



Scottish unconventional oil and gas:

Compatibility with Scottish
greenhouse gas
emissions targets

Committee on Climate Change

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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 Chairman of the Committee on Climate Change, Valpak Limited, and the Association of Professional Financial Advisors.



Professor Nick Chater

Professor Nick Chater FBA is Professor of Behavioural Science at Warwick Business School, having previously held chairs in Psychology at Warwick and University College London (UCL). He is particularly interested in the cognitive and social foundations of rationality, and in applying behavioural insights to public policy and business. He has served as Associate Editor for the journals Cognitive Science, Psychological Review, Psychological Science and Management Science. He co-founded and is a Director of the research consultancy Decision Technology Ltd.



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, and a Director at Vivid Economics. He is 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 is the Director of the Institute for Fiscal Studies 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 Financial Services Authority 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 a member of the council and executive committee of the Royal Economic Society and a member of the banking standards board. 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 he 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 CCC, 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. 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 the University of 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 Corinne Le Quéré

Professor Corinne Le Quéré FRS is Director of the Tyndall Centre for Climate Change Research and Professor of Climate Change Science and Policy at the University of East Anglia (UEA). She conducts research on the interactions between climate change and the carbon cycle. She has authored multiple assessment reports by the Intergovernmental Panel on Climate Change (IPCC), and is a member of the Scientific Committee of the Future Earth research platform for global sustainability.



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 on Climate Change has been asked by the Scottish Government to examine the impacts of extraction of Scottish unconventional oil and gas (UOG), comprising shale gas, shale oil and coalbed methane, on greenhouse gas emissions and climate targets.

It is outside the scope of the study to investigate other issues that have been raised in relation to UOG development, such as local noise, traffic, water and wider environmental impacts; some of these are covered by parallel studies commissioned by the Scottish Government. The Committee's advice relates solely to greenhouse gas emissions and the impact on Scottish emissions targets.

The implications for greenhouse gas emissions of UOG 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 continue to monitor developments and provide further advice should this be necessary.

A moratorium on planning consents for extraction of unconventional oil and gas resources in Scotland is currently in place. If exploitation of UOG is to be pursued, it requires that a strong regulatory framework is put in place. It may ultimately necessitate the establishment of a dedicated regulatory body.

Unconventional oil and gas exploitation at scale would have unique characteristics. The Scottish Government has recognised that stronger environmental regulations may need to be put in place during the moratorium period. This strengthening is essential before production can commence. The current regulatory framework in Scotland for greenhouse gas emissions from UOG lacks clarity over the responsibilities and roles of the various actors and may have gaps relating to regulation of emissions to air including fugitive methane emissions.

Our assessment is that exploiting unconventional oil and gas by fracking on a significant scale is not compatible with Scottish 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.
 - Strengthening of the regulatory system is essential before production can commence. Much greater clarity is necessary over the respective roles of different actors in this system, entailing full coverage of greenhouse gas emissions (i.e. including strict limiting of both CO₂ and methane from all sources, covering not just the production site but also associated infrastructure before the point of grid injection or delivery to end user);
 - A range of technologies and techniques to limit methane emissions should be required, including 'reduced emissions completions' (also known as 'green completions'), liquid unloading mitigation technologies (e.g. plunger lift systems) and vapour recovery units should these be needed, as well as flaring of methane rather than venting it;
 - A monitoring regime that catches potentially significant methane releases 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.

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- **Test 2: Consumption – fossil fuel consumption must remain in line with the requirements of Scottish emissions targets.** Scottish unabated fossil energy consumption must be reduced over time within levels we have previously advised to be consistent with the emissions targets. This means that Scottish unconventional oil and gas production must displace imported gas rather than increasing domestic consumption.
 - **Test 3: Accommodating unconventional oil and gas production emissions within Scottish emissions targets.** Additional production emissions from shale wells will need to be offset through reductions elsewhere in the Scottish economy, such that overall effort to reduce emissions is sufficient to meet emissions targets.

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

- **Lifecycle emissions of tightly regulated domestic unconventional oil and gas production as against imports.** The overall emissions footprint of Scottish shale gas, if tightly regulated, is likely to be broadly similar to that of imported gas. Tightly regulated domestic production may provide an emissions saving when displacing imports of liquefied natural gas, and would provide greater control over the level of emissions associated with supply. Liquids produced under this framework could have quite variable emissions footprints, and so it is difficult to say whether they would provide an emissions saving over imports.
- **Impact on the global energy system.** Initial evidence suggests that tightly regulated shale gas production is likely to have a broadly neutral impact on global emissions, with emissions savings due to switching from higher-carbon fossil fuels approximately offsetting emissions increases due to increased use of unabated gas. Within the context of a world committed to decarbonisation, it is likely that domestic production of hydrocarbon liquids would displace high-cost production elsewhere in the world rather than increasing overall oil product consumption or driving fuel switching.

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

Left entirely unregulated, the emissions footprint of unconventional oil and gas production could be substantial. Any significant level of exploitation of Scottish resources in this way would be inconsistent with emissions targets. However, there are technologies and techniques that are known to limit greenhouse gas emissions from shale production. Experience and data from the US provide estimates of the costs and effectiveness of many of these measures.

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.

There is currently a moratorium in place, during which the Scottish Government has pledged to look at further tightening of regulation. It is essential that this tightening does occur before any UOG production commences in Scotland.

The present regulatory regime in Scotland is unclear in relation to the respective roles of the different organisations in the permitting and planning process. There may also be gaps in relation to emissions occurring outside the production site (e.g. from supporting infrastructure such as pipelines, processing facilities and gathering stations) and more generally in relation to emissions to the atmosphere, especially fugitive methane emissions.

Before any production can occur, in order to ensure that domestic UOG production can be compatible with emissions targets:

- The regulatory regime requires much greater clarity over the roles of the different actors (Health and Safety Executive, Scottish Environmental Protection Agency and local authorities), and that these be managed seamlessly.
- The regulatory framework should also ensure that regulation covers all emissions of both CO₂ and methane, requires strict limiting of these emissions, entails long-term monitoring and has full geographical coverage of emissions related to UOG supply prior to the gas being injected into the gas grid or put to use (i.e. encompassing not only the production site itself but also related infrastructure).

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 Scottish emissions targets. 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 the requirements of Scottish emissions targets

Scottish emissions targets 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).

Scotland is part of an integrated UK gas network. 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 dependence on imported gas. There is no case, however, for higher levels of gas consumption than we have previously set out.

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

- **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.
- **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.

As well as providing a smaller market for fossil fuels, the greater pressure placed on Scottish 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.

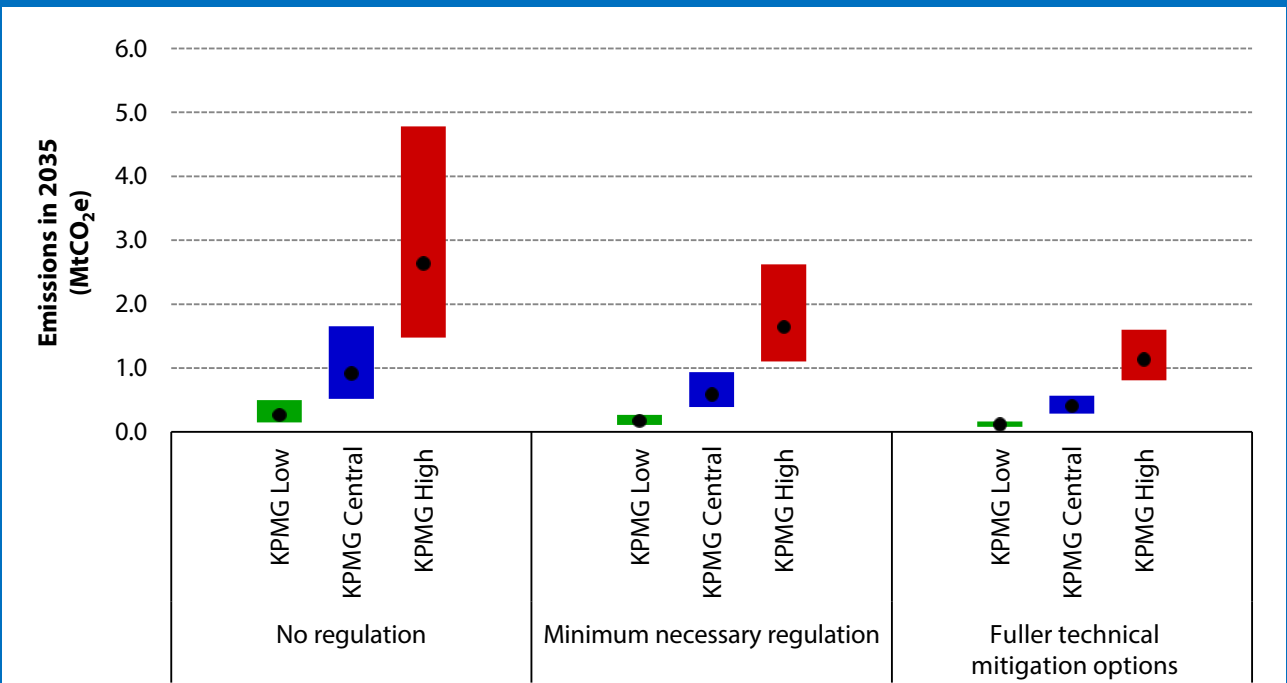
Unabated gas consumption must be consistent with the levels in the scenarios presented in our advice on Scottish annual targets, unless reductions in emissions beyond any the Committee has identified can be found elsewhere. Therefore, any new sources of Scottish production must be used to displace imports.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

Test 3: Accommodating unconventional oil and gas production emissions within Scottish emissions targets

Domestic production of unconventional oil and gas will lead to some additional Scottish emissions, even if fossil fuel 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.

In a high production scenario, in which the industry grows rapidly, the impact on domestic emissions from Scottish production could be around 1.6 MtCO₂e/year in 2035 under a tight regulatory regime (compared to around 0.6 Mt in a central scenario). This is slightly greater in magnitude to the emissions savings in the agriculture sector under our advice on Scottish annual targets. If regulation were more lax, emissions would be significantly higher (Figure 1).

Figure 1. Impact of Scottish unconventional oil and gas production on Scottish emissions (2035)



Source: CCC analysis.

Notes: Emissions from Scottish UOG production on a territorial basis. KPMG Low, Central and High refer to production scenarios presented in Chapter 2. Ranges around the black dots reflect uncertainty in our emissions estimates. The 'No regulation' case does not reflect the current or anticipated framework, but rather acts as a baseline for comparison purposes in order to show the emissions reductions available through regulation.

The high level of ambition embodied in Scottish annual emissions targets means that finding offsetting effort elsewhere in order to accommodate even moderate additional emissions from UOG production or other sources (e.g. aviation) would be challenging. Areas in which extra emissions reduction might be possible should be considered in RPP3, the report in which the Scottish Government must set out its plans to meet the annual targets to 2032.



Chapter 1:

Implications for fossil fuel consumption and climate impacts of methane and CO₂

The Committee on Climate Change has a duty under the Infrastructure Act (2015) to advise the UK 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). We submitted our first advice under the Infrastructure Act in March 2016, which was released in June 2016.¹

This report covers similar ground to the UK advice, in which we focused on shale gas, although there are important differences to consider between unconventional oil and gas in Scotland as compared to onshore petroleum for the UK as a whole. These include the coverage of shale oil as well as shale gas, allowing for the development of scenarios including shale oil by KPMG (Chapter 2); the regulatory regime in Scotland, which differs to that elsewhere in the UK (Chapter 3); and the more ambitious targets for emissions reduction in Scotland relative to those for the UK as a whole (Chapter 4). In addition, the Scottish Government asked us to consider the potential impact of Scottish unconventional oil and gas production on EU and global emissions. We cover this in Chapter 5.

In this chapter, we set out 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. Scottish sources of unconventional oil and gas
2. Implications for fossil fuel consumption of domestic unconventional oil and gas production
3. Comparing the climate effects of methane and carbon dioxide

Chapter 2 then considers the factors that would affect the size of a Scottish unconventional oil and gas industry over time, and presents scenarios for development of a Scottish industry. Chapter 3 analyses issues relating to the emissions footprint of domestic shale gas and shale oil 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 4, which presents emissions implications under different combinations of production scenarios and regulation cases. It then assesses the flexibility to accommodate these within Scottish emissions targets and draws out implications for the measures needed to limit emissions.

Chapter 5 then considers the impacts of exploitation of Scottish unconventional oil and gas resources on EU and global emissions.

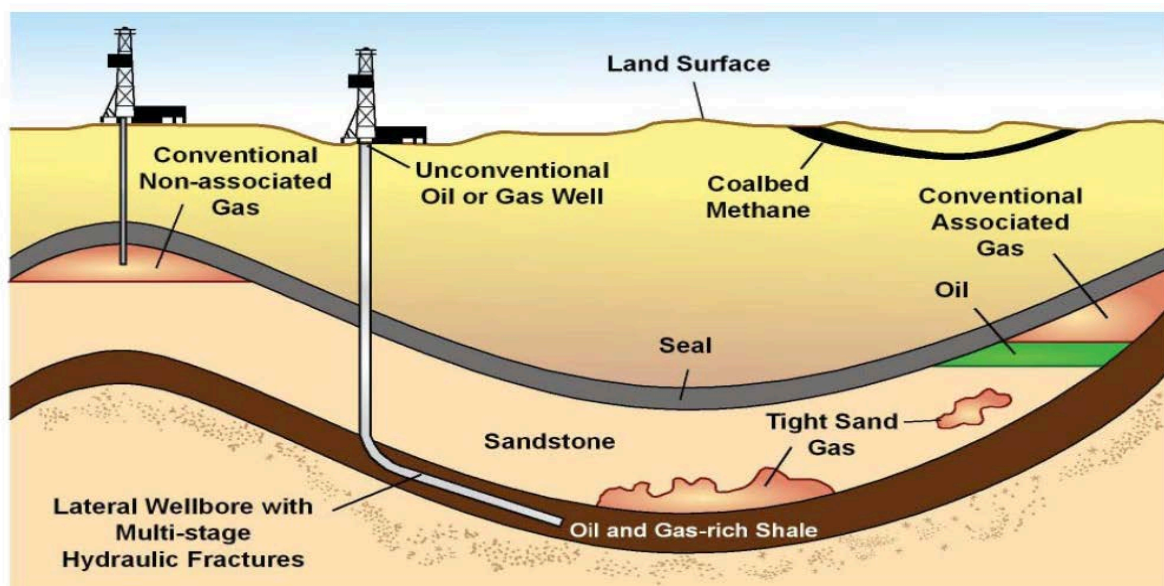
¹ CCC (2016) *Onshore Petroleum: The compatibility of UK onshore petroleum with meeting the UK's carbon budgets*. Available at <https://www.theccc.org.uk/publication/onshore-petroleum-the-compatibility-of-uk-onshore-petroleum-with-meeting-carbon-budgets/>

1. Scottish sources of unconventional oil and gas

The sources of unconventional oil and gas pertinent to our advice are limited to those relevant to Scotland: shale gas, shale oil and coal bed methane (CBM). Our advice therefore excludes consideration of production outside Scotland as well as offshore (North Sea) production. Underground coal gasification is being covered by a separate study,² while other excluded sources such as colliery gas, tight gas, oil sands, oil shale (which differs from shale oil) are considered unlikely to be developed in Scotland. However, to the extent that they contribute to Scottish fossil fuel supplies they will also contribute to its 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 1.1), and where the flow therefore needs to be stimulated through hydraulic fracturing or fracking (Box 1.1).

Figure 1.1. 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.

² Underground coal gasification is being covered in a separate study: <http://www.gov.scot/Topics/Business-Industry/Energy/onshoreoilandgas>

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.³

It is estimated that between 1,200 and 45,000 cubic metres of water per well is used in this process.⁴ 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.

Within the relevant sources of unconventional oil and gas, we have considered their potential to increase Scottish emissions, and the strength of the evidence base:

- **Shale gas.** Shale gas refers to natural gas that has remained in the source rock. Recent advances in technology for drilling and hydraulic fracturing have made extraction more economic.
 - The British Geological Survey (BGS) has studied the Midland Valley, the major shale basin in Scotland.⁵ BGS reports an estimated gas-in-place resource in the range 1.4 to 3.8 trillion cubic metres (tcm), with a central value of 2.3 tcm.
 - Economically recoverable reserves will be a fraction of this estimate of total resource (Box 1.2). In order to start to ascertain the Scottish 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 has been estimated such a process would take over two years 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.^{6,7}

³ Davies et al. (2012) Hydraulic fractures: How far can they go?, *Marine and Petroleum Geology*, 43, 519-521.

⁴ King (2012) *Hydraulic Fracturing 101*, http://www.kgs.ku.edu/PRS/Fracturing/Frac_Paper_SPE_152596.pdf

⁵ 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

⁶ IDDRI (2014) *Unconventional Wisdom*, http://www.iddri.org/Publications/Collections/Analyses/Study0214_TS%20et%20al._shale%20gas.pdf

⁷ Géný (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>

- **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 a detailed study, using seismic data and boreholes to estimate the shale oil resource in the Midland Valley in Scotland. They estimate the oil in place from 3.2 to 11 billion barrels of oil, with a central figure of 6 billion barrels.
 - The BGS report stresses that their estimates refer to the shale oil resource ('oil in place') and not how much can be recovered.
 - 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 in 2013.⁸ 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 Scotland.
 - In Scotland, there have been some CBM wells drilled in Airth, with the first gas produced in 2007. In 2010, Dart Energy Ltd acquired Composite Energy and drilled a further three wells. In 2012, Dart submitted an expanded Field Development Plan to DECC and sought SEPA permits and local planning permission.⁹
 - Dart's planning application for 14 proposed wells went to a planning inquiry in 2014. It received around 2,500 objections from members of the public. There was a lack of clarity over the boundaries between consideration of environment impact under the planning process and the remit of SEPA through licensing controls (e.g. on geology and hydrogeology). Before the application was resolved, the moratorium came into force; this application therefore remains unresolved, as does to the issue of the boundaries between the respective roles of the different actors.
 - 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 Scotland.
 - In 2004, a BGS study suggested that UK coal beds suffered from widespread low seam permeability, and low gas content. With the continued lack of development, there is little evidence to indicate that CBM will be commercially developed in Scotland.
 - Resources estimates for CBM are uncertain and thought to be located in the same geographical areas as shale gas and associated liquids. Based on surface access, geology, development costs and estimated well recovery costs, analysis from KPMG concludes that CBM is currently unlikely to be a major product in Scotland.¹⁰

⁸ Department of Industry and Science (2015) *Australian Energy Update*, <http://www.industry.gov.au/Office-of-the-Chief-Economist/Publications/Documents/aes/2015-australian-energy-statistics.pdf>

⁹ 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

¹⁰ KPMG have authored a separate study in parallel to this one, on economic impacts and scenario development.

In this advice, we therefore consider shale oil and shale gas. Of the two, shale gas has considerably larger potential implications for emissions and is the source for which the evidence base on emissions and mitigation measures is best developed. The production scenarios provided by KPMG in a parallel study (Chapter 2) include shale oil, enabling us also to include shale oil directly within our analysis.

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

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

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

- Only a fraction of shale resources are technically recoverable with current technology. BGS do not currently provide an estimate for the fraction of resource that is technically recoverable, stating that exploration needs to take place before an estimate can be made. Based on US experience on shale gas, the US Energy Information Administration estimates this proportion to be around 20% of the gas in place.¹¹
- Of this technically recoverable resource 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. These factors include: engineering design (such as the number of horizontal wells per pad and the techniques 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 market prices and production costs (see Chapter 2).

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://bookshop.europa.eu/en/macroeconomic-impacts-of-shale-gas-extraction-in-the-eu-pbKH0214481/>

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

2. Implications for fossil fuel consumption of domestic UOG production

As we set out in our UK advice, in order to be compatible with emissions targets any domestic production of unconventional oil and gas should not affect domestic consumption and should instead displace imports.

This conclusion is also valid for Scotland – that unabated fossil fuel 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 (Scotland).

The size of the domestic market for fossil fuels over the long term will be strongly affected by whether or not carbon capture and storage has a significant role in meeting the 2050 target. At the UK level, we analysed the level of natural gas and oil consumption that could be consistent with a 2050 target to reduce emissions by at least 80% on 1990 levels. This analysis showed that while there are ranges for the levels of consumption of oil and gas that could be consistent with meeting this target, the range is considerably wider for natural gas consumption and depends strongly on the availability of CCS:

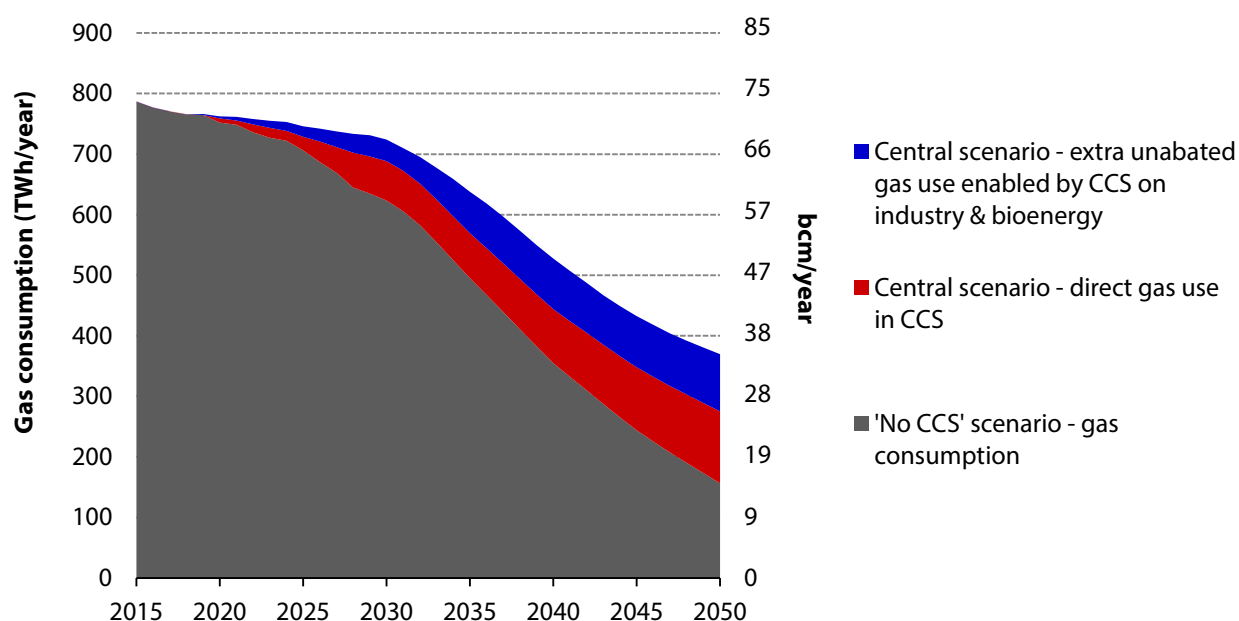
- **Gas:** under a 'no CCS' scenario that meets the 80% target, gas consumption in 2050 is around half the level under our Central scenario. Of the difference in gas consumption, around half is gas used directly with CCS, while the remainder is additional unabated use of gas allowed within the headroom created by using CCS in industry and with bioenergy (Figure 1.2);
- **Oil:** under a 'no CCS' scenario, oil consumption in 2050 is around 14% below the level in our Central scenario.

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.

Figure 1.2. Direct and indirect impacts of CCS availability on UK gas consumption to 2050



Source: CCC (2016) *The compatibility of UK onshore petroleum with meeting the UK's carbon budgets*.

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 the Scottish emissions inventory. 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 metrics for comparing different types of greenhouse gases, and each has its own characteristics. Whichever metric is chosen it is most important to be aware of its limitations and interpret results in light of those.

Our use of fixed multiplier of 25 reflects current standard practice under accounting for UK carbon budgets and Scottish emissions targets, as well as 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 the 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):

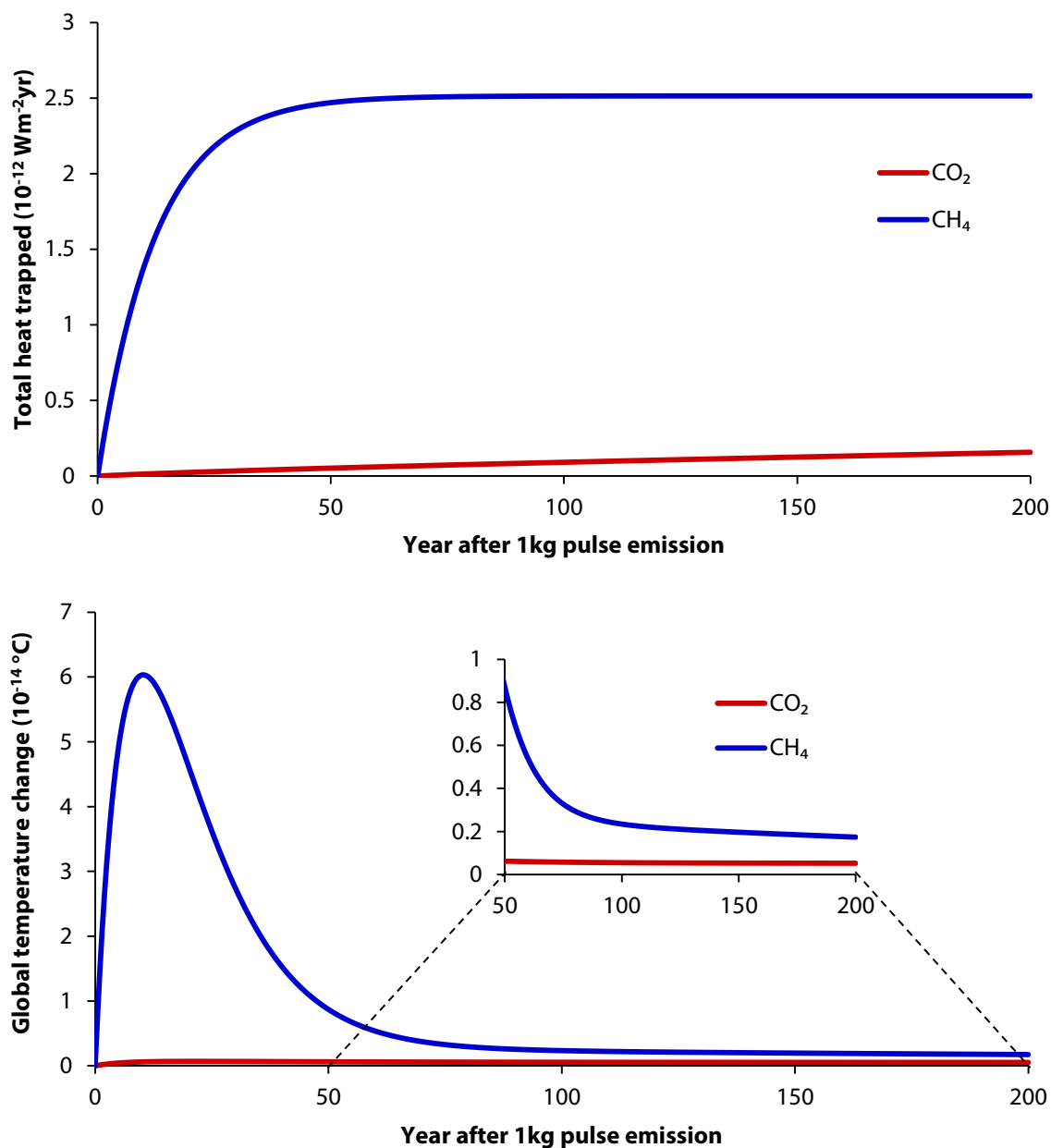
- The 100-year Global Warming Potential (GWP₁₀₀) is the standard metric used in domestic and international climate policy. It compares the total heat trapped in the atmosphere over a 100-year period after a pulse emission of a given mass of greenhouse gas, relative to the same mass of CO₂. In essence 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, such as the Global Temperature Potential (GTP), 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 5th Assessment Report (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 for Scottish unconventional oil and gas

A Scottish shale industry has not been developed to date. 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 Scottish unconventional oil and gas 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 Scottish unconventional oil and gas industry over time, presents scenarios for development of a Scottish industry and considers the likely impact on gas prices, in three sections:

1. Factors affecting the growth of a Scottish unconventional oil and gas industry
2. Production scenarios
3. Impact on fossil fuel prices

1. Factors affecting the growth of a Scottish unconventional oil and gas 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 Scotland:
 - **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, costs are likely to be significantly higher in Scotland due to tighter health and safety regulation and, at least in the initial stages, less competition in the supply chain.
 - **Fracturing stages.** The fracturing stage represents between 20% and 50% of overall well costs.¹⁷ Over time the number of fracture stages has tended to increase, which has increased the volume of shale per unit lateral length.¹⁸ It is expected that Scottish 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

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

¹⁷ Oilfield Technology (2013) *Taking Centre Stage*, https://www.slb.com/~media/Files/completions/industry_articles/201302_ot_taking_centre_stage_bakken_ia.pdf

¹⁸ MITeI (2015), *The Salient Distribution of Unconventional Oil and Gas Well Productivity*, <http://energy.mit.edu/publication/the-salient-distribution-of-unconventional-oil-and-gas-well-productivity/>

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 Scotland.¹⁹

- **Other costs.** The UK shale industry has a voluntary scheme, under which 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. One operator, Ineos, has pledged to go further than this, with 6% of revenues going to homeowners, landowners and local communities.²⁰ The UK Government is currently consulting on the delivery method and priorities of a Shale Wealth Fund.²¹ Each production 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 Scotland 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 Scottish 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 Scotland could require security during the well development stage and potentially beyond, adding to the costs for the site. Planning permission can be difficult to obtain due to local impacts.
- **Composition.** The composition of hydrocarbons extracted varies considerably between wells. Generally the composition is categorised into dry gas, wet gas, co-producing and oil-only: dry gas is mainly (greater than 90%) methane; wet gas contains a greater proportion of gases such as ethane, propane, butane and gas condensate; co-producing wells produce a wet gas and oil; and oil-only mainly produces oil, potentially with some associated gas. The longer hydrocarbons tend to have a greater value than methane and may be used as feedstocks in petrochemical plants rather than combusted for energy.

¹⁹ 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>

²⁰ <http://www.ineos.com/news/ineos-group/ineos-plans-25-billion-shale-gas-giveaway>

²¹ HM Treasury (2016) *Shale Wealth Fund: consultation*. <https://www.gov.uk/government/consultations/shale-wealth-fund>

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).

- **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 Scottish onshore wells. In any case this is likely to vary significantly within Scotland (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, while the oil price ranges from \$71-155/barrel.²⁵ 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. UOG 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 Government.

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.^{26,27} As Scotland has no exploration flow data, let alone production data, it is too early to speculate on the likely productivity of Scottish 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.²⁸ However, there is recent evidence that productivity per unit length in the US is declining. With the most

²⁵ In 2014 prices.

²⁶ IDDRI (2014) Unconventional Wisdom, http://www.iddri.org/Publications/Collections/Analyses/Study0214_TS%20et%20al._shale%20gas.pdf

²⁷ Browning et al (2013), *Barnett study determines full-field reserves, production forecast*, Oil & Gas Journal, <http://www.ogj.com/articles/print/volume-111/issue-9/drilling-production/barnett-study-determines-full-field-reserves.html>

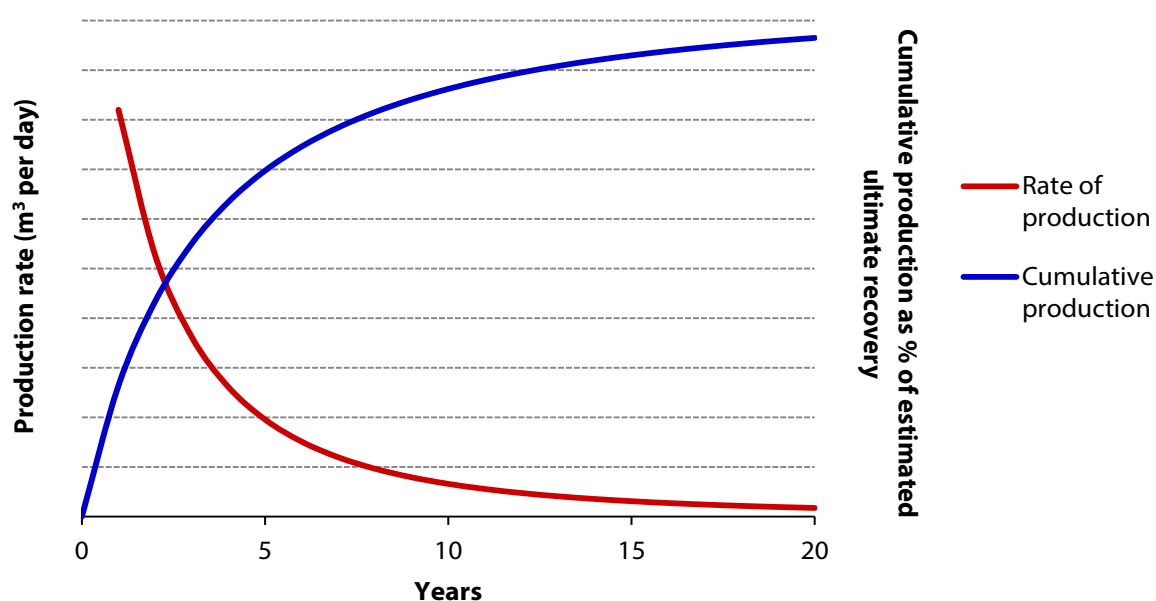
²⁸ Oilfield Technology (2013) *Taking Centre Stage*, https://www.slb.com/~media/Files/completions/industry_articles/201302_ot_taking_centre_stage_bakken_ia.pdf

Box 2.1. Well productivity

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.²⁹

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.

Figure B2.1. Modelled well production profile

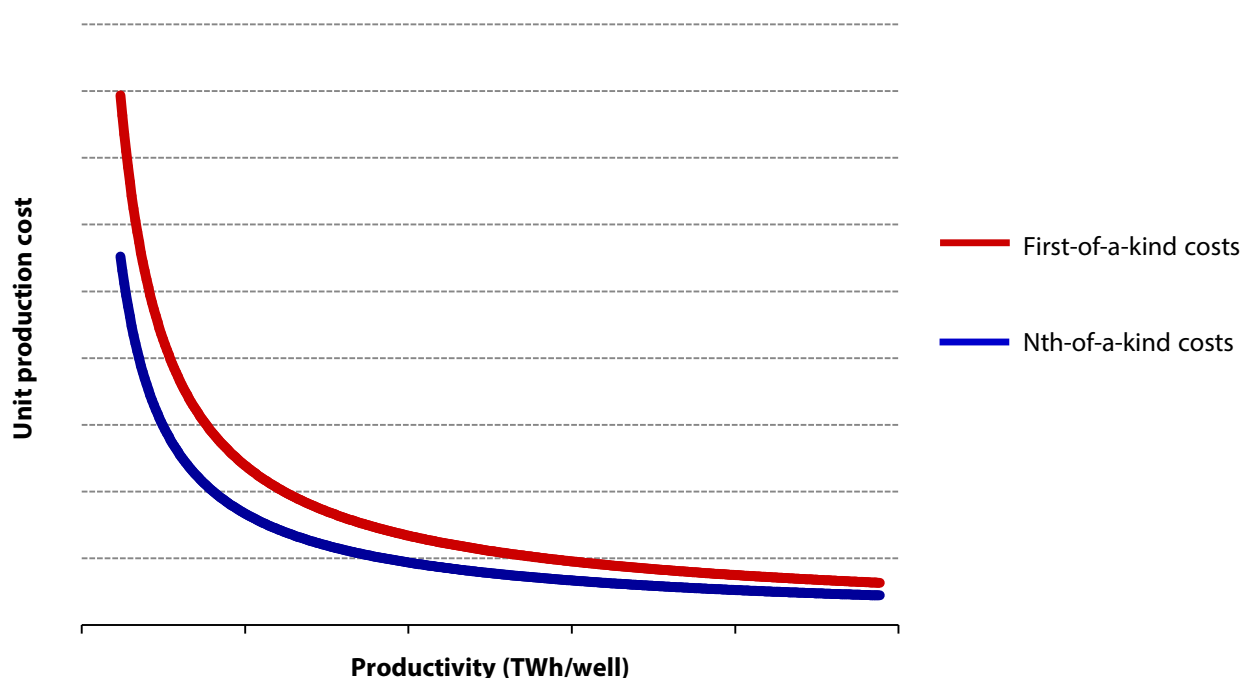


Source: CCC calculations.

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

²⁹ MITei (2015) *The Salient Distribution of Unconventional Oil and Gas Well Productivity*, <http://energy.mit.edu/publication/the-salient-distribution-of-unconventional-oil-and-gas-well-productivity/>

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



Source: CCC analysis.

2. Production scenarios

For our UK advice, we used a range of scenarios for shale gas production, based on scenarios available in existing literature. Shale gas production in 2030 under those scenarios varied by a factor of around 10 between the highest and lowest, reflecting the large amount of uncertainty over the potential size of a UK unconventional fossil fuel industry. This is also likely to be true for shale oil production.

For this advice on Scotland, we base our analysis on three scenarios developed in a parallel study by KPMG on economic impacts and scenario development. The range represented by these scenarios is again very wide, varying by a factor of 18 between the lowest and highest in 2030 (Figure 2.2). These scenarios include both gaseous and liquid products, from a mix of gas-only and co-producing wells.³⁰

The three scenarios reflect different assumptions regarding the number, productivity and timing of shale wells developed (Figure 2.3). For all scenarios, KPMG assumed that 75% of the wells would produce oil and gas, with the remaining 25% producing gas only. They further assumed

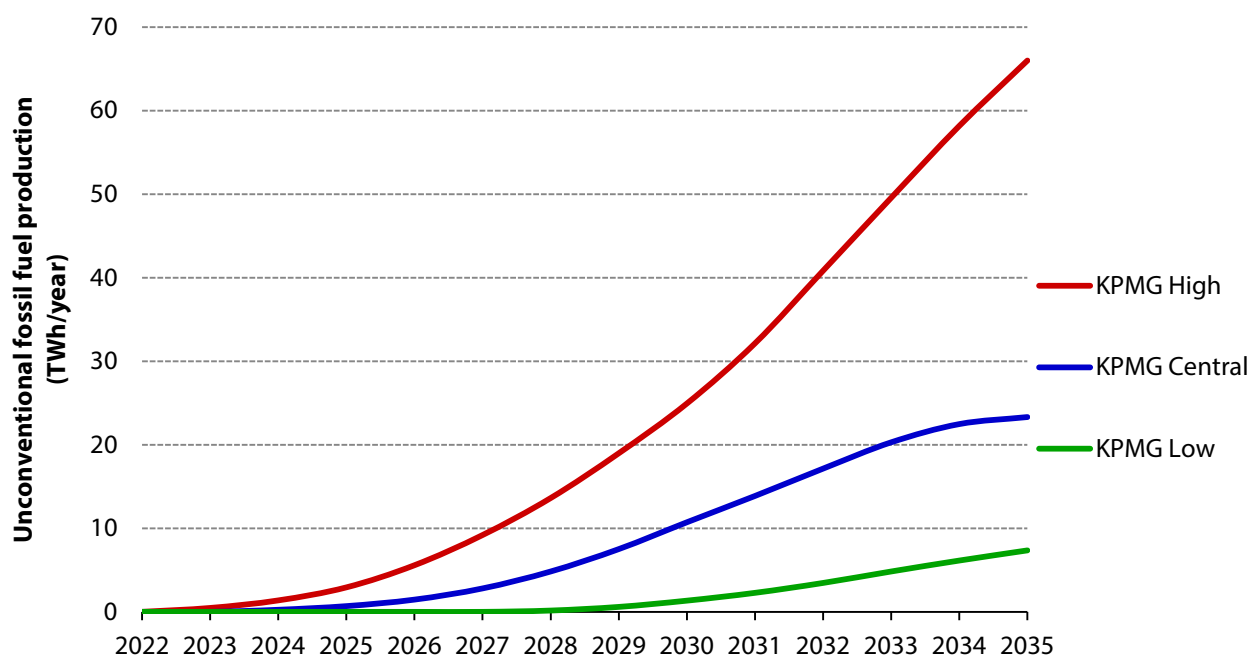
³⁰ The economic impact and scenario development report assumes that wells would produce shale gas, similar in composition to natural gas, with 75% of wells also co-producing a range of other products grouped under 'liquids'. KPMG did not break down 'liquids' within their scenarios into specific products, as they consider that the mix of products to be speculative until further exploration has taken place. Based on experience elsewhere, alongside methane production co-producing wells are likely to include a range of other hydrocarbons, both liquids and wet gas (e.g. comprising ethane, propane, butane and gas condensate), some of which could be used as petrochemical feedstocks rather than combusted (see Chapter 4). For our analysis, the precise mix of products is relatively unimportant, with the key distinction being between methane and non-methane hydrocarbons, due to methane being a potent greenhouse gas (see Chapter 1).

production per well to consist of 0.83 TWh (3.2 bcf) of gas and 0.1 TWh of liquids for co-producing wells, and the same gas production rate of 0.83 TWh for gas-only wells.³¹ We note that this is higher than the central assumption in our UK-level analysis of 0.52 TWh (2 bcf) per well, within a range of 0.26 to 1.3 TWh (1 to 5 bcf).

KPMG have produced three scenarios, which vary in terms of the number of wells and the timing of production:

- **KPMG Low scenario:** In this scenario UOG well development is initially slow, with drilling commencing in 2026. Production volumes only reach 2 TWh per year by 2030, rising to around 8 TWh by 2035.
- **KPMG Medium scenario:** Wells start to be drilled in 2023. Production volumes reach around 10 TWh per year in 2030, peaking at almost 25 TWh in the mid-2030s.
- **KPMG High scenario:** In the high scenario wells start to be drilled in 2022. Production volumes rise rapidly over time, reaching around 25 TWh per year by 2030 and around 65 TWh in 2035.

Figure 2.2. KPMG scenarios for Scottish unconventional oil and gas production

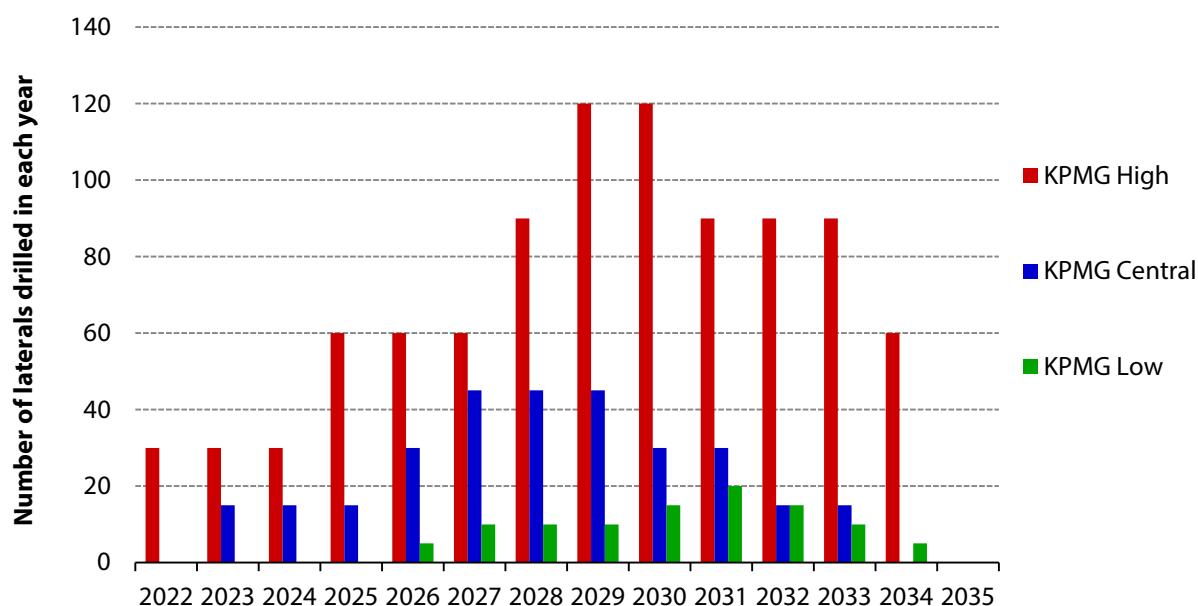


Source: KPMG.

Notes: Comprises both gas and liquids production under the KPMG scenarios.

³¹ It is likely that the volume of gas produced in co-producing wells will turn out to be smaller on average than those producing gas only. The composition of co-producing wells is also likely to have a smaller percentage of methane in the gas when compared to gas-only wells.

Figure 2.3. Wells drilled under the production scenarios (2022-35)



Source: CCC analysis, based on production scenarios supplied by KPMG.

3. Impact on fossil fuel 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 Scottish 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.
- Scotland is part of a highly connected gas network across Europe, which is the world's largest importing market. Additional Scottish 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 Scenario³² would decline to 425 bcm by 2030. Even Scottish shale gas production at the upper end of our scenarios for 2030 would be around 1% of this demand. Production at the low end of our range would be only around 0.1%.

For oil, prices are set on world markets. Again the volume of shale oil produced in Scotland would have a negligible effect.

Our assessment is therefore that Scottish unconventional oil and gas production will do little to reduce energy bills, with prices set by international markets. This finding is consistent with those

³² The IEA 450 scenario is broadly compatible with limiting average warming to 2C, and with the UK 2050 target for at least an 80% reduction in greenhouse gas emissions on 1990 levels. IEA (2015) *World Energy Outlook* <http://www.worldenergyoutlook.org/weo2015/>

of other studies³³, including that of KPMG. Production that bypasses wholesale markets could, however, reduce costs for some industrial consumers.

The weak 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.

³³ 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>



Chapter 3:

Emissions scenarios relating to unconventional oil and gas extraction

This chapter sets out estimates for the emissions relating to shale production in Scotland, 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 Scottish emissions due to production, rather than combustion, transmission or distribution, on the basis that Scottish fossil energy consumption and methane leaks from the gas grid are unaffected by the development of an onshore industry.

In principle, changes in 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 Scottish unconventional oil and gas production, opportunities to limit these emissions and how they compare to the emissions associated with imports, in three sections:

1. Sources of emissions relating to unconventional oil and gas production
2. Emissions mitigation opportunities and costs
3. The regulatory framework in Scotland

1. Sources of emissions relating to unconventional oil and 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 3.1). 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 3.2), in order to estimate ranges for potential emissions in a Scottish 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 3.1. 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.³⁴ 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 or estimate the emissions from an individual component or facility directly.³⁵

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.³⁶ In regions with a large proportion of oil production, as expected in Scotland, the fraction of methane production lost could be up to around 9%³⁷ (a higher proportion of a much smaller quantity of methane production).³⁸ 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.

The KPMG scenarios assume that the co-producing wells produce a significant volume of gas, which would mean it would be likely that gas produced is put to effective use. However, it may turn out that some shale wells produce small volumes of gas and it is therefore uneconomic to put this gas to effective use. Techniques and technologies exist to ensure that a very small proportion of the methane produced in this way is released to atmosphere (section 3).

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,³⁹ this period coincides with the development of unconventional oil 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.⁴⁰

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

³⁴ These 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).

³⁵ JISEA (2015), *Estimating US Methane Emissions from the Natural Gas Supply Chain*, <http://www.nrel.gov/docs/fy16osti/62820.pdf>

³⁶ 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.

³⁷ Karion et al. (2013), Methane emissions estimate from airborne measurements over a western United States natural gas field. *Geophys. Res. Lett.*, 40, 4393–4397.

³⁸ 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.

³⁹ 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.

⁴⁰ 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.

Box 3.1. Top-down vs. bottom-up estimates of methane emissions

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.⁴¹ 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.^{42,43}

Box 3.2. Sources for the data on emissions

We have obtained estimates for the greenhouse gas emissions associated with unconventional oil and gas exploitation from various sources:

- We have used various sources to estimate the emissions not currently covered by the UK greenhouse gas inventory, including emissions from unconventional oil and gas. The range of sources of unconventional oil and gas 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.

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. We therefore use a combination of measured emissions data (primarily for methane) and modelled data (primarily for CO₂). Our supporting annex sets out how we have used the available data to produce our quantitative analysis for this report.

⁴¹ Brandt et al. (2014), Methane Leaks from North American Natural Gas Systems, *Science*, 343, 733-735.

⁴² Zavala-Araiza et al. (2015), Reconciling divergent estimates of oil and gas methane emissions, *PNAS*, 112(51), 15597-15602.

⁴³ JISEA (2015), *Estimating US Methane Emissions from the Natural Gas Supply Chain*, <http://www.nrel.gov/docs/fy16osti/62820.pdf>

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.⁴⁴ Most studies analysing the GHG emissions from exploiting unconventional oil and gas either ignore this phase or assume the emissions are negligible.⁴⁵ 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 oil and 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 3.3). The volume of gas produced during completion is linked to the age of the formation, 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.
 - **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 source of emissions, 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.⁴⁶ Land-use change emissions may also be significant for other types of land.
- **Production.** Emissions from UOG production result from the general operation of the well. For the gaseous element this includes gathering and compression equipment, and gas processing, before injection into the gas grid. For the liquid element, this includes onsite

⁴⁴ 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

⁴⁵ SGI (2015), *Methane and CO₂ emissions from the natural gas supply chain*, <http://www.sustainablegasinstitute.org/publications/white-paper-1/>

⁴⁶ 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-Updated-8.Dec.14.pdf>

storage and transporting it for processing.⁴⁷ 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.⁴⁸
- **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.⁴⁹ It is currently uncertain how many shale wells in Scotland 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.⁵⁰
- **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,⁵¹ and are estimated to be responsible for 20% of emissions in the US.⁵²
- **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 evidence⁵³ 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 3.1 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

⁴⁷ It is assumed that no additional refining capacity is required.

⁴⁸ 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.

⁴⁹ SGI (2015), *Methane and CO₂ emissions from the natural gas supply chain*, <http://www.sustainablegasinstitute.org/publications/white-paper-1/>

⁵⁰ SGI (2015).

⁵¹ Blowdown is the venting of gas remaining in a compressor when that compressor is shut down.

⁵² SGI (2015).

⁵³ Zavala-Araiza et al. (2015), Reconciling divergent estimates of oil and gas methane emissions, *PNAS*, 112(51), 15597-15602.

unachievable, with suitable operational control and maintenance procedures these high emitters could be largely eliminated.⁵⁴ If the super-emitter sites could be brought in line with the average, then total supply chain emissions would be reduced by 65-87%.⁵⁵

- 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.⁵⁶

Box 3.3. 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 gas well could be vented to the atmosphere;⁵⁷ subsequently a large number of reports have produced modelled estimates for the completion emissions. Only recently have these emissions been measured.⁵⁸

Table B3.3 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.

Table B3.3. 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.

⁵⁴ SGI (2015).

⁵⁵ 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.

⁵⁶ Boothroyd et al. (2016) Fugitive emissions of methane from abandoned, decommissioned oil and gas wells, *Science and The Total Environment*, 547, 461-469.

⁵⁷ Howarth et al. (2011), Methane and the greenhouse gas footprint of natural gas from shale formations, *Climatic Change*, 106, 679–690.

⁵⁸ SGI (2015).

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.⁵⁹ 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.⁶⁰

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 production at costs well below UK Government carbon values:⁶¹

- **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 being put to productive use. REC can reduce the associated emissions from completion by between 90-99%.⁶² Abatement costs are estimated to range from being cost-saving up to £22/tCO₂e saved.⁶³
 - **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%.⁶⁴ Abatement costs are estimated to range from being cost-saving to £13/tCO₂e.
 - **Vapour recovery units (VRU).** The oil from co-producing shale wells also contains some dissolved gas (which is likely to be primarily methane). As this liquid is stored, the gas is released and can be vented to the atmosphere. A VRU will collect and compress this gas

⁵⁹ US EPA, *Recommended Technologies to Reduce Methane Emissions*, <https://www.epa.gov/natural-gas-star-program/recommended-technologies-reduce-methane-emissions>

⁶⁰ US EPA (2016), *Best Management Practice (BMP) Commitment Framework*, https://www.epa.gov/sites/production/files/2016-05/documents/methanechallenge_bmp_framework.pdf

⁶¹ The UK Government carbon values are broadly consistent with limiting average warming to 2°C and reducing emissions by at least 80%, and reach £78/tCO₂e in 2030. DECC (2009) *Carbon Valuation in UK Policy Appraisal: A Revised Approach*. Available at <https://www.gov.uk/government/publications/carbon-valuation-in-uk-policy-appraisal-a-revised-approach>

⁶² SGI (2015), *Methane and CO₂ emissions from the natural gas supply chain*, <http://www.sustainablegasinstitute.org/publications/white-paper-1/>

⁶³ US EPA (2011), *Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells*, https://www.epa.gov/sites/production/files/2016-06/documents/reduced_emissions_completions.pdf

⁶⁴ 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>

so it can be put to productive use. It is estimated that a VRU would have an abatement cost of around £4/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.
- **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 could reduce leakage by 40%, semi-annual by 60% and quarterly by 80%.⁶⁵ 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.

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.⁶⁶

⁶⁵ ICF (2015).

⁶⁶ US EPA (2011), *Install Electric Compressors*,
<https://www.epa.gov/sites/production/files/2016-06/documents/installelectriccompressors.pdf>

Regulation cases for emissions analysis

There is clear evidence that regulation of shale 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.⁶⁷

In our UK advice on onshore petroleum,⁶⁸ we set out four cases for the regulation of shale gas production, based on the evidence about the efficacy and cost of the various technologies and techniques to limit emissions from shale production. One of those cases, which we called 'Current UK position' reflected the Environment Agency's view that reduced emissions completions would be required.

The regulatory framework in Scotland differs from that in the rest of the UK. There is currently a moratorium in place, during which the Scottish Government has pledged to look at further tightening of regulation (section 3). The measures that would be required under the existing framework are also relatively unclear. We have therefore not attempted to reflect the current position, and instead present three cases for the regulation of onshore oil and gas production:

- **No regulation.** Under this case, no measures are implemented to limit greenhouse gas emissions. This does not reflect the current or anticipated framework, but rather acts as a baseline for comparison purposes in order to show the emissions reductions available through regulation.
- **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).
- **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 currently estimated to be higher than UK Government carbon values⁶⁹, which we use as a comparison to judge cost-effectiveness. However, evidence on costs to make this assessment is currently lacking.

It is likely that the industry would 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 onshore oil and gas trade body) has guidelines that state that “operators should plan and then implement controls in order to minimise all emissions.”

⁶⁷ US EPA, *EPA Proposes New Commonsense Measures to Cut Methane Emissions from the Oil and Gas Sector/Proposal Cuts GHG Emissions, Reduces Smog-Forming Air Pollution and Provides Certainty for Industry*, <https://www.epa.gov/newsreleases/epa-proposes-new-commonsense-measures-cut-methane-emissions-oil-and-gas-sectorproposal>

⁶⁸ CCC (2016), *The compatibility of UK onshore petroleum with meeting the UK's carbon budgets*, <https://www.theccc.org.uk/publication/onshore-petroleum-the-compatibility-of-uk-onshore-petroleum-with-meeting-carbon-budgets/>

⁶⁹ These Government values are broadly consistent with limiting average warming to 2°C, available at <https://www.gov.uk/government/publications/carbon-valuation-in-uk-policy-appraisal-a-revised-approach>

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.

In our analysis we have assumed that gas produced in co-producing well will be put to productive use, as the levels of productivity in the KPMG scenarios is likely to make this economic.⁷⁰ Should the gas co-produced with liquids be flared or vented instead then the emissions footprint attributable to the liquids will be considerably higher. This will vary on a case-by-case basis.

For each of the three regulation cases we have used the available evidence to produce low, central and high estimates for emissions that might occur (Box 3.4). Our supporting annex described the various stages at which emissions can occur, some of which 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 3.1 and 3.2).

Combining these sets of emissions requires an assumption on average well productivity (i.e. the energy produced per well). For consistency we have used a figure of 0.83 TWh/well for gas (for all wells) and 0.1 TWh/well for liquids (for 75% of wells) to combine these emissions (Figures 3.3 and Figure 3.4), based on data provided by KPMG. High levels of average productivity would imply lower emissions per unit of energy produced and also lower costs per unit energy (see Chapter 2), and conversely low productivity would lead to high unit emissions and unit costs.

Under central estimates, the 'Minimum necessary regulation' case saves 39% of emissions relative to the 'No regulation' case, compared with 58% savings under the 'Fuller Technical Mitigation Options' case (Figure 3.5).

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 3.6).

In these results, we present the emissions per TWh, treating oil and gas output equivalently. However, it is the gas production that leads to the large majority of the methane emissions and therefore the emissions per TWh produced will generally be higher for gas-only wells than for co-producing ones.

The results show that technologies and techniques to reduce emissions can have a substantial effect on the greenhouse gas footprint of production. For the high-end emissions estimates, the 'Minimum necessary regulation' case saves 54% of emissions relative to the 'No regulation' case, compared with 39% for central estimates and 25% 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.

⁷⁰ For co-producing wells, the oil-to-gas ratio will vary and in some cases the volume of gas may be insufficient to justify its productive use (e.g. piping to a processing facility and then injection into the gas grid) on an economic basis.

Box 3.4. Low, central and high emissions estimates

In order to produce our low, central and high emissions estimates for the median well in Scotland, we have applied, 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 Scotland. This high degree of uncertainty necessitates a large range in our emission factors.

- **High emissions estimate.** The high scenario is what we estimate to be the worse-case scenario for a typical Scottish shale 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 emissions estimate.** This represents our best estimate for a typical well in Scotland. It primarily uses the median emissions as presented in literature.
- **Low emissions estimate.** The low estimate represents what we assess to be the best-case scenario for a typical well in Scotland. It uses a combination of low and median values that we consider relevant to Scotland.

The methane emissions as a proportion of throughput are shown for our three regulations cases, under high, central and low assumptions in Table B3.4.

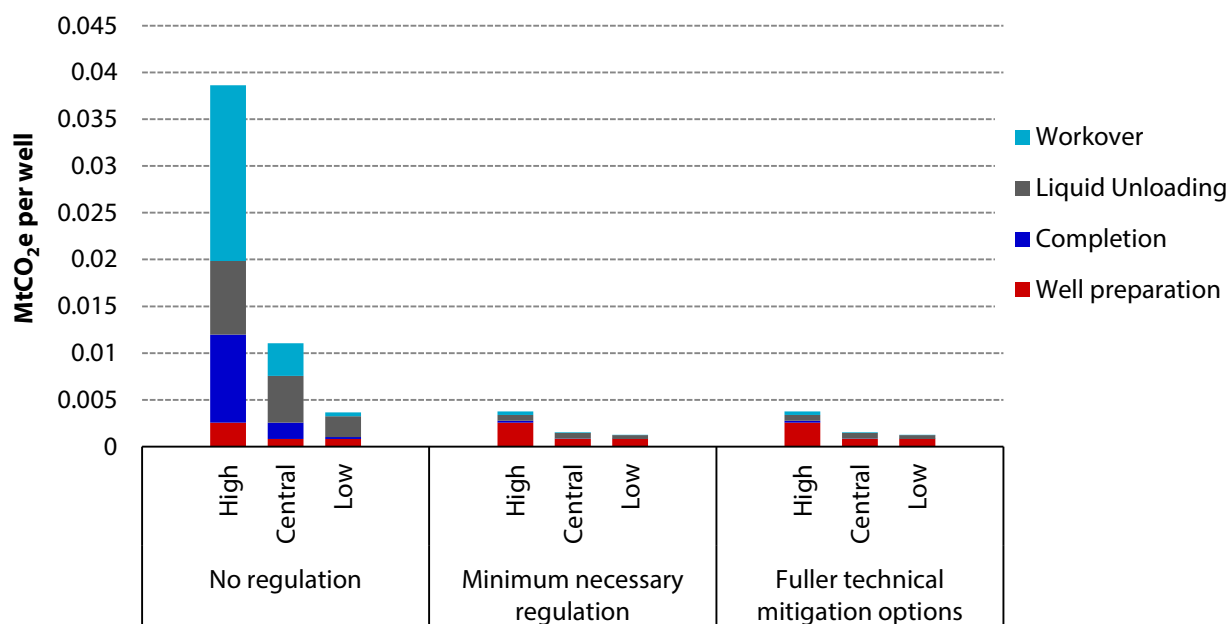
Table B3.4. Range of methane emissions as a percentage of gas throughput

	No Regulation	Minimum necessary regulation	Fuller technical mitigation options
High	4.9%	0.9%	0.6%
Central	1.8%	0.5%	0.3%
Low	0.7%	0.3%	0.2%

Source: Various, with CCC calculations.

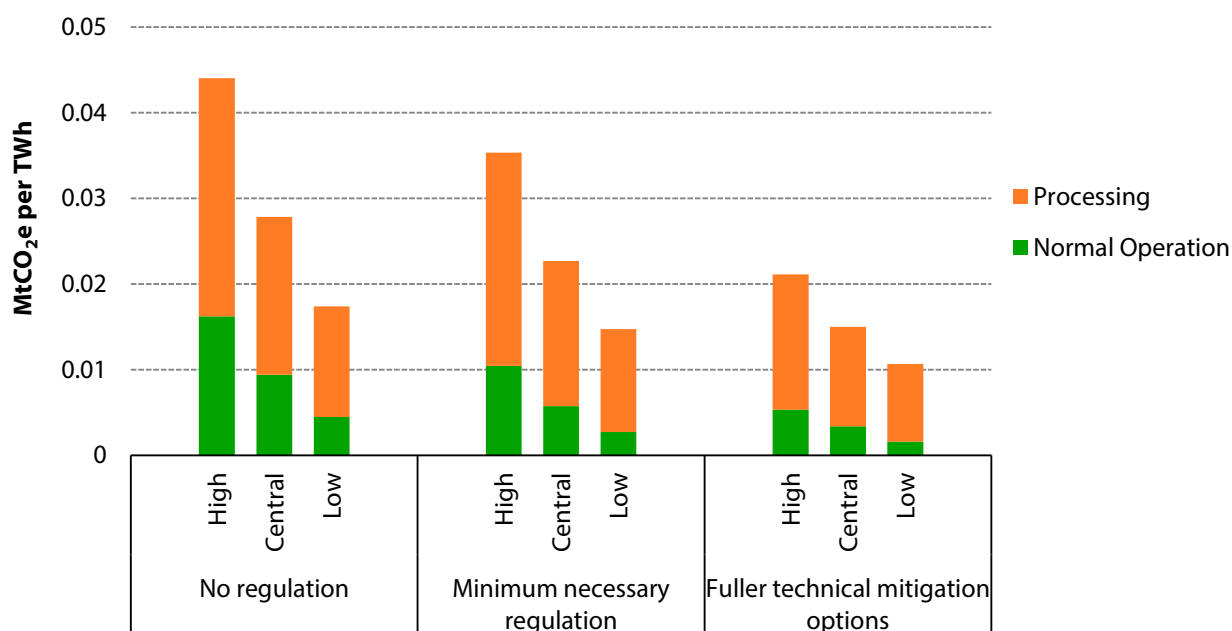
Notes: The 'No regulation' case does not reflect the current or anticipated framework, but rather acts as a baseline for comparison purposes in order to show the emissions reductions available through regulation.

Figure 3.1. Emissions that scale with the number of wells under different regulation cases



Source: CCC analysis.

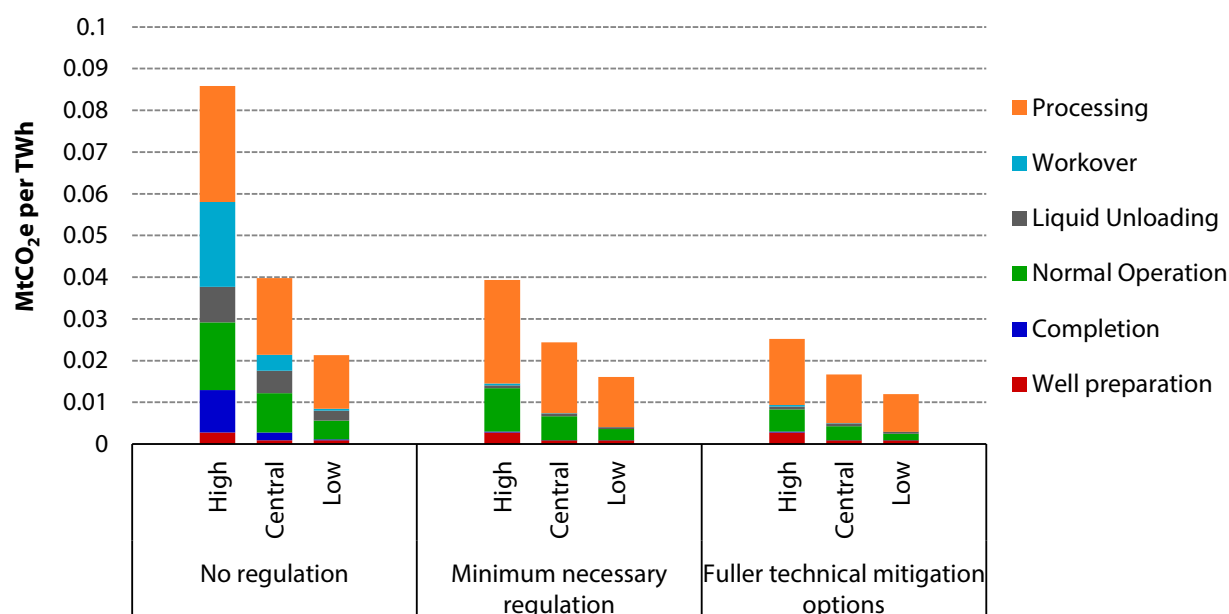
Figure 3.2. Emissions that scale with energy production under different regulation cases



Source: CCC analysis.

Notes: Processing is often required to ensure the necessary gas quality for gas grid injection. Normal Operation relates to operation of the well and gathering line (i.e. pipes and pumps moving the gas to the processing plant).

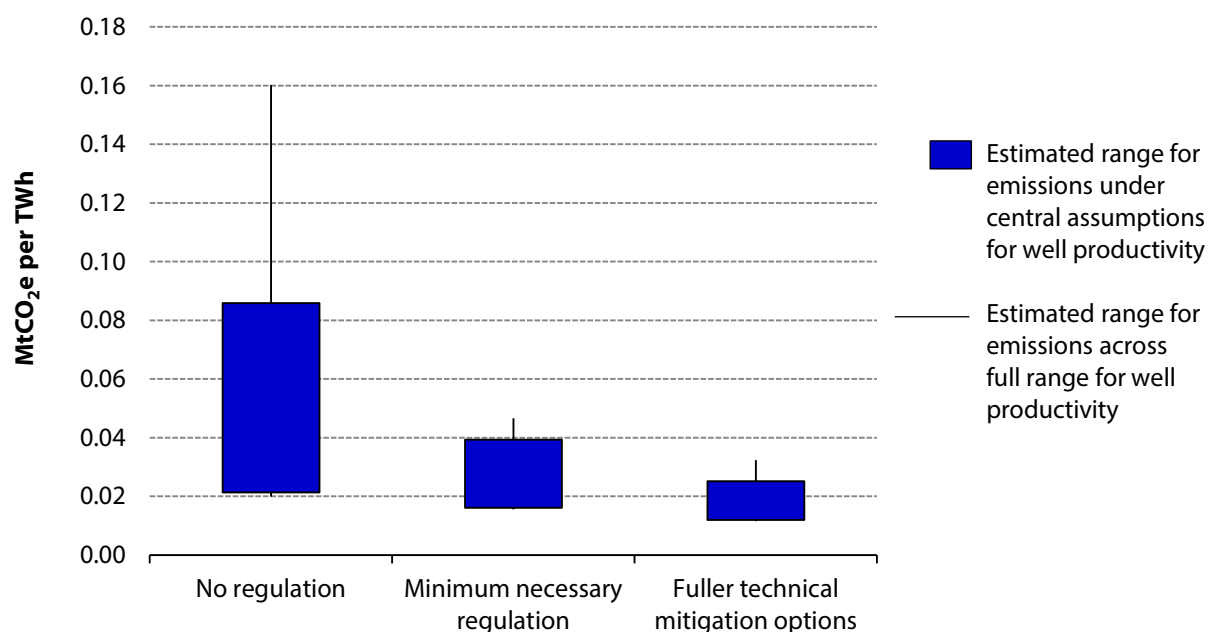
Figure 3.3. Total emissions with central well productivity assumptions under different regulation cases



Source: CCC analysis.

Notes: Data on per-well emissions (Figure 3.1) and per-TWh emissions (Figure 3.2) have been combined using a central assumption on median well productivity of 0.83 TWh gas (all wells) and 0.1 TWh liquids (75% of wells).

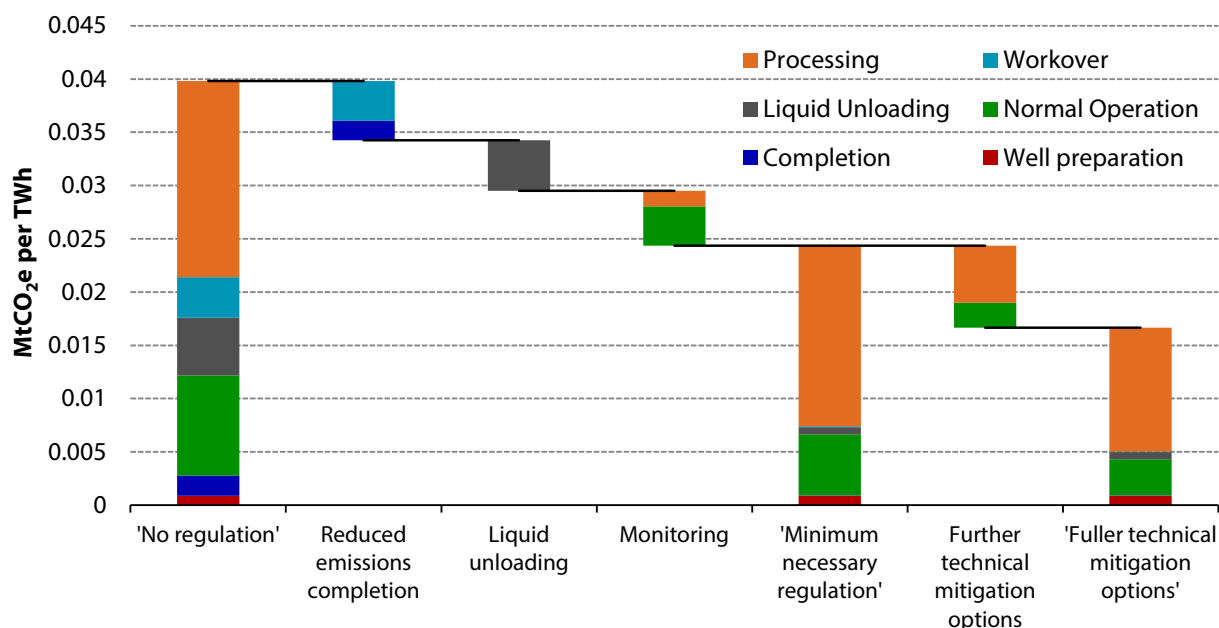
Figure 3.4. Total emissions depending on well productivity under different regulation cases



Source: CCC analysis.

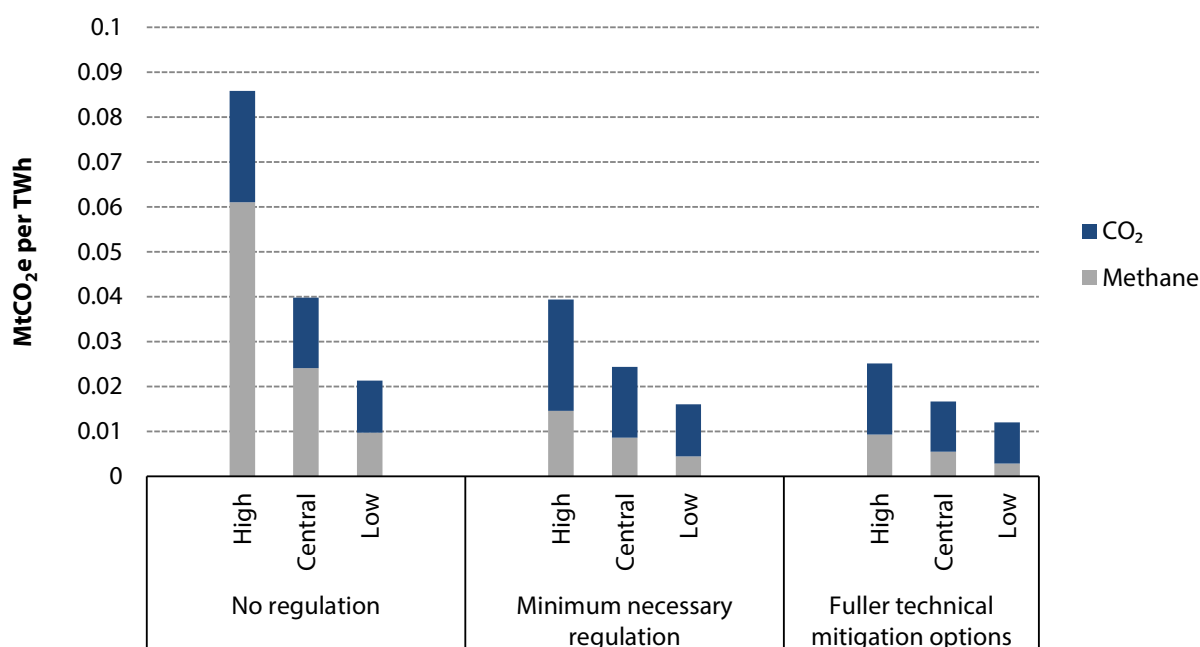
Notes: Based on a range of 0.26-1.3 TWh (1-5 bcf) gas per well, with a central assumption of 0.83 TWh (3.2 bcf).

Figure 3.5. Differences between the regulation cases under central estimates



Source: CCC analysis.

Figure 3.6. 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 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 of this treatment of emissions for meeting Scotland's emissions targets are explored in Chapter 4. Given the vote to leave the EU, the UK's future role in the EU ETS is uncertain. We will publish a further assessment of the issues in the autumn.

3. The regulatory framework in Scotland

Left entirely unregulated, the emissions footprint of unconventional oil and gas production could be substantial. Any significant level of exploitation of domestic resources in this way would be inconsistent with Scottish emissions targets. However, as set out in section 2 above, there are technologies and techniques that are known to limit greenhouse gas emissions from shale production. Experience and data from the US provide estimates of the costs and effectiveness of many of these measures.

There is currently a moratorium in place, during which the Scottish Government has pledged to look at further tightening of regulation.⁷¹ It is essential that this tightening does occur before any UOG production commences in Scotland.

The present regulatory regime in Scotland is unclear in relation to the respective roles of the different organisations in the permitting and planning process. There may also be gaps in relation to emissions occurring outside the production site (e.g. from supporting infrastructure such as pipelines, processing facilities and gathering stations) and more generally in relation to emissions to the atmosphere, especially fugitive methane emissions.⁷²

Before any production can occur, in order to ensure that domestic UOG production can be compatible with emissions targets:

- The regulatory regime requires much greater clarity over the roles of the different actors (Health and Safety Executive, Scottish Environmental Protection Agency and local authorities), and that these be managed seamlessly.
- The regulatory framework should ensure that regulation covers all emissions of both CO₂ and methane, requires strict limiting of these emissions and entails long-term monitoring.

⁷¹ Scottish Government (2015) *Moratorium called on fracking*. <http://news.scotland.gov.uk/News/Moratorium-called-on-fracking-1555.aspx>

⁷² Scottish Government (2014) *Independent Expert Scientific Panel – Report on Unconventional Oil And Gas*. <http://www.gov.scot/Resource/0045/00456579.pdf>

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- It is also 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 (i.e. encompassing not only the production site itself but also related infrastructure).

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 Scottish emissions targets. As evidence improves, it is likely to be cost-effective and necessary to require the inclusion of further emissions reduction measures.

The KPMG scenarios assume that the co-producing wells produce a significant volume of gas, which would mean it would be likely that gas produced is put to effective use. However, it may turn out that some shale wells produce small volumes of gas and it is therefore uneconomic to inject the gas into the grid or supply a customer directly. In this case, there may be available technologies (e.g. gas-to-liquids) that would enable the gas to be put to productive use, but at a minimum this gas should be flared, in a well-operated flare (i.e. one which continually combusts over 98% of the methane).

We have not considered in detail the possible implications for our analysis of the recent EU referendum result. To the extent that this weakens the regulatory framework on UOG production in Scotland then domestic regulations will be required to ensure that a strong system of regulation exists in Scotland for UOG exploitation.



Chapter 4:

Impact of unconventional oil and gas extraction on meeting Scottish emissions targets

In this chapter, we bring together the outputs of the preceding chapters to assess the possible impact of unconventional oil and gas development on Scottish emissions, and what that means for meeting annual emissions targets 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 Scotland rather than overseas. This would therefore increase Scottish greenhouse gas emissions, even if it leads to no greater consumption of oil and gas in Scotland and even if the overall greenhouse gas footprint of Scottish production is lower than that of imported gas.

On the basis that Scottish unconventional oil and gas production should displace imports rather than increasing domestic consumption, the scale of the impact of domestic production on Scottish emissions depends on two main factors: the level of production (Chapter 2) and the unit emissions associated with production (Chapter 3).

The emissions impacts presented in this chapter use the 100-year Global Warming Potential (GWP_{100}). This metric is used as standard in international, UK and Scottish emissions accounting, including Scottish annual emissions targets, UK 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 Scottish unconventional oil and gas on territorial emissions, how these could be accommodated under emissions targets and our conclusions and recommendations, in four sections:

1. Impact of domestic unconventional oil and gas production on Scottish territorial emissions
2. Emissions relating to additional economic activity within Scotland
3. Impact on meeting existing Scottish emissions targets
4. Conclusions and recommendations

1. Impact of domestic unconventional oil and gas production on Scottish territorial emissions

The implications for greenhouse gas emissions of unconventional oil and 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 Scottish production. In considering the implications for meeting annual emissions targets, 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 4.1):

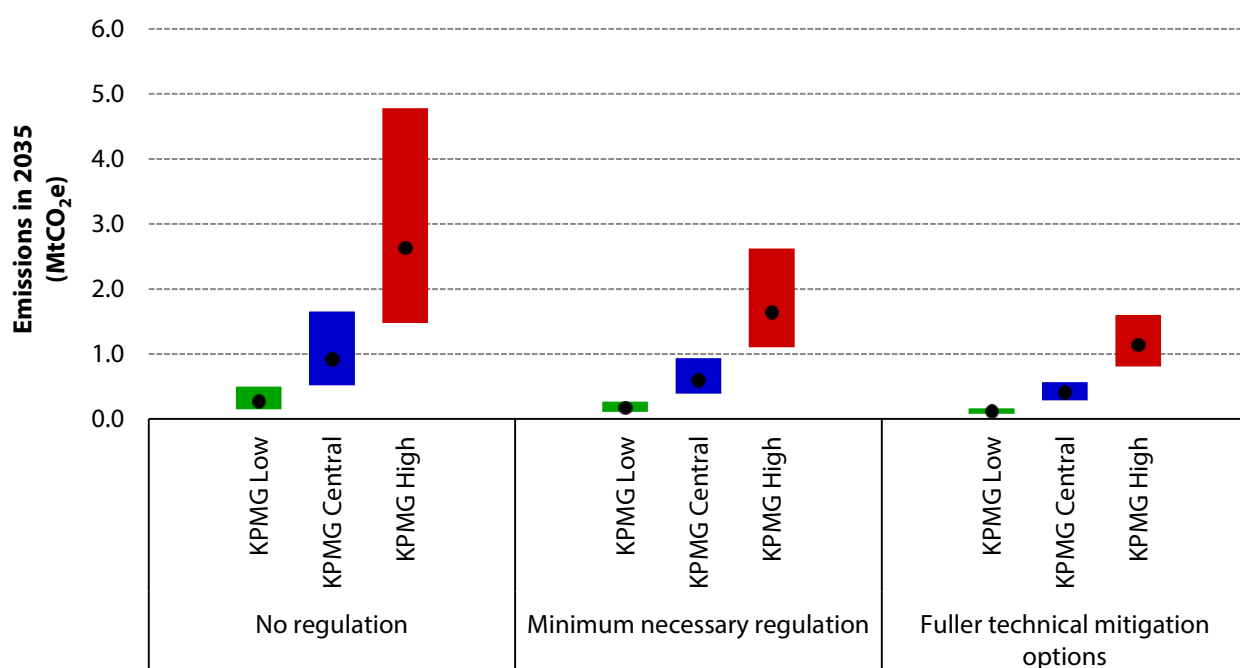
- **High-end estimates.** The increase in Scottish territorial emissions due to domestic unconventional oil and gas extraction under the KPMG High production scenario could be up to 4.8 MtCO₂e/year in 2035, if production were unregulated. The measures in our 'Minimum necessary regulation' case (i.e. monitoring, reduced emissions completion and addressing emissions from liquid unloading) reduces the upper end of the emissions range to about 2.6 Mt. The measures in our 'Fuller technical mitigation options' (e.g. electrification of compressors) reduce the high-end estimate further, to about 1.6 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 the KPMG High production scenario is 2.6 Mt/year in 2035, falling to about 1.6 Mt under our 'Minimum necessary regulation' case and to about 1.1 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 Scottish UOG production (36%-38% 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 (43%-46% as against the No Regulation case).

The emissions relating to production grow over time, broadly in line with the growth in hydrocarbons produced, peaking slightly after 2035 under each scenario (Figure 4.2).

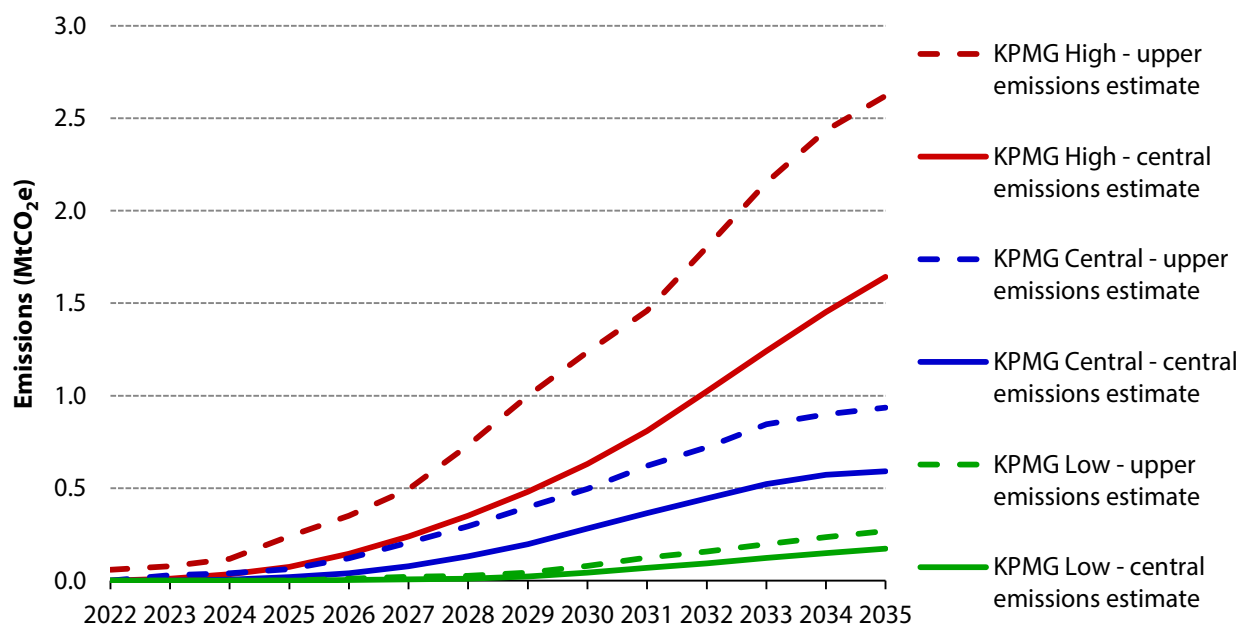
Figure 4.1. Scottish territorial emissions due to unconventional oil and gas production, depending on regulation (2035)



Source: CCC analysis.

Notes: Total emissions relating to Scottish unconventional oil and gas production, on a territorial (i.e. gross) emissions basis. KPMG Low, Central and High refer to the production scenarios presented in Chapter 2. The ranges around the black dots reflect the uncertainty in our emissions estimates. The 'No regulation' case does not reflect the current or anticipated framework, but rather acts as a baseline for comparison purposes in order to show the emissions reductions available through regulation.

Figure 4.2. Scottish territorial emissions due to unconventional oil and gas production under the 'Minimum necessary regulation' case (2022-2035)



Source: CCC analysis.

Notes: Total emissions relating to Scottish unconventional oil and gas production, on a territorial (i.e. gross) emissions basis. KPMG Low, Central and High refer to the production scenarios presented in Chapter 2. Chart presents central estimates of emissions under the 'Minimum necessary regulation' case only.

2. Emissions relating to additional economic activity within Scotland

In order for Scottish greenhouse gas emissions to meet the limits set by the annual targets, unabated fossil fuel consumption must decline over time. Any domestic production of unconventional oil and gas should not result in greater consumption of fossil fuels than is implied by those targets. Indeed, emissions relating to UOG production would necessitate additional offsetting action to reduce emissions elsewhere, which may well imply lower fossil fuel consumption than in a case without UOG production.

In addition to emissions relating directly to UOG production, there are three other routes by which these activities potentially affect Scottish emissions:

- **Gas prices.** As discussed in Chapter 2, the impact of Scottish UOG production on wholesale prices is likely to be very small, due to relatively small volumes anticipated and the degree of interconnectedness of international markets. Therefore we do not expect a significant impact on fossil fuel consumption from lower prices.
- **Direct supply of industry.** It may be that local hydrocarbon supplies would be attractive to Scottish 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. This was not examined quantitatively in the parallel study on economic impacts and scenario development. We have therefore been unable to assess this quantitatively.

- **Increased general economic activity.** Producing fossil fuels domestically rather than importing them would have a direct effect on employment in Scotland, with potential knock-on effects in the wider economy. The parallel study on economic impacts and scenario development has quantitatively assessed the possible size of such an effect. As the annual emissions targets have been set allowing for growth in the Scottish economy, it is not anticipated that such an increase in the level of general economic activity would jeopardise meeting these targets.

These further effects are difficult to quantify and/or are anticipated to be small. In our assessment of the compatibility of Scottish UOG production, we therefore focus on emissions directly associated with the production activity.

3. Impact on meeting Scottish emissions targets

Meeting annual emissions targets

In accordance with the Climate Change (Scotland) Act, in 2010 and 2011 annual targets for greenhouse gas emissions were set in legislation covering the period to 2027. As required under the Act, in March this year we provided advice on the levels of annual targets out to 2032. In doing so, we recognised that changes in the greenhouse gas emissions inventory had made it extremely difficult to meet its targets, and therefore alongside recommending targets covering 2028 to 2032 we also recommended realigning existing targets to 2027.⁷³

Subsequent to our March advice, further significant changes were made to the emissions inventory. As the process for legislating the annual targets had not yet taken place, in June the Scottish Government requested further advice regarding the implications for annual targets of these changes.⁷⁴ We responded in July with this advice, indicating that existing annual targets out to 2024 are now achievable, assuming strong actions consistent with our 'High Ambition' scenario, but those beyond 2025 go further than is achieved in our most ambitious scenarios.

In parallel with these developments, the Scottish Government has committed to bringing forward legislation to change the accounting basis for Scottish annual targets, to put them on a territorial (gross) emissions basis.⁷⁵ We will advise on the levels for these targets in due course.

Acknowledging this development, and that changing already-legislated targets under the existing Act is not straightforward, we outlined two possible ways forward in legislating annual targets under the existing Act (i.e. on a net basis) (Figure 4.3):

⁷³ CCC (2016) *Scottish emissions targets 2028-2032 – The high ambition pathway towards a low-carbon economy*. Available at <https://www.theccc.org.uk/publication/scottish-emissions-targets-2028-2032-the-high-ambition-pathway-towards-a-low-carbon-economy/>

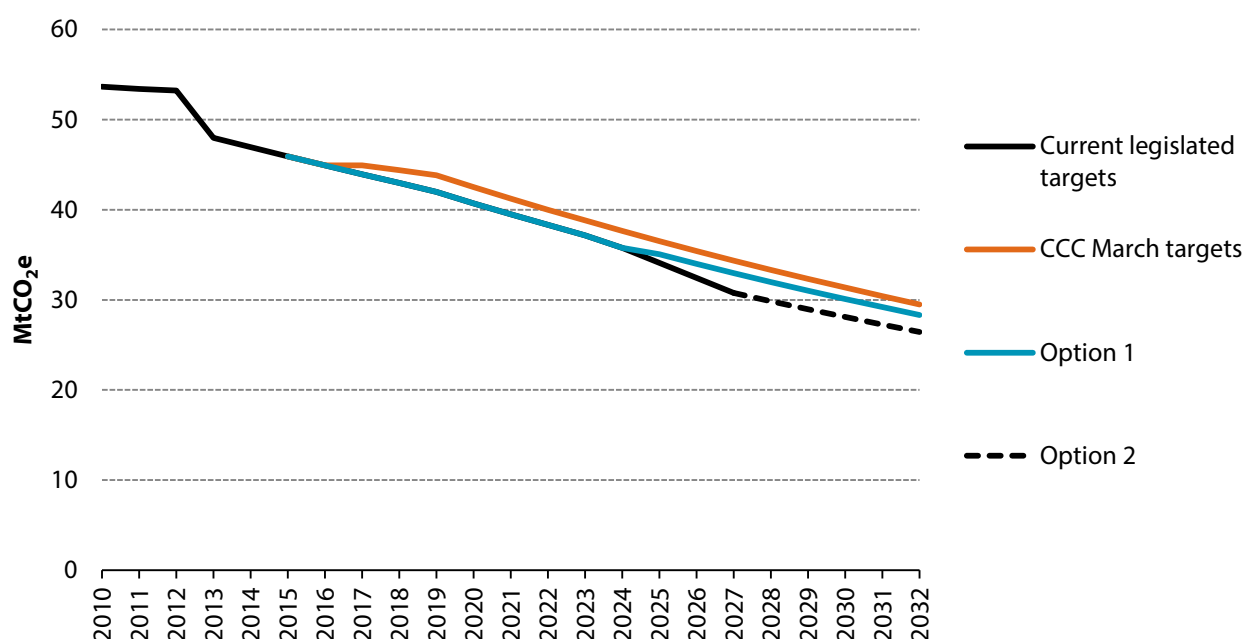
⁷⁴ Scottish Government (2016) *Letter from Roseanna Cunningham to Matthew Bell* <http://www.gov.scot/Resource/0050/00502164.pdf>

⁷⁵ CCC (2016) *CCC response to request for updated advice on Scottish emissions targets*. Available at: <https://www.theccc.org.uk/publication/ccc-response-to-request-for-updated-advice-on-scottish-emissions-targets/>

- **Option 1: Keep existing legislated targets to 2024 and alter and align 2025 to 2032 to latest assessment of target levels.** This option would bring the targets in line with the achievable target pathway to the 2050 target and be consistent with a steady rate of progress. They would give cumulative emissions of 1313 MtCO₂e (providing all future targets are met) from 1990 to 2050 and would limit the need for additional abatement beyond our high ambition scenario or credit purchase to 1.8 MtCO₂e per year between 2025 and 2032.
- **Option 2: Keep existing legislated targets to 2027 and then follow a 3% reduction per year to 2032.** If continued after 2032 this would achieve an 81% reduction in 2050 and imply cumulative emissions of 1277 MtCO₂e (providing all future targets are met) from 1990 to 2050. These targets would only be achievable through additional abatement beyond our high ambition scenario or through the purchase of an average of 3.5 MtCO₂e/year of credits (from 2025 to 2032).

We further recommended that if the new legislation is likely to be delayed beyond around 18 months then Option 1 is to be preferred, as it provides a stronger signal for emissions reduction at a sensible rate to 2032.

Figure 4.3. Legislated and proposed Scottish annual emissions targets (2010-32)



Source: CCC (2016) *CCC response to request for updated advice on Scottish emissions targets*. Available at <https://www.theccc.org.uk/publication/ccc-response-to-request-for-updated-advice-on-scottish-emissions-targets/>

Under the existing accounting framework for Scottish emissions targets, the relevant measure of emissions is known as the net Scottish emissions account (NSEA). Parts of the net Scottish emissions account are influenced by actual Scottish emissions, while other parts reflect a share of the EU-wide cap for the EU emissions trading system (EU ETS). Under the planned change to the legislative basis of annual targets, this would change.

In practice for Scottish UOG production, the choice of accounting system is unlikely to make a significant difference to the size of the impact on meeting annual targets (Box 4.1).

While the emissions relating to production grow over time, broadly in line with the growth in hydrocarbons produced, allowed economy-wide emissions under Scottish annual emissions targets fall by at least 3% per year. Over time, it is therefore likely to become increasingly challenging to accommodate emissions relating to domestic UOG production.

The impact on total Scottish emissions under the 'Minimum necessary regulation' case in the KPMG High production scenario rises to between 0.7 and 1.8 MtCO₂e/year in 2032 (3% and 6% of allowed emissions in that year), with a central estimate of around 1.0 Mt/year (4% of allowed emissions).

The compatibility of unconventional oil and gas extraction with emissions targets depends on whether these additional emissions can be offset by increased emissions reductions elsewhere in the economy. The annual targets we recommended for the period to 2032 already go at least as far as our High Ambition scenario for Scotland, which is at the limit of the quantitative scenarios we have developed.

While emissions reductions beyond this scenario may be possible, we do not have quantitative evidence to support this. Opportunities to go beyond our High Ambition scenario, in order to offset additional emissions from unconventional oil and gas production or from other sources (e.g. aviation), should be considered as part of developing RPP3, the report in which the Scottish Government must set out its plans to meet the annual targets to 2032.

Box 4.1. Implications of different accounting approaches for emissions under annual targets

While a change in accounting approach will affect some aspects of meeting the annual targets, in the case of unconventional oil and gas production it is unlikely to make a significant difference:

- **Current annual targets.** Under the existing accounting approach, the impact of unconventional oil and gas extraction on the net Scottish emissions account would consist of the non-traded sector portion of production emissions plus traded sector emissions eligible for free allocation of EU ETS allowances. A new onshore production industry is likely to receive free allowances as a new entrant.
- **New targets on a gross basis.** Once annual targets are on a territorial or gross basis, the emissions impact of UOG production will comprise actual emissions in both the traded sector and non-traded sector.

Given that the allocation of free allowances under the EU ETS would be likely to be similar in magnitude to the actual territorial emissions in the traded sector, in practice this is unlikely to affect significantly the quantity of emissions counted under the annual targets.

Meeting the 2050 target

The Climate Change (Scotland) Act specifies a target to reduce emissions across all domestic sectors, plus a Scottish share of international aviation and international shipping, by at least 80% on 1990 levels by 2050. 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 at least 80% domestically. The

Paris Agreement may imply that a more ambitious 2050 target would be appropriate; we will publish our analysis on this later in the year.

It is too early to estimate possible ranges for emissions that might be associated with unconventional oil and gas 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 fossil fuel extraction 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 UOG exploitation consistent with meeting emissions targets or the 2050 target.

Should the emissions impact in 2050 be similar to that in 2032 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 UOG 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.

4. Conclusions and recommendations

The prospects for a Scottish unconventional oil and gas industry are currently highly uncertain. It depends on the underlying economics of production, which in turn depend on the productivity of Scottish 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 Scottish onshore production in the context of developments in international fossil fuel markets.

Should an unconventional oil and gas industry be established in Scotland and grow quickly, this would have the potential for significant impact on Scottish emissions. In order to ensure that these are manageable within Scottish emissions targets, it is necessary that increased Scottish 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.

Our assessment is that exploiting unconventional oil and gas by fracking on a significant scale is not compatible with Scottish 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.
 - Strengthening of the regulatory system is essential before production can commence. Much greater clarity is necessary over the respective roles of different actors in this system, entailing full coverage of greenhouse gas emissions (i.e. including strict limiting

of both CO₂ and methane from all sources, covering not just the production site but also associated infrastructure before the point of grid injection or delivery to end user);

- A range of technologies and techniques to limit methane emissions should be required, including ‘reduced emissions completions’ (also known as ‘green completions’), liquid unloading mitigation technologies (e.g. plunger lift systems) and vapour recovery units should these be needed, as well as flaring of methane rather than venting it;
 - A monitoring regime that catches potentially significant methane releases 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 – fossil fuel consumption must remain in line with the requirements of Scottish emissions targets.** Scottish unabated fossil energy consumption must be reduced over time within levels we have previously advised to be consistent with the emissions targets. This means that Scottish unconventional oil and gas production must displace imported gas rather than increasing domestic consumption.
 - **Test 3: Accommodating unconventional oil and gas production emissions within Scottish emissions targets.** Additional production emissions from shale wells will need to be offset through reductions elsewhere in the Scottish economy, such that overall effort to reduce emissions is sufficient to meet emissions targets.

There are other issues linked to ongoing gas consumption and emissions targets, 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.



Chapter 5:

Impact on EU and global emissions

In this chapter, we consider the implications of domestic unconventional oil and gas (UOG) production on emissions elsewhere, both in terms of the global picture and at EU level.

Scottish UOG production should not be allowed to lead to greater unabated fossil fuel combustion within Scotland than would otherwise occur, as this would be inconsistent with meeting domestic emissions targets (Chapter 4). Any domestic UOG production must therefore displace imports, with the only emissions impact within Scotland being that directly resulting from the production process.

In global terms, the impacts on emissions can be divided into those relating to the supply of fossil fuels and any impacts on the combustion of different fossil fuels.

For supply, lifecycle emissions comparisons can identify the full set of emissions relating to different sources of fossil fuel supply, regardless of where these emissions occur. Therefore while domestic production increases Scottish emissions, these could be offset to a greater or lesser degree by reductions in emissions relating to production and supply elsewhere in the world.

There could also be further knock-on impacts on international emissions resulting from reduced Scottish demand for imported fossil fuels, depending on the extent to which reduced Scottish imports leads to reduced overseas gas production and whether it affects consumption of coal or low-carbon energy.

In this chapter, we consider the impacts in three sections:

1. Comparison of lifecycle emissions from Scottish shale gas with imported liquefied natural gas
2. Impact of domestic fossil fuel production on global emissions
3. Impact of domestic fossil fuel production on EU emissions

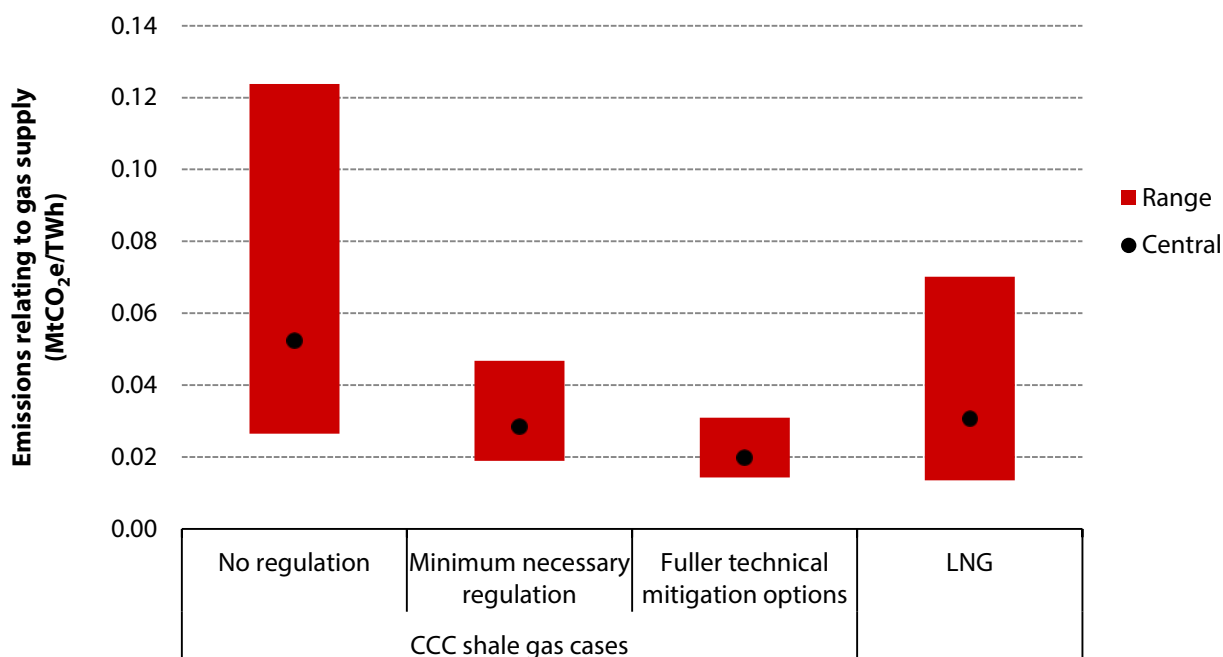
1. Comparison of lifecycle emissions from Scottish shale gas with imported liquefied natural gas

Any production of oil or gas is likely to lead to some greenhouse gas emissions. While increasing Scottish 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.

Current evidence suggests that well regulated domestic production could have an emissions footprint slightly smaller than that of imported liquefied natural gas (LNG) (Figure 5.1). Furthermore, while the central emissions estimate under the 'minimum necessary regulation' case for domestic production is only slightly below that of LNG, the high end of the range is around 50% higher for LNG. Tightly regulated domestic production would therefore reduce the risk that the greenhouse gas footprint of gas supply is high and would also provide greater control over the level of such emissions.

When taking into account CO₂ emissions from combustion, both Scottish shale gas and imported LNG have a considerably lower greenhouse gas footprint than coal on a GWP₁₀₀ basis (Chapter 1).

Figure 5.1. Lifecycle emissions of Scottish shale 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.

A comparison of domestic shale oil production with other sources is more difficult:

- In this study we have considered liquids co-produced with gas. While the incremental emissions for liquids production will be small for a given level of gas production (Chapter 4), the oil-to-gas ratio will vary between wells and in some cases the volume of gas may be insufficient to justify its productive use (e.g. piping to a processing facility and then injection into the gas grid) on an economic basis. Should the gas co-produced with liquids be flared or vented instead then the emissions footprint attributable to the liquids will be considerably higher. This will vary on a case-by-case basis.
- Similar issues affect the greenhouse gas footprint of potential sources of import into the UK. Again, in some cases methane will be flared or vented. The carbon intensity of various sources of crude oil in Europe has been estimated at between 0.014 and 0.047 MtCO₂e/TWh, excluding transportation to the UK.⁷⁶
- Differences in composition of oil produced will have different implications for how it needs to be refined, with implications for associated emissions. We have not addressed such issues in this study.

On the basis of tight domestic regulation, and on the assumption that co-produced gas is put to productive use, Scottish shale oil production may well have a smaller greenhouse gas footprint than imports, but this could vary widely across domestic and international sources.

⁷⁶ Jacobs (2012), *EU Pathway Study: Life Cycle Assessment of Crude Oils in a European Context*.

Comparisons between the emissions footprint of domestic and imported sources of oil and gas reflect the impact on global emissions in the case that Scottish UOG production directly leads to a commensurate reduction in the production and supply of fossil fuels from elsewhere in the world.

In reality, the complexity of international energy markets means that a range of dynamic effects are likely to ensue, potentially affecting the level and type of fossil fuel consumption in other countries. We turn to the impact on international fossil fuel consumption in the next section.

2. Impact of domestic fossil fuel production on global emissions

As part of this study, the Scottish Government specifically asked that it cover the impacts on global emissions. This is a large and complex question to which there is no simple answer. We have drawn on existing evidence and commissioned some new modelling work in addressing it.

Additional domestic production of fossil fuels 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 fossil fuel supplies could lead to a reduction in coal consumption (due to fuel switching), thereby reducing overall emissions. The switch away from coal is likely to occur primarily in the power sector and therefore be largely towards gas rather than oil.
- 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 Scottish UOG 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.

We have reviewed the literature in this area (Box 5.1) and commissioned some runs of the TIAM-Grantham model from Imperial College to provide insights into the possible change in global CO₂ emissions that could result from domestic shale gas production (Box 5.2).⁷⁷ We make the following observations with regard to shale gas:

- Global 'Abundant gas' scenarios see gas displacing a mix of coal and low-carbon (renewable and nuclear) energy sources. The net impact on global emissions tends to be small, with some studies suggesting a small upwards impact on global emissions. However, the results depend on strength of climate policy.
- The TIAM-Grantham model finds that differences in gas availability are unlikely to have a large impact on cost and feasibility of meeting a 2°C goal, excluding the impact of methane leakage. Therefore should Scottish UOG production proceed with tight regulation (Chapter 3), the overall impact on global emissions is unlikely to be significant.

⁷⁷ Due to the limited spatial resolution of the model, which divides the world into 15 regions, Scotland is contained within the TIAM-Grantham model's 'Western Europe' region.

- In the TIAM-Grantham and other modelling, estimated supply curves for unconventional gas tend to have higher costs than those for conventional gas, meaning that the modelling has to force in shale gas so as to assess its impacts. This provides an indication that the economics of unconventional gas in general are not favourable, unless local geology happens to be especially productive and units costs commensurately lower (Chapter 2).

On shale oil, the story may be different, with less scope for switching between oil and other fossil fuels such as gas and coal:

- We would expect shale oil production to displace high-marginal-cost oil production elsewhere in the world, rather than affecting consumption of coal, gas or low-carbon energy.
- However, there is a question over the extent to which domestic shale oil production would displace other sources of oil as against increasing total consumption.
- In world in which warming is limited to below 2°C, it is likely that consumption would be largely unaffected and that full displacement of other oil production would occur.

Box 5.1. Key findings on literature relating to the impact of shale gas on global emissions

There is limited evidence within the available literature, which generally uses integrated systems models across economy-energy-emissions, to consider the impact of increased gas supplies on global emissions. Our review of this literature is presented in a supporting annex.

There are a few studies that look at the implications of global increased gas supplies. Considering what can be drawn from these of relevance to the implications of Scottish supplies from unconventional sources, demands caution, for a number of reasons including:

- the assumed supply curve for unconventional gas (how much gas, at what cost) is speculative;
- results reported here relate, in general, to global increases in supply, and do not differentiate impacts as between specific regional markets;
- Scottish supplies are likely to be very small relative to the European market;
- results show significant variation depending on the assumptions and set-up of the specific model employed.

To the extent that a few broad conclusions can be drawn, these are:

- greater gas supplies lead to some displacement of coal, but also to displacement of low-carbon sources (renewables and nuclear);
- net impacts on global emissions tend not to be negative (i.e. emissions down), but are either very small or positive (i.e. emissions up);
- net impacts depend on the strength of climate policy;
- impacts on the overall costs and feasibility of meeting a 2°C target (if methane leakage is controlled) are small.

We provide more detail on the relevant findings of these studies in an Annex to this report.

Box 5.2. TIAM-Grantham modelling on the global emissions impact of shale gas in a decarbonising world

In order to gain insights into the impact of domestic shale gas production on global emissions, we commissioned some runs of the TIAM-Grantham model, which is developed and run at the Grantham Institute, Imperial College London. This is a version of the global, 15-region incarnation of the TIMES model, as developed and maintained by the Energy Technology Systems Analysis Programme (ETSAP).

- The model is a linear programming tool representing in rich resource and technological detail all elements of the reference energy system (RES) for each region represented, mapping energy commodity flows all the way from their extraction and refining to their distribution and end-use.
- TIAM has the ability to optimise the energy system for given climate constraints through either minimising the total discounted energy system cost over a given time-horizon, or through maximising total producer and consumer welfare when (optionally) accounting for elastic demand responses to energy prices.
- Energy system data such as technology costs, resource supply curves and annual resource availability are also input into the model. In solving, the model allows trade in energy commodities between regions.

The aim of the modelling was to examine the impact on global emissions of forcing in European shale gas in the context of global action consistent with limiting average warming to 2 °C and 'well below 2°C' by the end of the century, building on previous TIAM-Grantham modelling for the AVOID 2 programme.⁷⁸ We ran the model with two levels of global ambition on limiting climate change: a '2°C' run, which allowed cumulative greenhouse gas emissions consistent with a median expectation of 2°C, and a 'well below 2°C' run with a median temperature increase of 1.75°C. This is at the limit of the level of climate ambition for which the model is still able to solve.⁷⁹

The modelling focused on gas, as this provides more scope for fuel switching (e.g. away from coal or renewable electricity) than for oil.

- Initial runs were performed which constrained emissions to a level consistent with limiting warming by 2100 to 2 °C and 1.75°C, without any unconventional fossil fuel production in Western Europe (the region including Scotland);
- Follow-up runs were then performed, which took the shadow carbon prices from the initial runs⁸⁰ and forced in shale gas production in Western Europe (at 80% of potential shale production in the region) to understand the impact on consumption of gas, and of other energy sources (both fossil and non-fossil).

⁷⁸ Few, Gambhir et al. (2016), *The impact of shale gas on the cost and feasibility of meeting climate targets - a global energy system model analysis and an exploration of uncertainties - AVOID 2 report WPC6*. Available at <http://www.avoid.uk.net/2016/10/the-impact-of-shale-gas-on-the-cost-and-feasibility-of-meeting-climate-targets-c6/>

⁷⁹ The TIAM-Grantham model does not seek to represent all greenhouse gas emissions directly, but instead allows for non-CO₂ emissions based on other modelling (including using IIASA's GAINS model), leaving a cumulative CO₂ budget across the 21st century of 1,340 GtCO₂ in the 2°C run and 940 Gt in the 1.75°C run.

⁸⁰ The outputs of a model run include shadow prices associated with the emissions constraints imposed, reflecting the marginal costs in meeting the emissions constraint. Imposing these shadow prices in a second model run instead of emissions constraints would lead to an identical set of results within the model. However, doing so allows further changes made to the model set-up (e.g. forcing in shale gas) to be reflected in the model outputs as a change to emissions. Conversely, under emissions constraints, by definition the emissions will not change but the costs of meeting the constraints would do.

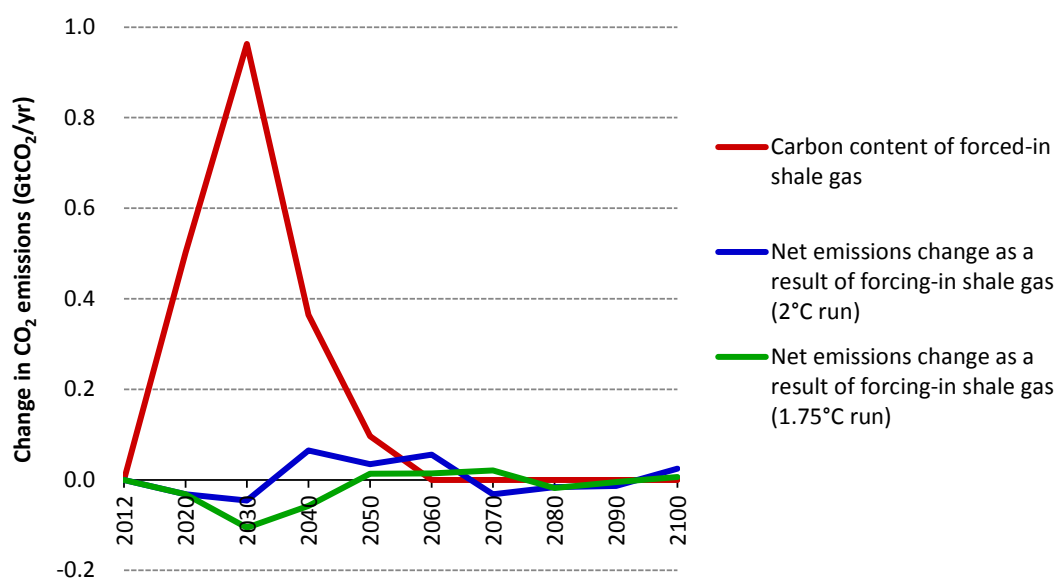
Box 5.2. TIAM-Grantham modelling on the global emissions impact of shale gas in a decarbonising world

In the model results, the overall impact of forcing in shale gas in Western Europe on cumulative CO₂ over the 21st century is extremely small, at an increase of 0.04 GtCO₂ in the 2°C run and a decrease of 0.16 Gt in the 1.75°C run, compared to the carbon content of the forced-in shale gas of 1.9 Gt (Figure B5.2a). The upward impact on global CO₂ emissions of increased European gas production was therefore offset by 98% to 108% by avoided emissions elsewhere in the global energy system as a result of reductions in gas, oil and coal supplies:

- In the 2°C run, the consumption of natural gas increases as a result of increased European production, although because of reduced gas production elsewhere the net increase in supply is only 5% of forced-in production. This net increase in gas production displaces a mix of oil supplies (26% of net increase in gas supply), low-carbon energy (36%) and a reduction in coal consumption even beyond that in the base 2°C run (15%), and leads to a slight increase in overall energy consumption (Figure 5.2b).
- In the 1.75°C run, the consumption of natural gas increases as a result of increased European production, although because of reduced gas production elsewhere the net increase in supply is only 11% of forced-in production. This net increase in gas production mainly displaces coal even beyond that in the base 1.75°C run (26% of net increase in gas supply), and leads to a slight increase in overall energy consumption (Figure 5.2c). Overall CO₂ sequestration is higher in the run with forced-in gas, leading to a slight reduction in overall emissions.

In both pairs of runs the impact on global emissions from forcing in European shale gas is close to zero, with one increasing emissions and one decreasing them, so it can be inferred that the effect is negligible.

Figure B5.2a. Net change in global emissions in a scenario with shale gas (2012-2100)

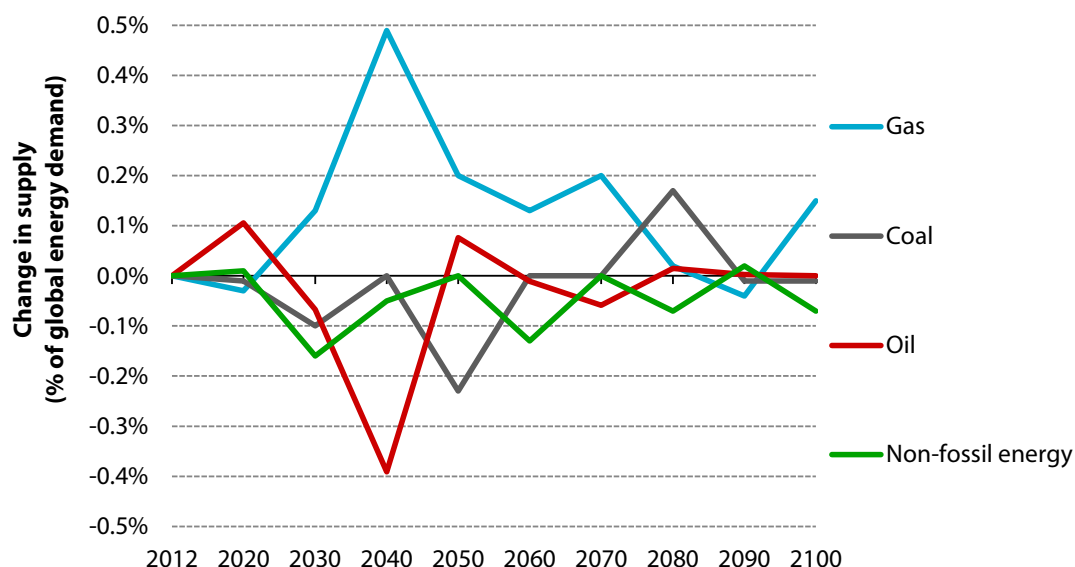


Source: Grantham-TIAM modelling for the CCC.

Notes: The red line represents the emissions impact were all the forced-in gas in the follow-up runs to be unabated and additional to fossil fuel consumption in the base run. The blue and green lines show the actual impact on emissions in the 2°C and 1.75°C follow-up runs, allowing for the model to respond to this additional supply by reducing energy supplies elsewhere.

Box 5.2. TIAM-Grantham modelling on the global emissions impact of shale gas in a decarbonising world

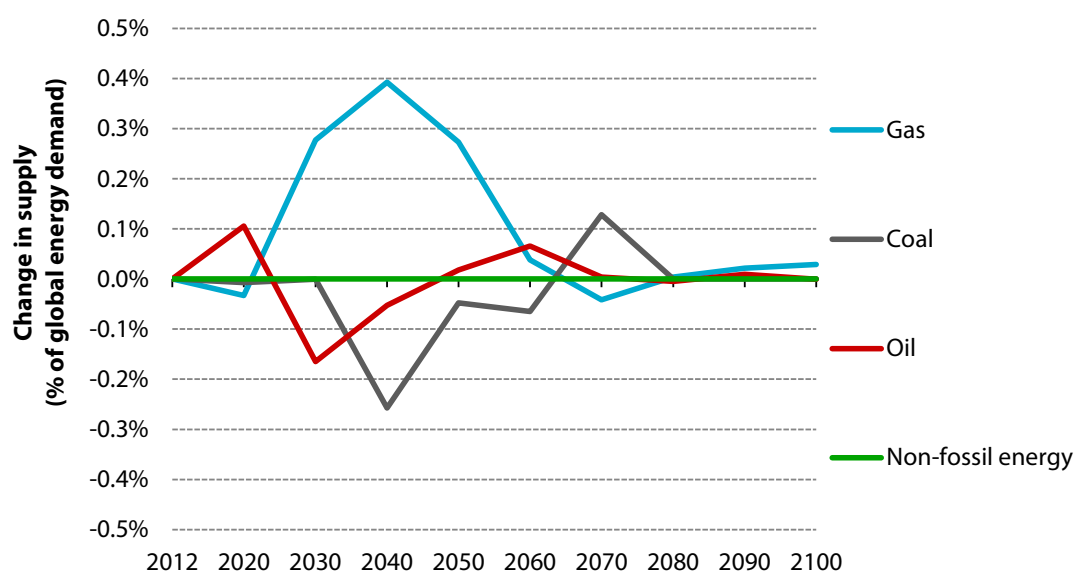
Figure B5.2b. Change in fossil and non-fossil energy supply in a 2°C run as a result of forced-in gas



Source: Grantham-TIAM modelling for the CCC.

Notes: Lines reflect change in energy supply from different sources, but not any change in the use of CCS.

Figure B5.2c. Change in fossil and non-fossil energy supply in a 1.75°C run as a result of forced-in gas



Source: Grantham-TIAM modelling for the CCC.

Notes: Lines reflect change in energy supply from different sources, but not any change in the use of CCS.

3. Impact of domestic fossil fuel production on EU emissions

As part of this study, the Scottish Government specifically asked that it cover the impacts on emissions in the EU and interactions via pan-EU mechanisms. In this section we therefore consider the knock-on implications of Scottish UOG production for the EU energy system and fossil fuel consumption, as well as specific interactions between Scotland and the rest of Europe via the EU emissions trading system (EU ETS).

More recently, the recent EU referendum result has raised questions in this area. We have not considered in detail the possible implications of that result for our analysis, but to the extent that the eventual impacts include weakening of the regulatory framework on UOG production in Scotland then domestic regulations will be required to ensure that a strong system of regulation exists in Scotland for UOG exploitation (Chapter 3).

The Committee will consider the implications of the EU referendum result in more detail over the coming months.

Impacts on the European energy system

The impact on EU emissions of Scottish unconventional oil and gas production equals the impact on Scottish emissions (i.e. emissions relating to production – Chapter 4) plus the impact on emissions in the EU outside Scotland.

We draw some insights from the global modelling set out in section 2 above, as well as an understanding of the context for Europe's energy system:

- The quantitative analysis of the impact on global emissions indicates that an increase in production of gas within Europe has a very limited impact on EU energy consumption.
- The EU is a significant net importer of both oil and gas, a situation on which Scottish production would have little impact. So there would not be a case for fossil fuel consumption to rise as a result of greater local supply.
- As discussed in Chapter 3, Scottish UOG production is unlikely to have any meaningful impact on fossil fuel prices in Scotland or elsewhere in Europe.
- It is possible that the initiation of unconventional oil and gas production in one part of Europe could have knock-on impacts, with other countries following suit to exploit their own domestic resources. We have not considered this possibility in detail, as such an effect is speculative.

It is therefore likely that there would be little if any impact on EU emissions outside Scotland from domestic UOG production.

Impacts relating to the EU emissions trading system (EU ETS)

As discussed in Chapter 4, there are unlikely to be any significant differences in accounting for Scottish emissions under annual targets depending on whether or not they are covered by the EU ETS, especially given the move to territorial (gross) emissions accounting. Therefore should Scotland no longer participate in the EU ETS there would be no significant impacts on meeting domestic emissions targets.

Should Scotland remain in the EU ETS, the impact on emissions across the other countries participating in the trading system is likely to be negligible:

- In principle extra Scottish emissions covered by the EU ETS could use up allowances, which under a finite cap would lead to emissions reductions elsewhere in the EU.
- However, in practice the EU ETS has a substantial oversupply, and the Market Stability Reserve mechanism to remove surplus allowances from the system temporarily makes the cap less 'hard'.
- Similarly, any upward effect on the price of allowances within the system is likely to be negligible.

Consequently, it is questionable whether any additional Scottish emissions under the EU ETS would lead to any emissions reductions elsewhere.

It is unclear what impact there be on emissions across all the countries participating in the EU ETS should Scotland leave the EU ETS, as it is unknown what would happen to the level of system's emissions cap in this situation.



Committee on Climate Change
7 Holbein Place
London
SW1W 8NR

www.theccc.org.uk

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