

Onshore Petroleum

The compatibility of UK onshore
petroleum with meeting the
UK's carbon budgets

Committee on Climate Change
March 2016

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Contents

The Committee	4
Executive summary	7
Chapter 1: Sources of onshore petroleum and climate impacts of methane and carbon dioxide	12
Chapter 2: Production scenarios	23
Chapter 3: UK fossil fuel consumption and import dependency	35
Chapter 4: Emissions relating to onshore petroleum extraction	46
Chapter 5: Impact of onshore petroleum on carbon budgets	62

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Foreword

Under the Infrastructure Act (2015), the Committee on Climate Change has a duty to advise the Government on the compatibility of exploiting domestic onshore petroleum, which includes shale gas, with UK carbon budgets and our 2050 emissions reduction target. The Committee has previously provided some assessment of emissions attached to shale gas, for example within our progress reports to Parliament, but this is our first assessment under the Infrastructure Act, allowing for more in-depth consideration.

Any assessment of the potential for shale gas exploitation in the UK is subject to considerable uncertainty. Not a single production well has yet been drilled. To inform our consideration, therefore, we have developed a number of scenarios for how production could develop and we have reviewed the international evidence for the emissions attached to production.

In the light of that assessment, we have concluded that exploitation of shale gas on a significant scale would not be consistent with UK carbon budgets and the 2050 target unless three tests are met. These tests relate to the need to regulate tightly production emissions; the need for such shale gas production as does happen to substitute for imported gas and not add to overall gas consumption; and the need to find additional abatement measures to compensate for the emissions attached to production, even under tight regulation.

If those conditions are met, then shale gas could make a useful contribution to UK energy supplies, including providing some energy security benefits.

The Government is required, under the Infrastructure Act, to lay our report before Parliament, alongside an official response. I look forward to a positive reply.

I am, as ever, extremely grateful for the guidance of Committee members in developing this advice, and to the team within the secretariat who have worked so hard to produce the report.



Lord Deben
Chairman, Committee on Climate Change

The Committee



The Rt. Hon John Gummer, Lord Deben, Chairman

The Rt. Hon John Gummer, Lord Deben, was the Minister for Agriculture, Fisheries and Food between 1989 and 1993 and was the longest serving Secretary of State for the Environment the UK has ever had. His sixteen years of top-level ministerial experience also include Minister for London, Employment Minister and Paymaster General in HM Treasury.

He has consistently championed an identity between environmental concerns and business sense. To that end, he set up and now runs Sancroft, a corporate responsibility consultancy working with blue-chip companies around the world on environmental, social and ethical issues. Lord Deben is also Chairman of Valpak Limited and the Association of Professional Financial Advisors.



Professor Samuel Fankhauser

Professor Samuel Fankhauser is Co-Director of the Grantham Research Institute on Climate Change and Deputy Director of the ESRC-funded Centre for Climate Change Economics and Policy, both at the London School of Economics. He is a Director at Vivid Economics and a former Deputy Chief Economist of the European Bank for Reconstruction and Development.



Professor Sir Brian Hoskins

Professor Sir Brian Hoskins, CBE, FRS is the Chair of the Grantham Institute for Climate Change and the Environment at Imperial College London and Professor of Meteorology at the University of Reading. His research expertise is in weather and climate processes. He is a member of the scientific academies of the UK, USA, and China.



Paul Johnson

Paul Johnson has been director of the Institute for Fiscal Studies since January 2011 and is a visiting professor at UCL. He is widely published on the economics of public policy including tax, welfare, inequality and poverty, pensions, education, climate change and public finances. He is also one of the authors of the “Mirrlees review” of tax system design.

Paul has previously worked at the FSA and has been chief economist at the Department for Education and director of public spending in HM Treasury, as well as deputy head of the UK Government Economic Service. He is currently a member of the council and executive committee of the Royal Economic Society, a member of the banking standards board, and has completed an independent review of consumer price inflation statistics for the UK Statistics Authority. Paul has previously served on the council of the Economic and Social Research Council. He was a founder council member of the Pensions Policy Institute and in 2010 led a review of the policy of auto-enrolment into pensions for the new Government.



Julia King, The Baroness Brown of Cambridge

Julia King DBE FREng, The Baroness Brown of Cambridge, is the Vice Chancellor and Chief Executive of Aston University. After an academic career at Cambridge University, Julia held senior business and engineering posts at Rolls-Royce for eight years. She returned to academia as Principal of the Engineering Faculty at Imperial College, London, becoming Vice-Chancellor of Aston University in 2006.

Julia advises Government as a member of the Committee on Climate Change, the Science and Technology Honours Committee and as the UK’s Low Carbon Business Ambassador. She is a member of the World Economic Forum Global Agenda Council on Decarbonizing Energy, and was an inaugural member of the European Institute of Innovation and Technology’s Governing Board. She is Chair of the Sir Henry Royce Centre for Advanced Materials, a non-executive Director of the Green Investment Bank and Offshore Renewable Energy Catapult, and a member of the Engineering and Physical Sciences Research Council. In 2015 Julia was elevated to the peerage as a crossbench peer.



Lord John Krebs

Professor Lord Krebs Kt FRS FMedSci ML was Principal of Jesus College Oxford from 2005-2015. Previously, he held posts at the University of British Columbia, the University of Wales, and Oxford, where he was lecturer in Zoology, 1976-88, and Royal Society Research Professor, 1988-2005. From 1994-1999, he was Chief Executive of the Natural Environment Research Council and, from 2000-2005, founding Chairman of the UK Food Standards Agency.

He is a member of the U.S. National Academy of Sciences, the American Philosophical Society, the American Academy of Arts and Sciences and the German National Academy of Sciences (Leopoldina). He was chairman of the House of Lords Science and Technology Select Committee from 2010 to 2014 and currently sits on the Energy and Environment Select Committee. He was President of the British Science Association in 2012.



Professor Jim Skea

Professor Jim Skea has research interests in energy, climate change and technological innovation. He has been RCUK Energy Strategy Fellow since April 2012 and a Professor of Sustainable Energy at Imperial College since 2009. He was Research Director of the UK Energy Research Centre 2004-12 and Director of the Policy Studies Institute 1998-2004.

He has operated at the interface between research, policy-making and business throughout his career. He is President of the Energy Institute and was elected co-Chair of IPCC Working Group III in 2015. He was awarded a CBE for services to sustainable energy in 2013 and an OBE for services to sustainable transport in 2004.

Executive summary

The Committee has a duty under the Infrastructure Act (2015) to advise the Government on the compatibility of exploiting domestic onshore petroleum, including shale gas, with UK carbon budgets and the 2050 emissions reduction target under the Climate Change Act (2008). This report provides our first advice under the Infrastructure Act. In this advice, the Committee focuses primarily on shale gas, as this has larger potential implications for emissions than other sources of onshore petroleum (e.g. shale oil).

It is outside the scope of the Committee's legal remit to investigate other issues that have been raised in relation to the development of shale gas, such as local noise, traffic, water and wider environmental impacts. The Committee's advice relates solely to greenhouse gas emissions and the impact on carbon budgets. There are other issues linked to ongoing gas consumption and carbon budgets but not specific to shale gas production, which we will consider separately in future reports including our annual Progress Reports to Parliament.

The implications for greenhouse gas emissions of shale gas exploitation are subject to considerable uncertainties, both regarding the size of any future industry and the emissions footprint of production. This uncertainty alone calls for close monitoring of developments. The Committee will report back earlier than its next statutory deadline five years from now should this be necessary.

The UK regulatory regime has the potential to be world-leading but this is not yet assured. The current regime includes important roles for the Health and Safety Executive and the relevant environmental regulators (e.g. the Environment Agency in England), which will need to be managed seamlessly. Onshore petroleum exploitation at scale would have unique characteristics in the UK. This may ultimately necessitate the establishment of a dedicated regulatory body. It certainly requires that a strong regulatory framework is put in place now.

Our assessment is that exploiting shale gas by fracking on a significant scale is not compatible with UK climate targets unless three tests are met:

- **Test 1: Well development, production and decommissioning emissions must be strictly limited.** Emissions must be tightly regulated and closely monitored in order to ensure rapid action to address leaks.
 - A range of technologies and techniques to limit methane emissions should be required, including 'reduced emissions completions' (also known as 'green completions') and liquid unloading mitigation technologies (e.g. plunger lift systems) should these be needed;
 - A monitoring regime that catches potentially significant methane leaks early is essential in order to limit the impact of 'super-emitters';

-
- Production should not be allowed in areas where it would entail significant CO₂ emissions resulting from the change in land use (e.g. areas with deep peat soils);
 - The regulatory regime must require proper decommissioning of wells at the end of their lives. It must also ensure that the liability for emissions at this stage rests with the producer.
- **Test 2: Consumption – gas consumption must remain in line with carbon budgets requirements.** UK unabated fossil energy consumption must be reduced over time within levels we have previously advised to be consistent with the carbon budgets. This means that UK shale gas production must displace imported gas rather than increasing domestic consumption.
 - **Test 3: Accommodating shale gas production emissions within carbon budgets.** Additional production emissions from shale gas wells will need to be offset through reductions elsewhere in the UK economy, such that overall effort to reduce emissions is sufficient to meet carbon budgets.

There are also potential implications of UK shale production for global emissions. There are two issues:

- **Lifecycle emissions of tightly regulated domestic shale gas as against imports.** The overall emissions footprint of UK shale gas, if tightly regulated, is likely to be broadly similar to that of imported gas. Tightly regulated domestic production may provide a small emissions saving when displacing imports of liquefied natural gas.
- **Impact on the global energy system.** Increased UK production of fossil fuels could affect global emissions, depending on the extent to which this displaces coal, displaces low-carbon energy or leads to increased fossil fuel consumption.

There has been insufficient time to assess the second of these fully. We plan to publish analysis and views of this issue in the summer of 2016 alongside our advice to the Scottish Government on Unconventional Oil and Gas.

Test 1: Well development, production and decommissioning emissions must be strictly limited

Left entirely unregulated, the emissions footprint of shale gas production could be substantial. Any significant level of exploitation of UK resources in this way would be inconsistent with carbon budgets. However, the current proposals from Government and regulatory bodies include action to regulate emissions and there are technologies and techniques that are known to limit greenhouse gas emissions from shale gas production. Experience and data from the US provide estimates of the costs and effectiveness of many of these measures.

The UK regulatory regime has the potential to be world-leading but this is not yet assured. Some technologies and techniques are likely to be required by the Environment Agency as a condition of the production licence. However, the precise nature of these standards needs to be clarified and must meet the tests set out above, before production could begin. These standards should apply not just to the well pad but to all associated infrastructure prior to the gas being injected into the grid or put to use.

US experience also indicates that an important contributor to methane emissions has been so-called ‘super-emitters’: large methane leaks left unchecked for extended periods of time. As a consequence, a small number of wells have been found to contribute disproportionately to

emissions. Limiting emissions therefore requires that the monitoring regime catches the super-emitters quickly and significantly limits the quantity of methane released to the atmosphere, alongside the technologies to limit known sources of emissions.

The minimum set of techniques and technologies required to limit emissions can do so at a cost comparable to the cost of reducing emissions elsewhere in the economy, consistent with the requirements of carbon budgets. As evidence improves, it is likely to be cost-effective and necessary to require the inclusion of further emissions reduction measures.

Test 2: Consumption – gas consumption must remain in line with carbon budgets requirements

Carbon budgets and the 2050 target can be met in a range of ways, which imply different balances of reductions in coal, oil and natural gas use, as well as the application of carbon capture and storage (CCS). But, in general, they require unabated consumption (i.e. without CCS) of all fossil fuels to decline over time, most likely reducing the use of fuels with the highest carbon intensity (e.g. coal) earlier and more strongly than those with lower carbon intensity (e.g. natural gas).

The UK currently gets around half its gas supplies from imports, mainly via pipeline from Norway and via liquefied natural gas (LNG) tankers. Domestic output is projected to continue its decline over the coming decades and most projections suggest that the share of imports may rise over time, even as consumption falls.

There may be benefits for energy security and domestic industry if new domestic sources of natural gas production reduce UK dependence on imported gas. There is no case, however, for higher levels of UK gas consumption than we have previously set out.

The long-term path for UK gas consumption, assuming carbon budgets are met, depends strongly on whether or not carbon capture and storage (CCS) is deployed (Figure 1):

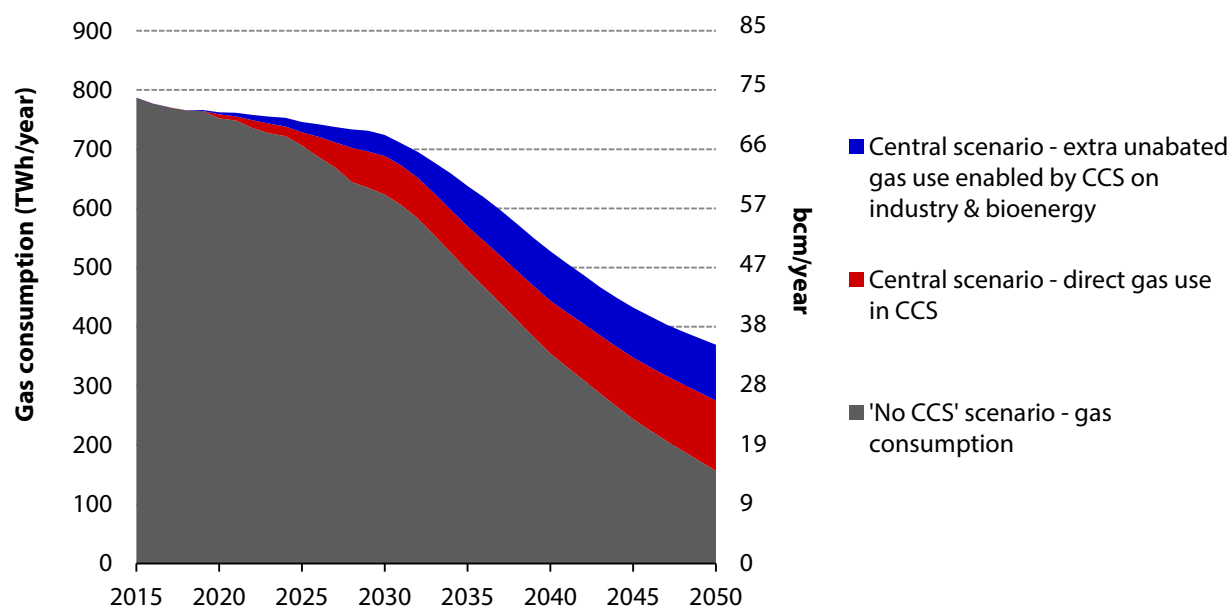
- **CCS widely deployed.** Use with CCS would provide a way to consume fossil fuels in a low-carbon way. It could also mean that some residual use of unabated fossil fuels in hard-to-decarbonise applications (e.g. some heavy vehicles or gas boilers) can be accommodated even in 2050. This is likely to imply a reduction in gas consumption by 2050 of around 50% relative to today's levels.
- **No CCS.** Should CCS not be deployed, meeting the 2050 emissions reduction target will require elimination of almost all fossil fuel use in power generation, transport and buildings. This implies a reduction in gas consumption by 2050 of around 80% on today's levels. It also implies that gas would cease to be used for electricity generation by the mid-2030s.

As well as providing a smaller market for fossil fuels, the greater pressure placed on UK emissions targets in the absence of CCS would also make it more difficult to accommodate the emissions associated with production, as there would be less scope to reduce emissions elsewhere in the economy in order to compensate.

A UK approach to delivery of carbon capture and storage (CCS) is urgently needed.

Unabated gas consumption must be consistent with the levels in the scenarios presented in our advice on the fifth carbon budget, unless reductions in emissions beyond any the Committee has identified can be found elsewhere. Therefore, any new sources of UK production must be used to displace imports. Allowing unabated consumption above these levels would not be consistent with the decarbonisation required under the Climate Change Act.

Figure 1: Direct and indirect impacts of CCS availability on gas consumption to 2050



Source: CCC analysis, based on scenarios in the fifth carbon budget advice.

Notes: The 'No CCS' scenario entails each sector following its Max scenario, excluding CCS measures, in order to meet the overall 2050 target.

Test 3: Accommodating shale gas production emissions within carbon budgets

Domestic production of shale gas will lead to some additional UK emissions, even if gas consumption is not affected and emissions relating to production are strictly limited through tight regulation and monitoring. The size of these extra emissions depends on the size of the future industry, about which there is considerable uncertainty.

Should the industry grow very quickly, the impact on overall UK emissions from UK production could be around 11 MtCO₂e/year in 2030 under a tight regulatory regime. This is similar in magnitude to the emissions savings in the agriculture sector under our central fifth carbon budget scenario. If regulation were more lax, emissions would be significantly higher (Figure 2).

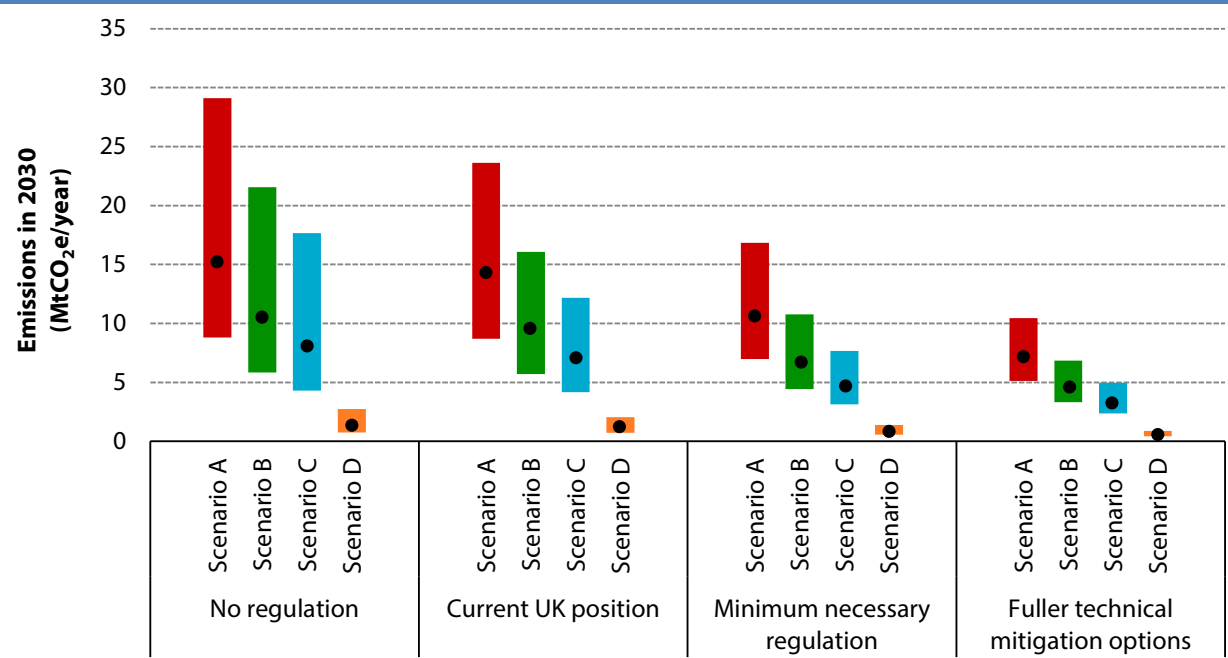
In this advice, we compare methane and CO₂ emissions using the 100-year Global Warming Potential (GWP₁₀₀) of 25. This metric is used as standard in international and UK emissions accounting, including carbon budgets and the 2050 target. We note however that the GWP₁₀₀ does not directly measure the effect of emissions on end-of-century global temperature, which is how international climate limits are framed (i.e. targets to hold the increase in global temperature to well below 2°C and pursue efforts to limit to 1.5°C). The relative effect of today's methane emissions on temperature in 2100 will be less than the GWP₁₀₀ implies, while those later in the century, closer to the point of peak temperature, will have a more significant effect.

Our analysis for the fifth carbon budget showed that there is uncertainty over the level of non-traded emissions in 2030 of around 23 MtCO₂e/year in both directions, and flexibility to increase the amount of emissions saving totalling around 26 Mt/year.

Given this, accommodating additional emissions from shale gas production of 11 Mt/year may be possible, although it would require significant and potentially difficult offsetting effort

elsewhere. This should be considered in the report that the Climate Change Act requires the Government to deliver by the end of 2016 setting out its plans to meet the fourth and fifth carbon budgets.

Figure 2: Impact of UK shale gas production on UK greenhouse gas emissions (2030)



Source: CCC analysis.

Notes: Scenarios A to D refer to the shale gas production scenarios presented in Chapter 2.

Chapter 1:

Sources of onshore petroleum and climate impacts of methane and carbon dioxide

In this chapter, we set out the Committee's duty under the Infrastructure Act, the state of the evidence base on onshore petroleum, and considerations around how to compare the relative climate impacts of methane and carbon dioxide, in three sections:

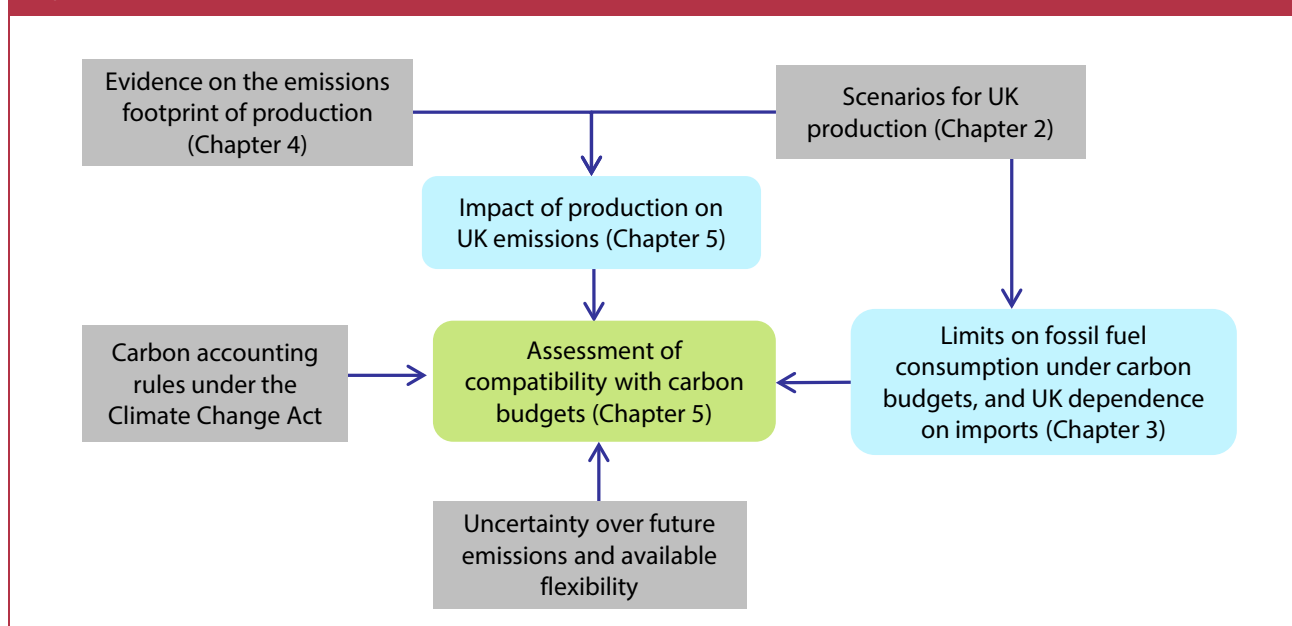
1. Our duty under the Infrastructure Act
2. UK sources of onshore petroleum
3. Comparing the climate effects of methane and carbon dioxide

Chapter 2 then considers the factors that would affect the size of a UK onshore industry over time, and presents scenarios for development of a UK industry. Chapter 3 sets out the level of UK unabated fossil energy consumption that is compatible with meeting carbon budgets and the 2050 target, and looks at the UK's import dependency.

Chapter 4 analyses issues relating to the emissions footprint of UK shale gas production, including opportunities to mitigate emissions and a comparison with the lifecycle emissions of imported sources of gas.

The production scenarios and emissions footprint are brought together in Chapter 5, which presents emissions implications under different combinations of production scenarios and regulation cases. It then assesses the flexibility to accommodate these within carbon budgets and draws out implications for the measures needed to limit emissions (Figure 1.1).

Figure 1.1: How the analysis in this report fits together



1. Our duty under the Infrastructure Act

Under the Infrastructure Act (2015) it is the Committee's duty to advise on:

"the impact which combustion of, and fugitive emissions from, petroleum got through onshore activity is likely to have on the Secretary of State's ability to meet the duties imposed by (a) section 1 of the CCA 2008 (net UK carbon account target for 2050), and (b) section 4(1)(b) of the CCA 2008 (UK carbon account not to exceed carbon budget)."

In other words, it is our responsibility to provide advice on the impact of UK production of onshore petroleum on meeting carbon budgets and the 2050 target to reduce emissions by at least 80% as against 1990 levels. This report presents our advice based on the current evidence base regarding onshore production and the associated greenhouse gas (GHG) emissions relevant to the UK.

Although the provisions in the Infrastructure Act relating directly to onshore petroleum extraction apply to England and Wales only, the duty on the Committee to advise on the compatibility with carbon budgets and the 2050 target pertains to the UK as a whole.

In this advice, we focus primarily on shale gas, as this has considerably larger potential implications for emissions than other sources of onshore petroleum (e.g. shale oil) and is the source for which the evidence base on emissions and mitigation measures is best developed (see Chapter 4).

It is outside the scope of the Committee's legal remit to investigate other issues that have been raised in relation to the development of shale gas, such as impacts on water, local noise, traffic, seismic activity and the wider environment. The Committee's advice relates solely to greenhouse gas emissions and the impact on carbon budgets.

Throughout this report, we highlight the uncertainty relating both to the emissions footprint of UK shale gas production and to the potential future size of a domestic industry. Further improvements to the evidence base are necessary, including research on detection and mitigation of emissions and evidence that emerges as any UK industry develops. This uncertainty alone calls for close monitoring of developments, and we will report back earlier than the next statutory deadline in the Infrastructure Act (five years from now) should this be necessary.

2. UK sources of onshore petroleum

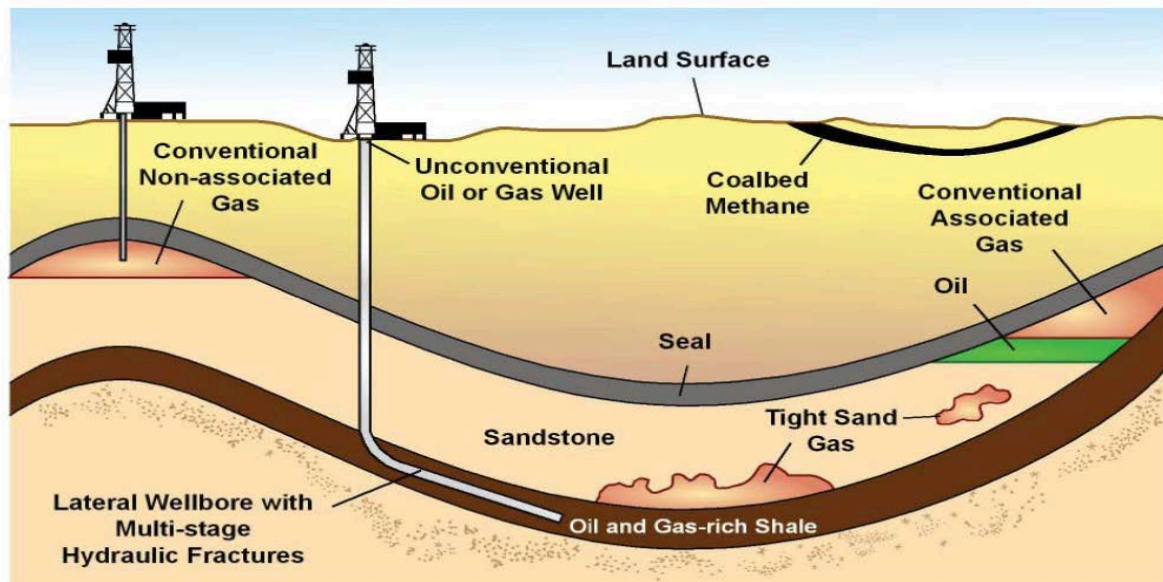
Petroleum is a class of fossil fuels, defined in the Petroleum Act (1998) as including "any mineral oil or relative hydrocarbon and natural gas existing in its natural condition in strata"; it includes both conventional and unconventional sources. The sources of onshore petroleum pertinent to our advice are limited to those relevant to the UK, which are conventional oil and gas, shale gas, shale oil and coal bed methane (CBM).

Our advice therefore excludes consideration of production outside the UK as well as offshore (North Sea) production. Also excluded from the definition of onshore petroleum are hydrocarbon sources such as colliery gas, tight gas, oil sands, oil shale (which differs from shale oil) and underground coal gasification. Although these are not covered in our advice, to the extent that they contribute to UK fossil fuel supplies they will also contribute to our greenhouse gas emissions.

The oil and gas extracted from conventional and unconventional sources are almost the same. The main differences relate to where the oil and gas is found and how they are commercially

extracted. Conventional oil and gas has migrated from its source and is found in porous formations, through which it flows easily. By contrast, unconventional hydrocarbons are trapped in source rocks with low porosity (Figure 1.2), and where the flow therefore needs to be stimulated through hydraulic fracturing or fracking (Box 1.1).

Figure 1.2: The geology of conventional and unconventional oil and gas



Source: US Energy Information Administration.

Notes: The schematic shows the various sources of conventional and unconventional sources of oil and gas. This is not to scale.

Box 1.1: Hydraulic fracturing

Hydraulic fracturing is a process in which a combination of water, a range of chemicals and a proppant (typically sand) are pumped down into the well at high pressure (e.g. 80 bar). This high pressure breaks up the shale, creating fractures that can extend to over 500 metres in height.¹

It is estimated that between 1,200 and 45,000 cubic metres of water per well is used in this process.² Hydraulic fracturing is carried out in stages, in which small sections of the well lateral (the horizontal section of well) are isolated before being hydraulically fractured, starting from the furthest point and proceeding backwards. Recent common practice in the US is to increase the number of stages, which has been found to result in increased well productivity.

¹ Davies et al. (2012) Hydraulic fractures: How far can they go?, *Marine and Petroleum Geology*, 43, 519-521.

² King (2012) *Hydraulic Fracturing 101*, http://www.kgs.ku.edu/PRS/Fracturing/Frac_Paper_SPE_152596.pdf

Within the relevant sources of onshore petroleum, we have considered their potential to increase UK emissions, and the strength of the evidence base:

- **Conventional oil and gas.** Oil and gas has been produced onshore in the UK since the mid-19th century, during which time around 2,000 wells have been drilled.³ Emissions from these activities are small, and have already been allowed for in setting carbon budgets. Onshore conventional production of oil and gas is expected to remain at similar levels for the foreseeable future, thereby leading to no significant increase in UK greenhouse gas emissions.
 - Cumulative UK onshore oil production to date is around 490 million barrels of oil. Around 250 oil wells are currently in operation, with production in 2014 of around seven million barrels.⁴ Onshore production of oil is dominated by the Wessex basin with its large Wytch Farm oilfield. Peak onshore oil production was around 40 million barrels in 1996, equivalent to around 7% of current UK demand.⁵
 - Onshore wells have also produced 5.7 billion cubic metres (bcm), or 60 TWh, of gas since 1991 (excluding associated gas). Onshore gas production has declined since 2001, with just 0.3 TWh of gas produced in 2014 (around 0.04% of UK demand).
 - The report on shale gas extraction by the Royal Society and Royal Academy of Engineering⁶ stated that around 10% of conventional oil and gas wells in the UK have been hydraulically fractured to boost flow from the well.
 - Conventional oil and gas exploration continues around the UK, with the latest licensing round opening up potential for further discoveries, but any new discoveries are expected to be small. Recent testing of the “Gatwick Gusher” has produced significant flow rates, although it is too early to predict whether this discovery will lead to a substantial increase in production levels.
- **Shale gas.** Shale gas refers to natural gas that has remained in the source rock. In chemical composition, shale gas is similar to conventional gas. Historically, shale gas was too difficult or uneconomic to extract. Recent advances in technology for drilling and hydraulic fracturing have made extraction more economic.
 - Across the UK there are numerous shale basins that are believed to be capable of producing shale gas. The British Geological Survey (BGS) has studied two of the major shale basins: the Bowland in the North of England, and West Midland Valley in Scotland.⁷ Although not widely surveyed, the Wessex basin may also have a significant gas-in-place resource (Figure 1.3).

³ RS & RAEng (2012) *Shale gas extraction in the UK*, <https://royalsociety.org/~media/policy/projects/shale-gas-extraction/2012-06-28-shale-gas.pdf>

⁴ DECC (2015) *Oil production since 1975*, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/434575/Appendix9.xls

⁵ BGS (2011) *Onshore Oil and Gas* <https://www.bgs.ac.uk/downloads/start.cfm?id=1366>

⁶ RS & RAEng (2012)

⁷ BGS (2014) *The Carboniferous Bowland Shale gas study*, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/226874/BGS_DECC_BowlandShaleGasReport_MAIN_REPORT.pdf

BGS (2014) *The Carboniferous shales of the Midland Valley of Scotland*, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/360471/BGS_DECC_MVS_2014_MAIN_REPORT.pdf

- For the Bowland and Midland Valley, BGS reports an estimated gas-in-place resource for the UK in the range 25 to 68 trillion cubic metres (tcm), with a central value of 40 tcm. The Bowland shale is estimated to be 5,000 metres thick in places, rather greater than many of the shale basins in the US.
- Economically recoverable reserves will be a fraction of this estimate of total resource (Box 1.2). In order to start to ascertain the UK reserve, a period of exploration would be required to find the most productive areas in the shale formation. In the US thousands of exploration wells were drilled before the industry took off. Trial and error identified the ‘sweet spots’ where productivity was highest, but even within these locations well productivity varies. A more systematic approach to exploration would speed up the exploration phase; it is estimated such a process would take over two years for Europe to ascertain the commercial viability of the industry, although some reports estimate that it could take as long as 10 years based on the US experience.^{8,9}
- **Shale oil** is similar in chemical composition to conventional crude oil. As with shale gas, it has remained in the source rock and has been made more economic by technological advances.
 - The BGS has produced two detailed studies, using seismic data and boreholes to estimate the shale oil resource in UK. They estimate the oil in place from 5 to 20 billion barrels of oil, with a central figure of 10 billion barrels, located in the Weald Basin in the South of England and in the Midland Valley in Scotland (Figure 1.3).
 - The BGS report stresses that their estimates refer to the shale oil resource and not how much can be recovered, and suggest that there may be little or no ‘free oil’ (oil which is trapped in the pore spaces of the shale) in the Weald Basin.
 - As with shale gas, exploratory wells would need to be drilled across the basin to prove that oil can flow at economic levels before commercial viability of this resource can be established.
- **Coalbed methane (CBM)** is a gas formed as part of the process of coal formation, and is physically adsorbed by the coal. It can then be released when the pressure surrounding the coal is decreased. CBM has been produced commercially since 1996 in Australia, providing over 10% of Australian gas production.¹⁰ However, it is at an early development stage in the UK, and there is still a great deal of uncertainty whether the Australian experience is replicable in the UK.
 - DECC’s 2012 report on the UK CBM resource states that over 55 licences have been approved, covering more than 7,000 km². Three CBM developments have been approved by DECC, although they are yet to start construction.
 - In the last 5 years, over 40 CBM exploration and appraisal wells and 12 pilot production development wells have been drilled. The gas produced from one of these pilot wells, developed by IGas and Nexen, is currently being used to generate

⁸ IDDRI (2014) *Unconventional Wisdom*,

http://www.iddri.org/Publications/Collections/Analyses/Study0214_TS%20et%20al._shale%20gas.pdf

⁹ Gény (2010) *Can Unconventional Gas be a Game Changer in European Gas Markets?*,

<https://www.oxfordenergy.org/wpcms/wp-content/uploads/2011/01/NG46-CanUnconventionalGasbeaGameChangerinEuropeanGasMarkets-FlorenceGeny-2010.pdf>

¹⁰ DCCCE (2011) *Coal Seam Gas*, www.ret.gov.au/energy/Documents/facts-stats-pubs/Energy-in-Australia-2011.pdf

electricity. IGas recently decided to cancel plans for further exploration in Cheshire, although they still have planning permission for test and pilot wells at a site in Scotland, which is currently under a moratorium.

- There is little data surrounding the sources and quantities of greenhouse gas emissions associated with CBM extraction. At the present time, the evidence is insufficient to estimate the GHG emissions from developing CBM wells in the UK.
- In 2004, a BGS study suggested that UK coal beds suffered from widespread low seam permeability, and low gas content. With the lack of continued development in CBM, there is little evidence to indicate that CBM will be commercially developed in the UK.

In this advice, we focus primarily on shale gas, as this has considerably larger potential implications for emissions than other sources of onshore petroleum (e.g. shale oil) and is the source for which the evidence base on emissions and mitigation measures is best developed.

We have not considered the impact of conventional onshore production in detail, as the industry already exists and is unlikely to expand significantly.

We set out the available evidence on the emissions footprint of shale oil production in Chapter 4. However, given that this is considerably smaller than that of shale gas production, and that studies have not set out the potential size of a UK shale oil industry, we do not include it in the assessment in Chapter 5 on how emissions could be accommodated under carbon budgets.

The evidence on coalbed methane (CBM) is even more limited, both regarding the emissions footprint and potential size of a UK industry. If exploitation of CBM were proposed in any significant way for the UK then we would come back to look at it in further detail.

Box 1.2: Getting from estimates of gas-in-place resource to economically recoverable reserves

The gas-in-place estimates produced by BGS do not indicate how much gas will be recovered. Several steps are required to translate these estimates of the resource into economically recoverable reserves:

- Only a fraction of shale gas resources are technically recoverable with current technology. BGS do not currently provide an estimate for the fraction of gas that is technically recoverable, stating that exploration needs to take place before an estimate can be made. Based on US experience, the US Energy Information Administration estimates this proportion to be around 20% of the gas in place.¹¹
- Of this technically recoverable gas some may be inaccessible, due to land-use constraints (e.g. populated or protected areas). In a report for the European Commission, ICF¹² estimated that less than 50% of the UK's shale gas resource is likely to be accessible. This reduces the central estimate for technical recoverable resource further.
- Although the factors affecting the recoverable fraction of the resource are mainly geological 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

¹¹ EIA (2015), *Technically Recoverable Shale Oil and Gas Resources: UK*, https://www.eia.gov/analysis/studies/worldshalegas/pdf/UK_2013.pdf

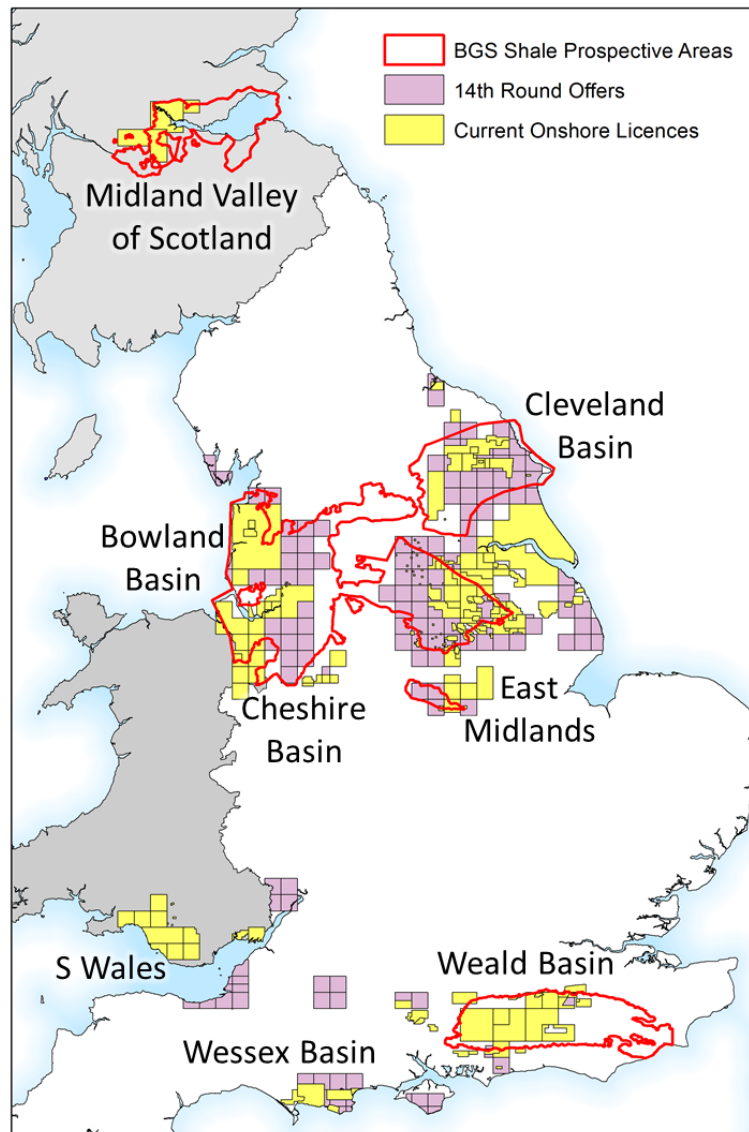
¹² ICF (2014), *Macroeconomic impacts of shale gas extraction in the EU*, <http://ec.europa.eu/environment/integration/energy/pdf/Macroec%20Impacts%20of%20Shale%20Gas%20Report.pdf>

Box 1.2: Getting from estimates of gas-in-place resource to economically recoverable reserves

used for hydraulically fracturing); the effect of the new protocols for earthquake mitigation and monitoring; land access; and environmental permit constraints.¹³

- The volume that is economically recoverable is likely to be smaller again than that which is technically recoverable, as it depends on gas prices and production costs (see Chapter 2).

Figure 1.3: Location of UK shale resources



Source: Oil and Gas Authority.

Notes: The map shows the regions that currently have a licence and areas covered as part of British Geological Survey studies on unconventional resources.

¹³ MacKay-Stone (2013), *Potential Greenhouse Gas Emissions Associated with Shale Gas Extraction and Use*, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/237330/MacKay_Stone_shale_study_report_09092013.pdf

3. Comparing the climate effects of methane and carbon dioxide

The major component of natural gas is methane. Not only does this produce CO₂ when combusted, but methane is itself a greenhouse gas included in UK carbon budgets. Methane is emitted to the atmosphere at various points along the lifecycle of gas use, from extraction to final use.

In this report we sum the total emissions of CO₂ and methane on a CO₂-equivalent (CO₂e) basis, assuming that a tonne of methane emitted is equal to 25 tonnes of CO₂e.

There are other possible ways to compare relative emissions, and a fixed multiplier of 25 has some limitations (Box 1.3). It overplays the relative importance of methane emissions for century-scale, irreversible temperature change, while underplaying the effect of methane on timescales up to a few decades. There are several potential alternative indices for comparing different types of greenhouse gases, and each has its own characteristics. Whichever index is chosen it is most important to be aware of its implications and interpret results in light of those.

Our use of fixed multiplier of 25 reflects current practice under both UK carbon budget accounting and UN-agreed international emissions reporting.

Box 1.3: Climate effects of methane and carbon dioxide

Methane is a more potent greenhouse gas than carbon dioxide (CO₂), trapping more heat in the atmosphere molecule-for-molecule. But it is much shorter-lived: it decays on a timescale of around 12 years, whereas around a fifth of the effect from CO₂ remains even after 1,000 years. This means a unit emission of CO₂ today will affect the climate in 2100 and beyond. In contrast, the same unit emission of methane will have little effect on climate in 2100, but a stronger effect on the climate of the next few decades (Figure B1.3).

Measuring the total effect of gas use (and comparing it to alternatives such as coal and renewables) requires a metric to put the climate effects of methane and CO₂ on a common scale. Various metrics exist (Table B1.3):

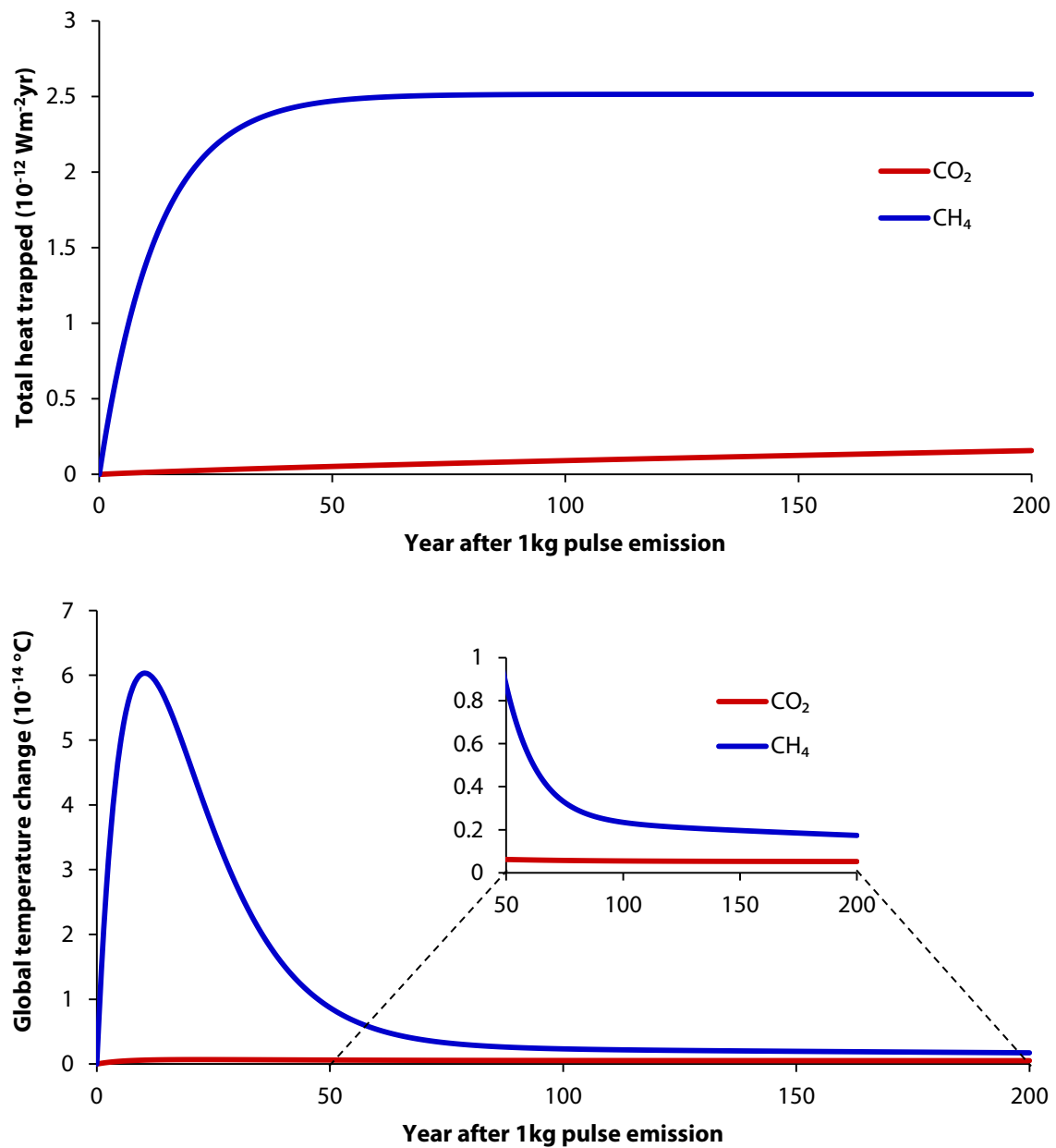
- The 100-year Global Warming Potential (GWP₁₀₀) is the standard metric used in domestic and international climate policy. It compares the total heat trapped in the atmosphere over a 100-year period after a pulse emission of a given mass of greenhouse gas, relative to the same mass of CO₂. In essence it is the ratio of the two lines shown in the top panel of Figure B1.3 at year 100 after the time of the emission.
- A GWP₁₀₀ of 25 for methane is currently used in policy, indicating that a tonne emitted is equivalent to 25 tonnes of CO₂. This value comes from the Fourth Assessment of the Intergovernmental Panel on Climate Change (IPCC AR4). However, GWP₁₀₀ estimates are revised over time as scientific understanding improves and the composition of the atmosphere changes. The IPCC's more recent Fifth Assessment gave GWP₁₀₀ for methane of 28, or 34 if the feedback of warming onto atmospheric CO₂ levels is accounted for.¹⁴
- The metric value depends on the time horizon chosen. Some studies of unconventional gas¹⁵ have chosen to use a shorter time horizon of 20 years (GWP₂₀), leading to a higher value for methane of 72.
- Since the GWP₁₀₀ measures time-integrated heating it does not relate directly to international policy goals, which are based on limiting global average temperature change (e.g. to well below 2°C). If we look instead at the effect on global temperature, we find quite different values for methane than that suggested by the GWP (Figure B1.3 bottom panel). For example, methane is about four times stronger than CO₂ after 100 years. As with the GWP, the value varies with time horizon. After just 20 years, the effect of methane on temperature is 67 times stronger than that of CO₂.

¹⁴ Global warming is expected to lead to a decrease in the effectiveness of natural CO₂ sinks, and hence an additional increase in atmospheric CO₂ concentration. This feedback was not fully accounted for in IPCC AR4 GWP estimates. IPCC AR5 provides GWP estimates without and with this effect, the latter being arguably the more consistent approach.

¹⁵ For example Howarth et al. (2011), Methane and the greenhouse gas footprint of natural gas from shale formations, *Climatic Change*, 106, 679–690.

Box 1.3: Climate effects of methane and carbon dioxide

Figure B1.3: Radiative forcing and temperature change for methane and carbon dioxide over different timescales



Source: CCC calculations based on the IPCC Fifth Assessment Report (AR5).

Notes: Total heat trapped in the atmosphere (top) and global average surface temperature change (bottom) from emission of carbon dioxide (CO_2) and methane (CH_4). The ratio of the curves in the top panel at 100 years gives the GWP_{100} value for methane, while the ratio of curves in the bottom panel gives the relative effect on temperature.

Box 1.3: Climate effects of methane and carbon dioxide**Table B1.3:** Alternative metrics for assessing the climate effect of methane emissions relative to the same mass of CO₂ emissions

GWP₁₀₀ (IPCC AR4)	GWP ₁₀₀ (IPCC AR5 excl. carbon cycle feedbacks)	GWP ₁₀₀ (IPCC AR5 incl. carbon cycle feedbacks)	GTP ₁₀₀ (IPCC AR5 excl. carbon cycle feedbacks)	GTP ₁₀₀ (IPCC AR5 incl. carbon cycle feedbacks)
25	28	34	4	11

Source: IPCC AR5 Working Group 1, Chapter 7.

Notes: The metric currently used for policy (GWP₁₀₀) is highlighted in bold. GTP₁₀₀ stands for 100-year Global Temperature Potential, and measures the relative change in global temperature a century after emission. The set of metrics shown here is not exhaustive.

Chapter 2: Production scenarios

The UK shale industry is currently in the early stages of development. Consistent well flow-rates of oil and gas across each of the basins can only be proved if there is a period of exploration. If flow-rate levels consistent with commercial exploitation can be established over a number of exploration wells the industry might then move on to development well drilling and the production phase of operations.

The rate at which a UK onshore petroleum industry might develop is uncertain, and depends on the rate at which the industry can feasibly be ramped up: economic factors affecting the profitability of production; the time required for and complexity of the planning and approval process; and, related to this, the extent to which public acceptability issues are a constraint.

This chapter considers the factors that would affect the size of a UK onshore petroleum industry over time, presents scenarios for development of a UK industry and considers the likely impact on gas prices, in three sections:

1. Factors affecting the growth of a UK onshore industry
2. Production scenarios
3. Impact on gas prices

1. Factors affecting the growth of a UK onshore industry

The profitability of the sector depends on the underlying costs of production, costs imposed by regulation and related policies, the composition of the gas produced, the productivity of the wells drilled, prevailing wholesale prices and the taxation regime:

- **Production costs.** Of the significant components of production costs, some can be inferred approximately from experience elsewhere and some are a function of the specific circumstances in the UK:
 - **Drilling the well.** The cost of drilling a well is related to the depth of the well and the length of lateral. The costs to drill wells in the US are decreasing, with recent cost estimates as low as \$2.6m per well.¹⁶ However, this does not take into account the greater depth of the UK shale formations; UK costs could be more comparable to the Haynesville formation that underlies parts of the US states of Arkansas, Louisiana and

¹⁶ Ikonnikova et al. (2015) Profitability of shale gas drilling: A case study of the Fayetteville shale play, *Energy*, 81, 382-393.

Texas, where wells cost in the region of \$9m to drill.^{17,18}

- **Fracturing stages.** The fracturing stage represents between 20% and 50% of overall well costs.¹⁹ Over time the number of fracture stages has tended to increase, which has increased the volume of shale per unit lateral length.²⁰ It is expected that UK practice would reflect this increased number of fracturing stages per lateral length, which is becoming common practice in the US. Both the drilling and fracturing stages are likely to be carried out by oilfield service companies. Due to lower competition than in the US, costs for their services are likely to be higher in the UK.²¹
- **Other costs.** The UK shale industry has agreed that the local community will be paid £100,000 when an exploratory well is hydraulically fractured and a further 1% of gross revenues for shale wells put into production. Each shale gas site will also have to pay business rates and potentially pay to lease the land. This is different from the US where the industry pay royalties to the land owner based on revenues.
- **Costs relating to environmental, planning and safety regulations.** Costs of environmental, planning and safety regulation are likely to be higher in the UK than the US. Examples of this are already occurring:
 - **Environmental.** Groundwater monitoring is required a year before hydraulic fracturing. An environmental risk assessment is also required. Many of the techniques and technologies to limit the emissions footprint of production will also increase costs, although this cost should be compared to the benefit from the reduction in emissions when deciding on implementation (Chapter 4).
 - **Safety.** Health and safety regulations are likely to increase costs of a UK well when compared to the US. Regulations mitigating the risk of well failure are stronger than they have historically been in the US, with greater numbers of casings²² being required. On top of this, independent well examiners are required to review the design, construction and decommissioning of wells, in order to provide independent assurance.²³ Employment law is also stricter, with regulations on working time increasing the size of crews working on the rigs.²⁴
 - **Planning.** Sites in the UK could require security during the well development stage and potentially beyond, adding to the costs for the site. Planning permission can be

¹⁷ Oil and Gas Journal (2014), *Haynesville Update*, <http://www.ogj.com/articles/print/volume-112/issue-1/exploration-development/north-louisiana-drilling-costs-vary-slightly-2007-12.html>

¹⁸ It should be noted that Haynesville formation has found to be over-pressured with high temperatures, making it more challenging to drill and increasing the average well costs.

¹⁹ Oilfield Technology (2013) *Taking Centre Stage*, https://www.slb.com/~media/Files/completions/industry_articles/201302_ot_taking_centre_stage_bakken_ia.pdf

²⁰ MITeI (2015), *The Salient Distribution of Unconventional Oil and Gas Well Productivity*, https://mitei.mit.edu/system/files/MITeI-WP-2015-05_Salient-Distribution-of-Unconventional-Oil-and-Gas-Well-Productivity.pdf

²¹ Gény (2010) *Can Unconventional Gas be a Game Changer in European Gas Markets?*, <https://www.oxfordenergy.org/wpcms/wp-content/uploads/2011/01/NG46-CanUnconventionalGasbeaGameChangerinEuropeanGasMarkets-FlorenceGeny-2010.pdf>

²² A well casing is a large diameter pipe inserted into a recently drilled borehole and held in place with cement.

²³ HSE *Shale gas and hydraulic fracturing*, <http://www.hse.gov.uk/shale-gas/assets/docs/shale-gas.pdf>

²⁴ Gény (2010).

difficult to obtain due to local impacts, with two wells in Lancashire failing on noise and traffic grounds; this process took over 15 months to assess. However, the Government recently announced a plan to fast-track the planning process for councils to come up with a planning decision within a 16-week statutory timeframe.

- **Composition.** The composition of hydrocarbons extracted varies considerably between wells. Generally gas is categorised into dry gas and wet gas: dry gas is mainly (greater than 90%) methane; wet gas contains a greater proportion of gases such as ethane, propane, butane and gas condensate, which tend to have a greater value than methane and may be used as feedstocks in petrochemical plants rather than combusted for energy.
- **Well productivity.** It is uncertain how relevant US data are in providing a guide to the productivity (i.e. the amount of hydrocarbon that will be recovered) for UK onshore wells. In any case this is likely to vary significantly within the UK (Box 2.1). A large proportion of production costs are fixed, so the unit costs of production are highly dependent on the quantity of output (Figure 2.1). There is a similar effect in relation to emissions per unit of production, as some sources of emissions relate to the number of wells rather than the quantity of energy produced (see Chapter 4).
- **Fossil fuel prices.** Beyond the short term, prices in wholesale fossil fuel markets are difficult to predict with any confidence. The gas price in DECC's fossil fuel price scenarios ranges from 36 to 95 p/therm for 2025 (Figure 2.2). It is therefore difficult to state with any certainty now whether onshore extraction will be economic during the 2020s, even with good knowledge of well development costs. Shale gas production does have the advantage that a high proportion of a well's total hydrocarbon production occurs in the first two years, which reduces this risk significantly at the level of an individual well. Nevertheless, at the industry-wide level, this is an area of considerable importance and uncertainty.
- **Taxation regime.** Should onshore production be profitable, the prevailing taxation regime will determine how much of the profits are retained by the producer and how much goes to the Exchequer. While there is a taxation regime currently in place, it is likely that this will be adjusted when more is known about the economics and profitability of UK production.

Box 2.1: Well productivity

The productivity of a well is dependent on its geologic characteristics, length of the lateral(s) drilled and the completion design, and could vary widely across a shale formation by a factor of up to ten.^{25,26} As the UK has no exploration flow data, let alone production data, it is too early to speculate on the likely productivity of UK wells, although we can look at US data to understand better how productivity varies across formations as well as between formations.

The way a well behaves over time varies between wells. Production generally declines rapidly over time due to loss of reservoir pressure, which makes it difficult to predict the well's overall production. A metric of estimated ultimate recovery (EUR) has therefore been developed to estimate the production across a well's life. These use models based on historical data and assuming a defined decline curve over an assumed well life (Figure B2.1). Small changes to the assumptions behind this curve can increase or decrease the estimated EUR significantly, thus giving a wide range of potential in the predicted EUR for a given well.

The EUR of wells in the US has tended to increase over time, with developments targeting 'sweet spots' and longer laterals, which have more than doubled in length over the last decade of development. This has been helped by development of hydraulic fracturing techniques; in general, as the lateral length increases, fracturing stage spacing becomes smaller, increasing the extractable volume.²⁷ However, there is recent evidence that productivity per unit length in the US is declining. With the most productive areas in mature shale gas formations having been developed, the pace of improvement in the effectiveness of extraction is being outstripped by the need to drill in less productive areas.²⁸

When assessing the economic case for developing a well, it is important to understand the EUR per unit length of lateral as well as the number of fracture stages. In theory, a well can be drilled to have any EUR assuming a sufficiently long lateral can be drilled, although this will increase the cost to drill and hydraulically fracture the well.

²⁵ IDDRI (2014) *Unconventional Wisdom*,

http://www.iddri.org/Publications/Collections/Analyses/Study0214_TS%20et%20al._shale%20gas.pdf

²⁶ Browning et al (2013), *Barnett study determines full-field reserves, production forecast*, Oil & Gas Journal,

http://www.beg.utexas.edu/info/docs/OGJ_SFSGAS_pt2.pdf

²⁷ Oilfield Technology (2013) *Taking Centre Stage*,

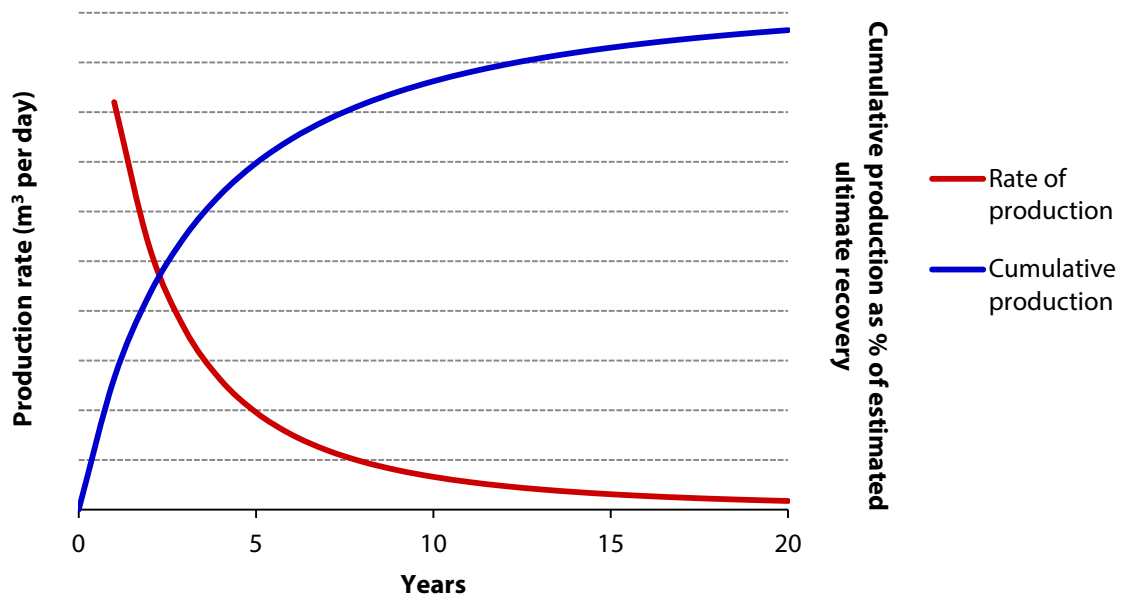
https://www.slb.com/~media/Files/completions/industry_articles/201302_ot_taking_centre_stage_bakken_ia.pdf

²⁸ MITeI (2015) *The Salient Distribution of Unconventional Oil and Gas Well Productivity*,

https://mitei.mit.edu/system/files/MITeI-WP-2015-05_Salient-Distribution-of-Unconventional-Oil-and-Gas-Well-Productivity.pdf

Box 2.1: Well productivity

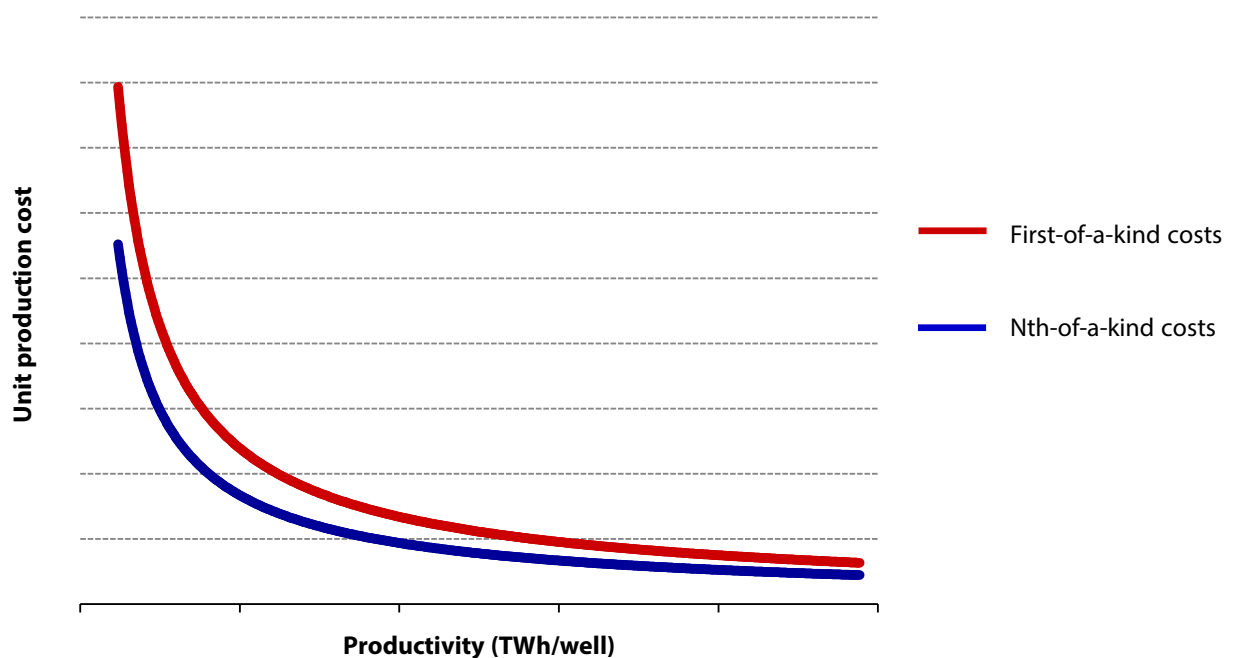
Figure B2.1: Modelled well production profile



Source: CCC calculations.

Notes: This shows an indicative production profile for a shale gas well, generated using Arps formula.

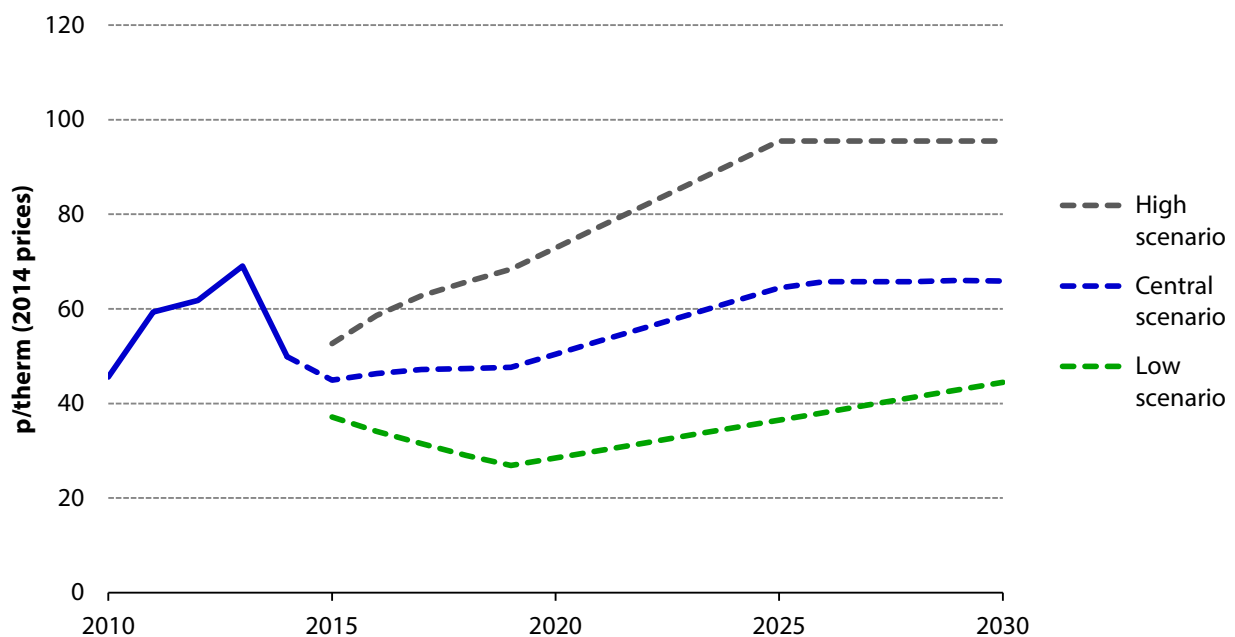
Figure 2.1: Impact of well productivity on the unit costs of gas production



Source: CCC analysis.

Notes: The unit cost of production decreases with increasing well productivity.

Figure 2.2: DECC wholesale gas price scenarios (2010-2030)



Source: DECC (2015) *Fossil Fuel Price Assumptions*. Available at <https://www.gov.uk/government/publications/fossil-fuel-price-projections-2015>.

2. Production scenarios

There are various UK production scenarios in the available literature. These focus entirely on shale gas production, with no published scenarios on UK production of coalbed methane or shale oil. Given the paucity of available evidence on these sources of onshore petroleum, as discussed in Chapter 1, this report does not assess their overall impact on UK emissions. We also assume that conventional onshore oil and gas production continues at approximately its current level, implying no new impact on carbon budgets. We therefore concentrate our analysis on shale gas.

Of the published scenarios for UK shale gas development, some have been produced using bottom-up assumptions, assessing the maximum build up rate of shale gas from an increasing number of drilling rigs, while others have used top-down methods:

Institute of Directors (IoD), 2013.²⁹ This study, which was funded by Cuadrilla, builds production scenarios bottom-up, based on an assumed build out of wells, overlaid with productivity assumptions of 0.62, 0.83 and 1.0 TWh³⁰ per lateral. It assumes the use of multilaterals, with four laterals being drilled per well (Box 2.2), although these are yet to be proven on a commercial scale for shale gas. This provides a range for production of 250-410 TWh (23-38 bcm) per year by 2030.

²⁹ IOD (2013) *Getting Shale Gas Working* http://www.iod.com/~media/Documents/PDFs/Influencing/Infrastructure/IoD_Getting_shale_gas_working_MAIN_REPORT.pdf

³⁰ In this report we give the well productivity in units of TWh per lateral or well, although it is more common to use units of billion cubic feet (bcf) 1bcf \approx 0.3 TWh gas.

- **National Grid, 2015.**³¹ The figures in National Grid's Future Energy Scenarios are based on the build-up scenarios in the IoD report. The High scenario is based on the IoD High scenario, although a delay has been allowed for as these scenarios have been published more recently. The National Grid Low scenario is half the High scenario. This produces a range of 180-360 TWh (17-33 bcm) per year in 2030.
- **Pöyry, 2011.**³² The Pöyry study is more top-down in approach, taking into account economic factors, such as ranges for production costs and wholesale gas prices. This yields a range for production of 15-50 TWh (1.5-4.5 bcm) per year in 2030. This study assumes a central well productivity of 0.7 TWh.
- **Broderick et al, 2011.**³³ This study focuses on Cuadrilla's licenced area on the Bowland Basin. The levels of production are based on figures provided by Regeneris Consulting. The highest scenario for production is around 30 TWh (3 bcm) per year in 2030, implying a well productivity of 1.1 TWh.

The full set of scenarios from these three studies provides projections of production ranging from 15 to 410 TWh (1.5 to 38 bcm) per year in 2030 (Figure 2.3). In part, this very wide range reflects current uncertainties in relation to factors including the productivity of UK geology, future fossil fuel prices and UK regulatory environment.

However, the range also reflects methodological differences: the Pöyry study incorporates the impact of economics on the rate of production, while the IoD, National Grid and Broderick scenarios focus on what is technically feasible, without directly considering economics. As such, the latter set of scenarios could be interpreted as those under which the underlying economics turn out to be favourable.

Box 2.2: Potential for multilaterals

A multilateral well is one that has more than one branch radiating out of the main borehole, providing a potential advantage of enabling a greater volume of the shale formation to be accessed from a single vertical well. They may only be used in regions where the shale resource is thick. Multilaterals could reduce unit costs considerably, with fewer wells required for the same production volume, and could be especially important given that the depth of some UK shale resources may mean high costs for vertical wells. It would also reduce the surface impact from production activities.

Multilaterals have been used widely on conventional wells; however it is unclear how many shale wells have been drilled using this method, with only one paper³⁴ reporting on a successful trial. Shale gas wells in the US are drilled in a 'factory production line' style, the simplicity of the well design enabling a large number of wells to be drilled quickly at a reduced cost. Multilateral shale wells add complexity to the well design and construction. As this technology is still at the early stages of development for the shale wells it may be considered risky. It therefore seems reasonable, at least in the early stages of a

³¹ National Grid (2015) *Future Energy Scenarios*, <http://fes.nationalgrid.com/>

³² Pöyry (2013) *Macroeconomic Effects of European Shale Gas Production*, http://www.poyry.co.uk/sites/poyry.co.uk/files/public_report_ogp_v5_0.pdf

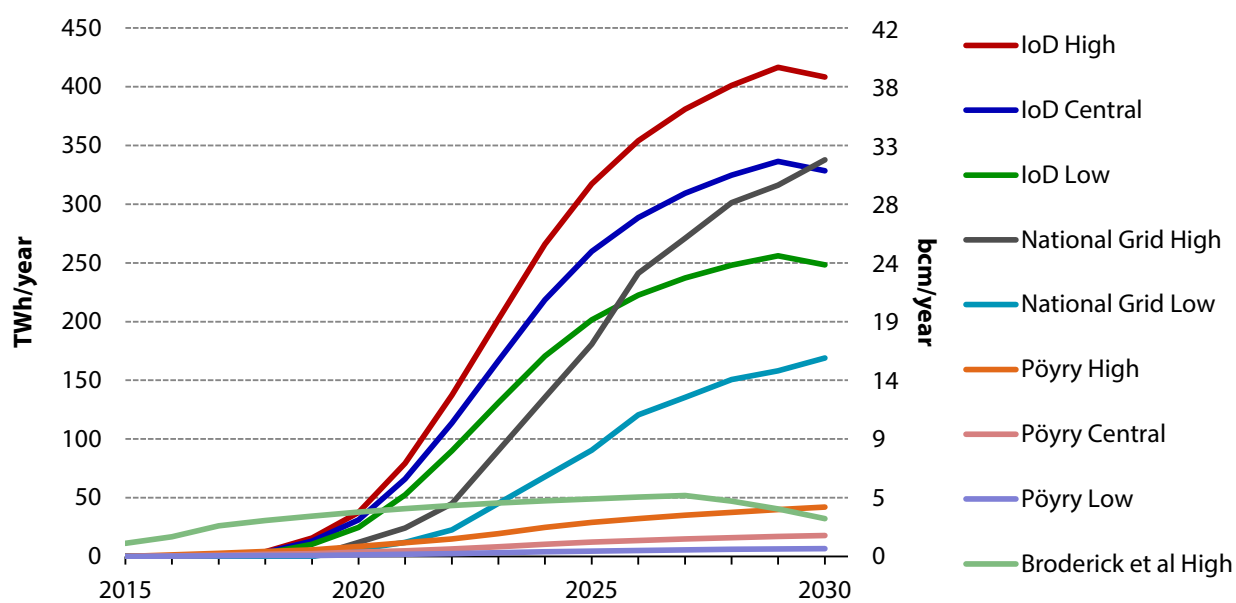
³³ Broderick et al. (2011), *Shale gas: an updated assessment of environmental and climate change impacts*, http://www.tyndall.ac.uk/sites/default/files/coop_shale_gas_report_update_v3.10.pdf

³⁴ Durst et al. (2013), *Unconventional Shale Play Selective Fracturing Using Multilateral Technology*, Society of Petroleum Engineers Middle East Unconventional Gas Conference and Exhibition held in Muscat, Oman, 28-30 January 2013.

Box 2.2: Potential for multilaterals

domestic industry, that shale wells in the UK would not utilise this technology, with production instead maximised through drilling long laterals. Multilaterals may be employed later.

Figure 2.3: Shale gas production scenarios from IoD, National Grid, Pöyry and Broderick et al studies



Sources: Institute of Directors, National Grid, Pöyry, Broderick et al.

Notes: Scenarios presented as published, without any adjustment of timing.

Although the IoD scenario is at the top end of the range of production estimates in terms of the number of wells drilled, the rate of drilling in the US expanded at an even greater rate (Box 2.3). While it may not be the most likely outcome, this scenario sets an upper bound on production and thus on potential emissions.

These studies were undertaken at different times. Therefore, although we use a selection of published scenarios as the basis for the production scenarios to 2030 considered in our analysis, we have made some adjustments to their timings so that all have production starting in 2020 (Figure 2.4):

- **Scenario A** is based on the IoD High (2013) scenario, with a 2-year delay;
- **Scenario B** is based on the IoD Low (2013) scenario, with a 2-year delay;
- **Scenario C** is based on the National Grid Low (2015) scenario;
- **Scenario D** is based on the Pöyry High scenario, with a 5-year delay.

These scenarios embody underlying assumptions for the rate at which wells and laterals are drilled. The IoD scenarios imply a rate at which wells are drilled rising to 100 wells/year in the late 2020s, with 4 laterals per well (i.e. 400 laterals drilled per year). We have inferred the rate of drilling in the Pöyry study, based on an assumption that their productivity is 0.77 TWh per lateral, resulting in a rate that rises to 50 laterals per year (Figure 2.5).

Although there is a value in medium-term projections, these become more uncertain the further out we look; we have therefore not attempted to extend the production scenarios to 2050. This may be possible with more information on the productivity of UK geology and the economic prospects for domestic production. The Committee is required to provide advice at least every five years and we will continue to review the evidence available for forecasting production levels.

Box 2.3: The US shale boom

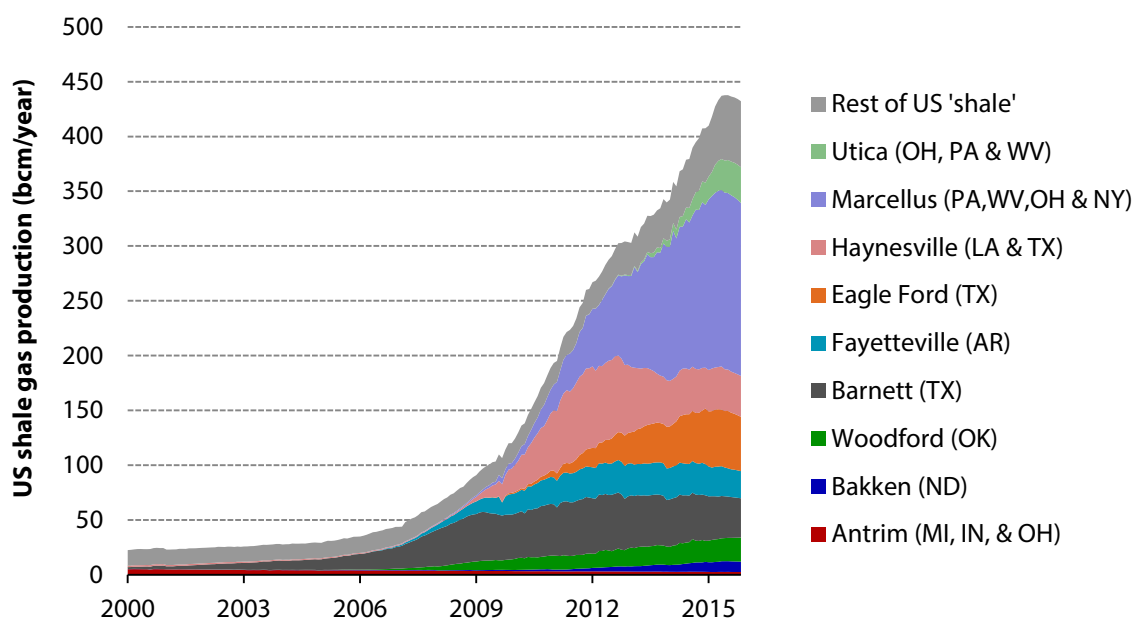
In the last decade, there has been a major expansion of unconventional gas production in the US. Shale gas rose from only 3.5% of US gas production in 2000 to 50% in 2014 (Figure B2.3). The current low gas prices are thought to be starting to bite with levels of activity expected to drop. The development of US shale gas occurred due to a number of circumstances:

- Investment by the US Government in R&D and a favourable tax regime in the 1980s resulted in technical developments in horizontal drilling and hydraulic fracturing as applied to unconventional resources.
- Combined with the high natural gas price, this resulted in a previously uneconomic unconventional reserves becoming economic.
- Other factors include favourable geology; a great knowledge of that geology, with over a million wells having been drilled; an initially 'light touch' regulatory regime; a developed oil and gas service sector, with over 80% of the world's drilling rigs; and private mineral ownership with large areas of undeveloped land, where the land owner benefits financially.

Combined with a public used to the sight of drilling rigs, this enabled the industry to expand at a rapid pace. The industry developed to a level where new wells were drilled like a factory production lines: simply and quickly with the well costs falling rapidly. These conditions may or may not be replicable in the UK. For example there are far fewer drilling rigs available in the UK.

Box 2.3: The US shale boom

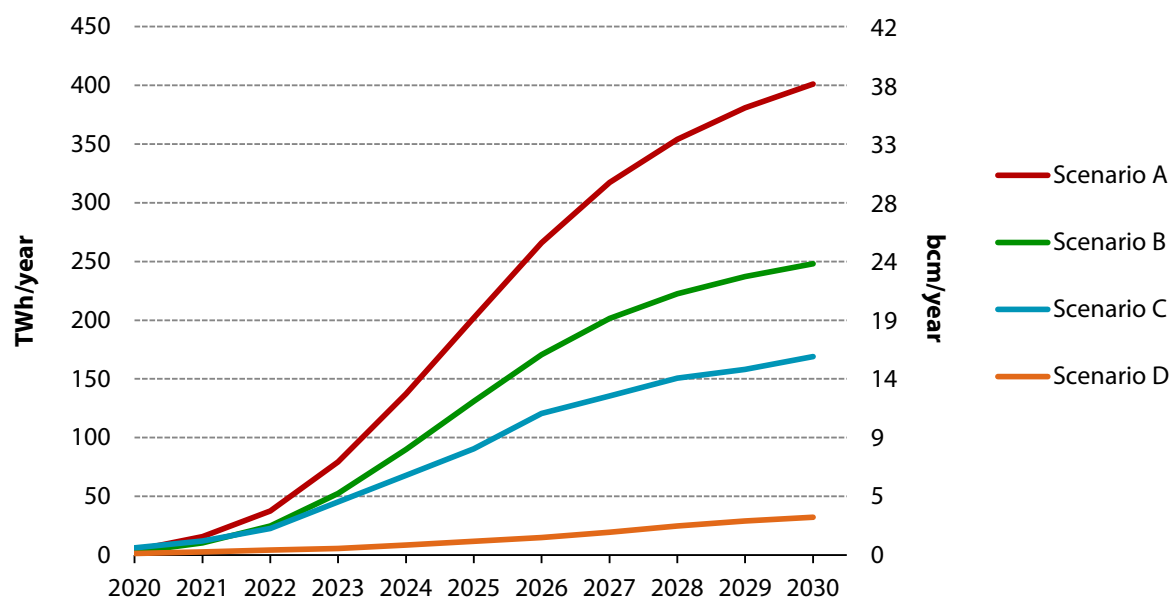
Figure B2.3: US shale gas production (2000-2015)



Source: Energy Information Administration derived from US state administrative data.

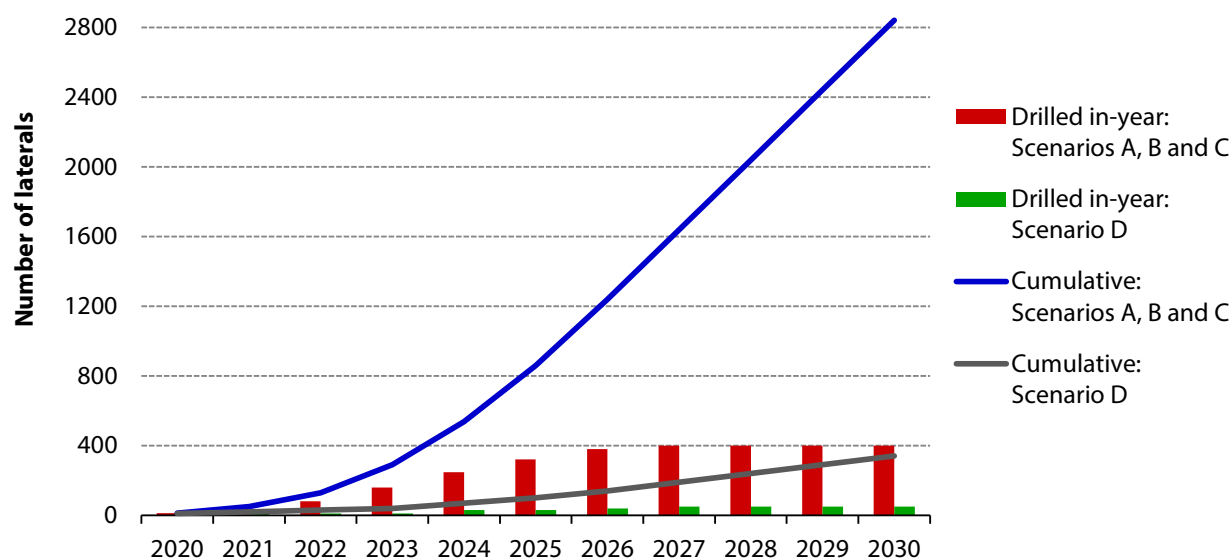
Notes: State abbreviations indicate primary US state(s).

Figure 2.4: Shale gas production scenarios used in this report (2020-2030)



Source: Based on a subset of the scenarios presented in Figure 2.3, adjusted so that production starts in 2020 in all cases.

Figure 2.5: Cumulative and annual drilling of laterals in our scenarios (2020-2030)



Source: IOD (2013) *Getting Shale Gas Working* and CCC calculations

Notes: The number of laterals was not specified for the Pöyry study, so were calculated based on wells with an assumed productivity of 0.7 TWh.

3. Impact on gas prices

In the US, the emergence of a shale gas industry produced a substantial decline in gas prices. It is unlikely that such an impact would follow from new UK production:

- In the US, shale gas production rose to around 50% of overall gas production in 2014. With little connectivity to international markets this added to supply for US consumption, and put downward pressure on prices.
- The UK is part of a highly connected gas network across Europe, which is the world's largest importing market. Additional UK production needs to be seen in the context of the overall size of the European system. Natural gas demand across the EU amounted to 471 bcm in 2013 and under the IEA 450 Scenario³⁵ would decline to 425 bcm by 2030. Even UK shale gas production at the upper end of our scenarios for 2030 would be less than 10% of this demand. Production at the low end of our range would be only around 1%.

Our assessment is therefore that UK shale gas production will do little to reduce energy bills, with prices set by international markets. This finding is consistent with those of other studies.³⁶ Production that bypasses wholesale markets could, however, reduce costs for some industrial consumers.

³⁵ IEA (2015) *World Energy Outlook* <http://www.worldenergyoutlook.org/weo2015/>

³⁶ For example, Pöyry found an impact of gas prices of 2-4% impact on gas prices in Pöyry (2012) *How will Lancashire shale gas impact the GB energy market?* <http://www.poyry.com/news/articles/how-will-lancashire-shale-gas-impact-gb-energy-market>

The weaker downward pressure on wholesale prices does, however, mean that profitability of production is less likely to be undermined. This is in sharp contrast to the US experience, where the fall in gas prices acted to limit the profitability of further production.

Chapter 3: UK fossil fuel consumption and import dependency

The combustion of fossil fuels leads to greenhouse gas emissions. In order to meet the UK's legally binding carbon budgets and 2050 target for an emissions reduction of at least 80%, consumption of unabated fossil fuels will have to fall substantially over the coming decades.

In this chapter, we set out our analysis of the impact of UK natural gas consumption on emissions, trajectories for fossil fuel consumption consistent with UK carbon targets and the potential for UK shale gas to displace imports, in three sections:

1. How UK shale gas production might impact on UK consumption
2. UK fossil fuel consumption consistent with UK carbon budgets and the 2050 target
3. North Sea natural gas supply and import dependency

1. How UK shale gas production might impact on UK consumption

The UK now imports around half the natural gas it consumes (section 3), using it in various parts of the economy, including for heat in buildings and industry, as a feedstock in industry and for power generation. UK shale gas production need not mean a rise in UK gas consumption in power generation or any other sector.

The three mechanisms by which UK shale gas production might affect consumption are via reduced prices, direct supply of hydrocarbons to industry or through policies that lead to higher gas consumption than would otherwise be the case. Of these, policy has the biggest potential to affect emissions:

- **Gas prices.** As discussed in Chapter 2, the impact of UK shale gas on wholesale prices is likely to be small, due to the degree of interconnectedness of the European gas market. Therefore we do not expect a significant impact on gas consumption from lower prices.
- **Direct supply of industry.** It may be that local hydrocarbon supplies would be attractive to UK industry, enabling long-term contracts insulated from the volatility of international markets. If this leads to increased hydrocarbon consumption as a feedstock (e.g. in the petrochemicals industry), there could be an impact on emissions. However, any such impact is likely to be small and we have not estimated the size of such an effect in our analysis.
- **Policy.** Government focus on encouraging development of a new industry in the UK could, though need not, reduce its focus on the measures needed to reduce emissions to meet carbon budgets and the UK 2050 target. Alternatively, the Government could introduce policies in which unabated gas substitutes for other fossil fuels, which in some cases would reduce near-term emissions.

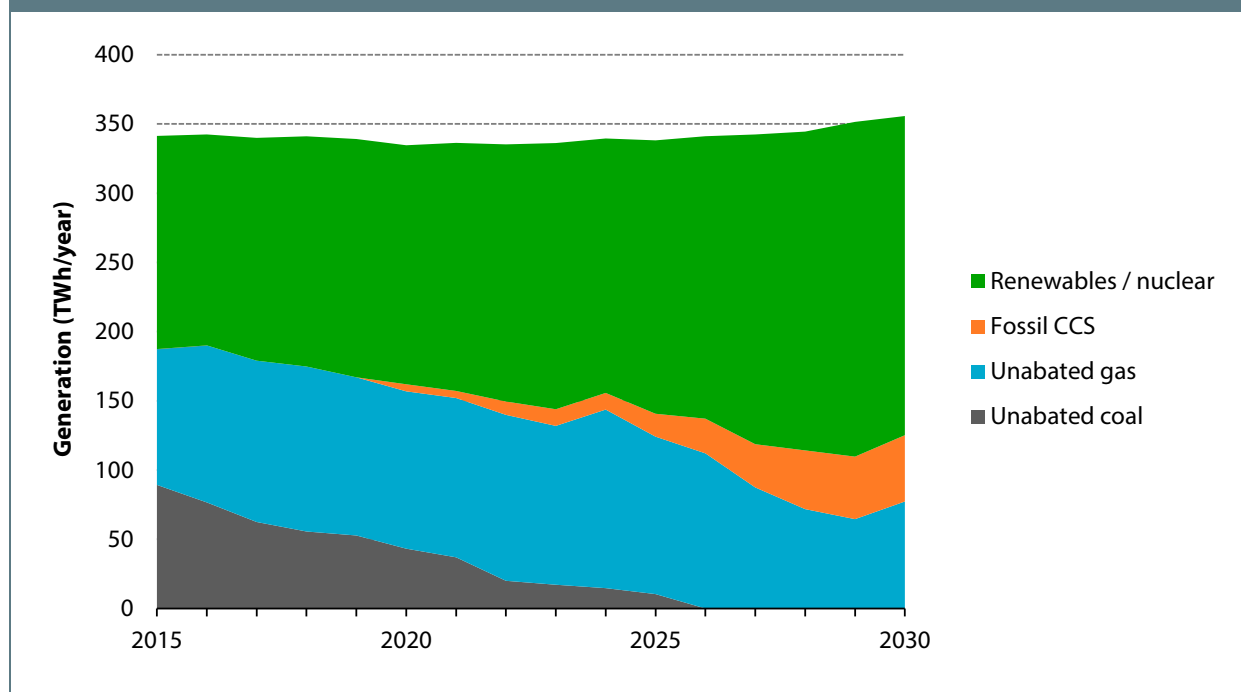
The impact of policy changes that lead to increases in gas consumption depends on whether this implies increased overall energy consumption, displacement of higher-carbon energy or displacement of low-carbon energy.

The opportunities for increased gas consumption to reduce emissions are its use with carbon capture and storage (CCS), by displacing higher-carbon fuels via coal-to-gas switching in the power sector and diesel-to-gas in heavy duty vehicles. These are all included in the scenarios for our fourth carbon budget and the fifth carbon budget advice (section 2 below). These do not imply a role for UK shale gas as a bridging fuel, given the relative timing of coal closures and potential UK shale gas production (Box 3.1).

There are also, however, many ways in which increased use of gas, or a reduced rate of decrease, would be inconsistent with the need to decarbonise. These include:

- **A large long-term role for unabated gas-fired electricity generation.** Investment in low-carbon power generation is a very important part of the least-cost path to meeting the 2050 target. Our scenarios consistent with this path have carbon intensity below 100 gCO₂ per kWh in 2030, including around 75% of generation coming from low-carbon sources (including gas CCS) with the remainder coming from unabated gas-fired capacity (Figure 3.1).
- **Failure to deploy energy efficiency and low-carbon heat in buildings and industry.** Decarbonisation of heat is very important in meeting carbon budgets and the 2050 target, requiring both substantial improvements in energy efficiency and deployment of low-carbon heat. Action to 2030 in these areas, including significant roll-out of heat pumps and heat networks, is essential in paving the way for considerably more rapid reductions in emissions from buildings in the period between 2030 and 2050.

Figure 3.1: Power generation from different sources in CCC Central scenario (2015-2030)



Source: CCC (2015) *Power sector scenarios for the fifth carbon budget*. Available at <https://www.theccc.org.uk/publication/power-sector-scenarios-for-the-fifth-carbon-budget/>

Box 3.1: Opportunities for increased gas consumption to reduce UK greenhouse gas emissions

The policy opportunities for increased gas consumption to reduce emissions are its use with CCS and by displacing higher-carbon fuels via coal-to-gas switching in the power sector and diesel-to-gas in heavy duty vehicles:

- **Gas consumption with CCS.** Use of CCS enables natural gas to be used in a low-carbon way. It reduces the carbon intensity of electricity generation from over 350 gCO₂/kWh to around 50g/kWh. This involves an increase in gas consumption per unit of electricity generated of around 15%, due to the energy penalty of the CO₂ capture process.³⁷ CCS can also be used when producing hydrogen from natural gas; this is likely to be the lowest-cost means of low-carbon hydrogen production.³⁸
- **Coal to gas in the power sector.** While most of the UK's coal fleet is coming towards the end of its technical lifespan, there is a short window of opportunity to accelerate its phase-out before the scope for unabated fossil generation disappears. The Government has committed to phasing out unabated coal generation by 2025, subject to sufficient gas-fired capacity being built to maintain system security. It would result in a short-lived emissions saving, and is already in the Government's plans and factored into our scenarios for future carbon budgets.
 - This phase-out of unabated coal is consistent with our assessment of the cost-effective path for decarbonisation of the power sector, and is included in our Central power scenario in the fifth carbon budget analysis. In this scenario unabated gas-fired generation reaches 38% of supply in the mid-2020s.
 - Given the need for strong medium-term decarbonisation of the power system in order to be on track for the 2050 target, the increase in unabated gas-fired generation is short-lived and its contribution reduces to 22% of supply by 2030 (Figure 3.1 above).
 - This brief increase in gas consumption for power generation does not require UK shale gas production. It could be met through a temporary increase in gas imports, for which the UK already has adequate infrastructure.
- **Switching to gas in heavy vehicles.** Switching from diesel to natural gas in heavy goods vehicles (HGVs) could have a small benefit in lifecycle greenhouse gas emissions savings, as long as leakage of methane in vehicle fuelling or operation (known as 'methane slip') is minimised.
 - Tests of natural gas in heavy duty vehicles have so far focused on dual-fuel compression-ignition engines, using a combination of diesel and methane, which could offer tailpipe CO₂ savings of up to 10%. However, there is some evidence that methane can leak through the exhaust while the HGV is in use, particularly in retrofitted dual-fuel vehicles. Spark-ignition engines are currently being tested and may avoid the methane slip issue, although as they are less efficient than diesel engines this will reduce the CO₂ savings.
 - Rather than greenhouse gas emissions, it may be that a switch to methane HGVs is driven by concerns over air quality and the local pollutants emitted by diesel engines. Therefore, while roll-out of methane HGVs during the 2020s would only lead to a small reduction in greenhouse gas emissions, it may be justified for other reasons.
 - Given the minimal reduction in greenhouse gas emissions, longer-term solutions such as hydrogen HGVs may be required to meet the 2050 target, and should be explored fully.

³⁷ Based on an unabated gas CCGT plant having an efficiency of 53%, and a post-combustion gas CCS plant having an efficiency of 46%, on a higher heating value basis.

³⁸ E4tech, UCL and Kiwa Gastec (2015) *Scenarios for deployment of hydrogen in meeting carbon budgets*, <https://www.theccc.org.uk/publication/e4tech-for-ccc-scenarios-for-deployment-of-hydrogen-in-contributing-to-meeting-carbon-budgets/>

2. UK fossil fuel consumption consistent with UK carbon budgets and the 2050 target

Shale gas is one source of fossil natural gas. Although natural gas has a lower carbon content than other fossil fuels, it is not low-carbon unless used with CCS. UK unabated consumption of oil and gas (i.e. without CCS) will need to fall over the coming decades in order to meet the carbon budgets and the 2050 target.

The extent to which a required emissions reduction translates into reduced consumption of a particular fossil fuel depends on relative prices and the substitution possibilities for those fuels:

- the relative prices of fossil fuels, including the internalised costs of carbon;
- scope to reduce energy consumption across sectors through energy efficiency and behaviour change;
- cost-effectiveness of different non-fossil technologies (e.g. renewables, nuclear, heat pumps and electric vehicles) to substitute for fossil fuels; and
- availability of CCS, which would allow fossil fuels to contribute to low-carbon energy supplies.

Policy effort is required to ensure that unabated fossil fuel consumption is consistent with carbon budgets, but there are different possible pathways to achieve this. In general, they require unabated consumption of all fossil fuels to decline over time, most likely reducing the use of fuels with the highest carbon intensity (e.g. coal) earlier and more strongly than those with lower carbon intensity (e.g. natural gas).

We assessed the cost-effective path for emissions reduction to 2032 as part of our advice on the fifth carbon budget.³⁹ In doing so, we constructed Central sectoral scenarios that represent our best assessment of the measures that reduce emissions at lowest cost and/or are required in preparing to meet the 2050 target. The Central economy-wide scenario, which aggregates these sectoral paths, forms the basis of our recommendation for the level of the fifth carbon budget.

The Central scenarios are not prescriptive and there are important uncertainties that imply that a different pattern of decarbonisation might be preferred, or that more or less effort may be required in order to reduce emissions to the necessary levels. We therefore also constructed Barriers, Max and Alternative sectoral scenarios, which vary the extent and composition of the emissions reduction in each sector (Box 3.2).

Box 3.2: Central, Barriers, Max and Alternative scenarios from our fifth carbon budget analysis

The Central sectoral scenarios from our advice on the Fifth Carbon Budget represent our best assessment of the technologies and behaviours required over the period from 2028 to 2032 to meet the 2050 target cost-effectively, while meeting the other criteria in the Act.

However, we also developed further scenarios that explicitly recognise uncertainty, in two ways:

- In addition to the Central scenarios, we developed Barriers and Max scenarios in each sector. The **Barriers** scenario represents unfavourable conditions for key measures (technological barriers, failure to achieve cost reductions, or market barriers), while the **Max** scenario represents maximum

³⁹ CCC (2015) *The Fifth Carbon Budget - The next step towards a low-carbon economy*, <https://www.theccc.org.uk/publication/the-fifth-carbon-budget-the-next-step-towards-a-low-carbon-economy/>

Box 3.2: Central, Barriers, Max and Alternative scenarios from our fifth carbon budget analysis

feasible deployment of key measures. This demonstrates that there is flexibility in how a given carbon budget could be met with varying degrees of effort across sectors.

- We also developed one or more **Alternative** scenarios in each sector, representing deployment of different measures to those in Barriers, Central and Max (e.g. greater use of hydrogen for transport or heat). This demonstrates some robustness within sectors to uncertainty over the types of abatement options that will ultimately prove to be better-performing and cost-effective.

The sectoral scenarios can be combined in different ways to be consistent with the recommended fifth carbon budget and the 2050 target. These would have different implications for the precise pattern of fossil fuel consumption across the economy.

The Central, Barriers and Max sectoral scenarios can be combined in many different ways. This enables us to compile economy-wide scenarios with similar overall emissions to the Central scenario, which are therefore consistent with meeting carbon budgets and the 2050 target.

In order to set out the range of possible consumption of oil and natural gas over the period to 2050 while meeting carbon targets, we have compiled four economy-wide scenarios. Each of these either meets or outperforms the legislated 2050 target and carbon budgets, as well as the recommended fifth carbon budget:

- **Central.** This economy-wide scenario reflects our best assessment of the cost-effective path for emissions reduction. Having formed the basis of the proposed fifth carbon budget, it is consistent with legislated and proposed carbon budgets and with meeting the 2050 target.
- **Barriers in Buildings,** a variant on the Central scenario, meets the carbon targets with less reduction in emissions from heating buildings in the medium and long terms, and greater effort in the transport, agriculture and industry sectors to compensate. The greater residual emissions from heating will tend to imply greater gas consumption than in the Central scenario, with commensurately lower consumption of other fossil fuels and/or greater deployment of CCS.
- **Barriers in Transport,** another variant of the Central scenario, has higher residual transport emissions, requiring greater effort in agriculture, industry and buildings. This leads to more oil and less gas consumption than under the Central scenario.
- **No CCS.** CCS is an important part of our Central scenario for meeting the 2050 target, and contributes emissions important reductions in heavy industry and when combined with bioenergy that cannot simply be replaced with alternative low-carbon technologies on a like-for-like basis. This means that additional reductions of at least 35 MtCO₂e/year need to be found from elsewhere in the economy in 2050, while doing so with a reduced set of decarbonisation options, as many of the options for further decarbonisation in end-use sectors depend on CCS to be feasible and cost-effective (Box 3.3). This entails each sector following the Max scenario, excluding CCS measures, in order to meet the economy-wide 2050 target.

Box 3.3: The role of CCS in decarbonisation options across the economy

We estimated in our advice on the fifth carbon budget in November 2015 that the absence of CCS in 2050 would require extra emissions savings elsewhere in the economy of at least 35 MtCO₂e per year in order to meet the 2050 target. This is likely to require almost full decarbonisation of buildings and surface transport by the middle of the century. The best current evidence suggests that this would be substantially more expensive than deployment of CCS, even allowing for the initial high costs of projects in a CCS commercialisation programme.

In part this reflects that CCS could support options for decarbonisation beyond its direct application, including:

- Use of hydrogen in transport, buildings and industry (the lowest-cost source of low-carbon hydrogen is likely to be from fossil fuels with CCS);⁴⁰
- Roll-out of heat networks (where a significant proportion of potential derives from using recoverable heat from thermal power stations);
- Use of heat pumps (where CCS power generation could be important in meeting the seasonal swing in electricity demand);
- Use of bioenergy in CCS plant (implying negative emissions that can offset hard-to-reduce emissions elsewhere in the economy and make the most of scarce sustainable bioenergy resource).

Delays to CCS deployment therefore reduce its likely direct contribution to lowering emissions, and also closes down a range of important options that could compensate for this shortfall. It is the combination of these two effects that leads to estimates by the Committee⁴¹ and the Energy Technologies Institute⁴² that the cost of meeting the 2050 target would double without CCS.

These four economy-wide scenarios are not exhaustive, but are designed to test the implications for consumption of different fossil fuels under a range of assumptions for the balance and effort across sectors, consistent with meeting carbon targets. The main variations are the balance between unabated gas compared to oil consumption, and the extent to which fossil fuels are used with CCS for low-carbon energy supply. Each of the scenarios includes an important but limited contribution to gas supplies from biomethane. As unabated coal will soon largely disappear from the energy system, we focus here on oil and natural gas.

The four scenarios produce a range for possible natural gas consumption in 2050 that could vary by a factor of four (Figure 3.2). By contrast, oil consumption varies much less with only around 40% higher consumption in the Barriers in Transport scenario compared to the No CCS one (Figure 3.3). Even under the 'No CCS' scenario, significant quantities of oil and gas are needed well beyond 2030:

⁴⁰ E4tech, UCL and Kiwa Gastec (2015) *Scenarios for deployment of hydrogen in meeting carbon budgets*, <https://www.theccc.org.uk/publication/e4tech-for-ccc-scenarios-for-deployment-of-hydrogen-in-contributing-to-meeting-carbon-budgets/>

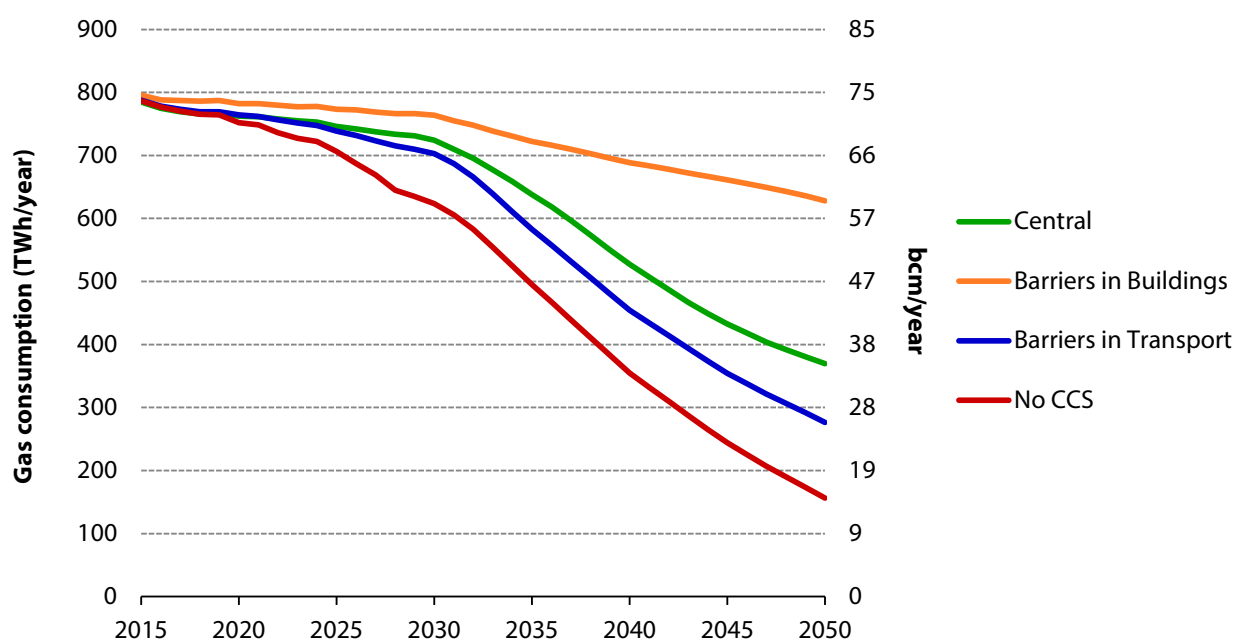
⁴¹ CCC (2012) *The 2050 target – achieving an 80% reduction including emissions from international aviation and shipping* https://www.theccc.org.uk/archive/aws/IA&S/CCC_IAS_Tech-Rep_2050Target_April2012.pdf

⁴² ETI (2015) *Building the UK carbon capture and storage sector by 2030 – Scenarios and actions* <http://www.eti.co.uk/wp-content/uploads/2015/03/CCS-Building-the-UK-carboncapture-and-storage-sector-by-2013.pdf>

- Across these scenarios, consumption of both oil and natural gas fall only moderately to 2030 (by up to 28% and 21% respectively, depending on the scenario), reflecting that fossil fuels will continue to be used in both surface transport and buildings well beyond this time.
- Looking out to 2050, the range for gas consumption varies by a factor of four across the scenarios, with the width of this range reflecting both the impact of the Barriers scenario for heat in buildings and the importance of CCS in providing a market for fossil fuels and providing headroom via application to industry and bioenergy.
- The range for oil to 2050 is considerably smaller, with the Barriers in Transport scenario having only around 40% greater consumption than under No CCS. This is primarily due to the lack of direct application of CCS to oil combustion in our scenarios.

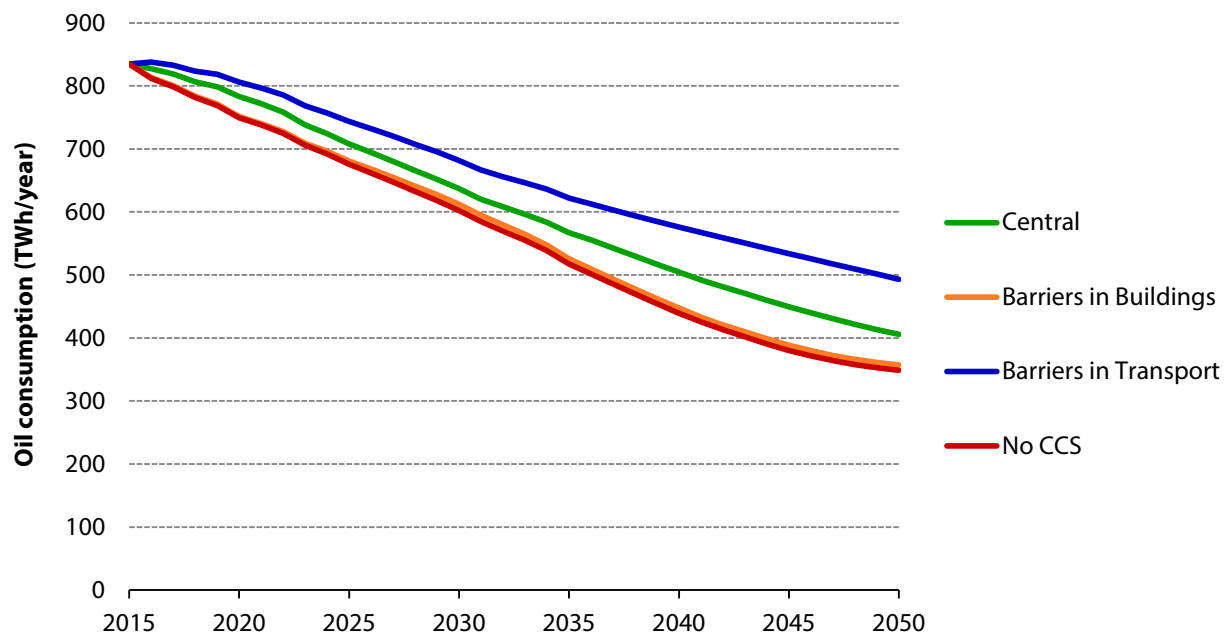
The availability or otherwise of CCS has major implications for the level of fossil fuel consumption in 2050 that is compatible with achieving the statutory emissions reduction of at least 80% on 1990 levels. This is both because CCS allows an additional market for fossil fuels in supplying low-carbon energy (e.g. in power generation or hydrogen production), but also because unabated fossil fuel use in end-use sectors (e.g. heat and transport) would need to be much more heavily constrained to offset the reduced abatement in industry and bioenergy in the absence of CCS (Figure 3.4).

Figure 3.2: Economy-wide gas consumption under different scenarios (2015-2050)



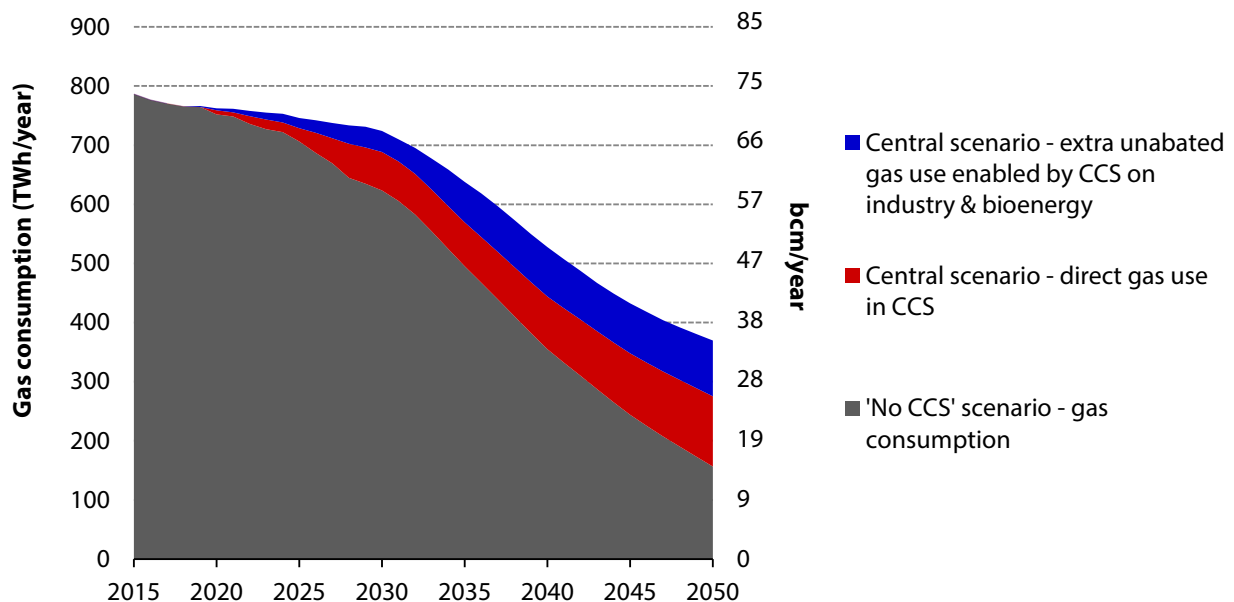
Source: CCC analysis, based on scenarios in the fifth carbon budget advice.

Figure 3.3: Economy-wide oil consumption under different scenarios (2015-2050)



Source: CCC analysis, based on scenarios in the fifth carbon budget advice.

Figure 3.4: Direct and indirect impacts of CCS availability on gas consumption to 2050



Source: CCC analysis, based on scenarios in the fifth carbon budget advice.

The recent cancellation of the UK CCS Commercialisation Programme does not mean that CCS cannot play a role to 2050, but this cancellation has raised doubts about that role and may imply a substantial delay in its deployment at scale. A significant delay could lead to less feasible CCS deployment over the period to 2050, reducing its role in decarbonisation and implying a lower level of fossil fuel consumption compatible with meeting the 2050 target.

As well as providing a smaller market for fossil fuels, the greater pressure placed on UK emissions targets in the absence of CCS would also make it more difficult to accommodate the emissions associated with production, as there would be less scope to reduce emissions elsewhere in the economy to compensate (Chapter 5).

A UK approach to delivery of carbon capture and storage (CCS) is urgently needed.

3. North Sea natural gas supply and import dependency

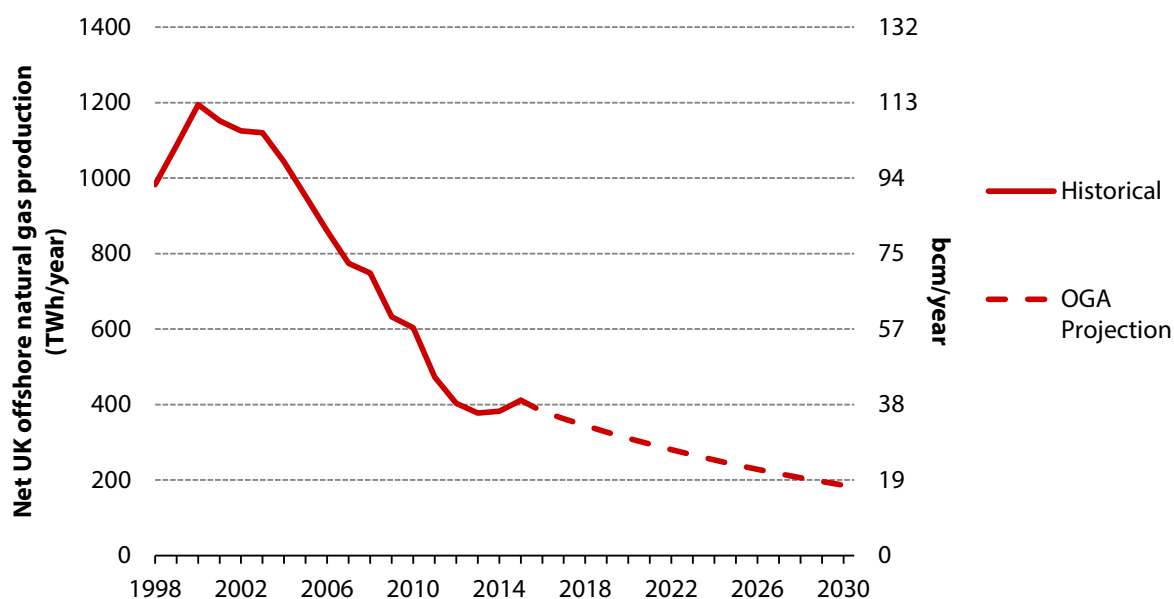
The UK currently gets around half its gas supplies from imports, mainly via pipeline from Norway and via liquefied natural gas (LNG) tankers. Domestic output is projected to continue its decline over the coming decades and most projections suggest that the share of imports will rise over time, even as consumption falls.

In 2015, the North Sea produced natural gas equivalent to around 54% of UK consumption.⁴³ In the absence of new supplies of onshore petroleum to contribute to overall fossil supplies in the UK, domestic production is projected to continue to fall as North Sea production declines (Figure 3.5).

Under our scenarios for gas consumption, domestic natural gas consumption would fall more slowly than the decline in North Sea production projected by the Oil and Gas Authority (OGA). As such, the gap between the two would grow, most quickly for the Barriers in Buildings scenario and least quickly for the No CCS scenario. Under all of the shale gas production scenarios, the UK would remain a net importer of gas (Figure 3.6).

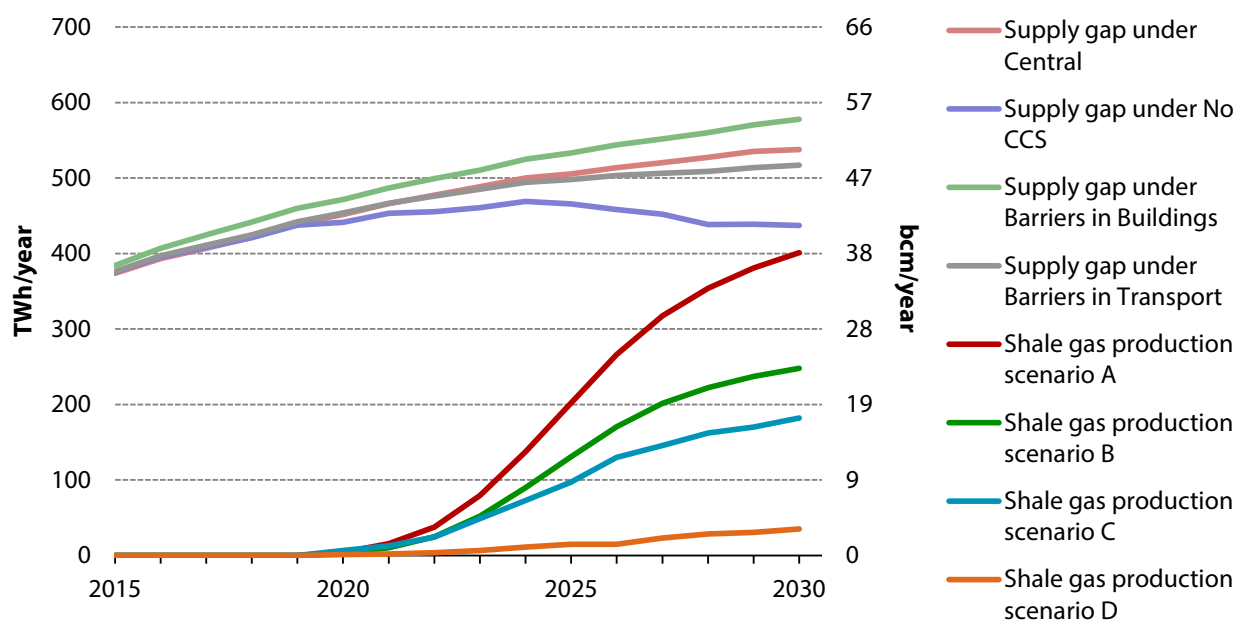
⁴³ OGA (2016) *UKCS Oil and Gas Production Projections February 2016* <https://www.gov.uk/guidance/oil-and-gas-uk-field-data>

Figure 3.5: Projected production of offshore natural gas production to 2030



Source: OGA (2016) UKCS Oil and Gas Production Projections February 2016 <https://www.gov.uk/guidance/oil-and-gas-uk-field-data>

Figure 3.6: Projected gap between offshore natural gas production and different consumption scenarios to 2030



Source: CCC analysis.

Notes: Supply gap represents the difference between UK offshore gas production (Figure 3.5) and fossil natural gas consumption under the economy-wide scenarios (Figure 3.2).

The UK is likely to remain a net importer of natural gas even as we reduce fossil energy consumption to meet carbon budgets. There may be benefits for energy security and domestic industry if new domestic sources of natural gas production reduce UK dependence on imported gas. There is no case, however, for higher levels of UK gas consumption than those set out above, consistent with meeting carbon budgets.

Unabated gas consumption must be consistent with the levels in our scenarios, unless reductions in emissions beyond those the Committee has identified can be found elsewhere. Therefore, any new sources of UK production must be used to displace imports. Allowing unabated consumption above these levels would not be consistent with the decarbonisation required under the Climate Change Act.

We consider the relative lifecycle emissions of UK shale gas and various sources of imported gas in Chapter 4.

Chapter 4: Emissions relating to onshore petroleum extraction

This chapter sets out estimates for the emissions relating to shale production in the UK, reviews the available technologies and techniques to mitigate them and presents comparisons with lifecycle emissions of imported gas.

We focus here on the impact on UK emissions due to production, rather than combustion, transmission or distribution, on the basis that UK fossil energy consumption and methane leaks from the gas grid are unaffected by the development of an onshore industry (i.e. consumption remains consistent with the fifth carbon budget scenarios set out in Chapter 3).

In principle, changes in UK gas consumption could also affect the level of fugitive emissions from the transmission and distribution grid. These emissions are important and should not be ignored; we intend to return to these emissions as part of our future work programme.

In this chapter, we set out our analysis on the range for the potential emissions footprint of UK onshore production, opportunities to limit these emissions and how they compare to the emissions associated with imports in four sections:

1. Sources of emissions relating to shale gas production
2. Emissions mitigation opportunities and costs
3. Emissions footprint of shale oil production
4. Comparison of lifecycle emissions from UK shale gas with imported liquefied natural gas.

1. Sources of emissions relating to shale gas production

Oil and gas wells are developed over four main stages: exploration, well development, production and well decommissioning and abandonment. Greenhouse gas emissions occur at each of these stages. We have included these emissions in our analysis in four categories:

- **Fugitive emissions**, which include both vented emissions and unintentional leaks. Vented emissions are a result of planned releases, where permitted, as a result of maintenance operations and safety concerns. Unintentional methane leaks include those from valves and pipe joints, compressors, well heads and accidental releases above and below ground from the well through to injection into the grid or before being put to use.
- **Combustion emissions** that occur from on-site burning of fossil fuels. The emissions come from engines, such as those used for drilling and hydraulic fracturing, as well as from any flaring of gas.
- **Indirect emissions** that result from transporting materials and waste to and from site.
- **Land-use change emissions**, which include the CO₂ released (e.g. from the soil) when land is converted from one use to another, as well as any emissions relating to land remediation during decommissioning.

Top-down approaches to estimating methane emissions, via sampling of atmospheric methane concentrations, tend to produce higher estimates for the proportion of gas being released than bottom-up studies (Box 4.1). However, top-down studies cannot currently attribute emissions to particular sources (e.g. shale gas production), nor do they allow detailed analysis of the opportunities for reducing these emissions.

We have therefore based our analysis on the best available bottom-up evidence base (Box 4.2), in order to estimate ranges for potential emissions in a UK context. We will keep top-down measurements under review to ensure that our estimates of methane emissions from onshore production reflect the available evidence as best as possible. The gap between top-down and bottom-up estimates for the US does, however, suggest there are risks of significant emissions from super-emitters. We reflect this in our consideration of regulatory issues below.

Box 4.1: Top-down vs. bottom-up estimates of methane emissions

There have been several recent studies aimed at further understanding fugitive methane emissions associated with onshore oil and gas production in the US.⁴⁴ A key focus of these studies has been regions with a recent increase in unconventional oil and gas production. The measurement surveys employed both 'top-down' and 'bottom-up' approaches. Top-down studies measure or estimate (from satellite remote sensing) the concentration of emissions in the atmosphere and use different modelling approaches to estimate the methane emitted from a region. Bottom-up studies measure the emissions from an individual component or facility directly.⁴⁵

A recent series of top-down studies, which measure the methane concentration in the atmosphere, have found methane emissions from mainly shale gas producing regions of up to 2.8% of throughput.⁴⁶ In regions more dominated by oil production, the fraction of methane production lost could be up to around 9%⁴⁷ (a higher proportion of a much smaller quantity of methane production).⁴⁸ This higher leakage rate is explained in part by gas not being the primary product, with some of the produced methane being flared (a proportion of methane will pass through the flare unburned) or vented due to the absence of gas infrastructure that would enable its productive use.

A recent study has further highlighted a 30% increase in atmospheric methane (both anthropogenic and biogenic) concentrations between 2002 and 2014 in the US. Although the paper does not attempt to identify the source of methane,⁴⁹ this period coincides with the development of unconventional oil

⁴⁴ These studies include studies by Allen et al. (2013), Zavala-Araiza et al. (2015), Pétron et al. (2014), Marchese et al. (2015), Karion et al. (2013), and Peischl et al. (2015).

⁴⁵ JISEA (2015), *Estimating US Methane Emissions from the Natural Gas Supply Chain*, <http://www.nrel.gov/docs/fy16osti/62820.pdf>

⁴⁶ Peischl et al. (2015), Quantifying atmospheric methane emissions from the Haynesville, Fayetteville, and northeastern Marcellus shale gas production regions, *J. Geophys. Res. Atmos.*, 120, 2119-2139.

⁴⁷ Karion et al. (2013), Methane emissions estimate from airborne measurements over a western United States natural gas field. *Geophys. Res. Lett.*, 40, 4393–4397.

⁴⁸ Peischl et al. (2015), Quantifying atmospheric methane emissions from the Haynesville, Fayetteville, and northeastern Marcellus shale gas production regions, *J. Geophys. Res. Atmos.*, 120, 2119-2139.

⁴⁹ Turner et al. (2016), A large increase in U.S. methane emissions over the past decade inferred from satellite data and surface observations, *Geophysical Research Letters*, 43.

Box 4.1: Top-down vs. bottom-up estimates of methane emissions

and gas. A further study has estimated that 40% of recent growth in atmospheric methane between 2007 and 2014 can be attributed to oil and gas activities.⁵⁰

Top-down studies do not yet have sufficient resolution to identify the source of emissions, so it is not possible to say whether these methane emissions are due to shale gas production. Attempts to reconcile top-down and bottom-up estimates suggest that the two approaches may not be inconsistent, although some increases to US inventory emissions factors may be necessary.⁵¹ The factors which may enable top-down and bottom-up estimates to converge are: ensuring top-down studies report fossil methane only; having accurate facility counts for bottom-up analysis; and characterising the contribution of super-emitters accurately.

It is therefore important that top-down studies are integrated further with the bottom-up approach in order to reduce the gap between the two techniques.^{52,53}

Box 4.2: Sources for the data on emissions

We have obtained estimates for the greenhouse gas emissions associated with onshore petroleum exploitation from various sources:

- **UK emissions inventory.** Greenhouse gas emissions from petroleum exploitation are estimated in the National Atmospheric Emissions Inventory (NAEI), which is produced annually under international reporting obligations. The inventory is used as the basis for reporting the UK's GHG emissions to the European Commission (EC) and United Nations Framework Convention on Climate Change (UNFCCC).
- The UK GHG inventory uses a range of generic emission factors, which have been developed for each piece of equipment, by sampling the potential GHG emissions from each piece. The emissions factor is then multiplied by an activity factor, which accounts for the number of each equipment type. The accuracy of the estimated emission depends very much on the quality of both emission factor and activity factor.
- We have used various sources to estimate the emissions not currently covered by the UK inventory, including emissions from unconventional oil and gas. The range of sources of onshore petroleum varies in quality and volume of information available:
 - A growing number of studies have been developed on the lifecycle analysis of natural gas supplies, with many comparing lifecycle emissions for shale gas to those for other sources of energy. Until recently the majority of these studies relied on engineering assumptions in the absence of primary data.
 - More recently, the Environmental Defense Fund, a US NGO, has funded a group of studies that measured both individual sites and entire regions.

⁵⁰ Hausmann et al. (2016), Contribution of oil and natural gas production to renewed increase in atmospheric methane (2007–2014): top-down estimate from ethane and methane column observations, *Atmos. Chem. Phys.*, 16, 3227–3244

⁵¹ Brandt et al. (2014), Methane Leaks from North American Natural Gas Systems, *Science*, 343, 733–735

⁵² Zavala-Araiza et al. (2015), Reconciling divergent estimates of oil and gas methane emissions, *PNAS*, 112(51), 15597–15602.

⁵³ JISEA (2015), *Estimating US Methane Emissions from the Natural Gas Supply Chain*, <http://www.nrel.gov/docs/fy16osti/62820.pdf>

Box 4.2: Sources for the data on emissions

In September 2015, the Sustainable Gas Institute (SGI) produced a comprehensive literature review on the available evidence on GHG emissions from the exploitation of gas. We have used this as the basis for our emissions data, supplemented by a few more recent studies.

The emissions associated with production primarily come from the well development and production stages:

- **Exploration** emissions are generally small, relating to transporting the seismic equipment and drilling the exploration well. Small volumes of gas may be generated during the development of the well, most of which is likely, at a minimum, to be burned in a flare. There is, however, little information available on emissions associated with exploration.⁵⁴ Most studies analysing the GHG emissions from exploiting onshore petroleum either ignore this phase or assume the emissions are negligible.⁵⁵ It should not be taken as a given that emissions from exploration will be low, especially for any extended well tests. Appropriate mitigation techniques should be employed where practical.
- **Pre-production / well development** emissions result from site preparation, transporting the equipment and construction materials to site, and drilling and completing the well. The key emissions from this stage are expected to be from well completion and potentially land-use change:
 - **Well completion.** Once hydraulic fracturing is complete a period of ‘flowback’ follows over a period of three to ten days, during which some of the fluids return to the surface mixed with increasing volumes of gas. In the US, the gas mixed in with the flowback fluid has historically been predominantly vented to the atmosphere. Emissions from this stage have been disputed, partly due to the use of modelled rather than measured emissions (Box 4.3). The volume of gas produced during completion is linked to the pressure of the well and the initial flow rate, both of which are indirectly linked to the estimated ultimate recovery (EUR) of the well (see Chapter 2). Therefore, the emissions associated with completion will be positively correlated with the EUR, although this relationship is unlikely to be directly proportional.

⁵⁴ MacKay-Stone (2013), *Potential Greenhouse Gas Emissions Associated with Shale Gas Extraction and Use*, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/237330/MacKay_Stone_shale_study_report_09092013.pdf

⁵⁵ SGI (2015), *Methane and CO₂ emissions from the natural gas supply chain*, <http://www.sustainablegasinstitute.org/publications/white-paper-1/>

-
- **Land-use change.** The SGI report indicates that the GHG emissions are small at all the stages up to well completion. However, a lifecycle analysis for the Scottish Government has highlighted a further potential key emission, suggesting that land-use change emissions could be significant if development occurs on carbon-rich land. For grassland, land-use change emissions are estimated to be in the region of 920 tCO₂ per well or 1,800 tCO₂ per TWh. However, should production instead occur in an area with deep peat soil, estimated emissions are around 10 times higher, at around 10,000 tCO₂ per well or 20,000 tCO₂ per TWh.⁵⁶ Land-use change emissions may also be significant for other types of land.
 - **Gas production.** Emissions from gas production result from the general operation of the well, gathering and compression equipment, and gas processing, before injection into the gas grid. The key emissions come from workovers, liquid unloading, leaks and vents:
 - **Workovers.** After a period of time the production well generally requires significant maintenance, known as ‘workovers’. This covers a range of tasks, such as fixing leaks, descaling the well, cleaning out the perforations, or creating new ones. It may also require some hydraulic fracturing work. The number of re-fracturing events varies considerably and is ultimately an economic decision to improve the productivity of the well. The frequency of workovers is estimated in the literature to be between one every six years and one every 30 years.⁵⁷
 - **Liquid unloading.** The flow of gas through the well may become impeded due to a build-up of liquids that accumulate at the bottom of the well, especially if the gas is wet. Early in the well’s life the flow of gas is sufficient to wash these out of the well, but when the flow of gas decreases liquids may begin to accumulate. The range of measured and estimated emissions from liquids unloading is extremely large, with little understanding for this variation and of how and why these emissions vary across wells in different regions and of various ages.⁵⁸ It is currently uncertain how many shale wells in the UK would require liquid unloading.
 - **Pneumatic devices.** Pneumatic devices are used widely in the gas production stage for control or measurement. They typically use the pressure of the natural gas in the pipeline for the operation of valves, instruments and pumps, which results in a small release of methane. Although each pneumatic device emits a small volume of methane there is likely to be a large number of devices throughout the supply chain. The US Environmental Protection Agency (US EPA) report that this contributes to 14% of gas supply-chain emissions in the US.⁵⁹

⁵⁶ Bond et al. (2014), *Life-cycle Assessment of Greenhouse Gas Emissions from Unconventional Gas in Scotland*, http://www.climateexchange.org.uk/files/2514/1803/8235/Life-cycle_Assessment_of_Greenhouse_Gas_Emissions_from_Unconventional_Gas_in_Scotland_Full_Report_Update_d_8.Dec.14.pdf

⁵⁷ The frequency of one workover every 30 years reflects a situation in which some wells do not have workovers, while others have them within the well’s economic life, which might be up to 20 years.

⁵⁸ SGI (2015), *Methane and CO₂ emissions from the natural gas supply chain*, <http://www.sustainablegasinstitute.org/publications/white-paper-1/>

⁵⁹ SGI (2015).

- **Compressors.** Compressors are also used throughout the gas production stage in order to boost the gas pressure. Compressors generally emit gas through seals and during blowdown,⁶⁰ and are estimated to be responsible for 20% of emissions in the US.⁶¹
- **Super-emitters.** One of the major contributors to overall production emissions is found to be from what are referred to as super-emitters: significant leaks of methane left unchecked for significant periods of time. There is recent evidence⁶² that 2% of oil and gas sites on the Barnett shale are responsible for half the methane emissions and that 10% are responsible for 90% of the emissions. This may help to explain some of the differences between ‘top-down’ and ‘bottom-up’ estimates of methane emissions (see Box 4.1 above). Locations of these super-emitters are hard to predict and change over time. Further work is required to understand the characteristics that cause individual sites to be a super-emitter. Although a complete avoidance of super-emitters may be unachievable, with suitable operational control and maintenance procedures these high emitters could be largely eliminated.⁶³ If the super-emitter sites could be brought in line with the average, then total supply chain emissions would be reduced by 65-87%.⁶⁴
- **Well decommissioning and abandonment.** Over time, the plugs intended to prevent further fluid migration can deteriorate, releasing to atmosphere the methane that has built up in the well. There is recent evidence to suggest that these emissions are low.⁶⁵

Box 4.3: Measured as against modelled emissions

Based on modelling of emissions from ‘flowback’ it has been estimated that over 3% of the gas produced from a shale well could be vented to the atmosphere;⁶⁶ subsequently a large number of reports have produced modelled estimates for the completion emissions. Only recently have these emissions been measured.⁶⁷

Table B4.3 shows the large discrepancy between the measured and modelled numbers over the range of literature as presented by the SGI. The SGI report suggests that this discrepancy is due to most of the modelled estimates being based on disputed engineering calculations based on initial gas production rates being constant throughout the well completion period. This assumption does not take into account fracturing fluid which returns during this process, which would limit the gas flow.

⁶⁰ Blowdown is the venting of gas remaining in a compressor when that compressor is shut down.

⁶¹ SGI (2015).

⁶² Zavala-Araiza et al. (2015), Reconciling divergent estimates of oil and gas methane emissions, *PNAS*, 112(51), 15597-15602.

⁶³ SGI (2015).

⁶⁴ Zavala-Araiza et al. (2015), Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites, *Environ. Sci. Technol.*, 49, 8167–8174.

⁶⁵ Boothroyd et al. (2016) Fugitive emissions of methane from abandoned, decommissioned oil and gas wells, *Science and The Total Environment*, 547, 461-469.

⁶⁶ Howarth et al. (2011), Methane and the greenhouse gas footprint of natural gas from shale formations, *Climatic Change*, 106, 679–690.

⁶⁷ SGI (2015).

Box 4.3: Measured as against modelled emissions

Table B4.3: Measured and modelled estimates of emissions from completion (m³ methane)

Source	Mean	Median	Min	Max
Measured data	11,900	5,800	300	537,000
Modelled estimates	606,000	245,000	1,300	6,800,000

Source: SGI (2015), *Methane and CO₂ emissions from the natural gas supply chain*, <http://www.sustainablegasinstitute.org/publications/white-paper-1/>

Notes: Table 1 in SGI reports the maximum measured data as 100,000 m³ but later in the discussion gives a figure of 537,000 m³.

2. Emissions mitigation opportunities and costs

The US natural gas STAR programme has investigated cost-effective technologies and practices that improve operational efficiency and reduce emissions of methane.⁶⁸ The programme has covered all the stages of the gas supply chain from production through to distribution, providing estimates for potential emissions mitigation, capital costs and payback relating to each mitigation technology.

The STAR programme is currently finalising its best management practices (BMP) commitment framework, where partner companies will employ appropriate mitigation technologies across their operations.⁶⁹

Measures to limit emissions can lead to cost savings, as they avoid leakage of product that could otherwise be sold. Those which incur net positive costs often save emissions at relatively low cost per tonne of CO₂-equivalent, due to the benefit of avoiding emissions of methane, which is a potent greenhouse gas (see Chapter 1). The evidence from the STAR programme shows that there is a range of ways to limit emissions from shale gas production at costs well below DECC's carbon values, which reach £78/tCO₂e in 2030.⁷⁰

- **Techniques and technologies.** There is a large range of available techniques and technologies which can be employed to mitigate fugitive methane. These techniques often enable the methane that would have been lost to be put to productive use. These include, but are not limited to:
 - **Reduced emissions completions (REC).** This is a series of processes that enables the capture of the gas associated with the 'flowback' fluid during well completion stage and it

⁶⁸ US EPA, *Recommended Technologies and Practices*, <http://www3.epa.gov/gasstar/tools/recommended.html>

⁶⁹ US EPA (2016), *Best Management Practice (BMP) Commitment Framework*, https://www3.epa.gov/gasstar/documents/MethaneChallenge_BMP_Framework.pdf

⁷⁰ DECC (2009) *Carbon Valuation in UK Policy Appraisal: A Revised Approach*, <https://www.gov.uk/government/publications/carbon-valuation-in-uk-policy-appraisal-a-revised-approach>

being put to productive use. REC can reduce the associated emissions from completion by between 90-99%.⁷¹ Abatement costs are estimated to range from being cost-saving up to £22/tCO₂e saved.⁷²

- **Liquid unloading plunger lift.** Instead of blowing out the liquids that can accumulate in the well, it is possible to use a plunger lift system which fits into the well bore. This uses the gas pressure in the well to bring the liquids to the surface, while limiting the amount of venting. The plunger lift system has been estimated to reduce emissions from liquid unloading by around 90%.⁷³ Abatement costs are estimated to range from being cost-saving to £13/tCO₂e.
- **Low-flow pneumatic devices.** Various types of pneumatic devices are used throughout the gas supply chain, including a 'high-bleed' device, which can emit up to 7,000m³ of gas each year. Many of these high-bleed devices can be replaced with low-bleed devices which emit 1,500m³ per year. Replacing an existing high-bleed device with a low-bleed is estimated to be cost-saving.
- **Dry seal compressors.** The seal on a compressor allows the rotating shaft to move freely. Traditionally, compressors have used an oil seal through which gas can escape. Dry seals reduce the volume of gas which leaks to atmosphere by over 90%. The cost of replacing a wet seal with a dry seal has an abatement cost of around £12/tCO₂e.
- **Vapour recovery units (VRU).** Shale gas wells may also produce quantities of crude oil or liquid condensate containing some dissolved gas. As this liquid is stored, the gas is released and can be vented to the atmosphere. A VRU will collect and compress this gas so it can be put to productive use. It is estimated that a VRU would have an abatement cost of around £4/tCO₂e.
- **Monitoring.** A large proportion of the gas which is emitted has been found to come from a small group of 'super-emitters'. An effective leakage detection and repair (LDAR) programme throughout the production stage would mitigate methane emissions. It is estimated that annual inspections would reduce leakage by 40%, semi-annual by 60% and quarterly by 80%.⁷⁴ Based on labour costs and equipment costs in Canada, it is estimated that it would cost around £20,000 to survey a gas pad and associated infrastructure for leaks and undertake repairs. For example, semi-annual monitoring could have an abatement cost of around £4/tCO₂e.

⁷¹ SGI (2015), *Methane and CO₂ emissions from the natural gas supply chain*, <http://www.sustainablegasinstitute.org/publications/white-paper-1/>

⁷² US EPA (2011), *Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells*, https://www3.epa.gov/gasstar/documents/reduced_emissions_completions.pdf

⁷³ ICF (2015), *Economic Analysis of Methane Emission Reduction Opportunities in the Canadian Oil and Natural Gas Industries*, <https://www.pembina.org/reports/edf-icf-methane-opportunities.pdf>

⁷⁴ ICF (2015).

Opportunities to reduce emissions exist beyond those for which cost estimates are available. While it is not possible at this stage to judge their cost-effectiveness, reasonable attempts can be made to estimate their emissions savings:

- **Electrification of pneumatic devices.** Pneumatic devices are used throughout the production stage, as they have a high response rate and can enable the system to be controlled independently. It is possible to use compressed air or a different compressed gas throughout the supply chain. This could result in an emission saving of between 200 and 2,000 tCO₂e/year per device, depending on the type of pneumatic device replaced.
- **Electrification of compressors.** Many compressors use a gas-fired engine to drive the compressor. Electric motors can be used instead, which have been found to reduce the chance of methane leakage (by eliminating the need for fuel gas), require less maintenance, and improve operational efficiency. It has been estimated that this could reduce methane emissions by around 3,000 tCO₂e/year per compressor.⁷⁵

Regulation cases for emissions analysis

There is clear evidence that regulation of shale gas production can lead to significant reductions in its greenhouse gas footprint. The US EPA has recently announced a programme of work to produce comprehensive regulations to reduce methane emissions from the oil and gas industry.⁷⁶

Based on the evidence about the efficacy and cost of the various technologies and techniques to limit emissions from shale gas production, we have constructed four cases for the regulation of shale gas production:

- **No regulation.** No measures are implemented to limit greenhouse gas emissions. This acts as a baseline for comparison purposes.
- **Current UK position.** This case reflects the stated position of the Environment Agency (EA) regarding the use of reduced emissions completions. This does not include further techniques and technologies that are likely to be required by the EA, which is currently conducting a consultation process covering this issue. However, in England the EA only regulates to the boundary of the shale well site. It is essential that the requirement for methane mitigation extends beyond the well pad to all associated infrastructure prior to the gas being injected into the grid or put to use.
- **Minimum necessary regulation.** This further assumes deployment of mitigation options available at low cost, according to the evidence outlined above. As well as reduced emissions completions, this includes liquid unloading mitigation technologies (e.g. plunger lift systems) and semi-annual monitoring. It does not, however, include technologies that are identified as cost-effective but where the quantity of abatement is uncertain due to the difficulty of estimating the quantity of devices (e.g. low-flow pneumatic devices, dry seal compressors and vapour recovery units).

⁷⁵ US EPA (2011), *Install Electric Compressors*,
<https://www3.epa.gov/gasstar/documents/installelectriccompressors.pdf>

⁷⁶ US EPA, *Methane Addressing Greenhouse Gases and Smog forming VOCs from the Oil and Gas Industry*,
<https://www3.epa.gov/airquality/oilandgas/methane.html>

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- **Fuller technical mitigation options.** This further assumes deployment of mitigation options for which the emissions saving can be reasonably estimated. This includes electrification of control valves and some compressors, although this entails some estimation of the quantity of abatement relating to the number of devices. This case could also include measures for which costs per tonne of CO₂e saved are higher than DECC's carbon values, which we use as a comparison to judge cost-effectiveness, but evidence to make this assessment is currently lacking.

Although the 'Current UK position' case only includes reduced emissions completions, this does not imply that this is the entire extent of anticipated regulation. This will be confirmed over time, as best available techniques and technologies are identified.

It is also likely that the industry would in any case employ at least those measures that are cost-saving, as the increased sales revenue would outweigh these costs. The UK onshore operators group (UKOOG – the shale gas trade body) has guidelines that state that "operators should plan and then implement controls in order to minimise all emissions."

The results presented here include estimates of land-use change emissions that result from development of wells on grassland. Were the development of wells instead to occur in areas that have much greater potential for carbon release (e.g. areas of deep peat soils), then land-use change emissions would be much greater and could dominate the results. Given the scale of such potential emissions, production on such land should not be allowed.

For each of the four regulation cases we have used the available evidence to produce low, central and high estimates for emissions that might occur (Box 4.4). Some of these emissions scale with the number of wells drilled (well preparation, completion, liquid unloading and workover), while others scale with the amount of gas produced (processing and normal operation) (Figures 4.1 and 4.2).

Combining these sets of emissions requires an assumption on average well productivity (i.e. the energy produced per well). We have used a central value of 0.52 TWh/well to combine these emissions (Figure 4.3), which we estimate to be a level of average productivity below which production in the UK may be uneconomic, with a range of 0.26 to 1.3 TWh per well⁷⁷ used to produce a range of emissions estimates per TWh (Figure 4.4). High levels of productivity would imply lower emissions per unit of energy produced and also lower costs per unit energy (see Chapter 2).

Under central estimates, the 'Current UK position' case saves 19% of emissions relative to the 'No regulation' case, compared with 46% savings under the 'Minimum necessary regulation' case and 62% under the 'Further Technical Mitigation Options' case (Figure 4.5).

Methane emissions dominate total greenhouse gas emissions in the cases with the highest emissions. These also have considerably greater potential to be abated than the CO₂ emissions, highlighting the importance of measures to limit methane emissions (Figure 4.6).

The results show that technologies and techniques to reduce emissions can have a substantial effect on the greenhouse gas footprint of production. This is particularly the case for the high-

⁷⁷ Based on CCC calculations suggesting that wells with a productivity below 0.52 TWh (2 bcf) are unlikely to be economic in the UK based on the current gas price predictions. The high productivity of 1.3 TWh (5 bcf) is the average productivity of a well in Haynesville with a 2 km lateral, calculated from Browning et al. (2015) *Study forecasts gradual Haynesville production recovery before final decline*, OGI.

end emissions estimates, for which the 'Minimum necessary regulation' case saves 55% of emissions relative to the 'No regulation' case, compared with 46% for central estimates and 29% for low-end estimates.

These results show that these measures to limit emissions are not only important in reducing central estimates for emissions, but are also essential in guarding against the risk of much higher emissions (e.g. due to super-emitters). This underlines the importance of a regulatory approach that requires such an implementation of techniques and technologies, with clear consequences should these requirements be violated.

Box 4.4: Low, central and high emissions estimates

In order to produce our low, central and high emissions estimates for the median well in the UK, we have taken, where possible, the measured range presented in literature from the recent bottom-up emission measurement campaigns. These have shown a large range in the measured results and represent only a small sample set when compared to scale of the industry in the US, so there is still a large degree of uncertainty surrounding them. It is also uncertain how applicable these emissions estimates are to any future industry in the UK. This high degree of uncertainty necessitates a large range in our emission factors.

- **High.** The high scenario is what we estimate to be the worse-case scenario for a typical UK shale gas well. It has been developed using a mix of both high and median data, depending on the extent and distribution of the available data.
- **Central.** This represents our best estimate for a typical well in the UK. It primarily uses the median emissions as presented in literature.
- **Low.** The low estimate represents what we assess to be the best-case scenario for a typical well in the UK. It uses a combination of low and median values that we consider relevant to the UK.

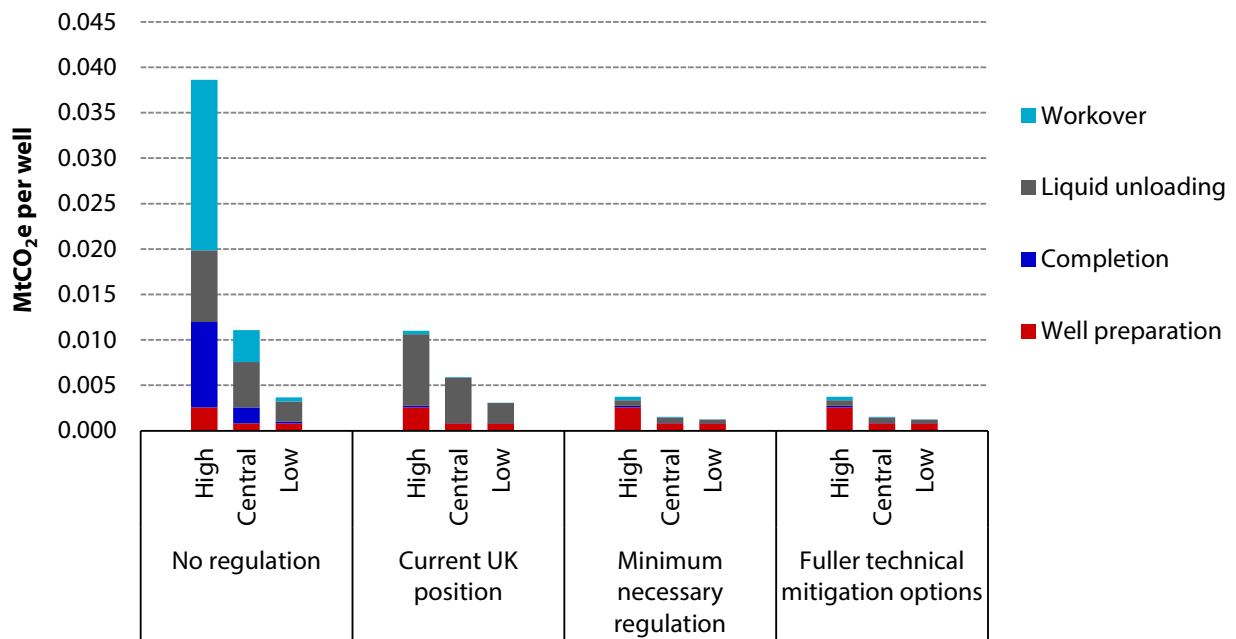
The methane emissions as a proportion of throughput are shown for our four regulations case, under high, central and low assumptions in Table B4.4. The precise estimates used in our analysis, and how these relate to the data in the literature, are outlined in our supporting annex.

Table B4.4: Range of methane emissions as a percentage of throughput

	No Regulation	Current UK Position	Minimum necessary regulation	Further technical mitigation options
High	4.9%	2.2%	0.9%	0.6%
Central	1.8%	1.3%	0.5%	0.3%
Low	0.7%	0.6%	0.3%	0.2%

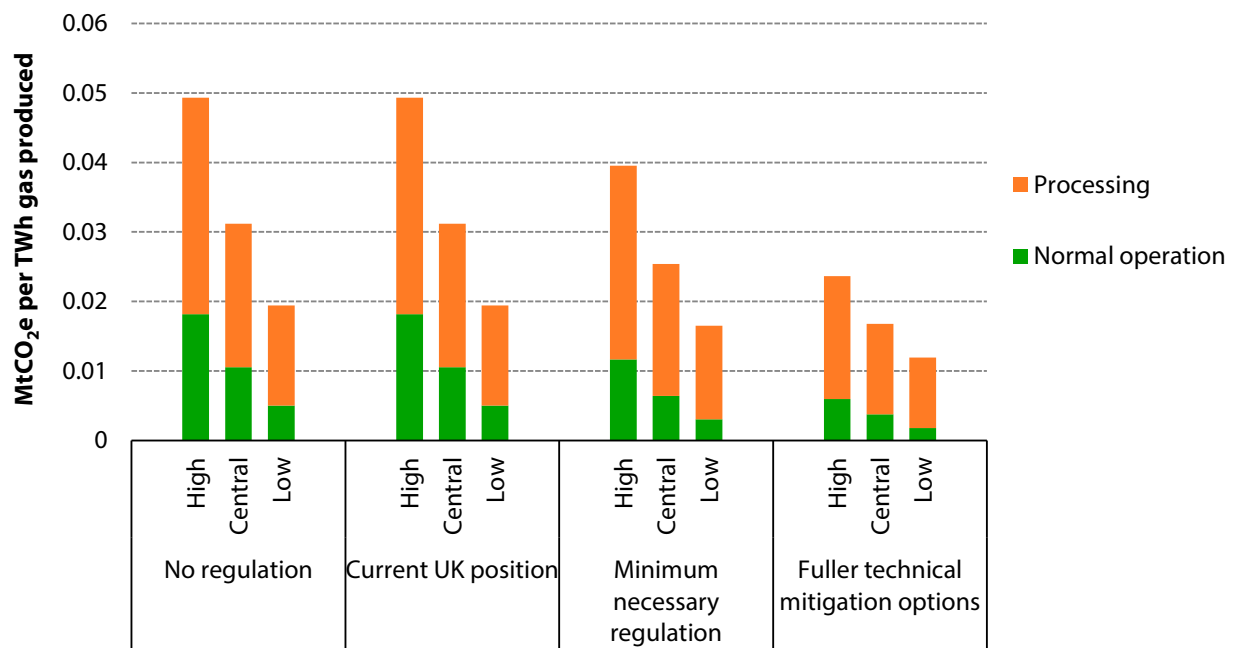
Source: Various, with CCC calculations.

Figure 4.1: Emissions that scale with the number of wells under different regulation cases



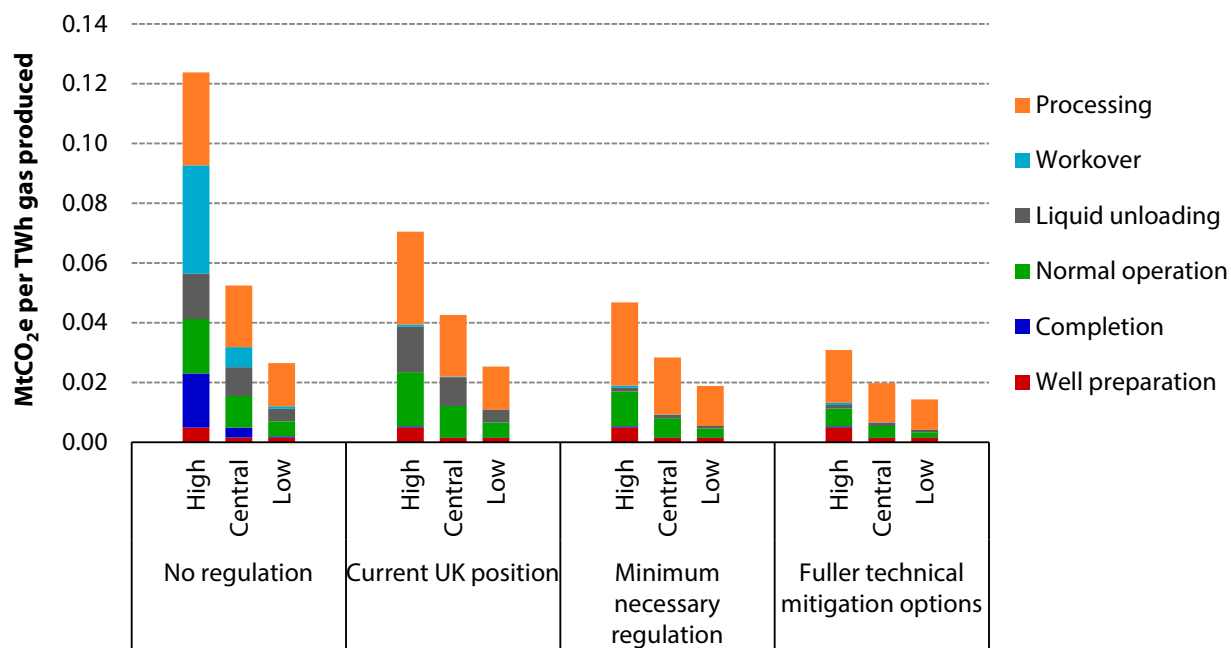
Source: CCC analysis.

Figure 4.2: Emissions that scale with energy production under different regulation cases



Source: CCC analysis.

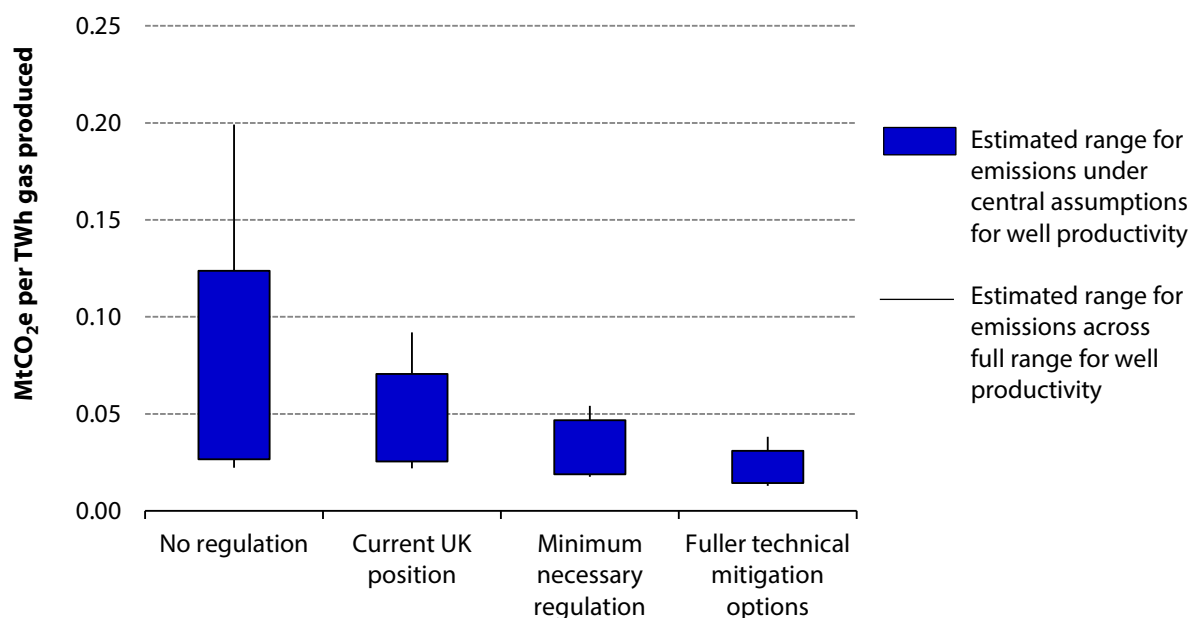
Figure 4.3: Total emissions with central well productivity assumptions under different regulation cases



Source: CCC analysis.

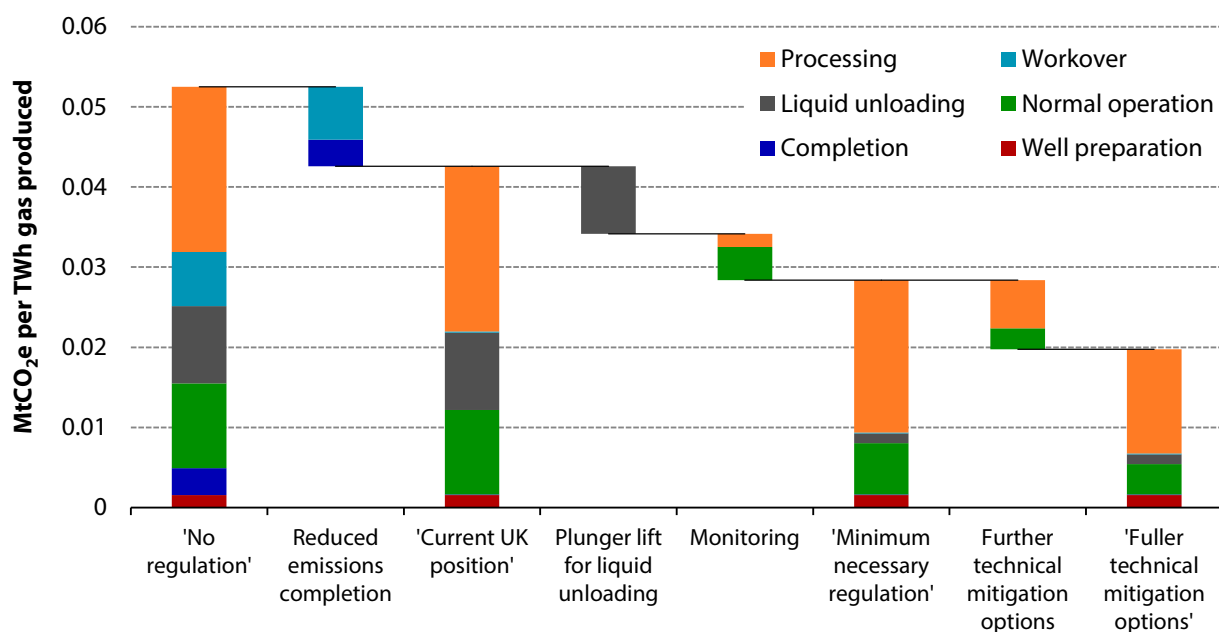
Notes: Data on per-well emissions (Figure 4.1) and per-TWh emissions (Figure 4.2) have been combined using a central assumption on median well productivity of 0.52 TWh per well.

Figure 4.4: Total emissions depending on well productivity under different regulation cases



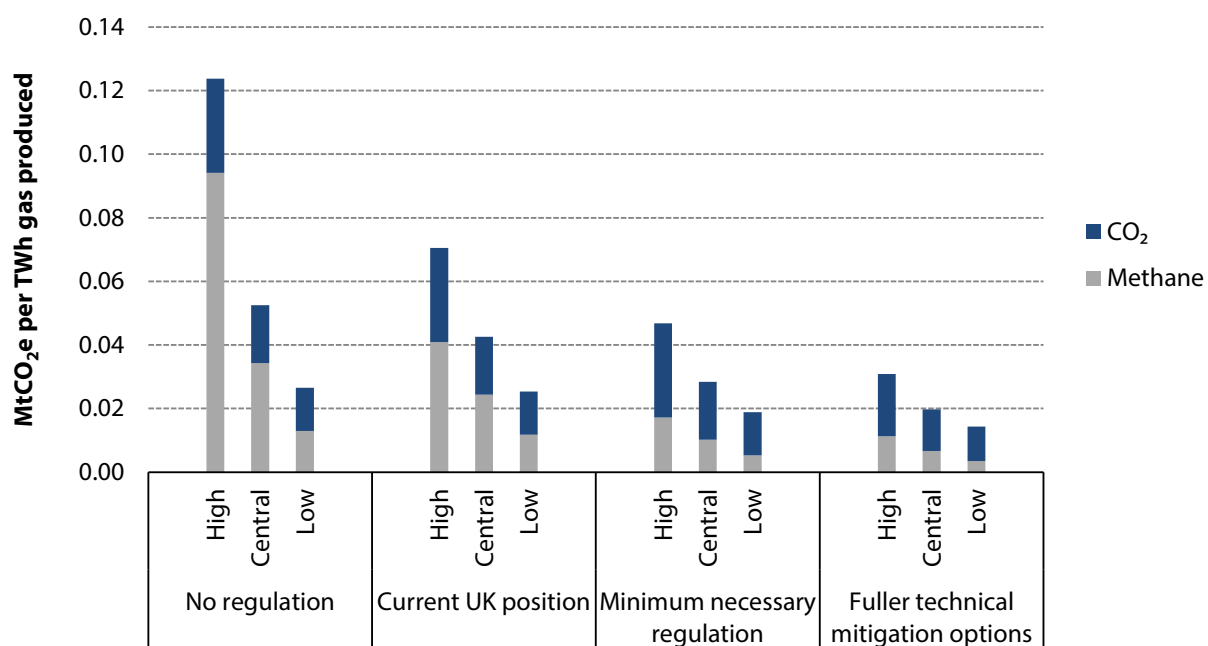
Source: CCC analysis.

Figure 4.5: Differences between the regulation cases under central estimates



Source: CCC analysis.

Figure 4.6: Emissions of methane and carbon dioxide under different regulation cases



Source: CCC analysis.

Notes: As discussed in Chapter 1, CO₂ and methane emissions are presented on a GWP₁₀₀ basis. Use of a different metric for emissions (see Box 1.3) would lead to a change in the relative emissions of methane and CO₂.

Traded vs. non-traded emissions

Within the overall emissions footprint relating to shale gas production, some emissions are in the 'traded' sector (i.e. covered by the EU emissions trading system – EU ETS), while other emissions are outside this and are therefore in the 'non-traded' sector:

- **Traded sector emissions.** Emissions covered by the EU ETS include CO₂ emissions from flaring, gas processing and power generation. Within this, electricity generation is not eligible for the allocation of free allowances under carbon leakage rules, while the other sources are eligible.
- **Non-traded sector emissions.** The EU ETS primarily covers CO₂ emissions, and all methane emissions are outside its scope.

The implications for carbon budgets of this treatment of emissions are explored in Chapter 5.

3. Emissions footprint of shale oil production

The major source of greenhouse gas emissions associated with shale oil exploitation is from the associated gas produced during well completion and production. To date there have been comparatively fewer sampling campaigns than for shale gas, so the evidence base is less well developed.

Top-down studies have identified that methane emissions in predominately shale oil producing regions can be as high as 9% of throughput, although the gas produced in this region is comparatively small (Box 4.1). A higher percentage for methane loss from shale oil production is to be expected, as it is not the primary product and the required infrastructure may therefore not be available to enable the natural gas to be put to productive use.

In 2014, the US EPA produced a white paper⁷⁸ on the potential methane emissions from hydraulically fractured oil wells. The data presented are based on a limited sample, onto which various assumptions have been overlaid. Although this is a good starting point from which to base emissions estimates for UK shale oil, it would be necessary also to take into account the UK's geology and well completion dynamics, as well as typical completion duration, reservoir temperature and pressure, and the gas-to-oil ratio.⁷⁹

The scale of any future industry will be a key determinant of the size of the emissions footprint. If the industry remains small, it is likely that it would not be economic to have the supporting infrastructure to enable the gas to be put to productive use. In such a scenario, it is likely that any associated gas would most likely be flared, including the gas produced while storing the oil (see VRU above), although gas should be put to productive use where possible.

Should a UK shale oil industry reach a sufficient scale for the supporting infrastructure to be economic, the gas should be put to productive use,⁸⁰ together with the deployment of mitigation techniques and technologies similar to those used for shale gas.

⁷⁸ US EPA (2014), *Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production*, <http://www3.epa.gov/airquality/oilandgas/pdfs/20140415completions.pdf>

⁷⁹ US EPA (2014), *Attachment C Hydraulically Fractured Oil Wells New Mexico Environmental Department*, <http://www3.epa.gov/airquality/oilandgas/2014papers/attachmentc.pdf>

⁸⁰ Productive use does not include using the gas in pneumatic devices.

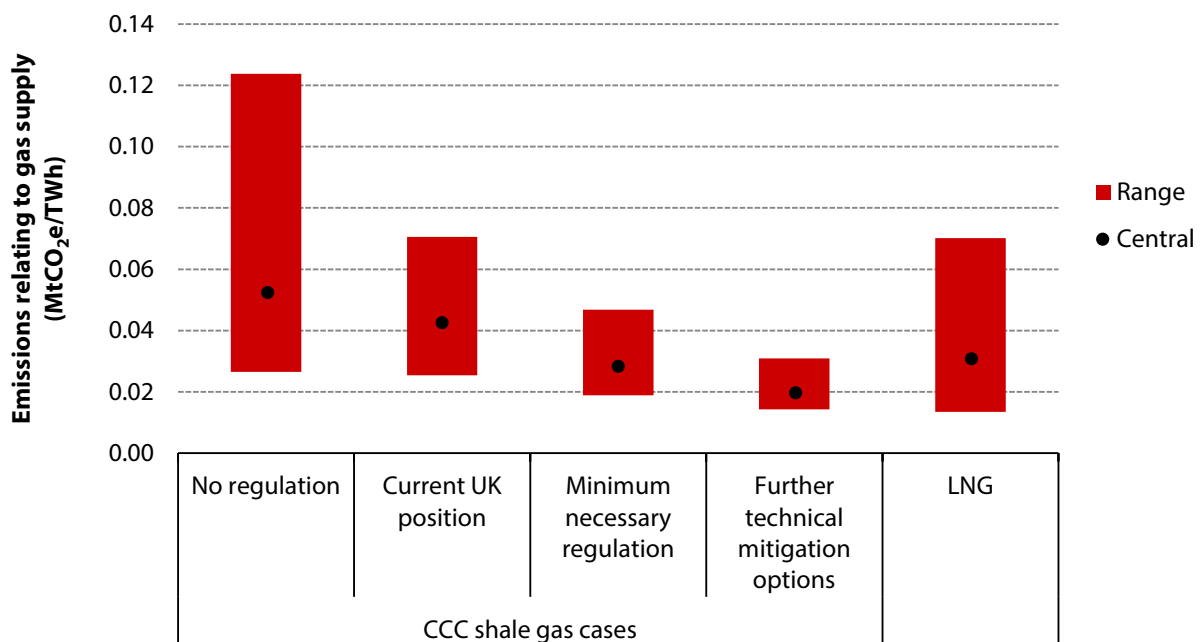
4. Comparison of lifecycle emissions from UK shale gas with imported liquefied natural gas

Any production of oil or gas is likely to lead to some greenhouse gas emissions. While increasing UK production will increase domestic emissions, should this be offset by reduced production elsewhere then the change in overall global emissions depends on the difference between the emissions footprint of domestic production relative to the overseas production displaced.

The current evidence base suggests that well regulated domestic production could have an emissions footprint slightly smaller than that of imported liquefied natural gas (LNG) (Figure 4.7). When taking into account CO₂ emissions from combustion, both UK shale gas and imported LNG have a considerably lower greenhouse gas footprint than coal on a GWP₁₀₀ basis (Chapter 1).

We will look further at the implications of UK onshore fossil fuel production for global emissions, and will publish this work later in the year.

Figure 4.7: Lifecycle emissions of UK gas production and liquefied natural gas imports



Source: CCC calculations for shale gas; SGI (2015) for LNG.

Notes: There is a lack of transparency in the literature for LNG, so it is not possible to speculate how reliable the emission estimates are. Further work is required in order to improve our understanding of the emissions relating to LNG supplies. Emissions relating to final combustion of the fuel are not included.

Chapter 5: Impact of onshore petroleum on carbon budgets

In this chapter, we bring together the outputs of the preceding chapters to assess the possible impact of onshore petroleum development on UK territorial emissions, and what that means for meeting carbon budgets and the 2050 target.

Even tightly regulated oil and gas production leads to some emissions. Domestic onshore production in place of imports would mean that production emissions occur in the UK rather than overseas. This would therefore increase UK greenhouse gas emissions, even if it leads to no greater consumption of oil and gas in the UK and even if the overall greenhouse gas footprint of UK production is lower than that of imported gas. Onshoring of production means onshoring of emissions relating to production.

In Chapter 3, we showed that UK shale gas production should displace imports rather than increasing domestic consumption. On this basis, the scale of the impact of domestic onshore petroleum production on UK emissions depends on two main factors: the level of production (Chapter 2) and the unit emissions associated with production (Chapter 4).

The emissions impacts presented in this chapter use the 100-year Global Warming Potential (GWP₁₀₀). This metric is used as standard in international and UK emissions accounting, including carbon budgets and the 2050 target, but it is important to understand how to interpret the results based on its use (Chapter 1).

In this chapter, we set out our analysis of the impact of UK shale gas on territorial emissions, how these could be accommodated under carbon budgets and our conclusions and recommendations, in three sections:

1. Impact of domestic onshore petroleum production on UK territorial emissions
2. Impact on meeting targets under the Climate Change Act
3. Conclusions and recommendations

1. Impact of domestic onshore petroleum production on UK territorial emissions

The implications for greenhouse gas emissions of shale gas exploitation are subject to considerable uncertainties, both regarding the size of any future industry and the emissions footprint of production.

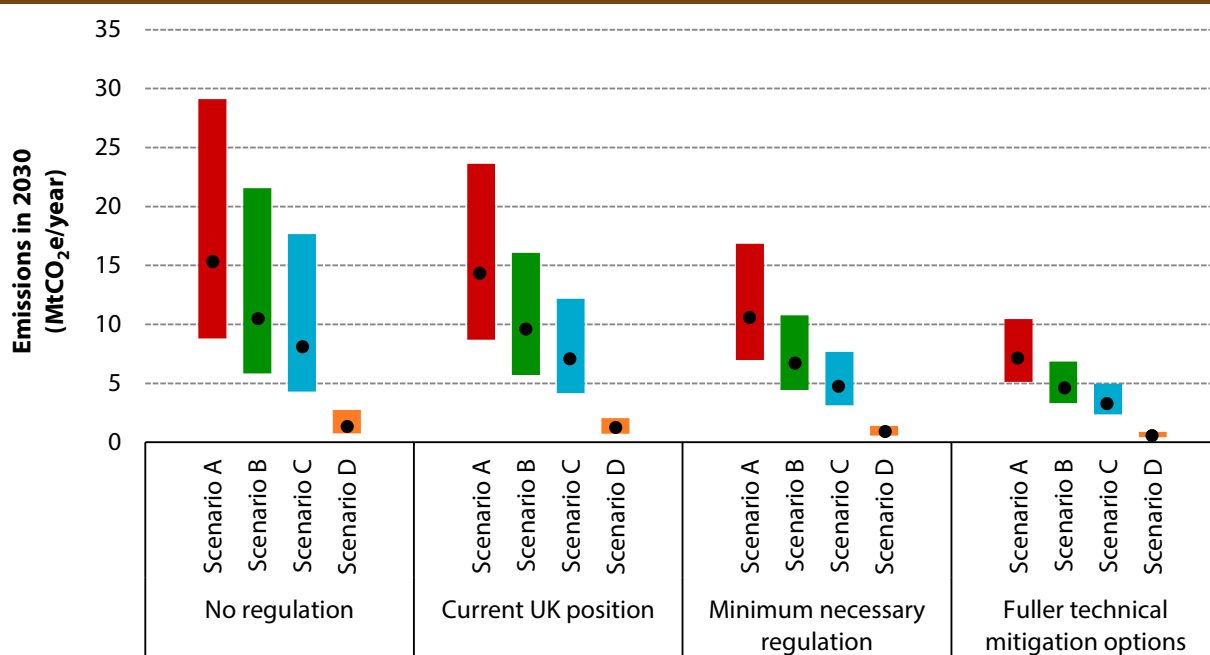
Tight regulation with a strong legal foundation can shift the estimated range for emissions downwards and also narrow this range. However, it is not possible to state with certainty the emissions impact of a given level of UK production. In considering the implications for meeting carbon budgets, it is essential not only to look at central estimates but also to look at a range for

possible production, and in particular the largest plausible production scenario and the upper end of the range impacts (Figure 5.1):

- **High-end estimates.** The increase in UK territorial emissions due to domestic onshore petroleum extraction under scenario A could be up to 29 MtCO₂e/year in 2030, if production were unregulated. Current UK position, which entails reduced emissions completion, reduces the upper end of the emissions range to about 24 Mt, while this would be reduced further to about 17 Mt with the measures in our 'Minimum necessary regulation' case (i.e. monitoring and addressing emissions from liquid unloading). Fuller technical mitigation options (e.g. electrification of compressors) could reduce the high-end estimate further, to about 10 Mt.
- **Central estimates.** The impact of onshore production on emissions under central estimates is also affected significantly by the level of regulation. Our central estimate for unregulated production under scenario A is 15 Mt/year, falling to about 14 Mt under the current UK position, to about 11 Mt under our 'Minimum necessary regulation' case and to about 7 Mt with fuller technical mitigation options.

Implementation of the measures in the 'Minimum necessary regulation' case is therefore essential. They make a significant reduction in the central estimate of the emissions impact of UK shale gas production (31-45% as against the No Regulation case, depending on the production scenario), but are also significant in risk mitigation terms by reducing the high-end estimate by a greater amount (42-57% as against the No Regulation case).

Figure 5.1: UK territorial emissions due to shale gas production, depending on regulation (2030)



Source: CCC analysis.

Notes: Total emissions relating to UK shale gas production, on a territorial (i.e. gross) emissions basis. Scenarios A to D refer to the shale gas production scenarios presented in Chapter 2.

2. Impact on meeting targets under the Climate Change Act

Meeting carbon budgets

Under the carbon budgets emissions accounting framework, the relevant measure of emissions is known as the net carbon account. Parts of the net carbon account are influenced by actual UK emissions, while other parts reflect a share of the EU-wide cap for the EU emissions trading system (EU ETS) (Box 5.1).

As part of our recommendations on the fifth carbon budget,⁸¹ the Committee recommended that the traded sector part of the net carbon account should be fixed at the estimated level when legislated, rather than using the outturn level, in order to maintain the integrity of carbon budgets (Box 5.2).

The Government has not yet responded to this recommendation. The precise impact of a UK onshore petroleum industry on the net carbon account depends on whether it is accepted:

- **Traded sector share fixed.** Should the traded sector share be fixed as we recommend, the impact of onshore petroleum extraction on the net carbon account would consist of the non-traded sector portion of production emissions (Figure 5.2).
- **Traded sector share not fixed.** Should the recommendation not be accepted, the impact on the net carbon account would be greater, comprising both non-traded sector emissions and those eligible for free allocation of EU ETS allowances. A new onshore production industry is likely to receive free allowances as a new entrant.

Depending on the Government's decision, the impact on the net carbon account under carbon budgets will therefore be between the non-traded portion of the total emissions relating to onshore production and the full amount of these emissions. Should the impact be the full amount of the estimated emissions, the additional emissions across the 5-year carbon budget periods could be around 27 Mt and 52 Mt over the fourth and fifth carbon budgets respectively, under central estimates for the 'Minimum necessary regulation' case.

⁸¹ CCC (2015) *The fifth carbon budget – The next step towards a low-carbon economy*, <https://www.theccc.org.uk/publication/the-fifth-carbon-budget-the-next-step-towards-a-low-carbon-economy/>

Box 5.1: How the net carbon account is calculated

The net carbon account under carbon budgets is calculated by adding:

- **Non-traded emissions:** actual UK emissions in the non-traded sector (i.e. sectors outside the EU emissions trading system or EU ETS); to
- **Net traded sector emissions:** the UK share of the EU ETS cap for sectors covered by the EU ETS. As the traded part of the net carbon account is deemed to be set by actual UK emissions plus net trading; by definition this equals the UK share of the EU ETS cap. Within this, it is important to distinguish between activities for which emissions allowances are auctioned as against being allocated free:
 - **Free allocation.** Activities at risk of carbon leakage receive a free allocation of allowances in order not to undermine their competitive position. On the same basis, new or expanding companies' needs are met through the New Entrant Reserve. The UK share of total allowances allocated this way depends on the size of UK industries eligible, which will change over time. Our methodology for estimating these in advance projects forward existing industries at their current size, and allows a generous 8 MtCO₂/year allowance for new entrants. Activities in gas production (e.g. flaring) covered by the EU ETS will generally be eligible for free allocation, with the exception of on-site power generation.
 - **Auctioned.** Activities for which no free allowances are allocated (e.g. power generation) must be covered by allowances acquired via auctioning. The size of the UK share of total auctioned allowances is entirely independent of actual UK emissions.

Although in estimating the future UK share of the traded sector cap we make allowance for the scale of free allocation, the development of a UK onshore petroleum industry would lead to a larger overall free allocation to the UK than otherwise and therefore greater emissions under the net carbon account.

Box 5.2: Recommendation on maintaining the integrity of carbon budgets

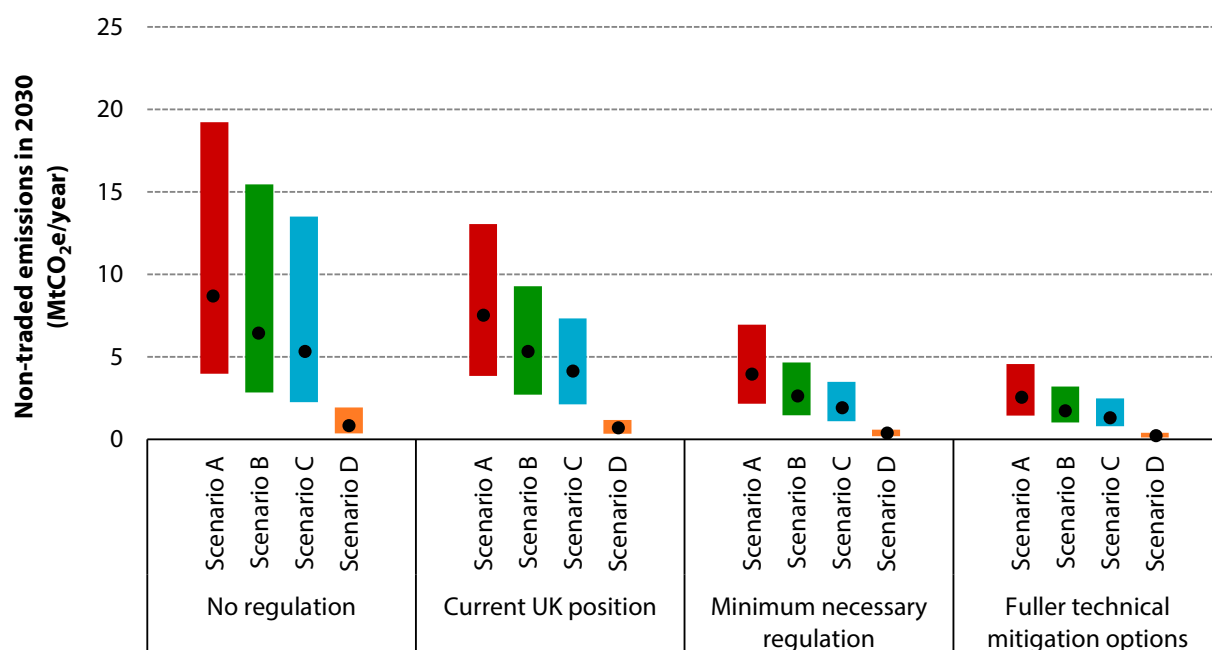
In recommending a carbon budget, we make an estimate of the UK share of the EU ETS cap. However, it is not possible in advance to estimate this share with complete accuracy.

Under the Climate Change Act's existing carbon accounting regulations, any difference between the outturn and the projected UK share of the EU ETS cap affects the level of emissions allowed in the non-traded sector, which is the residual from the total budget minus the share of the EU ETS cap. So far this has meant that carbon budgets now require less action than originally envisaged, as estimates of the UK share of the EU ETS cap have fallen significantly. In principle, however, it is also possible for the approach set out in the Act to have the opposite effect.

Setting a clear level of ambition in the non-traded sector that is independent of changes in the UK share of the EU ETS cap provides a guide to policymakers and a signal to businesses and consumers. We therefore recommended as part of our advice on the fifth carbon budget that the Government should use the Carbon Accounting Regulations to fix the net carbon account for the traded sector at the assumed level when legislating it, and not adjust for the outturn UK share of the EU ETS cap.

The Government has not yet responded to this recommendation.

Figure 5.2: Impact on the net carbon account, if traded sector share is fixed (2030)



Source: CCC analysis.

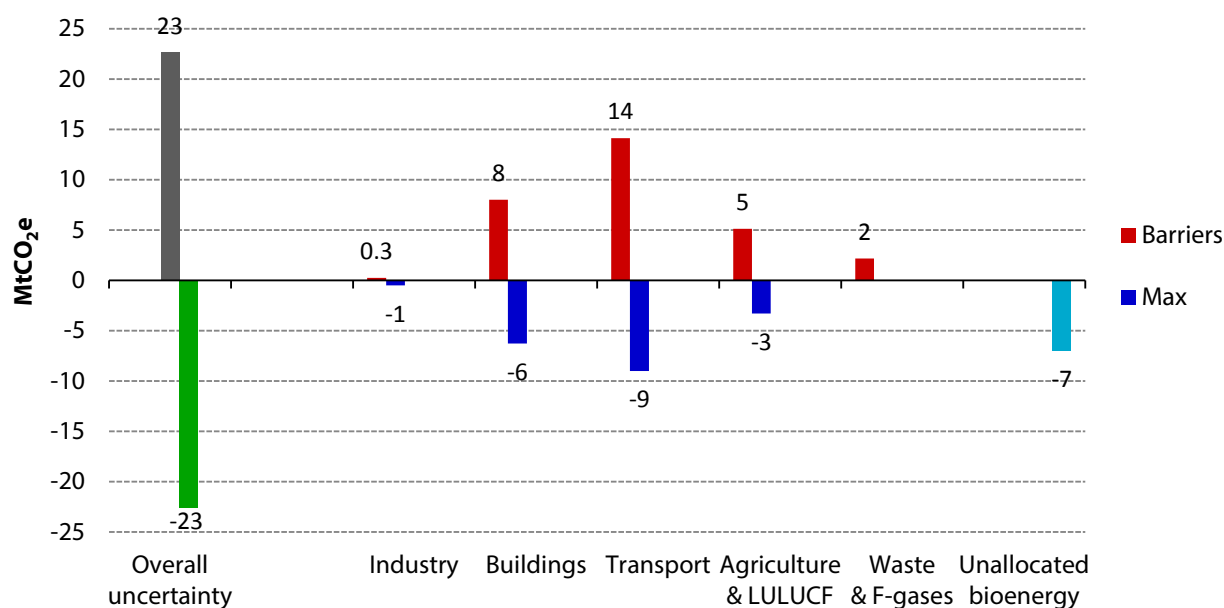
Notes: Non-traded sector emissions only. Scenarios A to D refer to the shale gas production scenarios presented in Chapter 2.

The compatibility of onshore petroleum extraction with carbon budgets depends on whether these additional emissions can be offset by increased emissions reductions in the non-traded sector. The impact on total UK emissions under the 'Minimum necessary regulation' case in production scenario A is between 7 and 17 MtCO₂e/year in 2030, with a central estimate of 11 Mt/year. Available flexibilities can be inferred by drawing on our scenarios from the fifth carbon budget advice, for example by going beyond the Central scenario to our Max scenario in one or more non-traded sectors (Figure 5.3):

- **Uncertainty.** Our advice on the fifth carbon budget identified uncertainty in non-traded emissions in 2030 of around 23 MtCO₂e/year in both directions, due to macroeconomic drivers such as population and the level of economic activity.
- **Flexibility.** The potential that we identified to go beyond our Central scenarios totalled 26 MtCO₂e/year in 2030 across the non-traded sectors, by moving to Max scenarios and utilising the full estimate of available sustainable bioenergy.

Given this, accommodating additional emissions from shale gas production may be possible, although it would require significant and potentially difficult offsetting effort elsewhere. This should be considered in the report that the Climate Change Act requires from the Government, in setting out its plans by the end of 2016 to meet the fourth and fifth carbon budgets.

Figure 5.3: Potential flexibilities in the non-traded sector (2030)



Source: CCC (2015) *The fifth carbon budget – The next step towards a low-carbon economy*, <https://www.theccc.org.uk/publication/the-fifth-carbon-budget-the-next-step-towards-a-low-carbon-economy/>

Notes: Uncertainty reflects the possible effect of macro drivers (e.g. population or GDP) upon non-traded sector emissions. Barriers and Max reflect lower or higher sectoral abatement relative to the Central scenario (see Box 3.2). The scenarios do not use the entire sustainable bioenergy resource estimated to be available to the UK. Further details are given in Chapter 1 of the Sectoral Scenarios report of the fifth carbon budget advice.

Meeting the 2050 target

The Climate Change Act specifies a target to reduce emissions in 2050 by at least 80% on 1990 levels. It is not clear that there will be much scope for international trading to meet this target, so it is sensible to plan to reduce emissions by 80% across all domestic sectors, plus a UK share of international aviation and international shipping (Box 5.3).

It is too early to estimate possible ranges for emissions that might be associated with onshore petroleum extraction in 2050. The Committee would make such estimates if the evidence base improves sufficiently.

It is also premature to attempt to identify with any confidence specific areas in which effort could be increased to offset new sources of emissions on that timetable. The 2050 target is very challenging to meet and requires major effort to reduce and limit emissions, so flexibility should not be taken as a given.

Should emissions in sectors excluding shale gas exploitation be allowed to go well beyond our Central scenario in one or more areas (e.g. uncontrolled expansion of aviation, little or no CCS, failure to decarbonise heat), then the 2050 target would be at risk and it is very unlikely that there would be scope for additional emissions from shale gas exploitation consistent with meeting carbon budgets or the 2050 target.

Should the emissions impact in 2050 be similar to that in 2030 it is likely to be considerably more difficult and expensive to find ways to offset this, due to the stretching nature of the 2050 target. In a case in which CCS is not deployed at all by 2050, this challenge would be much greater. Even without additional emissions from onshore petroleum extraction, our analysis shows that the absence of CCS is likely to require near-full decarbonisation of surface transport and heat in buildings by 2050. It is difficult to see how significant further emissions reductions could be found to offset the impact of additional fossil fuel production.

Box 5.3: Emissions accounting and the 2050 target

The Climate Change Act includes a requirement to reduce 2050 emissions by at least 80% relative to 1990, including the UK share of international aviation and international shipping. This implies a level of per-capita emissions in 2050, which if replicated globally, would be consistent with a path to limit global temperature increase to around 2°C.

The accounting for the 2050 target under the Climate Change Act allows emissions trading to contribute (i.e. the target is set on a 'net' basis). However, as we set out when we recommended the 2050 target, it is not sensible to rely upon being able to purchase emissions credits, given that all countries would need to be pursuing stretching targets and any available credits would be likely to be very expensive.

A more reasonable approach is to plan now to meet the 80% target via domestic effort (i.e. on a 'gross' basis), while retaining the flexibility to use credits as we approach 2050 if they turn out to be available and less costly than domestic action at the margin. This is the basis on which our scenarios to 2050 have been constructed.

3. Conclusions and recommendations

The prospects for a domestic onshore petroleum industry are currently highly uncertain. It depends on the underlying economics of production, which in turn depend on the productivity of UK geology. This can only be resolved via exploratory drilling. But even if such exploration produces favourable results, other uncertainties remain, including whether public acceptability challenges can be overcome and the viability of UK onshore production in the context of developments in international fossil fuel markets.

Should an onshore petroleum industry be established in the UK and grow quickly, this would have the potential for significant impact on UK emissions. In order to ensure that these are manageable within carbon budgets, it is necessary that increased UK production does not feed through into increased unabated consumption of fossil energy; that emissions associated with production are strictly limited; and that the production emissions that do occur are offset by actions to reduce emissions elsewhere in the economy in order to stay within overall carbon budgets.

Our assessment is therefore that onshore petroleum extraction on a significant scale is not compatible with UK climate targets unless three tests are met:

- **Test 1: Well development, production and decommissioning emissions must be strictly limited.** Emissions must be tightly regulated and closely monitored in order to ensure rapid action to address leaks.
 - A range of technologies and techniques to limit methane emissions should be required, including ‘reduced emissions completions’ (also known as ‘green completions’) and liquid unloading mitigation technologies (e.g. plunger lift systems) should these be needed;
 - A monitoring regime that catches potentially significant methane leaks early is essential in order to limit the impact of ‘super-emitters’;
 - Production should not be allowed in areas where it would entail significant CO₂ emissions resulting from the change in land use (e.g. areas with deep peat soils);
 - The regulatory regime must require proper decommissioning of wells at the end of their lives. It must also ensure that the liability for emissions at this stage rests with the producer.
- **Test 2: Consumption – gas consumption must remain in line with carbon budgets requirements.** UK unabated fossil energy consumption must be reduced over time within levels we have previously advised to be consistent with the carbon budgets. This means that UK shale gas production must displace imported gas rather than increasing domestic consumption.
- **Test 3: Accommodating shale gas production emissions within carbon budgets.** Additional production emissions from shale gas wells will need to be offset through reductions elsewhere in the UK economy, such that overall effort to reduce emissions is sufficient to meet carbon budgets.

There also remains a question over whether increased fossil fuel production in the UK would lead to higher overall emissions globally (Box 5.4). This is something that we have not been able to explore in this report, but are planning to look at later this year.

There are other issues linked to ongoing gas consumption and carbon budgets, but not specific

to shale gas production. These include methane emissions from the storage and transportation of gas and the future use of the gas grid. We will consider these issues separately in future reports, including our annual Progress Reports to Parliament.

This report provides our first advice under the Infrastructure Act. We are required to provide further advice at five-yearly intervals. However, given the pace at which things could develop, we will monitor this area and, if necessary, provide further advice outside this predetermined cycle.

Box 5.4: Global emissions impact of UK fossil fuel production

Onshore production of fossil fuels in the UK would, assuming that domestic consumption is unaffected, increase the availability of these fossil fuels on international markets. This could potentially affect global emissions in three different ways:

- An increase in gas supply could lead to a reduction in coal consumption (reducing overall emissions);
- Increases in fossil fuel supplies could displace low-carbon energy (increasing emissions);
- Increases in fossil fuel supplies internationally could lead to a reduction in their prices, leading to an increase in overall energy consumption (increasing emissions).

The overall impact of UK onshore production on global emissions depends on the balance between these three effects. It is likely that the global level of ambition to reduce greenhouse gas emissions would influence how each of these effects plays out. The size, and potentially the direction, of the emissions impact could vary significantly depending on whether the world is headed for temperature change of 2°C, or levels well below or above this.



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