The Petroleum and Renewable Energy Company Ltd

A REVIEW OF THE POTENTIAL IMPACT OF SHALE GAS AND OIL DEVELOPMENT ON THE UK'S COUNTRYSIDE

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EFFECTIVE DATE OF THE REPORT

This report was first drafted by January 2014. Some (but not all) events and publications that have been issued subsequently have been noted and in some cases commented on.

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Introduction

There has been increased interest in the shale gas industry in the UK in the last five years, following the award of licences for shale gas exploration in 2008. In 2013, the British Geological Survey (BGS) announced the results of a study quantifying the potential gas resource for the Carboniferous Bowland/Hodder shale and the UK's coalition government has expressed support for its development.

There are many interested parties with diverse opinions on the impact and benefits of establishing a shale gas industry in the UK. Supporters of shale gas development highlight the potential value such as increased tax revenues, security of energy supply, improved balance of payments, job creation and lower CO_2 emissions compared with coal. Opponents underline the impact on the environment including the potential contamination of water supplies, induced seismicity, the impact of CO_2 emissions from shale gas on climate change, the visual impact on the landscape, risks to the local environment and a concern that investments in shale gas development may detract from investments in renewable energy and other low carbon technologies. Nevertheless the coalition government has indicated that, given the potential benefits it sees at a national level, there is an overriding intent to promote at least the first stages of evaluating the potential.

Shale oil and gas development could have a profound impact on the UK countryside and in recognition of this the Countryside Alliance, sponsored by the late Mark Donegan, commissioned Petrenel to undertake a study to describe the shale gas and oil opportunity and the state of the emerging industry in the UK and assess the potential environmental impacts shale gas and oil development could have on the UK countryside. The intended use of the study was to help promote a discussion with decision makers and policy setters in government on the suitability of current legislation and the regulatory environment when considering the possible development of the shale gas and oil industry within the UK.

The study is being undertaken in two phases. Phase 1 has involved i) describing the shale gas exploration and development process, ii) providing an overview of the shale gas potential in the UK, iii) describing the state of the nascent shale gas industry in the UK and how it might evolve, iv) summarising current UK legislation as it applies to the industry, v) reviewing the potential effects shale gas and oil development could have on the environment, and vi) identifying and recommending further actions that could be taken to protect the environment. Whilst the original brief was to focus on shale gas, shale oil development could potentially effect some areas, and the study was extended to briefly cover this aspect. Phase 2, would include a more detailed assessment of issues and actions identified in Phase 1.

This report summarises the results of the first phase of the study. It is emphasised that this report has only addressed the potential environmental impact that shale gas exploration and development could have on the UK countryside. It has not considered the societal or economic impacts or benefits which could be significant.

Shale Gas and Oil and its Exploration and Development

Shale gas and oil is a naturally occurring petroleum fluid trapped within shale formations. Shale, a very fine grained low permeability rock, is present throughout the sedimentary stratigraphic column in the UK and underlies much of the country. However, not all shale, can be considered to be a potential source of gas or oil.

The shale needs to contain organic matter in relatively high concentrations and to have been buried sufficiently deeply and exposed to a high enough temperature over its geological history for that organic matter to have been transformed into oil and gas. The shale needs to be either of sufficiently low permeability or encased in low permeability rock that it has not lost its petroleum over geological time, and to contain either open natural fractures or thin more permeable beds of siltstone or limestone that will enhance the shale permeability and encourage the gas and oil to flow.

The processes involved in exploring for and developing shale gas and oil are essentially the same as those employed in conventional oil and gas exploration and production. The discovery, evaluation and development of a potential shale gas deposit, as with conventional petroleum deposits, typically follows five stages: exploration, appraisal, development, production, and decommissioning. Exploration and appraisal usually involves undertaking seismic surveys and drilling wells to test the vertical and lateral extent of the shale deposit and establish its physical and chemical properties.

Shale gas development typically involves drilling horizontal wells in the shale deposit at a relatively close spacing to maximise the efficient recovery of the petroleum fluid. The horizontal drain-holes are typically between 1 and 2 km long, between 1000 and 3000m deep, and between 100 and 600m apart, covering the area of the shale but potentially also the vertical section (depending on the thickness of the formation).

Wells are drilled from a surface location (known as a well pad or well lease) which typically has an area of about three to five acres depending on the number of wells drilled from that location. Multiple wells can be drilled from a single pad (typically between two and three, though numbers as high as 20 are known).

The horizontal wells are normally stimulated using hydraulic fracturing prior to their initial completion. Hydraulic fracturing involves pumping water, proppant (treated sand or man-made ceramic materials) and chemicals at high pressure into a well to create an artificial conduit that allows gas to flow more easily into the wellbore. Hydraulic fracturing is normally carried out shortly after the well has been drilled, but may be repeated at times during the well's life to sustain production. Multiple fractures may be carried out in each well (multi-stage fracturing) to maximise the well productivity and the recovery of gas and liquids.

Gas pipelines and gas processing facilities are installed to gather the gas and remove entrained liquids (water and condensate) and impurities such as carbon dioxide. The gas is compressed and metered before entering the export pipeline system (the National Transmission System in the UK). The condensate may be exported by road tanker. Produced (and drill) water may contain salts and other chemicals and may be removed by tanker and taken to a central processing facility or re-injected locally deep underground.

Access roads to each well pad, pipelines, processing facilities, camps, offices, and storage areas are also constructed. The number of centralised processing facilities that would be required would depend on the areal extent of the productive shale, accessibility, and environmental factors.

Development is likely to be phased and may start with a pilot project to prove that commercial development is feasible before embarking on a full scale development. Development is also likely to start in those areas with the most productive shale and the highest liquid yields at a relatively wide initial well pad and well spacing. Once production has started additional wells and well pads (known as infill wells) will be drilled to maximise the economic recovery. The initial development phase to establish production will typically last two to five years. Thereafter additional development drilling may continue for many years.

Once production has been established, the producing life of a shale gas deposit may be around 20-40 years. During the production phase, there are on-going operational activities to manage the assets and keep the wells and facilities operating safely. Production facilities may need to be repaired or altered and wells may need to be re-fractured or cleaned out to sustain production. These are intermittent activities and each well may not require significant attention for a number of years.

At the end of the productive life of the shale gas deposit the production facilities, wells and infrastructure are decommissioned. During the decommissioning phase wells that are no longer economic to produce are plugged with cement and well heads, pipelines and production facilities are removed and materials recycled. The well pads are decommissioned and rehabilitated to restore the site close to its original condition. The decommissioning phase may last a number of years and may start before the cessation of economic production from the field as a whole.

Experience in North America has shown that typically 10-20% of the gas initially in place can be recovered depending largely on the number of wells (or lateral branches) of wells that can be drilled into the shale, the initial production rates that can be achieved from each well after hydraulic fracture treatment and the properties of the shale rock.

Oil can be extracted from shale by both surface mining (oil shale) or subsurface methods (shale oil). Oil shale extraction, which has not been addressed in this report, is usually performed above ground by mining the oil shale and then treating it in processing facilities (as was carried out in Scotland until 1962). Shale oil extraction utilises methods that are similar to shale gas extraction including the drilling and fracturing of multiple (horizontal) wells. However the well density may be higher and heating of the ground may be required to improve the mobility of the oil. Oil may be exported by road, rail or pipeline and surplus gas may be either piped to the local gas network or, if quantities are small, may be flared.

Shale Gas and Oil Potential in the UK

Oil and gas bearing shale is present in the Central Lowlands of Scotland (largely shale oil with some gas potential), the Northern Pennine Basin (largely shale gas potential), and the Weald and Wessex Basins in Southern England (largely shale oil with possibly some limited gas potential). The Northern England Pennine basin is the most prospective area for shale gas and this area, as a consequence, has experienced the most interest to date, and is the region where shale gas development is most likely to start.

The prospective area for the Bowland shale in the North Pennine Basin covers an area of about 10,400 km^2 (or about 4.3% of the area of the United Kingdom), the prospective shale oil and gas area within the Weald and Wessex Basins amounts to about 800 km^2 (or about 0.3% of the UK land area), and the prospective area for shale oil and gas in the Midland Valley amounts to about 4000 km^2 (1.5% of the area of the UK). The prospective areas for shale oil and gas constitute only a relatively small proportion of the total land area. Large parts of the UK countryside will therefore be unaffected by shale gas or oil development.

The BGS have over the last few years assessed the potential quantities of shale oil and gas initially in place in these three prospective areas. The Carboniferous Bowland/Hodder shale in the North Pennine basis is gas prone with an expected (un-risked, potential) quantity of gas initially in place estimated to be 1329 tcf (trillion cubic feet) ranging from a low estimate of 822 tcf to a high estimate of 2281 tcf. The Jurassic shales in the Weald Basin have not been buried sufficiently for thermogenic production of gas to occur and the shales were more likely to contain oil. The expected (un-risked, potential) quantity of oil initially in place is estimated to be 3.2 billion bbls (barrels) (with a range of 2.2 to 4.4 billion bbls). The Carboniferous shale in the Midland Valley of Scotland potentially contains both oil and gas. The potential gas in place is estimated to be 80 tcf (range 49 to 135 tcf) and the oil in place was estimated to be 6 billion bbls (range 3 to 11 billion bbls).

Only a small proportion of this gas and oil in place will be potentially recoverable. With a higher population density, more restricted land availability, and a lack of infrastructure in the UK, the average well spacing and recovery factors for shale gas are unlikely, certainly initially, to reach the levels being achieved in the USA. Whilst there is considerable uncertainty in the magnitude of the recoverable shale gas resource in the UK and much of it is unproven at present, the potential volumes (even if say only 10% of the gas initially in place is recovered) are substantial.

Preliminary economic screening of a generic UK shale gas project, based largely on average data derived from shale gas projects in the USA but with adjustments for an early stage project in the UK, indicates that development could potentially be commercially viable on the assumption that UK gas prices remain at or above current levels. The economic threshold for shale oil will be higher (oil is much less mobile than gas and more difficult to extract) and is less likely to be commercially viable at current oil prices.

Despite the potential for shale gas (and oil) in the UK, the commercial viability of its development is uncertain, due to the limited testing of the shale to date. Whilst the country has significant shale gas and oil potential it is important, in formulating a sensible and pragmatic policy, to realise that there are still large technical, commercial, and political uncertainties, in particular those associated with the productivity of wells, the proportion of gas that can be recovered, and the general acceptance of the extraction methods by the public.

There is a significant chance that, after the initial exploration and appraisal phase in the UK, shale gas (and oil) development may prove not to be commercially viable (under current prices and fiscal conditions) and that the industry will see a reduction in interest and a decline in activity that may last for decades. This has happened recently in Sweden and in Poland where the shale gas prospectivity has proved disappointing when compared with initial expectations. Whilst there is considerable optimism in the press and government on the benefits of shale gas as well as concern about hydraulic fracturing, it is possible that these may never occur on the scale that some envisage.

The Shale Gas and Oil Industry in the UK

Shale gas industry is in an embryonic state in the UK and at an early exploration and appraisal phase. Although there has been significant media exposure and discussion, as well as a number of reports and government initiatives, with respect to the shale gas opportunity in the UK, the actual activity specifically targeted at shale gas exploration and development to date has been limited. Only a handful of exploration and appraisal wells have been drilled specifically for shale gas (for example by Cuadrilla Resources and IGas). There has been no development with regards to shale oil. Companies that currently hold onshore licences are largely pursuing conventional oil and gas or Coal Bed Methane (CBM) although many have recognized that the licences do cover areas that have shale oil or shale gas potential and have been collecting relevant subsurface data

Up until relatively recently the interest in shale gas has been confined to smaller onshore oil and gas companies, with none of the larger corporations owning all or part of any licences onshore in the UK. Many of the smaller current onshore operators do not have the capital to invest heavily in exploration, appraisal and commercial development. Some larger companies have recently begun investing in shale gas operations through transactions with the smaller companies. The increase in investment from larger companies is likely to speed up the rate of exploration and appraisal of the multiple basins across the north of England. If commercial rates are proven then it is likely further interest and investment will follow.

Notwithstanding the economic benefit that shale gas could potentially bring to the UK, it is likely that the scale and rate of development of shale gas that is occurring in the USA, will be much more difficult to reproduce in the UK given the relative scale of the shale gas deposits, constraints of population density, land use, lack of associated infrastructure and services, and concerns for the environment.

The rollout of shale gas exploration and development, despite the efforts of the government to promote its exploitation, is likely to be relatively slow given the UK planning process and public opposition from some quarters. Whilst pilot gas production could potentially start in the next few years, it may be many years before full scale development commences.

Firstly, the operators would look to prove the existence and the commercial viability of the gas resource. If further development is not viable, the rate of drilling additional wells is likely to be slow or curtailed. Should development look commercially attractive, the second stage would lead to a roll out programme, sighting well pads in locations which are most easily approved by the planning authorities (i.e. not in environmentally protected areas), and are least likely to cause public opposition.

During the third stage, to maximise the recovery and economic benefits, the operators would, over time, look to infill the remaining prospective areas by drilling more wells in their licence area. This may shorten the distance between well pads or result in more wells being drilled from existing pads. A denser well pad distribution would mean a greater impact on the landscape and the associated environmental risks. This is of a particular concern in ecologically, culturally and recreationally important areas. The location and density of drilling is likely to therefore depend on economics, surface constraints, regulatory approvals and public acceptance.

Oil and Gas Regulation in the UK

The UK has a well established set of regulations for managing onshore oil and gas operations. The Department of Energy and Climate Change (DECC) plus its regulatory partners are charged with permitting and oversight of both onshore and offshore exploration and development activity for the oil and gas upstream industry. At the present time the process of obtaining consent to drill a well is similar whether the well is targeted at conventional or unconventional hydrocarbons.

An operator proposing to drill an exploration well is required to hold a licence from DECC, negotiate access with landowners for the drilling pad area, seek planning permission from the Minerals Planning Authority (MPA) (or the local planning authority), obtain the appropriate environmental authorisation/permits from the Environment Agency, notify the Health and Safety Executive of the well design and operation plans, serve notification of an intention to drill to the Environment Agency, and apply for consent to drill from DECC. If the operator wishes to drill a further appraisal well or start production operations, it must start again with the process described above.

Under the existing system licence holders do not have automatic rights to drill under land owned by third parties without the land owner's permission. However, the UK government has issued a consultation document that seeks to streamline underground access through the introduction of a new Infrastructure Bill. The proposals would change access rights for petroleum exploration licence holders to make it easier for them to carry out drilling and well operations for shale gas beneath land owned by third parties.

Environmental Risks and Mitigation

Many of the environmental risks associated with shale oil and gas exploration and development are similar to conventional onshore oil and gas development. The principal difference is in the likely scale and intensity of the activities and the effect that this has on the probability and severity of the environmental risks.

The principal environmental risks associated with both conventional and unconventional oil and gas exploration and development are i) increased greenhouse gas and other potentially harmful emissions, ii) the potential contamination of surface water and soil due to oil, waste water and chemical spills from leaking wells and facilities and well blowouts, iii) the potential contamination of shallow aquifers through leaking wells and possibly uncontrolled hydraulic fracturing, iv) increased solid and liquid waste generation and disposal, v) increased ambient noise and road traffic, vi) increased water demand and consumption of other natural materials, vii) reductions in biological habitat and biodiversity due to changes in land use and deforestation, vii) the potential damage to property as a result of induced seismicity associated with hydraulic fracturing, and ix) the visual impact on the landscape.

Greenhouse gas (GHG) emissions associated with shale gas development include direct emissions (venting, flaring and fugitive emissions) and indirect emissions (resulting from products and processes used in the exploitation of shale gas). Shale gas and oil development is an energy intensive process and greenhouse gas emissions during construction are likely to be higher per unit of energy produced when compared with conventional oil and gas extraction. Carbon emissions from the energy supplied from shale gas are less than from coal or oil. However, continued exploitation of fossil fuels is likely to exceed global GHG emission targets set to avoid significant effects from climate change.

The risk of contamination of soil and surface waters due to oil, waste water and chemical spills will be higher than conventional oil and gas because of the larger number of wells and flow-lines being constructed and the greater number of vehicle movements. Whilst the probability of an individual well blowing out or leaking is relatively low (typically around 1 in 5000 for onshore wells), the large number of wells that need to be drilled increase the chance of such an event happening. The consequences of such an event however will be smaller than with conventional oil and gas well drilling as the effluent will primarily be gaseous and the low permeability of the formation will reduce emission rates and ease well control.

Contamination of shallow aquifers with water and chemicals used in hydraulic fracturing or with hydrocarbons through either induced fractures or leaking wells is considered by many to be a significant risk. However the shale gas deposits are usually many hundreds of meters below the depth of the base of potable aquifers and the intervening rock, as shown by micro-seismic monitoring, acts as an effective barrier to the vertical growth of hydraulic fractures. The chances of a properly designed, well placed, carefully monitored hydraulic fracturing operation causing contamination of a shallow aquifer is considered to be very low. The contamination of shallow aquifers with hydrocarbons due to migration through poorly constructed or old wells is much more likely.

There is a significant amount of water produced during shale gas operations including injected fracturing fluid, formation water, and drilling and completion fluids (flow-back fluid). The produced water may contain potentially harmful salts, hydrocarbons, and radionuclides. Activities associated with the collection, storage, transportation, treatment and disposal (or re-use) of this waste water may require additional facilities.

Construction of a shale gas well typically requires about 10,000-30,000 m3 (cubic metres) of water. With many thousands of wells to be potentially drilled, there could be a significant increase in the demand for water although the increase will represent only a relatively small proportion (less than 0.5%) of the total UK demand. The requirement to increase local supply to fulfil any significant increase in local demand is more likely to depend on establishing the basis of the source of that supply through the local water authorities and the regulator. Specific commercial arrangements may be required to alleviate any undue burden on local utility customers.

Whilst much attention has been focussed on the threat to property and human safety from induced seismicity associated with hydraulic fracturing (particularly in the UK as a result of the earthquake recorded during the fracturing of a Cuadrilla well), the risk to property and human safety associated with a properly designed and carefully monitored hydraulic fracturing programme in the benign tectonic environment in the UK is considered to be very low. Seismic events are always associated with hydraulic fracturing but these are generally small in magnitude (micro-seismic) and at the depths associated with a shale gas well are unlikely to have any noticeable surface impact. A large number of fracturing operations have already been carried out in the UK associated with conventional onshore oil and gas development with no significant consequential damage.

The increased noise and traffic associated with shale gas development is likely to be a significant environmental issue. The volume of traffic required to supply equipment and materials for the large number of wells to be drilled and for the hydraulic fracturing operation will be substantial. This results in increased noise, air pollutants, disturbance to communities and wildlife, damage to roads and bridges and increased risk to civilian transportation. However this will be intermittent and temporary as the greatest impact will be during well and facility construction and in particular during the hydraulic fracturing of wells. Access roads in the more remote parts of the country are small and may need widening.

Shale gas development will impose a larger environmental footprint on the land compared with conventional oil and gas. Construction of wells pads, infrastructure and drilling activities all result in vegetation and topsoil removal, noise, increased traffic and air pollution and habitat fragmentation. In the USA, intensive onshore oil and gas development, including shale gas, has led to a fragmentation of natural habitats and a loss of previously intact forest habitats in some areas. The size of the footprint will be more critical in areas of environmental, cultural and historic significance, such as sites with International, National and Local protection or designation (e.g. National Parks, Areas on Outstanding Natural Beauty, Sites of Special Scientific Interest, Special Areas for Conservation, Special Protection Areas, Ramsar Sites, National and Local Nature Reserves, Local Sites, World Heritage Sites, National Trails).

The visual impact of shale gas and oil development on the landscape will depend on the viewing point. It can be relatively small at ground level. Well pads, with their low vertical profile, can be hidden from sight with carefully placed trees and bushes. Wells and facilities are therefore capable of being shielded from a horizontal viewing point, except possibly during drilling operations. As an example of this type of camouflage for several decades there has been a large conventional oil development located in Dorset, in the Weald basin, (the Wytch Farm Oil Field), where the impact on the environment has been relatively small and largely unnoticeable. However shale gas operations are more intense than conventional oil and gas, and, depending on the scale of development, the visual impact on the landscape may be greater. This will be particularly evident from an elevated perspective and during the construction of roads, pipelines and facilities.

Although hydraulic fracturing and induced seismicity has been the subject of much controversy, the most significant environmental risks associated with the development of shale gas are similar to those associated with conventional oil and gas operations including:

- gas migration and groundwater contamination due to faulty well construction, blowouts etc;
- above-ground leaks and spill of waste water and chemicals used during drilling and hydraulic fracturing;
- the increased noise and traffic during construction; and
- the possible loss of natural habitats and biodiversity.

Effective monitoring will assist early identification of any indication of below-the-surface problems. There is some data available in the USA but in many cases this has been inconclusive partly due to the lack of baseline studies, the assessment of groundwater systems prior to the initiation of shale operations and long term monitoring. In the UK the BGS has initiated the preparation of baseline studies of aquifer systems etc. in order to make any contamination easier to identify.

The oil and gas industry has well established methods and techniques to minimise the potential impact of its operations on the environment. Petrenel supports the recommendations from the study conducted by the Royal Society and Royal Academy of Engineering in 2012 which concluded that the environmental, health and safety

risks associated with shale gas exploration in the UK could be managed effectively as long as operational best practices are implemented and enforced through regulation and effective monitoring.

Recommendations

There are a number of positive steps that could be taken by the government to ensure that operators maintain the use of best practices and that areas that are environmentally sensitive areas are not exposed to unnecessary risks.

The roll out of shale gas exploration, appraisal and development in the UK should be carefully regulated and staged to minimise the environmental impact on the countryside and maximise the benefits to the people that live within it and the population as a whole.

It is recommended that land that is least susceptible to incremental environmental damage be utilised at the early stages. Brownfield or existing well sites should be used for initial appraisal and development. Through monitoring those projects and proving their viability, a more informed decision can then be taken to allow expansion into other areas.

The protection already awarded to National Parks, Areas of Outstanding Natural Beauty, Sites of Special Scientific Interest and Nature Reserves to preserve and conserve these areas should not be undermined by any changes to current regulations or planning policy in order to establish a UK shale industry. Approximately 15% of the currently identified prospective shale gas areas underlie National Parks and any detrimental impact on these areas will have a negative impact not just on public opinion but also on the ability to gain planning approval in the future. Planning approval for shale gas operations proposed inside these protected areas should be avoided.

The UK shale gas industry needs to be closely supervised by government, its agencies and local authorities to ensure an orderly, staged process, taking into full account the impact of development on the local environment and to ensure that stakeholders fully support project development. It is recommended that adequate resources be made available to undertake this role.

Extending the Strategic Environmental Assessments to identify, for example, the suitability of existing infrastructure, the availability of water and availability of suitable well sites before issuing licences in a particular area will promote a better understanding of the impact of the full life cycle of exploration and development of a shale operation given this is likely to have a higher level of intensity compared to conventional oil and gas projects.

The government should exercise control over the renewal, re-issue or issue of future licences for petroleum exploration and the terms associated with each licence award. Licences that lie within prospective areas for shale gas should either exclude environmentally sensitive areas or include terms and conditions that restrict activities within these areas.

Prior to awarding licences, DECC normally reviews the technical and financial capability of applicants. It is recommended that this is extended to include an assessment of whether the company has sufficient insurance to cover any potential environmental liabilities and remediation if any damage were to occur during shale operations.

The National and local planning policies (including local Mineral Planning Policies) require updating in order to more thoroughly address the issue of shale operations. Where appropriate this may include the introduction of buffer zones between shale developments and local communities similar to those proposed in Scotland.

Oversight of large scale shale gas developments is likely to require a significant increase in regulatory manpower. In particular the environmental regulator will need sufficient resources and capacity to ensure operators carry out robust and long term monitoring programs on the impact of shale gas development on both air and groundwater quality.

The industry should be encouraged to invest in the further development of technology that promotes the efficient use of land space and minimises the number of surface locations for large scale shale gas operations.

Addendum

The announcement of the 14th Onshore Oil and Gas Licence Round subsequent to the completion of the drafting of this report and the significant area on offer (see map on page 13) has pre-empted some of the conclusions of this report before its final release. Although it does not change significantly the conclusions or recommendations contained herein it underlines the need for careful consideration in preserving the countryside in particular those areas that are already protected under agreed designations. The further guidelines issued by the government agree with that sentiment.

"Guidance on the environmental aspects of any application – landward", published in August 2014 states that applications which represent major developments in National Parks, the Broads and Areas of Outstanding Natural Beauty should be refused except in exceptional circumstances and where it can be demonstrated that they are in the public interest. Although this has merit in offering a level of protection for those areas it leaves some considerable uncertainty, for example it is not entirely clear how "exceptional circumstances" would be determined. This guidance omits Sites of Special Scientific Interest and Nature Reserves.

The applicant for a licence is also charged with providing an "Environmental Awareness Statement" and the inference is that information provided in this document will include material to assess both the applicant's awareness and their plans to preserve these areas.

The real test of this good intention will be judged when the scale of any shale operation is revealed and resources both in the operator's organization and in government and its agencies are shown to be adequate to implement and police operations to ensure compliance. Much will depend on an effective on-going working relationship between industry and government to address these issues. It would be worth considering whether additional obligations in the terms and conditions of the licence itself and the selective award of licence areas to initially avoid protected areas, could better enforce compliance and the required diligence to protect these areas.

1. INTRODUCTION

1.1 Project Context and Objectives

Project

The late Mark Donegan and the Countryside Alliance commissioned Petrenel to undertake a study into the impact Shale Gas development could have on the UK Countryside. The objective is to provide an unbiased view of the potential development of shale gas industry in the UK in relation to the likely environmental impact on the UK's countryside.

The work is being undertaken in two phases. Phase 1 is an initial review of the state of the nascent shale gas industry in the UK and its potential social and environmental impact on the UK countryside.

Phase 2 includes a more detailed assessment of industry practices and regulation and how these might be adapted (if necessary) in a sustainable way to the benefit of both the UK economy and the countryside. This report is a part of Phase 1 although the scope has been increased to also include some of Phase 2.

Objectives and Scope of Work
Objective:
To undertake an independent study to describe the shale gas industry in the UK in relation to the likely environmental impact on the UK's countryside.

Scope of Work (Phase 1):

- Prepare an objective overview of the shale gas opportunity in the UK.
- Provide an overview of current standard practices of the shale gas industry including the drilling and hydraulic fracturing process.
- Provide a description of the key drivers in the shale gas industry and the commercial framework.
- Outline the key environmental risks.
- Gather and prepare a summary of current UK legislation as applicable to the industry.
- Research and identify key players in the shale gas industry.
- Complete an example of a high-level overview of a typical UK shale project and its economic value.
- Describe how the roll-out of a UK shale gas industry might look.
- Recommend any areas where there may be opportunities to improve on the framework, especially the environmental aspects, for evaluating the control over shale gas development in the UK and how it is regulated.
- Translate the current slides together with these additions into a short report for public information.

The following areas have not been fully considered. Petrenel recognizes that these topics are important and should be addressed by others:

- The impact on local communities in terms of rural economic activity, services, house prices, transport, community harmony and other areas.
- The impact on amenity, rural recreation and leisure, including public rights of way and areas of open access.
- A broader appreciation of landscape character and quality (to include issues of tranquillity).The impact on archaeological, historical and cultural resources.

1.2 Shale Gas and Industry in the UK

Shale gas has become an increasingly important source of natural gas in the United States of America (USA) since the start of this century. In the year 2000 shale gas provided only 1% of USA natural gas production; by 2010 it was over 20% and the USA government's Energy Information Administration predicts that by 2035, 46% of the United States' natural gas supply will come from shale gas. The successful development of shale gas in the USA has spurred the evaluation of the shale gas potential in other areas of the world, including the United Kingdom. The Energy Information Administration (EIA) estimates that out of a possible world-wide future potential gas resource of over 22,000 tcf as much as 32% could potentially be sourced from shale. Shale gas exploration is now active in many parts of the world including Canada, China, South Africa and South America.

The first instance of gas being produced from shale in the UK was reported in 1875 when a well was drilled into the Upper Jurassic Kimmeridge Clay in Southern England. Research at Imperial College in London and published in 1987 identified Carboniferous age shale in the Midlands and Jurassic Shale in the Weald area of Southern England as having potential for gas production. Older Pre Cambrian and Lower Palaeozoic shale were considered to be too metamorphosed to be potential reservoirs and the younger Mesozoic and Cainozoic sediments were considered to be too immature to contain significant gas. Little interest was shown in shale gas potential of the UK until 2008 when several petroleum exploration licences were awarded to a number of oil and gas companies that allowed conventional and unconventional petroleum exploration. That same year the British Geological Survey (BGS) began to review the UK's shale gas potential.

A UK company, Cuadrilla Resources (Cuadrilla), drilled the first shale gas exploration well in 2010 and although results have not been released, the well is believed to have encountered gas bearing shale. In 2011 well stimulation using hydraulic fracturing resulted in the curtailment of operations when the fracturing was thought to have initiated a seismic event recorded at the surface. As a consequence Cuadrilla suspended further fracturing operations. The government agreed that a review will be carried out and temporarily withdrew their permission for continued shale gas activity. Cuadrilla carried out a number of studies following the seismic event and the government commissioned a review of the findings from these reports followed by a further review conducted by the Royal Society and Royal Academy of Engineering (Shale gas extraction in the UK: a review of hydraulic fracturing, 2012). The latter recommended that future operations should deploy certain best practises with effective monitoring to minimise risks to the environment and local communities.

In March 2013 the then Secretary of State for Energy and Climate Change, Ed Davey MP, established The Office of Unconventional Gas and Oil (OUGO) with the government's stated intent to promote the safe, responsible, and environmentally sound recovery of the UK's unconventional reserves of gas and oil headed initially by Mr Duarte Figueira. Ed Davey MP confirmed his opinion on UK shale gas in his quote: "But shale does... over-time, with public acceptance and weighed against its environmental impact,… shale does have the potential to contribute significantly to the UK's energy security, to attract inward investment, to boost growth and jobs in certain areas, and to make a notable contribution to the Exchequer." Countering this statement he also notes that: "The communities in which such rapid development... (of shale gas)… has taken place have found the attention they have received a curse as well as a blessing." He then cleared the way for re-starting exploration activity for shale gas.

The Energy and Climate Change Committee issued a report in April 2013 on the impact of Shale Gas on Energy Markets (HC 785) highlighting that the development of shale gas in the UK is unlikely to resolve energy supply issues for the future but the government should look to encourage the development of the skills necessary to develop shale gas. It was also recognised that shale gas development in the USA is unlikely to be developed in a similar way in the UK and gas prices are not likely to fall substantially as a result of a domestic shale gas industry. A government research briefing was issued in September 2013 to further elaborate on the background, regulatory regime, environmental considerations and government policy for shale gas (Shale gas and fracking, note SN/SC/6073). Also in September, DECC issued a report on "the Potential Greenhouse Gas Emissions Associated with Shale Gas Extraction and Use" (MacKay & Stone). The report concluded that if adequately regulated, local GHG emissions from shale gas operations should represent only a small proportion of the total carbon footprint of shale gas, which is likely to be dominated by CO_2 emissions associated with its combustion. In addition any local greenhouse gas (GHG) emissions from shale gas operations would fall within the non-traded sector of the UK's carbon budgets. If the carbon budgets impose a binding constraint, any increase in emissions associated with domestic shale gas operations would have to be offset by emissions cuts elsewhere in the economy. The carbon footprint of shale gas extraction and use was quoted as likely to be in the range which

makes shale gas's overall carbon footprint comparable to gas extracted from conventional sources and lower than the carbon footprint of Liquefied Natural Gas (LNG). Also, when shale gas is used for electricity generation, its carbon footprint is likely to be significantly lower than the carbon footprint of coal. However any additional fossil fuel resources, if then used to replace other sources of fossil fuel is likely to increase cumulative emissions in the long run and may therefore impact the intent to lower overall emissions and their effect on climate change. This potential issue is not specific to shale gas and would apply to the exploration of any new fossil fuel reserve (MacKay & Stone, 2013).

In July 2013 the Department for Communities and Local Government issued a guidance note "Planning practise guidance for onshore oil and gas" for planning applications including "unconventionals" (shale gas, shale oil and coal bed methane). Also in July the government issued a consultation paper "Harnessing the potential of the UK's natural resources: a fiscal regime for shale gas" for the taxing of shale gas production suggesting that there will be some relief applied to the existing conventional oil and gas tax levels to encourage shale gas development and offset high initial costs.

Surveys of public perception of shale gas, conducted by the University of Nottingham from March 2013 to September 2013 (O'Hara et al.) show an increased awareness about the shale gas industry in the UK: 37.6% of respondents acknowledging that they were aware of shale gas in 2012 compared with about 65% in September 2013. The latest survey was conducted after the protests in the Sussex village of Balcombe where Cuadrilla was drilling a well. Protests were widely covered in the media and results show that the publicity may have had an effect on public perceptions, as the percentage of respondents who believed that shale gas should be part of the energy mix dropped from 61.6% in July to 54.7% in September 2013 and shale gas was then at the bottom of the preferred list of energy sources.

1.3 Statement of Limitations

The Review is a limited and non-comprehensive assessment intended to provide an unbiased view of the potential development of the shale gas industry in the UK in relation to the likely environmental impacts in the UK's countryside.

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2. INTRODUCTION TO SHALE OIL AND GAS

2.1 Petroleum Geology

Hydrocarbons are found in a variety of settings. They can occur in 'conventional' reservoirs, whereby oil and/or gas are found within the pores of rocks or within naturally occurring fractures. Gas can be present in reservoirs independently of oil (this is known as non-associated gas), as well as occurring within solution in oil (this is known as associated gas). Unconventional hydrocarbons refers to hydrocarbons sourced from previously unknown mediums such as tight sands, coalbed methane, shale oil and gas.

Conventional hydrocarbon accumulations occur when all five parts of the petroleum systems concept are present:

- Source rock – the organic material where the gas is generated
- Migration Pathway – the route to a collection point in a reservoir
- Reservoir – the storage place over geologic time
- Trapping Structure – the method by which the reservoir forms a collection point for migrating hydrocarbons
- Seal – Part of the trap preventing upward escape of hydrocarbons

It's the job of geologists, geophysicists, geochemists and others to ascertain whether these requirements are present to justify the investment in drilling for hydrocarbons.

Natural gas is divided into two types: biogenic gas and thermogenic gas. The division is based on the way in which the gas is generated. Biogenic gas is created by methanogens, micro-organisms that produce methane as a metabolic by-product in marshes, bogs, landfills and shallow sediment in anoxic conditions. Thermogenic gas is generated by the maturation of organic material at greater temperatures and pressure, which increase with depth of burial.

A source rock is defined as a sedimentary rock with a high enough total organic content (TOC) that when buried and heated, will begin to generate and expel hydrocarbons. A typical TOC for a good source rock is anything greater than 2%. Some of the prospective shale rocks in the Jurassic Weald Basin have TOCs as high as 21.31%, such as the Kimmeridge Clay (BGS, 2014). The organic content is derived from algal material, planktonic debris and detrital plant debris.

For the organic detritus to be preserved, it needs to be deposited in anoxic-stagnant conditions, followed by rapid burial. As more and more sediment is deposited on top, the organic rich formation will get buried deeper. The temperature within the Earth's crust increases with depth. The increase in temperature eventually leads to the process of catagenesis, the formation of oil hydrocarbons from kerogen. This is followed by the process of metagenesis, the formation of gas from kerogen at higher temperatures. The formation of hydrocarbons occurs in two main windows: Oil is generated in the oil window between 60°C / 2 km and 120°C / 4 km, with gas generated in the gas window between 120°C / 4 km and 225°C / 9 km, below this no hydrocarbons are generated. The different hydrocarbons are generated at increasing depth and temperature through the Earth (See Figure 2.1.1).

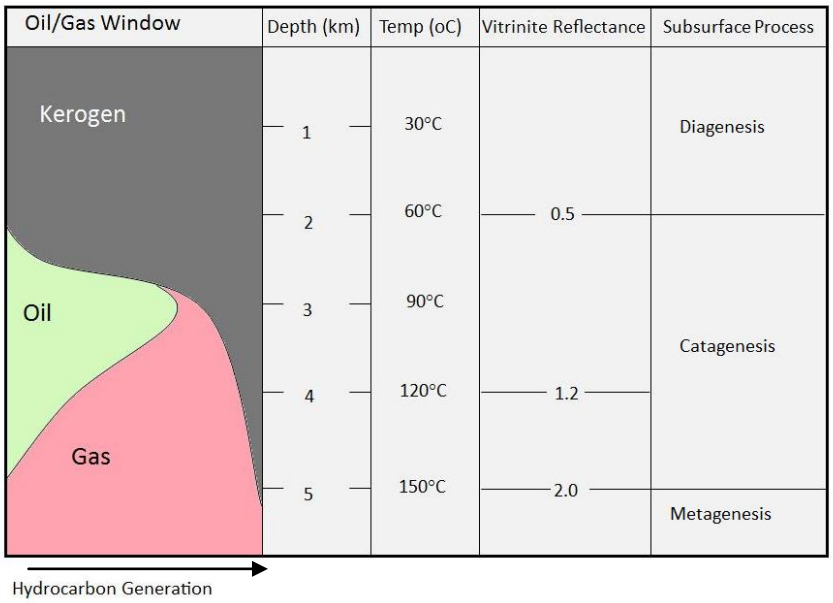


Figure 2.1.1 Hydrocarbon Generation Schematic showing the Different Proportions of Hydrocarbon Generation at Different Depths / Temperatures and the corresponding Geochemical Process

Source: Adapted from Tissot and Welte (1978)

The generated hydrocarbons can remain in the source rock but often escape and, if a migration pathway is available, will begin to rise due to their low density/high buoyancy. They will continue to rise to the surface unless they are trapped in place by a trapping structure and/or seal.

Shale is often the source rock for many petroleum systems around the world. The fine grained composition is associated with low enegery environments such as deep lakes and deep ocean floors; anoxic environments perfect for the preservation of detrital debris.

Conventional oil and gas accumulations are found within reservoir rocks where the porosity and permeability allows the sufficient charge and drainage of hydrocarbons. A good producing reservoir will need to have a high porosity (sufficient space between grains) and a good permeability (the connectivity of these pores for flow) (See Figure 2.1.2).

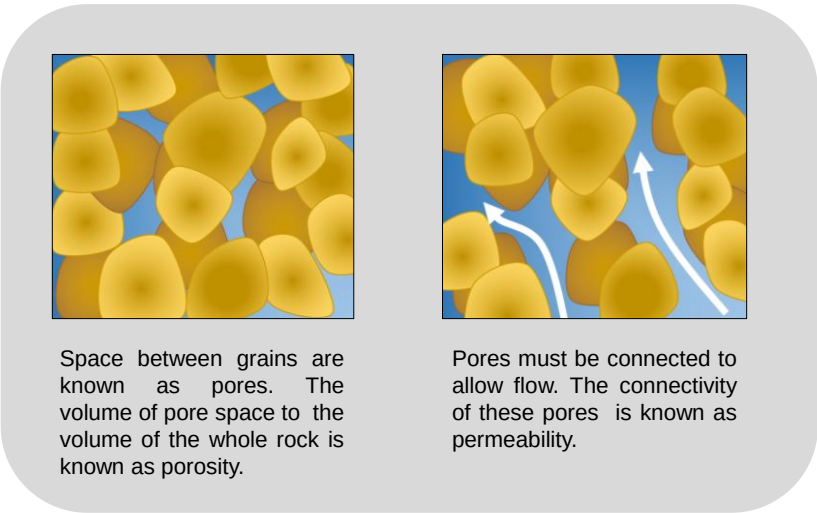


Figure 2.1.2 A Descriptive Illustration of Porosity and Permeability

Source: Petrenel

The best reservoirs are arguably sandstones and fractured or vuggy carbonates, with porosities reaching up to 30% whilst also having a high permeability. Some of the poorer reservoirs are muds and shales. The latter have average porosity around 1 to 3% and their permeability is as low as 0.001mD. Hence shales can act as both the source of hydrocarbons and as sealing layers above reservoirs, keeping hydrocarbons trapped in a reservoir.

A combination of a geological structure, reservoir and a sealing lithology may result in the trapping of hydrocarbons. Trapping structures can be created by both tectonic mechanisms, such as folding or faulting, or by stratigraphic processes such as erosion and truncation (Figure 2.1.3).

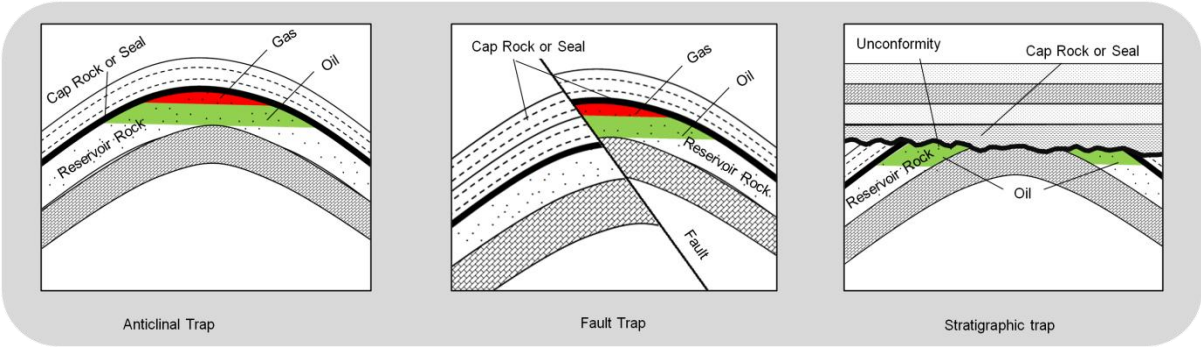


Figure 2.1.3 Different Types of Trapping Structures

Source: Petrenel

2.2 Shale Oil and Gas

The terms shale oil or shale gas refers to hydrocarbons which have been generated within the shale but have not yet completely migrated out of the shale. Conventional trapping mechanisms are not normally applied to shale gas, with the reservoir distribution presumed uniform unless proved otherwise by organic sweet spots or minor mircroscopic variations in the geology of the formation such as existing natural fractures or lateral variations in porosity associated with varying conditions in the environment of deposition.

Shale is a fine grained, dark rock composed of a mixture of minerals including clay, quartz, calcite, chlorite, and mica. Shale itself is not necessarily a homogenous rock. Shale varies layer by layer, with more silty and sandy layers present amongst clays and muds. Whilst some sand rich shales may be fissile, shale as a whole is a ductile rock. Many shale oil and gas wells target the sandy, silty and limestone layers within shale as they tend to be more fissile and thus are more prone to fracturing.

Shale Oil refers to oil which has been generated from thermally mature kerogen and has been expelled into the microscopic pore spaces within the shale. Oil Shale (not Shale Oil) refers to an organic rich shale in which the organic material (the kerogen) has not been buried/heated enough for oil generation to occur. Oil Shale is artificially heated either at depth or at the surface using retorting techniques to generate oil from the shale. This report doesn't consider the resource potential of Oil Shale in the UK. The report only focuses on Shale Oil and Gas.

Table 2.2.1 Highlights the differences between Oil Shale and Shale Oil

Oil Shale	**Shale Oil**
Shale rich in Kerogen. The organic matter within the rock has not been heated sufficiently to expel hydrocarbons. No free oil or gas.	Oil which has been generated following thermal maturity of kerogen within shale. Oil is present as a liquid in the pore spaces of the shale. (Can also be present in interbedded layers such as limestone, sandstone and siltstone.
Oil Shale must be heated to accelerate the maturation process. This is either done at depth or by mining the shale and heating it at the surface using retorting techniques.	Oil is extracted by wells following hydraulic fracturing.

Source: Petrenel

Figure 2.2.1 A Sample of Shale

Photo Courtesy of: Michael R. Clapp/BGPS

2.3 Shale Oil and Gas International Resources

Shale is a common sedimentary rock, accounting for 70% of all sedimentary rocks on Earth (Encyclopaedia Britannia, 2013). Sedimentary rocks are estimated to represent only 8% of the volume rocks present in the crust, the outer part of the Earth's structure (Buchner, 2011).

It occurs in a multitude of different basins to ancient cratons within the centre of continents.

Such is the abundance of shale that in 2013 the Energy Information Administration (EIA) conducted a full global study on prospective shale gas recoverable volumes. The findings of this are simplified in Table 2.3.1. The EIA believes that gas within shale across the world could account for 7,201 tcf (31.4% of possible future gas resources) which accounts for 61 years of current total world usage (EIA, 2010).

In 2013, the EIA followed up the study with an assessment of the prospective shale oil volumes around the world.

Table 2.3.1 The Energy Information Administration Estimates of Shale Gas Resources in tcf

Region	Jan 1 2013 Proved Natural Gas Reserves	2013 Unproved wet shale gas technically recoverable resources (TRR)	2012 Conventional unproved TRR wet natural gas	Total Technically Recoverable TRR wet natural gas	Unproved Shale gas as a percentage of TRR wet natural gas
Europe	145	470	184	799	58.8%
Former Soviet Union	2178	415	2145	4738	8.7%
North America	403	1685	2223	4312	39.0%
Asia Pacific	418	1807	858	2885	62.6%
South Asia	86	201	185	470	42.7%
M. East and N. Africa	3117	1003	1651	5772	17.3%
Sub Saharan Africa	222	390	831	1443	27.0%
South America and Caribbean	269	1430	766	2465	58.0%
Total World	6839	7201	8842	22882	31.4%

Data Source: EIA Technically Recoverable Shale Oil and Gas Resources Assessment, 2013

Table 2.3.2 The Energy Information Administration Estimates of Shale Oil Resources in tcf

Region	Jan 1 2013 Proved Oil Reserves	2013 Unproved Shale Oil technically recoverable resources (TRR)	2012 Conventional unproved TRR Oil	Total Technically Recoverable TRR Oil	Unproved Shale Oil as a percentage of TRR Oil
Europe	11,748	12,900	14,638	39,286	32.8%
Former Soviet Union	118,886	77,200	114,481	310,567	24.9%
North America	208,550	80,000	305,546	594,096	13.5%
Asia Pacific	41,422	61,000	64,362	166,784	36.6%
South Asia	5,802	12,900	8,211	29,913	43.1%
M. East and N. Africa	867,473	42,900	463,407	1,273,770	3.4%
Sub Saharan Africa	62,553	100	140,731	203,384	0.0005%
South America and Caribbean	325,930	59,700	258,234	643,864	9.2%
Total World	1,642,354	345,000	1,639,610	3,356,964	10.3%

Data Source: EIA Technically Recoverable Shale Oil and Gas Resources Assessment, 2013

Shale Oil and Gas plays occur in all different stratigraphic periods from the Pre-Cambrian to the Cenozoic. The major USA and European plays are found within the Devonian, Carboniferous, Jurassic and Cretaceous. In the UK, the two major age constrained shale formations are the Carboniferous Bowland/Hodder Formations in the North of England and the Jurassic shales of the Weald Basin in the South East (See Figure 2.3.1).

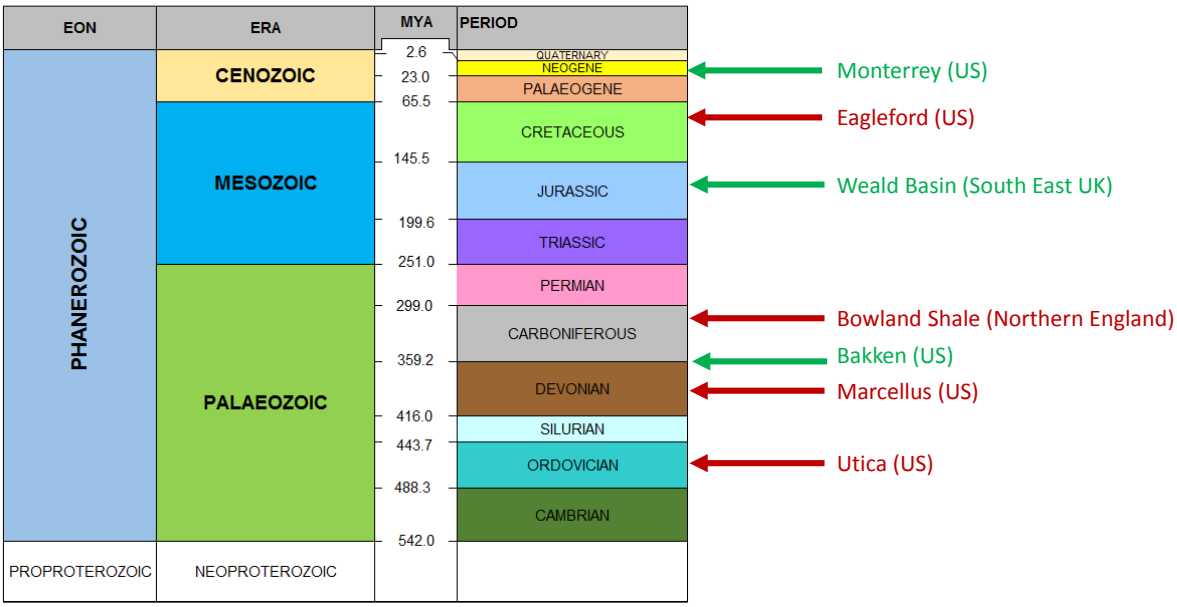


Figure 2.3.1 Stratigraphy of Major Shale Gas Plays (red denotes Shale Gas Formations, green denotes Shale Oil Formations)

Data Source: International Commission on Stratigraphy (2012)

2.4 The Exploration and Production Cycle

The search for hydrocarbons has developed dramatically over the past 100 years. In the late 19th century local exploration companies in the USA would only need to drill down a few hundred metres to encounter a gush of oil bursting out of the surface. Over time new technologies have been developed to explore and extract previously unobtainable hydrocarbons in many different environments. Offshore exploration and development was considered to be more unconventional when it began, but is now accepted as orthodox.

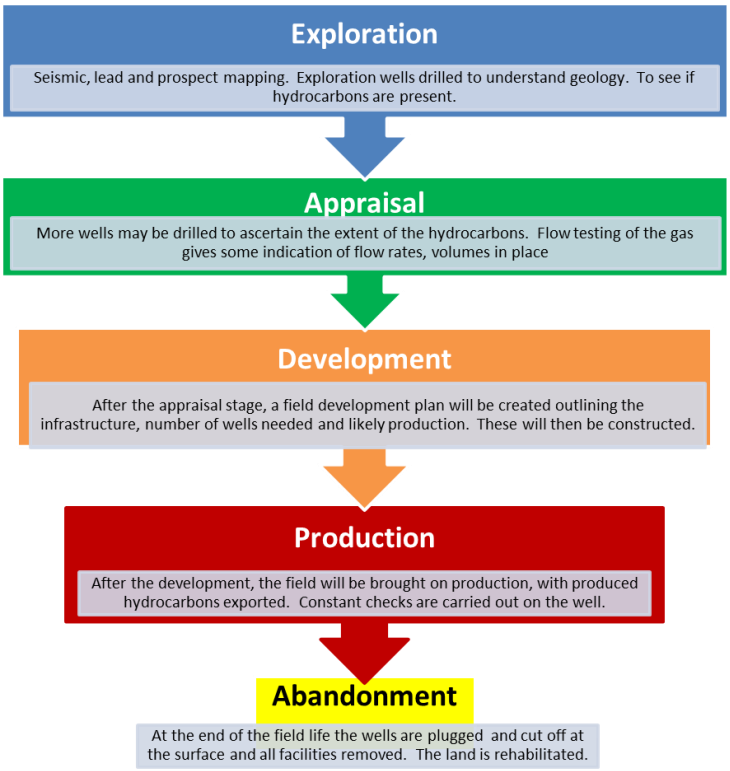


Figure 2.4.1 Exploration and Production Lifecycle of Hydrocarbon Fields

Source: Petrenel

The discovery, evaluation and development of a potential shale hydrocarbon deposit, as with conventional petroleum deposits, typically follows five stages: exploration, appraisal, development, production, and abandonment. During the exploratory stage desktop studies, using offset well, geophysical and geological data will initially be undertaken to establish the possible presence of organic rich shale in the area of interest. If the results are positive, geophysical surveys (usually 2D or 3D seismic) will be carried out to better define the likely extent thickness and depth of the potential deposit. An environmental impact assessment may also be carried out for shale oil or shale gas (currently the Minerals Planning Authority determines if it is required based on certain conditions). Exploratory drilling is then undertaken to confirm the presence of organic rich hydrocarbon bearing shale. Exploratory wells are typically drilled vertically and are logged and cored to establish the physical and chemical properties of the rock and to provide an initial indication of the thickness and hydrocarbon content of the prospective formation.

Wells are typically drilled to depths of 2-5 km and may take around one to three months to drill. Exploratory wells, if unsuccessful, are abandoned by plugging the well with cement and cutting and retrieving the surface wellhead and surface casing. If organic rich shale is found the well may be suspended to allow further hydraulic fracturing and testing to be undertaken. The exploratory phase may typically last between one and five years. Exploration for shale oil or gas may be being undertaken in areas that have already been explored and appraised for conventional hydrocarbons, in which case a considerable amount of relevant data may be available, and exploratory work may be limited to desktop studies only before proceeding to the appraisal phase.

Having discovered or confirmed the presence of organic rich hydrocarbon bearing shale, the deposit is then appraised to establish its likely vertical and areal extent, the quantity of in place and recoverable hydrocarbons and the productivity of the formation. During the appraisal phase, further geophysical surveys (usually additional 2D and 3D seismic) are undertaken and additional wells drilled. The extent of the geophysical surveys and the number of wells drilled will depend on the geological complexity and variability of the accumulation.

Figure 2.4.2 Aerial view of a Marcellus Shale well site near Waynesburg, PA

Photo Courtesy of: Michael Bryant

The objective of the appraisal phase is to reduce the uncertainties in the quantity of recoverable hydrocarbons and the productivity of the formation to the point where there is reasonable certainty that a commercial development is possible. During the appraisal phase, wells are logged and cored. Wells are generally vertical, but deviated drilling may be required if there are restrictions on well site locations. Wells may be drilled horizontally in the shale and may be tested to establish the productivity of the formation and, at this stage, wells may be hydraulically fractured to establish the productivity improvement that can be achieved with this type of treatment.

The development phase typically starts with feasibility studies followed by a declaration of commerciality. Having established that commercial development is feasible, a field development plan is prepared and submitted to the government (The Department of Energy and Climate Change - DECC) for approval. Front end engineering design (FEED) would be carried out to define the surface facility requirements, oil and gas sales agreements are put in place, and planning applications are submitted for the various development activities. Shale gas or shale oil development typically involves drilling horizontal wells in the shale deposit at a relatively close spacing because of the low formation permeability. The horizontal drain-holes are typically between 1 and 2 km long and between 100 and 600m apart, covering the area of the shale but potentially also the vertical section (depending on the thickness of the formation). This relatively close well spacing is required to maximize an efficient recovery of the hydrocarbons. The wells would generally be drilled in a common direction that is perpendicular to the maximum horizontal principle stress direction in order to intersect potentially open natural fractures and so that the wells can be stimulated using hydraulic fracturing. Wells will be drilled from a surface location using a land rig.

The surface location (known as a well pad or well lease) typically has an area of about 3 to 5 acres subject to the capabilities of the drilling rig, the pad size, the optimum location for well placement within the shale body and finalising the appropriate facilities design and engineering. This not only reduces the environmental impact (by reducing the land take) but may also be more efficient (fewer rig moves). In the USA the average number of wells drilled from a single well pad is between two and three.

The horizontal wells are stimulated using hydraulic fracturing prior to their initial completion. At this stage the process of hydraulic fracturing may include multiple fractures in each well (multi-stage) to maximise the recovery of hydrocarbons and the productivity of the well. Hydraulic fracturing involves pumping water, proppant (treated sand or man-made ceramic materials) and chemicals at high pressure into a well. The type of chemicals used may vary between different locations and the regulations covering the reporting and use of such chemicals varies between countries. In the UK, chemicals used in drilling and hydraulic fracturing fluids are assessed for hazards on a case-by-case basis for each well by the appropriate environmental regulator (the Environment Agency - EA, Natural Resources Wales - NRW or the Scottish Environment Protection Agency - SEPA). Operators must declare the full details of the chemicals to the regulator and will publish a brief description of the chemical's purpose and any hazards it may pose to the environment, subject to appropriate

protection for commercially sensitivity information (DECC, Feb 2014). The high pressure fluid causes the formation around the well to fracture and the water and sand to enter the induced fracture as it propagates away from the well bore. Pumping ceases after the fracture has propagated a few tens to a few hundred meters from the well bore. The water dissipates into the formation leaving sand to prop open the fracture and provide a conduit for hydrocarbons to flow to the well. Hydraulic fracturing is normally carried out shortly after the well has been drilled, but may be repeated at times during the well's life to sustain production.

On the surface, well heads, flowlines and separators are installed. This is to separate any gas produced from liquids. For shale gas development, gas pipelines and gas processing facilities are installed to gather the gas and remove entrained (carried along) liquids such as water and condensate (hydrocarbon liquid condensed from gas due to a change in pressure and temperature) and impurities such as carbon dioxide. Typically small diameter flow-lines would connect each well on the well pad to a production header (manifold). Gas and liquids are then piped from each well pad to a central processing facility where liquids are separated from the gas and the gas dehydrated to remove moisture. Other impurities such as carbon dioxide may also need to be removed in order to meet the sales gas specification and the gas may have to be compressed to meet the gas sales pipeline pressure. The conditioned gas is metered and pumped into an export system (the National Transmission System in the UK). Liquids produced along with the gas are separated into water and condensate and temporarily stored in storage tanks. The liquid condensate anticipated as associated with shale gas production is expected to be small and hence would probably be exported by road tanker. Even in a typical oil well, gas is produced as associated gas which comes out of solution in the well as pressure decreases closer to surface conditions. Oil produced from shale oil wells will most likely be stored in storage tanks and transported to a refinery by road tanker. Many of the producing oil wells in the South East already transport oil using this method. Produced (and drill) water may contain salts and other chemicals and may be removed by tanker and taken to a central processing facility. Where produced water contains contaminants from hydraulic fracturing fluids (flowback water) it cannot be re-injected without treatment if it does not meet certain specifications. In addition permits will now be required from the Environmental Agency prior to disposal. Access roads to each well pad, the pipelines, processing facilities, camps, offices, and storage areas are also constructed. The number of central processing facilities that would be required would depend on the areal extent of the shale development area, accessibility, and shale thickness as well as environmental factors.

Figure 2.4.3 The Impact on Rural Landscape from Building Shale Gas Storage and Processing Facilities in and around Carroll County, OH

Photo Courtesy of: David Beach, GreenCityBlueLake Institute of the Cleveland Museum of Natural History

Development is likely to be phased and may start with a pilot project to prove that commercial development is feasible before embarking on a full scale development. Development is also likely to start in those areas with the most productive shale and the highest liquid yields at a relatively wide initial well pad and well spacing. Once production has started additional wells and well pads (known as infill wells) will be drilled to maximise the economic recovery. The initial development phase can therefore last some considerable time and might typically be from two to five years.

Once production has been established the producing life of a shale gas deposit may be around 20-30 years. During the production phase, there are on-going operational activities to manage the assets and keep the wells and facilities operating safely. Production facilities may need to be repaired or altered and wells may need to be re-fractured or cleaned out to sustain production. These are intermittent activities and each well may not require much attention for a number of years.

At the end of the productive life of the shale deposit the production facilities, wells and infrastructure are abandoned. During the abandonment phase wells that are no longer economic to produce are plugged with

cement and the surface well heads and casing removed. The well pads are decommissioned and rehabilitated to restore the site close to its original condition. Surface facilities are removed and the steel recovered for scrap. Pipelines may either be left in situ or recovered and sold as scrap. Different parts of the shale deposit may reach their economic limit at different times. The abandonment phase may therefore last a number of years and may start before the cessation of economic production from the field as a whole. Wells, well pads, pipelines, and facilities, that individually have become uneconomic and where there is no foreseeable use for them, are generally abandoned as soon as practically possible.

2.5 Drilling and Completing Shale Oil and Gas Wells

Shale oil and gas wells are drilled in the same way as conventional wells. The technology known as 'fracking' is a colloquial term for the engineering practice known as hydraulic fracturing. The wells are drilled from a drill site (well pad) with drilling confined to a rotary table drilling platform with a drill derrick located vertically above the well bore. Wells are based on a similar design to conventional oil and gas wells. Figure 2.5.1 shows a typical vertical well completion schematic. Wells are drilled in stages, with different casings (steel tubes) placed in at each stage to seal off the well from the rock through which the well is drilled. Each casing is cemented in place to ensure an effective seal between the well and any permeable rock, such as aquifers, and also from the surface. This is designed to contain any fluids that are produced through the well in the well from the reservoir to the surface. Table 2.5.1 illustrates a typical casing programme that might be used in a well.

Drilling technology has improved substantially over recent times and, through improvements to drilling equipment such as top drive drilling rigs and bottom-hole rotary steerable tools, the ability of drillers to drill long horizontal wells and to place the bore-hole more accurately in specific locations has significantly improved.

After drilling wells can be stimulated by hydraulic fracturing, either using a method to fracture single sections of the rock or, through isolating sections of the rock in sequence, multiple fractures can be placed along the horizontal section.

Wells are then completed which may include the placement of a tubing string inside the casing which may be run with a rubber packer between the tubing and the casing to seal the annulus from the surface and which may also include sub-surface valves to seal the well in the event of an emergency.

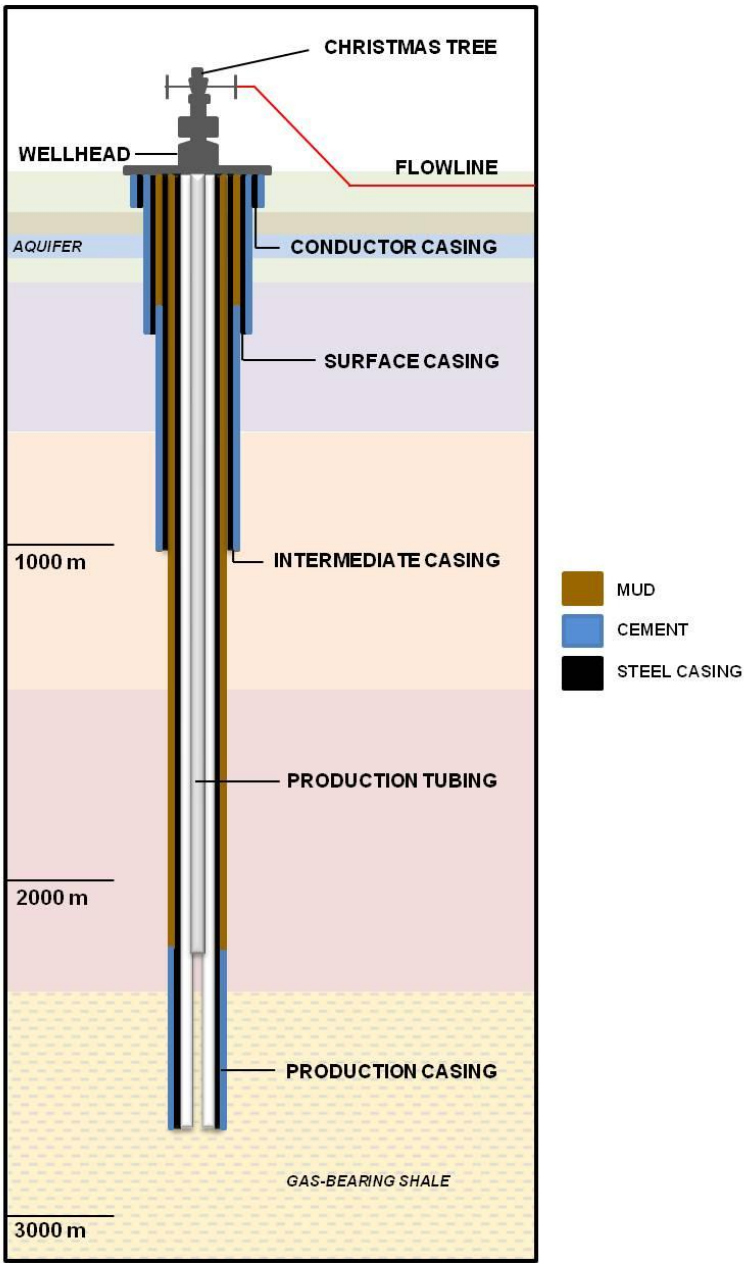


Figure 2.5.1 Typical Well Completion Schematic

Source: Petrenel

Table 2.5.1 A Description of the Types of Casing used in a Well

Casing	Description
Conductor Casing	During the first phase of drilling, a shallow steel conductor casing is installed vertically to reinforce and stabilise the ground surface.
Surface Casing	After installation of the conductor casing, drilling continues to the bottom of freshwater aquifers, at which point a second casing (surface casing) is inserted and cemented in.
Intermediate Casing	A third (intermediate) casing is installed from the bottom of the surface casing to a deeper depth. This is usually only required for specific reasons such as additional control of fluid flow and pressure effects, or for the protection of other resources such as minable coals or gas storage zones.
Production Casing	After the surface casing is set (or intermediate casing when needed), the well is drilled to the target formation and a production casing is installed either at the top of the target formation or into it.

Source: Adapted from Tyndall Centre (2011)

In a conventional reservoir, a well is drilled into the crest of the structure and hydrocarbons flow out due to their buoyancy and the pressure differential. The spatial distribution and low permeability of shale requires wells in shale gas operations to be closely spaced. The initial flow of hydrocarbons into the well will be from the artificially induced and natural fractures immediately next to the well. In relatively thin shales (<50 m) a vertical well will pass through only a relatively thin section, with limited shale thickness in contact with the well-bore. A horizontal lateral extension can extend as far as 2,000 metres and therefore, through a much larger flow area, a greater volume of hydrocarbons can flow into the well. It is important to note that in the UK, the prospective mature shales are much thicker than those in the USA, with the thickest part of the mature Carboniferous Bowland shale reaching 1900 metres. Therefore, theoretically, a vertical well in the thickest part of the Bowland shale could have the same coverage as a typical horizontal well in the USA. Also, multiple horizontal laterals off several wells at different depths could cover a large volume of shale, increasing production whilst minimising the surface impact.

Horizontal and long-reach wells are not a new concept and have been extensively used for conventional oil and gas development since the 1970s.

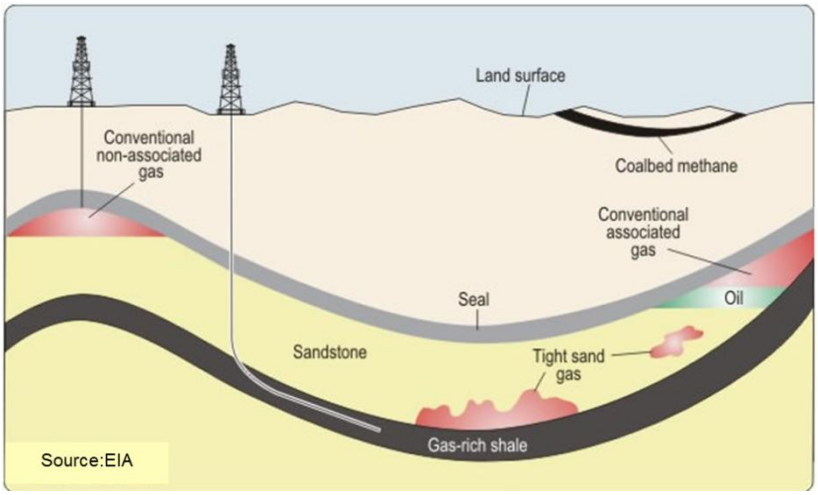


Figure 2.5.2 Shale Gas Horizontal Well Schematic

Source: U.S. Energy Information Administration, Shale Gas and the Outlook for U.S. Natural Gas Markets and Global Gas Resources, June 2011

2.6 Hydraulic Fracturing

In conventional reservoirs, artificial stimulation is sometimes required to increase the porosity and permeability around a well to enhance production rates. In limestones and calcite rich sandstones, stimulation can be done through the injection of acid into the formation, dissolving the calcite and creating artificial voids and pathways through which hydrocarbons can flow.

In formations where the permeability is low, a process called hydraulic fracturing is often used to increase permeability around a well. This involves pumping a water based fluid at high pressure with some or all of the following: proppant (treated sand or man-made ceramic materials) and chemicals such as hydrochloric acid, polyacrylamide, mineral oil, isopropanol, potassium chloride, ethylene glycol and low concentrations of pH buffers, corrosion inhibitors, biocides and gelling agents (Stuart, BGS 2012) into the shale to create and support fractures. As previously discussed, shale has very low permeability which means that for it to yield adequate hydrocarbon flow, stimulation through hydraulic fracturing is required. Figure 2.6.1 is an illustrative example of the process of hydraulic fracturing.

Hydraulic fracturing is not a new concept. The technique has been readily used in the hydrocarbon industry over the past 50 years. Hydraulic fracturing has occurred both onshore and offshore in conventional sandstone reservoirs where the permeability is low. Of the 2000 wells drilled onshore in the UK in the last 30 years, approximately 200 (10%) of these have been stimulated using hydraulic fracturing (Koppelman, B. et al, 2012). Examples include the Sherwood Reservoir at Wytch Farm and the Elswick gas Field in Lancashire, 4.5 km away from Cuadrilla's Preese Hall Well.

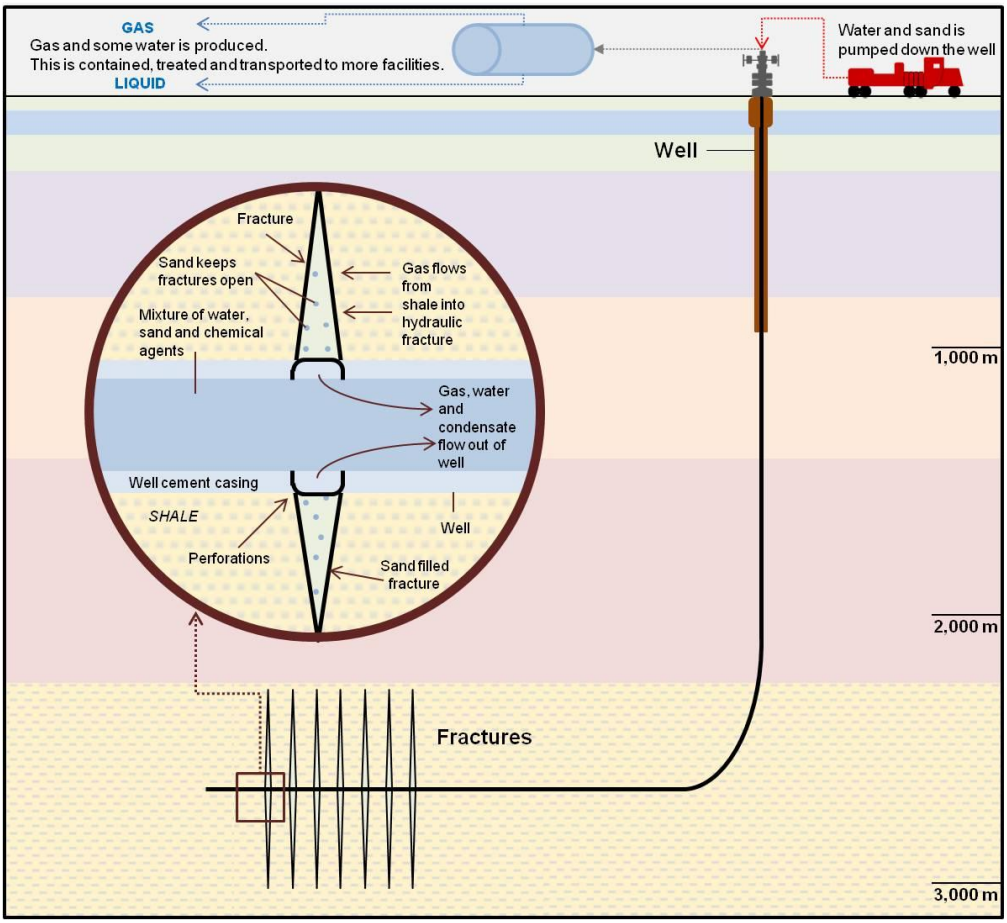


Figure 2.6.1 An Illustrative Example of the Process of Hydraulic Fracturing in a Gas Well

Source: Petrenel

2.7 Well Spacing and Hydrocarbon Recovery Factor

There are two variables to consider when estimating spacing between wells. One is the well pad spacing (i.e. distance between well sites on the surface) and the second is the distance between below ground well trajectories that may involve vertical, horizontal or multi-lateral wells drilled from the surface location. The licence sections in the USA are often related to the one square mile grid or 640 acres. The well trajectories, especially horizontal sections for wells, are often planned to both maximize the recovery of hydrocarbons, and minimize the potential interference between wells (both in the drilling/completion operation and when producing) as well as to optimize the orderly placement of the fractures along the horizontal section which are normally set in relation to the natural rock stress field for the area.

Dr Dave Healy (2012) notes that the nucleation and propagation of hydraulic rock fractures are chiefly controlled by the local in-situ stress field, the strength of the rock (stress level needed to induce failure) and the pore fluid pressure (Secor, 1965; Phillips, 1972). Temperature, elastic properties, pore water chemistry and the loading rate also have an influence.

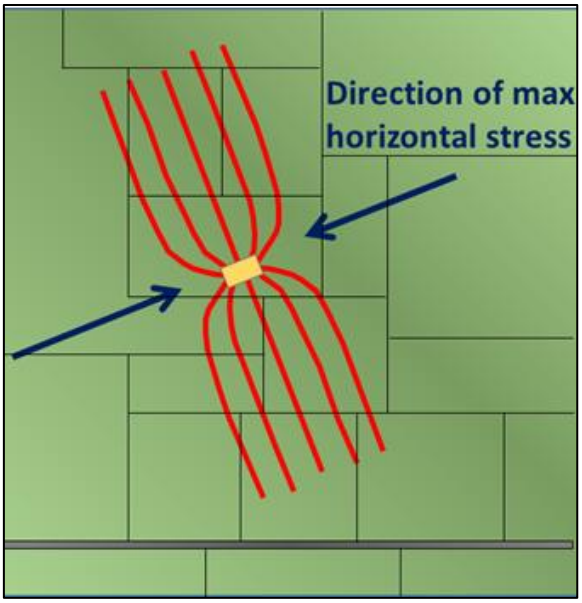


Figure 2.7.1 Well Orientation with Respect to the Direction of Maximum Horizontal Stress

Source: Petrenel

There is, therefore, a need to establish the local stress field in order to then orientate the planned well paths and drain a specific area that will largely depend on the number of wells that can be drilled from the surface location and the distance that can be reached in the horizontal plane. In addition the thickness of the shale at any one location may also determine whether horizontal sections can be "stacked" one above the other to deplete the shale at various vertical levels. The length of the horizontal section will depend on both the physical nature of the rock through which the well is drilled and the capability of the surface equipment. This is likely to range from as little as 500 metres up to 3000 metres. As shown above if the well grid is based on parallel multi-horizontal wells there is a closer distance between horizontal tracks as compared with the distance between drill centre lines**.**

In a comprehensive study of the Barnett shale development in the USA (Browning et al, 2013), a team from the University of Texas has reviewed the performance of over 15,000 shale gas wells in order to predict ultimate recovery. This study estimates that from the existing wells (just over 18,000) ultimate recovery is estimated to be around 10% of gas in place. The area covered by these wells results in an average well spacing of around 150 acres per well.

For an average horizontal well of, say, 1000 metres this would equate to spacing between horizontal tracks of around 600 metres. The study also predicts that additional drilling may see the ultimate recovery approach 19% of gas in place. Quoted well spacing from other sources ranges from 40 acres (160 metres between tracks) to 640 acres (2.5 km between tracks).

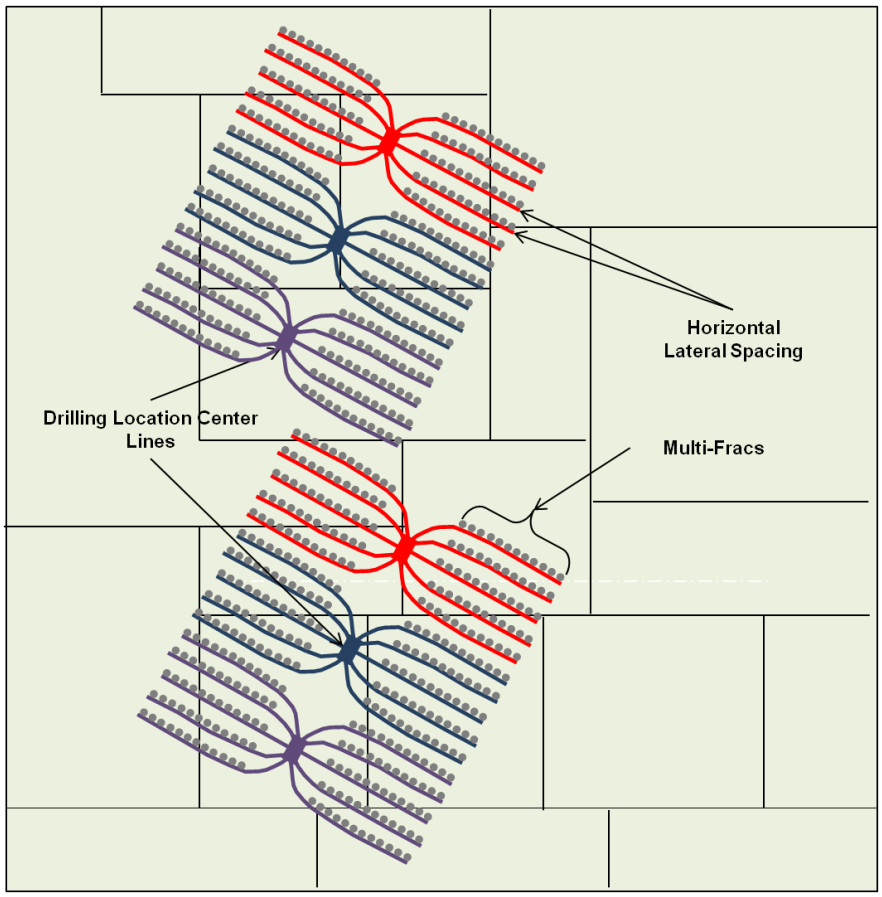


Figure 2.7.2 Drill Lines, Multi-Lateral Well and Multi Frac Spacing

Source: Petrenel

Petrenel has completed a generic simulation model to evaluate the behaviour of a single horizontal well placed in shale with typical shale parameters and has tested the factors that have an impact on well productivity and gas recovery (Appendix A). The model has been enlarged to assess well interference and spacing. According to a 2011 report published by DECC, the USA Barnett Shale may provide "an indicator of the possible productivity of the UK Carboniferous shale gas play" (DECC, 2011). This potential analogy between the Upper Bowland and Barnett shales lead to the selection of the reservoir parameters largely based on the data available from the Barnett shale.

Sensitivities were run on the following parameters: fracture dimensions (half-length, fracture width), reservoir thickness, permeability (matrix and fracture) and well type. (NB. Fracture half-length is the length of one side of the fracture assuming that the fracture propagates equally from two opposite sides of the well in the direction of the maximum principle stress).

These sensitivity runs confirmed some of the conclusions found in the literature; as fracture half-length increases, recovery increases (+50% fracture half-length results in an additional 41% gas recovered compared with the base case), as reservoir thickness increases recovery increases and as both the permeability of the fracture or the matrix increases, recovery increases. It is important to note that matrix permeability has a greater effect on the recovery than the fracture permeability. However, some parameters seem to have an optimum value: a horizontal well yields the largest recovery when the fracture spacing is 150m for the reservoir modelled. Well spacing also has an optimum value; a given well has a drainage area (0.87 km^2 or 214 acres in the model). When the model was run with closer spacing between wells and individual well drainage areas overlapped, negative interference occurred between the wells and fractures and the recovery per well decreased. Ultimate recovery from a single well ranged from 1.3 to 6.2 bcf with a base case of 2.4 bcf.

The simulation study confirms that the drainage area around each horizontal well is quite narrow and as stated above is dependent on the length of the fracture induced into the shale. If wells are closely spaced then these drainage areas (and potentially the fractures) may overlap and recovery will be less efficient, but this spacing is likely to be quite small before this occurs.

3. SHALE OIL AND SHALE GAS IN THE UK

3.1 Introduction

Although at a fledgling stage of evolution, the last two or three years has seen the initiation of a shale gas industry in the UK. There are many interested parties, some with diverse opinions as to the pros and cons of developing the industry in the UK. Notwithstanding the massive scale and rate of development that is occurring in the USA it is likely that a similar scale and rate of development in the UK would be challenging given the constraints of population density, land use, lack of associated infrastructure and concerns for the environment. Nevertheless the coalition government has indicated that, given the potential benefits it sees at a national level, there is an overriding intent to promote the first stages of evaluating the potential. To date there has been no advance in the development of a Shale Oil industry in the UK. The commercial proposition for shale oil and gas development is a complex issue in so far as it will depend on completion of the initial proving of the resource and a reduction in some of the uncertainty that surrounds the presence and yield of the resource. In evaluating the proposition the oil and gas industry and government continue to address a number of issues that still require further clarification:

- Ensuring there is adequate regulation for shale oil and gas development to address any additional risks compared with conventional oil and gas projects;
- Modifying planning policy and process where necessary to address the concerns of those effected by a shale project and allow the representative bodies who have an interest to play an effective part in the planning process without unreasonably delaying its progress;
- Ensuring there are adequate manpower resources for the regulatory bodies with oversight for such projects;
- Confirming the fiscal terms that will apply and ensuring adequate capital is targeted at such projects.

Although parallels obviously can be drawn by the experience of the industry in the USA, the method and rate of implementation of shale oil and gas development in the UK may differ in a number of ways because of the historical low level development of the onshore oil and gas industry in the UK and its limited infrastructure and support services as compared with the USA and also the difference in the current and future regulatory environment.

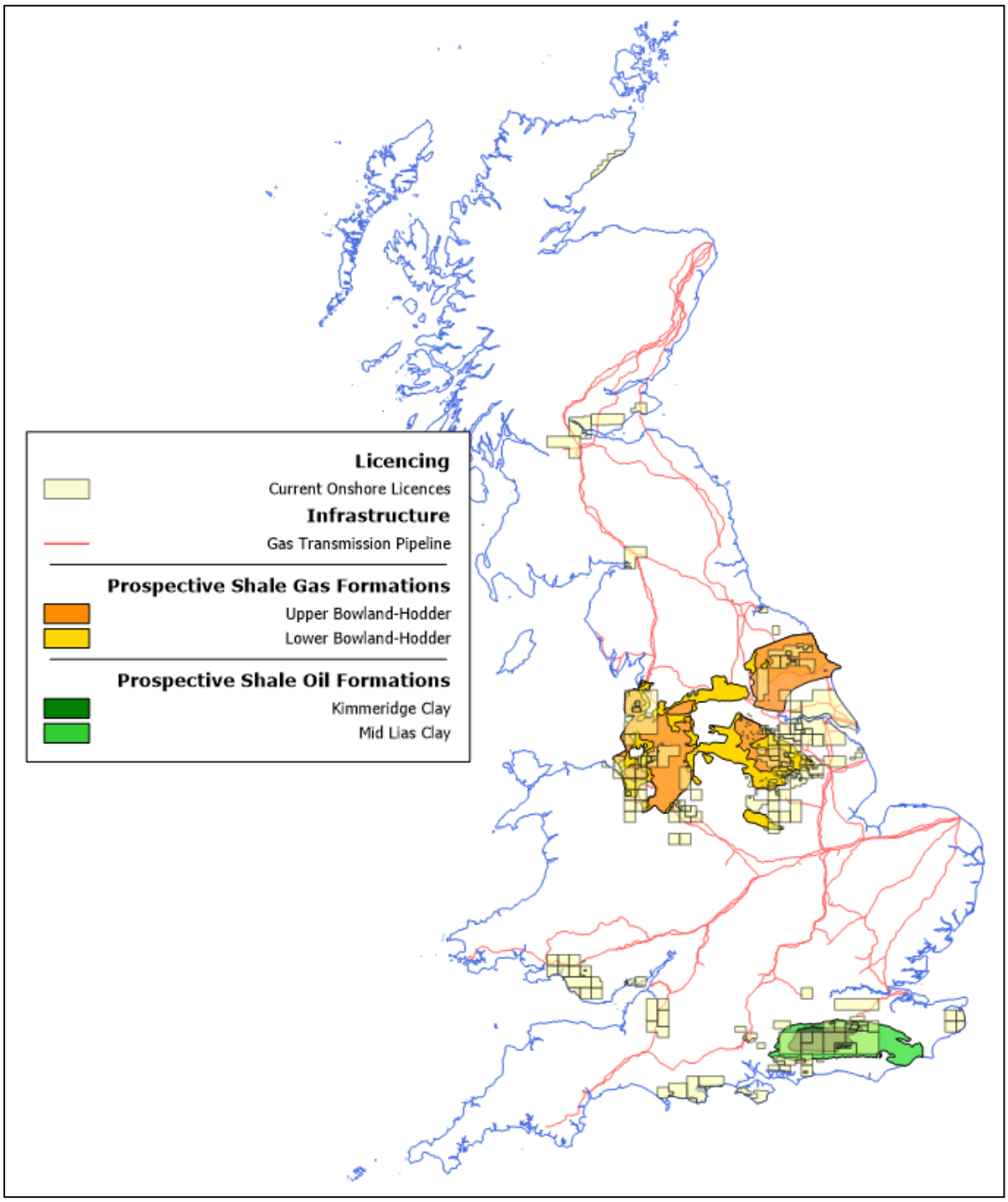


Figure 3.1.1 Prospective Shale Gas and Shale Oil Formations in the UK based on the two studies by the BGS

Data Source: BGS & DECC

The BGS 2013 report into the Bowland-Hodder formation of Northern England only considered the shale gas potential. It is likely that oil is present within the formation where burial did not reach the gas window.

3.2 Shale Gas Resource Potential

Shale is widely present within the geology of the British Isles, occurring across most of the UK in outcrop or subcrop. In the UK, the main age constrained potential shale gas formation is the Carboniferous Bowland-Hodder shale which is present in multiple basins across Northern England.

The BGS report (2013) that assessed the shale gas potential of the Carboniferous Bowland-Hodder Formation basins in the north of England, concluded that there is likely to be substantial volumes of gas in place across multiple basins (P50 of 1329 tcf).

The Jurassic shale formations of the Weald Basin and Wessex Basin are considered too immature for thermogenic gas generation. However, some academics believe that the Lower Lias may have been buried sufficiently for gas to be generated. This is disputed by the BGS in Andrews (2014) who believe that the Lower Lias may not have been buried sufficiently and that the organic content in the Lower Lias is too low for any substantial gas generation.

There are other potential shale gas plays including the Cambrian Tremadoc strata of Wales and Western England, the Carboniferous rocks of the Midland Valley basins in Scotland and the Palaeozoic basement of Southern England. The BGS is currently undertaking a third study examining the shale gas potential of the Midland Valley of Scotland. The results of this are due late 2014.

The Carboniferous Bowland-Hodder Shale of Northern England

Between 2012 and 2013 the British Geological Survey (BGS) and The Department for Energy and Climate Change (DECC) conducted a study which explored the resource potential of the Bowland-Hodder Carboniferous shale of Northern England. The report examined the spatial distribution of the shale, the vertical variation and it's prospectivity by postulating the likely upper limit of gas mature shale using maturity data from wells and boreholes. This information was collated to build a probabilistic model suggesting a net rock volume of gas mature shale.

The Bowland-Hodder Shales were deposited in a marine environment, across multiple tectonically active basins, during the Visean and Namurian epochs in the Carboniferous (circa 347-318Ma). The thickness of the Bowland-Hodder unit varies between the multiple basins and within each basin. The shales are generally much thicker than shales of similar age in the USA, with thicknesses within the basin depocentres reaching up to 5000m thick. For comparison the Carboniferous Barnett shale in the USA has a gross thickness of 50-250m.

Table 3.2.1 Total Organic Content Percentage of the Bowland-Hodder Shale and USA Analogues

Formation	Age	TOC Low (wt. %)	TOC High (wt. %)	TOC Avg (wt. %)
Barnett (USA)	Early Carboniferous	0.02	9.94	3.74
Fayettefille (USA)	Early Carboniferous	0.71	7.13	3.77
Bowland–Hodder (UK)	Early Carboniferous	1.00	8.00	3.00

Data Source: Adapted from DECC, 2013

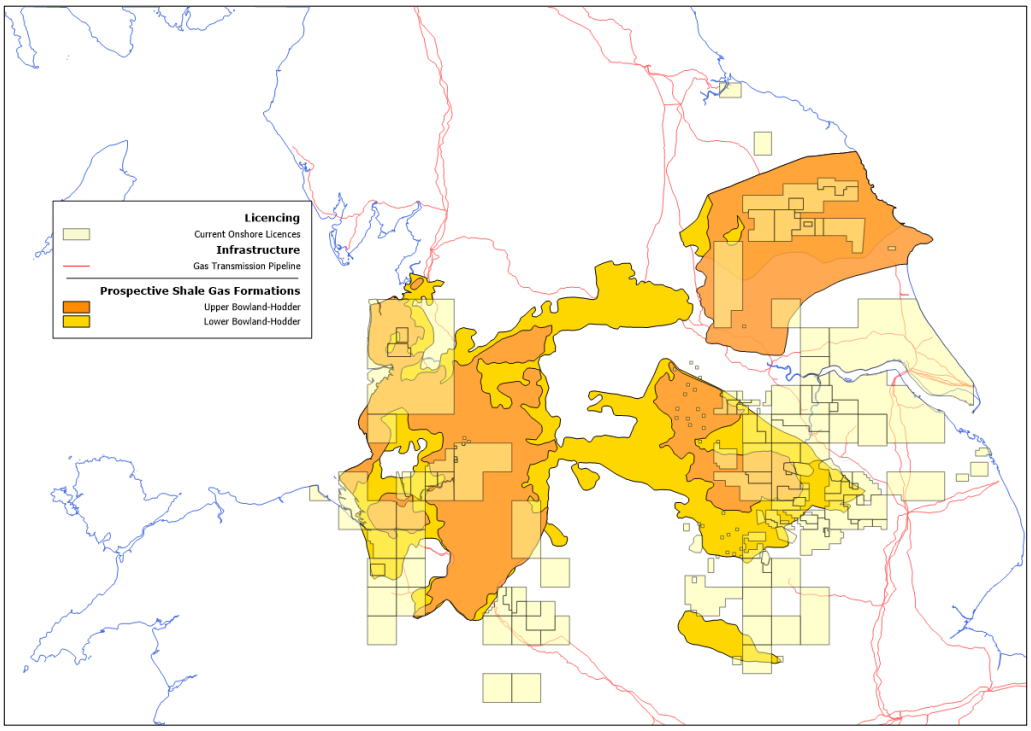


Figure 3.2.1 Spatial Distribution of the Upper and Lower Bowland Hodder Prospective Shale, whereby it is mature enough for gas generation using the cut offs of 5000ft and vitrinite reflectance greater than 1.1

Data Source: BGS & DECC

The BGS and DECC used the net volume of gas mature shale to calculate an estimate for gas initially in place (GIIP). This includes both free gas initially in place (GIIPf), gas located within the space between the sediment grains, and adsorbed gas (GIIPa), gas adsorbed to the surface of organic sediment. The BGS used a probabilistic model, with a Monte Carlo simulation predicting a range of possible volumes. Figure 3.2.2 shows the formula and data used to calculate the GIIP. Table 3.2.2 shows the results of the BGS' probabilistic model.

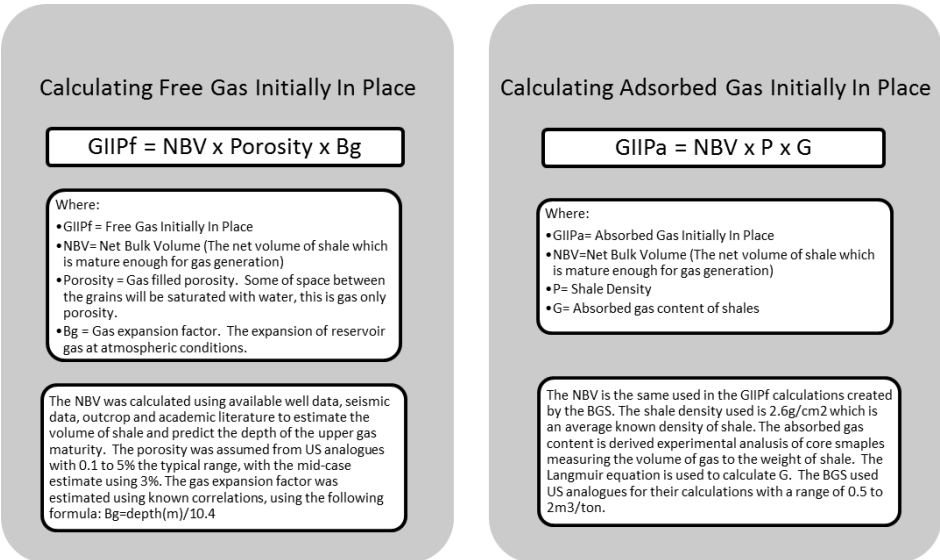


Figure 3.2.2 The calculations used by the BGS for both free gas and adsorbed gas volumes in place within the Bowland Shale, the values used and the source for these values

Source: Adapted from BGS

Table 3.2.2 Total GIIP Estimates of Prospective Bowland-Hodder Shale of the BGS' Probabilistic Model

Total Gas In Place Estimates (tcf)			
	Low (P90)	Mid (P50)	High (P10)
Upper Unit	164	264	447
Lower Unit	658	1065	1834
Total	822	1329	2281

Data Source: BGS

The Jurassic Shales of the Weald Basin

Between 2013 and 2014 the British Geological Survey (BGS) and The Department for Energy and Climate Change conducted a study which explored the resource potential of the Jurassic shales of the Weald Basin. The report concludes that the Jurassic shales have not been buried sufficiently for thermogenic production of gas to occur and the shales were more likely to contain oil. Section 3.3 examines the shale oil potential for the Weald Basin in more detail.

Despite the BGS' report concluding that it is unlikely that the Weald basin contains any formations mature enough for shale gas generation, there are some academic papers (Penn et al. 1987) that suggest the lowest part of the Lias formation, was buried deep enough for sufficient thermogenic gas generation to occur prior to tectonic inversion.

Current Gas Fields in the Weald Basin

Over the past 50 years there have been numerous discoveries of oil and gas in the Weald Basin. Whilst the number of oil fields outweighs the number of gas fields considerably, there have been three gas fields discovered in the basin depocentre at: Albury, Bletchingley and Godley Bridge. The source of the gas at Godley Bridge was investigated by Ebukanson and Kinghorn (1986). They reconstructed the base of the Lias in the deepest part of the basin in the North West Sussex and Southern Surrey region. The calculated TTI values suggest maturity levels around 1.2% R_0 at the Oligocene-Miocene boundary. The same authors suggest that, following the suggested modification of Lopatins TTI by Tissot, the base of the Lias in the basin depocentre must have been much higher than 1.2% at maximum burial prior to Miocence tectonic uplift. They also believe that the close association of gas in the area with the thickest Jurassic succession in the Weald appears to support a Liassic source of gas.

The Lias

The Lower Lias rocks of the Lower Jurassic (180-200 million years old) consist of cyclically interbedded shales, mudstones, marls and micritc limestones. The shale is thought to have been deposited in an anoxic deep water environment. The shale was originally rich in organic material, with Total Organic Contents (TOCs) primarily in the range of 0.5 to 2.1% (Butler and Pullan 1990), while some shales recorded TOCs of up to 7% (Penn et al. 1987). The Lias shale is known to be the source rock for several conventional oil and gas fields onshore in the UK, for example they are thought to be the main source at the Wytch Farm oil field in Dorset, Europe's largest onshore oil and gas field. The formation has been well studied in outcrop and from well data in the Wessex Basin and the Paris Basin. However, it is the view of the BGS that some authors have optimistically extrapolated data from Dorset to the subsurface of the Weald Basin, whilst other authors refer to a lowering of TOCs eastwards from Dorset into and across the Weald Basin. The BGS concluded that there is no significant Jurassic shale gas potential in the Weald Basin, and suggested that "even the deepest Lias Shales are unlikely to have attained sufficient maturity to allow for significant gas generation".

However some authors have suggested that the Lias may have been buried sufficiently for significant thermogenic gas generation. Penn et al. (1987) used Lopatin Time Temperature Index (TTI) calculations to

model the thermal maturity of the Lias across the Weald Basin. They were calibrated using basin wide kerogen maturation studies and found that the basin depocentres were mature enough for oil and gas generation. The same author stated that some of the Lower Lias shales had TOCs of up to 7% although these samples were from Dorset outcrops.

Whilst the Lias is a potential source of hydrocarbons, the exact maturity is variable, given the complex structural evolution of the basin and the lack of data of lateral variation in facies across the basin. The TTI profiles from Penn et al. (1987) predict that the Lias lies within the oil generation window for much of the Weald Basin, with the deepest axial part of the basin deep enough for sufficient gas generation. Ebukanson and Kinghorn (1986) estimate that the organic maturity (R_0) values for the Lower Lias is in the range 0.8 to 0.9% in the central Weald Basin at Penshurst.

The subsidence history was reconstructed by Penn et al. (1987) with the suggested onset of oil generation occurring during the Lower Cretaceous and peaking during the Mid Cretaecous. Thermogenic gas generation began during the Upper Cretaceous and peaked during the mid-Tertiary around 48Ma. Figure 3.2.3 shows the subsidence history of the three main Jurassic shales.

Other Formations

The other Jurassic formations have not been buried enough to reach thermal maturity for thermogenic gas generation to begin. The BGS report (2014) reports in detail the maturity levels of all Jurassic shale formations in the Weald Basin. Section 3.3 outlines the findings of this report and the impact on the shale oil potential of the other Jurassic formations.

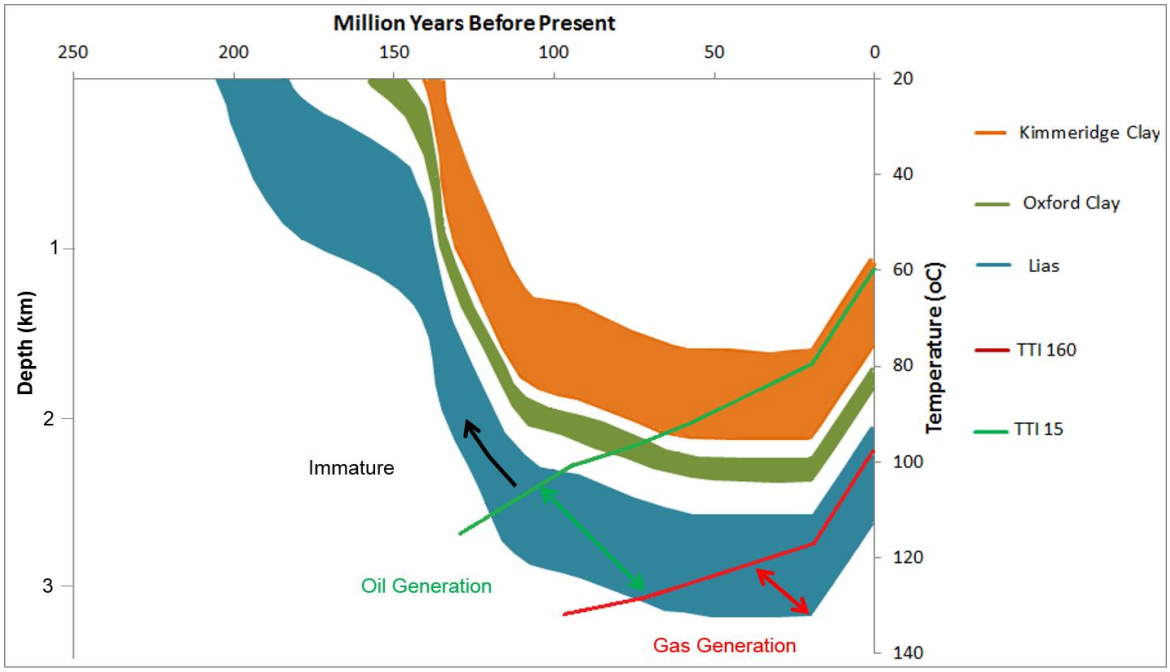


Figure 3.2.3 Subsidence History Curves for the Three Main Jurassic Source Rocks in the Central Weald Basin

The TTI values are plotted against this to give an indication of likely hydrocarbon generation. Only the Lias appears to have been buried deep enough for the generation of thermogenic gas.

Data Source: Penn et al, 1987

Estimates of Gas Initially In Place (GIIP)

The BGS report (2014) concluded that it is unlikely that there is any gas initially in place within the shale of the Weald Basin, however given the lack of well data from the deepest part of the basin, thermogenic gas generated in the lowest part of the Lias cannot be ruled out. There is also a possibility that gas in the area is sourced for an older pre-Jurassic source (Smith, 1993).

3.3 Shale Oil Resource Potential

As stated in section 3.1 and 3.2 the BGS conducted two studies on behalf of DECC examining the resource potential of two age constrained shale units: The Carboniferous Bowland-Hodder of Northern England (2013) and The Jurassic Shales of the Weald Basin (2014). The report into the Bowland-Hodder formation found that the shales had matured enough for significant gas generation. The report stated there are 'inadequate geotechnical data to estimate the amount of oil-in place". It is likely that there are volumes of shale oil present within the Bowland-Hodder, particularly in the younger parts of formation where burial has been restricted to the oil window. The distribution and volumes of potential shale oil in the Bowland-Hodder formation were not assessed. The report into Jurassic Shales of the Weald Basin (Andrews, 2014) concluded that oil could have been generated from any or all of the five shale formations in the Weald basin: the Mid Lias Clay, the Upper Lias Clay, the Oxford Clay, the Corallian Clay and the Kimmeridge Clay.

There are several criteria that determine the oil potential of a shale formation such as burial depth, kerogen type, original hydrogen index, clay content and porosity. The main properties that are evaluated to determine whether shale has good oil potential are:

- Total Organic Carbon (TOC). A shale must be rich in organic matter and have a high TOC. The BGS used a 2% cut off to determine a potentially viable shale oil.

- Free Oil (S1). Geochemical analysis is used to determine the 'free-oil' content within the shale. A shale with good oil potential should have S1 values greater than 2mgHc/g Rock (equiv to 50bbl of oil per acre-ft of rock).

- Thermal Maturity (R_o) – The depth to which a rock is buried, coupled with the proximity to a heat source determine the likely points at which kerogen matures and begins to expel hydrocarbons. Vitrinite Reflectance calculations or R_o give a typical percentage range at which oil is generated. R_o values for the oil window are typically 0.6-1.1%.

It is important to note that the BGS study focused on the TOC and Free oil content of the shale units and the prospectivity of these shales as producers of oil. In the USA many of the Shale Oil plays, such as the Bakken in North Dakota, target the interbedded different lithologies due to their natural higher permeabilities, higher porosities and higher fissility. Therefore the Oil Initially In Place OIIP does not reflect the volumes of prospective hybrid units, such as the micrites of the Kimmeridge Clay.

Lower Lias

In the 2014 study, the BGS concluded that although the Lower Lias is considered an important source by many authors, the transition from a shale to a limestone dominated formation from the Wessex Basin to the Weald Basin downgrades its significance as a potential source of hydrocarbons. The formation is composed of a basal limestone with the remainder of the unit composed of limestone and interbedded shales. The average TOC from the samples within the oil window is 0.9%, with the highest TOC samples from the formation in the west of the study area, further supporting the hypothesis that the source potential increases west into Dorset. Average S1 values in the formation are 0.28 mgHC/gr Rock.

The study acknowledged that the formation is mature enough for oil generation and may have reached the gas window but given the low TOCs and S1 values, the formation has organic carbon contents insufficient for hydrocarbon generation, for both oil and gas. However, the study also acknowledged that there is limited data from the deepest parts of the basin.

Middle Lias Clay

The Middle Lias Clay is represented by a 38-90m thick mudstone which is sandwiched between the Lower Lias Limestone-Shales and the Middle Lias Limestones. The Mid Lias Clay has an average TOC in the mature zone of 1.1% and an average S1 of 0.88 mgHC/g Rock. The Middle Lias is likely to have entered the oil window R_o > 0.6, but given the low TOC and lack of evidence of free oil within the rocks the Mid Lias Clay is considered to have limited Shale Oil potential. The Mid Lias Clay is immature for gas generation. Above the Mid Lias Clay is the Middle Lias Limestone.

Upper Lias Clay

Lying immediately above the Middle Lias Limestone is the 15-67m thick mudstone Upper Lias Clay. The formation has an average TOC of 1.45% within the oil window and an average S1 value of 1.07 mgHC/g Rock. The net thickness of mature organic rick shale in the basin depocentre is approximately 34m. However, similarly to the Mid Lias Clay, despite parts of the formation being mature enough for oil generation the Upper Lias Clay has limited shale oil potential given the lack of evidence of free oil within the formation and TOC values rarely exceed 2%. The Upper Lias Clay is immature for gas generation. Above the Upper Lias Clay is the Upper Lias Siltstones-Sandstones Formation.

Oxford Clay

The Oxford Clay varies in thickness across the basin but is approximately 60-150m thick in the central of the Weald Basin. The lithologies within the Oxford Clay vary across the Weald. In the extreme east there is a uniform gamma ray log response and elsewhere there is a carbonate-rich unit that separates an upper and lower shale formation. The lower shale formation is the most organic rich part with a log derived maximum TOC of 7.8%. There are limited samples of the Oxford Clay for S1 analysis, with the highest measured S1 yield of 2.6 mgHC/g Rock. However, of the few samples analysed the average present day S1 value is 1.16mgHC/g Rock. The lower shale unit is around 12-30m thick and is best developed in the west of the Weald Basin. The oxford clay is considered to have some potential for oil in the mature sections particularly in the lower section where free oil is known to exist. The Oxford Clay is immature for gas generation.

Corallian Group

The shift from shale to sandstone and limestone indicates the boundary between the Oxford Clay and the Lower Corallian of the Corallian Group. The sandstones and limestones of the Corallian group form the reservoirs of numerous oil and gas fields in the Weald Basin. The Corallian Clay is a 15-75m thick shale unit which lies above the Lower Corallian and below Upper Corallian. The Corallian Clay is not considered to be a major source rock for the Weald petroleum system, yet the average TOC is 1.1% with a highest TOC of 5.4%. The average present day S1 is 0.60mgHC/g Rock. The Corallian Clay is considered to have some shale oil potential in the mature sections where free oil is known to exist. The Corallian Clay is immature for gas generation.

Kimmeridge Clay

The reoccurrence of shale above the Upper Corallian indicates a transition back into a deep offshore environment. The formation is thickest in the basin depocentre with over a 550m thick section recorded and thins out radially. The average TOC in the formation is 2.8% which is the highest out of all of the Jurassic shale formations. The average present day S1 value in the core mature area is 1.21mgHC/g Rock. However, as with all of these samples the analysis doesn't take into account evaporitic loss. A 50% evaporitic loss adjusts the S1 to 2.42mgHC/g Rock in place. This equates to an average oil yield of approximately 62.6 bbls of oil per acre-ft of shale. The BGS noted that there are several coccolith micrite beds throughout the formation and these may be targets for a hybrid shale play, similar to plays seen in the Bakken Shale in northern USA.

Many authors such as Penn et al (1987) suggest that whilst the Kimmeridge Clay may be thermally mature in the deepest parts of the central Weald, it is likely to be immature across the rest of the Weald. However, the BGS noted the presence of oil within the Kimmeridge in the 'I Micrite' layer. This was reported to be a target in the Balcombe 1 well and could suggest that the Kimmeridge may be mature enough and have the ability to generate oil over a larger area than previously thought. The actual boundary of maturity is unknown given the uncertainty in vitrinite reflectance, particularly with data from the 1980s. It is likely that the Upper Kimmeridge has a smaller prospective area given its shallower maximum burial and shallower current day depth after uplift. Overall the Kimmeridge clay is considered to have the most potential of all of the Jurassic shales below the mature cut off, particularly given the known high TOC, its substantial thickness, its known maturity and free oil that exists. The Kimmeridge Clay is not mature enough for gas generation.

Estimates of Oil In Place

The BGS used seismic data, well logs, core samples and academic literature to create a 3D model of net organic rich and potentially productive shale. A minimum maturity cut off was applied of 0.6% R_o which represents maximum burial depth prior to Cenozoic uplift. The BGS also used minimum current day depth cut offs of 1000

and 1500m (this is based on the EIA's protocol that "areas shallower than 1000m have lower reservoir pressure and thus lower driving forces for oil and gas recovery. In addition, shallow shale formations have risks of higher water content in their natural fracture systems"). The BGS used a Monte Carlo simulation to determine oil in place for each of the five main Jurassic Shales using a maturity cut-off at 2,440m maximum burial depth. The results of this are shown in Table 3.3.1. Figure 3.3.1 describes the equations and values used in the calculations.

Calculating Oil Initially In Place

OIIP = NPPSV x FOY

Where:
- **OIIP = Oil Initially In Place**
- **NPPSV = Net organic rich and Potentially Productive Shale Volume (net mature shale volume x proportion of organic rich shale).**
- **FOY = Free Oil Yield (bbls/acre-ft) FOY=corrected S1 (mgHC/gRock) x rock density (g/cm^3) ÷ oil density (g/cm^3) x unit conversion factor**

The NPPSV is calculated using available well, seismic and academic literature to determine a net volume of organic rich and potentially productive shale which is within the mature zones where R_o > 0.6%. The FOY uses S1 values from Rock-Eval analyses from wells within the core mature area. The corrected S1 takes into account the free oil density (oil that is extractable) and evaporitic loss (see Andrews 2014). The study assumed typical shale densities 2.55—2.65 and oil densities of 25°, 40° and 45° API oil. The densities of oil from conventional fields in the Weald Basin fall in the range 35-42° API (Butler and Pullan 1990).

Figure 3.3.1 Equations and values used in calculating free oil initially in place within mature organic-rich shale

Source: Adapted from DECC

Table 3.3.1 Volumes of oil initially in place for the five potentially prospective Jurassic shale formations in the Weald Basin.

These are in place volumes, that is, oil found within the pore spaces of the shale. Actual recoverable volumes will be significantly less than this and will depend on a variety of engineering issues.

Total Oil In Place Estimates (Billion bbl)

	Low (P90)	Mid (P50)	High (P10)
Kimmeridge Clay	0.11	0.61	1.44
Corallian Clay	0.11	0.30	0.61
Oxford Clay	0.41	0.96	1.70
Upper Lias Clay	0.22	0.52	0.85
Middle Lias Clay	0.27	0.64	1.15
Total	2.20	3.21	4.40

Data Source: Andrews, 2014

3.4 The Government's View and Role

Government Publications

On its website the coalition government has stated that in its opinion shale gas has the potential to provide the UK with greater energy security, growth and jobs and is encouraging operators to determine the potential through a safe and environmentally sound exploration programme.

Following the drilling of the first shale gas well in recent times by Cuadrilla Resources in 2010, and the suspension of operations after the hydraulic fracturing of the well triggered a localised seismic event, the government agreed that a review be carried out and withdrew their permission for continued shale gas activity. Cuadrilla carried out a number of studies following the seismic event and the government commissioned a review of the findings from these reports followed by a further review conducted by the Royal Society and Royal Academy of Engineering (Koppelman, B., et al, 2012). This concluded that "the health, safety and environmental risks associated with hydraulic fracturing (often termed 'fracking') as a means to extract shale gas can be managed effectively in the UK as long as operational best practices are implemented and enforced through regulation." The report also reinforced the need for effective monitoring and proposed a "traffic light" management of similar future operations.

In March 2013 the then Secretary of State for Energy and Climate Change, Ed Davey MP, introduced The Office of Unconventional Gas and Oil (OUGO) with the government's stated intent to promote the safe, responsible and environmentally sound recovery of the UK's unconventional reserves of gas and oil, headed initially by Duarte Figueira. Ed Davey confirmed his opinion on UK shale gas in his quote: "But shale does….over-time, with public acceptance and weighed against its environmental impact…..shale does have the potential to contribute significantly to the UK's energy security, to attract inward investment, to boost growth and jobs in certain areas, and to make a notable contribution to the Exchequer." Countering this statement he also notes that: "The communities in which such rapid development... (of shale gas)… has taken place have found the attention they have received a curse as well as a blessing." He then cleared the way for re-starting exploration activity for shale gas.

The Energy and Climate Change Committee issued a report in April 2013 on the impact of Shale Gas on Energy Markets highlighting that the development of shale gas in the UK is unlikely to resolve energy supply issues for the future but that the government should look to encourage the development of the skills necessary to develop shale gas. It was also recognised that shale gas development in the USA is unlikely to be developed in a similar way in the UK and gas prices are not likely to fall substantially as a result of a domestic shale gas industry.

A government research briefing was issued in September 2013 to further elaborate on the background, regulatory regime, environmental considerations and government policy for shale gas. Also in September, DECC issued a report on "the Potential Greenhouse Gas Emissions Associated with Shale Gas Extraction and Use". The report concluded that if adequately regulated, local GHG emissions from shale gas operations should represent only a small proportion of the total carbon footprint of shale gas, which is likely to be dominated by CO_2 emissions associated with its combustion. In addition any local GHG emissions from shale gas operations would fall within the non-traded sector of the UK's carbon budgets. If the carbon budgets impose a binding constraint, any increase in emissions associated with domestic shale gas operations would have to be offset by emissions' cuts elsewhere in the economy. The overall carbon footprint of shale gas extraction and use was quoted as likely to be in the range which makes shale gas's overall carbon footprint comparable with gas extracted from conventional sources and lower than the carbon footprint of Liquefied Natural Gas (LNG). Also, when shale gas is used for electricity generation, its carbon footprint is likely to be significantly lower than the carbon footprint of coal. However the production of shale gas could increase the global cumulative GHG emissions if the fossil fuels displaced by shale gas are used elsewhere. 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 (MacKay & Stone, 2013).

In July 2013 the Department for Communities and Local Government issued a guidance note for planning applications associated with onshore oil and gas including "unconventionals" (shale gas, shale oil and coal bed methane). Also in July the government issued a consultation paper for the taxing of shale gas production suggesting that there will be some relief applied to the existing conventional oil and gas tax levels to encourage shale gas development and offset high initial costs.

Government Regulatory Control

The Department of Energy and Climate Change (DECC) plus its regulatory partners are charged with permitting and oversight of both onshore and offshore exploration and development activity for the oil and gas upstream industry.

At the present time the process of obtaining consent to drill a well is the same whether the well is targeted at conventional or unconventional hydrocarbons.

An operator proposing to drill an exploration well is required to:

- Hold a licence from DECC. DECC issues a licence in licence rounds which grant exclusivity to operators within the licence area.

- Negotiate access with landowners for the drilling pad area. Permission must also be obtained from the Coal Authority if the well encroaches on coal seams.

- Under the existing system licence holders do not have automatic rights to drill under land owned by third parties without the land owner's permission. However, the UK government has issued a consultation document that seeks to streamline underground access through the introduction of a new Infrastructure Bill. The proposals would change access rights for petroleum exploration licence holders to make it easier for them to drill and carry out hydraulic fracturing for shale gas beneath land owned by third parties (for more information see section 3.6).

- Seek planning permission from the Minerals Planning Authority (MPA) (in Scotland the local planning authority). Operators are advised to engage with local communities, the planning authority and other regulators before submitting a planning application. Furthermore, once an application is submitted, the planning authority is required to publicise it on its website and notify local residents through other means to enable local communities to comment on the proposed scheme. The planning authority will also determine if an environmental impact assessment (EIA) is required, which is dependent on exceeding certain thresholds or if operations may have significant environmental effects. For more information see the section on Legislation Overview.

- Obtain the appropriate environmental authorisation/permits from the Environment Agency (EA) in England, Natural Resources Wales in Wales, or the Scottish Environment Protection Agency (SEPA) in Scotland, to protect the local communities, land, water and air quality. These bodies are also statutory consultees to the Minerals Planning Authority or Scottish planning system. The EA has announced actions to streamline and simplify the regulation of exploratory activity.

- Notify the Health and Safety Executive, at least 21 days before drilling is planned, 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. HSE regulations also require examination of the well design and construction by an independent and competent person.

- Serve notification of an intention to drill on the Environment Agency under S199 of the Water Resources Act, 1991.

- Apply for consent to drill from DECC. DECC checks that the proposals make efficient use of the nationally owned resource, and it will impose limits on flaring if proposed. If hydraulic fracturing is intended, DECC will require that an evaluation is required to address the risk of induced seismicity and will review this plan before these operations are permitted. Finally, DECC will check that the environmental regulator and Health and Safety Executive have no objections to the proposed operations before consent is given.

If the operator wishes to drill a further appraisal well or start production operations, it must start again with the process described above.

3.5 Licensing

The Petroleum Act 1998 vests all rights to the nation's petroleum resources in the Crown, but the government can grant licences that confer exclusive rights to 'search and bore for and get' petroleum. Each of these confers such rights over a limited area and for a limited period.

Licences can be held by a single company or by several working together, but in legal terms there is only ever a single licensee despite the number of companies it may represent. All companies on a licence share joint and several liabilities for operations conducted under it. Each licence takes the form of a deed, which binds the licensee to obey the licence conditions regardless of whether or not they are using the licence at any given time.

Older types of UK onshore licence

Until 1996, the government issued a sequence of separate licences for each stage of an onshore field's life:

- Exploration Licence
- Appraisal Licence
- Development Licence
- Production Licence

Petroleum Exploration and Development Licences (PEDLs) were introduced at the Eighth Licensing Round (in 1996) to reduce the bureaucratic burden of issuing a series of licences. DECC no longer issues any licences of these types but a number of them, and older licences, are still in force.

The Petroleum (Production) (Landward Areas) Regulations 1984 replaced the previous system of the two types of licence (Exploration Licences (XL) and Production Licences (PL)) with three new ones: a new type of Exploration Licence (EXL), Appraisal Licences (AL) and Development Licences (DL).

The Department of Energy issued EXLs from the First Onshore Licensing Round (1986) until the Sixth (1992). Each Exploration Licence (EXL) ran for six years and carried an agreed Work Programme (in a similar way to the six-year Initial Term of a modern PEDL). The five-year Appraisal Licence gave the licensee time to prepare a development programme and gain long-term planning permission. Only if both of these were in place would the department consider issuing a 20-year Development Licence. EXLs which have not expired or been relinquished have been converted to the same terms as a PEDL but their names have not changed, e.g. EXL141 or EXL169.

Mining Licences (ML)

Dating from the 1950s, these are the oldest licences still in force.

Petroleum Exploration and Development Licence (PEDL)

This is the full name of the current Landward Production Licence. It is similar to the Traditional Seaward Production Licence, although for historical and practical reasons there are many differences in detail.

The Secretary of State issues landward production licences under powers granted by the Petroleum Act 1998. They confer the right to search for, bore for and get hydrocarbons, but do not confer any exemption from other legal/regulatory requirements such as:

- Any need to gain access rights from landowners;
- Health and safety regulations;
- Planning permission from relevant local authorities.

In particular, nothing in part I of the Act confers, or enables the Secretary of State to confer, any right to enter on, or interfere with, land (see section 9(2) of the Act). However, it should also be noted that section 7(1) of the Act applies the Mines (Working Facilities and Support) Act 1966 in England, Wales and Scotland for the purpose of enabling a licensee to acquire such ancillary rights as may be required for the exercise of the rights

granted by the licence. Applicants must prove technical competence, awareness of environmental issues and financial capacity before offer of a PEDL will be granted.

- Initial term – 6 years
- Second term – 5 years
- Third term – 20 years
- Mandatory relinquishment at end of initial term – 50%

Petroleum Exploration and Development Licences are valid for a sequence of periods, called terms. These are designed to comprise the typical life cycle of a field: exploration, appraisal and production. Each licence will expire automatically at the end of each term unless the licensee has sufficiently progressed to warrant a chance to move into the next term.

The initial term is usually an exploration period. For Petroleum Exploration and Development Licences, the initial term is set at six years and carries a work programme of exploration activity that DECC and the licensee will have agreed as part of the application process. This licence will expire at the end of the initial term unless the licensee has completed the work programme. At this time the licensee must also relinquish a fixed amount of acreage (usually 50%).

The second term is intended for appraisal and development. It is five years for Petroleum Exploration and Development Licences. Licences will expire at the end of the second term unless the Secretary of State has approved a development plan.

The third term is intended for production. It is 20 years for Petroleum Exploration and Development Licences. The Secretary of State has the discretion to extend the term if production is continuing, but DECC reserves the right to reconsider the provisions of the licence before doing so – especially the acreage and rentals.

All the qualifying criteria for continuation into the following term define the minimum amount of progress that the licensee must make. There is no suggestion that a maximum amount of progress is set, or that exercise of the licensee's rights is limited.

DECC expects companies to work their licences. Most licences follow a standard format but DECC is flexible with this and will consider adapting new licences to suit special scenarios. The Secretary of State has discretion in the granting of licences, which is exercised to ensure maximum exploitation of the national resource.

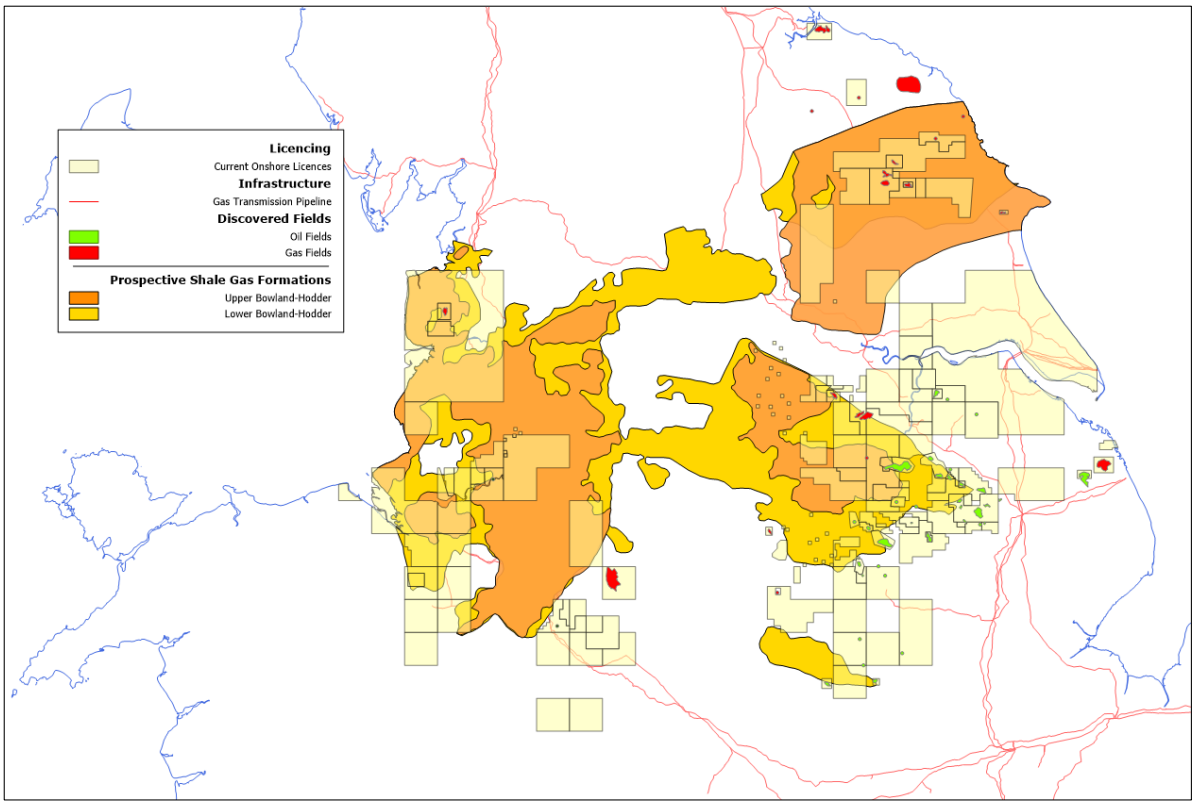


Figure 3.5.1 Licences held across the Bowland-Hodder Prospective Shale Gas Area

Data Source: BGS

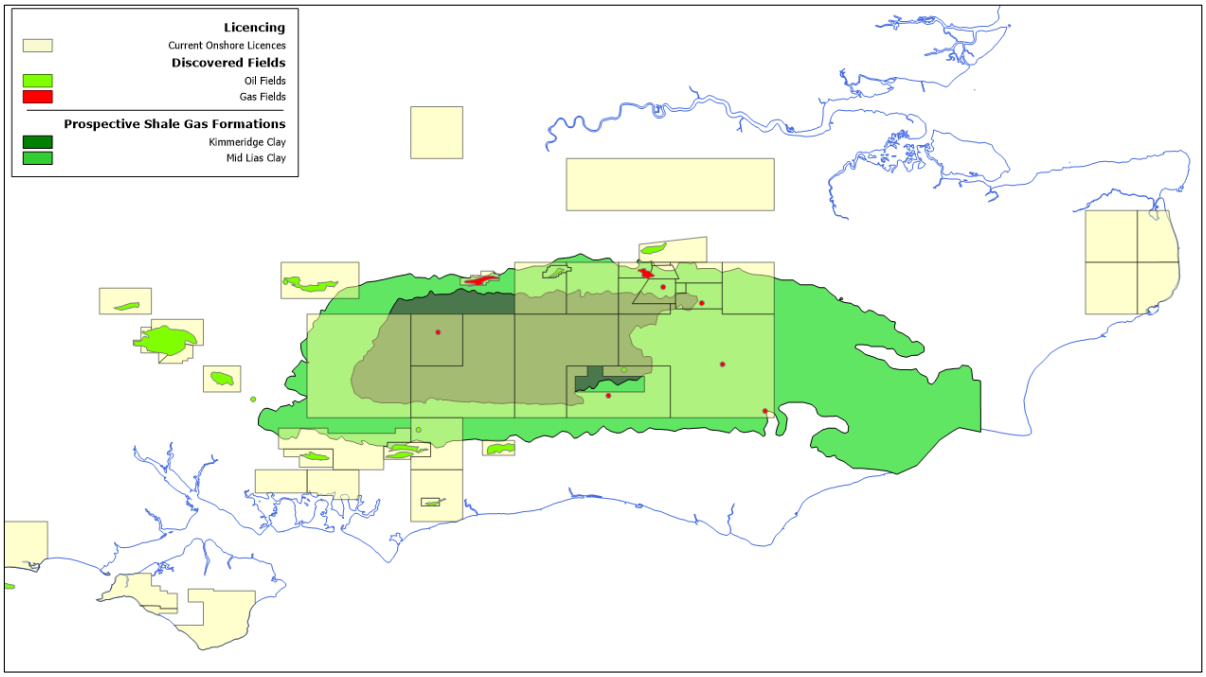


Figure 3.5.2 Licences held across the Weald Basin Prospective Shale Oil Area

The Mid-Lias is the deepest of the mature prospective Jurassic shales and represents the outer limit of prospective mature Shale Oil. The Kimmeridge Clay is considered to have the greatest potential and may be the focus of initial development.

Data Source: BGS

Licensees are entitled to 'determine' (i.e. surrender) a licence, or part of the acreage covered by it, at any time (unless the licence is still in its initial term and the work programme is incomplete). DECC positively encourages the surrender of acreage if the licensee does not intend to work it, and a minimum relinquishment of acreage at the end of the initial term is a condition of most licences. Licences usually have an obligation for the licensee to fulfil a work programme within a set period of time. This may include the obligation to drill one or more wells.

Partial surrenders are subject to restrictions, depending on the complexity of the area relinquished. DECC does not wish to create unlicensed areas so irregular in shape to be unattractive to other companies.

The government has announced the 14th licence round for awarding or renewing onshore licences. In 2010, DECC published and consulted on a Strategic Environmental Assessment (SEA) in preparation for the round, but this process was suspended following the seismic events encountered during hydraulic fracturing operations at the Cuadrilla Preese Hall site in Lancashire. In his statement to Parliament on 13 December 2012 announcing the introduction of new controls to mitigate against seismic risks, the Secretary of State confirmed that the SEA process would now be restarted in the light of new information arising since the 2010 consultation. Further announcements on the licence round are due.

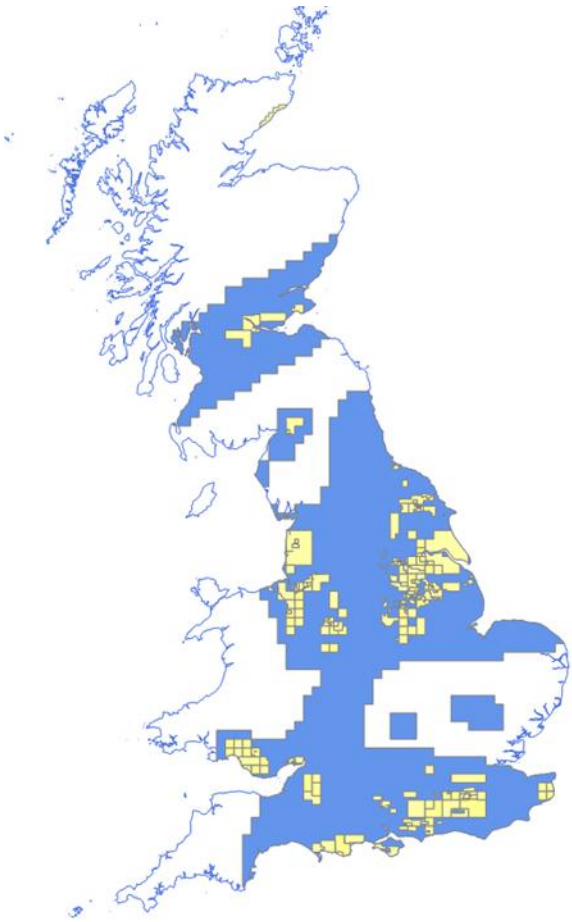


Figure 3.5.3 Licences held across the UK (yellow) and Areas Assessed by the Strategic Environmental Assessment (blue)

Data Source: DECC

What is apparent from this summary on licensing is that little if anything appears to be changing in the licensing process in the transition from conventional to unconventional oil and gas development. It may seem appropriate to expect the existing regulatory framework to be adequate for unconventional activities given the similarities between conventional and unconventional oil and gas operations. On the other hand the possible scale, and some of the more significant risks that might be encountered in the move towards unconventionals, is likely to require additional oversight and control. In other words, although the regulatory requirements are always going to be similar if not the same, controlling the rate of development, allowing for mistakes that are almost inevitable as part of the learning curve, and providing an adequate number of trained people to both carry out a well thought out approach to the operation and allow for adequate oversight, seems to be in the interest of all stakeholders.

Currently many of the potential licensees for shale gas hold their licenses because they signed up for a different reason compared to the exploration and development of shale. Therefore the intended process conducted by DECC, to evaluate licensees as companies that are both suitably qualified and funded to undertake major shale gas development, seems to have been by-passed. It would be appropriate that in the renewal, re-issue or future award for licences this is taken into account and that the areas over which the shale gas is allowed to progress is kept to a level that allows for an orderly and safe evolution.

3.6 Regulation Overview

Introduction

The key regulators for hydrocarbon extraction are:

- Department of Energy and Climate Change (DECC) – issues Petroleum Licences, gives consent to drill under the Licence once other permissions and approvals are in place, and has responsibility for assessing the risk of, and monitoring, seismic activity, as well as granting consent to flaring or venting;
- Minerals Planning Authorities (MPA) – grant permission for the location of any wells and wellpads, and impose conditions to ensure that the impact on the use of the land is acceptable;
- Environment Agency (EA) – protect water resources (including groundwater aquifers), ensures appropriate treatment and disposal of mining waste, emissions to air and suitable treatment, and manages any naturally occurring radioactive materials; and
- Health and Safety Executive (HSE) - regulates the safety aspects of all phases of extraction, in particular has responsibility for ensuring the appropriate design and construction of a well casing for any borehole.

Other bodies which may be involved in the consenting of the process include:

- the Coal Authority, whose permission will be required should drilling go through a coal seam;
- Natural England, who may need to issue European Protected Species Licences in certain circumstances;
- the British Geological Survey, who need to be notified by licensees of their intention to undertake drilling and, upon completion of drilling, must also receive drilling records and cores; and
- Hazardous Substances Authorities, who may need to provide hazardous substances consents.

There may also be additional consents and orders, such as suspending rights of way or temporary road orders, which must be obtained.

Minerals Planning Authority

As mentioned, before proceeding with an exploration well or development plan the operator must apply for permission to the local Minerals Planning Authority (MPA) (in Scotland the local planning authority). The minerals planning authority is the County Council in two-tier parts of the country, the Unitary Authority where there is one tier, or the National Park Authority if the proposed activity is inside one of the National Parks.

The Department for Communities and Local Government in July 2013 issued a guidance note for those applying for planning permission for onshore oil and gas extraction. The note covers the planning issues associated with the three phases of extraction of hydrocarbons i.e. exploration, appraisal and development. The document is intended to be read alongside other planning guidance and the National Planning Policy Framework. Paragraphs 142 to 149 of the National Planning Policy Framework sets out minerals planning policy. It makes clear that minerals planning authorities should identify and include policies for extraction of mineral resource of local and national importance in their area. This includes both conventional hydrocarbons and unconventional hydrocarbons such as shale oil, shale gas and coalbed methane. It also expects minerals planning authorities to ensure that mineral extraction does not have an unacceptable adverse impact on the natural or historic environment or human health.

The planning and other regulatory regimes are separate but complementary. The planning system controls the development and use of land in the public interest and, as stated in paragraphs 120 and 122 of the National Planning Policy Framework, this includes ensuring that new development is appropriate for its location taking

account of the effects (including cumulative effects) of pollution on health, the natural environment or general amenity, and the potential sensitivity of the area or proposed development to adverse effects from pollution. The planning process is therefore focused on whether the development itself is an acceptable use of the land and what impact it may have, as opposed to any control processes, health and safety issues or emissions that are subject to approval under other regimes.

The principal issues that minerals planning authorities are asked to address, although not all issues will be relevant at every site or to the same degree, include:

- Noise associated with the operation
- Dust
- Air quality
- Lighting
- Visual intrusion into the local setting and the wider landscape caused by any the placement of any building or structure within the application site area
- Landscape character
- Archaeological and heritage features
- Traffic
- Risk of contamination to land
- Soil resources
- The impact on best and most versatile agricultural land
- Flood risk
- Land stability/subsidence
- Internationally, nationally or locally designated wildlife sites, protected habitats and species, and ecological networks
- Nationally protected geological and geomorphological sites and features
- Site restoration and aftercare

In addition to the National Planning Policy Framework the MPAs have local minerals policies but many of these make no specific reference to the development of unconventionals even though they may reference conventional oil and gas. Examples of local MPA policy documents that fall in the areas of potential shale oil and gas development:

- Lancashire County Council: Minerals and Waste Local Plan (Part 2) 2006, Section 9.29 - Minerals and Waste Development Framework.
- Cheshire East/West Councils: The Cheshire Replacement Minerals Local Plan 1999, Chapter 7 - Hydrocarbons
- East Riding of Yorkshire Council: Joint Minerals Local Plan January 2004, Joint Minerals DPD with Hull City Council, Chapter 6 - Energy Minerals.
- West Sussex: Minerals Local Plan 2003
- East Sussex: Minerals Extraction Plan 1999

It is apparent that in some cases MPA policies may not have been updated for some time and hence are unlikely to have considered any impact from the development of shale oil or shale gas.

It is worth noting that at this time both the government and the industry see a need to approach the planning approval process on a local basis rather than through centralization. This approach is designed to treat all applications on a case by case basis and ensure local issues can be addressed properly.

Some issues may be covered by other regulatory regimes but may also be relevant to MPAs in specific circumstances. For example, the Environment Agency has responsibility for ensuring that risk to groundwater is appropriately identified and mitigated. Where an Environmental Impact Assessment is required, minerals planning authorities can and do play a role in preventing pollution from hydrocarbon extraction, principally through controlling the methods of site construction and operation, robustness of storage facilities, and in tackling surface water drainage issues.

Other Regulatory Bodies

Other regulatory bodies have responsibility for areas that may still be presented as part of the planning application:

- Mitigation of seismic risks – the Department of Energy and Climate Change is responsible for controls, usually through the licence consent regime, to mitigate seismic risks. Seismic assessment of the geology of the area to establish the geological conditions, risk of seismic activity, and mitigation measures to put in place is required by the Department of Energy and Climate Change for all hydraulic fracturing processes;

- Well design and construction – the Health and Safety Executive is responsible for enforcement of legislation concerning well design and construction. Before design and construction, operators must assess and take account of the geological strata, and fluids within them, as well as any hazards that the strata may contain;

- Well integrity during operation – under health and safety legislation the integrity of the well is subject to examination by independent qualified experts throughout its operation, from design through to construction and until final plugging at the end of operation;

- Operation of surface equipment on the well pad – whilst planning conditions may be imposed to prevent run-off of any liquid from the pad, and to control any impact on local amenity (such as noise), the actual operation of the site's equipment should not be of concern to minerals planning authorities as these are controlled by the Environment Agency and the Health and Safety Executive;

- Mining waste – the Environment Agency is responsible for ensuring that extractive wastes do not harm human health and the environment. An environmental permit is required for phases of hydrocarbon extraction and this will require the operator to produce and implement a waste management plan;

- Chemical content of hydraulic fracturing fluid – this is covered by the environmental permit as operators are obliged to inform the Environment Agency of all chemicals that they may use as part of any hydraulic fracturing process;

- Flaring or venting of any gas produced as part of the exploratory phase will be subject to Department of Energy and Climate Change controls and will be regulated by the Environment Agency. Minerals planning authorities consider how issues of noise and visual impact will be addressed;

- Final off-site disposal of water – Water that comes back to the surface following hydraulic fracturing may contain naturally occurring radioactive materials. Whilst storage on-site, and the traffic impact of any movement of water, is of clear interest to local authorities, it is the responsibility of the Environment Agency to ensure that the final treatment/disposal at suitable water treatment facilities is acceptable;

- Well decommissioning/abandonment – following exploration, the well is likely to be suspended and abandoned for a period of time. Health and Safety Legislation requires the suspension or abandonment to be secure ensuring, as far as possible, that there is no unplanned escape of fluids. The minerals planning authority is responsible for ensuring the wells are abandoned and the site is restored.

Specific Requirements

Environmental Impact Assessment (EIA)

EIAs assess the likely significant environmental effects of the proposed development enabling informed assessments to be made during the permitting process and in respect of the project generally. Under current regulations (Town and Country Planning, Environmental Impact Assessment Regulation 2011 for oil and gas developments) only those projects which extract at least 500 tonnes per day for petroleum and 500,000 cubic meters per day for gas require an EIA. For rates expected from individual wells it is unlikely that threshold would be achieved and hence an EIA would not be required. It is more likely however, that planning for development projects will consist of approval of a number of wells and the threshold and EIA would be required.

In the UK, the Minerals Planning Authority determines if an environmental impact assessment (EIA) is required. If the project is likely to have a significant environmental impact, the operator is required to complete the EIA. The results of the completed EIA are presented in the environmental statement submitted with the planning application.

On 9th October 2013 the European Parliament voted in favour of amending the EU's Environmental Impact Assessment Directive, which would require the EIA to be carried out for hydraulic fracturing in shale formations. However in December 2013 this proposal was dropped after the lobbying from the UK and Poland.

Requirement to Notify Residents about Horizontal Drilling

Although not entirely clear current interpretation of existing legislation suggests that those intending to drill must notify the relevant tenant or landowner if the planned path for the well-bore passes under that person's land. This is required by section 65 of the Town and Country Planning Act 1990, and article 11(2) of the General Permitted Development Order 2010. Developers have to give notice using a prescribed form.

In September 2013 the government issued a consultation paper (expected to run until 15th August 2014), proposing to reform the procedure for gaining underground access to oil or gas deposits and geothermal energy. The proposal will allow industry to drill below people's land in order to access energy resources without first negotiating a right of access, providing this is at depths of 300 metres or more.

The government is consulting on changes to the current system that would:

- Grant underground access rights to companies extracting petroleum resources (including shale gas and oil) and for geothermal energy in land at least 300 metres below the surface.
- A voluntary community payment of £20,000 for each unique lateral (horizontal) well that extends by more than 200 metres laterally. Alongside this will be powers to make such payments compulsory if companies fail to volunteer.
- A public notification system, under which the company would set out drilling proposals along with details of the voluntary payment.

This would remove the legal obligation to notify residents if horizontal drilling is taking place beneath their homes. The requirement to notify owners and tenants (of any of the land to which the application relates) of sites affected by above-ground works would be retained. The proposed changes in application would not require the developer to include the details on the extent of the underground activities. Details of the intended below ground drilling plans would then be included in the applications to DECC but not necessarily in the planning application. The consultation also proposed to make revisions to the Town and Country Planning (Fees for Applications, Deemed Applications, Requests and Site Visits) (England) Regulations 2012 to ensure that only above ground workings are taken into account in calculating any fee payable for onshore oil and gas developments including shale gas.

Countryside and Rights of Way (CROW) Act, 2000

Under the Countryside and Rights of Way Act 2000 (CROW), the public can walk freely on mapped areas of mountain, moor, heath, downland and registered common land without having to stick to paths. People across England now have approximately 865,000 hectares of land across which they can walk, ramble, run, explore, climb and watch wildlife as they are given the freedom to access land, without having to stay on paths. The new rights came into effect across all of England on 31 October 2005. The CROW Act allows a landowner or farm tenant to exclude or restrict access at their discretion in certain circumstances. Use of these powers must be notified to the Open Access Contact Centre.

3.7 Taxation

The Treasury is consulting on fiscal measures to incentivise shale activity, to lessen the impact of high upfront costs associated with unconventional projects.

Companies undertaking oil and gas exploration, development and production activities in the UK are subject to three tiers of direct taxation in the UK: petroleum revenue tax (PRT), corporation tax (CT) and supplementary charge (SC). PRT (at 50%) is deductible against corporation tax and supplementary charge. Corporation tax is currently chargeable at 30% on these activities and supplementary charge is levied at 32% in respect of profits accruing after March 23rd 2011 (previously 20%). The profit base for SCT is the CT profit base as adjusted for financing items.

For activities subject to PRT the maximum marginal rate is 81% (with the CT and SC effect), although the effective rate of tax can exceed this where companies are highly geared due to the lack of a deduction for interest costs for PRT and supplementary charges.

Petroleum Revenue Tax (PRT)

Petroleum Revenue Tax, which is currently charged at 50%, was introduced in 1975. It is levied on a field by field basis by reference to six-monthly chargeable periods ending June 30th and December 31st.

PRT has been abolished for all fields for which development consent was granted on or after 15th March 1993 but continues to apply to older fields. Hence it will not be applicable for new unconventional developments.

Corporation Tax (CT)

Corporation tax is levied on a company basis, rather than the field basis of PRT. A company with more than one field interest will therefore aggregate the results for those fields in arriving at its profits subject to corporation tax.

Taxable profits for corporation tax are determined by adjusting normal accounting profits; in particular, depreciation is disallowed and relief for capital expenditure given through specific capital allowances.

The current rate of 30% is applied for 'ring fence' profits. While all companies operating in the UK are within the corporation tax regime there are some additional rules (the ring fence rules) that relate to upstream oil and gas activities. These ring fence rules are designed to prevent companies reducing their upstream ring fence profits with reliefs and allowances from other activities.

The main restrictions are that losses and expenses from other activities, either within the company or accruing to an affiliate, cannot be deducted against ring fence profits. The deductibility of financing costs is also limited such that, broadly, interest deductions are only available in respect of monies borrowed which have been used in the ring fence business, and where the terms do not exceed those applicable at arm's length.

Neither capital expenditure nor the depreciation of those costs is allowable for corporation tax purposes; instead there are specific capital allowances available which are deducted from chargeable profits. The allowances that are of most relevance to upstream activities are research and development allowances (RDAs), plant and machinery allowances (P&M), and mineral extraction allowances (MEAs). No allowances are available until a company commences to trade, but once it does all capital costs incurred prior to commencement are deemed to have been incurred at commencement.

RDAs, for which relief at 100% is given, apply to all exploration and appraisal costs until such time as reserves in commercial quantities have been discovered. The costs must be first hand exploration or appraisal costs. No relief under these provisions is therefore available for reimbursing previously qualifying costs or when buying into a licence.

The capital cost of production and transportation facilities will generally qualify for plant and machinery capital allowances. Most costs incurred after 16th April 2002, and hence for shale oil and gas projects, will qualify for immediate 100% relief.

Mineral extraction allowances (MEAs) are available for mineral exploration and access expenditures (broadly all expenditures up to first production from a source) and on acquiring a mineral asset. The rates differ between the types of expenditure but mineral exploration and access expenditure in a ring fence trade incurred after 16th April 2002 qualifies for an immediate 100% first year allowance.

Trading losses may be carried forward indefinitely and set against future profits of the same trade. Losses may generally be carried back one year. To the extent that loss is generated by decommissioning expenditure there is three year carry back against total profits and thereafter a carry back against ring fence profits.

For accounting periods ended after 1st January 2006 Ring Fence Expenditure Supplement (RFES) may be available where a company makes a loss. The RFES allows companies to claim a 6% supplement on a company's ring fence trading loss for six, not necessarily consecutive, periods. It applies to losses accruing in periods commencing on or after 1st January 2006. The rate of supplement was increased to 10% for accounting periods commencing on or after 1st January 2012.

Supplementary Charge (SC)

A supplementary charge applies to ring fence profits accruing from 17th April 2002. The rate was originally 10%, increased to 20% in 2006 and to 32% in respect of profits accruing after 23rd March2011. The tax base is the ring fence profits of the company chargeable to CT after removing all financing costs.

The field allowance was introduced in the Finance Act 2009, with further allowances following. However for the shale gas industry the government has launched a consultation on a proposed tax amendment, including a new shale gas 'pad' allowance. The 'pad' allowance is based on the existing field allowances. The intention of the new allowance is to reduce the supplementary charge tax on a portion of a company's production income, hence reducing the effective tax rate from 62% to 30% at current rates. The amount of production income exempt from the supplementary charge would be a proportion of the capital expenditure incurred in relation to the shale gas pad. For the purposes of the pad allowance, capital expenditure would be limited to expenditure that would attract 100 per cent first year capital allowances.

Companies would start to generate and hold the allowance as soon as they incurred capital expenditure on a pad. Costs incurred prior to the effective date of the introduction of the pad allowance would not contribute to the generation of the allowance.

The amount of allowance activated (i.e. made available to offset against profits) in any accounting period would be no more than the amount of production income from the pad. Any activated allowance not used to reduce the supplementary charge otherwise payable by a company in a particular accounting period would be carried forward to the next.

At Budget 2013, the government also committed to extend the RFES for shale gas projects from six to ten accounting periods. This change was designed to recognize the longer payback period for shale gas projects. Steep production decline rates are expected to mean that high and continuous investment is required in wells, extending the period of investment over a longer timeframe than conventional projects. The extension of RFES is to allow companies without existing ring fence profits to maintain the time value of their losses over this longer payback period.

Given the similarities in cost and timing for shale gas and other onshore unconventional hydrocarbon projects, the government proposes to extend RFES from six to ten accounting periods for all of these projects.

Environmental legislation applicable to the onshore hydrocarbon industry and the UK domestic environmental legislation (DECC) are listed in Appendix E.

3.8 The Operators

Although there has been significant media exposure and discussion, as well as a number of reports and government initiatives, with respect to the shale gas opportunity in the UK, the actual activity specifically targeted at shale gas exploration and development to date has been limited. There has been no development with regards to shale oil. Companies that currently hold licences are largely pursuing conventional oil and gas or Coal Bed Methane (CBM) although many have recognized that the licences do cover areas that have shale oil or shale gas potential.

Up until relatively recently the interest in shale gas has been confined to smaller onshore operators, with none of the majors owning all or part of any licences onshore in the UK. Some larger companies have begun investing in shale gas operations through transactions with the smaller companies. In 2013 Centrica acquired a 25% interest in PEDL 165 from Cuadrilla Resources Ltd for £40m, along with a commitment to pay exploration and appraisal costs of up to £60m. Similarly in late 2013, French Utility company GDF Suez acquired a 25% interest in Dart Energy's 13 onshore licences for £7.4m with £16.7m for on-going costs. The company plans to work with Dart Energy to drill a number of exploration wells to appraise the shale gas potential of the East Midlands and Cheshire. In January 2014 French oil giant Total acquired a 40% interest in two of IGas Energy's onshore licence blocks in Lincolnshire. In the agreement, Total agreed to fund a work programme of £27m, with a minimum commitment of £11.5m. Many of the smaller current onshore operators do not have the capital to invest heavily in exploration, appraisal and commercial development. The increase in investment from larger companies is likely to speed up the rate of exploration and appraisal of the multiple basins across the north of England. If commercial rates are proven then it is likely further investment will follow.

Cuadrilla Resources has drilled three wells in its licence PEDL 165 (See Figure 3.9.1). At Preese Hall Farm, Weeton, Preston, Lancashire it initiated the drilling of a vertical exploration well in November 2009 although actual drilling did not commence until August 2010 and it was completed in December 2010. The well was targeted at the Bowland shale and the well was drilled to around 2773 metres. The shale was found to be around 792 metres thick. The drilling operation found sections of the well difficult to drill due to unexpected hard formations causing a slow drill rate. The well was hydraulically fractured but during the hydraulic fracturing operation induced seismicity was detected in the local area. At this point, Cuadrilla voluntarily suspended the fracturing process. A temporary plug was put in to suspend the well and the rig was removed. There are plans to return to the well and carry out further fracturing and testing of the well.

Temporary planning permission was granted in April 2010 for the drilling of an exploration well at the Grange Hill site, Singleton and a well was drilled to a target zone at 3261 metres in July 2011.

Temporary planning permission was also granted at the Becconsall site, near Banks on the 20th October 2010. Drilling began at the site in August 2011 and lasted for just over three months, reaching a target depth of 3200 metres. According to Cuadrilla there does not appear to be any intent to return to these two sites for further hydraulic fracturing and testing.

IGas Energy announced that an exploration well at their Ince Marshes site in Cheshire has found a 'very significant' area of shale gas. A shale section of at least 1,000 feet thick was encountered in the well. The well targeted coal bed methane but also evaluated the Bowland/Hodder shale.

Appendix C provides a further detailed report on the licences held and activities of the companies involved in the Bowland shale area, and Appendix D also lists those licences, companies and key licence terms for the southern England South Downs Weald Basin area.

The operating companies through the United Kingdom Onshore Operators Group (UKOOG - the representative body for the UK onshore oil and gas industry including exploration, production and storage) have set out their commitment to community engagement in a Charter (UKOOG - Community Engagement Charter Oil and Gas from Unconventional Reservoirs). This Charter sets out a commitment to engage with communities at an early stage and in advance of any application for planning permission.

The industry has also committed to a package for communities that host shale gas operations in their area. This includes:

- At exploration stage, £100,000 in community benefits will be provided per well-site where hydraulic fracturing takes place;
- 1% of revenues at production stage will be paid out to communities;
- Operators will publish evidence each year of how these commitments have been met;
- A continued consultation with local communities.

3.9 Possible Phased Development Scenarios

Introduction

Notwithstanding the rise of shale development in the USA and the fact that it has established a basis if not an analogue on which to estimate how the shale oil and gas industry might develop in the UK, the possible predictive scenarios for a UK shale industry will still depend on many factors. Some of these factors remain indeterminate, not least the outcome of initial exploration testing of the resource.

It is reasonable to assume that the future might take the form of a three staged process.

Firstly, the continuation of a first stage to prove up the existence of the resource and how easily it can be recovered and this is on-going. From the industry's perspective there is of course one simple main consideration for any progressive development plan, namely to determine if the proposition is commercially viable for investors, especially when working under any constraints. If the commercial viability is called into doubt then future development is likely to be very slow or curtailed.

A second stage might then be a pilot or early development programme that is based on sighting well pads in locations that are most easily approved by the planning authorities but which also cover the most prospective resource areas.

Over time the evolution of a third stage might be the infill opportunities that remain using a denser well pad distribution where feasible.

This section of the report attempts to look into a likely rollout scenario of shale gas to test the commercial proposition for an early stage development. Given the lack of initial development with regards to shale oil, this section refers specifically to shale gas development. Any differences with shale oil development are highlighted at the end of this section.

Well spacing, pad spacing and resource recovery

Expected gas yield from the different resource areas, the operations/drilling constraints of the operator/rig, and any restrictions on access to certain areas, all contribute to the variation in well spacing for USA shale gas developments. Similar considerations are likely in any development in the UK. However the presence of denser population areas, more local infrastructure, sensitive natural conservancy areas, land access etc. is likely to imply that initial optimal spacing for hydrocarbon recovery is compromised.

As described in Section 2.4 wells are drilled from the surface from well pads and well paths can be vertical, deviated or with a horizontal section through the shale. From a single surface hole wells can split into several lateral holes that can cover a wide horizontal area or be stacked vertically to drain a thick shale section. As described previously the wells tend to be drilled in parallel lines which are perpendicular to the plane of the regional principle stress in the rock. This facilitates the opening of fractures perpendicular to the well path using multi-stage hydraulic fracturing. In the UK horizontal wells are likely to be drilled in a NE-SW direction.

Ultimately well spacing for the development of UK shale gas, although based on a pattern to achieve highest technical recovery subject to the natural constraints, will also be constrained by the availability, access rights and regulatory approvals for the surface sites. Initially therefore well pads are likely to be chosen for ease of gaining regulatory approvals rather than maximising ultimate resource recovery, and will avoid environmentally protected areas.

In time, in-fill drilling will shorten the distance between pads if the regulatory approvals and surface constraints allow that to proceed. A variation in the quality/quantity of gas yield of the shale is also likely to attract attention to "sweet spots" for early stage development. This may include areas where gas resource is further enhanced in value through the presence of natural gas liquids (NGL's) that can be sold to increase revenues.

Recovery factors when measured against the gas in place are likely to be very low initially. As previously mentioned, estimated ultimate recovery factors from the Barnett Shale are currently forecast to be in the region of 10% of gas in place with the current number of wells drilled. With additional drilling the recovery may

increase possibly to 19%. For the 10% recovery, wells are spaced at about 600 metres apart with horizontal sections averaging 1000 metres or an average of 150 acres per well.

As an example of an active operator embarking on a roll-out programme in the UK, Cuadrilla's current exploration drilling programme in Lancashire may be looked upon as typical of those that are likely to follow in the future. In so far as the well pads from which the current wells are drilled are spaced out over the Cuadrilla licence area it would be reasonable to suggest that this pad spacing is not unreasonable for this early stage. Successful results from these wells may then lead to a pilot or early stage development programme.

The average well pad spacing marked out by Cuadrilla to date, if repeated across their licence where there is prospectivity as indicated by the BGS report (Andrews, 2013), would result in approximately 20 well pads. Divided over the area this would equate to around 12,000 acres for each pad. This would represent about 4,000 metre radius around each pad**. The area for each well is 1200 acres compared to the Barnett shale area per well of 150 acres thus this example represents an early stage development with considerable infill drilling opportunities to develop in the future.**

This spacing is less than one might select for optimum technical recovery and hence leaves scope for further infill drilling or the removal of the existing pads to replace at different locations at a later date.

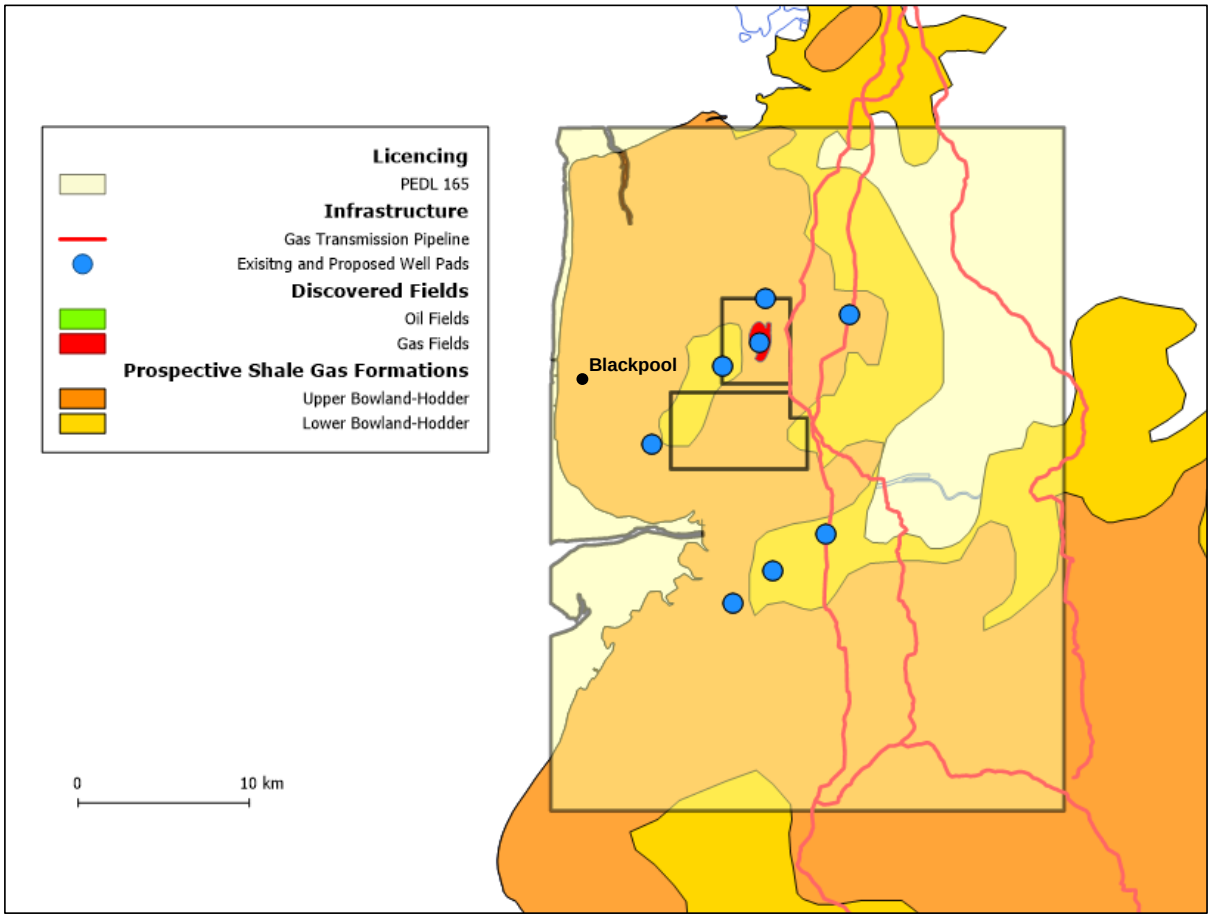


Figure 3.9.1 Cuadrilla Licence PEDL 165 showing Existing or Proposed Well Pads and nearby High Pressure National Transmission Gas Lines

Data Source: DECC & Cuadrilla website

Gas Sales and Infrastructure

In the USA some of the areas that have been extensively developed for shale gas enjoy local existing gas network infrastructure tied to a gas market or utilize the gas for power generation or petrochemical feedstock. Little, if any, similar infrastructure exists in the UK apart from the gas distribution pipeline network, including both high and low pressure systems. The two main options for gas sales in the UK are (i) pipelines to connect into the main UK gas pipeline network or (ii) on site electricity generation which is then connected into the national grid.

Local power generation is unlikely to maximize the energy efficiency use of the gas for two reasons. First, whilst gas fired combined cycle power generation (CCGT) is efficient (around 50-55% efficiency) it requires a minimum size power station of around 250 MW, which is a significant plant. Smaller gas volumes cannot use CCGT but instead are burnt in an open cycle gas turbine. Here the efficiency is around only 30 – 35%. It is possible to have efficient smaller scale power generation in the form of gas fuelled reciprocating engines with use of waste heat (known as combined heat and power), but there is often no use for the waste heat.

Hence, subject to access points and available capacity, delivering gas into the gas pipeline system (National Transmission System or NTS) is probably the most likely sales point for shale gas production. Both the location of the NTS with respect to proposed shale gas projects and the available capacity in the system will therefore have an impact on the commercial outcome of any project.

Gas Transporters (GTs) provide the pipelines through which gas is transported across the country to end-users; this is a licensed activity, and it is regulated by Ofgem (The Office of Gas and Electricity Markets). Ofgem is the organisation that supports the Gas and Electricity Markets Authority, which is responsible for economic regulation of the energy (gas and electricity) markets. Ofgem's principal objective is to protect the interests of consumers wherever appropriate by promoting effective competition.

There are various kinds of Gas Transporter. National Grid Gas plc has a licence, as Transmission System Operator (TSO), to own and operate the high pressure National Transmission System (NTS) as well as developing and maintaining the NTS. It is responsible for the energy balancing of gas entering and leaving Great Britain's onshore gas pipe-line system or network.

The Gas Distribution Networks (DNs) transport gas from the NTS and distribute it to end consumers and to Independent Gas Transporters. The DNs' pipe-lines operate at different levels, or tiers, of pressure. There are eight licensed DNs, owned and operated by 4 different organisations: National Grid Gas Distribution, Northern Gas Networks, Scotia Gas Networks and Wales & West Utilities. There are also smaller, independent companies known as Independent Gas Transporters (IGTs). These typically install and operate their own pipeline systems on new housing and commercial developments downstream of a DN's network.

Shippers make arrangements with Gas Transporters to convey their gas through the pipeline system. This is a licensed activity, regulated by Ofgem. More broadly, Shippers contract with producers to bring gas into the gas transportation system and they are in effect the wholesale merchants for suppliers, who have the contractual relationship with gas consumers. Shippers share a common (and therefore non-discriminatory) contractual relationship with the gas transporters, to allow them to use the pipelines to transport gas. The terms of this relationship are set out in a Uniform Network Code (UNC), a common set of rules for the transportation and trading of gas which underpins the effective operation of GB's competitive gas market.

Shale gas volumes are likely to be quite large in order to establish a commercial project threshold. Therefore it is more likely that gas will be sold into the NTS rather than into local networks that may not have adequate capacity or market to absorb that volume of gas. In the area around Lancashire there are NTS sections that feed some of the larger population areas of the UK and hence should have adequate capacity and market for shale gas. The NTS is less well represented across the Weald area and hence there would be a requirement for longer regional pipelines should there be any significant shale gas developed in this area.

Timing

The time required to carry out an exploration and appraisal programme to prove the resource will vary for different operators. Some operators have already stated that they expect this to be less than a year or two. However, it is quite probable that this may take longer especially if there are delays in receiving planning approvals for exploration wells.

Forecasting the future timing of the development of shale gas in the UK is very difficult. The regulatory environment including both domestic but also EU legislation imposes significant requirements on operators prior to embarking on field operations (see section on regulations). Recent examples of project timetables to develop conventional oil and gas onshore developments in the UK have had considerable delays in the planning phase.

It is therefore expected in this example of an early stage development that there could be at least two to three years for a significant ramp up in development for shale gas. This will require the necessary approvals but will also require establishing the necessary support services, available rigs and the hiring and training for a new work force.

Regeneris Consulting, in a report commissioned for Cuadrilla Resources to evaluate the economic benefits of a roll-out of a UK commercial shale gas development (Regeneris, 2011), estimated that up to six wells could be drilled per year per drill rig. However, the total number of wells to be drilled in any year will only become clearer as and when the results of the exploration phase are available and investment decisions made and of course will be subject to the necessary planning approvals.

3.10 Example Early Stage Generic Project

To consider, within a scale up development scenario for UK shale gas, if there is an acceptable investment proposition for operating companies, Petrenel has evaluated a conceptual generic model based on an early stage development plan (spaced out well pads rather than full technical recovery) using the Cuadrilla licence in Lancashire as a typical development area. This envisages approximately 20 well pads from which 10 horizontal wells per pad have been drilled. These could take the form of multi-laterals from two or three surface locations or also be stacked horizontals if they are drilled in areas where the shale is thickest. The wells are tied-in via flowlines to a manifold and connected via pipeline to a gas processing plant. The gas is assumed to be sold into the NTS system by tying into a connection point within approximately 20 km of the gas processing facility. Gas can be metered at the gas plant or prior to entering the NTS.

Resource estimates

Initial well productivity for a given well design is yet unknown for UK shales therefore average figures from USA shales reinforced by indicative values taken from Petrenel's reservoir modelling have been used in the assumptions (Appendix A). Resources attributed to each well are also modelled on the typical production profile shape i.e. a significant early decline followed by a flattening, and long life low level production. Petrenel has used a base case initial per well productivity of 3 MMscfd over a period of 30 years.

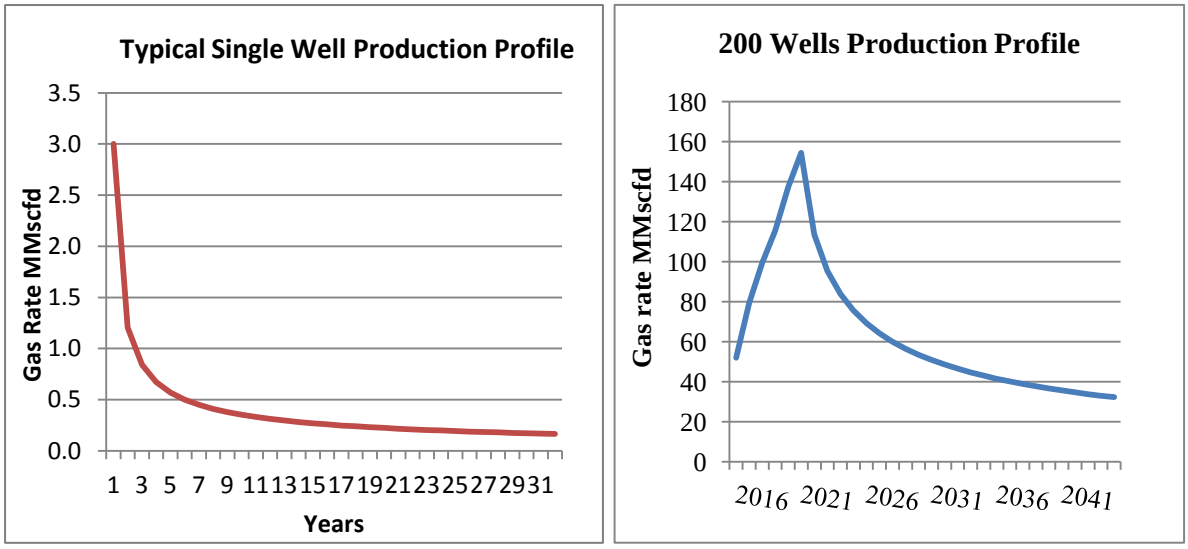


Figure 3.10.1 Base Case Production Profiles

Source: Petrenel

Facilities

Given the area covered is estimated to be over 200,000 acres (over 800 km^2) it is proposed that gas would be processed in two newly built facilities. These facilities might include:

Inlet Facilities

Gas arriving from the manifolds will pass through a high pressure separator to make sure that any liquids not separated at the well site are removed and do not cause damage to the plant downstream of this point. Liquids collected will be directed to the liquids handling area of the plant.

Compression

Compressors may be required to increase the pressure of the gas from the well to that required at the sales point.

Sweetening

If there are any non-hydrocarbon gases that may cause problems or mean that the gas does not meet sales gas specification then a sweetening plant may be required.

Hydrocarbon and Dew Point Control

Hydrocarbon and water dew point control removes the higher hydrocarbons in the gas to prevent them condensing as a liquid in the NTS when the gas enters the system. The plant also water dries the gas so that water cannot condense out of the gas and freeze in the pipeline. Some condensate will be produced in the dew point control plant and this has, eventually, to be taken from site when sufficient quantities build up.

Liquids Handling (Condensate stabilization and glycol recovery)

When liquids (condensate and water) are produced they will be conveyed into a liquids handling area consisting, principally, of a three phase separator and various holding vessels. A heater will also be needed to heat the condensate, stabilization of which essentially consists of raising the temperature of the condensate to eliminate dissolved gases. It is not yet known how much liquid is likely to be produced alongside the gas.

Metering and Gas Quality

Fiscal metering is required prior to export to the NTS grid, and an accurate calorific value (CV) measurement is required by the regulations and approved by OFGEM. The siting of the metering system may depend on where the tie-in point will be for a sales point.

Wells

With little oil and gas well drilling taking place in the UK the cost of rigs is initially likely to be significantly higher than the USA especially if rigs are mobilized from outside the region. In addition the support and contract services that are readily available in the USA are not well established in the UK although, given a ramp up of activity in shale gas development, some services will migrate from the traditional offshore support centres in SE Anglia and Aberdeen.

Optimum design of the wells will also depend on a number of parameters yet to be established (the nature of the resource and distribution of the gas, drilling conditions, well pattern and spacing, length of horizontal sections etc.).

Wells are likely to be drilled using a typical land based 1000 to 1500 HP (horsepower) rig although to speed up tripping time operators will be keen to convince the local planning authority that allowing more height for rigs will potentially speed up the time to drill and hence reduce the time for the rig to be required on site. For a 1000 HP rig, as was used by Cuadrilla to drill the Preese Hall well, the current market rate is about £18,000 to £19,000 (approx. US$30,000) per day. For a 1500 HP rig, the range is more likely to be £21,000 to £24,000 (approx. US$36,000) per day. For a longer term operation it may be possible to build new rig packages locally. These are likely to cost in the region of £20 million (US$32 million).

Support services and tangible costs are likely to increase the overall drilling day rate by three to five times. Drilling conditions are likely to vary across the shale gas area. Harder than expected rock was encountered in the wells drilled by Cuadrilla in Lancashire and hence drill times initially were longer than expected. Wells in this area might take 30 to 40 days to drill. Further east where conventional oil and gas wells have been drilled over many years the drill times may well be significantly less. Should a significant rate of development be achieved then it is expected that drill times will improve over time with local experience and establishment of local services.

Fracturing costs are more difficult to estimate until the supply and demand equation is better known. The equipment for a fracturing operation might be in the region of US$500,000 to US$700,000 per day initially and, depending on the number of stages per well that are selected, the estimated costs for the hydraulic fracturing operation are likely to be between US$5 to US$10 million.

Hence both drilling and hydraulic fracturing have a significant range of possible duration and cost per well.

Water Supply and Waste Water Management

Both the drilling operation and the stimulation of wells (hydraulic fracturing) require the use of a significant volume of water. Some operations in the USA are reported to have utilised four to five million gallons of water per well. Sources for water supply include tapping into a local water supply, usually through the local water utility company, and trucking the water, or constructing a water pipeline from a larger source, or drilling a water supply well to a local aquifer.

During the flowback period of producing a shale gas well significant volumes of water that have been pumped into the well during the hydraulic fracturing operation will be returned to the surface. Treatment of this waste water and waste water/mud from the drilling operation will be required prior to disposal or re-use. For single exploration wells it is likely that the most cost effective approach will be transportation of the waste water to a treatment plant. For larger developments it may well be more cost efficient to treat waste water in a location closer to the operation and hence construction of a waste water treatment plant may be preferred.

Costs

Petrenel has used a total well cost including fracturing of US$18.5 million per well for early stage exploration wells and US$12 million per well for development stage wells. The Regeneris report (2011) estimated a 2010 cost estimate of £10.5 million (US$17 million) for an exploration well and £9 million (US$14.5 million) for a "commercial" well hence Petrenel's assumptions may be considered optimistic. However for a 200 well programme it is expected that there will be improvements in drill time and cost per well.

Facilities have been assessed at a total of US$ 240 Million including the cost of two regional gas processing plants and a tie-in to the NTS.

The operating costs for a shale gas operation within a UK environment are difficult to estimate. Petrenel has therefore relied on costs being similar to USA operations but recognizes that this has yet to be proven. A range of operating costs is shown in the figure below. Petrenel has chosen a base case of a $1.5/Mcfe plus a fixed cost G&A.

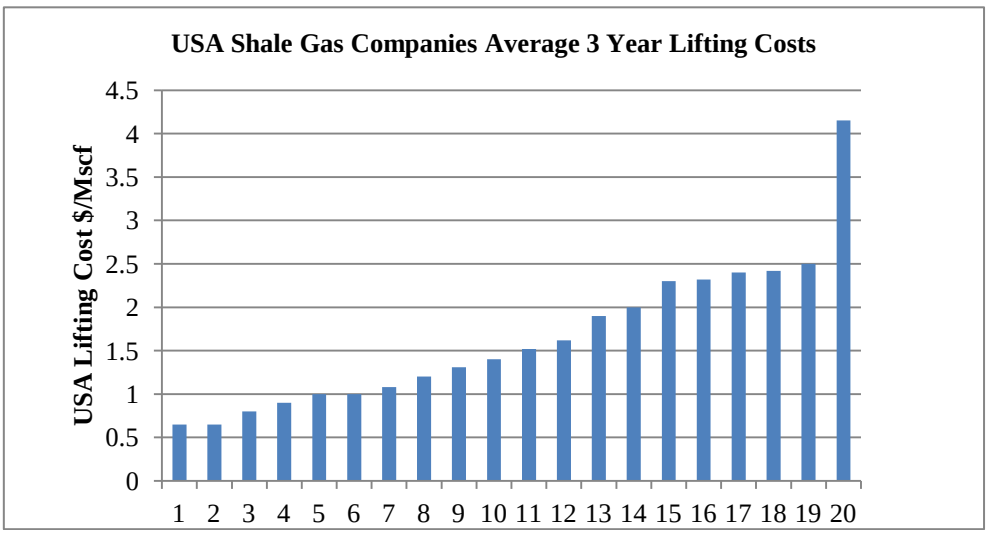


Figure 3.10.2 USA Shale Gas Companies Average 3 years Lifting Costs

Data Source: Public filings

Economic Evaluation and Sensitivities

Three economic cases were evaluated for Low, Expected and High scenarios and combined to give an Expected Value.

Base Case assumptions include:

- Gas Price: 60 pence per therm escalated at 2% per annum. Opex escalated at 2% per annum.
- No liquids sales.
- Pad Allowance taken as 50% of the expenditure associated with a pad. No revenue royalty was included for local communities as is proposed by the operating companies.
- No costs included for well abandonment or re-instatement of land.

Low Scenario: Four Exploration wells drilled, one per year starting in 2013. Decision for development is approved in 2017. Development wells drilled: Five in 2018, 10 in 2019, 25 in 2020, 30 in 2022 and 2023 and 35 in 2024 and 2025, total 200 wells. First gas plant is built in 2017/18. Production starts up in 2018. Average well productivity is 2 MMscfd and recovery per well is 2.5Bscf over 30 years. Total resource recovery is 285 Bscf.

Expected Scenario: As per Low Case except decision to develop is taken in 2015 so development drilling starts in 2016. Average well productivity is 3 MMscfd and recovery per well is 3.8 bcf over 30 years. Total resource recovery is 470 bcf.

High Scenario: As per Low Case except decision to develop is taken in 2014 and development drilling starts in 2015. Average well productivity is 4 MMscfd and recovery per well is 5.2 bcf over 30 years. Total resource recovery is 652 bcf.

Table 3.10.1 Indicative economics for a 200 well early stage UK shale gas development

Case	Gas Resource (Bscf)	Recovery Factor[(1)] %	Capex £MM	Opex £MM Ave/Yr	NPV@10% £MM	IRR%	EMV@10% £MM
Low	285	0.11%	1,666	22	-160	2%	
Expected	470	0.18%	1,666	34	99	14%	91
High	652	0.24%	1,666	46	331	25%	

[(1)] Recovery Factor Measured Against Free Gas In Place for the Entire Licence

Source: Petrenel

At first glance therefore, and subject to the assumptions used, an early stage development project can be shown to be economic subject to proving the well productivity and recovery of the resource. Further infill drilling more closely approaching the USA model is likely to improve the incremental value. A slow rate of development and disappointing well performance may see the opportunity wane.

Sensitivities to the Expected Case:

Table 3.10.2 Base Case Sensitivities

Case	**Gas Resource (Bscf)**	**Recovery Factor[1] %**	**Capex £MM**	**Opex £MM Ave/Yr**	**NPV@10% £MM**	**IRR%**
Gas Price 50p/Therm	470	0.18%	1,666	34	-70	7%
Gas Price 70p/Therm	470	0.18%	1,666	34	388	21%
+20% Capex	470	0.18%	2,000	34	-38	9%
+20% Opex	470	0.18%	1,666	40	55	12%
Pad Allowance 100%	470	0.18%	1,666	34	99	14%
Pad Allowance 25%	470	0.18%	1,666	34	99	14%

Source: Petrenel

Hence variation in gas price has a significant impact on the outcome followed by capital costs.

3.11 Shale Oil development

The development of unconventional resources in the UK has been heavily focused on Shale Gas and Coal Bed Methane, with little focus on the potential for oil present within shale which may be present in both the Bowland-Hodder Formation and Jurassic Shales of the Weald Basin. Given the industry focus on shale gas, it is unlikely that shale oil development will begin within the next 5 years. However, if or when the development occurs, it is likely that industry will follow the same progression as shale gas development; an exploration phase, followed by single shale oil wells from single pads with infilling of more pads when more is known about the geology and subsequent recoveries.

Shale Oil wells tend to be, on average, more closely spaced than shale gas wells. The U.S. Geological Survey (USGS) concluded that optimal shale oil well spacing in the Bakken Play is approximately 400m with half widths of 200m. The closer proximity of wells, compared with shale gas operations has led to concern that such an industry in the UK may not be viable given the difference in mineral rights, land access and planning regulations.

The surface footprint of a large shale oil development is likely to be similar to slightly larger than the shale gas development envisaged earlier. However, this depends entirely on the field development plan submitted by the operator and is subject to planning regulation. It is unlikely that the UK will follow the same field development and well pad spacing as seen in the Bakken Shale Oil Play in the USA.

The associated facilities also differ slightly. After drilling, the onsite facilities will consist of a well head, flowline, and initial processing facilities which comprise of a separator, stock tank, storage tanks, and if applicable a gas processing and storage plant. A typical shale oil development is likely to have one central flowstation with flowlines connecting multiple well heads. Produced oil is likely to be stored in large storage tanks and given the lack of onshore crude oil pipelines, oil is likely to be transported by road tanker to the refinery. It is also likely that artificial lift will be needed to maintain commercial flow rates. Beam pumps, often referred to as 'nodding donkeys', are commonly used for low rate wells.

Any produced gas is likely to be small in volume. Small quantities of produced gas are used for onsite power generation. Gas that isn't used may be flared. If commercial volumes are produced then the gas may be processed and exported from the site.

3.12 Public Perception

Introduction

Overall there is high public support for shale gas development in the USA. While concerns about environmental impacts have been rising, the economic benefits are perceived to outweigh the risks. In Canada shale oil is being produced in Alberta, while Quebec imposed a moratorium on shale gas in the Lowlands of the St Lawrence River.

In Europe, the public debate is mostly focused on environmental issues. In Germany and the Netherlands the significant public concern about environmental and health issues led to temporary bans, and further studies are being carried out. Currently, there is a moratorium on shale gas in Bulgaria, France, and the Czech Republic. Governments of Poland, UK, Romania, Lithuania, Spain and Denmark are encouraging shale gas development.

United States

In 2008, the United States imported 13% of its natural gas supply. With the exploration and production of shale gas in the USA they expect to reduce this figure to nearly 1% by 2035 (KPMG, 2011), and with this resource opportunity they are becoming both self-sufficient and a key player in this industry. A Deloitte study (2012) results showed that the general USA population, residents from areas with mature exploration and production industries, and residents living in areas where shale gas development is a recent interest, shared similar understandings of the shale gas industry (Appendix B). All sample groups responded with the media delivering a "somewhat trustworthy" unbiased coverage of the industry (44% – general population; 41% – mature shale; 55% - new shale). This suggests that the media plays a key role in how the USA population perceives the shale gas industry. Water contamination and the impact on land use are the two main environmental concerns. Overall, this survey found that 58% of the respondents felt that the benefits of shale gas "far" or "somewhat" outweigh the risks.

Canada

A CRA study (2011) (Appendix B) based in New Brunswick resulted with an equal distribution of respondents (45%) in support and opposition of natural gas exploration. 19% "completely opposed" the idea in contrast to 11% fully supportive of exploration. 10% of those surveyed were unsure of their opinions. 34% of the respondents "mostly agree" economic rewards do not exceed the importance of protecting the environment. Although, over half of the respondents (41% – "mostly agree"; 18% – "completely agree") believe that the exploration and production of shale gas should be carried out, if regulations are correctly implemented. 48% "mostly agree" the development of shale gas would bring long term economic benefits, and 58% "completely agree" that new industries must be developed for the Province to grow and prosper.

Holland

A study, Shale gas production in a Dutch perspective (2012), addresses the topic of public perception in Holland. The study suggests that there is general public concern towards shale gas exploration in the Netherlands, linked to the risks of broader industrial activities. Concerns include the lack of rules and regulations formulated for new technologies, and the question of how to cope with risks that are not yet identified. In addition, people may be sceptical toward the effectiveness of the regulatory framework and there is doubt as to whether an industrial party would actually adhere to the agreements made. It is often concluded that, despite its highly unlikely occurrence, an accident could still occur. Moreover, the public and organisations question if there is a need for shale gas development and why money is allocated to the production of fossil fuels instead of renewable energy sources (Royal Haskoning Enhancing Society, 2012).

Poland

A CBOS study discovered that 78% of the Polish respondents supported shale gas in Poland (2013), with a 5% increase from 2011. One reason for Poland's support of shale gas could be the country's dependence on importing gas from Russia. The majority (80%) of the population surveyed believe that shale gas will contribute to the country's energy security. 40% of the surveyed residents are not concerned about the potential environmental and human health risks associated with shale gas exploration, and more than half of those

questioned in the 2011 nationwide survey had no issues even if it was coming "close to where they live" (Natural Gas Europe, 2012).

UK

Public perception and opinion can influence government policy. In the last few years there have been a number of surveys and studies of public opinion regarding the shale gas development in the UK. The results of these surveys and polls show different conclusions. The variation in the results of these polls may be influenced by the way in which the questions are phrased and the information given before the question is asked however notwithstanding any bias placed over this data it is apparent that there are a wide range of views.

Public opinion about shale and oil gas development does change and can be influenced by new events and information publicised through media coverage. For example, the ongoing research undertaken at the University of Nottingham, which conducted series of survey from March 2012 (O'Hara et al, 2012, 2013) shows a declining trend in public support for shale gas. This is thought to be attributed to a change in sentiment due to the protests that took place during the drilling of a well at the Balcombe site in Sussex.

To show the range of opinions that have been expressed about shale projects, during the literature review for this report, Petrenel compiled a summary of some of the "pros" and "cons" arguments see Table 3.12.1 below.

Table 3.12.1 Opinions on Potential Benefits and Risks from Shale Gas Development in the UK

Issue	**Pro Shale Gas**	**Against Shale gas**
Revenue generation	Attractive tax revenue stream for the UK.	Income stream generated by developing fossil fuels.
Security of supply	Security of an indigenous energy supply within the UK, reducing gas imports and improving balance of payments.	In deciding on future sources of energy, consideration should be given to the full implications of health, social welfare and environment for current and future generations. Short term benefits of securing energy supplies without due respect for the environment may be outweighed by the long-term costs (monetary and social welfare). By utilizing shale gas now, future source of indigenous supply will be lost should gas imports become unavailable in future.
Energy supply cost to the UK	Currently cheaper than nuclear and renewable energy.	More expensive to develop than conventional oil and gas especially in the UK where there is less infrastructure, higher population density and limited support services.
Flexible energy source	Controllable resource close to consumer markets.	More infrastructure will be required to deliver the resource (well pads, pipelines, roads, processing plants, waste treatment facilities).
Effect on gas prices	High volume shale gas may lower UK's gas prices with subsequent benefits to households and businesses.	Volume of shale gas in the UK is not large enough to impact average trading prices in the European market.
Impact on local community	Additional employment opportunities. Commercial benefits to the local economy, fringe businesses.	Additional pressures on local infrastructure, increases in local traffic, light, noise, air and visual pollution from operations effecting local community's way of life.
Impact on the environment	Best practises, effective monitoring and regulation enforcement can minimise effects on the environment. Other fossil fuels may have similar or worse impact.	Compared with conventional gas development, operations are likely to be more intense and larger scale leading to a more significant impact and higher risks.

Climate change and CO_2 emissions	Lower CO_2 emissions compared with coal and oil. With shut-down programme for coal fired power stations shale gas can provide a bridging path to renewable or other low carbon technologies.	Higher emissions compared with conventional gas and renewables. Using fossil fuels releases carbon removed from the atmosphere millions of years ago and contributes to climate change. Shale gas development prolongs further reliance on using fossil fuels. It may have an impact on the continuing development of renewable and other low carbon technologies. If coal is used elsewhere this would result in increased global carbon emissions (e.g. coal displaced by shale gas in the USA is being exported to China and other countries)
Intergenerational equity / sustainability	Providing benefits for current generation - economic benefits, and energy. Revenue from shale gas development can help with balance payments, reducing debt for future generations.	Shale gas is a finite resource, once used up it will not address the economic needs or provide energy for future generations.

Source: Petrenel

4. The Potential Impact of Shale Oil and Gas Development on the UK's Countryside

4.1 Introduction

Operational practises and processes for shale oil and gas activities are similar to conventional oil and gas operations. In the UK potential key differences will be the scale and volume of activities due to the requirements of a commercial shale oil or shale gas project versus a conventional oil and gas field.

The lifecycle of an oil and gas project, and specifically for a typical shale gas project, is described in more detail in Section 2.4 and includes exploration, appraisal, development, production and abandonment phases.

Operational activities during the exploration and appraisal phase are similar to the development stage, but are shorter term and are conducted on a smaller scale. Typically exploration activities include site preparation and development of access roads in order to conduct seismic surveys and drill exploratory wells. During the drilling operation there will be increases in local traffic and, in order to carry out hydraulic fracturing on wells, there will be further requirements for water resources and the need to dispose of or treat waste substances.

During the development phase these activities become more intense with the requirement for many more wells and the construction of new gas plants, compressor stations and pipelines to bring gas to the market. On completion of the initial drilling and completion stage much of the main well-site equipment including rigs will be removed and just protected well-heads are retained on the well pads. Wells are then produced over many years. During this period there will be a need to maintain and repair facilities. Wells may require work-overs using a rig or work-over rig and may also require re-fracturing.

At the end of their life wells and facilities require abandonment, whereby production facilities are removed and the area is expected to be remediated and restored. Wells are re-entered, plugged and then aboveground equipment is removed and sites are restored.

During each of these activities there are certain effects and increased threats that can be expected on the local environment and local communities. Specifically, a shale oil or shale gas operation brings:

- A significant land use for development. The development of facilities is likely to change the character of the landscape and compete with other land uses. The operation will result in increased traffic, noise, dust and will impact local communities visually.
- An increase in polluting emissions from construction equipment and generators, vehicles, drill rig exhausts and flaring. Pollutants include particulates, oxides of nitrogen, carbon monoxide, sulphur dioxide and volatile organic compounds (VOCs). Methane gas can be released during the flowback of fractured wells and burning of fossil fuels causes increased carbon dioxide release into the atmosphere.
- An increased requirement for water resources and waste management.
- An increase in the risk to the local ecosystem and communities including:
    - Habitat fragmentation, deterioration of local vegetation, soil erosion;
    - Changes to habitat and wildlife;
    - Contamination of local water systems;
    - Polluting of air from leaks and fugitive emissions;
    - Harmful effects on the local population.

4.2 Differences between Conventional and Shale Oil and Gas Operations

Conventional onshore oil and gas operations have been conducted over many years in the UK, where the Health and Safety Executive (HSE) uses a "goal-setting" approach to safety legislation. This differs from the prescriptive style in that, rather than being given a fixed check list of things that must be done to meet a statutory requirement, companies are required to continually demonstrate to HSE that they are taking measures to minimise the risk of oil and gas releases to as low a level as is reasonably practicable. It is believed that the industry can therefore take a more responsive approach to choosing the best methods or equipment available at the time. Oil & Gas UK guidelines aid this process by promoting best practice across the industry. The HSE employs 115 inspectors to ensure that correct measures are being taken offshore (UK Oil and Gas, 2013).

The impact of a large shale oil or shale operation could be very significant with new challenges and risks that have not been experienced previously in the UK. As described in section 3.4, the government has set out its stall in addressing some of the initial concerns and to promote the evolution of the initial stages of a UK shale gas industry. This report is intended to further elaborate on some of the key areas that might be expected from a full development scenario and make recommendations where there are potential weaknesses in the proposed agenda.

Although, as previously stated conventional operations are similar to those used for shale oil and gas, areas where a large scale shale oil or shale gas project is likely to differ include:

- Large total area required for a commercial operation because of the high density of wells required;
- Large onshore drill rigs to drill long horizontal wells in the shale;
- Substantial increase in equipment supply specifically for unconventional wells and completions (this includes pump trucks, fracturing fluid tanks, higher spec casing strings etc.) and increase in the size of support service industries;
- Improved and potentially additional road access to handle increased volume of traffic to support a large scale drilling and hydraulic fracturing operation;
- Access to larger water resources and additional waste management systems required in both the drilling of wells and the hydraulic fracturing process. Produced waste and activities associated with different stages in the lifecycle of waste - collection of waste, storage, transportation, treatment and disposal (or re-use) cause an additional impact on the environment. If waste is not correctly handled or accidentally released, harmful elements of waste can pose a risk to land, water and living organisms.

4.3 Key effects on the environment and local communities

This section includes a high level overview of the key effects on the environment and local community of an oil and gas operation emphasizing, where appropriate, where it is relevant to shale gas projects.

GHG Emissions

Background and Framework

Under the Kyoto Protocol the UK government originally committed itself to a 20% reduction in Greenhouse Gas Emissions by 2010 and had a more long term aim of a 60% reduction by 2050. To achieve these reductions the government has used a range of legislation and campaigns to spearhead a UK reduction in carbon emissions. The Climate Change Act, 2008 introduced the world's first long-term legally binding framework to tackle the dangers of climate change, which targets a 34% reduction in greenhouse gas emissions by 2020 and 80% by 2050 (compared with 1990 levels), with an intermediate target of 34% by 2020.

Why is it relevant to conventional/shale gas projects?

Greenhouse gas (GHG) emissions associated with shale gas exploration and production include direct and indirect emissions. Below is an overview of GHG emissions from shale gas operations (DECC, 2013):

Direct

- Intentional vented emissions of methane and CO_2 during flowback, for safety reasons and during some maintenance operations;
- Emissions from combustion of fossil fuels on site (diesel engines used for drilling, hydraulic fracturing and natural gas, compression) and from flaring of shale gas;
- Fugitive emissions. These emissions are unintentional gas leaks and are difficult to quantify and control (leaking from valves, well heads, onsite accidents, accidental releases from well casing into groundwater);

Indirect

- Emissions resulting from product/processes used in the exploitation of shale gas, such as emissions from energy used in the treatment and transportation of water and wastewater, and in manufacturing the chemicals and materials for construction.

It is estimated that well completion accounts for a large part (about 80%) of the potential pre-production emissions, including venting (DECC, 2013). These fugitive emissions increase the carbon footprint of shale gas. The amount of methane released into the atmosphere during shale gas drilling is not exactly known, as there has been little measurement of direct and indirect methane emissions from shale gas exploration and production anywhere in the world. A number of studies estimated the potential emissions and these estimates range from 0.42% of gross gas production (Allen et al, 2013), to 0.47% (2011 US Environmental Protection Agency (EPA) inventory, to 3.6–7.9% escaping from venting and leaks over the lifetime of the well (Howarth et al, 2011).

Comparing lifecycle greenhouse gas for the generation of electricity, generating electricity from conventional gas produces around half (469 CO_2/kWh_e) of the carbon dioxide emissions of generating electricity from coal (1001 CO_2/kWh_e). Comparing with other energy sources, the lowest carbon dioxide emissions are from hydroelectricity (4 CO_2/kWh_e) and from onshore wind (12 CO_2/kWh_e) (IPCC). According to the study from DECC, 2013 on "Potential Greenhouse Gas Emissions Associated with Shale Gas Extraction and Use", the carbon footprint of generating electricity from shale gas is estimated to be 423-535g CO_2/kWh_e.

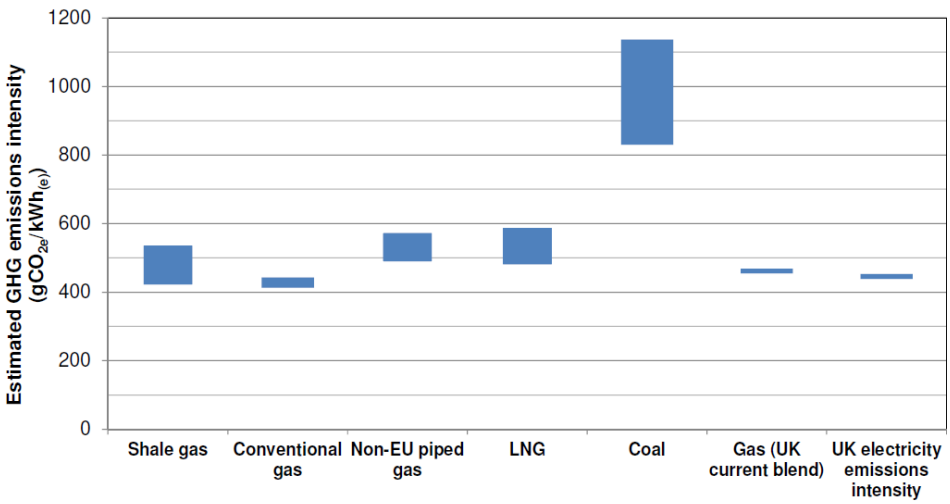


Figure 4.3.1 Comparison of the Life-Cycle Emissions for the Productions of Electricity from Various Sources of Gas and Coal

Source: DECC, 2013

Therefore lifecycle emissions from shale gas generation are 41-49% lower than emissions produced from coal fired power plants. However, comparing European shale gas with other sources of gas for electricity generation, GHG emissions from shale gas are 4 - 8% higher than conventional gas from within Europe, 2 - 10% lower than conventional gas outside Europe, and 7 - 10% lower than electricity generated from LNG imported to Europe, according to the study carried out by AEA Technology for the European Commission, 2012.

There is also a concern over the methane emissions from shale gas operations. Methane is 72 times more potent than carbon dioxide over a 20-year period and 25 times more potent over a 100 year period (IPPC, 2007). Scientists believe that it could be a particularly dangerous trigger for global warming feedback loops (EurActiv, 2013).

What is the effect?

Some of the conclusions of the "potential greenhouse gas emissions associated with shale gas extraction and use" study by DECC, 2013 are: if adequately regulated, local GHG emissions from shale gas operations should represent only a small proportion of the total carbon footprint of shale gas, which is likely to be dominated by CO_2 emissions associated with its combustion. The principal effect of UK shale gas production and use will be that it displaces imported LNG, or possibly piped gas from outside Europe. The net effect on total UK GHG emissions rates is likely to be small. The short-term and long-term effects of shale gas exploitation in the UK on global emissions rates are complex to predict and depend strongly on global climate policies. The production of shale gas could increase global cumulative GHG emissions if the fossil fuels displaced by shale gas are used elsewhere. This potential issue is not specific to shale gas and would apply to the exploitation of any new fossil fuel reserve (DECC, 2013).

According to the IPCC's Fifth Report (September 2013), if current emission trends continue, warming is likely to exceed 2˚, and could possibly exceed 4˚C by 2100 relative to 1850. This will result in large changes to most natural cycles. To avoid significant effects from climate change it is generally regarded within the scientific community that the average global temperature increase needs to be limited to 1 - 2°C compared with the pre-industrial average (Prof. Maslin, 2013).

According to the EIA's World Energy Outlook 2012, no more than one third of proven reserves of fossil fuels may be consumed prior to 2050 if the world is to achieve the 2°C global goal, unless carbon capture and storage technology is widely deployed. Almost four-fifths of the CO_2 emissions allowable by 2035 are already locked-in by existing power plants, factories and buildings. If action to reduce CO_2 emission is not taken by 2017, the energy-related infrastructure then in place will generate all the CO_2 emissions allowed up to 2035, leaving no room for additional energy infrastructure, unless it is zero-carbon.

What can be done about it?

Examples of climate change mitigation include measures to reduce or prevent carbon emissions by switching to low carbon energy sources, such as renewable and nuclear energy, protecting and expanding carbon sinks (forests and other sinks) to remove amounts of carbon dioxide from the atmosphere, improvements in energy efficiency (insulation of buildings, making equipment more energy efficient).

According to DECC, 100% venting will not be permitted in the UK. The study by DECC, 2013 shows comparison of lifecycle GHG emissions for the production of electricity from various sources. The study assumes that the 90% of methane released during completion would be captured and flared.

In terms of the UK's carbon reduction commitments, if shale gas development is used to displace the use of coal in the UK in line with planned closures of coal power plants in the UK, and as a bridging path to renewable or other low carbon technologies, it could help the UK to reduce its emissions. According to the study carried out by the Joint Research Council Scientific and Policy Reports (EU) on Potential Energy Market Impacts in the EU, 2012 the modelling results support the potential role of natural gas as a "bridging" fuel (the model used however does not consider GHG emissions during mining or transportation, and hence does not include complete life cycle comparison). However if the coal displaced by shale is used elsewhere, this would increase the global carbon emissions. For example, while domestic emissions in the USA have recently reduced as result of using less coal due to gas production from shale, the coal production continued, increasing the volume of exports, mostly to China.

If the development of shale gas is used to replace the development of the UK's capacity for renewable and other low carbon technologies, this could have an impact on the UK's objective to achieve its renewable energy targets, and hence reduce the long term capability to reduce its CO_2 emissions.

In managing the emissions during the exploration and production stages fugitive emissions can be reduced by recovering gas from flowback in a process called Reduced Emissions Completion (REC) which captures about 90% of the gas. Recovered gas is typically injected into a gas pipeline, although some sites may use a proportion of the recovered gas to power onsite equipment. The study conducted by Professor MacKay and Dr Stone, 2013 DECC on "Potential GHG emissions associated with shale gas extraction and use" makes some recommendations in relation to reducing GHG emissions:

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

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

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

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

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

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

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

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

Emissions: Gas Flaring

Background and Framework

Flaring is the burning of natural gas, NGL's or oil in the course of oil and gas operations during exploration, development and production. Flaring is the practice of burning gas that is deemed uneconomical or impractical to collect and sell and is also used to burn gases that would otherwise present a safety problem. Flaring is also a major contributor to greenhouse gas emissions including CO_2. Worldwide, flaring accounts for 1% of anthropogenic CO_2 emissions (OGP, 2000). In the UK, to flare onshore an operator will have to apply for a flare consent from DECC. The operator must provide information on the infrastructure and equipment along with calculations of the flaring amount on both a daily basis and total volume (DECC, 2013).

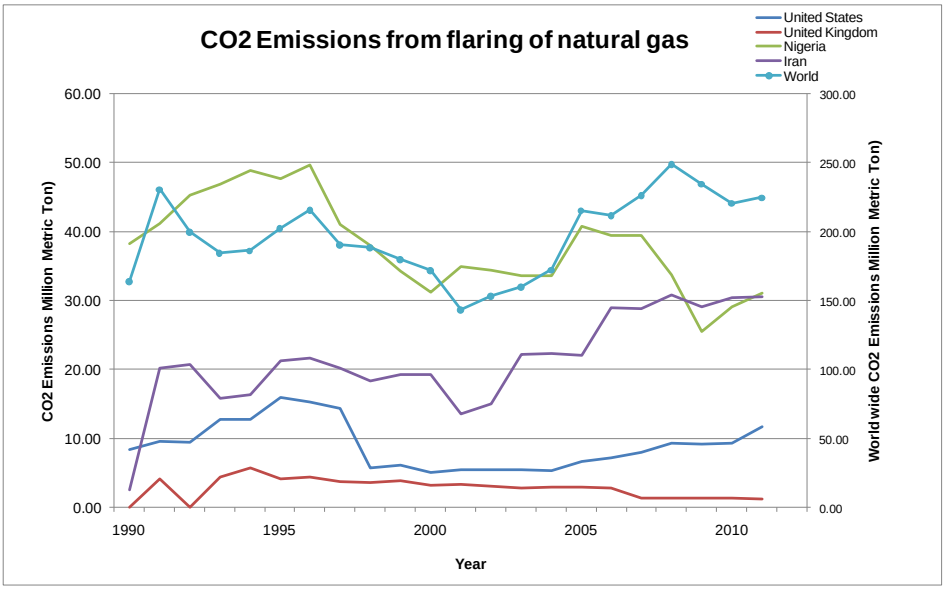


Figure 4.3.2 CO_2 Emissions from the Flaring of Natural Gas 1991-2011

Data Source: EIA, 2013

Flaring in the UK has continuously been a low percentage of the total worldwide flaring activities, reducing from a peak of 3.1% in 1994 to 0.52% in 2011.

Why is it relevant to conventional/shale gas projects?

Flare systems are installed at most well sites and processing facilities. Flaring occurs during testing operations, when there is no infrastructure available for exporting the oil or gas, and during production as a safety prevention mechanism, where excess gas is burnt to evacuate gas in the process system. Flaring reduces the risk of venting of natural gas. The risk of overpressure in a process system could lead to a major incident and a greater environmental catastrophe unless vessels are equipped with safety valves allowing gas to be vented.

What is the effect?

Flaring is normally visible and generates both noise and heat. Flare stacks and burning gas can be unsightly to those living near the site and a visual detriment to the aesthetics of the community. Flaring emits a number of pollutants, depending on the chemical composition of the gas and the efficiency of the flare. Flaring equipment is required to meet certain specifications. If flares are improperly operated, they may emit methane, VOCs, sulfur and nitrogen oxides, smoke, dioxin, and may include unburned fuel components such as toluene, benzene and xylene, which may lead to significant health problems.

Figure 4.3.3 Oil Field Flare Stack

Source: Petrenel

If hydrogen sulphide is present in large enough amounts in the natural gas, flaring also results in hydrogen sulphide emissions. Flaring can impact wildlife by attracting birds and insects to the flame. For example, in a recent incident in Canada, about 7,500-6,800 migrating songbirds were killed by the flare at Canaport gas plant.

What can be done about it?

Certain practices can be followed to reduce the overall impact of flaring. Flaring quantity can be limited to the minimum required for a safe and practical operation. Flaring can be re-sited to be less visible. This will reduce the visual impact but not the air emissions. Planned flaring associated with flow testing, can be restricted to certain times to reduce the visual impact on the countryside. The environmental impact assessment considers the effects on wildlife and the least harmful methods available.

Figure 4.3.4 Shale Gas Well Flaring, Washington County, Pennsylvania

Photo Courtesy of: Robert M. Donnan

Land Use and Footprint

Background and Framework

Shale gas development is an intensive process, imposing a larger environmental footprint on the land compared with conventional gas extraction.

Many more wells are required for the recovery of shale gas compared with conventional extraction of gas.

In the UK, land that is acquired for well pads is likely to be targeted where planning permission is forthcoming and hence away from more environmentally protected areas. Spacing between pads will probably be quite wide initially but later, infill drilling will create a denser pattern subject to planning consent.

Figure 4.3.5 Photo of Natural-Gas Wells in the Jonah Field, Wyoming

Photo Courtesy of: EcoFlight, **Photo Credit:** Bruce Gordon

Why is it relevant to conventional/shale gas projects?

The number of unconventional natural gas wells in the USA rose from 18,485 in 2004 to 25,145 in 2007 and is continuing to increase at least until 2020. The large number of wells has transformed the landscape in some parts in the USA.

Based on the data from Canada and the UK the land footprint for a well pad ranges from three to five acres, with an average size of three acres per pad. In addition to the land impact arising from drilling, during the development stage there will be new infrastructure such as gas pipelines, gas processing facilities and waste treatment facilities, increasing the land requirement.

Figure 4.3.6 The Impact on Rural Landscape from Building Shale Gas Storage and Processing Facilities in and around Carroll County, Ohio

Photo Courtesy of: David Beach, GreenCityBlueLake Institute of the Cleveland Museum of Natural History

The required land footprint would be dependent on the scale of the potential shale gas development. Ultimately for maximising the recovery of gas there could be a large number of wells – for example, in the U.S. Barnett shale play almost 15,000 wells were drilled by the end of 2010 over an area of 13,000 km², with an average well density of 1.15 wells per km² and this may increase to ~6 wells per km² (Lechtenböhmer et al., 2011).

What is the effect?

Depending on the scale of the shale gas development (density of well pads drilled) the potential impact can have major implications for local communities, land use and water resources. The size of the footprint is more critical in environmentally protected areas. In the case of a large scale shale gas development, with frequent well pad spacing, there are cumulative effects on the fragmentation of landscape, habitats and farmlands and it may not be possible to fully restore certain sites.

Figure 4.3.7 Aerial view of a Marcellus Shale well site near Waynesburg, PA

Photo Courtesy of: Michael Bryant

The map below shows locations with prospective areas for the Bowland/Hodder shale in the north and the Weald shale in the south, the high pressure NTS pipeline network, and some protected areas such as National Parks, Areas of Outstanding Natural Beauty, SSSI, National and Local Nature Reserves. For a list of the main protected areas see Appendix F.

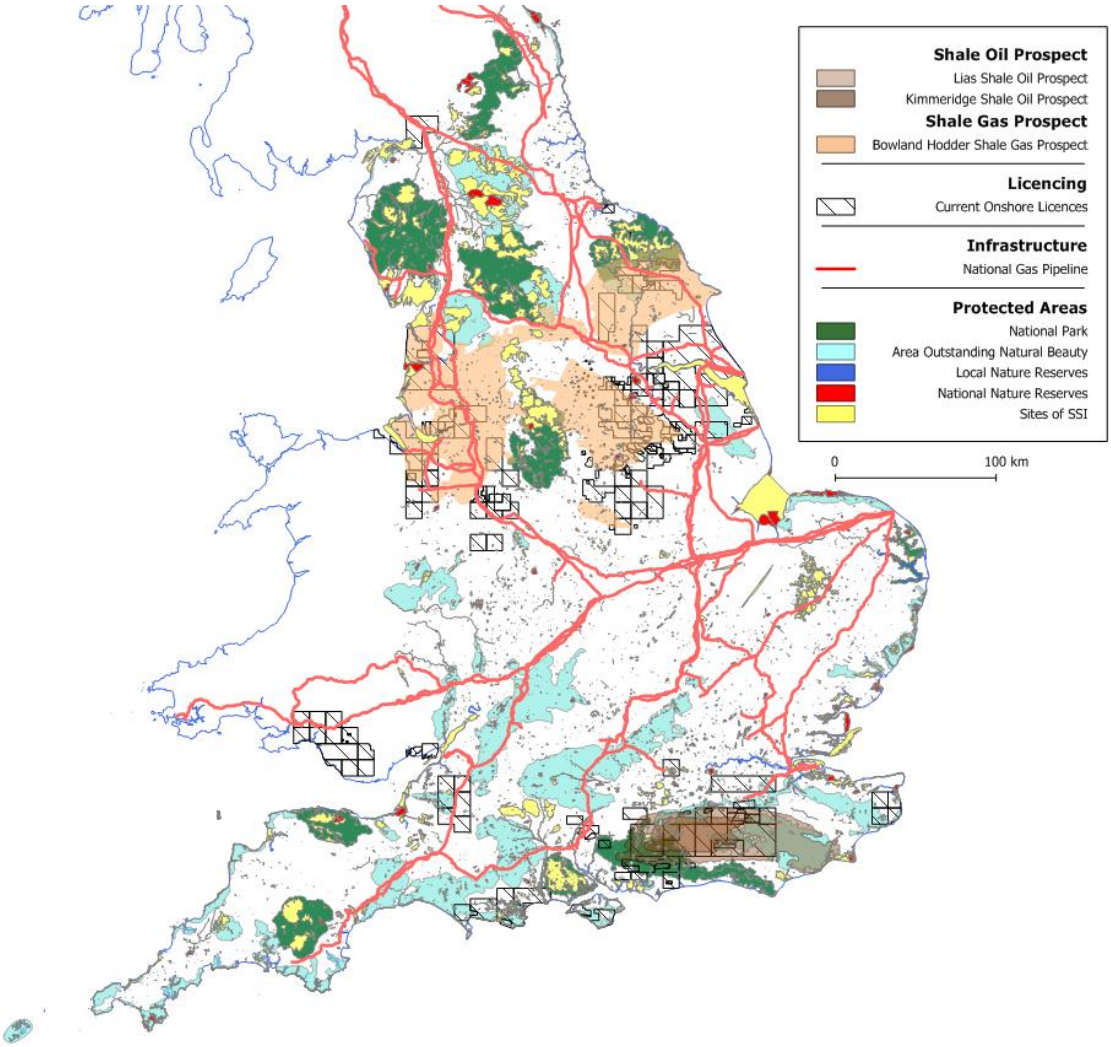


Figure 4.3.8 Shale Gas Resources, Licence Blocks, Protected Areas and Gas Pipeline Network

Data Sources: Natural England; Environment Agency; Ordinance Survey National Grid; British Geological Survey

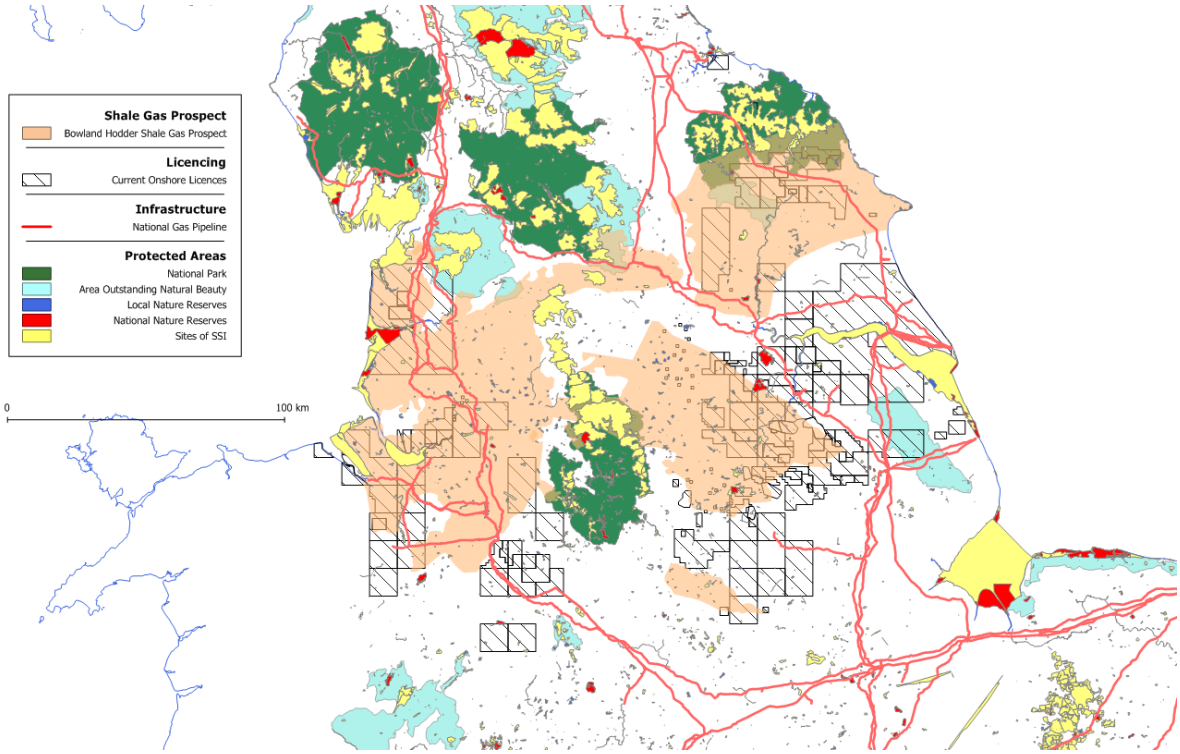


Figure 4.3.9 Shale Gas Prospective Area, Licence Blocks Protected Areas and Gas Pipelines - Bowland Prospects (both Upper and Lower Formations)

Data Sources: Natural England; Environment Agency; Ordinance Survey National Grid; British Geological Survey

In the map shown above some of the shale prospectivity lies in protected areas. Across the Weald area a substantial part of the outlined prospect is in a national park and other protected areas.

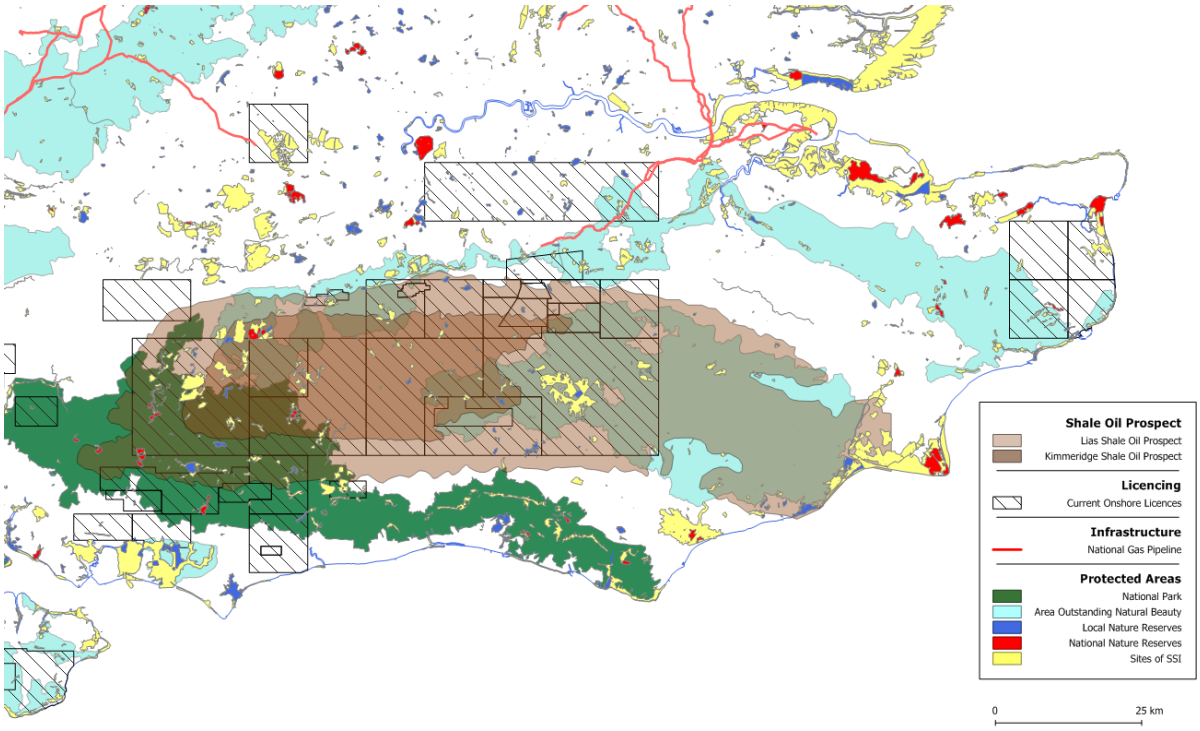


Figure 4.3.10 Shale Oil Prospective Area, Licence Blocks, Protected Areas and Gas Pipelines - Weald Basin

Data Sources: Natural England; Environment Agency; Ordinance Survey National Grid; British Geological Survey

If not already included in the Strategic Environmental Assessment which is being prepared for the upcoming licencing round, consideration should be given to reviewing licence areas for existing infrastructure, availability of water and site availability, to take into account the intensity of shale gas development rather than merely treat the award of licences as if it were for conventional oil and gas. Preference could also be given to award licences with shale gas potential which fall outside areas that are environmentally protected. For example, it can be seen from the map above that in the area of Weald, there is limited access to the NTS system. Development of further infrastructure in this area may be difficult without increasing the risks to the protected areas.

What can be done about it?

In the UK, the operators and other stakeholders are likely to target surface locations for early stage shale gas projects that are least likely to cause concern i.e. outside environmentally protected areas given that seeking planning permission for the latter areas is likely to be difficult and could at the very least result in significant delays.

It has been shown in other parts of the UK that petroleum development can be carried out with minimum environmental and visual impact. The visual impact of shale gas and oil development on the landscape will depend on the viewing point. It can be relatively small at ground level. Well pads, with their low vertical profile, can be hidden from sight with carefully placed trees and bushes. Wells and facilities are therefore capable of being shielded from a horizontal viewing point, except possibly during drilling operations. For example, the Wytch Farm Oilfield, situated in an area of Outstanding Natural Beauty, is often used as an example of one of the lowest visual impact sites in Europe. A wide array of environmental abatement measures were used in order to minimise the impact of the development by the operator in collaboration with Dorset County Council. A site design was used that blends into the environment including painting equipment earth–tone colours, pointing all lighting downwards, installing a noise control package on the drilling rig, regular atmospheric monitoring, and regular groundwater monitoring.

However production from shale gas wells is considerably lower than conventional gas wells and this leads to a more intense development to achieve comparable field production rates, and, depending on the scale of development, the visual impact on the landscape may be greater. This will be particularly evident from an elevated perspective and during the construction of roads, pipelines and facilities.

Land footprint of oil and gas developments including shale gas can be reduced by the use of multiple wells in a single pad. For example there could be as many as 40 wells or multi-laterals drilled from one pad, with the footprint of about three to five acres during the drilling and fracturing stage. This would reduce the frequency of the well pads in a given area. The distance between well pads would depend on optimising the well spacing requirements to achieve maximum gas recovery versus sighting pads in locations that will receive the required planning consent and minimise the impact on the local environment.

Figure 4.3.11 Wytch Farm, Dorset

Source: Google Earth

For example, in a licence of 1400 km^2, if 20 well pads were developed (using multiple horizontal wells from a single pad), the distance between them would be 9.5 km, for 40 well pads the distance would reduce to 6.7 km, and for 80 well pads the distance between them would be 4.7 km.

The image below gives an illustration of the visual impact, of large well pads (about five acres), spaced 4 km by 3 km, during the drilling stage. The impacts from roads, pipelines and required infrastructure have not been shown.

Figure 4.3.12 View from Harting Down, South Downs Way looking North East with Well Pads at 4 km x 3 km with Seven of Seven Large Well Pads Displayed

Photo Courtesy of: Andrew Mair (with additions by Petrenel)

Impact on Ecosystems and Habitats

Background and Framework

In the USA, intensive onshore oil and gas development, including shale gas, has lead to a fragmentation and of natural habitats and a loss of previously intact forest habitats in some areas (Souther et al., 2014). There are concerns about shale gas development impact on the natural environment and on wildlife in the UK. Habitat fragmentation from any development can reduce dispersal, foraging and mating success, increasing species risk of local extinction. Opening of formerly remote areas can facilitate poaching of imperilled and sensitive species, serve as a conduit for invasive and non-native species and provide a gateway to further and more permanent development (Souther et al., 2014).

Landscape disturbance associated with petroleum development infrastructure directly alters habitat through loss, fragmentation, and edge effects, which in turn alters the flora and fauna dependent on that habitat. The fragmentation of habitat is expected to amplify the problem of total habitat area reduction for wildlife species, as well as contribute towards habitat degradation. Fragmentation alters the landscape by creating a mosaic of spatially distinct habitats from originally contiguous habitat, resulting in smaller patch size, greater number of patches, and decreased interior to edge ratio. Fragmentation generally results in detrimental impacts to flora and fauna, resulting from increased mortality of individuals moving between patches, lower recolonisation rates, and reduced local population sizes. The remaining patches may be too small, isolated, and possibly too influenced by edge effects to maintain viable populations of some species (Slonecker et al., 2012).

Why is it relevant to conventional/shale gas projects?

Shale gas operations are by nature an intense, heavy industrial activity affecting in a number of ways natural environment and wildlife.

Figure 4.3.13 Photo of Natural-Gas Wells in the Jonah Field, Wyoming

Photo Courtesy of: EcoFlight

What is the effect?

The construction of wells pads, infrastructure and drilling activities result in vegetation and topsoil removal, noise, increased traffic and air pollution and habitat fragmentation. This threatens the integrity of ecosystems and may lead to population declines, disturbance, or the displacement of some species.

There can be permanent effects on both animal and plant species, such as changes in food and nutrient supply, breeding areas, migration routes and changes in grazing patterns.

What can be done about it?

One of the ways to ensure effective protection in environmentally sensitive areas, as well as controlling the development, is through the renewal, re-issue or issue of future licences for petroleum exploration. To ensure the protection of priority habitats and areas of high ecological and recreational value, it is best to exclude such areas from the licence areas. Risks could also be minimised through evaluation and planning. The EIA can be used to plan operations to avoid protected areas and sensitive habitats. Operations can also be scheduled around areas of high biodiversity and during the least sensitive periods.

Figure 4.3.14 Gas Pipeline Construction near Fredericktown, Pa

Photo Courtesy of: Robert M. Donnan

Transportation

Background and Framework

In any oil and gas development there is a transportation requirement associated with drilling and construction and for shale gas operations the potentially large number of wells and the need to hydraulically fracture each well increases the logistics.

Increased traffic affects air quality. In the UK, DEFRA is required to ensure EU limit values are met in the UK by coordinating assessment and air quality plans. The Local Authority is responsible for ensuring local air quality is meeting national standards, and for monitoring local increases in air pollution, including traffic-induced pollution.

Why is it relevant to conventional/shale gas projects?

Shale gas projects will result in a higher traffic volume compared with conventional oil and gas activities due to the larger number of wells required for development. Transportation of water is required for drilling and hydraulic fracturing unless a local water supply is available. In addition, higher volume traffic will be present during the construction stages for bringing appropriate equipment to the site, such as the rig itself and transport of drill pipe, casing etc.

What is the effect?

Higher traffic volume results in increased air pollutants such as carbon dioxide, particulate matter (PM_{10} & $PM_{2.5}$), SO_x, and NO_x, thus increasing risks to human health and to the local ecosystem. The disturbance from truck movements can lead to the displacement of species susceptible to noise in areas with significant biodiversity value.

Heavy traffic also causes damage to roads and bridges, and an increased risk to civilian transportation. Well pad locations may require the development of additional transport routes, introducing traffic into new areas. This may encourage increased urbanisation along new access routes.

What can be done about it?

An assessment of the proposed transportation system associated with a shale operation will be considered during the application for planning approval to ensure compliance with the requirements as outlined in the national planning policy framework and local planning policies. These will include applying best practises for accessibility to the operations sites by all required means of transport and minimising the effects on local communities, congestion and greenhouse gas emissions especially during periods of high activity such as construction or drilling phases. Signage to and from sites can be introduced to direct drivers onto specific routes to avoid noise in sensitive areas.

For the transport of products to and from the sites consideration should be given for the use of below ground pipelines or other means of transport that may alleviate road congestion. Sourcing water locally to the site and the treatment and recycling of contaminated produced water on-site can also reduce truck movements.

Water Consumption

Background and Framework

Two-thirds of water in the UK comes from surface sources and a third from groundwater. Sources vary by region, and in London and the South East groundwater accounts for around 70% of the total water supply. Demands for water are continuing to rise and maintaining supplies to meet these demands is becoming increasingly difficult. Over the past few years, several water suppliers have reported water deficiencies within their regions due to the more extreme weather conditions, population growth and changing lifestyles. In November 2013 Water UK and UKOOG signed a Memorandum of Understanding to work together throughout the shale gas exploration and extraction process to help minimise the impact of onshore oil and gas development in the UK on the country's water resources (Water UK).

Why is it relevant to conventional/shale gas projects?

A typical shale gas well will require 10,000 to 30,000m^3 of water over its lifetime (10 to 30 million litres of water) (DECC, 2013). The source of this water is of concern to the public particularly in the South East where water resources are already under intense stress (Environmental Agency, 2013). Compared with the usages of other industires, it is the equivalent of the amount needed to water the average golf course for a month, and the amount needed to run a 1000 MW coal-fired power plant for 12 hours. However, a large amount of water is also lost every day from the water network through leakages. A shale gas operator can apply for a water abstraction from groundwater permit from the environment agency if more than 20 cubic metres a day is required, or water can be obtained directly from a provider.

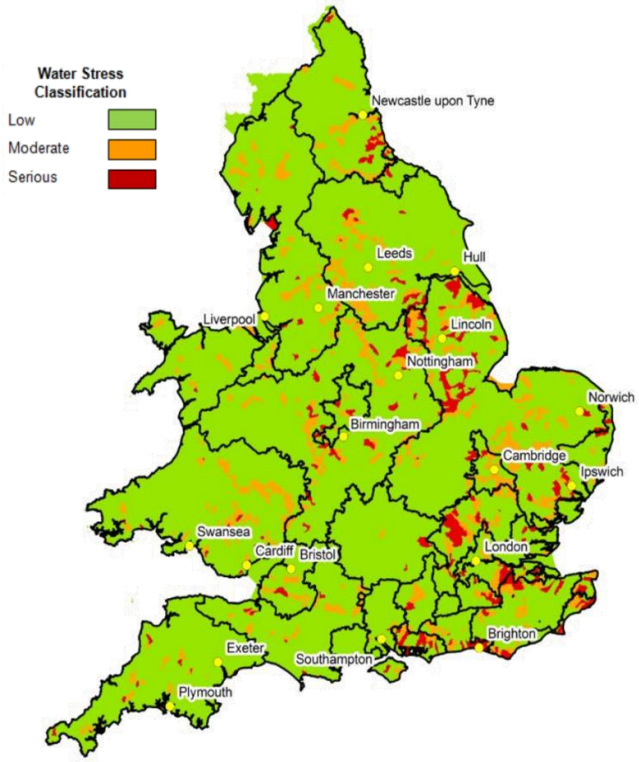


Figure 4.3.15 Water Stress Map (Based on Water Providers and Available Water)

Source: Environment Agency, 2013

What is the effect?

Many parts of the UK have experienced drought in recent years. Population growth is expected to increase water demand, which can lead to further pressure on regions already experiencing drought. In addition it is predicted that, due to climate change effects, there may be reductions in summer rainfall and increase in winter rainfall in the UK (Osborn and Maraun, 2008), which would increase the pressure during summer months and increase the likelihood of flooding in winter months. Water demand from shale gas development would put additional pressures on water resources in the UK.

What can be done about it?

The water demand can be reduced by onsite treatment of produced water and re-use for further fracturing operations. This would also reduce the number of truck movements to deliver water. Local water utility providers decide whether or not they can meet the extra demand to support the shale gas industry through mains supply. Water utility providers are managing the additional pressures and the increasing water demands. They are required to produce water management plans every five years to show how demand for water is to be managed and met over a 25 year period, and to produce a drought plan every three years. The Environment Agency is the regulatory body which approves water abstraction greater than 20 cubic metres a day. It can refuse permission if it believes the abstraction will endanger future supplies.

Waste Disposal

Background and Framework

Both drilling and hydraulic fracturing operations create different types of waste, from waste water and mud to cuttings and sludge. In the USA, returned water from wells is often pumped into big, open, plastic lined pits before being removed for disposal. There is concern that there could be possible leaks from these liners. In the UK the use of open storage pits is not permitted. Instead all returned fluids on land must be stored in metal containers before treatment. Operators must carry out laboratory and batch scale tests to identify the best options for the disposal of the flow-back fluids.

Figure 4.3.16 Water Storage Tank

Source: Petrenel

In the UK, the exploration and extraction of hydrocarbon operations must follow "The Groundwater (England and Wales) Regulations 2009". When produced water comprises of formation water only it can be re-injected into geological formations. The injection of flowback water is banned in the EU by the Water Framework Directive (AEA, 2012) unless treated until it can be classified as fresh injection fluid (EA, 2013).

Why is it relevant to conventional/shale gas projects?

The largest amount of waste being produced by shale gas operations is waste water - the injected fracturing fluid which flows back to the surface (flowback fluid) together with formation water. During hydraulic fracturing operations each well on a multi-well pad will generate between 1,300 and 23,000m³ of flowback fluid. Flowback of fracturing fluid and produced water usually contains a mixture of water, fracturing chemicals and subsurface elements mobilised during the process - brine (e.g. sodium chloride), gases (e.g. methane, ethane, carbon dioxide, hydrogen sulphide, nitrogen, helium), trace elements (e.g. mercury, lead, arsenic), naturally occurring radioactive material NORM (e.g. radium, thorium, uranium) and organic material (e.g. acids, polycyclic aromatic hydrocarbons, volatile and semi-volatile organic compounds). Normally NORM concentrations are low, but sometimes these concentrations can be unusually high.

What is the effect?

Activities associated with different stages in the lifecycle of waste - collection of waste, storage, transportation, treatment and disposal (or re-use) cause additional impact on the environment. If waste is not correctly handled or accidentally released, harmful elements of waste can pose a risk to land, water and living organisms.

What can be done about it?

In the UK, the operator must have an environmental permit for waste storage and subsequent treatment and disposal. Wastewaters are labelled as "extractive waste". Disposal is regulated in the UK under the Mining Waste Directive and Water Framework Directive. This requires operators to prepare waste management plans for addressing waste reduction, treatment and disposal procedures. The operator is required to identify environmental and health impacts, and prepare plans for mitigation, control and monitoring. An environmental permit and pre-treatment would be required before injection into a disposal well. The radioactivity of the shale can be evaluated before production commences using gamma ray logs.

Contamination of Ground Water Systems

Groundwater contamination is possible from both conventional and shale oil and gas activities on the surface and below the ground. Wells drilled to explore for and extract hydrocarbons must penetrate shallower strata before reaching the target horizons. Some of the shallower strata may contain groundwater used for human consumption or which supports surface water flows and wetland ecosystems. This section briefly describes the key risks of groundwater contamination, likelihood of occurrence and control and prevention measures.

The two potential areas of water resource degradation not associated with waste water treatment (see the section on Waste Disposal) that are illustrated schematically in Figure 4.3.17 are:

- Shallow aquifers contaminated by fugitive natural gas or oil from leaking oil and gas wells and/or contamination from stray hydraulic fracturing fluids and/or saline formation waters.
- Surface water contamination that may find its way into groundwater systems from spills, leaks, and the disposal of inadequately treated wastewater or hydraulic fracturing fluids.

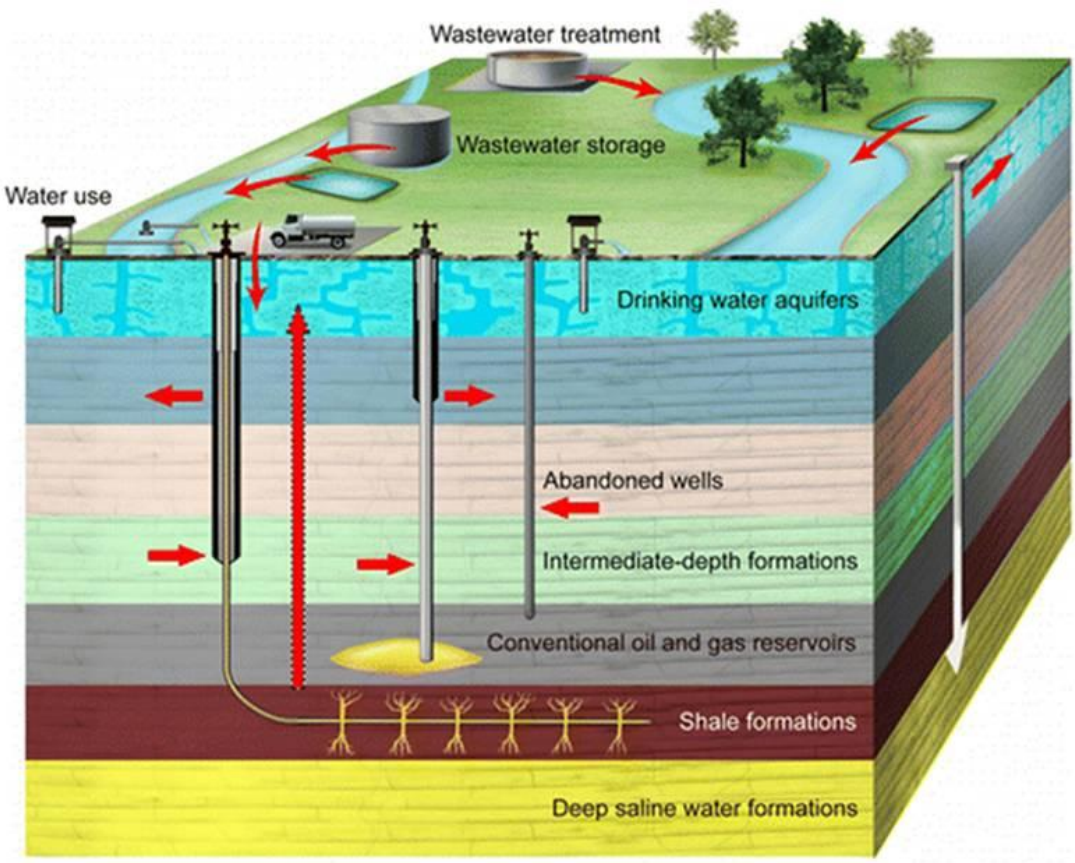


Figure 4.3.17 Schematic diagram showing typical oil / gas well completion through surface strata

Source: Vengosh, 2014

A. Contamination below ground

Background and Framework

Within oil and gas producing wells there are a nested collection of pipe, cement, seals, and valves that form multiple barriers between produced well fluids and the outside environment. Barrier and integrity in well-design technology is loosely defined as containment elements that can withstand a specific design load. These may comprise pipe that is effectively cemented, seals, pipe body, valves, and pressure-rated housings. Typical design-load parameters include operating environment factors such as temperature, pressure, fluid composition,

fluid velocity, and exposure time. Design of containment systems are adapted for the geological environment and the safe and effective drilling of wells.

Multiple barriers are designed and built to withstand a specific load but also bring added protection and build in redundancy to avoid complete integrity failure and any resultant escape of fluids. If an inside (or outside) barrier fails, the next barrier will provide isolation so that a leak path will not form. In modern designs, the number of barriers is typically proportional to the hazard potential in specific well areas. When a barrier failure occurs assessment of any risks to safety and environment would normally lead to remedial action to repair or replace the failed barrier. In the United States, state and federal regulations cover exemptions that may or may not be granted to continue to operate. Monitored barriers may have fluid-filled spaces (annuli) between barriers that can be monitored for pressure increase or fluid invasion. Annular spaces that are cemented to the surface are usually not monitored. Well-integrity failure is an undesired result in which all barriers in a potential leak path fail in such a way that a leak path is created. Whether or not pollution occurs, however, depends on the direction of pressure differential and buoyancy of the leaking fluid. There is a natural pressure gradient outside the well, established by fluids and trapped pressure environments. The gradient inside the well is a function of the pressure at the highest point of containment and the fluid-density gradients from top to bottom. Because multiple fluid phases, often with pressure-dependent densities, are commonly present in a wellbore in both flowing and static conditions, the potential for pressure underbalance and/or overbalance is difficult to describe, and a leak path from a well could flow fluid outward in one operating condition and inward in another operating condition.

Thus for oil or gas to migrate requires a pathway either through or behind the casing and other equipment or tubulars in a well or through natural or anthropogenic fractures and faults in the rock. The flow depends on the drive mechanism which may be due to a difference in fluid density or through pressure differential. Some formations exhibit over-pressure i.e. pore pressures that significantly exceed a normal hydrostatic gradient at a given depth. However, shale deposits normally exhibit very low permeability and hence compared to conventional wells the rate of leakage is likely to be slow. The release of hydrocarbons that ultimately appear at the surface through well integrity failure can result in a well "blowout" where hydrocarbon can escape into the atmosphere in an uncontrolled way with the added possibility of catching fire and causing significant damage.

Stray gas or oil migration into shallow aquifers can therefore potentially occur by the release of hydrocarbons through well integrity failure. This may occur in any type of well including abandoned wells. Hydrocarbons can also be transported along existing or incipient faults or fractures close to main reservoirs or adjacent stratigraphic formations following drilling and hydraulic fracturing. Given the possible life of a well there is a potential long-term risk to shallow groundwater aquifers.

In addition to the effects of hydrocarbon contamination, shallow aquifers could potentially be contaminated by the migration of hypersaline water or hydraulic fracturing fluids through similar pathways. The potential upward flow of water based fluids is controversial; one model has suggested that the advective preferential flow through fractures could allow the transport of contaminants from the fractured rock to overlying aquifers in a relatively short time. Other studies have disputed this model suggesting that the upward flow rate of brines would typically be fairly low because of low overall permeability of rocks overlying the prospective formations, low upward hydraulic gradients, and the high density of fluids. The hydraulic conductivity along a fault zone seems to have an important effect on the potential for upward migration of hydraulic fracturing fluid or underlying brines.

Micro-seismic data that is acquired to aid map out the fractures suggest that the deformation and fractures developed following hydraulic fracturing typically extend less than 600m above well perforations, suggesting that fracture propagation is insufficient to reach shallow drinking-water aquifers in most situations.

Research in the USA by Fisher and Warpinski (2012) and in the UK by Davies et al. (2012) examined the fracture propagation heights of hydraulically induced fractures. Only 1% of the fractures examined were greater than 350m, and the largest fracture was less than 600m. The probability of fracture propagation being greater than 350m is 1%, with any further less than this. Fracture propagation height for different wells in the Barnett Shale, with the depth of the deepest known aquifer for that location superimposed.

Naturally occurring fractures ranged in height from 200-400m with very few fractures exceeding beyond 700m. It is also extremely rare for a single fracture to exceed 1000m. This is due to the variation in rock layers.

Heterogeneous rocks have differing mechanical properties. As a fracture propagates it will need high stress concentrations to overcome the mechanical strength of the differing layers.

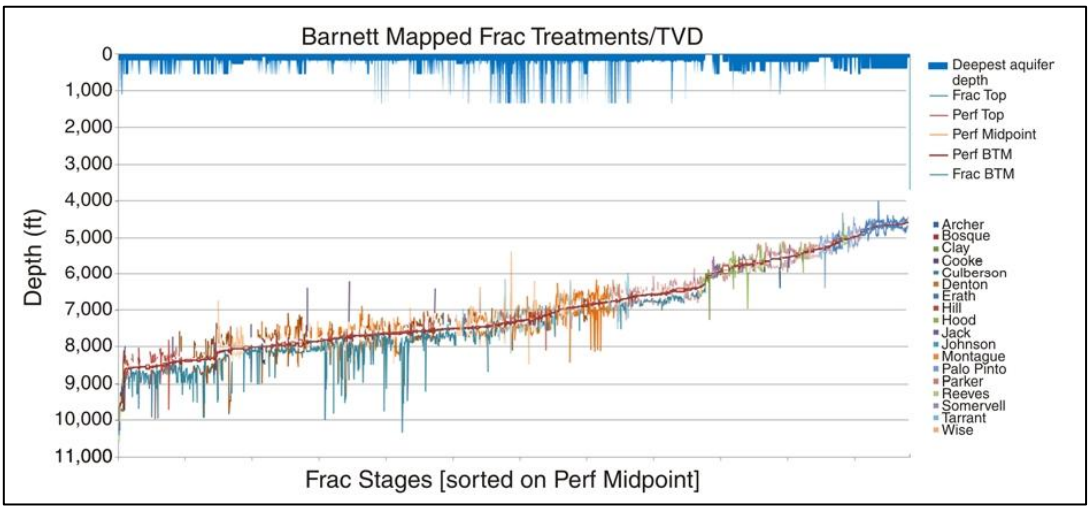


Figure 4.3.18 Fracture Stages Depth and Depth of Deepest Aquifers in the Barnett Shale

Source: Fisher and Warpinski, 2012

Fracture propagation is dependent on many factors including the geological environment, the volumes pumped, the size of the pumps and the limitations of the well completion design.

Why is it relevant to conventional/shale projects?

Given there is similarity in operations between conventional oil and gas development and the exploitation of shale the only reason for there being a higher level of risk of groundwater contamination in shale exploitation is the expected large number of wells required for a commercial shale operation and the higher dependency on and scale of the hydraulic fracturing. More data would be required to determine if there is an increased risk from shale operations. It is possible that high levels of activity and the benefit of greater experience and much more data will be utilised to improve working practises.

There are a number of reports on the available statistics for wells with failed barriers, loss of well integrity and recorded incidents. Establishing their relevance and applicability to aid in the prediction of future shale operations is challenging and significant caution is required when trying to interpret such data. Some figures such as those presented by Ingraffea, 2012 report that in the Pennsylvania Marcellus shale play between 6% to 9% of wells drilled recorded some sort of well failure highlighting that in some cases increasing annular pressure may have been indicative of gas leaking to surface. However, presupposing that this may be relevant for a prognosis on the likely risks in the case of a UK shale gas operation is speculative. Well, or to be more specific, casing, cement, valves or other equipment etc, would have to be analysed in more detail both to determine whether the incident posed a risk of leakage and, if so, what are the consequences.

Vengosh et al approached the problem by targeting data that establishes the nature of hydrocarbon presence in aquifers that indicate that contamination may have taken place i.e. a more direct indicator rather than an inferred one. One of the challenges in establishing contamination is the requirement to first record baseline studies over time to set the background norms. This has rarely been recorded consistently over time and hence criteria for changes in water quality may again not be definitive. Natural gas migration and solubility in water can of course occur naturally and hence variations in the presence of natural gas caused by shale operations has to be distinguished from any natural occurrence.

Vengosh et al also established that across the northeastern Appalachian Basin in Pennsylvania, shallow groundwater had detectable, naturally occurring, methane with thermogenic (i.e. derived from pressure and temperature effects on buried organic matter) stable-isotope fingerprints. This distinguishes that gas from biogenic gas that is derived from organisms that exist in marshes, landfills etc. Shallow drinking water wells,

however, showed elevated methane, ethane, and propane levels less than 1 km from shale gas drilling sites which were consistent with Marcellus production gases from the region which suggests that stray gas groundwater contamination may, in part, be sourced from the shale formations.

In contrast other investigators have suggested that higher methane concentrations in shallow groundwater were natural and could be explained by topographic factors associated with groundwater discharge zones. Geochemical data do suggest that some natural gas migrated to shallow aquifers through geologic time.

Collecting data that is more informative will depend on sufficient monitoring both prior to and during shale operations. Without more data it is difficult to assess whether data has both relevance in assessing the risks to the water systems in the location where it is collected and in extrapolating that dataset to assess the risks in a new operations area where there may be a different set of conditions e.g. differences in the regulatory environment, the geological setting, the method of well design and completion etc.

What is the effect?

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. In general groundwater has many benefits:

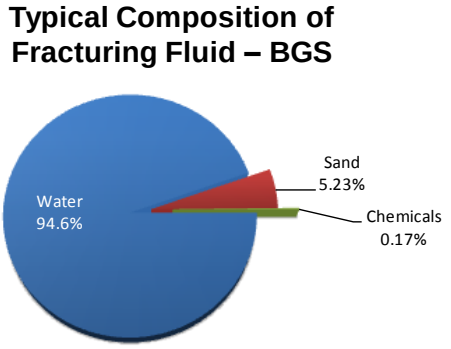
- It provides water that needs little treatment before it can be consumed.
- It provides water for rivers, wetlands and water supplies. All rivers are partly fed by groundwater. Some rivers and wetlands depend on it completely.
- It provides essential water for industry and agriculture.

Polluted groundwater systems can be difficult and expensive to clean up although water passing naturally through aquifers is naturally filtered and many pollutants are degraded during the slow passage to the water table. This helps to maintain the relatively good quality of groundwater.

Pollutants are substances that can either occur naturally but are concentrated by human activities, or they can be substances that are synthesised by humans and do not normally occur in nature. Pollutants can be divided into those that break down easily (degradable pollutants) and those that do not (non-degradable pollutants). The Environmental Agency Water Framework Directive introduced the concept of 'hazardous substances' and 'non-hazardous pollutants'. A key element in the Water Framework Directive is the requirement to set up drinking water protected areas (DrWPAs). The aim in these areas is to manage water resources and to prevent deterioration in water quality that could increase the treatment of water supplied for potable purposes under the Drinking Water Directive (80/83/EEC as amended by Directive 98/83/EC). All groundwater bodies in England and Wales have been designated DrWPAs.

Hazardous substances are the most toxic and the Environmental Agency's policy is to prevent these from entering groundwater. Substances in this list may be disposed of to the ground, under a permit, but must not reach groundwater. They include pesticides, sheep dip, solvents, hydrocarbons, mercury, cadmium and cyanide. Non-hazardous pollutants are less dangerous and can be discharged to groundwater under a permit, but must not cause pollution. Examples include sewage, trade effluent and most wastes. Non-hazardous pollutants include any substance capable of causing pollution.

The water from any fractured well during flowback can contain hazardous substances. These may include methane, carbon dioxide, hydrogen sulphide, nitrogen, helium, trace elements such as mercury, arsenic and lead, naturally occurring radioactive material (radium, thorium, uranium) and volatile organic compounds (VOC) such as benzene. The amount of material dissolved varies widely, from 13,000–120,000 ppm in the USA shale gas plays.



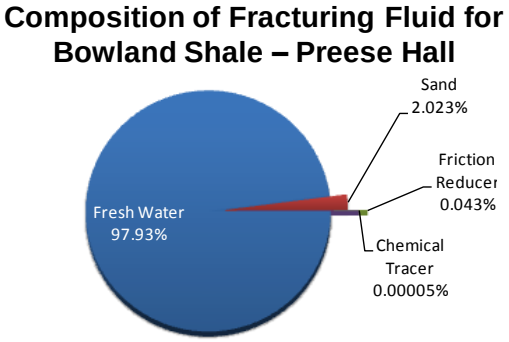


Figure 4.3.19 Examples of Different Fracturing Fluid Compositions

Data Source: British Geological Survey **Data Source**: Cuadrilla Resources Ltd.

In conclusion therefore in the event that the barriers to confinement fail in the wells drilled for shale exploitation or hydraulic fractures connecting to open fault systems are connected to shallower formations, groundwater systems could potentially be contaminated both from the hydrocarbons within the shale, from the injection of water containing additives used for hydraulic fracturing and from flowback water. In the event methane is transported to the surface due to barrier failure it becomes an explosive hazard at concentrations of 5–15% by volume in air. Statistical evidence to date is inconclusive as to the likelihood of this occurring in a UK shale operation.

If well design and integrity and hydraulic fracturing operations are managed correctly the likelihood of leaks into groundwater systems is extremely low.

What can be done about it?

The Environmental Agency (EA) is reponsible for the monitoring of ground and surface water contamination that could potentially affect the drinking water quality and wetland habitats. This includes hazardous chemicals released into the biosphere impacting wildlife and local communities, inhalation of pollutants which can lead to health risks and increased pollution levels that can affect aquatic and terrestrial organisms. It may be difficult to determine the source of any leakages.

The Environmental Agency also intends to review any plan to decommissioning a well. Their interest is to ensure that there is no risk – even in the very long term – to any geological formations that contain groundwater and which require protection under the Water Framework and Groundwater Daughter Directives.

Understanding the current distribution of methane in UK groundwaters will provide a baseline against which any future changes caused by shale operations can be assessed. The need for a methane baseline in the UK was recognised in the 2012 report on shale gas extraction published by the Royal Society and Royal Academy of Engineering. In the UK, BGS scientists are building on previous work and measuring methane concentrations in groundwater in a range of aquifers before any shale gas development gets underway. The measured methane may not necessarily originate naturally from geological sources — in some cases it may have been produced or released because of human activities such as coal mining or landfill operations.

The oil and gas operators are responsible for the design and safety of any well and the well site. The UK Health and Safety Executive scrutinises the working practices adopted by operators to ensure operators manage and control safety risks, conforming to the requirements of the Health and Safety at Work etc. Act 1974, and the following regulations made under the Act:

- The Borehole Site and Operations Regulations 1995 (BSOR) apply to all oil and gas well operations onshore, including shale gas operations. These regulations are primarily concerned with the health and safety management of the site.

- The Offshore Installations and Wells (Design and Construction, etc) Regulations 1996 (DCR) apply to all wells drilled with a view to the extraction of petroleum (whose definition includes shale gas) regardless of whether they are onshore or offshore. These regulations are primarily concerned with well integrity.

- The Reporting of Injuries Diseases and Dangerous Occurrences Regulations 1995 (RIDDOR) set out a specific set of Wells Dangerous Occurrences in Schedule 2, Part I, that the Well Operator has to report to HSE.

Reporting of well incidents enables the HSE Energy Division (ED) to investigate those that would have an effect on well integrity and ensures the Well Operator secures improvements to his operations. For the drilling process, HSE initially scrutinises the well design for safety and then monitors progress on the well to determine if the operator is conducting operations as planned. HSE uses an inspection and assessment process.

For the short-term future, to establish public confidence in the process the HSE/EA intend, as a minimum to jointly inspect drilling operations at shale gas borehole sites, paying particularly attention to well integrity and cementing issues and jointly inspect fracking operations. HSE will also request and review an independent analysis of logging outcomes, used to verify cement job/zonal isolation, during the standard scrutiny of the operator's weekly drilling reports.

The integrity of wells is planned through a combination of a well design created by competent personnel in compliance with appropriate health and safety regulations, specifically the Offshore Installations and Wells (Design and Construction, etc) Regulations 1996 (DCR) which apply to all wells drilled with a view to the extraction of petroleum regardless of whether they are onshore or offshore. These regulations require:

- a well design process that has identified any well bore hazards and mitigated them;
- a review of the well design by an Independent Well Examiner;
- review of the well design by a HSE Wells inspector against construction Standards in HSE guidance and in the Well Integrity Guidance;
- construction of the well in compliance with the design by competent personnel with any significant changes subject to the same scrutiny as described above;
- monitoring of the construction phase of the well and subsequent maintenance by the Independent Well Examiner and by the HSE Wells Inspector.

Well design and construction operations follow a recognised industry design and construction process (e.g. the API Guidance Document HF1 – 'Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines'). Such processes ensure that wells have 'safety features' incorporated into their design. Specific design and construction requirements include:

- a well design based upon a review of the local geology, to plan for any forecast well bore hazards;

- the size and grade of casing is selected based on the results of a casing design process. The casing design analyses the burst, collapse, tensile and triaxial loads that it may be subjected to;

- when the type of casing and its setting depths have been selected, the cementation programme is developed in consultation with the well operator's specialist cementing contractor. This design process analyses the rock strength and isolation requirements of the cement slurry so that it is placed as per the well design requirements;

- drilling conducted so that any loss or gain can be closely monitored within a 'closed' circulating system, and blow-out preventers shut in to control any unplanned flow from the well;

- casings being cemented in place and closely monitored to ensure correct placement of the cement slurry between the outside of the casing and the well bore. Casings should be cemented back into the previous casing or back to surface for shallow casings. If monitoring of the process indicates that the

height of cement may be insufficient, then a cement bond log may be run to verify that there is sufficient cement behind the casing.

- once cemented, the casing is pressure tested to ensure its integrity.
- completed wells are monitored at the surface for any annulus pressure (pressure in the spaces between the different strings of casing) to verify ongoing integrity. Additional measurements can be made at depth if there is any doubt about the integrity of the well.

Cement bond logging (CBL) can be a useful means of verifying integrity where there is a single casing. CBL cannot verify the cement integrity through double casing of pipe and cement. Where there is a double casing, the best method and standard industry practice is to monitor the annular pressures. As an additional protection, the industry is recommending surface methane and groundwater monitoring, with any anomalies to be reported to EA, HSE and DECC, and compared with data from the National Baseline Methane Survey, being undertaken by the British Geological Survey.

Regulation 18 of the Offshore Installations and Wells (Design and Construction, etc) Regulations 1996 requires the Well Operator to set up a Well Examination scheme and appoint a Well Examiner. The Well Examination Scheme and involvement of the Well Examiner is for the complete lifecycle of the well from design through to final plugging and decommissioning. The Well Examiner is an independent competent person who reviews the proposed and actual well operations to confirm they meet the Well Operators policies and procedures, comply with the Offshore Installations and Wells (Design and Construction, etc) Regulations 1996 and follow good industry practice. During assessment and inspection activities, HSE checks that the operator has these arrangements in place. Well examiners can examine certain well integrity and fracturing operations in real time, especially during the early stages of a development, to provide a further level of independent assurance.

Geodetic and micro-seismic instruments can be installed around sites to monitor fracture propagation and micro-seismic events and to plot the extent of fractures created in the rock. Each shale gas play is unique and the detailed geometry of the shale gas formation in relation to local aquifers can be assessed and the risks of hydraulic connectivity between the two can be evaluated before hydraulic fracturing operations begin. Before commencing with hydraulic fracturing, it may be feasible to assess the rock stress conditions of the area and identify the location of existing natural faults and fractures to determine whether there is likely to be any unplanned connectivity to shallower formations.

Careful chemical monitoring of hydraulic fracturing fluids, including the flowback fluid and produced water, is required to mitigate the risks of contamination (Healy, 2012). In the USA it is not required to disclose the chemical compositions of these fluids. In the UK, operators must provide details of the chemicals used within the fraccing fluid. This can be published on the company's website or on a third-party developed website. The information put forward should inform the public of what chemicals are being used, why these chemicals are being used and potential environmental threats. The EA and SEPA assesses the hazards presented by these fluid additives on a case by case basis, and therefore only the substances proposed for use in UK operations have so far been assessed as a potential hazard. They can only be approved if they meet specific standards, which are provided in the "Environmental Permitting Regulations (England and Wales) 2010".

In many reports to date on the likelihood of pollution from shale operations many conclude that much depends on the effectiveness of monitoring agencies and their requirement for sufficient resources to undertake their duties to maintain a competent level of review of planned operations and oversight during those operations. In the UK with the cut back of government spending it remains to be seen that in the event of a significant rise in the scale of shale operations whether these resources will be adequate.

B. Surface Water Contamination

Background and Framework

Well and process facilities sites involved in shale operations will handle various materials during operations some of which may be hazardous. These will include transportation and power fuels, chemical additives used in drilling and hydraulic fracturing operations, drilling muds and flow-back fluids. No permit is required to discharge clean surface water to a watercourse. However in conventional and shale exploitation operations any run-off from rain or clean water is required to be managed so as to ensure it stays clean and uncontaminated and any spillage of hazardous material is contained within the site and can be recovered and safely disposed of wherever possible.

Establishing whether spillage (deliberate or accidental) of drilling, hydraulic fracturing, flow-back or other hazardous materials has taken place is again subject to the limitations of the monitoring, reporting and substantiation of data recorded in operational areas.

Why is it relevant to conventional/shale gas projects?

Shale gas operations use significant water volume during the drilling and hydraulic fracturing operation. Some of the fluid (10 to 40%) injected into the formation will be returned to the surface where it may require processing or safe disposal if it contains unacceptable levels of hazardous material. Given that produced waters may have much higher salinities than surface waters disposing of even small quantities of untreated fluid into the ground may cause problems in the local surface and groundwater systems. There are potentially three possible ways in which these fluids could be lost into surface water: (1) surface leaks and spills from containment vessels or pits or during transportation; (2) direct, unauthorized, or illegal disposal of untreated material and (3) inadequate treatment and discharge of fluids (e.g., treatment at plants not sufficiently designed to remove hazardous material).

Vengosh et al. reports that a survey of surface spills from storage and production facilities at active well sites in Weld County, Colorado, USA that produces both methane gas and crude oil, showed elevated levels of benzene, toluene, ethylbenzene, and xylene (BTEX) components in affected groundwater. Also a study conducted by the Environmental Protection Agency study in Pavillion, Wyoming found increased concentrations of benzene, xylenes, gasoline range organics, diesel range organics, hydrocarbons, and high pH in two shallow monitoring wells. The U.S. Geological Survey conducted a follow up study and found similar elevated levels of specific conductance, pH, methane, ethane and propane, yet low levels of organic compounds. The shallow groundwater contamination was linked in part to surface pits used for the storage/disposal of drilling wastes and produced and flowback waters.

The rapid growth and intensity of unconventional drilling could lead to a higher probability of surface spills or leaks.

What is the effect?

The loss of hazardous material or pollution of surface water could ultimately detrimentally affect groundwater systems, potable water supply and local habitats and environments including wetlands, woodlands, river systems etc.

What can be done about it?

Similar to below ground contamination there is a requirement for monitoring and reporting and an effective permitting process supervised by the same government agencies.

Well and facility operators must be aware of any specific planning or environmental permits that may set out requirements in respect of baseline groundwater surveys. This will allow for subsequent pre- and post-fracturing sampling of the groundwater that can then be compared with the "baseline" value. This may include:

1. Surface water sampling at the well site prior to the start of site construction.

2. Groundwater sampling prior to the start of site construction.

3. Surface sampling following site construction, drilling and fracturing operations.

4. Groundwater sampling following site construction, drilling and fracturing operations.

Operators should ensure that all water sampling and analysis is carried out by qualified third party organisations using recognised sampling and analytical methods.

Operators should disclose all on-going water testing results in accordance with any specific planning requirements or environmental permits. Any anomalies detected that are connected with operations should be risk assessed and reported as required by the regulator.

The above survey data should also be reported to the British Geological Survey (BGS) who are collating similar data across the UK.

With respect to site containment, site pollution control is a part of the local planning process and operators are required to demonstrate best practice in this area, including the prevention of contamination of soils, by the provision of suitably designed impermeable site underlay systems and site drainage arrangements etc as well as compliant storage vessels using bunding or double skin construction. During high pressure hydraulic fracturing operations, correct well completion design is important to ensure that the risks of failure are minimised.

Produced water can be treated either on- or offsite. Given the high volume use of water resources it may be appropriate to provide local treatment in order to lower transportation requirements and recycle water usage.

Induced Seismic Activity

Background and Framework

Fractures propagate when the fluid pressure within a hydrofracture exceeds the tensile strength of the host rock, with propagation occurring at the tip of the fracture. As the fracture propagates, a microseismic event occurs. Microseismic events can be monitored using geodetic and microseismic monitoring process systems. These detect the opening, propagation and extent of hydrofractures. They also measure the magnitude of the associated seismic activity. Such events are undetectable by humans and even the BGS' nationwide seismic network.

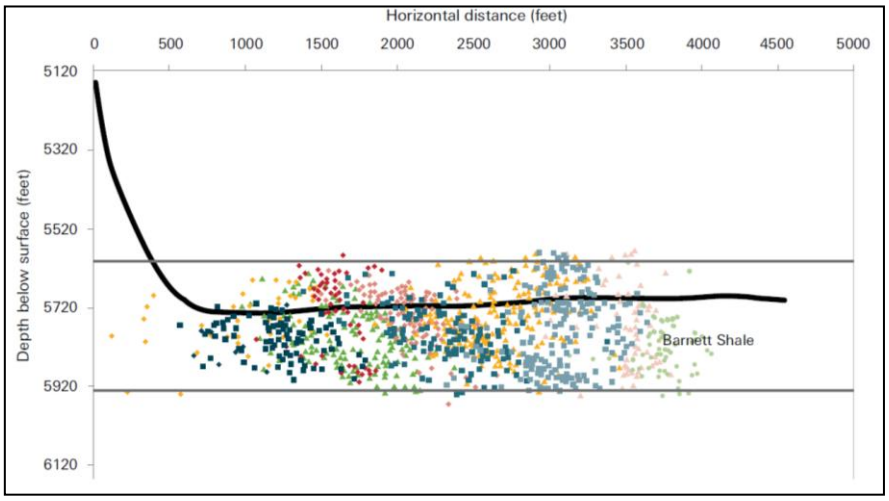


Figure 4.3.20 Microseismic Events from the Barnett Shale Gas Well (Cross Section)

Source: Zoback et al., 2010

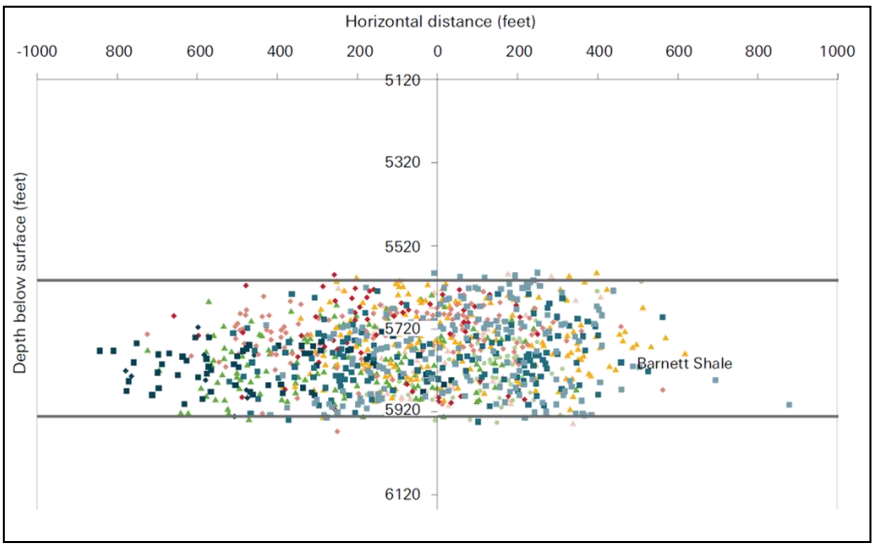


Figure 4.3.21 Microseismic Events from a Barnett Shale Gas Well (Bird's Eye View)

Source: Zoback et al., 2010

Why is it relevant to conventional/shale gas projects?

The magnitude of the fracking induced microseismic events is usually in the region of -3.0 to 0 on the richter scale. However, larger, rarer seismic events can occur as a result of hydraulic fracturing operations whereby fluid can enter a pre-stressed fault plane, resulting in fault slip. There is public concern in the UK for seismic events associated with hydraulic fracturing (University of Nottingham, 2013).

What is the effect?

A microseismic event of -3.0 on the richter scale will result in a slip displacement of 40µm (0.04mm) over a surface area of 0.02m², with no impact on the Earth's surface. However, a larger seismic event, such as 2.0 on the richter scale, will result in a slip of 1cm over an area of 3000m² with a noticeable earth tremor on the Earth's surface.

Two earthquakes near Cuadrilla's Preese Hall well were recorded during periods of hydraulic fracturing, the first 2.3M and the second 1.5M on the Richter scale. The earthquakes were deemed to be unusual due to the low natural seismicity of the area, even by UK standards. Two reports concluded that the earthquakes were down to Cuadrilla's hydraulic fracturing operations, with injected fluid entering a previously unidentified, pre-stressed fault.

Figure 4.3.22 is a plot which displays the distribution of microseismic events by magnitude from the same hydraulic fracturing programme in the same well as Figure 4.3.20 and

Figure 4.3.21.

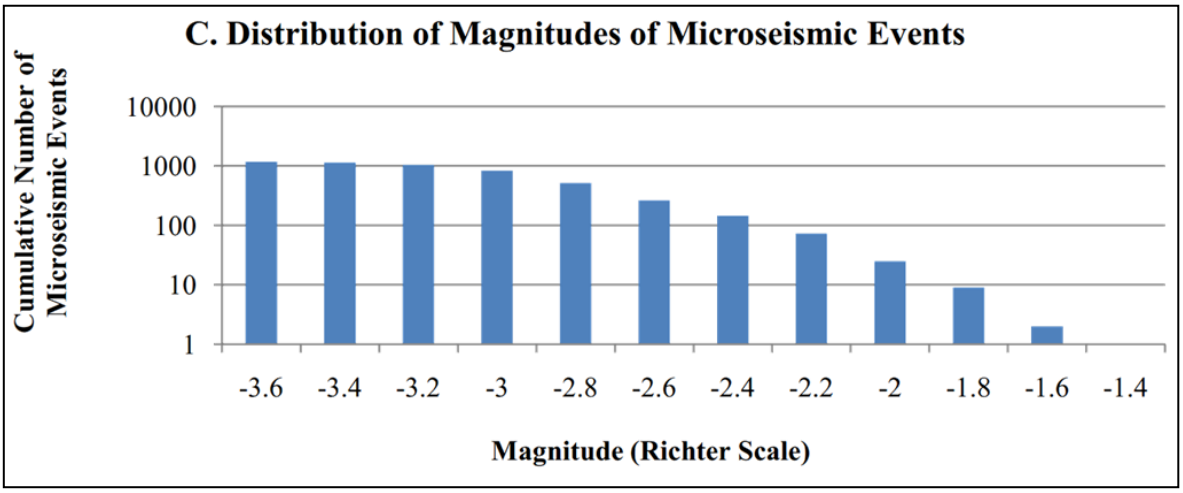


Figure 4.3.22 Frequency and Magnitude of Microseismic Events for a Barnett Shale Gas Well

Source: Zoback et al., 2010

What can be done about it?

Whilst it is important to note that it is difficult to reduce the risks of induced seismic events to zero, through evaluation of the presence of faulting in the area and understanding of the stress field for the rocks to be fractured, the risks of induced seismicity will be reduced. Greater 3D seismic coverage, well data and outcrop information will assist in the pre-determined location of any pre-stressed minor faults. Understanding the local stress regimes of the rocks will give an understanding of the required stress needed for fractures to propagate.

5. RECOMMENDATIONS

There are a number of positive steps that could be taken by the government to ensure that operators maintain the use of best practices and that areas that are environmentally sensitive areas are not exposed to unnecessary risks.

The roll out of shale gas exploration, appraisal and development in the UK should be carefully regulated and staged to minimise the environmental impact on the countryside and maximise the benefits to the people that live within it and the population as a whole.

It is recommended that land that is least susceptible to incremental environmental damage be utilised at the early stages. Brownfield or existing well sites should be used for initial appraisal and development. Through monitoring those projects and proving their viability, a more informed decision can then be taken to allow expansion into other areas.

The protection already awarded to National Parks, Areas of Outstanding Natural Beauty, Sites of Special Scientific Interest and Nature Reserves to preserve and conserve these areas should not be undermined by any changes to current regulations or planning policy in order to establish a UK shale industry. Approximately 15% of the currently identified prospective shale gas areas underlie National Parks and any detrimental impact on these areas will have a negative impact not just on public opinion but also on the ability to gain planning approval in the future. Planning approval for shale gas operations proposed inside these protected areas should be avoided.

The UK shale gas industry needs to be closely supervised by government, its agencies and local authorities to ensure an orderly, staged process, taking into full account the impact of development on the local environment and to ensure that stakeholders fully support project development. It is recommended that adequate resources be made available to undertake this role.

Extending the Strategic Environmental Assessments to identify, for example, the suitability of existing infrastructure, the availability of water and availability of suitable well sites before issuing licences in a particular area will promote a better understanding of the impact of the full life cycle of exploration and development of a shale operation given this is likely to have a higher level of intensity compared to conventional oil and gas projects.

The government should exercise control over the renewal, re-issue or issue of future licences for petroleum exploration and the terms associated with each licence award. Licences that lie within prospective areas for shale gas should either exclude environmentally sensitive areas or include terms and conditions that restrict activities within these areas.

Prior to awarding licences, DECC normally reviews the technical and financial capability of applicants. It is recommended that this is extended to include an assessment of whether the company has sufficient insurance to cover any potential environmental liabilities and remediation if any damage were to occur during shale operations.

The National and local planning policies (including local Mineral Planning Policies) require updating in order to more thoroughly address the issue of shale operations. Where appropriate this may include the introduction of buffer zones between shale developments and local communities similar to those proposed in Scotland.

Oversight of large scale shale gas developments is likely to require a significant increase in regulatory manpower. In particular the environmental regulator will need sufficient resources and capacity to ensure operators carry out robust and long term monitoring programs on the impact of shale gas development on both air and groundwater quality.

The industry should be encouraged to invest in the further development of technology that promotes the efficient use of land space and minimises the number of surface locations for large scale shale gas operations.

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APPENDICES

Appendix A: Shale Gas Recovery Process

Introduction

Unconventional gas can be found in shales, a rock type that is both reservoir and source rock. Shale us a very fine grained, tightly locked rock and so shale gas reservoirs are characterised by low permeability, low porosity and few open natural fractures. Gas in shales is trapped in small matrix pores, within small fractures or adsorbed onto the particles' surface. Shale gas reservoirs are nanodarcy reservoirs. In USA Shales (such as Marcellus and Barnett) permeability has been found to be between 1E-3 to 1E-7 mD. In order to produce such reservoirs the wells drilled must maximise the flow surface in contact with the well and they require stimulation, usually through hydraulic fracturing.

The Barnett shale in the Fort Worth Basin, USA, was the first shale gas play to be successfully economically developed. Based on the extensive experience gained in the Barnett Shale, the most effective wells are horizontal wells as they increase the contact area between the reservoir and the wellbore. However, the increase in contact area does not improve the ability of the fluid to flow, so stimulation is still required. Shale gas well stimulation typically refers to hydraulic fracturing. The purpose of hydraulic fracturing is to open up existing closed fractures in the rock to create a flow path from the reservoir into the wellbore.

Key Factors Pre Production Start

Factors that must be taken into account prior to shale gas development can be divided into technical (reservoir properties, well design), surface (area required for development) and economic components.

Rock properties, and in particular rock hardness and reservoir thickness have an impact on key aspects of well production: well type, well extent and fracturing treatment requirements.

Wells can be separated into two types: horizontal and vertical. Franz et al (2005) analysed data from Barnett shale operators and found that horizontal wells could be up to three times as productive as vertical completions (in terms of well length life and ultimate recovery). This is because horizontal wells increase the contact area between the wellbore and the reservoir. Vertical wells also benefit greatly from vertical permeability, which in shales is also typically very low if not zero ($Kv \approx 0$). Horizontal wells have thus become the usual well type for shale gas production. However, the hardness of the rock will dictate the lateral length that can be drilled and the number of horizontal laterals possible. Laterals are boreholes (normally horizontal) drilled from a common, single well borehole connected to the surface. As stiffness increases, achievable lateral length and number of possible laterals decreases.

A well's design encompasses the well characteristics, its location (relative to the reservoir and to the principal stresses within the rock matrix), depth and the extent of the connected fracture network (also known as the stimulated reservoir volume).

Hydraulic fracturing in nanodarcy reservoirs is an essential component of economic well development and has the greatest impact on well production and deliverability. The stimulation process aims to induce dendritic fractures as they are more effective than planar fractures. Stimulation treatments typically require high power pumps, large wellhead pressures (over 10,000 psi) and high water volumes pumped at high rates (80-120 barrels per minute). As such, well design criteria such as casing size, wellbore diameter and drilling operations are dictated by the requirements of the stimulation process.

Other key well characteristics are the length of the horizontal leg and the number of laterals. As the horizontal leg length and the number of laterals increase the recovery increases. The location of the well and the fracture

network are interlinked and are especially important for horizontal wells. The well's laterals must be placed so that any fractures resulting from hydraulic fracturing are perpendicular to the minimum principal stress to achieve the highest fracture propagation possible (fractures will propagate more easily in the direction of the maximum principal stress) (Royal Society, 2012). It is also preferred that no interference occurs between different fractures and fracture stages. As fractures propagate they create a fracture network, thus easing flow from the reservoir matrix to the wellbore. The degree of complexity of the fracture network and the characteristics of main fractures (fracture width, spacing, half-length and vertical extent) serve to artificially improve the reservoir's effective connectivity. Some fracture characteristics always have a positive impact on recovery: as fracture half-length increases, recovery increases and as fracture vertical extent increases, recovery increases. On the other hand fracture spacing has an optimum value; past this any further increase in spacing does not cause a resulting increase in recovery. The spacing between wells will also be important for recovery. An optimum number of wells is also required for extraction and past that number no further fluid is recovered for primary extraction (Keuengoua C.D.S., and Amorin R., 2011).

The Bowland shale is heterogeneous, with rock in the western section considerably harder to drill than others. The stress state of the reservoir rock is important during hydraulic fracturing. The level of stress anisotropy has an impact on the width of the induced fractures: as anisotropy increases, fracture width decreases and more fracture stages are required to stimulate a given volume (Parshall, J., 2008).

The location of exploration sites will also be an important decision: typically exploration and early development will be focused on areas where economics will be most favourable, where recovery is likely to be highest and where the presence of natural gas liquids is more likely. The location of the sites will have an impact on the establishment of drill sites and the associated surface requirements.

Surface requirements have a high impact on the economics of a project and its potential for development. They have a high impact on the environment, including on community relations as well as wildlife and fauna and it is a particularly key issue in areas of high population density. As surface requirements increase (area of land, fluid treatment equipment type and size, personnel number) negative impacts such as detriments to the local fauna and flora and deterioration in public sentiment can increase.

The surface requirements are an important part of the economics of the project as they include the costs of the stimulation treatment: the water volumes and storage tanks, pumps and fuel demand. Shale gas wells have high initial production (IP) rates and sharp declines. In order for a project to be economic, further development is likely to be required to maintain economic rates. Such additions include infill drilling, refracturing and workovers. Due to the high rates at which large volumes are pumped, wear and tear is also an important issue and economic factor. All these factors are important as, ultimately the development of a shale gas project depends on its economic future. The programme must provide sufficient return on investment; the gas must be produced in sufficient quantities at sufficient rates and sold at a market competitive price.

Shale Gas Exploitation Stages

The process, from exploration through to production can be summarised on the diagram below.

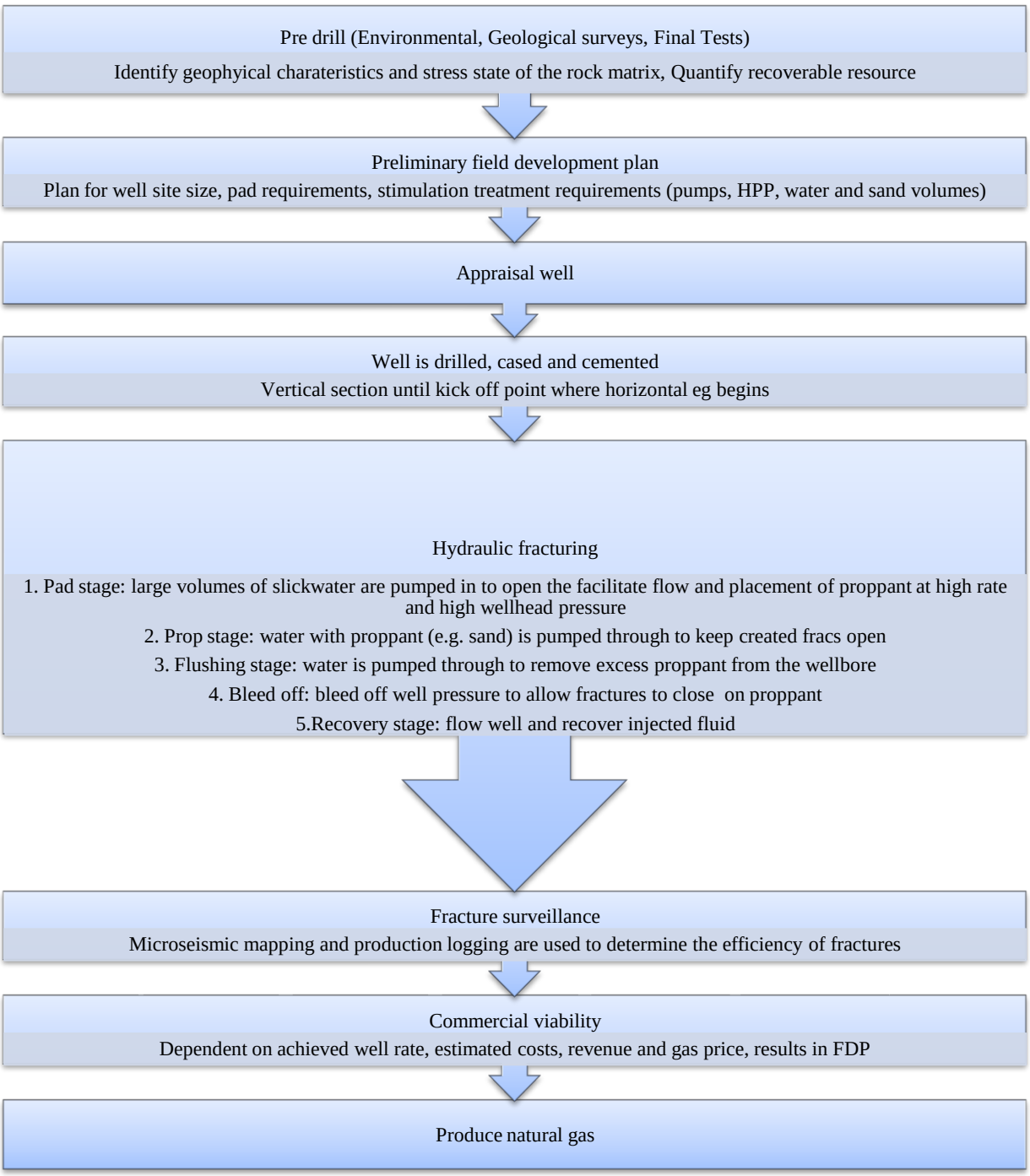

Figure 1A - Shale Gas Recovery Process Stages

Data Source: FracFocus, 2013

The first step in petroleum exploitation is the application for prospecting licences. Once licences have been obtained for geological investigation it is important to ascertain the potential of a given area. Surveys are also carried out to select an appropriate well site taking into account location, level of urbanisation, proximity to nearest towns, electric supply capacity, site accessibility and water availability and disposal options. The local flora and fauna is also taken into account (OECD/IEA, 2012). Seismic surveys are carried out to establish the presence of hydrocarbon and quantity present. They also provide information regarding the below ground strata. This information is used to construct a field development plan (FDP).

The preliminary FDP includes the number of wells and associated pads (number and size), the quantity of equipment for the fracturing stage and fluid treatment and the number of access roads required. A first pass estimate of the stimulation treatment required is also planned, so that water tanks/pits, pumps and power requirements can be planned for. A site is then built to allow the drilling of the appraisal well.

An appraisal well is drilled to test findings from the pre drill phase (the seismic survey and initial hydrocarbon in place estimates), primarily the reservoir quality and the presence and type of hydrocarbons (if applicable). The appraisal well confirms further the strata identified in the surveys and provides a basis for the rock's properties. The reservoir thickness and porosity have a high impact on recoverable resource and this new data is used to further refine the preliminary FDP. The development of shale gas wells is unusual in that fields can seldom be delineated in the same manner as conventional hydrocarbon fields; the hydrocarbons are present over an extensive but less well defined area (DECC). Furthermore, the presence of shale gas does not guarantee its extraction; in the Barnett shale ultimate recovery is estimated at 8-10% using the existing well performance (assuming fracturing and horizontal drilling) (Hu, Q. Et al, 2012).

If the appraisal well is successful the full development will then be initiated. Shale gas wells are drilled in pads to reduce surface requirements and disturbance. The well construction phase is the most visible and inconvenient for the local environment (both people and wildlife).

The combination of horizontal wells and hydraulic fracturing technology has resulted in a drastic improvement in production from shale gas reservoirs, as can be seen in the Barnett shale (The American Oil and Gas Reporter, 2011). Nevertheless the fracturing process is inefficient. A study by Kyel Hodenfileld states that 15-20 percent of fracture stages and 35-40 percent of clusters do not contribute to production (The American Oil and Gas Reporter, 2012).

Hydraulic fracturing requires large volumes pumped at high rate which successfully create a large surface area in contact with the wellbore. Unfortunately not the entire generated surface contributes to production. This inefficiency in horizontal wells is primarily due to reservoir heterogeneity, rock anisotropy, and in situ stresses. Well characteristics such as landing point and lateral direction and well drilling are also important.

Basin heterogeneity causes poor fracture efficiency, variations in production rates (between wells, and in some cases across the laterals), complicates well completions and inhibits fracture propagation. Fracture containment is also difficult within heterogeneous rock so some fracture network may be created outside of the good quality rock. Rock anisotropy and basin heterogeneity also have an impact on proppant transport and distribution. If fractures are not correctly propped they may not remain open nor conduct fluid to the wellbore. The in situ stresses dictate the direction of propagation and the magnitude of induced fractures.

Drilling and completing the wells (casing, cementing and flushing) have an important impact on the total volume of stimulated and conductive volume. Once the well is drilled, the fracturing process occurs. To fracture a formation typically 0.8-1.6 millions of gallons of fluids are pumped into the reservoir at 80-120 barrels per minute at high pressures of 12000-14000 psi. Proppant is then introduced to keep newly opened fractures open, which may require 200,000-400,000 lbs of proppant such as treated sand or man-made ceramic materials.

During the flushing stage it is important that the wellbore not be overflushed, as it runs the risk of removing near well placed proppant, thus reducing near well conductivity. Completions should aim to be fully in contact with good quality reservoir, due to the potential of basin heterogeneity and its impacts described above. Furthermore it is important that wells are cased and cemented correctly as they provide isolation of the wellbore and thus they protect the surrounding strata (including any potential aquifers, although they tend to be found at shallower depths than hydrocarbon reservoirs- typically 1,000 to 4,000ft vs. 6,000 to 10,000ft) (FracFocus, 2013).

Once the well has been stimulated it is important to quantify and evaluate the effectiveness of the treatment. The monitoring of fractures is important to fully understand the behaviour of the well and the efficiency of the stimulation treatment. It is also used to understand the reservoir and plan for maximum drainage efficiency. Fractures can be monitored post stimulation using microseismic mapping.

Microseismic (MS) mapping is the process of measuring shear fractures and resolving their location to create a map of the events. These shear fractures are caused by changes in stresses and pressures that are typically induced during the hydraulic fracturing process. From this, fracture diffusion has been analysed and conclusions have been drawn. Fractures are not single planar features that extend over large distances; they are a series of interconnected fracture segments (Warpinski, N.R., 2011). These segments have many internal terminations and interactions with the rocks which complicate fracture analysis. Fractures will propagate in the same direction across whole fields, as their azimuth is dictated by the in situ stresses and the minimum principal stress. In a heterogeneous reservoir fracture growth will be limited; energy and fluid will be lost across layers as fracture growth is diminished in higher stress layers. Changes in layer properties are more significant vertically and so fractures will propagate more easily horizontally. The growth of a fracture will also be dictated by the local stresses and the stimulation treatment. Studies have found that up to 75% of each hydraulic fracture does not contribute to production (The American Oil and Gas Reporter, 2012) and typically fracture stages have been found to become less effective with increasing distance along the horizontal leg. However, although MS mapping is important in fracture detection and understanding it cannot measure the location of the proppant and so effective conductivity is hard to measure. Nevertheless fracture monitoring is key to identifying non stimulated zones and planning re fracturing (where desirable), which may affect the project's commerciality.

The use of horizontal drilling not only has an impact on the commerciality of the well but also the potential deliverability of wells and their surface requirement. Horizontal well drilling technology decreases the number of well pads required and their required surface area; a 20-well horizontal drilling pad requires about 5% of the land required by 20 vertical single well drilling pads (Canadian Association of Petroleum Producers, 2012).

Well pads are areas of land required for the drilling of wells and their size depends on the number of wells they are to hold, the topography of the land and the pattern layout. The pads may include the wellheads, tanks, hydraulic fracturing and production equipment (e.g. separators). In the USA horizontal drilling has reduced the number of wells that are required and consequently well pad size has decreased. Traditionally in the USA, vertical wells were drilled on 40-acre spacing, with 16 wells per square mile at separate surface locations (SGEIS, 2011). According to a 2011 report by the New York State Department of Environmental Conservation (2011), the average size of a multi well pad for the drilling and fracturing phase of operations is 3.5 acres (2.2-5.5), but decreases to 1.5 (0.5-2.0) acres after partial reclamation (excluding any area disturbed for site preparation and construction). New York Department of Environmental Conservation has stated in its 2011 study that spacing units of 640 acres are likely for well pads with multiple horizontal wells. Nevertheless it is important to note that in the USA drilling density is dictated in part by mineral rights ownership.

When all the required wells have been drilled, stimulated and completed all the surplus equipment is removed from the site i.e. partial reclamation. This equipment includes all the hydraulic fracturing equipment; pumps, storage tanks/pits (which are filled in). The site is returned as closely as possible to its original state. Only key equipment, such as the wellhead, some fluid treatment facilities and the pipelines (to deliver production to further treatment plants) are left. Wastewater from hydraulic fracturing is disposed of appropriately. After

treatment and removal of additives, sands and potential clay minerals, the water may be discharged in local rivers or used in agriculture.

The commercial viability of a shale gas project is predominantly affected by the price at which gas will be sold. As the gas price increases the number of economic projects, all other factors remaining equal, also increases. A decrease in costs (capital, production and development) also increases a project's commercial viability. Shale gas developments are particularly costly as they require a large number of wells, stimulation and long horizontal wells (which in turn affect the volumes of fluid and proppants required for stimulation). As the number of wells increases the total development cost goes up. To minimise this, drilling multiple wells from a single well pad has become an industry standard for shale gas development as savings are made in terms of costs and time and the impact on the environment is lessened. The commerciality of a project will be evaluated based on a field development plan centred around maximising returns and extracting reserves as economically and efficiently as possible.

Once established as feasible, both economically and technically, the wells required will be drilled, infrastructure according to the FPD will be constructed and the project will be put on production.

A shale gas field is designed to have a 30 year life span. At the end of it, the land will be reclaimed; a process which can take five years (Canadian Association of Petroleum Producers, 2012) and includes capping the well, removing all equipment, cleaning any spills or contaminants and replacing soil and natural vegetation.

Production Profile

The production performance of a well will have an important impact on its economics and commerciality. Typically shale gas wells start production at high rates before a sharp decline. A study by O'Sullivan and Paltsev (2012) found that in 2010 average well initial production rates in the Barnett shale varied but averaged 110,900 m^3/d (cubic metres per day). Decline curve types vary but tend to be hyperbolic [Arp's b factor has been found to range from 0.64 (Fayetteville) to 1.59[1] (Barnett shale)] (The American Oil and Gas Reporter, 2011 & Bailhy J., et al). The production rates of shale gas wells will usually decline between 50% and 75% in the first year of production (OECD / IEA, 2012). The sharp decline will be followed by a long period of low production rates. These low rates are often partly due to inefficient fracturing as mentioned earlier. The practical implications of fast decline and inefficient fracturing are that in the USA a common "rule of thumb" established in the shale gas production industry (the 1/3 rule [Refer to: Hu, Q. et al, 2012]) is that for a given development 1/3 of wells will not be profitable, 1/3 will breakeven and 1/3 will effectively pay for the programme (SPE, 2013). As such, development of a shale gas well may require further treatment, fracturing or infill drilling to maintain economic rates.

It is important to note that although fracturing is inefficient, shale gas wells in a given play tend to have a similar decline profile (with a different initial production rate but following the same trend) (The American Oil and Gas Reporter, 2011). Thus the decline for wells from a given play tends to be estimated from analogous wells that have a longer production history.

Modelling in the Literature

Reservoir modelling is the preferred method to evaluate shale gas reservoir performance as it can incorporate the key parameters which complicate the evaluation and prediction of shale gas wells' productivity (Yu. W. & Sepehrnoori K., 2013). Such parameters include low matrix porosity, low matrix permeability (shale gas reservoirs have nanodarcy permeability) and complex fracture growth. Reservoir modelling is further complicated by the presence of free and adsorbed gas. Free gas is present in the matrix's pores and once channel

[1] B exponents >1 are realistic for shale gas reservoir.

pathways are open, can flow into the wellbore. Adsorption is a process by which fluid molecules adhere to a surface (in shale, gas molecules stick to the surface of the pore matrix).

The presence of adsorbed gas and its contribution to field production complicate shale gas reservoir modelling. Work by Cipolla et al has found that in some shale reservoirs, desorbed gas only contributes to production once pressures have depleted. Their study found that in the Barnett shale up to 41% (Cipolla C. L. et al, 2010) of the total gas is adsorbed yet desorbed gas contributes between 8.5% and 15% of production after 30 years, correlating findings published by Frantz et al in 2005. Yu and Sepehrnoori found that desorbed gas could contribute up to 20.7% after 30 years. Cipolla et al also found that proppant distribution is important for efficient fracture conductivity and production. If proppant concentration is too low network fracture conductivity will be unaffected but if proppant is confined to a main fracture, other fractures will behave as if unpropped and conductivity will be low.

It is important to optimise well characteristics for a given reservoir (well length, spacing, fracture stages and spacing, fracture half length and width). They have an impact on the stimulated reservoir volume which, in cases of poor optimisation, can lead to well competition and reduced production (Yu. W. & Sepehrnoori K, 2013).

In reservoir models fractures are simulated through local grid refinement. The reservoir is assumed to have stress independent porosity and permeability without any water influx.

Applications to Petrenel Model

Recommendations from previous modelling work were applied to the model created to support this report.

Introduction

A model was created to support this report and its main objectives were to investigate the impact of well spacing, reservoir thickness, permeability and fracture dimensions on shale gas recovery. This would serve to fully understand the drivers for a shale gas project and the potential surface impact of a shale gas field development if it were in the UK.

According to a 2011 report published by DECC, the USA Barnett Shale may provide "an indicator of the possible productivity of the UK Carboniferous shale gas play" (DECC, 2011). The potential analogy between the Upper Bowland and Barnett shales was used in the reservoir modelling. Due to the absence of petrophysical data for the UK Bowland shale some of the Barnett shale parameters were used.

As part of the modelling work a base model was created to understand the behaviour of a single well and the factors that affected productivity. The model was then enlarged to assess well interference and spacing.

The model created was a single porosity (as it assumed no open natural fractures) gas water model. Fractures were modelled through local grid refinement.

Table 1A - Parameters used in Model

Parameters	**USA Barnett**	**Parameters used in Base case to model UK Upper Bowland**
Depth	2134m (7000 ft)	2100m
Reservoir Pressure	262 bar (3800 psi)	267 bar@2134m
Net Pay	91m (300 ft)	120m
Matrix Permeability	1 E-5 to 1E-4 mD	1E-4 mD
Fracture Permeability	0.61- 1.52 mD/m *(2-5 mD/ft)*	0.61- 1.52 mD/m *(2-5 mD/ft)*
Porosity	3%	3%
Gas gravity		0.585
Reservoir temperature		82.2ºC

Source: Petrenel

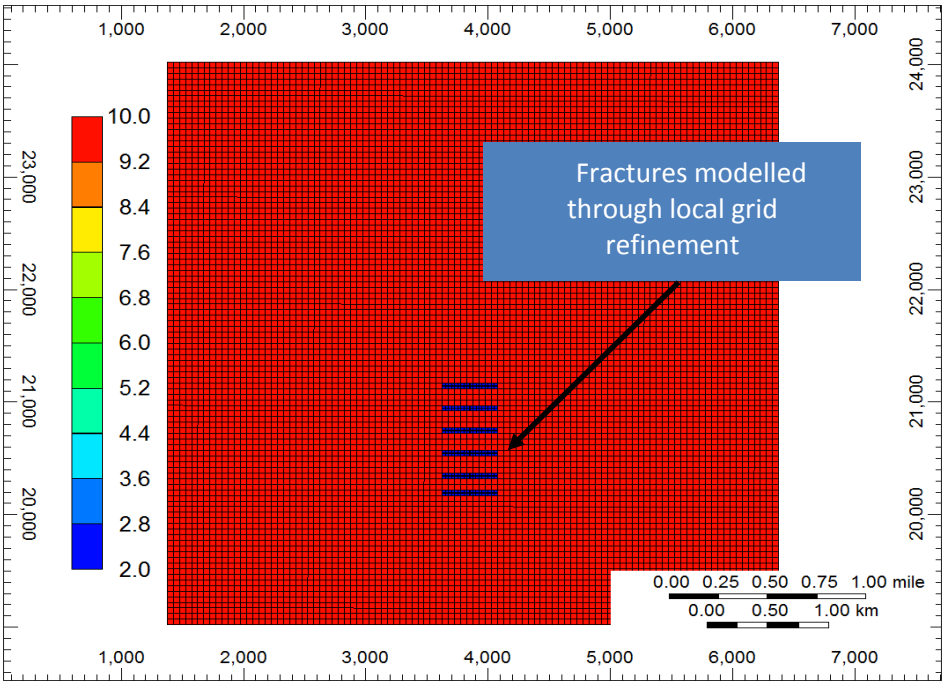

Figure 2A - Areal View of Fractures Induced in the Model

Source: Petrenel

The model built is speculative; it uses analogous data (well data is not yet available for the Upper Bowland shale) but aims to provide a better understanding of the productivity and technical preferences regarding development.

Sensitivities

Three types of sensitivities were run on the model: sensitivities on the outcome of hydraulic fracturing, on the properties of the reservoir and sensitivities on the type of well bore itself.

Two types of wells can be drilled in shale: vertical or horizontal wells. Extensive research in the Barnett shale (USA) has established that shale gas is best developed (economically and technically) through horizontal wells. According to Dan Arthur and Dave Cornue, the use of horizontal wells in the Barnett shale has allowed three or four vertical wells to be replaced by a single horizontal well (The American Oil and Gas Reporter, 2010). However, vertical wells may still be an option where reservoir thickness is high. The table below compares recoveries from a vertical and horizontal well, with all other factors remaining the same;

Table 2A - Comparison between Horizontal and Vertical Wells

Grid size: 5×5 km **Simulation: 50 years**												
	Characteristics*							**SI**			**Field**	
Model	**Frac wdth**	**Frac. half length**	**Frac. spg**	**Res. Thick-ness**	**Hort. leg**	**Mat. perm.**	**Frac. perm.**	**GIIP**	**Rec.**	**RF**	**GIIP**	**Rec.**
	mm	m	m	m	m	mD	mD	MM m3	MM m3	%	Mscf	Mscf
Horizontal well	5	200	150	200	1050	0.0001	3280	13766	68.4	0.50	483,834	2,403
Vertical well	5	200	150	200	1050	0.0001	3280	13766	6.5	0.05	483,834	228

Source: Petrenel

*In Table 2A above:

- Frac. wdth: fracture width;
- Frac. half length: fracture half length;
- Fra. spcg: fracture spacing;
- Res. thickness: reservoir thickness;
- Hort. leg: length of the well's horizontal leg (i.e. lateral);
- Mat. perm.: Matrix permeability (permeability of the reservoir);
- Frac. perm: permeability of the induced fracture;
- GIIP: gas initially in place;
- Rec.: recovery;
- RF: Recovery factor.

As illustrated on Table 2A above, the recovery of a vertical well is much lower (228 MMScf) compared with the horizontal well (2403 MMscf). It is important to note that vertical wells are cheaper to drill than horizontal wells

and so may still be viable where multiple fractures can be used and reservoir thickness is high. In the model, a horizontal well with a single lateral was assumed, as illustrated by Figure 3A. The fractures were modelled using a local grid refinement.

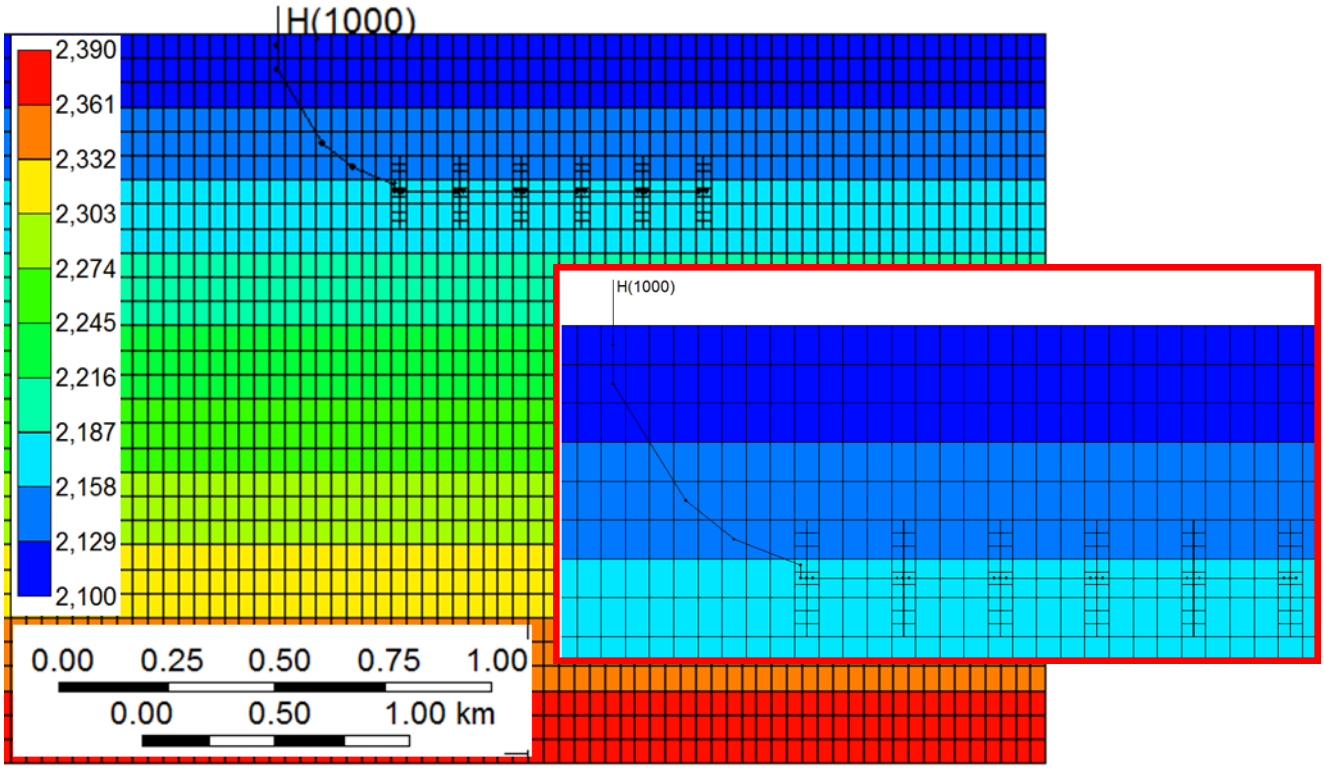

Figure 3A - Well Profile

Source: Petrenel

When designing a stimulation program for a well some of the outcome of a hydraulic fracturing treatment for a well can be generally described using the key factors of fracture width, the fracture half-length and the fracture stage spacing along the well.

Fracture width typically varies between 2.5mm and 25.4mm (George E. King, 2009) and 5mm was used in the model. The length of the well laterals depends on the operator but in the Barnett shale typical lateral lengths are 2500ft to 3500ft (Halliburton White Paper, 2008) (762m to 1067m) and the model assumes a 1050m lateral length. This reflects the trend to drill longer lateral lengths (the rise in production in the Barnett shale is in part due to improved fracturing treatment, well drilling and lateral length achieved).

The fracture half-length has a significant impact on how successful is the treatment. It directly affects the potential production from the fractures. The average full length of the induced fractures in the USA shales is reported to be 200-600m (half lengths are thus 100-300m).

Table 3A - Half Length Impact on Recovery

Grid size: 5×5 km **Simulation: 50 years**												
	Characteristics*							**SI**			**Field**	
Model	**Frac wdth**	**Frac. half length**	**Frac . spg**	**Res. Thick-ness**	**Hort . leg**	**Mat. perm.**	**Frac. perm.**	**GIIP**	**Rec.**	**RF**	**GIIP**	**Rec.**
	mm	m	m	m	m	mD	mD	MM m3	MM m3	%	Mscf	Mscf
SG_FS150_FW05_KV_FH100	5	100	150	200	1050	0.0001	3280	13766	38.5	0.28	483,834	1,353
Base Case	5	200	150	200	1050	0.0001	3280	13766	68.4	0.50	483,834	2,403
SG_FS150_FW05_KV_FH300	5	300	150	200	1050	0.0001	3280	13766	96.4	0.70	483,834	3,389

Source: Petrenel

As expected, as fracture half-length increases recovery increases.

The spacing between the fracture stages is also important. The model found that there is an optimum spacing between fracture stages, past which recovery decreases. For this reservoir the optimum fracture spacing is 150m. As can be seen on table 4A below the recovery decreases significantly when fracture spacing increased from 150m to 200m, which could be due to a decrease in stimulated reservoir volume.

Table 4A – Impact of Fracture Spacing on Recovery

Grid size 5×5 km **Simulation: 50 years**												
	Characteristics							**SI**			**Field**	
Model	**Frac wdth**	**Frac. half length**	**Frac . spg**	**Res. Thick-ness**	**Hort . leg**	**Mat. perm.**	**Frac. perm.**	**GIIP**	**Rec.**	**RF**	**GIIP**	**Rec.**
	mm	m	m	m	m	mD	mD	MM m3	MM m3	%	Mscf	Mscf
SG_FS100_FW05	5	200	100	200	1050	0.0001	3280	13766	96.4	0.70	483,834	3,389
Base- (Kv≠0)	5	200	150	200	1050	0.0001	3280	13766	103.2	0.75	483,834	3,627
SG_FS200_FW05	5	200	200	200	1050	0.0001	3280	13766	88.1	0.64	483,834	3,096

Source: Petrenel

The thickness of the reservoir has an impact on both the volumes of gas in place and, hence, the volumes of recoverable gas. Sensitivities were run varying reservoir thickness as illustrated on Table 5A and it was found that as the thickness increases the recovery per well increases (with all other factors remaining the same).

Table 5A – Impact of Reservoir Thickness

	Characteristics							SI		Field	
Model	**Frac wdth**	**Frac. half length**	**Frac . spg**	**Res. Thick-ness**	**Hort . leg**	**Mat. perm.**	**Frac. perm.**	**GIIP**	**Rec.**	**GIIP**	**Rec.**
	mm	m	m	m	m	mD	mD	MM m3	MM m3	Mscf	Mscf
SG_FS150_FW05_KV_t100	5	200	150	*100*	1000	0.0001	3280	6645.4	53.9	233,566	1,893
Base case	**5**	**200**	**150**	***200***	**1000**	**0.0001**	**3280**	**13766**	**68.4**	**483,834**	**2,403**
SG_FS150_FW05_KV_t300	5	200	150	*300*	1000	0.0001	3280	20922	69.6	735,346	2,445

Source: Petrenel

Table 5A shows that as thickness increases, recovery increases. It must be noted that as thickness increases, the number of potential laterals per well also increases, which would boost recovery further. Thus thick reservoirs would have more laterals and potentially fewer wells (which in turn would decrease the surface impact of the exploitation programme).

Reservoir thickness is not the only reservoir characteristic that was investigated in the modelling phase. Sensitivities were run on the matrix permeability. Typical matrix permeability for shales mature for gas production in the USA has been quoted as ranging between 1E-3 mD and 1E-7mD, and for the Barnett shale between1E-3 mD and 1E-5 mD (Cipolla C. L. et al, 2010). Simulations were run at intervals in that range and are summarised in Table 6A.

Table 6A – Sensitivities' on Matric Permeability

Grid size 5×5 km **Simulation: 50 years**												
	Characteristics*							SI			Field	
Model	**Frac wdth**	**Frac. half length**	**Frac . spg**	**Res. Thick-ness**	**Hort . leg**	**Mat. perm.**	**Frac. perm.**	**GIIP**	**Rec.**	**RF**	**GIIP**	**Rec.**
	mm	m	m	m	m	mD	mD	MM m3	MM m3	%	Mscf	Mscf
SG_FS100_FW05	5	200	150	200	1000	0.001	3280	13766	178.46	1.30	483,834	6,272
Base- (Kv≠0)	**5**	**200**	**150**	**200**	**1000**	**0.0001**	**3280**	**13766**	**68.36**	**0.50**	**483,834**	**2,403**
SG_FS200_FW05	5	200	150	200	1000	0.00001	3280	13766	19.789	0.14	483,834	696

Source: Petrenel

Table 6A illustrates the importance of correct measurements/estimates of matrix permeability. As permeability increases by a factor of 10 (from 1E-4 mD to 1E-3 mD), recovery increases 2.6 fold. A similar decrease (from

1E-4mD to 1E-5mD) results in a 3.5 times decrease in recovery. It is the factor with the single greatest impact on recovery.

Hydraulic fracturing artificially increases the permeability of the reservoir through the creation of flow channels (the fractures). However, not all the fracture will be open. Once created, the fractures are flushed to recuperate the fracturing fluid. This allows the rock to close on the fracture. A portion of it will remain effectively open, some will be propped and the tail end will be effectively unpropped. The effectiveness of the stimulation treatment will dictate the permeability of the induced fractures. Typically values for the Barnett shale are between 0.5mD/ft to 5mD/ft (Cipolla C. L. et al, 2010).

Table 7A – Sensitivities of Fracture Permeability

Grid size **5×5 km** **Simulation: 50 years**												
	Characteristics*							**SI**			**Field**	
Model	**Frac wdth**	**Frac. half length**	**Frac . spg**	**Res. Thick-ness**	**Hort . leg**	**Mat. perm.**	**Frac. perm.**	**GIIP**	**Rec.**	**RF**	**GIIP**	**Rec.**
	mm	m	m	m	m	mD	mD	MM m3	MM m3	%	Mscf	Mscf
SG_FS100_FW05	5	200	150	200	1000	0.0001	1312	13766	66.3	0.48	483,834	2,329
Base- (Kv≠0)	**5**	**200**	**150**	**200**	**1000**	**0.0001**	**3280**	**13766**	**68.4**	**0.50**	**483,834**	**2,403**
SG_FS200_FW05	5	200	150	200	1000	0.0001	6562	13766	67.7	0.49	483,834	2,381

Source: Petrenel

The horizontal leg length (or lateral length) is most commonly affected by drilling restrictions (equipment capacity) and rock strength and stiffness. Published papers vary in their estimates of lateral length but in the Barnett shale typical lateral lengths are 2500ft to 3500ft (Halliburton White Paper, 2008) (762m to 1067m). The impact of the lateral length on the model is summarised in table 8A below. As lateral length increases, recovery increases.

Table 8A - Impact of Lateral Length on Recovery

Grid size **5×5 km** **Simulation: 50 years**												
	Characteristics*							**SI**			**Field**	
Model	**Frac wdth**	**Frac. half length**	**Frac . spg**	**Res. Thick-ness**	**Hort . leg**	**Mat. perm.**	**Frac. perm.**	**GIIP**	**Rec.**	**RF**	**GIIP**	**Rec.**
	mm	m	m	m	m	mD	mD	MM m3	MM m3	%	Mscf	Mscf
SG_FS100_FW 05	5	200	150	200	650	0.0001	3280	13766	46.0	0.33	483,834	1,617
Base- (Kv≠0)	**5**	**200**	**150**	**200**	**1000**	**0.0001**	**3280**	**13766**	**68.4**	**0.50**	**483,834**	**2,403**
SG_FS200_FW 05	5	200	150	200	1250	0.0001	3280	13766	79.5	0.58	483,834	2,796

Source: Petrenel

The model well had, in all sensitivity runs, a very similar drainage area.

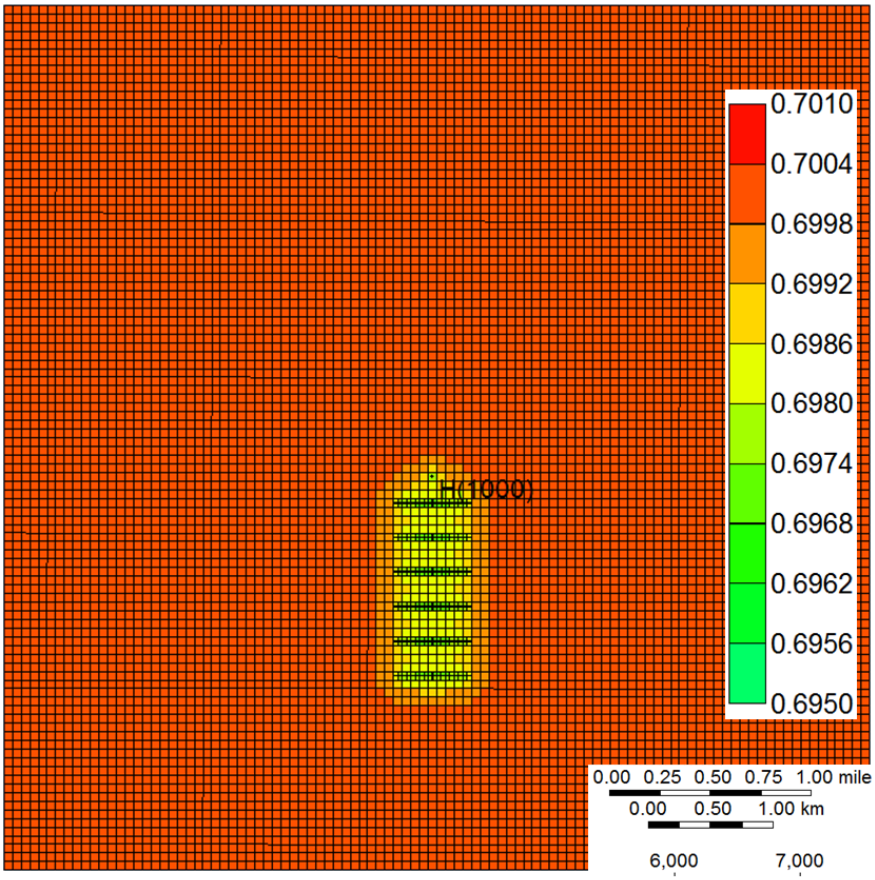

Figure 4A - Well Drainage Area

Source: Petrenel

The drainage area shown in Figure 4A is 0.87 km^2 (214 acres). Figure 4A shows the decrease in gas saturation for that layer of the model after 30 years of production. As can be seen on the image's scale the drainage is less than 1% after 30 years. This highlights the difficulty of obtaining large recoveries from producing shale gas wells.

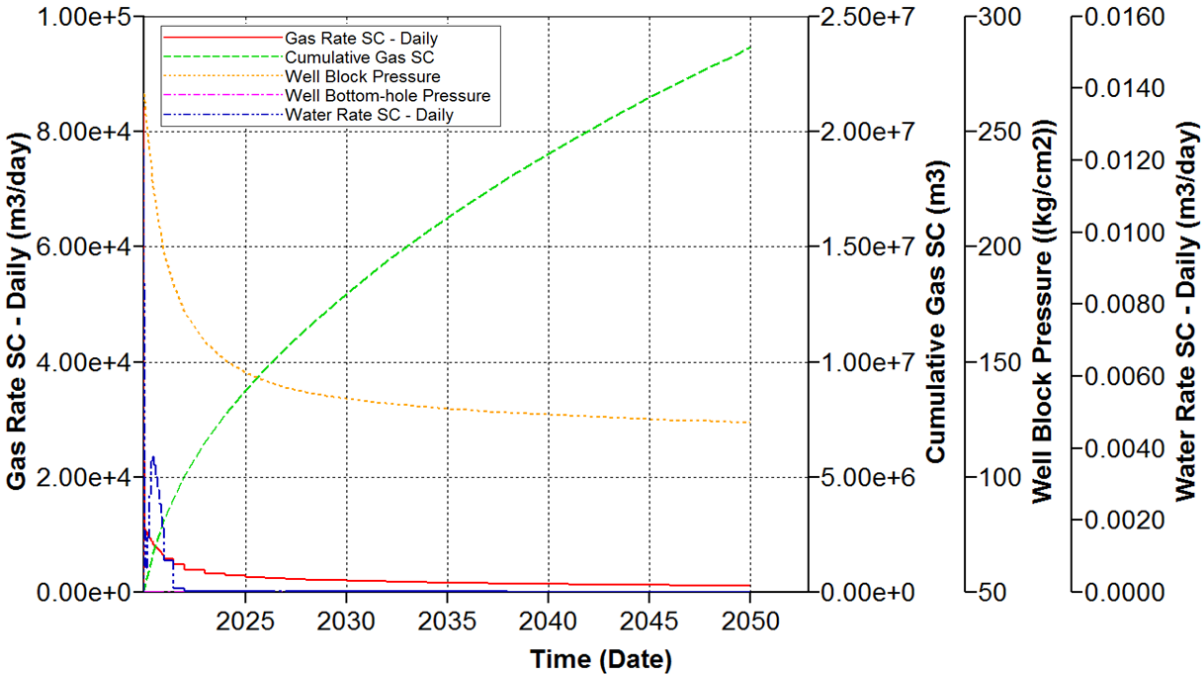

Figure 5A - Production Profile for a Single Well

Source: Petrenel

Figure 5A illustrates the production profile of the well over 30 years. The production peaks at 2.96 MMscfd but declines sharply to 0.04 MMscfd, confirming findings from published literature that describe a first production year decline of 55-75% (OECD/IEA, 2012).

Cumulative production for the well is 837 MMscf when vertical permeability is assumed to be 0. This rises to 3627 MMscf (i.e. 3.6 bcf) when vertical permeability is 1E-4mD (i.e. permeability is homogenous).
Pressure declines from 265 bars to 123 bars. There is virtually no water production; it is less than 0.02 m^3/d, as has been found in the Barnett shale).

Well Interference

Once the drainage area had been established the model was run with multiple wells at a spacing closer than the drainage area. Five wells were placed 110 acres (0.445 km^2) apart.

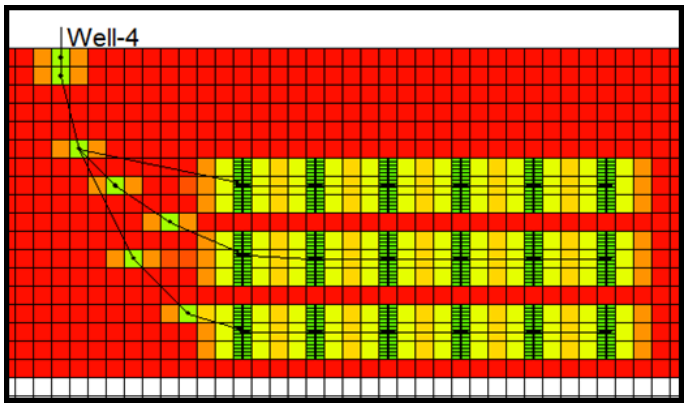

Figure 6A - Well Profile with 3 Laterals

Source: Petrenel

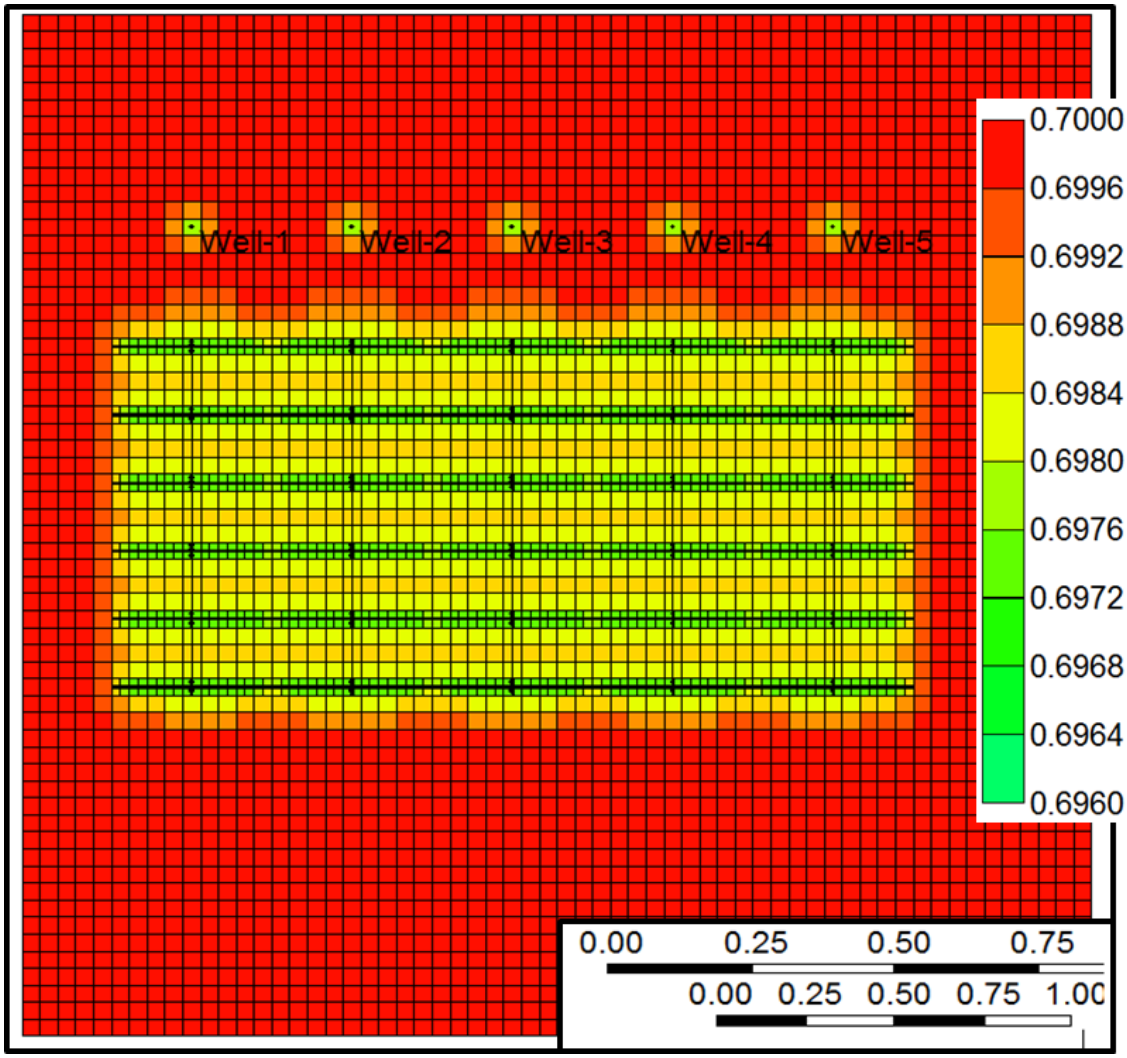

Figure 7A - Well Interference Pattern over the Field

Source: Petrenel

As shown on Figure 7A the drainage areas of each well overlap. The result per well was a decrease in production. It peaks at 2 MMscfd (vs. 2.96MMscfd with no interference) with a short plateau (49 days) and decreases to 0.11 MMscfd in 2050. Well block pressure decreases are the same, from 267 bars to 124 bars and water production is negligible.

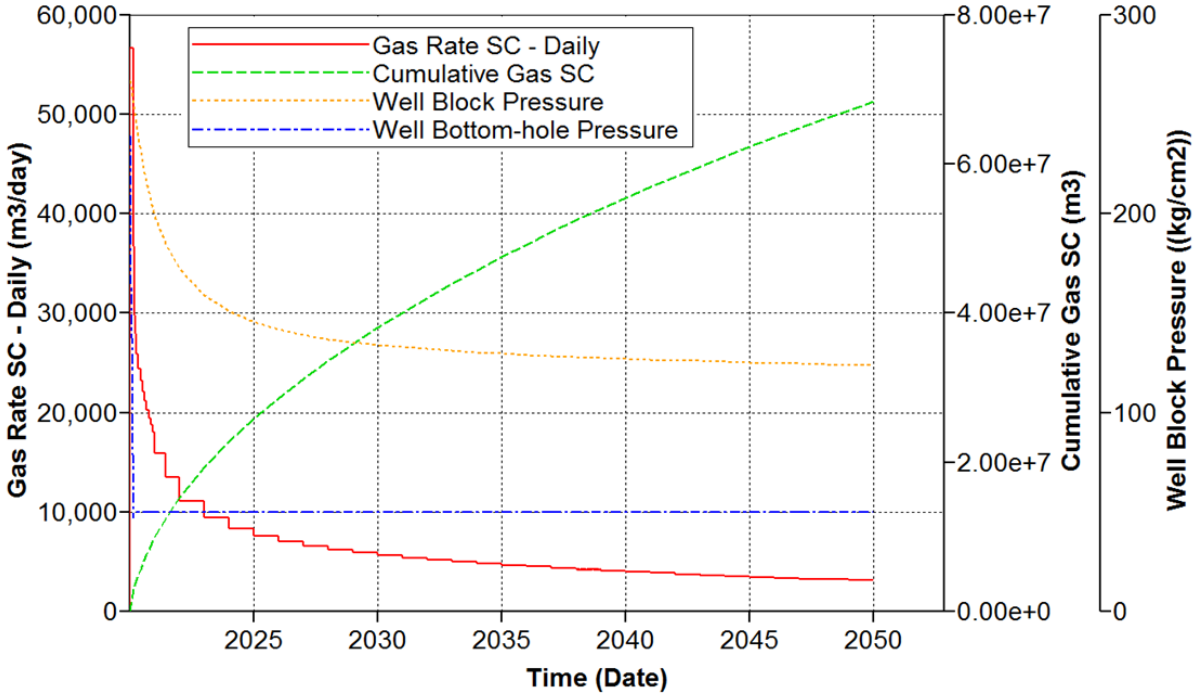

Figure 8A - Production Profile for one Well in the Well Interference Case

Source: Petrenel

The interference and no-interference cases have been compared. Due to the interference between the wells average well recovery decreases from 2473 MMscf/well to 2375MMscf/well (between the no interference and the interference case), as summarised in Table 9A.

Table 9A - Comparison between the Interference and No Interference Cases

Model	Recovery	Number of wells	Average recovery /well
	MMscf		MMscf/well
No Interference	1407.3	20	2473.1
Interference	**338.0**	**5**	**2375.1**

Source: Petrenel

Conclusions

The model confirmed findings in published papers; increases in fracture half length or matrix permeability both increase recovery. There is an optimum fracture spacing and an optimum number of wells for a given field that depends on drainage radius. Vertical permeability has a high impact on recovery as discussed in the section on well interference. A shale gas well with some vertical permeability can recover 3.7 bcf(with an initial rate of 3.0 MMscfd), whereas if vertical permeability is 0 cumulative production reduces to 837 MMscf (3.0 MMscfd). Recoveries from shale gas fields are low and interference between wells is undesirable.

Appendix B: Public Perception (Global)

Canada

There is substantial shale gas potential in New Brunswick, Canada. Corporate Research Associates (CRA) investigated the public perception associated with the exploration and production of shale gas in New Brunswick. There were 400 residents above the age of 18 surveyed.

Table 1B - Balanced Views on Shale Gas Developments in New Brunswick, Canada

Would you say you completely support, mostly support, mostly oppose or completely oppose the exploration for natural gas in NB, in principle?	
Completely support	11%
Mostly support	34%
Mostly oppose	26%
Completely Oppose	19%
Don't know	10%

Data Source: CRA, 2011

The results provided in Table 1B show an equal distribution of 45% in support and in opposition for natural gas exploration. However, a larger percent 'completely opposed' the idea (19%) in comparison with the percent fully supportive of exploration (11%) in New Brunswick. A percentage as low as 10 represents those uncertain of their opinion, suggesting the majority of the New Brunswick residents are well-informed with the issues relating to unconventional gas.

Table 2B - Survey Results on Public Opinions for Shale Gas Developments

	Level of agreement or disagreement with each statement.				
	Completely Agree	Mostly Agree	Mostly Disagree	Completely Disagree	Don't know
Exploration and production of natural gas from shale gas deposits can be done safely if the appropriate regulations are in place.	18%	41%	19%	14%	8%
Exploration of natural gas from shale deposits will have negative environmental impacts that outweigh the economic benefits.	24%	34%	21%	9%	11%
Development of natural gas exploration in New Brunswick will lead to long term economic benefits for the Province.	16%	48%	17%	12%	7%
Regulations will be required, but I still worry about the environmental impact of natural gas exploration in the Province.	37%	46%	9%	9%	2%
We need to develop new industries in New Brunswick in order for the Province to grow and prosper.	53%	39%	4%	3%	1%

Data Source: CRA, 2011

The majority of the surveyed "mostly agree" (41%) exploration and production of shale gas can be done, if regulations are correctly implemented. The residents also "mostly agree" that the economic rewards are not worth putting the environment at risk (34%); while only 9% "completely disagree". However, 48% of those surveyed "mostly agree" the development of shale gas would bring long term economic benefits, and 58% "completely agree" new industries must be developed for the Province to grow and prosper.

The CRA study concluded that the New Brunswick residents are aware of the economic benefits associated with shale gas exploration, and although there are concerns with the negative environmental impacts, over half of the surveyed residents agreed that these developments could be carried out if regulations are applied correctly (18% "completely agree"; 41% "mostly agree").

Poland

A CBOS study discovered that 78% of the Polish respondents supported shale gas in Poland (2013), with a 5% increase from 2011. The reason for Poland's high level of support for shale gas developments could be due to their dependence on Russia's exports. The majority (80%) of the population surveyed believe that shale gas will contribute to the country's energy security. 40% of the surveyed residents are not concerned about the potential environmental and human health risks associated with shale gas exploration, and more than half of those questioned in the 2011 nationwide survey had no issues even if it was coming "close to where they live" (Natural Gas Europe, 2012).

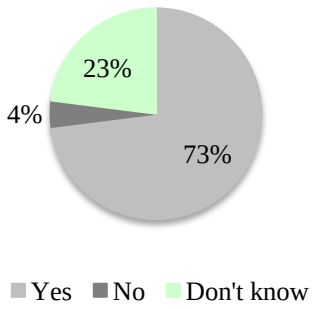

Figure 1B - Shale Gas Support in Poland (2011)

Data Source: CBOS, 2011

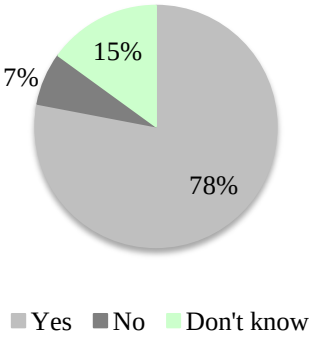

Figure 2B - Shale Gas Support in Poland (2012)

Data Source: CBOS, 2011

United States

The United States currently imports 13% of natural gas. With the exploration and production of shale gas in the USA it expects to reduce this to ~1% by 2035 (KPMG, 2011), so with this resource opportunity it is becoming both self-sufficient and a key player in this industry.

Deloitte (2012) carried out a study to investigate the public perception of shale gas developments in the USA. There were three different types of residents involved in this study:

1. General population (surveyed 1,694 U.S residents);
2. Residents from areas with mature exploration and production industries (Texas, Louisiana, and Arkansas); and
3. Residents living in areas where shale gas development is a recent interest (New York and Pennsylvania).

Deloitte asked the sample groups what words they associate with natural gas, how trustworthy they think the media is in relation to the natural gas industry, and what they think are the most significant environmental concerns.

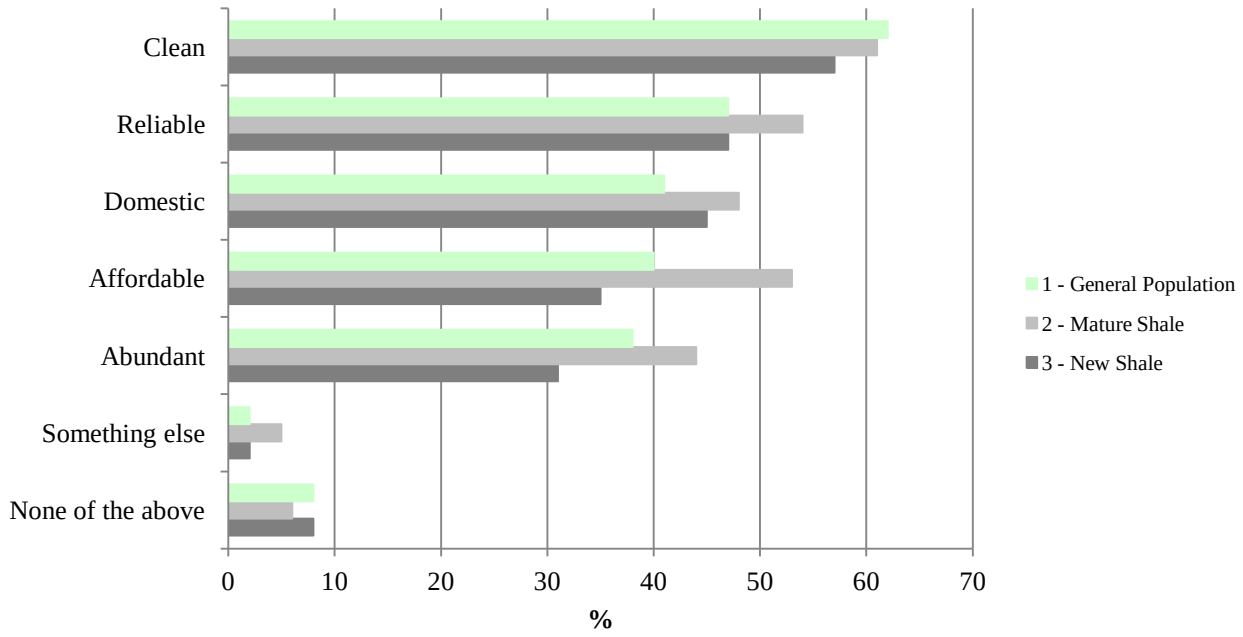

Figure 3B - Most Common Words USA Residents Associated with Natural Gas

Data Source: Deloitte, 2012

In this study, all three sample groups had similar results. The most frequently used words to describe natural gas were "clean" and "reliable". The mature shale group also used the word "affordable" upon association with natural gas. The new shale results have slightly lower results for all words, excluding "domestic" and "none of the above", when comparing with the mature shale and general population groups. This could be a result of the new shale group not having the same amount of exposure to the shale gas industry as the other two sample groups.

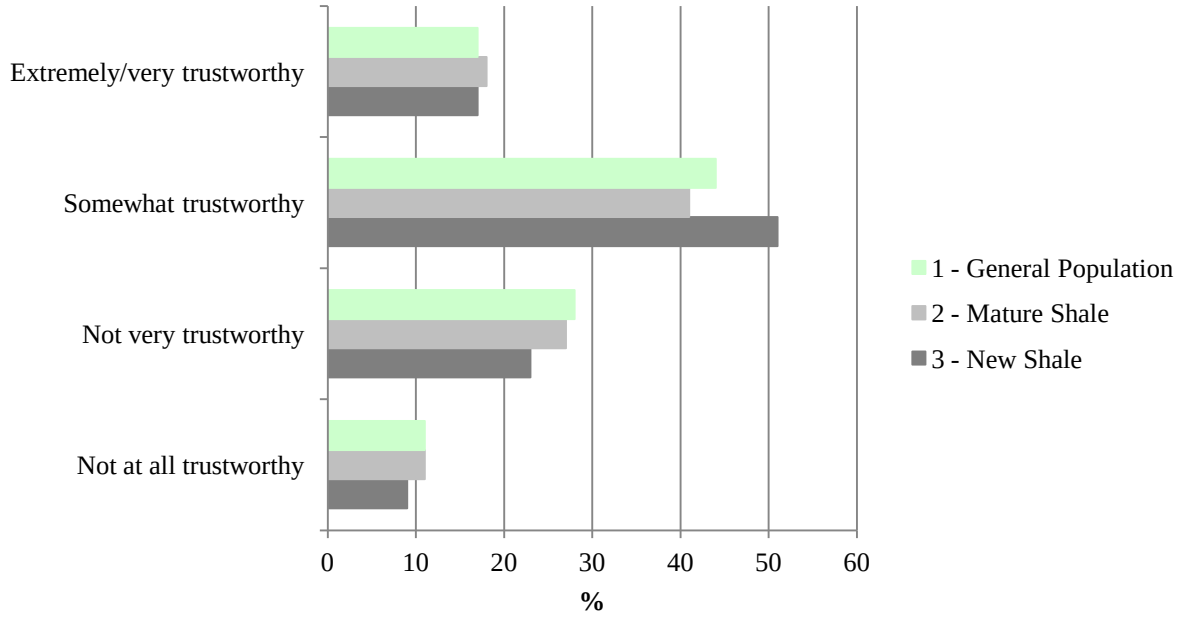

Figure 4B - How Trustworthy the Media are considered to deliver Unbiased Coverage on the Natural Gas Industry

Data Source: Deloitte, 2012

The three sample groups had the highest percentage (new shale – 51%; general population – 44%; mature shale – 41%) with the media delivering "somewhat trustworthy" unbiased coverage of the natural gas industry. This suggests that all studied groups mostly support the media concerning shale gas.

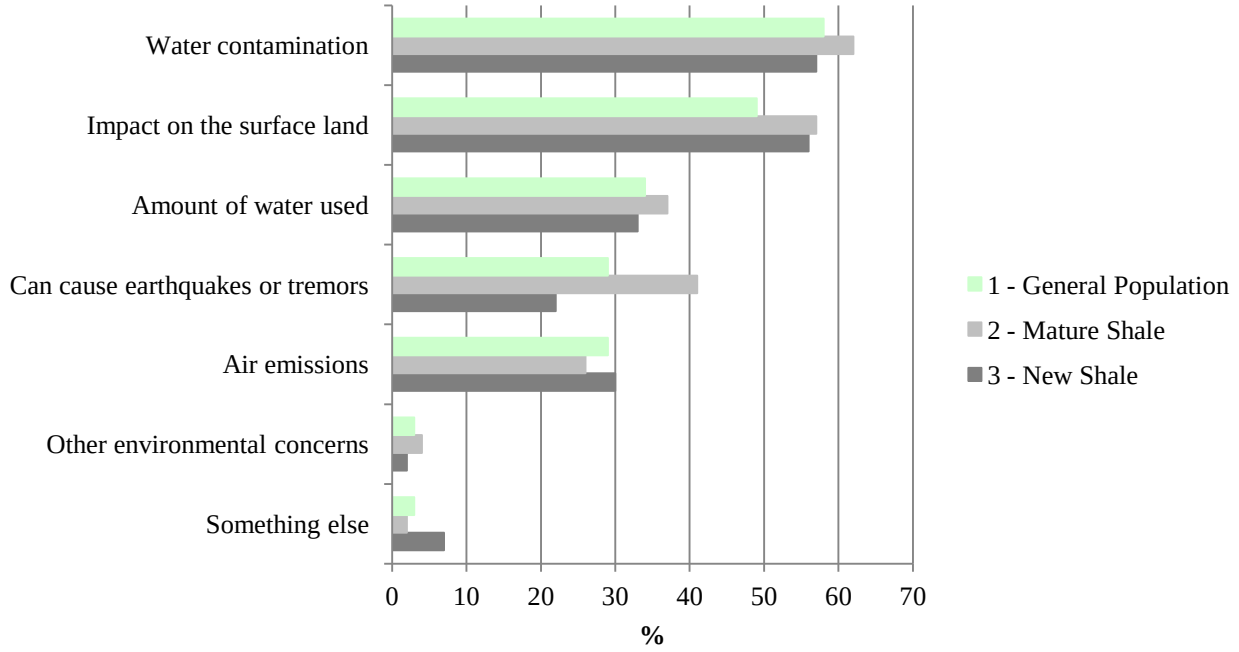

Figure 5B - Main Environmental Concerns Raised by USA Residents

Data Source: Deloitte, 2012

The sample groups have heard issues about shale gas having an impact on water contamination and the surface land. This also supports Figure 4B, as most articles of environmental concern have been linked to water contamination and the impact on the surface land. This survey also showed that 58% nationally feel benefits "far" or "somewhat" outweigh risks.

Penn State University, amongst other organisations[2], investigated the public perception of individuals living in shale gas exploration areas. One of the questions directed at 1,461 USA households revealed the extent of what the local areas know about shale gas developments.

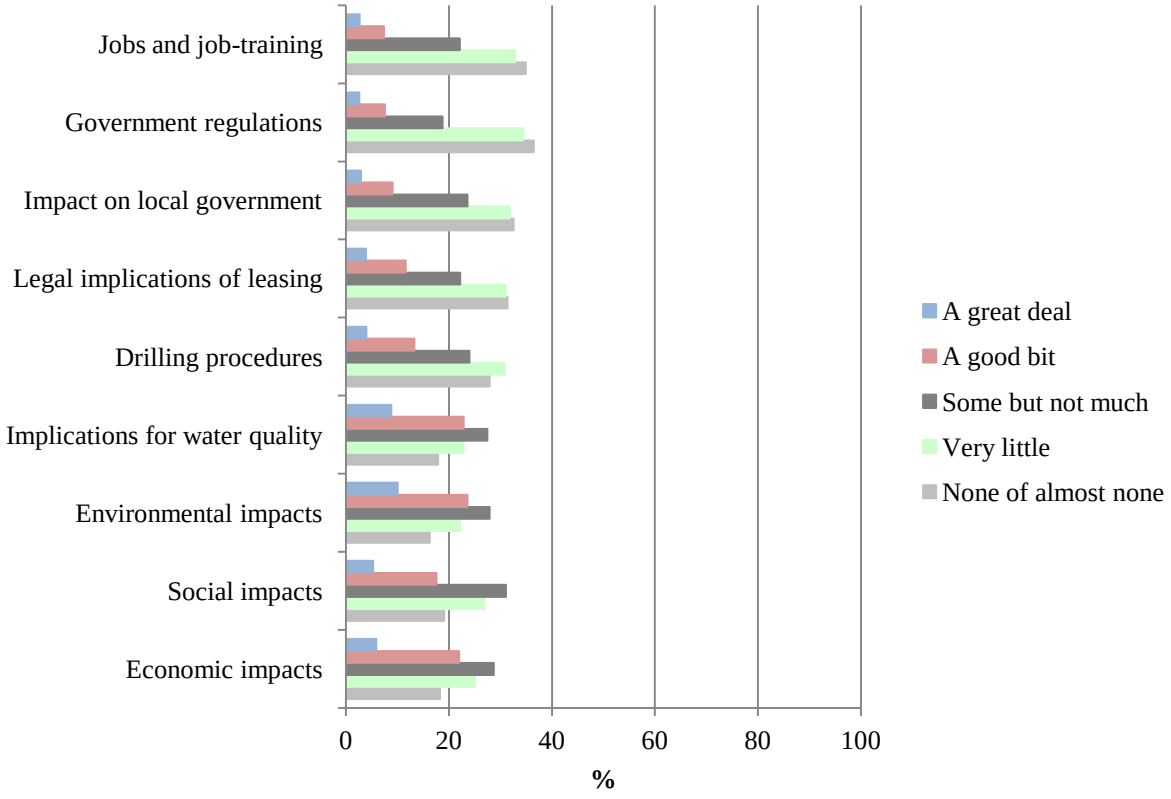

Figure 6B - General Understanding of the Shale Gas Industry in the USA

Data Source: "Baseline Socioeconomic Analysis for the Marcellus Shale Development in Pennsylvania" report, 2010

Figure 6B demonstrates that there is a limited understanding of the shale gas industry processes and impacts, as none of the percentages are higher 36.5%. It shows that 38% knew "nothing" (16%) or "very little" (22%) about the environmental impacts, and only 34% knew a "good bit" (24%) or a "great deal" (10%). 41% of those surveyed suggested that they had no knowledge or little understanding of the impacts of shale gas on water quantity and quality.

The overall level of understanding of shale gas developments, for those surveyed in this particular study, is fairly low. This could be a result of insufficient media coverage or poor communication from the government and/or the exploration and production companies.

[2] Cornell University, the Institute for Public Policy and Economic Development, and the Appalachian Region Commission.

Appendix C: Companies holding Licences in the Bowland Shale Area

Dart Energy

Listed on the Australian ASX market, head office in Singapore, approx. market cap US$129m. Company holds licences in prospective coal bed methane areas and shale gas. Also has assets in China and Indonesia.

Bowland Shale: Licences with prospectivity in the Bowland shale: PEDL's 12, 139, 140, 146, 147, 176, 185, 186, 187, 188, 189, 200, 207, 210, EXL288.

Total area: 1041 sq kms in the western region and 1235 km^2 in the eastern region.

Table 1C - Dart's Estimates Of Gas In Place And Resources For The Shale Gas Play

Licence	Interest	Operator	Location	Gross Area (km^2)	OGIP bcf	Prospective Resource bcf
PEDL 133	100%	Dart	Scotland		795	116
PEDL 133	49%	Dart	Scotland		1,753	255
PEDL 147, 186, 187	100%	Dart	UK Cheshire	260	19,277	
PEDL 185, 188, 189	100%	Dart	UK Cheshire	400	11,273	
PEDL 200, 207, 210	100%	Dart	UK East Midlands	257	19,036	
EXL 288	100%	Dart	UK East Midlands	51	4,016	
PEDL 012	100%	Dart	UK East Midlands	86	6,426	
PEDL 139	16.5%	eCORP	UK East Midlands	100	1,723	
PEDL 140	16.5%	eCORP	UK East Midlands	141	1,259	

Dart estimates its total gas in place potential in the shale gas play to be 63 to 110 tcf.

On 22nd October 2013 Dart announced that it had entered into a farm-out agreement relating to thirteen of its UK licences with GDF SUEZ E&P UK Ltd. This comprised part of a broader strategic cooperation in relation to unconventional gas being implemented between the two companies at the same time. GDF SUEZ E&P UK is a wholly owned subsidiary of GDF SUEZ, a Paris-headquartered global energy group, with a significant exploration and production presence in the UK. GDF SUEZ is listed on the Paris, Brussels and Luxembourg stock exchanges, has annual revenues in excess of US$120 billion, and employs more than 130,000 employees worldwide. GDF SUEZ E&P UK is one of the UK's leading operators with a reputation for safe and responsible exploration and production activities.

The farm-out relates to thirteen licences (out of a total of 31) held by Dart in the U.K. All farm-out licences are in England / Wales, in both the western and eastern parts of the Bowland Basin, an area considered highly prospective for shale gas. Dart is currently the operator of these licences and holds a 100% interest in each. GDF SUEZ E&P UK will acquire a 25% working interest in each licence. Dart will retain a 75% interest and operatorship of each licence.

As consideration for the interest acquired, GDF SUEZ E&P UK will pay to Dart US$12 million in cash, and meet Dart's 75% share of costs up to US$27 million (as well as meet GDF SUEZ E&P UK's 25% share). The funding will support an agreed unconventional exploration and appraisal program over a three year period, including drilling up to four shale gas exploration wells in different areas of the Bowland basin and ten Coal Bed Methane (CBM) exploration wells.

Alongside the farm-out, Dart and GDF SUEZ have established a broader strategic cooperation between the two companies, focussed on unconventional gas activities (and especially shale). This includes provision of various support services from GDF SUEZ and partner company SUEZ Environnement in the field of environmental service and water management, and the sharing of best practice.

Southern England: Dart holds no licences in southern England.

Igas Energy Plc

Listed on the London AIM market, head office in London. Approximate market cap US$330m.

IGas Energy is a British oil and gas explorer and developer, producing approximately 3,000 barrels of oil and gas equivalent per day from over 100 sites across the country and employing some 170 staff. It operates the largest number of onshore oil and gas fields in Britain focussed on the East Midlands and the Weald Basin in the south of England. It holds licences with potential of other resources such as gas from shale and coal bed methane.

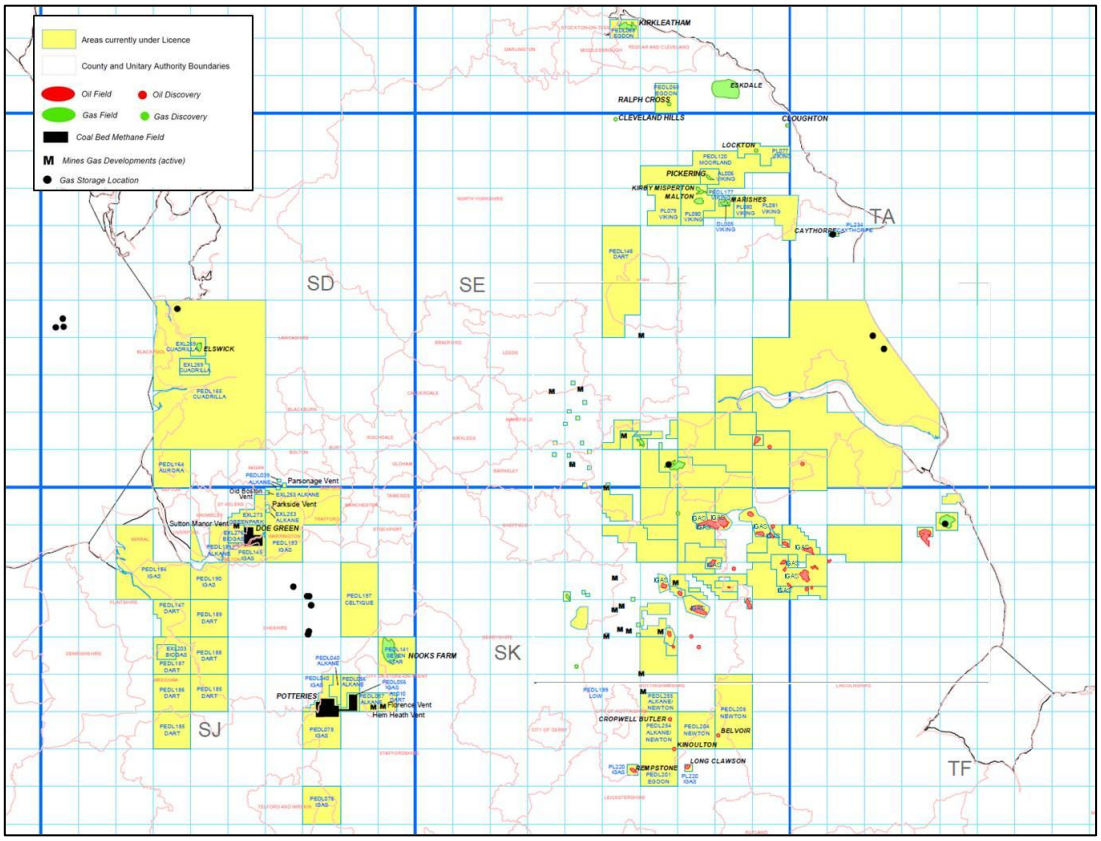

Figure 1C - Licences in the North East and West areas of England showing Igas conventional oil and gas developments

Source: DECC

Bowland Shale: Licences with prospectivity in the Bowland shale: PEDL's 6, 116, 145,184, 190, 193, PL 178, ML 6, ML 3, ML 7, ML 4.

Gas in place estimated by the company for Bowland shale 15 to 172 tcf. Drilled a CBM well at Ince Marshes but now identify the area as having shale gas potential.

Southern England: Company also holds licences in the Weald Basin: PL 233, DL 2, PL 233, PL 249, PL 211 DL 4, PL 205, ML 21, ML 18, PL 182, PEDL's 21, 70, 235, 240.

The majority of activity to date in this area has been the exploration and development for conventional oil and gas.

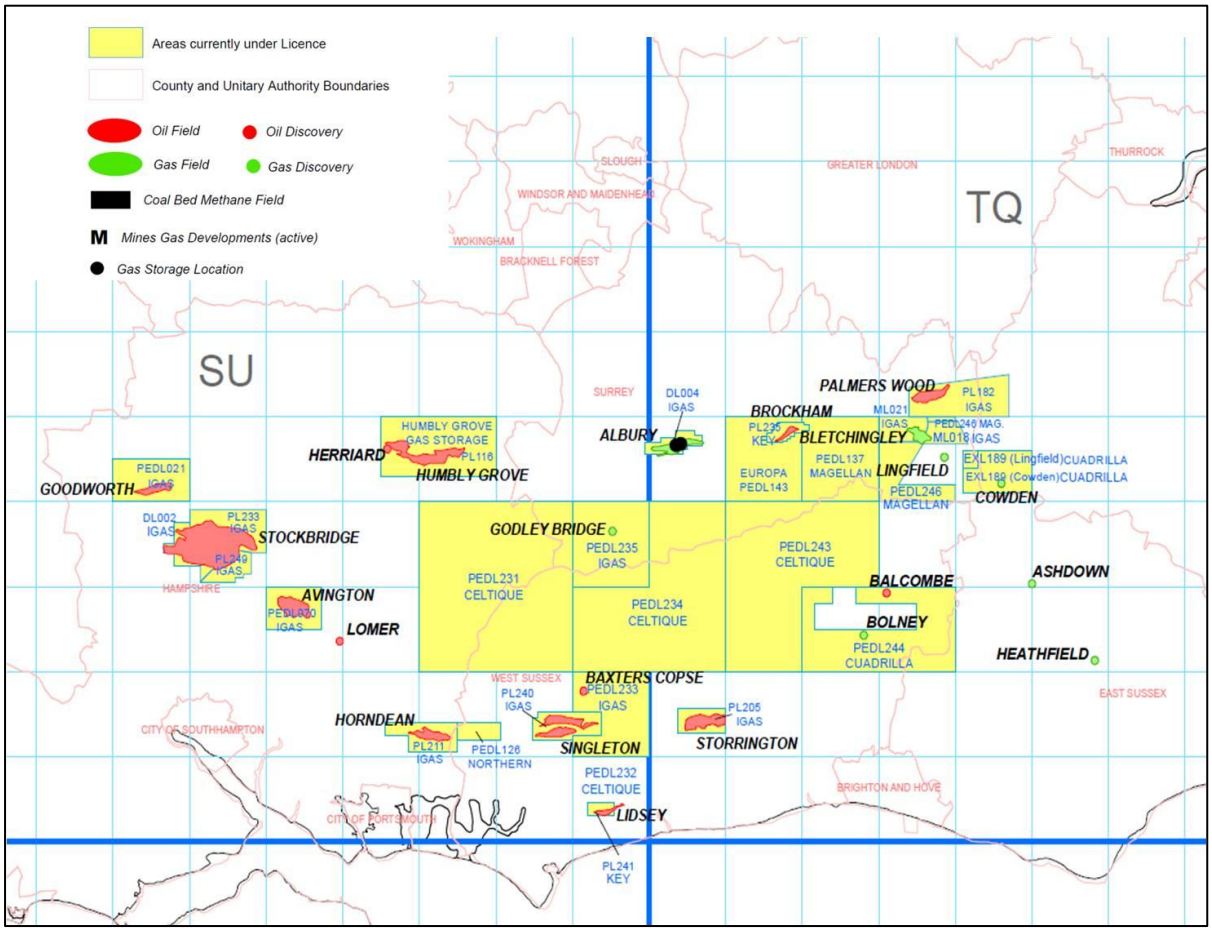

Figure 2C - Licences in Southern England showing Igas conventional oil and gas developments

Source: DECC

Alkane Energy

Alkane Energy is listed on the London AIM market. Approximate market cap US$81 million.

Alkane Energy is an independent power generator. The Company operates mid-sized 'gas to power' electricity plants. Alkane has a total of 81MW of installed generating capacity and an electricity grid capacity of 100MW. Alkane's main operations are based on a portfolio of coal mine methane ('CMM') sites enabling the Company to extract gas from abandoned coal mines. The company holds various onshore licences that include CMM, natural gas, coal bed methane and shale gas potential. The company is mainly pursuing a conventional gas discovery at Three Nooks Farm Staffordshire at this time.

Bowland Shale: Licences with prospectivity in the Bowland shale: PEDL's 39, 43, 130, 169, 191, PL 161, EXL 253.

Southern England: Alkane does not own licences in Southern England.

Cuadrilla Resources

Cuadrilla is a UK company based in Staffordshire. Formed in 2007 as a privately owned exploration and production company, it is targeting conventional and unconventional oil and gas.

It has a number of exploration sites in the Bowland Shale basin in Lancashire. In addition, it also has a production site at Elswick which has been generating electricity from natural gas since 1993.
The company is privately owned by its management team and two investors, AJ Lucas and Riverstone LLC. The company is registered in the UK.

Bowland Shale: Licences with prospectivity in the Bowland shale: PEDL 165, EXL 269.

Southern England: Company also holds licences in the Weald Basin: PEDL 244, 247, PL 55, EXL 189.

Recent publicity surrounded the Cuadrilla activities at the Balcombe well site. According to Cuadrilla's application for planning consent the Balcombe well was targeted at micrite limestone layers that are situated within the Upper Jurassic Kimmeridge Clay interval. It proposed to drill a 600 metre horizontal section but had not declared any intent to fracture the well. Although this well will pass through the Kimmeridge Clay (which is a shale) the target formation indicates that the primary reason for the well was to target conventional hydrocarbons in the micrite layers.

Egdon Resources

Egdon was formed in 1997. In 2000 Egdon gained its first operated licence and listed on the OFEX market. In 2004 Egdon listed on the AIM. Approximate market cap US$17.2 million.

In January 2008 Egdon demerged its gas storage business, Portland Gas plc (now renamed Infrastrata), and again became an exploration and production business.

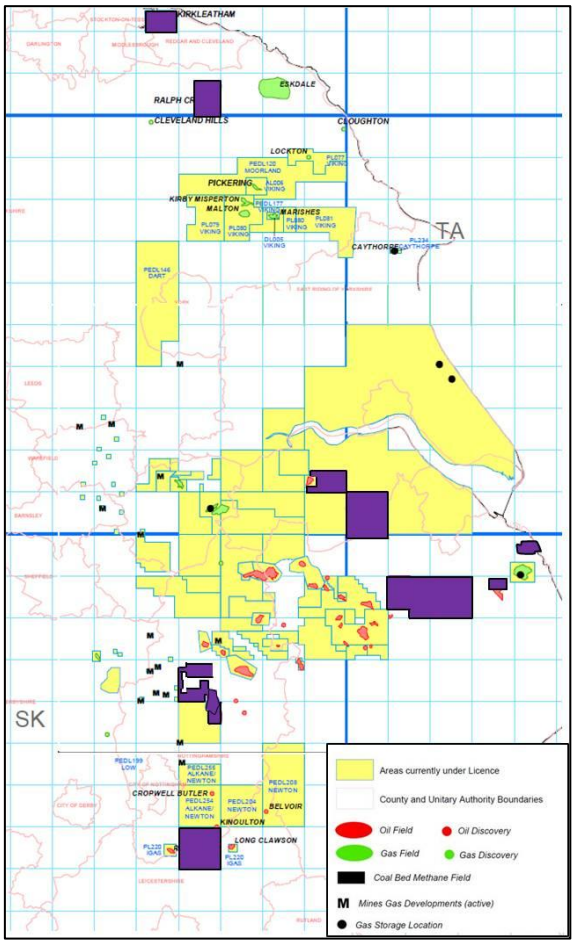

Figure 3C - Egdon Resources Licences in the North East (purple)

Data Source: DECC

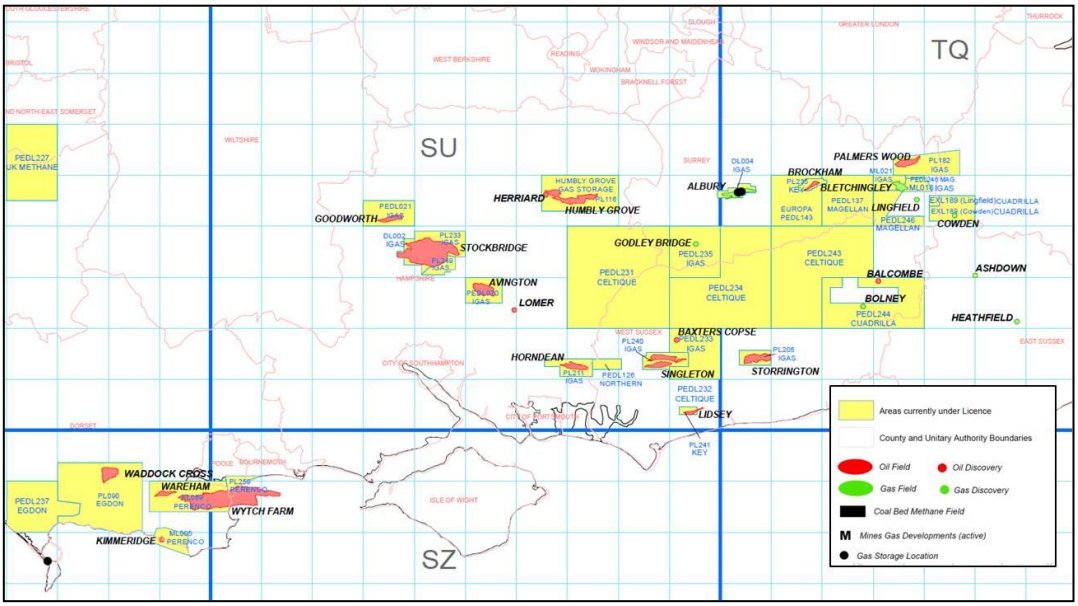

Figure 4C - Licences in Southern England showing Edgon Resources conventional oil and gas developments

Source: DECC

Bowland Shale: Licences with prospectivity in the Bowland shale: PEDL's 130, 139, 140, 201.

Shale gas resources evaluated by RPS for PEDL's 139 and 140. Gross gas in place estimated at 10.2 to 16.0 tcf. Estimated resources are 0.9 to 1.9 tcf.

Southern England: Company also holds licences in the Weald Basin: PEDL's 70, 126, 143, 155, 256.

Third Energy

Third Energy is an exploration, development and production of company. Third Energy has significant licence acreage in North Yorkshire, consisting of producing fields, non-discoveries and exploration acreage. The company produces and transport hydrocarbons from fields for onward treatment and generation to the Knapton Generating Station. The Knapton Generating Station (KGS) is the largest generating station in the UK that utilises onshore gas. KGS and its associated gas fields are operated by Viking UK Gas ltd. RGS Energy Ltd own the power generation station. Viking UK Gas Ltd and RGS Energy Ltd are wholly owned subsidiaries of UK Energy Systems Ltd, which was acquired by Third Energy Holdings Ltd in 2011. The company is currently focussed on conventional gas production. Third Energy Holdings Limited is financed by private equity, through

Barclays Natural Resource Investments ('BNRI') which is a division of Barclays Capital, and the management team.

Bowland Shale: Licences with prospectivity in the Bowland shale: PL 79, PL 80, PL 81, PL 77, AL 6.

Southern England: Third Energy holds no licences in southern England.

Blackland Park Exploration

Chairman is Rupert Lycett Green. The company owns and operates the Whisby oil field located in Lincolnshire. Small privately held company.

Bowland Shale: Licences with prospectivity in the Bowland shale: PL 215, EXL 141, PEDL's 90, 209.

Southern England: Blackland Park holds no licences in southern England.

Europa Oil and Gas

Europa is listed on the London AIM market. Approximate market cap is US$24 million.

Europa Oil & Gas (Holdings) plc is an AIM listed exploration and production company focused on Europe. It holds exploration assets in the Porcupine Basin offshore Ireland and the Berenx gas appraisal project onshore France, as well as interests in three producing assets onshore UK.

Bowland Shale: Licences with prospectivity in the Bowland shale: PEDL 150.

Southern England: Europa has an interest in PEDL 143 and is pursuing a conventional oil play in the Jurassic Sandstones reservoir of the Weald Basin.

Celtique Energie

Celtique Energie Holdings Ltd (Celtique) is a privately owned, British-based oil and gas exploration company with subsidiaries and operations across five European countries (France, Switzerland, Germany, Poland and the UK). The company explores for and develops conventional and unconventional oil and gas reserves. The company holds 19 licences across Europe, of which 13 are operated by Celtique, the others by partner companies.

Bowland Shale: Licences with prospectivity in the Bowland shale: PEDL's 197, 201

Celtique has a 100% operated interest in PEDL 197 which is located in the Cheshire Basin of northwest England. The licence was awarded in July 2008 for an initial 6-year term and covers an area of 200 sq. km.

Table 2C

Name	Eqty %	Holder	Operator	Partner	Awarded	Expiry	Gross km^2	Net km^2
PEDL 197	100	CEPL	Celtique		1 Jul 08	1 Jul 14	200.0	200.0

The East Midlands Basin is the main historic centre of oil production in onshore England. Celtique was awarded three licenses from the Department of Energy and Climate Change (DECC) in July 2008 as part of the Government's 13th onshore licensing round.

Table 3C

Name	Eqty %	Holder	Operator	Partner	Awarded	Expiry	Gross km^2	Net km^2
PEDL 180	33	CEPL Egdon Europa	Egdon	Egdon Europa	1 Jul 08	1 Jul 14	100.0	33.0
PEDL 181	25	CEPL Egdon Europa	Europa	Egdon Europa	1 Jul 08	1 Jul 14	540.0	135.0
PEDL 182	33	CEPL Egdon Europa	Egdon	Egdon Europa	1 Jul 08	1 Jul 14	40.0	20.0
PEDL 201	50	CEPL Egdon	Egdon	Corfe Egdon Terrain	1 Jul 08	1 Jul 14	100.0	50.0
PEDL	50	CEPL	Egdon	Egdon	1 Jul 08	1 Jul 14	110.0	55.0

241	Egdon	Europa

Southern England: Company has an interest in PEDL 231, 232, 234, 243.

In 2008, Celtique Energie Weald Ltd and its joint venture investment partner – Magellan Petroleum (UK) Ltd - were awarded four PEDL licenses in southern England's Weald area from the Department of Energy and Climate Change (DECC), three in Central Weald and one in South Weald. All licences are valid for an initial six year term. This was part of the Government's 13th onshore licensing round.

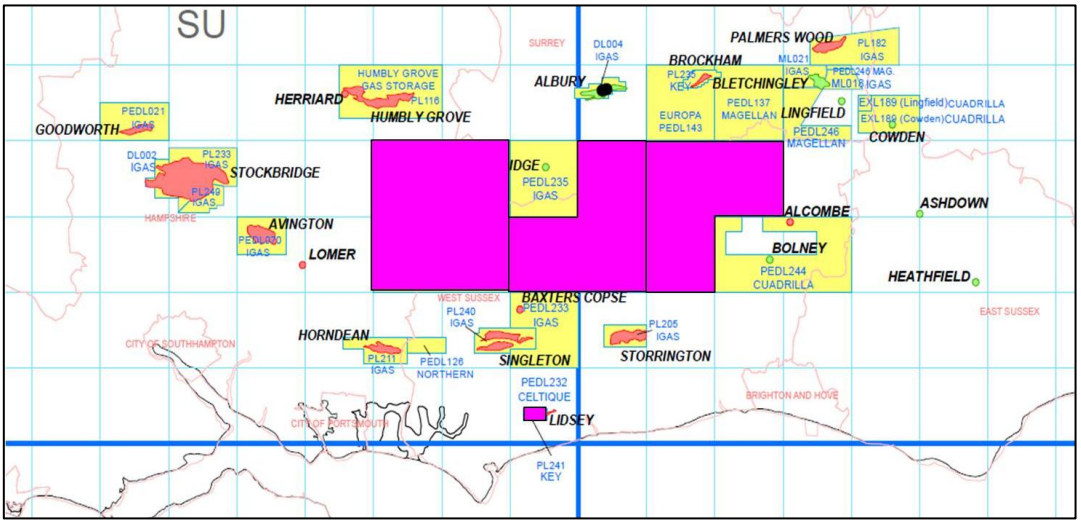

Figure 5C – Celtique Energie Weald Ltd Licences in Southern England (pink)

Data Source: DECC

Table 4C

Name	Eqty %	Holder	Operator	Partner	Awarded	Expiry	Gross km^2	Net km^2
PEDL 231	50	CEWL Magellan	Celtique	Magellan	1 Jul 08	1 Jul 14	400.0	200.0
PEDL 232	50	CEWL Magellan	Celtique	Magellan	1 Jul 08	1 Jul 14	94.0	47.0
PEDL 234	50	CEWL Magellan	Celtique	Magellan	1 Jul 08	1 Jul 14	300.0	150.0
PEDL 243	50	CEWL Magellan	Celtique	Magellan	1 Jul 08	1 Jul 14	300.0	150.0

Currently the company states that it is pursuing conventional oil and gas in these licences.

Other companies holding licences in the Bowland shale area:

A J Lucas (PEDL 165)

Altwood Petroleum (PEDL 141)

Angus Energy Limited (PEDL 203, 118)

Aurora Petroleum Limited (PEDL 164)

Biogas Technology (EXL 203, EXL 276)

Corfe Energy (PEDL 201)

Ecorp International (PEDL 139, 140)

Greenpark (EXL 273)

Moorland Energy (PEDL 120)

Onshore Oilfield Services Limited (PL 215)

Scottish Power Plc (PL 161, PL 162)

Terrain Energy (PEDL 201)

Valhalla Oil and Gas (PEDL 150)

Warwick Energy (PEDL 120)

Appendix D: Southern England Licence Summaries

Table 1D - Southern England Licence Summaries

Igas PLC	
PEDL 70	Igas, Aurora, Corfe Energy, Egdon Resources, Northern Petroleum - Avington Oil Field.
DL 2 PL 249 PL 233	Stockbridge Oil Field. This field was also referred to as Larkwhistle Farm in some DECC publications. Discovered during 1984, the Stockbridge Oilfield lies on the south-western margin of the Weald Basin in Hampshire, and produces mainly from the Great Oolite Group. Its structure is formed by a broad E-W elongated dome, divided into two major fault blocks by an E-W oriented fault (Trueman 2003). Estimated STOIIP is 171 MMbbls.
DL 4	Albury Gas field. The Albury Gas Field lies on the northern margin of the Weald Basin, in Surrey, and has sands and limestones within the uppermost Jurassic Purbeck Group as its main producing horizon. It was found in 1987 in a broad E-W trending inversion anticline in the hanging-wall of the Hogs Back fault system (Trueman 2003). Modelled GIIP varies between 7 bcf (based upon the Albury 1 well) and up to 22 bcf (down to the structural spill point).
PL 116	Humbly Grove Field. The Humbly Grove Oilfield is located in northeast Hampshire, on the northern margin of the Weald Basin. The geology and development of the oilfield have been summarised by Sellwood et al. (1985) and Hancock & Mithern (1987). The original licence PL116 was awarded in 1969 and, following relinquishments in 1975, PL116B was retained. Seismic reflection surveys totalling 72 km were acquired in 1977, 1978 and 1979, and their interpretation revealed the existence of an E-W trending horst, fault closed to the north and south and dip closed to the east and west, with 1250 acres areal closure and 60 msecs TWTT of vertical closure. Geochemical analyses suggest that the principal source rock interval is probably basal Jurassic shales of the Lower Lias. Tertiary inversion had little effect on the Humbly Grove structure, but terminated hydrocarbon generation from its source rocks. The discovery well, Humbly Grove 1 (HG1-X1), was drilled in May 1980. It encountered 136ft (4m) of hydrocarbon-bearing reservoir in Great Oolite Group (Bathonian) limestones (Hancock & Mithern 1987), and tested 39o API oil at 72 bopd. Further seismic data totalling 136 km were acquired between 1980 and 1982, further delineating the structure and providing sites for three appraisal wells. Spudded in 1982, HG2-A1 well was drilled on the structural crest. It encountered a gas cap and a sharp permeability interface, separating the Great Oolite reservoir into an upper zone of relatively high permeability (20-200 mD) and an underlying low permeability zone (0.5-2 mD). Drill stem testing confirmed high productivity of 750 bopd from the oil reservoir. The well also encountered gas in the Upper Triassic Rhaetic Formation, which was tested at 1.09 MMscfd gas with condensate – this formation had been water-bearing in HG1-X1 well. Following the appraisal programme, proven and probable reserves in the Great Oolite limestones were estimated at 13 MMbbls of 39o API oil, with a gas cap of 3 bcf. Development of the field commenced in two phases. In 1984, Phase I began production from the high-permeability reservoir, whilst appraising the low-permeability and Rhaetic reservoirs. Phase II, commencing in 1988, covered the development of the low-permeability reservoir. Field development has shown the Great Oolite to have a 75ft (23m) gas column and a 70ft (21m) oil column within the higher permeability reservoir, and a low permeability reservoir containing a long transition zone of 295ft (90m) of increasing water saturations. Development well HG-X4 subsequently also found oil in the previously discovered Rhaetic gas accumulation, which on test flowed 1469 bopd of 49o API oil (Hancock & Mithern 1987). A gathering station, pipelines, and a rail export terminal have been constructed. During 2005, four horizontal wells were drilled into the Great Oolite reservoir

	gas cap, then two further horizontal wells were drilled into the Rhaetic for gas storage purposes. Gas storage commenced during November 2005, and the field is currently operating as a gas store with 10 bcf working gas capacity whilst continuing to produce oil (Hurren & Hancock 2009). From gas storage start-up until February 2009, total gas imports and exports amounted to some 95 bcf.
PL 182	Palmers Wood Oil Field. Discovered in 1983, the Palmers Wood Oilfield lies on the northern margin of the Weald Basin, south of London, and produces from Upper Jurassic Corallian sands. Trueman (2003) estimated the field's STOIIP as 11.73 MMbbls, and recorded a cumulative production of 2.82 MMbbls.
PL 205	Storrington Oil Field. The Storrington field was discovered in March 1986 and its reservoir is the Great Oolite Group. It lies on the southern margin of the Weald Basin in West Sussex, on trend with the nearby Horndean and Singleton oilfields. The trap is located on an E-W trending horst with dip closure to the east and west (Trueman 2003).
PL 211	Horndean Oil Field. The Horndean Oilfield lies on the southern margin of the Weald Basin, with the Middle Jurassic Great Oolite Group forming its producing reservoir. It was discovered during early 1983. A development well drilled in 1990 was the first horizontal well to be drilled in the Great Oolite Group in southern England. The field is an E-W elongate tilted fault block. With an original estimated STOIIP of 37 MMbbls, Trueman (2003) recorded a cumulative production of 1.6 MMbbls.
PL 240	Singleton Oil Field. Discovered in 1989, the Singleton Oilfield lies on the southern margin of the Weald Basin, east of Horndean. Its main producing horizon is the Middle Jurassic Great Oolite Group. Two production wells were drilled in 1991 to a depth of approx. 4,100 feet. There are now six wells producing about 600 bbls/d. The bores deviate to the south with up to 2,000 feet horizontally drilled through the reservoir rock of Great Oolite limestone. The site is currently being expanded with a new multi-lateral horizontal production well to the south-west. This is 16,800 feet in length with 4,000 feet of it within the reservoir. Further development will increase production up to 1,000 barrels per day and, ultimately, 1,500 barrels per day. Singleton has produced 3.7 million barrels of oil since 1989 and has an estimated capacity of 107 million barrels of oil with a potential recovery factor of 10%.
ML 18 ML 21	Bletchingley Gas Field. Four wells were drilled on the Bletchingley structure on the northern margin of the Weald Basin, Surrey during 1965-1966. Wells 1, 2 and 3 tested gas from the Upper Jurassic Corallian Limestone, but well 4 was dry since the reservoir section was found to be absent due to faulting (Trueman 2003). The Corallian Limestone is reported to be 130ft thick, characteristically massive carbonate, occasionally oolitic, reefal in places with vugular and leached intergranular porosity.
PEDL 21	Goodworth Oil Field. The Goodworth Oilfield lies on the northern margin of the Weald Basin, in Hampshire, close to the north-west of Stockbridge Oilfield. Oil production is from the Great Oolite Group (Trueman 2003).
PEDL 233	Igas and Northern Petroleum – Baxters Copse Oil Field - The Baxters Copse discovery is located c. 5 km northeast of the Singleton oil field production facilities. Gross 2P and 3P reserves of 5.36 million stock tank barrels (MMstb) and 15.06 MMbbls respectively of undeveloped reserves estimated in 2010.
PEDL 235	Originally Star Energy, Now Igas; Initial Term 6 years from 1st July 2008. Work Programme: Firm commitments - The Licensee shall: shoot 30km of 2D seismic data; complete a 30 km refraction

survey; and reprocess 120 km of 2D seismic data.

Drill-or-drop commitment - The Licensee shall either: drill one well to a depth of 2200m, or elect to allow the licence to automatically cease.

NUMBER	WELLSORTABLE	NAME	OPERATOR	TYPE	LICENCE	SPUD	COMPLETION
LR/27- 2Z	LR/27- 002Z	GODLEY BRIDGE 2Z	CONOCO	COG	PL203	03-Dec-86	07 January 1987
LR/27- 2	LR/27- 002	GODLEY BRIDGE 2	CONOCO	COG	PL203	08-Nov-86	03 December 1986
LR/27- 1	LR/27- 001	GODLEY BRIDGE 1	CONOCO	COG	PL203	21-Nov-82	11 February 1983

Godley Bridge Gas Field – 18 bcf.

No new wells.

Cuadrilla Resources

PEDL 244 Cuadrilla and AJ Lucas; Initial term 6 years from 1st July 2008 (expires 1st July 2014); Work Programme:

PART I - Firm commitment - The Licensee shall obtain 200 km of 2D seismic data.

PART II - Drill-or-drop commitment - The Licensee shall either: drill one well, or elect to allow the licence to automatically cease.

(Note – "The Balcombe well licence").

NUMBER	WELLSORTABLE	NAME	OPERATOR	TYPE	LICENCE	SPUD	COMPLETION
LR/30- 5Z	LR/30- 005Z	BALCOMBE 2Z	CUADRILLA RESOURCES LIMITED	COG	PEDL244	05-Sep-13	
LR/30- 5	LR/30- 005	BALCOMBE 2	CUADRILLA RESOURCES LIMITED	COG	PEDL244	02-Aug-13	05 September 2013

PEDL 247 Originally Weald Petroleum Development Limited - Now Cuadrilla Weald Limited; Initial term 6 years from 1st July 2008 (expires 1st July 2014); Work Programme:

PART I - Firm commitment - The Licensee shall obtain 100 km of 2D seismic data.

PART II - Drill-or-drop commitment - The Licensee shall either: drill one well to a depth of 900m, or elect to allow the licence to automatically cease.

No wells drilled.

PL 55 Originally BP and the Gas Council – Now Cuadrilla Weald Limited; Signed 22nd February 1968, Licence commenced 31st December 1967 Work Programme: Geological studies and seismic survey and one well to be drilled in PL55, PL 56 or PL57. (Still valid?)

EXL 189 Not available – Cuadrilla - There is no intention at the current time to carry out any additional work at Cowden in Kent following some initial evaluation in 2010 of the well, which was drilled by a previous operator in 1999.

Egdon Resources

PEDL 143	Europa Oil & Gas Limited, Altwood Petroleum Limited, Warwick Exploration and Production Limited, Egdon Resources (UK) Limited. Initial term 6 years from 1st October 2004; Work Programme: PART I - Firm commitment - The Licensee shall drill one well. No wells drilled.

Celtique Energie

PEDL 231	Celtique Energie Petroleum Ltd; Magellan Petroleum (N.T.) Pty. Ltd; Initial term 6 years from 1st July 2008; Work Programme: PART I Firm commitments - The Licensee shall: shoot 200 km of 2D seismic data; and obtain and reprocess 400 km of 2D seismic data. PART II Drill-or-drop commitment, The Licensee shall either: drill one well to a depth of 2440m, or elect to allow the licence to automatically cease. No well drilled.
PEDL 232	Celtique Energie Petroleum Ltd; Magellan Petroleum (N.T.) Pty. Ltd; Initial term 6 years from 1st July 2008; Work Programme: PART I Firm commitment - The Licensee shall obtain and reprocess 100 km of 2D seismic data. PART II Drill-or-drop commitment - The Licensee shall either: drill one well to a depth of 1220m, or elect to allow the licence to automatically cease. No well drilled.
PEDL 234	Celtique Energie Petroleum Ltd; Magellan Petroleum (N.T.) Pty. Ltd; Initial term 6 years from 1st July 2008; Work Programme: PART I Firm commitments - The Licensee shall: shoot 150 km of 2D seismic data; and obtain and reprocess a further 300 km of 2D seismic data. PART II

Drill-or-drop commitment - The Licensee shall either: drill one well to a depth of 2440m.

No well drilled.

PEDL 243 Celtique Energie Petroleum Ltd; Magellan Petroleum (N.T.) Pty. Ltd; Initial term 6 years from 1st July 2008; Work Programme:

PART I

Firm commitments - The Licensee shall: shoot 90 km of 2D seismic data; and obtain and reprocess 300 km of 2D seismic data.

PART II

Drill-or-drop commitment - The Licensee shall either: drill one well to a depth of 2440m, or elect to allow the licence to automatically cease.

No well drilled.

Northern Petroleum

PEDL 126 Northern Petroleum (GB) Limited, Magellan Petroleum (NT) Pty Limited.

Initial term 6 years from 1st July 2003; Work Programme:

Firm commitment:

The Licensee shall acquire 150 km of 2D seismic data in respect of the Licensed Area.

Drill or drop commitment:

Notwithstanding Clause 3 above, this Licence shall expire three years after the date set out in that Clause unless the Licensee has by that date submitted to the Minister an application for consent to drill one well, together with all supporting documentation necessary for the Minister to consider it. If consent is granted, the Licensee shall drill the well into the Great Oolite before the end of the Initial Term.

Drilled well – Markwell's Wood in 2010

NUMBER	WELLSORTABLE	NAME	OPERATOR	TYPE	LICENCE	SPUD	COMPLETION
L99/01- 6	L099/01- 006	MARKWELL'S WOOD 1	NORTHERN PETROLEUM (GB) LIMITED	COG	PEDL126	21-Nov-10	26 December 2010

PEDL 155 NP Weald Limited, Magellan Petroleum (N.T.) Pty Ltd.

Initial term 6 years from 1st October 2004; Work programme:

DRILL-OR-DROP WORK PROGRAMME: Part 1: Firm commitment.

The Licensee shall obtain 33 km of 2D seismic data.

Part 2: The Licensee shall drill one well.

	No well drilled.
PEDL 240	Originally Encore Oil Plc, Magellan Petroleum (N.T.) Pty. Ltd, Montrose Industries Limited, Northern Petroleum (Gb) Limited, Oil & Gas Investments Limited. Initial term 6 years from the 1st July 2008; Work Programme: Drill-or-drop commitment - The Licensee shall either: drill one well to a depth of 2440m, or elect to allow the licence to automatically cease.
PEDL 256	Originally with Encore Oil Plc, Magellan Petroleum (N.T.) Pty. Ltd, Np Weald Limited (Northern Petroleum & Operator), Oil & Gas Investments Limited – Encore now Egdon Resources. Initial term 6 years from 1st May 2009; Work Programme: Firm commitment - The Licensee shall drill one well to a depth of 1500m TVDSS or 15m into the Fullers Earth, whichever is the shallower. No wells drilled.
Magellan Petroleum (N.T.) Pty Ltd	
PL 137	Initial term 6 years from 1st October 2004; Work Programme: DRILL-OR-DROP Part 1 - Firm commitment - The Licensee shall obtain 25 km of existing 2D seismic data. Part 2: - The Licensee shall drill one well.
PL 246	Initial term 6 years from 1st July 2008; Work Programme: DRILL-OR-DROP Part 1 - Firm commitment - The Licensee shall obtain and reprocess 100 km of 2D seismic data. Part 2: - Drill-or-drop commitment - The Licensee shall either: drill one well to a depth of 2135m, or elect to allow the licence to automatically cease.
Midmar Energy Onshore Limited	
PL 248	Midmar Energy Onshore Limited, Mpx Energy Limited; Initial term 6 years from 1st July 2008; Work Programme: Part 1 - Firm commitment - The Licensee shall reprocess 60 km of 2D seismic data. Part 2: - Drill-or-drop commitment - The Licensee shall either: within two years of the beginning of the Initial Term, drill one well to a depth of 300m, or elect to allow the licence to automatically cease.

	No wells drilled.
Northdown Energy Limited	
PL 245	Originally Aimwell Energy Limited, Fox Energy Exploration Limited, now Northdown and Aimwell; Initial term 6 years from 1st July 2008; Work Programme: Part 1 - Firm commitment - The Licensee shall obtain 60 km of 2D seismic data. Part 2: - Drill-or-drop commitment - The Licensee shall either: within two years of the beginning of the Initial Term, drill one well to a depth of 1000m, or elect to allow the licence to automatically cease. No wells drilled.

Appendix E: Environmental Legislation Application to the Onshore Hydrocarbon Industry

Table 1E - Environmental Legislation Applicable To The Onshore Hydrocarbon Industry

Key EC and UK Environmental Legislation

EC Legislation	Associated UK Legislation	Main Requirements	Regulator, Applies in
EC Directive (85/337/EEC): Assessment of the effects of certain public and private projects on the environment.	1. Town and Country Planning (Environmental Impact Assessment) (England and Wales) Regulations 1999. 2. Environmental Impact Assessment (Scotland) Regulations 1999	Requires certain developments to prepare an Environmental Statement as part of the planning approval process.	1. Local Authorities, England and Wales. 2. Local Authorities, Scotland.
EC Directive (92/43/EEC): Conservation of natural habitats and of wild fauna and flora.	Conservation (Natural Habitats) Regulations 1994.	Requires developments to take account of Special Areas of Conservation in their environmental impact assessment. Approvals granted via the above Regulations.	EA or English Nature, England and Wales SEPA or Scottish Natural Heritage, Scotland.

EC Directive (96/82/EC): Control of major accident hazards.	1. Control of Major Accident Hazards (COMAH) Regulations 1999. 2. Planning (Control of Major Accident Hazards) Regulations 1999 [2000 in Scotland].	Authorisation is required for storage of listed hazardous substances. Requires operators to implement certain management practises and report to the competent authorities.	1. EA & Local Authorities, England and Wales. 2.SEPA & Local Authorities, Scotland.
EC Directive (80/68/EEC): old Groundwater Directive (in force until Dec 2013); and (2006/118/EC) Groundwater Daughter Directive; and EC Directives 2006/118/EC and 2008/105/EC.	1. The Environmental Permitting Regulations in England & Wales. 2. The Water Environment (Controlled Activities) (Scotland) Regulations 2011.	Systems of permits and registrations to control inputs of pollutants to the water environment.	1. EA, England and Wales. 2.SEPA, Scotland.

Water Framework Directive.	1. The Environmental Permitting Regulations. 2. The Water Environment (Controlled Activities) (Scotland) Regulations 2011.	Prevent deterioration and achieve good status for all water bodies, reduce pollution from priority substances in surface waters, reverse significant and sustained upward trends in concentrations of pollutants in groundwater, prevent or limit inputs of pollutants to groundwater.	1. EA, England and Wales. 2.SEPA, Scotland.
Directive 2004/35/EC on environmental liability with regard to the prevention and remedying of environmental damage.	1. The Environmental Liability (Scotland) Regulations 2009. 2. The Environmental Damage (Prevention and Remediation) Regulations 2009.	To introduce a system of reporting and management of significant releases of pollutants to land and the water environment.	SEPA, England and Wales.
EC Regulation (259/93): Supervision and control of shipments of waste within, into and out of the European Community.	Transfrontier Shipment of Waste Regulations 1994.	A licence is required to control the transport and disposal of movement and disposal of hazardous waste.	Environmental Agency, England, SEPA, Scotland.

EC Regulation (3093/94): Substances that deplete the ozone layer.	Environmental Protection (Controls on Substances that Deplete the Ozone Layer) Regulations 1996. Ozone Depleting Substances (Qualifications) Regulations 2006 SI 1510. Fluorinated Greenhouse Gases Regulations 2008 (S.I No 41).	A licence is required for the production, supply, use, trading and emission of certain "controlled substances" that deplete the ozone layer.	DEFRA, England, Wales & Scotland.
EC Directive 96/61/EC concerning integrated pollution prevention and control.	1. The Environmental Permitting Regulations. 2. The Pollution Prevention and Control (Scotland) Regulations 2000 (as amended).	Control of emissions from industrial premises through requirement to apply Best Available Technology Permitting.	1. EA, England and Wales. 2. SEPA, Scotland.
Industrial Emissions Directive.	To be transposed into Scottish Legislation by 2012.	Brings together previous Directives on IPPC, WID, LCP, SED and TiO2 into single text.	
CCS Directive.		Sets out requirements for carbon capture and storage.	

Source: DECC

Table 2E - UK Domestic Environmental Legislation

Key UK Domestic Environmental Legislation		
UK Legislation	**Main Requirements**	**Regulator, Applies in**
Town and Country Planning Act 1990 (England and Wales) as amended by the Planning Act 2008. Town and Country Planning (Scotland) Act 1997 as amended by the Planning etc (Scotland) Act 2006. Planning and Compensation Act 1991 (as amended); and Environment Act 995 (as amended).	Planning permission is required for all hydrocarbon developments.	Local authorities / county councils, England, Wales & Scotland.
Petroleum Act 1998; and The Petroleum (Production) (Landward Areas) Regulations 1995.	A licence is required for exploration, development, production and abandonment of all hydrocarbon fields.	DECC, England, Wales & Scotland.
Pipelines Act 1962; and Pipe-line Works (Environmental Impact Assessment) Regulations 2000.	Requires Environmental Statement for pipelines over 16 km in length to as part of the approval process.	DECC, England, Wales & Scotland
Gas Act, 1986; and Public Gas Transporter Pipe-line Works (Environmental Impact Assessment) Regulations 1999.	Requires Environmental Statement for certain pipeline developments as part of the approval process.	DECC, England, Wales & Scotland.
Environmental Protection Act 1990, Part II.	Most wastes may only be disposed of at a facility operated by the holder of a suitable permit.	Environment Agency / SEP.A
Environmental Protection Act 1990, Part III.	Statutory nuisance (i.e. non-regulated activities), noise, odour, antisocial behaviour, etc.	Local authorities.

Energy Act 1976; and The Petroleum Act 1998.	Consent is required for flaring or venting of hydrocarbon gas. Requires licensees of an onshore field to ensure that petroleum is contained both above and below ground.	DECC, England, Wales & Scotland.
Air Quality Regulations 2000; The Air Quality Standards (Scotland) Regulations 2007. Scottish Statutory Instrument No. 182; The air Quality Standards (Scotland) Regulations 2010. Air Quality (Scotland) Regulations 2000. Scottish Statutory Instrument No. 97. The Air Quality (Scotland) Amendment Regulations 2002.	Sets emission limits for certain substances and requires authorities to take action where quality parameters are exceeded. Provides SEPA with reserve powers to improve AQ by LAs where not being achieved.	Local authorities/SEPA.
Control of Pollution Act 1974, Part III; Environmental Protection Act 1990, Part III; and Environment Act 1995, Part V.	Requires local authorities to take action where noise limits are exceeded.	Local authorities, England, Wales and Scotland.
Environmental Protection Act 1990, Part I; Environmental Protection (Prescribed Processes and Substances) Regulations 1991.	Requirement to license certain potentially polluting processes. Industries must demonstrate environmental management through Best Available Technology Not Entailing Excessive Cost (BATNEEC) for IPC.	Environment Agency & Local Authorities, England and Wales. SEPA & Local Authorities.

Source: DECC

Table 3E - Application of This Legislation in Relation Current Onshore Operations

Application of Environmental Legislation	
Legislation	**Application**
Town and Country Planning Act 1990 [1997 in Scotland], Planning and Compensation Act 1991, Environment Act 1995.	Applies to all hydrocarbon developments.
Town & Country Planning (Environmental Impact Assessment) (England and Wales) Regulations 1999, Environmental Impact Assessment (Scotland) Regulations 1999.	New onshore fields, unless on the production scale of Wytch Farm, would only require an Environmental Statement if determined by the Local Authority as having potentially significant environmental effect.
Pipelines Act 1962; and Pipe-line Works (Environmental Impact Assessment) Regulations 2000.	Construction of pipelines over 16 km in length would require an Environmental Statement.
Gas Act, 1986; and Public Gas Transporter Pipe-line Works (Environmental Impact Assessment) Regulations 1999.	Construction of pipelines over 40 km in length or 800mm diameter would require an Environmental Statement.
EC Directive (96/82/EC): Control of major accident hazards; and a) Planning (Control of Major Accident Hazards) Regulations 1999 (2000 in Scotland); b) Control of Major Accident Hazards (COMAH) Regulations 199.9	Conventional onshore fields are unlikely to store hydrocarbon products in sufficiently large volumes so as to warrant control under these Regulations.

EC Directive (80/68/EEC): Protection of groundwater against pollution. EC Directive (99/31/EC) on the landfill of waste. Directive 2000/60/EC The Water Framework Directive. Directive 2006/118/EC Protection of groundwater against pollution. The Water Environment and Water Services (Scotland) Act 2003 Transposes Directive 2000/60/EC. Directive 2008/105/EC Environmental Standards. The Water Environment (Controlled Activities) (Scotland) Regulations 2011 Provides regulatory framework for activities likely to cause adverse effects to the water environment. The Water Environment (Groundwater and Priority Substances) (Scotland) 2009 Regulations Introduce the regulatory requirements of Directives 2006/118/EC and 2008/105/EC. Directive 2004/35/EC Environmental Liability Directive. The Environmental Liability (Scotland) Regulations 2009 transpose the requirements of Directive 2004/35/EC.	Activities (including re-injection of produced water) at the following onshore fields are permitted under the Environmental Protection Regulations. These Regulations also cover the requirements for protecting groundwater. • Wytch Farm • Whisby • Welton • Singleton • Palmers Wood • Humbly Grove • Horndean Periodic reviews of permits for these activities are required to check whether permit conditions continue to reflect appropriate standards and remain adequate in light of experience and new knowledge.
EC Regulation (259/93): Supervision and control of shipments of waste within, into and out of the European Community; and Transfrontier Shipment of Waste Regulations 1994.	It is unlikely that any onshore field would require to ship waste outside the UK.
Environmental Protection Act 1990, Part I; Environmental Protection (Prescribed Processes and Substances) Regulations 1991; and Pollution Prevention and Control Act 1999 and Pollution Prevention and Control Regulations 2000. The Pollution Prevention and Control (Scotland) Regulations 2000 (as amended).	Onshore fields will require an IPPC licence under the new legislation, depending upon the activities undertaken at the site. In Scotland would require a PPC licence under Scottish regulations.

Emissions Trading System. Directive 2009/29/EC (Phase III). The Greenhouse Gas Emissions Trading Scheme Regulations 2005 (S.I. 2005/925) (as amended).	DECC/SEPA/EA.
Petroleum Act 1998; Energy Act 1976; and The Petroleum (Production) (Landward Areas) Regulations 199.5	All onshore hydrocarbon fields will require a licence for development, production, venting and flaring of gas, and abandonment.

Source: DECC

Appendix F: UK's Main Protected Area

Special Areas of Conservation (SACs) are areas which have been given special protection under the European Union's Habitats Directive. SACs provide increased protection to a variety of wild animals, plants and habitats and are a vital part of global efforts to conserve the world's biodiversity.

A Special Protection Area (SPA) is an area of land, water or sea which has been identified as being of international importance for the breeding, feeding, wintering or the migration of rare and vulnerable species of birds found within the European Union. SPAs are European designated sites, classified under the European Wild Birds Directive, which affords them enhanced protection.

Sites of Special Scientific Interest (SSSI) - are the country's very best wildlife and/or geological sites. SSSIs include some of the most spectacular and beautiful habitats: wetlands teeming with wading birds, winding chalk rivers, flower-rich meadows, windswept shingle beaches and remote upland peat bogs.

Ramsar sites - are wetlands of international importance, designated under the Ramsar Convention. Protect internationally important sites for wetland birds.

National Nature reserves - is one of the finest sites in England for wildlife and/or geology. Almost all NNRs are accessible and provide great opportunities for people to experience nature.

A Local Nature Reserve (LNR) – A place of special local wildlife or geological interest or significance identified by the local authority. Wide application spanning towns, cities, villages and countryside, for both people and wildlife. LNRs offer people special opportunities to study or learn about nature or simply to enjoy it.

An Area of Outstanding Natural Beauty (AONB) is an area of high scenic quality which has statutory protection in order to conserve and enhance the natural beauty of its landscape. AONB landscapes range from rugged coastline to water meadows to gentle lowland and upland moors.

National Trails - a series of long-distance trails routed through some of our finest landscapes (National Parks/AONBs) with the intention of providing a high quality opportunity for people to experience and enjoy the natural environment.

World Heritage Sites - An ICOMOS designation for places of international importance to the conservation of our cultural and national heritage. The Jurassic Coast World Heritage Site was designated on account of its geological heritage.

Heritage Coasts - Area of coastline managed to conserve and enhance its natural beauty and to facilitate and enhance the enjoyment, understanding and appreciation of the public, and to maintain and improve the environmental health of inshore waters affecting the wider area within the boundary. Account should also be taken of the needs of land based industries i.e. agriculture, forestry and fishing.

Local Sites - Sites of importance for their scientific, educational and historical value as well as their visual qualities. Several different titles including Sites of Importance for Nature Conservation (SINCS), Sites of Nature Conservation Importance (SNCIs) and County Wildlife Sites.

Global Geoparks - Areas selected to co-ordinate the conservation of geological heritage and its enjoyment while supporting sustainable development. All Geoparks are part of the Global Geopark Network supported by UNESCO, proposals are appraised through this mechanism.

Biosphere Reserves - Nominated by national governments and designated under UNESCO's Man and the Biosphere Programme. They seek to i) contribute to the conservation of landscapes, ecosystems & species, ii) foster economic & human development, iii) provide support for research, monitoring, education & information exchange.

Environmentally Sensitive Areas - (ESA) a type of designation for an agricultural area which needs special protection because of its landscape, wildlife, or historical value. The scheme was introduced in 1987, in 2005 the scheme was superseded by Environmental Stewardship and closed to new entrants. Existing agreements remain active until they expire, meaning the designation will remain active until 2014.

Source: Natural England.

List of Abbreviations

2D	Two Dimensional
2P	Proven Reserves + Probable Reserves
3D	Three Dimensional
3P	The sum of 2P and Possible Reserves
AEA	A Leading International Energy and Environmental Company
AIM	Alternative Investment Market
AL	Appraisal Licences
API	American Petroleum Institute
AQ	Air Quality
ASX	Australian Securities Exchange
Ave/yr	Average per Year
BATNEEC	Best Available Technology Not Entailing Excessive Cost
bbls	Barrels
bcf	Billion Cubic Feet
Bg	Gas Expansion Factor
BGS	British Geological Survey
BNRI	Barclays Natural Resource Investments
bopd	Barrels of Oil Per Day
Bscf	Billion Standard Cubic Feet
CA	Countryside Alliance
CBM	Coal Bed Methane
CBOS	Public Opinion Research Centre
CCGT	Combined Cycle Power Generation
CCS	Carbon Capture and Storage
CEWL	Celtique Energy Weald Ltd
CIA	Chemical Index of Alteration

cm	Centimetres
CMM	Coal Mine Methane
CO_2	Carbon Dioxide
COMAH	Control of Major Accident Hazards
CPF	Central Processing Facility
CRA	Corporate Research Associates
CSR	Corporate Social Responsibility
CT	Corporation Tax
DCLG	Department For Communities and Local Government
DECC	Department of Energy and Climate Change
DEFRA	Department for Environment, Food and Rural Affairs
DL	Development Licences
EA	Environmental Agency
EBA	Environmental Baseline Assessment
EC	European Community
EIA	Energy Information Administration
EIA	Environmental Impact Assessment
EMV	Expected Monetary Value
EPA	Environmental Protection Agency
Eqty	Equity
EU	European Union
FDP	Field Development Plan
Fra.Spcg	Fracture Spacing
Frac. Half Length	Fracture Half Length
Frac. Perm	Permeability of the Induced Fracture
Frac. Wdth	Fracture Width
Ft	Feet
G	Absorbed Gas Content Of Shales

G&A	General and Administrative Expenses
GB	Great Britain
GDF SUEZ	A French Multinational electric utility company
GHG	Greenhouse Gas
GIIP	Gas Initially In Place
GIIPa	Absorbed Gas Initially in place
GIIPf	Free Gas Initially In Place
GWPC	Gulf Western Petroleum Corporation
HF	Hydraulic Fracturing
Hort. Leg	Length of the Wells Horizontal Leg (i.e. Lateral)
HP	Horsepower
HPP	High Pressure Feed Pump
HSE	Health and Safety Executive
HVHF	High Volume Hydraulic Fracturing
IEA	International Energy Agency
IoD	Institute of Directors
IP	Initial Production
IPC	Installed Production Capacity
IPCC	Intergovernmental Panel on Climate Change
IPPC	Integrated Pollution Prevention and Control
IRR	Internal Rate of Return
KGS	Knapton Generating Station
KM	Kilometres
KM^2	Square Kilometres
KPMG	A Leading Provider of Professional Services
kWh	Kilowatt per hour
lbs.	Pounds (Weight)
LCP	Large Combustion Plants

LNG	Liquefied Natural Gas
m	Metre
me	Metres Cubed
M_L	Magnitude
Mat. Perm	Matrix Permeability
Mcfe	Thousand Cubic Feet of Natural Gas Equivalent
mD	MiliDarcy
MEA	Mineral Extraction Allowances
m^3	Cubic metres
mm	Millimetres
MM	Million
MMbbls	Million Barrels
MMBO	Million Barrels of Oil
MMscfd	Million Standard Cubic Feet per Day
MMstb	Million Stock Tank Barrels
MPA	Mineral Planning Authorities
Mscf	Million Standard Cubic Feet
MW	Megawatt
NBV	Net Bulk Volume
NGL	Natural Gas Liquids
NGO	Non-Governmental Organisation
No_x	Oxides Of Nitrogen
NORM	Naturally Occurring Radioactive Materials
NPV	Net Present Value
NTS	National Transmission System
NW	North West
OFGEM	Office of Gas and Electricity Markets
OFEX	Off Exchange

OH	Ohio
OUGO	Office for Unconventional Gas and Oil
P	Shale Density
PEDL	Petroleum and Exploration Development Licences
PL	Production Licences
PM_x	Fine Particles
PON4	Petroleum operations notice
PPC	Pollution Prevention and Control
ppm	parts per Million
PRT	Petroleum Revenue Tax
psi	Pounds Per Square Inch
PWT	Produced Water Treatment
PWTP	Produced Water Treatment Plant
REC	Reduced Emissions Completions
Res. Thickness	Reservoir Thickness
RF	Recovery Factor
RFES	Ring Fence Expenditure Supplement
SAC	Special Areas of Conservation
SC	Supplementary Charge
scf	Standard Cubic Feet
SCI	Sites of Community Importance
SEA	Strategic Environmental Assessment
SED	Solvent Emissions Directive
SEPA	Scottish Environmental Protection Agency
SGEIS	Supplemental Generic Environmental Impact Statement
SO_x	Oxides of Sulphur
SOW	Scope of Work
Sq.	Square

SSSI	Site of Special Scientific Interest
STOIIP	Stock Tank Oil Initially in Place
tcf	Trillion Cubic Feet
TiO2	Titanium Dioxide
TOC	Total Organic Content
TTI	Time Temperature Index
TRR	Technically Recoverable Resources
TVD	True Vertical Depth
UKOOG	United Kingdom Onshore Operators
VOC	Volatile Organic Compounds
WID	Waste Incineration Directive
WONS	Well Operations and Notifications System
wt.%	Weight Percentage
XL	Exploration Licences
ϕ	Gas Filled Porosity