraction from groundwater.
[36] http://www.ukconversionfactorscarbonsmart.co.uk/

and taken away, the estimated emissions would be about 5 tCO_2e per well for transporting the water by pipe and 16 tCO_2e per well for wastewater treatment.

57. If the same volume of water is delivered by trucks over a distance of, say, 20 km, with an energy intensity of 1 kWh per t-km[37] and carbon intensity of 250 gCO_2e per kWh, then the additional emissions from transporting the water would be 75 tCO_2, which is larger, but still small compared with the other emissions associated with pre-production.

Workover

58. During the operational life of a well, gas production will drop off. To enhance production, an old well may undergo a workover which involves re-fracturing the well or liquid unloading. In the USA, liquid unloading is initially carried out using a plunger lift system. Towards the end of the well's life, liquid unloading is carried out by venting gas to the atmosphere via a gas/liquid separator for a short period of time; it is uncertain whether this practice would be used on wells in the UK.

59. Estimates of GHG emissions from workover depend on the assumed frequency of workover activity. Skone (2011)[38] and Hultman et al. (2011)[39] assume that each well is worked over once, and they estimate the emissions from workover are similar to those produced during well completion.

Gas production and processing

60. The most significant GHG emissions associated with this stage are from compressors, dehydration equipment, CO_2 scrubbing, chemical processing, and fugitive releases. The treatment processes required are likely to vary between shale formations, depending on the raw gas quality (see Table 1). This treatment may also require the addition of propane or an inert gas in order to meet the UK's gas transmission quality standards.

61. As the quality of UK shale gas is yet to be determined, this study assumes that shale gas in the UK would require similar treatment to conventional gas. The Digest of UK Energy Statistics estimates the GHG emissions associated with production and processing for conventional gas to be 100 tCO_2e per million m^3 which equates to approximately 9 gCO_2e/kWh. This figure includes fugitive emissions. The industry should work towards reducing these emissions by continuing their current air monitoring programme[40] throughout production so that leaks can be quickly identified and sealed.

62. As mentioned in paragraph 37, Jackson et al. (2013)[41] found evidence of gas escaping from wells into aquifers, concluding that the likely cause is poor well construction. We believe that sufficient regulations are in place that leakage of gas into aquifers is unlikely to occur – UKOOG guidelines clearly set out good practice in well design and these guidelines should be made mandatory. Future advances in self-healing cement are likely to mitigate this risk further. It is recommended that further research is carried out on self-healing

---

[37] www.dft.gov.uk/pgr/statistics/datatablespublications/energyenvironment
[38] Life Cycle Greenhouse Gas Inventory of natural Gas Extraction, Delivery and Electricity Production- NETL. http://www.netl.doe.gov/energy-analyses/pubs/NG-GHG-LCI.pdf
[39] Hultman et al. (2011), "The greenhouse impact of unconventional gas for electricity generation", Environmental Research Letters, 6(049504). http://iopscience.iop.org/1748-9326/6/4/044008
[40] Such as Cuadrilla's http://www.cuadrillaresources.com/our-sites/balcombe/
[41] Jackson et al. (2013), Increased stray gas abundance in a subset of drinking water wells near Marcellus shale gas extraction

cement and on early warning monitoring techniques and it is recommended that industry continue their ground water measurements to reassure the public.

Estimated shale gas carbon footprint for the UK

63. The following section combines the evidence from available sources to estimate the credible range of potential GHG emissions from the production of shale gas in the UK. The results carry significant uncertainties because of the limits to available evidence and the lack of data for the UK.

Key assumptions

64. In the absence of information on the properties of UK shale gas we have assumed that:

- unprocessed shale gas is 86% methane, see Table 1;
- there is 3% (by volume) CO_2 in unprocessed shale gas, see Table 1 (entry to the gas network requires a CO_2 concentration of 2.5%, therefore at least 0.5% CO_2 will need to be removed);
- processed gas is 100% methane[42];
- the calorific value of processed gas is 52 MJ/kg or 40MJ/m^3;
- the gas has a density of 0.76 kg/m^3;
- the global warming potential for methane compared to carbon dioxide is 25, based on a 100 year time horizon[43]; and
- overall productivity or estimated ultimate recovery (EUR) of a well is between 2 and 5 bcf (approximately 57–140 million m^3) with a central value of 3 bcf (85 million m^3).

65. We have calculated emissions associated with pre-production and production, i.e. to the point where gas is injected into the gas network. We measure emissions in units $gCO_2e/kWh_{(th)}$ of gas produced.

We have estimated the pre-production emissions for four well completion scenarios:

- "100% vented" – assumes all the gas released during flowback is vented to the atmosphere;
- "90% capture and flare" – assumes 90% of methane is captured and 95% of captured methane is flared[44];

[42] 100% has been used for simplicity in the calculations, in reality the percentage of methane in natural gas will vary between 82 – 97%.
[43] Consistent with an agreement at the United Nations Framework Convention on Climate Change to adopt the Intergovernmental Panel on Climate Change's 2007 fourth assessment report (AR4).
[44] http://www.ogp.org.uk/pubs/288.pdf

- “REC” – assumes 90% of the methane contained in flowback is captured[45] and injected into the gas network; and

- “100% capture” – in a personal communication Cuadrilla have told us that they aim for 100% gas recovery. Separately, BP engineers have advised us that on certain shale formations a well-designed REC could capture almost 100% of the gas.

66. We have assumed that the well would undergo one refracturing workover, resulting in a doubling of the emissions associated with completion (see paragraph 59).

67. We estimated the total gas emissions, for each well-completion method by adding the site preparation, drilling and fracking, chemicals, water and wastewater related emissions, detailed in Appendix A and production phase emissions (Appendix B). We obtained central, low and high estimates by using the mean, the 5th percentile, and the 95th percentile of all the pre-production emissions data.[46]

68. Finally, to obtain emission intensities per kWh of gas shown in Figures 4 and 5, three well productivity scenarios were used (see paragraph 35).

- “Low EUR” – 2 bcf (57 million m^3);

- “Central EUR” – 3 bcf (85 million m^3); and

- “High EUR” – 5 bcf (140 million m^3).

69. Appendix D includes detailed outputs from the calculations.

Comparison of shale gas with LNG

70. When transporting natural gas long distances, it is common practice to liquefy the gas so that its volume is much smaller. Natural gas is liquefied by cooling to -162^{o}C. LNG accounted for almost 25% of the total gas consumption in the UK in 2011.

71. Table 2 shows the range of data found in the literature for the life-cycle GHG emissions from LNG (to the point where it is injected into the National Transmission System). It should be noted that the UK’s inventory would include only GHG emissions resulting from regasification, as the production and transport emissions fall outside UK borders. Further details are provided in Appendix C.

Table 2: GHG Emissions associated with LNG production, transportation and regasification, from various sources (see Appendix C)

	GHG emissions per unit of thermal energy $gCO_2e/kWh_{(th)}$
Maximum	89
Central Value	57
Minimum	38

[45] EPA analysis suggests greater than 90% of methane contained within flow back can be captured (U.S. EPA, 2012b)
[46] Using the Microsoft Excel PERCENTILE function.

Summary of LCA results

72. As discussed in Appendix A, many experts consider the results from Howarth et al. (2011) study on the Haynesville formation to be an outlier. It is not the intention of this study to comment further on this data point; instead, we present results without it (Figure 4) and with it (Figure 5).

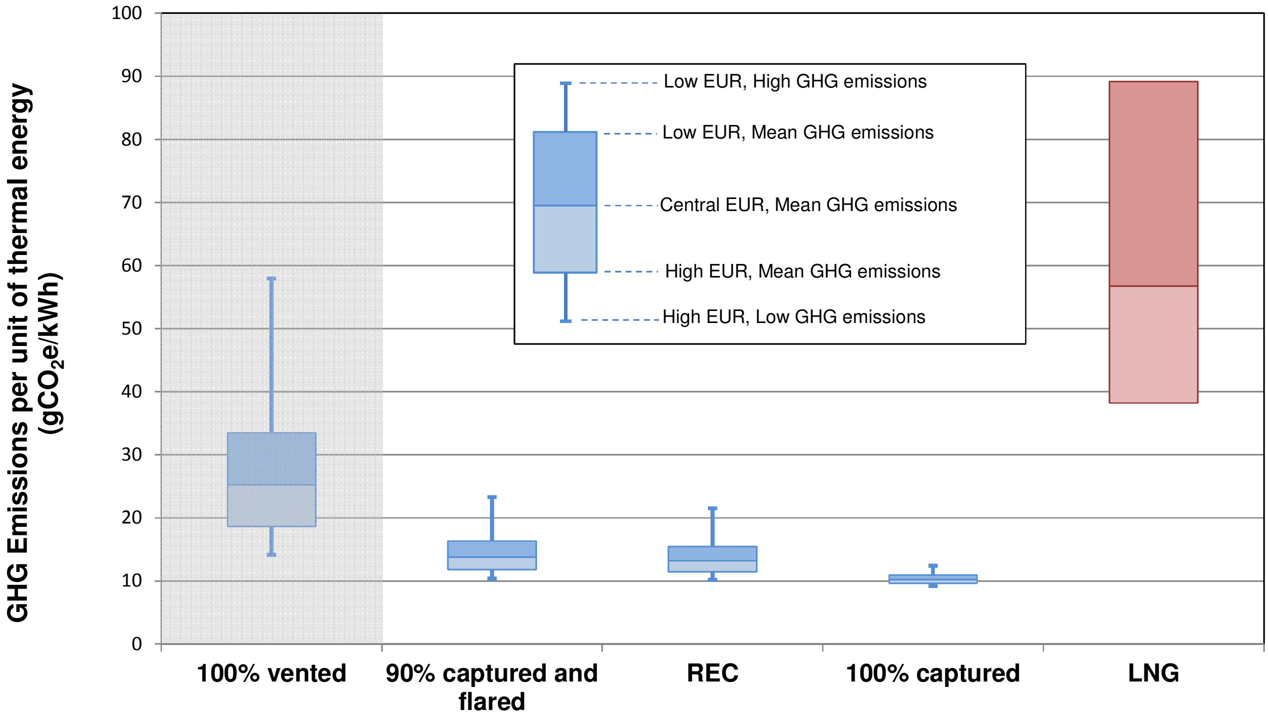

Figure 4: Comparison of the life-cycle emissions from various shale gas production scenarios with LNG delivery (excluding Howarth Haynesville data, considered by many to be an outlier). Combustion of the gas emits an additional 190 g/kWh. (100% vented scenario would not be permitted in the UK).

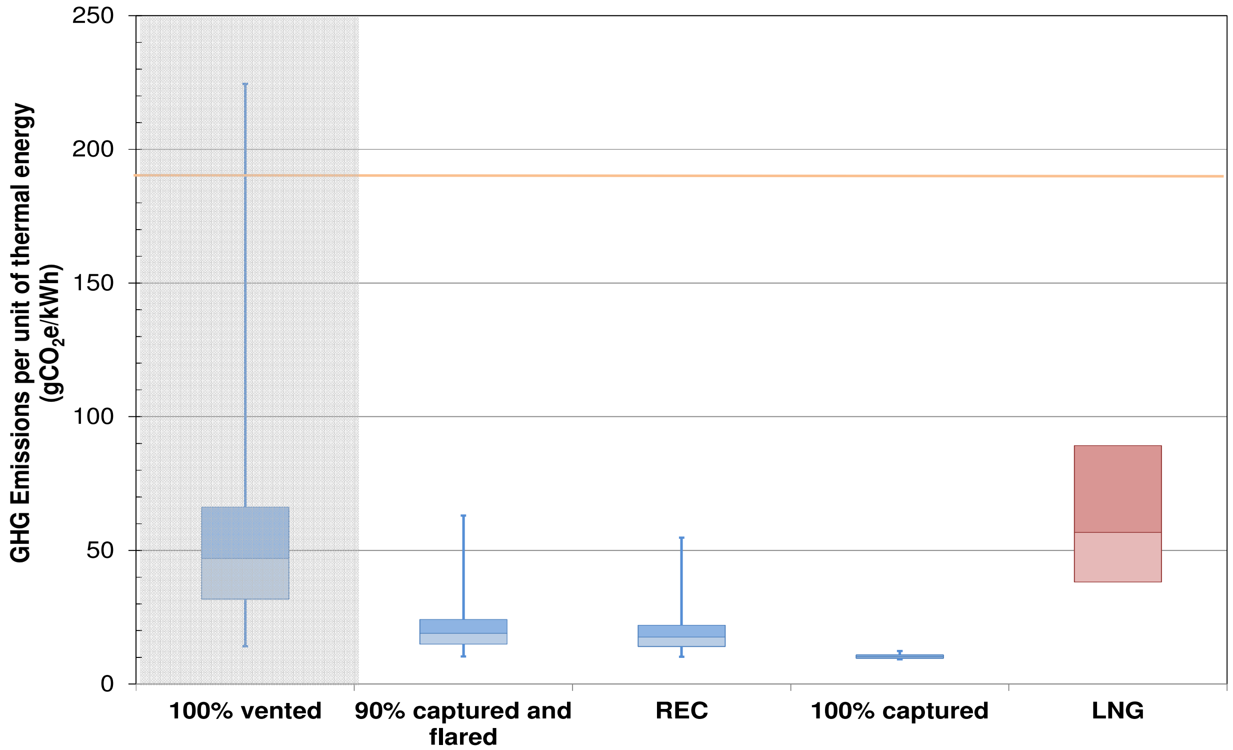

Figure 5: Comparison of various shale gas production scenarios with LNG (including Howarth Haynesville data, considered by many to be an outlier). The orange line represents the GHG emissions associated with complete stoichiometric combustion of methane (190 gCO2e/kWh). The scale of the vertical axis is different to Figure 4. For a further description of the variables please refer to paragraphs 65 - 68 (100% vented scenario would not be permitted in the UK).

73. Our LCA analysis suggests that the two biggest factors affecting the specific GHG emissions resulting from production are:

a. **completion techniques;** improved capture techniques will reduce the emissions from the well; and

b. **well productivity (EUR);** the more productive a well is, the less pre-production and post-production emissions will influence the overall specific (per kWh) emissions. Halving the EUR would almost double the specific emissions.

74. Emissions from shale gas extraction are only part of the story and must be added to those due to the combustion of the gas. The combustion emissions for methane are approximately 190 gCO_2e/kWh[47] and are represented as the orange line on Figure 5. In the most extreme of the hypothetical cases[48], shown in Figure 5 as "100% vented", the extraction emissions could more than double those associated with combustion alone. We therefore recommend that, in managing fugitive, vented or flared methane throughout the exploration, pre-production and production of shale gas, operators should adopt the principle of reducing emissions to as low a level as reasonably practicable (ALARP). In

[47] UK Government conversion factors for Company Reporting, version 1.1, Tables: WTT-Fuels, Water supply, Water treatment (Defra, 2013)
[48] The high GHG emissions (mainly due to flowback) and low EUR scenario is unlikely to occur (the high flowback emissions are associated with the Haynesville formation which also records the highest EUR)

particular, “reduced emissions completions” (REC) or “green completions” should be adopted at all stages following exploration. Government should discuss with regulators appropriate mandatory requirements to be applied at each stage to ensure that the best available technology is implemented in all cases.

Comparison to other sources of fossil fuels

75. While almost 70% of gas in the UK is used for heat, the carbon footprint of shale gas is often compared to coal, which in the UK is principally used for power generation. Figure 7 compares the life-cycle emissions of electricity generated from various sources of gas and coal. The calculations assume the thermal efficiency of gas fired electricity generation is 47%.

76. In a scenario where pre-production emissions are captured and flared, the carbon footprint (emissions intensity) of shale gas extraction and use is likely to be in the range 200 – 253 g CO_2e per kWh of chemical energy, which makes shale gas’s overall carbon footprint comparable to gas extracted from conventional sources (199 – 207 g $CO_2e/kWh_{(th)}$), and lower than the carbon footprint of Liquefied Natural Gas (233 - 270g $CO_2e/kWh_{(th)}$). When shale gas is used for electricity generation, its carbon footprint is likely to be in the range 423 – 535 g $CO_2e/kWh_{(e)}$, which is significantly lower than the carbon footprint of coal, 837 – 1130 g $CO_2e/kWh_{(e)}$.

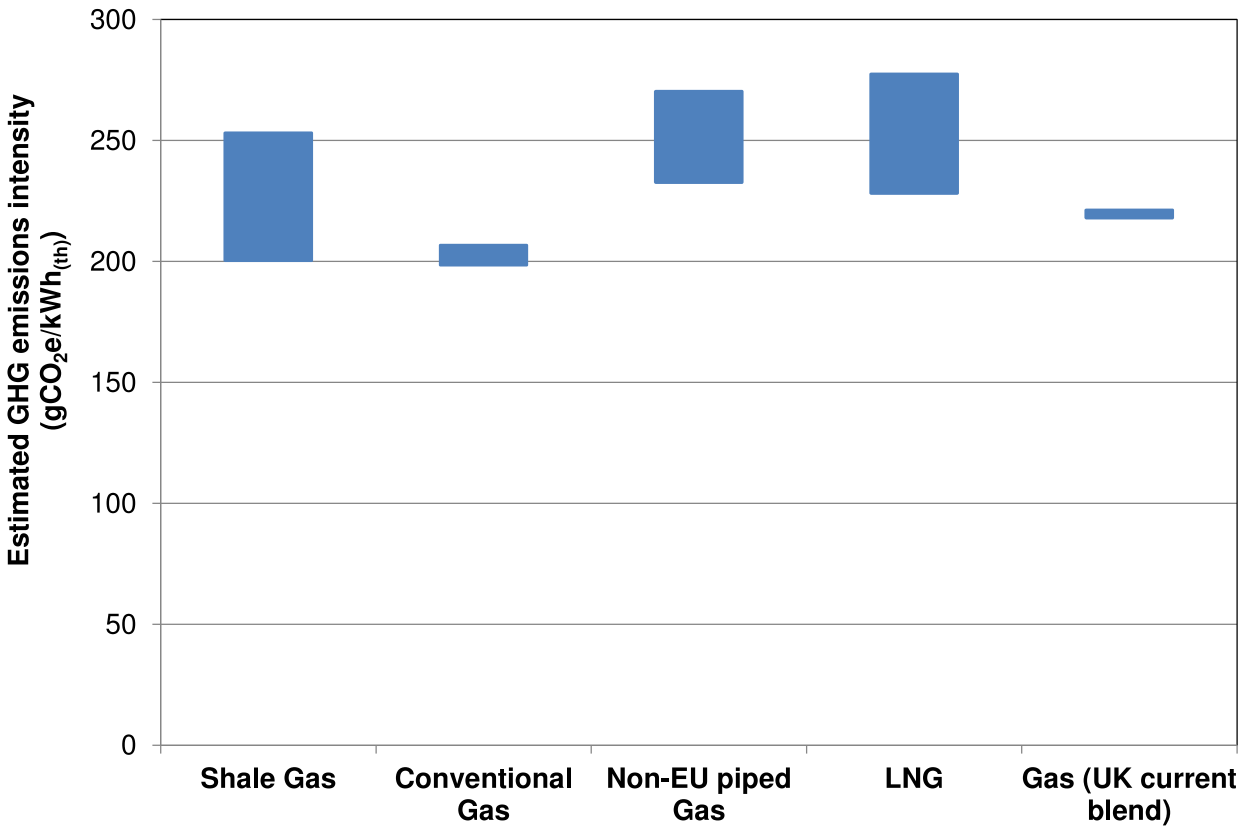

Figure 6: Estimated greenhouse gas (GHG) emission intensity for various sources of gas including combustion emissions. For shale gas the emissions intensity depends on the assumed completion method; here it has been assumed that methane released during completion would be 90% captured and flared.

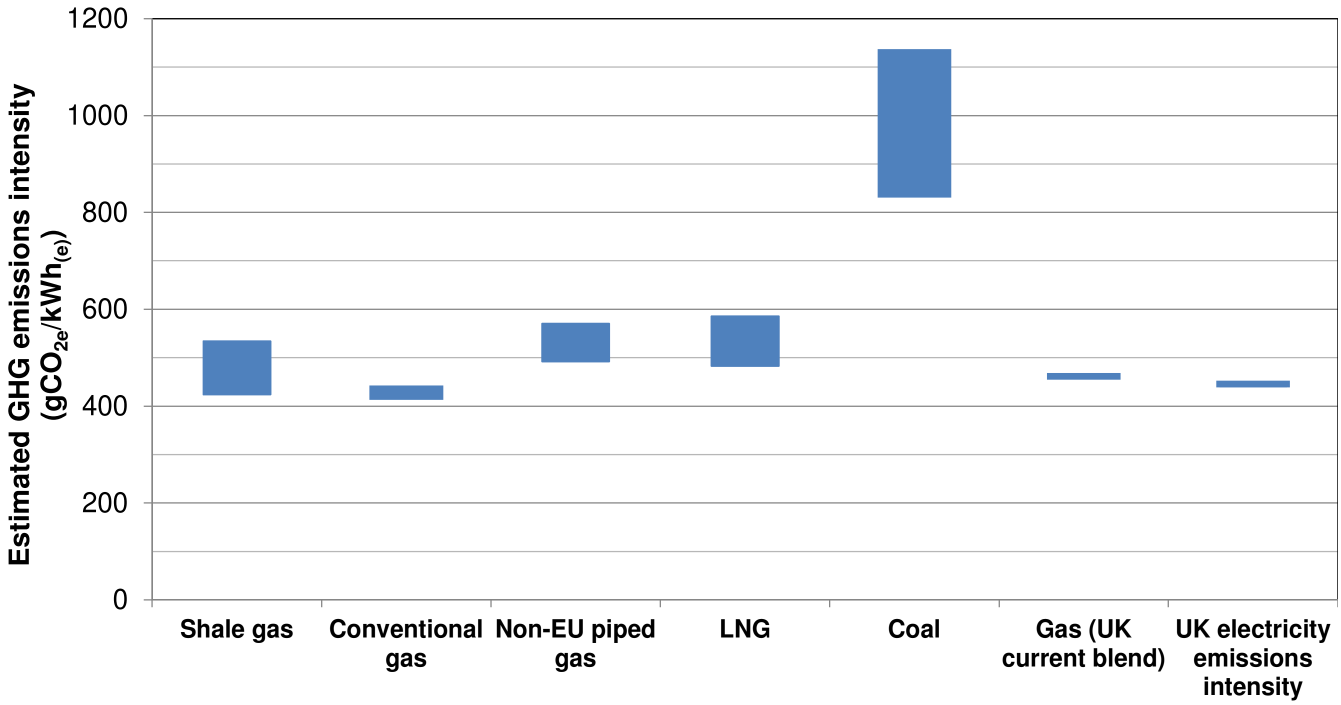

Figure 7: Comparison of the life-cycle emissions for the production of electricity from various sources of gas, and coal. For further information see Appendix C.

77. As long as venting scenarios are excluded, the data indicate that the total carbon footprint of shale gas exploration, extraction and transmission and use is likely to be similar to that of gas derived from conventional wells in the UK, LNG and non-EU piped gas. All gas sources are likely to be significantly less polluting, in terms of emissions per unit energy produced, than coal.

Shale gas use's influence on UK and global emissions rates

78. The effect of a given level of UK production of shale gas on emissions, whether in the UK or globally, will vary over time. Most of the effects arise through changes in (relative) prices affecting demand for and supply of gas and other fuels, especially coal, given the substitutability of gas and coal in electricity generation. In the longer term, price changes may cause changes in investment in alternate supplies of gas, changes in investment in competing energy sources, and changes in investment in demand-side efforts such as efficiency measures. Therefore, the effects on emissions will vary over time in ways that are challenging to predict.

79. The short-term effect of shale gas use on emissions depends on the price of the shale gas relative to LNG imports and relative to coal. In the USA, over the last four years, the price of shale gas has been low enough (Figure 8) that LNG imports to the USA have declined, and there has been a significant switch from coal to gas in electricity production. This switch has significantly reduced the USA's emissions rate. An IEA report[49] states:

---

[49] http://www.iea.org/newsroomandevents/news/2012/may/name,27216,en.html

"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, higher oil prices and the economic downturn which has cut vehicle miles travelled) and a substantial shift from coal to gas in the power sector."

80. Globally, however, the USA's switch from coal to gas has been accompanied by an opposite effect: the reduction in coal demand in the USA has led to exports of coal to other regions, including Europe, where the carbon intensity of electricity production has increased. Coal's share in UK power generation increased from a low of 27% in 2009 to 39% in 2012 (with total generation falling just 3.6%)[50]. The longer-term effect of the USA's shale gas boom on global markets and investment decisions is yet to be seen.

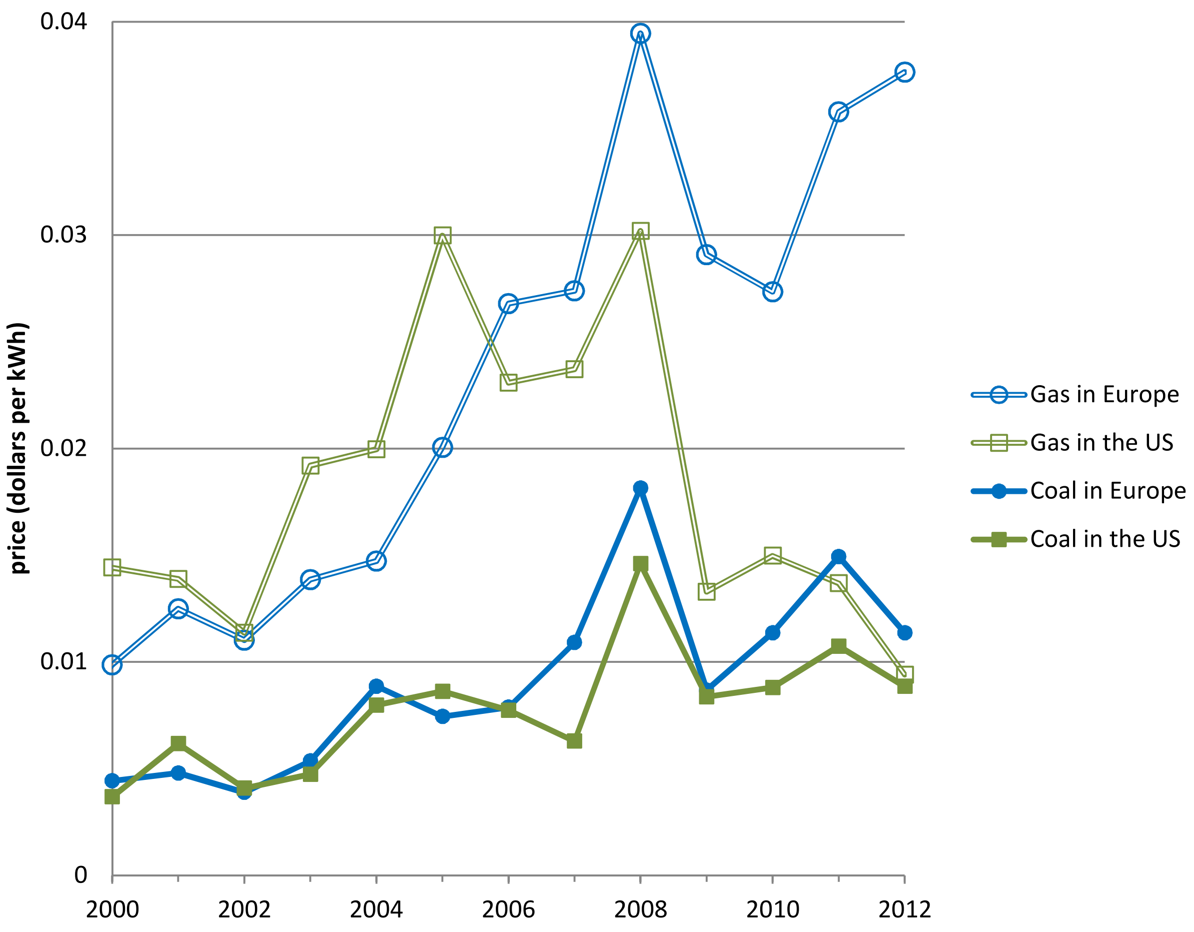

Figure 8: Recent history of gas and coal prices in the USA and Europe.[51]

81. Expert views differ on the overall effect that shale gas production would have on global emission rates. At one end of the spectrum it is argued that shale gas enables a switch from coal to gas, which has lower carbon intensity and thus reduces emissions.[52] At the other end of the spectrum it is argued that, in an energy-hungry world "it is difficult to envisage a situation other than shale gas largely being used *in addition* to other fossil fuel

---

[50] https://www.gov.uk/government/publications/electricity-section-5-energy-trends

[51] Data from BP: http://www.bp.com/sectiongenericarticle800.do?categoryId=9037181&contentId=7068643, converted to dollars per kWh using 1 million Btu = 293 kWh and assuming 8139 kilowatt hours per tonne of coal.

[52] Written evidence from Scotia Gas Networks and Shell. House of Commons Energy and Climate Change Committee "Shale Gas Fifth Report of Session 2010–12 Volume II, Additional written evidence"

reserves and adding a further carbon burden."[53] One might hold the first view if one believed that total final energy demand is relatively insensitive to price. One might hold the second view if one believed that energy demand is being constrained by high prices, with rents accruing to suppliers, and that a technological breakthrough which lowers costs and prices would allow more overall energy demand to come forward. The truth must lie somewhere between these two views; the effect of additional gas depends on the price-elasticities of demand and supply of gas and coal, on transport costs, and on the substitutability of gas and coal in different regional markets.

82. We now discuss the question "what is the effect on global emissions of putting into play a large gas reserve in Europe?" (We emphasize that our consideration of this scenario does not imply whether or not it is judged likely to come to pass.) We have not found in the open literature an explicit quantitative answer to the question, but there are several reports that address similar questions for the USA, from which we can make tentative extrapolations for the European question.

83. A background paper by Brown, Gabriel, and Egging (2010)[54] modelled five scenarios for the USA, with different levels of natural gas availability and with different climate policies, using NEMS-RFF, which is a version of the US Department of Energy's National Energy Modelling System. Brown, Gabriel and Egging ask whether more-abundant natural gas might reduce CO_2 emissions in the USA and whether it might lower the cost of policies to reduce USA CO_2 emissions. The climate policy they modelled was similar to the Waxman-Markey[55] proposals. Brown, Gabriel, and Egging find that, *without* low-carbon policies (such as cap-and-trade system or a carbon tax), more-abundant natural gas does not reduce CO_2 emissions. The paper states "Although greater natural gas resources reduce the price of natural gas and displace the use of coal and oil, they also boost overall energy consumption and reduce the use of nuclear and renewable energy sources for electric power generation. As a result, projected CO_2 emissions are almost one per cent higher [in 2030]." On the other hand, with appropriate carbon policies in place, they find that natural gas "can play a role as a bridge fuel to a low-carbon future". In their model, the price of CO_2 allowances falls slightly when natural gas is more abundant, so the cost of the climate policy is slightly reduced. Brown, Gabriel, and Egging emphasise the importance of developing policies (such as carbon pricing) that are robust across different projected futures.

84. Jacoby, O'Sullivan, and Paltsev (2012)[56] describe similar results using the MIT Emissions Prediction and Policy Analysis model. They study scenarios with and without economically-extractable shale gas, and with or without two alternative climate policies: (a) a mild regulatory policy, which mandates a renewable energy standard (25% of electricity by 2030) and retirement of 50% of coal plants by 2030; and (b) a more stringent policy that applies an emissions price to meet an emissions target of a 50% reduction by 2050. Jacoby, O'Sullivan, and Paltsev find, in the mild climate-policy scenario (a), that the shale resource boosts economic growth and increases energy use. Shale gas is found to increase emissions: whereas with no shale gas, emissions in this policy scenario would

[53] Has US Shale Gas Reduced CO_2 Emissions? Examining recent changes in emissions from the US power sector and traded fossil fuels, October 2012. Dr John Broderick & Prof Kevin Anderson, Tyndall Manchester, University of Manchester http://www.tyndall.ac.uk/sites/default/files/broderick_and_anderson_2012_impact_of_shale_gas_on_us_energy_and_emissions.pdf
[54] Brown (2011) "Abundant Shale gas Resources: Some Implications for Energy Policy", *Resources for the Future*. http://www.rff.org/Documents/Features/NEPI/RFF-BCK-Brownetal-ShaleGas.pdf.
[55] H.R.2454 American Clean Energy and Security Act of 2009 http://thomas.loc.gov/cgi-bin/bdquery/z?d111:H.R.2454:
[56] Jacoby et al. (2012), "The Influence of Shale Gas on U.S. Energy and Environmental Policy," *Economics of Energy and Environmental Policy*, 1(1), 37-51

reduce by 2% below 2005 levels by 2050, shale gas availability causes the modelled emissions to increase by 13% over 2005 by 2050. In the more-stringent policy scenario (b), emissions are cut by 50%, by definition, with or without the shale gas resource, but the pace of technology development is strongly affected by the shale resource: with the shale resource in play, gas CCS (carbon capture and storage) is developed earlier, coal CCS is developed significantly later, and the rate of market penetration of renewables is reduced. The paper warns that a gas "revolution" might temporarily reduce interest in low-emission technologies such as CCS, which nonetheless *are* needed in the long run: "in the shale boom there is the risk of stunting these programs altogether." Summarising their work, Henry Jacoby said "People speak of gas as a bridge to the future, but there had better be something at the other end of the bridge."

85. This warning about technology development is echoed by Harvard Professor of Geology, Environmental Science and Engineering, Daniel Schrag (2012).[57] Schrag warns that even if a shale gas boom might reduce short-term greenhouse gas emissions, the availability of low-price gas might reduce investment in energy efficiency and in the research, development, and deployment of truly low-carbon technologies, including renewable energy, nuclear power, and carbon capture and storage, leading to an increase in long-term emissions and cumulative emissions. Schrag's analysis is not quantitative, but he argues that, from the climate perspective, the negative impacts of cheap, abundant natural gas on innovation appear to outweigh the benefits of a marginal reduction in emissions from reduced coal consumption. He suggests that these negative impacts could be avoided by introducing a significant price on carbon, which would benefit renewables, nuclear power, energy efficiency, and natural gas, which would be favoured over coal.

86. Two papers from the Tyndall Centre discuss the climate change impact of shale gas and analyse the recent historical impact of US shale gas on emissions.[58] Broderick et al. (2011), like Schrag (2012), warn that shale gas in the UK might reduce investment in much-lower carbon energy supply, and suggest that under the UK's Copenhagen Accord commitments, shale gas "offers no meaningful potential even as a transition fuel", unless allied with carbon capture and storage technologies "as yet unproven at a large scale". In a world with no carbon constraint, they argue that shale gas exploitation is likely to lead to increased energy use and increased emissions. Shale gas use in countries that have a carbon cap *might* lead to a reduction in global emissions, but it might lead to an overall increase. Indeed, pointing to IEA and US Energy Information Administration projections, Broderick et al. (2011) suggest the latter outcome is the more likely: without significant pressure to reduce carbon, "additional fossil fuel resources that are exploited will be used in addition to existing resources". For this not to be the case, Broderick and Anderson (2012) continue, "consumption of displaced fuels must be reduced globally and remain suppressed indefinitely; in effect displaced coal must stay in the ground. The availability of shale gas does not guarantee this." While the US's domestic consumption of coal has declined since 2007, the displaced US Coal has *not* stayed in the ground to the same degree; rather, the USA's net coal exports have increased substantially. Broderick and Anderson (2012) suggest that more than half of the emissions avoided over the period 2008-2011 thanks to coal-to-gas switching (645 $MtCO_2$) were displaced outside the US via coal exports (338 $MtCO_2$).

[57] Schrag (2012), "Is Shale Gas Good for Climate Change?", *American Academy of Arts & Sciences*, 142(2), 72-80. http://www.mitpressjournals.org/doi/abs/10.1162/DAED_a_00147
[58] Broderick et al (2011) "Shale gas: an updated assessment of environmental and climate change impacts"; Broderick and Anderson (2012) "Has US Shale Gas Reduced CO_2 emissions?".

87. The UK is much smaller than the USA, and European energy markets are different, so we extrapolate from the American studies with caution. That said, if shale gas were extracted in the UK, and if the price of shale gas were low enough, one would expect, as in America, (a) an increase in demand for gas; (b) a switch of electricity production from coal to gas; and (c) that UK shale gas production would substitute for a mix of UK production and imports, the latter of which could be by pipeline from Norway or the Continent or as LNG. Because the UK has strong links to the North West European gas market, production from unconventional gas in the UK alone is unlikely to have a significant impact on the wider European market price[59] so the increase in gas demand and the coal-to-gas substitution are expected to be small. The first-order effect of the switch of electricity production from coal to gas would be to reduce the emissions-rate of the electricity production sector. Since this sector falls within the emissions trading scheme, there might be no effect on the overall emissions rate in the EU ETS (the reduction in electricity emissions would cause the value of emissions permits to fall slightly, and emissions-reduction effort in other sectors in the EU ETS would decline such that the emissions rate remained at the level set by the cap). On the other hand, governments might choose to tighten the emissions cap, which would mean that shale-gas use led to a reduction in the EU's emissions rate. The effect of a switch from imported LNG to domestically-produced gas on domestic emissions rates is expected to be small. Paragraph 76 indicates that there is probably only a small difference in emissions-intensity between LNG and well-regulated shale gas extraction. Moreover, if shale gas production in the UK produced any significant emissions, then those emissions would fall within the UK's emissions cap, so the on-shoring of gas production into the UK would tend to force other reductions in emissions. But these production-emission effects are expected to be small compared with the emissions associated with gas use. The short-term and long-term effects of shale gas exploitation in the UK on global emissions rates are complex to predict, and depend strongly on global climate policies. In the absence of global climate policies, we believe it is credible that shale-gas use would increase both short-term and long-term emissions rates.

Shale gas use's influence on *cumulative* global emissions

88. What really matters, for long term global temperature rise, is not rates of emissions but cumulative global emissions of carbon over all time. [60,61]. If a country brings any additional fossil fuel reserve into production, then in the absence of strong climate policies, we believe it is likely that this production would increase cumulative emissions in the long run. This increase would work against global efforts on climate change. This potential issue is not specific to shale gas and would apply to the exploitation of any new fossil fuel reserve.

89. Society could counteract this tendency, and ensure that additional fossil fuel exploitation does not increase cumulative emissions, in several ways. We first describe what would

---

[59] Gas hubs in north-west Europe are closely integrated. Any analysis of future scenarios must consider the UK gas market as part of a north-west European market with far greater traded volumes than if the UK were isolated. The IEA forecasts European natural gas demand to reach 669 bcm per year in 2030 (New Policies Scenario). There are a wide range of external forecasts for UK shale gas production. The Institute of Directors has published a high forecast of 39.3 bcm in 2030 Directors ("Getting shale gas working", IoD, 2013, www.iod.com/.../IoD_Getting_shale_gas_working_MAIN_REPORT.pdf). This estimate is 6% of European gas demand. The impact on prices is highly uncertain at this stage. Analysis from Bloomberg New Energy Finance suggests that "the cost of shale gas extraction in the UK is likely to be significantly higher than in the US, and the rate of exploitation insufficient to offset the decline in conventional gas production, meaning market prices will continue to be set by imported gas". http://about.bnef.com/press-releases/uk-shale-gas-no-get-out-of-jail-free-card

[60] Allen et al. (2009), "Warming caused by cumulative carbon emissions towards the trillionth tonne", *Nature*, 458, 1163 – 1166. http://www.nature.com/nature/journal/v458/n7242/abs/nature08019.html.

[61] Meinshausen et al. (2009), "Greenhouse-gas emission targets for limiting global warming to 2C", *Nature*, 458, 1158-1162. http://www.nature.com/nature/journal/v458/n7242/full/nature08017.html.

need to happen physically, and then for each physical action we discuss the sorts of approaches that have been suggested in relation to those technologies by bodies such as the Intergovernmental Panel on Climate Change, the UK's Committee on Climate Change, and the Royal Society. We emphasize that in noting this range of approaches to the issue, it is not our intention here to recommend any particular policies; policies would clearly be a matter for the individual governments involved. Three broad categories of measures exist:

a. **CCS activity** proportional to the additional fossil fuel extraction. Increasing efforts to develop carbon-capture technology was one of the recommendations of the House of Commons Energy and Climate Change Committee in its Shale Gas Report[62]. As an indication of scale, for every 100 bcm of gas extracted over 20 years, one would need roughly three CCS power stations[63], and an extra 200 Mt of CO_2 storage. An increase in CCS activity could be driven by targeted **technology support** or through higher **carbon prices**; higher carbon prices themselves could be supported by **international agreements** on carbon prices or emissions targets.

b. **Negative emissions technologies**[64] (for example, reforestation; direct air-capture (e.g. artificial trees) with carbon storage; or enhanced weathering of rocks)). Most of the IPCC's emissions scenarios that are expected to keep below 2.8^{o}C the global mean temperature rise above pre-industrial at equilibrium (assuming the "best estimate" of climate sensitivity) involve the deployment of negative emission technologies during this century[65]. A paper in a Special Issue of the journal Climatic Change[66] says that "without the possibility of negative emissions, pathways meeting the 2^{o}C target with high probability need almost immediate emission reductions or simply become infeasible"[67]. However, for most negative emissions technologies, current understanding of the costs, feasibility, environmental impacts and societal impacts is limited and considerable research is needed[68]. As an indication of scale, the combustion of 100 bcm of gas could be neutralised by permanently reforesting 5500 km^2 of deforested land. Alternatively, the same emissions could be neutralised over 20 years by 20,000 artificial trees each the size of a shipping container, with a combined heat and power demand of roughly half a zero-carbon power station,[69] and 200 Mt of CO_2 storage. Reforestation might be delivered by international agreements on land use and forestry. An increase in the deployment of other negative emissions technologies could be driven by **targeted technology support** or through higher **carbon prices**, as long as there is a coupling of the price of positive emissions to payments for negative

[62] http://www.publications.parliament.uk/pa/cm201012/cmselect/cmenergy/795/795.pdf - Shale Gas Fifth Report of Session 2010–12 Volume I: Report, together with formal minutes, oral and written evidence: "The emergence of shale gas—and the likelihood that it will lead to the increased use of gas in power plants—means that we need to pursue with increased urgency the development of carbon capture technology suitable for gas as well as coal."

[63] 5 bcm/year, at 50% efficiency, delivers about 26 TWh(e)/year, and one "average power station" delivers about 8.8 TWh(e)/year; 1 bcm of gas creates 2 $MtCO_2$ on combustion.

[64] http://royalsociety.org/policy/publications/2009/geoengineering-climate/

[65] Climate Change 2007: Working Group III: Mitigation of Climate Change. Summary for policy makers, section D. https://www.ipcc.ch/publications_and_data/ar4/wg3/en/spmsspm-d.html

[66] Climatic Change, May 2013," Special Issue: Science and Policy of Negative Emission Technologies", *Climate Change*, 118(1), http://link.springer.com/journal/10584/118/1/page/1

[67] van Vuuren et al. (2013), "The role of negative CO_2 emissions for reaching 2C - insights from integrated assessment modelling", *Climatic Change*, 118(1), 15-27. http://link.springer.com/article/10.1007/s10584-012-0680-5#

[68] Massimo Tavoni and Robert Socolow. Modeling meets science and technology: an introduction to a special issue on negative emissions. Climatic Change (2013) 118:114. DOI 10.1007/s10584-013-0757-9

[69] The energy demand of artificial trees is uncertain; here we have assumed 0.5 kWh of low-grade heat and electricity are required per kg of CO_2 captured.

emissions. Given geographical and geological differences between countries, it might be most cost-effective for society if such a coupling enabled a country to pay for negative emissions outside its own borders.

c. Leaving other fossil fuel reserves that would have been exploited under business-as-usual in the ground. This outcome might be achieved in various ways. Governments could invest in **innovation support** to drive down the costs of "clean technologies" sufficiently that low-carbon technologies become cheaper than fossil fuels. Demand for fossil fuels is driven by prices, so **tax measures** could be employed that counter the changes in prices induced by the additional reserves. **International agreements** could be put in place that ensure (through carbon prices or other mechanisms) that the cumulative emissions of carbon over all time are capped.

Because of the complex and non-linear relationships involved, there is a clear need for systems thinking in this area.

Impact on the ease of achieving UK GHG targets

90. Under international reporting obligations, the UK is required to prepare a greenhouse gas inventory on an annual basis. This provides detailed estimates of the UK's greenhouse gas emissions measured on a "territorial" basis and includes only the emissions which occur within the UK's territorial borders. The inventory is used as the basis for our reporting to the European Commission (EC) and United Nations Framework Convention on Climate Change (UNFCCC), and also for reporting against the UK's own Carbon Budgets.

91. Any local GHG emissions from shale gas operations would fall within the non-traded sector of the UK's carbon budgets. If the carbon budget imposes a binding constraint, any increase in emissions associated with domestic shale gas operations would have to be offset by emission cuts elsewhere in the economy. This increase in emissions accounted to the UK would be an example of on-shoring; bringing production, and any emissions associated with production, back to the UK and displacing imported LNG. In the UK, shale gas operations are expected to be subject to a stricter environmental regime compared with many other locations in the world.

92. The net impact on emissions would depend on the fuel that shale gas displaces and the degree to which price changes increase energy demand. If the displaced fuel has higher carbon intensity than shale gas, then in the absence of price changes the emissions are likely to decrease, assuming fugitive methane emissions from shale gas extraction are minimised. On the other hand, if the fuel displaced by shale gas is of equal or lower carbon intensity than shale gas, emissions are likely to increase. Using CCS on shale gas power generation (or any other uses of gas) would of course help meet climate targets.

Emissions minimisation and monitoring

93. We recommend that operators should assess and manage risks from fugitive and vented methane emissions throughout the exploration, pre-production and production of shale gas according to the principle of reducing risks to as low as reasonably practicable (ALARP).

94. It is credible that shale gas exploration in the UK is likely to result in *some* GHG emissions of methane at or around the exploration site; we need to better understand the potential scale of these emissions. Consent to either vent or flare methane is required from DECC, which already requires that these emissions are minimised. We consider that consent for other emissions should only be granted if there is no other practical option or if the emissions are required for safety reasons.

95. DECC, industry regulators, and the UK Onshore Operators Group have developed guidelines for shale gas operations[70], which set out good practice for minimising fugitive emissions. The guidelines state that:

> "Operators should plan and then implement controls in order to minimise all emissions. Operators should be committed to eliminating all unnecessary flaring and venting of gas and to implementing best practices from the early design stages of the development and by endeavouring to improve on these during the subsequent operational phases."

96. GHG emissions are just one part of potential environmental impacts from shale gas exploitation. Other potential environmental impacts such as the release of pollutants to air, water and land are being considered separately, and are outside the scope of this study.

Emissions reporting and monitoring

97. Under the UK's international GHG reporting obligations, DECC is required to include in the greenhouse gas inventory accurate estimates of fugitive methane emissions from any fossil fuel activities carried out within UK territory.

98. As previously discussed, there is a large degree of uncertainty surrounding the GHG emissions from shale gas exploration, pre-production, production, processing and post-production. Uncertainty is not confined to estimates of emissions from shale gas operations. Estimates of operational methane emissions from other fossil fuel extractive operations are also uncertain[71].

99. The majority of estimates of methane emissions from shale gas operations are based on engineering calculations and approximately measured gas flows. As yet no comprehensive study has been published that measures and verifies emissions from a wide variety of wells and shale formations.

100. The Environment Agency's latest approach to permitting of shale gas exploration sites will consider releases to air within environmental impact assessments (EIAs) required by the Mineral Planning authority. The Agency will review the EIAs for individual sites in order to determine if there is a need to quantify their releases, and if so it may require that monitoring or other methods are used for that purpose. The Environment Agency's latest approach is to harmonise its regulation of all onshore sites for exploration and production of oil or gas, so that the regimes for "conventional" and "unconventional" sites are similar. The Environment Agency is reviewing the considerations to be addressed when quantifying fugitive methane releases to air from shale gas exploration sites. This review will help

[70] http://www.ukoog.org.uk/elements/pdfs/ShaleGasWellGuidelines.pdf
[71] Ricardo-AEA, Methane GHG Inventory summary Factsheet, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/210502/12_Methane.pdf

design appropriate monitoring regimes and identify situations where generic emission estimates may be used, or where they may need to be developed.

101. While it may be possible to estimate GHG emissions from UK sites on the basis of experience in other countries, this experience may not be directly transferable to the processes, controls, and specific hydro-geological regimes applicable in the UK. We therefore consider that the best and most responsible approach to estimating these emissions will be by making in-situ measurements of GHG emissions at and around each gas exploration site.

102. Because the industry is in the early stages of development, the UK is in a strong position to comprehensively measure GHG emissions and potentially relate them to the geological conditions. It is recommended that a detailed pilot programme is set up at one or more sites, to establish the geological conditions within the shale formation and to identify when and where emissions are released and in what quantities. The information obtained from such a programme of study could then be used to design detailed studies at further sites. The monitoring should continue for an extended period to take into account emissions during production, workover and liquid unloading.

103. It is recommended that the research is independent and managed jointly between government and industry. The results should provide satisfactory evidence on whether regulatory monitoring should be mandatory and the type of monitoring required or whether it is possible to produce generic emission factors linked to each process stage and geology, which would enable emissions to be accurately estimated on other shale gas wells. The emissions data should also be used to guide improvements, such as in equipment or technology, required to ensure that all stages of shale gas exploitation use the ALARP principle for minimising emissions.

Conclusions and recommendations

104. There has been no production of shale gas in the UK and only limited exploration. There are almost no data on fugitive emissions of GHG from shale gas operations in the UK. There are increasing data on GHG emissions from shale gas operations in the USA and a small number of analytical studies, including estimates of the carbon footprint of shale gas.

105. We have used these US studies to estimate the potential for fugitive emissions from shale gas in the UK, with the understanding that actual emissions will vary according to local circumstances and that we must be cautious when extrapolating results. We have gathered available information on the carbon footprint of shale gas to inform our estimate of the potential impacts of shale gas exploration, extraction and use in the UK on UK climate change objectives.

Conclusions

106. With the right safeguards in place, the net effect on UK GHG emissions from shale gas production in the UK will be relatively small.

107. The production of shale gas could increase global cumulative GHG emissions if the fossil fuels displaced by shale gas are used elsewhere. This potential issue is not specific to shale gas and would apply to the exploitation of any new fossil fuel reserve.

108. The potential increase in cumulative emissions could be counteracted if equivalent and additional emissions-reduction measures are made somewhere in the world. Such measures are well established in the scientific and policy literature and include: carbon capture and storage; carbon offsetting through additional reforestation or negative emissions technologies that reduce CO_2 concentrations; and other measures that would lead to fossil fuel reserves, that would have been developed under business-as-usual, remaining in the ground. The view of the authors is that without global climate policies (of the sort already advocated by the UK) new fossil fuel exploitation is likely to lead to an increase in cumulative carbon emissions and the risk of climate change. We would strongly encourage continued efforts from the UK and internationally to address this issue, proportionate to the emissions involved.

Recommendations

109. We recommend:

a. in managing fugitive, vented or flared methane throughout the exploration, pre-production and production of shale gas, operators should adopt the principle of reducing emissions to as low a level as reasonably practicable (ALARP). In particular, “reduced emissions completions” (REC) or “green completions” should be adopted at all stages following exploration. Government should discuss with regulators appropriate mandatory requirements to be applied at each stage to ensure that the best technology is implemented in all cases;

b. shale gas exploration and production in the UK should be accompanied by careful monitoring and inspection of GHG emissions relating to all aspects of exploration, pre-production and production, at least until any particular production technique is well understood and documented in the context of UK usage (see Research, below);

c. thereafter operators should monitor their sites to: (1) ensure early warning of unexpected leakages; and (2) obtain emissions estimates for regulators and government;

d. shale gas production in the UK should be accompanied by research into development of more effective extraction techniques, such as improved reduced emission completion (REC) and self-healing cements, which minimise wider environmental impacts including whole-life-cycle GHG emissions;

e. government and industry should actively pursue new techniques to minimise GHG emissions associated with exploration, pre-production and production of shale gas and also reduce the impact on local environment and infrastructure;

f. the shale gas industry should research methods to minimise water demand and vehicle movements, so as to reduce greenhouse gas emissions and the impact on local infrastructure;

g. there should be a detailed scientific research programme of methane measurement, aimed at better understanding and characterising sources and quantities of methane emissions associated with shale gas operations; and

h. this research programme should be independent and managed jointly between government and industry. The research should aim, for example, to reduce uncertainty associated with estimates of local methane emissions from shale gas operations and also to guide the optimisation of regulatory monitoring. The research could also provide information on the effectiveness of operators' actions to minimise methane emissions.

APPENDICES

APPENDIX A: Life-cycle emissions from shale gas

108. This section provides further detail on the GHG emissions associated with each stage of shale gas pre-production and explores points of discussion not already mentioned in the main body of the report.

Exploration

109. The exploration of shale gas involves two stages. The first stage includes drilling a well and taking core samples which are examined for hydrocarbons. The second stage involves flow testing, where the well is hydraulically fractured and the flow of gas recorded to test whether the well is considered commercial. In the UK, any releases of methane in either stage would be flared or put to commercial use[72].

110. There is little information available on emissions associated with exploration. Emissions from drilling and flow testing are expected to be small in comparison to the total life-cycle emissions.

Site preparation

111. Jiang et al. (2011) and Santoro et al. (2011)[73] have calculated emissions from site preparation, concluding that these emissions are negligible. These studies omit emissions from transportation of the drill rig (which we class as part of site preparation). These transport emissions have been investigated in NYSDEC (2011) and shown to be significantly lower than the other emissions from site preparation.

Table A 1: Estimates of Site Preparation Emissions.

Source	Emission Estimate (tCO_2e per well)	Notes
Jiang et al. (2011)	300 – 360	Site preparation, excluding drill rig transportation
Santoro et al. (2011)	158	Site preparation, excluding drill rig transportation
NYSDEC (2011)	15	Transportation of the drill rig only

112. Broderick et al. (2011)[74] refer to plans by Cuadrilla for exploration and production from the Bowlands Shale in the UK. Cuadrilla's planning application quoted a well pad size of 0.7 ha, containing 10 wells. This size of pad is considerably smaller than that assumed by both Jiang et al. (2011) and Santoro et al. (2011), which were based on US data, therefore the site-preparation emissions may be lower in the UK. But at the present early stage of exploration, the spatial footprint of future UK production operations is unknown.

[72] http://www.ukoog.org.uk/elements/pdfs/communityengagementcharterversion6.pdf
[73] Santoro et al. (2011), "Indirect Emissions of Carbon Dioxide from Marcellus Shale Gas Development", a technical report from Cornell University
[74] Broderick et al. (2011), "Shale gas: an updated assessment of environmental and climate change impacts", a report by researchers at the Tyndall Centre, University of Manchester

Drilling and fracking

113. Table A2 shows the range of emissions associated with drilling and fracking, which appears to be governed by the range of assumed power requirements for the drill and pump and the time required for completion. The estimate from Broderick et al. (2011) is lower than the other estimates, particularly for drilling. This can in part be attributed to that study only considering additional sources of emissions compared to conventional production. The results do not include the emissions from off-site transport of the fracking fluids.

Table A 2: Emissions associated with drilling and fracking a shale gas well.

Source	Emission Estimate (tCO_2e per well)[75]	Notes
Jiang et al. (2011)	610 – 1100	Drilling
	230 – 690	Fracking
	840 – 1790	**Total**
Santoro et al. (2011)	**1426**	Drilling and fracking
Stephenson et al. (2011)[76]	**711**	Drilling and fracking
Broderick et al. (2011)	49 – 74	Drilling
	295	Fracking
	344 – 369	**Total**
NYSDEC (2011)	277	Drilling
	379	Fracking
	656	**Total**

Chemicals

114. Hydraulic fracturing requires the addition of chemicals and proppant (sand), the production and transport of which both have associated emissions. Jiang et al. (2011) estimate the associated emissions to be up to 300 tCO_2e per well.

Well completion

115. Table A3 shows the range of emissions associated with flowback. An outlying result is the estimate by Howarth et al. (2011) for emissions from well completion in Haynesville, which is almost six times greater than the next highest (O'Sullivan and Paltsev (2012)), notably also an estimate of emissions from Haynesville.

[75] Some calculations were carried out on the data provided in literature in order for it to be presented consistently in this table

[76] Stephenson et al. (2011), "Modelling the Relative GHG Emissions of Conventional and Shale Gas Production", *Environmental Science & Technology*, *45* (24), 10757–10764. http://pubs.acs.org/doi/abs/10.1021/es2024115

Table A 3: Flowback emissions estimates, based on a methane GWP of 25. These are for the entire volume of gas released during flowback and do not take into account various completion options to reduce emissions.

Source	Site	Volume of Gas released during flowback ($x10^3$ m^3 per well)	GHG emissions (tCO_2e per well)
Jiang	Marcellus	603	9100
Howarth	**Haynesville**	**6800**	**102 000**
Howarth	Barnett	370	5600
EPA	Various	260	3900
O'Sullivan and Paltsev	Haynesville	1180	18 000
O'Sullivan and Paltsev	Barnett	273	4100
O'Sullivan and Paltsev	Fayetteville	296	4400
O'Sullivan and Paltsev	Marcellus	405	6100
O'Sullivan and Paltsev	Woodford	487	7300

116. The estimate by Howarth et al. (2011) for Haynesville was based upon gas flow-rate data for 10 well tests. The interpretation of these data has been criticised in a number of studies. Cathles et al. (2012)[77] argue that the assumption by Howarth et al. (2011), that the initial production gas flow-rate can be assumed to be the same as the gas entrained in the flowback fluid, is incompatible with the basic physics of shale gas production, because the initial production gas flow-rate is the highest flow achievable from the well head, therefore when the gas is mixed with substantial volumes of flowback fluid, the flow of gas must be lower (this could also apply to the estimate by Jiang et al. (2011)). It is also argued that the volumes of gas allegedly vented by this site would represent $1,000,000 worth of gas and lost revenue, as well as a fire or explosion hazard that no company would countenance (Cathles et al. 2012). Further criticism is made by IHS (2011)[78], a commercial organisation, whose report was cited by Howarth et al. (2011) as the source of the Haynesville data. IHS (2011) state that Howarth et al. (2011) made an "improper calculation of the average of the individual well flow rates" and an "improper attribution of the (improperly calculated) average flow rates from all the wells as occurring during flow-back operations".

[77] Cathles et al. (2012), "A commentary on "The greenhouse gas footprint of natural gas in shale formations" by R.W. Howarth, R. Santoro, and Anthony Ingraffea", *Climate Change*, 113(2), 525-535. http://link.springer.com/article/10.1007/s10584-011-0333-0#.
[78] Mismeasuring Methane: Estimating Greenhouse Gas Emissions from Upstream Natural Gas Development. http://www.ihs.com/images/MisMeasuringMethane082311.pdf

117. Howarth et al. (2012)[79] produced a rebuttal to Cathles, standing by their conclusions, and suggested that further work is required to truly understand GHG emissions from shale gas production and that regulations should be put in place to ensure emissions are kept to a minimum.

Appendix B: Life-cycle emissions from production and processing of shale gas

118. In the absence of information about the quality of the UK's shale gas we have assumed that shale gas would produce similar emissions to those in the production and processing of conventional gas.

119. The Digest of UK Energy Statistics estimates the GHG emissions associated with conventional gas production and processing including combustion sources offshore and at terminals, and the fugitive sources and gas production flaring and venting to be 100 tCO_2e per million m^3. This equates to 9 gCO_2e/kWh, and is in the range given in other studies.

- Howarth et al. (2011): 8.0 gCO_2e/kWh
- Stephenson et al. (2012): 15 gCO_2e/kWh
- Skone (2011): 13 gCO_2e/kWh

Appendix C: Life-cycle emissions of various sources of gas and coal

120. This section provides the data used in the comparison between various sources of gas and coal.

[79] Howarth et al. (2012), "Venting and leaking of methane from shale gas development: response to Cathles et al.", *Climate Change*, 113 (2), 537-549. http://link.springer.com/article/10.1007/s10584-012-0401-0

Table A 4: Life-cycle emissions associated with natural gas production, liquefaction, and transportation, in units $gCO_2e/kWh_{(th)}$ of gas produced.

Source	Natural gas production	Liquefaction Process	Transport	Total
AEA (2012)	8.8	21	8.9	**38**
PACE (2009)[80]	3.3	25	20	**48**
Tamura et al. (2001)[81]	3.5	22	20	**46**
Skone (2011)	-	-	-	**66**
Reuther (2005)[82]	3.5	22	19	**45**
JRC Reference Report (2009)[83]	6.5	32	50	**89**
DEFRA[84]	-	-	-	**65**

Table A 5: Life-cycle emissions from conventional gas produced in North-West Europe, in units $gCO_2e/kWh_{(th)}$ of gas produced.

Source	Natural gas production	Natural Gas Processing	Transport	Total
GEMIS 4.8[85]	1.3	2.5	13	**17**
JRC Reference Report	-	-	-	**9**

[80] Life Cycle Assessment of GHG Emissions from LNG and Coal Fired Generation Scenarios: Assumptions and Results. http://www.lngfacts.org/resources/LCA_Assumptions_LNG_and_Coal_Feb09.pdf
[81] Tamura et al. (2001), "Lifecycle CO2 Analysis of City Gas and LNG", *Applied Energy*, 68 (3), 301–319
[82] Life-Cycle Analysis of Greenhouse Gas Emissions for Hydrogen Fuel Production in the United States from LNG and Coal, http://www.netl.doe.gov/energy-analyses/pubs/h2_from_coal_lng_final.pdf
[83] Liquefied Natural Gas for Europe – Some Important Issues for Consideration, http://ec.europa.eu/dgs/jrc/downloads/jrc_reference_report_200907_liquefied_natural_gas.pdf
[84] UK Government conversion factors for Company Reporting, version 1.1, Tables: WTT-Fuels, Water supply, Water treatment (Defra, 2013) http://www.ukconversionfactorscarbonsmart.co.uk/
[85] GEMIS 4.8, http://www.eea.europa.eu/data-and-maps/data/external/gemis-4.8

Table A 6: Life-cycle emission for Non-EU piped gas, in units $gCO_2e/kWh_{(th)}$ of gas produced.

Source	Natural gas production	Natural Gas Processing	Transport	Total
Lechtenböhmer[86] (2005)	-	-	-	**42**
Lechtenböhmer (2005)	-			**80**
GEMIS 4.8	3	10	59	**72**
JRC Reference Report (2009	-	-	-	**80**

Table A 7: Life-cycle emissions from coal for electricity production, in units of $gCO_2e/kWh_{(e)}$.

Source	Life-cycle Emissions
Koornneef et al.[87](2008)	837
Koornneef et al.(2008)	1092
Whitaker et al.[88] (2012)	890
Whitaker et al. (2012)	1130
DUKES (2012) and Defra emission factors	1047

86 Greenhouse Gas Emissions from the Russian Natural Gas Export Pipeline System , Wuppertal Institute, http://wupperinst.org/uploads/tx_wupperinst/1203-report-en.pdf

[87] Koornneef et al. (2008), "Life cycle assessment of a pulverized coal power plant with post-combustion capture, transport and storage of CO2", *International Journal of Greenhouse Gas Control*, 2(4), 448-476

[88] Whitaker et al. (2012), "Life Cycle Greenhouse Gas Emissions of Coal-Fired Electricity Generation Systematic Review and Harmonization", *Journal of Industrial Ecology*, 16 (S53–S72)

Appendix D: Scenario calculations

Table A 8: Emissions from pre-production and processing, assuming the methane released during flowback is 100% vented, including Howarth et al. (2011) Haynesville data.

Emissions (tCO_2e/Well)						
Stage	Pre-production emissions assumption	Maximum	95th percentile	Mean	Median	5th percentile
Site Preparation		360	351	208	229	36
Drilling and Hydraulic Fracturing		1790	1681	877	711	352
Well Completion		204680	137015	35699	12191	7983
Water/Wastewater Transport and Treatment		21	21	21	21	21
Chemicals		300	300	300	300	300
Pre-production Total		**207151**	**139368**	**37104**	**13452**	**8691**
	Productivity					
	High	14150	14150	14150	14150	14150
	Central	8490	8490	8490	8490	8490
	Low	5660	5660	5660	5660	5660
Emissions Intensity (gCO_2e/kWh(th))						
	Productivity					
	High	137	95	32	17	14
	Central	222	153	47	23	18
	Low	329	224	66	30	22

Table A 9: Emissions from pre-production and processing, assuming the methane released during flowback is 100% vented, excluding Howarth et al. (2011) Haynesville data.

Emissions (tCO_2e/Well)						
Stage	Pre-production emissions assumption	Maximum	95th percentile	Mean	Median	5th percentile
Site Preparation		360	351	208	229	36
Drilling and Hydraulic Fracturing		1790	1681	877	711	352
Well Completion		35518	29439	14576	11664	7963
Water/Wastewater Transport and Treatment		21	21	21	21	21
Chemicals		300	300	300	300	300
Pre-production Total		**37989**	**31792**	**15982**	**12925**	**8672**
	Productivity					
	High	14150	14150	14150	14150	14150
	Central	8490	8490	8490	8490	8490
	Low	5660	5660	5660	5660	5660
Emissions Intensity (gCO_2e/kWh(th))						
	Productivity					
	High	32	28	19	17	14
	Central	48	42	25	22	18
	Low	68	58	33	29	22

Table A 10: Emissions from pre-production and processing, assuming the methane released during flowback is 90% captured and flared, including Howarth et al. (2011) Haynesville data.

Emissions (tCO_2e/Well)						
	Pre-production emissions assumption	Maximum	95th percentile	Mean	Median	5th percentile
Stage						
Site Preparation		360	351	208	229	36
Drilling and Hydraulic Fracturing		1790	1681	877	711	352
Well Completion		48929	32745	8531	2914	1908
Water/Wastewater Transport and Treatment		21	21	21	21	21
Chemicals		300	300	300	300	300
Pre-production Total		**51400**	**35098**	**9937**	**4175**	**2617**
	Productivity					
	High	14150	14150	14150	14150	14150
	Central	8490	8490	8490	8490	8490
	Low	5660	5660	5660	5660	5660
Emissions Intensity (gCO_2e/kWh(th))						
	Productivity					
	High	41	30	15	11	10
	Central	62	45	19	13	11
	Low	88	63	24	15	13

Table A 11: Emissions from pre-production and processing, assuming the methane released during flowback is 90% captured and flared, excluding Howarth et al. (2011) Haynesville data.

Emissions (tCO_2e/Well)						
	Pre-production emissions assumption	Maximum	95th percentile	Mean	Median	5th percentile
Stage						
Site Preparation		360	351	208	229	36
Drilling and Hydraulic Fracturing		1790	1681	877	711	352
Well Completion		8469	7023	3482	2788	1904
Water/Wastewater Transport and Treatment		21	21	21	21	21
Chemicals		300	300	300	300	300
Pre-production Total		**10940**	**9376**	**4887**	**4049**	**2612**
	Productivity					
	High	14150	14150	14150	14150	14150
	Central	8490	8490	8490	8490	8490
	Low	5660	5660	5660	5660	5660
Emissions Intensity (gCO_2e/kWh(th))						
	Productivity					
	High	16	15	12	11	10
	Central	20	18	14	13	11
	Low	26	23	16	15	13

Table A 12: Emissions from pre-production and processing, assuming the methane released during flowback is 90% captured and injected into the gas grid, including Howarth et al. (2011) Haynesville data.

Emissions (tCO_2e/Well)						
	Pre-production emissions assumption	Maximum	95th percentile	Mean	Median	5th percentile
Stage						
Site Preparation		360	351	208	229	36
Drilling and Hydraulic Fracturing		1790	1681	877	711	352
Well Completion		40936	27403	7140	2438	1597
Water/Wastewater Transport and Treatment		21	21	21	21	21
Chemicals		300	300	300	300	300
Pre-production Total		**43407**	**29756**	**8546**	**3699**	**2305**
	Productivity					
	High	14150	14150	14150	14150	14150
	Central	8490	8490	8490	8490	8490
	Low	5660	5660	5660	5660	5660
Emissions Intensity (gCO_2e/kWh(th))						
	Productivity					
	High	36	27	14	11	10
	Central	54	39	18	13	11
	Low	76	55	22	14	12

Table A 13: Emissions from pre-production and processing, assuming the methane released during flowback is 90% captured and injected into the gas grid, excluding Howarth et al. (2011) Haynesville data.

Emissions (tCO_2e/Well)						
	Pre-production emissions assumption	Maximum	95th percentile	Mean	Median	5th percentile
Stage						
Site Preparation		360	351	208	229	36
Drilling and Hydraulic Fracturing		1790	1681	877	711	352
Well Completion		7104	5888	2915	2333	1593
Water/Wastewater Transport and Treatment		21	21	21	21	21
Chemicals		300	300	300	300	300
Pre-production Total		**9575**	**8241**	**4321**	**3594**	**2302**
	Productivity					
	High	14150	14150	14150	14150	14150
	Central	8490	8490	8490	8490	8490
	Low	5660	5660	5660	5660	5660
Emissions Intensity (gCO_2e/kWh(th))						
	Productivity					
	High	15	14	11	11	10
	Central	19	17	13	12	11
	Low	24	22	15	14	12

Table A 14: Emissions from pre-production and processing, assuming the methane released during flowback is 100% captured and injected into the gas grid.

Emissions (tCO_2e/Well)						
	Pre-production emissions assumption	Maximum	95th percentile	Mean	Median	5th percentile
Stage						
Site Preparation		360	351	208	229	36
Drilling and Hydraulic Fracturing		1790	1681	877	711	352
Well Completion		-	-	-	-	-
Water/Wastewater Transport and Treatment		21	21	21	21	21
Chemicals		300	300	300	300	300
Pre-production Total		**2471**	**2353**	**1406**	**1261**	**709**
	Productivity					
	High	14150	14150	14150	14150	14150
	Central	8490	8490	8490	8490	8490
	Low	5660	5660	5660	5660	5660
Emissions Intensity (gCO_2e/kWh(th))						
	Productivity					
	High	10	10	10	10	9
	Central	11	11	10	10	9
	Low	13	12	11	11	10

Department of Energy & Climate Change
3 Whitehall Place
London SW1A 2AW
www.gov.uk/decc

URN 13D/230