Shale Gas and Water

An independent review of shale gas exploration and exploitation in the UK with a particular focus on the implications for the water environment

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www.ciwem.org/shalegas

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In compiling this review CIWEM has consulted widely with its membership and technical panels, hosted a national conference on shale gas and met with the key stakeholders from the government, regulators, shale gas and water industries and civil society groups.

Who we are, and what we do

CIWEM is the leading Chartered Professional Body covering all aspects of water and environmental activity, sustaining the excellence of the professionals who protect, develop and care for our environment.

CIWEM:

- Supplies independent advice to governments, academics, the media and the general public
- Qualifies Professionals; provides training and development opportunities
- Provides a forum for debate, knowledge sharing and networking through conferences, events and publications
- Works with governments, international organisations, businesses, NGOs, the creative industries and faith groups for a holistic approach to environmental issues
- Brings members from all over the world together under common policy and technical issues
- Supports professionals throughout the environment sector and across the world, having members in over 90 countries

Front cover image: Photo © Cuadrilla, Preese Hall, Lancashire

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Executive Summary

Purpose

The use of water in hydraulic fracturing to unlock natural gas trapped in shale formations has brought the water-energy nexus to the fore. Extracting shale gas via hydraulic fracturing generally poses greater environmental challenges than conventional methods of gas extraction and a robust regulatory regime will be required to mitigate risks and to improve general public confidence in what is presently a highly controversial process.

The environmental risks include water resource requirements, the potential contamination of ground, surface waters and aquifers with methane and other pollutants used in the drilling and hydraulic fracturing process, the release of fugitive methane, localised air pollution, landscape and visual amenity intrusion and the potential consequences of induced seismicity.

This report reviews publicly available evidence to understand the likely viability, scale and timing of shale gas exploitation in the UK. From consultation with experts, it then considers if an industry of any significant scale were to develop, what the implications of hydraulic fracturing of shale would be for water resources, water treatment and the water environment. In this context, the report also considers the regulatory requirements that are currently being put in place and if they will be able to mitigate the industry's impact on the environment.

This report does *not* consider in detail whether shale gas can be a sustainable, bridging energy source for the UK as part of a longer-term programme of decarbonisation, nor does it assess the robustness of UK Government's wider energy policy. These issues and wider environmental issues, such as the release of fugitive emissions and induced seismicity, are examined in a separate policy position statement by CIWEM[i].

CIWEM's Position

Shale gas

The UK Government has expressed a commitment to facilitate exploration for shale gas and is putting in place a regulatory regime which it hopes will provide appropriate safeguards to communities, employees and the environment, whilst at the same time avoiding obstruction to the industry to a level that would discourage interest in this exploration. Exploration involving drilling is necessary to properly understand the size of the shale gas resource and, in the event that this is sufficiently large, how economically the gas might be extracted. Until such exploration has taken place a reliable estimate of the likely size and nature of any subsequent production industry is extremely uncertain.

It is important to emphasise that despite the extensive UK media coverage of the issue in recent years and the often vociferous nature of opposition from a growing number of local pressure groups, the activity, even at this very early exploration stage, is embryonic in the UK. In addition and for various reasons which are discussed in this report, the expansion of any industry, in the event of promising exploration outcomes, will almost certainly not be quick.

It is equally important to emphasise that whilst politicians may wish to draw favourable comparisons with experiences in the United States of America (US), the observed dramatic

i CIWEM. 2012. Hydraulic fracturing of shale in the UK. www.ciwem.org/fracking downward pressure on wholesale gas prices experienced there will almost certainly not be seen in the UK. Likewise, because of factors such as population density, associated local opposition, geology, technological advancement and a more robust regulatory regime, any industry will look quite different to that in the US and what is commonly depicted by opposition groups with very large fields of drilling pads causing widespread landscape impact. It will need to be a well run industry, operating with a high level of transparency, suitably involving stakeholders at all levels and employing best available techniques in order to minimise disruption. In order for it to operate in this way, lessons will need to be learned from the US experience.

An understanding of the likely size of any shale gas industry, together with its geographical focus is essential in order to appreciate the impact of this activity on the water environment. However, despite the absence of this picture, we can identify the key risks and assess impacts across a likely scale. We can also recognise the priorities for information sharing and disclosure and make recommendations for where improvements in current industry and regulatory practice should be considered.

Water use

The volume of water used in hydraulic fracturing for shale gas when viewed in isolation appears large. However, when set in the context of national or regional water supply, it constitutes a very small fraction and compares with other industrial uses. The water industry does not for the time being appear concerned about its ability to supply a shale gas industry as a customer and there are other options for supply, such as direct abstraction, should supply from a water company not be appropriate.

There may be local consequences should a significantly sized production industry develop, particularly in some catchments in the south east which are already water stressed. It will be up to the water companies to decide if they are able to supply the water or the relevant environmental agency if it is to be abstracted. Where there is overlap between water stressed catchments and shale gas licence areas, operators will need to be aware of the risk that there may be fewer volumes available in the future. The likelihood of water shortages may increase and such incidences may restrict the industry's operations. There is the potential for drilling and fracturing processes to be timed as to when volumes of water are available. Furthermore, research is ongoing into methods to increase the proportion of flowback water that could be treated and reused directly on site.

It is therefore considered that water supply issues will be local and early engagement by shale gas companies with the environment agency and water companies is essential to establish the nature of any risks and manage them accordingly.

Water pollution

Shale gas wells may be drilled in areas where there is also groundwater present. It is essential that these water resources are protected from contamination and the risk of this occurring will need to be thoroughly assessed during the planning and permitting stages.

In order to establish the current condition of the water environment and successfully identify where contamination may have occurred, either as a result of shale gas-related activities or others, good baseline data is required. Experience from the US and Australia shows that without good baseline data, it is hard to scientifically establish a cause of contamination and this fosters conjecture, commonly leading to a polarised discussion lacking in robust evidence. It is important that before shale gas activities commence, baseline data for appropriate contaminants is obtained for potentially affected ground and surface waters.

Risks to groundwater from wellbore failure must be seriously considered by all appropriate regulators and construction closely monitored to ensure that best practice is followed. The term failure does not necessarily indicate the leakage of contaminants to the environment. Even so, where there is any doubt over risk to potable groundwater, the Environment Agency must adopt a precautionary approach. Rigorous well testing can help to identify any potential problems that can then be repaired.

Other risks to groundwater quality, such as contamination from mobilisation of methane, are generally considered to be low in the UK where target shales often exist at considerable depths below aquifers and gas would be required to migrate many hundreds of metres between source rock and sensitive groundwater. Where the source rocks are shallower, we consider a detailed risk assessment is needed to examine the relationship between the shale and the aquifer including a thorough evaluation of geological and hydrogeological setting.

Other risks relate to the management of flowback and produced water on site. Any negligence associated with storage, transportation and operational spills represent the greatest threats to surface water, as well as to groundwater. These can be effectively managed through robust best practice and there is no reason why this should not be achievable. Close monitoring and scrutiny by regulators, allied to strict enforcement, is essential to ensure that the industry acts in an appropriately responsible manner. Treatment of produced and flowback water is an area where technology is rapidly developing and may enable extensive on-site treatment by the time an industry is in any way mature in the UK. Otherwise, a supply-chain of specialist treatment facilities will need to develop to meet market need where this cannot already be provided by larger public wastewater treatment sites.

Stakeholder engagement

CIWEM considers that the importance of clear, open stakeholder engagement from all parties cannot be overstated with respect to an issue which is subject to such passionate debate. Water lies close to the majority of concerns expressed by stakeholders in this discussion and it is important that all parties properly understand the impacts of the current exploration industry as well as those that are likely to require management were a moderately sized extractive industry to develop.

In some cases, such as with respect to resources, we believe that these risks are often overplayed. In others, such as with regard to potential local damage to sensitive habitats or contamination of groundwaters through wellbore failure, they may not be and must be robustly regulated. It is important that the public are reassured that this regulation is fit for purpose and that transparency is displayed on all levels in order to establish trust. There appears to be scope for improvement on these fronts at the present time.

Whilst a profitable shale gas industry may be attractive to the Treasury, this must not be achieved via light touch regulation at the expense of critical environmental resources. This will not occur without cost to the industry which may prove restrictive on the rate of expansion of any industry and its ultimate size. However, given the proximity of any industry to local populations in the UK and the ability of opposition groups to mobilise against risks they perceive to be unacceptable, any UK shale gas industry will need to be an exemplar of good practice, alongside those bodies which govern and regulate it.

Finally, in compiling this report we have observed a disappointing degree of defensiveness from many of those closely involved in the subject which only serves to underline the extent of polarisation within the debate thus far. We are pleased to observe that on the surface the UK is moving in the right direction and many of the requirements we have set out now exist or are in train. However, this does not preclude the need for continual scrutiny and diligence by all parties concerned and it is important that moving forward, all those involved cooperate more fully in order to identify and take forward best practice.

Summary of CIWEM's conclusions

1 **Government departments and agencies should actively promote informed understanding among stakeholders using clear scientific evidence, transparency and consistent messages, across a range of media and forums. Government Ministers should ensure that their messages on shale gas are consistent with those of the departments.**

2 **The industry should ensure it complies with the UKOOG community engagement charter so that the public are involved within the planning process with adequate notice and information. The production of guidance for local communities on what they can expect and where they can and cannot influence would be helpful.**

3 **Further collaboration between the agencies involved in advising and regulating the industry is required. As regulation is developed for the appraisal and production phases, a rationalised and integrated system of risk assessment should be included to avoid confusion, increase public engagement and reduce delays.**

4 **CIWEM believes water and sewerage companies should become statutory consultees in the shale gas planning process regardless of whether they continue to provide and treat water for the industry. They must be engaged with early and provided with the right information to meet their duties.**

5 **The importance of baseline monitoring cannot be overstated. Regulators must ensure that an environmental baseline is fully established before any commencement of drilling activity and this should include both deep and shallow aquifers for radio-nuclides and other contaminants. Full details of the environmental monitoring programme should be disclosed.**

6 **The long-term monitoring of relative conditions to the environmental baseline in the vicinity of the well and nearby receptors throughout the lifetime of the well will be important to detect any contaminants. In developing production guidance, parameters on the frequency, locations and time scale of measurements should be included.**

7 **The protection of groundwater must be made a priority and the environmental regulator should continue to adopt the precautionary principle where there is insufficient certainty to protect groundwater. Operators should provide the environmental regulator with a detailed risk assessment to examine the relationship between the shale and the aquifer including a thorough evaluation of geological and hydrogeological setting.**

8 **Further research is needed into hydraulic fracturing with lower quality waters and also waterless techniques to minimise water use and thus requiring less subsequent treatment.**

9 **Research and development is needed in water treatment and decontamination technologies that exhibit reduced energy consumption, as well as into onsite and mobile treatment solutions that reduce the risks of transporting waste.**

10 **The reuse of hydraulic fracturing fluid on site is the preferred option of the industry and the regulator. Given that there is common ground between the industry and regulator, they should work closely together to identify optimum solutions.**

Abbreviations

BGS	British Geological Survey
CAMS	Catchment Abstraction Management Strategy
CCGT	Combined cycle gas turbines
CCS	Carbon capture and storage
DEFRA	Department for Environment, Food and Rural Affairs
DECC	Department for Energy and Climate Change
EA	Environment Agency
EIA	Environmental Impact Assessment
EPR	Environmental Permitting Regulations
ERA	Environmental Risk Assessment
GHG	Greenhouse Gas
GIP	Gas in place
HFP	Hydraulic Fracturing Programme
HSE	Health and Safety Executive
LNG	Liquified natural gas
NIEA	Northern Ireland Environment Agency
NORM	Naturally occurring radioactive materials
NRW	Natural Resources Wales
OUGO	Office of Unconventional Oil and Gas
PEDL	Petroleum Exploration and Development Licence
SEPA	Scottish Environmental Protection Agency
TRR	Technically Recoverable Resources
UKOOG	UK Onshore Operators Group
WFD	Water Framework Directive
WRMP	Water Resource Management Plan

1. Context

Shale gas - Why is it unconventional?

The UK has a long history in the production of oil and gas from 'conventional' hydrocarbons found in both onshore and offshore fields. This is where hydrocarbons are found in reservoirs and can be accessed by drilling an oil well. 'Unconventional' hydrocarbons are termed such on the type of rock in which they are found and on the basis of their relative difficultly in extraction. Unconventional gases include shale gas, coal bed methane and tight gas and exploration for each of these is currently underway in the UK (figure 1.1). These sources are now being developed as technological breakthroughs have allowed them to be more readily accessed and therefore more commercially viable.

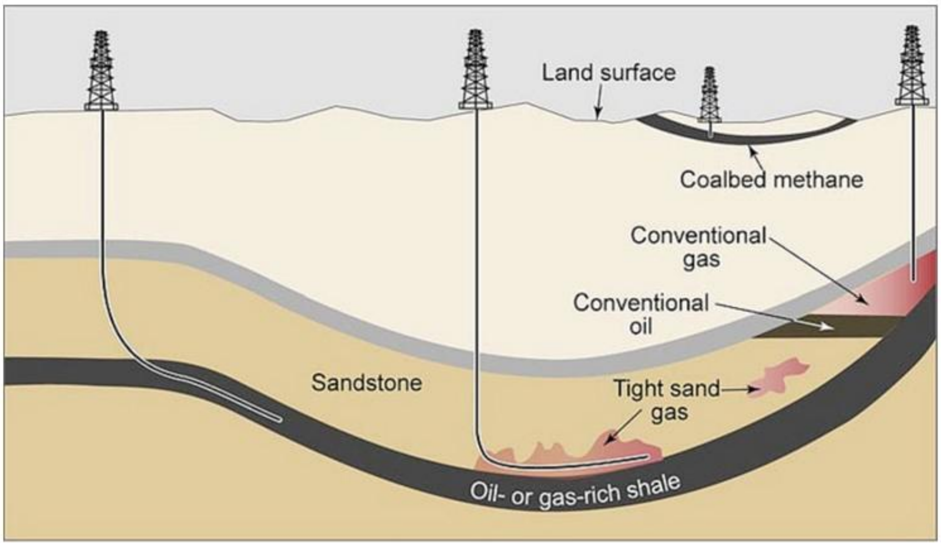


Figure 1.1 – Schematic geology of natural gas resources[ii].
NOTE – Not to scale. UK Shale formations lie at a greater depth and are thicker (up to 5km deep and 1.5km thick) than those depicted here which is from the US

Unconventional hydrocarbons are found under conditions that do not allow them to flow and be easily captured. Shale gas is mostly composed of methane or 'natural gas' that is trapped within the pores of shale rock. The extraction of shale gas from rocks with low permeability at economically viable flow rates relies on the use of two technologies; horizontal drilling and hydraulic fracturing (figure 1.2).

As shale gas deposits are typically deeper than conventional reservoirs and coal bed methane sources, they require deeper wells and the use of horizontal wells to maximise the amount of shale area that can be fractured. Horizontal drilling allows this to take place. To enable the gas to flow from the shale to the well it has to be systematically fractured or 'fracked' using pressurised fluids to create fractures in the rock. Water, chemicals and other materials (proppants) are pumped at high pressure to fracture and then hold open fissures in the rock to encourage the oil or gas to flow to the well. This is hydraulic fracturing.

Horizontal wells are fractured in stages with a lateral drilled, perforated and then fractured; a mechanical plug is put in place to stop the gas from flowing back up the well whilst the next

[ii] US Energy Information Administration and US Geological Survey

section is perforated and fractured. This process continues until the whole lateral has been fractured, the plugs are then drilled through to allow the fracturing fluid and gas to flow up the well.

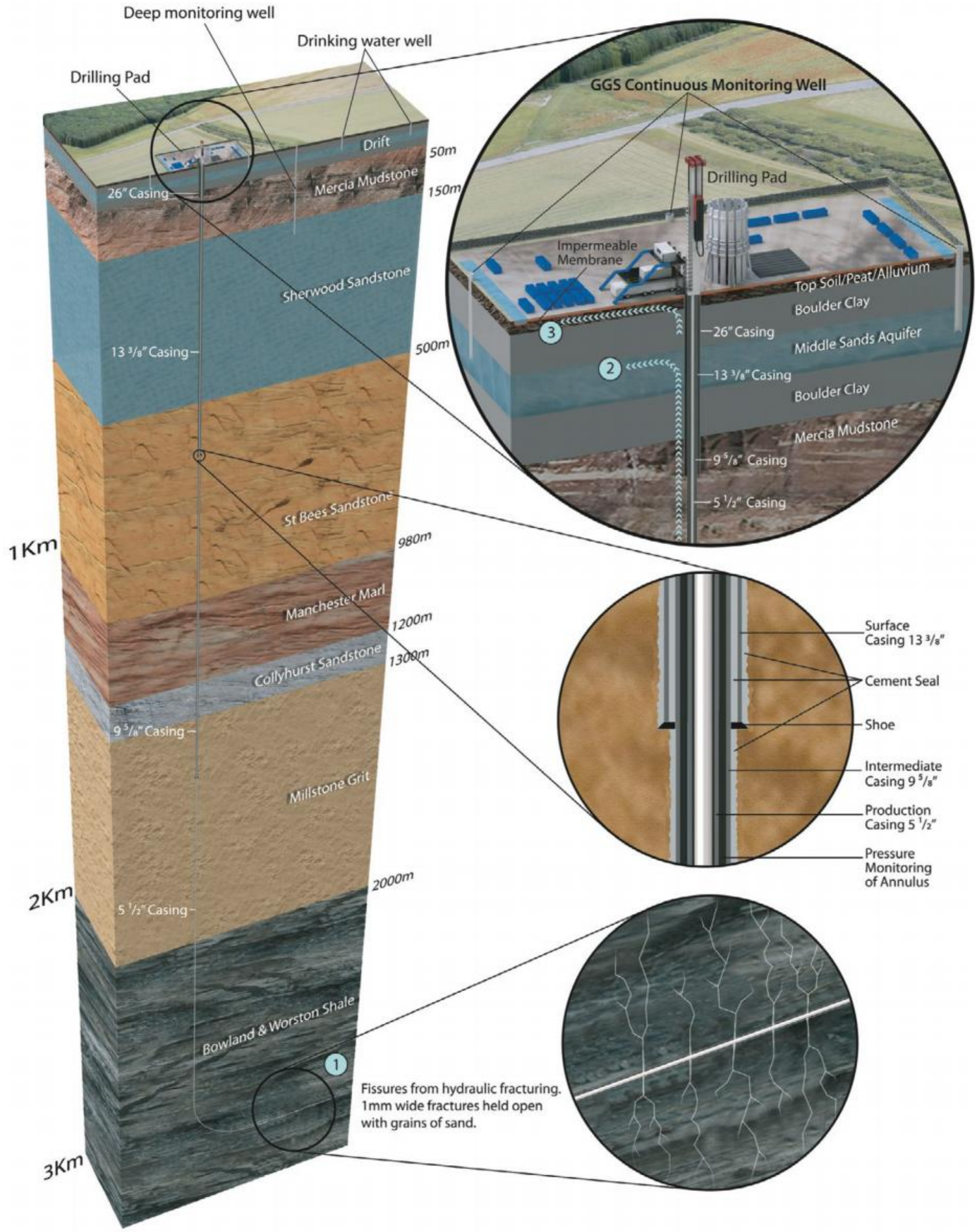


Figure 1.2 Shale gas, fracking and environmental monitoring for north west England via GGS Ltd

Hydraulic fracturing is a process not solely associated with extracting gas from shale but is routinely used in conventional oil and gas fields and hydrothermal wells to extract hydrocarbons. It is also occasionally used in water wells to enhance well yield and in geothermal energy production. Many of the environmental risks that are attributed to hydraulic fracturing may be nothing to do with the fracturing process itself and may be a result of poor well design and construction or poor handling of chemicals or returned waters.

What makes hydraulic fracturing in shale gas extraction different from other hydrocarbon extraction techniques is that it is on a greater scale; the wells are often drilled deeper than conventional wells and a greater number of wells (including lateral wells) are needed to access the resource. Shale also requires higher volumes of water and chemicals and higher water pressures[iii] due to the depth of the well and because there are very few natural fissures in the rock. This can present engineering challenges.

The Government's position – why the interest?

'Natural gas' is used to generate electricity, is a key feedstock to the chemicals industry and is the gas used in domestic heating and cooking in homes. Currently 80 per cent of our domestic heat comes from gas[iv]. It forms an integral part of the UK's electricity generation mix[v], playing a role in maintaining energy security, affordability and being 'cleaner' than coal for the same energy output.

Since the early 1990s, investment in gas electricity generation infrastructure has been a key component of investment in the energy sector, accounting for nearly 70 per cent of new capacity coming online between 2000 and 2011. This 'dash for gas' saw around 20 GW of new Combined Cycle Gas Turbines (CCGT) coming online and there is now around 32 GW of CCGT capacity in the UK[vi]. Modelling by the Department for Energy and Climate Change (DECC) suggests an estimated total capacity[vii] of 37 GW of CCGTs in 2030 which will provide around 30 per cent of our total energy capacity (Figure 1.3).

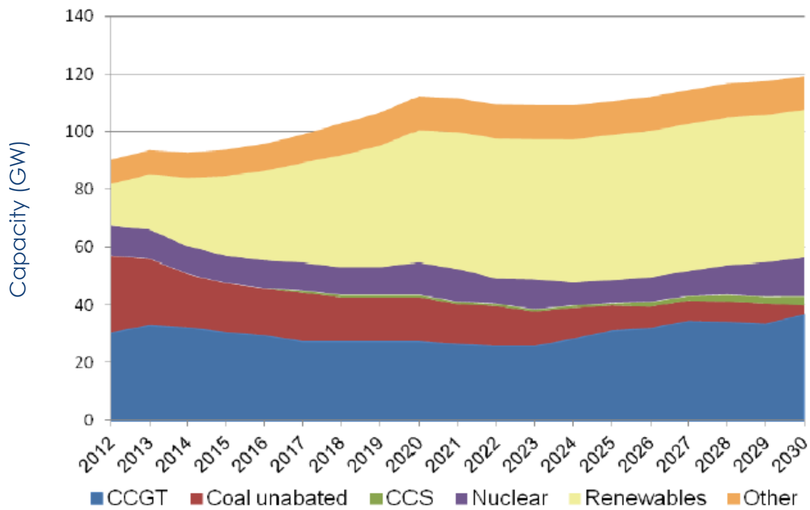


Figure 1.3 Estimated Total Capacity 2012 – 2030, Gas shown in blue.

iii The range of fluid pressures used in high volume hydraulic fracturing is typically 10,000–15,000 psi, and exceptionally up to 20,000 psi. This compares to a pressure of up to 10,000 psi for a conventional well. Environment Agency. 2012. Monitoring and control of fugitive methane from unconventional gas operations.

iv DECC. 2013. Energy Consumption in the UK overall data tables 2013 update. Table 1.07

v This is true for both the GB electricity market and in Northern Ireland (which is part of the Single Electricity Market and has a separate regulator and planning regime).

vi DECC. 2012. Gas Generation Strategy

vii Up to 26 GW of new plant could be required by 2030 (in part to replace older coal, gas and nuclear plant as it retires from the system)

With this continued demand for gas and as wholesale imported gas prices are speculated to rise, the potential to extract domestic gas is particularly attractive. The Government's desire[viii] to maximise indigenous gas production allows the UK to reduce our reliance on energy imports which are expected to increase from 50 per cent to 76 per cent by 2030, and provides considerable tax benefits to the Treasury.

How long might a shale gas industry take to develop?

The UK's onshore oil and gas industry began with the first oil discovered in 1919 and the first hydraulic fracture believed to have been performed in the mid to late sixties. Now 2000 oil and gas wells have been drilled and 10 per cent of which have been hydraulically fractured[ix]. Yet our shale gas industry is still only in its infancy. For successful commercial shale gas extraction a development must go through the stages of exploration, appraisal and production and to date we have only drilled a small number of exploration wells to assess the resource size.

Recent resource estimates have fuelled speculation of an energy revolution with lower gas prices and self sufficiency in the medium term. This has brought much conjecture over both the size of a potential industry and how quickly it will be able to establish itself in the UK. Political rhetoric has seized on the example set by the US where it has reinvigorated its economy; gas prices have halved and thousands of jobs have been created. The Prime Minister has even stated: "*If we don't back this technology, we will miss a massive opportunity to help families with their bills and make our country more competitive. Without it, we could lose ground in the tough global race.*" [x]

However until exploration takes place on any meaningful scale, certainty regarding how much gas is available and at what cost is very low and is likely to change considerably again once production starts and expands. DECC has confirmed that "*at present, neither DECC nor the industry currently have the engineering, geological or cost information to make a meaningful estimate of recoverable reserves*"[xi].

This is a reality which is at times not well reflected in the discussion of shale gas extraction within the popular press, nor in the comments made by prominent politicians, who may reflect the polarisation of opinion on what has become a controversial subject.

DECC has admitted that it is likely that the pace of development of shale gas in the UK will be slower than has been seen in the US: "*If exploration is successful, early production is likely to be seen in the second half of this decade, but any substantial contribution to the UK's gas supply is unlikely until further into the 2020s*"[xii].

The Institute of Directors speculate that 100 pads of 10 wells each could, were exploration successful, reduce UK natural gas import dependency by 50 per cent by 2030. The Oxford Institute for Energy Studies highlights a potential obstacle: "*The main issue however is the drilling intensity... required to achieve meaningful production levels in the context of UK domestic natural gas consumption. This is the key feature of shale gas development which appears to have bypassed media commentary in the UK*"[xiii]. To achieve the level of ambition desired is likely to be affected by a number of factors; these are shown in figure 1.4 and discussed further in the next section.

viii Speech by Rt Hon Michael Fallon MP, Minister for Energy, 17th July 2013

ix UKOOG. 2013. Onshore oil and gas in the UK.

x *Ibid* & "We cannot afford to miss out on shale gas". David Cameron. 11 August 2013

xi House of Commons Energy and Climate Change Committee. 2013. The Impact of Shale Gas on Energy Markets: Government Response to the Committee's Seventh Report of Session 2012–13. Appendix: Government Response.

xii DECC. 2012. Gas Generation Strategy

xiii The Oxford Institute for Energy Studies. 2013. UK Shale Gas – Hype, Reality and Difficult Questions.

Viability of commercial shale gas development in the UK

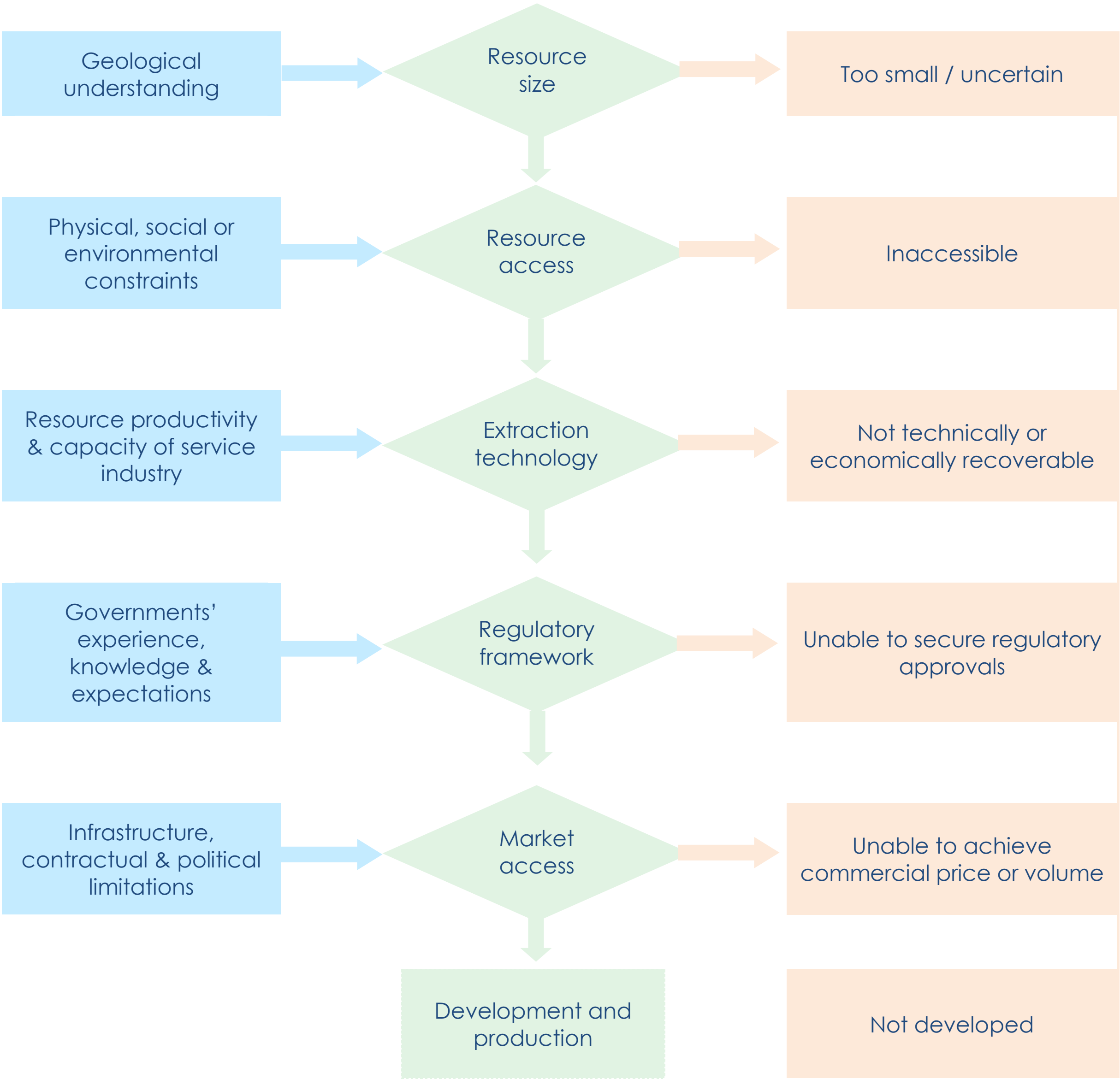


Figure 1.4 Flowchart illustrating factors determining the viability of natural gas developments[xiv]

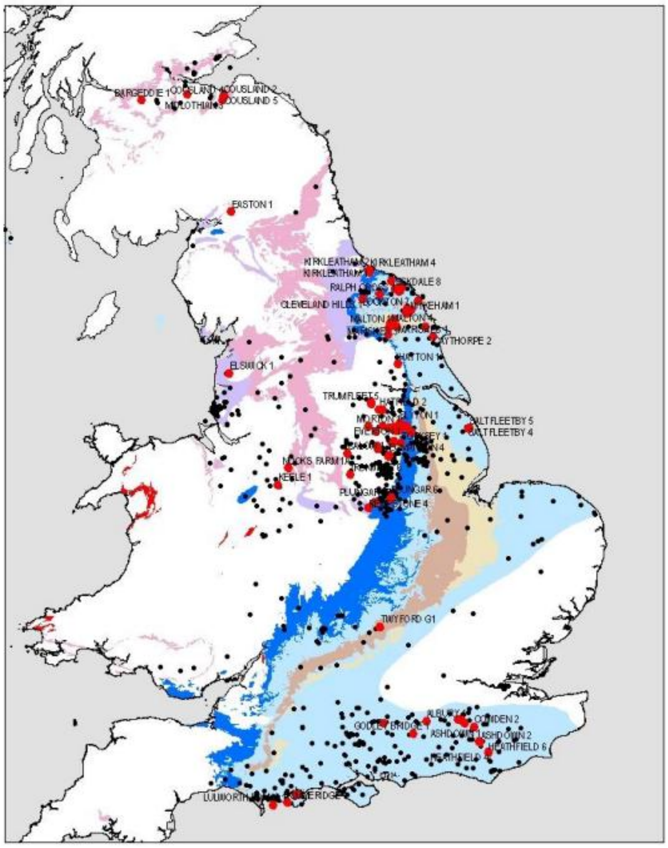
xiv Adapted from: International Energy Agency. 2011. World Energy Outlook 2011 Special Report: Are we entering a golden age of gas?

This section discusses the viability of shale gas as an economically extractable fuel resource for the UK and centres upon the following key issues:

- **Resource size** with the need for sufficiently large and appropriate gas-bearing shale formations to make exploration and exploitation worthwhile as a means of providing an indigenous source of gas.
- **Extraction technology** that enables extraction to be economically viable and a skilled workforce and service sector to enable the gas to be safely secured.
- **Environmental regulation** to ensure a streamlined system that does not threaten the environment nor restrict an industry from developing.
- **Public trust** providing a social licence to operate for the shale gas operators. Public acceptance of the visual and physical disruption associated with the drilling process in particular, especially in areas where there might be a high density of shale gas well pads.
- **Economics** of extraction and market access to be sufficiently attractive to enable a profitable industry to develop.

Resource size

Figure 1.5 shows areas of the UK which feature geology with potential for rich resources of shale gas.



Kimmeridge Clay outcrop
Oxford Clay outcrop
Lias Outcrop
Namurian (Millstone Grit) outcrop
Cambrian including Tremadoc outcrop
Conventional wells which flowed gas
Conventional wells drilled
Jurassic Lias Subcrop
Namurian Subcrop

Figure 1.5 Main areas of prospective UK Shale formations[xv].
NOTE: Prospective formations may be found below other formations at depth. Further information on each formation can be found in the source document.

[xv] Harvey and Gray. 2010. The unconventional hydrocarbon resources of Britain's onshore basins – shale gas, Department of Energy and Climate Change.

The existence of appropriate geology does not mean that it will necessarily be suitable as a source of shale gas for extraction. Shale gas *resources* are the estimated total volume of gas (gas-in-place (GIP)). Potentially (or Technically) Recoverable Resources (TRR) are those that are estimated as extractable from the total resource. Shale gas *reserves* are the fraction of the TRR that is deemed to be commercially recoverable using today's technologies[xvi]. A resource play is an accumulation of hydrocarbons known to exist over a large area, believed to have a lower geological and/or commercial development risk. In order to establish a realistic estimate of the reserve volume exploratory drilling and testing will need to be undertaken.

Preliminary studies are currently being undertaken by the British Geological Survey (BGS). The current areas that are or have been studied are highlighted in figure 1.6:

- the Lower carboniferous shales around the Pennines, particularly the Bowland-Hodder basin in southern Lancashire
- the Weald[xvii] in Wessex, Sussex and Surrey (consisting of three Jurassic formations)
- the Upper Cambrian formation in the Midlands
- the Midland Valley of Scotland
- It is also considered likely that there would be significant areas of appropriate geology offshore.

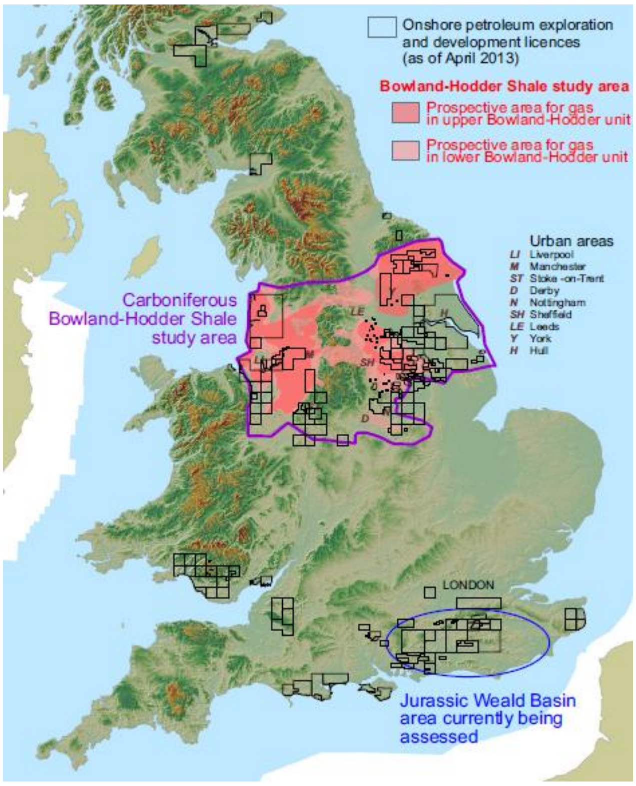


Figure 1.6 Location of the DECC/BGS study area in central Britain, together with prospective areas for shale gas, currently licensed acreage and selected urban areas.

NOTE: DECC's licences do not distinguish between shale gas and other forms of hydrocarbons. Comparing these to the geological maps may indicate which are in areas of shale gas potential.

In 2013 DECC commissioned the BGS to undertake a detailed GIP analysis for part of central Britain in an area underlain by the Bowland Shale which extends across a significant area of England from the Midlands northwards[xviii]. The Bowland Shale is believed to be the rock type with the greatest potential for shale gas in the UK as it occurs at both depth and at outcrop and it is known from previous studies and investigations to be an excellent hydrocarbon source rock.

xvi International Energy Agency. 2013. From resources to reserves

xvii The Weald may have more prospective shale oil rather than shale gas

xviii Andrews, I.J. 2013. The Carboniferous Bowland Shale gas study: geology and resource estimation. British Geological Survey for Department of Energy and Climate Change, London, UK.

The study involved integrating 15,000 miles of seismic data with outcrop and fault mapping, well data, historical and newly-commissioned laboratory studies to identify the potential volumes of shale gas. The central estimate of GIP was 37.6 trillion cubic metres (tcm $1x10^{12}$) which was greater than initially expected from a 2010 study. Using similar recovery factors to the US (8-29 per cent) gives a TRR estimate between 1.8 – 13 trillion cubic metres (UK annual gas consumption is 77 billion cubic metres (bcm $1x10^{9}$))[xix]. These studies are not able to accurately to predict reserves (i.e. that will be technically and commercially produced) and exploratory drilling will be required.

A similar study by the BGS is underway for the Jurassic Weald Basin in Southern England. Potential shale formations exist in Scotland and it the next area under assessment by the BGS. In Wales permission for drilling has been granted at two sites but hydraulic fracturing has not yet been authorised. In Northern Ireland there are petroleum licences but no applications for hydraulic fracturing. There is an interest to extract shale gas in an area between Northern Ireland and the Republic of Ireland which has led to a move to develop a transboundary regulatory framework[xx].

In the experience of the USA, resource estimates increased by 40 per cent over the two years between 2007 and 2009[xxi]. However elsewhere in areas of Norway, Poland, China and South Africa resource estimates were revised lower in 2013 than their 2011 estimates[xxii]. It may require a period of around two years of exploratory drilling in order to establish the viability of shale gas in the UK[xxiii]. Until that point, very low levels of certainty can realistically be attached to claims on either side of the discussion. This uncertainty is of greater relevance in the case of unconventional oil and gas than for more conventional sources, which are easier to assess and predict.

xix BGS. 2013. The extent of shale across the UK and the latest shale gas resource estimates. Presentation to CIWEM Shale gas conference 6th November 2013.

xx Royal Society and RAEng. 2012. Shale gas extraction in the UK: a review of hydraulic fracturing

xxi Energy and Climate Change Committee. 2011. Fifth Report: Shale Gas.

xxii USEIA. 2013. Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States

xxiii The Oxford Institute for Energy Studies. 2013. UK Shale Gas – Hype, Reality and Difficult Questions.

Extraction technology

The existence of an extensive shale gas resource is only part of the equation; critical is whether the technology exists to make it economically viable to extract and sell. The UK has areas of deep shales which may make the process more challenging and expensive but could also reward operators who invest in technological development.

The Bowland Shale formation in Lancashire exists at a great depth and thickness; up to 5km deep[xxiv] compared to the often shallower and thinner plays found in the US. This is fortunate as it can minimise surface disruption and achieve more gas from the same entry point, reducing the social limitations. However not all the shale plays in the UK have the same vertical extent as the Bowland, there are those that come to the surface but also run to a considerable depth. Until DECC publish their resource estimates we will not know the differences in their thicknesses and distributions and where is prospective.

Where there is a great vertical extent to the shale formation, this presents a greater opportunity to liberate more gas from the same well, but will require deeper wells and more lateral drilling. The technology exists to drill more than one lateral from a well so there is no fundamental barrier to extracting shale gas should the geology in the UK indeed be appropriate. However for one particular field in the US which features geology of a similar depth to that which would be expected in the UK (3.5km), almost twice the amount of hydraulic horsepower was needed, with higher treating pressures and more advanced fluid chemistry than that for the Barnett and Woodford shales[xxv]. There may have been other contributing geological factors in this case but it is worth noting that processes and therefore costs will have to be scaled up to deal with a more challenging environment.

Technological advancement may help to bring down costs by maximising the efficiency of wells. In the US completion and drilling techniques are well established and drilling efficiencies continue to improve even as laterals extend to increasing lengths (figure 1.7). In the Barnett shale, initial laterals were around 1500ft long with five staged fractures, now they are 2000 to 6000ft long with 20 to 30 staged fractures[xxvi]. Infill drilling (between existing wells) and the re-fracturing of the first horizontal wells are both expected to improve Estimated Ultimate Recovery from 11 per cent to 18 per cent in the area[xxvii].

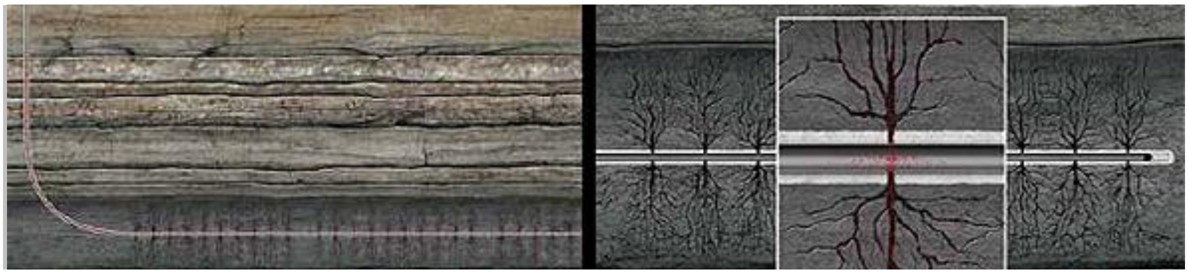


Figure 1.7 Stages of a hydraulically fractured lateral well

xxiv Harvey & Gray. 2010. The unconventional hydrocarbon resources of Britain's onshore basins – shale gas, Department of Energy and Climate Change.
xxv This was also a factor of the geology being highly laminated. Halliburton. 2008. An Unconventional Resource. Unconventional Challenges.
xxvi Cuadrilla. 2013. Pers comm. & Society of Petroleum Engineers. 2012. Hydraulic fracturing 101.
xxvii Halliburton. 2008. An Unconventional Resource. Unconventional Challenges.

Ernst & Young[xxviii] has identified obstacles to rapid shale gas development in Europe as a lack of oilfield service sector capacity, equipment and appropriately skilled labour. It notes that the service level intensity is higher for unconventional oil and gas than for conventional hydrocarbons, and that in the US the sector has developed significantly to provide skills and services for shale gas and is now looking to export expertise internationally.

"Green completion" technologies are used in the US which separate out gas, water and sand in the flowback fluid before directing the recovered gas into pipelines. This means that methane and carbon dioxide emissions are reduced compared to venting and flaring methane, respectively[xxix] provided the gas is sold or otherwise used. As regulations are developed for the production phase green completions should be added as best practice.

The UK has the benefit of a historically strong service industry, having a small onshore industry and an extensive offshore industry associated with North Sea oil and gas. Although this is in conventional sources, the sector has also been required to innovate given the challenges of working in a hostile environment, thus it is potentially well placed to expand into unconventional oil and gas should the economic drivers be sufficiently attractive.

xxviii Ernst & Young. 2011. Shale gas in Europe: Revolution or evolution?
xxix Royal Society and RAEng. 2012. Shale gas extraction in the UK: a review of hydraulic fracturing.

Environmental regulation

The conventional oil and gas industry is mature in the UK and is already tightly regulated both onshore and offshore. Unconventional oil and gas exploration and exploitation is regulated by appropriate sections of DECC, the Environment Agency (EA) and the Health and Safety Executive (HSE). It is also subject to planning requirements through the Department for Communities and Local Government (DCLG) and local authorities (figure 1.8). Elsewhere in the UK the Scottish Environmental Protection Agency (SEPA), Natural Resources Wales (NRW) and the Northern Ireland Environment Agency (NIEA) fulfil the role of the environmental regulator. These bodies ensure compliance with European Directives and legislation and also that which is in place at the national level.

Within DECC, the Office of Unconventional Gas and Oil (OUGO) has been set up to co-ordinate the activity of the regulatory bodies and Departments and to deliver a streamlined planning and regulation system. There is an obvious need to ensure integration across the bodies and regulation which will be paramount to deliver environmental objectives. In addition to the regulatory framework an industry code of practice has been developed by UKOOG (UK Onshore Operators Group).

DECC have recently produced regulatory roadmaps for onshore exploration in England, Scotland, Wales and Northern Ireland to clarify the process[xxx]. Much of the guidance that has already been produced is for the exploration stage only and this is reflective of the infancy of the industry. As it is developed, regulation will need to distinguish between the different impacts associated with exploration and that of production as there will be different requirements for the control, monitoring and local issues for whether there are one or two wells or several hundred.

Initially, for a company to commence drilling a Petroleum Exploration and Development Licence (PEDL) must be obtained from DECC[xxxi]. These licences are issued on a competitive basis of licensing rounds and grant exclusive rights to explore, drill and produce hydrocarbons within a small defined area subject to appropriate licences and permissions. A new round of onshore licensing (the 14th round) will open early in 2014 and there is likely to be a great deal of interest.

An Environmental Risk Assessment (ERA) is required by DECC at the pre-planning stage for each site for hydraulic fracturing, which will be used to ensure that any potential risks are identified and acted on. DECC requires compilation of an ERA as a matter of good practice and it should include the participation of stakeholders including local communities.

Shale gas operators must then obtain planning permission from the relevant Mineral Planning Authority in order to conduct the surface activities associated with exploration and production. Mineral Planning Authorities will have their own Mineral Local Plans under the National Planning Policy Framework which will be permissive but will detail any restrictions with regards to surface or groundwater resources or any impact on designated habitats[xxxii]. DCLG has published planning guidance that clarifies the interaction of the planning process with the environmental and safety consenting regimes[xxxiii]. This explains that a planning authority need not assess any issue that is covered by a regulator but will need to satisfy itself that these issues can be adequately addressed by taking advice from the relevant regulatory body. The guidance also sets out when an accompanying Environmental Impact Assessment (EIA) is required. The industry has voluntarily agreed to undertake an EIA for all sites that involve fracking and these should be submitted to the Mineral Planning Authority as part of the planning application process.

xxx DECC. 2013. Regulatory roadmap: Onshore oil and gas exploration in the UK
xxxi DECC. 2013. Oil and Gas Licensing.
xxxii DCLG. National Planning Policy Framework
xxxiii DCLG. 2013. Planning practice guidance for onshore oil and gas

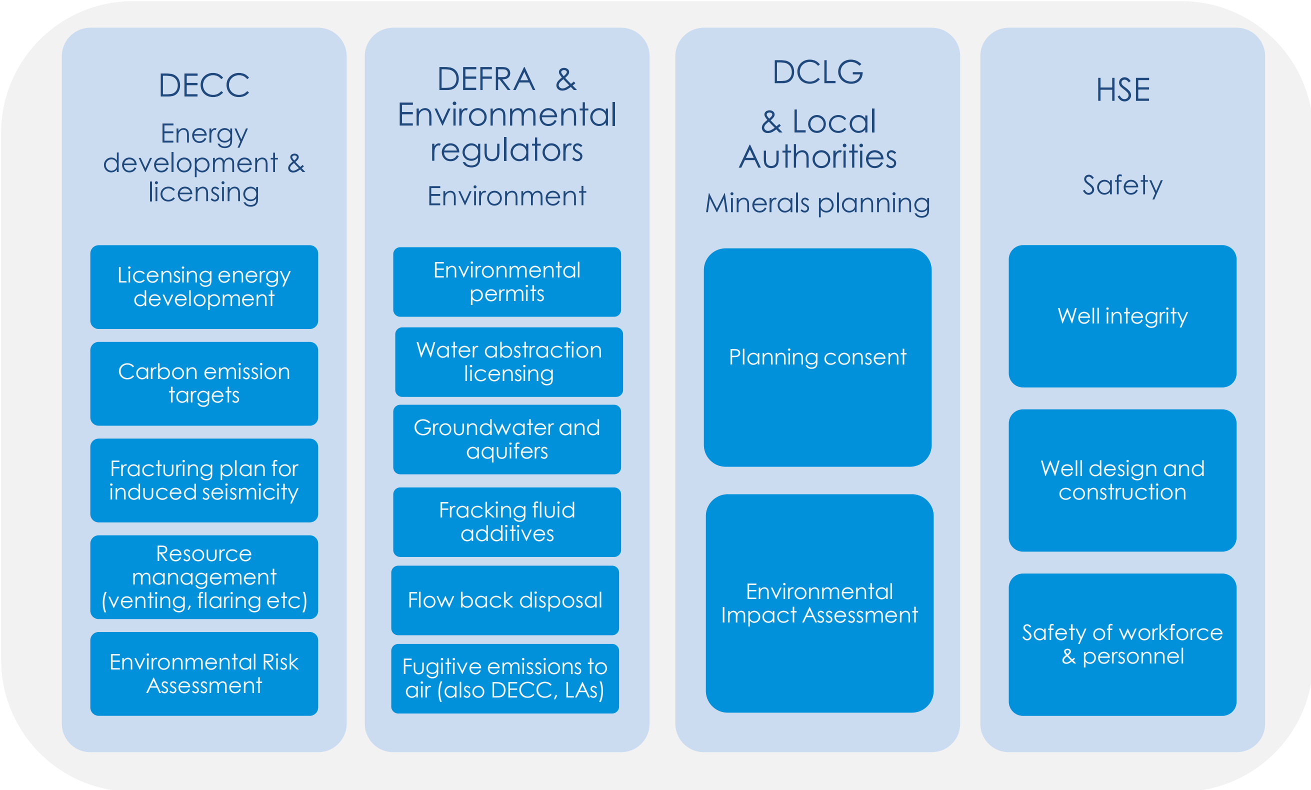


Figure 1.8 Regulatory bodies and their responsibilities in the shale gas industry
NOTE: There is some overlap of roles and the bodies will have to work together within this framework to ensure local scrutiny and engagement

Shale gas operators may also need to apply for environmental permits, with most falling under the Environmental Permitting Regulations 2010 (EPR), to allow drilling to take place. The EA's draft technical guidance[xxxiv] clarifies which environmental regulations apply to the onshore oil and gas exploration sector and what operators need to do to comply with those regulations:

- *A notice to be served on us under section 199 of the Water Resources Act 1991 to 'construct a boring for the purposes of searching for or extracting minerals'*
- *Environmental permits for:*
  - *A groundwater activity – unless the EA is satisfied there is no risk of inputs to groundwater*
  - *A mining waste activity – likely to apply in all circumstances*
  - *An installation under the Industrial Emissions Directive – when it is intended to flare more than 10 tonnes of waste gas per day*
  - *A radioactive substances activity – likely to apply in all circumstances where oil or gas is produced*
  - *A water discharge activity – if surface water run-off becomes polluted, for example, due to a spill of diesel or flowback fluid*
- *A groundwater investigation consent – to cover drilling and test pumping where there is the potential to abstract more than 20 cubic metres per day (m^3/day)*
- *A water abstraction licence – if it is planned to abstract more than 20 m^3/day for your own use rather than purchasing water from a public water supply utility company*
- *A flood defence consent – if the proposed site is near a main river or a flood defence.*

xxxiv Environment Agency. 2013. Consultation on technical guidance for onshore oil and gas exploratory operations

For many sites only two permits are likely to be required. In applying for a permit, an operator will be required to provide information including a geological assessment, casing design detail and hydraulic fracturing fluid composition. At the moment a bespoke environmental permit will be required and these normally take 13 weeks to determine, including a four week public consultation period. However the EA are working to develop "standard rules" environmental permits for operators so, under certain circumstances they will not have to apply for multiple bespoke ones. The EA is also a statutory consultee for planning applications and EIAs associated with unconventional oil and gas. SEPA undertakes a similar role in Scotland under the Water Environment (Controlled Activities) (Scotland) Regulations 2011[xxxv].

Following planning consent and environment permitting the operator will need to notify the HSE. The HSE monitors shale gas operations from a well integrity and site safety perspective, under the Borehole Site and Operations Regulations 1995 and the Offshore Installations and Wells (Design and Construction, etc) Regulations 1996 which despite its name also applies onshore[xxxvi]. At least 21 days before drilling is planned, the HSE must be notified of the well design and operation plans to ensure that major accident hazard risks to people from well and well related activities are properly controlled. Together the EA and the HSE must be satisfied that wells are designed, constructed and operated to standards that protect people and the environment.

The operator must also notify the BGS with details of the drilling and permission must also be obtained from the Coal Authority if the well encroaches on any coal seams. Finally DECC will provide consent to drill after scrutinising fracture plans and once any controls to mitigate seismic risks are put in place. The landowner is also able to impose conditions.

It remains to be seen what regulation process will be like for exploration and after the outcomes of the EA's technical guidance consultation there may be more guidance. With the European Commission looking into regulation there may also be national and European requirements that promote duplication and result in changes to UKOOG or EA guidance. In terms of the impact on the rate of growth of the industry, regulation and uncertainty in regulation is likely to be the greatest source of frustration despite the work carried out to streamline the process. Shale gas operators have noted that the process is not comparable to the risk and there is duplication of effort, for example having to produce both an ERA and EIA. Standard permits should reduce this burden but that is not to say that regulation should become more lenient; environmental protection must be the mainstay.

Industry code of practice

DECC, EA, SEPA, HSE and shale gas operators have worked with the UKOOG to codify best practices for onshore shale gas exploration wells. The Onshore Shale Gas Well Guidelines[xxxvii] detail the Hydraulic Fracturing Programme (HFP): the detailed risk assessment now required as part of DECC consent and covers groundwater isolation, fracturing containment and induced seismicity. This guidance emphasises the need for transparency, stating:

"*Operators need to explain openly and honestly their drilling, fracturing design and operational practices including environmental, safety, and health risks and how they are addressed. The public needs to gain a clear understanding of the challenges, risks and benefits associated with the development*.

xxxv Water Environment (Controlled Activities) (Scotland) Regulations 2011
xxxvi HSE. 2013. The regulation of onshore unconventional oil and gas exploration (shale gas)
xxxvii United Kingdom Onshore operators Group. 2013. UK Onshore Shale Gas Well Guidelines: Exploration and appraisal phase.

Referring specifically to hydraulic fracturing, operators should measure and disclose operational data on, for example:

- *Water use*
- *The volumes and characteristics of waste water*
- *Produced water disposal methods*
- *Fracturing fluid additives (constituents) concentrations and volumes*
- *Shale gas volumes including any emissions*
- *Fracture design and containment*
- *Any induced seismicity"*

These guidelines are not mandatory but failure to comply with them may lose the operator membership of the trade body. Good data, measurement and transparency are vital to secure public confidence.

Public acceptance

The population density of the UK is far higher in some areas than those where hydraulic fracturing has taken place in the US or Australia, which is likely to result in the exposure of greater numbers of people to the visual and physical disruption associated with the industry.

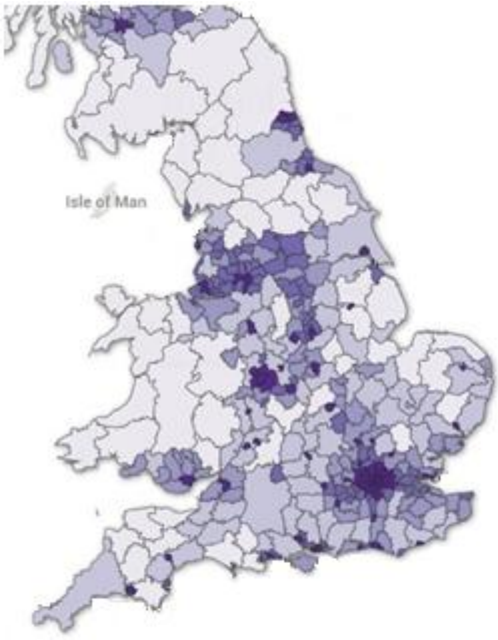


Figure 1.9 ONS population density data for 2011

Population densities by geographical location (figure 1.9), although a broad analysis, show considerable correlation between the areas of current geological interest for shale gas and high levels of population density in the north west and south east of England. This could lead to a difficult public relations situation for the industry and a supportive government.

A key public concern relates to disruption from vehicle movements, which have been reported in the press in the region of 1000 vehicle movements per day to a site in the US[xxxviii]. We would not expect this number in the UK as these trucks largely brought water to the site but during the exploration and early production phases the work is intensive and for 24 hours a day. Once this phase is complete, restored pads, according to industry advice, may be approximately the size of a football pitch, containing up to ten wells, each projecting only a few metres in height with minimal disruption.

According to the Oxford Institute for Energy Studies public acceptance will be a key factor in limiting either or both the extent and speed of the industry's development in the UK and

[xxxviii] The Times. 2013. Rich pickings for landowners as fracking transforms Pennsylvania backwater. 16th August 2013

potentially more so than the hard economic factors: "*Whether these economic benefits at the national and local level are perceived by inhabitants in the vicinity of shale gas operations to adequately compensate for increased traffic and visual impact during drilling operations is the key issue*[xxxix]."

UKOOG and the Government[xl] have sought to counter the already vociferous public opposition to possible future widespread construction of well pads in parts of the country with an incentive package for local communities, comprising £100,000 for communities sited in the vicinity of exploratory wells and one per cent of revenues from production. With mineral rights in the UK being vested by the Crown Estate and licensed by DECC the incentive package has to come from the industry. This is a far cry from the situation which prevails in the US, where in some states property owners have mineral rights and up to 20 per cent of production revenues may be paid to individual land owners[xli].

The Prime Minister has also announced[xlii] that councils can keep 100 per cent of the business rates they collect from shale gas sites, double the current 50 per cent figure. Local authorities who are considering planning applications will need to take great care to ensure that their planning decisions are very robust in light of this conflict of interest.

In addition to financial incentives offered to local communities and councils, the UK government has also sought to take steps to reduce the burden on the industry as far as land use planning is concerned. It has proposed to remove any requirement for shale gas operators to serve notice to landowners or tenants of the land beneath which gas may be extracted[xliii]. The rationale for this is that the exact routes of lateral drilling will not be known at the application stage since this will depend on the geology, which can only be accurately known once drilling has commenced. As the area is widely drawn on the application significant numbers of owners would be required to have notice served and they believe this to be unreasonable and impractical. Whilst this could make the planning process easier, it could inflame the situation with local pressure groups.

The potential for local opposition to planning applications to local authorities is likely to be significant and may constitute the largest hurdle as far as the industry's development is concerned. To date the public consultation process has been poorly implemented in areas of shale gas exploration[xliv] so it is important that the industry improves upon this. They will need to be transparent about the risks and the management measures they are putting in place.

However the point is also made, in the context of planning objections by local communities, that the UK's onshore oil and gas industry already has 120 sites, the public awareness of which is apparently low, despite the fact that hydraulic fracturing has taken place at several of these sites for 30 years[xlv]. This shows that the challenge can be met if shale gas operators earn public trust through careful planning, engagement and adherence to good practice. UKOOG has established a binding community engagement industry charter[xlvi] for its members that cover how operators will communicate and engage and also makes specific commitments with respect to logistics, health and safety, environmental compliance and local needs. It is important that as the industry develops these are adhered to.

xxxix The Oxford Institute for Energy Studies. 2013. UK Shale Gas – Hype, Reality and Difficult Questions.

xl Initially proposed by UKOOG and adopted by the Government

xli Congressional Research Service. 2009. Unconventional Gas Shales: Development, Technology, and Policy Issues

xlii DECC. 2014. Local councils to receive millions in business rates from shale gas developments. Press Release 13th January 2014.

xliii DCLG. 2013. Revised requirements relating to planning applications for onshore oil and gas – Proposals.

xliv Ribble Estuary Against Fracking. 2013. Wider environmental issues from a community group perspective. Presentation to CIWEM Shale gas conference 6th November 2013.

xlv Business Green. 2013. Fracking industry boss: Expect to see 50 to 60 test sites. 5 September 2013

xlvi UKOOG. 2013. Community Engagement Charter Oil and Gas from Unconventional Reservoirs

Economics, market access and political limitations

The geopolitical factors associated with the supply of gas to the UK are of major interest. With the decline of North Sea oil and gas supplies, the UK is increasingly reliant on gas supplies from locations of potential political instability such as Russia and Qatar[xlvii]. The attractiveness of a potential new indigenous supply of hydrocarbons is thus understandable geopolitically speaking.

Yet a key question mark hangs over the costs associated with extracting shale gas. The unconventional hydrocarbons industry is still young and advances are occurring at a good pace, meaning that exploitation costs are quite likely to fall over coming years and decades.

In addition to the technologies of horizontal drilling and hydraulic fracturing, the shale gas boom in the US resulted in no small part from a number of crucial factors which made it highly economically attractive. Firstly, that land owners often own the rights to minerals beneath their own land. This provided an enormous economic incentive for land owners to allow exploitation of any gas reserves present and has made many people wealthy as a result. The second concerned the existence of a substantial onshore oil and gas service industry which was able to develop solutions to unconventional hydrocarbons quickly, combined with highly favourable geology, both of which resulted in low production costs (as low as $3 (£1.8)/British Thermal Unit (MBtu)[xlviii]). Additionally, environmental regulation of the industry varies significantly between states and has been taken advantage of where it is relatively relaxed compared to the regime in the UK and wider Europe.

In the US, the gas market is largely domestic, due to strong levels of domestic demand and an un-developed export industry (though this is now being expanded in response to strong supply). This has allowed the sudden influx of cheap shale gas to reduce the wholesale price dramatically. The effect of cheap natural gas on the US economy has been positive and has caused a reduction in coal consumption and its associated emissions (though this has been displaced by increased use in Europe). The reduction of customer fuel bills has been seized by advocates of shale gas in the UK (such as the Prime Minister and Chancellor of the Exchequer) and makes the potential of shale gas development in the UK politically attractive if the same effect may be predicted in the UK.

However, in UK and Europe, two factors are likely to conspire against this characteristic. Firstly, production costs are likely to be higher; in the UK a reflection of the more challenging geology, greater regulatory burden and other social pressures requiring technological innovation to reduce the physical impact of the shale gas industry (production costs are estimated to be in the range of $8-12 (£5-7))/MBtu[xlix]). Secondly, gas prices in the UK are less liquid than those in the US, with the UK having closer ties to the European and Asian (and in the future US) supply markets which are traded on a longer term basis, so a reduction in price and any associated stimulus to the economy is likely to be significantly less marked. This latter situation is evolving quite quickly with an increasing number of gas deals becoming decoupled from oil indexing. Increasing supplies of LNG are favouring importers when it comes to negotiating contract lengths and prices, however this is not considered to be sufficient to change the overall impact of shale gas on price.

In terms of promising lower bills, higher wholesale prices may offset higher production costs to an extent, but the downward impact on customer (and hence voter) bills is likely to be less pronounced. The political rhetoric surrounding such benefits has been widely questioned by

xlvii After being a net gas exporter from 1997 to 2003, the UK became a net gas importer in 2004. In 2011 40 per cent came from Qatar – DECC. 2012. Gas Generation Strategy

xlviii Ernst & Young. 2011. Shale gas in Europe: Revolution or evolution?

xlix Ernst & Young. 2011. Shale gas in Europe: Revolution or evolution?

economists[l]. The Treasury has published draft fiscal measures to incentivise shale activity, recognising the high upfront costs associated with shale gas projects[li]. The pad allowance cuts the tax on a portion of production income from 62 per cent to 30 per cent at current rates.

Politically, the latest International Panel on Climate Change report[lii] underlines the urgency of action to avoid the costly consequences of climate change, in both economic and human terms. Due to conflicting reports on fugitive emissions, a government commissioned study reviewed all the available evidence and found that if adequately regulated, local greenhouse gas (GHG) emissions from shale gas operations should represent only a small proportion of the total carbon footprint of shale gas. On overall emissions it concludes "*the net effect on greenhouse gas emissions from shale gas production in the UK will be relatively small*"[liii]. However this is subject to the caveats that shale gas will replace our current LNG use and the increase in cumulative emissions (as it is a fossil fuel) will have to be counteracted in other areas.

The view of the authors of the DECC review is that without global climate policies new fossil fuel exploitation is likely to lead to an increase in cumulative GHG emissions and the risk of climate change. Gas is still a fossil fuel and in the longer term any electricity generation infrastructure will have to have Carbon Capture and Storage (CCS) technology if it is to provide significant amounts of generation as part of a low-carbon energy mix. This could render many plants to be uneconomic.

In terms of lifecycle greenhouse gas emissions in electricity production, natural gas has the lowest intensity of all the fossil fuels. As such it is being touted as a bridging fuel that can be used whilst renewable energy sources are developed to achieve grid parity. A concern with putting the emphasis on the development of a shale gas industry as a bridging fuel is its potential to distract from decarbonising the electricity sector. The lead-in time for shale gas may reduce its effectiveness as a bridging fuel, whereas if renewables were scaled up they could be achieving grid parity far sooner[liv].

The independent Committee on Climate Change's view is that a well regulated shale gas industry could have economic benefits to the UK and reduce our dependence on imported gas[lv], but that it could only meet our commitments under the Climate Change Act if it was later followed by a 'dash for renewables'.

Whilst we need a diverse energy sector, developing renewable energy sources and delivering energy efficiency must be completed in parallel and this requires continuous investment to increase renewable capacity on a steady basis. There will in the medium term always be a need for gas for delivering heat but only with sustained investment in renewables will we be able to achieve our climate change commitments and decarbonise the electricity sector.

l Bloomberg New Energy Finance. 2013. UK shale gas no "get out of jail free card" and Professor Paul Ekins. 2013. The Fracking Battle: No way to conduct energy policy, University College London and Deutchebank. 2011. European Gas a first look at EU shale gas prospects.

li HM Treasury. Finance Bill 2014. 10th December 2013.

lii IPCC. 2013. Climate Change 2013 The physical science basis.

liii MacKay, DJC and Stone, TJ. 2013. Potential Greenhouse gas emissions associated with shale gas extraction and use. DECC

liv Grid parity is where the cost of alternative energy source can generate electricity at less than or equal to the price of buying electricity from the grid.

lv Committee on Climate Change. 2013. Next steps on Electricity Market Reform – securing the benefits of low-carbon investment

2. Risks to the water environment and how they can be managed

The impacts of shale gas extraction on water are likely to be local and dependent on whether the geographical location of any productive areas of geology coincide with areas of particular water resource pressure, or are near to groundwater resources or sensitive aquatic environments.

The Bowland-Hodder basin in the north west of England is currently the main area of interest, with subsequent exploration and theoretically production likely in the south east. In terms of the water implications of the industry, both of these areas will have distinct characteristics relating to water resources, demographics and local environments which will require careful consideration and management by regulators and the water industry.

This chapter investigates:

- How much water will be needed for the processes of drilling and fracturing
- Where the water will be sourced and how it will be transported
- Whether there will be enough water available in the future as an industry develops
- The potential for contamination of groundwaters or the local environment from chemical additives in the fracture fluid, poor well design or failure, mobilisation of solutes or methane and from the risk of flooding
- The risks from the storage and transportation of the returned fluids
- Whether there is the treatment capacity to clean up the flowback and produced water
- The potential for reuse of water in the hydraulic fracturing process
- Protecting groundwaters during and after decommissioning

Water resources

Water is a renewable but finite resource. It has an economic value in all its competing uses, except crucially that for the environment. The failure to value water for environmental needs has been the root cause behind a large number of examples of environmental degradation.

Water abstraction is the process of removing water from natural sources such as rivers, lakes and aquifers and is regulated through a system of licences. Overabstraction can result in a decrease in the availability of public water supply, adverse effects on aquatic habitats and ecosystems from water quality degradation, changes to water temperature and erosion. There is also the potential for the underlying geology to become destabilised due to upwelling of lower quality water or other substances and as a result of a reduction in pore water pressure.

Demands on water vary across the UK and the amount of water available for use also varies geographically and temporally. The environmental regulator is responsible for deciding the maximum amount of water that may be taken from the environment for domestic and business use, without compromising environmental needs.

How much water is needed?

There are various processes involved in the hydraulic fracturing of shale and these involve differing amounts of water: drilling, fracturing and production. As described earlier (figure 1.3), the process is carried out in stages to fracture the shale progressively along the horizontal wellbore (lateral). This may take a few weeks with each stage taking around a day. Sites tend to alternate the operation between perforating a length of casing and then fracturing the rock, with each element taking around 24 hours in a non-stop rotating operation. Once the well has been drilled and fractured a significant amount of fracturing fluid (up to 80 per cent) returns to the surface as flowback fluid. Overall, when compared to the life time of a shale gas well the period for water demand is quite short and focussed at the early stages of the well.

Compared to other fossil fuels, experience from the US has shown that the water intensity is relatively low: (0.6 – 1.8 gal/MMBtu (million British Thermal Units) for shale gas, 1 to 8 gal/MMBtu for coal mining and washing, and 1 to 62 gal/MMBtu for onshore oil production[lvi]). The difference being with shale gas is that the water consumption is front loaded, used in the drilling and fracturing stage, so there is a large upfront water usage over a few days or weeks, after which the natural gas is produced over many months or years. As the hydraulic fracturing process itself is short operators may be able to choose the optimal time to fracture to avoid coinciding with times of water stress and drought.

Estimates of water use in the literature have ranged from 250 - 4000m^3 for drilling and 7000 – 23,000m^3 for hydraulic fracturing[lvii] per well. This large variation in estimates of water use reflects the complexity of drilling, geological conditions, borehole depth, pressure, thickness of the gas reservoir and other factors. Figure 2.1 shows the range of volumes for each stage and a comparison with regional and national water demand/abstraction. The scenarios are for a well (i.e. one lateral well). As suggested earlier the geology of the UK may provide more opportunity to drill a number of horizontal wells from the same vertical well which would proportionally reduce the volume of water required.

Process	Water use per well		Duration
	BGS figures[lvii]	AMEC figures[lviii]	
Drilling	0.25 – 4Ml	1-2 Ml	2 – 8 weeks
Hydraulic fracturing	7 – 23 Ml	10 – 20 Ml	5 – 7 weeks
Production	0 Ml (potential for reuse of returned water)		5 – 20 years
Comparison			
United Utilities water demand (Regional)[lviii]	12,180 Ml		1 week
National groundwater abstraction[lviii]	42,000 Ml		1 week
National surface water abstraction[lviii]	119,000 Ml		1 week

Figure 2.1 Comparison of water use and duration for stages of the hydraulic fracturing process. There is also water use associated with the processing of proppant.

NOTE: 1m^3 = 1000L = 10^3 L
1ML = 100000L = 10^6 L

lvi Mielke, Diaz Anadon, Venkatesth. 2010. Water Consumption of Energy Resource Extraction, Processing, and Conversion. Belfer Center for Science & International Affairs, Harvard University.

lvii BGS. 2013. Potential environmental considerations associated with shale gas literature review

lviii AMEC. 2013. Shale Gas: Water resources and groundwater – an overview. Presentation to CIWEM Shale gas conference 6th Nov 2013. Figures based on UKWIR "Understanding the potential impacts of shale gas fracking on the UK Water industry-Stage 1" and Environment Agency "Review of assessment procedures for shale gas well casing installation"

To put this into perspective, to meet ten per cent of the UK gas demand from shale gas over 20 years (9bn m^3 gas) would require 25 – 33 million m^3 of water, or 1.2-1.6 million m^3 per year[lix]. Although this may sound a large amount, when compared to licensed water abstraction per year in England and Wales (12.6×10^3 million m^3) it equates to less than $1/10^{th}$ of one per cent of total abstraction[lx].

Water use is therefore low in national terms, but there could be local or regional consequences should a large industry develop which will have to compete against different users. The key question will be how many wells there will be in a given area and over what timeframe will they be hydraulically fractured? The likely production scenario will see multiple wells stimulated across a field development, with many wells in production at the same time, depending on the number of operating sites. Modelling by AMEC has shown that for a regional scenario of 1000 wells, the estimated peak demand is 2.2 Ml/d. As figure 2.1 shows the amount of water a single company might be asked for is small in comparison to other demands. This is just one scenario and many others are possible, for instance with more recycling of water the demand would be less, but it is indicative of the likely scale of water use.

Where will the water come from?

Water sourcing is largely a local issue as by its nature water can be energy intensive to transport. Water interconnectivity is fairly limited in the UK although more water transfers and trades are beginning to take place.

Shale gas operators have the option to source water directly from the environment via abstraction, purchase it from a water company and receive it via the mains or from tankers or they may recycle a proportion of their own water.

If they source water from the local area by abstracting it directly from a river or groundwater source they will need a licence from the relevant environmental regulator. A licence would only be granted where there is a sustainable source of water as assessed by the EA's Catchment Abstraction Management Strategy (CAMS) (see figure 2.2). Potential abstractors also need to demonstrate to the EA that their operations will not damage European Habitats and Birds Directives sites before an abstraction licence will be granted.

The CAMS process provides information on how much water is available for future abstraction licensing (new water resources) on a catchment by catchment basis[lxi]. The 2012 analysis shows that twenty five per cent of water bodies in England and seven per cent of water bodies in Wales will provide a reliable source of water for abstraction for less than 30 per cent of the time (pale blue in figure 2.2)[lxii]. This means that there are unlikely to be many new abstraction licences issued in these areas.

Where there is overlap in water stressed catchments and shale gas licence areas, operators will need to be aware of the risk that water may not be available in the future. The north west is generally much less water stressed than the south east (in terms of the overall supply-demand balance, except in a few zones such as Cumbria). Early engagement with the EA or local water company, depending on where the water is sourced, will be important to ascertain available volumes. CIWEM considers that shale gas operators should provide a profile of water use and flowback over life of the shale well to help establish any pinchpoints in supply. This point is returned to in *future water resource availability.*

lix Broderick. J., et al: 2011, Shale gas: an updated assessment of environmental and climate change impacts. The Co-operative, undertaken by researchers at the Tyndall Centre, University of Manchester

lx Environment Agency. 2011. The case for change – current and future water availability

lxi Environment Agency. 2013. CAMS webpage

lxii Environment Agency. 2011. The case for change – current and future water availability

Comparison of water resource availability with areas with indicative geology for shale gas

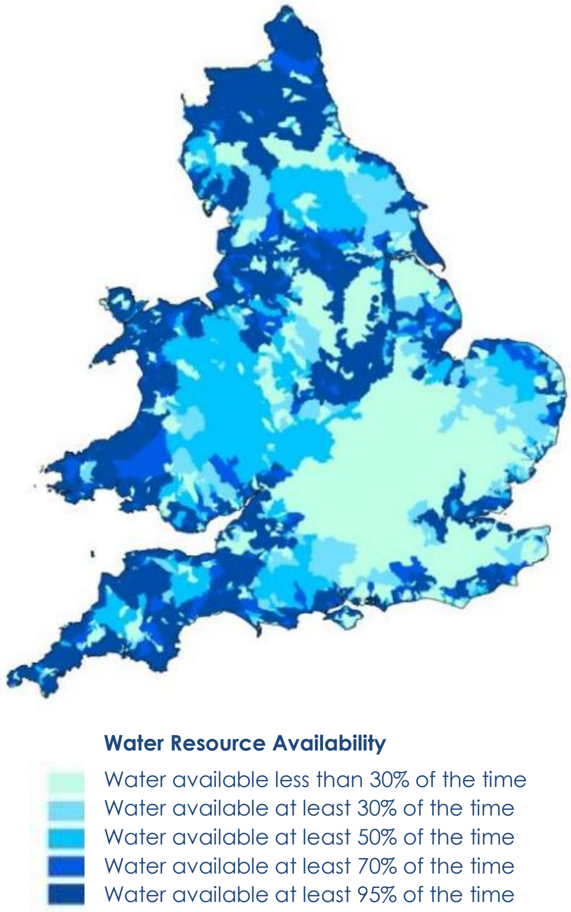


Figure 2.2 Water resource reliability: percentage of time water would be available for abstraction for new licences. EA and CEH, 2012[lxiii].

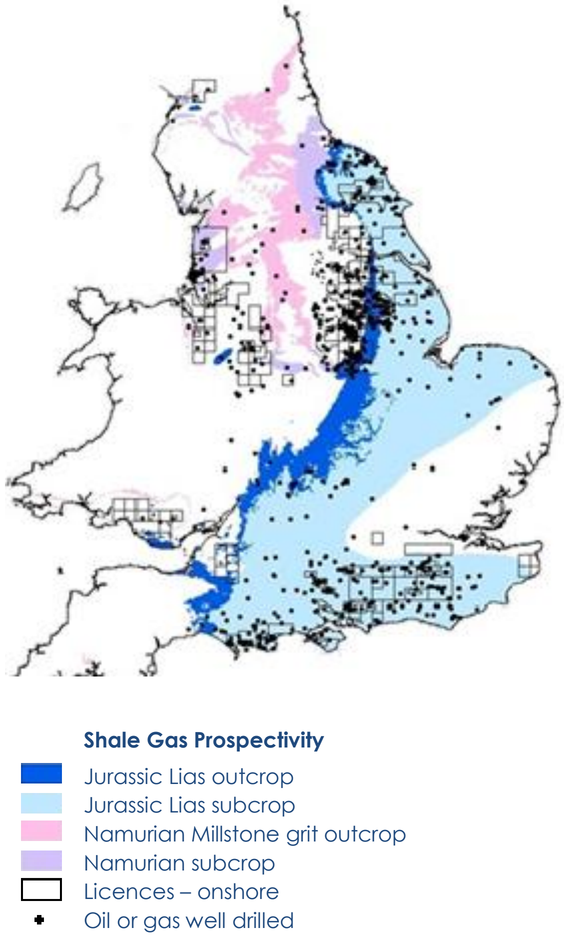


Figure 2.3 Shale gas prospectivity, 2013, DECC[lxiv]. NOTE: DECC's licences do not distinguish between shale gas and other forms of hydrocarbons.

Operators may source water directly from the public water supply. The exploration that has already taken place in the UK such as Cuadrilla's in the north west utilised water from the mains supplied by United Utilities. Under the Water Industries Act 1991[lxv] a water company has a duty to provide water for non-domestic purposes but this is subject to certain exceptions. Usage of mains supplies requires the agreement of the water company, and that such supplies are available[lxvi]. If a public water supply is used then any additional infrastructure that will have to be put in place to transport the water will be at the expense of the shale gas operator.

If there is no network nearby, a shale gas operator can purchase the water from a water company and have it transported by tanker. Although tankering can solve problems with local water stress and the need for water infrastructure, there are the additional impacts from intense truck movements which have certainly led to public disquiet in the US. There may also be a need to reinforce the road network in some of the prospective areas of shale

lxiii Environment Agency. 2013. Managing Water Abstraction
lxiv DECC. 2013. The Unconventional Hydrocarbon Resources of Britain's Onshore Basins - Shale Gas
lxv Water Industries Act 1991
lxvi House of Commons Energy and Climate Change Committee; *Shale Gas: Government Response to the Committee's Fifth Report of Session 2010–12.*

gas to support the increased number of vehicle movements, and additional health and safety risks from accidents or spills.

There may be scope for larger companies to recycle their water for future fractures following the treatment of flowback water. The returned water can be between 20-80 per cent by volume of that put into the ground. This would require treatment on site (see more information below). Some[lxvii] have suggested the use of seawater to avoid the water stress issue. However the water used does have to be of a certain input quality; treated water is more ideal as it is already clean and has a built in biocide from the chlorine that is routinely added to supply. At present it is cheaper to use pre-treated mains water than to treat sea-water so it is likely that this practice will continue. Research is also underway to look into hydraulic fracturing with lower quality waters and also waterless techniques.

The industry body Water UK claim that in reality, water sourcing is likely to vary from site to site. It foresees a number of approaches, with a connection to the mains augmented with recycled water, on site storage and tankers to meet the peak demands[lxviii]. The configuration may vary locally and perhaps even seasonally.

Future water resource availability

With production not expected until further into the 2020s[lxix] it is worth looking at the future water resource availability. Water availability is due to decline in the future due to the demands of a growing population and the permitted quantity that will be able to be taken from the environment will also decrease from the impacts of climate change, sustainability reductions required under the Water Framework Directive and the Government's intention to reform the abstraction regime to correct historical over-abstraction.

The European Water Framework Directive (WFD)[lxx] came into force in 2000 and was transposed into UK law in 2003. Its purpose is to enhance the status, and prevent further deterioration, of the ecology of aquatic ecosystems and their associated wetlands and groundwater. Around 13 per cent of river water bodies in England and four per cent in Wales are failing to support Good Ecological Status (GES) due to over abstraction[lxxi]. As a result the WFD requires water companies to take less water out of natural resources in the form of 'sustainability reductions'. This could be up to eight per cent per AMP (the water industry's five year asset planning cycle).

One of the biggest pressures on water resources is projected population growth. By the 2030s, the population of England is expected to grow by an extra 9.2 million people and 0.4 million people in Wales[lxxii]. This is not evenly distributed with London, the east and the East Midlands regions all projected to grow at a faster rate than the rest of the country[lxxiii]. Combined with other trends, such as the increasing number of smaller households which can lead to rises in personal consumption, overall demand for water is likely to grow, with some scenarios suggesting growth of around five per cent by 2020 and as much as 35 per cent by 2050[lxxiv].

lxvii Rao, V. 2012. Shale Gas: the promise and the peril.
lxviii Marshall, J. (Water UK). Understanding the impacts of shale gas on the UK water industry. Speech given at UK Shale 2013, 17 July 2013
lxix DECC. 2012. Gas Generation Strategy
lxx EC. 2000. Directive 2000/60/EC of the European Parliament and of the Council of 23 October 2000 establishing a framework for Community action in the field of water policy
lxxi Environment Agency. 2013. Managing Water Abstraction
lxxii ONS. 2009. National Population Projections Statistical Bulletin – 2033 projections
lxxiii ONS. 2012. 2010-based sub national population projections for England
lxxiv Water Resources in the South East Group. 2013. Water Framework Directive

Climate change is likely to alter the water cycle significantly in the future. The amount and distribution of rainfall will vary[lxxv], a reduction of 40 per cent in summer rainfall by the end of the century may occur in the south of England[lxxvi] and there are likely to be changes to the frequency of drought conditions[lxxvii].

The geology, soils and vegetation of the UK are varied, and these lead to different hydrological responses to rainfall. In the north and west of England the surface geology is relatively impermeable so rainfall tends to run quickly into in streams and rivers and water sourced from surface water dominates. In the south and east chalk rock and the overlying superficial deposits are more permeable leading to water sourced from groundwater. Surface water responds more quickly to rainfall events than groundwater.

Our current understanding of the impact of climate change on water resources in England and Wales is based on the Future Flows[lxxviii] project by Defra, BGS, CEH and partners. This work used the UKCP09 scenarios and ran them through river flow and groundwater models to produce river flow maps of changes for the 2050s. There are large uncertainties around the extent of the changes. Most scenarios indicate decreases in flows, especially in the south and east (up to -80 per cent) whilst in the west and north changes can be small:

- *For surface water in winter there is a mixed picture with between a +40 per cent or -20 per cent change in water availability. In summer scenarios predominantly show decreases in runoff, ranging from +20 per cent to -80 per cent.*

- *The picture for groundwater is still unclear. Early results suggest that in some climate scenarios increased winter rainfall leads to increased recharge and higher groundwater levels that persist into the summer, but in others recharge reduces, leading to lower groundwater levels and reduced availability of groundwater for abstraction.*

The EA's report on current and future water availability[lxxix] uses scenarios to combine the impacts from the pressures on water resources in the future and predicts an overall decrease in the amount of water available. It is for Water Companies to plan for how they will meet these challenges. Water Resource Management Plans (WRMPs) are produced every five years by water companies to assess how much water will be needed for the next 25 years.

Although current abstraction licences issued take into account population growth and climate change to protect the environment, existing licences that may have been granted decades ago may not provide the level of protection that is required today. As a result Defra and the EA are currently looking at reforming the abstraction system to consider alternative options for water allocation and charging while protecting environmental flows in the future. This means there may be fewer licences or volumes per licence available from 2020 which could affect shale gas operators.

Many of the locations of onshore licences on the Weald in the south east coincide with areas that are already over-abstracted and where fewer resources will be available in the future (figures 2.2 and 2.3). Recent estimates based on Environmental Flow Indicators for each water company in the south east suggested that the total target of sustainability reductions could be as much as 50 per cent higher than original estimates from the EA[lxxx]. This is a considerable challenge to the companies who must also deal with increased demand and the pressures of climate change.

lxxv Environment Agency. 2011. The case for change – current and future water availability
lxxvi LWEC. 2013. Climate change report card
lxxvii Met Office. 2010. An extreme value analysis of UK drought and projections of change in the future. *Journal of Hydrology.*
lxxviii Defra, EA, CEH, BGS, NERC, UKWIR and Wallingford hydrosolutions. 2012. Future Flows and Groundwater Levels.
lxxix Environment Agency. 2011. The case for change – current and future water availability
lxxx Water Resources in the South East (WRSE) http://wrse.org.uk/water-framework-directive

However the south east has particular scope to share extra headroom. Currently Southern Water can receive 15 million litres water a day from Portsmouth and supply 31 million to South East Water, 1.3 million to Affinity and 0.3 million to Wessex Water. Water Transfers are likely to become more common locally as a result of the Water Bill. South East Water has noted that hydraulic fracturing has not been specifically included in its WRMP but will consider it on a case by case basis[lxxxi].

Water resources in the north west can be prone to drought as it is typically surface water fed and is predicted to have the largest percentage decrease in rainfall from climate change. United Utilities WRMP states: "*we do not consider that the provision of water for hydraulic fracturing would impact on the water resources available across our region, but we will assess each request on a site by site basis to ensure that the supplies to our existing customers are not affected*[lxxxii]".

Looking at the potential shale gas licence areas, if an industry were to develop it is likely to affect Southern Water, Sutton and East Surrey Water, South East Water, United Utilities and perhaps Thames Water, Yorkshire Water and Severn Trent Water. A Memorandum of Understanding (MoU) has been signed by the industry bodies UKOOG and Water UK specifying that the shale gas industry should produce "*onshore oil and gas company development plans, including scenarios for expansion of exploration and development within a local area and what this means for short and long-term demand for water at specific locations*"[lxxxiii].

CIWEM is fully supportive of this approach and believes it should benefit all parties in planning water resources for the future. However we consider it would also be of great benefit to go a step further and have the water and sewerage companies become a statutory consultee in the planning process of shale gas operations to ensure that they are engaged with from the outset to plan for future water demand and any associated water treatment.

lxxxi South East Water. 2013. Draft Water Resource Management plan

lxxxii United Utilities. 2013. Draft Water Resources Management Plan

lxxxiii Water UK and UKOOG. 2013. Water UK and UKOOG to work together to minimise the impact of shale gas development on water resources in the UK. Press release 27/11/13

Potential for contamination of groundwater and the local environment

A frequently expressed concern associated with shale gas operations is that contamination of groundwater could occur. This may result from a catastrophic failure or loss of integrity of the wellbore, or if methane or contaminants can travel from the target fracture through subsurface pathways[lxxxiv]. There is also the potential for pollution of the local land and water environment if the returned water from the hydraulic fracturing process is not appropriately contained, managed, and treated prior to eventual disposal. Any material spilt on or applied to the ground has the potential to reach the water table. Whether it will or not depends on the material involved and the ground conditions at that site.

What is in the fracture fluid?

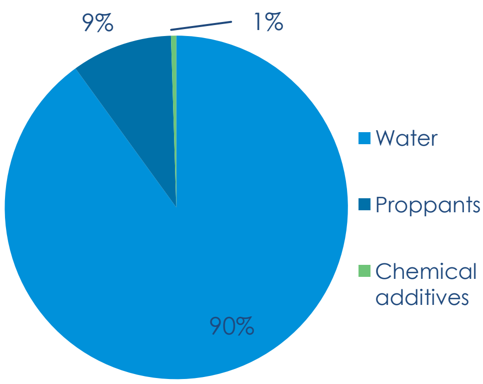


Figure 2.4 Constituents of fracture fluid

Hydraulic fracturing fluid is generally made up of water, sand and chemical additives (figure 2.4). A proppant is added to the hydraulic fracturing fluid to keep the induced fractures open in the rock; this is a granular material, usually sand. Other commonly used proppants include resin-coated sand, intermediate strength proppant ceramics, and high strength proppants such as sintered bauxite and zirconium oxide. After water and sand, chemical additives make up 0.05 – 2 per cent of the hydraulic fracturing fluid. These may be added to act as biocides, acids, friction reducers, corrosion inhibitors, gelling agents, scale inhibitors, pH adjusting agents etc.

In the US the typical constituents include hydrochloric acid, polyacrylamide, isopropanol, potassium chloride, ethylene glycol, sodium carbonate and citric acid[lxxxv]. There has been much controversy in the past over the disclosure of chemical additives within hydraulic fracturing fluid in the US; when a Congressional Committee launched an investigation into products used between 2005 and 2009, it found the use of toxic and carcinogenic substances, such as benzene and lead[lxxxvi].

The UK is keen to avoid such controversy. Using information from the shale gas operator the EA will assess whether an additive is hazardous or a non-hazardous pollutant using a methodology that follows the requirements of the Groundwater Daughter Directive and under the EA technical guidance WM2[lxxxvii]. The Directive requires that no hazardous substances are allowed to enter groundwater and that non-hazardous pollutants do not cause pollution. The EA expects shale gas operators to propose only non-hazardous substances. Cuadrilla has disclosed that it has only used polyacrylamide in fracturing activities to date.

Shale gas operators will need to keep EA informed of the nature and quantities of the chemicals they propose to use in the hydraulic fracturing process, including carrier fluids, at the pre-application and planning application stages. They will also need to confirm their

lxxxiv Stuart, M.E. 2012. Potential groundwater impact from exploitation of shale gas in the UK. British Geological Survey

lxxxv Gregory, 2011 and Ground Water Protection Council and ALL Consulting, 2009 in Stuart, M.E. 2012. Potential groundwater impact from exploitation of shale gas in the UK. British Geological Survey. A full list is available at FracFocus chemical disclosure registry

lxxxvi US House of Representatives Committee on energy and commerce. April 2011. Chemicals used in hydraulic fracturing.

lxxxvii Environment Agency. 2013. Hazardous Waste WM2 Guidance proposals at the permitting stage. This ensures that the proposed borehole construction, casing and completion can be assessed as adequate. Approval for the use of chemicals in shale gas operations will be considered on a case by case basis as part of the environmental permitting process. Allowing the use of a chemical at one site may not mean it will be automatically allowed elsewhere as the site conditions and environmental risks may vary[lxxxviii].

There is however a concern that as we reach the production phase, to achieve greater drilling efficiencies, companies may push for the use of more chemicals or more hazardous chemicals to be used. Yet in the UK under European REACH regulations if more than a certain volume (1 tonne per year) of a chemical is to be used the chemical has to be registered and assessed for the specific use. Each EU member country is responsible for appointing a regulatory agency (the EA) who is responsible for ensuring that REACH regulations are abided by. Under the UKOOG guidelines all operators will be expected to disclose all chemicals by name, volume and concentration on their website and also on UKOOG's website.

On-site spills or leaks could potentially occur during the transportation of chemicals to the site and in the mixing and preparation of hydraulic fracturing fluids (see more on storage and transportation below). The baseline monitoring of aquifers and surface water prior to fracking and related activities as well as continuing monitoring during and after production has been agreed by the industry. Any monitoring programme needs to focus on the detection of the chemicals used in the fracking fluid[lxxxix].

Groundwater protection

Groundwater supplies about one third of mains drinking water in England and up to 10 per cent in Wales. It also supports numerous private supplies. Groundwater is water stored below the water table in rocks or other geological strata called aquifers. It is usually well protected from contamination from the overlying soil and rock, however protecting groundwater is essential as once it becomes polluted it is difficult to clean up[xc]. Under existing regulations shale gas companies can be fined if they cause pollution.

Three main regulatory frameworks are in place to protect groundwater:

- operators monitoring well integrity under Health and Safety regulations;
- the appropriate design and operation of surface operations, governed by the land use planning process; and
- the permitting of treatment and disposal by the appropriate environmental regulator, e.g. EA, SEPA, NRW, NIEA.[xci]

Under the WFD water bodies that are used for the abstraction of drinking water have to be delineated and designated drinking water protected areas (DrWPAs). All groundwater bodies in England and Wales are classified as DrWPAs due to the low abstraction thresholds set in the Water Framework Directive. Article 7.3 requires the protection of these water bodies "*with the aim of avoiding deterioration in their quality in order to reduce the level of purification treatment required in the production of drinking water*".

The potential for shale gas extraction and related activities to impact on public drinking water supplies is considered minimal as the Water Supply (Water Quality) regulations provide

lxxxviii EA assessments are peer-reviewed by the Joint Agencies Groundwater Directive Advisory Group (JAGDAG) made up of representatives of the UK environment agencies, the Environmental Protection Agency of the Republic of Ireland, the Health Protection Agency, Defra, the Welsh Government and industry.

lxxxix Public Health England. 2013. The potential public health impacts of exposures to chemical and radioactive pollutants as a result of shale gas extraction. Presentation to CIWEM shale gas conference 6th Nov 2013.

xc Environment Agency. 2013. Groundwater Protection Principles and Practice (GP3) Guidance

xci DECC. 2013. About shale gas and hydraulic fracturing (fracking).

for the protection of the public from any substance or organism likely to cause a threat to public health. The regulations require Water Companies to assess risks to their supply systems, identify any potential hazards and have appropriate mitigation measures in place. Local authorities will also need to consider the implications for their risk assessments of private water supplies.

One way to protect groundwater is to ensure that shale gas operations do not take place in the nearby area. Figure 2.5 shows the locations of principal aquifers in the UK and source protection zones. There is an overlap in the north west, north east and south east with licence areas, although these maps do not illustrate the underlying geology or depths of aquifers. The UK has a complex geological sequence that needs to be understood to assess the risks. The BGS and EA are currently mapping the three dimensional spatial relationship between potential shale gas source rocks and principal aquifers in England and Wales.

The EA's groundwater guidance[xcii], states that it will object to shale gas extraction infrastructure or activity within Source Protection Zone 1[xciii] (SPZ1) through planning or permitting controls. There should be no drilling activity within an SPZ1, although horizontal drilling deep below the base of this aquifer may be acceptable. Outside of SPZ1, the EA will also object where the activity would have an unacceptable effect on groundwater, or if it is close to sensitive receptors it will adopt the precautionary principle.

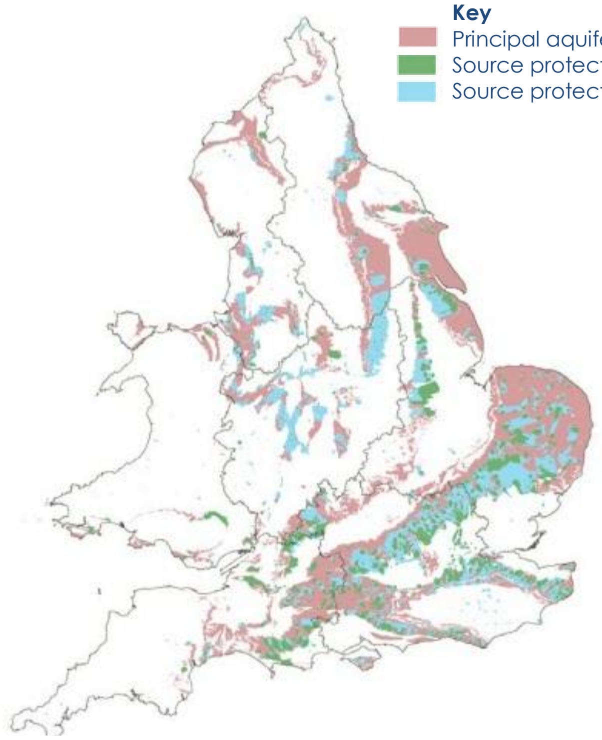


Figure 2.5 Principal aquifers and source protection zones in England and Wales, 2013, EA[xciv]

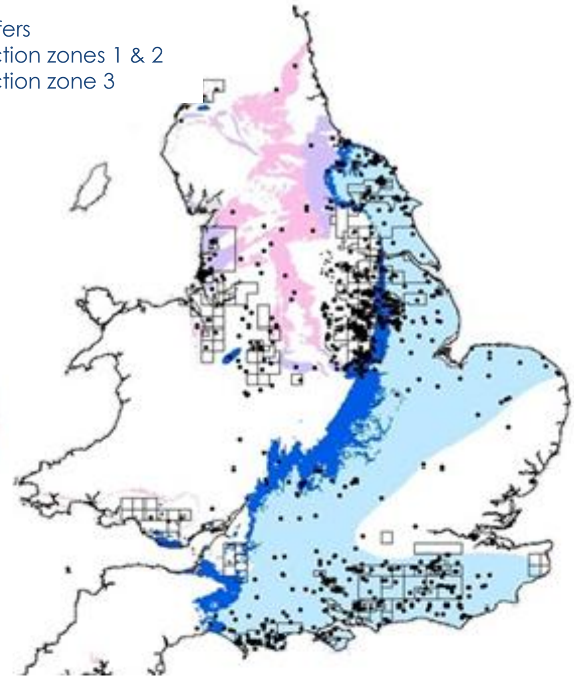


Figure 2.6 Shale gas prospectivity, 2013, DECC[xcv]

xcii Environment Agency. 2013. Groundwater protection: Principles and Practice (GP3)

xciii SPZs are used to identify areas close to drinking water sources where the risk associated with contamination is greatest. SPZ1 is the inner source protection zone defined by 50-day travel time of groundwater from the borehole and a minimum 50 metre radius. SPZ2 is the outer protection zone defined by a 400-day travel time from a point below the water table. SPZ3 is the source catchment protection zone defined as the area around a source within which all groundwater recharge is presumed to be discharged at the abstraction source.

xciv Environment Agency. 2013. Groundwater protection: Principles and Practice (GP3)

xcv DECC. 2013. The Unconventional Hydrocarbon Resources of Britain's Onshore Basins - Shale Gas

Contamination of groundwater from poor well design or failure

Wells can provide the pathway for pollutants (figure 2.7). The most likely pathway of contamination to groundwater is from failure of the cement or casing surrounding the wellbore. The industry has oil and gas well integrity guidelines which specify the design and number of casings of the well which are determined by its depth and the zones of separation.

The EA expects that where a shale gas development does proceed, there will be established good practice in groundwater protection applied where any associated drilling or operation of the boreholes or shafts passes through a groundwater resource. Groundwater including any local aquifers should be carefully delineated by the operator as part of the well design and fracturing risk assessment process.

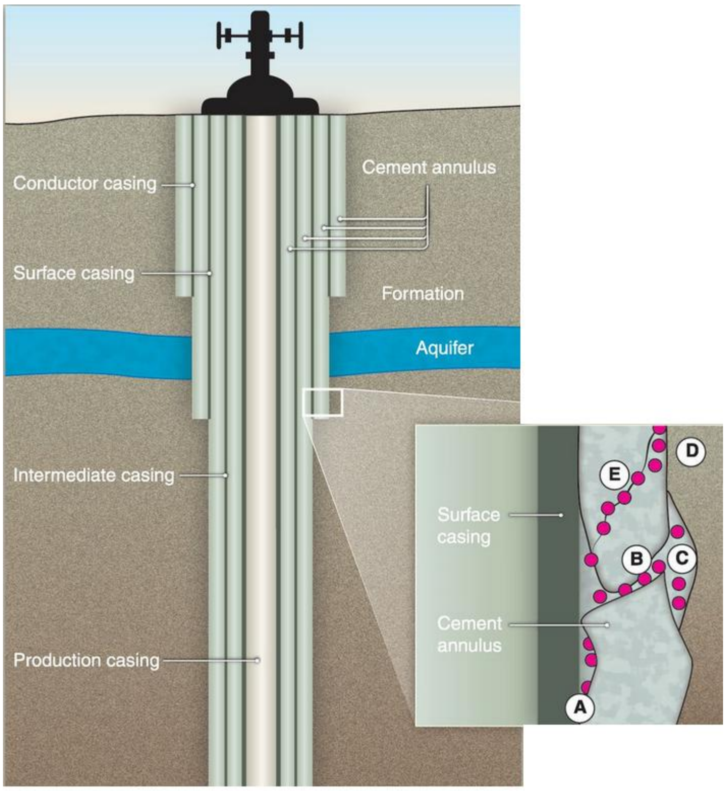


Figure 2.7 Shale well and potential for cement failure (not to scale)[xcvi]
A between cement and casing
B through fractures
C through gaps
D between cement and formation
E through cement

The Offshore Installations and Wells (Design and Construction, etc) Regulations 1996[xcvii] apply to all wells drilled with a view to the extraction of petroleum regardless of whether it is onshore or offshore. These specify that the operator should ensure that there can be no unplanned escape of fluids from the well.

During drilling the operator must case off the aquifer and pressure test each casing before changing to a non-freshwater mud or on encountering hydrocarbons. Cementing is a critical part of well construction and is a fully designed and engineered process. The cement must be properly set or the gas has an easy access route up to the aquifer along the annulus outside of the pipe. Best practice is to cement casings all the way back to the surface, depending on local geology and hydrogeology conditions[xcviii]. Operators should use best available techniques[xcix] and industry standards for cement to ensure risks are minimised. Cement evaluation tools often known collectively as cement bond logs can be used to support other evidence to determine if the casing has been successful or not.

On completion of drilling, the process of hydraulic fracturing and induced seismicity could itself damage the well casing and affect well integrity. DECC licensing requires seismic monitoring to assess likely faults and thus potential impact on well integrity using a traffic light

xcvi From http://www.rheothing.com/2013_05_01_archive.html
xcvii The Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996
xcviii Royal Society and RAEng. 2012. Shale gas extraction in the UK: a review of hydraulic fracturing. Chapter 3
xcix Such as such as API, BS and ISO, these are detailed in appendix 4 of the UKOOG guidance

monitoring system. If a seismic event is determined to be large enough by the monitoring system then operations will cease. The well can then be repaired.

There has been widespread public concern over well failure with an industry report[c] estimating that by the time a gas well is 15 years old there is a 50 per cent chance of failure, and two out of four of Cuadrilla's wells in Lancashire have failed. These are alarming statistics, however in spite of any drilling-related difficulties; the term failure does not necessarily mean any indication of leakage of contaminants to the environment, and this was not the case in Lancashire[ci].

Well failure refers to the failure of any barrier element within a multiple barrier system and is reported to the appropriate regulatory agency[cii]. Failure to pass a barrier test does not mean that a leak to the surrounding environment has or will occur and rigorous well testing can help to identify any potential problems that can then be repaired. The multiple barrier system enables the optimum level of protection through the geology within which the bore is drilled.

Responsibility for the monitoring of well integrity, and ensuring the competence of those doing so, lies solely on the well operator as duty holder. There is also an independent well examiner. Monitoring of well operations during construction are based on weekly operations reports submitted to HSE by the well operators to ensure the construction matches the design, alongside both planned and subject to ad-hoc site inspections. The HSE's role is one of sampling to verify that regulations are complied with and taking appropriate enforcement action where they are not.

Contamination of groundwater due to the mobilisation of solutes or methane

Another concern is that from the potential contamination of groundwater from the mobilisation of solutes or methane as a result of the fracturing process deep underground. Due to the much greater depths at which some UK shales are likely to be exploited compared to the US, there is less risk to groundwater from the mobilisation of solutes or methane as it would have to migrate through many hundreds of metres and many layers of rock to reach an a freshwater aquifer. The BGS believes such contamination is unlikely to occur if shale gas exploitation is restricted to depths greater than 1500m[ciii].

Hydraulic fracturing could take place at shallower depth so to reduce the risks companies will have to ensure that fracture sequences are monitored. UKOOG guidelines suggest[civ] operators develop a Hydraulic Fracturing Programme (HFP) "*that describes the control and mitigation measures for fracture containment and for any potential induced seismicity*". This should include the proposed design of the fracture geometry including target zones, sealing mechanism and the location of aquifers, so as not to allow fracturing fluids to migrate to groundwater. Fracturing operations should be monitored using performance standards, these will be well-dependent but might include microseismic and tiltmeter monitoring of hydraulic fracture growth. The HFP and fracturing operations should be examined as part of the well examination arrangements.

The EA has stated that a permit[cv] will be required if it considers well stimulation might lead to the movement of pollutants into adjacent groundwater that would not otherwise have

c Schlumberger. 2003. From mud to cement. Oilfield review
ci Green, Styles & Baptie. 2012. Preese Hall shale gas fracturing review and recommendations for induced seismic mitigation
cii Conoco Phillips. 2013. Onshore well integrity fact sheet.
ciii Stuart, M.E. 2012. Potential groundwater impact from exploitation of shale gas in the UK. British Geological Survey
civ UKOOG. 2013. UK Onshore Shale Gas Well Guidelines: Exploration and appraisal phase.
cv Under The Environmental Permitting (England and Wales) Regulations 2010

received them. There is a complex relationship between the shale and the aquifer and CIWEM believes a thorough evaluation of geological and hydrogeological setting by a suitably qualified geologist should be undertaken by the operator and scrutinised by the EA who could place conditions such as a maximum fracture growth height.

Methane is a common trace component of groundwater so the presence of methane in an aquifer is not proof of contamination. Methane in groundwater is formed by one of two processes: biogenic and thermogenic. Biogenic methane is bacterially produced and is associated with shallow anaerobic environments (e.g. peat bogs, wetlands) and is generally the most common form of methane detected in shallow groundwater. Thermogenic methane is formed from thermal decomposition of organic matter at depth and under high pressures and is often associated with coal, oil and gas fields. Conventional natural gas is thermogenic gas.

In the UK most methane in groundwater is likely to be biogenic in origin, although thermogenic contributions may be locally important where gases have migrated from depth or there is slow release from previously deeply buried, low permeability, organic-rich rocks[cvi]. The depth of shale gas extraction makes it difficult to track and attribute pathways of contamination of groundwater from the extraction process. However biogenic and thermogenic methane have different characteristics so dissolved gas and stable isotope analysis of groundwater samples can be used to identify the different sources and potential origin of methane.

The BGS is undertaking a national baseline survey of methane, covering all prospective areas for shale gas in England and Wales as suggested by the Royal Society/Royal Academy of Engineering review[cvii]. Initial results were published in June 2013[cviii]. These data will enable environmental regulators to understand background methane levels prior to assessing permit applications[cix] and provide a baseline from which any future changes can be measured.

Risk of contamination from flooding

There is a risk based approach to preventing operations in areas of flood risk. Local planning authorities' Strategic Flood Risk Assessments will assess the risk to an area from flooding from all sources (including rising groundwater and from 'artificial sources') to inform land use planning. A site-specific flood risk assessment is required for all developments in areas where flooding is an issue, and for all development sites of at least one hectare, and the environmental regulators can also incorporate conditions into a site's environmental permit to ensure that flood risk is managed appropriately. Surface water flooding may need to be a greater consideration, where climate change predicates more extreme weather events.

A surface water drainage system is necessary to ensure controlled waters are not polluted and this should be detailed to the EA. The applicant should include construction details, including the design of tanks and reference to how ditches will be lined. They should also provide rainfall and runoff calculations to demonstrate that the drainage system can accommodate storm events. This is relevant because if the drainage system or tanks are inadequate and become surcharged, it could lead to contaminated surface water running off the site. In the event that a discharge is proposed, further information and an appropriate permit application will be required.

cvi BGS. 2013. Baseline methane survey of UK groundwaters webpage

cvii Royal Society and RAEng. 2012. Shale gas extraction in the UK: a review of hydraulic fracturing.

cviii BGS. 2013. Baseline methane survey of UK groundwaters webpage

cix DECC. 2013. About shale gas and hydraulic fracturing (fracking).

Management of flowback and produced water

Flowback and produced water are the returned waters which flow back up the well following the hydraulic fracturing process. The quantity of the returned waters will relate to the amount that was used in the fracturing process and is produced over a period of several months. It is expected this will range from 1,000 to 10,000m^3 per well based on anecdotal evidence from the US and subject to the geological conditions encountered.

Typically between 20-40 per cent returns to the surface in the first few days to a week, and is stored in holding and treatment tanks[cx]. This relatively low proportion in comparison to the volume initially pumped down the well is due to the dessicated nature of shale, which absorbs much of the initially injected water. Of the water that remains underground, much of it returns to the surface, up the bore with the gas, over the lifetime of the well at a slower flowrate. Returned waters can be up to 80 per cent of the volume pumped into the ground.

Flowback and produced water returns to the surface with a range of organic and inorganic substances in solution or suspension, including heavy hydrocarbons, naturally occurring radioactive materials (NORMs), a range of minerals and salts representative of the geology, as well as a small proportion of the proppants and lubricant substances which were added prior to fracturing. It is another potential source of contamination, be that to soil, surface or groundwater from spills.

Within Europe, flowback and produced water is classified as mining (or 'extractive') waste under the EU Mining Waste Directive. This means that an operator is required to obtain an environmental permit[cxi] from the EA (NRW, NIEA or SEPA) to send the water to a wastewater treatment works, or to safely dispose of the returned water.

Sites will have to produce and implement a Waste Management Plan. This will need to state the characteristics of each waste[cxii] and the estimated total quantities of extractive waste that will be produced. It will also need to consider how waste can be reduced and its harmfulness and any subsequent treatment of each waste should be indicated.

In order to effectively manage any radioactive component, a radiological assessment will also be required for any application for a permit to dispose of radioactive waste. This will be a case specific consideration and disposal routes must again be through appropriately permitted facilities. If flow back or produced water is found to contain a sufficiently high concentration of radioactive material, it will require a Radioactive Substances Regulation (RSR) permit under Schedule 23 of the EPR[cxiii] from the EA. Sands, sediments, scales and sludges in gas, oil or water process vessels may become contaminated and may also need to be covered by a permit; they will need to be assessed against the threshold concentrations in the EA's technical guidance[cxiv].

Storage

It is likely that storage would only take place whilst flowback and produced water were being treated on site for re-use or was awaiting collection for transportation to an appropriate treatment works. Guidance from the EA states that storage of flowback fluid should be for as short a time as is reasonably practical and should be indicated in the site's

cx Cuadrilla. 2013. Website
cxi The Environmental Permitting (England and Wales) Regulations 2010
cxii As laid down by Annex II of the Mining Waste Directive. The wastes should be characterised accurately as inert, non-hazardous non-inert, or hazardous
cxiii The Environmental Permitting (England and Wales) Regulations 2010
cxiv Environment Agency. 2013. Hazardous Waste WM2 Guidance

waste management plan[cxv]. In the future there may be more need for onsite storage as water resource issues and treatment capacity could present issues with downtime.

It has been common practice in the US to store flow back and produced water temporarily on site in specifically constructed containment ponds. These ponds are one of the most visible and readily identifiable components of a shale gas pad, which also contribute considerably to their footprint in terms of land take. However due to concerns over the release of fugitive emissions and for pond liners to leak, under the UKOOG guidelines appropriate above ground tanks that are fit for purpose and meet industry standard practice for fluid storage is recommended to ensure no risk of fluid leaks or spillages[cxvi]. The EA's draft technical guidance explicitly prohibits the use of open lagoons for storage of produced water and bunded storage tanks will be needed for any radioactive wastes.

Transportation

On-site spills or leaks could potentially occur during the transportation of returned waters that require treatment. Preventative measures should be included in the waste management plan. If the waste is determined to be hazardous, those involved in its transportation must be a carrier licensed by the EA to transport hazardous or industrial wastes and undertake it in appropriate tankers. The levels of waste arising will have to be assessed against the Carriage of Dangerous Goods regulations[cxvii]. Shale gas operators are keen to develop onsite treatment processes so that they reduce the risks associated with transporting hazardous waste.

Treatment

The nature of the substances concerned mean that the water may not be of an appropriate chemical composition to be sent to a typical municipal wastewater treatment works and may require specialist industrial treatment or pre-treatment in order to enable this. It may be highly saline and contain NORMs but the exact composition, pH and other characteristics will vary depending on geological characteristics as well as timing. Flowback associated with the initial fracture may contain higher concentrations of chemicals than the latter produced water which reaches the surface together with the gas during the production phase.

It is the responsibility of shale gas operators to undertake laboratory and batch scale trials of these wastewaters and ensure that they are disposed of through an appropriately licensed facility. There are three possible avenues open to operators for treatment, reuse or disposal of flowback and produced water:

- On-site treatment in order to allow re-use of a proportion of the water (usually blended with fresh water prior to re-use), with disposal of any solids and effluent to an appropriately licensed treatment and disposal facility;
- Removal from site, either via constructed pipeline or tanker, to an appropriately licensed treatment and disposal facility; or
- Discharge to a foul sewer with treatment at a municipal wastewater treatment works (with appropriate permission of the environmental regulator and the water utility in question). Peak flows to the sewer can be controlled by the closing of a well and by storing any additional produced water on site.

Assuming that the contaminant profile of flowback and produced water is appropriate for treatment at a municipal wastewater treatment works, a local water company should be

cxv Environment Agency. 2013. Consultation on technical guidance for onshore oil and gas exploratory operations
cxvi UKOOG. 2013. UK Onshore Shale Gas Well Guidelines: Exploration and appraisal phase.
cxvii The Carriage of Dangerous Goods and Use of Transportable Pressure Equipment Regulations 2009 (CDG 2009)

willing to receive it if they had the right permits in place. Wastewater that does not contain NORMs will not pose a technical problem and the only issue will be the cost of treatment.

If NORMs are at a level that requires a facility to have the requisite permit, then this could have a major financial implication, to the extent that may question the financial viability of hydraulic fracturing from that particular site. Water companies will have to balance the costs of permitting and compliance for receipt of NORMs and a highly saline waste against the benefits of increased business. Shale gas operators will need to inform water companies over the volumes and timescales of discharge so they can calculate if the waste can be accepted. If a water utility was unwilling to receive wastewaters containing NORM, there would be a need to send the water to a more specialised industrial wastewater treatment plant, of which there are many in a competitive market[cxviii].

Treatment facilities will need:

- Experience of operating the acid/alkali treatment process[cxix]
- An environmental permit required under Schedule 10 of EPR2010
- To be in close proximity to the source of the waste
- Spare capacity
- Permitted to accumulate and dispose of radioactive waste under Schedule 23 of EPR2010;
- Radiological Impact Assessment of the discharge to sewer and resultant release to the environment.

Thermal processes and reverse osmosis have been the most common treatment processes in the US and Australia[cxx]. Other options are available but can rapidly increase the energy used in treatment. The easiest option to treat the highly saline waste would be to use a treatment works that discharges into an estuary to reduce the need for dilution. It may be cheaper to transport the material to such a treatment plant, rather than expensive salinity reduction before discharge into a freshwater receiving watercourse (depending of course on how far the site is from an estuary).

Concern has been expressed about experiences in the US with some municipal treatment works having significant problems coping with both the volume and chemical composition of wastewaters[cxxi]. At the exploration stage there does not appear to be such concern within the UK as there are water company treatment works with the capacity to cope with a range of contaminants and a number of industrial wastewater treatment works. Similarly, a support industry for the management of wastes specifically associated with the offshore oil and gas industry indicate that treatment capacity should not represent a problem. If treatment and disposal capacity is restricted or temporarily unavailable then wells can be temporarily suspended. As the industry grows a supply chain will also have to grow to support it.

The EA is content with the level of its regulatory powers associated with the management and disposal of flowback and produced water, considering that the EPR are adequate to ensure the protection of the environment. Shale gas operators have stressed that the regulations may be overly stringent for naturally occurring radionuclides in light of normal background radiation. The House of Commons Energy and Climate Change Committee has emphasised the importance of regular and random monitoring of wastewaters to ensure compliance with these regulations[cxxii].

The main implication for the shale industry is the overall financial cost of compliance with the UK and EU's robust water regulation regime. Due to the tightening of Radioactive

[cxviii] Petts, L. 2013. Wastewater treatment in numbers, presentation to CIWEM Shale gas conference 6th Nov 2013

[cxix] An existing and widely used physico-chemical treatment process commonly employed in processing a wide range of industrial wastes for disposal. Cuadrilla, 2013. RSR Permit application

[cxx] MWH. 2013 Produced water treatment. Presentation to CIWEM Shale gas conference 6th Nov 2013

[cxxi] Potocnik. J. 2012 Transmission Note on the EU environmental legal framework applicable to shale gas projects.

[cxxii] House of Commons Energy and Climate Change Committee. 2011. Fifth Report: Shale Gas.

Substances Regulation limits the waste may need to be transported further for treatment which would increase costs in addition to the further cost to treat waste to a higher standard. There is very little disposal capacity at present for non-nuclear radioactive waste, which is normally considered to be Very Low or Low Level Radioactive Waste. This might elevate risk considerations where additional storage and transport are required.

In this context, there are likely to be drivers for technological advances in terms of fracturing processes which require less water in the first instance, thus producing less flowback and produced water for subsequent treatment, should a shale gas industry develop to a significant scale in the UK.

Reuse

Reuse of flow back and produced water arguably represents the most sustainable process and is likely to be permissible following treatment and dilution of the wastewater prior to re-injection. This would have to take place on site to comply with the European Mining Waste Directive. If returned fluids are appropriately treated, produced water can be reused in a number of ways; in Australia, where there are water resource pressures it has been used in aquifer recharge, supply for other industrial uses such as cooling, irrigation and release to surface water.

The difficulty in reusing flowback water in the hydraulic fracturing process is that it can be very high in concentrations of scale-forming constituents including barium, calcium, iron, magnesium, manganese, and strontium[cxxiii]. These can readily form precipitates which then block the fractures in gas bearing formations. Depending on the makeup of the flowback water, pre-treatment may be necessary to reduce their concentrations.

Research is currently underway to develop onsite treatment processes with less need for transport. This will also improve re-use levels and close the loop by turning the waste salts into a resource that other industries can utilise. The consultancy firm MWH are currently looking into trailer mounting thermal distillation plant as a mobile solution to treatment[cxxiv]. The EA is supportive of this approach: "*we consider the reuse of flowback fluid following treatment and blending with fresh water to be the preferred and sustainable option for its management*". Shale gas operators have claimed they would like to be able to explore potential not only to reuse the water but to sell on other by-products such as salts. Given there is common ground between the industry and regulator on this they should work closely together to identify optimum solutions.

Restoration of shale pads

Following production wells must be properly closed with cement plugs and/or mechanical barriers in the wellbore to eliminate the pathway to the surface or freshwater sources. In restoring a shale gas pad there will need to be suitable decommissioning materials for the entire length of the well and an appropriate methodology to provide assurance that cross contamination of different aquifers (particularly in the long term) will be prevented. As boreholes pass through different geologies, at great depths, the groundwater conditions have the potential to vary greatly. UKOOG recommend using a completed borehole log (a record of the actual geology of the exploration borehole as drilled), rather than a prediction of the geological layers. This enables a better design of the restoration phase to protect the groundwater environment.

cxxiii Stuart, M.E. 2012. Potential groundwater impact from exploitation of shale gas in the UK. BGS
cxxiv MWH. 2013 Produced water treatment. Presentation to CIWEM Shale gas conference 6th Nov 2013

3. Discussion & Conclusions

Viability of commercial shale gas development in the UK

Whilst there has been much speculation on both sides of the shale gas discussion as to whether an industry might be viable, without further assessment neither the government nor the industry have the information to make a meaningful estimate of recoverable reserves at the current time. The discrepancies evident between the projections made by opponents and proponents underline the requirement for clear scientific evidence and transparency to be at the centre of the debate.

If we take the assumption that exploration is successful, production is still unlikely to make a meaningful contribution to the UK's domestic natural gas supply until the 2020s. The drilling intensity required to achieve this level of production may be limited by resource access, technology, the regulatory framework or market access. Provided there is a suitable resource, the technology does exist to extract it and future technological advancement may help to bring down costs by increasing the efficiency of wells. What will be needed however is growth of service sector capacity for the supply chain, for example in wastewater treatment capacity.

Having assessed each of the limitations in turn CIWEM believes that although OUGO has been set up to streamline the planning, permitting and regulation of shale gas, this remains likely to present the greatest barrier to the quick development of an extensive industry. Despite this we believe it is important that the Government continues its commitment to a tightly controlled industry and ensures that the regulators as properly resourced to undertake their duties. The regulatory regime currently only applies to the exploration phase and may be modified for production to reflect the more intensive conditions associated with it. Standard permits may help speed up permitting but public opposition to the planning process could present a major barrier. The European Commission[cxxv] could also add its own requirements to the process and cause further regulatory hurdles and duplication of effort.

High population densities and active public opposition groups have the potential to oppose planning applications to local authorities and could lead to a difficult public relations situation for the government and the shale gas industry. There has already been a widespread emergence of local public opposition groups, even in areas where there has been little realistic indication of future shale gas exploitation. It is evident in this that there is significant mistrust of the industry and its ability to operate at low levels of risk. This mistrust may be amplified by poorly implemented public consultation processes in areas of shale gas exploration to date. UKOOG and shale gas operators have talked confidently of involving communities but the experiences of some local stakeholders[cxxvi] indicate that putting community engagement into practice still poses challenges. This is an aspect which the industry clearly needs to improve on in order to establish a clear social licence to operate.

DECC, through OUGO, is aiming to improve levels of social understanding of the process, industry, risks and safeguards. The department is in the process of expanding its portfolio of public facing information which now includes an extensive FAQ document, fact sheet[cxxvii] and regulatory roadmaps[cxxviii]. This is welcome as previously its public engagement appeared limited which at the time did little to mitigate the sensationalist debate in the media. DECC with the industry's various regulators, should continue to improve their public engagement. There appears to be considerable lack of clarity from the media on the

cxxv Potočnik, J. 2013. A European strategy for shale. Speech/13/840 21/10/2013.
cxxvi Ribble Estuary Against Fracking. 2013. Wider environmental issues from a community group perspective. Presentation to CIWEM Shale gas conference 6th November 2013.
cxxvii DECC. 2013. Developing onshore shale has and oil, facts about fracking
cxxviii DECC. 2013. Regulatory roadmap.

timescales for likely industry development, what each stage of development involves and the differences between exploration and full production.

Another aspect of public acceptance is where shale gas fits into our overall energy policy. Reducing levels of fugitive emissions must also be resolved. The strategic lead role for gas must also be set within clear decarbonisation targets and alongside renewable energy and energy efficiency policies.

It is important that there is clarity, robustness and openness in the messages coming from the senior parliamentarians on all these aspects. The polarised and politicised media debate does not help in this respect.

1 **Government departments and agencies should actively promote informed understanding among stakeholders using clear scientific evidence, transparency and consistent messages, across a range of media and forums. Government Ministers should ensure that their messages on shale gas are consistent with those of the departments.**

2 **The industry should ensure it complies with the UKOOG community engagement charter so that the public are involved within the planning process with adequate notice and information. The production of guidance for local communities on what they can expect and where they can and cannot influence would be helpful.**

3 **Further collaboration between the agencies involved in advising and regulating the industry is required. As regulation is developed for the appraisal and production phases, a rationalised and integrated system of risk assessment should be included to avoid confusion, increase public engagement and reduce delays.**

Assessment of risks to water resources

Compared to other fossil fuels the overall water use intensity of shale gas is low and claims by some opponents that the shale gas industry represents a threat to the security of public water supplies is alarmist. Nevertheless the water consumed is front loaded for a short period of time at the beginning of the life of a well, which could have local impacts for catchments and water sourcing for the industry may require a certain element of temporal planning. There has been a wide variation in the estimates of water use in the different stages of shale gas production but this still allows certain conclusions to be drawn.

At the exploration stage water demand is not likely to be significant compared to other users and it is likely that operators will continue to source water on a site by site basis depending on the closest source and ease of connectivity.

Should a large industry develop in a small geographic area there could be local or regional consequences. The industry will have to compete against different users and should there be any temporary water use restrictions put into place, it could in theory be affected. Taking a regional scenario the water required by the industry is comparable to other industrial users and would face the same drought restrictions.

If water companies have the available resources and there is a close mains connection this is possibly the easiest option; tankers may also be used. Operators can also source their own water from the environment either via borehole or direct abstraction from a watercourse should the Catchment Abstraction Management Strategy deduce that there is spare water. Early engagement with the EA or local water company, depending on where the water is sourced, will be important to ascertain available volumes. CIWEM considers operators should provide a profile of water use and flowback over life of the shale well to help establish any pinchpoints in supply.

Where there is overlap between water stressed catchments and shale gas licence areas, operators will need to be aware of the risk that there may be smaller volumes available in the future. Drilling and fracturing processes may have to be timed as to when volumes of water are available. The MoU between UKOOG and Water UK should assist in planning water resources in the future for the industry and is a good first step towards water and sewerage companies becoming a statutory consultee in the planning process.

4 CIWEM believes water and sewerage companies should become statutory consultees in the shale gas planning process regardless of whether they continue to provide and treat water for the industry. They must be engaged with early and provided with the right information to meet their duties.

Assessment of risks to the water environment

The impacts of shale gas extraction on groundwater are likely to be local, dependent on whether the geographical location of any productive areas of geology coincides with areas of particular water resource pressure and/or near to groundwater resources or sensitive aquatic environments. These will need to be thoroughly assessed during the planning stage to ensure they are protected.

CIWEM believes that if shale gas is to be developed safely, ensuring due regard for protection of the wider environment, exploration should not be permitted in areas where there is a genuine risk to valuable drinking water resources located in groundwater. Groundwater including any local aquifers should be carefully delineated by the operator as part of the well design and fracturing risk assessment process. The mapping of the relationship between potential shale gas source rocks and principal aquifers should be used to assess applications with strong enforcement by the Environment Agency through planning or permitting controls to protect groundwater. This would help to minimise the risks from the mobilisation of solutes or methane in areas of natural faults or in areas of shallow shale plays.

Contamination of aquifers from mobilisation of solutes and methane is unlikely where shale plays exist at depth in the UK. The BGS believes such contamination is unlikely to occur if shale gas exploitation is restricted to depths greater than 1500m[cxxix]. Where the source rocks are shallower there could be a greater risk and companies will have to ensure that fracture sequences are monitored using performance standards. Fracturing operations should be examined as part of the well examination arrangements.

Loss of well integrity has been recognised as one of the pathways of contamination to groundwater quality and must be seriously considered by all appropriate regulators with construction closely monitored to ensure that best practice is followed. Seismic monitoring should be used to assess any potential impact on well integrity, in line with UKOOG guidelines. The HSE must undertake an active role in visiting sites for verification inspections of monitoring operations and take enforcement action where it is found to be inadequate.

Contamination of soil, surface or groundwater from spills of returned waters is a considerable hazard. Risk assessments need to consider all potential sources of pollution, potential pathways and receptors. Evidence from the US suggests that the maintenance of well

[cxxix] Stuart, M.E. 2012. Potential groundwater impact from exploitation of shale gas in the UK BGS

integrity, including post operations, and appropriate storage and management of fracking fluids and wastes are important factors in controlling risks[cxxx]. Massachusetts Institute of Technology reviewed[cxxxi] 10,000 wells and found that of 43 pollution incidents related to natural gas operations, 50 per cent were related to the contamination of groundwater due to drilling operations and 33 per cent due to surface spills of stored fracking fluids and flowback water. Appropriate regulatory control is needed to ensure returned waters are appropriately contained, managed, and treated prior to eventual disposal. Best practice for fluid storage is needed to ensure no risk of fluid leaks or spillages. This includes the use of appropriate above ground tanks that are fit for purpose and meet industry standards.

Accurate baseline environmental monitoring is essential to assess the impact of shale gas extraction on the environment and any implications for public health and should begin immediately. In both Australia and the US, where the regulatory framework developed at the same time as the industry, no environmental baseline was established which has led to what amounts to conjecture on both sides of an extremely polarised debate. Good data, measurement, and transparency by the industry are vital to environmental protection and public trust. Given the relative abundance of monitoring data in the UK, it may be comparatively well placed to develop a baseline in a comprehensive and cost effective manner. CIWEM welcomes the BGS study currently underway into assessing baseline levels of methane in groundwater. Other programmes of study will need to be established in the vicinity of shale gas operations for both deep and shallow aquifers for radio-nuclides and other contaminants.

Following the production of a baseline, the long-term monitoring of relative conditions will be required. This should be carried out throughout the lifetime of development, production and post-production. CIWEM considers that guidance is needed on the parameters, frequency, time scale and depth of monitoring on wells and other monitoring locations (e.g. surface water streams).

5 The importance of baseline monitoring cannot be overstated. Regulators must ensure that an environmental baseline is fully established before any commencement of drilling activity and this should include both deep and shallow aquifers for radio-nuclides and other contaminants. Full details of the environmental monitoring programme should be disclosed.

6 The long-term monitoring of relative conditions to the environmental baseline in the vicinity of the well and nearby receptors throughout the lifetime of the well will be important to detect any contaminants. In developing production guidance, parameters on the frequency, locations and time scale of measurements should be included.

7 The protection of groundwater must be made a priority and the environmental regulator should continue to adopt the precautionary principle where there is insufficient certainty to protect groundwater. Operators should provide the environmental regulator with a detailed risk assessment to examine the relationship between the shale and the aquifer including a thorough evaluation of geological and hydrogeological setting.

[cxxx] Public Health England. 2013. Review of the potential public health impacts of exposures to chemical and radioactive pollutants as a result of shale gas extraction

[cxxxi] Massachusetts Institute of Technology. 2011. The future of natural gas

Assessment of risks associated with water treatment

The returned waters from the hydraulic fracturing process require treatment as they may be highly saline and include naturally occurring radioactive materials. This presents further financial and regulatory risk to meet compliance with the UK's robust water regulation regime.

The nature of the substances concerned mean that the water may not be of an appropriate chemical composition to be sent to a typical public wastewater treatment works and may require specialist industrial treatment or pre-treatment in order to enable this.

At the exploration stage there seems to be enough capacity to treat returned waters as public treatment works are able to cope with a range of contaminants and there are a number of industrial wastewater treatment works in the UK. However returned waters are likely to be highly saline and to be able to treat by dilution a municipal treatment plant may be needed that discharges to an estuary. There are other technologies available but these entail greater energy consumption and cost. It is certain that if the industry grows, and wastewater volumes increase, water treatment capacity will need to expand to support it. There also needs to be further consideration given to disposal of the solid residues from some treatment options.

Reuse of flow back and produced water arguably represents the most sustainable process and the regulatory systems should aim to encourage this. The development of onsite treatment processes will also reduce the risks associated with transporting waste.

8 Further research is needed into hydraulic fracturing with lower quality waters and also waterless techniques to minimise water use and thus requiring less subsequent treatment.

9 Research and development is needed in water treatment and decontamination technologies that exhibit reduced energy consumption, as well as into onsite and mobile treatment solutions that reduce the risks of transporting waste.

10 The reuse of hydraulic fracturing fluid on site is the preferred option of the industry and the regulator. Given that there is common ground between the industry and regulator, they should work closely together to identify optimum solutions.

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